CONSULTANT REPORT

EUROPEAN RENEWABLE DISTRIBUTED GENERATION INFRASTRUCTURE STUDY – LESSONS LEARNED FROM ELECTRICITY MARKETS IN GERMANY AND SPAIN

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PREFACE

Governor Jerry Brown's Clean Energy Jobs Plan established a goal of installing 20,000 megawatts (MW) of renewable energy by 2020, including 12,000 MW of localized distributed electricity generation. As reflected in the California Energy Commission's previous *Integrated Energy Policy Report* proceeding, the Energy Commission is interested in determining how certain European countries integrate large quantities of intermittent distributed renewable electricity into their electric distribution systems and still maintain system control and reliability. This report examines the European experience related to integrating large amounts of distributed generation, compares the electric distribution systems in Europe and California, and explores lessons learned that are directly applicable to the California market.

ABSTRACT

This report was prepared for the California Energy Commission in support of the *2011 Integrated Energy Policy Report* proceeding. Governor Jerry Brown set a goal of 12,000 megawatts (MW) of localized, renewable energy by 2020. This report examines the European experience integrating large amounts of renewable distributed generation (DG); compares electric distribution systems in Germany, Spain, and California; and explores lessons for California.

Although German and Spanish distribution system voltage levels and equipment are comparable to California, there are some important differences. For example, both national policy and protection system design standards in Germany allow back-feed (when electric power flows in the opposite direction than its usual flow), but regulations in Spain allow distribution companies to cap renewable DG at 50 percent of peak demand in each area to prevent back-feed.

Germany and Spain have taken steps to provide real-time visibility and accurate forecasts of electricity from DG. Even so, during 2010, German transmission system operators had to take curtailments almost daily to protect grid reliability.

The electricity system may need upgrades in many parts of California as the amount of renewable DG increases, such as replacing substation relaying to accommodate back-feed, reconfiguring voltage control apparatus and controls on distribution feeders, and deploying appropriate smart-grid technologies on distribution and transmission grids. Energy storage devices may become essential to modulate effects of intermittent resources and provide acceptable levels of balancing area frequency control.

Due to differences in distribution grid rules, distribution system design, interconnection facility planning processes and cost allocation mechanisms, there is likely to be less DG capacity (relative to statewide peak demand) that can be easily integrated into the California distribution grid than in Germany and Spain. However, the scope of this study did not specifically address whether achieving California's 12,000 MW DG goal is achievable by 2020 or what level of grid costs are required.

Keywords: Renewable, distributed generation, transmission, distribution, grid, voltage, network, photovoltaic, wind, solar, frequency, Germany, Spain, California

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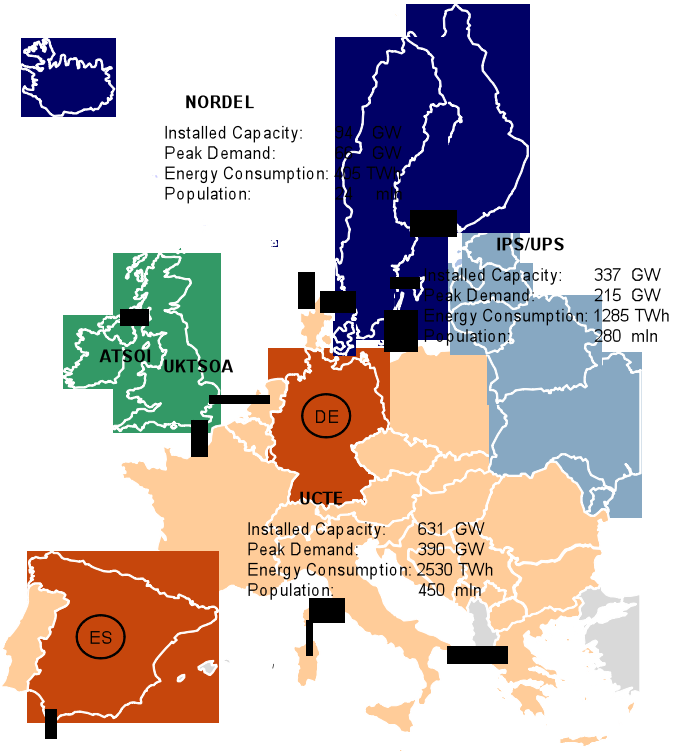
EXECUTIVE SUMMARY

Governor Jerry Brown recently set the ambitious goal of installing 12,000 megawatts of localized, renewable energy (for example, wind, solar, and biomass) by 2020. This goal presents many challenges for California, particularly with respect to identifying how to integrate high levels of distributed generation in a cost-effective, safe and reliable manner.

In support of the *2011 Integrated Energy Policy Report* proceeding, KEMA studied how certain European countries integrate large quantities of intermittent renewable electricity into their electric distribution systems while still maintaining system control and reliability. This study addresses this issue by comparing some of the electric distribution systems in Europe to California's distribution system with the goal of capturing key lessons learned from the European experience.

This study focuses on two of the largest electricity markets in Europe – Germany and Spain. Both countries are part of the Union for the Coordination of the Transport of Electricity, one of the largest interconnected systems in the world, as shown in Figure E-1. Both Germany and Spain are characterized by a high penetration of renewable energy. The installed capacity of renewable energy (excluding hydro) represents roughly 50 percent of annual peak demand in both countries.

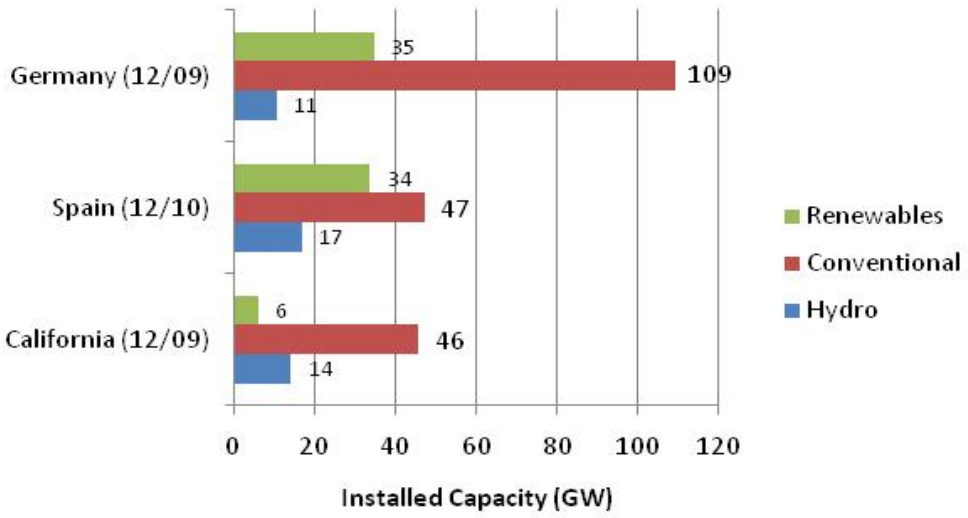
Figure E-1: Focus of EU DG study – Germany (DE) and Spain (ES)



Source: KEMA and Bruce Jones Designs, Inc.

A comparison of installed capacity in Germany, Spain and California is shown in Figure E-2. As displayed, California's total *installed capacity* is comparable to Spain and California's hydroelectric resource capacity is also comparable to Spain and Germany. However, both Germany and Spain have a significantly higher proportion of other renewable resources than California.

Figure E-2: Comparison of Installed Capacity in Germany, Spain, and California



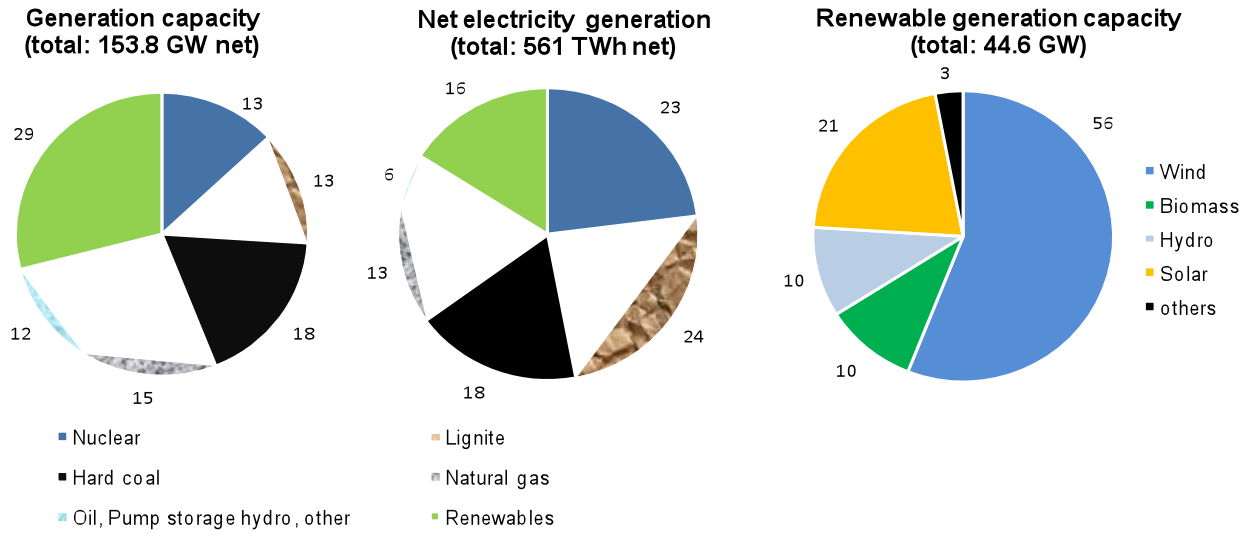
Source: KEMA

Germany and Spain both rely on large scale pumped hydro (presently 6.6 gigawatts in Germany and 4.9 gigawatts in Spain) at the transmission level to provide balancing and regulation for intermittent renewable resources. So far both countries have been able to accommodate renewable distributed generation (small-scale power generation that is located close to the load that it serves) expansion without requiring distribution system energy storage technologies, but they are evaluating the use of smaller-scale storage technologies as an option to support future distributed generation expansion.

At of the end of 2009, about 16 percent of the German electrical energy production came from renewable energy sources.[1] German grid operators have dealt with the challenge of significant renewable integration for the last 5 to 10 years and have developed technical rules and guidelines to ensure secure network operation. A comparison of all types of installed generation capacity in Germany, including both renewables and conventional generation, is shown in Figure E-3.

1 German Statistics of Renewable Energy Sources, December 2010.

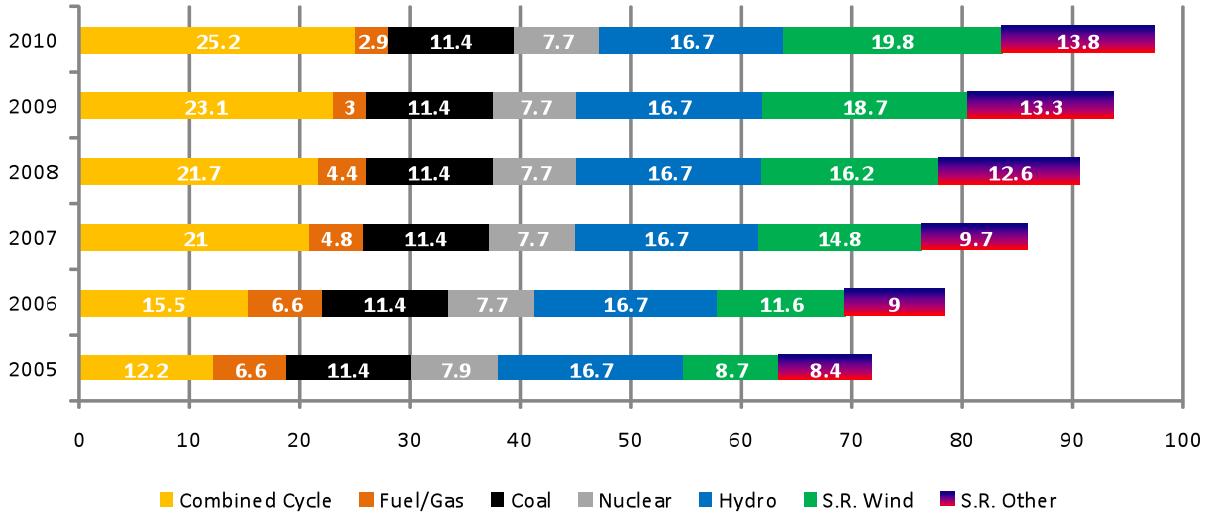
Figure E-3: Generation Mix in Germany at End of 2009 (All Data in Percentages)



Source: BDEW: German Energy Market, 2010

Figure E-4 shows the breakdown of generation types installed at each voltage level in Germany as a percentage of the total generation capacity installed at that voltage in Germany. As displayed, solar power installations tend to be rather small (mainly roof-based installations) and are mostly connected to the low-voltage network (that is, 400 volts). On the other hand, wind projects are developed over a much wider range of sizes (for example, wind farms) and therefore are connected at many different voltage levels.

Figure E-4: Relationship Between Network Connection Level and Technology for Installations Eligible Under the 2008 Renewable Energy Act[2] in Germany



Source: Bundesnetzagentur EEG-Statistikbericht 2008 (Translated – Regulator's EEG Statistical Report, 2008)

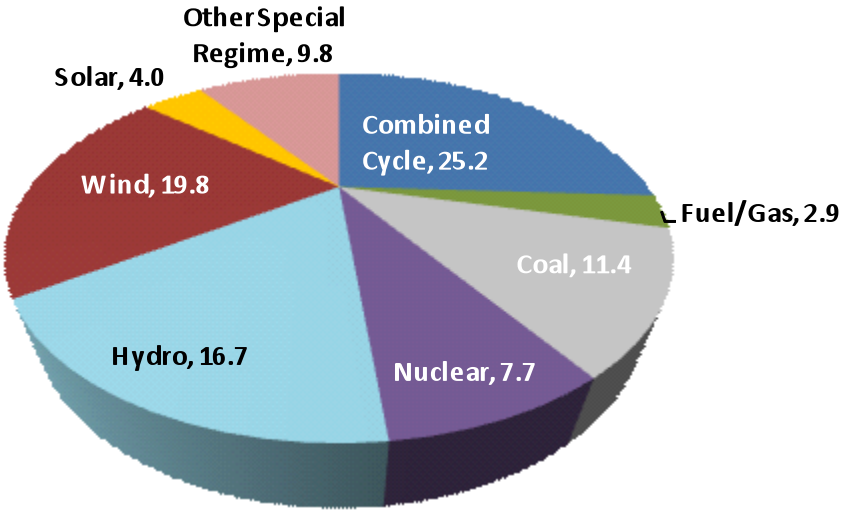
The rapid growth of renewable energy in Germany has not been without problems. Forecasts for wind and solar power are mainly used by the German transmission service operators today, who work separate from the distribution system operators who have not made regular use of such tools so far. The German regulatory authority issued a position paper in late 2010 that requires the distribution system operators to implement adequate forecast methods by April 1, 2011. This new requirement stems from the increase of forecast errors for solar power in 2010, resulting in the need to activate 100 percent of all contracted operating reserves for several hours on September 6, 2010. The regulator has refrained from specifying which model to use but has required the transmission system operators and distribution system operators to coordinate the implementation of such systems.

In 2010, Spain had a total installed capacity in electric power production of 97.5 gigawatts. As shown in Figure E-5, the total installed capacity in solar and wind power production was 23.8 gigawatts (24 percent of the total installed capacity) at the end of 2010. Next to combined cycle plants, which account for 25.2 percent of the total resource capacity, wind was the next largest block at 20 percent of total with an installed capacity of 19.8 gigawatts. About 40 percent of this wind generation is from projects smaller than 20 megawatts, which are connected to the distribution system and the remaining wind projects are connected at the transmission level. More than 75 percent of the 4 gigawatts of solar photovoltaic projects are connected at the distribution level.

2 Installed geothermal capacity is negligible. "Gases" refers to waste gas projects (for example, mine gas.)

Spain has recently reviewed its policy regarding support of renewable energy. As a result, the price paid for wind resources has been reduced by roughly 35 percent for 2011 through 2013. The reduction also applies to existing wind farms installed since 2007 under the pool price option (Royal Decree 661/2007). Solar photovoltaics have also been affected by this policy and pricing review. The feed-in tariff for ground-based solar photovoltaics has been reduced by 45 percent, while the one for large rooftop installations (> 20 kilowatts) was reduced by 25 percent. A smaller reduction of 5 percent was applied to the feed-in tariff of smaller rooftop installations (<= 20 kilowatts). Similar to wind farms, the reduction applies to any solar installations commissioned since September 2008. Renewable energy associations are of the view that these changes will put Spain's 2020 renewable energy targets at risk. At the same time, the fact that the smaller installations get a lower reduction shows the government's intent to have smaller generators (micro-generators) connected in the low-voltage distribution grid, which is a paradigm change compared to the past when most renewable energy plants were several megawatts or larger and connected to the medium or high voltage grids.

Figure E-5: Breakdown of the Total Installed Capacity by Technology at the End of 2010 in Spain[3]



Source: REE (Red Eléctrica de España)

Distributed generation in Germany and Spain is a generic term but generally consists of generation connected to low-voltage and medium-voltage distribution grids close to energy consumers, and generation used by energy consumers for self-supply. Recently, distributed generation is mostly based on renewable energy sources. In other words, the rated capacity of distributed generation is not limited to any specific size, but rather comprises all generation plants that are connected to low- and medium-voltage distribution grids. In practice, this

3 The category "Other Special Regime" includes cogeneration and waste-to-energy plants below 50 MW.

generally means that individual distributed generation projects in Germany and Spain are smaller than 20 megawatts.

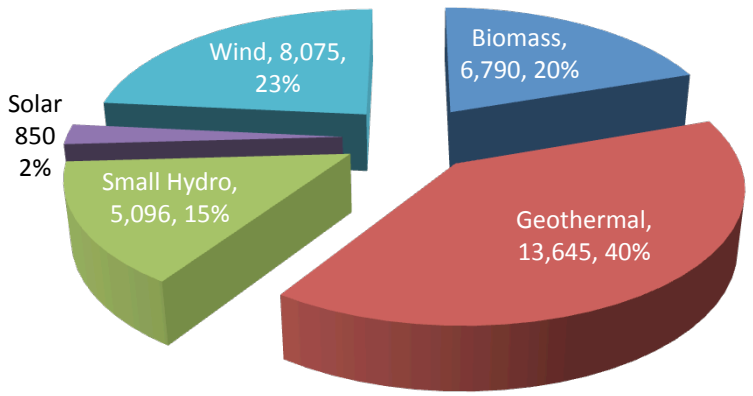
Table E- 1 and Figure E-6 display California's 2009 renewable generation mix for both in-state and out-of -state renewable resources. In California, geothermal and wind resources represent the largest share of renewable generation, representing 40 percent and 23 percent of total renewable generation in 2009, respectively.

Table E- 1: Renewable Generation Consumed by California Load in 2009

Fuel Type	California In-State Generation (GWh)	Percent of California In-State Generation	Imports (GWh)	Total California Power Mix (GWh)	Percent of Total California Power Mix
Biomass	5,905	2.90%	885	6,790	2.30%
Geothermal	12,907	6.30%	728	13,645	4.60%
Small Hydro	4,044	2.00%	1,052	5,096	1.70%
Solar	850	0.40%	0	850	0.30%
Wind	4,949	2.40%	3,127	8,075	2.70%
Total	**28,655**	**13.90%**	**5,802**	**34,456**	**11.60%**

Source: 2009 Total System Power, http://energyalmanac.ca.gov/electricity/total_system_power.html.

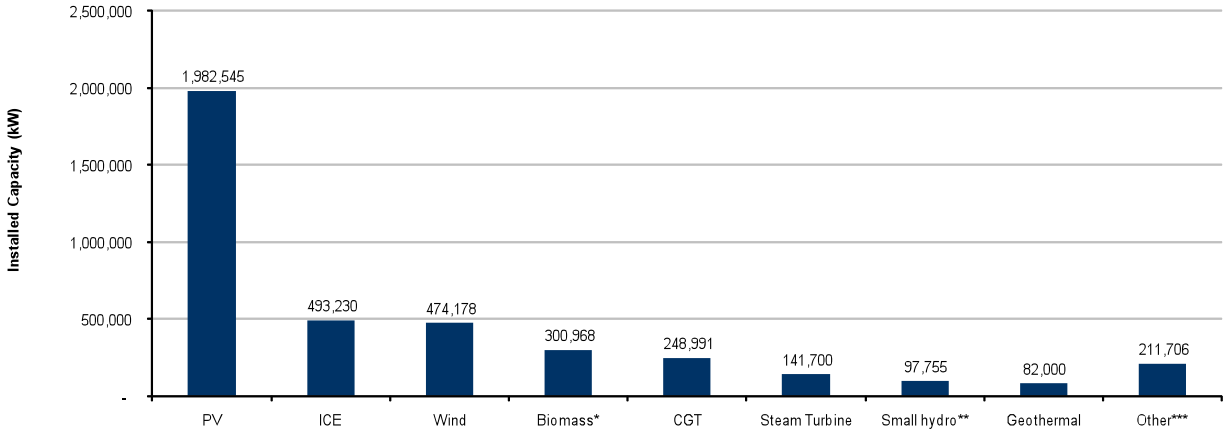
Figure E-6: Renewable Generation Consumed by California Load in 2009



Source: 2009 Total System Power, http://energyalmanac.ca.gov/electricity/total_system_power.html.

The distributed generation picture in California is different. As displayed in Figure E-7, solar photovoltaic represents the largest share of distributed generation in the state representing roughly 78 percent of total installed distributed generation capacity (including renewable and nonrenewable capacity).

Figure E-7: Estimated DG Penetration in California in 2011

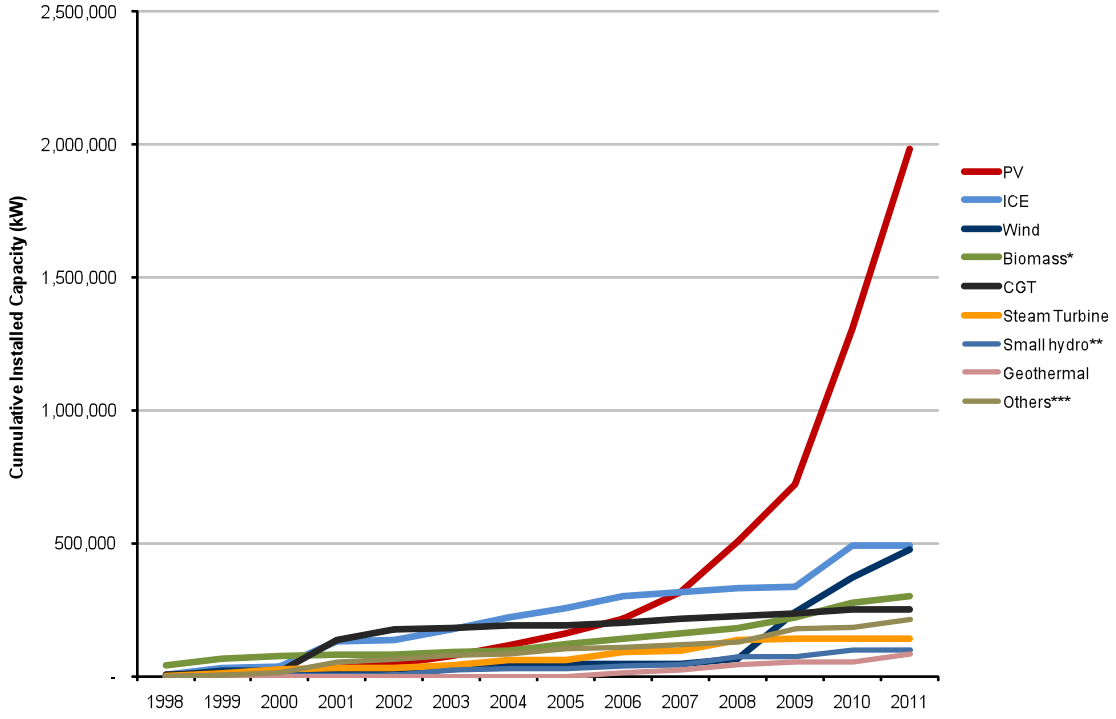


* Biomass includes biomass, landfill Gas, Digester Gas, MSW, Biogas, ** Small Hydro includes small hydro and conduit hydro. *** Others include Combined Cycle, Solar Thermal, Fuel Cell, Microturbine, and Conventional Hydraulic Turbine

Source: KEMA - Includes CSI, SGIP, ERP, NSHP, POU databases (Does not include utility-owned solar).

Although solar represents roughly 2 percent of California's total renewable generation, it is on a very strong growth trajectory. In fact, solar photovoltaics has demonstrated an extremely strong growth rate relative to the other distributed generation technologies in all regions examined. It is expected that a strong growth of solar will continue as the levelized cost of energy for photovoltaics continues to decline.

Figure E-8: DG Growth Trends in California (1998 – 2011)



* Biomass includes biomass, landfill gas, digester gas, MSW, biogas, ** small hydro includes small hydro and conduit hydro, *** Others include combined cycle, solar thermal, fuel cell, microturbine, and conventional hydraulic turbine

Source: KEMA – Includes CSI, SGIP, ERP, NSHP, POU, QFER and RPS databases

Physical Infrastructure and Distributed Generation Connection

The comparison of physical infrastructure focused on Germany and Spain, which have some of the highest levels of distributed generation deployment in Europe. Even though the increasing production of renewable energy from distributed generating units affects the grid at all voltage levels, no fundamental changes in the approved grid structure and planning directives have been made to date in either country. However, technical guidelines have been developed to ensure secure operation of the grid under all conditions while connecting distributed generation in an economic, least cost manner from the perspective of grid expansion options. Any large-scale grid expansion and redesign measures in Germany and Spain to date have been driven primarily by overall long-term grid planning goals and not primarily by distributed or renewable generation. Recent policy initiatives and studies in Germany suggest that a new grid investment paradigm may be developing. This is due in part to public policy concerns over the level of dependence on nuclear resources in Germany's long-term energy plan and the goal of significantly reducing this dependence at least partly through integration of even higher levels of renewables.

Table E-2 compares common voltage ranges found in the California electric grid to the corresponding ranges used in Germany and Spain and shows that there is a close correlation at all of the network levels.

Table E-2: Comparison of AC Voltage Levels in California and Europe (Phase-to-Phase Voltages)

Network Level	Germany	Spain	California
Extra-high voltage	380 kV, 220 kV	400 kV, 220 kV	500 kV, 345 kV, 287 kV, 230 kV, 220 kV
High voltage	110 kV	132 kV, 110 kV 66 kV, 45 kV	138 kV, 115 kV, 69 kV, 66 kV
Medium voltage	30 kV, 20 kV, 15 kV, 10 kV	30 kV, 20 kV, 15 kV, 13.2 kV, 11 kV	34.5 kV, 21 kV, 13.8 kV, 12 kV, 4.8 kV, 4 kV
Low voltage	400 V	400 V	480 V, 208 V

Source: KEMA

One difference worth noting in regard to Table E-2 is a possible skewing of medium-voltage distribution circuit mileage in Germany and Spain toward the 15-30 kilovolts range as compared to California, where the predominant distribution voltages are in the 12.0-13.8 kilovolts range, plus a substantial amount of older distribution load in the state that is still served by facilities below 5 kilovolts. This could have a direct effect on distributed generation integration in California versus Europe because the power delivery capability of any size electrical conductor varies proportionally with the operating voltage. If a conductor is capable of carrying 6 megawatts at 10 kilovolts, the same conductor could carry 12 megawatts at 20 kilovolts. Therefore, any skewing of distribution voltages in Europe toward the higher end would promote greater distributed generation integration. Furthermore, converting the operating voltage of an existing distribution grid from a lower to a higher nominal operating voltage would virtually entail a complete rebuild of the associated infrastructure (such as, substations, pole lines, underground cables, and primary to secondary transformers). It is assumed that the wholesale conversion of those lines would be cost-prohibitive, except in the case of areas that have antiquated distribution grid infrastructure and need replacement due to high failure rates. In most cases, a more cost-effective approach to integrating distributed generation on lower-voltage distribution systems would be to use one of the other planning options discussed in Section 1.1 under "Technical Options to Ensure Secure Grid Operation in Germany." Again, each lower voltage distribution grid in California would need to be studied to determine the best planning option.

Another difference between distribution grids in California and Europe is the use of a three-phase circuit configuration throughout the distribution system in Europe, including customer service points. Common practice in California is to use a three-phase configuration on the main trunk lines leaving distribution substations, but to drop to fewer phases for many smaller downstream branches and taps, which requires use of fewer wires. A potential effect of this design difference is that if renewable distributed generation projects are added on single-phase distribution branches in California, it may be more difficult for utility system planners to balance loading among all three of the phases on the main feeders and substations. If a significant imbalance in loading exists between phases, it could, under worst case conditions, accelerate the need for reconductoring of a feeder. However, a number of other lower cost options such as transferring customer loads or distributed generation between phases can typically be used to rebalance loading on the main feeder. Therefore, KEMA concludes that this difference in distribution system design between California and the European Union should have a negligible effect on distributed generation integration at the medium-voltage level. However, the use of three-phase configurations in Europe for low-voltage networks and customer service points may make it easier to connect smaller distributed generation projects in the 5 kilowatts to 50 kilowatts range at customer locations in Europe.

The high-voltage and extra-high-voltage grids in Germany, Spain, and California have a number of similarities including:

- Planning and design of extra-high-voltage and high-voltage networks to withstand at least single contingencies without interruption of service to customers, loss of generation, or system instability.
- Planning and design of high-voltage to medium-voltage substations with either redundant transformer capacity or a spare transformer that can be energized in the event of a transformer failure.

Grid planners and operators in Germany and Spain do not intentionally ignore the consequences of greater penetration of distributed generation in their distribution grids or willingly take additional risks compared to those taken by distributed generation operators in California. Based on the analysis, the technical performance requirements specified in the German grid codes that apply to connection of distributed generation projects appear to be at least as rigorous as those in California.

Network Planning and Operations Impacts of Distributed Generation

One important aspect of the network infrastructure in Germany that clearly bears on successful integration of distributed generation capacity is the requirement that all distributed generation units above 100 kilowatts must have remote observability and dispatchability by the transmission system operator. (Photovoltaics in Germany is exempt from this requirement as long as no single photovoltaic panel in the facility is rated 100 kilowatts or higher, but this may

change in the near future.)[4] While this infrastructure requirement doesn't directly affect the maximum distributed generation capacity that can be integrated at a given location in the network, it clearly impacts the ability of the German grid to accept more total distributed generation capability in aggregate (that is, the total PV within a network) than California could. This is due to the ability of the German grid operators to observe the output, as well as the authority to re-dispatch these distributed generation units in real time when needed for system emergencies. This has clear benefits to German transmission system operators in terms of congestion management, load-resource balancing, and frequency regulation if the normal market mechanisms are failing to correct for these conditions. On an aggregate level, the lack of comparable distributed generation observability and control by the California Independent System Operator and other California transmission operators pose a practical constraint to the total amount of renewable distributed generation that can be integrated into California's grid.

In Spain, monitoring and control of renewable distributed generation are handled by a centralized wind resource control center, but in Germany it is handled directly at the transmission system operator level. Unlike Germany, the California Independent System Operator has no visibility of the energy production of distributed generation resources connected to the distribution system and cannot send dispatch commands to these distributed generation resources. This is especially true for distributed generation resources that are connected behind the meter at a customer site and the output is netted with the customer load. By virtue of its balancing area authority status, the California Independent System Operator must be prepared to cover the total load at the customer site in the event that the distributed generation unit shuts down, but the amount of load being offset by distributed generation output is typically unknown to the California Independent System Operator. This has not posed a serious problem to date since the amount of distributed generation in California is been relatively limited. However, with the amount of distributed generation—especially solar photovoltaics—projected to grow significantly in the next decade, the potential impact of an unexpected shutdown of these resources could represent a future reliability problem for the California Independent System Operator—and for California.

Operational planning and forecasting tools and approaches related to renewable distributed generation are also different in the three countries. Only Spain has a centralized approach in this regard by virtue of the centralized wind resource control center, which resides on the control room floor at the national transmission system operator. In Germany and California, these functions are handled by the individual grid operators, which includes multiple transmission system operators in Germany and the California Independent System Operator various public power entities in California. The centralized wind resource control center employs a wind generation forecasting system composed of three components: a database on

4 Even so, about 25 percent of solar capacity output data is currently provided to the DSOs in near real time (such as, 15 minute data) to assist the DSOs with solar production forecasting. This is provided voluntarily or under agreement between the PV producers and respective DSO. Communication of this data is provided via ripple control transmitter/receiver attached to the PV inverter, or via telecom cable connection, and is called up as needed by the respective DSO.

the wind farms, a prediction algorithm based on a self-adaptive time series, and a forecast module. In the future, the centralized wind resource control center plans to expand its capabilities to include other categories of renewables.

For the California Independent System Operator to handle much larger amounts of distributed generation on the system in the future, enhanced data collection systems, telemetry, controllability, and improved forecasting models would need to be successfully developed and implemented. However, this would require close cooperation and collaboration with other state agencies, distribution companies, and grid operators to lay a solid foundation for distribution system enhancements, enhanced observability and dispatchability, and improved operational planning and forecasting models.

Distributed Generation on Public Property

Historically, municipalities in Germany and Spain have not played a major role in developing electricity generation apart from establishing favorable local conditions related to permitting and private investment in renewable facilities. In recent years, the municipal role has expanded to include making project development on public lands and buildings easier; however, these projects are almost always owned and operated by private investors. For the most part, lack of public ownership of renewable projects is attributable to the considerable investment requirements, economic risks, and other institutional barriers.

Increased activity by the public sector is expected to occur throughout Europe stemming from the European Union Directive 2009/28/EC. This directive stipulates that Member States shall ensure that new public buildings and existing public buildings subject to major renovation shall comply with standards for zero energy housing, or by providing that the roofs of these public or mixed private-public buildings are used by third parties for installations that produce energy from renewable sources (Article 13.5). European Union Directives require municipal authorities to check their internal processes for sustainability and energy efficiency and to serve as an example to the private sector.

In Germany, recent amendments to the Renewables Act (introduced in 2000 to increase power generation from renewable sources to 30 percent by 2020) pave the way for project development on slopes along highways and railways and noise protection (abatement) walls along motorways. These areas have been added as eligible categories due to their large potential for solar power development and the significant economic savings and conservation of land that can result from project development in these categories. For instance, solar panels attached to noise abatement walls may contribute to covering the costs for building and maintaining the walls.

KEMA found no expedited permitting processes or special incentives for renewable generation placed on government property and/or along highways or waterways in Germany and Spain. In fact, the report noted that solar projects built on municipal property may in fact take more lead time to develop as there may be lengthy and complex approval process due to public safety, health, environmental impact, and insurance issues.

Key Lessons Learned for California Policy Makers

1) The technical performance requirements specified in the German and Spanish codes that apply to the connection of distributed generation projects are at least as rigorous as those in California. Grid planners are obligated under current laws in Germany and Spain to identify a reliable service plan and to connect any distributed generation project, consistent with grid-code technical specifications. The costs of the required grid upgrades are then socialized to a large extent, particularly in Germany. The distributed generation connection planning process in California is less compulsory and more subject to lengthy planning studies and negotiation over the scope of the required grid upgrades and the allocation of cost.
2) German grid rules and planning processes allow back-feed conditions at all voltage levels and do not restrict distributed generation expansion due to back-feed. In comparison, distribution companies in Spain invoke an arbitrary cap on renewable distributed generation expansion at 50 percent of the peak demand in each area to prevent back-feed. Neither Germany nor Spain intentionally accepts additional reliability risks for distributed generation integration.
3) Although European distribution system voltage levels and apparatus are comparable to California, there are some important differences in distribution system design compared to California that promote distributed generation integration. These include protection system design standards in Germany that allow back-feed, the use of looped medium-voltage distribution circuits in at least the urban areas of Germany and Spain that provide 100 percent circuit backup capability for loss of the primary source, and the use of three-phase construction throughout European distribution grids, including individual customer service points.
4) Some key differences on cost-sharing for distributed generation interconnection facilities exist. In Germany, each distribution system operator determines what interconnection plan of service to use for distributed generation additions, but the distributed generation developer pays for only what it would cost to interconnect to the nearest point of common coupling. The remaining costs are socialized (rate based by the system operators). Cost-sharing rules in Spain are less explicit and subject to more negotiation between the distribution system operator and distributed generator.
5) The systemwide operating impacts of deploying nondispatchable distributed generation on a large scale are a significant concern to transmission system operators in Germany, Spain, and California. To address this concern, both Germany and Spain have taken steps to insure that transmission system operators have adequate visibility of renewable distributed generation dispatch levels in real time and accurate distributed generation forecasting tools. Transmission system operators in Germany and Spain are also allowed to curtail renewable distributed generation when necessary to maintain overall system stability or to mitigate congestion. However, German law requires that transmission system operators must exhaust all available market options before curtailing renewables. Even so, the number of out-of-market renewable curtailments required by German Transmission System Operators has grown significantly in recent years. During 2010, German transmission system operators had to take curtailments almost daily.

Additional rules and requirements for distributed generation monitoring and curtailment introduced in Germany in 2011 will better equip transmission system operators to deal with such events. Germany also experienced a sizeable increase in day-ahead forecast error levels for solar PV in 2010. In fact, German Transmission System Operators had to activate 100 percent of all contracted negative balancing reserves (about 4,800 megawatts) for several hours on September 6, 2010. As a result, German regulators and industry representatives agreed to implement improved photovoltaic forecasting tools at both the Transmission System Operator and Distributed System Operator levels as of April 2011.

6) Although Germany and Spain have been able to accommodate high-penetration renewable distributed generation to date without requiring widespread distribution system upgrades or energy storage technologies, a collaborative German industry study recently projected more sweeping infrastructure upgrades will be needed to support future distributed generation expansion. While the government's energy strategy published in 2010 envisions a total installed solar power capacity of roughly 33 gigawatts in 2020 (doubling the current installed solar power capacity), the Federal Ministry of Environment estimates that by 2020 there will be another 36 to 52 gigawatts of installed capacity added from solar power and smaller onshore wind parks. Given this forecast, the recent draft German industry study concludes that by 2020 it would need to build between 195,000 kilometers and 380,000 kilometers of additional lines on the German high voltage and medium voltage distribution voltage networks. The associated capital cost is estimated to be €13 billion to €27 billion between now and 2020. It can be inferred from this that previously underused distribution grid capacity in Germany (for example, "low hanging" fruit) as now been largely consumed by the significant distributed generation expansion that has already taken place.
7) A recently published German study also projects that a major expansion of the existing transmission grid will be required to accommodate wind resources. According to one major wind resource expansion study[5] completed in 2010, up to 3,600 kilometers of new transmission lines are needed to accommodate renewable growth, particularly large offshore wind, by 2020. This would require about €1 billion/year in additional grid expansion costs for new transmission lines. Another expansion scenario considered increased use of high-temperature transmission conductors that would reduce the mileage of new lines to some 1,700 kilometers but would also require some 5,700 kilometers of existing lines to be modified. This scenario would increase the expansion costs to €1.6 billion/year. Based on these study results, it can be concluded that future renewable expansion will require more costly transmission grid upgrades in Germany.
8) Accommodating back-flow conditions caused by distributed generation integration does not appear to require sweeping changes to California's basic distribution infrastructure. However, a number of secondary measures would be required, such as replacing substation relaying to accommodate back-feed, reconfiguring voltage control apparatus

5 *Deutsche Energie-Agentur Network Study II – Planning of the Grid Integration of Wind Energy in German Onshore and Offshore up to the Year 2020* (Dena Grid study), 2010.

and controls on distribution feeders, and deploying appropriate smart-grid technologies on California's distribution and transmission grids. As renewable levels continue to increase, the installation of energy storage devices on the transmission and distribution system—and in some cases at distributed generation sites—may become essential to modulate the affects of the intermittent resources and provide acceptable levels of balancing area frequency control.

9) It is possible that selective changes to ratemaking design and capital cost allocation policies in California related to integration of distributed generation into the distribution and transmission grids could incentivize a higher rate of distributed generation growth in California. Similarly, it would be beneficial to explore the range of distributed generation scheduling/redispatch/curtailment options that could be implemented in distributed generation interconnection agreements, tariffs and market models in California to increase participation by distributed generation producers in supporting the operational reliability needs of the distribution and transmission grids. Regulators can help to steer the direction of such options through policies regarding equitable compensation for curtailments, lost opportunity costs, and so forth.
10) Software tools used by grid operators for distributed generation interconnection planning in Germany and Spain are comparable to those used in California, and some of the same vendor's load-flow tools are employed. However, the German grid codes also provide simplified rule-of-thumb formulas that estimate the technical performance levels of any proposed distributed generation project and point of common coupling. Applying similar rule-of-thumb formulas may be useful in California.
11) Due to the differences in distribution grid rules, basic distribution system design, interconnection facility planning processes, and cost allocation mechanisms, there is likely to be less distributed generation capacity (relative to statewide peak demand) that can be easily integrated into the California distribution grid than in Germany and Spain. However, the scope of this study did not specifically address the question of whether achieving California's 12,000 megawatts of distributed generation goal is achievable by 2020 and/or what level of grid costs are required for this level of deployment.

Introduction

This report provides an overview of representative electric distribution systems in Europe and draws comparisons to the distribution infrastructure in California with the key objective of identifying differences that might affect California's ability to successfully integrate high levels of intermittent renewable distribution generation (DG) into the electric distribution system in California.

The report is organized by the following three topical areas:

- Section 1: Physical infrastructure and DG connection
- Section 2: Network planning and operational impacts of DG
- Section 3: DG on public property in European Union (EU) countries.

Section 1

The first section of this report describes the physical distribution infrastructure in Germany and Spain. It examines the requirements and processes for interconnecting DG to the distribution infrastructure and compares the relevant characteristics in these European countries to corresponding characteristics in California. The analysis focuses on medium- and low-voltage distribution grids but also outlines relevant aspects and impacts of renewable generation at higher voltage levels. The following questions are examined:

- How are the electric transmission and distribution systems configured in Germany and Spain? Does this topology increase opportunities for renewable DG integration?
- Have grid operators changed the configuration of their distribution systems to allow for greater penetration of renewable DG? What are the changes from a qualitative sense (what have they done) and a quantitative sense (how much of it have they done, how are they treating cost allocation, what is the quantitative relationship between changes in infrastructure and DG penetration)?
- Do grid operators use ancillary technologies (such as, battery storage, and flywheel) and policy levers that allow for greater backflows on the distribution system without threatening grid stability (such as, protection devices, and curtailment)? Or do they simply allow greater penetration under some circumstances without concern?
- Is higher penetration of renewable DG likely to cause voltage issues and potential back-feed issues? How does the electric distribution system of Germany and Spain address the back-feed issue in light of active power flow from the medium-voltage (MV) circuits up to the transmission / subtransmission high voltage (HV) circuits?

Section 2

The second section provides an overview of network planning and operational impacts in Germany and Spain. This section identifies the analytical and simulation methods used for network planning and operation in Germany and Spain and reviews the technical requirements for the interconnection of DG and technical integration issues. It frames the network operation aspects for the distribution network and the transmission system and describes the connections between the behavior of the generating units and the network operation, along with the control performance standards and measures used.

The findings address the following issues and questions:

- What definition of DG can be specified, and is DG limited to the size of electricity generators?
- Which analytical methods and simulation software are available to help network operators plan the integration of DG?
- How can grid operators monitor and control their network or system and improve the integration of DG into the electric network?
- Summarize new analytical and simulation models available to help DG operators plan the integration of photovoltaic (PV) planning and operational software.
- Summarize how Germany and Spain conduct the operational planning and dispatch coordination of their electric distribution systems as well as how they monitor and control their systems. Examine how much variability these countries experience (ramp, load following, and regulation) and their forecasting accuracy.
- Do these countries have a large amount of conventional electricity generation that can easily be turned on to manage the variability? Identify the type of the conventional electricity generation and the relative quantities of each type to gain a better understanding of how these countries use their fleet of electric generators to manage variability.
- Describe the dispatcher training that is provided to improve the integration of renewable DG into the electric distribution systems.
- Describe how curtailment is done in the context of operational planning and dispatch coordination.
- Compare the North American Electric Reliability Corporation (NERC) control performance requirements to the control performance requirements for the German and Spanish systems.

Section 3

This section addresses the topic of solar power and DG projects on public property in Germany and Spain. Key questions examined in this section include:

- Do Germany and Spain place solar DG on government buildings? Is this a common practice or a new practice?
- Do renewable DG projects on government properties go through the normal permitting process, or are they permitted through an expedited process?
- How do the European programs for renewable DG address issues such as construction safety issues associated with building along highways, condensation issues on or around waterways, security of equipment, maintenance of equipment and surrounding area, interconnection issues, and public experience of equipment being highly visible?
- How are renewable DG projects that are placed on government property in these European countries financed? Are there special or higher incentives or tax credits for renewable DG placed on government property? What are the ownership and revenue structures of the renewable DG projects?

Renewable Market Structure and Mechanisms in Germany and Spain

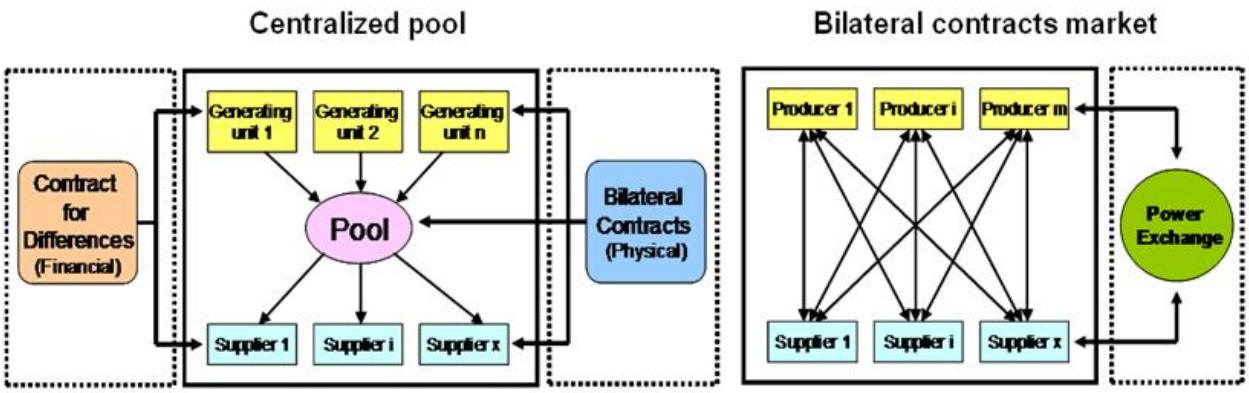
The following provides a high-level overview of the renewable market structure in Germany and Spain. As discussed below, the electricity markets in Germany and Spain differ significantly.

The electricity wholesale market in Germany is based on the bilateral contracts model with self-scheduling and self-dispatch. This means that market participants are allowed to engage in transactions for the sale and purchase of electricity with other parties, and renewable producers are able to schedule and dispatch their own plants. As a consequence, the bilateral contracts market allows exchanges between any two market participants and in effect allows market participants to act as traders. In other words, a producer may enter into both purchase and sale transactions for energy with any other party in the market.

Germany is organized as a uniform pricing zone and is operated by a separate transmission service organization (TSO). The market is mainly characterized by bilateral over-the-counter trading arrangements. Furthermore, the German market is supplemented by a voluntary power exchange, which differs in the contracts and energy products market in that participants may trade. The German power exchange (EEX) provides a two-sided day-ahead market, a same-day spot market, and a future market. As in most Western European countries, there is also a balancing market and a market for ancillary services. In the balancing group model, parties that provide balancing act as counterparties for imbalance settlement with the TSO.

In contrast, the Spanish electricity market operates on a centralized pool. The difference between bilateral and pool markets is illustrated in Figure 1.

Figure 1: Comparison of Bilateral and Pool Markets



Source: KEMA

In the pool approach, as used in Spain, there is centralized scheduling of all generation dispatch and all energy is bought and sold through the pool. Under Spain's pool, producers must sell to the pool, and distribution service providers must purchase from the pool. However, the Spanish pool market is supplemented by physical bilateral contracts and a forward market. Bilateral energy supply contracts between buyers and sellers are incorporated into the overall dispatch once the daily pool market has closed. Finally, Red Eléctrica de España (REE), as the national TSO, determines regulating reserve requirements based on the daily market results and to cover for any real time deviations occurring after the daily market closes.

Both countries have retail competition in the sense that consumers may freely choose their supplier. These markets are highly fragmented with a large number of local/ municipal utilities and many independent supply and trading companies. Despite the privatization of public utilities, many local government entities have kept majority stakes in the local utility. According to European legislation on unbundling, network operation and energy supply are separated from each other and are provided by different entities, though these may belong to the same utility holding company.

Renewable Promotion Schemes in Germany and Spain

The EU and European countries examined have adopted ambitious mid-term and long-term targets on climate change and energy policy. Renewables play a key role for accomplishing these targets.

National energy policies set the legal framework for the establishment of an economic promotion scheme for renewable energy. This is usually based on some form of a renewable electricity law that differs depending on the country examined. Therefore, each nation's energy policy may reflect a different set of promotion schemes. The promotion scheme introduced in Germany during 2000 has often been used as a benchmark for successful renewable energy policy-making due to its effectiveness in boosting development of renewable resource capacity.

The feed-in tariff (FIT) model is common in both Germany and Spain. Eligible producers of electricity from various sources, including solar power have access to the renewable regime. Both countries rely on a FIT scheme, as well as a national renewable electricity law that establishes provisions on:[6]

- Connection and access of renewable power generation assets to transmission and distribution networks.
- Applicable ancillary equipment requirements (for example, remote control and metering)[7].
- Promotional FITs for electricity from eligible sources.
- Market access and integration of electricity from renewables sources.
- The FIT provides an energy-related remuneration for the generator's output (in €c/kilowatt-hour).

In general, tariffs for renewable energy sources are differentiated by type (technology), size (installed capacity), and fuel type.[8] They are typically guaranteed for a certain period, for example, 20 years. A tariff digression factor is applied periodically[9] to reflect cost reductions resulting from technological progress and to adjust the level of financial incentive based on progress already achieved toward renewable targets. This means that the tariff rate for a particular technology and project size category decreases over time for new installations, and earlier investors are rewarded the most. Publishing of future digression factors allows each new block of renewable generators coming on-line to know – before they actually build – which tariff rate will apply to projects added in each future year.

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6 Germany: Gesetz zur Neuregelung des Rechts der Erneuerbaren Energien im Strombereich und zur Änderung damit zusammenhängender Vorschriften vom 25. Oktober 2008 (EEG); Bundesgesetzblatt Jahrgang 2008 Teil I Nr. 49, ausgegeben zu Bonn am 31. Oktober 2008 (German Law on the Renewable Energy Sources, October 2008); Spain: Royal Decree RD 661/2007

7 For further information, please refer to Section 1.1 (Grid Operation in Germany)

8 In Germany for instance, feed-in tariffs do not only differentiate between biomass and biogas, but also between different types of fuels, such as biogenic waste, biogas, and other solid and liquid materials.

9 In Spain the FIT rate for future renewable projects is generally adjusted downward on an annual basis. In Germany, the percentages by which tariffs decrease for future renewable generators are determined by amendments to the Renewable Energy Act adopted every 3□4 years.

Table 1 summarizes the main aspects of the primary renewable electricity promotion schemes implemented in the four countries.

Table 1: Comparison of Feed-in Tariff Schemes

	Germany	Spain
Promotion model applied	FIT	Hybrid: FIT and Market Premium
Purchase obligation by system operator, market operator or network operator?	Yes: for all renewable electricity, unless producers arrange remuneration via bilateral contracts outside the FIT scheme	Yes
Tariff (rate) digression (e.g., annually) for new installations?	Yes:	Yes
Are total promotional funds and/or annual capacity increment capped?	No	Yes
Is solar power promotion split according to installation type?	Yes	Yes
Can grid operator curtail renewable DG resources?	Yes, TSOs can curtail any DG 100 kW or larger (PV is exempted)	Yes, the TSO can curtail any DG unit over 10 MW

Source: KEMA

Spain combines its FIT with a market premium in a hybrid approach. Under the premium scheme the remuneration for electricity from renewable sources has two components: a reference price and a supplemental price. The reference price is often market based and equals the market value of the renewable technology. However, because most renewable sources are not competitive with conventional generation costs, renewables in Spain receive a supplement that covers the difference between the cost of generation and the reference price. Therefore, in Spain a renewable electricity producer may choose between: a) a guaranteed FIT for the electricity produced or b) a market premium on top of the hourly electricity market price if it decides to sell its output directly on the wholesale market (either through the organized market or a negotiated bilateral sale). Switching between the remuneration models is allowed, with a waiting period of up to one year.

There is no discrimination between private entities and public authorities in accessing the primary FIT promotion scheme for renewables. However, other promotional funds, provided by federal, state, or municipal administration(s), may be restricted to the private sector,

although municipalities may have access to specific funds provided by state or federal programs.

SECTION 1:

Physical Infrastructure in Germany and Spain

This section focuses on the physical characteristics of the infrastructure in Germany and Spain. The following questions are examined:

- How are the electric transmission and distribution systems configured in Germany and Spain? Does this topology increase opportunities for renewable DG integration?
- Have grid operators changed the configuration of their distribution systems to allow for greater penetration of renewable DG? What are the changes from a qualitative sense (what have they done) and a quantitative sense (how much of it have they done, how are they treating cost allocation, what is the quantitative relationship between changes in infrastructure and DG penetration)?
- Do grid operators use ancillary technologies (such as, battery storage and flywheel) and policy levers that allow for greater backflows on the distribution system without threatening grid stability (for example, protection devices and curtailment)? Or do they simply allow greater penetration under some circumstances without concern?
- Is higher penetration of renewable DG likely to cause voltage issues and potential back-feed issues? How does the electric distribution system of Germany and Spain address the back-feed issue in light of active power flow from the MV circuits up to the transmission/subtransmission HV circuits?

This section is organized as follows:

- Section 1.1 reviews the current state of physical grid infrastructure in Germany.
- Section 1.2 reviews the current state of physical grid infrastructure in Spain.
- Section 1.3 provides a comparison to grid infrastructure in California.
- Section 1.4 provides a summary of key lessons learned.

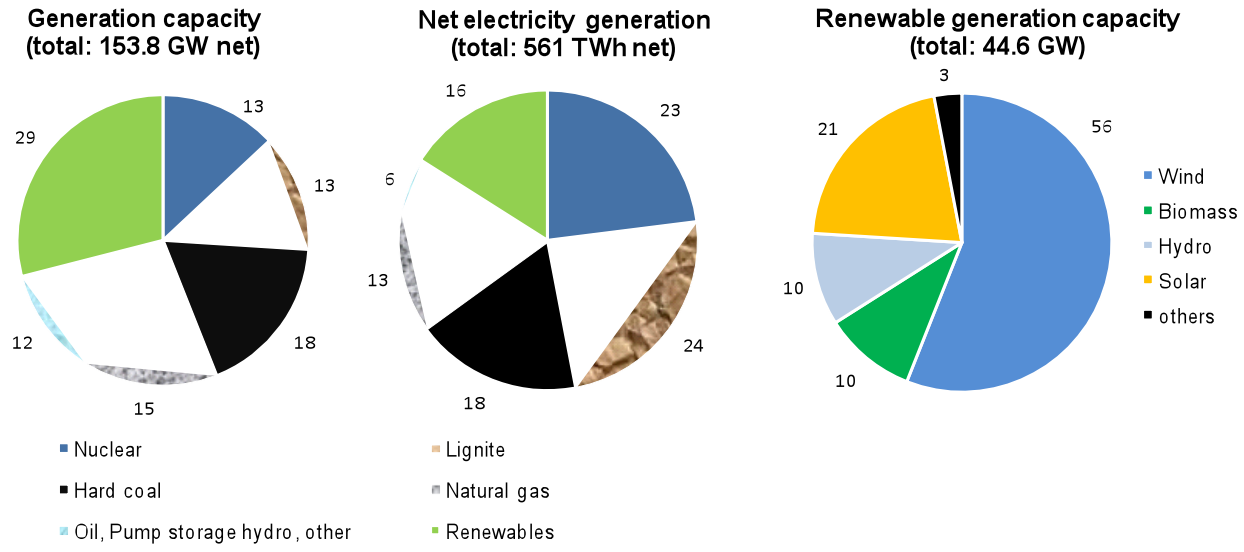
Section 1.1 □ Current State of Market and Physical Grid Infrastructure in Germany

Regional and Quantitative Allocation of Renewable Energy in Germany

At the end of 2009, about 16 percent of the German electrical energy production came from renewable energy sources.[10] The growth of renewable DG in Germany continues unabated. German grid operators have dealt with the challenge of significant renewable integration for the last 5 to 10 years and have developed technical rules and guidelines to ensure secure network operation. An examination of the German power system is therefore useful for a comparative analysis.

The extent of deployment of each type of renewable generation depends on many factors such as local climate conditions, land use, and population levels. A comparison of all types of installed generation capacity in Germany, including both renewables and conventional generation, is shown in Figure 2.

Figure 2: Generation Mix in Germany at End of 2009 (All Data in Percentages)



Source: BDEW: German Energy Market, 2010

The type of renewable energy source often affects the size of the generation plants and thereby the type (for example, voltage level) of the grid connection. As a general rule for the German

10 *German Statistics of Renewable Energy Sources*, December 2010.

grid, the voltage level at the point of common coupling (PCC) for DG plants follows the schema shown in Table 2. The corresponding voltage (kilovolts - kV) ranges are defined in Table 4.

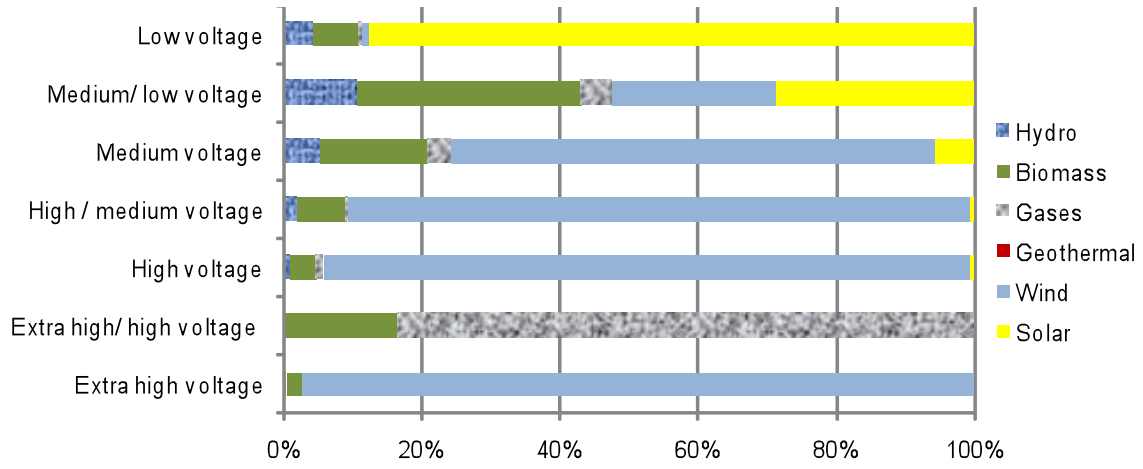
Table 2: General Rules for Selecting the Voltage Level of the Point of Common Coupling, According to the Rated Power of Generation Plants

Rated power of the generation plant	Voltage level of grid connection
Up to 30 kW	Low-voltage grid without verification
30 to 200 kW	Low- or medium-voltage grid
0.15 to 20 MW	Medium-voltage grid
15 to 80 MW	High-voltage grid
80 to 400 MW	Extra-high voltage grid

Source: *Potentialermittlung für den Ausbau der Wasserkraftnutzung in Deutschland, Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (BMU)*, September 2010 (Capacity of hydro power in Germany, September 2010)

In actual practice there can be deviations from the general rule based on the results of specific studies for DG interconnection. Figure 3 shows the breakdown of generation types installed at each voltage level as a percentage of the total generation capacity installed at that voltage. The size of the generator is a key parameter as it requires a corresponding capacity both at the network connection point and for transporting the electricity produced from that point to the system. For instance, solar power installations tend to be rather small (mainly roof-based installations) and are mostly connected to the low-voltage (LV) network. On the other hand, wind projects are developed over a much wider range of sizes (for example, wind farms) and therefore are connected at many different voltage levels.

Figure 3: Relationship Between Network Connection Level and Technology for Installations Eligible Under the 2008 Renewable Energy Act[11]



11 Installed geothermal capacity is negligible. "Gases" refers to waste gas projects (for example, mine gas).

Source: *Bundesnetzagentur EEG-Statistikbericht 2008* (Translated – Regulator's EEG Statistical Report, 2008)

Additional general observations in regard to network integration of DG on the German network are as follows:

Wind Energy

A high concentration of wind energy plants occurs in rural, sparsely populated areas in northern Germany. The individual generating units mostly have a rated power from 1 megawatt (MW) to 3 MW. Hence, the PCC for plants this size is most often located on a MV grid. However, when individual units are collected into wind farms with rated power from 20 MW to 80 MW, they are usually connected to the HV grid. A few large wind farms generate 80 MW to 400 MW of electric power apiece and are directly connected to the extra-high voltage (EHV) grid via separate substations.

Solar Energy

Even though the percentage of electrical energy generated by solar power was only about 7 percent of all renewable energy by the end of 2009, solar power has had the strongest growth rate for the last two years. A significant amount of solar energy generating units has been installed particularly in southern Germany. The installed solar generation capacity increased by 3,800 MW in 2009 and by about 7,400 MW in 2010. Including additional growth to date in 2011, this brings the total installed solar capacity to about 18 gigawatts (GW) as of July 2011. Of the 18 GW, the vast majority of the systems are under the 100 kilowatt (kW) size range.

In urban areas, small solar generation plants (PV modules and converters) are installed on roofs of homes (rated power 3 kW to 5 kW) or commercial and public buildings (100 kW to 1 MW). According to grid code, small units up to 5 kW peak can be connected as a single-phase installation at a customer service point.[12] Units up to 30 kW are allowed to connect as a three-phase installation at any customer service point on the LV grid without technical verification. However, the presence of multiple DG projects within an individual LV grid can cause severe voltage or power quality issues, particularly in rural areas, if not properly mitigated. (See Section 2 for further discussion.)

Biomass in Cogeneration Plants

By the end of 2009, the fraction of renewable electrical energy generated from biomass was roughly 30 percent of all renewable energy production. Hence, biomass is the next most important renewable energy source after wind in Germany and has high growth rates. Co-generation plants for biomass are installed all over Germany, particularly in rural areas. Small units with generating capacity up to 150 kW are connected to the LV grid. The majority of units range from 500 kW to 5 MW and are connected to the MV grid. Large units with considerably more than 5 MW exist and are connected to the MV or HV grid according to their rated power.

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12 *Eigenerzeugungsanlagen am Niederspannungsnetz – Richtlinie für den Anschluss und Parallelbetrieb von Eigenerzeugungsanlagen am Niederspannungsnetz; VWEW Energieverlag GmbH*; September 2005 (*German Technical Guideline – Generating Plants Connected to the Low-Voltage Network*, September 2005.)

Since biomass is consistently available, it is less of a concern to network operation than fluctuating resources, such as wind and solar power.

Hydropower

Hydropower resources are considered to be well developed in Germany. Therefore, the amount of hydropower has remained nearly constant over the last few decades since most of the potential locations are already used. Hydropower stations of various sizes have been installed in mountainous areas and along rivers in central and southern Germany. Hydro generation represents about 25 percent of all German renewable energy generation.

In addition, several large pumped-storage power plants connected to the EHV grid contribute to the load balancing and frequency control of the transmission system. Table 3 provides an overview of the number of hydro generation plants in several power categories and the installed power.

Table 3: Hydropower Plants in Germany, Categorized by Number and Installed Power

	Hydropower units with less than 1 MW	Hydropower units with more than 1 MW	Pumped- storage plants
Number of units	~6,500	~400	~30
Installed Power	~600 MW	~3,500-4,000 MW	~6,500 MW

Source: KEMA

In 2010, there were thousands of hydropower stations in operation, most of which consist of small units. Total installed capacity amounted to more than 10 GW. Out of the total, there were about 30 pump storage stations consisting of 100 units with a combined installed capacity of around 6.5 GW. Among remaining conventional hydro power units, there were about 350 □ 400 stations larger than 1 MW with a total installed generation capacity of 3.5 □ 4.0 GW. More than 20 hydro stations (125 units) had an installed capacity of 30 MW or larger, with a combined installed generation capacity for such stations of 1.80 GW.[13]

Network Structures in Germany

In the next part of this section, the basic technical layouts and configurations of German transmission and distribution grids, including substations and LV (for example, 400 volt) networks are described. Then the general and technical requirements for the interconnection of DG from a German perspective are then considered. Finally, the most common network upgrade options to manage the integration of renewable energy sources and comply with technical requirements are examined.

13 Source: Platts Power Plant database.

Grid and Voltage Levels in Germany

The European power grid is a three-phase alternating current grid operated at a frequency of 50 Hertz at all voltage levels.[14] Four common voltage groups (EHV, HV, MV, and LV) have been established in the German power grid per International Electrotechnical Commission (IEC) definitions. The existing grid voltages for each of these groups in Germany are shown in Table 4.

Table 4: Overview of Voltage Levels in Germany

IEC Definition Name	Abbreviation	Rated Voltage	Role
Extra-high voltage	EHV	380 kV, 220 kV	Transmission grid
High voltage	HV	110 kV	Distribution grid
Medium voltage	MV	30 kV, 20 kV, 15 kV, 10 kV	
Low voltage	LV	400 V	

Source: KEMA

Transmission Grid in Germany

The European transmission grid is operated primarily at 380 kV and partially at 220 kV, but the latter is on the decline. This EHV network provides the basis for the electrical energy transport between large-scale power plants, the connected distribution grids, and neighboring countries. The European transmission grid is an integrated network designed to ensure reliable, efficient, and secure electrical energy supply based on the rules of the Operation Handbook of the European Network of Transmission System Operators for Electricity (ENTSO-E).[15] According to the German Transmission Grid Code,[16] the main task of the transmission grid operators is to assume responsibility for the whole system of electrical energy supply, including:

- The balance of load within a control area, especially in case of a resource contingency, and thereby maintaining system frequency stability
- Network security, such as, the security of supply, secure operation, the compliance with voltage and other operational limits and the (n-1) criterion

14 The railway power grid is distinguished from the public power grid by frequency and generation. It is a two-phase AC grid operated at 16.7 Hz.

15 UCTE Operation Handbook (OH), Version 2.5, level E, dated 24.06.2004, Union for the Co-ordination of Transmission of Electricity" (UCTE); Brussels.

16 Transmission Code 2007, Netz- und Systemregeln der deutschen Übertragungsnetzbetreiber, Version 1.1, August 2007, Verband der Netzbetreiber – VDN – e.V. beim VDEW, Berlin (Transmission Code 2007, *Network and System Rules of the German Transmission System Operators*, August 2007.)

- The ongoing evaluation of system operating conditions and initiation of required corrective measures that will involve the associated distribution grid operators as needed.

The transmission grid is a meshed system with high standards for system stability (frequency, voltage, dynamic stability) and security of supply. The transmission infrastructure in Germany is predominantly overhead construction.

Distribution Grid in Germany

Distribution Grid at the High-Voltage Level

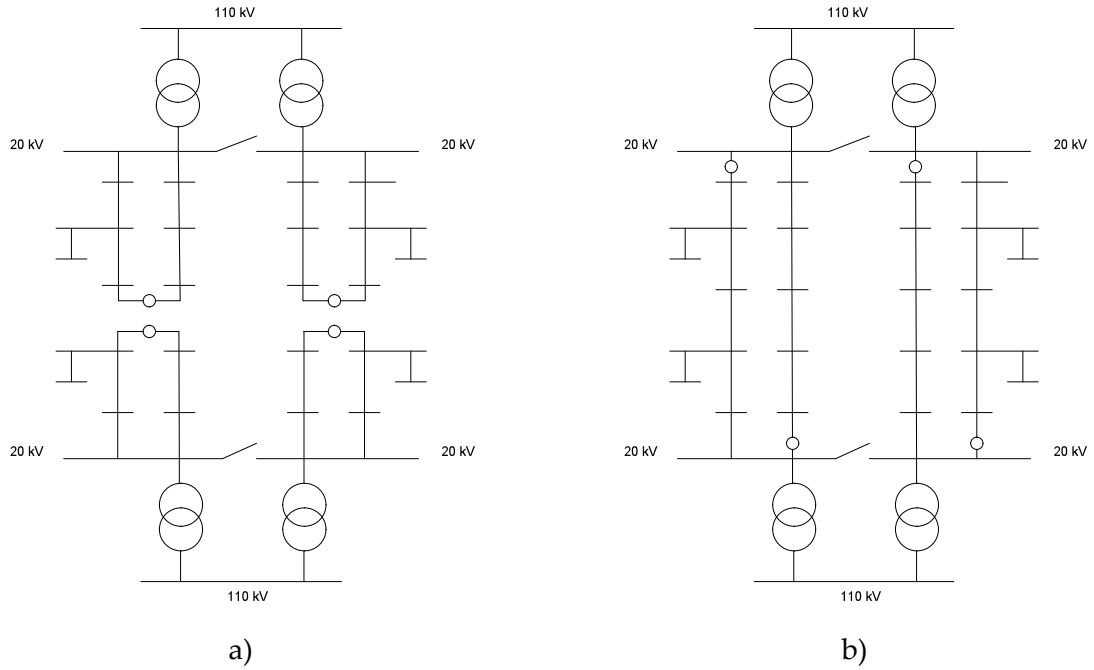
The 110 kV HV grid serves as the transport grid for medium distances and carries the electric energy from exchange points on the transmission grid toward urban or rural MV grids. The requirements concerning security of supply are again covered by compliance to the (n-1) contingency criterion. The grid is meshed and consists mainly of overhead lines. In urban areas, underground cables are often installed at 110 kV. High loads with high demands (for example, large industrial loads) and generating units exceeding a power limit of about 20 MW are primarily connected to this grid level.

Distribution Grid on Medium-Voltage Level in Germany

The MV grid mainly consists of the voltage levels 30 kV, 20 kV, 15 kV, and 10 kV. Urban and rural MV grids significantly differ in their characteristics.

A high geographic density of loads and relatively high demand levels are typical for urban areas and cause heavy usage of the MV grid equipment (transformers and cables). Appropriate for these requirements, urban MV grids in Germany consist largely of cables with a typical cable cross-section of 150 to 300 square millimeters (mm^2) (nominally equivalent to a range of 300 circular mil - kcmil - to 636 kcmil) and with a comparably short cable length as compared to rural systems. The urban MV grids are generally operated at voltage levels of 10 kV and 20 kV. They are set up as looped networks with open loops under normal operating conditions as displayed in Figure 4, where the smaller circles represent normally open switchgear and the larger circles represent substation transformers.

Figure 4: Medium-Voltage Grid Layouts



a) Normally open loops; b) Circuits with two source stations and normally open contact at one station

Source: KEMA

The MV grids are connected to the HV grid (110 kV) via substations with two or more HV/MV transformers in a rated power range from 31.5 megavolt ampere (MVA) to 63 MVA. The power transformers are typically equipped with tap changers and automatic voltage control to guarantee a fixed voltage at all MV bus bars. As link to the LV grids, the secondary substations mainly consist of single MV/LV transformers in a rated power range from 400 to 1,000 kilovolt amperes (kVA). If direct customer connections to the MV grid are needed, transformers up to 1,600 kVA can be used. To be able to supply each MV circuit through the normally open tie point (see Figure 3) during outages of the primary source, the conductor size of each MV feeder is generally consistent over the entire length of the feeder. As a result of the high installed power transformer capacity and the relatively short cables with large cross-sections, the network impedance is comparably low throughout the whole urban MV grid. Hence, more DG can be connected with minimal risk of voltage drop and other power quality issues.

Medium-Voltage (MV) Distribution Grids in Germany

Rural areas are characterized by larger geographic areas and lower load density. This results in long lines, higher network impedances, and lower use of the equipment capacity. In rural MV grids in Germany, underground cables and overhead lines are installed in nearly equal shares.

Typical underground cable cross-sections range from 120 to 240 mm² (nominally equivalent to a range of 4/0 American wire gauge [AWG] to 400 kcmil). The cross-sections of overhead lines range from 70 to 120 mm² (nominally equivalent to a range of 2/0 AWG to 4/0 AWG).

Rural MV grids are operated at various voltage levels; most common are 10 kV, 15 kV, 20 kV, and 30 kV. Like urban areas, rural MV grids are set up as looped networks with one source open under normal operating conditions, or lines are connected between two stations with a normally open contact at one end (see Figure 3). Usually, the grids are connected to the HV grid (110 kV) via substations with two HV/MV transformers in a rated power range from 16 to 40 MVA. The power transformers are typically equipped with tap changers and automatic voltage control to guarantee a fixed voltage at all MV bus bars. The secondary substations consist of single MV/LV transformers in a rated power range from 100 to 400 kVA.

In a few cases, intermediate 30 kV grids operate to supply remote, lightly loaded areas. These 30 kV distribution grids are configured as closed loops and supply lower-voltage 10 kV grids.

Due to the long lines, smaller cross-sections, and the comparably low installed transformer capacity of rural MV grids, the network impedance increases significantly towards the remote line terminal. Voltage drop and power quality issues occur more frequently due to DG interconnection and operation. (See further discussion in Section 2.)

Low-Voltage (LV) Distribution Grid in Germany

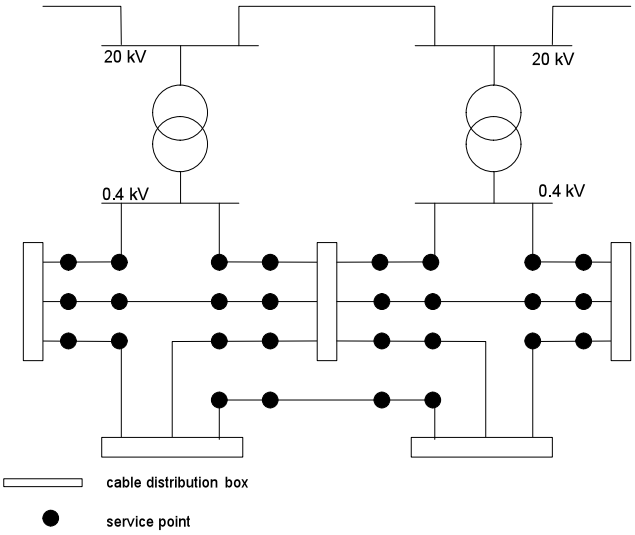
The LV grid is a 400 volt (V) network and remains a three-phase grid (or three-phase plus neutral phase) up to the customer service points (and even into customer homes). In general, outgoing cables in secondary substations are protected by a LV, high-load breaking capacity fuse. Service point connections are protected for a maximum permissible current of 63 amperes (A) (equal to 25 kVA). Similar to MV grids, urban, and rural LV grids have different grid characteristics.

Urban Low-Voltage Grids

According to the high spatial density of urban loads, LV grids in these areas consist of relatively short grid cables with typical cable cross-sections of 150 to 240 mm² (nominally equivalent to a range of 300 kcmil to 400 kcmil). From the grid cables, service point cables with a cross-section of 35 – 50 mm² (nominally equivalent to a range of #2 AWG to #1 AWG) branch off to customers.

The urban LV grids are operated as meshed grids connected by means of cable distribution boxes. The LV grids can be fed by a single secondary substation or by one or two MV circuits. (See Figure 4 for an example of the latter option.) The urban secondary networks contain multiple cable distribution boxes that serve as coupling points for the 400 volt circuits. The meshed grid structure ensures high service reliability, allows for high usage, and reduces voltage drops and power quality issues.

Figure 5: Typical Urban Low-Voltage Grid Layout



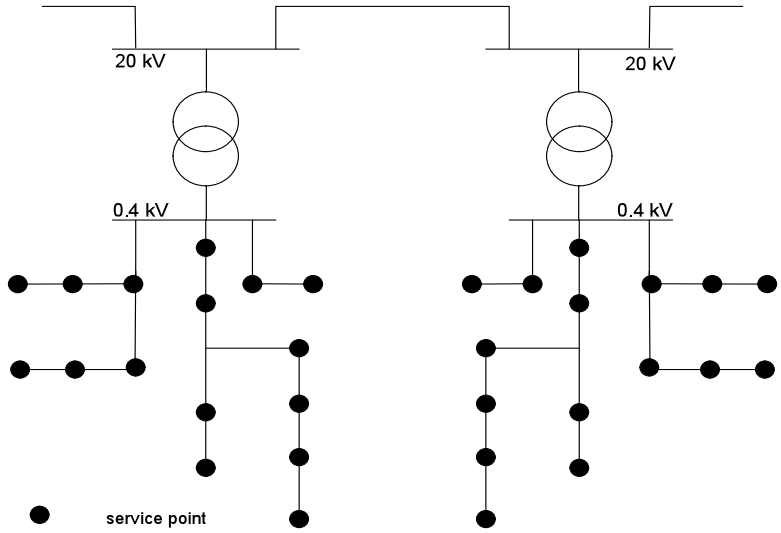
Source: KEMA

Rural Low-Voltage Grids

Due to the geographic expansion of service areas in rural zones and the lower load density, rural LV grids in Germany are mainly configured radially. They may be underground cable or overhead lines. For underground, typical cable cross-sections range from 95 mm² to 150 mm² (nominally equivalent to a range of 3/0 AWG to 300 kcmil). The cross-sections of overhead grid lines range from 50 to 95 mm² (nominally equivalent to a range of #1 AWG to 3/0 AWG). The customer service point connections are typically done through 35 mm² cables (nominally equivalent to #2 AWG). Occasionally, overhead lines with cross-section of 25 to 35 mm² (nominally equivalent to a range of #4 AWG to #2 A WG) are used.

As displayed in Figure 6, the rural secondary substations typically contain up to eight outgoing LV circuits operated as radial grids fed by a single secondary substation. The long lines and decreasing cross-sections toward the line ends cause higher network impedances. Thus, the sensitivity to voltage deviation and system perturbations (power quality issues) due to DG installations increases significantly.

Figure 6: Typical Rural Low-Voltage Grid Layout



Source: KEMA

In addition to the standard task of supplying end-use customers, the distribution operators (DSO) must connect DG units in the most cost-efficient, technically secure way. Therefore, the DSO first uses any existing reserve capacity in the grid for connecting a DG. If these reserves are exhausted, the PCC can either be moved to a higher voltage level grid (depending on the DG size), or the lower voltage grid must be upgraded to accommodate the new DG. In the case of a grid extension or upgrade, the grid planner considers existing grid expansion requirements and network planning directives in conjunction with the technical rules for the grid connection of DG to come up with the overall lowest cost grid expansion plan.

Implications of DG on Grid Planning and Operation in Germany

Even though the increasing production of renewable energy from DG units affects the grid at all voltage levels, no fundamental changes in the grid structure and planning standards have been made in Germany. However, due to the scale of DG growth in the last decade, the level of DG output on MV and LV grids now exceeds local load in many places in Germany. Hence, back-feed conditions occur in some regions of the network. In general, back-feeds are permitted in Germany. The metering and protection have to be designed for bidirectional flow. A four-quadrant meter is necessary, and the protection system has to allow back-feeds.

Network connections and upgrades are planned, based on the expected level of back-feed, so that this condition causes no overloads. Therefore, a back-feed condition during normal operation should not lead to curtailment or tripping the DG. In fact, under the German rules, TSOs must first exhaust all other available market options before curtailing renewable DG. Rules applying to DG curtailment by DSOs are not as clear, and the DSOs also have fewer

options than the TSOs. However, if a renewable DG is curtailed by either a TSO or a DSO, the DG still receives its normal FIT remuneration for any curtailed energy (it does not reduce the DG's revenue).

Given that the costs of network upgrades related to DG in Germany are socialized, network planners seek the lowest cost plan of upgrade to satisfy DG integration needs. Up to now, the planning for DG integration has generally been done as part of the regular grid expansion planning process with normal expansion planning and replacement needs considered first, then DG integration layered on top of that.

Grid Dimensioning in Germany

In the past, MV/LV grids were designed and dimensioned based on the peak load scenario. The grid dimensioning and operation now have to account for the following four scenarios for load and DG output:

- Peak load / low DG output
- Peak DG output / low load
- Peak load / peak DG output
- Low load / low DG output

The first two scenarios have become the most critical cases for grid planning and operation. The power lines and transformers at each voltage level of the grid must be sized to manage the emerging renewable DG power production.

Protection Aspects

The protection devices and settings in German distribution grids generally allow for back-feeds. The overload protection depends on the loading limits of the grid assets and is independent of the flow direction.

DG plants have to be equipped with overvoltage and undervoltage protection. The time delay of the protection devices has to be adjusted to allow for the time delay of the automatic tap changers on HV/MV power transformers supplying that part of the network. Additionally, DG plants in MV grids and above must be equipped with underfrequency and overfrequency protection. Furthermore, a power circuit breaker within the DG plant must guarantee the disconnection of the DG project from the grid in case of a short circuit in the plant.

Grid Operation in Germany

German TSOs are responsible for managing operational issues due to the high concentration of wind and PV generation plants on the system, including:

- The impact of fluctuating renewable output on balancing of the load forecast and generation schedules, in both the traditional scheduling intervals and real-time operation.

- The considerable back-feeds from low load/high DG areas that must be transported to large load centers and reducing any congestion this causes in the transmission grid.
- The curtailment of conventional power plants to accommodate renewable output, and the associated reduction in frequency control and short-circuit duty that can affect the dynamic stability of the system

According to the German law EnWG, grid operators at all voltage levels can invoke renewable generation curtailment to cope with congestion and other critical operational situations that jeopardize the network security, after market-based options are exhausted. For this purpose, DG plants with rated power of more than 100 kW must be equipped with remote telemetering and control capability to communicate their real-time output to the grid operator and allow for the TSO to send automatic power curtailment instructions to these generators. However, under current German law a PV project is only subject to this requirement if it has an individual PV panel rated 100 kW or larger (such as, the composite output of the PV project does not apply). However, the German legislature has recently passed legislation that, if signed by the executive branch, would essentially revoke this exemption for PV.

General and Technical Interconnection Requirements in Germany

General Requirements

The implementation of renewable energy sources is an important national strategy of the German government. In this context, the federal government has developed a legal framework for the development of DG. As a result, important new laws (EnWG[17] and EEG[18]) were enacted. These laws obligate German grid operators to connect all DG applications and grant a priority to renewable energy sources over conventional energy sources, in the dispatch order during curtailments. TSOs and DSOs need to ensure that DG units are able to feed into the grid and that the total installed power can be transmitted under normal conditions. (Pending changes in German law may reduce this requirement to 70 percent of rated capacity for smaller DG units connected to the LV system.) Furthermore, the DG project is responsible only for the cost of connecting to the nearest PCC even if it isn't a feasible connection location given the grid technical limitations. About 25 percent of the existing DG projects require greater grid upgrades to connect (above the nearest PCC), but under German law these additional connection costs are socialized. An exception applies to DG units with an installed power below 30 kW. For these

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17 EnWG Zweites Gesetz zur Neuregelung des Energiewirtschaftrechts vom 7. Juli 2005; Bundesgesetzblatt Jahrgang 2005 Teil I Nr. 42, ausgegeben zu Bonn am 12. Juli 2005 *(Second German Law on the Energy Industry, July 2005).*

18 EEG – Gesetz zur Neuregelung des Rechts der Erneuerbaren Energien im Strombereich und zur Änderung damit zusammenhängender Vorschriften vom 25. Oktober 2008; Bundesgesetzblatt Jahrgang 2008 Teil I Nr. 49, ausgegeben zu Bonn am 31. Oktober 2008(*[German Law on the Renewable Energy Sources, October 200).*

units the PCC is always defined as the point in the LV grid closest to the service connection of the owner of the DG unit.

There has been a continuing evolution in the technical rules used for evaluating the impact of the DG project at the PCC and developing the interconnection plan of service. However, the rules have consistently been driven by the following targets:

- The PCC should be as close as possible to the location of the DG.
- Secure grid operation must be maintained under all conditions, including the full output of the distributed generator, regardless of system demand level.
- The operation of DG should have negligible impact on other customers.
- Specific power quality parameters have to be maintained.

Given this context, DG plants are connected at various voltage levels depending upon their location, the type of energy source, and the generating capacity installed. The actual interconnection plan is chosen by the DSO and/or TSO (depending on voltage level) and the DG contributes only to the capital costs based on the cost of connecting to the closest possible PCC, regardless of the actual plan of service (such as interconnection plan and upgrades) adopted by the grid operator. Any additional grid capital costs are socialized. The following summary describes the technical norms and rules regarding DG connected to MV/LV grids.

Technical Requirements

Technical rules exist for the grid connection of DG units to the MV grid[19] and to the LV grid[20], respectively. Generating units that are connected to the MV or LV grids should not cause overloads, undervoltages, or overvoltages. To ensure a secure operation of the grid under all conditions, the main points addressed by the grid operator in DG interconnection planning are as follows:

- All components used for the interconnection shall be properly dimensioned for the size of the renewable project.
- The range of operating voltages that occur at the point of connection shall be within the acceptable range.
- The use (such as loading) of all electrical grid components shall not exceed the rated current of the respective component(s), as defined per industry norms.

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19 *Erzeugungsanlagen am Mittelspannungsnetz – Richtlinie für den Anschluss und Parallelbetrieb von Erzeugungsanlagen am Mittelspannungsnetz;* VWEW Energieverlag GmbH; Juni 2008 (*German Technical Guideline – Generating Plants Connected to the Medium-Voltage Network, June 2008).*

20 *Eigenerzeugungsanlagen am Niederspannungsnetz – Richtlinie für den Anschluss und Parallelbetrieb von Eigenerzeugungsanlagen am Niederspannungsnetz*; VWEW Energieverlag GmbH; September 2005 (*German Technical Guideline – Generating Plants Connected to the Low-Voltage Network, September 2005).*

In addition, the grid rules specify a variety of technical requirements. Several key requirements are summarized below, but a detailed description of the German technical requirements is given in Section 2.1:

Permissible Voltage Range

The permissible voltage range for MV/LV grids is defined in the norm DIN EN 50160.[21] On the one hand, the maximum voltage should not exceed the insulation level of the electrical components. On the other hand, the minimum voltage at each PCC must allow an undisturbed operation of all customer devices connected to the grid. In this context, the voltage at each PCC should be in a range of ± 10 percent of the rated voltage under normal operating conditions.

Power Quality

Additionally, DG plants should not interfere with other customers (consumers or generating units). To ensure acceptable power quality parameters, the following system perturbations associated with a DG are considered:

- Voltage increase at the PCC
- Flicker
- Harmonics

Admissible limits for voltage deviation, nonsymmetry, flicker, and harmonic levels are defined in Section 2.

The Most Critical Issue: Voltage Increase

Generally, voltage increase is the most critical issue at the service point (PCC) for DG units. Without any distributed generators, voltage along a distribution circuit typically drops from the circuit source to the individual customer service points along the circuit. When DG is added at some point along the circuit, a voltage increase occurs due to the power injected from the generating unit. Specifically, the flow of this power through the grid's electrical impedance causes a voltage increase from the circuit source (for example, distribution substation transformer) to the service point location (PCC). The magnitude of the voltage rise is a function of the size of the circuit impedance and the maximum power output of the DG. This effect is illustrated simply in Figure 7, which shows the circuit "one line" diagram on top and the corresponding voltage profile below. The bottom line in the voltage profile graph shows the voltage along the circuit without the DG, and the top line in the graph reflects the new voltage profile with the DG in operation.

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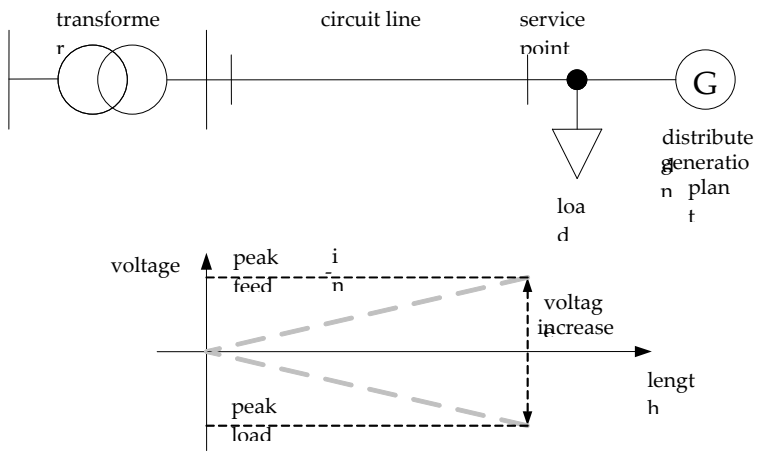
21 DIN EN 50160 – *Merkmale der Spannung in öffentlichen Elektrizitätsversorgungsnetzen*; April 2008 (German Norm 50160 – *Voltage Characteristics of Electricity Supplied by Public Distribution Networks*, April 2008).

Figure 7: Voltage Increase Caused by Distributed Generation



Source: KEMA

The actual voltage profiles are calculated using a power flow program, and the maximum difference between PCC voltages with and without DG operation are defined in the German grid rules in Section 21. If multiple DG projects are to be connected in the same area, the combined impacts must be studied.

The short-circuit duty at a PCC can serve as a measure for the network impedance. High short-circuit duty reflects a low network impedance and vice versa. Therefore, in areas with low short-circuit power (such as rural areas), the voltage increase is usually higher than in areas with a higher short-circuit power (such as urban areas). If the voltage increase exceeds the limit value, either grid upgrades are required to reduce the network impedance, or the distributed generating unit has to be connected to another PCC.

In addition, other types of system perturbations (such as flicker and harmonics) are also evaluated in regard to the short-circuit power at the PCC. The respective TSO or DSO considers all of the performance rules during planning studies for each DG connection, and appropriate planning options are employed, as discussed in the next section.

Technical Options to Ensure Secure Grid Operation in Germany

Due to the distinct electrical characteristics of each MV/LV grid, the maximum acceptable level of DG capacity can be limited at any given point in the network. To ensure secure grid operation the DSO selects from different grid planning options when needed to increase the acceptable amount of DG in a given part of the network. When the closest connection point is inadequate, German network planners consider all possibilities to determine the minimum level of grid investment using a variety of technical options, which include:

- Directly connecting the DG into a substation.
- Upgrading of the network circuit thermal capability to the DG location.

- Upgrading of upstream transformer capacity.
- Rerouting the circuit to reduce circuit length and reduce impedance.
- Relocation of the network loop normally open disconnect point.
- Set point adjustment of automatic voltage control on network transformers.
- Using reactive power capabilities of distributed generating units.
- Construction of a new substation.
- Changes to grid topology.
- Upgrade of the network's rated voltage level.
- Installation of supplemental reactive power compensation equipment.
- Implementation of rotating and nonrotating energy storage systems.

These possibilities are described in more detail below. The options appearing in the bottom half of the above list, starting with set point adjustment of automatic voltage control on network transformers, are particularly applicable when planned DG expansion would cause voltage regulation issues at existing substations in the grid.

Direct Connection at a Substation

If the voltage increase exceeds the limit value, other PCCs should be justified. In this context, the direct connection of a distributed generating unit to a network substation is one of the most commonly used solutions in Germany. This option can also be used if other system perturbation factors exceed the permissible limits. It requires relocation of the planned DG to a site adjacent to the network substation or construction of a gen-tie line from the DG site to the network substation.

Upgrade of Conductor Size

An upgrade of grid underground cable or overhead lines can be used if the connection of the DG to the nearest grid line exceeds critical performance parameters. Depending on the grid load, this approach may allow additional distributed generating units to be integrated into the grid. In Germany, this solution is often used for older grid lines, and conductor replacement needed due to the age of the grid line can sometimes be combined with integration of DG. This solution is also used to raise short-circuit duty at the PCC. Therefore, this option can also be used to solve problems regarding critical voltage increases. However, Germany avoids upgrading of the distribution grid solely for integrating a lot of DG. Depending on the amount of DG projects added to a portion of the grid, upgrade of line conductors may only be a short-term option. In all cases, relevant near-term and long-term grid planning factors should be taken into account.

Upgrade of Transformer Capacity

Similar to line upgrades, the upgrade of upstream transformer capacity is also used in Germany for some DG interconnections. This option may be preferable, especially for older transformers, and allows more power output by DG.

Reduction of the Circuit Length

This option can be realized by replacing grid line(s) to the DG site with an alternative route that creates a shorter circuit length and lower network impedance. However, the feasibility of this option depends on the geography of the specific grid area. Moreover, the resultant benefits in many cases are relatively low.

Relocation of the Network Normally Open Disconnect Point

A short-term option to reduce voltage increases on grid lines can be the relocation of the normally open disconnect point of a grid loop.[22]

In Germany this option is only a short-term solution and is used more from the grid operation side. The impact of the relocation of the disconnection point on the ability to integrate DG is comparably low and may increase the network electrical losses. With respect to the dynamic growth of renewable energy generation, there are superior options for medium-term or long-term grid planning.

Adjustment of Automatic Voltage Control Set Point on Transformers

An adjustment of the transformer voltage control set point is also considered a short-term option but in some cases can be used to keep the voltage level at a downstream DG connection point within the permissible range.

This option can be used only in MV grids in Germany because only the HV/MV power transformers are equipped with automatic voltage control systems (tap changing under load). Therefore, application is limited to larger DG facilities that need to connect to MV networks. This option is occasionally used in Germany.

Using Reactive Power Production Capabilities of Distributed Generation Plants

Some distributed generators are equipped with automatic voltage regulators that can absorb reactive power from the grid (underexcited operation) or provide reactive power to the grid (overexcited operation). Underexcited DG operation can be used to decrease connection voltage, while overexcited operation causes voltage increase. In Germany, this option is being used with increasing frequency as part of the long-term goal for distributed generating units to contribute to the voltage control of the grid. In the past, DG units were not usually capable of producing reactive power. Although the strong growth of DG did not directly cause any immediate problems with regards to voltage stability, it did create concerns about the potential risks in network with a high penetration of DG. To avoid or at least to reduce the corresponding risks, different technical rules were developed that include the requirement for DG capability to provide reactive power and to control voltage. Therefore, stricter technical requirements have

22 The disconnection point defines the normally open point in a network loop (see Figure 1a).

been implemented for DG units connected on the MV grid, requiring them to provide reactive power and control voltage to the grid. Furthermore, in July 2010, a leading industry association ("VDE-FNN")[23] presented a draft revision of the guideline for connection to LV networks that is expected to come into effect in mid- to late 2011. It invokes similar provisions to those that already exist for connection to the MV network and specifically requires the following reactive power provisions:

- Generators above 13.8 kVA will need to be capable of generating over a power factor range of 0.90 leading (overexcited) to 0.90 lagging (underexcited).
- Generators above 3.86 kVA will need to be capable of generating over a power factor range of 0.95 leading (overexcited) to 0.95 lagging (underexcited).

Construction of a New Substation

A new substation can be necessary if several components—transformers and grid lines—reach critical usage levels due to DG integration. The construction of a new substation implies extensive grid extension measures. It is the most costly option and is therefore avoided in Germany. However, this option may be necessary in areas experiencing an excessive concentration of DG expansion in one location, including preventing unacceptable voltage swings at existing substations as a result of planned DG interconnection. Some new HV/MV substations have been constructed in the northern part of Germany exclusively for DG (wind farm) integration.

Changes to the Grid Topology

Changes to existing grid topology can be costly and are typically carried out in Germany only if needed as part of a comprehensive grid expansion plan. While DG alone is not a trigger for changing grid topology in Germany, it is one of the many factors considered in long-term grid expansion planning.

Upgrade of the Rated Voltage Level

The rated voltage level of MV grids in Germany has been upgraded in some areas. In most cases, the upgrade was from 10 kV to 20 kV. These upgrades allow for a greater penetration of DG. However, when this option has been used, it was selected due to its compatibility with the overall grid expansion planning needs. DG has not been used as the sole driver for this option in Germany.

Installation of Supplemental Reactive Power Compensation

The implementation of supplemental reactive power compensation systems (such as, shunt reactors and flexible AC transmission systems or "FACTS"), is hardly ever used for controlling overvoltages on MV/LV grids in Germany. Whether the installation of more reactive power compensation systems in MV/LV grids will take place in Germany is unclear at this time.

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23 VDE is the Association for Electrical, Electronic & Information Technologies and prepares electro-technical standards and regulations. It is one of the largest technical and scientific associations in Europe. The Forum on Network technology / Network operation ("FNN") is a committee of VDE.

Implementation of Rotating and Nonrotating Energy Storage Systems

Energy storage systems can store output from fluctuating renewable energy sources at times when the output exceeds the needs of the grid, and the stored energy is released back into the grid at a later time when needed. However, storage systems have not been used in MV/LV grids in Germany for DG integration to date because the costs of such technologies are not economically justified. However, pumped-storage hydro projects have been used extensively on the EHV grid for regulating purposes. Future implementation of distributed storage systems for renewable integration on HV and MV grids is still considered to be a long-term possibility in Germany.

Most Frequent Application of Options in Germany

The most frequently used options are summarized in Table 5 and are categorized according to the most common reason for use.

Table 5: Most Frequently Used Options to Integrate Distributed Generation in Germany

Option	Grid overload	Critical voltage variation	Power quality issues
Direct connection to a substation		□	□
Upgrade of grid circuit conductors	□	□	□
Upgrade of upstream transformer capacity	□	□	□
Reduction of the grid circuit length		□	□
Relocation of the loop normally open disconnect point	□	□	
Set point adjustment of transformer automatic voltage control (tap changer)		□	
Using reactive power capabilities of distributed generation plants		□	
Construction of a new substation	□		

Source: KEMA

Automatic Curtailment Option

In general, the grid operators of MV/LV grids in Germany have not used automatic curtailment of DG as an option for expansion planning. However, this option has recently been under discussion. In this scenario the DG plant would need to be capable of automatically reducing its output in the event of specific overvoltage or overload condition, even without a remote control

signal from the grid operator (based only on local sensing). Technical rules have not yet been established for this potential option, but it might be implemented in the future as an option.

Grid Connection Costs

Cost for network connection may be split up into the following cost items:

- Costs for internal electrical installations in the power plant
- Connection of the generator to the network
- Grid upgrading measures[24]
- Other costs, such as, technical feasibility study and fees.

Costs for Internal Electrical Installations in the Power Plant and Grid Connection

According to the Renewable Energy Act (§ 13) the shallow pricing principle applies for network connection of renewable sources. Costs related to connection between the generator's plant and the default network connection point or another point chosen by the generator are borne by the generator. The generator also has to carry the cost for installing electrical devices, such as electricity metering devices or remote control (so far only applicable to nonsolar installations above 100 kW).

The network operator bears the additional cost that arises when assigning a network connection point different to the default/closest one. KEMA's research indicates that, in the majority of cases (about 75 percent of all cases), network connection is provided at the default point, either with or without short-term upgrade of the network infrastructure.

For connection of smaller DG units to the MV network, a fixed connection fee in the range of €500-1000 applies), or a sliding scheme with the fee being a function of the generator capacity to be connected. For connection of small units to the LV network, the fee is negligible, as for instance for PV the house service connection is in general used as connection point of the solar power installation.

Cost for Grid Re-enforcement and Extension

The network operator bears the costs of necessary network optimization, reinforcement, and extension. These costs includes the obligation of another network operator to carry out necessary network extension measures on its network as far as it is affected by a generator's network connection to an adjacent network not under its control.

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24 Including short-term measures (optimization of existing infrastructure, adapted procedures for energy management) and long-term grid investments (reinforcement and extension of existing transmission and distribution lines and substations, establishment of new transmission and distribution line substations, establishment of new voltage control devices such as capacitor banks or advanced SVC device, establishment of back-up capacity).

Other Costs

Large generators with more than 100 MW installed capacity have to bear the cost of feasibility and network stability studies required for preparing network connection. Relying on KEMA internal experience, the cost of the technical feasibility study carried out by the TSO is roughly €30,000 but may vary among different TSOs. This is, and will continue to be, of interest to large operators of offshore wind parks with installed capacity that exceeds 100 MW. Moreover, in the case of an affirmative answer to the application for connection, the applicant has to exercise a network capacity reservation fee of €1000/MW.

Recent Network Planning Policies and Studies in Germany

Even though the increasing production of renewable energy from distributed generating units affects the grid at all voltage levels, no fundamental changes in the approved grid structure and planning directives have been made to date. Technical guidelines have been developed to ensure a secure operation of the grid under all conditions while connecting DG in an economic, least-cost manner from the perspective of grid expansion options. Any large-scale grid expansion and redesign measures in the past have been driven primarily by overall long-term grid planning goals and not primarily by distributed or renewable generation. However, recent policy initiatives and studies in Germany suggest that a new grid investment paradigm may be developing. This is due perhaps in part to concerns over the level of dependence on nuclear resources in Germany's long-term energy plan and the possibility of significantly reducing this dependence through integration of even higher levels of renewables.

Most relevant to the current KEMA investigation, recently published German study reports conclude that a major increase in the scope of distributed and renewable generation would require considerable expansion of existing transmission and distribution networks. According to one major wind resource expansion study[25] completed in 2010, in the base renewable expansion scenario studied up to 3,600 km of new transmission lines are needed to accommodate renewable growth, particularly large offshore wind, by 2020. This would require about €1 billion/year in additional grid expansion costs for new transmission lines. Another expansion scenario considered increased use of high-temperature transmission conductors that would reduce the mileage of new lines to some 1,700 kilometers (km) but would also require some 5,700 km of existing lines to be modified. This scenario would increase the expansion costs to €1.6 billion/year, which is the highest of all the scenarios analyzed.

These results are complemented by another draft study by a major German industry association (BDEW), which quantifies the network expansion necessary to meet mid-term renewable policy goals and forecast.[26] It is based on a forecast by the Federal Ministry of Environment, which

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25 *Deutsche Energie-Agentur Network Study II – Planning of the Grid Integration of Wind Energy in German Onshore and Offshore up to the Year 2020* (Dena Grid study), 2010.

26 Draft report by the Federal Association of the German Energy Industry (BDEW), March 2011.

projects that by 2020 there will be another 52 GW of installed capacity added from solar power and smaller onshore wind parks (for example, an increase in DG and renewables comparable in magnitude to what was installed as of 2010).[27] Given this forecast, the BDEW draft study concludes that by 2020 Germany would need to build 195,000 km to 380,000 km of additional lines on the HV and MV distribution voltage networks. The associated capital cost is estimated to be €13 billion to €27 billion. Based on these latest study results, it can be concluded the majority of the low-hanging fruit has been picked in terms of under used grid capacity available for DG/renewable integration.

The German government has recently announced potential legal changes to the transmission planning process to accelerate the process and reduce the considerable time delays associated with siting and permitting new transmission lines.

Section 1.2 □ Current State of Physical Infrastructure in Spain

Regional and Quantitative Allocation of Renewable Energy in Spain

Basic principles for achieving sustainable development from an economic, social, and environmental point of view in Spain today include reducing dependence on foreign energy, better use of available energy sources, and a greater awareness of the environment. These goals increasingly demand the deployment of renewable sources of energy, increased efficiency in electric generation, and a reduction in greenhouse gases in accordance with the commitments acquired on signing the Kyoto protocol, by means of a search for energy-efficient generation of electricity.

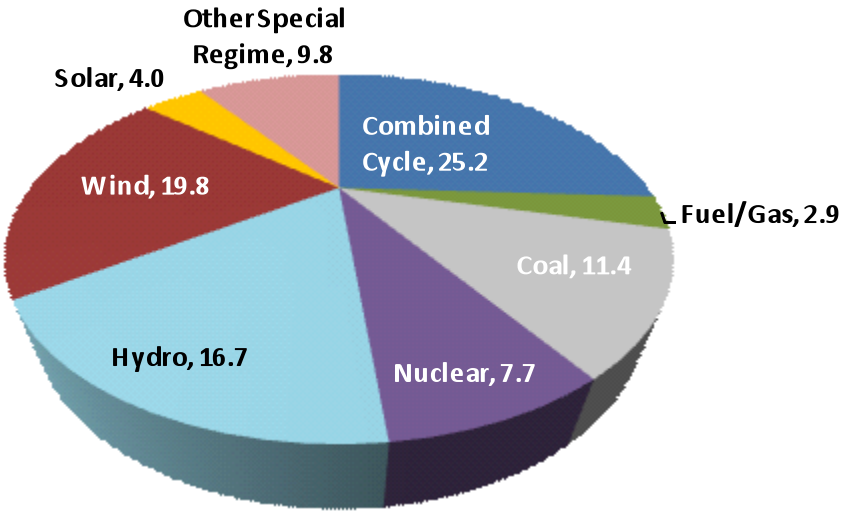
Targets for renewable energy and combined heat and power are covered in the Renewable Energy Plan 2005-2010 and in the Strategy for Energy Saving and Efficiency in Spain (E4), respectively. Electricity producers in Spain are subject to different legislation depending on the technology and energy source used. Producers are classified in two main groups: special regime (renewable energy sources) and ordinary regime (conventional power plants such as nuclear power stations). Creation of the special regime for the generation of electricity set an important milestone in Spain's energy policy. Although growth in the special regime for electricity generation has been outstanding, in certain technologies the targets are still far from being reached.

Renewable Energy Sources (RES) in Spain

Figure 8 shows a breakdown of the total installed capacity by technology at the end of 2010.

27 In addition to the 40 GW of renewables (excluding hydro) installed in Germany at the end of 2009, another 7.4 GW of solar PV was installed in 2010 bringing the total installed renewables to at least 47 GW (about 30 percent of 2011 peak demand), and raising the total installed solar PV capacity to about 18 GW (about 20 percent of 2011 peak demand).

Figure 8: Breakdown of the Total Installed Capacity by Technology at the End of 2010 in Spain[28]



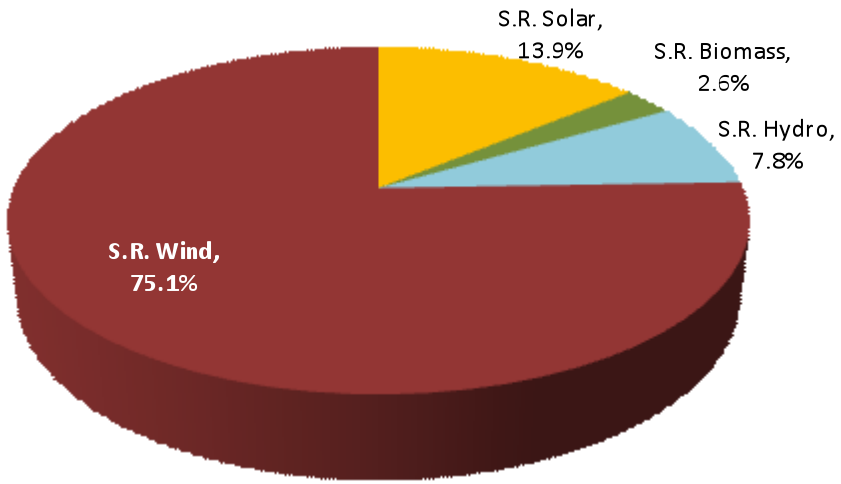
Source: REE (Red Eléctrica de España)

In 2010, Spain had a peak demand of 44 GW and a total installed electric power production capacity of 97.5 GW (peninsular system). The total installed capacity in solar and wind power production was 23.8 GW (24 percent of the total installed capacity) at the end of 2010. Next to combined cycle plants, which accounted for 25.2 percent of the total resource capacity, wind was the next largest block at 19.8 percent of total with an installed capacity of nearly 20 GW. About 40 percent of this wind generation is from projects smaller than 20 MW connected to the distribution system, and the remainder at the transmission level. There are also more than 3 GW from solar PV projects connected to distribution. Continued growth of distributed renewable generation seems unabated.

Figure 9 shows the share of the different renewable technologies to the total installed capacity in renewable electricity production for the special regime (displayed as S.R. in the figures below). Wind comprised more than 75 percent of total installed renewable capacity in 2009.

28 The category "Other Special Regime" includes cogeneration and waste-to-energy plants below 50 MW.

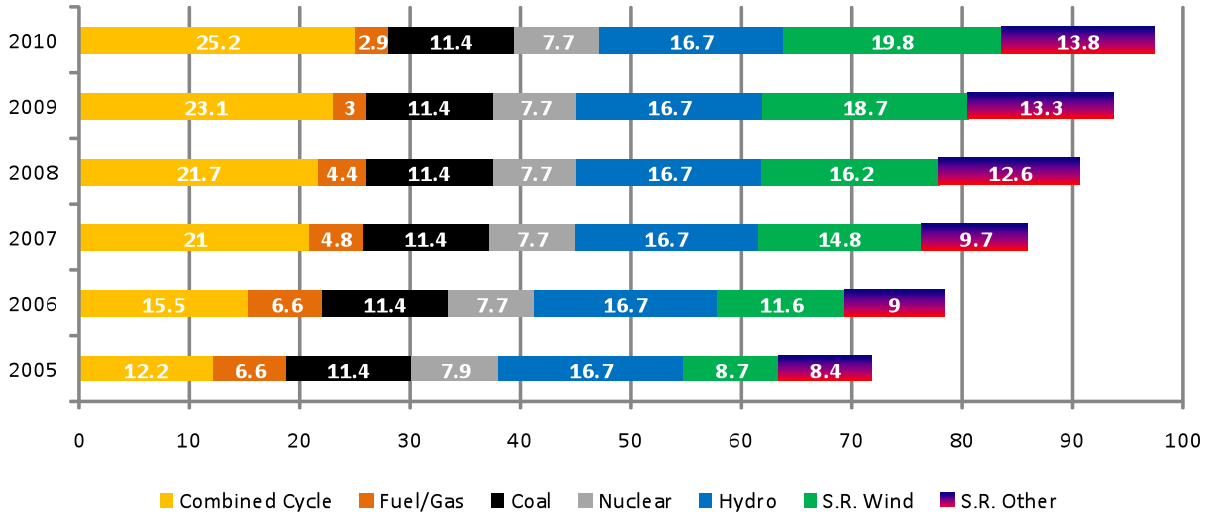
Figure 9: Breakdown of the Total Renewable Installed Capacity by Technology at the End of 2009



Source: REE (Red Eléctrica de España)

Figure 10 shows the annual evolution of the installed power by technology from 2005 to 2010 in Spain.

Figure 10: Annual Growth of Spain's Installed Power Generation (GW)

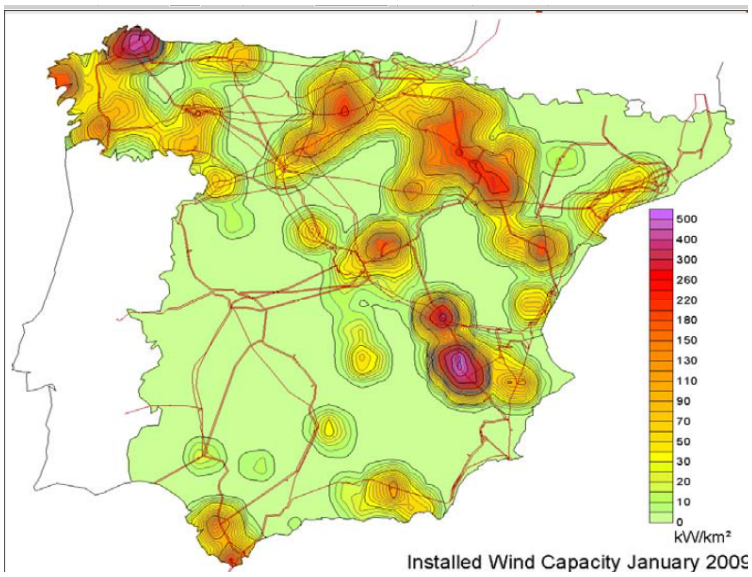


Source: REE (Red Eléctrica de España)

Wind Energy

Wind power is the renewable source that has experienced the largest development in Spain. The population density in large areas with good wind resource is much lower than in Germany, which has provided opportunities to build larger wind farms. The development has taken place through large investors such as electricity and construction companies. Recently, the trend is for nonelectric companies to sell their installations due to the increasing technical requisites in this sector. The development of the wind power sector goes in the direction of larger wind farms connected directly to the transmission grid due to the technical development of wind turbine technology and the available capacity in the transmission grid to transport more electric power, largely resulting in better prices. When the installed capacity of wind farms exceeds 50 MW, promoters developers divide the wind farm into several installations under 50 MW to get the highest payment. About 60 percent of the total installed wind power is connected to the 400 kV and 220 kV transmission grids, which is under the control of the national TSO. Of the remaining 40 percent connected to the distribution system, the majority is connected to MV 132/110/66 kV distribution grids, under the control of various DSOs. Only 2□5 percent is connected to radially operated distribution grids (30 kV and below). Wind power is distributed all over the country, but there is significant incidence of large wind farms in the northern regions of Galicia and to the southeast in Castilla-La Mancha. Figure 11 shows the installed wind capacity density (kW/km2) in Spain.

Figure 11: Wind Capacity Geographic Density in Spain



Source: REE (Red Eléctrica de España)

Spain's wind production is highly variable both hour by hour and day to day. For example, Spain's record high wind production was about 11:00 a.m. on February 24, 2010, at 12,916 MW, and the record low was on June 3, 2009, at 164 MW in the early afternoon. On most days, wind

production peaks at night and reaches a minimum between noon and 2:00 p.m. Downward ramps in wind production in the mornings often increase morning ramp-ups of conventional generation in the summer along with dispatch of pumped hydro plants. Some key facts about wind power in Spain:

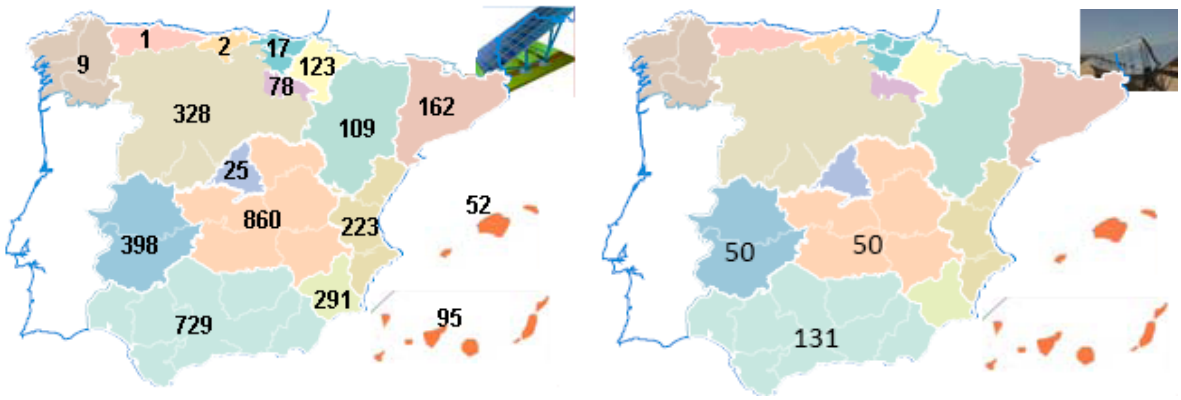
- Renewable energy plan for Spain (2005-2010): ~ 20,000 MW (accomplished)
- Official network renewable planning capacity target for 2016: 29,000 MW
- Further increase expected for 2020 in compliance with proposed EC initiatives
- Production records: 54 percent of demand at 3:50 a.m. on December 30, 2009

Solar Energy

Spain leads the world in the development of solar energy, as it is one of the sunniest countries in Europe. More than 95 percent of the total PV installed capacity is connected to the distribution grid (below 220 kV) as well as about 35 percent of the total thermal (conventional) installed generating capacity.

Figure 12 shows the distribution of solar PV and solar thermal power in the Spanish autonomous communities by the end of 2009. At this time, about 3.3 GW of solar PV was connected to the grid. While solar thermal is present only in the communities of higher solar radiation exposure, such as Andalucia, solar PV is much more uniform along the country, although still dominated by the southern communities.

Figure 12: Installed Solar Power (MW) in the Autonomous Communities of Spain by End 2009



a) b)

a) PV and b) Solar Thermal

Source: REE and ASIF (Associacion Industrial Fotovoltaica)

At present, the TSO has no remote monitoring or remote control capability for any of the 3.3 GW of PV power generation because telemetry to the TSO is required only for DG projects of 10 MW or larger, and there are no PV projects of this size in Spain. Of this 3.3 GW of PV, roughly

2.7 GW is consists of PV systems in the 5-100 kW size range while the remainder is composed of systems above 100 kW. As the installed MW of solar PV expands, the lack of telemetry on these projects will create greater operating problems for the TSO.

Another concern is that Spain's winter peak demand is in the evening when PV makes no contribution. However, there is clear potential for integrating concentrating solar power in combination with the use of molten salt energy storage and hybridization with natural gas[29] to produce solar-powered generation during the winter peak demand hours.

Due to the large share of Spain's resources that come from nondispatchable wind generators, the country has implemented a centralized national wind generation control center, which is discussed in more detail later in the report. Another measure implemented by Spanish DSOs to avoid potential detrimental impacts on the distribution grid is an arbitrary cap on DG expansion at 50 percent of each respective area's peak demand.

Renewable Energy Source Compensation Arrangements in Spain

Renewable energy source (RES) revenues can be determined by one of the two following alternatives:

- FIT: The price paid per each kilowatt-hour (kWh) produced by a RES installation is regulated and fixed to a constant value, independent of market fluctuations. The annual evolution of this tariff depends on the evolution of the average reference electricity tariff (RT) in Spain as FITs are set as a percentage of the RT. The tariff is fixed for a certain contract duration (for example, 15 years). The regulated FIT for each RES technology depends on the type of the technology and on the year when the installation is put on service. This alternative is a heritage of the previous regulation. RES facilities greater than 10 MW are committed to give to DSOs a production schedule 30 hours in advance, being allowed to adjust such schedule 1 hour ahead of each intradaily market (six calls during a day). Hourly energy deviations from the production schedule are penalized at a price per kWh deviated equal to 10 percent of the RT. This penalization does not apply in a dead-band of 20 percent of the production scheduled for RES facilities. This rule, which implies a big change in RES regulation from the previous framework, will apply to wind farms only since January 1, 2006. As the government RES targets are reached, the FIT decreases. When the FIT contract period for a given RES project is over, its energy is sold at the market (pool) price.
- Wholesale market: Renewable energy sources are given incentives to join the wholesale market, following in this case practically the same rules as ordinary generators. As the RES will face new technical and economic constraints by doing so, their remuneration scheme provides an additional economic incentive. The total income is the sum of the

29 Hybridization with natural gas is limited by Spanish regulations to 15 percent of solar thermal plant capacity, whereas hybridization with biomass or biogas is allowed up to 50 percent.

market selling price, plus a premium that represents the externalities in a similar way to previous regulation, plus the above-mentioned additional incentive to access the market. The premium and the additional incentive are set also as a percentage of the RT. As renewable energy sources are integrated in the wholesale market, they have access to all the rest of electricity markets (daily, intra-daily, ancillary services). They can earn money if they are able to participate in such markets or pay if they use such services, being the most important the cost of production deviations from the predictions. In this case, there is no dead-band, and the price is settled through market mechanisms.

Since March 2004, RES in Spain has had an additional revenue component associated with supply or consumption of reactive power that depends on the period (peak, shoulder, or off-peak hours), and can be positive or negative, depending on the power factor the unit is providing. The bonus can be as large as 8 percent of the price of active power for producing with a power factor below 0.95 (leading) in peak hours, or a penalty of 4 percent for consuming reactive power in peak hours at a power factor below 0.95 (lagging). This income encourages RES to consume reactive power (lagging power factor) in valley hours and to supply reactive power (leading power factor) in peak hours. In previous regulations there was an incentive to keep the power factor equal to one.

An interesting aspect of current Spanish legislation is the economic incentive that has been put in place for wind farms that have low-voltage-ride through (LVRT) capability that enables them to remain on line during transient faults on the grid. This performance feature is important for maintaining grid stability. In fact, on January 19, 2007, three successive grid disturbances led to tripping of 500 MW, 400 MW, and 1000 MW of wind farms, respectively. To reduce the associated risk of such events, Spain has is an economic incentive of 5 percent of tariff for each kWh sold by wind parks with LVRT capability, which is paid only during the project's first four years of operation. For wind farms that were in operation before January 2008, there is an economic incentive of 3.8 € per megawatt-hour (MWh) produced for a period of five years if they add LVRT capability. However, wind farms that started operation after January 1, 2008 are required to comply with the fault-ride-through regulation to obtain permission to interconnect to the grid. As a result of these measures, the capacity of wind farms in Spain without LVRT capability dropped from about 13.5 GW in 2007 to less than 3.5 GW by 2009.

Overall System Planning and Development in Spain

In May 2008, the Spanish Ministry of Industry, Trade and Tourism passed the 2008-2116 planning document for the gas and electricity sectors to ensure the safety and quality of the energy supply. This plan sets out a substantial program involving the construction of new power installations.

Red Eléctrica de España (REE), the Spanish corporation that operates the nation's power transmission system and electricity grid, is carrying out investments aimed at reinforcing the grid to cover increases in demand in some areas of the mainland and to promote the installation of new generation, mainly combined cycle and wind-power plants and, to an increasing extent, solar thermal plants.

In the following sections, the research team presents the main voltages of the transmission and distribution networks in Spain. The team then addresses the most frequently used technical options and facilities to manage the integration of renewable energy sources and thereby to comply with technical requirements and guidelines.

Network Structures in Spain

The Spanish grid operators in recent years have developed technical rules and guidelines to maintain secure network operation with large amounts of renewables. The Spanish Ministry of Industry, through the Institute for Energy Diversification and Saving (IDAE), has developed the website Renovables (Renewables) Made in Spain, http://www.renovablesmadeinspain.com/ to inform the world about the significant penetration of renewable energy in Spain and the leadership of Spanish companies and organizations that have made this possible.

This part of the report describes the basic technical configurations of Spanish distribution grids including substations and secondary substations. The analysis focuses on MV/LV distribution grids. It also outlines relevant aspects of DG at higher voltage levels in Spain.

Grid and Voltage Levels in Spain

The Spanish power grid at all voltage levels is a three-phase alternating current grid operated at a frequency of 50 Hertz. Four common voltage levels have been established in the Spanish power grid as shown in Table 6. This classification of voltages is according to the IEC definitions.

Table 6: Overview of Voltage Levels in Spain per IEC Definitions

System Name *(IEC Definition)*	Abbreviation	Rated Voltage	Role
Extra-high voltage	EHV	400 kV, 220 kV[30]	Transmission grid
High voltage	HV	132 kV, 110 kV 66 kV, 45 kV	Distribution grid
Medium voltage	MV	30 kV, 20 kV, 15 kV, 13.2 kV, 11 kV	
Low voltage	LV	400 V	

Source: KEMA, Inc.

30 In the past, the DSO's controlled parts of the 220 kV network, but it has mostly been moved to the TSO.

Spanish legislation (Royal Decree 223/2088) gives a similar classification for lines above 1 kV:

- Special category: Lines of nominal voltage above or equal to 220 kV, or the ones of lower voltage that are operated by the TSO.
- First category: Lines of nominal voltage below 220 kV and above 66 kV
- Second category: Lines of nominal voltage equal to or below 66 kV and above 30 kV
- Third category: Lines of nominal voltage equal to or below 30 kV and above 1 kV.

The characteristics and functions of the main voltage levels are discussed below.

Transmission System in Spain

The typical voltage levels for the transmission grid in Spain are 400 kV and 220 kV. The international connections are also considered as a part of the transmission system. REE is the national TSO and owns about 99.8 percent of the 400 kV power lines and 98.5 percent of the 220 kV power lines. According to current Spanish regulations all 220 kV still owned by DSOs must be transferred to the TSO.

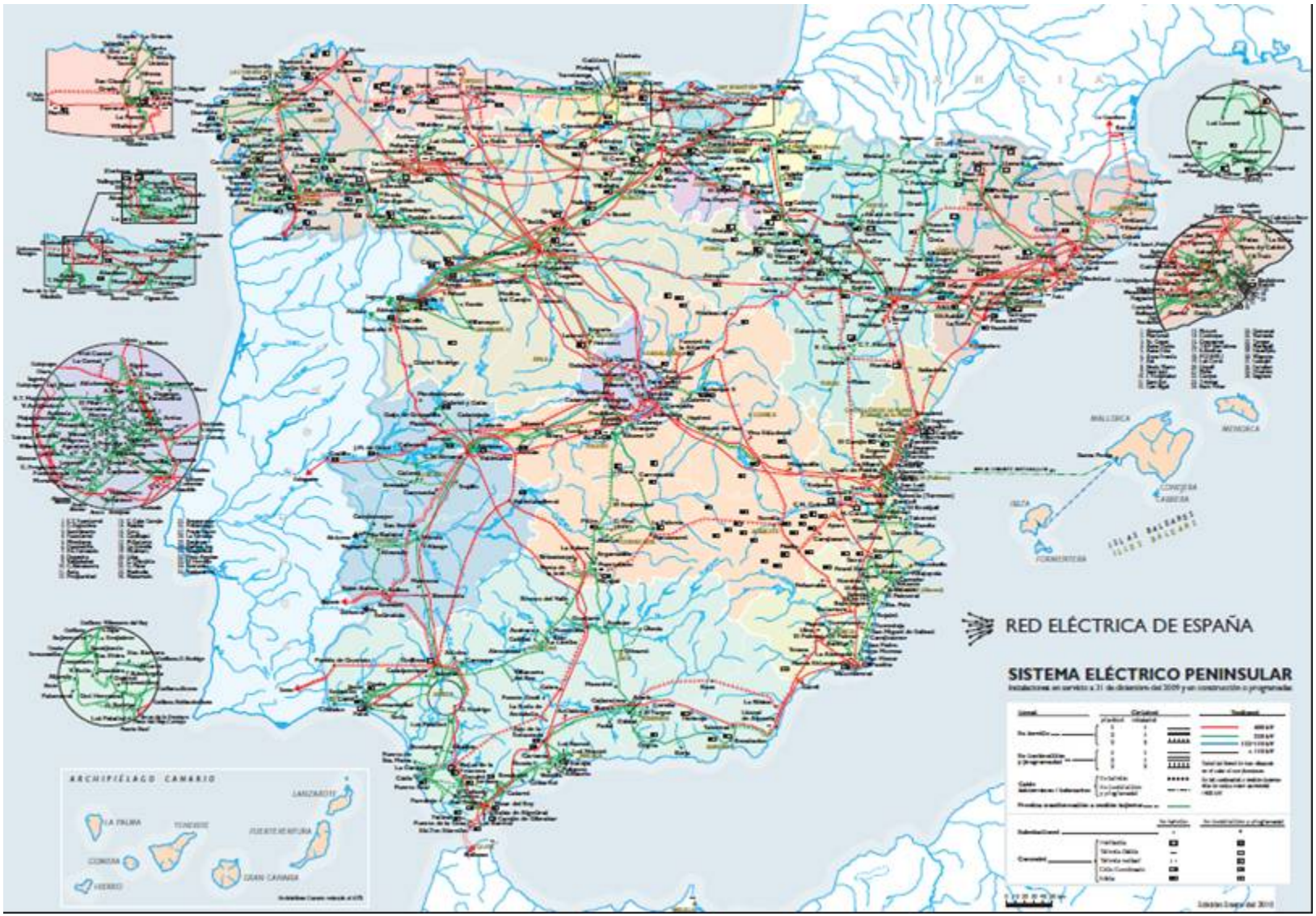
The Electricity Sector Act 54/1997 confirmed the role of REE as a cornerstone of system operation. This law created a wholesale power market that required an effectively managed transmission grid to work properly and a coordinated operation of the generation-transmission system to ensure that demand would be satisfied at all times.

Act 17/2007 of 4 July in Spain amended the previous law to adapt it to European Directive 2003/54/CE, which established the common guidelines for the domestic power market. This law has resulted in the definitive consolidation of the REE's TSO model. In this regard, REE, as the system operator, guarantees the continuity and security of the power supply and the proper coordination of the production and transmission system, performing its functions based on the principles of transparency, objectivity, and independence.

REE is not just the manager (operator) of the transmission grid, but likewise has exclusive responsibility for development and maintenance of the grid. This is different from the German case where several transmission grid owners and operators coexist.

Like Germany, Spain is part of the European Network of Transmission Operators for Electricity (ENTSO-E) and therefore operates according to rules in the Operation Handbook of ENTSO-E. The transmission grid is a meshed system with high standards for system stability (frequency, voltage, dynamic stability) and security of supply. Overhead lines dominate the grid infrastructure. Figure 13 illustrates the Spanish transmission system with 400 kV lines represented in red and 220 kV lines represented in green.

Figure 13: Spanish Transmission System



Source: REE (http://www.ree.es/transporte/mapa_red_transporte.asp)

Distribution System in Spain

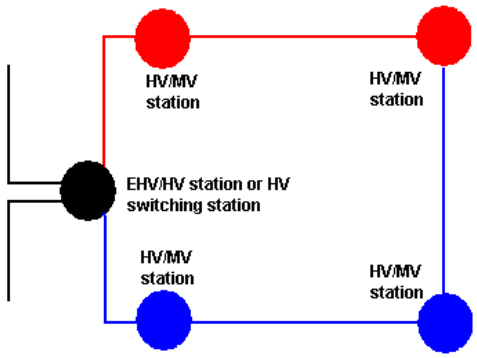
The typical distribution voltage levels in Spain are 132 kV, 110 kV, 66 kV, 45 kV (HV), 30 kV, 20 kV, 15 kV, 13.2 kV, 11 kV (MV), and 380 V (400 V in the latest regulation, Royal Decree [RD] 842/2002, LV).

In Spain the main DSOs are Iberdrola, Endesa, Gas Natural Fenosa, Hidrocantábrico, and E.On with a market share of 40 percent, 39 percent, 15 percent, 2.5 percent, and 2.5 percent each, which combined represent 99 percent of the total distribution activity. DSOs in Spain do not buy or sell electricity. They are responsible only for building, operating and maintaining distribution networks. All purchase and sale of electricity are left to trading companies.

HV Distribution Grid in Spain

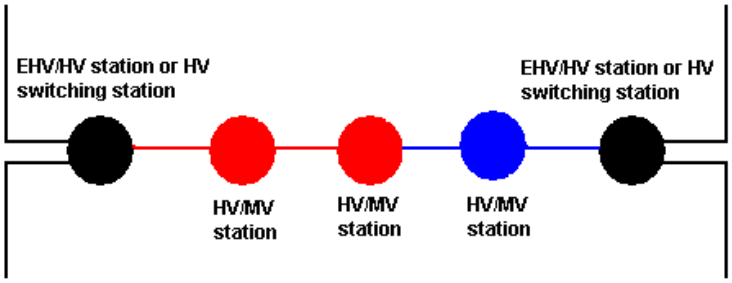
Spanish HV grids are of meshed topology (more or less complex) and can be operated in a meshed philosophy (closed loop) or radial (open loop). The exception are a few radial built networks in rural areas, but even in these areas the most common topology is the open loop, so there is possibility of support through a second line. This grid is used to feed the distribution substations that are connected to the MV grid. The layout of the HV bus bar of these distribution stations depends on the area they are built. Most of the HV grid complies with n-1 security criterion (for transformers and lines). Security criteria n-2 can be applied for HV grids associated to urban areas, when there are, for example, substations fed by critical double circuit lines. Figure 14 through Figure 18 illustrate different network topologies applied at the HV level in Spain.

Figure 14: Looped HV Grid (Single Source Point)



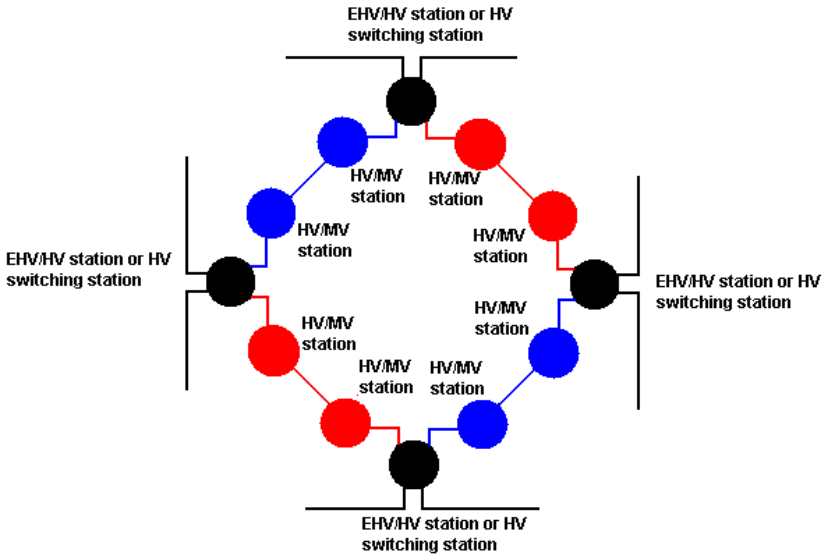
Source: KEMA

Figure 15: Bridge Configuration (HV Grid Fed From Two Points)



Source: KEMA

Figure 16: HV Mesh Configuration



Source: KEMA

MV Distribution Grid in Spain

The Spanish MV grid in Spain is differentiated by urban, semi-urban, and rural areas that have different power quality, reliability, and continuity of supply requirements.

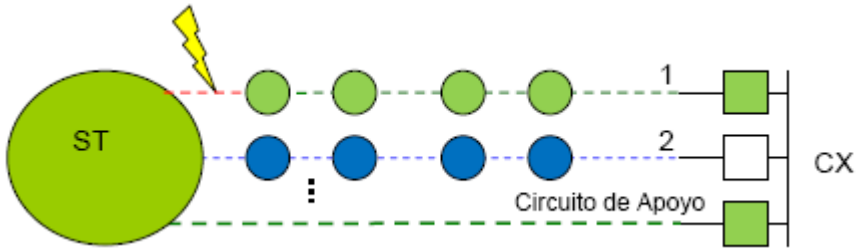
Urban Medium-Voltage Grids: Urban MV grids in Spain serve high-density urban areas fed by underground cables. The typical cable cross section is 240 to 400 mm² (nominally equivalent to a range of 400 kcmil to 750 kcmil), but there is a significant variation in the range of cable sizes especially in the large cities due to changes in planning criteria and network design standards over the decades.

The design philosophy of MV grids in Spain is to serve the MV/LV stations in a way they can always be fed from at least two points. The goal is to avoid placing MV/LV stations on single, radial MV sources. This goal is achieved by applying mainly two standard network designs:

- Reflection point and support circuit
- Distribution point.

Figure 17 illustrates the concept behind the reflection point and support circuit design. The idea is to have a normally open backup circuit (Circuito de Apoyo) that, in case of fault, one of the main feeders will be able to close into the reflection point and feed the load on the healthy portion of the faulted feeder after the fault has been isolated by remote controlled switches. These switches are associated to Ring Main Units (RMUs) in the MV/LV stations (circles in the figure). In the example shown in Figure 17, a fault (indicated by the lightning bolt) has occurred on the first section of Circuit 1 near the source station (ST), which has been isolated and the remainder of the circuit load picked up from the reflection bus via the backup circuit. (Green indicates a closed breaker, and white indicates an open breaker.)

Figure 17: Urban MV Grid: Reflection Point and Support Circuit Design[31]

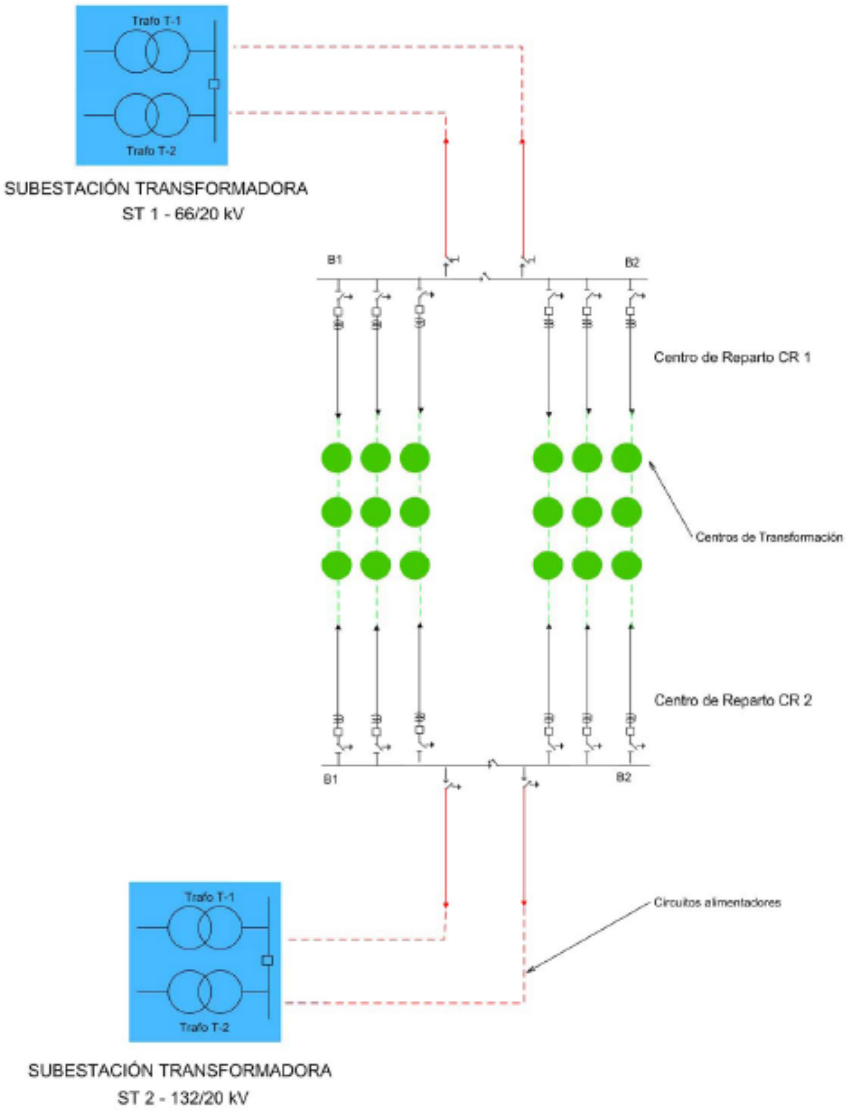


Source: Universidad Pontificia Comillas: Master Thesis by Trinidade Moya

Figure 18 illustrates the distribution point design that is used mainly in high-density load areas. Reliable distribution centers are built as close as possible to the load center, and two or more high-capacity trunk feeders (circuitos allementadores) are constructed from the remote HV/MV transformation substations to the distribution centers. No load is connected directly to the trunk feeders. Multiple distribution circuits emanate from each distribution center and feed multiple MV/LV stations, each containing one or more 400 kVA transformers, within the high load density area. Figure 18 illustrates a configuration with two such distribution centers, but other combinations can be used.

31 "ST" means substation. "Circuito de Apoyo" means backup circuit. "CX" means reflection point a bus with circuit breakers and ground switches used to ground the circuits when the breakers are open.

Figure 18: Urban MV Grid: Distribution Point Design[32]



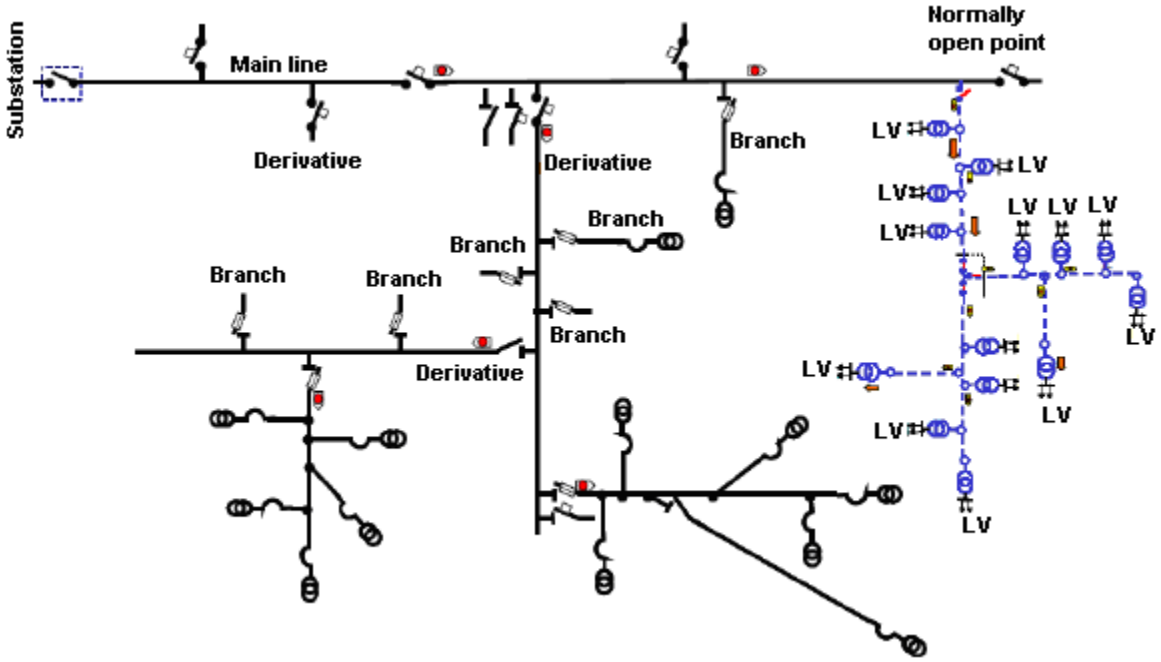
Source: Universidad Pontificia Comillas: Master Thesis by Trinidade Moya

Rural MV Grids: Spain has made a differentiation between concentrated and dispersed rural areas. Both are fed mainly by overhead lines, though dispersed rural areas have longer lines, commonly causing voltage drop problems related to the large impedance of the long overhead lines. The design normally consists of a main feeder with the same conductor cross section over its full length, from which several derivative feeders (branches) are supplied—typically with smaller conductors.

32 "Centro de Reparto CR 1 and 2" means "Distribution Centers No. 1 and 2"; "Subestaciaon Tranformadora" means Transformation Substation; "Trafo T-1 and T-1" mean Bank 1 and 2.

Unlike urban areas, MV/LV stations in rural areas are usually supplied from a single circuit rather than a looped supply. Similar to the United States, the rural MV networks in Spain are equipped with switches along the lines (reclosers and sectionalizers) to more efficiently isolate faulty sections and restore the supply to the healthy ones. The rural MV network can typically be fed from either the primary source or an alternative backup source, which is connected through a normally open tie point. This allows the restoration of supply to at least some of the circuit in the event of faults on the main distribution line/source. The typical Spanish rural MV grid structure is illustrated in Figure 19. As shown, radial LV networks are supplied by MV/LV transformers connected at various points on the MV grid.

Figure 19: Rural MV Grid Structure

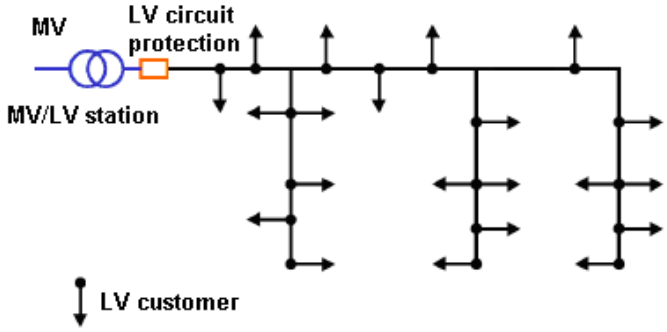


Source: KEMA

LV Distribution Grid

The LV grid is a three-phase 400 V system, including a neutral wire. These LV grids in Spain are built and operated in a radial fashion, regardless of whether they are in an urban or rural area. Urban grids are dominated by underground cables, while rural grids are dominated by overhead lines. Rural grids are more exposed to voltage deviations (drop or rise) due to their higher per unit impedance combined with longer length. The typical Spanish LV grid structure is illustrated in Figure 20.

Figure 20: LV Grid Structure



Source: KEMA

Distributed Generation

In recent years DG has received increasing attention as it can contribute to the various goals of EU energy policy. Enhanced diversity of supply, a reduction in greenhouse gas emissions, efficiency gains, and more flexibility in investments are some of the major benefits associated with DG. However, when the amount of distributed electricity supply of RES surpasses a particular level, it can no longer be ignored in planning and operation of the electricity supply system. Therefore, improvements of the regulatory framework of the electricity supply systems are required along with the growth of the electricity supply from DG.

Generally, DG comprises generation plants that are connected to LV/MV distribution grids close to energy consumers and generation plants for self supply. However, this definition as such is not used in practice in Spain. Although there are different remuneration schemes for generators of different size, which therefore will be connected to distinct voltage levels, the main split in Spain is made between the so-called ordinary and the special regime. The technologies eligible for special regime are cogeneration, RES, and waste. According to the Spanish law RD 661/2007, the RES group is divided in eight subgroups as follows:

- b.1: solar energy
- b.2: wind energy
- b.3: waves, geothermic, tides
- b.4: and b.5: hydropower
- b.6, b.7, and b.8: biomass and biogas

Installations with an installed capacity larger than 50 MW are not included in the special regime. However, if these installations produce renewable energy they receive a premium equal to that paid to smaller renewable projects (such as, those less than 50 MW) but discounted by 20□80 percent. Due to this financial disincentive, there are no individual renewable energy projects in Spain with installed capacity over 50 MW.

Point of Common Coupling (PCC)

The definition of PCC in Spain is similar to Germany, such as, it is the grid connection point of a generation plant. Its location depends on the rated power of the generation plant and technical and economic aspects of the power grid (voltage level, utilization of assets, and network impedance). The process for determining the PCC and related grid upgrades in Spain is less rigid than in Germany, and DG cost responsibilities are also more subject to negotiation.

General and Technical Interconnection Requirements in Spain

RES producers that wish to connect at the EHV level must connect a minimum capacity of 100 MW at any one point of interconnection to the 220 kV grid or at least 250 MW at any point of connection with to the 400 kV grid. It is possible for several smaller project developers to apply jointly to the TSO to fulfill this requirement. RD 436/2004 defines additional criteria and is stated again in the RD 661/2007 (annex 11) with some modifications:

1. The combined capacity of all special regime generators connected to one line of the distribution grid cannot exceed 50 percent of the capacity of the line.
2. The combined capacity of all special regime generators connected to one distribution substation or substation transformer cannot exceed 50 percent of the capacity of the respective substation or transformer serving that voltage level.
3. For producers without storage capabilities or not able to directly manage their output, such as wind power and PV producers, it is also established that the MW capacity of the producer or group of producers sharing a connection point (the PCC), will not exceed 5 percent of the grid short-circuit duty (at that point on the system) expressed in MVA. For dispatchable generators (biomass, solar thermal), the MW capacity shall not exceed 10 percent of the grid short-circuit duty (at that point) expressed in MVA. This is intended to limit the maximum voltage deviation due to DG operation to the range of 5-10 percent of the local grid's nominal voltage.

For the time being, an installed DG cap of 50 percent of peak load in any given area of the system is being used by the DSOs as a proxy for above Criteria 1 and 2 to prevent back-feed. Because of such limitations on DG, very few back-feed situations have developed in Spain. In practice, the above criteria restrict only the connection to the distribution grid and not the connection to the transmission grid. Based on utility experience regarding connection to the distribution grid, Criteria 3 is limiting in about 90 percent of the cases.

Photovoltaic plants smaller than 100 kVA and connected to low-voltage networks (below 1 kV) have specific connection requirements enacted in the RD 1663/2000. The most relevant requirements of this legislation are the obligations to maintain voltage at the interconnection point at ± 5 percent of the nominal voltage and operate at a power factor as close as possible to unity.

Implications on Power Grid Operation

The national TSO (REE) has historically experienced routine wind generation farm tripping events due to voltage dips and has been monitoring voltage and generator performance since 2005. As noted, Spain implemented LVRT requirements for wind generators in 2007, and most existing plants have made the necessary retrofits to comply. Some 1,000 MW to 1,500 MW plants still need to be adapted.

In addition REE runs real time simulations to model grid fault scenarios at 70 key locations on its 400 kV system. These simulations allow the TSO to determine the amount of wind generation that is at risk of tripping for such events and thereby to take actions such as pre-emptive wind generation curtailment to ensure safe system operation and avoid the risk of widespread wind generation tripping.

Steady-state voltage control also presents a concern to REE in areas where a large penetration of renewable generation exists. As noted, REE has instituted a system to offer incentives for renewable generators to provide reactive power and issues instructions to renewable producers to modify their power factor settings. Specifically, in March 2004, legislation was passed to offer incentives to renewable generators to provide reactive power. Generators receive a bonus or suffer a penalty of +8 percent to -4 percent of the active power price, based on the power factor at which they operate. Since 2007, these percentages are applied at the fixed reference price value of 78.44 €/MWh.

Since April 1, 2009, REE has also ordered all DG units above 10 MW to operate at power factors between 0.98 and 0.99 inductive ("lagging") to eliminate sudden changes in the voltage profile and avoid high voltages. REE believes that the ultimate solution is to enable voltage scheduling capability for all generators greater than 10 MW. A key issue that remains to be resolved is when and how to automate DG voltage control and whether this requires a local, regional, or national control system structure.

Connection Process to Transmission Network in Spain

Connection Application Phase

There are two stages, according to P.O 12.2 of REE:

- 1 - Request for access to the transmission grid.
- 2 - Request for connection to the transmission grid.

For Stage 1, the generator must submit a request for access to a specific network location (node) and supply a variety of technical data about its generating plant from rated power to PSS/E control block models for dynamic analysis. REE also requests the seasonal generation patterns. It is a complete set of data on the generating unit, which is complemented with data on interconnection lines and also with data on step-up transformers. Furthermore, there are different requests, depending on the generation technology. REE P.O 12.1 annexes list all the necessary data for different generation technologies. After receiving the request for access accompanied by the generator data, the Spanish TSO has two months to determine if the system capacity will support the connection. If so, the generator advances to Stage 2.

At Stage 2 the generator must submit the basic design of its installation, the construction program, and a report showing that the installation fulfills all the connection requirements in "Instalaciones conectadas a la red de transporte: Requisitos minimos de diseño y equipamiento." This document defines protection requirements, grounding requirements, and switchgear arrangements. The generator has one month to deliver these documents after receiving a positive Stage 1 approval. In turn, the TSO has one month to decide if the generator's documentation is adequate.

The generator does not have to perform any studies itself, since the studies are carried out by the TSO using data supplied by the generator. The generator is free to ask the TSO for information about a particular location or node of the grid if he wishes to perform his own studies to evaluate the feasibility of the interconnection in a given node. The (deciding authority) uses the TSO studies for its decision.

If the State 1 proposal fails, the generator can propose alternative connection points or request information on the grid reinforcement costs necessary to eliminate the restrictions. If the developer is willing to pay for these reinforcements, while advancing to Stage 2, he must pay upfront for 20 percent of these costs.

Commissioning Phase

Two months before the planned interconnection date, a generator connecting to the transmission grid must provide the TSO with a test program and the dates for first interconnection and start of commercial operation. Generators must conduct specific tests, taking into account the expected absorption/supply of active and reactive power. The generator must also provide a single line diagram of the installation, including ancillary services. He must provide updated information on the installation according to P.O. 9 of REE. P.O. 9 asks for information necessary for real-time operations; so along with standard generator characteristics, it includes information on control systems such as islanding ability. The information to be supplied varies with the generation technology.

The TSO must plan the commissioning date of the interconnection facility, taking into account the necessary outages and their effect on network security. Once a date is established, the TSO is responsible for scheduling a meeting with the generator where the following aspects will be clarified with the relevant stakeholders:

- Necessary outages
- Network situation before commissioning of the generator
- List of tests and actions associated to each phase of the commissioning along with verifications
- Network situation after generator commissioning is finished
- Intermediate configurations during the commissioning stage
- Future generation operating conditions
- Impact of the new generator on network black-start and recovery plans

The relevant studies are made by the TSO, so there is no need to validate modeling from the generator. However, in the public documents there is no reference to a network model validation method. It seems the TSO does not have to prove the validity of his models. If there is noncompliance, the generator cannot begin commercial operation and is given the opportunity to correct the problems and repeat the tests. The process will happen as many times as necessary until there is compliance with all aspects demanded by the TSO.

Connection Process to Distribution Network in Spain

The special system's connection process to the installation network has six phases (excluding Project Execution), ending with the invoicing process, as shown in Figure 21.

Figure 21: DG Connection Process

Source: KEMA

The phases of this process differ depending on whether the installation is photovoltaic or another type (wind, solar thermal, small-scale hydro, cogeneration, biomass, or waste).

RES Installations (Nonsolar)

For installations contemplated by the special regime that are not photovoltaic, the phases for connecting to the network are as follows:

Request by the Developer

The developer formalizes a guarantee to the Autonomous Community for €20/kW. The developer must request a connection point from the distributor. The distributor issues a report that includes the connection point requirements. The developer notifies the distributor that it is in compliance with the report and connection point requirements.

Approval of the Project by the Autonomous Community

The developer, when applicable, requests administrative authorization and presents the basic project and execution program. The developer will present a copy of the request for administrative authorization and proof of presentation to the Autonomous Community of the basic project and execution program. The developer grants administrative authorization and approval of the project.

Connection to the Network

The distribution company formalizes a technical contract with the producer and issues a certificate of reading if the installation's power is less than or equal to 450 kW, as well as a certificate of access and connection. If the DG is larger than 450 kW, their meters and interconnection must be certified by the TSO.

Contracting

If the connection occurs at the HV level, the developer must formalize the supply contract with an authorized commercialization company. For a LV connection, the developer must contact the distributor to formalize the supply contract. The developer signs the supply contract. The terms of this contract are regulated by the Ministry of Industry and apply for at least five years. The contract has to specify the following:

- Location of metering devices and connection point to the network. It also has to specify the characteristic of control, protection, and metering devices
- Estimations of the expected volume of sold energy and, when applicable, energy consumption, specifying maximum demand and production
- Possible causes for modification and cancellation of the contract
- Technical aspects of the interconnection, such as circumstances in which the distribution company will not be able to absorb the energy production
- Economic terms and conditions, which includes the chosen alternative for selling the energy and the agreement on how to remunerate the DG for production of reactive power (if applicable). The distribution company must pay within 30 days of receiving of each bill.

The distribution company must sign the contract in the three months after the agreement on the location and technical conditions, even if the RES generator does not supply energy. The distribution company has to pay RES all the items corresponding to the special regime (premiums and economic incentives) in the 30 days after it receives the bill. If the distribution company does not pay during this period, it has to pay a penalty of 1.5 percent of the bill.

Installation of Metering Equipment

Metering equipment may be owned by either the developer or the distributor. Some distributors provide the option of renting this equipment (except equipment connected to LV installations with a power exceeding 15 kW). Installations having a rated power output greater than 15 kW are required to be equipped with remote telemetering equipment, but remote control is not required. The distributor inspects and seals the metering equipment. The developer provides a copy of the definitive inscription in the Autonomous Community's Registry of the Special System.

Photovoltaic Installations

Below is summary of the requirements and procedures that must be in compliance with producers of the special system in the event of photovoltaic installations.

Request by the Developer

The developer, when the installation is based on the ground, must formalize a guarantee to the Autonomous Community for €500kW (excluding roof-based installations). The developer asks the distributor for a connection point. The distributor issues a report with the connection point requirements. The developer notifies the distributor of its compliance with the report and connection point requirements.

Approval of the Project by the Autonomous Community

The developer, when applicable, will request administrative authorization from the Autonomous Community and present the basic project and execution program. The developer will present the distributor a copy of the request for administrative authorization and proof of the presentation. Lastly, the developer will present the distributor with the administrative authorization and project approval granted by the Autonomous Community.

Connection to the Network

The distribution company will issue a connection contract and certificate of meter reading, if the installation's power is up to 450 kW, and a certificate of access and connection. If the DG is larger than 450 kW, their meters and interconnection must be certified by the TSO.

Contracting

In the case of high-voltage connections, the developer must contact an authorized selling company to sign the supply contract. In the case of a LV connection, the developer must contact the distributor to formalize a supply contract. The developer signs the supply contract. The terms and conditions of this contract are similar to the ones applicable for other RES.

Installation of Metering Equipment

Metering equipment may be owned by either the developer or the distributor. Some distributors provide the option of renting this equipment, except DG installations larger than 15 kW that are required to be equipped with remote meter reading equipment.[33] Also, for PV projects, bidirectional meters are required for both active and reactive power. The terms and conditions of the contract are similar to the ones applicable to other RES.

Main Reasons for Success of RES in Spain

There have been two steps in the promotion of RES in Spain. The second step has just begun, so it is only possible at this time to judge the first step's results (RD 2818/1998). In this initial scheme, special regime generators had fewer technical obligations, had the right of selling all their production, and were economically supported through a feed-in-tariff or market price plus a premium. The results depended on the economic support level and on the administrative authorization process.

The results show that expansion of wind has been a success in terms of installed capacity. However, there are some regions of Spain where wind development has been completely blocked until an official wind plan has been developed, while other regions have just begun to give the mandatory authorizations to promoters.

There are around 30,000 MW of additional wind installed capacity in different stages of registration as special regimes. This does not mean that all of them will be built and operated,

33 These billing meter requirements should not be confused with the real-time telemetry required on units of 10 MW and above by the grid operator.

but it gives an idea of the strength of wind expansion in Spain. It appears that only administrative barriers or technical limits of integration can stop the expansion of wind resources on the Spanish grid.

On the other hand, the level of development to date of other RES technologies is still not considered satisfactory by the government, and it is unlikely that proposed targets for those categories will be reached.

Remaining Barriers to Development of DG in Spain

The main stakeholders (renewable developers and DSOs) have identified several barriers to full development of renewable technologies in Spain:

- Technical requirements:
  - Connection standards (particularly short circuit limits) are viewed as conservative by promoters and, in many cases, require them to connect at a higher voltage than originally planned.
  - Monitoring and communication devices may represent a barrier in case of trying to access the market.
  - In the case of wind generator, its ability to cope with voltage/frequency dips without tripping may become essential.
  - Network capacity for delivery of renewable energy: Renewable resources, especially wind parks, are not always situated near the electrical network and may require construction of high voltage lines. The approval process for line construction can be slow due to environmental issues, and delays in construction may be as long as five years.
  - The DSOs perceive DG as an added complexity in their networks that do not provide any economic benefits and bring additional operational and planning problems such as: grid operation and maintenance personnel safety; impact on grid operation regarding short circuit levels, voltage control, and interruptions due to failures; impact on network reinforcements to accommodate new DG connections; unpredictable energy deviations with respect the scheduled program; and the difficulty to maintain certain power factors at consumption points on the transmission grid.
  - A major revision of distribution system regulations is expected in Spain. Under these changes stakeholders expect that DG expansion will need to be considered as a more integrated component of the overall grid planning process. The revised regulation should provide DSOs with option(s) to recover the cost of network reinforcements due to the connection of DG. Significant connection charges are imposed on DG projects in Spain, which creates issues for renewable expansion.
  - A distribution congestion management procedure to dispatch DG in case of network congestion should be designed and implemented.

- The definition of DSOs with associated functions should be clarified in Spain, in line with the Directive 2003/54/EC. Operational procedures for DSOs should be clearly stated, as it was done for the TSO.
- Administrative processes: A developer has to negotiate with the state ministry, the regional authority, the municipality, the electrical company, and, in case of accessing the market, with the market operator and system operator as well. Due to the complexity of this process, experience shows that building a wind park may take five years.
- Economic support: As the premium is calculated ex-ante and decided by the regulator, not by the market, the fixed amount may be insufficient to recover renewable project costs. Conversely, in the case of wind power, the premium may be too high, which could become a barrier to renewable development in the future if all the economic resources have been dedicated to the first wind parks.[34]

Impact of DG on Spain's Network Infrastructure

The Spanish electric power grid is designed to meet reliability requirements at all voltage levels. This is reflected in the established grid structures at the various grid levels and provides a solid basis for the grid integration of renewable energy sources. Therefore, no fundamental changes in the topology of the Spanish grid have been required to date due to the interconnection of renewable energy sources. Changes have been limited to local/specific reinforcements in the distribution grid, mainly associated to the growth of solar PV and the need to maintain voltage within acceptable boundaries. Most of the renewable energy connected over the past decade has been in the form of large wind farms interconnected on the transmission grid.

Spanish law (RD 436/2004 and stated again in the RD 661/2007) mandates the connection point of larger renewable generators (tens of MWs or more) to higher voltage grids where they usually do not cause grid problems. This current restriction in Spanish law may be reviewed in the future, as more operating experience is gained with interconnection of renewable/DG on the MV and LV grids. Although such limits on connection points are seen as too restrictive by renewable promoters, to date it has enabled Spain to integrate a massive amount of renewable energy with rated capacity (excluding hydro) of 35 percent of Spain's peak demand. This has been accomplished with minimum disturbance to operation of the grid, while achieving ambitious national emission reduction targets.

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34 FIT would normally be reviewed every 2-4 years. However, due to the combination of economic issues with large growth of installed power in certain technologies (such as, solar PV) the review period has been shortened. Since 2007, the FIT for solar PV has already been reduced twice. The most recent of these reviews took place in 2010. The consequence of this last review was a reduction in the feed-in tariff prices with retroactive effects that are likely to reduce or even halt the growth in solar PV. Experience in Spain shows that the decision of FIT value may lead to unexpected responses from the market, such as the huge growth in PV solar installations that occurred in 2008. Such events require correction both due to technical (grid capacity) constraints and economical (tariff deficit) constraints.

From a technical perspective, to be able to continue integrating large amounts of DG, Spain has established national and regional control centers for renewables monitoring and control, coupled with establishing incentives for curtailing wind. Frequency regulation is provided when necessary due to excess resources by spilling wind (and other intermittent resources). This approach provides operational flexibility that allows maximizing renewable energy production while maintaining reliability, and, in Spain's experience, does not result in massive curtailment of renewable generation. For example, in 2009 Spain curtailed 54 GWh of wind production, which represents about 0.15 percent of annual total wind energy production. Wind generators in Spain are compensated for real-time curtailments at 15 percent of the wholesale electrical market price (without any premium). This compensation does not apply if reductions are scheduled (planned) in advance.

Spain's wind control centers include state-of-the-art renewable forecasting technology, including ramp-rate prediction software. Although Spain's wind forecasting technology is world class, the discipline needs substantially more research and development to optimally operate a power system with substantial penetration of renewables. At the same time grid codes are being updated and will require all renewable generators over a certain size to provide zero voltage ride-through capability and mandatory Volt/ volt-ampere-reactive (VAR) control capability to support the system contribute to maintaining the system voltage within acceptable boundaries in the steady state. Volt/VAR control capability in wind power generation can be provided by the use of power electronic interfaces on wind turbine generators such as doubly fed induction generators or advanced inverters on PV systems. These updated requirements apply to all wind generators connected to the transmission grid, as well as those connected to distribution if they fall within the following characteristics:

- Their rated installed power is above 10 MW.
- Their rated power is between 1 MW to 10 MW, but they are also part of a group of DG units for which the combined power output into a zone served by a single transmission node exceeds 10 MW.

Section 1.3 □ Comparison to Grid Infrastructure in California

Like the European power grid, the California grid is a three-phase alternating current (AC) grid. The California grid, like most of North America, is operated at a frequency of 60 Hertz at all voltage levels. However, the difference between the 60 Hertz AC system in California and 50 Hertz in Europe has no effect on renewable integration. In addition, the California grid has two major high-voltage direct current (HVDC) 500 kV transmission lines that are closely integrated with the AC system and interconnect California to the Pacific Northwest and Rocky Mountain regions. Likewise, in KEMA's opinion, the presence of these HVDC lines has no direct bearing on integration of renewables within California.

Table 7 compares common voltage ranges found in the California electric grid to the corresponding ranges in used in Germany and Spain and shows that there is a close correlation at all of the network levels.

Table 7: Comparison of AC Voltage Levels in California and Europe (Phase-to-Phase Voltages)

Network Level	Germany	Spain	California
Extra-high voltage	380 kV, 220 kV	400 kV, 220 kV	500 kV, 345 kV, 287 kV, 230 kV, 220 kV
High voltage	110 kV	132 kV, 110 kV 66 kV, 45 kV	138 kV, 115 kV, 69 kV, 66 kV
Medium voltage	30 kV, 20 kV, 15 kV, 10 kV	30 kV, 20 kV, 15 kV, 13.2 kV, 11 kV	34.5 kV, 21 kV, 13.8 kV, 12 kV, 4.8 kV, 4 kV
Low voltage	400 V	400 V	480 V, 208 V

Source: KEMA

This comparison clearly shows much similarity between the network voltage ranges in the three regions. Although California's 230 kV and 220 kV voltages are grouped with the EHV network classification in Table 7, they are not generally considered EHV voltages by U.S. standards. The functions of the 34.5 kV through 138 kV systems in California can be deemed to be transmission, subtransmission or distribution, depending on the facility owner.[35] Regardless of the nomenclature used by California utilities for 34.5 kV to 230 kV systems, their electrical function is similar to the European HV and MV categories, and they are simply grouped by these categories for comparison purposes in Table 7.

The similarity of system voltages shown in Table 7 suggests that the DG interconnection capability of individual distribution grids in both the EU and California should be comparable. For example, it is possible to interconnect DG projects up to about 20 MW in California at many 34.5 kV substations or on a 69 kV line. Likewise, based on Table 2, DG projects in the range of 5 MW to 10 MW could be connected into either a typical 30 kV MV line in Germany or a typical

35 For example, San Diego Gas and Electric's (SDG&E) 138 kV and 69 kV systems, and much of Pacific Gas and Electric's (PG&E) 115 kV system, are considered transmission and are under the California ISO's operational control. On the other hand, SCE's 66 kV and 115 kV systems are considered distribution, and not under California ISO control.

34.5 kV line in California.[36] The maximum DG project size on a typical 10 kV to 15 kV distribution line in either Germany or California is likely to be several megawatts. However, this conclusion applies only for distribution circuits of comparable voltage and would not be valid for comparing say a 12 kV circuit in California versus a 20 kV circuit in the EU. Finally, renewable project sizes at HV and EHV voltage levels in Table 2 are also comparable to generation plant sizes interconnected on the HV and EHV grid in California.

However, one difference worth noting in regard to Table 7 is the possible skewing of MV distribution circuit mileage in the EU toward the 15-30 kV range as compared to California, where the predominant distribution voltages are in the 12.0-13.8 kV range. Also, a substantial amount of older distribution load is still served by facilities below 5 kV. This could have a direct impact on DG integration in California vs. Europe, since the power delivery capability of any size electrical conductor varies proportionally with the operating voltage. Therefore, if a conductor is capable of carrying 6 MW at 10 kV, the same conductor could carry 12 MW at 20 kV. Therefore, the skewing of distribution voltages in Europe toward the higher end would ease greater DG integration. However, making such an increase in the operating voltage of an existing distribution grid in California would entail virtually a complete rebuild of the associated infrastructure (substations, pole lines, underground cables, and primary to secondary transformers.) It can be assumed that the costs of such a wholesale conversion would be prohibitive, except perhaps in the case of an antiquated distribution grid that is experiencing high failure rates and needs to be replaced. In most cases a more cost-effective approach to integrating DG on such lower voltage distribution systems would be to use the other planning options discussed in Section 1.1 such as upgrade of conductor and/or transformer capacity, construction of a new substation, and changes to grid topology. Again, each local system would need to be studied to determine the best planning option.

Other differences exist that are not obvious from Table 7. One key factor that has a bearing on DG integration is the difference in typical MV system topologies between Europe and California. In California, while there are some exceptions, it is common to use a radial MV circuit topology for both urban and rural areas. Conductor sizes on MV circuits in California generally get smaller as they get more distant from the source substation, since they have less load left to be served at those points. In California, MV circuits are often connected to adjacent MV circuits at one or more locations via normally open switches. This provides a backup source of supply in the case of faults or maintenance on an MV circuit. However, these tie points are usually not strong enough to back up the full load off an adjacent MV circuit. In contrast to this, the typical approach used throughout Germany, as well as in the urban areas of Spain, is to provide 100 percent back-up capability from an alternate source to every MV circuit. This approach requires more capacity to be built into the full length of the MV circuit to insure that it's capable of carrying 100 percent of circuit load from either source. This means that there is more uniform conductor capacity over the full length of MV circuits in Europe, which also

36 An exception to this may be if a DG connects to a long 34.5 kV distribution circuit in rural area of California, where the point of common coupling is extremely remote from the source substation. However, similar circumstances could also occur in Germany.

means less conductor impedance going back to the source of each circuit. In the researchers' opinion, this typical European topology promotes higher levels of DG integration.

Another difference in design is the absence of LV distribution networks in California. While these are commonly used in the EU for supply to residential customers, this topology is not in common use in California.[37] In Germany and Spain, residential and small commercial customers in urban areas are served directly from such three-phase 400 V networks. In comparison, the approach used in California is to serve customers from the MV circuits via distribution transformers rather than first stepping down the voltage from MV to LV. The resulting "LV system" in California (typically referred to as secondary voltage) only distributes power to relatively few customers (for example, 1 to 20 customers) near the MV to LV transformer – in contrast to many hundreds (or thousands) of customers on a typical LV network in Germany. These secondary voltage levels are shown in Table 7 under the "LV" category for comparison to the European LV voltages.

Some examples of fully meshed LV networks, like those in Europe, exist in other parts of the United States—particularly in large urban settings where the LV supply system originally evolved along this model (for example, New York City and Boston). Connecting DG to fully meshed networks can be problematic, partially because such networks are designed to prevent reverse power flow through the MV/LV transformers. Industry experts are developing standards and practices that would allow for DG connection to these LV networks. Obviously, the general absence of fully meshed LV networks in California renders this a moot point for DG integration in the state.

Another difference between distribution grids in California and Europe is the use of a three-phase circuit configuration throughout the distribution system in Europe, including customer service points. Common practice in California is to use a three-phase configuration on the main trunk lines leaving distribution substations, but to drop to fewer phases for many smaller downstream branches and taps, which requires use of fewer wires. A potential effect of this design difference is that if renewable DG projects are added on single-phase distribution branches in California, it may be more difficult for utility system planners to balance loading among all three of the phases on the main feeders and substations. If a significant imbalance in loading exists between phases, it could, under worst case conditions, accelerate the need for reconductoring of a feeder. However, a number of other lower cost options such as transferring customer loads or DGs between phases can typically be used to rebalance loading on the main feeder. Therefore, KEMA concludes that this difference in distribution system design between California and the EU should have a negligible effect on DG integration at the MV level.

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37 An exception to this in California is the occasional use of LV spot networks (for example, 240 volts) for supply of localized customer load centers in urban areas (for example, selected office complexes and shopping malls), but these are relatively limited in scale compared to the widespread LV networks found in Europe. Larger commercial customers and smaller industrial customers in Europe are typically served from MV distribution systems.

However, the use of three-phase configurations in Europe for LV networks and customer service points may make it easier to connect smaller DG projects in the 5 kW to 50 kW range at customer locations in Europe.

Typical network topologies and equipment ratings used for HV and MV distribution grids in Germany and Spain are described in the earlier sections of this report. While there are nuances to the topologies and equipment ratings in all three regions (Germany, Spain, and California), the higher voltage EHV and HV grids have the following in common:

- Planning and design of EHV and HV networks to withstand at least single contingencies without interruption of service to customers, loss of generation, or system instability
- Planning and design of HV to MV substations with either redundant transformer capacity or a spare transformer that can be energized in the event of a transformer failure.

One important aspect of the network infrastructure in Germany that clearly bears on successful integration of DG capacity is the requirement that all DG units above 100 kW must have remote observability and dispatchability by the network operator, (PV in Germany is exempt from this requirement as long as no single PV panel in the facility is rated 100 kW or higher.) While this infrastructure requirement doesn't directly affect the maximum DG capacity that can be integrated at a given location in the network, it clearly affects the ability of the German grid to accept more total DG capability on a macro level than California. This is due to the ability of the German grid operators to observe the output, as well as the authority to redispatch these DG units in real-time when needed for system emergencies. This has clear benefits to German TSOs in terms of congestion management, balancing, and frequency regulation if the normal market mechanisms fail to correct for these conditions. On a macro level, the lack of comparable DG observability and control by the California Independent System Operator (California ISO) and other California transmission operators pose a practical constraint to the total amount of renewable DGs that can be integrated into California's grid.

Another aspect of the infrastructure that appears to be different is the typical system protection design at HV/MV distribution substations. The standard protection system design for such substations in Germany is a four-quadrant relaying approach that allows back-feed conditions. Because MV feeders in the United States are usually a radial configuration, fault detection and/or overload protection (especially on older feeders) is often provided by simple, nondirectional overcurrent relaying. In such cases, if there is a back-feed condition due to DG and the magnitude of the backflow exceeds the settings of the overcurrent relays, they will operate and trip the circuit breaker at the substation, de-energizing the feeder. In some cases in the United States, the distribution substation transformers also have reverse power relays that are intended to prevent back-feed into the transmission system that serves the distribution substations. In such locations, a backflow condition could cause an outage of an entire HV/MV transformer bank or substation. There can also be substation protection designed to avoid circulating current between two transformers operating in parallel the same substation, if they are connected to common high-side and low-side buses. Typically, such protective schemes are used to prevent circulation of reactive power due to differences in tap settings between parallel

transformers, but they could also operate due to DG back-feed. Therefore, if such scenarios develop in California due to increasing DG deployment, affected portions of the existing substation protection equipment might need to be changed to accommodate back-feed. The simplest change is at the feeder level, where it may be possible to reset older electro-mechanical over-current relays to accommodate backflow or to replace them with newer solid-state relaying that is more flexible. Solid-state relays are already in place on many feeders.

Finally, there appears to be a difference between the U.S. approach and those used in Germany and Spain with respect to certain options available to DG developers and associated grid operator study processes. Under the typical Federal Energy Regulatory Commission (FERC) open-access transmission tariffs in the United States, an independent power producer (IPP) seeking connection to the grid has the option to simply apply for interconnection to the grid or can also elect to apply for delivery rights over the grid. If the latter is elected, a bifurcated application and study process results. In the first phase, the required interconnection study only needs to show that there is a plausible system load and dispatch condition for which the IPP's full power output can be reliably fed into the grid. This phase does not explicitly address deliverability from the IPP point of interconnection to any other point(s) on the grid. However, if the IPP also seeks assurance of such delivery capability, a second phase of study is required. In this second phase a range of stressed system load and dispatch conditions is typically studied, and additional grid upgrade requirements may be determined. An IPP seeking such deliverability rights is responsible for the upfront capital costs of such grid deliverability upgrades but may be eligible for a refund of such capital contributions from the grid owner after the IPP project achieves commercial operation. The basic interconnection study process used for DG units in the German and Spanish grids seems similar to the two-phase study process that is used in the United States only if an IPP applies for interconnection plus deliverability. For IPPs that seek only interconnection, it appears the United States study process is narrower in scope than the planning process in Germany and Spain. If so, it clearly has implications regarding the likelihood of dispatch constraints for such projects in the United States.

Section 1.4 □ Summary of Key Lessons Learned From Germany and Spain

The impacts of renewable DG integration on the distribution grid and the choice of appropriate countermeasures depend heavily on regional and locational aspects such as load density, the type and amount of DG capacity per region/substation/circuit/location, the original grid utilization conditions, and other factors. Given these many variables and interdependencies, one must be careful in deriving conclusions regarding the effects of distribution infrastructure on DG integration in Europe versus California. Even so, based on KEMA's review of the most common DG grid characteristics and integration issues, options, and countermeasures in Germany and Spain, the following conclusions can be made in regard to infrastructure effects on DG integration in California versus Germany and Spain:

- There are some key differences in the basic distribution infrastructure design between Germany, Spain, and California that are likely to be a factor in how much DG can be integrated into the respective systems. Some of these are due to the historical development of the respective systems over the past century and would be difficult and/or cost prohibitive to retrofit in California. Such examples are the use of three-phase configurations throughout the European distribution system and the looped backup source design used for MV circuits in most areas of Germany and urban areas of Spain. However, one important difference in infrastructure – the widespread requirement under German grid codes for DG projects to have telemetry to the TSO could be implemented relatively easily in California. In California, remote metering and/or telemetry requirements currently exist for projects that elect to execute a participating generator agreement (PGA) with the California ISO. This PGA requires that all intermittent renewable projects of 1 MW or greater are required to have telemetry that allows the ISO to see unit status and output level. Other types of participating generators that are 10 MW or larger must also have telemetry. It can be concluded that the lack of adequate DG visibility is likely to inhibit DG expansion in California.
- In addition, existing rules in Germany and Spain allow the TSOs to curtail renewable DGs if market mechanisms alone fail to address system reliability constraints in actual operation. Such DG redispatch authority is not generally available to grid operators in California, unless it has been packaged (for example, aggregated) by an ancillary service provider and made available through bid/contract mechanisms to the grid operator. On a macro level, the inability of California TSOs to curtail renewable DG output for system reliability constraints could inhibit statewide DG expansion.
- Grid operators in Germany and Spain have not changed the basic configurations of their distribution systems to allow for greater penetration of renewable DG. The types of grid upgrades considered by grid planners and operators for integrating DG projects in Germany and Spain are comparable to the options employed by grid planners and operators in California. However, there are differences in how the cost is assigned for such upgrades compared to California. In all three countries the connection option selected may affect the costs borne by the DG developer (such as the cost to construct a longer gen-tie lead to an upstream substation). Significant connection charges are currently imposed on DG projects in Spain, which impedes renewable expansion. However, pending changes in Spanish law could socialize more of these costs. Similar cost allocation issues exist in California.
- To date, grid operators in Germany and Spain have not used ancillary technologies (that is, battery storage and flywheels) to integrate DG on the distribution system. However, there is significant reliance on existing pumped-hydro storage plants on the EHV grid level in Germany and Spain to balance the intermittency of wind generation for regulation and frequency control.
- Grid planners and operators in Germany and Spain do not intentionally ignore the consequences of greater penetration of DG in their distribution grids or willingly take additional risks compared to those taken by DG operators in California. The technical

performance requirements specified in the German grid codes that apply to connection of DG projects are at least as rigorous as those in California.

- Grid planners in Germany and Spain address back-feed conditions from the MV distribution grids to the HV distribution grids due to DG integration by considering the same range of planning options as used in California. However, they are obligated under current laws in Germany and Spain to identify a reliable service plan to connect any DG project, consistent with the grid-code technical specifications. The cost of the required grid upgrades is then socialized to a large extent, especially in Germany. The DG-connection planning process in California appears to be less compulsory and more subject to negotiation over the scope of the required grid upgrades and the allocation of cost responsibilities between the grid operator and DG provider.
- Though the cost of grid upgrades for DG deliverability are largely subsidized in Germany, and to less of an extent in Spain, the capital investment strategy in both countries to date has been to minimize the incremental distribution grid upgrades for DG integration. This is similar to the situation in California. However, there is growing pressure in Germany to consider changing this strategy. Draft study results by German industry based on a government forecast of 36 to 52 GW of potential renewable generation expansion by 2020 (roughly equal to a 70 to 100 percent increase above the current installed renewable capacity) indicates that €13 billion to €27 billion of capital upgrades may be needed on the German HV and MV distribution grids to reliably integrate this level of renewables. This figure excludes EHV grid expansion costs that may also be needed for large-scale wind farm integration in Germany. However, it may be some time before the results of national policy debate on these options will be known.
- Accommodating back-flow conditions caused by DG integration does not appear to require sweeping changes to California's basic distribution infrastructure. However, a number of secondary measures will be required such as replacing substation relaying to accommodate back-feed, reconfiguring voltage control apparatus and controls on distribution feeders, and deploying appropriate smart-grid technologies on California's distribution and transmission grids. As renewable levels continue to increase, the installation of energy storage devices on the transmission and distribution system—and in some cases at DG sites—may become essential to modulate the effects of the intermittent resources and provide acceptable levels of balancing area frequency control.
- It is possible that selective changes to ratemaking design and capital cost allocation policies in California related to integration of DG into the distribution and transmission grids could incentivize a higher rate of DG growth in California.
- Similarly, it would be beneficial to explore the range of DG scheduling/redispatch/curtailment options that could be implemented in DG interconnection agreements, tariffs, and market models in California to increase participation by DG producers in supporting the operational reliability needs of the distribution and transmission grids. Regulators can help to steer the direction of such options through policies regarding equitable compensation for curtailments, lost opportunity costs, and so forth.

Section 2:

Network Planning and Operational Impacts in Germany and Spain

This section identifies the analytical and simulation methods used for network planning and operation in Germany and Spain and reviews the technical requirements for the interconnection of DG and technical integration issues. It frames the network operation aspects for the distribution network and the transmission system and describes the connections between the behavior of the generating units and the network operation, along with the control performance standards and measures used.

The findings address the following issues and questions:

- What definition of DG can be specified, and is DG limited to a certain size of electricity generators?
- Which analytical methods and simulation software are available to help network operators plan the integration of DG?
- How can grid operators monitor and control their network or system and improve the integration of DG into the electric network?
- Summarize new analytical and simulation models available to help DG operators plan the integration of PV planning and any applicable operational software.
- Summarize how Germany and Spain conduct the operational planning and dispatch coordination of their electric distribution systems as well as how they monitor and control their systems. Examine how much variability these countries experience (ramp, load following, and regulation) and their forecasting accuracy.
- Do these countries have a large amount of conventional electricity generation that can easily be turned on to manage the variability? Identify the type of the conventional electricity generation and the relative quantities of each type to gain a better understanding of how these countries use their fleet of electric generators to manage variability.
- Describe the dispatcher training that is provided to improve the integration of renewable DG into the electric distribution systems.
- Describe how curtailment is done in the context of operational planning and dispatch coordination.
- Compare the North American Electric Reliability Corporation (NERC) control performance requirements to the control performance requirements for the German and Spanish systems.

This section is organized as follows:

- Section 2.1: Network Planning and Operational Impacts of DG in Germany
- Section 2.2: Network Planning and Operational Impacts of DG in Spain

- Section 2.3: European Standards on Frequency Control and Balancing Services
- Section 2.4: Comparison to the Situation in California
- Section 2.5: Summary of Key Lessons Learned.

Section 2.1 – Network Planning and Operational Impacts of DG in Germany

This section provides an overview of the network planning and operation impacts of DG in Germany. The existing technical guidelines regarding the connection of DG in Germany[38][39] can be used to evaluate the PCC. These guidelines, including their methods, are described further below.

In general, the rated power of DG is not limited (for example, not capped at 5 MW). The local grid has to be able to transmit the output from DG. Hence, all components of the individual grid must be considered. Because of the different components in the grid, the PCC has to be evaluated.

Network Connection Technical Rules and Planning Tools in Germany

Generally, assessing the technical feasibility of the point of common coupling is at the sole discretion of the responsible grid operator. In this context, the following effects should be addressed according to German codes:[40]

- Loading capability of the existing grid components
- Voltage increase
- Voltage deviation caused by switching
- Flicker
- Harmonics
- Commutation notches
- Impacts on audio frequency ripple control
- Asymmetrical currents.

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38 *Erzeugungsanlagen am Mittelspannungsnetz – Richtlinie für den Anschluss und Parallelbetrieb von Erzeugungsanlagen am Mittelspannungsnetz*; VWEW Energieverlag GmbH; Juni 2008 (*German Technical Guideline – Generating Plants Connected to the Medium-Voltage Network*, June 2008).

39 *Eigenerzeugungsanlagen am Niederspannungsnetz – Richtlinie für den Anschluss und Parallelbetrieb von Eigenerzeugungsanlagen am Niederspannungsnetz*; VWEW Energieverlag GmbH; September 2005 (*German Technical Guideline – Generating Plants Connected to the Low-Voltage Network*, September 2005).

40 *German Norm 50160 - Voltage Characteristics of Electricity Supplied by Public Distribution Networks*, April 2008, and *German Technical Guideline – Generating Plants Connected to the Medium-Voltage Network*, June 2008.

Technical investigation of the grid loading and voltage effects is usually performed by the grid operator using network calculation software able to carry out steady-state load-flow calculations and simulation of DG properties at the PCC. Many comparable software tools are available in the industry. Some of the more popular tools used in Germany and Spain include Siemen's PSS/E software, Dig Silent's Power Factory software, and KEMA's Elektra software.(The PSS/E software is also used by many utilities in California, along with GE's PSLF software.) Such network calculations model the existing grid components and their technical properties (that is, rated current), as well as the technical data of the conventional and DG plants.

Simplified calculation methods are also available for performance factors that do not require the use of full load-flow models, as indicated in the discussion below.

Transmission Capability of the Existing Components

All components in the MV and LV grids have to be able to transmit the output of DG. That means grid overloads should not occur. In this context, the rated current and consequently the transmission capability of all existing components must not be exceeded if all DG units are feeding into the grid. It is essential that:

$$S_r > \frac{\sum P_{DG}}{\cos \phi_{DG}} \qquad (1)$$

S_r Rated Apparent Power (Transmission Capability) [kVA]
P_{DG} Peak power output from DG [kW]
$\cos \phi$ Value is a function of the power factor of the DG output (typically 0.95 or higher)

This capability should be checked by doing a load-flow calculation or in a simplified network through comparison of the installed transmission capacity versus the connected power of DG, adjusted for any coincident customer demand at the DG site.

Voltage Increase

Voltage increases are caused by the injected power of generating units. The power transmission over the network impedance causes a voltage drop from the point of common connection to the network supply point. The magnitude of the voltage deviation relates to the size of the impedance. Existing standards define the maximum voltage deviation difference of the connection point voltages with and without the DG. Again, use of load-flow software is required for an accurate calculation. In German codes, a relative limit of 2 percent has been defined for the steady-state voltage increase. However, at this time a new technical guideline that would increase the steady-state voltage limit to 3 percent for low-voltage grids is being discussed.[41] Hence, it is essential that:

41 *Draft: German Technical Guideline Generating Plants Connected to the Low-Voltage Network*, July 2010.

$$\Delta u \leq 2...3\% \qquad (2)$$

□u Steady-state voltage increase [percent]

The steady-state voltage increase should be checked by doing a load-flow calculation considering all DG units that are connected to the same grid. If no software is available, a rough estimation can be done using the following formula:[42]

$$50 \leq \frac{S_{SC}}{\sum P_{DG} \cdot \cos \phi_{DG}} \qquad (3)$$

SSC Short-circuit duty at the point of common coupling [kVA]
PDG Peak power output from distributed generation [kW]

The short-circuit duty at a PCC (available from the grid operator) acts as a measure for the network impedance. High short-circuit duty relates to low network impedance and vice versa. Short-circuit duty is usually calculated using the same network calculation tools mentioned above.

Voltage Deviation Caused by Switching

The switch-on and switch-off process of distributed generating units causes transient voltage deviations as well. To avoid a negative impact on other customers connected to the grid, applicable limits should not be exceeded. The permissible relative voltage deviation in Germany depends on the switching frequency. With respect to German guidelines, the voltage deviation caused by switching should be within the following range:

$$\Delta u_s \leq 2...6\% \qquad (4)$$

□us Transient voltage deviation caused by switching [percent]

Voltage deviation can be simulated by dynamic network calculations using a typical transient stability model. In this context, a more detailed model of the distributed generating units is necessary. Again, the previously mentioned network calculation software tools have such

42 *German Norm 50160 □ Voltage Characteristics of Electricity Supplied by Public Distribution Networks*, April 2008, and *German Technical Guideline □ Generating Plants Connected to the Medium-Voltage Network*, June 2008.

modeling capability. However, if detailed data of the distributed generating unit are not available, a rough calculation can be made according to German guidelines as follows:[43]

$$\Delta u_s = k \cdot \frac{S_{SC}}{P_{DG} \cdot \cos \phi_{DG}} \qquad (5)$$

us	Transient voltage deviation caused by switching [percent]
k	Switching current factor
SSC	Short-circuit power at the point of common coupling [kVA]
PDG	Peak power output from distributed generation [kW]

The formula includes a switching current factor (k). This factor is the ratio of peak current and rated current of the distributed generating unit. For a rough calculation, the following values can be assumed:[44]

k=1.2	Synchronous machine
k=1.5	Inverter-fed asynchronous machine
k=4.0	Asynchronous machine

Flicker

Flicker is category of voltage deviation that causes visible fluctuations in illumination. To check this voltage deviation, the flicker coefficient of the individual distributed generating unit must be known. According to German guidelines it is essential that:

$$0.46 \geq c \cdot \frac{P_{DG} \cdot \cos \phi_{DG}}{S_{SC}} \qquad (6)$$

c	Flicker coefficient [from manufacturer's test report]
SSC	Short-circuit power at the point of common coupling [kVA]
PDG	Peak power output from distributed generation [kW]

43 *German Norm 50160 Voltage Characteristics of Electricity Supplied by Public Distribution Networks*, April 2008, and *German Technical Guideline Generating Plants Connected to the Medium-Voltage Network*, June 2008.

44 *German Technical Guideline–Generating Plants Connected to the Medium-Voltage Network,* June 2008.

Harmonics

Distributed generating units can cause harmonics that can influence other customers connected to the grid. In this context, German guidelines define limits of harmonic currents that may be generated by the individual generating unit. The permissible harmonic currents are related to the network short-circuit duty at the PCC. It is essential that:

$$I_p = i_p \cdot S_{SC} \qquad (7)$$

I_P	Permissible harmonic current [A]
i_P	Permissible related harmonic current [A/MVA]
S_{SC}	Short-circuit duty at the point of common coupling [MVA]

The permissible related harmonic current depends on the voltage level. In this context, the German guidelines define the following parameters.[45]

45 *German Technical Guideline–Generating Plants Connected to the Low-Voltage Network*, September 2005, and Draft: *German Technical Guideline – Generating Plants Connected to the Low-Voltage Network*, July 2010.

Table 8: Permissible Related Harmonic Currents

Harmonic □	i_p Permissible Related Harmonic Current [A/MVA]			
	0.4kV Grid	10kV Grid	20kV Grid	30kV Grid
3	3.0	-	-	-
5	1.5	0.058	0.029	0.019
7	1.0	0.082	0.041	0.027
9	0.7	-	-	-
11	0.5	0.052	0.026	0.017
13	0.4	0.038	0.019	0.013
17	0.3	0.022	0.011	0.07
19	0.25	0.018	0.009	0.006
23	0.2	0.012	0.006	0.004
25	0.15	0.010	0.005	0.003
Uneven-numbered				
25 – 40	0.15 x 25/□	0.01 x 25/□	0.005 x 25/□	0.003 x 25/□
□ > 40	4.5/□	0.18/□	0.09/□	0.06/□
Even-numbered				
□ < 40	1.5/□	0.06/□	0.03/□	0.02/□
□ > 40	4.5/□	0.18/□	0.09/□	0.06/□

Source: *Eigenerzeugungsanlagen am Niederspannungsnetz – Richtlinie für den Anschluss und Parallelbetrieb von Eigenerzeugungsanlagen am Niederspannungsnetz*; VWEW Energieverlag GmbH; September 2005 (*German Technical Guideline □ Generating Plants Connected to the Low-Voltage Network*, September 2005); and ENTWURF: *Erzeugungsanlagen am Niederspannungsnetz – Technische Mindestanforderungen für Anschluss und Parallelbetrieb von Erzeugungsanlagen am Niederspannungsnetz*; VDE; Juli 2010 (*Draft: German Technical Guideline □ Generating Plants Connected to the Low-Voltage Network*, July 2010)

Commutation Notches

Commutation notches occur with inverter-fed generating units. With respect to German guidelines, commutation notches should be within the following range:

$$\Delta c \leq 2.5...5\% \tag{8}$$

□c Commutation notch [percent]

To check commutation notches, detailed data from the individual distributed generating unit are necessary.

Impacts on Audio Frequency Ripple Control

Generally, the grid operator's audio frequency (audio-tone) protection and control systems that rely on a modulated signal (for example, "ripple") superimposed on the normal 50 Hertz waveform should not be influenced by DG. The frequency of such communication signals depends on the responsible grid operator. With respect to the German guidelines, the level of the audio frequency must not be reduced by more than 5 percent.

Asymmetrical Currents

According to technical guidelines in Germany, small units up to 5 kW_{peak} can be served by a single-phase connection to the LV grid without a detailed study. Larger DG units require a three-phase connection and may require more detailed study.

Network Operation Impacts of DG in Germany

In general, in Germany the following networks can be differentiated according to their operational functions:

- Distribution networks
- Transmission systems.

The respective functions of these networks are legally stated in the German EnWG (law on the energy industry).[46]

Distribution Networks

The DSOs should operate a secure, reliable, and efficient energy supply network. Therefore, DSOs have the responsibility to receive generated power – in the distribution network or from the transmission system – and to distribute it to the customers. DSOs must also connect generating units to their networks without discrimination. Consequently, distributed generating units must be accepted onto the MV and LV grid if they fulfill the respective technical network connection requirements.

Distributed generating units must fulfill the corresponding valid network connection guidelines. However, they must also fulfill specific grid operational requirements to support a secure operation of the distribution networks in Germany. The relationship between the behavior of the generating units and the operation of MV and LV networks is described later in this section.

Transmission Systems

In addition to coordinating with the DSOs, TSOs are responsible for operation of the overall electrical energy supply system as a whole. Therefore, each TSO is responsible for the wide-area

46 *Second German Law on the Energy Industry*, July 2005.

network and system security. Among other duties, this includes maintaining ("regulating") system frequency, which is a function of the active power balance in the network, as well as maintaining the voltage, which is a function of the reactive power balance in the network. The frequency control performance standards are defined in the German Transmission Grid Code DSO.[47]

As a result of the combined operation of all distributed generating units in subordinate distribution networks, system conditions can occur in a transmission system that threaten secure operation. In the case of such events, for the protection of system security, the responsible TSO is responsible to act according to § 13 EnWG[48] and take certain operational measures. These measures can also affect the network operation of the subordinate DSOs. The applicable measures, as well as the effects on DSO network operation, are described in the following section.

Operation of Distribution Networks and Distributed Generation

As of April 2011, revised rules were implemented that require all new generating units that connect to the medium- and low-voltage networks to contribute to specific network ancillary services, including:

- Steady-state voltage control (i.e., reactive power production)
- Dynamic grid support
- Active power reduction.

These requirements and their intended benefits to system operation and reliability are discussed below.

Steady-State Voltage Control

Generating units will need to contribute to the steady-state voltage control of the grid. Therefore, they must be capable of injecting reactive power into the MV or LV grid. The technical guidelines for Germany contain the requirements for the reactive power supply for distributed generating units and require that generating units can be operated at every operation point within the following power factor (cos ϕ) range:

$$\cos\phi_{DG} = 0{,}95_{over-excited} \ldots 0{,}95_{under-excited} \qquad (9)$$

Within this range, a set point value can be predetermined by the DSO and transmitted by a remote control system. The following operating standards can be invoked for the reactive power supply from distributed generating units in Germany:

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47 *Transmission Code 2007, Network and System Rules of the German Transmission System Operators*, August 2007.

48 *Second German Law on the Energy Industry*, July 2005.

- Operate at a fixed cos ϕ – value
- Operate with a variable cos ϕ – value depending on the active power
- Operate with a fixed reactive power value
- Operate with voltage-dependent reactive power output according to a defined characteristic curve.

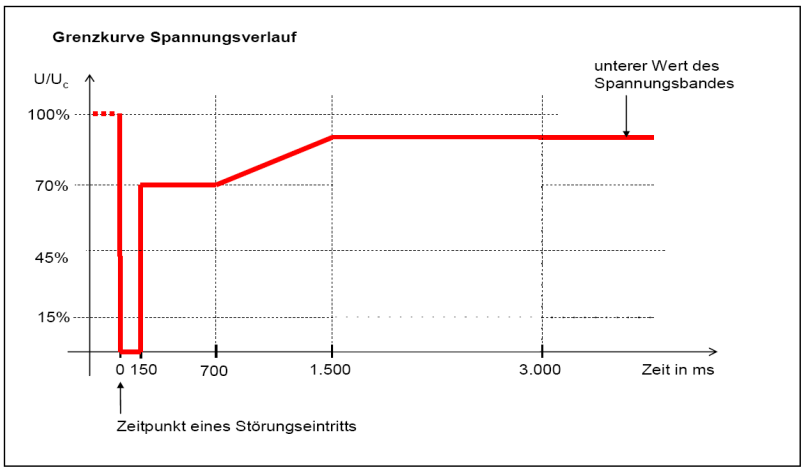
Dynamic Grid Support

Dynamic grid support refers to stable behavior of a generation plant in case of voltage depressions caused by grid faults (that is, fault ride-through capability.) This is necessary to avoid the sudden disconnection of generating units in MV and LV networks during normal clearing of faults on the network. DG must therefore fulfill the following requirements per the latest technical guidelines in Germany:

- During faults, distributed generating units should not disconnect from the grid.
- During faults, reactive power for grid voltage stability must be supplied by the distributed generating units.

These performance criteria should be met during all fault types (that is, three-phase faults and line-to-ground faults). In addition, the operation of the DG unit must continue for a specified fault duration. An example of fault ride-through time requirement for a synchronous machine is depicted in Figure 22.[49]

Figure 22: Fault Ride-Through Characteristic for a Synchronous Machine Following Fault Initiation (Point of Failure)



Source: KEMA

49 *German Technical Guideline - Generating Plants Connected to the Medium-Voltage Network,* June 2008.

The ratio U/Uc equals the instantaneous connection point voltage divided by the nominal connection point voltage. The technical guidelines stipulate similar requirements for other types of distributed generating units.

Active Power Dispatch Reduction

Distributed generating units should be able to reduce their output. This can be necessary to avoid critical overloads in the network or other unacceptable grid conditions. The assessment of critical system conditions is carried out by the responsible TSO. Determination of the set points for DG active power dispatch reductions are also made by the TSO and are issued to DGs via remote control (telecommunications). According to the technical guidelines in Germany, the following power level steps have been established as a minimum requirement:[50]

- 100 percent rated power
- 60 percent rated power
- 30 percent rated power
- 0 percent rated power.

Under the guideline, the active power reduction must take place through the action of a remote control system within one minute (for example, cannot depend on action by the DG plant operators). DSOs also have authority to curtail DGs for emergency conditions, but DSO curtailment authority is less clearly defined than TSO authority. Therefore, DSOs may request the TSO to initiate the action.

Operation of Transmission Systems and Distributed Generation

Unbalanced system conditions can occur in transmission systems due to the operation of distributed generating units in subordinate distribution networks that can present a threat to a secure operation, including disturbances in the system load and supply balance. The following fundamental criteria are defined for assessment of the operating status of the transmission system:

- Active power balance and frequency stability
- Reactive power balance and voltage stability
- Angular stability of the generators.

The German EnWG[51] obliges the TSO to assume responsibility for system security and stability. During a threat to the system security, the responsible TSO must take measures that ensure a secure network operation. These measures can occur at two levels:

- Network-related measures
- Market-related measures.

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50 *German Technical Guideline - Generating Plants Connected to the Medium-Voltage Network*, June 2008.

51 Second German Law on the Energy Industry, July 2005.

At the first level, the network-related measures are intended to eliminate threats through switching processes in the transmission system. If a threat is not eliminated by means of network-related measures, market-related measures are to be used at a second level. Market-related measures can include the use of operating reserve, load shedding, and the reduction of active power generation (dispatch curtailment). Therefore, DG dispatch and DSO network operation can be directly influenced by the TSO.

A precondition for the early recognition and rapid mitigation of conditions that threaten the system is a remote control connection to the distributed generating units. According to EnWG, all generating units larger than 100 kW in Germany must be equipped with a remote control system. This helps the TSOs to determine the status and output of DG units and to use this input in their renewable operating predictions. DSOs must also convey certain real-time information to the TSOs regarding operating status of the distribution networks.

However, with regard to the requirement for generating units larger than 100 kW to be equipped with remote control and telemetry, PV projects are currently exempt from these requirements as long as the rated power output of each PV panel in the project is below 100 kW. The practical consequence of this under current regulations is that entire solar power installations are exempted from the obligation to have remote control and metering devices, even though an installation's total installed capacity is greater than 100 kW. But, due to the growing challenges to grid operation as a result of the recent boom in German PV expansion, an amendment to Renewable Energy Act that includes the following changes in PV remote control requirements was adopted by the German Parliament in July 2011. Assuming it's approved by the executive branch, the law will become effective in 2012 and impose the following changes:

- The notion of a "solar power installation" will refer to the sum of devices, and not to a singular module, if all such devices are located on the same property or close to each other and are all placed into operation within 12 months. In this case the total installed capacity for determining remote control requirements will be calculated as the sum of individual generation capacity of all PV devices on the property.
- Operators of a solar power installation in this sense with total installed capacity
  - Between 30□100 kW must install technical equipment for remote control.
  - Below 30 kW must either have a remote control device or permanently limit their active power injected into the network to 70 percent of their total installed capacity.
- Telemetering is still not required for PV installations below 100 kW under these revised rules; however, existing installations and projects installed before 2012 are subject to the following requirements for projects with installed capacity ranges of:
  - Exceeding 100 kW (per the above definition)
    - Projects will have to retrofit with remote control and telemetering by mid-July 2012 (that is, with a time lag of 6 months after the law goes into effect)
  - Between 31□100 kW, which were put into operation in 2009 or later
    - Projects have to provide for remote control by 2014 (but don't need to add telemetry).

Intermittent renewable energy sources such as wind and solar can disrupt the system load and resource balance due to rapid ramping or tripping, including fluctuations in the output from groups of distributed generating units. A significant imbalance between grid loads and resources can be a critical risk to network frequency and stability. DG impacts on these operating issues are discussed in the following paragraphs.

Active Power Balance and Frequency Stability

Maintaining the active power balance of the system and the related frequency stability require quantitative measurement of the system status. If measurement and forecast values of supply and demand are fairly accurate, the system balance can be appraised in real-time or projected for the future. This information can also be used to identify potential network congestion. The active power balance can be controlled by the use of operating reserve from conventional power plants as well as the active power reduction from other generating units. In Germany, distributed generating units with active power greater than 100 kW must be able to be reduce their output in a stepwise fashion when needed. The determination of the required active power reductions are carried out by the TSO.

To date, solar inverters have been preset by producers such that, in accordance with technical rules in Germany for connection and operating solar power on the low-voltage network, they disconnect from the power system at a defined frequency of 50.2 Hertz to help prevent any further increase in frequency. However, with 18 GW of solar PV now installed in Germany, the overall level of PV generation has become a significant factor for power system operation. In particular, there is concern that the 50.2 Hertz setting for automatic PV disconnect may endanger system stability, since a sudden generation loss of 18 GW could lead to a significant drop of grid frequency. Hence, the system may further destabilize and may enter into successive cycles of PV disconnection and reconnection as frequency bounces up and down (for example, a "yo-yo effect").

As interim solution, the VDE FNN[52] has prepared a technical guideline for frequency-dependant active power control. It stipulates that the current presetting for disconnection of solar power inverters at excess frequency shall be replaced by a sliding disconnection scheme between 50.3 to 51.5 Hertz. It requires inverter producers to use the entire spectrum for disconnection with 0.1 Hertz steps when designing their systems. As a result, new inverters will not disconnect at 50.2 Hertz, but in increments at specific frequencies in the above mentioned range. The guideline is a nonbinding recommendation, but inverter producers have declared their intention to adopt and implement the guideline as of April 2011.

Moreover, VDE is planning to issue a new guideline (VDE-AR-N 4105) in 2012 that will replace the above interim solution. Preliminary plans on the new guideline indicate that the response of solar inverters, operating in the range of 50.2 and 51.5 Hertz, shall adjust active power by 40 percent per 1 Hertz of frequency deviation. In case that frequency falls below 50.2 Hertz, those

52 Association for Electrical, Electronic & Information Technologies prepares electro-technical standards and regulations and is one of the largest technical and scientific associations in Europe. The Forum network technology / network operation in the VDE (FNN) is a committee of VDE.

installations that are running at curtailed mode, that is, the active power of which is inferior to their installed power, may not increase their active power by more than 10 percent of their installed power per minute (power gradient). At a frequency above 51.5 Hertz, the installation will be required to immediately disconnect. PV installations may (re)connect only if system voltage stays in the range of 85□110 percent and frequency is between 47.5 to 50.05 Hertz for at least 60 seconds. Moreover, inverter active power output may only be increased such that maximum power is achieved after 10 minutes.

Admittedly, the proposed technical changes constitute a considerable change. However, it applies only to new solar power installations, while the 50.2 Hertz trip point will continue to apply to existing PV inverters. Therefore, German TSOs are still campaigning for a retrofit of existing installations as well, through amendment to the Renewable Energy Act due in 2012 or subordinate legislation.

Reactive Power Balance and Static Voltage Stability

The steady-state voltage stability and the reactive power balance on the grid also affect the energy supply system. On long transmission routes that are heavily loaded, the impedance increase that occurs through the failure of any of the parallel transmission system elements can lead to critical grid voltage conditions. Using measurement technology, steady-state voltage stability can be assessed, and reactive power reserves can be dispatched to counteract critical voltage conditions. Distributed generating units can be used for such network support if they are capable of supplying reactive power into the network. Therefore, the TSO and DSO can determine appropriate set-point values regarding voltage or reactive power that are transmitted by means of a remote control system to distributed generators on the MV and LV networks.

Training and Forecasting for Renewable Impacts

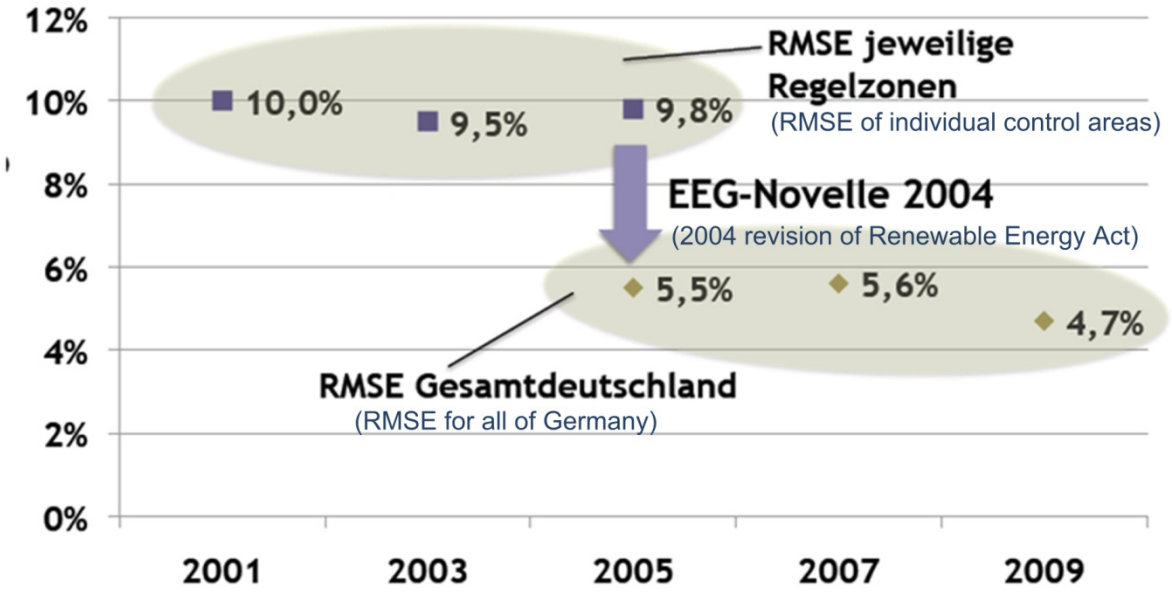
Trends and forecast data in network operation, including renewable production, should be included at the earliest possible recognition of critical system conditions. Real-time measurement, assessment, and operator alarms for critical system conditions are necessary. These can be accomplished through algorithmic models that are integrated into the control system(s) of a TSO to provide computer-aided decision support for control center operational personnel. The specific requirements for such models and tools have been the subject of extensive discussions in Germany and are under development.

Over the past decade, German TSOs have been confronted with an increasing portfolio of intermittent generation: first from wind power and more recently from solar power plants. Already at an early stage, this development triggered intensive cooperation among individual TSOs and various public and private meteorological and other research organizations. All four German TSOs use wind-power forecasting services from a public research institute known as

IWES.[53] The wind forecasting methodology of IWES, which is widely regarded as one of the leading and most advanced in Europe, uses a variety of wind and weather forecasts from meteorological services, as well as a large number of online wind measurements from all over Germany to derive wind forecasts for increments from 15 minutes to 48 hours in advance. Apart from the German TSOs, these models are used today by various other European TSOs and provide the basis for the forecasting tools that are used by several commercial service providers.

As illustrated by Figure 23, the forecast accuracy of IWES' model has significantly increased over the past decade and is above 95 percent. While the normalized root mean square error (RMSE)[54] for individual control-area day-ahead forecasts used to be approximately 10 percent, it has dropped to below 5 percent nationally in Germany in recent years. In 2007, the corresponding values for one- and two-hour forecasting horizons were 1.61 percent and 2.59 percent, respectively. Based on the recent DENA Grid Study II,[55] IWES expects that it will be possible to nearly double the forecast accuracy of the combined onshore and offshore production by 2020.

Figure 23: Error Levels for Day-Ahead Wind Power Forecasts in Germany Between 2001 and 2009



Source: Neubarth, Jürgen. Integration Erneuerbarer Energien unter besonderer Berücksichtigung der Regelenergie. Presentation at E-world 2010. Essen. February 9, 2010, p. 11

53 Fraunhofer-Institut für Windenergie und Energiesystemtechnik, which is based in the towns of Kassel and Bremerhaven.

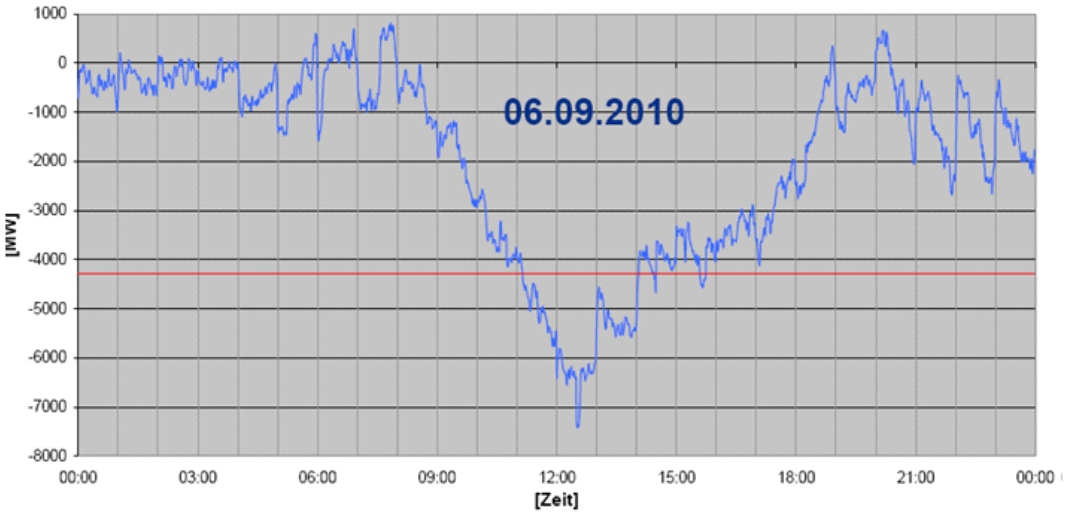
54 Root mean square error, related to total installed (wind) capacity.

55 *Deutsche Energie-Agentur Network Study II – Planning of the Grid Integration of Wind Energy in German Onshore and Offshore up to the Year 2020* ("DENA Grid Study II"), 2010.

In recent years, similar efforts have been made on developing corresponding tools and methods for solar power forecasting. Today, the German TSOs use the forecasts of several service providers, including IWES as well as two privately owned companies (meteocontrol and Suncast). Similar to the approach for wind power forecasts described above, these tools use different combinations of weather forecasts, satellite data on global radiation, statistical methods, and quarter-hour online data for hundreds of PV installations to create 15-minute to 4-day forecasts in advance. Besides global and regional forecasts, for instance, EnBW from Southwestern Germany is researching the development of detailed locational solar-power forecasts[56] to detect potential congestion.

In general, the forecast accuracy for solar power production is similar to wind power. For example, Suncast reports a RMSE accuracy at about 4.5 percent for day-ahead and less than 4 percent for intraday forecasts. For forecasting horizons for a very few hours ahead, other sources report an RMSE of about 1 percent (excluding night hours). However, increased forecast errors for solar power were observed during 2010, resulting in the need to activate 100 percent of all contracted operating reserves for several hours on September 6, 2010. This event is illustrated in Figure 24.

Figure 24: Negative Balancing Power Requirement vs. Contracted Reserves (9-6-2010)



Notes: "Zeit": Hour; Blue line: total negative power balancing reserve actually required; Red line: sum of negative secondary and tertiary power reserve contracted (over and above primary regulating reserve of approximately 600 MW)

Source: KEMA

56 Schierenbeck, S. et al. "Ein distanzbasierter Hochrechnungsverfahren für die Einspeisung aus Photovoltaik." *Energiewirtschaftliche Tagesfragen*. 60. Jg. (2010), Heft 12, pp. 60 – 64.

In late 2010, the German regulatory authority issued a position paper addressing the September 2010 incident and the TSOs' claim that policy intervention is required. The regulator's paper requires the implementation of a so-called "reference metering procedure" for solar forecasting, already recognized in the wind sector. The aim is to increase DSOs' forecast and extrapolation capabilities to provide better data to the TSO to support control area distributed generation data gathering. This procedure shall extrapolate data from representative solar power installations with 15-minute output metering of the installations in the DSO's area. The regulator has refrained from specifying what model to use but leaves it to the TSOs and downstream distribution network operators to coordinate the implementation of such systems. Further consultation between the regulator and industry representatives has produced the following agreements:

- Large DSOs implement "reference metering procedure" by April 1, 2011, in coordination with the TSO and successively implement similar or equal systems with their corresponding downstream network operators.
- DSOs have to improve data provision to the TSO, updating with monthly frequency information on actual installations (capacity and location) or best-available estimations and forecasts.
- As long as "reference metering procedure" is not the default forecast and extrapolation procedure, approaches for forecasting nonmetered generation have to be adjusted such that they consider daily sunrise and sunset data; that is, generation profiles assuming constant output during the day are not allowed any more.

Based on the new requirements for solar power generation forecasting, providers of corresponding software services and products have released new applications. For instance, a product by Energy & Meteo Systems called Suncast has emerged in the market. Suncast is a forecast and extrapolation tool that operates on the basis of data from 22,000 reference installations. It combines various numerical weather forecasts with radiation prognostications and installation data. It may produce generation forecast for differently sized areas, with a lead time from 96 hours up to real-time, a time resolution of 15□60 minutes, potentially updated various times a day. It allows for incorporation of real-time meter data and processes different data formats. The service provider claims providing high forecast accuracy, namely an RMSE of 3.5 percent of total installed capacity in Germany for intraday forecasts and roughly 4.5 percent RMSE for day-ahead prognostication. Moreover, it counts three German TSOs among its references. The service provider offers similar tools for wind power.

Forecasts for wind and solar power are mainly used by the German TSOs today, whereas DSOs have not made regular use of such tools so far. However, the aforementioned paper by the federal regulator[57] explicitly called on DSOs to implement adequate forecast methodologies by April 1, 2011. However, the corresponding provisions of the position paper are not immediately

57 Bundesnetzagentur. Positionspapier zur verbesserten Prognose und Bilanzierung von Solarstromeinspeisungen. November 2010.

binding for DSOs, and it remains to be seen how German DSOs will implement them in practice.

To deal with the operational effects of intermittent generation, German network operators are also increasing their related training for operational personnel, including simulator-based training for dispatchers. However, the corresponding activities are related only partially to the challenges of integrating large amounts of renewables in the power system. Another major driver for expanded dispatcher training is the uncertainty due to increasing international energy transactions, the separation of generation, transmission and distribution system operation, and trading functions (unbundling) in the electricity market.

Over the past decade, German TSOs as well as several DSOs[58] have used a dispatch simulator, DUtrain,[59] a dedicated training facility based in Duisburg. The simulator, which was developed by the University of Duisburg, offers the real-time simulation of a power system, consisting of one or more transmission control areas, distribution networks, and generators. In contrast to typical simulation packages used with SCADA systems, the DUtrain system has been developed for training related to the interactions among different actors in a liberalized power market, such as TSOs, DSOs, and producers.

In contrast, the recent deployment of a dispatch simulator at the Technical University of Cottbus was directly triggered by the massive expansion of renewable energy sources in Germany. In addition to increasing international energy trading, the Eastern German grid operated by the TSO "50Hertz Transmission" has been exposed to other operational challenges caused by strong back-feed from distribution to transmission as well as associated challenges with regards to voltage control. Due to legal restrictions on the curtailment of renewable energy, the necessary countermeasures require close cooperation and coordination between the TSO, on the one side, and the DSOs, on the other hand.

As a result, "50Hertz Transmission" has initiated and invested in the development of a simulator and training center, in cooperation with the Technical University of Cottbus, the SCADA-system provider BTC, and KEMA. The goals of this training center are to:

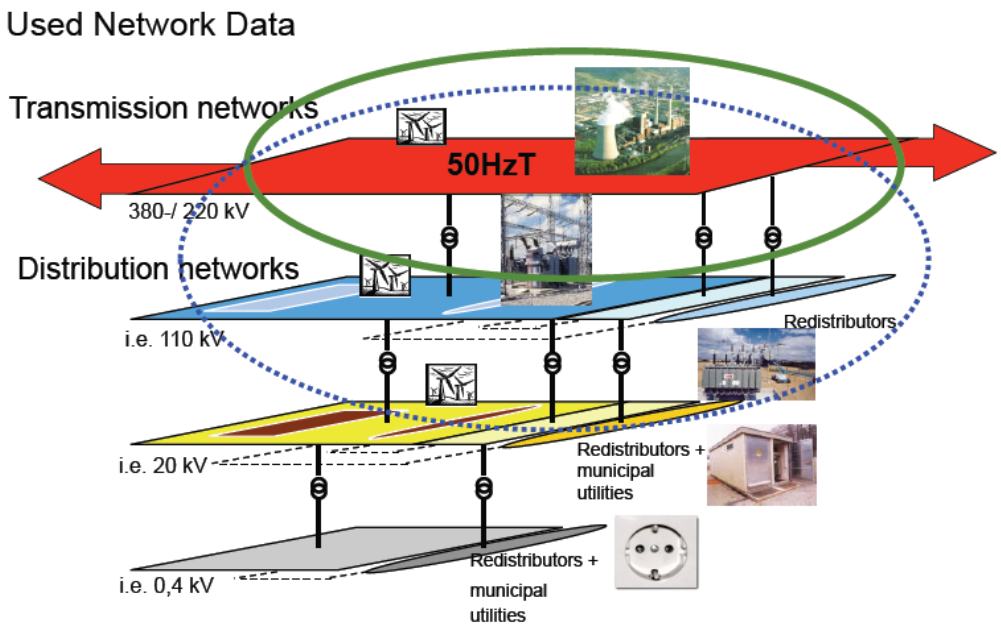
- Properly qualify operating personnel from the German network and power plant operators.
- Practice the interactions of the TSO, DSOs, and power plant operators, particularly in those situations that demand coordinated measures to assure secure operation.
- Alert the operational staff for critical system states, including network restoration after disturbances.
- Practice behavior and procedures for operational situations that endanger system security.

58 In addition, many other European TSOs, as well as virtually all Dutch and some other DSOs, have been using the simulator, often on a regular basis.

59 DUtrain is 60 percent owned by KEMA.

As illustrated by Figure 25, the training simulator in Cottbus has been designed to simulate all voltage levels, from 380 kV down to 0.4 kV.

Figure 25: Network Levels Represented by the Dispatcher Training Simulator in Cottbus



Source: 50Hertz Transmission

Section 2.2 □ Network Planning and Operation Impacts of DG in Spain

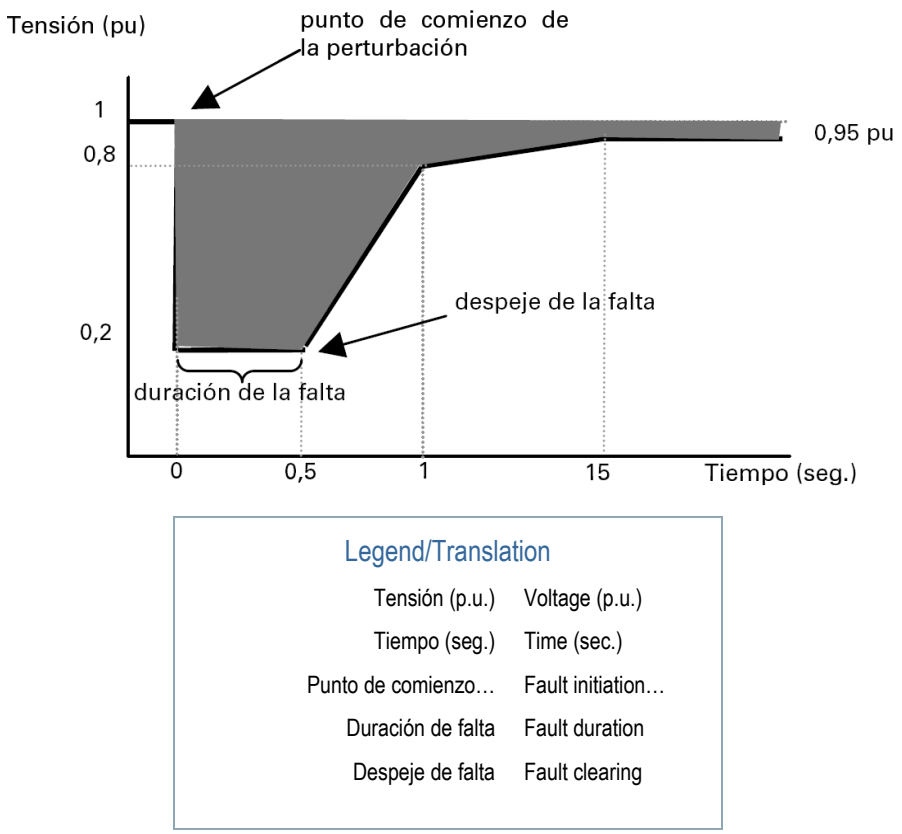
In Spain, the focus of renewable DG interconnection technical rules is on the fault ride-through (FRT) requirements of the units, as discussed below.

Existing Fault Ride-Through (FRT) Requirements

The FRT requirements for conventional generators connected to the transmission system states that the generation plants will not disconnect from the grid in the event of voltage sags associated to short-circuits that are correctly interrupted.

To reach that standard, the necessary design and control actions will be taken in the generation plants (all their components) for them to withstand three-phase, phase-phase (with and without ground), and phase-ground short circuits without disconnection. The voltage sags (independent of the short circuit type) at the connection point will not result in disconnection as long as the sag is located within the grey area of Figure 26 and Figure 27.

Figure 26: General FRT Requirement for Generators Connected to the Spanish Transmission System



Source: REE: P.O 12.3

Figure 26 applies to all generator sizes and types connected to the transmission grid. Customized FRT requirements have been developed specifically for wind generation, which are slightly different from those developed for conventional generation. Figure 26 also applies to wind generators but with the following modification(s):

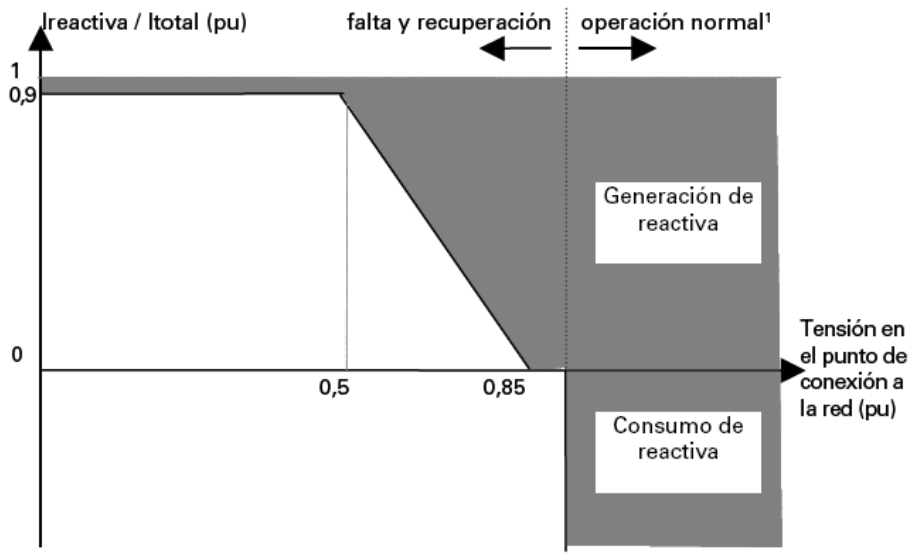
- The same limit applies to the voltage sags associated to three phase, phase-phase with ground, and phase-ground short circuits. For the voltage sags associated to phase-phase without ground short circuit, the same curve applies but with the lower limit at f 0.6 per unit (p.u.) instead of 0.2 p.u.

There are also requirements for reactive current support from wind generators during faults, which are illustrated in Figure 27. In general, for three-phase faults, both during the fault and at the recovery period (after fault elimination), the wind farm should not consume reactive power. Without contradiction to the previous general requirements, wind farms are allowed to momentarily consume reactive power for a period of 150 ms after fault initiation and 150 ms

immediately after fault elimination, as long as the following conditions are simultaneously respected:

- During a period of 150 ms after the fault initiation, the net reactive power consumption will never be more than 60 percent of the registered rated power in every cycle (20 ms).
- For 150 ms after fault elimination, the net reactive power energy consumption will not be more than the equivalent reactive energy corresponding to the wind turbine operating at 60 percent of the wind farm's registered, rated power during that period.
- The net consumption of reactive current in each cycle (20 ms) will not exceed 1.5 times the current corresponding to rated power.

Figure 27: Reactive Current Injection During Fault Requirements for Wind Turbines



Legend/Translation	
Ireactiva/Itotal (p.u.)	Reactive current/total current (p.u.)
Falta y recuperación	Fault and recovery
Operación normal	Normal operation
Generación de reactiva	Reactive power generation
Consumo de reactiva	Reactive power consumption
Tensión en el punto de conexión a la red (p.u.)	Voltage at interconnection point (p.u)

Source: REE: P.O 12.3

The wind farm is subject to the following:

- There shall be no active power consumption at the PCC during the period of fault duration and after fault clearing. Similarly to the previous case, the wind farm is

allowed under the technical rules to have momentary active power consumption during 150 ms after fault initiation and after fault elimination. Active power consumption is also allowed during the remaining periods of the fault as long as it is not greater than 10 percent of the rated power of the wind farm.

- The wind farm should provide the electrical power system at the PCC with the maximum possible current during the fault and during voltage recovery, according to the curve presented in Figure 27.
- The wind farm should comply with the curve 150 ms after fault initiation or after fault elimination. Therefore, for voltages below 0.85 p.u. at the PCC, the wind farm should generate reactive current, and for voltages values between 0.85 p.u. and the minimum voltage allowed in normal operation, the wind farm cannot consume reactive power. Above the minimum voltage allowed in normal operation, the wind farm should comply with the requirements for normal operation existing in the document "P.O. 1.4 Condiciones de entrega de la energia en los puntos frontera de la red gestionada por el operador del sistema." (Translation: “Operational Procedure 1.4 Conditions for power delivery in the interconnection points to grid management by the independent system operator.”)
- In general, for unsymmetrical faults (single-phase and phase-to-phase) the wind farm cannot absorb reactive power at the PCC during the fault and during voltage recovery. Still, it can momentarily consume reactive power for 150 ms immediately after the fault initiation and for 150 ms after fault elimination. Furthermore, it can consume transient reactive power during the remaining periods of the fault as long as:
    - The reactive energy consumption (at the three phases) is not more than the equivalent reactive energy of 40 percent of the nominal power registered during a period of 100 ms.
    - The reactive power consumption of the wind farm in each 20 ms cycle is not more than 40 percent of the nominal power registered.
- During the remaining periods of the fault, it can consume active power as long as:
    - Active energy consumption (at the three phases) is not more than the equivalent active energy of 40 percent of the nominal power registered during a period of 100 ms.
    - Active power consumption in each 20 ms cycle cannot be more than 30 percent of the nominal power registered.
- Furthermore, it can draw transient reactive power during the remaining periods of the fault as long as: the reactive energy consumption (at the three phases) is not more than the equivalent reactive energy of 40 percent of the nominal power registered during a period of 100 ms, and the reactive power consumption of the wind farm in each 20 ms cycle is not more than 40 percent of the nominal power registered. During the remaining periods of the fault, it can draw active power as long as: the active energy consumption (at the three phases) is not more than the equivalent active energy of 40 percent of the nominal power registered during a period of 100 ms, and the active power consumption in each 20 ms cycle cannot be more than 30 percent of the nominal power registered.

The existing wind farms at the time of the grid-code approval did not have to fulfill the requirements related with active and reactive power consumption during unsymmetrical faults unless the wind farm is significantly reinforced or improved.

The documents that specify these requirements are:

- Conventional generation P.O. 12.2 of REE "Instalaciones conectadas a la red de transporte: requisitos mínimos de diseño, equipamiento, funcionamiento y seguridad y puesta en servicio". (Translation: Operating Procedure 12.2 of REE – "Installations Connected to the Delivery Grid: Minimum Requirements for Design, Equipment, Functionality, Reliability and Energization") Approved February 11, 2005, by Resolution 3419 of the General Secretariat of Energy.
- Renewable generation P.O. 12.3 of REE "Requisitos de respuesta frente a huecos de tensión de las instalaciones eólicas". (Translation: Operating Procedure 12.3 of REE – "Time Domain Voltage Response Requirements of Wind (Power) Installations") Approved October 4, 2006, by Resolution 18485 of the General Secretariat of Energy.

Evolution of Fault Ride-Through (FRT) Requirements

The first Spanish grid code requirement regarding generators FRT capability was released in the P.O. 12.2 on November 2, 2005. Due to the increasing wind power integration in the peninsular system characterized by limited interconnection capacities with neighboring countries and the features of the existing wind power plants (without FRT), it was necessary to review the wind energy penetration that is technically permissible in the Spanish power system in peak and off-peak periods. The P.O. 12.3 released on April 10, 2006, contains the wind farm requirements necessary to secure a high wind power penetration in the Iberian system, guaranteeing security and quality of supply. These requirements are related with FRT capability and injection of reactive power during faults to support network voltage.

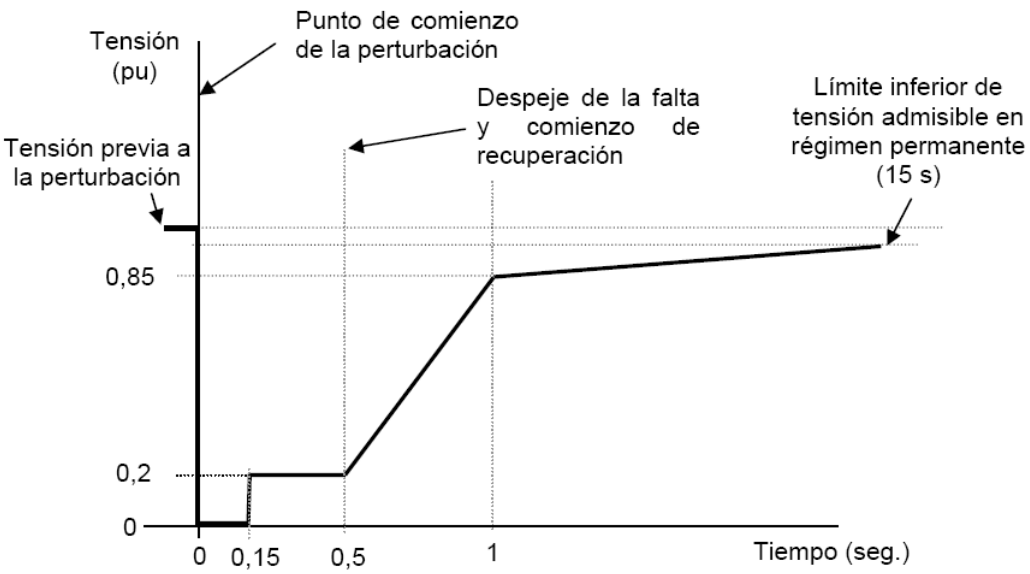
The appendix on technical requirements of the P.O. 12.2 is under revision. This revision is oriented to wind, solar power plants, and every technology not based on a synchronous generator directly connected to the grid. The following main modifications are proposed:

- The plant must withstand 0 percent residual voltage dips without disconnecting during 150 ms.
- The plant should be able to stand a voltage swell up to 130 percent at the connection point.
- The plant shall be able to generate/consume reactive current within the voltage margin defined by the set points sent by the TSO in less than 20 seconds. During transient grid voltage events the control will switch to an automatic voltage controller using the previous unaltered voltage set point as current set point. The control can be implemented as a voltage, reactive power, or power factor controller and will maintain the reactive current injection/consumption within the limits of saturation. The controller

will remain active for at least 30 seconds after voltage recovery returning then to the operational mode previous to the perturbation. Figure 28 illustrates this requirement.

- The plant shall include the required equipment to perform power-frequency control, equivalent to a proportional controller with adjustable dead band.

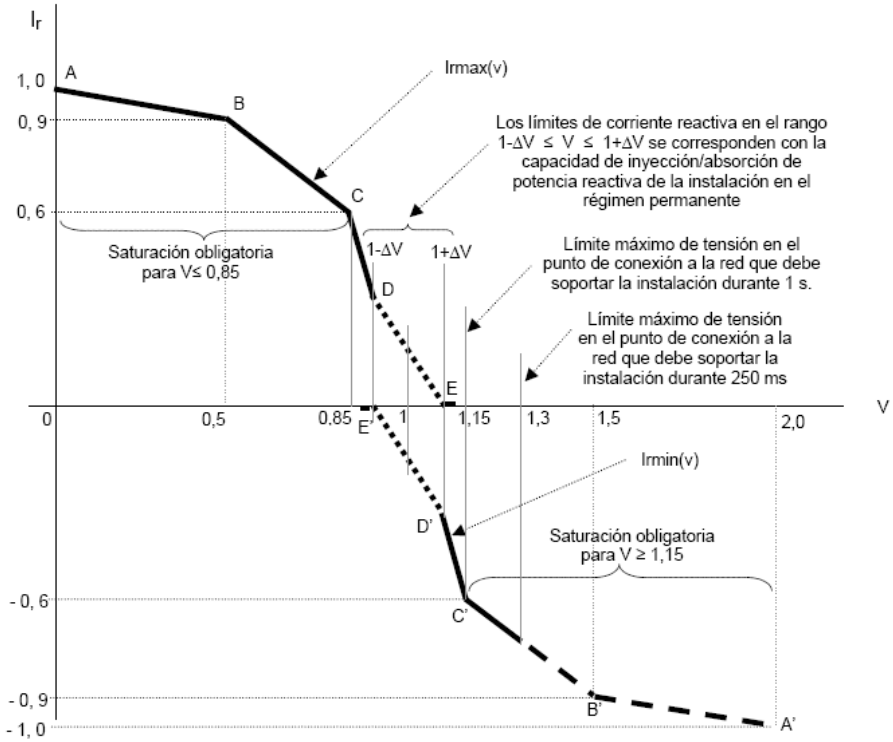
Figure 28: Proposal of FRT Requirement for Renewable Generation



Legend/Translation	
Tension (p.u.)/Tiempo (seg.)	Voltage (p.u.)/Time (sec.)
Despeje de la falta comienzo de recuperación	Fault clearing and start of grid recovery
Limite inferior de tension admissible en regimen permanente	Lowest voltage level that the generator is required to operate indefinitely
Tensión previa a la perturbación	Voltage prior to the grid disturbance
Punto de comienzo de la perturbación	Beginning of the grid disturbance

Source: REE: P.O 12.3

Figure 29: Proposed Reactive Current Injection During Fault Requirement for Renewable Generation



Legend/Translation	
I_r & I_{rmax} (p.u.)	Reactive current & Max. Reactive current (p.u.)
V	Voltage (p.u.)
Saturación obligatoria para V> 1,15	Reactive current required for Voltages > 1.15 (p.u.)
Saturación obligatoria para V< 0,85	Reactive current required for Voltages < 0.85 (p.u.)
Consumo de reactiva	Reactive power consumption
Limite maximo de tensión en el punto de conexión a la red que debe soportar la instalacion durante 250 ms	Voltage limit at interconnection point with grid that the generator must be able to support for up to 250 msec.
Limite maximo de tensión en el punto de conexión a la red que debe soportar la instalacion 1 s	Voltage limit at interconnection point with grid that the generator must be able to support for up to 1 sec.
Los limites de corriente reactive el el rango…	Limits of reactive current in the range of 0.90 < V < 1.00 (p.u.) that the generator must be able to inject or absorb (from the grid) on a continual basis

Source: REE: P.O 12.3

Control Center for Renewables

One of the hallmarks of Spain's leadership in integration of renewable generation is the creation of the Control Center for Renewable Energy (CECRE). CECRE was established by REE (TSO) and is integrated in its control room. It enables control and supervision of all of Spain's renewable power production. It presently focuses on wind farms, but there are plans to include solar, biomass, small-scale hydro, cogeneration, and municipal solid waste incineration plants. All renewables over 10 MW are required to be connected via telemetry to a renewable energy source control center, which in turn is linked to the CECRE. Specifically, the goal of CECRE is to maximize the production of renewable energy while maintaining system reliability.

A critical part of CECRE is a wind generation forecasting system. This forecasting system is composed of three components: a database on the wind farms, a prediction algorithm based on a self-adaptive time series, and a forecast combination module. It uses as input real-time wind power and probabilistic wind forecasting and combines them into a multimodel forecast.

CECRE has a solid communication link with generation control centers for monitoring and control. Presently, it can issue wind generation curtailment orders when demand falls below what is provided by must-run units. It also continuously runs real-time simulations of faults and analyzes the response of independent generators to these voltage sags. If an unsafe system situation is detected (mainly dependent on overloads on the tielines connecting to France), the renewable generators (for now only wind) will receive new operational set points to reduce their output, and conventional generation may receive more operational set points.

Although only about 40 percent of the wind power is connected to distribution, most of the curtailment orders issued by CECRE are due to requests from DSOs that have trouble running their infrastructure due to lack of coincidence between load (demand) and wind generation. The rules in Spain do not allow a DSO to order such curtailments directly, so curtailments must be done through CECRE acting on behalf of the DSO. This also allows CECRE to consider if there are any better options to address the operating condition of concern before ordering DG curtailment.

Dispatch Priority for Renewables

In Spain all generating units have to send their offers to the market operator, OMEL, which makes an economical match between bids and offers and establishes a market price. OMEL pays each generating unit that has offered its production below the market price the hourly market price for their production. However, the economically based generation selection made by OMEL may not be physically deliverable. Therefore, the TSO analyzes the deliverability of the program made by OMEL and generates a new dispatch program for all generating units in the list from OMEL. Those units that are decreased compared to the initial economical selection have to pay the TSO back for the decreased production at the market price. Those units that get increased production get paid for the increased production at the price they had offered, which can be more or less than the market price.

All conventional generating plants have the same priority order in the redispatch. However, renewable resources have priority over conventional in the redispatch. Within renewable resource group, the renewable energy sources without storage capability have the highest dispatch priority, according to RD 661/2007 published in June 2007. For example, this means that if there is a restriction related to the level of generation dispatch at a grid node where conventional power plants, hydropower plants with storage capabilities, and wind farms are all connected, then the conventional plants will decrease their production first. If that redispatch is not enough to reduce the grid constraint, then the hydropower plants with storage capabilities will be directed to decrease production. Lastly, the wind farms will be required only to decrease their production after all other generating units have been curtailed.

Operational Planning Related to DG/Renewables

Currently there are 4.9 GW of pumped hydro storage. Apart from that there are no other storage technologies deployed in the field. Alternatives such as demand side management are also not currently applied. To compensate for the variability of DG, particularly wind power, Spain either modulates hydro generation or cycles thermal generation, using mainly its natural gas-fired combined cycle units. Spain has 16.7 GW of hydro generation (includes pumped-hydro) and 25 GW of gas-fired combined cycle plants.

On a typical operating day combined cycle power plants have pronounced cycling behavior to offset nondispatchable wind production. As an example, on January 12, 2011, at the minimum load time (about 4 a.m.), there were 2.2 GW generated by combined cycle plants, while at the peak hour (9 p.m.), more than 9 GW of output was dispatched on combined cycle plants. The wind in Spain is highly variable. On the same day at the minimum load time, wind farms generated 8.3 GW, but at 10 a.m., they produced only 5.9 GW, almost a 2.5 GW reduction in three hours. At peak system demand that day only 4 GW of wind power was available and thus required conventional generating resources to ramp for both the loss of wind as well as the increase in demand. Again, combined cycle power plants take the main role in providing this ramp up capacity.

Combined cycle power plants that routinely operate under such a cycling regime require costly maintenance. To compensate, new combined cycle plants in Spain are compensated on their availability and capacity (capacity credit concept). Thus, there is still an incentive for combined cycle plants to be built, though renewable energy tends to dominate new generation technologies.

The renewables control center (CECRE) is responsible for wind generation forecasting. This system provides forecast of wind power up to 48 hours in advance and was developed using Matlab by The Spanish Meteorological Agency and Meteologica, a Spanish company specializing in forecasting and mathematical modeling services for wind power generation. In total, some 94 percent of the wind farms in Spain report to CECRE, and production data is updated every 20 minutes.

The errors of the wind forecast depend on the forecast horizon. Over a 48-hour horizon the maximum error in 2009 was just over 15 percent, while for a four-hour forecast the error was

about 12 percent. REE uses probabilistic wind forecasts to buy reserves for on a day-ahead basis. The forecast error has been decreasing over the years and, therefore, helping REE to reduce the amount of acquired reserves while still operating the system reliably.

Section 2.3 □ European Standards on Frequency Control and Balancing Services

Frequency control and balancing services usually require all services to maintain and/or restore system frequency to within acceptable levels as well as restore the energy balance of the system. Within the interconnected power system of continental Europe, which was formerly known as UCTE,[60] the following three main types of services are defined in the relevant guidelines and procedures:

- Primary frequency control is the automated, decentralized response of the governor controls on individual generators to any frequency excursion on the grid to counteract deviations of system frequency.
- Secondary frequency control[61] is based on the centralized control of particular generating units and helps to restore system frequency by restoring the area control error (ACE) of a given system to zero.
- Manually instructed reserves involves tertiary services with an advance notice time for activation (normally no less than 15 minutes), as well as any other spinning or non-spinning reserves that may be activated by a specific instruction from the system operator and that serve to restore the energy balance of the entire system.

The characteristics of these three services in the EU grid are further elaborated in Table 9.

60 Union for the Coordination of the Transport of Electricity (UTCE) was an association of TSOs that jointly operated the interconnected power system of continental Europe. It was set up to coordinate transmission system operation across control areas. As of 2005 the TSOs agreed upon the mandatory introduction of UCTE standards. From mid-2009 the newly founded European Network of Transmission System Operators for Electricity (ENTSO-E) absorbed the tasks of existing TSO associations, including UCTE.

61 This service is also known as power-frequency control, regulation, or automatic generation control (AGC) in other jurisdictions.

Table 9: Characteristics of the Three Frequency Control Reserve Levels in UCTE

	Primary Control	Secondary Control	Tertiary Control
Why is the control used?	To stabilize the frequency in case of imbalance	To bring back the frequency and the interchange programs to their target	To restore the secondary control reserve, to manage eventual congestions, and to bring back the frequency and interchange programs to their target if the secondary control reserve is not sufficient.
How is control achieved?	Automatically		Manually
Where is this control performed?	Locally	Centrally (TSO)	
Who sends the control signal to the source of reserve?	Local sensor	TSO	TSO or generators and consumers (after receiving instructions from the TSO)
When is the control activated?	Immediately	Immediately (seconds)	Decided by dispatcher
How long is the service provided?	Continuous		Based on instruction (Often scheduled)
What sources of reserves can be used?	Partially loaded units		Partially loaded units, loads fast/slow starting units, changes in exchange programs
Minimum reserve capacity	3,000 MW, shared by all the different control areas in EU	Secondary control reserve * $\sqrt{10\,L_{\max zone} + 150^2} - 150\, in\, MW$	Sufficient to cover at least the largest loss of power or to replace secondary control reserves
Timing** Start Full availability End	Immediate □ 30s □ 15min	□ 30s □ 15min As long as required	No recommendation Short time: often 15min No recommendation
Activation	Fully activated at frequency deviation of +/-200 MHz	Country-specific	-

* L max zone is the expected peak load in the zone for the considered period (e.g. one hour).

**It is recommended that secondary control is replaced by tertiary control as soon as possible.

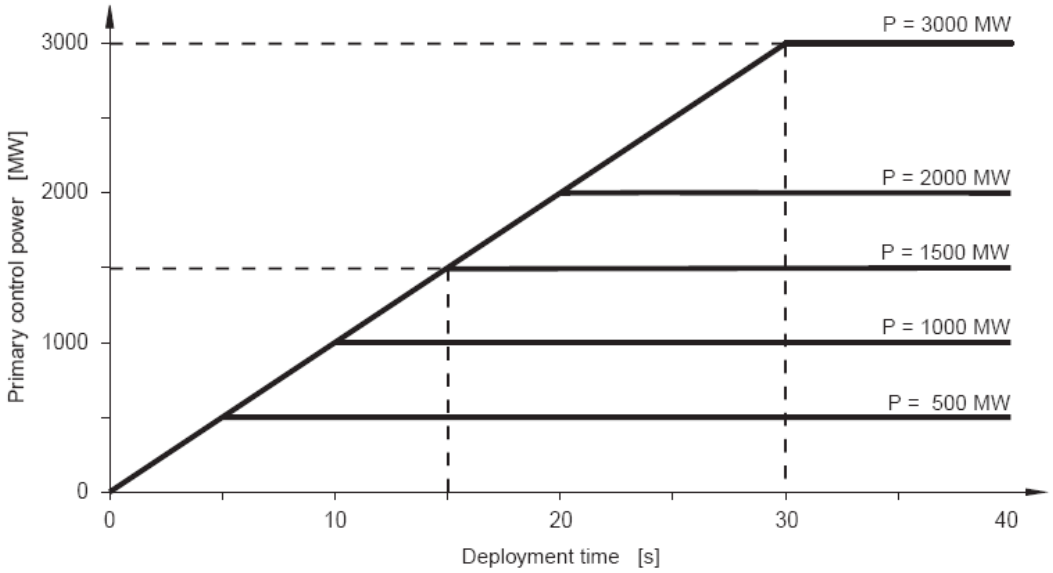
Sources: EU Directorate General for Competition Report on Energy Sector Inquiry 10 January 2007; and Rebours / Kirschen: A Survey of Definitions and Specifications of Reserve Services, 2005

In most continental European countries, the technical specifications of these services roughly correspond to UCTE requirements. However, the requirements of UCTE apply to system operators, while the respective national rules (for example, grid codes) typically specify the minimum requirements for generating units or other potential service providers, which may be different.

The provisions on the total reserve capacity in Table 9 represent minimum requirements, whereas each TSO decides on the level of reserves it holds in practice. The requirement for 3,000 MW of primary control has been mutually agreed upon by all TSOs, and the provision of each TSO's share of the total is a binding obligation. The formula for secondary control reserves has recently been declared by ENTSO-E to be a minimum requirement as well. In practice, many European TSOs apply the formula, while others procure more reserves. For instance, the German TSOs apply a probabilistic method, which results in a significantly greater need for secondary control reserves than suggested by the formula listed above.

Primary reserve covers a loss of generation or load up to 3,000 MW in the UCTE synchronous area. As soon as the reserve is required, it shall be activated according to the function shown in Figure 30. The figure distinguishes two scenarios and minimum requirements for deployment. First, 1,500 MW of primary control reserve have to be fully activated within the first 15 seconds after a disturbance (loss of generation or load). Secondly, if the disturbance is between 1,500 MW and 3,000 MW, full activation is required within the first 30 seconds after the start of the event.

Figure 30: Minimum Deployment of Primary Control Reserve as a Function of Time and Disturbance Magnitude



Source: UCTE. Operational Handbook, A1 – Appendix 1: Load-Frequency Control and Performance [E], A1-9.

Control Measurement

UCTE has not defined detailed control performance requirements for each of these services. For primary control, the *Operations Handbook* requires that the quasi-steady-state frequency deviation must not exceed ±180 mHz, while the maximum instantaneous frequency deviation must not exceed ±800 mHz. In contrast, there are no firm measures for secondary and tertiary reserves. However, UCTE does produce a confidential monthly report with performance statistics on the operation of primary and secondary control in each control area, which is largely based on a statistical analysis of frequency deviations and ACE.

Primary Control Reserve

The measurement of primary control reserve quality aims at evaluating the performance of control deployment and indicating operational reliability of the UCTE synchronous area. Quality control measurement is based on system frequency analysis after major disturbances. It relies on frequency measurements of both the entire synchronous area and each control area, using the following two indicators:

- Ratio of the power variation causing the disturbance and the quasi-steady-state frequency deviation in response to the disturbance
- Ratio of the variation in power generated in a control area in response to a disturbance and the quasi-steady-state frequency deviation in response to the disturbance, whereby cross-border exchanges and power deficits and surpluses at the interconnections between control areas have to be taken into account.

Both measurements have to be carried out simultaneously. Moreover, it is assumed that the major part of primary control reserve is activated within 20 seconds after the start of the event, and that the contribution of secondary control reserve is negligible.

TSOs must constantly record and analyze the quality of their primary control reserve as well as major disturbances from production or consumption outages. Such anomalies are considered significant if they exceed 1,000 MW. TSOs must exchange information on the location, time, type, and magnitude (amount of production/ consumption lost) of significant disturbances.

Secondary Control Reserve

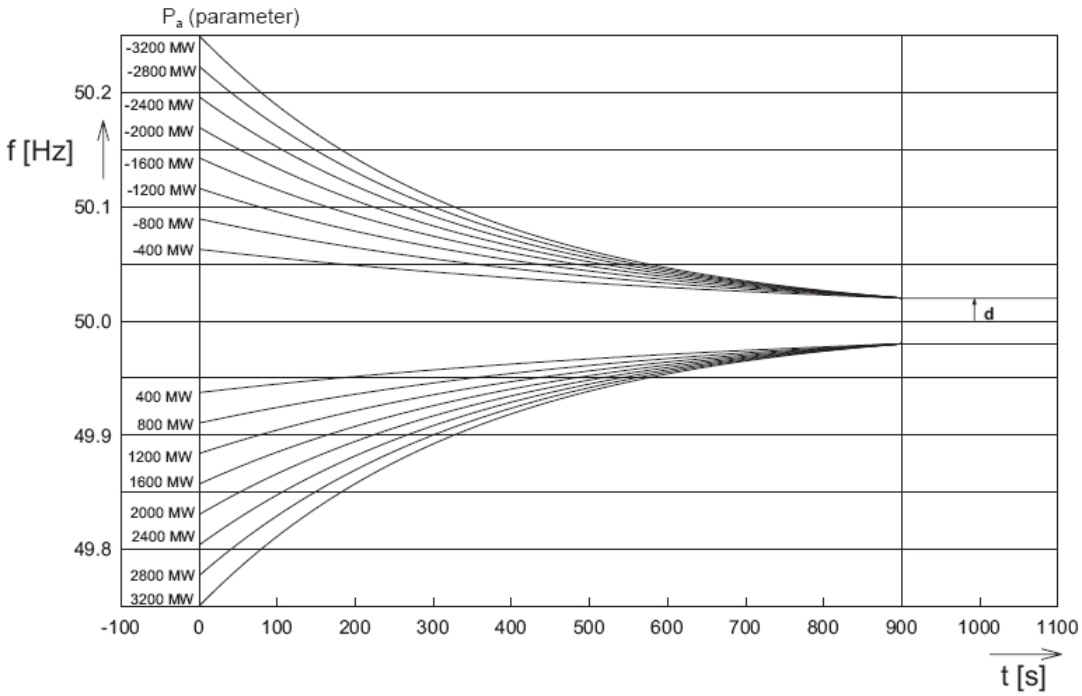
The cases of normal operation and abnormal operation are distinguished for measuring secondary control reserve quality. The former includes small disturbances and frequency deviations, while the latter embraces large deviations beyond 1,000 MW.

Under normal, continuous operation, the following indicators are used for quality control:

- Standard deviation of the average frequency deviations over each 15-minute interval in a month
- Number and duration of frequency corrections
- Proportion of time during that frequency deviations are greater than or equal to 50 mHz.

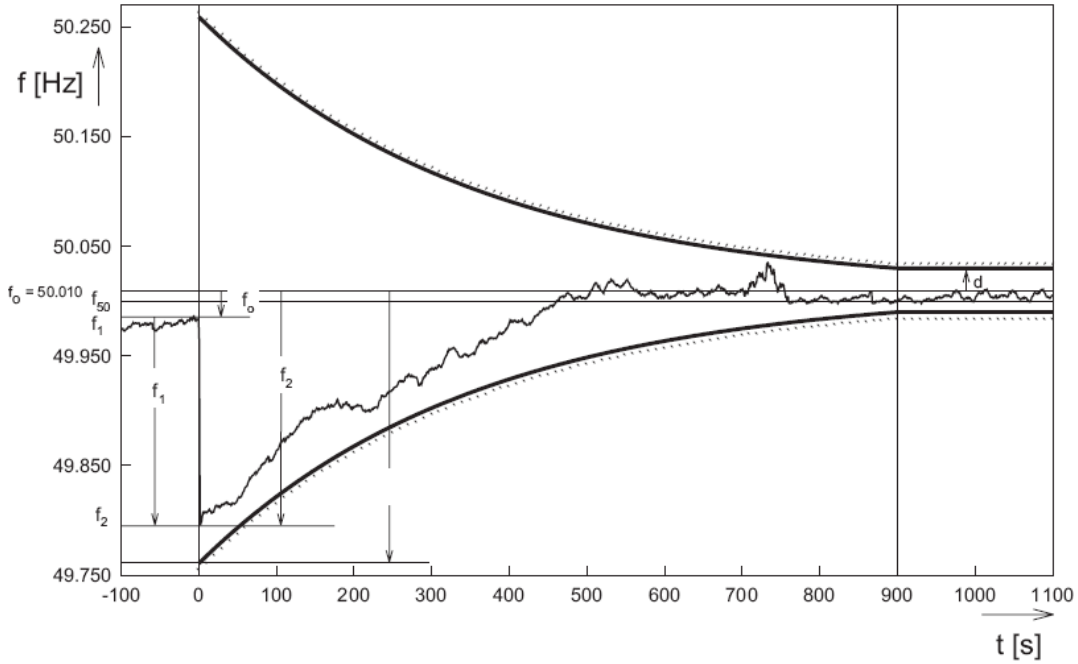
For large frequency deviations, the ability of secondary control reserve to bring the system frequency back to the standard value after a significant disturbance is checked based on the so-called *trumpet method*. Depending on the absolute frequency deviation assumed, a trumpet-shaped curve is plotted (see Figure 31), which indicates how the secondary control Reserve reacts and how default frequency is established. The aim is to maintain system frequency above the lower trumpet function in case of frequency decline or below the upper trumpet function in case of frequency excess during control reserve deployment (see figures 31 and 32 below). The aim is to restore the default frequency value within 15 minutes after an incident with an accuracy accepting a final deviation of +/-20mHz.

Figure 31: Trumpet Curve(s) for Secondary Control Reserve



Source: *UCTE Operational Handbook*, A1 – Appendix 1: Load-Frequency Control and Performance [E], A1-20- A1-21.

Figure 32: Trumpet Curve(s) for Secondary Control Reserve



Source: *UCTE Operational Handbook*, A1 – Appendix 1: Load-Frequency Control and Performance [E], A1-20- A1-21.

Procurement of Frequency Control Reserves

Besides the minimum technical requirements, there also exist major differences in the methods applied for the procurement of these services by TSOs. In Germany, reserves and balancing services are offered by generators (and consumers) voluntarily, while many other countries rely on compulsory offers. In the former case, all services are procured by separate tendering mechanisms regularly, which are jointly carried out by the four German TSOs. Besides primary, secondary, and tertiary reserves, the German TSOs have been procuring two other types of related services:

- Wind reserves, which have been used to compensate for unexpected fluctuations in the production by wind power plants and that may consist of several products, such as additional 15-minute reserves and hourly reserves[62]
- Redispatch services, which are used to resolve network constraints outside the balancing mechanism, which is, thus, limited to simple energy balancing.

62 The German TSOs also use secondary reserves for managing the real-time variability of wind power generation across the four control areas.

As of 2011, TSOs in Germany are no longer allowed to procure wind reserves for addressing renewables variability. It was allowed only as an interim basis and as a limited measure to help cover situations when the power exchange would not provide sufficient liquidity to buy and sell renewable power volumes that result from updated forecasts. However, in prior years two of the leading TSOs procured the following volumes of wind reserve regulation service.

Table 10: Levels of Wind Reserve Service Procured

Categories and Years	TSO1	TSO2
Upward Regulation (MW)		
2007	300	n/a
2010	100-150	30
Downward Regulation (MW)		
2007	300	n/a
2010	200	200-240

Source: KEMA

One of the main parameters for the required amount of frequency control reserves is electricity from intermittent renewable sources and the inaccuracy inherent to the short-term forecast of output from such sources, especially wind power. Most of the wind power forecast models used so far apply a global approach, providing a forecast for any weather conditions. A European study[63] compared the forecast quality of various models for a specific set of wind power installations and delivers some valuable results both on current and future forecast quality. According to the study, the forecast error depends on the model used, the wind power installation the model is applied to, and the complexity of the surroundings of the installation. For onshore wind power in plain areas (least complex), the average forecast error among all models considered is about 10 percent but increases to up to 21 percent for highly complex surroundings. The offshore wind forecast error is around 12 percent and, thus, comparable to installations in less complex onshore areas. Moreover, models tailored to specific wind power installations, their surroundings, and local climate conditions may perform up to 20 percent to 40 percent better than more generic models. For solar power the forecast error was estimated at 10 percent for 2005. For both wind power and solar power, scientific literature rates the potential for quality improvements at 40 percent.

If one considers the potential improvement in forecast quality, this may decrease the need for control power reserves or at least partially compensate for the increase of variability form increasing scales of renewable electricity in Germany. Two studies published in 2010 contribute

63 ANEMOS project (Kariniotakis et al., 2006), found in Dena Netzstudie II (see below).

to this issue and estimate the scales of control power reserves required in 2020. The results are shown in Table 11 but are not directly comparable as will be explained below.

Table 11: Size of Control Power Reserves

Control Power Reserve Type	2010 Actuals	2020 Forecast	
		Dena Grid Study II	Consentec Study
Secondary and tertiary reserves for upward regulation	~ 4,600 MW	3,867 – 4,180 MW	6,500
Secondary and tertiary reserves for downward regulation	~ 4,600 MW	3,145 – 3,317 MW	7,500 MW
Primary reserve	+/- 600-700 MW	-	

Source: KEMA

The first study[64] estimates that current forecast models may be improved so that a total performance (average absolute error) increase by 40 percent to 50 percent may be achieved. This would result in a stable need for total reserves required in 2020 compared to the volumes currently procured by German TSOs. This is despite the strong growth of renewables that is anticipated to occur by 2020. The study assumes that the reserves are determined including a one-hour wind power forecast and different security margins (confidence intervals), and subject to the assumption that energy deviations up to one hour before the fact are balanced by same-day trading at the power exchange.

The second study[65] concludes that the need for control power reserves would increase only slightly, while the share of renewable electricity will increase to 30 percent by 2020. It includes a forecast quality performance increase of 20 percent until 2015 and another 10 percent until 2020. The difference may be explained by the fact that, here, the estimated absolute values subsume all reserve capacity services currently procured by German TSOs, including wind reserve power (see above) and other balancing mechanisms. Moreover, the authors note that the current volumes procured by the TSOs are significantly below the model-based estimations. The study concludes that the reserve requirement would increase by 50 percent (upward regulation) and 30 percent (downward regulation), compared to the above scenario, if the renewables forecast performance does not occur to the extent mentioned above. And the authors assume that the more intermittent renewable sources are connected to the network (beyond the value of 30 percent assumed), the lesser the forecast quality improvement will compensate for the former.

64 Dena Netzstudie II, 2010, p.382ff. (engl. Dena Grid Study II – *Integration of Renewable Energy Sources in the German Power Supply System from 2015 – 2020 with an Outlook to 2025*).

65 Consentec /r2b: „Voraussetzungen einer optimalen Integration erneuerbarer Energien in das Stromversorgungssystem, 2010 (engl. Conditions for optimal integration of renewable sources into the electricity system).

Section 2.4 □ Comparison of Operational Impacts to Situation in California

Comparison DG Interconnection Rules in California

The rules in California governing DG interconnection are very different from Germany. First, the California ISO only has jurisdiction over generating resources that would interconnect to the California ISO-controlled transmission grid, and these resources are typically 1 MW or larger facilities.

California ISO is now using a cluster-study process to expedite processing for new generation interconnection studies. Separate from California ISO's interconnection procedures are metering and telemetry requirements for projects that sign a participating generator agreement (PGA) with California ISO. All participating generators 1 MW or greater must have California ISO metering. Telemetry is required for intermittent generators 1 MW or greater and for all other participating generators 10 MW or greater.

Generation that will interconnect to the utility-controlled, lower-voltage portions of the California grid are subject to the respective utility's interconnection process, such as Southern California Edison Company's (SCE) Wholesale Distribution Access Tariff (WDAT) rules. On March 1, 2011, SCE filed an amendment with FERC to request approval for a modified WDAT process, which will allow SCE to group generators in their interconnection queue into clusters for interconnection study. This is similar to the cluster study approach already being used by the California ISO.

DG resources that are 1 MW or less are subject to the local utility's interconnection rules that are approved by the applicable regulator, that is, FERC or the California Public Utility Commission (CPUC) for the investor-owned utilities or by the appropriate municipal utility board or irrigation district board. In addition, the CPUC has established Rule 21 as the standard for the interconnection of DG facilities to the distribution system. The DG units typically do not contribute reactive power for voltage support. They also are expected to disconnect from the distribution system in the event of a short circuit or system outage and not contribute to the ride through or recovery of the

Rule 21 Certification Codes and Standards

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

system from a disturbance.

Rule 21 specifies the applicable standards and codes the generator must meet. Generators no larger than 5 MW (up to 3 MW for a 21 kV interconnection, and up to 2 MW on a 12 kV interconnection) will be evaluated under a fast-track process. Generators that are larger than 5 MW require a more detailed interconnection study by the local utility.

Unlike Germany, the California ISO has no visibility of the energy production of DG resources connected to the distribution system and cannot send dispatch commands to these DG resources. This is especially true for DG resources that are connected behind the meter at a customer site and the DG output is netted with the customer load. By virtue of its balancing area authority status, the California ISO must be prepared to cover the total load at the customer site in the event that the DG unit shuts down, but the amount of load being offset by DG output is typically unknown to the California ISO. This has not posed a serious problem to date since the amount of DG in California is been relatively limited. However, with the amount of DG—especially solar PV—projected to grow to 3,000 MW or more in the next 10 years, the potential impact from an unexpected shutdown of these resources could represent a future reliability problem for the California ISO—and for California.

The California ISO previously had a set of tariff rules for the interconnection of small generation resources rated between 1 MW and 20 MW. However, its Small Generator Interconnection Procedure (SGIP) and their Large Generator Interconnection Procedure (LGIP) were merged into one Generator Interconnection Procedure (GIP) in December 2010. The California ISO Tariff – Appendix Y now covers interconnection process for all generators. It includes a section for small generator certification that reads as follows:

> "Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in GIP Appendix 9, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment."

The California ISO tariff applies only to DG units rated over 1 MW that seek to be interconnected to the California ISO-controlled grid. This includes DG interconnections to California investor-owned utilities' network facilities down to the 60 kV to 70 kV level in both the Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E)

service areas, but only at 220 kV and above in the SCE service area. The California ISO tariff does not apply to lower voltage DG interconnections or any DG facilities located in publicly owned utilities in California.

Comparison of EU Control Performance Standards to California

NERC sets the control performance standards for all control area operators (balancing authorities) in United States, Canada, and Northern Mexico. Additional or more stringent standards have also been approved that apply to only the balancing authorities in the Western Electricity Coordinating Council area (WECC), which includes California. The current applicable NERC and WECC standards are summarized in Table 12.

Table 12: NERC/WECC Control Performance Standards

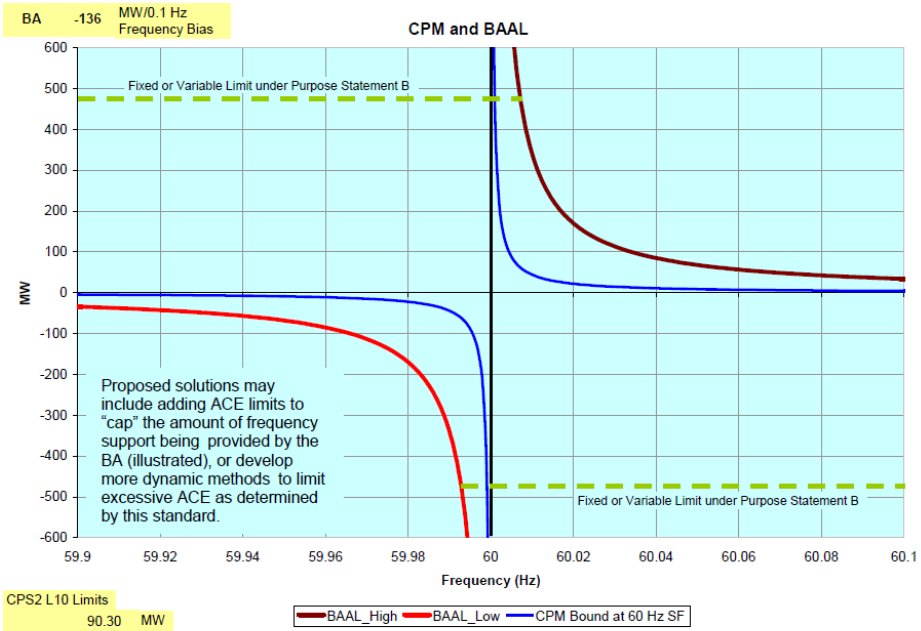
BAL-001-0.1a	**Real Power Balancing Control Performance** To maintain interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.
BAL-002-WECC-1	**Contingency Reserve (WECC)** Contingency reserve is required for the reliable operation of the interconnected power system. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment.
BAL-003-0.1b	**Frequency Response and Bias** This standard provides a consistent method for calculating the frequency bias component of area control error (ACE).
BAL-004-WECC-1	**Automatic Time Error Correction (WECC)** To maintain Interconnection frequency within a predefined frequency profile under all conditions (that is, normal and abnormal), and to ensure that time error corrections are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.
BAL-005-0.1b	**Automatic Generation Control** This standard establishes requirements for balancing authority automatic generation Control (AGC) necessary to calculate area control error (ACE) and to routinely deploy the regulating reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a balancing area so that balancing of resources and demand can be achieved.
BAL-006-2	**Inadvertent Interchange** This standard defines a process for monitoring balancing authorities to ensure that, over the long term, balancing authority areas do not excessively depend on other balancing authority areas in the interconnection for meeting their demand or Interchange obligations.
BAL-502-RFC-02	**Planned Resource Adequacy Assessment (RFC)** To establish common criteria, based on “one day in ten year” loss of load expectation principles, for the analysis, assessment and documentation of resource adequacy for load in the Reliability First Corporation (RFC) region.
BAL-STD-002-0	**Operating Reserves (WECC)** Regional reliability standard to address the operating reserve requirements of the western interconnection.

Source: KEMA

The NERC and WECC control performance standards are similar to the EU standards with one exception: There is no requirement for operators to hold reserves to replace energy from variable generating resources such as wind generation or solar. The WECC members cannot deploy contingency reserves, a subset of operating reserves, for replacement energy from variable generating resources.

The WECC members are testing a new control performance standard known as the Balancing Authority ACE Limit (BAAL) standard, which permits greater variance in frequency control and in the area control error (ACE) tolerance band. The new BAAL proposed standard is graphically represented in Figure 32, which shows the permitted system frequency variation with the balancing authority's ACE.

Figure 32: Proposed BAAL Balancing Area ACE Standard



Source: North American Reliability Corporation. Reliability-based Control Standard Drafting Team's Proposed Metrics. August 29, 2008. www.nerc.com/docs/standards/sar/Background_for_RBC_Metrics_Comment_Form.pdf - 2008-08-29

The WECC system has traditionally been operated to very tight frequency and interchange error-control standards. These standards have been lowered over the past 10 years due to criticism that the grid operators were required to overcontrol for system frequency and ACE, which has resulted in excessive, and possibly unnecessary, redispatching of generating units up and down throughout the day. The interconnection of large amounts of variable generation resources, such as wind and solar generation, further exacerbates such control problems if the system must continued to be operated to the same tight control performance standards.

Therefore, the new proposed BAAL standard would allow for larger ACE deviations, as long as the system frequency remains within acceptable limits. The BAAL standard would help balancing authorities, such as the California ISO, Sacramento Municipal Utility District, and Los Angeles Department of Water and Power, handle the minute-to-minute fluctuations of energy from variable generation resources. WECC members have been testing the BAAL standard for the past year to verify the interconnected system can still meet reliability levels expected by the public and regulators. In the researchers' opinion, the BAAL control standard is closer to the control standards (as previously described) for EU grid operations. However, it is unknown at this time if the proposed BAAL standard will be adopted in the WECC, or if it may be modified prior to adoption.

California ISO Rules for Dispatch of Renewable DG Connected at the Transmission Level If Grid Congestion Occurs

The California ISO's preferred method for relieving transmission congestion in real-time operations is to use market rules for reducing output from generators on the supply side of a congestion bottleneck and increasing the output from generators on the receiving side of the bottleneck. If there are no market-based resources to redispatch, then the California ISO can go out of market and send dispatch notices to any generator that could relieve the congestion or overload. The operator has 30 minutes to relieve a thermally overloaded transmission line but only 20 minutes to relieve a transient stability limited transmission line. If the California ISO declares an emergency, the ISO dispatcher has the authority to send command and control instructions to any generator connected to the grid if changes are required for system reliability. The operator often has no real-time information about DG units that are 10 MW or less and probably does not have a telephone number to contact the owner/operator of the individual DG units. If there is a compelling need to contact the DG facility, the California ISO would request the distribution system operator at the local utility to contact the DG operator and request the change.

California ISO Forecasting for Balancing Area Demand and Renewable Production

Over the past 10 years, major research and development have been devoted to improving forecasting models for wind generation energy production. California, Germany, Spain, Demark, Ireland, Australia, Canada, and other areas in the United States have all devoted considerable research dollars and talent to develop and improve wind generation forecasting models for short-term and day-ahead forecasts. The science and mathematical models for forecasting wind generation energy production are now production-grade. The accuracy of the forecasts, however, is very dependent on the accuracy of the meteorological data for day-ahead wind speed and wind direction at the wind generation hub height, which is typically 100 meters or higher. Poor weather data produces poor energy production forecasts with even the best mathematical models. Also, forecast error rates will usually be higher in mountainous areas like the Tehachapi Mountains where the wind speed and wind direction will vary substantially from wind park to wind park in that area. Forecast error rates tend to be less for flat terrain areas such as offshore wind farms and prairie areas like Alberta, Canada, as the wind will flow through the area with minimum turbulence. So when forecasting error rates between areas are compared, they should be qualified by the type of terrain and the availability of Class A

weather forecast data for the wind generation areas. So to do a fair comparison of forecast accuracy between California and other areas, the terrain of the wind parks and availability of wind forecast data should be included as qualifiers.

In 2002, FERC approved the Participating Intermittent Resource Program (PIRP) for wind generators where the California ISO would use a commercial forecasting service to forecast the average hourly energy production. This hourly energy forecast is used to "schedule" the wind energy for the real-time operating hour. The wind generators that signed up to participate in PIRP were shielded from deviation penalties as their minute to minute actual energy production varied from their hourly energy schedule. About one-third of the wind generators in the California ISO area signed up for PIRP, so the California ISO is only doing a forecast for this subset of wind generators in their area.[66]

The California ISO's day-ahead wind generation forecast error is below 15 percent, and the 1-hour-ahead wind generation forecast is typically less than 10 percent. The ISO is working on similar forecasting programs for solar generation resources to be able to forecast accurately the energy injection from solar. When the amount of DG increases in the future, it will be important to include energy production data from these resources in the forecast models. The ISO is working to improve the accuracy of both the short-term forecasts and the day-ahead wind and solar generation forecasts for the integrated forward market. In fact, the ISO sent a representative to visit both the control centers at both Spain's and Germany's TSOs in 2010 and has used the knowledge gained in that trip to implement a renewable resource coordinator position in grid operations at the California ISO on April 1, 2011.

This position would provide forecast information to the generation dispatcher on what changes in energy production to anticipate from wind and solar generation for upcoming 15-minute to 3- hour intervals ahead. This ensures that sufficient replacement energy is available from the real-time energy market in the event that some of the energy from variable renewables ramps down. Solar and wind generation can also ramp up in very short periods (less than 30 minutes), and it is important to forecast these events to ensure other generation can be rapidly ramped down to keep system frequency and ACE within standards. Because energy is scheduled on an hourly basis, the amount of deviation from schedule can be a very significant problem. For example, the diurnal wind energy production pattern on June 12, 2011, went from a high of 2,295 MW at midnight down to a low of 444 MW at noon, then returning to 2,285 MW at midnight. The wind generation schedule for June 12 is not available to compare the actual hourly production to the forecasted energy production so the forecast error not available. This change in wind energy production by nearly 2,000 MW (out of a total installed wind capacity of roughly 3,598 MW) in the same day clearly illustrates the need for accurate hourly and sub-hourly forecasts of wind and solar energy production.

The California ISO uses day-ahead and hour-ahead wind generation and solar generation forecasts that are provided by a professional forecasting service. A comparison of the current

66 The California ISO is forecasting the energy production for 2,782 MW of wind generation in PIRP out of a total installed base of 3,598 MW of wind generation.

level of renewable production forecasting error levels for the California ISO, Spain, and Germany is shown in Table 13 below.

Table 13: Comparison of Current Normalized Root Mean Square Error (nRMSE) Forecast Error for Wind Generation (Normalized for Total Installed Wind Capacity)

Renewables Forecast Error Category	Spain	Germany	California[67]
Day-Ahead	<5 percent percent	<5 percent percent	< 15 percent
1-2 Hour-Ahead	1.5 percent percent	1.5 percent percent	<10 percent[68]

Source: KEMA

The California ISO is also working to improve both the quality of data inputs available from all renewables in its balancing area and improve the tools available for use by its new renewable staff position in the ISO operating center. It is also important to use the renewable forecast data into the ISO's real-time State Estimator Model to accurately anticipate potential transmission operating constraints. The ISO is also working on implementing a voltage-stability analysis (VSA) tool to check for potential voltage collapse problems.

California ISO Strategy for Operational Planning of Large-Scale DG

Unlike Germany, the ISO has no visibility of the energy production of DG resources connected to the distribution system and cannot send dispatch commands to these DG resources. This is especially true for DG resources that are connected behind the meter at a customer site and the DG output is netted with the customer load. The ISO is expected to cover the total load at the customer site in the event that the DG unit shuts down, but the amount of load to be covered is often unknown. This has not been a serious problem to date since the amount of DG in California is been relatively limited. However, with the amount of DG, especially solar PV, projected to grow to 3,000 MW or more in the next 10 years, the potential impact from a sudden, unexpected ramp-down or shutdown of these resources could represent a future reliability problem for the California ISO and California.

The California ISO describes its plans for addressing the impacts of large amounts of DG on its system in publication *IC-3 Non-dispatchable Distributed Energy Resources (DER) Changes, ISPO Forecast and Unit Commitment Decisions*. Large amounts of DG is a relative concept, but California's ISO system is a 50,000+ MW system, so 3,000 MW of DG is less than 6 percent of the California ISO's peak load. However, a total of 3,000 MW of DG could be 10 percent or more of

67 Revised Analysis of June 2008 – June 2009 Forecast Service Provider RFB Performance, March 25, 2010. California ISO (http://www.caiso.com/2765/2765e6ad327c0.pdf). Only about three-fourths of the wind generation in the California ISO area is covered under PIRP an included in the ISO's forecasts and forecast error data.

68 This figure reflects the aggregate hour ahead forecast error reported by the California ISO in the above referenced report.

the total California ISO's generation dispatched during the spring's or fall's shoulder month load periods. If the amount of DG increased to 6,000 MW, or even 12,000 MW, it would represent a very significant portion of the energy supply for the state. The risks associated with losing a portion of this energy resource would have to be studied to assess the effect on reliability and necessary changes to operating practices. DG would likely be very geographically dispersed, so the probability is low that large quantities of DG will be lost during a common event. A big concern is that if a major breakup of the transmission grid occurs and numerous islands are formed—in some cases with isolated loads islanded with comparable amounts of DG—it will be difficult for the grid operator to resynchronize such islands and reconnect them to the system. This scenario provides a rationale for having California ISO telecommunications and remote control capability to at least some clusters of DG in each area, which could help resynchronize and reconnect islanded areas with the main grid.

The California ISO states that it does not need to know the output of a DG facility that is less than 1 MW, but it does need to know the potential total impact of the DG facilities that are installed in a load area. The concept is to collect daily net-load and weather information, probably with five-minute granularity, from substations that supply a distribution area. The goal is to create a predictive/forecasting model for each area that would reflect the amount of base load, temperature-sensitive load, price-sensitive load, solar energy production based on the amount of sunshine, and wind energy (if any) based on the amount of wind, and other known types of DG in the area. The ISO can use its weather forecast data and load forecast models to forecast the net load in an area for the next day and the potential amount of variability to expect. Based on these improved hourly and subhourly forecasts and aggregation of the area forecasts with diversity factors, it can then make more accurate predictions of the amount of energy, regulation, and operating reserves that will be required to ensure grid reliability for the next operating day. Based on these improvements in the forecast models, the ISO can then ensure the optimum amount of generating units are dispatched and scheduled for the next operating day.

There are two issues that will be initially addressed:

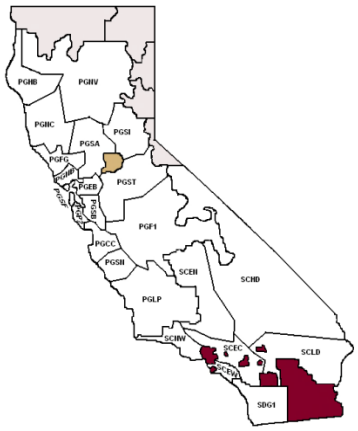
- The commitment of generating units for the next operating day
- The procurement of the optimum amount of regulation and operating reserves for the next operating day.

The potential consequences of ignoring this requirement for improved forecasting models that reflect the amount of DG on the system include major overcommitment of thermal generating units on days/hours when they are not needed, and this cost (potentially millions of dollars annually) is passed on to ratepayers. Another potential consequence is underestimation of the amount of load to be served if the DG energy does not show up in the real-time operating day, and there is insufficient quick start units available (reliability issue), or only peaker plants are available—at a very high additional cost for their energy.

The California ISO and other balancing authorities (BA) will need this information about the total amount of DG by type for major distribution load areas. They will need to work collaboratively with the load-serving entity (LSE) to insure the data collection systems are in place and the required data can be transmitted to the California ISO or the associated BA regularly. This includes planning and modeling data about the amount and type of DG that is connected in a load area. This data about the amount of installed DG should be updated quarterly and shared with the ISO or BA who will use it to update their load forecasting models. The second type of data needed is the actual net load for the area, the aggregate DG energy and the corresponding weather data for the area (temperature, solar, wind). Ideally this would be 1-minute data, but probably 5-minute data would produce acceptable results for updating the forecasting models, and it should be transmitted to the ISO or BA once a day. If it is going to be used by the ISO or BA for real-time operating decisions and real-time control, then it will need 4-second data to update the Energy Management System. The LSE may also want the same type of load forecasting model for its distribution planning purposes, although it has access to the data from all the smart meters installed at the customers in these areas.

Other questions are what size area should be selected for this type of net-load data collection, and what is the trigger for determining when an area warrants special forecasting treatment? FERC has encouraged the ISO to subdivide their Default Load Aggregation Point (DLAP) areas into smaller areas. The ISO would like to defer division of the DLAP areas until a future time. One possibility is to use the ISO's Sub-LAP areas as shown in Figure 33 for the DG aggregation and real-time demand response program. The ISO's current practice has been to allow aggregations of generators at the same substation and voltage level. Whether there would be broader allowable aggregations for DG would need to be determined. The ISO and the LSEs will need to develop criteria for aggregation of DG that is consistent with the need to accurate forecasting of net load for an area.

Figure 33: California ISO Default Load Aggregation Point (DLAP) Areas



Source: KEMA

A third issue is how to handle transmission-constrained areas with significant DG resources. It is conceivable that the amount of DG in a transmission-constrained area such as Humboldt County or some remote town in Southern California with large amounts of solar generation may eventually reach the point that local generation equals or exceeds the total amount of load in an area. The extreme case might be if over a period of years the net-load is driven to zero within an area, and the transmission to the area is underused routinely. However, if an event occurs that triggers the loss of major amounts of DG in the area, all loads could be dumped back onto the higher-voltage network, resulting in transmission line overloads. This risk can be avoided if the network is always planned and operated so that it doesn't depend on DG capacity for reliability. In fact, this is the approach used in Germany and Spain.

In summary, the California ISO should be able to handle much larger amounts of DG on the system in the future if the enhanced data collection system and improved forecasting models discussed above are successfully developed and implemented. It will require close cooperation and collaboration with the distribution companies to create the data collection systems and the new forecasting models.

Section 2.5 Summary of Key Lessons Learned Related to Operational Impacts

The following key observations can be drawn from the scope of the investigation covered in this section:

- In general, the definition of DG in Germany and Spain is not capped at a specific power level (for example, 5 MW, 10 MW, and 20 MW). Rather, it tends to be applied to any generating project that is small enough to connect to the HV, MV, or LV networks defined in Table 2. Generation projects requiring connection at the EHV level are excluded from the DG category. Based on Table 2, this would restrict use of the term DG to projects of 80 MW or less in Germany. As noted for Spain, projects with an installed capacity larger than 50 MW are excluded from the special regime; therefore, no individual renewables projects exist above this size in Spain, and use of the term DG in Spain seems limited to projects under 50 MW.
- Software tools used by grid operators for DG interconnection planning in Germany and Spain are comparable to those used in California, and some of the same vendor's load-flow tools are employed. However, the German grid codes also provide simplified rule-of-thumb formulas that estimate the technical performance levels of any proposed DG project and PCC. Applying similar rule-of-thumb formulas may be useful in California.
- There are significant differences between the ways that grid operators monitor and control distributed/renewable generation in the respective electric networks in Germany, Spain, and California. As noted in Section 2, one significant difference is the excellent level of visibility and control that grid operators have over DG/renewable dispatch in

Germany and Spain, which is vastly different from the current situation in California. In Spain, this is facilitated by CECRE, but in Germany it is handled directly at the TSO level. However, based on RD in Spain, renewable generation projects with no storage capability are the last tier of resources that can be curtailed to relieve grid constraints.

- The systemwide operating impacts of deploying nondispatchable DG on a large scale are a significant concern to TSOs in Germany, Spain, and California. To address this concern, both Germany and Spain have taken steps to insure that TSOs have adequate visibility of renewable DG dispatch levels in real-time and accurate DG forecasting tools. TSOs in Germany and Spain are also allowed to curtail renewable DG when necessary to maintain overall system stability or to reduce congestion. However, German law requires that TSOs must exhaust all available market options before curtailing renewables. Even so, the number of out-of-market renewable curtailments required by German TSOs has grown significantly in recent years. During 2010, German TSOs had to take curtailments on almost a daily basis. Additional rules and requirements for DG monitoring and curtailment introduced in Germany in 2011 will better equip TSOs to deal with such events. Germany also experienced a sizeable increase in day-ahead forecast error levels for solar PV in 2010. In fact, German TSOs had to activate 100 percent of all contracted operating reserves (more than 7,000 MW of negative balancing reserves) for several hours on September 6, 2010. As a result, German regulators and industry representatives agreed to implement improved PV forecasting tools at both the TSO and DSO levels as of April 2011.
- Operational planning and forecasting tools and approaches related to DG/renewables are also different in the three countries. Only Spain has a centralized approach in this regard by virtue of CECRE, which resides on the control room floor at the national TSO. In Germany and California these functions are handled by the individual grid operators, which includes multiple TSOs in Germany and both the California ISO plus the various public power entities in California. CECRE employs a wind generation forecasting system composed of three components: a database on the wind farms, a prediction algorithm based on a self-adaptive time series, and a forecast module. In the future, CECRE plans to expand its capabilities to include other categories of renewables.
- The California ISO has recently added a renewables forecasting position on the control room floor to monitor and forecast renewable production. This position will play a key role in ensuring the California ISO can continue to meet grid performance standards and have the optimum amount of dispatchable resources available under market protocols to handle the increased variability of renewable resources in its balancing area. In the future, the functions of this position at the ISO could expand into a scope closer to that of CECRE in Spain. However, this would require that the California ISO acquire additional authority for curtailing of renewables when needed for grid reliability. In addition, given the relatively high level of renewable forecasting error currently occurring in California (particularly in the day-ahead forecast), it appears that the ISO should continue to monitor the types of forecasting tools and processes used by grid operators in Europe as well as other balancing areas in the United States with large

amounts of renewables to determine best practices (for example, BPA and ERCOT) that can be incorporated into California ISO's renewable forecasts.

- The ENTSO-E has a requirement for a minimum of 3,000 MW of primary frequency control, and the provision of each TSO's share of the total is a binding obligation. This affects the daily unit commitment of conventional generators (for example, with governor response capability) by TSOs in the EU. Similar requirements exist for secondary control (that is, AGC units). Some individual TSOs also invoke additional unit commitment and AGC requirements within their respective control area. For example, the German TSOs apply a probabilistic method, which results in a significantly greater need for secondary control reserves than required by ENTSO-E.
- The German electricity generation profile relies on a balanced mix from various sources of installed capacity. Renewable sources are ranked first due to a strong increase of power from wind, solar and biomass in recent years. In California, electricity from nuclear and conventional generating plants still contribute more to the net electricity portfolio than renewables as the former provide the bulk of base load power.
- A comparison of installed generation capacity (conventional, hydro, and renewable) in Germany and Spain is shown in Table 14. While the level of installed renewables is similar in both countries, the ratio of conventional/hydro generation capacity to installed renewable capacity is much greater in Germany (3.5 to 1) than in Spain (1.9 to 1). This indicates that there are significantly greater reserves of conventional/hydro resources available in Germany to commit for system control, if needed. However, even with a ratio as low as 1.9 to 1, Spain has apparently been able to meet its ENTSO-E control performance requirements.

Table 14: Comparison of Installed Generation Capacity in Germany and Spain

Country	Installed Conventional Capacity (GW) [Excludes Hydro]	Installed Hydro Capacity (GW)	Installed Renewable Capacity (GW) [Excludes Hydro]
Germany (as of 12-31-09)	109.2	10.6	34.6
Spain (as of 12-31-10)	47.2	16.7	33.6

Source: KEMA

- Based on Table 14, it appears that the combination of California's installed conventional/ hydro resource capacity is comparable to Spain and roughly half of the capacity in Germany. However, this does not account for balancing resources that may be available over transmission ties with neighboring systems. For example, there is about 15 GW of tie capacity between the California ISO balancing area and neighboring systems.

Therefore, it should be possible for market participants in other regions of the WECC to bid on and provide a significant component of the California ISO's ancillary service requirements. Similarly, Spain has a major interconnection with France, and the loss of this intertie is studied routinely by CECRE because this contingency significantly affects reliability of the Spanish grid. In fact, based on its operational studies of this contingency, CECRE invokes a limit on the amount of renewable dispatch allowed to run at certain times to ensure that the system will remain stable if the contingency occurs. Germany is also interconnected with the Scandinavian market via several major ties:

  - Kontek cable (Denmark): 600MW
  - Baltic line (Sweden): 600MW
  - Jutland: 1,500MW import capacity and 950MW export capacity.

- In regard to implications on renewable integration of having multiple "balancing authorities" within California, this situation is comparable to Germany where there are multiple TSOs and each performs a similar set of operating responsibilities to that of a U.S. balancing authority. For example, each German TSO is required to maintain a predetermined share of the total reserve and balancing requirements of the overall German power system, and each has access to markets through the national power exchange. It does not appear that having multiple TSOs has in any way inhibited renewable/DG resource integration in Germany. Regarding multiple DSOs, a similar situation exists in California, Germany, and Spain. The main issue this has raised in Germany and Spain has been the need for improved coordination between the TSOs and DSOs in regard to renewable forecasting and curtailment actions. Similar issues are likely in California but should be solvable.
- German TSOs have been able to manage the renewable variability of generation by committing dispatchable generation assets combined with market-based ancillary services to meet system reliability requirements. Dispatch flexibility is provided by various generation technologies including nuclear power, hard coal, oil-fired installations, and gas-fired and large pump-storage hydro power plants. Moreover, as the scale of grid interconnections to neighboring countries increases, new electricity sources become available to supply ancillary services to the German power system. For instance, some Austrian power producers (predominantly hydropower) also participate in the German frequency control reserve markets and provide fast-reacting power reserves to German TSOs.
- The largest impacts on ramping, load following, and regulation in the German grid are from intermittent wind resources. To address these requirements, as noted in Section 3, the TSOs have monthly, seasonal, and annual auctions for bilateral contracts with conventional generators (usually hydro power or pumped hydro) for primary reserves that provide first level of redispatch related to wind. Contracts can also exist between TSOs for such reserves. Also, the TSOs have a monthly secondary reserve balancing market for energy and frequency regulation. Finally, the TSOs procure tertiary reserve daily for any ancillary services that can be handled/rebalanced through manual dispatch orders in a 15-minute time frame (for example, those services that do not require

automatic response). In recent years German TSOs responsible for regions with high wind power penetration conducted annual and monthly solicitations for wind reserves to augment their other categories of regulation services and execute bilateral contracts with the successful bidders to provide this supplemental service for up to 200 MW to 300 MW of bidirectional regulation. However, this option has been terminated in 2011, and TSOs must now rely on secondary reserves and the power exchange to manage control performance impacts of intermittent generation.

- For practical purposes, renewables do not participate in today's power reserve markets in Germany or Spain, as these suppliers cannot guarantee the provision of these reserves for a sufficient period, as required under the current procurement mechanism. However, it is assumed that wind and biomass power may contribute to frequency control in the future. A portfolio of dispersed wind power installations might provide significant amounts of downward regulation power, while biomass facilities may be able to provide control power for both downward and upward frequency regulation.
- New energy storage technologies (apart from pump-storage hydro power) and demand–side management in Germany, although not yet implemented, could be used to provide additional flexibility for addressing generation and consumption variability in the future. Similar benefits to large-scale renewable/DG integration can be realized from continued deployment of these same technologies in California.
- Deployment of large amounts of DG is going to challenge distribution planning engineers to perform rapid and comprehensive studies on the effect of each proposed DG facility on the distribution system. They will need to have the right tools for evaluating the voltage profile on the circuits for the following two extreme conditions: 1) Maximum DG output and low customer loads and 2) High customer loads and low or zero DG output. They will have to verify the circuit design that will keep voltages within acceptable limits and keep flicker and harmonics are within standards.
- Key load area substations in California must have data acquisition and information storage and communications to enable the load and DG generation forecasters to be able to build new models that reflect the net load for the area. These models must include temperature, wind, and solar data for the area. When California moves to price-sensitive loads, such as a lower nighttime price for charging plug-in electric and hybrid vehicles or other loads that would respond to price signals, then the forecasting models must be enhanced to predict the revised load for the area.
- The European experience shows that it is vital for the power system operator to be able to monitor the output of DG facilities as well as direct DG units to curtail dispatch when required for emergencies, such as grid reliability and safety.
- Findings on forecast error for renewables show that California is achieving a comparable forcasting accuracy as Spain at this time. Both countries are clearly not achieving the accuracy levels that are being achieved in Germany. However, this may not be an apples-to-apples comparison due to the amount of offshore and coastal wind in Germany, which has very consistent wind patterns. Regardless, KEMA believes the California ISO is well on track to continuously improve its renewables forecasting

methodology, particularly in light of its new state-of-the-art renewables desk at the control center staffed by a dedicated renewable resource coordinator.

SECTION 3:

DG on Public Property

This section addresses the topic of solar power and DG projects on public property in Germany, Austria, Switzerland, and Spain. Key questions examined in this section include:

- Do European countries place solar DG on government buildings? Is this a common practice or a new practice?
- Do renewable DG projects on government properties go through the normal permitting process, or are they permitted through an expedited process?
- How do the European programs for renewable DG address issues such as construction safety issues associated with building along highways, condensation issues on or around waterways, security of equipment, maintenance of equipment and surrounding area, interconnection issues, public experience of equipment being highly visible?
- How are renewable DG projects that are placed on government property in these European countries financed? Are there special or higher incentives or tax credits for renewable DG placed on government property? What are the ownership and revenue structures of the renewable DG projects?

This section is organized as follows:

- Section 3.1: Overview of public sector activity in Germany
- Section 3.2: Overview of public sector activity in Spain
- Section 3.3: Summary of key lessons learned

General Role of Public Authorities

Federal and state authorities serve to provide the legal and regulatory foundation to promote renewable project development, disseminate information on renewable energy, and provide economic incentives for research, development, and deployment of renewable sources and technologies. Indeed, renewable energy policy heavily promotes activities supportive of technological progress, provides funds for high-technology pioneer projects, and initiates pilot projects for educational purposes. Most important, the renewable policy sets the legal framework for increased use of renewable sources and incentivizes new private stakeholders to invest in renewables.

Municipal authorities are increasingly required to check their internal processes for sustainability and energy efficiency and to serve as an example to the private sector. For the most part, municipal authorities usually refrain from taking over a role in the development of renewable sources in their proximity due to economic risks, considerable investment

requirements, and other challenges. However, they are keenly aware of the significant economic and social benefits of local renewable resources. Hence, municipal decision makers have been very active in assigning new areas for renewable energy use and assisting individuals and companies with project implementation. In return, municipal authorities incur significant income from land sales, leasing fees, and taxes. Furthermore, the voice of citizens can be a driving force behind municipal administration action to promote climate change protection and sustainable energy policy for the public good. This has led to considerable differences in the intensity of renewable energy use by regions or municipality.

Increased activity by the public sector is expected to occur related to solar water, heating, and cooling provisions as soon as the EU Directive 2009/28/EC is incorporated into national legislation. This directive stipulates that "Member States shall ensure that new public buildings and existing public buildings that are subject to major renovation, at national, regional and local levels, fulfill an exemplary role in the context of this Directive from 1 January 2012 onwards. Member States may, inter alia, allow that obligation to be fulfilled by complying with standards for zero energy housing, or by providing that the roofs of public or mixed private-public buildings are used by third parties for installations that produce energy from renewable sources." (Article 13.5)

Germany is in the legislative process of adopting the directive by amending the Renewable Electricity Act and the Renewable Heat Act. The government estimates that every year some 2,500 buildings used by public authorities (rented or owned) will be required to adapt their heat supply according to the Renewable Heat Act. Solar heating will become the preferred technology at buildings used by public authorities to comply with the requirements of the law. An investment cost of €729 to €900 per square meter is estimated for installing this technology.

Activities

There is insufficient information available to determine the level of project development activity that can be directly attributable to municipal authorities within the four jurisdictions examined. Although renewable projects often have to register with the corresponding network operator and applicable administration, a central registry or database of renewable projects does not exist. Furthermore, public information that is available does not distinguish between municipal activities and privately driven projects.

The involvement of municipal authorities in renewable project development located on publicly owned property is limited at this time. Municipal authorities are involved primarily by adjusting local urban development plans and issuing construction approval, where required. Moreover, they sometimes ease project development by providing economic incentives, information, and advisory services. For instance, municipal authorities have been very active in assigning public territories to wind power or ground-based solar power use. In the case of small hydropower, municipal authorities have issued long-term water rights to licensees. In addition, there are a few examples of electricity generation from gases, biomass, and waste where local legislation has provided economic incentives or stricter environmental provisions that serve to promote renewable project development. Nevertheless, municipal resources are often not exploited by the administration itself, but rather by local utilities. In return, municipal

authorities incur significant income from land sales and leasing fees as well taxes from entrepreneurial activity.

Procedures

In general the promotion scheme does not discriminate or favor public authorities in their access to the feed-in tariff. However, when it comes to project planning and implementation, some differences may arise between a public property project and a private property project. Based on the research team's experience, small-scale/ building-based projects in the private sector do not require special permits from authorities but have to build in line with industry norms and standards and arrange for network connection with the local network operator in accordance with the technical network connection procedure. These projects can be completed rather quickly. In contrast, projects built on municipal property need more lead time due to the approvals required from various departments to solve issues like fire control, construction matters, environmental impact, insurance, or other issues of concern to public authorities. Moreover, public procurement procedures apply, which come into play as soon as solar panels have to be bought or an insurance product has to be selected. Further, public announcement and invitation to bid may be required for finding the contractual partner(s) in a public-private partnership. Finally, objections from the public and political parties may delay project implementation.

In the case of a public-private partnership for ownership and/or operation, other considerations such as security of equipment and installation maintenance are subject to contract negotiations or the operating service agreement between installation operator and owner.

Germany

This section provides a brief overview of the market in Germany particularly as it relates to promotion of renewable distributed generation projects on public property.

Overarching National Renewable Policy

Recent Changes to the Renewables Act That Affect DG on Public Property

Germany has adopted a goal to increase the share of renewable electricity in total electricity supply to 30 percent by 2020. To increase power generation from renewable sources, the German legislature has introduced a set of legal provisions and economic incentives.

The most important legal element is the Renewable Energy Law (EEG). It was first adopted in 2000 and has been amended various times, most recently in 2009 and 2010. The 2004 amendment introduced a (tariff) separation among building-based, ground-based, and other installations. Building-based installations included those built on roofs, building facades, and noise protection walls. Ground-based installations were only eligible for payment if they were commissioned for certain legally defined land categories and within the framework of a local

development plan and a planning procedure under the building code.[69] These land categories included:

- Sealed terrains.
- Grounds formerly used for military or commercial/ industrial purposes and made usable for other purposes (known as converted grounds).
- Green fields formerly used for agriculture.
- Other installations, including those mounted on or added on grounds or at facilities for which the primary purpose is not electricity generation from solar power (for example, industrial sites).

The 2009 amendment to the Renewables Act partially corrected for the changes introduced in 2004. Ground-based installations have been additionally allowed on converted areas that were formerly used for transportation (for example, roads) or housing. Moreover, it allows for solar panels on slopes along highways and railways as broad as 110 meters.[70] As of the end of 2010, green fields formerly used as agricultural areas have been excluded.

Furthermore, the 2009 amendment requires a regular adaption scheduled every four years. For solar power the annual digression is set to 9 percent to 11 percent (depending on the installation type and size) but is kept variable, and the specific digression depends on the increment of total installed capacity of solar power realized in the prior year. Such dependency on actual growth was exacerbated by a July 2010 amendment along with a significant decrease in the nominal feed-in tariff amount. This was due to a strong drop in solar panel prices after 2008 and an increased gap between state subsidy under the EEG promotion scheme and the generation from solar panels.

General Role of Public Authorities in Germany

Until the last few years, it was commonly accepted that municipalities would not play a major role in electricity generation apart from helping ease project development. One of the most important arguments behind this assumption has been a German federal law that stipulates that municipalities have to cover their costs primarily from federal funds, such as, taxes and fees for public services provided by municipal authorities to its citizens for public good. Ideally, administration(s) should refrain from activities that compete with market forces or do not provide a public good. Moreover, making a profit may not be the sole reason for a municipal activity unless it relates to the provision of a public good according to the former principles.[71]

However, in recent years more municipalities have increased their activities in the renewables sector and have become more active in using municipal properties (grounds, infrastructure, and

69 See official Explanation to the 2004 Renewables Act.

70 Total width measured from the motorway's lateral edge on.

71 This argument probably also applies to other jurisdictions but has not been further investigated in this study.

buildings) for renewable DG applications. In doing so, they gain additional income from the Renewables Act and the largely unlimited federal funds associated with it.[72] The reason behind this change is the increasingly tight budget constraints both at the municipal and federal levels. Add to this the municipal decision makers' concerns to cover public expenses, contain debts, and activate new income sources. Moreover, a desire to improve their image in regard to energy education, environmental impacts, and sustainability may encourage local decision makers to become more active in renewable energy development. Municipalities that are more advanced in their approach to these issues have made considerable investments in DG and have reduced dependence on large electricity suppliers for their energy needs.

Activities Related to Solar Power

The following discussion focuses on PV projects on buildings and highways. Little can be said about PV along public waterways, since natural waterways are reserved for shipping, while watersheds and adjoining areas are often environmentally protected areas or used as flood plan buffer zones.

Roof-Based Installations

Due to relatively small amounts of funding required and high feed-in tariffs, PV power development has for the most part evolved around small-scale projects. Today, some 90 percent of German PV installations are roof-based modules smaller than 30 kW. They are typically connected to the low-voltage (400 V) network of the local network operator.

Municipalities today are making roofs of public buildings, such as schools and hospitals, more available for PV installations. Typically, they do not adopt a project development function but may engage in some form of public-private partnerships and put the corresponding areas at the disposition of the project. Different models for public-private partnerships have been developed and implemented for this purpose. The various models for private participation enable the municipality to promote civic participation and put forth a progressive image. But economic factors are often a significant market barrier to municipal ownership. For those municipalities that do have an ownership share, they incur significant (and predictable) income from electricity production. Alternatively, they may incur revenue from leasing land or other areas to renewable developers. Moreover, they may have educational goals in sight. For instance, school administrators and students' parents often encourage the use of school rooftops for solar panel installation as this serves to educate school children on the benefits of renewable technology.

Apart from setting appropriate investment conditions in urban development plans or making public property available, municipalities break new ground as well by providing useful information and endorsing new scientific methods to investigate solar potential. For example, new approaches combine flyover data measurements of building covering an entire urban area

72 As indicated above, the Renewables Act is the primary source of funding of electricity from eligible renewable sources. It does not discriminate plant operators as, according to the law, "installation operator shall mean anyone, irrespective of the issue of ownership, who uses the installation to generate electricity from renewable energy sources or from mine gas."

and structural analysis of individual buildings[73] along with data from local real estate maps. Going even further, there are some examples of what is known as municipal solar maps (cadastre) that provide online information on each building's estimated solar potential.

Public authorities are also required to check their internal processes for sustainability and energy efficiency and to serve as an example in the local community. Two relevant examples are:

- The Bonn office location of the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety delivers insight into its internal activities in the field of sustainability by means of its Environmental Statement. According to the 2010 statement, a roof-based solar power installation is planned for 2011.
- Within the framework of its comprehensive climate initiative, the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety has provided funds for building solar panels at schools and installing visualization tools to assist student's education. One program, Solar Support for Schools – Making Renewables Visible, covers 400 schools. The initiative also provides federal support for investments in energy efficiency and renewable energies by industry, municipalities, and consumers. Up to €400 million will be made available in 2011 from the sale of carbon dioxide emission allowances.[74]

Installations Along Highways and Railways

The 2009 amendment to the Renewables Act adds slopes along highways and railways to the list of approved project categories. In addition, noise protection (abatement) walls along motorways may be used, which fall into the category of "other" facilities. These areas have been admitted by the act due to their large potential for solar power. There are some 12,500 km of highways and some 34,000 km of railways in Germany.[75] There is the additional potential to combine these solar projects with noise abatement structures, requiring limited use of additional land and reducing competition for available land space.

In practice, there are no standard procedures for solar projects along highways due to a lack of relevant historical experience and established legal provisions. Approval responsibilities are also dispersed among federal, federal-state, and municipal administrations and can be complicated by complex land ownership rights. However, KEMA noted increasing engagement

73 Roof pitch, building orientation, height and so forth.

74 http://www.bmu-klimaschutzinitiative.de/en/press?d=100.

75 Verges may have different aspects, uses, and ownership structures, which might significantly reduce the total length of areas available for solar power.

of public administrations to promote these types of projects, largely driven by the need to ensure public good and the opportunity to incur economic incentives.[76]

The approval of land use related to noise abatement walls along highways for solar power by the Renewables Act boosted the interest from both municipal authorities and private investors. Numerous planned projects have been made public, and municipal activities for exploitation of the corresponding potential is occurring in even greater numbers. Local/municipal development plans are being adjusted to support private investors' desires to use lands purchased or leased from municipalities. They also have economic objectives to achieve by means of public/private partnerships on these lands, as has already been achieved on public buildings. For instance, solar panels attached to noise abatement walls may contribute to covering the costs for building and maintaining the latter. Project plans disclosed so far provide for various types of installations. They refer not only to slopes and noise abatement walls, but also to shelters above highway sections covered entirely by solar panel modules. Some examples of planned or completed projects include:

- The combination of solar power and noise protection on Highway A92 near Freising, commissioned in 2004, was the first of its kind in Germany. Solar panels were built on top of an earth wall separating the motorway from a business park nearby. Now expanded to some 1,200 meters long, it merges the cooperative installation built by a citizen consortium in 2003 with a second installation added later by a local utility. It has a total installed capacity of 717 kW (peak) and produces some 700 MWh per year (with separate metering for the two parts).[77] A similar installation is shown in Figure 34.

Figure 34: Example of Solar Power Installation at an Earthen Slope Used for Noise Abatement on Highway A96 (Similar to the Freising Project)

Source: www.ib-wimmer.de; found in the Photovoltaic Power and Noise Protection at the Motorways A10 concept of the municipality of Michendorf, 2010.

76 However, there are examples where projects have not turned out well, especially more complex projects and technologies. For instance, there are cases of citizen opposition to geothermal projects due to security concerns. Moreover, cases have been made public where municipal administration opted for geothermal heat on public properties and where earth movements have produced significant damages to buildings. Furthermore, wind power installations are often affected by objections from citizens living nearby with respect to shadowing and/or noise effects.

77 http://www.sonnenkraft-freising.de/pr_ssw.html.

- In 2009, a local utility providing energy and network service to the neighboring municipalities of Goldbach and Hösbach founded a project entity for enclosing a section of a nearby highway for a length of 2,000 meters, as shown in Figure 35. It currently has 8,500 solar panels that produce some 1.5 GWh annually, at an efficiency rate at 950 kWh/kW peak, and generating a revenue of €600,000 per year. The project required an investment of €6 million (10 percent of total investment was in equity residual funds came from local banks and citizen shareholding). The entity in charge is entirely owned by the utility, which itself is a municipal agency. A highway asset usage contract (with higher administration) was established for a contract term of 20 years (equals the Renewables Act promotion period) and has a potential extension by up to 10 years. Operation is monitored via real-time data provision and analysis at the utility. Total operational costs, including the leasing fee covered by the highway asset usage contract plus maintenance and insurance, amount to €75,000/year.[78]

Figure 35: A Pioneering 1.6 MW Project for Enclosure of Transportation Noise on Highway A3 Between Goldbach and Hösbach.[79]

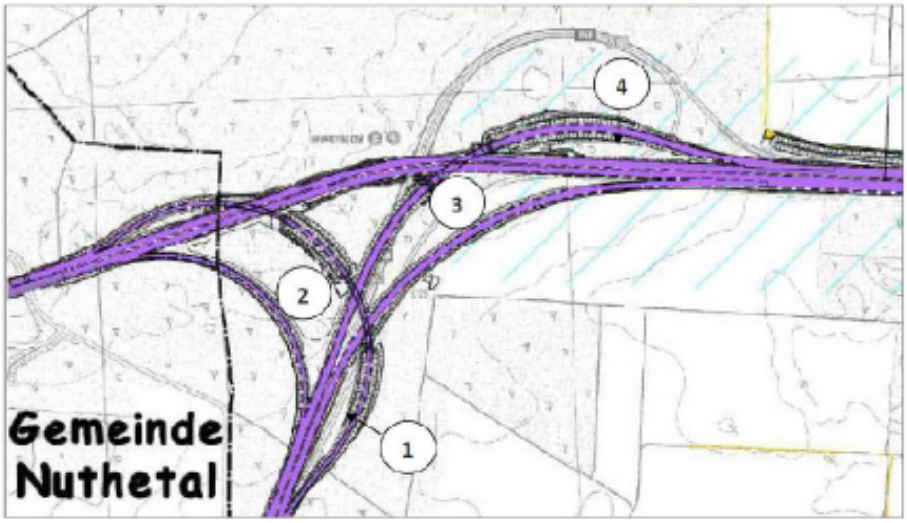
Source: www.a3solar.de

78 www.a3solar.de.

79 Comparable also to Solar Power Serpent Highway project proposed for Santa Monica (U.S.); http://buildaroo.com/news/article/solar-power-serpent-highway-santa-monica/

The state-owned German Unity Motorway Planning and Construction Company (DEGES)[80] has responded to the municipality of Michendorf's concept for improving noise reduction and prevention at a section of one of the most heavily used motorways in Eastern Germany. The local concept provides for a combination of reinforcing existing noise reduction walls and privately financed solar panels. DEGES has picked up the concept and expressed interest to gather information about potential investors and whether there are private entities interested in the project. The project envisions raising noise protection walls up to a height of 10 meters over a length of 5.5 km, which will probably be carried out by the federal transportation office. Moreover, the project stipulates that the investor shall be responsible for constructing solar panels (with potential noise reduction capability) over the same length, operating them for 20 to 30 years and decommissioning them afterward. It also has to bear the associated costs. The project cost is expected at €25 million based on a planned capacity of 13 MW (peak). A map and photograph of the project area are shown in the following figures. According to the project documentation, the investor is also liable for the additional cost of adapting the walls to the solar panel construction, as well as a fee equivalent to a percentage of the income from electricity sales (presumably equivalent ownership Model 2 as discussed later in this chapter).

Figure 36: Proposed Areas 1 Through 4 for Ground-Based Solar Power at the Nuthethal Junction (Based on the Michendorf concept)



Source: Photovoltaic Power and Noise Protection at the Motorways A10 concept of the municipality of Michendorf, 2010.

80 Deutsche Einheit Fernstraßenplanungs- und -bau GmbH (DEGES) is a state-owned institution founded shortly after the reunification of former two separate German countries to support the new member provinces of the Federal Republic of Germany in construction and modernization of motorway infrastructure.

Figure 37: Proposed Area 3 for Ground-Based Solar Power at Nuthethal Junction

Source: "Photovoltaic Power and Noise Protection at the Motorways A10" concept of the municipality of Michendorf, 2010.

There are some cases where investors have not been able to convince municipal decision makers to change urban development plans to incorporate additional areas next to highways into the plan, partially due to public reluctance to do so. This might imply that, particularly in the case of small municipalities, special emphasis has to be given to public concerns and integrating them into the project plan, for example, including the advantages to be gained from noise abatement and recapitalization of municipal bonds.

Projects along railways have not been as prevalent as projects along highways. However, due to lack of data on this specific topic, it is difficult to assess why there is little activity along railways.

Other Aspects Relevant to Solar Power Along Highways

Potential investors may face significant challenges when exploring the potential for solar power along highways and railways. First, highways are federal property but are maintained and operated by specific highway operation offices subordinate to federal and state administration. They are responsible for managing the highways as well as slopes and protection walls, including maintenance and repair activities as needed to ensure traffic safety.

An important element to transportation safety is established by a federal law on highways (Law on Motor Ways). The law empowers the highway office to grant annulments of the legal ban on constructing facilities within the aforementioned distance(s) on a case-by-case basis. The law

prohibits installation of structures within 40 meters of the highway.[81] In addition, within a further distance of 60 meters, up to a total distance of 100 meters from the lane's edge, a construction permit from the federal-state's highway operation office is required in addition to normal construction permits. Ground-based PV installations are only eligible for remuneration if they are commissioned within the framework of a local development plan and a planning procedure under to the building code. This implies the highway office's prior consent for construction and possibly an annulment of the ban on construction within 40 meters of the lanes.

Apart from safety concerns, land ownership is also an issue for solar panel proliferation next to highways or railways. Other than highway service areas, land space along highways primarily encompasses arable land, forests, residential development, and urban facilities owned by either the private sector (companies and individuals) or local municipalities.

Financing and Ownership

Investment credits are often provided from funds granted by federal, state, or municipal authorities and/or from the state-owned KfW bank, although double funding is often not allowed. The access to investment credits and foreign capital at preferential conditions is often limited to individuals and private enterprises, while municipalities are excluded. Public-private partnerships, by virtue of the private entity, have access to these investment credits and foreign capital. For fully dedicated municipal projects, financing typically comes from municipal budgets as well as from (local) banks. Local banks also play an important role in financing local public/private partnerships.[82]

In general the following models for financing renewables projects are common practice in Germany:

- **Operational Responsibility and Ownership by Municipal Administration**
  - The municipality finances a project from its budgets or by credit for energy self-supply, often to decrease dependency from nonrenewable sources and to become more energy-efficient.
- **Public Ownership**
  - Public administrations hold stakes in the project indirectly via a new project entity or local utility (can be wholly or partly privatized). The project entity is responsible for the operational issues of the project. Often various utilities or administrations from different municipalities cooperate for joint operation, especially when capital requirements cannot be met by a single municipality. This approach may be combined with a public-private partnership approach, for example, cooperative

81 This is the primary reason why there are no advertising panels along motorways that might distract drivers and is contrary to other European countries' policies.

82 Information taken from *Renewable Energy Projects in Municipalities – Success Factors for Planning and Implementation* (translated), Renewable Energies Agency, 2010; available at www.kommunal-erneuerbar.de.

citizen participation (see below). Municipalities earn income from energy sales and leasing fees, depending upon the specific contractual arrangements for the project.

- **Energy Contracting**
  - A contracting service company is responsible for planning, construction, and operation of a renewable project built on municipal property. Under the terms of a contract, the service provider incurs income from energy provision to the administration. After a contract period the installation passes into public ownership. For instance, formerly public services often have been outsourced to a semi-privatized local utility that owns or operates the assets and provides services to the public and the administration. Assets are operated and maintained in a more efficient way, and investments are not financed from public budget (for example, thermal heating for buildings and hot water in public swimming pools.)
- **Cooperative Projects**
  - Projects are initiated and financed by neighborhood/ citizen cooperatives. Municipalities may provide public property, initiate the project, or even participate in the cooperative. Citizens hold shares in the cooperative which kick-starts the project; missing capital may be provided by local banks and cooperative banks.
- **Investor-Led Projects**
  - The investor (bank or project developer) develops the project, assuming responsibility for planning, financing, construction, and operation. It sells shares, for example, via renewables capital investment funds. The role of the municipality is limited to setting appropriate investment conditions in terms of planning law, urban development plans, and providing public property (particularly open areas).

Specific Models for Solar Power in Highway Corridors

In late 2010, the scientific service to the German parliament evaluated different ownership models for combining solar panels with noise protection (abatement) facilities on highway corridors. According to its report,[83] an exceptions permit from the federal-state transportation office is required, based on a written agreement between the authority and the investor. The report assumes that investors prefer leaving the ownership of the noise protection (abatement) facilities with the administration (federal or federal-state[84]), while ownership of the solar panel installation is done under one of the three models discussed below:

- Model 1: ownership and operation by the administration

83 The report has not been made public, and the information provided here is taken from the municipality of Michendorf's concept for improving noise reduction and prevention, DEGES's expression of interest (see above) refers to.

84 The term federal-state refers to a regional administration of the federal German government, similar to the 50 state governments in the United States.

- Model 2: ownership by the administration, but construction and operation of the solar installation by the investor, which is additionally liable to a noise reduction contribution fee
- Model 3: construction, operation, and ownership of the solar installation remaining with the investor, which is also liable to provide additional noise protection[85]

Apart from ownership, these models also consider the desire for additional noise abatement measures as well as income from electricity generation.

According to the service's analysis, the first two models are difficult to realize, and the third model is preferred. This is due to potential budget law restrictions concerning income from the Renewables Act incurred by administration under the first two models. The analysis concluded that there is no experience combining solar panels with noise abatement in terms of the ownership and permitting process. Therefore, an amendment of federal legislation in this regard is recommended.

Permitting Process

Large ground-based installations require permits. They have to be added to the local urban development plan or be registered under municipal construction planning before the project can start. In contrast, most of the smaller PV projects are built on private property, and no specific construction permit is required, unless it is a property that is officially listed as a historical or architecturally protected building.

Administrations may exert further influence on private PV projects in different ways. They may establish specific requirements on building orientation or roof structure in the urban development plan and subsequent local construction planning procedures. Differences often arise between the federal/state and municipal levels. The two administrative levels have primary influence on regional and local development plans, taking into account infrastructure projects, urban expansion, environmental protection, and economic development goals.

Spain

This section provides an overview of the market in Spain, particularly as it relates to the promotion of solar projects on public property.

Overarching National Renewable Policy

Spanish Renewable Energy Plan As It Relates to DG on Public Property

The Spanish Renewable Energy Plan (REP) 2005-2010 sets up the Spanish objectives in renewable energy generation, defines the global strategy for its achievement, and describes the

85 Two alternatives exist: combining solar power with noise reduction facilities, that is, the physical attachment of solar panels to the latter, alternatively, using multifunctional solar panels with integrated noise protection (though researchers do not know which is more probable or suitable).

framework by identifying regulatory aspects, market actors, market barriers, and R&D activities.

The Spanish Energy Policy is established by the Ministry of Industry, Tourism and Commerce (MITYC). The Ministry of Industry is advised by the Institute for the Diversification and Energy Saving (IDAE), an institute that is independent of the ministry. The IDAE is a public, business-structured organization reporting to the ministry through the General Secretariat for Energy. Its strategic goal is to promote energy efficiency and the rational use of energy in Spain, to support the diversification of sources of supply, and promote the use of renewable energy. IDAE is the organization in charge of the elaboration and follow-up of the Renewable Energy Plan (Plan de Energías Renovables) for Spain, 2011-2020 (PER 2011-2020), currently in draft format.

There are RDs established mainly to achieve the political goals established in the REPs. For instance, according to RD 2818/1998, renewable electricity (RES-E) producers in Spain with a capacity below 50 MW were provided the option to choose between two payment schemes:

- Fixed regulated feed-in tariff
- Market option (electricity market price plus a fixed premium).

n 2008 the Boletín Oficial del Estado published a new RD 1578/2008 regarding the feed-in tariff for PV plants. This decree established provisions that are in line with the REP 2005-2010 and update tariffs that were previously governed by RD 661/2007. The publication of the RD 1578/2008 was motivated by the following main factors:

- The growth of the installed solar PV capacity far exceeding the goals of the REP 2005-2010 after the publication of the RD 661/2007. For instance, the goal for the solar PV sector defined in the REP 2005-2010 was achieved far ahead of schedule in 2007.
- The need to promote the development of rooftop PV plants, according to the general policy of supporting distributed small plants and following the example of other countries such as Germany.
- The need to enhance the competitiveness of PV technology, putting pressure on market prices of solar modules to achieve convergence with the cost of conventional generation technologies within a reasonable timeframe.
- The desire to avoid the fragmentation of single plants to benefit from more favorable feed-in tariff (many parks have been divided into 100 kW plants, formally owned by different companies but managed centrally).

The new tariffs established by RD 1578/2008 distinguish between two types of PV installations, as shown in Table 15.

Table 15: PV Installation Categories Under Spain's RD 1578/2008

Type	Description	Introductory feed-in tariff (€/kWh)
I	Installations located on the roofs or the façades of immovable, closed constructions, made of resistant materials, that are used for residential, service, commercial or industrial purposes, including agricultural uses. This type also includes installations located on immovable support structures used to provide shade or cover parking lots. These installations are further divided into two installation subtypes, depending on the capacity involved.	
I.1	Plants with capacity less than or equal to 20 kW	0.34
I.2	Plants with capacity greater than 20 kW and less than 2 MW	0.32
II	All other plants not included in type I (i.e., ground photovoltaic plants) Plants with capacity less than 10 MW	0.32

Source: KEMA

The total annual capacity quota is 500 MW, and two-thirds of it will be reserved for rooftop PV plants. Furthermore, there is no division of free-range plants into 100 kW-sized projects, and the tariff will only be paid for 25 years. It is also now mandatory for PV plants to deposit a guarantee of €500/kW for Type I.2 and €50/kW for Type I.1.

In 2012, it is expected that a decree will be issued regarding a new compensation structure.

General Role of Public Authorities

The role of the State General Administration and other public authorities is to remove technical, administrative, and market barriers for renewable energy development and promote energy efficiency and the rational use of energy.

Activities Related to Solar

The autonomous communities have established their own measures to promote renewable energies through their Energy Plans, based on the REP 2005-2010. Spanish municipalities have been adopting this measure to promote the implementation of RES-E technologies in new as well as in old, highly refurbished buildings.

Many municipalities have taken initiatives to improve the sustainability of their cities through solar initiatives on public properties (see Figure 38). In general, there are no expedited permitting processes or special incentives for renewable generation placed on government property and/or along highways or waterways.

Listed below are some examples of municipal solar initiatives:

- Barcelona

- A 1.3 MW solar PV plant in the Forum Barcelona area

Figure 38: Photovoltaic Pergola in Barcelona

Source: KEMA

- Castilla-La Mancha
  - Under Law 1/2007 to promote renewable energies, energy saving, and efficiency, all the buildings owned by the autonomous body, public companies, and other entities comprising the regional public sector as well as the public buildings to be constructed or acquired in future shall be compliant with the Technical Building Code, regarding energy efficiency and renewable energies. This includes a minimum solar-thermal contribution for water heating and photovoltaic contribution for electricity production.
- Andalucia
  - Under Law 2/2007 to promote renewable energies, energy saving, and efficiency in the community of Andalucia, regional public buildings shall incorporate solar energy installations that can be replaced or be complemented with other energy sources as cogeneration or residual heating.
- Island of Grand Canary
  - There is about 100 kW of solar power installed on the roof of every public school, adding up to a total 3 MW.

Summary of Key Findings

Key findings from examining the regulations and developments in Germany and Spain with respect to renewable project development on public property are summarized below.

Key findings include:

- Historically, municipalities in Germany and Spain have not played a major role in developing electricity generation apart from establishing favorable local conditions related to permitting and private investment in renewable facilities. In recent years, the municipal role has expanded to include facilitating project development on public lands and buildings; however, these projects are almost always owned and operated by private investors.
- Germany and Spain are becoming more and more proactive in promoting the use public buildings and lands for renewable project development. However, public sector resources are often not developed by the municipality itself, but rather by local utilities or private developers. In return, municipal authorities incur income from land sales, leasing fees and taxes.
- For the most part, lack of public ownership of renewable projects is attributable to considerable investment requirements, economic risks, and other institutional barriers.
- A wide range of ownership and operating models for projects on public lands and buildings have been demonstrated in the two countries examined. The various models for private participation enable the municipality to promote civic participation and put forth a progressive image to the public. Public-private partnerships are becoming increasingly more common and several different models for these partnerships have been developed on a pilot scale basis.
- There has been minimal development of small wind projects on public transportation corridors or PV project development along railways or waterways. The use of such corridors for distributed generation projects may be limited in large part by environmental constraints, safety concerns and opposition from the public.
- The local public, largely motivated by climate change protection and sustainable energy policy, can serve as a driving force behind municipal administration action to promote local renewable project development on public property. This has lead to considerable differences in the intensity of renewable energy use on public property by region or municipality.
- Increased activity by the public sector is expected to occur throughout Europe stemming from the EU Directive 2009/28/EC. This directive stipulates that "Member States shall ensure that new public buildings and existing public buildings that are subject to major renovation, at national, regional and local levels, fulfill an exemplary role in the context of this Directive from 1 January 2012 onwards. Member States may, inter alia, allow that obligation to be fulfilled by complying with standards for zero energy housing, or by

providing that the roofs of public or mixed private-public buildings are used by third parties for installations that produce energy from renewable sources." (Article 13.5)

- In Germany, recent amendments to the Renewables Act pave the way for project development on slopes along highways and railways and noise protection (abatement) walls along motorways. These areas have been added due to their large potential for solar power development and the significant economic savings and conservation of land that results from project development in these categories. For instance, solar panels attached to noise abatement walls may contribute to covering the costs for building and maintaining the walls.
- In Germany, the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety has provided funds for building solar panels at schools and installing visualization tools to assist student's education. One program, Solar Support for Schools – Making Renewables Visible, covers 400 schools. The initiative also provides federal support for investments in energy efficiency and renewable energy by industry, municipalities, and consumers. Up to €400 million will be made available in 2011 from the sale of CO2 emission allowances.
- KEMA found no expedited permitting processes or special incentives for renewable generation placed on government property and/or along highways or waterways. In fact, the report noted that solar projects build on municipal property may in fact take more lead time to develop as there may be a lengthier and complex approval process due to the public procurement process and public safety, health, environmental impact and insurance issues.
- EU Directives require municipal authorities to check their internal processes for sustainability and energy efficiency and to serve as an example to the private sector.

ACRONYMS

AC	alternating current
AMI	advanced metering infrastructure
Amp	ampere
AMR	automatic meter reading
ANSI	American National Standards Institute
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
CVR	conservation voltage reduction
DA	distribution automation
DC	direct current
DFR	digital fault recorder
DG	distributed generation
DMS	distribution management system
DOE	U.S. Department of Energy
DR	demand response
DSO	distribution system operator
FA	feeder automation
FCI	fault current indicators
FCL	fault current limiter
FDIR	fault detection, isolation, and recovery
FERC	Federal Energy Regulatory Commission
FLISR	fault location, isolation, and restoration
GW	gigawatt
Hz	hertz

IEEE	institute of electrical and electronic engineers, inc
IOU	investor-owned utility
IP	Internet protocol
IRC	ISO RTO Council
ISO	independent system operator
IT	information technology
IVVC	integrated volt/var control
Kbps	kilobytes per second
kV	Kilo-volt
kW	kilowatt
kWh	kilowatt hour
LADWP	Los Angeles Department Of Water And Power
LAN	local area network
LV	low voltage (for example, 220 or 120 volts AC)
MAN	metro area network
MHz	megahertz
MIU	meter interface unit
MV	medium voltage
MW	megawatt
NASPI	North American SynchroPhasor Initiative
NCU	network control unit
NERC	North American Electric Reliability Corporation
NIST	National Institute Of Standards And Technology
O&M	operation and maintenance
OSI	Open Systems International
P2P	point to point

PBM	performance-based maintenance
PCT	programmable communicating thermostat
PD	partial discharge
PDOL	partial discharge detection online with localization
PG&E	Pacific Gas and Electric
PLC	power line carrier
PLC	programmable logic controller
PMU	phasor measurement unit
PPA	power purchase agreement
PV	photovoltaic
R&D	research and development
REC	renewable energy credit
REE	Red Eléctrica de España
RF	radio frequency
RIG	remote intelligent gateway
RMR	reliability must run
RPS	renewables portfolio standard
RTO	regional transmission organization
RTU	remote terminal unit
SA	substation automation
SAIDI	system annual interruption duration index
SCADA	supervisory control and data acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SDR	software-defined radio
SEGIS	Solar Energy Grid Integration System
SG	smart grid

SMUD	Sacramento Municipal Utility District
SOE	sequence of events
SW	software
T&D	transmission and distribution
TCP	transmission control protocol
TLM	transformer load management
TSO	Transmission system operator
U.S.	United States
UPS	uninterruptible power supply
V	volt
VAR	volt-ampere-reactive
WAMS	wide area monitoring system
WAN	wide area network
WECC	Western Electricity Coordinating Council