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Public Service Commission of Wisconsin
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DAIRY BUSINESS ASSOCIATION

KEEPING THE COWS IN WISCONSIN™

February 17, 2009

Public Service Commission of Wisconsin
610 North Whitney Way
P.O. Box 7854
Madison, Wisconsin 53707-7854

RE: Docket 5-EI-148, "Investigation on the Commission's Own Motion Regarding Advanced Renewable Tariff Development."

The Wisconsin Dairy Business Association (DBA) is a statewide organization of dairy producers, vendors, allied industry partners, and professionals actively working to assure that dairy producers, large and small, remain an active, thriving part of Wisconsin's economy, communities, and food chain. DBA members appreciate this opportunity to offer input and advice to the Public Service Commission's consideration of establishing more uniform ARTs across all Wisconsin electric utilities.

Wisconsin leads the nation in the use of manure digester technology. To date, more than 25 farms are using manure digesters generating biogases from cow manure -- which, in turn, fuel internal combustion engines driving generators. The generators produce electric power used for the operations electrical needs and feed the surplus energy back onto the electric utility grid as an environmentally-friendly source of energy helping utilities meet requirements. In the future, the possibility exists for our members to utilize other renewable energy systems such as solar photovoltaic and wind generation; and some of our members are researching other possible energy production processes. To date, our members experience is limited to manure digester technologies. As such, our responses to the Commissions questions will focus on the technology and economics of manure digester technology.

DBA continually reviews documents related to technologies that will integrate all of the nutrient management activities on the farm while addressing the environmental issues, and making manure into an income generator for the farm. DBA is working to make manure handling activities revenue neutral, or better yet, positive to the overall farm operation. We recommend that the Public Service Commission consider reviewing the following documents which directly address the mechanics, advances and economics of manure digestion technology as a source of environmentally-friendly energy. DBA has electronic copies of these documents on file and would be pleased to share them with the Commission.

2. Research and Experience Outside Wisconsin.

- The document titled "Current Experience With Net Metering Programs" delivered at the 1998 Wind Power Conference in Bakersfield California, authored by Yih-huei Wan and H. James Green of the National Renewable Energy Laboratory (NREL)
- The November 2006 document titled "Freeing the Grid" produced by the "Network For New Energy Choices," forwarded by Michael Dworkin, Professor of Law and the Director of the Institute for Energy and the Environment, Vermont Law School.

3. Costs of Producing Electricity from Renewable Resources.

As noted in our introduction, DBA's member experience is primarily with the use of manure digester technology. In 2005, the cost of a digester and electric generator and other necessary equipment to operate the systems were estimated to cost from $325 per cow to $ $550 per cow. The cost of anaerobic digestion for biogas production and utilization will vary with system type and size, type of livestock operation, and site-specific conditions. To provide some preliminary guidance with respect to expected cost, the AgSTAR program has performed a series of analyses to determine the relationships between capital cost and size for different types of operating digesters for dairy and swine manures with internal combustion engine-generator sets. Results of these analyses in combination with other information were used to develop the cost algorithms used in FarmWare, Version 3.0. The graphics below provide a snap shot of these relationships[1].

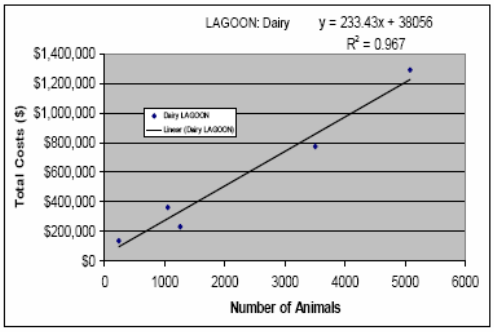

Figure 5. Covered lagoon digester cost – relationship to dairy herd size.

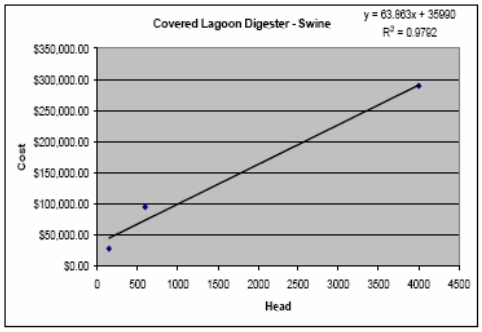

Figure 6. Analysis of covered lagoon digester system costs (swine).

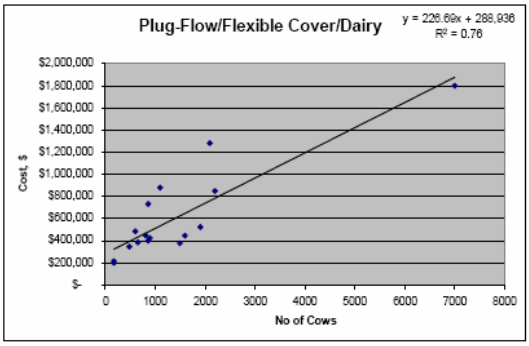

Figure 7. Plug flow/flexible cover digester system cost relationship to dairy herd size.

[1] http://www.epa.gov/agstar/pdf/2006digest.pdf

4. How much energy (in kilowatt-hours (kwh)) will be produced over the useful life of a typical customer-owned renewable energy system in Wisconsin using each of the following technologies? Please be explicit about sources of data, assumptions, and how production might vary based on system size, location, or other variables.

A 2002 document titled, "Final Report Haubenschild Farms Anaerobic Digester" conducted by the "Minnesota Project"[2], noted "there are three types of digesters most often considered for dairy farms, the Covered Lagoon, Complete Mix Digester and Plug Flow Digesters. The Covered Lagoon Digesters are used for liquid manure (less than 2 percent solids) and require large-volume lagoons. Because the methane production rate is dependent on ambient temperatures with a covered lagoon system, it is not considered cost effective to use the biogas for energy production in Minnesota's or Wisconsin's climate. It has been used in cold climates for odor control, however, including in Wisconsin. This type of digester is the least expensive of the three."

"The financial viability of the project is sensitive to the selling price of excess electricity. With a selling price of 2 cents/kWh (scenario A), the simple payback for the 1998 Projection scenario is 11 years, but reduces to 7 years if the sale price of excess electricity increases to 7.3 cents/kWh (scenario B). The selling price of electricity could make or break a project for a farmer, unless they received some other financing assistance, or were able to achieve high biogas production, as Haubenschild Farms has.[3] With 750 cows, current output per cow is over 93 cubic feet/cow/day, and electricity production is about 4.0 kilowatt hours/cow/day, or about 40 percent greater than design specifications.

The Dairy Business Association has been co-operating with companies with an interest in significantly increasing the number of on-farm manure digesters. According to our sources, biogas plants are base load, continuous power and, as such, can reliably be expected to operate for 8,000 hours per year, allowing a safe allowance of 760 hour.

A company is developing a 4.8 MW facility in Wisconsin. Their research shows the total lifetime power output of the 4.8 MW facility would be 744,960 MWh and the total aggregate output of a combined 14.8 MW installed base would be 2,296,960 MWh over 20 years.[4]

5. What should the goals and objectives of an ART policy be?

a) What would you consider to be the primary purpose of an ART policy? Is the primary purpose to accelerate renewable energy installations, lower the cost of renewable energy, help utilities meet renewable portfolio standard (RPS) obligations, increase the diversity of installed renewables, reduce greenhouse gas emissions, or something else?

DBA finds that the single largest obstacle our larger producers face when considering construction of a renewable energy resources is the cost and underfunded competitive subsidy programs. It is our position that the Public Service Commission policy should be encouraging all renewable energy projects but weigh-in the balance of cost benefit ratio of each. Biogas generation on Wisconsin's dairy

[2] www.mnproject.org cnelson@mnproject.org
[3] http://www.mnproject.org/pdf/Haubyrptupdated.pdf
[4] http://www.stormfisher.com/contact.htm

farms have multiple benefits that other renewables don't have. Aside from being a predictable source of alternative energy, digester technology also benefits society by significantly reducing greenhouse gas emissions, nutrient storage problems, odor control issues and landspreading of farm waste. Wisconsin is home to 1.25 million dairy cows producing 37.5 million tons of manure a year. With the right incentives, like the ART policy in place, the problem of odor, groundwater runoff, greenhouse gases, pathogens and weed seed spread becomes a solution of green energy and organic fertilizer. In this respect, biogas stands alone among other renewable as its environmental benefits reach beyond just the provision of green energy.

Considering the primary purpose of the ART policy, what short- and long-term goals might be appropriate? In other words, how should the success of an ART policy be measured?

The State of Wisconsin's Clean Energy Program, along with the Focus on Energy office, have established the base statistics for where Wisconsin was at when it changed course and renewable energy sources became a priority. The tools to measure the success of programs are already accessible. We can measure by job growth in businesses producing products or projects related to renewable energy and see investment in the state by new or expanding companies responding to the demand for renewable energy equipment. Percent (%) increase in RPS targets met versus years where ART policy was not in place and as demand for products grow new jobs will be created.

a) *Should the Commission establish ARTs for all electric utilities regulated by the Commission, all investor-owned utilities or all Class A utilities? Why or why not?*

The commission should establish ARTs for all electric utilities under their regulation. The benefit of investment in equipment and new jobs should be the same statewide energy developers within the state, must be assured that regardless of the location of facilities they will obtain a fair rate for power they generate.

b) *What role, if any, should small, customer-owned renewables play in helping utilities meet RPS obligations?*

With the right incentives in place with respect to demand side management and conservation, these can contribute as much to the RPS goals as renewable energy can. These should be considered alongside an ART policy. Demand side management, net metering and conservation all play a role in reaching RPS requirements.

Should utilities seek to meet RPS obligations at the lowest possible price, or should other factors be considered?

Other factors must be considered. Wind and solar are important sources of renewable energy, but they are unpredictable and intermittent forms of power. Wisconsin's most abundant and available resource is manure -- more so than wind or solar. At present, the majority of this resource is not beneficially used. Wisconsin sees dairy farming as a growth industry. We should look at every new or expanding farm, not only for the dairy jobs they produce. but for their stable energy generation abilities. Any ART policy should reflect the state's need for this resource to be converted into energy.

c) What role, if any, should small, customer-owned renewables play in helping utilities reduce greenhouse gases?

Customer-owned renewables provide an indirect benefit. They reduce the consumption of utility regeneration and some may be putting some of that energy back onto the grid. Calculations should be done to determine what level of greenhouse gas reductions is achieved. The calculation should include all uses of energy not just those provided by utilities.

What ART structure would best incentivize the reduction of greenhouse gases?

Any Adjustable Rate Tariff should anticipate that as demand grows, innovation in means of production will grow as well. Whatever form it takes -- it needs to appeal to developers and maximize their ability to procure as many Renewable Energy Credits as possible demonstrating evidence of the maximum available greenhouse gas offset. RECs (but not other environmental attributes) and would become the property of the utility as part of the ART

6. What are desirable and appropriate design structures?

a) Should the ART directly target new capacity and new generation?

Yes, because it drives the industry to continue producing new renewable energy sources shifting the production to more modern and environmentally sound production facilities.

b) How can ART payment levels be structured such that producers are not undercompensated or overcompensated over the duration of the contract?

ART payment levels must account for the type of technology used, as well as the size of the projects. The best way to accomplish this is to speak directly with developers of renewable energy systems in each sub-segment to understand not only the cost of installed capacity per kW, but just as importantly, the cost of capital and their required rates of return. The ART's must also consider the economy and the market's perception of higher risk when investing

c) Is long-term forecasting of renewable technology economics reliable enough to offer price guarantees? How should long-term forecasting affect ART structures?

Dairy farmers invest large amounts of capital at the front end of a project and therefore require certainty of off-take price for a fixed period of time to achieve financing. If these expensive installations were subject to spot market pricing, they would not be built.

d.) How should the availability of financial incentives for renewable technologies through the Focus on Energy program and voluntary utility programs affect decisions regarding ART payment amounts?

Biogas projects can have a significant impact on smaller scale projects. Focus on Energy grants are capped at low amounts, (typically $250,000), and have little to no impact on medium to larger scale projects. Feed-in tariffs will insure that costs of operations and maintenance do not exceed the revenue stream. Intelligent project developers will only build when they are assured that there will be a

sustained demand for their power and it comes at a fair price. Demand and stable prices will likely reduce the demand on government funding.

7. Other Policy Questions

a) Are there any legal issues which constrain the Commission's ability to develop and implement an ART policy?

DBA is not qualified to answer this question accurately.

b) What effects might ARTs have on jobs, fossil fuel imports, and agriculture?

One DBA member, Conestoga-Rovers % Associates, prepared a report noting that for each $1.00 spent to acquire energy resources from outside a community, only about $0.33 of economic activity is generated within the community. On the other hand, each $1.00 spent within the community produces (through the economic 'multiplier effect') approximately $1.67 of local economic activity. Biogas generated by agriculture is a benefit to the local community and the operator. They have pride of ownership in the facility, therefore they will manage it as an asset that is helping to solve manure management problems at the same time it reduces utility costs.

c) Should utilities allow customers to voluntarily choose to purchase electricity generated from a specific technology (e.g., solar PV)?

Utilities are in a better position to answer this question. They would best understand the supply and demand complexity of this consideration.

ART Design Issues

8. Overall Tariff Structure

a) Should ARTs offer a fixed price (e.g., lO$/kWh), a fixed premium (e.g., 4$/kWh above the Locational Marginal Price), a hybrid of the two structures, or some other structure?

The ART should offer a fixed price that escalates with inflation. Project proponents are generally unable to raise financing based on contracts with floating prices, notwithstanding any premiums, on electricity-generating projects, given the localized nature of electricity markets relative to natural gas markets, for example.

b) How might an ART be designed to incorporate components of both a fixed price structure and a fixed premium structure?

Not recommended. These projects are likely unable to achieve financing for the project, especially given current market conditions.

c) Should customers be able to choose between a fixed rate and a fixed premium when signing an ART contract?

Again, Utilities are in a better position to answer this question.

9. Program Size Limitations

a) Should the Commission limit the total program size of all ART offerings for the state as a whole, for individual utilities, and/or for specific technologies? If so, why?

Additional limitations will only serve to curb investment; except perhaps to the limits of the state's RPS.

b) If the Commission limits total program size, what should the basis be for such limits?

RPS targets.

Should limits on ARTs be based on participation levels, installed capacity, actual generation, RPS obligations, costs, or something else? Should limits on ARTs be fixed amounts or proportional to total capacity, generation, costs, etc.?

If limits are in place, these should reflect actual grid availability, availability of spend for renewable premiums by utilities, or other truly-limiting metrics. If certain types of renewable energy are to be promoted over others, this should be done not through limits -- but through pricing differentials and/or 'adders.'

c) If program size limits are imposed, should enrollment be on a "first come, first served" basis or based on some other criteria?

A "first come, first served" basis would work if there was a fair announcement process for enrollment. Speculators should not be able to get prior knowledge giving them the opportunity to gain from reserving grid capacity before enrollment is announced.

10. Covered Renewable Energy Technologies

a) Are there any specific technologies for which all utilities should be required to offer an ART?

Renewables should be defined to include all pertinent technologies and these should form the basis for the ART across the state -- for the sake of uniformity and so as not to create iniquities between utilities.

b) On what basis should the Commission decide whether it is appropriate to offer an ART for a given technology?

The Commission should review and be familiar with the best practices in European and Ontario ARTs which provide strong definitions of what technologies should be included in ARTs. Generally, these are: Wind, Small hydro, Solar Pv, Biogas, Biomass and landfill gas. The Commission should follow precedents in this respect.

c) Should the ART be technology-specific or apply to a generic definition of renewables?

ART should apply to a generic definition of renewables.

11. Individual Project Size Limitations

a. What project size limits, if any, are appropriate for each technology, and why?

Biogas provides base load, distributes power to the grid and solves myriad other issues, while wind only provides intermittent power. A 5 MW biogas plant is not cost competitive with a 100 MW wind farm on a per MW basis, but provides more benefits per MW. As long as these differences are accounted for by separate prices per kWh, this is not an issue.

Typical on-farm systems will be less than 1 MW, but larger farm systems which beneficially utilize other substrates could generate from anywhere between 2 MW and 10 MW. This is based on the largest dairy farms in the state utilizing an appropriate mixture of off-farm substrates for maximum biogas generation (50 to 70 percent).

b) Should project size limits be uniform across utilities?

If project size limits are put in place, they should be uniform across utilities.

12. Contract Duration

a. Should utilities offer the same duration for all ART contracts regardless of the technology?

Yes, the same duration of contract should be available regardless of technology. A 20-year contract would be preferred and would provide more secure returns and alleviate risk to a project lender. The ART should also be tied to an inflationary adjustment factor such as the GDP Price Deflator published by the Department of Commerce each year.

b) What is the optimum duration for ART contracts and why?

Europe and Canada have had significant experience with this subject. They have shown that it is virtually impossible to demonstrate satisfactory returns to project financiers on contracts of less than 20 years.

13. Cost Recovery

a) Why and under what circumstances might it be appropriate for ART costs to be recovered through ordinary rates paid by all customers or a class of customers?

For purposes of answering this question, assume "ART costs" means all costs arising from the administration of the ART.

While Wisconsin ratepayers will benefit from the additional benefits of an increased portion of renewable supply—cleaner air, cleaner water, and increased compliance with environmental standards that are on the horizon. Not all citizens have the same ability to absorb significant utility rate increases. The Wisconsin Legislature should be tasked with publically debating any fees or cost increases.

b) Why and under what circumstances might it be appropriate for ART costs to be recovered through a utility's voluntary renewable energy program?

A voluntary program will see progressive ratepayers shoulder a larger portion of the ART costs, which makes sense from a market supply/demand standpoint.

c) Should utilities have the discretion to choose the best means of cost recovery for each specific tariff, or should the Commission seek a uniform approach?

No opinion.

14. Renewable And Environmental Attributes

a) Should ownership of associated renewable and environmental attributes (such as Renewable Energy Credits or greenhouse gas offsets) be consistent across all ARTs in Wisconsin?

The REC portions of renewable energy credits should become title of the utilities and not non-electricity environmental attributes. Some biogas plants create a natural replacement for chemical fertilizer, thereby offsetting greenhouse gases from chemical fertilizer use and production. The environmental attributes associated with this process are key to defraying the capital and operating costs of pelletizing equipment, which is used to create the natural fertilizer, and is altogether distinct from the electricity generating process.

b) Should ARTs be established with separate prices depending on which party owns the renewable and environmental attributes?

No Opinion

15. Basis for Setting Tariff Price

a) For a given technology, should there be any differentiation in ART prices based on design characteristics (e.g., vertical versus horizontal axis wind turbines), fuel source (e.g., biomass crops versus wood waste), or location (e.g., terrestrial versus offshore wind)?

It will be very difficult to create a tariff that strong enough to handle all reasonable variations and it would add complexity and cost to the process. This should only be done in the event that specific technologies, fuel sources or locations are highly prized by utilities or the state and developers and incentives need to be offered to undertake projects which match one or more of these criteria.

b) For a given technology, should ART prices decline as project size increases? If so, should size bands be created or should the price decline in linear proportion to size? How might the Commission decide on appropriate size bands?

Yes, ART prices should decline as project size increases. Ideally, prices should decline in linear proportion to size as some technologies have distinct step functions (e.g. wind turbine sizes range from 50 kW to 5 MW; biogas reciprocating engines can increase in size from one model to the next in 500 kW intervals, etc.). If logistically feasible, a linear function is more efficient from a development standpoint.

c) Should ART payment levels include any form of a capacity payment in addition to energy payments? Does your answer vary by technology? Could an auction or tender-based system for renewable capacity payments (similar to Forward Capacity Markets) help increase economic efficiency and/or reduce risk on behalf of the investor?

Payment should reflect actual generation. The simpler and more transparent the program, the more traction it will gain with project financiers and project proponents.

Auction and other systems for payments favor only the largest developments, which are capable of providing resources to manage this process, and are not recommended.

d. Should ART prices be set at a level such that a typical participating customer will earn a positive return on their investment in renewable energy? If so, what might be an appropriate return?

Appropriate returns depend highly on circumstances such as prevailing market conditions during the period when ART contracts are to be signed, security of the program itself and its guarantors, etc. Individual companies, individual technologies, and individual projects will all have their own risk/reward criteria which will form the required rate of return. The most effective way of determining this is to gain an understanding of all these levers from developers themselves and price the power purchase terms accordingly.

e) Should utilities offer separate prices for on-peak and off-peak generation or a single blended ART price? Should the utility or the customer be allowed to decide on their preferred approach?

Yes, utilities should offer separate prices for on-peak and off-peak to encourage more on peak production generation.

f. Should ART contracts include an automatic adjustment in the price based on inflation?

Yes, ART contracts should be keyed to any adjustments as inflationary pressures will affect project costs in real terms each year, particularly where the operating and maintenance costs are high as with biogas.

g. If the Commission does not require utilities to offer uniform contract duration for all ARTs, should utilities offer different prices for different contract durations?

It is not recommended that contract durations vary, but if they do, premiums should be paid on shorter term contracts to assist in finance ability.

h) If any fixed premium ARTs are established (rather than fixed cost ARTs), should the premium be over and above the Locational Marginal Price, or should it be tied to some other number? Since a fixed premium would result in a variable price, should there be a price cap or other measures to prevent unacceptable profits or losses?

Fixed cost ARTs are the preferred mode for renewable energy developers because they provide known returns based on performance.

i) Should ART prices be automatically reduced annually (or periodically) to reflect the maturation of technologies and the need for renewables to become cost competitive without price supports?

ART prices should be reduced periodically for new contracts and projects to reflect the maturation of technologies, but should not be reduced for existing contracts as the technologies were at an earlier point of maturity when the capital expenditures were made.

j) Are there any benefits to customers unrelated to electricity generation that should be reflected in the tariff prices?

In the case of biogas, additional benefits include:

- A more sustainable way to manage organic by-products, e.g. food scraps
- Additional greenhouse gas reduction potential due to methane destruction of manure and other organic by-products
- Nutrient management for farms -- as, in many cases, excess farm nutrients are converted into natural fertilizer
- Reduction of odor, weed seeds and pathogens
- Increased stewardship of water resources
- Job creation, particularly in rural areas

16. Other

a) Are there any other ART design considerations that you feel the Commission should consider?

No Opinion.

Again, DBA members thank you for this opportunity to offer input and advice to the Public Service Commission's consideration of establishing more uniform ARTs across all Wisconsin electric utilities.

Sincerely,

Laurie Fischer
Executive Director
Wisconsin Dairy Business Association

Current Experience With Net Metering Programs

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PRESENTED AT WINDPOWER '98
Bakersfield, CA USA
April 27 - May 1, 1998

Abstract

Net metering is a utility metering practice that encourages direct consumer investment in renewable energy technologies. Laws and regulations that establish net metering practices now exist in 22 states. Net metering enables electricity customers with small generators to receive a higher value for some or all of the electricity they generate. This is accomplished by allowing the electric meters of such customers to turn backward when there is more generation than demand. It effectively allows customers with small generators to use the electricity they generate to offset their usage over an entire billing period. This paper reports on the current status of net metering laws and rules in the United States. In particular, the extent of the net metering authority in each state is highlighted. Differing requirements for grid-interconnection have introduced significant variations in the actual implementation of net metering programs. Interconnection requirements from specific utilities are collected to understand how net metering programs have been affected.

I. Introduction

Net metering is a practice in which utilities measure and bill for the net electricity consumption or generation of their customers with small generating facilities. This is accomplished either by allowing a meter to turn backward or by using two meters-one to record generation and one to record consumption and manually subtracting the two readings. Without net metering, small customer-owned generators are usually treated by electric utilities as if they were qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 (PURPA) and subsequent implementation rules by the Federal Energy Regulatory Commission (FERC). Such customers must enter a net purchase and sale agreement with the utilities. Utilities always install two meters for each account to record separately the net energy used by customers and the net excess energy produced by the customer. These customers pay retail rates for the energy they use, and the utilities reimburse customers at the utility's avoided cost for the energy they produce. The differences between a utility's retail rate and the avoided cost can be substantial, as high as 10 cents (differential) per kilowatt-hour (kWh).

Under a net metering program, customers can use their generation to offset their consumption

over the entire billing period, not just the instant there is a demand. The arrangement allows the customers to use the utility grid to "bank" their electricity produced at one time and consume it at another time. This form of energy exchange is especially useful for intermittent renewable energy technologies. It allows all or a substantially bigger portion of the customer-generated electricity to the receive retail price and thus increases the economic value of small renewable energy technologies for customers. The ability to "bank" electricity affords customers more flexibility in self-generating. Customers do not have to alter their consumption or install energy storage devices to maximize the value of their generation. The generating facility may be sized to match long-term energy consumption. On the other hand, customers with net purchase and sale agreements are more likely to install smaller generators so as not to exceed their instantaneous power demand.

Utilities may also benefit from net metering. By encouraging distributed customer generation through net metering, utilities can improve their distribution voltage profile and reduce system losses. In addition, net metering can help utilities minimize the administration cost for customers with small generating equipment.

Net metering programs exist because of state initiatives. PURPA encourages cogeneration and renewable energy technologies by requiring utilities to interconnect with cogenerators and renewable energy facilities and to purchase power generated by them. When designing rules to implement PURPA and FERC regulations, some states decided to take the intent of PURPA one step further by including net metering as an option for smaller generators. For example, the Arizona Public Utilities Commission (PUC) ordered net metering for QFs in 1981, and Minnesota enacted a net metering statute in 1983. Now, a total of 20 states have enacted net metering laws or regulations. In addition, individual utilities in at least two other states offer net metering tariffs to their customers.

II. Rationale for Net Metering Programs

The main objective for states implementing net metering programs is to encourage private investment in renewable energy resources. Other goals include stimulating local economic growth, diversifying energy resources, and improving the environment. The appeal of net metering arises from its simplicity: the use of a single, existing electric meter for customers with small generating facilities. After the program is implemented, no regulatory interaction or supervision is needed. As a policy option, it makes renewable energy technologies more economically attractive without requiring public funding. Net metering also addresses a perceived equity issue of utilities gaining an unfair advantage over customers by paying customers only avoided cost but charging them retail price for electricity.

Nevertheless, many utilities still oppose net metering programs for several reasons. Most do not want another state mandate imposed on them. Some maintain that paying retail prices for customer-generated electricity amounts to a subsidy because retail prices also include the costs of transmission and distribution, administration, and profits in addition to a utilities' energy cost. Others express concern about revenue losses. Some utilities oppose net metering because they believe it violates PURPA and FERC implementing rules by requiring utilities to pay higher than their avoided costs for QF generation. Other utility opposition to net metering includes safety issues and the loss of actual customer load information.

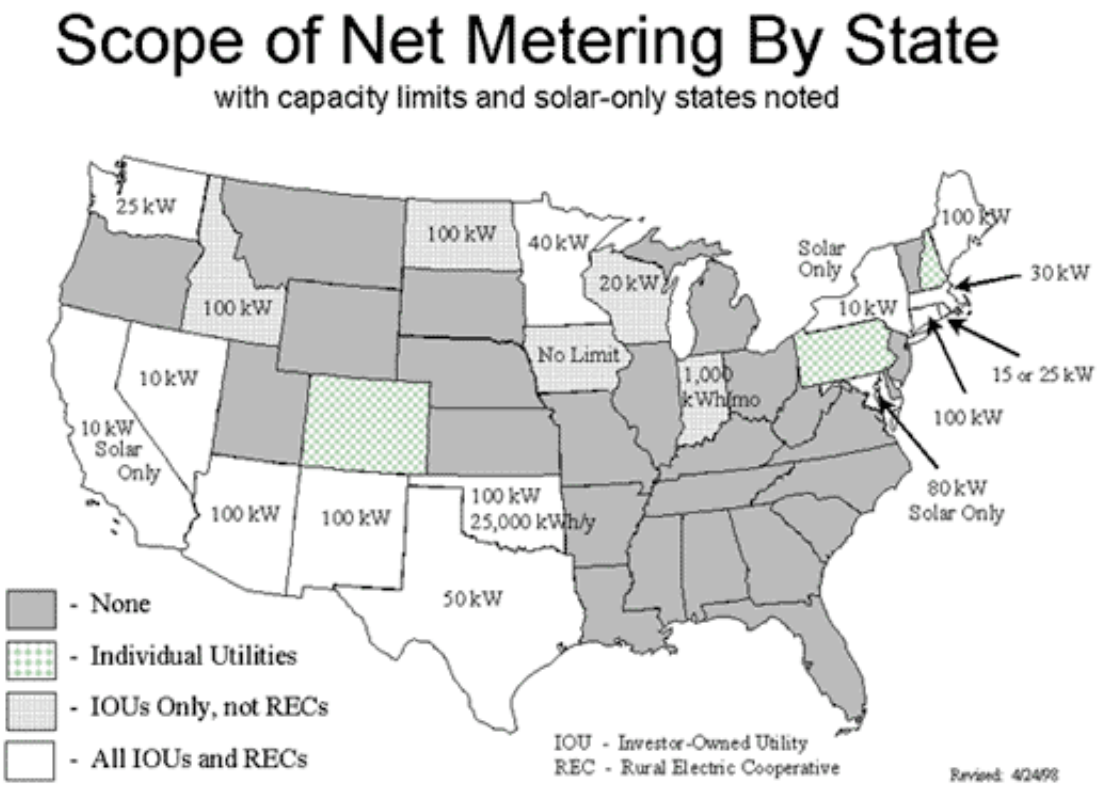
On the other hand, there are a few utilities offering net metering without a commission order or a state law. Some of these utilities support net metering for renewables because they want to be seen as friendly to the environment and responsive to their customers' needs and concerns. For others, the primary motivation is avoiding the extra cost associated with installing and maintaining a second meter, processing separate accounts, and preparing payment checks for small generators.

III. Existing Net Metering Programs

Currently, net metering programs are available in 22 states. These programs have three sources of implementation authority: state law, PUC orders, and individual utility tariffs. Six states have enacted net metering laws, and 14 other states have established net metering programs through regulatory processes. Utilities in Colorado and Pennsylvania chose to offer net metering at their own discretion without a prior commission order or state law. In addition, net metering legislation is pending in several other states. Table 1 summarizes various features of available net metering programs in the 22 states. Early net metering programs, except for Minnesota, were initiated by state PUCs through regulatory processes. However, the recent trend has been for states to establish net metering through legislative processes.

Net metering programs established by state law are applicable to all utilities in the state, regardless of whether a utility is under the jurisdiction of the state utility commission. Net metering established by PUC orders apply only to utilities that are rate-regulated by the PUCs. Since many states do not rate-regulate rural electric cooperatives, the net metering option is often not available for rural customers even if the PUC has issued net metering orders. However, rural customers are better candidates to install wind turbines than their urban counterparts because they are less constrained by issues such as zoning, noise, lack of space, visual impact, and safety. This leads to a disparity between the availability of net metering for solar and wind generation as shown in Figure 1, a map of net metering availability by state. Of the 22 states which offer net metering, four are solar-only states. In five of the remaining 18 states, only investor-owned utilities are required to offer net metering. In two other states, net metering is limited to just one or two utilities. That leaves just 11 states in which net metering is universally available to rural residents, the most likely users of small wind turbines.

Figure 1.



Various approaches have been taken to the treatment of net excess generation (NEG). Excess generation occurs when a customer-owned generator produces more electricity than the customer's total electricity demand during the utility's billing cycle. The magnitude of NEG depends on the size of the load, the capacity of the generating equipment, and the availability of renewable energy resources. The net metering states require utilities to purchase customers' NEG either at the utility's avoided cost or at the retail rate (MN and WI), or they let utilities take the

NEG without paying anything to their customers. While PV systems seldom generate more electricity than a residential or commercial building can use during a month, a residential wind system in a good wind resource region can produce more energy than is consumed during a utility's monthly billing cycle. Thus, the treatment of the customer's NEG can significantly affect the economics of a small wind system.

Most states direct utilities to use their normal monthly billing cycle to determine the NEG, but New York and Washington direct their utilities to assess NEG annually. Annual assessment will only benefit users of renewable energy because energy produced during a high resource season of the year can be used to offset consumption during a low resource season.

Net metering generally is not available to customers on time-of-use (TOU) rates or demand charge rates. Current TOU meters for small customers do not turn backward. Besides the need for a second meter, applying net metering to TOU customers raises the issue of which time period (on peak or off peak) the energy should be credited to. Only New York currently allows TOU customers to have net metering options, but how the utilities will accomplish it is still being decided. In some cases, utilities require customers who exceed a particular threshold in monthly demand to switch from an energy-based tariff to a demand-charge tariff. Since demand charge meters typically do not run backwards, this may eliminate access to net metering. Even if the meter issue is resolved, renewable generation by a demand-charge customer will only offset the energy charge portion of the monthly bill, but not the demand charges. This will, of course, reduce the economic benefit of net metering.

Today's net metering programs have great diversity as to who is eligible to participate and under what conditions. Because of the nature of the political process, every net metering program represents some sort of compromise reached by various stakeholders during the legislative or regulatory process. These compromises include limits on facility size, program size, customer classes, and allowable technologies. These limits are designed to ensure that the net metering program will have a minimal impact on utilities and other ratepayers.

Utilities in several states have challenged net metering orders or petitioned the PUCs to terminate the net metering requirements. So far none has succeeded in overturning an existing net metering order. Utility challenges have been based on the premise that net metering orders violate PURPA and often cite the FERC decision on Connecticut Light and Power, No. EL-93-55-000, which states that PURPA bars the states from requiring utilities to pay QFs the retail rate. PUCs of Maine and Minnesota did rule on the PURPA issue related to net metering in 1997, and both upheld their net metering requirements. PUCs of both states found that net metering requirements do not violate PURPA because utilities are not required to purchase electricity from customers at a rate higher than utility avoided cost. They also ruled that the Connecticut Light and Power decision, which involves wholesale transactions, does not apply to retail metering and billing. Both PUCs maintain that the state has the right to establish alternative billing and metering practices for retail transactions and these rights are not preempted by PURPA. In March 1998, the Iowa Utilities Board withdrew a proposal to eliminate Iowa's existing net metering rule following a significant display of public support. However, the legal issues arising from net metering orders are not completely resolved, and utilities may continue their challenges at the state level. Another uncertainty is utility restructuring and retail competition. It is not clear at present what impact this will have on net metering programs.

IV. Utility Interconnection Requirements

Safety is the most critical concern of utilities when interconnecting small customer-owned generating equipment. Utility distribution systems are not designed to have generators. When customer-owned generators are interconnected to the distribution network, they become a safety concern for utilities because they may upset the coordination of protective devices or accidentally energize a supposedly "dead" circuit. Other technical issues with small generator interconnections include power quality, service reliability, equipment protection, and metering arrangements.

There are national standards to address the safety, power quality, reliability, and protection issues. However, utilities have the discretion to establish their own criteria and guidelines based on these national and industrial standards. An investigation of interconnection criteria and guidelines of 13 utilities has shown that the scope of the rules are very similar, but that there are significant variations in the specific details such as allowable relay type and ranges of relay settings for fault monitoring and clearing.

Utilities require the customer-owned generating equipment and its installation to meet the National Electrical Code (NEC) and applicable local codes. Without an exception, utilities require all customer-owned small generators that are connected at the distribution voltage level to be off-line when the utility lines are out. Many give specific relay requirements and settings for how to accomplish this. Almost all utilities require the customers to install a manual, lockable disconnect switch that is accessible to utility personnel so they can isolate the customer-owned generating equipment. Requirements related to power quality (allowable flicker and harmonics) are also universal, but the specifications vary from one utility to the next. Some utilities want to inspect and test the customer's facilities before interconnection, and at a minimum, all utilities will explicitly mandate the right to do so. Differences exist in how utilities address service issues. For example, some utilities require a separate transformer for every customer with generating equipment while others will evaluate the need for such a transformer on a case-by-case basis. Another example is synchronizing devices; some utilities require them, but others leave this to customer discretion.

Utilities also differ on the meter arrangement in implementing net metering. Conventional electromechanical meters are capable of turning in both directions. Most utilities will simply use the existing meter when net metering is required. However, some utilities insist on using two meters to accomplish net metering and ask the customers to pay the cost of the additional meter. Those utilities claim that running a typical residential customer meter in reverse may not have the accuracy required by state regulations and may result in billing disputes.

In summary, these variations in the interconnection requirements do present a barrier to net metering customers and to equipment manufacturers because individual installations may require custom engineering designs. A set of uniform interconnection standards is needed to encourage implementation of net metering practice.

Greater variation in utility interconnection requirements are found in areas that do not contribute directly to operational safety or service reliability. Utilities have proposed a variety of liability insurance, property easement, and legal indemnification requirements. Some utilities also demand metering calibration charges, engineering study fees, or standby charges. They may also require customers to keep records of all maintenance and operation. These additional requirements tend to reduce the incentive provided by net metering and may deter customers from participating. As an example, two California investor-owned utilities originally structured net metering contracts that set a substantial monthly customer charge and standby charge. This essentially made net metering unattractive until the California PUC banned the imposition of customer charges.

State PUCs have widely varying attitudes toward these additional requirements. For example, PUCs of Oklahoma, California, and New York concluded that additional liability insurance was excessive and burdensome to net metering customers and do not allow utilities to require it. Maryland and Nevada net metering statutes specifically prohibit utilities from requiring additional liability insurance and additional testing if the customer's facilities meet applicable national and industry standards. On the other hand, Idaho PUC permits Idaho Power Company to require $1,000,000 liability insurance from its customers who want net metering. The New York Public Service Commission has chosen to disallow property easement provisions.

The actual operating experience of customer-owned small generators does not justify the utility requirements for high liability insurance. In fact, there is no example of utility personnel injury or death resulting from a customer-owned generator accidentally energizing an otherwise "dead" utility line. The utility concerns of safety, power quality, and service reliability are legitimate, but

the record suggests that the established industry standards adequately address these concerns.

V. Impact on Renewable Energy Technologies

When states develop net metering initiatives, the most frequently stated goal is to encourage direct customer investment in renewable energy technologies. Despite the fact that net metering programs for small renewable energy generating systems have been available in some states for more than 10 years, their actual impact on the renewable energy technology market has been limited. For example, in Minnesota where the first net metering law was enacted in 1983, there were 110 net metering customers (all but 3 are small wind systems) as of 1996. We have found that exact numbers are not available in other states because utilities and state energy offices are not required to keep accurate records. Although no hard statistics exist about the number of customers and total installed capacities under net metering programs, the anecdotal information we have collected suggests that relatively few customers participate in these programs in other states. According to PUC staffs of several states and advocacy group members contacted for this work, it appears that net metering programs' small impact on the renewable energy market to date can be attributed to several factors:

1. Economics of Net Metering - Low electricity prices and high costs of small renewable energy systems are significant barriers. Repeated opinion polls and the experiences of utilities' green pricing and marketing programs have demonstrated the public's desire to support clean energy options and their willingness to pay more for them. However, the present monetary gap between costs and benefits needs to be narrowed further to attract a larger number of customers to net metering programs.

2. Lack of Public Awareness - A number of net metering programs are still in their infancy, and information about existing programs has not been made widely available since utilities usually do not actively promote them. So, in many cases, customers are not aware of their net metering option and/or the potential benefits.

3. Program Limitations and Restrictive Interconnection Requirements - The many limits of individual net metering programs noted in Table 1 reduce the overall opportunity. This is particularly true for wind energy because the programs in 11 states either restrict wind energy generation altogether or do not extend net metering to all rural customers. Various interconnection requirements demanded by utilities also act as barriers to small net metering customers.

VI. Conclusions and Recommendations

Net metering programs can be an appealing policy option for advancing renewable energy technologies. The programs enhance economic incentives to the owners of small renewable energy systems and encourage private investment in renewable energy technologies without requiring public funding. They are easy to implement and require no constant regulatory interaction or supervision after they are in place. The attractiveness of net metering in high electric rate regions may provide a boost for the renewable energy industry in those regions. And perhaps more importantly, as the cost of renewable energy technologies continues to decline, net metering programs will become more effective in facilitating widespread applications of small renewable energy systems.

However, net metering programs still face many obstacles and uncertainties. Although several states have enacted net metering programs for some time, their impact on renewable energy technologies has been small to date. The interconnection, liability insurance, and indemnification requirements demanded by utilities discourage net metering customers. Costs of small renewable energy systems are also a barrier. Wind energy technology is further hampered by the disparity in net metering availability for solar and wind generators. Some utilities may decide to challenge

net metering orders again. A bigger uncertainty facing net metering programs is utility restructuring.

There are steps that can be taken by stakeholders to further net metering programs. A set of uniform interconnection standards will go a long way in facilitating the implementation of net metering. The renewable industry needs to work closely with utilities and standard-setting organizations in developing such standards. Increasing customer awareness of available net metering programs is also important to increase participation. Increased communication efforts by the renewable industry, utilities, state energy offices, PUCs, and advocacy groups could increase participation in net metering programs, yielding benefits to utilities, customers, and society.

VII. Acknowledgements

We wish to acknowledge Thomas J. Starrs of Kelso Starrs & Associates, and Kevin Porter of NREL for their peer review of this paper. Their insights and criticism have been most helpful. While Y. Wan has independently researched and confirmed the data contained in Table 1, we gratefully acknowledge the ongoing exchange of information with Mr. Starrs which has helped us make this table more current and accurate. We are also indebted to a prior publication by Mr. Starrs for the format used in this table as well as for his excellent description of net metering.

This work was funded by the U.S. Department of Energy's Wind Energy Program and was conducted at the National Wind Technology Center, part of the National Renewable Energy Laboratory, Golden, CO.

For the most recent information on state net metering programs, see our updated table.

Table 1. Summary of State Net Metering Programs

State	Allowable Technology and Size	Allowable Customer	Statewide Limit	Treatment of Net Excess Generation (NEG)	Authority	Enacted	Scope of Program	Citation/Reference
Arizona	Qualifying facilities £ 100 kW	All customer classes	None	NEG purchased at avoided cost	Arizona Corporation Commission	1981	All IOUs and RECs	PUC Order Decision 52345, Docket 81-045
California	Solar only £ 10 kW	Residential only	0.1% 1996 peak	NEG purchased at avoided cost	Legislature	1995	All utilities in state	Senate Bill No. 656 (effective 1-1-96)
Colorado	Qualifying facilities £ 10 kW	All customer classes, Public Service of Colorado only	None	No purchase of NEG, excess is granted to utility	Utility tariff	1994	Public Service of Colorado Company	Safety, Interference and Interconnection Guidelines for Cogenerators, Small Power Producers, and Customer-Owned Generators
Connecticut	Renewables £ 100 kW Cogenerators £ 50 kW	All customer classes	None	NEG purchased at avoided cost	Public Utility Commission	1990	All IOUs, No REC in state.	CPUCA No. 159
Idaho	All technologies £ 100 kW	All customer classes	None	NEG purchased at avoided cost	Public Utility Commission	1980	IOUs only, RECs are not rate-regulated	Idaho PUC Order #16025 and #26750 (1997) Tariff sheets 86-1 thru 86-7

Indiana	Qualifying facilities £ 1,000 kWh/month	All customer classes	None	No purchase of NEG, excess is granted to utility	Public Utility Commission	1985	IOUs only, RECs are not rate-regulated	Indiana Administrative Code 4-4.1-7
Iowa	Renewables No limit per system	All customer classes	105 MW	NEG purchased at avoided cost	Iowa Utility Board	1993	IOUs only, RECs are not rate-regulated*	Iowa Administrative Code paragraph 199-15.11(5)
Maryland	Solar only £ 80 kW	Residential only	0.2% of 1998 peak	No purchase of NEG, excess is granted to utility	Legislature	1997	All utilities in state	Article 78, Section 54M
Maine	Qualifying facilities £ 100 kW	All customer classes	None	NEG purchased at avoided cost	Public Utility Commission	1987	All utilities in state (IOUs and RECs)	Code Me. R. Ch. 36, ¤1(A)(18) & (19). ¤4(C)(4)
Massachusetts	Qualifying facilities £ 30 kW	All customer classes	None	NEG purchased at avoided cost		1982	IOUs only, No REC in state	220 CMR ¤8.04(2)(C)
Minnesota	Qualifying facilities £ 40 kW	All customer classes	None	NEG purchased at utility average retail energy rate	Legislature	1983	All utilities in state	Minn. Stat. ¤216B.164
Nevada	Solar & Wind £ 10 kW	All customer classes	First 100 customers for each utility	No purchase of NEG, excess is granted to utility	Legislature	1997	All utilities in state	Nevada Revised Statute Ch. 704
New Hampshire	Renewables £ 25 kW per system	Residential customers of Public Service of New Hampshire only	500 kW	No purchase of NEG, excess is granted to utility	Utility tariff	1994	Public Service of New Hampshire	PSNH Order No. 21,163
New Mexico	Qualifying facilities £ 100 kW	All customer classes	None	NEG purchased at avoided cost with additional customer charge, or no NEG purchase and no additional charge	Public Service Commission	1988	All utilities in state (IOUs and RECs)	PSC Rule 570
New York	Solar only £ 10 kW	Residential only	0.1% 1996 peak demand	Annualized NEG purchased at avoided cost	Legislature	1997	All utilities in state	Assembly Bill 8660--A
North Dakota	Renewables & cogeneration £ 100 kW	All customer classes	None	NEG purchased at avoided cost	Public Utility Commission	1991	IOUs only, RECs are not rate-regulated	North Dakota Admin. Code ¤69-09-07-09
Oklahoma	Renewables & cogeneration £ 100 kW and	All customer classes	None	No purchase of NEG, excess is granted to utility	Oklahoma Corporation Commission	1988	All utilities in state except for municipals and G&Ts	OCC Order 326195

	£ 25,000 kWh/year							
Pennsylvania	Solar only (None specified)	Residential only	None	NEG purchased at average utility billing rate	Utility tariff	1996	PECO Energy Company	Supplement No. 5 to Tariff Electric PA PUC No.2
Rhode Island	Renewables & cogeneration £ 25 kW for larger utilities £ 15 kW for smaller utilities	All customer classes	None	NEG purchased at avoided cost	Public Utility Commission	1985	IOUs, No REC in state.	Supplementary Decision and Order, Docket No. 1549
Texas	Renewables only £ 50 kW	All customer classes	None	NEG purchased at avoided cost	Public Utility Commission	1986	All IOUs and RECs	PUC of Texas, Substantive Rules, ¤23.66(f)(4)
Washington	Solar, wind and hydropower £ 25 kW	All customer classes	0.1% of 1996 peak demand	Annualized NEG granted to utilities at the end of each calendar year	Legislature	1998	All utilities in state	House bill B 2773 Title 80 RCW
Wisconsin	All technologies £ 20 kW	All customer classes	None	NEG purchased at retail rate for renewables, avoided cost for non-renewables	Public Service Commission	1993	IOUs only, RECs are not rate-regulated by PSC	PSCW Order 6690-UR-107

Notes:

IOU - Investor-owned utility
G&T - Generation and transmission cooperatives
REC - Rural electric cooperative

The original format for this table is taken from:

Thomas J. Starrs (September 1996). *Net Metering: New Opportunities for Home Power.* Renewable Energy Policy Project, Issue Brief, No. 2. College Park, MD: University of Maryland

FREEING THE GRID

REPORT NO. 01-06
November 2006

How Effective State Net Metering Laws Can Revolutionize U.S. Energy Policy

Forward By
MICHAEL DWORKIN
Professor of Law and Director of the Institute for Energy & the Enviroment
Vermont Law School

NETWORK FOR NEW ENERGY CHOICES

The **Network for New Energy Choices** is a New York based nonprofit organization committed to providing U.S. state and local governments with ideas and information to generate clean, affordable power from local, renewable energy sources. Working with a growing coalition of nonprofit groups, municipal officials, business leaders and academics, NNEC is promoting creative and objective ideas for financing community-based clean energy, helping to dispel misinformation about renewable energy in the media and advocating critical utility policy reforms that will usher in a new world of energy choices for all Americans.

Chris Cooper | *Executive Director*

James Rose | *Research Director*

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Network for New Energy Choices

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How Effective State Net Metering Laws Can Revolutionize U.S. Energy Policy

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Forward by Michael Dworkin

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Network for New Energy Choices

Forward by Michael Dworkin

All Hands on Deck

Recruiting Clean, Secure and Distributed Help for America's Energy Needs

When a sailing crew, in peril on the sea, saw storms ahead, the cry rang out: "All hands on deck!" For those who now see perils before us in the worlds of utilities and energy, there is a lesson to be found there.

In six years as Chairman of a state utility commission, I saw a lot of rough water and a few storms, but none as large and dark as those now facing our nation and our world. We face an "Energy Trilemma," – an energy world strained by the three forces of financial stress, environmental constraints and security risks. We all need solutions now that help us on some or all of these fronts, without making others worse. Yet, all too many of the remedies that some propose for one or two parts of the Trilemma tend to worsen the others. To make progress, we need to find new patterns, going beyond the way the electricity grid has functioned for almost a century. In a very real sense, we need to seek and welcome "new hands on deck."

Why do I say this?

Well, on the financial front, we all get monthly reminders of some of the past costs of our electric needs. But, few Americans have yet been shown the financial costs of the traditional ways of meeting future needs. Every look at increased demand and known resources says that strains will increase fast.

The North American Electric Reliability Council's 2006 annual report says that generators and utilities now have contracts with new plants for only one-third of what NAERC predicts will be needed. At the same time, Regional Transmission Organizations – the RTOs- cry out that we must set up payment plans right now to build capacity in years ahead, with billions needed to buy thousands of mega-watts from fossil-fired, centralized power plants. Yet, Edison Foundation's June 2006 study says that utilities' financial strengths have weakened and that they will need to raise rates to finance upgraded transmission and distribution systems. In other words, bringing in investments from old sources of capital will be difficult – which means costly.

On the environmental front, the dollar costs of sulfur containment and of nitrogen control are showing up in the bills charged by some utilities. The costs of mercury controls will come on soon. The financial costs of carbon capture lie ahead. The costs of land for power plants and transmission lines are rising fast. And, yet, those 'costs' in bills and rates, are but a small part of the true environmental costs that we all face, and an even smaller part of the true environmental costs that we are passing on to our children. We have now reached the point where environmental harms will be not just a cost, but a constraint on the electricity system.

When we turn to security, we all have seen images of flames and smoke when central focal buildings are destroyed, and we all know of days of loss and nights of darkness when the central grid fails for millions of us time after time. The costs of patching up and reinforcing the central station-focused grid are high indeed. But despite costly investments, it will never yield true reliability.

We have now reached the point where environmental harms will be not just a cost, but a constraint on the electricity system.

Why not ease this stress on the transmission grid by calling in the help of those who will invest in small, clean power plants installed right next to the electricity demand? A few utilities are taking the first-steps toward this transition (for example, Con Edison is seeking bids for 123 MW of demand-side resources -- including distributed generation -- to meet growing energy demands in 14 specific locations). But we need to pick up the pace. It is time for baby-steps to mature into healthy strides.

As a former rate-regulator, I know how it feels to have a utility come and say it needs to increase rates to cover new investments in transmission and distribution: it doesn't feel good at all. So, when we have a chance to recruit and encourage folks who will install their own small, clean generation, right next to the load that it will serve, the message is: "Many hands make lighter work; welcome to the task that we all face!"

What must we do to welcome those new hands? The Network for New Energy Choices has looked in detail at decades of experience in dozens of states. They offer here the "lessons-learned." And they do so, not as an academic exercise, but with tools for all of us to see and use.

What are some of the key lessons they present?

- That states and cities are taking up the challenge of meeting our national needs; truly thinking globally and acting locally. Efforts like NNEC's analysis can offer uniform models that will help meet larger goals. At the same time, the consistency of model laws and standards can ease the path for investors.
- To treat net-metering as a vital part of a larger effort to supplement our current centralized, fossil-fired, costly electric grid with clean, secure, and cost-effective energy resources. Thus, energy efficiency and renewable resources distributed throughout the system can both help, and be helped by, investments in clean net-metered generation.
- To keep our eyes open, as net metering occurs, for chances to transition to smart meters that incorporate time-of-use pricing and smart tariffs for all generators.
- To take a dozen steps, detailed within, to make that hope a true reality.
- And, perhaps most importantly, to encourage, not discourage, small, clean, distributed investments that can help all of us on all three fronts of our energy trilemma -- finance, environment, and security.

These are valuable lessons for utility regulators. I know from personal experience. They are also valuable lessons for us all.

And so I close by asking these questions, and thanking NNEC for help with the answers:

Is an energy storm coming?

It surely is.

Does America's electricity grid need help?

It surely does.

Can net-metering of clean, secure, distributed resources help meet the needs that we all face?

The folks that can do this are among the hands we want on deck.

How do we invite those hands to join us on the deck?

By using all the tools **NNEC** sets out for us in this report.

We've never needed the education that NNEC offers here as much as we do now – so my message to states and cities, to legislatures and commissions, is: "*Let's put these tools and lessons to work now.*"

The Network for New Energy Choices has looked in detail at decades of experience in dozens of states. They offer here the "lessons-learned."

Michael Dworkin, Professor of Law and Director of the Institute for Energy and the Environment at Vermont Law School, has also been a litigator for US EPA, a management partner in an engineering firm, and a utility regulator.

Professor Dworkin was Chair of the Vermont Public Service Board from 1999 to 2005 and he chaired the national utility commissioners' Committee on Energy Resources & the Environment. In 2003, on behalf of the Public Service Board, he received the "Innovations in American Government Award" from the Kennedy School of Government for helping oversee Efficiency Vermont's development into one of America's five most innovative and effective public service programs.

Michael is now a non-utility Trustee of the Electric Power Research Institute and was recently elected to Board of the American Council for an Energy Efficient Economy. For many years, he has helped pursue more sustainable energy portfolios, with special emphasis on energy-efficiency and renewable energy choices, including rural and agricultural options.

A graduate of Middlebury College and the Harvard Law School, Michael's work has focused on the points where technical, economic, and legal issues intertwine. He believes that: "*Energy policy is our world's most pressing environmental challenge, and environmental issues are the energy sector's most important constraint.*"

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: Executive Summary

American consumers face a crisis at the plug that is every bit as serious as the crisis at the pump. Recognizing an impending climate catastrophe and facing the unmet promises of electricity deregulation, consumers are beginning to revolt against rising utility costs.

This fall, for example, voters in Illinois waged a modern-day version of the Boston Tea Party, sending teabags to the state's utility in protest of projected rate increases of 22% to 55% in 2007. In Boston, homeowners and small businesses have seen electricity prices rise by 78% since 2002, from 6.4 cents a kilowatt hour to 11.4 cents a kilowatt hour.[1] As utilities scramble to address the reality of global climate change, retrofitting dirty, coal-fired power plants with carbon capture technology could raise the cost of electricity generation by 43% to 91%.[2]

States will be the Source of Innovative Energy Policies

Given relative inaction by the federal government, Americans are taking matters into their own hands. A record number of homeowners and small businesses are declaring their independence from utility monopolies by finding ways to meet their electricity needs more cheaply (and more cleanly) on their own. And more state governments are assuming control of their energy future by intervening to encourage this energy self-reliance.

For nearly 25 years, states have been the crucible for innovative policies to promote small-scale, renewable energy generation. By 2006, 36 states had adopted statewide programs that set rules by which customers who generate their own electricity can interconnect to the central transmission grid. Known as "net metering," these programs have been described as "providing the most significant boost of any policy tool at any level of government…to decentralize and 'green' American energy sources."[3] By compensating customers for reducing demand and sharing excess electricity, net metering programs are powerful, market-based incentives that states can use to encourage energy independence.

Lessons Learned

The Energy Policy Act of 2005 (EPAct) requires all states to "consider" a net metering program by 2008 or explain why their existing program is sufficient. Many states are already in the process of examining their existing programs to determine their effectiveness.

1 Smith, Rebecca (2006). "Emboldened states take charge of energy issues," Wall Street Journal. October 12. p. A6.

2 Intergovernmental Panel on Climate Change (2006). "Climate capture and storage," IPCC Special Report. Table 8.3a, p. 347.

3 Ferrey, Steven (2003). "Nothing but net: Renewable energy and the environment, MidAmerican legal fictions, and supremacy doctrine," Duke Environmental Law & Policy Forum. 14:1-120.

State Rankings Using NNEC Metric

Rank	State	Grade	Percentile	Score
1	New Jersey	A	100%	305
2	Montana	A	97%	67
3	California	A	94%	15
4	Oregon	A	91%	14
5	Nevada	A	88%	7
6	Minnesota	A	82%	6
7	New Hampshire	A	82%	6
8	Wisconsin	A	79%	4
9	Hawaii	B	64%	3
10	Vermont	B	64%	3
11	Wyoming	B	64%	3
12	Ohio	B	64%	3
13	Louisiana	B	64%	3
14	Utah	B	61%	2
15	Connecticut	C	48%	1
16	New York	C	48%	1
17	New Mexico	C	48%	1
18	Georgia	C	48%	1
19	Washington	D	36%	0
20	Virginia	D	36%	0
21	Kentucky	D	36%	0
22	Maine	D	36%	0
23	Massachusetts	F	27%	-1
24	Iowa	F	27%	-1
25	Delaware	F	27%	-1
26	Colorado	F	9%	-2
27	North Dakota	F	9%	-2
28	Indiana	F	9%	-2
29	Maryland	F	9%	-2
30	Texas	F	9%	-2
31	Arkansas	F	9%	-2
32	Rhode Island	F	3%	-3
33	Pennsylvania	F	3%	-3
34	Oklahoma	F	0%	-4

The Network for New Energy Choices (NNEC) has developed a metric to compare, grade and rank the 34 existing statewide net metering programs so that states can make a rational determination of how effective or ineffective their programs have been. We have determined which states are most effective and how states that have ineffective programs can adopt best practices to empower customers to generate their own clean energy.

By analyzing the evolution (and performance) of effective and ineffective state programs, we have identified pitfalls in the rulemaking process and ways to overcome them. Our comprehensive analysis reveals some fundamental lessons for states considering how to improve their net metering programs:

Ineffective Programs Discourage Small-Scale Renewable Energy

Most utilities are vocal opponents of net metering, mistaking self-generation as a revenue loss rather than as a demand-reduction strategy. Smart utilities should see every household and every small business as a potential contract generator, contributing clean, renewable electricity to the central transmission grid, helping the utility ensure reliable electrical service in a market strained by rising demand.

But in an effort to appease false concerns over lost revenue, many states have erected common barriers to self-generation by:

- Restricting commercial, industrial or agricultural customers from eligibility
- Limiting the size of eligible renewable energy systems
- Preventing customers from receiving credit for excess electricity
- Capping the total number of participants
- Charging discriminatory fees and standby charges
- Demanding unreasonable and redundant safety requirements
- Requiring unnecessary additional insurance
- Failing to promote the program to eligible customers

Analyzing the evolution of restrictive and ineffective regulations, we have discovered lessons for all states that want to avoid regulatory pitfalls and encourage energy independence.

Efforts to protect the economic interests of one sector (electrical utilities) often hurt other sectors in the state (like manufacturing).

Example: Indiana

Despite entreaties from the state's legislature, Indiana's regulatory commission decided to restrict commercial and industrial customers from participating in net metering. Indiana utilities argued that these customers, who could generate a substantial amount of their electricity demand themselves, would represent too great a revenue loss for the utility. As a result, Indiana's technology and manufacturing companies suffer from higher operational costs which limit their economic competitiveness.

Commissions that attempt to balance utility concerns with customer interests often undermine the intent of state legislators and adopt regulations that effectively destroy the program.

Example: Arkansas

In an effort to appease utility concerns that net metering represents a subsidy to participating customers, Arkansas' commission allowed the state's utilities to seize (without compensation) any excess electricity generated by customers at the end of every month. Denied fair compensation for excess electricity, only three Arkansas customers have enrolled in the state's program since it was initiated in 2001.

Effective Programs Revolutionize Energy Production

Several states have experienced rapid growth in small-scale renewable energy generation. In California, legislators had to increased the cap on total eligibility by 250% to meet demand (see page 14). In New Jersey, the state regulatory commission is overwhelmed with new applications.[4]

How do states craft an effective net metering program?

- Focus on goals rather than on balancing interests
- Allow monthly "banking" of excess electricity
- Reduce unnecessary and burdensome red tape
- Link net metering to statewide Renewable Portfolio Standards (RPS)
- Create net metering as a comprehensive package of incentives
- Require regular performance measurements

Example: New Jersey

In 2004, the Governor's Renewable Energy Task Force amended the state's net metering rules to help reach the state's ambitious goal of 20% renewable energy production by 2020. Jeanene Fox, the state's powerful utility board President, evaluated proposed changes with a singular focus: do the changes encourage or impede the development of a statewide renewable energy industry? Using this calculus, the state expanded eligible customer classes, instituted generous credits for excess generation and adopted the highest cap for eligible system sizes of any state in the nation. As a result, New Jersey has experienced the highest rate of enrollment of any state, increasing the number of installed solar systems more than fivefold.

Simple Solutions: Model Statutes and Regulations

Applying the lessons we have learned from 34 state net metering programs, the Institute for Energy & the Environment at Vermont Law School has crafted model statutory language for state legislators and model interconnection standards and regulations for state utility commissioners. As states consider adopting or expanding net metering programs in 2007, these models provide an easy way to emulate effective programs and avoid mistakes.

Ideally, a uniform national renewable energy policy would stem from federal leadership. The wide discrepancy in the design and implementation of 50 different state net metering programs has the potential to create uneven playing fields for renewable energy service providers and for regulated utilities. Uniform federal net metering standards could create a level playing field as well as provide greater regulatory predictability than a patchwork of 50 state-based programs.

4 Lacey, Stephen (2006). "The price of success: Inside the NJ clean energy program," RenewableEnergyAccess.com, October 10. Accessed at http://www.renewableenergyaccess.com/rea/news/story?id=46172

I : Introduction

The State of Net Metering

Buried within the mammoth Energy Policy Act of 2005 (EPAct) is a little paragraph that could have profound effects on renewable energy generation in the United States.

In Section 1251 of EPAct, the U.S. Congress required every state to "consider" issuing net metering standards and by 2008 "make the determination" of such standards.[5] As legislative language goes, the word "consider" is as precise as words like "gourmet" or "sustainable". It is impossible to say what constitutes consideration or what distinguishes it from cursory rejection. The "determination" part of the provision isn't much clearer, but appears to require states to make a decision on whether to adopt some kind of net metering program by 2008. It is, however, silent on just what a good net metering program should look like.

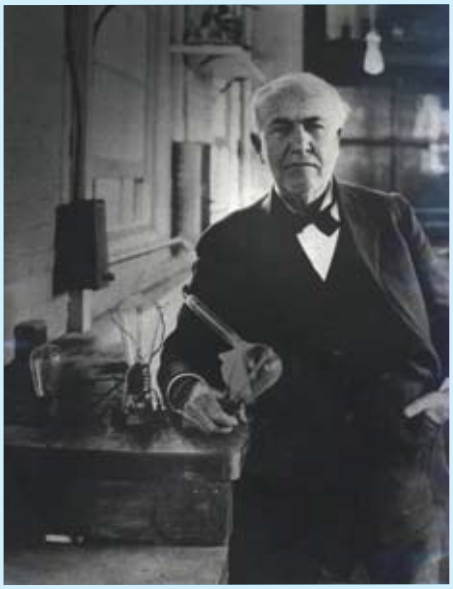
In its simplest form, net metering employs a standard electrical meter to record the flow of energy back and forth between a generator and the utility's power grid.[6] Since most meters are already capable of running in both directions, they provide an easy way to record the net excess electricity consumed or produced by participating customers during a given billing cycle. Across the nation, some 36 state legislatures and/or utility commissions have gone through the arduous process of crafting and passing 'net metering' rules - programs that require utilities to credit customers for generating their own electricity from renewable resources and to purchase any excess generation. Net metering is usually created as an incentive for homeowners and small businesses to invest in renewable power systems and to help decrease demand on the central transmission grid. In many states, the programs are seeing hundreds of new participants each year, jump-starting new renewable energy service companies and creating robust markets for off-the-shelf solar and wind systems.

But in many states, net metering has proven a poor mechanism for promoting small-scale, on-site renewable energy. By 2004, there were only about 15,200 customers nationwide participating in net metering programs, with 13,000 of them in California alone.

- Outside California, there are fewer than 2,200 customers in the United States participating in net metering programs.
- Three states have net metering standards and no participating customers at all.
- Six states registered five or less participating customers.
- In many states, more energy has been lost crafting the Byzantine interconnection rules governing net metering than has been generated by the programs themselves.
- In some states, the number of participating customers actually has decreased as many customers, deterred by burdensome paperwork requirements and hidden utility fees, simply dropped out.

5 Energy Policy Act of 2005. (2005) Subtitle E, Amendments to PURPA, Section 1251, Net Metering and Additional Standards.

6 U.S. Environmental Protection Agency. (2000) Net Metering, State & Local Climate Change Program. January. http://yosemite.epa.gov/OAR/globalwarming.nsf/UniqueKeyLookup/SHSU5BUTYL/$File/netmetering.pdf



Central Versus Distributed Generation

"I can only invent under powerful incentive," Thomas Edison was fond of saying. Often Edison meant money, not scientific curiosity.[7] Edison's obsession with profiting from his invention of the electric light bulb laid the groundwork for our nation's current dependency on an inefficient transmission grid controlled by utility monopolies.

The preeminent industrialist financier, J. P. Morgan, who bankrolled much of Edison's early work with electricity, wanted to sell the machinery that generates electricity rather than get involved in the messy details of creating and selling the electricity itself. It is far easier to build and sell a widget, Morgan thought, than trying to manage an entire commodity market. But Edison preferred to keep a tight leash on the generation technology and wanted instead to profit from selling the electrical current, much like gas companies profited by selling gas.[8]

Unfortunately for us, Edison's vision prevailed. Over a century later, American consumers have come to depend on a rickety, unreliable transmission grid, stitched together from networks controlled by regional franchises. In our modern electronic society, it is increasingly a grid strained to capacity and unlikely to meet future demand.

It is also staggeringly inefficient. By the time electricity reaches the customer, nearly two-thirds of the energy in the original fuel has been wasted.[9] American consumers pay up to 2.6 cents per kWh for electricity lost in transmission.[10] Grid failures cost an additional $80 billion to $123 billion each year and add 29% to 49% to the cost of every kW of power transmitted in the United States.[11]

Had the U.S. electrical system followed J.P. Morgan's model, it may have looked far simpler and operated far more efficiently than our current model of centralized generation. Customers would produce their own electricity close to where it is consumed, with generators scaled to fit their demand and using fuels befitting the geography. Electricity guru Amory Lovins has documented over 200 benefits from this type of 'distributed generation' model – from reducing the number of customers affected by blackouts to making beneficial use of local fuels that would otherwise be discarded.[12]

While some utilities are beginning to understand the benefits of distributed generation and starting to invest in smaller, modular power systems, many continue to fight the participation of homeowners and small businesses by discouraging on-site renewable energy generation.[13]

7 Munson, R. (2005) From Edison to Enron: The business of power and what it means for the future of electricity. Praeger: West Port, CT (p. 18).

8 Goodell, J. (2006) Big Coal: The dirty secret behind America's energy future. Houghton Mifflin: New York, NY (p. 103).

9 Munson, R. (2006) Yes, in My Backyard: Distributed electric power. Issues in Science and Technology, Winter. http://www.issues.org/22.2/munson.html

10 Smeloff, E. (2005) Quantifying the benefits of solar power in California. Vote Solar. January. http://www.votesolar.org/resources/downloads/tools_QuantifyingSolarsBenefits.pdf

11 Casten, T. and Downes, B. (2005) The case for decentralized generation of electricity. Skeptical Inquirer. January/February.

12 Lovins, A., et al. (2002) Small is Profitable: The hidden economic benefits of making electrical resources the right size. Rocky Mountain Institute: Snowmass, Colorado.

13 U. S. Department of Energy. (1999) Distributed Generation: Securing America's future with reliable, flexible power. Office of Fossil Energy, Federal Energy Technology Center, October. http://www.distributed-generation.com/Library/FETC.pdf

In 1983, Minnesota became the first state in the U.S. to mandate net metering by legislative statute.[14] Proponents of the legislation believed that the program was an easy way to promote investment in renewable energy without spending a substantial amount of public funds. By providing a market mechanism for compensating customers for excess generation, the program was intended to offset some of the up-front capital costs associated with installing renewable energy systems.

After nearly 25 years of experimenting with net metering, there is a dearth of information comparing state programs and little guidance for states that must now consider establishing net metering policies or make improvements in existing programs. While some environmental groups and government agencies have issued reports attempting to evaluate the effectiveness of net metering, in most cases these reports have described the regulatory environment, evaluated differences between programs, and speculated about the effects of various rules. Most attempts to assess the effectiveness of net metering using more objective criteria have been hampered by the lack of available data on customer participation rates, the amount of renewable energy generated, or the effects of the programs on service quality.[15]

Starting in 2002, the U.S. Energy Information Administration (EIA) began collecting data on state net metering programs. The EIA has only made public data sets from 2002-2004. Because no complete set of data is available for all states since 2004, a comparative analysis of more recent policy changes is impossible. Instead, we take a snap-shot in time and compare the performance of state net metering programs at that time. The result is a comprehensive analysis of how different state net metering arrangements have affected customer participation over a specific time period (2002-2004). In many states, significant policy changes have occurred since 2004. Where possible, we have noted these changes and their effects on participation rates.

By comparing regulatory arrangements (and participation rates) across states from 2002-2004, we have identified how unnecessary regulations and burdensome requirements (often adopted at the behest of utilities opposed to net metering) have limited the ability of the programs to meet their intended goals. What emerges is a picture of state legislatures often undermined in their attempts to promote clean, distributed power by utilities that perceive on-site renewable generation as a threat to their bottom line. Taking the lessons learned from a quarter-century of net metering policy in multiple states, we attempt to dispel myths, identify best and worst practices and make recommendations for policy reforms.

What emerges is a picture of state legislatures often undermined... by utilities that perceive on-site renewable generation as a threat to their bottom line.

For over two decades, states have been the crucible for innovative policies to promoting small-scale renewable energy. Some states have seen remarkable success. Others have failed.

This report is a call to action. It is time to apply the lessons learned from successful (and unsuccessful) state net metering programs to reform and improve existing policies, to create new state initiatives where they do not exist and ultimately to adopt a model policy that offers new energy choices to all Americans.

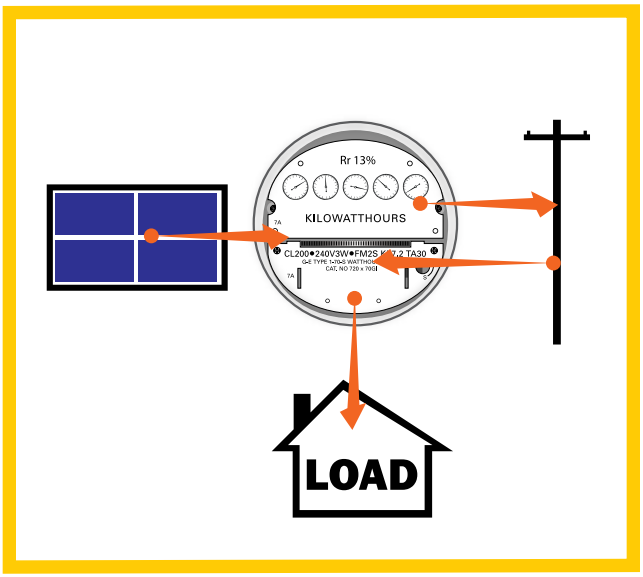
14 American Wind Energy Association. (2005) Small Wind in Minnesota. http://www.awea.org/smallwind/minnesota_sw.html

15 The Michigan Public Service Commission, for example, has attempted to make an accurate assessment of its state program since 1999. Their report was still in draft form as of October, 2006.

Methods of Metering Small-Scale Renewable Energy

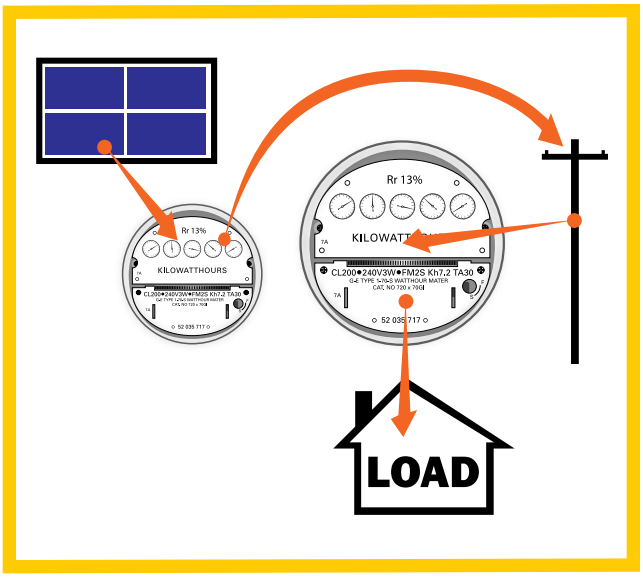
Net Metering

The most common method of "basic" net metering uses a single bi-directional meter that registers the flow of electricity in two directions to record the customer-generator's net energy consumption or production over a single billing period. The meter spins forward during periods of electricity consumption from the grid, similar to any ordinary meter. Alternatively, the meter spins backwards during periods of excess energy production to register the flow of electricity fed into the grid. Many existing meters have this capability. At the end of each billing period, the utility company bills the customer-generator only for the net energy consumed by the grid (the difference between the energy consumed and the energy produced on the grid). In the situation of net metering with rolling credit, the utility should credit the customer for any excess generation at the retail rate for electricity and carry that credit to the next billing period indefinitely.[16]



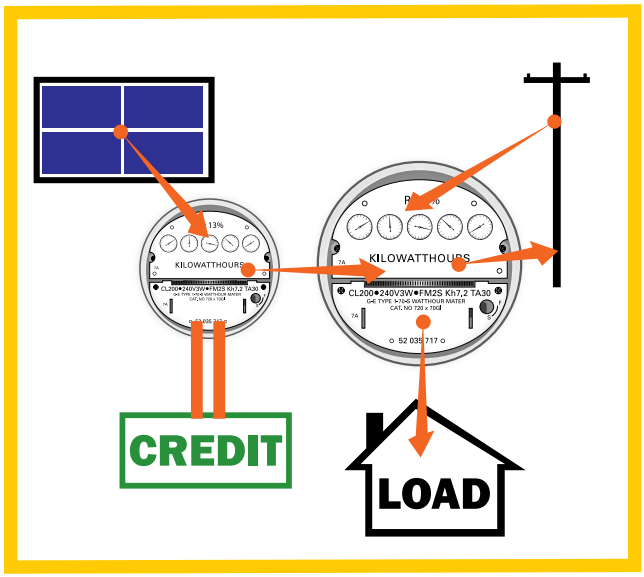
Dual Metering

Dual metering, another method of metering, should not be confused with net metering. Unlike net metering, which uses a single, bi-directional meter, dual metering requires two separate meters: one to measure the electricity consumed from the grid and another to measure the distributed generation (DG) produced electricity sold to the grid. Dual metering typically costs more than net metering for both the utility and the customer. The customer generally pays for the secondary meter, while the utility incurs the extra administrative costs associated with processing the data from two separate meters.[17] Under dual metering, the customer-generator feeds any electricity produced from a DG-system directly onto the grid, which the utility purchases at avoided cost (the amount it would cost the utility to place the power in the grid itself) and credits the amount purchased to the customer's monthly bill. The key difference between net metering and dual metering is that a net metered customer receives credit at the retail rate (the price the electricity would cost the customer at the time it is used), while in dual metering, the customer receives the (much lower) avoided cost, or wholesale rate, for electricity generated by a DG system.



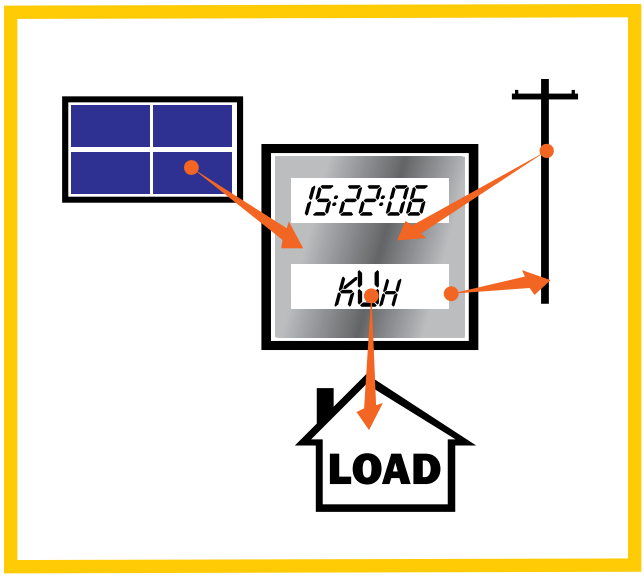
16 Hughes, Larry and Bell, Jeff. (2006) Compensating customer-generators: a taxonomy describing methods of compensating customer-generators for electricity supplied to the grid. Energy Policy. Vol. 34. No. 13. pg. 1532 – 1539.

17 Wiese, Steven M., John E. Hoffner, Erin Scott, Jane Pulaski, Russel Smith. (2005) Interconnection and Net Metering of Small Renewable Energy Generators in Texas: Final Report of the Texas RE-Connect Project. Million Solar Roofs Project. June 11. http://www.treia.org/pdf_files/Final%20Report.pdf



Net Billing[18]

Another two-metered system, called net billing, uses a bidirectional meter to record the net energy consumption, while a secondary meter records the total output of electricity fed into the grid from the DG system.[19] As in bi-directional metering, the customer is credited the retail rate for the electricity generated. For some customer-generators, total output is awarded performance based incentives, such as Renewable Energy Credits (RECs), tradable commodities that represent the attributes of energy produced by renewable sources. However, for smaller PV systems, REC distributors often estimate potential output and award RECs based on that estimate.



Smart Metering[20]

A final type of metering system is smart metering. Smart metering allows customer to gauge the real-time price, or 'time of-use' rate, for electricity. This enables customers to base their electricity consumption patterns on the retail prices of electricity. The use of smart metering in conjunction with net metering encourages customer-generators to make more informed electricity consumption decisions, which can drastically reduce demand on the electricity grid as well as the customer's monthly bill. For example, customer-generators with smart metering reduce demand by producing their own electricity during peak load intervals (conveniently, the time when PV systems are at optimal performance), and reduce their monthly bills by performing energy intensive chores (like household laundry) when retail rates of electricity are lowest. Also, smart meters can differentiate between sources of energy and can track DG production, which can facilitate the use of performance-based incentives.

18 "Net billing" is sometimes lumped into the "net metering" or "dual metering" categories. As it is listed here "net billing", with net excess generation credited at the retail rate, falls more in line with "net metering". "Net billing" will be included in the definition of "net metering" for the remainder of the report.

19 Hughes, Larry and Bell, Jeff. 2006. Compensating customer-generators: a taxonomy describing methods of compensating customer-generators for electricity supplied to the grid. Energy Policy. Vol. 34. No. 13. pg. 1532 – 1539.

20 Similar to "net billing", "smart metering" will fall under the definition of "net metering".

II : Why Few Customers Participate

Most states that have adopted net metering statutes have done so in pursuit of the same goals:

- To encourage greater renewable energy generation
- To promote distributed generation of electricity
- To reduce demand on central transmission grids
- To reward early investment in renewable technologies
- To facilitate energy self-reliance

Yet, even where states have adopted similar net metering statutes, no two states share the exact same regulations or procedures governing how the programs are implemented and monitored. In an effort to appease utility concerns about lost revenues, some state legislators have adopted statutory language that intentionally limits participation in net metering programs. In other states, well-intentioned state legislators have been thwarted by the addition of burdensome requirements and fees inserted at the regulatory level. In either case, these common barriers to participation are universally unnecessary and generally counterproductive.

Restrictions on Eligibility

Some state net metering rules restrict the customer classes that are eligible to participate in the program, often excluding commercial customers who may have the most substantial effect on reducing demand on the central transmission grid.[21] Since these customer classes typically consume more power than residential customers, they are also more likely to view net metering as an economic incentive to invest in on-site generation.

Most net metering programs are intended to encourage investment in technologies that are being delayed by market barriers. Restricting customer classes is often counterproductive to this goal. The Texas State Energy Conservation Office has noted, "It would make more sense to limit the eligibility of a technology for a period of time, say five or ten years, in order to give the technology a period in which it has the opportunity to become commercially viable, than to limit the size of the initial market, when the goal is creating a critical mass of market demand."[22]

Allowing commercial and industrial classes to be eligible for net metering is essential to jump-starting new renewable energy markets and reducing electricity demand.

21 Indiana, for example, allows only schools and residential customers to participate in the state's net metering program.

22 Texas State Energy Conservation Office. (2002) An Analysis Working Paper on Net Metering as an Incentive for Fuel Cell Applications. September 10. http://www.seco.cpa.state.tx.us/zzz_feulcell-initiative/fciac_incen_netmeter.pdf

Limits on System Sizes

Most individual state net metering standards impose a limit on the maximum allowable capacity size of individual net metered systems, ranging from a system size limit of 10 kW in several states up to 1 MW in California and 2 MW in New Jersey.[23]

Many states restrict net metering customers from participating in power sales and subsequently discourage customers from investing in renewable energy systems larger than necessary to meet on-site demand.[24] In other states, statutory limitations on the size of eligible technologies prevent customer-generators from correctly sizing a renewable energy system to provide most (or all) of their on-site demand. For example, New Hampshire's net metering statute limits commercial customers to solar PV systems smaller than 25 kW. As a result, commercial customers with loads greater than 25 kW and the capability of installing larger systems are limited to a grid-tied system that can only generate the first 25 kW of their demand.[25]

Some of the least effective net metering programs do not allow customers to bank excess generation, letting utilities seize it at the end of a given monthly billing cycle.

Uniformity of size limits reduces regulatory confusion while promoting the broadest population of renewable energy generating systems. It is no longer uncommon to see renewable energy systems in the 100 kW to 2 MW range. Increasing the eligible facility size for non-residential systems also could encourage participation by large investors in net metering programs. Several project developers in Oregon, for example, have argued that the transactional cost of systems less than 100 kW are too great to interest large investment partners.[26] Projects like FedEx's 904 kW net-metered solar system in Oakland, California would not be possible under many states' current regulations.[27]

In 2005, the Federal Energy Regulatory Commission (FERC) issued uniform standards for interconnecting small generators and required public utilities that own or control interstate transmission lines to abide by the standards. FERC standards define "Small Generators" as having a capacity of no more than 20 MW and further create a special class of "Certified Inverter-Based Small Generating Facilities" no larger than 10kW.[28] For practical purposes, system size limits contained within state net metering regulations should reflect the limits defined by FERC. Should states adopt system size limits at all, they should limit eligibility to systems that qualify as "Small Generators" under FERC's standards - 10kW for residential customers and up to 20MW for commercial and industrial customers.

Restrictions on "Banking" Net Excess Generation (NEG)

When customers generate more electricity during a monthly billing period than they consume, some states allow customers to "bank" the excess generation. The utility credits the customer for any excess electricity generated in a monthly billing period and

23 Database of State Incentives for Renewable Energy (DSIRE). 2006. www.dsireusa.org

24 Maine Public Utilities Commission. (1998) IPP Net Metering News: Statement of Policy. April. http://www.i2p.org/news.htm.

25 Hamrin, Jan, Dan Lieberman, and Meredith Wingate. (2006) Regulators Handbook on Renewable Energy Programs and Tariffs. Center for Resource Solutions. March. http://www.resource-solutions.org/policy/TariffHandbook/Handbook_on_Renewable_Energy_Programs_&_Tariffs.pdf

26 Oregon Department of Energy. (2006) Net Metering: Comments by Kyle L. Davis of Pacificorp. July 10, 2006. Page 3. http://www.oregon.gov/ENERGY/RENEW/docs/ODOENetMeteringPaper-Revisions.pdf.

27 Corum, Lyn. 2006. Investing in a Clean Energy Future. Distributed Energy. July/August. http://www.forester.net/de_0607_investing.html

28 U. S. Federal Energy Regulatory Commission (2005) Standardization of Small Generator Interconnection Agreements and Procedures, 18 CFR Part 35 [Docket No. RM02-12-000; Order No. 2006]. May 12. http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp

carries this credit forward to subsequent billing periods either throughout the year or indefinitely. Some of the least effective state net metering programs do not allow customers to bank excess generation, granting the utility excess electricity generated during a given monthly billing cycle. Other states limit the time that excess generation can be applied to future electricity bills.

Restrictions on banking are more a function of utility billing cycles than a rational public policy. Just because utilities bill on a monthly cycle does not mean that customers generating excess electricity for the grid should not be adequately compensated for the electricity they contribute to the grid. Compensation for excess generation encourages customers to participate in net metering programs and install systems that generate more renewable energy than is consumed on-site.[29] Utilities also benefit from banking because they do not incur the administrative costs associated with paying for small amounts of excess generation on a monthly basis. To be successful, a net metering program must facilitate banking so that customer-generators can receive credit for excess energy generated during the seasons when renewable output is highest and apply it toward their consumption when output is lower.

Total Program Capacity Limits

In a nod to utility concerns that on-site generation represents lost revenues, half of the states have limited the total capacity of electricity that is eligible for net metering. In most cases, the utilities are only required to honor net metering arrangements until the total amount of renewable energy generated by net metered customers reaches a certain percentage of the utility's aggregate peak demand. Generally, states have set capacity limits well below one percent of aggregate peak demand. In a majority of states, the limits are well below one half of one percent.[30] Once the total capacity of eligible net metered systems reaches the limit, the utility is no longer legally obligated to offer net metering to new customers.

It makes little sense to limit the total amount of clean energy that customers may generate and contribute to the electricity grid. Utilities do not have a divine right to charge for electricity that customers can otherwise generate more efficiently and more cleanly on their own. Capacity limits artificially restrict the expansion of on-site renewable generation and curtail the market for new renewable energy distributed generation (DG) systems.[31]

Utilities do not have a divine right to charge for electricity that customers can otherwise generate more efficiently and more cleanly on their own.

Capacity limits also create uncertainty for new customers considering net metering. Since customers have no way of knowing when capacity limits will be met, they cannot effectively plan for future DG installations and know for sure that those installations will qualify for net metering.[32] This regulatory uncertainty complicates calculations of buyback periods on capital investments and inhibits renewable energy services companies from providing accurate long-term cost projections to potential investors.

29 Hamrin, Jan, Dan Lieberman, and Meredith Wingate. (2006) Regulators Handbook on Renewable Energy Programs and Tariffs. Center for Resource Solutions. Page 52. March. http://www.resource-solutions.org/policy/TariffHandbook/Handbook_on_Renewable_Energy_Programs_&_Tariffs.pdf

30 DSIRE. 2006. www.dsireusa.org

31 California Energy Commission. (2004) Integrated Energy Policy Report 2004 Update. http://www.energy.ca.gov/reports/CEC-100-2004-006/CEC-100-2004-006CMF.PDF

32 Pacific Gas and Electric Company, Generator Interconnection Services Department. (2006) Pacific Gas and Electric Company's Position on the Net Energy Metering Enrollment Cap. http://www.pge.com/suppliers_purchasing/new_generator/solar_wind_generators/nem_enrollment_cap.html

California

Caps can be counterproductive

California amended its net metering statute in 2002. The original law required utilities to provide net metering to customers until the total energy generated by net metering met 0.5% of the utility's aggregate peak demand. The state adopted this cap as a concession to utility companies, and justified it "due to the unknown impacts of increased customer-owned generation on the grid, particularly after the maximum capacity size was increased from 10 KW to 1 MW" in 2002.[33] By June 2006, the three major California utility companies (PG&E, SCE and SDG&E) were all close to reaching this cap, and some experts estimated the generation from net metered customers would likely exceed the cap before the end of the year.

If the aggregate number of customers happens to reach the maximum enrollment, the utilities would have no longer been required to offer customers net metering. At the time, many in the solar industry feared that there would be a significant decrease in demand for PV systems.[34, 35]

In partial response to the enrollment cap conundrum, in August 2006, California's state government passed SB1, the Million Solar Roofs Bill. This bill raised the enrollment cap to 2.5% of a utility's aggregate peak demand and provided additional funding for solar programs.

33 California Public Utilities Commission Energy Division. (2005) Update on Determining the Costs and Benefits of California's Net Metering Program as Required by Assembly Bill 58. California Public Utilities Commission Energy Division. March 29. http://www.cpuc.ca.gov/WORD_PDF/REPORT/45133.PDF

34 Krauss, Leah. (2005) California Nears Net Metering Cap. United Press International. June 5. http://seia.org/solarnews.php?id=113 .

35 Pearson, Aria. (2006) It's Nearly Lights Out for PG&E's Solar Power Buybacks. RenewableEnergyAccess. June 9. http://www.renewableenergyaccess.com/rea/news/story?id=45118

Discriminatory Standby Charges

Many utilities claim that, in the event that net metered systems fail, the utility is required to meet the resulting customer demand. As a result, many states allow utilities to impose a stand-by fee on net metered customers that is intended to cover the cost of the electricity the utility would otherwise be required to generate should the system fail.

The logic behind standby charges strains credulity. Some researchers have noted that they are "analogous to assigning standby fees to residential customers who purchase high efficiency air conditioning units."[36]

In some cases, standby charges are equal to or even exceed rates for full electrical service, in effect creating an economic disincentive for customers to install renewable energy DG systems. Indeed, in states where utilities have imposed these charges, the number of grid-tied solar PV installations has tended to decrease.[37]

Standby charges are particularly burdensome to small generators. Utilities only need to provide a negligible amount of back-up power for these customers. Yet standby fees may be so exorbitant that they diminish most, if not all, of the economic incentive net metering was intended to offer smaller generators. As well, when standby charges are levied, smaller generators, without leverage to negotiate a more reasonable rate with the utilities, are placed at a disadvantage to larger generators who may have more leverage with the utilities or more resources to devote to negotiating.[38]

36 Wenger, Howard, Tom Hoff, and Jan Pepper. (1996) Photovoltaic Economics and Markets: The Sacramento Municipal Utility District as a Case Study. California Energy Commission. September. http://www.energy.ca.gov/papers/1996-09_SMUD_SOLAR_STUDY.PDF

37 Alderfer, R. Brent, M. Monika Eldridge, and Thomas J. Starrs. (2000) Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects. National Renewable Energy Laboratory. July. http://www.nrel.gov/docs/fy00osti/28053.pdf

38 Larsen, Chris and Chris Cook. (2004) Connecting to the Grid: A Guide To Distributed Generation Interconnection Issues, Fourth Edition. Interstate Renewable Energy Council (IREC) and North Carolina Solar Center. http://www.irecusa.org/pdf/guide.pdf

Unreasonable Safety Requirements

In theory, net metered systems present a safety hazard if the central grid either shuts down or loses power but the interconnected systems continue to produce power without the utility's knowledge (a situation utilities call "islanding"). Potentially, line workers could come in contact with an unexpectedly energized line. Many utilities site these safety concerns to require that net metered customers install and test external shut-off switches on any interconnected system. However, the practical effect is that, like hidden interconnection fees, requiring additional external shut-off switches only adds unnecessary costs and discourages customers from investing in renewable energy systems.[39]

It is important to note that not one accident resulting from the "islanding" of net metered renewable energy systems has ever been reported in the United States.[40] More importantly, utility workers are trained to treat all lines as live and a variety of other safety precautions are required as part of standard operating procedures of line workers.[41] An external shut-off switch represents a 4th or 5th level of redundancy that is only relevant if a utility worker ignores his or her training and does not act according to protocol. If a worker is following proper protocol, none of the levels of safety preceding an external disconnect switch will ever be needed, much less the switch itself.[42]

Requiring additional external shut-off switches is also unnecessary since all inverters that meet Institute of Electrical and Electronics Engineers standards (IEEE1547) have automatic shut-off capabilities integrated with the systems.[43] All modern inverters, for example, shut down interconnected systems automatically in the event of grid failure.[44]

As well, recent studies have found that requiring additional, expensive safety equipment for net metered installations may inadvertently decrease worker safety by encouraging illegal interconnections or by forcing line workers to traverse customer property to access equipment (see page 77).

Unnecessary Insurance and Indemnification Requirements

Because of potential personal injury and property damage liability risks associated with interconnection of net metering systems, most state commissions allow utilities to impose additional, and often excessive, liability insurance requirements on net metered customers. Several utilities have required customer-generators to carry comprehensive general liability policies with one hundred thousand dollars or more in coverage to protect utilities from being held financially responsible for problems caused by interconnecting net metered systems. A limited number of states have enacted regulatory limits on the amount of additional insurance a utility may impose on a customer, and a few states prohibit utilities from imposing any additional insurance requirements for net metering.

39 Cook, Christopher. (no date) Interconnected PV - The Utility Accessible External Disconnect Switch. www.e3energy.com/Extdisc.doc

40 Xu, et al. (2004) An Assessment of Distributed Generation Islanding Detection Methods and Issues for Canada. CANMET Energy Technology Centre – Varennes, Natural Resources Canada. Report #CETC-Varennes 2004-074(TR).

41 National Renewable Energy Laboratory. (2005) Million Solar Roofs Case Study: Overcoming Net Metering and Interconnection Objections New Jersey MSR Partnership. September. http://www.nrel.gov/docs/fy05osti/38666.pdf

42 Cook, Christopher. (no date) Interconnected PV - The Utility Accessible External Disconnect Switch. www.e3energy.com/Extdisc.doc

43 Institute of Electrical and Electronics Engineers (IEEE). (2003) 1547-2003 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

44 Larsen, Chris and Chris Cook. (2004) Connecting to the Grid: A Guide To Distributed Generation Interconnection Issues, Fourth Edition. Interstate Renewable Energy Council (IREC) and North Carolina Solar Center. http://www.irecusa.org/pdf/guide.pdf

There has never been a documented case of a small-scale net metered system causing grid failure or creating potential personal injury or property damage liabilities for a utility. [45] Renewable energy technologies manufactured and installed in compliance with national interconnection standards significantly reduces the risk of potential safety issues and electrical failure problems.[46] Furthermore, product liability insurance carried by equipment manufacturers as well as the ability of these manufacturers to indemnify customers or utilities from liability for product failures negates the need for additional insurance.[47]

Excessive insurance requirements may also provoke customers to interconnect without informing the utility, which, as one utility executive noted, "will create safety problems in the name of safety."

Excessive insurance requirements only serve to discourage customers from investing in renewable energy systems and participating in net metering programs. Requiring customer-generators to obtain and maintain million-dollar insurance policies is impractical because the high premiums associated with these policies will likely exceed the economic benefits of participating in net metering programs. For example, a Florida utility imposed a $1 million insurance policy with an annual premium of $6200 that effectively shut down a commercial photovoltaic installation entirely.[48]

Excessive insurance requirements may also provoke customers to interconnect without informing the utility, which, as one U.S. utility executive stated, "will create safety problems in the name of safety."[49]

Lack of Public Awareness

Because many utilities view net metering requirements as revenue losers, they do not readily promote their programs.[50] Most state net metering statutes do not include any public information requirements. As a result, many customers remain unaware of the opportunities and benefits associated with investing in net metered systems.

In some cases, lack of promotion may limit participation even more directly. Building code officials unfamiliar with renewable energy technologies or state net metering regulations may add unnecessary permitting requirements that delay or discourage installations.[51] States should do a better job of promoting their net metering programs either by inserting public information requirements in their statutes or by directing state agencies to initiate public information efforts and fully funding their campaigns.

45 Starrs, Thomas J. (no date) Barriers and Solutions to Interconnection Issues for Solar Photovoltaic Systems. Prepared for the Solar Electric Power Association. http://www.resourcesaver.com/file/toolmanager/O63F14189.pdf

46 Ibid.

47 Starrs, Thomas J. and Robert K. Harmon. (2000) Allocating Risks: An Analysis of Insurance Requirements for Small-Scale PV Systems. http://www.millionsolarroofs.org/articles/static/1/binaries/Allocating_Risks_Analysis_of_Insurance_Requirements_for_Small_Scale_PV_Systems.pdf

48 Alderfer, R. Brent, M. Monika Eldridge, and Thomas J. Starrs. (2000) Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects. National Renewable Energy Laboratory. July. http://www.nrel.gov/docs/fy00osti/28053.pdf

49 Starrs, Thomas J. and Robert K. Harmon. (2000) Allocating Risks: An Analysis of Insurance Requirements for Small-Scale PV Systems. http://www.millionsolarroofs.org/articles/static/1/binaries/Allocating_Risks_Analysis_of_Insurance_Requirements_for_Small_Scale_PV_Systems.pdf

50 Wan, Yih-huei and H. James Green. (1998) Current Experience with Net Metering Programs. Green Power Network Online Report. http://www.eere.energy.gov/greenpower/resources/pdfs/current_nm.pdf

51 Starrs, Thomas J. and Howard J. Wenger. (1998) Promoting Profitable Home Power. Home Energy Magazine. http://www.homeenergy.org/archive/hem.dis.anl.gov/eehem/98/980111.html.

III : Comparing States

To measure the effectiveness of 34 statewide net metering programs[52], we developed an index that rewards program elements that promote participation, expand renewable energy generation or otherwise advance the goals sought by net metering.

Conversely, the index assigns demerits to program components that discourage participation, limit renewable energy generation or otherwise retard the goals sought by net metering programs.

We limited our analysis to statewide net metering programs. In many cases, these programs require that multiple utilities comply with the same set of state net metering rules. In Arizona, Florida, Idaho, and Illinois, utilities operate voluntary net metering programs. Since these programs are self-imposed and limited to certain parts of the state, we did not include them in our analysis.[52 53]

We measured program components as well as their impacts and assigned numerical values to each. For example, a value of zero means that the program component offers little to no incentive for a customer to participate. Negative values represent factors that undermine the effectiveness of the net metering program. Positive values represent additional incentives that contribute to program effectiveness.

Applying these numerical values to program components allows us to plot the effectiveness of each state net metering program on a continuum ranging from -8 to +316, where:

-8: characterizes the program that most discourages the goals of net metering

0: characterizes a minimal net metering program, but one that does not strongly encourage or discourage program goals.

+316: characterizes the program that displays the most features that encourage the goals of net metering.

52 Rhode Island's net metering program was created through public utility commission order for Narragansett Electric, which make up 99% of the mainland electric sales. Rhode Island is included in our analysis because the mandated rules cover the majority of the state's customers.

53 We excluded Michigan, North Carolina, and Washington D.C. all of which began their program after 2004.

Measures of Program Effectiveness

Customer Participation – The number of customers enrolled in net metering programs indicates how effective the net metering policies are at creating incentives for participation. Effective programs should see progressively increasing numbers of participants. We compared the most recent, publicly available data from the U.S. Department of Energy, Energy Information Agency (EIA), which has surveyed the number of net metering participants in each state since 2002 and published data sets for 2002, 2003 and 2004.

To account for variable population densities, we translated raw participation numbers into the number of net metering customers per million utility customers within each state. This calculation allows us to more accurately compare the rate of growth in participation between states with widely varying populations.

-1: The number of participants declined

0: Fewer than 10 customers per million joined the program from 2002-2004.

- The states in this range were neutral or marginally better than neutral. We decided that single digit growth did not represent a positive/effective program.

1: 10 to 99 customers per million joined the program.

- Programs with participation levels in this range indicate that the program was marginally effective.

+1 point: We assigned one point for every additional 100 participants per million utility customers.

The Magic of 67

A cursory examination of raw participation numbers reveals that many states have few, if any, participating customers. We have examined why participation rates are so low in these states. However, low raw figures complicate any analysis of the change in participation rates over the limited time period for which data is available. For example, Utah registered not a single net metering customer in 2002, 1 customer in 2003, and 10 customers in 2004. A crude calculation of Utah's rate of participation would reveal a 1000 percent increase from 2002 to 2004. However, such a calculation would reflect an inaccurate assessment of the effectiveness of Utah's program.

To account for states with low participation rates, we performed a regression analysis that plots the age of a state's net metering program against the number of net metering participants per million utility customers (see Appendix A). The results of the regression analysis conclude that the age of a state's net metering program is not a significant factor in customer participation rates. We found that just because a program has been

in place for several years, it does not mean that the number of customers participating in the program will have increased.

More importantly, our regression analysis reveals that the change in program participation from 2002 to 2004 is only a relevant calculation for states that have overall participation rates exceeding 67 net metering participants per million electricity customers. In states that have adopted net metering programs, our analysis shows that the expected rate of participation is 67 customers for every million electric utility customer, all other factors being equal. Therefore, we used 67 participants as a "floor" for factoring the change in net metering participation as a measure of program effectiveness. For states with less than 67 program participants per million utility customers, we ignored any growth in participation rates from 2002 to 2004, since any changes are below what is expected in any case. For states with participation rates exceeding 67 net metering participants per million utility customers, we calculated the percent change from 2002 to 2004 and rewarded any growth accordingly.

0: <67 Customers

- Less than 67 participants per million customers indicates that the net metering program was ineffective.

1: 0 to 99% Growth

- For states having more than 67 net metering participants per million utility customers, we assigned one point for any growth in participation rates from 2002-2004.

+1 point: Every 100% increase in growth

- States earned one point for every additional 100% increase in their state's participation rate. For example, Nevada experienced 236% growth from 2002 to 2004. Therefore, the state scored 3 points: 1 point for growth from 0 to 99%, 1 point for the next increment of growth (100% to 199%), and 1 point for next increment of growth (200% to 300%).

System Size Limits (residential) – Residential electricity loads generally range between 2kW and 4kW. State net metering programs that allow residential systems above 10kW create incentives for excess generation for almost all residential customers. We used the following values to assess residential system size limits:

-1: Net metering regulations limited renewable generators to less than 2kW in overall capacity. Limits this low will not allow customer-generators to produce enough electricity to cover their entire on-site demand.

0: Net metering regulations allowed for renewable generators from 2 to 10kW in overall capacity.

1: Net metering regulations allowed for renewable generators in excess of 10kW in overall capacity.

System Size System (non-residential) – Non-residential loads tend to be larger than residential. To be as inclusive as possible for all non-residential customer loads, system size limits should be large enough to exceed the on-site demand of most commercial operations. We used the following values to assess non-residential system size limits:

-1: Net metering regulations limited renewable generators to less than 25kW in overall capacity. Limits this low will alienate larger customer classes from producing a substantial portion of their load with on-site renewable generation.

0: Net metering regulations allowed for renewable generators from 25 to 149kW in overall capacity. This range will cover most commercial classes, but still may be too small for most industrial loads.

1: Net metering regulations allowed for renewable generators from 150 to 999kW in overall capacity. Renewable energy systems in this range should cover a majority of non-residential classes.

2: Net metering regulations allowed for renewable generators in excess of 1000kW in overall capacity. Above the 1000kW threshold, nearly all loads will exceed on-site demand, allowing commercial and industrial customers to take advantage of any incentives for net excess generation.

Interconnection Standards – Without interconnection standards determined by statute, utilities can charge high interconnection fees and delay the installation process with long and complicated rules and procedures. In 2005, the Federal Energy Regulatory Commission (FERC) issued uniform interconnection standards for small generators and required all public utilities that own, control or operate interstate electricity transmission lines to comply with them. However, since our analysis looks specifically at the effectiveness of state program prior to 2005, we included an assessment of interconnection standards and assigned the following numerical values:

-2: The state had not adopted a standard or the standard varied by utility and was not determined by statute – OR – Interconnection rules were left to the utility's discretion.

-1: The state was developing a standard, but no statewide standard existed by 2004.

0: The state had adopted a practical and reasonable standardized process for application and approval.

Treatment of Net Excess Generation (NEG) – Compensation for net excess generation provides a powerful economic incentive to invest in on-site renewable energy systems and helps offset the capital costs associated with interconnection. We assigned the following values based on how the net metering program credits NEG.

-3: NEG was gifted to the utility on a monthly basis

- This situation denies the customer any way of banking excess generation and applying the credit to the next billing cycle. Monthly gifting does not account for the seasonal variability of renewable generation. If a customer-generator wants to be energy self-reliant, they must size their system to the season of least energy generation, but lose the value of any excess energy produced during seasons when generation is greatest.

-2: NEG was sold to the utility at the avoided cost on a monthly basis

- While crediting monthly excess generation at the avoided cost creates some financial incentive for production, it presents similar problems associated with season variability and allows the utility to pocket the profits from selling NEG to other customers at the retail rate.

-1: NEG was sold to the utility at the retail rate on a monthly basis

- Close in financial terms to month-to-month banking, this situation would have the utility incur additional administrative costs associated with purchasing small amounts of electricity on a monthly basis. Currently, no state programs require utilities to purchase NEG at the retail rate on a monthly basis.

0: Excess generation was granted to the utility at the end of an annual billing cycle.

- A minimally satisfactory net metering program will allow the customer-generator to install a DG system that will provide enough electricity for on-site demand. Gifting NEG to the utility on an annual basis allows the customer to take advantage of month-to-month banking, but does not provide a mechanism to compensate customers for any generation exceeding annual on-site demand.

1: NEG was purchased by the utility at the utility's avoided cost on a yearly basis.

- This situation creates an incentive for customers to install renewable energy systems large enough to generate more energy than they consume and gives consideration to the seasonal variability of renewable energy generation.

2: NEG was purchased by the utility at the retail rate on an annual basis or carried over at the retail rate indefinitely.

- Purchasing NEG at the retail creates a larger economic incentive for customers to invest in renewable energy systems that exceed on-site demand and ensures that any profit from selling the excess generation is passed on to the renewable generator.

Total Capacity Limits - Capacity limits stunt the growth of renewable energy DG systems by artificially limiting the number of systems that are eligible for net metering benefits. We assigned numeric values to total capacity limits as such:

0: Net metering regulations prohibit total capacity from exceeding a certain percentage of peak load.

1: Net metering regulations do not include maximum capacity limits.

Additional Installations – Extraneous devices add to the cost of a renewable energy DG system, creating a financial disincentive for participation. We assigned the following values to regulations requiring additional installations:

-1: Individual utilities determine if additional installations (such as mandatory external shut-off switches) are required and whether the customer bears the cost.

0: Customers are not required to purchase or install additional devices.

Liability Insurance Requirements – Requiring additional insurance for net metered renewable energy DG systems can make the systems prohibitively expensive. We assigned the following values to liability insurance requirements:

-1: Additional liability insurance is required of all net metering participants or is otherwise left to the discretion of the utility.

0: Customers are not required to purchase additional liability insurance.

Chart 3.1: Overview of State Net Metering Programs in 2004[55]

State	Arkansas	California	Colorado*	Connecticut†	Delaware	Georgia
Grade	F	A	F	C	F	C
Rank	31	3	26	15	25	18
Number of net metering customers per million (2004)	2	1101	44	22	0	1
Change in the number of net metering customers per million: 2002-2004	0%[56]	435%	0%	0%	0%	0%
Limit on total capacity	None	0.5% of a utility's peak	None	None	None	0.2% of a utility's annual peak demand
Eligible Technology	Solar, Wind, Hydro, Biomass, Fuel Cells, Geothermal, Microturbines	Solar PV, Wind, Anaerobic Digestion, Landfill Gas, Fuel Cells	Solar, Wind, Biomass, Small Hydro, Landfill Gas, Anaerobic Digestion, Fuel Cells (Renewable)	Solar, Landfill Gas, Wind, Biomass, Fuel Cells, Small Hydro, Tidal Energy, Wave Energy, Municipal Solid Waste, Ocean Thermal	Solar, Wind, Hydro, Biomass, Geothermal	PV, Wind, Fuel Cells
System size limit / Customer class	25kW/Residential 100kW/Commercial	1MW/Commercial, Industrial, Residential	10kW / Commercial, Industrial, Residential	100 kW (renewable), 50kW (fossil)/ Residential, Commercial	25kW / Commercial, Residential	10kW / Residential, 100kW / Commercia
Treatment of Net Excess Generation (NEG)	Granted to Utility monthly	Credited at retail rate month-to-month; granted end of annual billing cycle	Credited at retail rate to next bill month-to-month	Purchased at avoided-cost at end of billing period	Varies by Utility	Credited at retail rate month-to-month; granted end of annual billing cycle
External Shutoff Switch Required	Yes	Yes[57]	No	Yes	Yes	No
Additional Insurance Required	No	No	No	Yes	Yes	No
Interconnection Standards	Yes	Yes	No	Yes	Yes	Yes

55 State net metering programs are represented as they appeared in 2004. Data from: DSIRE/IREC. 2006. www.desireusa.org , U. S. Dept. of Energy, Office of Energy Efficiency and Renewable Energy. July 12, 2004 http://www.eere.energy.gov/greenpower/pdfs/metering_0604.pdf , Union of Concerned Scientists. March 2003., Customer Data from U. S. Dept. of Energy, Energy Information Agency

56 States with fewer than 67 customers per capita are not included in the growth rate column for reasons explained above.

57 Systems greater than 1 kW

* indicates states that enacted state programs during or after 2002
† indicates amendments or additions to program during or after 2002

State	Hawaii†	Indiana*	Iowa	Kentucky†	Louisiana*	Maine
Grade	B	F	F	D	B	D
Rank	9	28	24	21	13	22
Number of net metering customers per million (2004)	118	6	6	1	0	0
Change in the number of net metering customers per million: 2002-2004	317%	0%	0%	0%	0%	0%
Limit on total capacity	0.5% of a utility's annual peak demand	0.1% of a utility's most recent peak summer load	None	0.1% of a utility's single hour peak load during the previous year	None	None
Eligible Technology	Solar, Wind, Hydro, Biomass	PV, Wind, Small Hydro	PV, Wind, Hydro, Biomass, Municipal Solid Waste	PV	PV, Wind, Hydro, Biomass, Fuel Cells (Renewable), Geothermal, Microturbines	Solar, Wind, Biomass, Geothermal, CHP, Hydro, Fuel Cells, Municipal Solid Waste, Tidal Energy
System size limit / Customer class	50kW/Commercial, Industrial, Residential	10kW/Residential, Schools	500kW / Commercial, Industrial, Residential	15 kW / All Electric Customers	100kW / Commercial, Agricultural; 25 kW / Residential	100kW / Commercial, Industrial, Residential
Treatment of Net Excess Generation (NEG)	Credited to utility at end of the month	Credited to customer's next bill indefinitely	Purchased at avoided monthly cost	Credit at retail rate to customer's next bill indefinitely	Credit at retail rate to customer's next bill indefinitely	Credited at retail rate to next bill; granted at end of annual billing cycle
External Shutoff Switch Required	Yes	Yes	No	No	Yes	No
Additional Insurance Required	No	Yes	No	No	No	No
Interconnection Standards	Yes	No	No	No[58]	Yes	No

58 Individual utilities have filed interconnection tariffs

* indicates states that enacted state programs during or after 2002
† indicates amendments or additions to program during or after 2002

State	Maryland†	Massachusetts	Minnesota	Montana	Nevada†	New Hampshire
Grade	F	F	A	A	A	A
Rank	29	23	6	2	5	7
Number of net metering customers per million (2004)	4	66	106	432	107	142
Change in the number of net metering customers per million: 2002-2004	0%	0%	231%	5955%	236%	114%
Limit on total capacity	0.2% of state's adjusted peak load in 1998	None	None	None	1% peak capacity	0.05% peak capacity
Eligible Technology	PV, Wind	Solar, Wind, Biomass, Municipal Solid Waste, CHP, Fuel Cells, Hydro	PV, Wind, Hydro, Biomass, Municipal Solid Waste, CHP	PV, Wind, Hydro	Solar, Wind, Biomass, Hydro, Geothermal	PV, Wind, Hydro
System size limit / Customer class	80kW / Commercial, Residential, Schools	60kW/Commercial, Industrial, Residential	40kW/ Commercial, Industrial, Residential	50kW / Commercial, Industrial, Residential	30 kW / Commercial, Industrial, Residential	25kW / Commercial, Industrial, Residential
Treatment of Net Excess Generation (NEG)	Granted Monthly	Purchased at avoided monthly cost	Purchase at retail rate	Credited at retail rate to next bill; granted at end of annual billing cycle	Credit at retail rate to customer's next bill indefinitely	Credited at retail rate to customer's next bill
External Shutoff Switch Required	No	No	Yes	No	No	No[59]
Additional Insurance Required	No	No	Yes	No	No	No
Interconnection Standards	Yes	No	Yes	Yes	Yes	Yes

59 Yes, for systems larger that 10 kW

* indicates states that enacted state programs during or after 2002
† indicates amendments or additions to program during or after 2002

State	New Jersey†	New Mexico	New York	North Dakota	Ohio	Oklahoma
Grade	A	C	C	F	B	F
Rank	1	17	16	27	12	34
Number of net metering customers per million (2004)	93	14	13	13	4	20
Change in the number of net metering customers per million: 2002-2004	30,141%	0%	0%	0%	0%	0%
Limit on total capacity	0.1% peak capacity or $2 million annual impact	None	0.1% of 1996 demand in (solar), 0.4% of 1996 demand (farm biogas), 0.2% of 2003 demand (wind)	None	1% of a utility's peak demand	None
Eligible Technology	Solar, Wind, Biomass, Hydro, Geothermal, Tidal Energy, Fuel Cells (Renewable), Wave Energy	Solar, Wind, Biomass, Hydro, Municipal Solid Waste, Fuel Cells, CHP, Geothermal, Microturbines	PV, Wind, Biomass	Solar, Wind, Hydro, CHP, Geothermal, Biomass, Municipal Solid Waste	Solar, Wind, Hydro, Biomass, Fuel Cells, Microturbines	Solar, Wind, Hydro, Biomass, Geothermal, Municipal Solid Waste, CHP
System size limit / Customer class	100kW / Commercial, Residential	10kW / Commercial, Industrial, Residential	10kW (solar)/ Residential, Agricultural; 400kW (biogas) 125 kW (wind)/ Agricultural; 25 kW (wind)/ Residential	100kW/ Commercial, Industrial, Residential	No Limit, 100kW (microturbines)/ Commercial, Industrial, Residential	100 kW (up to 25,000 kWh/ year) / Commercial, Industrial, Residential
Treatment of Net Excess Generation (NEG)	Credited at to next bill; purchased at avoided cost at end of annual billing cycle	Credited to next bill or purchased at avoided-cost at end of annual billing cycle	Credited to customer's next bill; purchased at avoided-cost at end of annual billing cycle.[61]	Purchase by utility at avoided-cost rate at the end of a monthly billing period	Credited at utility's unbundled-generation rate to customer's next monthly bill	Granted to utility monthly or credited to next bill at avoided-cost; utility's choice
External Shutoff Switch Required	No	Yes	Yes	Yes	No[62]	No
Additional Insurance Required	No	No[60]	No	Yes	No	No
Interconnection Standards	Yes	No	Yes	Yes	Yes	Yes

60 Public Regulation Commission may require insurance
61 Wind >10 kW credited month-to-month at avoided-cost
62 Utilities may require an external disconnect switch

State	Oklahoma	Oregon†	Pennsylvania†	Rhode Island	Texas	Utah*
Grade	F	A	F	F	F	B
Rank	34	4	33	32	30	14
Number of net metering customers per million (2004)	20	152	17	59	72	12
Change in the number of net metering customers per million: 2002-2004	0%	1019%	0%	0%	0%	0%
Limit on total capacity	None	0.05% of a utility's peak load	None	1 MW	None	0.1% of 2001 peak demand
Eligible Technology	Solar, Wind, Hydro, Biomass, Geothermal, Municipal Solid Waste, CHP	Solar, Wind, Hydro, Fuel Cells	Renewable energy including fuel cells	Solar, Wind, Hydro, Biomass, Geothermal, Fuel Cells, Municipal Solid Waste, CHP	Solar, Wind, Biomass, Hydro, Tidal, Wave, Geothermal, Fuel Cells, Microturbines	Solar, Wind, Fuel Cells, Hydro
System size limit / Customer class	100 kW (up to 25,000 kWh/ year) / Commercial, Industrial, Residential	25kW / Commercial, Industrial, Residential	10kW / All customer classes	25kW / Commercial, Industrial, Residential	50kW/Commercial, Industrial, Residential	25kW/ Commercial, Industrial, Residential
Treatment of Net Excess Generation (NEG)	Granted to utility monthly or credited to next bill at avoided-cost; utility's choice	Credited at retail rate to customer's next bill or purchased by utility at avoided-cost rate	Granted Monthly	Granted to utility monthly	Purchased by utility monthly at avoided-cost rate	Credited to next bill; granted at end of annual billing cycle
External Shutoff Switch Required	No	No	No	No	Yes	No
Additional Insurance Required	No	No	No	No	No	No
Interconnection Standards	No	Yes	No	No	Yes	Yes

* indicates states that enacted state programs during or after 2002
† indicates amendments or additions to program during or after 2002

State	Vermont†	Virginia†	Washington	Wisconsin	Wyoming
Grade	B	D	D	A	B
Rank	10	20	19	8	11
Number of net metering customers per million (2004)	226	6	28	85	47
Change in the number of net metering customers per million: 2002-2004	152%	0%	0%	127%	0%
Limit on total capacity	1% of peak demand of 1996 or recent year	0.1% of annual peak demand	0.25% of a utility's 1996 peak load	None	None
Eligible Technology	PV, Wind, Biomass, Fuel Cells	Solar, Wind, Hydro	Solar, Wind, Hydro,Biogas, Fuel Cells, CHP	Solar, Wind, Biomass, Hydro, Geothermal, CHP, Municipal Solid Waste	Solar, Wind, Biomass, Hydro,
System size limit / Customer class	150kW / Agricultural 15kW / Commercial, Residential	500 kW / Non-residential 10 kW / Residential	25kW / Commercial, Industrial, Residential	20kW / Commercial, Industrial, Residential	25kW / Commercial, Industrial, Residential
Treatment of Net Excess Generation (NEG)	Credited at retail rate to next bill; granted at end of annual billing cycle	Credited to next bill; granted at end of annual billing cycle	Credited to next bill; granted at end of annual billing cycle	Renewable energy purchased by utility at retail rate / Non-renewable at avoided-cost rate	Credited to next bill; purchased at avoided-cost rate at end of annual billing cycle
External Shutoff Switch Required	Yes	Yes	No	Yes	Yes
Additional Insurance Required	Yes	Yes	No	Yes	No
Interconnection Standards	Yes	Yes	No	Yes	Yes

* indicates states that enacted state programs during or after 2002
† indicates amendments or additions to program during or after 2002

Grading the States

We assigned a grade to each state's net metering program by ranking the state's based on their index score and then calculating a percentile based on the highest-ranked state (New Jersey) representing 100 percent (an A).

Since an index score of zero should represent a minimally satisfactory net metering program, we assigned states with index scores of 0 the grade of "D" or just passing. Our calculation roughly translates as >75th percentile = A, 55th-74th percentile = B, 40th-54th percentile = C, 30th-44th percentile = D, and <30th percentile = F. Chart 3.2 displays each state's index score, percentile, and grade.

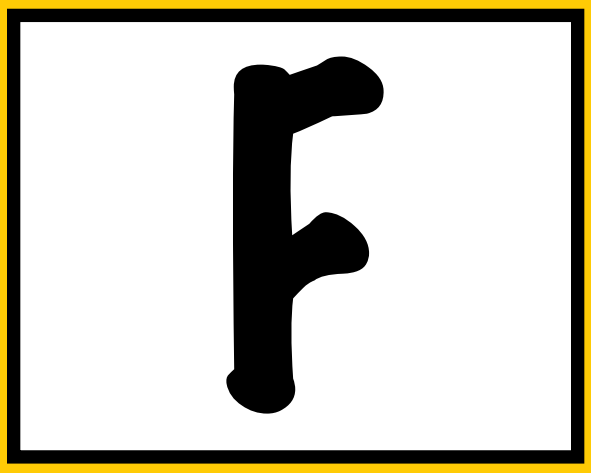
Although many of the 34 state net metering rules are similar, each has its idiosyncrasies. After we used the index system to create a way of generalizing effective versus ineffective net metering rules, we compared individual state programs with the same index score and made more specific evaluations to break ties (see Appendix B). We ranked states that had the greatest customer growth and highest overall participation higher than other states.[54]

54 Our justification for weighting certain program components as more important than others is primarily a reflection of customer participation. The primary indicator for an effective program is participation. Additional ranking factors are explained in our comparison of 'worst practices' in Arkansas and Indiana. By comparing the affect of different program components on participation rates in each state, for example, we deduced that the treatment of net excess generation had a more significant impact than total capacity limits.

Chart 3.2: Grading State Net Metering Programs

Rank	State	Grade	Percentile	Score
1	New Jersey	A	100%	305
2	Montana	A	97%	67
3	California	A	94%	15
4	Oregon	A	91%	14
5	Nevada	A	88%	7
6	Minnesota	A	82%	6
7	New Hampshire	A	82%	6
8	Wisconsin	A	79%	4
9	Hawaii	B	64%	3
10	Vermont	B	64%	3
11	Wyoming	B	64%	3
12	Ohio	B	64%	3
13	Louisiana	B	64%	3
14	Utah	B	61%	2
15	Connecticut	C	48%	1
16	New York	C	48%	1
17	New Mexico	C	48%	1
18	Georgia	C	48%	1
19	Washington	D	36%	0
20	Virginia	D	36%	0
21	Kentucky	D	36%	0
22	Maine	D	36%	0
23	Massachusetts	F	27%	-1
24	Iowa	F	27%	-1
25	Delaware	F	27%	-1
26	Colorado	F	9%	-2
27	North Dakota	F	9%	-2
28	Indiana	F	9%	-2
29	Maryland	F	9%	-2
30	Texas	F	9%	-2
31	Arkansas	F	9%	-2
32	Rhode Island	F	3%	-3
33	Pennsylvania	F	3%	-3
34	Oklahoma	F	0%	-4

Arkansas



Number of customers 2004	**3**
Change per million customers (2002- 2004)	**0%***
System size limit	**25 kW for residential systems; 100kW for commercial systems**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Granted to utility monthly**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Hydroelectric, Biomass, Fuel Cells, Geothermal Electric, Microturbines using renewable fuels**
External shut-off	**Yes**
Additional insurance	**Utility discretion**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

On April 19, 2001, Arkansas Governor Mike Huckabee signed into law a bill (HB 2325) requiring the state's electric utilities to offer net metering for solar, wind, hydroelectric, geothermal, and biomass systems. In addition, fuel cells and micro turbines are required to be fueled by renewable sources. The Arkansas Public Service Commission (APSC) approved final net-metering rules in July 2002.

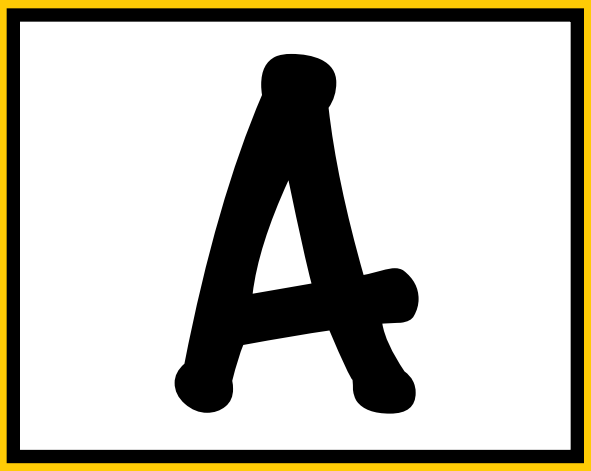
The APSC allows residential systems up to 25 kilowatts (kW) and commercial systems up to 100 kW to be eligible for net metering. There is no total capacity cap, however, APSC Order No. 02-046-R states that any net excess generation (NEG) will be credited to the utility at the end of the billing period without any compensation to the customer. Utilities are granted the discretion to charge interconnection fees and require customers to install external disconnect switches. Utilities may also require additional liability insurance up to $1 million.

Developments since 2004: In July, 2006 the APSC began its consideration of the state's net metering rules pursuant to EPAct and designated all of the state's regulated utilities as official parties to the proceedings. All other parties had to petition to intervene by August 25, 2006. Only two additional non-utility interveners (a consumer group and a renewable energy service provider) were granted permission to submit comments.

Recommendations:

- Amend official docket procedures to allow open public comment periods on Commission rulemakings
- Allow monthly banking of net excess generation, purchased annually at the retail rate
- Allow systems up to 2MW to be eligible for net metering
- Remove utility discretion to charge interconnection fees, require external shutoff switches and additional liability insurance.

California



Number of customers 2004	**13,506**
Change per million customers (2002- 2004)	**435%***
System size limit	**1 MW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited at retail rate month-to-month; granted end of annual billing cycle**
Limits on enrollment	**0.5% of a utility's peak**
Eligible technologies	**Solar PV, Wind, Anaerobic Digestion, Landfill Gas, Fuel Cells**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**All utilities (solar and wind); Investor-owned utilities (biogas and fuel cells)**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page X).

California's net metering law took effect in 1996. All utilities must permit net metering for solar, hybrid, and wind-energy systems with a capacity limit of 1 MW; investor owned-utilities must also allow net metering for biogas-electric systems and fuel cells. Significant amendments were made in 2002 under AB 2228, notably relating to biogas systems, fee structures, and system size limits for wind energy projects.

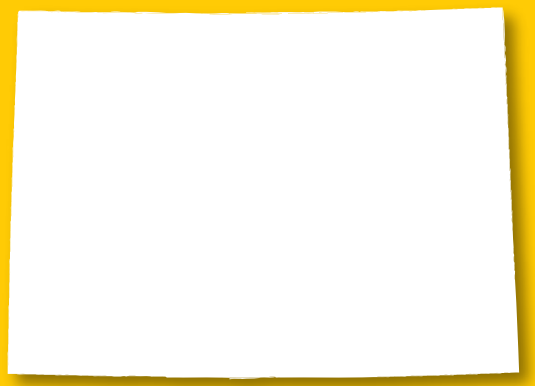
Developments since 2004: In September 2005, AB 728 further extended eligibility requirements for biogas-powered systems. Authored by Senator Kevin Murray, SB 1 was unanimously approved on August 8, 2006 by the California Senate Energy, Utilities and Communications Committee as a net metering bill which raises the cap on investor-owned utilities' load from 0.5% to 2.5%. Rep. John Campbell (R) and Senator Dianne Feinstein (D) also advocated for the new legislation. The bill supports the California Solar Initiative, which has a goal of installing 3,000 MW solar systems by 2017, and has been applauded by solar advocates as a step towards making the Solar Initiative program economically feasible for participants.[64]

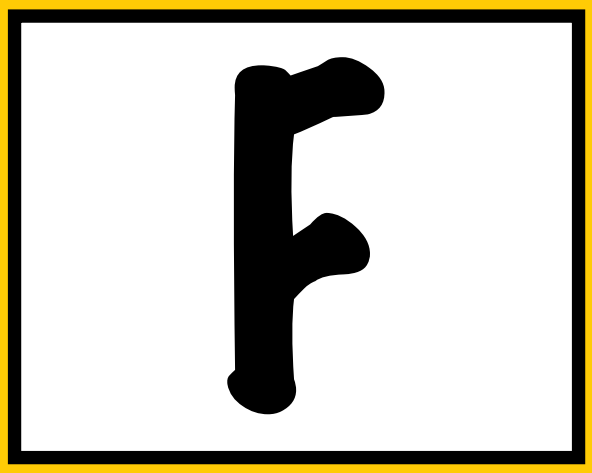
Recommendations:

- Remove limits on aggregate enrollment
- Increase system-size limit to at least 2 MW
- Remove requirements for external disconnect switch

64 Electric Power Daily, August 9, 2006.

Colorado





Number of customers 2004	**87**
Change per million customers (2002- 2004)	**0%***
System size limit	**10 kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited at retail rate to next bill month-to-month**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Biomass, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal, Municipal Solid Waste**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utility**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Because our data set was limited to publicly available data on net metering customer participation from 2002-2004, Colorado's grade and ranking reflect the lackluster net metering program put in place by the Colorado Public Utilities Commission (CPUC) prior to 2004.

Developments since 2004: In November 2004, Colorado became the first state in history to put a renewable energy portfolio (RPS) up for a vote rather than go through the state's legislature. After failing four times in the legislature, 52% of Colorado voters approved Amendment 37, requiring a 10% renewable energy generation by 2015 and establishing statewide net metering rules.

In December 2005, after extensive meetings with many renewable energy interest groups, the CPUC issued an order adopting implementation rules for Amendment 37. The CPUC now allows systems up to two megawatts (MW) in capacity to be eligible for net metering. Electricity generated at a customer's site can be applied toward meeting the utility's renewable generation requirement. Colorado's RPS requires that 4% of the requirement be met with solar energy, half of which must come from customer-generators.

Net excess generation (NEG) is credited to the following month's billing cycle. At the end of an annual billing cycle, the utility must reimburse the customer for the excess generation at the utility's average hourly incremental cost for the prior 12-month period. Systems over 10 kilowatts (kW) in capacity require a second meter to measure output that counts toward renewable-energy credits (RECs). Customer-generators retain ownership of all renewable-energy credits (RECs) associated with the generation of electricity.

Applying NNEC's metric to the program adopted in 2005, Colorado would rank in the top 5 statewide net metering programs and receive an A rating!

Connecticut

C

Number of customers 2004	**31**
Change per million customers (2002- 2004)	**0%***
System size limit	**100 kW (renewable), 50kW (fossil)**
Eligible classes	**Commercial, Residential, Multi-Family Residential**
Net excess generation	**Purchased at avoided-cost at end of billing period**
Limits on enrollment	**None**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Fuel Cells, Municipal Solid Waste, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**Investor-owned utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Connecticut first implemented net metering legislation in 1990, under the DPUC (Connecticut Department of Public Utility Control) Ruling 159. With this ruling, utilities had to purchase NEG from qualifying facilities with a maximum capacity of 50 kW non-renewable energy systems, and 100 kW for renewable-energy systems. Following the electric restructuring bill of 1998, all investor-owned utilities were required to offer net metering to customer-generators using renewable energy sources, including solar, wind, hydropower, landfill gas, fuel cells, and/or sustainable biomass.[65] In June 2003, amendments were enacted to include wave and tidal energy sources and decreased monetary restrictions for units less than 10kw.[66] Though distribution companies are only required to offer net metering to residential customers, Connecticut Light & Power Company (CL&P) and United Illuminating Company (UI) provide net metering to commercial entities that meet certain conditions.[67]

Developments since 2004: In May 2006, renewable energy proponents tried to pass SB 211, which would have increased kilowatt limits and the carryover billing period,[68] however the bill was stalled in the Senate.[69]

Recommendations:

- Include industrial as part of eligible customer classes
- Increase system-size limits to at least 2MW
- Amend treatment of net excess generation to be purchased at retail rate at end of annual billing cycle
- Exclude any external shutoff switch or additional insurance requirements

65 "Connecticut Incentives for Renewables and Efficiency." DSIRE:Database of State Incentives for Renewable Energy. http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CT01R&state=CT&CurrentPageID=1&RE=1&EE=1.

66 Issue: Net Metering. State Environmental Resource Center. http://www.serconline.org/netmetering/stateactivity.html

67 Ibid

68 Filler, Stephen. 2006. Net Metering Bill in CT Needs Help. Green Counsel Blog: State and Local Government. 5 May 2006. http://nylawline.typepad.com/greencounsel/state_and_local_government/index.html

69 Substitute Bill No. 211. http://www.cga.ct.gov/asp/cgabillstatus/cgabillstatus.asp?selBillType=Bill&bill_num=211&which_year=2006&SUBMIT.x=11&SUBMIT.y=9

Delaware

D

Number of customers 2004	**0**
Change per million customers (2002- 2004)	**0%***
System size limit	**25kW**
Eligible classes	**Commercial, Residential**
Net excess generation	**Varies by Utility**
Limits on enrollment	**None**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Delaware adopted net metering legislation in 1999 under HB 10, the Electrical Restructuring Act. The act required that Conectiv (now Delmarva) and Delaware Electric Cooperative (DEC) offer net metering to residential and commercial customers with systems up to 25kW, with no limit on capacity for renewable energy.[70] Technical standards and treatment of net excess generation vary between these two utilities. However, the state's nine municipal utilities, which are not included in the act, have not adopted any net metering policies and consist of 30% of the Delaware consumer market. [71]

Recommendations:

- Include industrial in eligible customer classes
- Increase system size limit to at least 2MW
- Create a standard treatment of net excess generation in the state, to be credited at retail rate and carried over indefinitely
- Remove external shutoff switch and additional insurance requirements

70 "Delaware Incentives for Renewables and Efficiency" DSIRE:Database of State Incentives for Renewable Energy.<http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=DE02R&state=DE&CurrentPageID=1&RE=1&EE=1

71 Burton, Sandra A.H., Gallagher, Brian P., "Market Barriers to Grid-Interconnected Photovoltaics: A Survey of Delaware's Municipal Electric Utilities." Green Plains Energy, Inc. 12 Dec. 2003. http://www.greenplainsenergy.com/documents/DEMEC%20PV%20Barriers%20Study-12-12-03.pdf

Georgia

C

Number of customers 2004	**2**
Change per million customers (2002- 2004)	**0%***
System size limit	**10kW/ Residential, 100kW/ Commerical**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited at retail rate month-to-month; granted end of annual billing cycle**
Limits on enrollment	**0.2% of a utility's annual peak demand**
Eligible technologies	**Photovoltaics, Wind, Fuel Cells**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Georgia's net metering rules went into effect under SB 93, the Cogeneration and Distributed Generation Act of 2001, which was a restructuring of Georgia's 1979 cogeneration law. The bill took about a month to move from a favorable review in Senate committee to the Governor.[72]

Georgia's legislation combines net metering with green pricing. The nonprofit Georgians for Clean Energy (GCE) worked closely with Georgia Power - a subsidiary of Southern Company - in the development of the law. Also supporting the law as it moved through the legislature were the Georgia Electric Membership Corporation, the Municipal Electric Authority of Georgia, and various environmental and consumer groups. However, Georgia Power and the state's other utilities have not yet established their green pricing program, and the green pricing tariffs still need to be filed.

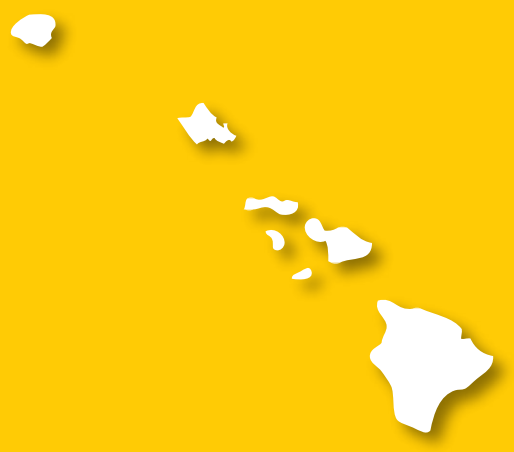
Power flows to and from the home are separately measured. Customers are given a choice of metering arrangements: the customer's system can be interconnected on the customer side of the meter with a bi-directional meter to measure flows in each direction, or customers can send all of the power from their system directly to the grid.

Recommendations:

- Increase system-size limits to at least 2 MW
- Remove aggregate limit on enrollment
- Reimburse NEG to customer-generator at retail rate at end of 12-month period

72 Georgia General Assembly. 2001. SB 93 - Georgia Cogeneration and Net Metering Act; program for operators of solar electrical cogeneration. http://www.legis.ga.gov/legis/2001_02/sum/sb93.htm

Hawaii



B

Number of customers 2004	**46**
Change per million customers (2002- 2004)	**317%***
System size limit	**50kW**
Eligible classes	**Commercial, Residential, Local Government, State Government, Fed. Government**
Net excess generation	**Credited to next month's bill; granted to utility at end of 12 month period**
Limits on enrollment	**0.5% of a utility's annual peak demand**
Eligible technologies	**Solar Photovoltaics, Wind, Biomass, Hydroelectric**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

As an island state without many energy resources, Hawaii is in a position that requires innovative energy solutions. Hawaiian officials have looked into a variety of energy options including renewable and waste-to-energy technologies. Even with those options, the state still relies on oil for nearly 80% of its electricity. Realizing this one-sided production, Rep. Hermina Morita, chairperson of the House Energy and Environmental Protection Committee, helped lead the way towards more renewable energy and energy efficiency.

In 2001, she helped House Bill 173 pass through the legislature. This bill created a state renewable portfolio standard and included net energy metering provisions to help promote distributed renewable energy systems.[73] The net metering provisions were revised in 2004 by HB 2048, expanding the system capacity limit from 10 kW to 50 kW.

Developments since 2004: In 2005, Hawaii's net metering law was again amended by HB 606, eliminating a provision allowing utilities to impose additional requirements on net-metered systems. In the same year, SB 1003 allowed the PUC to increase limits imposed in the 2001 rules, as well as permitted NEG to be carried over to subsequent bills.[74]

Recommendations:

- Increase system-size limits to at least 2 MW
- Remove limits on aggregate enrollment
- Remove requirements for external disconnect switch
- Credit all NEG at retail rate

73 Leone, Diana. June 10, 2001. Plugged in: Hawaii's quest for power boosts interest in renewable resources. Honolulu Star-Bulletin. http://starbulletin.com/2001/06/10/news/story3.html Accessed on September 7, 2006.

74 DSIRE Hawaii Incentives for Renewable Energy, http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=HI04R&state=HI&CurrentPageID=1&RE=1&EE=0. Accessed 10-11-06.

Indiana

F

Number of customers 2004	**16**
Change per million customers (2002- 2004)	**0%***
System size limit	**10kW**
Eligible classes	**Residential, Schools**
Net excess generation	**Credited to customer's next bill indefinitely**
Limits on enrollment	**0.1% of a utility's most recent peak summer load**
Eligible technologies	**Solar Photovoltaics, Wind, Small Hydroelectric**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Despite opposition from several utilities, in 2004 the Indiana House passed HB1212 which would have required Indiana utilities to make renewable energy systems up to 2MW eligible for net metering. However, when the bill reached the Indiana Senate, Senator Jim Merrit (R-Indianapolis), Chair of the Senate Utility and Regulatory Affairs Committee, refused to give it a hearing. At the urging of supportive House members, the Indiana Utility Regulatory Commission (IURC) announced that it would initiate rulemaking in the summer of 2004.

By September 2004, the IURC adopted net metering rules allowing residencies and k-12 schools to interconnect systems up to 10kW. Under IURC rules, net excess generation (NEG) is credited toward the customer's next billing cycle. The rules do not address when this banking expires and do not provide for the purchase of NEG.

Recommendations:

- Increase eligible system sizes to 2MW
- Expand eligible customer classes to include commercial, industrial and agricultural generators
- Allow the annual purchase of net excess generation at the retail rate
- Remove limits on statewide enrollment

Iowa

C

Number of customers 2004	**8**
Change per million customers (2002- 2004)	**0%***
System size limit	**500kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Purchased at avoided cost monthly**
Limits on enrollment	**None**
Eligible technologies	**Solar Photovoltaics, Wind, Biomass, Hydroelectric, Municipal Solid Waste**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**Investor-owned utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page18).

The Iowa Utilities Board adopted net metering guidelines in 1983.[75]

Customer-generators with alternative energy generation systems are permitted to net meter with investor-owned utilities, with no cap on system size or total enrollment. However, the Iowa Utilities Board granted waiver TF-01-293 to MidAmerican Energy in 2002, limiting individual net-metered systems to 500 kW. Interstate Power and Light has a similar waiver arrangement. Iowa's net-metering rules require NEG to be purchased at the utility's avoided-cost rate; however, MidAmerican Energy and Interstate Power and Light instead credit NEG for use in future months, as part of their waivers arrangement. [76]

Though the Iowa Utilities Board issued a draft order in December 1997 to eliminate net metering for residential renewable energy systems, public support of net metering resulted in the order being withdrawn.[77] Furthermore, despite utilities' efforts to overturn net metering and a ruling to this effect from the Iowa Supreme Court , FERC ultimately ruled in favor of net metering in Iowa.[78]

Recommendations:

- Credit NEG at retail rate annually
- Increase system size limit to 2MW for all customer classes
- Set interconnection standards as recommended by FERC and IREC

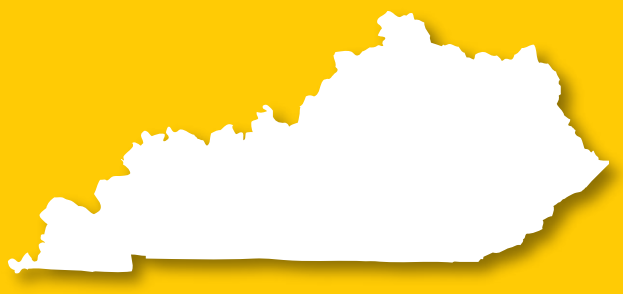
75 DSIRE. 2006. Database of State Incentives for Renewable Energy

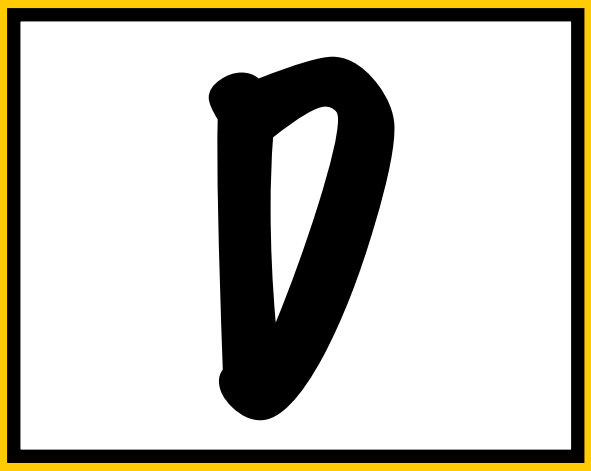
76 Cook, Chris. 2004. State Supreme Court Rules in Favor of Small Generator, Orders Net Metering. IREC Connecting to the Grid. August 9. http://irecusa.org/articles/static/1/1092076572_987096450.html

77 http://www.nrel.gov/analysis/sren/sren20.html

78 Pearce, John. 2001. Renewable Energy Development Under Iowa's Alternate Energy Production (AEP) Statute. http://www.econ.iastate.edu/outreach/agriculture/programs/2001_Renewable_Energy_Symposium/Pearce.pdf

Kentucky





Number of customers 2004	**2**
Change per million customers (2002- 2004)	**0%***
System size limit	**15kW**
Eligible classes	**Commercial, Residential, Nonprofit, Schools, Local Government, State Government, Agricultural, Institutional**
Net excess generation	**Credit at retail rate to customer's next bill indefinitely**
Limits on enrollment	**0.1% of a supplier's single-hour peak load during the previous year**
Eligible technologies	**Solar Photovoltaic**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**Investor-owned utilities, rural cooperatives**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Kentucky's net metering regulations began in March 2002 when the Kentucky Public Service Commission began a 3 year pilot program requiring Louisville Gas and Electric and Kentucky Utilities Company to offer net metering to the first 25 customers. They then measured the costs and benefits to those 25 customers.[79]

Kentucky's current net metering rules were passed on April 22, 2004 by Governor Ernie Fletcher under SB 247. Interconnection standards were set in October 2004.[80]

Recommendations:

- Increase system size limit to at least 2 MW
- Do not limit overall enrollment capacity
- Offer all renewable technologies
- Allow all customer classes to participate

79 Issue: Net Metering. State Environmental Resource Center. http://www.serconline.org/netmetering/stateactivity.html

80 Kalland, Stephen. 2004. KENTUCKY - Statewide Net Metering Legislation Enacted; IC Standards to Be Developed. IREC. May 8. http://www.irecusa.org/articles/static/1/1084067685_987096450.html

Louisiana

B

Number of customers 2004	**0**
Change per million customers (2002- 2004)	**0%***
System size limit	**100kW/ Commercial, Agricultural; 25kW/ Residential**
Eligible classes	**Commercial, Residential, Agricultural**
Net excess generation	**Credit at retail rate to customer's next bill indefinitely**
Limits on enrollment	**None**
Eligible technologies	**Solar Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells (Renewable Fuels), Microturbines**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

The Louisiana Renewable Energy Development Act (HB 789)[81] was introduced in March 2003 by Rep. William Daniel (D-District 68) after collaboration with Jeff Shaw, director of the Louisiana Solar Energy Society. It was signed into law on June 27, 2003 by Governor M.J. "Mike" Foster.

Though Rep. Daniel's original proposal was considered a strong net metering bill, it received opposition from Entergy Corp., a local investor-owned utility. After two months of negotiations, amendments were agreed upon which significantly weakened the bill, including removal of specific language designed to protect customer-generators during the interconnection process. The bill can now only cursorily be defined as a net metering provision, due to problems posed by ambiguous metering arrangements, fee structures, references to electricity "sales," and the bill's treatment of net excess generation.[82]

Developments since 2004: In 2005, the Louisiana Service Commission set regulations for net metering and interconnection similar to those of Arkansas. These standards required that net metering be offered by public owned utilities and rural electricity cooperatives. The renewable energy technologies included were solar, wind, hydroelectric, geothermal, and biomass for residential customers up to 25kW and commercial customers up to 100kW. The utilities are also required to pay for a two way meter, but customers are expected to pay an installation charge. Net excess generation is credited indefinitely at the avoided-cost rate. [83]

Recommendations:

- Include industrial customer classes as eligible and increase system size limit to 2MW
- Credit NEG at retail rate
- Remove external disconnect requirement

81 House Bill 789 http://www.lses.org/hb789.pdf

82 Kalland, Stephen and Rusty Haynes. 2003. The IREC Interconnection Newsletter, July 2003. NCSU Solar Center, Volume 6, Number 7. http://www.irecusa.org/articles/static/1/1057546474_987096476.html

83 DSIRE. 2006. Louisiana. www.dsireusa.org

Maine

D

Number of customers 2004	**0**
Change per million customers (2002- 2004)	**0%***
System size limit	**100kW**
Eligible classes	**Commercial, Residential, Agricultural**
Net excess generation	**Credit at retail rate to customer's next bill indefinitely**
Limits on enrollment	**None**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Municipal Solid Waste, CHP/Cogeneration, Tidal Energy**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Net-metering began in Maine in 1987 for cogeneration and small producing facilities with a maximum capacity of 100kW.[84] In December 1998, legislators passed an electrical restructuring bill that allowed the Maine Public Utilities Commission to amend net metering rules. The PUC's regulations did not go into effect until March 2000 and allowed excess electricity to go back on the grid for renewable energy under similar regulations as the 1987 standards.[85]

Recommendations:

- Increase system size for commercial, industrial and residential to 2MW
- Change treatment of net excess generation to carry credited retail rate over indefinitely
- Include interconnection standards that follow FERC or IREC standards
- Promote program to increase participation rates

1 DSIRE. 2006. www.dsireusa.org

2 Issue: Net Metering." State Environmental Resource Center. http://www.serconline.org/netmetering/stateactivity.html

Maryland

F

Number of customers 2004	**9**
Change per million customers (2002- 2004)	**0%***
System size limit	**80kW**
Eligible classes	**Commercial, Residential, Schools, Local, State, and Federal Government**
Net excess generation	**Granted monthly**
Limits on enrollment	**0.2% of state's adjusted peak load in 1998**
Eligible technologies	**Photovoltaics, Wind**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Beginning in 1997, Maryland first issued net metering legislation allowing up to 80 kW for residential customers and schools. The Maryland Energy Administration conducted a study of the economic impacts of net metering on utility companies after the program was first implemented and found them inconsequential.[86]

Developments since 2004: Since 1997, Maryland has expanded net metering regulations in May 2004, April 2005 and most recently in April 2006 under SB 167. In 2004, Governor Robert L. Ehrlich signed HB 1269 and expanded net metering to wind energy less than 80kW. Additionally, the law included private businesses and nonprofits under the residential eligibility class and schools under the institutional class.[87] Changes made in 2005 included biomass eligibility, an increase from 80kW to 200kW, and capacity limit to 500kW. SB 167 in 2006 made net metering eligible to solar, wind and biomass, allowed net excess generation to carry over annually and required additional dual meters in some cases. These provisions encouraged the Public Service Commission to develop a credit formula.[88]

Recommendations:

- Remove the limit on total capacity
- Amend eligible customer classes to include industrial
- Increase system size for commercial, industrial and residential to 2MW
- Amend treatment of net excess generation to be purchased at retail rate annually
- Remove requirements for additional dual meter

86 Cook, Christopher and Cross, Jonathan. 1999. A Case Study: The Economic Cost of Net Metering Maryland: Who Bears the Economic Burden? Maryland Energy Administration. http://www.e3energy.com/net-meter.pdf

87 State Renewable Energy Network, National Renewable Energy Lab. 2004. Maryland. State Renewable Energy News. Vol. 13. No. 2. http://www.nrel.gov/analysis/sren/sren38.html

88 DSIRE. 2006. Maryland. www.dsireusa.org

Massachusetts

F

Number of customers 2004	**170**
Change per million customers (2002- 2004)	**0%***
System size limit	**60kW**
Eligible classes	**Commercial, Residential, Industrial**
Net excess generation	**Credited to next month's bill at average market rate**
Limits on enrollment	**None**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Fuel Cells, Municipal Solid Waste, CHP/Cogeneration**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**Investor-owned utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Massachusetts currently has no state net metering legislation. The Department of Public Utilities allocated standards in 1982 through 220 Code of Massachusetts Regulation, Section 8.04(2)(C). Initially, renewable energy-based and combined-heat-and-power systems with a generating capacity limit of 30 kW were eligible for net metering; NEG was purchased at the avoided-cost rate.

In 1997, the Department of Telecommunications and Energy issued net metering amendments through 220 Code of Massachusetts Regulation, Section 11.04(7)(C). Changes included an increased system capacity from 30kW to 60kW, as well as allowing NEG to be credited to the customer generator's next bill at the average monthly market rate. Investor-owned utilities are required to offer net metering and municipal utilities may do so voluntarily.

The primary purpose of net metering regulations in Massachusetts was to increase the diversity of resources in the area and promote small power production facilities. It was not meant as part of a larger renewable energy initiative.[89]

Developments since 2004:
In 2004, the Massachusetts Department of Telecommunications and Energy (DTE) began interim interconnection standards through the Distributed Generation Collaborative. These standards expedite the process of connecting distributed systems to the grid and are under a two-year performance evaluation.

Recommendations:
- **Increase system size limit for eligible classes to 2MW**
- **Amend treatment of NEG to be purchased at retail rate annually**

89 Massachusetts Net Metering Program. No date. State Environmental Resource Center. http://www.serconline.org/netmetering/stateactivity.html

Minnesota

Number of customers 2004	**233**
Change per million customers (2002- 2004)	**231%***
System size limit	**40kW**
Eligible classes	**Commercial, Residential, Industrial**
Net excess generation	**Purchased at retail rate minus fixed costs**
Limits on enrollment	**None**
Eligible technologies	**Photovoltaics, Wind, Biomass, Hydroelectric, Municipal Solid Waste, CHP/Cogeneration**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

In 1983, Minnesota became the first state to adopt a net metering program by legislative statute. Minnesota's law applies to all investor-owned utilities, municipalities and rural electric cooperatives. Qualifying residential commercial and industrial facilities up to 40 kilowatts (kW) in capacity are eligible and there is no enrollment or total capacity cap.

Regulated utilities must purchase net excess generation (NEG) at the utility's average retail rate, which equals the total annual revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour (kWh) sales. Wisconsin and Minnesota are the only states that require NEG be purchased at the modified retail rate.

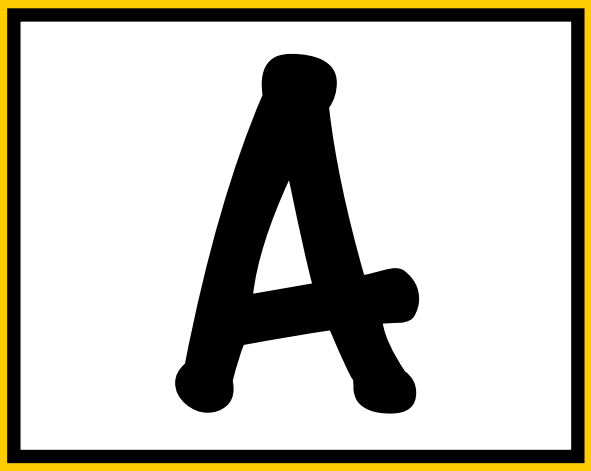
Minnesota has adopted a state renewable portfolio standard (RPS) requiring utilities to use renewable energy to meet 10% of their retail electricity sales by 2015. Customer-generators retain ownership of all the renewable-energy credits (RECs) associated with renewable generation used to meet their on-site demand. Utilities purchase any RECs that adhere to NEG purchased from customer-generators.

Minnesota also offers progressive tax incentives for renewable energy generation, production incentives and sales tax exemption for wind energy, and a rebate program for grid-connected solar electric systems. On May 25, 2005, Governor Pawlenty signed into law the Omnibus Energy Bill of 2005 which established a tariff of up to 2.7 cents per kWh for community-based wind energy production.

Recommendations:

- Raise limits on eligible system sizes to 2MW
- Delete requirements for external shut-off switches and additional liability insurance

Montana



Number of customers 2004	**186**
Change per million customers (2002- 2004)	**5955%***
System size limit	**50kW**
Eligible classes	**Commercial, Residential, Industrial**
Net excess generation	**Credited at retail rate to next bill; granted at end of annual billing cycle**
Limits on enrollment	**None**
Eligible technologies	**Photovoltaics, Wind, Hydroelectric**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

Montana's net-metering legislation was sponsored by Senator Jon Ellingson (D-Missoula) and supported by organizations such as the Renewable Northwest Project, National Resource Defense Council and the Montana Environmental Information Center.[90] When SB 409 passed unanimously in the Senate and in the House by 96-3, renewable energy advocates considered it one of the most progressive programs in the nation.[91] The bill applies to NorthWestern Energy, one of the largest providers in the region, and remains voluntary for rural cooperatives and non-investor owned utilities.[92]

Recommendations:

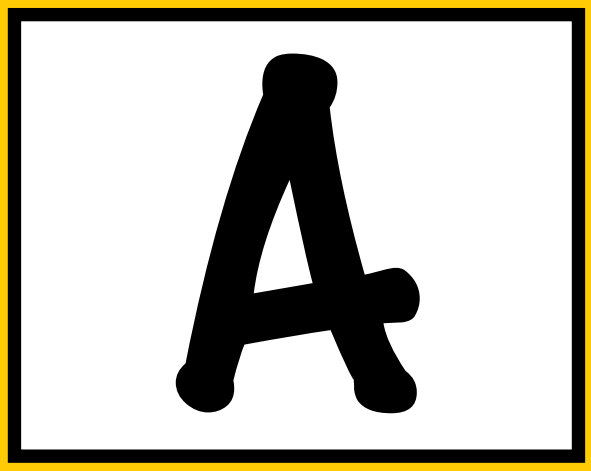
- Include all types of renewable energy in eligibility
- Increase system size limit for eligible classes to 2MW

90 Becker-Dippmann, Angela. 1999. Montana Energy Laws: Net Metering Becomes Law in Montana. Pacific Northwest Energy Conservation and Renewable Energy Newsletter. April 30. http://www.newsdata.com/enernet/conweb/conweb40.html

91 Lawmakers Honored with Prestigious Eagle Award. The Energy Activist. Winter 1999. http://www.nwenergy.org/publications/activist/99_winter/99_winter_5.html

92 Programs Through Utilities. 2005. Montana Department of Environmental Quality. http://www.deq.state.mt.us/Energy/Renewable/TaxIncentRenew.asp

Nevada



Number of customers 2004	**100**
Change per million customers (2002- 2004)	**236%***
System size limit	**30kW**
Eligible classes	**Commercial, Residential, Industrial**
Net excess generation	**Credited at retail rate to customer's next bill indefinitely**
Limits on enrollment	**1% peak capacity**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**Investor-owned utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

In 1997, Nevada enacted net metering legislation allowing solar and wind systems with a maximum capacity of 10 kW. Legislators revised regulations in 2001 under AB 661 and removed limits on electricity amounts a utility can receive. In 2003 AB 429 increased the system capacity from 10kW to 30kW and included hydropower as an eligible source.[93]

Developments since 2004: Nevada legislators amended net metering in 2005 by increasing system capacity to150kW for all classes under AB 236. [94]

Recommendations:
- Remove limits on total capacity
- Include all types of renewable energy technologies
- Increase system size limit to 2MW

93 "Nevada Incentives for Renewables and Efficiency" DSIRE:Database of State Incentives for Renewable Energy. http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NV04R&state=NV&CurrentPageID=1&RE=1&EE=1

94 "Nevada Incentives for Renewables and Efficiency" DSIRE:Database of State Incentives for Renewable Energy. http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NV04R&state=NV&CurrentPageID=1&RE=1&EE=1

New Hampshire

A

Number of customers 2004	**81**
Change per million customers (2002- 2004)	**114%***
System size limit	**30kW**
Eligible classes	**Commercial, Residential, Industrial**
Net excess generation	**Credited at retail rate to customer's next bill**
Limits on enrollment	**0.05% peak capacity**
Eligible technologies	**Photovoltaics, Wind, Hydroelectric**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

New Hampshire passed net metering legislation under HB 485 in June of 1998. However, the law required that the state Public Utilities Commission make "reasonable interconnection requirements for safety and power quality". This commission included the state's largest utility company, Public Service of New Hampshire, the New Hampshire Office of Energy and Planning, and representatives from the inverter industry.[95] The legislation specified no date for the implementation and federal litigation from the PUC and PSNH stalled completion.[96] Rules for net metering and interconnection were not set until 2001.

Recommendations:

- Remove limits on total capacity
- Include all types of renewable energy technologies
- Increase system size limit to 2MW
- Carry over net excess generation indefinitely

95 Larsen, Chris. 1998. From the States: IREC's Interconnection News. IREC. December, 1998. Vol. 1 No. 2 http://www.irecusa.org/articles/static/1/binaries/con9812.pdf

96 Renewable Energy 2000: Issues and Trends. Energy Information Administration, U.S. Department of Energy. Feb. 2001. p. 102 http://tonto.eia.doe.gov/FTPROOT/renewables/06282000.pdf

New Jersey

A

Number of customers 2004	**307**
Change per million customers (2002- 2004)	**30,141%***
System size limit	**100kW**
Eligible classes	**Commercial, Residential**
Net excess generation	**Credited at retail rate to customer's next bill; purchased at avoided-cost at end of annual billing cycle**
Limits on enrollment	**0.1% peak capacity or $2 million annual impact**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Anaerobic Digestion, Tidal Energy, Wave Energy, Fuel Cells (Renewable Fuels)**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

New Jersey established its net-metering program in 1999. This program capped net-metering system capacity at 0.1% of a utility's peak demand or at an annual financial impact to the utility of $2 million. It also limited eligible system sizes to 100kW and eligible customer classes to commercial and residential generators. However, the program provided for monthly banking of net excess generation (NEG) and required utilities to purchase NEG at avoided cost a the end of the annual billing cycle.

In March 2001, the New Jersey Board of Public Utilities (BPU) approved funding for renewable-energy programs, including a rebate program for renewable generation at homes, businesses, institutions and non-profit facilities. New Jersey also offers a full exemption from the state's 6% sales tax for all solar and wind-energy equipment. This exemption is available to all taxpayers.

New Jersey's status as the most effective state program is largely based on satisfactory components of the original program and the rapid growth in participating customers from 2002-2004.

In September 2004, with the strong support of then-Governor McGreevey, the New Jersey Board of Public Utilities (BPU) expanded the state's program to include solar technologies, wind, fuel cells, geothermal technologies, wave or tidal energy, methane gas from landfills and biomass. In addition, the new rules increased the maximum capacity of these systems from 100 kilowatts (kW) to 2 megawatts (MW) and removed the limitation on total enrollment.

New Jersey allows renewable energy credits (RECs) from customer-generators to apply toward the stringent requirements of the state's renewable portfolio standard (22.5% renewable by 2021) only if they are generated from systems that are eligible for net metering.

New Mexico

C

Number of customers 2004	**11**
Change per million customers (2002- 2004)	**0%***
System size limit	**10kW/ Commercial, Industrial, Residential**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited to next bill or purchased at avoided-cost at end of annual billing cycle**
Limits on enrollment	**None**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Municipal Solid Waste, CHP/Cogeneration, Microturbines**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**Investor-owned utilities and cooperatives**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

In 1999, the New Mexico Public Regulation Commission (PRC) required all utilities to offer net metering to small power producers with systems up to 10 kilowatts (kW) in capacity. Municipal utilities, which are not regulated by the PRC, are exempt. There is no statewide cap on the number of systems eligible for net metering.

For net excess generation (NEG), the utility must either credit the customer for the net kilowatt-hours of energy supplied to the utility or pay the customer for the net energy supplied to the utility at the avoided cost. Monthly banking of NEG is allowed. If a customer with credits exits the system, the utility must pay the customer for any unused credits at the utility's avoided cost rate. Customer-generators retain ownership of all renewable-energy credits (RECs) associated with the generation of electricity.

Developments since 2004: In 2005, Governor Bill Richardson proposed expanding the state's net metering program to increase system size limits to 100kW, but cap total capacity at 1% of utilities' aggregate peak load. The New Mexico Senate amended the bill to include rural cooperatives, added several other requirements and attached a renewable portfolio standard. Governor Richardson pocket vetoed the final version of the legislation.

In a status report issued in October 2006, NMPRC staff recommended that the Commission change the state's net metering program to increase system size limits to 100kW, but give utilities the discretion to charge customer-generators for additional equipment and liability insurance.

Recommendations:

- Increase system size limit for commercial and industrial classes up to 2MW
- Remove the requirement for an additional external shut-off switch
- Reject PRC staff recommendations giving utilities discretion to charge additional interconnection fees and require additional liability insurance for systems larger than 50kW

New York

C

Number of customers 2004	**87**
Change per million customers (2002- 2004)	**0%***
System size limit	**10kW (solar)/ Residential, Agricultural; 400kW (biogas) 125 kW (wind) / Agricultural; 25kW (wind)/ Residential**
Eligible classes	**Residential, Agricultural**
Net excess generation	**Credited to customer's next bill; purchased at avoided-cost at end of annual billing cycle**
Limits on enrollment	**0.1% peak capacity or $2 million annual impact**
Eligible technologies	**Photovoltaics, Wind, Biomass**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

The New York State legislature gave net metering its first push in the mid-nineties, creating legislation applicable only to residential photovoltaic systems with a maximum capacity of 10kW. The bill's language was similar to California's, with a few notable exceptions prohibiting extraneous insurance, fees, or controls.[97] However, Governor Pataki vetoed the bill citing "grave concerns relating to safety standards and the exposure of citizens and utility workers to serious or fatal injury," Utilities that opposed the bill raised these same safety issues.[98]

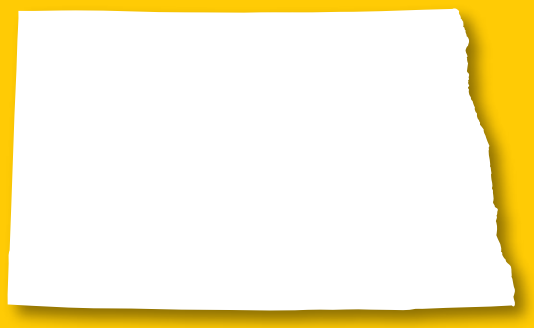
When the governor vetoed the bill, he made a commitment to institute incentives for solar energy. As a result, he proposed legislation that created a residential solar tax credit and net metering for solar systems.[99] The "Solar Choice Act of 1997" passed through the state legislature and was signed into law.[100] Developments in net metering legislation occurred in 2002, when SB 6592 made agricultural biogas systems eligible for net metering; in 2004, SB 4890-E (of 2003) further increased the scope of net metering legislation to permit residential wind turbines up to 25 kW and farm-based wind turbines up to 125 kW.

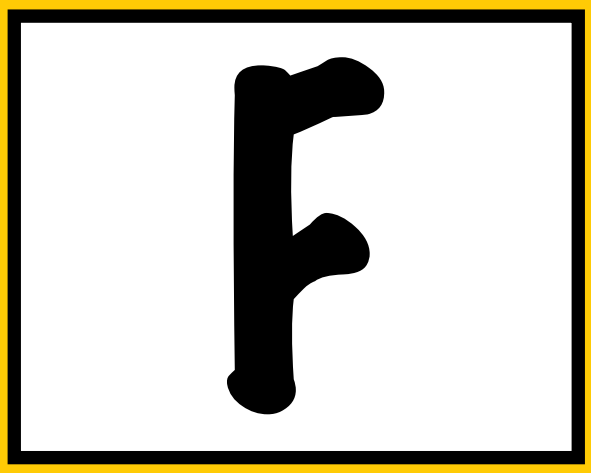
Recommendations:

- Increase system-size limits to at least 2 MW
- Purchase all NEG at retail rate
- Remove limits on aggregate enrollment
- Remove requirement for external disconnect switch

97 State Renewable Energy News. National Renewable Energy Laboratory. Summer 1996. Vol. 5. No. 2. http://www.nrel.gov/analysis/sren/sren14.html
98 State Renewable Energy News. National Renewable Energy Laboratory. Fall 1996. Vol. 5. No. 3. http://www.nrel.gov/analysis/sren/sren15.html
99 State Renewable Energy News. National Renewable Energy Laboratory. Summer 1997. Vol. 6. No. 2. http://www.nrel.gov/analysis/sren/sren17.html
100 State Renewable Energy News. National Renewable Energy Laboratory. Winter 1997. Vol. 6. No. 3. http://www.nrel.gov/analysis/sren/sren18.html

North Dakota





Number of customers 2004	**4**
Change per million customers (2002- 2004)	**0%***
System size limit	**100 kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Purchased by the utility at the avoided cost monthly**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Hydroelectric, Biomass, Geothermal, CHP, Municipal Solid Waste**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**Investor operated utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

In January 1991, the North Dakota Public Service Commission passed its net metering ruling, ND Administrative Code 69-09-07-09. The ruling established net energy billing and required that investor-owned utilities pay for power purchased from qualified facilities. However, the North Dakota Legislative Council's Committee on Administrative Rules objected to the PSC ruling, based on the fact that 1991 SB 2463, which would have required net metering for sales involving investor-owned utilities and rural cooperatives, failed to pass the Senate on a vote of 6 to 43. As a result, rural electric cooperative members are not subject to net metering legislation in North Dakota, and net metering is provided only by the three investor-owned utilities under the PSC.

North Dakota's net-metering rules apply both to renewable-energy generators and combined-heat-and-power systems up to 100 kW in capacity. There is no statewide limit on the total capacity of all net-metered systems. At the end of a monthly billing period, the utility must purchase any NEG at the avoided-cost rate.

Recommendations:

- Increase system size limit to at least 2 MW
- Include rural electric cooperative members under net metering ruling
- Allow banking and carryover of NEG month-to-month

Ohio

B

Number of customers 2004	**18**
Change per million customers (2002- 2004)	**0%***
System size limit	**No limit for renewable energy; 100 kW for micro turbines**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited to the next bill at the unbundled-generation rate**
Limits on enrollment	**1% of a utility's peak demand**
Eligible technologies	**Solar, Wind, Biogas, Hydroelectric, Fuel Cells, CHP/Cogeneration**
External shut-off	**No (if system is smaller than 10 kW)**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Ohio's net metering law took effect in 1999 as part of electric-utility restructuring legislation, requiring investor-owned utilities to provide net metering to customers using wind, solar, biomass, landfill gas, hydropower, fuel cells or micro turbines for electricity generation. Systems must explicitly be designed to offset part or all of the customer-generator's electricity demand, and there is no cap on system size, except for micro turbines, which are limited to 100kW. Each utility is required offer net metering until total generating capacity reaches 1% of the utility's aggregate customer peak demand in Ohio.

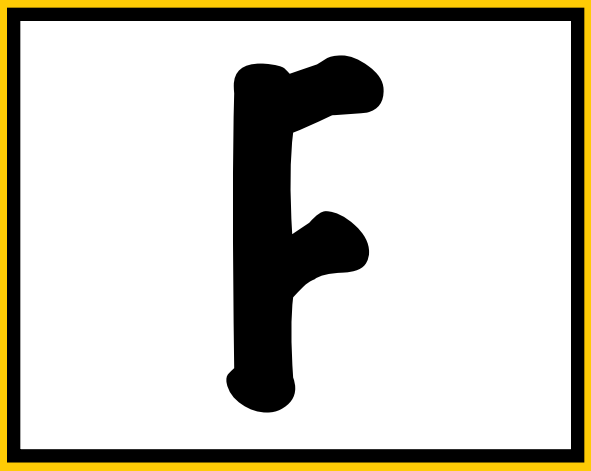
The Public Utilities Commission of Ohio (PUCO) initially ordered utilities to credit NEG at the retail rate. However, in June 2002, the **Ohio Supreme Court (Case No. 01-0573)** decided that such exchange was illegal, despite the comments submitted in support of PUCO's policy by the **American Solar Energy Society** (ASES), **American Wind Energy Association** (AWEA), **Solar Energy Industries Association** (SEIA), **Ohio Partners for Affordable Energy** (OPAE), **Ohio Environmental Council** (OEC) and the **Ohio Consumers' Council** (OCC).[101] Based upon the Supreme Court ruling, utilities must credit NEG to the customer at the utility's unbundled generation rate.

Developments since 2004: In December 2005, the PUCO opened a docket (Case No. 05-1500-EL-COI) to evaluate the state's current interconnection standards and net-metering rules.[102]

Recommendations:
- Credit NEG at avoided cost rate, at minimum
- Eliminate cap on total generating capacity

101 Green Energy Ohio. Ohio Supreme Court Limits Net Metering Incentive. http://www.greenenergyohio.org/page.cfm?pageId=322. Accessed 9-25-06.
102 Report by the Public Utilities Commission of Ohio, Case No. 05-1500-EL-COI. August 28, 2006.

Oklahoma



Number of customers 2004	**31**
Change per million customers (2002- 2004)	**0%***
System size limit	**100 kW (up to 25,000 kW a year)**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Granted to the utility monthly or credited to next bill at avoided cost**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Hydroelectric, Biomass, Geothermal, CHP, Municipal Solid Waste**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Net metering in Oklahoma was first established by Oklahoma Corporate Commission (OCC) Order 326195 in 1988. The order requires investor-owned and municipal utilities under the OCC's jurisdiction to file net-metering tariffs applicable to customer-generators with renewable energy and combined-heat-and-power facilities. No statewide limit for aggregate net-metered capacity has been established, though individual system-size is limited to 100 kW. Under the order, rural co-operatives are not regulated by the OCC, and therefore cannot be required to offer net metering to their customers. Utilities are also not required to purchase net excess generation from customers, though a customer may request it. If the utility agrees, NEG is purchased at the avoided cost rate.[103]

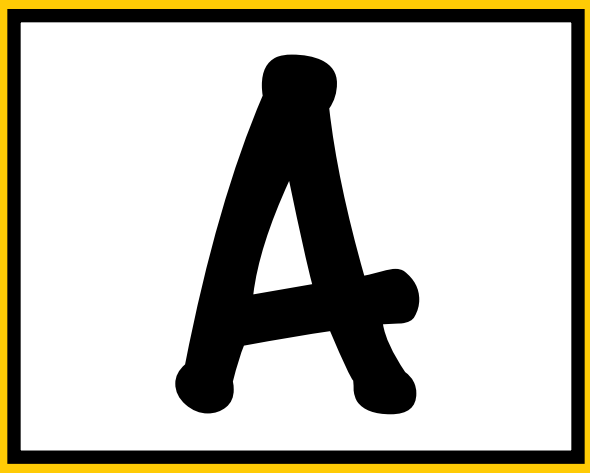
Because of lack of public support, Oklahoma has been unsuccessful in addressing utility company opposition to net metering. Since 1999, several bills have been proposed by Rep. James Covey (D) with the intent of creating a statewide net metering rule, though none of these have become law due to opposition by utilities.

Developments since 2004: The Oklahoma Wind Power Assessment Committee, established by SB 1212 in 2004, has recommended that statewide net metering provisions encompassing all utilities be implemented in Oklahoma.

Recommendations:
- Include all utilities under net metering ruling
- Require purchase of all NEG from customer-generators at retail rate
- Increase system-size limit to at least 2 MW

103 DSIRE Ohio Incentives for Renewables and Efficiency, http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=OK01R&state=OK&CurrentPageID=1&RE=1&EE=1. Accessed 10-9-06.

Oregon



Number of customers 2004	**232**
Change per million customers (2002- 2004)	**1019%***
System size limit	**25 kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited at retail rate to customers next bill or purchased by utility at avoided cost rate**
Limits on enrollment	**0.5% of a utility's peak load**
Eligible technologies	**Solar, Wind, Hydroelectric, Fuel Cells**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page18).

Oregon's original 1999 net metering law, HB 3219, was sponsored by the Committee on Commerce upon the request of the Renewable Northwest Project and the Solar Energy Industry Association of Oregon. It passed unanimously in both the House and Senate, and was supported by over twenty environmental groups, industry associations and utilities statewide. The law allowed net metering for customers with solar, wind, or hydropower systems up to 25 kW.

Presently, residential and commercial customers are permitted to net meter up to a total installed capacity of 0.5% of a utility's historic single-hour peak load. When installed capacity exceeds this limit, net metering may be limited by the regulatory authority.

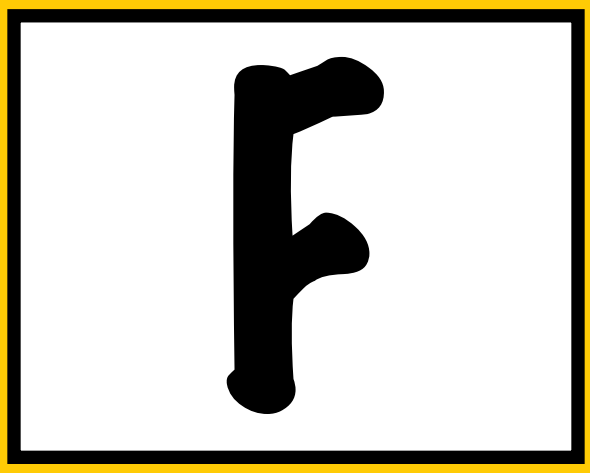
Net excess generation is purchased at the avoided cost rate or credited to the customer-generator's next monthly bill. At the end of an annual period, any unused credit is granted to the electric utility.

Developments since 2004: In June 2005, SB 84 expanded net metering to include landfill gas, digester gas, waste, dedicated energy crops, and low-emission, nontoxic biomass derived from wood, forest, or field residues. Furthermore, the Oregon Public Utilities Commission is authorized to increase the 25-kW system limit for customers of investor-owned utilities.

Recommendations:
- Remove limits on enrollment
- Increase system size limit to at least 2 MW
- Purchase NEG at retail rate
- Credit excess NEG at end of annual period to customer-generator

Pennsylvania

STATE REPORT



Number of customers 2004	**89**
Change per million customers (2002- 2004)	**0%***
System size limit	**10kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Granted to the utility monthly**
Limits on enrollment	**None**
Eligible technologies	**Renewable energy and fuel cells**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Pennsylvania law introduced met-metering in 1996 under the Electricity Generation Customer Choice and Competition Act to include all renewable energy sources (including fuel cells up to 10kw).[104]

Developments since 2004: In November 2004, Governor Edward Rendell signed the Alternative Energy Portfolio Standards Act requiring net metering and interconnection standards to be set within 9 months. The rules were heavily influenced by the Mid-Atlantic Distributed Resources Initiative, or MADRI, consisting of a coalition of regional state utility commissions including Pennsylvania, the Federal Energy Regulatory Commission (FERC), PJM Interconnection L.L.C. (a large Mid-Atlantic and Northeast utility company), the U.S. Department of Energy, the EPA and the Institute of Electrical and Electronics Engineers Standard for Interconnecting Distributed Resources with Electric Power Systems or "IEEE 1547".[105] The PUC issued net metering and interconnection regulations in June and August of 2006, increasing system size limits to 50kW for residential and 1MW for non-residential. Additionally net excess generation is credited at the end of the month to the customer at the utilities' avoided cost.[106]

Recommendations:

- Increase system size limit to 2MW
- Purchase net excess generation annually
- Create interconnection standards similar to those recommended by FERC or IREC
- Credit customers at retail rate annually for net excess generation

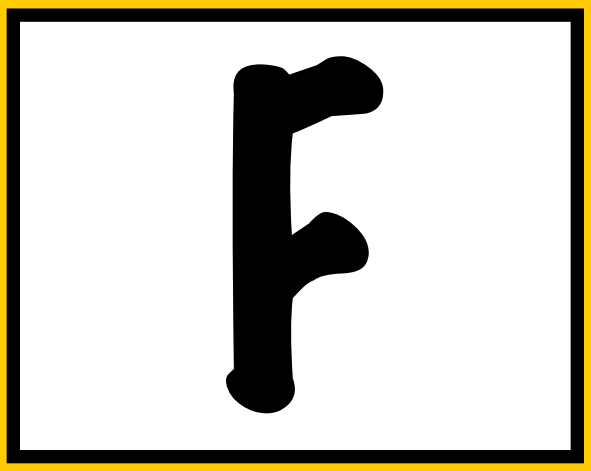
104 "State Regulations" Resource Dynamics Corporation: Distributed Generation. http://www.distributed-generation.com/state_regulations.htm#Pennsylvania

105 "Notices: Pennsylvania Public Utility Commission" The Pennsylvania Bulletin. 23 March 2005. <http://www.pabulletin.com/secure/data/vol35/35-15/676.html

106 "Pennsylvania Incentives for Renewables and Efficiency" Database of State Incentives for Renewable Energy. 27 Sept. 2006. http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=PA03R&state=PA&CurrentPageID=1&RE=1&EE=1

Rhode Island

STATE REPORT



Number of customers 2004	**25**
Change per million customers (2002- 2004)	**0%***
System size limit	**25kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited to the following month; granted to utility at the end of a 12-month period.**
Limits on enrollment	**1 MW**
Eligible technologies	**Solar, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, CHP/Cogeneration, Fuel Cells**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**Narragansett Electric Company**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

In 1998, after hearing a compelling case made by several state-based renewable energy experts, the Rhode Island Public Utilities Commission (PUC) required Narragansett Electric to provide net metering to customer-generators using renewable energy sources, including fuel cells, up to a 25 kW system limit. Eligible technologies are listed in Rhode Island's Utility Restructuring Act, R.I.G.L. §39-2-1.2(b).

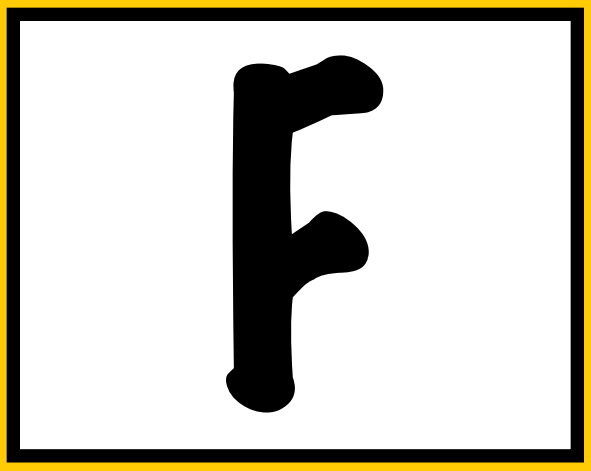
At the end of each month, NEG is credited to the following month, and unused credits are granted to the utility at the end of a 12-month period. Narragansett Electric's aggregate net-metered capacity limit is one megawatt.

Recommendations:

- Remove system size limit and aggregate capacity limit
- Reimburse NEG at the retail rate
- Involve more utilities

Texas

STATE REPORT



Number of customers 2004	**16**
Change per million customers (2002- 2004)	**0%***
System size limit	**50 kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Purchased by the utility monthly at the avoided cost**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Hydroelectric, Fuel Cells, Hydroelectric, Tidal, Wave, Geothermal, Microturbines**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**Investor operated utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Net metering in Texas, ordered by The Public Utility Commission of Texas under Substantive Rules, Section 23.66(f)(4), took effect in 1986. Part of the objective in promoting net metering was to promote small wind power and PV markets within the state. Beginning in 1999, however, statewide electricity market deregulation significantly hindered the efficacy of Texas' net metering rule. Though the right to interconnect to the grid was generally strengthened during the deregulation process, the ability to net-meter these interconnections diminished.[107]

Following deregulation, electric utilities comprised two categories with respect to net metering: (1) integrated IOUs outside the Electric Reliability Council of Texas (ERCOT) with a clear regulatory obligation to permit net metering up to 50 kW for facilities using renewable resources, and (2) electric cooperatives, municipal utilities and river authorities with no obligation to permit net metering. For deregulated entities within ERCOT, clear net metering rules do not exist, and no modifications to existing rules have been made in order to resolve this ambiguity.[108]

Developments since 2004: The Texas Million Solar Roofs Program, Texas Renewable Energy Industries Association, and Conservation Services Group are among the organizations which coordinated the **Texas RE-Connect Project**, which published its final report in April 2005. The objective of the report was to assist Texas utilities in sharing best practices and creating voluntary net metering and interconnection programs for small renewable energy systems.

Recommendations:

- Require all utilities to permit net metering through revision/clarification of existing rules
- Remove external shut-off requirement
- Increase system-size limit to at least 2 MW
- Credit all NEG to customer-generator at retail rate

107 Wiese, Steven M., John E. Hoffner, Erin Scott, Jane Pulaski, Russel Smith. 2005. Interconnection and Net Metering of Small Renewable Energy Generators in Texas: Final Report of the Texas RE-Connect Project. Million Solar Roofs Project. June 11. http://www.treia.org/pdf_files/Final Report.pdf

108 DSIRE. 2006. Texas Incentives for Renewable Energy, http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=TX02R&state=TX&CurrentPageID=1&RE=1&EE=0. Accessed 10-9-06.

Utah

STATE REPORT

B

Number of customers 2004	**10**
Change per million customers (2002- 2004)	**0%***
System size limit	**25kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited to the next bill at the retail rate; granted to the utility at the end of annual billing cycle**
Limits on enrollment	**0.1% of a utility's 2001 peak load**
Eligible technologies	**Solar, Wind, Hydroelectric, Fuel Cells**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**Investor-owned utilities, Electric cooperatives**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

On March 15, 2002, Governor Michael O. Leavitt signed into law HB 7, Net Metering of Electricity, sponsored by Rep. Gordon E. Snow (R). The bill was recommended by the Public Utilities and Technology Interim Committee, and passed unanimously in both the House and Senate. The legislation received support from a broad coalition of interested parties, including environmental groups and Utah Power.

Utah's net-metering law requires all electric utilities and cooperatives, excluding municipal utilities, to permit interconnection of renewable energy systems to the electric grid. Eligible renewable energy systems include fuel cells, solar, wind or small hydropower facilities with a maximum generating capacity of 25 kilowatts. Total participation of customer-generators is restricted to 0.1% of the 2001 cumulative generating capacity of the electrical corporation's peak demand. The utility is required to credit the customer for any NEG at the utility's avoided cost rate or higher. NEG is carried over monthly to the next customer's next bill until the end of each calendar year, at which point any remaining NEG is granted to the utility. Utilities are not permitted to issue additional charges or fees for net-metered customers, unless authorized to do so by the Utah Public Service Commission.

Recommendations:

- Increase system size limit to at least 2 MW
- Eliminate the cap on total eligible capacity
- Require municipal utilities to permit interconnection
- Require purchase of NEG at retail rate

Vermont

STATE REPORT

B

Number of customers 2004	**67**
Change per million customers (2002- 2004)	**152%***
System size limit	**15 kW for Residential and Commercial; 150 kW for Agricultural**
Eligible classes	**Residential, Commercial, Agricultural**
Net excess generation	**Credited to the next bill at the retail rate; granted to the utility at the end of annual billing cycle**
Limits on enrollment	**1% of peak demand for 1996 or current year**
Eligible technologies	**Solar Photovoltaic, Wind, Biomass, Fuel Cells**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

Vermont's net metering program is generally limited to renewable energy systems under 15 kW. However, farmers who generate electricity using eligible renewable-energy resources may net meter systems up to 150 kW, based on certain conditions. There is also a provision for "group net metering," allowing farm systems to credit on-site generation against all meters designated to the farm system. The state public service commission may allow net metering for up to 10 systems per year for non-farm generators greater than 15 kW, but no greater than 150 kW of capacity. A utility and on-farm system owner may also jointly petition the PSB for permission to exceed the 1% aggregate enrollment cap. NEG is granted to the utility without compensation to the customer-generator annually.

Vermont's initial net metering legislation, H.605, was sponsored by Rep Kathleen C. Keenan (D), and became law on April 22, 1998. Despite reservations expressed by utility companies, H.605 was amended in 1999 by H.705, and in 2002 by S.138, increasing the maximum capacity of farm systems and expanding eligible energy sources for net metered systems.

Developments since 2004: 212 net-metered systems (54 wind, 157 solar and one farm-waste methane), with an aggregate capacity of 811 kW, had received a "Certificate of Public Good" in Vermont as of November 2005.

Recommendations:

- Remove capacity cap on total enrollment
- Increase system size limit to at least 2 MW
- Require utilities to purchase NEG at the retail price annually

Virginia

STATE REPORT

D

Number of customers 2004	**19**
Change per million customers (2002- 2004)	**0%***
System size limit	**10 kW for Residential; 500 kW for Non-Residential**
Eligible classes	**Residential, Commercial, Nonprofit, Schools, Government**
Net excess generation	**Purchased at retail rate for renewable energy; purchased at avoided cost for non-renewable energy**
Limits on enrollment	**0.1% of annual peak demand**
Eligible technologies	**Solar, Wind, Hydroelectric**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Net metering in Virginia was originally established in 1999 as part of SB 1269, an amendment to the Virginia Electric Utility Restructuring Act. The net metering rules were developed in part through a July 1999 Commission survey sent to utilities and renewable energy stakeholders. Under SB 1269, Virginia's net-metering law applied to residential systems up to 10 kW in capacity and non-residential systems up to 25 kW in capacity. Eligible systems were limited to solar, wind or hydro energy sources, and customer-generators were not credited for NEG unless a power purchase agreement was established with the utility. Aggregate enrollment capacity was established at 0.1% of each electric utility's peak demand forecast for the previous year.

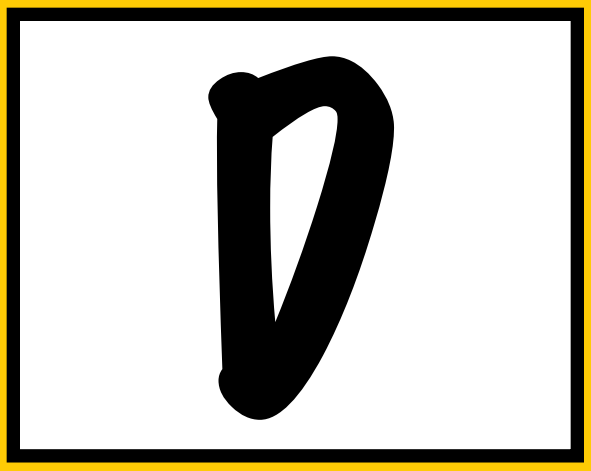
Developments since 2004: In 2004, maximum capacity for non-residential distributed generation systems was increased from 25 kW to 500 kW by SB 651. On March 31, 2006, Virginia Governor Tim Kaine signed HB 1541, extending eligibility to all renewable energy generation systems based upon "energy derived from sunlight, wind, falling water, sustainable biomass, energy from waste, wave motion, tides, and geothermal power." (Previously, net metering was limited to solar, wind or hydro resources.) HB 1541 also permitted net-metering systems to be eligible for lease financing.

Recommendations:

- Eliminate cap on total enrollment capacity
- Purchase all NEG at the retail rate
- Eliminate requirements for external disconnect switch and additional insurance
- Increase system-size limit to at least 2 MW

Washington

STATE REPORT



Number of customers 2004	**73**
Change per million customers (2002- 2004)	**0%***
System size limit	**25kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited to the next bill at the retail rate; granted to the utility at the end of annual billing cycle**
Limits on enrollment	**0.25% of a utility's 1996 peak load**
Eligible technologies	**Solar, Wind, Biogas, Hydroelectric, Fuel Cells, CHP/Cogeneration**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Net metering in Washington State was first enacted in 1998 by the Revised Code of Washington chapter 80.60, establishing the limit on total capacity at 0.25% of a utility's peak demand during 1996, and reserving at least .05% for production from solar, wind, or hydropower. Under the original code, NEG was credited at the retail rate to the customer's next bill, with remaining NEG granted to the utility without compensation to the customer at the beginning of the calendar year.

Developments since 2004: Substitute HB 2352 of 2006 increased system size limits from 25 to 100 kW, and expanded the definition of renewable energy to include solar, wind, hydro, biogas from animal waste, or combined heat and power technologies (including fuel cells). HB 2352 also increased the total capacity cap to 0.5% of a utility's peak demand in 1996, effective 2014. Unused NEG is still credited to the utilities on April 30 of each calendar year.

The revised bill was sponsored by Representatives Morris, Hudgins, and B. Sullivan, with supporting testimony provided by a representative of the Department of Community, Trade & Economic Development. Despite opposing testimony by a representative of Avista Corporation, HB 2352 passed with an overwhelming majority in both the House and Senate and took effect on June 7, 2006.

Recommendations:

- Eliminate the cap on total eligible capacity
- Increase the system size limit to at least 2 MW
- Require utilities to purchase NEG at the retail rate annually

Wisconsin

STATE REPORT

A

Number of customers 2004	**212**
Change per million customers (2002- 2004)	**127%***
System size limit	**20 kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Purchased at retail rate for renewable energy; purchased at avoided cost for non-renewable energy**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, CHP/Cogeneration**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**Investor-owned utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

Wisconsin's net metering legislation is based upon a letter order issued by the Public Service Commission of Wisconsin (PSCW), confirmed on September 18, 1992, and applicable to all investor-owned utilities. Though rural electric cooperatives in Wisconsin are not rate-regulated by PSCW, they often voluntarily abide by the Commission's rulings; several rural electric cooperatives are preparing to offer net metering to their customers.[109]

In Wisconsin, net metering is available to customer-generators with a maximum system capacity of 20 kW. All systems are eligible, including renewable energy and combined heat and power. Utilities pay the retail rate for NEG produced by renewable energy-run systems, while customer-generators using non-renewable resources receive the avoided-cost rate.

Developments since 2004: In January 2006, the PSC accepted a proposal by investor-owned We Energies to permit customers with wind turbines ranging from 20-100 kW in capacity to be eligible for net metering. The first 25 eligible applicants will be permitted to participate in this program for a 10-year term.

Recommendations:
- Increase system size limits to at least 2 MW
- Include rural electric cooperatives under net metering legislation
- Do not require an external disconnect switch or additional insurance

109 State Environmental Resource Center, http://www.serconline.org/netmetering/stateactivity.html. Accessed 9-25-06.

Wyoming

STATE REPORT

B

Number of customers 2004	**11**
Change per million customers (2002- 2004)	**0%***
System size limit	**25 kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited to next bill; purchased at avoided cost at the end of the annual billing cycle**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Biomass, Hydroelectric**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**Investor-owned utilities, Electric cooperatives**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

On February 22, 2001, Governor Jim Geringer signed into law HB195[110], requiring Wyoming's investor-owned utilities, including electric cooperatives and irrigation districts, to offer net metering for solar, wind, and hydroelectric systems of 25 kW or less. The legislation took effect on July 1, 2001.[111] Upon the passage of Senate Bill 106 on July 1, 2003, biomass also became an eligible renewable fuel. Net excess generation in one month is credited to the following month. At the end of an annual billing period, the utility must purchase unused credits at the avoided-cost rate.

Developments since 2004: In 2006, The Wyoming Public Service Commission (PSC) proposed to adopt and incorporate two sections of EPAct 2005 verbatim into its Procedural Rules and Special Regulations, requiring utilities to allow interconnection based on the IEEE 1547 standard, and requiring utilities to offer net metering to customers. A public hearing took place on November 1, 2006 to address this issue.[112]

Recommendations:

- Increase system-size limit to at least 2 MW
- Remove requirement for external disconnect switch
- Purchase NEG at the retail rate

110 Wyoming State Legislature. 2001. http://legisweb.state.wy.us/2001/introduced/hb0195.htm

111 State Environmental Resource Center. http://www.serconline.org/netmetering/stateactivity.html. Accessed 8-29-06.

112 Haynes, Rusty. 2006. Interstate Renewable Energy Council "Connecting to the Grid" Newsletter, Vol. 9 No. 10. http://www.irecusa.org/connect/enewsletter.html. Accessed 9-18-06.

IV: Worst Practices

Indiana & Arkansas

The crafting of the net metering programs in Indiana and Arkansas provides a useful illustration of how the good intentions of state legislators can go astray during the evolution of policy through the regulatory process.

While our analysis did not rank either Arkansas or Indiana as having the worst net metering program, we did find that both the Indiana Utility Regulatory Commission (IURC) and the Arkansas Public Service Commission (APSC) failed to establish effective net metering programs largely because of undue deference given to utilities during the rulemaking process.

In the absence of explicit federal legislation to guide the development of individual state net metering programs, both the Indiana and the Arkansas state legislature delegated the task of developing comprehensive net metering rules to their respective state commissions. Both commissions released draft proposals of their net metering rules for public comment. In addition, each held at least one public hearing during which staff heard comments on net metering from utilities, individual customers, public interest groups and other stakeholders.

Despite the diversity of the comments by stakeholders in both states, key provisions of the resulting regulations (effective as of 2006) reflect the concerns of regulated utilities, most of whom proposed modifications to the draft rules that effectively restricted the number of eligible customers and often unfairly limited the economic benefits of net metering.

APSC's decision to give utilities net excess generation at the end of each month instead of facilitating month-to-month banking can be traced to utility concerns about cross subsidy issues and fears of lost revenue. Similar concerns by utilities in Indiana led its commission to adopt very restrictive limits on eligible system sizes and exclude many customer classes altogether.

In the first two years of its program, Arkansas recorded exactly zero participating customers. By 2004, Arkansas and Indiana could not count more than 20 participating customers between them.

Utility concerns over lost revenue were more effectively allayed than anyone may have imagined. In the first two years of its program, Arkansas recorded exactly zero participating customers. By 2004, Arkansas and Indiana could not count more than 20 participating customers between them.

Indiana

Preventing Legislators from Balancing Economic Interests

Despite overwhelming support for a net metering bill passed unanimously by the Indiana House of Representatives in February 2004, State Senator James Merritt, Chair of the Indiana Senate Utility and Regulatory Affairs Committee, refused to consider the issue,[113] claiming that it "invaded the province of IURC" and that the Commission alone should be responsible for developing net metering rules.[114]

In September 2004, the IURC adopted a formal net metering rule for Indiana, "albeit on a more modest basis," than proposed under HB 1212 or requested by the specific state legislators.[115] Unlike the bill passed in the State House, which would have required the state's electric utilities to make net metering available to any customer with a renewable energy system up to 2 MW in size, the net metering provisions issued by IURC only require the state's investor-owned utilities to make net metering available for residential customers or K-12 schools with systems up to 10 kW. In addition, IURC required eligible customer-generators to obtain insurance for net metered systems of at least $100,000 and gave utilities the discretion to require an additional external shut-off switch installed at the customer's expense.

In 2002, long before issuing its net-metering rules, IURC began collecting information about distributed generation that was to be used in the development of the state's comprehensive net metering rules.[116] IURC issued a request for responses to a list of technical questions associated with initiating a statewide net metering program. By March of 2002, eight of the state's utilities as well as the Citizen Action Coalition (CAC) submitted their comments in response to the IURC's request. [117] Although the Commission initially intended for the program to provide incentives for individual customers to invest in small-scale renewable generation,[118] the language of its final rules reflects substantially the comments made by the state's utilities.

One main argument made by Indiana's utilities involved unfounded claims that net metering results in "the subsidization of customers with net metering by other customers and by the utility,"[119, 120] an argument known as 'cross-subsidization' (see pages 70-71). In order to limit this problem, the utilities suggested that, "net metering should be limited to a small generator (i.e. maximum 10 kW nameplate rating) for primarily residential or small commercial application." [121]

113 Indiana regulators adopt final net metering rules, but AG still must review. (2004) Electric Utility Week. The McGraw-Hill Companies, Inc. Sept 13. P. 21.

114 DeAgostino, Martin. (2004) Heat deposit bill off Senate's plate; Power generating, utility issues seen URC responsibility. South Bend Tribune Corp. Feb. 18. P. A2.

115 Indiana regulators adopt final net metering rules, but AG still must review. (2004) Electric Utility Week. The McGraw-Hill Companies, Inc. Sept 13. P. 21.

116 Indiana Utility Regulatory Commission (IURC). (2002, 2003)Distributed Resources Workgroup. IURC. http://www.in.gov/iurc/utilities/energy/drw/drw_index.html

117 Indiana Utility Regulatory Commission Staff. (2002) Distributed Generation White Paper. IURC. Jan. 25. http://www.in.gov/iurc/utilities/energy/drw/whitepaper_012502.pdf

118 ibid.

119 American Electric Power. 2002. Comments of Indiana Michigan Power Company, d/b/a American Electric Power, on the Indiana Utility Regulatory Commission Staff's Distributed Generation White Paper. IURC. March 1. http://www.in.gov/iurc/utilities/energy/drw/aep_comments_030102.pdf

120 Southern Indiana Gas and Electric Company, d/b/a Vectron Energy Delivery of Indiana, Inc. 2002. Response to Distributed Generation Rule Making. IURC. February 28, 2002. http://www.in.gov/iurc/utilities/energy/drw/sigeco_comments_030102.pdf

121 Brothers, Ronald J. 2002. Comments of PSI Energy, Inc. and Cinergy Corp. Concerning the Indiana Utility Regulatory Commission's Advanced Notice of Proposed Rulemaking Concerning Distributed Generation. Indiana Utility Regulatory Commission, Mar. 1. http://www.in.gov/iurc/utilities/energy/drw/psi_comments_030102.pdf

The final rules reveal that the utilities were effective at persuading the IURC to limit eligible system sizes to 10kW, despite entreaties by the state legislature to allow net metering of systems up to 2 MW.

One Indiana utility, Richmond Power and Light, argued for restricting eligible customer classes because "in the context of industrial or commercial customers," who may be capable of generating a substantial amount of their electricity demand on-site, allowing month-to-month banking would be "disastrous and confiscatory."[122] Indiana Technology and Manufacturing Companies, ITAMCO, with 75 employees in its 100,000-square-foot factory, "where precision work requires costly air conditioning," countered that on-site power generation would reduce operational costs and make the company more economically competitive. [123] David Neidig, marketing VP at ITAMCO, explained that the company's interest in participating in net metering was partly because it "is a great way for (ITAMCO) to be more competitive as an Indiana manufacturer, and at the same time be environmentally conscious, and be a good neighbor of the community." [124] ITMACO noted that, because a 1.5 MW wind turbine would cost the company about $1.5 million, net metering was "essential to (ITAMCO's) cost equations" when planning to invest in the its renewable energy system. In the end, IURC's net metering rules excluded commercial and industrial customers and Indiana companies like ITAMCO were unable to benefit from net metering.

Indiana's experience with net metering reflects how state regulations crafted to protect the economic interests of one sector (electrical utilities) may have unintended negative consequences on other sectors (like precision tool manufacturing).

Indiana's experience with net metering reflects how state regulations crafted to protect the economic interests of one sector (electrical utilities) may have unintended negative consequences on other sectors (like precision tool manufacturing). More importantly, Indiana's experience reveals how, in the absence of explicit statutory guidance, state public utility commissions can thwart the intention of legislators seeking to more effectively balance the economic interests of the state.

Arkansas

Allowing Utilities to Discourage Participation

In response to increasing demand for energy in Arkansas, on April 13, 2001, the state legislature enacted the Arkansas Renewable Energy Development Act of 2001, which mandated that electric utilities make net metering available to residential, commercial and agricultural customers. [125] The legislature intended the program to increase the use of renewable energy sources, decrease the use of foreign fossil fuels and encourage customers to invest in renewable energy technology.[126] Eligible technologies under the Act included solar, wind, hydroelectric, geothermal, and biomass systems with generating capacities up to 25kW for residential

122 Indianapolis Power & Light Company. 2002. Comments and Attachments to Advanced Notice of Proposed Rulemaking on Distributed Resources. IURC. Feb.15, 2002. P. 3. http://www.in.gov/iurc/utilities/energy/drw/drw_index.html accessed on August 10, 2006.

123 DeAgonstino, Martin. (2004) Company looks to wind for savings; Bill benefits small-scale power generators. South Bend Tribune (Indiana), Monday Marshall Edition. Feb. 16. P. C1.

124 ibid.

125 Avery, Chad. (2002) Survey of Legislation. 2001 Arkansas General Assembly. Regulated Industries. 24 U. Ark. Little Rock L. Rev. 595, 600.

126 The Arkansas Renewable Energy Development Act of 2001. Ark. Code Ann. § 23-18-602(a).

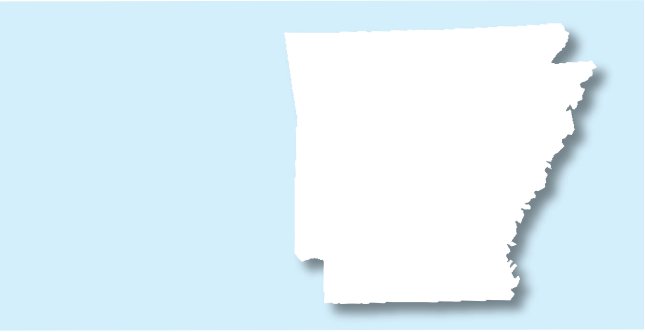
customers and 100kW for commercial and agricultural customers. However, although the statute makes net metering available for several technologies and multiple customer classes, it does not establish the rates, terms or conditions for net metering contracts. Instead, the legislature allocated this task to the Arkansas Public Service Commission (APSC). As in Indiana, utility influence over the final design of the Arkansas' net metering regulations effectively undermined the legislature's intentions by creating economic disincentives for investments in renewable energy systems.

As in Indiana, utility influence over the final design of Arkansas's net metering regulations effectively undermined the legislature's intentions by creating economic disincentives for investments in renewable energy systems.

Instead of allowing a net metered customer to bank net excess generation each month, Arkansas's net metering rules grant all excess generation to the utility at the end of an applicable billing period. The limitation on banking in the final rule reflects the suggestions of the regulated utilities and indicates that APSC staff was more deferential to utility comments than to the public's interest in expanding the use of renewable technologies.

Initially, APSC prepared two versions of draft net metering rules, the first draft on December 7, 2001 and a revised draft on February 20, 2002. APSC received comments submitted in response to each draft and held a public hearing to gather additional information on net metering. Despite the strong support for allowing month-to-month banking by Arkansas's Attorney General and individual utility customers, the Commission adopted the position of the utilities, holding that net excess generation should be donated to the utility at the end of every monthly billing cycle.[127]

The APSC supported its decision by parroting the arguments submitted by regulated utilities. First, the utilities argued that allowing month-to-month banking would enable the customer-generator to "become a quasi-power supplier to the electric utility as opposed to offsetting customer's requirements for electricity."[128] This argument rests on a definition without a distinction. Customer-generators that are offsetting generation from the utility are necessarily supplying that generation to themselves. Monthly banking does not directly compensate a net metered customer for electricity generation. It merely credits the same customer to offset future demand so that self-generating customers are not artificially beholden to the monthly billing cycles of regulated utilities. If offsetting demand makes sense as a matter of public policy, then so does monthly banking, especially as banking allows excess generation from one customer to be used to meet another customer's demand.



Second, Arkansas utilities claimed that banking would over-compensate the customer-generator, since NEG would be credited at the retail price of electricity, which includes costs associated with transmission, distribution and administration.[129] Electricity generated and consumed by the customer always offsets electricity supplied by the utility at the retail rate, regardless of whether the electricity is consumed this month or next. Monthly banking allows excess generation produced this month

127 Arkansas Public Service Commission. (2002) In the Matter of a Generic Proceeding to Establish Net Metering Rules, Docket No. 02-046-R, Order No. 3. APSC. June 3. P. 5-7.

128 Elrod, W.W. II. (2002) In the Matter of a Generic Proceeding to Establish Net Metering Rules, Docket No. 02-046-R, Initial Comments of American Electric Power, Inc. Southwestern Electric Power Company. APSC. April 2, 2002. p 3.

129 Arkansas Public Service Commission. (2002) In the Matter of a Generic Proceeding to Establish Net Metering Rules, Docket No. 02-046-R, Order No. 3. APSC. June 3. P. 5-7.

to offset the same kind of electricity consumed the next. If the electricity is no different, why should the price of the offset change? As well, the excess generation not credited to the customer in one month is consumed by the grid and sold to other customers at the retail rate. By profiting from the excess electricity produced by customer-generators, are not utilities being 'overcompensated' for electricity they did not produce?

Finally, utilities argued that banking would provide more benefits to the customers already participating in net metering rather than encouraging more customers to participate. By this logic, the entire net metering program should be rejected as merely providing economic compensation for customers with existing renewable energy systems. Since the ability to bank net excess generation decreases the payback time for renewable energy installations, it provides as much of an economic incentive to invest in new renewable systems as the inherent ability of any net metering program does by offsetting customer utility bills in any given month.

States that allow monthly banking of net excess generation (NEG) experience larger and faster growth in participation than states that disallow it. Four out of five of the states that experienced the greatest growth in net metering participation from 2002-2004 allow month-to-month banking of NEG.

More importantly, the argument that monthly banking does not encourage greater rates of participation is contradicted by empirical data. Our analysis of participation rates in state net metering programs from 2002-2004 finds that states that allow monthly banking of NEG experience larger and faster growth in participation than states that disallow it. Four out of five of the states that experienced the greatest growth in net metering participation from 2002-2004 allow month-to-month banking of NEG.[130]

In Arkansas, APSC's decision to prevent monthly banking of NEG increased the pay-back period for individual net metered systems significantly.[131] Consequently, the longer pay-back periods effectively discouraged customer investment in renewable technology and impeded the expansion of renewable energy sources.[132] Although the state's Attorney General and three individual electric customers raised many of the points we raise here, APSC maintained that no evidence suggested that allowing customers to bank excess generation would encourage more customers to invest in renewable technology.

APSC further limited customer participation in net metering by agreeing with utility suggestions that the rules should limit the size of eligible net metered system so as not to "exacerbate" cross-subsidization issues.[133]

130 New Jersey, Montana, Oregon and California all allow monthly banking of NEG credited at the retail rate. Hawaii, with the fifth largest increase in participation from 2002-2004, grants NEG to the utility at the end of each month.

131 Ball, William. (2002) In the Matter of a Generic Proceeding to Establish Net Metering Rules, Docket No. 02-046-R, Reply Comments of William Ball. ASPC. April 2. http://www.apscservices.info/PDF/02/02-046-r_20_1.pdf

132 ibid

133 Arkansas Public Service Commission. (2002) In the Matter of a Generic Proceeding to Establish Net Metering Rules, Docket No. 02-046-R, Order No. 3. APSC. June 3. P. 5-7. http://www.dsireusa.org/documents/Incentives/AR03Ra.pdf

Cross-Subsidization:

The Boogey-Man of Net Metering

Cross-subsidization is how utilities refer to the problem of non-participating customers paying for benefits that accrue to participating customers under a net metering program. When meters run backwards, net metered customers essentially are being credited for the full retail price of electricity, which includes the actual costs of many other things (transmission lines, maintenance, administration, etc).

Utilities argue that net metered customers continue to benefit from transmission lines and other utility amenities even though they are supplying their own electricity. The cost of these other things is, therefore, borne by non-participating customers who end up paying higher electricity rates. In a 1999 report on net metering for the Solar Energy Society of Canada, Andrew Pape explains the cross-subsidization argument this way:

"There are three types of subsidies implicit in net metering. First, bundled retail rates typically include fixed costs. By crediting customer-generators based on retail rates, they may effectively avoid some of these fixed costs (e.g. fixed T&D costs), although they continue to benefit from them (e.g. standby service). Second, power production from customer-generators that is credited by the utility may coincide with periods of the day or year when power is less valuable (e.g. summer days), yet customer-generators may consume utility power at zero net cost during periods when power is more valuable. Finally, net metering programs may entail additional costs that are recovered from all ratepayers, not just program participants."[134]

While couched in a level of economic sophistication, the cross-subsidization argument is a contortion of logic bordering on the absurd. It is akin to arguing that customers who use less electricity, and thus pay less, should have to pay a monthly fee to make up the difference. Otherwise, the utility will increase costs for the customers who use more electricity.

Whatever merit exists to the cross-subsidization argument stems entirely from the fact that utilities enjoy a monopoly on the transmission and distribution systems that all customer-generators are required to use. Utilities do not enjoy a monopoly on transmission by divine right. Since utility monopoly is the result of policy made ostensibly to promote the public good, policymakers may surely change the policy in pursuit of even greater public good.

For the cross-subsidization argument to make much sense, utilities must mischaracterize net metering as a separate electricity sale from the net metered customer to the utility, rather than as an offset of electricity demand. The cross-subsidization argument is irrelevant until a net metered system generates more electricity than is being consumed by the customer and the meter runs backward. It is only when the meter runs backward that the utility is crediting the customer for net excess generation contributed to the grid. Until then, there is no more cross-subsidy inherent in the arrangement than there would be when a utility customer, for example, installs an energy efficient air conditioner. Not demanding as much electricity from the grid is not the same thing as requiring the utility to credit excess electricity at the retail rate. It is simply demanding less.

Even when net metered customers are generating excess electricity, there is little justification for limiting net metering in some crude attempt to spread the fixed costs of transmission and distribution equitably among ratepayers. To begin with, many utilities already 'unbundle' fixed costs by charging an initial connection fee and/or delineating separate transmission and distribution charges on a customer's bill. Under these circumstances, the fixed transmission, distribution and administration costs associated with managing the grid are not subsumed by the retail rate of electricity and thus the cross-subsidization argument is not a justification for denying net metered customers the full credit for the electricity they generate.

Cross-subsidization already occurs as a result of fixing transmission costs in the first place. Presumably, customers benefit from the transmission grid in ways not reflected by their electricity

134 Pape, Andrew E. (1999) Clean Power at Home. David Suzuki Foundation: Ottawa (p. VIII). http://www.davidsuzuki.org/files/clean.pdf

bill. It costs much more to transmit electricity to some areas than others. Customers who consume electricity close to where it is generated subsidize the transmission of electricity to customers who reside far from power plants. Retail prices do not reflect the unequal costs of transmission lines and load losses. Instead, all customers are charged as if they contributed equally to transmission expenses. Even today, transmission system controllers must use brownouts and rolling blackouts rather than electricity price to manage demand in excess of capacity[135]. These crude tools require some ratepayers to subsidize electrical reliability for others. And yet utilities remain largely silent about these inherent inequities until the issue of net metering is raised.

The second component of the cross-subsidization argument (that crediting excess generation rewards off-peak generation at on-peak prices) is even more preposterous. Multiple empirical studies demonstrate that renewable energy DG systems (particularly solar PV systems) generate excess electricity during peak demand periods.[136] Rather than net metered customers claiming credit for excess electricity when it is "cheap" and applying the credit when electricity is "expensive", in practice the opposite has been the case. By providing excess electricity to the grid during periods of peak demand, the net metered customer not only is helping the resource-constrained utility meet its demand, but is offsetting the most expensive type of electricity, that provided by pricey "peaking facilities" that come online only when base loads are exceeded. What's more, if the utility fails to credit excess generation at the retail price of electricity, the utility will simply be taking the excess generation from net metered systems and charging other customers the full price. Talk about cross-subsidization! Without paying for any additional infrastructure investment, the utility is simply commandeering the energy generated by net metered customers, selling it to non-net metered customers and pocketing the profit.

The final component of the cross-subsidization argument raises the specter of unspecified "additional costs" associated with net metering that must be recovered from all customers, not just participants. One can only speculate what these fees may entail, if not the same fixed costs we have already dealt with above. Some possibilities (application processing fees, interconnection safety, insurance and indemnification) simply constitute hidden participation fees that we have already demonstrated are unnecessary. Whatever nominal costs result from interconnecting net metered systems are far overwhelmed by the benefits net metering brings to electricity reliability, national security and the environment.[137]

135 In fact, during peak summer demand, the New York City mayor's office required large operations to use their generators in order to relieve system stress.. (Cardwell, Diane and James, Karen. (2006) City's Strategy Helped Avert Wider East Side Power Failure. New York Times. August 5.)

136 Nakarado, Gary L. (2006) Of Red Herring, Straw Men, and the Ugly Duckling Grows Up. Presented at PURPA's Net Metering Standard: Net Benefit or Net Detriment, Edison Electric Instititue E-Forum. June 22.

137 Sovacool & Cooper. (2006) Green Means 'Go?': The Case for an Advanced National Renewable Portfolio Standard. Electricity Journal. 19:7. August/September (pp. 19-32).

If the cross-subsidization argument were true, it would justify rejecting the entire net metering program, rather than limiting system sizes with an artificial (and ineffective) "mitigation" of the problem. Limiting the size of eligible systems does not address the problems raised by cross-subsidization. Even with stringent size limits, non-participating customers would, in theory, still be subsidizing a large number of small systems instead of a small number of large systems. The size of eligible systems has little relation to the total amount of net metered energy that would be "cross-subsidized".

The lackluster participation rates in Arkansas provide a good example of how restrictions in one area (eligible system sizes), adopted in an attempt to 'balance' customer interests with the interests of the regulated community, may have the unintended consequence of destroying the entire program.

Presumably, by voting to establish a net metering program at all, the Arkansas legislature already rejected the cross-subsidization arguments raised by regulated utilities during rulemaking. However, the APSC used cross-subsidization as a justification for substantial limits to eligible system sizes and ended up adopting a cure worse than the disease. With only two residential customers and one commercial customer participating in net metering in Arkansas as of 2004, the results of Arkansas program speak for themselves. By giving deference to ill-conceived utility arguments, APSC crafted final net metering rules that effectively undermined the intention of the state legislature and did little to encourage the use of renewable energy technologies in Arkansas.

V : Best Practices

New Jersey

In the quiet New Jersey hamlet of Verona, Prout Funeral Home became the first funeral home in the northeast to install and operate a solar system that not only will power the entire operation, but will turn a profit.

The Prout story is the result of a unique combination of an enterprising mortician and the landmark restructuring of its net metering program in 2004. Since 2004, New Jersey's incentives for small-scale renewable energy, especially its generous net metering program, have been widely considered the best in the country and our analysis of 34 statewide net metering programs confirms that New Jersey's program is the most effective.[139,140]

Two simple metrics quickly confirm the success of New Jersey's approach: First, the number of net metered customers after the program was implemented; and second, the cumulative potential capacity of the small-scale renewable energy systems installed since the program was initiated. By both of these measures, New Jersey has instituted a comprehensive program that other states would be wise to emulate.

Early results indicate that New Jersey is experiencing a tremendous rate of growth in both customer participation and the cumulative capacity of installed renewable energy systems.[141] In 2004, the first year under New Jersey's restructured net metering program, the number of net metering customers in the states increased from zero to more than 300.[142] Since then, the number of solar panels in New Jersey has increased more than fivefold to 1,665.[143]

The rapid growth in customer participation can be traced to the process by which New Jersey restructured its program. By testing proposed changes against objective research and a clearly defined goal, New Jersey was able to craft net metering regulations that avoided the pitfalls bedeviling many other state programs.

Development of New Jersey's Legislation

New Jersey first adopted a net metering program in 1999. However, in 2004, New Jersey's Board of Public Utilities (BPU) ordered amendments which strengthened the program significantly. [144] Without doubt, the strength of New Jersey's new program is due largely to how it originated as part of a comprehensive strategy, including generous rebates and tax incentives, to expand renewable energy statewide.

138 Youngsworth, Jack., (2006) 'The Sun Also Rises': Funeral Home Adopts Solar Power to Lower Costs. PR Newswire US. February 22.

139 Fox, Jeanne M. (2005) Net Metering in New Jersey. August 3. http://www.energypulse.net/centers/article/article_display.cfm?a_id=1065.

140 Reilly, Mike. (2005) Making Energy While the Sun Shines - Jersey's Program a Model for the Nation. The Star Ledger. August 22. p. 13.

141 While California has the highest raw numbers in either of these categories, New Jersey surpasses California in growth rate.

142 U.S. Dept. of Energy, Energy Information Agency. (2005/2006) Green Pricing and Net Metering Programs. http://www.eia.doe.gov/cneaf/solar.renewables/page/greenprice/greenpricing_netmetering04.pdf http://tonto.eia.doe.gov/FTPROOT/features/grnprcreport.pdf

143 New Jersey's Clean Energy Program. (2006) Supported Solar Installations. August. http://www.njcep.com/html/res-installed/solar-list.html.

144 DSIRE. (2006) www.dsireusa.org.

A Foundation of Support from the Governor

Although New Jersey already had demonstrated a strong commitment to clean energy, in 2003 Governor James McGreevey created a Renewable Energy Task Force charged with making recommendations on how the state could increase its consumption of renewable energy.[145] The Task Force concluded that the state should double its requirements for renewable energy production by 2008, and also recommended a statewide goal of producing 20% of its energy from renewable sources by 2020.[146] Although the Task Force did not specifically recommend a new net metering law, the recommendations laid the foundation for significant amendments to the state's existing program.

Strong Leadership from the Commission

The Board of Public Utilities (BPU) was charged with implementing the recommendations of the Governor's Task Force. Although the Task Force had recommended a substantial increase in renewable energy generation, particularly solar, it had not specified exactly how to accomplish the increase. BPU's President, Jeanne Fox, who had also served as Task Force's chairwoman, felt that a strong net metering law was necessary to meet the Task Force goal of 20% renewable production by 2020.[147] Fox believed that it was necessary to enable customers to purchase and install larger systems than the state's previous net metering legislation if the state was to meet its renewable energy production goals. At Fox's recommendation, in 2004 the New Jersey legislature adopted a system size limit for net metered systems of 2 MW, the largest systems eligible under any existing net metering program in the nation.[148]

Focusing on Goals Rather than Consensus

Unlike many other states, New Jersey did not begin the process of amending its net metering regulations by trying to establish a consensus position with all stakeholders. A powerful Renewable Energy Task Force led by the President of the state's utility commission resulted in an approach to net metering law that kept as its focus the goal of allowing small-scale renewable energy to compete equally with conventional power.

According to drafters of the legislation, New Jersey began the process of amending the state's net metering statute by trying to determine what would attract the distributed generation (DG) industry to the state. Drafters solicited the input of utility companies, but only adopted the recommended changes when they did not compromise the primary goal of expanding the state's DG market. Changes that would have impeded the development of statewide DG industry generally were overruled.

For example, New Jersey's statue allows only residential or "small commercial customers" to participate in the state's net metering program. The precise definition of small commercial customers was critical to determining who would be eligible. A narrow definition would exclude customer classes that could provide more generation for meeting the

145 Renewable Energy Task Force. (2003) The Renewable Energy Task Force Report. Submitted to Governor James M. McGreevey, April 24. http://www.state.nj.us/bpu/reports/RenEnergyTFR.pdf

146 New Jersey Board of Public Utilities. (2003) McGreevey Receives Renewable Energy Task Force Report. September 5. http://www.state.nj.us/bpu/renewEnergy/renEnergy.shtml.

147 New Jersey Regulation Text. (2003) NJAC 14:4-9.1, 9.2, 9.3, 9.4 thru 9.11. Proposed Rule. December 01, 2003. Board of Public Utilities. BPU Docket Number EX 03100795.

148 Ibid.

state's goal. A broader definition would allow more potential customers to participate. The bill's drafters reviewed the programs in other states and decided on a definition of "small commercial customer" as non-residential customers with less than 10MW of peak demand – a definition that was supported by the solar industry. The utilities, however, strenuously objected to this definition, and proposed a much smaller limit of 150kW.[149] Had the utilities' definition been adopted, it would have greatly reduced the number of commercial customers eligible for New Jersey's net metering program and would have artificially excluded larger generators. In the end, New Jersey's drafters rejected the utility recommendations and adopted a final rule that allowed systems up to 2MW in size to qualify as small commercial customers.[150]

Linking Net Metering to Renewable Portfolio Standards

New Jersey's amendment of its net metering program coincided with an aggressive expansion of the state's Renewable Portfolio Standard (RPS). RPS are laws that require utilities to produce a certain percentage of their power from renewable resources. New Jersey, which has had an RPS law since 1999, made changes in 2004, which required each utility serving retail customers to include 22.5% renewable energy in its electricity mix by 2021.[151]

Electricity suppliers were allowed to meet RPS requirements by investing in their own renewable energy generation or by purchasing renewable energy certificates (RECs). RECs are credited to renewable generators and represent the monetary value attached to the renewable nature of the electricity they generate. New Jersey's RPS statute issues RECs for renewable energy generated by customer-generators. However, New Jersey went a step further by allowing regulated utilities to apply RECs from customer-generators toward their RPS mandates only if those customers were also eligible for net metering. By linking net metering to the state's RPS mandates, New Jersey created an economic incentive for regulated utilities to pursue aggressive expansion of the state's net metering program. Every new net metering customer became a potential new source of renewable energy to help the utility meet its RPS requirements.

By linking net metering to the state's RPS mandates, New Jersey created an economic incentive for regulated utilities to pursue aggressive expansion of the state's net metering program. Every new net metering customer became a potential new source of renewable energy to help the utility meet its RPS requirements.

Part of a Package of Incentives

New Jersey treated its net metering program as part of a broad package of incentives designed to encourage the adoption of renewable energy.[152] Recognizing that net metering alone is not sufficient to offset the high initial costs associated with on-site renewable energy generation, New Jersey adopted a variety of rebate and tax reimbursements to reduce capital costs even further.

In addition to tax incentives, New Jersey collected a "Societal Benefits Charge" on all public utility customers and adopted a broad-based rebate program that pays renewable generators a premium on each kilowatt of electricity generated by small solar, wind

149 Ibid.

150 New Jersey Regulation Text. NJAC 14:4-9.1, 9.2, 9.3, 9.4 thru 9.11 Adopted Rule, September 15, 2004. Board of Public Utilities. BPU Docket Number EX 03100795

151 Ibid.

152 Reilly, Mike. (2005) Making Energy While the Sun Shines - Jersey's Program a Model for the Nation. The Star Ledger. August 22. p. 13.

and sustainable biomass generators. The rebate is scaled to provide greater payment for initial kilowatts and less as generation increases. By making the rebate progressive in this way, New Jersey tilted the economic incentive to favor a larger number of small generators.

Rather than institute a number of individual state subsidies, New Jersey linked tax incentives, progressive rebates and a broad-based net metering program to create market-based inducements for investment in small-scale renewable energy.

Features of New Jersey's Program

In addition to generous system size limits, New Jersey's net metering program includes specific components that help expand both the number of participating customers and the total amount of renewable capacity that is eligible.

Streamlined Application Process

A hallmark of New Jersey's net metering program is its streamlined and transparent application process. New Jersey designed its application regulations both to overcome customer concerns about the complexity of the process and to minimize the extent to which utilities may delay applications. Prior to New Jersey amending its program, the U.S. Department of Energy released research indicating that customers who encountered major delays in application processing ultimately were discouraged from participating in net metering.[153] To address this issue, the drafters of New Jersey's statute proposed a rule requiring utilities to respond promptly to customer applications. If a utility does not approve or deny a standard residential customer's application within 20 days of having received the application, the rule considered the application approved automatically.[154] Not surprisingly, utilities objected to this proposal and requested a longer time period to review applications.[155] Ultimately, New Jersey's lawmakers rejected an extended review period and adopted the 20-day rule.

Simplified Interconnection Standards

Interconnection standards govern the manner in which customers can connect to the power grid. Effective net metering legislation is only possible if the interconnection standards enable customer-generators to connect to the grid with minimum difficulty. The New Jersey BPU understood the importance of interconnection standards to net metering and adopted model standards developed by the Interstate Renewable Energy Commission (IREC) and National Association of Regulatory Commissioners (NARUC).[156] New Jersey's standards allow all DG technologies to interconnect, do not require the customer to purchase additional insurance and impose a minimal application fee (which is waived altogether in certain cases).[157]

153 National Renewable Energy Laboratory. (2005) Million Solar Roofs Case Study: Overcoming Net Metering and Interconnection Objections New Jersey MSR Partnership. September. http://www.nrel.gov/docs/fy05osti/38666.pdf

154 New Jersey Administrative Code. Title 14. Board of Public Utilities. Chapter 4. Energy Competition. Subchapter 9. Net Metering and Interconnection Standards For Class 1 Renewable Energy Systems N.J.A.C. 14:4-9 (2006). (14:4-9.7 (o))

155 New Jersey Regulation Text. NJAC 14:4-9.1, 9.2, 9.3, 9.4 thru 9.11 Adopted Rule. September 15, 2004. Board of Public Utilities. BPU Docket Number EX 03100795

156 New Jersey Regulation Text. NJAC 14:4-9.1, 9.2, 9.3, 9.4 thru 9.11. Proposed Rule. December 01, 2003. Board of Public Utilities. BPU Docket Number EX 03100795.

157 Interstate Renewable Energy Council (IREC) (2006) "Connection to the Grid" Project. Interconnection Standards for Distributed Generation. June. http://www.irecusa.org/connect/state-by-state.pdf

Reduced Unnecessary Safety Requirements[158]

When New Jersey was establishing its net metering law in 2004, drafters recognized that many utilities were using safety concerns to require customers to install external disconnect switches that could be accessed easily by utility company workers. New Jersey's lawmakers suspected that the external disconnect switch might be redundant with safety mechanisms inherent in all certified inverters and feared that the requirement was acting as a disincentive to customers who wanted to install renewable energy systems.

With a grant from the nationwide Million Solar Roofs campaign, the New Jersey Public Utilities Commission contracted with Chris Cook, an expert in interconnection standards, to investigate the issue.[159] Cook thoroughly researched external disconnect switches and found that the switches were rarely, if ever, used by utility company workers and that they did almost nothing to protect the workers anyway.

The external switch requirement may even be harmful to workers both by giving them a false sense of security and by requiring them to traverse private property to access the switches.

In fact, Cook found that the external switch requirement may even be harmful to workers both by giving them a false sense of security and by requiring them to traverse private property to access the switches. In addition, the added expense of external switches created an incentive for customers to connect unauthorized systems that present a much greater safety concern to workers. An entire underground movement of illegal interconnection has sprung up in some states as a result of such requirements.[160]

In the end, New Jersey's statute prohibited utilities from requiring unnecessary and expensive additional safety equipment. Pre-tested, off-the-shelf renewable units are certified as safe and the certification removes the necessity for additional equipment. By basing its statute on a thorough investigation of utility concerns, New Jersey helped pave the way for customer-friendly interconnection standards that better protect utility industry workers.[161,162]

High System Size Limits

New Jersey allows renewable energy systems up to 2 MW to be eligible for net metering, the highest limit of any net metering legislation in the nation. A high system size limit allows non-residential customers, who have greater loads than most residencies, to participate in net metering and gives business owners an incentive to install systems capable of generating the entire on-site demand. In New Jersey, many businesses and schools have taken advantage of the 2 MW limit and installed DG systems up to the allowable limit.[163] Because these non-residential customers consume larger amounts of power, their DG systems have the added benefit of significantly reducing demand on the transmission grid while furthering New Jersey's goal of expanding statewide production of renewable energy to 20% by 2020.

158 This section is based on a Department of Energy/Million Solar Roofs publication. For more information see: National Renewable Energy Laboratory. (2005) Million Solar Roofs Case Study: Overcoming Net Metering and Interconnection Objections New Jersey MSR Partnership. September. http://www.nrel.gov/docs/fy05osti/38666.pdf

159 National Renewable Energy Laboratory. (2005) Million Solar Roofs Case Study: Overcoming Net Metering and Interconnection Objections New Jersey MSR Partnership. September. http://www.nrel.gov/docs/fy05osti/38666.pdf

160 See Home Power's guerilla solar archive. http://www.homepower.com/magazine/guerrilla.cfm

161 National Renewable Energy Laboratory. (2005) Million Solar Roofs Case Study: Overcoming Net Metering and Interconnection Objections New Jersey MSR Partnership. September. http://www.nrel.gov/docs/fy05osti/38666.pdf

162 Cook, Christopher. (no date) Interconnected PV - The Utility Accessible External Disconnect Switch. www.e3energy.com/Extdisc.doc

163 New Jersey's Clean Energy Program. (2006) Supported Solar Installations. March. http://www.njcep.com/html/res-installed/solar-list.html.

Broad Customer Classes

High system size limits alone are not sufficient to enable commercial classes to participate in net metering programs. As mentioned, New Jersey's statute provides an expansive definition of "small commercial customers". Without this explicit customer class, commercial customers may have been restricted and the high system size limit would be rendered largely irrelevant since most residential customer-generators would never approach 2MW of capacity. New Jersey's statue allowed no room for regulatory interpretations that would exclude larger customer-generators.

Monthly Banking of Excess Generation

Our analysis found that monthly banking of net excess generation is one of the most important factors in the effectiveness of any net metering program. For net metering customers, the grid acts like an energy bank; they deposit energy into the grid when their system produces more than they consume and withdraw energy when demand exceeds what their systems can supply. To be successful, a net metering program must facilitate banking so that customer-generators can receive credit for excess energy generated during the seasons when renewable output is highest and apply it toward their consumption when output is lower.

New Jersey's statute facilitates month-to-month banking in two ways. First, for the first 12 months of a customer's participation, the utility is required to credit customers for excess generation at the retail rate of electricity. This is important because the excess power contributed to the grid by net metered customers is sold to other consumers at the retail price. If not for monthly banking, regulated utilities would get to pocket the profits from renewable energy that they did not create. By passing those profits on to the generators of renewable energy, New Jersey's net metering program provides a strong incentive for customers to purchase systems large enough to produce an abundance of clean power. These larger systems, in turn, help reduce demand on the transmission grid and save the utility the added expense of costly additional plats that come online only during periods of peak demand.

If not for monthly banking, regulated utilities would get to pocket the profits from renewable energy that they did not create.

One potential limitation of New Jersey's program is that, at the end of the initial 12-month period, the added economic incentive created by the requirement to credit net excess generation at the retail rate disappears. From that point on, utilities are required to purchase net excess generation at the wholesale rate (or "avoided cost"). That is, no renewable energy generator can receive actual payment for excess energy at more than the wholesale rate[164]. Since the wholesale rate of electricity is generally less than the retail rate, the requirement diminishes the incentive to install systems that exceed on-site demand.

164 It is questionable whether it is even legal for states to pass legislation that would require utilities to purchase net excess generation at anything other than the avoided cost. The federal Public Utilities Regulatory Policies Act (PURPA) requires utilities to purchase electricity from qualified renewable energy facilities at the avoided cost and states that mandate any other price may be deemed in violation of PURPA. Courts have yet to settle whether states have ultimate jurisdiction to determine the rate at which net metered electricity must be purchased or if net metered customers constitute PURPA qualified facilities, in which case Congress would have to amend PURPA to allow states to set rates that exceed avoided costs.

Does not limit total capacity

Some states place a cap on the total amount of electricity that can be generated by all net metered systems (i.e. 0.1% of a utility's total capacity). This limits both the number of customers who will participate as well as the total amount of electricity produced by renewable DG systems. Placing a cap on the number of customers who can net meter is counter-productive, potentially impeding the growth of the very technologies net metering is designed to promote. New Jersey places no limit on capacity from net metering customers and has helped spark a robust DG market as a result.

Placing a cap on the number of customers who can net meter is counter-productive, potentially impeding the growth of the very technologies net metering is designed to promote.

Inclusive Definition of Eligible Technologies

One of the greatest assets of New Jersey's net metering law is its inclusive definition of eligible technologies. Solar (photovoltaic) and wind power are the two most popular distributed generation technologies for residential use, and some net metering policies include only those two technologies. New Jersey's law is inclusive of a diversity of renewable technologies (fuel cells, biomass, small hydro, landfill gas, tidal and wave energy), which is important for two reasons:

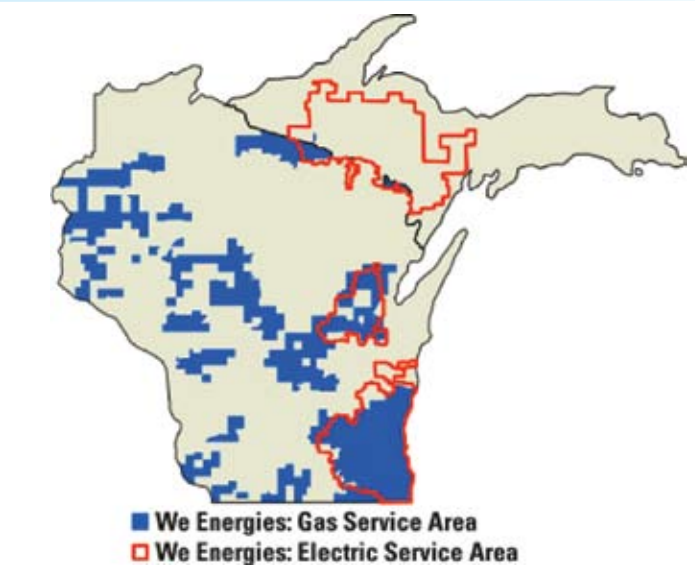
One of the most important goals of net metering is to encourage the adoption and use of distributed renewable resources. While most state programs include common renewable technologies like solar PV and wind, New Jersey's program allows fuel cells, biomass, small hydro, landfill gas and tidal and wave energy This broad definition of renewable energy helps spur the further development of novel ways of harnessing diverse renewable sources of distributed generation.

An inclusive definition of renewable energy also facilitates a more diverse net metering customer base. For example, customers involved in agriculture can use biomass, like wood pellets and switch grass, in ways that residential customers might not. It is important to include these customers in a net metering program since they use substantially more energy than residential customers and their participation can lead to more significant reductions in demand.

Regular Performance Measurements

Virtually all state-level net metering legislation incorporates some type of reporting requirement. New Jersey requires utilities to submit annual reports that include information on all customer generators in general, and net metering customers in particular. This information is valuable in judging the effectiveness of a state's net metering legislation and in determining the true costs and benefits of net metering to customers and utilities.

Rules Matter: **Michigan vs. Wisconsin**



Wisconsin Electric Power Company provides electric service to areas of Michigan's Upper Peninsula as well as parts of Wisconsin. This unique situation allows us to analyze two similar states that share a utility, but have vastly differing net metering policies. Both Michigan and Wisconsin have electricity rates under 10¢/kWh and their utility customers share similar demographics (see table 4.a). WE Energies, a subsidiary of Wisconsin Electric Power Co. is Wisconsin's largest energy provider and also serves Michigan's Upper Peninsula, which includes 22,000 customers in the Edison Sault Electric (another subsidiary of Wisconsin Electric) region (US Census Bureau, Wisconsin Electric Power).

Customers in the two states have the ability to interconnect with the same electric utility; however, customers in Michigan have less of an incentive to do so because of its lack of a net metering program. Michigan's program requires a $100 minimum filing fee and the state grants net excess generation (NEG) to the utility at the end of the annual billing cycle. Wisconsin's utilities, on the other hand, buy NEG at the retail rate and only charge fees on systems greater than 20kW, which is about five times greater than a typical residential customer load.

Table 4.a - Demographic comparison

State	Per capita incomes	Median income	Home-ownership rate	Electricity price
Wisconsin	$21,271	$46,538	68.4%	9.988 ¢/kWh
Michigan	$22,168	$46,291	73.8%	9.313 ¢/kWh

Data: Wisconsin Electric Power (WE Energies), US Census Bureau

Table 4.b - Net metering comparison for WE Energies customers

State	Net Metering Customers 2002	Net Metering Customers 2003	Net Metering Customers 2004	% Change in Net Metering Customers 2002-2004	Total Wisconsin Electric Customers	Number of Net Metering Customers per Million
Michigan	4	3	4	0%	73,981	54.1
Wisconsin	70	74	79	13%	1,060,333	74.5

Data: Wisconsin Electric Power (WE Energies)

A comparison of Michigan and Wisconsin demonstrates that incentives associated with state net metering laws play a role in promoting renewable energy DG systems. Table 4.b shows that Wisconsin saw 13% growth in the rate of participation from 2002 to 2004 and has 20 times the raw number of net metering customers as Michigan.

According to Tom Stanton of Michigan's Public Service Commission (PSC), the state's current net metering provisions are simply not generous to customers.[165] On the other hand, Patrick Keily, a representative of WE Energies, believes Wisconsin customers are net metering at a higher rate because of the economic incentive provided by Wisconsin's net metering program, which requires utilities to purchase NEG at the retail rate of electricity.[166]

The differences in the two state net metering programs reflect differing goals. Michigan's policy discourages customers from installing renewable energy systems with capacities greater than on-site demand. The primary aim of Michigan's program, according to Steve Stubleski of Michigan's Consumers Energy, "is to allow customers to self- generate electricity to meet their energy needs, not become a supplier." The program is not seeking to advocate renewable energy generation, but merely to give customers the option of generating their own electricity. The program treats non-renewable DG in the same manner as renewable generation.[167]

The primary goal of Wisconsin's program, however, is expanding the use of renewable energy. The state's net metering program is part of larger state-wide initiative that priorizes energy production in the following manner:[168]

1. Energy conservation and efficiency
2. Noncombustible renewable energy resources
3. Combustible renewable energy resources
4. Nonrenewable combustible energy resources

The differing policy priorities between Michigan and Wisconsin demonstrate how net metering rules can influence customer participation and investment decisions, all other factors being equal. WE Energies customers in Michigan and Wisconsin are nearly identical, but are subject to differing net metering laws. Wisconsin has seen significant growth in participation Michigan has not.

we energies®

165 Stanton, Tom. Personal Communication. May 23, 2006.

166 Keily, Patrick. Personal Communication. May 19, 2006.

167 Stubleski, Steve. Personal Communication. May 25, 2006

168 Wisconsin Statutes and Annotations. (2006) Chapter 1: Sovereignty and Jurisdiction of the State. 1.12(4) Priorities. http://www.legis.state.wi.us/statutes/Stat0001.pdf

VI: Simple Solutions

How to Make Net Metering Work

Model Net Metering Statute and Regulations

Developed by the Institute for Energy & the Environment, Vermont Law School[169]

This model net metering statute and interconnection standards are applicable to all retail utilities operating within the state. The adoption of interconnection standards and regulations is delegated to the state utility regulatory commission.

In an attempt to reach a broader class of customers, the statute allows customers who generate less than 2MW of capacity to qualify for net metering. Renewable energy sources have also been defined broadly to encourage increased participation. Additional efforts to encourage participation are demonstrated through the proposed credit system. Customer-generators are allowed to "bank" excess power to the next billing period until the end of the annual billing cycle, when they are then compensated by the utility for any excess.

Retail utilities are not allowed to discourage net metering by imposing additional fees and charges that are not ordinarily charged to customers who do not participate in net metering. Utilities are also prohibited from requiring additional equipment and insurance for systems that are in compliance with accepted standards.

Program progress is tracked in an annual report compiled by the retail utility and submitted to the state utility regulatory commission. This report serves as a check on the utility to ensure that it is in compliance with the statute and is not discouraging customers from participating in net metering.

We have provided the option of including additional renewable energy sources in the definition of renewable energy. Group net metering is also encouraged because it could increase rates of participation. Group net metering allows for the cost of the renewable energy systems to be divided among a group (farm compacts, residential co-ops, etc.) so more people are able to utilize renewable energy at a decreased cost.

Educating the community about available alternatives to buying electric energy from the retail utility allows customers to make more informed decisions about their energy choices. Once more customers are aware that net metering is an available option, we believe more customers will choose self-generation as their primary electric supply.

169 In crafting these models, Vermont Law School relied, in part, on Model Net Metering Rules developed by the Interstate Renewable Energy Council in 2006 (http://www.irecusa.org/connect/netmeteringrules.pdf), FERC Order No. 2006 [18 CFR Part 35], IREC MR-I2005 Model Interconnection Standards (http://www.irecusa.org/connect/modelrules.pdf), and model interconnection procedures from the Mid-Atlantic Distributed Resources Initiative (MADRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Model Statute: The Energy Self-Reliance Act (ESRA)

Subchapter 1: Scope and Implementation

(a) This Chapter sets forth net metering requirements and interconnection standards that apply to Retail Utilities operating within the state.

(b) The state utility regulatory commission shall, after notice and opportunity for comment, adopt interconnection standards and regulations as necessary to implement this statute and promote renewable net generation (as authorized by this Chapter) throughout the state. Standards adopted pursuant to this Chapter may thereafter be amended, adopted or readopted by the state utility regulatory commission, but shall not, absent a finding of urgent public necessity, be modified so as to reduce the value of customer-generation investments upon less than 36 months prior notice.

Subchapter 2: Definitions

The following words and terms, when used in this Chapter, shall have the following meanings, unless the context clearly indicates otherwise.

"**Annualized Period**" means all billing periods within a single year. A customer-generator's first annualized period begins on the first day of the first full billing period after the customer-generator's facility is interconnected and is generating electricity.

"**Applicant**" means a person who has filed an application to interconnect a customer-generator facility to an electric delivery system.

"**Customer-generator**" means a residential, commercial, industrial, nonprofit, school, utility, agricultural, institutional, local government, state government, or federal government customer that generates renewable electric energy on the customer's side of the meter.

"**Customer-generator Facility**" means the equipment used by a customer-generator to generate, manage, and monitor electricity. A customer-generator facility includes an electric generator and/or an equipment package, as defined herein.

"**Electric Delivery System**" means the infrastructure constructed and maintained by a Retail Utility, as defined herein, to deliver electric service to end-users.

"**Group System**" means a group of physically contiguous customers located in a single electrical service provider territory that has elected to combine meters as a single billing entity in order to offset that billing against a net metered generation facility located on property owned by a group member and physically contiguous to the group members.

"**Net Metering**" means that the customer-generator is billed according to the difference between the amount of electricity supplied by the Retail Utility in a given billing period and the amount of electricity delivered from the customers' side of the meter using renewable energy systems, where customer-generator electricity delivered in excess of electricity supplied is credited over an annualized period.

"**Renewable Electric Energy**" means energy generated through the use of such resources as: (1) Solar Thermal Electricity, (2) Photovoltaic, (3) Landfill Gas, (4) Wind, (5) Biomass, (6) Hydroelectric, (7) Wave or Tidal Power, (8) Geothermal Electricity, (9) Waste-to-Energy (including Municipal Solid Waste and Agricultural Waste), (10) Fuel Cells using Renewable Fuels.

"**Retail Utility**" means any utility offering retail electric service in the State.

"**Service Entrance Capacity**" means the rating of the customer's electric service, determined by multiplying:

(1) the voltage provided to the customer by the Retail Utility

by

(2) the ampere rating of the customer's primary over-current protection device (fuse or circuit breaker)

by

(3) the appropriate multiplier for multi-phase service and generators.

Subchapter 3: Net Metering General Provisions

(a) All Retail Utilities shall offer net metering to customer-generators with renewable energy generation that are interconnected with the Retail Utility pursuant to interconnection rules adopted to implement this statute, provided that the generating capacity of the customer-generator's facility meets both of the following criteria:

1. The rated capacity of the generator does not exceed two megawatts (MW); and

2. The rated capacity of the generator does not exceed the customer's service entrance capacity.

(b) The Retail Utility shall develop a net metering tariff that provides for customer-generators to be credited, in kilowatt-hours (kWh), at a ratio of 1:1, for any production by the customer's generating facility that exceeds the customer-generator's on-site consumption of kWh. The credit shall be applied in the billing period following the billing period of excess production. However, any excess kWh credits shall not reduce any fixed billing period customer charges imposed by the Retail Utility.

(c) The Retail Utility shall carry over any excess kWh credits earned by customer-generators under paragraph (b) and apply those credits to subsequent billing periods to offset any customer-generator consumption in those billing periods. The carry over will continue until all credits are used or the end of the annual billing cycle is reached.

(d) At the end of each annual billing period, the Retail Utility shall compensate the customer-generator for any excess kWh credits at that customer-generator's otherwise applicable retail rate for marginal electric energy usage.

(e) If a customer-generator terminates its service with the Retail Utility [[*or switches electricity suppliers*]], the Retail Utility shall compensate the customer-generator for any excess kWh credits at that customer-generator's otherwise applicable retail rate for marginal electric energy usage, over the billing period immediately prior to termination of service.

(f) A customer-generator facility used for net metering shall be equipped with metering equipment that can measure the flow of electricity in both directions at the same

rate. For customer-generator facilities less than 10 kilowatts (kW), this may be accomplished through use of a single, bi-directional electric revenue meter that has only a single register for billing purposes.

(g) A customer-generator may choose to use an existing electric revenue meter if the following criteria are met:

1. The meter is capable of measuring the flow of electricity both into and out of the customer generator's facility at the same rate and ratio; and

2. The meter is accurate to within plus or minus 5 percent when measuring electricity flowing from the customer-generator facility to the electric distribution system.

(h) If the customer-generator's existing electric revenue meter does not meet the requirements at (g) above, the Retail Utility shall install and maintain a new revenue meter for the customer-generator, at the Retail Utility's expense. Any subsequent revenue meter change necessitated by the customer-generator, whether because of a decision to stop net metering or for any other reason, shall be paid for by the customer-generator.

(i) The Retail Utility shall not require more than one meter per customer-generator. However, an additional meter may be installed under either of the following circumstances:

1. The Retail Utility may install an additional meter at its own expense if the customer-generator consents; or

2. The customer-generator may request that the Retail Utility install a meter, in addition to the revenue meter addressed in (g) above, at the customer-generator's expense. In such a case, the Retail Utility shall charge the customer-generator no more than the actual cost of the meter and its installation.

(j) A customer-generator owns the renewable energy credits (RECs) of the electricity it generates, and may apply to the state regulatory commission or its authorized designee for issuance of solar RECs (S-RECs) or RECs as appropriate and based on actual on-site electric generation, or the calculated estimate of on-site electric generation for generators less than 10 kW in rated capacity and as further defined in Section [[*reference any state renewable portfolio standard (RPS) requirements here*]].

(k) A Retail Utility shall provide to net-metered customer-generators electric service at non-discriminatory rates that are identical, with respect to rate structure, retail rate components, and any monthly charges, to the rates that a customer-generator would be charged if not a customer-generator.

(l) A Retail Utility shall not charge a customer-generator any fee or charge, or require additional equipment, insurance, or any other requirement not specifically authorized under this paragraph or the interconnection rules adopted to implement this statute, unless the fee, charge or other requirement would apply to other similarly situated customers who are not customer-generators.

(m) Each Retail Utility shall submit an annual net metering report to the state regulatory commission. The report shall be submitted by the end of each calendar year, and shall include the following information for the previous compliance year:

1. the total number of customer-generator facilities;

2. the total estimated rated generating capacity of its net-metered customer-generators;

3. the total estimated net kilowatt-hours received from customer-generators, expressed as both an aggregated absolute amount and, also, as a percentage of total kilowatt-hours provided to retail customers by the Retail Utility;

4. the total estimated amount of energy produced by the customer-generators; and

5. outreach and information efforts engaged in by the Retail Utility in order to inform customers about the availability of net metering service pursuant to this chapter.

Subchapter 4: Other qualifying customer-generators [[optional]]

(a) Biomass generators that run on-peak at 100% capacity and qualify for an air permit or otherwise meet criteria established by the Department of Environment.

(b) Combined heat and power (CHP) generators with efficiency greater than two times the system average (and qualifies for an air permit or otherwise meets criteria established by the Department of Environment).

(c) Group Net Metering Systems that consist of a group of physically contiguous customers located in a single electrical service provider territory that has elected to combine meters as a single billing entity in order to offset that billing against a net metered generation facility located on property owned by a group member and physically contiguous to the group members.

(d) Waste-to-Energy (including Municipal Solid Waste and Agricultural Waste).

Subchapter 5: General Provisions

(a) If a net metering interconnection has been approved under the interconnection rules of Section [*reference state interconnection rules here*], the Retail Utility shall not require a customer-generator to test or perform maintenance on its facility except for any manufacturer-recommended testing or maintenance.

(b) A Retail Utility shall have the right to inspect a customer-generator's facility during reasonable hours and with reasonable prior notice to the customer-generator. If the Retail Utility discovers that the customer-generator's facility is not in compliance with the requirements of the interconnection rules in Section [*reference state interconnection rules here*] or the requirements of IEEE Standard 1547, and the non-compliance adversely affects the safety or reliability of the Retail Utility's or other customers' facilities, the Retail Utility may require the customer-generator to disconnect the customer-generator facility until compliance is achieved.

Subchapter 6: Public Outreach and Understanding

(a) The state regulatory commission shall conduct a comprehensive statewide public outreach process regarding net metering and interconnection, [[*focused on promoting renewable electric energy*]]. The state regulatory commission shall develop and implement a public outreach and understanding process through a request for proposals that meet the following requirements:

1. provide a strong information dissemination component, in order to develop a shared foundation of credible information that may serve as a basis for engaging in meaningful dialogue;

2. engage a broad base of citizens, including those who are currently engaged in energy issues as well as those who have not yet been engaged;

3. reach throughout the state and establish a model for educating the public about the electric energy supply challenges facing the state.

Model Interconnection Standards & Regulations

Subchapter 1: Definitions

"**Area network**" means an electric delivery system served by multiple transformers interconnected in an electrical network circuit, of the type generally used in large metropolitan areas that are densely populated in order to provide high reliability of service, and having the same definition as the term "secondary grid network" as defined in IEEE standards.

"**Customer**" means a potential customer-generator that will generate renewable electric energy on the customer's side of the meter.

"**Equipment package**" means a group of components connecting an electric generator with an electric delivery system, and includes all interface equipment including switchgear, inverters, or other interface devices. An equipment package may include an integrated generator or electric source.

"**Fault current**" means electrical current that flows through a circuit and is produced by an electrical fault, such as to ground, double-phase to ground, three-phase to ground, phase-to-phase, and three-phase.

"**Good Utility Practice**" means a practice, method, policy, or action that is engaged in, and/or accepted by, a significant portion of the electric industry in a region, and that a reasonable utility official would expect, in light of the facts reasonably discernable at the time, to accomplish the desired result reliably, safely and expeditiously, but that is not inconsistent with these rules. This term has the same definition as the term is used in the interconnection rules promulgated by the FERC.

"**Group system**" means a group of physically contiguous customers located in a single electrical service provider territory, where the group has elected to combine meters as a single billing entity in order to offset that billing against a net metered generation facility located on property owned by a group member that is part of the physically contiguous properties of the rest of the group members.

"**IEEE**" means the Institute of Electrical and Electronic Engineers.

"**IEEE standards**" means the standards published by the Institute of Electrical and Electronic Engineers, available at www.ieee.org.

"**Interconnection Agreement**" means an agreement between a customer-generator and a Retail Utility, which governs the connection of the customer-generator facility to the electric delivery system, as well as the ongoing operation of the customer-generator facility after it is connected to the system. An interconnection agreement shall follow the standard form agreement developed by the state utility regulatory commission, which shall be posted on the state utility regulatory commission's website.

"**Minor System Modifications**" are those activities that entail less than 4 hours of work and not more than 5% of total system costs in materials, such as changing the fuse in a fuse holder cut-out, changing the settings on a circuit recloser, and other such activities.

"**Point of Common Coupling**" means the point in the interconnection of a customer-generator facility with an electric delivery system at which the harmonic limits are applied. This term shall have the same meaning as in IEEE Standard 1547.

"**Spot network**" means a type of electric delivery system that uses two or more inter-tied transformers to supply an electrical network circuit. A spot network is generally used to supply power to a single customer or a small group of customers and has the same meaning as the term is used in IEEE standards.

Subchapter 2: Interconnection Standards for Customer-Generator Facilities

(a) There are two interconnection review paths for interconnection of customer-sited generation.

1. Simplified – This is for qualified inverter-based facilities with a power rating of 10 kW or less on radial or spot network systems under certain conditions.

2. Standard – This is for certified generating facilities that pass certain pre-specified screens and have a power rating of 2 MegaWatts (MW) or less.

(b) In order to qualify for Simplified or Standard Interconnection Procedures, generators no larger than 2 MW must be certified pursuant to paragraph (c) to comply with the following codes and standards as applicable:

1. IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems or IEEE 929 for inverters less than 10kW in size

2. UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

3. When any listed version of these codes and standards is superseded by a revision approved by the standards-making organization, then the revision will be applied under paragraph (c).

(c) Certification of Equipment Packages: Interconnection equipment shall be considered certified for interconnected operation if it has been tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous interactive operation with a utility grid and meets the definition for Certification under FERC Order 2006.

(d) Screening Criteria for Determining Grid Impacts: A proposed interconnection that meets the following applicable screening criteria shall be processed by the Retail Utility under Standard Interconnection Procedures and, if qualified, for net metering.

1. For interconnection of a proposed generator to a radial distribution circuit, the aggregated generation, including the proposed generator, on the circuit will not exceed 15% of the total circuit annual peak load as most recently measured at the substation.

2. The proposed generator, in aggregate with other generation on the distribution circuit, will not contribute more than l0% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of common coupling.

3. The proposed generator, in aggregate with other generation on the distribution circuit, will not cause any distribution protective devices and equipment (including but not limited to substation breakers, fuse cutouts, and line

reclosers), or customer equipment on the system, to exceed 90% of the short circuit interrupting capability; nor is an interconnection to be proposed for a circuit that already exceeds 90% of the short circuit interrupting capability.

4. The proposed generator, in aggregate with other generation interconnected to the distribution low voltage side of the substation transformer feeding the distribution circuit where the generator proposes to interconnect, will 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 (e.g., 3 or 4 transmission voltage level busses from the point of common coupling).

5. The proposed generator is interconnected to the Retail Utility as shown in the table below:

6. If the proposed generator is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generator, will not exceed 20 kiloVolt-Amps (kVA).

7. If the proposed generator is single-phase and is to be interconnected on a transformer center tap neutral of a 240 volt service, its addition will not create an imbalance between the two sides of the 240 volt service of more than 20% of nameplate rating of the service transformer.

8. The proposed generator's Point of Common Coupling will not be on a transmission line.

Primary Distribution Line Configuration	Interconnection to Primary Distribution Line
Three-phase, three wire	If a 3-phase or single phase generator, interconnection must be phase-to-phase
Three-phase, four wire	If a 3 phase (effectively grounded) or single-phase generator, interconnection must be line-to-neutral

(e) Special Screening Criteria for interconnection to Spot Networks and Area Networks. The Screening Criteria under this paragraph shall be in addition to the applicable Screens in paragraph (d).

1. For interconnection of a proposed generator to a spot network circuit where the generator or aggregate of total generation exceeds 5% of the spot network's maximum load, the generator must utilize a protective scheme that will ensure that its current flow will not affect the network protective devices including reverse power relays or a comparable function.

2. For interconnection of a proposed generator that utilizes inverter based protective functions to an area network, the generator, in aggregate with other exporting generators interconnected on the load side of network protective devices, will not exceed the lesser of 10% of the minimum annual load on the network or 500 kW. For a solar photovoltaic customer-generator facility, the 10% minimum shall be determined as a function of the minimum load occurring during an off-peak daylight period

3. For interconnection of generators to area networks that do not utilize inverter based protective functions or inverter based generators that do not meet the requirements of subparagraph (e)(2) above, the generator must utilize reverse power relays or other protection devices to ensure that there will be no export of power from the customer's site, including any inadvertent export (under fault conditions) that could adversely affect protective devices on the network circuit.

(f) Each Retail Utility shall have a Simplified Interconnection Procedure for Inverter Based Generators not exceeding 10kW in capacity, which shall require the following steps.

1. The customer submits an application, filled out properly and completely, indicating which certified generator or equipment package the customer intends to use.

2. The Retail Utility acknowledges to the customer receipt of the application within 3 business days of receipt.

3. The Retail Utility evaluates the application for completeness and notifies the customer within 7 business days of acknowledgement of receipt that the application is or is not complete, and whether the generating facility equipment passes screens 1, 6, 7 and 8 in paragraph (d). If incomplete, or if the generating facility equipment does not pass the appropriate screens, the application is rejected and returned to the customer with a list of items needed to make it complete.

4. If the application is complete, and the generating facility equipment passes the applicable screens, then within 3 business days of the customer notification under subparagraph (f)(3), the Retail Utility will execute and send a Simplified Interconnection Agreement to customer.

5. If the Retail Utility does not notify a customer in writing or by e-mail whether the interconnection is approved or denied within 20 business days after the receipt of an application, the interconnection shall be deemed approved. The 20 days shall begin on the date that the Retail Utility sends the written or e-mail notice that the application is received.

6. Upon receipt of the signed Simplified Interconnection Agreement and completion of installation, the Retail Utility may inspect the generating facility for compliance with standards and may arrange for a witness test.

7. Provided the inspection/test is satisfactory, the Retail Utility must notify the customer, in writing, within 15 business days that interconnection is allowed, and approved. If the inspection/test is unsatisfactory, the Retail Utility must notify the customer, in writing, within 15 business days, explaining the reasons for disapproval of interconnection. Final interconnection of the generator is subject to approval by the appropriate electrical code officials.

8. The Simplified Interconnection is provided at no cost to the customer. Additional protection equipment not included with the certified generator or interconnection equipment package may be added at the Retail Utility's discretion as long as the performance of the system is not negatively impacted

in any way and the customer is not charged for any equipment in addition to that which is included in the certified equipment package.

(g) Each Retail Utility shall have a Standard Interconnection Procedure for customer-sited generators not subject to paragraph (f) above and not exceeding 2 MW in capacity that will use existing customer facilities, which shall require the following steps.

1. To assist customers in the interconnection process, the Retail Utility will designate an employee or office from which basic information on the application can be obtained through an informal process. On request, the Retail Utility will provide the customer with all relevant forms, documents, and technical requirements for filing a complete application for interconnection of generators not exceeding 2 MW to the Retail Utility's electric power system. Upon the customer's request, the Retail Utility will meet with the customer prior to submission of an application for Standard Interconnection.

2. The customer shall submit an application for Standard Interconnection to the Retail Utility and may, at the same time, submit an Interconnection Agreement executed by the customer.

3. The customer will be notified by the Retail Utility within 3 business days of its receipt of an interconnection application.

4. The Retail Utility will notify the customer within 7 business days of acknowledgement of receipt of the application whether it is complete or incomplete. If the application is incomplete, the Retail Utility will at the same time provide the customer a written list detailing all information that must be provided to complete the application. The customer will have 10 business days to submit the listed information following receipt of the notice. If the customer does not submit the listed information to the Retail Utility within the 10 business days, the application shall be deemed withdrawn. An application will be complete upon the customer's submission of the information identified in the Retail Utility's written list.

5. Within 10 business days after the Retail Utility notifies customer it received a complete application, the Retail Utility shall perform an Initial Review of the proposed interconnection, which shall consist of an application of the screening criteria set forth in paragraphs (d) and (e). The Retail Utility shall notify customer of the results, providing copies of the analysis and data underlying the Retail Utility's determinations under the screens. During the Initial Review, the Retail Utility may conduct, at its own expense, any additional studies or tests it deems necessary to evaluate the proposed interconnection.

6. If the Initial Review determines that the proposed interconnection passes the screens set forth in paragraphs (d) and (e) as applicable, the interconnection application will be approved and the Retail Utility will provide the customer with an executable Interconnection Agreement within 5 business days after the determination.

7. If the Initial Review determines that the proposed interconnection fails one or more screens in paragraphs (d) and (e), but the Retail Utility determines through the Initial Review that the small generator may nevertheless be interconnected consistent with safety, reliability, and power quality, with or without minor system modifications, the Retail Utility will provide the customer with an executable Interconnection Agreement within 5 business days after the determination. The generator is responsible for the cost of any minor system modifications required.

8. If the Initial Review determines that the proposed interconnection fails one or more screens in paragraphs (d) and (e), and the Retail Utility does not or cannot determine from the Initial Review that the generator may nevertheless be interconnected consistent with safety, reliability, and power quality standards, then the Retail Utility will offer to perform an additional review if the Retail Utility concludes that additional review might determine that the generator could qualify for interconnection pursuant to the Standard Procedures. The Retail Utility will provide a non-binding, but good faith estimate of the costs of such additional review when it notifies the customer that its proposed interconnection has failed one or more screens in paragraphs (d) and (e).

9. Each Retail Utility will include in its net metering and interconnection compliance tariff the procedure it will follow for any additional review including the allocation of cost responsibility to the customer.

10. Final interconnection of the customer's generator is subject to commissioning tests as set forth in the IEEE standard 1547 (paragraph (b)) and approval by the appropriate local electrical code officials.

11. An application and processing fee may be imposed on customers proposing interconnection of generators under Standard Interconnection Procedures provided the total of all fees to complete the interconnection does not exceed $50 plus $1.00 per kilowatt of the capacity of the proposed generator. Additional fees may only be charged to customers if their generator interconnection requires minor system modifications pursuant to subparagraph (g)(7) or additional review pursuant to subparagraph (g)(8). Costs for minor system modifications or additional review will be based on quotations for services from the Retail Utility and subject to review by the state utility regulatory commission or its designee for such review.

(h) An electric distribution company may not require a customer-generator whose system(s) meets the Simplified or Standard Interconnection standards in paragraphs (b) through (g) above, as applicable, to install additional controls, perform or pay for additional tests or purchase additional liability insurance, except as agreed to by the customer in paragraph (g) above.

(i) Each customer-generator approved for interconnection shall affix to their electric revenue meter a standard warning sign as approved by the state utility regulatory commission that notifies utility personnel of the existence of customer-sited parallel generation.

Subchapter 3: Miscellaneous

(a) A Retail Utility that charges a fee for an interconnection study shall provide the customer-generator with a bill that includes a clear explanation of all charges. In addition, the Retail Utility shall provide to the customer-generator, prior to the start of the interconnection study, a good faith estimate of the number of hours that will be needed to complete the interconnection study, and an estimate of the total interconnection study fee.

(b) If a customer-generator's facility complies with all applicable standards in subchapter 2, the facility shall be presumed to comply with the technical requirements of this paragraph. In such a case, the Retail Utility shall not require a customer-generator to install additional controls (including but not limited to a utility accessible disconnect switch), perform or pay for additional tests, or purchase additional liability insurance in order to obtain approval to interconnect.

(c) Once an interconnection has been approved under this paragraph, the Retail Utility shall not require a customer-generator to test its facility except that it may require the following:

1. an annual test in which the customer-generator's facility is disconnected from the Retail Utility's equipment to ensure that the generator stops delivering power to the grid;

2. any manufacturer-recommended testing; and

3. a test to verify continued interconnection after a power outage.

(d) A Retail Utility shall have the right to inspect a customer-generator's facility both before and after interconnection approval is granted, at reasonable hours and with reasonable prior notice to the customer-generator. If the Retail Utility discovers the customer-generator's facility is not in compliance with the requirements of subchapter 2 and the non-compliance adversely affects the safety or reliability of the electric system, the Retail Utility may require disconnection of the customer-generator's facility until it complies with this paragraph.

Subchapter 4: Group Net Metering [[*optional*]]

(a) Electric energy measurement for net metering systems using a group system shall be calculated in the following manner:

1. Net metering customers that are group systems may credit all on-site generation against all meters designated to the group system.

2. If the electricity generated by the group system is less than the total usage of all meters included in the system during the billing period, the customer shall be credited for any accumulated kWh credit and then billed for the net electricity supplied by the electric utility.

(b) [[*In addition to any other requirements of an applicable state statute*]], before a group system including more than one meter may be formed and served by a Retail Utility, the group system shall file with the state utility regulatory commission and the serving Retail Utility, the following information:

1. the meters to be included in the group system, which shall be associated with buildings and residences owned or occupied by the person operating the group system, identified by the most relevant pre-existing account number and location or, if no such account number exists, by location and proposed point of interconnection to the utility system

2. a method for adding and removing meters included in the group system;

3. a designated person responsible for all communications from the group system to the Retail Utility, for receiving and paying bills for any services provided by the Retail Utility for the group system, and for receiving any other communications regarding the group system; and

4. a binding process for the resolution of any disputes within the group system relating to net metering that does not rely on the Retail Utility or the state utility regulatory commission.

(c) Group system customers shall, at all times, maintain a written designation to the Retail Utility of a person who shall be the sole person authorized to receive and pay bills for service provided by the Retail Utility, and for any other communications regarding the group system.

(d) The Retail Utility shall implement appropriate changes to a group system within thirty days after receiving written notification from the person designated under subchapter 4, paragraph (c). However, written notification of a change in the person designated under subchapter 4, paragraph (c) shall be effective upon receipt by the Retail Utility. The Retail Utility shall not be liable for action based on such notification, but shall make any necessary corrections and bill adjustments to implement revised notifications.

(e) In cases of non-payment of group system bills, the electric utility may disconnect all meters associated with the group system [[*in accordance with the same state utility regulatory commission rules as are applicable to the most nearly analogous customers without netmetering*]].

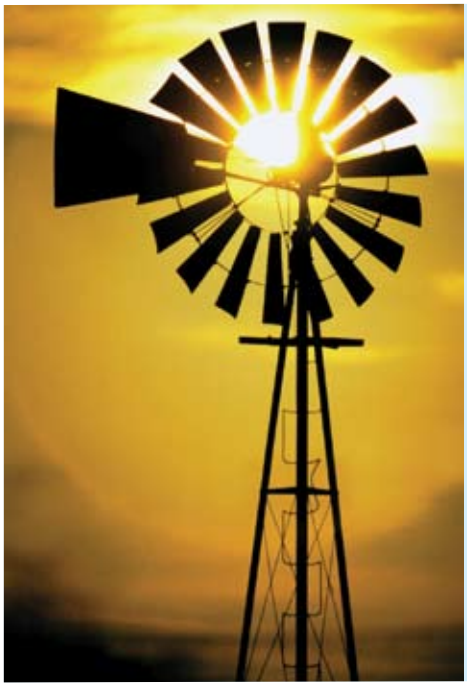
Subchapter 5: Dispute Resolution

(a) The state utility regulatory commission may from time to time designate a hearing officer or technical master for the resolution of interconnection disputes. If the state utility regulatory commission has so designated, the parties shall use the hearing officer or technical master to resolve disputes related to interconnection and such resolution shall be binding on the parties.

(b) The state utility regulatory commission may designate a Department of Energy national laboratory, college or university, or an approved Federal Energy Regulatory Commission (FERC) Regional Transmission Office with distribution system engineering expertise as the technical master. Should the FERC identify a national technical dispute resolution team, the state utility regulatory commission may designate said team as its hearing officer or technical master.

A Federal Net Metering Program

While individual states can and should improve their net metering programs by adopting the model statutes we have recommended, the wide discrepancy in both the design and implementation of individual state net metering programs has created an uneven playing-field, both for regulated utilities and for small-scale renewable generating facilities. Ideally, a uniform national renewable energy policy would stem from federal leadership. Unifying the country behind the important goal of increasing renewable energy output could be achieved with a cleverly-designed national net metering policy that standardizes net metering procedures and overcomes the limitations often created by a patchwork of state-based initiatives.



Our analysis of 34 existing state net metering programs reveals that most utilities are likely to embrace changes in net metering mandates with the enthusiasm of a tax audit[170]. Because most utilities perceive net metering programs as revenue-losers rather than demand-reduction strategies, they have lobbied at the state level for unnecessary restrictions, burdensome procedures and excessive fees that limit participation.[171] As we have shown, in many states the regulatory barriers established at the behest of utilities have effectively thwarted the original intentions of the net metering programs.

Individual states that have been the most effective at promoting clean energy have treated net metering as a demand-reduction strategy that is part of a broad system of incentives to encourage the adoption of renewable energy technologies. Because renewable systems typically produce the most electricity during hours of peak demand (solar panels, for instance, generate the most electricity in the afternoon, when demand on the grid is greatest), net metered customers generally consume electricity from the grid during off-peak hours. Therefore, net metering should be perceived as a benefit to regulated utilities by reducing peak demand at the times when the grid is most strained.

A novel way to create the perception among utilities that net metering is an effective demand-reduction strategy is to establish a national renewable portfolio standard (RPS) that requires by a date certain that all regulated utilities meet a percentage of net electricity demand through qualified renewable resources. For example, a national RPS statute might mandate that by 2020, all regulated utilities are required to meet 20% of net electricity demand from electricity generated by qualified renewable sources. This approach sets the renewable energy goal as a function of electricity *demand* rather than electricity *generation*.[172]

Calculating RPS goals as a function of electricity demand provides utilities with additional flexibility that some state RPS architectures do not. By making the national RPS goal a function of demand, the ultimate compliance level is placed squarely in the hands of utilities, encouraging them to view on-site renewable generation as a demand

170 When New York recently solicited comments pursuant to its consideration of the state's net metering program as required by EPAct, regulated utilities almost universally commented that no additional expansion was warranted.

171 Graves, F. (2006) Net Metering Under EPAct 2005: Setting Customer Credits and Related Issues. Presented at PURPA's Net Metering Standard: Net Benefit or Net Detriment, Edison Electric Instititue E-Forum, June 22.

172 NNEC Executive Director Chris Cooper and Board Member Dr. Benjamin Sovacool first proposed this idea in a recent Electricity Journal article that provides greater detail. See Sovacool, B. and Cooper, C. (2006) Green Means 'Go?': A Colorful Approach to a U.S. National Renewable Portfolio Standard. Electricity Journal. 19:7. August/September (pp. 19-32).

reduction strategy that helps them meet their regulatory requirements. Every reduction in demand also reduces the total amount of renewable energy that utilities are required to generate on their own. By creating a regulatory framework where utilities view net metering programs correctly as demand-reduction strategies, a national RPS would promote increased participation in net metering programs and encourage utilities to support higher capacity caps, expand the number of eligible customer classes, and decrease the unnecessary regulatory burdens that have tended to discouraged participation in many states.

A national program provides a level of regulatory predictability that should be embraced by the growing number of utilities operating across states that are required to develop net metering programs.

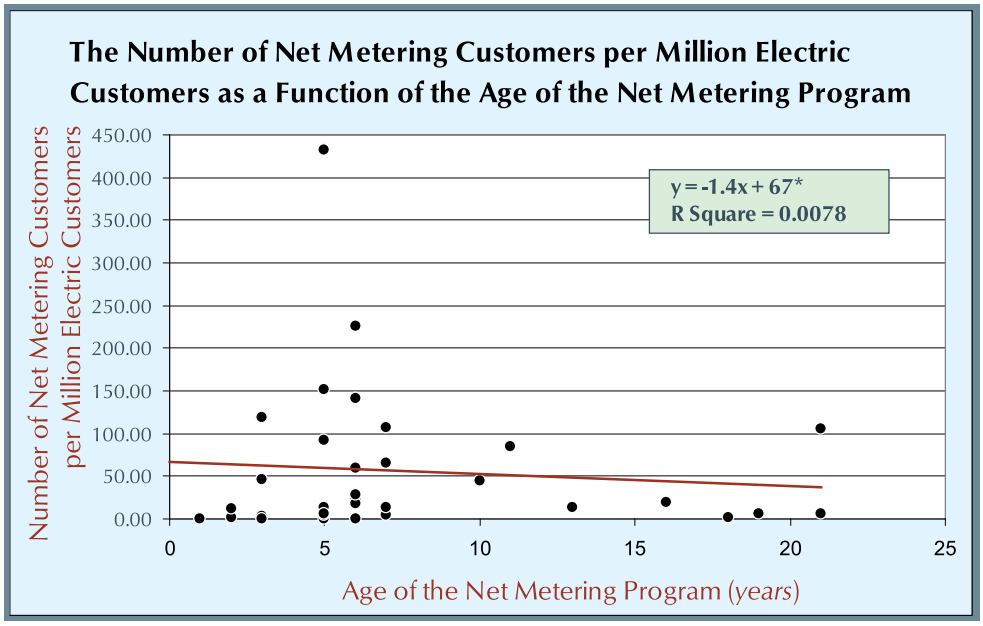
For the renewable energy services sector, a national net metering scheme would allow market forces to dictate the geography of energy investments. A national strategy would allow certain technologies to flourish where they are most useful and encourage a greater diversity of electricity generation across states.

Standardized national net metering rules would also create a uniform curriculum for training technicians and create a more diverse pool of expertise that would reduce the amount of time (and money) individual states spend developing their own curriculums and training their own technicians. National standards would also expand job opportunities for certified technicians by allowing greater employment mobility. Expertise developed in one state would be just as useful in any other state.

For utilities, a uniform, federal net metering program should prove more attractive than a network of 50 state-based regulatory schemes. A national program provides a level of regulatory predictability that should be embraced by the growing number of utilities operating across states that have yet to develop net metering programs as required by EPAct. Even for utilities focused exclusively on the bottom line, the devil you know is better than the devil you don't.

: Appendix A

Explaining the Magic Number 67



Data: DOE EIA, DOE EERE, and Union of Concerned Scientists[173]

Appendix A is a regression comparing the number of net metering customers with the age of the net metering statute. The most recent available customer data is from 2004 and therefore we based the age of the statute on a 2004 starting point. We determined that California, with over 13,000 net metering customers, is an outlier and not included in this analysis.

The results of the regression show that, although the equation is negative, there is not a significant change in the number of net metering customers over the course of time ($p = 0.63$). Although the slope of the line is not significant, we can infer that newer net metering programs tend to have more customers when compared to older ones.

The Y intercept - 67 - is significant ($p = 0.017$), which means that we have confidence that any net metering program, no matter its age, should have at least 67 customers. Therefore, we characterize effective state net metering programs as having at least 67 customers enrolled. Based on this analysis, we expect new state programs to have enrollment numbers of this size.

173 Energy Information Agency. Green Pricing and Net Metering Programs 2004. March 2006. http://www.eia.doe.gov/cneaf/solar.renewables/page/greenprice/green_pricing.html

Union of Concerned Scientists. Summary of State "Net Metering" Programs. April 2006. http://www.ucsusa.org/assets/documents/clean_energy/State_Net_Metering_Rules.pdf

U. S. Dept. of Energy, Office of Energy Efficiency and Renewable Energy. July 12, 2004 http://www.eere.energy.gov/greenpower/pdfs/metering_0604.pdf.

: Appendix B

Breaking Ties

The table below lists the reasons for breaking ties between states that have the same index score. Most ties were broken by evaluating the rate of growth in participation or the total number of participating customers.

Rank	State	Grade	Percentile	Score	Reason for Higher Ranking
1	New Jersey	A	100%	305	
2	Montana	A	97%	67	
3	California	A	94%	15	
4	Oregon	A	91%	14	
5	Nevada	A	88%	7	
6	Minnesota	A	82%	6	Greater growth rate
7	New Hampshire	A	82%	6	
8	Wisconsin	A	79%	4	
9	Hawaii	B	64%	3	Greater growth rate
10	Vermont	B	64%	3	More participating customers per capita
11	Wyoming	B	64%	3	More participating customers per capita
12	Ohio	B	64%	3	More participating customers per capita
13	Louisiana	B	64%	3	
14	Utah	B	61%	2	
15	Connecticut	C	48%	1	More participating customers per capita
16	New York	C	48%	1	More participating customers per capita
17	New Mexico	C	48%	1	More participating customers per capita
18	Georgia	C	48%	1	
19	Washington	D	36%	0	More participating customers per capita
20	Virginia	D	36%	0	More participating customers per capita
21	Kentucky	D	36%	0	Has participating customers
22	Maine	D	36%	0	
23	Massachusetts	F	27%	-1	More participating customers per capita
24	Iowa	F	27%	-1	Has participating customers
25	Delaware	F	27%	-1	
26	Colorado	F	9%	-2	More participating customers per capita
27	North Dakota	F	9%	-2	More participating customers per capita
28	Indiana	F	9%	-2	More participating customers per capita
29	Maryland	F	9%	-2	More participating customers per capita
30	Texas	F	9%	-2	Net excess generation purchased, not granted, by the utility monthly
31	Arkansas	F	9%	-2	
32	Rhode Island	F	3%	-3	More participating customers per capita
33	Pennsylvania	F	3%	-3	
34	Oklahoma	F	0%	-4	

: Appendix C

Glossary of Terms

DG – Distributed Generation

Also known as 'Community-Based Power', distributed generation is Electricity generation that occurs at or near the site of ultimate consumption as opposed to most electricity which is generated at a remote site and transported by long-distance transmission lines to the consumer.

EIA – Energy Information Administration (Department of Energy)

The Energy Information Administration (EIA), as part of the U.S. Department of Energy, collects and disseminates data on energy reserves, production, consumption, distribution, prices, technology, and related international, economic, and financial matters. Coverage of EIA's programs includes data on coal, petroleum, natural gas, electric, and nuclear energy.

EPAct – Energy Policy Act of 2005

Also know as 'The Energy Bill, EPAct was intended to establish a comprehensive, long-range energy policy. It provides incentives for traditional energy production as well as newer, more efficient energy technologies, and conservation. More than 1,700 pages long, the Act has hundreds of provisions affecting energy generation and utility policy.

FERC – Federal Energy Regulatory Commission

An independent federal agency, FERC regulates the interstate transmission of electricity, natural gas, and oil. FERC also reviews proposals to build liquefied natural gas (LNG) terminals and interstate natural gas pipelines as well as licensing hydropower projects.

IEEE1547 – Institute of Electrical and Electronics Engineers standard

IEEE 1547 is the Institute's standard for interconnecting distributed resources (DG systems) with electric power systems and was approved by the IEEE Standards Board in June 2003. It was approved as an American National Standard in October 2003.

NEG – Net Excess Generation

When a net metered customer produces more electricity than it consumes during a utility billing cycle, the difference is called the net excess generation.

PUHCA – Public Utility Holdings Company Act of 1935

A 'New Deal' law to protect consumers and investors. It placed geographic restrictions on mergers and limitations on diversification into non-utility lines of business and takeovers of electric and gas utilities, and also established regulated monopoly markets or service territories for utilities.

PURPA – Public Utility Regulatory Policies Act of 1978

PURPA was passed during the 1970's energy crisis to encourage the conservation and efficient use of energy resources and to encourage the development of alternative power supplies capable of displacing the inefficient use of oil and natural gas by electric utilities. PURPA requires electric utilities, when they need power, to purchase power from qualifying alternative energy facilities (QFs) at the utilities' avoided cost, provide back-up power to QFs, interconnect with QFs, and operate with QFs under reasonable terms and conditions.

PV – Photovoltaic

Photovoltaics (PV) or solar cells as they are often called, are semiconductor devices that convert sunlight into direct current (DC) electricity. Groups of PV cells are electrically configured into modules and arrays, which can be used to charge batteries, operate motors, and to power any number of electrical loads. With the appropriate power conversion equipment, PV systems can produce alternating current (AC) compatible with any conventional appliances, and can operate in parallel with, and interconnected to, the utility grid.

RECs – Renewable Energy Credits

Also known as Green Tags or Tradable Renewable Certificates (TRCs), RECs represent the environmental benefits associated with generating electricity from renewable energy sources. RECs function as a non-governmental subsidy on pollution-free electricity generators. Within REC trading markets, a certifying agency gives each REC a unique identification number to make sure it doesn't get double-counted. The clean energy is then fed into the electrical grid and the accompanying REC can then be sold separately from the electricity.

RPS – Renewable Portfolio Standards

A policy set by federal or state governments that a percentage of the electricity supplied by generators be derived from a renewable source by a date certain.

T&D – Transmission & Distribution

Electric power transmission is one process in the transmitting of **electricity** to consumers. The term refers to the bulk transfer of electrical power from place to place. Typically, power transmission is between the **power plant** and a **substation** near a populated area. This is distinct from **electricity distribution**, which is concerned with the delivery from the substation to the consumers. Due to the large amount of power involved, transmission normally takes place at high voltage (110 kV or above). Electricity is usually transmitted over long distance through overhead power transmission lines (such as those in the photo on the right). Underground power transmission is used only in densely populated areas (such as large cities) because of the high cost of installation and maintenance.

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