National Regulatory Research Institute

What Is an Effective Feed-In Tariff for Your State?

A Design Guide

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Online Access

This report can be accessed online at: http://www.nrri.org/pubs/multi-utility/NRRI_FIT_design_april10-07.pdf.

NRRI Knowledge Communities

NRRI is launching a project called *Knowledge Communities*, which is an online tool for regulators to share experiences, learn from each other, and collaborate to develop solutions. We have a community specific to feed-in tariffs. The community includes discussions, numerous uploaded documents, and wiki capability. Please check it out at http://communities.nrri.org/web/electricity-feed-in-tariffs/community-home-and-charter.

Executive Summary

Numerous states are considering requiring their utilities to offer feed-in tariffs (FiTs) to encourage renewable energy development. FiTs provide standardized compensation and terms to eligible generators. They come in many shapes and sizes, differing in eligibility, size, compensation mechanisms, and terms and conditions. The appropriate design of a FiT depends on the specific policy objectives and resources of the jurisdiction that is considering a FiT. This paper guides policymakers through the process of crafting FiTs that reflect their goals and resources by describing options and offering recommendations.

Feed-in tariffs can facilitate rapid renewable energy development by providing revenue certainty. They also can also increase consumer costs. While this paper addresses various FiT characteristics, it does not evaluate the efficacy of FiTs compared to other policies. We do not support or oppose FiTs, but seek to inform policymakers on how to design effective programs.

Section One discusses how policymakers can consider program context, including state goals, other renewable energy programs, available resources, and cost constraints. Section Two examines program parameters, including eligibility and program caps. Section Three explores compensation mechanisms and options for setting rates. Section Four examines non-rate terms and conditions, such as duration, buyer and seller obligations, reporting requirements, and the ownership of renewable energy credits. Finally, Section Five discusses FiT administration.

Our recommendations include:

1. Match technology and system size eligibility criteria to available tax credits, rebates, or low-interest loans if possible.
2. Include multi-year caps on installed capacity. Such caps limit costs, particularly until the market develops and cost and performance data improve. Such caps could feature technology carve-outs to ensure development of specific technologies.
3. Design fixed cost-based rates that provide a rate equal to the levelized costs of producing energy over the term of the FiT, which should approximate generators' useful lives.
4. Base rates on the costs and performance on that of average projects, as opposed to most projects or only the most cost-effective projects.
5. Confer all renewable energy credits, carbon credit value, or other green attributes to the purchasing utility.
6. Provide utilities with the option to continue purchasing energy from participants at the feed-in tariff rate after the FiT term.
7. Reexamine eligibility, caps, rates, and terms and conditions every two to three years through a transparent process.
8. Require extensive reporting of costs, use of rebates and tax benefits, and production by larger projects, and require limited reporting by smaller projects.

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A Design Guide

Many U.S. legislatures and regulatory commissions are considering implementing feed-in tariffs (FiTs) as a tool to facilitate the rapid development of renewable energy.[1] FiTs vary based on eligibility criteria, overall cap size, compensation mechanisms, non-rate terms and conditions, and program administration. Design decisions for each such element determine program outcomes, including the cost, size, and technology of resulting projects, and development speed. This paper discusses the consequences of various design decisions and offers recommendations.

This paper does not evaluate the efficacy of FiTs compared to other policies. Consequently, we neither support nor oppose FiTs, but seek to inform policymakers on how to design effective programs. Further, FiTs do not address all of the barriers to renewable energy adoption. Other policies can help develop transmission to interconnect resources and facilitate project siting and permitting, for instance.

Section One discusses how policymakers should consider program context, including state goals, other renewable energy programs, available resources, and cost constraints. Section Two examines program parameters, including eligibility and caps. Section Three explores compensation mechanisms and options for setting rates. Section Four examines potential non-rate terms and conditions, such as duration, buyer and seller obligations, reporting requirements, and the ownership of renewable energy credits. Finally, Section Five discusses program administration.

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[1] For the purposes of this paper, a FiT is defined as a publicly available legal document, promulgated by a state commission, that obligates the utility to purchase electricity from an eligible renewable energy seller at specified prices for a specified period of time; and which, conversely, entitles the seller to sell to the utility at those prices for that period of time, without the seller needing to obtain additional regulatory permission for that sale. FiTs also typically contain standardized terms and conditions and interconnection procedures.

I. Evaluate Context

Before addressing the nuts and bolts of designing FiTs, policymakers should prioritize program goals and examine the regulatory and resource context. Policy goals and context, such as natural resources and existing policies, dictate FiT effectiveness at eliciting generation and program cost.

A. What are the state's renewable energy goals?

Below, we identify five potential FiT goals. These goals, while not exclusive, favor different FiT designs.

Reduce carbon emissions. All renewable energy technologies reduce carbon emissions compared to fossil fuel generation. Some, however, do so at a lower cost than others. For example, on a per-MWh and tons-of-carbon-dioxide-emission-reduction basis, wind generation is cheaper than solar. Policymakers should examine their states' current generation profile and determine which generation renewable energy would displace. Solar energy is disproportionately produced during peak periods in most places, generally reducing the use of inefficient peaking generators. Wind generation, conversely, occurs largely in off-peak periods, so in some places it would displace coal generation while solar would displace gas. Biomass, biofuel, and geothermal technologies are dispatchable and in some cases baseload. Depending on the region, these technologies could offset coal or gas.

Large projects reduce carbon emissions more cost-effectively than small ones do because most renewable energy technologies feature economies of scale. Wind in particular is much cheaper on a levelized basis for large wind farms than for small single turbines.

Reduce energy imports/diversify energy sources. Some states, such as Hawaii, seek to reduce energy imports. Biomass and wind generators typically reduce the use of fossil fuels at the lowest per-kWh cost. Other states might seek to reduce exposure to volatile natural gas prices. Again, policymakers should examine which fuels various renewables would offset and tailor their FiT policies accordingly.

Spur economic development. Some states and countries, including California and Germany, have enacted renewable energy policies such as FiTs to spur economic development. Ideally, by creating a favorable economic environment, renewable energy companies, in particular research or manufacturing firms, would locate in an area. In addition to serving the local market, these businesses could sell products or services elsewhere, creating additional jobs and net benefits to the region. States should evaluate the potential size of their market, the presence of existing renewable energy companies, and the level of development of various technologies before implementing a FiT to spur economic development.

Germany and California became centers for solar development—and, in Germany's case, manufacturing—by offering generous programs earlier than most other places did.[2] They both feature large markets and adequate natural resources, making them attractive locations for manufacturing. Smaller markets are less likely to attract such industry clusters. For instance, a state with limited wind resources will not likely become a center for wind manufacturing on the basis of a favorable policy (though perhaps other factors or policies could attract such manufacturing). Where policymakers prioritize economic development, FiTs could include new and perhaps expensive technologies, thereby increasing the opportunity to attract research or manufacturing facilities associated with those technologies.

Another element of economic development, the size and diversity of the local renewable energy industry, stems in part from the number and technological variety of projects. If several projects consume the FiT's whole cap (assuming there is a cap), relatively few developers and contractors will enter the market. Some jurisdictions have concluded that a diverse local industry provides value to the state economy. Policymakers can promote this goal by (a) not capping the total size of the FiT, (b) limiting eligibility to relatively small projects, or (c) "carving out" a percentage of the FiT for small projects or specific technologies.

In some cases, the desire to spur the economic development of some sectors could favor the inclusion of a technology in a FiT, even if that resource is limited or expensive. For example, policymakers could include anaerobic digesters in the list of eligible technologies to support their agricultural sector.

To the extent that FiTs increase short-term electricity costs, they could render the state less attractive to certain industries. Policymakers should evaluate how a state's current and potential businesses, particularly manufacturers, would react to the resulting electricity rate increases. Potentially, the negative consequences could exceed the program's economic benefits.

Encourage distributed generation. Unlike central-station generation, distributed generation does not usually require substantial new transmission and distribution infrastructure. Distributed generation provides the most value where such upgrades are expensive or difficult to site. Policymakers seeking to promote distributed generation should consider including small solar PV, wind, and anaerobic digestion projects in potential FiTs.

Improve or maintain reliability. In addition to favoring distributed generation, where policymakers want to avoid new transmission or peak capacity development, they should favor technologies that are either dispatchable or operate during peak periods. Specifically, solar energy production occurs heavily during the middle of summer days, near the hours when most utilities experience their peak loads.[3] Solar generation reduces the peak demand served by

[2] Whitlock, Craig, "Cloudy Germany a Powerhouse in Solar Energy," *Washington Post*, May 5, 2007.

[3] http://1.bp.blogspot.com/_yr3xF4J1UVg/RquNMdO2HJI/AAAAAAAAANw/f3k1y_97B4c/s400/Solar+Output+and+California+Demand.jpg

conventional generators. When distributed, it reduces the amount of energy transmitted over transmission and distribution lines, which can reduce congestion. Wind turbines typically generate the most electricity during night hours and during colder months, which in most places feature the lowest loads. Thus, wind generation does not offset peak demand as much as solar does.

Dispatchable technologies such as biomass, biofuel, and geothermal generators benefit systems compared to intermittent generation. Unlike intermittent resources, utilities do not need back-up generation capacity to "shape" dispatchable generation. Dispatchable generators lead to lower capacity market costs or require fewer needed additional peakers to accommodate intermittent generators' peaks and valleys. Dispatchable generators can either provide baseload generation or follow load. Where capacity margins are low, such technologies can improve, or at the very least not harm, system reliability.

B. What are the state's resources?

Policymakers should next examine their states' natural resources. FiTs cost the least if they provide eligibility only for technologies that the state possesses in abundance. For instance, due to lower solar radiation levels, a cost-based FiT rate for solar PV would feature higher rates in Maine than in Arizona. The same logic applies to wind, biomass, and agricultural methane. Some generation resources are not viable even with generous FiTs. For instance, certain states lack developable geothermal or hydro resources.

C. What are the economic constraints?

FiTs, at least in the short run, usually provide compensation to project owners in excess of market wholesale electricity prices. Policymakers should quantify the size of the acceptable "subsidy" and the amount of acceptable resulting short-term rate increases and then weigh such costs against FiT benefits. Failure to consider such matters could lead to high costs to consumers, as happened in Spain, and potentially a ratepayer backlash.[4] This determination should inform overall caps and technology and project size eligibility decisions, discussed in Section II. Such subsidy calculations could consider likely carbon policies.

FiTs' above-market compensation will often increase short-term rates. Several factors determine the size of the resulting rate increase:

Existing wholesale energy costs. A FiT offering $0.20 per kWh will not increase rates as much where electricity already costs $0.12 cents per kWh as it will where it costs $0.07 per kWh. The "subsidy" part of the rate and resulting rate increase would be smaller for the former utility.

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[4] Spain initially offered either a premium above the avoided cost or a fixed FiT rate. When natural gas prices caused the avoided cost to increase, most developers opted for the latter, leading to high rates and subsequent programmatic reforms. *The Application of Feed-in Tariffs and Other Incentives to Promote Renewable Energy in Colorado*, Brent Burgie & Kelly Crandall, 2009.

Eligible technology rates and capacity factors. A FiT including only low-cost renewable technologies on a per-kWh basis, such as biomass and wind, will feature lower rates and thus a lower "subsidy" than one accommodating more expensive technologies such as offshore wind and solar PV. Certain renewable technologies, such as wind, can compete with conventional generation in some places without state policies, rendering FiT eligibility unnecessary.

The total cost to ratepayers depends on two factors: the rate paid to a generator compared to the cost of conventional generation and the capacity factor of that generator. The "subsidy" equals the expected average difference between the FiT rate and the cost of conventional generation times the capacity factor. For example, a 100-kW solar project paid $0.25/kWh, with a capacity factor of 15%, would have a lower overall total cost (though not per kWh cost) than a 100-kW anaerobic digester paid $0.20/kWh with a capacity factor of 80% if the expected cost for conventional generation for the FiT term equals $0.15.

"Subsidy" for the first year hypothetical comparison

Annual Production × (rate minus conventional cost) = subsidy

High cost/low capacity factor technology: (100 × 365 × 24 ×.15) × (.25 - .15) = $13,140

Low cost/high capacity factor technology: (100 × 365 × 24 ×.80) × (.20 - .15) = $35,040

Policymakers should examine both technologies' rates and capacity factors when evaluating their rate consequences. They could also evaluate technologies' subsidy in nominal terms as shown above or as a percentage of overall costs. For the above example, for the high-cost technology, the subsidy was 40% of the total cost ($0.10 of $0.25).

The "subsidy" does not reflect the total cost—or savings—from the FiT. Policymakers should also examine how FiT generation could affect market-clearing prices in organized wholesale markets. The presence of increased generation purchased directly by the utility could create downward pressure on demand in wholesale markets. Some reports contend that FiTs could cause (and in Europe have caused) downward pressure on wholesale prices, such that aggregate savings exceed the "subsidy" for FiT generators.[5]

Eligible project sizes. On a per-kW or per-kWh basis, small projects cost more than large ones. For FiTs lacking caps, however, exclusion of large projects would likely elicit less development, leading to lower costs than inclusion of all project sizes. Similarly, limiting the FiT to projects too large to use net metering would reduce the pool of eligible projects and thus overall program costs.

Requisite system upgrades. FiTs including projects requiring substantial additional transmission or distribution infrastructure or additional back-up generation capacity investments

[5] Sensfuss, F., Ragwitz, M., Genoese, M. (2009). "The Merit-Order Effect: A Detailed Analysis of the Price Effect of Renewable Electricity Generation on Spot Market Prices in Germany." *Energy Policy 36*(8), pp. 3086-3094.

by the utilities cost more than FiTs limited to projects with few such costs or placing such costs on developers. Distributed technologies typically require less additional transmission and distribution infrastructure than generators located far from load. Dispatchable resources require less back-up capacity or storage than intermittent ones.

D. What are the existing renewable energy programs—and how would a FiT interact with them?

Many states, municipalities, and utilities feature programs to encourage renewable energy development. Below we discuss how FiTs could consider various programs.

1. Competitive bidding processes

Most large renewable energy projects sell their power to utilities either by winning competitive bidding/request-for-proposal processes or through power purchase agreements (PPAs) that they negotiate bilaterally with the utility. Competitive solicitation processes, and to a certain extent negotiated PPAs, push prices down to the competitive level. Both, however, provide uncertain compensation for developers and often entail substantial time and transaction costs. FiTs with standard rates and conditions represent an alternative approach. These contracting methods can, however, complement each other if applied to different types of projects.

As discussed in Section III, setting rates for cost-based FiTs is difficult and imprecise. Consequently, acquiring energy through FiTs, particularly without a cap, could prove much costlier than acquisition via conventional methods. Large projects feature the greatest potential for overpayment, particularly for developing technologies, such as solar PV, that feature high but rapidly falling costs. Additionally, the time and resources needed to participate in competitive bidding processes cost more (as a percentage of total costs) for small projects than for large ones. Finally, large projects often cause reliability concerns and necessitate system upgrades, requiring a longer vetting process than smaller projects typically require. Accordingly, current U.S. FiTs only accommodate small projects. See Section II.B for such examples.

Recommendation: Employ competitive bidding for larger projects, initially limiting the FiT to smaller projects.

Certain projects feature unique system benefits and costs such that the FiT would not accommodate them, although they could still benefit ratepayers. Consequently, negotiated PPAs should remain an available option for all projects.

2. Tax benefits

Some states, counties, or municipalities provide individuals or corporations with tax incentives for renewable energy projects. Such benefits include credits to income taxes and exemptions from sales, excise, or property taxes. As discussed in Section III.A, most FiTs feature cost-based rates, covering project costs and providing a reasonable rate of return. Consequently, cost-based rates that do not consider tax incentives could provide excessive returns—which are not just and reasonable.

As discussed in Section III, most FiTs feature different rates for different technologies and project sizes. A problem arises where the FiT size or technology eligibility criteria differ from those of state tax credits or rebates. In such situations, only some FiT projects in a given size or technology tier could use such credits, creating excessive returns for some projects or insufficient compensation for others. Alternatively, provide separate rates for projects that do and do not receive tax benefits. Policymakers can also render FiT participation exclusive to projects not receiving tax credits if such credits are not available to most potential projects.

Recommendation: Consider all state tax benefits in FiT rates. If possible, align FiT eligibility requirements such as project sizes with those of tax benefits to avoid certain projects within a size class receiving them and not others. Alternatively, include separate rates for projects based on their tax credit eligibility. Determining the difference in levelized costs for projects that do and do not receive credits is not difficult. As such, we recommend separate rates rather than blanket exclusion for projects receiving these credits where eligibility criteria do not align.

3. Rebates and grants

Some states, such as Maryland, as well as municipalities or utilities, offer rebates or grants to renewable energy projects.[6] Unlike tax credits, most rebate programs feature budgets, limiting the number of recipients. Such budgets create a tension with FiTs that do not consider rebates or grants when setting rates by providing those who receive them with excessive returns. Conversely, FiTs that assume their use would provide inadequate rates for projects that cannot receive rebates or grants because there are insufficient funds for all eligible projects.

To avoid this scenario, policymakers can align FiT caps with rebate limits. For example, if a state offers a $3-per-watt rebate for solar PV up to 20 kW with a total cap of $6 million, it would offer the rebate to the first 2 MW of new PV capacity each year. The FiT could feature the same cap and have one size tier from zero to 20 kW. Alternatively, policymakers could make the FiT and rebates mutually exclusive, rendering projects receiving the rebate ineligible for the FiT or set separate rates for projects that do and do not receive rebates. In Vermont, the board overseeing the state's Clean Energy Development Fund determined that it would not provide grants to any project receiving FiT prices. Because ratepayers fund both FiTs and rebates, excluding FiT projects from available grant or rebate programs increases the total amount of incentives available for renewable projects.

Recommendation: Exclude projects receiving state, local, or utility rebates and grants from FiT participation unless the size and eligibility criteria for FiT projects and available grants and rebates match. If the rebate or grant program is large and grant sizes are predictable, offer separate rates for projects that do and do not receive rebates if the eligibility criteria align.

[6] http://mlis.state.md.us/asp/web_statutes.asp?gsg&9-2007

4. Loans

Some states or utilities offer low-interest loans for renewable energy projects.[7] Similar to rebates, a conflict arises when the loans are limited in scope or have different eligibility criteria from the FiT. Policymakers can either match FiT caps and eligibility requirements to the loan program or render the two programs exclusive to prevent recipients of both from enjoying excessive returns.

Recommendation: Ensure that FiT projects are not eligible for state, local, or utility loans unless the size and eligibility criteria for FiT projects and available loans match, in which case rate calculations should consider such benefits.

5. Renewable portfolio standards

Most states have adopted renewable portfolio standards (RPSs), which mandate that load-serving entities supply a minimum percentage of their energy via renewables. FiTs can operate in conjunction with RPSs, though each creates a market for renewable energy, lessening the need for the other. FiTs reduce investor risks and increase compensation, while RPSs mandate a level of demand for renewable energy. RPSs do not provide investors with revenue certainty or reduce the time and cost of attaining a PPA as FiTs can.

Some RPSs attempt to create markets (albeit ones using bilateral transactions like that provided by Evolution Markets rather than commodities exchanges) for tradable renewable energy credits (RECs), sometimes referred to as renewable energy certificates, to demonstrate compliance with RPS obligations. If FiT rate calculations do not consider RECs as cost offsets or if RECs do not go to the purchasing utilities, project owners would receive excessive returns. RECs feature volatile prices, which can change dramatically based on a single large project. Consequently, estimating the value of RECs to craft rates would prove difficult and imprecise. In addition, FiTs can increase the number of renewable projects, thereby lowering REC prices.

Recommendation: Consider limiting FiTs to projects that due to technology or size feature costs too high to be economical from the sale of electricity and RECs alone. For instance, without carve-outs, RPSs in most places would not encourage solar development because the technology is more expensive than wind or biomass. A FiT could fill this gap if policymakers want to ensure the development of that technology. Where these two policies overlap, confer all RECs or other green attributes to the purchasing utility, thereby negating the need to estimate REC value when calculating FiT rates.

6. Net metering

Most states mandate that utilities offer net metering. Through net metering, the meters of customers with distributed renewable energy generators run backwards when they produce more energy than they consume. Consequently, customers receive compensation at retail rates, even

[7] New Jersey Clean Energy Solutions Capital Investment Loan/Grant. http://www.njeda.com/web/Aspx_pg/Templates/Npic_Text.aspx?Doc_Id=1078&menuid=1360&topid=722&levelid=6&midid=1357.

though they provide wholesale electricity to the grid. In some states, at the end of a year or billing cycle, utilities must compensate customers at wholesale or retail rates if the customer has on net contributed electricity to the grid. Net metering programs vary in eligible project sizes, with some only covering residential-sized projects and others applying to MW-class projects.

Net energy metering programs can either work in conjunction with FiTs or in isolation. Most states with FiTs, including California, force projects to choose between net metering and the FiT.[8, 9] If customers consume the power they generate but sell excess power back at the FiT rate, the value of the savings or compensation could exceed the value of either using net metering (most of which only compensate project owners at the avoided cost rate) or the FiT (assuming the rate is below the retail rate for electricity), making it difficult to set accurate rates.

Recommendation: For simplicity as well as to render the compensation for renewable projects predictable, offer owners of new projects a one-time choice between FiTs and net metering. Offer FiT rates only to new projects and not to existing net-metered projects, as enabling owners to switch between programs could increase compensation without encouraging additional renewable energy generation. Only states that strongly value developing distributed generation should consider allowing customers to operate under net metering *and* sell excess generation back at FiT rates.

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8 The exception is Hawaii, which has a hybrid approach: Customers can sell excess power at FiT rates at the end of a billing cycle, but the meter never runs backwards.

9 California Senate Bill No. 32. See page 5. http://info.sen.ca.gov/pub/09-10/bill/sen/sb_0001-0050/sb_32_bill_20090915_enrolled.pdf

II. Determine Parameters

After evaluating state goals, resources, economic constraints, and other renewable energy programs, policymakers need to determine eligibility standards and overall program size.

A. Technology eligibility

As discussed above, state goals, available resources, and financial constraints should inform technology eligibility decisions. Policymakers concerned with program costs can provide eligibility for expensive technologies if the FiT compensates projects based on avoided-cost/market rates rather than for cost-based FiTs (discussed in Section III.A). Avoided-cost rates provide the same rate for all technologies, likely rendering more expensive technologies uneconomic, while cost-based rates require setting rates for each technology, facilitating more expensive technologies. Accordingly, California's FiT applies to all RPS-eligible renewable technologies, though the state provides additional incentives for solar projects.[10]

Technologies differ in cost and other pertinent characteristics. We provide the following table to summarize the major attributes of most renewable energy technologies:

Technology	Costs	Operating Characteristics	Resource Availability and Siting	Other Notes
Onshore Wind	-Levelized costs of approximately $60-$70 per MWh for large projects and more for small ones - Economies of scale for large projects, which can sell for as low as $50 per MWh	-Intermittent -Produces heavily during cold months and night hours -Large turbines are curtailable	-Difficult to site in non-rural areas, limiting distributed generation potential -Best resources are in the Great Plains and mountainous areas	-Avian- and bat-harm mitigation challenges -Most established renewable technology providing certainty but limited opportunities for economic development
Offshore Wind	-Costs are higher than onshore but uncertain—none constructed in U.S.	-Produces heavily during cold months and night hours -Most viable for largest turbines -Higher capacity factor than onshore wind -Less intermittent than onshore wind	-Available only on the coasts and Great Lakes -View-disruption siting difficulties[11]	-Maintenance costs of operating in saltwater are unclear

[10] California SB 32 at page 7. http://info.sen.ca.gov/pub/09-10/bill/sen/sb_0001-0050/sb_32_bill_20090915_enrolled.pdf

[11] See Cape Wind history: http://www.reuters.com/article/idUSN1930289620071019

Technology	Costs	Operating Characteristics	Resource Availability and Siting	Other Notes
PV Solar	Levelized costs of $250 per MWh for central station projects and more for distributed. Costs are falling rapidly. Some projects have sold energy for as little as $155 per MWh.	-Intermittent -Typically non-curtailable -Highest production during midday summer hours -Viable at very small or large sizes	-Best resources in Southwest -Easiest resource to site in urban areas -Large projects are land-intensive: roughly 7 acres per MW of capacity	-Costs are rapidly falling due to improved efficiency and increased global manufacturing capacity
Concentrated Solar	Levelized costs of approximately $220 per MWh, though costs can be lower without thermal storage capability	-Intermittent, but lends itself to back-up firming generation -Only viable at 500 kW+ sizes	-Best resources in Southwest -Needs flat land, typically non-urban	
Biomass	-Moderate levelized cost $100-$110 per MWh for combustion -Feedstock prices and availability vary and affect costs	-Dispatchable	-Air permitting can prove challenging	-Established technology -Potentially differentiated among waste, wood, CHP (combined heat and power), and agricultural anaerobic digestion
Hydropower	-For small-scale and developed sites levelized cost of $80 per MWh	-Non-dispatchable, and output is subject to weather	-Need undeveloped rivers -Relatively small project sizes	-Typically limited to run-of-river projects
Geothermal	-Low-cost with strong resources like those in California, but high-cost in many places. Levelized cost for flash and binary generation of $80 per MWh	-Baseload and dispatchable	-Most viable (surface) geothermal limited to several Western locations -Limited to larger project sizes	-Long lead time of exploration and building plant
Wave/Tidal	-Costs are uncertain but initially high	-Potentially dispatchable and baseload	-Available on coasts, particularly the Puget Sound for tidal power	-Technologies are unproven
Biogas	- Relatively low levelized costs and uses conventional technology: $50-$80 per MWh ($100-$170 for anaerobic digestion)	-Potentially baseload and dispatchable -Anaerobic digesters are distributed gens	-Agricultural and landfill resources needed -Air permitting can prove difficult	

* Most costs are median estimates for central station generation and are from the California Energy Commission.[12] Costs include federal tax credit offsets. Costs for smaller, distributed projects are higher than these estimates.

[12] http://www.energy.ca.gov/2009_energypolicy/documents/2009-08-25_workshop/presentations/04_Al_Alvarado_CEC.PDF

B. Project size eligibility

State goals, resources, and financial constraints should inform project size eligibility decisions. To date, unlike certain European FiTs, U.S. FiTs feature size limits (or lower overall caps), including the examples below:

Vermont: 2.2 MW[13]
Hawaii: 5 MW limit on Oahu and 2.72 MW on Maui and the Big Island[14]
California: 3 MW[15]
Gainesville: No size limit but 4 MW annual cap[16]
Sacramento: 5 MW[17]
Oregon: 500 kW[18]

1. The case for including large generators

Large generators feature lower levelized costs than do small generators due to component-cost, production-efficiency, and installation-cost economies of scale. For example, large wind farms feature much lower levelized costs than do small, individual wind turbines.[19] Additionally, certain technologies, such as concentrated solar and geothermal, are either not cost-

13 http://psb.vermont.gov/sites/psb/files/docket/7523/7523_interim_price_order.pdf. Page 36.

14 Hawaii PUC September 22, 2009 Decision and Order in Docket 2008-0273. See page 22.

15 http://leginfo.ca.gov/pub/09-10/bill/sen/sb_0001-0050/sb_32_bill_20090915_enrolled.pdf

16 http://www.renewableenergyworld.com/rea/news/article/2009/02/gainesville-solar-feed-in-tariff-a-done-deal

17 http://www.smud.org/en/community-environment/solar-renewables/pages/feed-in-tariff.aspx

18 Oregon House Bill 30309 http://www.leg.state.or.us/09reg/measpdf/hb3000.dir/hb3039.en.pdf

19 "Wind Energy, Surprisingly to Some, Has Economies of Scale Too." Matthew L. Wald, *The New York Times*, March 8, 2008. http://www.nytimes.com/2007/03/08/business/worldbusiness/08iht-energy.4848576.html

effective or not technologically feasible at small sizes.[20] Finally, absent a cap, offering FiT eligibility to large projects maximizes the total renewable energy development and project diversity.

2. The case for limiting the FiT to small generators

Due to inherent rate-setting imprecision and variations in costs and performance, FiTs compensate some projects more than they need to enter the market. Such imprecision could run in the tens of millions of dollars for projects in the hundreds of megawatts. Consequently, policymakers should consider limiting such costs by requiring larger projects to apply for PPAs via competitive solicitations. Further, one of the strengths of FiTs is that they can streamline the process of obtaining both contracts with the utility and interconnection because they feature standardized rates, terms, and conditions. Large projects often cannot use this streamlined interconnection process when they require extensive reliability investigations and potentially transmission upgrades prior to interconnection.

For capped FiTs, a small number of large projects could consume the entire cap. Such lack of project diversity would negate another FiT benefit—economic development stemming from numerous projects. A large number of small- to medium-sized projects can better sustain a diverse local industry than several large projects, which could necessitate the use of companies from outside the state, rather than local firms, to develop projects. Thus, limiting a capped FiT to smaller projects renders economic development benefits to the state more likely.

Recommendation: Particularly for FiTs that include high-cost technologies, do not initially include large projects. As long as the levelized cost of solar (and its corresponding FiT price) substantially exceeds the wholesale price of electricity, unless states seek to become a center for solar development and manufacturing, FiTs should exclude large solar (or other high-cost technology) projects. Exclusion of large projects prevents locking in high costs for ratepayers and encourages project diversity for capped FiTs.

C. Existing project eligibility

Developers in some jurisdictions, such as Hawaii, have sought the option to convert existing projects to FiT rates, claiming that such an option puts everyone on a level playing field. Such transfers should not be a major issue because costs and thus rates for most renewables continue to fall.

Recommendation: Do not allow the conversion of existing projects to FiTs, which increases ratepayer costs without increasing the amount of renewable energy generation. Prior to the FiT, project owners developed based upon the existing market prices and programs. They presumably determined that such prices were sufficient.

In states where legislatures include default statutory rates for FiTs, policymakers could differentiate between projects that sought permitting approval after the statute authorizing the

[20] See Sopogy March 31, 2009 Final Statement of Position in Hawaii FiT Docket No. 2008-0273.

FiT was enacted, but prior to the implementation of the statute. In such cases, developers can learn, through the legislatively set rates, of potential general program design and rates.

D. Caps

FiT rate-setting is inherently imprecise. For example, wind generation component costs increased during 2008, when developers tried to finish projects before the expiration of the Production Tax Credit (since extended), and have subsequently fallen due to increased manufacturing capacity and the global recession. Policymakers would likely not have predicted such cost swings. Similarly, solar module prices have fallen (leading Germany to reduce its FiT digression for PV solar), but some fear that a coming shortage of key materials like polysilicon could increase prices in the future.[21] Similarly, energy production improves with technological advances and interconnection costs can change with the addition of more projects. Policymakers cannot predict all these trends. A fine line exists between a FiT that is too low to elicit any activity and one that produces a gold rush because rates are particularly generous, as was the case in Vermont and Spain.

As discussed in Section I, in the short term, FiTs, especially if they support high-cost technologies, will likely increase cost to ratepayers. Particularly given the aforementioned cost and performance uncertainty, where policymakers want to limit the initial bill increases, they can cap total capacity or costs. Caps can also render the output of the FiT, in terms of energy production, costs, and reliability consequences, more predictable, assisting in integrated resource planning.

Project developers need time and resources to identify potential projects and apply for the FiT. Caps increase the risk that developers could incur predevelopment expenses but not receive FiT compensation. Caps could also bias the FiT in favor of technologies or project sizes that can be readily developed. Policymakers can mitigate these concerns through the implementation of a transparent queuing process and technology or size-specific carve-outs.

1. Cost-based versus capacity-based caps

Cost-based caps provide cost certainty but feature more administrative burdens than do capacity-based caps. To determine how much a given project counts against the cap, program administrators must estimate the production of each project technology and multiply it by the corresponding rate. Most renewable energy technologies feature high production variability, causing such calculations to be imprecise.

Where policymakers implement cost-based caps, they could consider defining cost not in absolute terms but as cost above avoided cost in order to limit *cost increases* (“subsidies”) compared to conventional alternatives. Such an approach would require establishing a baseline cost, presumably corresponding with the current or historic average wholesale electricity cost (or some other variation on avoided cost, such as long-run marginal cost), and count against the cap only costs in excess of this figure.

[21] http://seekingalpha.com/article/30022-how-the-polysilicon-shortage-affects-solar-energy-stocks

Capacity-based caps. Most capped FiTs, including Hawaii's, Vermont's, and Gainesville's, feature capacity caps. Developers in Hawaii favored capacity-based caps over cost-based caps, citing perceived better predictability of the former over the latter, which would require them to predict not only the quantity of development, but how much of it would be taken by various technologies (which have different rates).

Where FiTs contain multiple technologies, capacity caps do not provide certainty for the amount of energy produced, as capacity factors vary substantially by technology. For instance, biomass facilities can feature capacity factors in excess of 80 percent, while few solar PV generators exceed 15 percent. Theoretically, a FiT could include a production- rather than capacity-based cap, though this would create additional uncertainty for investors and administrative complexity for program administrators.

Due to variations in project size, uncertainty could arise regarding the last project to be eligible under the cap. For example, if a program has a 50-MW capacity-based cap and there are currently 49 MW in the queue, a decision has to be made as to which project is eligible to enter the queue. Under a hard cap, projects with a capacity greater than one MW could not enter the queue, while a later-filed project with a capacity of exactly one MW could enter. Under a soft cap, the next filed project could enter the queue, even if it has a capacity greater than one MW, provided that there is a programmatic limit to the size of individual projects. Such soft caps provide increased administrative efficiency and reduce developer risk.[22]

Recommendation: Utilize capacity-based caps due to their simplicity and relative predictability for developers.

[22] The statute creating Vermont's FiT states that contracts are available until the cumulative "capacity equals or exceeds" 50 MW. 30 V.S.A. § 8005(b)(2). The Vermont Public Service Board interpreted this language as providing a soft cap on the program and allowing a cumulative capacity greater than 50 MW. *See* Vermont Public Service Board Docket No. 7533, Order of 9/30/09 at 9-10.

U.S. examples of FiT caps:

Hawaii: 5% of 2008 peak demand total over 3-yr period[23]
Vermont: 50 MW total[24]
California: Statewide cap of 750 MW total[25]
Wisconsin: 300 kW for Wisconsin Public Service, and 683 kW for Wisconsin Power and Light total[26]
Sacramento Municipal Utility District: 100 MW[27]
City of Gainesville, Florida: 4 MW for year[28]
Oregon: 25 MW[29]

2. Cap period

Caps could feature annual limits or extend over a longer period. Annual caps limit the pace of development, preventing the explosion of development (and cost) elicited by some FiTs (such as Gainesville's, which is fully subscribed through 2015).[30] Annual caps, however, create uncertainty for developers, based on the short time before the cap fills that they have to design and submit applications. Further, annual caps initially bias the FiT towards technologies, such as solar PV, that are relatively simple to design. With annual caps, if rates are too high, policymakers will see a frenzy of activity in that first year and could downwardly adjust rates

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23 Hawaii's PUC September 22, 2009 Decision and Order in Docket 2008-0273. Page 55.

24 http://www.leg.state.vt.us/statutes/fullchapter.cfm?Title=30&Chapter=089

25 http://leginfo.ca.gov/pub/09-10/bill/sen/sb_0001-0050/sb_32_bill_20090915_enrolled.pdf. Page 4

26 http://www.wind-works.org/FeedLaws/USA/WisconsinPSCapprovesFITforPV.html

27 http://www.smud.org/en/news/documents/09archive/07-17-09_smud_feed-in-tariff.pdf

28 http://www.gainesville.com/article/20090206/ARTICLES/902061014?Title=Commission-gives-its-approval-to-feed-in-tariff-for-solar-power

29 Oregon House Bill 30309 http://www.leg.state.or.us/09reg/measpdf/hb3000.dir/hb3039.en.pdf

30 http://www.grist.org/article/2009-08-13-north-american-feed-in-tariff-policies-take-off

before locking consumers into too many long-term contracts. Conversely, longer caps enable developers to more carefully plan and evaluate potential projects, presumably improving project quality and likelihood of completion.

Recommendation: Match the cap period with the period prior to the first periodic program review, discussed in Section V.A. We recommend conducting such reviews every two to three years, as a middle ground between annual and very long cap periods. Implement annual caps only where the FiT contains technologies with especially uncertain costs, leading to FiT rates that are potentially much higher than necessary by the end of a longer period.

3. Carve-outs

Policymakers seeking to ensure the development of specific technologies or project sizes can create carve-outs in the cap. For instance, Hawaii, which seeks development of distributed generation, reserved five percent of its cap for projects under 20 kW.[31] This practice mirrors the carve-outs in certain state RPS policies, some of which reserve space for biomass or solar energy.[32] Where the carve-outs apply to high-cost technologies or project sizes, though, they can raise the FiT's cost.

Conversely, policymakers can limit the percentage or total capacity of particular technologies. For example, Vermont limited any one technology from occupying more than 25% of the application queue. In establishing this limitation, the Vermont Public Service Board determined that the enabling statute specifically envisioned multiple technologies participating in the program and also cited the different benefits that different technologies provide to the electric system.[33] Policymakers should employ maximum development levels for specific technologies where they want to ensure technological diversity or prevent a high-cost technology from comprising the bulk of the cap.

Recommendation: Where cost minimization is a priority, create maximum limits for high-cost technologies. To ensure the development of a specific technology or of distributed generation, create carve-outs for those technologies. To ensure project diversity, employ limitations for all technologies. Barring the dominance of any one of these priorities, we recommend not employing carve-outs.

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[31] Page 57 of the Hawaii Utilities Commission's September 25, 2009 Decision and Order in Docket 2008-0273.

[32] Maryland, Washington, D.C., and Delaware are among states with such RPS carve-outs.

[33] Vermont Public Service Board Docket No. 7533, Order of 9/30/09 at 11-16.

III. Set Rates

After determining program parameters, policymakers can set rates. This section describes the two primary forms of compensation from FiT rates.

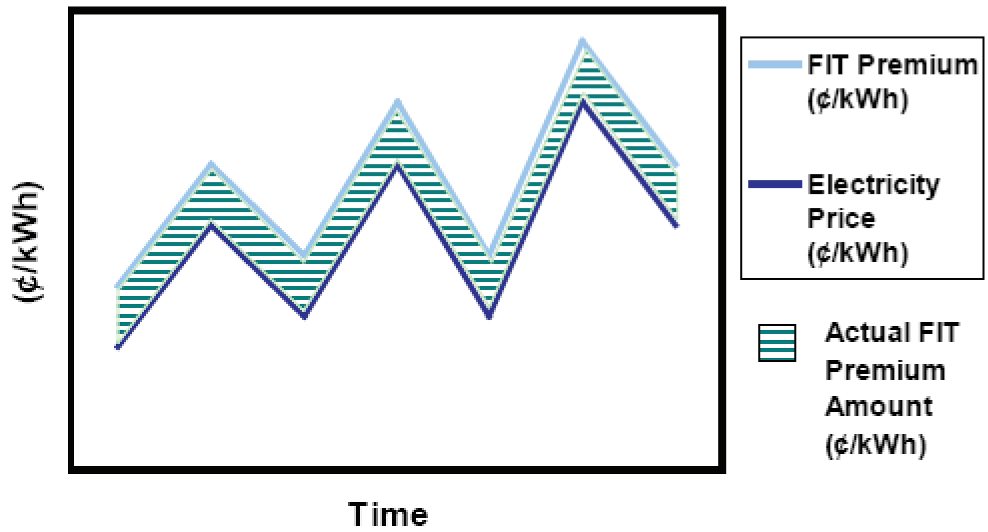
A. Rate types: Avoided-cost/market- and cost-based rates

Avoided-cost/market rates. Avoided-cost FiTs require utilities to compensate projects based upon the cost that the utility would otherwise pay. Such rates reflect market conditions such as demand, the need for additional capacity, and the price of displaced fuel. Avoided-cost rates could also consider the costs of carbon legislation compliance or externalities, such as avoided pollution or environmental degradation. Utilities have offered avoided-cost rates to qualifying facilities in compliance with the Public Utilities Regulatory Policy Act of 1978. Rates equal to the utility's avoided cost render ratepayers indifferent to whether the utility buys from the non-utility generator.

Premium price rates—a variation of avoided-cost rates—provide the avoided-cost rate plus a premium for the avoided negative externalities of conventional fuels. Rates thus exceed those offered for conventional wholesale electricity. Spain's initial FiT provided the choice between this type of market-based rates and stable cost-based rates. At first, virtually all participants chose the latter, but when electricity rates increased they chose the former, at great cost to consumers, such that Spain modified its FiT to reduce potential windfalls.[34] Such FiTs provide more opportunity than fixed rates for project owners to earn substantial returns. They do not, however, provide ratepayers or developers with cost certainty. The following image from the National Renewable Energy Laboratory depicts market-based rates that include a premium.[35]

[34] *The Application of Feed-in Tariffs and Other Incentives to Promote Renewable Energy in Colorado*, Brent Burgie and Kelly Crandall, 2009, pp. 8 and 9.

[35] "FiT Policy: Design, Implementation, and RPS Policy Interactions." Karlynn Cory, Toby Couture, and Claire Kreycik, March 2009, National Renewable Energy Laboratory.



Fixed Rates. Most FiTs feature fixed rates that compensate project owners for fixed and variable costs over their projects' lives and provide a reasonable return. Thus, in addition to costs and production, such rates must consider the term duration, discussed in Section IV.A. These cost-based tariffs, sometimes referred to as "project-based tariffs," provide revenue and cost predictability for developers, utilities, and consumers. Studies have shown that this predictability reduces financing costs, lowering overall costs.[36] Such rates also create an upside for consumers: in the future, the rates paid for existing FiT generation could fall below that paid for conventional generation if wholesale electricity costs increase. Setting rates that elicit development but do not overpay for it, however, has proven difficult, often resulting in programs that elicit little response if rates are too low or immediately fully subscribe if rates are too generous.

Hybrids between market-based and cost-based FiTs also exist. Such rates vary with market prices but contain floors and/or ceilings to prevent insufficient or excessive returns to project owners. They provide some measure of cost or compensation certainty for developers and/or customers. The below image from NREL depicts a FiT with a price ceiling.

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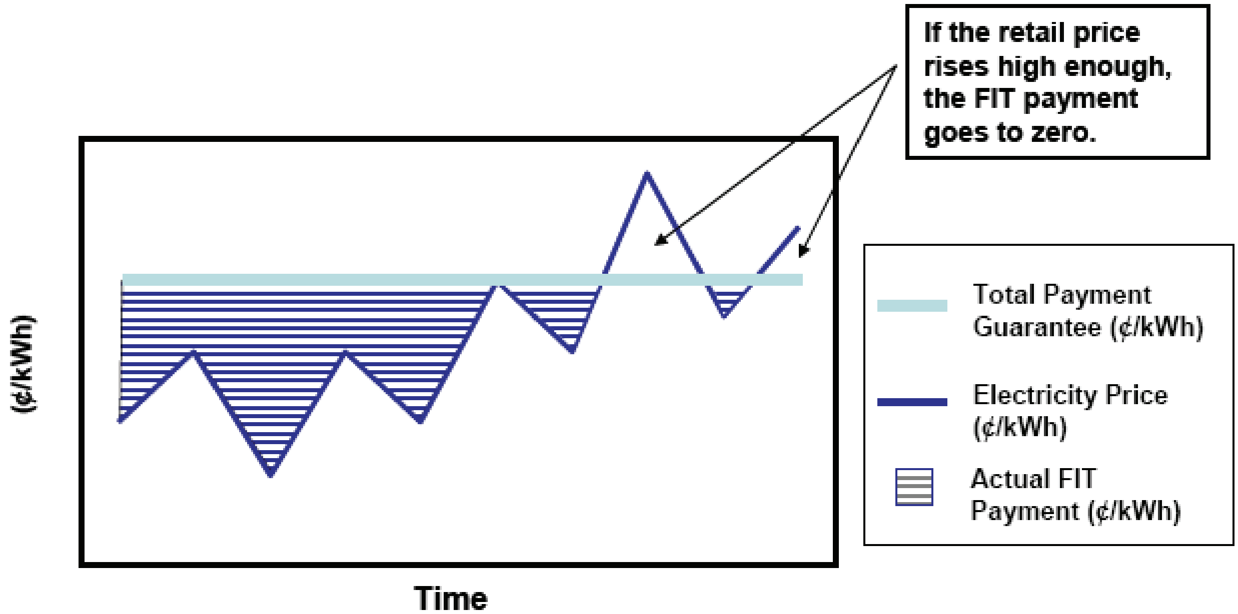
[36] de Jager, D., Rathmann, M. (2008). "Policy Instrument Design to Reduce Financing Costs in Renewable Energy Technology Projects." ECOFYS, Commissioned by the International Energy Agency – Renewable Energy Technology Deployment, Utrecht, October 2008. Accessed at http://www.iea-retd.org/files/RETD_PID0810_Main.pdf



Recommendation: Adopt cost-based rates because of the certainty they provide to developers, utilities, and customers. Pinning FiT rates to wholesale electricity costs, even with a premium, can lead to little development when electricity prices are low or excessive compensation when electricity prices are high.

The remainder of this section discusses setting cost-based rates.

B. How cost-effective do eligible projects need to be?

Before examining elements of rates or calculation methodologies, policymakers, based on their goals and cost constraints, should determine cost-effectiveness standards. This decision will inform which data they use to set rates. Where policymakers want to limit costs, they can set rates to cover the cost and provide a reasonable return for *only the most cost-effective* projects. Such rates would assume limited interconnection costs paid by the developer, as well as low component and installation costs and high performance. They would also assume use of all available tax incentives, rebates, or grants. FiTs that provide compensation sufficient for only the most cost-effective projects will likely elicit limited development.

At the other extreme, where policymakers want to encourage rapid development, they can set rates to accommodate *most* projects. While such rates would cause higher resulting customer costs, proponents would argue that they increase the development speed. Supporters of generous renewable programs also extol the resulting increased likelihood of the state becoming an industry hub. Generous rates could cause a public backlash when rates increase.

Recommendation: Design rates that accommodate projects with *typical or average* cost and performance for a given geographic area. Where possible, use data from existing projects to establish such an average. Aside from moderating between the two above extremes, this standard enables the use of more data, some of which is expressed in averages, when setting rates.

C. Rate components

Policymakers should examine the following elements to calculate rates.

1. Rate of return

Opinions on the appropriate implicit rate of return vary, with some developers asking for returns at or above the utility's regulated rate of return and other parties pointing out low risks in certain respects as justifying lower returns. Some FiT rates approximate utility returns. Ontario, for instance, offers an after-tax return on equity of 11%, typical of that allowed for utilities.[37] So long as the utility counterparty possesses strong credit ratings, there is very little risk on the part of the developer; multi-utility FiTs in which a state-sanctioned entity is the counterparty entail even less risk. Newer technologies such as offshore wind feature a higher performance risk that the technology will not produce the anticipated amounts than do established technologies. Thus, their investors require higher returns.

Overall returns include the cost of equity and debt. The level of debt and required return differ by project size. Owners of residential projects are less likely than owners of large projects to access debt, particularly long-term debt, which lowers the overall return.

Recommendation: Base the return on equity on the regulated return provided to the utility so as not to create a bias in favor of utility-owned or FiT projects. If required returns diverge for different technologies, increase returns for high-risk technologies. Examine differences in the ability of variously sized projects to access debt markets, as larger projects or those using more established technologies could receive debt financing on more favorable terms.

2. Cost and performance data

Policymakers should examine several types of cost data. First, they should seek cost and performance information from developers of local projects. Developers possess intimate knowledge of the costs of development and maintenance, as well as production figures and the ability to utilize tax credits, rebates, or loans. In some cases, developers have proven unwilling to divulge specific cost data, perhaps for fear that it would harm their negotiation positions when negotiating PPAs with utilities. Policymakers could request their data and indicate that the FiT will feature conservatively low rates if developers do not divulge cost and performance data.

Next, gather data from state or national databases and research institutions. Policymakers should examine whether costs and performance in their state match those of the states the data comes from and make adjustments if needed. Where possible, examine data from nearby states whose costs and performance data are most likely to be similar. For example, in setting its interim FiT rates for solar resources, Vermont relied to a large extent on data from the

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37 http://fit.powerauthority.on.ca/Page.asp?PageID=834&ContentID=10510&SiteNodeID=1126

Massachusetts Technology Collaborative.[38] Recognize, however, that historic data might not reflect current trends, such as market decreases in solar PV costs, necessitating certain adjustments.[39] Below are several publicly available sources of renewable energy cost and performance information[40]:

1. The California Solar Initiative has kept records of participant project costs, which could inform PV costs.

2. The California Energy Commission and Cornell University have reviewed anaerobic digester biomass facilities, thereby shedding light on costs and performance.[41, 42]

3. The National Renewable Energy Laboratories has created tools to estimate the levelized costs of wind generation.[43] The American Wind Energy Association (AWEA) also provides cost estimates, though policymakers should recognize AWEA's bias as a trade association.[44] The Department of Energy has examined wind energy costs as well.[45]

4. The National Renewable Energy Laboratory offers the PV Watts Calculator, which provides estimated PV solar production in hundreds of U.S. locations.[46]

5. The California Energy Commission has examined the costs of biomass and concentrated solar technologies.[47]

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[38] Massachusetts Technology Collaborative (2009). Commonwealth Solar – Information on Installers and Costs. Available online at http://www.masstech.org/SOLAR/CSInstallerCostLocationData.xls.

[39] *See* Vermont Public Service Board Docket 7523, Order of 9/15/09 at 30-31.

[40] The NRRI *Knowledge Communities* Feed-in Tariff community features numerous web resources and documents with cost and performance data. See http://communities.nrri.org/web/electricity-feed-in-tariffs/community-home-and-charter

[41] http://www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-500-2009-058

[42] http://www.manuremanagement.cornell.edu/

[43] http://www.nrel.gov/wind/coe.html

[44] http://www.awea.org/faq/cost.html

[45] "Annual Report on US Wind Power Installation, Cost and Performance Trends: 2007." http://eetd.lbl.gov/ea/EMP/reports/lbnl-275e-ppt.pdf

[46] http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version2/

Where few or no existing projects of a given type exist in a state, rates from other FiTs can help bound the reasonableness of rates. Such comparisons are not always apples-to-apples, though. Project costs and performance vary by location, as do tax credits, rebates, and REC values. When using rates from other jurisdictions, also consider differences in FiT program goals and priorities, which dictate cost-effectiveness standards.

Recommendation: Use developer information where possible. Next, use national data—particularly large government databases and data from nearby states. Because cost, performance, and cost offsets vary by location, do not base rates on those offered by other FiTs. Rather, compare proposed rates to those of other FiTs, to assess their reasonableness. Where proposed rates vary markedly from those offered in other FiTs, assess (a) the cost and performance differences between locations and (b) the level of development for the technologies in question elicited by the other FiT.

3. Interconnection costs

Interconnection costs can vary substantially between projects, particularly where the grid features limited spare transmission capacity. These costs could either (a) lead to unacceptably high ratepayer costs or (b) cause rates to be insufficient or overly generous for many projects. Policymakers should clearly define which interconnection costs developers and utilities must bear and include developer costs in rate calculations.

In addition to defining what interconnection costs rates include, policymakers can employ cost/benefit analyses to ensure reasonable interconnection costs. For example, The Ontario Power Authority included the following language in its FiT:

> "The economic connection test determines whether the costs of the required grid upgrades to allow reasonable generation to connect are justifiable and can be included in grid expansion plans.
>
> The OPA will perform the test for transmission expansions and will consider:
>
> - Network facility reinforcements
> - Connection facility reinforcements
> - Enabler facilities"[48]

The OPA has not specified how it intends to conduct such cost/benefit analyses.

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[47] http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-16_workshop/presentations/Alvarado_Intro_to_COG_Project.pdf

[48] Ontario Power Authority "FiT Program, Program Overview v. 1.1," http://fit.powerauthority.on.ca/Storage/97/10759_FIT-Program-Overview_v1.1.pdf

Recommendation: Given the large variation in potential interconnection costs, any estimate included in rates could result in substantial overpayments to project developers or in rates that are insufficient to support the development of all but the best-sited projects. As such, we support requiring utilities to pay for (and capitalize) all interconnection costs on both sides of the interconnection up to a typical amount determined in advance for each project size and technology. Project owners would bear any interconnection costs above this level. Rate calculations would not assume any interconnection costs. This policy would (a) not force ratepayers to fund high interconnection costs, and (b) not provide excessive returns to projects with low interconnection costs. It would also provide utilities with a benefit of the FiT from an increased rate base.

4. Cost offsets – State and federal tax credits, rebates, grants, RECs, and carbon credits

As discussed in Section I, FiTs should complement other renewable energy programs. FiT policymakers should consider the financial consequences of such programs when determining rates. Policymakers should consider the following questions:

What portion of project owners could utilize the benefit?

Is the size of the benefit predictable?

a. Renewable energy credits/green attributes

As discussed in Section I.C, many states feature RPSs where load-serving entities can fulfill their obligations by obtaining tradable RECs. Regional or national carbon policies could feature tradable credits, such as those used in the Regional Greenhouse Gas Initiative in the Northeast.[49] Project developers can also sell voluntary RECs, primarily to corporations wanting to publicly reduce their carbon footprint; voluntary renewable energy credits feature low prices.[50]

Through FiTs, consumers pay rates that, at least in the short term, exceed the wholesale market rates for electricity, in order to support renewable energy. Thus consumers, via their utilities, already pay for the green attributes. To avoid having consumers pay for the RECs twice—and giving excessive returns to developers—policymakers can build estimated REC values into rates as cost offsets or confer them to the purchasing utilities. The ongoing evolution of such markets (and a national carbon policy), however, renders value estimation difficult. In addition, new markets for environmental attributes could develop over the FiT contract term.

Recommendation: Provide all RECs, carbon credits, or any other green attributes including any future transferable commodities attributable to the generation of electricity from the plant, to the utility.

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[49] http://www.rggi.org/home

[50] http://new.evomarkets.com/pdf_documents/November%20REC%20Markets%20Update.pdf

b. State, local, or utility tax credits, grants, rebates, and loan guarantees

Optimal treatment of tax benefits, rebates, grants, and loan guarantees depends on whether the size and eligibility for these programs matches those of the FiT.

Recommendation: Where FiT eligibility and caps match those of tax credits, grants, rebates, and loan guarantees, and benefit sizes are predictable (some grant programs provide variable grant sizes), assume use of these programs and build them into rates as cost offsets or offer separate rates for projects that do and do not use them. Render them mutually exclusive if the size of benefits is uncertain or if you value maximizing policy simplicity. In most cases, where the benefits are local (e.g., county tax benefits) and do not cover the entire utility service territory, render using such benefits exclusive to the FiT or provide separate rates, favoring the latter if a large share of the utility's customers are eligible for benefits.

c. Accelerated depreciation

Renewable energy projects can utilize Modified Accelerated Cost Recovery System (MACRS) accelerated depreciation for federal taxes.[51] For tax purposes, project owners can write off their projects over five years, far faster than the useful life of the project. In the past, tax-equity investors monetized the value of this timing differential by absorbing losses to offset taxable earnings from other sources. For tax years 2008 and 2009, the poor economy shrunk the pool of investors able to use this benefit.

Recommendation: As of the writing of this paper, do not consider accelerated depreciation in rate calculations because few investors can use them at this point in time. When reexamining rates, determine whether most investors can monetize accelerated depreciation. If they can do so, calculate the value of accelerated depreciation by using a discount rate equal to the rate of return to calculate the value of the timing difference benefit of accelerated depreciation and reduce the estimated cost of projects by this percentage. Incorporate this benefit only in calculations of rates for larger projects because residential customers typically do not use accelerated depreciation.

D. Granularity – Different rates based on project sizes, locations, or time of energy production

1. Differentiation by size

In addition to offering different rates for different technologies, many FiTs differentiate rates by project size. Such differentiation acknowledges economies of scale that reduce the levelized costs as projects get larger. Without such differentiation, either large projects would receive excessive compensation or rates would prove insufficient to support smaller projects. Size diversity is not an end in itself. Policymakers concerned chiefly with cost effectiveness could disregard the financial needs of smaller, more expensive projects. Those concerned with

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[51] http://www.dsireusa.org/documents/Incentives/US06F.htm

the economic benefits of project diversity or ensuring the development of small, distributed projects should, however, develop separate rates for large and small projects.

Recommendation: Where strict cost minimization is not the chief priority, differentiate rates by project size for each applicable technology. The size cut-offs should correspond, where possible, to differences in project type (*e.g.*, cutoffs between residential and commercial projects) and cost, as well as the availability of tax credits, rebates, or low-interest loans. For instance, most residential solar PV installations feature capacities of 10 kW or less.

Depending on the size of the program cap, if one is in place, we recommend initially using no more than four size tiers (two if the FiT covers only smaller projects) and perhaps adding tiers later. FiTs containing numerous size tiers, particularly in small states or for FiTs with modest caps, might not elicit enough activity in each size tier to indicate for future adjustments whether rates were high, low, or appropriate.

2. Differentiation by location

Different locations vary in resource quality and interconnection costs, and thus levelized cost. Policymakers can set different rates by resource quality. Germany awards the same incentive amount to all wind energy producers for the first five years. After five years, the government compares the individual turbine's output to a specified "reference" turbine operating with expected efficiency and conditions, and the FIT payment is adjusted to better match the actual performance of the wind resource at that area.[52]

Where all ratepayers over a wide geographic area bear FiT costs, for equity reasons, policymakers could use locational differentiation to ensure the wide distribution of economic development benefits. Locational differentiation also maximizes the total amount of viable locations and thus total development (assuming no cap) without providing excessive returns to projects in low-cost/high-performance locations. Consequently, policymakers who prioritize immediate development should consider locationally differentiated rates.

Locationally differentiated rates reduce the economic incentive for developers to locate projects where resources are best and costs are least. Much like rates for high-cost technologies, rates for high-cost locations increase total program costs. Locationally differentiated rates can also prove more difficult to set and adjust because there could be a shallow pool (if any) of projects of given size and technologies in each particular sub-region to provide information.

Recommendation: Do not initially differentiate rates by location. Doing so adds complexity to setting and adjusting rates and increases program costs. Only differentiate rates by location if the state's resources vary enough that, without such differentiation, large portions of the state would likely enjoy no renewable energy development *and* if policymakers value such geographic diversity of economic benefits more than cost minimization. Augment FiTs with

[52] Grace et al. "Exploring FiTs for California: FiT Design and Implementation Issues and Options." California Energy Commission, June 2008, p. 42.

such locational differentiation only after several years of FiT operation and data to inform levelized cost calculations for different locations.

3. Differentiation by time of energy production

FiTs can feature different rates based on the time of day or season of the year when the project produces electricity. Such rates reward projects that produce energy when it is most valuable. California's FiT features such differentiation.[53] Most renewable energy generators produce energy whenever their resource is available, however, so such incentives would not affect performance.[54] Additionally, such rates require advanced meters capable of recording the timing of energy production.

Time-differentiation suits avoided-cost, and not cost-based, rates. For avoided-cost FiTs, which do not aim to cover costs and provide a target return, rates should correlate to the actual value of electricity during different periods. Rates can use the same ratios for peak and off-peak periods as the ratios of peak and off-peak periods in time-of-use rates, if they are available. Such rates should already capture when electricity is most valuable. FiT rates could also track the real-time costs of electricity based on hourly day-ahead markets.

For cost-based rates, time differentiation complicates designing rates. Rate calculations would have to estimate when electricity would be produced, increasing imprecision.

Recommendation: Differentiate avoided-cost-based rates by production time to reflect the value of avoided energy production. Do not differentiate cost-based rates by production time because it either (a) provides excessive returns to generators that produce on peak or (b) requires the policymaker to predict when the project will operate to set rates that cover cost and provide a reasonable rate of return, increasing inaccuracy.

E. Rate adjustment mechanisms

Initial rates likely inaccurately reflect project costs and a reasonable return or will become inaccurate. Rates for new projects that stay the same for an extended period despite falling levelized costs would provide excessive compensation. Frequent resetting of rates, however, increases investor uncertainty and undermines the predictability that FiTs provide, as it takes time and resources to develop projects.

Several mechanisms, discussed below, can mitigate the potentially high returns that such cost declines cause and attempt to match rates with actual costs.

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[53] California SB 32. http://leginfo.ca.gov/pub/09-10/bill/sen/sb_0001-0050/sb_32_bill_20090915_enrolled.pdf

[54] Geothermal, biomass, and biogas generators, however, are dispatchable, so such peak-time rates could encourage more production during peak periods and less in off-peak periods (assuming they don't already run all the time).

1. Predetermined schedule of rate declines

FiTs can feature degression rates, whereby rates for new (not existing) projects fall by a certain percentage each year. Germany's FiT features such a provision. Between such reexaminations, rates fall for new projects of each technology each year by a predetermined percentage, which varies by technology, to reflect technology improvements. Where FiTs contain degressions, consider reevaluating degression rates periodically based on historic cost and performance trends. For instance, Germany's parliament in 2008 adjusted the feed-in tariff degression rates. Among other changes, it increased the degression rate for PV tariffs from approximately 6.5% annually to 10% annually in response to rapid PV growth under the 2004 law.[55]

This adjustment method encourages immediate development, as rates will fall. It also provides predictability for developers, who know what the rates will be years in advance. The degression rates prove inherently imprecise, however, because of the difficulty in predicting technological learning curves and other factors that affect price. Consequently, Germany's parliament not only adjusted the degression rates but reduced the solar PV FiT rate by another 15% in 2010. This move has proven highly contentious.[56]

2. Rate declines via triggers

Rates for new projects can also fall upon reaching predetermined trigger points. Though not a FiT, the California Solar Initiative (CSI) features this mechanism. The CSI's rebate sizes for each utility fall by a predetermined amount upon reaching installed capacity thresholds. The threshold levels and price declines appear well calibrated because the pace of development has been strong but relatively even over the two years of the program.[57] Below is California's schedule for each utility.[58]

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[55] "Revision of Germany's FiT in Process." June, 2008. http://renewenergy.wordpress.com/2008/06/06/revision-of-feed-in-tariff-in-germanys-in-progress/

[56] "German Solar FiT to Sink Another 15 Percent." http://www.renewableenergyfocus.com/view/6682/german-solar-feedin-tariff-to-sink-another-15/

[57] California Solar Initiative - California Public Utilities Commission, Staff Progress Report, October 2009. http://www.energy.ca.gov/2009publications/CPUC-1000-2009-033/CPUC-1000-2009-033.PDF

[58] http://www.csi-trigger.com/

Administrator	Customer Class *	Current Step	Initial MW in Step	Unused MW from Previous Steps	Revised Total MW in Step	Issued Conditional Reservation Letters (MW)	MW Remaining	MW Under Review
PGE	Residential	6	27.40	1.03	28.43	16.42	12.01	1.40
	Non-Residential	6	55.60	22.44	78.04	28.96	49.08	4.90
SCE	Residential	4	19.70	1.28	20.98	12.47	8.50	2.31
	Non-Residential	5	49.30	32.08	81.38	43.29	38.09	13.65
CCSE	Residential	6	6.50	0.08	6.58	2.90	3.68	0.32
	Non-Residential	6	13.10	0.47	13.57	6.55	7.02	2.39

		EPBB Payments (per Watt)			PBI Payments (per kWh)		
Step	Statewide MW in Step	Residential	Non-Residential		Residential	Non-Residential	
			Commercial	Government/ Nonprofit		Commercial	Government/ Nonprofit
1	50	n/a	n/a	n/a	n/a	n/a	n/a
2	70	$2.50	$2.50	$3.25	$0.39	$0.39	$0.50
3	100	$2.20	$2.20	$2.95	$0.34	$0.34	$0.46
4	130	$1.90	$1.90	$2.65	$0.26	$0.26	$0.37
5	160	$1.55	$1.55	$2.30	$0.22	$0.22	$0.32
6	190	$1.10	$1.10	$1.85	$0.15	$0.15	$0.26
7	215	$0.65	$0.65	$1.40	$0.09	$0.09	$0.19
8	250	$0.35	$0.35	$1.10	$0.05	$0.05	$0.15
9	285	$0.25	$0.25	$0.90	$0.03	$0.03	$0.12
10	350	$0.20	$0.20	$0.70	$0.03	$0.03	$0.10

Rates that fall with triggers somewhat negate the need to establish FiT caps to protect consumers. If rates fall steeply enough at high levels of development, either (a) renewable energy will become relatively inexpensive, and thus not substantially in excess of the cost of conventional generation; or (b) the market will slow or stop when rates get low enough, thereby limiting costs and offering policymakers the ability to readjust rates to the “sweet spot” of a moderate pace of development.

3. Rate inclines with caps

Another option that has been discussed but not utilized increases rates on a predetermined schedule.[59] For instance, rates could start out relatively low—to facilitate only the most cost-effective projects—and increase by 3% a month for the first year. Such a mechanism resembles a reverse auction. By raising rates in steps to induce project applications when they are first economically viable, this approach minimizes the excess profits of the least expensive projects. In doing so, this approach minimizes total costs.

Such a policy would work best for FiTs with a relatively small cap. Where the cap will likely be reached, developers would likely apply for the FiT as soon as the rate is sufficient. Conversely, where caps are large or absent, such an approach would encourage developers to wait as rates increase. Also, if costs decline over time, this approach would eventually lead to overly generous rates. Consequently, policymakers should reexamine rates after no more than two or three years and perhaps thereafter adopt constant or declining rates.

Recommendation: Where FiTs feature low to moderate caps, establish inclining rates to minimize costs by providing lower rates to low-cost projects, reducing total ratepayer costs. Rates can subsequently decline after the first periodic reexamination. Where programs lack caps or feature large caps, offer rates that decline based on predetermined triggers. Such an approach starts rates relatively high to ensure some development but prevents excess compensation for most projects. It also uses market mechanisms for price discovery, which could inform subsequent FiT updates.

F. The process of setting rates

Regulators or legislatures can craft FiT policies. The Hawaii PUC instigated an investigatory proceeding, provided a scoping paper with questions for parties, conducted a hearing, and invited comments and data from developers, the utility, and other parties. The parties also met informally to negotiate FiT terms and filed post-hearing briefs. In Vermont, the legislature, when establishing a FiT, specifically required that initial rates be set through a process that did not utilize contested case procedures (i.e., no *ex parte* restrictions, no requirement for notice, and opportunity for hearing). The Vermont Public Service Board developed a working group of interested stakeholders to develop a model and the necessary inputs to establish the initial rates. The Vermont legislation required that the rates be recalculated four months after the initial rates were adopted. In the subsequent proceedings, the Vermont PSB required that interested parties file testimony and be subject to cross examination under oath. We recommend crafting rates through regulatory bodies rather than legislatures, as the former possess greater familiarity with electric utility and energy matters and can instigate proceedings to gather data and analysis from parties.

[59] Haiku Design and Analysis Opening Brief in Hawaii Docket No. 2008-0273, June 12, 2009 at page 28.

1. Stakeholder meetings

Policymakers should engage a range of stakeholders, such as utilities, consumer groups, and developers, when crafting FiTs. Stakeholder input enables policymakers to understand varying stakeholder goals and needs and determine appropriate rates for cost-based FiTs. Policymakers should also understand the logistical, financial, and reliability concerns of utilities and address these to the extent possible. Engaging stakeholders can also mitigate customer backlash after resulting rate increases.

Recommendation: Allow submissions, public meetings, and hearings for developers and utilities to provide data and policy recommendations.

2. Use of third parties or utilities to determine rates

Many state commissions and legislatures lack the internal capacity or experience to gather data and calculate rates. The National Renewable Energy Laboratory is assisting several commissions in doing so. Certain consultants can also gather data and calculate levelized rates. Developers could prove more reluctant to divulge cost information to utilities than to commissions or third parties because giving information to utilities could harm their negotiation position for non-FiT PPAs.

Policymakers can also task utilities with gathering data and calculating rates. Hawaii took this approach, although it enabled other parties to comment on proposed rates and made final rates subject to PUC approval. The Vermont PSB was responsible for calculating rates, and utilized an outside technical expert to provide expert testimony on the development of the model and the assumptions used in the model.

Recommendation: Commissions or legislatures should calculate rates if possible. If they lack the internal staffing to do so, they should hire or require their utilities to hire third parties to gather data and calculate rates. Policymakers should still determine what factors rates should include (*e.g.*, inclusion or exclusion of tax incentives) and the overall shape of the FiT (*e.g.*, eligibility*)*.

3. Rate calculation techniques

a. Levelized rates

Cost-based rates attempt to cover project costs (both initial and ongoing) and provide a reasonable return on investment. Rates calculations must consider the time value of money. The discount rate used to calculate FiT rates could range from that of the historic inflation rate to the rate of return earned by the project.

Most FiTs feature levelized rates, which are the same each year of the term. Levelized rates, also common among power purchase agreements, provide a fixed revenue stream to project owners. Such payments align with fixed payments for loans that many developers assume. Black and Veatch developed a publicly available levelized cost model that allows users to toggle inputs such as maintenance cost and the discount rate.[60]

b. Inclining rates

Alternatively, rates can increase by a predetermined percentage each year. Such rates mirror certain PPAs that increase each year based on an inflation adjustment. Such rates would start lower than levelized rates and increase over time, ending at a higher rate than levelized rates would. This approach reduces the potential for initial rate increases. Non-levelized rates would also avoid the intergenerational inequity of levelized rates by increasing rates as the value of money decreases due to inflation.

Non-levelized rates, however, increase the complexity of setting rates. Additionally, they would provide lower revenues in the early years of project operations, potentially lengthening the time it takes for investors to reach target returns. Longer time frames needed to reach target returns could in turn make it more difficult for developers to secure equity investment or increase investors' required returns. Additionally, lower revenues early on could reduce the amount of debt that developers can assume by creating low cash flows during early years. Lower debt levels increase the overall cost of capital because the returns required by investors exceed debt interest rates.

c. Declining rates

Conversely, rates that initially exceed the levelized cost could decrease total costs. They would do so by increasing up-front payments, which would allow the assumption of more debt financing, which is less expensive than equity financing. Such rates would also reduce cost-recovery risk, potentially reducing investors' required return on equity; however, declining rates would raise initial ratepayer cost increases and exacerbate intergenerational inequity.

Recommendation: Offer levelized rates. Inclining rates could suit policymakers who are particularly concerned with short-term ratepayer consequences but could increase long-term costs and would increase financing complexity. Conversely, declining rates would encourage immediate development but increase up-front costs and place a large portion of the total costs of renewable energy for long durations on current customers.

[60] "RETI Documents, Report, and Other Files," California Energy Commission, http://www.energy.ca.gov/reti/documents/index.html

IV. Determine Terms and Conditions

A. Obligation term

Policymakers must determine FiTs' terms before calculating rates, so as to recover costs and provide a reasonable return over the FiT term. Ideally, the true life of each project would match its FiT term, providing the anticipated level of cost recovery and return. Shorter obligation terms lead to higher rates in order to cover all project costs and provide a reasonable return during the term. Terms exceeding the likely project life increase the risk that investors would not recover all of their costs and earn the anticipated return.

Many renewable energy technologies feature uncertain useful lives due to their novelty or changes over time, making such precision difficult. For example, off-shore wind generators did not exist 25 years ago and solar PV technologies have evolved. Additionally, wind turbines have grown larger over the past 25 years, leading to different operational and maintenance concerns. Where lifespan information is lacking, policymakers can match FiT obligation terms to typical PPA durations, provided there is some connection between the PPA duration and the expected life.

Each state's resources will also inform the appropriate term. For example, Vermont's FiT included shorter terms for landfill gas facilities because any new facilities would be located at closed landfills with limited methane production.[61]

Recommendation: For cost-based FiTs, align the obligation term with the expected project life. Where project life is uncertain, provide conservatively short terms to ensure that most projects will operate until the end of the obligation term. In such cases, consider a 15- or 20-year FiT.

B. Reporting requirements

Policymakers should require FiT participants to provide data to their utility or commission to enable administrators to effectively refine rates while avoiding unduly burdening participants. Such data includes costs and performance information. Policymakers could also require information on the utilization (and value) of rebates, tax incentives, and RECs in order to appropriately build them into rate calculations. Commissions can also aggregate the data to determine costs and performance in order to adjust rates in the next periodic reexamination. Such data can also reveal cost and performance trends and help calibrate any predetermined rate decreases, discussed in Section III.D.

Reporting requirements can differ for large and small projects. For instance, FiTs should require only large projects to annually report operations and maintenance expenditures or break

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[61] Vermont Public Service Board Docket 7533, Order of 1/15/10 at 88-89. (The only currently operating landfills in Vermont had developed landfill gas generation facilities prior to the establishment of Vermont's FiT.)

down the cost components of projects. Many owners of residential solar PV projects make one payment that includes numerous cost components or offsets, so they would not have such information. Substantial ongoing reporting requirements for small projects could burden owners and commissions due to the potentially large number of small projects.

Recommendation: Require large projects to report a range of information necessary to refine future FiT rates, but require limited information (overall costs, use of tax credits, and annual production) from projects of 20 kW or less—the typical maximum size for residential projects. Such cutoffs could differ by technology to accommodate different residential wind, biomass, or solar projects. The Appendix shows the reporting requirements of Hawaii's FiT.

C. Obligations of project owners

FiTs legally obligate utilities to offer tariffs containing specified terms and conditions. Policymakers should also consider placing obligations on project owners in order to maximize benefits to consumers and minimize uncertainty for utilities. Below are several potential project owner obligations.

1. Obligation to sell all power to the utility

Lack of obligation to continue selling all output to the utility for the duration of the FiT term favors project owners at the expense of ratepayers. With the exception of biofuel or biomass generators, renewable energy generators consume no fuel, rendering costs predictable for project owners and ratepayers. Consequently, such projects benefit ratepayers by hedging against fuel cost variability, though this hedge value exists only if project owners cannot opt out of long-term deals.

Electricity costs have increased over the past 30 years.[62] If they continue to rise, FiT rates could shift from exceeding to being lower than wholesale electricity prices, providing ratepayer savings. If, however, project owners can opt out of the FiT if market prices exceed the FiT rate, they would deny ratepayers such savings or cost certainty. Further, project owners would receive excessive returns—being subsidized by the FiT early and then receiving higher compensation through the market later.

Recommendation: Obligate project owners to sell all power produced by the facility to the utility for the duration of the FiT term. We do not recommend obligating them to sell a specific quantity of power, however. Such obligations would increase the consequences of technology underperformance—increasing project risk and thus requiring increased investor returns and lender interest rates. If a project produces less energy than expected, its owner suffers the financial consequences via decreased revenues.

2. Obligations after the term of the FiT

Policymakers should state in advance obligations after the FiT term. They can choose from several options:

[62] http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_a.html

No obligations. Neither party has any obligation to buy or sell. If the project is still operational, parties can negotiate a PPA or the owner can sell electricity to another party. This option provides flexibility but not predictability.

Option for project owner to continue selling at FiT rate. This option provides owners with the certainty of a minimum sale price but does not benefit ratepayers.

Option for utility to continue purchasing power at FiT rates. This option provides additional potential benefits to ratepayers if projects outlive the FiT term and wholesale electricity prices exceed their FiT rates. This option also benefits ratepayers by adding predictability to their utilities' resource planning because they would know the cost and availability of resources. The FiT rate encourages project owners to maintain their projects. If policymakers adopt this option, they should limit it to technologies whose costs are mainly up-front (solar, wind, geothermal, hydro) and not those whose costs are largely ongoing (biofuel and biomass), or allow inflation adjustments in the FiT rate for increases in operating or fuel costs.

Recommendation: Provide utilities with the option to continue purchasing power at FiT rates after the obligation term. If FiTs cover project costs and provide a reasonable return over their term, for renewable energy projects whose costs are mostly up-front, most additional sales revenues become earnings. Consequently, providing customers with additional upside beyond the term through such optionality would not result in project owners' failing to cover costs and earn a reasonable return. Allow inflation adjustments for biofuel or biomass projects or others with substantial operations and maintenance costs or exempt them from this utility option.

Stipulate that the utility must decide if it will continue purchasing power from the project at FiT rates at least six months prior to the end of the term. Such a requirement provides project owners with a chance to negotiate new rates with the utility or another buyer prior to the end of the FiT if the utility does not exercise this option.

3. Notice to cease operations

Many PPAs contain stipulations, and in some cases penalties, for failure to deliver energy. Sudden interruptions in electricity supply, even if intermittent, can cause additional costs or reliability problems for utilities. As such, utilities should receive some notice to plan for the ceasing of operations of large FiT generators.

Because initial capital costs, rather than fuel or ongoing operating expenses, compose the bulk of total costs for most renewable energy projects, projects would not, in most cases, cease operation barring catastrophic events, even if the owners fail to recover all of their initial costs. If the rates prove insufficient for a given project, owners would more be likely to sell it at a loss or suffer a poor return on investment than mothball the generator. The possible exceptions include biofuel and biomass projects, which could mothball due to fuel costs or availability.

Recommendation: For large projects (exceeding 500 kW), require owners to give six months' notice before ceasing power production, subject to financial penalties. Such provisions should include an exception for non-insurable catastrophic events or technology failure. This provision should not apply to small project owners (those or 20 kW or less), as such a provision could unduly burden small project owners, such as residential solar PV owners, while providing relatively little value for utilities.

D. Utility obligation to maintain reliability

An FiT should obligate the utility to interconnect eligible projects where it can do so without harming reliability. The utility, and in some cases the RTO, legally must maintain reliability. Certain states have also placed stipulations on project eligibility based on project usefulness to the system or lack of reliability detriments. Accordingly, California's 2009 FiT legislation restricted project eligibility to those that "[are] strategically located and interconnected to the electrical transmission and distribution grid in a manner that optimizes the deliverability of electricity generated by the facility to load centers." [63]

The same legislation describes the rights and obligations of the utility and project owner with respect to reliability:

> (n) An electrical corporation may deny a tariff request pursuant to this section if the electrical corporation makes any of the following findings:
> (1) The electric generation facility does not meet the requirements of this section.
> (2) The transmission or distribution grid that would serve as the point of interconnection is inadequate.
> (3) The electric generation facility does not meet all applicable state and local laws and building standards, and utility interconnection requirements.
> (4) The aggregate of all electric generating facilities on a distribution circuit would adversely impact utility operation and load restoration efforts of the distribution system.
> (o) Upon receiving a notice of denial from an electrical corporation, the owner or operator of the electric generation facility denied a tariff pursuant to this section shall have the right to appeal that decision to the commission.
> (p) In order to ensure the safety and reliability of electric generation facilities, the owner of an electric generation facility receiving a tariff pursuant to this section shall provide an inspection and maintenance report to the electrical corporation at least once every other year. The inspection and maintenance report shall be prepared at the owner's or operator's expense by a California licensed contractor who is not the owner or operator of the electric generation facility. A California licensed electrician shall perform the inspection of the electrical portion of the generation facility.

Recommendation: Require that the utility determine whether projects unduly harm reliability and, if necessary, refuse to interconnect projects that would cause unacceptable reliability risks.

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[63] California SB 32 at page 14. http://info.sen.ca.gov/pub/09-10/bill/sen/sb_0001-0050/sb_32_bill_20090915_enrolled.pdf

Policymakers should also avoid situations in which ratepayers must fund expensive radial transmission lines, substations, or other upgrades to accommodate single projects without harming reliability. To the extent possible, create standards for such evaluations prior to the start of the FiT to minimize additional risk for developers or the possibility of undue discrimination by utilities. Ensure that this process is transparent, potentially including an independent observer. Also require the utility to file with the commission the specific reasons for rejections or modification requirements.

Technically, with enough system upgrades any project could connect to the system without harming reliability. Policymakers should, however, allow utilities, subject to challenge, the discretion to rule out projects that would entail excessive ratepayer costs due to high interconnections costs, if they are borne by ratepayers and not project owners. As we discussed in Section III.C.3, utilities could fund only interconnection costs up to a predetermined amount, negating the need for such judgments by utilities.

V. Administer Program

Policymakers should balance providing program flexibility and predictability. They should define up-front program administration parameters, including the following.

A. Periodic reviews

Policymakers should periodically modify FiTs to accommodate changes in costs or other policies and to change eligibility or other terms based on additional information.

1. Subjects for modification

Eligibility: As technology costs decrease, performance improves, and utilities learn how to integrate new technologies, policymakers should consider expanding eligibility to additional technologies. Also consider expanding project size eligibility. Although costs vary somewhat based on project size, as costs become more certain the potential downside (paying unacceptably high costs) diminishes. We recommend starting with a modest group of eligible sizes and technologies to evaluate and expanding that group during the periodic reexaminations.

Rates: Examine the cost and performance information submitted by projects, as well as trends in costs and performance, and modify rates accordingly. Also examine the use of tax incentives, rebates, and loan programs to recalculate rates. If the FiT contains degressions, evaluate whether rates still correlate to industry experience and future expectations for cost reductions. For FiTs with triggers for rate declines, consider readjusting the size of the declines or triggering events based on new information and analysis.

Locational differentiation: Reported data from FiT projects could facilitate more accurate rate differentiation by location.

Terms and conditions: Update the FiT terms and conditions based on new information, such as data on expected project life. Consider modifying reporting requirements and other obligations, such as the level of required insurance, based on utility and developer comments.

2. Reexamination frequency

Reexaminations should balance FiT flexibility and predictability. Frequent reexaminations increase the risk that developers might spend money investigating and planning a project based on one set of assumptions, only to see rates change, potentially rendering their project unviable. Frequent reexaminations also consume the time and resources of policymakers, utilities, and developers. At the same time, FiTs should feature adjustments frequent enough to ensure that rates are just and reasonable.

Recommendation: Conduct an initial reexamination after two or three years and subsequent reexaminations every three years. Consider a shorter period before the initial

re-examination than between subsequent reexaminations to adjust for initial rate inaccuracies or other program suboptimalities. Match any cap duration with the date of the expected final order or legislation from the periodic reexaminations. States concerned with cost minimization should consider more frequent reexaminations.

3. Reexamination process

We recommend that policymakers determine the reexamination process in advance so that parties can prepare to participate constructively. Make this process public and transparent so that interested stakeholders understand, and can comment on, any possible changes. Here is one such process:

1. Provide aggregated data provided by FiT participants to parties.

2. Allow parties to submit filings describing any suggested modifications to eligibility, rates, or terms and conditions.

3. If suggested changes are large and the record needs to be further enhanced, or if policymakers are independently weighing substantial specific changes, hold public meetings or a hearing.

4. Calculate new rates, if needed, by using transparent formulas.

B. Queuing procedures

FiTs, because they can offer higher rates, reduce uncertainty, and eliminate the costs of negotiating terms and rates with utilities, can elicit a large number of project applicants. Even without FiTs, certain regions such as the Midwest have large queues of projects waiting to interconnect. The waits result from several factors, including an explosion in the number of proposed wind projects, insufficient utility or RTO staff to review projects, interconnection cost allocation procedures, the time needed to build transmission system upgrades, and "phantom" projects dropping out of the queues. In 2008 FERC ordered RTOs to develop new queuing and interconnection procedures. States (particularly those outside of RTOs), considering FiTs should evaluate whether such queuing procedures enable the timely examination of interconnection feasibility and required system upgrades. Otherwise, FiTs could lose one of their primary benefits, expediency.

Queuing procedures should include the following elements:

1. Deposits based on installed capacity that developers lose if they do not meet development milestones on schedule or if they withdraw their project application. Milestones could include site control, permitting approval, or a contract for components.

2. Clustering of projects in a given geographic area when conducting interconnection analyses.

3. Oversight by an independent party. A third party, such as the state commission or an independent observer, would mitigate any utility bias or discrimination, particularly if utility affiliate projects are FiT-eligible, and ensure a fair and orderly process.

C. FiTs covering multiple utilities

Most states contain multiple utilities. A FiT applied to all utilities until the cap is reached could impose disproportionate costs on the utility located in the most attractive places to build new projects. Without cost sharing or limits to development in each service territory, this utility would shoulder a disproportionate amount of system upgrades. Its customers would bear most of the "subsidy" from the FiT. Further, FiTs create future utility financial obligations that affect cash flow. Much as they do for PPAs, credit rating agencies consider such payments when calculating imputed debt. Large amounts of imputed debt can financially harm utilities absent countervailing measures.

Two policy designs can avoid saddling utilities and their ratepayers with a disproportionate amount of the cost of the feed-in tariff.

One option creates a separate cap for each utility. Hawaii did this, though largely for reliability reasons. Similarly, the recent modifications to California's FiT increased the caps for each of the state's investor-owned utilities and large municipal utilities, rather than modify a single state-wide cap.[64] This method could hinder development if projects feature different costs in different regions, potentially necessitating setting rates that vary by sub-region.

A second method, recently proposed in Indiana, creates a state equalization fund, where utilities would pay into—or receive money from—a fund based on their proportion of total sales and renewable energy.[65] In this way, projects would still locate where they are most economically feasible, but utilities and their ratepayers would share the cost burden. Vermont adopted a similar approach. Vermont's FiT applies to all utilities, including municipal and cooperative utilities. In Vermont, a single entity contracts with the project owners, regardless of where the projects were located in the state. This entity then distributes the power and costs to each utility, in proportion to the MWh share of each utility.

Recommendation: Divide caps among utilities in proportion to their percentage of MWh electricity deliveries, particularly if a state has multiple large utilities, except where policymakers seek to spread costs and promote rapid development, in which case they should consider an equalization fund approach or a single entity to distribute the power and FiT costs.

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[64] http://docs.cpuc.ca.gov/Published/Agenda_resolution/78711.htm and http://info.sen.ca.gov/pub/09-10/bill/sen/sb_0001-0050/sb_32_bill_20090915_enrolled.pdf at page 5.

[65] http://www.in.gov/legislative/bills/2010/IN/IN1190.1.html

Appendix: Hawaii FiT Reporting Requirements

Project owners must file:

(a) The cost of project design, permitting, and construction costs, including labor and materials costs;

(b) Financing or capital cost;

(c) Land cost or actual cost of site acquisition;

(d) Interconnection and metering costs incurred by the project developer;

(e) Other project costs incurred in developing and constructing the project;

(f) Tax credits, rebates, incentives received and applied to the project development cost;

(g) Maintenance and operation labor and non-labor costs;

(h) Fuel supply costs (for biomass and biogas projects);

(i) Monthly land or site leases; and

(j) Other operations and maintenance costs.[157]

In addition, owners of projects over 20 kW must file an annual report with the commission in this docket (no later than January 31 of each year), which contains the following information: 1) annual electricity production in kWh; and 2) annual operating costs, including operations and maintenance costs, lease expenses, insurance, and property taxes. The commission will not require such annual filings from projects below 20 kW in order to prevent unduly burdening the owners of small projects.