The German Feed-in Tariff: Recent Policy Changes

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Summary

- German feed-in tariffs (FITs) for the generation of electricity from renewable sources, under the Act on Granting Priority to Renewable Energy Sources ("the EEG"), are entering their third phase of existence. In Phase One (2000-2009) Germany focused on scaling up domestic renewable electricity generation. With the costs of electricity from technologies such as solar PV far from cost competitiveness, Germany established a FIT policy design that provided Transparency, Longevity, and Certainty (TLC) to investors. During this period, degressions in FIT rates were modest and adjustments to the EEG occurred at regular intervals. During Phase Two (2009-2011) rapid declines in the cost of solar PV modules prompted Germany to more actively adjust its PV FIT in order to manage the volume of annual PV installations under its FIT programs (by, for example, linking FIT degressions for PV to the volume of PV installations in previous periods and reviewing the PV policy more frequently). In Phase Three (2012 –), continued cost declines are making solar PV, wind, and biomass increasingly competitive with traditional sources of electricity; in response, the key elements of Germany's 2012 EEG – including reduced FIT payments, a market premium option, a 90% cap on FIT-eligible PV electricity, and addition of a 52 GW PV capacity threshold – all mark an evolution of German FITs toward a "grid parity" future where policy is more flexible and may offer less TLC to investors. Indeed, in terms of "gird parity", the cost of electricity from small PV systems in Germany is in some cases already below retail rates.

- Costs are attracting increasing attention politically ahead of next year's general election in Germany. Continued declines in the cost of renewable generating technologies have *decreased* the level of the FIT payments required to make investment in renewable electricity financially attractive. At the same time, strong growth in the volume of FIT contracts has *increased* the size of the EEG surcharge that is passed on to ratepayers. The 2012 EEG (and subsequent June 2012 PV Amendment) respond to both of these developments by (1) trimming FIT payments for onshore wind and solar PV generators; and (2) accelerating FIT degression schedules for biomass, onshore and offshore wind, geothermal, and solar PV. During Phase Three, the progression to cost competitiveness for renewables will be accompanied by diminished levels of government support -- continuing a trend established during the first two Phases. It is likely that policy costs will continue to be an issue of discussion, particularly as the new EEG surcharge for 2013 will be announced on October 15, 2012. For example, in August 2012, Germany's Environment Minister Peter Altmaier published a 10-point energy and environmental plan that – while emphasizing continued support for scaling up renewable energy sources - encourages "a fundamental revision of the Renewable Energy Law (EEG)".[2] Among

[1] We thank the following individuals for additional review and support: Jonathan Crowe (Meister Consultants Group, Inc.), Summer Jackson (Meister Consultants Group, Inc.), Chad Gordon (Meister Consultants Group, Inc.), and Jolanta Jasina (IFOK GmbH).

[2] Peter Altmaier (August 2012), Mit Neuer Energie:10 Punkte für eine Energie- und Umweltpolitik mit Ambition und Augenmaß.

other topics, Minister Altmaier's plan focuses on the need to ensure affordable energy, and keeps open the possibility of abandoning feed-in tariffs for renewable energy in favor of a quota system.[3] Altmaier's document also raises the possibility of additional revisions to the EEG, and questions how to balance the impact on ratepayers with the need to meet Germany's energy transition goals.

- A central goal of Phase Three is to encourage renewable generators to behave more like conventional generators – chiefly, in considering the wholesale market value of the energy that they produce. Traditional FIT contracts reward the production of renewable electricity irrespective of where and when that electricity is produced. In Germany, rapid addition of wind and solar generation has resulted in the supply of electricity exceeding demand during several periods of the year, which has caused electricity market prices to plummet to zero (and below). While beneficial to some consumers (in the short term, at least), such events illustrate the economic value of electricity to depend heavily on when and where it is produced. The 2012 EEG includes several revisions designed to encourage investment in more competitive renewable electricity. Under the new "market premium option" FIT-eligible generators can elect to sell directly into the spot market, and supplement spot market revenues with a FIT payment that varies inversely with the average monthly electricity price. Payment of a market premium (rather than a traditional FIT) creates incentives to maximize the market value of generation and to master wholesale market operations. Moreover, for commercial-scale PV systems (10 kW – 1 MW), 10% of electricity generated is no longer eligible for FIT payments, but must instead be consumed onsite, sold in the wholesale market, or compensated at the average daytime spot market price. Again, this 10% requirement provides an incentive to site commercial-scale PV systems in higher-value applications and locations.

- As renewable generating technologies become more cost-competitive, there is increased potential for FIT-eligible installations to surprise on the upside – particularly for modular, rapidly-installed systems such as solar PV. Building on the volume-based degression schedules for solar PV instituted in Phase Two, Phase Three seeks to further minimize upside volume surprises by (1) raising the amount of total potential FIT cuts (such that the solar PV FIT could decrease by up to 29% over a 12-month period); (2) adding additional milestones that must be met in order for PV systems to "lock in" a given FIT rate ; and (3) imposing a 52 GW capacity threshold on the cumulative amount of PV that is eligible for FIT payments under the EEG. Once this threshold is crossed, an unspecified new policy framework – in which incentive payments will no longer be recoverable through the EEG ratepayer surcharge – will come into force.

- Phase Three of the German FIT is likely to see increased scrutiny of how much the FIT payments cost and how that cost is allocated among different classes of ratepayers. The German grid operator forecasts that in 2012 the FIT program will yield a net cost of €12.7bn that must be recovered from ratepayers; to cover this shortfall, in October 2012 Germany may raise the 2013 EEG surcharge from 3.6 € cents/kWh to 5 or 6 € cents/kWh (well above the 3.5 € cents/kWh limit on the EEG surcharge that Chancellor Merkel proposed in 2011). In addition to the absolute impact, there is a distributional question as this cost is allocated unevenly among different classes of ratepayers. Large industrial customers, for example, pay the full EEG surcharge on only 10% of the electricity they consume – even though they are the primary beneficiaries of the lower spot market power prices brought about by increasing amounts of wind and solar generation. Given such disparities, Phase Three of the German FIT program may see politicians revisit the question of how to distribute the above-market costs of renewable energy.

- From an investor perspective, the EEG 2012 generally leaves intact the TLC that the German FIT program provides to investors in wind or biogas energy generating capacity. The June PV Amendment does, however, reduce slightly TLC for investors in new solar PV capacity. These reductions come about largely as a result of the efforts, outlined above, to further integrate PV generators into Germany's electricity markets. Provisions of the June PV amendment that diminish TLC for investors include:
  - The new PV degression schedule, which increases uncertainty for investors in new PV systems about what FIT rates they will qualify for (hence their future revenues). Given the short lead times required to complete PV projects in Germany, however, this policy change may not be as significant as it would be countries with longer installation timelines.[4] That said, more frequent degressions in FIT rates complicate project financing for investors seeking to plan over a longer-term horizon.
  - The 90% FIT-eligibility cap on generation from solar PV systems, which further increases revenue uncertainty.
  - The 52 GW capacity threshold, which decreases longevity and certainty because future policy options after the threshold is reached are uncertain.

[3] See DB Research, "German environment minister has presented a 10-point energy programme," September 3 2012.
[4] According to the PV LEGAL study, residential systems may take 6 weeks to develop, commercial rooftop systems 17 weeks, and large-scale ground-mounted systems may take 90 weeks., http://www.pvlegal.eu/

As noted, the above changes reflect a shift in the EEG's evolution toward a next phase of policy evolution.

- Broadening the question of cost beyond FIT payments, Phase Three begins to broach the topic of how to allocate the costs that variable renewable generators impose on the German electricity system. For example, so as to reduce risks to stable grid operation, the 2012 PV Amendment requires all PV systems (both new and existing) to be able to curtail power output. Existing PV system owners must pay 50% of the cost of installing curtailment equipment, and any power that is curtailed is compensated at only a 95% FIT rate (thus discouraging installation of new systems in already congested areas). As solar PV and other variable generation sources continue to penetrate the German power supply, the question of how to allocate the system-wide costs of variability is likely to grow in importance.

I. Introduction

Germany's FIT regime has been essential to the country's successful drive to meet and exceed its aggressive renewable electricity goals to date. The FIT policies have been designed to support market rapid scale-up, and stand out as a policy that has delivered Transparency, Longevity, and Certainty (TLC) to investors in German renewable energy projects. As its renewable electricity share scales up from the 24% achieved by the first half of 2012 to meet national targets of 50% in 2030, 65% in 2040, and 80% in 2050, however, Germany is beginning to explore new policies to govern both conventional and renewable energy generation.

It is clear from the policy changes that came into effect at the beginning of 2012 that Germany is shifting to a third phase of policy development under the EEG. In Phase One (2000-2009) Germany focused on scaling up domestic renewable electricity generation.[5] With the costs of electricity from technologies such as solar PV far from cost competitiveness, Germany established a FIT policy design that exemplified how policy can provide TLC to investors. During this period, degressions in FIT rates were modest and adjustments to the EEG occurred at regular intervals. During Phase Two (2009-2011) rapid declines in the cost of solar PV modules prompted Germany to more actively adjust its PV FIT in order to manage the volume of annual PV installations under its FIT programs (by, for example, linking FIT degressions for PV to the volume of PV installations in previous periods and reviewing the PV policy more frequently). In Phase Three (2012 –), continued cost declines are making solar PV, wind, and biomass increasingly competitive with traditional sources of electricity; in response, Germany has modified its FIT program to pursue goals beyond simply increasing the volume of annual renewable energy installations. Specifically, new mechanisms in Phase Three encourage more active participation of renewable generators in the wholesale electricity markets. This third phase will also diminish TLC for investors in solar PV, the most rapidly growing segment of Germany's renewable generation portfolio through changes to the solar PV FIT such as (1) more frequent and potentially significant decreases in FIT payment levels; and (2) "volume triggers" that link FIT payments to how much PV has been installed in a given period, and (3) a 52 GW limit on the amount of PV that will be supported under the FIT policy.

Phase Three is also likely to see solar PV reach "grid parity" in a manner that begins to drive investment decisions and increasingly informs government policy decisions on renewable energy regulation. Key issues to be managed during these next two phases of policy development include (1) how the cost of FIT payments affects retail electricity rates; (2) how this added cost is being allocated among different classes of customers (e.g. industrial versus residential); and (3) how increasing penetration of variable renewable generators alters wholesale power prices (for example causing prices to plummet to zero or below during certain hours of the day). These issues raise important questions about strategies for managing the transition to an energy system based primarily on renewables in both Germany and beyond.

In previous research efforts, DBCCA analysis has concluded that advanced FITs have been the most effective policy for catalyzing the deployment of capital and for achieving rapid renewable energy scale-up.[6] Of the more than 65 feed-in tariffs around the world, DBCCA has also found that Germany's policy has served as a best-in-class example of delivering TLC to investors. During the past two years, however, renewable energy policy in Germany and around the world has remained dynamic as countries have reacted to quickly changing market conditions by amending their renewable energy policies. In 2011, DBCCA took another look at the German FIT, with a specific focus on the government's approach to managing solar PV market volume in the face of rapidly declining solar panel prices. The report concluded that the Germany's approach to PV volume management using unscheduled price decreases could enable the country to adapt to faster-than-expected decreases in PV module prices and attendant stronger-than-expected growth in annual PV installations (at least in the near term). The report also recommended continued monitoring of several issues that included, among others:

- ***FIT policy revisions.*** Under the new Act on Granting Priority to Renewable Energy Sources (i.e., the EEG[7]), which was written in 2011 but came into effect at the beginning of 2012 ("the EEG 2012"), Germany's FIT policy is reviewed and revised every four

[5] Prior to the EEG, Germany relied on a separate FIT system from 1991-2000 called the Stromeinspeisungsgesetz.
[6] DB Climate Change Advisors. (2011). *The German feed-in tariff for PV: Managing volume success with price response*. New York, NY: Deutsche Bank Group.
DB Climate Change Advisors. (2011). *GET FiT Plus: De-risking clean energy business models in a developing country context*. New York, NY: The Deutsche Bank Group.
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[7] *Erneuerbare-Energien-Gesetz,* officially translated as the "Renewable Energy Sources Act."

years.[8] The last report emphasized the need to monitor how Germany manages its reviews because if not carefully structured, they can decrease investor transparency.

- ***Volume-responsive degression.*** Germany has introduced a volume-responsive, or "corridor", degression system for PV under which the FIT rates decrease based on the amount of installations in prior periods. If more PV was installed than expected, the magnitude of the FIT price decrease in would be higher and vice versa. The previous report, however, pointed out that this approach introduced the risk of "overshooting" the market result if installation volumes drove prices too low for projects to be built.
- ***Grid parity.*** The 2011 report noted that the proximity of the PV FIT rates to parity with retail electricity rates raised important questions about the future of both the PV market and the structure of FIT policies in the future.

This report explores each of these three issues as part of a broader overview of the current status of policy and market conditions in Germany following the most recent legislative updates. Specifically, this report focuses on the implications that the EEG revisions will have for the wind and biogas markets. The report also focuses on the most recent amendments to the PV FIT[9], which were concluded on June 29th, 2012 (the "June PV Amendment"). As will be discussed in detail in Section IV, the June PV Amendment introduced new, lower rates and established a 52 GW threshold for PV installations. Once PV capacity reaches 52 GW, an alternative policy to support PV will be triggered, and PV will become ineligible for support under the FIT. The report concludes that *while the recent changes in law preserve Transparency, Longevity and Certainty (TLC) for investors in the wind and biogas industries, the recent PV amendments will reduce investor security as Germany begins to position the PV market for a post-incentive environment*. The report is structured as follows:

Section I presents an overview of the major changes under the EEG 2012, with a focus on the structure of the new market premium option.

Section II benchmarks market growth to date against the projections included in Germany's 2010 National Renewable Energy Action Plan.

Section III discusses the policy changes for wind and biogas generators to date and their implications.

Section IV summarizes the changes introduced under the June PV Amendment, with a focus on both the near-term and mid-term implications for PV market growth.

II. Overview of the EEG 2012: Recent Policy Changes

Enactment of the EEG 2012

On June 30, 2011, the German Parliament (*Bundestag)* adopted the EEG 2012, which subsequently came into effect on January 1, 2012. As discussed in our previous report,[10] the revisions were enacted against the backdrop of the Fukushima crisis in Japan and the political backlash against nuclear power that the crisis has inspired in Germany. In the summer of 2011, the German government closed several of the country's nuclear plants and the Parliament voted to accelerate to 2022 the deadline for a full nuclear phase-out. It was noted in 2011 that these events would likely sustain momentum for renewable energy in Germany, although the precise contents of the 2012 revision were at that time unclear.

The EEG 2012 is longer and more detailed than its predecessors. It largely preserves the framework that has successfully driven rapid renewable energy scale-up in Germany, but creates new options for generators to sell power into the wholesale electricity market. Aside from the 52 GW PV threshold, the new EEG law did not introduce major structural changes and, for some technologies such as offshore wind, it is clear that the intent of the revision is to accelerate market growth. The June PV Amendment, however, did introduce limitations on the PV FIT, which are discussed in detail in Section IV.

The EEG 2012 also sets a new renewable electricity target of at least 35% by 2020 which replaces the previous mandate of at least 30% by 2020 introduced in the previous EEG ("EEG 2009"). In addition, the EEG 2012 codifies longer-term renewable electricity targets of at least 50% by 2030, 65% by 2040 and 80% by 2050.[11] The other major changes made in the EEG 2012 and June PV Amendment include:

- ***Revisions to FIT compensation rates.*** The FIT rates paid to generators have been revised downward (except for geothermal, offshore wind and biomass), in order to reflect market conditions and place downward price pressure on developers and manufacturers.

- ***Revisions to FIT degression rates.*** The German government increased the degression rates for biomass, on- and offshore wind, geothermal, and solar PV, thus placing additional downward pressure on prices.[12] Solar PV, which is explained in further detail in

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[8] §65 and §65a of the EEG 2012 specify the review schedule and require that progress towards the national RE targets be evaluated on an annual basis.
[9] The amendment is known as the "*PV-Novelle 2012*." The full and formal title of the amendment is the "*Gesetz zur Änderung des Rechtsrahmens für Strom aus solarer Strahlungsenergie und weiteren Änderungen im Recht der erneuerbaren Energien*."
[10] DB Climate Change Advisors. (2011). *The German feed-in tariff for PV: Managing volume success with price response*. New York, NY: Deutsche Bank Group.
[11] At the time of the previous report, these long-term targets had been introduced in the government's Energy Concept policy document, but had not been formally incorporated into the law. *See* BMWI & BMU. (2010). *Energy concept for an environmentally sound, reliable and affordable energy supply*. Berlin.
[12] Annual degression for Biomass increased from 1% to 2%; off-shore wind from 5% to 7%; on-shore wind 1% to 1.5%; geothermal 1% to 1.5%; solar PV 8-11% to 1.5-24%.

Section IV, still uses volume-based triggers which adjust the future degression rates up or downwards. Solar tariff rates will now drop on a monthly basis, however, depending on the actual capacity added in the previous 12-month period. The target amount of annual PV installations, also called the "capacity corridor," will remain at 2,500 – 3,500 MW until an installed capacity threshold of 52 GW is crossed.

- ***Market premium payments.*** The EEG 2012 also encourages the direct sale of renewable electricity on the spot market through the introduction of a market premium (*Marktprämie*). Prior to the introduction of the market premium, most renewable energy generators sold their power under long-term contract at a generation cost-based rate and had no incentive to participate in the wholesale market.[13] The goals of the market premium are to increase the participation of new and existing renewable energy generators in the wholesale market and to begin the transition away from fixed price incentives. The new payment option, which is described in detail below, has already caused a significant shift towards wholesale market participation among certain renewable energy technologies.

The New Market Premium Option

Under the fixed price FIT system, power is purchased by the distribution system operators, who then sell the power on the spot market at the highest available price. Under the market premium model:

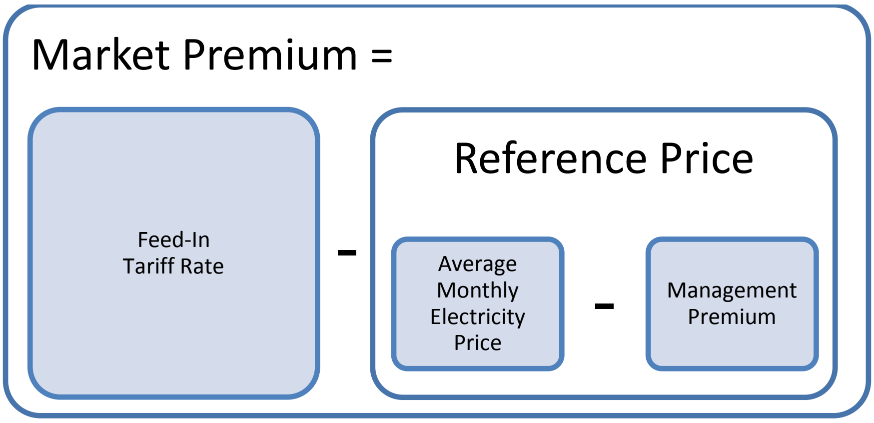
1. Power producers sell their electricity directly into the wholesale market, rather than receiving the fixed feed-in tariff payment.
2. In addition to the electricity market price, generators also receive the "market premium" payment. The amount of this market premium is calculated on a monthly basis and is equal to the difference between the **feed-in tariff** and a **"reference price,"** which is calculated at the end of each month.
3. The **feed-in tariff rate** that is used to calculate the market premium is based on the FIT available in any given month. The FIT rate used in the calculation therefore decreases over time according to the degression schedule.
4. The reference price has two components: the **average wholesale market price** and the **management premium**.
    - The average wholesale market price is an average of the spot market prices for the previous month.
    - The management premium is a proxy for the additional costs that generators incur from participating in the wholesale market, i.e. the costs of actively managing their electricity sales.[14] As can be seen in the table below, the management premium (in € cents/kWh) is differentiated by technology to reflect the fact that wind and solar generators may face a greater amount of administrative complexity, e.g. because of the need to forecast their power, etc. The management premium declines over time to provide an incentive for early participation and to reflect the fact that transaction costs should decrease as generators become more experienced.

Year	Onshore Wind	Offshore[15] Wind	Solar	Other[16]
2012	1.20	0.00	1.20	0.30
2013	1.00	1.00	1.00	0.275
2014	0.85	0.85	0.85	0.25
2015-on	0.70	0.70	0.70	0.225

5. In order to calculate the "reference price," the management premium is *subtracted* from the average wholesale market price, as can be seen in Exhibit 1 below. A larger management premium therefore leads to a smaller reference price. Since the market premium is calculated by subtracting the reference price from the feed-in tariff rate, a smaller reference price has the effect of yielding a larger market premium. In other words, **a larger management premium yields a larger market premium**. It is important to note that the management premium is a *component* of the market premium calculation, and is not a separate or additive premium payment.

Exhibit 1: Market Premium Calculation under the Current German FIT

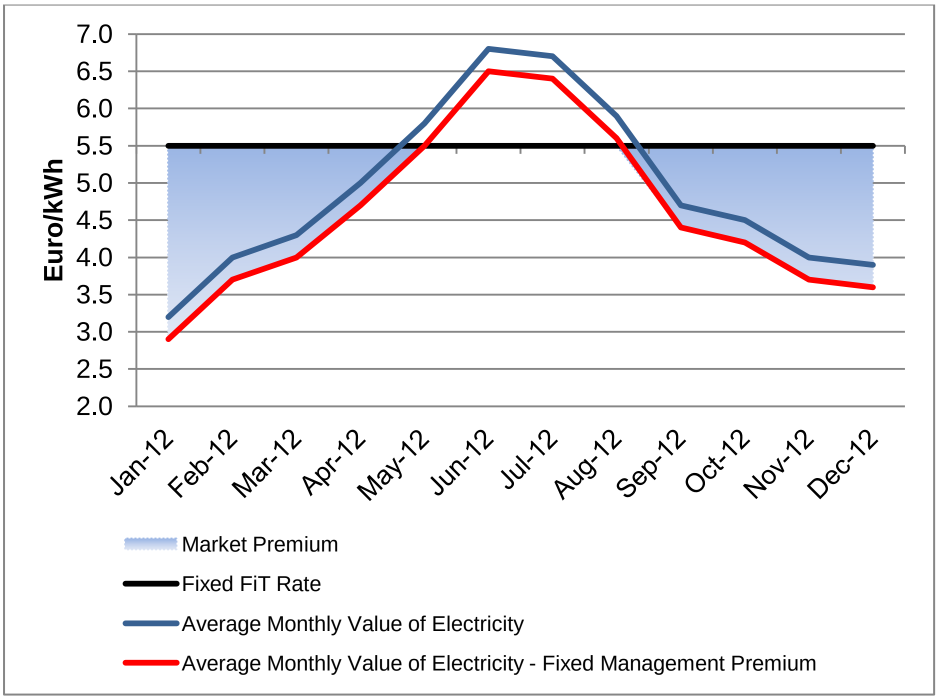
[13] There have been exceptions to this, however. Some hydropower plants, for example, have sold power in the wholesale market because the available FIT rate is lower than the spot market price. Many wastewater treatment plant digesters, on the other hand, have chosen to offset their retail electricity purchases because the retail rate has been higher than the FIT rate and because wastewater treatment plants have a high and steady, year-round onsite load that can absorb all of the power output.
[14] These costs include, "stock exchange admission, the trading connection, the transactions for recording the current values and billing, for the IT infrastructure, for staff and services, for preparing forecasts and for variations of the actual feed-in compared to the forecast." EEG 2012 Annex 4, § 1.1.
[15] No management premium for offshore wind in 2012, per Annex 4, § 2.3.4 EEG (2012).
[16] Other technologies, which are called "accessible" technologies in the EEG 2012, include hydropower, landfill gas, sewage gas, mine gas, biomass or geothermal.



Source: EEG 2012, Annex 4

As can be seen in the illustrative example in Exhibit 2 below, the market premium can fall to zero if electricity prices are high enough and this ensures that the amount per kWh paid to generators is effectively capped (e.g. no market premium would be paid during the period May-August 2012 in the Exhibit).

Exhibit 2: Forecast Payments to Generators under the Market Premium System over Time



Source: DBCCA Analysis 2012

6. Generators can switch back and forth between the market premium model and the fixed FIT payment on a monthly basis.

7. A significant feature of the market premium system is that older generators with lower rates from previous years can switch to the market premium – which is then calculated using the currently available FIT compensation rates. Under the EEG 2004, for example, wind generators locked into a rate of 8.7 € cents/kWh for at least the first five years of operation and then dropped down to 5.5 € cents/kWh for the remainder of the 20 year contract.[17] As will be discussed in Section II, these wind rates are lower than the wind FIT rate that is currently used to calculate the market premium. By February of 2012, 18,000 MW of renewable energy capacity had opted to take the market premium system, and many of these were existing generators.[18]

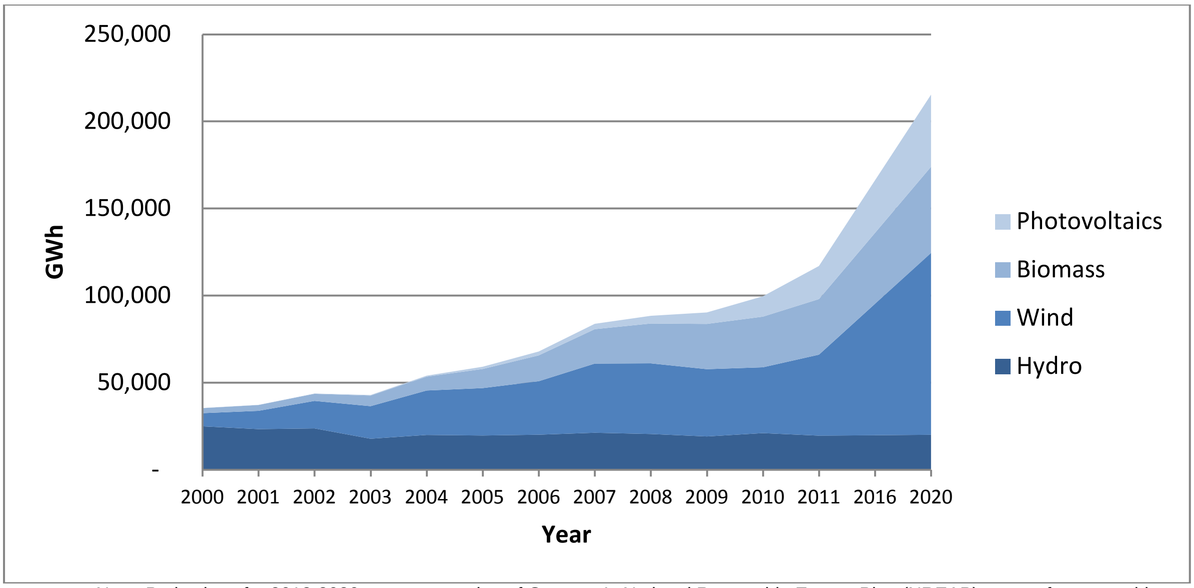
[17] As under the EEG 2012, however, the higher initial payment is extended for longer than 5 years in areas with lower wind resources.
[18] Global Wind Energy Council. (2012). *Global wind report: Annual market update 2011*. Brussels, Belgium.

Previous DBCCA publications have stated that “all in” fixed price payments are preferable to variable premium payments. There is a greater amount of risk under the market premium system than under the fixed FIT because the *actual* payments received by generators during the course of a month may be different than the average market price that is used to calculate the market premium. As a result, the degree to which the market premium “closes the gap” between the market price received and the fixed FIT payment is uncertain each month. This risk is somewhat reduced, however, because of the existence of the management premium, which partially decouples the market premium from the calculation of wholesale market price. The fact that generators can switch back and forth between the different rates also prevents generators from “locking in” permanently to a comparatively disadvantageous rate. However, the fact that the FIT rate used in the calculation also decreases over time further contributes to revenue uncertainty.

III. Renewable Energy Scale-up in Germany to Date

In 2010, Germany was required by the EU to publish projections of potential renewable energy market growth through 2020 as part of its National Renewable Energy Action Plan (NREAP). Under the NREAP, Germany developed trajectories for each renewable energy technology and projected that the country could achieve 38.6% of its power from renewables[19] by 2020 (which exceeds the current 35% by 2020 target). This would equate to 216 TWh of electricity production, versus 122 TWh of renewable generation at the end of 2011.[20] The NREAP does not represent a formal target, but it can serve as a useful benchmark against which to measure the pace of German market expansion. Exhibit 3 illustrates the growth that is projected on a technology-by-technology basis under the NREAP through 2020 – updating the original projections with the actual generation recorded in 2010 and 2011. As can be seen in the graph below, a steep ramp up in renewable generation will be required in order to stay on track with the NREAP projections.

Exhibit 3: Electricity Generation in Germany, 2000 – 2020 (GWh)[21]



Note: Projections for 2012-2020 assume meeting of Germany's National Renewable Energy Plan (NREAP) targets for renewable generation.
Source: Federal Republic of Germany (2011) & BMU (2011)

Exhibit 4 below presents another way to compare NREAP projections with actual market growth to date in order to evaluate recent trends. For each technolgy the "2010 est." and "2020 est." columns represent the values projected in the NREAP. The "2010 actual" and "2011 actual" columns contain the actual amount of generation in those years. The final two columns show how actual market growth through 2011 compares to the NREAP trajectories: first, by calcuating the average amount of GWh that will need to be added to the grid every year from 2012-2020 in order to maintain the trajectory, and second by showing how annual increases in renewable electricity generation to date compare with the average annual additions required to meet NREAP.[22] As can be seen in Exhibit 4, the amount of wind generation has thus far lagged behind what was projected on an annual basis. As of 2011, the actual amount of wind generation added has been only 93% of the average annual additions in the NREAP. This is largely due to the slower than expected uptake of the offshore wind energy sector. As a result, more wind energy than initially projected will need to be added on an annual basis through 2020 in order to maintain the NREAP trajectory.[23] A the same time, the amount of PV and biomass (primarily biogas) added during the same period significantly exceeds the NREAP trajectory. Overall, the progress of PV and biomass make up for the performance of wind. As will be discussed in Section IV, however, the 52 GW capacity threshold introduced under the June PV Amendment may constrain the ability of PV to continue to make up for sectors that lag behind.[24]

[19] Pursuant to § 3 (3) of the EEG, the following technologies qualify as "renewable energies": hydropower (including power generated from wave, tidal, current and osmotic power); wind power; solar radiation; geothermal and energy derived from biomass (including biogas, biomethane, waste and landfill gas, and gas stemming from biodegradable household and industry wastes).
[20] For targets: BMU. (2011). *Hintergrundinformationen zum Ausbau der Erneuerbaren Energien in Deutschland bis 2020*. p. 1
[21] For generation data: http://www.erneuerbare-energien.de/english/renewable_energy/data_service/graphics/doc/39831.php
[22] Hydropower is excluded from the table because it is expected to remain relatively stable for the period 2010-2020.
[23] It is important to consider, however, that a large amount of offshore wind capacity is currently in the pipeline.
[24] The 52 GW threshold is similar in magnitude to the 51.75 GW of PV installed capacity that was projected for 2020 under the NREAP. The 52 GW threshold and the NREAP projection are not formally related, however.

Exhibit 4: Current and Expected RE Generation Necessary to Meet NREAP Projections (GWh)

Technology	2010 est. GWh	2020 est. GWh	2010 actual GWh	2011 actual GWh	Avg. additional GWh required p/a to meet NREAP (2012-2020)	% of avg. NREAP GWh p/a
Wind Energy	44,668	104,435	37,800	46,500	6,437	93%
Biomass	32,788	49,457	33,900	36,900	1,395	120%
Solar PV	9,499	41,389	11,700	19,000	2,488	128%
Total	86,955	195,281	83,400	102,400	10,320	105%

Source: Federal Republic of Germany (2010) & BMU (2011)

IV. Wind and Biogas under the EEG 2012

While the NREAP can serve as a yardstick for market development, it does not represent an official target or a cap. To date, the German FIT remains one of the few feed-in tariffs that does not utilize capacity caps to control market growth for all technologies.[25] Instead, the German government has relied on using price signals to influence the amount of supply that enters into the market. This section reviews the current status of two key technology markets – wind and biogas – and discusses the recent FIT revisions and their implications for market development.

Onshore Wind

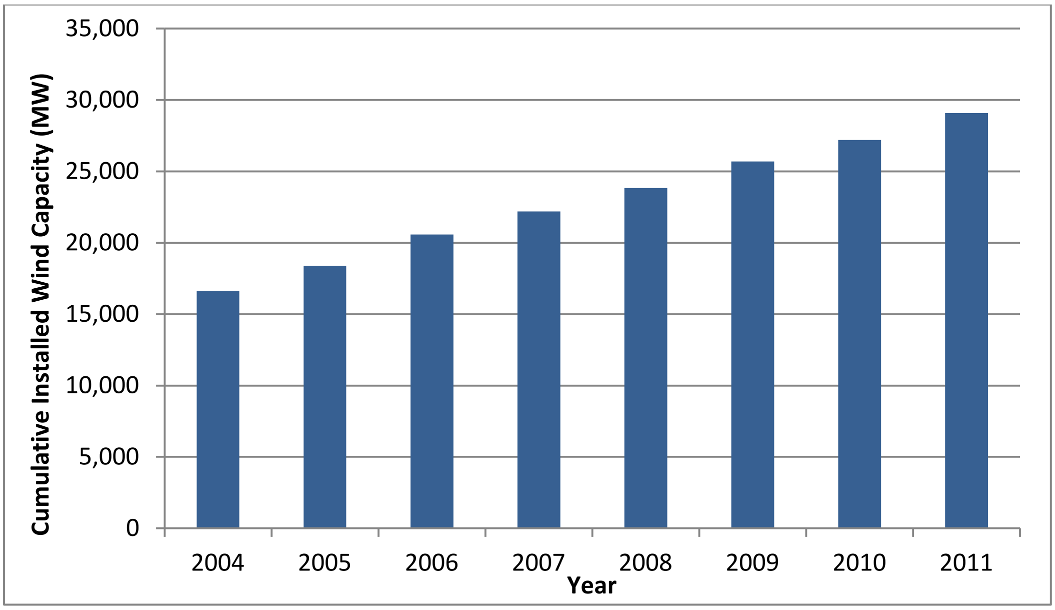
Germany added 2,086 MW of wind energy generating capacity in 2011, which made it the largest wind energy market in Europe and the 4th largest wind energy market in the world behind China, the US, and India. In total, Germany has 29,060 MW of installed wind energy capacity, which generated approximately 8% of national electricity in 2011.

Growth in the German wind energy market was slower in the second half of the last decade than during the first. Since 2007, cumulative capacity has increased by 6-8% each year, compared to double digits from 2000-2005. Although growth during the past five years has been more modest overall, the additions in 2011 represent a significant jump over the 1,437 MW installed in 2010 and reflect improving economic conditions in the wake of the recession.

The vast majority of Germany's wind capacity additions are new generators, although 238 MW of capacity came from repowered plants.[26] Exhibit 5 below shows cumulatively installed onshore capacity over time.

[25] Some analysts have referred to the 52 GW limit on PV as a cap. It is important to note, however, that the 52 GW threshold does not trigger a hard cap on the amount of PV that is installed within the country. Instead, the 52 GW threshold triggers a change in the policy utilized to support PV.
[26] Pursuant to § 30 (1) of the EEG 2012, to "repower" a plant means to permanently replace one or more existing installations with one or more new installations within the same or adjoining area.

Exhibit 5: Annual Cumulative Installed Wind Capacity (Onshore)



Source: BMU (2012)

Tariff Structure

All onshore wind projects get the same FIT payment for the first five years ("initial payment"). After the initial payment, sites with the strongest wind resources are paid at a lower level for the remaining 15 years of the FIT contract ("base payment"). Sites with less strong resources are paid the initial payment for a longer period of time before they drop down to the base payment. The amount of time that wind turbines are paid under the initial payment is calculated using a formula that compares each project's wind resource against a benchmark for annual output, called the "reference yield."[27]

As can be seen in Exhibit 6 below, the initial feed-in tariff rate available for onshore wind energy declined annually under a degression schedule between 2004 and 2008. During the drafting of the EEG 2009, lawmakers concluded that the initial rate should be raised in order to reflect the higher installed costs that had resulted from increases in steel and copper prices. Starting in 2009, the initial rate increased to 9.2 € cents/kWh and the base rate was set at 5.02 € cents/kWh with an annual degression schedule of 1% per year. Repowered sites were eligible for an additional 0.5 € cents/kWh during the period of the higher initial payment.[28]

The EEG 2012 picks up where the previous law left off by setting the initial payment at 8.93 € cents/kWh and the base tariff at 4.87 € cents/kWh. The annual degression rate, however, has been increased to 1.5%. The 2012 EEG increased the repowering tariff[29], but the installed capacity must now be at least twice as great as the capacity in place before the upgrade, and the plant being repowered must have been installed before 2002. A side-by-side comparison of the wind tariffs from the EEG 2009 and the EEG 2012 is included in Exhibit 6 below:

[27] The reference yield is calculated as the output that the project would have at a site where the annual wind speed is 5.5 meters per second at a height of 30 meters above ground, with a wind shear profile and roughness length of 0.1 meters.

[28] Under EEG 2009, wind turbines that conformed to the technical ordinance for grid integration before 2014 also received an additional bonus of 0.5 € cents/kWh for the period of the initial payment The ordinance requires that wind farms be built to meet certain standards for flicker control, harmonics, and low voltage ride-through, etc. *See* http://www.bmu.de/erneuerbare_energien/doc/44629.php. Under the EEG 2012, access to the wind integration bonus was extended until the end of 2015, but the bonus was reduced to 0.48 € cents/kWh.

[29] The EEG 2009 and EEG 2012 repowering bonuses both begin at 0.5 € cents/kWh for the first year of EEG policy implementation but decrease annually/biannually by 0.01 € cents/kWh in subsequent calendar years. In 2011, the bonus under the EEG 2009 was 0.49 € cents/kWh for repowered installations.

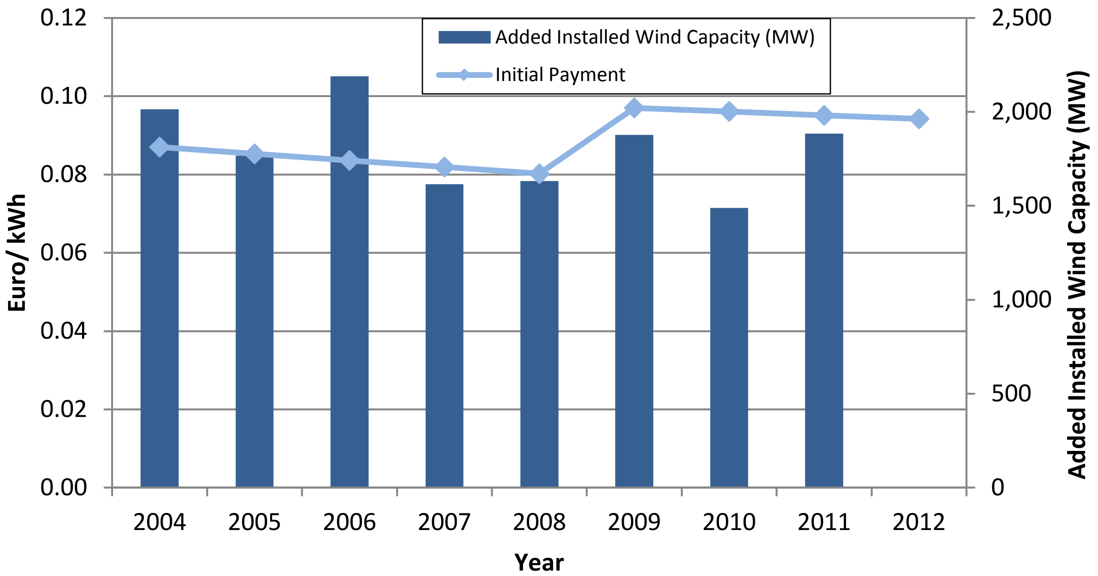
Exhibit 6: Onshore Wind FIT Rates

	EEG 2009	EEG 2012
Initial payment (€ cent/kWh)	9.2	8.93
Base payment (€ cent/kWh	5.02	4.87
Repowering bonus (€ cent/kWh)	0.5	0.5
System services bonus (€ cent/kWh)	0.5 if installed before 1/1/2014	0.48 if installed before 1/1/2015
Degression rate (p/a)	1%	1.5%

Source: BMU (2009) and BMU (2012)

Exhibit 7 shows yearly capacity additions overlaid with the evolution of the initial wind payment level over time.[30]

Exhibit 7: Annual Added Installed Wind Capacity Compared to FIT Payment



Source: BMU (2012)

Offshore Wind

Offshore wind has been comparatively slow to develop in Germany, with only ~200 MW of total installed capacity, of which 108 MW was installed in 2011. Development activity has picked up significantly, however, and by the end of 2011, 28 wind parks totaling 19.4 GW[31] were approved and at the initial stages of construction (*Erste Bauphase*) in both the North Sea and the Baltic Sea. Sixty-three additional wind parks with a total of over 28 GW capacity are awaiting approval from the German authorities.[32] However, many of these plants are facing significant delays related to grid connections and other factors.[33]

The offshore incentives are structured similarly to the onshore incentives in that generators receive a high initial payment, which subsequently drops down to a lower payment level. Under the EEG 2012, offshore generators can get a payment of 15 € cents/kWh for 12 years, which drops down to a base payment level 3.5 € cents/kWh. The EEG 2012 also enables offshore generators to elect an initial payment of 19 € ct/kWh – but for only an eight year period. This “front-loaded” option, with higher initial payments for a shorter period of time, is designed to allow projects to pay down their debt more quickly. There is no degression scheduled for offshore wind generators until 2018, at which point the annual degression rate will be 7% p/a.

[30] The base payment level and the repowering bonus are not included in the graph.
[31] Deutsche Energieagentur. *Übersichtstabelle Winparks* (as of June 2012).
[32] Germany Trade & Invest. *Germany's Wind Energy Industry- Market Conditions, Investment Environment and Business Opportunities*.
[33] James Quilter. (June 2012). *RWE Wants Compensation Over German Offshore Connection Delay.* Windpower Monthly.

In light of the recent development delays, on August 28, 2012 the German Cabinet agreed[34] on a payment system for offshore plants. Offshore plant operators whose plants cannot be connected to the grid on schedule because of transmission construction delays will receive 90% of the FIT payments that they would have otherwise received had the plant been connected in time.[35] If enacted into law, this will apply to power generators that cannot be connected owing to reasons beyond their control (e.g. because of delays in constructing sub-sea transmission lines). The grid operators, in turn, may pass the costs of this new policy on to ratepayers in the form of a new surcharge (*Belastungsumlage*).[36]

Implications of EEG 2012 for the Wind Market

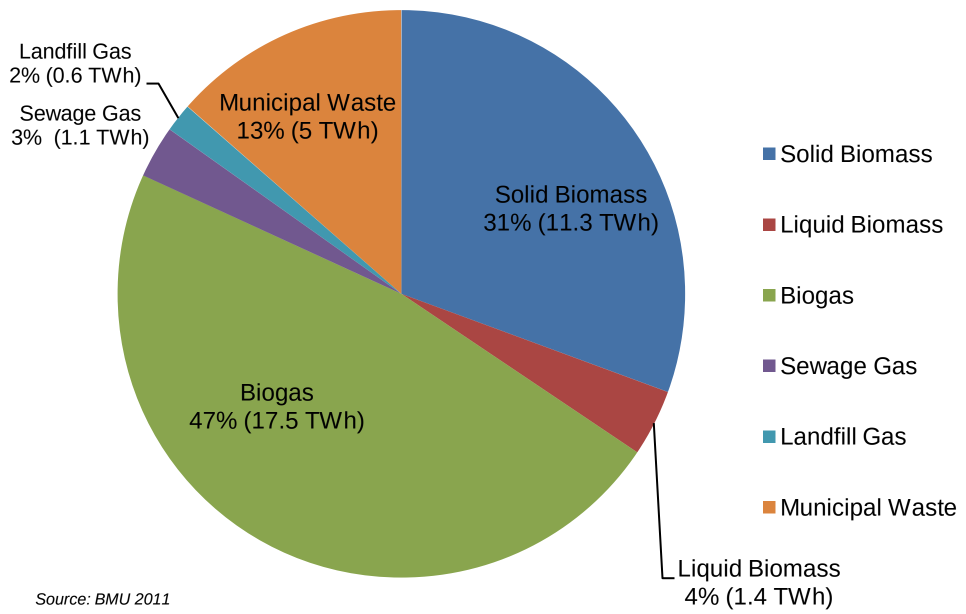
From an investor perspective, the EEG 2012 does not significantly alter TLC for investments in wind energy. Developers continue to have access to a guaranteed electricity offtake at a known price, as well as a transparent schedule of future price declines. At the same time, however, the EEG 2012's market premium option has proven attractive to wind generators because of the potential for higher payments than many plants currently receive. Of the 18,000 MW that had opted for the premium as of February 2012, 16,500 were onshore wind generators, or approximately 57% of the total wind capacity in the country.

In terms of future growth, the German wind industry estimates that 2,200 MW will be installed in 2012, which represents an increase over the amount installed in 2011.There are a number of challenges that could limit market development, however, such as height and setback restrictions and transmission system constraints..

Biomass and Biogas

During the decade between 2000 and 2010, the total amount of electricity generated from biomass under the feed-in tariff expanded sevenfold. By 2011, biomass accounted for nearly a third of renewable electricity in Germany and for 6% of the national portfolio. The German government categorizes and tracks a broad range of different biomass feedstocks, as can be seen in Exhibit 8 below. The Exhibit shows each feedstock's share of the biomass market as well as associated electricity generation, in 2011.

Exhibit 8: Biomass electricity generation by feedstock in 2011[37]



Source: BMU 2011

[34] As of the publication of this report, the government draft has not yet been signed into law.
[35] BMU. (July 2012). *Acceleration of Offshore Grid Expansion.*
[36] German Federal Government (August 2012), Entwurf eines Dritten Gesetzes zur Neuregelung energiewirtschaftsrechtlicher Vorschriften, p. 2. The surcharge is capped at € 0.25 cents/KWh for ratepayers with an annual energy consumption of less than 1 million KWh; and at €0.05 cents/KWh for any additional KWh in excess of 1 million KWh.
[37] Municipal waste refers to energy generated from the organic portion of the waste stream; liquid biomass includes vegetable oil.

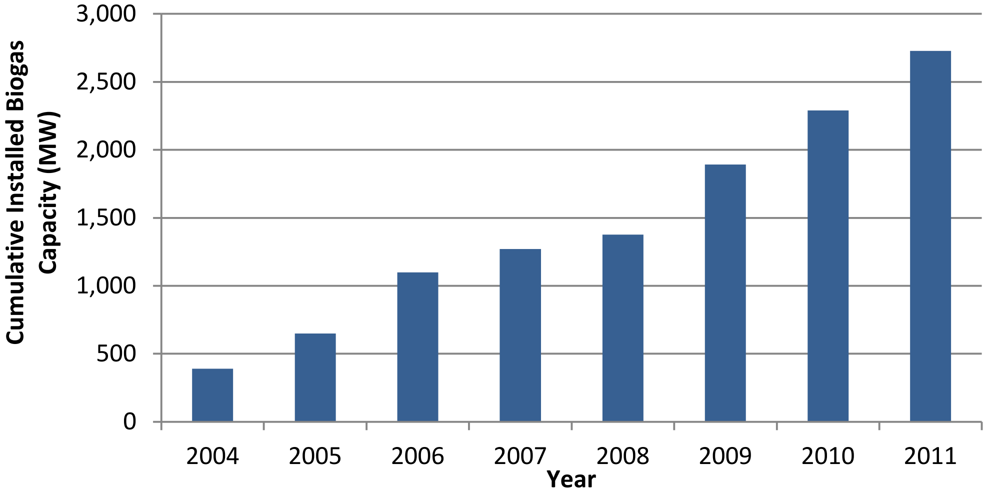
All biomass sources have expanded during the past decade under the FIT, but the technology with the most rapid growth has been gaseous biomass (i.e. biogas, sewage gas and landfill gas), which expanded from 3,600 GWh of production in 2005 to 19,200 GWh in 2011 – overtaking solid biomass. Biogas has accounted for the majority of this expansion. Landfill gas expansion is limited by Germany's ban on land-filling organic wastes, and sewage gas expansion is limited because the available sewage gas resource has largely been developed. This section focuses primarily on biogas.

Germany currently produces 61% of the biogas in Europe and has one of the world's largest fleets of biogas electricity generators. In 2011, Germany connected 1,300 new biogas plants to the grid, bringing the total to 7,215 biogas plants with a combined 2,904 MW of capacity.[38] Cumulative biogas capacity by year is shown in Exhibit 9. Biogas generated approximately 3% of Germany's total electricity consumption, comparable to the amount of power generated by hydroelectricity plants.

The vast majority of biogas is currently utilized for electricity projection. Incentives for the injection of biogas into the natural gas pipelines were introduced under the EEG 2009, but only 87 biogas plants have been designed to produce pipeline-quality biomethane to date.

Exhibit 10 below charts the annual growth in Germany's cumulative installed biogas capacity from 2004 to 2011.

Exhibit 9: Cumulative Installed Biogas Capacity, by Year



Source: BMU (2012)

Tariff Structure

The feed-in tariffs for biomass in Germany are comparatively complex because they support a range of different conversion technologies and feedstocks. The EEG 2009 and 2012 laws are similar in that both of them contain "base" rates for biomass, which are differentiated by four size categories. Exhibit 10 below compares the rates for each size category from the two versions of the FIT. The rates in each of the categories have been raised between 2009 and 2012, except for the largest plants, which have been reduced. The degression rate has also been increased from 1% to 2% p/a under the EEG 2012.

Exhibit 10: Base rates for Biogas Generation under the EEG 2009 and EEG 2012

	2009 EEG	2012 EEG
150 kW <	11.67 € ct/kWh	14.3 € ct/kWh
150-500 kW	9.18 € ct/kWh	12.3 € ct/kWh
500 kW - 5 MW	8.25 € ct/kWh	11 € ct/kWh
5 - 20 MW	7.79 € ct/kWh	6 € ct/kWh
Degression	1%	2%

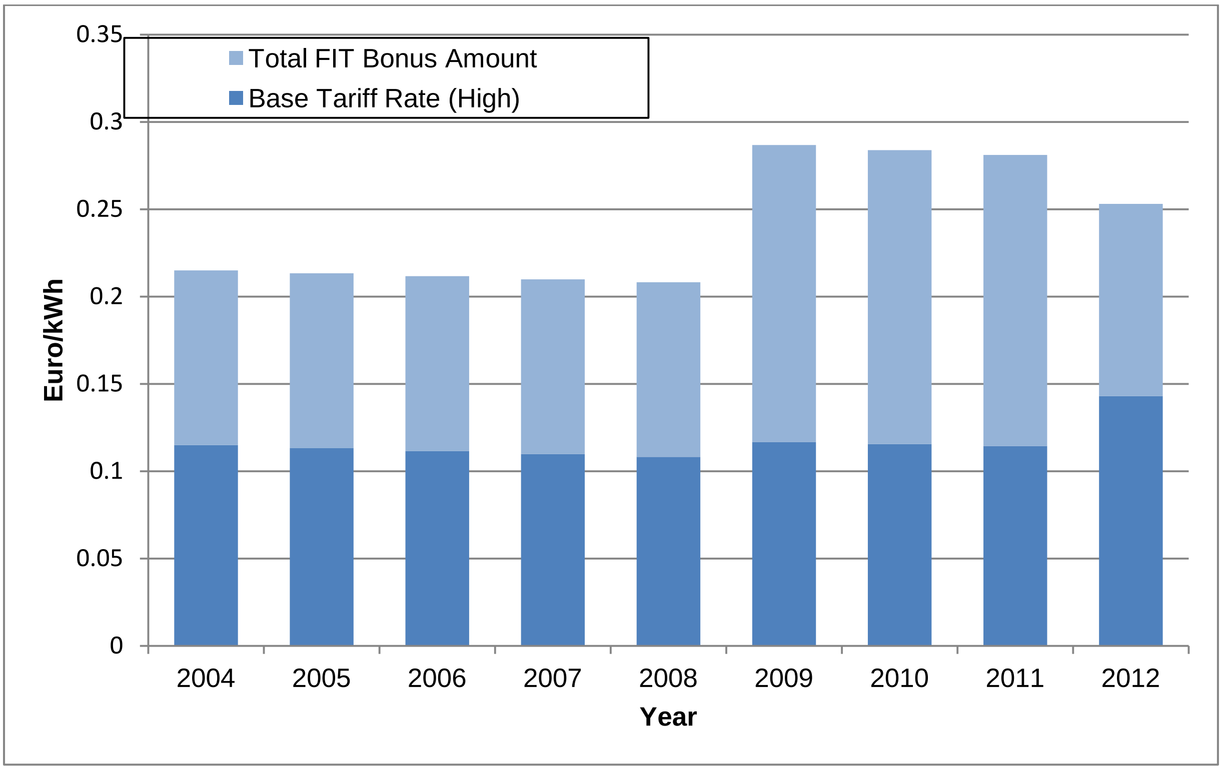
Source: EEG 2012

[38] Fachverband Biogas e.V. (June 2012). *Branchenzahlen 2011 und Branchenentwicklung 2012/2013*.

Since the EEG 2004, each of the FIT laws has contained provisions for additive bonus payments that modify the base rates in ways that specifically support biogas. The EEG 2004, for example, contained bonus payments for energy crops, for advanced energy technologies, and for CHP. These bonuses could be claimed simultaneously. Under the EEG 2009, there were separate bonuses to support the processing of pipeline-grade biomethane, the utilization of highly efficient conversion technologies such as CHP, the use of energy crops and manure as feedstocks, the production of biogas, and adherence to biogas air quality standards. Most of these bonuses could also be claimed in parallel, such that biogas plants that utilized (for example) energy crops and CHP would get multiple bonuses on top of the base rates.

The 2012 legislation preserves the focus on differentiated rates for different types of biogas and different feedstocks, but has introduced a new system of bonus payments. Exhibit 11 below shows the evolution of the maximum level of available biomass base rates, adders, and the total potential rate available to biogas generators, over time. As can be seen in Exhibit 11, the maximum base payment level has increased, while the total bonus payments available have been reduced. Several of the bonus payments have been removed or lowered because they were judged to be ineffective, overly complex and/or too generous. The EEG 2012 bonus systems and their implications for the biogas market are discussed in detail below.

Exhibit 11: Evolution of Biomass rates and adders



Sources: EEG 2004, §8, EEG 2009, §27 and EEG 2012, §27.

Bonus payments for specific feedstocks. The 2012 revision defines two classes of feedstocks that can qualify for bonus payments, depending on the size of the project. The feedstock classes, and the bonus payments associated with each class, are contained in Exhibit 12 below.[39] Referring back to the base rates in Exhibit 10 above, a 150 kW biogas generator using manure as a feedstock could receive 22.3 € cents/kWh utilizing this bonus system. Although biogas plants can utilize many of these feedstocks and will therefore be eligible for these bonuses, biogas plants that take this bonus will be capped at 750 kW in size starting in 2014. The law also limits the share of maize and corn that can serve as a feedstock to 60%.

[39] In order to be eligible for these rates, plants must also generate 60% of their electricity during combined heat-and-power mode. For biogas plants, heat utilized for heating the digester can account for 25 of these percentage points. A plant does not have to meet these CHP requirements if it is a biogas plant that utilizes manure for at least 60% of its feedstock.

Exhibit 12: Biogas Bonus Classes

	Class I	Class II
Bonus payment	4 – 6 € ct/kWh	6 – 8 € ct/kWh
Feedstocks	Grains and cereals such as corn, haulm, sugar beets, mangold, and sunflowers	Animal manure, and plant waste

Source: EEG 2012

Bonus payments for biomethane processing. Biogas and all other renewable gas facilities are eligible for bonus payments if their gas output is processed to be of high enough quality to be fed into the natural gas pipelines. The bonuses are differentiated according to the amount of gas that can be processed at an installation as detailed in the exhibit below.

Exhibit 13: Biomethane Production Bonus, Differentiated by Plant Size

Plant size	Tariff
700 cubic meter / hour processing capacity	3 € ct/kWh
1,000 cubic meter / hour processing capacity	2 € ct/kWh
1,400 cubic meter / hour processing capacity	1 € ct/kWh

Source: EEG 2012

Digestion of biowaste. A separate set of tariffs is available to biogas that is generated from the organic component of waste diverted from landfills. Although the tariffs are listed for plants up to 20 MW in size, the maximum plant size will be capped at 750 kW starting in 2014. These tariffs cannot be combined with the biomass base rates or with other bonuses.

Exhibit 14: Biowaste Digestion Bonus Rates, Differentiated by Plant Size

Plant size	Tariff
< 500 kW	**16 € ct/kWh**
500 – 20 MW	**14 € ct/kWh**

Source: EEG 2012

Small-scale biogas. Another separate tariff of 25 € ct/kWh is available for onsite biogas plants of 75 kW and under that utilize manure for at least 80% of the feedstock. This tariff cannot be combined with the biomass base rates or with other bonuses.

Implications of EEG 2012 for the Biogas Market

From an investor perspective, the EEG 2012 does not significantly alter TLC for investments in biogas generating capacity. As with the wind rates, developers continue to have access to a guaranteed electricity offtake at a known price, as well as a transparent schedule of future price declines.

Although conditions support TLC, the biogas industry projects that installations will slow considerably from the 613 MW installed in 2011, to 281 MW in 2012 and 127 MW in 2013.[40] The reasons for this is that the new bonuses are not as favorable to the use of energy crops and farm waste as they were under the EEG 2009 and because the amount of the total potential bonuses are now lower. With regard to biomethane, there are currently an additional 39 plants under construction and 63 in the planning stages. If all of these plants are completed, it will raise the total pipeline injection capacity to over 100,000 m^3 per hour.[41] The growth in biomethane, however, will not compensate for potential declines in biogas for electricity in terms of annual investment.

While the business models that have driven biogas expansion to date may not be as profitable as previously, the new bonuses may create the conditions for new models to emerge over time. Under the market premium option, in particular, there is an additional provision

[40] German Biogas Association, *Biogas Segment Statistics 2011* (as of 6/2012).
[41] Deutsche Energieagentur. (June 2012). *Branchenbarometer Biomethan*.

specifically for biogas[42] generators that enables both new and existing biogas plants that sell power into the wholesale electricity markets to claim a "flexibility" premium if they can be configured to be dispatchable during periods of peak demand (e.g. by adding storage). The flexibility premium, which is calculated annually based on the capacity of the system, is additive to the market premium and is paid for a ten-year period.[43] This and other bonuses may prompt the development of new modes of biogas plant development.

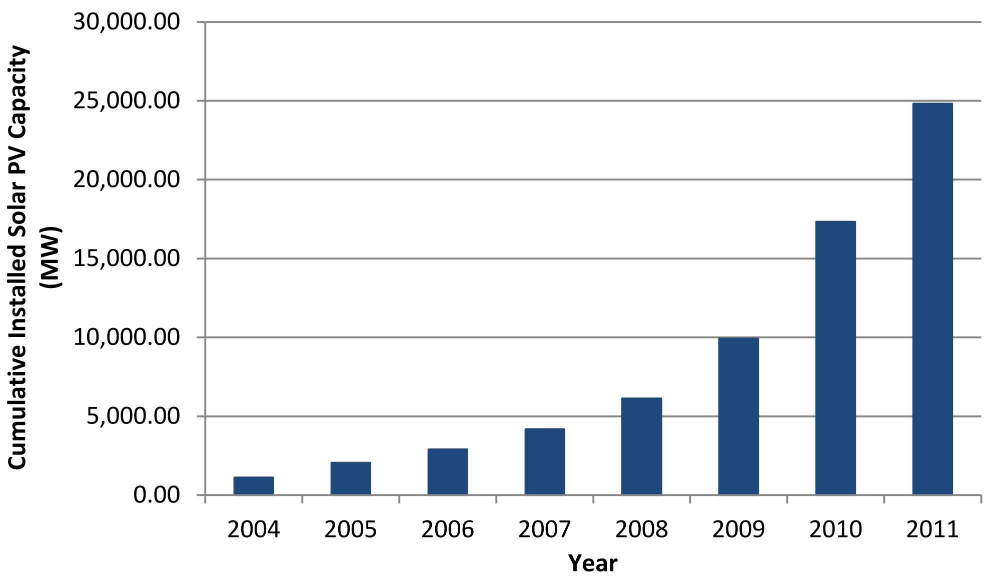
At present, 1,500 MW of biomass electricity sell power under the market premium and it is estimated that approximately one third of these are biogas generators.[44] Only ~20 plants currently claim the flexibility premium and industry representatives claim that the difference between on-peak and off-peak spot market prices are not significant enough to warrant the construction of storage required to take advantage of the premium.

V. Overview of Germany's Solar PV Policy and Market Trends

PV Market Growth

DBCCA's 2011 paper on the German approach to PV market volume management provided an overview of how the EEG policy evolved in response to rapidly changing PV market dynamics. As PV panel prices dropped dramatically and repeatedly, other major markets such as Spain, the Czech Republic, and France introduced policy changes that caused their markets to contract. Germany effectively served as a "backstop" for the global PV market since its PV policy was uncapped. In 2010, ~7,400 MW of PV were installed in Germany, despite an unscheduled mid-year decrease in the PV FIT rate. In 2011, slow market growth during the first half meant that the potential mid-year, volume-based degression was not triggered. The market accelerated rapidly in the second half of the year, however, with ~3,000MW installed in the month of December alone.[45] In total, another ~7,400 MW of PV were installed in 2011. In both 2010 and 2011, the amount installed was more than double the 3,500 MW average trajectory envisioned under the NREAP. Germany had ~24,700 MW of PV installed as of the end of 2011, which accounted for approximately 3% of national electricity supply. The cumulative amount of PV capacity installed in Germany through 2011 can be seen in Exhibit 15 below. By the first half of 2012, 4.4 GW of PV had already been installed and the share of national electricity production had increased to 5.1%.[46]

Exhibit 15: Cumulative Installed Solar PV Capacity (2004-2011)



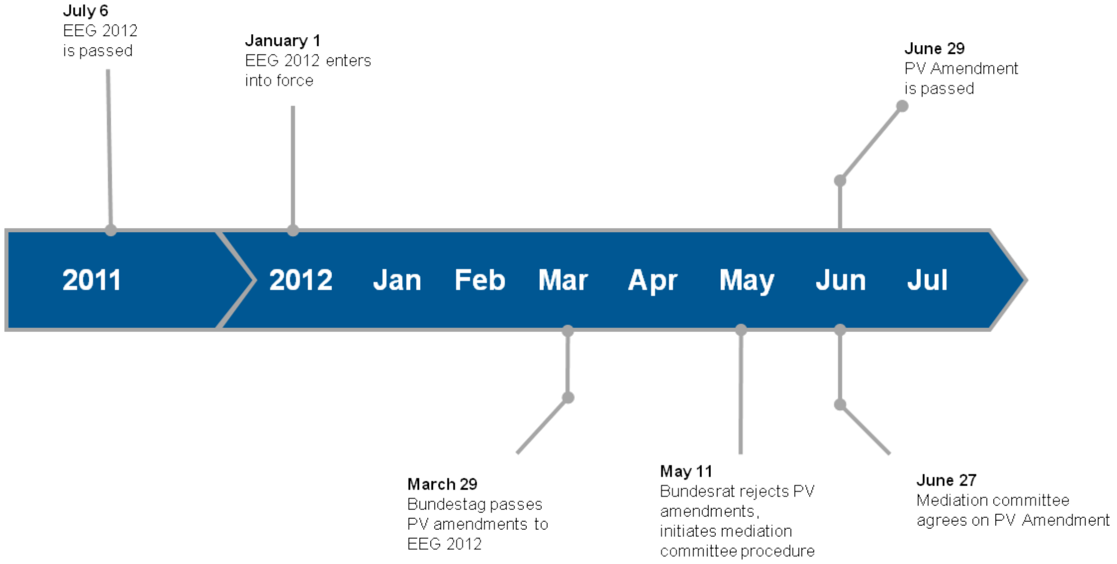
Source: BMU (2012)

[42] There is also a higher flexibility premium paid for facilities that produce biomethane.
[43] The formula for calculating the flexibility premium can be found in Annex 5 of the EEG 2012
[44] Analysis from the German Biogas Association (*Fachverband Biogas*)
[45] BSW-Solar. (June 2012). *Entwicklung des Deutschen PV-Marktes Jan-Apr 2012*.
[46] BSW-Solar. (August 2012) *Entwicklung des deutschen PV-Markts, Jan-Jun 2012;* BDEW (2012). Entwicklungen in der deutschen Stromwirtschaft im 1. Halbjahr 2012. Sitzung der Arbeitsgemeinschaft Energiebilanzen 26.-27. Juli 2012 in Berlin.

The EEG 2012 PV Amendment of June, 2012

Although the EEG 2012 law was passed in June 2011, the scale-up of PV installation volumes in Germany inspired a series of discussions during the second half of 2011 among policy makers and industry as to whether additional measures to govern the PV market should be introduced. Economic Minister Philipp Rösler, for example, advocated for a 1 GW cap on solar incentives in December of 2011. The Environmental Minister at the time, Norbert Röttgen, agreed that PV market growth needed to be brought more in-line with the NREAP trajectories. The two Ministers jointly proposed an amendment to the PV portion of the EEG 2012. The PV amendment originally passed the Bundestag, but was rejected by the Bundesrat, where a coalition of state government representatives concerned over solar industry jobs voted to address their concerns with the proposed amendment through a Mediation Committee (*Vermittlungsausschuss).*[47] The Mediation Committee is a formal part of the German parliamentary system and is composed of delegates from each of Germany's houses (*Bundestag* and *Bundesrat)* who are tasked with finding a suitable compromise. The Mediation Committee delegates reached a compromise on June 27th, and the proposed amendments were passed by the Bundestag on June 28th, 2012 and then by the Bundesrat on June 29th, 2012. The timeline in Exhibit 16 summarizes these policy developments. The major policy changes under the PV Amendment (summarized in further detail below) are the introduction of the 52 GW capacity threshold, reductions to the available PV rate, a revised volume-based degression schedule, and the introduction of limits on the amount of electricity that PV generators can export to the grid. Collectively, these changes represent an effort to transition PV to a new, incentive-free policy paradigm, but they also reduce TLC.

Exhibit 16: Timeline of the EEG 2012 and PV Amendment



Major Policy Changes under the PV Amendment

Capacity threshold

One of the most significant outcomes of the Mediation Committee is that only 52 GW of cumulative solar capacity will be eligible for financial incentives support under the EEG. Once the threshold of 52 GW is crossed, it will trigger the introduction of a different policy framework governing new PV installations. The details of the next generation policy framework have not yet been determined. PV electricity will continue to be eligible for priority access to the grid, but incentive payments will no longer be recoverable through the ratepayer surcharge that funds FIT payments.

Revised FIT rates and categories

As can be seen in Exhibit 17 below, the June PV Amendment significantly reduces the FIT rates from those originally established under the EEG 2012. The Amendment also slightly shifts the size categories from those in the EEG 2012.

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[47] The*Vermittlungsausschuss* is a board composed of 16 members of the *Bundestag* and 16 members of the *Bundesrat*. Elected *Bundestag* participants are proportionately represented by party whereas there is one *Bundesrat* participant from each German state. The *Vermittlungsausschuss* is tasked with moderating disagreements between parliamentary houses and finding a suitable compromise. This compromise is then voted upon by both the *Bundestag* and *Bundesrat* in order to come into effect.

Exhibit 17: EEG PV FIT Payments under the EEG 2012 and the PV Amendment

Installation Type	EEG 2012	EEG 2012	PV Amendment	PV Amendment
Roof-mounted PV	<30 kW	28.74 € ct/kWh	<10 kW	19.5 € ct/kWh
	30 kW – 100 kW	27.33 € ct/kWh	10 - 40 kW	18.5 € ct/kWh
	100 kW – 1 MW	25.86 € ct/kWh	40 - 1000 kW	16.5 € ct/kWh
	>1 MW	21.56 € ct/kWh	1-10 MW	13.5 € ct/kWh
Freestanding PV		21.11 € ct/kWh - 22.07 € ct/kWh		

Source: BMU 2012. (June 28, 2012). *Die wichtigsten Änderungen der EEG-Novelle zur Photovoltaik 2012*.

Degression

Under the amended EEG 2012, Germany will continue to adjust PV rates periodically in an attempt to keep annual PV installations within a target "corridor." The current annual installation corridor is 2,500 to 3,500 MW.

In order to maintain the corridor, the PV rates will change on a monthly basis according to a volume-based degression schedule, which is shown in Exhibit 18. The monthly degression is adjusted every three months, based on the amount of PV capacity installed during the prior 12 month period. As can be seen in the Exhibit below, the available FIT rate will decrease by 2.8% each month for three months if 7,500 MW of capacity are installed during the prior 12 month period. If less than 1,000 MW is installed during the prior twelve month period, the FIT rate will increase by 0.5% for three months. In total, the FIT could decrease by a maximum of up to 29% or increase by up to 6% over a 12 month period.

Exhibit 18: Volume-based, Monthly Degression Schedule, Determined by Capacity Installed During Prior 12-Month Period

Installed capacity during prior 12-month period	Monthly degression
7,500 MW	2.8%
6.500 MW	2.5%
5,500 MW	2.2%
4,500 MW	1.8%
3,500 MW	1.4%
2,500 – 3,500 MW (target corridor)	1%
Less than 2,500 MW	0.75%
Less than 2,000 MW	0.5%
Less than 1,500 MW	0%
Less than 1,000 MW	-0.5%

Source: BMU 2012. (June 28, 2012). *Die wichtigsten Änderungen der EEG-Novelle zur Photovoltaik 2012*.

The new degression schedule will not be immediately implemented, and will instead be introduced in three distinct phases. These phases are described below and summarized in Exhibit 19 below:

- **Phase I – Flat monthly degression.** In Phase I (May 1 - October 31, 2012),[48] a flat degression of 1% will be applied to the FIT payment rate at the end of each month. At the end of October, the PV payment rate will have decreased by a cumulative 6%.[49] At the time of writing this report, the FIT payment level has already decreased by 1% each month from the initial level depicted

[48] The PV Amendment is retroactively effective to PV systems installed as of April 1, 2012. The market was aware that the *Bundestag* and *Bundesrat* would make changes to the rates and regulations and it appears that developers were not adversely affected by retroactive application of the June PV Amendment. For rooftop mounted PV, the compensation and degression rates under the EEG 2012 continue to apply if the formal application for grid connection was filed before February 24, 2012 and the system was completed before June 30, 2012. For freestanding PV systems, which are subject to the formal plan approval procedure under German law, a transition period has been approved to enable plan approvals to be completed. Specifically, the EEG 2012 compensation and degression rates will apply to systems where the installation was commissioned between April 1 and June 30, 2012 and the required decision on drawing up or amending the local development plan (*Bebauungsplan*) was handed down before March 31, 2012. For installations on land used for economic, transport, housing or military purposes, where the installation was commissioned between July 1 and September 30, 2012 - and the required decision on drawing up or amending the local development plan was handed down before March 31, 2012 - the feed-in tariff rate is set at €15.95 cents per kWh. This corresponds to the EEG 2012 compensation, incorporating the planned 15% midyear degression.
[49] BMU 2012. (June 28, 2012). *Die wichtigsten Änderungen der EEG-Novelle zur Photovoltaik 2012*. .

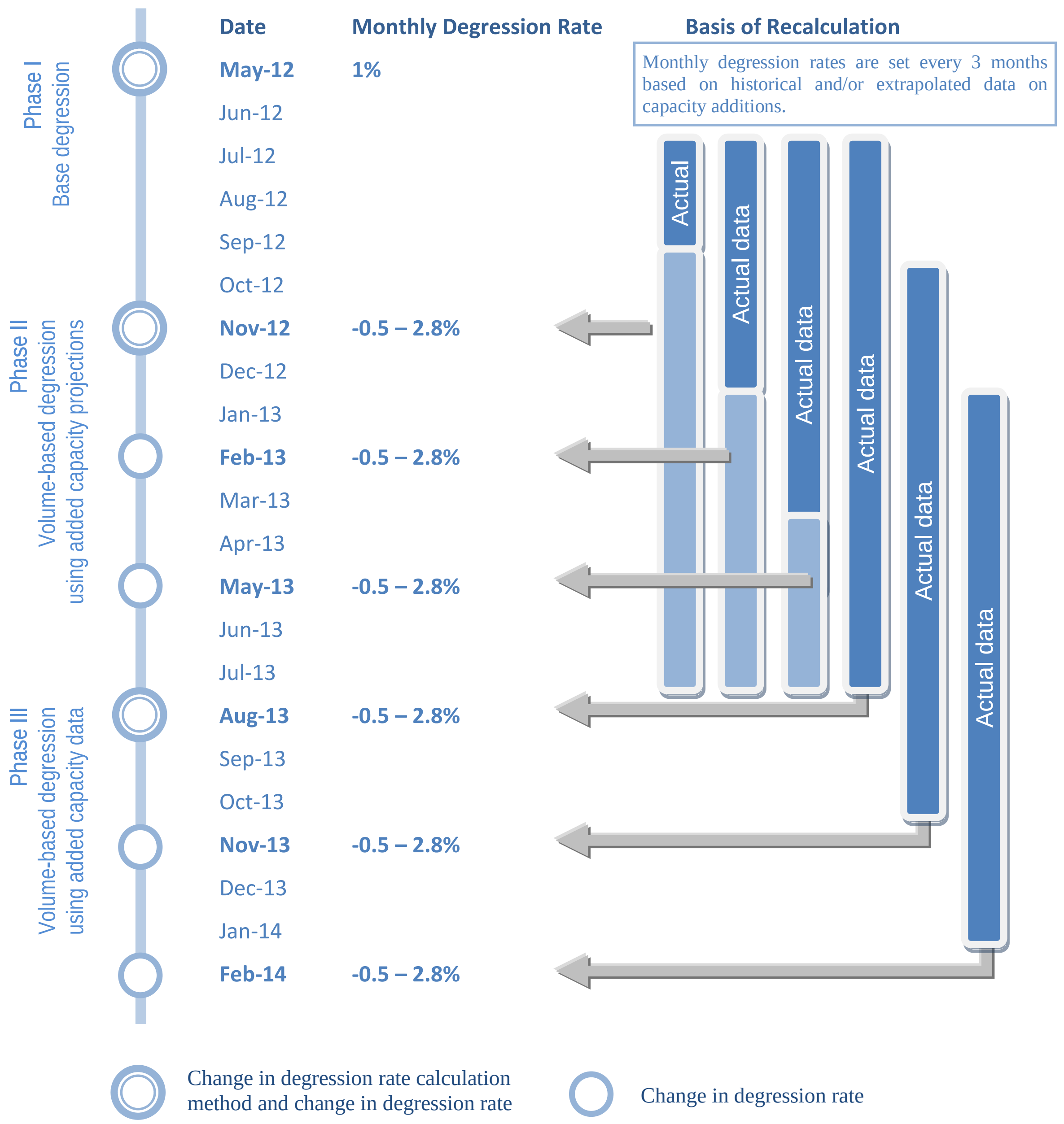
in Exhibit 18 such that, for example, the FIT payment for a small roof mounted PV installation (<30KW) commissioned in August 2012 was 18.73 € cent/kWh.

- **Phase II – Volume-based degression, with the prior 12-month period extrapolated.** During Phase II (November 1, 2012 – July 31, 2013), the first volume-based degression will be calculated and applied. Since the 12-month period prior to November 1, 2012 included explosive growth (e.g. 3 GW in December, 2011 alone) under significantly higher FIT rates, policymakers have elected not to use those twelve months as the basis for the initial degression calculation. Instead, the actual growth rates from the three month period of July 1, 2012 to September 30, 2012 will be used to extrapolate a 12-month capacity addition. The volume-based degression rate will then be calculated using this extrapolated figure and applied each month from November 1, 2012 to January 31, 2013.

  Two more adjustments based on extrapolated growth will occur. The February 1, 2013 adjustment will extrapolate market growth using data from the six month period of July 1, 2012 – December 31, 2012 and the May 1, 2013 adjustment will extrapolate market growth using data from the nine month period of July 1, 2012 – March 31, 2013.

- **Phase III – Volume-based degression, using actual data from the prior 12-month period.** Phase III (August 1, 2013 – future) begins once a full 12-month period of PV market growth data has been collected. In August, the volume-based degression will be calculated based upon actual added capacity data from the period July 1, 2012 to June 30, 2013. The volume of installed capacity will determine the monthly degression rate for the next three month period. This process will repeat itself four times a year: November, February, May, and August. This process will continue forward until the 52 GW capacity threshold has been reached.

Exhibit 19: Solar PV FIT Degression Timeline, May 2012 – February 2014



Source: BMU 2012. (June 28, 2012). *Die wichtigsten Änderungen der EEG-Novelle zur Photovoltaik 2012.; DBCCA analysis, 2012.*

Limit on PV Output Sold under the FIT

Another major policy change under the PV Amendment is that the amount of electricity compensated under the FIT is limited to 90% of system output for systems 10 kW to 1 MW in size. The remaining 10% can be consumed onsite, sold in the wholesale market, or compensated at the average daytime spot market price (i.e. approximately 3-5 € cents/kWh). The 10% of the electricity sold outside the FIT, however, is ineligible for the market premium. PV installations smaller than 10kW or over 1 MW may continue to receive incentives for 100% of their generated power, though they also have the option to consume electricity onsite and forgo FITs. Similar to the market premium, the 90% provision is designed to encourage PV generators to begin to exercise other options for selling their power outside of the FIT framework. Although the generators have a range of choices, this new policy currently creates an incentive for onsite consumption since the retail electricity rate is higher than the average daytime spot market price.

Other Policy Changes under the PV Amendment

In addition to the major policy changes described above, there are several additional policy updates which have gone into effect under the PV Amendment.

- **Project size cap on freestanding systems**. The Amendment introduces (with some exceptions) a project size cap of 10 MW on EEG-incentivized PV systems. To prevent developers from gaming the system by artificially separating larger systems into smaller systems, the revised EEG added in a provision that defines freestanding installations built within 24 months of each other and within a 2 kilometer space as a single installation.[50]
- **Self-consumption bonus removed**. Under the EEG 2009, PV generators were able to receive a bonus payment on top of the retail rate for electricity if they consumed their power onsite. The PV Amendment eliminated the self-consumption option.
- **Changes to rate "lock-in."** PV generators could previously "lock in" to a FIT rate once the solar panels were mounted on the rooftop. Under the PV Amendment, PV systems must now be firmly mounted to the rooftop, have a power inverter, and have already produced power in order to lock in.[51] A grid interconnection, however, is not required, in order to protect developers from delays beyond their control.
- **Curtailment capability**. The new laws also require all PV systems to have curtailment capability in order to shut off during periods of potential grid instability and reduce the need to expand the grid to absorb output. Previously, this requirement was only in place for projects 100 kW and larger. The Amendment specified that, for existing systems, generators would pay half the cost of enabling curtailability, with the other half recovered from ratepayers. Generators are compensated for any energy that is curtailed, but they are paid at 95% of the feed-in tariff rate in order to create an incentive for generators to be sited in less congested areas.

Implications of EEG 2012 and the June PV Amendment for the PV Market

The stated intent of the June PV Amendment is to slow market growth in the near-term – specifically from the 7.4 GW p/a growth experienced in 2010 and 2011 to an annual corridor of 2,500 MW to 3,500 MW p/a. There are currently a wide range of opinions as to how much the PV market actually will grow under the new system. If the target corridor pace can be maintained, then the 52 GW threshold will not be crossed until 2019-2022. The German Minister of Environment, Peter Altmaier, on the other hand, recently stated that the 52 GW threshold might be reached as early as 2014- 2015.[52] The German market is already off to a strong start in 2012, with 4.4 GW connected this year as of June, but it is unclear how much the market will grow through the end of the year as the monthly degression continues. A recent survey of industry forecasts revealed that -- on average –analysts predict that 6.7 GW will be installed in Germany in 2012.[53]

A second goal of the June PV Amendment is to continue to encourage the integration of PV into the electricity grid and into electricity markets by continuing to drive PV to grid parity by placing downward pressure on prices, encouraging onsite consumption through the 90% sales limit, and through technical requirements such as the curtailment capability.

From an investment perspective, however, the changes introduced by the June PV Amendment diminish TLC compared to the previous EEG framework for several reasons:

- **Degression creates planning uncertainty.** The time required to complete PV projects in Germany has decreased markedly as the markets have grown and the supply chain has become more efficient. Residential systems, for example, can take around 6 weeks to complete, but there have been recent reports of systems that have been fully installed and interconnected in as little as 8-10 days.[54] As a result, the monthly degression schedule may not create as much uncertainty for project developers in Germany as in other countries where development timelines are significantly longer. The fact that the degression level stays the same for three months can also give developers a degree of transparency. Nevertheless, the fact that the degression rate changes every three months will decrease TLC for developers that operate with longer planning horizons, such as those building larger projects or those attempting to develop a pipeline of projects over multiple years.
- **The 90% production limit decreases revenue certainty.** The introduction of the 90% output limit creates revenue uncertainty for PV. As discussed above, the 90% limit creates an incentive for generators to consume their output onsite. The amount of generation that can be consumed, however, and the rate at which the generation will be credited are uncertain. First, the amount of onsite load may not be sufficient to absorb the output from the PV system and/or may not be well-matched to PV production. Buildings that shut down on weekends, for example, may not be able to consume weekend PV output. Similarly, buildings without tenants may not be able to offset onsite load. Second, onsite consumption is credited at the retail electricity rate. This rate can change, however, with

[50] *BMU 2012.* (June 28, 2012). *Die wichtigsten Änderungen der EEG-Novelle zur Photovoltaik 2012*.
[51] *Ibid.*
[52] (July 11, 2012). *Interview with the Passauer Neue Presse*,(in German).
[53] Photon International, *Not enough*, published by PHOTON Europe GmbH (July 2012), p, 55.
54 Photon (2012). Blink and You'd Miss It. San Francisco: California. Issue 7.

changes in electricity prices, changes in taxes or surcharges, and changes in the host site's rate class. A related consideration is that the "off-taker" for onsite consumption of PV electricity is the host site, which is likely less creditworthy than a long-term off-take agreement from a utility under the FIT. Finally, onsite consumption generates savings for the system host, but not revenue from power sales. Investors must be comfortable that the end user can and will use the savings from the PV system to pay back the investments over the long-term since a bank cannot take over the operation of a PV system and get revenue from it should the system owner go bankrupt. These factors contribute to a reduction in TLC compared to being able to sell 100% of PV generation under the FIT and may make projects more difficult to finance.

- **The 52 GW threshold reduces longevity and transparency.** The 52 GW threshold introduces a limitation of policy longevity and also decreases transparency in the mid-term since it is not clear when the threshold will be reached (e.g. 2014/15 vs. 2020/21). More importantly, it is also not clear what policy options may (or may not) be on the table once the threshold is crossed.

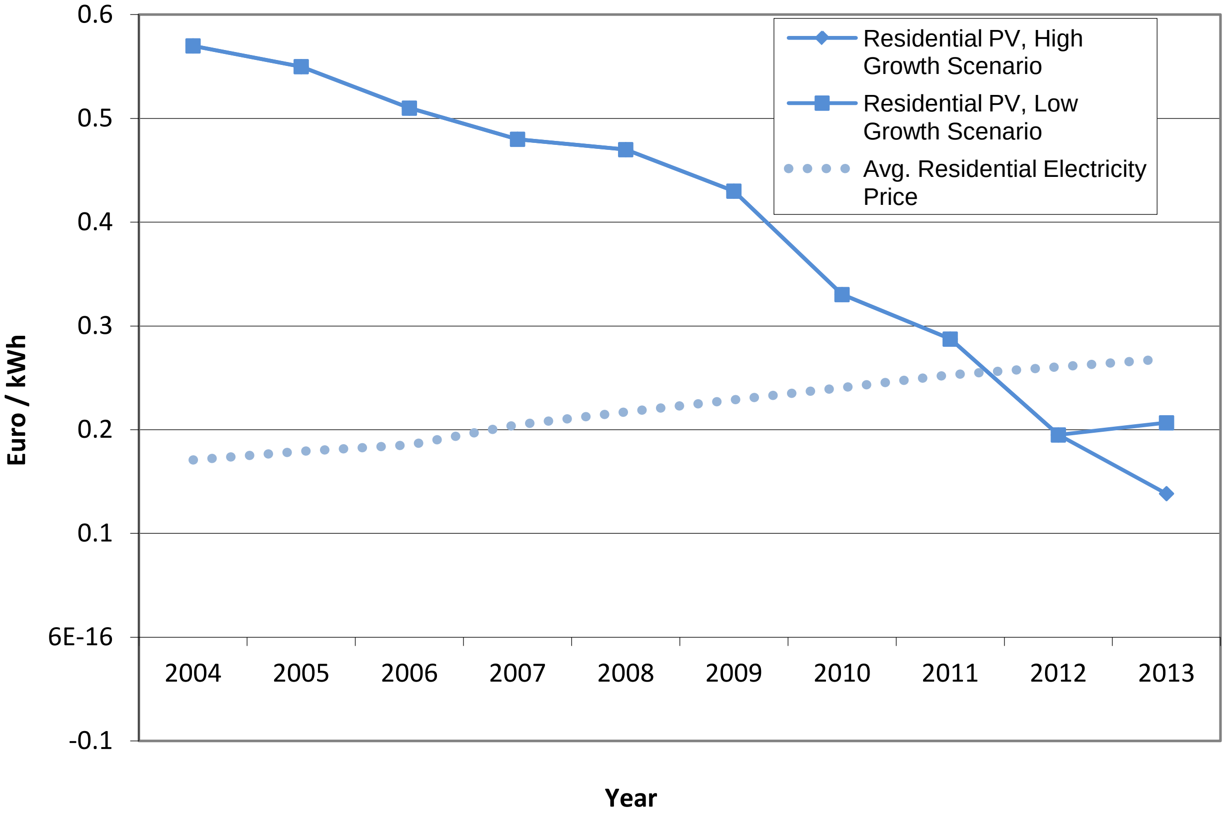
The current period of German PV policy making can be characterized as a transition between a scale-up phase, which lasted until the passage of the EEG 2012, and a period during which the levelized cost of PV electricity drops significantly below retail electricity rates at some point during the next several years. The two key issues that will need to be monitored and managed during this transition phase are the "tipping point" at which PV becomes broadly cost-competitive and issues related to policy cost and economic equity.

Grid Parity

The concept of grid parity has been held up as a "holy grail" for renewable energy scale-up, with the implication that renewable energy markets will be able to expand rapidly once they are cost-competitive with conventional alternatives. It is important to differentiate between the abstract concept of "grid parity," however, and the conditions that will lead to investment. This section focuses primarily on the concept of retail parity, the point at which PV becomes competitive with the electricity purchased by end consumers from the grid. The section also provides a discussion of wholesale parity, the point at which PV becomes competitive with conventional generation.

Retail grid parity. When PV reaches the point of retail grid parity, it is assumed that many potential PV owners will opt to offset their own retail electricity consumption, rather than taking the feed-in tariff payment or opting to sell power at the significantly lower spot market rate. PV system owners are well-positioned to consume their own power onsite because – unlike other renewable energy technologies – the majority of PV systems in Germany are located on the rooftops of homes and businesses that need power. The feed-in tariff rates paid to PV generators in Germany are already below the average retail rate for electricity. As can be seen in Exhibit 20, the rate for small-scale PV (i.e. the highest PV rate currently available) is already lower than the average residential retail electricity price. The two trajectories in 2012 reflect the fact that PV rates could theoretically increase or decrease under the degression schedule, depending on the volume of PV installed.

Exhibit 20: FIT Rate for Small-Scale Systems versus Residential Retail Electricity Rates in Germany



Although the fact that FIT rates are lower than retail electricity rates is an important milestone, this development has not yet driven the widespread emergence of new investment models based on onsite consumption of PV electricity for several reasons:

- **Grid parity differs on a case-by-case basis**: Grid parity is determined by a broad range of factors, including project cost, PV system output, and the retail rate. Different customer classes, for example, have different retail rates. Customers with high retail rates and better PV output will reach grid parity before customers with lower retail rates and a lower solar resource.
- **On-site load requirements**: The load profile of the end user – i.e. the volume and timing of onsite electricity consumption -- impacts where a generator stands relative to grid parity. In order for onsite consumption to be competitive with the FIT, 100% of the power must be utilized on site. The FIT guarantees that 100% of a system's power will be purchased. With onsite consumption, however, the onsite load must be large enough and timed appropriately such that PV output can be utilized.
- **FIT payments are more bankable than onsite consumption**: As discussed above in the section on the 90% PV production limit, onsite consumption introduces uncertainties with regard to the total amount of revenue a PV system will realize, the value of that revenue over time, and the creditworthiness of the offtaker. Onsite consumption will therefore likely require a higher cost of capital to finance than a long-term, fixed price payment stream under a FIT. A given FIT payment level may be equivalent to the retail electricity rate, but the two are not at "parity" from an investor perspective because a system that generates retail electricity rate savings would cost more to finance.

Together, these factors mean that grid parity will arrive in different parts of Germany at different times. Moreover – without the introduction of new policy frameworks -- the levelized cost of electricity for PV may need to fall significantly below the retail rate before the prospect of onsite consumption alone becomes a practical driver for investment.

At present, there are a few locations and a few building types with large and steady loads (e.g. hospitals) where grid parity is beginning to drive investment, but it is not yet widespread. The German Solar Energy Industry Association projects that PV investment based on retail grid parity will begin to gain momentum starting in 2017. When this occurs, the incentive to forego the FIT rate in favor of self consumption will increase dramatically and self-consumption will begin to dominate investor considerations. This will likely require the development of new policy and regulatory frameworks to address issues such as revenue loss for utilities from behind-the-meter consumption and the emergence of new business models, such as the third-party PPA model that has helped drive PV markets in the US. On the other hand, the prospect of retail grid parity may also inspire changes to retail rate structures, etc., that would serve to push the parity point further into the future. There are also policy considerations that may argue for the preservation of elements of the FIT structure, even under widespread retail grid parity: for some investors, for example, a long-term contract may continue to be more attractive to finance than onsite consumption; for some customers, a long-term offtake contract for power may be preferable because they are unable to consumer power onsite (i.e. because of a lack of onsite load); and for ratepayers it would be lower cost if generators were obliged to sell power at the generation cost-based FIT at below retail rates, rather than being credited at the higher retail electricity rate.

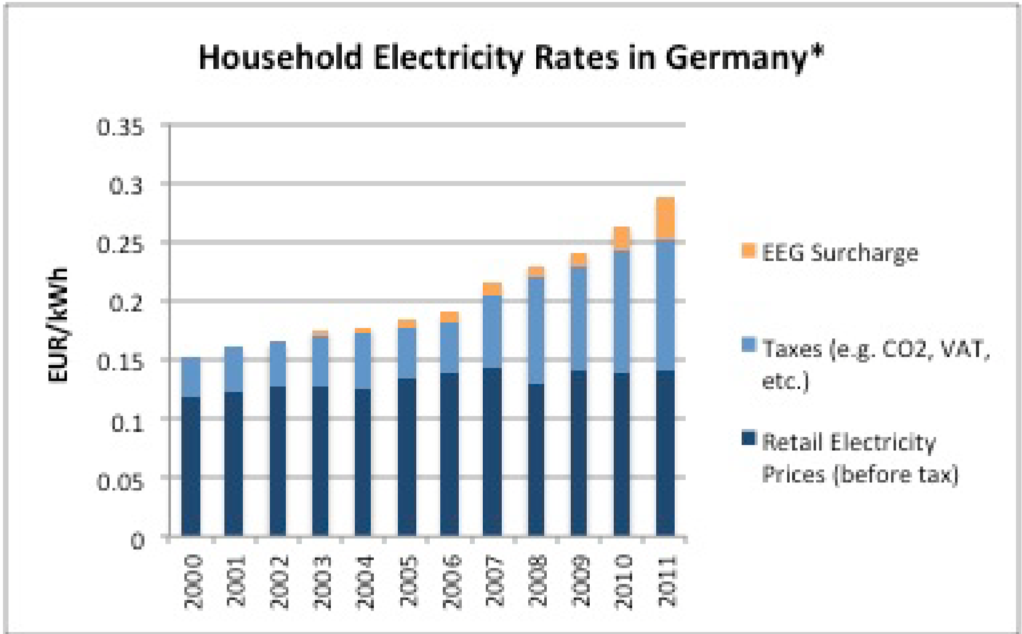
Wholesale grid parity. A second potential milestone is when renewable energy technologies become “competitive” with conventional alternatives. This milestone could be defined as the moment at which the LCOE of renewable energy technologies becomes competitive with wholesale spot market prices. During 2010-2011, the wholesale spot market price was approximately 3-5 € cents/kWh. If the current degression rate of 1.5% for onshore wind and the 7% degression rate for offshore wind were continued indefinitely, the average rates for offshore and onshore wind prices would reach the 3-5 € cents/kWh level during the 2020s. It is not certain, however, whether wind costs can maintain this trajectory and whether the FIT policy will continue in its current form through the 2020s. Moreover, future wholesale market price trends are unclear, and so it is difficult to project when wholesale parity might occur. Such calculations are complicated by the fact that renewable energy is suppressing the wholesale electricity price because of the merit order effect. Low wholesale prices, for example, have already resulted in the cancellation of several planned conventional generation plants. Renewable energy market growth under the FIT may continue to push wholesale parity further out as it continues to place downward pressure on spot market prices.

This dynamic raises important questions about the future use of spot market pricing as a benchmark for renewable energy. At what point can renewable energy realistically reach “parity” with spot market prices if increasing the amount of renewable energy places downward pressure on spot market prices? Should the difference between FIT rates and spot market prices be used as a proxy for the incremental cost of renewable generation if increasing penetration of renewables causes that difference to expand? Should other proxies for “parity,” such as the cost to build new conventional generators be used in policy making? Finally, will the market premium system be an effective mechanism to transition renewable energy to market competition if renewable energy is reducing wholesale market prices? Questions such as these point to a need to explore the relationship between renewable energy and current market structures, and the development of “next generation” policies that will enable Germany to attain its renewable electricity goals.

Ratepayer Impact and Equity

The debate in Germany over the social and economic impacts of the EEG has grown in recent years as the share of renewable energy has expanded, and retail electricity prices have increased. Germany already has among the highest electricity prices in the EU, providing additional fuel to those who argue that the EEG is imposing excessive costs on German households and businesses.

Exhibit 21: Breakdown of household electricity rates in Germany (2000-2011)



**Medium-sized household, defined by Eurostat as a household with an annual consumption of 2500-5000kWh.*
Sources: EUROSTAT 2011[55]; BMU 2012[56]

[55] Eurostat 2011

Low-income and long-term unemployed recipients of Germany's Hartz IV, the country's social benefits and protection program, are required to use a portion of their payment toward energy costs. Hartz IV recipients are increasingly finding that their electricity costs are surpassing the support that they are receiving, making them unable to pay their electricity bills.[57] As Germany looks to redefine the EEG surcharge in October 2012, there is a risk that it will increase from 3.5 € cents/kWh to 5 € cents/kWh. This raises the question of what distributional effects are occurring due to the EEG and growth in Germany's renewable energy market.

Some consumer groups and politicians are arguing that the energy bills of low-income consumers are subsidizing solar project development which benefits large utilities and wealthier homeowners. On one hand, Germany has committed to its energy transition – a phase-out of nuclear energy and investment in renewable energy growth – which is not without cost. On the other hand, Minister Altmaier has said that he is committed to reaching an agreement on creating affordable energy nationwide.[58]

According to the German grid operator, the forecast for the total cost of FIT payments in 2012 is €17.6Bn.[59] In turn, the projected revenues that it expects from selling this power on the exchange amount to €4.9Bn. This leaves an approximate shortfall of €12.7Bn, which represents the total amount that must be recovered from electricity consumers via the EEG surcharge.[60]

Under the current rules, large electricity-intensive industrial customers that consume over 10GWh of electricity per year only pay a surcharge of 0.05 € cents/kWh on 90% of the electricity they consume, only paying the full surcharge (currently of 3.59 € cents/kWh) on the remaining 10%. Furthermore, industries that consume over 100GWh per year and whose electricity costs represent more than 20% of their gross value-added are exempted from the latter, paying only the surcharge of 0.05 € cents/kWh on all generation consumed. These exemptions have been a long-standing part of the German policy framework, and were initially designed to protect Germany industry from significant cost increases.

However, a shift has begun to take place in the German electricity market, as a growing share of renewables is sold on the spot market, either directly, or via the grid operator. In particular, when solar and wind production is high, they have begun to put downward pressure on wholesale market prices. In fact, prices on the power exchange were 17.3% lower in the first five months of 2012, when compared to the prices during the same period last year.[61] During the first five months of 2012, prices have averaged 4.37 € cents/kWh. Some have estimated that solar PV alone has depressed spot prices by an average of 10% between 2007 and 2011.[62] More strikingly, power is now cheaper on some days at 2PM in the afternoon than it is overnight, due largely to the growing share of solar PV on the system.[63]

These effects are gradually transforming the electricity market in Germany, reversing long-held assumptions about the functioning of the power market, some observers even question the current functioning of the market overall. [64] One of the consequences of this is that large industrial customers (which purchase power on the wholesale market) are benefiting from cheaper power now available on the exchange while simultaneously being sheltered from cost increases by the exemption created for large industries. This debate has been brought to a head by recent proposals to decrease the threshold of eligibility for large power users from 10GWh per year to 1GWh per year, a move that would significantly increase the number of firms eligible for the exemption, and therefore distribute the costs of the EEG across a smaller consumer base. Thus, for individual households, the concerns over rising electricity prices remain.

It is unclear whether or how the political calculus underpinning Germany's energy transition will evolve if costs continue to rise. On the one hand, it appears that the national discussion about the future costs of renewable energy is becoming more partisan with the FDP party calling for greater feed-in tariff cost containment and the Green Party calling for greater progress towards the energy transition. There will be additional discussions about the FIT in October 2012, which should be monitored, but it is not anticipated that there will be significant changes entertained or considered before the next federal election.

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[56] BMU 2012
[57] Neubacher, Alexander and Schroeder, Catalina. (June 6, 2012). *Germany's Nuclear Phase-Out Brings Unexpected Costs*. Spiegel.
[58] Buchsteiner, Rasmus. (July 11, 2012). *Ich kämpfe für bezahlbare Strompreise*. Passauer Neue Presse.
[59] BMU. (October 2011). *Height of the EEG Surcharge Changed Only Slightly in 2012.*
[60] According to a comprehensive quantitative study of September 2011 by Prof. Erdmann from the Technical University Berlin, the overall costs of the EEG 2012 could amount up to €335bn. from 2010 to 2030, expecting at a minimum an increase in the EEG surcharge to 6ct/kWh by 2025. *See* Vereinigung der Bayrischen Wirtschaft (publisher), *Kosten des Ausbaus der erneuerbaren Energien,* September 2011. The author reasserted this assessment after the PV amendment had passed the final legislative hurdles in June 2012, *See* SPIEGEL ONLINE International, *Germans cough up for Solar Subsidies* (July 4, 2012). Available at: http://www.spiegel.de/international/germany/german-solar-subsidies-to-remain-high-with-consumers-paying-the-price-a-842595.html
[61] (June 19, 2012). *Debate over Cost Renewables in Germany*.
[62] Eva Hauser. (January 31, 2012). *Preissenkende Effekte der Solarstromerzeugung auf den Borsenstrompreis.* Bundesverbandes Solarwirtschaft.
[63] See Photon.info. (April 27, 2012). *Strompreis fahrt Achterbahn*.
[64] In a recent statement, representatives of the Stadtwerke Leipzig, a public utility from one of the major East German cities, commented that the German electricity markets are defunct: According to them, there are now effectively two separate markets: one for FIT tariff generated electricity from renewable energy with zero margin costs, and the other for conventional electricity generation using coal and gas. RWE and E.ON, two of the four major German power producers, already announced that they would hold back with new investments in gas- or coal-fired plants for fear of expected unprofitability under the current market design. *See* Bloomberg News, *Renewables make German Power Market Design Defunct, Utility says,* (June 26, 2012), available at: http://www.bloomberg.com/news/2012-06-26/renewables-make-german-power-market-design-defunct-utility-says.html

VI. Conclusion

Germany's EEG 2012 and June PV Amendment enacted several changes to the Germany FIT program that are relevant to investors, including:

- The addition of a market premium option, as a means to encourage renewable generators to participate in the wholesale electricity market
- Reduced FIT payments and degression schedules for most technology classes
- Revised PV degression schedule
- Payment of 90% of PV solar power generated under the FIT rather than payment for 100% of electricity produced
- Addition of a 52 GW PV capacity threshold

These policy changes represent a shift toward a second stage in the EEG's policy evolution: a diminished emphasis on renewable energy scale-up for rapidly growing technologies, an increased focus on participation in the wholesale electricity market, and tentative policy steps toward policy management in a grid parity future.

Under Germany's EEG 2012 and June PV Amendment, policymakers have preserved TLC for investors in wind and biogas generating capacity but have reduced TLC for investors in solar PV. Recent changes to the PV FIT in particular presage a future where PV is more systematically integrated into electricity markets and the electricity grid. Germany's 52 GW PV capacity threshold and aggressive degression schedule make it unlikely that Germany will continue to serve as a "demand back-stop" for the global PV market.

Key issues for research on the German FIT going forward include:

- How will Germany manage onsite renewable energy generators as the cost of renewable generating technologies continues to fall below electricity retail rates?
- What impact will increasing penetration of low-marginal cost renewable generation have on the operation of the German power market?
- How will Germany account for the added costs that variable renewables such as wind and solar PV may create for Germany's electricity grid in the future (for example due to the need for increased regulating reserves and standby power)?
- How will Germany continue to allocate the costs of its FIT policies among the different classes of residential, commercial, and industrial electricity consumers?

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