2011

Alternative Energy Resource Market Assessment

NARUC Grants & Research

NARUC

September 2011

The National Association of Regulatory Utility Commissioners

A report for the Public Utility Commission of Ohio
Funded by the U.S. Department of Energy

The report you are reading was created under the State Electricity Regulators Capacity Assistance and Training (SERCAT) program, a project of the National Association of Regulatory Utility Commissioners (NARUC) Grants & Research Department. This material is based upon work supported by the Department of Energy under Award Number DE-OE0000123.

The report was authored by Ed Holt & Associates, Inc., with Exeter Associates, Inc. and Sustainable Energy Advantage LLC. Throughout the preparation process, the members of NARUC provided the author(s) with editorial comments and suggestions. However, the views and opinions expressed herein are strictly those of the author(s) and may not necessarily agree with positions of NARUC or those of the U.S. Department of Energy.

Special thanks to the Commissioners and staff at the Public Utilities Commission of Ohio for guiding this work, and to the Office of Electricity Delivery and Energy Reliability and the National Energy Technology Lab for their continued technical assistance to NARUC.

Please direct questions regarding this report to Miles Keogh, NARUC's Director of Grants & Research, mkeogh@naruc.org; (202) 898-2200.

Alternative Energy Resource Market Assessment

Prepared for

Public Utilities Commission of Ohio
National Association of Regulatory Utility Commissioners

Prepared by:
Ed Holt & Associates, Inc.
Harpswell, Maine

Exeter Associates, Inc.
Columbia, Maryland

Sustainable Energy Advantage LLC
Framingham, Massachusetts

September 30, 2011

EXECUTIVE SUMMARY

Market Assessment

An assessment of the alternative energy market in Ohio was undertaken to determine the availability of renewable energy resources eligible to satisfy Ohio's Alternative Energy Portfolio Standard (AEPS). Based on a spreadsheet model developed for the purpose, the estimated supply of Ohio-eligible renewable energy resources in Ohio and the five contiguous states was compared with estimated demand for Ohio-eligible renewable energy resources coming from those same six states. The supply estimates were based on known and planned renewable energy resources in the six state region, while the demand estimates were based on legislated renewable targets and assumptions about how those targets would be met.

As shown in Figure ES-1, the results indicate that there is sufficient current and projected supply in the scenarios considered to meet the renewable energy resource requirements of the Ohio AEPS (including the solar requirement) and the renewable energy requirements or goals in Pennsylvania, Michigan, Indiana, West Virginia, and Kentucky through 2020. The results are displayed as "net supply," meaning a surplus (or shortage) of supply over demand for eligible energy resources for the renewable energy goals and requirements. In Figure ES-1, any number above the x-axis indicates a surplus, while any number below that axis would indicate a shortage.

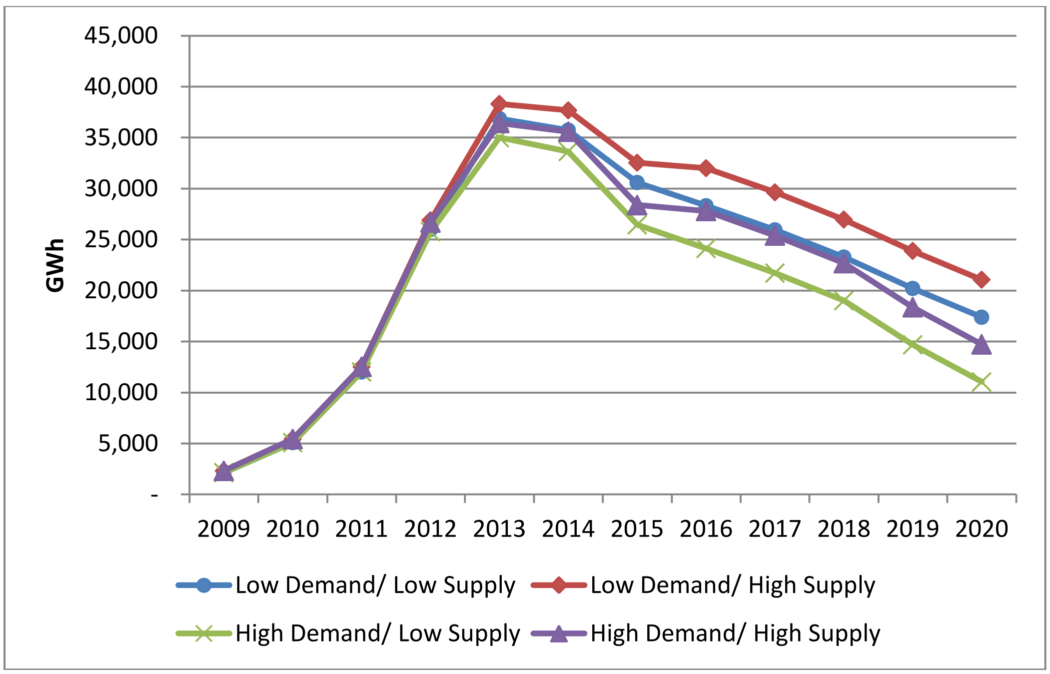


Figure ES-1. Net Supply Results by Scenario for the Ohio Renewable Energy Requirement

The supply estimates take into account the possibility that some proposed projects may not get built. This is incorporated by assigning a probability of completion to each planned project based on its status in the interconnection process. The sharp growth of renewable energy resources over the next two years assumes that all the new projects identified (subject to the probabilities of completion) are financeable. This is a critical assumption if they cost more than wholesale electricity prices, and points to the importance of other policies that support above-market renewables.

The net supply surplus declines after 2013 because the supply estimates do not reflect new eligible generating resources that may be developed before 2020 but which have not yet filed interconnection applications with the applicable transmission operator, nor do they reflect small generators that will interconnect at the distribution level.

At least half of the renewable energy requirement in the Ohio AEPS must come from renewable energy generation located in Ohio. For in-state renewable energy resources, the supply scenarios vary depending on assumptions about how much biomass is co-fired, while demand is constant as determined by 50% of the annual renewable energy targets. The results of the model assumptions, shown in Figure ES-2, indicate sufficient in-state supply, subject to the same caveats mentioned for the six-state supply-demand comparison above.

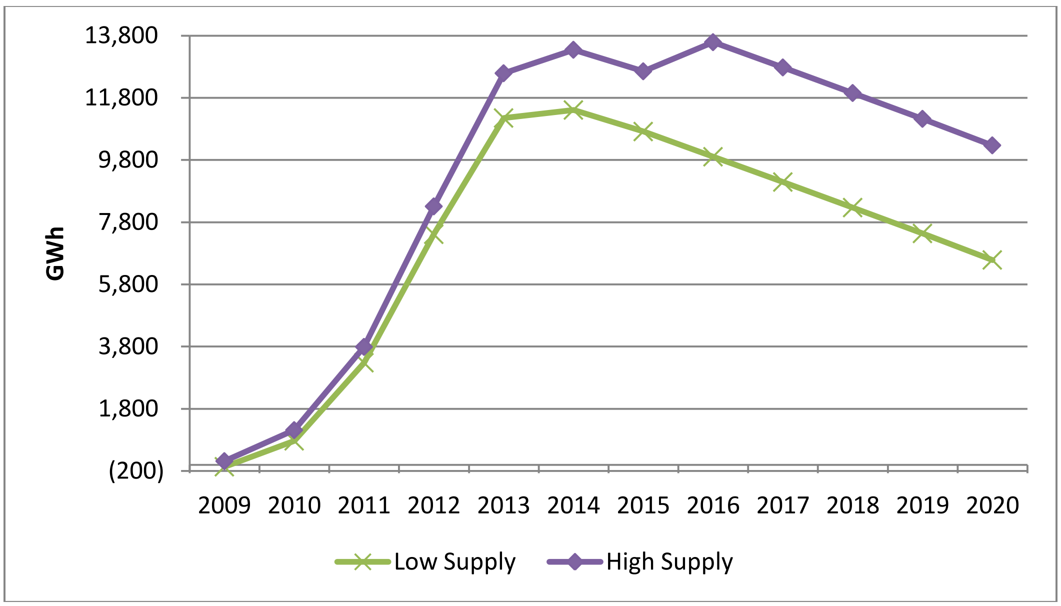


Figure ES-2. Net Supply Results for the In-State Renewables Requirement of the Ohio AEPS

The Ohio AEPS further stipulates a solar requirement within the renewable energy resources requirement, with a separate target for each year. Solar supply and solar-specific state demand are constant across all supply and demand scenarios. When comparing only the Ohio demand for solar resources against the regional solar supply, there is a net surplus in all years of the study period, starting at small levels in 2009, peaking in 2014 and then declining to 2020. However, there is also a solar-specific requirement in the Pennsylvania RPS, and therefore Ohio will be competing with Pennsylvania for regional solar supply. When Ohio and Pennsylvania demand are both accounted for, there is a solar supply shortage beginning in 2018 and extending to 2020, as shown in Table ES-1.

It is worth pointing out that of a total installed and planned solar capacity of 1,390 MW identified in the analysis, 89% is proposed (and possibly speculative) projects in the PJM queue, so completion of these projects should be monitored closely as an indicator of potential solar supply problems. Also, 80% of the total solar capacity installed or proposed is located in Pennsylvania. That state, seeing its success, could choose to increase its solar targets, with a consequent impact on the supply available to Ohio.

Table ES-1. Net Supply Results for the Solar Portion of the Ohio AEPS

	Regional Solar Supply vs. Ohio Solar Requirement (GWh)	Regional Solar Supply vs. Ohio and Pennsylvania Solar Requirements Combined (GWh)
2009	9	5
2010	39	22
2011	220	177
2012	629	560
2013	810	695
2014	824	627
2015	777	432
2016	727	262
2017	662	115
2018	596	(38)
2019	530	(202)
2020	462	(375)

The model estimates a shortage of supply to satisfy the combined Ohio and Pennsylvania demand for solar in the years 2018-2020. That projected shortage, coupled with the fact that Ohio's solar alternative compliance payment (SACP) starts at $450/MWh in 2009 and then declines by $50 every two years until it reaches a minimum of $50/MWh in 2024, suggests that the SACP may be insufficient to motivate sufficient solar generation in the later years of the projection. This is just a cautionary note, however, because the growth of small customer-sited solar projects is not included in the assessment, but may nevertheless be stimulated by other incentive programs. Also, over the term of the projection, the cost of solar is expected to decline, which could make it economically feasible even with lower SACPs. This is an area where the cost of solar compared to electricity prices should be reassessed regularly.

Ohio also applies its 50% in-state requirement for renewable energy resources to the solar component of that demand. The modeling results estimate an in-state surplus of solar supply that peaks at 94 GWh in 2013 and then declines, turning into a shortage in 2017 that grows to -102 GWh in 2020. Again, these results assume no additional capacity to solar that is not already in operation or currently planned.

The near-term surplus supply shown in each of these model runs suggests initially, at least, that utilities should be able to meet their AEPS obligations without resorting to the alternative compliance payment (ACP).

Setting the Level of Alternative Compliance Payments

A second focus of this study was to provide recommendations about methodologies for determining solar and non-solar renewable alternative compliance payment levels. The study examined options based on examples from other states, including coordinating ACP levels among neighboring states, tracking REC prices for greater price transparency, monitoring reliance on ACPs for compliance, and using cost of entry for new projects as the basis for setting ACP levels. Of the different approaches described, there are elements of several that, in combination, could provide a very effective method for determining when, and how, to adjust the ACPs. This combined approach includes the following:

- *Monitor reliance on ACPs for compliance*. Monitoring compliance using ACPs is factual, not subject to guesswork, has minimal administrative cost, and imposes no burden on market participants. Reliance on ACPs for compliance provides an early warning of a potential problem, but it is not determinative. Instead, it could trigger further investigation by the commission. The commission might wish to establish a specific threshold of ACP use that would trigger a review.

- *Continue to assess supply and demand of renewable energy resources*, as directed by statute. This would help determine whether reliance on ACPs for compliance is because there is insufficient supply of eligible resources, and whether that insufficiency appears to be long-term or temporary. For example, the supply and demand assessment might show that there are plenty of projects in the pipeline but they just have not come to fruition yet. Further investigation could determine the causes of the backup, such as difficulty obtaining siting and construction permits or financing.

- *Analyze the levelized cost of energy for new eligible projects*. If the analysis indicates that the incremental cost of renewable energy resources exceeds projected wholesale electricity costs, then the incremental cost should be the basis for adjusting the ACPs. The ACPs should be a multiple of (two to three times) the incremental cost.

- *Encourage greater price transparency for renewable energy credits*. In addition to providing insights to regulators about market conditions, better price information would provide broader benefits to market participants.

The concepts and methods discussed above apply to both ACPs and solar ACPs, but the ACP and solar ACP levels would be different because they are separate and distinct markets, and have very different compliance costs.

Additional Policies

The third section of the study considers additional strategies to encourage the use of alternative energy resources in supplying the state's electricity needs. The specific options reviewed are long-term contracting policies, feed-in tariffs, customer-sited or distributed generation support, tax incentives, and public benefit charges and fund administration. For each type of policy, the report describes state experience, summarizes results, and offers considerations in implementing such policies.

Contents

Introduction

In 2008 Ohio adopted an alternative energy resource standard that requires 25% of the electricity sold by Ohio's electric distribution utilities and electric services companies must be generated from alternative energy sources by 2025. At least half of this requirement must be served by eligible renewable resources.

The Ohio Revised Code, Section 4928.64, requires the Public Utilities Commission of Ohio (PUCO or commission) to "establish a process to provide for at least an annual review of the alternative energy resource market in this state and in the service territories of the regional transmission organizations that manage transmission systems located in this state."

The statute goes on to state that " the commission shall use the results of this study to identify any needed changes to the amount of the renewable energy compliance payment specified under divisions (C)(2)(a) and (b) of this section…"

The PUCO, with the financial and administrative support of the National Association of Regulatory Utility Commissioners (NARUC), engaged a team of consultants to do this work. Specifically, NARUC contracted with a team led by Ed Holt & Associates, Inc., with Exeter Associates, Inc. and Sustainable Energy Advantage LLC, to do the following:

- Determine Ohio's alternative energy market availability and potential; and
- Provide recommendations about methodologies for determining solar and non-solar renewable alternative compliance payment levels.

NARUC and PUCO also requested the consulting team to:

- Provide recommendations regarding additional policies, deployment strategies, and incentives to improve market availability of eligible resources; and
- Provide training to PUCO staff in the use and application of a financial model to help determine appropriate renewable energy compliance payment levels.

This report covers the first three items plus a discussion of ways to establish and adjust the renewable energy compliance payment levels. The fourth item, training in the use of the financial model, has been provided separately, but a summary of the model analysis to estimate the cost of new projects is included as Appendix B to this report.

This report is organized as follows. It first summarizes the results of the market assessment, including both supply of and demand for Ohio-eligible energy resources. The model used to conduct this assessment is provided as a separate electronic spreadsheet. The second section addresses ways to determine the appropriate level of the renewable energy compliance payment for solar and non-solar requirements. This is generically referred to as an alternative compliance payment or ACP. The third section discusses five ways to encourage the additional development of new renewable energy, as requested by PUCO staff to explore options used elsewhere. While staff is not necessarily endorsing these specific mechanisms, staff felt these topics were worthy of inclusion in this market assessment given the statutory requirement to consider strategies to encourage the use of alternative energy resources in supplying the state's electricity needs. The specific options are long-term contracting policies, feed-in tariffs, customer-sited or distributed generation support, tax incentives, and public benefit charges and fund administration. The report concludes with appendices documenting the supply and demand assessment model, and the financial model used to determine the levelized cost of energy for wind and solar energy projects.

Assessment of Supply and Demand

The statutory requirement to assess the alternative energy resource market in Ohio and in the service territories of the regional transmission systems that serve the state has been interpreted by the PUCO, for the purposes of this market assessment, as Ohio and contiguous states, meaning Indiana, Kentucky, Michigan, Pennsylvania and West Virginia. This is because the Ohio Alternative Energy Portfolio Standard (AEPS) requires that renewable energy generation located outside of Ohio must be deliverable into the state.[1]

The consulting team developed a spreadsheet model to assess the supply of Ohio-eligible resources in Ohio and the contiguous states, and to estimate demand for Ohio-eligible resources coming from those same six states.[2] We compared estimated supply and demand to determine if a supply surplus or deficit of eligible resources would result. The details of this model, and our assumptions, are provided in Appendix A.

There is considerable uncertainty around these estimates of supply and demand. On the supply side, there is uncertainty about how much new capacity will be built. New projects must apply to their respective regional transmission organizations (RTOs) for interconnection, and projects that have done so are listed in each RTO's interconnection queue. There are a series of security deposits and analytical studies that must be processed as part of the interconnection process. Not all projects in the queue will ultimately be built, others may be built later than the timing in the queue, and still others not presently in the queue may be developed at a later time. Power plants configured to co-fire biomass with a fossil fuel also introduce supply uncertainty because plant operators can choose whether or not to co-fire biomass depending largely on the cost of biomass fuel and on available competing options in the wholesale market. Other supply uncertainties pertain to small generators that interconnect at the distribution system level and therefore do not appear in the RTO interconnection queue.

On the demand side, Ohio is not the only state placing demand on eligible supply. Other surrounding states also have an RPS, but the technology and geographic eligibility rules vary from one state to another and do not match precisely the eligibility rules for Ohio. Hence it requires some educated guesswork, based on definitions of eligible resources, to assume how much demand each of these other states will place on Ohio-eligible resources. In addition, load

[1] Facilities from outside this geographic range can be eligible if they can demonstrate deliverability to Ohio.

[2] It is possible that more remote RPS states might place a demand on Ohio-eligible RECs. New Jersey, Maryland and Delaware could draw upon Pennsylvania or West Virginia RECs, for example, but if demand from these states were taken these into account, we would also need to evaluate the supply available in these states and in other states where eligible generators (for these states) may be located. An examination of other state RPS rules suggests that little demand would be placed on Ohio-eligible RECs. For example, Illinois requires that RPS targets be met with in-state RECs (or adjoining states after 2011) unless they are proven not cost-effective, and only then can Illinois utilities look further afield. Other states often require accompanying electricity delivery to the state or control area, and because of the added transmission costs, it seems less likely that resources outside PJM or MISO would be used. Most of Illinois, most of North Carolina, and all of New York and Missouri are in different reliability control areas and transmission markets. This leads us to believe that such demand would not be significant, although North Carolina accepts a portion of compliance with unbundled RECs (i.e. without electricity delivery) from outside the state.

demand may vary over time, affecting the amount of eligible resources required under the Ohio AEPS.

Because of the supply and demand uncertainties, the consulting team made different assumptions for low and high supply of Ohio-eligible resources, and low and high demand for Ohio-eligible resources. Combining low and high demand cases with low and high supply cases resulted in four scenarios: Low Demand/Low Supply, Low Demand/High Supply, High Demand/Low Supply, and High Demand/High Supply, illustrated in matrix form in Table 1.

Table 1. Scenarios in the Spreadsheet Model

		Supply	
		Low	High
Demand	Low		
	High		

The Ohio AEPS target for renewable energy resources is 12.5% by 2025, and a fraction of that is required to be met specifically by solar resources. In both cases, annual targets are specified. The AEPS also calls for 25% of retail electric demand to be met by renewable and advanced energy by 2025, but there are no annual or intermediate targets specified for the increment above 12.5%. The model is constructed to enable an assessment of supply of and demand through 2020 for renewable energy resources and for the solar requirement that is included in the renewable energy resource target.[3] The model can also be used to examine the AEPS supply of and demand for renewable energy and advanced energy combined, but this application requires that the targets be specified annually.

Summary of Results

The results indicate that there is sufficient current and projected supply in all four scenarios to meet the renewable energy resource requirement of the Ohio AEPS (including the solar requirement) and the renewable energy goals or requirements in the states included in the model (Ohio, Pennsylvania, Michigan, Indiana, West Virginia, and Kentucky) through 2020. The results are displayed as "net supply," meaning a surplus (or shortage) of supply over demand for eligible energy resources for renewable energy goals and requirements. In Figure 1, any number above the abscissa indicates a surplus, while any number below that axis would indicate a shortage. Table 2 provides numerical information in summation for key years.

[3] The model projects supply and demand only to 2020 because that is the extent of the PJM forecast of season-weighted peak load growth for Ohio. In addition, the consulting team was asked to look only at near-term supply, and beyond 2015 in particular the results are less reliable because less information is available with respect to supply in those years, and the information that is available is less certain. For future use, the projection could be extended as updated load growth forecasts become available.

As shown in Figure 1, the net supply peaks in 2013 before beginning a steady decline.[4] Table 2 shows more clearly that the surplus is largest in the Low Demand/High Supply scenario, which makes sense since there is low demand for Ohio-eligible resources from contiguous states and more supply assumed to come from biomass co-firing.

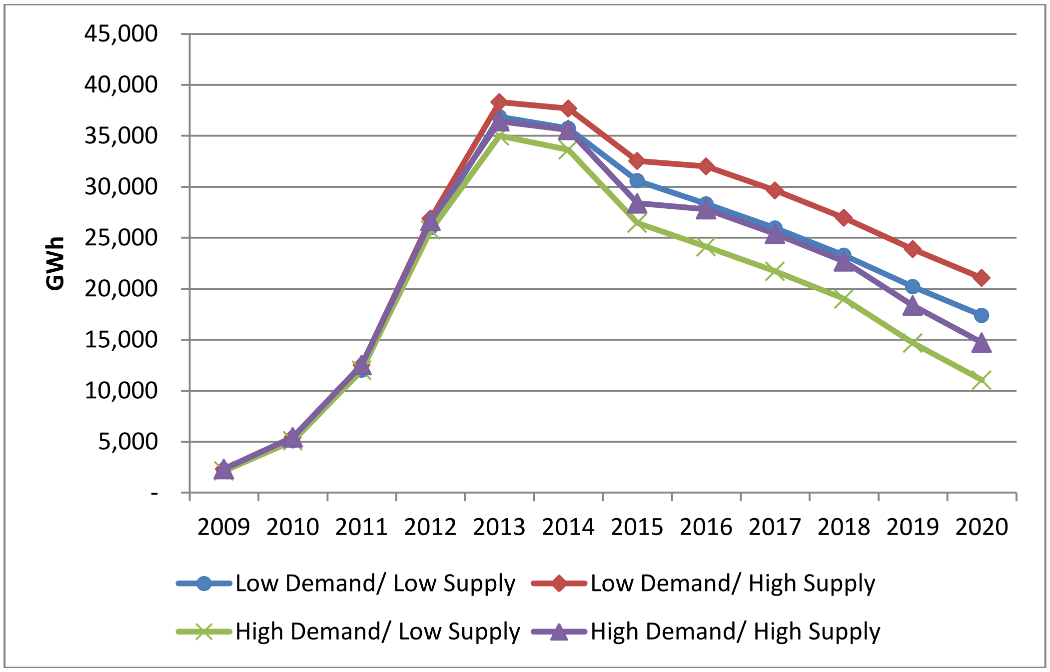


Figure 1. Net Supply Results by Scenario for the Ohio Renewable Energy Requirement

Table 2. Net Supply Results by Scenario for the Ohio Renewable Energy Requirement

Ohio-Eligible Renewable Energy Net Supply [Surplus or (Shortage)] (GWh)			
	2011	2015	2020
Low Demand/ Low Supply	12,013	30,598	17,382
Low Demand/ High Supply	12,522	32,535	21,068
High Demand/ Low Supply	12,013	26,443	11,036
High Demand/ High Supply	12,522	28,380	14,721

It should be noted that the supply assumptions do not reflect new eligible generating resources that may be developed before 2020 but which have not yet filed interconnection applications

[4] The growth of renewable energy resources assumes that they are financeable. This is a critical assumption if they cost more than wholesale electricity prices, and points to the importance of other policies that support above-market renewables.

with PJM or MISO,[5] nor do they reflect small generators that will interconnect at the distribution level.

Of course, these results are dependent on the assumptions used to formulate the model. Therefore, the results may change if overall electricity load is lower or higher than projected; if the assumed technology capacity factors are lower or higher; if the projected capacity of planned projects comes on-line earlier or later, or does not come on-line at all; and if demand for Ohio-eligible resources is lower or higher in states contiguous to Ohio. These and other assumptions can be changed, allowing model users to analyze the sensitivity of results to different assumptions.

At least half of the renewable energy requirement in the Ohio AEPS must come from renewable energy generation located in Ohio. The results of the model assumptions, shown in Figure 2, indicate a small shortage in 2009 for the low supply case (negative 65 GWh), but a surplus for the high supply case. (For in-state renewable energy resources, the supply scenarios vary depending on assumptions about how much biomass is co-fired, while demand is constant as determined by 50% of the annual renewable energy targets.) In-state eligible renewable energy supply peaks in 2016 in the high supply case and in 2014 in the low supply case.

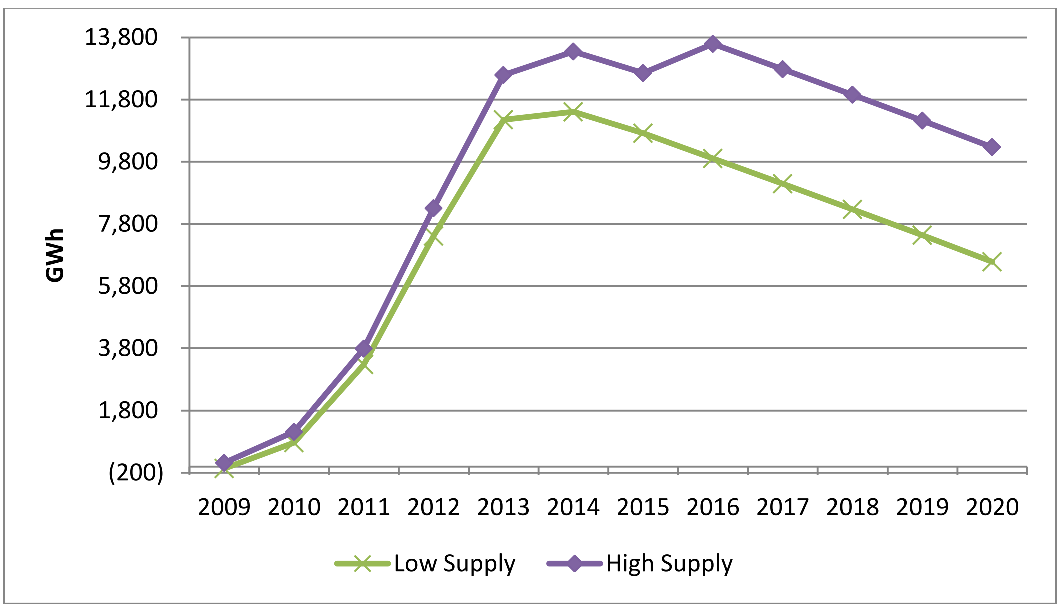


Figure 2. Net Supply Results for the In-State Renewables Requirement of the Ohio AEPS

The Ohio AEPS further stipulates a solar requirement within the renewable energy resources requirement, with a separate target for each year. Solar supply and solar-specific state demand are constant across all four supply and demand scenarios. The solar-specific demand is fixed by the minimum state solar requirements. For solar supply, we assumed no growth in solar above

[5] On the other hand, it does not completely reflect the possibility that some projects that are in the interconnection queue may never get built, but the model does discount the probability of such projects being completed depending on their stage in the queue.

what is currently certified by the PUCO, registered with the PJM EIS Generation Attribute Tracking System (GATS) and located in Ohio or in one of the adjacent states (but not certified by PUCO), in the PJM or MISO interconnection queues, or registered with the Michigan Renewable Energy Certification System (MIRECS). Therefore, in this model, the high and low cases of supply and demand are irrelevant in meeting the Ohio solar requirement. When comparing only the Ohio demand for solar resources against the regional solar supply, there is a net surplus in all years of the study period, starting at small levels in 2009, peaking in 2014 and then declining to 2020. However, there is also a solar-specific requirement in the Pennsylvania RPS, and therefore Ohio will be competing with Pennsylvania for regional solar supply. When Ohio and Pennsylvania demand are both accounted for, there is a solar supply shortage beginning in 2018 and extending to 2020, as shown in Table 3.

It is worth pointing out that of a total solar capacity of 1,390 MW identified in the named information sources in the previous paragraph, 89% is proposed (and possibly speculative) projects in the PJM queue, so completion of these projects should be monitored closely as an indicator of potential solar supply problems.[6] Also, 80% of the total solar capacity installed or proposed is located in Pennsylvania. That state, seeing its success, could choose to increase its solar targets, with a consequent impact on the supply available to Ohio.

Table 3. Net Supply Results for the Solar Portion of the Ohio AEPS

	Regional Solar Supply vs. Ohio Solar Requirement (GWh)	Regional Solar Supply vs. Ohio and Pennsylvania Solar Requirements Combined (GWh)
2009	9	5
2010	39	22
2011	220	177
2012	629	560
2013	810	695
2014	824	627
2015	777	432
2016	727	262
2017	662	115
2018	596	(38)
2019	530	(202)
2020	462	(375)

The model estimates a shortage of supply to satisfy the combined Ohio and Pennsylvania demand for solar in the years 2018-2020. That projected shortage, coupled with the fact that Ohio's solar ACP (SACP) starts at $450/MWh in 2009 and then declines by $50 every two years until it reaches a minimum of $50/MWh in 2024, suggests that the SACP may be insufficient to

[6] The solar capacity currently certified by the PUCO is 89 MW; 41.3 MW of solar are registered with GATS but not certified by the PUCO, presumably because the owners haven't asked; 1,234.4 MW (mostly large solar projects) are in the PJM queue; one 25 MW project is in the MISO queue; and about 1.1 MW are registered with MIRECS.

motivate sufficient solar generation in the later years of the projection. This is just a cautionary note, however, because the growth of small customer-sited solar projects is not included in the assessment, but may nevertheless be stimulated by other incentive programs. Also, over the term of the projection, the cost of solar is expected to decline, which could make it economically feasible even with lower SACPs.[7] This is an area where the cost of solar compared to electricity prices should be reassessed regularly.

Ohio also applies its 50% in-state requirement for renewable energy resources to the solar component of that demand. As shown in Table 4, the modeling results estimate an in-state surplus of solar supply that peaks at 94 GWh in 2013 and then declines, turning into a shortage in 2017 that grows to -102 GWh in 2020. Again, we caution that these results assume no additional capacity to solar that is not already in operation or currently planned, because we have no basis for projecting solar supply.

Table 4. Net Supply Results for the In-State Solar Portion of the Ohio AEPS

Ohio Solar In-State Net Surplus/(Shortage) (GWh)											
2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
3	11	42	74	94	80	56	31	(1)	(34)	(68)	(102)

The near-term surplus supply shown in each of these model runs suggests initially, at least, that utilities should be able to meet their AEPS obligations without resorting to the alternative compliance payment (ACP), and from this one might conclude that the ACP need not be adjusted. That conclusion depends on the assumption that all the prospective supply can in fact be built and operated with a REC premium of up to $45/MWh. It may not, for example, guarantee that the biomass co-firing potential will be realized. Hence the PUCO should consider other information in evaluating whether to recommend adjusting the ACP. This is the subject of discussion in the next section.

[7] If solar costs do not continue to decline, then LSEs may prefer simply to make the SACP payment, although they may also be deterred from doing so by the fact that such payments are not recoverable from consumers in Ohio. This will be a policy call for Ohio, as it presents the trade-off between minimizing compliance costs (through making the SACP instead of paying more for generation) or supporting more solar development.

Setting the ACP and Solar ACP

Setting the alternative compliance payment (ACP) for any RPS tier (standard or solar) should be linked to state policy objectives. For example, policy makers might want the ACP to motivate compliance purchases that result in the target being met, to cap REC prices so as to mitigate the costs borne by ratepayers, to establish a source of funds to finance desired renewable or efficiency programs, or to penalize obligated entities for not complying with the renewable energy targets. Policy can encompass more than one of these objectives at the same time, although the specific combination might lead to different implementation details.

There are also different approaches to establishing the ACP level. The ACP may be linked to observed REC market prices or some multiple thereof, set as a function of utility reliance on the ACP, or based on estimates of the incremental cost of new renewable projects. There may also be benefits to coordinating ACPs in a region with shared power markets.

The most common objective behind the ACP is to incentivize compliance with an RPS. To accomplish this, policymakers with this objective typically seek to establish an ACP at a level high enough above the market price of RECs to motivate developers to build new projects and to motivate utilities to acquire RECs rather than simply make a compliance payment, yet low enough to serve as a reasonable cap on ratepayer cost exposure and on the potential exercise of market power.[8]

Several states have adopted multiple classes or tiers within their RPS, each with their own targets and different ACP levels that depend in part on the cost of the eligible resources for the class. Ohio, for example, has a renewable energy target and a separate solar target, each with its own ACPs. For purposes of this analysis, the ACP levels in other states refer to the class or tier with similar eligibility to Ohio's renewables target, unless the ACP is for solar, in which case solar ACP (or SACP) is clearly identified.

This section presents options based on examples from other states, including coordinating ACP levels among neighboring states, tracking REC prices, and monitoring reliance on ACPs for compliance. The advantages and limitations of each approach are discussed. This section also provides a summary of the analytical results of modeling the cost of new renewable projects in Ohio, information useful to understand the need for REC prices that cover the gap between market prices and the cost of energy. The section concludes with some recommendations.

Coordinated ACPs among States in the Same Region

Massachusetts, Connecticut, Rhode Island, Maine and New Hampshire are all part of the same certificate tracking system and the same REC market, so with the exception of Connecticut, these

[8] In New Jersey, for example, the ACP (and solar ACP) must be higher than (1) the cost of meeting the requirement by purchasing a REC (or solar REC), or (2) the cost of meeting the requirement by generating the required renewable energy.

states decided to coordinate their ACPs.[9] They recognized that adopting different ACPs could direct the REC market to the state with the highest ACP first, the next highest second, and so on. In that case, if the market is short, the state with the lowest ACP could find that compliance is met only with compliance payments rather than by supporting renewable energy generators. Massachusetts was the first of these states to establish an ACP. In the base year 2003, the ACP was set at $50, to be adjusted annually to account for inflation. Other states followed suit, and all had a 2010 ACP of $60.93. The Massachusetts ACP was recently adjusted to $62.13, and the other three states will probably adjust their ACPs likewise in their own regulatory proceedings. Connecticut's ACP was set by statute at $55, so it has not been adjusted for inflation, and as a result it is currently slightly lower than the other RPS states.

It would be challenging to adopt similar, if not identical, ACPs in the PJM region, especially since ACPs are already established, but that should not preclude Ohio from matching the ACP of its most relevant neighbor if it so desired.

- The initial New Jersey ACP level was set by BPU order at $50 per MWh in 2004. These levels were subsequently renewed several times without changes. The ACP remains unchanged at $50 per MWh for its Class I and II resources.
- Pennsylvania statute establishes an ACP of $45 per megawatt-hour for shortfalls in Tier I and Tier II resources.
- Maryland's ACP for non-solar Tier 1 shortfalls was originally set at $20 per MWh, but this was changed by statute to $40 per MWh effective in 2011.
- Suppliers in the District of Columbia that fail to comply with the requirements must pay $50 per MWh of shortfall from required Tier 1 resources.
- Delaware takes a different approach and increases the ACP with each use by an obligated entity, starting at $25 per MWh, increasing to $50 per MWh and finally to $80 per MWh. The State Energy Coordinator has the authority to review and adjust the ACP and solar ACP given certain market conditions.
- There is no ACP in Michigan.
- Illinois ACPs are entirely different from the other states described, and are not comparable. The objective for Illinois ACPs appears to be to provide revenue for a renewable energy fund. ACP levels differ for each utility and for alternative retail electric suppliers (ARES). In fact, ARES are required to meet at least half of their RPS obligations by making alternative compliance payments, rather like a systems benefit charge.

ACP levels and approaches are summarized in Table 5. Because Ohio, Pennsylvania, New Jersey, Maryland and the District of Columbia all have a similar approach, it might be possible for each to make adjustments and adopt consistent ACPs for the renewable energy main tier or class of resources, but it would require political will in each state to pursue this. The benefits are uncertain, and the motivation is weak unless the region is in short supply of eligible resources. As a smaller step in this direction, Ohio could match the ACP of its most relevant neighbor. Pennsylvania's ACP started the same as Ohio, at $45, but Ohio's is adjusted for inflation, so the two will slowly diverge.

[9] These states, including Connecticut, all require that eligible generators be part of the New England grid (ISO-NE) or deliver energy into ISO-NE. Vermont does not have a mandatory RPS.

Table 5. ACPs for Ohio and Contiguous States and Other States with RPS in PJM

State	Main Tier ACP ($/MWh)	Solar Tier ACP ($/MWh)
OH	$45 for 2009 (adjusted annually based on CPI)	$450 (2009), $400 (2010-2011), then reduced by $50 every two years thereafter to a minimum of $50 (2024)
PA	$45	200% of the average market value of SRECs and levelized value of solar rebates paid upfront
MI	No provision for ACP	No solar tier
WV	$50 or 200% of the average market value of RECs	No solar tier
IN	Voluntary goal; no ACP	No solar tier
KY	No RPS	No RPS
NJ	$50	Rolling 8-year schedule (to be extended to 15 years): $711 (2009), $693 (2010), $675 (2011), $658 (2012), $641 (2013), $625 (2014), $609 (2015), $594 (2016)
DE	$25 for first time use, increasing to $50 for second time use, increasing to $80 thereafter	$400 for first time use, increasing to $450 for second time use, increasing to $500 thereafter
MD	$40	$450 (2009-2014) then declining in $50 increments to $50 in 2023 and beyond
DC	$50	$500
IL	$0.0512-0.0422 for ComEd and Ameren; $0.211-0.256 for alternative retail electric suppliers	No solar tier

Source: U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency 2011

Advantages:

- Coordinating ACPs across the region would create a broader market, although eligibility for Ohio compliance would not be affected, so this broader market would not be as robust as if the RECs were interchangeable.
- A regional common market for RECs could be big enough for exchange platforms and brokers to track and report REC prices (not just solar RECs). This would increase price transparency (discussed further in the next option).

Limitations:

- Each state would probably need to request changes to statutes, either to specific ACP levels or to the authority and latitude granted to the regulatory commissions, and it would be difficult to get multiple states legislatures to agree on the same outcome.
- Approaching the legislature for changes requires political capital and carries the risk of opening the portfolio standard for reconsideration.
- While some states have concluded that any generation in PJM is deliverable within PJM, and possibly the same is true for MISO generation, the Ohio requirement that generation located outside Ohio must be deliverable to Ohio may limit the benefit of broader regional coordination.

Tracking REC Prices

For an ACP to be a real incentive to RPS compliance using RECs, the ACP level must be significantly higher than REC prices. It also requires that policy-makers have adequate and accurate information about REC prices.

Pegging the ACP to some multiple of REC market prices is easier said than done, however. In Ohio, as in many other states, there is very little REC price transparency. Available price data is spotty and tends to reflect short-term deals reported by REC brokers, which are only a small part of the market. Further, some market participants trade RECs over the counter, or through brokers, with the express requirement that the price not be divulged so they can be ahead of the market. This also reduces the usefulness of broker data as a window to actual prices.

If a commission were to track REC prices, it should be aware that REC prices can be different for short-term trades and for long-term contracts. Short-term markets are strongly influenced by supply and demand, and high prices may simply be a sign that demand is growing faster than new projects can get built. Long-term contract prices are a better reflection of actual project cost, and therefore can better inform the incremental cost that must be recovered via REC revenue. This REC gap or “cost of entry” is discussed more fully below.

Because of Ohio's requirement that at least 50% of renewable energy, and solar, come from in-state resources, in-state REC prices might diverge from out-of-state resources. For example, if in-state prices are higher than out-of-state prices, it reflects a shortage of supply to meet the in-state requirement. The policy response might be to determine whether obligated entities are relying on paying the ACP to satisfy the in-state requirement, and second to review supply and demand, and perhaps to raise the ACP if there are insufficient new projects in the pipeline. If on the other hand out-of-state prices are higher than in-state prices, it wouldn't matter so much because the in-state requirement would be met and any excess in-state supply could be used to satisfy the remainder of the requirement.

There are several ways that price transparency could be supported.

1. The PUCO could require AEPS-obligated entities to report publicly the total cost expended for compliance RECs, which could yield and annual, after-the-fact reporting of average REC prices. This type of requirement exists, for example in Maryland, Pennsylvania, and the District of Columbia. The delay in reporting this information, typically one-half year to a year after the fact, limits its usefulness as an indicator of the current market price. Nevertheless, it does provide price trend information, and it could be supplemented by forward prices available through brokers and exchanges.
2. The PUCO could require market participants to enter price data in the REC tracking systems. This information is more current than what would be included in an annual compliance report, and it is more complete than broker-reported data.
3. The PUCO could require reporting of REC price data, not as public information, but as privileged and confidential data. Regulated utilities are already under the commission's jurisdiction for such a requirement, but competitive retail electricity suppliers often balk at such requests, citing confidentiality of competitive information, but they could be

required to provide such data as a condition of licensing. All the data doesn't have to be public for the commission to reach conclusions about the adequacy of the ACP.

4. The PUCO could encourage or designate an exchange or trading platform for unbundled REC transactions that reports all bids and offers in real time. There are at least two platforms that already report solar REC prices for Ohio, specifically SRECTrade.com and Flett Exchange, but not for non-solar RECs.

Advantages:

- Creating greater REC price transparency would give the PUCO a much closer price monitoring capability that could be used to inform ACP level adjustments.
- Price transparency could also lead to greater confidence in the market and in the revenue from REC sales. Further, to the extent that price transparency supports the development of forward price curves, it will support decisions to invest in new projects.
- It would be technically easy to automate reporting of aggregate price data by building price reporting into the certificate tracking systems as a condition of transferring RECs between account holders.
- Confidential information could be protected by offering privacy protection for price data, or by only reporting summary data in public.
- Trading platforms are already in operation, at least for solar RECs, so it would be worth encouraging them to add trading for non-solar RECs.

Limitations:

- Many transactions will still take place via power purchase agreements in which the RECs are bundled with the energy sale. REC value may not be identified separately in these contracts, or if it is, the split could be arbitrary.
- Long-term contract prices are not indicative of short-term market prices (which reflect supply and demand), but may be more reflective of actual costs and therefore reveal the incremental cost of new renewables.
- Market participants may resist reporting requirements for fear of disclosing competitive information, and for the extra step required in reporting transactions.
- Requiring obligated entities to report price data, either after the fact or as part of each transaction, may require additional legislative authority, a process that has its own pros and cons.
- Trading platforms report only what is transacted on their sites, and most of it is short-term purchases, so they don not give a complete picture of prices.
- Power purchase agreements with bundled RECs are usually customized, and thus may not be suitable for trade on exchanges that require standardized products.
- Directing market participants to one or another REC exchange would require a competitive selection process by PUCO and would probably limit choices for trading platform.

- Trading platforms are already in operation, suggesting that the market is responding to business opportunities without intervention by regulators.

Monitor Compliance Using ACPs

A simpler approach is to determine what percentage of compliance has been met by ACPs at the end of each compliance year. If the reliance on ACPs has been minimal, then it is evidence that the ACP is doing its job and need not be changed, or might be adjusted only for inflation. On the other hand, if reliance on the ACP has exceeded a pre-established threshold, then it could be evidence that the ACP should be raised.[10] The Commission would need to establish a threshold of ACP reliance that is actionable. For example, if 10% of compliance (weighted average) is met by use of ACPs, then the Commission could conclude that the ACP needs to be raised; to avoid a single year anomaly, and to demonstrate an ongoing compliance issue, the threshold could be established as 5% or more ACP reliance three years in a row, or an average of 5% over any consecutive three-year period.

In addition to setting the threshold for raising the ACP level, the Commission or the legislature should provide guidance about the level of the ACP—by how much should it be raised? That is where information about the market price of RECs would be most useful, because the ACP should be higher than the current market price, or the above-market cost of new renewable energy projects.

Alternatively, if determining current REC prices proves too challenging, the ACP could be increased by an absolute amount that is predetermined. For example, Delaware increases the ACP automatically after each use. If a utility relies on the ACP in one year, its ACP is increased for any subsequent year. Specifically, after the first year that a utility has paid an ACP of $25 per MWh of shortfall, its future ACP level will be $50, and after it has paid an ACP of $50, any future ACP would cost $80. There is no provision for increasing the ACP beyond $80. The Delaware rule applies to individual utilities—one utility that has made ACP payments in one year will be facing an ACP of $50, while another utility that has not resorted to the ACP would still be facing an ACP of $25. This approach suggests that Delaware’s policy objective is to use the ACP as a graduated penalty for failure to comply using RECs. Ohio could do something similar that applies to utilities individually, or it could follow a predictable ACP increase for all obligated entities if the ACP threshold has been breached in aggregate.

Advantages:

- Monitoring ACP reliance does not depend on an assessment of supply and demand, which is fraught with assumptions and uncertainties.
- Monitoring ACP reliance is less time-intensive than an assessment of supply and demand, and less data-intensive than monitoring REC prices closely.
- Monitoring ACP reliance places no burden on market participants to report prices or to trade via particular REC exchanges.

[10] It could also be a sign of a REC shortage (demand exceeding supply) that is unrelated to the ACP being too low. In that case, raising the ACP would just penalize electricity consumers.

Limitations:

- Although monitoring ACP reliance is easily done, it may require a change in statutory authority if it is used as a trigger to a change in the ACP level.
- Monitoring ACP use is probably not a stand-alone solution because reliance on the ACP could be a reflection of short-term demand exceeding supply while new projects are in the development pipeline.

Cost of Entry as Basis for Setting ACP Levels

The difference between the long-term levelized cost of energy (LCOE) from the marginal AEPS-eligible resource – the last resource needed to reach the demand target – and the expected levelized commodity market revenues available to that marginal AEPS-eligible resource, defines the revenue gap or the REC revenue required for a project to get built. This can be thought of as the "cost of entry" for a new project, and is manifested in the REC price needed to bridge the revenue gap. The logic is that if the ACP is set lower than this cost of entry, new generation will not be built to meet the AEPS, and those with compliance obligations will typically rely on making ACP payments rather than supporting the development of eligible supply through their REC purchases. On the other hand, if the ACP is set too high above the cost of entry, *and* supply is inadequate, then ratepayer impact is likely too severe. A typical approach consistent with best practices is to set the ACP at some multiple of the cost of entry or REC price sufficiently high to incentivize compliance while low enough to protect ratepayers in the presence of a shortage. Therefore, setting the ACP should take into account an assessment not only of supply and demand but also of the REC cost of entry.

To determine the revenue gap or cost of entry, we estimated the LCOE using the Cost of Renewable Energy Spreadsheet Tool (CREST), a model developed for the National Renewable Energy Laboratory to analyze the costs and economic drivers of renewable energy projects. Separate models were used to estimate the LCOE from representative wind and solar projects. The use of the wind CREST model represents the assumption that wind will be the marginal resource deployed to meet Ohio's renewable energy objectives. The model was populated with input values for installed cost, operating cost, capital structure and financing costs, incentives and performance (capacity factor) estimated to represent a relatively large, cost effective wind generator operating in Ohio or adjacent states. The use of this model to gauge the cost of entry and the revenue gap for Ohio is documented in Appendix B of this report.

The results of the CREST model analysis suggest that for Ohio, the LCOE for a hypothetical 125 MW wind project is approximately $75/MWh. If assumptions about the capital cost and capacity factor are varied, the LCOE is in the range of $65-85/MWh. Given the expected levelized wholesale value of electricity is $61.18/MWh over that same period, the revenue gap, or REC revenue requirement, is about $10-$20/MWh. We also looked at a low case scenario, which combines assumptions that result in a low LCOE with a high estimated wholesale value of electricity, and a high case scenario, which combines assumptions that result in a high LCOE with a low estimated market value. In the low case, the REC revenue requirement is reduced to near zero, and in the high case, it is about $30/MWh. Based on the above-described assumptions, developers for the hypothetical wind project need a REC price of $5-30/MWh just to break even in the Ohio market. To provide sufficient likelihood that they can get this price, regulators should consider setting the ACP for the renewable energy requirement at a multiple of this incremental cost. One additional, and critically important, variable in this analysis is the looming potential expiration of the Federal production tax credit and investment tax credit – currently set to expire on December 31, 2012. If these incentives are not extended, the REC revenue requirement for the same prototype wind project – but without federal incentives – would be $45/MWh.

For the solar market, we analyzed two hypothetical installations. One is a 500 kW project installed at a commercial customer's premises and interconnected on the customer's side of the meter to take advantage of net-metering. All power is assumed to be consumed on-site, so the customer benefits from avoiding the full retail price of generation and distribution. Analysis shows that the LCOE for this project is about $260/MWh. Given the expected levelized retail value of electricity is $131/MWh, the REC revenue gap, or cost of entry, is about $125.

The second hypothetical solar project is a 1,500 kW project that is interconnected directly to the utility grid. Because of the larger size of this project, the LCOE is estimated to be slightly lower than the customer-sited project, or about $230/MWh. Because this project is not net-metered, it is competing with the projected and levelized wholesale cost of electricity, $61.18/MWh, and the resulting REC revenue gap is about $170/MWh.

It should be noted that the LCOE for both solar projects are sensitive to assumed project costs.[11]

Based on these assumptions, developers would need a solar REC price of $130 to $170/MWh just to break even in the Ohio market, and that to provide sufficient likelihood that they can get this price, the solar ACP should be set at some multiple of this incremental cost.

Advantages:

- Analysis focuses on the economic barriers facing project developers rather than short-term REC market prices, which are heavily influenced by supply and demand.
- The long-term cost of entry is more reflective of project financial needs than short-term REC prices.
- Analytical tools are available, and documented, to conduct this type of analysis.
- Tools generally support sensitivity analyses of a range of assumptions, which can be insightful in setting ACP levels.
- To increase the credibility of project assumptions, the PUCO can solicit input from stakeholders with more direct technological knowledge.

Limitations:

- Any analysis tool is limited by its sophistication and the input assumptions.

[11] Solar prices have been declining significantly in the past couple of years, although we believe that costs vary geographically depending on the size of the market, the market infrastructure, and the level of financial incentives offered.

- It is hard to be certain about all assumptions input to any model.

Summary and Recommendation

Of the different approaches described, there are elements of several that, in combination, could provide a very effective method for determining when, and how, to adjust the ACPs.

As a first step, the PUCO should monitor reliance on ACPs for compliance. Monitoring compliance using ACPs is factual, not subject to guesswork, has minimal administrative cost, and imposes no burden on market participants. Reliance on ACPs for compliance is analogous to the canary in the coal mine, providing an early warning of a potential problem, but it is not determinative. Instead, it could trigger further investigation by the commission. The commission might wish to establish a specific threshold of ACP use that would trigger a review.

Second, the PUCO would continue to assess supply and demand of renewable energy resources, as directed by statute. This would help determine whether reliance on ACPs for compliance is because there is insufficient supply of eligible resources, and whether that insufficiency appears to be long-term or temporary. For example, the supply and demand assessment might show that there are plenty of projects in the pipeline but they just haven't come to fruition yet. Further investigation could determine the causes of the backup, such as difficulty obtaining siting and construction permits or financing.

Third, assuming that an adjustment is indicated, and that the objective of the ACP is to provide motivation for the development of new renewable energy and solar resources, we believe the most logical approach is to analyze the cost of energy for new eligible projects. If the analysis indicates that the incremental cost of energy exceeds projected electricity costs, then the incremental cost should be the basis for adjusting the ACPs. If analysis of the levelized cost of energy shows that the REC revenue gap is diminishing, we recommend that the ACPs be maintained and not lowered, because ACP predictability is important to new project developers.

The level of the ACPs is often recommended to be two to three times the market price of RECs,[12] but as noted previously, the market price of RECs tends to reflect short-term supply and demand rather than the long-term incremental cost of new projects. The ACPs should therefore be a multiple of the incremental cost. Nevertheless, encouraging greater REC price transparency should be encouraged because it would provide broader benefits to market participants.

The concepts and methods discussed above apply to both ACPs and solar ACPs, but the ACP and solar ACP levels would be different because they are separate and distinct markets, and have very different compliance costs.

[12] For example, the Pennsylvania RPS calls for the solar ACP to be 200% of the average market value of solar RECs sold during the reporting period within the service region, including, where applicable, the levelized up-front rebates received by sellers of solar RECs in other jurisdictions of PJM.

Finally, we note that in Ohio, ACPs are not recoverable from consumers by regulated distribution utilities with compliance obligations, but that the prices charged by competitive retail electricity suppliers are not regulated. As a result, the ACPs would provide a cap on how much competitive providers would be willing to pay for RECs, but utilities might prefer to pay a REC price higher than the ACP because the REC costs are theoretically recoverable whereas the ACP payment is not. This means that in a tight market, REC prices might settle a little higher than the ACP. Despite these different dynamics, the ACP should be the same for both regulated utilities and competitive providers.

Additional Policies

Beyond requiring utilities to meet renewable or alternative energy targets in a portfolio standard, states have a number of policy options to foster the development of eligible resources. This section describes several that were selected with the help of PUCO staff: long-term contracts, feed-in tariffs, financial incentives for small or distributed generation projects, tax incentives, and public benefits funds. We describe each option in general terms, provide one or more examples, and discuss considerations for implementation. Based on the practice and experience of various states, it is becoming clear that each approach has its own strengths and weaknesses, but the most robust policies are those undertaken in combination.[13]

Long-term Contracts

Developers of new projects often have proposed sites, and have applied for permits, but as difficult as siting and permitting can be, a critical step is obtaining financing for the project. Unless the project is being developed by a company with sufficient financial resources to finance the project itself, finance is usually provided by third-party lenders (banks) and investors. Lenders and investors want security for their money, to ensure that the project will actually produce the projected revenue so they will get their money back.[14]

For security, virtually all lenders or investors require a long-term contract between the project owner and a purchaser(s) of the electricity and/or renewable energy certificates (RECs).[15] Whether the contracts are for bundled electricity and RECs, for electricity only, or for unbundled RECs, the increased revenue certainty and reduced risk can be significant in attracting financing to new projects. Long-term contracts also support access to financing at more favorable terms (such as lower expected rates of return or interest rates), especially if the contracts are with counterparties with strong credit.

Long-term contracts are needed for at least the larger revenue stream, which is usually energy unless the project is a solar development in a state with a solar tier as part of its RPS, in which case a contract for the solar RECs would be preferred.

Ideally for developers, the contracts would be long enough to amortize the capital investment, return on investment, and debt service, which is usually 10 to 20 years. Generation developers and owners would generally prefer the contracts to be 20 or 25 years or the expected life of the project. Buyers, on the other hand, might prefer contracts of 10 years or less because the price that looks reasonable today may turn out to be higher than market prices in a decade.

---

[13] C. Kubert and M. Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*. Clean Energy States Alliance, December 2009. http://www.cleanenergystates.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf

[14] K. Cory, J. Coughlin, T. Jenkin, J. Pater, B. Swezey. *Innovations in Wind and Solar Financing*. NREL/TP -670-42919. Golden, CO: National Renewable Energy Laboratory, February 2008. http://www.nrel.gov/docs/fy08osti/42919.pdf.

[15] E. Holt, J. Sumner, L. Bird, *Role of Renewable Energy Certificates in Developing New Renewable Energy Projects*. TP-6A20-51904. Golden, CO: National Renewable Energy Laboratory, July 2011. http://apps3.eere.energy.gov/greenpower/pdfs/51904.pdf.

If contracts are less than 10 years, new projects may be too risky for investors to undertake because of uncertainty about energy and REC prices and revenues in the later years of the project's life. Even assuming that such projects would be built, the uncertainty would increase the cost of capital, leading to higher prices at which the electricity would have to be sold.

In states with restructured electricity markets, like Ohio, long-term contracts may not be available to project developers, however, because utilities (the providers of last resort) and competitive energy suppliers will not or cannot sign long-term contracts due to uncertain future load requirements and consequent uncertain future RPS obligations. Ohio distribution utilities may be reluctant to enter into long-term contracts due to the short-term nature of their electric security plans.[16]

At least 15 states, including nine states with restructured markets, have some form of long-term contracting (see Table 6) for regulated utilities to provide certainty of demand and price for new projects under development.

Table 6. State Long-Term Contracting Requirements

State	Contract Requirement	Cost Recovery
CA	10+ years	Yes. Procurement and administrative costs associated with long-term contracts approved by the commission shall be deemed reasonable and shall be recoverable in rates. Cal. Public Utilities Code § 399.14(g)
CO	20+ years	Yes, if approved by the commission, the contract shall be deemed to be a prudent investment, and the commission shall approve retail rates sufficient to recover all just and reasonable costs associated with the contract
CT	150 MW, 10–20 years	Yes
CT	LT contracts for RECs—*permissive*; maximum 15 years	Yes, through Generation Service Charge rates
IA	Ownership or long-term contract	Cost recovery not determined
IL	central procurement with up to 20-year contracts	Cost recovery not determined
MA	10-15 years	Yes, subject to review and approval by the DPU. 220 C.M.R. §§ 17.00 et seq.
MD	For solar, 15+ years	Yes. Electricity suppliers may recover actual costs incurred in complying with the RPS, in the form of a generation surcharge payable by all current electricity supply customers. Md. Public Utility Companies Code §7–706
ME	10+ years	Yes
MI	Contract term to be specified in bids	Yes. The cost of contracts deemed by the Commission to be consistent with an approved renewable energy plan will be recovered based an approved non-volumetric cost recovery mechanism, subject to rate impact caps. Michigan Complied Laws Chap. 460.1021, 460.1033
MT	10+ years	Yes, if approved in advance by the commission. Montana Code Annotated 69-3-2005
NV	10+ years	Yes, if approved by the Commission, it shall be deemed a prudent investment and the utility may recover all just and reasonable costs associated with the contract. Nev. Rev. Stat. 704.7821
NY	Central procurement, 10-	Responsibility for contracting lies with state agency (NYSERDA).

[16] An electric security plan (ESP) is a rate plan for the supply and pricing of electric generation service.

	year terms for RECs	Funding is through a volumetric RPS surcharge
NC	Solar, sufficient length to stimulate development	Yes. RPS incremental costs, specifically for RECs, are recoverable if they are reasonable and prudent, and not subject to the per-account cost cap. 4 N.C.A.C. Chap. 11, R8-67(e)
PA	Good faith compliance effort includes seeking long-term contracts	As a cost of compliance, REC costs are recoverable through an automatic adjustment clause. 52 P. C.75.66(e)(4)
RI	10–15 years	Yes

Source: Wiser and Barbose 2008, with additions and updates.

In states with restructured electricity markets, it can be more difficult to encourage long-term contracts because competitive electric service providers are unable or unwilling to play the role in long-term resource acquisition that has traditionally been played by regulated utilities.[17] In these states, policymakers have to balance the benefits of competitive wholesale and retail electricity markets against a policy preference, in many cases, for cleaner and more diverse sources of supply. Policymakers and regulators in restructured states have therefore had to be especially creative in placing requirements on regulated distribution companies.

The long-term contracting requirements (or encouragement for such contracts) that we have reviewed share several characteristics:

- Requirements do not apply to all renewable energy contracts entered into by utilities. States may establish capacity targets for resources under long-term contracts, for example, that are only a portion of overall compliance needs.
- Some contracting requirements apply only to smaller distributed generation projects that may involve higher cost resources.
- Projects recommended for long-term contracts generally must be selected using a competitive process unless they are part of a standard offer, usually for smaller projects.
- Statutes or administrative rules generally require commission approval of contracts, and if approved, generally provide for recovery of costs from ratepayers.
- If a state RPS has a cost cap, for example in terms of rate impact or revenue requirements, the cost of long-term contracts is generally subject to that calculation.

Following are more detailed descriptions of several of these contracting policies that have been selected to illustrate different approaches, particularly in states with restructured markets.

Ohio

Ohio has approved several electric distribution utility programs to acquire solar or small wind RECs via long-term contracts. The standard contract for two of the programs is for 15-year terms, but the price paid changes annually according to market prices. The contracts are for RECs from customer-sited projects, so project size tends to be small and in some cases may be explicitly limited to 100 kW capacity.

[17] They may be unable if they lack the creditworthiness required by lenders and investors of counterparties in long-term purchase agreements, and they may be unwilling because their future load is uncertain. Nevertheless, some Ohio distribution companies may have the option of building renewable generation for compliance, with filed resource and electric security plans, and as discussed later, some Ohio utilities have agreed to enter into long-term renewable energy certificate (REC) purchase agreements for projects that meet certain criteria.

Long-term contracts in Ohio are challenged by the short-term nature of utility electric security plans (ESPs). These are usually three-year rates that may escalate but are fixed for each year of the plan. Entering into long-term contracts puts the electric distribution utilities (EDU) in the position of incurring costs that will continue beyond their currently approved ESP. To reduce their exposure to risk, they would likely want to be assured of cost-recovery over the life of the contract, and as Table 6 shows, a number of states do pass "reasonable and recoverable" judgments when approving contracts.

Because EDUs are providers of last resort in Ohio, they may be uncertain of future load they will have to serve, and may therefore feel at risk of buying more than they need to satisfy their AEPS obligations. Some other states have addressed this concern by requiring the EDUs to enter into long-term contracts, even more than for their own needs, and directing them to dispose of the energy or RECs by various means. When EDUs act thus as intermediaries, as described in several state examples below, they are essentially protected.

Ohio competitive retail electric suppliers are in a weaker position to support long-term contracts. For project financing, lenders and investors require long-term contracts with creditworthy counterparties. Many, but not all, such competitive suppliers are not large enough, or do not have a stable enough customer base, to meet the creditworthiness criteria. Although they are not limited by ESP rates, as the EDUs are, they are subject to competitive market forces that naturally limit how much they can charge their customers. They are also more likely than EDUs to experience customer switching and therefore greater volatility in their AEPS compliance obligations.

Massachusetts

The Green Communities Act requires that electric distribution companies solicit long-term contracts (defined as 10-15 years) for RECs, energy, or for a combination of RECs and energy from renewable energy developers two times between July 1, 2009 and June 30, 2014.[18] Long-term contracts executed by the distribution company must be filed with and approved by the Department of Public Utilities (DPU) before they become effective. After purchasing renewable energy, or RECs, or both, a distribution company may:

a) Sell the energy to its basic service customers, and retain RECs for the purpose of meeting the applicable annual RPS requirements;
b) Sell the energy into the wholesale electricity spot market, and sell the purchased RECs through a competitive bid process; or
c) Select an alternative transactional approach, in consultation with the Department of Energy Resources and subject to review and approval of the DPU.

If the distribution company sells both the energy and RECs, it must reconcile costs and revenues in a process that must be approved by the DPU.

[18] St. 2008, c. 169, § 83, an Act Relative to Green Communities. Also Massachusetts Department of Public Utilities, Docket 10-58, Order Adopting Emergency Regulations, June 9, 2010. http://www.env.state.ma.us/dpu/docs/electric/10-58/6910dpuord.pdf.

Distribution companies are not required to enter into long-term contracts if such contracts in aggregate would exceed 3% of total annual energy demand (in MWh) from all distribution customers in the service territory of the distribution company.

If RPS requirements terminate, a distribution company's obligation to solicit long-term contracts will cease, but contracts already executed and approved by the DPU will remain in full force and effect.

Connecticut

Connecticut has adopted permissive rules for long-term contracting (up to 15 years), and mandatory rules for long-term contracts to meet specific capacity targets.

The Department of Public Utility Control (DPUC)[19] will allow, but not require, the electric distribution companies (EDC) to procure REC contracts for existing and new Class I resources. To encourage long-term REC contracts, the DPUC will authorize a maximum of 0.4 mills per kWh as incentive compensation. Any RECs obtained through long-term contracts must be used to meet the EDCs' standard service and supplier of last resort RPS requirements. All costs associated with the long-term REC contracts will be recovered through Generation Service Charge rates. The DPUC strongly encourages a competitive REC procurement, but will not preclude negotiated contracts, provided the EDCs submit sufficient documentation proving favorable market conditions and ratepayer benefits. All EDC proposed contracts must be submitted to the DPUC for determination in a non-contested case docket. The DPUC will require specific terms and conditions in contract provisions to maximize ratepayer benefits and minimize risk.[20]

Connecticut also mandates that EDCs contract a minimum of 150 MW of clean energy resources by October 1, 2008. Under Project 150, the EDCs will enter into power purchase agreements with generators of Class I renewable energy for no less than a 10-year period. Pricing under these contracts will include a premium of up to 5.5 cents per kWh. The implementation process charged the Connecticut Clean Energy Fund with soliciting proposals from developers and with the initial screening and analysis to select projects that will benefit all Connecticut consumers. The process also involves review and selection by the state's two EDCs and final approval by the DPUC. Those receiving long-term contracts also receive funding from CCEF.[21]

Maine

Maine law permits the Maine Public Utilities Commission to direct the regulated transmission and distribution utilities to enter into 10-year contracts for capacity, associated energy or renewable energy credits, even though distribution utilities are not responsible for providing generation service. The utilities act as the agent or intermediary and either sell or assign those contracts to default service providers, sell the energy into the wholesale electricity market

[19] The Department of Public Utility Control has recently been renamed the Public Utilities Regulatory Authority as part of a reorganization that places it within a new Department of Energy and Environmental Protection.

[20] Connecticut Department of Public Utility Control, Docket 07-06-61, DPUC Examination of Electric Distribution Company Contracts for Renewable Energy Certificates. Decision, July 30, 2008.

[21] Connecticut Department of Public Utility Control, Docket 03-07-17, DPUC Review of Long-Term Renewable Energy Contracts. Decision, October 20, 2004. This docket has been reopened several times and updated.

through periodic competitive auctions, or other means available. The utilities are allowed to recover in rates the net cost, if any, of the contracts.[22]

In response to this law, the Commission directed two investor-owned utilities to enter into 20-year contracts with a new wind project. The contracts were structured as a discount off market prices but contain a price floor to protect the project owner and a price ceiling to protect ratepayers. Essentially, "the contracts provide a ratepayer hedge against a future of higher than expected market prices."[23] Although the Commission has since issued two more RFPs, additional contracts have not yet come to fruition, and in 2011 the Maine Legislature amended the contracting statute by requiring additional benefits to ratepayers.

Rhode Island

In 2009, the Rhode Island legislature adopted a Long-Term Contracting Standard for Renewable Energy that requires each electric distribution company (EDC) to solicit proposals from renewable energy developers annually. If the proposals received are determined to be commercially reasonable, the distribution companies will enter into contracts of up to 15 years (or longer, if the commission approves) for the purchase of capacity, energy and attributes from newly developed renewable energy resources. The minimum long-term contract capacity is 90 MW, of which 3 MW must be solar or photovoltaic projects located in Rhode Island. This target may be phased in over a four-year schedule, as shown in Table 7.

Table 7. Rhode Island Long-Term Contracting Requirement

By Date	Percent of Target	Capacity	
12/30/2010	25%	22.5 MW	May be earlier if approved by commission
12/30/2011	50%	45 MW	
12/30/2012	75%	67.5 MW	
12/30/2013	100%	90 MW	

For accepting the financial obligation of these long-term contracts, EDCs are entitled to financial incentives in the form of annual compensation equal to 2.75% of the actual annual payments made under the contracts for those projects that are commercially operating. This compensation is over and above the base rate revenue requirement established in the EDC's cost of service for distribution ratemaking.

The EDCs must file tariffs for commission review and approval that net the cost of payments made to projects under the long-term contracts against the proceeds obtained from the sale of energy, capacity, RECs or other attributes. The difference will be credited or charged to all distribution customers through a uniform fully reconciling annual factor in distribution rates. The reconciliation will ensure that customers are credited with any net savings resulting from the long-term contracts, and the EDC recovers all costs incurred under such contracts, as well as recovery of the financial incentive described above.

[22] Maine Revised Statutes Annotated (MRSA). (2001). 35-A M.R.S.A § 3210-C. Capacity Resource Adequacy. http://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3210-C.html.

[23] Maine Public Utilities Commission, Docket No. 2008-104, Resource Planning and Long-Term Contracting. Order Directing Utilities to Enter into Long-Term Contract, 8 October 2009. These first contracts did not include RECs because at the time the RFP was issued, long-term contracting for RECs was not authorized by statute. The law has since been amended to allow the Commission to direct long-term contracts for RECs as well.

The EDCs must submit their solicitation method and schedule to the commission for approval. Further, each long-term contract must be reviewed and approved by the PUC before it is considered effective. All energy and capacity purchased must be immediately sold by the EDC into the wholesale spot market, or, with commission approval, the EDC may resell the energy and capacity to customers. The RECs purchased under the long-term contract will be sold through a competitive bid process, or, with commission approval, they may be used to meet the EDC's RPS obligations.[24]

Considerations
In each of these cases, the states may describe certain criteria that must be met for long-term contract approval, such as cost-effectiveness, net benefits to consumers, or not exceeding a cost cap. We are not aware of any analyses of the effectiveness of long-term contracting in general, although some states (e.g. Connecticut's Project 150) have experienced considerable debate about implementation issues, and these dockets may contain some insights.

Long-term contracts are important, and risks associated with over-commitment can be managed. Among the factors the Commission should consider are the following:

- Long-term contracts reduce risk to investors and lenders, enabling project developers to obtain financing. This is widely accepted not just by developers but has also been clearly articulated by lenders, investors and financial/legal project facilitators.
- The economics of long-term contracts depend on projections of future energy prices, and there is a risk that future market prices may be lower than the contracted price. This risk can be managed by competitive procurements, careful scrutiny of proposed contracts, and by considering the long-term contract as part of a larger resource portfolio.
- Options to reopen the contract depending on market prices, or to reconsider the amount purchased, would reduce the security of the contracts and make it more difficult for new projects with such contract provisions to obtain financing. This added risk will be incorporated into the contract price. To our knowledge, for these reasons, contract language that allows a utility to exit from the agreement based on market prices is rarely used.
- If the RPS is subject to a cost cap, regulators should determine as part of the contract review process, whether the addition of the proposed contract is likely to trigger the cost cap. Once the long-term contract has been approved, however, subsequent events should not affect the status of the contract. Contracts with such a provision would not likely be financeable.
- Similarly, language that would terminate the agreement if the RPS law or regulations change (e.g. for eligibility) is also not included in long-term contracts. Examples from Massachusetts, Connecticut, New York, Nevada and California, among other states,

[24] Rhode Island General Laws Title 39 Public Utilities and Carriers, Chapter 39-26.1 Long-Term Contracting Standard for Renewable Energy**.** http://www.rilin.state.ri.us/Statutes/TITLE39/39-26.1/INDEX.HTM

expressly state that if the RPS changes after the effective date of the contract, the buyer is nevertheless obligated to honor the agreement, if it has been approved by regulators.

- Utilities are an important party to long-term contracts; they are generally credit-worthy off-takers because of their stability and reliable revenue streams.
- Even if utilities are long on overall electricity supply, new projects or contracts that are cost-effective should be undertaken because the definition of cost-effective means that the investment or contract will lower long-run costs. Alternatively, states with sufficient energy and capacity could adopt long-term contracting requirements with relatively small initial targets until the supply assessment changes, at which time contracting targets could be increased. Finally, states should consider the policy intent of the RPS legislation—generally the purpose is to change the state's resource mix, subject possibly to a cost-cap.
- Contracts for bundled electricity and RECs do not generally distinguish a price for the two commodities because the seller does not care whether the revenue comes from the sale of energy or RECs as long as the total covers the project's amortization costs, and the buyer does not care as long as the total cost does not exceed the agreed upon price. As a condition of long-term contract approval, the Commission could require that the parties specify the REC price based on (a) currently available projections of wholesale electricity price (they wouldn't have to reveal profitability, only the electricity price projection and the REC price assumption); (b) an annual report of the difference between the fixed price and the wholesale electricity prices (for the 3% cost cap); or (c) staff's own projections of the revenue gap/REC revenue using a model like CREST.
- Long-term contracts may be a significant economic development tool for the state and region, assuming that energy must be deliverable to Ohio.

Feed-in Tariffs

Feed-in tariffs (FITs) provide a specified rate for generation from eligible energy technologies for long terms (usually 10 to 25 years), with prices typically set (but not always) equal to the expected cost of production plus a profit. FITs represent one form of long-term contracts discussed above. By creating revenue certainty, FITs can help support investor confidence and thereby lower financing costs and a project's required rate of return. FITs can be offered as a fixed rate, a premium over prevailing market prices, or (less common) a price set by auction. Another common feature of FITs in some countries is guaranteed interconnection and priority dispatch for specified technologies.

A variant of FITs is a standard offer contract that basically provides for the guaranteed availability of payments per kilowatt-hour for an eligible energy resource. Like FITs, standard offers are usually long-term, 15 to 20 years in length and typically are based on market prices or by a forecasted avoided cost of other generation or power purchases. Nevertheless, FITs and standard offers share several similarities and there are not precise definitions that differentiate the two. Standard offer contracts are discussed further in the section on Customer Sited or Distributed Generation Support, below.

FITs are essentially the inverse of a renewable purchasing requirement such as a renewable portfolio standard (RPS). Under a RPS, a quota of electricity from eligible generation is set, and the market determines the price paid, usually restricted by some combination of legislated cost caps, rate impacts, or alternative compliance payments. A FIT sets a technology-specific price, and the market responds with an undefined amount of eligible energy capacity (unless program-wide caps or technology-specific caps are imposed).[25]

Although simple in concept, no two feed-in tariffs are designed the same because political jurisdictions have different policy objectives. Design differences include:

- Eligible resources and technologies
- Length of contract
- How prices are adjusted over time
- Performance milestones
- Ownership (Payments are sometimes differentiated by ownership type. Ontario's FIT, for example, provides higher prices for systems owned by municipalities or First Nations.)
- Location or application (such as offshore wind or building-integrated PV)
- Projected installation date
- Project capacity limits
- Program capacity limits (capped or uncapped)
- Resource intensity (e.g., different rates for wind or solar energy depending on the site's resource availability)[26]

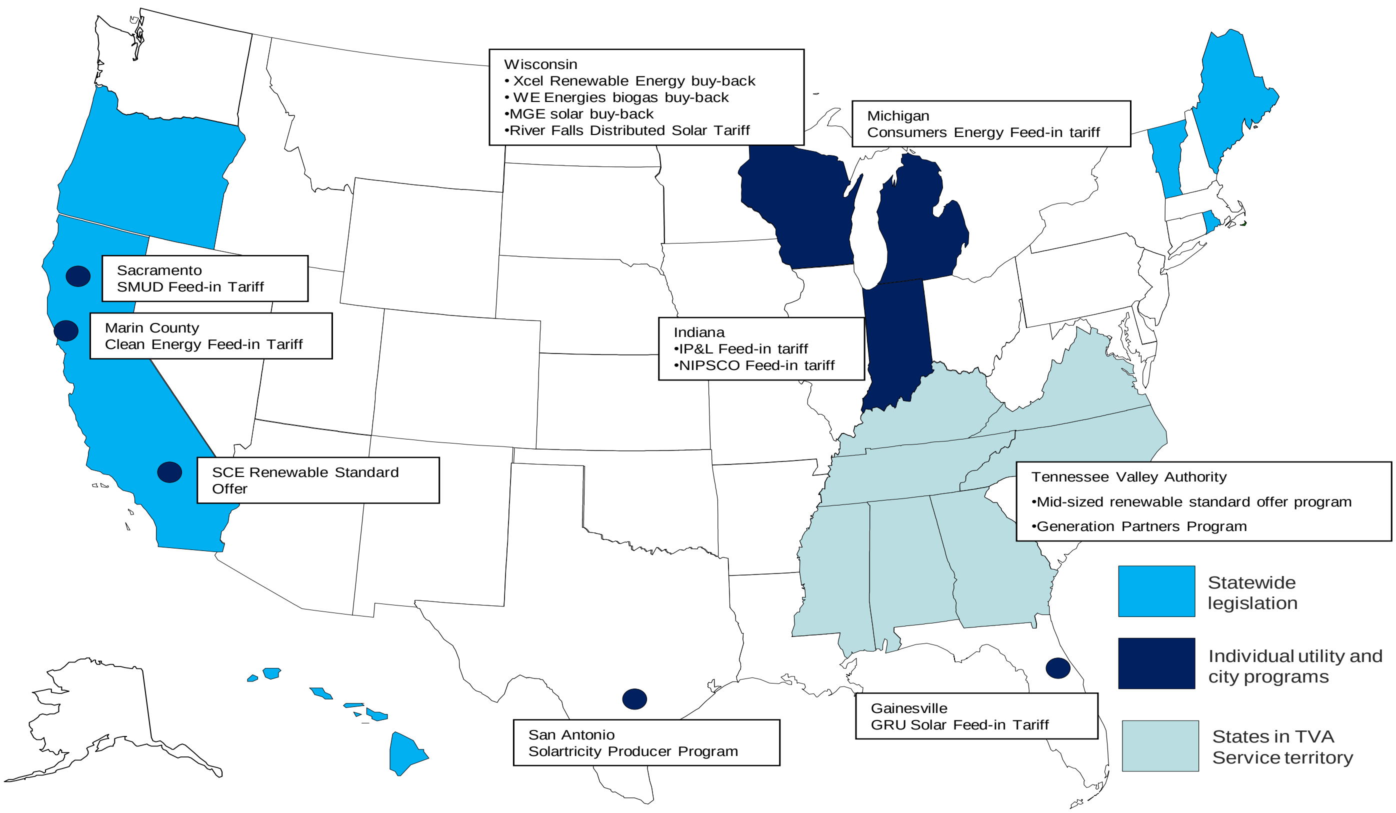
State Examples
As illustrated in Figure 3, experience with FITs in the United States is limited and is generally restricted to smaller projects or to certain technologies such as solar PV. States also often adopt caps on project size and overall capacity. Hawaii has a feed-in tariff that applies to most renewable energy technologies, with rates differing by technology and system size. The Hawaii PUC approved rates and standard interconnection agreements in October 2010, and plans to review the FIT two years later and every three years thereafter. The Hawaii FIT applies to three investor-owned utilities and has three tiers:

- Tier 1 includes all islands and eligible technologies where the project is less than or equal to 20 kilowatts in capacity.
- Tier 2 includes systems sized greater than 20 kW and less than or equal to: 100 kW for on-shore wind and in-line hydropower on all islands; 100 kW for PV and CSP on

[25] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit,* Montpelier, VT: Clean Energy States Alliance, December 2009, http://cleanenergystates.bluehousegroup.com/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.
[26] KEMA, Inc, "Exploring Feed-In Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options," *Final Consultation Report prepared for the California Energy Commission*, CEC-300-2008-003-F, November 2008, http://www.energy.ca.gov/2008publications/CEC-300-2008-003/CEC-300-2008-003-F.PDF.

Lanai and Molokai; 250 kW for PV on Maui and Hawaii; 500 kW for CSP on Maui and Hawaii; and 500 kW for PV and CSP on Oahu.

- Tier 3 is for systems up to 5 megawatts on Oahu and 2.72 MW on Maui and Hawaii. Wind projects on Maui and Hawaii have to comply with the Tier 2 caps.[27]



Source: Meister Associates, July 2011.

Figure 3. Feed-In Tariffs in the United States

Vermont has a pilot feed-in tariff with a maximum total capacity of 50 MW and a project-specific cap of 2.2 MW, while Maine also has a pilot feed-in tariff of 50 MW, with projects limited to 10 MW, and no more than 25 MW at any Maine utility. Two utilities are in the process of implementing feed-in tariffs in Indiana. Northern Indiana Public Service Company has a FIT for solar, biomass and wind between 5 kW and 5 MW in size, up to a maximum of 30 MW. No technology can account for over 50% of capacity under NIPSCO's FIT. Indianapolis Power and Light (IP&L)'s FIT also encompasses solar, wind and biomass up to 1% of the utility's retail sales in Indiana. No project can be over 10 MW, while not being less than 10 kW (solar) or 50 kW (wind).[28] The cities of Gainesville, Florida; San Antonio, Texas; and

[27] U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, *Hawaii Feed-in Tariff* http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=HI29F&re=1&ee=1, November 8, 2011.
[28] Indiana Distributed Energy Advocates' Blog. "Feed-in Tariffs," http://indianadg.wordpress.com/feed-in-tariffs/.

Sacramento, California, and various utilities in Wisconsin have implemented small feed-in tariffs. Marin County in California has a feed-in tariff for renewable energy systems of 1 MW or less (with an overall 2 MW program cap), with pricing depending on whether the facility is a baseload, peaking or intermittent generator.[29]

California instituted a limited feed-in tariff encompassing investor-owned utilities for systems up to 1.5 MW, up to a maximum capacity of 500 MW. However, the tariff is based on the state's Market Price Referent, or the cost of building a new gas-fired generating plant, and is not differentiated by technology or capacity.[30] Contracts are accepted until the 500 MW cap is reached. The California General Assembly raised the 500 MW cap in 2009 to 750 MW and required public utilities to participate; however, the California Public Utilities Commission has not issued implementation regulations yet. To date, 40 MW of projects are under contract, with 12.6 MW in operation.

California also has a separate policy, the Renewables Auction Mechanism (RAM), aimed at intermediate-sized renewable energy projects up to 20 MW. The RAM combines elements of competitive bidding with standard contracts and feed-in tariffs. A 1,000 MW goal for the first two years has been set for the three investor-owned utilities in California, who will simultaneously hold two auctions annually. Winning projects must be on-line within 18 months, with one six-month delay allowed due to regulatory delays. Utilities are only required to accept bids up to a "reasonableness threshold" or price cap.[31]

Results

Feed-in tariffs have been widely adopted for developing renewable energy, especially in Europe. At least 50 countries and 25 states and provinces have implemented feed-in tariffs as of early 2010.[32] Of the 27 countries in the European Union, 23 have feed-in tariffs in place.[33] More than half of the world's wind capacity and 75% of the world's solar capacity have been developed under feed-in tariffs.[34] Germany and Spain, both countries with feed-in tariffs, are among the world leaders in both installed solar and wind capacity. In particular, Germany receives over 16% of its electricity from renewable energy generation as of 2009, up from 4.8% in 1998, and 77% of Germany's renewable energy generation receives payments under Germany's FIT.[35] In North America, Ontario is projected to install more than 400 MW of solar in 2011, more than

---

[29] U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, *Marin Clean Energy Feed-in Tariff*, January 25, 2011. http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA226F&re=1&ee=1.

[30] Paul Gipe, "SB 32 CalSIA FIT Bill Becomes Law – Could Bring Incremental Improvement," October 11, 2009, http://www.wind-works.org/FeedLaws/USA/SB32CalSIAFITBillPasses.html.

[31] Alex Pennock, Ryan Wiser and Joanna Lewis. "California's Renewable Auction Mechanism: An Intermediate Point between Bidding and Feed-in Tariffs," (presentation), July 21, 2011.

[32] Ren21, *Renewables2010 Global Status Report*, September 2010, Revised Edition, http://www.ren21.net/Portals/97/documents/GSR/REN21_GSR_2010_full_revised%20Sept2010.pdf.

[33] Wilson Rickerson, *Renewable Energy Policy: Low-Risk Designs for Mobilizing Capital* [slides], March 16, 2011, World Bank Energy Week 2011, Washington, MA.

[34] Paul Gipe, "Bringing the Renewable Energy Revolution Back to California with Feed-in Tariffs," *Presentation before the Kern County Audubon Society*, March 1, 2011, http://www.wind-works.org/FeedLaws/USA/Gipe%20Audubon%2020110201.pdf.

[35] Sari Fink, Kevin Porter, and Jennifer Rogers, *The Relevance of Generation Interconnection Procedures to Feed-in Tariffs in the United States,* October 2010, NREL/SR-6A20-48987, http://www.nrel.gov/docs/fy11osti/48987.pdf.

twice what was installed in California in 2010. By 2015, Ontario could have more than 2,650 MW of solar, more than what the U.S. has installed in over 30 years.[36]

Considerations

Because individual FITs can differ in policy design and implementation, it is difficult to make generalizations about FITs. The design and implementation of the individual FIT will have much to do with whether the FIT is successful at stimulating additional eligible energy generation or not. Some general observations are provided below, but this central point should be kept in mind.

Many people consider FITs to be successful in stimulating additional renewable energy capacity at lower costs than other policies.[37] That does not mean FITs do not have cost impacts—depending on how the FIT is designed, there can be near-term upward pressure on electricity rates, particularly if there is growth in higher-cost renewable energy technologies. It can also be difficult to control costs under FITs, as it is not easy to estimate how the market will respond to FITs or to project future technology cost reductions that may occur over time.[38] Three broad approaches have been implemented in an attempt to control costs under FITs:

- Caps on overall or individual project size capacity; total program cost; or on energy production (i.e., as a percentage of total retail sales).

- Payment level adjustment mechanisms, such as pre-determined degression in payments to projects that become operational in subsequent years, or capacity-based price degression (whereby prices are reduced as capacity targets are met, according to a pre-established schedule).

- The use of auctions and competitive bidding, such as the California RAM approach described earlier.

Each of these approaches to controlling costs under FITs offers advantages and disadvantages. While caps directly reduce costs under a FIT, they can also reduce the ability to utilize economies of scale, depending on the level set for the cap. It can also be difficult to evaluate when a cap is reached, introducing uncertainty for project investors and regulators. Caps can also contribute to speculative queuing, although this can be addressed through a combination of application fees, security deposits, and the requirement to meet periodic milestones as a means of eliminating non-operating projects from the queue. Payment level adjustment mechanisms can provide a more self-correcting means of controlling prices paid to eligible generators under FITs without regulatory intervention, and can work well for technologies with rapid changes in costs over time, such as photovoltaics. However, payment level adjustment mechanisms based on

---

[36] Brennan Louw, Jon Worren, and Tim Wohlgemut, *Executive Summary: Ontario PV Market Forecast 2011-2015*, ClearSky Advisors, February 2011, http://www.wind-works.org/FeedLaws/Canada/ClearSky%20Advisors%20ON%20PV%20Forecast%20Exec%20Summary20110224.pdf.

[37] Nicholas Stern, *Stern Review on the Economics of Climate Change*, London, UK: HM Treasury, 2006, http://www.hm-treasury.gov.uk/sternreview_index.htm.

[38] Toby Couture, Karlynn Cory, Claire Kreycik, and Emily Williams, *A Policymaker's Guide to Feed-In Tariff Policy Design*, National Renewable Energy Laboratory, July 2010, http://www.nrel.gov/docs/fy10osti/44849.pdf.

caps can create market uncertainty if it is not easy to estimate when caps will be reached. Finally, auctions and competitive bidding can be a flexible means of acquiring new eligible generation capacity, but designing and implementing an auction for multiple renewable energy technologies will be challenging because of the different characteristics, different technology status, and different risks of project completion and performance among the individual renewable energy technologies. Auctions can also be susceptible to speculative bidding unless such steps as fees, deposits and the requirement to meet periodic milestones are implemented ahead of time.

FITs require regulatory oversight and administration in setting the FIT rates, in reviewing the FIT periodically, and possibly making mid-course corrections that could be required in the wake of technology cost reductions or overly generous tariffs. Such mid-course governmental reviews of FITs could provide a forum for revisiting the effectiveness and cost impacts of FIT policies, although at the potential risk of undermining policy predictability and stability. High tariffs and a plentiful solar resource led to a market rush for solar in Spain, prompting Spain to review its FIT and impose an annual cap on solar installations to 500 MW for 2009 and 2010 and 400 MW for 2011 and 2012.[39] That resulted in a drop in installed solar capacity in Spain from 2,600 MW in 2008 to about 100 MW in 2009.[40] A revision of FIT rates can be necessary as conditions change, but such revisions can be disruptive to the market and contribute to policy instability. If possible, preferred approaches include designing cost containment into the FIT policy from the beginning and reducing tariff prices over time to capture declining technology costs.[41]

Finally, the regulatory and legal structure of electric power regulation in the United States may significantly impede the implementation of FITs. The Federal Energy Regulatory Commission (FERC) has exclusive authority under the Federal Power Act to set wholesale rates for generation and transmission. Therefore, a primary basis of a state FIT—a state setting wholesale rates for utility purchases from eligible generation—is not permitted under the Federal Power Act. Interconnection guarantees for certain technologies, another common feature of FITs world-wide, are also incompatible with FERC's practice of ensuring comparability of generation interconnection requests, regardless of generation source. FERC has issued clarifications that provide states with some flexibility, however.

States are allowed under the Public Utility Regulatory Policies Act of 1978 (PURPA) to set wholesale avoided cost rates for eligible generators, primarily renewable energy generators and cogeneration projects that meet certain steam efficiency requirements, with avoided costs defined as the incremental costs of energy or capacity a utility would not incur if it generated itself or purchased the power from other sources. Avoided cost rates may not be sufficient to support development of new renewable energy projects, particularly emerging technologies. Earlier FERC orders suggested that states could supplement avoided cost rates with state tax incentives, direct payments or revenues from renewable energy credit sales without violating the avoided

---

[39] Claire Kreycik, Toby D. Couture, and Karlynn B. Cory. *Innovative Feed-in Tariff Designs That Limit Policy Costs*. National Renewable Energy Laboratory, June 2011, http://www.nrel.gov/docs/fy11osti/50225.pdf.

[40] Paul Gipe, "Spanish Tariff Revisions Update," July 23, 2010, http://www.wind-works.org/FeedLaws/Spain/SpanishTariffRevisionsUpdate.html.

[41] Toby Couture, Karlynn Cory, Claire Kreycik, and Emily Williams, *A Policymaker's Guide to Feed-In Tariff Policy Design.* National Renewable Energy Laboratory, July 2010, http://www.nrel.gov/docs/fy10osti/44849.pdf.

cost restrictions of PURPA.[42] A more recent FERC order suggested that avoided cost rates could be differentiated by other factors, such as state renewable energy purchasing requirements or the supply characteristics of the different technologies.[43] In addition, the Energy Policy Act of 2005 (EPACT 2005) allows utilities to petition FERC to be exempt from making future purchases under PURPA. In its implementation rule, FERC stated that competitive energy markets such as PJM and the Midwest ISO would be presumed to meet the intent of EPACT 2005. Presumably, utilities in Ohio are exempt from making future purchases of generation from qualifying facilities under PURPA, so the option of implementing a FIT under PURPA may be foreclosed for Ohio.

Alternatively, Ohio could direct its distribution utilities to sign contracts for a specified quantity of MW of renewable energy and have those utilities file those contracts at FERC for approval under cost-based rates or market-based rates, after a showing is made that the renewable energy developer does not have market power. States can review whether to allow the costs of the renewable energy contracts into retail rates, but that is a yes-or-no decision—the rate itself cannot be adjusted.[44]

Customer-Sited or Distributed Generation Support

States encourage small projects—often sited on customer premises to serve part of their load—by adopting focused policies. The purpose of these policies typically is to support distributed generation or specifically renewable generation, promote resource diversity, and encourage local investment and jobs.

As part of their RPS, several states, including Ohio, have mandated a separate tier or target for solar, customer-sited generation, or distributed generation.[45] Even when a mandate is present, however, small projects still face unique hurdles. These include higher costs (no economies of scale), access to competitive financing terms (credit-worthiness, transaction costs for small projects), weak service infrastructure (design, specification, installation or maintenance), and access to REC markets (lack of understanding, transaction costs).[46]

There are a number of policy approaches to address these challenges.

- Rebates: These are upfront payments usually based on the capital cost. A classic example of a rebate is a $/Watt "buy-down," although a rebate could also be based on the capital

[42] For a legal analysis of these FERC orders, see Scott Hempling, Carolyn Elefant, Karlynn Cory and Kevin Porter. *Renewable Energy Prices in State-Level Feed-in Tariffs: Federal Law Constraints and Possible Solutions*. National Renewable Energy Laboratory, January 2010, http://www.nrel.gov/docs/fy10osti/47408.pdf.
[43] FERC. *Order Granting Clarification and Dismissing Rehearing*. 133 FERC ¶ 61,059, October 21, 2010.
[44] Scott Hempling, Carolyn Elefant, Karlynn Cory and Kevin Porter. *Renewable Energy Prices in State-Level Feed-in Tariffs: Federal Law Constraints and Possible Solutions*. National Renewable Energy Laboratory, January 2010, http://www.nrel.gov/docs/fy10osti/47408.pdf.
[45] Ryan Wiser, Galen Barbose and Edward Holt, *Supporting Solar Power in Renewables Portfolio Standards: Experience from the United States*. LBNL- 3984E. Berkeley, CA: Lawrence Berkeley National Laboratory, October 2010. http://eetd.lbl.gov/ea/emp/reports/lbnl-3984e.pdf
[46] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit* (December 2009), Clean Energy States Alliance, http://www.cleanenergystates.org/Publications/cesa-financial_Toolkit_Dec2009.pdf

cost of the system. Rebates can be capped by placing a limit on the total amount of money that may be paid for any one project, or by limiting the size of eligible projects.[47]

- Performance-based Incentives: This approach provides a stream of revenue based on actual output of the generator. In many ways, performance-based incentives are (or can be) very similar to a feed-in-tariff. Most examples with which we are familiar offer a fixed performance payment per kWh for a fixed term of years.
- Loan Programs: Loan programs are often introduced to address the capital cost of renewable energy investments. Because lending institutions are not always familiar with the technology, loan programs also may establish technical criteria or standards, or may be pre-screened and approved by utilities, so that banks or other lending institutions can focus on the credit risk, which is what they know best.

Rebates

Rebates and buy-downs have been a popular policy approach to encouraging small-scale projects.[48] There are many variations in the way rebate programs are designed, and the rebate levels are often different because market conditions (including the retail price of electricity) vary. Here we give an example of a rebate program—operated at a state level—that differs depending on the location of the on-site system.

In June 2011, AEP Ohio received approval to offer a rebate program to its customers for solar photovoltaic and wind energy systems. Customers who participate agree to assign the RECs from their systems to AEP for 15 years. The rebates vary according to customer type, with limitations on incentive per customer and total funding amounts, as shown in Table 8.

Table 8. AEP Rebate Program

System Type	Customer Type	Incentive Amount	Minimum System Size	Maximum Incentive as % of System Cost	Maximum Incentive per Customer	Annual Funding Cap
Solar Photovoltaic	Residential	$1.50/watt	2 kW (dc)	50%	$12,000	$400,000
	Non-Residential	$1.50/watt	10 kW (dc)	50%	$75,000	$600,000
Wind	Residential	$0.275/kWh	3,000 kWh/yr (ac)	50%	$7,500	$187,500
	Non-Residential	$0.275/kWh	3,000 kWh/yr (ac)	40%	$12,000	$62,500

Source: Ohio Power Company, PUCO No. 19, Renewable Energy Technology Program Rider, effective July 1, 2011

Energy Trust of Oregon operates a Solar Electric Buy-Down Program that offers a classic PV rebate program. The incentives for customers of Portland General Electric and of Pacific Power vary based on size and ownership of the PV system, as well as between the utilities, as shown in Table 9.

[47] Although the distinction between grants and rebates is often blurred, grants tend to be for new technologies and demonstration projects.
[48] Eric Lantz and Elizabeth Doris, *State Clean Energy Practices: Renewable Energy Rebates*. NREL/TP-6A2-45039. Golden, CO: National Renewable Energy Laboratory, March 2009. http://www.nrel.gov/docs/fy09osti/45039.pdf

Table 9. Oregon Solar Photovoltaic Rebates

Ownership	PGE Buy-Down	Pacific Power Buy-Down
Residential (homeowner)	$1.75/Watt$_{dc}$ $20,000 max	$1.50/ Watt$_{dc}$ $20,000 max
Residential (third party owned)	$1.25/ Watt$_{dc}$ $10,000 max	$1.00/ Watt$_{dc}$ $5,000 max
Nonprofit & Govt (up to 30 kW)	$1.50/ Watt$_{dc}$ $200,000 max	$1.25/ Watt$_{dc}$ $150,000 max
Nonprofit & Govt (30-200 kW)	$1.50 – 1.00/Watt$_{dc}$* $200,000 max	$1.25 – 0.75/ Watt$_{dc}$ $150,000 max
Commercial, Industrial, Third Party owned (up to 30 kW)	$1.25/ Watt$_{dc}$ $500,000 max or $600,00 for multiple sites	$1.00/ Watt$_{dc}$ $100,000/max
Commercial, Industrial, Third Party owned (30-200 kW)	$1.25 – 0.75/Watt$_{dc}$* $500,000 max or $600,00 for multiple sites	$1.00 – 0.50/Watt$_{dc}$ $100,000/max

Source: U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency; Energy Trust of Oregon; and individual utility websites.
*The per-watt incentive rate is at its highest rate for systems up to 30 kW and declines linearly for systems sized between 30 and 200 kW.

States with more comprehensive rebates or grants differentiate the incentive according to the end-use sector, technology, size of system (capacity), and like Oregon, sometimes utility territory. In some cases the incentive amounts may be reduced on a predictable schedule, or as specific capacity (MW) targets are met. Cost caps may be a percentage of the total cost or a fixed amount, and sometimes the lesser of these two combined.

Performance-based Incentives

Although rebate and grant programs are easy to understand, and provide certainty about how much financial support will be provided, the trend at the state level appears to be to convert financial incentives to pay-for-performance, also called performance-based incentives.[49] The rationale is mostly philosophical in that pay-for-performance aligns the incentive with actual results, rather than basing the incentives on cost.

Performance-based incentives can be like FITs (described above), or may rely on market-based payments that are based on performance but which are not guaranteed. When performance-based incentives are configured as a fixed payment and coupled with a fixed-term contract, they are also sometimes referred to as a standard offer.

Several Ohio utilities have recently instituted REC purchase programs based on system performance. Beginning in 2009 and continuing into 2010, Duke Energy Ohio, First Energy, Dayton Power & Light, and American Electric Power all filed proposals for approval by the PUCO. The programs differ in their details, but they all provide performance-based incentives. Duke, for example, will enter into agreements to purchase solar RECs from residential customers through the end of 2012, for a term of 15 years. Except for the year 2010, when the price was set at $300, the amount paid for the RECs is based on market prices determined annually. First Energy offers a similar program. AEP will purchase RECs from solar or small wind systems at a

[49] G. Barbose, R. Wiser and M. Bolinger, *Designing PV Incentive Programs to Promote Performance: A Review of Current Practice*. LBNL-61643. Berkeley, CA: Lawrence Berkeley National Laboratory, October 2006.

predetermined price, but only for three years. These program parameters highlight the issues of whether to pay a fixed price and whether to do so for an extended period of time—both issues that relate to the allocation of risk between the customers who own the systems (or their financiers) and the company's rate payers. Duke and First Energy opted for a guaranteed purchase but an uncertain price, while AEP chose to offer a guaranteed price but without a long-term purchase guarantee. The success of these programs will depend not only on whether customers can get financing based on the performance-based incentives, but also on the stability of the programs themselves. The offers are available for only two to three years (the end date is different for each utility), suggesting that these are viewed as pilot programs, but installer expectations of the availability of such offers will probably affect their willingness to invest in expanding their services and infrastructure in Ohio.

The Tennessee Valley Authority (TVA) offers two programs for qualifying new renewable energy projects. Under Generation Partners, customer-sited projects from 500 W up to and including 200 kW are eligible if they use solar, wind, low-impact hydropower, or biomass (including solid, liquid and gaseous forms of woody waste, agricultural crops or waste, animal or other organic waste, energy crops and landfill gas or wastewater methane). TVA will buy the output, including the RECs, at a rate of 12 cents per kWh above the retail electric rate for solar, and 3 cents above retail for all other renewable sources. New participants will receive an additional $1,000 to help offset start-up costs. The contract term is for 10 years.

The second program is called the Renewable Standard Offer, and is for projects from 200 kW to 20 MW. All of the major renewable power generating technologies are eligible, including solar, wind, biomass gasification, and mature renewable technologies, such as biomass direct combustion, methane recovery, and co-firing of 50% or more biomass. The price paid varies by season and time of day (the base price average is $0.0561/kWh). The same prices apply to all technologies, with the average hourly base price escalated annually by a constant percentage over the length of the contract. As a result, technologies that operate during peak hours (e.g. solar) will receive the benefit of higher prices during those periods. The Standard Offer price is not a premium price, but it has the benefit of a secure contract. Developers can choose contract lengths of 10, 15, and 20 years.

A number of states, by adopting solar set-asides, or a special tier in their RPS for solar energy, have created solar REC (SREC) markets to provide the payment based on performance.[50] An SREC is produced for every MWh of electricity generated by an eligible solar project. Obligated entities will purchase these SRECs for compliance with the RPS, providing the owners of these projects with a revenue stream. Because the SREC value is tied to supply and demand, however, the revenue is uncertain and may not provide the security that a lender would need for project finance. A fixed price under a standard REC offer provides more certainty for the participant and for a lender, making the project more financeable, but may create more risk for ratepayers if the fixed price exceeds market price.

Some states have added program features that make it easier for solar owners to sell their SRECs. For example, New Jersey has figured out a way to securitize the revenue stream. In one approach, three electric distribution companies (EDCs) offer 10- to 15-year contracts for the

[50] These states include Massachusetts, Maryland, New Hampshire, New Jersey, Ohio and Pennsylvania.

purchase of SRECs, with projects selected through periodic competitive solicitations. In 2009, the BPU approved the contracting programs of these three EDCs for a three-year period, with a cap of 65 MW. Because the EDCs are not obligated entities under the RPS law in New Jersey, they auction the SRECs to those who do need them for compliance. In a different approach, the state's largest EDC (PSE&G) has created a solar loan program. The utility loans customers a portion of the up-front cost of a PV system, and the customer repays the loan either in cash or in the form of SRECs generated by their PV system over a 10-15 year term. For purposes of loan repayment, SREC prices are equal to the greater of the prevailing market price for SRECs or a pre-established floor price that varies by customer segment and by loan origination date. PSE&G also auctions these SRECs to those with an RPS compliance obligation. PSE&G's current Solar Loan II Program is approved for a two-year period, with a cap of 51 MW.[51]

New Jersey has also established a rolling 15-year solar alternative compliance payment (SACP) to provide some certainty about the upper value of SRECs, and has adopted a mechanism for automatically increasing the solar set-aside targets in the event of an SREC surplus and declining SREC prices in three consecutive years, also with the intent of increasing revenue certainty for solar project developers and investors.

Loans
There are many state and utility loan programs, many of them established originally to service energy efficiency investment and later expanded to include renewable energy supply.[52] Some of the key variants in the programs are what customers are eligible (end-use sectors), what technologies are eligible (broad eligibility or narrow focus), limits on loan amounts, market rate or subsidized interest rates, who originates and services the loans, and the source of funding.

Minnesota, for example, has a suite of loan programs, including the following two:

- The Agricultural Improvement Loan Program provides low-interest loans to farmers for wind (up to 1 MW), biomass and anaerobic digestion. It is administered by the Minnesota Department of Agriculture through the Minnesota Rural Finance Authority (RFA). Loans are made by individual financial institutions working with the RFA. The RFA has a Master Participation Agreement with over 400 financial institutions throughout the state. RFA participation in a project is limited to 45% of the principal amount of the loan or $300,000, whichever is less. As of September 2010 the interest rate offered by the RFA was 4.5%. Terms for the remainder of the loan are negotiated between the participant and the lender.

---

[51] Jason Coughlin and Karlynn Cory, *Solar Photovoltaic Financing: Residential Sector Deployment*. NREL/TP-6A2-44853. Golden, CO: National Renewable Energy Laboratory, March 2009. http://www.nrel.gov/docs/fy09osti/44853.pdf
Ryan Wiser, Galen Barbose and Edward Holt, *Supporting Solar Power in Renewables Portfolio Standards: Experience from the United States*. LBNL- 3984E. Berkeley, CA: Lawrence Berkeley National Laboratory, October 2010. http://eetd.lbl.gov/ea/emp/reports/lbnl-3984e.pdf

[52] For more information on loan programs, see Clean Energy States Alliance, *Developing an Effective State Clean Energy Program: Clean Energy Loans*. Briefing Paper No. 4 March 2009. http://www.cleanenergystates.org/assets/Uploads/Resources-pre-8-16/CESA-cleanenergy-Loan-Programs-March09.pdf

- The Neighborhood Energy Connection (NEC) offers secured, low-interest loans for qualified energy efficiency and renewable energy improvements (solar hot water, photovoltaic) to Minnesota residences. Loans are limited to owners with household incomes of $96,500 or less, in amounts ranging from $2,000 - $35,000. Loan repayment terms vary from 1 to 20 years according the amount of the loan at a fixed interest rate of 5.75%. Most costs of this financing offer, including a 1% origination fee, credit report fee, and document preparation fee can be rolled into the loan. All loans are secured by a mortgage on the property. In order to be eligible for a loan, qualified homeowners must schedule an energy audit. The actual improvements undertaken are up to the homeowner, but financed projects must include at least one of the recommendations made by the auditor. The Minnesota Energy Loan is funded by Minnesota Housing and Finance Agency and processed and underwritten by the NEC.

Pennsylvania also has a number of different loan programs, including the following:

- The Alternative and Clean Energy Program provides loans to businesses or economic development organizations for energy generation projects that meet the eligibility criteria of the Alternative Energy Resource Standard. Loans may not exceed $5 million or 50% of the total project cost, whichever is less. Interest rates for alternative energy production projects are set at 5% currently, but may change based on market conditions. Loans must be repaid within 10 years. The loans require equal matching funds from new public or private investment in the proposed project. All loans are secured by a lien on the asset financed. The Program is administered jointly by the Department of Community and Economic Development (DCED) and the Department of Environmental Protection (DEP), under the direction of the Commonwealth Financing Authority, and is funded by the Alternative Energy Investment Fund (state issued bonds).

- Pennsylvania also offers a Solar Energy Program through the same agencies, which provides loans to business, economic development organizations and political subdivisions for solar photovoltaic and solar hot water systems. The maximum loan amount is $5 million or $2.25 per watt, whichever is less, and has similar loan terms as described for the Alternative and Clean Energy Program. According to the CFA website, however, Solar Energy Program applications are no longer being accepted because the funding has been exhausted.

Results

An assessment of the Database of State Incentives for Renewables and Efficiency shows that these types of programs are widespread. Thirty-five states support rebates for renewable energy generation; 31 sates have performance-based incentives; and 39 states have loan programs for renewable energy projects.[53] Eighteen states have all three types of these programs; 20 states

[53] This count includes the District of Columbia, and numbers states with state-wide programs as well as states whose major utilities offer programs of these types. Many states have more than one program of each type, targeted to different technologies or to different end-use sectors; these are counted only once. It excludes programs offered by local government and non-profit organizations. Programs focusing on energy efficiency, including geothermal heat pumps, are also not included.

have two of these types of programs; 11 states have only one of these types of programs; and two have none.

Loan programs serve an important function, which is to address the barrier of high initial costs of renewable energy technologies. This is especially true for smaller scale, customer-sited generation. Accessible financing is just one challenge for new projects, however, and states should consider other options for a more robust policy portfolio to support the development of renewable energy.[54]

For rebates, setting the buy-down amount can be a challenge, especially as technology costs change, and project economics vary depending on size, electricity prices, REC prices and other incentives that may be available. In some states, the level of rebate or buy-down has resulted in heavy demand, placing stress on budgets and creating the need for application queues and waiting lists. New Jersey, for example, has had a Renewable Energy Incentive Program for a decade, and still offers rebates for biomass and fuel cell systems including combined heat and power, but rebates for wind energy systems are temporarily on hold and new applications are not being accepted at this time. Further, the demand for solar rebates was so high that the cost to continue paying rebates was unsustainable. New Jersey therefore transitioned the solar support to an SREC program that lets the market create the added value.

Performance-based incentives have grown in popularity over the last several years because they align the owner's interest with the public interest in maximizing output. It is payment based on performance that encourages owners to maintain the systems at top efficiency. Performance-based incentives also face some of the same challenges as setting rebate levels, though, because it can be hard to keep up with technology differentiation and shifts in the underlying costs. Nevertheless, when combined with security of a long-term contract and certain payments, performance-based incentives are very effective in motivating new project development.

Considerations

Rebates or one-time incentive payments are relatively simple to administer, and once eligibility criteria are met, the state or utility paying the incentive has no lingering obligation. Rebates are usually based on a portion of the cost of the new project, however, and cost-based incentives do not necessarily motivate lower-cost projects.

Because rebate payments are paid up front, they place the risk of non-performance on ratepayers (who are presumably paying for the incentives) rather than on project owners. Of course, project owners still have an interest in performance, but it is limited to say a net metering billing credit which may be significantly lower than the direct financial incentive.

Performance-based incentives, on the other hand, align owner interests with ratepayer interests, because owners want to maximize payments, and for ratepayers, value is maximized by ensuring payment for actual output. Cost of the installed generator is not a factor except insofar as funding caps may be applied to each project.

---

[54] E. Lantz, *State Clean Energy Policies Analysis: State, Utility, and Municipal Loan Programs*. NREL/TP-6A2-47376. Golden. CO: National Renewable Energy Laboratory, May 2010. http://www.nrel.gov/docs/fy10osti/47376.pdf

Performance-based incentives require servicing and monitoring over the life of the purchase agreement, but this is also true of programs that provide upfront payments if the agreement requires the transfer of renewable energy certificates (RECs) to the purchaser. Regardless of the incentive mechanism used, if the RECs are sold or transferred to another party, the project owner or third party must read meters report production data to REC tracking systems and manage a REC account.

Regardless of whether the financial incentive is paid upfront or paid over time based on performance, the level of the incentive may be based on several alternative approaches:

- The utility's avoided cost;
- A portion of the project's capital cost;
- The market value of the RECs; or
- The incremental cost of the project above the levelized cost of electricity.

Equivalence between an upfront payment and a stream of payments over time would be established by present valuing the stream of estimated performance payments to create a single upfront payment.

If the basis of the incentive is the utility's avoided cost, it is likely that it will not be sufficient to motivate new projects whose costs are usually higher than market prices of electricity. If the basis of the incentive is a portion of the project's capital cost, this is simply an estimate of what it would take to interest project developers, and will probably require regular adjustment to reflect market demand and changing technology prices.

Incentives based on the market price of RECs depend on the assumption that REC prices reflect the cost of market entry, meaning the incremental cost of the proposed project above the appropriate electricity price benchmark. The price of RECs, however, is influenced most strongly by supply of and demand for RECs, not by the incremental cost that must be covered for a project to be financially feasible.[55] Basing the incentive on the market price of RECs may be acceptable if the policy objective is to satisfy the RPS at the least cost, but if the policy objective is to stimulate new renewable energy projects for environmental, economic development, or resource diversity reasons, then the value of RECs may not be sufficient. It can also be difficult to have a comprehensive view of the cost of RECs. Brokers report only the deals they arrange, which is usually only a small part of the market. Competitive solicitations for RECs will give a good idea for the size of projects that are bidding, but these are probably not the same as the customer-sited projects that are the focus of financial incentives. Solicitations may also be only for a short term, which would tend to reflect current supply and demand, rather than the long-term prices that would be needed for new projects.

Incentives based on the incremental cost of a project relative to the appropriate electricity price benchmark have the best chance of being approximately right because they would reflect the

[55] Edward Holt, Jenny Sumner and Lori Bird, *The Role of Renewable Energy Certificates in Developing New Renewable Energy Projects*. NREL/TP-6A20-51904. Golden, CO: National Renewable Energy Laboratory, June 2011. http://apps3.eere.energy.gov/greenpower/pdfs/51904.pdf

financial hurdle facing the project developer—the cost of entry to the market. For large projects, the appropriate comparison would be to a projection of wholesale energy prices; for net-metered projects, the appropriate comparison would be to a projection of retail generation prices. This approach does require analysis of prototypical installations, and will require periodic updating to reflect changing electricity prices and technology prices. The analysis could be done using a financial model such as CREST.

State Tax Incentives for Renewable Energy Technologies

Depending on the design of the particular tax incentive, renewable energy tax incentives are intended to at least partly (or fully) bridge the price gap between conventional generation and renewable energy by reducing personal or corporate tax liability, thereby either reducing consumer costs or increasing the value of renewable energy generation.

Tax incentives are a commonly used policy mechanism for incentivizing renewable energy technologies. Some form of tax incentives for renewable energy technologies is currently available from the U.S. federal government and from all but three states (Arkansas, Delaware and Mississippi) and the District of Columbia. There are several types of tax incentives in place—the mechanisms reviewed here include:

1. Personal and corporate tax incentives
2. Production-based tax incentives
3. Sales tax incentives
4. Property tax incentives
5. Manufacturing tax incentives

Personal and Corporate Income Tax Incentives

A personal or corporate tax incentive decreases a taxpayer's income tax liability for part of the costs of installing eligible renewable energy technologies. Tax credits are used by both federal and state governments to stimulate clean-energy markets. In the U.S., personal and corporate tax credits for renewable energy exist at both the federal government and state government levels. The federal government offers a 30% corporate tax credit for solar, fuel cells and small wind technologies and 10% for geothermal, microturbines and combined heat and power. In addition, the federal government offers a 30% residential tax credit for solar electric and solar heat technologies, geothermal heat pumps, wind, and fuel cells. Both the corporate and personal federal tax credits expire at the end of 2016. Twenty-four states offer personal and/or corporate tax incentives for renewable energy technologies.[56]

Production Tax Credit

A production-based tax incentive earns income tax credits for eligible renewable energy facilities, at a specified amount per kilowatt-hour. The best known example is the federal Production Tax Credit, or PTC. The federal PTC was initially set at 1.5¢/kWh in 1993 dollars and is now 2.2¢/kWh, after being adjusted for inflation. As indicated in Table 10 below, the

[56] U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, *Summary Tables (for Financial Incentives)* [web page], thttp://www.dsireusa.org/summarytables/, retrieved April 28, 2011.

PTC lasts for 10 years under most circumstances,[57] and certain technologies only receive half of the PTC.[58]

Table 10. U.S. Production Tax Credit Eligibility by Resource Type

Resource Type	In-Service Deadline	Credit Amount
Wind	December 31, 2012	2.2¢/kWh
Closed-Loop Biomass	December 31, 2013	2.2¢/kWh
Open-Loop Biomass	December 31, 2013	1.1¢/kWh
Geothermal Energy	December 31, 2013	2.2¢/kWh
Landfill Gas	December 31, 2013	1.1¢/kWh
Municipal Solid Waste	December 31, 2013	1.1¢/kWh
Qualified Hydroelectric	December 31, 2013	1.1¢/kWh
Marine and Hydrokinetic (150 kW or larger)	December 31, 2013	1.1¢/kWh

Source: U.S. Department of Energy, Database of State Incentives for Renewables and Efficiency, *Federal Incentives/Policies for Renewable Energy: Renewable Electricity Production Tax Credit*, May 4, 2010, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F&re=1&ee=0

In 2009, the U.S. Congress allowed the sponsors of eligible renewable energy projects to choose between the PTC, the federal investment tax credit, or a cash grant equal to the value of the federal investment tax credit (i.e., 30% in most instances). The financial crisis and the accompanying economic recession significantly reduced the number of companies with sufficient income tax liability to fully utilize either the PTC or the federal investment tax credit, prompting Congress to allow cash grants as a temporary measure until economic conditions improved.[59] To utilize the grant, construction on the eligible renewable energy project must begin by December 31, 2011.

In addition to the federal PTC, at least five states—Arizona, Iowa, Maryland, New Mexico, and Oklahoma—offer state-level production tax incentives.[60] These state PTCs are described more below:

- Arizona provides a state production tax credit of 1 cent/kWh for wind, landfill gas and biomass systems installed after December 31, 2010, for 10 years, up to a maximum of $2 million per year per project. Photovoltaic and solar thermal electric systems are eligible for higher incentives that decline over time, beginning at 4

[57] Exceptions include open-loop biomass facilities in operation before October 22, 2004, which can receive the PTC for five years, and open-loop biomass, geothermal, small irrigation hydro, landfill gas and municipal solid waste combustion facilities that entered commercial operation after October 22, 2004 but before August 8, 2005, that can also can receive the PTC for five years.

[58] U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, *Federal Incentives/Policies for Renewable Energy: Renewable Electricity Production Tax Credit*, May 4, 2010, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F.

[59] Mark Bolinger, Ryan Wiser, and Naïm Darghouth, *Preliminary Evaluation of the Impact of the Section 1603 Treasury Grant Program on Renewable Energy Deployment in 2009,* Lawrence Berkeley National Laboratory, LBNL-3188E, April 2010, http://eetd.lbl.gov/EA/EMP/reports/lbnl-3188e.pdf.

[60] U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, *Performance-Based Incentive for Renewable Energy* [web page], http://www.dsireusa.org/incentives/index.cfm?SearchType=Production, retrieved April 29, 2011.

cents/kWh for the first two years and declining to 1 cent/kWh by the 9th and 10th years, also subject to the $2 million annual cap. State-wide, there is a $20 million cap. The Arizona Department of Revenue accepts applications in January following the year the credit is claimed until the $20 million cap is reached.

- Iowa has two production tax credits, one for wind and the other for wind and other renewable energy technologies. The wind-only incentive offers 1 cent/kWh for wind projects of at least 2 MW but no more than 30 MW that are in-service by July 1, 2012.[61] A state-wide cap of 50 MW applies. As of May 2011, 24.5 MW of the 50 MW cap has been used. Wind projects must be on-line within 18 months after receiving approval from the Iowa Utilities Board (IUB) to retain eligibility, unless project owners apply for and receive approval from the IUB for a 12-month extension.

  Iowa's other PTC offers 1.5 cents/kWh for wind, solar electric, landfill gas, biomass hydrogen, and anaerobic digestion projects. Qualifying owners must own at least 51% of the project, and overall project capacity cannot exceed 2.5 MW per owner, or 5 MW overall for non-wind projects. A state-wide cap of 363 MW applies for wind, and a 53 MW cap is in place for non-wind technologies. At least 10 MW of nameplate generating capacity of any type of eligible renewable energy must be "incorporated within or associated with" ethanol cogeneration plants that sell fuel to any states required to meet a low carbon fuel standard. Eligible projects must be in operation within 30 months of receiving IUB approval; wind projects can apply to the IUB for a 12 month extension, and non-wind projects can apply for a 24 month extension.[62]

- Maryland's PTC is for 0.85 cents/kWh (0.5 cents/kWh for co-fired generation) for solar electric technologies, landfill gas, wind, biomass, hydro, geothermal, municipal solid waste, co-firing, anaerobic digestion, and ocean energy. In 2010, the Maryland General Assembly passed legislation stating that no less than $1,000 can be awarded (meaning eligible facilities must generate about 23.5 MWh per year to qualify). A project cap of $2.5 million over 5 years is applied, or up to the credit equal to the maximum production estimated by the Maryland Energy Administration. Credits in excess of income tax liability in a tax year are refundable. The eligible renewable energy facility must be in operation before January 1, 2016.[63] A state-wide cap of

[61] Applications from schools, colleges, universities, and hospitals filed on or after July 1, 2009, are required to have a minimum nameplate capacity of 750 kW. See U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, "Iowa Renewable Energy Production Tax Credits (Corporate)", http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=IA13F&re=1&ee=0, retrieved July 26, 2011.

.

[62] U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, "Iowa Renewable Energy Production Tax Credits (Corporate)", http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=IA13F&re=1&ee=0, retrieved July 26, 2011.

[63] Co-firing must take place after 2006, but the non-renewable portion of the generating plant can come on-line earlier than 2006.

$25 million applies, and the credit expires at the end of 2015 although approved projects may continue to claim the tax credit for a total of five years.[64]

- The New Mexico Production Tax Credit applies to solar electric, wind, biomass, landfill methane, municipal solid waste, and anaerobic digestion systems of at least 1 MW installed after 2002 and before the end of 2017. Except for solar, eligible facilities receive a state production tax credit of 1 cent/kWh for 10 years for the first 400,000 MWh annually. Solar electric begins at 1.5 cents/kWh in the first year and increases by 0.5 cents/kWh to 4 cents/kWh in year 6 before declining by 0.5 cents/kWh by the tenth and final year. A 200,000 MWh annual cap applies to solar. A state-wide annual cap of 2 million MWh applies, plus an additional 500,000 MWh for solar.[65]

- Oklahoma's Zero-Emission Facilities Production Tax Credit applies to wind, geothermal, hydro and solar electric projects of 1 MW or greater. The credit varies between 0.25 cents/kWh and 0.75 cents/kWh for a 10-year period, depending on when the project was placed into service.[66] No technology-specific or state-wide caps are in place, and the credit is slated to expire at the end of 2015.[67]

Sales tax incentives

Sales tax incentives either exempt or refund the sales tax for eligible clean-energy systems and/or energy-efficiency equipment.[68] One goal of these tax incentives is to reduce or eliminate the higher impact of sales taxes on capital-intensive renewable energy technologies as compared to conventional energy resources. Secondary goals are to draw attention to and make clean-energy investments more attractive to consumers. State sales tax incentives are in place in 27 states and Puerto Rico. Local governments can also exempt clean-energy systems from local sales taxes.

State sales tax incentives usually apply to all renewables, but only electricity-producing renewable energy technologies are eligible in a few states, including Idaho, Kentucky, Utah, and Washington. Some states—Kentucky, Ohio, Utah, and Wyoming—restrict sales tax exemptions

---

[64] U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, "Maryland Clean Energy Production Tax Credits (Corporate)", http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=MD16F&re=1&ee=0, retrieved July 26, 2011.
[65] U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, "New Mexico Renewable Energy Production Tax Credits (Corporate)", http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=NM02F&re=1&ee=0, retrieved July 26, 2011.
[66] The Oklahoma credit is 0.75 cents/kWh for eligible energy generation in 2003; 0.5 cents/kWh for eligible energy generation between 2004 and before 2007; 0.25 cents/kWh for eligible energy generation between 2007 and before 2012; and 0.5 cents/kWh for eligible energy generation after 2007 but before 2016. U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, "Oklahoma Zero-Emission Facilities Production Tax Credit (Corporate)", http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=OK02F&re=1&ee=0, retrieved July 26, 2011.
[67] U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, "Oklahoma Zero-Emission Facilities Production Tax Credit (Corporate)", http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=OK02F&re=1&ee=0, retrieved July 26, 2011.
[68] Unless otherwise indicated, this material is drawn from: U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency (DSIRE), *Sales Tax Incentives*, http://www.dsireusa.org/solar/solarpolicyguide/?id=12.

to commercial systems or for systems that are at or exceed a minimum size. Massachusetts and New York restrict sales tax incentives to residential systems only. Although this is not usually the case, sales tax incentives can be directed towards specific technologies (e.g., solar) or applications (e.g., residential only).[69]

Property tax incentives
Loosely described, property tax incentives provide exemptions, abatements, credits, or special assessments that reduce or eliminate the increase in the assessed value of a property due to the installation of a renewable energy system. Because renewable energy technologies are generally capital-intensive, a higher property tax burden results if the basis for assessment is equipment cost. The intent of property tax incentives, therefore, is to reduce the costs of renewable energy systems as compared to other conventional electricity sources.[70]

Thirty-four U.S. states and over a dozen local governments offer property tax incentives for renewable energy systems. In most states, the property tax incentive simply excludes qualifying clean-energy equipment when valuing a property for taxation purposes. Typically, there is no expiration of the property tax incentive. Some states do limit the term of exemptions, varying from five years in Iowa and North Dakota to 25 years in Hawaii. In addition, more than half a dozen states authorize, but do not require, local governments to provide property tax incentives for renewable energy installations. Depending on the state, though, only partial abatement is available for larger renewable energy systems, with full abatement for smaller, residential renewable energy systems.[71]

Manufacturing tax incentives
Manufacturing tax incentives are directed to companies that establish, expand, or convert facilities for the purpose of manufacturing clean-energy technologies. Manufacturing tax incentives can be credits or exemptions for any federal, provincial, state, or municipal tax paid by manufacturing firms; corporate, property, or payroll taxes.[72] Prominent examples include:

- Washington State's Tax Abatement for Solar Manufacturers and Renewable Energy Production Incentives attract equipment and component manufacturers. The tax abatement permits a 43% reduction in the business and occupation tax rate for in-state manufacturers and wholesale marketers of photovoltaic (PV) modules or silicon components of those systems. Businesses are required to file annual reports with the

[69] Elizabeth Doris, Joyce McLaren, Victoria Healey, and Stephen Hockett, *State of the States 2009: Renewable Energy Development and the Role of Policy*, National Renewable Energy Laboratory, NREL/TP-6A2-46667, October 2009, http://www.nrel.gov/docs/fy10osti/46667.pdf.
[70] Unless otherwise indicated, this material is drawn from: U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency (DSIRE), *Property Tax Incentives*, http://www.dsireusa.org/solar/solarpolicyguide/?id=11.
[71] David Clement, Matthew Lehman, Jan Hamrin, and Ryan Wiser, *International Tax Incentives for Renewable Energy: Lessons for Public Policy*, Center for Resource Solutions, Draft Report, June 17, 2005, http://www.resource-solutions.org/lib/librarypdfs/IntPolicy-Renewable_Tax_Incentives.pdf.
[72] Unless otherwise indicated, this material is drawn from: U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency (DSIRE), *Industry Recruitment and Support*, http://www.dsireusa.org/solar/solarpolicyguide/?id=14.

Washington Department of Revenue detailing employment, and wages, health, and retirement benefits paid.

- Oregon's Tax Credit for Renewable Energy Equipment Manufacturers allows a tax credit of 50% of the construction costs of a new or expanded renewable energy manufacturing facility, up to a maximum of $20 million per manufacturing plant. This credit is paid out in equal installments over five years.

Results

The federal PTC helped make the U.S. a world leader in wind energy. Wind capacity increased from 2 GW in 1999 (when the PTC was first enacted) to over 35 GW in 2010. About 75,000 people were working in the wind power industry in the U.S. as of the end of 2009.[73] Although not solely responsible, the federal corporate and business tax credits has also fueled large growth in the solar energy industry, with 878 MW of photovoltaic and 78 MW of concentrating solar power capacity installed in 2010, with the PV capacity more than doubling installations in 2009.[74] Another 252 MW of PV was installed in the first quarter of 2011, bringing total solar grid-connected capacity in the United States to over 2.85 GW.[75]

There are also some examples of state PTC policies helping to stimulate renewable energy capacity. In New Mexico, four wind projects and one 30 MW biomass plant are in operation, with two more wind projects planned. Should all projects come on-line, the New Mexico state PTC will support 734 MW of renewable energy capacity. The cost of the New Mexico PTC is estimated to be $12 million with the four wind projects and the 30 MW biomass project, and will increase to $20 million if the other two wind projects come on-line. If the solar set-aside is fully subscribed, then the annual cost increases to $33.5 million.[76] Through March 10, state production tax credits totaling $5.1 million have been issued to 10 eligible facilities in Maryland, with three landfill gas projects and one wind project accounting for the majority.[77]

There is no comprehensive information about the impact of state tax incentives other than production tax credits. Other research has determined that these state tax incentives by themselves are not likely to motivate significant investment in and development of renewable energy projects, but may (in combination with other supportive policies) help "tip the scales."[78]

---

[73] Ryan Wiser and Mark Bolinger, *2010 Wind Technologies Market Report,* Lawrence Berkeley National Laboratory, June 2011, http://eetd.lbl.gov/EA/EMP/reports/lbnl-4820e.pdf.

[74] Solar Energy Industries Association. "US Solar Energy Industry Experiences Record-Breaking Growth in 2010," March 10, 2011. http://www.seia.org/cs/news_detail?pressrelease.id=1292.

[75] Solar Energy Industries Association. "U.S. solar market continues strong growth in Q1 2011, both in new installed capacity and increases in U.S. solar manufacturing," June 16, 2011. http://www.seia.org/cs/news_detail?pressrelease.id=1418.

[76] Eric Lantz and Elizabeth Doris. *State Clean Energy Policies Analysis (SCEPA): State Tax Incentives*. National Renewable Energy Laboratory, NREL/TP-6A2-46567, October 2009. http://www.nrel.gov/docs/fy10osti/46567.pdf.

[77] U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, "Maryland Clean Energy Production Tax Credits (Corporate)", http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=MD16F&re=1&ee=0, retrieved July 26, 2011.

[78] Elizabeth Doris, Joyce McLaren, Victoria Healey, and Stephen Hockett, *State of the States 2009: Renewable Energy Development and the Role of Policy*, National Renewable Energy Laboratory, NREL/TP-6A2-46667, October 2009, http://www.nrel.gov/docs/fy10osti/46667.pdf.

Considerations

State tax incentives for renewable energy technologies are a popular policy mechanism.[79] State tax credits are usually more politically feasible than cash payments (i.e. grants or rebates) because once they are established tax credits can usually be maintained without any legislative appropriation of funds. In addition, the most successful state tax incentive programs may have a neutral or even positive effect on total public revenues as a result of the increased tax revenues from leveraging private expenditures and economic development in the associated clean-energy technology industries.

State tax incentives offer other advantages as well, as they can be targeted towards supporting specific renewable energy technologies or a combination of renewable energy technologies. Because state tax incentives are well understood, they can be applied in states where renewable energy policy is new or controversial. State tax incentives may also be advantageous in states where renewable energy development costs are higher than in adjacent states because of higher labor rates, higher property values, or lower quality renewable energy resources. Targeted state tax incentives can help overcome those disadvantages.

As stated earlier, state tax incentives alone are seldom enough to stimulate market development of clean-energy technologies. Therefore, state tax incentives are usually most effective in combination with other policies such as net metering and clean-energy purchasing requirements. Although state tax incentives are not often the major factor attracting consumers to renewable energy investments, state tax incentives can help "seal the deal" and are particularly valuable where direct funding sources are limited or unavailable.[80]

Other challenges arise in designing state tax incentives. Designing the proper incentive level is critical to ensure that the state tax incentive has the desired outcome of stimulating renewable energy projects, yet because of changing market conditions and changes in the costs and the technology status of individual renewable energy technologies, it can be difficult to design the state tax incentive at the right level. In addition, some state tax incentives can have a large impact on state budgets. States can avert that by putting in funding or capacity caps, as is the case with most of the states with state production tax credit policies.

State tax incentives will not necessarily result in technology diversity unless state tax incentives are specifically designed to do so (i.e., differentiated state tax incentives for different renewable energy technologies). A general state tax incentive applicable to multiple renewable energy technologies will generally benefit only the technology that is closest to (or is at) market competitiveness.[81]

---

[79] Unless otherwise indicated, this discussion encompasses all of the state tax incentives discussed as a group.

[80] U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, *Tax Credits*, http://www.dsireusa.org/solar/solarpolicyguide/?id=13.

[81] Eric Lantz and Elizabeth Doris. *State Clean Energy Policies Analysis (SCEPA): State Tax Incentives*. National Renewable Energy Laboratory, NREL/TP-6A2-46567, October 2009. http://www.nrel.gov/docs/fy10osti/46567.pdf.

Another concern about state tax incentives is that taxpayers may have insufficient tax liability to take full advantage of the tax incentive, or may not pay taxes at all. Depending on program design, state tax incentives will not be of use to low-income consumers and nonprofit agencies including governments. Some states are also experimenting with allowing public entities to transfer tax credits to other market participants in exchange for a lump-sum cash payment. For example, Oregon's business energy tax credit allows a project owner (such as a local government or school), once a project is installed, to transfer a tax credit to a pass-through partner in exchange for a lump-sum cash payment equal to the net present value of the tax credit. The pass-through provision can be used by governmental agencies, nonprofit organizations, schools, other public entities, and businesses with or without a tax liability. Participating organizations transfer their tax credit to a market participant that does have a tax liability. Similarly, Arizona's nonresidential solar tax credit permits a third-party company to claim the tax credit, if the third-party finances and installs a system on a tax-exempt organization's facility.[82] In addition, some states allow for unused production tax credits to be either refunded or rolled over into subsequent years.

State tax incentives are not a direct cash payment and will not necessarily meet lender cash-flow requirements in order to receive lower lending rates, or to receive financing at all. In contrast, a direct cash subsidy can be used to meet debt requirements and will act to reduce investor risk and the cost of capital.

State tax incentives can also increase the federal tax burden of a taxpayer if state tax expenditures are claimed as a deduction on federal tax forms. Because the state tax incentive reduces the amount of state taxes that can be deducted, the state tax incentives can have the perverse effect of raising the amount of federal taxes. Effectively, the value of the state income tax is "taxed" at the federal rate.[83]

Personal and corporate tax incentives have been criticized for rewarding expenditures and investments and not necessarily project performance. More recent state corporate tax incentives have attempted to address this issue. Some states require applications and pre-approval before receiving a tax credit. Others may require system warranties and meet either state or national certification or testing standards.

Manufacturing incentives can result in increased tax revenues if incentives are more than offset by gains in personal and corporate income, indirect and induced economic effects. Achieving positive total public revenues requires precise program design, though. Programs typically place conditions on recipients, such as minimum thresholds for capital investment, job creation, product output, or product sales. Program rules sometimes require repayment of tax credits if some or all of the conditions are not met. Without attention to policy design and implementation, costs of manufacturing incentives can be high. In addition, policymakers need to be careful in selecting industries and technologies to support. The risks are backing

[82] U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, *Tax Credits*, http://www.dsireusa.org/solar/solarpolicyguide/?id=13.

[83] Eric Lantz and Elizabeth Doris. *State Clean Energy Policies Analysis (SCEPA): State Tax Incentives*. National Renewable Energy Laboratory, NREL/TP-6A2-46567, October 2009. http://www.nrel.gov/docs/fy10osti/46567.pdf.

suboptimal technologies and missing more cost-effective opportunities that would not be eligible for incentives.

Public Benefit Charges and Fund Administration

Public benefit charges, also known as system benefit charges or public benefit funds, are typically pools of money raised through a non-bypassable surcharge on customer electric or gas utility bills and spent on programs designed to confer benefits to the public. Other funding sources include the sale or auction of emission credits (such as the periodic auctions of greenhouse gas emission credits as part of the Regional Greenhouse Gas Initiative in the Northeastern U.S.), from the payment of alternative compliance payments (ACPs) in lieu of acquiring RECs for RPS compliance, from settlements in utility merger or rate cases, or from state appropriations. Public benefit charges were generally implemented as part of retail electric restructuring legislation as a means of preserving activities with broad public benefits that might not be supported in a competitive electric power market, although public benefit charges have been created in both vertically integrated and restructured electric markets.

Ohio has a public benefits fund that was authorized under restructuring legislation enacted in 1999. Known as the Ohio Advanced Energy Fund, the fund is administered by the Ohio Department of Development's Office of Energy Resources Division.[84] A rider of $0.09 per utility bill per month was levied on retail electric rates through the end of 2010, with a cap on allowable funding of $15 million per year through 2005 and $5 million per year from 2006 through 2010, up to a maximum of $100 million. However, the rider expired at the end of 2010. With the expiration of the rider, funds are now provided through ACPs under the Ohio AEPS.

The Ohio Advanced Energy Fund provided grants for energy efficiency and renewable energy projects. To qualify for funding, the projects had to be located in Ohio and in the service territories of one of the four participating electricity distribution companies: AEP-Ohio, Dayton Power & Light, Duke Energy, or First Energy. Eligible technologies included energy efficiency, solar water heat, solar space heat, solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, fuel cells, municipal solid waste, CHP/cogeneration, fuel cells using renewable fuels, and microturbines. As of September 1, 2011, the Ohio Advanced Energy Fund supported 660 projects and expended $44.7 million.

Because of the expiration of the funding rider, the Ohio Energy Resources Division is restructuring the Ohio Advanced Energy Fund and funding support for individual projects will not be provided at the same level as in the past. More details were scheduled to be released before the end of 2011.

In the U.S., 18 states plus the District of Columbia have public benefit charges that support renewable energy.[85] Public benefit charge programs for renewable energy initiatives expend

[84] Established under Ohio Revised Code (ORC) section 4928.63, the Advanced Energy Fund was funded under ORC 4928.61.
[85] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit* (December 2009), Clean Energy States Alliance, http://www.cleanenergystates.org/Publications/cesa-financial_Toolkit_Dec2009.pdf;

about $600 million annually. The amount of annual expenditures from state public benefit charges varies considerably by state, ranging from about $400 million in California to under $1 million in some states.[86] By 2017, states are expected to collect $7.2 billion in public benefit charges for renewable energy technologies, with $4.6 billion of that in California alone.[87] These state public benefit charges account for over 80% of state and utility renewable energy program spending.[88] By percentage of retail electric sale revenues, public benefit charges for renewable energy technologies typically do not exceed 0.75% of such revenues, compared to up to 3% for energy efficiency.[89]

Public benefit charges are typically earmarked for different program areas, and how funds are divided differs by state. For example, California initially appropriated $540 million for renewable energy, $872 million for energy efficiency, and $62.5 million for research, development & demonstration.[90] For its public benefits charge, the Oregon Legislature allocated 17.1% to renewables, 56.7% to energy-efficiency programs, and the remainder for energy assistance to low-income housing and energy conservation programs in schools.[91]

Within each program area, public benefit charges typically employ several strategies, such as production incentives for new renewable energy projects; loans and grants for renewable energy, energy-efficiency and clean-energy projects; consumer rebates for energy efficiency, renewable energy projects, and clean-energy projects; public education programs; financial support for existing renewable energy projects; and direct investment in energy-efficiency, renewable-energy, and clean-energy companies.

Public benefit charges are administered in different ways: by utilities; a state energy office, state public utility commission or other state agency; or through independent entities formed for the

---

Elizabeth Doris, Joyce McLaren, Victoria Healey, and Stephen Hockett, *State of the States 2009: Renewable Energy Development and the Role of Policy*, October 2009, National Renewable Energy Laboratory, NREL/TP-6A2-46667, http://www.nrel.gov/docs/fy10osti/46667.pdf.

[86] Charles Kubert and Mark Sinclair, *State Support for Clean Energy Deployment: Lessons Learned for Potential Future Policy*, National Renewable Energy Laboratory, NREL/SR-6A20-49340, April 2011, http://www.cleanenergystates.org/assets/Uploads/49340.pdf.

[87] U.S. Department of Energy, Database of State Incentives for Renewables & Efficiency, *Public Benefits Funds For Renewables* [web page], thttp://www.dsireusa.org/summarytables/.

[88] Charles Kubert and Mark Sinclair, *State Support for Clean Energy Deployment: Lessons Learned for Potential Future Policy*, National Renewable Energy Laboratory, NREL/SR-6A20-49340, April 2011, http://www.cleanenergystates.org/assets/Uploads/49340.pdf.

[89] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit* (December 2009), Clean Energy States Alliance, http://www.cleanenergystates.org/Publications/cesa-financial_Toolkit_Dec2009.pdf; Elizabeth Doris, Joyce McLaren, Victoria Healey, and Stephen Hockett, *State of the States 2009: Renewable Energy Development and the Role of Policy*, October 2009, National Renewable Energy Laboratory, NREL/TP-6A2-46667, http://www.nrel.gov/docs/fy10osti/46667.pdf.

[90] The California Assembly, during the state's retail electric industry restructuring in 1996, established the Public Benefits Funds for Renewables & Efficiency. Assembly Bill 1890, Chapter 854, California Assembly, February 24, 1995, http://www.leginfo.ca.gov/pub/95-96/bill/asm/ab_1851-1900/ab_1890_bill_960924_chaptered.html. Those budget amounts were later increased when the legislature extended the programs.

[91] ECONorthwest, *Report to the Legislative Assembly on Proposed Modifications to the Public Purpose Charge: Final Report,* October 6, 2006, http://energytrust.org/About/PDF/061006_PPC_Modifications_Final.pdf.

purpose of managing public benefit charge programs.[92] In general, utilities administer technology-specific incentive programs that will include customer outreach and technical assistance, while state agencies or third party administrators oversee more comprehensive renewable energy programs. A summary of the advantages and disadvantages of each approach is below:

- The advantages of utility-administered programs are that utilities have existing relationships with customers and are considered trusted leaders on energy consumption, energy efficiency and renewable energy technologies. Utilities also have more flexibility in contracting than state agencies. However, utility-administered programs may not be as advantageous in states with several public power utilities and rural electric cooperatives. Also, in states with multiple utility-administered programs, there will be additional program development, administration and evaluation costs that would likely be less under a single state-wide program administered by state agencies or independent parties.

- State-administered programs have the advantages of centralizing program administration, thereby lowering administrative costs as compared to multiple utilities administering their own programs. For states with multiple utilities or with several public power and rural electric cooperatives, state-administered programs can also have unified programs and marketing as compared to individual programs implemented by multiple utilities. However, state-administered programs are prone to political pressure in funding risk and program design and may face less flexibility in contracting than utilities.

- Independent entities have the advantage of having a well-defined role and objectives defined in its contract with the state. The independent entity also has staff devoted to only managing renewable energy programs, as compared to staff with the utility-administered or state-administered program that may have other duties. Independent entities may also offer protection from funds being raided by state legislatures, as the funds are committed by contract. Independent entities can also be effective in states with multiple utilities. States can also subject independent entities to performance incentives for meeting or exceeding performance goals. However, independent entities do not have the same strength of customer relationships as electric utilities, and will likely have higher administrative and overhead costs compared to state-administered programs, although states could minimize these costs through competitive bidding solicitations.[93]

---

[92] For a survey of fund administration pertaining to energy efficiency, but of related interest for renewable energy funds, see Cheryl Harrington and Catherine Murray, *Who Should Deliver Ratepayer Funded Energy Efficiency? A Survey and Discussion Paper*. Gardiner, ME: The Regulatory Assistance Project, May 2003. http://www.raponline.org/search/.

[93] Charles Kubert and Mark Sinclair, *State Support for Clean Energy Deployment: Lessons Learned for Potential Future Policy*, National Renewable Energy Laboratory, NREL/SR-6A20-49340, April 2011, http://www.cleanenergystates.org/assets/Uploads/49340.pdf.

Results

The Clean Energy States Alliance (CESA) reports that from 1998 through 2009, state system benefits charge programs helped fund over 74,000 renewable energy projects, representing 3 GW of capacity. In doing so, the states invested $2.7 billion and leveraged another $9.7 billion in outside investment, meaning that each dollar in state system benefits charge investment leveraged over $3 of external investment. CESA estimates that these renewable energy projects generate 8.3 GWh annually and help avoid 3.6 million tons of carbon dioxide.[94] CESA estimates that state system benefits charge investments in 2008 alone created over 5,000 jobs.[95]

Considerations

Public benefit charges are quite flexible—states can utilize public benefit charges to support near-commercial renewable energy technologies, or states can choose to support longer-term initiatives such as research and development. Public benefit charges can be used to narrow the difference between the market price of electricity and the generating costs of renewable energy technologies; tackle the technical, regulatory, and market barriers for renewable energy technologies; encourage the development of industries and infrastructure that are necessary for the success of renewable energy technologies; and advance consumers' awareness of renewable energy technologies. Public benefit charges can also work effectively in either a regulated utility structure or in a deregulated retail electric market. Furthermore, public benefit charges can use different mechanisms to support renewable energy technologies, such as grants, loans, production incentive payments or direct investment in renewable energy companies.

Public benefit charges can also be changed in response to changing market conditions, and can help support and make more effective other state and federal renewable energy policies, such as federal tax incentives and renewable portfolio standards (RPS). Public benefit charges also typically rely on a funding mechanism (the non-bypassable surcharge) and do not depend on annual state budget appropriations, although as noted below, state legislators may tap public benefit charge funds to close budget gaps.

The flexibility that is generally an advantage of public benefit charges can also be a disadvantage. Depending on program design and statutory requirements, state public benefit charge programs may have overly broad program requirements and insufficient funding to support those requirements. Funding limitations can also prevent applicants from fully utilizing available grants, loans and rebates, or can restrict the program administrator from investing in all of the companies or projects they would like. In addition, budgetary pressures have prompted several states to dip into public benefit charges to balance state budgets, reducing the ability of administrators to meet program goals and to fund program activities. Public benefit charges are typically authorized for a period of time (e.g., five years) and must be renewed by local or state governments or by a utility regulatory commission, leading to some unpredictability and instability. Finally, if the non-bypassable surcharge is set as a volumetric fee, the surcharge will have larger cost impacts on customers that consume more electricity.

---

[94] Clean Energy States Alliance and Peregrine Energy Group, *State Clean Energy Fund Support for Renewable Energy Projects*, Winter 2011, http://www.cleanenergystates.org/assets/Uploads/CESA-RE-Database-3.pdf.

[95] Clean Energy States Alliance, *2010 Report: State Efforts to Advance Clean Energy*, http://www.cleanenergystates.org/assets/Uploads/Resources-post-8-16/CESA-2010-Members-Report.pdf.

Several "best practices" have emerged from the experiences of public benefit charges that are now operating, as described below:

- *Determine the appropriate level of financial support for individual types of eligible energy technologies by evaluating the cost-competitiveness of each technology* compared to conventional energy technologies, market prices or avoided costs. Different technologies have different costs; one level of support does not necessarily work for all.
- *Determine the most effective type of program support by assessing the specific challenges facing different technologies, or different size installations*. Public benefit charge programs typically encompass several program options for both emerging and technically proven technologies.
- *Promote year-to-year funding consistency*. Allowing public benefit charge funds to carry forward funds and excess contributions can be helpful, particularly in the early years when staff and programs are ramping up. Setting the public benefits charge to a fixed percentage tariff can also help ensure consistent funding levels.
- *Design programs to work with and leverage other state and federal clean energy initiatives*, such as state RPS policies, state and federal tax credits, and state and federal loan programs.
- *Develop measurable targets*, such as green power participation rates or megawatts of new capacity and periodically evaluate the progress in meeting the targets.
- *Consider changing funding priorities* and design new or change existing programs as technologies and markets change and evolve.[96]

[96] Elizabeth Doris, Joyce McLaren, Victoria Healey, and Stephen Hockett, *State of the States 2009: Renewable Energy Development and the Role of Policy*, October 2009, National Renewable Energy Laboratory, NREL/TP-6A2-46667, http://www.nrel.gov/docs/fy10osti/46667.pdf.

Appendix A: Supply and Demand Model Documentation

This appendix describes the contents of the spreadsheet model to assess the Ohio AEPS market, specifically Ohio-eligible renewable and solar energy resources, and the assumptions the consulting team used in compiling the model. The spreadsheet includes individual tabs on overall results; supply for the Ohio AEPS; demand for RPS-eligible resources from Ohio, Pennsylvania, Michigan, Indiana, West Virginia and Kentucky; the probability of planned projects coming on-line; and other tabs for notes and documentation.

Load and RPS Demand

The Alternative Energy Resource Standard (AEPS) requires that eligible resources be "deliverable into this state," which is interpreted by rule to mean that the electricity originates from a facility within a state contiguous to Ohio, although generators in other states may be eligible if they can demonstrate that the energy is deliverable to Ohio. Therefore, Indiana, Kentucky, Michigan, Pennsylvania, and West Virginia are included in addition to Ohio in the spreadsheet. Although Indiana has a voluntary renewable energy standard, we assumed full compliance by Indiana's electric utilities. Kentucky does not have a RPS but it is included in the spreadsheet model since eligible generation in Kentucky can potentially be used to meet RPS requirements in Ohio and the other named states.

The demand tab in the spreadsheet includes projected demand estimates for overall electricity load and for state RPS requirements to 2020. For load demand, the consulting team used 2009 retail electric sales from the U.S. Energy Information Administration (EIA). Ohio sets its AEPS requirement based on the average retail sales for the three preceding years, which is reflected in the spreadsheet model.[97] The load demand in the spreadsheet is also adjusted downwards for load-serving entities that are exempt from state RPS policies such as municipal electric utilities and rural electric cooperatives. Five of the six states exempt municipal utilities and rural electric cooperatives from their RPS requirements; Michigan is the exception. In addition, Pennsylvania exempted utilities from RPS compliance if they were still operating under retail price caps. We made estimates of the retail load in Pennsylvania that would be exempt from the Pennsylvania AEPS for 2009 and 2010, after which all utility price caps expired.[98] After 2009, annual projected load for each state was derived from PJM's peak load forecast.[99]

Once each state's current and projected load requirements are determined, the annual GWh requirement for each state RPS is derived for 2009 through 2020. An 8% loss factor was added to retail sales to represent transmission losses.

---

[97] As an example, the 2009 AEPS obligation is based on the average of electric retail sales from 2006 through 2008.

[98] Pennsylvania also measures RPS compliance from June through May instead of a calendar year basis as is the case in other states. To convert to a calendar year format, the two compliance years were averaged with a 5/12 ratio (January-May) and with a 7/12 ratio (June-December).

[99] PJM, *PJM Load Forecast Report*, January 2011. http://www.pjm.com/~/media/documents/reports/2011-pjm-load-report.ashx.

Several adjustments were made to account for particular requirements of individual state RPS policies. First, solar tiers or set-asides were calculated separately for states that had them (Ohio and Pennsylvania). In Ohio's case, the solar requirement was netted from the overall renewable energy and advanced energy resources requirements, while Pennsylvania's Alternative Energy Portfolio Standard (AEPS) has a separate solar tier that is additive to Pennsylvania's requirement.

Second, the Ohio AEPS includes year-by-year requirements for the renewable energy and solar levels (12.5% by 2025) but does not have a year-by-year requirement for the overall (renewable plus advanced energy) Ohio AEPS other than 25% by 2025. The model nevertheless enables an annual level for the AEPS by doubling the renewable energy standard for each year. The model includes toggle switches for the user to change between the renewable energy and the overall energy requirements of the Ohio AEPS. A toggle switch is also available to include or exclude the solar requirement of the Ohio AEPS, and another to include or exclude the Pennsylvania Tier 1 or Pennsylvania solar requirement of the state's RPS. By clicking on any of these toggles, and selecting 'Exclude', the selected portion of the state's demand will automatically be removed from the demand calculations. Alternatively, selecting 'Include' will automatically alter all calculations to add in this portion of demand to all applicable calculations.

Third, The Ohio AEPS requires that at least 50% of its renewable energy requirement, and separately its solar requirement, be met by generation from facilities designated as in-state. In the demand tab, the model shows the calculation of the in-state requirement for each of these requirements separately, and the results tab shows the in-state surplus (shortage). Pennsylvania does not have location-specific solar requirements. It was assumed that solar resources located in either state could meet requirements in the other state (as well as its own), subject to Ohio's minimum 50% of renewable and solar resources being located in Ohio.

Fourth, demand for Tier 2 resources in Pennsylvania's AEPS was excluded from our analysis because it encompasses generating resources not eligible to meet the renewable energy portion of the Ohio requirement. The spreadsheet includes a toggle switch where the user can include or exclude the Tier 2 resources from the estimates of demand, as well as the solar resources in Pennsylvania from the spreadsheet model.

Fifth, Michigan's RPS requires utilities to meet an increasing portion of the difference between a baseline renewable energy generation level from October 2007 through September 2008 and the 10% RPS requirement from 2012 through 2014, before meeting the overall 10% requirement in 2015. The incremental targets are as follows:

- 2012: The existing renewable energy baseline plus 20% of the gap between the renewable energy baseline and 10%.
- 2013: The existing renewable energy baseline plus 33% of the gap between the renewable energy baseline and 10%.
- 2014: The existing renewable energy baseline plus 50% of the gap between the renewable energy baseline and 10%.
- 2015: The 10% requirement must be met in full.

Communications with the Michigan PSC staff determined that the renewable energy baseline has not been defined but will be in the near future. For this project, the consulting team used data from EIA for renewable energy generation in Michigan in 2009 (3,956 GWh), but PUCO staff should recognize that the Michigan PSC will be setting the renewable energy baseline in the future and receive that data from Michigan in running the spreadsheet model in the future. The consulting team also used the following equation in estimating the incremental renewable energy requirements between 2012 and 2014:

$$(\text{Retail Sales in Year X})*(10\%) – \{\text{Baseline} + [\text{Incremental Gap}*(10\% - \text{Baseline})]\}$$

Finally, a row on voluntary green power sales was added to the spreadsheet but was not populated, as actual and projected green power sales are difficult to determine between individual purchases of green power, purchases by corporations, and individual utility green power programs. It also is not clear whether green power purchases will or will not compete for Ohio-eligible resources. Should the Ohio PUC staff wish to experiment with estimating the impact of green power sales on compliance with the Ohio AEPS, the spreadsheet is capable of doing that.

Potential Demand for Renewable Energy Generation in Ohio from Other State RPS Policies

Technology eligible for the Ohio AEPS is broad and can overlap with RPS policies in the five contiguous states. If eligible resources were identical in each state, then the RPS demand in Ohio and its contiguous states would be 100% additive. The demand from all six states could be summed and could potentially be satisfied by the pool of resources located in those six states. Some of those states, however, can satisfy their RPS demand with resources that are located in other states, which would lower the demand for resources within Ohio and contiguous states. Further, the definitions of eligible resources are not identical in the six-state region; in some cases they vary significantly. These resource definition differences and geographic eligibility differences are summarized in Appendices C and D.

To account for the fact that resource eligibility and geographic eligibility in the contiguous states differ from Ohio, the estimates of demand on the pool of Ohio-eligible resources have been reduced in some cases. We came up with a range of demand estimates (represented by a percentage of each state's total RPS demand), and combined the low estimates into a “low case” and the high estimates into a “high case.” The low demand case and the high demand case represent the consulting team's best estimate of the potential demand on Ohio-eligible resources located in the six-state region. Because these estimates are strictly the consulting team's judgment, PUCO staff may wish to adjust these assumed levels of demand in the model to represent different assumptions about the level of demand from each state. The assumptions adopted for each state are discussed below.

Indiana: Indiana's voluntary renewable energy target requires that at least half of the eligible generation come from resources located in-state. Since Ohio can also draw upon Indiana generation to meet its AEPS, at least half of Indiana's target can compete directly with Ohio-eligible supply. However, in Indiana nuclear energy and natural gas plants are eligible to meet the voluntary target if they are constructed after July 1, 2011 and they displace electricity from coal. According to the PJM interconnection queue, there is currently only one gas plant planned in Indiana. If new gas is relied upon to meet Indiana's target, perhaps only 10% of Indiana's goal will compete for Ohio-eligible resources, and in the high demand case we assumed that 50% of Indiana demand will be placed on in-state resources that are also eligible in Ohio.

Michigan: The geographic eligibility requirements for the Michigan RPS are unclear. The statute reads as follows:

> "a renewable energy system that is the source of renewable energy credits used to satisfy the renewable energy standards shall be either located outside of this state in the retail electric customer service territory of any provider that is not an alternative electric supplier or located anywhere in this state. For the purposes of this subsection, a retail electric customer service territory shall be considered to be the territory recognized by the commission on January 1, 2008 and any expansion of retail electric customer service territory recognized by the commission after January 1, 2008 under 1939 PA 3, MCL 460.1 to 460.10cc. The commission may also expand a service territory for the purposes of this subsection if a lack of transmission lines limits the ability to obtain sufficient renewable energy from renewable energy systems that meet the location requirement of this subsection."[100]

Because the majority of Michigan's load is served by two utilities located in Michigan (Consumers Energy and Detroit Edison), and the utilities that could take advantage of this out-of-state provision serve relatively small loads in Michigan (e.g., Xcel Energy, Wisconsin Electric Power Company, Wisconsin Public Service Corporation), we assumed that the majority of Michigan's RPS will be met by resources located in Michigan and therefore will draw from eligible supply that is also eligible for Ohio's AEPS. In the low demand case, we assumed that 80% of Michigan's RPS will compete for Ohio-eligible resources, and in the high demand case, we assumed that 95% of Michigan's RPS will compete for Ohio-eligible resources.

Pennsylvania: The technology and geographic eligibility provisions of the Pennsylvania AEPS are largely consistent with the Ohio AEPS. Therefore, we assumed that Pennsylvania AEPS demand and Ohio AEPS demand will compete directly for the same supply pool of eligible resources, and we did not discount Pennsylvania demand in either the low or high demand scenarios, i.e., we assumed 100% for both scenarios.

West Virginia: Natural gas and pumped storage hydro are both eligible resources to serve the West Virginia RPS. In the low demand case, we assumed a value of 0%, meaning that West Virginia could meet its RPS demand entirely with resources not eligible in Ohio. In the high demand scenario, we assumed that 40% of West Virginia's RPS demand might be served from the pool of Ohio-eligible resources.

---

[100] Michigan Legislature Act 295 of 2008, http://www.legislature.mi.gov/%28S%28zovnn1an1tdvcy55sp04phbe%29%29/documents/mcl/pdf/mcl-Act-295-of-2008.pdf.

Supply

A spreadsheet database of Ohio-eligible renewable resources in the states of Ohio, Michigan, Indiana, Pennsylvania, West Virginia and Kentucky was compiled and is located in the "AEPS Supply" tab. Sources for the information include the Ohio PUC's list of certified generators for the AEPS; generators registered in PJM's Generator Attribute Tracking System (GATS) that are located in Ohio and contiguous states; generators registered in the Michigan Renewable Energy Certification System; and the PJM and MISO generator interconnection queues. We also examined generators registered in the Midwest Renewable Energy Tracking System (MRETs) but did not find any registered generators that would be eligible for the Ohio AEPS.[101]

What is Included in the Supply Tab

The information in the spreadsheet includes the following:

- Plant name
- The source of the information
- Whether the plant is eligible as a renewable energy resource or as an advanced energy resource in Ohio. This is a toggle switch that the user can switch between eligibility for the renewable energy part or the advanced energy part of the Ohio AEPS
- Whether it is certified as an eligible resource in Ohio
- The state and control area (PJM or MISO) where the plant is located
- Fuel type
- Nameplate capacity (in MW)
- Estimated capacity factor (described in more detail below)
- Development status (also described in more detail below)
- The earliest month and year a plant is expected to come on-line
- Estimated annual generation, un-derated. This is calculated by multiplying nameplate capacity by the estimated plant capacity factor and the number of hours per year (8760)
- Probability of plant operation, depending on queue status (described in more detail below)
- Derated nameplate capacity, accounting for the probability of plant operation
- Estimated un-derated annual generation by plant from 2009 through 2020, representing the product of the probability of plant operation by a particular year and estimated annual plant generation
- Estimated derated annual generation by plant from 2009 through 2020, representing the product of nameplate capacity times the estimated probability of coming on-line
- Incremental pipeline capacity coming on-line by year between 2009 and 2020, for plant capacity that is both un-derated and derated
- Number of projects expected to come on-line annually between 2009 and 2020
- Projected annual generation by case between 2009 and 2020
- Incremental capacity by case by case between 2009 and 2020

[101] MRETs does not list generator location. The consulting team reviewed the Illinois Commerce Commission's May 2010 compilation of facilities in MRETs with generator location but did not find any generators in locations that would be eligible for the Ohio AEPS.

Projects in the Queue

For the PJM and MISO generator interconnection queues, each proposed generating plant is assigned a probability of whether it would come on-line, based on the plant's status in the PJM or MISO generator interconnection queue. The probabilities are listed in Table A-1.

Table A-1. Estimated Probability of Planned Generating Projects Becoming Operational

Interconnection Queue Status	Abbreviation	Probability of Operation
Suspended	S	10%
Feasibility Study	F	20%
System Impact Study	SI	40%
Facilities Study	FS	60%
Interconnection Agreement Executed	I	80%
Under Construction	C	100%
In Service	IS	100%

The PJM and MISO generation interconnection queues may only provide a queue number and not provide the project name or the name of the project developer. Projected in-service dates may have already passed if the project has been delayed. In these instances, the on-line date has been assumed to be 2011. In-service dates may not always include the expected month of operation for the project; in these cases, the month is set to October for 2011 and January for all other years.

Assumed Capacity Factors by Technology or Fuel Source

Capacity factors by technology or fuel source were assigned, as represented in Table A-2.

Table A-2. Capacity Factors Assumed by Renewable Fuel Type or Technology

Technology Type	Estimated Capacity Factor
Biological sludge	85%
Biomass	75%
Coal Methane	85%
Cogeneration	85%
Hydro	50%
Industrial Waste Energy	75%
Landfill Gas	85%
MSW	75%
Solar	20%
Solid Waste	75%
Storage	70%
Tire Derived Fuel	75%
Waste-Heat Recovery	50%
Wind	30%

The capacity factors for all but biomass, hydro and wind were estimates by the consulting team based on professional judgment. Biomass capacity factors were based on a brief survey of multiple biomass plants, where capacity factors ranged from about 65% to 80%. Wind capacity factors were based on annual capacity factors of wind plants in Indiana, Pennsylvania and West Virginia, and selecting a capacity factor that was judged as representative. Hydro capacity factors are roughly the median of estimates from an Idaho National Engineering Laboratory report of capacity factors of potential hydro plants in Ohio, Indiana, Pennsylvania, West Virginia, Michigan and Kentucky.[102]

Ohio-Eligible Technologies

Some technologies will not qualify for the renewable energy portion of the Ohio AEPS under some circumstances, such as solid waste technologies that rely on combustion to generate electricity. Some planned projects that are in either the PJM or MISO interconnection queues may not have filed for certification with the Ohio PUC for eligibility under the Ohio AEPS. For industrial waste energy, co-generation, waste heat recovery, municipal solid waste, and tire derived fuel projects that have not been certified by the Ohio PUC as renewable energy projects, the consulting team assumed that these resources would qualify for the advanced energy portion of the Ohio AEPS, but not for the renewable energy portion.[103] That assumption affected eight projects in the model. To the extent any of these eight projects are certified as renewable energy projects under the Ohio AEPS, PUCO staff should adjust their eligibility in the spreadsheet as a renewable energy project rather than as an advanced energy project.

Biomass Co-firing

The PUCO's list of AEPS-certified facilities included biomass co-firing facilities, some with limited or no information on nameplate capacity, on-line dates or the amount of expected biomass co-firing. The PUCO staff provided additional information on these facilities, and the consulting team reviewed the individual applications for certification under the Ohio AEPS. The additional information from the PUCO staff included dates for projected system testing and potential operation that had passed, as well as wide ranges for the expected contribution from biomass co-firing. The consulting team contacted the individual plant owners and heard from FirstEnergy and AEP that there are no immediate plans to co-fire biomass because of high biomass fuel prices and low wholesale prices. Although Duke Energy did not respond to the consulting team's query, the company said in a recently filed integrated source plan that it also has no near-term plans for biomass co-firing.[104]

[102] Douglas G. Hall, Richard T. Hunt, Kelly S. Reeves, and Greg R. Carroll. *Estimation of Economic Parameters of U.S. Hydropower Resources.* Idaho National Engineering and Environmental Laboratory, June 2003. http://hydropower.inel.gov/resourceassessment/pdfs/project_report-final_with_disclaimer-3jul03.pdf.

[103] For other projects that have not yet been certified as a renewable energy resource for the Ohio AEPS but would almost certainly would be (e.g., wind and solar projects), the consulting team assumed these projects qualify as renewable energy projects.

[104] Matyi, Bob. "Duke Ohio to Close 862-MW Coal Plant; Eyes More Wind, Solar, Gas in Short Term." *Electric Utility Week*, July 25, 2011, pp. 30-31.

Given these uncertainties, biomass co-firing plants are represented under low and high cases, where the low case represents the minimum amount of biomass co-firing (usually zero) and the high case represents the maximum expected amount of biomass co-firing. Because most of these plants are operating conventional-fueled units that filed at the Ohio PUC to be certified under the Ohio AEPS as a biomass co-firing facility, we represented the on-line date as when the plant began or expects to begin co-firing biomass. For units that have not begun biomass co-firing and information is not available on when biomass co-firing might occur, January 2016 is used as the projected co-firing date. Because nearly all of these plants are already on-line, the "success probability" column for biomass co-firing facilities was used to represent the expected amount of biomass co-firing (e.g., 10%), not the probability of whether the plant will come on-line.

The following assumptions were used for the low and high biomass co-firing cases, by individual plant:

- Bay Shore Unit 1—the projected biomass co-firing date is January 2016, with 0% co-firing used in the low case and 25% in the high case.

- AEP, the owner of Unit 3 of the Conesville Generating Station, Picway and Muskingum River Plants, said it has no plans to begin biomass co-firing at any of these plants, so 0% was used for both the low and high biomass co-firing scenarios.

- The PUCO staff provided a November 2009 date for biomass co-firing at the Killen Generating Station, with biomass co-firing expected to range from 0 to 10%. Therefore, 0% was used for the low biomass co-firing case and 10% for the high case.

- The Smurfit facility co-fires wood fuels and biological sludge with natural gas. As explained further below, different expected capacity factors are used for wood fuels and biological sludge. Therefore, the Smurfit facility is divided into two parts in the spreadsheet, one co-firing wood and the other co-firing biological sludge. Because it was unclear if the project is on-line, 0% was used as a low case assumption for both Smurfit facilities. For the high case, 85.32% was used in the high case for co-firing of wood, and 3.3% in the high case for co-firing biological sludge.

- Biomass co-firing of up to 5% may occur at three of the six units at the Walter Beckjord generating plant. Therefore, a 0% co-firing was assumed for the low case and 5% for the high case.

- No projected date for biomass co-firing is given for either the W.H. Zimmer or Units 7 and 8 of the Miami Fort Generating Station, so a January 2016 projected biomass co-firing date was used for both. Both facilities may co-fire biomass up to 10%, so 0% was used for a low co-firing case and 10% for a high co-firing case.

- The South Point Biomass Generating Plant will combust 100% wood waste so is not, strictly speaking, a biomass co-firing plant. It is projected to come on-line in September 2012, so a value of 0% was used for the low scenario and 100% for the high scenario.

Energy Efficiency and Demand Resources

We did not try to estimate the potential contribution of energy efficiency and demand response resources that are eligible for some state RPS policies, including the Ohio AEPS, because it was beyond the scope of our work. We note, however, that states have differing definitions of eligible efficiency improvements; the information on potential projected amount of energy efficiency and demand response resources may be scattered; and the method of estimating the contribution of energy efficiency and demand response resources would be very different from estimating renewable energy generation.

Appendix B: CREST Analysis Documentation

This section provides a description of the methodology used to estimate the Levelized Cost of Energy (LCOE) associated with one prototype wind and two prototype solar projects located in Ohio or adjacent states. This section also provides the cost, performance and market value assumptions used in the Cost of Renewable Energy Spreadsheet Tool (CREST) model developed for each representative project. The CREST analysis provides a range of LCOE and REC revenue requirement for each modeled project, including a sensitivity analysis to changes in key inputs. The CREST model and its outputs are intended to serve as one in a series of useful tools and information used to establish ACP rates.

The LCOE is the single value, expressed in cents per kilowatt-hour, which has the equivalent economic effect over the analysis term as a year-one price with an escalation factor that is sufficient for the project to recover its capital and operating costs and meet its investors' minimum required rate of return.

The REC revenue requirement is calculated by subtracting the market value of production from the project's total cost per kWh. In many cases, the market value of production includes the sale of both energy and capacity. Due to the uncertainty of future capacity market prices, and the relatively low capacity contributions of wind and solar projects, only the market value of energy is subtracted from LCOE in this analysis. If capacity revenues are present, they would further reduce the gap required to be made up by RECs.

For any given project, the REC revenue requirement can be calculated on either a levelized or annual basis. For the purpose of establishing a comparison to ACPs, however, it is appropriate to calculate the REC revenue requirement on an LCOE basis for the year in which the modeled facility is assumed to come on-line. In other words, the ACP should be compared to the LCOE minus the 20-year levelized market value for the year of market entry. If REC revenue requirement calculations are to be made for future years, the LCOE and the 20-year levelized market value should both be calculated beginning in the future year to be evaluated.

Methodology

NREL's CREST model was selected to perform this LCOE analysis for the PUCO because it was specifically designed for use by state policymakers, regulators, utilities, and stakeholders to assist in rate-setting processes for implementing cost-based incentives and other renewable energy policies. The CREST models, User Manual, and technical report titled Renewable Energy Cost Modeling: A Toolkit for Establishing Cost-Based Incentives in the United States are available at NREL's Renewable Energy Project Finance Website.

This modeling exercise is intended to inform the ACP rate-setting process. For the broad Renewable Energy Resource requirement, utility-scale wind projects are assumed to be the marginal (and therefore price-setting) resource. This analysis models a prototype 125 MW project, and provides a sensitivity analysis to demonstrate the impact of potential changes in cost, wind resource, and other factors from project to project. For the solar requirement, this analysis models two projects in order to provide insight into the range of potential cost outcomes associated with solar deployment: a commercial-scale project assumed at 500 kW, and a utility-scale project assumed at 1.5 MW. The inputs and LCOE CREST outputs are provided below for each project. While it is likely that many future projects serving the solar portion of the Ohio AEPS will be much larger than 1.5 MW (in fact, several have already been certified and are under development), installation and operating cost data are not readily available for such projects. As such data become available, this analysis can be updated to reflect larger projects actively meeting the solar AEPS demand.

For the assumed marginal wind project, the REC revenue requirement is calculated by subtracting the estimated levelized wholesale market value of energy from the CREST-based LCOE. The resulting REC price, or a multiple thereof, can be used to inform the ACP. For the commercial-scale solar project, the REC revenue requirement is calculated by subtracting the estimated levelized retail market value of production from the CREST-based LCOE. This method assumes that the modeled commercial-scale project is interconnected behind the retail customer meter, with all power consumed on-site and therefore offsetting not only generation charges, but also transmission and distribution charges as well – to the extent that such charges are assessed on a cents per kWh basis (the potential impact of behind-the-meter solar on kW-based demand charges is beyond the scope of this analysis). For the utility-scale solar project, the REC revenue requirement is calculated by subtracting the estimated levelized wholesale market value of energy (same as used for the wind model) from the CREST-based LCOE.

For both wind and solar, the modeled LCOE and REC revenue requirements are estimates for projects entering commercial operation by year-end 2012 – and are meant to reflect the current equipment supply, demand and price environment as well as all current federal incentives (which are set to expire on 12/31/2012 for wind and 12/31/2016 for solar). LCOEs and REC revenue requirements for projects entering commercial operation in future years are not forecasted. To this end, it may be prudent for the PUCO to use the CREST model to conduct revisions to this analysis periodically.

CREST Modeling Inputs

All inputs for this analysis were derived based on a combination of published reports, regulatory proceedings in other jurisdictions and the consultants' industry experience.[105] Close scrutiny of the sensitivity analyses provided in this report is particularly important due to the site-specific variation in costs for renewable energy projects. In future proceedings, it may also be useful to include a forum in which stakeholders can submit data regarding Ohio-specific wind and solar project costs. Combinations of these additional data could also be run through CREST.

Table B1: Summary of Assumptions for CREST-driven Cost of Generation Estimates

[105] Sources used to inform these inputs include:
2010 Wind Technologies Market Report, Wiser & Bolinger, June 2011
Tracking the Sun IV: An Historical Summary of the Installed Cost of Photovoltaics in the United States from 1998 to 2010, Barbose, Darghouth & Wiser, September 2011
Renewable Energy Cost of Generation Update, KEMA, Prepared for the CA Energy Commission, August 2009

Input	Wind	Solar (commercial-scale)	Solar (utility-scale)
Project Size	125 MW	500 kW	1.5 MW
Net Capacity Factor	33%	15%[a]	16.1%[a]
Production Degradation (%/year)	0.25%	0.5%	0.5%
Useful Life (years)	20	25	25
Total Project Cost ($/kW)	$2,000	$4,000[b]	$3,600[b]
Fixed O&M ($/kW-Yr)	$60[c] (Yr 1)	$75[d] (levelized)	$85[d] (levelized)
Variable O&M (cents/kWh, 2.5% esc.)	0.58 (Yr 1)	NA	NA
D/E	Based on available cash flow and average DSCR (1.45X)		
Interest Rate	6%	6%	6%
Debt Term	15 years	15 years	15 years
After-Tax Equity Return Requirement	12%	12%	12%
Investment Tax Credit	30% of costs depreciated on 5-year MACRS basis		
Deprecation	94% allocated to 5-year MACRS 50% Bonus Deprecation assumed available		
Utilization of Tax Benefits	Assumed monetized in the same period as generated.		

[a] Ohio-average DC capacity factor per NREL database; utility scale facility assumes fixed tilt facing south at 25 degrees; commercial-scale facility assumes average of utility and residential average capacity factor.
[b] solar total project costs include interconnection, 20-year inverter warrantee and all financial transaction costs.
[c] fixed O&M, incl. insurance and taxes, adjusted from CA to OH per the Army Corps of Engineers state cost index.
[d] includes maintenance, repair, insurance, administration, tax and lease payments.

CREST Modeling Results

The inputs above were deployed in the wind and solar CREST models, respectively. The tables below provide results along a continuum that tests the sensitivity of LCOE to key inputs:

Table B2:

CREST Wind Analysis: Sensitivity of LCOE to Changes in Capacity Factor and Total Project Cost

		Total Project Cost ($/kW)		
Net Capacity Factor (%)	***(cents/kWh)***	**$1,800**	**$2,000**	**$2,200**
	30%	**7.45**	**7.95**	**8.45**
	33%	**6.75**	**7.25**	**7.75**
	36%	**6.25**	**6.65**	**7.15**
Sensitivity: Federal Incentives Expired, 33% CF			**10.55**	

Table B3: CREST Solar Analysis: Sensitivity of LCOE to Changes Total Project Cost

	Total Project Cost ($/kW)				
(cents/kWh)	**$3,600**	**$3,800**	**$4,000**	**$4,200**	**$4,400**

Commercial-Scale Solar	**23.75**	**24.65**	**25.65**	**27.00**	**27.65**
	$3,200	**$3,400**	**$3,600**	**$3,800**	**$4,000**
Utility-Scale Solar	**21.35**	**22.25**	**23.25**	**24.15**	**25.15**

The range above represents the estimated levelized cost of energy from new market entrants developed to meet the AEPS and solar AEPS, respectively.

Market Value of Production

In order to calculate the REC revenue requirement – and gain insights into the appropriate levels at which to set ACPs – the levelized market value of production from the modeled facilities must be subtracted from the LCOE. For the wind and large solar project, a 20-year forecast of Ohio locational marginal prices (LMPs) is used. For the commercial-scale solar project, an estimated 20-year average retail rate forecast is used. As described above, the retail rate includes generation, transmission and distribution charges to the extent that they are assessed on a per kWh basis. This is consistent with the assumption that the production from the commercial-scale project is consumed behind the meter. Current average retail rates for commercial customers in Ohio was taken from EIA Electric Power Annual 2009, State Historic Tables for 2009 and are assumed to apply at time of commercial operation of the modeled facilities. For future years, approximately 40% of the retail rate is assumed attributable to wholesale power costs and is escalated using an index created from the LMP forecast. The remaining 60% is assumed attributable to transmission and distribution service and is escalated using the Consumer Price Index – All Urban Customers. Both forecasts are levelized using a 7% discount rate, which is intended to serve as a proxy for the weighted average cost of capital for Ohio electric utilities.

Table B4: Forecast of Ohio Wholesale and Retail Electricity Prices, 2012 - 2031

Calendar Year	Forecast of Ohio LMPs[1] ($/MWh)	Forecast of Average Ohio Retail Rate (cents/kWh)
2012	$37.29	9.65
2013	$40.10	10.05
2014	$44.25	10.60
2015	$46.43	10.96
2016	$50.64	11.52
2017	$54.53	12.06
2018	$58.56	12.63
2019	$61.47	13.08
2020	$64.36	13.53
2021	$67.15	13.96
2022	$69.88	14.38
2023	$72.46	14.79
2024	$73.27	15.02
2025	$78.42	15.70
2026	$81.17	16.14
2027	$84.16	16.61
2028	$87.65	17.12
2029	$92.36	17.77
2030	$97.80	18.48

2031	**$103.22**	**19.20**
Levelized @ 7%[2]	**$61.18**	**13.12**
[1]*Based on Ohio PROMOD run, supported by Ventyx PowerBase. LMPs are for Ohio aggregate delivery points.* [2] Proxy for Ohio EDU weighted average cost of capital.		

REC revenue requirements are calculated by subtracting the levelized market value from the levelized cost of energy:

Table B5: Estimation of REC Revenue Requirement

$/MWh	**Low** (Low LCOE, High MV.)	**Base** (Base LCOE, Base MV)	**High** (High LCOE, Low MV.)
Wind (125 MW)	**REC sales may not be necessary to meet revenue requirement**	**≈ $10 If Federal Incentives Expire: ≈ $45**	**≈ $30**
Solar (500 kW)	**≈ $100**	**≈ $125**	**≈ $160**
Solar (1,500 kW)	**≈ $145**	**≈ $170**	**≈ $195**
MV = Market Value of Production			

It is important to remember that numerous market and regulatory uncertainties will impact the future cost of renewable energy policies. The inputs contained in this analysis are based on available data and current market conditions.

The presence of long-term, or recurring, uncertainties may lead to increased costs or pipeline attrition, which could lead to a shortage of resources to meet policy objectives. The leading examples of such uncertainty include the potential future expiration or extension of the federal production tax credit and investment tax credit, the potential for carbon dioxide emissions regulation, changes in energy and capacity market prices, changes in equipment and financing costs and – at the regional level – future public and private decisions with respect to regional transmission.

Appendix C: Resource Eligibility for Portfolio Standards in Ohio and Contiguous States

Coding	
PA	1 = Tier 1
	2 = Tier 2
MI	R = Renewable Energy Resources
	EO = Energy Optimization
WV	R = Renewable Energy Resources
	A = Alternative Energy Resources
	O =Other
OH	R = Renewable
	A = Advanced

Eligible Resource	Indiana	Michigan	Ohio	Pennsylvania	West Virginia
Advanced Nuclear			A		
Significant improvements to existing facilities			A		
Advanced solid waste or construction and demolition debris conversion technology			A		
Advanced stoker technology			A		
Advanced fluidized bed gasification technology			A		
Fractionation			A		
Biomass		R	R	1(1)	R
Pulp Mill Sludge			R		R
Agricultural crops and crop wastes		R	R		
Short-rotation energy crops		R	R		
Herbaceous plants		R	R		
Trees and wood		R(2)	R		
Paper and pulp products		R	R		
Pre-commercial wood thinning waste, brush, or yard waste		R	R		

Eligible Resource	Indiana	Michigan	Ohio	Pennsylvania	West Virginia
Wood wastes and residues from the processing of wood products or paper		**R**	**R**		
Animal Wastes/Byproducts	**X**	**R**	**R**		
Wastewater sludge or sewage		**R**	**R**		
Aquatic Plants/Algae	**X**	**R**	**R**		
Landfill Gas: Methane		**R**	**R**(3)	**1**	**R**
Food production and processing waste		**R**	**R**		
Dedicated Crops grown for energy production	**X**		**R**		
Black Liquor			**R**	**1**(4)	
Organic Waste Biomass	**X**		**R**		
Agricultural Wastes	**X**(5)		**R**		
Wood Wastes	**X**		**R**		
Paper Pulp Products			**R**(6)	2(7)	
Biologically derived fuel			**R**		**R**
Ethanol			**R**		**R**
Biodiesel Fuel		**R**(8)	**R**		**R**
Coal					
Advanced Coal Technology(9)			**A**		**A**
Clean Coal			**A**(10)		
Fuel produced by a coal gasification or liquefaction facility			**A**		**A**
Integrated combined coal gasification technology			**A**	**1**	**A**
Waste coal				**2**	**A**
Coal Bed Methane	**X**				**A**
Coal Mine Methane			**R**	**1**	
Combined Heat and Power Systems	**X**		**A**		
Demand side management/ Energy conservation	**X**(11)		**A**	**2**	**O**
Load management		**EO**(12)		**2**	**O**
Industrial By-Product Technologies				**2**	**O**
Infrastructure and Modernization Projects					**O**
Customer-sited generation, demand-response, energy efficiency or					**O**

Eligible Resource	Indiana	Michigan	Ohio	Pennsylvania	West Virginia
peak demand reduction capabilities committed to demand-reduction					
Energy Efficiency Initiatives	**X**(13)	**EO**	**A**		**O**
Energy Efficiency Technologies				**2**	**O**
Distributed generation systems			**R**(14)	**2**	
Energy conservation		**EO**(15)			
Energy Derived from Advanced Solid Waste Conversion Technologies	**X**		**R**(16)		
Energy Storage Systems or Technologies	**X**		**R**(17)		
Fuel Cells	**X**		**R**(18)	**1**	**R**
Geothermal Energy	**X**	**R**	**R**	**1**	**R**
Greenhouse Gas Emissions Reduction or Offset Project					**O**(19)
Hydrogen	**X**				
Hydropower	**X**		**R**(20)		
Run of River Hydropower					**R**
Water released through a dam		**R**			
Low-Impact				**1**	
Large-scale				**1**(21)	
Industrial Byproduct Technologies that use fuel or energy that is a byproduct of an industrial process	**X**				
Natural Gas	**X**(22)				**A**
Nuclear Energy	**X**				
Ocean		**R**(23)			
Pumped storage hydroelectric projects			**R**		**A**
Recycled Energy(24)					**R**
Solar Energy	**X**	**R**	**R**	**1**	**R**
Solar Thermal	*(25)	**R**	**R**	**1**	**R**
Synthetic Gas					**A**
Waste Heat recovery from capturing and reusing the waste heat in industrial processes for heating or for generating mechanical or	**X**				

Eligible Resource	Indiana	Michigan	Ohio	Pennsylvania	West Virginia
electrical work					
Waste to Energy	**X**		**R**(26)		
Municipal Solid Waste		**R**		**2**	
Tire derived fuel					**A**
Wind	**X**	**R**	**R**	**1**	**X**
Offshore Wind			**R**(27)		
Any method or any modification or replacement of any property, process, device, structure, or equipment that increases the generation output of an electric generating facility to the extent such efficiency is achieved without additional carbon dioxide emissions by that facility			**A**		

(1) Tier 1 and Tier 2 definitions for biomass: While the PA AEPS overview website lists Biomass as Tier 1, and Black Liquor as PA Only - as specified in this table - 66 Pa.C.S. § 2814 expanded the definition of Biomass such that that produced in the Commonwealth is Tier 1, and outside of it is Tier 2.
(2) Only if derived from sustainably managed forests or procurement systems.
(3) Both biologically derived methane gas and fuel derived from solid wastes through biological decomposition are classified as renewable energy resources.
(4) Tier 1 from PA only .
(5) Agricultural crops and agricultural wastes and residues.
(6) Energy derived from non-treated by-products of the pulping process or wood manufacturing process (including bark, wood chips, sawdust, and lignin in spent pulping liquors).
(7) Generation of electricity utilizing by-products of the pulping process and wood.
(8) Organic by-products from the production of biofuels.
(9) Including carbon dioxide capture and sequestration technology, supercritical technology, advanced supercritical technology as determined by the Public Service Commission, ultrasupercritical technology, and pressurized fluidized bed technology.
(10) That includes a carbon-based product that is chemically altered before combustion to demonstrate a reduction, as expressed as ash, in emissions of nitrous oxide, mercury, arsenic, chlorine, sulfur dioxide, or sulfur trioxide in accordance with the American society of testing and materials standard D1757A or a reduction of metal oxide emissions in accordance with standard D5142 of that society, or clean coal technology that includes the design capability to control or prevent the emission of carbon dioxide, which design capability the commission shall adopt by rule and shall be based on economically feasible best available technology or, in the absence of a determined best available technology, shall be of the highest level of economically feasible design capability for which there exists generally accepted scientific opinion.

(11) Demand side management designated as a clean energy resource by the commission that reduce electricity consumption or implement load management, demand response, or energy efficiency measures designed to shift customers' electric loads from periods of higher demand to periods of lower demand.

(12) To the extent that the load management reduces overall energy usage.

(13) Energy efficiency initiatives designated as a clean energy resource by the commission that reduce electricity consumption or implement load management, demand response, or energy efficiency measures designed to shift customers' electric loads from periods of higher demand to periods of lower demand.

(14) A distributed generation system used by a customer is eligible if it generates electricity from a renewable energy resource.

(15) Only to the extent that the decreases in the consumption of electricity produced by energy conservation are objectively measurable and attributable to an energy optimization plan.

(16) See Ohio Administrative Code rule 4901:1-40-04(A)(5) Solid waste energy derived from fractionalization, biological decomposition, or other process that does not principally involve combustion.

(17) To be eligible, the electricity used to pump the resource into a storage reservoir must qualify as a renewable energy resource, or the equivalent renewable energy credits must be obtained.

(18) Including proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, and solid oxide fuel cell.

(19) Including methane capture and destruction from landfills, coal mines or farms; forestation, afforestation or reforestation; nitrous oxide or carbon dioxide sequestration through reduced fertilizer use or no-till farming.

(20) Located on water discharged to a river.

(21) Tier 1 with certain restrictions; Tier 2 otherwise.

(22) At in-state facilities constructed after July 1, 2011 that displaces electricity from coal.

(23) Kinetic energy of moving water, including waves, tides, and currents.

(24) Recycled energy, which means useful thermal, mechanical or electrical energy produced from: (i) exhaust heat from any commercial or industrial process; (ii) waste gas, waste fuel or other forms of energy that would otherwise be flared, incinerated, disposed of or vented; and (iii) electricity or equivalent mechanical energy extracted from a pressure drop in any gas, excluding any pressure drop to a condenser that subsequently vents the resulting heat.

(25) The law defines eligible technologies to include those "used in connection with the production or conservation of electricity" while also referring to solar energy as an eligible resource. Thus, it would appear that solar thermal technologies would qualify for inclusion under the standard to the extent that they conserve electricity, however there is currently no defined metric for how this would be counted under the Indiana RPS.

(26) See Ohio Administrative Code rule 4901:1-40-04(A)(5) Solid waste energy derived from fractionalization, biological decomposition, or other process that does not principally involve combustion.

(27) Wind turbine located in the state's territorial waters of Lake Erie.

Appendix D: Geographic Eligibility for RPS in Ohio and Contiguous States

	Indiana	Michigan	Ohio	Pennsylvania	West Virginia
In-state Resource	At least 50% of the MWh of clean energy obtained by the participating electricity supplier to meet the energy requirements of its Indiana retail electric customers during the CPS goal period under consideration must originate from clean energy resources located in Indiana.	RECs can come from facilities in state or from out of state, as long as they are located in the service territory of a retail electric supplier that is not located in Michigan or is registered as a retail electric supplier in Michigan, with some exceptions.*	At least 50%	Generally, must originate in-state or within the PJM RTO.	Resource must be generated or purchased from a facility in state or located outside of the geographical boundaries of this state but within the service territory of a regional transmission organization that manages the transmission system in any part of this state.
Out-of State Resource		See Above.	Remainder after in-state requirement: met with resources that can be shown to be deliverable into this state.	Alternative energy systems located outside of the Commonwealth, but within MISO, may only be used in the areas of Pennsylvania that overlap MISO's service territory.	See above; Resource can be from a facility in state or in the regional transmission organization which serves the state.

*The renewable energy system location requirements do not apply if 1 or more of the following requirements are met:

a) The renewable energy system is a wind energy conversion system and the electricity generated by the wind energy system, or the renewable energy credits associated with that electricity, is being purchased under a contract in effect on January 1, 2008. If the electricity and associated renewable energy credits purchased under such a contract are used by an electric provider to meet renewable energy requirements established after January 1, 2008 by the legislature of the state in which the wind energy conversion system is located, the electric provider may, for the purpose of meeting the renewable energy credit standard under this act, obtain, by any means authorized under section 27, up to the same number of replacement renewable energy credits from any other wind energy conversion systems located in that state. This subdivision shall not be utilized by an alternative electric supplier unless the alternative electric supplier was licensed in this state on January 1, 2008. Renewable energy credits from a renewable energy system under a contract with an alternative electric supplier under this subdivision shall not be used by another electric provider to meet its requirements under this part.

b) The renewable energy system is a wind energy conversion system that was under construction or operational and owned by an electric provider on January 1, 2008. This subdivision shall not be utilized by an alternative electric supplier.

c) The renewable energy system is a wind energy conversion system that includes multiple wind turbines, at least 1 of the wind turbines meets the location requirements of this section, and the remaining wind turbines are within 15 miles of a wind turbine that is part of that wind energy conversion system and that meets the location requirements of this section.

d) Before January 1, 2008, an electric provider serving not more than 75,000 retail electric customers in this state filed an application for a certificate of authority for the renewable energy system with a state regulatory commission in another state that is also served by the electric provider. However, renewable energy credits shall not be granted under this subdivision for electricity generated using more than 10.0 megawatts of nameplate capacity of the renewable energy system.

e) Electricity generated from the renewable energy system is sold by a not-for-profit entity located in Indiana or Wisconsin to a municipally-owned electric utility in this state or cooperative electric utility in this state under a contract in effect on January 1, 2008, and the electricity is not being used to meet another state's standard for renewable energy.

f) Electricity generated from the renewable energy system is sold by a not-for-profit entity located in Ohio to a municipally-owned electric utility in this state under a contract approved by resolution of the governing body of the municipally-owned electric utility by January 1, 2008, and the electricity is not being used to meet another state's standard for renewable energy. However, renewable energy credits shall not be granted for electricity generated using more than 13.4 megawatts of nameplate capacity of the renewable energy system.

g) All of the following requirements are met:

   a. The renewable energy system is a wind energy system, is interconnected to the electric provider's transmission system, and is located in a state in which the electric provider has service territory.
   b. The electric provider competitively bid any contract for engineering, procurement, or construction of the renewable energy system, if the electric provider owns the renewable energy system, or for purchase of the renewable energy and associated renewable energy credits from the renewable energy system, if the provider does not own the renewable energy system, in a process open to renewable energy systems sited in this state.
   c. The renewable energy credits from the renewable energy system are only used by that electric provider to meet the renewable energy standard.
   d. The electric provider is not an alternative electric supplier.