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VERMONT'S FEED-IN TARIFF: PROGRESS AND CHALLENGES

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ABSTRACT

In 2009, 45 percent of the nearly 4 trillion kilowatt-hours of electricity consumed in the US was produced using coal. Electricity production in the US accounts for 40 percent of the carbon dioxide equivalent emissions released each year into the atmosphere. Policymakers recognize the need to promote clean, low-carbon sources of power production. This paper provides an update on Vermont's cost-based standard offer program, modeled after the European-style feed-in tariff approach. Vermont was the first state to initiate a full system of advanced renewable tariffs passed by the legislature. The Vermont program has been in effect since September 2009. To date 2.37 MW of new renewable energy systems have been installed of the 50 MW program limit, which includes solar PV (1.056 MW) landfill methane (0.56 MW) projects, and two farm methane (750 kW) projects. Over 22 MW of projects awarded initial standard offer contracts were withdrawn from the program.

1. INTRODUCTION

According to the US Department of Energy's Energy Information Administration, 45 percent of electricity production in 2009 in the US used coal as the primary energy source (1). Furthermore, the electric power sector in the US contributes 40 percent of the total carbon dioxide equivalent emissions each year that are released in the atmosphere contributing to global climate change. According to National Oceanic and Atmospheric Association scientists, 2010 tied with 2005 as the warmest year of the global surface temperature on record (2). During the summer of 2010 17 nations either surpassed or equaled their all-time heat records, with Pakistan experiencing a record high temperature of 128.6º F.

Policymakers generally agree that promoting the development of the renewable energy industry is critical to meeting longer-term climate stabilization and economic development objectives. However, there is no broad consensus on the best policy mechanism to promote a growing renewable energy sector. Governments in Europe have favored a feed-in tariff (FIT) approach, which provides guaranteed payments for renewably generated power over a specified timeline. The feed-in rates are determined based on the cost of producing power from the various technologies, including a reasonable rate of return on the necessary investment.

In the United States, the dominant policy mechanism to promote the development of renewable energy projects is through a quota-based system generally referred to as a renewable portfolio standard (RPS). According to the Database of State Incentives for Renewables and Efficiency (DSIRE), 45 states and the District of Columbia have either a state, utility, or local RPS requirement (3). In general, a RPS sets specific targets for renewable energy stated as a percentage of total energy delivered by load serving entities operating within the state's boarders by some date certain. For example, in North Carolina investor-owned utilities must procure 12.5 percent of the energy delivered to customers from renewable sources by 2021, while electric cooperatives and municipal utilities must achieve 10 percent by 2018 (4).

2. VERMONT SPEED PROGRAM

In 2005 the Vermont General Assembly established the Sustainably Priced Energy Enterprise Development (SPEED) program to encourage the development of renewable energy resources in Vermont, as well as the purchase of renewable power by the State's electric distribution utilities. The SPEED goal or target is to supply all new load growth from January 1, 2005 to July 1, 2012 with SPEED qualified resources. These resources include new renewable electric generation capacity that is not net-metered and brought on line after December 31, 2004. In addition to offsetting new load growth, a minimum of 5 percent of Vermont's 2005 load (equivalent to 287,421 MWh) from SPEED resources was also included in the law. In addition the SPEED program has a goal of meeting 20 percent of Vermont's load with qualified resources by 2017.

While Vermont is included in the DSIRE list of states having adopted a RPS, Vermont SPEED program is actually a voluntary RPS program. However, if the Vermont Public Service Board determines that the established minimum obligations of the SPEED program are not met, then the State's utilities would be required to meet a binding RPS. Furthermore, the Vermont program does not require utilities to acquire the renewable energy attributes in the form of renewable energy certificates (RECs). The SPEED program is designed to encourage utilities to sign long-term supply contracts with renewable energy generators; the utilities are free to sell the RECs.

2.1 SPEED Standard Offer Provision

In May of 2009 the Vermont legislature passed Act 45 (the Vermont Energy Act of 2009), which included revisions to the SPEED program. These revisions included a provision to create standard offer prices for different technologies and scales modeled after the European-style cost-based feed-in tariff (FIT) approach. Vermont was the first state calling for a full system of advanced renewable tariffs to pass the legislature and become law. As codified in Act 45, the SPEED facilitator is required to purchase, on behalf of Vermont's electric distribution utilities, energy from developers accepting the terms and prices established in the standard offer contract.

Renewable energy projects less than 2.2 MW are eligible for a standard offer contract, and the entire program is capped at 50 MW. The Public Service Board also stipulated that no one technology could exceed 25 percent of the total, thus effectively establishing a sub-cap of 12.5 MW for all eligible technologies. This was a temporary cap to address the potential that a single technology category could dominate the program. The technology cap is scheduled to be revisited in May, 2011.

The Vermont Public Service Board (PSB) was asked to review the statutorily defined standard offer rates to make the determination if they were sufficient to encourage in-state renewable resource development. Through Docket 7523 stakeholders met during the summer of 2009 to review the standard offer rates established in Act 45. The standard offer rates were assessed based on the objective of providing an after tax return on equity equal to 12.13 percent, which is the highest allowed return to investor-owned electric utilities in Vermont. At the conclusion of Docket 7523 the PSB made the determination that:

> "…with the exception of farm methane resources, for which we establish a higher interim price, the default prices established by statute are a reasonable approximation of the price that would be paid for renewable resources when applying the criteria established by the Act. These determinations apply during the first few months of the program and will likely change following the more detailed determinations due on January 15, 2010." (5)

The PSB issued an Interim Price Order on September 15, 2009 establishing the standard offer rates for the first round of solicitations that was scheduled to take place in October of 2009.

Subsequently, October began the second set of hearings through Docket 7533 with the specific purpose to set the final rate for each technology under the SPEED standard offer program. These hearings and filings were more formal than Docket 7523, requiring significant background work, the creation of public models that would set a platform for future determination of pricing, as well as various formal memos and orders issued by the PSB officers during the open docket (6). The PSB issued the final standard offer rates on January 15, 2010. Table 1 includes the interim and final standard offer rates, along with the contract terms.

TABLE 1: VERMONT STANDARD OFFER RATES AND CONTRACT TERMS

Technology	Interim Rate ($/kWh)	Final Rate ($/kWh)^	Contract Terms (yrs.)
Solar PV	$0.300	$0.240	25
Hydro	$0.125	$0.118	20
Landfill Methane	$0.120	$0.087	15
Farm Methane	$0.160	$0.136	20
Wind < 15 kW / < 100 kW*	$0.200	$0.208	20
Wind > 15 kW / > 100 kW*	$0.125	$0.113	20
Biomass	$0.125	$0.121	20

^ These are the first year rates, which change slightly over the life of the contract.
*The size categories for wind rates were altered between the time the interim rates were set and the final rates.

The response to the standard offer program was very positive with 238 applications for more than 208 MW of capacity received; PV and biomass reached the 12.5 MW technology sub-cap in the first day of the program. The response was particularly strong for PV projects, with more than 172 MW of solar applications submitted within the first 8 hours of opening the standard offer program. A lottery process was put in place to select the projects that would be awarded standard offer contracts to the over subscribed solar and biomass categories.

Hill (2010) identifies some of the key lessons learned from the launch of Vermont's standard offer program. This includes the issues associated with a program that becomes immediately over subscribed and the potential negative impact that this can have on market development. The lottery system added additional market uncertainty. The relatively simple application process allowed developers with little experience to enter the queue. The lottery process did not involve any rank ordering based on project feasibility. Hill (2010) states:

> "A completely inexperienced applicant, with no financing, or a technically infeasible site or project plan, had equal chance of taking a lottery slot as a more fully developed project proposal with solid partners, financial backing and site characterization and selection." (7).

Hill (2010) also describes the challenges with both Dockets 7523 and 7533 in establishing a cost-based standard offer rates for each eligible technology. This is particularly challenging given that many of the technologies can be deployed at different scales, which impacts overall project costs. Interconnection requirements, economies of scale, and different capital and financing structures can result in significantly different returns to projects at different scales. The working group focused on establishing the standard offer rates included stakeholders that brought different models and assumptions to the process leading to widely different estimates. For policymakers, the essential challenge is to establish rates that stimulate development, but at the same time do not over pay for new renewable generation.

Hill (2010) suggests that perhaps a different approach to establishing contract rates. He states:

> "A declining price auction can be used to identify bidders willing to develop projects sufficient to meet renewable development targets. In order to qualify to bid, projects could be required to meet certain minimum pre-project feasibility criteria. The declining price auction would permit market actors to determine their own risk tolerance, required rate of return, and financial input assumptions, rather than relying on regulatory or stakeholder processes to set prices." (8).

However, Toby D. Couture of E3 Analytics produced a "policy brief" and makes the case that standard offer rates established using a cost-based model of renewable energy project costs may be preferred to auctions. Couture (2010) argues that the market stability offered by a pre-set rate for renewable energy generation, may provide benefits beyond the efficiency in rate setting based on auction mechanisms (9).

3. VERMONT STANDARD OFFER CONTRACT STATUS

Table 2 illustrates the number of initial standard offer contracts offered, contracts that withdrew, projects completed, and new contracts awarded by technology.

TABLE 2: VERMONT STANDARD OFFER PROGRAM PROJECT STATUS

Technology	Initial Contracts (MW)	Contracts Withdrew (MW)	Projects Completed (MW)	New Contracts (MW)
Solar	14.25	1.69	1.06	0.00
Biomass	14.02	11.82	0.00	2.04
Wind	15.10	5.15	0.00	3.10
Hydro	7.77	3.07	0.00	1.15
Farm Methane	6.53	0.54	0.75	0.45
Landfill Methane	1.71	0.15	0.56	0.00
Total	59.38	22.42	2.37	6.74

Table 1 does not captured projects currently under construction. These include one large solar project (2.2 MW), one hydro project (675 kW), and several farm methane projects. One of the most important observations from Table 2 is the fact that 38 percent of projects awarded an initial contract were withdrawn from the program. The fact that over one-third of the original contracts awarded were withdrawn from the program may be linked to the fact that by design, Vermont's standard offer contract applications was simple and required very little due diligence. Applicants needed to demonstrate ownership or the right to access and use the land where the project would be sited. Once the initial contracts were awarded, further financial analyses may have revealed that the proposed project(s) were not financially feasible and thus led to developers withdrawing projects from the program.

The standard offer rates, after more detailed financial analysis, may not have been sufficient to provide an adequate return on investments. Act 45 stipulated that the standard offer rates should seek to create a rate of return on equity not less than the highest rate of return on equity received by Vermont investor-owned utilities at the time that the standard offer program begins. Standard offer rates based on a return on equity for the investor-owned utilities may make early stage projects like those being proposed under the standard offer program not financially viable.

In developing the rules to participate in the standard offer program, the Vermont PSB may have been influenced by State-wide deliberative polling results on renewable energy conducted in 2007. The polls found that Vermonters enthusiastically support renewable energy and have a strong desire to participate in renewable energy project development. As a result, the PSB created low barriers to entry for developers seeking to participate in the standard offer program. In fact, applicants for PV projects in particular included some of Vermont's larger real estate developers and other commercial entities that were new to the solar industry.

3.1 Additional Explanations for Projects Withdrawing

While it is difficult to know exactly why a particular developer withdrew a proposed project from the standard offer program, here we explore some of the likely issues. Figure 1 illustrates the percentage of contracts that were withdrawn from the program relative to the initial contracts awarded by technology category.

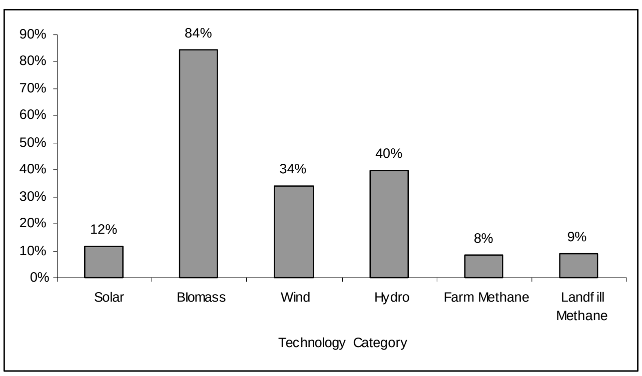

Fig. 1: Percent of Projects (MW basis) that Were Withdrawn Relative to Initial Contracts Awarded

Biomass projects experienced the highest withdrawal rate from the program at 84 percent. One provision of the legislation required that woody biomass projects must achieve an overall (thermal and electric) design system efficiency of at least 50 percent. This requirement was buried within Act 45. Once the contracts were awarded, this requirement could have come to the attention of the project developers and their engineering staff and thus disqualified some proposed projects. The intent of the provision was to encourage the use of woody biomass in combined heat and power applications. However, a system efficiency of 50 percent is extremely difficult to achieve without a full-time thermal load in close proximity to the biomass facility.

A controversial issue in Vermont for solar projects is linked to the State's 30 percent business solar tax credit, which ended on January 1, 2011. The Clean Energy Development Fund (CEDF) Board received applications for $28.8 million in tax credits associated with 208 solar projects by the July 15, 2010 deadline. Act 159 was passed in 2010 and contained a number of provisions including requiring the CEDF Board to certify no more than $9.4 million in solar tax credits. Subsequently, at the CEDF Board's July 12 meeting it determined that only $7.5 million is actually available for certification given the Fund's balance and projected revenue.

The business solar tax credits were allocated first to projects that were already completed. Next, projects were awarded the business tax credit based on the application date for a Certificate of Public Good (CPG), Vermont's project permitting process. Finally, any remaining funds were allocated to projects based on the date of their application for the business solar tax credit. Once the $7.5 million was allocated, remaining unfunded projects were placed on a waiting list if and when additional funding for business tax credits became available. In 2011, an additional $1 million was allocated to the business tax credit program and allocated accordingly. The 12 percent of the original solar projects awarded contracts that were withdrawn from the standard offer program may be a result of not being awarded the business tax credit, thus making the project(s) uneconomic.

Lack of financing may have been an additional factor leading to projects being withdrawn from the standard offer program. The continued credit crunch, resulting from the financial collapse that occurred in 2008, and the lack of support by regional banks for project financing may have created difficulties for developers working to acquire the necessary funding.

3.2 New Contracts Awarded

As indicated in Table 2, since the initial contract awards additional projects totaling 6.74 MW were awarded, representing approximately 30 percent of projects that were withdrawn from the program. Figure 2 indicates the percentage of new contracts relative to projects that were withdrawn by technology category.

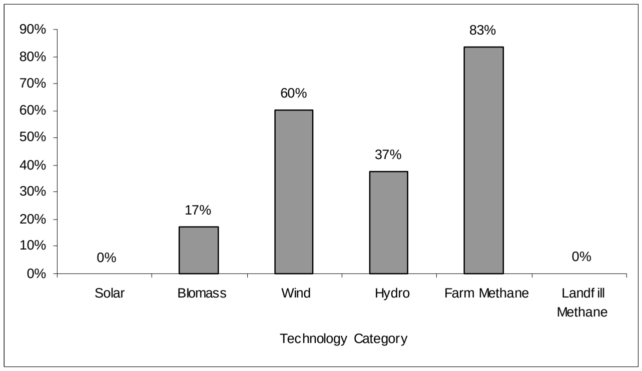

Fig. 2: Percent of New Contract Awards (MW basis) Relative to Projects that Were Withdrawn

Farm methane projects, with the lowest rate of attrition (see Figure 1) had the highest rate of new project awards relative to project that were withdrawn. Two 225 kW projects by the same developer were awarded new contracts. Wind projects awarded new contracts account for 60 percent of the initial projects awarded contracts that were subsequently withdrawn from the program. This includes one proposal for a 100 kW wind system and two 1.5 MW projects proposed by the same developer. Three new biomass projects with total installed capacity of just over 2 MW represents just 17 percent of the biomass projects awarded initial contracts that were withdrawn. And two hydro projects with total capacity of 1.6 MW were awarded new contracts, representing 37 percent of the original projects that were withdrawn from the program. Both solar and landfill methane categories have not seen any new contracts awarded since the initial round of applications.

In summary, accounting for projects awarded initial contracts and that were subsequently withdrawn, plus new contracts, Vermont's standard offer program has 43.7 MW worth of projects currently in the program. This is 6.3 MW below the program cap of 50 MW. It is difficult to say how many of these projects will be completed. Projects must be completed within 3 years with very few milestones prior to commissioning.

4. CONCLUSIONS AND FUTURE PROSPECTS

The US is heavily dependent on coal for power production, which has the highest carbon content of the fossil fuels. Increasing concern about climate change among state policymakers and the desire to stimulate a new green economy have led to the development of policies and programs to promote clean, renewable forms of energy. Most US policy makers have chosen quota-based systems frequently referred to as renewable portfolio standards. Alternatively, European countries have favored a feed-in tariff approach, whereby renewable generators are guaranteed a rate per kWh for production over a specified timeframe. Many advocates point to the role that this policy mechanism has played in making Germany the leading country in the deployment of renewable energy technology.

Vermont was the first state in the US to pass legislation mandating a European-style advanced feed-in tariff program referred to as the SPEED standard offer program. The program was initiated in September of 2009 and received a great deal of initial interest. Two of the technology categories—solar and woody biomass—quickly became over subscribed on the opening day.

Initially 59.38 MW of projects were awarded standard offer contracts, 9.38 MW over the legislated program cap of 50 MW. Subsequently, 38 percent of the projects awarded an initial contract were withdrawn from the program. A number of factors can be attributed to the program's high attrition rate. It is likely that many projects were submitted without adequate due diligence, given the fact that the standard offer application process did not require a full project feasibility study. Upon more detailed financial analysis, many of the projects may have proven to not be financially viable.

For woody biomass in particular, with an 84 percent attrition rate, the requirement that projects achieve a 50 percent efficiency target may have been unattainable for all but a few projects. The inability to obtain financing due to the onset of the nation-wide credit crunch and the lack of bank support for project financing may have also contributed to projects withdrawing from the standard offer program.

Of all the technologies, the solar and farm methane categories seemed to benefit most from Vermont's standard offer program. Vermont will see its installed PV base rise dramatically, with several large 2 MW+ projects completed, under construction, or in the planning phase. Although individual farm methane projects are relatively small, the program seems to be enabling a number of projects that may have not been developed in the program's absence.

Most technologies may be resource constrained in Vermont and thus their future prospects may not be as promising as solar. For example, most of the good hydro sites have been exploited in Vermont and there are a finite number of farms and landfills that can be exploited for methane to produce power. Furthermore given that each project has a cap of 2.2 MW, additional wind development will be limited to specific areas with a good resource that can accommodate a small number of turbines economically. In Vermont, the best wind resources are found along ridgelines, which typically have limited access and high development costs.

The Vermont standard offer program is still in its early stages of development. It is likely that the State Legislature may choose to make revisions to the program. The technology caps will be revisited soon by the PSB. As discussed above some technologies are resource constrained and may not reach their caps. To meet the overall program goal of 50 MW, the cap on solar may have to be revised to allow more projects to go forward. The Vermont PSB will once again revisit and review the standard offer rates no later than January, 2012.

Noted renewable energy advocate Paul Gipe rated the Vermont standard offer program with a D. While Vermont is a national leader pioneering a feed-in tariff approach in the US, there is much room for improvement, according to Gipe, including lifting the program cap.

The transition to renewable energy is a key challenge facing society. Vermont has played an important role in demonstrating the potential of a feed-in tariff program in the US, albeit with some constraints that limit the pace of renewable energy technology deployment.

6. ACKNOWLEDGEMENTS

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SUSTAIN ANGOON: SOCIAL AND CULTURAL CHANGE IN RURAL SOUTH EAST ALASKA THROUGH A RENEWABLE ENERGY DEMONSTRATION PROJECT

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ABSTRACT

This paper explores the social and technical issues involved in the planning, execution, and successful implementation of a solar electric, solar thermal, wind and efficiency project in Angoon, a remote Native community in Alaska. High cost of energy exacerbates a wide range of social and economic problems and threatens the continued viability of communities like Angoon. A coalition of community organizations, businesses, a university, a Tribe, and a utility came together to do renewable energy education through highly visible demonstration projects in energy efficiency, PV, solar hot water, wind power, real time monitoring of energy and renewable resources, and media projects including a web site and a film project. This paper is written from the perspective of the University team that designed and installed the renewable energy systems and energy monitoring systems.

1. THE COMMUNITY

Southeast Alaska is made up of 23 incorporated and 21 unincorporated communities and villages with an estimated population of 69,200. Covering a 500-mile long stretch of mainland and islands, the archipelago is 120 miles at its widest point. Out of 44 communities, only four are accessible from the rest of the State by road.

Angoon is a Tlingit community of 400 located at the tip of Admiralty Island, 5 hours by ferry from Juneau, Alaska. It is a typical isolated rural community. Archeological evidence suggests that the Alaska Native people have been living in this area for 10,000 years.

Residents of Angoon rely on ferry, barge, and air service for personal transportation and delivery of goods. Like other Southeast Alaska communities, Angoon imports almost everything it consumes, including heating fuel and diesel to generate electricity. High transportation costs translate into high cost of imported goods and energy. A gallon of milk costs from $6 to $8; a dozen of eggs--up to $12. Electricity costs range from 49¢/kWh to 59¢/kWh, depending on the fluctuating price of diesel, with an average rate for 2008 of 54.7¢/KWH. An electric and heating bill for a typical household in Angoon ranges from $300 to $900 dollars a month and can be as high as $1,200.

The high cost of energy represents a significant barrier to economic development, contributing to unemployment, lack of opportunity, depression, substance abuse, and suicides. It disproportionately and adversely affects Alaska Native populations. Fifty percent of the adult population is unemployed. Over the eight-year time period, the population of Angoon decreased by more than 1/3, from 572 in 2000 to 430 in 2008. According to the 2000 Census, approximately

30% or 160 people live below the poverty line.

Additionally, the use of diesel for electric generation is damaging to human health. Burning diesel fuel produces harmful exhaust, which includes cancer-causing chemicals, such as benzene, arsenic and formaldehyde.
Angoon was selected as a site for the demonstration project because it shares all the major characteristics and issues of a typical rural, isolated community. The project aimed to demonstrate energy solutions that could be applied to other isolated, diesel-dependent communities in Alaska, thus helping address multiple economic and social issues in these communities.

2. CURRENT ENERGY SOURCES

Inside Passage Electric Cooperative (IPEC) serves Angoon and four other communities in this region. IPEC is a non-profit, independent electric utility owned by its members. Electric cooperatives are democratically governed businesses, ensuring their consumers closely regulate them. A Board of Directors elected from the membership, which sets policies and procedures that are implemented by the cooperatives' professional staff, governs IPEC. IPEC currently serves Hoonah (459 services), Kake (290 services), Chilkat Valley (238 services), Angoon (239 services) and Klukwan (60 services) for a total of 1,286 customers.

Two diesel generators owned and operated by IPEC supply electricity in Angoon. Diesel fuel is barged in several times a year. Heating oil, gasoline, and propane are shipped in and distributed by a local merchant. Energy prices in the community change depending on the fluctuating price of diesel, and generally remain high and as much as 10 times the US average. For example in 2008, heating fuel costs in Angoon and several other communities in the region peaked at over $7 per gallon. Current electricity rate in Angoon is 54 cents per kWh, but often it reaches 62 cents per kWh and higher.

3. PROJECT HISTORY AND PURPOSE

Angoon Demonstration Project is a response to high and rising energy costs that put into question the survival of more than 300 rural communities in Alaska. Most of them are powered by diesel and other fossil fuels despite abundant renewable alternatives. These fossil fuels are not only furthering climate change and degrading air quality, but the cost of oil is creating severe hardships for Alaskan communities and families. The goal of the project is to demonstrate the feasibility and effectiveness of energy efficiency retrofits in combination with renewable energy systems. The project took place in Angoon, Alaska, in the climate of high humidity, cloudy conditions, and cold winters. Temperatures range from a low of 10 degrees in the winter to highs in the upper 60's in the summer.

The project retrofitted an existing home using affordable, commercially available energy efficiency technologies, aiming to cut down electric and heating costs by 60 to 80 percent, and demonstrate savings of thousands of dollars in disposable income for the participating household.

To ensure that the project had statewide benefits, a short film was produced and distributed online and in DVD formats. Six hundred DVDs are to be burned and distributed to rural community leaders around the State.

Alaska Native values served as a strong foundation for the project. Native peoples of Southeast Alaska are traditional stewards of the air, land and sea; they see it as their duty to help diminish the dependence on fossil fuels in their communities. Diesel-dependence hurts them and the environment where they live. New technologies and weatherization techniques hold potential to make Alaska Natives and their communities healthier and help fight outmigration.

Holding each other up; sharing resources; and taking only what's needed are some of the core Alaska Native values that became a part of the project. High energy costs represent a significant burden for many rural communities in Alaska, and educating rural residents about the benefits of energy efficiency and renewable energy is important. Angoon Demonstration project was about holding each other up by showing those who live in Angoon and in other rural communities how to use energy wisely and efficiently. Just like Native people help each other within the Tribe, project partners worked closely and shared resources so that all could benefits from the project. Project partners came from many places, bringing a variety of resources to the table. They all shared the same goal of improving the environment, health, and socioeconomic conditions in rural communities. Alaska Native people and their ancestors always respected Nature and took only what they needed to provide for their families and no more. The Angoon Demonstration Project is about taking only what is need; using only as much energy as needed; using only as much diesel-generated electricity and heating oil as necessary, and no more.

The project grew out of a community education program that was started in 2008 as a collaboration between the Economic Development Office (headed up by Andrei Chakine) of the Central Council of Tlingit and Haida Indian Tribes of Alaska (CCTHITA) in Juneau, Alaska and staff and students (headed up by Lonnie Gamble) of the

Sustainable Living Program at Maharishi University of Management (MUM) in Fairfield, Iowa. The idea was further developed into a grant application by CCTHITA and Southeast Alaska Conservation Council (headed by Rob Cadmus and Dan Lesh), which was funded by the Alaska Native Health Consortium. During its course, the project brought together a diverse group of partners. Each partner brought resources and unique expertise to the table. By September 2010, the following entities comprised the project team:

- Central Council Tlingit and Haida Indian Tribes of Alaska (CCTHITA) is the Tribal Government representing approximately 26,000 Tlingit and Haida Indians worldwide. It is a sovereign entity that has a government-to-government relationship with the United States.
- Angoon Business Center serves the community through creating and promoting local businesses while offering a wide variety of resources such as a public computer lab, one on one business counseling, business/entrepreneurship workshops, job searching and resume building.
- Tlingit-Haida Regional Housing Authority is Southeast Alaska's largest provider of affordable housing. Established in 1973, the private non-profit housing authority owns and manages nearly 1,000 structures located throughout the region.
- Southeast Alaska Conservation Council is a coalition of 14 member groups in 12 communities, stretching along the coast from Ketchikan to Yakutat; its goal is to safeguard the integrity of Southeast Alaska's unsurpassed natural environment, while supporting the sustainable use of the region's natural resources.
- Maharishi University of Management is an accredited institution of higher education with a strong emphasis on sustainability and consciousness-based education.
- Ideal Energy is a for-profit company dedicated to optimizing the energy performance and sustainability of the built environment.
- Tidal Wave Group is a media company in the business of creating social change. Tidal Wave Group works as a consulting firm that helps clients with communication, marketing and media tools to generate and organize social change that is replicable and based on a vision of a just and sustainable planet.
- Alaska Native Health Consortium - a nonprofit organization dedicated to addressing health-related issues facing Alaska Natives.
- Inside Passage Electric Cooperative is a local nonprofit utility.
- TED The Energy Detective
- Butler Sun Solutions Inc.
- Tyler Rentals
- S-5! The Right Way!
- Local organizations, governments, and individuals.

4. <u>SELECTING A TEST HOUSE</u>

In July of 2010 the organizations involved in the project gathered in Angoon to select a host home for the project. The selection criteria included being willing to show the systems as part of the promotional and educational parts of the project, be eligible for weatherization programs offered by CCTHITA Regional Housing, and have adequate access to solar and wind resources. We toured interviewed six homeowners. We selected the home of Peggy and Kelley Williams.

An important factor was that Peggy and Kelley are elders and well respected in the community. The home is 900 square feet, of wood frame construction and was originally built in the 1960s. The home had a south-facing roof that provided a good location for solar hot water panels. The west yard had good solar exposure and we placed the PV panels there. The batteries, inverter, and control equipment were placed in a pantry and food storage room adjacent to the front door. Despite these advantages, the Williams home was unsuitable for a wind turbine because there was not enough room between them and the adjacent houses for an adequate fall zone. Thus, we decided to install a wind generator at the high school.

5. RENEWABLE RESOURCE AVAILABILITY

Renewable energy resources available in Angoon include direct solar for electricity and hot water, biomass, a large tidal range with some of the strongest currents in North America, and a hydro electric power site 6 miles from town. While the wind resource low, it is available more often in the winter when output from solar is low, so it is a good compliment to PV. PV output was estimated from NREL'S PV Watts web site, using data from Annette, Alaska. Annual average daily insolation is 3.10 kWh/m2/yr, with monthly average maximum in August of 4.69 kWh/m2/yr and monthly average minimum of 1.62 kWh/m2/yr. Wind power densities are not yet available. We are collecting data, results are not available as of the date of this publication (March 2011). Insolation levels at the site can be seen on the Internet from the project web site (www.sustainangoon.org).

6. RESOURCE MONITORING

Wind and solar insolation are monitored with three devices: an Onset Data Hobo U30 unit (insolation), a TED AC energy monitor (PV system output) located at the William house, and an Energy Prospector wind and solar insolation monitoring system on top of a 70 foot water tower located on one of the highest points in the village.

The insolation devices use silicon pyranometers. In addition to the solar and wind resource, we also monitor solar electric and solar thermal system parameters, and AC electrical energy use and production. The Onset Hobo U-30 and the TED data collection devices automatically post data to the Internet. The U-30 posts to a web site operated by Onset Computing (https://www.hobolink.com/sessions/new; Login: Angoon; Password: sailboat). The TED unit uses Google power meter (https://www.google.com/accounts/ServiceLogin?continue=http%3A%2F%2Fwww.google.com%2Fpowermeter&service=powermeter&passive=1; Email Address: sustainangoonproject; Password: sun1sun1). The Energy Prospector unit has an SD card that must be manually removed from the unit, downloaded to a computer, and uploaded to an Internet site operated by Energy Prospector (http://www2.powerpredictor.com/). Posting data from all these devices is free. Data is collected from the U-30 at 10 second intervals and posted to the web once an hour.

7. RENEWABLE ENERGY SYSTEM DESIGN AND INSTALLATION

The installation was done during the month of September, 2011. There are two host sites for the project: the home of Peggy and Kelley Williams and the Angoon High School. We installed 2 kw of grid tied, battery back up solar electric and 60 square feet of solar thermal at the Williams Home. We installed a 1 kw, 8.2 foot diameter Bergey XL 1 wind turbine on a 100 foot tower at the school. The school system is off-grid, and powers a laundry. Installation and coordination activities took three weeks on –island. We arranged for the equipment to ship by barge by barge to Juneau by late August. Juneau has electrical supply houses, industrial hardware stores, and a Home Depot. Several Juneau businesses became partners in the project (list). We spent two days staging up the project in Juneau, making sure we had all parts and tools, as supplies are limited in Angoon. On the first of September, we packed all of or equipment, tools, a new energy efficient washer and dryer, a new water heater tank, LED bulbs, food for a month and 2000 lbs of concrete for the wind turbine tower into a 24 foot moving van and boarded the ferry at 6 am for the 5 hour trip to Angoon.

7.1 Solar Electric

The solar electric system was sized based on the amount of money we had available to do the project. For the money available, we were able to install a 2 kw ground mount PV array (ten REC 215 watt panels at an angle of 48 degrees), Xantrex XW 4000 watt inverter, 2 Xantrex XW 60 amp charge controllers, and 440 amp hours of battery storage. The system DC voltage is 24 volts. We decided on a grid tie/battery back up because we were unsure of the level of support from the local utility. During the construction of the project, the utility became a sponsor of the project and we installed a grid tie configuration.

Other than installing the concrete for the array rack in the rain, we had sunny and mild weather for the three weeks we were on-island and the installation proceeded smoothly. The only major problem was swapped wires between PV arrays and the two charge controllers that gave intermittent operational problems. We were able to work out the problem with excellent assistance from Xantrex technical support.

Based on our monitoring, the solar electric system is working perfectly. We do not expect problems with this system; in fact, it can run for a very long time without problems or maintenance. The battery water level will need to be checked once a month. We left a bottle of distilled water on the cover over the batteries. We do not expect much water usage with the settings on the system (grid support voltage set to 25.5). The system is complete and functioning well. On sunny days in late September, it produced more energy in a day than the Williams use. Based on insolation data from Annette Alaska and system performance to date, we expect provide 1600 kWh per year, about ¼ to 1/2 of the Williams current electrical usage.

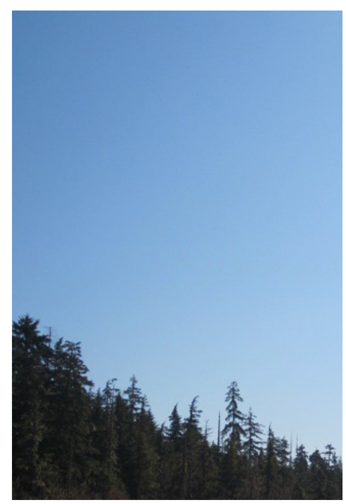
7.2 <u>Solar Domestic Hot Water</u>

The system is a closed loop antifreeze system. The solar hot water system consists of 60 square feet of double glazed selective surface collector, a Butler Sun Solutions wand, an over-temperature device manufactured by Butler Sun Solutions, and a DC pump powered by a solar panel.

It is a two-tank system, with heating oil back up. While the system is complete and functioning, tank temperature doesn't rise as expected by temperature difference across the panels reported by the data logger. The team plans to visit the site in spring of 2011 to troubleshoot the system. Panels may need to be moved to a higher angle for optimum hot water production. The panels were put at the roof angle (25 degrees) degree, which favors summer hot water production.

7.3 <u>Wind System</u>

The wind system is off-grid system and is composed of a Bergey xl 1 1000 watt, 8.2 foot diameter wind turbine on a 100 ft. tower, a Xantrex XW inverter, and 220 amp hours of lead acid battery storage.



It is installed at the school. Originally we intended to install the wind system in a home, but the initial home we chose was not suitable. At the last minute, the school agreed to be a host site. The Xantrex inverter requires 120/240 split phase, and the school only has 120/208 available. The team plans to return in spring 2011 to install an adapter to allow grid tie. Currently the system powers the school laundry.

8. EFFICIENCY

Efficiency of energy is essential for the effectively harnessing renewable energy. An analysis was done of kWh usage in the Williams Home (test house) using a TED and a Kill-a watt meter. The Williams use 640 kWh per year. We removed the few remaining incandescent lights and swapped out 10 CF bulbs for LEDs. We replaced the existing top load washer with a front load washer and replaced the electric dryer with a gas dryer. We minimized phantom loads with the use of power strips.

9. FILM

We created a documentary film "Sustain Angoon" to share the results of the demonstration project with other tribal communities and rural residents throughout the region, and to encourage all Tribal members to make weatherization improvements. The film tells a compelling and emotional story of Angoon residents who strive to meet their daily needs in the environment of severe economic deprivation created by the high energy costs. But it is not a sad story. On the contrary, the Angoon story is a story of hope in social and economic resurrection of the community. The story of Angoon people is the story of many Southeast Alaska residents living in the isolated villages and trying to make their ends meet. That is why the documentary was such an effective tool to show that the weatherization techniques and the renewable energy sources can work in Southeast Alaska and their implementation will ultimately lead to a higher quality of life and greater independence via increased disposable income through energy cost savings.

To empower other tribal residents and to inspire them for action the documentary's message needed to be successfully communicated. Saul Alinsky wrote that "[c]ommunciation with others takes place when they understand what you are trying to get across to them. [...] People only understand things in terms of their experience, which means that you must get within their experience" (Alinsky, 1989, p. 81). Thus, it was important for the story to be told by Native leaders and village residents versus outsiders. The documentary features interviews with local residents; tribal and city council members; representatives of tribal and state government; and representatives of the Native corporations. Through the process of interviewing we allowed for individual stories and voices to be heard and validated. All parties were given the chance to express the unique challenges they face with this energy crisis, from the community's struggle of living with high-energy costs, to the organizations that are providing the services to these remote villages. Seeing the various perspectives in the documentary gives the audience an opportunity to gain a broader view that we are all in this together. The film also shows how Angoon residents participate in every stage of the project: energy efficiency retrofitting, installation of renewable energy systems, and systems' monitoring. The "Sustain Angoon" documentary film demonstrates the project was for the people and by the people.

The stories about the documentary were featured in a number of regional newspapers and radio stations, including the story in the Capital City Daily (http://capitalcityweekly.com/stories/022311/new_789888368.shtml) and the interviews aired on the public broadcasting KTOO Radio Station. The film was shown at the Silverbow Movie Theater in Alaskan capital Juneau on Februray 24, 2011 and was meet with enthusiasm and substantial interest from the community. It is currently available online at http://vimeo.com/19845038. The movie was also promoted on the project's website www.sustainangoon.org, as well as on SEACC's and other partner's websites.

When done correctly, the process of filmmaking, as well as the documentary itself, is a powerful tool for social change and should be considered in the budget when attempting projects that have deep social, political, and environmental impact.

10. COMMUNITY REACTION AND LESSONS LEARNED

Outreach and presentation of the results of this demonstration project were used to promote the environmental, economic, and health benefits of energy conservation and benefits of renewable energy region wide. Local involvement in the project is effective way of impacting the community's energy usage. Prior to starting the weatherization project, during the weatherization retrofit, and upon completion of the projects, Angoon residents were engaged through presentations, workdays, interviews, and one-on-one discussions.

Even before the project started, there were many challenges that had to be overcome. One of the project goals was to inspire change, and change is difficult. The following are some lessons learned.

- Demonstration projects offer an effective way to "get your foot in the door." If successful, they dissipate skepticism and secure public support for larger projects and initiatives that might not have been possible otherwise due to resistance from local stakeholders.

- CCTHITA, being a regional tribe, was in a difficult situation coming from the outside into the community and offering solutions to local issues. Moreover, it brought in with it many outside agencies and organizations. Naturally, some local organizations felt it was an intrusion on their territory. It helped when CCTHITA and project partners "gave away" their leadership roles to local organizations and community leaders, giving them ownership of the project. Angoon residents, governments, and organizations made the project their own, turning it into "local people finding solutions for local issues."
- When it comes to promoting change, very often we find people and organizations that are invested in "status quo" and may refuse to cooperate. It is important to try and make those entities part of the new future and give them a central role to play in the project. By sharing, or giving away completely the spotlight to such organizations and individuals, it might be possible to neutralize potential opposition and even secure additional resources to support change, saving hours of valuable time and significant resources that otherwise would have to be spent on overcoming resistance.
- When it comes to promoting change, making people change their behavior can be a challenge. No matter how politically correct and gently we try offer alternative courses of action, some or many can get offended and become defensive. Rationalizing new behaviors may not always work because people usually would rationalize their current behaviors in response. Instead of changing the behavior, we learned that it is easier to change one's self-image. We all try to be consistent with who we think we are. In our behavior we try to be consistent with our self-image. By changing self-image of a person or organization, we can promote desired changes in their behavior. This way we can encourage organizations to support positive change in their community; we can encourage people to save energy.
- When promoting change, one thing we strive to do is to make change sustainable. We learned that working with community's self-image is more important for achieving that sustainability than securing community's commitment to a specific project. If a demonstration project fails, and the community is very committed to the project, people will get disappointed, discouraged and may not try similar projects and initiatives again. They are likely to become more risk averse and this failure will turn into a lesson to not try anything new next time. However, if the community believes themselves to be pro-sustainability, pro-clean energy, pro-clean environment (self-image), a failure of the demonstration project would mean little. They will keep trying looking for sustainable solutions, in this case to the diesel-dependency problem, because this is who they are. They are not emotionally invested into a specific initiative, and a failure is more likely to energize the community to act again and continue investigating new solutions.

The most striking result of the project was the change in thinking on the community concerning renewable energy. People were stunned to see solar panels producing energy and a wind turbine spinning in Angoon. We heard comments like, "I've seen these on TV but I never expected to see them in Angoon". Initial skepticism turned into enthusiastic support once people saw the Williams meter spinning backwards and the wind turbine (which is visible all over town) go up. The mayor and city councilors are actively planning for 100 homes powered by solar and have asked Southeast Alaska Conservation Consortium (SEACC) to help secure grant funding for the next phase of the project. One issue is to make sure that people don't have unrealistic expectations about what solar and wind can do in Angoon.

11. SUMMARY AND FUTURE WORK

A coalition of community, tribal organizations, non-profits, a university, and a utility designed and implemented a demonstration project that that was comprised of installing solar electric, solar thermal, and wind systems; implementing efficiency measures; and creating a documentary film. The demonstration project took place in Angoon, a remote Tlingit community in Southeast Alaska. The high cost of energy (over 60 cents per kWh for electricity and $7.00 per gallon for heating oil) exacerbates a wide range of social problems and threatens the continued viability of communities like Angoon. Preliminary results suggest that efficiency coupled with residential scale solar and wind power are viable strategies in remote communities in Southeast Alaska with high energy costs and are worthy of wider implementation.

Sometime in April or May of 2011, one or two members of the Fairfield team should return to Angoon to review the operation of the systems, expand the monitoring systems, do any repairs or adjustments to settings, and to do more community education. Grant applications have already been made to expand the project to other communities and to do a feasibility study for using these ideas and others to reduce dependence on fossil fuels in Southeast Alaska Native communities.

If grant money is available, a small film crew should create an addendum to the documentary that will investigate how the project has affected the William's. What have they learned? Would they recommend it to others? The addendum should investigate what the community is thinking now that the project has been in their town a year. What steps are they taking to organize more projects? Is the community embracing renewable energy? Why, why not? How has this project affected the town? This footage can be very useful in building buy-in for future projects, and can be a resource for lessons learned which could speed up the transition from fossil fuel to renewable energy in Southeast Alaska.

In the film, Mayor Albert Howard says that the success of the project "brought hope where none existed before".

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METRIC DEPENDENCE OF PV ECONOMICS

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ABSTRACT

Photovoltaic (PV) systems are installed by several types of market participants, ranging from residential and commercial customers that buy or lease systems for their roofs, to large-scale system developers building several megawatt ground-mounted systems. The relative returns on a PV investment can be very different for each market participant. This is partially driven by fundamental differences in PV prices, incentives, financing options, and the value of PV electricity generated in wholesale or retail markets. It can also be driven by the use of different economic performance metrics to characterize PV value. Here, we evaluate the relative performance of PV investments using several economic performance metrics, including payback time(s), net present value, profitability index, benefit to cost ratio, internal rate of return, monthly bill savings, and the levelized cost of electricity. We evaluate the relative PV performance for each metric over a range of system characteristics, including PV price, performance, financing and market conditions. Lastly, we highlight the potential unintended consequences of policy design based on the different, metric-driven PV returns seen by each market participant.

1. INTRODUCTION

The modularity of PV systems has lead to several types of market participants developing PV projects, ranging from residential and commercial customers that buy or lease small (few to tens of kW) rooftop systems, to utility-scale PV developers that install large (>1 MW) ground-mounted systems. Each market participant typically looks for different types of returns from a PV investment. For example, residential customers frequently use payback times or monthly electric bill savings to evaluate a PV or energy efficiency investment [1,2,3]. Commercial customers frequently use the net present value (NPV), profitability index (PI) [4], benefit to cost (B/C) ratio, or the internal rate of return (IRR) [5]. Vertically integrated utilities or independent power producers may use the levelized cost of electricity (LCOE) to rank a PV development project relative to other potential investments [6].

Each PV market participant will see different returns from a PV investment. These are driven both by fundamental differences in PV prices and revenues available to each participant, and from the use of different economic performance metrics to characterize investment returns. For example, large PV systems (>1 MW) are frequently developed at a far lower costs (per unit capacity) than small residential or commercial rooftop systems. However, the electricity produced by large PV systems will frequently be valued at, or near, wholesale electricity rates through a power purchase agreement (PPA) with the local utility, while rooftop PV systems will offset electricity use in the retail market at rates that are frequently twice as high as wholesale rates [7].

In addition to the different PV price and performance characteristics, the perceived value of a PV investment is also dependent on the economic performance metric(s) used to characterize PV returns. For example, a large PV system developer may use the relationship between the project LCOE and the PPA rate offered by a local utility to value a PV investment, while a residential customer may use their projected monthly bill savings or a PV payback time to evaluate the investment. Even if PV price and performance characteristics were identical, the use of different metrics could encourage the residential customer invest but discourage the large PV developer, or vice versa.

This study focuses on how the use of different economic performance metrics affects the perceived value of a PV investment, and highlights the potential unintended consequences of policy design.

2. ECONOMIC PERFORMANCE METRICS

Table 1 summarizes different economic performance metrics that are frequently used to inform PV investment decisions.

TABLE 1: ECONOMIC METRICS COMMONLY USED TO CHARACTERIZE PV PERFORMANCE

Metric	Equation
Net Present Value (NPV)	$NPV = \sum_{0}^{N} \frac{Revenue_t - Cost_t}{(1+d)^t}$
Profitability Index (PI)	$PI = \frac{\sum_{t=0}^{N} \frac{Revenue_t - Cost_t}{(1+d)^t}}{Investment\ Cost}$
Benefit to Cost (B/C) ratio	$BCR \quad \frac{\sum_{t=0}^{N} \frac{Revenue_t}{(1+d)^t}}{\sum_{t=0}^{N} \frac{Cost}{(1+d)^t}}$
Internal Rate of Return (IRR)	$IRR:\ NPV = \sum_{t=0}^{N} \frac{Revenue_t - Cost_t}{(1+IRR)^t} = 0$
Modified Internal Rate of Return (MIRR)	$MIRR = n\sqrt{\frac{Future\ Value(positive\ cash\ flows, re\text{-}investment\ rate)}{-Present\ Value(negative\ cash\ flows,\ finance\ rate)}}\quad 1$
Payback Time	$Simple\ Payback = \frac{PV\ Price - Federal\ ITC}{Annual\ PV\ Revenue - O\&M}$ $TNP\ Payback: \sum_{t=0}^{TNP\ Payback} Cashflow_t > 0$ $IRR\ Payback: (1+IRR)^{IRR\ Payback} = 2$
Levelized Cost of Electricity (LCOE)	$LCOE = \frac{\sum_{t=0}^{N} \frac{Cost_t}{(1+d)^t}}{\sum_{t=1}^{N} \frac{Electrical\ Energy_t}{(1+d)^t}}$

Several economic performance metrics have one clear definition, like NPV or LCOE. However, other metrics like payback time can have several commonly used definitions [8]. We include three payback metrics in this analysis: 1) simple payback time, defined as the time required for undiscounted PV revenues to equal the undiscounted capital cost [9]; 2) time to net positive cash flow payback (TNP payback), defined as the time required for PV revenues to exceed the cost of ownership [10]; and 3) IRR-based payback times, defined as the time required for an investment accruing at a rate equal to the system IRR to double in value [11].

Different customer types use different economic performance metrics largely because they are looking for different types of returns on their investments. For example, a residential home owner may be interested in short payback times because they are uncertain how long they will remain in their house, and are uncertain about how a PV investment will affect their home value. Commercial customers may be interested in characterizing the annualized return on a PV investment—using B/C ratios, PIs, or IRRs/MIRRs—to help them rank a PV investment relative to other investment opportunities. Large PV developers may be interested in several performance metrics, including LCOE to rank the cost of PV electricity relative to a PPA offering, or additional metrics like B/C ratio, NPV, and others to rank the performance of a PV investment relative to other investment opportunities.

3. PV CASH FLOWS

We start by evaluating reference PV performance for each economic performance metric, using the PV price, performance, financing and market assumptions listed in Table 2. We then vary several PV system characteristics to capture the relative sensitivity of PV performance using each metric. With the exception of tax structures and incentives, we assume the same PV price and performance characteristics for all PV systems in the reference case to focus on how the choice of economic performance metric affects the perceived value of a PV investment. We evaluate PV performance over a wide range of system prices and financing parameters in the sensitivity analysis, and some of these system characteristics may better represent PV price and performance in different markets than the reference parameters.

TABLE 2: REFERENCE PV SYSTEM PARAMETERS

Effective PV Price[1]	$4,000/kW
Capacity Factor[2]	17%
Annualized Electricity Rate	15 ¢/kWh
PV Degradation	0.5%/year
Down Payment	20%
Loan Rate (real)	5%
Loan Term	20 years
Capital Re-investment Rate[3] (real)	8%
Discount Rate[4] (real)	5%
Incentives	30% federal ITC; MACRS depreciation for commercial and utility-scale developers
Net Metering	Full

Annualized O&M payment	$35/year first 10 yr $25/yr for next 10 yr $20/yr for final 10 yr
Analysis Term	30 years
Tax Implications	After tax energy payments for residential; Before tax energy payments for commercial systems

[1]Effective PV price includes state and local PV incentives, but not the 30% federal ITC.
[2]A 17% PV capacity factor represents PV output from a fixed tilt (tilt=latitude) residential PV system in Kansas City, MO [12]. Similar PV systems are likely to perform better in some locations (21.5% capacity factor in Phoenix, AZ) or worse in others (15.5% capacity factor in Chicago, IL) [12].
[3]The capital re-investment rate is used to calculate MIRRs, and represents the company's opportunity cost of capital.
[4]We assume a discount rate equal to the loan rate in the reference scenarios to avoid introducing a time value for borrowed money.

We assume that all PV systems are debt financed, and receive the 30% federal ITC (directly for customer owned systems, and indirectly as a reduced system cost for third party owned systems). PV systems installed by for-profit commercial entities can also depreciate the value of the PV asset following the 5-year Modified Accelerated Cost Recovery System (MACRS) depreciation schedule. The upfront payment of tax incentives significantly impacts PV returns for some, but not all, economic metrics.

In addition to the customer-owned system parameters in Table 2, we estimate third-party owned system parameters by assuming lower financing costs (3% real interest rate), shorter loan/lease terms (15 years), and lower relative PV costs (25% less than customer owned systems). These parameters are used to characterize the monthly bill savings that could be offered by the leasing company to a customer, and we use bill savings as a proxy to compare the relative economics and sensitivities of leased PV systems to customer owned systems. There is a large range in historical lease offerings, based on local PV incentives and PPA offerings by the local utility [13], and the reference parameters are within the range of historical offers.

Figure 1 shows annual after-tax PV cash flows generated using the reference assumptions in Table 2. PV costs are primarily composed of the initial down payment, followed by annual loan payments and O&M costs. These costs are partially offset by system tax benefits, including the tax-deductable payments on loan interest and MACRS depreciation for commercial customers. PV revenues are based on the combination of PV output and the value of PV electricity, which can be challenging to quantify because electricity rates frequently depend on the time of day or season (time of use rates), and customer demand (tiered rates for residential customers, demand-based rates for commercial customers). Additionally, PV revenues are frequently impacted by state and local net metering policy[1]. We approximate PV revenues by defining an annual mean PV capacity factor[2] and an annualized effective electricity rate that represents the mean value of PV-generated electricity.

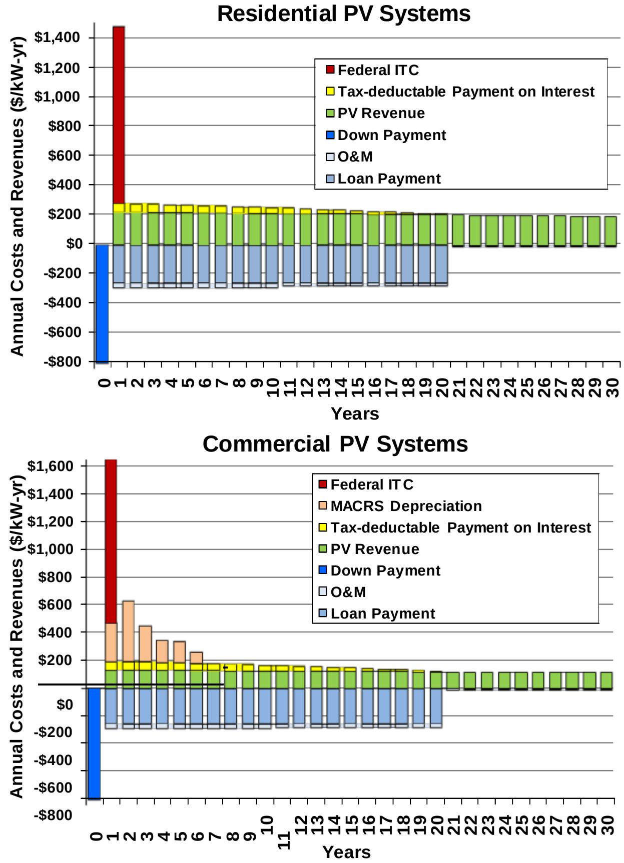

Fig. 1: Residential and commercial PV system costs, revenues, and tax benefits.

Figure 1 shows that the largest annual PV costs (down payment) and tax incentives (federal ITC and MACRS) occur in the first few years of system ownership. After this, the reference PV costs and revenues are nearly identical leading to small net revenues or net costs each year. The up-front nature of PV costs and incentives has a significant

[1] Net metering is a market mechanism that sets the value of PV generation that exceeds electricity use. In areas with full net metering, excess PV electricity is purchased by local utilities at retail electricity rates. Other areas have partial net-metering policies where excess PV generation is valued similar to wholesale electricity rates that roughly capture the value of offsetting fossil fuel use. Other areas have no net-metering policy, and excess PV generation is given to the utility for no cost.
[2] PV capacity factors represent the amount of alternating current (AC) electricity generated by a given amount of direct current (DC) PV capacity, where Capacity Factor = Annual Electricity Generation /(8760 * System Capacity).

impact on some economic performance metrics (IRR and TNP payback), but not others (LCOE, simple payback).

4. RESULTS

Different economic performance metrics frequently show different price and performance thresholds for when a PV investment begins to look attractive. Here, we evaluate relative PV performance over a range of system parameters.

4.1. PV Price

Figure 2 shows relative PV performance for several economic metrics, calculated for a range of effective PV prices from \$1,000 - 7,000/kW[3]. Effective PV prices represent the total installed system price after taking state and local incentives, but before taking the 30% federal ITC. These effective prices represent the range of PV prices currently seen by U.S. customers, which are subject to a wide range in state and local PV incentives offered in the form of rebates (ranging from \$500-4,000/kW in Maryland and Florida), and tax incentives (ranging from 10-50% of system costs in Kansas and Louisiana) [14].

The economic performance metrics used to characterize a PV investment returns can be categorized into those that show a nearly linear response to PV prices—NPV, monthly bill savings, MIRR, simple and MIRR-based payback times, and LCOE—and those that show non-linear responses to changing prices—IRR, B/C ratio, PI and TNP payback. This distinction is important because several of the non-linear economic performance metrics show strong performance thresholds. For example, the IRR metric shows a 4% return for a \$4,800/kW residential PV system, and over a 30% return on a \$4,400/kW system. Commercial PV systems show more dramatic IRR thresholds because of the upfront nature of MACRS capital depreciation (Figure 1) in addition to the 30% federal ITC. TNP payback times also show strong threshold behavior.

Each economic performance metric shows a different price threshold for when a PV investment begins to look attractive. For example, NPVs become positive for \$4,700/kW residential PV systems and \$6,000/kW commercial PV systems. However, monthly bill savings do not become positive until PV system prices are lower than \$4,000/kW, and PV LCOEs do not reach retail electricity rates until PV systems prices are lower than \$3,000/kW. System NPVs look more attractive than system LCOEs at higher PV prices because NPVs are sensitive to the timing of PV revenues and cost streams, whereas LCOEs are only affected by the timing of costs.

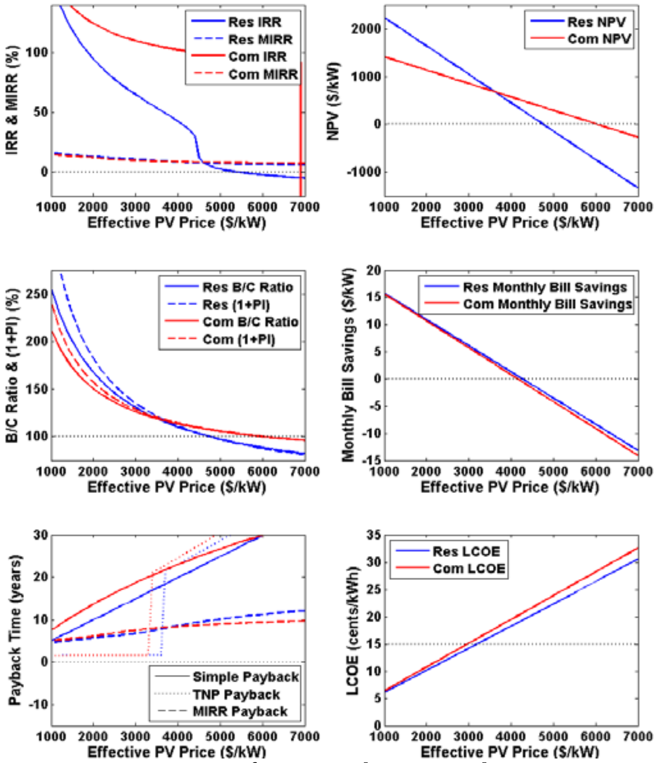

Fig. 2: PV economic performance characterized using several metrics for a range of capital costs, for both residential (blue) and commercial (red) systems. The profitability index (PI) is shifted by adding one (1+PI) to better compare PI performance with B/C ratios.

The difference in PV price thresholds between metrics could significantly impact how potential PV customers perceive the value of a PV investment. For example, a commercial customer may be interested in investing in a \$6,000/kW PV system if they use a NPV>0 criteria in their investment decision. However, a large PV developer may require effective PV prices to be less than \$3,000/kW for the project LCOE to be equal to, or less than, the retail electricity rate (or similar PPA offer). In this case, the choice of economic performance metric could have as much impact on the investment decision as decreasing (or increasing) PV prices by a factor of two. This is similarly true for other economic metrics, as shown by the large differences in prices required for IRRs, MIRRs, B/C ratios, monthly bill savings and payback metrics to begin looking attractive.

4.2. Non-Price Economic Drivers

Non-price system characteristics can significantly impact PV economic performance. However, the relative

[3] Here and elsewhere, all costs and revenues are given in units of 2011 U.S. dollars. Cost and revenue projections are given in real, not nominal, dollars.

sensitivities to non-price characteristics are frequently inconsistent across metrics.

4.2.1. Threshold-driven Metrics

The relative timing of PV costs and revenues are critically important for some metrics like IRR and TNP payback times. Here, we evaluate how financing, PV performance and market characteristics lead to threshold behavior.

Figure 3 shows the impact of non-price system characteristics on PV payback times (simple payback and time to net positive cash flow (TNP) payback). Simple payback times are insensitive to system financing parameters, and show smooth monotonically decreasing relationships to increasing electricity rates and capacity factors. Simple payback times are longer than 10 years for the full range of system assumptions, and a $4,000/kW PV system is not likely to look attractive to the majority of customers using this metric [15].

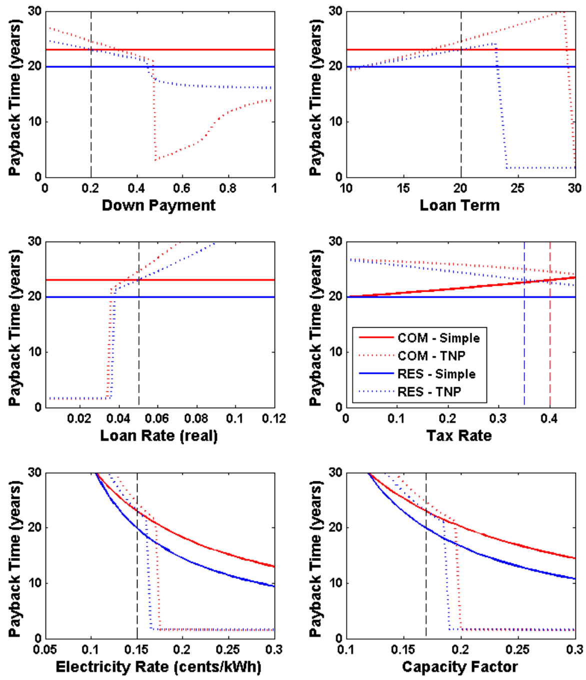

Fig. 3: Payback times for $4,000/kW residential and commercial PV systems over a range of financing, performance, and market parameters. Both simple and time to net positive cash flow (TNP) payback times are shown for commercial and residential systems.

TNP payback times are similar to simple payback times for the reference system assumptions, but are much more sensitive to varying system parameters and show discontinuous performance thresholds. For example, decreasing the loan interest rate from 4% to 3% (real, not nominal) decreases payback times from over 20 years to less than two years. This is because the cost of the system down payment is offset by the 30% federal ITC after the first year of ownership, leading to a positive net cash flow after the first year. If the loan rate is 4% (real), the loan payments and O&M costs are higher than system revenues, leading to a slightly negative cash flow by the end of the loan term (20 years). If the loan rate is reduced to 3% (real), PV revenues are higher than loan payments and O&M costs for most of the loan term, and system net revenues remain positive from the end of the first year on. This discontinuous nature of the TNP payback times is seen for several system parameters that affect the timing of PV costs (down payment fraction, loan term) and increase PV revenues (electricity rates and capacity factors). In most cases, the threshold behavior shifts TNP payback times from over 20 years to less than a few years for small changes in input assumptions.

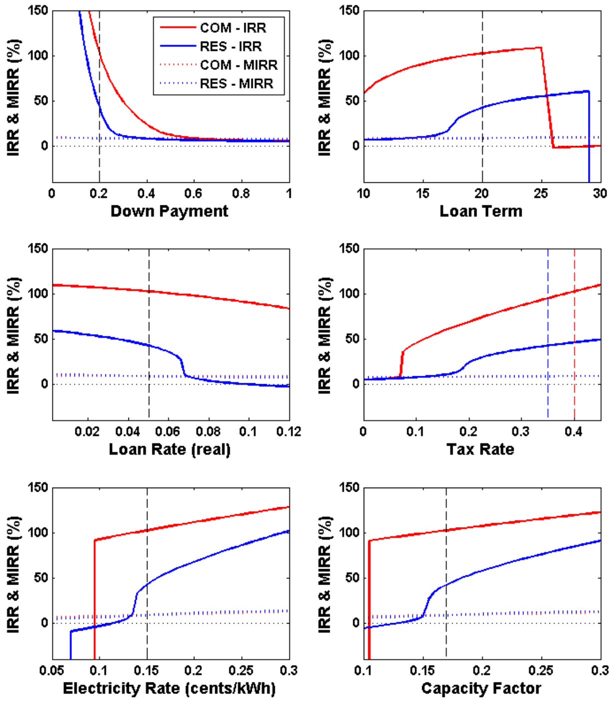

Fig. 4: Internal rate of return (IRR) and modified internal rate of return (MIRR) for $4,000/kW residential and commercial PV systems over a range of financing, performance, and market parameters.

Figure 4 shows PV IRRs and MIRRs for commercial and residential systems. Both commercial and residential IRRs show strong threshold behavior, primarily because annual PV cash flows oscillate between negative (system down payment), to positive (federal ITC and MACRS for commercial systems), to negative (loan payment plus O&M costs exceed system revenues), to positive (PV revenues after the loan term has ended). This threshold behavior is particularly strong for U.S. systems because of the upfront nature of the federal ITC and MACRS depreciation, and not as strong for systems with production-based incentives [5].

Commercial IRRs are typically much higher than residential IRRs because the upfront nature of MACRS depreciation (Figure 1) has a larger impact on system IRRs than the decrease in revenue (commercial energy costs are tax deductible, decreasing the value of PV electricity). IRRs are very sensitive to variables that affect the timing of PV costs and revenues, seen by the sensitivity to financing terms and tax rates. IRRs are less sensitive to parameters that affect mean system costs (loan rates) or system revenues (electricity rates, and capacity factors).

The sensitivity of IRRs to the down payment fraction is particularly important because commercial companies have a wide range of debt-to-equity ratios, both within and across industries. A company's debt-to-equity ratio can also change over time. The 20% down payment assumption corresponds to a relatively high debt-to-equity ratio of 4. A common commercial debt-to-equity ratio is 1.5, and the resulting 40% down payment fraction reduces IRRs to about 20%.

We find similar IRR relationships to those found in previous studies [5, 10]. However, IRR performance in this analysis is far more driven by threshold behavior because U.S. systems typically have several up front incentives like the 30% federal ITC, and MACRS capital depreciation. Since these tax benefits offset costs early in the investment, they tend to make positive IRRs very positive [16], and exacerbate threshold behavior. We find a significantly higher impact of tax rates on PV IRRs than shown by *Talavera et al.* [5], because tax rates directly scale MACRS depreciation in the U.S. Unlike previous studies, we find that the strong threshold behavior of PV IRRs make them a poor metric for characterizing the returns on a PV investment.

MIRRs have been proposed as a better metric for characterizing investment returns than IRR [16]. However, the upfront nature of PV down payments and tax incentives reduce the sensitivity of MIRRs to the range of variables explored, and we find that MIRRs are dominated by the assumed reinvestment rate (8%). For example, the reference commercial MIRR is 8.7%. This MIRR increases to 9.9% if the annualized electricity rate is increased from $0.15/kWh to $0.20/kWh, and increases to 12.6% if electricity rates are increased to $0.30/kWh. MIRRs also show a similarly small increase for decreasing PV prices (Figure 2). These, and other, changes in PV price and performance characteristics have a far greater impact on the other economic performance metrics. The lack of MIRR responsiveness to shifting input parameters, and the strong dependence of MIRRs on the assumed re-investment rate (because of the upfront nature of costs and incentives) decreases the utility of MIRRs for characterizing the value of a PV investment.

4.2.1. Smoothly-varying Metrics

Figure 5 shows annualized monthly bill savings for residential and commercial PV customers. Monthly bill savings show smoothly varying, monotonically increasing or decreasing sensitivities to the range of system parameters explored. Monthly bill savings increase most with increasing loan terms (and corresponding lease terms) and increasing revenue streams (increasing electricity rates and capacity factors). Monthly bill savings are less sensitive to varying tax rates.

Monthly bill savings are positive for the reference conditions ($1.26/kW-month for residential and $0.73/kW-month for commercial systems). The actual monthly bill savings received by a customer is based on the PV system size. Residential PV systems are typically about 5 kW and commercial systems are around 100 kW, leading to annual bill savings of $76/yr for residential customers and $878/yr for commercial customers.

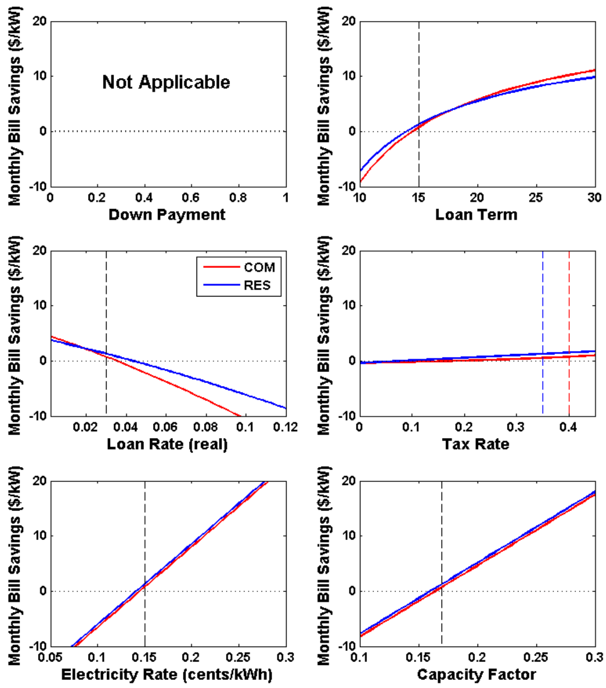

Fig. 5: Annualized monthly bill savings, given in units of $/kW of PV capacity, for residential and commercial PV systems.

The reference PV cost and performance parameters for third party systems represent monthly bill savings that are likely to be attractive to a customer. However, similar reference parameters led to PV payback times that were greater than

20 years, and are not likely to be attractive to the majority of customers. This is partially due to the lower PV costs assumed for third party sellers (based on reducing the depth and cost of the PV supply chain) and lower financing rates (better access to low cost capital), but is also caused by the different dynamics of the monthly bill savings metric as compared to payback times. This suggests that if the reference parameters are met, there is the potential for robust market growth for third-party owned systems but not for customer owned systems if they use payback time to inform investment returns. However, the performance gap between monthly bill savings and TNP payback times decreases considerably for lower effective PV prices, lower loan rates, or higher revenues (increasing capacity factors and electricity rates) because of the threshold nature of the TNP payback metric.

Figure 6 shows the sensitivity of residential and commercial LCOEs to the range of PV financing, market and performance assumptions. The assumed retail electricity rate of \$0.15/kWh is shown in all figures except for the electricity rate figure, where the reference line tracks the increase in electricity rates. LCOEs show smoothly varying, monotonically increasing or decreasing sensitivities to the range of financing, market and performance parameters. While LCOEs are unaffected by PV revenue streams, LCOEs become closer to, or less than retail electricity rates as rates increase.

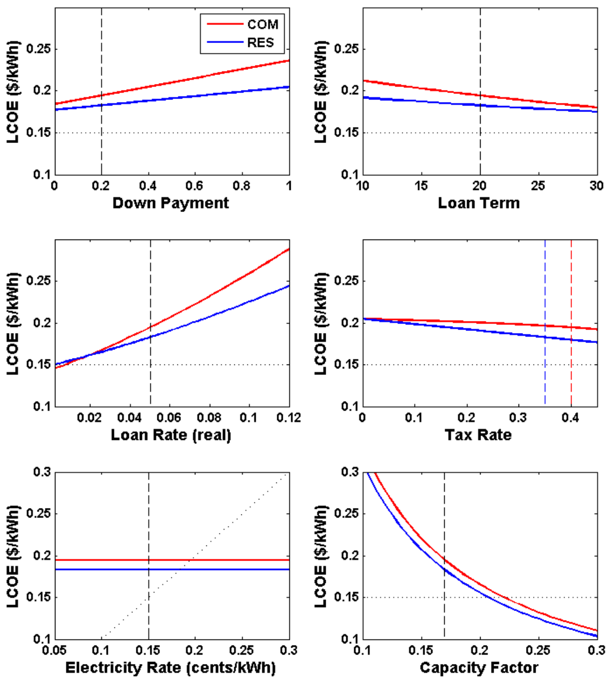

Fig. 6: Levelized Cost of Electricity for \$4,000/kW residential and commercial PV systems over a range of financing, performance, and market parameters.

PV LCOEs are higher than the assumed retail electricity rates for the reference assumptions and for several variations in parameters. LCOEs are not particularly sensitive to the timing of PV costs and revenues (financing terms and tax rates). LCOEs are more sensitive to the system capacity factor, where a 21% residential capacity factor and a 22% commercial capacity factor allow PV LCOEs to reach retail rates. For comparison, a fixed tilt (tilt=latitude) residential PV system located in Phoenix, AZ could reach a 21.5% capacity factor [12].

However, as mentioned previously, NPVs typically become positive for PV prices far below when LCOEs reach retail electricity rates, based on the timing of system costs and revenues. Because of this, customers using LCOEs may be less inclined to invest in PV than customers using different economic performance metrics. Additionally, comparing PV LCOEs with mean electricity rates can significantly underestimate the value of PV electricity in regions with time of use rates, tiered rates, or demand-based rates [17].

One challenge in comparing relative PV performance across different metrics is that each metric typically uses different units to characterize returns. These include years for payback times, annualized returns for IRRs, dollar amounts for NPV, and the cost of electricity for LCOEs. While we can evaluate the unique sensitivities in PV performance across a range of system parameters and define performance thresholds, we cannot compare relative sensitivities exactly because they are measured in different units.

5. CONCLUSIONS

The PV market has several market participants that frequently use different economic performance metrics when evaluating a potential PV investment. We show that the perceived value of a PV investment can be highly metric dependent, and the relative inconsistency in PV returns across metrics could significantly affect the growth of different market segments.

We show that the effective price required for a PV investment to look attractive (e.g. NPV>0) can be very different for each economic performance metric. In some cases, the choice of metric could impact the investment decision by as much as increasing (or decreasing) the effective PV price by a factor of two. The relative sensitivity of PV performance to non-cost drivers also shows strong metric-dependence. The IRR and time to net positive cash flow (TNP) payback metrics show strong threshold behavior, and are very sensitive to the timing of PV costs and revenues. Other metrics, like monthly bill savings and

LCOEs are less sensitive to the relative timing of system costs and revenues, and do not exhibit threshold behavior.

The metric dependent nature of PV performance has strong implications for successful policy design. Even if PV cost and performance characteristics were identical across markets, we show that the use of different economic performance metrics can make a PV investment look profitable in one market (e.g. commercial customers using NPV or PI) for the reference conditions, and not in other markets (e.g. large system developers using LCOE). Additionally, different incentive types are likely to have very different impacts on PV performance. For example, the upfront nature of the 30% federal ITC disproportionately increases system IRRs and TNP payback times relative to monthly bill savings, NPV, and other metrics. Access to low-cost, long term financing would similarly improve IRRs and TNP payback times by more than other smoothly varying metrics. Understanding both the differences in relative price thresholds and the relative sensitivity to changing system parameters is necessary for developing targeted, efficient demand-side policy.

6. ACKNOWLEDGMENTS

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CLEAN ENERGY POLICIES FOR TRANSFORMING MARKETS

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ABSTRACT

This paper builds on the National Renewable Energy Laboratory's State Clean Energy Policy Analysis. It examines policies that work together strategically to bring about clean energy and energy efficiency market transformation at the state level, linked together to promote an infrastructure for market transformation, and indentifies policies and groups of policies that are effective at meeting state goals for economic development including job creation, price stability, and environmental degradation reduction. Case studies from Colorado, Missouri, and Vermont are highlighted. This information can assist state policymakers in designing the best policy solutions to reach their own state goals for clean energy and energy efficiency.

1. INTRODUCTION

In the United States, state-level energy policy development is a mechanism for the creation and development of markets for energy efficiency and renewable energy (henceforth: clean energy) (1,2,3). The role of state policies in market creation includes the development of mandates such as higher energy efficiency building codes and energy efficiency and renewable energy portfolio standards as well as policies that alleviate regulatory barriers such as those that facilitate and streamline access to the electricity grid for distributed generation. Market development policies include non-financial incentives such as density bonuses for builders who implement beyond code efficiency measures and financial incentives from rebates for niche efficiency and renewable energy products to large-scale feed-in tariffs intended to broadly increase the amount of renewable energy on the electricity grid.[i]

The role of state policy is intertwined to varying degrees, depending on which policy and which state, with federal and local policy as well as the environment in which development is taking place (4,5). In the case of high efficiency building codes, for example, the federal government develops model energy codes for use by states—states typically[ii] adopt building codes, and implementation takes place on the local level. To maximize the energy efficiency reaped through the implementation of these codes, some level of cooperation between different jurisdictions is necessary.

In addition to this inter-jurisdictional interaction, state policymakers act with the influence of many in-state factors as well. The existing policy, economic, and energy market and regulatory environment (including energy costs), environmental considerations, energy (clean and fossil) resource availability, and political will all play roles in the development and implementation effectiveness of clean energy policy.

The current literature surrounding state energy policy is large and varied from addressing policy design details (e.g., 6,7,8)—from specific single policy reviews and case studies (e.g., 9,10,11) to narrow and broad evaluations of policies, groups of policies, and non-policy factors on the development of clean energy technologies (e.g., 3, 12)

The paper presents the clean energy policy histories of Vermont, Colorado, and Missouri. These case studies focus on the process for and lessons learned from development and address multiple markets and multiple technologies. Although not the only states to consider and implement clean energy policy, these three represent a broad range of political and geographic contexts. The purpose is to better understand how states can move toward in transforming energy markets from the currently aging technology and infrastructure marketplace to a more efficient, cost effective, and cleaner one. A further purpose is to see if and how states have moved toward their economic development and energy diversity goals through policy development.

This illustration of the different approaches to energy policies at the state level adds to the current body of literature by considering the difficulties and impacts of addressing multiple clean energy challenges in three different jurisdictions. The final outcomes are illustrations of how states in different situations have moved toward energy policies as well as a series of conclusions that policymakers and staff can consider in the development of clean energy policies within other states.

2. VERMONT

The history and growth of the clean energy programs in Vermont could be looked at as a long progression, with the legislature attempting a number of solutions over time. Although there were activities leading up to it, the first large-scale clean energy activity occurred in Vermont in 1990 when the regulatory body, the Public Service Board (PSB), issued a finding that utilities in the state were to use integrated least cost resource planning and promote energy efficiency as a resource. This conceptual change in the way utilities view energy efficiency, as an energy resource as opposed to an additional cost, set the stage for the following two decades of efforts toward clean energy market transformation. In order to solidify the finding, the legislature required the utilities to submit least cost plans to the PSB every three years.

In 1997, the Vermont Department of Public Services (DPS) issued the Statewide Energy Efficiency Plan (13), concluding (among other things) that the relatively large, twenty-two, number of utilities serving Vermont customers created challenges in producing uniform, effective energy efficiency programs. Part of that plan was the initiation of an ―Energy Efficiency Utility‖ in which all of the utility energy efficiency plans would be combined into a single entity. The resulting entity, Efficiency Vermont, officially opened in 2000 and is funded by a public benefits charge, a volumetric charge assessed to all utility customer bills (14), and implemented by the Vermont Energy Investment Corporation. The benefits of a statewide utility for energy efficiency include singular branding for energy efficiency efforts across the state and an economy of scale in terms of the provision of energy efficiency programs.

The Efficiency Vermont programs provide financial incentives to consumers in Vermont, primarily rebates for residential and commercial consumers and a loan program for commercial consumers (15). In addition to these financial incentive programs, Efficiency Vermont offers a variety of technical assistance services and information available to the public on their website, http://www.efficiencyvermont.com/.

Although the legislature did enact interconnection and net-metering provisions in 1998, the first major thrusts for renewable energy development came in 2005. That year the legislature initiated the Vermont Sustainably Priced Energy Development Program (SPEED) and the Clean Energy Development Fund (CEDF). The SPEED program is a goal-based renewable portfolio standard (RPS) [iii] without penalties for non-compliance until 2017, when, if the 20% generation goal is unmet, utilities will be bound to a mandated RPS. In 2009, the legislature further refined this program by allowing the SPEED program to include standard offer and feed-in tariff programs (16).

The CEDF is administered by DPS ―to increase the development and deployment of cost-effective and environmentally sustainable electric power resources‖ (10 V.S.A. Sec. 6523). The funding for the program is directed to come from the state proceeds of an agreement with Entergy Nuclear VT and Energy Nuclear, Inc. The funding agreement is in place until 2012. The CEDF has funded a loan program, the Business Solar Tax Credit, and Municipal Technical Assistance Grants (15).

The activities in Vermont lend themselves to some lessons learned regarding a more holistic approach to policy development, in which, over time, a comprehensive portfolio of policies has emerged:

- Setting the stage with energy efficiency allowed for public buy-in and a more cost effective implementation of renewable energy policies in later years.
- Developing a comprehensive energy efficiency plan (in 1997) for the state did not herald the completion of the effort but instead was the roadmap for achieving the benefits of energy efficiency throughout the state.
- Funding by multiple sources (in the case of Vermont, a public benefits fund and a nuclear fund agreement) can provide a wider range of clean energy efforts.
- Evaluating the effectiveness of policy leading to revisions and updates (such as those for interconnection and net metering as well as the Efficiency Vermont and SPEED programs) to meet the goals and the current market can help keep energy policy relevant and evolving with the current energy markets and consumer demands.

3. <u>COLORADO</u>

Colorado's most recent clean energy policy development began in the late 1990s with a coalescence of technological, regulatory, and market forces. Due to technological advances, electricity generation from wind became cost competitive with fossil fuels (17). In 2001, the Colorado Public Utilities Commission (PUC) determined that wind was a least cost resource and ordered Xcel Energy to buy wind power to meet its customer load (18). At the same time, consumer demand for green power was growing (17).

In 2004, voters in Colorado passed ballot initiative Amendment 37 to establish an RPS called a renewable energy standard (RES). This was the first voter-approved mandate for renewable energy in the United States. The state legislature had failed on three previous attempts to pass an RPS, so a citizen group quickly mobilized to put the initiative on the 2004 state ballot. The citizen group was led by Environment Colorado and the Colorado Public Interest Research Group (CoPIRG), both clean energy advocacy groups (18). The advocacy was primarily funded by the national advocacy group, the Public Interest Research Group (PIRG), of which CoPIRG is an affiliate.

The RPS, as originally passed, applied to utilities serving over 40,000 customers and required utilities to purchase clean energy to supply 10% of their retail sales (CRS 40-2-124). In 2007, the legislature increased the RPS requirements to 20% and expanded the requirements to include electric cooperatives (4 CCR 723-3-3650 et seq.).[iv] In 2010, the legislature acted again to increase the RPS requirements to 30% of retail electricity sales by 2020, clarify the rules to require the investor-owned utilities (IOUs) to supply 3% of their retail sales from distributed generation, and expand the list of eligible renewable energy resources (CPUC Decision No. C10-0952) (19).

The RPS was not the only policy activity in Colorado in the late 2000s. In 2006, Denver's District Attorney Bill Ritter won the Governorship running on the platform of creating a –New Energy Economy,‖ an economic transformation evolved through policy and economic development actions to change the way energy is produced and consumed. The New Energy Economy was also a strategy to link addressing climate change and reducing Colorado's dependence on foreign oil by creating jobs through attracting clean energy companies and clean energy research to Colorado (17). Governor Ritter's campaign document, –The Colorado Promise,‖ outlined his vision for the New Energy Economy (20).

The policy components of the New Energy Economy are integrated into Colorado's existing and developing infrastructure. Colorado's highly educated workforce, research facilities, and partnerships are all contributing factors (17). The Governor's Energy Office (GEO) has formed multiple partnerships to promote energy efficiency and renewable energy. These partnerships involve school districts making school buildings more energy efficient, state and local economic development offices attracting new industries and jobs, and local communities helping disburse incentives. These partnerships were formed to help ensure a long-lasting legacy of clean energy and to disseminate GEO policies and programs to a broad audience (21).

In 2007, the Ritter Administration participated in a collaborative effort with business and community leaders to develop the Colorado Climate Action Plan (CCAP). The plan was developed in a series of nine roundtable meetings and spanned multiple economic sectors (17). While the plan did not include specific policy action, it outlined the goals and actions for the New Energy Economy (22).

Before the 2007 legislative session, the Governor laid the groundwork for extensive partnering with public and private institutions to accomplish the goals of the New Energy Economy. Immediately upon election, Governor Ritter met with the president of the Colorado Senate and the Speaker of the House to advance the New Energy Economy through policy. Expanding the RPS (from 10% –20%) was a top priority to signal policy certainty and development of a market to the business community (17).

In addition to working with external partners, Governor Ritter dedicated staff to the effort and ensured that all his cabinet agencies were empowered to work toward the New Energy Economy. In addition, he issued –greening government‖ goals and redefined the mission of the GEO to build markets for the New Energy Economy through programs that would help residents and businesses incorporate energy efficiency and renewable energy (17). He also appointed Colorado's first Climate Change Advisor and public utility commissioners who would share his vision for the New Energy Economy. These appointments proved critical as the PUC had to implement regulations resulting from the new clean energy laws (17).

From 2007–2010, the GEO, the state's General Assembly (the legislature), and the PUC worked together to enact the Governor's New Energy Economy strategy. In all, Governor Ritter worked with the General Assembly on passing 57 laws pertaining to the New Energy Economy between 2007 and 2010 (23). Addressing financial barriers, attracting capital, and creating partnerships were key to developing the New Energy Economy.

Key legislation during the 2007 legislative session included removing barriers to transmission, net metering, and establishing a Colorado Energy Task Force whose responsibilities included mapping out Colorado's renewable energy resources and laying out a roadmap for achieving the goals set out in the New Energy Economy and CCAP (17). The results are maps that identify where wind and solar can provide utility scale power; local development opportunities for geothermal, hydroelectric power, biomass, and ethanol; and areas where transmission is needed to bring renewable resources to market (24).

In addition, in an effort to draw clean energy businesses, the Colorado legislature allocated $10 million of the state's gaming receipts and severance tax to the Clean Energy Fund (CRS. 24-75-1201). This fund invests in attracting renewable energy investment, assisting in technology transfer, and providing market incentives for energy efficiency and renewable energy (19).

In 2008, clean energy legislation that helped grow the marketplace was passed. Laws passed provided for expanding net metering to municipal utilities and rural electric associations (CRS 40-2-124) and advancing the solar marketplace by prohibiting homeowner associations from enacting restrictive covenants on solar (17).

The suite of policies enacted in 2009 and 2010 worked to remove financial barriers and increase Colorado's clean energy market competitiveness. These laws provided financing tools, tax incentives, and property tax valuation rules to pave the way for the development of solar, small hydro, biomass, biofuels, and energy efficiency [CRS 24-38.7-101.5, CRS 39-4-102(1)(e)(I)(A), and (1.5)(b)(iv) and CRS 39-4-101(3)] (17). Solar energy systems for residents and businesses became more accessible with the allowance of third-party financing models to overcome the first cost barrier [CRS 40-9.7-102(2)] (17) and a requirement for new home developers to offer homes prewired for solar energy (CRS 38-35.7-106).

Governor Ritter's efforts surrounding New Energy Economy was attractive to renewable energy and energy efficiency companies looking to locate in Colorado. As companies were drawn to the state, they created a variety of jobs in the New Energy Economy (17). For a listing of companies and jobs created see: http://rechargecolorado.com/images/uploads/pdfs/Ritter_Energy_Book_F_ForWeb.pdf.

One of the companies, Vestas, a Denmark-based wind turbine manufacturer, located its North American manufacturing facilities in Colorado and brought with it $1 billion in investments and over 2,000 new jobs. Vestas was looking at other states that could offer more financial incentives but Colorado's strong labor force, administrative structure,[v] and committed Governor convinced them to locate in Colorado (17).

Some of the other results to date of the New Energy Economy Efforts include:

- Colorado has the fourth highest concentration of clean energy workers in the country and more than 1,500 clean energy companies.
- The number of clean energy businesses has grown 18% since 2004, making it Colorado's fastest growing energy sector.
- Colorado has attracted the third highest amount of venture capital funding from 2008–2010.
- Governor Ritter, GEO, and the Office of Economic Development were directly involved in 32 companies expanding or relocating to Colorado, creating 6,500 jobs (Source: State of Colorado, undated news release).

4. MISSOURI

Missouri has the shortest history of clean energy development of the states presented here, and is presented for that reason. While the activities are relatively new, they illustrate the ability of a state to move quickly and develop clean energy programs and policies in coordination with an economic recovery strategy. In addition, the Missouri story illustrates the potential for state policymakers, the public, and private industry to work together to form a broad range of clean energy activities that drive toward state economic development goals. While the long-term impacts remain to be seen, initial impacts appear positive.

Historically, Missouri's clean energy actions have centered around improvements to public buildings (R.S. Mo 640-651) over which the legislature has direct jurisdiction. Until 2007, a tax incentive for wood energy production and rules surrounding solar easements were the only private sector targeted legislative efforts.

In 2007, the legislature signaled a shift in thinking regarding clean energy and enacted a voluntary RPS goal for utilities statewide (including municipal utilities and cooperatives) of 11% of generation or procurement by 2020, including both energy efficiency and renewable energy. The legislature also passed interconnection and net-metering laws to promote the development of distributed generation resources. While voluntary RPS policies have not been shown to be effective at driving the market for clean energy (25), and the interconnection and net-metering rules do not meet best practices for driving the market for increasing distributed generation (6), the development of these policies in the legislature signaled interest in clean energy development and opened the door for more stringent and effective policies in the following years.

The election in 2008 ushered in a suite of changes in Missouri's energy policy strategy. First, the state became the second in the union to have a voter-driven RPS, the RES, which required IOUs to generate or procure 15% of their electricity from renewable resources by 2021 and includes a 0.3% solar set aside. Second, the voters elected Democrat Jay Nixon as Governor on a platform of economic and clean energy reform (26). Finally, the Republican-led legislature passed more stringent requirements for new public buildings (SB 1181), a tax deduction for home energy efficiency improvements [R.S. Mo 143.121(8)], and an annual sales tax holiday for ENERGY STAR rated appliances (R.S. Mo 144.526).

The three-pronged approach: voter driven, legislative driven, and executive driven resulted in a flood of new laws and regulations surrounding clean energy development. The RES went into effect after the development of regulation in August 2010 with a number of changes from the legislative side (e.g., a change in eligible technologies) and a number of negotiated items on the regulatory side (e.g., refinement of the solar set aside provisions). The effectiveness of the RES will be evident in the next few years as IOUs begin to report their progress toward the goal.

With the RES regulation development as a backdrop, the Department of Natural Resources, the Missouri agency that implements the federal state energy program, developed two primary programs with Missouri's formula-driven American Recovery and Reinvestment Act of 2009 funds. The programs target the residential and agricultural segments, two of the largest sectors in the state. The effectiveness of these programs is not yet known.

In a relatively short period of time, the state of Missouri has made major voter-driven, legislative, and executive moves toward supporting clean energy development in the state for the purpose of both bolstering the economy and decreasing costs to consumers. While confronting implementation challenges and faltering economic conditions, the state has worked to make progress in a short amount of time. The impact of the combined efforts of different stakeholders shows promise through the effectiveness of activities to date, and the overall effectiveness of the portfolio will be evident in future years.

Parsing out the impacts of policy on the development of clean energy in Missouri is complicated by the leadership of the private sector in that state. Data show that clean energy development including an increase in wind and solar energy development, began in 2007 (27) before state policies were fully implemented. This indicates activities driving development beyond the policy sector and evaluating the impacts of policies with that context in mind will be required.

5. CONCLUSIONS

The three case studies presented here reflect a range of different approaches U.S. states have taken to develop clean energy policies. The states were chosen because of their policy and geographic diversity, but six common themes emerged regarding effective policy development across the states. Understanding these themes can assist state policymakers and staff in designing and implementing suites of clean energy policies.

A Champion, Even if Not Traditional, is a Necessity. All three states had or developed longer-term energy champions of one form or another. In Vermont, research efforts did not identify a single champion but instead the general public, and the apparently statewide ethic of self reliance, low-cost energy procurement, and clean energy created an environment where successive legislatures were empowered and expected to improve the energy situation for their constituents. In Colorado, a less pronounced but clearly existing (manifested through the voter-passed RPS) public support is evident through the literature. Building on this to catalyze and lead the drive for policy implementation in Colorado was Governor Bill Ritter, who initiated the Clean Energy Economy suite of policies and programs. This more traditional champion was well placed politically to drive extensive policy change. Although a newer organized effort is taking place in Missouri to develop clean energy policy, it appears that the champion in that state may be private industry, the public, and a set of non-profits, as evidenced by the voter passage of an RPS and the development of significant renewable energy resources before policies were in place. While the legislature led by passing the voluntary standard in 2006, the public, likely buoyed by the development of successful, job developing, clean energy projects in the state, drove the required standard a year later.

Starting with Energy Efficiency, following with Renewable Energy. All three states are taking an approach that focuses first on energy efficiency in the public sector, then the private sector, and finally on renewable energy. This structure is logical in that it reflects policymakers taking advantage of their direct jurisdiction (e.g., public buildings) as well as the lowest cost clean energy improvements (energy efficiency) over the typically more expensive (renewable energy) ones.

A Long Policy History has Benefits, but They are Not Necessary for Impact. The State of Vermont has the longest standing history of clean energy policy development. This 30-year history of promoting clean energy has led to a comprehensive policy portfolio for energy efficiency and, in the past 10 years, a broad approach to the development of renewable energy resources. This example illustrates the impact of long-term policy planning and implementation. While the Vermont example illustrates the importance of longevity, the Colorado example illustrates the impact of a compressed, holistic effort. While building on an existing effort and climate well prepared for a rapid increase in clean energy as well as a history of public interest generally in energy policy, the election of Governor Ritter on a clean energy development platform transformed previously piecemeal efforts into a unified push for job development and energy security through clean energy. The success of the effort in drawing manufacturing companies and creating jobs (see the case study for more details) in a relatively short, single administration, illustrates the opportunity for high impact over a short period of time.

Multiple Policies for Multiple Markets. Colorado and Vermont exemplify a holistic policy approach. That is, both states have a history of approaching multiple markets and multiple technologies through policy development. This wide array of policies allows for the creation of multiple markets for clean energy and gives the markets the opportunity to then succeed or fail without further policy intervention. This increased opportunity for success through multiple approaches assisted in the creation of multiple markets in both states.

In the same vein, no single policy has been found to provide all of the solutions for effective state strategies for clean energy development. In Colorado, the development of the RPS is the centerpiece for many of the policies developed subsequently. However, in Vermont, there has been much progress even in the absence of an RPS, illustrating that a policy alone does not always drive development.

A Variety of Funding Mechanisms Offer Broad Support. Financial support for most policies and programs is critical to their success. Both Vermont and Colorado use the public benefit fund mechanism to support clean energy programs. Since 2005, Vermont has also had a fund of money for clean energy from a nuclear settlement. Consistent, secure funding to support developing policies provides investor certainty and creates an environment conducive to long-term clean energy development (such as in Vermont). Missouri is yet to adopt a uniform funding mechanism to support program implementation.

Effective Marketing and Branding of a Policy Suite can Help Drive Toward Goals. The Colorado example illustrates the speed at which these policies, when taken holistically and with a political champion, can be effective at driving toward the state goals (in this case, the goal of job and manufacturing creation in the state). A piece of the effort that appears to have driven the success is the existence of a single brand, the Clean Energy Economy, which became the umbrella structure under which all the new policies and programs were presented. This branding fostered broad buy-in and facilitation for the policies.

Overall, the case studies show the range of policy efforts ongoing in U.S. states and provide samples of policy development options for state stakeholders. The studies also showcase the different strategies that states are using in policy development, such as using a mandate as the centerpiece of policies or implementing broad programs to support voluntary development. In the midst of the differences, there are also similarities that can be applied in a wide variety of state contexts to meet the economic development and environmental and energy security goals of policymakers and constituents.

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[i] Definitions of policies as well as summary maps of current implementation can be found in several locations, including the Department of Energy (DOE) sponsored http://www.dsireusa.org, http://www.aceee.org/sector/state-policy, and http://bcap-ocean.org/.

[ii] Thirty-eight states currently implement statewide building codes, with the remaining states allowing for –home rule‖ in which localities develop and implement building codes.

[iii] For more information on RPS, see (26).

[iv] The 2007 and 2010 increases in the RPS were accomplished through a PUC ruling.

[v] Administrative structure means that efforts were made to reduce any barriers for Vestas, including assigning a full-time employee to work with Vestas and reducing permitting lags (19).

CLEAN ENERGY POLICIES: QUANTIFYING EFFECTIVENESS

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ABSTRACT

The increase in the use of state policy to drive energy efficiency and renewable energy market transformation is leading to extensive research on determining the best policies and policy designs to achieve this goal. There is growing interest in quantifying the connection between policies and development. This report uses statistical methods to better quantify the connection between a broad array of energy efficiency and renewable energy (collectively known as clean energy) policy and actual reductions in energy use and increases in renewable resource development. Using a multi-faceted dataset including policies, socioeconomic factors, and electricity information, ordinary least-squares regression is used to identify relationships between policy implementation and development.

1. INTRODUCTION

Significant efforts have been made to document success stories and lessons learned from past and recent policy implementation. Case studies reviewing the anecdotal evidence of policy effectiveness are common; they provide important insights and inform the growing field of literature on policy design practices (e.g., 1; 2; 3; 4; 5; 6).

Less common, but growing in number, are quantitative evaluations of policy effectiveness. To date, most of the research has focused on wind energy development. Menz and Vachon (7) looked at the connection between wind resource development and various state policies, finding supporting evidence that some mix of mandatory rules and regulations [i.e., renewable portfolio standards (RPS), fuel generation disclosure, and mandatory green power purchasing] is associated with increased wind energy development. Bohn and Lant (8) found that states with standardized siting and permitting procedures have a strong association with increased wind resource development. This work also looked at factors beyond policy and resource availability that drive the development of wind, finding that population distribution, electricity demand, and access to transmission are determinates in resource development. More generally relating RPS to renewable energy generation, Carley (9) found that there is a relationship between the number of years an RPS is in place and higher generation from renewable sources but not the existence of the policy alone.

In this context, the aim of this research is to augment and build on traditional case studies and narrower quantitative analyses to develop a quantitative understanding of policy impacts using statistical and empirical methods, as well as to open the door for more thorough analyses of policy options, inform future policy development, and ultimately optimize the market share of renewable energy resources. Ideally, the outcomes will be useful for policymakers to elect policies that will work within their context to meet the goal of increased clean energy development.

2. METHODOLOGY

The methodology for these analyses splits clean energy resources into energy efficiency and renewable energy technologies, primarily because the metric for success differs between the two. Energy efficiency improvements in the commercial sector are measured by commercial energy use (10) normalized for economic change by gross state product in the same year. Energy efficiency improvements in the residential sector are measured by residential energy use normalized for population in the same year. Renewable energy improvements are measured by increased energy supply and are therefore measured by increased capacity and generation of electricity from renewable resources. It is crucial to note that this methodology tests only in-state development and some policies are designed to target regional growth. The regional clean energy impacts of these policies will not be directly captured by this methodology.

We focus on individual policies as they are currently being implemented and, to a limited extent, combinations of policies. The methodology will not result in recommendations for altering policy implementation strategies but instead reflects clean energy development impacts of the current mix of state policies.

Table 1 summarizes the definitions of statistical terms used in this analysis.

TABLE 1: DEFINITIONS OF TERMS

Adjusted R^2	• A measure of the amount of variation about the mean explained by the model, adjusted for the number of independent variables
	• Increases *only* when the additional variable in question improves the model more than what would be expected by chance
Constant	• Linear regressions require a y-intercept term to be present
Beta	• The change in the dependent variable per a one-unit change in the value of the independent variable
P-Value	• Probability of obtaining a test statistic at least as extreme as the one observed
	• At the 5% significance level, a p-value of less than 0.05 means that the observed result cannot be ascribed to chance alone
Error Term	• An estimate of the unobservable statistical error

2.1 Energy Efficiency[i]

In this analysis, the dependent variable for commercial energy efficiency is commercial energy use normalized for economic changes by the gross state product in the same year, and the dependent variable for the residential sector is residential energy use normalized for population in the same year. The independent variables in this analysis are the existence of:

1. High efficiency (equal to or better than ASHRAE 90.1 2004) statewide commercial building code (11)
2. High efficiency (equal to or better than IECC 2006) statewide residential building code (11)
3. Commercial electricity price in 2009 (12)
4. Residential electricity price in 2009 (12)
5. Energy Efficiency Resource Standard (EERS) (13)
6. State personal tax incentives (14)
7. State rebates (14)
8. State loans (14)

Only commercial and residential energy consumption were used as a proxy for overall building efficiency; the industrial sector was omitted because it consumes energy in a different way, through industrial processes as well as building efficiency.

Every independent variable in this energy efficiency analysis was expected to have a negative impact on energy use (lower commercial energy use/Gross State Product (GSP) and lower residential energy use/capita). Regardless of whether a state had all four incentives/standards or not, it was kept in the dataset (since every state consumes energy in the commercial and residential sectors), resulting in 51 observations in each model.

Betas were estimated using ordinary least-squares (OLS) methodology. The variables were analyzed for multicollinearity through a bivariate correlation table. A test of the variance inflation factors (VIF) was conducted as well, which is commonly used as an indicator of the severity of multicollinearity (15). A VIF value in excess of 10 is an indication that multicollinearity is influencing the OLS estimates, and the average electricity price (both residential and commercial) is the only variable that exceeded this threshold, albeit only slightly. Given the lack of multicollinearity based on this test, the analysis proceeded with the original variables, taking into consideration that the electricity price variable may be inflating the variance of the estimated coefficients.

2.2 Renewable Energy

Two dependent variables for each renewable technology [wind, photovoltaics (PV), geothermal, and biomass] were used: end-of-year 2009 cumulative capacity (MW) and 2009 annual generation (MWh). For PV, only capacity data was utilized because the state-by-state generation data that the Energy Information Administration (EIA) classifies as –solar‖ is over 90% concentrated solar power, which is not included in this analysis due to its limited geographic application. Capacity data for wind is from the AWEA's –Year End 2009 Market Report‖ (16), PV capacity data is from Larry Sherwood's –U.S. Solar Market Trends 2009‖ (17), geothermal capacity data is from GEA's –U.S. Geothermal Power Production and Development Update‖ (18), and biomass capacity data is from EIA's –Electric Power Monthly‖ (19). Generation data for biomass, geothermal, and wind are gathered from Form EIA-923 (20). Discrepancies between capacity and generation may stem from a number of factors, including but not limited to: varying data reporting regulations and data collection methods, ranges of efficiencies, plant outages, and power purchase agreements. Table 2 summarizes the policies that serve as the independent variables in comparison to the dependent renewable resource variable. In addition to tests comparing the currently available policy information and capacity and generation data, time lag analyses were completed for several policies (the independent variable being 2007 policy existence) to measure if the length of time a policy has been in place is associated with increased renewable energy generation.

TABLE 2: STATE POLICY OPTIONS AND TYPICAL APPLICATION TO RENEWABLE RESOURCES

	PV	Wind	Geothermal	Biomass
Access Laws	1			
Bonds				
Construction and Design				
Contractor Licensing	1	1	1	1
Corporate Tax Incentives	1	1		1
Equipment Certification	1			
Generation Disclosure				
Grants	1			
Industry Support		1	1	1
Interconnection	1	1		
Line Extension Analysis	1		1	
Loans			1	1
Net Metering	1	1		
Personal Tax Incentives	1		1	
Production Incentives	1	1	1	1
Property Tax Incentives	1			1
Rebates	1			
RPS	1	1		
RPS with Solar Set Aside	1			
Sales Tax Incentives	1	1		
Voluntary and Mandatory Green Power	1	1		

Regression models for each of the renewable energy technologies were structured in the same way as the energy efficiency models shown earlier (definitions for variables can be found at http://www.dsireusa.org). The independent variables for each technology tested include:

- Selected policies applicable to the specific technology being tested (shown in Table 2)
- Average 2009 state electricity price
- The –Freeing the Grid‖ interconnection grade (21)
- The number of distinct types of renewable energy policy in each state
- Population
- Whether the state has undergone electricity market restructuring
- The number of years the RPS (if one exists) has been effective

The Betas were estimated using OLS methodology. A bivariate correlation table was constructed for each model, and the resulting intercorrelations were found not to be a concern. A VIF test was conducted on each model. For biomass, geothermal, and wind (both capacity and generation), average electricity price and the number of policies had a VIF in excess of 10 and were therefore dropped from the model. For PV capacity, the average electricity price, net metering, and the number of policies all exhibited a VIF in excess of 10 and were removed.

As each model was run, variables that were not significant to the model and that degraded the R^2 were removed until the model was left with the most efficient set of variables to explain renewable energy build-out for each technology. If a variable was not significant at the 0.05 level but improved the R^2, it remained in the model.

3. RESULTS

The analysis produced several unexpected results, and while they may appear to indicate that certain policies are not associated with clean energy development, further research with refined datasets is necessary. It should also be noted that there are methodological challenges in this type of quantitative analysis. Specifically in this exercise, the limitations include:

- The relatively small sample size (50 states plus the District of Columbia) limits the observations to a maximum of 51 for any regression.
- The time series data for policies dates back to only 2007, so a two-year time lag is currently the maximum that can be tested.
- The policy terms can vary from state to state, and the differences are difficult to reflect in this type of analysis. Not all policies are designed to spur in-state development but rather target regional growth.
- It is possible that omitted variable bias would cause the independent variable (capacity/generation) to be correlated with the error term, therefore distorting the coefficients estimated in the analysis and producing inconsistent estimates. This methodology attempts to capture omitted variable bias by including more

variables then necessary and reducing down to an optimal regression equation. However, macroeconomic variables (including changes in demographics) could have impacted energy use and capacity development and unintentionally been omitted from the analysis.

The dependent variable is absolute renewable capacity or generation, not the percent of total capacity or generation that is a renewable resource. RPS policies typically target growth of the percent of total generation that is composed of renewable energy and may be a better metric to test in the future.

Biomass and geothermal projects typically require a construction schedule in excess of two years, and therefore the effects of a policy would have corresponding longer lag.

As a result of these limitations, outcomes from this analysis should be taken in hand with other quantitative and qualitative work in the area of clean energy policy and its relation to clean energy technology development.

Table 3 shows that in general, this methodology produces an adjusted R^2 of 46% for residential sector state energy use and 67% for commercial sector state energy use. For renewable energy resources, policy and the other macroeconomic factors tested produce an adjusted R^2 of 43%–63% for capacity and generation, depending on the measure and the renewable technology being tested.

TABLE 3: PERCENT OF VARIATION BETWEEN STATES EXPLAINED BY MODELS (ADJUSTED R^2)

	2009 MW/MWh vs 2008 Policies (One Year Lag)	
Technology	**Capacity (MW)**	**Generation (MWh)**
Biomass	43.7%	46.7%
Geothermal	47.2%	47.4%
Photovoltaic	58.2%	
Wind	47.5%	45.7%

	2009 MW/MWh vs 2007 Policies (Two Year Lag)	
Technology	**Capacity (MW)**	**Generation (MWh)**
Biomass	49.8%	52.6%
Geothermal	49.8%	50.5%
Photovoltaic	63.3%	
Wind	45.5%	43.6%

	Impact of Policy on Efficiency 2009 Energy Use vs 2008 Policies
Commercial	67.5%
Residential	46.1%

The remainder of the results section is structured to show detailed results by resource evaluated. For the energy efficiency evaluations, only a one-year time lag of the policies (2008) produced meaningful results, so only those are presented. For each renewable technology, the first table presents results using a one-year time lag with 2008 incentive data, and the second table presents the results of the two-year time lag analysis (e.g., incentives available in 2007 compared to current capacity or generation).

3.1 Energy Efficiency

Tables 4 and 5 are the results from the energy efficiency analysis. In this analysis only the one-year time lag data led to meaningful results, so only those are presented here. Table 4 shows that in the residential analysis, none of the incentives (e.g., personal tax incentives, rebates, and loans) were significant in explaining energy use per capita. There was a relationship with high efficiency residential building codes with a p-value of 0.072, making it significant only at the 0.10 level. A state having an EERS is also more likely to exhibit lower energy use per capita. Residential electricity price had a significant, negative relationship with per capita energy use. Of all the rules, incentives, and macroeconomic factors tested, this methodology can explain only 46.1% of the variation in residential state energy use.

TABLE 4: IMPACT OF POLICY ON RESIDENTIAL EFFICIENCY: RESIDENTIAL CONSUMPTION/ CAPITA (2008 INCENTIVES)

Variable	Beta	P-Value	
Constant	101.8	0.000	
High Efficiency Residential Building Code	-5.1	0.072	*
Average Residential Electricity Price (2009)	-1.8	0.000	
Energy Efficiency Resource Standard (EERS)	-5.6	0.047	
Adjusted R^2	0.461		
Number of Observations	51		

**Not significant at the 5% level.*
(11; 12; 22; 23)

In the commercial sector, the model is able to explain 67.5% of the variation between state consumption/GSP. There is a relationship between high efficiency commercial building codes, EERS, higher commercial electricity price, and reduced commercial consumption. However, the existence of personal tax incentives is associated with increased commercial energy use in the model. It is not clear why personal tax incentives would affect commercial energy use, but it is possible that the existence of those incentives indicates a prioritization of residential energy use reduction. Further refinements of the datasets and additional data could increase the understanding of why these variables are significantly correlated with commercial energy efficiency.

TABLE 5: IMPACT OF POLICY ON COMMERCIAL EFFICIENCY: COMMERCIAL CONSUMPTION/GSP (2008 INCENTIVES)

Variable	Beta	P-Value
Constant	2,029.5	0.000
High Efficiency Commerical Building Code	-104.7	0.042
2008 Personal Tax Incentives	154.4	0.010
Average Commercial Electricity Price (2009)	-48.8	0.000
Energy Efficiency Resource Standard (EERS)	-193.8	0.000
Adjusted R^2	0.675	
Number of Observations	51	

(11; 12; 22; 23)

3.2 Biomass

Very little biomass capacity has come online in recent years, so finding relationships between current policies and increased development was a challenge. In addition, state policies do not target biomass development in the same way that wind and solar are targeted. In general, biomass development is impacted by factors outside of the policy arena, including feedstock availability and the ability to meet emissions criteria. That being said, this initial analysis into the policies that may be related to biomass development is a first step and indicates that further analysis and refinement of the data is necessary to better understand the relationship between policy and biomass resource development.

The two-year policy lag model is shown here as the Adjusted R^2 is better than in the one-year policy lag model. Only contractor licensing, loans and population are associated with higher capacity and generation from biomass resources, though only population was significant at the 0.05% level. A time lag of two years for loan programs was also associated with higher biomass levels, though not at the 0.05 significance level. Corporate and property tax incentives appear to be a deterrent to biomass development, but those results are not statistically significant and more targeted datasets in subsequent research may illuminate this relationship more clearly.

TABLE 6: IMPACT OF POLICY ON BIOMASS POWER DEVELOPMENT (2007 INCENTIVES)

	Capacity (2009)		Generation (2009)	
Variable	Beta	P-Value	Beta	P-Value
Constant	123.0	0.087 *	475.5	0.120 *
2007 Contractor Licensing	116.8	0.157 *	401.0	0.252 *
2007 Corporate Tax	-103.7	0.094 *	-519.9	0.050
2007 Loans	85.6	0.177 *	457.4	0.092 *
2007 Property Tax	-119.8	0.062 *	-513.5	0.061 *
2009 Population	28.6	0.000	129.4	0.000
Adjusted R^2	0.498		0.526	
Number of Observations	49 (1)		49 (1)	

(1)District of Columbia and Wyoming are removed: zero capacity and generation and none of the policies being tested.

**Not significant at the 5% level.*

(11; 12; 22; 23)

3.3 Geothermal

Similar to biomass, very little geothermal capacity has come online in recent years, and finding relationships between the current portfolio of policies and an increase in geothermal development is difficult. Much of the geothermal capacity in the United States was brought online decades ago, spurred by incentives that have since expired. Like biomass, policies specifically targeting geothermal do not currently exist in the same way that there are policies targeting wind and solar production. While this initial effort at identifying connections between policy and geothermal resource development may illuminate the relationships, further research and data refinement to better connect policies that are truly targeting geothermal development are necessary to better understand the relationship between geothermal development and policy implementation.

Again, the two-year policy lag model is shown here as the Adjusted R^2 is better than in the one-year policy lag model. Industry support, both in 2008 and 2007, is negatively associated with electricity development from geothermal sources. Contractor licensing, loans, personal tax, and production incentives are all positively associated. The number of years an RPS is effective is not a significant variable in any of the biomass or geothermal regression models, but it does appear significant in every wind and solar model. An interpretation and implications of these results are discussed in the following chapter.

TABLE 7: IMPACT OF POLICY ON GEOTHERMAL POWER DEVELOPMENT (2007 INCENTIVES)

	Capacity (2009)		Generation (2009)	
Variable	**Beta**	**P-Value**	**Beta**	**P-Value**
Constant	-225.3	0.004	-1,167.4	0.003
2007 Contractor Licensing	160.5	0.163 *	809.4	0.161 *
2007 Industry Support	-220.5	0.032	-1,105.6	0.032
2007 Personal Tax	178.2	0.043	926.1	0.037
2007 Production Incentives	218.7	0.081 *	1,019.9	0.104 *
2009 Population	31.4	0.000	162.2	0.000
Adjusted R^2	0.498		0.505	
Number of Observations	44 [(1)]		44 [(1)]	

[(1)]Kentucky, Illinois, Georgia, Indiana, South Dakota, West Virginia, and the District of Columbia are removed: zero capacity and generation and none of the policies being tested.

**Not significant at the 5% level.*

(11; 12; 22; 23)

3.4 Photovoltaics

Compared to biomass and geothermal, policies appear to play a stronger role in the PV models, potentially because more policies are tailored toward the development of PV resources. The two-year policy lag model is shown here as the Adjusted R^2 is better than in the one-year policy lag model. Policies currently available, including corporate tax incentives, equipment certification, grants, interconnection, sales tax, and green power all appear to have a negative relationship with PV capacity. However, as stated above, the number of years an RPS is positively associated with PV resource development, implying that it is not the existence of a policy but rather the length of time the policy is in place that drives PV development. Contractor licensing, production incentives, rebates, access laws, and personal tax incentives are all positively associated with PV capacity.

TABLE 8: IMPACT OF POLICY ON PV DEVELOPMENT (2007 INCENTIVES)

	Capacity (2009)	
Variable	**Beta**	**P-Value**
Constant	-28.2	0.265 *
2007 Access Laws	30.0	0.181 *
2007 Contractor Licensing	47.9	0.081 *
2007 Corporate Tax Incentives	-71.6	0.005
2007 Grants	-41.1	0.054 *
2007 Green Power	-33.0	0.189 *
2007 Interconnection	-24.3	0.313 *
2007 Personal Tax Incentives	72.1	0.003
2007 Production Incentives	43.6	0.155 *
2007 Rebates	27.4	0.225 *
2007 Sales Tax	-37.5	0.081 *
2009 Population	9.8	0.000
RPS Effective (Num. of Years)	3.3	0.163 *
Adjusted R^2	0.63	
Number of Observations	51	

**Not significant at the 5% level.*

(11; 12; 22; 23)

3.5 Wind

Wind regression results (Table 9) are similar to the existing literature in terms of the policies that are shown to influence development. In contrast to the other renewable energy technologies, the one-year policy lag model had better results than the two-year policy lag model for wind. Contractor licensing, state production incentives, and having a grade of ―C‖ or better from the ―Freeing the Grid‖ report (21) are negatively associated with wind resource build-out. Industry support and the number of years an RPS was effective are both positively associated with wind power development.

TABLE 9: IMPACT OF POLICY ON WIND POWER DEVELOPMENT (2008 INCENTIVES)

	Capacity (2009)		Generation (2009)	
Variable	**Beta**	**P-Value**	**Beta**	**P-Value**
Freeing The Grid Good Grade	-944.6	0.004	-1,970.2	0.005
2008 Contractor Licensing	-895.5	0.039	-1,845.7	0.042
2008 Industry Support	538.6	0.118 *	1,126.5	0.119 *
2008 Production Incentives	-627.2	0.218 *	-1,113.1	0.296 *
2009 Population	141.3	0.000	282.1	0.000
RPS Effective (Num. of Years)	103.3	0.002	212.1	0.003
Adjusted R^2	0.475		0.457	
Number of Observations	49 [(1)]		49 [(1)]	

[(1)]Alabama and Mississippi have been removed: zero capacity and generation and none of the policies being

tested.
**Not significant at the 5% level.*
(11; 12; 22; 23)

4. DISCUSSION

Generally, results from this analysis align with the existing literature (7; 8; 9), especially in the conclusion that policy, in concert with other macroeconomic factors, is connected with renewable energy development. The findings of this work expand the current body of research to include a more detailed evaluation of the connections between energy use and energy efficiency policies as well as a broader review of renewable energy policies and renewable energy technologies. That is, the current body of literature is primarily focused on the development of wind resources and RPSs, and this work reviews a broader array of clean energy resources and policies, as well as certain macroeconomic factors (e.g., electricity price and population). Several broad conclusions can be drawn from this analysis:

- Policy alone does not explain variability in state clean energy growth. When other variables (including population, electricity price, and number of years a policy is in place) were incorporated into the models, the results better explained the variation among state clean energy development.
- It appears from this methodology that the current set of policies is more targeted at influencing wind and solar development than developing biomass and geothermal resources. This indicates that state policies, while broadly applicable across renewable energy technologies, may not be usable by developers of those technologies because the policies do not meet the technologies' needs. For example, a rebate program with a capacity limit of 5 kW may be available to geothermal project developers, but because electricity generation from geothermal resources is commonly on a larger, multi-megawatt scale, the rebate program may not provide enough of an incentive to drive development. Policies, even if applicable to a wide range of technologies, often are designed to promote one or two specific resources—in this case, wind and solar are targeted far more frequently than geothermal and biomass. Programs tailored to the specific needs of the technology may be more beneficial to renewable energy development.
- Where significant relationships were found, mixes of policies explained growth best. For example, a wide variety of policies contributes to PV development across states. These policies, along with non-policy factors, explain variation among states in wind growth. This may indicate that the specific policies in place are less important than the grouping of policies. In other words, state policymakers that create an environment for investment in clean energy by implementing a suite of policies may be more effective at driving clean energy development than those that choose a single or small number of mechanisms.
- Policies are more connected with clean energy development the longer they are in place. The methodology presented here compared current development with current policies as well as those policies that were put in place in the previous two years. Findings indicate that connections are more pronounced when the time lag is incorporated. This indicates that policy longevity is an important aspect of effectiveness. Furthermore, due to more intensive construction requirements for geothermal and biomass projects, a longer study period may be needed to quantify policy impacts on the development of these technologies.

While the methodology applied in this report produced valuable results, as previously discussed, an evolution of this methodology in subsequent reports may better handle the unique nature of this type of data. OLS regression assumes normality of data, and performing OLS on the ranks of data may result in a better fitting model. Not only would it address the issue of high-leverage values and data normality, but this adjustment would also address the clear outliers in both total renewable energy installed capacity and generation in California and Texas.

This research provides another piece in the understanding of how policy interacts with market development of clean energy. Further experience with policies and research are necessary to better understand these relationships. As policies are in place for longer periods of time, their impacts on clean energy development will become clearer, as it takes time to develop clean energy projects once the environment is established for their development.

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[i] For a broader look at the impact of policy and different factors on the development of energy efficiency resources, see ACEEE's Scorecard for Energy Efficiency (http://www.aceee.org).

HALVING WHOLE TREES AND DOUBLING WASTE: RENEWABLE ENERGY, ENVIRONMENTAL QUALITY AND THE BIOMASS CONTROVERSY IN NORTH CAROLINA

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ABSTRACT

The North Carolina Utilities Commission ("NCUC") issued an unfortunate ruling in October 2010. The ruling permits electric utilities to meet North Carolina's Renewable Energy Portfolio Standard ("REPS") requirements through energy generated from whole trees.

In order to build its domestic energy production capabilities and improve environmental quality, North Carolina must focus on the development of renewable energy. However, using whole trees for energy production is counterproductive, adding to carbon dioxide in the atmosphere, disrupting ecosystems, and damaging North Carolina's forests.

For the purposes of meeting REPS requirements, (1) sustainability provisions should be mandated and (2) for meeting REPS requirements, energy generated from the use of whole trees should be capped or eliminated altogether.

Biomass energy generated from waste, however, should be encouraged. Such energy production reduces overall carbon dioxide emissions and preserves North Carolina's environmental resources.

INTRODUCTION

North Carolina has powerful incentives to develop its own renewable energy sources. Currently, it relies on foreign imports and other states to fulfill the bulk of its energy needs, leaving North Carolina without control of its own energy future and subjecting it to supply disruptions due to events in distant lands.

Fortunately, North Carolina has abundant capacity to develop its renewable energy industry. It already produces significant hydropower and its solar industry is growing rapidly. Wind power has tremendous potential, though its development has so far been hampered by unfortunate political obstacles. Biomass, the primary focus of this paper, has long provided a substantial share of North Carolina's (admittedly small) renewable energy production. With increased demand for energy produced from biomass, largely due the passage of North Carolina's REPS (discussed below), an important debate has opened up regarding what types of biomass can be used to fulfill utilities' REPS requirements. This debate centers especially on whether energy produced from whole trees should be permitted to count toward REPS requirements, with the NCUC recently ruling that it does so count.

The basic argument in this paper is that energy produced from whole trees should (1) be certified as grown sustainably and (2) be strictly limited in the percent of REPS requirements that it can fulfill, or be discounted, or both. As discussed below, the burning of whole tree to produce energy is inefficient and environmentally destructive. The production of energy from waste, however, should be encouraged since it can solve multiple environmental problems while producing much needed energy.

ENERGY PRODUCTION AND CONSUMPTION IN NORTH CAROLINA

North Carolina has tremendous natural resources – a spectacular ocean front with glorious beaches, lovely mountains, rich forests, abundant sunshine, shimmering lakes and beautiful rivers. Still, North Carolina lacks fossil fuel resources, without significant supplies of natural gas, coal, or oil.[1] North Carolina imports all of its petroleum production from other states and from abroad. For instance, in 2008, the latest year for which data is available, North Carolina ranked 12th in total energy consumption, consuming 2702.2 trillion BTU. Of that amount, North Carolina produced 573 trillion BTU, 415.8 billion BTU through nuclear power generation and 167.2 trillion BTU from renewable sources.

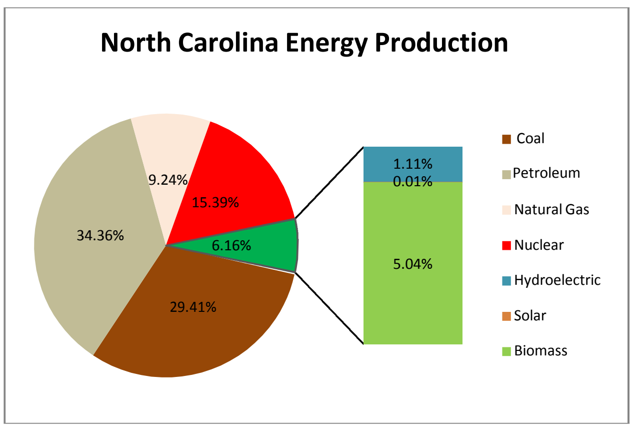

Fig. 1: Energy Production in North Carolina – 2008
Source: EIA,
http://www.eia.gov/emeu/states/sep_use/notes/use_print2008.pdf

While a total of approximately 6% of North Carolina's energy needs were met with renewable energy resources, the percentage of electric power generated by renewable resources is somewhat lower, standing at 4% in 2008. In 2008, North Carolina generated 125 million MWh of electricity. Of that amount, North Carolina produced 35.7% from domestic sources – with 31.8% coming from its nuclear power plants and 4.0% coming from renewables (primarily its hydroelectric dams).

[1] See North Carolina's Energy Profile, United States Energy Information Administration ("EIA").

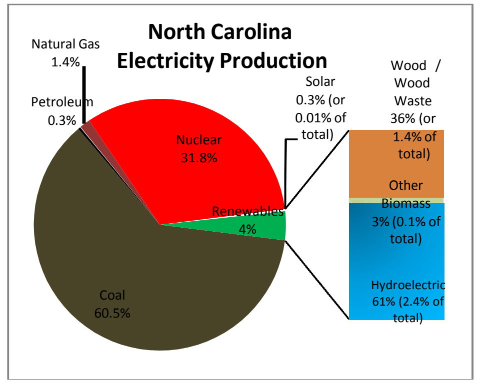

Fig. 2: Electricity Production in North Carolina – 2008
Source: EIA,
http://www.eia.doe.gov/cneaf/solar.renewables/page/state_profiles/north_carolina.html

North Carolina ranked 18th overall in renewable energy generation in 2008.[2] Solar power production capacity has grown considerably in North Carolina since 2008, reaching 12.5 MW by the end of 2009. North Carolina ranked 10th in solar power production capacity.[3] Though the growth of this technology is promising and mirrors national trends, solar power currently only produces a small fraction of North Carolina's electricity. North Carolina has yet to tap its significant potential in wind power. The United States Energy Information Administration ("EIA") estimates that North Carolina ranks among the top 10 states in wind power potential.[4] Nationwide, wind power has provided the bulk of gains in renewable energy production in recent years.[5]

[2] See EIA,
http://www.eia.doe.gov/cneaf/solar.renewables/page/state_profiles/r_profiles_sum.html.

[3] See U.S. Solar Market Trends 2009, Interstate Renewal Energy Council.

[4] See North Carolina's Energy Profile, EIA.

[5] United States Energy Production - 2008

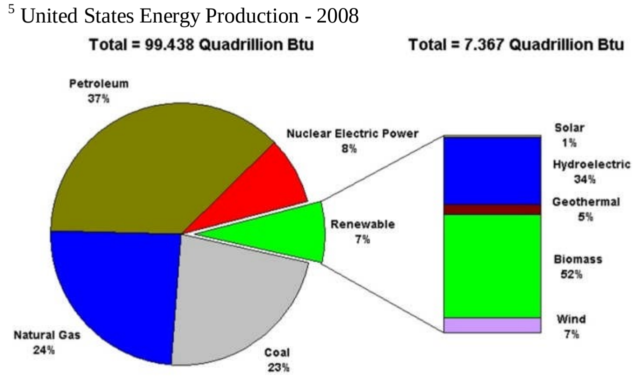

Fig. 2
Source: EIA

NORTH CAROLINA'S RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD

In August 2007, with the signing of Session Law 2007-397 (Senate Bill 3), North Carolina became the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard (REPS).[6] Under this law, by 2021, investor-owned utilities in North Carolina will have to produce at least 12.5% of their energy through renewable energy resources or energy efficiency measures. By 2018, rural electric cooperatives and municipal electric suppliers will be subject to a 10% REPS requirement.

North Carolina's REPS sets mandatory minimums for certain sources of renewable energy production:

Solar:	0.2% by 2018
Swine Waste:	0.2% by 2018
Poultry Waste:	900,000 MWh by 2014

Although North Carolina's REPS apply most directly to the production of electric energy, the law also allows for utilities to meet 25% of their REPS requirement through improved energy efficiency. Consequently, production of other types of energy (e.g., heat) through renewable energy can count towards a utilities REPS requirement so long as it replaces the production of electricity.

BIOMASS

As shown in Figures 1 and 2, the vast majority of North Carolina's renewable energy production comes from biomass and hydropower. There are several ways that energy can be produced from biomass.

United States Energy Production - 2009

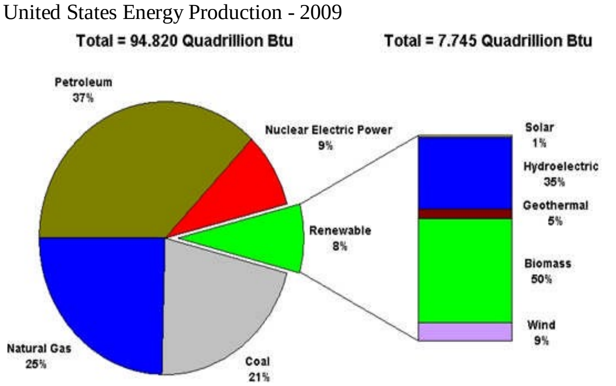

Fig. 3

Source: EIA

[6] North Carolina's REPS is codified as N.C. Gen. Stat. § 62-133.8.

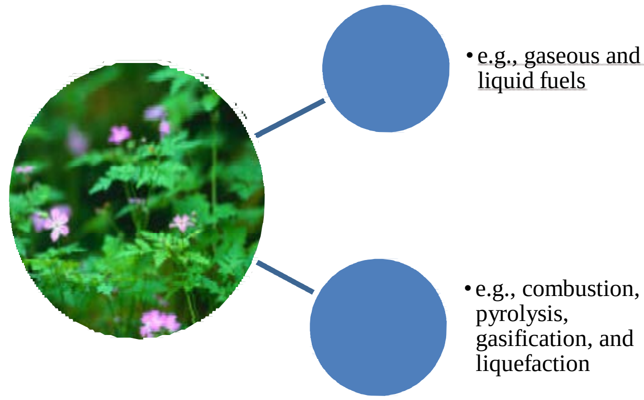

Fig. 4: Energy Production from Biomass
Source: Cantrell 2008.

The U.S. Department of Energy defines biochemical conversion processes as the use of living organisms or their products to convert organic material to fuels. Such conversion processes can be realized by both anaerobic and photosynthetic microorganisms to produce gaseous and liquid fuels. Often the residual by-product from these processes is nutrient-rich and can serve as an alternative fertilizer. The biological-based conversion process requires an extended amount of reaction time (days, weeks or months).

The thermochemical platform is a physical conversion of biomass. This process uses high temperatures to break the bonds of organic matter and reform these intermediates into hydrocarbon fuels, synthetic gas, and/or a charcoal residual.[7] Thermochemical conversion processes can quickly (seconds or minutes) yield multiple complex end-products.[8] Thermochemical conversion processes include pyrolysis, gasification, liquefaction, and combustion.[9]

[7] See Bridgwater, A.V., 2003. Renewable fuels and chemicals by thermal processing of biomass. Chem. Eng. J. 91, 87–102; Cantrell, K., Ro, K., Mahajan, D., Anjom, M., Hunt, P.G., 2007. Role of thermochemical conversion of livestock waste-to-energy treatments: obstacles and opportunities. Ind. Eng. Chem. Res. 46, 8918–8927; McKendry, P., 2002a. Energy production from biomass (part 2): Conversion technologies. Bioresource Technol. 83, 47–54; McKendry, P., 2002b. Energy production from biomass (part 3): Gasification technologies. Bioresource Technol. 83, 55–63

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GENERATING ENERGY FROM WHOLE TREES

In October 2010, the North Carolina Utilities Commission ("NCUC") issued a pivotal decision resolving uncertainty and confusion about the types of biomass resources eligible under North Carolina's REPS. The Commission held that "[w]ood fuel derived from whole trees through primary harvests is an organic material that qualifies as a 'biomass resource' and a 'renewable energy resource'" under North Carolina's REPS (emphasis added). Senate Bill 3 defines "renewable energy resource," in relevant part, as "a biomass resource, including agricultural waste, animal waste, wood waste, spent pulping liquors, combustible residues, combustible liquids, combustible gases, energy crops, or landfill methane." The Commission concluded that (1) the General Assembly did not intend to limit "biomass resource" to the listed items insofar as a term of enlargement (i.e., "including") precedes this list; (2) as organic plant material, whole trees are, at least in its widest sense, a "biomass resource;" and (3) since they grow and can be replanted, whole trees are a "renewable" energy resource. While somewhat troubled by this third conclusion, the Commission was "encouraged" by the steps that Duke Energy (the entity requesting that whole be included in the REPS definition) has taken to ensure sustainability.[10]

There are several problems with including whole trees as a renewable energy resource. North Carolina's REPS contain no requirements regarding forestry best practices or sustainable harvesting of forest products. Consequently, there is nothing to prevent utilities from meeting North Carolina's REPS from energy generated by clear cutting of old growth forest. According to the Environmental Working Group, the annual aboveground growth of U.S. forests counteracts about 14 percent of all emissions from power generation.[11] Cutting down trees will disturb one of our major defenses against carbon buildup in the atmosphere.

Using whole trees to produce energy is doubly inefficient: (a) more carbon dioxide is produced per kilowatt hour using a biomass plant than from using coal or gas and (b) while the carbon in trees is released virtually instantaneously upon burning, re-growth, and the recapture of the release carbon is a long, slow process, requiring decades. Producing electricity from wood biomass is very inefficient, large-scale power plants typically operate at less than 25% efficiency, meaning that for every 4 tons of wood burned only 1 ton is converted to electric power – but all 4 tons emit carbon dioxide.[12] Such power plants emit 1.5 times more carbon dioxide per kilowatt hour than coal plants and 4 more than gas fired plants. The double inefficiency occurs because not only is this carbon released, but the carbon that these trees would have absorbed is now lost – at least for many years.

Finally, using whole trees, especially when clear-cut, can disrupt ecosystems, where trees play an important and complex role. For instance, trees provide habitats, food, shelter, climate control, moisture retention and erosion control.

The Massachusetts legislature recently became concerned enough about the environmental impacts of the use of biomass, especially the use of whole trees, to produce energy that it suspended all applications for certification of biomass plants as renewable facilities. The Massachusetts Department of Energy's final report found that biomass "generally emits more greenhouse gases than fossil fuels per unit of energy produced."[13]

Given these considerations, NCUC's decision to include whole trees as a "biomass resource" and "renewable energy resource" hardly seems consistent with the General Assembly's intention to shift part of North Carolina's energy production to renewable sources. Energy generated from the use of whole trees should be discouraged through a statutory amendment that (a) prohibits the use of whole trees unless they are sustainably harvested and (b) sets a maximum percentage – subject to further empirical study on the environmental impacts – on the energy produced from whole trees that can count as fulfilling a utility's REPS requirement (for example, limiting such energy produced from this source to 20% of a utility's REPS requirement).

GENERATING ENERGY FROM WASTE

While the use of whole trees should be discouraged, the use of waste to produce energy should be encouraged. Currently, North Carolina's REPS mandate a gradually increasing minimum percentage of a utilities' energy production must come from energy produced from waste. This is a useful forcing mechanism and, in February 2010, several major utilities issued a Request for Proposals for converting swine waste to energy. Still, producing energy from waste, with proper environmental safeguards, is especially to be encouraged because it turns a problem,

[10] Perhaps the Commission's interpretation of the REPS is justified based on the language in the bill. If so, this article points more to the difficulties with the bill than with the Commission's interpretation.

[11] See "Clearcut Disaster: Carbon Loophole Threatens U.S. Forests," Environmental Working Group.

[12] See "Clearcut Disaster."

[13] "Biomass Energy and Carbon Policy Study," Massachusetts Office of Energy and Environmental Affairs.

what to do with waste, into a solution, how to produce the energy necessary for a modern economy. Treatment processes can be designed to recover nutrients, solve odor problems, reduce volume, decrease pollution and wastewater runoff, as well as recover renewable energy. [14]

Utilities should be encouraged to go beyond the mandated minimum requirements by incorporating into the statutory language the mandate that energy produced by waste would be inflated from the actual production for the purposes of utilities meeting North Carolina's REPS (for example, producing 2% of a utility's electric energy needs from waste would count as 3%). Given the widely disparate environmental impacts, energy produced from waste should not have to compete head on for resources with energy produced from whole trees.

Further, from an economic perspective, several trends make energy production from animal waste attractive. First, technologies for converting animal waste to energy are rapidly improving.[15] Second, increasing concentration of animals in large scale farming operations makes production of energy from animal waste more cost effective.[16] Third, energy can be produced relatively cheaply.[17] Fourth, North Carolina is the number two producer of hogs in the country[18] and among the largest producers of poultry, eggs, and turkey,[19] which entails that swine and poultry manure is plentiful.

From an environmental perspective, the advantages of converting waste to energy are compelling. In addition to avoiding the problems pointed out above with the use of whole trees, processes such as capture of methane from waste actually prevents the release of a greenhouse gas (i.e., methane) over 20 times more potent that carbon dioxide and makes productive use of this "waste" product. Further, conversion processes can help ameliorate odor and waste runoff problems.

CONCLUSION

North Carolina has powerful incentives to invest in renewable energy resources. First, it is impoverished when it comes to fossil fuels, relying for supply on foreign nations and other states – making it vulnerable to supply disruption. Second, it has significant renewable energy resources – hydropower, wind, solar, and biomass – that can be converted to a reliable source of energy. Hydropower has been used for decades to produce electricity. Solar and wind are both promising resources. The solar energy field is growing rapidly in North Carolina. Wind power has recently gained prominence. Although there is still considerable controversy surrounding this source of energy and although no industrial scale project has yet been cited and built, in the end, the promise is too rich and threats to North Carolina's energy supplies too significant to ignore the development of this resource.

Biomass has long been used as a source of energy. However, with the passage of North Carolina's REPS in 2007, the details of precisely how energy is produced from biomass, and indeed the very definition of "biomass," have taken on increased importance. With the NCUC's recent ruling that energy produced from whole trees can be used to make an electric utility's REPS requirements, the significance of these issues has risen further. Careful analysis shows that converting biomass waste to energy should take priority over using whole trees to produce energy. The environmental benefits to North Carolina are too critical to simply ignore the important distinctions between the sources of biomass energy, and allow whole trees to compete directly with waste for resources to develop energy production facilities. The use of whole trees, on the one hand, should be handicapped both (1) by putting a strict cap on the amount of energy that can be produced from this source and still count as meeting an electric utility's REPS requirements and (2) by discounting such production (perhaps allowing 0.8 of actual production to count towards the REPS requirement). The use of waste, on the other hand, should be encouraged both (1) by increasing the mandatory minimums when the data becomes available to update the current requirements and (2) by inflating such production (perhaps allowing 1.2 of actual production to count to the REPS requirement).

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[14] Cantrell 2008.

[15] Id.

[16] Id.

[17] See www.epa.gov/wastes/nonhaz/define/pdfs/biomass-manure-final.pdf
and http://energy.cas.psu.edu/costcomparator.html

[18] http://www.edf.org/page.cfm?tagID=68

[19] http://www.ncpoultry.org/facts/facts.cfm

REVIEW OF THE FEDERAL ENERGY REGULATORY COMMISSION SMALL GENERATOR INTERCONNECTION PROCEDURES (FERC SGIP) TECHNICAL SCREENS

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ABSTRACT

The Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (SGIP) rule governs the interconnection of non-utility owned distributed generation sources up to 20 MW connecting to FERC jurisdictional lines or making wholesale sale of electricity. These procedures were issued in 2005 and have not been updated since the recent explosion of the PV industry. This study seeks to help initiate an update to the FERC SGIP fast track screens, which determine which generators may use the fast track interconnection process. To obtain input 154 subject matter experts (SMEs) were surveyed. Based on SME consensus, it is recommended that FERC and NARUC collaborate to update the following screens: Screen 2.2.1.7 by redefining the terms of the capacity limit on a single phase shared secondary, Screen 2.2.1.9 by clarifying the stability requirement, and Screen 2.2.1.3 by including area networks and increasing the generation limits. Additional recommendations for further studies and a competitive fairness policy are also made.

1. STUDY BACKGROUND

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers. The Solar ABCs is a collaborative effort funded by the U.S. Department of Energy that dedicates experts to transforming solar markets by improving building codes, utility interconnection procedures, and product standards, reliability, and safety. The first Solar ABCs paper on the topic of interconnection procedures was published in 2008, and titled Comparison of the Four Leading Small Generator Procedures (Keyes & Fox, 2008). The report reviewed the four sets of interconnection procedures that regulators often consider when developing state and local procedures. The report at hand describes a Solar ABCs effort to examine the Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (SGIP) focused on the FERC SGIP fast track technical screens. A detailed report on this study was published by Solar ABCs in October, 2010. (Cleveland et al., 2010). Section 2.2.1 of the FERC SGIP contains several screens used to indentify generators eligible for fast track interconnection (FERC, 2005), and some of those screens may be unnecessarily restrictive for photovoltaic generators. Revising these screens to simplify interconnection and increase the number of systems that pass the fast track screens (and the 10 kilowatt [kW] inverter process) can reduce barriers to PV installations. This project sought to gather expert input and synthesis that input into update recommendations for the FERC SGIP.

2. ROLE AND STATUS OF THE FERC SGIP

2.1 Background on the FERC SGIP

The experience gained over the last decade confirms that distributed generation (DG) is far more likely to be deployed if developers and utility customers can readily discern the costs of interconnection and the length of time required for the interconnection approval process. Although regulators have a challenging task in formulating interconnection procedures, the benefits of implementing procedures that function effectively are substantial.

FERC issued the FERC SGIP procedures as a final rule in 2005 (Order 2006) (FERC, 2005), then clarified and refined the procedures in 2006. FERC developed the SGIP with extensive participation by utilities, regulators, renewable energy advocates, industry, and government experts. Through this process, FERC hoped to minimize the federal-state division and promote consistent, nationwide interconnection rules by adopting many of the best practices interconnection rules recommended by the National Association of Regulatory Utilities Commissioners (NARUC). Incorporated into the final FERC rule was the Small Generator Interconnection Agreement (SGIA). FERC issued the current versions of the SGIP and the SGIA as a final amended rule on August 28, 2006 (see Order 2006-B) (FERC 2006-B, 2005).

Order 2006 (et seq.) required all public utilities that own, control, or operate facilities under FERC's jurisdiction to file standard interconnection procedures (the SGIP) and a standard interconnection agreement (the SGIA) to interconnect generating facilities up to 20 megawatts (MW). The SGIP applies directly to large DG sources interconnecting to FERC jurisdictional lines or those making FERC jurisdictional sales of electricity. For interconnection of DG smaller than a few megawatts, which constitutes the vast majority of such interconnections, the FERC SGIP rarely applies as a result of current FERC recognition of state public utility commission jurisdictions. Small DG sources are usually interconnected to distribution lines which are governed by state interconnection rules rather than to transmission lines where the FERC SGIP would apply.

Unless they're very small, most utilities own or operate some FERC-jurisdictional utility lines. They are thus required to file interconnection procedures that follow the FERC SGIP. There would therefore by some procedural uniformity if DG interconnections to their non-FERC-jurisdictional lines also used the FERC SGIP, or a very similar rule. However, most state's interconnection procedures covering small generators are not directly based on the FERC SGIP. Although the FERC SGIP may have been intended to serve as a model for state utility commissions, as a practical matter the effect of the FERC SGIP as a model has been limited, however it is still well positioned as the federal small generator interconnection rule to serve as a model for state interconnection rules.

Connecting to the Grid is a monthly electronic newsletter published by IREC. Connecting to the Grid editor Laurel Varnado says the FERC SGIP screens have been adopted in a number of state and utility interconnection standards (personal communication, March 12, 2010). According to Varnado, Colorado and Connecticut based their interconnection procedures on the FERC SGIP model, and 14 states use FERC SGIP-based technical screens in their interconnection procedures. Further, the updates suggested in this report are largely based on positive experience with state-originated "best practices."

2.2 <u>Overview of the FERC SGIP screens</u>

The FERC SGIP contains the technical procedures that a small generator and utility must follow when connecting the generator to utility lines subject to FERC jurisdiction. The standards include provisions for three levels of interconnection based on generator size:

- The "10 kW Inverter Process" for certified, inverter-based systems no larger than 10 kW
- The "Fast Track Process" for certified systems no larger than 2 MW
- The default "Study Process" for systems no larger than 20 MW, including those that fail to pass the fast track screens

The standards are embodied in a single set of ten screens for both the 10 kW Inverter Process and the Fast Track Process. Systems that pass all ten of the screens (some state and model small generator interconnection procedures use a subset of the ten screens in the 10 kW Inverter Process) may interconnect without going through the in-depth study process, which requires additional time and expense. The goal of these technical screens is to reduce resistance to adding new DG capacity by providing a quick and simple method to determine which DG systems can be safely interconnected with negligible risk of negatively impacting grid function. The FERC SGIP screens (§ 2.2.1) are summarized below:

- 2.2.1.1: The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Transmission Provider's Distribution System that is subject to the Tariff. (Note: This screen is non-technical and was not reviewed in this study.)
- 2.2.1.2: If the interconnection is to a radial distribution circuit, the interconnection may not facilitate an increase in aggregated generation on the circuit that exceeds 15% of the line section annual peak load. A line section is a portion of an interconnected utility's electric system bounded by automatic sectionalizing devices or the end of a distribution line.
- 2.2.1.3: The interconnection of inverter-based generation may not facilitate an increase in aggregated inverter-based generation to the load side of spot network protectors that exceeds the smaller of 5% of a spot network's maximum load or 50 kW.
- 2.2.1.4: The interconnection may not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.
- 2.2.1.5: The proposed interconnection may not cause any distribution protective devices and equipment or interconnection customer equipment to exceed 87.5% of the short circuit interrupting capability.

- 2.2.1.6: The proposed interconnection must use the correct type of interconnection (3-wire to 4-wire) to the primary distribution line given the type of electrical service provided to the interconnecting customer.
- 2.2.1.7: If the proposed generation is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary including the new generation may not exceed 20 kW.
- 2.2.1.8: If the proposed generation is single-phase and is to be interconnected on a center tap neutral of a 240-volt service, its addition may not create an imbalance between the two sides of the 240-volt service of more than 20%
- 2.2.1.9: The proposed generation may not exceed 10 MW if interconnected to the transmission side of a substation transformer feeding the circuit in an area where there are known, or posted, transient stability limitations (three or four transmission busses from the point of interconnection, for example).
- 2.2.1.10: Construction would not be required by the utility. (Note: This screen is nontechnical and was not reviewed in this study.)

The FERC SGIP screen 2.2.1.2 is of particular interest, because it typically limits the size and number of DG systems that can be interconnected quickly without going through the "Study Process." In other words, it is the screen most likely to be failed as PV systems reach higher penetrations. The technical reasons for the capacity limit are related to minimum daytime load on the line section, not peak load. Specifically, the aggregate DG must never be greater than the load on the line section. However, unlike peak load data, minimum load data is currently not uniformly available to utility planners. The 15% threshold of the peak load is therefore an estimate of 50% of the minimum load on a line section. For most distribution systems, a line section minimum load is in the range of 30% of the peak load. Thus, the 15% limit on aggregate generation capacity would represent only half the minimum load of the line section.

The U.S. Department of Energy's (DOE's) 2008 Renewable Systems Interconnection (RSI) studies attempted to address the 15% line section threshold level defined by Screen 2.2.1.2. These studies modeled some of the impacts of high penetration of grid-tied PV systems. One of the RSI reports on voltage support concludes, "In all the cases studied, PV inverters can positively contribute to the feeder voltage regulation and result in an improved voltage profile. At a high enough penetration, PV inverters may be able to provide feeder voltage support" (Kroposki et al., 2008). However, none of the RSI studies addressed safety issues (i.e. islanding) associated with the 15% line section threshold. This screen was meant to flag interconnection applications that may impact distribution system operation, safety, or reliability—and thus prevent unintended islanding. In addition, inverter-based and rotating generators should probably receive separate treatment in the 15% screen.

2.3 <u>Status of the FERC SGIP Today</u>

In the FERC Order 2006 dated May 12, 2005, FERC stated they "believe that the thresholds used in the screens to be conservative and that there is negligible chance that a proposed interconnection could pass the screens and actually impact the safety and reliability of the Transmission Provider's electric system" (FERC, 2005). The need to update the small generator rules was foreseen in FERC's Final Rule, which stated that "beginning two years from the issuance of this order, [we will] consider and recommend consensus proposals for changes in the Commission's rules for small generator interconnections" (FERC Docket RM02-12-000, 2005). To the authors' knowledge, the study described in this paper is the first review of the fast track screens or proposal to update the FERC SGIP screens.

Currently, interconnection rules in the United States are based upon submissive contribution of grid-tied PV systems. These standards were, of course, originally developed when there was a very low level of penetration of grid-tied PV systems, and even less documented experience. Now is the time to update regulatory rules like FERC SGIP based on the decade of experience since the foundations of these rules were codified. Updated rules based on these experiences may avoid the time delays and expense of unnecessary interconnection system impact studies, prevent regulatory lag, and enforce the replacement of fossil fuel and imported oil – all while maintaining reliability and safety. California is currently overhauling their state interconnection rules in preparation for gigawatts of PV installations expected in the near future.

The solar industry has steadily reduced the costs of PV DG systems during the past 10 years, and prices for conventional forms of electricity are likely to rise—perhaps substantially—in the coming decade. These trends are almost certain to dramatically increase the penetration of grid-tied PV systems, so it is imperative to prepare for this opportunity by developing regulatory procedures that maximize the contribution of PV systems to the electric power system. In addition to reducing prices, inverter and grid technologies are rapidly advancing, which could enable inverter-based DG to provide additional value such as providing voltage and volt-ampere reactive (var) support. These movements need to be considered when updating interconnection standards.

3. <u>RESEARCH STUDY</u>

3.1 <u>Goal of Study</u>

The goal of this project was to gather the opinions of Subject

Matter Experts (SMEs) who work in the field of small generator interconnections and to synthesis their input along with the recent RSI studies to recommend near-term updates to the FERC SGIP fast track screens.

3.2 Study Methodology

The study used an internet-based questionnaire to collect SME input. We developed the questionnaire, as well as the list of SMEs, with input from energy professionals from across the country who participated in two stakeholder planning meetings, in late 2009, before distributing the questionnaire. The questionnaire was carefully constructed to elicit insightful ideas and opinions from the respondents. The questionnaire asked for SME input on the eight technical fast track screens in the FERC SGIP and about the system capacity threshold for the simplified interconnection process for inverter-based systems currently known as the 10-kW Inverter Process.

The presentation of the survey was modeled after a voter information guide, providing unbiased information supporting both sides of an issue. Prior to the questions about each screen, the questionnaire provided the SMEs a summary of the screen, arguments for updating the screen, and arguments for leaving the screen unchanged. In addition to the arguments, references, examples, and links to relevant reports were provided. The complete questionnaire is available in the Solar ABCs paper. (Cleveland et al., 2010) The following questions were asked about each screen and the 10kW inverter process size limit:

- Question #1:
  Do you support updating this screen?
  (Response options of Yes, No, or Can't answer because _________.)
- Question #2:
  If you support updating this screen, what change would you recommend?
  (One to five possible screen updates were presented in multiple choice fashion, always including the option to write in a response.)
- Question #3:
  Please briefly provide an explanation of your position.

SMEs were required to reply to the first question, but the following two questions were optional. In general, everyone who responded "yes" to question 1 also answered question 2, and the vast majority of SMEs also responded to question 3 for each screen. This provided the researchers with a lot of data with which to work. Demographic information was also collected.

3.3 The Subject Mater Experts

The questionnaire was sent to the following 154 SMEs:

- All Members of IEEE 1547.6 Power System Distribution Secondary Networks Working Group
- All Members of IEEE 1547.7 Distribution Impact Studies Working Group
- Eight additional individuals identified by Solar ABCs (two at national labs, two at utilities, two consultants, and two in the PV industry).

The 37 SMEs who responded to the questionnaire were a good balance between utility engineers and consultants (see Fig. 1).

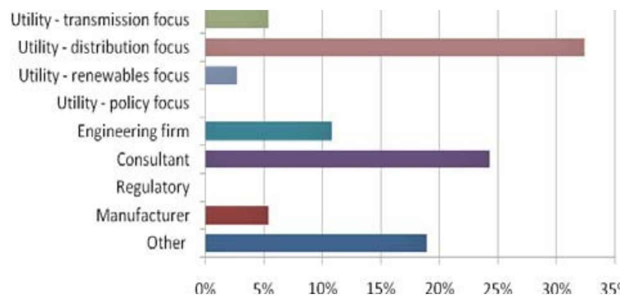

Fig. 1: Industry Position of the Responding SMEs

4. STUDY RESULTS AND RECOMMENDATIONS

A review of the responses found that roughly two-thirds or more of the SMEs (considered a consensus for the sake of this report) recommended an update of only three of the FERC SGIP screens. Based on this and input from other studies, particularly the DOE Renewable Systems Integration studies, we recommend that all three of these screens be strongly considered for updating. We also recommend that a fourth very important screen (Screen 2.2.1.2) be aggressively studied to determine how its penetration limit may be increased so that it does not create an unnecessary barrier to PV development or lead to safety or reliability problems. For similar reasons, we suggest studying the size limit of the 10 kW inverter process to determine the appropriateness of increasing it.

A discussion of the SME questionnaire responses about these four screens and the 10 kW inverter process is below. Detailed response results of the entire questionnaire are available in the original Solar ABCs report on this study. (Cleveland et al., 2010)

4.1 Comparison of Utility Versus Non-Utility SME Respondents

Before providing discussion of the screens with update recommendations we would like to present some additional detail about the questionnaire results. There were significant differences in the responses of SMEs who identified themselves as currently having a role with a utility and those who identified themselves as having a non-utility affiliation. Figure 2 shows a comparison of the support of utility vs. non-utility SME respondents for updating the limits of the 10 kW Inverter Process and each of the eight FERC SGIP screens they were asked about. The issue with the largest difference of position of these two groups was the 10 kW Inverter Process. There was also a significant difference on several other issues. Perhaps most noteworthy are screens #2 and #3 dealing with capacity limits. The non-utility SMEs were more supportive of updating these screens as well as the 10 kW Inverter Process.

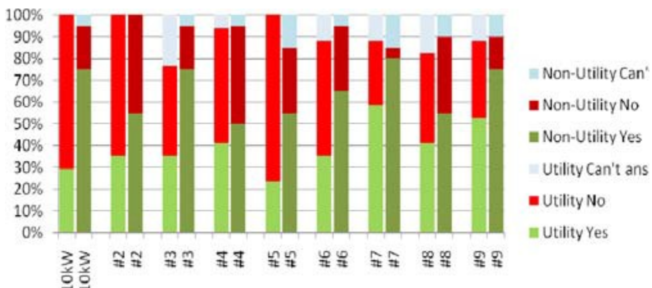

Fig. 2: Summary of SME Responses to Question #1

Surprisingly, only two of the 17 (11.8%) utility SMEs indicated recent DG interconnection experience in California, yet 14 of the 20 (70%) non-utility SMEs indicated recent California experience. More than half of the interconnected inverter-based DG systems installed in the United States are installed in California, so—not surprisingly—many areas with the highest levels of PV grid penetration are in that state. We were interested in the support of SME respondents with DG interconnection experience in California on the issue of updating the 15% line section limit (Screen #2) compared to the support of the complete pool of SME respondents. Of the 17 respondents who indicated California DG interconnection experience, ten said they would support updating Screen #2 (59%) and only seven (41%) did not support updating this screen. Of those supporting updating Screen #2, nearly two-thirds supported increasing the limit to 30% of line section peak load.

4.2 Recommendations for Update

4.2.1 Screen 2.2.1.7

The existing screen is: "If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW."

The vote on this screen was 26 for an update versus 6 against, thus showing the strongest support for change of any screen. The change supported by the majority of the SMEs was to base the screen on a percentage of the transformer nameplate power rating instead of a static system size. The comments in favor of an update include, "I do not clearly understand the technical basis of the FERC 20 kW limit. I personally prefer the limit to be based on service transformer nameplate capacity." SMEs opposed to changing this screen said, "Actually, the aggregate capacity of DG installed on a shared secondary should be limited to 10 kW. Simply because there are two customers on a single secondary does not mean that you can safely double the capacity limit of 10 kW. Although the 65% rule applied to a 15 kV transformer limits the aggregate capacity to 10 kW, applying the rule to larger transformer allows the customer to bypass the capacity rules by installing/requesting a larger transformer. As far as safety, I am leaning slightly towards allowing the 65% transformer capacity rule if each customer is constrained to a maximum of 10 kW. Therefore, I am unable to support the change." There is also a precedent for changing this screen to a percentage of the service transformer nameplate power capacity basis set by New Mexico. Their small generator interconnection procedures have the following screen: "If the proposed Generating Facility is to be interconnected on a single-phase Shared Secondary, the aggregate Generating Facility capacity on the Shared Secondary, including the proposed Generating Facility, shall not exceed 65% of the transformer nameplate rating." Due to the strong SME support in the questionnaire responses and the New Mexico precedent, we recommend that the FERC SGIP screen on shared secondary be updated to a limit based on service transformer nameplate power capacity.

4.2.2 Screen 2.2.1.9

The existing screen is: "The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (three or four transmission busses from the point of interconnection, for example)."

This screen received the second highest number of votes for change—24 voted to change it, nine wanted it to remain the same. Comments ranged from "Utility distribution engineers do not know how to address the screen as it is written now" to "The trouble is, a 10 MW [system] can represent a significant amount of generation depending upon the transmission or sub-transmission to which it is connected. This is particularly true in rural systems. The loss of 10 MW of generation could be significant and result in voltage stability problems. FERC and NERC [North American Electric Reliability Corporation] regulations of stability do not apply [to] voltage levels below 100 kV. Therefore, any change to increase the aggregate capacity above 10 MW should be, at a minimum, tied to system voltage." We believe that this screen is vague and thus frequently misunderstood by SMEs, so it is recommended that this screen be changed to address specific safety or reliability concerns.

4.2.3 Screen 2.2.1.3

The existing screen is: "For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW."

The networks screen vote results were 21 for updating, 11 against, effectively meeting the two-thirds consensus threshold. We believe this screen needs two updates. First, FERC SGIP screen 2.2.1.3 should expand its narrow focus on spot networks, which typically serve one large building, to also address area network interconnections (FERC Docket RM02-12-000, 2005) that may supply several city blocks. Second, the limit should be raised in accordance with new rules adopted at the state level. Specifically, the state of Connecticut drafted a rule on networks stating, "Total aggregate generation interconnected to an area network will be limited to 3% of the maximum network transformer connected kVA with the feeder supplying the largest number of network units out of service, or a maximum of 500 kW, whichever is less" (Connecticut, 2010). It should be noted that this Connecticut rule also defines some additional technical criteria, which cannot be overlooked, but does not change the significance of this 3% or 500 kW rule.

Additionally, Consolidated Edison of New York, Inc. (Con Ed), in an effort to reduce barriers to interconnection of customer-owned DG, announced that inverter-based systems sized between 25 kW and 200 kW may follow the expedited application process for interconnection to the utility's distribution network systems as long as the inverter-based system has been certified and tested in accordance with UL 1741 (November 2005 revision) and the utility has approved the project accordingly. While the Con Ed networks in New York represent the majority of the area networks in the United States, they are not necessarily representative of all U.S. area networks.

Furthermore, the IEEE 1547.6, "Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks," has passed an initial working group vote and is now going through final revisions. When released, the results of this guideline are expected to promote DG interconnection on area networks, and should be considered when deciding on a possible update to screen 2.2.1.3.

4.2.4 Screen 2.2.1.2

The existing screen is: "For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the Small Generating Facility, on the circuit shall not exceed 15% of the line section peak load as most recently measured at the substation. A line section is that portion of a Transmission Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line."

The votes to update this screen were split—18 in favor, 20 opposed. An SME's comment in favor was, "I believe that the majority of the interconnections of (aggregate) gens sized between 15% to 30% of peak load will cause no additional issues, but there may be a few where genuine concerns should be addressed. The key is to have a simple supplemental review process with secondary screens to quickly address the question." An SME concerned about the change wrote, "I think increasing the limit ultimately would be OK if a study focused on min/max loading ratios, time of day aspects, etc., that demonstrates the 15% number is predominantly too conservative an estimate of daytime low load conditions."

The nearly even split in opinion among all the SMEs contrasts with the more favorable response from the California SMEs. Many of the SMEs who voted against raising the limit cited safe operations (islanding) as the issue. Low limits in the screen tend to burden the PV industry with the cost and time delay of system studies. On the other hand, setting the level higher than necessary increases risk and may lead to grid problems, inviting potential backlash that could damage any progress being made in adopting PV. However, raising the limit is vital for continued rapid growth in PV, so it is prudent to determine the appropriate limit. Many SMEs providing input—as well as authors of recent research reports—believe the safe limit is significantly higher than the current 15% limit in this screen. Therefore, we recommend that DOE or NREL develop a study to address the concerns identified by the SMEs and to determine the procedures and limits that will preserve safety and reliability without hampering PV development.

One facet of the solution may be to treat inverter-based generators separately from other generators. Rotating generators (i.e. those powered by engines, wind, or hydropower), which pose more difficult technical questions and may use slower mechanical relays to accomplish interconnection, are treated differently in the codes and standards. The authors believe that they should also receive separate treatment in sections of the FERC SGIP, particularly in Screen 2.2.1.2.

4.2.5 10 kW Inverter Process

"The procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the Section 2 screens. The [10-kW Inverter] application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Attachment 5."

The votes in favor of updating this facet of the FERC SGIP were 21 votes for and 16 against. While these numbers do not reflect a two-thirds majority threshold, we felt that several SMEs who supported an update made strong arguments in favor of it and the arguments made for keeping the existing screen were weaker. For example, one SME with a strong argument explained his support of an update like this, "I favor the increase to 25 kW because of the precedent (in New York, for example), the lack of issues that have arisen from sizes in this range, and most importantly, because the systems still have to pass the fast-track screens. This should adequately protect against systems being installed without proper scrutiny." It should be noted that more than 75% of the SMEs who support increasing the size limit indicated they would support moving the limit to 25 kW or higher.

Even though 16 SMEs did not support updating the screen, their comments shed light on the fact that more dialogue is necessary before a final decision about updating this screen is made. We believe that many of the SMEs who voted against updating this screen may be convinced of the appropriateness of the update if there is an opportunity for open dialogue among SMEs about this screen. For example, one SME said, "Standards such as [Underwriters Laboratories] UL/IEEE/NEC [National Electrical Code] do not address multiple DR [distributed resources]. Twenty-five kW DR, in aggregate, could very quickly cause problems on distribution secondaries," which suggests that this SME did not consider that to be eligible for the 10 kW Inverter Process a system must pass all 10 fast track screens.

Several states (New York and Connecticut, for example) recently adopted small generator interconnection procedures that have a 25 kW system size limit on the streamlined inverter process. Additionally, IREC's model small generator interconnection procedures, which represent best practices, contain a 25 kW limit to its streamlined inverter process, referred to as the Level I process. These procedures were developed more recently than the FERC SGIP, thus allowing IREC to consider recent industry experience with significantly more distributed PV systems than during the development of the FERC procedures.

Considering the responses of the SMEs and the precedents set by the recent state and model small generator interconnection procedures, we believe there is considerable justification to increase the inverter process system size. Despite the lack of a two-thirds majority for updating the screen, but due to the positive responses from many of the SMEs, a lack of issues with systems this size, and the recent precedents set by state and model small generator interconnection procedures, we believe FERC and NARUC should facilitate additional dialogue on the issue and consider increasing the system size limit for the Inverter Process.

4.2.6 Other Screens

For the remaining screens, no consensus was reached by the SMEs. They were mixed about their support of updating those screens, and many mentioned serious concerns regarding both the current versions and the considered updates of these screens. We believe that the process to address issues and concerns in the remaining screens requires additional interactive discussion that is beyond the scope of this report.

4.2.7 Competitive Fairness

Prior to February 2008, utilities were not eligible to receive the 30% investment tax credit (ITC) for PV. When the law was amended to extend the ITC to investor owned utilities (IOUs), it resulted in a dramatic increase in utility solar installations. According to SEIA, the utility installations increased from 22 MW in 2008 to more than 240 MW in 2010. Allowing access to the ITC by IOUs subjects the marketplace to an increased potential for conflicts of interest—when the utility directly competes with non-utility competitors who need the utility's interconnection, for example. The utility's business interest for promoting its own PV installations presents a clear conflict with its role as aggregator and interpreter of study information, federal and state regulations, and industry guidelines for PV installations. Without clear direction from regulators, utilities might discriminate against competitors to maximize shareholder value.

Anecdotal problem reports are abundant. For example, the authors know of a situation in which a utility installed a 3.7 MW synchronous generator on its system without a transfer trip or three-phase circuit breaker, even though it consistently requires both pieces of equipment for interconnection of customer-owned facilities. The cost savings evident in the discriminatory requirements give the utility a significant advantage. This denies the public the benefit of a real market, and allows the beneficiary of a state-granted monopoly to use its monopoly power for its own gain.

Fair-trade practices require utility-owned PV and non-utility-owned PV providers to follow the same rules, often known as anti-discrimination. Therefore, the Solar ABCs recommends that FERC and NARUC be vigilant in ensuring that utilities follow the same procedures that are imposed on other generators. This might be achieved by jointly developing an enforceable non-discrimination policy or rule to ensure uniform application of the technical requirements of all DG systems, regardless of whether they are utility-owned.

5. RECENT CHANGES IN CALIFORNIA SGIP

On December 16, 2010 FERC approved tariff revisions proposed by the California Independent System Operator Corporation (CAISO) revisions to the CAISO generator interconnection process. CAISO proposed to harmonize its large generator interconnection procedures (LGIP) and its small generator interconnection procedures (SGIP). According to CAISO, the proposed tariff revisions, known as the generator interconnection procedures (GIP), are necessary to address inefficiencies in CAISO's current process for interconnecting small generators to its transmission system due to an increasing volume of small generator interconnection requests and the conflict between CAISO's study processes for small and large generators. CAISO states that the proposal addresses these issues by adopting, in most cases, an integrated cluster study process for both small and large generators, as opposed to the current serial process for small generators. (FERC, 2010). CAISO must now conform technical requirements for small and large generators to a single standard, and develop study methodology to determine voltage impacts pursuant to FERC's 2010 order

The modification of CAISO's tariff has prompted some of the California utilities to seek to mimic the same procedures so that they can effectively conduct studies which require coordination with the CAISO's cluster studies. PG&E and SCE both filed at FERC this month seeking to substantially revise their Wholesale Distribution Access Tariffs, which previously had closely followed the FERC pro forma SGIP, in order to better match up with the CAISO process. As other RTOs and ISOs consider adoption of the cluster study approach we could see similar filings by utilities. However, it is not clear that it is necessary for the utilities to mimic the ISO's process and California poses a unique set of circumstances due to the high number of wholesale interconnections being sought as a result of implementation of the state's RPS program. Once FERC rules on the changes proposed by PG&E and SCE it will become more clear how willing FERC is to approve modifications to the pro forma SGIP.

6. ACKNOWLEDGMENTS

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SOLAR 2011: WHY BOTHER? CAPTURING THE VALUE OF NET METERING IN COMPETITIVE CHOICE MARKETS

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ABSTRACT

In regulated electricity markets, net metering can be a relatively straightforward transaction between a utility and an electric customer. The introduction of retail choice and competitive suppliers, however, present complicating factors which are not widely appreciated. This paper follows the authors' prior work describing the operation of net metering in retail choice states to explore what net metered distributed generation means to competitive suppliers. It begins by reviewing the mechanics of net metering operation in retail choice markets. It continues by describing how behind-the-meter generation is valued in wholesale electricity markets, whether these practices provide value for competitive suppliers, and how distributed generation may fit with a competitive business model. The paper follows up with further considerations regarding marketing and customer sign up, power purchase agreements and rate structure. It concludes with recommendations for ways to more fully integrate customer-sited distributed generation, net metering, and retail choice.

1. INTRODUCTION

Net metering has long been identified as one of the most important, least-cost policies by which owners of solar or other renewable systems may recoup their energy investment and ultimately save money on electricity purchases. Similarly, the potential for consumer electricity cost savings is typically among the chief justifications for opening electricity markets to retail competition.

Due to the diverse and complex nature of retail choice markets and the frequent lack of statutory and regulatory clarity on how net metering and competitive supply options operate in conjunction with one another, net metering in restructured states has traditionally not been well understood in the industry. In a prior research report published in December 2010, titled, *The Intersection of Net Metering and Retail Choice, An overview of policy, practice and issues*, the authors identified the basic net metering requirements placed on competitive suppliers and the crediting mechanisms between competitive supplier, utility, and customer in each of the 14 states which offer retail choice.[1]

The "retail" transaction involving the customer-generator, typically defined to some extent by state net metering laws, is only a part of the picture. This paper builds on the December 2010 study to describe in greater detail the implications of distributed generation (DG) for competitive electricity suppliers.

2. BACKGROUND ON RETAIL CHOICE AND NET METERING

2.1 Retail Choice

The electric industry is essentially a sum of its component pieces: production, transmission, distribution and customer service. Traditional, vertically integrated electric companies incorporate all four of these elements. As a result of restructuring in 14 states, plus the District of Columbia[2] beginning in the early 1990's, these functions are performed by separate companies, comprised of : competitive suppliers that provide energy, distribution utilities that deliver the energy, and end-user customers, all operating in a functioning, competitive energy market.

Competition was introduced into the electricity market to encourage greater efficiencies on the grid and reduced costs to the end user. [3] Many researchers argue, however, that competitive markets do not encourage renewable energy investments due to their inherent purpose of finding the lowest-cost electricity for customers.[4] Others argue that "competitive electricity markets provide the lowest possible cost resources, improve reliability, and are good for the environment because they reduce pollution through improved operations, more efficient generating plants, greater demand responsiveness, and market entry by renewable resources."[5] Despite over a decade of experience with competitive markets, the jury is still out on whether competitive markets encourage or discourage renewable energy investments, in aggregate.

2.2 Net Metering and Competitive Suppliers

As detailed in the *Intersection of Net Metering and Retail Choice* report, five states require competitive suppliers to offer net metering, seven states explicitly do not require them to offer net metering and the remaining four states' rules are silent on the issue. Regulatory silence is a troublesome because it creates uncertainty for all involved. However, even in states which place a net metering obligation on competitive suppliers, the enforcement of such a requirement is problematic. After all, competitive suppliers choose their own customers, which leads to questions about how an obligation to provide service to net metered customers could be enforced. Ultimately, it may rest on the willingness of competitive suppliers to offer net metering service or otherwise serve DG customers out of simple good faith, or because doing so is economically advantageous.

So why would competitive suppliers want to have a DG customer? At first glance, it seems as though serving net metering customers is diametrically opposed to goals of competitive suppliers (i.e., the sale of electricity) because customer generation reduces purchases from the supplier. While this argument does have merit, we believe that it is overly simplistic and that there are in fact a variety of other incentives and disincentives involved. The following sections describe both the energy related and non-energy related considerations of DG from the perspective of a competitive supplier.

3. CUSTOMER-SITED GENERATION AND WHOLESALE ELECTRICITY MARKETS

3.1. Overview

On a real time basis, the energy production of a distributed generation customer can be separated into two distinct quantities: the energy produced and used immediately on-site, and the energy exported to the electric grid when on-site demand is lower than production. The first quantity is the functional equivalent of energy conservation or energy efficiency (i.e., forgone grid consumption). The second is akin to wholesale energy production, albeit at much smaller scale than that typically found in the electricity industry.

From the perspective of the customer, the value of the first quantity is equivalent to the retail value of the volumetric energy charges paid by the customer. The value of the second quantity is generally determined by state net metering laws (or lack thereof). From the perspective of an electricity supplier providing service to a distributed generation customer, the value of both quantities is determined by the wholesale energy market and how it operates.

3.2 Wholesale Market Settlement

Market settlement is the process by which a wholesale market operator (e.g., the Electric Reliability Council of Texas, a.k.a. ERCOT) determines how much a market participant owes or is owed for the provision or use of market services over a specific time period. In terms of energy, the basic idea is that each unit of energy that is put on the grid or pulled off the grid has a specific value according to when it was generated or used. For the purpose of settlement, energy use must be balanced exactly with generation, imports, exports, and losses (i.e., energy in = energy out). The process itself can be exceedingly complicated and the details vary from market to market. However, the following simplified description is useful in understanding where customer-sited systems fit into the larger wholesale electricity picture. This description is based largely on the description of real time energy settlement practices contained in the Pepco Holdings Inc. *Supplier Operating Manual*[6], but similar processes exist in other jurisdictions.

A competitive supplier serving retail customers can be seen as an energy purchaser at the wholesale level. The customers that the supplier services have a demand for energy that varies over the course of each day, and which collectively must be met in real time with an equivalent amount of generation. The supplier therefore has a time-varied *energy obligation* for its collective customers within a given geographic region. Because electricity prices vary significantly over time, for settlement purposes the energy obligation is broken into smaller intervals (e.g., hours or even shorter intervals). Using hours as the interval, a supplier has an hourly energy obligation for each of the 24 hours of the day.

On a daily basis, a supplier's hourly energy obligation for a given region is arrived at using a combination of actual metered data and estimates of customer usage. The calculation process is typically performed by a utility for customers and their suppliers within its service territory. For customers with interval meters which are read daily, actual values would be used. For most customers however, meter reading does not take place on a daily basis, so hourly loads are estimated using load profiles. A customer load profile is a representation of how the electricity use of a given type of customer is expected to vary over time, adjusted for a variety of potential factors (e.g., weather, location, etc.). On a daily basis, each customer is assigned an hourly load value based on actual or estimated hourly use. This value is then typically adjusted to incorporate expected energy losses in the electric transmission and distribution grid. The hourly values are summed together to arrive at a preliminary estimate of a supplier's hourly energy obligation for its collective customers. This is "energy-out" part of the equation.

The "energy-in" part of the equation for a given area is measured by the meters installed at all points from which energy can enter or leave the system. The energy-in and energy-out values must match for settlement purposes, but in reality the sum of all hourly supplier energy obligations for a geographic area (i.e., a utility service area) will not match the total load that the market operator calculates for that area based on metered generation, imports, and exports. The difference could be positive or negative and is often referred to as unaccounted-for energy (UFE).

Accounting procedures for UFE vary, but in this case an adjustment is applied across all hourly supplier obligations within a geographic area on a pro-rated basis. In other words, a supplier with 5% of the total load from 10 AM – 11 AM would be allocated 5% of the UFE calculated (positive or negative) for 10 AM – 11 AM for that day. A supplier's "bill" for real-time energy purchases is based upon this hourly energy obligation as well as a variety of other factors (e.g., energy purchases from the day-ahead market), price at some variation of the hourly market price.

The aggregation process described above takes place on a daily basis. A further reconciliation is necessary to incorporate actual meter data from customers whose meters are read on a monthly rather than a daily basis. The methodology is essentially the same; actual hourly metered values are used if they are available and load profiles are used to estimate hourly load if this is not the case.

3.3 <u>Potential Value of Customer-Sited Generation</u>

It is indisputable that just as generation from a typical centralized power station has value, so does the much smaller amount produced by a customer-sited energy system. However, in an industry dominated by large central station power plants, small customer-sited energy generation is in many cases relegated to being an afterthought (or perhaps a never thought). The immediate consequence of this is that customer-sited generation may be left out of bulk electric power market protocols and ultimately not valued on equal footing with more conventional wholesale power generation. Under these circumstances, whatever the potential, it remains unrealized.

An overview of the ERCOT market settlement procedures is instructive in understanding where potential value lies and how it can be realized. In ERCOT settlement procedures, the use of customer-sited solar in distributed applications can benefit suppliers in two ways. The first way a competitive supplier in ERCOT can benefit from serving a solar customer is due to the fact that all other things being equal, solar customers tend to have lower energy demands during the middle part of the day because this is the time when a solar system produces the most energy.

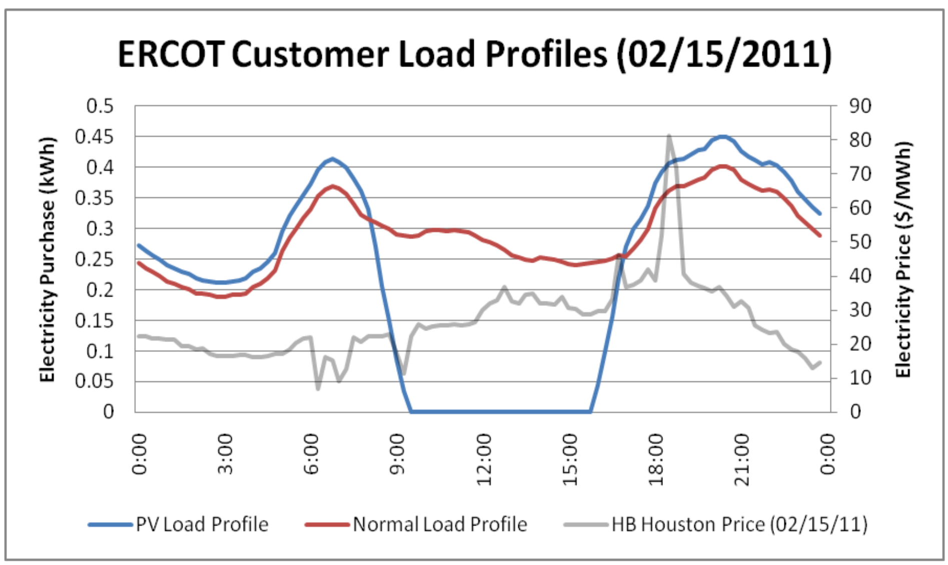

Fig. 1: ERCOT Customer Load Profiles for 2/15/2011.

The ERCOT settlement process recognizes that customers equipped with DG systems have different electricity purchase patterns than non-DG customers, and that different types of DG system (e.g., solar, wind, etc.) have different characteristics which also affect the temporal variation in customer electricity demand. This is illustrated by the use of solar specific load profiles for customer loads that are not equipped with interval meters.[7] Figure 1 shows a graphical representation of the back-casted (i.e., actual) load profiles for February 15, 2011 which would apply to a residential electricity customer in the coastal region of ERCOT with a high winter demand, varied by whether or not the customer site is equipped with a PV system.[8] The graphic also includes representative electricity prices for the same time period and location.[9] February 15 was chosen simply because load profile and price data for that date were easily obtainable.

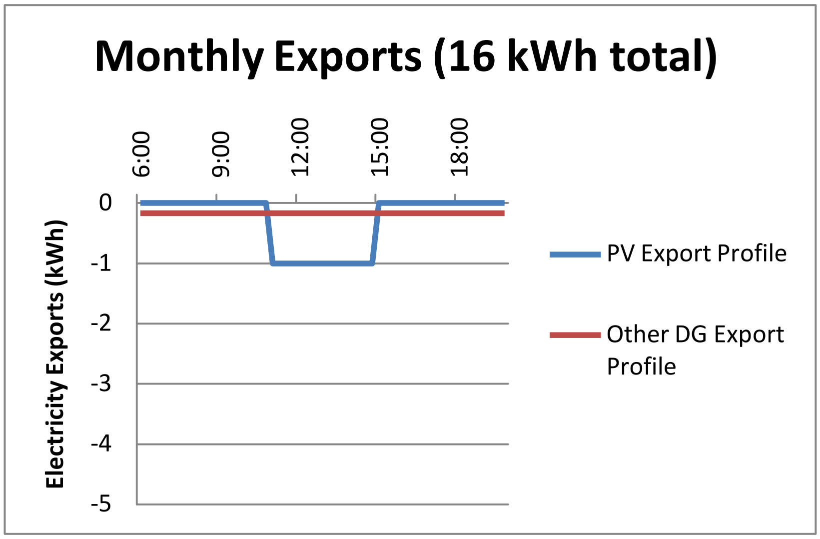

Fig. 2: Monthly Exports (16 kWh total).

The PV customer's load profile shows an obvious dip during the middle part of the day where the customer requires a lower amount of electricity from the grid due to the electricity produced by the PV system. The potential benefit to the supplier depends on how wholesale electricity prices vary over time. If prices are comparatively higher during time periods when the PV system is producing significant amounts of energy (i.e., lowering grid purchases), the average cost the supplier bears for serving this customer will be lower than for an otherwise similar non-PV customer.

The second way a supplier may benefit from serving a PV customer is based on the value of the electricity exported by the system. Figure 1 shows that for a significant period of time throughout the day the customer has a load of zero, or less as the case may be, though the profile is not actually permitted to go negative. ERCOT uses a separate methodology to account for electricity exports. As illustrated in Figure 2, ERCOT addresses the value of exported energy from non-interval-metered customers by measuring the volume of gross exports for a billing period and evenly distributing it among the 16 pricing intervals which define the daily period from 11 AM to 3 PM. This exported energy is subtracted from the supplier's load through the aggregation and settlement process. For other distributed generation customers who are not on interval meters, the exports are applied evenly to the supplier's load across all intervals.[10]

Again, the ultimate benefit to the supplier depends on wholesale electricity prices for the period in question, as well as the level of compensation paid to the customer for this exported energy (if any).

The reader should also note that while the processes described above are specific to profiled customer loads, the effect would be similar for customers with interval meters. Indeed, the use of interval meters which can accurately collect time-differentiated data on customer imports and exports essentially places the customer-sited systems on a similar playing field to traditional wholesale generators in the energy value arena. The use of a solar load profile in ERCOT, while interesting, is essentially a second-best option if the goal is to accurately value the energy produced by customer-sited energy systems at the wholesale level.

3.4 Settlement and Value Issues

While the ERCOT example provides some insight into how customers-sited energy production *could* be valued, in practice the ERCOT system is unique, both in the use of solar load profiles, and in providing a well-defined system for valuing generation in excess of on-site needs. In other wholesale electricity markets the protocols are frequently unclear as to the place of customer-sited generation. As a result, utilities which perform the load aggregation and summing processes for settlement are seemingly left to their own devices, and our research indicates that treatment varies by utility.

To the authors' knowledge, outside of ERCOT there are no examples of customer load profiles specific to customer-sited generation for use in energy settlement. In this area, the picture is fairly clear. Utilities publish information on customer load profiles and, due to its importance in the settlement process, such information is typically prominently displayed in the supplier information section of a utility's web site.

Treatment of net excess generation or, in effect, negative load for a given time period, is often harder to ascertain. Despite extensive searching through available documentation (largely standard utility-supplier agreements and utility published supplier manuals), the authors were only able to identify two examples where the issue of excess generation by net metered customers is specifically addressed in the context of load balancing and settlement (Bangor Hydro and Central Maine Power). Several potential scenarios exist depending on utility practices and the information available through actual meter readings.

Scenario 1: Negative load values on an interval or monthly metered basis are interpreted as errors and are assigned zero values in the load aggregation process. This practice results in customer energy exports being classified as UFE (or an equivalent), which effectively lowers the hourly energy obligations of *all suppliers* with hourly energy obligations in a geographic region during a given time period.

EXAMPLE: *National Grid in Rhode Island*. Net metering proceedings in Rhode Island which took place in 2008 suggest that that this scenario applies (at least at this time) for suppliers providing service to net metered customers in National Grid's service territory. National Grid's response to a Rhode Island Public Utilities Commission data request describes an outcome where customer exports reduce supplier settlement obligations for National Grid's territory as a whole rather than for a specific supplier of a net metered customer.[11]

Scenario 2: Negative load values on a monthly metered basis are processed as a reduction in a supplier's hourly energy obligation. For non-interval metered customers, in the absence of a specific methodology for "profiling" excess customer generation, the excess would be applied uniformly across all hourly periods.

EXAMPLE: *Central Maine Power*. The utility addresses net metered customers in standard utility supplier agreements.[12] While these documents do not explain exactly how negative customer loads are addressed, Central Maine Power indicates that negative customer load is expressed as a reduction in supplier hourly energy obligation evenly distributed across all hourly periods for which a supplier's energy obligation is calculated. The utility does not have any net metered customers on interval meters. [13] Notably, the even allocation method is also used for customers in ERCOT that are equipped with other forms of customer-sited generation (e.g., wind) and are not on interval meters.

Scenario 3: Negative load values on an interval-metered basis are applied as a reduction in supplier load for the time period during which they took place.

EXAMPLE: *Pepco, possibly other Mid-Atlantic utilities*. Comments made by Washington Gas Energy Services during recent net metering rulemaking proceedings in Maryland suggest that several utilities support this methodology, but it remains unclear if, and how widely, it is being implemented. The comments do not address an equivalent accounting procedure for non-interval metered customers.[14] Pepco personnel indicate that hourly supplier loads reported to the PJM are reduced for negative customer load up to the zero point for negative meter readings of interval customers but that PJM does not accept negative values for hourly energy obligations. Non-interval negative loads are assigned zero values so they do not reduce supplier hourly energy obligations, effectively becoming UFE.[15]

These examples highlight practices which could prevent a supplier from realizing value from customer energy exports, or lessen that value. The use of non-interval meters is likely to result in any exports being applied evenly across all time intervals. The value that photovoltaic systems add by producing energy during day time hours when electricity is typically more valuable is lost under these circumstances. Moreover, as indicated in Scenario 3, it could be that non-interval metered exports are not reflected as reductions in supplier hourly energy obligations.

Interestingly however, if exports do accrue to the grid as a whole instead of to a specific supplier, it would likely be to the supplier's advantage for the exports to come from a non-interval-metered customer. A recent analysis based on Maryland customer load and insolation data indicates that the monthly net excess generation zero point (i.e., no months with monthly negative load) is associated with average annual system energy production sufficient to cover 65% of residential consumption and 72% of commercial consumption (referred to as the *coverage* ratio). On an hourly basis though, the report suggests that customers with a coverage ratio as low as 20% will likely have some hours of net excess generation.[16]

A further possibility is that the supplier's total hourly load obligation (the aggregate of all its customers) could be negative. The likelihood of this seems exceedingly small since net metered customers are a small part of the electricity consumer customer base (competitive or default), and even for systems with high coverage ratios, on an hourly basis the net excess generation from these customers will only be a fraction of the actual energy produced by the system. This would be balanced by positive energy usage at a higher rate per customer over a much larger customer base. Unlikely however, does not mean impossible (e.g., a supplier with a single large industrial customer), and as described in the Scenario 3 example, such negative values may not be accounted for in the settlement process.

4. OTHER IMPLICATIONS OF HAVING DG CUSTOMERS

In addition to the treatment of DG in wholesale load settlement, there are also other considerations for a competitive supplier as it contemplates serving a DG customer. The following section describes several of these issues.

4.1 The Sales Reduction Disincentive

Serving DG customers presents an obvious quandary for competitive suppliers. How is a supplier to make money selling energy if its customers are supplying their own needs, and upon occasion, producing more than they need and even receiving compensation for this excess? The disincentive is not insignificant, but we think it is likely less significant than it initially appears to be.

For one, customers who will be purchasing little or no energy are not likely to be in the competitive supply market in the first place. From the customer perspective, there simply is not much point to pursuing competitive supply options if grid electricity purchases are minimal anyway. Following this line of thought, the group of DG customers who remain potential competitive supply customers must still have significant energy costs. If such customers see value in exercising their retail choice option, it seems as though there must also be value in providing them with energy service.

The supplier's dilemma does however include at least one other element: opportunity cost. Does pursuing a "lower value" DG customer prevent or inhibit a supplier from signing up more lucrative customers? It is reasonable to believe that there is at least some cost. After all, marketing, sales, and negotiation take staff time and resources, which would then be less available for other potential customers. If this cost is greater than the money to be made on sales to the DG customer, the supplier has little reason to offer service. The magnitude of this concern is not clear to the authors at this time.

4.2 Marketing and Increased Customer Sign-up

From discussions with competitive suppliers, the marketing value of "green options" may be one of the most valuable aspects to a competitive supplier. The ability to market their services to a customer that may or may not install DG, but who wants to keep the option open, essentially expands the pool of potential customers available to the supplier. All other things being equal a customer who is interested in solar is more likely to sign up with a competitive supplier that provides an option for customer-sited DG, rather than one that does not allow it. For a supplier that does not offer net metering service, the increasing prevalence of customer-sited energy generation represents a diminishing pool of potential customers.

Competitive suppliers usually "lock-in" customers with contracts of varying length. Contract termination penalties, in addition to the burden associated with investigating and choosing another supplier may discourage a customer from switching suppliers frequently. Thus, the benefit to a supplier is perhaps two-fold. The supplier has a new customer for the immediate term of the contract, but it has also has the advantage of a longer term relationship in the form of contract renewals, provided of course that the customer remains happy with the service and terms being offered.

To build upon the prior section, the appropriate comparison is not between having a DG customer and having a customer with "normal" electricity use levels (normal sales vs. lower sales) but between having a DG customer and not having a customer at all (lower sales vs. no sales). As evidenced by the prevalence of "green" supply offers, it is also clear that a well-established market for environmentally conscious energy purchases now exists.[17] In some circles distributed renewable generation is considered even "greener" than other forms of renewable energy. A proven record of supporting distributed generation may therefore have additional marketing value beyond customers who have seriously considered DG options.

4.3. Business Diversification through Power Purchase Agreements

The third-party power purchase agreement (PPA) model has become increasingly prevalent in the solar industry during the last several years. Under the PPA model, the service provider owns a PV system on the customer's property and sells that customer the energy from the system for a set contract term (often 10 years or longer). The solar energy sales allow the provider to recoup their investment over time and make a guaranteed return on that investment. The customer, on the other hand, does not have to bear the burden of upfront system costs and generally does not have to worry about the operations and maintenance of the system. While now common in the solar industry, the model has appeared more recently in a handful of service offerings from energy service providers not specifically oriented around solar energy (e.g., Con Ed Solutions, Constellation New Energy, Washington Gas and Energy Services). The competitive suppliers offering this service have added a variation to the model by also offering commodity energy service for the balance of on-site energy needs.

There are several interesting results of this arrangement. For one, it eliminates the effects of customer-sited distributed generation on energy sales to the customer, and from the perspective of the supplier, circumvents the issue of offering net metering service to the customer. The existence of the long-term PPA also creates a firm long-term relationship between the supplier and the customer, potentially increasing opportunities for the provision of other services (e.g., commodity energy service).

A further implication is that owning a customer-sited solar system potentially increases a supplier's flexibility in meeting mandatory renewable portfolio standard (RPS) obligations. If the supplier owns the solar RECs (which it typically would), it could use them to meet the RPS obligations it carries for its other retail sales, or it could sell to other parties with RPS obligations. The potential benefit to the supplier in this area is to shield it from, or position it to take advantage of, price volatility in solar REC markets, while also improving its ability to plan for meeting its RPS obligations far into the future.

4.4. Service Costs

The administrative and billing costs associated with net metering have recently been studied by several state public utilities commissions, including California and New Jersey.[18] These and other studies have shown that utilities use different formulas for assessing net metering costs, and while the overall cost is minimal compared to other utility programs, it is not zero. While not all of these costs are a concern for competitive suppliers (e.g., forgone distribution revenues), some are potentially applicable.

A supplier may bear costs associated with customer compensation for net excess generation which it is unable to recoup (see Section 3 for details).Moreover, a supplier may bear costs for billing and other administrative procedures if it operates a separate billing system from the utility. There is also the possibility that a lack of experience with DG customers, or lack of information on the patterns of DG customer electricity usage could lead a supplier to make sub-optimal decisions in arranging energy supply for a DG customer.[19] Costs which are minimal to a utility may be more significant to an individual supplier operating on a significantly smaller scale.

5. DISCUSSION AND RECOMMENDATIONS

As described in Section 3, inconsistencies exist in how wholesale electricity markets address distributed generation. Above the somewhat technical issues looms a fundamental question of whether such imperfections are significant enough to merit the time, effort, and expense of devising remedial measures. The relative need for change is a matter of perspective.

From the perspective of the bulk electricity markets as a whole, one could easily conclude that it is of minimal importance due to the small scale of customer energy exports relative to wholesale energy generation. Why quibble over a few dollars when millions change hands every day?

An opposing perspective however, is that one of the guiding purposes behind competition is to create an environment where electricity is priced based on its value at any point in time. If this is truly the goal, then systems should be designed to account for the added complexity of customer-sited generation to the extent it is possible to do so. Moreover, with the prevalence of state net metering laws and state renewable portfolio standards which support customer-sited generation, the scale of the issue itself is destined to grow over time.

Yet another perspective is that of the individual supplier. A supplier in any given state is operating at a much smaller scale than the system as a whole, so each transaction has a somewhat greater importance. A final perspective is that of the distributed generation customer who would presumably want to be able to participate in both retail choice and net metering if they so choose. Yet defining the true character of a state-induced net metering "obligation" for competitive suppliers can be difficult and such requirements ultimately may rest on tenuous ground. Assuming that a net metering requirement can be enforced, the supplier bears a cost (i.e., reduced purchases, customer compensation) without being able to realize some of the potential benefits of having such a customer (i.e., lower overall energy costs). The alternative to coercion is to present a supplier with circumstances which support a decision to voluntarily serve DG customers.

Wholesale market treatment of distributed generation is part of this equation, although it is certainly not the only consideration. We have described a series of factors which may influence supplier decisions, although a more quantitative evaluation may be in order for decision-making purposes. It is, however, obvious that some suppliers see potential in DG-based business models, even if some of the appeal seems to rest in avoiding the issue of net metering altogether. The somewhat different approach of using net metering as a marketing tool is not widely apparent, but our analysis of the costs and benefits suggests to us that it has greater promise than is currently recognized.

Improved protocols for addressing customer-sited DG in wholesale markets may be a large part of the solution. Allowing suppliers to realize tangible energy cost benefits from DG customers would almost certainly affect how they view DG customers as a whole and how they market their services. Enhanced metering systems with interval data recording capability will likely be part of this, albeit costly. A good middle ground between the status quo and a fully revamped metering infrastructure could be the use of load profiling and accounting procedures such as those currently used in ERCOT. While this strategy undoubtedly would involve a certain amount of time and expense as well, it seems as though the relatively simple ERCOT model could serve as a good example.

In this regard, simplicity is paramount. The issue of wholesale valuation of net metered energy is at this point relatively minor when seen in the context of the wholesale electricity markets in aggregate. Elaborate mechanisms are not needed to improve on the current state of affairs. Moreover, ERCOT enjoys the advantage operating only within the confines of a single state. It stands to reason that any uniform treatment would need to be simple in order to accommodate a multitude of possible state and regional circumstances. The issue will certainly bear watching in the coming years as more distributed generation systems are installed among competitive choice customers. Competitive suppliers would be wise to take note of this evolving marketplace and consider ways to evolve their own businesses to capitalize on the opportunities it presents.

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DOES RESOURCE EFFICIENCY LEAD TO SUSTAINABILITY? REFLECTIONS ON THE JEVONS PARADOX

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ABSTRACT

Central to the renewable energy discourse is a focus on improvements in energy efficiency as a major strategy for moving towards a future sustainable society. Yet the savings from energy efficiency do not happen in a vacuum. As opposed to efficiency generated savings, the take-back effect, whereby both the demand and supply-side monetary savings from efficiency measures are re-invested into energy-intensive pursuits, has been estimated at anywhere from 10% to over 100% (The Jevons Paradox).

As scientists and designers, we understand the effects of efficiency as inextricable from the context of multiple intersecting complex adaptive systems. We propose a concrete on-the-ground operational system that establishes a new paradigm of development – a city that in both form and function is dynamically responsive to the synergistic and cumulative effects of human actions in a world of limited environmental resources. By flipping conventional analytical tools on their head, we create a holistic game-based approach to resource and waste issues. This allows sustainability to become an answer to the question: “Building different socially and scientifically generated design scenarios, how can we manage available ecological resources to support the highest sustainable quality of life among our citizens?”

1. RESOURCE EFFICIENCY AND ITS DISCONTENTS

We live in a time of great confluence in global trends. As the population of the planet explodes, the demands on energy and material resources are also climbing at unprecedented rates.[1] Simultaneous to these demands, the scientific consensus is established that the extraction and burning of fossil fuels poses dire consequences for the biophysical health of all life on the planet.[2] We are observing rising global temperatures and sea levels, a cataclysmic rate of species extinction, increased volatility of major storms, as well as incidence of devastating drought- the growing list of consequences is by now quite familiar. Indeed, the effects of global change are well underway and already being felt by millions. The confluence of these trends poses serious consequences for the way in which we will all live in the future.[3]

1.1) New Policies for a Changing World

Increasing scarcity of access - coupled with a moral and political imperative to establish policies for coping with carbon emissions head-on, promises sweeping changes in the way we manage and consume material and energy resources. The more of us there are on the planet, the more difficult mitigating these consumption-based problems will become.[4]

Though no human being will be left beyond the reach of each of these trends, it is difficult for either individuals or governments to know what measures to take to either counteract or adapt to them. Resource efficiency measures reign unquestioned as a best place to start, and these measures have become increasingly popular policy approaches for tackling both resource scarcity and carbon emissions.

By now these initiatives are quite familiar to those in all sectors of the consumption cycle: compact fluorescent lighting, better fuel economy, increased building insulation, streamlined manufacturing processes, recycled materials, reusable components, etc. For the most part, efficiency measures enjoy political popularity, acting in congruence with an established way of life and of doing business.[6] They ask of us: "How can we continue our modern lifestyle, but do it even more cheaply?"

I = PAT

Environmental Impact is a function of Population, consumption of resources (Affluence) and the efficiency with which those resources are consumed (Technology)

Fig 1. The I PAT equation[5] (1971).

The assumption is one of resource decoupling – the theory that in advanced industrial economies, continued technical advance allows for the production of more and more products from fewer and fewer resources.[7] The projected environmental impact from increased Population (P) and Affluence (A) (Fig. 1) is assumed to be counteracted by a concurrent improvement in resource efficiency, or Technology (T). For all of these measures, a major selling point is that they are supposedly both good for the environment as well as (usually for both producer and consumer) for the financial bottom line.[8]

1.2 <u>TheBroaderProblemsofEfficiency</u>

Examined individually, each one of these technologies seems able to provide a "win-win" result. Efficiency pro- ponents can, with good empirical evidence to support their claims, advocate that energy efficiency policies save money for both consumers and producers while also reducing short- term energy use. The compact fluorescent light bulb (CFL) is projected to save 75% of electricity use over an incandescent.[9] Bolstered automobile fuel economy standards from 30 MPG to 20 MPG have the potential to save the average household $880 and almost half a ton of CO2 emissions each year.[10] Yet studies of both individual behavior and economy-wide resource use indicate that these immediate benefits do not necessarily continue as we might expect in a long-term analysis.[11] Where do the savings, of both energy and money, go?

Basic economics tells us that an energy service with a cheaper marginal utility encourages increased usage of that resource. In the case where a driver does not use fuel savings to increase miles traveled, the monetary savings get re-invested somewhere else. Long studied as the consumer "take-back effect" or "rebound effect" by energy economists, a number of critical studies have been appearing, challenging the ultimate fate of energy savings in the macroeconomy. This research examines the essential notion of efficiency aggregated at a community scale, and in many cases offers sobering conclusions. The take-back effect, whereby both the demand and supply-side monetary savings from efficiency measures are re-invested into energy-intensive pursuits, has been projected to be 10-87% in different economic sectors.[12]

1.3 <u>Rebound and the Macro-Economy</u>

As simple as the mechanisms for rebound are to understand, they have proven difficult to measure. A household that is able to save on a monthly energy bill through new insulation or the purchase of a fuel-efficient car makes use of the resulting savings in different ways. Studies of these households show that 10-40% of this savings is reinvested in the same energy service.[13] A car with high fuel economy encourages more driving, and a lower heating bill encourages turning up the thermostat. This type of rebound, called "direct rebound" is relatively easy to measure and its existence is widely acknowledged. "Indirect rebound," where savings are used to purchase a vacation abroad or otherwise invested in different products and services in the economy, proves much more difficult to quantify.

Efficiency savings represent an increased capacity for consumption- patterns that reverberate throughout the economy in multiple steps that elude precise measurement. Economists liken this process as having the same material effects that are seen following an increase in income.

1.4 <u>Rebound,Backfire,andEconomicGrowth</u>

The discipline of economics is poised for a fierce debate. The earth and its resources are finite. Neoclassical economic theory, therefore, has relied upon the theory of decoupling of energy consumption from material affluence as standard of living rises in maintenance of economic growth. Evidence continues to mount in refutation of the paradigm of decoupling. Demand for energy, in both developing and advanced industrial societies, is not showing any signs of peaking. A centuries' long stream of economists have put forward competing theories that challenge the assumed mechanisms of growth and resource use altogether.[14] The progenitor of this debate is the late 19th century economist William Stanley Jevons, also one of the founders of classical economic theory. Jevons' famous paradox proved altogether too true: rather than reducing demand for coal, innovations in the efficiency of the steam engine not only expanded use of the steam engine itself, but set in motion a continuous increase in the demand for coal and for the development of an economy of cheap and widely used fuels.

In the century since Jevons, diverse approaches to both resource economics and the assumed means of macro-economic production have formed a new confluence of interest surrounding the question of resource efficiency. Jevons' original proposition was that the take-back effect could exceed 100%, or 'backfire'. He proposed that an improvement in the mechanism of resource efficiency would not only cause some degree of take-back effect, but that use of the resource in question would also ultimately increase.[15]

A number of contemporary economists argue that economic growth itself is the causal result of improvements in energy efficiency.* In a counterintuitive macro-paradox, the rate at which natural resources are consumed may be in direct proportion to the efficiency growth of those conversion processes. With evidence for these theories gaining momentum at the same time that the argument of energy decoupling weakens, resource efficiency as a stand-alone policy in the name of environmental protection would appear a fallacy indeed.

2. THE STRATEGIES OF ENVIRONMENTALISM

Modern environmentalism seeks to identify and implement market and policy mechanisms that will protect the natu- ral resources of the planet while providing for a sufficient human quality of life. When analyzed in isolation, resource efficiency policy appears to be a win-win policy in this worldview. Individual people require fewer resources, while both producers and consumers save money.

Efficiency appears as a simple solution in an array of sustainability-oriented programs. Consumers can point to a heating bill and identify both energy and economic savings. Indeed, the efficiency discourse has served to bring thousands of individuals on board an agenda of environmental protection, offering tangible and attainable points of local victory. Unfortunately, many studies and economic models show this simple solution to be counter-intuitive in the aggregate. Individual savings seem to only reshuffle the end-game of the financial system in which they are embedded.[16] As the research in Section 1 illustrates, the aggregate effects of these successes may offer a much less rosy picture.

*Footnote:
For more reading on the economic production function, look to the following authors: Roberty Ayres, Leonard Brooks, Herman Daly, & Benjamin Warr.

2.1 EfficiencyandEnvironmentalPolicy

Efficiency measures for both production and consumption have varying effects at different scales of the economy. Sustainability researchers now theorize that they either cause or mutually reinforce the process of increased resource use through economic growth. Policy experts working on the problem of aggregated efficiencies agree that the best-case scenario for energy efficiency as an environmental policy strategy would be if sufficiency were seen as a subsidiary part of a larger highly regulated system. Such restrictions would be necessary to ensure that savings from an individual process are not reabsorbed into the energy intensive sectors of the larger economy. In such a regulatory regime, the general operating proposal is that a base amount of energy and resources would be provided at a certain rate, with a luxury tax on consumption above that rate.[17]

2.2 Energy and Sustainability

Direct regulation, on the whole, is not a popular policy strategy. Market mechanisms such as Cap and Trade tend to be more palatable, especially in the business sector. Not only does Cap and Trade reward efficiency, but such a policy framework could be used to limit the macroeconomic expansion of emissions by providing a total system cap. It is these boundary conditions capping the negative effects of unsustainability that are seen as providing the best possible basis for leverage in harnessing a positive movement towards a sustainable society.

2.3 Definitions

It is important to recognize that, while many positive efforts are currently being undertaken in the name of environmental and social sustainability, such a society has yet to exist as a modern society on this planet. The number of tools we are developing - resource and energy efficiency among them - to move towards such a goal is vast. Yet the ways in which those tools will need to interact and synergize has yet to be hammered out. Multiple definitions of sustainability have been put forward along with many principles by which a future sustainable society might operate.

The Brundtland definition of sustainability, along with many of similar content and spirit, is still the most often quoted:

Sustainable development is development that meets the needs of the present without compromising the ability of future generations to meet their own needs[18] (1987)

The Brundtland definition provides a sentiment of who sustainability shall serve, commonly interpreted as imparting security for the worlds poor and future generations. The definition tells us nothing about what kinds of practices we might employ to arrive at such a society. Any of the sustainability-oriented tools and policies familiar today can be seen as falling within the scope of this definition. Indeed, Economist Robert Solow's reactionary view of efforts towards sustainability could be construed as being in step with Brundtland's vision. Solow is famously in support of a do-nothing policy vis-à-vis environmental protection. A recipient of the Nobel Prize, he famously followed the assertion of neoliberal theory to it's logical conclusion. Assuming that future generations will be vastly more wealthy than we are, and that we can't expect to anticipate the needs and values of any future civilization: "We don't owe the future any particular things."[19]

As citizens of a finite planet and its interconnected communities, we view this assertion as ecological suicide.

2.4 The Sustainable-Area Budget (SAB)

We understand sustainability as a process. Human and natural ecologies are embedded and interact through complex adaptive systems with multiple feedback loops on intersecting scales. A successful sustainability process will be one that works with this reality of complexity through interconnectedness. Our modern culture is one of increasing material demand in a world of limited biophysical resources. Fundamental to our understanding of a sustainability process is that it must be dynamically responsive and not extend beyond the boundary conditions of a reasonable biophysical limit. We developed the Sustainable-Area Budget (SAB, Fig. 2) as the guiding operational principle for a sustainability process.[20] The SAB is the aggregated land area based budget that a community has to work with on an equitable basis, within which it obtains its resources and balances out its wastes on a net regenerative basis. The SAB is similar to the Ecological Footprint approach to measuring un-sustainability. But, while the Ecological Footprint model answers the question, "How much land area is the metabolism of our city appropriating?," the SAB says. "This is the amount of land to which we are entitled." We have thus flipped an analytical tool on its head and turned it into a design problem. In the process, sustainability becomes a question to be addressed by a given citizenry in a given place in any number of unique ways. Through a participatory process, they can create alternative scenarios addressing the question: "How can we explore different scenarios for the design of our city and the use of our available ecological resources to support the highest quality of life among our citizens?"

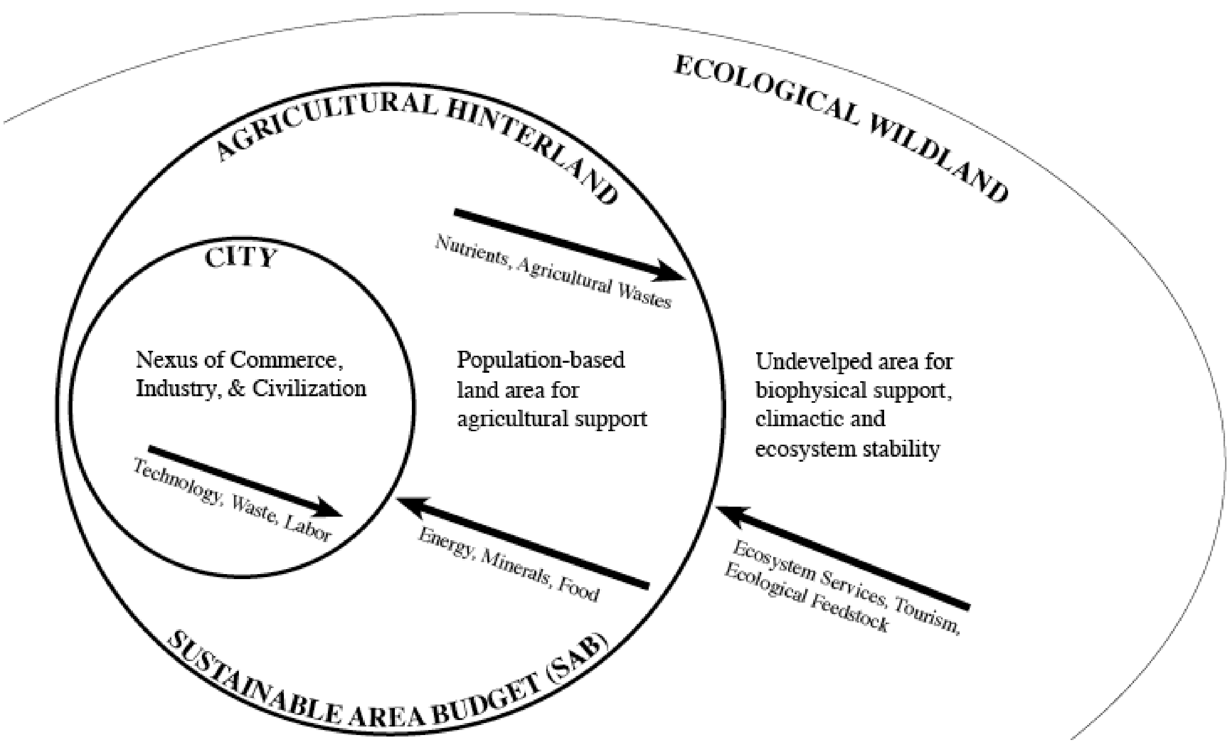

Fig 2. A conceptual diagram of a city and its hinterland operating within biophysical limits, while preserving areas for wild nature.

3. SUSTAINABILITY: AN OPERATIONAL DEFINITION

We have identified the scale at which the design and negotiation of sustainability is possible. This is the scale and place where the negotiation of balance has historically always existed - the city-region. The city, with its agricultural hinterland, is at once large enough to accommodate aggregate efficiencies and small enough to be a cultural organism of local accountability. The city allows the environmental effects of human actions to be understood within a discreet boundary of appropriate size and limitations, it is the necessary place where sustainability is to happen.

From these principles, we have developed what may be the only operational definition of sustainability currently being advanced:

Sustainability is a local, informed, participatory, balance-seeking process, operating within its Sustainable Area Budget, and in so doing exports no negative imbalances beyond its territory or into the future, thus opening spaces of possibility and opportunity.[21] (1998)

Local: a specific place, a city-region or what we have termed a “Sustainable Urban Implantation,” where Sustainable Development can find a place.

Informed: the role given to science to provide the process and its stakeholders with the scientifically and systematically determined information as to how their proposals and scenarios will play out in terms of balances within the SAB.

Participatory: the social dimension of sustainability where a full range of representative movements, interest groups, and business, government, labor, and citizen organizations are invited to become stakeholders in the Sustainable City Game.

Balance-Seeking Process: the interactive arena where any proposition may be put on the table, with the implications of its reverberations through the city-system being tested through scientific modeling, and its negative imbalances being brought towards equilibrium through these negotiation and modeling processes.[22]

3.1 Sustainability on the Ground

The operational definition allows on-the-ground deployment of an advanced democratic sustainability process. This is accomplished through delineating the physical and resource boundaries of human activity (the SAB), defining a participatory process that promotes equity within those boundaries, and providing a scale appropriate for the feedback mechanisms of the process to develop and compliment each other (the city). Interdisciplinary teams of local stakeholders and design scientists carry forward numerous designs scenarios and partial scenarios to compare with and inform one another.

This process happens through the Sustainability Engine™ and the Sustainable City Game™, modeling and feedback tools that are deployed to build systems models of emerging city design scenarios. The effects of such scenario building come through in both parts and wholes, making it possible to see how scenario proposals will work as a system within the budget.

3.2 The Sustainable City as a System

The sustainability process starts out as the Sustainabil- ity Game™, an iterative process of scenario building for stakeholders. The nature of the Sustainability Game™ is to pursue the satisfaction of ones individual self-interest while maintaining the viability of the city/system. As an individual, industry, or sector will be incapable of satisfying its own needs without engaging other interests, it becomes necessary to work with others to both provide those means, (the energy and the material) and to correct for the imbalances caused by the satisfaction of those needs. Using the Sustainability Engine™, each stakeholder will attempt to satisfy his or her needs and interests through a variety of different scenarios, each involving different strategies and different partners.

3.3 The City as a Learning Ecology

In the Sustainability Game, strategies that throw the city/system out of balance are quickly eliminated or rebalanced through the introduction of new ideas or processes with different attributes. Over time more favorable strategies are built upon and elaborated while less favorable strategies are put aside. Importantly, rejected strategies are still stored in the Sustainability Engine™, allowing the possibility that they may be revisited when circumstances change at a later date. Scenarios are favored and pursued when they satisfy multiple interests, when they bring the city/system toward balance and when they hold the promise of equity for all stakeholders. As the Sustainability Game proceeds, the stakeholders increasingly realize that they share a common destiny and that significant synergies will result from their creative encounters and negotiations. As the game proceeds, it becomes less of game and more a real economy and urban construct. The city/region is therefore understood as an urban ecosystem and the nature of play moves stakeholders towards the building of common wealth.[23]

In the Sustainability Game, it is the role of science to determine the state of balance of the proposed city-systems scenarios. In response to a problem or a need, questions like these arise during the playing of the game: What if we try a new process for materials manufacturing? Does it solve the perceived problem? What are its larger effects on the city-system? If the local solution causes problems elsewhere in the city-system, what can we do to compensate for those imbalances? As the effects of these proposals and our attempts to compensate for the imbalances they cause reverberates through the city-system, is the overall level of problems and the attendant resiliency of the system increasing or decreasing? Is the overall effect of the proposal, which in the first instance seemed to be an excellent idea, finally worth the larger imbalances it may be causing?" And again: if it is worth doing, what new measures do we have to take to bring the city-system back toward balance?

4. CONCLUSION

The overarching problem that this generation faces is sustainability: how to live as human communities within finite planetary resources. Energy and resource efficiency are tempting tools to approach this problem, yet they only offer partial solutions that are quickly subsumed within a complex and interconnected economic system. Additionally, there is ample evidence to suggest that, pursued without regard to biophysical context and economic limits, the economic signals given by energy and resource efficiencies are the primary drivers of resource consumption.
Through a multi-stakeholder scenario-building process, we propose a place-based context where the needs of people can be mutually negotiated within the limits of nature: the sustainable city.

For additional proposals as to how that may occur, refer to the prior research of the current authors and through: www.centerforsustainablecities.com

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SOLAR FOR SCHOOLS: A CASE STUDY IN IDENTIFYING AND IMPLEMENTING SOLAR PHOTOVOLTAIC (PV) PROJECTS IN THREE CALIFORNIA SCHOOL DISTRICTS

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ABSTRACT

The Department of Energy‘s (DOE) Solar America Showcase program seeks to accelerate demand for solar technologies among key end use market sectors. As part of this activity, DOE provides technical assistance through its national laboratories to large-scale, high-visibility solar installation projects.

The Solar Schools Assessment and Implementation Project (SSAIP) in the San Francisco Bay Area was selected for a 2009 DOE Solar America Showcase award. SSAIP was formed through the efforts of the nonprofit Sequoia Foundation and includes three school districts: Berkeley, West Contra Costa, and Oakland Unified School Districts.

This paper summarizes the technical assistance efforts that resulted from this technical assistance support. It serves as a case study and reference document detailing the steps and processes that could be used to successfully identify, fund, and implement solar photovoltaics (PV) projects in school districts across the country.

Keywords: schools; solar photovoltaics

1. INTRODUCTION

School districts across the United States face trying times due to decreasing budgets and rising energy costs. Districts are required to do more with less. At the same time, schools provide a unique opportunity for energy efficiency and renewable energy application and education, not only through curriculum but also through technology deployment. California is an example of a state with significant budget deficits and a high potential for solar electricity, or photovoltaic (PV), technology deployment. The Sequoia Foundation is supporting three California school districts—Oakland, Berkeley, and West Contra Costa Unified School Districts—in the development of Solar Master Plans (SMP), documents that are intended to be incorporated in the districts‘ Facilities Master Plans. The National Renewable Energy Laboratory (NREL) is providing technical assistance to these school districts and the Sequoia Foundation as part of the DOE‘S Solar America Showcase program.[1]

The Solar America Showcase program seeks to accelerate demand for solar technologies among key end use market sectors. As part of this activity, DOE provides technical assistance through its national laboratories to large-scale, high-visibility solar installation projects that have the ability to impact the market for solar technologies through large project size, use of a novel solar technology, and/or use of a novel application of a solar technology. Selected showcase projects are replicable or have replicable components.

This paper will summarize the technical assistance efforts that have resulted from this technical assistance support. It will serve as a case study and reference document detailing the steps and processes that could be used to successfully identify, fund, and implement solar PV projects in school districts across the country. The goal of the technical assistance support was to enable and empower district representatives to understand PV technologies and opportunities, identify potential financing mechanisms, and institutionalize the inclusion of PV in the district master planning process.

Technical support included education of district stakeholders in the areas of PV technologies and financing options, electricity rate analysis to identify the most PV-friendly rates for the districts, building structural assessments, and an analysis of technical potential for solar PV. The support will culminate in the development of comprehensive, district-wide Solar Master Plans.

2. DISTRICTS OVERVIEW

The three school districts participating in the SSAIP (BUSD, WCCUSD, and OUSD) represent a total enrollment of nearly 78,000 pre-K-12 students and an annual budget of over $835 million, and occupy nearly 200 school buildings, administrative offices, and adult education sites—many of which are candidate sites for future solar installations. Each of the three districts offers significant opportunities for PV installations:

WCCUSD has a current total enrollment of 30,832 pre-K-12 students who attend its 53 schools. The district maintains over 70 separate facilities. Its current annual General Fund budget is approximately $285M.[2]
BUSD has nearly 9,300 students who attend its 20 schools. It also maintains a number of administrative and support facilities, adding to a total of over 100 buildings in the district.[3]
OUSD has an enrollment of almost 37,000 students in 91 K-12 schools spread over 5.8 million square footage of facilities.[4]

All three school districts are members of the Collaborative for High Performance Schools (CHPS) and have passed Board Resolutions supporting adherence to the CHPS Best Practices and CHPS-Rated Schools requirements in their design and construction programs.[5] The mission of the Collaborative for High Performance Schools is to facilitate the design, construction, and operation of high performance schools. CHPS helps facilitate and inspire change in our educational system. The goals of CHPS are to:

- Increase student performance with better-designed and healthier facilities;
- Raise awareness of the impact and advantages of high performance schools;
- Provide professionals with better tools to facilitate effective design, construction and maintenance of high performance schools;
- Increase school energy and resource efficiency; and
- Reduce peak electric loads.[6]

Public school districts have shown an interest in installing PV systems. In 2004, the California Energy Commission (CEC) and the California Power Authority created the Solar Schools Program. This program was jointly funded by the CEC's Emerging Renewables Program and the Attorney General's Alternative Energy Retrofit Account and provided school districts with rebates that were twice the amount offered to residential customers.[7] The program attracted applications from over 60 school districts, but due to limitations in funding, only 28 schools received the incentives. A total of $4.5 million was awarded, which enabled the 28 CA schools to purchase and install solar PV systems with an expected generating capacity of 642 kilowatts (kW).[8]

BUSD and WCCUSD have shown their commitment to solar PV by installing a total of 237 kW on an elementary school and a high school. BUSD and WCCUSD plan to install four more systems in the summer of 2011. OUSD has small demonstration solar projects on four sites and ongoing energy efficiency projects on many of its older facilities, identified through energy audits coordinated by Pacific Gas and Electric Corporation (PG&E).[9] OUSD is considering the installation of PV at 17 sites over the next 18 months.

3. ENERGY EDUCATION

Not every school is an appropriate location for siting PV. This technology relies on good access to the sun and locations with large amounts of shading, or north-facing orientations are not practical. Other school-specific considerations include the age of the roof, a school's designation as historic or emergency shelter, the size of the roof, and the electrical load and associated electric costs of the school. School district staff can begin to assess the potential for PV at their schools with a basic understanding of the technology and these siting considerations.

This component of the technical support was education for school district staff. It included training in Energy Star's Portfolio Manager program and in solar mapping software. NREL also provided district staff with an overview of PV technology options and potential solutions to two common issues associated with PV installations at schools—theft and vandalism of panels.

3.1 Energy Star's Portfolio Manager Program

Cost-effective energy efficiency measures should always be considered as the first step in an energy program, and energy efficiency should be implemented prior to or at the same time as renewable energy technologies. Behavior change is also an important component towards achieving energy efficient school operations. The least efficient schools in our country use three times more energy than the best energy performs, and the top-performing Energy Star labeled schools cost forty cents per square foot less to operate than the average performers.[10]

All three districts recognize the importance of implementing energy efficiency measures and have initiated a benchmarking process for their facilities through Energy Star's K-12 Portfolio Manager Program. Portfolio Manager is an interactive energy management tool that allows users to track and assess energy and water consumption across an entire portfolio of buildings. Portfolio Manager can be used to set investment priorities, identify under-performing buildings, verify efficiency improvements, and receive EPA recognition for superior energy performance.[11]

NREL staff provided initial support to the districts as they began using Portfolio Manager, including setting up a Portfolio Manager training and providing guidance as the districts began to use this software tool.

3.2 Solar Technology Overview

3.2.1 Training

District representatives requested training in identifying opportunities for PV technologies on their facilities. NREL staff compiled and presented an overview of PV technologies, siting considerations, and web-based solar mapping tools, including NREL's In My Backyard (IMBY).[12] A solar PV mapping tool visually represents a specific site and calculates PV system size and projected electricity production.[13]

IMBY:

- Estimates the electricity that can be produced with a PV array or wind turbine at a home, business, or school.
- Uses a map-based interface to allow the user to choose the exact location of to place the PV array or wind turbine.

This training was an effort to inform district representatives about the considerations for siting PV and to enable them to begin to identify appropriate locations on their own.

3.2.2 Technology Overview

NREL developed a brief report for district representatives that details the commercially available and emerging PV technologies; associated efficiencies, costs, and benefits; maintenance requirements; and other siting considerations. It includes single and multi-crystalline and thin-film technologies, as well as more recent applications such as building-integrated PV (BIPV), solar inks, and concentrated PV (CPV).

PV arrays convert sunlight to electricity without moving parts and without producing fuel wastes, air pollution, or greenhouse gases (GHG) during operation. They require very little maintenance and make no noise. Arrays can be mounted on all types of buildings and structures. PV direct current (DC) output can be conditioned into grid-quality alternating current (AC) electricity or used to charge batteries.

Traditional ―mono-crystalline‖ solar cells are made from silicon, are usually flat-plate, and are generally the most efficient. ―Multi-crystalline‖ are a similar technology but are slightly less efficient. Efficiencies for crystalline panels range from 13 to 19 percent.[14] A third type called ―thin-film‖ solar cells are made from amorphous silicon or nonsilicon materials such as cadmium telluride. Thin-film solar cells use layers of semiconductor materials only a few micrometers thick. Efficiencies for thin-film panels range from four to 12 percent.[15] Because of their flexibility, thin-film solar cells can be integrated into building materials (called Building Integrated PV or BIPV) such as rooftop shingles and tiles, standing seam metal roofs, or building facades.

Third-generation solar cells are being made from variety of new materials besides silicon, including solar inks using conventional printing press technologies, solar dyes, and conductive plastics. They are technically attractive because they are made of low-cost materials. Manufacturing these cells could be significantly less expensive than older solid-state cell designs. However, the efficiency expects to be a lot lower than the typical thin-film. A very promising new technology option is concentrating PV, or CPV. This tubular technology uses concentrators to focus direct solar radiation onto PV cells. Some of these currently available technologies reach efficiencies up to 29%.[16]

Most PV systems currently being installed are in flat-plate configurations, which are typically made from modules that hold about 40 cells. Many solar panels combined together to create one system is called a solar array. For large electric utility or industrial applications, hundreds of solar arrays are interconnected to form a large utility-scale PV system.[17] These systems are generally ‗fixed' in a single position, but can be mounted on structures that ‗track' or tilt toward the sun on a seasonal basis or on structures that roll east to west over the course of a day.[18]

The cost of PV-generated electricity has dropped 15- to 20-fold in the last 40 years, and panels typically last 20 years or longer.[19] Grid-connected PV systems currently sell for about $5/Wp to $8/Wp (20¢/kWh to 32¢/kWh), including support structures and power conditioning equipment. Costs reported for PV projects are changing (decreasing) rapidly, so a local solar installer may be the best source of cost information. Operation and maintenance costs are reported at $0.008/kWh produced, or at 0.17% of capital cost without tracking and 0.35% with tracking.[20]

The amount of electricity that a system produces depends on the system type and orientation and the available solar resource. The solar resource is the amount of the sun‘s energy reaching the earth‘s surface, which varies across the United States. A higher solar resource means that more of the sun‘s energy is reaching the surface, which is optimal for PV system performance. Resources are highest in the Southwest, and fairly high throughout the western states, Texas, and Florida.

The document also includes an overview of PV monitoring equipment. Monitoring of PV systems can be essential for reliable functioning and maximum yield of a system. It can also be a valuable tool for community outreach and education. Especially in a school, displays of PV output and performance can be highly educational.

Monitoring can be as simple as reading values locally on an LCD display on the inverter such as produced AC power, daily kWh and cumulative kWh. For sophisticated monitoring and control purposes, environmental data—such as module temperature, ambient temperature, solar radiation, and wind speed—can be monitored. Remote control and monitoring can be performed by various remote connections, which can also send alerts and system messages. Data can be stored in inverters memory or in external data loggers for further system analysis.

The report also details possible solutions to potential barriers that districts sometimes face when PV systems are installed on schools—vandalism and theft. Some solutions are technical:

- Installing keyed fasteners at intermodule and end clamps. These fasteners use a unique pattern, which regular wrenches and screwdrivers are useless against. It‘s the same concept used for expensive automobile wheel fasteners. The installer or owner keeps the key needed to unfasten the hardware. A fastener costs about $2–$5.
- Install a reliable security camera system. Post signage around the perimeter of the system alerting of the security systems in place.
- Engrave each system component with school name to make it harder for vandals to resell them.

Some solutions are process- or maintenance-based:

- Check fences and gates for damage. Make repairs and keep gates locked.
- Cut back weeds and other vegetation around the campus to reduce fire risk and hiding places.
- Keep surrounded areas clean. Loose rocks that can be used by vandals should be removed.
- Check all lighting on campus. Replace all burned-out bulbs. Install lighting in currently dark areas. Consider installing motion sensor lights.
- Add or increase nightly patrols of campus, especially during the summer months when the weather is warmer and the days are longer.

Some solutions are education-focused:

- Get the community involved. Encourage the community to be concerned and watch for vandalism and theft.
- Add warnings about potential hazard and electric shocks from the system.
- Educate the staff and students on the consequences of vandalism and create a sense of ownership of the solar photovoltaic system.

4. SOLAR MAPPING

Solar mapping analyses can be used to inform decision makers about the availability of promising land or roof areas for PV, quantify that available space, and calculate potential PV capacity and electrical production. PV costs and electricity cost savings are also sometimes calculated.

4.1 SunPower Corporation‘s Analysis

SunPower Corporation provided aerial mapping estimates of solar potential for two districts and is currently completing the mapping assessment for the third district.[21] This mapping estimate used an aerial snapshot of each school and employed a calculation methodology to determine the potential for PV installations at each location. Ideal locations for PV were manually selected such to avoid areas that appeared to be shaded based on the aerial imagery. The analysis did not take into account roof age or structural integrity.

These results are a high-level, first-cut attempt to quantify the potential for PV installations on these schools. It is a good way to identify potential sites and to begin to prioritize those for which a more detailed, on-site analysis of feasibility should be conducted.

The analyses for BUSD and WCCUSD have been completed; the analysis for OUSD is currently underway. SunPower is also currently updating the analyses for BUSD and WCCUSD.

The SunPower analysis for BUSD was completed in December 2009 and assumed:

PG&E Electric Rate A6 yielding year 1 solar savings = $0.223/kWh;
Incentives at California Solar Initiative (CSI) Tier 6 = $0.26/kWh;[22]
A total cost per Wp installed = $5.75;
Year one electric yield = 1,350 kWh per kWp; and
Size and location of systems will vary significantly after design completion.

The SunPower analysis found a total potential PV capacity of 1,880 kWp at 11 schools in the BUSD. It estimated that on an annual basis these systems would produce approximately 2,500,000 kWh and save $565,000 in avoided electricity costs.

The SunPower analysis for WCCUSD was completed in May of 2010, and it assumed:

PG&E Electric Rate A6 yielding year 1 solar savings = $0.19/kWh;
Incentive at CSI Tier 7 = $.19/kWh;[23]
A total cost per Wp installed = $5.75;
Year one electric yield = 1,350 kWh per kWp; and
Size and location of systems will vary significantly after design completion.

This analysis found a total potential PV capacity of 7,251 kWp at 42 schools in the WCCUSD. It estimated that on an annual basis these systems would produce approximately 9,700,000 kWh and save $1.8 million in avoided electricity costs.

4.2 NRE L' s Analysis

NREL, expanding on SunPower's initial assessment, is working to take into account additional factors for identifying promising sites for PV feasibility. Considerations of roof age, structural integrity, electricity use, and costs, combined with the district's input, will result in a listing of schools from most promising to least for PV installation.

4.2.1 Structural Assessments

Based on findings from the SunPower and NREL analyses and district preferences, each district selected five of the most promising locations to receive structural assessments. The purpose of the structural evaluations was to rapidly assess if the existing framing can support a PV array and determine if there are potential structural deficiencies that may preclude the addition of a PV array. The evaluations were based on an in-house review of the available –as-built‖ drawings furnished by school districts; no site visit has been performed as part of this phase of the work.

4.2.2 Solar Master Plans

Based on findings from SunPower's solar mapping analyses, NREL's solar mapping analyses, and the structural assessments, and taking into account other considerations such as roof age, electricity use and costs, and the district's input, NREL will generate a listing of schools, from the most promising to least, for PV installation for each district. This listing, which will form the foundation of a Solar Master Plan for each district, will serve as either a stand-alone document or be integrated with five- or ten-year Facilities Master Plans. By institutionalizing planning for PV installations into traditionally accepted and commonly used construction planning mechanisms, such as Facilities Master Plans, districts will likely have greater success in planning for and implementing PV.

5. FINANCING OPTIONS

It can be difficult, especially in today's budget climate, for districts to procure funding for energy efficiency and renewable energy (EERE) projects. There are a variety of financing mechanisms for EERE technologies that can be employed by districts. As part of this project, a financing guide was developed; this guide provides an overview of financial options, a variety of templates, signed project documents, and other reference materials that school districts can review as they pursue their own respective solar electricity generation projects.

The document is divided into three sections:

Section I: Provides an introduction to financing PV on schools, including consideration of energy efficiency, roof viability and classroom impact.

Section II: Discusses a direct ownership option, where the solar project is procured through a design-build contract. Here the school finances the project's purchase price with 100% debt financing which may include either traditional tax-exempt municipal bonds or taxable bonds that provide a form of federal subsidy; namely, Build America Bonds, Clean Renewable Energy Bonds, Qualified Energy Conservation Bonds, Qualified School Conservation Bonds, and Qualified Zone Academy Bonds.

Section III: Focuses on the third party finance model, including Power Purchase Agreements and Energy Services Performance Contracts, with a brief description of New Markets Tax Credits and examples.

Case studies are incorporated into the document when relevant and available. The reference section of this report includes a number of pertinent documents related to financing solar installations on public schools and other public facilities. This document will serve as a resource for district representatives, and it is specifically crafted for schools.

6. RATE ANALYSIS

Compensation for commercial net-metered PV systems is dictated primarily by the utility rate structure under which the PV system and building operates. Electric utility tariffs across the United States consist of many different rate components, all of which have an impact on PV system economics. Identifying the effects of rate structures on system economics can help individuals and entities make informed choices on available rate structures in order to maximize their investment returns.[24]

An abundance of utility rate structures exist for school districts and these options can be confusing to understand. Advantages, disadvantages and other implications of each rate structure are sometimes hard to identify. As school districts implement energy efficiency measures and renewable energy technologies, the school‘s electric load will be reduced (assuming no changes in operations such as additional students or operating hours). It is important, and complex, to consider the interactions on rate structure and total electricity costs of a reduced load, and school districts should be examining which rate structure each school is on and working to identify which structure is most beneficial (i.e., most cost-effective) to the school. This is especially important to consider when installing PV systems, as some rate structures are more economically favorable than others.

As part of this project, NREL conducted a utility rate analysis comparing the value of PV electric generation for different rate structures.

6.1. Berkeley High School Case Study

The Berkeley High School case study explores the impacts of various applicable retail rate structures on the value of electricity generated from a potential rooftop PV system. The analysis uses NREL‘s System Advisor Model (SAM) and the OpenEI Online Utility Rate Database.[25,26] Inputs included measured building electrical load data, simulated solar data (using measured meteorological data from the same time period and location as the building load data), retail rate structures, and any applicable incentives. SAM used these inputs and other user specified parameters to evaluate system economics under each utility rate and PV penetration scenario. PV penetration is the percent of the building‘s annual electric load that is met by the PV system. The results allow us to understand under which scenarios a PV system becomes economical.

First, the economic value of PV was examined under six applicable PG&E electric rate structures. The rates are: A-6, A-1 TOU, A-1, A-10, A-10 TOU, and E-19. The PV values, expressed in $/kWh, under each of the six applicable rates are shown below in Fig. 1. Certain rates (E-19, A-10, A-10 TOU) yield values that vary with PV penetration. This is because these rates have demand charges, while the others do not.

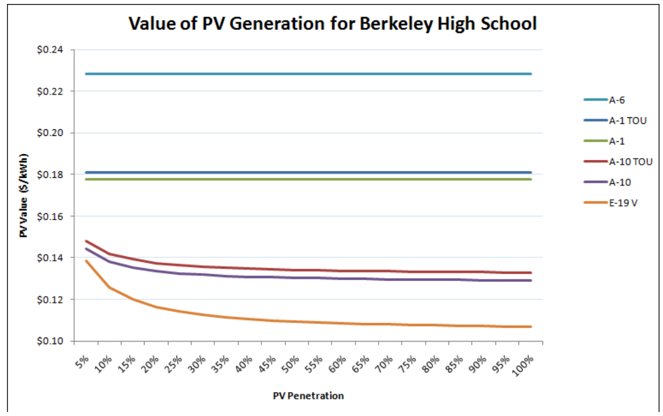

Fig. 1: Value of PV generation for Berkeley High School.

Next, the value of PV generation was calculated by comparing the building‘s electricity cost with and without the PV system. The difference yields the PV value, which can be divided by total PV kWh generation to get a $/kWh number. This method of calculating PV value is very useful when evaluating each rate independently. However, when comparing multiple rates, it is more useful to evaluate the *net* PV value. This compares the building‘s electricity cost without the PV system *always using the least expensive rate(s)* and the building‘s electricity cost with PV under the rate in question. The difference yields the *net* PV value. The data in Fig. 2 shows that rate E-19 is the most economical rate until a 35% PV penetration, after which rate A-6 becomes the most economical.

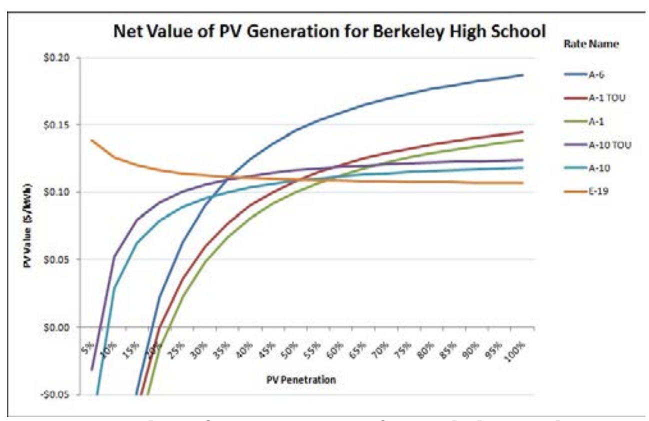

Fig. 2: Net value of PV generation for Berkeley High School.

PV value alone may not provide enough information for decision makers to understand what impacts they can expect on their electricity bill. To understand bill impacts, the cost of the PV system must be subtracted from the value it provides. If the PV value is greater than the cost, then the system yields a net electricity bill savings. The data below illustrates how Berkeley High School's bill savings varies with PV penetration and cost, based on *using the most economic rate(s)*. In this situation, the least expensive rates are E-19, up to 35% penetration, and A-6 for 35% penetration and beyond.

PV systems that are \$3/Watt (W) or below will always result in a positive bill savings, while systems \$5/W and above results in a net loss. These values can vary depending on how the system is financed and the availability of incentives. This is graphically represented in Fig. 3.

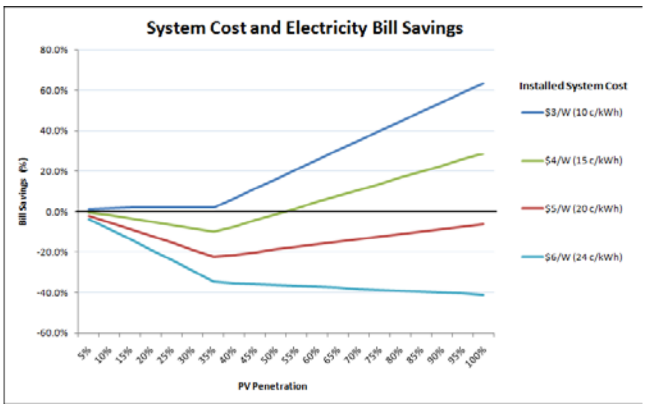

Fig. 3: System cost and electricity bill savings.

7. CONCLUSION

Schools present a unique opportunity for energy efficiency implementation as well as renewable energy deployment. They tend to have high and very consistent electricity loads with corresponding high utility bills. They also often have large land or roof areas for which to site PV technologies. Installing energy efficient or PV technologies on a school and incorporating these systems into curriculum is an effective, hands-on way to educate students about these important technologies.

This paper summarized the technical assistance efforts that were a result of the Solar America Showcase award. Information contained in this report can serve as a case study and reference document detailing the steps and processes that could be used to successfully identify, fund, and implement solar PV projects in school districts across the country. The goal of the technical assistance support was to enable and empower district representatives to understand PV technologies and opportunities, identify potential financing mechanisms, and institutionalize the inclusion of PV in the district master planning process.

Technical support included education of district stakeholders in the areas of PV technologies and financing options, electricity rate analysis to identify the most PV-friendly rates for the districts, building structural assessments, and an analysis of technical potential for solar PV. The support will culminate in the development of comprehensive, district-wide Solar Master Plans.

As school districts are currently faced with budget uncertainties in parallel with energy reduction and renewable energy use goals, districts can integrate PV installations into the planning process through education, planning, and preparation for PV implementation.

One method for institutionalizing this process is to develop Solar Master Plans. These enable school districts to phase in solar projects over time, either by using voter-approved construction bonds or by taking advantage of financing (either low-cost or third-party). In some instances the PV system can even be used to generate revenue.

8. ACKNOWLEDGMENTS

This work was made possible by the Solar America Communities program of the Solar Energy Technologies Program at DOE. The author wishes to thank Sean Ong of NREL for conducting the rate analysis, Kosol Kiatreungwattana of NREL for compiling the technology overview, Jason Coughlin of NREL for compiling the financing guide, Tom Kelly of KyotoUSA for organizational and leadership support of this project, and BUSD, OUSD, and WCCUSD district staff for their efforts to support PV installations in their districts.

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IMPLEMENTING SOLAR PHOTOVOLTAIC PROJECTS ON HISTORIC BUILDINGS AND IN HISTORIC DISTRICTS

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ABSTRACT

Many municipalities, particularly in older communities of the United States, have a large amount of historic buildings and districts. In addition to preserving these historic assets, many municipalities have goals or legislative requirements to procure a certain amount of energy from renewable sources and to become more efficient in their energy use; often, these requirements do not exempt historic buildings.

This paper details findings from a workshop held in Denver, Colorado in June 2010 that brought together stakeholders from both the solar and historic preservation industries. Based on these findings, this paper identifies challenges and recommends solutions for developing solar photovoltaic (PV) projects on historic buildings and in historic districts in such as way as to not affect the characteristics that make a building eligible for historic status.

Keywords: historic buildings; solar photovoltaics

1. INTRODUCTION

Historic properties and districts in the United States provide valuable insight into the nation's past. Buildings, sites, districts, structures, and objects are being protected across the nation in order to present future generations with a link to the country's heritage. The National Park Service reports that "since its inception in 1966, more than 80,000 properties have been listed in the National Register. Together these records hold information on more than 1.4 million individual resources—buildings, sites, districts, structures, and objects—and therefore provide a link to the country's heritage at the national, state, and local levels."[1] More buildings become eligible for listing on the National Register of Historic Places every day, due to their age or because they possess unique characteristics, such as a famous architect or a significant event occurring at the property.

Besides protecting our heritage, historic preservation is a mechanism for saving resources. Continuing to use historic buildings should be a key strategy in sustainability, as it maximizes the use of existing buildings, therefore reducing the use of virgin materials to build new ones, and it does not make waste of the embodied energy therein. Standards and guidelines have been established for historic preservation. While these standards vary between local, state, and federal jurisdictions they are crucial to the process of implementing PV on historic buildings.

In addition to protecting the nation's heritage, there is also growing emphasis on protecting natural resources. Resource efficiency has been the focus of many federal mandates, corporate responsibility statements, and volunteer reduction programs. In addition to historic preservation responsibilities, many municipalities have goals or legislative requirements to procure a certain amount of energy from renewable sources and to become more efficient in their use of energy. Oftentimes these energy efficiency and renewable energy requirements do not exempt historic buildings from the requirements of the law.

Despite a global recession, the number of solar photovoltaic (PV) installations in the United States grew 40% between the years 2008 to 2009; this growth in PV system installation is likely to continue.[2] There is currently pressure to consider renewable energy projects at historic buildings and in historic districts in order to meet sustainability goals, however renewable energy projects may be viewed as complicated by historic preservation requirements.

In 2007 the U.S. Department of Energy (DOE) designated 25 major U.S. cities as Solar America Cities and provided financial and technical assistance to help the cities develop comprehensive approaches to accelerate the adoption of solar energy technologies. The Solar America Cities partnerships represent the foundation of DOE's larger Solar America Communities program. Through this program, DOE identified the implementation of solar projects on historic properties and in historic districts as one crucial topic to address. A workshop was held in June 2010 titled –Implementing Solar Photovoltaic (PV) Projects on Historic Buildings and in Historic Districts‖ to provide a venue for solar industry and historic preservation representatives to discuss barriers and identify potential solutions.

During the workshop, a need was identified for general education on the historic preservation process for the solar industry and on solar PV principles for the preservation community. Based on the dialogue and findings from the workshop, this paper provides general information on historic preservation and solar PV, and identifies a process for implementing solar projects on historic buildings and in historic districts.

2. SOLAR PHOTOVOLTAICS

Conservation efforts, environmental concerns, and mandates have prompted agencies, municipalities, and other entities to consider energy efficient and renewable energy technologies at facilities. Solar energy technologies such as solar PV are mature, commercially-available renewable energy technologies that are applicable in a multitude of applications and locations.

2.1 Solar PV Technology Overview

PV arrays convert sunlight to electricity without moving parts and without producing fuel wastes, air pollution, or greenhouse gases (GHG) during operation. They require very little maintenance and make no noise. Arrays can be mounted on all types of buildings and structures. PV direct current (DC) output can be conditioned into grid-quality alternating current (AC) electricity or used to charge batteries.

Traditional –mono-crystalline‖ solar cells are made from silicon, are usually flat-plate, and are generally the most efficient. –Multi-crystalline‖ are a similar technology but slightly less efficient. A third type called –thin-film‖ solar cells are made from amorphous silicon or nonsilicon materials such as cadmium telluride. Thin-film solar cells use layers of semiconductor materials only a few micrometers thick. See Table 1 for an overview of module efficiencies for each type of module. The efficiency in Table 1 is the fraction of incident solar radiation converted to electricity.

TABLE 1: TYPICAL EFFICIENCY OF DIFFERENT TYPES OF PV MODULES AND AREA ASSOCIATED WITH 1KW

Type	Efficiency	Area of System (ft^2)
Mono-Crystalline[3]	14–19%	55 ft^2
Multi-Crystalline[4]	13–17%	71 ft^2
Thin-Film[5]	4-12%	99 ft^2

Because of their flexibility, thin-film solar cells can be integrated into building materials (called Building Integrated PV or BIPV) such as rooftop shingles and tiles, standing seam metal roofs, or building facades.[6] Figure 1 shows an example of this technology integrated into shingles. BIPV can add cost and complexity to a project and may not be universally available, but they may help enhance acceptance of a PV installation on a visible roof as they tend to visually blend into building materials.

Fig. 1: Thin-film solar PV shingles. Image courtesy of NREL, PIX 13572.

A newer technology option that shows promise for historic applications is called concentrating PV, or CPV. This tubular technology uses concentrators to focus direct solar radiation onto PV cells. Some of these currently available technologies reach efficiencies up to 29%.[7] CPV technology might have applicability for historic buildings due to its high efficiency, which may allow for the use of less space for the panels. Also, because these panels operate at high levels of efficiency even when laid flat, low-profile, minimally-visible installations are possible.

The cost of PV-generated electricity has dropped 15- to 20-fold in the last 40 years, and panels typically last 20 years or longer.[8] Grid-connected PV systems currently sell for about $5/Wp to $8/Wp (20¢/kWh to 32¢/kWh), including support structures and power conditioning equipment. Costs reported for PV projects are changing (decreasing) rapidly, so a local solar installer may be the best source of cost information. Operation and maintenance costs are reported at $0.008/kWh produced, or at 0.17% of capital cost without tracking and 0.35% with tracking.[9]

The amount of electricity that a system produces depends on the system type and orientation and the available solar resource. The solar resource is the amount of the sun's energy reaching the earth's surface, which varies across the United States. A higher solar resource means that more of the sun's energy is reaching the surface, which is optimal for PV system performance. Resources are highest in the Southwest, and fairly high throughout the western states, Texas, and Florida.

2.2 Siting of Solar PV

The major challenge with PV technologies is appropriate siting for maximum electricity production. In the northern hemisphere, an ideal solar installation would be situated in an unshaded, south-facing location with an optimum tilt angle and would supply electricity to a site where there is a demand for the electricity being produced.[10]

There are a few rules of thumb that may help determine when solar technologies are appropriate for a site.

- It is important to identify an unshaded area for solar PV installation, particularly between the peak sun hours of 10 a.m.–3 p.m. Shade caused by trees, nearby buildings, and features such as chimneys will reduce the output of a solar panel.[11]
- It is best to orient fixed-mount panels due south in the northern hemisphere. Siting panels so that they face east or west of due south will decrease efficiency. However, that effect varies by location and could be minimal.
- For locations with latitudes less than 20 degrees, the optimal tilt angle for achieving the highest performance from a fixed-mount PV panel is a tilt angle equal to the latitude of a location. At higher latitudes, the correlation is not valid based on an analysis by Christensen and Barker (2001).[12] For instance, at a location of 40° north latitude, an optimal tilt varies from 30° to 35° to maximize the annual energy production.[13] Fixed-mount solar panels can be flush- or tilt-mounted on roofs, pole-mounted on the ground, or integrated into building materials such as roofs, windows, and awnings. However, the optimal tilt angle for electricity production is not always feasible because of factors such as roof pitch, wind, or snow loading considerations. It is possible to install panels at a different angle. The impact of a non-ideal tilt angle varies by location and could be minimal.
- Since PV modules have different efficiencies, it is important to consider the efficiency versus the available or required area of the PV system. Fewer modules made of a higher efficiency cell (such as single-crystalline) would be needed for approximately the same power output as more modules made of a lower efficiency cell (such as thin-film). Therefore, if a project location is space-constrained, then a higher-efficiency, and potentially higher-cost, module may make the most sense. If a project has an abundance of space, then a lower-efficiency, less-costly module may be most practical. Efficiency and the typical area of a system, by type are summarized in Table 1.
- The size and nature of a site's electricity consumption, as well as interconnection and net metering laws, must be well understood to properly select the type and size of the PV system. PV systems can be designed to power any percent of an electric load, from a very small percentage to over 100% of the load, depending on available area for the panels and availability of the sun. When considering a system that will be tied to the utility grid, it is essential to understand the applicable net metering rules and interconnection standards for the relevant electric utility company.

2.3 Resources for Assessing Solar PV Potential

Many tools exist to help assess the technical and economic potential for solar PV at a specific location. These free tools can be used as a preliminary estimate of project potential. However, a detailed feasibility study should be performed prior to ruling out or committing to a project.

- PVWATTS (http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/): The PVWatts calculator determines the energy production and cost savings of grid-connected photovoltaic (PV) energy systems.
- IMBY (http://www.nrel.gov/eis/imby/): The In My Backyard (IMBY) tool estimates the amount of electricity that can be produced with a solar photovoltaic (PV) array or wind turbine at a home or business.
- SAM (https://www.nrel.gov/analysis/sam/): The System Advisor Model (SAM) is a performance and

economic model designed to facilitate decision making for people involved in the renewable energy industry.

DSIRE (www.dsireusa.org): The Database of State Incentives for Renewables and Efficiency (DSIRE) is a comprehensive site for incentives and policies relating to energy efficiency and renewable energy.

3. HISTORIC PRESERVATION PROCESS

Not all historic preservation projects require the same process or required reviews; the process depends on the type and location of project, the funding of the project, and the designation of the resource. Historic properties may be listed in the National Register of Historic Places (National Register), a state register of historic places, or a local designation of historic landmarks and districts.

The National Historic Preservation Act (NHPA, 1966—last amended in 2000) calls for the preservation of our nation's heritage in the built environment. The NHPA established the Advisory Council on Historic Preservation (ACHP) and the National Register of Historic Places. The term "historic property" is defined in the NHPA as "any prehistoric or historic district, site, building, structure, or object included in, or eligible for inclusion on the National Register.‖ The Act does not prescribe specific measures within these historic property boundaries.[14] Rather, Section 106 of the Act describes the process that federal agencies, or projects receiving federal funding, must conduct in order to comply with the law. The process involves participation by a large range of stakeholders, including the general public. The State Historic Preservation Officer (SHPO) and the ACHP are participants in any Section 106 review.

The Secretary of the Interior's (SOI) Standards list four treatments: preservation, rehabilitation, restoration, and reconstruction. Rehabilitation is generally the most appropriate approach for integrating solar projects onto historic buildings or into historic districts.

Rehabilitation and Character-Defining Features: Rehabilitation is defined as ―altering or adding to a historic property to meet continuing or changing uses while retaining the property's historic character.‖[15] There is an emphasis on Standards for Rehabilitation (versus restoration) because they are the most widely used and the only set of Standards that would allow for the installation of solar panels. In rehabilitation, historic building materials and character-defining features are protected and maintained.[16] The initial step in the rehabilitation process is to identify the form and detailing of the architectural materials and features that are important in defining the building's historic character.

The SOI's Standards for rehabilitation as they apply specifically to solar PV installations are summarized as follows:

The historic character of a property will be retained and preserved. The removal of distinctive materials or alteration of features, spaces, and spatial relationships that characterize a property will be avoided.

Each property will be recognized as a physical record of its time, place, and use. Changes that create a false sense of historical development, such as adding conjectural features or elements from other historic properties, will not be undertaken.

Distinctive materials, features, finishes, and construction techniques or examples of craftsmanship that characterize a property will be preserved.

New additions, exterior alterations, or related new construction will not destroy historic materials, features, and spatial relationships that characterize the property. The new work shall be differentiated from the old and will be compatible with the historic materials, features, size, scale and proportion, and massing to protect the integrity of the property and its environment.

New additions and adjacent or related new construction will be undertaken in such a manner that, if removed in the future, the essential form and integrity of the historic property and its environment would be unimpaired.

State and local governments may have their own local review processes; sometimes this process is mirrored after the Section 106 review, but it is dependent on locally approved design guidelines and review processes. These might include applicable building permits, local government design review, local zoning, neighborhood association rules, and other requirements that might affect the addition of solar panels. Typically, review is through the planning department, which may refer review to a historic preservation commission.

3.1 Resources for Historic Preservation

National Register of Historic Places (http://www.nps.gov/nr): The National Register provides information on historic properties that can be helpful in understanding the planning requirements for a property or district.

SOI's Standards for the Treatment of Historic Properties (http://www.nps.gov/history/hps/tps/download/standa rds_guidelines.pdf): Standards for preservation, rehabilitation, restoration, and reconstruction are available to guide planners and preservationists. Rehabilitation standards may apply specifically to historic properties attempting to install solar projects.

National Trust for Historic Preservation (http://www.preservationnation.org/issues/sustainability/solar-panels): NTHP solar and historic preservation information related to installation of solar panels including a list of preferred treatments.

State Historic Preservation Offices (http://www.ncshpo.org):.The NHPA provides for the designation of a SHPO in each state

4. COLLABORATION BETWEEN HISTORIC PRESERVATION AND SOLAR DISCIPLINES

Given the large number of buildings and districts that qualify or are designated as historic and the growing prominence of sustainable operations, collaboration between the historic preservation community and the solar discipline is a necessity. Criteria for successful identification and installation of solar PV are necessary, as is consideration of the technical, cultural, and institutional values that exist.

4.1 Criteria for Success

Each project and solar installation is unique. There is not one single technical solution that will work in all applications. Therefore, defining an effective process for identification and installation is necessary. The criteria for successful projects can be broken into two different categories: solar and historic preservation.

4.1.2 Solar

Criteria for a successful *solar* project are predominantly driven by the PV system performance and economics, both of which are largely dependent on project siting and location. A detailed overview of these considerations is provided in Section 2.2.

Performance: The performance of a PV system is dependent on the type of technology selected, as well as site characteristics such as available resource, impact of shade, and orientation and tilt angle.

Economics: The economic feasibility of a project is dependent on the performance of the PV system as well as cost factors such as initial cost, operation and maintenance (O&M) costs, availability of incentives, and other economic factors such as discount rate and fuel escalation rate.

4.1.3 Historic Preservation

A successful project as it relates to *historic preservation* depends largely on consistency with the applicable requirements. Although these vary by project and location, the SOI's Standards are a good reference. Working with an historic preservation professional to identify the character-defining features and the potential location for a PV system is an important early step in the process to ensure that the system does not negatively impact these features or negate the intent of the SOI's Standards.[17] Furthermore, designing ―a new addition which obscures, damages, or destroys character-defining features‖ is not recommended.[18] Historic preservationists, preservation agencies, and preservation organizations are the best references for determining the character and unique features of an historic property.

After identifying the character-defining features of a building, it is helpful to reference the guidance for ―energy efficiency/accessibility considerations/health and safety code considerations.‖[19] This guidance provides information on retrofitting measures to improve energy efficiency.

If the PV system will be roof-mounted, it is necessary to first identify, retain, and preserve roofs—and their functional and decorative features—that are important in defining the overall historic character of the building.[20] If the roof is deemed to be a character-defining feature of the building then consider alternative siting options, and even in cases when it is not character-defining, it is important to consider the SOI's Standards when installing PV systems on historic buildings.
Many historic districts have their own requirements and guidelines. Some districts model their guidelines after the federal guidelines, but when working in an historic district, local guidelines should be used.

It is also important to note that the guidance recommends retaining plant materials, trees, and landscape features that perform passive solar energy functions such as sun shading and wind breaks. This is generally in line with common practice in the solar industry, which most often does not advocate removing these items in an effort to improve solar access.[21] If a site or location does not have adequate access to solar resource, a more appropriate site should be considered.

5. PROCESS FOR IMPLEMENTATION

The steps, challenges, and solutions associated with the process for implementing solar projects on historic buildings and in historic districts were identified during the aforementioned workshop held in June 2010. Through large and small group discussions, a process was devised for successful implementation of solar PV projects.

5.1 Step 1: Identify Potential Projects and Stakeholders

Stakeholders are those with a compelling or regulatory stake in the completed project. Projects will have a greater chance of success with abundant stakeholder contributions. Early identification and engagement of all relevant stakeholders is a large determinant of project success. Stakeholders may include facilities, engineers, and solar installation companies who can assist with the implementation of the project. Easement holders and private and commercial property owners will be important stakeholders due to their control over the property or land where installations might be possible. Other stakeholders include federal, state, and local governments who may have funding and renewable energy targets that need to be met, as well as financiers with knowledge of rebates, grants, third party financing, tax credits, etc. For projects that receive federal funding, the Section 106 review of that project is required. Programs may currently exist for funding opportunities, which will dictate specific criteria for projects. With all historic projects, it is important to engage the State Historic Preservation Officers (SHPOs) at an early stage to ensure that requirements for historic preservation are being met.

The identification of potential projects ideally begins with an initial goal-setting exercise. Determining (with appropriate stakeholders) what the motivations and goals of the project are will help define and drive the project development throughout the entire implementation process. For example, goals could be related to municipality energy reduction, renewable energy goals, building or neighborhood Leadership in Energy and Environmental Design (LEED) certification requirements, and building owner or tenant motivations.

Identification of potential projects on historic properties may indicate that other stakeholders should be engaged, but it will also involve a process of elimination of property types. Project identification may include an analysis of building stock to determine which buildings are the most feasible for PV, an assessment of the potential impact to the character-defining features, consideration of electricity costs or good PV incentives, and an understanding of energy efficiency measure implementation.

Multiple barriers may present challenges during the process of implementing solar projects on historic buildings or in historic districts. Identifying potential barriers early in the implementation process will also allow stakeholders to plan for challenges and highlight potential solutions. Every project is unique, so barriers and challenges will not be the same; just as each project has its own unique challenges, each project will also have its own unique solutions. This activity will increase the level of success of the project.

5.2 Step 2: Engage Stakeholders

After stakeholders and projects have been identified, it is important to engage stakeholders to ensure requirements of historic preservation are met, resources are fully utilized, and informed decisions are made. The process for engaging stakeholders depends on the location and scale of the project. Different stakeholders will be involved in different phases of the process.

The process of engaging various entities could be partially stipulated by legal requirements or local code. The process of engagement could be done through third party advocates, public notices, statutes and mandates, internet announcements, conferences, workshops, awards, newsletters, advertisements, funding announcements, or public hearings.

5.3 Step 3: Observe All Requirements

Requirements for historic preservation, technical installation, funding programs, and local planning will vary depending on the designation of the building, the stages of the planning process, the location and complexity of the project, and the funding mechanism being utilized. There are federal, state, and local requirements in place to preserve historic properties and districts, to alleviate lawsuits and create fairness within projects, and to safely and effectively manage the installation of PV technologies.

Requirements may be relevant to Section 106 (federal and state equivalent), the National Environmental Policy Act (NEPA), local zoning and ordinances, local and national code requirements, electrical codes, structural integrity of properties, federal, state and local environmental goals, SOI's Standards, setback codes, or LEED requirements in certain cities (such as Boston). There may also be requirements to meet for funding mechanisms such as grants, incentives or third-party financing agreements [such as Energy Savings Performance Contracts (ESPCs), Utility Energy Services Contracts (UESCs), and Power Purchase Agreements (PPAs)]. If requirements are not observed, lawsuits may be actioned and responsible parties may be fined or issued stop-work-orders or citations.

The age and condition of a building may impose restrictions. The age of roof structures and materials are important in evaluating whether they can support a solar PV array. This may lead to a greater emphasis on solar arrays that are ―near‖ the historic buildings as opposed to ―on‖ them. Projects may consider solutions other than the roof-mounting on the historic structure, such as roof-mounting on a nearby, non-historic structure, a carport over a parking area, or ground mounted array elsewhere on the property.

5.4 Step 4: Implement Project

The project is ready to be implemented once the project location, PV technology and size have been identified, stakeholders have been engaged, and all requirements have been considered and met. As previously mentioned, implementation may involve a number of stakeholders and will also require open communication between the solar installation sector and the historic preservation community. Consideration should be given to the impact of project implementation and construction on the function of the building or district and its occupants. Also, projects must be implemented to maintain structural and historical integrity while ensuring solar projects are installed to maximize generation of energy.

5.5 Step 5: Evaluate Effects of Project

Evaluating a project after implementation is an important step when installing solar projects on historic properties. By reviewing what was successful in the project implementation process, as well as what could be improved upon, the overall process can be improved to increase the rate of success of such projects in the future. Case studies or best practices can be created in order to share the experiences with other entities trying to replicate similar projects as well as with the public. Evaluations may be required through Section 106 during consultation, funding mechanisms (e.g. often grants will not be awarded in full without a post-installation evaluation), or for tax purposes. Evaluations are not typically done by historic preservation officers, but this may represent an area for improvement.

The project should be reviewed both during the process and after installation to analyze the coordination of stakeholders. The review should also consider impacts on historic integrity, policies, neighbors, appeal boards, SHPOs, etc. Some questions to ask during the review process include:

- Does the installation meet goals and expectations from an historic preservation perspective and from a technical, solar generation perspective?
- Is the system performing as expected, and is it cost effective?
- Does the completed project meet SOI Standards? and
- Did the project discourage project owners or stakeholders from undertaking future efforts?

In all instances, whether beneficial or negative, there is much to be learned from evaluating the process after the installation has been completed. The results of the evaluation should be shared with all stakeholders in order to inform future projects. The installed project can also be used for outreach and education to the historic and solar communities and the general public.

6. CASE STUDY

The Colorado Capitol Complex comprises 18 buildings in the downtown Denver, Colorado area. The maintenance staff faces issues like a limited budget for controlled maintenance, causing them to look for innovative ways to take care of buildings. In October 2008, Governor Bill Ritter announced that the Colorado State Capitol building was to become the first in the nation to obtain LEED certification for Existing Buildings (LEED-EB) for energy efficiency and environmental upgrades made over four years. The Capitol building, built between 1895 and 1903, was the first building in the country to receive the U.S. Green Building Council's new LEED-EB: Operations & Maintenance designation. The LEED certification system provides an outline for buildings to use less energy, water, and natural resources, and improve the indoor environment. The LEED-EB certification is awarded to those who can certify that an existing building has been retrofitted in a manner that demonstrates certain efficiency standards for its ongoing operations and maintenance. The Colorado State Capitol building received 41 out of 44 points submitted to attain certification. Other buildings within the Capitol Complex have received LEED certification as well.

The annual budget for energy within the Capitol Complex is approximately $3 million. Approximately $1 million is being saved annually due to the energy-saving retrofits, specifically lighting upgrades, the improvements to windows, boilers and chillers, and the electricity offset by the PV panels. The renovation team worked for more than four years to improve the energy efficiency of the buildings while protecting their historic integrity.

Building-specific improvements that have been made to the Capitol building in order to obtain LEED-EB certification include:

- Water conservation efforts such as low-flow toilets
- Use of low-energy light bulbs and T-8 light fixtures

- Improved energy controls
- Use of green cleaning products
- Initiation and maintenance of a recycling program
- Purchase of Energy Star® electronics and equipment
- Use of environmentally friendly landscaping products and plans
- Installation of 10-kW PV system.

The 10-kW PV system (approximately 40 panels) on the roof of the Capitol was intended as a demonstration project with educational benefits. The attic was converted into an educational area called Mr. Brown's Attic, where visitors can learn about Colorado's early history, Capitol construction, and the legislative process. From Mr. Brown's Attic, visitors can ascend 99 steps to an interior observation area that provides a 360-degree panoramic view of downtown Denver as well as a view of the PV system.[22]

With special access, visitors can also view the two inverters that convert the energy being produced by the solar panels from direct current (DC) into alternating current (AC) electricity so it can be used within the building's electrical systems. The panels are situated on the roof, just below the Capitol dome, so that they're not visible from street level. They face due south and due west to determine the decrease in efficiency between south-facing (optimal placement) and west-facing (less efficient) panels.

This project was funded through an Energy Savings Performance Contract with Chevron Energy. An additional project has been funded by a grant of $4.7 million from DOE for a ground-source heat pump heat/cool project in the Capitol as part of the Chevron Energy performance contract, which is estimated to cut utility bills by 30%. The savings associated with this additional work is $100,000 per year.

7. CONCLUSION

Addressing the barriers associated with siting PV installations on historic properties can help expand the nation's potential solar resources while also preserving its heritage. In this way, the solar and preservation communities can work together to meet growing renewable energy needs.

The first step to overcoming barriers successfully is to better understand the processes for both historic preservation and solar PV project implementation. Establishing criteria for each sector assists in achieving a successful project. Solar PV projects can be assessed based on performance, cost, and economic payback of the system. Historic preservation can be assessed subjectively based on how the project maintains cultural resources, minimizes impacts to the structure or area, and preserves the integrity of historic characteristics.

8. ACKNOWLEDGMENTS

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IMPROVING DISTRIBUTED WIND'S BOTTOM LINE: POLICY BEST PRACTICES

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ABSTRACT

This paper summarizes a financial analysis conducted to identify policy best practices as part of a project aiding the U.S. Department of Energy in reaching its goal to expand the number of distributed wind turbines deployed domestically fivefold by 2015. The project"s web-based policy comparison tool allows users to examine policies that have the most (and least) impact on improving the bottom line of wind turbines up to 100 kW in capacity that provide electricity for on-site use. The tool and accompanying guidebook, to be released in mid-2011, show how various policy combinations impact project economics and aid policymakers in determining the cost-effectiveness of incentive programs. To highlight attractive markets and policy targets that offer the quickest return on investment, states are ranked based on their current distributed wind incentives and market environments, and impacts on distributed wind project economics are calculated for various levels of a national feed-in tariff (FIT).

1. DISTRIBUTED WIND INCENTIVES: AN OVERVIEW

State and federal policies and incentives for distributed wind[1] have evolved during the last decade as the distributed wind market has matured. In 1999, 25 states offered financial incentives that supported distributed wind installations; 24 of these states provided tax incentives, one provided a rebate (California), and one provided both a rebate and tax incentive (Illinois).[2] Since then, policies for distributed wind have shifted from tax incentives towards rebates (also known as buy-downs), performance incentives, and grants. The number of states with tax incentives for distributed wind shrank from 24 in 1999 to 17 in 2010. Twenty-three states[3] plus Washington D.C., Puerto Rico, and the U.S. Virgin Islands provided rebates and/or performance-based incentives in 2010 for distributed wind installations, and an additional eight states operated grant programs.[4]

Six of those states (Arkansas, Colorado, Georgia, Minnesota, Utah, and Virginia), plus Puerto Rico and the U.S. Virgin Islands used federal funding made available through the American Recovery and Reinvestment Act of 2009 (ARRA) State Energy Program (SEP) to offer incentives for distributed wind. Several states, including Maine, Maryland, Vermont and Wyoming, supplemented existing programs that supported distributed wind with ARRA funding. Most of the ARRA-funded programs have already expired or will expire soon, and unless the states secure new funding mechanisms, these programs will not be continued. Ohio"s distributed wind incentive program was the only state-funded program that closed in 2010 because the state"s Advanced Energy Fund expired under state law. Other states, such as Illinois and New Hampshire, saw funding gaps in 2010 that temporarily closed their incentive programs.[5]

As of 2010, 43 states (and Washington D.C., Puerto Rico, and the U.S. Virgin Islands) had established net metering policies, compared to 27 states that had established such policies as of 1999. However, only 13 states[6] mandate true statewide net metering policies that apply to investor-owned utilities, rural electric cooperatives and municipal utilities; 19 state net metering policies apply only to investor-owned utilities whose primary customer base tends to correspond to urban and suburban areas, which in turn tend to have lower wind resources and additional zoning or permitting challenges when compared to rural areas. More recent additions to the distributed wind policy landscape include meter aggregation within net metering policies, incentive designs based on actual or estimated production instead of capacity, and Property Assessed Clean Energy (PACE), which to date has been applied only a handful of times for distributed wind installations and is currently in flux as a viable policy option.

In addition, many state incentive programs require that turbines and/or installers be certified in order for a project to qualify for funding. The Energy Trust of Oregon and Wisconsin"s Focus on Energy program are the first to require certification from the Small Wind Certification Council (SWCC) in order for turbines to be eligible for incentives (starting January 1, 2012). The New York State Energy Research and Development Authority (NYSERDA) accepts SWCC certification for qualification for rebates, and the Massachusetts Clean Energy Center (MassCEC) now requires either SWCC certification or NYSERDA qualification. Programs in California, Colorado, Iowa, Maine, Maryland, Minnesota, Nevada, and Vermont have indicated their intention to follow suit.[7]

Another policy relevant to the distributed wind market is the renewables portfolio standard (RPS). Twenty-nine states have established RPS policies, and several of these policies specifically address distributed generation and directly affect the distributed wind market. For example, New York and New Hampshire fund their respective rebate programs through their RPS policies. Renewable energy credits (RECs) may also represent a revenue stream for distributed wind facilities both within compliance markets and voluntary markets throughout the United States, particularly in states with RPS carve-outs for distributed generation (including Arizona, Colorado, and New Mexico). It should be noted that some incentive programs and some net metering policies require that the distributed generator relinquish RECs to the program administrator or utility in order to receive the incentive or participate in net metering. In these situations, the distributed wind generator would not be able to sell those RECs separately.

On the federal side, tax incentives for distributed wind have improved greatly in recent years. The federal government removed dollar caps in 2008 for Investment Tax Credits (ITC), so eligible homeowners and businesses are allowed to claim a full 30% ITC for qualified distributed wind energy property placed in service through 2016. In lieu of tax credits, the federal government offers U.S. Treasury Grants for commercial projects that begin construction before the January 1, 2012. Also, in 2008 the Modified Accelerated Cost-Recovery System (MACRS) was expanded to include distributed wind in its five-year schedule.

Federal grants and loans are also playing a role in the growth of distributed wind. The USDA operates several programs that provide grants and loans for distributed generation, including the Rural Energy for America Program (REAP), Rural Business Opportunity Grants, and the Value-Added Producer Grants program. Other federal programs, such as Energy Efficiency and Conservation Block Grant program (EECBG), and the Tennessee Valley Authority have supported distributed wind projects.

1.1 Project Background

"Power Through Policy: „Best Practices" for Cost-Effective Distributed Wind" is a Department of Energy (DOE)-funded project to identify distributed wind technology policy best practices and help utilities and policymakers examine their effectiveness using a pro forma model. The project is one of 53 awarded with funding in part provided through ARRA to address market challenges identified in DOE"s "20% Wind Energy by 2030" report.[8] Project team members include eFormative Options, Pacific Northwest National Laboratory, National Renewable Energy Laboratory (NREL), and the North Carolina Solar Center.

The project"s main deliverables include the web-based Distributed Wind Policy Comparison Tool and accompanying guidebook, to be released in mid-2011. The guidebook will summarize the findings of the project"s distributed wind best practices research and include case studies in a comprehensive format written primarily for state-level decision makers – the target audience. The tool and guidebook are designed to help policymakers, utilities and advocates advance the market for on-site wind generation across the nation. The project is focused on addressing key market challenges and helping to ensure public dollars supporting distributed wind are spent wisely. With improved policies in place, wind turbines sited near the point of end-use can quickly ramp-up to meet local demand, allowing distributed wind to play an important role in reaching DOE"s 20% wind by 2030 goal and in our energy future.

1.2 Distributed Wind Policy Comparison Tool

The web-based Distributed Wind Policy Comparison Tool allows users to examine policies that have the most (and least) impact on improving the bottom line of wind turbines up to 100 kW in capacity that provide electricity for on-site use, with the goal of expanding the distributed wind market through an improved U.S. policy environment.

1.3 Purpose of Tool

The web tool‟s financial pro forma model measures the impact of various policy combinations on distributed wind turbine project economics and can be used to rank the "best" and "worst" state markets. The model allows each state‟s incentives to be modeled for a variety of ownership sectors, turbines and wind resources. The tool calculates cost of energy (COE), net present value (NPV), internal rate of return (IRR), and simple payback for each scenario. Designed for broad policy analysis, the model is not a project-specific siting tool and is not capable of addressing site-specific variables.

Based on the initial inputs of state and project sector (residential, non-taxed or commercial), the tool is populated with default values based on current market conditions, reasonable assumptions, and a link to a customized, live data feed from the Database of State Incentives for Renewables & Efficiency (DSIRE) that is regularly updated as incentives and policies evolve. The web tool provides users with the base-case scenario, and users may adjust numerous default values through a dashboard interface. Enabling adjustable inputs allows the tool to stay current and flexible as state policies and market conditions change. While primarily aimed at providing users an easy way to understand the anticipated financial outcome, the dashboard environment allows "what if" scenarios to be evaluated very quickly. This feature will allow electric utilities, policy decision makers, and others to view and understand the impact of various factors, such as tariff rates and REC prices, on specific project scenarios. Also, modeling different combinations of these variables (and adjusting the variables themselves) allows users to see the effects that distinct policy options have on the COE and project economics and to identify optimal combinations of policy options that maximize cost-effectiveness of distributed wind turbines.

1.4 Inputs and Assumptions

The tool‟s inputs include income and sales tax rates, income tax credits (federal and state), income tax deductions, wind turbine performance, estimated project costs, and tower heights, capital cost rebates and performance-based incentives, discount rates for net present value calculations, cost-escalation rates, depreciation, interconnection and permitting costs, state production tax credits (PTC), RECs, wind power class resources and state net metering policies. Federal and state grants are not included. Given the competitive nature of grants, there is a great deal of uncertainty that a particular project would receive such an award and therefore, grants are excluded. The lone exception is the U.S. Treasury Grant (in lieu of the federal ITC), which is included. The federal PTC is excluded because this tool is intended to model project economics assuming on-site consumption of energy generated by distributed wind turbines. (To qualify for the federal PTC, energy must be sold to an unrelated third-party.) State PTCs, where applicable, are included. The model does not attempt to capture and monetize state property tax incentives because site-specific property tax rates (which are locally determined) and property values must be known.

The model assumes that project owners may claim all of the available tax credits and deductions in the year such incentives are awarded. In other words, the project owner‟s tax liability is always greater than tax incentives. Also, the model makes assumptions regarding what is considered taxable income, and what is tax-deductible.

Not all turbines within the model are eligible for incentives in every state, based on state-specific turbine certification requirements. However, the model does not take those certification requirements into account and for comparison purposes treats all turbines as eligible as long as size eligibility requirements are met.

A state is considered to have a state-wide net metering policy only if net metering is consistently offered by the rural electric cooperatives, municipal utilities, and investor-owned utilities operating in that state. The net metering rate is assumed to be the full retail rate in these cases. For states without net metering, or for which net metering policies only apply to certain utilities, the assumption is that the electricity generated would only receive the avoided-cost rate from the utility (estimated at 41% of retail value).

Each turbine/tower combination is assigned default zoning/permitting and interconnection costs based on team research and feedback from turbine manufacturers and installers. While many states have established interconnection policies, teasing out costs (which are usually correlated with turbine size) from those policies was challenging. In reality, different states, counties, municipalities and even utilities have specific (and highly variable) costs associated with zoning, permitting and interconnection. Documenting those costs and including them in this model are beyond the scope of the project.

The model was pre-populated with specific turbines at varying hub heights, selected based on their U.S. market share and progress toward SWCC certification. Specifications are based on manufacturer documentation and standards. Turbine power curves are manufacturer-supplied or those tested and verified by NREL. Ultimately, the project would like to include SWCC-certified power curves in the model when they become available. The power curves assume standard conditions (0 feet elevation, sea level air density) reflecting how manufacturers‟ curves are typically presented.

Wind power resource options are limited to low and mid Class 2 (average 5.1 – 5.5 m/s at 30 m hub height[9]), low and mid Class 3 (average 5.8 – 6.1 m/s at 30 m), and low Class 4 (average 6.4 m/s at 30 m), with each state assigned a default wind resource class based on AWS Truepower‟s ranking.[10]

A complete list of assumptions used in the model is included with the web-based tool.

2. CASE STUDIES

While the guidebook will include a variety of case studies, two case studies were prepared for this paper. The first case study ranks all the states based on their current incentives and policies. The other exercise demonstrates the impact a national FIT would have on distributed wind project economics across the states. Both case studies were assembled based on incentives and policies as of February 2011.

For these case studies, the economics for each state and each sector were established with base case assumptions as follows:

- The typical wind resource assigned to each state is based on state wind resource maps. These wind resources are either low Class 2, mid Class 2, or low Class 3 to represent the fact that distributed wind turbines are typically not located in high wind resource areas.
- The Commercial sector default wind turbine is the Northwind 100 kW, with a 121-foot (37 m) tower.
- The Non-Taxed sector (Governmental and Non-profit entities) default wind turbine is the Endurance E3120 50 kW, with a 140-foot (43.7 m) tower.
- The Residential sector default wind turbine for these case studies[11] is the Southwest Windpower Skystream 2.4 kW, with a 70-foot (21.3 m) tower.

2.1 State Ranking

To rank the states, the IRR and COE results from each sector were averaged for each state (Figures 1 and 2). In cases where the IRR was indeterminable (i.e., there were no positive cash flows over the 20 year project life), an IRR value of 0% was assigned to use in the average calculations.

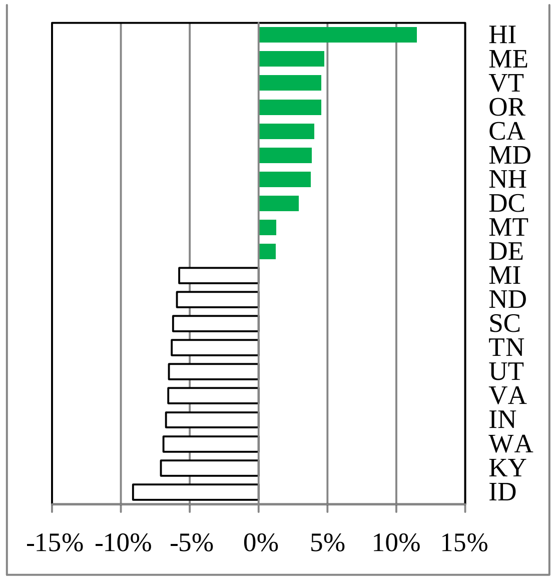

Fig. 1 Average IRR results of base case scenarios of current policies and incentives.

With respect to average IRR across the sectors, the top 10 states are Hawaii, Maine, Vermont, Oregon, California, Maryland, New Hampshire, the District of Columbia, Montana, and Delaware. The bottom 10 states are North Dakota, South Carolina, Michigan, Tennessee, Utah, Virginia, Indiana, Washington, Kentucky, and Idaho.

It is not surprising that Hawaii comes out on top given that its retail electric rates are the highest in the county. Hawaii also has statewide net metering and a tax credit. The remaining top nine states have favorable economics as well given relatively high electric rates (with the exception of Oregon and Montana) as well as a combination of favorable policies and incentives. All of the top ten states have actual statewide net metering policies. With the exception of Vermont, all of the top ten states also have RPS policies. (Vermont‟s RPS policy is technically a goal.) Eight of these states provide rebates for distributed wind. And, several of the top ten states offer at least two financial incentives available for distributed wind installations.

Idaho has the worst average IRR in the United States; it also has the lowest electricity rates for each sector and does not have a statewide net metering policy. Idaho does offer a tax deduction, but no additional incentives for distributed wind projects. Net metering is not available statewide for any of the states with the lowest IRR. Only two of the bottom states (Michigan and Washington) have RPS policies, and three states (North Dakota, Utah, Virginia) have non-binding RPS goals. The remaining bottom five states have not established an RPS policy. Regarding financial incentives offered in these states, only Washington offers a cash incentive, which is performance-based and limited to $5,000 per year for wind. South Carolina and Virginia do not offer any financial incentives for distributed wind. Michigan, North Dakota, Tennessee and Indiana offer property tax incentives, but property taxes are not included in this analysis. North Dakota, Utah, Kentucky and Idaho provide either an income tax credit or a tax deduction. Finally, Utah, Washington and Idaho offer sales tax incentives for distributed wind. Despite these incentives, the average IRR results for these states are not favorable.

With respect to average COE across the sectors, the top 10 states are Oregon, Massachusetts, Minnesota, Montana, New Jersey, Georgia, Iowa, Nevada, North Carolina and Vermont. The bottom 10 are Kentucky, Virginia, West Virginia, South Carolina, Michigan, Florida, Connecticut, Tennessee, Mississippi and Indiana (Fig. 2).

It is important to examine both metrics because some incentives do not impact the cash flows of a distributed wind project and others do not reduce the costs of the system. For example, the sale of RECs improves the cash flows of a project, but it does not impact the COE. The COE takes into account equipment and installation costs and taxes, rebates (capacity-based and production-based), grants, income tax credits and deductions, and the tax shield effect of depreciation and loan interest payments.

Oregon‟s tax credit, rebate and lack of a state sales tax effectively lower the COE of distributed wind in that state. Alternately, Indiana offers no incentives that impact the COE.

2.2 Impact of Feed-in Tariff

The next case study demonstrates the impact a national FIT would have on distributed wind project economics across the U.S. states by presenting the residential sector results from a few states chosen to represent different regions of the country. When a project owner elects to participate in a FIT program, the owner is typically not eligible to also participate in a net metering program. In addition, the RECs associated with the energy sold through a FIT are typically transferred as part of the FIT. Therefore, the FIT case study assumes no net metering or REC sales in any of the states.

Figure 3 and Table 1 show the results of the different FIT rates on the residential sector for each of the selected states with each state‟s assigned typical wind resource. The residential sector wind turbine is the Southwest Windpower Skystream 2.4 kW, with a 70-foot (21.3 m) tower. Given that the FIT is not a cost, but a revenue stream, it does not affect the scenario‟s COE. The project economic metrics improve as the amount of the FIT increases.

For states with few or no distributed wind policies or incentives and modest wind resources, such as Virginia, it takes a FIT of $0.50/kWh, similar to the level offered in the UK, to achieve positive project economics. For states with strong incentives and wind resources, such as Minnesota, it is possible to achieve positive project economics with a lower FIT rate.

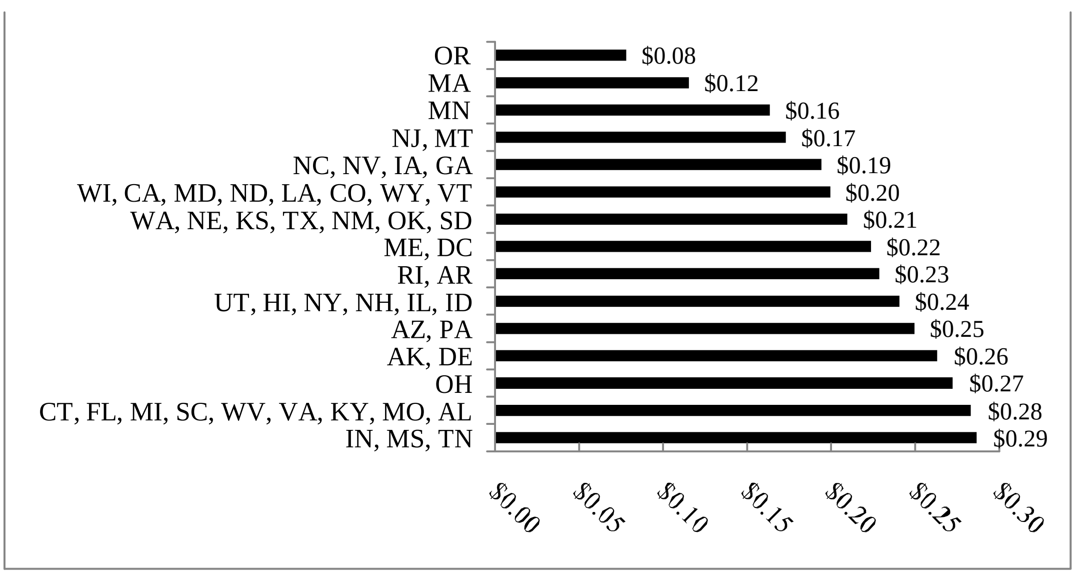

Fig. 2 Average COE results of base case scenarios of current policies and incentives.

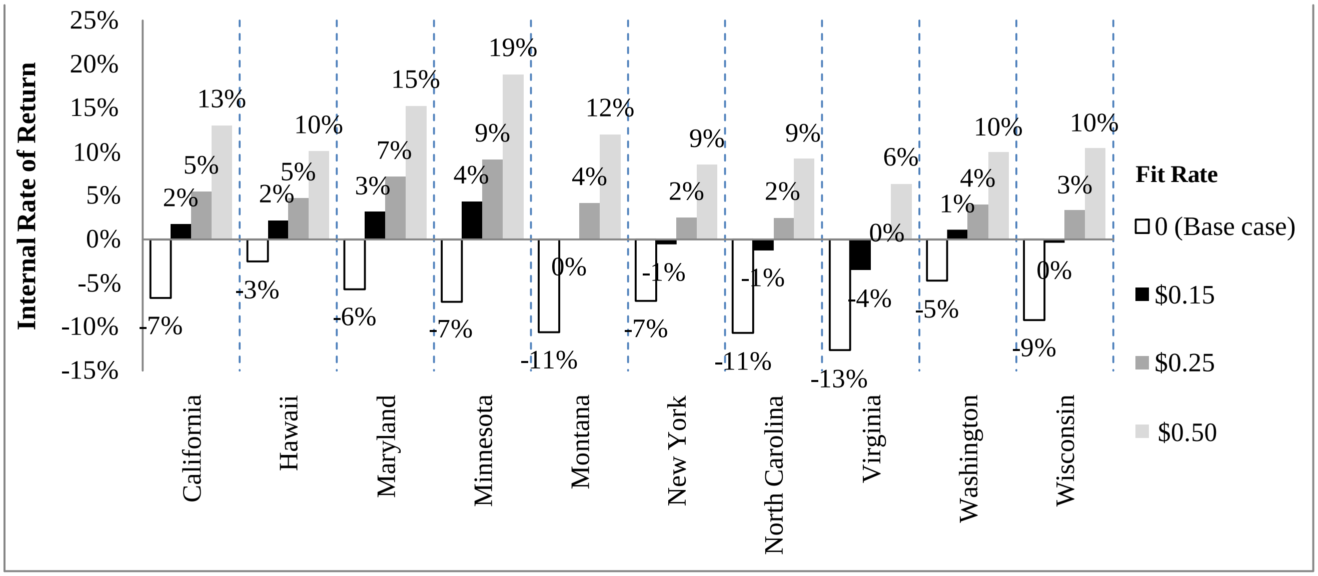

Fig. 3 Select IRR Results of modeling FIT rates vs. base case for the residential sector.

TABLE 1. RESULTS OF MODELING FIT RATES VS. BASE CASE FOR THE RESIDENTIAL SECTOR

		California	Hawaii	Maryland	Minnesota	Montana	New York	Carolina North	Virginia	Washington	Wisconsin
	Wind Res ource	Low Clas s 2	Low Clas s 2	Low Clas s 2	Mid Clas s 2	Low Clas s 3	Low Clas s 2	Low Clas s 2	Low Clas s 2	Low Clas s 2	Low Clas s 2
FIT Rate,	**COE, $/k Wh**	$0.27	$0.38	$0.24	$0.19	$0.28	$0.38	$0.26	$0.42	$0.30	$0.31
0 (Bas e cas e)	**NPV, $**	($6,888)	($7,893)	($5,785)	($6,641)	($11,336)	($9,975)	($9,531)	($12,825)	($9,023)	($8,677)
	IRR	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
	Simple Payback,	> 20	> 20	> 20	> 20	> 20	> 20	> 20	> 20	> 20	> 20
$0.15	**NPV, $**	($2,990)	($4,028)	($1,834)	($1,201)	($5,741)	($6,122)	($5,693)	($8,864)	($4,903)	($4,811)
	IRR	2%	2%	3%	4%	0%	-1%	-1%	-4%	1%	0%
	Simple Payback,	17	17	15	14	> 20	> 20	> 20	> 20	18	> 20
$0.25	**NPV, $**	($392)	($1,452)	$799	$2,427	($2,011)	($3,553)	($3,135)	($6,223)	($2,155)	($2,233)
	IRR	5%	5%	7%	9%	4%	2%	2%	0%	4%	3%
	Simple Payback,	12	13	11	9	14	16	16	> 20	14	15
$0.50	**NPV, $**	$6,105	$4,990	$7,384	$11,495	$7,314	$2,870	$3,261	$378	$4,712	$4,210
	IRR	13%	10%	15%	19%	12%	9%	9%	6%	10%	10%
	Simple Payback,	7	9	6	5	8	10	9	11	9	8

3. SUMMARY

The two case studies provided demonstrate how the tool can both provide insight into a “what if” scenario and also allow the current status of incentives to be examined. Federal and state polices and incentives evolve regularly. The tool can be used to gauge how those changes impact the economics of distributed wind, and subsequently its market growth, and allow policy makers to determine the effectiveness of individual incentive programs, thereby addressing market challenges identified in the DOE “20% Wind Energy by 2030” report.

The goal of the DOE Wind & Water Power Program's distributed wind energy activities is to expand the number of distributed wind turbines (1 kilowatt to 1 Megawatt) deployed in the U.S. market fivefold, from a baseline of 2,400 turbines installed in 2007 to 12,000 turbines installed by 2015.[12] Distributed wind‟s market growth is on a strong trajectory to meet or surpass this goal, even despite the fact that the number of 1-100 kW wind turbines installed in the U.S. in 2009 was down 20% from 2008. (The average kW of installations increased due to larger average turbine sizes.)[13]

By measuring the impact of various policy combinations on the cost of energy and highlighting attractive state markets for small wind turbines, this project‟s web tool and guidebook will assist to advance on-site wind energy and promote market growth. The case studies and interactive web tool provide valuable information on market opportunities, benefits, challenges, and needed improvements. In providing a simple and clear policy analysis tool that estimates financial performance, the project is expected to enhance market expansion by increasing and refining the understanding of distributed wind costs, incentives, and key market opportunities.

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Additional information for this project was provided by state energy program managers. Numerous reviewers and advisers provided valuable feedback on draft materials.

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[1] Defined for this project as grid-connected wind turbines up to and including 100 kilowatts (kW)

[2] Forsyth, T., P. Tu, and J. Gilbert (2000). Economics of Grid-Connected Small Wind Turbines in the Domestic Market. National Renewable Energy Laboratory, Golden CO. NREL Report No. CP-500-26975 www.nrel.gov/docs/fy00osti/26975.pdf

[3] AR, CA, CO, DE, GA, HI, IL, ME, MD, MA, MN, NV, NH, NJ, NY, OH, OR, UT, VT, VA, WA, WI, WY.

[4] Database of State Incentives for Renewables & Efficiency (DSIRE) www.dsireusa.org

[5] Ibid.

[6] The 13 states with net metering policies that apply to all types of utilities are CA, DE, GA, HI, LA, ME, MD, MN, MT, NE, NH, OR, VT; DSIRE

[7] Small Wind Certification Council January 2011 newsletter www.smallwindcertification.org

[8] The full report is available on the US DOE web site: www1.eere.energy.gov/windandhydro/pdfs/41869.pdf

[9] 30 m = approximately 98 feet; model assumes shear factor of 0.18, typical for areas with low surface roughness; shear at actual sites varies from 0.1 - 0.3

[10] AWS Truepower state ranking: www.windpoweringamerica.gov/wind_maps.asp#potential

[11] The web-based Policy Comparison Tool also offers the Bergey Excel 10 kW with a 100-foot (30.5 m) tower as an alternate default wind turbine selection for the Residential sector

[12] Wind and Hydropower Technologies Program. Wind Energy Multiyear Program Plan for 2007-2012 www1.eere.energy.gov/windandhydro/pdfs/40593.pdf

[13] AWEA Small Wind Turbine Global Market Study 2010 http://www.awea.org/learnabout/smallwind/loader.cfm?csModule=security/getfile&PageID=4420

DESERTEC AND TRANSGREEN

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A CASE STUDY FOR LOCAL, NATIONAL AND INTERNATIONAL JURIDICIAL BARRIERS FACED BY CONTINENTAL-SCALE SOLAR GENERATION DEPLOYMENT

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ABSTRACT

This study examines and identifies the extant localized, regional and international statutory and regulatory barriers faced by DESERTEC and similar continental-scale solar initiatives. Through examination of primary stakeholders' varied motivations and competing interests we identify the primary technical, political and financial rationale behind such barriers. Furthermore, by comparing regulatory initiatives successful in overcoming similar barriers around the world, we propose a portfolio of solutions applicable to the DESERTEC concept.

Finally, we provide a brief discussion of the statutory and regulatory parallels between DESERTEC and continental-scale solar generation deployment scenarios in North America.

1. INTRODUCTION

The world's sub-arctic deserts cover approximately 36 million km^2, or nearly 25% of the earth's landmass.[1] These deserts receive—in just under six hours—enough solar energy to meet global primary energy demands for an entire year. With current solar PV technologies, it is possible to economically convert ~15% of the incoming solar resource into electricity. Therefore, only 1% of the world's desert surface area is required to produce all of mankind's energy needs via the production of electricity.[2]

The idea of harnessing energy from the world's deserts has been percolating within the scientific community for quite some time. The combination of vast tracts of –otherwise unproductive-- land with extraordinarily high levels of solar resource in the Saharan and Arabian deserts make the production of electricity from solar energy technologies in these areas a logical conclusion.

Multiple proposals for large-scale solar development and widespread electrical-grid interconnection in the Europe, Middle East and North Africa (EUMENA)[1] region hope to meet several parallel goals. The first and most important of these is providing emissions-free electricity to meet growing demand on both sides of the Mediterranean—thereby helping to stymie the inexorable march of climate change and help to mitigate its potentially deleterious effects. The second is to help further develop regional cooperation by strengthening economic and political ties amongst the individual sovereign states. It is thought that this will help engender peace, stability and social welfare for those living in this region.[3]

The furthest developed of these proposals is the DESERTEC initiative—which sets a target of providing 15% of Europe's electrical energy needs from the trans-Mediterranean import of solar and wind power generated in the Middle Eastern and North African (MENA) region by 2050. A complementary French-led initiative—Transgreen—focuses on the construction of requisite sub-sea High-Voltage DC (HVDC) transmission grids than the construction of solar generating facilities themselves.

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[1] The EU part of EUMENA includes all EU-member countries while the MENA part of EUMENA includes Morocco, Algeria, Tunisia, Libya, Egypt, Yemen, UAE, Saudi Arabia, Qatar, Kuwait, Bahrain, Oman, Syria, Lebanon, Jordan, Israel, Iraq and Iran.

Both initiatives fall under the regulatory framework of the European Union's Mediterranean Solar Plan (MSP)—one of several plans for economic and social rapprochement in EUMENA set forth by the European Union's External Action Service. This plan targets installation of 20 GW of solar energy capacity in the Mediterranean basin by 2020. While these goals are certainly laudable, and one might argue; necessary, they are not without their obstacles. This paper will detail the most influential of these developmental barriers, and discuss possible regulatory solutions to help overcome or circumvent these obstacles.[2]

2. DESERTEC: PROSPECTS, MOTIVATIONS

DESERTEC is an abbreviation of "DESERts TEChnology", and was incorporated as a not-for-profit foundation in Germany in January of 2009. The primary goal of the DESERTEC foundation, as mentioned above is to facilitate the widespread deployment of solar (and other renewable) technologies in the Saharan and Arabian Deserts and an interconnected electrical power grid in the EUMENA region.

2.1 PV, CSP and an HVDC 'Supergrid'

The DESERTEC plan calls for supplying a 'substantial part' of the energy needs of the MENA countries and for meeting 15% of Europe's electricity demand from imported wind and solar sources by 2050. [2] Most of the Maghreb, Sahara, Nile Valley and Arabian Peninsula are stipulated to be regions for construction of CSP plants. Likewise, the high-wind areas along the Atlantic and North Sea EUMENA coasts are proposed sites for most of the wind generation proposed in the plan. Estimated cumulative investment required to construct the power generation facilities to meet the 15% by 2050 target are upwards of $350 Billion.

HVDC 'supergrid': Because of the high loss-factors inherent in transmission of power over long distances via conventional AC lines, in order for substantial power to be transferred at low loss across the Mediterranean, a high-voltage DC backbone is proposed. Total cumulative capital outlays to construct this network are estimated to reach $45 Billion by 2050.[2, 4, 5]

As proof of concept, many high-capacity underwater HVDC cable systems are already operating in Europe as of this writing. At least 13 such lines bridge the British Isles to continental Europe and connect the considerable hydropower resources of Scandinavia to Germany, Poland and the Netherlands. Indeed, over 100 HVDC projects worldwide have been constructed since the groundbreaking of the first such project in 1954: the Gotland Link.[6] Four main interconnections that form the core of the DESERTEC vision propose to connect Western Algeria to Spanish Andalusia, Eastern Algeria to Sardinia and Sicily to Tunis and Tripoli.[2]

A critical pre-requisite of the DESERTEC plan is keeping the cost of electricity generated from these sources to a minimum. At today's costs, a CSP plant in the MENA region generates (unsubsidized) electricity at 0.14 c/kWh. Once the total installed capacity of CSP facilities reaches the 100 GW mark (we are at 415 MW today), scale economies are expected to drive the cost down to 0.04 c/kWh.[2]

3. SOCIO-POLITICAL/ECONOMIC VIABILITY

The support of decision-makers on both sides of the Mediterranean both within the context of individual countries, and on an international level are required to transform the DESERTEC vision into reality. In the following section, we will explore some of the sometimes hidden motivations and agendas that influence political discourse and development of regulation. Correspondingly, we will discuss some of the primary barriers to financial viability of the project and highlight ways in which various stakeholders have or are planning to overcome these barriers. Of course, both political viability and financial viability are heavily interdependent, and while one might not necessarily imply the existence of the other, understanding the motivations underlying the actions of key stakeholders is central to crafting effective legislation.

3.1 Political Viability: Barriers and Solutions

There are many ways in which the government of a sovereign state in the EUMENA region can engender the development of renewable energy on their own. In many cases though, the economic interrelationships, vested interests and nature of the political structures make a multi-lateral approach to diffusion of renewable energy more preferential.

Vested Interests and Stranded Costs: If by 2050, as DESERTEC envisions, Nuclear Energy is to be entirely phased out in Europe and the fossil fuel generating capacity

[2] As Transgreen is a much more recent initiative, there is little literature on the specifics of the initiative. As such, most of the discussion in this paper is centered around the much older DESERTEC concept, although lessons learned and issues identified affect both initiatives equally.

is to be halved (in Europe) or remain at present-day levels (in North Africa), there are sure to be some big losers.

The context that first comes to mind is the case of the France, which derives nearly 80% of its power from its fleet of 59 nuclear reactors.[7] Ever since the nationalization of the French electric power industry in 1946, Electricite de France (EDF) has been central to the rapid transition of France's power generation schema to one wholly dependent on Nuclear Power. In effect, the French taxpayer has footed the bill for the decades of massive capital expenditures that helped to facilitate this process. Clearly, EDF—the largest energy company in the world which is still over 80% owned by the French Government—has enormous sunk costs on its balance sheet that it is intent on repaying.[8]

Similarly, Areva NC, the 'largest nuclear company in the world,' which is vertically integrated in every aspect of the nuclear fuel-cycle from mining and milling to reprocessing and recycling is 93% owned by the French government.[9]

Even though popular support errs slightly against the Nuclear industry in France—57% of the French population were 'opposed to nuclear energy' according to a recent poll—French politicians stand to lose an enormous amount of political capital if they promote a technological paradigm that threatens the entrenched interests of the French nuclear industry.[10]

In the MENA region, many of these countries' entire economies are predicated on the exportation and cheap availability of fossil fuels. The United Arab Emirates for example, derives 85% of its export revenue from the trade of petroleum and natural gas. Additionally, because of its status as a major oil producer, the UAE is able to massively subsidize the cost of electricity—supplied at as little as 5% of generation costs. Because of the power and wealth concentration native to absolute monarchies, the decision-making process often winds up in the hands of the Emirs, who are very clearly benefactors of the lucrative status-quo.[11, 12]

Despite the outward appearance that there is little (financial) incentive for UAE leadership to push for development of (initially) more costly renewable technologies, some Emirates—like Abu Dhabi—are spearheading initiatives that are doing just that. Of particular interest is Masdar: a globally backed, $22 billion project initiated in 2006 that hopes to turn Abu Dhabi into an "international hub for renewable energy." Key to this proposal are the ideas that this project should help Abu Dhabi turn into a net technology developer and exporter in the renewable energy field and help transform the Emirate into a knowledge based economy.[13]

It seems that any vested financial interests the UAE decision-makers might have in the fossil fuel industry are in this case offset by the promise that economic diversification can bring. Throughout the MENA region, wherever economies are dominated by particular exports, potential legislation has to ensure that those with vested stakes in the current paradigm are offered a chance to collaborate in any development that DESERTEC, Transgreen, or similar initiatives might bring.

<u>Regional Economic Growth:</u> Although the proposed CSP-centric DESERTEC proposal forecasts a reduction in the cost of electricity to well below today's levels by 2050—owing to economies of scale—the costs are currently much higher than electricity generated from traditional sources. If these costs are indeed higher in the DESERTEC CSP scheme, what will be the impacts on regional economic growth? In many of the MENA countries this growth is predicated on high consumer subsidies for electricity—as highlighted previously. [2, 11, 12]

On the surface, the economic interests of the MENA countries who are proposed to host the majority of the solar generation capacity would appear to be harmed. Upon closer examination, it is clear that the benefits to development could outweigh the costs if policies are appropriately structured. Firstly, employment creation is necessary for large-scale development projects of this nature. Locally-sourced labor for the construction, operation and maintenance of the CSP, PV and wind facilities, and transmission networks are an expected consequence. Energy exports, if the sovereignty of the host countries decides to pursue them, could supplement or eventually take the place once held by fossil fuel exports.

Key drivers for buy-in from the leadership of MENA countries (as aside from Morocco, there is no high-level state support for DESERTEC or related initiatives) are the concepts of technology- and knowledge-transfer.[14] Only by ensuring host countries are not left out of the value chain—manufacturing, development, design, and education—will the DESERTEC and Transgreen proposals enjoy broad-spectrum political support. Were one to place oneself in the perspective of a lawmaker in Tunisia considering a subsidy to CSP development in one's jurisdiction, one would want to ensure that some of the capital outlays wound up back in the hands of Tunisian manufacturers. In a recent report published by a prominent Algerian think-tank, these concerns are echoed.

According to the report's authors, the three primary goals which surfaced in discussions amongst leadership of Algeria's major political parties were: "Creation of jobs in the Algerian economy; Establishment of a domestic renewable energy industry; and Transfer of know-how and technologies from Europe to Algeria."[14]

Ethical Responsibility – Colonialism's Aftershocks: In the words of former Algerian Energy Minister Chakib Khelil: "We don't want foreign companies to exploit our energy resources." This lack of trust between high-ranking officials in MENA states and their European counterparts is still strong—and perhaps warranted--as the colonial legacy is not remembered so positively.[15]

Do European countries have an ethical responsibility to repay countries they exploited for the windfall profits their companies made under colonial rule, and should this figure into plans for multinational solar development plans envisioned by DESERTEC and Transgreen? The issue of reparations is highly contentious: arguments beseeching reparations for the slave trade nearly grounded the World Conference Against Racism in Durban in 2001.[16] Luckily, the DESERTEC vision foresees an enormous foreign investment potential in the MENA countries. The influx of capital and creation of jobs—as long as it is paralleled by a transfer of knowledge and technology to MENA-based entities--will likely assuage fears of renewed colonial exploitation.

Facilitating Trade: The countries that form the EU-27 have been running a consistent trade deficit with their neighbors to the south of the Mediterranean (MED countries) for at least the past decade. The latest reported statistics (2008) from the European Commission cite the highest recorded trade deficit with MED countries in history—€38 billion—owing mostly to the rise in cost and quantity of fossil fuels imported into mainland Europe from Algeria and Libya.[17] How will the proposed DESERTEC initiative affect the balance of interregional trade, and should these considerations influence policymakers on either side of the Mediterranean?

One can imagine a hypothetical scenario surrounding the construction, operation and development of a large-scale CSP facility of the variety suggested by DESERTEC. If, at the behest of pressures within MENA countries, enough knowledge and technological prowess is transferred to these countries from Europe, the EU stands to lose even more ground to competitors in the manufacture of goods and the supply of high-tech services. Likewise, if as prognosticated, power will be sold from the MENA countries to the EU, the trade imbalance promises to widen even further.

Herein lies the paradox of the DESERTEC plan—in order to incentivize MENA leadership buy-in, EU leaders would be well served to facilitate greater technology transfer towards the MENA states. But by so doing, EU member states could stand to further widen their trade deficits—which could spell loss of employment on the European continent.[18] Thus, a careful consideration is needed when strategizing how to finance and structure off-take agreements at the international level, to ensure that bilateral flow of goods and services is—at the very least—maintained at current levels.

Trade between countries on either side of the Mediterranean Sea is loosely governed by an agreement called the 'Euro-Mediterranean Partnership.' This agreement was ratified in 1995 as "The Barcelona Process by Foreign Ministers of each of the then 15 EU member states and 14 Mediterranean partners with the eventual goal of establishing a Euro-Mediterranean Free Trade Area.[19] The Barcelona Process/Euro-Mediterranean Partnership has since expanded its scope to include all manner of social, political, cultural and human rapprochement—in addition to continuing moves toward open regional trade—and is called the Union for the Mediterranean (UfM.)

The UfM has indeed helped reduce trade barriers on both sides of the Mediterranean since the inception of the Barcelona Process: Exports to the MED countries from the EU have jumped by 5% while imports from the MED countries have jumped by over 8% from 1995-2004. Although these statistics represent a divergence in imports and exports, it has certainly spelt a rapid increase in the quantity of foreign direct investment (FDI) in the region.[20] Both DESERTEC's and Transgreen's plans seem at the outset to meld well with the stated mission of the UfM and its EUMENA partners as expounded in the Barcelona Declaration. The initiative promises to strengthen economic (and technological) interconnectedness while further stimulating interregional dialogue—even though it may if not properly negotiated increase trade imbalances.

Siting Concerns: Some would argue that the DESERTEC foundation's plan to pave over the MENA's deserts to generate electricity from the sun is a double-edged sword. On the one hand, renewable power purports to bring with it all of the environmental benefits inherent to carbon and atomic-neutral power generation, yet on the other, law makers and citizens are—rightly—concerned about the sensitivity of the desert ecosystem. [21] While skepticism is always justified, when put into context, it is clear that the environmental 'burdens' are largely outweighed by the benefits. According to studies by the German Aerospace Institute (DLR), the 15% target for power imports from MENA to Europe by 2050 will require 2,500 km^2 of desert surface area for the CSP plants themselves and 3500 km^2 covered by the new HVDC lines proposed throughout the EUMENA. While these seem like large numbers, this combined area amounts to just over one hundredth of one percent of the 12 million km^2 MENA region. In fact, the man-made Nasser Reservoir, which dams the Nile River near the Sudanese border in Egypt, floods about the same desert surface area as would the proposed CSP and HVDC network above—and only produces 3% of the power.[2, 4, 5]

Why not continue with smaller, decentralized PV and wind projects in Europe itself instead of enormous centralized solar facilities in the desert? Similar arguments that are made against the centralized nature of conventional power generation can also be made against the DESERTEC concept—that small, decentralized solar and wind plants located in proximity to load centers offer an environmental advantage in the reduction of transmission costs and their associated burdens.[22] On the flip side, in large un-built tracts of the desert, scaling and the associated cost reductions there-from are more readily achieved. Many corollary socioeconomic benefits also stem from buildup of infrastructure in the MENA region, a fact that is of certain consideration for decision-makers crafting enabling policy frameworks. We will discuss these in detail in the following sections.

3.2 Financial Viability: Barriers and Solutions

Perhaps antecedent to political viability, or certainly strongly co-dependent upon it, is the economic or investment viability for the development of large-scale solar facilities and associated infrastructure in the desert.

Lack of Internal Financing: Wind and Solar development projects are characterized by high up-front capital costs and long payback times. As the non-Gulf states in MENA do not have adequate pubic and private capital internally available to meet the rapid deployment of the DESERTEC plan, financing such development will likely fall to the external capital and debt markets. A central 'Sustainable Energy Financing Initiative' handling mobilization of financing on the international level was recently proposed by the European Commission to be jointly chaired with the European Investment Bank (EIB.) This investment vehicle would essentially combine public and private funding to provide leveraged access to low interest financing for such projects as DESERTEC.

Under the banner of the UfM, and the European Union's targets for renewable energy adoption and CO_2 emissions reductions, the EIB has pledged to extend their lending capacity for renewable energy projects to €3 billion until 2013. Helping to overcome the capital cost hurdle, the EIB promises to finance up to 75% of the project costs for approved projects.[23] Similar initiatives at the World Bank follow binding statements the released by the organization at the Bonn Renewable Energy conference in 2004—that the bank would drive a 20% annual increase in lending to renewable energy projects.[24]

Instruments arising from the Kyoto Protocol, including the Clean Development Mechanism (CDM) and the Joint Implementation Mechanism (JI), were widely heralded at their inception and thought to offer the prospect of an additional funding source for DESERTEC and related projects. Since then, however, both have been dismissed as ineffective—largely because of the bureaucratic nightmare surrounding the accounting of intangible attributes and the failure to promote renewable energy development.[25]

War, Conflict and Political/Financial Stability: Concerns over the rise of radical Islam in MENA and longstanding concerns over the Israeli-Palestinian conflict reverberate strongly in the investment community. These concerns are mirrored by recent turmoil that has up-ending long-established regimes in Egypt, Yemen, Syria, Libya, and Tunisia. In terms of investment quality, the 'risk rating' for corporate and/or sovereign debt in Libya, Egypt, Syria Lebanon, Iran and Iraq are all 'B-grade' or lower—owing to a combination of political or financial security concerns. However, one recent assessment for North African countries determined these types of security risks to be 'inconsequential.'[26] To institutional investors, and prospective developers, overcoming these perceived risks—whether substantiated or not—is critical to facilitating the rapid growth envisaged by DESERTEC.

The World Bank has conducted three major assessments of regulatory risks vis-à-vis North African Investments. The studies identified pressing problems in each major country based on surveys with companies involved in foreign direct investment (FDI). Across the North African countries, corruption was indicated as the most significant problem, followed by high taxes, and complicated regulations. In the most Kafkaesque of survey results, over 50% of respondents in Morocco required a full-time staff member just to 'deal with bureaucracies.'[27] Perhaps in response to their own proscriptions, the World Bank expanded the scope of their 'Multilateral Investment Guarantee Agency' (MIGA) in to provide loan guarantees for renewable energy projects in developing countries.[28]

A possible tactic for lawmakers in Europe to pursue, if their goal were to facilitate the flow of private capital to these risky countries, is to provide loan guarantees to European companies developing these projects. Yes, the risk burden is then on the shoulders of the taxpayer, but private capital may be hard to attract if lenders are fully exposed to project risks.

Perhaps the best tactic to combat threats to political and socioeconomic stability is to work multilaterally in addressing a common goal: promoting the welfare of future generations. One would like to think that initiatives like DESERTEC, and the interregional, cross-cultural dialogue around a common goal they inspire would further combat the divisive forces of the region's fringe elements.

Taxation and Import Duties: Although the situation varies from country to country, many countries in MENA have historically employed protectionist economic policy—such as preferential tax rates for indigenous corporations and import tariffs. In the case of Algeria, the new 2010 financial law does still bequeath a preferential tax rate to repatriated revenues generated by foreign investment.[29] It also stipulates that foreign investors can only hold up to 49% of an Algerian company. While these policies are not the definition of open economic policy, it is unclear whether or not these prove strong enough disincentive for investment in the country.

As a counter-example, the Jordanian government has recently passed the 'Renewable Energy Law', which—among other provisions—proposes to partially exempt renewable energy investors from income taxes and includes provisions for exclusion from customs tariffs if the imported materials will be used in the construction of renewable generation facilities.[30]

Owing to the aforementioned massive capital outlays requisite for development of renewable technologies on the DESERTEC scale, host countries in MENA would be well suited to follow suit with the Jordanians with respect to tax policy and customs exclusion. 'Soft incentives' of this sort may be the most politically tenable solutions for many countries before the gap between the costs of grid electricity and CSP-generated electricity is bridged. These 'soft incentives' can also be expanded to include production or investment tax credits (PTC, ITC) or accelerated depreciation schemes that have worked to some degree of success in the Unites States. However, as the MENA region has a lower tax-base, tax incentives would seem to be poorly suited as a strong developmental incentive.[31]

Guaranteed Off-take Agreements: DESERTEC's long-term strategic vision targets 15% of Europe's energy to be sourced from MENA-based CSP and wind facilities. Because wind and solar are still expensive relative to conventional power—especially in relation to the heavily subsidized electricity rates in many MENA states—guaranteed cash-flows, and the long-term contractual power off-take agreements they imply are critical for the critical mass of investors that will be required. The reason guaranteed cash flows are of such importance to renewable project finance is because the uncertainty imposes a risk that returns end up lower than predicted—making it more challenging to find financial supporters. For an investor, the longer the contract term and the more certain the rate the renewable facility will be paid for the power they generate is, the better.

Not only trans-Mediterranean off-take agreements will be needed either, local off-take agreements are equally important. Local off-take agreements are critical in the initial phases of the DESERTEC plan, when the first pilot projects are being unveiled and before large-scale electrical interconnections are deployed. There are a number of strategies by which favorable off-take agreements can be facilitated, and the method requiring the least political involvement is the Power Purchase Agreement (PPA.)

PPAs usually involve a single large off-taker—a large industrial facility for example. In such an agreement, a 20-year contractual obligation to purchase the renewable energy according to a predefined rate schedule is signed by the renewable power plant owner/operator and the off-taker. The advantage to this model is its inherent modularity: facilitating PPAs doesn't require much concerted action on the part of the pertinent governmental bodies—unless the PPA is between two international entities.

Perhaps the most successful strategy in the lawmaker's 'renewable energy market stimulation' tool-belt is the *Feed in Tariff*, which resembles a PPA except the off-taker pays a fixed premium for the renewable power, decided by legislation. Additionally, the off-taker in a FiT is typically the local utility and is only an off-taker under governmental mandate. In Germany, the Renewable Energies Act (Erneuer-Energien-Gesetz – EEG), which included a sizable FiT for Solar PV and passed in 2004, went on to poise Germany as the global industrial leader in Solar Power. FiT premiums are borne equally amongst all of the German utilities and ultimately passed down to ratepayers. The German EEG was so successful that its initial target of supplying 12.5% of German power with renewable energy by 2010 was surpassed in 2007.

The Spanish FiT, called the 'Regimen Especial' or 'Special Regime' was even more successful than the EEG—29% of energy in Spain comes from renewable sources as of this writing and the country houses 45% of the cumulative global installed PV capacity to date. So successful was the Regimen Especial that the Spanish government vastly curtailed their FiT program in 2008, sending the international PV industry into unanticipated crisis. The chief downfall of the Spanish FiT model lies in the fact that the remuneration rate was set to float with the electricity spot-market price—ergo solar power plant operators were guaranteed a premium above the market. With peaking fuel prices in 2008, Spanish Solar companies were making windfall profits at the taxpayer's expense.[32]

Germany's EEG was inherently more sustainable than the Spanish model because it was a market-independent, fixed-price model: the FiT-rate was fixed (for the life of the system) and not inflation-adjusted. Not only does this model require less bureaucratic oversight, but it allows project developers to have a very high confidence as to what their future revenues will be, thereby increasing the investment in Renewable Energy's attractiveness.[33]

Some MENA countries already have feed in tariff legislation. For example, in Algeria, a FiT exists that offers 300% of the 'base value of power' to a renewable facility. However, what exactly the 'base value of power' entails is still being debated in the Algerian parliament and until consensus is reached, no entrepreneurs will be able to put the policy to use.[14]

Renewable Portfolio Standards: Renewable Portfolio Standards (RPSs) are a regulatory tool that sets targets for the amount of renewable generation—usually in terms of the fraction of demand met by specific renewables—by a certain date. Depending on the country, these can be binding or voluntary. If binding, RPS initiatives are often packaged with a penalty mechanism—typically a monetary fine if the party set to meet the target has not done so. The European Parliament recently passed an update to their existing RPS targets which went unmet. *The New Directive on Renewable Energy* sets renewable energy targets for each member state and intends to supply 20% of European electrical demand from Renewable sources by 2020.[34] Although the targets at the EU and member-state level only set 'indicative' targets, the member states are obliged to set them nonetheless.

Setting an RPS is often combined with a quota system to meet targets. This system is designed around the creation of (fungible) certificates that represent the fact that a certain amount of renewable energy was sent into the grid. In Belgium, for example, electric utilities have to show regulators that they have enough certificates to meet their quota. Utilities can either build generation facilities themselves and collect the certificates they generate, or purchase certificates from renewable generators elsewhere in Belgium. Regimes following the RPS approach have not been (on average) nearly as successful in the diffusion of renewable energy technologies as those using a FiT model.[35] MENA countries are not excluded from setting RPS either (or enacting FiTs for that matter.) In fact, every country from Mauritania to the Sinai Peninsula has set RE targets. The most ambitious of these is that of the Kingdom of Morocco; which aims at reaching 28% RE capacity by 2020.[36]

4. CONCLUSIONS

The multifaceted political, socioeconomic, cultural, demographic and meteorological variability across the EUMENA region is what makes the region such an interesting place, but these differences also make the task of suggesting effective policy a daunting task. What makes the DESERTEC vision—and others like it—so promising is that they hold the potential of uniting such a disparate blend of humans under a common cause. A common cause, however, doesn't imply a common solution.

In this report, we have highlighted the major parameters that define financial, technical, and political viability in the DESERTEC context. The degree to which these parameters are influential varies greatly on the many characteristics inherent to each particular nation, and each nation deserves its own unique solution—a task that was beyond the scope of this paper. Several solutions to the identified developmental barriers were proposed and their selection was justified in the context of past precedent where possible.

The majority of these barriers and solutions hold true if a similar multinational initiative involving continental-scale solar can be imagined between the islands of the Caribbean, North and South America. However, the particularities of energy policy vary greatly not only across international borders, but—as is the case in the United States—across internal (state) boundaries. Assessing appropriate regulatory policies to overcome barriers set by incongruent regional energy policy is the subject of ongoing research.

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RE AND EE INTERPLAY: OREGON'S ENERGY TRUST

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ABSTRACT

This is about the interplay between energy efficiency (EE) and renewable energy (RE), in a state with low electricity rates, and modest insolation. It shows the impact of politics on energy policy, and traces the considerable success of the Energy Trust of Oregon [ETO] in its nine years of life thus far.

Oregon has among the lowest electricity rates in the US, thanks to the Bonneville Power Administration (BPA). Yet Oregonians invest readily in both energy efficiency and renewable energy. This contrasts with states served by the Tennessee Valley Authority (TVA), a similar entity to BPA, with similarly low electricity rates.

The ETO was created in 1999 in a political compromise. Republicans wanted energy de-regulation, while Democrats wanted a 3% public purpose fee on investor-owned electric utility bills.

Because of ETO's success with the electric utility energy efficiency programs after several years, the investor-owned natural gas utilities asked us to take over their conservation programs as well. This has given us the advantage of being "fuel-blind" in our recommendations to customers for EE investments.

1. CONTRASTING FEDERAL POWER ENTITIES

There are two Federal electric power entities that were founded on abundant hydropower from large dams. The Tennessee Valley Authority (TVA) generates power from the Tennessee River and tributaries, while the Bonneville Power Administration (BPA) generates power from the Columbia River and its tributaries. In both these service districts, other benefits such as flood control, recreation on reservoirs, and irrigation water supply have resulted. The down side includes negative environmental impacts, especially with native fish populations.

Inexpensive electricity remains available in both BPA and TVA districts. This is a benefit for large power-intensive industries. It also acts as a disincentive for energy efficiency investments; why spend money on conservation when rates are so low? The same argument also discourages renewable energy investments because of their higher first cost.

There is a marked contrast, however, between the impact of low electricity rates, energy efficiency, and renewable energy on the states within the BPA and the TVA. Table 1 compares the national rankings of these states, as complied by the American Council for an Energy Efficient Economy (ACEEE).

TABLE 1. ENERGY EFFICIENCY RANKING

State	ACEEE Overall rank	Overall points 50	Utility, public funds 20 pts	EE all other 30 pts
BPA				
Oregon	3	37	14.5	22.5
Washington	6	31.5	12.5	19
Idaho	26	18	8.5	9.5
Montana	33	14	4	10
TVA				
Tennessee	35	11	1.5	9.5
Kentucky	36	10.5	3.5	7
Alabama	48	3	0	3
Mississippi	50	2	0	2

ACEEE, The 2010 State Energy Efficiency Scorecard

This contrast is even sharper when electricity rates are considered, as shown in Table 2. The somewhat higher rates in Mississippi and Alabama should encourage both EE and RE investments. The U.S. Energy Information Agency lists U.S. average rates for 2009 as 11.51 ¢/KWh residential, 10.26 ¢/KWh commercial.

TABLE 2. AVERAGE ELECTRICITY RATES

State	¢/KWh Residential	¢/KWh Commercial
BPA		
Oregon	8.82	7.74
Washington	7.81	7.28
Idaho	7.83	6.7
Montana	8.8	7.93
TVA		
Tennessee	8.87	8.93
Kentucky	8.03	7.15
Alabama	10.08	9.61
Mississippi	10.3	9.5

Source: Energy Bible

The United States now has 19 states, and the District of Columbia, with "clean energy " funds. These are used for increasing electricity production through renewable energy sources. In separate actions, renewable portfolio standards (RPS) have been adopted in at least 29 states and the District of Columbia. In Table 3, the BPA/TVA renewable energy impacts are contrasted.

TABLE 3. STATES WITH CLEAN ENERGY FUNDS

	Renewable Energy Standard	Rank, Clean Energy Fund States*
BPA		
Oregon	25% by 2025	2
Washington	15% by 2020	4
Idaho	---	---
Montana	15% by 2015	---
TVA	---	
Tennessee	---	---
Kentucky	---	---
Alabama	---	---
Mississippi	---	---

* Clean Edge: U.S. Clean Energy Leadership Index

2. CREATION OF THE ENERGY TRUST OF OREGON

In the late 1990s, two hot energy topics in Oregon were **energy deregulation**, severing the ties between energy generation and distribution; and **public purpose funds**, assessed on utility bills to achieve energy conservation and develop renewable electricity sources. In Oregon, the Republicans liked deregulation, which was seen as a way to reduce energy costs through free market competition, while the Democrats liked public purpose funds. Neither party liked the other's favorite. With Democrats in control of the Governor's office and Senate, and Republicans running the House, neither of these ideas could pass without some compromise.

Oregonians thus got both deregulation and public purpose funds in a 1999 restructuring bill. The Energy Trust of Oregon [ETO] was established to collect and administer funds for both energy efficiency and renewable electricity. Answerable to the Oregon Public Utility Commission, the ETO board was appointed in 2001. Within a year it had hired a staff and commenced business.

Meanwhile the Enron scandal erupted. One of the ETO's funding utilities, Enron-owned Portland General Electric, lost millions in pension funds, and for Oregon, deregulation was effectively dead. Republican resentment over the failure of deregulation threatened the Energy Trust in those early years. Alas, even energy efficiency can come under attack from that party, and renewable energy is even less popular.

ETO's funds come from a surcharge on the electric bills of the two major investor-owned electric utilities, Pacificorp and Portland General Electric. These two serve about two-thirds of Oregon's population. The 1999 restructuring legislation specified that 2.46 percent of their total billings go to ETO. Initially this amounted to some $45 million annually. Of that amount, 77 percent was spent on energy efficiency projects and the remaining 23 percent went toward generation of electricity from renewable sources. ETO was given 10 years of life, and we set ambitious goals: by our sunset in 2012, achieve energy efficiency equivalent to 300 megawatts; and help Oregon to install 450 MW of renewable energy sources.

3. RE AND EE FUNDING CONTRAST

A fiscal split personality has resulted. For energy efficiency, we were limited to "cost-effective" investments, which means the technology funding must amount to less than the "avoided cost" of new electricity generation in the region; for residential measures, this is currently about 40 ¢/KWh.

For renewable energy investments, we were limited to "above-market" costs. On the one hand we tell people interested in energy efficiency "You are limited to less than this much;" on the other we ask people interested in renewable energy "How much more do you need?"

To my lasting chagrin as an architect and passive solar enthusiast, direct use of solar energy for anything other than making electricity is lumped under energy efficiency, limited to a maximum of the avoided cost. This means that daylighting, water heating, passive solar heating and passive cooling are considered as efficiency rather than as energy production. The ETO can give a residence or a business more per kilowatt-hour for a PV system than for a more efficient solar water heating system. The only way to change this is through new legislation, and our staff is divided as to whether putting direct-use solar into the renewable pot would result in more money for direct use. After all, renewables get at most 23 percent of our funds, while the "cost-effective" limit is rising, enabling more investments in energy efficiency.

Compare solar water heating [considered EE] and PV [obviously RE} in this example for a Pacificorp customer:

For PV = $1.50/wattDC. A 2 kW PV system that generates approx. 2,200 kWh/year would receive a **$3,000** incentive ($1.50 x 2,000 watt).

For SWH = $0.40/kWh. A typical residential system rated by SRCC to save 2,200 kWh/year would receive a **$880** incentive ($0.40 x 2,200 kWh).

4. <u>EE SUCCESS BRINGS ADDITIONAL FUNDS</u> With

an energetic, talented staff and consistent levels of funding, we soon established energy savings that surpassed the past efforts of the utilities, with their historically ambivalent attitude about conservation: "Fewer kilowatt-hours sold meant lower profits," if one ignored how much more expensive new electricity generation is than the prevailing rates charged to customers.

Impressed by our electricity savings, in 2003 Oregon's largest natural gas utility, Northwest Natural, asked the Oregon Public Utilities Commission to decouple their rates from profits, while giving ETO 1.5 percent of their residential and commercial billings for energy efficiency investments. This ringing endorsement of our work, barely a year into our programs, enables us to be fuel-neutral in our efficiency programs.

Subsequently Cascade Natural Gas, a smaller utility, also asked us to take over their energy efficiency programs. Then we were asked by Northwest Natural to do their EE programs in Clark County in Washington State, across the Columbia from Portland; we gained the approval of Washington's utility regulators, and we now serve some area beyond Oregon's boundaries.

5. <u>RE SHIFTS IN EMPHASIS</u>

When the ETO was founded, everyone considered renewable energy sources to be extraordinarily expensive compared to the hydropower, coal and natural gas generation that dominate in our region. As large-turbine wind farms multiplied, taking advantage of strong winds in the Columbia Gorge, the cost of wind power dropped. To counter the notorious variability of wind speed, utilities take advantage of the storage offered by the huge dams on the Columbia; less wind = more flow through the dam's turbines, and vice versa.

Of all the events of the past nine years, I especially cherish the moment in 2004, when we were ready to give $2 million to Portland General Electric for a wind farm, amounting to the above-market costs of the wind farm compared to the cost of a comparable-size natural gas-fired plant. When the final calculations were complete, we gave them nothing: the two were of equal cost!

After the 2006 elections Democrats controlled both houses of the Oregon legislature, and they enacted an ambitious renewable portfolio standard (RPS) of 25% of Oregon's electricity by 2025. They also extended ETO's life to 2025, and mandated additional funds for energy efficiency. The RPS required utilities to fund wind farms and certain other renewables without ETO help. Our ETO renewable funds, undiminished, are now capped at 20 MW per installation.

The ETO budget for 2011 is $130,900,000 for EE, $15,300,000 for RE. Our investments in RE, capped at 20 MW, will include both intermittent and 24/7 renewable resources.

4.1 Widely Distributed Resources, Intermittent

Table 4 shows the aMW of the distributed and intermittent RE sources, installed with ETO help each year since 2002.

PV investments will continue, with both small and large systems. We have seen benefits from smaller-system standardization in our "Solarize Portland" efforts, and architects are working with designs that incorporate building-integrated PV (BIPV). Larger systems have included the U.S.' first highway-side PV array of 104 KW DC, and a 1.3 MW PV array at an Interstate-5 rest area near Portland is soon to be constructed. We have also installed large roof top arrays at warehouses near Portland's airport.

Through 2010, we've funded 20.355 MW of PV, in 2,651 installations, with incentives totaling $32,050,434. Since our solar program began in 2003, Energy Trust has installed 12 times as many solar electric systems as were installed in Oregon's entire prior history.

Geography is a factor; eastern Oregon is largely rural with more plentiful solar resources thanks to a semi-desert climate. Pacificorp serves that area, and our funds for PV incentives in their service territory are quickly exhausted each year. In more overcast western Oregon, Portland General Electric has less demand for solar incentives, so we do some additional promotion.

Solar thermal suffers from lower incentives than PV, and the same geographic constraints.

TABLE 4. INTERMITTENT RE INVESTMENTS

Year	PV aMW	Solar HW aMW	Solar HW KTherm	Wind Utility aMW	Wind Small aMW
02	0.002				
03	0.043			14.25	
04	0.079	0.008	10.27		0.005
05	0.049	0.019	19.13		0.001
06	0.089	0.028	30.96		0.001
07	0.153	0.050	35.51	46.774	
08	0.508	0.048	27.69	30.1	0.004
09	0.764	0.046	35.36		0.018
10	1.291	0.029	23.87		0.021
Total	2.987	0.229	183.093	91.124	0.049

Community wind, consisting of a few medium-size turbines per installation, stands to benefit from used turbines that become available as larger wind farms upgrade. Now that some of the best wind resources in the Columbia Gorge are taken, wind farms are expanding into regions even more scenic, and a backlash is growing from those opposed to the aesthetic intrusion of larger towers.

4.2 Concentrated Resources, Available 24/7

Table 5 shows the aMW of the constant (24/7) RE sources, installed with ETO help each year since 2002.

Central Oregon has many rural irrigation districts, taking advantage of relatively plentiful water resources in a hot-dry summer climate. We have invested in smaller hydropower in several irrigation districts, with the added benefit of water conservation as open ditches are replaced with piped water. This allows increased hydropower production at the same time as the pipes significantly lower losses from evaporation and leakage. Such systems perform 24/7, but in summer-fall season only. There are several other irrigation districts with promising possibilities for hydropower.

Biogas captured at wastewater treatment plants can be burned to produce steam and thus generate electricity. There are added benefits from sharply reduced air pollution, and the capture of methane that is such an accelerant for climate change. Biogas capture at dairies and food processing is now joining our program. An intriguing possibility: using this biogas, properly cleaned, as a contributor to natural gas mains, rather than burning it to generate electricity.

A modest investment in geothermal-produced electricity was added in 2010; this is an innovative lower-temperature well system at the Oregon Institute of Technology in Klamath Falls.

TABLE 5. 24/7 RE aMW INVESTMENTS

Year	Hydro Irrigation	Biopower	Geothermal
02			
03			
04			
05		0.406	
06		1.908	
07			
08	0.003	2.688	
09	0.468	1.388	
10	1.893		0.086
Total	2.364	6.39	0.086

Our efforts in renewable energy have been helped substantially by Business Energy Tax Credits, offered through Oregon Department of Energy.

6. OTHER RENEWABLE INVESTMENTS, PROSPECTS

Western, central and southern Oregon have a widespread lumber industry with history of electricity generation. The advantage of burning wood waste from forest slash as well as lumber mill waste is that the resulting steam can first power generators, and then be used to kiln-dry lumber products. This process is known as co-generation. This practice is not without controversy, as decomposing forest slash could contribute to forest health if widely spread, and air pollution from cogeneration is a concern due to particulates. The ETO invested in a 1.5 MW cogeneration facility at southern Oregon mill in 2006; more installations are expected.

Wave energy is of substantial interest in the future. Oregon and Washington coasts have very strong wave action, and a leading ocean energy research facility is at Oregon State University. Of particular interest is the synchronicity between solar and wave energies: waves have a stronger winter season, while solar is of course strongest in summer.

Today, Oregon is moving steadily towards a sustainable energy economy, thanks to greatly increased efficiency and a welcome infusion of renewable electricity.

ASSESSING THE ANNUAL PERFORMANCE OF GRID TIED PHOTOVOLTAIC INSTALLATIONS IN OREGON

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ABSTRACT

For the purposes of validating estimates of energy generation claimed for photovoltaic installations and allowing for the possibility of Renewable Energy Certification (REC) registration, Energy Trust of Oregon program staff has conducted an analysis of the measured output of photovoltaic systems installed through its incentive program since 2003. The AC kilowatt-hour (kWh) production of all installed systems has been logged by a mandatory revenue-grade meter and the data was solicited from the system owners by direct mail postcards sent on the one year anniversary of the installation.

Postcard solicitations proved to be easy, cheap and effective, generating a response rate of 60% of 1-year anniversary solicitations. Meter readings were collected for 700 residential and commercial systems ranging in size from 800 watts to 160 kilowatts. The program learned early on that it must record an initial meter reading and date stamp for each system shortly after commercial operation to establish a starting point for energy generation over time.

Measured kWh generation for each system was compared with forecasts estimated using several different methodologies employed by the program over time. The analysis also sought to determine whether the type of equipment installed or site conditions played a significant role in the accuracy of the performance predictions.

Production estimates that used a low resolution insolation assessment, modified by an assumed overall system conversion efficiency of 80% were exceptionally accurate in predicting the average production of systems, yet showed a wide degree of variability across individual installations. Surprisingly, estimates that used a higher resolution insolation assessment based on more recent typical meteorological year (TMY) and satellite weather data, modified by a calculated conversion efficiency based on the particular system components, yielded nearly equivalent degree of precision in estimating the output of individual systems. Accuracy varied among the methods, but could be addressed by modifying the portion of the system efficiency derate factor attributed to balance of system losses.

The study finds that the low resolution estimation methodology is satisfactory for forecasting energy generation at the programmatic level, and offers a quick solution for solar installers if the estimates must be calculated by hand. Higher resolution estimates which take into account local climate variations and the inefficiencies of individual components did not, with any statistical significance, yield a better prediction of kWh generation than the low resolution estimates, however.

1. INTRODUCTION

Energy Trust of Oregon, a nonprofit organization funded through a public purpose charge collected from electric ratepayers, has offered financial incentives for photovoltaic (PV) installations since 2003. Energy Trust reports annual kWh generation expected from new PV systems installed under its incentive program. In order to verify the program's annual generation claims and to allow for the potential to measure RECs for the systems, Energy Trust has required that all systems include a "PV generation meter," a revenue grade meter (accurate to ±2%) installed on the AC output from the inverter(s). Energy Trust requests that system owners read their PV generation meters and report their cumulative kWh generation to Energy Trust on the 1-year and 5-year anniversaries of the installation of their systems. This effort has provided the program with an opportunity to evaluate the effectiveness of our methodology for predicting kWh generation, to alert system owners to underperforming systems that may require service and potentially to spot trends owing to faulty products or poor installations. This paper presents a brief analysis of 1-year generation data received by Energy Trust through October 2010.

2. DISCUSSION OF DATA

2.1 Data Collection

Early in Energy Trust's solar program history, meter readings were solicited from system owners by phone -- a very effective (95% response rate) but staff-intensive process. As program volume increased, we replaced the phone calls with postcards which listed instructions for recording the correct reading from the PV generation meter and asked questions about the service history of the system. System owners could mail the completed postcards back to Energy Trust, postage paid, or report their meter readings by phone or through our website. The postcards receive a response rate of 60% from system owners and require very little staff time to administer.

In addition to the solicited meter readings, Energy Trust records details of each system installed, including system size, module manufacturer and model, inverter manufacturer and model, array tilt angle, azimuthal orientation and shading.

2.2 Data Sample

The data used in this study include all first year measured kWh generation of systems installed between July 2003 and October 2009. 699 measurements were recorded, comprising 61.5% of eligible systems from that period. Of that sample, 39 were excluded because the project data was incomplete or incorrect, or the system included features which were atypical and not accounted for in the production calculations (e.g. tracking systems, or expanded systems).

2.3 Data Quality

Over the life of the program, there have been several databases used to archive the system information and meter readings. As a result, there are some data quality issues, especially when dealing with the earliest records.

2.3.1 Initial Meter Readings

To establish a baseline, Energy Trust records an initial reading of the PV generation meter during its quality assurance inspection of each system. For many systems, this initial meter reading is 0 kWh. However, two data quality issues existing regarding these initial meter readings:

a. For the first two years of the program, initial meter readings were not recorded. As a result, the 1-year meter readings for these early systems, representing approximately 22% of the sample, may slightly overstate the first year kWh generation.
b. In some cases, the initial meter reading is logged prior to commissioning, and there may be a period of several days to several weeks after the Energy Trust inspection where the system is inactive while awaiting the installation of a new bidirectional utility meter. As a result, the 1-year meter readings for these systems, representing approximately 6% of the sample, may slightly understate the first year kWh generation.

2.3.2 Customer-reported Readings

The 1-year meter readings are recorded by system owners and thus more suspect than if they were recorded by an inspector or technician. The postcard soliciting the meter reading contains pictures and instructions about which meter to read, but inevitably there are mistakes. Readings mistakenly taken from the utility meter instead of the PV generation meter are generally easy to identify because they are grossly different from the expected generation, and were eliminated from the sample. Readings mistakenly taken from an inverter or a monitoring system instead of the revenue grade meter, however, are not detectable because they are close to the expected generation, were not eliminated from the sample, and introduce random error into the sample.

2.3.3 Performance Estimates

The assumptions used to calculate the performance estimates under the Energy Trust Performance Model (described below) are based on a Local Production Capacity (LPC) methodology that shifted slightly several times over the course of the program. Adequate information is not available to recalculate those estimates at the latest LPC rates, so therefore all Energy Trust Performance Model estimates are as the values calculated at the time of project application.

3. DATA METRICS

3.1 Adjusted Annual Production Calculation

Meter readings were typically requested during the month of the system's one year anniversary. However, it was rare that the meter readings were recorded on the exact day of the system's initial reading. Readings vary from the anniversary date by several days to several months. Therefore, the measurements were normalized to one year by dividing the recorded production between the date of the baseline reading and the requested customer reading by a factor equal to the percent of typical annual insolation received at the site between those two dates. The exact methodology is detailed in the equation below.

$$R_A = \frac{R_f - R_i}{\frac{1}{I_A}\left(\sum_{m_i+1}^{m_f-1} I_M + \frac{I_M * \Delta D_i}{D_{mi}} + \frac{I_M * \Delta D_f}{D_{mf}}\right)}$$

Where:
R_f = Recorded final meter reading [kWh]
R_i = Recorded initial meter reading [kWh]
R_A = Adjusted 1-yr system production [kWh]
I_A = Average annual PVWATTS insolation [kWh/m^2-yr.]
m_i = Month of initial meter reading
m_f =Month of final meter reading
(m_f – m_i may be greater than 12)
I_M = Monthly average PVWATTS insolation *(will vary for each month)* [kWh/m^2-mo.]
ΔD_i = Days remaining in month of initial meter reading
D_{mi} = Total days in month of initial meter reading
ΔD_f = Days remaining in month preceding final meter reading
D_{mf} = Total days in month of final meter reading

3.2 Performance modeling

Three separate performance models were evaluated in this analysis.

3.2.1 Energy Trust Performance Model

For the first six years of the program, Energy Trust utilized a performance model that was based on the National Renewable Energy Laboratory's (NREL) tool, PVWATTS, and supplemented by research performed at the University of Oregon Solar Radiation Monitoring Lab (UO SRML) by Dr. Frank Vignola. The Typical Meteorological Year (TMY2) data for Oregon used in PVWATTS is based on weather and insolation data collected by UO SRML from nine sites throughout the state. In addition, Dr. Vignola's lab monitors the performance of several PV installations throughout the state [1].

From this data, Energy Trust divided the state of Oregon into geographic regions of similar insolation, increasing from 7 regions in 2003 to 12 in 2010. Each region was assigned a Local Production Capacity (LPC) [kWh/m^2-yr/Watt$_{STC}$]. The LPC combined the modeled insolation for that region with a standard derate factor to cover all conversion, efficiency and ohmic losses in a photovoltaic system. The figures were then further derated to account for site-specific shading and orientation losses.

The great benefit of the LPC was that it provided a single production coefficient for each geographical region, so that contractors completing incentive forms could quickly and easy calculate any system's estimated energy production. All of the sites in the sample used this methodology to calculate the kWh generation claimed by the Energy Trust program. The LPC values and numbers of regions were adjusted several times over the life of the program (see data quality section above).

3.2.2 40 km^2 Grid Model

The program recently transitioned to an online incentive application service provided by a third party. The software calculates the performance of each individual system, using NREL's enhanced spatial resolution. Instead of limiting insolation data to the nine TMY2 sites in Oregon, the model also incorporates local data including dry bulb temperature and cloud cover data collected by radar and satellite, and interpolates the regions between stations based on the additional information. This increases the resolution of the TMY2 data to 40 km squares. This would seem to be a clear benefit in a state with such varied geography as Oregon [2].

To closely approximate the model utilized by the software, the modules were calculated at their PTC efficiency, and the California Energy Commission weighted inverter efficiency which includes tare losses was factored in as well. The figures were then derated to account for site-specific shading and orientation losses, and an additional ~17% penalty was added for balance of system losses [3].

3.2.3 10 km^2 Grid Model

The final model uses methods similar to the interpolation procedure described for the 40 km^2 grid data above, but is purportedly able to achieve 10 km^2 resolution by relying heavily on satellite data. The method was developed by a team of solar researchers from top institutions around the world, and was described in Perez et al, 2002. Like the 40 km^2 data, the 10 km^2 data is available in GIS form from NREL [4] [5].

To maintain a consistent basis for comparison, the 10 km^2 data was calculated with the same derate factors as the 40 km^2 described above.

4. ANALYSIS

4.1 Purpose

Energy Trust estimates the annual kWh generation of new systems to serve two parties, each possessing separate interests:

a. The organization wishes to accurately assess the system production so that it may make verifiable claims on the amount of energy generated by *the entire program*. This was evaluated by comparing *mean* system production to the predictions of the Energy Trust Performance Model.
b. The system owner wishes for an accurate estimate so that he or she may have a reasonable estimate of the amount of energy that *their own system* will generate each year. This was evaluated by comparing *median* system production and comparing to the predictions of the three different performance modeling methodologies.

4.2 Outliers

Outliers exist in the data at both extremes. Measurements showing kWh generation to be greater than double the system estimate were assumed to be the result of either an incorrect meter reading or a system which was expanded without the program's knowledge. These systems were eliminated from the sample.

On the other hand, outliers on the left side of the curve are more difficult to eliminate. It is possible that systems with very low measured kWh generation are also the result of incorrect meter readings, but it may more likely be a consequence of component malfunction. Several of these malfunctions are known to the program and resulted in equipment recalls.

All underperforming systems were retained in the sample used in the analysis to determine the total

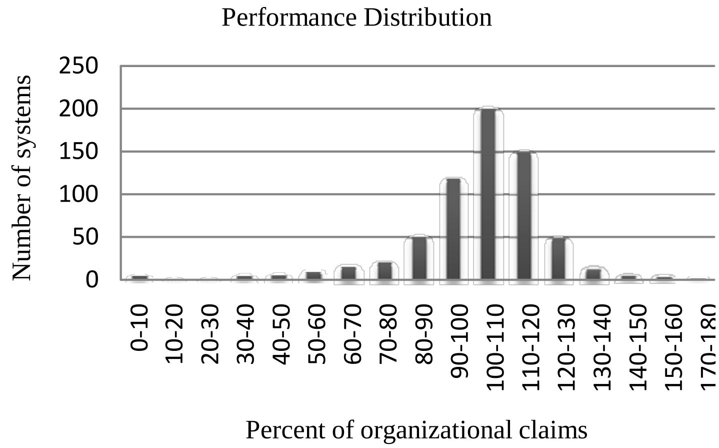

Fig. 1: Distribution of first year system production as a percentage of organizational claims calculated using Energy Trust performance model.

kWh generation of all systems for the purpose of validating program claims. Data from underperforming systems are also important in establishing a system failure rate for the program.

However, systems with known malfunctions are not useful in establishing reliable performance estimates for customers because they skew the data and are not representative of the average PV owner's experience. Therefore, systems with documented component malfunctions were eliminated from the sample used in the analysis to determine the best performance forecast model.

4.3 Evaluating Organizational Claims and the Energy Trust Model

As the program is primarily interested in validating its production claims, the total kWh produced, along with the mean performance rate are of primary importance. The analysis found that these two figures were essentially equal at 102% of the value claimed or estimated at the time of installation, with a compact confidence interval of ±1% due to the large sample size.

4.4 Evaluating Alternative Performance Models

In general, the median system performed slightly better than the mean. The standard deviation was 21%, indicating that the precision of the individual estimates was less than desirable.

Because the purpose of this portion of the analysis was to accurately assess the production that the *average system owner* can expect, it was necessary to remove the atypical malfunctioning systems from the sample. After eliminating 64 sites from the sample due to reported system malfunctions, the only consequence was a modest improvement to the standard deviation, and a 2% increase in the bias error.

The higher resolution models were tested in this stage of the analysis to determine their benefit to the system owner. Table 1**Error! Reference source not found.** illustrates that there is very little difference between the variance of the three models. More aggressive efforts to eliminate outliers led to very similar results. Although the average values appear to be much higher for the 40 km^2 and 10 km^2 models, this is simply a bias error resulting from the choice of values for the 'balance of system losses' and can be easily corrected. The important point is that the lower resolution model delivers the same precision as the competitors, and carries the additional benefit of being calculable by hand.

TABLE 1: COMPARISON OF PREDICTION MODELS (MALFUNCTIONING SYSTEMS REMOVED)

	Energy Trust Estimate	40 km^2 / PVWATTS	10 km^2 satellite
Mean	104%	109%	108%
Median	106%	109%	109%
Std Dev	17.3%	18%	17.3%

One observation that is important to note here is that the availability of incentive dollars and the population differential between urban and rural Oregon have led to a very high density of system installations in urban areas. This geographic homogeneity prevents us from drawing conclusions about the relative precision of the high resolution models if they were to be applied to a more geographically diverse dataset.

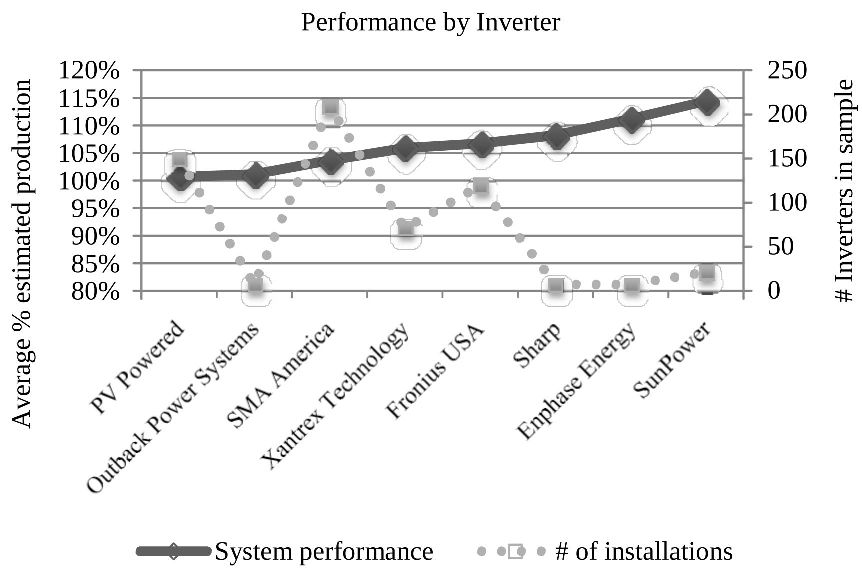

Fig. 2: System performance as a function of inverter manufacturer

4.5 Equipment

Examining the effect of installed equipment on the accuracy of the estimates yielded some interesting results.

When other variables were controlled, it was the brand of the inverter that showed the strongest correlation to the systems' production. This can be seen in , which shows the production figures for each inverter manufacturer that was used in 10 or more installations. It should be noted that all systems installed with Outback inverters are battery back-up systems, and the complicated metering arrangement may lead to underestimates of total production. Additionally, the sample set included a number of PV Powered inverters which required warranty service early in the program's life, and may therefore have skewed the average.

When examining PV modules, the brand had a stronger correlation to the variance (s^2) of the measurements than to the average production. Fig. 3 illustrates this relationship, indicating that the average difference between the estimated annual production and the measured annual production was lowest in systems featuring Sanyo modules, and greatest in Sharp module installations.

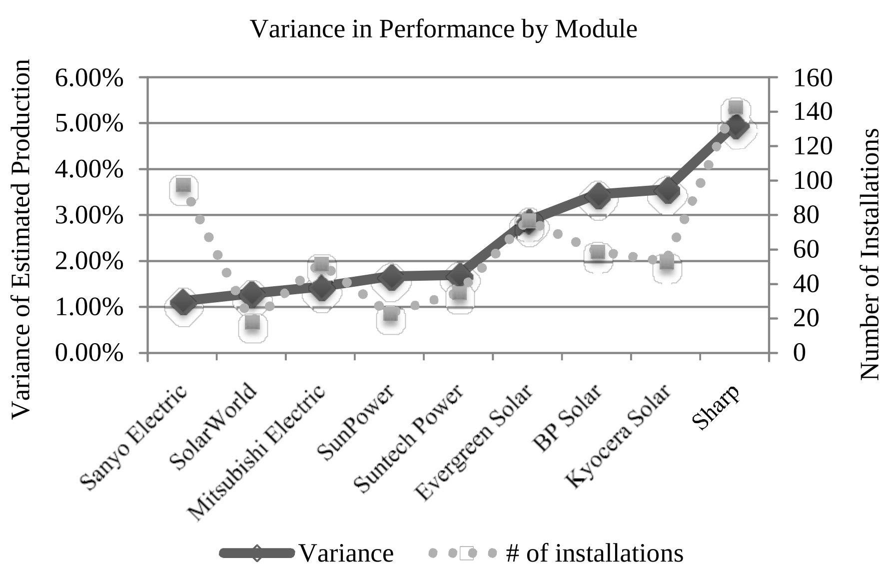

Fig. 3: Variance (s^2) in system production as a function of photovoltaic module manufacturer

4.6 Site Conditions

Shade evaluation is an issue that has caused controversy and consternation within our program. The program requires each contractor to submit a shade evaluation with each incentive application, indicating the amount of shade at the worst point on the array. The program accepts reports from the professional tools available such as Solar Pathfinder™, Wiley ASSET and Solmetric SunEye™, as well as hand drawn suncharts using the Energy Trust's template, and does not offer incentives for systems with a solar resource less than 75%.

TABLE 2: COMPARISON OF DEGREE OF SHADE AND SYSTEM PERFORMANCE

Percent of *unshaded* solar access	System production as % of program estimate
75-80%	107%
80-85%	106%
85-90%	107%
90-95%	106%
>95%	101%

Table 2TABLE 22 indicates that applications submitted indicating little or no shading tend to underperform compared with those that indicate some degree of shading. Since our model includes a deduction based on the amount of shade indicated by the report, there are two possible conclusions that one may draw from this:

a. Our methodology for estimating the deleterious effect of shade on system production is overly conservative.
b. Installers may be submitting shade reports which indicate that no shade is present when in fact there is some degree of shading.

5. CONCLUSIONS

The large sample size and relatively high number of parameters has allowed us to confidently draw several conclusions from the data. First, the study has indicated that Energy Trust's solar program has in fact resulted in the kWh generation that we have claimed, with a slight overage as a result of our conservative performance estimates. Additionally, despite a fairly wide variance in the performance of the installations, nine out of ten systems installed produced at least 80% of our estimate. Further, the study found that, for our program, there was no additional precision gained by using performance estimation models which have a higher geographic resolution or use component-specific efficiencies, but, as noted, this conclusion may not be appropriate for datasets with greater geographic diversity.

The collection of detailed system information has allowed us to spot some interesting trends in the data. Variance in system performance had a stronger correlation to the brand of inverter installed than the brand of PV module. And, while our estimates of the performance losses due to the tilt and orientation of the PV array were reasonably accurate, performance losses due to shading were likely overstated.

Overall, the solicitation of meter readings by postcard proved to be an inexpensive and efficient way to collect system data. The response rate to these requests has been sufficient to yield a high level of confidence in our data. Despite the inevitable shortcomings and complications of a customer reported monitoring arrangement, the meter evaluation process has proved quite effective in validating claims and assessing the health and performance of photovoltaic systems in Oregon.

6. ACKNOWLEDGEMENTS

The authors would like to acknowledge Elizabeth Rubado and David McClelland for their work developing and refining the normalization methodology and their countless hours spent contacting system owners and logging meter readings. Additionally, we would like to acknowledge Dr. Frank Vignola for his work in developing the Energy Trust Performance Model.

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IS GERMANY BECOMING THE NEXT FAILED STATE ON SOLAR ENERGIES?

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ABSTRACT

This paper explains the role of solar energy in the German context, of a rapid and profound transformation of its energy market towards a low carbon industry. In this context the German solar energy market has come under strong pressure recently as it generates electricity at a relatively high cost. While installation of photovoltaic power plants grew at a very fast rate over the last few years, the financial strain is becoming a central topic in energy politics. Strong interest groups are lobbying to put a cap on all renewable energy sources and abandon preference regulations for renewables. Several possibilities of near future scenarios are discussed.

key words: Feed-in Tariff, Renewable Energy Source Act, German Solar, EEG

1. INTRODUCTION

Solar Energy production is currently maturing, having grown up from a very limited niche market to become a considerable market force in several counties. It is predicted that solar power will generate more electricity than nuclear power on certain days during 2011 in Germany. However, not everybody is content with these developments. Criticism is expected to come from the large, established utility firms seeking to protect their dominant market position as well as important environmentalist organizations and research institutions favouring a slower photovoltaic (PV) build-up. Concern surrounds the high, yet rapidly falling cost of PV generated electricity. Such cost might serve as a reason to slow the build-up of renewable energies as a whole.

Several countries in Europe, whose incentive programs created a rapid increase in installed PV generation capacity, have had to adjust their programs which many times generated a big marked disturbance. Spain put a moratorium on its Royal Degree "Real Decreto (RD) 661/2007" resulting in a sharp drop of PV installation from 2.7 GW_p in 2008 to almost zero, 0.04 Gw_p in 2009. The Czech Republic, the world´s third largest PV market in 2010, had a moratorium in place, drastically decreasing it´s remuneration and putting a withholding tax of 26% on all installations from 2009 onwards. In Flemish Belgium, PV is going through uncertain times while in France,a very promising market in 2010, established a memorandum in December 2010.

As Germany´s PV market absorbs almost half of worldwide PV systems alone, any major market upset in Germany will severely effect other PV markets globally.

So how is Germany's global-dominant market in PV technology performing?

2. HISTORY OF THE GERMAN ELECTRICITY MARKET

Until the 1990s, the West German electricity market was legally divided into spheres of interest of the four utility firms, allowing for a minor role to be played by municipality owned utility firms in their entities. With the fall of the Berlin Wall in 1989 the West German system extended to the new territories, shutting down many of the lignite based, technically outdated, thermoelectric plants as well as the two Nuclear Power Plants (NPPs) of the East. The German power mix by then consisted roughly in 56% coal, 31% nuclear, 10% gas and petroleum, and 1% renewable, predominantly mid size hydro-power [1].

During the 1960s and 1970s there was a huge optimism towards nuclear power, planning up to 1000 NPPs to be build until 2000 in the US alone [2]. Still in 1983 planning for construction of 13 new reactors in Germany was in an advanced stadium, none of which finely were realized [3]. Nonetheless public opposition was strong and more so after the Three Mile Island near core melting in 1979 . Disputes around nuclear technology sparked a widespread interest in German society about alternative ways of electricity generation. The Chernobyl accident in 1986 can be seen as the final blow to new NPP construction in (West-) Germany, establishing the maximum number of operative NPPs in East and West Germany combined at 28 units ($27GW_{el}$) [4].

When in 1998 a Social Democrat – Green Party coalition gained power, energy issues became an important political topic. Two decisions were to have an important impact on the structure of the German electricity market: a legal binding agreement with the four NPP owners about the successive phase out of all 19 remaining NPPs until 2021 and the implementation of the Renewable Energy Source Act (EEG).

The phase out agreement was signed in 2002 and obliged the NPP owners to shut down their plants after an operative time of 32 years. The remaining time was calculated based on the average energy production, so lower the average energy production or a temporarily shut down could extend permitted life time. The government agreed on not imposing new measures like higher safety standards, a more strict supervision, higher minimum insurance, to impose new taxes and the like. While 2 NPP actually was shut down during this period the utilities succeeded in maintaining operative the remaining stations until a new Conservative – Liberal government extended the permitted life time to 40 years for older, and 44 years for newer NPPs. Given that all 127 worldwide so far shut down NPP had an average operation time of 22 years and only 23 reached a operating time of more than 30 years [3], this new life time extension seams to impose no restriction at all. This political decision contradicts efforts by smaller utilities (the NPPs are run by the “big four” of Germany's power utilities: E-ON, Vattenfall, EnBw and RWE) to install green energy and flexible generation capacity to meet the demand of a market that might be up to 40% in energy production coming from fluctuating renewable sources in 2020.

3. RENEWABLE ENERGY SOURCE ACT (EEG)

A so far more profound and long-lasting impact was established by the Renewable Energy Source Act (EEG). This law passed the legislation process in April 2000 with the approval of almost all of the deputies from all parties. It establishes the right of whatever producer of electricity from renewable sources to sell all or part of the generated electricity to the local grid operator at a fixed price. These Feed-in Tariffs were calculated on a 7% return of interest for an above average site installation and would be paid for a period of 20 years plus the year of installation. Anticipating a drop in installation prices, in particular for wind and solar power, a yearly digression factor of 1% to 15% was included so more recently build installations would receive lower retribution then installations constructed earlier. By this means retribution for small PV plants up to 30kWp, the most expansive of all, fall to half in 7 years only, from 57.4€ct in 2004 to 28.74€ct in 2011 [5]. Nonetheless compared with the average generation cost of conventional base load energy sources of 3-5€ct costs remain high.

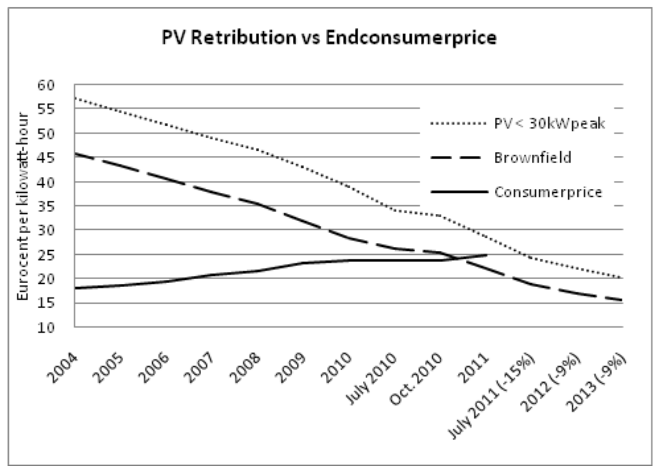

Fig. 1: the figure shows the Feed-in Tariffs for large PV plants constructed on brownland and small PV installations in comparison with average end-consumer prices. Feed-in Tariffs from July 2011 on might differ depending on real new PV installations installed in the first half of 2011 [5].

As the law gives feed in preference status to renewable electricity, all the electricity coming from renewables has to be accepted by the grid operator and sold first to the consumer. By this means conventional power plants becoming successively only a complementary form of power generation. When Renewable Energy (RE) power plants have to be shut down buy the grid operator as a last mean to avoid a collapse of the grid due to overload, the owner of the RE plant has to be compensated by the grid operator for the energy not sold. Grid operators have to enable the connection to the next technical feasible power line of all RE plants that wish to fall under this Feed-in Tariff (FIT) scheme. For small size PV installations up to $30kW_p$ this refers normally to the house metering point and the only obligation consists in advising the grid operator about size, location and planed production start.

Under this law there is no cap foreseen for any of the different RE sources so installation depends only on economic and technical feasibility.

While most of the public discussion of this Feed-in Tariff scheme revolves around the right amount of recompense for each of the energy sources, easy grid connection procedure, no limitation on installed capacity and preference in electricity marketing to RE are as crucial as well. As fast falling PV installation cost and Feed-in Tariffs drop below end-consumer prices these three factors might actually become more important than the Feed-in Tariff established by the law.

In 2001, a European Court decision [6] ruled that the Feed-in Tariff system established by the EEG is not considered to be a subsidy measure but a market regulatory framework. Nonetheless it generates extra costs, like safety regulations for NPPs or CO_2 certificates for coal plants, which will be included in the pricing of electricity sold to the consumer.

4 RENEWABLE ENERGY: CAPACITY AND COST

Before 1990 the only relevant RE capacity installed in Germany was based on hydroelectric power, contributing a 1% to Germany's electricity production. Since then RE generation has increased 17 fold, generating 102 Twh, or 17% in 2010 [7].

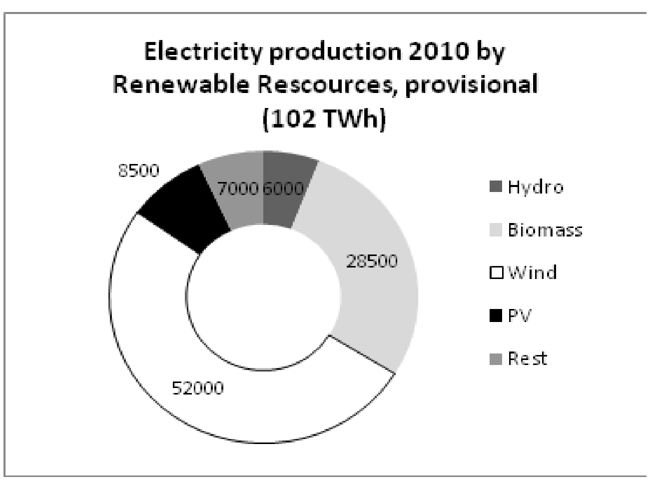

Fig. 2: provisional energy production from renewable resources (only under EEG scheme) in 2010

As clearly seen the new backbone of renewables in Germany consists of wind power, biomass and hydropower. Whereas in 2009 hydro, biomass and wind combined generated 66437.2 GWh (88.5% of all RE generation) of electricity it contributed with 69.3% to the financial burden of the EEG. In contrast, PV absorbed almost one third of financial retribution but generated less than one tenth of total renewable energy that year. Energy generated by PV systems received 3,156 million € (29.3% of total) generating 6,578.3GWh (8.8%) of electricity, translating to an average cost of 48.97€ct/kWh whereas average wind energy generated cost translated to 8.8€ct/kWh [8].

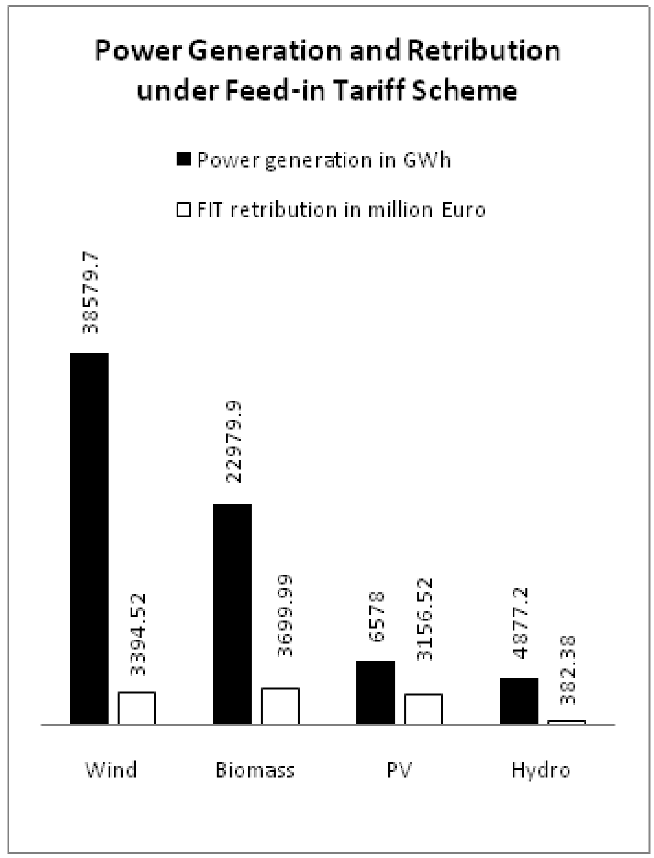

Fig.3: Distribution of Energy-generation and retribution paid under the EEG scheme in 2009. Total retribution in 2009: 10.78 Billion Euro.

Recent studies suggest that the German goal of 30 % of electricity coming from renewable resources in 2020 will be surpassed. An already outdated Federal Environment Agency (UBA) study foresees a 30.9% share in 2020 [9] while The German Renewable Energy Federation considers 47% to be more likely [10]. Large scale innovative projects like the DESERTTEC concept are not yet taken into account.

5. RAPID PHOTOVOLTAIC GROW: BLESSING OR BURDEN?

Solar Energy generates 30% of the total cost of the German Feed-in Tariff system while contributing with only 8.8% to total RE power generation. Whereas remuneration per kilowatt-hour fall sharply from 57.4 €ct in 2004 to 28.74€ct in 2011 for new systems, average PV electricity cost remains as high as 48.97 €ct/kWh in 2009 due to the effect of older installations receiving a high retribution for 20 consecutive years. Production cost in new installations is expected to be lower than consumer prices (grid parity) in 2012 or 2013, presenting the highest depletion potential of all common RE technologies. Nonetheless it is expected to remain a relative cost intensive way of electricity production given Germany's relative low annual solar yield of 900 -1150 kwh/kw_p.

Actual PV installation surpassed projected capacity build-up for almost every year since 2004. This success generates costs not foreseen when establishing the actual version of the EEG. German Federal Government in late 2009 anticipated 23 GW_p of PV being installed in 2020 [11], a number that most likely will be reached in 2011.By the end of 2010 total installed PV capacity in Germany reached 17.2 GW_p.

Of the 24€ct paid by the average private consumer for every kilowatt-hour in 2010, almost 10% (2.047€ct) contributes to the extra cost of RE generation. For 2011 this share in the costs will be established in 3.35€ct, or almost 15% of electricity cost. While RE does also generate a cost-dampening effect due to squeezing out of the market of the most expensive conventional generation capacity (merit order effect) and the positive effects of decentralized power production, these effects are difficult to calculate, prone to manipulation and difficult to explain to the public.

So far public opinion guaranteed political support from all relevant political parties but many observers fear that, with rising costs being attributed to renewable in general this support might wane. Without strong public backing it will be more likely that the big utility-firm lobbying groups would succeed to thwart the breakthrough of RE.

For 2012 a regular revision of the EEG is planed and it might result in a more restrictive framework then the actual one. To ease political pressure the German solar industries agreed on yet another midterm cut in solar retribution established in the EEG if new installation in the first half of 2011 surpasses 1.75GW_p. Depending on the amount of new installations this mid-term cut might be as high as 16% resulting in a retribution for solar power in the second half of 2011 of as low as 18.75€ct to 24.4€ct/kwh depending on PV size and type.

If power input preference for renewables is canceled or a cap is placed on all of the RE the actual development towards a carbon- free electricity sector might be interrupted.

There are basically four options to manage extensive costs generated by the massive PV build-up:

- Cutting retribution for yet existing installations
- Implementing a massive reduction in Feed-in Tariffs for new installations
- Putting a cap on new PV installations
- Wider spreading of Feed-in Tariffs between small scale and big scale installations

Whereas cutting the retribution for yet existing PV plants might show the strongest results, it remains the least probable option. German laws make it almost impossible to impose measures of this kind. Even if PV associations would agree to this measure to avoid more radical measures in the future, private owners of PV installations would succeed in bringing down such policy by court ruling. The impact on investment decisions, not only in the German PV market, could not be underestimated. Backdating by a few days of the last midterm cut of solar Feed-in Tariffs in 2010 already raised concern of that kind.

The two remaining options are widely discussed. An extensive 2011 study by the German Advisory Council on the Environment comes to the conclusion that a 100% renewable electricity supply is possible in Germany by 2050 and would result in a generation cost of around 7€ct/ kWh [12]. This study, based on cost effectiveness and feasibility, contributes only a marginal part of further power generation to solar. While it indicates that the extension of operative life time of NPPs is contradicting RE build-up efforts and also otherwise takes a strong pro RE stand, it suggests that there should be a relative low cap of 1-2GW_p/a implemented on PV. Implementing a low cap of maybe one or two GW_p per year of new installations would reverse many of the central concepts implemented by the EEG. A regulatory body would have to administer installation rights, resulting in a stop and go for new installations that would benefit the investor holding the right but not necessarily counting with an ideal site. By this way it would contradict the strong market-force factor central to the EEG. Whereas this scenario would facilitate to defend market shares of high end- high price modules of German/ European origin a sharp cut in solar retribution for new installations will most likely result in a mayor shakeout of German module producers.

In December 2010 a group of senior RE researchers and directors of reputable environmental and energy research institutions published an urgent plea [13] demanding political steps to maintain intact the actual legal framework of the EEG. To dampen the excessive cost effect of accelerated PV generation they demand proactive steps to limit new PV build up to a maximum of 3.5GW/a. Matt Chaney considers an immediate cut to 15€ct per kilowatt-hour the best option [14]. Extra cost would decrease dramatically due to lower capacity build-up and low retribution prices.

A wider spreading of Feed-in Tariffs between small scale (<30kW$_p$) and big scale (>1MW$_p$) installations might be considered a less harmful option for German module producers and an effective way to bring down installation prices rapidly in the more professionalized segment of the market. As further market penetration depends strongly on political decisions it would be unwise to exclude the potentially strong pressure group of small private investors prone to install PV on the roof of their house.

As so far the biggest part of PV production capacity build- up around the world is closely connected with the increase in PV installation in Germany, a sharp drop in PV installation would have a considerable impact on the solar industries worldwide resulting in bankruptcy of many solar firms and a pull-out of many investors as other markets like Italy, California, Czech Republic, China and Japan would not have the capacity to absorb a radical German cut [15].

6. CONCLUSION

The accelerated PV build-up based on Germany's innovative Feed-in Tariff system is generating costs that might discredit renewable energy as a whole. Given the so far low contribution of solar energy to the German electricity pool and its high cost compared to other renewable energies a slowing down of new installations could be necessary to avoid a total collapse of the so far very successful German policy on renewables. A wider spreading of Feed-in Tariffs between small scale and big scale installations might be the most viable option taking into account not only financial but industrial policy considerations as well. The reconsideration of a memorandum on nuclear energy, abandoned in fall 2010, and the possible rapid shut down of Germany's older nuclear power plants after the nuclear catastrophe in Fukushima in March 2011 might have es strong impact on further development of German energy policies.

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REVIEWING THE CODES: HOW MODEL ORDINANCES MAY HAVE UNINTENDED CONSEQUENCES FOR LOCALLY DERIVED RENEWABLE ENERGY ZONING

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ABSTRACT

Local governments often struggle with developing or updating their policies for distributed renewable energy generation projects, especially for residential wind turbines and solar arrays. The prevalence of model ordinances has led to wider awareness and adoption of regulations that assist planning officials with answering inquiries from potential system owners and installers. Some jurisdictions have developed ordinances that effectively pave the way for local renewable energy installations. Others, however, have adopted policies that only appear receptive but actually severely limit and possibly prevent small residential systems from being installed.

As a step toward a more comprehensive comparison of ordinances, this paper examines two community approaches to zoning and permitting to highlight how model ordinances were modified for the local social and political contexts. At issue is whether or not the adopted ordinances ultimately permit residential renewable energy systems to fully capture available resources and to what extent the communities share benefits of locally generated renewable energy.

1. RENEWABLE ENERGY PERMITTING AND ZONING: AN OVERVIEW

Local government zoning and planning officials have become the primary gatekeepers for approval of distributed renewable energy projects in many states. Currently, cumbersome permitting practices and unnecessarily restrictive regulations are reported to be major market barriers and discourage customer interests and investments in residential renewable energy projects.[1] Sometimes, design standards or other universally applicable regulations inadvertently prohibit renewable energy equipment, forcing permit applicants to apply for discretionary review of the project. With citizen calls for designating renewable energy installations as a *permitted use by-right* and streamlining the permitting process, local governments are coming to grips with enacting ordinances that they hope will make renewable energy permitting easier to understand and permits easier to process.

When faced with proposals for renewable energy installations within their jurisdictions and in the absence of renewable energy ordinances, many local governments look for guidance from neighboring jurisdictions or from their state energy offices. Local planning commissions, especially, must devise an interpretation of ordinance recommendations that is sensitive to the local context or needs. A major issue for wind turbines is whether or not the adopted ordinance ultimately permits systems to effectively capture the available wind resource due to tower height limitations and setbacks. The same principle holds true for solar panels and access to sunlight.

Most model ordinances contain a common core of requirements that include the zoning districts where renewable energy systems can be installed, the allowed capacity of the systems, and visual appearance. For wind turbines specifically, the restrictions include tower height, set backs, and sound levels. There may also be special considerations and sometimes a commission includes language that addresses turbine certification, environmental compliance, and/or shadow flicker. Both solar and wind energy systems usually must meet building and electrical codes as well. These are the basic variables that planning commissions must consider when they determine whether and how renewable energy systems fit into their communities. When taken together, these criteria often form a complex set of circumstances that must be balanced to meet the community’s needs.

2. CASE STUDIES

2.1 Methods

The two cases chosen for this paper represent municipalities that have a history of local renewable energy projects, are relatively receptive to renewable energy in general, and have recently adopted renewable energy ordinances. One is located in Cape Charles, VA, and the other in Grand Rapids, MI. Cape Charles is the site of the Sustainable Technologies Industrial Park, a unique commercial building that hosts 30 kW of building-integrated solar PV. Grand Rapids received a national sustainability award from the U.S. Chamber of Commerce in 2010, which made it an intriguing case to investigate. The contrasting sizes of the communities also made them interesting cases. While both communities are incorporated, Cape Charles is much smaller and situated in a rural agricultural area. Grand Rapids is an urban center. Data collection consisted of interviews and primary source research.

2.2 Cape Charles Case

Cape Charles is a small town located on Virginia's Eastern Shore, a region that is becoming an epicenter for utility scale renewable energy development. Just nine miles from Cape Charles, a 20 MW solar PV farm is close to becoming a reality and across the bay in Chesapeake, Virginia, the Offshore Wind Technology Center will open soon. With its deepwater port, Cape Charles is well situated to be a service center for a prototype offshore turbine developed at the Center. Area residents are well aware of the potential economic impact renewable energy may have on the depressed region.

The vast majority of Cape Charles' residents live within the core of a National Historic District. In 2009, the Town's Historic District Review Board adopted rules regarding the addition of solar panels to homes stating that panels are not permitted within the District if they are visible from the street. In addition, the Board recently denied an applicant permission to attach a roof-mounted wind turbine to a house. This last development, as well as an increase in inquiries about inland residential wind energy installations, motivated the Cape Charles Town Council to create an ordinance that would preserve the "historic character" of the Town (i.e. no roof-mounted wind turbines), and also allow for wind energy development outside of the Historic District. Because the Town did not have a wind energy ordinance, the Town Planner was tasked with drafting one.

The Virginia Center for Wind Energy at James Madison University is the State's primary site for information about wind energy and provided an example of a model ordinance to the Cape Charles Town Planner. It was used to craft an ordinance that met the Town Council's objectives: to communicate the Town's desire to promote renewable energy, restrict micro-wind turbine installations, and reserve the possibility for constructing a large turbine to power Town water projects (≤1 MW). The Town Planner reviewed several model ordinances from neighboring towns and counties and attended a Center for Wind Energy workshop on local zoning ordinances while he crafted the Cape Charles ordinance.[2]

In March 2011, the Cape Charles Town Council passed their Wind Turbine Ordinance. With the exception of set back restrictions and minimum lot size specifications, the requirements for a 1 kW turbine are identical to a 1 MW turbine. In addition, all wind turbine projects must apply for a Conditional Use Permit before construction begins. Conditional Use Permits require a Planning Commission review as well as a public hearing.

The only Town regulations regarding solar energy apply to homes in the Historic District, and any proposal to install solar energy equipment there must be approved by the Historic District Review Board. According to the Town Planner, the orientation and the architectural style of the homes is not conducive to solar energy equipment installation. In addition to these physical limitations, a tree ordinance requires at a minimum 10% tree cover in the Town. In the planned unit development portion of the Town, the architectural review board determines the panel placement. These circumstances account for about 95% of the Town's residences.

Cape Charles is a good example of a jurisdiction that has adopted an ordinance that may appear receptive to promoting residential renewable energy, but actually limits most systems from being installed.

2.3 Grand Rapids Case

Grand Rapids was recently recognized for its successful sustainable development master plan that organized the work of its city government around the triple bottom line of economic strength, environmental stewardship and social equity. A small-wind turbine rotor manufacturer has its headquarters in the city. In 2010, the local electric utility introduced a temporary, experimental feed-in tariff program for solar PV customers/generators that pays them up to 65 cents/kWh for the next 12 years. The utility is also working toward achieving 100% of their electricity originating from renewable energy by 2020. The city has proposed to install two 2.0 MW turbines on property it owns next to its water filtration plant, approximately 25 miles west of Grand Rapids, along the shore of Lake Michigan.

In 2008, the City adopted an Alternative Energy Ordinance to guide residential scale renewable energy development based on model zoning ordinance recommendations distributed by the Michigan Energy Office.[3, 4] The model ordinance classifies some categories of projects – towers less than 60 feet (18.3 m) – as a *permitted use by-right* and recommends no additional zoning overview (e.g. planning commission and/or public hearing). Turbines on towers greater than 60 feet require a Planning Director's review. While the State's recommendations were not specifically created for urban areas, Grand Rapids copied many of the recommendations for on-site wind turbines but extended the set-back requirements (100% to 120% of tower height), added requirements for an environmental assessment, and an analysis for shadow flicker.

Grand Rapids considers both wind and solar energy installations to be an accessory use and as such only require a "counter review" of applicable building and electrical permits. However, installing solar panels on the front of a residential dwelling requires an "administrative departure" approval by the Planning Director, but does not trigger the need for a conditional or special use permit. The Planning Director considers the potential for on-street glare, roof orientation, site alternatives, and the effects upon the designated Neighborhood Classification.

3. DISCUSSION

Both of these cases provide the backdrop for issues regarding the adoption of a model renewable energy ordinance for populated areas. Cape Charles and Grand Rapids sought to establish ordinances and champion the goal of promoting renewable energy by adopting model ordinances and tailoring them for their communities. However, whether the adopted ordinances will enable the communities to benefit from residential renewable energy systems is doubtful. Key requirements of two ordinances are summarized in Table 1.

Foremost for Cape Charles was to limit the visual impacts of residential small wind turbines, but also allow larger wind turbines for future Town water projects. Residential wind energy projects are now difficult if not impossible to install in Cape Charles due to the Conditional Use Permit (CUP) requirements (including a public hearing) preceded by the Historic District Review Board process. The Grand Rapids ordinance makes it easier to get a wind energy project started by eliminating the need to apply for a CUP. Schools and demonstration sites are perfect candidates for this type of installation where the return on investment is not the primary reason for the installation.

For solar installations, the ordinances allow access to the resource but disallow installations that may be counter-productive. In Cape Charles, since most homes have roof surfaces that do not face south, attaching the mounting hardware to those structures might require tricky engineering. Both communities, however, are concerned with the visual impact on neighbors so their ordinances defer to discretionary reviews when the solar panels can be seen from the street.

TABLE 1: SUMMARY OF KEY RESTRICTIONS

WIND	**Grand Rapids**	**Cape Charles**
Permitted zones	All zones	All zones
Capacity	Not stipulated	25 kW*
Height Limit	< 60 ft* (18 m)	120 ft (37 m)
Set back	120% of tower height*	150% of tower height*
Noise	60 dbA	60 dbA
Process	Building permit	Planning commission approval* + permit
Environ. Assessment	Yes	Yes
Flicker Analysis	Yes*	No
SOLAR	**Grand Rapids**	**Cape Charles**
Permitted zones	All zones	All zones (not allowed in one if visible from street*)
Placement	Roof or accessory structure	Roof or accessory structure
Process	Building permit	Building permit
Expedited	No	No

* Especially restrictive or burdensome provisions that prevent or preclude cost-effectiveness of most installations

Both communities had good intentions for enacting their ordinances, but had to make tough choices due to the political realities in each community. The Cape Charles ordinance effectively prohibits on-site small wind energy generation by requiring potential project owners not only to apply for a CUP, but also to meet fairly strict environmental assessment criteria, including reviews and comments from state and federal natural resource agencies. While Grand Rapids' ordinance does not require a CUP, it goes one step further by requiring a shadow flicker analysis for all installations. Such environmental review requirements can take months to complete and involve considerable expense and time contacting many government agency offices.

The difficulty with siting small wind turbines in populated locations is a recognized issue and probably contributed to the reason the Michigan Office of Energy model ordinance stated, "This material is not intended to apply in urban areas." For example, the Grand Rapids ordinance, taken from the State Energy Office, requires a set back that would require 0.37 acres of open land for a wind turbine on a 60 foot tower (18 m), the maximum height for permitted use. The set back requirements or "fall zones" alone eliminate most property owners from considering wind energy as a possible electrical generating source.

In Cape Charles, a 100 foot (30 m) wind turbine tower, 20 feet (6 m) below the allowed height, requires a 150-foot (46 m) set back or at least 1.6 acres. This ordinance does, however, leave open the potential for larger wind turbines to be installed in the Town because the ordinance provisions do not vary from those for larger turbines in other areas. The ordinance effectively allows the city to eventually site a turbine if the opportunity arises.

It is unfortunate that these two ordinances (and, based on a review of a number of other ordinances, most ordinances for wind energy) do not address tower placement in relationship to obstructions such as buildings and trees and their effect on the wind movement. Using an accepted heuristic of "at least 30 feet (9 m) above any obstruction within 300 feet (90 m)" in an ordinance would guide property owners who wish to see their wind energy system become a worthwhile investment.

4. CONCLUSION AND NEXT STEPS

Enacting a renewable energy ordinance assures communities that safety and welfare are primary considerations when renewable energy systems are installed. However, merging the political and socio-cultural context into the reality of renewable energy often entails a delicate balancing act. The Cape Charles Town Planner explained, "We'd like to encourage wind . . . we're pro-alternative energy to the best that it would fit into our community." [5]

Grand Rapids' story is similar. When asked about the effect their ordinance had on new projects, a city planner there explained, "We don't really have a good wind regime."[6] Also, the feed-in tariff program expired and solar installations have declined as the community waits for the utility to extend the incentive to more subscribers.

These two cases demonstrate that challenges remain for residential scale renewable energy projects. Even with ordinances in place, there is no guarantee that these will foster more residential projects. Because most people in the U.S. live in urban or populated areas, there is an increasing desire for more locally produced, residential scale forms of electricity generation. For the time being anyway, the technical specifications and land requirements appear to make wind energy better suited for rural landscapes. Solar energy should have the upper hand with residential applications in more populated settings, but challenges still remain. Eventually, a greater appreciation for the benefits of clean energy may lead to wider acceptance of renewable energy structures in both the built and natural environments.

A comparative analysis of a wider variety of city and county zoning ordinances and permitting regulations is warranted to highlight "best and worst" practices. Similar to the Freeing the Grid project, which has led to marked improvement in net metering and interconnection policies, such an effort could raise awareness among local and state governments wanting to attract clean energy development and green jobs and help them ascertain whether their intended outcomes are actually being achieved.

A simple A-F scoring system could expose how the use of model ordinances have affected residential renewable energy installations, which tailored local policies and streamlined processes earn high marks, and which serve as major barriers for local sustainable energy development. For example, a robust online permit submission and approval system can save time and costs for all parties.

Linking proposed renewable energy ordinances to sustainability plans and green zoning policies may assist officials with the "heavy lifting" associated with policy changes. Wind turbine policies have typically been enacted as discrete entities without considering broader green zoning codes that connect sustainable development practices with environmentally friendly zoning. Such an approach could guide appropriate use and siting of renewable energy installations in local jurisdictions.

In promoting community energy initiatives, ordinances can create the conditions to increase energy sustainability, reduce emissions, keep energy dollars and economic activity local, and build support for clean energy as visible reminders of local benefits.

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RENEWABLE ENERGY MODEL ORDINANCES & LOCALLY DERIVED ORDINANCE SOLUTIONS

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ABSTRACT

Local governments often struggle with developing or updating their policies and regulations for distributed renewable energy generation projects, especially for residential small-scale wind turbines and solar arrays. The prevalence of model ordinances has led to a wider awareness and adoption of regulations that assist planning officials with answering inquiries from potential renewable energy system owners and installers. Some jurisdictions have developed ordinances that effectively pave the way for local renewable energy installations. Others, however, have adopted policies that only appear receptive but actually prevent small systems from being installed.

This paper examines two community approaches to zoning ordinances and permitting processes to highlight how model ordinances were modified to fit the local social and political contexts. At issue is whether or not the adopted ordinance ultimately permits a small renewable energy system to fully capture the available resource and to what extent does a community share in the benefits of locally generated renewable energy.

1. RESIDENTIAL RENEWABLE ENERGY ORDINANCES AND PERMITTING: AN OVERVIEW

Currently, poor permitting practices and unnecessarily restrictive regulations are reported to be major market barriers and discourage customer interests and investments in residential renewable energy projects.[1] Sometimes, design standards or other universally applicable regulations inadvertently prohibit renewable energy equipment, forcing permit applicants to apply for discretionary review of the project. With citizen calls for designating renewable energy installations as *permitted use by-right* and streamlining the permitting process, local governments are coming to grips with enacting ordinances that they hope will make renewable energy permitting easier to understand and permits easier to submit.

When faced with proposals for renewable energy installations within their jurisdictions and in the absence of renewable energy ordinances, many local governments look for guidance from neighboring jurisdictions or from their state energy offices. Local planning commissions, especially, must devise an interpretation of ordinance recommendations that is sensitive to the local context or needs. A major issue for wind turbines is whether or not the adopted ordinance ultimately permits the system to effectively capture the available wind resource due to tower height limitations and setbacks. The same principle holds true for solar panels and access to sunlight.

Most model ordinances contain a common core of requirements that include the zoning districts where a renewable energy system can be installed, the capacity of the system, tower height (wind), set backs (wind), and sound levels (wind), among others. These systems must also meet building and electrical codes. In the case of wind turbines, there may be a need to comply with FAA regulations. These are the basic variables that planning commissions must consider when they determine whether and how renewable energy systems fit into their communities. For wind turbines, there may also be special considerations and a commission might include language that addresses turbine certification, environmental compliance, and conformity to historic district standards. When considered together, these criteria form an incredibly complex set of circumstances that must be balanced to meet the community's needs.

2. CASE STUDIES

2.1. Methods

The two cases chosen for this paper represent municipalities that have a history of local renewable energy projects, are relatively receptive to renewable energy in general, and have recently adopted renewable energy ordinances. One is located in Cape Charles, VA, and the other in Grand Rapids, MI. Cape Charles is the site of the Sustainable Technologies Industrial Park, a unique commercial building that hosts 30 kW of building-integrated solar PV. Grand Rapids received a national sustainability award from the U.S. Chamber of Commerce in 2010, which made it an intriguing case to investigate. The contrasting sizes of the communities also made them interesting cases. While both communities are incorporated, Cape Charles is much smaller and situated in a rural agricultural area. Grand Rapids is an urban center.

Data collection consisted of interviews and primary source research.

2.2. Cape Charles Case

Cape Charles is a small town located on Virginia's Eastern Shore, a region that is becoming an epicenter for utility scale renewable energy development. Just nine miles from Cape Charles, a 20 MW solar PV farm is close to becoming a reality and across the Bay in Chesapeake, Virginia, the Offshore Wind Technology Center will open soon. With its deepwater port, Cape Charles is well situated to be a service center for a prototype offshore turbine developed at the Center. Area residents are well aware of the potential economic impact renewable energy may have on the depressed region.

The vast majority of Cape Charles' residents live within the core of a National Historic District. In 2009, the Town's Historic District Review Board adopted rules regarding the addition of solar panels to homes. (Panels are permitted provided they are not visible from the street.) The Board had recently denied an applicant permission to attach a roof-mounted wind turbine to a house. This last development, as well as an increase in inquiries about inland residential wind energy installations, motivated the Cape Charles Town Council to create an ordinance that would preserve the historic character of the Town (e.g. no roof-mounted wind turbines), and also allow for wind energy development outside of the Historic District. Because the Town did not have a wind energy ordinance, the Town Planner was tasked with drafting one.

The Virginia Center for Wind Energy at James Madison University is the State's primary site for information about wind energy and it had examples of model ordinances that the Town Planner accessed to craft an ordinance that met the Town's objectives. It had to communicate the Town's desire to promote renewable energy, restrict micro-wind turbine installations, and reserve the possibility for constructing a large turbine to power Town water projects (≤1 MW). He reviewed several model ordinances from neighboring towns and counties and attended a Center for Wind Energy workshop on local zoning ordinances while he crafted the Cape Charles ordinance.

In March 2011, the Town Council passed its Wind Turbine Ordinance. With the exception of set back restrictions and minimum lot size specifications, the requirements for a 1 kW turbine are identical to a 1 MW turbine. In addition, all wind turbine projects must apply for a Conditional Use Permit before construction begins. Conditional Use Permits require a Planning Commission review as well as a public hearing.

As mentioned above, the only Town regulations regarding solar energy apply to homes in the Historic District and any proposal to install solar energy equipment must be approved by the Historic District Review Board. According to the Town Planner, the orientation and the architectural style of the homes is not conducive to solar energy equipment installation. In addition to these physical limitations, a tree ordinance requires at a minimum 10% tree cover in the Town. In the planned unit development portion of the Town, the architectural review board determines the panel placement. These circumstances account for about 95% of the Town's residences.

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In 2008, the City adopted an Alternative Energy Ordinance to guide residential scale renewable energy development. The ordinance is based on a model zoning ordinance distributed by the Michigan Energy Office. The model ordinance classifies some categories of small renewable energy projects as a *permitted use by-right* and recommends no additional zoning overview (e.g. planning commission and/or public hearing). While the State's recommendations were not specifically created for urban areas, Grand Rapids copied most all of the recommendations for on-site wind turbines and then extended the set-back requirements (100% to 120% of tower height), added requirements for an environmental assessment, and an analysis for shadow flicker.

Both wind and solar energy installations are considered to be an accessory use and as such only require a "counter review" of applicable building and electrical permits. However, installing solar panels on the front of a residential dwelling requires an "administrative departure" approval by the Planning Director, but does not trigger the need for a conditional or special use permit. The Planning Director will consider potential for on-street glare, roof orientation, site alternatives, and the effects upon the designated Neighborhood Classification.

A summary of the two ordinances is captured in Table 1.

WIND	**Grand Rapids**	**Cape Charles**
Permitted zones	Permitted in all zones	Permitted in all zones
Capacity	Not stipulated	25 kW
Height Limit	< 60 feet	120 feet
Set back	120%	150%
Noise	60 dbA	60 dbA
Process	Building permit	Planning Commission approval + building permit
Environ. Assessment	Yes	Yes
Flicker Analysis	Yes	No
SOLAR	**Grand Rapids**	**Cape Charles**
Permitted zones	Permitted in all zones	Permitted in all zones
Placement	Roof or accessory structure	Roof or accessory structure
Process	Building permit	Building permit
Expedited	No	No

Table 1. Ordinance requirements

3. DISCUSSION

Both of these cases provide the backdrop for issues regarding the adoption of a model renewable energy ordinance for populated areas. Cape Charles and Grand Rapids sought to establish ordinances and champion the goals of renewable energy by adopting model ordinances and tailoring them to fit their communities.

Foremost for the Cape Charles ordinance was to limit residential small wind energy generation, but also allow larger wind turbines for future Town water projects. Residential small wind energy projects will be difficult to complete because of the Conditional Use Permit [CUP] requirements (including a public hearing) preceded by the Historic District Review Board process. The Grand Rapids ordinance makes it easier to get a wind energy project started by eliminating the need to apply for a Conditional Use Permit; but, the tower height limit of 60 feet, even though it may be appropriate in a populated area, makes access to the available wind resource difficult. Schools and demonstration sites are perfect candidates for this type of installation where the return on investment is not the primary reason for the installation.

For solar energy projects, the ordinances effectively allow access to the resource by disallowing installations that are counter-productive. In Cape Charles, since most homes have roof surfaces that do not face south, attaching the mounting hardware to those structures might require tricky engineering and consequently are not candidates for solar panels. Both communities, however, are concerned with the visual impact on neighbors so their ordinances defer to discretionary reviews when the solar panels can be seen from the street.

Both communities had good intentions for enacting their ordinances. Despite these intentions, both communities had to make tough choices in order to blend their enthusiasm for renewable energy with the political realities in each community. The Cape Charles ordinance effectively makes on-site small wind energy generation prohibitive by requiring potential project owners to not only apply for a CUP, but they must meet fairly strict environmental assessment criteria, including reviews and comments from state and federal natural resource agencies. While Grand Rapids' ordinance does not require the CUP, it goes one step further by requiring an analysis of shadow flicker for all installations. The requirements for environmental reviews can take months to accomplish and involve contacting many government agency offices.

The difficulty with siting small wind turbines in populated locations is a recognized issue. This is the reason the Michigan Office of Energy model ordinance stated, "This material is not intended to apply in urban areas."

For example, the Grand Rapids ordinance, borrowed from the State Energy Office, requires a set back for a 60-foot tower and turbine (maximum height for permitted use) of 0.37 acres of open land. The set back requirements or "fall zones" alone eliminate most property owners from considering wind energy as a possible electrical generating source.

In Cape Charles, a 100 foot-high turbine and tower (just two-thirds of the allowed height) requires a 150-foot set back. The amount of land needed to meet the requirement is 1.6 acres. This ordinance does, however, leave open the potential for a larger turbine to be installed in the Town because the ordinance provisions do not vary from those for larger turbines in other areas. The ordinance effectively allows the city to eventually site a turbine if and when the opportunity comes along.

After reviewing a number of ordinances, it is unfortunate that these ordinances (and most ordinances for wind energy) do not address tower placement in relationship to obstructions such as buildings and trees and their effect on the wind movement. Using an accepted heuristic of "30 feet above any obstruction for 300 feet" in an ordinance would guide property owners who wish to see their wind energy system become a worthwhile investment.

4. CONCLUSION

Enacting a renewable energy ordinance assures the community that its health, safety and welfare are primary considerations when renewable energy systems are installed. However, merging the political and socio-cultural context into the reality of renewable energy requires a delicate balancing act. The Cape Charles Town Planner reinforced the tough choices he has had to make when he said, "We'd like to encourage wind . . . we're pro-alternative energy to the best that it would fit into our community." [2]

Grand Rapids is no different. A city planner there said, "We don't really have a good wind regime" when asked about the effect their ordinance had on new projects.[3] Also, without the feed-in tariff, solar panel installations have declined.

These two cases demonstrate that challenges remain for residential scale renewable energy projects. Even with ordinances in place, there is no guarantee that these will foster more residential projects. Because most people in the U.S. live in urban or populated areas, there is an increasing desire for more locally produced, people-friendly forms of electricity generation. For the time being anyway, the technical specifications and land requirements appear to make wind energy better suited for rural landscapes. Solar energy should have the upper hand on people-friendliness, but issues remain. Eventually, a greater appreciation for the benefits of clean energy may lead to wider acceptance of renewable energy structures in both the built and natural environments.

[1] Brooks, Bill. Expedited Permit Processes for PV Systems. Solar America Board for Codes and Standards Report. 2009.
Pitt, Damien. Taking the Red Tape Out of Green Power. Network for New Energy Choices. 2008.
Johnson, Scott & van Dam, C.P. Small Wind Permitting Challenges. California Wind Collaborative. 2009

[2] Personal communication. March 9, 2011.

[3] Personal communication, March 9, 2011.