

The German Energy Transition – Issues and Perspectives

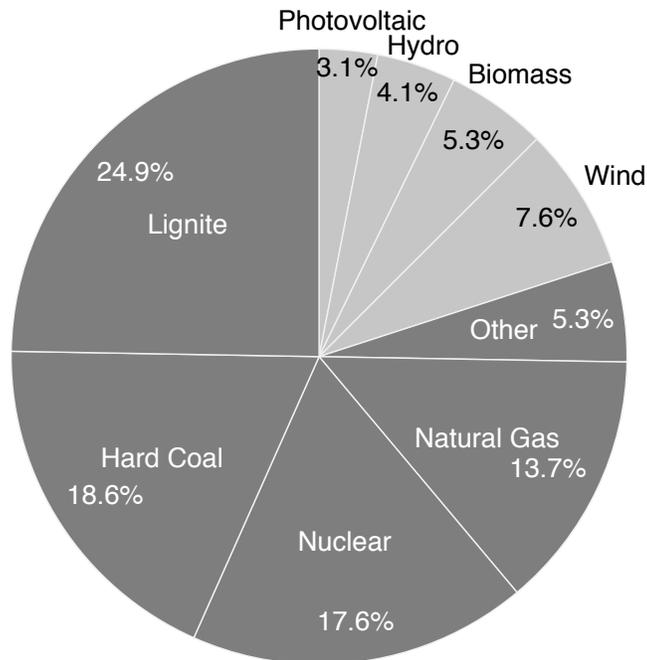
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Introduction: A Revolution in the German Electric Power Sector

The reaction of German energy policy to the 2011 Fukushima catastrophe was swift and radical. The conservative-business liberal coalition in power committed to a spectacular political u-turn as it enacted an extension of the operation periods of German nuclear power plants just one year before the accident. An immediate shutdown of eight nuclear power plants and a stepwise nuclear phase-out of all remaining nine plants were supposed to make German electric power industry nuclear free by 2022.

Germany in fact committed to the most radical and ambitious electric energy plan of any major industrial country as it vowed to replace not only most nuclear capacity losses but also increasing the shares of conventional hydrocarbon based thermal power plants with renewable sources. As of 2010, nuclear power accounted for 17.6% of total gross electric power consumption while hydrocarbons summed up to 58.3% (see chart 1). The most CO₂ intensive energy source, coal, amounted to 43.5%. The majority of that block was accounted for by lignite or brown coal, which has even higher emission values of all pollutants and green house gases than hard coal.

Chart 1: Germany Before Fukushima. Output Shares in 2011

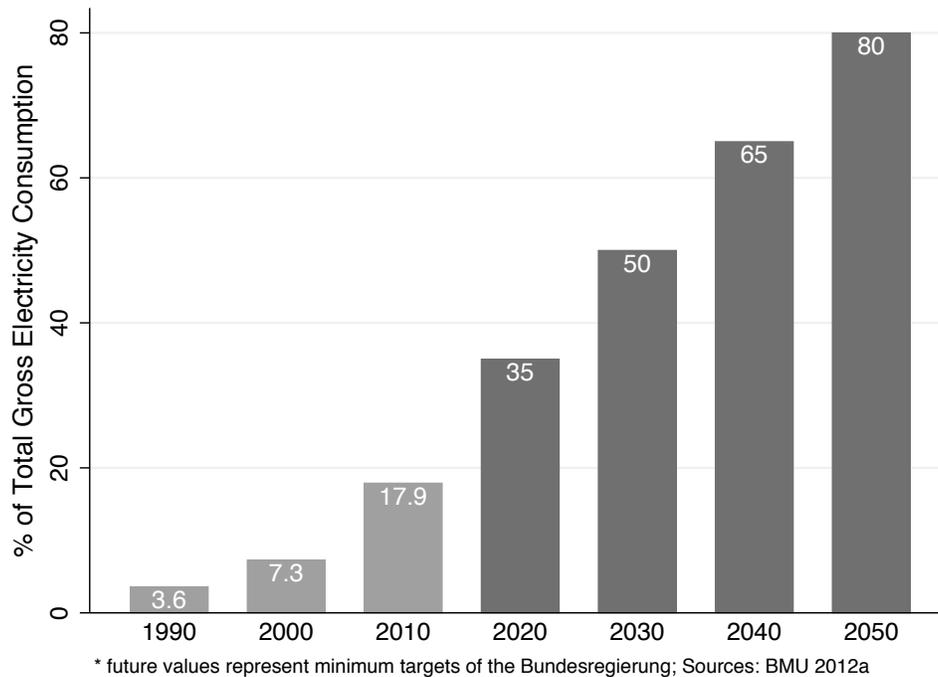
* In % of Total Gross Electric Power Consumption; Source: BMWi 2012

The term 'Energiewende' became one of the most present words in contemporary political debates and in the echo from German media. It describes the transformation of this heavily coal and nuclear power dependent electric power industry into a sector that will be dominated by the reliance on clean and renewable sources that have not been used extensively in the past: mainly wind and solar energy. The pact is non-partisan in every sense of the word as it is supported by every single relevant political party and based on a broad consensus within German society.

Following the 'Energiekonzept' of the administration, green energy is supposed to grow dramatically from a share of 21% in 2011 and is targeted to account for more than 50% of the electric power generation in less than 18 years (see chart 2). In the U.S., this compares only to California's plan which is, however, less ambitious as the state not only aims with one third at a lower percentage in 2020 but can also rely with a share of 9% more than Germany on hydroelectric power - a long established source that is extremely cost competitive, easy to integrate and often highly flexible.¹

¹see CEC 2012. However, it is also characterized by a very limited growth potential in most countries.

Chart 2: Renewable Energy in Germany: Past and Future*



With a share of 25.1% in the first six months of 2012, the German electric power sector is not only on track so far, but 'threatening' to overshoot the 2020 target. This is why the head of the federal ministry for the environment, nature conservation and nuclear safety recently proposed to elevate this target to 40%. The opposition rejected this idea arguing that it would require a slowdown - which is true given the current rates of annual capacity additions especially in the photovoltaic (PV) segment.

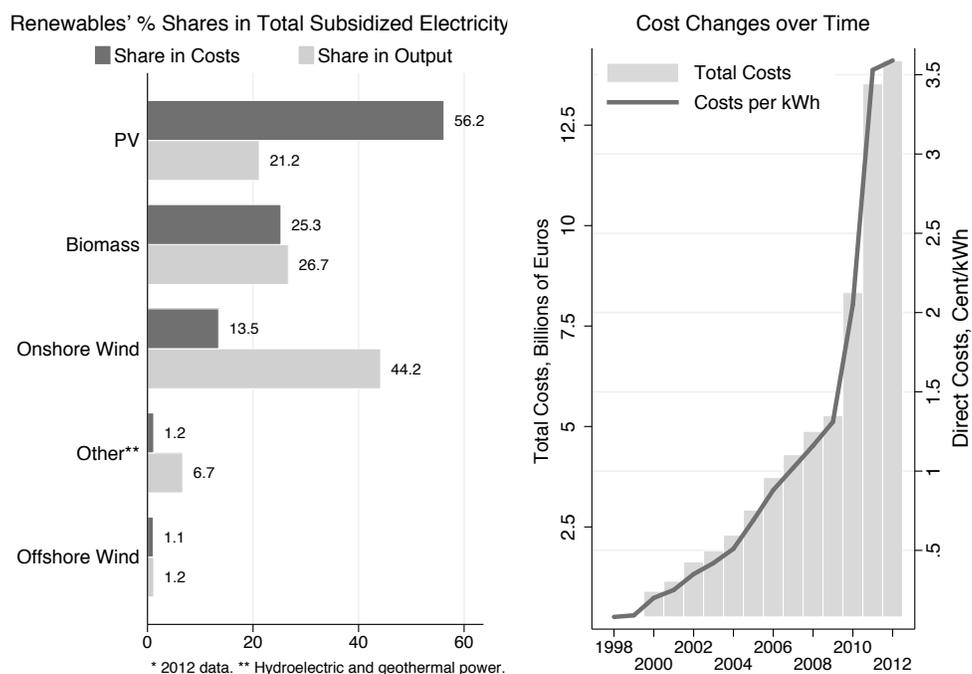
However, the transition still faces a wave of paramount headwinds that is already felt today and that is likely to grow in importance in the near future. It revolves mainly around the costs of the transition and the technical integration of renewable energy that ensures the stability of the grid network. These two issues will be analyzed in the following.

I. Economic Hurdles: Costs Competitiveness

Subsidies for renewable energy in Germany are provided through the system of feed-in tariffs for energy from green sources. Since 1991 it guarantees a minimum compensation for producers of

renewable energy and requires transmission system operators to integrate output from renewable sources produced by third parties. The compensation varies by technology, type and size of the installation. It is limited for a period of 20 years. For roof top mounted PV installation with up to 10 kW of peak capacity 18.73 cents/kWh are granted for 20 years as of August 2012 while ground mounted installations receive 12.97 cents/kWh. Onshore wind farms get 8.93 cents/kWh for the first 5 years and 4.87 cents/kWh thereafter.² Offshore installations receive 15 cents/kWh for the first 12 years and 3.5 cents/kWh thereafter.³ The costs caused by this feed-in system (the difference of the paid guaranteed preferred rate to the market price) are transferred from transmission operators down to utilities and endusers.

Chart 3: Costs Caused by the German Renewable Energy Act



Source: BDEW 2012.

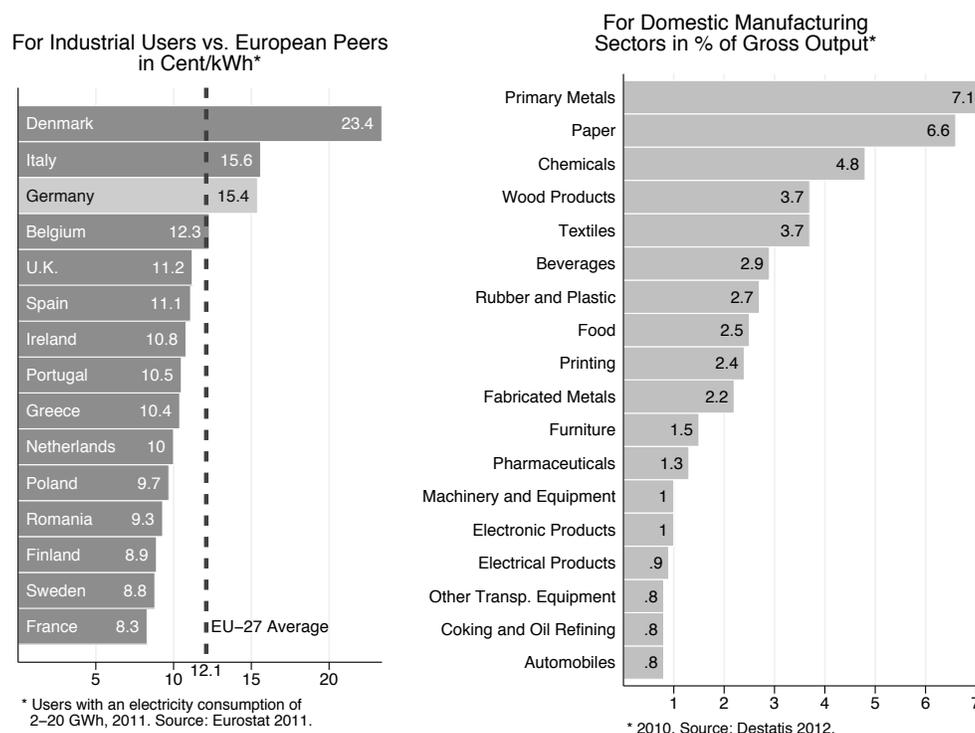
The right hand graph in chart 3 shows how the renewable energy act caused electricity prices to spike up. It illustrates the cost levy that subsidies for renewable energy pass on energy users

²See BDJ (2012a). The initial period of elevated compensation is being extended for installations that yield less than a certain benchmark value (by 2 months for every .75 percent below 150% of the benchmark value). There is an additional bonus of .48 cents for the first five years for certain wind turbines installed before January 1st 2015 and one amounting to .5 cents for repowered turbines. The average compensation for onshore wind was 8.85 cents/kWh and ranged from 5.39 to 10.20 in 2010 (BDEW 2012).

³See BDJ (2012b). The initial compensation period extends for installations located farther from the shore line than 12 nautical miles (.5 months for each additional nautical mile) and/or in waters deeper than 20 meters (1.7 months for each additional meter of depth).

(without preferred treatment). The rise was extremely significant in 2010 and 2011. The left hand graph in the chart shows how different renewable sources contribute to the total costs caused by the subsidy of renewables and what their output contribution is. A lot of the costs and of the cost spike has been caused by small scale PV installations. Their relatively small output contribution illustrates a point advanced by some in the debate that there has been a misallocation of resources that supports less efficient technologies more. This is a valid critique from a cost perspective and implies that a given amount of subsidies should be allocated more towards wind energy and more cost effective utility scale PV installations that currently receive much lower tariffs. On the other hand one can argue that the whole nature of a subsidy is to support young and currently less competitive technologies (PV more than wind) which have a realistic perspective to become commercially viable in the future. In addition to that, some argue that part of the increase in 2012 is the result of an augmentation of exceptions for energy intensive industries from bearing the costs of integrating renewable energy.

Chart 4: Energy Costs in Germany

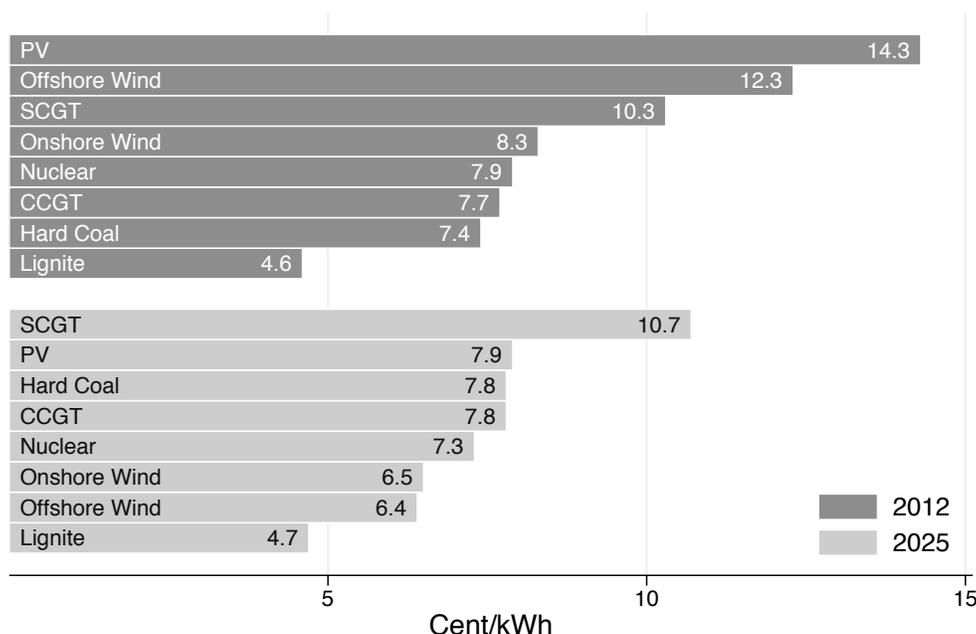


Nevertheless, the Energiewende contributes to already relatively high electricity prices for German households and industrial consumers. The left hand graph in chart 4 shows how German electricity costs for industrial consumers compare to European rivals.⁴ The only major European

⁴The picture looks similar for prices paid by households where Germany's 24.4 cents exceeded the European average of 17.1 cents significantly and are only topped by Denmark.

economy that faces higher costs is Italy. Prices lie 25% above the European average and are roughly double the costs of French industrial companies. Higher costs for electricity represent a competitive disadvantage that can make a difference for energy intensive German manufacturing industries.⁵ The right hand side of chart 4 illustrates the energy costs of major German manufacturing sectors. One can assume that without subsidies an industry such as aluminum production would be uncompetitive or that electric arch furnaces produce with lower operating costs elsewhere in Europe. At the same time, core German construction and manufacturing sectors such as mechanical engineering of course continue to be fully dependent on the use of these products as intermediate inputs.

Chart 5: German Electricity Generation Cost at Current Capacity Factors, in Cent/kWh*



* New plants. SC & CCGT: Single & Combined Cycle Gas Turbine. PV: southern Germany, utility scale. Wind: north German coastal conditions. Own calculations and projections (see text for assumptions).

As long as renewables involve higher generation costs, there will be a cost push due to subsidies and/or elevated average electricity generation costs to accomplish the energy transition. Chart 5 shows the current competitive situation of different techniques in the country. At the cost

⁵Of course, one has to account also for the quality of electricity. With respect to that, the German electric industry outperforms other European countries with much fewer annual blackout minutes. The stability of frequency and load in the network is very important for various electric power dependent industrial applications where only marginal fluctuations in the voltage can cause damages and break downs of production.

levels of 2012, almost all three major renewable sources⁶ of the future energy mix that have to grow significantly are more expensive for plant owners than all major conventional techniques. The model parameters used in the calculations of conventionals and renewables reflect the costs and electricity generating conditions faced by utilities for newly built state-of-the-art plants.⁷ The levelized costs of electricity (LCOE) model for PV installations assumes a southern German location and utility scales. Onshore wind power is assumed to occur under average north German coastal conditions while the offshore scenario has 40 meters of water depth and a distance of 20 km to the shore line. Due to the speculative nature of long term predictions, especially under technological change that is impossible to predict today while likely to occur in the different plant types, a forecast beyond 2025 was omitted. However, the chart also includes a prediction of generation costs in 2025 at current capacity utilization rates. It illustrates that by 2025, PV will produce cheaper load than single cycle gas turbine (SCGT) plants that also deliver peak load and that are the main competitor of PV in the current electricity market. Onshore and offshore wind installations will produce for less than the future generating costs of nuclear, hard coal and combined cycle gas turbine (CCGT) power plants. While the Energiewende is causing a price spike today and in the near future, there will be stronger cost reducing effects that can flatten future cost increases and potentially act as a limit and lead to a plateau rather than an ever increasing path. The 2025 picture is based on three crucial assumptions: 1. moderate or even no price increases of emission rights and hydrocarbon fuel prices; 2. continuing investment cost declines (and technological improvements) for renewables (and thermal plants); 3. constant capacity factors. The first assumption is unlikely to hold if emerging markets continue to grow and consume more energy fuels. Natural gas exports from the US or the emergence of fracking in Europe could lower natural gas prices while increasing American coal exports could have a similar, but more limited effect. The second assumption imposes the most probable scenario based on current knowledge but involves a lot of true uncertainty. The third assumption is wholly counterfactual and explicitly assumes that the current industry structure and capacity mix will not change. Doing this allows to isolate the effect of future price changes and technological improvements on the competitiveness of different technologies. The change in the energy mix and implied alterations in operating modes and capacity utilizations will be discussed below. Last but not least, all of these numbers include direct costs only that have to be paid for by market participants. There is no attempt to include externalities such as health care costs that result from low air quality and emissions from thermal plants or negative effects due to climate change that is accelerated by green house gas emissions. Such costs might of course substantially change

⁶The cheapest source with a limited potential, hydropower is not included and usually runs at less than 4 cent/kWh in large applications. Costs of biomass are heterogeneous and depending on the exact source and technology used as well as how heat output is handled in such popular joint production processes.

⁷See the appendix for assumptions for 2012 and 2025.

the picture but are generally hard to estimate.

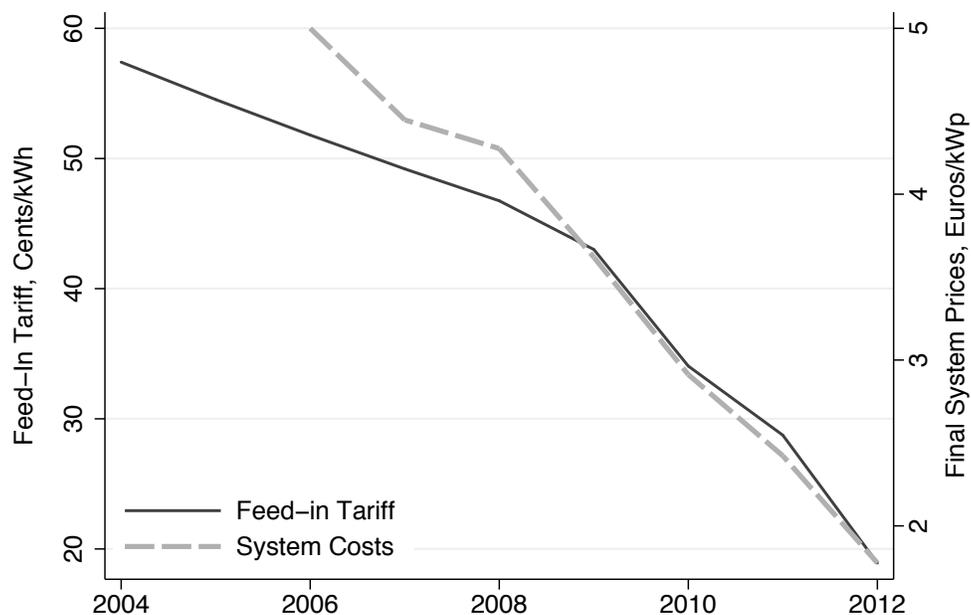
The 2025 scenario involves significant declines in generation costs from PV. The mayor driver of LCOE of PV power are the initial investment costs per kW of peak (nameplate) capacity installed, usually expressed as EUR/kWp (the other dimension of vast importance is the annual solar power radiation which is given for every location). Chart 6 shows how the tariff degression closely correlates with the secular decline in average total system costs in the case of small photovoltaic applications which account for most of the costs from the feed-in system. The traditionally largest cost factor of PV installations, the module prices, have fallen even more: Chinese producers of crystalline silicon modules that account for the lion share of the market dropped from 2.95 EUR/Wp in January 2009 by 47% during that year, 5% during 2010 and 46% during 2011. From January to June 2012 a further decline by 16% left a price of only 66 cents/Wp for these producers. CdTe thin film modules cost also fell over that period and were on average 6 cents lower while German silicon module manufacturers were 40% more expensive in June 2012.⁸ In the early 70s, panel prices were above \$50 in current dollars (Tracy and Sweet 2012). As neither moving parts nor fuel and emission costs are involved, operating and maintenance costs are very low.⁹ One can expect the decline of module and total system prices to continue as costs of production keep continuously falling. However, the fall will be less spectacular as the excess capacities that imply losses for most manufacturers today cannot prevail on the long run. Still, leading module equipment manufacturers quote production costs of less than 40 Cents/Wp for thin film modules with current state of the art manufacturing technology in large scale applications (Manz 2012). The future tariff level trajectory anticipates such a decline as the degression amounts to 1% of the tariff levels each month for newly installed PV panels.¹⁰ The long term decline in prices for PV modules is to a large extent due to economies of scale and a move along a mainly volume dependent learning curve. With Germany accounting for most of the world market, this phenomenon is a direct result of the German feed-in system and its success in inducing growth in renewable energy installations. One can also expect that raising efficiencies will continue to move more into the focus of manufacturers as this is the most effective mean to reduce BoS costs which account for most of the installation costs already.

⁸See Solar Server 2012. It should be noted that even though the differential of market prices narrowed a lot, the edge that thin film manufacturers have with respect to costs of production can be assumed to be larger.

⁹Balance of system as well as installation costs (which are also shrinking secularly) are becoming more important as module prices fall dramatically. Today, these costs can be assumed to account for more than 50% of total capital expenditures already. One way to lower these is to increase module efficiencies since higher output per module area implies that fewer mounting parts, wire connections and less installation work will be required. This development puts pressure on thin film and other manufacturers of lower efficiency modules.

¹⁰The rate can be less or more if new capacity installments fall out of a target volume corridor of 2.5 to 3.5 GW per year - a measurement that should prevent unexpected future cost explosions.

Chart 6: Trends for PV. Feed-in Tariffs and System Prices



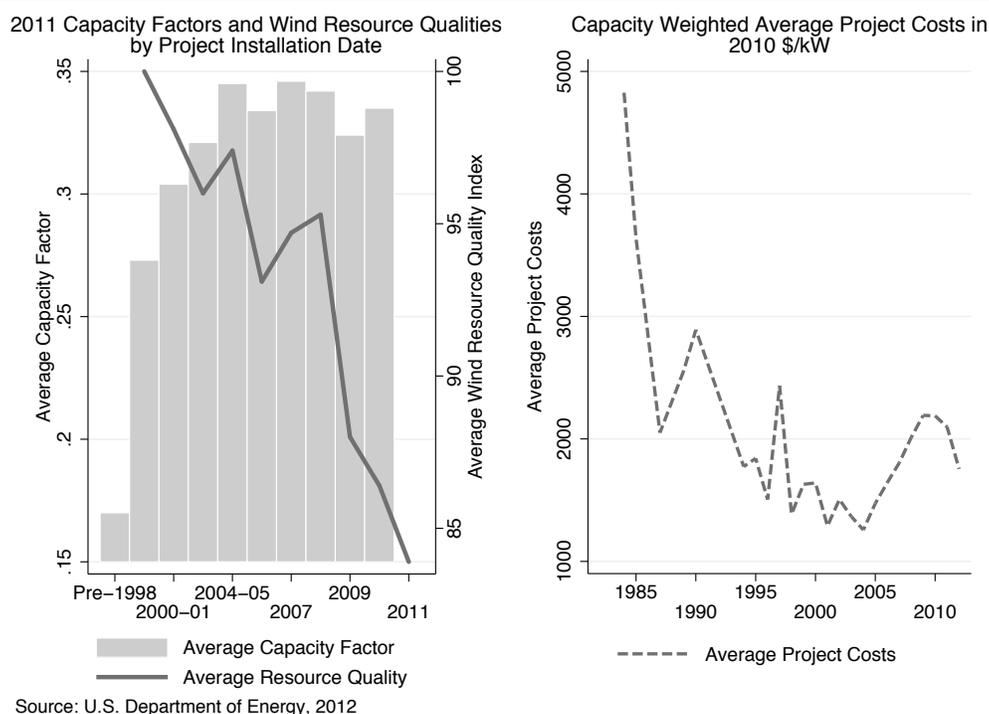
* Sources: <http://www.photovoltalk-web.de>; <http://www.solarwirtschaft.de>. System Prices are second quarter total end user price averages for ready-to-use roof top mounted installations of up to 100 kWp. Feed-In Tariffs are July rates for installations of up to 30 kWp (2012: 10kWp).

There has also been a trend of falling investment costs in wind generation due to larger units and projects as well as increasing manufacturing scale and learning curve effects. The capacity weighted average installed project capital costs in 1980 declined from \$3,500/kW in Denmark and over \$4,500/kW in the U.S. to less than \$1,500/kW in 2004. Due to high excess demand for turbine manufacturers, spikes in steel and copper prices as well as yield improving design modifications, costs for turbines went up and caused significant price increases from around \$800/kW in 2001 to \$1,500/kW in 2009. Total installation costs increased to more than \$2,000/kW in Denmark and the U.S. Today prices fell back to levels ranging from \$900/kW to \$1,270/kWh in the first half of 2012, implying approximately \$1,750/kW in total capacity weighted average costs (Wiser et al. 2012, Lantz et al. 2012: 4-5, Wiser and Bolinger 2012: 34). Since turbines account for 65 to 85 percent of total capital expenditures, the latter did largely move in the same directions as the former. The right hand side of chart 7 illustrates this development of installed wind power project costs.

Onshore cost competitiveness also continues to increase because of improvements in turbine technology and design. One important factor is size. Standard total turbine sizes increased from 37.5 meters and 30 kW nameplate capacity in the 80s to over 150 meters and 3,000 kW today (BWE 2012, RWE 2011). Greater hub heights and longer rotors allow to reach more stable and strong winds. An increase in the hub height from 65 to 120 meters allows for a 45% increase in

yield (WindGuard 2012: 5). This is especially important when it comes to lower wind resources. A larger swept rotor area per nameplate capacity allows to achieve higher capacity yields and to operate better under low wind power conditions. This is important as the growing installation of wind turbines forces operators to retreat to less suited areas with more unstable and weaker winds. The largest state of the art turbines sweep areas that are more than 10,000% larger than those ones of turbines of the very first generation. The left hand side of chart 7 shows how wind resource quality and capacity factors changed for projects depending on their year of installation. While average capacity yields increased significantly until 2004¹¹, it looks as if a plateau has been reached due to the sharp decline of resource quality. Depending on the magnitude of new installments, one must expect capacity yields to increase sooner or later when repowering kicks in and old low efficiency turbines that are located at prime sites are being replaced at the end of their operating life.

Chart 7: Wind Power Trends



A large portion of the increase in turbine costs over the levels of 2001 as illustrated in chart 7 is due to the growth of low wind turbines with larger swept area/nameplate capacity ratios and greater hub heights. Other innovations also lead to efficiency improvements while causing

¹¹The “pre-1998” value of 17% is already an increase over rates of 13% that could be expected in the 80s (BWE 2012: 13; RWE 2011: 68).

cost increases. Direct drive systems used with permanent magnets e.g. produce partial load efficiencies that are up to 10 percentage points above conventional turbines (at 5% of rated capacity). Removing the gearbox also reduces O&M costs by allowing for a simplified design that eliminates up to 50% of all moving parts. In many applications (as in offshore farms) these advantages are likely to thwart the need for a larger nacelle, a more powerful tower and higher initial capital expenditure requirements.¹² The overall effect of the developments in onshore turbine technology and investment costs is a reduction in the electricity generation costs of 17% to 31% between 2002 and 2012 (Wiser et al. 2012). In the long run, generation costs in the U.S. fell from levels of \$250/MWh (in 2010 \$) to less than \$80/MWh (Lantz et al. 2012: 15). As this trend is also present in Germany, feed-in tariffs are degressing in the future by 1.5% annually for onshore wind farms and starting in 2018, by 7% per year for offshore installations (BDJ 2012c).

Offshore turbine sizes are scaled up even more than new onshore equipment - to currently up to 7.58 MW nameplate capacity. The first German offshore wind park Alpha Ventus produced a utilization rate of 50.8% in 2011, 15% more than the initially expected value (LORC 2012, BMU 2012) and far higher than the capacity rates of onshore wind in Germany (19%) and even natural gas or hard coal power plants. The two finished German offshore farms are running since the beginning of their operation frequently at full capacity during periods where all onshore installations together were practically standing still. One can assume that future developments in the offshore wind industry are going to experience more spectacular improvements in technology and costs than in the onshore sector.

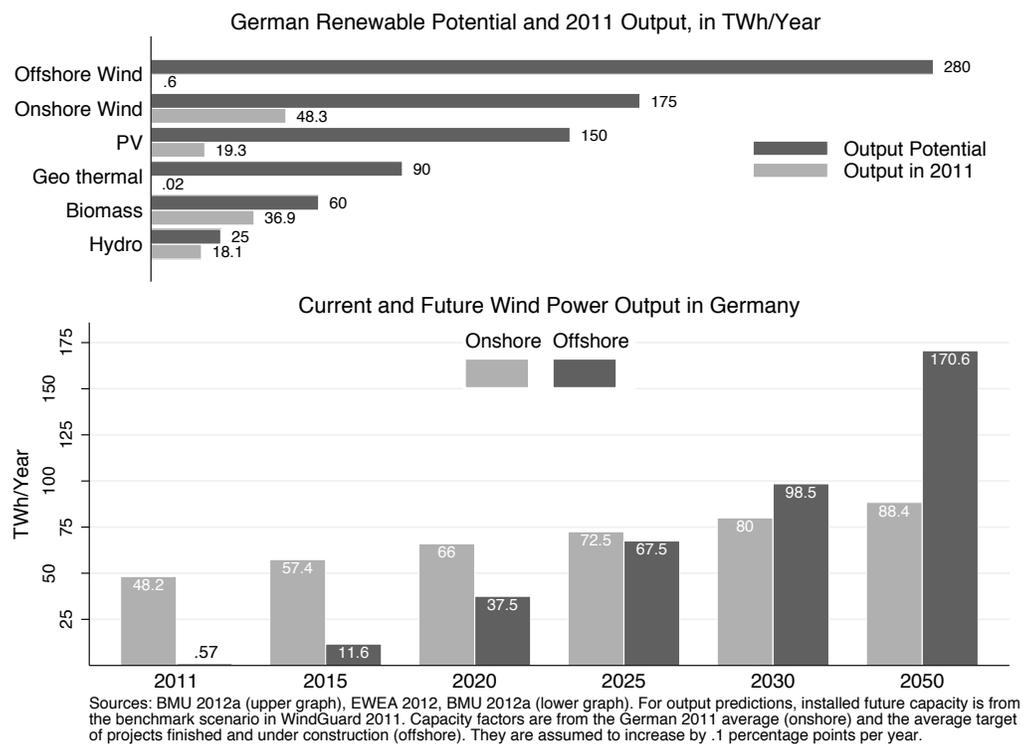
II. Technical Hurdles 1: The Growth in Renewable Capacity

Besides the necessity to keep costs in check, there is also the problem to build enough new renewable capacity that is able to replace conventional power plants which go offline. This can be a challenge as resources for renewables are also limited. Such limitations are mainly the availability of suitable space. Chart 8 illustrates the potential of the different renewable energy sources and how much is already in use today. It is clear that the largest untapped potential lies in offshore wind - more than the combined unused potentials of the next two largest renewable sources, PV and onshore wind power. At a total annual load of 629 TWh/year it is not possible to power Germany with renewable energy without tapping offshore wind. Accordingly, the official

¹²GE currently works on the application of superconducting materials in turbines that have the potential to be much smaller than permanent magnets and could result in nacelles that are smaller than current 4 GW permanent magnet direct drives while supporting capacities of up to 15 MW (Zipp 2011).

goal of the federal administration is to construct 10 GW of offshore capacity by 2020 and 25 GW by 2030 (Bureg 2012). This is the equivalent of 20 nuclear power plants. Presently, total installed capacity amounts to only 200.3 MW (Offshore 2012). The lower half of chart 8 shows the annual output that corresponds to these targets and includes forecasts for onshore and for 2050 as well as output from offshore and onshore installations in 2011. An explosive growth in offshore wind generation is a precondition for the Energiewende as it is currently envisioned.

Chart 8: The Importance of Offshore Wind in the Future



The process is far from being smooth and several major obstacles are looming today. Costs of the latest wind farm that will go online in 2013, BARD 1, are about to exceed the planned budget by over 50%. Banks are set to lose at least 1 Billion Euros on the project with a volume of 2.9 Billion Euros for 400 MW of installed capacity (Maier 2012). One major problem are technical difficulties in the installation process. The latter is dependent on weather conditions and has to be permanently interrupted. The results are huge delays and painful cost spikes as one construction ship costs up to 80,000 EUR per day (up to four are currently working to finish BARD 1). Constructing all projects that are approved today at the same time would not be possible due to the limited availability of ships. Another issue is the connection of offshore wind farms to the grid which causes a lot of uncertainty about the points of time when wind farms can be take online. Transmission system operators that are required to connect the installations

lack the capital necessary for financing the wind power integration (Paul 2012). A second, even larger obstacle is the transportation of electricity from (on- and offshore) wind farms in the north to the southern industrial centers that consume most of the energy. The extension of the grid network imposes major challenges and it is far from clear today if it can be completed in time to allow sufficient capacities to be installed.

In the case of onshore wind, a major share of the capacity and output additions that are shown in chart 8 will have to come through repowering since the use of new areas often turns out to be complicated, time consuming and is in general limited (to approximately 2% of the area in Germany according to the German wind energy industry association). While most turbines are designed to operate for 25 years, repowering can in many cases be a profitable option before the end of that life cycle as technical improvements make new models more profitable (lower O&M costs, higher capacity factors). The current version of the German Renewable Energy act gives an additional incentive for repowering with a bonus compensation of .5 ct./kWh. In 2011, more than half of the 22,000 wind turbines were older than 10 years. There are 6,100 MW of first generation turbines in 2012 with an average rated capacity of 650 MW. On average, onshore new installations are rated at 2.3 MW and often at 3 MW or more which means that in many cases repowering cuts the amount of turbines by half while tripling capacity at the same time.¹³ However, there are obstacles such as rules that impose maximum height limits and transportation complications of large components. In 2011, only 170 installations with a capacity of 170 MW got replaced by new ones with a capacity of 238 MW (BWE 2012).

II. Technical Hurdles 2: Matching Supply to Demand, Grid Stability

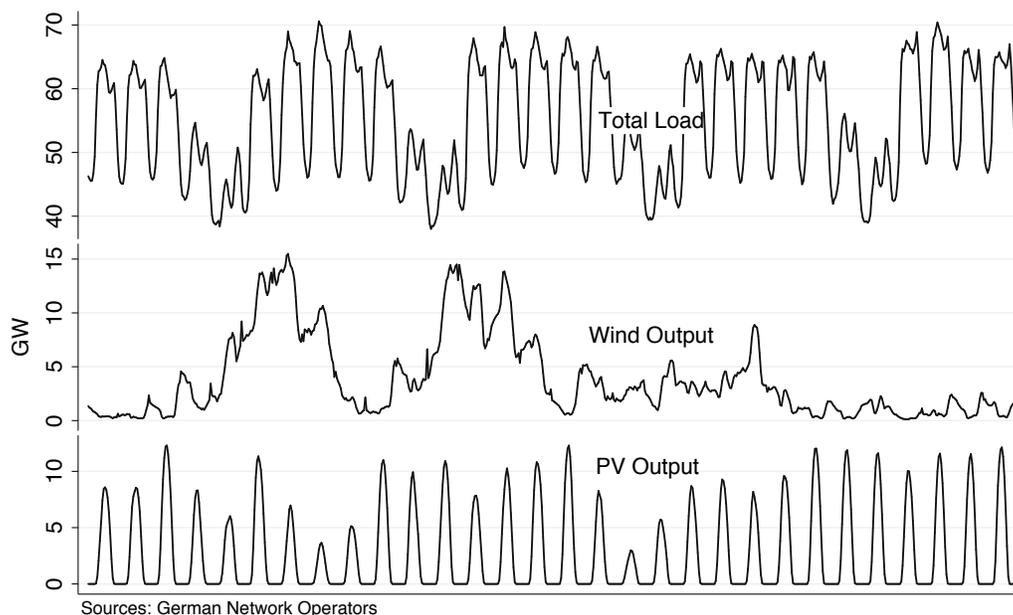
The problems of constructing sufficient offshore capacity and extending the grid have immediate importance today. Crucial in the long run are the fundamental patterns of total electricity consumption and generation from intermittent renewables over daily, monthly and annual periods as well as the availability of storage units and of other flexible capacities that produce electricity on demand. It depends on these factors if electricity consumption can be met, if the network breaks down, if (or how much) output is being lost on a regular basis and how the economics of the electricity industry change.

¹³In order to be classified as repowered installations and to qualify for the compensation bonus, the installations need to have at least double the capacity with the same or a fewer amount of turbines (BDJ 2012d).

II. 1. Intermittent Load from Solar and Wind Energy

In any grid network, the amount of energy used must correspond to the electricity produced at any point of time. If the very small tolerance threshold is violated, blackouts are the result. Traditionally, supply adjusts to fluctuating demand in two different ways - through energy storage and flexible excess capacity. The energy generation from renewable sources such as wind and PV power is creating an additional challenge as it is intermittent: output fluctuates according to a combination of different normal and random patterns between zero and full capacity. Their “must-take loads” have to be integrated by law as well as due to plain economics, once systems are already installed: their variable operating costs are lower than the ones of conventional power plants while initial fixed capital investment costs are high (see appendix). The use of their output thus saves fuel expenses and other operating and maintenance (O&M) costs associated with thermal plants.

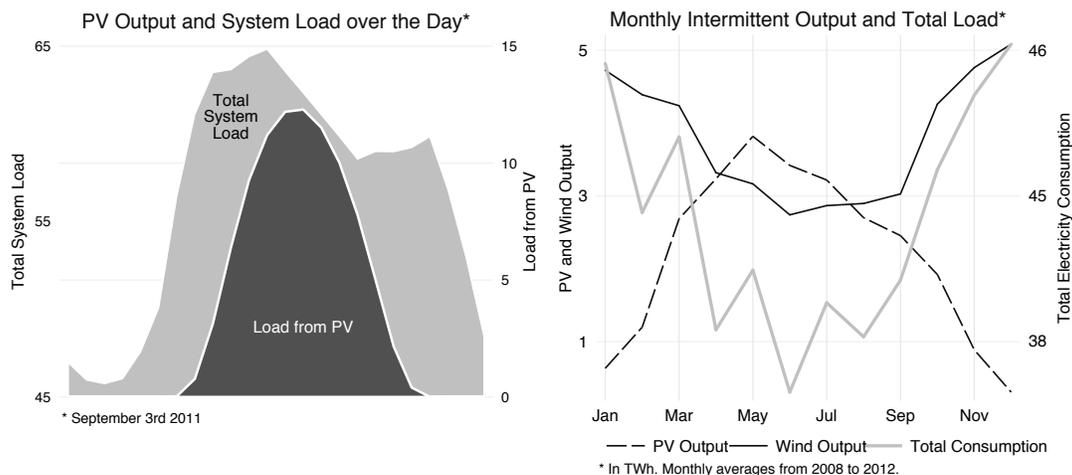
Chart 9: Total Load, Wind and Solar Power Output in Germany, September 2011



Loads from renewable sources behave very differently. One can easily see in chart 9 the relatively regular patterns of PV output and of electricity usage over the day and the week. The chart 10 shows that PV can be used very well as a source that serves expensive peak load. As the latter comes in Germany from the most costly conventional sources such as SCGT, PV power competes with the highest cost alternative for grid parity. However, it is clear that PV cannot serve all of the peak load directly as peaking kicks in before dawn and spikes up again after dark. Today, more than 30 GW are installed in Germany as of August 2012. As there is never more

than 80% of installed PV capacity fed into the grid network even during the sunniest days (e.g. because of fog or local clouds), one has to expect a daily PV load fluctuation of currently up to 20.5 GW while the average daily maximum of PV output in a summer month will involve fluctuations of 13.2 GW. As the daily electricity consumption in summer months under the week usually peaks at around 70 GW while it usually drops as low as 50 to 40 GW at night, there is no major threat for network stability. In the summer months, PV serves to replace a significant amount of expensive peaking plant power without forcing the less flexible base load to adjust or causing overproduction of electricity that could not be used. Peaking plants will still be required, especially before and after the hours of maximum solar radiation. In the winter months, PV has the same impact but on a much smaller scale. Once PV capacity doubles to 60 GW, PV power will regularly exceed peak system load by orders or 10 GW. Such an overshooting could be captured through storage (for less than 24 hours as it could be used to replace peak load after and before the daily solar radiation reaches its maximum output). Doing this would provide most of the summer's peaking power. Alternatively, there could of course be temporary and rapid reductions of what has traditionally been base load from conventionals which need to give way to flexible hard coal, natural gas or biomass or become flexible themselves.

Chart 10: Daily and Annual Patterns



Sources: German Network Operators, own calculations.

Wind energy follows largely a random pattern over the week and the month that might include two or three weeks of near zero output, as shown by chart 9. On the other hand, it is not unusual that a single offshore farm operates at nominal capacity for several weeks with only relatively short interruptions. Still, the pattern of wind output requires that as soon as wind capacity reaches a

certain share, there needs to be either 1. storage that provides negative and positive load reliably for days weeks and at some point for weeks; 2. conventional capacity that is highly flexible and that can rapidly reduce load to a small share of installed capacity if necessary; 3. transmission lines that allow to export and imports electricity to and from other countries; 4. an efficiency and a cost level of wind power that allows utilities and investors to still operate profitably even when large shares of output (10% or 20%) are not fed into the grid due to recurring periods of persistent overproduction. The statistical analysis shows that even at the aggregate, one has to expect variations between 0 and nearly 24 GW of wind output already today (there are 30 GW of capacity installed as of June 2012 and the aggregate utilization usually can go up to almost 70%). At least for the case of Germany this proves the often stated idea wrong, that output fluctuations from different sites cancel each other out so that wind power could produce base load power up to a certain percentage of installed aggregate capacity. Since output spikes can occur any time, one cannot rely on flexible natural gas peaking capacity in a stable recurring way to adjust output as this can be done with PV, whose spikes are always feeding into peak demand. To integrate wind energy, it is necessary to regularly adjust the base load spectrum in order to match output to consumption - which is more complicated. This problem will grow significantly as new capacities get online. Plants designed for constant output will have to operate cyclically. This being said, the geographical extension of wind installations still does create a somewhat higher degree of stability as the correlation of load from different wind sites is known to decrease with distance. Weather conditions prevailing in offshore territories are also very different from onshore conditions. Future wind installations' growth is taking place in exactly these untapped low wind and offshore sites. The 15 minutes interval output data from January 2010 to the end of June 2012 shows that the correlation between offshore wind farms connected to the Tennet TSO's network and installations located in the area of the southern German network operator TransnetBW was as low as .14.¹⁴ The trend of further increases of hub heights and rotor diameters will also result to higher capacity factor persistence. While one can thus expect the output pattern to smooth moderately, swings in load from renewables due to new wind power capacity additions will still have to be compensated. One advantage of wind energy is that it is more closely correlated with power consumption over the year as both are peaking in the winter. PV on the other hand runs in opposite to electricity consumption as it peaks in the summer (see chart 10). These patterns thus allow to combine PV and wind power in such proportions that seasonal storage can largely be avoided even with a small amount of flexible conventional or renewable capacity. For Germany, the monthly sums of PV and wind power output track monthly system load best when PV electricity amounts to around 25 % of total renewable electricity output. A negative

¹⁴The pairwise correlations between onshore wind output values from installations in the four different grid network zones range from .44 to .86.

correlation of outputs from PV and wind does not only exist over the year, but also in the short run. The inverse relation is due to the fact that strong winds appear more often when it is cloudy and sun radiation is weak. The correlation of 15 minutes interval total wind and PV capacity factors for the two years from July 2010 lies at $-.122$ for all intervals where aggregate PV output is greater than zero ($-.11$ without this restriction). The correlation between PV and wind utilizations amounts on average to $-.03$ when computed within each month for every time interval (in order to eliminate seasonal patterns) and $-.05$ for all periods where PV output is bigger than zero.

The intermittent character of PV and wind combined with the growth of installed capacities and shrinking consumption will lead to potential output losses due to temporary overproduction. While losses can be due to overload of the grid at certain points of the network or too strong winds that force wind farms to shut down temporarily, such losses are hard to estimate and are likely to be limited if the network extension is accomplished successfully. On a more basic level, overproduction will result if total load is below the output of PV, wind and power plants that cannot be regulated or lowered below a certain capacity factor. Shortages can occur if there is not sufficient flexible load available on demand from conventional plants, storage units or imports.

II. 2. Inflexible and Flexible Conventional Capacity

In the conventional energy mix, nuclear and lignite power plants are usually used to produce base load. Their inflexible operation is due to the fact that these plants involve operating costs that are historically lower than the ones of more flexible thermal plants like hard coal or natural gas. It is also explained by technical reasons, large unit sizes and technical issues. Partial load results in extraordinary strain on the material, are sometimes associated with safety issues and have negative environmental impacts as emissions are higher and efficiencies lower at partial load. Output changes can often be implemented only very slowly. Restarts from a cold plant state can take a time from several hours to days until full load is being reached. All this makes them unsuitable to be used as cold reserves or to be operated permanently in a deep load following mode. While there are claims of relatively low possible minimum utilizations and high ramp rates, practically all existing plants of these types are in base load mode and follow load only very moderately when other capacities have already been adjusted. One can assume that there is a minimum utilization below which plants cannot be operated economically and/or technically. The product of the capacities of lignite or nuclear plants and their respective minimum utilization rates should thus be viewed as a form of quasi-must-run load. The difference between the minimum and the maximum utilizations should be classified as at least moderately flexible. There are also renewable sources that are inflexible: non-adjustable hydroelectric run-of-river power

(which account for 80% of hydroelectric capacity in Germany) as well as biomass fired heating or combined heat and power producing plants that generate electricity as a secondary output.

From the standpoint of the technical integration of renewables, higher shares of this inflexible conventional capacity represent obstacles as their minimum utilization of power from nuclear and lignite plants needs to be added to the load from wind and PV to arrive at the real total must-take-load. The higher the share of inflexible capacity, the smaller the space for PV and wind capacity as they are more likely to produce more than what can be used in the system at certain points of time. Accordingly, the nuclear power phase-out is opening up a huge gap that makes the realization of higher renewable shares without too much overproduction easier. Conversely to the effect of inflexible load, higher amounts of flexible conventional load make the integration much easier as they can produce load when the wind does not blow and the sun does not shine.

Table 1: Operating flexibilities

	Nuclear	Lignite	Coal	CCGT	SCGT	Hydro
Min. utilization	70%	50%	35%	25%	<20%	0%
Cold start from in minutes			300	120	25	<2
Max. ramp rate, % of capacity	5	4	6	10	20	100
Number of starts possible			6,000	8,000*		
Min. cold start costs, EUR/MW			8.6	2.5	1.5	

* Fast starts can reduce the number to 800; Sources: Auer and Keil (2012), Vuorinen (2007), Kehlhofer (1998), Quinkertz et al. (2008), Kumar et al. (2012), Meinecke and Pickard (2011).

To match supply to demand, utilities use hard coal power plants that are more flexible and usually follow load while highly flexible gas turbines (especially when installed in a single cycle) are generating peak load. The average utilization of gas and hard coal fired plants in Germany lies at 36% and 44% respectively (when calculated from the total installed capacities where, however, some plants are used as cold reserves). Gas turbines are in general significantly more flexible than steam turbines with respect to start-up time, minimum load factors as well as maximum ramp rates and are thus better suited for cyclical operation. Technical flexibilities are high for most thermal plant types and can be utilized in emergency situations while normal operating conditions impose significant restrictions that are based on economic, safety and environmental considerations.¹⁵ Costs result e.g. from stress on plant equipment when exposed to steep and fast thermal variations, differences in temperatures of different equipment parts or startup fuel

¹⁵This leads to wide variations in the description of technologies when it comes to possible minimum loads and maximum output ramp rates.

requirements. These costs rise with growing thermal variations in a given time interval, implying that cold starts are more expensive than warm or hot starts (the longer the time of the unit being offline the greater the decreases of material temperature at the beginning of the restart); restarts are more expensive than load cycling operations; costs increase with the steepness of load variations under load following mode. Furthermore, flexible operation is more expensive for large than for small units and for technologies relying on steam turbines than for gas turbines (Lefton and Hilleman 2011). While larger unit designs have advantages with respect to operating efficiency and costs at or close to nominal output, they are usually also slower in adjusting their output. Safety risks generally result from stressed material and from more possibilities for human errors while efficiencies and emission statistics deteriorate as plants operate below nominal capacity. While technical and economic characteristics differ vastly across power plants within every plant type, table 1 shows the most important plant characteristics with respect to operating flexibility under partial load and suitability to operate as reserves. It shows that the most flexible source of energy comes from dammed (and pumped) hydroelectric plants, followed by simple cycle natural gas turbine power plants - all of which are suited very well to deliver peak load and operating reserves. Hard coal plants and CCGT plants are in an intermediate position between lignite or nuclear power and SCGT while CCGT units have advantages e.g. by allowing twice the amount of start-ups throughout the lifecycle (300 per year over 20 years for new state of the art CCGT plants) and a much lower minimum utilization when constructed in multi-shaft designs where for example one of two gas turbines in a 2x1 shaft outlay can be switched off (not shown in table) (GE 2012, Meinecke and Pickard 2011, Quinkertz et al. 2008).

Due to the sudden loss of nuclear power, there has been a rise in the share of coal in the German energy mix in 2012. Traditional coal heavy weight RWE AG has been racing to put new, cleaner, more efficient and flexible lignite capacity online.¹⁶ The latest 2.1 GW “optimized lignite technique” plant installed in Neurath, Northrhine-Westphalia, contains major improvements over past state of the art techniques with respect to flexibility. While old lignite plants could not run in some cases at less than 75% of installed capacity, the new Neurath units’ minimum utilization is 50%.¹⁷ Retrofits of the control systems at older units allowed to increase the maximum change of output per minute from 5 MW for a decrease and 3 MW for an increase to 10.5 MW per minute for any adjustment. Lower minimum utilizations and faster output adjustment speeds are also being pursued in new hard coal units. The minimum capacity factor can be pushed down to

¹⁶Of course, RWE started to become also very aggressive (given its financial weakening due to the nuclear phase out) in pushing their renewable capacity with offshore projects that target 6.5 GW of installed capacity by 2025 (Gassmann 2012) and its innovative pitch to install more than 1 GW of PV panels by the end of 2012 on commercial buildings of various supermarket and other chains (FTD 2012).

¹⁷The new plant design also raised efficiency from the German lignite plant average of 36% to 43% and allowed to lower emissions from 1.14 kg CO₂/kWh for older plants to .95 kg (RWE 2011b).

25% if necessary from as much as 55 to 70%. New small and flexible hard coal units are able to sustain 8 times as many hot starts while requiring 30% less time to reach a 100% load during a cold start (RWE 2009).

The federal Government is banking mainly on the construction of new flexible natural gas fired capacity in Germany. However, utilities have claimed that this would be uneconomic given the high price of European natural gas and the great amount of uncertainty about the future utilization of plants. There has been some debate on the introduction of a capacity market where operators get paid for just holding flexible capacity available on demand - independently of whether plants are being put to work. This might be an option but policy makers currently believe that additional incentives are not necessary for a profitable operation of new natural gas plants. While gas fired plants are more expensive at delivering base load power in Europe, their cost disadvantage shrinks significantly when other conventional plants are forced to operate in flexible modes since their start-up costs are higher and the greater initial investment expenditures of coal and nuclear power translate into higher fixed capital costs per kWh. A wild card for natural gas fired plants would be an unexpected growth of hydraulic fracturing in European countries. While the situation seems to be not too promising for the oil and gas industry in countries like Germany and France, Polish authorities e.g. have been more determined to get their hand on the country's vast shale gas reserves. Successful extraction could have a depressing effect on gas prices even in neighboring countries. Even a moderate fall in the European natural gas price would allow plant owners to operate profitably while obtaining lower output prices and running at lower capacity utilizations since pure fuel costs account for as much as 65% of total final costs per kWh (other conventional plants have to calculate with proportionally higher capital costs and non-fuel operating expenses). A similar effect on gas prices would come from possible liquified natural gas exports from the U.S. even if the quantities would be relatively low. There seems to be a good chance for the construction of the required facilities. However, exports would first go to Asia where prices are again even much higher than in Europe.

II. 3. Electricity Storage

Storage of electric energy is a way to ease the integration of intermittent sources from wind and solar power by storing output in excess of current consumption and reusing it to meet demand when their output falls below demand. This potentially solves their most fundamental technical problem and is in most countries the only way to enable a renewable share of 100%. Today, pumped hydro power and compressed air energy storage plants use electricity to store energy in a different form when too much is being produced and prices are low and reverse this

step when electricity usage and prices spike back up.

In pumped storage hydro power plants (PSH), water flows from an upper reservoir under pressure through a pipe to turbines whose generators produce electricity on demand. When required, it uses electricity that transforms the generators into electric motors and the turbines into pumps that transfer water from a lower to an upper reservoir where the converted electrical energy is stored in the form of the water's potential energy. Such plants are in continuous operation in Germany for more than 90 years already and by far the most inexpensive method to store energy. They also represent the most efficient centralized technique with an efficiency of over 80%. Germany has currently 30 plants with an aggregate turbine capacity of 6.7 GW and a storage capacity of 40 GWh online (Auer and Keil 2012). The world's largest existing plant is located in the Bath County, Virginia and operated by Dominion Power. Its pumping capacity is large enough to store the output of three nuclear reactors running at full capacity at the same time. The biggest problem of the technology is that the potential for adding new capacity is very limited as it depends on natural conditions of the landscape. The latter is also impacted significantly and there are usually problems with neighboring communities and environmental protection groups. However, due to incentives for plants installed before 2019, there are several projects in construction and different planning stages which have a total turbine capacity of 5.9 GW. Plants involve investment costs of EUR 1,200 / kW. PSH operators need electricity price margins of at least 3 cents/kWh to cover the full costs faced by plant operators (unless prices for electricity happen to be negative) while total costs of this renewable energy on demand amounts to 12.5 cents/kWh if the electricity originally cost 8 cents per kWh. Compressed air energy storage or CAES is the second technique that is being used today in grid connected, centralized applications for short term electricity storage. In storage mode, electricity is being used to power compression units that compress air and pump it into underground salt caverns. To generate electricity, the air is being released, heated with natural gas and used to power a modified gas turbine. The technology is less mature as there are only two plants existing world wide up to date - one in Huntorf, Germany and one in McIntosh, Alabama. Both are being operated commercially by electric utilities since 1978 and 1991 respectively. Huntorf has seen a makeover in 2006. It runs fully automated and is controlled remotely. Efficiencies of existing plants reach up to 54% and can be expected to lie at 60% for new installations. Storage costs are above the ones of pumped hydro power plants. A German utility is currently developing a new version of the technology ("advanced adiabatic" or AA- CAES) that does not rely on natural gas for offloading the stored energy. Instead, plants capture, store and reuse thermal energy produced by the compressor during the loading phase. This allows to raise the efficiency to 70% and drive down operating costs significantly. The great advantage of CAES technology is that it has a large unused potential. Caverns are being produced artificially by washing out salt domes. Very large

and deep domes are being used extensively today already to store natural gas, hydrogen and oil. The potential for installing salt caverns can be assumed to be sufficient to satisfy all demands for short term energy storage in Germany or the US (Auer and Keil 2012). There has been for example a project in the U.S. to construct a CAES plant with a turbine capacity of 2.7 GW and a storage capacity of 518 GWh that was not realized due to turmoil of the financial crisis. Another benefit of CAES is the flexibility in plant design where turbine, compression as well as storage capacities can be scaled according to needs. With EUR 1,000-800/kW, investment costs are lower than for PSH. Renewable energy on demand from CAES that costs initially 8 cent/kWh will end up at a total cost of 15 cent/kWh while plant operators can calculate with at least 3.7 cents. The disadvantage of the mechanical storage systems PSH and CAES is their very limited long-term storage capacity.¹⁸ Existing units are only designed to operate for storage cycles of hours and in exceptional cases a few days. They are not capable of matching intermittent supply to demand for longer periods like weeks of exceptionally strong or zero wind speeds and especially not seasonal fluctuations. These types of output smoothing are precisely what will be needed at some point when the share of renewables keeps growing. The approach that could solve this problem is electrochemical power-to-gas storage. It involves the production of hydrogen (H₂), its storage and reconversion into electricity. Electrolysis can be operated well under partial load, involves high ramp-up rates that allow to react to load alternations flexibly as well as short start-up times that are similar to SCGT. The storage in salt caverns is relatively inexpensive and already proven to work without major technical obstacles. It exploits an energy density that is 360 times as high as the one from PSH and can be implemented on a scale that would solve all long term energy storage problems. H₂ can also be added to natural gas and transported in pipelines without causing any significant problems for the infrastructure or users if it represents not more than 5 percent of the volume or 1.5 percent of the energy (relatively minor technical modifications of the infrastructure and adjustments of units using natural gas could raise the proportion of H₂ to 10 to 20 %). The 500,000 km-long grid has a storage capacity of over 200 TWh of natural gas and can transport 1,000 TWh of energy per year, allowing to store 3 TWh of H₂ at any point of time and 15 TWh over the course of the year. Transportation capacities and losses are much lower than for standard electricity power lines. However, the high volatility of the gas imposes complications for pure H₂ in the existing infrastructure. An alternative is to produce synthetic methane through a second electrochemical process. While this raises the energy density and the ease to handle and use the gas, it worsens the already problematic cost and efficiency situation (less than 50 % for the whole cycle). While fuel cells allow for very high conversion efficiencies (more than 80 % for this gas to storage sequence) and operate very well under partial load,

¹⁸Battery storage is not discussed here as this alternative short term storage system suffers from cost disadvantages versus the two mechanical storage technologies discussed here.

they are still very expensive, technologically complex and in an immature stage (Auer and Keil 2012). As an alternative, H₂ can be used for cofiring in most thermal plants. More importantly, conventional gas turbines that burn anything from blast furnace gas to methanol and heavy oil (Kehlhofer 1997: 144) can be run on H₂ instead of natural gas with efficiency losses of less than 2 % (Chiesa et al. 2005). Assuming costs of 1,000 EUR/kW for an electrolyzer and 750 EUR/kW for a CCGT plant that run together for 25 years with an annual utilization of 30%, an 80% and a 60% electrolyzer and CCGT efficiency, 2% maintenance rates and 200% of applicable variable and fixed CCGT costs, renewable energy that is produced for 8 cents/kWh will cost roughly 21 cents when stored and reconverted through hydrogen.¹⁹

II. 4. Future Electricity Market Simulations

In order to assess the magnitudes of the issues of overproduction losses, storage volumes and necessary flexible reserve capacity I used a simulation model. Its most important input are 15 minutes interval data on wind, PV output and system load.²⁰ Data from the four German network operators on wind output cover the four year period starting in July 2008 while data on PV output covers two years starting in July 2010.²¹ Using monthly data from the federal network agency on aggregate capacities installed, I obtained actual capacity factors for the 15 minutes intervals. The capacity factors were used to scale the past output time series of PV and wind power in such a way that PV and wind output of every point of time reflects exactly the total PV and wind capacities that I forecast to be installed in my future scenarios for 2025 and 2040 and the utilization rate at each of the past 15 minutes intervals recorded.²² Equivalently, the total load was scaled to match precisely the total energy consumption per year predicted by multiplying each load value with the quotient of future annual energy consumption over the annual sum of load values of the respective data year. The four year period allowed to calculate an annual average that was less prone to be disturbed by a year with exceptional weather conditions (wind or solar radiation) or unusual load behavior (e.g. in an economic boom or bust). With these data, it was in turn possible to simulate and evaluate future energy production from renewables on a relatively high level of precision. Modeling involved besides this scaling and reshaping of output from wind and PV power as well as of the system load (step 1) also the simulation of these storage units' activity (step 2) and of the output from flexible power sources (hard coal, lignite, natural gas,

¹⁹Operators' own direct costs can be less than half of that value.

²⁰They have been obtained from the four German network operators.

²¹These longer periods are chosen to migrate annual fluctuations that can occur in a single year. For the model evaluations, results for the average year out of the patterns in the years described are presented.

²²As the improvement in future capacity factors means that output will tend to be higher under conditions that have previously yielded only partial load (wind turbines e.g. usually do not produce more load than 110% of nominal capacity), I scaled loads corresponding to lower capacity factors with greater weights than loads close to full capacity.

hydroelectric, biomass and other) with their predicted installed capacities and technical features (step 3). The model does not consider any electricity exports and imports as this would require modeling electricity markets of other economies and does not provide a solution for the nature of the problem.²³

The simulation allows to predict how much electricity will be lost in an average year in the different future scenarios described below; how much energy can be stored and reused; how big eventual electricity shortages will be; what the average capacity utilizations of all the different electricity sources will be; how capacity factors and output patterns will effect the electricity generation costs and the relative competitiveness of the different plant technologies.

The scenarios used here assume that offshore wind installations come online according to the current plan with 17.5 GW by 2025 and that there will be annual additions amounting up to 200 MW after 25 GW are installed in 2030, which will lead to 27.7 GW in 2040 including offshore repowering effects (see next paragraph). In the scenario applied here in the study, new onshore installations are assumed to grow by only 50 MW annually. However, data on past annual installments indicate that there will be 6.1 GW of capacity that are going to be older than 25 years by 2025 and that have to be retired or replaced. Assuming that 60% of all turbines will be repowered with an increased capacity of 200% per turbine, will yield 7.31 GW in new onshore capacity (a net addition of 1.2 GW). Under the same assumptions, 24.1 GW will go offline between 2025 and 2040 and repowering will produce 28.9 GW of new turbines (a net plus of 4.8 GW). Equivalently, the first offshore turbines will retire in 2039: by 2040 3.5 GW will have to go offline and 4.2 GW of new turbines will replace them. The result of this offshore heavy growth in new installation and of (mainly) onshore repowering effects is an increase of wind power capacity from 30 GW in 2012 to 49.5 GW by 2025 and 65 GW by 2040. Due to continuing technical improvements and more importantly, a rise in the share of offshore wind power, average capacity factors of cumulated total capacity installed are increasing from 18.5% to 28% in 2025 and 32% in 2040.²⁴ Such advancements are assumed to raise annual wind outputs to 121.5 TWh in 2025 and 182.4 TWh in 2040. In order to stay with the scenarios as close as possible to the official targets of the government, these estimations are overly conservative as it is likely that technical improvements (mainly greater hub heights and larger rotor diameters) take place at a faster pace. Actual repowering could also have a greater impact as some installations should go offline before they reach an age of 25 years and new turbines often increase capacity by much more than 200%.

²³Besides differences in national interests, “solving” problems of the technical integration of renewables by just assuming imports and exports to work issues out means also in some way nothing but exporting the problem to other countries that need to deal with it in the same way and/or shifting the problem to a higher level rather than solving it. Countries like Denmark or the Netherlands are also augmenting the shares of renewables and face exactly the same problems as the Germans and integrating these into one market just bundles integration issues.

²⁴Utilizations of new on- and offshore turbines are assumed to increase by 0.1 percentage points annually.

Of course, it is also possible that more than 60% of all retired turbines could be replaced.

In the scenario used here, PV capacity will grow from 30.031 GWp installed in August 2012 to 57 GW by 2025 and 63.5 GW by 2040 as well as annual PV outputs of 53.5 TWh and 69.5 TWh respectively. These values result from a growth path of PV capacity that equals the average value of the current target corridor of the federal government (3 GW) until 52 GW of installed capacity are reached (the subsidy for PV is being discontinued for new installations once 52 GW of PV capacity are installed according to the newest revision of the German Renewable Energy Act). After that target has been reached, capacity is assumed to grow by 1 GW per year until 2025 and by 500 MW per year after 2025.²⁵

Table 2: Summary of baseline scenarios (in GW)

Capacities	2012	2025	2040
Wind	30	49.5	65
PV	30	57	63.5
Nuclear	20.3	0	0
Lignite	20.3	14	9.9
Hard Coal	28	23.5	8.8
Natural Gas	25.7	16.2	11.5
Hydro	4.7	5.2	5.7
Biomass	4.8	7.5	10
Other	6.5	3.2	2.5
Capacities by Category			
Intermittent	60	107	129
Flexible	72	53	35
Unflexible	35	13	10
PSH Capacities			
Intermittent	6.7	9.7	9.7
Pump	6.3	9.7	9.7
Storage (hours)	40	58	58

Abandoning the nuclear reactors is about to free up 20.5 GW by 2025 that have been operational in 2010. In an earlier paper we estimated net loss of around 7 GW in lignite and 4.5

²⁵Furthermore, I assume that installations will produce power for 30 years and that after that period 30% of PV installations will not be replaced while 70% will be repowered. Repowering is predicted to increase capacity by 35% since rising efficiencies allow to install more kWp per square meter. It is assumed that the average capacity factor of newly installed modules increases every year by 0.2 percentage points due to continuing trends of technical improvements (such as rising inverter efficiencies). At the same time, annual output is assumed to fall by .5% per year for modules installed in the past due to technical module degeneration. This implies overall increases of average utilizations from 10.5% today to 11% in 2025 and 12.5% in 2040.

GW in hard coal capacity by 2025 if no new plants will come online (besides the ones that are already in construction) and if there is no extension of existing plants' planned operating life (see Auer und Keil 2012). Predictions for natural gas have been handled in the same way. The declines result from the retirement of overaged plants and the implied scenarios can be reviewed in table 2. The German park of lignite and nuclear plants is assumed to be able to operate at minimum capacity rates of 75 % in 2012 which falls due to technical improvements to 65 % in 2025 and 50 % in 2040. The scenario assumes that inflexible hydroelectric installations (80 % of all hydroelectric capacity) run constantly at 45 % of capacity, which is roughly the average annual value in Germany. 25 % of all biomass capacity is assumed to produce primarily heat while generating electricity only as a secondary product. They are modeled to constantly run at 80 % of capacity. 30 % of other sources (which in the future will be mainly energy from waste) are assumed to run permanently while the aggregate can be ramped up to 80% if required.²⁶ These considerations imply together with the future capacities that available base load which has a quasi-must-take character will shrink in the scenario applied here from a gross load of 35 GW in 2010 to 13 GW in 2025 and to 10 GW in 2040 (assuming no new conventional plants that are not already being built will be put online). These losses will open a huge gap between the quasi-must-take base load and the consumption of electric power. This can be filled at least partly with power from PV and wind without leading to too high losses due to overproduction. Total flexible net capacity available will change from 72 GW in 2010 to 53 GW in 2025 and 35 GW in 2040 if there are not any new conventional plants being put online beyond those that are presently constructed today.²⁷ Total guaranteed capacity from conventionals, hydro and biomass power amount to 107 GW, 66 GW and 45 GW. I assume that aggregate turbine capacity of PSH plant will rise from 6.7 GW today by 3 GW until 2025 (future pumping capacity is assumed to be the same as turbine capacity). Storage capacity increases in the scenario by the same proportion from 40 GWh to 58 GWh. This is also the baseline scenario for 2040. As the scenario used here follows the government plans to shrink electricity consumption by 10% until 2020 and 25% until 2050 (which is equal to a consumption of 548 TWh in 2012, 480 TWh in 2025 and 438 TWh in 2040), maximum system load declines from 90 GW in 2010 to 79 GW and 72 GW.

Quasi-must-take base load modeling is trivial and undertaken in step 1 before modeling storage units. It involves constant outputs that result from minimum utilizations (average utilizations in the case of hydro and heat generating biomass) multiplied by installed capacities. The aggre-

²⁶This limited flexibility is being chosen as waste is delivered to plants on a constant flow basis while storage capacities are somewhat limited.

²⁷Flexible capacity consists of the nominal capacity of nuclear and lignite power minus their minimum loads as well as the nominal load of natural gas and hard coal. It includes 75% of the biomass capacity that does not primarily produce heat as well as 80% of power from other capacity less the 30 % of its capacity that is assumed to be running permanently. Flexible hydro is assumed to be able to deliver up to 70 % of capacity on demand at any point of time and this share of its capacity is also included.

gate of all storage plants is assumed to operate in a way that enables the better integration of renewables.²⁸ They charge whenever there is any excess supply from PV, wind and other quasi-must-take base load above total load. The limit is of course given when the capacity maximum is reached. PSH is programmed to discharge as soon as this sum falls below total load and until the charge level reaches zero. Pump and turbine activity reflects energetic losses due to efficiencies below 100 %.²⁹ Maximum charging and discharging rates are given by the pump and turbine capacities.

Flexible load was modeled differently for each plant type, but it follows in each case cost minimizing, legal and / or system stability ensuring criteria. First, the difference of the sum of PV, wind, base load and storage action on the one and system load on the other side was calculated. Whenever it implied a shortage, output from flexible renewables - biomass that produces primarily electricity, flexible hydroelectric power and energy from waste - would start or in the case of waste plants ramp up production. This seems realistic as renewable electricity enjoys priority in being fed into the grid. Whenever they would reach their maximum and could not close the load gap, lignite plants would ramp up output from their minimum utilization up to full capacity. As start-ups are costly and lignite plants run already at low capacity (as well as with operating costs below hard coal and gas plants), this is a reasonable method since utilities operate in a cost minimizing way whenever they are not regulated and forced to consider external costs. Whether gas or hard coal plants are following on the next step depends on two factors: how long hard coal plants can expect to operate (their startup costs are higher and make a restart only commercially viable if they are able to operate for some time) and if gas plants are able to close the remaining gap alone. Assuming that the future system load and intermittent output can be predicted for a horizon of 24 hours into the future, hard coal plants start to produce on the next step only when they are able to produce at least 24 straight hours or if gas power plants alone cannot produce enough load to close the gap. Once hard coal hits its limit, gas plants kick in. In all other cases, gas power plants restart before hard coal goes online.

²⁸In reality it is of course the case that some units provide at least partly services for the grid system with their capacities and that there will be no cycling up to the technical minimum and maximum of every unit. The program is an ideal one here. It will also be the case that charging starts before there is any excess supply, as many owners operate on a purely commercial basis in the open market. They charge when the spot price for electricity is low and discharge when it is high. However, as the price will depend mainly on the existence of excess supply and energy shortages, these assumptions are not too far from reality: excess supply will actually yield negative electricity prices while low output from PV and wind relative to system load will lead to high electricity prices as other conventional capacity is limited.

²⁹For 2012 I used 86 % efficiency at the pump and 90 % at the turbine. These values are increasing by one percentage point each in 2025 and by another one in 2040.

Table 3: Grid balance, average annual values

	Electricity consump- tion in TWh	Over produc- tion in TWh	Share stored in %	Annual shortages in TWh	Maximum shortfall in GW
2012	547	1.2	69%	0	0
2025	479	4.3	62%	0.08	8.9
2040	438	24	31%	3.7	23.6

Coming to the model outcomes, the sum of PV, wind and conventional quasi-must-run load at the capacities installed in August 2012 exceeds the total use of electricity only rarely. For a normal year, the excess output one can expect will rise moderately until 2025 and more rapidly by 2040 (see table 3). It will amount in the three scenarios to .2 %, .9 % and 5.5 % of annual electricity consumption. This overproduction will either be lost, stored and reused or exported. With the PSH capacities assumed in the scenario, total energy stored and reused amounts in the 2012 scenario in an average year to 650 GWh, in 2025 to 2.1 TWh and in 2040 to 6 TWh. A total of 385 GWh, 1.6 TWh and 16 TWh is not used while 190 GWh, 550 GWh and 1.4 TWh is being lost at the pump and the turbine in the storage cycle in the three scenarios. To achieve this, PSH will have to work for a total of 126 full load hour equivalents in the 2012 configuration, 274 in 2025 and 766 in 2040.

One can calculate the shares of output from sources that do not produce on demand that are lost during overproduction by dividing the output stored and lost into electricity from PV, wind, lignite and other not-on-demand producing sources by multiplying the lost and stored output at every point of time with the shares of each source's output in total output at that respective moment. The sum throughout the simulation period reveals the percentages of PV, wind and other output that is being lost in the storage cycle or that is not used as well as the percents that are being stored and reused. Table 4 illustrates this and shows that PV power will be the main contributor to excess output even though its annual output is much lower than of the other intermittent and inflexible sources. This is due to the extreme spikes that will occur once capacity has doubled from its 2012 levels.

Table 4: The structure of overproduction

		PV	Wind	Lignite	Other
2025	Output in TWh	54	121	112	101
	Lost or not used	1.4%	0.8%	0.3%	0.1%
	Stored & reused	1.4%	0.7%	0.3%	0.1%
2040	Output in TWh	66	182	64	94
	Lost or not used	6.9%	5.7%	2.1%	1.4%
	Stored & reused	2.9%	1.7%	0.8%	0.5%

As shown in table 3, there will also be shortages. They amount to 0 %, 1.9 % and 5.4 % of the annual electricity consumption in the three scenarios. However, the largest load gaps in any 15 minutes interval one can expect will amount to rather large values. In order to avoid recurring blackouts, these gaps need to be closed with imports and / or flexible back up capacity that will be idle most of the time. The import option requires huge transmission capacities to other countries while back up capacity might be only feasible with a capacity market where the provision of back up capacity is being compensated. SCGT plants would be the most economic option as they involve the lowest capital costs. Capacity utilizations for such additional plants would be on the aggregate less than 1 % in 2025 (2 % in 2040). If in the 2040 scenario all lignite plants were replaced by CCGT or SCGT; if biomass and energy from waste facilities operated wholly flexible between zero and 100 % utilization rates and in a way to support grid stability, then annual shortages would sum up to 3.1 instead of 3.7 TWh while overproduction would fall from 24 to 11 TWh (mainly due to the substitution of natural gas for lignite plants).

Table 5: Future operating modes, annual averages

		Lignite	Hard Coal	Natural Gas	Other	Total**
Utilization	2025	91%	33%	15%	72%	49%
	2040	73%	21%	24%	58%	46%
Restarts	2025	231*	142	465		
	2040	308*	189	395		

* number of ramp-ups from minimum utilization; ** all sources but PV and wind

The simulation implies a fall in the utilization rates of already installed power plants due to the fact that they will run more and more under deep load following modes, remain for longer times at their minimum utilization rates and / or will be wholly switched off for extended periods. Table 5 summarizes total and individual annual capacity factors (after overproduction and storage cycle losses). Of course, these values have to be viewed with caution due to the relatively simple modeling assumptions. Still, the reported aggregate utilization of all non-PV and non-wind energy sources gives an indication for future power plant potentials and economics while differences in numbers for the individual plant types hint at how alternative technologies become economically more or less suited for playing a role in the future energy mix. The core messages that can be drawn are that capacity utilizations for all but renewable sources will be falling in the future and that natural gas will become more suited for the German electricity market than hard coal plants as shut downs will increase, deep load following modes will be required and average annual low utilization rates have to be expected.

As shrinking conventional capacities in the used scenarios lead to greater gaps between system load and renewables, natural gas fired plants will be running for longer time periods. This is reflected in the rise of their utilization (and the fall in annual start-ups from 2025 to 2040). That trend shows how gas turbine plants are economically more suited for providing electricity in the future energy mix than hard coal. Lignite plants become less useful as their limited flexibility causes more excess production (not shown in the table) while plants are forced to operate cyclically on a permanent basis and correspondingly need to live with lower capacity factors and more costly ramp ups from minimum to higher loads. At the utilizations that are predicted in the 2025 (2040) scenario for hard coal and for natural gas plants, electricity generation costs will amount to 9.2 (12.5) cent/kWh for coal, 11.9 (10.5) cent/kWh for SCGT and 11.6 (9.7) cent/kWh for CCGT plants, not considering start-up costs.

The table also includes the number of restarts and shut downs of the most economical plants of each type of conventional thermal technologies (the most economical are usually assumed to be the first ones to cut in and the last ones to go offline). In the case of lignite the numbers reflect the average annual number of ramp-ups from minimum utilization. While there are no data for plants today, it is clear that these numbers represent steep increases from past and more conventional operating modes. The numbers increase again in 2040 compared to 2025 for lignite and coal plants. Natural gas fired installations have two to three times as many annual restarts as hard coal plants - on average more than once a day while coal fired plants start-up roughly every second day. The costs of this flexibility can be estimated with information from Kumar et al. (2012) and plant equipment manufacturers on additional capital and maintenance, fuel and other costs as well as fuel and CO₂ prices from the 2025 scenario, emission characteristics described in the appendix and annual utilization rates from the simulation model. Start-ups amount annually

to .35 (.73) cents for hard coal in 2025 (2040), .49 (.26) cents for CCGT and .41 (.22) cents for SCGT.³⁰

While the utilization rates in future scenarios are very low, the picture would look very different if lignite plants were replaced by natural gas plants and all biomass and waste energy facilities were required to run flexible and in adjustment to intermittent power and system load stability parameters. In this modification of the 2040 scenario to a more flexible one (it is discussed only in this paragraph), the utilization rates of the 2040 scenario for hard coal and natural gas would increase from 21 to 41 % and from 24 to 30 % respectively. These values are much better and not too far from the annual rates that can be found in the recent past and are not unlikely to provide enough economic incentives for the construction of such plants. The utilization of biomass, flexible hydroelectric and waste energy would lie at 66 %. In this version of the scenario it would even be possible to cover 100 % of all shortages with SCGT capacity in a relatively economical way: assuming additional 22.5 GW of SCGT capacity (the maximum shortfall observed), the aggregate utilization of gas fired plants would amount to 15.6 %. Many peaking SCGT plants operate at such rates today. Depending on the electricity prices, capacity markets might only need to provide very limited compensation for capacity provision to avoid losses. With all of these modifications in the flexible 2040 scenario, the renewable energy share would amount to just below 80 %.

III. Summary and Policy Recommendations

The paper outlined the nature of dramatic changes in the German electricity industry. While the Energiewende leads to unpreceded challenges, this analysis shows that they can be overcome: cost declines from wind and solar power make these energy sources more and more competitive on a pure cost basis; a market design that encourages plant operators to invest in flexible technologies on a sufficient scale and use them to integrate intermittent renewables allows to ease the technical problems of PV and wind power integration that seem to be unsolvable today. However, there are several aspects of the German path towards a green economy that could be improved for the sake of cost containment and wind and PV integration. Shifting incentives from offshore to the repowering of onshore wind power, the cheapest clean source available in Germany today, could be an alternative strategy to build renewable capacity required for the energy transition while still keeping costs tighter in check. If, for example 80 % of turbines would be repowered and the replaced capacities increased by 250 % (instead of 60 % and 200 % respectively), repowering

³⁰These numbers assume that the average start is equivalent to a warm start which amounts to 7 cent/kW of capacity for hard coal and 1.4 (1.2) cent/kW for CCGT (SCGT) plants.

would add 12.2 GW with a net gain of 6.1 GW by 2025. Of the 24.1 GW which need to retire after 25 years between 2025 and 2040, 48.1 GW of newly repowered capacity would emerge - adding 24 new GW with significantly increased annual capacity utilizations. If repowering kicked in after only 20 years of operating life and not 25, there would be net additions of onshore capacity in this scenario of 18.4 GW by 2025 and 24.2 GW by 2040. Another alternative growth path for turbine capacity would of course be to add more new installations. The annual additions of 50 MW assumed here might be cranked up significantly, especially as technological advancements aim at increasing capacity factors and improving economics in low wind speed resource areas. The two southern German states Bavaria and Baden-Württemberg e.g. are the largest and third largest by area and only have less than 5% of total turbine capacity installed due to low wind speeds. Benefits of a heavier onshore focus would be that not only the offshore wind power costs differential could be saved, but also that much fewer investments into the network extension would be required. For the sake of cost control and the migration of risks associated with trailing behind the network extension plan, current policy would do good to give at least a greater weight to repowering. However, this way requires the government to ease regulations - e.g. with regard to maximum turbine heights allowed in certain areas.

Another different path towards the green electricity industry is of course a stronger augmentation of PV installations that proceeds with the current speed of capacity additions. At the growth rate of 7.5 GW per year the administration struggles to achieve its goal of limiting costs by slowing down PV. An alternative could be shifting the support from small scale PV installations more towards large, utility scale PV installations in southern Germany. Economically it does not make much sense to pay significantly higher feed-in tariffs to the much more expensive small scale PV installations. Data for the US, where utility scale installations have a higher relative importance, suggest that investment costs of utility scale applications are 30 to 40 % lower than for residential ones. Operating and maintenance cost have also proven to offer scale advantages (Price and Margolis 2010). In the LCOE model used here, this implies a differential of more than 3 cent/kWh.³¹ A shift towards utility scale PV installations could be accomplished through feed-in tariffs that are identical and independent of size and type of installations. They would make the subsidy more efficient and be an alternative mean to keep costs in check in a tighter way while building enough capacity to keep the country electrified. Besides this cost argument, granting unnecessarily elevated feed-in tariffs for small scale PV installations implies also a questionable redistributive policy from the bottom to the top through elevated electricity bills: people without an own home that usually belong to lower income classes are forced to subsidize more wealthy home and land owners that invest in PV installations. Other advantages of making PV more

³¹It is likely that the differential in Germany does not exceed 30% in most cases as the market is mainly focussed on the residential scale where prices are significantly lower than in the American residential market.

affordable and by doing that also augmenting its role would be that the centers of electricity generation are at the centers of electricity consumption in the south and installed in a more decentralized way. This would require fewer grid network extensions. PV energy is also easier to integrate up to a certain threshold as its output peaks at peak demand and exhibits a much more regular pattern than wind energy which can be at high or low output levels for weeks. Excess output can thus much easier be reused through short term electricity storage (see below). Even utility scale PV plants have the advantage that citizen opposition is much lower than for wind projects. Given the high amount of agricultural subsidies paid to German farmers - currently 164 Billion Euros (Focus 2011) - there might even be some potential to achieve the goals of managing the energy transition in an affordable way and of keeping rural areas afloat and compensate farmers for landscape conservation through a redistribution of subsidies that are already in place. Equivalently, utility scale PV can replace areas and subsidies for growing biomass fuels. The latter require dramatically more space to produce one kWh of electricity while the bio fuel subsidies are already contributing to price explosions of agricultural land by over 40% in the last five years in some areas in Germany (Bremser 2012). Downsides of all plans that focus less on offshore wind power are of course that one cannot take advantage of superior wind resource conditions offshore and the technology's potential to become more competitive than onshore wind and PV power in the future.

Temporary periods of overproduction and shortages will emerge in the future scenarios described. While they amount to relatively small percentages of total annual electricity consumption, they will be significant with over 5 % respectively. In the case of shortages, the largest gaps require huge investments into back up capacity that will be in cold reserve most of the time. Another solution would be the development of long term electricity-to-gas storage technology on a scale of several terra watt hours. Until fuel cell technology is fully available, the infrastructure could already be build while feeding hydrogen into the natural gas grid and using it for heating and electricity generation in gas turbines could be already available bridge technologies. Still, technological improvements that raise efficiencies are necessary and costs of the full storage cycle have to come down. There is another option that is in principal readily available today and that would ease these integration issues: connecting Germany and other European countries with high shares of intermittent energy sources to Scandinavian and especially Norwegian networks and their huge dammed hydroelectric reservoirs would be by far the most cost effective solution (with well below costs of one cent/kWh of additional transportation costs and losses). Norway and Sweden taken together have capacities that store water with an electric equivalent of up to 118 TWh and generate around 200 TWh over the year. Lines between Norway and the Netherlands already exist while one between Germany and Norway is already under construction. Once connected through enough lines, shortages in Germany could be satisfied with elevated output from hydroelectric

plants that sell cheap electricity at high prices while overproduction would lead to their shut down and a supply of northern consumers by southern wind power at prices that would be very low in such a situation. The only problems are that transmission lines need to be constructed which can carry very large loads and that it must be guaranteed to Scandinavian economies that their price and reliability levels will not be negatively effected.

The simulation revealed that the inflexibility and the scale of lignite plants cause unnecessary losses due to overproduction. They also cause utilization rates of other more flexible plants to be much less economic than the ones they are operating with today. Those biomass and waste energy plants that do not operate flexibly and according to electricity market price signals and stability requirements have the same unfavorable impact. The implication is that a flexible operation needs to be encouraged or even enforced for the latter plant types. Flexible hard coal and natural gas plants need to be favored against less flexible technologies such as lignite and more variable individual plant designs have to be preferred if output losses are to be minimized and remaining flexible plants to be allowed to operate without losses or additional subsidies. While potential for optimization exists and looming adverse effects have to be avoided, it is possible that the transition can be managed successfully. Accomplishing the tasks ahead will produce unique knowledge in the electric and in related manufacturing industries that can help other countries on their paths towards more ecologic sustainability. It will at the same time be a competitive advantage for domestic industries in an area that is being called a mega trend and an argument for more products to be labeled 'made in Germany'.

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Appendix - Levelized Costs of Electricity Model Assumptions

I assumed real capital costs of 7 % for each technology. The price of natural gas used in the calculation reflects the September 2012 spot price level with 26 EUR/MWh. The price of hard coal used is \$ 90 per metric ton (the early September 2012 spot market price on Australian thermal coal). Transportation costs include the sea vessel discharge to trains or river vessels and the transportation to power plants. Emission rights are assumed to cost at 8 EUR/Ton of CO₂, which is the spot market price of the first week of September 2012. As utilization rates I applied average values for the most recent past and assumed a difference of 12 percentage points between SCGT and CCGT plants. The parameters used are summarized in table 1. They are based on own research and information from a major German electric power utility.

Table 6: LCOE assumptions for thermal power plants

	Nuclear	Lignite	Coal	CCGT	SCGT
Investment cost (EUR/kW)	4,000	1,600	1,500	750	500
Construction time (years)	6	4	4	3	2
Lifetime (years)	50	50	50	40	40
Variable O&M costs					
Efficiency	36%	44%	46%	60%	40%
Emissions (t CO ₂ /MWh th)	0	0.41	0.34	0.2	0.2
Other variable costs (EUR/MWh)	4.50	0.40	0.50	0.16	0.16
Fuel costs* (EUR/MWh th)	2	5	11.5	26.5	26.5
Total variable (ct/kWh)	1.0	1.9	3.1	4.7	7.1
Fixed O&M costs					
Staff (people/MW)	0.12	0.1	0.1	0.06	0.08
Staff costs (EUR/person)	90,000	90,000	90,000	90,000	90,000
Outage insurance (EUR/kW)	8	8	8	8	8
Maintenance rate (% of CAPX/a)	2	1.5	1.5	1.8	1.8
Total fixed (EUR/kW)	98.8	41	39.5	26.7	24.2
Annual utilization	75%	75%	44%	42%	30%

*Includes transportation costs.

The 2025 scenario for conventionals differs from the current one through a CO₂ price of 10.3 EUR/Ton in current euros when an average inflation rate of 2 % is assumed (the early September price of 2020 emission futures is 12 EUR/Ton), lower capital expenditures for nuclear plants (3,500 EUR/kW) due to learning effects and higher efficiencies for CCGT (63%), SCGT (43%) lignite (47%) and hard coal 49%).

Hard coal and natural gas prices were taken from the most distant EEX traded futures with available data: 108.4 EUR/Ton (115 EUR/Ton for 2015) and 24.9 EUR/MWh (27 EUR/MWh for 2016) in 2012 euros. It is likely that these as well as the CO₂ emission rights underestimate the future 2025 prices.

For PV, 1,200 kWh/p.a./m² were taken (an average value for Bavaria where most capacity is installed). The output depression is assumed to be .5% p.a., the lifetime 30 years and the initial performance ratio 83%. For operating costs without inverter replacement 12 cent/kW/a were taken and inverter costs assumed to amount to 20 cent/Watt with an expected inverter life of 15 years. Total utility scale investment costs in the model lie with 1.400 EUR/kWp 20 below the current total final system cost average. This corresponds with the average wholesale selling prices of Chinese manufacturers or CdTE thin film producers of 60 Cent/Wp in fall 2012, a 20% retail

margin as well as system and installation costs that amount to 50% of the final system costs. The 2025 scenario assumed PV costs to experience a 20% reduction in operating and inverter replacement costs and in initial investment cost declines of 10% p.a. for the next 3 years, 5% p.a. until 2020 and 2.5% thereafter for modules. Half of these rates of change for balance of system and installation costs due to direct cost declines and improving module efficiencies. The resulting 840 EUR/kWp imply a fall in total investment costs of 40 % from current levels - less than the percentage decline of PV modules in the year 2011 alone. Inverter and module lives are assumed to increase by 5 years each while the performance ratio increases by 5 and the annual module degradation by 2 percentage points. Onshore wind power installation final costs are assumed to amount to 1.650 EUR/kW for a more advanced design (10 % less in 2025), which is significantly more than the current average for the cheapest turbine classes. Accordingly, one can calculate with a higher capacity factor of 25 % for a north German coastal location (10 % more than that in 2025). The lifetime taken was 25 (2025: 30) years. Operating fixed and variable costs for the first five years lie at 11.1 EUR/kW/a and .65 cent/kWh in the first five years. After that, a 46 % increase in both categories is assumed. This is usually not done but evidence shows that this time pattern is a quite important phenomenon and should be accounted for. All of these costs are 10 % lower in the 2025 scenario. Offshore installations differ through the cost dimension which lies with 4.000 EUR/kW today (-40 % in 2025) far above onshore turbines. The construction time becomes significant with 24 months (2025: 20). Utilizations amount to 45 % (2025: 49.5 %) and variable operating costs range from 1.5 to 2.1 cent/kWh in the first 5 and next 20 years while fixed costs amount to 27.9 EUR/kW in the beginning and 41 EUR/kW later. They are all reduced by 40 % until 2025 while the operating life rises to 30 years.