The Application of Feed-in Tariffs and Other Incentives to Promote Renewable Energy in Colorado

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Executive Summary

Feed-in tariffs (FIT) are a financial incentive designed to encourage the installation and use of renewable energy (RE) generation systems. FITs have also been referred to as Feed-in Laws, Renewable Energy Payments, Renewable Energy Dividends, and Standard Offer Contracts. Generally, a FIT incentive program can be characterized based on the following traits:

- The utility is obligated to enter into long-term contracts (typically 15-20 year terms) with RE generators;
- The RE generator receives a guaranteed payment from the utility for the system's actual production for the entire term of the contract, typically set administratively based on the actual costs of generation with a modest rate of return included;
- Rates can be differentiated based on RE source, technology type, capacity size, the date the system becomes operational, and geographic locale;
- The utility is obligated to purchase all electricity generated, with the generator obligated to sell all electricity generated to the utility;
- Program rate adjustments can be made in the future based on inflation, technological innovation resulting in reduced system and installation costs, and successfully meeting generation capacity benchmarks.

A successful FIT design is one that has been developed based upon clear policy goals in order to ensure that the incentive is tailored to meet them. Since over sixty-three countries have adopted a FIT to encourage RE production, many pitfalls have been identified to assist in the development of future programs.

Other financial incentive and regulatory programs can work hand-in-hand with a FIT to ensure effective RE capacity growth. The Renewable Portfolio Standard (RPS) is a regulatory policy that has become increasingly popular among the states, and in particular Colorado, as a mechanism to promote renewable energy. An RPS can work cooperatively with a FIT depending upon how compliance with the RPS is defined. Net metering, on the other hand, is a policy which likely conflicts with a FIT, but which could be used in a hybrid system for those net metered systems not included within the FIT. Other financial incentives a RE system owner may receive, such as rebates or tax credits, should offset the FIT rate offered to prevent double compensation.

There are certain legal concerns that must be addressed within a FIT design. Rates within a FIT are generally set at by a state administrative agency at a level higher than a utility's traditional cost of generation, which could raise the potential for federal preemption. However, this can be avoided if an avoided cost methodology is pursued or if the rate needed to ensure compensation, based on cost of generation, is bundled into the renewable energy credits (RECs) the system produces. Additionally, Colorado currently imposes rate caps for the purpose of compliance with the state's RPS that would likely need to be addressed if a FIT is to be adopted.

Finally, because FITs are such a widespread mechanism for incentivizing RE growth, there are many examples of how to design the program to ensure those goals are achieved. These lessons learned are extremely valuable for entities planning to design such a program.

TABLE OF CONTENTS

1.0 Introduction

This white paper addresses fundamental design features, legal challenges to implementation, and policy issues related to feed-in tariffs. FITs are incentive programs in which utilities are obligated by a long-term contract to purchase, at a guaranteed rate, all electricity generated by qualifying renewable energy installations in their service areas. One of the beneficial attributes of a FIT is that it can be tailored to address unique local conditions, and this in part has led to their adoption in over sixty jurisdictions worldwide. The popularity of FITs as a policy tool for fostering renewable energy development has escalated in recent years, with a growing number of states, municipalities, and utilities in the U.S. considering or implementing their own FITs.

This white paper proceeds by first analyzing common FIT design and implementation features and considering specific trade-offs between them, with a particular emphasis on reducing risk for participating parties. Section 3 then evaluates other financial incentives and regulatory policies that may be cooperative or competitive with FITs in renewable energy development. Next, Section 4 considers legal issues related to FITs, emphasizing those relevant to Colorado. This is followed by a section that considers several metrics which could be used to compare FITs to other incentives or regulatory policies and looks specifically at the ability of FITs to fulfill commonly-stated goals, such as capacity addition. Section 6 synthesizes this research into a "lessons learned" section that presents possible goals that states or municipalities might prioritize. Several general design considerations are suggested to help fulfill each goal. Section 7 presents brief conclusions drawn from this research.

1.1 Scope of Research

In developing this white paper, we conducted extensive research on both foreign and domestic FIT programs. The conclusions that follow come from the study of legislation, regulations, and FIT contracts, as well as academic reports and assessments from experts in the FIT policy field. Because of the extensive consideration of foreign FITs, we have tried to clarify currencies and note where programs are unclear, particularly in places where we rely on unofficial translations. The raw data collected on domestic and international feed-in tariffs that was collected as part of this study can be found in two spreadsheet files that accompany this report: *FIT Summaries—Domestic, 31Aug09.xls* and *FIT Summaries—International, 20Aug09.xls.*

1.2 Technologies Addressed

The primary focus of this paper is the applicability of FITs to solar photovoltaic (PV) facilities, including ground-sited, roof-mounted, and building-integrated photovoltaics (BIPV). PV is composed of semiconducting cells that convert energy from sunlight into electricity (DOE EERE, 2008). Where applicable, we also considered FIT programs that supported solar thermal systems (i.e., solar heating) and concentrated solar power (CSP). Solar thermal systems generally collect light energy and use it to heat water or other heat-transfer fluids. CSP installations "collect and concentrate . . . the solar energy in sunlight to generate electricity" (DOE EERE, 2008). FITs are less commonly applied to these latter two technologies. In particular, because CSP is not implementable at a small scale, only a few countries provide FITs for it. Wind, biomass, hydropower, geothermal, and cogeneration were researched when the structure or effects of FIT policies directed toward them was particularly relevant in some way.

1.3 Status of FIT Programs Worldwide

At the beginning of 2009, FIT programs existed in approximately sixty-three countries, states, and provinces around the world (REN21, 2009, p.26). The number of FITs worldwide has escalated in recent years, and they have grown increasingly larger and more complex. This section briefly summarizes the state of FITs both internationally and domestically.

1.3.1 International Programs

While Europe is the predominant location of FIT programs, FITs also may be found in Canada, Israel, and Australia, as well as in numerous developing nations including Thailand, Kenya, Ecuador, South Africa, Brazil, and India. The first FIT-type program in existence was the Public Utilities Regulatory Policy Act (PURPA)[1] of 1978 in the United States, but FITs languished for over a decade until Germany adopted a basic program in 1990. The number of FITs grew slowly in the 1990s but exploded after the year 2000, growing from thirteen to sixty-three between 2000 and 2009, with other programs in the pipeline.

Numerous FIT programs have been revised, some several times. Germany and Spain have been the countries most willing to overhaul their FITs. Only Denmark and India appear to have eliminated (or attempted to eliminate) their FITs (REN21, 2009, p.26). India discontinued its FIT program for unclear reasons but reinstated it in 2008, while Denmark passed a bill in 2000 that limited FITs to existing installations while attempting to institute a tradable green certificate (TGC) program (Sijm, 2002, p.10). Denmark's transition may have been in large part due to its policy of providing carbon tax refunds to RE generators which, when added to a FIT based on 85% of consumer electricity prices, led to a program cost of 75 million Euros (Sijm, 2002, p.10-12). However, the phase-out of the Danish program has been delayed repeatedly, so its status is uncertain at this time and the transition may have been rejected (conversation with Paul Gipe, 2009).

1.3.2 Domestic Programs

FIT programs have been slow to take hold in the United States. Recently, states have begun to take a sincere interest in their promise with the introduction of FITs at the municipal, utility, and state levels. Over a third of states have either adopted a FIT program or introduced legislation intended to implement one. California, Maine, Oregon, and Vermont have all passed legislation adopting a FIT, either targeting specific utilities (e.g., California's FIT applies to the state's investor-owned utilities), or implementing a pilot program to assess the relative benefits and

[1] PURPA was passed by the US Congress in 1978 as part of the National Energy Act. It was originally intended to promote greater use of renewable energy by forcing electric utilities to purchase electricity from non-utility producers at the utility's *avoided cost* rate. Although a Federal law, implementation was left to the individual states. In Colorado, PURPA has not played an important role, partly because the Colorado Public Utilities Commission rules require utilities to rely on a competitive procurement process to set qualifying facility tariff rates for resources greater than 100 kW in capacity.

impacts (e.g., Oregon).[2] California's FIT has an overall program cap of 500 MW of RE generating capacity, with individual project caps set at 1.5 MW.[3] RE generators participating in this program receive payments based on the Market Price Referent, which is a calculation similar to the utility's avoided cost of generation or acquiring needed energy by other means.[4] Vermont's FIT is intended to install 50 MW of solar electric capacity, with individual project caps set at 2.2 MW.[5] The legislature set an initial rate of $0.30/kWh (regardless of the installation's overall capacity size) of solar generation provided to the utility, with the Vermont Department of Public Service to adjust this rate in the near future. Finally, Oregon passed a pilot FIT program (25 MW program cap, 500 kW project cap), with a rate structure intended to compensate the solar generator for the utility's avoided cost of the energy, the avoided cost of transmission and distribution, and all RECs produced.[6] At least twelve other states acted to potentially implement a FIT, with eleven electing to introduce legislation and two opening administrative dockets to assess the suitability of a FIT for their state (with Hawaii doing both).[7]

Numerous utilities have implemented FITs to encourage renewable energy generation within their service territories. Many of these programs are solar-electric specific, in order to acquire the RECs produced by the RE system. For example, Xcel Energy in New Mexico offers an incentive to new and existing PV systems, allowing them to comply with the state's RPS solar carve-out requirement.[8] Wisconsin investor-owned utilities offer ten-year power purchase agreements, offering anywhere from $0.23 to $0.30/kWh to PV generators for the energy and RECs their systems generate.[9] Though these programs may be intended to spur further PV development so that utilities may comply with RPS requirements, they demonstrate an acknowledgement at the regional level of the potential for FITs to encourage RE development.

Additionally, certain municipalities have attempted to implement FITs. Gainesville, Florida passed the first municipal-level FIT in the country.[10] The municipal utility began accepting PV applications March 1, 2009, and has already attained its initial program limit of 4 MW. This FIT program tiered the rates depending upon capacity size and installation type—whether the PV installation is building- or ground-mounted.[11] Three cities in California—Los Angeles, Palm

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[2] CA S.B. 1969 (2006), S.B. 380 (2008); ME L.D. 1075 (2009); OR H.B. 3039 (2009); VT H446 (2009).
[3] The California Public Utilities Commission currently has an open docket assessing whether to increase the project caps and whether it can legally increase tariff rates above utility avoided costs (Docket R0808009). Additionally, legislative bills (S.B. 32 and A.B. 1106) introduced within the California State Assembly would increase the individual project caps in order to spur additional RE generation capacity.
[4] CA P.U.C. Order 07-07-027 (07/2007).
[5] H446 (2009).
[6] OR H.B. 3039 (2009).
[7] Arkansas: H.B. 1851 (2009) ; Hawaii: S.B. 1196 (2009), HPUC Docket No. 2008-0273; Illinois: H.B. 5855 (2008) ; Indiana: H.B. 1622 (2009); Iowa: H.F. 412 (2009); Michigan: H.B. 5218 (2007); Minnesota: H.F. 932 (2009) ; New Mexico: H.M. 87 (2009) ; New York: S2715A (2009), A08679 (2009); Rhode Island: S.B. 487 (2009); Washington: H.B. 1086 (2009); Wisconsin: PSC Docket No. 5-EI-148 (opened 1/8/09).
[8] New Systems: 0.5 kW- 100.0 kW: $0.20 per kWh; Existing System: $0.10/kWh; Systems 100.1 kW-2 MW determined through R.F.P.
[9] Madison Gas & Electric, WE Energies, Wisconsin Power and Light (Alliant Energy); Wisconsin Public Service Corporation.
[10] Available at http://www.gru.com/OurCommunity/Environment/GreenEnergy/solar.jsp (accessed 7/17/09).
[11] $0.32 Building or Pavement Mounted; $0.32 Ground Mounted < 25kW; $0.26 Free Standing > 25 kW.

Desert, and Santa Monica—have also attempted to introduce legislation to implement a municipal FIT, but each failed in its attempt.[12]

2.0 Defining and Designing Feed-In Tariff Programs

FITs may be designed to accomplish several goals, among them increased installation of RE generation capacity, security from volatile electricity prices and fossil-fuel dependence, reduction of greenhouse gas (GHG) emissions, and the general promotion of environmental benefits by making RE sources competitive with traditional electricity sources. This section overviews basic and advanced design features of FITs, describes how to approach some of the complex political and administrative balancing that they require, and briefly summarizes the state of FITs worldwide.

2.1 Defining FITs

FITs incentivize the generation of renewable electricity. Because tariff rates are paid based on the actual amount of electricity generated from renewable resources rather than on the installation of capacity, FITs can be considered production-based incentives (PBIs) (Couture et al., 2009, p.2). Generally, FIT programs require utilities, grid operators, or electricity consumers to establish long-term purchase contracts with RE generators in order to provide investment stability. However, beyond this basic level, FITs can take diverse forms: one of their primary benefits is that they can be tailored to accommodate the circumstances—renewable resources, domestic industries, and electricity markets—of the specific jurisdiction.

2.1.1 What Tariff Amounts Are Offered?

The tariffs offered for renewable energy differ widely depending on the jurisdiction, the source of electricity, and a multitude of other factors, including installation size and geographic location. Tariffs for solar installations, generally PV although also solar-thermal energy and CSP, are among the highest granted to renewable resources. In 2009, solar PV tariffs range from approximately \$0.23/kWh in Thailand to \$0.97/kWh in Greece (Gipe Tables, 2009); however, rates may be as low as about 7 €cts/kWh in Estonia (Klein, 2008, p.20 figure 3-5). In contrast, Germany offers about 7.79 to 11.67 €cts/kWh for biomass and 9.2 to 13 €cts/kWh for onshore and offshore wind, respectively (BMU, 2009, p.4, 8-9). Therefore, while solar tariffs trend toward the high side, they still vary greatly depending on the countries that grant them.

2.1.2 Governmental Responsibility for Setting FITs

FIT policies and rates are set by governmental bodies. Although utilities or grid operators are the purchasers of renewable electricity, the amount they must pay under FITs is set by either the legislature or an electricity regulator rather than by the utilities or grid operators themselves. Beginning in 1990, the Bundestag, Germany’s parliamentary body, passed detailed FIT laws including the Electricity Feed-In Law of 1990, the Renewable Energy Sources Act of 2004

[12] Los Angeles: Measure B defeated 03/2009; Palm Desert: CA AB432 introduced, 2/24/09, withdrawn by author 4/20/09; Santa Monica: SB 523; Introduced 2/27/09, referred to California Senate Committee on Energy, Utilities and Commerce on 3/12/09, first hearing set 4/15/09 (hearing cancelled at author's request).

(EEG), and EEG amendments in 2007 and 2009. Similarly, the Republic of Slovenia defines the FIT schedule by law each year, incorporating price information from the Statistical Office. In Spain, the National Energy Commission (CNE), which is a division of the Ministry of Industry, Tourism, and Commerce and acts as Spain's energy regulator, provides recommendations on FIT schedules to the federal government, which then passes FIT laws by royal decree (as Spain is a parliamentary monarchy). As in Slovenia, the annual inflation adjustment is legislatively adopted.[13]

Most countries that offer FITs typically adopt them legislatively rather than by delegating authority to an energy regulatory body. Notable exceptions include Ontario, Canada, and South Africa. The Green Energy Act of 2009 provides the first step in authorizing the Ontario Power Authority (OPA), which was created during the restructuring of Ontario's electricity market in order to plan resources, procure transmission, and achieve other governmental energy goals, to develop a FIT.[14] The National Energy Regulator of South Africa (NERSA) also developed FIT guidelines under delegation from the national government (NERSA, 2009, p.2-3). Additionally, regulatory bodies may have control over minor adjustments, such as the selection of the appropriate schedule for degression by Germany's Federal Network Agency based on the fulfillment of capacity caps.[15]

2.2 FIT Design Features

The creation of a FIT schedule is a complex process that involves the consideration of national priorities for the development of renewable energy. Broadly, the process includes several steps:

1. Consider the policy question of which renewable resources should be subsidized and who may participate in the program;

2. Select a cost calculation methodology which can be used to determine the baseline level of FIT payments and the duration of the power purchase agreement;

3. Decide whether the FIT payment will be awarded at a fixed level or as a premium over market-based rates;

4. Develop a combination of tariff differentiation, adders, adjustment, revision, and degression in order to prioritize different types, sizes, and locations for RE plants, as well as to accommodate changes in technological progress and inflation; and

5. Consider the allocation of purchase, forecasting, and other obligations between the parties to the FIT contract, and the effect that all of these factors have on the pass-through of costs to ratepayers.

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[13] Royal Decree 436/2004, 25, *available at* http://www.feed-in-cooperation.org/images/files/rd436_2004_en.pdf.

[14] Ontario Bill 150, Green Energy and Green Economy Act, Part V.20.7 (2009), *available at* http://www.ontla.on.ca/web/bills/bills_detail.do?locale=en&BillID=2145&detailPage=bills_detail_the_b.

[15] Act Revising the Legislation on Renewable Energy Sources in the Electricity Sector and Amending Related Provisions § 20 (2008), *available at* http://www.feed-in-cooperation.org/images/files/NationalDocuments/Germany/renewable-energy-sources-act_2009%20en.pdf.

2.2.1 Eligibility of Resources and Participants

The selection of which renewable energy technologies to incentivize may be based on several factors. First, policymakers should consider the country's renewable resource base. For instance, in regions of the world that receive little sunlight, providing high tariffs for solar PV may not be an appropriate use of resources. Second, cost-effectiveness may be a consideration. Where certain renewable resources are limited, a country must decide whether it wishes to encourage their development anyway, or whether it would be best to allocate funds toward developing technologies that are easier to bring to market. A corollary to this concern is how much cost increase ratepayers are willing to accept in exchange for encouraging RE development. Third, the potential for developing a domestic manufacturing industry for a specific type of RE technology may be relevant. Ultimately, a country's or state's environmental, social, and economic priorities can help it determine the appropriate RE technologies to incentivize.

While countries may select different suites of renewable resources to be eligible for FITs, developers and utilities alike generally may seek tariffs. However, there have been exceptions: Germany initially prohibited utilities from receiving subsidies for increasing RE generation, although this policy changed in 2000 (Stenzel & Frenzel, 2008, p.2649-50). Germany's program also bars installations that are over 25% funded by the sixteen German states (Länder) or the federal government from receiving FITs if they were commissioned before 2004.[16] Otherwise, the only requirement for participation in FIT programs is going through the administrative process established by the country offering the FIT.

2.2.2 Cost Calculation Methodology

Governmental agencies or utilities set tariffs based on cost calculation methodologies (CCM) that are used to determine the baseline level of compensation for RE producers (Couture et al., 2009, p.3). A CCM differs from a tariff adjustment or revision, although all of these processes are related and combine to create the final tariff schedule. There are three basic CCMs that are used to determine tariff rates: fixed price, avoided cost of generation, and actual cost of generation. The last approach is the most common, but each will be discussed in turn.

A fixed rate FIT might be founded on a level of support for RE generators without consideration of the actual or avoided costs of electricity generation. While this approach is administratively simple, it is used infrequently, perhaps because of the risk of either windfall profits for generators if it is set too high or, conversely, a limited ability to stimulate RE generation if set too low.

The second approach, the avoided costs model, was first adopted as part of the Public Utilities Regulatory Policies Act of 1978 mentioned earlier in section 1.3.1. PURPA obligates utilities to purchase renewable energy from qualifying facilities based on the utility's avoided costs of

[16] Act Revising the Legislation on Renewable Energy Sources in the Electricity Sector and Amending Related Provision at § 66.

providing that energy.[17] But, as noted earlier, implementation has been inconsistent across the states. Avoided costs may include direct costs (such as construction, operations, and maintenance), indirect costs (e.g., environmental externalities), and opportunity costs (Beecher, 1996, p.29). Portugal is one of the few countries that employs avoided costs for its FIT. RE generators in Portugal receive a monthly payment based on several factors, including:

- The cost of power plants that do not have to be built due to the use of RE (based on the efficiency and capacity of the RE plant and designed so that the more efficiently the plant operates, the greater will be the avoided costs);

- A variable factor based on the estimated generation of electricity by conventional power plants that were not built because of RE;

- An environmental factor which provides an additional sum for the CO_2 emissions that were avoided because conventional power plants were not built, multiplied by a coefficient that varies depending on the type of RE resource.

This sum is then multiplied by other factors, including an optional time-of-day differentiation, an inflation adjustment, and a factor that is based on the transmission losses that were avoided by using RE and accounts for the capacity of the RE installation (Heer & Langniß, 2007, p.8-10). Despite the complexity of this program, which makes it difficult for investors to assess, as of 2005, Portugal had the fifth-largest amount of RE-based electricity generation in the EU-15 (IEA, 2006, p.6).

The third and most commonly-applied CCM is based on the actual cost of RE generation and provides a subsidy for production plus a reasonable rate of return, which is included in the final tariff. Spain's CNE, for instance, considers a reasonable rate of return to be 7% after tax, while Germany includes a 5-8% nominal composite interest rate for twenty years for PV (Santos, 2008; BMU, 2007, p.167 table 15-1). The actual cost model accounts for the initial costs of constructing a plant (differentiated by RE resource), obtaining licensing and permits, inflation, operations and maintenance (O&M), interest rates and profit margins for investors, and cost of fuel (if applicable), among other inputs (Klein, 2008, p.9). The German model specifically includes the costs of consulting, commissioning, and fundraising, among other payments, although tax subsidies are not included in the calculation (BMU, 2007, p.165-67).

In the German process, these factors are used to create a model RE plant that is "assumed to be a freestanding, newly constructed plant[] on [a] greenfield site[] with the potential to be connected to existing infrastructure . . ." (BMU, 2007, p.164, 168-69). The annuity calculation model is then used to determine the average annual payments needed for this RE plant to be profitable, and converts them into a price per kilowatt-hour that is paid to the generator. This approach is popular because it can preclude RE generators from receiving windfall profits while providing them a subsidy that is closely tied to their actual investment. Moreover, because the costs of generating electricity may differ dramatically based on the source, it helps justify tariff differentiation based on the type of renewable resource.

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[17] 26 U.S.C. § 45; 18 C.F.R. 292.304.

2.2.3 Duration of FITs

The duration of the power purchase agreement between the RE generator and the grid operator or electricity supplier is a major component in CCM calculations. For instance, shorter contracts may require larger tariffs to provide an appropriate level of support. Typically, the agreement lasts for between ten and twenty years for PV installations, but may range from a low of seven years (Turkey) to a high of more than twenty-five years (Spain). However, the precise level of support may vary over the duration of the contract (Gipe, Model Advanced Renewable Tariff Legislation, 2008).

2.2.4 Fixed Versus Premium Prices

Once the baseline tariff and duration of payment have been calculated, policymakers must determine whether or not to tie the subsidy to the market. Thus, FITs may be paid either as a fixed rate or as a premium on top of the spot market price of electricity. Fixed FITs are used in almost every program in the world, their popularity stemming from their independence from volatile market prices. In contrast, premium FITs have the advantage of helping to incentivize RE generation during peak periods, but when electricity prices rise overall, they also lead to windfall profits for generators and excessive costs to ratepayers.

Only a few countries subsidize RE generation with premium FITs. Spain and Slovenia allow RE generators to opt for either fixed or premium FITs. Beginning in 1998, Spain allowed RE generators to select either option but provided that they could change their mind each year (Klein, 2008, p.44-47 and figure 3-17). From 1998 to 2004, RE generators in Spain selected the fixed FIT without exception, but between 2004 and 2008, the increasing cost of natural gas caused electricity prices to skyrocket and made premium FITs the more attractive option. By 2008, 91% of RE generators were remunerated under the premium FIT. However, at the time, the premium was only allowed for PV installations of 100 kW or greater, meaning that most solar power continued to be subsidized under the fixed FIT. A directive in 2007 eliminated the premium for PV entirely.

In 2007, the high cost of the premium program led Spain to adopt a complex floor-and-ceiling approach which limits the profits of RE generators who select the premium option (Klein, 2008, p.51). A baseline reference premium is set administratively, but more or less than that amount may be paid out depending on the market price of electricity. If the sum of the market price and the reference premium is lower than the floor price, RE generators will receive the higher floor rate. If the sum is within the limits of the floor and cap, RE generators receive that sum. However, once the sum exceeds the cap, only up to the cap price is paid (i.e., beyond a certain point, the premium declines as the price of electricity rises). Finally, if the market price of electricity rises above the cap, the market price alone is paid without an additional premium.

Fixed FIT rates do not appear to be negotiable under any of the national programs reviewed for this study. Rather, they are legislatively or administratively set. Greater flexibility exists under premium FIT programs. Until 2008, the Netherlands allowed RE generators to negotiate with grid operators for the purchase rate, and then provided a premium on top of that rate (Klein, 2008, p.53).

While the premium program is innovative, and can be used to stimulate more generation during peak times, it is also complex and may remove some investor security. Moreover, PV installations are not always eligible to receive premium FITs even when they are offered. Even though Spain offers both fixed and premium tariff options, PV installations became ineligible to receive premium FITs after 2007 (Klein, 2008, p.47). The reasons behind this decision are unclear.

2.2.5 Differentiation and Adders

The process of differentiating FITs generates complex "stepped" or "tiered" tariff schedules. Although differentiating FITs and providing adders are two slightly different processes, the end result is the same: the development of unique rates for different approaches to RE generation. FITs may be differentiated based on the type of RE resource or technology, the size of the installation, the time of day or season in which generation occurs (i.e., peak or off-peak), and the geographic location or resource intensity of the RE plant. Adders might be provided for achieving social goals or for using certain types of technology. Although adders and premiums appear similar, premiums sit on top of the electricity market price whereas adders may provide a small bonus of a few cents onto a fixed rate (or potentially a premium) for fulfilling certain conditions. Examples of differentiation and adders follow:

- **Fuel type**: Numerous countries worldwide offer different tariff rates for a range of RE sources, including solar, wind (onshore and offshore), small hydro, geothermal, and biomass, in addition to other technologies like CHP (Klein, 2008, p.14-15 table 3.3).

- **Technology type**: PV, BIPV, solar thermal, and CSP may all receive different tariffs.[18] Additionally, some countries, such as Switzerland, differentiate between roof-mounted PV, freestanding or ground-mounted PV, and BIPV (Gipe, Swiss Adopt Aggressive Law, 2008).

- **Size**: Almost all FITs provide different tariff rates to RE installations depending on their size. For instance, Italy provides different FITs to 1-3 kW, 3-20 kW, and 20+ kW projects, and Germany offers different rates for installations of < 30 kW, 30-100 kW, > 100 kW, and > 1 MW (Tilli et al., 2008, p.4; BMU, 2009, p.10). Typically, higher tariffs are paid to smaller installations due to economies of scale in larger plants. However, the use of capacity thresholds rather than a linear capacity progression can lead RE developers to size to the limit of the highest rate, focusing on capacity rather than actual output (Couture et al., 2008, p.20-21, 23).

- **Time of day/season**: Several countries, among them Austria, Greece, Hungary, Portugal, Slovenia, Spain, and Uganda, provide higher pricing for peak as opposed to off-peak generation (Klein, 2008, p.59-62).

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[18] *Compare* South Africa (CSP and no PV, http://www.nersa.org.za/UploadedFiles/ElectricityDocuments/REFIT%20Guidelines.pdf) *with* Greece (PV and solar thermal, Gipe) *with* Spain (PV and solar thermal, NREL).

- **Geographic**: Greece provides the highest tariff rate to small (< 100 kW) PV installations on its islands as opposed to those on the mainland, probably in part to reduce the need for investment in massive transmission infrastructure between the islands (Gipe, New Solar PV Tariffs Announced for Greece, 2009).

- **Resource equalization**: A few countries, such as Germany and France, offer different tariffs based on the yield of the RE plant. This is particularly applicable to wind farms, and helps incentivize distribution of RE plants throughout the country instead of just in the most wind-intensive areas, with the effect of reduced local opposition to RE site selection. Germany pioneered this complex approach: its FIT program compares the yield of a turbine for the first five years against that of a model or reference turbine, and decreases the FIT for the following fifteen years if the actual yield is greater than 150% of the reference yield (Klein, 2008, p.33; BMU, 2007, p.23). However, under the 2004 EEG, a turbine could incur an additional two months of FIT payments for every 0.75% it performed under the reference yield. Thus while payments for turbines with yields below 60% of the reference yield are discontinued, a generator exceeding 60% of the reference yield can receive the starting FIT rate for up to twenty years. Unfortunately, this process could also be viewed as a counterincentive that discriminates against more efficient resources.

- **Technology type adder**: Germany formerly offered a 5 €ct/kWh bonus for BIPV installations, but deleted this adder in the 2009 FIT schedule for reasons which remain unclear (BMU, 2009, p.10).

- **Social responsibility adder**: Ontario, Canada offers a premium of a few cents for RE projects that are community-based (1.0 CAN-cts/kWh) or partly- or fully-owned by aboriginal peoples (1.5 CAN-cts/kWh) (OPA, FIT Pricing Schedule Draft July 8, 2009, p.2). Thailand provides a 9.5 Baht/kWh (about US$0.28) premium for PV projects in its three southernmost provinces to compensate for investment risks due to sectarian violence (Gipe Tables, 2009; Ruangrong, 2008, p.3).

- **Repowering adder**: This adder generally applies to wind turbines. Denmark, Germany, and Spain award a small bonus for replacing (usually) pre-1995 turbines with newer, more efficient models (Couture et al., 2009, p.33).

- **High efficiency adder**: Germany and France offer small bonuses for the use of combined heat and power (CHP) with biomass and biogas facilities, and for pairing cogeneration with geothermal power (Couture et al., 2009, p.32).

Figure 2-1: 2009 Tariff Schedule for Germany, €ct ($ct)/kWh (BMU, 2009, p.10)

Size	< 30 kW	30-100 kW	> 100 kW	> 1000 kW
Roof-mounted	43.01 (60.63)	40.91 (57.67)	39.58 (55.79)	33 (46.52)
Free-Standing	31.94 (45.02)			
Electricity Produced & Used On-Site	25.01 (35.25)		n/a	

Figure 2-2: 2008-09 Tariff Schedule for France, €ct ($ct)/kWh (Gipe Tables, 2009)

Base FIT	32.8 (44.8)
BIPV (2008)	60.1 (82)
Rhone-Alps Region (2009)	40 (54.6)
Commercial Buildings (2009)	45 (61.4)
Overseas Territories	43.7 (59.6)

2.2.6 Adjustment and Revision of FITs

FITs, once given basic shape by the CCM and differentiated consistent with national priorities, may be adjusted over time to accommodate price changes: either increases due to inflation and commodity shortages or decreases due to technological advance and economies of scale. FITs may be adjusted up or down for new and existing projects alike. Accordingly, adjustment provides both an incentive for RE generators to reduce costs as well as a method by which to progressively reduce the burden on ratepayers while still protecting long-term investors.

Next, we discuss two types of tariff adjustment in detail and briefly summarize a few additional adjustment options. The first concept is degression, which applies to new projects, and the second is inflation adjustment, which can apply to new or existing projects. Additionally, front-loaded and capacity-based adjustments will be considered briefly. Finally, these concepts will be compared to the process of revision, which is a more comprehensive overhaul of the FIT schedule. The frequency of revisions may affect the need to apply adjustments, and vice versa.

2.2.6.1 Degression

Degression is the process of reducing a tariff progressively (usually annually) for new RE generators who apply in the years after the tariff is introduced. For example, assuming a FIT duration of twenty years and that no other tariff adjustments are applied, project X, which comes online in 2007, will receive the full tariff it contracted for in 2007, but project Y, which comes online in 2008, will receive a lower tariff as stipulated by the degression schedule. Degression assumes that as more RE installations are built, new capacity will become cheaper. In sum,

> [t]he tariff level depends on the year[] when the RES-E plant starts to operate. Each year the level for new plants is reduced by a certain percentage. However, the remuneration per kWh for commissioned plants remains constant for the guaranteed duration of support. Therefore the later a plant is installed, the lower the reimbursement received (Klein, 2008, p.40).

Degression can occur automatically or based on a trigger. Both France and Italy automatically degress their tariffs by 2% each year: France for wind and Italy for PV (conversation with Paul Gipe, 2009). The Czech Republic adjusts its tariffs administratively each year, but limits the amount of change to less than 5% (Klein, 2008, p.21). The 2009 German PV tariff is unique in that it provides for a high rate of degression that varies based on a capacity cap (BMU, 2009, p.11). Freestanding PV will degress at 10% in 2010 and 9% in 2011, roof-mounted PV systems of less than 100 kW will degress at 8% in 2010 and 9% in 2011, and roof-mounted PV of 100 kW or more will degress at 10% in 2010 and 9% in 2011.[19] These degression rates will increase by 1% if certain capacity levels are exceeded (1500 MW in 2009, 1700 MW in 2010, 1900 MW in 2011) or decrease by 1% if installed capacity fails to exceed specified levels (1000 MW in 2009, 1100 MW in 2010, 1200 MW in 2011).

A well-structured degression program provides transparency to investors about the tariff rates they can expect in the future. However, it may not be flexible enough to keep pace with changing prices, including higher commodity prices due, for instance, to resource shortages. Another conflict may occur because although degression can cause a boom in installations at the outset as generators clamor to get higher rates, it could potentially lead to the lock-in of less efficient systems. Therefore, it has been suggested that a degression component be implemented as part of a FIT revision rather than at the outset, so as to gain a sense of the effect of the FIT on RE markets (conversation with Paul Gipe, 2009).

2.2.6.2 Inflation Adjustment

Another way to modify FITs is the process of inflation adjustment. FITs may be adjusted upward for inflation for both new and existing installations: adjustment might be used to mitigate the impacts of full degression for new installations or throughout the course of an existing contract. The rationale for increasing FITs to accommodate inflation, at least within existing contracts, is to protect investors, who are committed to renewable energy projects for as much as forty years. Unfortunately, this goal actively conflicts with the desire of governments to shelter ratepayers from price volatility (conversation with Paul Gipe, 2009). Moreover, increasing tariffs due to inflation counteracts the idea that the primary cost of RE generation is up-front, i.e. installation.

Generally, programs use the consumer price index ("CPI") to determine inflation (Couture et al., 2009, p.28). CPIs may be calculated differently in each country, but broadly are "economic indicators constructed to measure the changes over time in the prices of consumer goods and services acquired, used or paid for by households" (Eurostat, 2004, p.3). CPIs may include housing, transportation, medical care, recreation, and numerous other expenses; moreover, they

[19] The 2009 FIT schedule states that roof-mounted PV systems of capacity < 100 kW will degress at 10% in 2010 and 11% in 2011, but the 2008 Act clarifies that this was a transposition error (p.6-7 § 20).

may include volatile goods like food and energy, although in the U.S. a separate figure, the "core CPI," calculates inflation without those inputs (U.S. Dept. of Labor, 2009). The inclusion of energy in the CPI calculation can be problematic when it is being used to determine inflation adjustments for RE prices. If fossil-fuel energy prices suddenly skyrocket, then including them in the CPI and using the CPI to scale up the prices paid under FITs can artificially raise the price of renewable energy and strip ratepayers of the price stability that FITs are supposed to provide (conversation with Paul Gipe, 2009). FIT programs that do adjust for inflation may provide that the CPI calculation cannot be used to decrease the tariffs, as is planned by Ontario (OPA, Draft FIT Rules July 2009, p.14).

To provide a compromise between investor and ratepayer protection, FIT program designers may choose only to adjust tariffs by a specified percentage of the CPI. For example, France adjusts its tariffs by 60% of the CPI both within existing FIT contracts as well as new installations (Gipe, Inflation Adjustment of Renewable Tariffs, 2008). Spain will adjust its FITs upward by 75% of the CPI until 2012 and 50% thereafter (Gonzalez, 2008, p.2926). Ontario's May 2009 rules provided for an adjustment of 20% of the CPI for the period between contract execution and operation, but its July 2009 rules indicate that the full contract price will be adjusted by the CPI (OPA, Pricing Slides Update and Rule Changes, May 12, 2009, slide 40; OPA, July 2009 Draft FIT Rules, p.14).[20] Ultimately, however, a program may successfully increase capacity without providing inflation adjustments, as exemplified by Germany's FIT.

2.2.6.3 Other Methods

In addition to degression and inflation indexing, there are other, similar methods of FIT adjustment. In order to provide stability, a country might provide that an existing tariff be front-loaded and then decrease automatically after a certain number of years. For instance, Austria provides a stable FIT for the first ten years of a PV installation, and then 75% of the FIT in the eleventh year and 50% in the twelfth (Gipe Tables, 2009). In Slovenia, fixed FITs decrease by 5% after five years and 10% after ten years (BMU, Legal Sources on Renewable Energy).[21] A very few countries, Spain among them, provide the tariff for the entire life of a PV, but the level of support decreases after twenty-five years (BMU, Legal Sources on Renewable Energy). Until 2008, the Netherlands applied a unique approach in which RE generators could obtain ten-year FIT contracts in which they received a premium above the spot market price. At the end of the contract, they were compensated at the spot market price without the premium (Couture et al., 2009, p.30).

Another approach uses triggers to adjust prices. Some programs apply capacity caps beyond which no support is granted or which lead to revision. Other programs consider resource intensity. For instance, Germany adjusts FIT rates based on a reference turbine model so as to account for differences in wind resource throughout the country. These methods are rare compared to degression and inflation adjustments, however.

[20] Ontario's program is somewhat confusing because the May rules appear to adjust the contract price by a percentage of the CPI while the July rules appear to adjust a percentage of the contract price by the full CPI.
[21] However, the duration of FIT contracts is also described as being 10 years, therefore it is unclear whether the contracts reduce by 10% or terminate at that time.

2.2.6.4 Revision

In contrast to an adjustment, a revision is a broader process in which the FIT may be substantively altered (Couture et al., 2009, p.40). A revision is like an adjustment in that both processes may take into account commodities markets, investor needs, ratepayer burdens, and technological progress. However, while adjustments are prospective because they are established in advance to predict changes in RE markets, revisions can be retrospective, considering actual market changes in order to refine or overhaul the FIT schedule. When the time between revision cycles is long, adjustments may not accurately account for market changes because of the complexities of predicting electricity and commodity markets. For this reason, when revisions are scheduled to occur frequently, adjustments—at least of the tariffs provided to new installations—may be less imperative. While Germany applies a five-year revision cycle and intermediate tariff degression, Ontario opted for a two-year revision cycle in place of degression because its FIT program developers believed that this was a better way to account for changes in RE markets (Gipe Tables, 2009; conversation with Paul Gipe, 2009). Theoretically, more frequent revisions may increase investor uncertainty if, for instance, it becomes difficult to predict whether and by how much new tariff rates might change. Similarly, capacity-based revision triggers can create uncertainty if many potential developers are queuing for access to FITs.

2.3 Obligations of Parties to the FIT Program

RE generators and electricity transmitters and distributors acquire different rights and obligations based on national laws and the terms of their purchase power contracts. Grid operators and electricity suppliers are frequently committed by law to purchase renewable energy from generators. In turn, RE generators may be obligated to measure their production and predict their output. Moreover, the costs of interconnection of RE plants to the grid may be paid by either party, depending on regulation. Each of these obligations will be briefly discussed.

2.3.1 Purchase Obligations

A purchase obligation commits a utility or grid operator to buy electricity from RE generators under the FIT price schedule and for a specified duration. Fixed FIT programs may include not only purchase obligations, but also prioritization of RE purchases. While premium FITs could include purchase obligations by designating an end utility purchaser to pay spot market prices, in practice they do not (Couture et al., 2009, p.49). One major impetus for the purchase obligation is the European Commission's 2001 directive that all member states "guarantee the transmission and distribution of electricity produced from renewable energy sources" (Directive 2001/77/EC). In addition, European nations must publish standardized interconnection policies and may opt to prioritize RE purchases ahead of the purchase of fossil fuel generation. Outside of Europe, South Africa obligates its national public utility, Eskom, to purchase renewable energy and pay RE generators a FIT (NERSA, 2009, p.4, 8). Sometimes the obligation may take unusual forms. Estonia, for example, instead of requiring grid operators to purchase all electricity generated by RE plants requires only that they purchase up to the level of their transmission losses (Mendonça, 2007, p.93).

2.3.2 Obligations for RE Generators

RE generators are sometimes required to measure their electricity output to the grid and to provide grid operators with data about their projected output. However, few countries have instituted these requirements. Germany requires installations of over 500 kW to measure and record their electricity output, but does not appear to require reports to grid operators (BMU, 2007, p.22). NERSA, South Africa's energy regulatory agency, has stated that it intends to audit output information for all RE installations over 10 MW, with random sampling of those under that threshold (NERSA, 2009, p.9). Spain, Slovenia, and Estonia appear to be the only countries that require RE generators to forecast their output and to provide this information to grid operators (Klein, 2008, p.10 table 3.1). However, only Spain charges generators if their actual electricity output deviates from their predictions. Under Spain's FIT program, RE generators must report their projected output for each hour in a day to the grid operator at least thirty hours before that day (Gonzalez, 2008, p.2920, 2925, and table 2). Beginning in 2004, an RE generator could be required to pay a penalty, calculated based on the average electricity tariff and the amount of the deviation, for deviating by more than 20% from solar and wind electricity predictions (or 5% for other sources). Reportedly, RE generators considered this an acceptable cost of doing business. In 2007, the deviation trigger was dropped to 5% for all RE sources, but generators were allowed to correct their predictions up until one hour before delivery.

2.4 Distributing Interconnection Costs

The cost of interconnecting distributed generation to the grid may be borne by either party or both. There are four predominant approaches to interconnection cost-sharing (Knight et al., 2005, p.7). The first is shallow interconnection, in which RE generators pay only the cost of equipment for connecting to the grid. Grid operators must pay for network reinforcement, and may recover those costs through use-of-system fees. Second, deep interconnection requires RE generators to pay all costs of connection—not only physical interconnection, but grid reinforcement and repair if applicable. The third approach, hybrid interconnection, compels RE generators to pay the cost of physical interconnection and a portion of grid reinforcement costs based on use of the network. Finally, "true" interconnection forces RE generators to pay the costs of physical interconnection to the nearest point on the grid that would not need additional reinforcement. While this latter method may stimulate distributed generation in regions with stronger grid infrastructure, the costs for RE generators may be higher even than those under the deep approach.

The method of interconnection cost-sharing chosen may depend on the size and location of RE installations to be encouraged or on other factors. As of 2005, eight of the EU-15 countries applied deep interconnection charges (Knight et al., 2005, p.3). Presumably, these expenses are factored into the amount of the FIT. Germany, which applies shallow interconnection charges, specifically includes costs of interconnection infrastructure in the development of an actual cost of generation model (BMU, 2007, p.165-66). The Ontario program appears to impose shallow connection charges, with an Economic Connection Test run in each province every six months to determine whether the connection costs being passed on to ratepayers are reasonable (OPA, Ontario FIT Program Draft Rules Mar. 2009, Rule 4.3(d)). South Africa has similarly opted to apply shallow connection charges (NERSA, 2009, p.7-8).

2.5 Paying for FITs

The cost of a FIT is ultimately borne by the electricity ratepayer. A utility will pay an RE generator per kilowatt-hour of production and then increase rates to consumers of electricity to recover the outlay. Germany's Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) notes that in some rare cases, such as the Czech Republic, electricity suppliers are barred from recouping their costs from ratepayers, though it did not provide additional information for these instances (http://res-legal.eu/en.html). However, if a utility in a competitive market accepts a large quantity of RE generation (perhaps because it is located in a geographically-superior region for RE development), it may be put at a disadvantage compared to a utility that purchases conventionally-generated electricity because it probably will be forced to raise rates for its consumers (Couture et al., 2009, p.75). Therefore, several methods have emerged to more equitably distribute the burdens of RE subsidization among ratepayers.

Many countries, including France, Italy, and Slovenia, pass through the burden of paying for FITs proportionately to all ratepayers based on electricity use (Klein, 2008, p.10 table 3-1). However, some countries, including Austria, Germany, and Denmark, have divided support levels to ensure that energy-intensive industries are not so burdened that they cannot compete internationally.

Distributing the burden in this manner involves considering the amount and cost of electricity consumption by an industry, as well as the voltage level of its connection to the grid. For example, Austria separated electricity consumers into seven levels based on the voltage of the section of the grid they were connected to, ranging from 400 volts to 380 kV (Klein, 2008, p.65-66). In 2006, the average fee per consumer was 0.42 €cts/kWh, but energy-intensive industries paid only 78% of that amount (about 0.33 €cts/kWh) while residential customers paid 111% (about 0.47 €cts/kWh). In 2007, this program changed to a fixed fee of €15.00 per year for residential consumers.

Germany, in contrast, apportions the burden based on the relative cost of electricity in an industry, resulting in benefits to the metal (particularly iron and steel), chemical, and paper industries (BMU, 2007, p.146-49). Companies that are eligible for reduced rates are manufacturing enterprises with consumption of greater than 10 GWh at the point of delivery, as well as those for whom the cost of electricity accounts for more than 15% of their gross value added (this includes some railways). These industries need only pay 0.05 €cts/kWh, and if their consumption is at least 100 MWh and the value of their electricity consumption is 20% or more of their gross value added, they need not pay any fee toward the FIT. Non-privileged consumers, including households, paid closer to 0.75 €cts/kWh. In Denmark, utilities charge customers a public service obligation (PSO) tariff based on their electricity consumption, but customers whose load exceeds 100 GWh per year pay only 37–39% of the PSO (Klein, 2008, p.67).

Several other methods have been considered for funding FITs. The most prominent alternatives are a general value-added tax (VAT) or a carbon tax, but a tax-based structure has rarely been tried and further research is needed to investigate its applicability to the U.S. market (Klein, 2008, p.75).[22] GHG allowance auctions, utility tax credits, and revolving loans have also been suggested as methods for funding FITs (Klein, 2008, p.76-77). However, none of these options appear to have gathered traction.

2.6 Problems and Constraints

Feed-in tariffs have a reputation for driving massive capacity increases by providing risk mitigation and profitability for investors. Naturally, the design of a FIT and the national context in which it is implemented play a substantial role in its success, and can contribute to political controversies. While the previous sections discussed many of the trade-offs inherent in the process of designing and implementing a FIT schedule, this section addresses a few of those problems in more depth.

2.6.1 Balancing Competing Goals

Determining the proper amount and design for a FIT involves the consideration of multiple sets of competing goals. The first is the distinction between short-term and long-term RE capacity growth. High FITs that incentivize an RE technology that is currently nascent, inefficient, uneconomic, or speculative may encourage rapid installation of that technology at the expense of more developed, efficient, and economic approaches. Yet high FITs also lead to massive capacity increases when coupled with a beneficial regulatory environment, while low FITs may not provide sufficient incentive for investors to fund RE projects.

FIT design can lead to other conflicts. The design process balances the competing goals of investors, who may be tied to a project for decades, and ratepayers, who directly subsidize the cost of incentivizing RE projects through increases in their electricity bills. Evidence in Spain suggests that while public aid, including FITs, will only comprise 2.9% of the funding required to meet the nation's 2005-2010 goals for renewable electricity generation, debt financing will make up 77.1% (Ministerio de Industria, Turismo, y Comercio, 2005, p.57). Importantly, FITs can help make RE financially attractive by reducing three types of investor risk: demand, credit, and sale price risk (Diaz, 2008, slide 6). However, policymakers are also faced with the politically-difficult position of favoring RE generation while simultaneously appeasing the utilities or grid operators that are required to compensate RE generators or, potentially, transmit renewable electricity at the expense of their own generation.

The different concerns that investors, ratepayers, and utilities bring to FIT design manifest themselves in the distribution of obligations, duration of contracts, adjustment of tariffs by setting degression and inflation rates, and the establishment of pass-through provisions. These problems will be discussed in more detail throughout the following sections.

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[22] For instance, in 1996, the Netherlands introduced an "ecotax" on small- and medium-sized electricity producers. RE generators were not only exempt, but received 2 €cts/kWh from the tax revenues along with 6 €cts/kWh in ratepayer funding. However, because increasing consumer demand for green power could not be met by domestic RE production and the subsidies applied to foreign generators as well, the policy led to a "an unintentional mass 'export' of national support for renewable energy." In 2003, the policy was revised into a more traditional FIT program funded by an annual levy on household connections (Rooijen et al., 2006, p.62-63).

2.6.2 Administrative Barriers

The necessity of balancing competing goals means that FITs can be legislatively difficult to set and may be in need of continuous guess-and-check revision. For instance, Germany's FIT program began in 1990 but has been amended or revised in 2000, 2004, 2006, and 2008. Among the complex tasks regulators accept in setting FITs include establishing the FIT schedule, assessing interconnection costs, limiting the impacts on ratepayers, and monitoring to prevent fraud. Specific problems that arise with regard to capacity caps and speculative queues will be discussed in the following section.

To determine a FIT schedule, a regulatory body must consider from the start the different interests of investors, ratepayers, and generators; which RE technologies it wants to stimulate; actual or avoided costs of generation; and the future of RE markets. Setting a yearly degression rate can incentivize research and development that would, hopefully, decrease costs of RE technologies, but if degression is set too far in advance, it may not sufficiently account for volatility in energy and commodities markets (conversation with Paul Gipe, 2009). Similarly, if the tariff is high but the degression occurs too quickly or the capacity cap for FIT eligibility is too low, manufacturers of RE technology components may suffer. While Spain was a major destination for PV panels in 2007-2008, with approximately 1.7 GW purchased for installation, at least one estimate suggests that only about 800 MW were installed before the FIT degressed in 2008, leading to major losses for manufacturers, distributors, and developers sitting on unused panels (Wang, Solar a Bust in Spain, 2008). Those on the development side, including manufacturers and investors, may also be harmed by the uncertainty that comes with frequent administrative revision of FITs. As of June 2008, the Spanish government had not come forward with a plan of action for the FIT program, which was scheduled to end in September. Solar manufacturers and developers feared reduced tariffs and many hurried their developments to receive higher FITs before degression or expiration of the program (Kho, Solar Firms Struggle to Forecast 2009, 2008).

Another dimension of administrative complexity emerges when connecting generators to the grid. For instance, unclear or complex application processes can lead to interconnection delays and, correspondingly, to reduced capacity. France's bureaucracy, which requires RE generators to go through twenty-seven separate public bodies to obtain permits, is considered a major factor in its limited wind capacity despite its high FITs (Szarka, 2007, p.325-26). Furthermore, adding interconnection costs may scare investors who lack information on their extent upfront. And, while it can ensure that RE generators site in areas that already have stable grids, this may not encourage utilization of the best resource locations. On the other hand, if utilities must pay for grid extension and stabilization to high-resource areas, the cost to ratepayers will increase proportionately.

Finally, limitations on the amount which a tariff can change may burden the government even as it tries to unburden ratepayers. For instance, from 2004 until 2006, Spain provided that both fixed and premium tariffs were set as a percentage of the average electricity price (AET); PV and solar thermal FITs were priced at around 90% of the AET (Gonzalez, 2008, p.2920 table 2; APPA, 2004, p.4 fn.4). The AET was administratively set each year and considered the actual costs of electricity generation as well as consumer demand. However, when increasing oil and gas prices caused the cost of electricity generation to rise, Spain could not correspondingly increase consumer rates because of a law that the AET could only rise between 1.4 and 2% each year (Ardour Capital, 2009, p.6-7). Because the rates paid by consumers were less than the resulting costs of generation, the Spanish government had to pay utilities the difference in addition to the FITs. This tariff deficit remains in the billions of Euros and led to the establishment of a cap and floor on tariff rates (Klein, 2008, p.49; Gonzalez, 2008, p.2926).

2.6.3 Specific Problems of Applications, Capacity Caps, and Queuing

Some countries set capacity caps for individual RE technologies that either limit new installations or trigger tariff rate degression. The rationale for this design feature, in part, is the fear of a so-called "wind rush," that is, a "single-minded attention to capacity increases" which can lead to the overdevelopment and lock-in of inferior technology at the best resource sites, as well as to conflicts with community members who live nearby (Szarka, 2007, p.321). Such restrictions directly conflict with the goal of major capacity increases that typically animates FIT programs. However, the problem is perhaps not the cap itself, which is potentially useful to limit the impact of large-scale RE development on ratepayers who shoulder the cost, but the fact that procedures for getting in under the cap vary from country to country and are often unclear, leading to uncertainty on the part of investors and even fraud on the part of developers. This section will briefly discuss application procedures for receiving FITs and the problems of speculative queuing and fraud created by capacity caps.

The application process for obtaining a FIT varies between national programs, but there are several common characteristics. Generally, an RE generator must obtain a license or permit from a regulatory authority and provide various information about the project, including, for instance, evidence of valid title to the site, the project's environmental impact, and funding. The application might also be contingent on providing security. Subsequently, the RE generator contracts directly with the utility or grid operator that manages its service area to sell electricity in exchange for the FIT. However, the establishment of the tariff rate varies by program. For instance, in South Africa the tariff is set based on when NERSA issues the RE generator a production license, whereas in Ontario the RE generator receives an electronic time stamp upon submitting a standard application thereby locking in the tariff (NERSA, 2009, p.6; OPA, July Draft Rules, p.6).

A transparent application process is particularly important when there is a cap on the amount of capacity that is eligible for a certain FIT. If an RE developer successfully applies for a FIT through a program with a capacity cap, he or she can lock in a higher tariff even if the program subsequently bars further application or degresses the rate provided to new applicants. FITs cannot be awarded until there is actual electricity generation, so this procedure protects against delays between permitting and construction. For instance, Greece provides that RE developers who sign a grid connection agreement in 2009 can lock in the current tariff for eighteen months, even after the rate degresses in August 2010, to allow them to complete installation (HELAPCO, 2009). However, this procedure can also lead to *speculative queuing*, in which developers rush into projects without having done much legwork (Couture et al., 2009, p.59). Additionally, depending on what is required to lock in a FIT, the time required to obtain actual interconnection to the grid may be longer than any grace period provided.

One potential solution to the problem of speculative queuing is to require developers seeking FITs to pay deposits when they get in line. For instance, Ontario's draft rules suggest that a non-refundable fee of CAN$500-$5,000 as well as a CAN$20,000/MW refundable deposit will be required for PV installations (OPA, July Draft Rules, p.3). Yet while Spain's 2007 amendments to its FIT required a deposit of €20/kW for RE interconnection in general and €500/kW for PV plants, the country's program has become, in the last few years, an unfortunate example of what not to do in FIT cap design (Gonzalez, 2008, p.2927). To limit the impact on ratepayers, Spain originally capped PV capacity at 400 MW for 2007 to 2010, but 344 MW were already installed by September 2007 (Wang, Spain Approves 500 MW for Solar, 2008). In 2008, it increased the cap to 500 MW for 2009 and 460 MW for 2010. However, approximately 3.1 GW of solar power were installed in Spain in 2008, drastically surpassing the cap and thus much of it not eligible for FITs (Wang, Spain Installed More Than 3 GW of Solar in 2008, 2009).[23] At the same time, tariffs of about 0.45 €/kWh decreased to closer to 0.32 €/kWh in September 2008, leading to a frenzied attempt to complete PV projects in time to receive the higher tariff. In the rush, some developers appear to have claimed their projects were complete even though they were only partially-finished or contained fake panels (Wang, Solar Fraud Could Eliminate Spanish Market, 2008). According to Spain's National Energy Commission, only ninety-seven out of 287 recent solar farms seeking the higher tariff—about 44%—were legally finished by September 2008. This is especially problematic because it is possible that delayed or fraudulent PV installations that did not meet the September 2008 cut-off will get first priority to gain FITs under the 500 MW cap for 2009, meaning that the cap might already be filled. Furthermore, the development frenzy made PV sufficiently valuable that six government employees were found to have illegally granted permits to their relatives.

2.6.4 Reactions of Utilities and Communities

The creation of a FIT program may lead to a combative response from utilities, communities in which RE plants are sited, or both. Germany's 1990 FIT law barred utilities from receiving FITs if they owned shares amounting to more than 25% of an RE plant, providing exemptions only if the plant was located outside the utility service area (Stenzel & Frenzel, 2008, p.2649-50). By 2000 this policy was replaced with a participatory model for utilities, but in the meantime it generated animosity in the form of political lobbying and even a failed suit in the European Court of Justice. Because the utilities managed the grids and electricity consumption did not increase substantially during that time period, the purchase obligation for RE electricity displaced conventional electricity that the utilities had been providing. In contrast, Spanish utilities were encouraged to develop small RE installations, and dealt with an independent grid operator (Stenzel & Frenzel, 2008, p.2654). Where the German utilities initially fought the FIT, the Spanish utilities embraced it.

FIT programs can also spur conflict among individuals in communities who live near RE plants. Wind turbines and other RE technologies can lead to "not in my backyard" (NIMBY) reactions, even from people who otherwise support renewable energy development. Particularly when the plants are installed by large, impersonal companies, as occurred in the UK, local opposition may thrive (Meyer, 2007, p.351; Stenzel & Frenzel, 2008, p.2648). However, this problem can be addressed in two ways. The first is by differentiating tariffs based on resource intensity, e.g.,

[23] However, only 2 GW have been connected to the grid, and the figure might not account for fraud.

through the use of the German "reference turbine" model. This process incentivizes RE development in areas with less readily-available resources, ensuring that the regions with the strongest resources are not inundated with installations. The second approach is by actively promoting local cooperative ownership, as has been done in Denmark with wind turbines (Meyer, 2007, p.360). These issues might be best addressed at the outset through a stakeholder discussion process like that being attempted by the Ontario Power Authority, which hosts frequent public workshops where it gathers comments on the development of its FIT program (OPA, Stakeholder Engagement Sessions, 2009).

3.0 Financial Incentive and Regulatory Policy Alternatives to FITs

States have experimented widely with policy design to encourage the development of solar electricity generation. Although individual components of these policies vary from state to state, they generally fall into two broad categories: financial incentives or regulatory policies such as RPS set-asides. An excellent compilation may be found in the Database of State Incentives for Renewables and Efficiency (DSIRE).[24] Incentive-based and regulatory programs in the United States cover two main forms of solar technology for distributed generation: (1) solar PV; and (2) solar thermal. Concentrated solar power is generally regarded as centralized utility scale generation and thus will not be discussed within this section. Since the purpose of this investigation is in part to analyze alternative approaches used to encourage solar development, the following descriptions will be confined to incentive and regulatory policies that specifically address electricity generated from solar PV technologies, and how they cooperate or conflict with FITs.

3.1 Types of Alternative Incentive and Regulatory Programs

The top ten states for cumulative grid-installed solar PV through 2008, as compiled by the Interstate Renewable Energy Council, were sampled for their solar financial incentives and regulatory policies (Sherwood, 2009, p. 9). This list includes Arizona, California, Connecticut, Hawaii, Nevada, New Jersey, New York, North Carolina, and Oregon. Colorado ranks third on this list with 36MW of grid-connected PV cumulative installed capacity, representing 5% of the nation's overall market share.

This section includes a sampling of the programs these ten states have offered to encourage development of solar generation that may be regarded as an alternative to a feed-in tariff. Accordingly, financial incentives and regulatory policies that are complementary, not necessarily competitors to a FIT, such as state-level income tax credits and deductions, state and local sales and use tax waivers, local-level property tax waivers, and state-sponsored public benefit funds are discussed in appendix A. However, where a policy is discussed in this section, it does not necessarily imply that it cannot co-exist with a FIT, it only means that it is more likely to be seen as a competing or perhaps a complementary approach (see Section 3.4 for a discussion of how/if these policies can cooperatively mesh with a FIT). This section also discusses currently enacted Colorado and federal incentive and regulatory programs available to investors in Colorado.

[24] See www.dsireusa.org, an online database maintained by the U.S. Department of Energy, North Carolina Solar Center, and the Interstate Renewable Energy Council (IREC) of state programs in renewable energy and energy efficiency.

3.1.1 Financial Incentives—Cash-Based Incentives

The goal of a financial incentive, in the present context, is to foster the development and deployment of solar technology. The following incentives supply the system owner with a payment to offset the system's materials and installation costs and may be paid in a lump sum or throughout the system's lifetime. The amount of the payment may be based upon the system's installed capacity, actual output per kilowatt-hour of electricity generated, or for the RECs produced along with the electricity. This discussion is focused predominantly on state-sponsored financial incentives, though the actual payment may be made by a utility.

3.1.1.1 Rebates

Rebates for solar PV are primarily used to encourage the installation of new capacity and are delivered to the system's owner after installation to offset up-front costs already incurred. The majority of programs providing support for the installation of solar PV are administered by states, investor-owned utilities (IOUs), municipally-owned utilities (MOUs), and occasionally by rural electric associations (REAs). These programs vary widely, depending upon the size and type of installation and the program administrator

California has the most aggressive statewide incentive rebate program in terms of the number of different types of incentives, the total funding available, and statewide capacity goals.[25] The California Solar Initiative (CSI) aims to install 1,940 MW of new PV within the state by the end of 2016. As of July 8, 2009, an estimated 226 MW of residential solar PV has already been installed, with another 147 MW of capacity pending installation. See appendix A for a more detailed description of the CSI.

Of the other states sampled, five provide a state-sponsored rebate for the installation of solar PV. These incentive programs can typically be categorized by sector, project cap, and project capacity limits. For example, the New York State Energy Research and Development Authority (NYSERDA), the program administrator for New York's state-sponsored financial incentives, offers a rebate for the following sectors: residential, non-residential or schools, non-profit organizations (NPOs), and municipalities. The rebate ranges from \$2.00/W to \$5.00/W and is based on the sector and total project size. New York also offers a \$1.50/W bonus for Energy Star Homes and Building Integrated PV.

IOUs, MOUs, and REAs provide similar rebates. These programs can be used to acquire renewable generation and RECs to satisfy state RPS requirements, including solar and DG set asides (see Section 3.1.2.1 for a discussion of RPS set-asides).

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[25] This includes three programs: (1) the California Solar Initiative, discussed above; (2) California Energy Commission's (CEC) New Solar Homes Partnership, with a program budget of \$400 million and solar goals of 360 MW capacity of solar PV on new homes built within large IOU service areas; and (3) programs funded by municipally owned utilities (MOU), with a net budget of \$784 million and goal to install 700 MW new solar PV within their service territories. Overall, the total impact of the CSI, CEC and MOU programs is a net budget of \$3,351 million with an installed solar goal of 3,000 MW of capacity. *See* California Solar Initiative Annual Program Assessment (6/30/09) at http://docs.cpuc.ca.gov/PUBLISHED/Graphics/103173.PDF.

3.1.1.2 Grants

Similar to rebates, cash grants are intended to assist in paying down the up-front costs of installing a solar electric system. However, a grant is generally distributed to a system owner prior to the installation of the system and can even be used to encourage R&D or support commercialization (though a discussion of financial grants for these purposes is beyond the scope of this paper). Grant programs can be made available to any sector, though the majority of them are designed for larger solar installations (e.g., commercial, industrial, and government). Applications for solar electric grant programs can be competitive, with administrators assessing the viability of a project based on the overall size of the installation, energy needs of the applicant, and expected lifetime performance of the system.

Connecticut has established two capacity-based grant programs under its Clean Energy Fund (CCEF), each targeted with defraying costs for larger solar PV installations. The first, the On-Site Renewable Energy Distributed Generation Program, is available to commercial, industrial and institutional buildings. The program funds the installation not only of PV systems, but also landfill gas, wind, biomass, fuel cells, small hydroelectric, tidal and wave energy, and ocean thermal (Class I). For PV projects the incentives range from \$3.50/W to \$4.75/W, with a cap per project of \$850,000. The pay-out per solar PV project is dependent upon the type of project (e.g. whether the owner's business is for-profit), system size, and level of certification under the LEED program, a green building rating system developed by the U.S. Green Building Council. Solar PV projects are limited by a project cap of 200 kW and the overall grant payment is limited by the difference between a facility's peak demand and overall base load in the most recent 12-month period. The CCEF takes ownership of all PV system RECs.

The CCEF also established the Project 150 Initiative, which requires the state's two largest electricity distribution companies to enter into long-term purchase power agreements to acquire 150 MW of Class 1 electricity generating resources. As a result, the CCEF created this grant program to encourage Class I generators to enter into these long-term PPAs. This program has a project minimum of 1 MW capacity and a corresponding minimum grant amount of \$50,000 per project. PPAs between a distribution company and Class I generator must have been in place by October 1, 2008 and were required to include a premium of \$0.055/kWh.

NYSERDA has established a cost based, low income grant program in which a single-family household could receive a grant for up to 50% (maximum \$5,000) of the cost of installing a PV system.[26] The grant increases to 60% or \$6,000, whichever is lower, for customers of National Grid Gas. Eligibility for the program is restricted to households earning no more than 80% of the state median household income or 80% of the median household income in the county in which the building is located.[27]

[26] This low-income household grant program is available to distribution company customers paying into NYSERDA's SBC.

[27] The \$5,000 and \$6,000 project caps double where the tenants of a building with 2-4 units also qualify under the income cut-off threshold.

3.1.1.3 Production-Based Incentives

A PBI can either work in tandem with the two up-front cash incentives or replace them altogether. Generally, PBIs provide cash payments for a defined period, even up to the system's life, based on the number of kWh's of electricity it generates. As opposed to up-front cash incentives, payments are made according to the actual performance of the PV system, rather than its expected performance as predicted by capacity.[28]

Although the form of a PBI may seem similar to a FIT, there are some distinctions. First, although a FIT is a type of PBI, it is considered a subset of the overarching PBI category. Next, rates under a PBI are established up front and may not be tied to estimated costs of RE generation or to actual market prices. Though the amount of a PBI may exceed the utility's avoided costs, the adder is merely an administratively set premium meant to encourage installation of the favored form of renewable technology, rather than the contextually crafted rates more often seen with a FIT. In addition, a FIT is more likely to completely subsidize the up-front installation costs of the system through the periodic payments over its lifetime, with the potential to make a reasonable profit in the long term, whereas a PBI may not fully compensate an owner for the initial purchase and installation costs of a PV system.

In addition to the rebate programs already discussed, the California Solar Initiative offers a PBI for PV installations through the General Program. Eligible PV generators (see appendix A for CSI PBI incentive levels) may choose this incentive irrespective of the system's overall installed capacity, but any system above 50 kW automatically opts for the PBI (this threshold drops to 30 kW January 1, 2010.) The PBI is available for sixty consecutive monthly payments upon the system becoming operational. Rates for all sectors currently vary between $0.26 and $0.32/kWh. These PBI payments will continue to degress until the CSI has reached its desired capacity goal.

New Jersey has implemented a PBI centered on the acquisition of Solar RECs (SRECs) to satisfy the state's RPS solar set-aside (see Section 3.1.2.1).[29] Failure to comply with the solar requirement results in a fine for every MWh of solar electricity the retail supplier failed to acquire. For the 2008-09 reporting year, that fine was $711/MWh. The New Jersey Board of Public Utilities (NJ BPU) released the following solar alternative compliance payment (SACP) degression chart, demonstrating the cap price assessed to electricity suppliers to provide guidance for future strategic decisions:

[28] Though up-front cash based incentives do attempt to predict the expected performance of a solar PV system prior to its installation by accounting for its geographic location, tilt, orientation and shading.
[29] N.J. Stat. § 48:3-87; N.N.J.A.C. § 14:8-2.2; N.J. B.P.U. Solar Transition Order (09/12/2007)

Table 4-1: NJ BPU SREC Degression Chart

Reporting Year	SACP($/MWh)
2008-09	$711
2009-10	$693
2010-11	$675
2011-12	$658
2012-13	$641
2013-14	$625
2014-15	$609
2015-16	$594

The SACP ceiling amount for SRECs created a market for their sale by solar PV generators within the state. Brokers or aggregators purchase the SRECs from individual solar generators, who then bundle them for sale to electricity suppliers. The average price of an SREC in New Jersey for March 2009 was $467/MWh (approximately $0.47/kWh). The result of New Jersey's SACP is the registration of 63 MW of new solar PV capacity in the state since the SREC program's inception in 2007. Though these capacity increases have been hailed as a success, the NJ BPU is currently in the process of modifying its solar program to move away from a reliance on a state sponsored rebate program and toward a market based approach. In July 2008, the BPU issued an order for the state's electric distribution utilities to begin entering into long-term contracts (10-15 years in term) with new solar electricity generators, segmenting the market between systems under 50 kW and between 50-500 kW.[30]

The City of Palo Alto, California has established a REC Purchase Program similar to New Jersey's, wherein the city is the buyer and enters into long-term SREC purchase agreements with PV generators to satisfy customer demand for the solar portion of their retail green-power purchase program.[31] Each SREC is the equivalent of 1MWh of solar-generated electricity, with the municipal utility currently paying generators $50/SREC. The city anticipates that this price will fluctuate between $30/MWh and $150/MWh in the future.[32] As of June 2009, the utility had entered into a 20-year purchase agreement with Solar Power Partners, Inc who installed a 906 kW rooftop PV system at the Palo Alto campus of Roche, the international biomedical research company, which is forecasted to generate 1,400 MWh's of electricity annually.[33]

A final PBI example is the Tennessee Valley Authority's (TVA) GreenPower Switch Generation Partners Program, which purchases power from solar generators in seven states.[34] The TVA created this program to acquire "green power" for ratepayers within the utility's service area to purchase. The program offers PV, wind, low-impact hydropower, or biomass energy generators a minimum ten-year contract to provide all power generated from their system to the TVA. In

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[30] N.J. B.P.U. Solar Financing Board Order (07/30/09)
[31] Resolution 8773 (2007).
[32] See http://www.cityofpaloalto.org/civica/filebank/blobdload.asp?BlobID=9933 (accessed 9/28/09). The document contained no evidence to support this estimate of future REC prices.
[33] The City also provided Solar Power Partners, Inc with a $2,240,000 production-based incentive. See http://www.cityofpaloalto.org/depts/utl/news/details.asp?NewsID=1182&TargetID=235 (accessed 7/17/09).
[34] See http://www.tva.com/greenpowerswitch/partners/ (accessed 7/8/09).

exchange, the TVA will pay a solar PV generator $0.12/kWh above the retail rate, as well as fuel cost adjustments for all electricity generated by the system.[35] Additionally, TVA will pay the generator up to a $1,000 rebate to assist with the up-front costs of the PV installation. As of July 16, 2009, this program had 68 Generation Partner installed sites, generating 25,720 kWh per month.

3.1.2 Regulatory Policy Requirements

In contrast to financial incentives, executive orders, administrative rules, and legislation may be enacted to require that utilities comply with policy directives. This approach can be more effective than financial incentives alone for ensuring that utilities increase their renewable energy portfolios, though in practice the two are often combined.

3.1.2.1 Renewable Portfolio Standard with RECs

A renewable portfolio standard[36] requires the utilities of a state to acquire a certain percentage or amount of generating capacity of the electricity they distribute at the retail level from renewable energy sources. Compliance with an RPS may often be demonstrated by acquiring Renewable Energy Certificates (RECs), which represent the environmental attributes associated with a specified amount of renewable energy generation (e.g., 1 MWh). These RECs are then retired by a utility to demonstrate compliance with the RPS's renewable energy requirement. RPS policies will generally allow the utility to acquire the renewable energy or REC within a certain time period, and may even allow it to bank excess RECs in years in which it exceeds RPS requirements or future use.

An RPS is best suited for states that have assessed where their most cost-effective renewable resources are located and have a plan of how best to transmit energy generated from their utilization (Hurlbut, 2008, p.3), so long as they elect to require qualifying energy to be sited within that state. This encourages development within the state aimed at harnessing the energy potential of those renewable sources. However, an RPS can also be developed to allow for utilities to acquire renewable energy or RECs, with or without the associated RE, from generators located outside the state. How a state elects to address these RPS component issues depends, at least in part, on the policy motivations for implementing the standard.

Many RPSs contain a set-aside (or carve-out) requiring that a certain percentage of the RPS requirement be generated from a specific renewable source, most commonly solar or DG. Presently, twenty-nine states and the District of Columbia have passed an RPS, with eleven of those states and the District of Columbia incorporating solar set-asides of varying amounts.[37] Of the nine sampled states, all have passed statewide RPSs, with three specifically including a solar set-aside:

- Nevada: 1.5% of the state load by 2025, estimated at 180 MW;

[35] All other renewable generators receive $.03 on top of the retail rate and fuel cost adjustments for all power generated by those systems.
[36] Also commonly referred to as a Renewable Energy Standard (RES).
[37] http://www.dsireusa.org/documents/SummaryMaps/Solar_DG_RPS_map.ppt (accessed 7/28/09).

- New Jersey: 2.12% of state load by 2021, estimated at 2,300 MW; and
- North Carolina: 0.2% of state load by 2018 from solar electric and solar thermal, estimated at 280 MW.[38]

New York passed a customer-sited DG set-aside of 0.1452% of the state's total load, requiring energy generated from fuel cells, PV, wind turbines and methane digesters in amounts comparable to the normal monthly load of the customer's meter.[39] Arizona also passed a DG provision in which 30% of the RPS obligation must be satisfied by distributed RE, with half generated from residential systems and the other half from non-residential, non-utility applications.[40]

Thus far, solar set-asides have shown a great deal of promise in driving PV installation. New Jersey's set-aside has created the most growth (in conjunction with the state's SREC program). Through 2008, New Jersey was estimated to have solar electric grid-tied capacity of 70.2 MW.[41] Maryland, though not currently within the U.S. top ten for grid-tied solar electric capacity, is likely to soon join that list due to a recently added (April 2007) RPS obligation to obtain 2% of the state's total load from solar electric by 2022 (estimated at 1,500MW installed capacity of solar).[42]

Another feature states have incorporated into their RPS to encourage development of a favored renewable energy technology is a REC multiplier. A multiplier of 2, for example, allows a single REC to be counted by the compliance entity as 2 RECs for compliance purposes. In the case of solar REC multipliers, seven states and the District of Columbia have incorporated varying levels into their RPSs.[43] Within the states sampled, only Nevada and Colorado have combined a REC multiplier with a solar set-aside, though Colorado's set-aside requirement (4% of the annual RPS requirement) is imposed only on the state's two IOU's and the multiplier is available only for REAs and MOUs.[44] In recent years, REC multipliers have become less popular (Wiser and Barbose, 2008, p.16), with only two states (Texas and Washington) using solely a REC multiplier without also requiring a solar set-aside to encourage development.[45] Most experts, and the available evidence, find REC multipliers to be an inferior method to set-asides as an incentive mechanism. One important reason is that they fail to properly account for the true differences in the installed costs of respective renewable technologies.

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[38] N.R.S. 704.7801 though 701.7828 (2006); N.J.A.C. § 14:8-1.1 through $14.8-2.12 (2001); N.C. Gen. Stat. § 62-133.8 (2007).
[39] N.Y. P.S.C. Order, Case 03-E-0188 (2004).
[40] A.A.C. § 14-2-1801 through §14-2-1816 (2006).
[41]New Jersey qualifies for 2nd highest amongst states, with California first with 530.1 MW of grid-tied solar electric capacity.
[42] Md. Pub. Util. Co. Code § 7-703 (2004).
[43] Colorado (REAs and MOUs only: 3x for solar, 1.5x for community based projects); Delaware (3x for solar not used to comply with solar carve-out obligations); District of Columbia (1.1-1.2x for solar for electricity suppliers); Michigan ((3x for all solar installations); Nevada (2.4-2.45x for customer-sited/maintained PV); Texas (2x for all non-wind); Vermont (2.4x for solar); and Washington (2x for DG).
[44] § 40-2-124(1)(a) C.R.S (2004).
[45] Neither is specifically targeted at developing solar either, with Texas' multiplier for non-wind installations and Washington for distributed generation.

Accordingly, if the intent is to increase the amount of solar capacity that is installed within a state, a solar set-aside may be the most effective RPS component to encourage such development.[46]

3.1.2.2 Net Metering

Net metering allows for customers of a utility to generate their own electricity from a solar electric generating system while still allowing them to receive electricity when needed from their utility, most typically through the use of a single, bi-directional meter. When the customer is generating more electricity than she requires, the excess is directed back to the grid. This amount is typically credited against any electricity the customer receives from the utility, which he or she must purchase at the utility's retail price. The majority of states (forty-two, as well as the District of Columbia) require utilities to allow some degree of customer net metering.[47] These policies are commonly distinguished by limits in customer type, system size, renewable technology and system application.

Each of the ten sampled states has a net metering policy. The purpose behind net metering is not necessarily to encourage large increases in solar distributed capacity. Rather, it is to ensure that owners of DG systems are able to obtain credit for the excess electricity they produce and send back to the grid. Colorado's net metering policies were recently revised and will be discussed further in section 3.3.

3.2 Federal Financial Incentives & Regulatory Policies Affecting State-level Solar Energy Generation

3.2.1 Financial Incentives

Federal incentives are worth mentioning, as they may be used in conjunction with state financial incentive and regulatory programs. Individuals and businesses can take advantage of income tax credits, grants, and loans programs to fund their solar generating systems. Many of these programs have been recently amended by the American Reconstruction and Recovery Act of 2009 (ARRA).

Federal income tax credits are available for both personal[48] and business entities[49] choosing to install solar PV systems. Each of these credits was expanded from a business energy tax credit established by the Energy Policy Act of 2005 (H.R. 1424), increasing the credit from 10% to a 30% investment tax credit ("ITC").[50] More recently both of these credits were further expanded by ARRA, lifting a $2,000 project cap for individuals and allowing business entities to elect to take the ITC or to take an up-front grant from the United States Department of Treasury for up to 30% of the basis of the solar energy property.[51]

[46] Electricity rate impact must also be considered if this course is pursued.
[47] Available at http://www.dsireusa.org/documents/SummaryMaps/Net_Metering_map.ppt (accessed 7/14/09).
[48] 26 U.S.C. § 25D.
[49] 26 U.S.C. § 48.
[50] The federal production tax credit (PTC) is not mentioned within this section as it applies only to wind and geothermal technologies.
[51] H.R. 1 (2009).

A point worth mentioning in regard to a solar property owner taking the ITC and utility incentive is that in some instances it may be unclear how certain non-federal incentives are to be treated for the purposes of valuing the ITC (Coughlin and Cory, 2009, p.14). For example, an individual participating in Xcel Energy's Solar Rewards program receives two payments: (1) an up-front rebate of $2.00/W of system capacity and (2) a REC payment of $1.50/W of system capacity (as a surrogate for the value of 20 years worth of future RECs to be generated by the system). Section 136(a) of the Internal Revenue Code states, "[g]ross income shall not include the value of any subsidy provided (directly or indirectly) by a public utility to a customer for the purchase or installation of any energy conservation measure." Therefore, the adjusted basis of the property would have to be reduced by the value of the subsidy—in this case the rebate—for the purposes of valuation of the ITC. What may be misunderstood is how to treat the REC payment. If the REC payment is determined to be a subsidy, then that must also be taken from the initial value of a solar system. However, the purchase and sale agreement signed by customers seems to indicate that this is payment for the sale of 20-years of future RECs which makes the REC payment ordinary income that must be reported but which is not excluded from the basis of the asset.

Section 168 of the Internal Revenue Code provides a Modified Accelerated Cost Recovery System, essentially allowing commercial and industrial sector solar system owners to recover the initial costs of the system through accelerated income tax deductions for depreciation. Qualifying equipment that "uses solar energy to generate electricity" must be depreciated at a five-year, 200% declining balance. In most cases, 100% of the costs of a solar PV system will qualify for this depreciation schedule. As noted previously, the initial basis of the system may vary depending upon the utility-level incentives the property owner has accepted.

There are also various federal agency grant programs available to prospective solar PV owners. In addition to the aforementioned 30% Treasury grant the Department of Agriculture's Rural Energy for America grant program may provide up to 25% of project costs to qualified business and government entities.[52]

Finally, there are federal financing incentives that offer favorable loan terms for prospective solar PV owners. The Clean Renewable Energy Bond program can help non-taxable entities and public power providers, who are otherwise unable to access the ITC and PTC, obtain financing for renewable projects.[53] The incentive program allows these entities to obtain the equivalent of a zero-interest loan, when various transaction costs are ignored (Bolinger, 2009, p.7). Energy Efficient Mortgages are available to residential homeowners and provide funding at approximately 5% interest levels.[54] Finally, the Department of Energy has established a financing program for large-scale renewable projects.[55] The goal of this program is to encourage early commercial use of new or significantly improved technologies in energy projects.

[52] 7 USC § 8106 (2002).
[53] 26 U.S.C. § 54B (2008) ; 26 U.S.C. §54C (2008).
[54] Available at http://www.resnet.us/ratings/mortgages (accessed 7/29/09).
[55] 42 U.S.C. § 16511; H.R. 1 (2009).

3.2.2 Regulatory Policies—PURPA

The Public Utility Regulatory Policies Act (PURPA) was passed as part of the National Energy Act of 1978.[56] The intention behind PURPA was to increase renewable energy generation at a time when electricity prices were high, and it did this by requiring utilities to buy electricity from independent renewable energy and co-generation plants. Prior to PURPA, utilities were vertical in structure as they self-generated the majority of the electricity they distributed, so their costs to ratepayers were based on their cost-of-generation. However, PURPA required utilities to purchase electricity generated from renewable resources based on the utilities' "avoided costs" (e.g. the cost that the utility would pay for generating its own power or acquiring it from another source). Calculation of avoided costs was left to the discretion of the individual states, with certain guidelines on how to forecast future costs.[57] Certain states, such as California and New York, chose to calculate the value of avoided-cost based on long-term estimates of future generation costs, while other states elected for a scheme in which utilities were required to enter into long-term contracts with these independent power producers.

Problems under PURPA arose during the 1990s when the avoided costs of utilities began to plummet as they switched from coal to then-inexpensive natural gas. Because these utilities were still obligated to these long-term purchase contracts, their retail rates were unduly inflated from what they would have charged their retail customers if the electricity they were distributing was only from gas generation. Accordingly, a negative association attached to PURPA due to this expensive burden placed on ratepayers. Certain analysts have claimed that PURPA is a predecessor to European FITs (Rickerson and Grace, 2007, p.13), making the idea of adopting a FIT an uncomfortable thought for present-day utilities, policy makers and regulators.

There are distinctions that can be made between present-day FITs and the avoided-costs calculation of PURPA in the 1980's which help to alleviate much of this negative connotation. First, there has been a societal shift recognizing that a premium must be paid for renewable energy. At the time many of PURPA's long-term contracts were entered into, ratepayers were seeking lower rates and did not place a value on the environmental benefits of renewable energy. Additionally, these technologies have not yet become cost competitive with most fossil fuel generation. While some renewables are approaching grid parity, their intermittent nature adds to their competitive disadvantage relative to baseload fossil fueled generation.

FITs can be designed to ensure that long-term power purchase contracts signed under a FIT do not overly burden retail rates. For example, states may place caps on individual project and overall program sizes as a way of limiting increases on overall retail rates. And, unlike PURPA, FIT rates can be periodically adjusted (degression) to capitalize on cost reductions due to technological advance and deployment experience.

Thus, although FITs have been burdened with a negative perception as a result of similarities to the avoided costs contracts signed under PURPA, a present-day FIT may be designed to avoid those pitfalls.

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[56] 16 U.S.C. §§ 2601-2645 (1978).

[57] See Section 4.1 on Jurisdiction for a further discussion on factors for states to consider when calculating utility avoided costs.

3.3 Colorado's Current Solar Energy Generation Financial Incentives and Regulatory Requirements

3.3.1 Financial Incentives

Colorado does not presently offer any state-administered cash incentives for solar PV installations. However, as part of the state's RES, each of the state's IOUs, Public Service Company of Colorado[58] (as a part of Xcel Energy's Solar*Rewards Program) and Black Hills/Colorado Electric,[59] must provide a Standard Rebate Offer (SRO) for customers within their service territory with an installed capacity size of 500 kW or less. The SRO consists of a $2.00/W rebate plus a capacity-based REC payment presently set at $1.50/W (for systems up to 10 kW) or a REC payment of $110/MWh paid monthly for larger systems. These incentive payments are funded through a Renewable Energy Standard Adjustment (RESA), a rate-rider presently set at 2% of a customer's total electric bill. Three of the state's REAs (Holy Cross Energy, La Plata Electric Association, and Southeast Colorado Power Association) and one MOU (Colorado Springs Utilities) also offer a rebate for solar PV installations. The city of Boulder, Colorado offers a grant program for low- to middle-income individuals in single and multi-family homes and non-profit facilities, through which up to 50% of the total project costs may be covered.[60]

Colorado has also instituted a local option financing program, similar to one in Berkeley, California, in which a homeowner can finance the installation costs of a solar PV system and pay back the loan through an increased property tax evaluation over a set period of years.[61] To participate in the program, an individual must live within a Clean Energy Finance District, which is created by voter approval. Upon approval, the local government must then propose financing measures, which then must be endorsed by the State Treasurer. Boulder County became the first in the state to implement this financing incentive with its ClimateSmart Loan Program.[62]

3.3.2 Regulatory Policies

The current version of Colorado's RES, requires the state's IOUs to generate or purchase 20% of the electricity they sell at the retail level from renewable sources by 2020.[63] Four percent of the standard must be generated from solar electric technologies, with half of that coming from customer-sited generation. Additionally, MOUs serving more than 40,000 customers and all REAs are required to acquire 10% of the electricity from renewable sources by 2020, but have no solar set-aside. Compliance with the RES comes from the acquisition and retiring of RECs, which may be acquired from out-of-state generators.

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[58] http://www.xcelenergy.com/RESIDENTIAL/RENEWABLEENERGY/SOLAR_REWARDS/Pages/home (accessed 7/28/09).
[59] http://solarrebates.blackhillsenergy.com.
[60] http://www.bouldercolorado.gov/index.php?option=com_content&task=view&id=7700&Itemid=2845 (accessed 7/28/09).
[61] § 1-24-38.7 C.R.S (2008).
[62] http://www.beclimatesmart.com/ (accessed 9/18/09).
[63] § 40-2-124 (2007).

Colorado's net metering program was recently updated by the state legislature and is scheduled to take effect on September 1, 2009.[64] SB 09-051, which applies only to installations within the service territories of the state's two IOUs, changed the renewable energy system size from a cap of 2 MW to a maximum capacity of 120% of the average annual electricity consumption at that site.[65] Additionally, the bill redefined an eligible property as including all contiguous property owned by the consumer. Furthermore, a renewable energy system owner is now able to make a one-time election to have his annual net excess generation carried forward as a credit from month-to-month indefinitely, rather than being automatically paid annually for the average hourly incremental cost of the excess generation for the year. Once this election has been made, the customer may not revert back to the previous credit payment method. Municipal utilities serving at least 5,000 customers and all rural electric cooperatives must also offer net metering but at a reduced scale.[66]

3.4 Interaction of FITs with Other Incentives and Regulatory Policies

This section will discuss the practicality of implementing FITs in conjunction with other regulatory or incentive programs, including RPSs, RECs, tenders, rebates, grants, PBIs, tax-based incentives, financing, and net metering. While all of these options can help with the cultivation of RE resources, RPSs, tenders, tax-based incentives, and financing options seem to be compatible with FITs whereas RECs, cash-based incentives, and net metering must be adjusted if a feed-in tariff is also to be available. Unlike Europe, where multiple incentive programs may be offered in conjunction, many passed or attempted U.S. FIT laws provide for a cap on the amount that an RE generator can obtain by specifying that, where other incentives are available, the FIT payment should be reduced proportionately.

3.4.1 Renewable Portfolio Standards

European commentators have written extensively about whether FITs and RPSs can interact, largely because the European Commission pushed to harmonize RE incentive programs among member states, starting with Directive 2001/77/EC (art. 4). At this time, the EC has suggested that full harmonization—i.e., making a choice to consistently implement throughout the EU either FIT programs or national RPSs with tradable green certificates (TGC, the European term for RECs)—is unnecessary because both types of programs require more study. In fact, the majority of EU member states apply both renewable obligations and FITs simultaneously.

Despite numerous discussions about whether FITs can interact with RPSs on a policy level, they frequently operate in conjunction with each other in practice, particularly in Europe but also in the U.S. States that enact an RPS may require utilities under their jurisdiction to obtain minimum percentages of renewable electricity out of the total amount of electricity they sell. Utilities may choose to install their own RE generation, obtain it from independent power

[64] S.B. 09-051 (signed April 2009).

[65] H.B. 08-1160 (codified within §40-2-124 C.R.S.) requires all MOU's with more than 5,000 customers and all REA's to offer net metering, with a 10 kW project cap for residential and 25 kW project cap for commercial and industrial installations.

[66] § 40-2-124 C.R.S. (2005); 4 C.C.R. 723-3, Rule 3664 (2005); § 40-9.5-118 C.R.S. (2008).

producers, or purchase RECs from in- or out-of-state. See Sections 3.1.2.1 and 3.3.2 for Colorado's requirements.

RECs add complexities to the coexistence of RPSs and FITs, but the existence of a general RE generation mandate would appear to work in favor of FITs rather than against them. There are several suggestions for how an RPS and a FIT can work together to increase RE capacity, operating either in parallel or in conjunction with each other. First, utilities may be provided with an option to acquire resources via either a FIT or a conventional solicitation process. In this manner, FITs could provide a "safety net" for RE projects that fail to meet the least-cost or similar bidding requirements by guaranteeing a source of revenue for the developer. FITs could also be targeted toward specific technologies or ownership models (Grace et al., 2008, p.67-69).

One risk that does exist if an RPS coexists with a generous FIT program is that if the RPS percentage requirement is high, the costs passed through to the ratepayers will also be high. And allowing utilities to purchase and bank RECs may result in lower compliance costs than if utilities are obligated to purchase renewable generation under a high FIT. One solution to the problem of rates increasing beyond acceptable levels may be a cap on the amount of renewable generation that a utility must acquire under the FIT.

3.4.2 Renewable Energy Credits

The interaction between RECs and FITs is one of the most challenging aspects of developing a comprehensive RE incentive program because of the risk of double-counting and windfall compensation. Variations in the definition and ownership of environmental attributes may further complicate program design.

3.4.2.1 Defining RECs and Environmental Attributes

Renewable electricity is composed of both the electricity itself and its "green" attributes, which are themselves tradable commodities. These environmental attributes are intangible, but are generally included in the definition of a REC. Each REC, which is created as a result of the generation of one megawatt-hour of electricity from renewable resources, can be sold unbundled as a separate commodity from the actual electricity generated. Where REC markets operate, renewable electricity cannot be accurately described "renewable" unless it is bundled with a REC (Holt & Bird, 2005, p.7).

As will be discussed in sections 3.4.2.2 and 4.1.2, FERC explicitly stated that RECs are creations of the states, which may define the attributes they include and allocate ownership rights between RE generators and utilities (105 FERC ¶ 61,004 ¶¶ 23-24). Therefore, decisions about the environmental benefit attributed to a REC are made by each state, and can influence the relative prices of RECs throughout the U.S. and their marketability.

The most common definition of a REC vaguely describes it as a commoditization of environmental attributes associated with RE generation, including the creation of positive externalities and the reduction of negative ones. For instance, Colorado's RES rules define a REC as

> "…a contractual right to the full set of non-energy attributes, including any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, directly attributable to a specific amount of electric energy generated from an eligible energy resource. One REC results from one megawatt-hour of electric energy generated from an eligible energy resource (4 CCR 723-3 § 3652)."

However, some existing or proposed FIT programs and contracts in the U.S. use the terms "environmental attributes" or "green attributes" instead of RECs. This form of usage frequently indicates that environmental attributes include RECs, but RECs are not the exclusive commoditization of the environmental attributes. For instance, PG&E's Small Renewable Generator PPA defines "green attributes" as RECs and avoided emissions of air, water, or soil pollutants and GHGs (Sample Form No. 79-1103, 2009, §3.1).[67] The definition used in the most recent FIT contract offered by Gainesville Regional Utilities (GRU) defines "environmental attributes" as

> "any and all regulatory credit or market value accrued as the result of generating solar energy, including but not limited to renewable energy credits, carbon offsets, SO_2 and NOx emission offsets, and any other environmental benefits, reductions, offsets, allowances, certificates, or green tags resulting from the generation of Solar Energy or the avoidance of the emissions of any gas, chemical or other substance to the air attributable to the electricity generated by the Facility (SEPA V072209 § 1.2)."[68]

These definitions leave open the possibility that the tradable environmental benefits and reductions associated with renewable electricity generation can be parsed out. For example, carbon offsets theoretically could be disaggregated from RE generation and traded on a different market than the REC. Whether disaggregation is viable is a state-by-state decision, unless Congress decides otherwise in the process of implementing federal climate change legislation. Under the version of the Waxman-Markey bill that emerged from the House earlier this year, electric utilities may be responsible for procuring both RECs and carbon dioxide allowances, potentially leading to double-counting. Moreover, while FERC will define qualifications for national RECs, the EPA has responsibility for determining offset eligibility—this division of labor could lead to certain types of projects becoming eligible for both categories and thus increasing the risk of double-counting.

3.4.2.2 Allocating Ownership

REC definitions become legally problematic for FITs because they can lead to questions of ownership. The first problem is that multiple parties may lay claim to all or part of the same unit of renewable electricity, creating a liability risk under both consumer protection and contract law. Consumer protection might be invoked if, for instance, a state provides that utilities obtain RECs with power purchases but an RE generator continues to claim its electricity output is

[67] *Available at* http://www.pge.com/tariffs/tm2/pdf/ELEC_FORMS_79-1103.pdf.
[68] *Available at* http://www.gru.com/Pdf/futurePower/Sample%20SEPA%207-22-09.pdf.

"green." Consumer protection law is largely irrelevant for the purposes of this discussion unless the RECs are sold to consumers under a voluntary green pricing program. However, contract remedies may be available between the utility and the RE generator depending on the scope of the power purchase agreement.

The second problem is the risk that a utility may have to compensate an RE generator twice for the same quantity of electricity, at the expense of ratepayers: first, by providing the FIT payment per kWh for all generation, and second by separately purchasing RECs if the utility is obligated to fulfill a state RPS requirement. Alternatively, the RE generator could receive a FIT payment and then trade the REC, resulting in double compensation. This latter problem may occur particularly where REC definitions vary between states and trading is allowed. This is more of a policy issue than a legal impediment.

According to the FERC, state law rather than contracts entered into subject to PURPA serve to allocate REC ownership rights (¶ 24 ("[w]hile a state may decide that a sale of power at wholesale automatically transfers ownership of the state-created RECs, that requirement must find its authority in state law, not PURPA")). Subsequently, only a few states have made determinations regarding REC ownership. The Connecticut Department of Public Utility Control (CDPUC) held that it approved a long-term power purchase agreement between a utility and a landfill-gas electricity generator based on its determination that landfill gas was a renewable resource, meaning that it contemplated the transfer of renewable attributes as part of the contract (Docket No. 96-07-21RE01, Mar. 19, 2004, p.13-15).

Most FIT bills in the U.S. that have been proposed, passed, or failed have provided that utilities contracting with RE generators will receive the RECs. GRU's contract states that it will purchase environmental attributes bundled with electricity from RE generators (GRU, SEPA, 2009, p.1). Vermont and Oregon specify that retail electric suppliers that purchase renewable electricity also receive RECs that can be used toward RPS compliance (H446, 2009, p.9-10; HB 3039, 2009, p.3). Vermont, moreover, allows the public service board to authorize the project facilitator to purchase environmental attributes from projects receiving the FIT and then to resell them based on the board's requirements (H446, 2009, §4.315). However, bills in Hawaii and Washington have awarded RECs to RE generators, and Ontario allows the parties to contract for this arrangement (SB 1196, 2009, §269-O; SB 5101, 2005, §3(9); OPA, Draft Contract, June 2009, §2.10). New York, on the other hand, denies that RECs are created for any party under FIT contracts—instead, it directly counts renewable electricity purchased under those contracts toward the parties' RPS obligations (S2715, p.6).

An example might better illustrate the policy conflict where FITs and RECs coexist. If the state of Hawaii implements its FIT bill awarding RECs to RE generators, those generators could trade their RECs to utilities in other states that need them for voluntary or compliance programs. Because Colorado's RES does not limit the location of origin of the RECs purchased by qualifying utilities, Colorado utilities could pay Hawaiian RE generators a price for RECs in addition to the guaranteed amount that the generators already receive from their own utility. An identical concern was expressed in the 2007 Public Service Company of Colorado RES

Compliance Plan docket when the utility purchased RECs from California resources that had already received incentive payments under the California Solar Initiative.[69]

In addition to the policy problem of providing windfall profits to RE generators at the expense of ratepayers, the decision to pay RE generators who have already been compensated for the environmental benefits of their electricity may not be prudent (4 CCR 723-3 § 3613). However, further information on this subject is needed.

3.4.2.3 Strategies to Increase Compatibility Between RECs and FITs

There may be ways to make RECs and FITs more compatible. The most obvious way is to provide that utilities that purchase renewable electricity receive all RECs bundled with it. Typically, contracts specify that the utility that purchases renewable electricity in exchange for a FIT will receive RECs; it can then pass the cost through to its ratepayers. This arrangement avoids double payments to RE generators in the form of both the FIT and the tradable REC. Assuming that the FIT is designed with an appropriate rate of return built in, the generator should have no need for the additional compensation. An alternative is to reduce the FIT payment by an amount proportionate to the benefit that may be received by the REC, just as may be done with an RE project that is eligible for federal or state incentives. However, that process adds a layer of administrative complexity that may be untenable because the market-based nature of RECs, and the variable definitions of RECs across state lines, means that prices may be difficult to predict. For the same reason, though—the potential for the REC market to shift prices quickly—RE generators may not receive compensation for RECs in tune with market prices because FITs are generally only revised every few years.

Another approach would utilize FITs and RECs at different stages in the same RE investment program. FITs would be used to stimulate less economically-efficient technologies to make them competitive with cheaper renewables and conventional electricity. When they later obtain that level of efficiency, they could then enter the REC market (Midttun & Gautesan, 2007, p.1419-22).

Accordingly, while RECs and FITs do not initially appear compatible, a clear delineation of what attributes are included in a REC, how they are allocated at state law and in contracts, and how they are counted for purposes of compliance, can help align the two policies.

3.4.3 Tenders

Tenders are structured like auctions, and offer the chance for RE developers to bid to develop certain amounts of capacity. Once the capacity is offered, the developers can accept and then receive a fixed payment for their generation. France, Ireland, and Latvia provide tender programs wherein they offer special FIT rates for RE installations (RES-Legal, 2009). Theoretically, the use of tenders should not conflict with FITs; rather, they can provide a clear application process for RE developers. The structure of the FIT would be slightly different because the purchase obligation would not kick in until the contract was awarded, as opposed to

[69] Answer Testimony of Richard P. Mignogna, PUC Staff, Docket 06A-478E, p.37-38 (addressing Public Service Company of Colorado's application for approval of its 2007 RES compliance plan).

the typical FIT structure of providing a purchase obligation for any RE generator that can fulfill basic requirements.

However, the selection of RE projects based solely on least cost can be problematic. For instance, the UK's non-fossil fuel obligation (NFFO) offered a series of auctions from 1990 to 1998 to select wind farm developers. Despite awarding almost 1000 MW of capacity during that time, only about 161 MW were actually installed—a contract failure rate of 83%. The focus on cost as the sole means of selection meant that large developers frequently underbid smaller community developers who might have been more effective in combating NIMBYism. Local objections and thin profit margins therefore defeated many projects (Stenzel, 2008, p.2648). However, a well-structured tender program with clear rules and considerations other than cost could be applied alongside a FIT. For instance, Colorado's RES rules allow IOUs to use competitive bidding for solar projects greater than 100 kW and to consider environmental impacts, transmission capacity, project viability, and other factors in awarding the bid (4 CCR 723-3 § 3655).

3.4.4 Tax-Based and Cash-Based Incentives

Tax-based and cash-based incentives, the latter of which includes grants, rebates, and PBIs (see section 3.1), are problematic for FITs because they can be used to dramatically increase funding for RE generation beyond what was intended within the FIT design. Because one conflict inherent in FIT design is the balance between subsidizing RE capacity installation and avoiding providing developers with windfall profits, the availability of additional incentives can tip the balance to overpaying RE generators beyond an economically efficient level. While FITs provide payback over the life of a project, tax- and cash-based incentives can reduce up-front costs, making a long-term contract less imperative. As a result, some states and countries prohibit RE generators from obtaining FITs and other incentives at the same time. For instance, a Hawaii bill would bar recipients of income tax credits or PV rebates from receiving FITs (SB 1196 § 269-S).

Other FIT programs simply include the possibility of obtaining other incentives as one of the factors to be considered in setting the tariff rates, and may lower those rates accordingly. Failed bills in Indiana and Illinois would have required rate reductions proportional to state or federal incentives, and California's AB 1106 is structured similarly. While H446 in Vermont allows the state public service board to proportionately decrease rates based on other incentives, the availability of RECs does not count as an incentive that can be used to decrease the tariff (§ (b)(2)(B)(i)(I)). These actions can help protect ratepayers from inordinate rate impact. On the other hand, allowing both FITs and other incentives can provide extra benefits to RE developers engaging in expensive projects. A failed Minnesota bill, for instance, exempted PV installations from the proportional tariff reduction and allowed them to obtain other incentives on top of a FIT (HF 932 subdiv. 6).

The experience in Europe has been mixed. While Germany has explicitly allowed RE generators to receive subsidies on top of administratively-set FITs, Denmark's initial policy of providing carbon tax rebates to RE generators in addition to FITs led to high costs that caused it to rethink its program (see section 1.3.1).

3.4.5 Loan Programs

At first glance, loan programs appear to provide similar conflicts with FITs as do tax-based and cash-based incentives. However, instead of reducing up-front costs, they reduce up-front risk by providing low-interest loans. Therefore, FITs that adjust for inflation or provide for certain rates of return could become windfalls for developers who have already received low-interest loans on their projects. As with other types of incentives, the FIT payment could, theoretically, be adjusted to compensate for the other benefits provided to the RE developer.

3.4.6 Net Metering

Many states, and a collection of utilities and municipalities, offer net metering programs (DSIRE, 2009).[70] Net metering is frequently allowed as an alternative to a FIT program for smaller projects, especially residential. California AB 1106 offers net metering as an option for generators of 5 MW or less (§399.21(a)(3)(A)(i)) and Italy offers it for plants under 20 kW (RES-Legal, 2009). The UK appears to be the only country that has suggested a mixed FIT/net-metering program. Its newly-released program offers a payment based on all generation rather than what is exported into the grid: in other words, a "gross FIT" that provides a fixed rate for all electricity produced regardless of whether it is used on-site, as well as a bonus for every kWh that is fed back into the grid.[71] Although this type of program may increase on-site efficiency and increase the amount of electricity fed into the grid, it has been criticized as expensive. For that reason, Victoria, Australia has resisted calls for gross metering in favor of a "net FIT" scheme that would provide payments only for the net electricity that is returned to the grid.[72] While the same incentive for on-site efficiency exists under this scheme, the dramatically lower overall payments have led to concerns that the FIT design is insufficient to stimulate distributed generation. Therefore, even though some countries are attempting to operate net metering and FITs together, in general they are mutually exclusive systems.

4.0 Legal Issues with FITs

This section considers several specific legal issues related to FIT enactment, both in general and from a Colorado-specific standpoint. These issues include jurisdiction, utility applicability, and Colorado's retail rate impact restriction for additional RE procured for compliance with the state's RPS.

4.1 Jurisdiction

Federal pre-emption is a jurisdictional concern that must be addressed since wholesale rate-setting is almost exclusively a federal activity, due to its impact on interstate commerce. In particular, rates for RE generation in a FIT are generally in excess of a utility's avoided cost of generation. In Colorado, the utility avoided cost would tend to be based on the generation of electricity from fossil fuels. The increased rates under a FIT raise the specter of federal

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[70] http://www.dsireusa.org/summarytables/rrpre.cfm

[71] RE Financial Incentives Consultation, p.63-69, available from http://www.decc.gov.uk/en/content/cms/consultations/elec_financial/elec_financial.aspx.

[72] http://www.theage.com.au/national/brumbys-solar-scheme-a-dud-say-state-officials-20090128-7s0k.html

preemption, as 16 U.S.C. § 824 delegates to the Federal Energy Regulatory Commission (FERC) almost exclusive jurisdiction for wholesale rate-setting, which is defined as the "sale of electric energy to any person for resale." Herein lies the potential jurisdictional conflict: renewable generators are selling their power to utilities, which are then re-selling that same power to their retail customers. If states are to require their incumbent utilities to offer state-set tariffs to RE generators, a legal foundation must be established showing the tariffs are not preempted by FERC jurisdiction. A state would likely have two grounds to base their authority to establish price levels under a FIT program, either under PURPA or by setting the price for RECs.

4.1.1 PURPA Avoided Cost

The first of these would be to justify the FIT rate structure under PURPA. PURPA allows individual states to set rates for their utilities to purchase power from a qualifying facility (QF), most commonly a cogeneration facility or a small power producer.[73] The rate setting requirements for states of QF-utility power purchases are defined rather loosely, stating that the rate a utility must purchase power from a QF must:

(1) Be just and reasonable to consumers;
(2) Be in the public interest;
(3) Not discriminate against QFs; and
(4) Not exceed the purchaser's incremental alternative cost.[74]

This incremental alternative cost is more commonly known as a utility's "avoided cost," which is defined as "the cost to the electric utility of the electric energy which, but for the purchase from such . . . [QF], such utility would generate or purchase from another source."[75] Colorado's implementation of PURPA has used a similar definition for a utility's avoided cost.[76]

Within PURPA's statutory framework, the FERC has afforded states a wide degree of latitude in setting avoided cost rates. Given that rate setting is a particularly nuanced exercise and many utility-QF power purchase agreements are entered into long-term, it seems appropriate for the FERC to defer to states when setting these rates in conjunction with fulfilling particular state policy goals. Moreover, the FERC permits an avoided cost calculation in which the forecast of long-term costs differs from a utility's avoided cost at the time of actual delivery.[77] In fact, the following factors, pursuant to 18 C.F.R. §292.304(e), have been issued to guide states when setting avoided cost rates:

(1) Data regarding the utility's cost structure and plans to add capacity;

(2) The availability of capacity or energy from a qualifying facility during daily and seasonal peak periods, including:

[73] See 18 C.F.R. §§ 292.203(a), 292.204[73], 292.205, and 292.207 for size, fuel use, energy output and certification requirements.
[74] 16 U.S.C. §824a-3(b)
[75] 16 U.S.C. § 824a-3(d)
[76] Rule 3901(a), 4 C.C.R. 723-3.
[77] 18 C.F.R. §292.304(b)(5)

(i) The ability of the utility to dispatch the qualifying facility;
(ii) The reliability of the QF;
(iii) Contract terms;
(iv) The extent to which scheduled outages of the qualifying facility can be coordinated with scheduled outages of the utility's facilities;
(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies;
(vi) The individual and aggregate value of energy and capacity from QFs on the electric utility's system;
(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from QFs.

(3) The relationship of the availability of energy or capacity from the QF to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use;

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

This list should not be considered exhaustive, given the FERC's stated position to allow states a wide degree of deference when setting utility avoided costs.

The above factors can be applied to solar PV in justifying a FIT rate for solar PV generators. With respect to factor two, solar PV is ideal for contributing electricity during peak times. Sunshine, or in particular solar radiation, is a reliable resource in Colorado, and is most often available during peak times [factor 2(ii)]. Solar PV can also be taken offline [factor 2(iv)], and placed back on-line for use during system emergencies [factor 2(v)]. Additionally, considering Colorado's RPS, and in particular its customer-sited solar requirement, a high aggregate value should attach for all energy these systems produce [factor 2(vi)]. Finally, capacity additions from solar energy generating sources can be installed at set quantities, depending upon the size of program goals and lead time for RE generators to get their system online, these capacity additions could be much faster than fossil fuel capacity additions [factor vii].

Similar to factor three, PURPA's original intent was to encourage the development of smaller generators, which may tend to have a greater degree of system variability. Certain RE generation systems have a great degree of variability. FERC regulations recognize this diversity by allowing differentiation of avoided cost rates, depending upon technology, to be based on the supply characteristics of a particular form of technology.[78] Solar generators are installed with a great amount of system diversity, making differentiated rates a critical part of a FIT program. If a single rate were only offered, it may hinder growth of certain forms of solar technology, installation type, system size, and ownership arrangement. However, allowing avoided cost calculations to consider the particular form of RE technology alleviates this concern.

[78] 18 C.F.R §292.304(c)(3)(ii)

RPS obligations add a further wrinkle for utilities in their energy acquisition efforts. Simply stated, they require a utility to obtain a certain percentage of their energy from renewable sources. Colorado's RPS does exactly this.[79] Renewable energy is now a component of a utility's distribution portfolio to retail consumers, and has become a reality for all utilities in the RPS era. As a result, avoided cost rate setting must be flexible enough to consider these additional renewable acquisition obligations imposed on utilities.

Colorado's current set of PURPA regulations, Rules 3900-3953 of the Rules Regulating Electric Utilities, 4 Code of Colorado Regulations (CCR) § 723-3, describe how these tariffs are to be set. The state's utilities must file tariffs with the Colorado Public Utilities Commission for QFs with up to 100kW in design capacity.[80] A bid, auction, or combination of both procedures is used to establish avoided cost rates for facilities with a design capacity between 100 kW and 10 MW. There is no obligation for the utility to ultimately accept any new capacity proposed within this range.[81] Colorado's PURPA regulations only allow for utilities to enter into purchase power agreements with QFs in excess of 10 MW design capacity.[82]

For a FIT's rate structure to be justified under PURPA in Colorado these rules will need to be revised. In particular, the Commission must determine the rate setting methodology for QF-utility PPAs. The current stance is to allow the utilities to submit tariffs for Commission-approval for QFs with capacity size 100k and smaller. This protocol could be maintained with instructions to the utilities based on the FIT rate pricing design chosen. On the other hand, the Commission could issue differentiated tariffs for systems up to 100 kW, and retain the bid/auction procedure for generators between 100 kW and 10 MW. Regardless, a modification is necessary if a FIT is justified based on the deference given for QF rate setting under PURPA.

4.1.2 State Authority to Set REC Prices

A state may also encourage renewable generation by setting the price for RECs. FERC has specifically deferred to states the ability to regulate RECs for compliance with a state imposed RPS, and REC programs do not come within the purview of FERC jurisdiction (see also section 3.4.2.2).[83] As such, states appear to have the ability to establish and regulate utility REC obligations as they see fit.

RECs could be used to overcome any shortcomings in rate design, since a state has the exclusive ability to regulate how they are purchased and sold. If a FIT's rates were closer in resemblance to the actual avoided costs a utility would incur from the generation or purchase of electricity from traditional fossil fuels, without bundling the corresponding RECs, a state could regulate how those RECs are then transferred from the generator to the utility for compliance with an RPS. This could be in the form of a separate charge for the REC, apart from the actual electricity. The REC transfer could also mimic a purchase power agreement in overall term

[79] §40-2-124 C.R.S. (2007). See Section 3.3.2 for a discussion of Colorado's RES.
[80] Rule 3902(b), 4 C.C.R. 723-3.
[81] Rule 3901(c), 4 C.C.R. 723-3.
[82] Rule 3900, 4 C.C.R. 723-3.
[83] FERC Docket No. EL03-133-000 (2003); American Ref-Fuel Co. 105 ¶ 61004 at p. 23 (2003)

length, but be a separate purchase agreement. Each of these options would appear to give a state the ability to ensure that a generator receives a targeted rate under a FIT program.

Additionally, the transfer of RECs could be differentiated based upon the renewable energy source, technology type, project size, proximity to distribution or transmission, etc. This could allow a state to have a great degree of flexibility in implementing its particular policy targets.

State jurisdiction over RECs could be complicated later in 2009 or 2010, if Congress passes federal legislation aimed at addressing climate change. Within this legislation could be a federal RPS, which may alter definitions for RECs. However, even if this legislation attempts to establish the attributes of a REC at the federal level, any alteration of state REC programs could be challenged on the grounds of a Fifth Amendment taking if just compensation is not also included, given that the FERC has already ruled that RECs are state-created property.

4.2 Applicability to Utilities

Colorado retail electric providers can be divided into three main categories: investor-owned; municipally owned; and cooperative rural electric associations. The Colorado PUC has at least limited jurisdiction to regulate certain activities of these utility ownership types. Within the Colorado Rules Regulating Electric Utilities, and in particular the rules dedicated to the state's RPS,[84] Colorado makes a distinction amongst these ownership classifications by establishing a qualifying retail utility (QRU), which is defined as any retail electric provider, other than a municipally owned electric utility that serves less than 40,000 customers.[85] This QRU classification is utilized to set the renewable portfolio requirements for a utility, be it an IOU, MOU, or cooperative. These classifications are useful, as they have established Colorado's RE obligations for retail electric providers under the state's RPS. If a FIT program is to be introduced within this state, these classifications could be extended to the obligations imposed upon a utility, depending upon ownership structure and number of customers serviced.

Other states have also provided examples of how to apply a FIT to retail utilities based on their ownership structure. Wisconsin's Public Service Commission currently has an open docket to assess whether to further expand the state's advanced renewable tariff (ART) policy.[86] The ART is a voluntary PBI that the state's IOUs may adopt for newly installed RE generators within their service territories. One aspect being examined is whether to make the program mandatory for all utilities operating in the state under Commission jurisdiction, not just the IOUs.[87] The WI PSC has commented that a mandatory ART for all utilities may need to be differentiated based on the size of the utility, but not necessarily for ownership structure.[88] This could be done by setting program caps based on utility size or simply restricting the program to utilities of a certain size, making the program mandatory for utilities annually distributing energy above a certain threshold quantity.

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[84] Rule 3650-3665, 4 C.C.R. 723-3.

[85] Rule 3652(k), 4 C.C.R. 723-3.

[86] PSC Docket No. 5-EI-148.

[87] The Wisconsin Public Service Commission lacks jurisdiction over the state's cooperative electric associations.

[88] See WI PSC Revised Briefing Memorandum available at: http://psc.wi.gov/apps/erf_share/view/viewdoc.aspx?docid=114021 (accessed 8/6/09).

California's FIT limits buy-sell requirements based on the individual utility, seemingly according to utility size.[89] California's PUC only has jurisdiction over the state's IOUs, not publicly-owned (i.e., municipal) or cooperatively-owned utilities. San Diego Gas and Electric Company, Pacificorp, Sierra Pacific Power Company, Bear Valley Electric Service Division of Golden State Water Company, and Mountain Utilities are only required to purchase power under the FIT from water and wastewater customers, whereas Southern California Edison and Pacific Gas and Electric Company must buy power from any customer-sited RE generation system within their service territories. California's FIT has set program limits depending upon the utility, though these are subject to change due to a California Public Utilities Commission administrative docket investigating whether to expand the program by increasing project limits.[90] However, distinctions within the program are currently based on the size of the IOU.

The Colorado PUC has rate regulation authority only over the state's two investor owned utilities. Even so, the political reality makes it likely that state legislative action would be required before it attempted to initiate a FIT within the IOU territories. One reason for this, alluded to earlier, is the complexity of coordinating the FIT with other statutorily mandated renewable incentive programs. Furthermore, any hope of mandating a FIT in MOU or REA service territories would clearly require legislative action and fierce opposition is to be expected.

4.3 Retail Rate Increase Restriction

A further legal restriction to consider is how a FIT would conflict with the retail rate impact rule established to limit costs passed on to consumers due to RPS requirements. Under this rate test, there are percentage limits that a utility may pass on to its customers due to the above market cost of energy acquired from RE generators for the purpose of RPS compliance. Investor-owned QRUs are restricted from passing along a net impact of more than 2% annually to their customers to comply with the RPS.[91] The Colorado Rules Regulating Electric Utilities describe a relatively detailed forecasting method for estimating the annual retail rate impact for large investor owned QRUs, i.e. Public Service Company of Colorado.[92] An alternative calculation method is available for an investor-owned QRU with annual retail sales of less than five million megawatt hours, i.e. Black Hills/Colorado Electric.[93]

The Electric Rules also establish a 1% retail rate impact cap for cooperative electric association QRUs.[94] Noteworthy is the fact that there is no detailed description for how these cooperative electric association QRUs are to estimate the annual retail rate impact limit, just an expressed expectation of compliance and a requirement to describe the method used in the utility's annual RPS compliance report. Also noteworthy is the fact that there is no annual retail rate impact cap for municipally owned utilities.[95]

[89] Available at http://docs.cpuc.ca.gov/word_pdf/NEWS_RELEASE/78824.pdf (accessed 8/6/09).
[90] CA PUC Rulemaking Docket 08-08-009.
[91] Rule 3661(a), 4 C.C.R. 723-3.
[92] Rule 3661(h), 4 C.C.R. 723-3.
[93] Rule 3661(i), 4 C.C.R. 723-3.
[94] Rule 3661(b), 4 C.C.R. 723-3.
[95] Rule 3653(a)(iii), 4 C.C.R. 723-3.

Based on the more stringent computational requirements imposed on large IOUs to comply with the 2% annual cap, the emphasis of this cap appears to be on mitigating and monitoring any significant impact on retail rates charged by PSCo. Though there is the stated 1% retail rate impact cap for REA QRUs, thus far all but one have relied primarily on their wholesale suppliers to meet their compliance obligations in their behalf and none claim any impact on retail rates.

Because of this focus upon how RE capacity additions affect retail rates, a FIT may have to be designed to ensure that this retail rate impact test is not violated due to additions in solar capacity. In the alternative, the retail rate impact test could be replaced under a FIT with a capacity cap, founded on the estimated impact on retail rates. The course taken would likely depend upon the policy and program goals established within the feed-in tariff.

5.0 Analysis of the Comparative Success of FIT Versus Non-FIT Programs

This paper next considers the effectiveness of FIT programs in achieving both their commonly-stated goals, as evidenced by national legislation and policy analyses, and other potential policy goals that might be valued by the state of Colorado or other actors. FITs are frequently said to promote dramatic capacity additions, job creation, reduction of risk by investors, fulfillment of renewable electricity goals, and GHG emissions decreases, among other benefits. This section is intended to be an introduction to these concepts rather than an in-depth analysis, and is subject to future expansion.

5.1 Capacity Addition

This subsection briefly discusses PV capacity addition in FIT and non-FIT countries, and compares installed capacity against solar electricity potential and FIT adjustment/revision schedules. A major goal of any FIT program is to directly increase the generation of renewable electricity by stimulating capacity additions. The overall amount of solar PV installed worldwide has increased dramatically within the last several years, from less than 1 GW in 2000 to approximately 15 GW by the end of 2008 (see appendix B, figure B-4; EPIA, 2009, p.3-4; Liu, 2009). About 6 GW of this amount were added in 2008 alone, with 81% installed in Europe, predominantly in Spain (about 2.5 GW) and Germany (about 1.5 GW). Outside Europe, the U.S., South Korea, and Japan were the major destinations for PV capacity additions in 2008 (see appendix B, figure B-6).

By 2009, the top five countries with the most solar PV capacity installed were Germany, Spain, Japan, the U.S., and Italy (see appendix B, figure B-6). Germany leads the world with over 5 GW installed, but PV capacity has skyrocketed in several countries since 2007. For instance, notable capacity additions recently occurred in Spain (increasing 534% between 2007 and 2008), South Korea (440%), Italy (381%), and Portugal (380%) (see appendix B, figure B-4).

5.1.1 Correlation Between Potential and Actual Solar Development

Effective policymaking may be driving PV capacity additions as much as the presence of a specific suite of resources. Substantial solar electricity potential exists in the southwestern U.S., North Africa, the Middle East, southern Asia (particularly India), and Mediterranean Europe (see appendix B, figures B-1 to B-3). While Spain, Italy, and the U.S. are among the top five countries worldwide for PV installation, Germany leads them all despite having in most regions approximately one-half the annual global irradiation of southern Spain (appendix B, figure B-2). In 2006, Colorado was ranked as having the fifth-highest solar potential in the US, meaning it may rival Spain in its ability to generate solar electricity (Government of Nebraska, 2006).

5.1.2 Correlation Between Capacity Additions and FITs

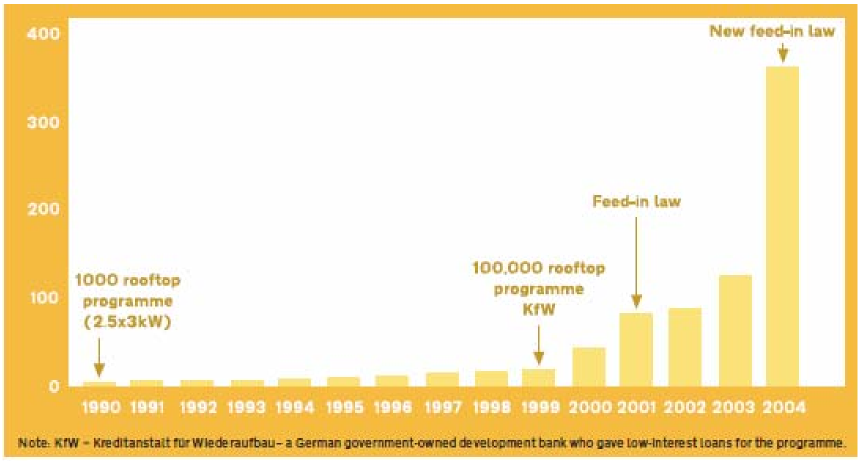
There appears to be a strong correlation between the enactment or revision of a FIT and capacity additions in several countries. The three- to fivefold capacity additions in Spain, South Korea, Italy, and Portugal, as described above, correspond with changes to FIT programs. About 2.5 GW of Spain's 3.5 GW of solar PV were installed in 2008, after a 2007 FIT revision (Wang, Spain Installed More Than 3 GW in 2008, 2009).[96] Similarly, Italy introduced a PV FIT in 2005 with revisions in 2006 and 2007, leading to a nearly fourfold capacity increase from 120.2 MW in 2007 to 458.3 MW in 2008.[97]

South Korea's PV market appears to be extremely sensitive to changes in its FIT program. Starting in October 2008, South Korea's tariff was differentiated and dropped from 711.25 to 646.96 Won/kWh for systems less than 30 kW and from 677.38 to between 472.70 and 620.41 Won/kWh for those greater than 30 kW, over fifteen years (Yoon & Kim, 2009, p.9). 276 MW of solar PV went in during 2008, but only 10 MW came online between October 2008 and March 2009 (Burgermeister, 2009). If capacity additions in 2009 do not meet the 500 MW cap, new tariffs will be announced for 2010; correspondingly, an estimated 625 MW is in the pipeline and waiting to learn about rate revisions.

Germany's FIT, which began in 1991 and was revised in 2000, helped spur an addition in capacity from 113.7 MW in 2000-2001 to 5.3 GW in 2008 (see also figure 5-1).[98] However, outside of a large increase between 2003 and 2004 after the 2004 EEG adjustment, Germany's PV capacity appears to have steadily increased somewhat independently of subsequent alterations.

[96] IEA PV Trends 2007 and 2008; (noting that it is unclear whether this figure includes fraudulent claims of connection).
[97] IEA PV Trends 2007; Tilli et al. p.3.
[98] IEA PV Trends 2007; EEG Progress Report 2007 p.121 table 11-2.

Figure 5-1: Influence of FIT on Annual PV Installation in Germany (MW)[99]



The connection between enacting, altering, or revising a FIT and adding capacity is not always direct. For instance, a FIT program in Austria has contributed to capacity additions, but not by nearly as large a margin as those in other countries—from a few hundred kW in the early 1990s, it now claims about 30 MW installed (see appendix B, table B-1). Similarly, PV in France more than doubled between 2006 and 2008, but by the end of 2008 it still had only about 91 MW, despite having among the highest tariffs offered in Europe during those years.

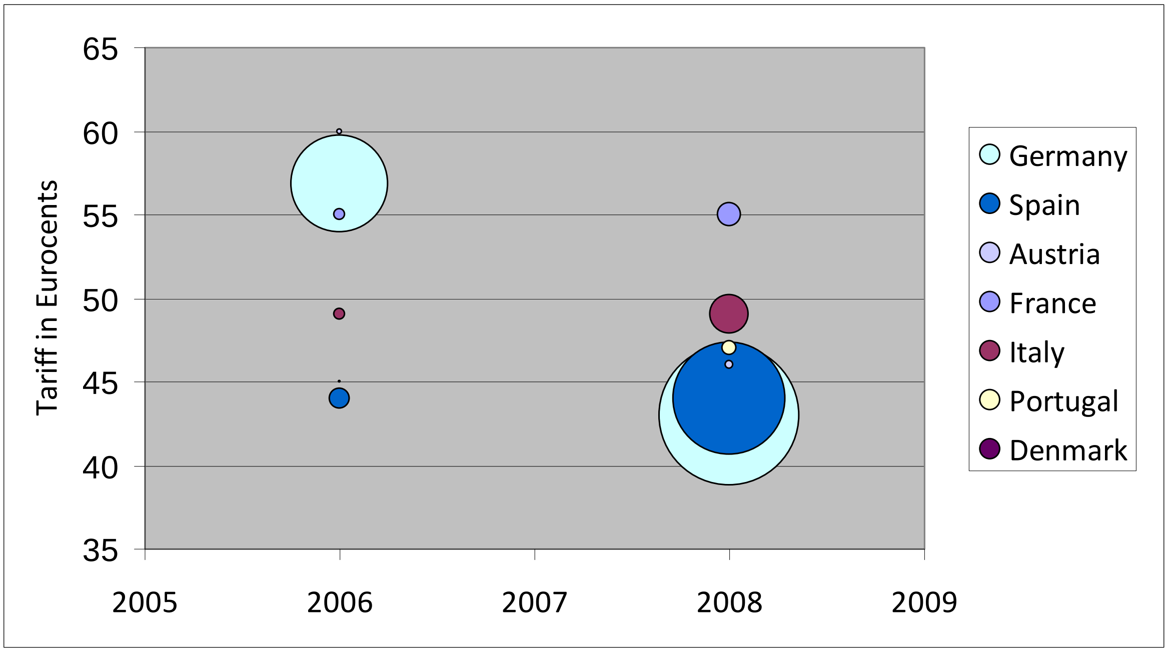
Therefore, while low FITs may not promote the installation of comparatively expensive renewable energy technologies like PV, high FITs may not either when coupled with administrative barriers that deter investor confidence (see Sections 2.6.2, 5.2).

Moreover, not all capacity increases are linked to FITs. Of the top five countries with installed PV capacity, neither the US nor Japan have national FITs. The majority of Japan's capacity increases came about due to generous subsidies offered for homeowners installing DG, beginning in 1994 (Bolinger & Wiser, 2002, p.2-3). National subsidies paid up to 50% of the installed costs for PV on single- and multi-family residential units beginning in 1994, dropping to 33% in 1997. Participants could accept additional subsidies from their local governments as well. By the end of FY2006, 350,000 houses had PV systems (EPIA & Greenpeace, 2009, p.68). By the end of 2007, approximately 95% of the cumulative PV capacity in Japan of 1.9 GW appeared to be residential DG of 3 to 5 kW per installation (IEA-PVPS for Japan, 2007, p.9-10).[100] Therefore, large up-front subsidies can be an effective method for spurring capacity additions, as can FITs.

[99] World Future Council, Feed-In Tariffs—Boosting Energy for Our Future 9, *available at* http://www.worldfuturecouncil.org/fileadmin/user_upload/Rob/press/publications/Feed-inGuidePrint.pdf.

[100] The text is somewhat ambiguous on this point.

Figure 5-2: Tariff Rates and Comparative PV Capacity (MW), 2006 & 2008[101]



5.2 Risk Reduction

Different types of risk may fall on different parties affected by renewable energy policies, including RE generators, retail electric suppliers, product manufacturers, and ratepayers. FITs can decrease certain types of risk that may exist under other regimes, but if not carefully designed, they may increase other types of risk.

FITs can reduce price, volume, and balancing risk as opposed to other policies. Mitchell et al. determined that Germany's EEG was more effective at building capacity than the UK's Renewables Obligation (RO)—which functioned like an RPS with RECs—because it provided RE generators with a guaranteed price in a potentially volatile market, removed the possibility that renewable electricity would go unsold by obligating utilities to purchase all RE production, and placed the risk on the transmission operators rather than the generators to shape the load profile (2006, p.301).

RE generators are frequently debt-financed—as noted, policymakers in Spain concluded that the cost of the capacity necessary to reach the country's 2005-2010 goals for RE generation would be 2.9% financed by public aid and 77.1% financed by debt (Ministerio de Industria, Turismo, y Comercio, 2005, p.57). Mitchell et al. further noted that many RE generators are risk-averse because of this financing structure. This means that predominant aspects of FIT policies are focused on reducing the risk to investors. FITs can reduce credit risk by basing tariff rates on the actual installation cost of the project and including a guaranteed rate of return. Moreover, FITs allow for different tariffs based on the cost of different types of technology, and overcome barriers to bringing smaller generators into the market so as to encourage distributed generation.

[101] Based on figures from Klein (2008); IEA-PVPS (2009); Crandall, international FIT summary chart.

Another risk reduction technique is to include a partial-to-full adjustment for inflation on FIT levels throughout an existing contract. However, while inflation adjustments are attractive to investors, they fail to protect ratepayers because they can remove some of the hedge against energy price volatility that fixed tariffs provide.

FITs can be adapted to reduce other types of risk. For example, well-designed FITs can lessen the chance that utilities may fall short of reaching their RPS goals. While Germany made massive wind and solar capacity additions through its FIT program, the UK experienced high contract failure rates for wind farms under its Non-Fossil Fuel Obligation program in the 1990s. Of 247 wind projects (comprising 972 MW) awarded in a series of tenders, only 74 projects (161 MW) were installed (Stenzel & Frenzel, 2008, p.2648).

Additionally, by allowing utilities to pass through the costs of FITs to ratepayers, their financial risk is limited. However, allowing pass-through creates other risks. The first is that ratepayers will be unfairly burdened if a generous tariff coupled with a purchase obligation means that utilities are forced to pay substantial sums for renewable energy. This problem can be addressed by enacting an annual capacity cap on the amount of RE that will be accepted. An additional risk created by pass-through is that, if the cost of RE is passed through to ratepayers in proportion to electricity consumption, energy-intensive domestic industries may be negatively affected. Some countries have solved this problem by aggregating costs and distributing them differently among different classes of consumers—this frequently involves increasing the residential rate burden and decreasing it for industrial users. However, this process also means that residential customers subsidize the electricity use of perhaps heavily-polluting industries. The final risk that pass-through creates is that, in competitive markets, utilities with service areas that are particularly suitable for RE development will be unfairly burdened because they will be increasing rates for their consumers to pay for FITs (in Colorado, the present solar set-aside, required only of IOUs and their customers, imposes a similar burden). Some countries have solved this problem by collecting cost data from all utilities with a purchase obligation and redistributing the costs among all ratepayers.

However, poorly-designed FIT programs may increase certain types of risk. For instance, France and Greece have lagged behind in capacity installed—despite high solar potential and relatively high FITs—in part because of the difficulties prospective RE generators face in obtaining site permits before construction and interconnection access afterward. Because RE generators cannot receive payment under a FIT until generation occurs, the possibility of lengthy delays to obtain interconnection may scare off investors.

Additionally, poor design can create boom-and-bust cycles, as recently occurred in Spain, increasing risk for manufacturers and ratepayers as well as investors and developers. Starting in 2007, Spain provided high tariffs and a capacity goal but no clear trigger for degression (Voosen, 2009). The development rush was exacerbated when the government announced plans to substantially reduce the tariff in September 2008 and the frenzy to get projects connected led to fraud. 3 GW of solar PV were installed in Spain in a year and a half, committing ratepayers to over $26 billion in payments to generators. Meanwhile, the high demand for PV panels caused oversupply that cut prices in half, leading to the loss of 20,000 solar industry jobs in Spain as well as layoffs at factories abroad. The lack of clarity in the program with regard to FIT queuing, and the program's limited responsiveness to changing market conditions, contributed heavily to the problem. Consequently, a clear and transparent FIT design and revision process is necessary to fulfill the policy's risk reduction potential.

5.3 Job Creation

One common goal of FIT programs is the creation of a domestic renewable energy industry with substantial employment gains, particularly in rural areas. This rationale motivated proponents of the FIT in Spain, which had among the highest unemployment rates in OECD countries in the early 2000s (Gonzalez, 2008, p.2923; del Río & Gual, 2007, p.1009; del Río & Unruh, 2007, p.1509). However, while a moderate amount of data exists regarding levels of employment in the PV industry, particularly within European countries, it is often incomplete, estimated, or unclear as to how it was gathered and whether it refers to direct or indirect employment. Moreover, most national statistics on job creation in the RE industry consider only gross employment, rather than net job creation once losses in other industries are included.

Worldwide, employment in the PV sector has increased substantially in the last several years, particularly within a few countries and when indirect job creation is considered as well. For instance, China's PV workforce reportedly increased from about 13,800 to 82,800 between 2005 and 2007 (including indirect jobs) (EPIA & Greenpeace, 2009, p.70-71). Spain and Germany have also seen large employment increases in recent years. PV industry employment in Spain increased from about 2,500 people (with an additional 1,500 indirect jobs) in 2005 to closer to 17,000 by 2007 (del Rio & Unruh, 2007, p.1509; EPIA & Greenpeace, 2009, p.63).

Germany appears to be the only country thus far that considers the net job gain rather than simply the total number of jobs created within the RE industry, meaning it accounts for losses in other fields resulting from the transition to other types of energy. Germany's Ministry for the Environment, Nature Conservation, and Nuclear Safety (BMU) reported that the number of people employed in all renewable energy-related industries increased from 160,000 in 2004 to 236,000 in 2006, with about 134,000 total jobs directly resulting from the EEG (BMU, 2007, p.8). Out of that figure, PV contributed around 27,000 jobs (29,635 according to appendix B, Figure B-10) and wind gained 82,000, with the balance going toward bioenergy and hydropower. BMU also noted that despite the loss of some jobs in other industries, resulting in part from higher electricity prices putting pressure on consumer spending, the net job change was still positive, with an estimated increase of 67,000 to 78,000 jobs in 2006. Table B-2 in appendix B shows a more specific breakdown of German PV jobs beginning in 2001 and including estimates through 2010.

Increases in employment occurred in Spain and Germany seemingly in conjunction with FIT adjustments or revisions. For instance, from the end of 2003 to the end of 2004 in Germany, employment in the PV sector nearly tripled, in conjunction with the adjustment of a FIT which had originally been set in 2000. Beginning in 2000, Germany offered a tariff of 50.62 €cts/kWh for PV installations with a 350 MW capacity cap. Starting in 2002, however, a degression rate of 5% per year meant that by 2004, the tariff offered would have been about 46 €cts/kWh (EEG, 2000, p.9).[102] Germany's decision in 2004 to remove the PV capacity cap and offer as much as 57.4 €cts/kWh for BIPV installations correlated with an employment increase (EEG, 2004, p.13).[103] Similarly, employment increases in Spain correlate with changes to its FIT structure in 2004. Before 2004, tariffs were limited to PV installations of less than 5 kW, but after 2004 installations of up to 50 MW became eligible (Gonzalez, 2008, p.2922 table 3). While China has only recently discussed implementing a FIT for solar power, its dramatic increase in jobs in the PV industry may, in part, be due to the FITs in Spain and Germany. In 2007, China became the world's top PV producer, manufacturing over 1 GW of panels and about 29% of total output worldwide (Greenpeace EPIA, 2008, p.29, 71). Japan followed with 22% and Germany with 20%.

Domestic RE industry development, then, may depend on resource availability and government R&D investment. Spain installed 1.5 GW in 2008 but had limited domestic manufacturing capacity, meaning much of its PV was imported, particularly from China (EPIA, 2009, p.4). Additionally, Spain's solar industry may have lost as many as 20,000 jobs in 2008 because of the boom-and-bust cycle described in Sections 2.6.3 and 5.2 (Voosen, 2009).

5.4 Consumer Rate Impact

The impact a FIT may have upon ultimate consumer retail rates is a policy consideration that must be looked at closely when determining the design of the FIT. Colorado renewable energy policy has already shown a keen sensitivity to ensuring moderate retail rate increases for renewable energy capacity additions under the state's RPS. As mentioned previously, additions in renewable capacity intended for RPS compliance are subject to a retail rate cap for IOUs (2% annual cap) and REAs (1% annual cap). Because these restrictions are already in place, any new capacity additions under a FIT may also be similarly restrained to ensure retail rates are not unduly influenced. However, Colorado's two IOUs are already bumping up against the 2% rate cap with virtually all of the available funding going to solar resources. It is difficult to see how this rate cap could be maintained in the presence of a broad FIT to further stimulate solar penetration.

Consumer retail rate increases can be protected from excessive annual increases from the implementation of a FIT by designing the FIT to serve this policy goal. In particular, annual and overall program caps can work to ensure that any new renewable generation is sufficiently restrained by only allowing a certain target amount, either through an overall program cap or annual caps. If an overall program cap is established, then degression may be necessary to attenuate the effects of new generation established under the FIT. Higher rate increases may be seen in the short-term for a program cap, but over a longer period of time those rate increases will slow as lower rates are offered for new renewable generation.

A FIT can also be designed to affect only certain utilities. This can be accomplished based on either the utility's ownership structure or overall number of customers served. Obviously, this is

[102] *Available at* http://www.feed-in-cooperation.org/images/files/renewable%20energy%20sources%20act%20-%20eeg%20-%202000.pdf.
[103] *Available at* http://www.feed-in-cooperation.org/images/files/amandmend%20of%20the%20renewable%20energy%20sources%20act%20-%20eeg%20-%202004.pdf.

subject to the jurisdiction afforded to the state's utility regulatory bodies. For example, California's FIT applies only to the state's IOUs, with higher program caps for Southern California Edison and Pacific Gas & Electric than the state's remaining IOUs.[104] Wisconsin has opened a docket to investigate whether to expand its Advanced Renewable Tariff, a PBI voluntarily offered by the state's IOUs, and has expressed that restricting a FIT based upon the size of a utility's customer base could protect them from undue rate increases.[105]

Germany is an example of a country that has implemented a FIT, installed large amounts of new renewable generating capacity, and also protected retail rates from large annual increases. Costs arising from renewable electricity generated under the FIT amounted to 13% of the retail price increases for the residential sector from 2002-2006 (EEG Progress Report, 2007). In 2006, the surcharge applied for additional renewable capacity amounted to 4% of the average residential electricity bill. Therefore, these increases did not unduly burden residential retail rates in Germany, a country where renewable energy generation amounted to approximately 12% of the country's electricity consumption in 2007. As seen with Germany's FIT, retail rates can be protected depending upon policy goals behind the implementation of a FIT.

5.5 Cost of Solar Energy

Solar PV is a technology that is gradually becoming more competitive with other lower-cost forms of renewable energy and fossil fuel generation. However, it has yet to reach a point where it can be considered the equivalent of either. The Lawrence Berkeley National Laboratory recently showed that solar PV systems have decreased in the United States for all installations from $10.50/Watt in 1998 to $7.60/Watt (before financial incentives), representing a 3.5% decline per year (Wiser et al., 2008). Smaller solar PV systems, those under 100 kW, fell from $11.80/W to $8.30/W within that same time period.

United States cost estimates have not reached the level that certain international solar PV programs have thus far attained. For example, the average cost of residential solar PV in 2007 (excluding sales and volume taxes) in Germany and Japan were $6.60/W and $5.90/W respectively (Wiser et al., 2008, p. 14). When compared to the United States, these average installed costs are significantly lower. Each of these countries has much larger installations of cumulative grid-tied solar PV than the U.S, with Germany estimated at 3,800 MW and Japan with 1,800 MW in 2007. In contrast, the U.S totaled only 500 MW in 2007. The reasons for the difference in unit costs and installed capacity are not clear but are likely multifaceted. One reason could be that higher energy costs in Europe make solar nearer to grid parity than in the US. Others have speculated that the difference in price for smaller residential solar PV could be directly attributable to how aggressively that country may be pushing for additional solar energy capacity, though it is not clear precisely how that would reduce costs other than, perhaps, for economies of scale.

Costs of solar PV can also vary extensively in the United States based upon the system size and the state's cumulative grid-tied PV capacity. For solar PV systems under 10 kW in capacity, 2007 costs ranged from $7.60/W in Arizona to $10.60/W in Maryland (Wiser, Barbose and

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[104] California Admin. PUC Order 07-07-027 (07/2007).
[105] Wisconsin Public Service Commission Docket 5-EI-148, Revised Briefing Memorandum (05/20/2009).

Peterman 2008, p. 16). Average systems costs vary as well, with Arizona, California, and New Jersey in the \$7.70-\$7.80/W for systems installed in 2007. Whereas, Illinois's average costs for PV systems installed in 2007 appear to be an outlier at \$12.40/W.

Preliminary data for solar PV installations in Colorado indicates an average cost of \$8.47/W for PSCo's under-10 kW program since inception in 2006. The same data, stratified by year, reveals that the average cost had fallen to roughly \$7.70/W by 2009. Complete data for installations in Black Hills territory was not available.

5.6 Ease of Implementation

An additional consideration in measuring the success of a FIT program is how easily the program was implemented. Administrative and political barriers may complicate whether and how a FIT may be implemented.

5.6.1 Administrative Obstacles

The biggest administrative hurdle when designing a FIT is ensuring that it will meet the policy goals to be served by its implementation. As a result, the body looking to enact a FIT should clearly identify why they are enacting a FIT and ensure that the intended effect of the FIT will most closely resemble those goals. Moreover, developers, manufacturers, ratepayers, utilities, and policy makers may represent a multitude of conflicting stakeholder interests further complicating program design.

Additionally, grid reliability and management issues must also be kept in mind where additional penetration of intermittent resources is to be achieved. In particular, solar and wind are not base load generation sources. Accordingly, when the wind and sun are not available, a back-up generating source must come on line to compensate for the lack of solar or wind energy generation. Since the Colorado RES already requires a solar set-aside, the state's IOUs are aware of how the grid is affected when solar energy generating resources are unavailable to generate electricity. A FIT would likely further increase the state's portfolio of solar generating resources, thereby offsetting the need for electricity generated from fossil fuel combustion. Because the renewable resources would be generating power during peak times, the state's IOUs would still require a back-up generating resource when solar in unavailable.

5.6.2 Political Obstacles

5.6.2.1 Legislative Versus Administrative Adoption

An initial determination regarding the implementation of a FIT is who is to enact the incentive: the state's legislature or utility regulatory authority. For example, the FITs enacted by California, Maine, Oregon and Vermont were done so by the legislature. Eleven other states have introduced legislation, which though they vary in overall design, could loosely be identified as FITs.[106]

[106] Arkansas, Hawaii, Illinois, Indiana, Iowa, Michigan, Minnesota, New Mexico, New York, Rhode Island, and Washington.

Only two states have attempted to adopt a FIT by other means. The Governor of Hawaii, along with other state executive branch agencies and the Hawaiian Electric Company established the Hawaii Clean Energy Initiative on October 20, 2008 and implemented a FIT in 2009.[107] Hawaii's Public Utility Commission opened a docket on October 24, 2008, with the anticipated publication of tariff rates set for July 31, 2009.[108] Wisconsin also appears to be adopting a strictly administrative approach, with an open Public Service Commission docket investigating whether to expand the state's Advanced Renewable Tariff program.[109]

Overall, it appears that both domestically and internationally, the preferred method of FIT adoption is via legislative action.

5.6.2.2 Utility Cooperation

Positive strategic reactions by a state's utilities are also vital to the successful implementation of a FIT. In Spain, the incumbent utilities proactively embraced the FIT, which consequently caused a widespread penetration of renewable energy at wholesale rates (Stenzel & Frenzel, 2008, p. 2651-54). In contrast, utilities in Germany and Great Britain were slower to adapt, causing a slower rollout of renewable generation increases and widespread implementation. Accordingly, designing a FIT in such a way that the state's utilities are more likely to quickly adopt and employ its requirements can greatly assist in the realization of the benefit of added renewable capacity growth.

5.6.2.3 Consumer Education

A final political obstacle is overall consumer response and understanding of the program. In Colorado, consumers have come to rely upon rebate and net metering programs for smaller solar PV systems, along with the bid/auction format for larger renewable installations. However, a FIT is a completely different financial accounting mechanism. Therefore, consumer awareness programs should also be included to educate them on the requirements, benefits, and costs of the program. In California, the CEC held a series of workshops to elicit public opinion and assist in developing its recommendation on how to expand the state's current FIT. This type of cooperation with the general public could be beneficial in ensuring public acceptance of the program.

5.7 Deployment Models for PV

FITs and other programs can be constructed to encourage the deployment of renewable resources in various ways. The selection and construction of an incentive or regulatory program can help influence whether the RE capacity installed is grid-interconnected or off-grid, and distributed or utility-scale.

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[107] http://fit-hawaii.com/?Hawaii_Clean_Energy_Initiative (accessed 08/25/2009).
[108] The HI PUC Docket 2008-0273 had yet to issue this order as of 08/30/2009.
[109] WI PSC Docket 5-EI-148. Notice of Investigation filed 01/16/2009.

5.7.1 Grid vs. Off-Grid Installation

Most solar PV systems worldwide are grid-connected. By the end of 2007, the nineteen countries participating in the OECD's International Energy Agency (IEA) Photovoltaics Power Systems Programme (PVPS) had approximately 7.8 GW cumulative PV capacity installed, of which about 6 GW was grid-connected distributed generation and 1 GW was grid-connected central station (i.e., utility-scale) PV (IEA-PVPS, 2008, p.6). In countries without FITs or with FITs that have only recently been enacted or exist only at state government levels—such as Canada, Mexico, Australia, Israel, and Sweden—off-grid PV meets or sometimes exceeds grid-connected levels. For example, in 2006, 98% of the PV installed in Israel was off-grid, 93% was off-grid in Canada, and 85% was off-grid in Australia (Green Cross International, 2009, p.16, 26, 109). However, countries with well-developed FITs, such as Germany (where less than 1% of systems are off-grid), have primarily grid-connected PV, likely because utilities are required to connect RE generators to the grid under a FIT program. Similarly, 85% of the PV in Spain was grid-connected in 2006, and Japan had approximately 95% of its PV capacity connected to the grid (p.75, 95). There are exceptions: 91% of U.K. PV capacity is grid-connected, but there were only about 14 MW of installed PV in the U.K. in 2006 (p.104). Additionally, the majority of U.S. PV installations are grid-connected, with 74% in 2006, 78% in 2007, and 84% in 2008.[110]

Along with the increased connection of renewable resources, however, comes the need for increased investment in infrastructure to accomplish several goals, among them transporting renewable electricity from high-resource areas to high-demand areas, maintaining the reliability of the grid when generation from renewable resources is intermittent, and shaping renewable electricity production to match peak demand using storage. Expanding and upgrading transmission infrastructure is often considered one of the most urgent steps that should be taken to increase the penetration of RE into electricity markets. However, more research is needed to determine how much of the cost to upgrade transmission infrastructure can be traced to the implementation of FITs or other incentive-based or regulatory programs.

5.7.2 Distributed Generation versus Utility-Scale Development

FITs are generally offered for smaller installations to spur distributed generation (DG), but they have been provided to larger projects too. The definition of DG varies by country. It is usually considered to be small-scale electricity generation that is consumed at the point of generation or supplied to consumers through a distribution network at the substation level. DG has increased in importance both because of its potential contribution to diversifying and securing the electricity supply as well as because of market liberalization (Pepermans et al., 2005, p.794; IEA, 2002, p.22).

Generally, FIT programs incentivize smaller, DG photovoltaic installations rather than utility-scale PV or CSP, and the tariffs decrease as the size of a plant increases to account for economies of scale. Moreover, FITs may be specifically targeted toward traditionally small-scale installations like BIPV, a tack that France's program has taken, potentially at the expense of larger PV development. South Africa is the only country that incentivizes CSP and not PV,

[110] Personal e-mail from Larry Sherwood, Interstate Renewable Energy Council [IREC], to Rich Mignogna, Colorado PUC (Sept. 23, 2009) (noting that the grid-connected figures are more precise than the off-grid figures).

hoping to lure large, utility-scale plants in order to help it deal with supply shortages (Osterkorn, 2007, p.28-30).

In practice, though, most countries enacting FITs do not appear to limit the eligibility of PV projects based on size. Those that do limit the size of installations include 100 kW in the Netherlands, 1 MW in Luxembourg, 10 MW for ground-mounted PV in Canada, 12 MW in France, 50 MW in India, and 100 MW in Spain and Estonia (RES-Legal, 2009).

5.7.2.1 Utility-Scale Development

At this time, thirty-eight of the fifty largest solar PV installations worldwide are located in Spain, with the largest installation reaching 60 MW (Lenardič, 2009). Large CSP installations are online or planned for the southwestern U.S., Spain, Australia, South Korea, Germany, and Portugal (Hudson, 2009).

5.7.2.2 Distributed Generation

Up-front payments appear to be more common for supporting small, residential installations than larger systems where PBIs tend to dominate. DG is prevalent in Japan and Germany, which have both provided targeted programs to homeowners. In Japan, large grants were available for small residential PV (IEA-PVPS, 2007 Report, p.9). This program led to the installation of about 335 MW of PV between 1999 and 2003 by providing 0% loans for the full project cost until 2000 and 1.9% loans afterward. Although initially the program waived participants from paying the final installment (up to 12.5% of the full cost), this benefit was removed in 2000. Similarly, Germany's 100,000 Roofs program, which ran between 1999 and 2003, subsidized homeowners up to 35% of the cost of installing PV (REACT, 2004, p.2-3).

Distributed generation predominates where community ownership models are encouraged. While RE generators in the U.S. are frequently debt-financed (project financing) or collateralized by borrowing against a firm's assets (corporate financing), RE generators in Europe may often be financed through community ownership schemes (Bolinger, 2001, p.2-3). Community ownership may involve communities of interest (i.e. like-minded investors) or communities of locality (i.e. neighbors). This latter type of system, in which a group of neighbors raises capital to finance a small amount of RE capacity and then sells its output to a utility, has several advantages. Because it comes from community members, it provides local benefits and it may be easier to permit. The rate of return demanded may also be lower, and there is less risk of NIMBYism. Additionally, the gradual installation of small amounts of capacity can prevent boom-and-bust cycles in the RE industry. However, smaller projects may also be difficult to manage and less able to take advantage of economies of scale. Before the decision to move from a FIT to a REC-based program in 2000, households in Denmark owned 80% of the wind capacity in the country (p.9).

Colorado's RES explicitly contemplates distributed generation and community ownership models. IOUs are required to obtain at least 4% of their RE requirements from solar, and at least one-half of that amount must be from customer sited solar facilities (4 CCR 723-3 § 3654). The RES rules also offer a multiplier of 1.5 kWh for every kWh of electricity generated by a "community-based project" (4 CCR 723-3 § 3652). Community-based projects must be located in Colorado, less than 30 MW in capacity, and owned by community residents, a cooperative, or a local nonprofit, governmental entity, or tribal council. Additionally, there must be a resolution of support from the local government of the jurisdiction(s) in which the project is located. Alternatively, the RES provides a 1.25 multiplier for kWh of electricity generated in-state (§ 3654).

5.8 Fulfillment of RPS

A FIT can be used to accomplish the legal and policy goals of an RPS and can be the driving mechanism enabling utilities to meet their renewable requirements. IOUs in Colorado, and in particular PSCo, currently add renewable generation by a combination of standard rebate offers and competitive solicitations, depending upon the capacity of the generator. The Staff of the California PUC has recently proposed a reverse auction market, with auction's occurring biennially, for generators with a capacity of 1 MW-20 MW.[111] Presently, California's FIT is only available to generators with a maximum capacity of 1.5 MW, which is presenting significant difficulties for the state's IOUs in reaching the stated renewable portfolio goal to have 33% of the state's load come from renewable by 2020.[112] This proposal, if adopted, would likely retain the FIT for systems smaller than 1 MW installed within the service territories of the state's three main IOUs. The PUC Staff argues that the reverse auction would protect consumer rates by selecting the lowest-cost renewable generators that would add up to 1,000 MW installed renewable capacity. A hybrid system such as this could protect consumers from large retail rate increases due to the larger renewable generators while still allowing smaller DG generators access to a FIT.

5.9 Reduction of GHG Emissions

One suggested goal of FITs is reducing carbon dioxide emissions by substituting renewable generation for fossil fuel based electricity. Germany's BMU announced that generating electricity from RE saved about 44 million metric tons of CO_2 in 2006, of which around 1.5 million came from the use of solar PV (BMU, 2007, p.7, 33). Similarly, in Spain, 35 million metric tons of CO_2 were avoided between 2000 and 2005 by increasing electricity from RE sources (Pöyry, 2009, p.55). However, it is unclear how these reduction figures are calculated and whether RE sources are in fact replacing fossil fuels such that a true reduction of CO_2 emissions is occurring. Substantial additional research will be necessary to clarify these issues. And, as noted earlier, the issue of CO_2 emissions reductions is interwoven with questions of "environmental attributes" definition and ownership (see Section 3.4.2.1).

6.0 Lessons Learned in FIT Design

The following table (figure 6-1) presents a series of prospective goals that renewable energy policies might attempt to fulfill. Based on the data and analysis from the previous five sections, we then make a series of basic recommendations for design features that policymakers might

[111] http://greeninc.blogs.nytimes.com/2009/08/28/a-reverse-auction-market-proposed-to-spur-california-renewables/ (accessed 8/29/09).
[112] California Governor's Executive Order S-14-08 (11/17/2008).

consider depending on how they prioritize the goals. These recommendations are brief and lack nuance—in places, they may conflict depending on policy goals. While most of the recommendations address FIT design, occasionally suggestions for other incentives or regulatory policies appear where they are particularly relevant or complementary to FITs.

Figure 6-1: Lessons Learned in FIT Design & Implementation

Goals	Design Approach	§ Referenced
Large Capacity Addition	• Base tariff on actual cost with guaranteed rate of return • Purchase obligation • Develop transmission infrastructure	§2.2.2, 2.3, 5.7.3
Investor Risk Reduction	• Streamlined permitting procedures to reduce transaction costs • Ensure that any revisions are clear and conducted well in advance of deadlines • Provide clear parameters and cost estimates for interconnection (which may be included in the tariff level); apply shallow interconnection • Clear application process, particularly where there is a capacity cap—i.e. consider a grace period between application and completion in which a certain FIT level can be locked in • No penalties for violating forecasting obligation (or no forecast obligation) • Purchase obligation • Consider adjusting tariff for inflation within contract • Base tariff on actual cost with guaranteed rate of return • If a premium payment is applied, consider a floor	§2.2.4, 2.2.6, 2.3, 2.5, 2.6, 5.2
Ratepayer Protection	• Cap eligible capacity that may receive tariffs • Awareness of other federal, state, and local incentives that might provide a windfall profit to developers • Adjust FIT by only a fraction of the inflation level or avoid adjusting for inflation (and particularly avoid using an inflation calculation that includes the cost of electricity) • Provide a cap on premium FITs, if offered • Reduce impact for more energy-intensive industries (although this is beneficial for international competition, it is not necessarily beneficial for the environment) • Improve monitoring, verification, and enforcement to eliminate invalid projects • Degression triggers • Tenders for specified amounts of capacity (but considering factors other than least-cost, e.g. likelihood of success) • Provide for RECs to go to utilities and be retired for RPS compliance	§2.2, 2.4, 2.5, 2.6, 3.4, 5.4
Develop Domestic Industry	• Limit developer windfall to prevent boom-and-bust cycles • Government R&D funding • Encourage repowering	§2.2.1, 5.3
Distributed Generation	• Promote community ownership structures • Provide low-interest loans or up-front grants for small residential installations • Reduce risk for small investors	§2.2.1, 2.2.5, 2.3, 2.4, 2.6, 3.1.1, 5.2, 5.7

Security of Energy Supply; Grid Reliability	• Forecast obligation for RE generators to encourage better modeling • Provide peak/off-peak pricing differentiation • Encourage development in areas with better grid resources	§2.2.5, 2.3, 2.4, 2.5, 5.1, 5.2, 5.7
Prevent NIMBYism	• Promote community ownership structures • Resource equalization • Equalize ratepayer pass-through between all utilities, not just within their service areas • Reduce risk for small investors to encourage residential DG • Provide social responsibility adders • Engage stakeholders in FIT development	§2.2.5, 2.4, 2.5, 2.6.4, 5.7
Administrative Simplicity	• Streamline application/permitting procedures; consider requiring a deposit as a component of the application process • Have clear interconnection rules available up-front • Consider actual instead of avoided costs • Consider more frequent revisions instead of simple adjustments so that changes in commodities markets and technological progress can be considered	§2.1.2, 2.2.2, 2.2.6, 2.3, 2.4, 2.6, 5.6
Limiting Utility Hostility	• Allow pass-through to ratepayers • Require forecasting by RE generators • Consider allowing FITs for utility-scale projects	§2.5, 2.6.4, 4.2, 5.4, 5.6, 5.7
Diversity of Energy Resources	• Carefully consider domestic access to RE resources, manufacturing, etc. • Provide capacity caps on certain types of technologies • Use differentiation and adders, particularly to encourage DG	§2.2.1, 3.4, 5.5

7.0 Conclusion

FITs have increased in popularity dramatically worldwide in recent years for several reasons. They contribute to capacity additions and may lead to net job creation. Countries with FITs have, in many instances, reached or exceeded national RE generation goals. Proponents also claim that they can reduce GHG emissions. However, careless FIT design can lead to boom-and-bust cycles as occurred in Spain in 2008, leading to fraud, ratepayer outrage, and a PV market glut that leads to depressed prices. Moreover, fast capacity additions can challenge grid reliability when large amounts of intermittent RE resources are interconnected. Careful design, however, can contribute to achieving a multitude of goals. Depending on the priorities of policymakers, the available RE resources, and the structure of an electricity market, U.S. jurisdictions may be able to develop uniquely-tailored FITs which they can use to make RE resources more competitive with conventional electricity generation and to fulfill goals related to increasing the penetration of RE on the electric grid.

Appendix A: Financial Incentives & Regulatory Policies That May Work With FITs

Income Tax-Related Incentives—Personal/Corporate Taxes & Credits

States have established income tax incentives, most commonly in the form of a credit, to encourage both individual households and corporations[113] to invest in solar PV systems. These incentives are not competitive with FITs, as they are not meant to actually pay for the system, rather they offset a certain percentage of the costs of the system. There are maximum limits on the allowable credit depending on the program, though many programs allow for a rollover of the credit for a specified number of years if the eligible taxable liability is less than the overall credit permitted in the taxable year the solar PV system was installed. Individual and corporate tax credits tend to allow for either a certain percentage of the system costs to be claimed (up to a set maximum) or a specific amount per Watt of solar capacity installed.

Table A-1: States offering tax credits for PV installation by individuals and corporations

State	Eligible Sector	Percentage of Project Costs	Maximum Credit Limit	Additional Notes	Authority
Arizona	Individual Household Residential	25	$1,000	n/A	A.R.S. § 43-1083 (1995)
	Commercial, Industrial, Nonprofit, Schools, Government, Agricultural, Institutional	10	$50,000	N/A	A.R.S. §43-1085 (2006); A.R.S. §43-1164 (2006)
Hawaii	Individual Household Residential	35	$5,000	N/A	HRS §234-12.5 (1990; Amended 2003)
	Commercial, Multi-Family Residential	35	$500,000	N/A	HRS §234-12.5 (Enacted 1990; Amended 2003)
New York	Individual Household Residential	25	$5,000	10 kW household capacity limit; 50kW max for condominium or cooperative HOAs.	NY CLS Tax, Article § 22 606 (g-1) (1997)
	Commercial, Construction, Multi-Family Residential	Not Stated	$2,000,000 over 5 years	Part of Green Building Tax Credit Program	NY CLS Tax, Article 1 § 19 (2005)
North Carolina	Individual Household Residential	35	$10,500	N/A	N.C. Gen Stat. § 105-129.15 (1977)
	Commercial, Industrial	35	$2,500,000	N/A	N.C. Gen Stat. § 105-129.15 (1977)
Oregon	Individual Household Residential	50	$6,000 total; $1,500 per taxable year	$3/peak watt credit, subject to other limitations	OAR 330-070-0010 thru 0097 (2008)
	Commercial, Industrial, Construction, Multi-Family Residential, Agricultural, Equipment manufacturers	50	$10,000,000 over 5 years	May claim entire credit if total credit less than $20,000	OAR 330-090-0105 to 330-090-0150 (2008)

[113] The sector of corporate entity will be defined in each state example provided.

As seen above, either North Carolina's or Oregon's credit for individual households and corporate sectors is the most favorable of the states listed, depending upon whether the installation is large enough to reach the project credit limit. Though rebates and grants are often seen as the incentive with the most generous up-front offset of installation costs, a state tax credit can offer another opportunity for operators to take advantage of and defray their system costs.

Sales Tax Incentives

A sales tax incentive will generally take the form of an exemption from state and/or local sales taxes, and in certain states use taxes, for the purchase of a solar PV system. Five of the nine states sampled provide sales tax incentives, with four of them providing a complete waiver from state-imposed sales (or sales and use) taxes. Those four states, Arizona, Connecticut, New Jersey, and Nevada, have all waived their sales taxes for the sale of solar PV systems across all sectors.[114] The final state, Nevada, allows for a sales tax and use tax abatement, abating everything above 0.6% for a period of three years (starting in 2009), then returning back to the standard state sales tax rate of 2%.[115] Therefore, where states have elected to exempt a solar electric system sale from sales or sales and use tax, the majority choose to completely waive the tax altogether.

Property Tax Incentives

A property tax incentive may partially or totally waive property taxes imposed at the local, regional or state level for the added value a new solar-electric generating system would add to the owner's property. This incentive can take the form of an exemption, exclusion or credit.

The exemption (or total waiver) is the more common form of property tax incentive, with Arizona, California, Connecticut, Nevada, New Jersey, and New York all incorporating it into their respective solar financial incentive packages.[116] Each of these state exemptions is available for commercial, residential, and industrial sectors, with Connecticut and New York also extending it for agriculture. Arizona's property tax exemption is limited to solar energy devices designed for the production of solar energy for on-site consumption. New Jersey's exemption applies only to local taxes, as the state does not impose a statewide income tax on its residents. New York's property tax exemption has two components: (1) a complete exemption from general municipal property taxes, school district taxes, and special ad valorem taxes (does not apply to special assessments) for single-family to four-family dwellings; and (2) a 15-year complete exemption, which local governments have the option to refuse to enforce if they so choose.

[114] A.R.S. §42-5075(14) (1997); Conn. Gen. Stat. § 12-412 (2007); N.J. Stat § 54:32B-8.33 (2008); NY CLS Tax, Article 28 § 1115 (ee) (2005).
[115] N.R.S. § 701A.230 (2009); AB 522 (2009)
[116] A.R.S. §42-11054 (2006); Cal.Rev. & Tax Code § 73 (2008); Conn. Gen. Stat. § 12-81(57) (2007); N.R.S. § 701A.200 (1975); New Jersey S.B. 241 (2008); and N.Y. C.L.S. Real Property Tax, Article 4 § 487 (1977).

Two sampled states also have partial property tax exemptions. North Carolina exempts 80% of the appraised value of a solar electric system from property taxes.[117] Also, Arizona has another property tax exemption that applies to owners of solar electricity generating equipment producing electricity exclusively for off-site consumption, and allows for an assessed valuation at 20% of its depreciated costs for the purpose of determining property taxes.[118] This statute is targeted at reducing the value of solar generation equipment installed by IOUs, MOUs, and REAs, which are generating electricity for consumption at different sites.

Once again, the most common form of property tax incentive is to completely waive the added value a solar electric generation system would contribute to a property for the purposes of property tax valuation.

Financing Incentives

A loan program can be an attractive option for potential solar electric generating systems by providing security to finance the purchase of these systems with zero-interest or low-interest financing. States offer these favorable financing terms to spur solar generation growth, with most programs being distinguishable based on sector.

Connecticut, North Carolina, and New York offer financing incentive programs to all sectors (with the one notable exception that North Carolina does not offer to the residential sector).[119] Connecticut's loan program focuses on offering low-interest loans (never higher than the prime interest-rate) for customer-side distributed generation. The program has a project capacity range of 50 kW to 65 MW, so the intention is to attract larger solar electric generating systems. Both New York and North Carolina require all loans to be paid back within a ten-year term, with North Carolina offering a 1% interest loan and NYSERDA guaranteeing a rate at least 4% below lender rate (with the potential to increase to 6.5% for particular commercial and multifamily borrowers within Con-Edison's service territory).

New York also offers a residential sector-only loan, essentially targeting smaller distributed solar electric systems.[120] This loan figure ranges in amount from $2,500 to $20,000, with the cap set at $15,000 to $20,000 (depending upon credit score). Interest rates are offered at 5.99%, with the term of the loan set at 3, 5, 7, or 10 years. As noted earlier with NYSERDA's up-front cash grant program, only customers paying into NYSERDA's SBC are eligible to apply for the financial incentives.

An agricultural/aquacultural sector-only loan is offered by Hawaii.[121] The loan covers up to 85% of system and installation costs, with a project cap set at $1,500,000 and a term that may extend for as long as forty years. Agricultural applications qualify for a 3% interest rate, whereas solar generating systems associated with an aquacultural operation can secure a 5%

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[117] N.C. Gen. Stat. § 105-275 (2008)
[118] A.R.S. § 42-14155 (2000).
[119] Conn. Gen Stat. § 16-243j (2005); http://www.nyserda.org/loanfund/ (accessed 7/13/09); N.C. Gen. Stat. § 143-345.18 (2001).
[120] http://www.getenergysmart.org/SingleFamilyHomes/ExistingBuilding/HomeOwner/Financing.aspx# (accessed 7/13/09).
[121] H.R.S. § 155-8 (2008).

annual interest rate. A final requirement for applications under this program is that the borrower must have a quality credit score, as determined and approved by the Hawaii Department of Agriculture.
Finally, the Berkeley, California's Financing Initiative for Renewable and Solar Technology (FIRST) is a local loan program worth mentioning for its innovativeness.[122] Essentially, FIRST allows property owners to borrow money from the City, which funds the program through the issuance of special government tax bonds, to install PV systems and repay the cost over twenty years through an annual special surcharge on property tax bills. There is a $37,500 cap per project for residential and commercial properties, with an effective rate (as of June 26, 2009) set at 7.75%. If the property owner chooses to sell the property, the solar system and remaining balance of the loan will run with the property. Participation in the program does not preclude the property owner from also taking advantage of California's other financial incentive programs, such as the CSI rebate.

Public Benefit Funds

Public Benefit Funds (PBFs), which may be funded via a system benefit charge (SBC), are programs established to target and ensure support for new renewable energy systems, energy efficiency initiatives, and low-income energy measures. The SBC is generally a very small surcharge per kWh, applied to the electricity consumption of ratepayers within a specified service territory. These ratepayers are then eligible for the benefits available from the fund.

California and New York each have each established a PBF to finance many of the renewable energy initiatives they have established.[123] In addition to those two, Connecticut, New Jersey and Oregon have funds as well.[124] Each of these funds supports renewable energy, energy efficiency and R & D initiatives.

A common thread among these programs is a requirement for the IOUs of each respective state to collect and return a certain percentage or specified amount back to the fund annually in order fund the financial incentive programs within that state. Therefore, the utility collects the surcharge for the purpose of replenishing the fund, which is overseen by a program administrator. In Connecticut, Connecticut Light and Power and United Illuminating charge their customers $0.001/kWh to raise $20 million per year for the renewable projects CCEF.[125] Municipal utilities in Connecticut are also required to create their own PBF, which is to be funded by the ratepayers of the municipality.[126] These funds are used to provide renewable energy, energy efficiency, conservation, and load-management programs.

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[122] http://www.berkeleyfirst.renewfund.com (accessed July 28, 2009).
[123] California: A.B. 1890 (1996), A.B. 995 (2000), S.B. 1194 (2000), S.B. 1036 (2007); New York PSC Opinion No. 96-12 (Case 94-E-0952) (1996), New York PSC Order (Case 94-E-0952) (2001), New York PSC Order (Case 05-M-0090) (2005).
[124] Conn. Gen. Stat. § 16-245n (1998); N.J. Stat. § 48:3-60 (1999); O.R.S. 757.612 (1999).
[125] Connecticut also operates a separate PBF for energy efficiency and low-income projects, the Connecticut Energy Efficiency Fund ("CEEF"). The CCEF is funded by a separate $.003/kWh surcharge applied to the bills of the state's two main IOUs.
[126] Conn. Gen. Stat. § 7-233(y) (2000).

New Jersey's PBF imposes a non-bypassable SBC to all customers of the state's seven IOUs for the purpose of funding renewable energy, energy-efficiency, and low-income initiatives. From 2001 through 2012, the fund should raise approximately $2.439 billion.[127] The use of this fund is heavily weighted toward energy efficiency, with 80% of all monies dedicated toward these initiatives (and the remaining 20% toward renewable energy programs).

The scope of these funds can be quite large in terms of the amount raised to fund renewable energy and energy efficiency programs. Additionally, cost to ratepayers is relatively minimal as the per kWh charge is nominal. Therefore, PBFs can be a desirable alternative for a state looking to offer certain financial incentive programs.

California Solar Incentive Program

The California Solar Initiative, which is funded by a statewide systems benefit charge (SBC), is an umbrella program that includes five different solar incentives, three of which provide rebates for PV projects.[128] The CSI has three subprograms that offer rebates for PV installations: (1) the General Market Solar Program (General Program); (2) the Single-Family Affordable Solar Homes (SASH) Program; and (3) the Multifamily Affordable Solar Housing (MASH) Program.[129] Applications for this program are due July 31st of each year.

The largest of these programs, the General Program, has a goal of 1,750 MW of installed PV capacity and a ten-year budget of $1.9 billion.[130] It offers two payment options: a PBI for all installations and a cash rebate available only to smaller qualifying systems. To qualify for either incentive, a project must be an existing residential property or a new or existing commercial, industrial, or agricultural property. Systems smaller than 50 kW installed capacity may elect for either the rebate or PBI, while PV systems of greater capacity are required to accept the PBI (as of Jan. 1, 2010, all systems greater than 30kW will be required to take the PBI). The payment level is adjusted for expected performance based on the characteristics of the PV system, including the slope of the roof, orientation of the panels, and the presence of any obstructions resulting in shading. Both the rebate and PBI decrease over the 10-year life of the General Program, though the PBI is only available for sixty consecutive monthly payments once the system becomes operational.

The following tables describe the current status of each IOU's rebate and PBI program:

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[127] 2001-04 $482 million, 2005-08 $745 million; and estimated to raise $1.213 billion from 2009-12.
[128] *See* California S.B. 1 (2006); CSI Program Handbook (2009), *available at* http://www.gosolarcalifornia.org/documents/csi.html.
[129] The General Program and MASH programs are available only to ratepayers within the service territories of Southern California Edison ("SCE"), Pacific Gas & Electric ("PG&E"), and San Diego Gas & Electric ("SDG&E"). The SASH program is administered by a statewide program manager, GRID Alternatives.
[130] The SASH and MASH programs each have a budget of $108 million and installed capacity goals of 85 MW.

Table A-2: Status and Degression of CSI's General Market Solar Program

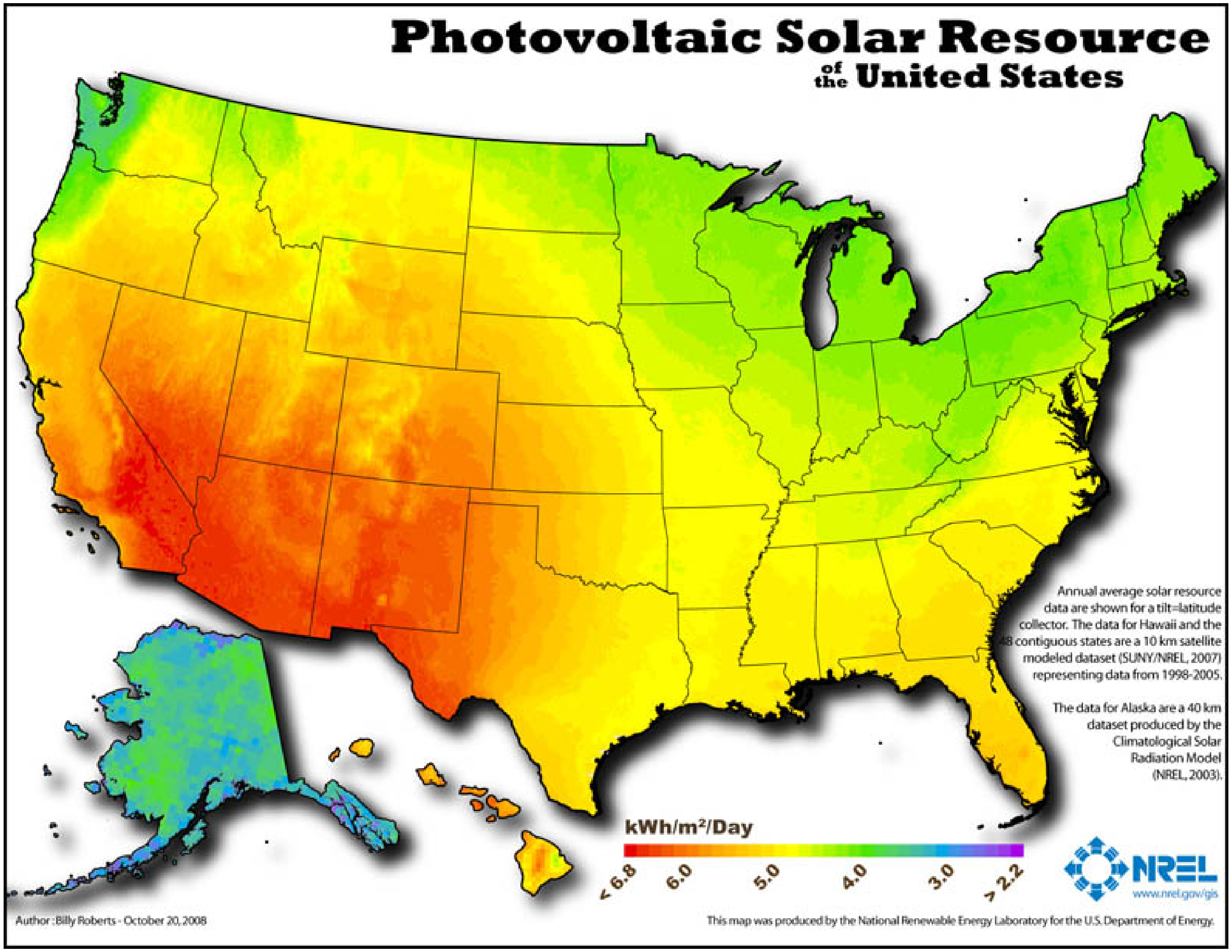
Administrator	Customer Class *	Current Step	Initial MW in Step	Unused MW from Previous Steps	Revised Total MW in Step	Issued Conditional Reservation Letters (MW)	MW Remaining	MW Under Review
PGE	Residential	5	23.10	1.04	24.14	15.63	8.51	0.58
	Non-Residential	6	55.60	8.27	63.87	14.98	48.90	2.84
SCE	Residential	4	19.70	0.10	19.80	1.24	18.56	1.42
	Non-Residential	5	49.30	28.40	77.70	19.98	57.72	13.14
CCSE (administers SDG&E service territory)	Residential	5	5.40	0.00	5.40	0.59	4.81	0.67
	Non-Residential	5	11.10	4.56	15.66	2.28	13.38	1.04

Table A-3: Status & Degression of CSI's General Market Solar Program's Rebate & PBI Payment Options

		Rebate Payments (per Watt)			**PBI Payments (per kWh)**		
Step	**Statewide MW in Step**	**Residential**	**Non-Residential**		**Residential**	**Non-Residential**	
			Commercial	**Government/ Non-Profit**		**Commercial**	**Government/ Non-Profit**
1	50	n/a	n/a	n/a	n/a	n/a	n/a
2	70	$2.50	$2.50	$3.25	$0.39	$0.39	$0.50
3	100	$2.20	$2.20	$2.95	$0.34	$0.34	$0.46
4	130	$1.90	$1.90	$2.65	$0.26	$0.26	$0.37
5	160	$1.55	$1.55	$2.30	$0.22	$0.22	$0.32
6	190	$1.10	$1.10	$1.85	$0.15	$0.15	$0.26
7	215	$0.65	$0.65	$1.40	$0.09	$0.09	$0.19
8	250	$0.35	$0.35	$1.10	$0.05	$0.05	$0.15

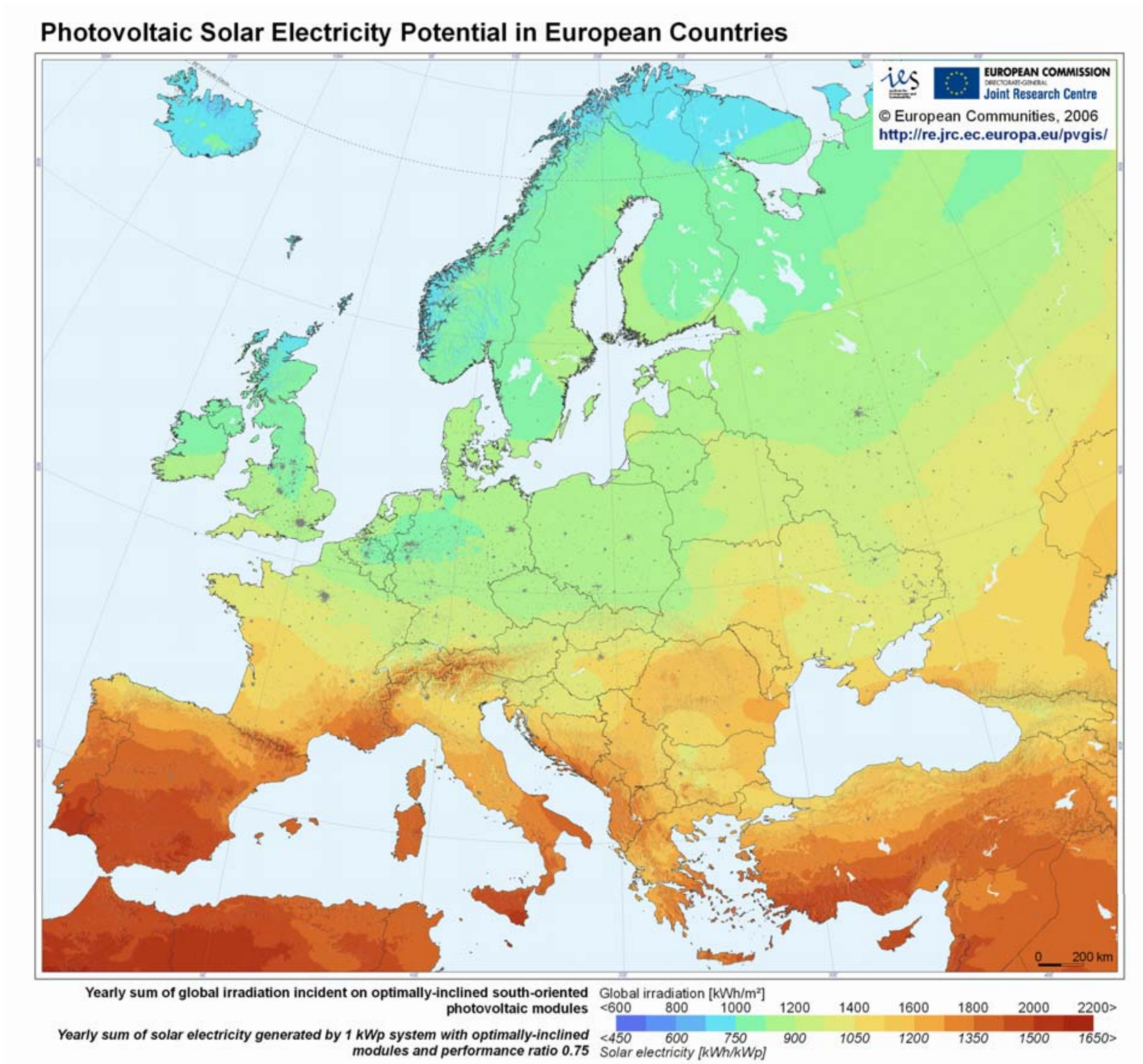
Appendix B: Data for Comparison Metrics

Figure B-1: Map of US PV Potential, $kWh/m^2/day$[131]



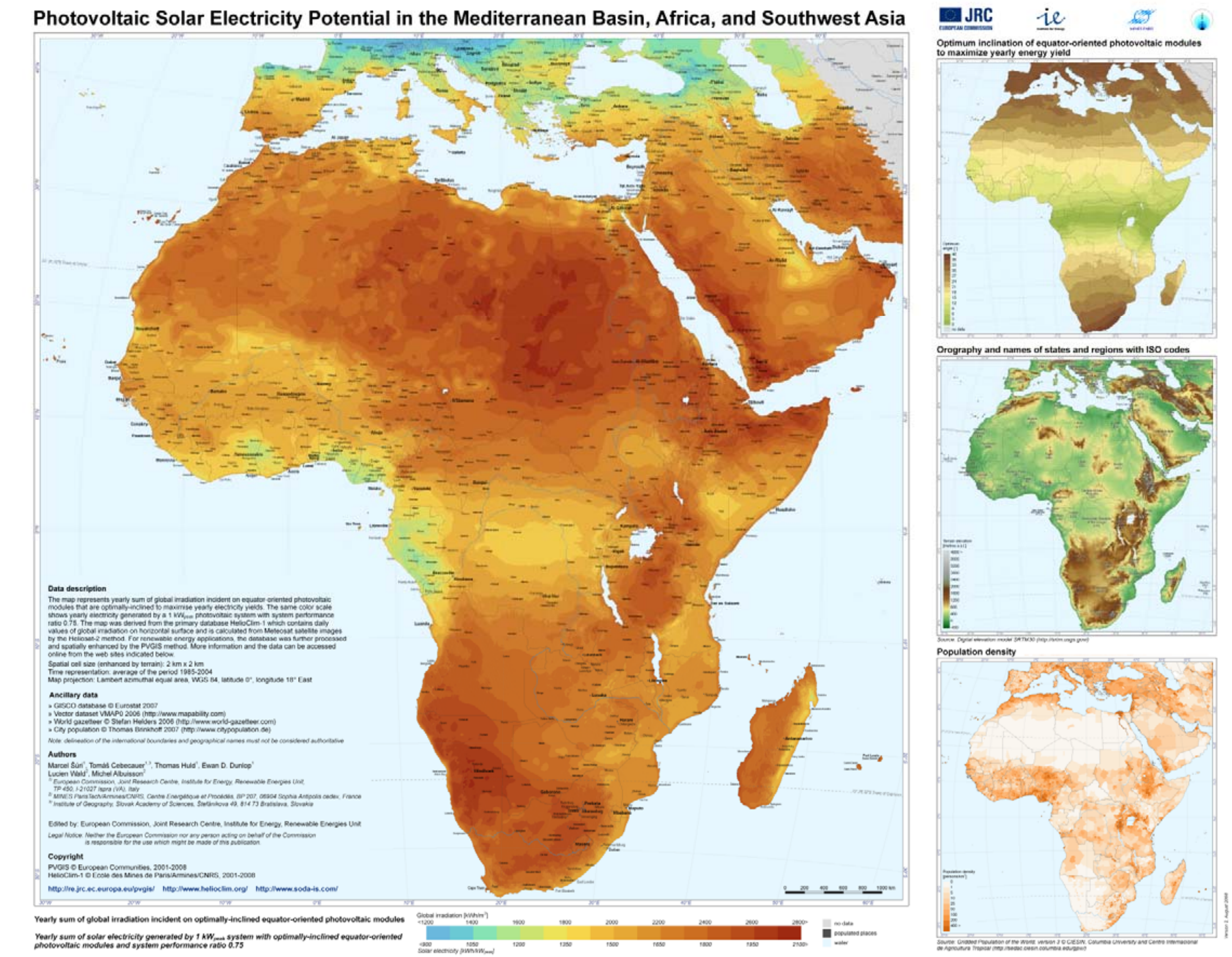
[131] *Available at* http://www.nrel.gov/gis/images/map_pv_national_lo-res.jpg.

Figure B-2: Map of European PV Potential, kWh/m² [132]



[132] *Available at* http://re.jrc.ec.europa.eu/pvgis/cmaps/eu_opt/pvgis_Europe-solar_opt_publication.png.

Figure B-3: Map of African PV Potential, kWh/m^2 [133]



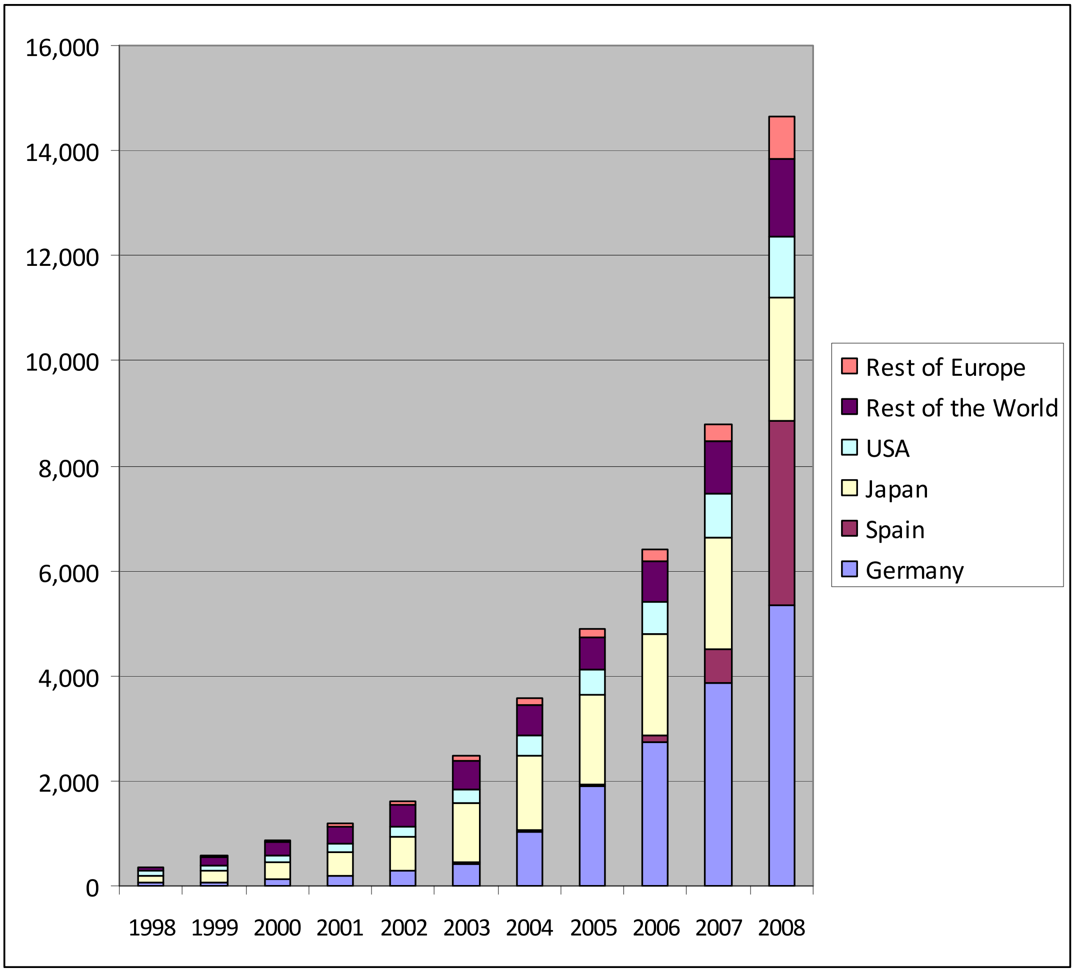
[133] *Available at* http://re.jrc.ec.europa.eu/pvgis/countries/afr/PVGIS_Africa_SolarPotential_img_v2.png.

Figure B-4: Cumulative Installed PV Capacity (MW) by Country[134, 135]

Country	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Australia	7.3	8.9	10.7	12.7	15.7	18.7	22.5	25.3	29.3	33.6	39.1	45.6	52.3	60.6	70.3	82.5	*n/a*
Austria	0.6	0.8	1.1	1.4	1.7	2.2	2.9	3.7	4.9	6.1	10.3	16.8	21.1	24.0	25.6	27.7	30.2
Canada	1.0	1.2	1.5	1.9	2.6	3.4	4.5	5.8	7.2	8.8	10.0	11.8	13.9	16.7	20.5	25.8	32.7
Denmark	0.0	0.1	0.1	0.1	0.2	0.4	0.5	1.1	1.5	1.5	1.6	1.9	2.3	2.7	2.9	3.1	3.3
France	1.8	2.1	2.4	2.9	4.4	6.1	7.6	9.1	11.3	13.9	17.2	21.1	26.0	33.0	43.9	75.2	91.2
Germany	5.6	8.9	12.4	17.7	27.8	41.8	53.8	69.4	113.7	194.6	278.0	431.0	1034.0	1897.0	2727.0	3862.0	5340.0
Israel	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.5	0.9	1.0	1.3	1.8	*n/a*
Italy	8.5	12.1	14.1	15.8	16.0	16.7	17.7	18.5	19.0	20.0	22.0	26.0	30.7	37.5	50.0	120.2	458.3
Japan	19.0	24.3	31.2	43.4	59.6	91.3	133.4	208.6	330.2	452.8	636.8	1132.0	1421.9	1708.5	1918.9	*n/a*	*n/a*
Mexico	5.4	7.1	8.8	9.2	10.0	11.0	12.0	12.9	13.9	15.0	16.2	17.1	18.2	18.7	19.7	20.8	*n/a*
Netherlands	1.3	1.6	2.0	2.4	3.3	4.0	6.5	9.2	12.8	20.5	26.3	45.9	49.5	51.2	52.7	53.3	55.0
Norway	3.8	4.1	4.4	4.7	4.9	5.2	5.4	5.7	6.0	6.2	6.4	6.6	6.9	7.3	7.7	8.0	*n/a*
Portugal	0.2	0.2	0.3	0.3	0.4	0.5	0.6	0.9	1.1	1.3	1.7	2.1	2.7	3.0	3.4	17.9	68.0
South Korea	1.5	1.6	1.7	1.8	2.1	2.5	3.0	3.5	4.0	4.8	5.4	6.0	8.5	13.5	35.8	81.2	357.5
Spain	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	3.0	7.0	11.0	22.0	45.0	143.0	655.0	3500[136]
Sweden	0.8	1.0	1.3	1.6	1.8	2.1	2.4	2.6	2.8	3.0	3.3	3.6	3.9	4.2	4.8	6.2	7.9
Switzerland	4.7	5.8	6.7	7.5	8.4	9.7	11.5	13.4	15.3	17.6	19.5	21.0	23.1	27.1	29.7	36.2	*n/a*
United Kingdom	0.2	0.3	0.3	0.4	0.4	0.6	0.7	1.1	1.9	2.7	4.1	5.9	8.2	10.9	14.3	18.1	22.5
United States	43.5	50.3	57.8	66.8	76.5	88.2	100.1	117.3	138.8	167.8	212.2	275.2	376.0	479.0	624.0	830.5	1168.5

[134] Based on http://www.iea-pvps.org/products/download/rep1_17.pdf and supplemented with most recent national trends reports.
[135] Includes both grid-connected and off-grid capacity.
[136] Estimate.

Figure B-5: Cumulative Growth of the Global Annual PV Market by Region in MW[137]



[137] EPIA Global PV Market to 2013, p.4 from figure 2.

Figure B-6: Top Five Markets for Cumulative Installed PV Capacity, in MW[138]

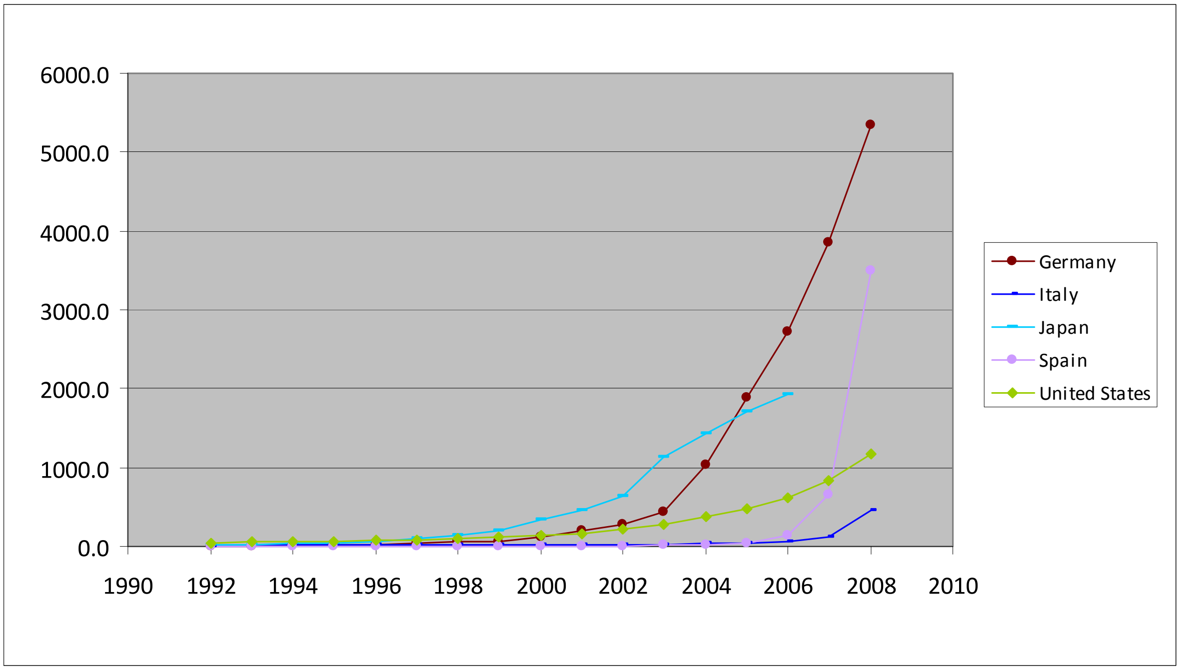
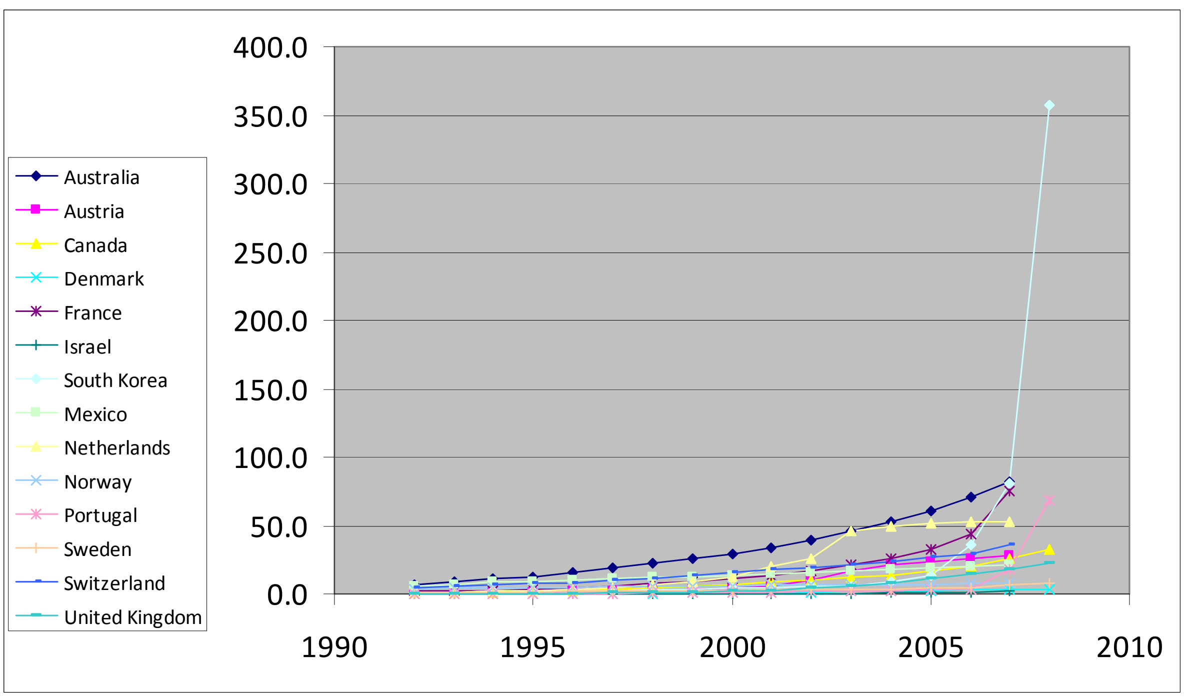


Figure B-7: Cumulative Installed PV Capacity for Specified Countries, in MW[139]



[138] Based on data collated from Klein (2008); IEA-PVPS (2009).
[139] *Id.*

Figure B-8: Capacity Additions by Country or Region in 2008, in Percent of Total MW[140]

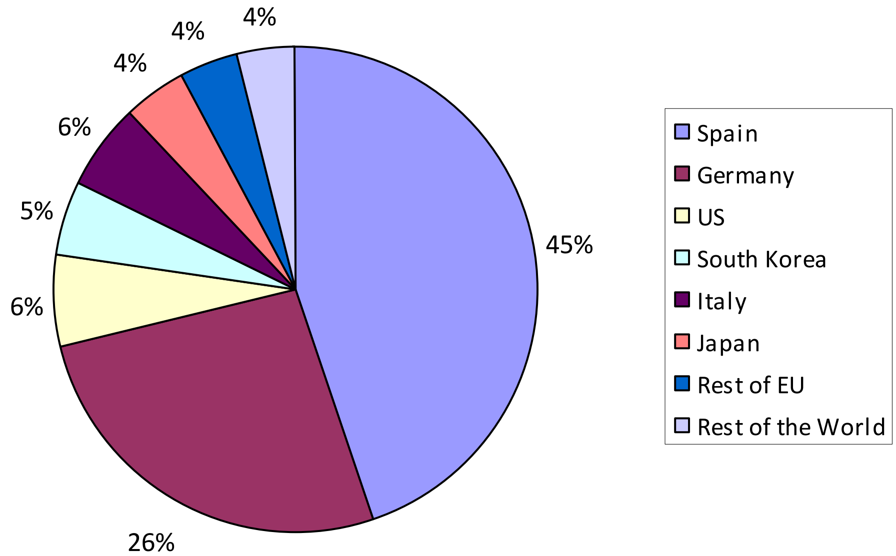
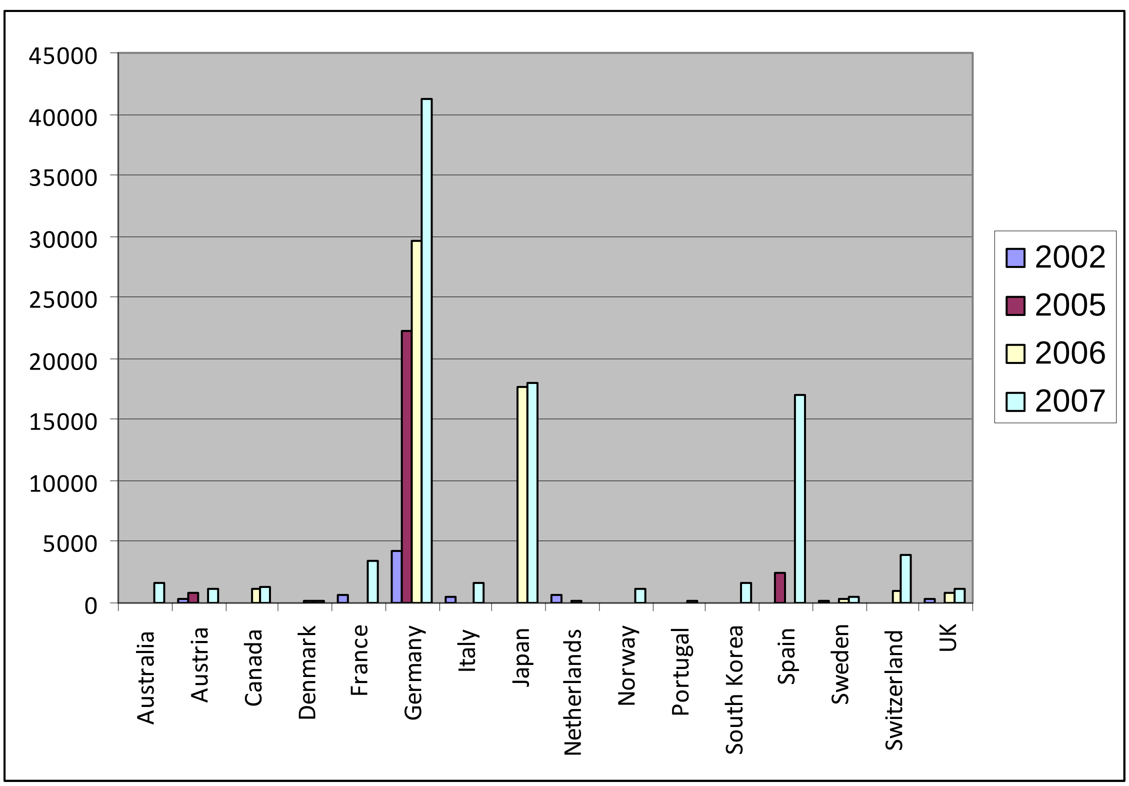


Figure B-9: Gross Direct Job Creation by Year in the PV Sector in Selected Countries[141]



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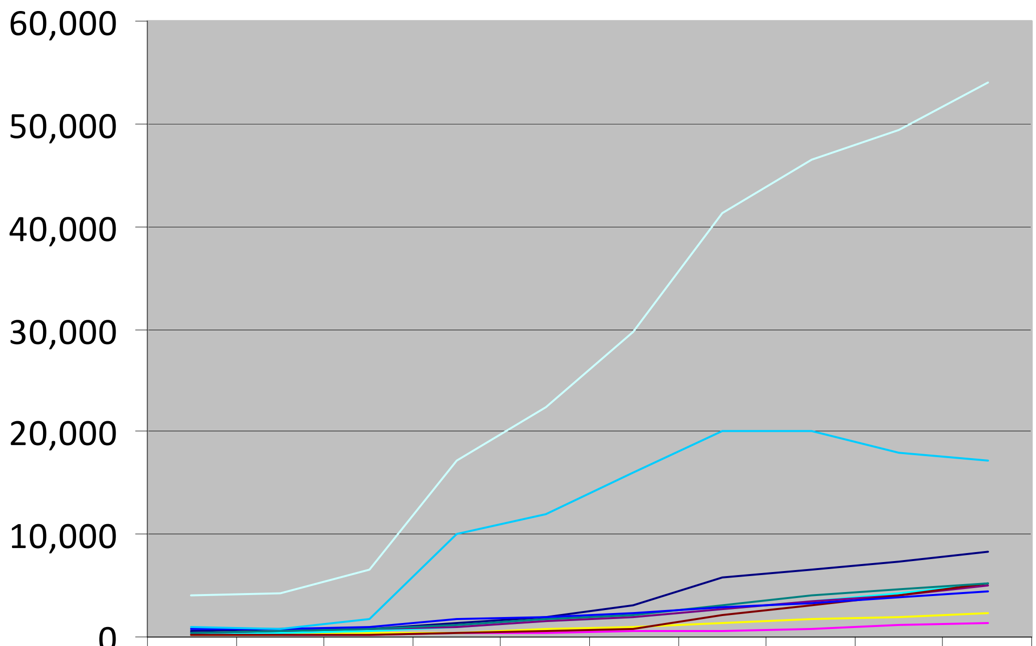
[140] *Id.*
[141] Based on data from IEA-PVPS, Greenpeace EPIA, del Rio & Unruh p.1509.

Figure B-10: Jobs in the German PV Industry, 2001-2010[142]



	2001	2002	2003	2004	2005	2006	2007e	2008e	2009e	2010e
Silicon	666	713	761	1,379	1,937	3,036	5,847	6,551	7,339	8,222
Wafer/Ingots	119	151	217	295	475	531	576	844	1,064	1,348
Cells	173	219	316	428	690	996	1,332	1,732	1,992	2,286
C-modules	368	465	671	909	1,465	1,877	2,742	3,549	4,283	5,168
Thin film	389	492	710	962	1,550	2,022	2,740	3,443	4,132	4,966
Modules	124	157	226	307	495	828	2,057	3,014	4,036	5,210
BOS	433	548	790	1,071	1,727	2,067	3,105	4,086	4,722	5,299
Wholesaler	769	865	1,057	1,825	1,960	2,278	2,861	3,314	3,840	4,448
Craftsmen	1,000	700	1,800	10,000	12,000	16,000	20,000	20,000	18,000	17,100
Total	4,041	4,310	6,548	17,176	22,299	29,635	41,260	46,533	49,408	54,047

142 Based on data from BSW-Solar, slide 22, http://www.german-renewable-energy.com/Renewables/Redaktion/PDF/en/Vortraege-2009/en-Renexpo-2009-Urbschat,property=pdf,bereich=renewables,sprache=en,rwb=true.pdf.

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