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CALIFORNIA FEED-IN TARIFF DESIGN AND POLICY OPTIONS

FINAL CONSULTANT REPORT

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CALIFORNIA ENERGY COMMISSION

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Abstract

This report explores using feed-in tariffs for renewable electricity generation projects in California and makes recommendations for future policy development. California has a Renewables Portfolio Standard (RPS) that requires the state's investor-owned utilities, community choice aggregators, and energy service providers to provide 20 percent of retail sales with renewable resources by 2010; publicly owned utilities are required to develop RPS programs as well. As noted in the *2007 Integrated Energy Policy Report*, California is not currently on track to meet this mandate. The Governor has endorsed, under Executive Order S-14-08, a further enhanced goal of 33 percent from renewable energy by 2020. The Executive Order requires new policy tools to meet this aggressive target. It is clear that renewable energy must play a significant role in meeting the state's aggressive carbon-reduction goals.

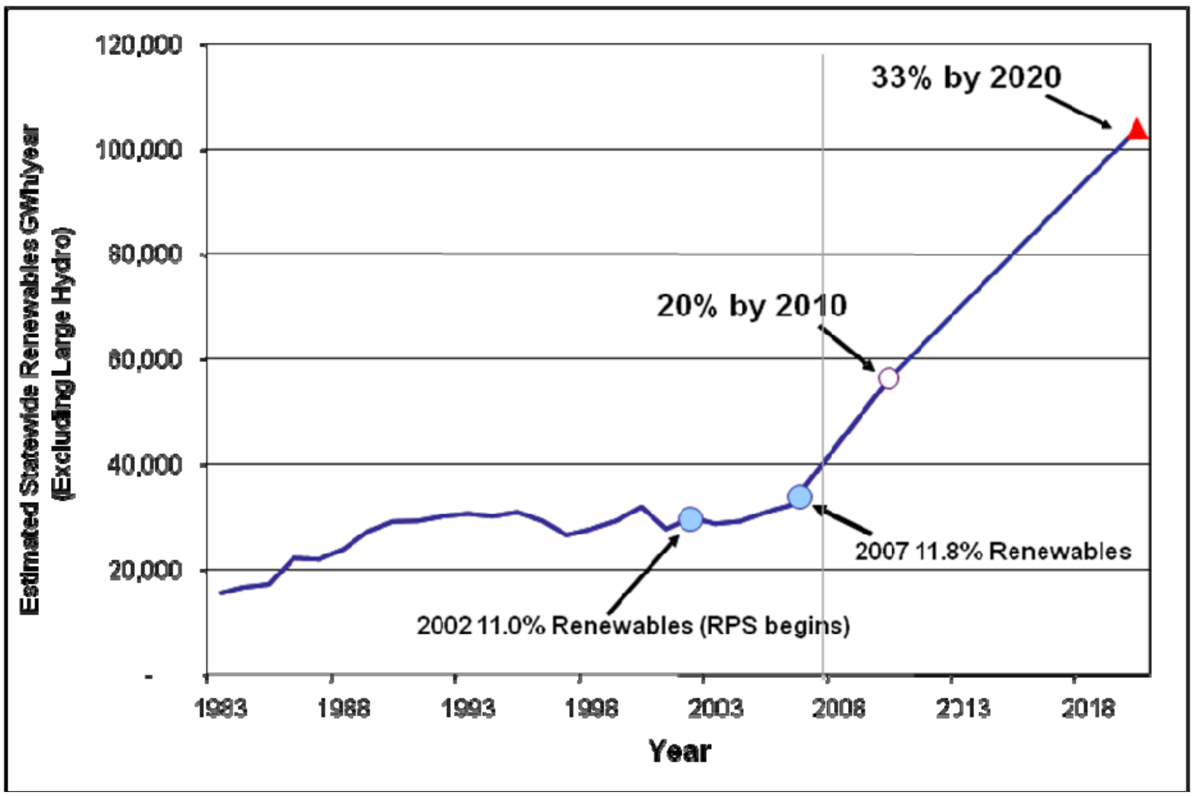
This report explores the potential to use feed-in tariffs as a tool to aid in making California's renewable generation goals a reality. There are a variety of potential feed-in tariff policy design options and policy paths including appropriate tariff structure, eligibility, and pricing. This report considers policy goals and objectives; stakeholder comments presented in the Energy Commission's June 30, 2008, October 1, 2008, December 1, 2008, feed-in tariff workshops and subsequent direction from the California Energy Commission Commissioners; the findings of a companion report, *Exploring Feed-In Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options*; and lessons learned from feed-in tariff experience elsewhere, primarily in Spain and Germany. This report reviews the pros and cons of six representative policy paths that were identified for further consideration, explores the potential interaction of these policy paths, examines the interaction of feed-in tariff policies with other related policies, and recommends a policy path that California develop a cost-based, feed-in tariff for projects 20 megawatts or less that would be technology-specific (each eligible technology receives a differentiated rate as compared to other technologies) and differentiated by project size. This report also recommends that the Integrated Energy Policy Report process consider several issues related to feed-in tariffs, such as how to establish initial feed-in tariff prices; how, when, and how often to adjust feed-in tariff prices; how to design feed-in tariffs for efficient transmission, distribution and power supply planning; Federal Energy Regulatory Commission jurisdictional issues; what potential legislative issues may be involved; and further exploration of feed-in tariffs for facilities greater than 20 megawatts.

Keywords: Feed-in tariff, tariff design, energy policy, Renewables Portfolio Standard (RPS), renewable resources, renewable energy policy, interconnection, grid access, cost allocation, fixed-price payments, greenhouse gas emissions

Executive Summary

California established a Renewables Portfolio Standard (RPS) with the enactment Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002). SB 1078 required the state's investor-owned utilities, community choice aggregators and energy service providers, to provide 20 percent of retail sales with renewable resources by 2010; publicly owned utilities are required to develop RPS programs as well.[1] The *2007 Integrated Energy Policy Report* (*2007 IEPR*), pointed out that California is not currently on track to meet this mandate. Additionally, the Governor, under Executive Order S-14-08, has endorsed a further enhanced target of 33 percent for renewable energy by 2020 (Figure 1) which requires new policy tools to meet this aggressive goal.

Figure 1: California's Renewable Energy Goals



Source: California Energy Commission, 2007 Net System Power Report[2]

This report explores the potential to use a feed-in tariff as a tool to aid in making California's renewable generation goals a reality. A feed in tariff is an offering of a guaranteed payment over a specified term with specific operating conditions to eligible renewable generators. There

[1] See Public Utilities Code Section 387, Subdivision (a).

[2] *2007 Net System Power Report. California Energy Commission.* April 2008. Publication number: CEC-200-2008-002.

are a variety of potential feed-in tariff policy design options and policy paths including appropriate tariff structure, eligibility and pricing. This report considers policy goals and objectives, stakeholder comments presented in the Energy Commission's June 30, 2008, workshops on feed-in tariff design issues and options, the October 1, 2008, and December 1, 2008, workshops on tariff design and policy options, and lessons learned from feed-in tariff experience in Spain and Germany. The report explores and analyzes the potential interaction of six representative policy paths and examines the interaction of feed-in tariff policies with other related policies (Table 1). Finally, it concludes with a recommended policy path for development and implementation in the Integrated Energy Policy Report process. The report incorporates public comments from the December 1, 2008, workshop and subsequent direction from the California Energy Commission Commissioners.

As can be seen in Table 1, Policy Path 1 is similar to the feed-in tariff system currently used in Germany, except that the feed-in tariff in Policy Path 1 would be triggered if California's 20 percent renewable energy goal is not met by 2010. Under this option, tariffs would become available in the 2012-2013 timeframe to help assure that the 33 percent renewables target would be met by 2020. There are no restrictions on generator size, and all contracts are fixed-price and long-term. The tariffs would be differentiated by technology and project size. It is cost-based, and the preliminary price settings would be set competitively through a bidding or auction process, not administratively by analytical analysis of estimated cost. The use of emerging resources would be capped to limit ratepayer impacts. Using long-term contracts and prices based on technology would provide a degree of price stability to investors, while promoting a diversity of renewable resources.

Policy Path 2 is a pilot program within one utility for generators greater than 20 megawatts (MW), and would go into effect immediately without any trigger mechanisms. Long-term fixed-price contracts would be available for projects coming on-line within a three-year window, after which the policy would be reevaluated. There would be no limit to the quantity of generation eligible to use this tariff, since the limited duration would constrain its overall use. Tariff payments under this option would be value-based, with payments differentiated only by production profile (time of production, contribution to peak, and so forth) and/or environmental adders, rather than being based on the costs of different technologies. The value-based payments could alleviate some ratepayer concerns regarding cost-based alternatives, but this path may not promote the resource diversity that Policy Path 1 provides.

The following table (Table 1) summarizes the key elements of the following descriptions of Policy Paths 1 through 6.

Table 1: Policy Paths for Further Discussion

	Policy Path 1	Policy Path 2	Policy Path 3	Policy Path 4	Policy Path 5	Policy Path 6
Resource Type	All	All	All	Solar	Biomass (sustainable)	All
Vintage	New, separate price for repowering	New + repowering	New	New	New	New, separate price for repowering
Size	No limit	> 20	> 1.5	> Net metering threshold	> 1.5	< 20
Timing	Trigger (RPS < 20 percent under contract by 2010, implement Feed-in Tariff in 2012/13)	Now (available for 3-year duration)	Automatically in 2010/11 (so projects are developed in parallel with transmission)	Now	Now	Now
Scope	Full Market	Pilot (limited time, one utility)	CREZ-Only	Pilot (e.g. within one utility)	Full Market	Full Market
Setting the Price	Cost-based with initial differentiated auction without MPR to set competitive benchmark for subsequent tariff	Value Based (time & peak differentiated with CO_2 & other adders)	Cost-based	Cost-Based w/ Competitive benchmark	Cost-based, calculated to consider sustainable yield of local biomass sources	Cost-based
Contract Duration	Long-term	Long-term	Long-term	Long-term	ST/MT	Long-term
Tariff Differenti-ation	Differentiation by technology & size	Not applicable	Wind by size, geothermal, biomass by size, solar by technology	By size, type	By fuel and size	Differentiation by technology & size
Limits	Capped at RPS targets; caps on more expensive technologies	Uncapped	Capped at CREZ Transmission limit	Capacity limit will be established for the sponsoring utility.	Uncapped	Uncapped

Source: KEMA

Policy Path 3 would initiate feed-in tariff procurement in the 2010/2011 timeframe in a designated Competitive Renewable Energy Zone (CREZ), allowing generation within that CREZ to proceed aggressively once transmission expansion is committed, without being constrained by the timing and complexity of an RPS solicitation or the risk of not being selected. It is cost-based, but tariff prices would be set administratively rather than through use of competitive benchmarks (targeting generators over 1.5 MW). This option would be limited geographically by the CREZ footprint, and the quantity eligible to take the feed-in tariff price would be capped at the CREZ transmission limit. Based on the renewable resource potential and available/planned transmission in the CREZ, this option would help alleviate concerns of under subscription of new transmission lines and support a diverse mix of renewable resources.

Policy Path 4 is a solar-only pilot feed-in tariff, including cost-based rates using a competitive benchmark and elements of Policy Paths 1 and 3. Rather than being limited to a specific window of time, however, this pilot feed-in tariff would be accomplished by limiting long-term contract availability to a single utility territory. Eligibility would be limited to solar installations larger than the net metering limit of 1 MW. It is also envisioned that there would also be a capacity cap on this option. Policy Path 4 could be established independently or in concert with another policy path.

Policy Path 5 is limited to a single technology, sustainable biomass. Tariffs would be cost-based and differentiated by size and by biomass fuel feedstock. Unlike the solar-only option, the biomass path would be available in every market, rather than on a pilot scale in a single utility, and would not be capped. The contract term would be either short- or medium- term to reflect the fuel price risk that longer term contracts would place on biomass developers and investors. This option could also be established independently or in concert with another policy path.

Policy Path 6 would immediately establish, without conditions, a feed-in tariff available statewide to generators 20 MW or less in size and would help address a perceived gap in the current RPS solicitation process.[3] It would offer cost-based, long-term prices differentiated by size and technology. Unlike Policy Path 1, however, prices would not be based on a competitive benchmark, and the tariff quantity would be uncapped. It is not limited to one technology, and therefore could help the state meet its diversity goals.

This report discusses the advantages and disadvantages of each policy path, and their effectiveness to meet the specific objectives. The policy paths identified in this report, while distinct, should not be thought of as independent alternatives. Some could be adopted in

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[3] During the three workshops, many stakeholders commented that there is a gap of existing renewable RPS solicitations and bilateral contracts for facilities of capacity 20 MW or less in size. This hypothesis is supported by examination of the Energy Commission's "Database of Investor-Owned Utilities' Contracts for Renewable Generation, Contracts Signed Towards Meeting the RPS Targets" where less than 1 percent of total cumulative MW of all active new RPS projects fall below the 20 MW project size range. See http://www.energy.ca.gov/portfolio/contracts_database.html.

combination with others, and those that do not apply to the entire California market, or are on a pilot scale or duration, can be thought of as potentially working together along a *policy trajectory*. A policy trajectory might incorporate modest initial steps before the launch of a comprehensive feed-in tariff policy regime.

This report recommends that California develop a cost-based, feed-in tariff for projects 20 MW or less that would be technology-specific (each eligible technology receives a different rate compared to other technologies) and differentiated by project size. This report also recommends that the IEPR process consider several issues, such as how to establish initial feed-in tariff prices; how, when and how often to adjust feed-in tariff prices; how to design feed-in tariffs for efficient transmission, distribution and power supply planning; FERC jurisdictional issues and what potential legislative issues may be involved.

CHAPTER 1: Introduction

Feed-In Tariffs as Renewable Energy Policy

At its simplest, a feed-in tariff is an offering of a guaranteed price providing a predictable revenue stream to eligible renewable energy generators over a specified term with specified operating conditions. Feed-in tariffs can offer either an all-inclusive rate or a premium payment on top of the prevailing spot market price for power. The price paid represents estimates of either the cost or value of renewable generation. The tariff is generally offered by the interconnecting utility and sets a standing price for each category of eligible renewable generator; the price is available to all eligible generators. Tariffs are often differentiated based on technology type, resource quality, or project size and may decline on a set schedule over time.

Feed-in tariffs have similarities and differences compared to California's historical Standard Offer contracts. California's Standard Offers have been cited as being similar in structure to early European feed-in tariffs that were modified and targeted to related but somewhat more specific policy objectives. The policies are similar, to the extent that they both offer a standard price and other terms and conditions to qualifying generators. They are also both based on an assumed cost of generation, but the basis for establishing prices is quite different: Feed-in tariffs typically are based on estimated project costs, while California's standard offers were based on the estimated cost of a combustion turbine as a proxy for capacity, and short run avoided cost, which is a system energy cost (system heat rate proxy) times expected natural gas price projects. There are, additionally, several other important distinctions between California's old standard offers and feed-in tariffs. The feed-in tariffs rates discussed in this report would be levelized rather than escalating. In addition, the feed-in tariffs can be designed to drive costs down by dropping rates over time, and quantities can also be capped, whereas California's Standard Offers were available in unbounded quantities.

An earlier consultant's report for the Energy Commission that explored feed-in tariffs, *Exploring Feed-In Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options* (*Issues & Options Report*),[4] identified a comprehensive list of feed-in tariff design issues and options associated with each issue. These are summarized in Appendix A. This report builds upon the *Issues & Options Report*, examines six policy paths related to feed-in tariffs for different sized electricity generation projects in California, and recommends a policy path for development and implementation.

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[4] Grace, Robert, W. Rickerson, K. Porter, J. DeCesaro, K. Corfee, M. Wingate and J. Lesser (KEMA) *Exploring Feed-In Tariffs for California*. California Energy Commission. Publication Number: CEC-300-2008-003-F.

Benefits and Limitations

As with other policies, feed-in tariffs provide benefits and limitations, depending on the design of the tariff. From the generator's perspective, the benefits of a feed-in tariff include the availability of a guaranteed price, buyer, and long-term revenue stream without the cost of a solicitation. Market access is enhanced by feed-in tariffs, as project timing is not constrained by periodic solicitations. In addition, completion dates may not be constrained by contractual requirements, quantities are often uncapped, and interconnection is typically guaranteed. Together, these characteristics can help to reduce or alleviate generator revenue uncertainty, project risk, and associated financing concerns. Feed-in tariffs reduce transaction costs for both buyer and seller and are more transparent to administer than the current system. Because responding to standing tariffs is likely to be substantially less costly and less complex than competitive solicitations, feed-in tariffs may increase the ability of smaller projects or developers to help the state meet its Renewables Portfolio Standard (RPS) and greenhouse gas emission reduction goals. It should also be noted that the upfront costs associated with participating in a solicitation process represent an at-risk investment for the generator under the current system. Such at-risk upfront capital is the most expensive form of capital, and can add materially to the development capital needs of a project developer. It is also the hardest capital to raise, compared to financing of a project with known and secured revenue stream. Access to such capital is a substantial barrier for smaller developers, and the costs are substantially higher on a per-unit basis for small projects. Policy makers can target feed-in tariffs to encourage specific types of projects and technologies if so desired.

However, there are limitations to how a feed-in tariff might function in California. Total feed-in tariff costs cannot be predicted accurately because, despite the predetermined payments, the quantity of generation responding to a feed-in tariff is not typically predetermined (though it can be, and sometimes is, capped). One key issue is how the tariff fits in a deregulated market structure, including questions of who pays, how payments are distributed, what portion of rates would be used to recover tariff costs, and how to integrate electric production purchased through feed-in tariffs into utility power supplies. Another question specific to California is whether feed-in tariffs would work in concert with California's existing RPS law or would require changes in that law.

Getting the price right can be challenging. If the price is set too high, the tariff introduces the risk of overpaying and over stimulating the market. This risk may be exacerbated when the tariff is open to large projects in regions with ample resource potential. On the other hand, if the tariff is set too low to provide adequate returns to eligible projects, it may have little effect on stimulating development of new renewable energy generation. Of course, it is also critically important to examine ratepayer protection issues when weighing the pros and cons of the different options. In the process of establishing prices for feed-in tariff implementation, the tradeoff between the policy's effectiveness at increasing quantity of renewable energy and its ratepayer impact can be managed through determining how aggressive or conservative the price is set for each technology. For instance, concerns about the rate impact of feed-in tariffs without caps on the more costly technologies could be reduced by setting the prices for those technologies somewhat more conservatively than the lower-cost technologies. A range of approaches for setting the price are discussed in the six options considered in this report.

Design Issues

Proper design is critical to the success of a feed-in tariff. If the tariff rates are fixed and cannot be adjusted, for example, they may not be flexible enough to respond to changing market conditions. Moreover, some feed-in tariffs intentionally or unintentionally favor less efficient plants. As renewable energy resource potential is not uniformly distributed across California, unequal costs are likely to be incurred by interconnecting utilities, raising the issue of cost allocation. Finally, tariff quantity limitations or declining tariff price blocks may encourage speculative queuing, in which projects with no real commercial prospects detract from the success of a feed-in tariff by reserving funds that are ultimately not disbursed or are later released at a lower incentive level. Policy makers should strive to minimize such negative, unintended outcomes with careful feed-in tariff design.

Energy Commission's Exploration of Feed-In Tariffs

In 2007, the California Energy Commission's *2007 Integrated Energy Policy Report* (*2007 IEPR*) recommended that the Energy Commission, in collaboration with the California Public Utilities Commission (CPUC), draft a white paper that explores the use of feed-in tariffs for electricity generation projects greater than 20 MW in California.

California has an RPS that requires the state's investor-owned utilities, energy service providers, and community choice aggregators to serve 20 percent of retail sales with renewable resources by 2010; publicly owned utilities are required to develop RPS programs as well.[5] As indicated in the *2007 IEPR*, California is not currently on track to meet the 20 percent requirement. California has also set a renewable energy target of 33 percent by 2020 and is expected to need new policy tools to meet this target. In addition, it is clear that renewable energy must play a significant role in meeting the state's aggressive carbon-reduction goals. The California Air Resources Board in October 2008 released a plan for meeting the reductions in greenhouse gas emissions required by the enactment of AB 32 in 2006. Among other things, the plan calls for a 33 percent renewable energy requirement by 2020.[6]

A number of market barriers exist to meeting the current RPS, including:

- Permitting and siting challenges.

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[5] See Public Utilities Code Section 387, Subdivision (a).

[6] California Air Resources Board (2008). *Climate Change Proposed Scoping Plan.* http://www.arb.ca.gov/cc/scopingplan/document/psp.pdf.

- Transmission availability, timing, and cost allocation.
- Development risks, including securing site control and obtaining financing.
- Complexity of the RPS solicitation processes, including suitability of RPS solicitation processes for smaller projects.
- Lack of transparency.
- Contract failure, which may be caused by a wide variety of reasons, including over-aggressive bidding in solicitation processes.[7]
- Cost changes during the project development process, which may cause some projects to become infeasible; such cost changes are often caused by external factors, ranging from whether federal tax credits will be extended to rising costs of equipment.
- Potential limitations on the availability of funds for any contract costs that are above the market price referent (MPR).

Feed-in tariffs have driven rapid expansion in renewable energy development in some markets and may provide California with a tool to increase the pace of renewables development, reduce the rate of renewable energy contract failure, address the discrepancies between the MPR and the cost of renewable project development, and promote renewable projects in areas that require new transmission.

Feed-in tariffs could potentially address a number of the barriers identified above and help California meet its 33-percent-by-2020 renewable energy target. Feed-in tariffs can:

- Reduce project developer costs, risks, and complexity without increasing ratepayer cost (relative to the cost of viable projects, as opposed to speculative bids, which result in contract failure).
- Reduce utility and regulator administrative burdens.
- Reduce transaction costs. Current complexity hampers the ability for small businesses and small projects to participate.
- Increase the willingness of developers to take on risk in addressing siting, permitting, or other barriers because the reward has a higher degree of certainty than under the current regime.
- Add the possibility of lower overall costs. Currently, low-cost, viable projects could target their bid to the anticipated MPR. In contrast, a feed-in tariff could be bid below the MPR for these resources.
- Shift competitive pressure from generators to manufacturers and suppliers of renewable energy generation equipment.

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[7] Wiser, R., O'Connell, R., Bolinger, M., Grace, R., and Pletka, R. (2006). *Building a "Margin of Safety" Into Renewable Energy Procurements: A Review of Experience with Contract Failure* (CEC-300-2006-004). Sacramento, California: California Energy Commission.

- Reduce the rate of contract failure.

Many cost factors can change between a solicitation response and a project's permitting, siting, interconnection, and equipment procurement.[8] Once projects have progressed to the point where costs become certain, previously signed contracts may become infeasible. Under the current approach, such contracts would fail (or their proponents would seek to renegotiate with the purchasing utility, a practice that would tend to encourage more speculative bidding). With feed-in tariffs, it is possible that a greater number of projects could move forward because the potential for reduced costs under a feed-in tariff regime could leave a project with a greater ability to absorb cost increases related to potential project delays.

In May 2008, the Energy Commission commissioned this study to explore the potential use of feed-in tariffs for California, originally focusing on RPS-eligible generators larger than 20 MW.

In June 2008, the Energy Commission released the *Draft Issues & Options Report* described earlier. The *Draft Issues & Options Report* explored the implications of the possible use of feed-in tariffs as a policy tool in the California context, informed policy makers and stakeholders on design issues and options available for feed-in tariffs, and identified the advantages, disadvantages, and tradeoffs of alternative design approaches. Ultimately, the report was intended to support informed discussion and stakeholder input and feedback on appropriate feed-in tariff objectives, measures of success, and design features of feed-in tariffs for renewable energy in California.

The Energy Commission held a staff workshop (Workshop 1) on June 30, 2008, to discuss the *Draft Issue & Options Report*. At that workshop, presentations explained the context for the Energy Commission's motivation for exploring feed-in tariffs, the status of RPS procurement experience, the experience with feed-in tariffs internationally and in North America, and feed-in tariff design and implementation issues. Public comment and discussion of these topics at Workshop 1, as well as an on-line survey posted to seek detailed stakeholder feedback on questions on design and implementation informed the development of a first draft of this report.

The Commission held a staff workshop (Workshop 2) on October 1, 2008, to discuss the six policy options outlined in Chapter 5 and their potential interactions. The outcomes of Workshop 2, including workshop participant comments and subsequent written stakeholder comments, informed the recommendations contained in Chapter 7.

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[8] In response to solicitations, projects often bid before having cost certainty. Fixing a project's costs requires substantial progress through permitting, interconnection, commitment to equipment orders, construction contracts, and financing. Obtaining cost certainty requires commitment of substantial funds, something many developers are unable to do without the certainty of a contract. In addition, a competitive solicitation without substantial bid security requirements encourages bidders to price aggressively, with little to lose if the price becomes infeasible.

A third workshop (Workshop 3) was held on December 1, 2008, to present the second draft of the *Issues & Options Report* and provide an opportunity for stakeholder comment. Stakeholders provided oral comments at the workshop as well as submitted written comments.

A summary and discussion of these comments is included in Appendices B, C, and D of this report, and the full comments are posted on-line.[9]

Purpose of This Report

The *2007 IEPR* recommended that a paper be developed to investigate the advantages and drawbacks of adopting feed-in tariffs in California. This paper will build upon the *Issues & Options Report* by exploring possible future feed-in tariff policy paths for California for generators of all sizes, by:

- Analyzing each of the building blocks of feed-in tariff design identified in the *Issues & Options Report*, based on a variety of factors—the pros and cons identified in *Issues & Options Report*, practical constraints, Energy Commission consultant and staff analysis, alignment with Energy Commission goals, and stakeholder comments.
- Sorting these design issues into those that comprise critical characteristics for assessing alternative feed-in tariff policy paths, policy choices that are independent of the ultimate policy path taken, and implementation details.
- Narrowing the options for each design issue to either a single viable design option for further consideration, or a narrowed set of options for further consideration.
- Developing and articulating a range of representative feed-in tariff policy paths for the Energy Commission, legislators, and stakeholders to consider further.
- Based on the evaluation criteria described in Chapter 4, identifying the ability of each representative policy path to meet articulated policy goals.
- Recommending a final feed-in tariff design based on consideration of these alternative paths and suggesting additional issues for consideration in the IEPR process.

Leading up to the *Draft Issues & Options Report*, the focus of the Energy Commission's attention was to explore the use of feed-in tariffs for electricity generation projects greater than 20 MW. Stakeholder comments during and after Workshops 1 and 2 indicated broad support for considering a wider range of generator sizes and emphasizing, at least in the near-term, smaller generators. Based on this feedback, this report considers a range of future feed-in tariff policy options that also includes smaller generators.

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[9] For the proceedings of the three staff workshops on renewable energy feed-in tariffs see: http://www.energy.ca.gov/portfolio/documents/.

Organization of This Report

The remainder of this report is organized as follows:

- Chapter 2 summarizes feed-in tariff experience outside California and lessons learned from that experience pertinent to California's consideration of feed-in tariffs as a potential policy tool.
- Chapter 3 outlines the policy goals and objectives for feed-in tariffs in California and their use as evaluation criteria for potential policy design.
- In Chapter 4, design issues are sorted into those critical for defining alternative policy paths, those independent of the policy path chosen, and those to be addressed at a later date if feed-in tariffs are adopted on a broader scale. Within each of the design issues, the options identified in the *Issues & Options Report* are then narrowed to those that will comprise the six policy paths considered in Chapter 5.
- Chapter 5 lays out a representative range of six potential policy paths for expanded implementation of feed-in tariffs in California, discusses each path's advantages and disadvantages and effectiveness at meeting the articulated objectives, and recommends how these policy paths might be considered.
- In Chapter 6, the interaction of feed-in tariff policies with other related policies is discussed.
- In Chapter 7 offers recommendations for feed-in tariff design and implementation and recommended next steps.
- Chapter 8 presents a summary of report findings and outlines proposed next steps.
- Appendix A summarizes the feed-in tariff design issues. It outlines possible attributes of a feed-in tariff and provides various sub-options to each attribute.
- Appendix B summarizes stakeholder written comments on the *Issues & Options Report* from Workshop 1.
- Appendix C summarizes stakeholder written comments on the six policy paths outlined in this report and at Workshop 2.
- Appendix D summarizes stakeholder written comments from the December 1, 2008, workshop
- Appendix E summarizes European approaches to cost setting for feed-in tariffs.

CHAPTER 2:
Feed-In Tariff Experience in Europe and Lessons Learned

Learning From European Experience

The *2007 Integrated Energy Policy Report (2007 IEPR)* recommended that a feed-in tariff, if developed, should incorporate "features of the most successful European feed-in tariffs." The definition of success and the identification of best practices to achieve that success are highly dependent upon the objectives that the policy is meant to achieve. Internationally, the principal laboratory for feed-in tariff development has been Europe,[10] where 18 European Union (EU) countries and non-EU countries such as Switzerland, the Ukraine, the Republic of Macedonia, and Albania,[11] have adopted feed-in tariff policies.[12] Of the national policies in the EU, a European Commission analysis concluded that feed-in tariffs were the most successful policy type.[13] From the European Commission perspective, success is measured by a policy's effectiveness in increasing renewable electricity generation and by the level of payment received by generators in comparison to the level they require for profitability. Using these success criteria, the EU concluded that feed-in tariffs achieve greater growth in renewable energy generation than do other policy types, and that they do so at a lower cost. The primary driver for this success was the investor security created by feed-in tariffs, which resulted in low financial risk, low financing costs, and rapid market growth. These findings were echoed by the

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[10] Feed-in tariffs have also been developed in a broad range of non-European countries as well (for example, Algeria, Brazil, Israel, South Korea, etc.), and feed-in tariffs are the most prevalent national policy globally – see Martinot, E. (2008*). Renewables 2007 Global Status Report* (Paris: REN21 Secretariat and Washington, DC: Worldwatch Institute). There has also been an increase in interest in feed-in tariffs in the US, with six states considering feed-in tariffs, eight states discussing feed-in tariff regulation, and a federal feed-in tariff bill introduced in Congress, during 2006-2007 – see Rickerson, W., F. Bennhold, and J. Bradbury. (2008*). Feed-In Tariffs and Renewable Energy in the USA: A Policy Update*. Raleigh, NC, Washington, DC, and Hamburg, Germany: North Carolina Solar Center, Heinrich Böll Foundation North America, and the World Future Council.

[11] Gipe, P. (2008). Swiss adopt aggressive feed law for renewable energy. RenewableEnergyWorld.com Retrieved August 8, 2008, from http://www.renewableenergyworld.com/rea/news/story?id=53026; see also Energy Community Secretariat. (2008). *Report on the Implementation of the Acquis under the Treaty Establishing the Energy Community.* Vienna, Austria.; *see also* Konechenkov, A. (2008). Ukraine adopts green tariff. Bonn, Germany: World Wind Energy Association.

[12] Rickerson, W., and R. C. Grace (2007). *The Debate Over Fixed Price Incentives for Renewable Electricity in Europe and the United States: Fallout and Future Directions*. Washington, D.C.: Heinrich Böll Foundation North America.

[13] Commission of the European Communities. (2005). *The Support of Electricity From Renewable Energy Sources.* Brussels.

Stern Review on the Economics of Global Climate Change,[14] and again more recently by the International Energy Agency's Global Best Practice in Renewable Energy Policy Making Expert Meeting, which concluded that, "Renewable energy policy effectiveness is more affected by the perceived investment risks on renewables projects than on their potential profits and/or costs."[15]

A major focus of the Energy Commission's feed-in tariff stakeholder process is to identify the policy goals and objectives of a potential feed-in policy in California (Chapter 3). Based on those policy goals and objectives, sets of best practices for a broad array of design and implementation issues can be identified. California's policy objectives, electrical infrastructure, and market context may ultimately dictate a different set of feed-in tariff design choices than those found in Europe. However, a review of European experience with feed-in tariffs and lessons learned is useful to the stakeholder process.

Several recent studies have compared feed-in tariff designs internationally,[16] and the recent *Issues & Options Report* prepared for the California Energy Commission references a broad range of international policy designs. Rather than summarizing these cases again, this section focuses on Europe's two largest renewable energy markets, Germany and Spain, and provides an overview of market performance to date, feed-in tariff policy evolution, and comparative policy design.

Germany

Market Growth to Date

Germany leads the world in installed capacity for both photovoltaics (PV) and for wind energy as a result of its feed-in tariff policies. By the end of 2007, Germany had 22,622 MW of wind and 3,800 MW of solar PV capacity installed in the country, with annual additions of 1,667 MW of wind and 1,100 MW of PV added in 2007 alone.[17] Germany's biogas market has also seen

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[14] Stern Review. (2006). "Policy Responses for Mitigation: Accelerating Technological Innovation (Part IV, Chapter 16)". In *The Economics of Climate Change*. Cambridge, UK: Cambridge University Press.

[15] International Energy Agency. (2007, June 29). *Workshop Proceedings*. Proceedings of the Global Best Practice in Renewable Energy Policy Making Expert Meeting, Paris, France.

[16] Klein, A., A. Held, M. Ragwitz, G. Resch, and T Faber (2007). *Evaluation of Different Feed-In Tariff Design Options: Best Practice Paper for the International Feed-In Cooperation*. Karlsruhe, Germany and Laxenburg, Austria: Fraunhofer Institut für Systemtechnik und Innovationsforschung and Vienna University of Technology Energy Economics Group; See also Morthorst, P. E., B. H.Jørgensen, P.Helby, J. Twidell, O. Hohmeyer, D. Mora, et al. (2005). *Support Schemes for Renewable Energy: A Comparative Analysis of Payment Mechanisms in the EU*. Brussels, Belgium: European Wind Energy Association.

[17] European Wind Energy Association. (2008). Wind map 2007. Retrieved August 8, 2008, from http://www.ewea.org/fileadmin/ewea_documents/mailing/windmap-08g.pdf *See also* Bundesverband Solarwirtschaft. (2008). *Statistische Zahlen der deutschen Photovoltaikbranche*. Berlin, Germany.

explosive growth, doubling from 650 MW to 1,271 MW between 2005 and 2007.[18] In Germany, renewables supplied 14.2 percent of the national portfolio in 2007.[19] The German national government subsequently revised its long-term targets to 25 to 30 percent by 2020.[20]

Feed-In Tariff Design

Germany's original feed-in tariff, which came into effect in 1991, guaranteed interconnection to renewable energy generators and a standard offer price set at a percentage of the average retail rate, which varied from year to year. Wind and solar projects received 90 percent of the retail rate. Hydropower, biogas, and biomass plants under 500 kW received 80 percent of the retail rate; whereas plants over 500 kW, but under 5 MW received 65 percent of the retail rate.[21] The ratepayers of each utility were responsible for the above market costs within their utility territory, and total generation was capped at 10 percent of each utility's portfolio. In the late 1990s, the retail rate began to fall, which caused renewable market growth to slow. Moreover, the utility-by-utility cost distribution system placed some utilities at a competitive disadvantage as electricity markets liberalized. Also, the tariff, although partially differentiated by technology and by size, was primarily an incentive for wind generation, and did not encourage emerging resources such as solar photovoltaic.

In response to these concerns, a new feed-in tariff was established in 2000, which established 20-year, fixed-price payments targeting specific technology types.[22] The payments were based on the estimated generation cost by technology type, plus a reasonable profit. Tariffs were further differentiated to prevent windfall profits for generators operating under more advantageous conditions. Most technologies, for example, were differentiated by size whereby large systems received a lower payment than did small systems that could not take advantage of the same

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[18] Rickerson, W., S. E. Baker, and M. Wheeler (2008). "Is California the Next Germany? Renewable Gas and California's New Feed-In Tariff." *BioCycle*, 49(3), 56-61.

[19] Böhme, D., W. Dürrschmidt, M.van Mark F. Staiß, C. Linkohr., F. Musiol, et al. (2008). *Development of Renewable Energies in Germany in 2007*. Berlin, Germany: Federal Ministry for the Environment, Nature Conservation and Nuclear Safety.

[20] Bundesministerium für Umwelt Naturschutz und Reaktorsicherheit. (2007b). *The Integrated Energy and Climate Programme of the German Government*. Berlin, Germany.

[21] International Energy Agency. (2008). Global renewable energy policies and measures database: Electricity Feed Law (EFL) (Stromeinspeisungsgesetz). Retrieved September 23, 2008, from http://www.iea.org/textbase/pm/?mode=re&id=1057&action=detail.

[22] For an overview of the technologies supported by the German and Spanish feed-in tariffs, including incentives levels received, see Held, A., M. Ragwitz, C. Huber, G. Resch, T. Faber, and K.Vertin (2007). *Feed-In Systems in Germany, Spain and Slovenia: A Comparison*. Karlsruhe, Germany: Fraunhofer Institut für Systemtechnik und Innovationsforschung.

economies of scale. Wind generators were differentiated by wind resource such that projects in better wind regimes received lower payments than those in slower wind regimes.

To control costs, the 2000 law set a schedule of rate declines by which the fixed-price payment decreased over time, based on each technology's projected experience curve. The law also required this so-called *degression rate* to be reviewed periodically to determine if the rate should be revised. Finally, to make the policy competitively neutral for utilities, the law established a national redistribution mechanism, managed by the transmission system operators.

In 2004, the German Parliament amended the new feed-in tariff. The 2004 law adjusted the payments for biomass, PV, and geothermal generators to more accurately reflect generation costs and to target specific applications, such as façade-integrated PV; fuels, such as manure and energy crops for biogas; and conversion technologies, such as fuel cells and organic Rankine cycles.[23]

In 2008, the German Parliament again adjusted the feed-in tariff degression rates, most notably eliminating the bonus payment for façade-integrated PVs, and increasing the degression rate for PV tariffs from 5 to 6.5 percent annually to 8 to 10 percent annually in response to PV's rapid market growth under the 2004 law.[24]

Spain

Market Growth to Date

Like Germany, Spain's feed-in tariff has also driven it to a global leadership position in terms of both renewable energy installed capacity and market growth. By the end of 2007, Spain had installed 15,145 MW of wind capacity, and 500 MW of PV capacity.[25] During 2007, Spain's wind capacity additions set a European record, with 3,522 MW installed in a single year, and Spain's PV market grew by over 300 percent. Although Spain's biomass and hydropower markets remained relatively stagnant, its solar thermal electric market also appears poised for growth.

Spain was the first country in the world to include a specific solar thermal feed-in tariff. As of February 2009, there were 81 MW of solar thermal installed in the country, and there are 617

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[23] Sösemann, F. (2007). EG - *The Renewable Energy Sources Act: The Success Story of Sustainable Policies for Germany.* Berlin, Germany: Federal Ministry for the Environment, Nature Conservation and Nuclear Safety.

[24] Bundesministerium für Umwelt Naturschutz und Reaktorsicherheit. (2008). 2009 EEG payment provisions: Payment provisions in the future EEG for the year 2009, as adopted by the German Bundestag Parliamentary Decision from June 6, 2008. Berlin.

[25] Ibid. European Wind Energy Association (2008); See also Salas, V., and E. Olias (in press). Overview of the photovoltaic technology status and perspective in Spain. *Renewable and Sustainable Energy Reviews*

MW of additional capacity under construction.[26] Market projections indicate that large scale solar thermal electric generation could grow to 2,000 MW by 2025.[27]

Feed-In Tariff Design

Spain's feed-in tariff design evolved through a series of laws that built upon early legislation targeting renewable energy in 1980 and 1994.[28] In 1997 and 1998, Spain established the Special Regime for targeting renewable energy, which allowed generators to choose either a feed-in tariff, similar to Germany's, or a premium payment on top of the electricity market price. Both the tariff and the premium options were generation-cost-based and differentiated by technology, with some tariffs also being differentiated by size. The price levels for both the tariff and the premium options were adjusted annually by the government to account for changes in the market, and costs were nationally distributed from the outset. In contrast to the German system, the Spanish feed-in tariff also required that generators over 10 MW forecast their generation 30 hours in advance.

In 2004, the feed-in tariff was amended to further differentiate resources by size, including an increase in the PV system size eligible for the most generous tariff from 5 kilowatts to 100 kilowatts.[29] To increase investor security, the annual price adjustments were pegged to the average annual retail price, rather than set by government decision, and full reviews of the payment levels were scheduled for every four years. The contract length was set at the life of the system. Unlike the German feed-in tariff, the 2004 Spanish feed-in tariff also included capacity goals for each technology that would trigger a policy revision by the government when reached.[30] The 2004 amendment also clarified forecasting rules for generators, such that 30-hour forecasts could be altered up to 1 hour before the start of the daily market and that penalties would be assessed for deviations from the forecast. Finally, to encourage generator participation in the electricity market, the 2004 amendment included an additional incentive for generators to choose the premium option.[31]

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[26] TSK Energía y Plantas Industriales. (2008). *La energía Termosolar*. Proceedings of the V Edición de las Jornadas Quinta La Vega, Gijón, Spain.

[27] Geyer, M. (2008, March 4-7). *Introducing Concentrated Solar Power on the International Markets: Worldwide Incentives, Policies and Benefits*. Proceedings of the 14th Biennial Solar Power and Chemical Energy Systems (SolarPACES) Symposium, Las Vegas, NV.

[28] Del Río González, P. (2008). 'Ten Years of Renewable Electricity Policies in Spain: An Analysis of Successive Feed-In Tariff Reforms." *Energy Policy*, 36(8), 3345-3359.

[29] Ibid.

[30] Ibid. Wind: 13,000 MW, biomass: 3,200 MW, hydro: 2,400 MW, solar thermal: 200 MW, PV: 150 MW.

[31] Ibid. Del Río González (2008).

In 2007, the feed-in tariff regime was revised again. Following the 2004 amendment, the majority of renewable generators opted to take advantage of the more generous premium option, rather than the tariff payment. Spot market prices increased more than projected, however. To control costs, the law removed the incentive for choosing the premium and established both a floor and a ceiling value for the premium. The law also pegged the annual adjustments to the consumer price index, rather than the average retail price.[32] With regard to grid integration, the amendment required generators over 10 MW to bear the cost of connecting to a generation control center managed by the system operator and also provided an additional incentive for wind generators that installed equipment to prevent voltage dips.

The 2007 amendment also raised the capacity goals for certain resources but included grid access deposits to discourage speculative queuing. The law further differentiated biomass by fuel type and increased biomass payment levels. Finally, the law also established a voluntary differentiation for on-peak and off-peak generation, whereby a generator would get 104.62 percent of the payment for on-peak power and 96.70 percent of the payment during off-peak generation.

In 2008, the Spanish PV market far exceeded its capacity goal.[33] As a result, the government introduced a cap of 500 MW on annual solar installations in 2009 and reduced the incentives approximately 25 percent.[34]

Comparing the German and Spanish Feed-In Tariffs

The German and Spanish feed-in policies provide long-term, technology-specific payments that are based on generation cost. They also contain fixed-price elements that encourage investor security. The policies differ significantly, though, in terms of the availability of a premium option, the existence of capacity-based policy revision triggers, and the existence of an annually variable component to the payments. Table 2 compares some of the key components of the two.

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[32] Ibid. Held et al. (2007).

[33] The revised 2007-2010 capacity goal for PV had been 400 MW. In 2008 alone, it is estimated that Spain will install 1,400 MW of ground-mounted PV capacity; see Rutschmann, I. (September 2008). "A Country of Megawatt Parks: PHOTON Counted the Amount of Large Spanish PV Parks - The Result Is Impressive." *PHOTON International*, 32-39.

[34] Wang, U. (September 26, 2008). Spain approves 500 MW for solar; The country's cabinet has approved a higher cap for solar installations – and also voted for a smaller reduction in feed-in tariffs – than the government had initially proposed. Available at: http://www.greentechmedia.com/articles/spain-approves-500mw-for-solar-1478.html.

Table 2: Comparison of German and Spanish Feed-in Tariffs

<table>
<tr><th colspan="2">Design Issue</th><th>Germany</th><th>Spain</th></tr>
<tr><td colspan="2">Contract length</td><td>20 years</td><td>Project life</td></tr>
<tr><td colspan="2">Tariff structure</td><td>Fixed payment</td><td>Fixed payment or fixed premium</td></tr>
<tr><td colspan="2">Incentive basis</td><td>Generation cost</td><td>Generation cost</td></tr>
<tr><td rowspan="3">Differentiation</td><td>Technology</td><td>Yes</td><td>Yes</td></tr>
<tr><td>Size</td><td>Yes</td><td>Yes</td></tr>
<tr><td>Resource quality</td><td>Yes</td><td>No</td></tr>
<tr><td colspan="2">Tariff adjustment</td><td>Tariffs locked in for 20 years, applicable to a generator coming on-line in a particular year; for each subsequent year, the fixed 20-year rate declines according to a schedule that tracks experience curves</td><td>• Annual tariff and premium rates pegged to CPI
• Payment revised periodically by government
• Premium payment sits atop variable wholesale electricity market price, but total remuneration is bounded by floor and ceiling</td></tr>
<tr><td colspan="2">Tariff revision</td><td>4 years</td><td>4 years, or by capacity triggers</td></tr>
<tr><td colspan="2">Policy caps</td><td>None</td><td>Technology-specific capacity triggers, with grid access deposits</td></tr>
<tr><td colspan="2">Forecast obligation</td><td>No</td><td>Yes</td></tr>
<tr><td colspan="2">Voltage support incentive available to generators</td><td>No</td><td>Yes</td></tr>
<tr><td colspan="2">Peak generation differentiation</td><td>No</td><td>Voluntary</td></tr>
<tr><td colspan="2">Project size cap</td><td>None</td><td>None</td></tr>
</table>

Source: KEMA

Lessons Learned From Germany and Spain

During the past two decades, both Germany and Spain have engaged in iterative feed-in policy development processes that have yielded several lessons that may guide feed-in tariff consideration in California. These include:

- **Long-term, generation-cost-based payments can rapidly grow renewable energy markets and achieve national targets.** In both Germany and Spain, incentives set according to generation cost have spurred rapid market growth and have significantly increased the proportion of renewable electricity in the national supply. Germany has achieved its renewable goals ahead of schedule and has set new targets as a result.
- **Technology-specific tariffs create diversity when set at the appropriate levels.** Germany's early value-based feed-in tariff created incentives for wind but did not accelerate markets for other technologies. The technology-specific tariffs in Germany and Spain, by contrast, caused rapid market acceleration across a portfolio of mature and emerging technologies. The portfolios differed, however, based on the policy

priorities in both countries and the manner in which generation cost was defined. In Germany, biogas tariffs have been set high enough to encourage the cultivation of energy crops specifically for anaerobic digestion, whereas in Spain, the pending solar thermal electric development reflects the fact that tariffs have been set at levels sufficient to encourage thermal with storage capacity.

- **Investor security is determined both by price certainty and policy certainty.** The European Commission study on comparative policy effectiveness highlighted the importance of investor security. From this perspective, it is interesting to compare the German and Spanish feed-ins. While both policies provide long-term payments to generators—minimizing risk to individual projects—the German feed-in tariff provides more price and policy certainty over time than the Spanish policy does. Not only does the Spanish tariff adjust each year (according to the Consumer Price Index), but the tariff also has revisions, triggered by capacity goals, without clear rules as to what types of revisions might occur. This uncertainty created widespread concern when installed PV capacity recently crossed the trigger point, and the market stalled.[35] The subsequent, sudden, and significant decrease in PV incentive levels contrasts with the comparatively orderly and phased schedule of PV degression rate decreases in Germany.
- **Incentives may or may not put downward pressure on renewable energy prices.** Related to the issue of policy revision is the issue of incentive adjustment. In Germany, rates are fixed for 20 years, but the fixed rate available to generators declines each year according to a schedule based (at least theoretically) on experience curves.[36] This approach provides a degree of planning certainty to developers and also puts downward pressure on prices. By contrast, the Spanish approach includes more risk and does not put downward pressure on prices for investors and developers because both the tariff and premium options vary with the Consumer Price Index and because the premium option varies with the wholesale market price. By tying price to variable values, rather than a decreasing schedule of fixed payments, there is a greater chance that support levels and generation costs will diverge. If the value indicator decreases significantly, it can mean that generators will not receive the payments they need to remain viable, whereas if the value indicator increases significantly, this can lead to overcompensation, as with the Spanish premium option, which is now capped to avoid some of this risk. Moreover, setting feed-in tariffs at a premium on top of market prices diminishes the ability of fixed-price contracts to serve as a hedge against rising electricity prices. This problem also occurs when feed-in tariff payments are pegged to indicators that increase over time.

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[35] Rutschmann, I. (July 2008b). "The Paralyzed Market: Spain's PV Industry Is Concerned About Deep Subsidy Cuts and Is Upset With Its Own Association." *PHOTON International*, 44-49.

[36] For example, a generator that came on-line in Year 1 would get a certain fixed rate for 20 years. A generator coming on line in Year 2 would get a fixed rate that is 5 percent below the rate received by the generator in Year 1.

- **Implementing support for emerging resources is challenging.** At the EU level, analysis has concluded that support for emerging resources in the short-term could decrease renewable energy policy costs in the long term.[37] Along these lines, Spain and Germany have each created feed-in tariffs for both near-market and emerging renewable resources. This policy decision can be challenging, however. In the case of PV, for example, both countries have acknowledged that the high price paid for PV creates additional policy costs, but that these costs are justified because they are blended with the savings created by near-market resources and by the fact that promotion of PV is an industrial (that is, market capture) policy, in addition to an energy policy.[38] Despite their commitment to PV, both countries have also attempted to address political concerns over policy cost by recently decreasing their PV feed-in tariffs.[39]
- **Setting the correct price for biomass can be challenging.** In both the Spanish and German cases, the biomass markets initially did not respond as projected to the feed-in tariff levels and did not accelerate at rates comparable to either wind or solar. The European Commission[40] cited the comparative complexity of the biomass market, with its different feed stocks, plant sizes, fuel supply logistics, and conversion technologies, as one of the reasons that biomass market was slow to respond to initial feed-in tariff rates. In both the Spanish and German cases, the feed-in tariffs for biomass were increased and were further differentiated by fuel and/or conversion technology.
- **Feed-in tariffs can suppress wholesale market prices.** Despite the perceived high cost of feed-in tariff policies, recent analyses from both Germany[41] and Spain[42] have

[37] Ibid. Held et al. (2007); see also Huber, C., T. Faber, R. Haas, G. Resch, J. Green, S. Ölz, et al. (2004). *Green-X: Deriving Optimal Promotion Sstrategies for Increasing the Share of RES-E in a Dynamic European Electricity Market*. Vienna, Austria: Vienna University of Technology Energy Economics Group; Huber, C., L. Ryan, B. Ó Gallachóir, G. Resch, K. Polaski, and M. D. Bazilian (2007). "Economic Modeling of Price Support Mechanisms for Renewable Energy: Case Study on Ireland." *Energy Policy*, 35(2), 1172-1185.

[38] del Río, P., and M. A. Gual (2007). "An Integrated Assessment of the Feed-In Tariff System in Spain". *Energy Policy*, 35(2), 994-1012; Nitsch, J., W. Krewitt, M. Nast, P. Viebahn, S. Gärtner, M. Pehnt, et al. (2004). *Environmental Policy: Ecologically Optimized Extension of Renewable Energy Utilization in Germany* (Summary). Berlin, Germany: Federal Ministry for the Environment, Nature Conservation and Nuclear Safety

[39] Ibid. Rutschmann (2008a, 2008b); Podewils, C. (July 2008). "Constant State of Revision: The Conservatives Are Already Looking for the Next Chance to Revise the New EEG Tariffs." *PHOTON International*, 28-33

[40] Ibid. Commission of the European Communities (2005).

[41] Bundesministerium für Umwelt Naturschutz und Reaktorsicherheit. (2007a). Erfahrungsbericht 2007 zum Erneuerbaren-Energien-Gesetz (EEG). Berlin, Germany; Sensfuß, F., and Ragwitz, M2007). *Analysis of the Price Effect of Renewable Electricity Generation on Spot Market Prices*. Karlsruhe, Germany: Fraunhofer Institut System- und Innovationsforschung.

concluded that the rapid expansion of renewable electricity has decreased wholesale spot market prices. In both cases, the estimated savings have been comparable or have exceeded the cost of the policy itself. This wholesale market price suppression effect is not unique to feed-in tariffs and could result from large-scale renewable energy market growth spurred by any policy type (such as a Renewables Portfolio Standard). To the extent that price suppression benefits are realized through the addition of renewable energy generation, if feed-in tariffs accelerate the pace of renewable energy development, then price suppression benefits may be realized earlier.

- **Long-term payments have been used successfully in Germany and Spain.** Both countries have guaranteed generators long-term feed-in tariff payments or contracts. The primary difference is that the payments are provided for a fixed term in Germany (20 years)[43], whereas the payment in Spain is guaranteed for the life of the system.[44] European analysts[45] have noted that the German system provides more certainty about policy cost and policy duration than the Spanish model.
- **Both Spain and Germany distribute policy costs nationally.** Both Germany and Spain evenly distribute the costs of their feed-in tariff policies nationally. Germany initially limited its feed-in tariff cost distribution within each utility service territory but eventually switched to a broader socialization system in light of cost imbalances and their effect on competition in the electricity industry.
- **Feed-in tariffs can promote technological innovation.** There have been questions raised in the United States as to whether feed-in tariffs support or stifle innovation in renewable energy technology and project development. In Europe, feed-in tariffs have driven technology cost decreases in key markets, and have also created the conditions for technological advances[46] and innovation. These gains have come as a result the

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[42] Sáenz de Miera, G., P. Del Río González, and I. Vizcaíno. (2008). "Analysing the Impact of Renewable Electricity Support Schemes on Power Prices: The Case of Wind Electricity in Spain." *Energy Policy*, 36(9), 3345-3359.

[43] After the 20-year term expires, generators are free to sell their electricity according to the options available at the time. Onsite systems that currently sell their power into the grid rather than offsetting onsite load (e.g. PV) may find that offsetting onsite load offers the most attractive alternative after the 20-year feed-in tariff ends. Other generators may opt to sell into the wholesale market. For a brief discussion of these options, see Solar Electric Power Association, Northwest Solar Center, and World Future Council. (2008). *Solar Fact Finding Mission to Germany for Utility Decision Makers: Suummary Report, June 9-13, 2008*. Washington, D.C.

[44] As noted earlier, the feed-in tariff in Spain also varies annually with the Consumer Price Index, whereas the German feed-in tariff is fixed over its entire term.

[45] Ibid., Held et al. (2007).

[46] Johnstone, N., I. Hascic, L. Clavel, and F. Marical. (2007). *Renewable Energy Policies and Technological Innovation: Empirical Evidence Based on Patent Counts*. Proceedings of the Grenoble Applied Economic Laboratory Environment, Innovation, and Performance Conference, Grenoble, France.

ability of feed-in tariffs to support rapid technology diffusion[47], and to create a stable investment climate. Feed-in tariffs have enabled manufacturers to expand production[48] and to invest in product and process efficiencies. Feed-in tariffs have also encouraged innovation by shifting the basis of market competition from generation price to equipment price and installation labor cost.[49] Developers that are able to use more efficient, less expensive technologies are able to garner higher profits under fixed-price, feed-in tariffs. Manufacturers, therefore, must compete to provide the most efficient product. This shift in competitive focus can have important implications for capital-intensive renewable technologies, such as wind and solar power.[50] An additional driver for innovation is the use of degression schedules, like that in Germany, which are intended to place downward pressure on renewable energy prices over time.

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[47] Söderholm, P., and G. Klaassen (2007). "Wind Power in Europe: A Simultaneous Innovation-Diffusion Model." *Environmental and Resource Economics*, 36(2), 163-190.

[48] Lewis, J., and R. Wiser (2005). *Fostering a Renewable Energy Technology Industry: An International Comparison of Wind Industry Policy Support Mechanisms* (LBNL-59116). Berkeley, CA: Lawrence Berkeley National Laboratory.

[49] Menanteau, P., D. Finon, and M. L. Lamy (2003). "Prices Versus Quantities: Choosing Policies for Promoting the Development of Renewable Energy." *Energy Policy*, 31(8), 799-812.

[50] Hvelplund, F. (May 2001). "Political Prices or Political Quantities? A Comparison of Renewable Energy Support Systems." *New Energy*, 18-23.

CHAPTER 3:
Feed-In Tariff Policy Goals, Objectives, and Evaluation Criteria

Since any feed-in tariff program is likely to have multiple goals and objectives, policy makers must first determine specifically what they wish to achieve and consider how they will prioritize or weigh those goals and objectives against one another. Only then can a feed-in tariff program be designed that achieves those goals subject to applicable constraints, such as achieving the objectives at the lowest possible cost.

Policy Goals and Objectives

As articulated in the *2007 IEPR*, there are two major policy goals driving renewable energy development in California:

1. Reducing greenhouse gas emissions.
2. Managing cost and risk to ratepayers.

These policy goals are reflected in the policy objectives of achieving 20-percent renewable energy penetration in California by 2010 and 33-percent penetration by 2020. The state's current strategy for achieving those objectives is the RPS procurement process, with each utility typically conducting an annual solicitation for RPS-eligible resources. Feed-in tariffs offer a second potential strategy for attaining these renewable energy objectives. The state has also articulated other policy goals pertaining to renewable energy, including support for renewable energy resource diversity (reflected by solar and biomass[51] policy targets).

With respect to feed-in tariffs, the Energy Commission's staff, in consultation with the Energy Commission's Renewables Committee, articulated and prioritized a set of additional policy drivers, shown in Table 3. These policy drivers have been applied as evaluation criteria for considering feed-in tariff design choices in constructing and evaluating the alternative policy paths discussed in Chapter 5.

[51] Governor Schwarzenegger's Executive Order S-06-06.

Table 3: Prioritized Feed-In Tariff Policy Drivers

	Category	Driver	Rationale	Priority
1	Quantity	Develop a sufficient quantity of renewable energy in the medium-term timeframe to meet California RPS objectives.	Promote projects that can feasibly help reach the RPS objective of 33 percent by the 2020 timeframe.	High
2	Financial Security	Market certainty and financial security for developers and investors.	Provide the market certainty and financial support that developers and investors need to bring new projects on-line.	High
3	Diversity-A	Promote a diverse mix of renewable resources through technology-specific or attribute-specific tariffs (for example, feed-in tariff for solar not covered by CSI or higher tariff rate for peak generation).	Increase renewable energy generation across technology and attribute types to increase reliability and meet desired mix of "operational characteristics," such as peak generation or system integration.	Medium
4	Sustainable Renewable Energy	Develop a self-sustaining renewables industry.	Rates designed to help with market penetration, but eventually ratcheted down as facilities become able to compete effectively in the market.	Medium
5	Price Stabilization	Help stabilize the cost of generation.	By increasing the mix of renewable energy technologies, the cost of generation can be insulated from fluctuations in the price for natural gas.	Medium
6	Diversity-B	Meet specific policy objectives already articulated. Examples: IEPR recommendations or Biomass Executive Order (S-06-06).	Focusing on increasing renewable energy derived from biomass technologies will also help to increase system mix and reliability.	Low

Source: KEMA

Constraints

There are practical constraints that limit the ability of the state to achieve its renewable energy objectives through either the existing RPS solicitation or through an expanded feed-in tariff. For example, maximizing the quantity of renewable energy generated will be subject to the constraints of available transmission, the ability to site and permit generators, financing, and the time necessary to site, manufacture, and construct that quantity of generation. Another constraint that should be considered in selecting from among the potential feed-in tariff policy paths is cost-effectiveness; that is, accomplishing the objectives in a manner that seeks to minimize the rate impact of achieving a specific end point (including minimizing transmission and integration costs associated with meeting renewable energy objectives). Finally, resource sustainability should also be considered a constraint on an effective policy. Perhaps the most pertinent example is the physical constraint of the sustainable yield of biomass so that consumption does not exceed regeneration.

Project Scale

In addition to the policy objectives identified at the outset of this proceeding, stakeholder feedback also led the Energy Commission to add expanding the diversity objective to include a diversity of project sizes. The *2007 Integrated Energy Policy Report* (*2007 IEPR*) direction motivating this report focused on feed-in tariffs for electricity generation projects greater than 20 MW in California. However, Workshop 1, Workshop 2, and subsequent stakeholder comments (see Appendices B and C) revealed a preference among many stakeholders for limiting feed-in tariffs to projects 20 MW or less. During these workshops, a common theme was identified – that only a small percentage of RPS contracts are for facilities 20 MW or less of capacity. Analysis of IOU contracts bears this out. Less than one percent (See Figures 2 and 3) of contracted generation capacity is coming from these size projects. However, based on the results of the German tariff, which significantly expanded generation from projects 20 MW or less, there is ample potential in California to also greatly expand the amount of generation from projects in the 20 MW or less size range. Figures 2 and 3 illustrate this imbalance in distribution toward projects greater than 20 MW under the RPS solicitation process.[52]

Figure 2: IOU Contracted Projects

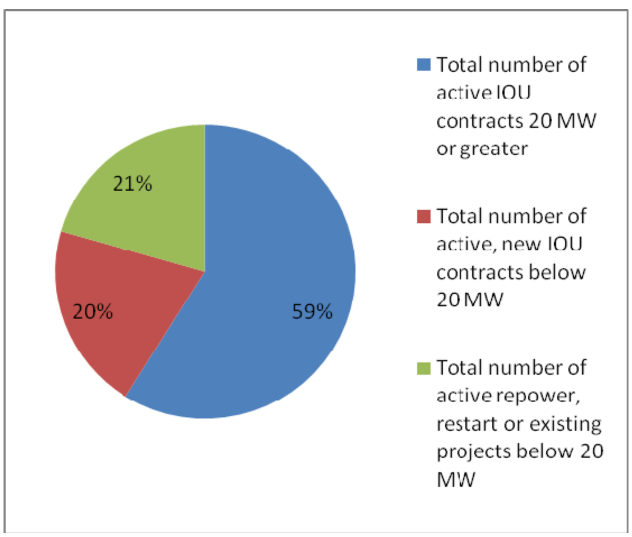
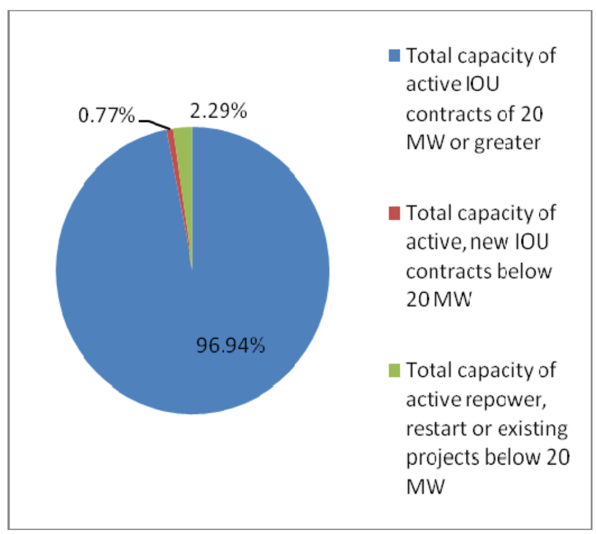


Figure 3: IOU Contracted Capacity (MW)



[52] Based on contract information publically available on the Energy Commission's Database of Investor-Owned Utilities' Contracts for Renewable Generation, Contracts Signed Towards Meeting the California RPS Targets webpage, updated January 18, 2009, http://www.energy.ca.gov/portfolio/contracts_database.html.

Figure 2 shows the proportion of active contracts with a capacity of 20 MW or greater, active contracts for repower, restart, or existing projects below 20 MW, and active contracts for new facilities below 20 MW. Figure 3 displays the contracted capacity associated with the same contracts. As displayed, the contribution to the capacity procured through the RPS solicitation process from active contracts for *new* projects in the less than 20 MW size range is less than 1 percent of total capacity under active contract.

The number of contracts less than 20 MW and the capacity for the contracts less than 20 MW in the IOU database are displayed in figures 4 and 5, respectively. The projects fall into two columns, online projects and projects not on-line. The data is further divided according to vintage and whether the contract is active or inactive.[53] The contract data indicates that there are only 22 contracts for new projects less than 20 MW. These 22 contracts comprise nearly 80 MW out of roughly 9,600 MW under active contract in the Database of Investor-Owned Utilities' Contracts for Renewable Generation, Contracts Signed Towards Meeting the California RPS Targets. This data supports the conclusion that renewable generation projects less than 20 MW are not competing effectively under the current RPS solicitation approach.

Figure 4: IOU Contracts Less Than 20 MW

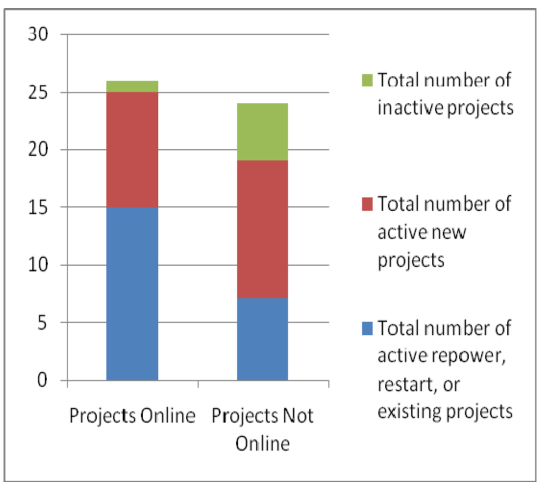
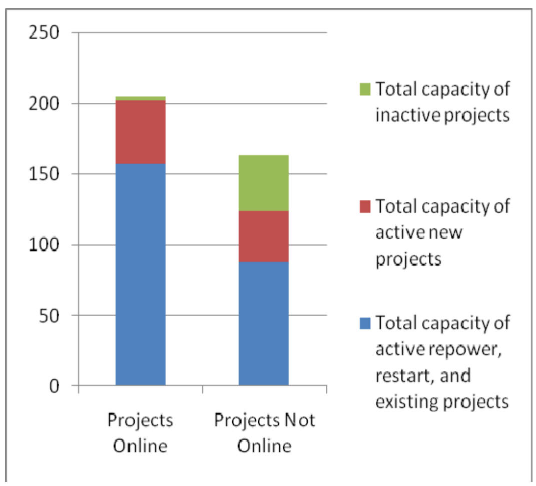


Figure 5: Capacity of IOU Contracts Less Than 20 MW



The majority of new projects in Germany are under 20 MW. Given the success of feed-in tariffs in Germany there is convincing evidence that the current RPS solicitation process is not tapping into a distributed generation market that could advance attainment of California's RPS goals. The current RPS solicitation process combined with the under 1.5 MW tariff offering (Senate Bill 380 [Kehoe, Chapter 544, Statutes of 2008]) and SCE's expanded programs have yielded less

[53] An inactive project does not have an active RPS contract with an IOU, however there is one on-line project that is generating electricity without a contract; this is reflected in the first bar in Figures 4 and 5.

than 1 percent of contracted new capacity. California could accelerate the task of achieving its renewable energy goals by putting forth a policy that would tap the portion of renewable resources that fall in the 20 MW or less range. To that end, the implementation of an under 20 MW feed-in tariff could incentivize and expedite the development of projects in this size range.

In addition to incentivizing development of projects under 20 MW, stakeholders also preferred a near-term focus on smaller generators in order to gain more experience before a wider application. As a result, this report explores various policy options for implementing a feed-in tariff over a range of project scales to support attaining RPS goals.

CHAPTER 4: Analysis/Narrowing the Options

Approach

The *Issues & Options Report* outlines a broad range of policy options that California would need to consider as it moved from feed-in tariff design to feed-in tariff implementation. Issues identified in the *Issues & Options Report* are subdivided for this analysis into three categories:

- **Core policy issues** are issues that would dictate California's feed-in tariff strategy and that constitute critical characteristics of alternative feed-in tariff policy paths. These are essentially the high-level policy decisions, most of which would create different approaches to implementing expanded feed-in tariffs in California.
- **Non-core policy issues** consist of important policy issues that would modify the feed-in tariff design, but not fundamentally alter its core structure. They would require decisions to move forward with expanded feed-in tariffs, but they are independent of the policy path selected. The resulting design choice could be appended to any of the selected policy paths.
- **Implementation details** are issues that must be addressed in implementing feed-in tariffs but do not require major policy decisions. For these, further discussion can be deferred until after a decision on whether to pursue expanded feed-in tariffs is made.

For those feed-in tariff design issues in the first category, this chapter narrows the design options identified in the *Issues & Options Report* to those deemed viable for further consideration as components of alternative future policy paths. The narrowing was accomplished through:

- Consideration of the advantages and disadvantages of options as identified in the *Issues & Options Report*.
- Consideration of practical constraints and California precedent.
- Consideration of stakeholder comments as described in Appendix B.
- Consideration of the policy goals and objectives articulated in Chapter 3.
- Input from the Energy Commission's Renewables Committee members.
- Analyses from Energy Commission staff and consultants.

This process resulted in a narrower range of design components from which alternative policy paths could be crafted for further consideration. After review, some issues were determined to have a single possible design choice. The narrowing of design options is described further in this chapter.

Table 4 outlines key issues examined for:

- Core feed-in tariff design policies.
- Non-core feed-in tariff design policies.
- Implementation issues.

This report deals principally with core threshold design issues, with the goal of organizing these options into different representative policy paths (see Chapter 5) and recommending a specific design for development and implementation.

Table 4: Feed-In Tariff Design Issue Summary

Issue	Sub-issues
Core Design Issues	
1. Generator eligibility	• Resource type • Vintage • Project size
2. Price-setting method	• Value-based • Generation cost-based • Competitive benchmark
3. Price adjustment	• Approaches • When to adjust • How to adjust
4. Caps and limitations (for example, based on capacity and/or cost)	-
5. Tariff Differentiation (for example, by size, by technology, etc.)	-
6. Contract Duration	-
7. Access	• Who pays costs of interconnection • Who pays for upstream transmission
8. Tariff structure	-
9 Which entity offers the tariff (who buys?)	-
10. Timing	-
11. Scope	-
Non-core Policy Issues	
12. Generator eligibility - location	• Based on generator location, for which tariff(s) is a generator eligible? - Interconnecting utility, other • If other than interconnecting utility, under what conditions? - no restriction or condition - only if no interconnecting option - to nearest or any tariff • If other than interconnecting utility, energy delivery or RECs? • Generators within CA only, or WECC?
13. Price-setting method, secondary issues	• If value-based: wholesale vs. retail measure of value? Adders to value for time of production, or grid-side benefits or air emissions? • If cost-based: how to set profit level? Aggressive or conservative estimate of cost? • If competitive benchmark: Is everything eligible or differentiated? What is mechanism and frequency for determining benchmark? Is there an adjustment facto?
14. Interconnecting utility requirements offered by all (statewide) or just IOUs?,	-
15. What is being sold/purchased?	-
16. Who pays (cost allocation/distribution)?	-
17. Cost recovery mechanisms	-
18. Integration of purchased energy and other commodities into power supply of utilities and others	-
19. Development security requirements	-
Implementation Issues	
20. Operational security requirements	-
21. Tariff standardization with CPUC Rule 21	-
22. Management and oversight of feed-in tariff payments	-
23. Queuing procedures if caps are in place	-

Source: KEMA

Core Design Issues Comprising Potential Feed-In Tariff Policy Paths

The components of each issue are discussed below.

Issue 1: Generator Eligibility

The issue of generator eligibility addresses whether to allow all generator types to participate in a feed-in tariff, or whether to limit the feed-in tariff only to certain subsets of generators.

- **1.a. Generator Eligibility—Resource Type.** This issue pertains to whether to allow the same resources that are eligible under the Renewables Portfolio Standard (RPS) to participate under a feed-in tariff or allow only certain technology types.

  Narrowed options: The primary option would be to design a feed-in tariff open to all RPS-eligible technology types—similar to the current feed-in tariff for small-scale generators. Based on stakeholder input and on California policy priorities, such as the Executive Order targeting biomass, feed-in tariffs targeting single resources—solar and biomass—were also selected as options for further consideration. In addition, also based on stakeholder input, a stipulation that feed-in tariffs target only sustainable[54] biomass was added to the options.

- **1.b. Generator Eligibility—Vintage.** This issue involves whether to allow all generators, regardless of their date of operation, to qualify for the feed-in tariff rate or limit eligibility to resources of only a certain vintage.

  Narrowed Options: The vintage eligibility options identified in the *Issues & Options Report* included all generators, regardless of age; only new generators; and generators that came on line after a target date. A fourth option was to create a "qualification life" for feed-in tariffs, based on an approach proposed under the recent New Jersey RPS proceedings. Stakeholder support for the qualification life option and for the option to define eligible vintage based on a certain date was low, so these were removed from consideration. Based on the Energy Commission policy priority to meet RPS goals and maximize generation, the options selected for further consideration were to allow either only new resources or to allow both new and repowered resources.

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[54] There are many possible definitions of "sustainable" biomass; several states, including New Jersey and Connecticut, have taken different approaches to defining a standard of sustainability as it pertains to RPS biomass eligibility. For defining policy paths for consideration in this paper, the intent here is to pose a hypothetical, more stringent biomass eligibility requirement than exists under the current RPS, which would reflect the physical constraint of the sustainable yield of biomass so that the rate of consumption does not exceed the rate of biomass regeneration. If such a definition were to be pursued, then a detailed standard would need to be developed.

- **1.c. Generator Eligibility—Project Size.** This issue addresses whether to allow generators of all sizes to participate in the feed-in tariff or limit the feed-in tariff to projects of certain sizes.

  Narrowed Options: The initial options included caps or floors based either on capacity or on energy production. There was little stakeholder support for energy-based caps or floors, so these were discarded. As described in the stakeholder comment summary in Appendix B, stakeholders suggested a broad range of specific capacity caps and floors, including support for a scenario without size limits. The original scope of the Energy Commission study was to explore feed-in tariffs for projects greater than 20 MW. Based on stakeholder comments, however, a range of policy options were selected for inclusion in the policy paths in order to reflect the broad range of opinion. These options included: no limits, setting 1.5 MW as the capacity floor, setting 20 MW as the capacity floor, and setting 20 MW as the capacity ceiling.

Issue 2: Price-Setting Method

The three choices for price-setting methods include whether to set the price based on the value of the electricity supplied, based on the generation cost of eligible technologies, or to use a competitive benchmark to establish the price.

Options: Each of the three price setting methods has its own subset of policy options to consider. For example, if a value-based method is selected, then value could be defined as a function of wholesale or retail prices (for example, 90 percent of average retail electricity as in Germany during the 1990s), or using a definition of avoided cost that takes externalities such as grid-side benefits or air emissions into account. For the cost-based method, choices include whether to set the price on an aggressive or conservative basis. Each of these secondary options depends on the primary method selected, however. As a result, the secondary options could be viewed as non-core policy options.

On the one hand, the value-based approach fits within the current least-cost, best-fit framework of the California RPS. On the other hand, stakeholder input at Workshop 2 revealed broad support for a cost-based approach as discussed in Chapter 2, generation cost-based feed-in tariffs have driven rapid market growth internationally and could support the objective of meeting state renewable energy targets on schedule. Stakeholders also supported a competitive benchmark approach to setting the tariff, although it was noted that this approach has not been implemented elsewhere. As a result of the broad range of opinions and the potential merits of all three approaches, all were selected for further consideration. Some secondary policy options were also specified in the policy paths (for example, the decision to use a differentiated competitive benchmark) to encourage stakeholder feedback during the comment process.

Issue 3: Price Adjustment

- **3. a. Price Adjustment—Approach.** This design issue deals with whether to have one price that does not adjust over time, or whether to adjust the price based on reference indicators or a pre-established schedule.

  Options: The initial options considered were to have a fixed price with no adjustment (and therefore have the price automatically devalue over time with inflation); index the tariff to economic indicators such as the consumer price index or inflation; adjust the tariff based on a measure of value (similar to the market price referent); or whether to set a degression schedule that would reduce the price over time in line with technology advances and scale economies, as is in place in Germany. There was little stakeholder support for the 'no adjustment' option and so it was discarded. Opinion was fairly evenly divided regarding the remaining three options, and it is conceivable that any of the three could be integrated into any of the policy paths.

- **3. b. Price Adjustment—When to Adjust.** If tariff prices are to be adjusted, the issue of when to make such price adjustments must be addressed.

  Options: The initial options identified in the *Issues & Options Report* were to schedule periodic price adjustments based on a specified amount of time (for example, the degression schedule in Germany), have revisions automatically occur when certain capacity amounts are reached (for example, the California Solar Initiative block schedules), or to schedule a periodic administrative review to determine how the policy should be adjusted. There was no clear best practice or stakeholder preference expressed among the three "pure" options, and in fact many current feed-in tariffs opt for hybrids and combinations of the three options. Germany, for example, combines periodic price adjustments with periodic administrative review, whereas Spain uses capacity goals to trigger administrative review—in addition to a scheduled administrative periodic review. In light of this, a hybrid combining capacity-based revisions with periodic administrative review (to make sure the preset capacity-based revisions still make sense) was selected for further consideration.

- **3. c. Price Adjustment—How to Adjust.** If tariff prices are to be adjusted, policy makers must decide whether to pre-schedule incentive decreases in uniform steps or tie the decreases to other benchmarks.

  Options: This issue becomes relevant if a regular schedule of declining incentives (for example, time based or capacity based, etc.) is selected. In this case, it becomes necessary to determine in what increments the incentive will be adjusted. The two options identified in the *Issues & Options Report* were to decrease the payments in uniform steps, or alternatively, try to tie the adjustments to a technology's projected experience curve. The experience curve approach is theoretically compelling, but it can be challenging to set correctly since experiential improvements are not always smooth.[55] Both of these options were retained for further consideration.

Issue 4: Cap and Limitations

This issue involves whether to allow generators to access the incentive indefinitely or whether to limit the tariff.

Options: The initial options considered were to have no cap on the policy, to cap the policy based on capacity, to cap the policy based on a target amount of energy generation, or to cap the policy based on its cost impact. Although a slight majority of stakeholders favored an unlimited policy, there was also strong support for caps under certain circumstances. With regard to the type of cap that could be employed, a cost-based cap was discarded because it is the least transparent and conflicts with the policy objectives of encouraging investor security. The remaining options—no cap, a capacity cap, and a generation cap— were retained to be considered in design potential feed-in tariff policy paths.

Issue 5: Tariff Differentiation

The issue of tariff differentiation involves whether to have a single "neutral" tariff for all generators types or whether to differentiate tariff payment levels to take into account different generation costs and production profiles.

Options: The tariff differentiation options would only need to be considered if California moves forward with a differentiated, rather than a neutral, feed-in tariff structure. The original differentiation options identified in the *Issues & Options Report* included project size, resource quality, ownership structure, transmission access, location (for example, to target a load pocket), and commercial operation date (for example, to encourage repowering). Differentiating by resource quality, as is done in Germany for wind, and differentiating by ownership structure, such as the proposed community-ownership feed-in tariff in Minnesota, were removed from consideration because of lack of support during the stakeholder process. Differentiating the tariff by generator location (for example, different rates for Competitive Renewable Energy Zone (CREZ) than non-CREZ generators) was eliminated from consideration as a means of tariff differentiation; however, a related concept was considered as a dimension of policy scope, e.g. tariff only in a CREZ.

There was clear support from a broad range of stakeholders for both differentiation by technology and differentiation by project size, and both were selected for inclusion in the policy path scenarios. To respond to the Executive Order on Biomass, tariff differentiation

[55] Alsema, E., A. Seebregts, L. Beurskens, H. de Moor, M. Durstewitz, M. Perrin, et al. (2004). *Synthesis Report Photex Project*: European Union Photo-voltaic systems and Experience curves (PHOTEX) Project.

by biomass fuel type was selected for inclusion in a biomass-only policy path. The policy objectives embodied by the other tariff differentiation options were generally captured by other design options and were judged not to need explicit, differentiated tariff levels.

Issue 6: Contract or Payment Duration

This issue involves the duration of the standard contract, if a contract is used, or the payment, more generally.

Options: The initial contract duration options included short-term (3 to 7 years), medium-term (8 to 14 years), long-term (15 to 20 years), generator choice, and indefinite. The indefinite payment option was discarded because of the uncertainties it created over policy duration and policy cost and because of a lack of stakeholder support. There was little or no stakeholder support for either allowing the generator to select its own term (this was also rejected from further consideration for reasons of administrative complexity) or for short-term durations. The long-term contract option was selected as the primary choice because of its positive impact on investor security and its potential to enable lower contract prices. The one exception to this was for the biomass-only policy path, under which a short- or medium-term option was selected to reflect the fact that longer-term contracts increase biomass generators' exposure to fuel price risks.

Issue 7: Access to the Grid

The issue here is which entity would be responsible for paying the interconnection and upstream transmission system costs associated with new generation.

Option: This was an instance where a single option was selected. There was not a strong case made for reversing or amending the status quo in which generators are responsible for paying for interconnection. In this case, the costs of transmission improvements would be fronted by the generator and subsequently paid back by the transmission owner over a period of time, per current California Independent System Operator practice. [56]

Issue 8: Tariff Structure

The tariff structure refers to whether to structure the payment as a fixed price payment, or not.

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[56] One potential gap is for generators over 10 MW that connect with the distribution grid, as Rule 21 in California applies to generators 10 MW or below. Technical questions on whether the distribution grid can incorporate such levels of generation would have to be addressed. This issue was identified in *Exploring Feed-In Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options* (CEC-300-2008-003-F).

Options: Although several options were discussed, including a fixed price with a tradable renewable energy credit hybrid, a contract-for-differences structure, and a premium like that used in Spain, there seemed to be clear support through stakeholder opinion and reviews of international experience to date that a fixed price would be the most appropriate structure for California.

Issue 9: Which Entity Offers the Tariff (Who Buys?)

This issue involves identifying which entities are responsible for offering the feed-in tariff and providing the feed-in tariff payments to generators.

Options: The *Issues & Options Report* identified two alternatives: The party to offer the tariff could conceptually be either the transmission and distribution system owners/operators (investor-owned utilities [IOUs] or publicly owned utilities [POUs] if applicable), or the load serving entities (IOUs, POUs, community choice aggregators (CCAs) and energy service providers [ESPs]). Due to practical constraints, the only option included for further consideration at this time is to assign providers of transmission and distribution the task of providing the feed-in tariff payment to generators. While each generator can have only one interconnecting utility, non-utility load serving entities have no physical presence on the transmission or distribution system. As a result, a generator cannot interconnect to a CCA or an ESP, so there is no obvious means by which to select *which* load serving entity's tariff would be applicable to any particular generator. In addition, CCAs and ESPs have no obligation to operate within a utility service territory for the duration of the feed-in tariff payment obligation. Therefore, load-serving entities were ruled out as the entities offering a feed-in tariff due to incompatibility with the market structure.

Issue 10: Timing

The issue of timing refers to when a feed-in tariff policy would go into effect.

Options: This issue was initially related to the issue of how the feed-in tariff might interact with the RPS, but was subsequently identified as a distinct characteristic of potential policy paths in response to stakeholder and Energy Commission staff input. The options include having a feed-in tariff take effect immediately, having the feed-in tariff come into effect at a specified future date, or having the feed-in tariff come into effect when triggered by a certain milestone (for example, failure to meet the RPS[57]). All three options were integrated into the final policy paths to elicit further stakeholder comment. Under one scenario, the feed-in tariff goes into effect immediately; under a second scenario, the feed-in tariff goes

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[57] Senate Bill 107 (Sher, Chapter 464, Statute of 2006).

into effect if the 2010 RPS goals are not met[58]; and under a third scenario, the RPS goes into effect automatically in parallel with the commitment to construction of CREZ transmission. A fourth and final option was selected to complement the pilot scope discussed below, under which the expanded feed-in tariff would go into effect immediately as a pilot, which would then terminate after three years.

Issue 11: Scope

The scope of a feed-in tariff policy involves whether the feed-in tariff should be offered comprehensively to the full market, or instead on a more limited basis, either only in specific locations, or introduced as a limited pilot at first.

Options: The three primary options are whether to roll out the feed-in tariff statewide upon implementation, whether to limit a tariff to generators only in specific locations, or whether to create a limited pilot policy to test the policy's impact. This option was not among the options introduced in the *Issues & Options Report* but was subsequently added in response to stakeholder and staff input. During the stakeholder proceedings and subsequent Renewables Committee review process, the issues of transmission constraints and CREZ planning was identified as a policy priority in need of further consideration. Under the pilot scenario, the feed-in tariff would be available only within one utility's territory, and/or would be available only for a limited time. This approach has been employed by California for several of its policies, including the development of the pilot performance-based incentive for photovoltaics and the development of a pilot program for solar hot water heating. Full-scale tariff availability, the option of limiting feed-in tariff eligibility to only those generators located within a CREZ, and pilot feed-in tariffs were selected as options for further consideration.

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[58] Implementation of a trigger for failing to meet the 2010 RPS target could be set off in two ways. Under the current RPS, the IOUs, CCAs and ESPs are required to have 20 percent renewable contracted by 2010. If the IOUs, CCAs, and/or ESPs fail to contract an energy mix of 20 percent renewables, a feed-in tariff would be implemented automatically in 2011. The other scenario would be that IOUs, CCAs and ESPs contract 20 percent of their energy mix with renewables by December 31, 2010, however they fail to meet the three- year window in which the generators have to interconnect and start generating. If the contracted generators fail to interconnect and beginning generating by December 31, 2013, a feed-in tariff would be automatically implemented in 2014.

Non-Core Policy Issues

The non-core policy issues would modify the feed-in tariff design but not fundamentally alter its core structure. They represent important policy design decisions that will need to be made to implement expanded feed-in tariffs, but they are independent of the policy path selected. These design choices could be appended to any of the selected policy paths. Table 4 provides a summary of these issues, whereas the full menu of options that impact each issue is included in Appendix A.

Implementation Issues

The implementation issues outlined in Table 4 will not be addressed within the scope of this paper because they are issues related to policy implementation, rather than core design. As a result, further discussion of these issues can be deferred until after a decision on whether to pursue expanded feed-in tariffs is made. The full list of options associated with each of the issues in Table 4 is included in Appendix A.

CHAPTER 5: Six Potential Policy Paths for Feed-In Tariffs in California

The core design issues listed in Table 4 and their associated options could be combined into many different permutations and could be used to create a broad range of very different feed-in tariff policies. Exploring all possible combinations would be neither practical nor fruitful. Based on the stakeholder process, input from the Renewables Committee, and staff analysis, the core design issues and associated options were packaged into six representative *policy paths* as a useful starting point for the discussions that took place in Workshop 2. These policy paths do not reflect the full range of possible feed-in tariff designs that California could consider but reflect a range of different approaches to achieving the policy objectives outlined by the Energy Commission.

These feed-in tariff policy paths were not posed as substitutes for the current Renewables Portfolio Standard (RPS) solicitation process, but complements that could either focus narrowly on gap not well addressed by the RPS solicitation process, or broader policies that could operate in parallel.

Representative Policy Paths for Future Discussion

The six different policy paths listed in Table 5 contain options that were selected for further consideration following Workshop 1. These policy paths span a range of policy directions, as well as timing and scope. In addition to the six options below, there is an implicit seventh choice—maintaining the status quo. This section provides a short profile for each policy path and discusses the pros and cons of each.

Table 5: Policy Paths for Further Discussion

	Policy Path 1	Policy Path 2	Policy Path 3	Policy Path 4	Policy Path 5	Policy Path 6
Resource Type	All	All	All	Solar	Biomass (sustainable)	All
Vintage	New, separate price for repowering	New + repowering	New	New	New	New, separate price for repowering
Size	No limit	> 20	> 1.5	> Net metering threshold	> 1.5	< 20
Timing	Trigger (RPS < 20 percent under contract by 2010, implement Feed-in Tariff in 2012-13)	Now (available for 3-year duration)	automatically in 2010-11 (so projects are developed in parallel with transmission)	Now	Now	Now
Scope	Full Market	Pilot (limited time, one utility)	CREZ-Only	Pilot (e.g. within one utility)	Full Market	Full Market
Setting the Price	Cost-based with initial differentiated auction without MPR to set competitive benchmark for subsequent tariff	Value Based (time & peak differentiated with CO_2 & other adders)	Cost-based	Cost-Based w/ Competitive benchmark	Cost-based, calculated to consider sustainable yield of local biomass sources	Cost-based
Contract Duration	Long-term	Long-term	Long-term	Long-term	ST/MT	Long-term
Tariff Differenti-ation	Differentiation by technology & size	Not Applicable	Wind by size, geothermal, biomass by size, solar by technology	By size, type	By fuel and size	Differentiation by technology & size
Limits	Capped at RPS targets; caps on more expensive technologies	Uncapped	Capped at CREZ Transmission limit	Capacity limit will be established for the sponsoring utility.	Uncapped	Uncapped

Source: KEMA

Policy Path 1

This policy path is designed to be similar to the feed-in tariff system currently in place in Germany, but only to be implemented if the RPS fails to make progress in meeting policy objectives. Under this option, long-term, fixed-price contracts would be made available to all new renewable resources that are eligible under the RPS, regardless of size. There would be no cap on generator size, and the tariffs would be differentiated by technology and by project size. This policy path also includes preferential treatment for repowered resources.

The key differences between this policy path and the German feed-in tariff approach are that the initial price would be set using a differentiated competitive benchmark process, rather than through an administrative process, and there would be caps on certain emerging resources to limit policy cost impacts.

A central feature of this policy path is that its imposition would be conditional, only taking effect if the RPS target of 20 percent by 2010 was not satisfied. Under the current RPS, the IOUs, CCAs, and ESPs are required to have 20 percent renewable contracted by 2010. If the IOUs, CCAs, and/or ESPs fail to contract an energy mix of 20 percent renewables, a feed-in tariff would be implemented automatically in 2011. The other scenario would be that IOUs, CCAs, and ESPs contract 20 percent of their energy mix with renewables by December 31, 2010, however they fail to meet the three-year window in which the generators have to interconnect and start generating. If the contracted generators fail to interconnect and beginning generating by December 31, 2013, a feed-in tariff would be automatically implemented in 2014.

Pros: This policy could rapidly accelerate the development of renewable resources in California to help meet the 2020 goal on schedule. The long-term, technology-differentiated contracts would also likely contribute to investor security and promote a diverse mix of renewable resources. The existence of uncapped, standard-offer contracts for near-market renewables could also help stabilize rates and potentially suppress wholesale prices, whereas the cap on emerging renewables could help control policy costs. Finally, the inclusion of a trigger mechanism allows the RPS more time to perform, while at the same time providing insurance that increased progress toward the 33-percent goal could be made if the RPS does not meet the 2010 target.

Cons: As discussed previously, an uncapped feed-in tariff open to generators of all sizes creates uncertainty in terms of the level of policy response and, therefore, policy impact and policy cost. Exactly how such a tariff would interact with the RPS solicitations would need to be worked out. Also, the competitive benchmark approach has not been used widely in the United States or internationally, and it is uncertain how it would perform. Finally, this policy path would not address technical barriers such as the lack of transmission in the most resource-rich areas.

Policy Path 2

Similar to Policy Path 1, Policy Path 2 would provide generators with a long-term, fixed-price contract but would have several critical differences. This policy path would go into effect immediately, rather than waiting for a trigger mechanism, but would be implemented as a short-term, three year pilot program, rather than a full-scale, unbounded incentive program. Generators would have a three year window to come on line and lock into their long-term feed-in tariff rates, after which the program would be evaluated. The pilot would be available only to projects 20 MW and larger and would have no caps. Finally, the tariff would be value based, rather than cost based, and would be technology neutral.

Pros: Option 2 moves into feed-in tariff implementation immediately and would give the state experience with standing prices offered to larger projects in conformance with the original scope of the 2007 *Integrated Energy Policy Report* (*2007 IEPR*) direction for feed-in tariff evaluation. Moreover, the pilot nature of the tariff and the fact that it was value based could address stakeholder concerns over uncertain policy duration and cost.

By focusing on larger projects that might respond to RPS but in the context of a pilot program, this policy path would help identify the degree to which some issues identified with respect to the current RPS solicitations process are actually barriers. Some questions that could be answered by such a pilot include:

- Will a standing price at a comparable level help reduce development costs and transaction costs to make projects more viable?
- Will certainty of a long-term contract make more projects viable at a value-based price by lowering risk and cost of capital?
- Will availability of a price similar to those available under RPS solicitations on a standing basis overcome issues associated with solicitation timing and the chicken-and-egg challenge of providing firm pricing before resolving all permitting and transmission issues?

Cons: By targeting only technologies larger than 20 MW using a value-based method, it is unlikely that the feed-in tariff would achieve the policy priority of creating a diverse mix of renewable resources—both in terms of project size and technology type. Furthermore, given the pilot nature of the policy, it is unlikely that a sufficient quantity of renewable resources would be developed to meet the RPS objectives. In particular, long lead-time projects such as biomass projects would not be likely to participate unless already well into the development process by the time the tariff was offered. Finally, depending on the value upon which the policy is based was determined (for example, a natural-gas-based market price referent [MPR]), the policy might not allow for long-term contracts for renewable resources to serve effectively as hedges against conventional fuel prices.

Policy Path 3

Like Policy Path 1 this option also resembles the German feed-in tariff in which generators are eligible for long-term, fixed-price contracts that are technology specific and differentiated by project size. The primary differences with Policy Path 1 are that the tariffs would be set administratively, rather than through a competitive benchmark, and the policy would be triggered not by RPS performance, but by the establishment of Competitive Renewable Energy Zones (CREZs) by 2010/2011. Most significantly, the feed-in tariff would be geographically limited to resources located within a CREZ footprint, and the quantity eligible to take the feed-in tariff price would be capped at the transmission capacity in place and /or planned for the CREZ. This policy path would specifically be designed to encourage generation within a CREZ as soon as possible after transmission becomes available, but renewable energy projects would proceed along their own development timeline and would not be otherwise constrained by the timing of transmission completion and associated RPS solicitations. It would also be designed to limit exercise of market power in CREZ areas, a concern discussed in the *2007 IEPR*. Finally, the policy would target systems over 1.5 MW, in acknowledgment of the fact that there is already a feed-in tariff in place for generators below that threshold and that few small projects would likely be developed in a CREZ footprint whose purpose is to assist in transmission planning to bring large amounts of energy from renewable rich areas to load.

Pros: According to recent state estimates, there is sufficient renewable resource potential in the CREZs to meet the long-term renewable goal of 33 percent by 2020.[59] As a result, Option 3 would have many of the same positive aspects as Option 1 in that the policy would help meet the state targets, would contribute to a diverse mix of renewable resources, and would encourage investor security. The primary benefit over Policy Path 1 is that CREZs will define areas with high quality renewable energy resources. As a result, cost-based feed-in tariffs could be set lower than comparable tariffs in less resource rich areas of the state.

The limitation of a feed-in tariff for renewable development to the CREZ would also address some of the concerns about how to implement a feed-in tariff more generally, about how a feed-in tariff would interact with the RPS, and the effectiveness of feed-in tariffs in a transmission-constrained environment. By establishing the feed-in tariff availability and pricing once the commitment was made to move forward with constructing transmission to the CREZ, this policy path could eliminate the multiple-contingency (transmission being built and winning a solicitation) chicken-and-egg barriers to renewables development, allowing generators to move more aggressively in their development once transmission construction is committed.

This policy option could also help streamline administrative review of proposed renewable generation by encouraging CREZ-based interconnection studies and programmatic environmental impact studies.

[59] For more information see *2004 IEPR Update* http://www.energy.ca.gov/reports/CEC-100-2004-006/CEC-100-2004-006CMF.PDF.

Cons: This policy path would face many of the same concerns as Policy Path 1 over cost control, especially since there is no cap on emerging resources, but to a lesser degree since the quantity would be limited by CREZ transmission capacity. By limiting the categories of eligible resources to nearer-market types, or limiting the quantity of emerging resources, these concerns could be mitigated. This policy path would also face the challenges inherent in establishing the "right" cost-based price administratively, as discussed in the *Issues & Options Report*. Finally, because of the quantity limits imposed by CREZ transmission capacity, there could be speculative queuing issues that would need to be addressed.

Policy Path 4

This policy path constitutes a solar-only pilot feed-in tariff. It combines elements of Policy Paths 1 and 2, in that it is cost-based and a pilot program. Rather than being limited to a specific window of time, however, the pilot-scale for the tariff would be accomplished by limiting it to a single utility territory. Eligibility would be limited to solar installations larger than the net metering limit of 1 MW. It is also envisioned that there would also be a capacity cap on this option.

Pros: The availability of long-term, technology-specific contracts for solar power would provide investors and developers with market certainty and enhance financial security (particularly if the tariff was set at an aggressive price point), and the existence of a solar-specific feed-in tariff would provide an incentive for systems larger than the net metering threshold. The technology would also provide an opportunity to develop solar thermal electric systems in resource-rich areas in the near term. This policy path directly contributes toward partially meeting the diversity goals enumerated by the Energy Commission and, as discussed below, could be established independently (in concert with) another policy path.

Cons: This policy path is unlikely to fully achieve the state's diversity or renewable energy quantity goals unless combined with other paths. Moreover, the focus on solar energy alone might not contribute to the goal for renewable energy to help stabilize rates since solar energy is likely to be above-market. The quantified caps could undermine some of the investor confidence created by the long-term contracts, depending on the structure of the cap.

Policy Path 5

Similar to Policy Path 4, this policy path is limited to a single technology—in this case, sustainable biomass. Tariffs would be cost-based and differentiated by size and differentiated by fuel to take into account different costs and characteristics of different feedstocks. All feedstocks would need to meet applicable sustainability criteria.[60] Unlike the solar-only option, the biomass path would be available in every market, rather than on a pilot scale in a single

[60] The specific definition of sustainability would need to be worked out if this policy path is pursued.

utility, and would not be capped. Finally, unlike the other policy paths, which would incorporate long-term contracts or price guarantees, the contract term in this path would be either short- or medium-term in acknowledgement of the fuel price risk that longer term contracts would place on biomass developers and investors. As discussed below, this option could be established independently (in concert with) another policy path.

Pros: The feed-in tariff would respond to Executive Order S-06-06 relative to biomass, partially contribute to diversity goals, and also reinforce the importance of identifying sustainable feedstocks and resource management strategies for biomass.

Cons: Similar to the solar option (Policy Path 4), the limited eligibility of the biomass-only option would prevent this policy path alone from fully achieving a diverse mix of renewable energy resources or 33 percent by 2020.

Policy Path 6

This policy path follows the approach advocated through stakeholder comments to concentrate feed-in tariff attention on generators under 20 MW. A feed-in tariff applied to this size range has been getting greater attention as the CPUC has recently been considering raising the current feed-in tariff project size cap from 1.5 MW to 20 MW[61], as well as SCE's proposal to offer standard contracts to all RPS-eligible generators 20 MW and under in their 2009 RPS Procurement Plan[62]. Like Policy Paths 1 and 3, it resembles the German approach—cost-based long-term prices, differentiated by technology and size. Unlike Policy Path 1, however, prices would not be based on a competitive benchmark, and the tariff quantity would be uncapped. It would be established immediately statewide.

Pros: As RPS stakeholders suggested solicitations have done little for generation less than 20 MW, this approach fills a perceived gap. As discussed in Chapter 3, the IOU Contracts Database lists 24 active contracts for new facilities for a cumulative total of 108.5 MW of capacity.[63] Thus, the contract gap between projects greater than 20 MW and projects under 20 MW is a real issue and supports a feed-in tariff for projects under 20 MW. As such, it would augment the RPS and therefore help contribute to meeting the quantity goals, accelerating the pace of development towards 33 percent by 2020 without delay. As it involves smaller generators, the ultimate rate impact concerns are mitigated.

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[61] *California Public Utilities Commission. Amended Scoping Memo and Ruling of Assigned Commissioner Regarding Phase 2 of Tariff and Standard Contract Implementation for RPS Generators.* June 5, 2008. http://docs.cpuc.ca.gov/efile/RULC/83784.pdf.

[62] *Southern California Edison Company's 2009 RPS Procurement Plan*, Attachment I. CPUC Rulemaking 08-08-009, September 15, 2008.

[63] http://www.energy.ca.gov/portfolio/contracts_database.html.

Cons: The biggest drawbacks to this policy path are that it might make only limited progress towards meeting a 33-percent goal due to the maximum generator size, and would present the challenge of choosing the "right" price administratively, as discussed in the *Issues & Options Report*.

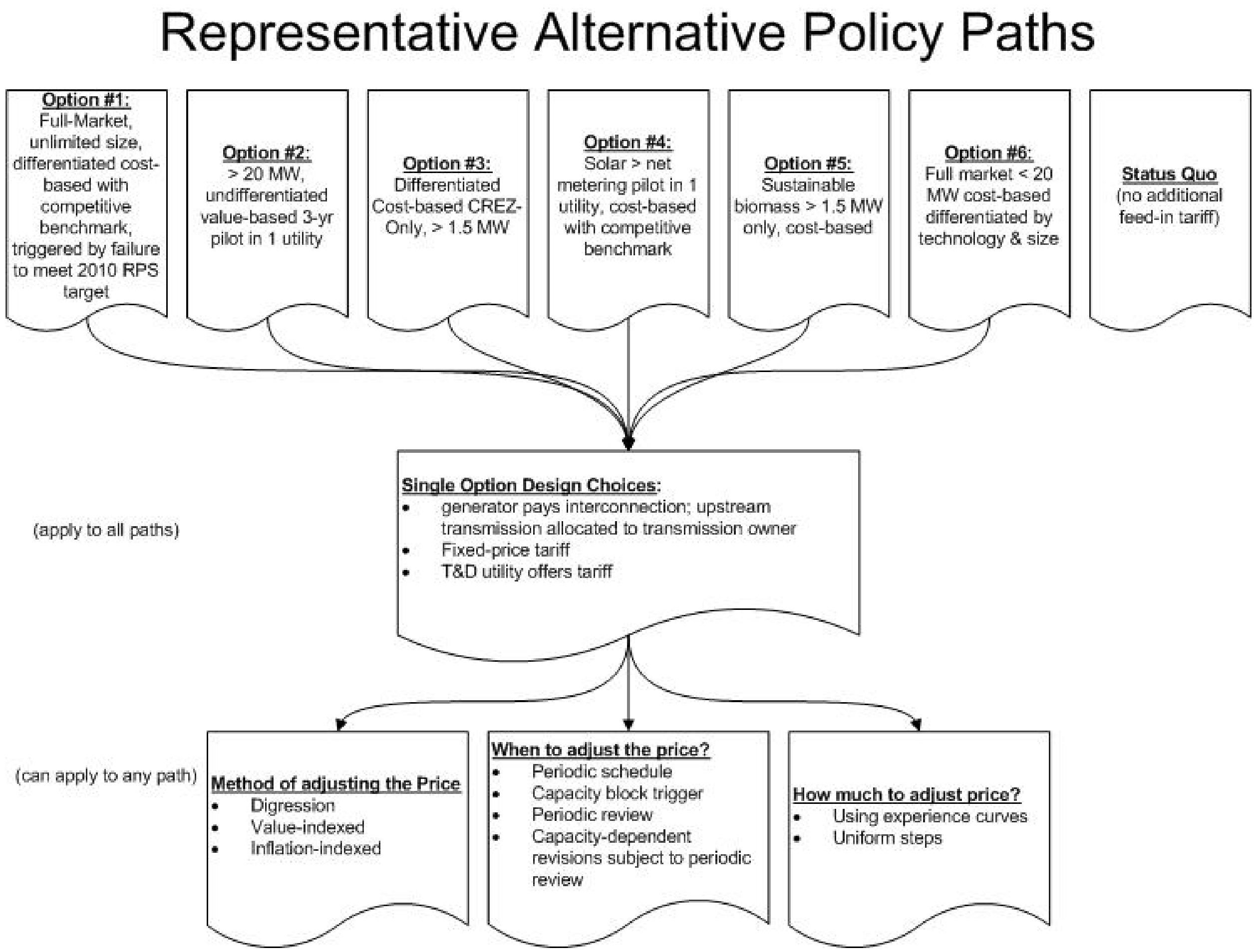
Expanded Policy Paths

The policy paths outlined in Table 5 above are incomplete, in that they do not list options for all of the design issues designated as *core issues*. This is because the remainder of the core issues did not constitute distinguishing features among the policy paths. Once the policy path is decided, the policy path characterization can be completed by:

- Adding the design features from the three core design issues for which a single viable design choice has been identified—a fixed-price tariff, offered by the transmission and distribution utility to whom the generator interconnects, with the generator paying for interconnection (and transmission company supporting network upgrades) as done today.
- Selecting from among the remaining design options for three price-related dimensions of policy design—the method of adjusting price, as well as when and by how much to adjust the price.

A diagram depicting these expanded policy paths is shown in Figure 6.

Figure 6: Expanded Policy Paths

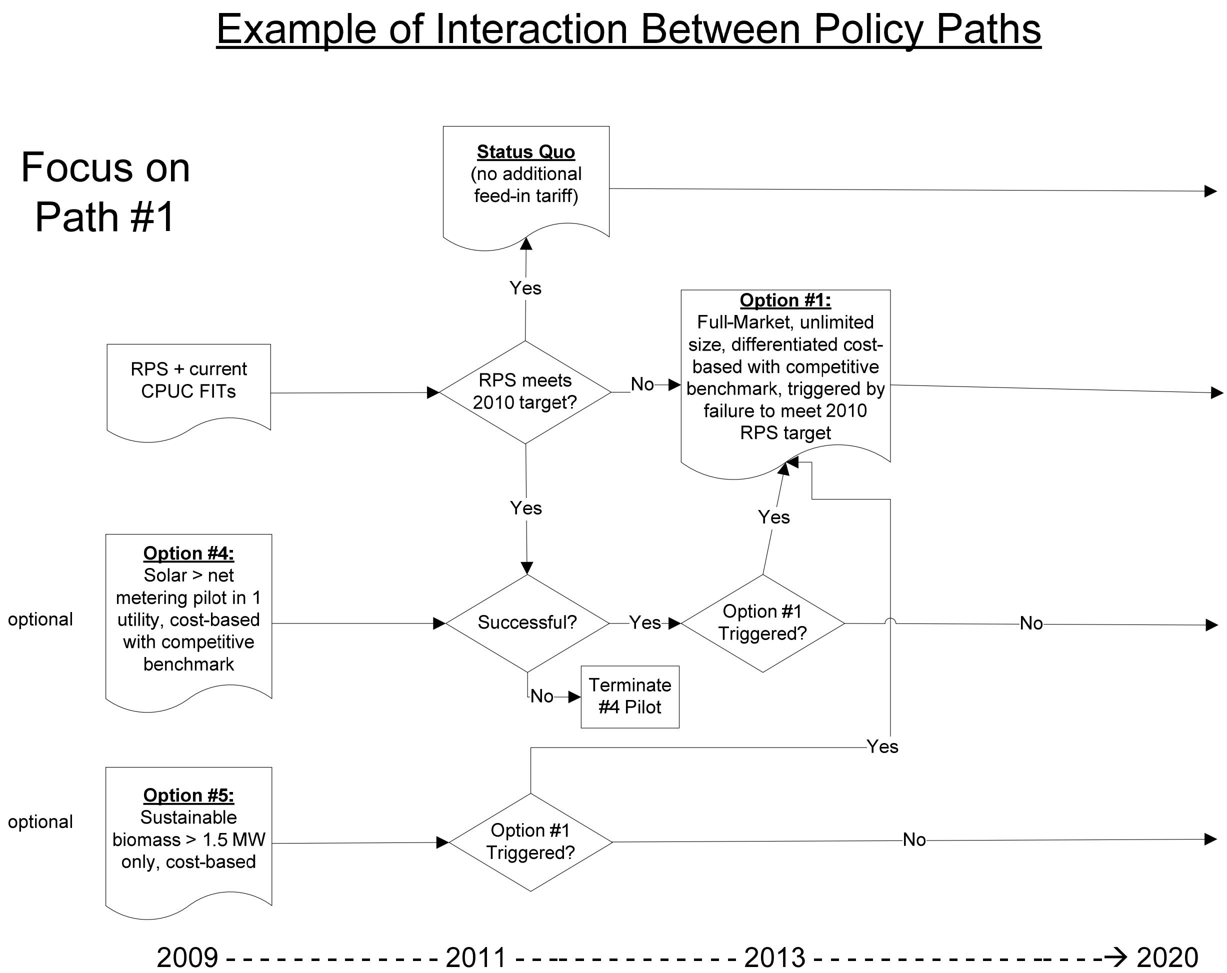


An additional choice, when a cost-based approach without competitive benchmark is used, is whether to set a cost-based tariff at an aggressive or conservative price level.

Policy Trajectories—The Potential Interaction of Policy Paths

The policy paths identified in this report, while distinct, need not be thought of as independent alternatives. Some could be adopted in concert with others or interact, and those that do not apply to the whole of the California market, or are on a pilot scale or duration, can be thought of as potentially working together along a *policy trajectory*. A policy trajectory might allow for incremental steps in advance of a comprehensive feed-in tariff policy regime. One example of a policy trajectory map is laid out in Figure 7.

Figure 7: Illustration of the Interaction of Policy Paths 1, 4, and 5



This example focuses on the perspective of Policy Path 1, Policy Path 4, and/or Policy Path 5 being implemented, Policy Path 4 on a pilot scale for solar, Policy Path 5 for biomass only statewide—while waiting to see if the trigger event for implementing the comprehensive cost-based feed-in tariff outlined in Policy Path 1 would occur. If the RPS targets are met and the Policy Path 1 feed-in tariff is not triggered, then Policy Path 4 can be judged on its own merits as either successful and continued, or not. Similarly, Policy Path 5 would continue unaffected. However, if Policy Path 1 was to be triggered, then Policy Path 4 could be folded into the broader statewide, cost-based, differentiated set of tariffs if it were deemed successful, thereby constituting a transition policy. If Policy Path 4 is deemed unsuccessful at the end of the pilot period, it could be shut down. Similarly, the biomass tariff of Policy Path 5 could also be folded into the set of differentiated tariffs in Policy Path 1.

Similar policy trajectory maps could be developed from the perspective of Policy Paths 2, 3, and 6. Policy Path 4 can be thought of as a transition to a broader policy that would, if successful, potentially be expanded to all utilities. Policy Path 5, on the other hand, would either constitute its own path, or be an adjunct to broader policy paths.

CHAPTER 6:
Policy Interaction

As stated in the 2007 *Integrated Energy Policy Report* (*2007 IEPR*), there is currently a need to establish more cohesive statewide approach for renewable development that identifies preferred renewable generation and transmission projects. This chapter examines areas of policy overlap related to feed-in tariffs and other statewide initiatives.

Integration of Feed-In Tariffs With the Existing RPS Framework

As examined in the *Issues & Options Report*, a key question is how best to integrate feed-in tariff design with the existing framework in California. Feed-in tariffs offer an alternative approach to funding renewable generation and may help to achieve larger deployment of renewable generation at lower costs, provided that the tariffs are designed in a cost-effective manner. California is already experimenting with feed-in tariffs through several different mechanisms:

- Assembly Bill 1969[64] requires that each electrical corporation develop a tariff for public water and wastewater facilities up to 1.5 MW in size, priced at the market price referent (MPR), up to a statewide cap of 250 MW.
- California Public Utilities Commission (CPUC) Decision 07-07-027 implemented Assembly Bill 1969 and also requires that Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) implement feed-in tariffs priced at the MPR for up to about 230 MW of renewable facilities, each up to 1.5 MW in size and owned by customers other than public water and wastewater agencies.[65] Through Decision 08-09-033 the CPUC recently extended this to SDG&E as well[66].
- Senate Bill 380[67] formally extended the feed-in tariff to all small renewable generation and to all customers of electrical corporations and expanded the statewide feed-in tariff capacity cap to 500 MW.
- SCE offered standard contracts for biogas and biomass generators less than 20 MW priced at the 2006 MPR of approximately $0.08 per kilowatt hour (kWh). [68]

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64 Assembly Bill 1969 (Yee, Chapter 731, Statutes of 2006), codified in Public Utilities Code Section 399.20.

65 In Decision 07-07-027, the CPUC chose not to apply a feed-in tariff for customers other than public water and wastewater agencies to SDG&E, Sierra Pacific, or PacifiCorp.

66 California Public Utilities Commission. Interim Decision Regarding Extension of Tariff/Standard Contract to Other Customers of SDG&E. September 18, 2008. http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/91159.pdf.

67 Senate Bill 380 (Kehoe, Chapter 544, Statutes of 2008), codified in Public Utilities Code Section 399.20.

- For 2009, Southern California Edison developed the Renewables Standard Contracts Program[69], which includes two standard offer contracts for RPS eligible renewable resources ranging from 1.5 to 5 MW and above 5 to 20 MW.
- As part of its Customer Solar Program, the Los Angeles Department of Water & Power is implementing its own feed-in tariff. LADWP believes this component will provide up to 150 MW of solar energy by 2016.
- In June 2008, the CPUC issued an amended scoping memo and ruling of assigned commissioner on whether to raise the project cap from 1.5 MW to 20 MW.[70] The CPUC proceeding for expanding the current tariff at the MPR is ongoing.[71] The CPUC held a workshop on February 10, 2009, to take public comment on proposed feed-in tariff terms and conditions. This workshop was to determine if the existing feed-in tariff contract should require additional terms and conditions if the CPUC were to expand the existing feed-in tariff contract from 1.5 MW 20 MW or less. The CPUC has not yet determined whether to expand the existing feed-in tariff program. However, the CPUC Energy Division Staff recently released a Feed-in Tariff Proposal to expand the eligible generator project size in the existing must-take Feed-in Tariff program from 1.5 MW to 10 MW with the tariff based on the market price referent (MPR).[72] The Energy Division Staff also proposes to allow utilities to offer utility–specific standard offer contracts for projects in the 10–20 MW size range.

To meet the RPS requirements, however, California investor-owned utilities (IOUs) conduct annual RPS procurement solicitations that are approved by the CPUC. The RPS least-cost, best-fit provisions are somewhat at odds with a feed-in tariff policy, particularly if the state is considering a feed-in tariff that includes generation cost-based payments for emerging technologies. The IOUs could prepare periodic least-cost, best-fit reports and indicate to the CPUC which system factors they would like to see reflected in the feed-in tariff rates. However,

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[68] The expiration date for SCE's Standard Contract for Biomass is 12/31/2008 or 250 MW, whichever comes first. As of early June 2008, SCE has 11 MW under contract, 23 MW in negotiation, and 22 MW of inquiries. SCE plans to extend this standard contract to all renewable energy generators up to 20 MW in capacity in 2009. The SCE Biomass "Protocol" document is available at http://www.sce.com/EnergyProcurement/bsc.htm.

[69] http://www.sce.com/EnergyProcurement/renewables/renewables-standard-contracts.htm.

[70] California Public Utilities Commission. *Amended Scoping Memo and Ruling of Assigned Commissioner Regarding Phase 2 of Tariff and Standard Contract Implementation for RPS Generators*. June 5, 2008. http://docs.cpuc.ca.gov/efile/RULC/83784.pdf.

[71] California Public Utilities Commission. *Request for Comments Regarding Phase 2 of Feed-in Tariffs*, October 10, 2008. California Public Utilities Commission. *Request for Comments Regarding Feed-in Tariff for Small Renewable Generators: Terms and Conditions*, January 28, 2009 and Feed-in Tariff workshop, February 10, 2009. http://www.cpuc.ca.gov/PUC/energy/Renewables/FITPhase2.htm.

[72] CPUC Energy Division Staff FIT Proposal. March 29, 2009.

if the feed-in tariff were defined as a wholly separate funding strategy from the RPS solicitation the least-cost, best-fit requirements would not apply to the feed-in tariff. To avoid conflicts with the least-cost, best-fit requirement, the feed-in tariff should be separate from the RPS solicitations

The establishment of a feed-in tariff operating contemporaneously with utility RPS solicitations raises the question, however, of the impact that feed-in tariffs would have on RPS solicitations. The proposed feed-in tariff is for resources 20 MW and below, and so there would appear to be little impact on the current solicitation process, since the vast majority of responses to and contracts resulting from RPS solicitations have been from projects larger than 20 MW. Conversely, if feed-in tariffs were expanded to projects exceeding 20 MW, then there is greater potential for interaction with the RPS solicitation process. This interaction could create additional opportunities for developers between RPS cycles without detracting from RPS solicitations, or could result in projects gravitating toward whichever avenue – feed-in tariffs or requests for offers (RFOs) – offered more lucrative contracts, to the exclusion of the other. The interaction may depend heavily on the relative tariff price levels for various technologies relative to the MPR and is likely to differ by technology and/or project size. For cost-based feed-in tariffs, this in turn depends on technology costs, how aggressively or conservatively the tariffs are set, how such prices would compare against the MPR, and the dynamics of project timing and other policy drivers (such as production tax credit expiration dates). In the absence of specific parameters, the authors cannot predict how generators would approach the tradeoff of certain access to a long-term revenue stream versus potential for being selected for RPS contracts under an RFO. Nonetheless, this subject merits further systematic consideration (perhaps using game theory techniques) if feed-in tariffs are considered for generators in excess of 20 MW, once specific feed-in tariff prices have been proposed.

A related issue to how feed-in tariffs and the RPS would interact is how renewable energy credits and environmental attributes would be treated under a feed-in tariff. As noted earlier in Appendix B, stakeholders recommended that feed-in tariffs incorporate environmental attributes and renewable energy credits (RECs), and that all benefits should be held by the utility to count towards its RPS procurement targets.

Senate Bill 107 (Smitian and Perata, Chapter 464, Statutes of 2006) granted the California Public Utilities Commission (CPUC) the ability to authorize the use of renewable energy credits (RECs) toward RPS obligations. However, the CPUC and the Energy Commission must first jointly conclude that the tracking system is operational, capable of independently verifying that all renewable energy used for RPS compliance is generated by an eligible facility and delivered to the retail seller, and can ensure that renewable energy credits shall not be double counted by any seller of electricity within the service territory of the Western Electricity Coordinating Council (WECC). To this end, the CPUC and Energy Commission adopted the *Joint Commission Report on Tracking System Operational Determination (Tracking System Report)* November 21, 2008, and December 3, 2008, respectively. The *Tracking System Report* demonstrated that the tracking system, known as the Western Renewable Energy Generation Information System (WREGIS), has met the conditions required by Senate Bill 107. Feed-in tariffs could function with or without the establishment of a RECs tracking system like WREGIS.

Interaction of Feed-In Tariffs With Assembly Bill 32

The California Air Resource Board released the AB 32 Draft Scoping Plan in June 2008, which states the following: "Based on Governor Schwarzenegger's call for a statewide 33 percent RPS, the Draft Scoping Plan anticipates that California will have 33 percent of its electricity provided by renewable resources by 2020, and includes greenhouse gas emission reductions based on this level in the Draft Plan."[73]

Assembly B 32 (Núñez, Chapter 488, Statutes of 2006) sets a goal of reaching 1990 emissions by 2020. The Governor has set a long-term goal of GHGs being 80 percent below 1990 levels by 2050. Renewable energy development policies should be designed to meet the 2020 goals in a way that sets the state on a path to reach the 2050 goals.

Interaction With Competitive Renewable Energy Zones

As noted in the *2007 IEPR*, investments in California's transmission infrastructure are required to access in-state and out-of-state renewable resources. For that reason, any distinction among the policy mechanism(s) used to support renewables will be muted unless additional transmission is built.

Efforts to address this need include the California Independent System Operator's location-constrained resource interconnection process and the Renewable Energy Transmission Initiative (RETI), which the Energy Commission is funding and is a major participant. Some early successes for the Competitive Renewable Energy Zone (CREZ) like process have been realized—the Tehachapi transmission project is under construction that will access up to 5,000 MW of wind when fully in service. Competitive Renewable Energy Zones are being developed in the RETI process to facilitate transmission planning to renewable rich areas.[74] There is a similar renewable energy zone process underway for the WECC.[75]

Transmission additions are lumpy, adding hundreds or even thousands of megawatts, depending on the size of the transmission project. To avoid the risk of under-utilized transmission lines, keep downward price pressure on renewable generators in newly interconnected CREZ areas, facilitate geographically clustered interconnection studies and programmatic environmental impact studies, and build investor confidence in renewable energy development, the timing and capacity levels of feed-in tariffs could be designed to match expected new transmission additions. A feed-in tariff targeting CREZs could be

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[73] California Air Resources Board (2008). *Climate Change Proposed Scoping Plan.* http://www.arb.ca.gov/cc/scopingplan/document/psp.pdf.

[74] For more information visit http://www.energy.ca.gov/reti/index.html.

[75] For more information visit http://www.westgov.org/wga/initiatives/wrez/index.htm.

established before the transmission is placed into operation to enable the development of renewable energy projects while the transmission is being constructed. Such a phased approach could more effectively and rapidly use CREZ transmission and should be explored further.

Feed-In Tariffs for Onsite Generators

In Europe, generators that take advantage of feed-in tariffs typically sell all of their electricity into the grid, regardless of whether they are located onsite or are central station plants.[76] If a feed-in tariff is developed for generators 20 MW and under in California, however, an important design and implementation question will be in what form the feed-in tariff will be available to onsite generators.

Onsite generators in California can currently choose from between two separate policy frameworks governing renewable electricity. Under the state's net metering statutes, renewable generators up to 1 megawatt in size can receive retail credit for the excess electricity they generate over the course of the year, so long as the excess can offset net purchases at other times during the year. At the end of the year, excess generation is granted to the utility. Alternatively, generators that are 1.5 MW in size or below can take advantage of the state's current feed-in tariff. Under the feed-in tariff, generators have the option to either sell 100 percent of their electricity at the feed-in rate or sell only the excess generation that is not consumed onsite.

If a feed-in tariff for generators 20 MW and under is adopted, and current laws remain in place, certain generators could have a choice between net metering, the currently available feed-in tariff, and the new feed-in tariff. There would be no direct interaction between these three policies, however, and generators could not take advantage of more than one.

Utility Ownership of Feed-In Tariff Generators

If feed-in tariffs are established in California, one policy question that arises is whether utilities would be allowed to own such generation and recover the cost of that generation at tariff rates. It is the CPUC's purview to address utility ownership of generation. As a matter of precedent, the authors imagine that the CPUC would likely apply principles consistent with other decisions on the subject, e.g. in D.07-12-052[77]. In any event, the role of utility ownership is an issue to be resolved in the implementation process and should be explored in the IEPR process.

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[76] Although most renewable generators in Germany opt to take advantage of the feed-in tariff, there are some cases (e.g. wastewater treatment plants) in which the value for using onsite renewable generation to offset retail purchases is greater than selling at the feed-in tariff rate. In these cases, generators opt to consume electricity onsite.

[77] http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/76979.pdf.

Interaction With a Feed-In Tariff and the Public Utility Regulatory Policies Act

There have been concerns raised in California, and beyond, that the Public Utility Regulatory Policies Act (PURPA) would effectively limit the CPUC's ability to set rates at levels higher than the short run avoided cost (SRAC). Of course, this limitation, if applicable, would only apply to qualified facilities, rather than to wholesale rate setting in general. For PURPA to apply to a feed-in tariff, a generator would have to register at the Federal Energy Regulatory Commission (FERC) as a qualifying facility. This is unlikely, because feed-in tariffs based on MPR or cost of generation rates are likely to be higher than SRAC. Furthermore, it would not be surprising if in the near future, particularly once the California ISO implements its Market Redesign and Technology Update, FERC is petitioned by California utilities to exempt them from future PURPA purchases as allowed by the Energy Policy Act (EPAct) of 2005 under certain conditions. Therefore, PURPA may not be relevant to California in the mid-to-long term.

More likely, a feed-in tariff generator will register as an exempt wholesale generator under EPAct. FERC may rule on purchases from a feed-in tariff generator but under a "market-based" doctrine, where the market will likely be defined as the market for renewable energy generators.

Jurisdictional Issues Between FERC and State

In addition to the empirical rational for focusing feed-in tariffs on smaller generators–the fact that few small generators have competed successfully in utility RPS procurements–there are two additional reasons for focusing on smaller generators. The first is also the rationale for selecting 20 MW as a threshold for this recommendation. The Federal Energy Regulatory Commission (FERC) selected 20 MW as a threshold for small generators that merits standardized interconnection rules.[78] And while the rules applied to FERC-jurisdictional facilities, FERC indicated that "our hope is that states may find this rule helpful in formulating their own interconnection rules". [79] In essence, FERC's deliberations found 20 MW to be an appropriate breaking point for small generation meriting standardized treatment to overcome diseconomies of scale and facilitate their timely development.

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[78] FERC Order Nos. 2006-A, In 2006 required all public utilities owning, controlling, or operating facilities for interstate transmission to file revised open access transmission tariffs containing standard small generator interconnection procedures and a standard small generator interconnection agreement, and to provide interconnection service under them to small generating facilities of no more than 20 megawatts. http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.

[79] 18 CFR Part 35 [Docket No. RM02-12-000; Order No. 2006] Standardization of Small Generator Interconnection Agreements and Procedures (Issued May 12, 2005) http://www.ferc.gov/industries/electric/indus-act/gi/small-gen/05-12-05-order2006.doc.

The second reason is one of jurisdiction. It is possible that FERC could assert jurisdiction over feed-in tariff sales for generators connected to FERC-jurisdictional facilities as being wholesale in nature. As a result, subject to further legal research, the FERC/state jurisdictional boundary might dictate the limits of a state's ability to institute feed-in tariffs.

If FERC jurisdiction were to constitute such a limit to feed-in tariffs, the limitation may not be 20 MW, but rather the voltage and functional characteristics of the interconnecting line. FERC defined the approach to designating which facilities are state and which are FERC jurisdictional.[80] FERC indicated that there is not a bright line separating unbundled retail transmission and distribution; rather, the distinction must be considered on a case-by-case basis using the following seven-factor test:

1. Local distribution facilities are normally close to retail customers
2. Local distribution facilities are primarily radial in character.
3. Power flows into local distribution systems; it rarely, if ever, flows out.
4. When power enters a local distribution system, it is not transported to another market.
5. Power that enters a local distribution system is consumed in a comparatively restricted geographic area.
6. Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.
7. Local distribution systems will be of reduced voltage.

Furthermore, for states with retail competition, FERC will defer to state recommendations on where to draw the boundary between transmission and distribution and how to allocate costs for transmission and distribution between FERC and the states, as long as states use the seven-factor test.

However, subject to further research, FERC might simply consider feed-in tariffs under their market-based rules. If feed-in tariff generators qualified as exempt wholesale generators and not qualifying facilities, FERC may assert jurisdiction but find that the rates under feed-in tariffs are market-based and therefore meet the just and reasonable standard under the Federal Power Act. Put more simply, FERC may assert jurisdiction but with no real practical impact. Such an outcome may hinge in part on how the tariff is structured and what is being purchased. If bundled electricity and RECs are purchased, it is possible that by designating a market-based portion of the rate as payment for electricity and the remainder as payment for the REC, that constraints of the Federal Power Act could be respected, since FERC has ceded to the states jurisdiction over RECs as a mechanism of state policy.[81]

[80] FERC Order 888.

[81] FERC Docket No. EL03-133-000, "Order Granting Petition for Declaratory Ruling," October 1, 2003. American Ref-Fuel Co. et al., 105 FERC 61,004 (2003).

This issue should be looked at more closely in the IEPR process.

Interaction Between State and Federal Feed-in Tariffs

The vigorous debate on whether to have a national renewable portfolio standard[82], appears to be giving way to a discussion of how best to structure a national renewable portfolio standard, given President Obama's pledge to set a renewable electricity standard of 10 percent by 2012 and 25 percent by 2025. An important and complex part of this discussion is how a federal renewable portfolio standard might interact with the existing 33 state renewable portfolio standards and goals. These discussions currently assume that the national RPS will primarily use a system of tradable renewable credits for compliance[83]. In parallel to federal RPS initiatives, however, there is also a federal feed-in tariff proposal, and this section reviews the potential interaction of state and federal feed-in tariffs. The interaction between the proposed California feed-in tariff and the proposed federal feed-in tariff would be less complex than between federal and state tradable credit systems.

The federal feed-in tariff bill was introduced in May 2008 by Congressman Jay Inslee (D-Wa).[84] The bill would establish guaranteed interconnection through uniform minimum standards, a mandatory electricity purchase from renewable generators smaller than 20 MW under a fixed rate, 20-year contracts, and rate recovery through a national system benefits charge regionally partitioned according to NERC regions. The rates for the feed-in tariff are not explicitly established in the bill, but the legislation does specify that the rates should be set to provide a 10 percent internal rate of return to the owners of facilities installed at sites within the nation's top 30th percentile of resource conditions.[85]

The incremental cost of the federal feed-in tariff rates would be paid for through a regional fund. Each state in the region would have to pay into the fund based on a non-bypassable surcharge. States that set feed-in tariff rates at the federal minimums would be permitted to

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[82] Sovacool, B. K., and C. Cooper, (2007). "Big Is Beautiful: The Case for Federal Leadership on a National Renewable Portfolio Standard." *The Electricity Journal*, 20(4), 48-*61;* Ralls, M. A. (2006). Congress Got It Right: There's Not Need to Mandate Renewable Portfolio Standards." *Energy Law Journal*, 27(451-472).

[83] Wiser, R. (2008, June, 24). *Designing a Federal RPS That Builds on State Programs: Principles and Issues for Consideration*. Proceedings of the State/Federal RPS Collaborative Webinar.

[84] For discussions about the bill, *see* Rickerson, W., F. Bennhold, and J. Bradbury. (2008). *Feed-In Tariffs and Renewable Energy in the USA: A Policy Update*. Raleigh, NC, Washington, DC, and Hamburg, Germany: North Carolina Solar Center, Heinrich Böll Foundation North America, and the World Future Council; Hering, G. (April 2008). "Whispers of a New Direction: First National Feed-In Tariff Legislation to Be Introduced in US Congress." *PHOTON International*, 44-46; Tezak, C., and K. W. Stanco. (2008). *Renewable Feed-In Tariffs American Style?* Washington, DC: Stanford Group Company.

[85] As discussed elsewhere in this paper, rates would be set based on analyses by National Renewable Energy Laboratory and the Lawrence Berkeley National Laboratory.

access the fund. States that did not set the minimum feed-in tariff rates would still be required to pay the surcharge, but would not be able to access the fund. States would be permitted to set feed-in tariffs at rate above the federal minimums, but the incremental costs of these policies above those of the federal feed-in tariff would not be recoverable through the regional funds.

Policy Path 6 shares many design similarities with the proposed federal feed-in tariff, in that both policies would employ a generation cost-based feed-in tariffs for projects 20 MW or less in size using long-term contracts. If both California and the federal government were to establish feed-in tariffs similar to those discussed herein, however, the interaction between the two policies would be limited to cost allocation and would depend on California's rates, per the above. If California were to match the federal minimum, then the policy costs would be allocated regionally. If California were to exceed the tariffs, then the incremental costs of California's policies would be allocated within the state. If California were to set feed-ins below the federal minimum, then the state would bear the cost of the federal policy, but would not be able to benefit from the regional fund.

Preference Order of Renewable Energy Generation Types

California's Energy Action Plan[86] establishes a preference or loading order for resources that lists energy efficiency as first in the loading order, followed by demand reduction measures, distributed generation, renewable generation and conventional generation resources. However, there are no policies that establish preferences or a loading order for the different renewable energy technologies within the renewable energy generation category at this time. Although there are incentive programs for some existing and emerging renewable energy technologies, the current RPS procurement policy requires all eligible technologies to compete based on ability to meet the least-cost, best-fit criteria. Alternative policies could establish a preferential hierarchy of different renewable energy generation or simply remove the natural bias towards cheaper technologies.[87] Key design issues include:

- The policy could favor particular characteristics of renewable energy generation, for example, technology, fuel type, size, vintage, or ownership type.
- Alternatively, the policy could eliminate the price bias that favors cheaper technologies. The goal of such a policy would be to reduce contract failure and achieve a more diverse portfolio of renewable energy generation.

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[86] http://www.energy.ca.gov/2008publications/CEC-100-2008-001/CEC-100-2008-001.PDF.

[87]For more information visit Green Power Institute's comments for the July 21, 2008, IEPR Workshop http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-21_workshop/comments/TN_47448_Green_Power_Institutes_Comments_on_Staff_Workshop.pdf and discussion from the August 21, 2008 IEPR Workshop. http://www.energy.ca.gov/2008_energypolicy/documents/2008-08-21_workshop/2008-08-21_TRANSCRIPT.PDF.

If a loading order for renewable energy is established, feed-in tariffs could be designed to target technologies at the top of the loading order or the technologies that are under-served by the current RPS procurement policy. The establishment of a preference or loading order for renewable energy generation could be establish through the IEPR process for consistency with state policy.

CHAPTER 7: Recommendation and Implementation Issues

As discussed previously, the policy paths outlined in Chapter 5 were developed in response to the outcomes of the June 30, 2008, staff workshop[88] (Workshop 1), overseen jointly by the Energy Commission's Integrated Energy Policy Report Committee and the Renewables Committee.

On October 1, 2008, the contents of Chapters 2-6 of this report were explored in a second Staff Workshop (Workshop 2) during which staff, Commissioners, and stakeholders examined potential feed-in tariff designs using the policy paths (and policy trajectories) discussed in Chapter 5 as a starting point. Stakeholders provided oral comments at Workshop 2, as well as submitting written comments in response to the workshop. A summary and discussion of these comments is included in Appendix C, and the full comments are posted online.[89]

A third workshop (Workshop 3) was held on December 1, 2008, to provide stakeholder comments on the second draft of this report. Stakeholders provided oral comments at Workshop 3, as well as submitting written comments in response to the workshop. A summary and discussion of these comments is included in Appendix D, and the full comments are posted on-line.[90]

Based on the stakeholder comments, input from the Energy Commission's IEPR and Renewables Committees, and analysis from Commission staff, this section recommends a feed-in tariff design for implementation and identifies additional issues for consideration in the upcoming IEPR process.

Recommended Feed-In Tariff Design

The outcome of Workshop 2 and 3 provided clear direction on feed-in tariff policy direction for California. Of the policy paths presented in Chapter 5, there was by far the strongest oral and written support from stakeholders for a cost-based feed-in tariff for new projects 20 MW or less (Policy Path 6) as a means to accomplish the stated policy objectives listed in Table 3 (Chapter 3). As a result, the authors recommend that a cost-based feed-in tariff be developed in California for projects 20 MW or less in size.

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[88] For proceedings of the June 30, 2008 staff workshop, see: http://www.energy.ca.gov/portfolio/documents/index.html#063008.

[89] For the proceedings of the October 1, 2008, staff workshop, see:

http://www.energy.ca.gov/portfolio/documents/index.html#100108.

[90] For the proceedings of the December 1, 2008 staff workshop, see: http://www.energy.ca.gov/portfolio/documents/2008-12-01_workshop/comments/.

Cost-based Feed-In Tariff for New Projects 20 MW or Less

The authors recommend that the *IEPR* consider a feed-in tariff policy that includes the following design characteristics:

- A *must take* tariff offering long-term[91] contracts open to all RPS-eligible resource types whose first point of interconnection is to a California electric distribution utility.[92]
- Similar to European feed-in tariffs, each of the interconnecting IOUs and POUs would be required to purchase renewable electricity from all eligible renewable energy generators.
- The feed-in tariff should be initially limited to projects 20 MW or less in size.
- Full-scale implementation. The feed-in tariff should not be launched on a pilot basis for a limited amount of time, nor only in one utility territory. Furthermore, tariff implementation should not be contingent upon a trigger mechanism (e.g. the utilities do not meet the 2010 RPS goals). Each of these "go slow" alternatives was represented in one or more of the policy paths, and each garnered little or no stakeholder support.
- The feed-in tariff should be technology-specific, meaning that each target technology receives a differentiated rate that allows it to be viably developed, rather than setting a single value-based price or price structure applicable to all technologies.
- The feed-in tariff should be size-differentiated, meaning tariffs may be differentiated by size for those technologies with strong economies of scale.
- The feed-in tariff should be cost-based, meaning that the technology-differentiated feed-in tariff rate is based on the generation cost of target technologies, plus a reasonable profit, rather than exclusively on a measure of value, such as retail electricity rates, avoided cost (SRAC) or other market proxies such as the Market Price Referent.
- The feed-in tariff should be broadly applied, such that (a) a feed-in tariff is available to all eligible generators 20 MW or less interconnecting within the state, and (b) there is a broad allocation of costs to all customers statewide.

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[91] Up to 20 years, as appropriate per technology; shorter terms may be appropriate for fuel-based generators. See *Exploring Feed-In Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options* (CEC-300-2008-003-F), Chapter 5 for detailed discussion.

[92] The concept of a feed-in tariff offered only by the interconnecting utility, as implemented elsewhere, is discussed in *Exploring Feed-In Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options* (CEC-300-2008-003-F) at p. 18. Such an approach also most clearly fits the state's jurisdiction to govern rates. It also allows system planners to rely on interconnection requests as both a means to anticipate and plan for the quantity and location of renewables reacting to the feed-in tariff, and to anticipate whether changes in tariff rates is necessary to mitigate potential rate impacts.

- Project eligibility should be based, in part, on the Energy Commission RPS guidelines as set forth in its *Renewables Portfolio Standard Eligibility Guidebook.*[93] To qualify for feed-in tariffs projects would need to be certified as RPS-eligible in accordance with the *Renewables Portfolio Standard Eligibility Guidebook*..[94]
- In addition to new projects, a feed-in tariff could be established for repower[95] projects. A separate feed-in tariff for repowered projects would be necessary to account for the differences in cost of generation.

Potential for Broader Application in the Future

A further recommendation, also supported by the stakeholder process, is that the recommended feed-in tariff should be thought of as a potential component of a larger policy trajectory. The *2007 IEPR* recommended exploring a feed-in tariff for greater than 20 MW, based on European best practices. In response to the feed-in tariff stakeholder process, the Commission shifted its immediate focus to a feed-in tariff for projects less than 20 MW. The currently recommended feed-in tariff, however, is a potential bridge to establishing feed-in tariffs for projects larger than 20 MW. The Energy Commission will continue to explore feed-in tariffs for greater than 20 MW through its IEPR process.

As discussed in Chapter 6, one future alternative to universal expansion of feed-in tariffs to projects greater than 20 MW would be to remove the 20 MW project size cap for generators sited in CREZs, similar to the design suggested by Policy Path 4, with specialized eligibility, pricing, timing, and queuing provisions geared to optimize the use of new transmission facilities most effectively and cost-effectively. An expanded feed-in tariff, designed to coincide with a CREZ, would not only address transmission concerns associated with larger renewable

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[93] California Energy Commission, January 2008, , *Renewables Portfolio Standard Eligibility Guidebook*, CEC-300-2007-006-ED3-CFM, http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF.

[94] This guidebook defines a project as a group of one or more pieces of generating equipment and ancillary equipment necessary to attach to the transmission grid that is unequivocally separable from any other generating equipment or components. Two or more sets of generating equipment that are contiguous or that share common control or maintenance facilities and schedules and are located within a one-mile radius of each other shall constitute a single project, except in the case of a conduit hydroelectric facility. A conduit hydroelectric facility may be considered a separate project even though the facility itself is part of a larger hydroelectric facility, provided that the larger hydroelectric facility commenced commercial operations prior to January 1, 2006, and the conduit hydroelectric facility commenced commercial operations on or after January 1, 2006, is separately metered to identify its generation, and is separately certified as RPS-eligible by the Energy Commission.

[95] A repower facility is generally a facility that's prime generating equipment is new and that capital investment made to repower the facility equals 80 percent of the total value of the repowered facility. See Renewables Portfolio Standard Eligibility Guidebook (CEC-300-2007-006-ED3-CMF).

development, but would also give investors and planners assurance that CREZ resources would have the policy support needed to be developed. The establishment of a cost based feed-in tariff associated with CREZ development may lead to some renewable resources being procured at lower cost than the MPR benchmark.

Feed-In Tariff Implementation Issues

To move forward with implementing the recommended feed-in tariff design, there are numerous issues to be addressed and resolved. Implementation of the recommended feed-in tariff would require addressing both the non-core policy issues and implementation issues identified in Table 4. The authors highlight several of the key issues for resolution in the IEPR process, including:

- How to establish initial feed-in tariff prices.
- How, when and how often to adjust feed-in tariff prices.
- What happens at the end of the feed-in tariff term.
- What happens if the RPS goals of a utility are met.
- How to design feed-in tariffs to encourage sufficient foresight necessary for efficient planning of both the transmission and distribution system and the generation portfolio.
- What potential legislative issues are raised by the feed-in tariff recommendation.
- Other next steps required for implementation.

The CPUC is currently responsible for feed-in tariffs that are in place and under development for California's IOUs. As such, the CPUC would also be ultimately responsible for implementing, approving, and overseeing the recommended tariffs for the IOUs. Requiring the POUs to adopt feed-in tariffs may require some legislative changes as discussed further below.

How to Set the Initial Feed-In Tariff Prices?

The most obvious next step is determining how to set the initial feed-in tariff prices. A few alternatives are available:

- Government-established: For example, the German Federal Government is responsible for setting prices, but contracts the task of doing so out to specialized consultants to develop rates for each technology type. [96] Representative Inslee's proposed Federal Feed-in Tariff Bill would assign this task to the National Renewable Energy Laboratory

[96] Personal communication with Dr. Martin Winkler, Clearingstelle EEG.

and the Lawrence Berkeley National Laboratory. See Appendix E for Summary of European Approaches to Cost Setting.

- Using current and applicable market information: This approach might be used to provide sufficient information to establish prices for a subset of technology types and project sizes, if good information is available. For example, market information could be available from recent competitive benchmarks, if the results from a recent solicitation for an eligible technology and project scale are publicly available, or if government entities have been tracking cost data for specific support programs.

- In all cases, it is recommended that some degree of stakeholder and public input be sought. Some options for California include:

  - Conducting a MPR-type proceeding. The CPUC holds annual proceedings to determine the market price referent, taking into account projected natural gas costs, the time of day and value of the delivered power, and projected greenhouse gas adders, based on publicly available data. Under this option, the CPUC could open a docket requesting parties to propose the feed-in tariff rate for eligible technologies, with support from data that is filed in the docket. The CPUC may wish to set parameters or define proposals for some of the other factors, such as the appropriate profit rate.
  - Set up technology working groups, similar to the Procurement Review Groups used in the California RPS, and allow these groups to review confidential and industry-sensitive cost data, subject to the working groups signing confidentiality agreements. These groups would review the data submitted and make recommendations on what price should be set per technology. (Note the Energy Commission does not support of this approach since it does provide transparency for policy makers and the public.)
  - Either the Energy Commission or the CPUC's Energy Division could prepare recommended cost of generation for each technology based on publicly available data sources, and the CPUC could hold a proceeding to take and review comments and then make a determination. The Energy Commission's Public Interest Energy Research (PIER) program offers an existing institutional framework for such an effort, and already conducts relevant research; using PIER would be preferable to establishing a new institutional home for such analysis.
  - Release aggregated prices by technology from the utility RPS solicitations conducted to date and use these as a starting point for a CPUC rulemaking to determine the appropriate price, at least for some technologies. Some gaps will inevitably occur, such as for small PV systems.
  - A technology-specific auction could be used to set the price.

Note that setting feed-in tariffs at a premium on top of market prices diminishes the ability of fixed-price contracts to serve as a hedge against fossil fuel driven rising electricity prices. The

IEPR process can be used to consider the available options and establish one or more approaches for implementation.

Adjustments to the Price

Almost as important as determining the initial feed-in tariff price for each technology is determining the remaining core issues of the method of adjusting the tariff price, when to adjust the price, and how much to adjust the price. The options for each of these are summarized in Figure 6 (Expanded Policy Paths), and the pros and cons of these options are discussed in the Issues & Options Report. In general, to give the market sufficient time to respond, to minimize administrative complexity and minimize market uncertainty, leaving the initial tariff prices alone for two to three years should be initially considered.

Method of Adjusting the Price

The IEPR process needs to consider a method of adjusting price designed to place downward pressure on prices over time. Three options have been presented in Figure 6. One such method, called degression, would be to set up a schedule reducing over time the levelized prices available to new projects, in line with technology advances and scale economies. A value - indexed method would adjust the tariff based on changing measures of value of technology and potentially may lead to an increased tariff. An un-indexed fixed tariff would keep the tariff at the same price as the first year of implementation, effectively using the burden of inflation to drive down the value of the tariff.

When to Adjust the Price?

The implementation process should review various options for determining when to adjust the price. The simplest method to implement would be to devise a schedule working with a degression method in which prices are reduced periodically according to temporal triggers. Review of the CSI experience could inform the implementation process with valuable feedback for capacity block triggers. Furthermore, this method could be revised to combine a periodic review with the use of capacity blocks and should be visited through the implementation process. The implementation process should also explore a method that does not set a specific time to adjust the price, rather relying on periodic reviews to decide if adjustments are necessary.

How Much to Adjust the Price?

In considering how much to adjust the price over time, the IEPR process should consider whether recent experience with volatile commodity costs (e.g. the cost of steel and other inputs) compounds the challenges with applying experience curves as a basis for price degression sufficiently to justify utilizing capacity blocks with prices decreasing in uniform steps.

What Happens at the End of the Feed-In Tariff Term?

A longer-term implementation issue is to articulate what rights and opportunities generators have at the end of the feed-in tariff term, and how (if at all) the renewable resources are counted toward policy goals after the end of the tariff term. The key question is whether policy should enable or constrain generators' ability to sell attributes associated with their renewable generation. Under a laissez-faire approach, generators would retain full rights to sell energy, RECs, or other environmental attributes into whatever markets may exist at the end of the feed-in tariff approach. A second option would be to prescribe alternative support mechanisms for the feed-in tariff generator. In Spain, the feed-in tariff lasts for 25 years for resources such as solar and small hydropower. After that period, the feed-in tariff rate drops to a lower level and is paid for the remainder of the project life.[97] In contrast, Portugal's feed-in tariff life is set at 15 years, at which point the generators is able to sell RECs if a REC market has developed. If no REC market exists, then the tariff is extended for another five years.[98] This is an important issue that needs to be planned for during the development of the feed-in tariff.

What Happens if the RPS Goals of a Utility Are Met?

Applying feed-in tariffs broadly, such that there would be a tariff available to all generators 20 MW or less interconnecting within the state, would necessitate that each utility offer a tariff (or a single tariff be offered through all utilities by a central entity), even if the utility's own RPS goal has been fully met. Cutting off tariff availability due to the interconnecting utility having met its renewable energy goals would undermine having a tariff available to all generators and thereby introduce an artificial barrier to meeting statewide renewable energy goals. Instead of creating such a barrier, tariff access could be continued, accompanied by a reallocation of such costs (and RECs, or compliance credit) to other utilities or load-serving entities that are short of their goals. If accepting a disproportionate fraction of renewable generators imposes excess integration costs upon that utility, the IEPR process should explore how such costs could also be reallocated broadly.

Encouraging Feed-In Tariffs to Support Efficient Transmission and Distribution and Supply Portfolio Planning

Several issues and challenges were identified pertaining to how feed-in tariffs could be designed to most effectively support efficient planning for transmission and distribution investment and supply portfolio planning. These issues and challenges merit further

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[97] Del Río González, P. (2008). "Ten Years of Renewable Electricity Policies in Spain: An Analysis of Successive Feed-In Tariff Reforms." *Energy Policy*, 36(8), 3345-3359.

[98] Heer, K.-D., and O. Langniß, (2007). *Promoting Renewable Energy Sources in Portugal: Possible Implications for China*. Stuttgart, Germany: Centre for Solar Energy and Hydrogen Research. Prepared for the Center for Resource Solutions China Sustainable Energy Program.

exploration within the IEPR process. Each issue pertains to the nature of a feed-in tariff as a standing obligation to purchase, and how a lack of visibility to those planning the grid or procuring the remainder of generation resources to serve load could introduce inefficiencies in the system. Specifically, this class of issues includes:

- Identifying ways to incentivize generators to produce at highest system value.
- Providing some visibility to system planners as to what generators will be added, in what location, and when, including solidifying commitments and limiting speculative queuing so that system planners are not building transmission for generation that will not materialize.
- Considering whether either pre-operational or operational performance requirements enhance or impede the implementation of a must-take feed-in tariff.

Features of the feed-in tariffs can be designed to address, in whole or in part, these concerns. To this end, the IEPR process should consider the following:

Creating feed-in tariffs to encourage generation with highest system value and discourage generation with lowest system value

As discussed in the *Issues & Options Report*, a cost-based tariff price can be set either aggressively (set high enough to allow a broad range of systems of different sizes and types) or conservatively (designed to target only the most competitive developers, or most competitive project scale or resource quality, within each technology type). If specific system values of interest are identified – such as a need for more base-load or peak-coincident generation, or locations (e.g. closer to load) where more generation should be encouraged or additional generation should be discouraged – the approach to modifying feed-in tariff could be designed to be responsive to these system values. For example, if the initial tariff prices for each resource type were set in a neutral manner reflecting the middle of the range of costs, the degression adjustments could be made more conservative or aggressive based on market changes over time. Alternatively, a positive or negative adjustment could be applied under each differentiated tariff applicable to generators in specific locations to encourage or discourage optimal location, without creating a profusion of tariff rates.

Providing visibility and a reasonable level of certainty to system planners of what generation is likely to come on-line, will come on-line, and when

Under the RPS solicitation process, the solicitation processes itself as well as the interconnection process provides some visibility to utility transmission and distribution system planners of potential new generation facilities. Contracts are entered into with selected generators, and although many contracted projects have not materialized, the quantity of generation under contract provides system planners with visibility as to where generation may be built, the earliest date by which it may reach commercial operation, and an upper bound on the quantity expected. Generator pre-certification for the RPS program also provides a degree of forewarning. Such visibility is necessary for planning and constructing infrastructure such that reliability is maintained and generation can get to market. With a must-take feed-in tariff, concerns have been expressed that such visibility and confidence would be diminished. However, despite the different process, many of the required steps that RPS generators take that create early visibility would already be present for, or can be incorporated into, a feed-in tariff regime.

Under the recommended feed-in tariff, nothing would relieve the generators from their obligations under current interconnection processes. Advance notice provisions to take advantage of feed-in tariffs may serve as a substitute for the visibility provided by the RPS solicitations today and should be considered in the IEPR process. For example, if a registration or application step were to be required of generators seeking feed-in tariffs, perhaps adapted from the generator pre-certification process required for the RPS program, that process would also provide generator visibility to system planners prior to projects coming on-line. Nonetheless, even with notice provisions, a must-take feed-in tariff without some means to solidify commitments and to identify non-performing projects could result in overbuilding infrastructure for projects that may never materialize.

Experience with feed-in tariffs in Europe suggests that system operators need to follow the progress of both interconnection and permitting to have sufficient lead time for system planning. Multi-step interconnection procedures also provide insight into whether a generator being developed in response to a feed-in tariff is serious, and when it is likely to come on-line. For example, projects may be required to show intention to interconnect, post a material deposit to fund studies, and ultimately commit the grid operators to build. In some cases (such as in Germany with offshore wind), grid construction work will only be commenced once the developer starts ordering major generator components, a clear sign that a generator is serious. In addition, in many EU countries banks financing most projects require a firm grid-connection contract, which can only be secured once a project has secured financing commitments. Project developers also may be required to pay all or a portion of the costs associated with interconnection. This is another implementation issue that will have to be worked out in the final feed-in tariff design.

Pre-operational performance requirements

In general, it is antithetical to the concept of a feed-in tariff to establish pre-operational performance requirements, since the primary objective of a feed-in tariff is to reduce generator risk by providing greater certainty for a reliable revenue stream. Nonetheless, the risk that projects providing notice may not perform can be exacerbated by design features that would encourage speculative queuing. As discussed in the *Issues & Options Report*, speculative queuing is a risk if there is a cap on the quantity that may participate (not part of the recommendation presented here), and when prices would drop over time (as proposed here). The means to solidify project commitments can be readily integrated into the design options that were identified in the *Issues & Options Report* as a means to mitigate speculative queuing. Options include provision of notice to utilize the feed-in tariff, along with a timetable within which specified actions (such as formal interconnection requests) must be made (and if not made, a project would have to go back and reapply). Provision of an application fee and/or posting of security, combined with a requirement to meet specified milestones or be required to increase the amount of security posted in exchange for time extensions, may also serve to mitigate this areas of concern, and should be explored further in the IEPR process. This is the approach included in the recently completed Hawaiian Electric Company Feed-in Tariff Program Plan.[99] In Europe, there are generally no pre-operational requirements imposed on feed-in tariff generators, other than the interconnection-related provisions mentioned above. There is little rationale to extend any additional preoperational requirements beyond those described here.

Operational performance requirements.

A separate issue is whether minimum requirements would be necessary under a feed-in tariff for projects after they commence operation. Two questions arise regarding operational requirements. The first is whether incentives are sufficient for projects to continue operating in a manner that seeks to maximize production. Because under a feed-in tariff the generator would only be paid for energy delivered, the incentive to operate to the fullest extent is already placed on generators; thus no further incentive would appear necessary to incentivize operation. If, however, a feed-in tariff payment were front-loaded (as is the case in many European feed-in tariffs[100] and for some wind generator tariff rates included in several feed-in tariff bills introduced in several U.S. states, including Michigan[101], Minnesota[102], Illinois[103], Indiana[104], Washington[105], and New York[106]), or had a duration less than the project's economic life, the inherent incentive to operate alone may not be sufficient. In the Netherlands, for example, the duration of tariffs was initially shorter than the economic life (e.g. 5-10 years). Under this regime, generators sometimes found it profitable to take wind turbines down and relocate them to qualify for another tariff premium. This led the Netherlands to alter the tariffs to offer lower

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[99] KEMA, Inc. *HECO Feed-In Tariff Program Plan*, prepared for Hawaiian Electric Company, Inc., Maui Electric Company, Limited, and Hawaii Electric Light Company, Inc. (2008). HECO's plan includes a refundable $/kW application fee assessed when a generator applies for a feed-in tariff, differentiated by project size. The application fee would be refunded once the generating project begins operating, but the application fee and the generator's place in the feed-in tariff queue would be lost should project development not be completed within specified timelines. Under the plan, a time extension matching the original project development timeframe (i.e., 12 months for certain projects, 24 months for other projects) can be gained with an additional fee. The plan is under review by the Hawaiian Public Utilities Commission.

[100] Ibid Klein, A., B. Pfluger, A. Held, M. Ragwitz, and G. Resch. (2008) Cyprus, France, Germany and the Netherlands have stepped tariffs that are front-loaded based on resource.

[101] HB 5218 (Law).

[102] HF 3537 (Bly), 2008.

[103] HB 5855 (May), 2008.

[104] H 1622 (Pierce), 2009.

[105] HB 1086 (McCoy), 2009.

[106] AB 187 (Hevesi), 2009.

premiums over longer periods matching the expected project economic life.[107] It would seem that in California, so long as tariffs are neither front-loaded or their durations short, there would be little reason to consider operational security requirements to address performance risk.

The second question is whether those obligated to comply with renewables targets need contractual protection against the risk that operating generators will cease to deliver and instead seek other markets for their production. It is assumed that such an action would be considered an event of default, addressed within the contract or tariff terms and conditions; conventional power purchase contracts provide for some degree of security to protect the buyer.

In Germany and the Netherlands, however, feed-in tariffs are general approached as a right to receive a subsidy, rather than a contract for delivery of energy. In Germany, the generator has the right to interconnect and receive a payment by the transmission and system operator (TSO), but there is no obligation to sell electricity into the grid. In general, it is believed that economic reasoning prevents early retirement of the generation.[108] In the Netherlands there is a provision in the law that early retirement may lead to repayments of subsidies, but this has always been ruled out by the courts, as the government may not force an enterprise into uneconomic behavior. This is now less relevant as payments are made for 15 years, more or less the economic lifetime of an installation. To address this issue in California, there will most likely need to be some form of contract or tariff terms.

The IEPR process should explore whether binding contracts with penalties and security for default would undermine the effectiveness of feed-in tariffs meeting the identified objectives.

Potential Legislative Issues

The recommendation to establish statewide cost-based feed-in tariffs for generators 20 MW or less raises questions regarding whether additional legislative authority would be required to implement the recommendation. Here, the authors consider some specific legislative questions raised by this question.

Is legislation required to ensure that the existing RPS mandate that IOUs purchase only 20 percent of their retail electricity from renewable generators does not serve as a cap on an expanded full-market feed-in tariff?

Two statutes apply to the question of whether legislation is necessary for using feed-in tariffs to meet a renewables target of 33 percent by 2020. The first is the existing RPS statute that requires

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107 Grant Scheme for the Environmental Quality of Electricity Production ('MEP grant'), Netherlands Court of Audit, May 2007, The Hague, The Netherlands.

108 http://www.erneuerbare-energien.de/files/pdfs/allgemein/application/pdf/eeg_2009_en.pdf.

20 percent by 2010. The statutory language is somewhat ambiguous. Public Utilities Code Section 399.11(a) states "in order to attain a target of 20 percent of total retail sales of electricity in California from eligible renewable energy resources by December 31, 2010" but states later in Section 399.14(C)(i) that "the flexible rules for compliance shall apply to all years, including years before and after a retail seller procures *at least* 20 percent of total retail sales of electricity from eligible renewable energy resources" (emphasis added). The latter suggests the 20 percent is a minimum. This position is reinforced by the law establishing the Energy Commission's Renewable Energy Resources Program, which provides in Public Resources Code Section 25740 that "It is the intent of the Legislature in establishing this program, to increase the amount of electricity generated from eligible renewable energy resources per year, so that it equals *at least* 20 percent of total retail sales of electricity in California per year by December 31, 2010" (emphasis added).

The "at least" language suggests that the Legislature views 20 percent as a minimum target, which could be raised by order of the CPUC. However, the fact that the California Legislature has considered legislation in at least the past two sessions to raise the RPS target to 33 percent by 2020, and a recent ballot initiative proposed to raise the RPS target to 50 percent, suggests that the 20 percent target is viewed as firm and action by either the legislature or by initiative is needed to raise it.

In addition to the RPS, there are various statutes and past CPUC orders that provide for a standard contract or feed-in tariff but under narrow circumstances.

- The California Legislature enacted legislation requiring the CPUC to enact standard contract terms and conditions for combined heat and power facilities below 20 MW (Public Utilities Code § 2840 et seq.; Assembly Bill 1613, effective January 1, 2008). The CPUC has not yet implemented this legislation.
- SB 380[109] authorizes the CPUC to enact a feed-in tariff for all facilities up to a facility cap of 1.5 MW and a statewide cap of 500 MW. The CPUC has previously established a "must purchase" obligation for qualifying facilities under 20 MW under PURPA (D.07-09-040, p. 20, citing Federal Energy Regulatory Commission Order 688, 71 Fed. Reg. 64352.). The rationale was that for qualifying facilities under 20 MW, it was burdensome to bid.

In implementing AB 1969[110], PG&E and SCE offered, and the CPUC accepted, to apply the feed-in tariff to all eligible renewable energy facilities, and that policy has since also been applied to SDG&E, but not to the publicly-owned utilities or to Sierra Pacific Power and PacifiCorp. The

[109] Senate Bill 380 (Kehoe, Chapter 544, Statutes of 2008), as codified in Public Utilities Code Section 399.20.

[110] Assembly Bill 1969 (Yee, Chapter 731, Statutes of 2006), codified in Public Utilities Code Section 399.20.

CPUC is considering raising the cap from 1.5 MW to 20 MW and raising the statewide cap of 500 MW as well. On October 10, 2008, the CPUC issued a request for comments concerning several questions the CPUC raised, including whether to raise the project cap.[111] Opponents are stating that the CPUC does not have legal authority to do this. That said, SCE now offers a standard offer contract for RPS-eligible facilities between 1.5 MW and 20 MW, which replaces the previous standard offer contract for biomass facilities between 1.5 MW and 20 MW. SCE currently has the option to enter into a contract, whereas a feed-in tariff would be “must-take.” One option, therefore, is for the CPUC to order PG&E and SDG&E to also offer standard contracts to renewable generators 20 MW or less as part of their 2009 RPS procurement plans, but that may not be a “must-take” as is common with feed-in tariffs. Furthermore, pricing would be at the MPR, which is more limiting than the recommendations made herein.

In conclusion, there is existing authority for the CPUC to require feed-in tariffs at market based rates for 20 MW or less. However the CPUC does not have authority to require IOUs to go beyond the 20 percent requirement in the RPS.

Does the CPUC have the authority to implement a cost-based rather than market-price feed-in tariff?

Public Utilities Code Section 399.15 (c) provides the CPUC authority “to determine the market price of electricity for terms corresponding to the length of the contracts with eligible renewable energy resources.” The law requires the CPUC to determine the price of electricity through a market-based methodology. In developing this method the CPUC consider other factors, including the long term market price of electricity, fuel costs, and value of electricity. Public Utilities Code Section 399.15 (a) allows for prices greater than the market-based value limited by a fixed cap, but neither section explicitly allows for a cost-based mechanism. Therefore, legislative direction is necessary to provide the CPUC with guidance and authority to establish a cost-based price of renewable electricity for use in establishing feed-in tariffs as well as provide for changes to the limits on the funding cap.

Do the requirements of AB 1969 and SB 380 need to be revised to provide the CPUC with the authority to implement the recommendation for a full market feed-in tariff?

In 2006, Assembly Bill 1969 (Yee, Chapter 731, Statutes of 2006), added Section 399.20 to the California Public Utilities Code. AB 1969 established a feed-in tariff for systems located at water and wastewater facilities with a capacity of 1.5 MW and below, capped at 250 MW total statewide. Generators can choose 10-, 15-, or 20-year contracts, and can opt to sell either 100 percent of their power, or offset their retail load and sell only their excess electricity. In both cases, electricity sold into the grid is sold at the "market price." In 2008, SB 380 (Kehoe, Chapter 544, Statutes of 2008) amended Section 399.20 to expand the statewide cap to 500 MW and extended the feed-in tariff to all onsite generation owners, instead of limiting the tariff to water and wastewater sites.

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[111] California Public Utilities Commission. *Request for Comments Regarding Phase 2 of Feed-in Tariffs*, October 10, 2008.

Although Section 399.20 creates the precedent of what the CPUC has characterized as possibly being a "form of a feed-in tariff" in California[112], it is likely that Section 399.20 would need to be revised to provide the CPUC with the authority to implement the feed-in tariff recommended in this document. First, the feed-in tariff in Section 399.20 is limited to onsite generation and is limited to generators that are 1.5 MW and below, whereas the recommended feed-in tariff is for generators 20 MW and below, regardless of siting. Second, the price offered to generators is defined as the market price, i.e. the MPR, rather than the recommended cost-based, technology-differentiated payment. Finally, the overall program is limited to 500 MW, whereas the proposed feed-in tariff does not have a statewide cap, reflecting the fact that significantly more renewable energy than 500 MW will be needed to meet the state's long-term renewable energy goal. Although the CPUC is currently considering the extension of Section 399.20 to systems larger than 1.5 MW, it is likely that legislation would be needed to authorize the CPUC to set differentiated, cost-based payments.

As discussed in Chapter 5 (discussion of Issue 9), the only viable option identified for who would offer a feed-in tariff is the utility to which a generator would interconnect. The implication is that if only the IOUs and POUs would be purchasing energy from generators under the recommended feed-in tariffs, community choice aggregators (CCAs) and energy service providers (ESPs) would not be purchasing renewable energy via the feed-in tariffs to meet their statutory obligations. In lieu of CCAs and ESPs purchasing directly from generators under a feed-in tariff, CCAs' and ESPs' Renewables Portfolio Standard compliance would need to be adjusted for purchases under the recommended feed-in tariff so that all customers are bearing the cost of the renewable energy obligation in equal proportion, and nobody should end up paying twice (e.g. through their utility and their ESP). Such adjustment could be accomplished through a process of reallocation. The IEPR process should therefore explore whether such a reallocation is best accomplished by allocating to ESPs and CCAs a share of the power supply purchased by the transmission and distribution utilities (IOUs and POUs), reallocating RECs, cost reallocation, or relieving the ESPs and CCAs of that portion of the renewable energy targets met through feed-in tariffs offered by the distribution companies. Depending on the details, legislation may be required to allow CCAs and ESPs to meet their mandated purchase requirements through such an alternative avenue.

Would legislation be required to make a feed-in tariff available to any generator located in California, including one interconnecting with a publicly owned utility?

If the state policy is to establish a statewide mandatory feed-in tariff in place of the existing Section 399.20 and voluntary feed-in tariff offerings, then legislation will be required to mandate that all IOUs and POUs offer a cost-based feed-in tariff. Funding for this tariff could be through existing electricity rate recovery mechanisms or through a non-bypassable surcharge

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[112] Amended Scoping Memo and Ruling of Assigned Commissioner Regarding Implementation of Pub. Util. Code § 399.20 (Assembly Bill 1969) Rulemaking 06-05-027 (Filed May 25, 2006) (Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program).

similar to the one that was created and implemented by Assembly Bill 1890 (Brulte, Chapter 854, Statutes of 1996) and Senate Bill 90 (Sher, Chapter 905, Statutes of 1997).

Potential Rate Impacts

The Western Power Trading Forum and the Alliance for Retail Energy Markets[113] expressed concerns that implementing feed-in tariffs could increase retail rates precipitously, citing experience with feed-in tariffs in Germany and elsewhere in the EU.[114] However, the rate impact expected to result from a feed-in tariff is a matter of both policy and design: what is the feed-in tariff trying to accomplish, and how is it designed to meet those objectives? Germany's goals include widespread geographic diversity of renewables, as well as the rapid acceleration of not just the quantity of renewable generation, but of the industry as a whole. Thus the German feed-in tariffs support project development in less resource-rich locations, and provide uncapped support for emerging resources to build scale economies, enable distributed installations, and promote export industry. California's goals differ and suggest differences in tariff design. For example, Germany offers more attractive tariffs to less energetic wind sites, an approach that would not be consistent with California's objectives.

Feed-in tariff design choices also allow a degree of control over the rate impact. For example, degression schedules are intended to push costs down over time. As described in the *Issues & Options Paper* and in Chapter 4, such schedules can also provide built-in protection to limit the risk of "windfall" overpayments. Particularly when combined with a periodic review, such a process can be used to adjust prices systematically to find the proper tariff pricing equilibrium. In addition, if response to tariffs for specific subsets of generation starts to become overheated, as was the case with solar in Spain and Germany, the policy can be adjusted accordingly (see, e.g. Chapter 2).

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[113] Written comments from the December 1, 2008, Feed-in Tariff Staff Workshop can be found at http://www.energy.ca.gov/portfolio/documents/2008-12-01_workshop/comments/.

[114] When discussing rate impacts and policy costs, it is important to isolate the incremental impact. In Germany, the total cost of feed-in tariff resources in 2007 was 7.9 billion Euros. Of this, however, only 4.3 billion were incremental costs above the cost of conventional generation. Taking into account the fact that the German feed-in tariff exempts large industrial customers from cost recovery surcharges, the incremental cost to German ratepayers of the feed-in tariff was approximately €0.01/kWh, or approximately €3.00/month per household in 2007. The German government projects that incremental feed-in tariff costs will peak near $8 billion near the end of the next decade and will then decline. *See* Staiß, F., C. Linkohr, U. Zimmer, F. Musiol, and M. Ottmüller (2008). *Renewable Energy Sources in Figures: National and International Development*. Berlin, Germany: Federal Ministry for the Environment, Nature Conservation and Nuclear Safety; and Nitsch, J., F. Staiss, B. Wenzel, B, and M. Fischedick. (2005). *Ausbau erneuerbarer energien im Stromsektor bis zum Jahr 2020: Vergütungszahlungen und Differenzkosten durch das Erneuerbare-Energien-Gesetz*. Berlin, Germany: Bundesministeriums für Umwelt, Naturschutz und Reaktorsicherheit.

As is the case with energy efficiency, looking at rate impacts alone may overstate the costs. For energy efficiency investments, bill impacts are more telling than rate impacts. For renewable energy policies – RPS, utility competitive procurements and feed-in tariff alike – electric bill impacts as well as total energy bill impacts (including natural gas usage) can reveal net benefits offsetting direct rate impacts. Increasing the penetration of renewables through either mechanism can produce two offsetting effects:

- Electricity price suppression (sometimes referred to as a 'merit order effect'), through which the clearing price of *all* electricity in a spot market environment is reduced by the introduction of low-variable cost, non-fossil generation to the system[115] and,
- Natural gas price suppression, through which reduced reliance on natural gas for electricity generation has a modest price-elasticity effect on the regional market price of natural gas for both electricity generation as well as heating and process uses[116].

The degree to which a tariff rate is set conservatively or aggressively can also have a significant effect on generator response and rate impact. As an example, consider a tariff rate set to make wind projects with capacity factors exceeding X percent feasible. Such a tariff would be highly unlikely to experience a "gold rush" if much of the wind potential in California was in less energetic locations with capacity factor of less than X percent. On the other hand, even rates based on conservative projections may still attract investors comfortable with a lower rate of return commensurate with the reduced risk of the tariff environment. It is quite possible that a feed-in tariff rate that would be acceptable to a project may be lower than the price at which that same project may have bid in an utility competitive solicitation, due to a lower cost of both development and permanent financing (commensurate with lower risk) combined with avoiding the costs and delays associated with the RFO process. In Germany, for example, feed-in tariffs are designed to provide a 5 percent-6 percent profit to generators, which is far lower a return than expected under other types of policy mechanisms.[117]

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[115] Munksgaard, J., and P. E. Morthorst. (2008). "Wind Ppower in the Danish Liberalised Power Market – Policy Measures, Price Impact and Investor Incentives." *Energy Policy*, 36(10), 3940-3947; Sáenz de Miera, G., P. Del Río González, and I. Vizcaíno. (2008). "Analysing the Iimpact of Renewable Electricity Support Schemes on Power Prices: The Case of Wind Electricity in Spain." *Energy Policy*, 36(9), 3345-3359; Sensfuß, F., M. Ragwitz, and M. Genoese (2008). "The Merit-Order Effect: A Detailed Analysis of the Price Effect of Renewable Electricity Generation on Spot Market Prices in Germany." *Energy Policy,* 36(8), 3076-3084.

[116] Wiser, R., M. Bolinger, and M. St. Clair (2005). "Easing the Natural Gas Crisis: Reducing Natural Gas Prices Through Increased Deployment of Renewable Energy and Energy Efficiency (LBNL-56756)." Berkeley, CA: Lawrence Berkeley National Laboratory; Elliott, R. N., and A. M. Shipley (2005). "Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets: Updated and Expanded Analysis (Report Number E052)." Washington, DC: American Council for an Energy-Efficient Economy.

[117] de Jager, D., and M. Rathmann (2008). *Policy Instrument Design to Reduce Financing Costs in Renewable Energy Technology Projects.* Utrecht, the Netherlands: Ecofys International BV. Prepared for the International Energy Agency, Renewable Energy Technology Development; Weiss, I., S. Orthen, J.

CHAPTER 8:
Summary of Report Findings and Next Steps

Key Findings

The current mix of California's renewable energy policies has not placed the state on a trajectory for achieving its renewable energy goals, and the need for a new policy tool to increase the pace of renewable energy development is clear. This circumstance has been the central driver in the Energy Commission's decision to explore the use of feed-in tariffs as an additional policy tool to help close the growing gap between renewable energy generation goals and actual generation achieved. Based on the analysis conducted by KEMA and Energy Commission staff, as well as stakeholder input, this report recommends adoption of a cost-based, must-take feed-in tariff as policy tool to help California meet its critical renewable energy goals. This recommendation flows directly from the inability of utility RPS procurements under the existing contracting process to maintain consistent and meaningful progress towards those goals. Many projects under RPS contracts are either not moving forward expeditiously or have fallen victim to contract failure. Since the existing RPS contract solicitation does not have the state on track to meet RPS goals[118], and because California needs aggressive action to meet an RPS goal of 33 percent of retail sales by 2020, the Energy Commission has concluded that it is imperative that the state take bold action to implement cost-based feed-in tariffs to help ensure that these renewable energy goals are met. Adoption of such tariffs would complement other actions being taken to remove the market barriers that RPS eligible projects face.

In addition to the legislative and regulatory initiatives surrounding feed-in tariffs, individual utilities have made, or are developing, voluntary CPUC-approved standard offers as referenced in Chapter 6. These voluntary tariff offerings demonstrate that there is an interest for a tariff amongst utilities and renewable energy developers. However, there has been little response to the current MPR-based feed-in tariff to date.

Stierstorfer and R. Gisler (2006). *European Best Practice Report: Assessment of 12 National Policy Frameworks for Photovoltaics.* Munich, Germany: WIP. Prepared for the PV Policy Group.

[118] As cited in the *2007 IEPR*, Figure 4.3, page 126, the percentage of generation from renewable resources in the State at the inception of the RPS in 2002 was 11 percent; by 2006 it had declined to 10.9 percent. There has been no significant increase in renewable generation since then, and generation from renewable resources remains at less than 12 percent statewide in March 2009. Given these facts, it is evident that the current RPS solicitation will not achieve the 20 percent RPS goal by 2010 and brings into question whether it can achieve the 33 percent goal by 2020.

Next Steps

Feed-In Tariff Policy Recommendation

The Energy Commission supports establishing a feed-in tariff program as an additional renewable energy policy to augment, not replace, the current RFO solicitations as mechanisms to support renewable energy project financing. Specifically, it is recommended that must-take feed-in tariffs for projects 20 MW or less in size, based on the cost of generation and differentiated by technology, be implemented immediately. Feed-in tariff should be available to all RPS eligible renewable generators 20 megawatts and below interconnecting to investor-owned utilities (IOUs) and publicly owned utilities (POUs) serving California electricity customers. This recommendation addresses the need for a transparent funding mechanism to expedite the creation of new renewable generation projects at the distribution system level, which are not able to compete effectively in the existing RPS solicitation process. It also sets the foundation that will allow further evaluation of feed-in tariffs for larger projects.

This recommendation is supported by the results achieved by feed-in tariffs in Europe. As discussed in Chapter 2 of this report, Germany has led the world in installed capacity for solar PV and wind as a result of its feed-in tariff policies. By the end of 2007, Germany had 22,262 MW of wind and 3,800 MW of solar PV capacity installed, with annual additions of 1,667 MW of wind and 1,100 MW of PV added in 2007 alone. Renewables supplied 14.2 percent of Germany's national portfolio in 2007. The vast majority of the renewable energy developed under the tariff is from projects under 20 MW in size. Based in part on the German experience, as well as the gap in RPS support for smaller projects in California, parties involved in the Energy Commission stakeholder process supported initially limiting the tariff to smaller size projects to immediately unleash the potential for new renewable energy generation at the distribution level while continuing to explore the desirability of a tariff offering for larger projects.

The selection of 20 MW projects or less also makes sense as an interim step because smaller size projects can interconnect to the grid at the distribution level and typically do not require new transmission investment. Smaller projects often do not require as extensive environmental reviews or as lengthy a permitting process as is required for larger projects. It is also costly for developers and IOUs to process RFOs for small projects. The streamlined feed-in tariff process can reduce costs to the IOUs and developers of small projects. Additionally, by creating a certain market, feed-in tariffs can eliminate the need for significant at-risk, up-front capital required to participate in a competitive procurement, which can add materially to the capital needs of a project developer and affect smaller projects disproportionately. Because such up-front, at-risk capital is the most costly form of capital and is far harder to raise than financing backed by a known and certain revenue stream, there is every reason to believe that providing certainty of revenue can reduce the capital requirements of smaller developers and projects, as well as reducing the risk and commensurate cost of capital.

The price certainty and transparency that feed-in tariffs provide will likely enable small-scale renewable energy developers and projects to secure the necessary project financing that they have had difficulty obtaining throughout the six-year tenure of the existing RPS solicitation process. A review of RPS experience to date reveals that the existing solicitation process, along with the bilateral contracting process, have resulted in only 22 active contracts for new facilities in the less than 20 MW size range. Contracts for active, new generation from projects under 20 MW represent less than 1 percent of total capacity for all active contracts in the Database of Investor-Owned Utilities' Contracts for Renewable Generation. As stated earlier, experience in Europe demonstrates that a feed-in tariff could greatly increase the number of projects built in this size range.

In regard to a tariff for larger projects, if implementation of a feed-in tariff for projects under 20 MW in size does not close the gap between operating projects and statewide RPS goals rapidly enough, then, based on the results of continuing analysis of a tariff for larger projects, this report recommends that a thoroughly vetted expanded tariff offering to generators larger than 20 MW also be implemented. Unless and/or until sufficient progress in meeting California's RPS goals is demonstrated, the implementation of a broader feed-in tariff strategy deserves ongoing consideration. To that end, the Energy Commission will continue to explore the efficacy of feed-in tariffs for utility scale projects through its stakeholder process for developing the *Integrated Energy Policy Report*.

Conversely, just as the currently growing renewable energy generation shortfall is signaling the need to offer feed-in tariffs, the tariff offering could be adjusted and/or the need for a continued feed-in tariff program could be reevaluated if RPS goals are met in the future. In addition, to guard against oversubscription of the tariff, which could have an adverse effect on rates and system operation, the tariff offering can be designed with capacity limits and sufficient pricing adjustments to respond to ratepayer impacts and market conditions.

Feed-In Tariff Legislation

To implement the feed-in tariff policy recommendation, policy direction is needed from the Legislature to establish a statewide feed-in tariff offering with clear goals and with a uniform design and structure. Rather than having piecemeal, local approaches to feed-in tariff development in California, it would be more efficient and effective to have one statewide tariff. Under existing law, however, the California Public Utilities Commission (CPUC) can only require IOUs to comply with a feed-in tariff offering in their service territory. Legislation is needed to require all utilities to also offer new or expanded feed-in tariffs statewide. To provide the necessary policy direction and authority the Legislature could direct the appropriate entities to develop a statewide tariff program that; (i) makes a feed-in tariff available to any generator whose first point of interconnection is a California electric distribution utility; (ii) establishes a statewide feed-in tariff based on the cost of generation that is funded by a Public Goods Charge similar to that currently in place; and (iii) is administered by the CPUC or other appropriate state entity designated by the Legislature.

Summary

The report's recommendation for a cost based feed-in tariff represents a significant departure from past RPS policy based on competitive solicitations, with a least-cost, best fit approach, and a price ceiling effectively established by an administratively determined market price referent (MPR) tied to the projected cost of a natural gas fired power plant. This link between the price for fossil fuel and the contract offering for renewable energy remains a significant economic and financial barrier to increasing the amount of renewable energy in the state. Establishment of a cost based feed-in tariff would be a crucial step for decoupling the revenue available to (and the cost to ratepayers from) renewable energy projects from the price of fossil fuels, as currently embedded in the MPR under the existing RPS solicitation. This change will provide for the expedited development of RPS qualifying renewable resources for projects 20 MW or less in size by providing the project developers with a guaranteed price that will adequately cover their costs and ensure a reasonable return. This revenue certainty will reduce risks and barriers thus better enabling such generators to obtain the financing they need to build their renewable energy projects, which are necessary if California is to attain its renewable energy and greenhouse gas reduction goals.

GLOSSARY

AMF	Above-MPR Funds
CCA	Community choice aggregator
CREZ	Competitive Renewable Energy Zone
CPUC	California Public Utilities Commission
EPAct	Energy Policy Act
ESP	Energy service provider
EU	European Union
FERC	Federal Energy Regulatory Commission
IEPR	*Integrated Energy Policy Report*
IOU	Investor-owned utility
kWh	Kilowatt hour
LSE	Load-serving entity
MPR	Market price referent
MW	Megawatt
PG&E	Pacific Gas and Electric Company
POU	Publicly owned utility
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
REC	Renewable energy credit
RETI	Renewable Energy Transmission Initiative
RFO	Request for offers
RPS	Renewables Portfolio Standard
SCE	Southern California Edison
SGIP	Self-Generation Incentive Program
SRAC	Short-run avoided cost

APPENDIX A:
Feed-In Tariff Design Issues and Options

Design Issue Category & Dimensions	Initial Options
Resource Type: Which Technologies Targeted?	1. All RPS-eligible renewables 2. Only for a certain subset of eligible resources, for example, mature vs. emerging resources 3. Specific ownership models (for example, community-owned, or wastewater or water treatment facilities)
Generator & Technology Eligibility - Vintage	1. Current RPS definitions (includes existing resources) 2. New generators only (typical European approach) 3. Qualification life = Contract duration - years in operation 4. Generators online after a certain date
Generator & Technology Eligibility - Generator Location	Generator eligible for… 1. Only for tariff of interconnecting utility 2. Any feed-in tariff for generators within California (with delivery, or without (for example, RECs)?) 3. Any California feed-in tariff conditioned on energy delivery?
Generator & Technology Eligibility - Generator Location: If a generator may choose from available feed-in tariffs…	1. Can any generator elect do so? Or only generators with no local option? 2. Could the generator elect any tariff or just the nearest? 3. Generation transmitted to utility paying feed-in tariff, or via RECs? 4. Open only to generators within California, or regardless of location?
Generator & Technology Eligibility - Interconnecting Utility Requirements	1. Require POUs and IOUs to establish feed-in tariff (statewide) 2. - Require only IOUs to establish feed-in tariff
Generator & Technology Eligibility - Project Size	1. -No Size limit - Capacity-based project size caps - Capacity-based project size floors 2. - Energy-based project size limits, for example, resource intensity or capacity factor
Setting the Price – Approach	1. Value based? 2. Cost-based? 3. Competitive benchmark (all head-to-head, vs. stratified?)
Setting the Price – Approach: If value based….	1. Base payments on value of energy delivered 2. Modified Avoided Cost Approaches (Time-of Delivery; Adders: Environmental Externalities, Grid-side benefits) 3. Wholesale vs. Retail Price Reference
Setting the Price – Approach: If cost-based…	1. Setting the profit level 2. Defining a generator cost level (Conservative: vs. Aggressive)

Design Issue Category & Dimensions	Initial Options
Setting the Price – Approach: If competitive benchmark…	1. What is eligible? (All, or differentiated by type?) 2. Mechanism and Frequency for determining benchmarks (for example, All prices determined by periodic auctions vs. Recent/ representative benchmark) 3. Adjustment Factor
Tariff Structure over multi-year contract	1. Fixed price 2. Stepped fixed-price 3. Fixed premium (adder on top of the market price) 4. Hybrid: only some disaggregated products sold under tariff 5. Contract-for-difference
Contract Duration	1. Short term (3-7 yrs) 2. Medium term (10-14 yrs) 3. Long term (10-20 yrs) 4. Developer choice 5. Indefinite term
Adjusting Price over Time	1. No adjustment 2. Fixed with inflation adjustment 3. Tariff degression 4. Indexed to change in measure of value
Adjusting Price over Time: When to adjust price?	1. Periodic revisions: Scheduled price decreases 2. Capacity dependent revisions: Quantity blocks. Price declines when a block is fully subscribed 3. Periodic review
Adjusting Price over Time - How much to Adjust Price?	1. Experience Curves 2. Uniform Steps
Tariff Differentiation	1. Technology Type 2. Project Size 3. Resource Quality 4. Commercial Operation Date (for example, target existing or repowered generators) 5. Ownership Structure 6. Transmission Access – Higher payments to facilities that are near transmission or load 7. Location – for example, Target load pocket or discourage transmission constraint area
What is being sold/purchased?	1. All commodities bundled 2. Commodity-only (for example, energy without RECs) 3. RECs only 4. Energy + RECs (that is, unbundled capacity rights & ancillary services) 5. Commodity + RECs
Cost Distribution/Allocation - Who Buys?	1. Retail generation sellers (IOUs, POUs, CCAs, ESPs) 2. - Providers of T&D service (IOUs & POUs if applicable)
Cost Distribution/Allocation - Who pays? (cost allocation)	1. Without statewide reallocation 2. Reallocate the aggregate annual feed-in tariff costs to equalize the costs among utilities with feed-in tariffs

Design Issue Category & Dimensions	Initial Options
	3. All customer classes vs. exempting some classes
Cost Distribution/Allocation - Cost Recovery Mechanisms	1. Through Generation rates 2. Through separate charge on T&D rates
Management of Cost Collection & Distribution - who manages/oversees?	1. State regulators? 2. Utilities? 3. Third party under contract?
Integration into Power Supply of Utilities & Others	1. All generation products sold into the spot markets; 2. All Generation products delivered to utility's system incorporated into the utility's own power supply 3. Allocate dollars if necessary 4. All generation products allocated to and delivered to each utility in proportion to their respective load.
Access - Who pays for direct costs of interconnecting feed-in tariff generators to the grid?	1. Generators pay (current policy) 2. Costs socialized
Access - Who pays for upstream transmission improvements required to interconnect a feed-in tariff generator for upgrades < 200 kV?	1. Costs allocated to local transmission owner (current California ISO practice) 2. Costs socialized more broadly
Access – Should CPUC Rule 21 address grid access for distributed generation for up to 10 MW? Should greater tariff standardization be pursued?	1. Update Rule 21 2. Status quo
Credit and Performance Assurance - Queuing Procedures: If price declines with quantity or quantity caps apply.	1. (non-refundable) Application fee 2. Security accompanied with project milestones (Up-front fee, refundable if project reaches fruition by milestone date) 3. Security increases in exchange for time extensions
Credit and Performance Assurance	1. Development security ; 2. Operation collateral or security
Quantity & Cost Limits	1. Quantity cap based on capacity 2. Quantity cap based on generation 3. Cost cap

APPENDIX B:
Summary of Public Comments – Workshop 1

Table 6: Summary of Public Comments From Workshop # 1[119]

Organization	No expanded tariff	20 MW or Less	Greater than 20 MW	All in	Notes
IEP		X			Support trying a tariff since RPS in underperforming
Mattesons & Assoc.	Doesn't take a position				Add sustainability as an eligibility requirement
SCE	X				Objective for an expanded tariff not clear/tariff would conflict with RPS
Constellation Energy Resources	X				FIT would replace market forces that keep costs down; foist risk from investors to ratepayers; would not fix problems with contract failure
Calif. Business Properties Assn.		X			FIT an essential tool for reaching RE goals and encourage commercial real estate sector to use RE.
City of Santa Monica		X			Need a FIT to significantly expand DG solar and help cities meet GHG reduction mandates
Central Calif. Power				X	FIT will reduce developer costs, risk and complexity without increasing rate payer costs
Breathe California		X			A FIT is an effective tool to meet RPS objectives and can greatly assist smaller projects that face obstacles in the existing solicitation.
PG&E	X				RPS working for projects > 1.5 MW; adding a FIT will increase costs to customers, and won't address other barriers

[119] Stakeholder comments were paraphrased in this table. For a full understanding of stakeholder positions, please refer to the comments posted on the CEC website at http://www.energy.ca.gov/portfolio/documents/.

Organization	No expanded tariff	20 MW or Less	Greater than 20 MW	All in	Notes
Green Power Institute		X			The RE market is out of balance with demand exceeding the supply of RE; must achieve this balance for market to function properly; FIT can help to increase supply to achieve that balance
Oak Creek Energy Systems	X				A FIT does not address the most significant issues impacting the development of RE, and would increase risk and uncertainty and delay project development
CREED		X			Urge the CEC to provide incentives with a variety of DG resources, with a preference for roof top solar.
Solar Alliance; Green Volts; Solar Energy Industries Assn.		X			There is a programmatic gap between the CSI and 20 MW threshold for which a FIT would be an appropriate policy tool to address; it would simplify the contracting process and create certainty for developers to obtain financity with; and is consistent with the CEC's guiding principle to establish a competitive, self-sustaining RE supply for Calif.

Position on Expanded Tariffs (based on comments from the June 30 Workshop)

APPENDIX C:
Summary of Public Comments – Workshop 2

Table 7: Summary of Comments From Workshop # 2[120]

Organization	Policy Path Option							Notes
	1	2	3	4	5	6	Other	
Wind Works	X							No trigger; no cap; tariff differentiated by technology, application, size, and (wind) intensity
Redwood Renewables	X					X		Modifications to Option 1: no trigger; no cap; tariff differentiated by technology, application, size, and (wind) intensity. Modifications to Option 6: no project size limit.
Joseph Langenberg	X							No trigger
Infinia	X					X		Modifications to Option 1: larger project designated to CREZs
Breathe California						X		
Sierra Club	X							Immediate implementation
CIWMB							X	Supports feed-in tariff for biomass under 20 MW
SolFocus, Inc.						X		
Constellation							X	Do not support expanded feed-in tariff
Gary Matteson							X	Supports long term contracts for feed-in tariffs
R. Dickerson							X	Supports feed-in tariff, especially for rooftop solar
SCE						X		Modifications: delivery and performance standards; equally distribute costs to all customers receiving benefits of renewable energy; program cost cap and project

120 Stakeholder comments have been paraphrased in this table. For a full understanding of stakeholder positions, please refer to the comments posted on the CEC website at http://www.energy.ca.gov/portfolio/documents/.

Organization	Policy Path Option							Notes
	1	2	3	4	5	6	Other	
								limits; mechanism to ensure grid reliability
Solar Alliance						X		
LADWP				X				
PG&E							X	Supports current small renewable energy feed-in tariff for under 1.5 MW
Fuel Cell Energy, LLC						X		
Union of Concerned Scientists						X		Once feed-in tariff is established, open 20 MW or less
Michael Hoexter			X			X		Option 6 with Option 3 for facilities greater than 20 MW
D. Scott Brasfield	X							Review tariff after first five years; adjusted for inflation; immediate implementation
Save the Foothills	Doesn't take a position							Encourages feed-in tariffs, especially for rooftop solar

Position on Expanded Tariffs (based on comments on the October 1 Workshop)

APPENDIX D: Summary of Public Comments – Workshop 3

Table 8: Summary of Comments From Workshop # 3[121]

Name or Organization	Feed-in Tariff Recommendation			Notes
	Support	Oppose	Not Stated	
Gregory Archbald	X			Strongly supports setting a feed-in tariff based on cost of generation plus reasonable profit. Recommends dropping the 20MW size limitation.
Wind Works			X	Tariff should be differentiated by resource intensity, especially for wind, as well as technology type. Tariff should not be limited to 20 MW size projects and below; degression should be used sparingly if at all.
Central California Power	X			Do not cap the tariff at 20 MW sized projects.
Albert Rosen	X			Feed-in tariffs will catalyze a massive increase in renewable energy production in California. There should be no lower limit to the size of the systems eligible to participate.
Solutions for Utilities	X			A tariff payment of 70% of retail could significantly shorten the time before producers would be signing up and fulfilling the goals of bringing renewable energy online.
Tom Faust	X			We need a policy that enables projects of all sizes, not just those less than 20 MW.
Sierra Club California	X			Strongly recommend against having a 20 MW project cap applied. Allowing larger projects immediately will help lower costs and provide other economic benefits.
PG&E		X		PG&E does not advocate an expansion of the existing feed-in tariffs as proposed in the KEMA report. First focus on permitting and transmission barriers that must be addressed so that signed RPS contracts can move forward.

[121] Stakeholder comments were paraphrased by CEC staff in this table. For a full understanding of stakeholder positions, please refer to the comments posted on the CEC website at http://www.energy.ca.gov/portfolio/documents/.

Name or Organization	Feed-in Tariff Recommendation			Notes
	Support	Oppose	Not Stated	
Solar Santa Monica	X			The City of Santa Monica supports the Commission's recommended pricing that abandons the utility avoided cost framework and replaces it with "reasonable profit" foundation for solar investors. Santa Monica supports abandoning the market price referent methodology.
Independent Energy Producers Association	X			IEP believers that issues associated with integrating renewables are both surmountable and future orientated and, therefore, should not restrict FIT consideration now.
Terraverde Solutions	X			Suggest that you raise the cap on project size to 100 or 200 MW to stimulate the growth of the most cost-effective but still underfunded renewable energy technologies: solar thermal electric with storage and large scale wind farms.
Community Environmental Council	X			A key feature of a robust feed-in tariff is the "must take" component. Standard offer contracts, proposed by some utilities as an alternative to a robust feed – tariff, are not an adequate substitute.
Pacificorp			X	Feed-in tariffs should not be a replacement for the renewables portfolio standard program. High prices expected to be paid under the tariff program would disproportionately affect PacifiCorp's system costs, and therefore, customers.
Infinia Corporation	X			Infinia supports the recommendation for a feed-in tariff. The cost of the current RPS process is a burden that when put on the smaller project makes it less competitive, or non-competitive, with larger projects. Yet many projects 20 MW or less could be developed close to load sources and be connected quickly to existing transmission and distribution system.
FuelCell Energy, Inc	X			FCE wishes to reaffirm its continued support for the creation of a feed-in tariff program. Based on its current work in California's biogas market, FCE is confident that a similar growth rate as to that achieved under the German biomass tariff is readily attainable in California once a suitable feed-in tariff is implemented.

Name or Organization	Feed-in Tariff Recommendation			Notes
	Support	Oppose	Not Stated	
Western Power Trading Forum, and Alliance for Retail Energy Markets		X		WPTF and AReM believe that competitive procurement rather than feed-in tariffs should remain the primary mechanism for ensuring compliance with the Renewables Portfolio Standard (RPS) as competition under the existing RPS solicitation will be the driving force for innovation and downward price pressure.
UC Berkeley Researchers	X			Much of the opposition to bringing a FIT online is the cost premium for renewable energy that is levied onto ratepayers. We have studied one way in which this effect is mitigated – the depression of natural gas price due to reduced natural gas demand from renewable deployment.
SCE			X	SCE comments on the following three points: cost allocation; performance requirement; and transmission constraints. The report does not address cost allocation at a level commensurate with the importance of the issue. Performance obligations (credit and collateral requirements to assure performance and delivery) are an essential part of any consideration of a feed-in tariff. A feed-in tariff will not address transmission constraints.
LADWP		X		As a part of its Customer Solar Program, LADWP will be implementing its own feed-in tariff. LADWP believes that a statewide tariff that would include POUs would be unnecessary, procedurally burdensome, and impede the ability of local authorities to provide the best-fit, least-cost renewable energy to their rate payers.
SDG&E		X		The recommendations in the draft report do not sufficiently deal with numerous implementation issues, particularly those related to the size of customer load. These issues should be examined as of the 2009 IEPR: cost impact analysis; interaction of FITs with RPS; interaction with RECs; performance requirements; and others.

Name or Organization	Feed-in Tariff Recommendation			Notes
	Support	Oppose	Not Stated	
GreenVolts	X			GreenVolts feels that there are several vital features to include in final FIT implementation, including: standard must take contract; differentiated, cost-based pricing; 20 year contract duration; and dedicated meters for FIT facilities. Performance assurances are unnecessary, projects will simply interconnect once they are built. Renewable attributes of power will belong to the purchasing utility.

Position on Recommended Feed-in Tariffs (based on comments on the December 1 Workshop)

APPENDIX E:
Summary of European Approaches to Cost Setting

Chapter 2 provides an overview of feed-in tariffs in Europe by focusing on the examples of Germany and Spain. This appendix explores European approaches to setting feed-in tariff prices in greater detail primarily through a case study of the process and methods used in the Netherlands[122].

Tariff-Setting Method

As discussed in Chapter 2, Europe has two primary types of feed-in systems, the feed-in tariff (FIT), and the feed-in premium. Germany has a FIT system, while the Netherlands has a feed-in premium system. In Spain, the generator can choose between either of these two options on an annual basis. Table 9 below summarizes the major design characteristics of each of these policies and highlights their differences.

Table 9: FIT Design Characteristics by Country

	Netherlands	Germany	Spain-FIP	Spain-FIT
FIT (FIT) or premium FIP	FIT	FIT	FIP	FIT
Categories for technology/fuel combination	Yes	Yes	Yes	Yes
Categories for size of installation	Yes	Yes	Yes	Yes
Stepped tariffs	Yes	Yes	Yes	Yes
location specific tariff for wind	Yes	Yes	No	No
Duration of subsidy (years)	12-15	20[123]	lifespan of installation	lifespan of installation
frequency of renewal of tariffs (years)	1	4	1	4
Budget maximum	Yes	No	No	No
Digressional tariffs	No	Yes	No	No

[122] KEMA (2008). *HECO Feed-In Tariff Program Plan*. Hawaii, United States.

[123] For some categories, also 15 or 30 years.

Although the structure of each of these polices is different, the intent of all three policies is to provide generators with an incentive level that corresponds to the cost of generation.

The process by which feed-in rates are set is central a central component of policy design and implementation. Tariffs set at the right level are needed to make a feed-in premium or tariff efficient and effective. If the tariffs are set too low, the renewable energy market will not react, but if the tariffs are set too high, society will pay a high price for renewable development, and energy developers will receive excess payments.

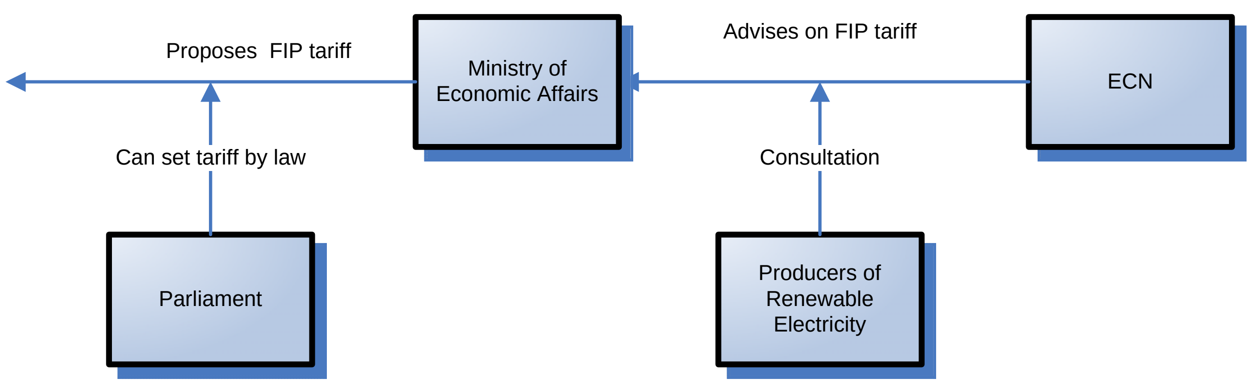
This section reviews how prices are set in the Netherlands, including the tariff setting process, the method for calculating electricity generation costs, and the approach to stakeholder consultation and engagement.

Tariff Setting in the Netherlands

Process Overview

In the Netherlands, the Ministry of Economic Affairs has the responsibility for recommending feed-in tariff levels. As shown in Figure 8, the Ministry is advised by both a non-profit entity, Energy research Center of the Netherlands (ECN), and a for-profit consultancy, KEMA. KEMA and ECN jointly analyze the financial and technical performance of each renewable energy technology and publish a draft advice notice to the Ministry of Economic Affairs on the cost levels for renewable generation. The draft advice is a public document, and selected stakeholders are asked for comments. On the basis of the findings, ECN and KEMA issue a final recommendation concerning the cost of generation levels for each category. Proposed tariff modifications are then forwarded to the Ministry of Economic Affairs.

Figure 8: Tariff Setting in the Netherlands



Method

There are different approaches to calculating the appropriate tariff rates in Europe. France, for example, has used an approach called the Profitability Index Method to set some of its tariffs.[124] In the Netherlands, KEMA and ECN use a cash-flow analysis to determine the financial performance of different renewable energy technologies. The required revenues from electricity sales for each renewable technology, plus a fixed return on equity, are then calculated using a net-present value approach. A sensitivity analysis is then performed for each tariff rate.

The equation used to calculate the generation costs of electricity from new plants includes two parts, the variable costs and the fixed costs. The variable costs include the cost of fuel and the cost of operations and maintenance. Fixed costs include the investment costs and the capital recovery factor. Investment costs differ by technology and energy source. For example, investment costs per unit capacity for small hydropower plants are generally more than double those for wind turbines. As most renewable energy technologies (with the exception of large scale hydro-power) are still not mature, investment costs are expected to decrease over time. The basic equation used for the cost method is included below:

$$C = C_{VARIABLE} + \frac{C_{FIX}}{q_{el}} = \left(C_{FUEL} + \frac{C_{O\&M}}{H} * 1000 \right) + \frac{1000 * I * CRF}{H}$$

Where:

C =	Generation costs per kWh [€/MWh]
q_{el} =	Quantity of electricity generation [MWh/a]
$C_{VARIABLE}$ =	Running costs per energy unit [€/MWh]
C_{FIX} =	Fixed costs [€]
C_{FIX} / q_{el} =	Fixed costs per energy unit [€/MWh]
C_{FUEL} =	Fuel costs per energy unit [€/MWh]
$C_{O\&M}$ =	Operation and maintenance costs per energy unit [€/(kW*a)]
I =	Investment costs per kW [€/kW]

[124] Chabot, B., P. Kellet, and B .Saulnier (2002). "Defining Advanced Wind Tariffs Systems to Specific Locations and Applications: Lessons From the French Tariff System and Examples." Proceedings of the Global Wind Power Conference, Paris, France.

CRF = Capital recovery factor

$$CRF = \frac{z*(1+z)^{PT}}{[(1+z)^{PT}-1]}$$

H =:

Z = Interest rate [1]

P = Payback time of the plant [a]

Full-load hours [h/a]

Once the rates for each technology are calculated and analyzed by KEMA and ECN, the results are combined and summarized in a draft document that is submitted to the Ministry. Table 10 has been translated from Dutch to English and displays the input parameters and output for a sample onshore wind project.

Table 10: Onshore Wind[125]

INPUTPARAMETERS	Value	Unit	Comment
Unit size	3000	kWe	
Unit size (electrical)	3000	kWe	
Operational time/ Full load hours	2000	Hours/Year	
Economic life	15	Year	
Electrical efficiency	0%		
Thermo efficiency CHP	0%		
Reference efficiency CHP	0%		
Saving fuel tax (BSB) for CHP	0.0000	Euro/m3	
Investment costs	1100	Euro/kWe	
Maintenance costs fixed	39	Euro/kWe	
Maintenance costs variable	0	Euro/kWhe	
Miscellaneuos operational costs	0	Euro/kWhe	
Energy content secondary fuel	0	GJ/ton	
Costs secondary fuel	0	Euro/tonne	
Fuel costs substituted fuel	0.00	Euro/tonne or Euro/m3	
Effectiveness fuel substitution	0%		
energy content substituted fuel	0	GJ/ton or GJ/m3	
Market price elektricity	0	Euro/kWh	
Balancing costs	0.006	Euro/kWh	
EIA applies?	**ja**		Choose 'yes' of 'no'
EIA	44%		Maximum that legally applies for EIA
EIA max	47,520,000	Euro	Maximum that legally applies for EIA
Part of the investment that applies for EIA	85%		
Return on debt	5%		
Required return on equity	15%		
Equity share incl. EIA effect	20%		
Debt share incl. EIA effect	80%		
Corporate (income) tax	26%		
Loan duration	15	Year	
Depreciation period	15	Year	
Policy period	15	Year	Period during which subsidies are paid

OUTPUT	Value	Unit
Financial Gap	8.4	Eurocent/kWh

[125] Example of a filled-in factsheet for the Dutch FIT (SDE) tariff setting for the category wind onshore (example sheet 'OT2008 Wind Offshore (UK), SDE, 2008). The EIA is a tax exemption measure for investments in energy-saving equipment and sustainable energy. This tax relief program gives a direct financial advantage to Dutch companies that invest in energy-saving equipment and sustainable energy. Forty-four percent of the annual investment costs of such equipment (purchase costs and production costs) are deductible from the fiscal profit over the calendar year in which the equipment was procured, subject to a maximum of EUR 111 million.

Stakeholder Process

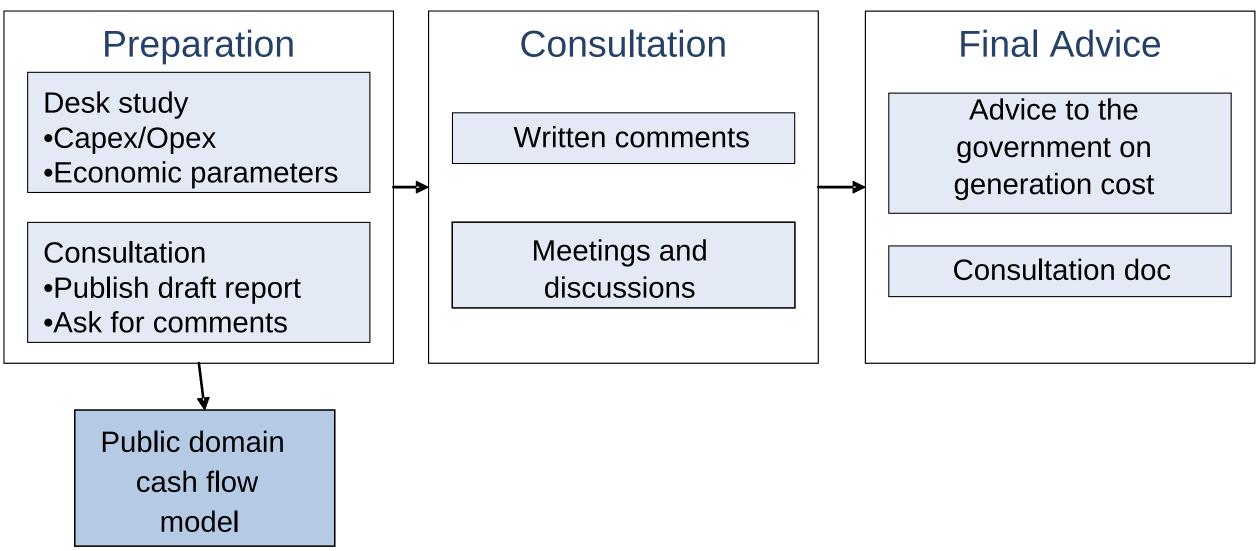
Governments typically do not have real access to market data and typically can only judge the accuracy of their policy decisions by observing subsequent market impacts. To inform the feed-in tariff rate setting process in the Netherlands, the government invites stakeholders and market participants to be directly involved.

The decision to incorporate stakeholder input is based on the premise that it is almost impossible for the government to know the costs of generation (investment costs, O&M costs, etc). This information is available only to the market players because they are involved in actual transactions (buying and selling equipment, power purchase agreements, fuel contracts, etc). Only by getting access to these data is it possible to determine a suitable generation cost level. The Netherlands uses a stakeholder consultation process to not only to derive more precise generation cost data, but also to increase stakeholder buy-in for the final feed-in tariff rates.

Although the stakeholder process is viewed as necessary in the Netherlands, it is also acknowledged that the process will not deliver perfect information because stakeholders have a vested interest in providing information that is "biased" toward influencing the final tariff level in a positive manner. The consultants hired by the government serve as a balance to stakeholder bias. The consultants have to guard their status as an independent institute and not lean toward one of the parties, otherwise its credibility will be lost.

Figure 9 depicts the approach to stakeholder engagement that has been successfully implemented in the Netherlands since 2003.

Figure 9: Stakeholder Process in the Netherlands



During the preparation phase, the consultants conduct preliminary research. In this phase, as much information as possible is collected based on publicly available data, market surveys, and international references. This information is compiled in a draft report, which provides an overview of the assumptions, and the costs of renewable electricity. The cost calculation is then performed using a public domain cash flow model, which is available to all the stakeholders, enabling them to check the calculations.

In the consultation phase, reactions on the report are actively sought. Stakeholders are asked to comment and send information. This information should be based on actual data such as contracts, quotations, fuel price references, etc. If needed, more information can be exchanged in meetings or workshops.

Finally, based on the draft report and information collected during consultation, an advice notice is prepared, which is then sent to the government. In response to stakeholder feedback, a consultation-response document is then prepared, which systematically addresses how each identified concern was considered.

During interaction with stakeholders, the consultant must respect confidentiality and the sensitivity of the data given and protect the interests of the actors. This is important as in most cases it is not a one time operation, but a process that is repeated regularly (annually).

The following Table 11 provides an overview of the primary stakeholders involved in the process, their key objectives and, in general, their resulting bias toward policy design objectives.

Table 11: Overview of Stakeholders involved in FIT Process in the Netherlands

Stakeholder	Objective	Resulting bias towards policy objectives
Government	Meet renewable targets Limited budget risk Low cost for consumer Sustainable generation	Low tariff prices Fixed budgets Sufficient generation
Project developer	High profits Controllable risks Bankable projects	Increase tariff prices Lower costs
Banks	Secure projects High interest rates	Stable support High stable cash flow
Manufacturers	Stable investment climate High revenue	Increase tariff prices Fixed O&M contracts

The Ratesetting Process in Other Countries

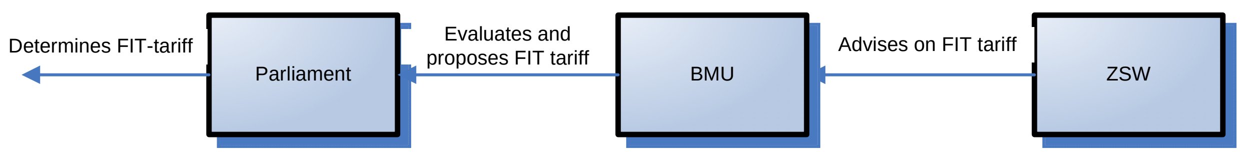
The feed-in tariff rate setting process in other European countries share similar characteristics with that in the Netherlands in that an objective third-party advises the government on rates, based to at least some extent on stakeholder engagement. The processes in both Germany and Spain are reviewed briefly below.

Germany

In Germany, the Ministry of Environment (Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit, BMU) is required to draft an evaluation report every four years. This report is written by a project group, headed by the ZSW (Zentrum für Sonnenenergieund Wasserstoff-Forschung) as shown in Figure 10. The report assesses costs for new projects in several categories. Generators and developers are obliged to provide relevant information to help determine the costs. Unlike in the Netherlands where stakeholders are actively engaged, stakeholders in Germany are involved only to the extent that they have opportunities to submit comments on proposed rates.

The last FIT evaluation report was drafted at the end of 2007 in Germany.[126] Once the evaluation report was filed, the parliament could then decide whether to modify the tariffs. Just as in the Netherlands, stakeholder organizations in Germany also have an opportunity to share their views with the parliament. The German *Bundestag* decided in June 2008 to pass the BMU's proposal with several amendments.

Figure 10: Tariff Setting in Germany



Tariff Setting in Spain

In Spain, tariff setting is performed by the Ministerio de Industria Turismo y Comercio and relies heavily on the research of the Comisión Nacional the Energía (CNE) as shown in Figure 11. Tariffs are not passed through parliament for approval but become effective after a so-called "Royal decision". CNE recommends modifications to the feed-in system, including the tariffs. CNE's uses input from a Commission that includes representatives of the most important stakeholders. Through participation in the Commission, stakeholders are indirectly involved in the FIT tariff decision-making process.

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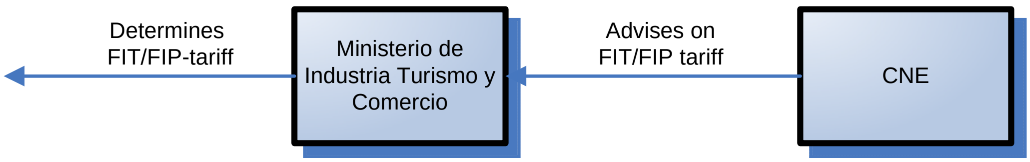
[126] Bundesministerium für Umwelt Naturschutz und Reaktorsicherheit. (2007). *Erfahrungsbericht 2007 zum Erneuerbaren-Energien-Gesetz* (EEG). Berlin, Germany.

Figure 11: Tariff Setting in Spain



Adjusting the Tariff

As detailed briefly in the *Issue & Options Report* there are a wide range of approaches to adjusting feed-in tariff levels over time. These include not adjusting the tariffs at all, as was done for some resources under the 2000 law in Germany, adjusting after periodic review, adjusting tariffs according to a predetermined schedule, as with the current German system, or adjusting the tariff according to a variable value indicator, such as average electricity rates (e.g. Spain[127]) or inflation (e.g. France and Portugal[128]).

When discussing tariff adjustment, it is also important to distinguish between two different types of adjustments. One type of adjustment – which will be referred to as an "external" tariff adjustment – occurs when a fixed, long-term tariff available in one year is adjusted in the following year. For example, a generator coming on-line in 2011 might lock into a lower fixed incentive level than a generator who came on-line in 2010. Once the incentive level is locked in, however, it does not change over the life of the contract. By contrast, the other type of adjustment – which will be referred to as an "internal" tariff adjustment–affects the payment levels themselves such that generators will receive a variable, rather than fixed, incentive payment over time. In Germany, an external tariff adjustment occurs annually according to a fixed degression schedule, and the degression schedule is reviewed once every four years. In France, there are both internal and external tariff adjustments based on inflation.

External tariff adjustments pegged to inflation are intended to account for inflation-related changes in fixed costs over time. Internal tariff adjustment pegged to inflation are intended to account for inflation related changes in operating costs over time. In Hawaii, the Public Utilities Commission Scoping Paper on feed-in tariffs suggests that inflation adjustments for operating costs may be appropriate, but that renewable generators that have "insignificant operating costs negate the need for an inflation adjustment.[129]"

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[127] Klein, A., B. Pfluger, A. Held, M. Ragwitz, and G. Resch (2008). *Evaluation of Different Feed-In Tariff Design options — Best Practice Paper for the International Feed-In Cooperation* (2nd ed.). Karlsruhe, Germany and Laxenburg, Austria: Fraunhofer Institut für Systemtechnik und Innovationsforschung and Vienna University of Technology Energy Economics Group.

[128] Ibid. Heer and Langniss (2007).

[129] Boonin, D. M. (2008). *Feed-In Tariffs: Best Design — Focusing Hawaii's Investigation*. Silver Spring, MD: National Regulatory Research Institute. Prepared for the Hawaii Public Utilities Commission.

Although inflation adjustments have been judged an attractive option in other jurisdictions, there are also arguments against their use. Inflation adjustments reduce the ability of long-term fixed price contracts for renewable energy to serve as a hedge against electricity prices. Finally, inflation adjustments can add unnecessary complexity to tariff management over time.