Innovative Feed-In Tariff Designs that Limit Policy Costs

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Acknowledgments

Executive Summary

Feed-in tariffs (FITs) are the most prevalent renewable energy policy used globally to date, and there are many benefits to the certainty offered in the marketplace to reduce development risks and associated financing costs and to grow the renewable energy industry (de Jager and Rathmann 2008; Deutsche Bank 2009; Mendonça et al. 2009; Ragwitz et al. 2007). However, concerns over escalating costs in jurisdictions with FIT policies (Deutsche Bank 2009; Germany 2010; Reuters 2010) have led to increased attention on cost control in renewable energy policy design. In recent years, policy mechanisms for containing FIT costs have become more refined, allowing policymakers to exert greater control on policy outcomes and on the resulting costs to ratepayers. As policymakers and regulators in the United States begin to explore the use of FITs, careful consideration must be given to the ways in which policy design can be used to balance the policies' advantages while bounding its costs.

This report explores various mechanisms that policymakers across the world have implemented to limit FIT policy costs. If designed clearly and transparently, such mechanisms can align policymaker and market expectations for project deployment. Overall, such certainty in the long-term expectations of capacity built and costs paid can help stabilize the market and help new projects secure financing. Three different policy tools are evaluated: (1) caps, (2) payment level adjustment mechanisms, and (3) auction-based designs. The report employs case studies to explore the strengths and weaknesses of these three different cost containment tools. These tools are then evaluated with a set of criteria including predictability for policymakers, predictability for the marketplace, and potential for unintended consequences.

The report finds that caps are commonly used in FIT policies and that they provide a predictable limit on program costs. However, program size caps can introduce access risk for developers, meaning that there is uncertainty regarding whether or not a developer will be able to access the FIT payments. Additionally, project size caps can limit the ability of a market to achieve economies of scale.

Payment level adjustment mechanisms have been developed to deal with the particularly thorny issue of setting appropriate payment levels. Payment level adjustment mechanisms allow the policy to respond directly or indirectly to prevailing cost trends and can help keep FIT payment levels aligned with market realities over time. If designed well, they can also provide valuable information about future price levels. While payment level adjustments alone cannot contain policy costs, they can help prevent overpayment and thereby prevent markets from getting overheated, a central aspect of containing overall policy costs.

Finally, due to growing interest in auction-based mechanisms as alternatives to FITs, this report reviews policy development in several jurisdictions that are exploring auction-based mechanisms. The report explores the potential application of auctions in a FIT context and weighs some of the advantages and disadvantages in relation to other policy mechanisms.

When used appropriately, FITs can help policymakers meet a host of policy objectives including, but not limited to, the acceleration of renewable energy deployment, economic development and job creation, and the diversification of electricity supply. Ultimately, there is an inherent tension between introducing free and open access to renewable energy FITs and limiting ratepayer costs. Through a series of case studies, this report evaluates policy options that have been developed to place bounds on FIT policy costs or reduce exposure to FIT overpayment.

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1 Introduction

In the nearly two decades since renewable portfolio standard[1] (RPS) policies have been used in the United States, they have played a significant role in advancing renewable energy (RE) development—particularly wind power development (Berry and Jaccard 2001; Wiser and Barbose 2008).

Since the late 1990s, certain states began to broaden their RE goals to include a wider set of considerations beyond least-cost procurement, including supporting other emerging technologies or applications (such as distributed generation) that may not presently be the least-cost RE alternatives. Either within the context of their RPS policies or as alternatives or supplements to the RPS, multiple states have begun to include specific mechanisms to encourage a wider range of technologies and ownership structures, including distributed solar photovoltaic (PV) and community wind. Examples of such policies include RPS set-asides and multipliers and, more recently, feed-in tariffs (FITs). A strict focus on least-cost expansion of RE would by definition exclude many of these policy approaches.

FIT policies are one of the more polarizing RE support policies because without proper checks they can become very expensive,[2] and it can be challenging to justify the use of anything but least-cost approaches from the ratepayer's perspective. FITs are typically designed to offer cost-based compensation for renewable electricity generation, with different prices offered to different technologies, project sizes, and regions. By doing so, they have proved to be highly effective at reducing uncertainty in expected revenues, helping projects secure financing and thus stimulating investment in specific RE technologies. However, employing a cost-based approach to RE generation places particular importance on wisely setting the payment level awarded to generators and ensuring that total program costs can be controlled. Furthermore, confidence in a particular FIT policy is compromised if it must be suddenly or reactively modified when uptake is higher than anticipated.

Concerns have arisen over escalating costs in FIT policies (primarily due to uptake in solar technologies) in jurisdictions including the Czech Republic (Reuters 2010), Germany (Germany 2010), and Spain (Deutsche Bank 2009). In particular, when FIT rates prove to be profitable, large-scale response can occur rapidly. Conceivably, this situation can lead to burdensome ratepayer costs before policymakers can recognize and react to the problem. In light of recent experience in these jurisdictions, outspoken advocates and staunch opponents alike have emphasized the necessity of appropriate cost controls to limit the retail rate impact of FIT programs.

Increasing interest in the FIT policy mechanism in the United States emphasizes the importance of communicating how FIT programs can be structured to contain costs. For the most part, U.S. policymakers and FIT policy advocates have considered creating FITs to support higher cost distributed energy technologies, much in the same way that RPS set-asides have been used. It is important to note that cost containment issues become more acute when higher cost technologies

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[1] RPS policies create an obligation to supply a minimum quota of a jurisdiction's electricity mix from eligible RE sources.

[2] Any uncapped policy that gives generators a target return on investment carries the risk of unacceptably high costs.

are included. Pricing changes in emerging energy technologies can be abrupt, for example, if manufacturers expand production quickly to reach expected demand.[3] If payment levels do not track technology cost reductions or market-pricing changes, policymakers may risk awarding excessive profits, which may result in a rapid influx of investment. This applies particularly to technologies such as solar PV, which, due to its greater "scalability," unconstrained resource potential, modest development lead times, and higher levelized cost can put upward pressure on electricity rates (Deutsche Bank 2009).

This report is intended to serve as a resource for policymakers who are interested in exploring ways of containing the costs of FIT policies while still delivering on renewable electricity objectives. The report identifies three categories of policy tools for containing costs under long-term contracting programs:[4]

- Caps

- Payment level adjustment mechanisms

- Auction and competitive bidding mechanisms.

It also surveys their implementation through a series of case studies. This analysis focuses on what may be considered more innovative policy approaches, either because they have recently appeared or because they are novel in the U.S. market. While not all of the case studies are derived from FIT policies, lessons from the selected examples apply to long-term contracting programs like FITs.[5]

Section 2 lays out the evaluation criteria used in each section to analyze the different policy mechanisms featured in the individual case studies. Section 3 surveys the use of policy caps as they apply to project size, program size, and overall program expenditures (e.g., budget cap or ratepayer impact cap). Section 4 focuses on various payment level adjustment mechanisms used to keep payment levels in line with levelized generation costs over time, and Section 5 analyzes the use of auction-based mechanisms. Finally, the report concludes by summarizing some of the key lessons from the use of cost containment measures around the world.

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[3] Note that this is occurring more rapidly with technologies such as solar PV, though it can be observed to a lesser degree in a number of other RE technologies.

[4] These cost containment mechanisms are not limited to long-term contracting programs. Many of these mechanisms can apply to other types of incentive programs (e.g., production-based incentives, which may or may not involve long-term contracts).

[5] In this context, it should be understood that extensive reviews of the various cost control mechanisms developed specifically for RPS policies have not been undertaken.

2 Evaluation Criteria

In order to evaluate the effectiveness of the different policy approaches to limit costs of FIT policies, it is important to consider the perspective of different stakeholders. The authors selected criteria based on their importance to two groups of stakeholders—policymakers and regulators—and market participants including developers, investors, and manufacturers. The main audience for this report is the former group, so much of the analysis should relate to designing policies with predictable outcomes while mitigating any unintended consequences. In implementing a FIT program, regulators (and the legislature to which they report) may only consider the program to be a success if it achieves stated policy objectives and if policy outcomes are predictable and manageable. Given the long history of policy experimentation with FITs in Europe, it is apparent that the analysis should focus on the marketplace implications of each policy approach. Outlined below are the three evaluation criteria selected, detailed with sub-considerations:

1. Predictable/manageable policy outcomes

    A. Is the approach effective at containing total and incremental costs?

    B. Are outcomes (costs, quantity of deployment, and mix of technologies) certain?

    C. Are future program costs predictable?

    D. What degree of oversight is required?

    E. To what extent does the approach help to achieve stated policy objectives?

2. Adverse/unintended policy consequences

    A. Does the policy approach encourage boom and bust cycles?

    B. Does speculative queuing interfere with policy outcomes?

    C. Are the benefits of the policy equitably distributed (i.e., is there a diversity of sellers)?

3. Implications for the marketplace

    A. Does the approach affect certainty of access for developers?

    B. Does the approach maintain a stable environment for financing?

    C. Is project development risk introduced due to the policy design?

    D. Does the approach allow investors, manufacturers, and other supply chain companies to develop long-term planning horizons?

    E. Does the approach affect the ability of the market to develop economies of scale (a key component in driving future RE cost reductions)?

3 Policy Caps

Caps have been used in one form or another in most RE policies implemented worldwide and are frequently found in FIT policies. Program caps limit ratepayers' exposure to a renewable electricity oversupply (as compared to the policy objectives) and are often implemented as a way to limit total FIT program expenditures. Caps can be applied on the FIT program as a whole (regardless of technology) or more narrowly applied to more costly technologies. Caps can be applied annually or over a longer time frame (e.g., 10–20 years), and they can be implemented in a variety of different forms. Some countries limit total expenditures on an annual or periodic basis, and some specifically limit the penetration of certain types of renewable generation. Others choose to limit the pace of development (and consequent cost impacts) by limiting eligibility to smaller projects. As seen in the case studies in Section 3.1, Section 3.2, and Section 3.3, the caps most frequently employed can be categorized as limits on one of the following:

- **Capacity** (either total megawatts installed or maximum project size)
- **Program cost** (total allowable program cost, often measured in ratepayer impact)
- **Energy production** (total percentage of retail sales).

This section draws upon examples from Spain, Gainesville Regional Utilities, and the State of Hawaii.

3.1 Spain's Transition to a Capped Feed-In Tariff Program

An uncapped solar FIT was used to support solar electricity generation in Spain between 1998 and 2008 (de la Hoz et al. 2010). However, a combination of factors (see text box) led to an overheated solar market from 2007 to 2008. According to best estimates from the International Energy Agency Photovoltaic Power Systems Program, nearly 560 MW of solar PV capacity was added in 2007 in Spain, while nearly 2,760 MW was added in 2008 (IEA 2010).

In September 2008, Spanish policymakers moved to scale back solar PV policy support. The new legislation (RD 1578/2008) imposed an annual cap on solar PV installations of 500 MW for 2009 and 2010 and a lower cap of 400 MW for 2011 and 2012 (Spain 2008). In addition to the annual cap for installations, Spain also lowered the capacity cap on project size to 10 MW for ground-mounted systems and 2 MW for roof-mounted systems (Spain 2008). The text box provides some background on the history of solar PV promotion in Spain as a cautionary example for policymakers.

Conditions Leading to Runaway Growth in the Spanish Solar Market

In 2005, Spanish legislators revised the national RE plan (known as PER 2005–2010), establishing an overall target of 12.5% RE by 2010 and setting capacity targets for each RE technology (Spain 2005). Under this legislation, the target for solar PV capacity was set at 400 MW by 2010 (Spain 2005). However, beginning in 2006, annual installed capacity quickly began to exceed the quantity required to keep Spain on track for meeting its PER 2005–2010 targets (de la Hoz et al. 2010).

Next, legislation enacted in May 2007 (RD 661/2007) had a destabilizing effect on the market (de la Hoz et al. 2010). Several factors were at play: the highly favorable FIT payment levels of RD 661/2007 (along with 25-year contract lengths) made solar PV a highly profitable investment. As the economy first displayed signs of weakening, investors flocked to the solar industry as a safe haven because other investments seemed more uncertain. New investors grabbed stakes in the market as installers and equipment dealers (de la Hoz et al. 2010). Spanish demand held worldwide PV component prices at artificially high levels, as evidenced by a crash in PV pricing in the months after Spain scaled back its support (Kreutzmann 2008; PHOTON Consulting 2009).

Additionally, a new trigger mechanism (introduced in article 22 of RD 661/2007) had an impact on investor perceptions on the future of the solar market. In anticipation that support for solar might dry up, solar developers were induced to rush to capitalize on the existing framework (de la Hoz et al. 2010). The mechanism operated as follows: once installed PV capacity reached 85% of the 400 MW target (dictated by PER 2005–2010), a one-year policy transition was initiated (Spain 2007). The legislation stated that developers had one full calendar year to develop projects before the new policy framework would come into force. Those projects under construction that failed to register in the FIT program before the end of the year would receive the final hourly electricity production market price—not the generous payment levels of RD 661/2007 (de la Hoz et al. 2010).

Together these factors resulted in an unprecedented boom in solar in 2007 and 2008. Subsequently, policymakers began to rethink the solar support scheme. The policy transition triggered by RD 1578/2008 capped solar deployment and instituted more restrictive requirements for generators in order to contain ratepayer impacts and yield a more predictable policy result.

In addition to the new caps, RD 1578/2008 also included two supplementary administrative requirements for prospective developers. First, developers must register their projects in a "registry of pre-approval" before being granted the FIT (Spain 2008). Second, capacity that fills the annual cap is now allocated in a more structured manner (i.e., developers must submit their project proposals in response to quarterly "calls") (Spain 2008).[6]

While Spanish legislators considered the provisions of RD 1578/2008 to be necessary to keep solar development in check and restrain costs, the sharp changes have led to a significant flight of capital from the Spanish PV market, spurring job losses and sending ripples throughout the global PV market (Deutsche Bank 2009). The sudden introduction of caps (and other administrative barriers) has increased the risk premium of investing in Spain's RE industry. Investors, uncertain of the future of the market, have looked elsewhere—investing in Italy, the Czech Republic, and other emerging solar PV markets (RenewableEnergyWorld.com 2010). Despite the large amount of new capacity installed in 2008, the pace of PV installations in 2009 and 2010 has slowed, falling short of the newly instituted program caps. An estimated 60 MW was installed in 2009 (IEA 2010), and industry sources project that 100 MW will be installed by year-end 2010 (RenewableEnergyWorld.com 2010).

3.2   Gainesville Regional Utilities

Gainesville Regional Utilities (GRU) implemented its initial FIT policy targeted at solar PV systems in March 2009 (GRU 2009). The Florida municipal utility offered a fixed price contract over 20 years for solar PV projects, with two different prices based on project size.[7] GRU's policy includes an annual program cap of 4 MW, which imposes an upper limit on the total allowable installed solar capacity in the utility's service territory (GRU 2009). GRU's 4 MW annual cap was designed to limit ratepayer impacts to roughly 1% per year (GRU 2009).

Within the first few months of launching the program in 2009, GRU received applications for enough capacity to fill the first five to six years of solar development. The first 4 MW were subscribed in a matter of days (Crider 2010). Because of this early program experience, GRU redesigned its queuing procedures for the FIT program beginning in 2011 (Crider 2010). Under the new approach, applications are accepted on a seasonal basis for projects to be completed that year (Crider 2010).

For the 2011 procurement, 10% of the 4 MW cap (400 kW) was reserved for projects under 10 kW in size;[8] these developers had an early opportunity (in October 2010) to submit their applications (GRU 2010a). Applications to fill the remainder of the annual cap will be accepted between January 17 and 21, 2011 (GRU 2010a). If more applications are received than available capacity, an independent third party selects projects by random drawing (GRU 2010a), and any

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[6] Payment levels are adjusted according to the developers' response to a given call. This mechanism was adopted to help align PV FIT payment levels with market costs. It is explained in more depth in Section 4.3.
[7] The initial payment levels (applicable for 2009 and 2010) were $0.32/kWh for rooftop and ground-mounted projects smaller than 25 kW and $0.26/kWh for projects greater than 25 kW. Payment levels were designed to allow investors to obtain an after-tax return of approximately 5% (GRU 2009). Payment levels are scheduled to decline annually between 2011 and the termination of the program in 2016 (Crider 2010; DSIRE 2010a).
[8] A new project size class was introduced for projects under 10 kW in 2010. These projects will benefit from more streamlined approvals as well as a higher per kilowatt-hour purchase price (Crider 2010).

unreserved capacity in a given year would roll over into the next year's procurement cycle (Crider 2010). This new approach will prevent the queue from filling up for years in advance, and in fact, builds in extra assurance that the most prepared projects will receive contracts (as they must reach commercial operation by the end of the year).[9]

The seasonal application system is likely to help maintain a steady flow of work for the PV installer market and associated supply chain, which can be important for jurisdictions seeking to foster a stable and prosperous RE sector (Crider 2010). It is anticipated that this framework could also help alleviate some of the start-and-stop characteristics that can emerge in capped FIT policy frameworks (wherein a rush of development to fill the cap may be witnessed, followed by a period of little to no growth as the existing projects are completed).

Additional caps on project size were proposed in 2010 and may come into effect in the future (Crider 2010). Caps for rooftop projects may be in the range of 250–300 kW, a measure designed primarily to distinguish between projects that require utility-side grid upgrades and those that do not. Ground-mounted systems are likely to be capped at 1 MW (Crider 2010).[10]

3.3 Hawaii

In Hawaii's FIT docket proceedings, it was noted that providing a FIT would require "utilities to accept large or unlimited amounts of renewable generation projects by tariff without project-by-project review and approval" (Hawaii PUC 2009, p. 52). Intervening parties to the docket proposed caps to contain total program cost[11] as well as mitigate reliability issues on the islands' grid systems.

Hawaiian Electric Company, Inc., (HECO) and its affiliates (together, HECO Companies), the obligated utilities under the impending FIT, have expressed concern that adding RE projects to constrained parts of the island grid system could exacerbate operational and reliability concerns and require costly grid infrastructure upgrades or further actions to manage the integration of new, distributed supply sources that may have variable output (e.g., solar and wind). HECO Companies argued that these mitigation efforts would come at an additional expense to ratepayers if other less expensive resources needed to be curtailed or if costlier resources needed to be deployed for balancing (Hawaii PUC 2009, p. 53). These problems are particularly acute for jurisdictions that are not meaningfully interconnected to a wider geographic area for balancing.

Due to these concerns, the Hawaii Public Utilities Commission (PUC) decided to implement quantity caps for each island that would constitute what were considered reasonable reliability-based limits to system penetration of FIT resources. The Hawaii PUC ruled that implementing such caps (prior to the first review of the program) was appropriate "given the inherent

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[9] A sample contract on GRU's website indicates that a single extension to the contracted completion date may be granted if at least 65% or more of the cost of the total budgeted equipment for the facility has been installed on-site by the completion date (GRU 2010b).

[10] A new project size class is also likely to be introduced for projects under 10 kW, which will benefit from more streamlined approvals as well as a higher per kilowatt-hour purchase price (Crider 2010).

[11] Although containing program costs was a stated concern of intervening parties, it is important to note that due to the high cost of electricity in Hawaii [average retail rates were $0.292/kWh in 2008 (EIA 2010)], all of the Hawaii FIT payment levels are less than the average retail electricity rates (DSIRE 2010b).

imprecision in setting initial FIT rates and the uncertainties of the types of projects likely to be constructed and at what locations" (Hawaii PUC 2009, p. 54).

The Hawaii PUC decided that initial total program caps on nameplate capacity should be equivalent to 5% of 2008 peak demand for each of the HECO Companies. Since alternative mechanisms exist for renewable generators to enter contracts (e.g., request for proposals), the cap of 5% of 2008 peak demand was decided to be a reasonable limit on the types of projects that the FIT policy supports. To encourage project diversity, the Hawaii PUC chose to reserve 5% of this quantity cap for residential and small commercial projects less than 20 kW. Instead of an annual cap, the cap is effective for the two-year period between reviews (Hawaii PUC 2009, p. 57).

In addition to program caps, Hawaii also implemented project size caps. These project size caps vary by technology and island.[12] The rationale behind these caps is also to ensure grid integrity and reliability, especially due to stability and related risks associated with placing larger projects at electrically weak locations on the smaller islands' grid system. Additionally, the Hawaii PUC's intent was not to have the FIT program overlap with the existing competitive bidding framework, nor to interfere with the state's existing net-metering policy (Hawaii PUC 2009, p. 46).

Because the policy is just getting underway, there has been no implementation experience in Hawaii, so the effectiveness of the cap cannot yet be evaluated. However, the Hawaii case study presents policy options and considerations, especially for jurisdictions with constrained electric grids. One key takeaway is that policies can be set conservatively in the beginning and can later be revised to include greater numbers of projects or to allow projects of larger sizes. In Hawaii's case, conservative project and program size caps will allow the Hawaii PUC and HECO Companies to maintain some control as they gain familiarity with the program.

The Hawaii PUC anticipates that a two-year period for the cap (instead of an annual cap) may prevent biases and queuing issues resulting from a developer rush to enter the program before it is fully subscribed (Hawaii PUC 2009, p. 57). One potential downside is that the first review of the program also coincides with the end of this two-year period (Hawaii PUC 2009, p. 17). If the program subscribes quickly, there may be significant lag time before the PUC reviews the program and makes payment level adjustments or changes to the size or scope of the program. The uncertainty of program revisions introduces some risk for developers, which may impact participation.

3.4   Analysis of Policy Caps
This section applies the criteria laid out in Section 2 to each of the three policy experiences and approaches.

3.4.1   Predictability and Manageability of Policy Outcomes
Caps provide an effective way to control the costs of RE policies. By limiting uptake of RE capacity to a known variable, capacity-based program size caps are a direct way of containing total costs of the policy over a period of time. Capacity-based project size caps can influence the

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[12] Project size caps of 5 MW on Oahu, 2.72 MW each on the Island of Hawaii and Maui, and 100 kW for Molokai and Lanai were chosen (Hawaii PUC 2009, p. 45).

incremental costs of entering into a contract with each generator but may not provide a firm cap on policy cost. Caps on total program cost or percentage of retail sales can be used to predict what the annual ratepayer impact of the policy will be.[13]

Caps can increase policymakers' confidence in policy outcomes, including the total program costs, the total amount of capacity developed, and the resulting mix of technology. Caps allow policymakers to estimate incremental as well as aggregate policy cost exposure over time. However, it may be challenging to predict current and long-run costs of any RE support policy given exogenous factors (e.g., cost reductions over time). Also, in contrast to capacity-based caps or energy-based caps, it may be difficult to evaluate when a direct cost cap is actually reached. Policymakers can choose to implement technology-specific caps or caps on system size or equipment type, which will allow them to exert greater control on the technology composition of RE market growth (e.g., how much wind and how much solar).

As a policy mechanism, capacity-based program caps require some oversight during implementation. That being said, after establishing queuing protocols (rules about how capacity is reserved) and developer requirements that ensure project viability, regulators can turn over FIT program administration to a third party. Careful management of the project queue will allow program administrators to evaluate when a cap has been reached.

Finally, while caps provide a direct and transparent way of containing policy costs, there are trade-offs that are worth considering when evaluating their use. By limiting investment in a technology or sector, caps can limit a jurisdiction's ability to foster the development of a clean energy industry as well as its ability to harness further benefits that can result from economies of scale. If a recognized policy objective is to stimulate the market or to encourage manufacturing and job creation, caps imposed too stringently will reduce the effectiveness of the FIT policy.

3.4.2 Unintended Consequences

As highlighted in some of the case studies above, caps could also have a number of unintended consequences. Long-standing policy experience in Europe has revealed ways to mitigate some of these possible negative outcomes, but a few are inherent to the policy design.

First, caps (especially annual caps) threaten to create a start-and-stop development pattern, as investment can grind to a halt once the cap is reached. This can pose a substantial barrier to market development and hinder both near- and long-term investment. One way to encourage long-term investment in a capped environment is to provide a clear signal about capacity desired for the long term.

A program cap (capacity, cost, or energy-based) structured over a short time period (e.g., annual caps) could lead to biases in favor of projects with faster development timelines, such as solar PV (Hawaii PUC 2009). If these projects that are developed more quickly have higher cost profiles, the implementation of a short duration cap may perversely put upward pressure on policy costs. Caps with a short duration can also favor developers who already have a foothold in the market and who are already familiar with the political and regulatory context. This may deter

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[13] Similarly, RPSs in the United States often include annual incremental targets as a percentage of electricity sales, which effectively cap the growth of new RE in a given year.

new investors, small developers, or foreign investors, leading to less capital investment and potentially to less competition in the supplier and installer markets.

Another important consideration for policymakers is how to mitigate the potential adverse impacts of speculative queuing, a problem that has been observed under some capped policy frameworks (Grace et al. 2008). Since FIT contracts are often awarded on a first-come first-served basis, developers must enter a queue for receiving a FIT contract. Rushing to compete for a limited number of contracts, some developers may attempt to reserve a place in the queue with project proposals that still have many development uncertainties (e.g., permits and financing). If these projects with high completion risks take up space in the queue, there is a risk that more viable projects will not have access to the FIT. Queuing issues could create antagonisms and potentially even legal conflicts between developers. To avoid this outcome, policymakers have implemented queuing procedures that include, for example, application fees, project viability criteria, and tying a security deposit to explicit development milestones (Grace et al. 2008).

A possible related consequence may be seller concentration. In this context, a small number of investors with FIT program experience and balance sheets sufficient to support a large number of projects may outcompete new investors. Seller concentration issues may be mitigated in the policy design of caps (at least for short-run caps) by specifying the maximum percentage of the cap for which one developer and its affiliates can receive contracts.[14]

Finally, because of the presence of scale economies, caps might ironically put upward pressure on incremental policy costs. In other words, caps might increase per-unit installed costs of the technologies that the FIT policy supports. For example, a cap on project size might result in more expensive projects because when project sizes are limited, developers cannot capitalize on economies of scale in development and construction. However, on the other side, caps could plausibly result in innovations that reduce costs through modularizing and standardizing installations.

It is important to note that economies of scale in manufacturing are separate and distinct from economies of scale in construction and installation. Economies of scale in manufacturing are a driving factor leading to technology cost reductions; therefore, cost reductions might not be as rapid in jurisdictions that pass a FIT policy with a stringent program cap. More aggressive policies (with less stringent caps) may stimulate larger local markets for manufacturing, integration, or installation. Local manufacturing scale or development of a more diverse and competitive installer base may ultimately result in lower installed costs.

Installed cost averages provide some evidence of the effects of scale economies in PV markets. In *Tracking the Sun II: The Installed Costs of Photovoltaics in the U.S. from 1998-2008*, Wiser et al. (2009) found that markets with large PV deployment programs tend to have lower average installed costs for residential PV. For example, average installed costs in 2008 for residential systems were $6.10/W in Germany (2008 market size; 5,300 MW) and $7.90/W in the United

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[14] One policy design that FIT policymakers have used to encourage a diverse pool of investors has been to include bonus payments for certain project ownership types (e.g., community ownership). For example, the Ontario FIT rules state that projects owned by Ontario community members and non-profits, as well as those owned by indigenous peoples, will receive higher payment levels than other private investors (Ontario Power Authority 2010). Another possible option could be to create caps for different project ownership types.

States (2008 market size; 800 MW) (Wiser et al. 2009). This difference may be partially attributable to the larger market size in Germany, though other variables are likely at play, including installation labor costs, foreign exchange rates, and transaction, permitting, and interconnection costs, among others (Wiser et al. 2009).

3.4.3 Implications for the Marketplace

Program caps, especially caps that are anticipated to be reached in a short period of time, increase uncertainties for project developers. This is because caps constrict the certainty of access provided by a FIT framework. Developers may choose not to take the risk of developing a project if it is uncertain whether or not they will be able to access a FIT contract.[15] In the absence of a well-defined queuing procedure, a project might be at risk of spending a significant amount of capital on a project that does not ultimately receive the FIT rate. Hence, program caps create the risk that developers who have done due diligence will still fail to receive a FIT contract. A recent empirical study of European solar developers demonstrates the importance of this non-economic policy risk (Lüthi and Wüstenhagen 2010). The researchers used choice experiments to uncover developers' willingness to accept the risk that a cap will be reached in one year. The study results revealed that on average, developers would require an 11 Euro cents/kWh premium under a FIT contract to keep the same level of attractiveness as an uncapped FIT program (Lüthi and Wüstenhagen 2010).

This problem of certainty of access may be exacerbated if policymakers do not award the FIT until a project has reached certain developmental landmarks (e.g., final regulatory approval or interconnection). The Hawaii PUC considered this approach but concluded that such a policy would be inadvisable because developers could be midway through construction or have already paid for an interconnection review study, only to find that the cap has been filled (Hawaii PUC 2009). This untenable project risk, not to mention the potential concerns over obtaining project financing without a binding contract, discourages development. Ultimately, the Hawaii PUC decided instead to require an application fee to ensure that capacity is reserved only for serious applicants (and to prevent frivolous projects from filling the queue and counting towards the caps) (Hawaii PUC 2009).

The sudden introduction of new caps, as with any abrupt policy change, negatively impacts investor certainty and could possibly lead to capital flight from the market. Policy stability, longevity, and transparency are critical factors that influence investment decisions for developers, investors, and manufacturers alike (Deutsche Bank 2009). Providing clarity on the planning horizon that policymakers are adopting can help to reduce investment risks. This could be as simple as clarifying the order of magnitude of development targeted, whether 100 MW or 1,000 MW, for instance.

Though capacity trigger mechanisms (as described in Section 3.1) are distinct from caps, their use necessitates a word of caution given the Spanish policy experience. Spanish policymakers passed a law that stated once 85% of a capacity target was reached, a policy transition would be initiated (Spain 2007). Given the economic context and the unacceptable economic consequences

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[15] Typically, developers queue up for the FIT according to the timestamp of their applications, and FIT contracts are awarded to developers in this order. For this reason, it may be difficult for developers to judge when the cap will be met and thus whether or not a project in development will be able to access the FIT payments.

if a developer did not complete a project before the new policy framework was in place, this mechanism led to runaway growth in the solar market. If policymakers consider the use of a trigger mechanism to initiate policy changes, they should make sure that the mechanism does not adversely affect investor confidence in the market.

4 Payment Level Adjustment Mechanisms

Pricing changes in emerging energy technologies can be abrupt due to the incorporation of learning effects as well as the ability to quickly react to expected demand through production expansion.[16] If payment levels do not track technology cost reductions or market-pricing changes, policymakers may risk awarding excessive profits, which may result in a rapid influx of investment. Therefore, payment level adjustment mechanisms are an important part of containing incremental and total policy costs. An added benefit of payment level adjustment mechanisms is that they can provide market signals about future payment levels and as such can encourage technological innovations that result in future cost reductions. Reducing uncertainty in payment levels (and thus project revenues) is instrumental in helping new projects to secure financing and secure financing at the most advantageous terms (i.e., the lowest interest rates).

There are several alternative methods to adjust payment levels to keep them in line with market realities over time. Generally speaking, payment levels can be adjusted annually or volumetrically or a combination of the two. This report characterizes the options as follows:

- A schedule of pre-determined annual degression rates[17] (see Section 4.1)

- A schedule of degression rates responsive to the annual installed capacity (see Section 4.1)

- A schedule of "volumetric" adjustments to payment levels (based on steps or a sliding scale) (see Section 4.2)

- A system of real-time, responsive adjustments based on capacity installed in a period of time (typically shorter than one year) (see Sections 4.3 and 4.4).

Pre-determined tariff degression adjusts the payment levels offered to RE producers downward over time for projects that come online in subsequent years.[18] This adjustment generally occurs on an annual basis and is applied to future projects as a percent reduction on the current tariff level. By being pre-determined, it provides greater predictability for developers and manufacturers. There are several risks. A substantial risk is that the anticipated rate of reduction in the payment "step down" will differ from actual price reductions that occur in the marketplace. Also, if deployment is more rapid than expected, the total cost to ratepayers can be higher than anticipated.

Responsive annual degression, on the other hand, takes a more nuanced approach to FIT rate setting. It allows market conditions to determine the rate of degression rather than the other way around. The first country to make use of responsive degression was Germany; they applied it to solar PV (Germany 2008).[19] Under this scheme, policymakers may change payment levels by a

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[16] Note that this is occurring more rapidly with technologies such as solar PV, though it can be observed to a lesser degree in a number of other RE technologies.

[17] Degression is defined as a pre-arranged schedule for declining payment levels. Degression is typically applied annually, as a percentage of the incentive level, and may vary by technology type.

[18] Note that tariff degression only applies to new FIT contracts, not existing FIT contracts. When a FIT contract is executed, the developer locks in at a payment level for the whole duration of the contract.

[19] Note that payment level adjustments can occur outside of the planned schedule, such as occurred in Germany in 2010 when cost reductions raced ahead of the scheduled degression.

certain percentage (up or down) according to the amount of capacity installed during a given period of time—in this case, one year. The rate of degression itself is therefore what changes (e.g., from an 8% annual reduction to 9%), which in turn reduces the actual payment level offered in the following year. Responsive degression has not been applied based on a metric other than time, but it may be possible to react to market prices or other public policy metrics.

A third approach is "volumetric," or capacity-based adjustments, where installed capacity milestones (rather than timelines) trigger predetermined payment level adjustments. One potential design is the California Solar Initiative's (CSI's) stepped financial incentive structure, where payment levels are reduced according to a pre-defined schedule when capacity milestones are met (CPUC 2010a).

The last approach discussed is the system of bidding that has been introduced in Spain for the solar PV FIT. This variant of the volumetric approach attempts to be more responsive to market conditions by tying payment level adjustments to the results of quarterly calls. In other words, if the program meets its quarterly volumetric target, payment levels can be reduced by a certain amount, but if capacity targets are not reached, payment levels can be maintained or adjusted upwards. Oregon has subsequently adopted a similar system for its solar FIT pilot program.

The following case studies describe implementation experience with predetermined degression, responsive degression, and volumetric payment level adjustments. Examples are drawn from the German FIT, the CSI program, the Spanish solar FIT, and the Oregon Volumetric Incentive Rate (VIR) pilot program.

4.1 Germany's Degression Frameworks
Germany makes use of both predetermined degression and responsive degression, reserving the latter for solar PV due to the more rapid cost evolution occurring in that technology class. Other technologies such as wind, biogas, and biomass continue to operate under a predetermined degression framework (Germany 2008).

4.1.1 Predetermined Degression
Beginning in its RES Act of 2000, Germany instituted an annual degression scheme designed to ratchet down the FIT payments over time. Each technology was assigned a different rate of degression, expressed in percentage terms (see Table 1). Due to the more rapid cost reductions anticipated in solar PV, the rate of degression applied to this technology has been consistently higher than that applied to wind power.

Predetermined degression remains in effect in Germany for all technologies except solar PV, though the percentage amounts have changed over time, as shown in Table 1.

Table 1. Germany's Tariff Degression Framework (2000–2009)

Technology	Annual Rate of Degression RES Act 2000 (applied as of Jan. 1, 2002)	Annual Rate of Degression RES Act 2004 (applied as of Jan. 1, 2005)	Annual Rate of Degression RES Act 2008 (applied as of Jan. 1, 2009)
Wind (Onshore)	1.5%	2.0%	1.0%[1]
Wind (Offshore)	N/A	2% (as of Jan. 1, 2008)	5% (as of Jan. 1, 2015)
Solar PV	5.0%	5%, 6.5% for ground-mounted systems	7%–11% (as of Jan. 1 2010)[1,2]
Biogas	0%	1.5%	1.5%[1]
Biomass	1.0%	1.5%	1.0%[1]
Geothermal	0%	1.0%	1.0%[1]
Hydro	0%	1.0%[3]	1.0%*

[1] Degression for these technologies applies to both the base tariff and to any applicable bonuses.
[2] Responsive degression came into effect January 1, 2009.
[3] Only applies to hydro systems larger than 5 MW.
Sources: Germany 2000; Germany 2004; Germany 2008.

4.1.2 Germany's Responsive Degression Framework for Solar PV

In its 2008 policy revision, German policymakers adopted a new responsive degression scheme to replace the existing framework for solar PV.[20] This new degression scheme set a benchmark rate of degression for each PV class (e.g., ground-mounted, residential rooftop projects less than 30 kW) and pegged each subsequent year's degression rate to the volume of annual installations in that year.[21] For instance, if annual solar installations were to exceed a certain threshold (e.g., 1,500 MW/year), policymakers would apply a rate of degression 1% higher than the benchmark rate and vice versa if the pace of deployment fell below a certain threshold (Germany 2008; Table 2).

Table 2. German Responsive Degression Scheme for Solar Photovoltaics (2009–2010)

Year	Annual Installed Capacity	Result on the Rate of Annual Degression
2009	< 1,000 MW	Declines 1% (e.g., 9% to 8%)
	1,000–1,500 MW	No change
	> 1,500 MW	Increases 1% (e.g., 9% to 10%)
2010	< 1,100 MW	Declines 1% (e.g., 9% to 8%)
	1,100–1,700 MW	No change
	> 1,700 MW	Increases 1% (e.g., 9% to10%)
2011	< 1,200 MW	Declines 1% (e.g., 9% to 8%)
	1,200–1,900 MW	No change
	> 1,900 MW	Increases 1% (e.g., 9% to 10%)

Sources: Adapted from Jacobs and Pfeiffer 2009; Germany 2008.

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[20] The rationale being that solar PV is unique among RE technologies for several reasons: costs have experienced rapid declines in recent years, PV manufacturing is rapidly scalable, and significant cost reductions are still anticipated as considerable innovation is still occurring (Couture et al. 2010; Jacobs and Pfeiffer 2009).

[21] Note that in addition to these automatic annual degressions, Germany's RES Act schedules a revision to the policy every four years, at which point changes to both the policy framework and to the tariff payment levels can occur.

However inventive, German policymakers decided that this scheme did not provide enough control over the actual payment levels provided, given rapid market changes in solar technologies. In 2010, German policymakers intervened to reduce solar PV FIT payment levels by 11%–16% from rates dictated by the previous schedule. These cuts have brought the FIT payments more closely in line with current solar PV market costs and will reduce the overall costs of the policy for German ratepayers.

Also in 2010, policymakers modified the solar PV responsive degression framework going forward. The new framework is designed to adapt more responsively to market realities by creating tighter steps for installed capacity and sharper FIT rate cuts given large amounts of annual installed capacity. The capacity steps provide investors with reference points for future rates of degression (Germany 2010). The amount of capacity installed in a given year is directly tied to the rate of degression for the following year. The shaded row in Table 3 represents the benchmark solar PV capacity anticipated by policymakers for 2011 and 2012, for which the benchmark degression rate will be 9%. Payment cuts can be as sharp as 12% at the conclusion of 2011 if between 5,500 MW and 6,500 MW are installed and as sharp as 21% at the conclusion of 2012 if over 6,500 MW are installed (see Table 3).

Table 3. German Responsive Degression Scheme for Solar Photovoltaics (2011–2012)

Year	Annual Installed Capacity	Resulting Rate of Annual Degression
2011	1,000–1,500 MW	Declines 6%
	1,500–2,000 MW	Declines 7%
	2,000–2,500 MW	Declines 8%
	2,500–3,500 MW	Declines 9%
	3,500–4,500 MW	Declines 10%
	4,500–5,500 MW	Declines 11%
	5,500–6,500 MW	Declines 12%
2012	1,000–1,500 MW	Declines 1.5%
	1,500–2,000 MW	Declines 4%
	2,000–2,500 MW	Declines 6.5%
	2,500–3,500 MW	Declines 9%
	3,500–4,500 MW	Declines 12%
	4,500–5,500 MW	Declines 15%
	5,500–6,500 MW	Declines 18%
	> 6,500 MW	Declines 21%

Source: Germany 2010

The ultimate goal of this framework is to attempt to moderate (and to some extent to control) the rate of market uptake by adjusting the rate of degression in a responsive (and theoretically self-correcting) fashion. The objective of this mechanism is simultaneously to limit the costs of the solar FIT for ratepayers and to allow market players (both investors and manufacturers) to anticipate future payment levels (and thus revenues), which can aid in investment planning.

Since policymakers have provided clear signals about future payment levels in multiple scenarios, manufacturers may be better equipped to plan for future levels of demand.

However, uncertainties still remain over whether responsive degression frameworks can control policy costs to the degree desired by policymakers. Also, more rapidly changing payment levels can make it difficult for manufacturers to adapt to changing market demand.

4.2 California Solar Initiative Program

CSI is a statewide financial incentive program that awards rebates and performance-based incentives (PBIs) to customers installing grid-tied distributed PV systems. Customers within the service territories of the three investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) participate in the general market solar program, a subset of the CSI program with a goal of 1,750 MW and a budget of $1,897 million by the end of 2016 (CPUC 2009). Three and a half years into the program, 20% of its total program goal has been installed, and the installation of pending projects would achieve another 22% of the goal (CPUC 2010a).

The CSI Program, overseen by the California PUC, employs a transparent volumetric payment level adjustment approach. At the program outset, the administrators established interim capacity targets (or steps) and set an explicit schedule for predetermined incentive level decreases that will take effect when these steps are reached (CSI 2010a). Potential applicants can track the capacity remaining in each step by using a publicly available website that is updated daily.

In order to deter speculative queuing, the program administrator has developed a rigorous three-step application process for projects over 10 kW in size (in the public, non-profit, or commercial sectors) (CSI 2010b).[22] Developers must submit a "Reservation Request" both online[23] and via mail to begin their application process. Additionally, they must submit a "Proof of Project Milestone Package" (and documentation of a pending request for proposal for an engineering and construction contract if non-profit or public) before their reservation can be confirmed (CSI 2010b). After milestones are reviewed, the administrator can choose to confirm or reject the reservation. If confirmed, the project gets locked in with the incentive level available on that date. This additional step provides the program administrator with greater assurance that the project is viable. After being confirmed, a project has only 18 months to achieve commercial operation or the reservation is relinquished. The final step in the process is to submit an incentive claim form once the project is operational (CSI 2010b). The California PUC has indicated that if a project falls through, the administrator can easily reallocate the unused capacity to the next incentive level step in the program (CPUC 2010a). This implies that if a project with a capacity reservation falls through, there may be unallocated capacity at that incentive level.

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[22] Small systems less than 10 kW in size can be confirmed without "Proof of Development Milestones," but these developers only have 12 months from confirmation to complete projects (CSI 2010b).
[23] Go Solar California. "PowerClerk – CSI Application Portal." https://csi.powerclerk.com/default.aspx. Accessed June 1, 2011.

The fundamental theory behind the volumetric incentive structure is that the market will experience PV cost reductions as greater amounts of capacity are installed.[24] Volumetric incentive steps may encourage installers to reduce their installation costs though the improvement of business processes and standardization of installations, for example.

Three years of CSI program data show evidence of a decline in the average cost of solar PV systems since the inception of the program (CPUC 2010a).[25] However, a system cost breakdown analysis showed that the observed price declines have been driven by panel price declines, as other balance-of-system (BOS) costs have remained relatively constant (CPUC 2010a). This implies that the declines in average costs have had more to do with global PV panel market dynamics than with cost reductions as solar installers have gained experience over the last three years. It will be interesting to compare these costs with those at the culmination of the 10-year program, when incentive levels are significantly lower, to analyze the impact of California's expanding local market for distributed PV. Because the market for PV modules is so dynamic, some analysts have hypothesized that a more responsive, real-time volumetric adjustment mechanism might better capture changes in PV system costs. Options are explored in the next two case studies.

4.3   Spain's Tariff Adjustment Mechanism

In September 2008, in response to an overwhelming increase in solar PV projects driven by the previous Royal Decree (RD 661/2007), Spain adopted a new mechanism to adjust the FIT payment levels offered to this technology (Spain 2008). It allows the payment level to adjust automatically either upward or downward in response to market development. This new framework requires Spanish administrators to issue a series of calls for specified blocks of solar capacity at a specified price. Developers can choose to bid at this price on a first-come, first-served basis.[26]

In this design, a downward adjustment to the subsequent FIT payment amount is triggered if more than 75% of the capacity target is reached in the previous call according to the following formula:

Percentage adjustment to actual FIT payment (if triggered) =

$$[(1-0.9^{1/m}) \times (P_0 - P) / (0.25 \times P_0) + 0.9^{1/m}]$$

where P_0 is the capacity target for the given call, P is the pre-registered capacity signed up during the previous call, and m is the number of annual calls (Jacobs and Pfeiffer 2009; Spain 2008).

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[24] The rationale behind this method comes from analysis of experience (or learning) curves, which find that certain levels of technology cost reductions can be expected with each doubling of cumulative production (Bhandari and Stadler 2009).

[25] The consultant Itron has analyzed average installed costs of host-customer owned systems (excluding third-party owned systems) over the course of the program. On an inflation-adjusted basis, small systems under 10 kW declined on average from $10.04/W to $8.49/W between the first quarter of 2007 and the fourth quarter of 2009, a decline of about 15% (CPUC 2010a). Average costs for systems between 10 kW and 1,000 kW fluctuated more significantly but also declined nearly 10% over the same period (CPUC 2010a).

[26] The language here, including calls and bids, implies that the mechanism operates like an auction. Indeed, the lines often blur around particular policy designs, and this system could be described just as easily as an auction mechanism for the purpose of this report. We treat the Spanish solar example in this section because an auction informs a specific payment level adjustment mechanism.

This formula, represented graphically in Figure 1, allows for up to a 2.6% downward adjustment in payment level when 100% of the capacity in the previous round is filled. Assuming four calls per year, the greatest annual downward adjustment possible is slightly over 10%.[27] However, according to the formula, if there were fewer than four calls per year, the annual downward adjustment could be greater.
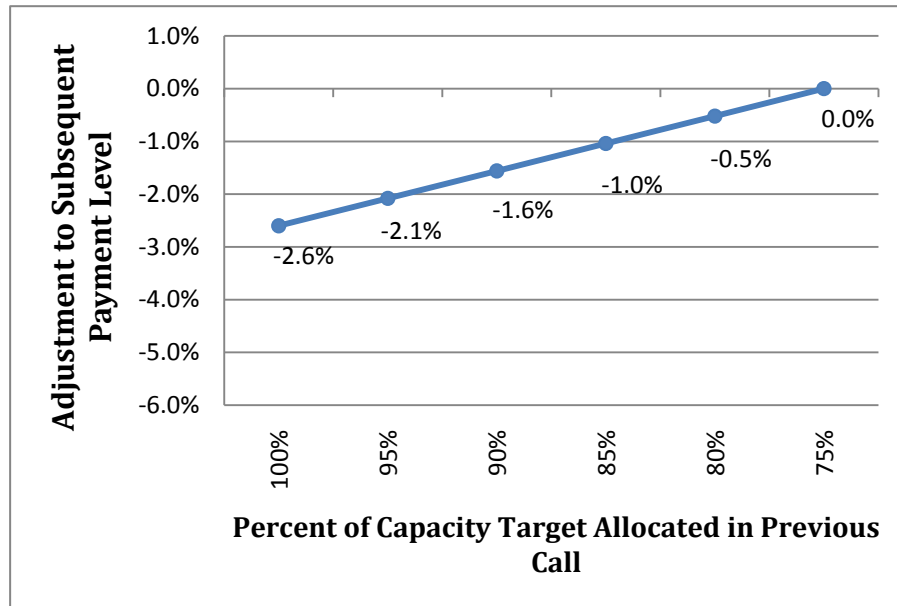

Figure 1. Spain tariff adjustment mechanism, where m = 4, P > 75%

If the capacity that responds[28] to any call meets between 50% and 75% of a given call, the payment level for the next call remains unchanged. But in the event that the capacity that responds is less than 50% of the allocated capacity block over two consecutive calls, then the FIT payment level is increased by 2.6%. This means that if the tariff drops below the level of revenue required by investors to ensure profitability, it is likely that the quota in subsequent calls will not be met, which triggers an automatic upward revision in the payment amount. Table 4 summarizes these three conditions.

Table 4. Spanish Solar Feed-In Tariff Adjustment Matrix

Spain Tariff Adjustment Mechanism for Solar PV (Spain 2008)	
Market Condition	**Impact on Payment Level**
If between 75% and 100% of a given call is reached…	Downward revision to the FIT payment level (between 0% and 2.6%) (See Figure 1)
If less than 75% of a given call is reached…	No change to the FIT payment level
If less than 50% of the call is reached in two consecutive calls…	Upward revision to the FIT payment level by 2.6%

Sources: Jacobs and Pfeiffer 2009; Spain 2008

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[27] A 2.6% decline repeated four times leads to a net tariff decline of approximately 10%.

[28] This is measured by capacity of projects that have registered in the registry of pre-approval—not by capacity built (Spain 2008).

In theory, the self-correcting mechanism could help ensure that prices remain in line with market costs by adjusting payment levels in response to a surplus or deficiency in the number of applications received. However, as previously noted, analysts suggest that the drastic policy shift has created considerable uncertainty in the Spanish market.

While the new system could help increase the transparency of future payment level adjustments, it is unlikely to replace periodic payment level revision through administrative review. Government intervention may be necessary, for example, if rapid changes in solar PV costs are experienced in the market.

4.4   Oregon Volumetric Incentive Rate Program

The Oregon legislature passed a bill (HB 3039) in July 2009 authorizing a pilot FIT program for solar PV. The program, penned the VIR pilot program, was created to support up to 25 MW of solar PV over four years installed in Oregon by the retail customers of the state's electric companies. The Oregon PUC opened the program on July 1, 2010. The VIR program consists of three standard offers: one for small systems (under 10 kW), one for medium-sized systems (between 10 kW and 100 kW), and one for large systems (between 100 kW and 500 kW) (Oregon PUC 2010).

Oregon's standard offer VIR for small and medium-sized systems is similar to a FIT but diverges on payment structure. Referred to in the Oregon PUC docket as the "Net Metering Option," the VIR incentive for small and medium-sized projects is paid on 100% of electricity that is consumed on-site (Oregon PUC 2010). Producers who enter these contracts will receive a set rate for the power produced and consumed on site for 15 years. Excess power sent back to the grid is either donated to the utility or sold at wholesale electricity rates [in order to take advantage of this, generators would have to obtain market rate authority from the Federal Energy Regulatory Commission (FERC)] (Oregon PUC 2010).

Under the net-metering option, capacity availability under the program is rationed over a four-year period. Bi-annual allotments are set at 1.5 MW for small systems and 1.0 MW for medium-sized systems. Applications for these contracts are reserved on a first-come, first-served basis until the capacity allocation for that six-month period is fully subscribed (Oregon PUC 2010). In the ruling, the Oregon PUC found that a bi-annual adjustment approach balances the need for flexibility in correcting rates with workable and reasonable administrative costs (Oregon PUC 2010).

Like in Spain, the Oregon PUC has implemented a rate adjustment mechanism for the VIR net-metering option that adjusts according to developer response. The rate adjustments are based on how quickly each bi-annual capacity allotment is subscribed (See Figure 2). For example, if the program is fully subscribed within three months from the program start date, VIR payments are reduced by 10% for the next six-month period. The following figure demonstrates how rates are changed under the program (dates are evaluated from the program start or from the beginning of a subsequent rate adjustment) (Oregon PUC 2010).
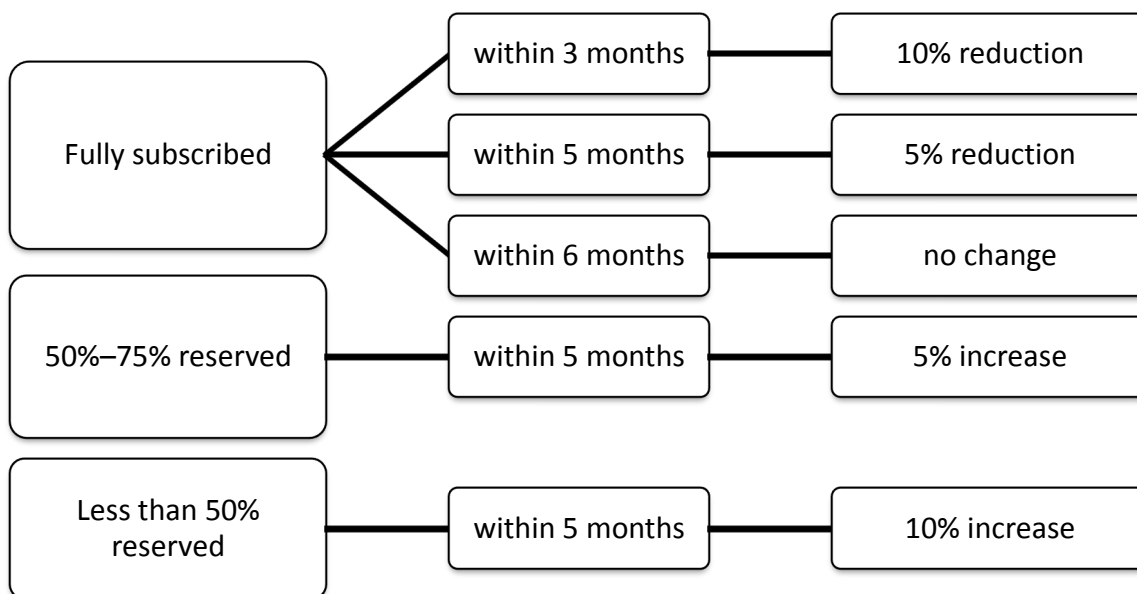
Figure 2. Payment level adjustments in the Oregon Volumetric Incentive Rate pilot program

The first round of the program started on July 1, 2010, and the capacity allowance was reserved within 15 minutes for the Pacific Power and Pacific Gas & Electric allocations, while all capacity was reserved for Idaho Power within half a day (Galbraith 2010). Those project developers who submitted their applications first will lock in to the first round payment levels (provided that the project successfully comes online). Because the capacity allocations were fully subscribed in less than a day, payment levels will be reduced in the next round by 10%. This program design is susceptible to speculative queuing due to uncertainty of what future payment levels will be.

As described in Section 4.3, this type of responsive adjustment mechanism may help align payment levels with the cost of PV in the market. Over a number of rounds, the mechanism may discover the "right" price to spur development without providing overpayment.[29] Because rates will adjust based on how fast the reservations are filled, the program requires minimal administrative work to update incentive levels according to market conditions. It is unclear at this point whether or not the program will be revisited or revised after the initial pilot.

In sum, the net-metering option under the VIR pilot program provides an alternative for how to adjust FIT payment levels. The mechanism is transparent, as the Oregon PUC has laid out a clear four-year schedule for the bidding rounds, capacity allocations, and payment adjustments. All the same, this scheme and the specific levels for the payment adjustments have not been tested fully in practice.

4.5   Analysis of Payment Level Adjustment Mechanisms
This section applies the criteria laid out in Section 2 to further explore the relative advantages and challenges with each of the four approaches to payment level adjustments.

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[29] Note that there is a mechanism for individuals to contest the rates established by the rate adjustment mechanism in the event that payment levels do not reflect solar PV cost reductions in the short term. Developers or industry players can argue to the Oregon PUC that the rates do not reflect solar PV pricing dynamics (Galbraith 2010).

4.5.1 Predictability and Manageability of Policy Outcomes

While payment level adjustment mechanisms do not provide a hard cap on total policy costs, they can reduce incremental policy costs (i.e., the incremental cost of each FIT project). In other words, where FIT payment levels are cost-based, adjustment mechanisms serve to limit ratepayer exposure to potential overpayments as technology costs are reduced over time. That being said, it is difficult to predict how the cost of a given technology will change over time (Jacobs and Pfeiffer 2009), so it may take time for policymakers to develop and refine payment level adjustment mechanisms.

Due to its simplicity and predictability, predetermined degression is a common payment level adjustment mechanism for FIT programs in Europe (Klein et al. 2008). While predetermined degression can be effective for technologies experiencing measured reductions in costs, it may not track short-term cost trends in a dynamic global market (i.e., solar PV) as accurately. Additionally, policy intervention may be necessary to fine tune rates of degression if they do not match market realities.

In the last few years, policymakers have introduced more refined methods of payment level adjustments in order to influence policy outcomes and to track short-run cost trends for dynamically changing markets. These mechanisms, described in this report as responsive or volumetric, theoretically limit the need for direct policy intervention if under- or overcompensation is perceived. They are beneficial because each project's payment level (and thus revenue) is relatively predictable (within a range), which reduces uncertainty so that projects can secure financing.

In Germany, responsive degression (as described in Section 4.1.2) is being used to temper policy outcomes without introducing capacity-based caps. The framework allows policymakers to attenuate oversupply of capacity by accelerating the rate of degression according to how much was installed in the prior year. Policymakers considering this strategy will need to define an allowable range of policy outcomes and experiment with different payment level adjustment factors to achieve desired results.

Spain and Oregon have implemented mechanisms to adjust payment levels upwards or downwards on a sub-annual basis, according to how developers respond (i.e., apply for FIT contracts) at different payment levels. This highly responsive approach might be effective at tracking short-run cost trends where caps are not prohibitive and where sufficient competition is occurring between product suppliers (Jacobs and Pfeiffer 2009). However, policymakers implementing small pilot programs utilizing this policy design may want to consider that pent-up demand may lead to a rapid decline in payment levels in the first few rounds, as developers may be willing to accept a lower return on investment on a project in order to gain a foothold in the market.

It is important to note that even with payment adjustment mechanisms in place, some degree of oversight is likely to remain necessary to ensure that pricing levels remain in line with market realities and to ensure that the pace of market growth is in line with both policymakers' expectations and other limiting factors such as available grid capacity. Most jurisdictions with FIT policies review their programs (including payment levels and adjustment mechanisms) periodically (every 2–4 years, on a predicable schedule).

If the goal of the FIT policy is to spur rapid deployment, these policy approaches may be effective tools because they build in incentives to invest in the short-run, as developers anticipate future payment level reductions. Also, it has been suggested that degression could be used to spur technological innovation because investors have incentive to reduce installation costs in order to secure a higher rate of return as payment levels decline (Frondel et al. 2010; Grace et al. 2008). In theory, degression could have modest cost-diminishing impacts, but no strong empirical evidence is available. For example, in Germany, payment levels are often adjusted upward during periodic program reviews, so the cost-diminishing effects of degression have not been observed (Frondel et al. 2010).

4.5.2 Unintended Consequences

If poorly designed, payment level adjustment mechanisms could exacerbate market volatility by introducing sudden and substantial price changes. Sharp changes in payment levels could contribute to the formation of boom and bust cycles as developers rush to lock in projects at a known price or step away from the market altogether in the anticipation of significant price cuts.

Also, under such a framework, it is possible that payment levels could deviate significantly from market realities over time. Thus, administrators may want to oversee market developments and characterize how payment levels line up with market costs. Program oversight can alleviate risk of under- or overpayment.

If market players anticipate large payment level reductions, they might rush to submit applications before these changes take effect. For example, this effect was witnessed in the Spanish solar market in late 2008 (de la Hoz et al. 2010). In the first half of 2010, CSI program administrators attributed program demand spikes to imminent incentive level reductions (CPUC 2010b). If payment level adjustments are expected to be sizeable or seem to be swiftly approaching (in the case of volumetric adjustments), developers may submit FIT applications without doing proper due diligence—a reality that might lead to nonperformance.

4.5.3 Implications for the Marketplace

It becomes more difficult for developers and investors to predict if a project under development will be economic at the point of commercial operation if a FIT payment level adjustment framework is in place. However, policymakers can boost investor confidence by laying out explicit schedules for payment level adjustments, as both the nature and extent of changes can be anticipated in advance.

With respect to the exact timing of payment level changes, annual adjustments tend to provide more certainty for investors than volumetric ones, but there are exceptions. Investors may have difficulty predicting when a particular volumetric target will be reached. This can create additional uncertainty in the marketplace unless regular updates on capacity installments are provided (as with the daily updates in the CSI). Volumetric adjustments can also add to uncertainty if the blocks of capacity are relatively small compared to the total size of the market.

Finally, when payment levels are adjusted by one of the aforementioned methods (and not through administrative review of cost characteristics), there is inherent risk that payment levels could deviate from market cost realities. This can be particularly important for manufacturers who are more exposed to front-line reductions in tariff payments due to their ownership of fixed

capital in production facilities. Divergence between market costs and payment levels could compromise long-run investor confidence, possibly resulting in capital flight.

5 Auction and Competitive Bidding-Based Mechanisms

Auctions are commonly used in bid-based energy markets, where electricity producers effectively "bid" into a marketplace at a price that approximates their marginal cost (Sioshansi 2008). "Sealed-bid" auctions, where a uniform price is set according to either the last winning bid or the first losing bid, are the most common auctions in electricity markets (David and Wen 2002). New Jersey electricity distribution companies (EDCs) commonly employ "descending-price clock" auctions to procure three-year contracts for "Basic Generation Service" (Tierney and Schatski 2008). Auctions or auction-based mechanisms have been used (or are planned to be used) for RE policy procurement in several jurisdictions, including Brazil, New York, Illinois, New Jersey, and California.[30] Policymakers are considering using auction-based mechanisms to set prices for FIT procurement.

It is important to note that an auction-based system differs from FITs in that they do not provide to developers and their investors what is considered to be the primary benefit of a FIT policy: assured access to a known long-term revenue stream. Assured access to a long-term FIT payment means that developers avoid risks and costs associated with (Corfee et al. 2010):

- Development timing (e.g., missed milestones)

- Contracting (e.g., investment in solicitations or contract negotiations without yielding off-take agreement)

- Contract price (e.g., setting a firm power purchase price before development contingencies are resolved and project costs are fully known)

- Revenue (adequacy of revenues to provide target returns).

For this reason, use of an auction or competitive bidding system is by definition a FIT policy *alternative*. Nonetheless, auctions or competitive bidding may be considered as preferred alternatives to FITs where concerns over FIT costs are present. Furthermore, good design is essential to yield successful competitive auctions, as described in the following text box. This section explores several auction systems and explains how they could be applied to FITs.

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[30] Whereas auctions are generally held for the renewable electricity generation itself, New Jersey's solar REC market has led to the development of forward contract auctions for RECs instead. New York's RPS Main Tier solicitations also offer long-term standardized contracts for "RPS Attributes" equivalent to RECs.

Auction Preconditions and Design Considerations

In order to yield a functionally competitive auction, the marketplace must be liquid and homogenous (Grace 2010). Liquidity is increased by market size—the more investors that can compete in the auction system, the more liquid the market becomes. Frequency of auctions and amount of RE generation auctioned increase market size and liquidity. Many auctions are technology-neutral to increase the pool of investors.

However, in price-only auctions, product homogeneity becomes important. The auctioneer needs a known commodity so that bids can be compared fairly. In electricity markets this equates to delivery characteristics, or "firmness" of power. Auctions for electricity can create conditions where products are more uniform in several ways, for example, by auctioning long-term contracts for RECs, by requiring electric generation to be firmed or shaped, or by creating separate auctions for baseload, peaking, and variable-output electricity products.

Homogeneity also reflects homogenous project completion risk, which is a challenge for new generation where permitting and financing risk can vary significantly from project to project (Corfee et al. 2010). For example, established developers may not have the same troubles obtaining financing as new developers. Some projects may run up against development hurdles, while others may find the process much easier. To ensure a higher level of financial homogeneity in an auction (which is difficult for projects that have not reached commercial operation), program administrators often include preconditions (that establish developer experience and project viability) or financial repercussions for nonperformance.

5.1 Renewable Energy Auctions in Brazil

Energy forward-contract auctions for RE have been held in Brazil for over five years. The auctions are carried out for resource adequacy purposes and standardized contracts are awarded for electricity delivery beginning three or five years after the bid selection. The auctions are held centrally—that is, electric distributors determine their demands for future delivery, and these estimates are aggregated into a large market block indicating new electricity requirements (Moreno et al. 2010a). From 2004 to 2009, Brazil carried out 16 long-term contract auctions for RE, contracting 37,000 average MW[31] of firm energy (from both new and existing generators). During this period, more than 20,000 MW of new capacity was acquired for delivery between 2008 and 2014, and the average contract price for new energy was US$76/MWh (Moreno et al. 2010b).

Brazil's auctions are held as standard financial forward auctions, wherein generators bid an energy price (effectively in $/MWh) to supply a specified quantity of firm energy[32] for the

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[31] An average megawatt is 1 MW of capacity produced continuously over a period of one year. 1 MW$_a$= 1 MW x 8,760 hours/year = 8,760 MWh = 8,760,000 kWh.

[32] Contracts need to be covered by adequacy guarantees in the form of "firm energy" or "firm capacity" certificates or any other credible measure of adequacy (Moreno et al. 2010a).

duration of a long-term contract.[33] Contract lengths have varied but typically range from 15–20 years for new supply (Moreno et al. 2010a).

The auctions are conducted in two rounds: a descending price clock auction and a final pay-as-bid round (Moreno et al. 2010a). In the first round, the auctioneer initiates the auction with a high-energy price that is anticipated to create excess supply. Generators bid in the quantity they would supply at this price. As the clock advances, while there is still excess supply, the auctioneer decreases the energy price. This phase is known as the classification phase, as it aims to provide price discovery. In the second round, generators bid a final sealed price, which cannot be higher than the price disclosed by the classification round (Moreno et al. 2010a).

The latest auctions for new renewable supply were held August 26–27, 2010. The country's distribution utilities signed contracts with 89 projects representing 2.9 GW of potential installed capacity (Zindler 2010). Contract prices were competitive: winning biomass developers received power purchase agreement (PPA) prices averaging US$83.50/MWh for 713 MW of potential capacity, and winning wind developers received on average US$74.40/MWh for 2.1 GW of potential capacity (Zindler 2010). Bloomberg reports that though these wind contracts are well within the range of current wind levelized cost of energy (LCOE) estimates, the average price for wind contracts represents a 42% decrease from those signed under Brazil's PROINFA RE subsidy program, which ran between 2002 and 2005 (World Resources Institute 2010; Zindler 2010). Furthermore, some winning bidders projected annual average capacity factors as high as 55% for their wind projects, which may be considered optimistic (Zindler 2010).

Auction-based approaches will only result in low-cost renewable generation if developers fulfill their contractual obligations. If developers are unable to recover their construction and operation costs given their bid, they may not go forward with the project (Wiser et al. 2006). The most recent Brazilian auction results suggest some underbidding by wind developers (Zindler 2010). This emphasizes the importance of including material financial repercussions for nonperformance. When developers perceive no repercussions for offering speculative bids, prices often turn out to be inadequate to make projects viable. Brazil's bid system does have penalties for developers who sign contracts that they cannot uphold, but it is unclear how binding these fees are (Zindler 2010).

On the whole, some analysts have found Brazil's auction mechanism to be effective at producing competitively priced contracts and to be reasonably efficient, especially since bids are submitted on energy price only (Moreno et al 2010a). Contracts are lasting and provide revenues essential for developers to obtain financing (Moreno et al. 2010a). Furthermore, the implementation of identical contracts and a centralized auction system is advantageous for generators as the period of supply, risks, and supply conditions are clear (Moreno et al. 2010a).

5.2 New Jersey Solar Renewable Energy Certificate Financing Program

The second example is derived from a new program in New Jersey that has been used by the EDCs, Jersey Central Power and Light Company (JCP&L), Atlantic City Electric Company (ACE), and Rockland Electric Company (RECO) to procure solar renewable energy certificates

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[33] Energy call options are also available in Brazil, an instrument where distributors can specify a quantity of energy that they would like to procure at or under a strike price. The distributor also pays a premium for capacity availability ($/kW/month or $/year) (Moreno et al. 2010b).

(SRECs) under long-term contracts. Under direction of the New Jersey Board of Public Utilities ("Board"), the EDCs have developed a small SREC auction program to enhance financing for developers of systems less than 500 kW in size (NERA Economic Consulting 2010a). The total program size is 64 MW (19 MW for ACE, 42 MW for JCP&L, and 3.769 MW for RECO) (NERA Economic Consulting 2010b).

The auctions are held for long-term SREC contracts (10–15 years in length). The program was designed to provide winning developers with a way to achieve cost recovery for investment in solar projects in New Jersey and ultimately to facilitate project finance. The contracts resulting from the auctions are standardized and non-negotiable, and developers are encouraged to bid for SREC contracts that would provide sufficient project returns.

Quarterly solicitations are held to select competitive proposals for SREC contracts. The bidder submits a pricing proposal ($/SREC and contract duration) and a summary of project qualifications (NERA Economic Consulting 2010c). Since bids may vary in terms, the auctioneer ranks each bid according to the net present value of payments under the SREC agreement. The Board has determined a capacity cap for each EDC in each solicitation,[34] and the auctioneer accepts bids in order of competitiveness up to that cap. There is an undisclosed price limit when evaluating bids, and the auctioneer decides whether or not there are enough competitive bids to meet the auctioned quantity (NERA Economic Consulting 2010d).[35] Five auctions have been held to date, and the aggregated results are summarized in Table 5.

Table 5. Results of the First Five Solicitations of New Jersey Solar Renewable Energy Certificate Auctions

	Solicitation 1	Solicitation 2	Solicitation 3	Solicitation 4	Solicitation 5
Date bids submitted	8/25/09	12/11/09	3/5/10	6/11/2010	10/14/2010
Bids submitted (participation)	8	44	63	23	57
Contracts awarded	7	39	57	20	55
Total capacity awarded (kW)	1,585 kW	6,522 kW	9,333 kW	3,932 kW	9,512 kW
Average size (kW)	226.5 kW	167.2 kW	163.7 kW	196.6 kW	172.9 kW
Average NPV for contracts ($/kW)		$2,864.93	$2,999.51	$3,296.71	$3,248.12
- Corresponding 10-yr REC contract price ($/MWh)	$409.71	$405.15	$424.17	$466.21	$459.34
Lowest NPV ($/kW)		$1,926.53	$2,473.10	$2,925.32	$2,967.72
- Corresponding 10-yr REC contract price ($/MWh)	$369.00	$272.44	$349.74	$413.69	$419.69

Sources: NJBPU 2009 ; NJBPU 2010a ; NJBPU 2010b ; NJBPU 2010c ; NJBPU 2011

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[34] For example, in the Fifth Solicitation (October 2010), ACE's planned capacity is over 5.8 MW, JCP&L's planned capacity is approximately 8.7 MW, and RECO's is nearly 1.5 MW (NERA Economic Consulting 2010d).
[35] A similar approach is used in Illinois and New York, which employ centralized procurement for their RPSs. The administrators have established (but not publicized) benchmark prices, above which no RE contract will be signed (Grace 2010).

The Board has found the program to be effectively competitive in each round yet is disappointed with the level of participation in the program to date (NJBPU 2010c), as there has been under-subscription of the capacity solicited since the program's inception (NERA Economic Consulting 2010b). In August 2010, the Board ordered an extensive review of the program with consultation from representatives from the solar industry in order to identify measures to improve program participation (NJBPU 2010c).

The novelty of the program, the 500 kW project size limit, and the small size of each solicitation has limited the universe of potential bidders in the program thus far. Another factor that might be suppressing the market is that developers may perceive bidding-related costs and risks to be large relative to the scale of revenues for such small projects.

5.3 California Renewable Auction Mechanism

California's new Renewable Auction Mechanism (RAM) program has been touted as an alternative to FITs in the U.S. context.[36] In August 2010, the California PUC issued a proposed decision establishing a technology-neutral auction program to be implemented by Southern California Edison, Pacific Gas & Electric, and San Diego Gas & Electric (CPUC 2010c). The RAM program requires each of these utilities to conduct auctions to procure an aggregate capacity of 1,000 MW.

Each utility is responsible for establishing bidding protocols and providing solicitation materials, including standard contracts, to potential bidders. An auction must be held every 180 days, and the utilities must coordinate and conduct their auctions concurrently so that bidders can enter all three auctions if desired (CPUC 2010c). The utilities are to solicit three different products through auctions: firm, non-firm peaking, and non-firm non-peaking renewable electricity supply. The generation units must be between 1 MW and 20 MW of capacity (CPUC 2010c).

The auctions will be conducted through as-bid price auctions; each utility buyer must award contracts sequentially to generators from lowest price bid to highest. Those selected will receive their proposed payment level and standard contract terms. Utilities are only obligated to select bids up to a "reasonableness threshold," or price cap. This price cap, penned the Simplified Preapproval Threshold (SPT), is equivalent to 150% of the California PUC-adopted market price referent (MPR), adjusted by California's time of delivery (TOD) factor. The generation profile of each individual bid is compared against the SPT value, adjusted by the TOD factor (CPUC 2010c).

In order to create a reasonable level of financial homogeneity, the California PUC has established minimum project viability criteria, including proof of site control, documented developer experience, use of equipment approved by the California Energy Commission and certified to meet Underwriter's Laboratory testing standards, use of commercial technologies,[37] and an interconnection agreement filed by the date of the auction (CPUC 2010c). Once a bid is

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[36] Oregon has also implemented a similar program for its FIT pilot program (for projects between 100 kW and 500 kW) (Oregon PUC 2010), and the Arizona Corporation Commission has expressed interest in the mechanism (Arizona Corporation Commission 2010).
[37] The specific definitions of "developer experience" and "commercial technologies" are provided in the decision but will not be emphasized here.

selected, there is a stringent requirement for placing the project online within 18 months of executing the contract. Development and performance deposits are also required for winning bidders, creating further product homogeneity through equivalent repercussions for non-performance (CPUC 2010c).

In order to maximize competition, California PUC ruled that each utility's auction must be held concurrently, and project developers are permitted to submit bids into all three auctions (CPUC 2010c). Also, projects may interconnect in an area wider than the utility's service territory (although RPS delivery requirement rules still hold and utilities can indicate preferred locations).

This program, billed by many as a market-based alternative to FITs, has garnered interest in the United States. However, proof of concept can only be established through successful implementation.

5.4 Competitive Bidding in China

Another innovative auction approach is being used in China, where competitive bidding is used to establish "competitive benchmarks" for cost-based FITs (Grace et al. 2008).

China has recently adopted FITs in certain provinces to accelerate RE development. In contrast to jurisdictions like Germany and Ontario where the FIT payment levels are established by a combination of market analysis, surveys, industry research, and public consultation, the FIT payment levels awarded to solar and wind power in China were derived through a competitive bidding process, or "prior tendering" (Han et al. 2009; Martinot 2010). This competitive bidding process provided a way of soliciting prices from a wider array of manufacturers and developers, providing direct access to information about RE costs. In this annual tendering process, a single-round, sealed-bid auction results in contract winners. The difference in China is that the bids are subsequently used to set region-wide prices, bringing the policy closer to a FIT in practice, but one in which the prices were competitively derived (Martinot 2010).

In China, the RE sector is undergoing rapid developments, and costs are being quickly reduced due to process improvements, cluster effects, increased efficiencies, and economies of scale. Given the sheer number and diversity of RE manufacturers, it would be difficult to administratively set standard FIT payment levels. Partly for these reasons, China opted to solicit bids from those producers and manufacturers and to set the prices awarded to wind and solar producers based on the results of the bidding (Han et al. 2009). Once set, these fixed purchase prices effectively function like FITs elsewhere in the world: the primary difference is the means by which these payment levels are derived.

It has become clear that many of the bids received during this process were too low, resulting in economically unviable projects and necessitating an after-the-fact revision of many of the contracts (Chan 2009; Han et al. 2009). While recent reports show that "concessionary bidding" is still being used for emerging technologies such as solar thermal power (BNEF 2010), China is beginning to move to a system of fixed FITs for technologies such as wind and solar PV[38] (Martinot 2010). China's National Development and Reform Commission (NDRC) explained in

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[38] China will continue to offer a premium-based FIT for biomass projects, which consists of a fixed premium that floats above the region-specific coal-based electricity price (Martinot 2010).

2009 that moving to a system of fixed FITs would "change current inconsistent pricing, foster clear expectations and facilitate investments in the sector" (Reuters 2009).

5.5   Analysis of Auction and Competitive Bidding-Based Mechanisms

Auctions and competitive bidding-based mechanisms have a variety of advantages and challenges with regards to promoting predictable and manageable policy outcomes, introducing unintended policy consequences, and evaluating impacts on the marketplace.

5.5.1   Predictability and Manageability of Policy Outcomes

In theory, auctions or bidding-based mechanisms could reduce the incremental costs of FIT programs by limiting the risk that FIT prices will be set too high. However, the costs and risks that auctions introduce for developers essentially remove the key benefits of the FIT approach, as described in Section 5.0.

Regardless, holding auctions can yield fairly predictable policy outcomes. Auction-based mechanisms have the advantage that they are issued for finite blocks of power[39] with specific, standardized conditions that define access and eligibility. If conditions are sufficiently competitive, then the winning price can be considered reflective of cost, limiting concerns associated with FIT overpayment. While most auction systems tend to select bids on the basis of price, policymakers could attribute weightings to non-price characteristics in order to customize the bid results to the targeted objectives. For instance, special considerations might include generator dispatchability, location on the grid, or economic benefits to the jurisdiction.

Also, auctions can provide a clear schedule over which the procurement of new electrical capacity will occur, which can facilitate future power planning. This may increase the predictability of future supply trends for policymakers, as the auctions can be tailored to suit near- to medium-term supply needs.

On the other hand, experience suggests that speculative underbidding during the auction process can lead to high attrition rates, which may jeopardize this certainty and lead to fewer projects being built than were initially contracted (Grace 2010; Wiser et al. 2006). Developers may also use unrealistic assumptions to bolster their chances of obtaining bids (Zindler 2010) in the hopes that future renegotiations will make up for the shortfall.[40] If competitive bids do not impose material financial repercussions for nonperformance, projects might not get built. Auctions for new generation still exposed to completion risk may reduce the likelihood that RE targets will be met on time due to the potentially high contract failure rates.

Additionally, program oversight akin to the level currently required by competitive solicitations for RE will be necessary to administer and verify the results of an auction. Emphasis on project viability assessments will increase the time required by the regulator to evaluate projects to be used for a FIT. On the other hand, China's competitive-bidding mechanism for setting FIT payment levels may require less administrative time and oversight needed in setting rates.

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[39] The Chinese example in this section is an exception, wherein the auction is held to determine the open-access FIT rate.

[40] This problem can potentially be remedied by placing a floor on eligible auction prices, but this brings the mechanism markedly closer to a FIT, which undermines its primary theoretical merit, namely, that of yielding market-based prices (Zindler 2010).

Despite these issues, policymakers whose goals are to obtain competitively priced contracts for their ratepayers may consider auctions or bidding-based mechanisms as a component of the FIT design or an alternative to FITs. The hybrid concept may be attractive because it provides investors with long-term revenues while selecting for the lowest price contracts.

5.5.2 Unintended Consequences

Where material financial repercussions are not associated with an auction, bids may turn out to be inadequate to make projects viable (or might end up higher than administratively set payment levels). Penalties for cases of conspicuous underbidding or for failure to deliver on the contract once signed may increase the overall success rate, but at a cost. The inclusion of significant repercussions to non-performance will inevitably limit competition, effectively compromising the ability to derive true price discovery due a smaller number of participants.

Another potential adverse consequence of an auction-based system for awarding long-term contracts is that it may lead to market concentration issues, where few sellers receive the majority of contracts. Auction results may be biased towards established, well-capitalized players who can shoulder the costs and risks of mounting a bid. However, policymakers can design auctions to reduce the risk of market concentration. For example, the New Jersey Board of Public Utilities addressed this issue by ordering that no one entity, and no combination of affiliated entities, could obtain more than 20% of the EDC's long-term contracts (calculated based on kilowatts) in any one year in both JCL&P and ACE[41] (NERA Economic Consulting 2010b).[42]

5.5.3 Implications for the Marketplace

Provided that there is sufficient homogeneity and liquidity in the bidding process, including a sufficiently large number of players, auction-based mechanisms can yield competitive outcomes. And if a fixed schedule of auctions is set forth at regular intervals (e.g., more than once per year), they can create a modest degree of certainty in the existence of a long-term market for investors and developers.

However, auctions introduce a new set of risks for investors, particularly when compared to a standard offer or FIT approach, which may reduce the access to markets for new participants and increase financing costs. In particular, developers must incur significant upfront costs in order to mount a bid with no assurance that they will obtain a contract. It is likely that this will reduce investment certainty, make project financing more tenuous, and limit the market to a smaller subset of players. Solicitations tend to favor well-capitalized organizations and could prove to be a substantial barrier for smaller, less well-capitalized firms. Auctions designed to have significant repercussions for non-performance are likely to introduce a higher barrier to entry for prospective developers.

Relative to a FIT policy, auctions could make it more difficult to develop and sustain a robust manufacturing sector if auctions are only offered periodically (e.g., once per year) and if there is no long-term procurement intention (e.g., a certain quantity of development over 5 or 10 years). More generally, auctions are likely to introduce greater uncertainty for market participants

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[41] In RECO, no more than 50% of allocated capacity can be developed by a group of affiliated entities.
[42] Note that this may be difficult to police since business models can include various multi-level contracts between parties, which may conceal the oligarchic nature of the FIT contracts (Crider 2010).

because bidders are not assured of winning. Furthermore, auction-based mechanisms could also create a new set of uncertainties for manufacturers and suppliers, as the reliability of demand is not only influenced by market and financing fundamentals but also by the overall effectiveness of the auction process at yielding viable contracts. If auctions are held infrequently, they could also create a start-and-stop pattern of development, putting additional strain on various constituents of the RE supply chain.

6 Conclusion

As FITs can catalyze significant amounts of renewable electricity generation relatively quickly, the importance of proper cost controls is critical in order to prevent excessive ratepayer cost.

Analysis of FIT policies has shown that stability and longevity are important to their success and that sudden, unpredictable changes can lead to capital flight (Couture et al. 2010; Deutsche Bank 2010). Implementing cost controls from the outset can avert the need for drastic policy corrections and can therefore help projects secure financing and provide greater certainty to investors and manufacturers while still enabling RE targets to be met on time.

The case studies of policy caps showed that caps are a direct way of limiting total expenditures in a FIT program. However, depending on the level established for the cap, project size caps may limit the ability to harness economies of scale. Also, it may be difficult to determine precisely when a cap on policy cost has been reached, introducing an element of uncertainty for both regulators and investors. The possibility that investors could invest in and build a project before learning that a cap had been reached, leaving it ineligible for the FIT, would be a worst-case scenario. Any uncertainty that makes this result more plausible means fewer projects will be able to secure financing. Also, caps can fuel speculative queuing, although this problem can potentially be remedied by requiring application fees or other forms of cash deposits or implementing milestones and other measures to expeditiously remove non-performing projects from the queue.

One of the key challenges to designing FIT policies is to successfully track market costs of RE technologies so that producers are not under- or overcompensated. While payment level adjustment mechanisms alone cannot provide a hard cap on total policy costs, they can be used to reduce the chances of overpayment, thereby reducing the likelihood of fueling an investment bubble as occurred in Spain in 2008 (Deutsche Bank 2009). A predictable framework for predetermined payment level adjustments is important to providing clarity and certainty to project investors and manufacturers.

In addition, responsive frameworks for price adjustment can provide a more "hands-off" approach, as the self-correcting nature of the mechanism adjusts the payment levels over time without direct intervention. Technologies like solar PV with more dynamic cost trends might be better suited for responsive degression or volumetric payment level adjustments. However, volumetric approaches could lead to more uncertainty in the marketplace, as it may be difficult to predict when a volumetric cap will be reached. Perhaps more importantly, adjustments strictly assessed on quantity of capacity installed may fail to coincide with actual price trends.

Finally, auction-based pricing can be applied to a FIT policy framework or in place of a FIT. On one hand, auctions can be a relatively flexible way of procuring new electrical supply, and auctioneers can initiate auctions for particular types of generation capacity: regional, technology-specific, or based on load characteristics. However, there are material challenges associated with implementing auctions for new RE projects with differing characteristics, different timing of commercial operation, and differing completion or performance risk. In order to be functionally competitive, the market must be sufficiently deep and liquid and the product being auctioned must be relatively homogenous both in definition and performance risk. Auctions can be prone to

speculative bidding if deterrents are not in place. These could include penalties for failing to fulfill the contract or a pre-screening process to eliminate improbable bids.

Some innovative approaches have been adopted to control the costs of FIT policies. However, care should be taken in implementing cost control measures to help mitigate unintended consequences while ensuring that policies ultimately deliver on their intended objectives.

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