AHEAD

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The response of market and policy design to increasing shares of renewables in California and Germany

Lessons learned and directions for the path ahead

Report

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Contents

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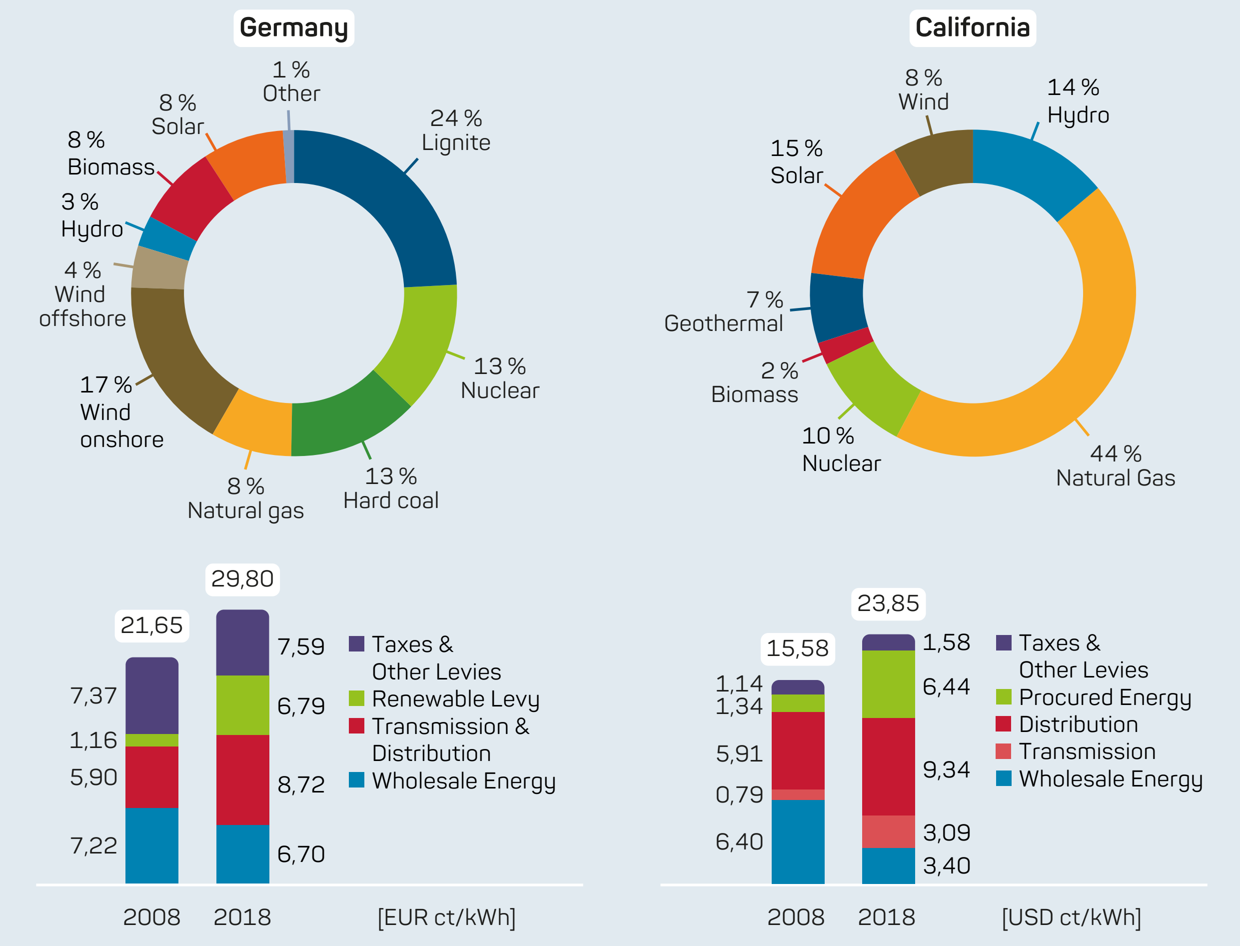
Executive Summary

Germany and California stand out as two of the world's leading jurisdictions in transforming their electricity systems to accommodate the integration of high shares of renewables.

In both jurisdictions, more than 30 percent of electricity consumption is drawn from generation with nonhydroelectric renewable resources (FIGURE ES-1). In Germany, renewable production even surpassed production from coal for the first time in 2018. Notably, this was accompanied by considerable changes in the retail rate components. Regarding the way ahead, both jurisdictions have ambitious targets. Germany has set a target for renewables of 80 percent of power consumption by 2050 intended to be the backbone of the energy transition to the "age of renewables," (Energiewende); California has a target of 60 percent renewables by 2030, and 100 percent clean energy by 2045—potentially allowing for a role for other technologies to achieve net-zero carbon emissions. These changes frame another transformation in the expected electrifica-

Figure ES-1 | In-state shares of net generation in Germany (top left) and California (top right) for 2018 (Source: Fraunhofer ISE and U.S. Energy Information Administration). Average residential retail price (nominal) in Germany (bottom left) and California (bottom right) in 2008 and 2018 (Source: Bundesnetzagentur (2018) and own calculations[1]).



1 For further details, please refer to https://energyathaas.wordpress.com/2018/10/08/100-of-what/.

tion of transportation and potentially heating and cooling in buildings and industry, possibly leading to substantial growth in electricity consumption.

The experiences in Germany and California offer important lessons for other jurisdictions. We consider whether the apparent convergence of policy and market design in Germany and California will reveal any general best-practice pathways. Alternatively, divergent pathways might suggest that best practice will differ among jurisdictions because of different regulatory traditions and other reasons, or that consensus around best practice has yet to emerge.

The objectives of the report are threefold:

1. To provide general background and a history of climate and electricity policy in Germany and California, describing important characteristics of their electricity systems, including regulation and market design, actors, and resources.
2. To investigate how markets and policies have evolved and improved, and how those trends have been affected by efforts to promote and accommodate increasing shares of renewables.
3. To identify options for the way forward to achieve greater integration of renewables and identify future inflection points where changes in regulatory policies or market design might become essential to achieve this outcome.

Section 1 provides an introduction to the two electricity markets and the related regulatory frameworks. In Section 2 we describe in some detail the historical development and broader situation in both jurisdictions. This provides the backdrop for the later analysis of the market and policy design adjustments in response to the increasing share of renewables, and we identify similarities and differences relevant for a comparison.

“In California, the market reforms following the 2000-2001 electricity crisis positioned the state well to accommodate subsequent rapid growth of renewables.”

In California, efforts were taken in the 1990s to deregulate the industry, but after the 2000–2001 electricity crisis the electricity market was substantially reformed, resulting in partial reregulation. Transmission and distribution services are regulated, and generation is competitive within a strong administrative framework that influences investment decisions. In 2009, California introduced a day-ahead market and locational marginal pricing, changes that occurred before renewables became significant and climate change emerged as an overarching focus of policy. Thus the state was well positioned to accommodate the rapid growth of renewables later that decade.

“In contrast, Germany started out with a problematic legacy electricity industry structure, which required substantial responses to growing renewables.”

In contrast, Germany, which also began to liberalize its market in the late 1990s, by and large retained its problematic legacy electricity industry structure and pursued a relatively disorganized “just do it” approach (Mitchell, 2010) focused on pushing renewables in the market. Only in the course of time did the problems and drawbacks of this approach unfold, for instance in the policy cost crisis triggered by uncontrolled deployment of solar photovoltaic. Furthermore, the policy-driven rapid introduction of renewable generation exacerbated the flaws in Germany’s market design. In retrospect the major obstacles to further expansion of renewables, namely grid bottlenecks and social acceptance problems more broadly, might have been avoided through a more carefully planned and integrated policy approach from the start. In 2011, Germany had its own catalytic event similar to California’s energy crisis when the country decided to phase out nuclear power and adopted the long-term renewable target. This had substantial impacts on both the market dynamics and the overall policy approach. In response, substantial adjustments to the electricity system have been made as explained in more detail below.

Several differences between the two jurisdictions need to be acknowledged. First, a high share of total consumption in Germany is provided by imported hard coal and domestic lignite, whereas in California, coal generation is located out of state and the share of coal has always been smaller. Coal now provides 4 percent of total power for California and will be phased out entirely. Second, the German market is highly interlinked with other markets, not least because it is located in the center of Europe, and subject to regulation to enforce the EU's Internal Energy Market. Although California imports 16 percent of its power from neighboring states, the formal wholesale market linkage has been limited. Third, industrial customers make up a higher share of consumption in Germany than in California or its neighboring states: This may explain why Germany prioritizes industrial processes to make demand more flexible whereas California focuses on residential consumers. Fourth, the electricity sector in Germany constitutes a larger share of the nation's emissions than is true for California. Finally, the major share of California's retail market is regulated, whereas Germany's market is completely liberalized.

"Historical differences diminish as both jurisdictions are trying to go where electricity systems have not gone before."

Yet the similarities between the two jurisdictions outweigh the differences—now and probably even more so in the years to come. Both have chosen pathways that explicitly provide a diminishing role for large-scale technologies like nuclear power and carbon capture and storage as mitigation pathways. The historical reasons for these choices vary, but the result is a common imperative for an expanded role of renewables to meet societal objectives—to grow their economies, to reduce conventional air pollutants, and especially to address climate change. With the recent decision to phase out coal, Germany's energy mix is bound to come closer to California's. Moreover, although their regulatory traditions are somewhat different and the (partly) regulated retail market in California provides policy options not available in Germany, these differences diminish at a closer look. Finally, the most important common theme is that both jurisdictions are trying to go where electricity systems have not gone before.[2]

"As renewable shares increased, efficiency and equity issues have become a major concern for regulatory responses."

In Section 3, we build on that background to consider how markets and policies have been designed and reformed to accommodate an increasing share of renewables in the electricity system. In general and as pointed out above, we observe that in Germany – after a prolonged period of "just do it" in which costs were not particularly worrisome – reaching a high level of renewable generation has been accompanied by substantial reforms in market and policy design to increase policy cost-effectiveness and make markets more efficient[3]. In contrast in California, market policy changes have been more incremental and were not necessarily driven by increasing renewables. At least lately the evolution of policy in Germany may be viewed as a more careful energy transformation developed through legal and regulatory reform, while in California the process has been driven by experimentation. Both jurisdictions have experienced energy cost increases that have sparked some backlash against aggressive policies promoting renewables, and both have become concerned with fixing regulatory flaws that sometimes provide inefficient or inequitable incentives for renewable investment. The most important developments and recent trends to accommodate renewables are summarized in TABLE ES-1.

The report culminates in Section 4 with an assessment of policy and future pathways. We evaluate the emerging pathways of electricity sectors in California and Germany from five perspectives.

2 See "Is California going the way of Germany when it comes to energy?" *San Diego Union-Tribune*, 11 November 2018.
3 For lessons for the New Green Deal proposal drawn from the German experience as assessed in this report see: "The Unrealistic Economics of the Green New Deal" *Wall Street Journal*, 13 February 2019.

Table ES-1 | Evolution of electricity sectors to accommodate renewable energy

	Germany	California
Renewable policy adjustments		
Policy design and complementary integration measures	→ Increasing policy costs of deployment precipitated gradual shift beginning in 2012 from fixed feed-in tariff (FIT) to competitively auctioned sliding market premium from 2015 on. → Increasing grid bottlenecks led to 2017 introduction of capacity caps in auctions for new wind capacity to limit deployment in grid-constrained regions. → Increasing congestion and curtailment costs have initiated a shift from physical dispatch priority for renewables to (partial) financial dispatch insurance and controlled balancing by transmission system operator.	→ Primary policy tool remains renewable portfolio standard (RPS). Targets have been adjusted upward several times. → Beginning about 2010, when RPS started to bind, more stringent requirements combined with smoother procurement process, including guarantee of cost recovery, substantially increased capacity.
Changing market structure	→ Shift from FIT to auctions and related transactions costs (e.g., permits) created market entry barriers for distributed renewables (typically deployed by households and small investors) and prompted branching of the policy pathway to establish a greater role of retail price incentives (e.g. net metering) alongside auctioning.	→ RPS initially applied to large investor-owned utilities (IOUs), later extended to publicly owned utilities (POUs) and community choice aggregators (CCAs), to relieve burden on IOUs.
Electricity wholesale market adjustments		
Market design	→ Increasing short-term volatility triggered strengthening and adaptation of intraday market to reduce lead time in spot market, introduce quarter-hour products. etc.* → Recently, dedicated “integration products” were added to include wind futures and hedge volume risk.*	To address declining and more volatile short-term prices, new market products reward flexible generation: → flexible ramping constraint in real-time market; → flexible ramping product that makes real-time payments to specified fast-ramping capacity; → long-term flexible capacity requirement that percentage of capacity comply with resource adequacy requirements by providing fast-ramping capabilities.
Flexibility	→ Anticipated need for flexible resources and EU legislation sparked interest in demand flexibility, resulting in 2016 legislation that determines roll-out schedule of smart metering infrastructure across consumer segments. → Introduction of possibility for distribution system operators to offer rates with reduced grid fees to flexible load.	→ Tariff design and other programs were introduced to reduce peak load. Interest in demand scheduling is growing. No adjustments to incentives for renewable supply in the RPS so far.

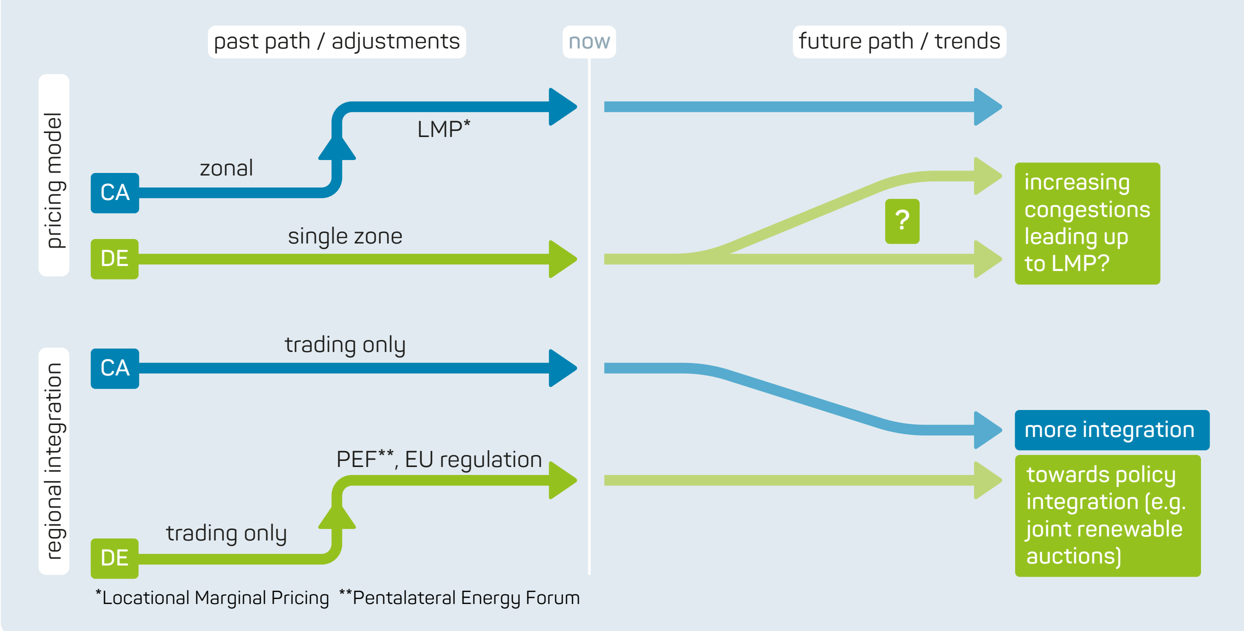
*Non-regulatory adjustments initiated by the privately operated power exchange.

	Germany	California
Transmission system operation adjustments		
Pricing model	→ Despite increasing congestions, no adoption of zonal or locational marginal prices, mainly for political reasons (transition to such pricing would delay expansion of grid and cause distributional issues, and insufficient liquidity in new zones or nodes). → Pricing model Despite increasing congestions, no adoption of zonal or locational marginal prices, mainly for political reasons (transition to such pricing would delay expansion of grid and cause distributional issues, and insufficient liquidity in new zones or nodes). → Ongoing redesign of balancing market products includes renewable and demand-side resources in power balancing.	→ Locational marginal pricing was adopted in 2009, but not specifically in response to higher share of renewables.
Grid expansion	→ Slow expansion of transmission grid caused measures to accelerate grid expansion, including centralization of the planning process, new coordination measures (e.g. grid development plan), and streamlining of permission procedures.	→ Reforms to generation interconnection process to better integrate transmission planning with resource planning. A continually evolving generation Resource Adequacy (RA) framework is attempting to maintain the financial viability of conventional resources needed to maintain reliability.
Regional cooperation	→ Increasing trade, differing policy priorities, and European Union regulation led to technical cooperation (use of common market-clearing algorithm, implicit allocation of transfer capacities through flow-based market coupling) with five large interlinked markets (Pentalateral Energy Forum). Improved coordination between system operators was triggered by anticipation of market diffusion of renewables.	→ Renewable expansion drives increased western US market coordination. Energy Imbalance Market (voluntary balancing market) is rapidly expanding into most western US states and British Columbia. Negotiations are under way to introduce day-ahead market. → Expansion of California system operator to US West would dilute California's influence. Concerns about ceding authority to federal regulators have stalled tighter integration of regional markets.

Electricity markets. Both jurisdictions are (generally) on good paths when it comes to their pricing models, procurement practices, and moves toward regional integration. (One exception is the increasing grid bottlenecks in Germany, where wind is mostly available in the north and demand is mostly in the south.) There remains room for improvement across all these areas, but the way forward is more or less clear. Opportunities to learn from each other's experiences and options going forward are available. For example, Germany might adopt California-style zonal or nodal pricing as a remedy to the constrained grid, and California would benefit from imitating Germany's regional cooperation initiatives. This assessment, summarized in FIGURE ES-2, is described fully in Section 4.1.

Renewable procurement. Both jurisdictions have moved well past the treatment of renewables as exotic technologies and now confront the integration of large shares of renewables into their incumbent electricity systems. Distributional issues, such us where to build new plants and how to distribute the policy costs, have become more important. Germany relies on a centralized procurement model. In California's decentralized ap-

Figure ES-2 | Electricity pricing model and regional market integration pathways



proach, the advent of unregulated community choice aggregators (CCAs) increasingly leads to customer defections. Going forward, California faces a choice: either try to adapt its renewable policies to a decentralized electricity market environment or concentrate its procurement decisions through a more centralized mechanism that again takes discretion out of the hands of individual retail providers. This trend is summarized in FIGURE ES-3 and described fully in Section 4.2.

Policy design. Although policies vary, both jurisdictions have evolved toward similar improvement in cost-effectiveness and increasing stringency of renewable procurement. There remain opportunities to achieve better integration through improved scarcity pricing—that is, to go beyond supporting generic MWhs and begin taking temporal and geographic scarcity into account. Furthermore, climate policy has become an increasingly important motivation for investment in renewables, and the challenge is to incorporate renewable technology policies into climate policy. Both jurisdictions have a mix of carbon pricing and companion policies, and the carbon markets (the EU Emissions Trading System and California's cap-and-trade program) are now sufficiently well established to contribute to more stringent emissions reductions.

Figure ES-3 | Renewable procurement

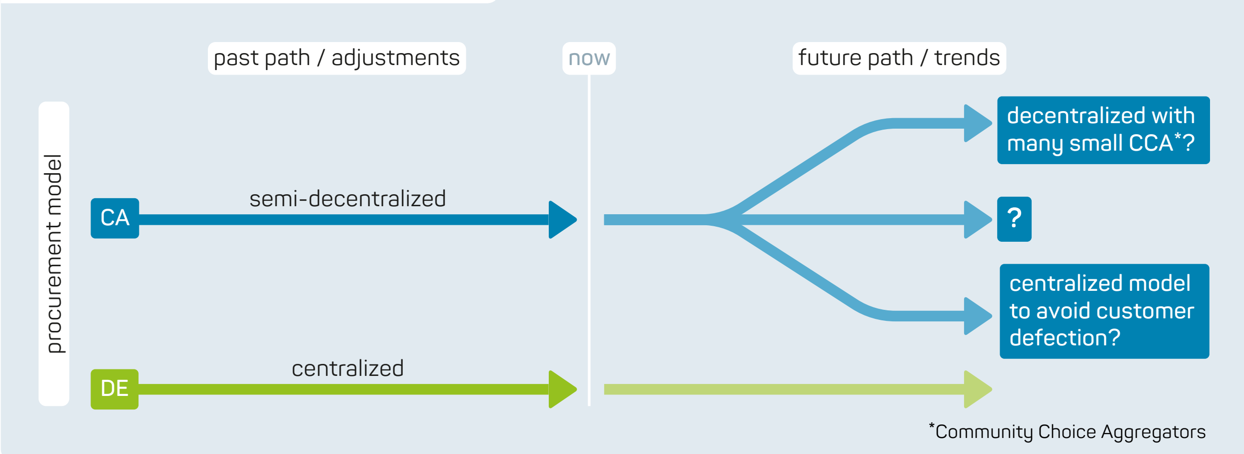
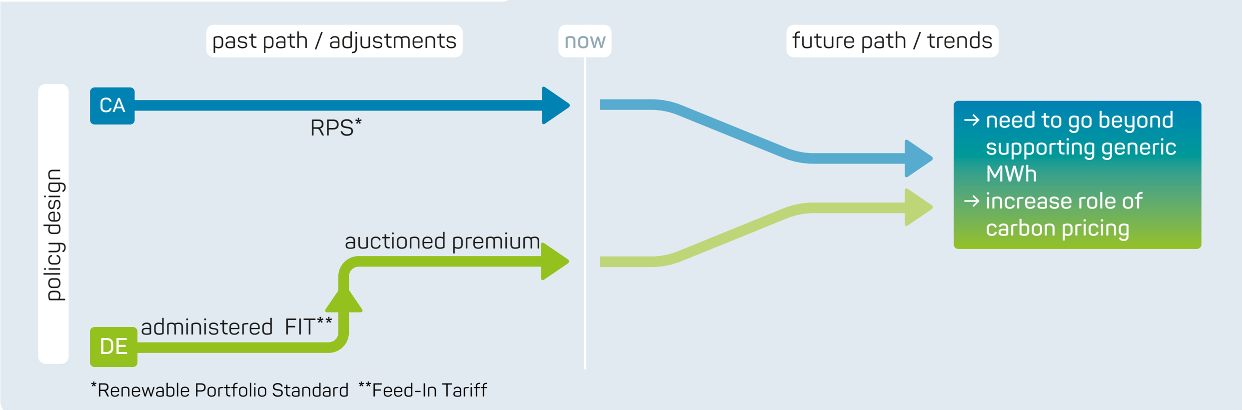


Figure ES-4 | Renewable policy designs



Less clear, however, is how to align renewable policies with carbon pricing. Carbon pricing is expected to provide a more efficient signal for investment than technology support policies; however, the carbon price is undermined by policies that push renewables through subsidies outside the carbon market. How can carbon pricing be positioned so that it plays an effective role in promoting technology investments? The recent trends and potential paths forward are illustrated in FIGURE ES-4, which is described in Section 4.3.

Demand flexibility. The advent of substantial renewable generation has exposed the importance of variability of renewable energy supply and made the activation of demand-side resources a pressing integration issue. Thus, the fourth domain in the evolution of markets and regulation is to align demand with the timing of renewable availability. For many economists, time-based electricity prices provide an intuitive option to achieve this coordination ("getting consumer prices right"). Smart-meter technology that would enable such pricing is being rolled out in both jurisdictions and regulatory steps appear imminent. However, the potential of time-based pricing remains largely untapped due to issues such as consumer reluctance including data security concerns, potential distributional issues, and general issues in rate design that conflicting goals of efficient pricing and the recovery of embedded system fixed costs. FIGURE ES-5, described in Section 4.4, illustrates the lack of progress to date and suggests possible pathways forward.

Electrification. Both jurisdictions acknowledge a role for electrification of transportation, heating/cooling, as well as new industrial processes. The technologies are either already becoming available or at least are in an early stage of development. The absence of physical infrastructure, for example for electric vehicle charging and other functions, the lack of a regulatory framework, and immature market institutions represent barriers to integrating supply

Figure ES-5 | Demand flexibility and retail rate design

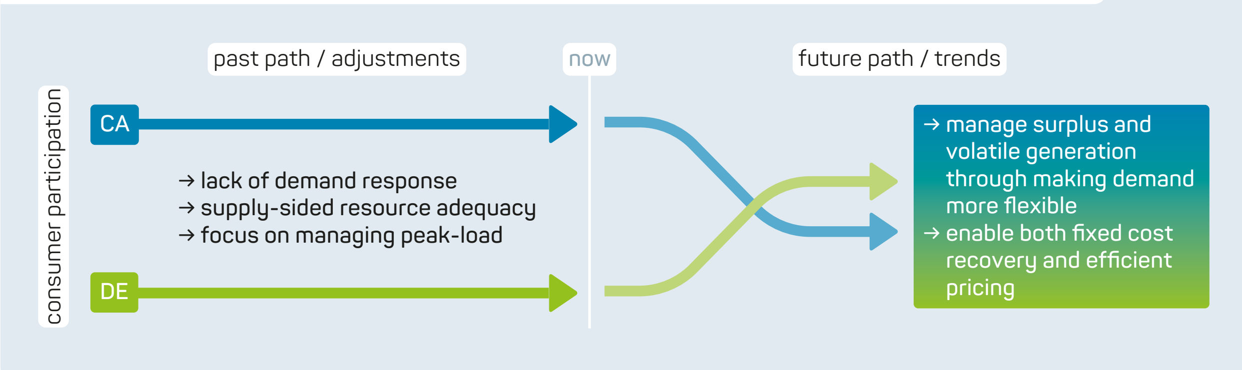
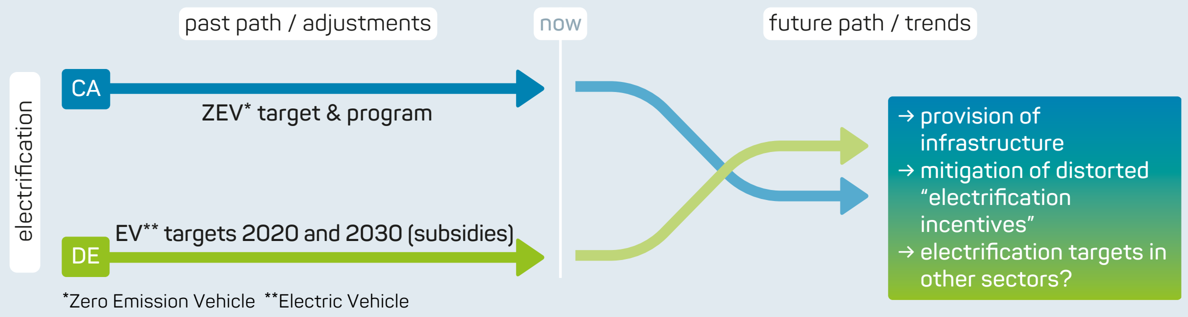


Figure ES-6 | Mainstreaming electrification



and demand in market equilibria and obstruct the electricity sector's potential role in decarbonization of the broader economy. FIGURE ES-6, drawn from Section 4.5, illustrates the lack of progress to date for electrifying transportation and suggests possible pathways forward.

These five perspectives describe a shifting paradigm. Up to the present, renewables have been deployed for technology development and co-benefits, such as creating jobs and improving air quality, but increasingly they are being put into the service of climate action— to electrify and decarbonize other sectors. This objective would make renewables the centerpiece of the electricity system. We find that Germany and California are headed in the same direction, asking the same questions, in trying to achieve this outcome.

"Both jurisdictions are entering a new round of market and policy design in search of solutions to expand the role of electrification."

Section 5 concludes with the observation that Germany and California are converging on a pathway that requires new policies and legislation—and ultimately, policy innovation. Many policy choices are still in the proposal stage, but their eventual implementation will initiate a new round of market and policy design, which will once again push the frontier and generate new evidence on how even higher shares of renewables can be integrated.

California and Germany now face several questions. What role can carbon pricing play for decarbonizing the power sector? Will companion policies needed or eventually be phased out? And finally, what is the appropriate medium-term target for renewables? The expected rapid expansion of the use of electricity and displacement of emissions from direct combustion of fossil fuels in other sectors may make expanding the role for electrification a higher priority than complete decarbonization of the electricity sector. At the same time, at least in Germany grid bottlenecks and the scarcity of new sites constitutes a barrier that increasingly limits renewable expansion.

Germany and California offer ongoing opportunities for joint experimentation and exchange of ideas. Their experiences to date provide lessons not only for each other but also for other jurisdictions moving along the path toward a decarbonized economy.

1 Introduction

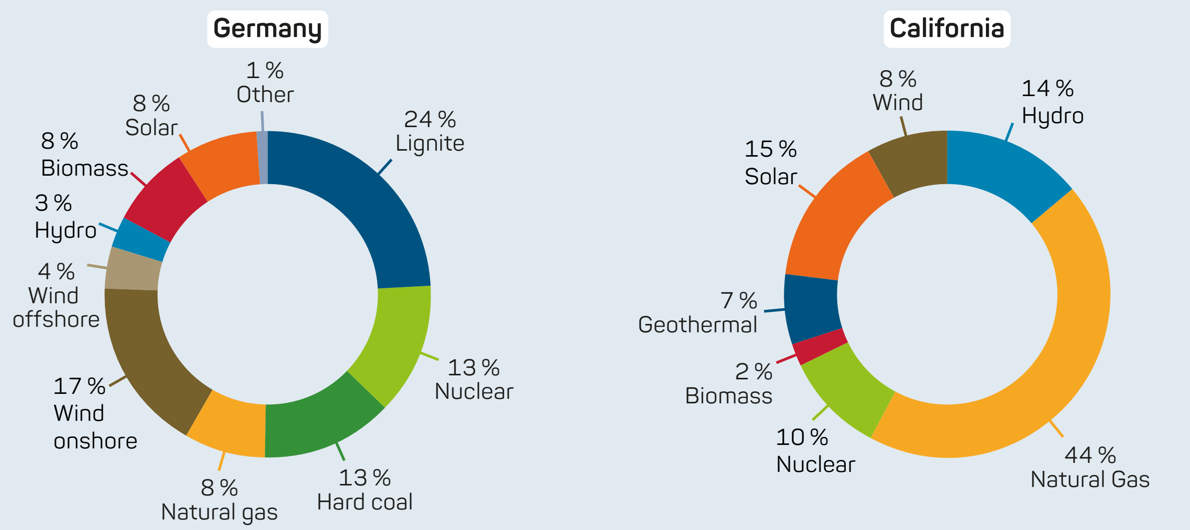
GERMANY AND CALIFORNIA STAND OUT AS TWO OF THE WORLD'S LEADING JURISDICTIONS IN TRANSFORMING THE ELECTRICITY SYSTEM TOWARD HIGH SHARES OF RENEWABLES.

Germany has a target for renewable generation of 80 percent of overall power consumption by 2050. As of 2018, the share of non-hydro renewable generation in total net electricity generation amounted to 37 percent, with almost 80 percent of that energy coming from variable renewable energy sources—wind and solar (FIGURE 1).[4] In the first half of 2018, renewable production exceeded production from coal for the first time.[5] California has set a target of 60 percent renewables by 2030 and 100 percent clean energy by 2045. As in Germany, by 2018, close to 32 percent of California's net electricity generation was based on non-hydro renewable energy sources[6], with more than two thirds coming from solar and wind.

On the way toward their targets, both jurisdictions seem to have reached an inflection point: whereas the previous focus of regulatory attention was to achieve substantial levels of market penetration, the relatively high shares that have been achieved increasingly necessitate a new focus: integration of renewables into the operation of the grid. Now that the first major milestone in the transformation of the energy industry has been reached, we can look back on the actions that have brought us here and seek insights for other jurisdictions.

Deep decarbonization will require changes in prevailing market and regulatory designs. Current systems are fundamentally tailored to dispatchable generation from fossil or nuclear fuels. As tradition-

Figure 1 | In-state shares of net electricity generation in Germany and California, 2018.
Sources: Fraunhofer ISE, U.S. Energy Information Administration.



4 Net electricity consumption amounted to about 508 TWh in 2018, of which about 30% have been covered by wind and solar energy (Fraunhofer ISE). For further details, please refer to: https://energy-charts.de/energy_de.htm?source=all-sources&period=annual&year=2018.

5 https://www.bdew.de/presse/presseinformationen/erneuerbare-ueberholen-erstmals-braun-und-steinkohle-bei-der-stromerzeugung/.

6 California's renewable goal covers generation from wind, solar, geothermal, biomass, and small hydroelectric facilities. This target is additional to generation from large hydroelectric facilities. http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

ally configured, markets take power from any offering based on short-run (marginal) cost to meet mostly inflexible electricity demand. The growing share of generation from low-marginal-cost, variable renewable resources presents challenges, including a decline in wholesale market revenue and a temporal shift in the demand for dispatchable generation to hours when variable resources are not prevalent. To accommodate a growing share of renewable generation, new designs need to expand the opportunities for system flexibility in its many variants, including scheduling of demand, price-responsive demand, and storage, as well as a more efficient use and supply of renewable power—for example, through expanded transmission and distribution capabilities. Furthermore, the ambitious climate policy targets in both Germany and California call for the electrification of transportation and buildings; that means the power sector needs to grow. Expanded electrification brings the opportunity for new investments in renewable electricity generation. With battery and thermal storage, the more flexible temporal nature of electricity demand in these sectors may provide new opportunities for integrating the growing generation from intermittent renewables. Such challenges, which confront both jurisdictions, are just a few among many that need to be solved if the renewable transformation is to reach the next level. Adjustments in market and regulatory design, regarded as the least-cost way to address them (cf. NREL 2014; Pérez-Arriaga et al. 2017), are the focus of this report.

This report has three objectives. The first is to provide general background and history of climate and electricity policy in California and Germany by describing characteristics of their electricity systems, including regulation and market design, actors, and resources.

The second objective is to draw lessons and insights on how market and policy design has enabled and responded to increasing shares of renewables. The discussions will be comprehensible for nonexperts in the economics of market design, but at the same time, we aim to convey specific features and mechanisms and describe the rationale and motivation for regulatory policies. Our main observations are summarized in the Executive Summary (TABLE ES-1).

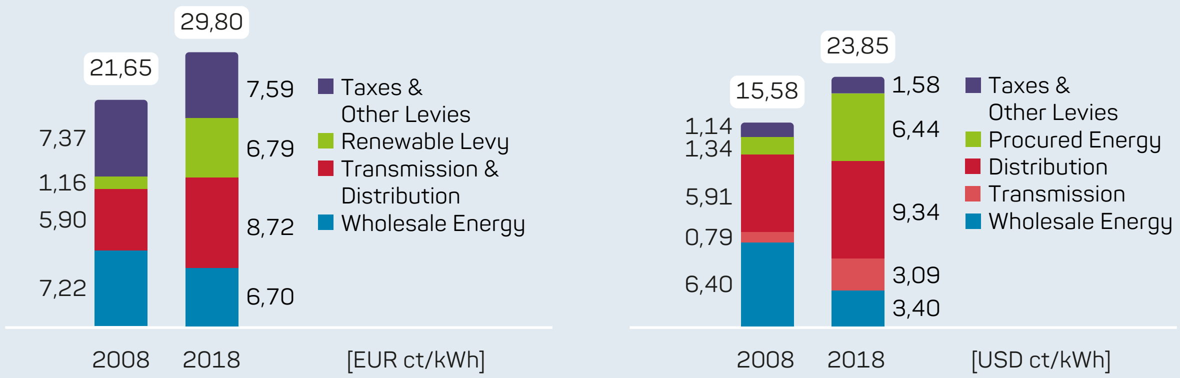
A major finding is that in Germany, the increase in renewable generation has been accompanied by reforms to increase policy cost-effectiveness and make markets more efficient, whereas in California, market policy changes have been more incremental and were not necessarily driven by increasing renewables. In the German case, the changes are all the more remarkable because the country has been criticized in the past for its unsuccessful liberalization (Joskow 2008). Indeed, there are some apparent deviations from the trend toward a more efficient market—for instance, the continued use of a single price zone for the whole German market. In contrast, although California has continued to add enhancements to its wholesale market, a main change wrought by increasing renewables has been to push its market toward tighter integration with neighboring electricity systems.

The third objective is to identify issues that should receive more attention if the share of renewables is to increase even further. These issues include the role of demand-side flexibility through time-based pricing, the need to reconcile retail tariff design with fixed-cost recovery, and challenges in electrifying final energy demand. Special attention will also be given to clean energy policies and the role of carbon pricing for driving the transformation. In the final section of this report, we discuss the potential convergence of the policy pathways in Germany and California toward either model or a new third way, identifying approaches that one jurisdiction may adopt from the other to address integration challenges.

A related scientific literature evaluates how the market has evolved thus far, and how it might enable further penetration of renewables. For example, Schmalensee (2012) evaluates previous policies to increase renewable electricity generation in several US states. Pollitt and Anaya (2016) conduct a comparative study of Germany, the United Kingdom, and New York State and discuss whether their electricity markets can cope with future high shares of renewables. Yet a thorough analysis of design and policy response in economies at the forefront of the energy transition, such as Germany and California, is missing.

The report is structured as follows. In Section 2 we provide a short historical account of the evolution of the electricity systems of Germany and California so far, as background for the subsequent analysis. In Section 3 we trace how market and policy design has responded to increasing shares of renewables in both jurisdictions. This section is structured by retail price components (FIGURE 2), which in both Germany and California have changed considerably in recent years, and which are at least partly indicative of the effects of (and responses to) higher shares of renewables. In Section 4 we turn to market and policy design that we perceive as crucial for transitioning to an efficient and equitable low-carbon power system. Finally, Section 5 concludes with a summary of the lessons learned from comparing the two energy transition frontrunners and assesses the transferability of the resulting insights to other jurisdictions.

Figure 2 | Average residential retail price (nominal) in Germany (left) and California (right) in 2008 and 2018. Source: Bundesnetzagentur (2018), own calculations[7]



7 For further details, please refer to https://energyathaas.wordpress.com/2018/10/08/100-of-what/.

2 The electricity market and policy architecture in Germany and California: Background

THIS SECTION PROVIDES THE HISTORICAL BACKGROUND TO THE CURRENT STATUS OF BOTH MARKETS, FOR READERS WHO ARE NOT FAMILIAR WITH THE SYSTEMS. THE COST-EFFECTIVENESS AND DISTRIBUTIONAL OUTCOMES STEMMING FROM PAST MARKET DESIGN AND POLICY RESPONSES WILL BE DISCUSSED IN THE SUBSEQUENT SECTION.

2.1 Germany

Three major decisions have shaped the development of Germany's electricity sector: the liberalization of the market in 1998, the implementation of a new renewables support scheme in 2000, and the nuclear phase-out decree in 2002. An overview of these decisions and related events is provided in TABLE 1.[8]

Table 1 | German electricity market regulation and policymaking, 1996–2017

Event	Date	Description
Liberalization (EU level)		
First EU Internal Energy Market Package (Directive 96/92/EC)	1996	Required member states to implement restructuring regarding generation and transmission ownership, retail competition, and grid access to third parties (introduced in national law in 1998)
Second EU Internal Energy Market Package	2003	See below.
Third EU Internal Energy Market Package	2009	See below.
EU communication, Clean Energy for All Europeans ("Winter Package")	2016	See, e.g., http://fsr.eui.eu/wp-content/uploads/The-EU-Winter-Package.pdf
Renewable and climate policy (EU and national level)		
Electricity Feed-In Act	1991	Original feed-in tariff, predecessor of Renewable Energy Sources Act
Renewable Energy Sources Act (RESA)	2000	Comprehensive technology-specific feed-in; dispatch priority for renewable energy generation, first deployment target formulated
EU Emission Trading System (ETS) launch	2005	Emissions trading implemented to achieve Kyoto targets (–12 % by 2012); covers energy and energy intensive industry sectors
Energy Concept	2010	Energiewende decision: 80% renewable energy in 2050; long-term climate goals (–80 %/95 % in 2050)

8 The most important sources we draw on are policy documents, monitoring reports from government agencies, such as the Federal Grid Agency (Bundesnetzagentur, BNetzA), and scientific publications. Also included are EU-level policies and regulation, which have been the major driver for liberalization in Germany.

Event	Date	Description
Act on the Digitization of the Energy Transition	2016	Selective roll-out of advanced metering infrastructure, definition of technological requirements and data security standards
RESA Amendment	2017	Public tender or auctions for renewable energy support
Nuclear energy policy (national level)		
Nuclear phase-out act	2002	Decision to phase out nuclear power by 2022 by limiting maximum hours of further operation
Prolongation of nuclear phase-out	2010	Remaining operation time extended by 8 years for older plants and 14 years for new plants
Prolongation revoked and moratorium for older plants	2011	In aftermath of Fukushima, immediate shutdown of eight oldest plants, 2002 lifetime limitation restored

2.1.1 Liberalization and regulation

Historically, the German market was organized in regional monopolies served by vertically integrated utilities (Brunekreeft and Bauknecht 2006). Monopolization was institutionalized not by federal law but through cartel agreements based on legally enforced demarcation contracts. The government never actively regulated the sector but, in line with German tradition, entrusted utilities to resolve network access and network charges through voluntary negotiations controlled by the cartel office and arranged collectively in so-called association agreements. With this combination of monopolization and lack of regulation, Germany was the exception in Europe.

A push toward liberalization began with the EU's first so-called electricity market package, adopted in 1996 and implemented in national law in 1998 (Meeus et al. 2005). Its main purpose was to gradually and partially open up the market for competition, with the long-term vision of creating an EU-wide internal market for energy. Competition was introduced, but the market was not restructured, nor were supporting regulatory institutions created. Lack of regulation led to an increase in concentration through mergers that eventually resulted in the dominance of Germany's "big four" suppliers (E.ON, RWE, Vatenfall, EnBW), which from 2000 on, controlled around 90 percent of the market. In consequence, although prices had initially fallen after the liberalization law took effect, they started to increase again. According to Joskow (2008), Germany's decision to refrain from sector regulation after the market was opened up and instead to continue relying on negotiated prices had been a clear mistake. During the early 2000s, renewables began to enter the market, driven by the feed-in tariff scheme, but by and large were still a niche. In 2005, the share of wind energy in total electricity consumption was below 5 percent, and the share of solar energy was negligible[9].

The unregulated German electricity sector began to change with the EU's second electricity market package, in 2003. Implemented into national law as the 2005 Energy Act, it altered regulation for network charges and investments, unbundled transmission system operators (TSOs) and distribution system operators (DSOs), and created a regulatory agency, the Federal Grid Agency (Bundesnetzagentur, or BnetzA). In the following years, a strong wholesale market developed and the European Energy Exchange gained increasing importance as a trading platform (Pfaffenberger and Chrischilles 2013). In addition, the European Commission (EC) took on the role of watchdog for competition and notably initiated an antitrust case against E.ON that eventually resulted in the company's selling a fifth of its generation capacity and parts of its distribution grid. The EC also conducted a sector inquiry to bring the still high concentrations of generation ownership in many European markets to regulators' attention.

9 See https://www.energy-charts.de/energy_pie_de.htm?year=2005.

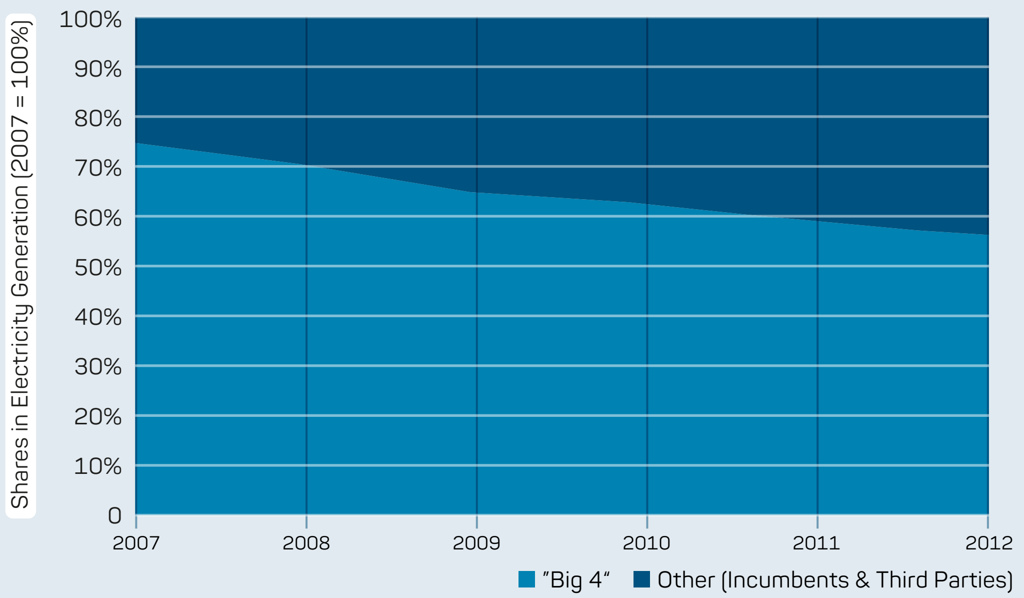
The third and most recent electricity market reform package, adopted in 2009, paved the way for stronger supranational governance.[10] Its main pillars are more effective unbundling, increased market transparency, more effective regulatory oversight by national authorities, establishment of the Agency for the Cooperation of Energy Regulators (ACER), and better cross-border collaboration and investment organized through a new European Network for Transmission System Operators.[11] ACER is assigned the task of developing EU-wide "framework guidelines," which set principles for developing specific network codes—for example, rules on management of the electricity transmission system in emergencies and blackouts. Through the technical network codes, the EC now indirectly advances harmonization and liberalization of member states' electricity markets. For example, a network code for electricity balancing defines common rules of an EU-wide balancing market.

2.1.2 Generation: Capacity expansion and market structure

At the start of the 2000s, the German market was characterized by high concentration and dominated by coal and nuclear generation sources. Mergers of the regional monopolists eventually formed Germany's big four (Section 2.1.1). More than half of all production was coming from coal (both lignite and hard coal), and another 30 percent from nuclear. Remaining suppliers were mostly small municipal utilities.

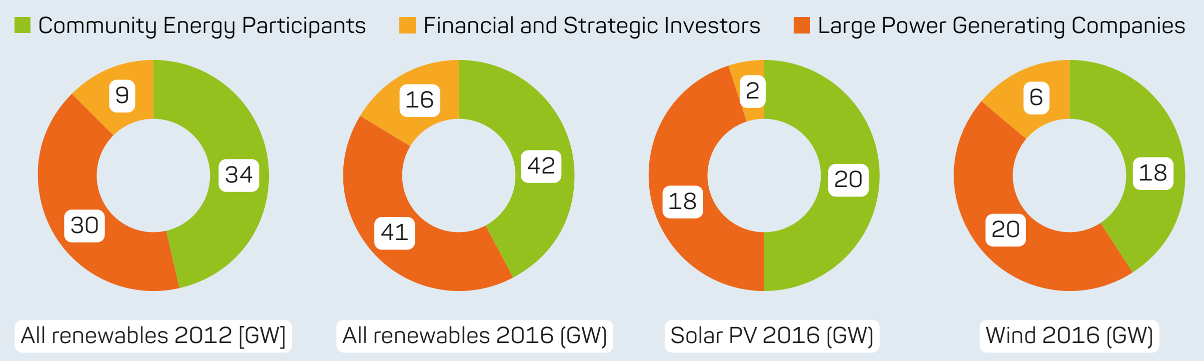
That market began to evolve at the turn of the millennium. Liberalization led to an entry of new, smaller players that mostly invested in relatively risk-free gas plants. In parallel, the first nuclear phase-out, decreed in 2002, initiated a "dash for coal" (Pahle 2010), with major investments in new hard coal and lignite plants to replace the nuclear capacity. This happened even as the EU Emissions Trading System (EU ETS) was being implemented in 2005 because the German government prioritized ending the use of nuclear energy over climate concerns and granted free emissions allowances to new coal plants. Of the new plants, a few were projects by foreign utilities, like France's GDF Suez, but most belonged to Germany's big four. However, as FIGURE 3 shows, over time their share decreased because of new players and additional regulatory intervention, like the EC's antitrust case against E.ON (Section 2.1.1).

Figure 3 | Market concentration in Germany, 2007–2012. Source: Brunekreeft et al. (2016).



10 See, for example, http://onlinelibrary.wiley.com/doi/10.1111/j.1468-5965.2010.02140.x/full.
11 http://europa.eu/rapid/press-release_MEMO-11-125_de.htm?locale=en.

Figure 4 | Installed renewable energy generation capacity in gigawatts (GW) by type of owner[13] and sector for 2012 and 2016. Source: Energy Atlas (2018).[14]



Renewable generators were a major new factor in the sector. The German Green Party, which was part of the government that implemented the Renewable Energy Sources Act (RESA) in 2000, deliberately designed that policy to create new and smaller players. This was partly for political reasons but also because the incumbents opposed renewables and were highly reluctant to change their traditional business model, which focused on large central-station plants. For instance, in 2005 the big four utilities' combined ownership of wind plants was just around 250 MW (Stenzel and Frenzel 2008). Larger scale[12] made investment in renewables more attractive, in particular in the emerging offshore wind market. Nonetheless, the share of renewable generation assets held by the large companies and their new "green" subsidiaries remains relatively small: in 2016 the portfolio of two largest utilities, E.ON and RWE's subsidiary, Innogy, included just 510 MW and 862 MW, respectively, according to their annual reports. This amounts to less than 3 percent of total installed wind (onshore) capacity.

Attracting small actors was accomplished by a combination of a guaranteed feed-in tariff and priority dispatch, which guaranteed risk-free return. In 2012, ownership of renewable capacity was dominated by households, small business, and project developers (FIGURE 4). Households and small businesses invested in decentralized renewables like rooftop solar PV, while project developers built utility-scale renewables like wind farms. The emergence of new firms and the declining market concentration among electricity generators are thus the result of the substantial integration of renewable energy sources (Brunekreeft et al. 2016).

2.1.3 Transmission, distribution, and ancillary services

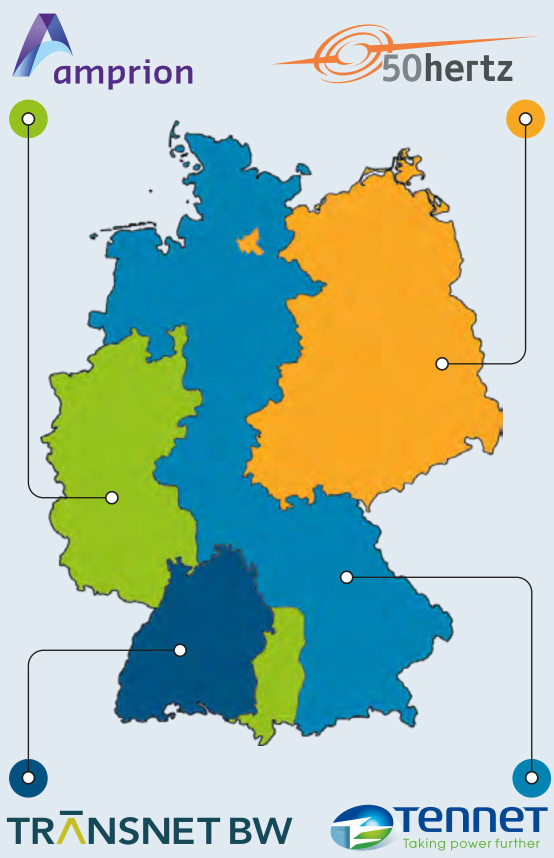
The organization of the German electricity transmission system is typical for power grid operation and management in most EU member states. Because member states were free to decide on the national implementation of EU electricity market reform, and each state still sought to be self-sufficient, national bidding zones were mostly national (the German-Austrian bidding zone being the only exception, until recently). With these national bidding zones, uniform pricing instead of locational marginal pricing became the standard at the national level, with Denmark, Sweden, Norway, and Italy being the exceptions in Europe (Egerer et al. 2016). This implies that the allocation of energy and transmission occurs separately. For the German market, this means that energy is traded on exchanges and bilaterally ("over-the-counter," OTC), whereas the allocation of transmission capacity is basically determined by four privately owned TSOs—Tennet, Amprion, Transnet BW, and 50Hertz—which

12 The largest onshore wind park in the country has a capacity of around 180 MW.
13 Community energy participants include e.g. fund investments, regional energy cooperatives, individual owners, farmers and farm cooperatives.
14 The Energy Atlas 2018 can be found here: http://www.foeeurope.org/sites/default/files/renewable_energy/2018/energy_atlas.pdf.

own and operate the high-voltage grids in their respective regions (FIGURE 5). The federal regulatory authority supervising these companies is the Federal Grid Agency.

Hence, once the day-ahead and intraday[15] markets are cleared (Section 2.1.5, FIGURE 8), the German Energy Act (§13 EnWG) requires that TSOs keep grid frequency at 50Hertz at every instant of time to guarantee the reliable functioning of the German power system. This includes the provision of corrective and preventive measures, also called ancillary services in Germany. Ancillary services[16] consist of congestion management measures such as redispatch[17] and countertrading, or counterflow,[18] as well as the provision of different types of balancing or control power and energy to correct for short-term imbalances in the grid region. Through specific auction formats, TSOs procure sufficient balancing power ex ante, which they can call on as needed. TSOs determine their demand for balancing power based on predetermined operating reserve requirements.[19] In response to the actual imbalances in a specific grid region, TSOs demand balancing energy from the suppliers of balancing power in real time.[20] The corresponding costs, like all costs accruing from TSOs' reliability services, are allocated among the final consumers.

Figure 5 | Grid control areas of Germany and responsible TSOs. Source: Netzentwicklungsplan Strom 2030, Version 2019. (Abb.1).[21]



15 The intraday market in Germany is typically referred to as the real-time market in the US context.
16 Note that ancillary services are defined differently in different contexts. The California Independent System Operator (CAISO) restricts the definition of ancillary services to spin/nonspin reserve power; in Germany the definition is broader and ancillary services basically include any short-term measures taken to warrant the reliable operation of the power system.
17 Redispatching consists of modifying the generation plan and/or load to modify the physical flows on congested transmission lines.
18 Countertrading describes a trade made between two TSOs in the opposite direction of the constraining flow between two control regions.
19 Operating reserve requirements in Europe are defined for different types of balancing power by the European Network of TSOs for Electricity (ENTSO-E, formerly UCTE). For primary control power, a deterministic-static approach is applied, which requires German TSOs to reserve roughly 600 MW of control power at every instant of time. For secondary and tertiary control power, TSOs are allowed to choose among different approaches. German TSOs use a static-probabilistic approach: a joint density function of imbalance levels is created based on historical data on the distribution of all random variables causing imbalances (e.g., wind, solar, or load forecast errors, power plant failures).
20 Each grid connection point is assigned to a balancing responsible party (BRP)—that is, public and private utilities, generators, large industrial consumers, and load-serving companies. Each BRP reports scheduled load and/or supply for every 15 minutes one day ahead to the respective TSO. BRPs can adjust their schedule forecasts up to one hour before delivery. After that, TSOs settle any imbalances arising from the announced schedules in their grid region by activating the procured control power—that is, by requesting energy. All BRPs whose schedule is out of balance pay a uniform imbalance price, defined for every 15 minutes. The imbalance price reflects the average costs of control energy activated and paid for by the TSOs. For further information, see https://www.regelleistung.net/ext/static/rebap?lang=en.
21 Document available at: https://www.netzentwicklungsplan.de/sites/default/files/paragraphs-files/NEP_2030_V2019_1_Entwurf_Teil1.pdf.

Electricity trading and transmission allocation are similarly separated for trades between adjacent markets. These trades are organized within the market coupling scheme of the EPEX Spot.[22] Market coupling allows bidders in each bidding zone to ignore cross-border transmission constraints. Based on the pan-European "price coupling of regions" solution, which is a uniform clearing algorithm to calculate electricity prices and flows in the covered network area on a day-ahead basis, energy exchanges optimize transmission capacity allocation to minimize the price difference between the coupled bidding zones. Trade results are reported to the respective TSOs, who resort to redispatch or countertrade measures contingent on any infeasible flows between interconnectors (flow-based methodology). This means that TSOs order generators (consumers) to increase (decrease) injections (withdrawals) to (from) the grid to make trades matching physical constraints. TSOs then remunerate generators and consumers for their adjustments and socialize the costs. Since February 2015, power exchanges in 19 EU member states are coupled in the Multi-Regional Coupling, covering 85 percent of European power consumption, which has led to converging energy prices and thus welfare gains in the coupled markets (Oggioni and Smeers 2013).

2.1.4 Transmission: Capacity expansion and market structure

After the unbundling of transmission asset ownerships during the second wave of liberalization (2005 Energy Act), transmission grid expansion became highly complex. Because of local public acceptance problems and a regionalization of permitting procedures combined with a lack of coordination among regional authorities, the process could take several years from planning procedures to project approval. To speed up grid expansion, the Power Grid Expansion Act of 2009 (EnLAG) and the Grid Expansion Acceleration Act of 2011 (NABEG; Section 3.1.3) are supposed to eliminate barriers by shifting permitting competences to the federal level. The legislation also involves local stakeholders in public consultations.

Transmission grid expansion is now mostly the responsibility of the Federal Grid Agency, which coordinates a five-step process.[23] The first two stages comprise estimation of refurbishing and expanding needs for the next 10 to 15 years by each TSO and for each control region, based on scenarios approved by the agency.[24] The resulting grid development plan is handed over for approval to the German government, which seeks in turn approval of a federal requirements plan (Bundesbedarfsplan) by the federal Parliament and subsequently by the federal Assembly.[25] In the final steps, which include federal sectoral planning and planning approval (Planfeststellungsverfahren), the exact route and transmission technology used for the new transmission line are determined either by each of the affected federal states or by the Federal Grid Agency. These decisions are subject to public and environmental consultations.

FIGURE 6 depicts the current state of transmission grid expansion projects in Germany based on NABEG. Even though the grid expansion process has been expedited, most lines are still in the planning or approval stage (orange, red, and blue lines). As we discuss in Section 3.1.3, this delayed grid expansion is increasingly seen as an impediment to the efficient expansion of renewables, creating a north-south bottleneck in the German grid.[26]

22 In 2006 the European Power Exchange EPEX Spot initiated a market coupling process, starting with a trilateral day-ahead auction format involving the French, Belgian, and Dutch spot markets. Since 2010, the German market has been coupled with French, Dutch, and Belgian day-ahead markets, defined as the Central West Europe market region, which has also been linked with the Nordic region. These markets are connected via the "NorNed" cable, which initially linked the Dutch and Norwegian power systems. For more details, see https://www.epexspot.com/en/market-coupling/another_step_towards_market_intergration (accessed 8/24/2017).

23 For more details, see https://www.netzausbau.de.

24 See § 12a EnWG for further details on the planning procedure.

25 This is based on the Federal Grid Expansion Plan Law; see http://www.gesetze-im-internet.de/bbplg/.

26 The estimated costs of approved transmission expansion through 2024 amount to €18 billion and €15 billion for grid expansion on land and offshore, respectively. This information is available from the Federal Grid Agency at https://www.netzausbau.de/SharedDocs/FAQs/DE/Allgemeines/05_Kosten.html.

2.1.5 Electricity wholesale market

When the German power market liberalization began, long- and short-term wholesale electricity trading was bilateral (over-the-counter) trading (Ockenfels, Grimm, & Zoettl, 2008). However, starting in the early 2000s, trading increasingly took place at exchanges in Frankfurt and Leipzig, and the German wholesale market evolved into a hybrid, with both exchange-based and bilateral trading.

Electricity can thus be traded on the European Power Exchange (EPEX Spot SE) in Paris, on the European Energy Exchange (EEX) in Leipzig, and

Figure 6 | State of current transmission grid expansion projects in Germany, according to Grid Expansion Acceleration Act of 2011, where new transmission lines are realized (green), approved (yellow), in planning approval phase (orange, either Federal Requirements Plan or Federal Sectoral Planning phase), and not yet in approval phase (blue). Source: (Bundesnetzagentur 2017).

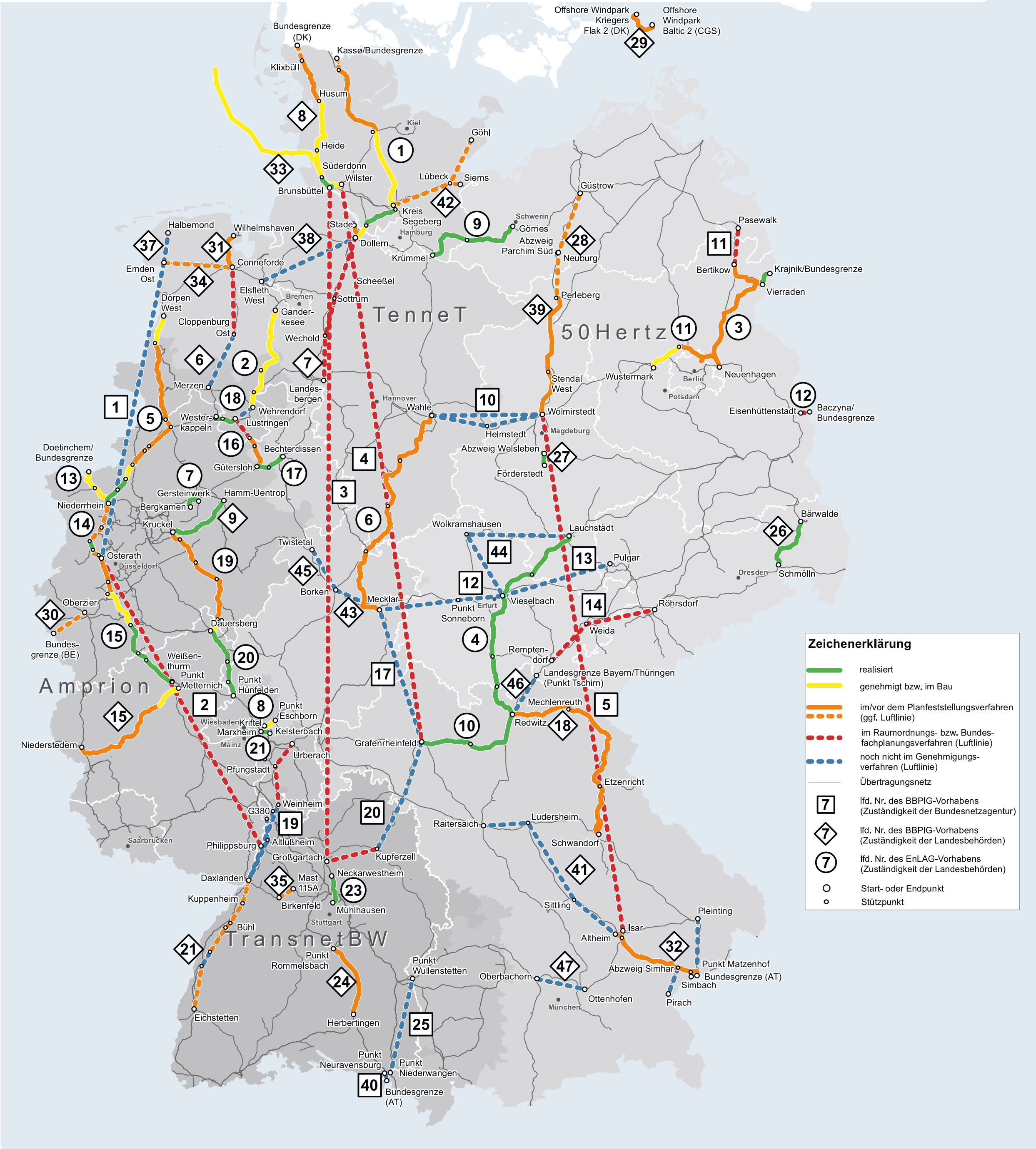
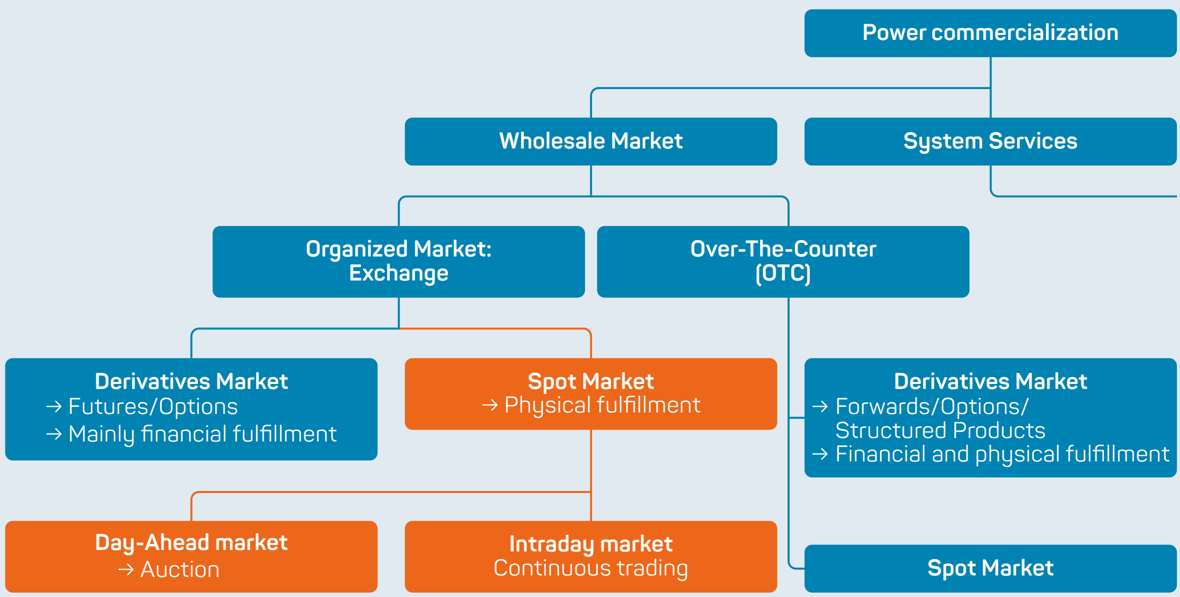


Figure 7 | Ways of trading power on Germany's wholesale market. Source: Vassilopoulos (2016).



on the Energy Exchange Austria (EXAA) in Vienna. Germany and Austria constitute a single electricity market area and one electricity price zone. Whereas EPEX Spot SE and EXAA are platforms for spot trading, EEX is a platform for futures trading involving standardized contracts with prespecified delivery points and durations. Complementary OTC trading is almost fully focused on forward contracts, which are more general than futures contracts and use bilaterally specified terms. OTC contracts can be cleared at each exchange, provided the products traded bilaterally equal those traded at the exchanges. This OTC clearing basically gives all contractual partners the same status as contractual partners at the exchange, whose default risk is fully borne by the exchange where they have traded. FIGURE 7 provides an overview of the different forms of trading power.

Figure 8 | Spot market trading in Germany. Source: Vassilopoulos (2016).

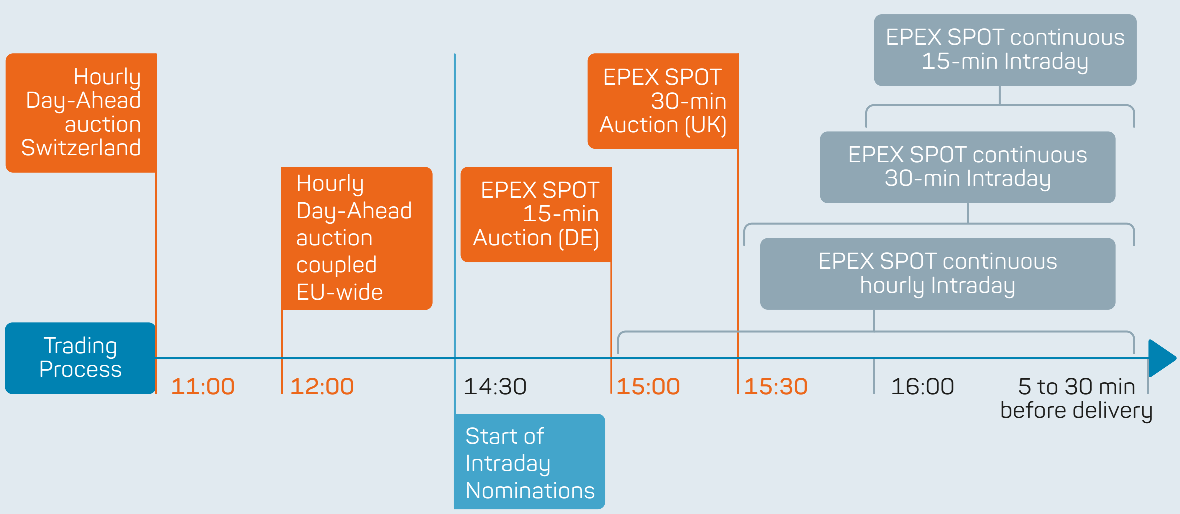


Figure 9 | Upper panel: Development of spot market volumes in Germany and Austria (EPEX Spot and EXAA) decomposed for day-ahead and intraday auctions [TWh]. Lower panel: Development of traded volumes of Phelix-Futures with different maturities at EPEX [TWh]. Source: (Bundesnetzagentur 2017).

The German and Austrian electricity spot market[27] has day-ahead call and intraday call as well as continuous auctions, where standard contracts for the physical delivery of electricity on the German and Austrian transmission system zones can be traded (FIGURE 8).

As FIGURE 8 indicates, the day-ahead call auction at EPEX Spot SE[28] takes place at 12 p.m. (auction results published at 12:40 p.m.) seven days a week; at EXAA it takes place at 10 a.m. (auction results published at 10:12 a.m.) five days a week. Day-ahead auction bids and orders are submitted for each hour or for standardized as well as customized ("smart") blocks of hours of the following day. At the EXAA, market participants are also able to trade quarter-hourly contracts.

While exchange-based physical "spot" trading has gained more importance between 2009 and 2016 (see upper panel of FIGURE 9), most electricity in Germany is traded as futures contracts (lower panel of FIGURE 9) both OTC and exchange based (Bundesnetzagentur 2017). At EPEX, forward contracts with different maturities can be traded (i.e., day, week, weekend, month, quarter, and year futures) and can also be traded as options. Contracts can be settled both financially and physi-

27 German TSOs estimate that the costs for offshore transmission expansion and refurbishment until 2030 could range between €17 billion and €24 billion. Investment costs for projected grid expansion and refurbishment on land until 2030 could reach up to €52 billion. These estimates stem from the second draft of the current "Grid Development Plan" (NEP 2030, Version 2019, 1st Draft) by the German TSOs available at: https://www.netzentwicklungsplan.de/sites/default/files/paragraphs-files/NEP_2030_V2019_1_Entwurf_Teil1.pdf.

28 https://www.epexspot.com/en/product-info/auction/germany-luxembourg

cally. Electricity futures include the German intraday-cap/floor-future, Phelix-DE-future, Phelix DE/AT-future, and wind-power-future.[29] Phelix-futures[30] are by far the most traded future at EEX, with a total volume of 1,466 TWh in 2016, which is about six times larger than the volume in 2009. Most of the Phelix-future contracts are traded for the following year (~66 percent) and two years ahead (~15 percent) (Bundesnetzagentur 2017). This also holds more or less for future contracts traded OTC, the total volume of which amounted to about 5,759 TWh in 2016.[31]

Uniform pricing is applied within the German bidding zone, implying that so-called balancing responsible parties, such as public and private utilities, generators, large industrial consumers, and load-serving companies suppliers, can ignore congestion when contracting. To balance supply and demand at every instant to stabilize the grid frequency at 50Hertz, TSOs are obliged to utilize corrective "out-of-market" measures—that is, ancillary services (Section 2.1.3).

2.1.6 Electricity retail market

In 2016, about 1,404 retail firms were selling electricity to about 50.2 million "final customers" (meters). About 85 percent of these retail firms serve fewer than 30,000 customers (Bundesnetzagentur 2017). Although the numbers suggest a high level of competition in the retail market, more than 70 percent of residential customers, who represent the vast majority of final consumers,[32] are supplied by their local utility rather than by a competing retailer.

On average, residential customers paid around 29 cents/kWh in 2016, of which only 21.5 percent was actual electricity wholesale costs (Bundesnetzagentur 2017); the renewable surcharge (support levy for previous and, to a lesser degree, incremental investments) and grid charges account for about 23 percent each. The remaining quarter is taxes and levies. Grid charges have remained more or less constant for the past decade, but growing renewable surcharges have sparked debates on the distributional effects of renewable energy support. Since 2006, support for the embedded cost of previous renewable investments increased by roughly 900 percent, to 6.88 cents/kWh in 2016. The rising costs and policy responses are discussed in more detail in Section 3.1.1.

A crucial distributional aspect is that many large commercial and industrial customers are exempted from or contribute far less to financing renewables support costs. §64 of the RESA specifies that customers whose annual consumption amounts to at least 24 GWh can under certain circumstances be exempted from 95 percent of the per unit surcharge for renewables. Moreover, §19 of the ordinance on grid fees (StromNEV 2005)[33] allows for reductions in regional grid charges of up to 80 percent for these customers, although there is considerable variation among industrial customers. Depending on eligibility for exemptions, prices

29 The intraday-cap/floor-future can be traded as a weekly contract for the current week up to four weeks ahead and is financially settled. It has been introduced to hedge against positive and negative price spikes on the intraday market. The asset underlying this future product is the EPEX Spot SE intraday index ID3-Price. The cap-future covers price risks beyond €40/MWh. The floor-future has been introduced only recently and covers price risks below €10/MWh. The wind-power-future, available since 2016, serves as a hedging instrument against the volume risk in wind energy output. The underlying asset is a normalized load-factor profile (quarter-hourly) of wind power in Germany (in MWh/MW), updated monthly. Contracts are settled financially. The Phelix-DE-future and Phelix DE/AT-future can be traded as a daily, weekly, monthly, quarterly, or yearly (up to six years ahead of delivery) maturity contract. Contracts are settled financially, but participants have the option to settle physically on the spot market. Phelix futures are available as base load, peak load, and off-peak contracts. The underlying asset is either the Phelix day base or Phelix day peak index, each of which reflects the average hourly day-ahead auction price for traded off-peak and peak hours at EPEX Spot SE. In 2016, Phelix futures constituted roughly 52 percent of all traded energy future contracts at EEX, and future trading at EEX constituted 37 percent of the overall future trading volume in Germany.

30 The Phelix, or "physical electricity index," is the arithmetic mean of the spot market prices at the EPEX SPOT for base-load hours 0 to 24 (Phelix base) and peak-load hours 8 to 20 (Phelix peak).

31 This number is obtained by the Federal Grid Agency from the largest brokers in the market. Of the total OTC future trades, 1367 TWh has been cleared at the EEX.

32 Roughly 94% of about 50.7 million metering points belong to residential customers (Bundesnetzagentur 2017).

33 The ordinance on grid fees can be found here (German only): https://www.bgbl.de/xaver/bgbl/start.xav?startbk=Bundesanzeiger_BGBl&jumpTo=bgbl105s2225.pdf#__bgbl__%2F%2F*%5B%40attr_id%3D%27bgbl105s2225.pdf%27%5D__1552067903740.

for industrial consumer range from 15.9 cents/kWh to 3.4 cents/kWh (BDEW 2017). Accordingly, prices for fully eligible industrial customers are only about 10 percent of the price paid by households.[34]

2.1.7 Renewables and climate policy

Renewable deployment at large scale began with the 2000 Renewable Energy Sources Act, which primarily aimed at technology development. The RESA built on a feed-in tariff implemented in 1991, which was widely thought to be a success in terms of creating market pull; in contrast, an earlier research and development program had failed to create a technology push.

In line with this approach, an influential idea for policy design at the time was to create a "lead market," a protected niche in which new technologies could develop until a level playing field was established. At the same time, the reluctance of the big utilities to engage in renewable energies (Section 2.1.2) led to a design specifically tailored to small investors (distributed renewables), which were thought to become main actors in creating the future renewables-based energy system. This background determined the general policy choice: a low-risk (to producers), long-term subsidy combined with the so-called priority dispatch. Although the instruments underlying the RESA have changed over time (Section 3.1.1), the core elements (Box 1) still largely resemble the original feed-in tariff.

Box 1 | Core elements of the Renewable Energy Sources Act

The legislation's cornerstone is a long-term (20–30 years) power purchase agreement set at fixed prices for different technologies and technology classes. The agreement guarantees feed-in of all renewable generation regardless of grid and market conditions ("dispatch priority"), and compensation is provided in case of unavoidable curtailment. The German transmission system operators (TSOs) are mandated by law to serve as counterparties, and they recover incurred costs by (a) selling renewable power to the market and (b) levying a fee on consumers to cover the difference between market prices and feed-in tariff levels. Differential costs are equalized: all consumers pay the same levy per unit of consumed electricity. However, industrial and commercial consumers with high energy use are partially or fully exempted from paying the levy. Furthermore, the RESA includes two additional grid-related incentives. First is a net metering clause, mandating that production for own consumption (self-generation) is exempted from the EEG levy. Second, grid operators are required to connect renewables plants to the grid without undue delay and are required to extend and upgrade the grid if necessary.

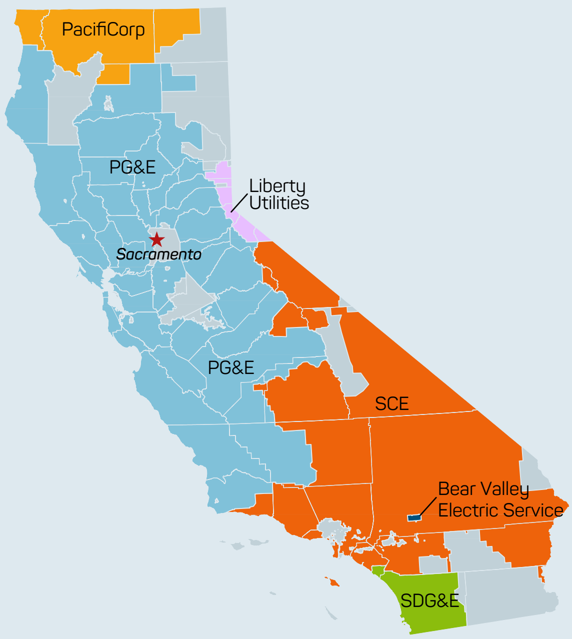
In recent amendments, the design has been altered such that project developers now carry a support allocation risk. For more details on different risks and their allocation to producers and consumer, see Pahle and Schweizerhof (2016).

Support for renewables and the need to deploy technological alternatives to nuclear power were the primary drivers of the low-carbon transformation, but in the middle of the first decade of the 2000s, climate change and respective dedicated policy instruments entered the stage, initially at the EU level. To implement the Kyoto Protocol, in 2005 the EU set up its Emissions Trading System, which includes the power and selected energy-intensive industry sectors. In 2007 the EU adopted a climate and energy package that set up legally binding targets for 2020 to unilaterally extend the Kyoto Protocol. That year also saw climate action on the national level. In 2007 a greenhouse gas (GHG) emissions target for 2020 was adopted, although not in a legally binding form and not backed by measures or policies. Instead, the targets for renewable shares were raised essentially because of the early success and political momentum it created.

In 2010, the German government adopted the Energy Concept, which sets forth long-term cli-

34 Furthermore, they may receive compensation for indirect CO_2 costs of emissions trading in the form of state aid. See https://www.dehst.de/SPK/SharedDocs/downloads/EN/Auswertungsbericht_2016_Englische_Version.pdf?__blob=publicationFile&v=2.

Figure 10 | California investor-owned utilities
Source: California Energy Comission.



mate and renewable energy goals until 2050 and foresees a prolongation of the use of nuclear power for 12 years. It explicitly mentions that the country takes a path toward the "age of renewables," the Energiewende. The reprieve for nuclear power was never implemented because the nuclear incident in Fukushima in March 2011 provoked fierce public opposition, and this aspect of the plan was abandoned a few months later. The long-term renewable targets for 2050 were implemented in the 2011 amendment of the RESA. As with previous climate policymaking, no dedicated measures to reach the targets were implemented.

In the following years, however, the discrepancy—having climate targets in place but no national policies to back them—became increasingly clear. The EU ETS carbon price plummeted in 2011, leaving the scheme by and large ineffective, and renewables support remained the only noteworthy policy to decarbonize the power sector. Yet the out-of-market deployment of renewables led to a decrease in energy prices, which pushed natural gas rather than coal out of the market. As a consequence, CO_2 emissions in the German power sector have remained roughly level in what has become known as the Energiewende paradox. In 2015, in an effort to contain CO_2 emissions, the government implemented a "climate reserve" to take eight older lignite plants out of the market prematurely. Contracts with generators specified that plants would be closed after four years in the reserve, and forgone revenues would be compensated based on cost estimates. Though a quick fix at best, the event spurred debate about the role of coal that continues today, most recently in the formation in 2018 of the Commission on Growth, Structural Economic Change and Employment (the "coal commission").

2.2 California

The California market has undergone several phases of transformation since 1990. To maintain our focus on this market's experience with high shares of renewables, we will only briefly discuss the early periods of restructuring before turning to the evolution of the market since 2009.

2.2.1 Liberalization and regulation

Prior to its major restructuring in 1998, the California market was dominated by three vertically integrated investor-owned utilities (IOUs; FIGURE 10) and several publicly owned utilities (POUs), the largest of which was the Los Angeles Department of Water. These integrated utilities were regulated or governed under cost-of-service principles. As described below, California pursued major investments in renewable generation in the 1980s and early 1990s during an experiment with deregulated, nonutility ownership of generation. The costs of these programs, combined with those of nuclear investments, contributed to make retail electricity prices in California considerably higher than in neighboring states.

Those stresses led to a radical restructuring of the industry in the latter half of the 1990s. The generation, transmission, distribution, and retail supply functions of the IOUs were unbundled and at least partially opened to competition.[35] The California Independent System Operator (CAISO) was established to oversee both the operation of the high-voltage transmission network and the reliability of the system through the operation of real-time balancing markets covering most of the state.[36] The gas-fired generation portfolios of the three dominant IOUs were divested to new entrants in the market, although the incumbent utilities retained their nuclear and hydroelectric generation assets. Initially, these assets were distributed among five nonutility generation companies.

As described below, the retail sector in the IOU service territories was also initially opened to new entrants for all customers. Importantly, however, a transition period was established to allow the IOUs to recover the stranded cost of legacy generation investments whose book value was well above their market value (Borenstein & Bushnell, 2015).

This transition was implemented through the establishment of a competition transition charge (CTC), which effectively froze residential retail prices from all retail suppliers at 5 percent below 1997 levels. The difference between this frozen retail rate and the retailers' sum of cost components (e.g., distribution and transmission costs, other fees, and the cost of wholesale power, as measured by the California Power Exchange spot price) was allocated to a special account targeting the recovery of IOUs' stranded costs. The intention was for the CTC to sunset once these costs were fully recovered, and it did so in the case of San Diego Gas and Electric in 1999. Once the CTC expired, retail prices would float at market-based levels (Bushnell and Mansur 2005).

That transition mechanism had many unintended consequences and was a major factor in the California electricity crisis of 2000–2001. The CTC effectively made the IOUs, still responsible for serving the bulk of California's residential customers, indifferent to wholesale prices because it moved inversely to those prices as long as they remained below the price cap. Consequently, the California IOUs engaged in minimal forward procurement and instead purchased the majority of their power on the daily Power Exchange market (Bushnell, 2004).

As subsequent research has shown, the lack of forward contract activity in an electricity market can significantly increase the potential for and severity of generator market power (Bushnell, Mansur, & Saravia, 2008). When market conditions began to tighten in 2000, this latent market power, concentrated almost completely into the daily market, was manifest in a quadrupling of wholesale energy costs and the financial insolvency of the two largest utility companies that remained subject to frozen retail rates under the CTC (Borenstein, Bushnell, & Wolak, 2002).

Emergency legislation then suspended retail choice and placed California state agencies temporarily in the position of a provider of last resort for retail customers of the state's two largest utilities. The market slowly transitioned into a structure featuring regulated procurement by monopoly retailers from a mixture of nonutility, public, and utility-owned generation sources. The current California market is therefore often described as a hybrid, combining elements of strong regulatory oversight of procurement with elements of competition in the supply of generation and a small component of retail competition.

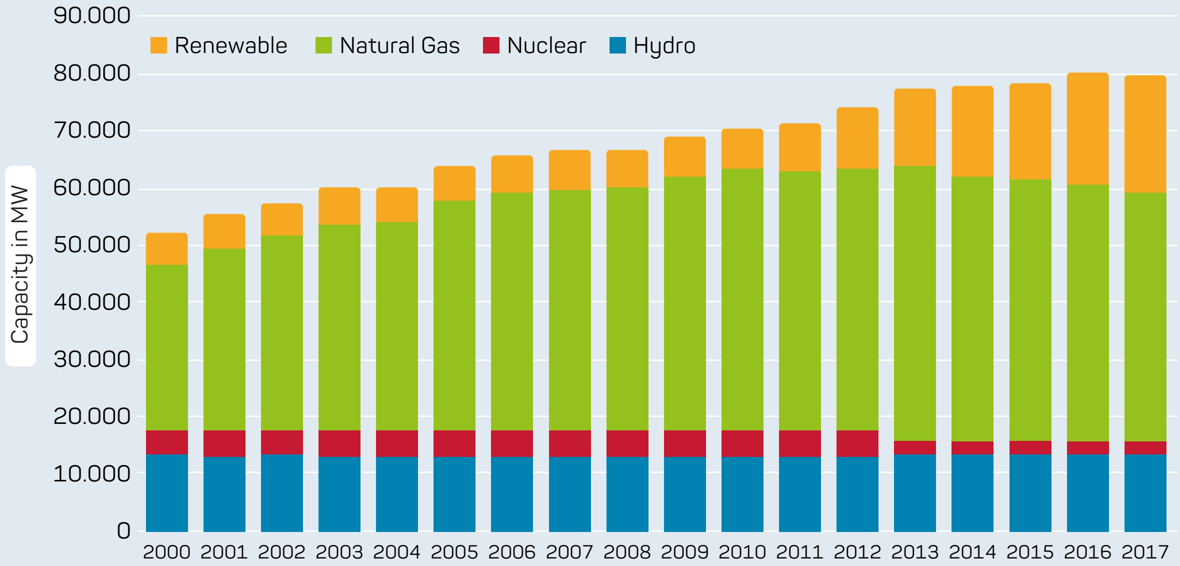
2.2.2 Generation

Generation ownership in California was dominated by the three IOUs until liberalization in 1998 but, even before that point, featured a substantial share of combined heat and power and mostly renewable nonutility generation. The fuel mix in the late 1990s was dominated by nuclear, hydro, and natural gas (FIGURE 11). Upon liberalization, almost all the natural gas–fueled generation was divested to nonutility new entrants. The nuclear and hydro portfolios remained with the incumbent utilities and continued to operate as regulated facilities.

35 The state's publicly owned utilities were exempted from the unbundling and retail open-access requirements. Although some smaller POUs chose to join the CAISO system for operational purposes, they have continued to operate as traditional vertical utilities in all other aspects. The Los Angeles utility has remained a separate integrated system operating independently from the CAISO, although there is substantial trade between the two control areas.

36 California Assembly Bill 1890. September, 1996. http://www.caiso.com/Documents/AssemblyBill1890.pdf.

Figure 11 | California generation capacity, by fuel type, 2000–2017.
Source: U.S. Energy Information Administration.



After the crisis of 2000–2001, the state worked to procure additional new capacity, focusing on long-term contractual arrangements with additional new firms. Although the crisis was not caused by a classic shortage of capacity, tight market conditions contributed to the market power of suppliers—the major factor in those disruptions. Planning and permitting processes were streamlined in an effort to add new capacity more rapidly and reduce the dominance of the nonutility producers.

In 2004, California adopted a resource adequacy requirement, which operates as a form of decentralized capacity market. This bilateral requirement obliges each retail provider to procure certified capacity sufficient to meet expected peak demand plus a reserve margin. In addition to the resource adequacy obligation, investment in generation since 2002 has been dominated by a regulated long-term procurement process overseen by the California Public Utilities Commission (CPUC). Through this process the three large distribution utilities, which serve close to 90 percent of CAISO customers and about three-quarters of all customers in the state, identified future needs, issued requests for proposals, and signed long-term contracts with new sources of supply. The utilities are guaranteed the recovery of these procurement costs. This environment, which can be characterized as regulated monopoly retail service, provided stability throughout the past 10 years but was dependent on a lack of open access by utility customers.

The long-term procurement process has been criticized at times as myopic and insufficiently competitive. One major criticism is the requirement that new supply contracts be reached only with newly built rather than incumbent supply. This requirement was partially motivated by a desire to expand capacity in the state, and partly as a punishment for incumbent generators that the state blamed for the 2000–2001 crisis. One result has been a steadily growing capacity reserve, and consequently consistently low prices in the resource adequacy market.

Since 2009, investment in new generation has been dominated by renewable sources, a development we discuss in more detail below. However, since 2016, the rising prominence of the new business model of community choice aggregation (CCA), an alternative form of retail service, has raised the prospect of significant migration of customers away from the IOUs to CCAs.[37] As a consequence, procurement by IOUs has been essentially frozen. The state is currently struggling to establish a new framework for supply procurement compatible with an emerging retail structure that could feature large-scale customer migration between IOUs and CCAs.[38]

2.2.3 Transmission capacity expansion

With the initial liberalization of the California market in 1996, responsibility for the oversight and management of transmission shifted from the IOUs to the CAISO. Financial ownership of transmission assets has remained with the utilities. The CAISO oversees a system of integrated planning for the expansion of the high-voltage transmission system. Investments are approved by the CAISO governing body, and with federal regulatory approval, capital costs are recovered through CAISO user fees.

With liberalization, the task of coordinating transmission and generation investment became more complex because generation entry was no longer subject to a centralized regulatory process. The task of transmission planning shifted from integrated planning to anticipating and accommodating market-based generation investment decisions. Methods were developed to evaluate the market, reliability, and environmental effects of transmission projects for purposes of cost-benefit analysis (Awad et al., 2010).

For many years, the transmission planning process was forced to be somewhat reactive to the decisions of the generation sector. Under federal open-access principles, ISOs must accommodate requests by generators to interconnect with their systems, subject to reliability requirements. Direct interconnection costs are borne by the individual connecting generator, but the "deep interconnection" investments necessary to upgrade the regional network are allocated to all network users. When renewables investment accelerated in response to state policy incentives, the queue of requested interconnections grew much faster than the ISOs' ability to reliably accommodate all the additions. Initially, interconnection requests were relatively low cost and evaluated on a first-come, first-served basis. Many proposed projects, some with little investment in the development effort, were speculative options for future market access. The lengthening queue increased delays, and relatively credible generation projects were blocked by less financially viable ones in the interconnection queue.

In 2012, the CAISO implemented two reforms in response. First, it established a more proactive and integrated transmission planning process intended to anticipate network investment needs rather than simply reacting to generation interconnection requests. Second, it established more stringent requirements for generation projects to enter and remain in the generation interconnection queue (Bushnell, Harvey & Hobbs, 2012). These changes occurred as energy procurement was becoming dominated by a centralized regulatory process. This made it more practical to again coordinate generation investment with transmission planning.

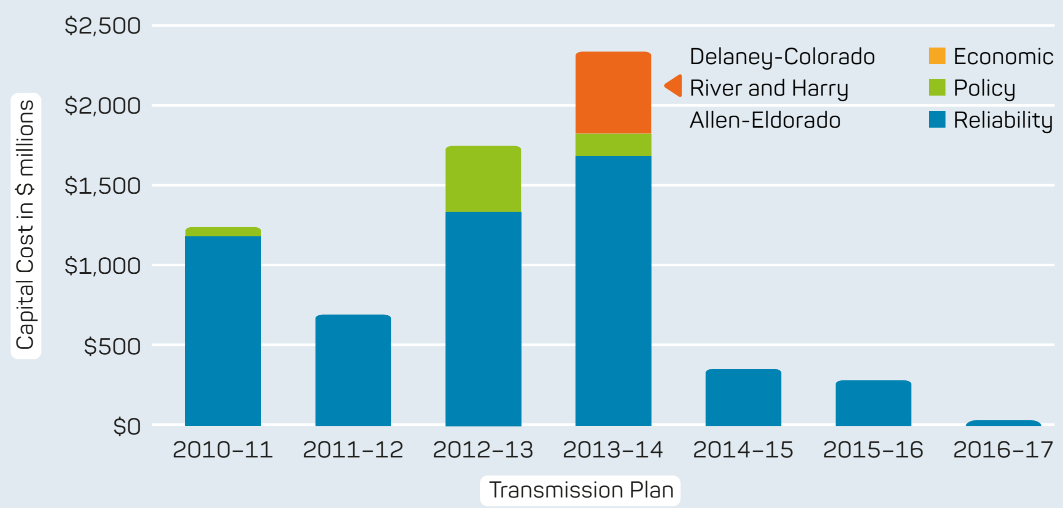
Investment in the high-voltage transmission system is subject to approval by the Federal Energy Regulatory Commission (FERC) under the principles established in the commission's order 1000. Generally speaking, transmission investments can be justified under one or a combination of three benefit categories: reliability, economic, or public purpose benefits. Reliability investments are triggered by needs to comply with regional reliability standards overseen by the North American Electricity Reliability Corporation. Economic Investments can be approved when demonstrated market benefits are estimated to exceed capital costs, even if not required for reliability. Historically, the vast majority of investments were justified under the reliability category.

The centralization of transmission planning and cost recovery, combined with the factors described above, rejuvenated investment in transmission

37 The California Public Utility Commission (CPUC) reports that with rooftop solar, CCAs, and direct access providers, as much as 25 percent of IOU retail electric load will be effectively unbundled and served by a non-IOU source or provider. That share could grow to 85 percent in the next decade (www.cpuc.ca.gov/retailchoiceenbanc).

38 CPUC, Current Trends in California's Resource Adequacy Program, February 16, 2018.

Figure 12 | Transmission investment in CAISO. Source: CAISO[39]



capacity relative to previous decades. FIGURE 12 summarizes the capital expenditures on new transmission, by category, for 2010–2017. Although reliability projects continue to dominate the profile, several major transmission projects have been developed with the specific purpose of accessing regions with high renewable energy potential.

2.2.4 Electricity wholesale market

The structure of California's wholesale energy market went through three major phases after its first implementation in 1998. The 1990s saw debates over the degree to which market operations should be centralized within a single institution (Chao & Peck, 1996; Singh et al., 1998; Wu et al., 1996). As a consequence, the first iteration of the California market featured two separate publicly chartered entities, one responsible for operating a day-ahead market (the California Power Exchange, PX) and a second responsible for grid reliability and the operation of a real-time balancing market (the California Independent System Operator, CAISO). The PX market was in principle a voluntary market that would compete with other trading platforms and bilateral markets. The CAISO served as the arbiter of transmission access and provider of reliability services to all platforms and types of day-ahead transactions. In practice, the PX handled the bulk of day-ahead market volume because of regulatory requirements that the large regulated load-serving entities rely on for their procurement. This decentralized structure proved awkward, particularly when it came to allocating and pricing scarce transmission capacity. The complexity contributed to the initial decision to limit differences in transmission prices to a small number of large transmission zones, as described below.

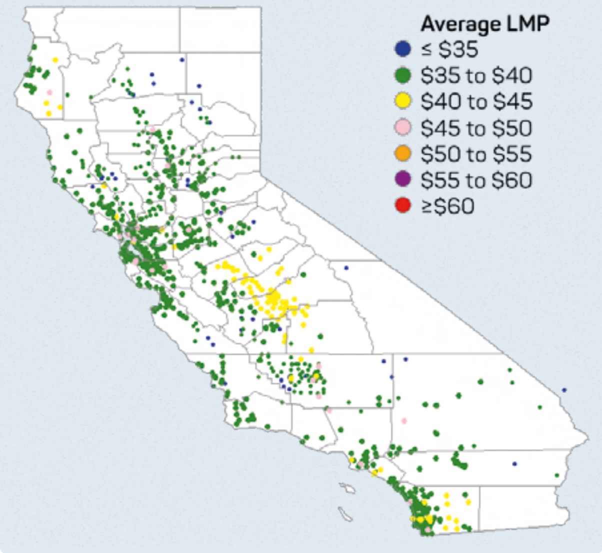
Extremely high wholesale prices during 2000, combined with the transition structure that effectively froze retail prices, placed the two largest load-serving utilities, Pacific Gas and Electric and Southern California Edison, under severe financial pressure. Both suspended payments to the PX in late 2000, triggering a series of supply disruptions. The utilities' actions in turn forced the PX, the financial counterparty to all transactions on its platform, into bankruptcy in early 2001. As the dust of the California electricity crisis settled by late 2001, only the CAISO and its imbalance remained as a viable functioning market.

This initiated the second phase of California's restructured wholesale market, which featured a set of decentralized bilateral platforms in the day-ahead period, and the CAISO's bid-based imbalance market, largely unchanged from the first phase, operating in real-time. Initially, state agencies, primarily

39 CAISO, Transmission Program Impact on High Voltage Transmission Access Charges, http://www.caiso.com/Documents/Presentation-2016-2017TransmissionAccessChargeForecastModel.pdf.

the Department of Water Resources, took over primary responsibility for procurement and daily scheduling of power on behalf of the financially distressed utilities and their customers. Retail choice for all customers who had remained with the utilities up to that point was also suspended. Over the first decade of the 2000s, procurement responsibility shifted back to the regulated utilities, but the market design remained limited to a real-time balancing market combined with ad hoc arrangements for allocating transmission access in the day-ahead timeframe. The CAISO initiated a process to redesign and expand its market in 2001, but the process was contentious and technically challenged. Full implementation of the redesign took most of the following decade.

Figure 13 | Average locational marginal prices in California, 2011–2014
Source: CAISO[40]



The third, current phase of California's wholesale market began in April 2009, when the CAISO market expanded to incorporate a "two-settlement" process involving a binding day-ahead and real-time market. All firms utilizing the CAISO transmission system are required to schedule or bid resources and load into the day-ahead market. The market-clearing process greatly increased in complexity, allowing generating plants to specify more than two dozen cost and performance characteristics that are solved for least-cost (bid-in cost) operations using mixed-integer programming. Methods for the automated review and possible mitigation of generation offers deemed to possess local market power were also added.

2.2.5 Transmission, distribution, and ancillary services

In addition to the day-ahead market, the other major shift in market design implemented in 2009 was a move from zonal to locational marginal pricing (LMP). Prior to 2009, the California market operated three transmission zones and allocated and priced access only on the interties between zones. Congestion within pricing zones (intrazonal congestion) was managed through out-of-market adjustments—sometimes called constrained-on or constrained-off payments—to specific generation units called on to relieve local transmission constraints. These out-of-market adjustment costs were recovered through an uplift payment uniformly applied to the load with each zone.

Although the zonal pricing scheme created inefficiencies, it was at least workable during the early years of the market and not a major contributor to the 2000–2001 crisis. Soon, however, the geographic coarseness of transmission prices became increasingly problematic. New generation plants entered the market in locations that were electrically remote from load but priced uniformly with all other locations in the same zone. For example, investment in natural gas–fired production on the California-Mexico border created intrazonal congestion in Southern California. Plants in these remote regions were eligible, under the pre-2009 market design, to earn the same energy prices as those in the Los Angeles area even though the grid was unable to take delivery of all the power they produced. This situation was exacerbated by the transmission interconnection policy described above.

FIGURE 13 illustrates the average LMPs in the CAISO system since 2011. Because it describes average

40 CAISO, Load Granularity Refinements: Pricing Study Results and Implementation Costs and Benefits Discussion, https://www.caiso.com/Documents/PricingStudyResults-ImplementationCosts-BenefitsDiscussionPaper_LoadGranularityRefinements.pdf.

outcomes, the figure does not capture the periodic extreme hourly variation in congestion costs. The shift to LMP dramatically changed the locational remuneration and incentives for generation sources. Under LMP, every major constraint is priced according to an optimization that minimizes bid-in production costs subject to all relevant transmission constraints. Plants in areas with too much generation, such as areas near the Arizona border, now faced extremely low marginal energy prices, while those in "load-pockets" with limited generation, such as the San Francisco and San Diego areas, earned much higher prices.

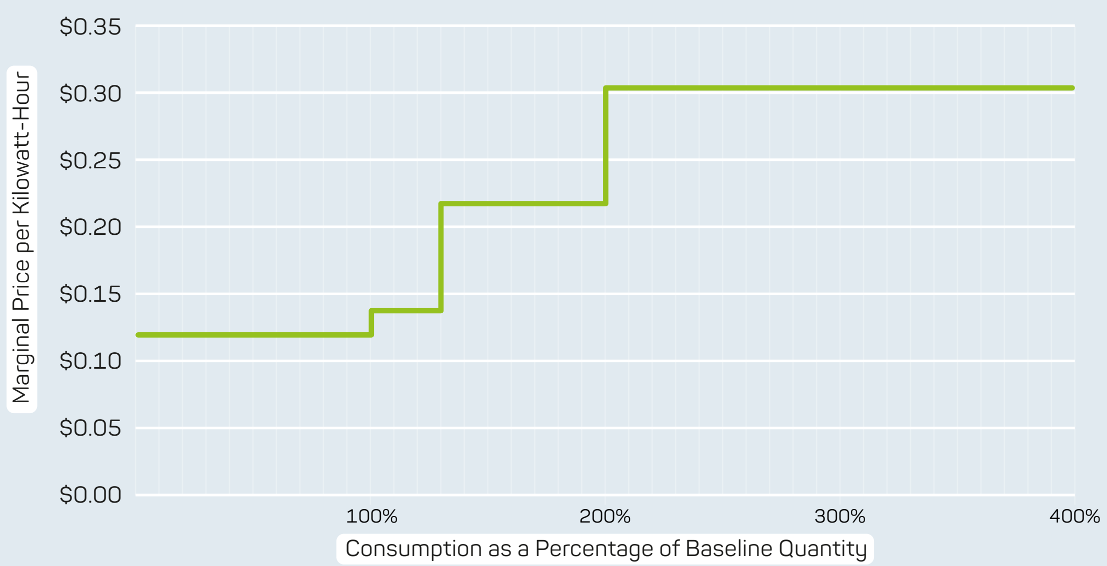
The 2009 market redesign also further centralized the provision of ancillary services. Traditional ancillary services, such as spinning and nonspinning (10-minute) reserves, as well as continuously responsive automated generation control, began being optimized jointly with the procurement of energy in both the day-ahead and real-time markets. Generation units now submit separate capacity price offers for each service, in addition to energy price offers and other operating parameters, such as ramp rates and minimum operating levels. Generation plant responsibilities are determined by a mixed-integer program that minimizes bid-in cost and assigns market awards.

Demand in the day-ahead market is also based on bids rather than forecast needs. However, most of the price responsiveness in these day-ahead demand bids reflects an implicit willingness to defer purchases to the real-time market rather than a willingness to curtail actual end-use consumption. In addition to the prospect of arbitrage by physical demand, explicitly financial "virtual bids" of supply and demand were allowed starting in 2010. The CAISO established a residual unit commitment process that allows it to position physical generation units for real-time supply if they do not clear the day-ahead market. This is meant to address concerns that underpurchases by demand or excess provision of virtual supply in the day-ahead market could cause a shortfall of physical generation in the real-time market.

2.2.6 Electricity retail market

When the market was restructured in 1998, the retail sector was opened to new entrants for all customers of the three IOUs. Other municipal utilities, including those in Los Angeles and Sacramento, retained their retail monopolies and generation portfolios while at least partially participating in the newly formed wholesale markets. Despite the public attention to this aspect of restructuring, retail choice was never a significant factor for residential customers. As described above, retail choice was suspended in 2001 for customers who

Figure 14 | PG&E residential tariff structure, 2015. Source: Borenstein (2017)



were currently served by their incumbent utility. Despite small adjustments over the subsequent decade, the IOUs remained monopoly providers for most of their customers until 2015.

Retail rates in the CAISO territory do not explicitly reflect the cost of renewables programs, which are supported primarily through implicit subsidies rather than explicit payments. Average retail prices ranged from 15 to 20 cents/kWh in the three IOU territories. A distinguishing feature of California retail prices, however, is the sharply increasing-block structure, in which marginal prices can be several multiples higher than baseline prices. FIGURE 14 illustrates the rate structure for PG&E. Rates up to 120 percent of a regulatory set baseline quantity have remained largely unchanged since 2001. This has concentrated cost increases in the upper tiers, applied to consumption greater than 120 percent of baselines. These high marginal rates have been a strong contributor to the deployment of rooftop solar projects, which can be marketed for flat prices below the levels of the upper two tiers (Borenstein 2017).

Starting in 2015, an alternative retail structure, community choice aggregation, gained prominence and could potentially dominate retail service in the IOU service territories. Provisions that authorized the formation of CCAs were included in legislation in 2004, but CCAs did not develop on any scale until a decade later. The popularity of CCAs has benefited from a combination of rising retail rates and local jurisdictions' preference for both local sources of generation and a higher percentage of renewable sources than the basic IOU portfolios.

2.2.7 Renewables and climate policy

Large-scale investment in grid-scale renewable electricity capacity in California occurred mostly in two separate decades, the 1980s and the 2010s. The earlier era in renewable energy production was spurred by the federal Public Utility Regulatory Policies Act (PURPA) of 1978. Among other provisions, PURPA required that electric utilities purchase power produced by qualifying nonutility generation sources—those utilizing wind, solar, and other renewable energy sources. The act is widely credited with creating a viable nonutility generation sector and taking the first step toward the liberalization seen in some parts of the country in the 1990s. Importantly, PURPA linked the renewable energy industry with the nonutility generation industry from its inception. As a consequence, ownership of renewable generation capacity has been dominated by unregulated firms.

PURPA created an environment for promoting renewable nonutility generation, but the specific details of its implementation were left up to individual states. California was one of a handful of states that pursued PURPA implementation aggressively. In the 1980s, the California Public Utilities Commission established a form of standard offer contracts available to any qualifying facilities to sell power under PURPA. The contract terms turned out to be extremely lucrative for nonutility producers and spurred a gold rush of renewable investment (Kahn, 1995).

The large amount of renewable and other forms of PURPA generation procured in the 1980s contributed to a glut of generation capacity in California and other states with favorable PURPA terms. This put upward pressure on electricity rates in those states and eventually played a significant role in spurring moves toward the more radical market reforms of the late 1990s (Ando and Palmer 1998).

During the 1990s, investment in almost all forms of generation was stagnant, and during the 2000s, new capacity was dominated by combined-cycle natural gas production. Following 2009, however, several California initiatives and federal incentives, detailed in the following section, led to a second wave of substantial investment in renewable capacity. California Senate Bill 350, passed in 2017, requires that load-serving electric utilities in California procure 50 percent of their energy from renewable sources by 2030. There is now discussion in regulatory and legislative circles of establishing higher targets, even a proposal for 100 percent renewable production.

3 Market and policy responses to increasing shares of renewables

THIS SECTION REVIEWS THE EVOLUTION OF MARKET AND POLICY DESIGN IN RESPONSE TO INCREASING SHARES OF VARIABLE RENEWABLE ENERGY (VRE) IN CALIFORNIA'S AND GERMANY'S MARKETS.

Market design changes play an important role for the integration of VRE because they can be regarded as least-cost options compared with infrastructural adjustments, such as transmission capacity expansion or advanced metering (NREL 2014; Pérez-Arriaga et al. 2017). In the German case, it is challenging to disentangle reforms intended to integrate VRE from those that reflect the parallel implementation of upper-level EU regulation. This puts the hypothesis that VRE diffusion induces efficiency-improving regulation and market design changes into perspective.

We start by highlighting renewable energy policy response and draw connections in a chronological manner to major developments in the two jurisdictions' wholesale electricity market systems, grid control operations, and provision of ancillary services.

3.1 Germany

3.1.1 Renewable policy adjustments and complementary integration measures

This section covers Germany's policy response to renewables as well as additional integration measures that have been taken in recent years. The policy is laid out in amendments to the Renewable Energy Sources Act, and integration has been addressed by new legislation or amendments of more overarching legislation, namely the Energy Industry Act (EIA). However, some changes in the RESA relate to dispatch (curtailment) and balancing and thus also facilitate integration.

3.1.1.1 Responses in renewable policy design

As described in the previous section, the major policy driving renewables deployment is the RESA. Since its introduction, it has undergone several reforms (TABLE 2).[41] Notably, the regulatory approaches initially pursued to diffuse renewables had put little emphasis on cost-effectiveness and instead stressed reducing the barriers for new and in particular smaller players to enter the market (Section 2.1.7). Many of the reforms and corresponding lessons learned described below were a direct response to excess costs that arose because of inefficient policy design and unanticipated market penetration of renewables.

Whereas the first two RESA amendments mainly scaled up policy ambition and dealt with cost distribution issues, the 2009 reform addressed two shortcomings of the dispatch priority—a core element of the feed-in tariff (Section 2.1.7)—that had become apparent at the time. Originally, the RESA had required TSOs to uptake and reimburse all electricity generated by any unit regardless of the current state of the market and potential imbalances. That is, dispatch was effectively uncontrolled, and generators did not react to price signals. Initially, effects were minor, but the rapid and clustered growth of onshore wind capacity, especially in the northern regions, caused increasingly frequent regional system imbalances. Lagging expansion of transmission capacity compounded the problem. In response, the 2009 amendment curbed the dispatch priority of VRE generators so that TSOs were now allowed, as a last resort, to order owners of renewable energy generation units to curtail their output if system security was at stake (§11, feed-in management). It also set rules on how to compensate curtailed production (§12).

41 Also see https://www.erneuerbare-energien.de/EE/Redaktion/DE/Dossier/eeg.html?cms_docId=71120.

Furthermore, the original type of contract for the uptake of produced electricity had been physical delivery: TSOs had made a forecast of renewable production at a constant level for each hour in a month (Monatsband), resembling a sort of base load profile. Retailers included this profile in their portfolios to serve load without considering deviations of actual production, which were managed by the TSOs. Downward deviations were compensated by activating balancing services, and upward deviations were traded at the power exchange (Andor et al. 2010). Accordingly, costs for downward deviations were reflected in the grid fees, and costs for upward deviation were reflected indirectly in both the wholesale price and the renewable surcharge.

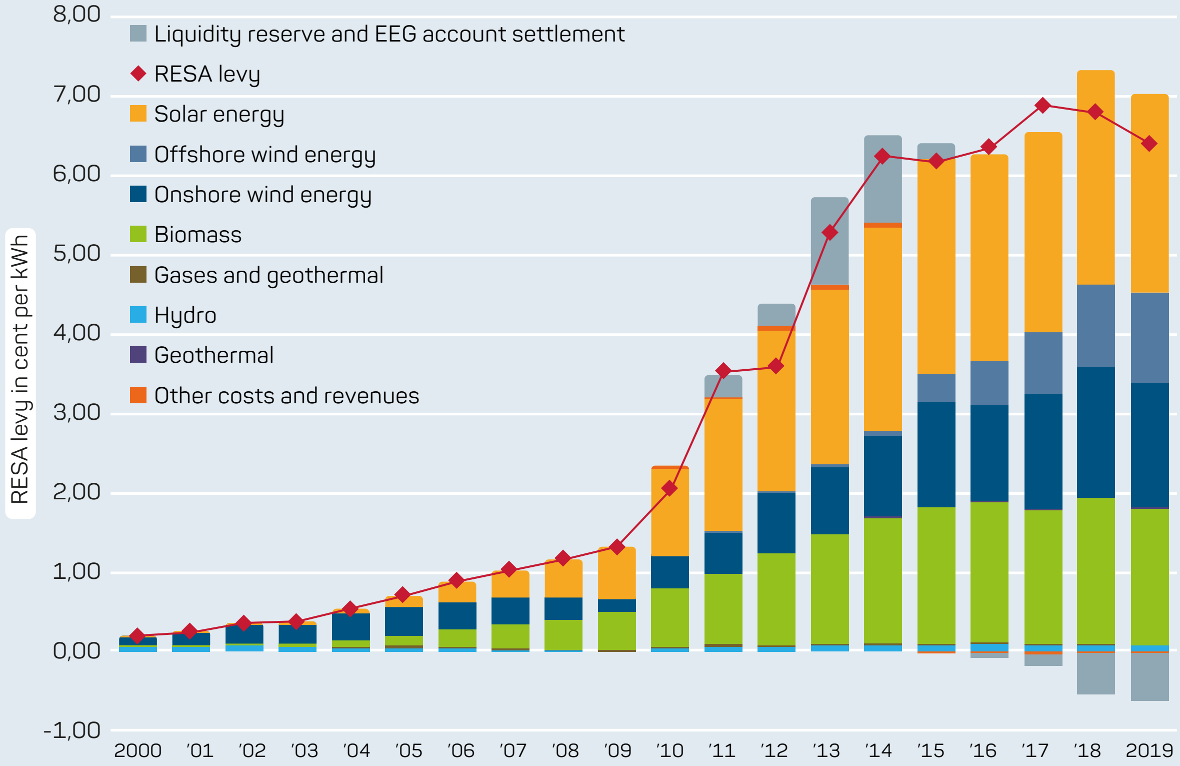
This inefficient contractual arrangement incurred estimated costs of around €570 million in 2007. These costs were covered by additional grid fees (Deutscher Bundestag 2009). In response, as part of the 2009 reform, a new ordinance (AusglMechV) for "efficient marketing" was enacted (§64(3)). This ordinance mandated TSOs to sell all renewable generation under the RESA directly to the market. Correspondingly, the contractual arrangement with retailers was changed to cash settlement—that is, they were charged the average per unit support payment per kWh calculated by the TSOs on an annual basis, which they pass on to consumers (RESA levy). In parallel, the EEX introduced negative bids down to €–3,000/MWh beginning in September 2008 to appropriately signal excess supply in the form of negative prices (Andor et al. 2010).

Table 2 | Major renewable policy design responses in Germany

Event	Date	Description
Renewable Energy Sources Act (RESA)	2000	→ Deployment target: Double share of renewable energy in total energy consumption by 2010 → Dispatch priority for electricity supply → PPA over 20–30 years, annually decreasing FITs (5 %) → Industry surcharge exemptions if consumption >100GWh/a
PV Interim Act	2003	→ Significant increase in FIT for PV → Removal of caps of utility-scale PV installations
RESA Amendment	2004	→ Target adjusted: 12.5 % in gross consumption by 2010, 20 % for in 2020 → Industry exemptions from surcharge to 10GWh/a,
RESA Amendment	2009	→ Dispatch priority "curbed" (§11); TSOs have to remunerate (barter) curtailed RE generators (§12) → Physical delivery to retailers replaced with cash settlement; TSOs sell all generation at EEX (§64) → PV FIT reduction/degression rate 8 % → Industry exemptions 1GWh/a
RESA PV Amendment	2012	→ Target adjusted: 35 % by 2020, 50 % by 2030, 65% by 2040, 80 % by 2050 → PV FIT reduction by 15 %, PV expansion corridor (2.5–3 GW/a) → PV capacity target 52 GW, flexible degression of FITs → Optional direct marketing coupled with market premium
RESA Amendment	2014	→ §15 EinsMan/Restricted dispatch priority: TSOs have to remunerate 95 % of lost revenue of curtailed RE generators → Mandatory direct marketing for wind power farms and utility-scale solar PV farms (>500 kW, since 2016 >100 kW) → Pilot phase: Public tender or auction for PV FITs (>750 kW)
RESA Amendment	2017	→ Public tender or auction for RE institutionalized → Grid capacity expansion regions, where new deployment is limited, are defined → Technology-neutral procurement → Provision to foster own-consumption in multifamily dwellings (Mieterstrommodell)

EEX = European Energy Exchange; FIT = feed-in tariff; PPA = power purchase agreement; PV = photovoltaic; RE = renewable energy; TSO = transmission system operator.

Figure 15 | Development of renewables support levy. Source: BMWi[42]



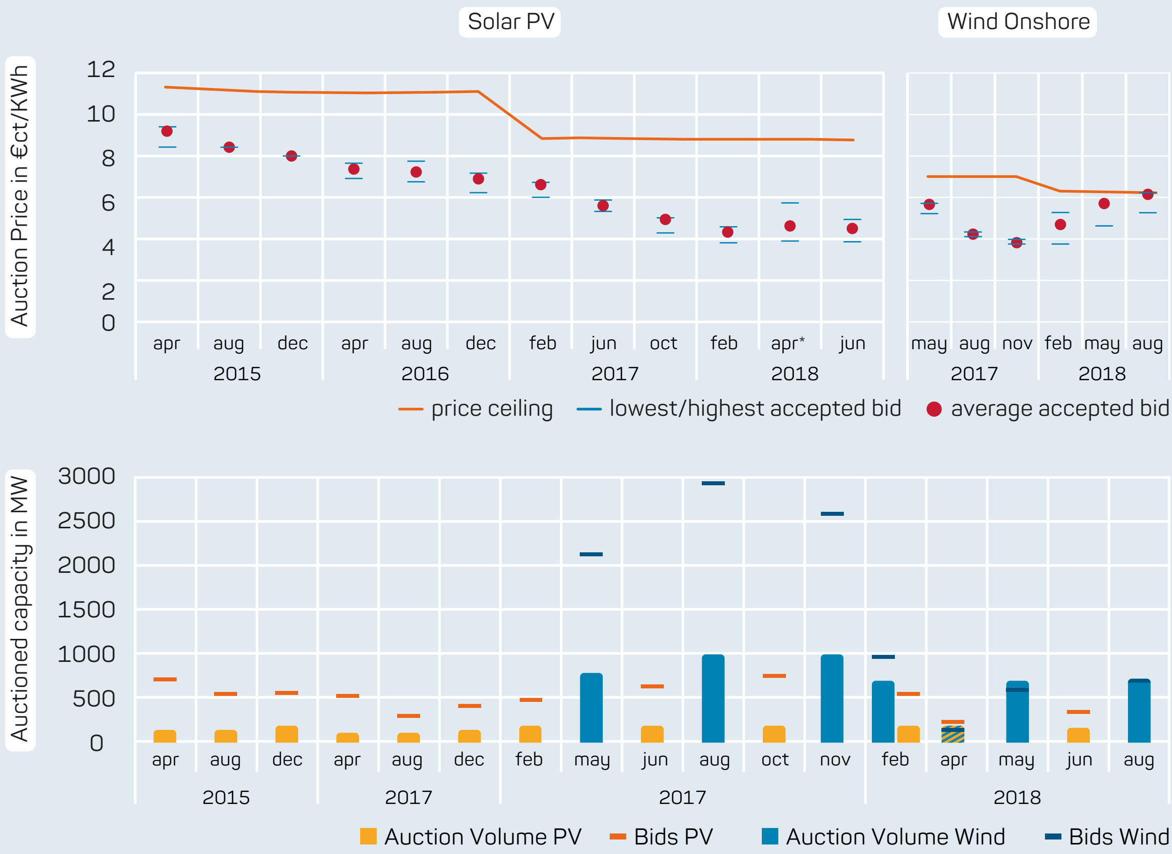
Other issues beyond rising system integration costs required responses in policy and market design. Between 2008 and 2011, the RESA levy collected from consumers for subsidizing renewables (Section 2.1.7) roughly tripled, from 1.16 cents/kWh to 3.53 cents/kWh (FIGURE 15). In the same period, generation increased by only around 32 percent, from 93 TWh to 123 TWh, largely because of the skyrocketing deployment of relatively costly PV installations, beginning around 2008. This in turn was due to the fact that that the feed-in tariff level at the time was set administratively by the German parliament, with updates only every four years. Moreover, there was no cap on annual capacity additions. Although this mechanism had worked in the first years, when prices for solar PV declined only moderately, surging world production contributed to sharp cost reductions beginning around 2008. The consequence was a surge in new installations as the gap between feed-in tariff levels and installations costs increased.

In response, the 2012 amendment introduced a new price mechanism to control deployment of new capacity (Atmender Deckel). Specifically, the Federal Grid Agency updated feed-in tariff levels monthly, based on the development of solar PV module market prices and the cumulative installed capacity in a year, to achieve a deployment corridor of 2.5 GW to 3 GW per year. In addition, the amendment defined a total PV capacity target of 52 GW and thus set a sunset clause for PV subsidies. This cap was set primarily for political reasons, to signal to consumers that costs would be contained.

Although those changes were more or less a solution to a technology-specific problem (PV), rising costs also increased awareness of the general lack of market elements in the support scheme. The original feed-in tariff was increasingly criticized because of the “invest-and-forget” mentality it induced in producers. The tariff encouraged developers to build new capacity and then generate

42 For more details, please refer to this link: https://www.erneuerbare-energien.de/EE/Redaktion/DE/Downloads/eeg-in-zahlen-xls.html.

Figure 16 | Prices, capacities, and bid volumes in renewable auctions, 2015–2018.[44]
Source: Tietjen and Schaeffer (2018).



regardless of market and grid conditions, leaving that issue to the TSOs, which were responsible for selling the power to the market. Accordingly, the 2012 amendment also took a first step toward improving market integration of renewables by introducing optional direct marketing by generators of renewable electricity at the wholesale market, in combination with a floating market premium. The latter is based on a reference tariff and revenue (the average spot price) per kWh, making revenues dependent on output decisions, at least partially.[43]

In the 2014 amendment, direct marketing became mandatory for wind and utility-scale solar PV farms with an installed capacity of at least 500 kW. This threshold was reduced to 100 kW in 2016. Additionally, this amendment initiated the pilot phase for publicly tendered floating market premiums for solar PV projects larger than 750 kW. Moreover, the previous general exemption of self-consumption from the RESA levy, which also included large industrial companies, was revised so that only small plants (<10 kW) were exempted. Another provision reduced subsidies in case of consecutive negative prices for six hours (§24).

The 2017 amendment made additional major reforms. Most importantly, to increase competition and contain costs, administratively set subsidy levels will be phased out and replaced by centralized renewable output procurement auctions. The intention is to mitigate the windfall profits experienced in the past—for instance, land rents for new wind farm sites. In the auctions for solar PV capacity, prices have declined steadily (FIGURE 16). As of 2017, public tendering auctions have be-

43 For more details, see Pahle and Schweizerhof (2016).
44 All auctions were pay-as-bid auctions, except the August and December PV auctions in 2015, which were uniform pricing auctions. Solar PV and wind onshore were jointly auctioned in April 2018 and only solar PV bids won. Average accepted bids are volume weighted.

Figure 17 | Grid capacity expansion regions. Source: Bundesnetzagentur.[45]

come mandatory not only for solar PV projects larger than 750 kWp but also for on- and offshore wind farms with an installed capacity of at least 750 kW and for biomass and combined heat and power plants with a capacity of at least 150 kW and 1 MW, respectively. The 2017 amendment also introduced technology-neutral auctions, beginning in 2018. Given that technology-specific subsidies have been an integral element of renewables support since its inception, supposedly to level the playing field, the move toward technology-neutral procurement represents a major step toward creating competition among technologies.

Apart from costs, a second major problem in recent years was that despite reformed planning procedures, expansion of transmission grids increasingly lagged behind deployment of new capacity (Section 3.1.3). In particular, the north-south connection constitutes a major bottleneck: wind power is mostly generated in the north and needs to be transported into the south. Moreover, power prices provide only weak incentives because they are smoothed and diluted through the floating premium (Section 2.1.7, BOX 1). In response, the location of wind farms is now controlled administratively through the definition of a grid expansion region in northern Germany (§36c RESA 2017), in which deployment of new capacity is limited (FIGURE 17).

Finally, the amendment included a special provision for tenants (Mieterstrommodell). It addresses equity concerns related to the fact that solar rooftop systems are typically installed by homeowners, who tend to be higher-income households, by offering special payments to landlords to compensate for the costs for installing metering equipment.

3.1.1.2 Responses related to complementary integration measures

A response to integration of renewable energy was the 2016 "power market 2.0," an amendment to the Energy Industry Act (EIA). In essence, it defines guidelines for the electricity market that aim at preserving the energy-only market, fostering demand-side and supply-side flexibility as well as sector coupling and promoting the integration of European electricity markets. Furthermore, it establishes so-called interruptible load (heat pumps, electric vehicles, etc.) to shave peak demand and thus reduce the need for distribution grid expansion. This measure has broader implications for future policy, discussed in more detail in the next section.

45 https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Ausschreibungen/Wind_Onshore/Netzausbaugebiete/NetzausbauGV_node.html.

Table 3 | Major complementary integration measures in Germany

Event	Date	Description
Act on the Digitization of the Energy Transition	2016	→ Timeframe for selective advanced metering infrastructure → Data security standards
Act on the Further Development of the Electricity Market	2016	→ Clarification of legal status of EV charging infrastructure operators to tap flexibility potential; interruptible load (Abschaltbare Lasten §14) → Reform of grid fees → With Federal Grid Agency approval, TSOs can define flexible gas power plants as system-relevant, which then cannot be shut down by plant owners → TSOs obliged to hold nonoperating capacity reserve → Lignite phase-out of seven plants or blocks until 2019 (§13g) → Peak shaving to reduce grid planning requirements → Opening of balancing markets → Greater market transparency

EV = electric vehicle; TSO = transmission system operator.

Further, the complementary 2016 Act on the Digitization of the Energy Transition represents a first step toward promoting demand-side flexibility and building a smart-grid infrastructure in Germany. It specifies a timeframe and the conditions for the selective roll-out of advanced meters and defines corresponding technological requirements and data security standards.

3.1.2 Electricity wholesale market adjustments

As described in Section 2, physical trading in the German wholesale market takes place at the spot market exchange, EPEX Spot SE, and EEX serves as a derivatives market. Since the beginning of the energy transition, both exchange platforms have restructured existing or introduced new products that appear more or less related to the growing shares of wind and solar generation (TABLE 4).

The most important development in wholesale market design, which was particularly motivated by the diffusion of VRE, is the strengthening and adaptation of the intraday market. Since its launch in 2006, continuous intraday trading has involved changes to product portfolio and trade lead times to address both uncertainty and variability in electricity supply from wind and solar power and thereby foster the market participation of these technologies. Specifically, the reduction in lead time from 75 minutes ahead of delivery to 45 minutes in 2011, to 30 minutes in 2015, and to 5 minutes[46] in 2017 is clearly aimed at mitigating the forecast errors about VRE supply. The reduction in contract duration from one hour to quarter-hour addresses the variability in wind and solar generation and also mitigates the risk of forecast errors. Additionally, increasingly variable and uncertain supply may increase price and volume risks involved with plant operation, possibly increasing the need for adequate financial hedging products.

Because direct marketing has become mandatory for a large class of utility-scale wind and solar PV farms, risk reduction supports wind and solar power asset holders. As of 2014, EPEX Spot has launched a day-ahead “intraday” auction, where participants can adjust their positions by trading 15-minute contracts day-ahead subsequent to the actual day-ahead auction for hourly contracts.

According to the Federal Grid Agency (Bundesnetzagentur 2016), EPEX Spot intraday trade volumes in Germany and Austria have increased sevenfold since 2006, amounting to 38 TWh in 2015, and have kept rising to 61.6 TWh in 2016 across all bidding zones (EPEX-Spot-SE 2017c). Compared with other bidding zones, continuous intraday trade in Germany and Austria has experienced particularly significant growth in monthly volumes (EPEX-Spot-SE 2017a). One can only speculate to what extent this rapid growth in liquidity and trading volumes is at-

46 Trade until five minutes ahead of delivery can occur only within a German TSO control region, not across regions.

tributable to the design changes. Introducing mandatory direct marketing of VRE output in 2014, after which volume growth spiked, may have also contributed to growth in continuous intraday trade (EPEX-Spot-SE 2017b).[47]

EEX has recently introduced product changes directly related to the spot market integration of VRE generation. In 2016, it opened auctions for wind power futures, which enable wind power generators and dispatchable plant operators to hedge volume risk. EEX also provides German intraday cap and floor futures, which allow for hedging price risks during high-price and low-price periods, respectively.[48]

Table 4 | Major wholesale market design responses in Germany

Event	Date	Description
EPEX Spot SE (spot market)		
EEX/Germany intraday auction launch	2006	Lead time 75 min. ahead of delivery, hourly contracts only, no implicit cross-border trading
EPEX Spot: Continuous intraday auction reform	2010	Intraday cross-border trading introduced
EPEX Spot: Continuous intraday auction reform	2011	Lead time reduced to 45 min ahead of delivery, quarter-hourly contracts
EPEX Spot: Continuous intraday auction reform	2012, 2013	Launch of intraday auction in Austria and Switzerland
EPEX Spot: Day-ahead intraday auction introduced for German TSO zones	December 2014	96 quarter-hour intervals traded day ahead
EPEX Spot: Continuous intraday auction reform[49]	July 2015	→ Lead time reduced to 30 min. before delivery for trades to any of 4 control zones, and to 5 min. within (not between) control zones → Hourly, quarter-hourly, and block contracts
EEX (derivatives market)		
EEX "energy turnaround products"	2016–2017	→ German intraday cap futures; → Wind power futures → Floor futures

EEX = European Energy Exchange; EPEX = European Power Exchange; TSO = transmission system operator.

47 See also EPEX Spot press release, 10 February 2017, http://www.epexspot.com/de/presse/press-archive/details/press/Direktvermarktung_wirkt_.
48 That is, participants can trade positive price spikes above €40/MWh and negative price spikes below €10/MWh up to four weeks ahead.
49 EPEX Spot press release, 16 July 2015, https://www.epexspot.com/en/press-media/press/details/press/EPEX_SPOT_and_ECC_successfully_reduce_lead_time_on_all_intraday_markets.

3.1.3 Transmission system operation adjustments and regional integration

This section covers responses in technical transmission system operation—mostly related to balancing and grid expansion—and regional integration to better integrate renewables across borders.

3.1.3.1 Responses in transmission system operations

Despite growing regional load and generation imbalances,[50] which require congestion management measures and raise costs (FIGURE 18), regionally differentiated prices will most likely not be introduced in the German electricity market in the foreseeable future.[51] Because uniform pricing will prevail,[52] the market for and relevance of ancillary services remain critical to reliable system operation. Adjustments in balancing power market design and coordination of TSOs' security of supply measures are thus vital to the integration of VRE generation.

Two developments stand out. First was the launch of national and international grid control coordination in 2008 and 2011, respectively. Second was another round of reforms to product and auction design for balancing power procurement, initiated by the Federal Grid Agency. Other measures are the introduction of restricted dispatch priority for VRE plants included in the RESA amendment of 2014 (Section 3.1.1), and an ordinance on interruptible load agreements from 2013 and 2016.

Growing shares of VRE supply are widely considered to have increased the frequency of unforeseen regional demand and supply imbalances, thus necessitating measures for balancing power (control power or operating reserves) and other security of supply services, such as redispatching power plants, countertrading electricity, and even curtailment of renewables (Hirth et al. 2015). Although TSOs' costs for security of supply measures have roughly quadrupled between 2011 and 2015 as installed wind and solar capacity increased 78 and 133 percent,[53] respectively, volumes and corresponding total costs of procured balancing power have steadily declined (Bundesnetzagentur 2016).[54] Similarly, the amount of activated balancing energy, one component of congestion management, dropped 55 percent by 2015.

One reason why demand for balancing power has been constantly decreasing is that since 2008, German TSOs have organized a central procurement auction for balancing power and have launched a coordination process on the expected need for balancing power as well as on activating balancing energy to prevent counteracting activation of balancing energy (netting out regional imbalances) as part of grid control coordination (Netzregelverbund) (Bundesnetzagentur 2016). Since 2011, German TSOs have also coordinated with Danish, Austrian, Dutch, Swiss, Belgian, and Czech TSOs on secondary control power imbalances, which may have also contributed to the reduced need for balancing power. These international coordination efforts among TSOs are closely linked to the pan-European market-coupling process, which began in 2010.

50 The imbalance of generation and load clusters increases particularly between the north and south of Germany. Several parallel developments in Germany's generation portfolio have led to an increasing geographic imbalance between load and generation. Much of Germany's heavy industry is located in the south, mainly Bavaria and Baden-Württemberg, which is also a densely populated area. Much of this area's high electricity consumption was served by nuclear power, which, as part of the energy transition legislation, will be phased out in 2022. Simultaneously, the bulk of Germany's onshore wind power capacity is installed in the north (Brandenburg, Thüringen, Lower Saxony, Mecklenburg-Vorpommern, and Schleswig-Holstein). Moreover, additions in both hard coal and gas-fired generation capacity will occur in the northern part (particularly North-Rhine-Westphalia).

51 In a press release, the Federal Ministry of Economic Affairs and Energy (BMWi) published a first amendment draft to the ordinance on third-party grid access, which explicitly aims at legally fixing the uniform pricing zone. For the amendment draft, see http://www.bmwi.de/Redaktion/DE/Downloads/Gesetz/referentenentwurf-stromnzv.pdf?__blob=publicationFile&v=6 [accessed 11/13/2017]. For the press release (in German) see https://www.bmwi.de/Redaktion/DE/Pressemitteilungen/2017/20171122-einheitlichkeit-der-deutschen-stromgebotszone-bleibt-gewahrt.html.

52 So far there appears to be no real case for introducing locational or zonal price signals in the German bidding zone; such price signals have been shown to yield few welfare gains, at least from a static point of view (Egerer et al. 2016).

53 During the same period, installed onshore wind capacity increased by 78 percent, from 27 GW to 48 GW. Installed solar PV capacity increased by 133 percent, from 18 GW to 42 GW (Bundesnetzagentur 2016).

54 The total annual costs for providing secondary (SC) and tertiary (TC) control power dropped by roughly 42 percent and roughly 48 percent, respectively, while costs for primary control (PC) power remained almost constant. The average amount of tendered PC power dropped by 12 percent, from 657 to 578 MW; for positive (negative) SC power, it dropped by 13 percent (12 percent), from 2199 (2091) to 1908 (1839) MW; and for positive (negative) TC power, it dropped by 45 percent (9 percent), from 2316 (2410) to 1269 (1924) MW (Bundesnetzagentur 2016).

Table 5 | Responses in transmission system operation in Germany

Event	Date	Comments
Grid control cooperation between German TSOs; inclusion of Amprion control area	2008, 2010	Establishes coordinated procurement of balancing power and dimensioning of required balancing power across 4 control areas, to prevent counteracting activation of balancing energy
International grid control cooperation	2011	Automatic netting of secondary control power imbalances across national control areas to avoid counteracting activation of balancing energy; initiated by German and Danish TSOs, IGCC now connects Austrian, Dutch, Swiss, Belgian, and Czech control areas
Grid Expansion Acceleration Act (NABEG)	2011, 2013, 2018	Aim is to increase speed of transmission grid expansion process to cope with diffusion of VRE capacity. Based on approved grid development plan provided by the Federal Grid Agency, NABEG sets requirements for → Determining corridor width of planned transmission line, which is part of Bundesfachplanung → Assessing environmental impacts of transmission line → Which institutions are overseeing the decision process for transmission line expansion 2013 Amendment: Federal Grid Agency coordinates process for transmission line expansion 2018 Amendment: Efficiency improvements to administrative approval process
Balancing power procurement auction reforms[55] (BK6 BK6-15-159, BK6 BK6-15-158)	2017	Secondary control power: → Reduced contract duration (from weekly to 4-hour product) → Lead-time reduction (from weekly to day-ahead auctions) → Minimum bid reduced to 1MW in exceptional cases (if bidder only provides 1 bid per product) Tertiary control power: Lead-time reduction (from weekly to day-ahead auction)

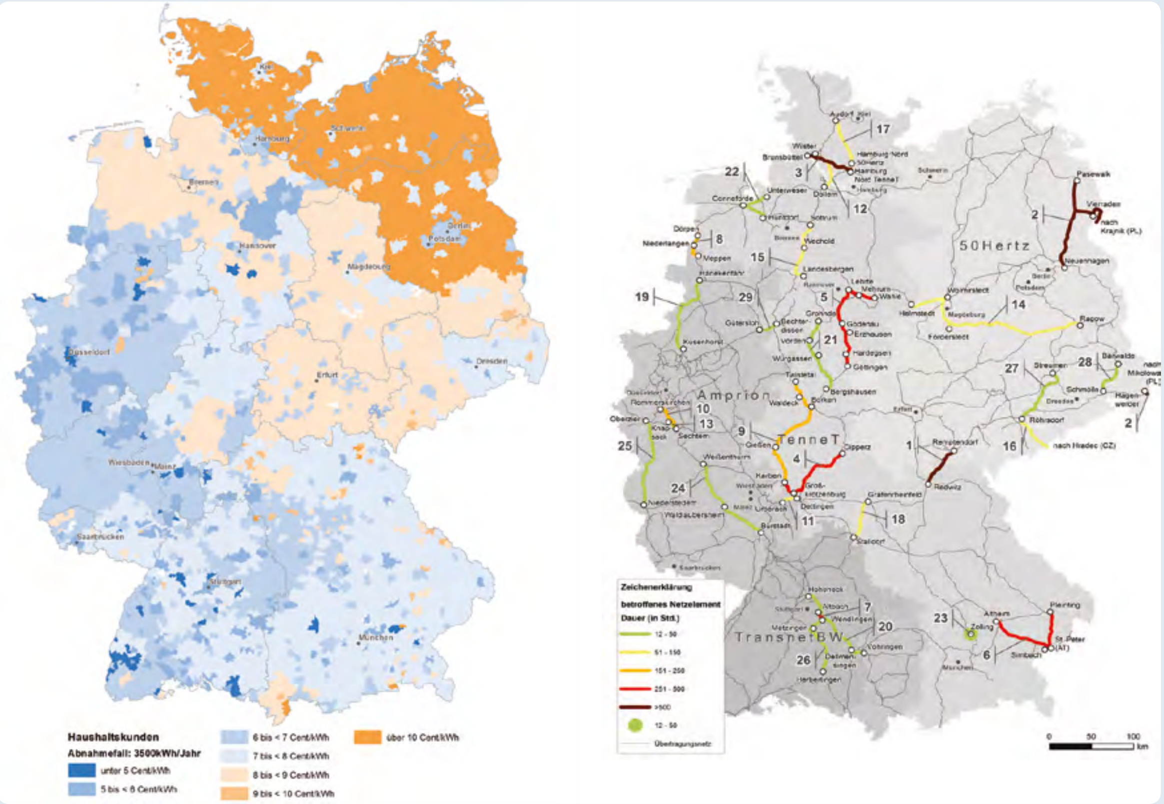
GCC = grid control cooperation; IGCC = international grid control cooperation; TSO = transmission system operator; VRE = variable renewable energy.

Coordination was initiated not primarily to improve VRE integration, however, but to comply with EU energy market regulation. Moreover, the aforementioned changes in continuous intraday auction and product design intuitively reduce the need to provide for unforeseen imbalances due to forecast errors, even though wind, solar, and load forecasts have improved significantly (Hirth and Ziegenhagen 2015). Hence, balancing power cost savings can partially be traced back to these developments.

Recent efforts enabling VRE and demand-response capacity to participate in secondary and tertiary control power auctions are considered to further balancing market efficiency. In particular, auction reforms[56] regarding secondary control power reduce the contract duration from weekly to four-hour commitments, the lead time to delivery from weekly to day-ahead auctions, and the minimum bid size to 1 MW (the bidder places only one bid per product).[57] Contract duration for tertiary control power was already down to four hours but is now

55 This reform explicitly aims at facilitating the participation of VRE, flexible loads, and storage facilities in the procurement auctions for secondary and tertiary control power. See Federal Grid Agency (Bundesnetzagentur), press release, June 2017.
56 The corresponding ordinances on auction design changes were enacted by the Federal Grid Agency in June 2017 and can be found here BK6 BK6-15-159 and here BK6 BK6-15-158 (last accessed 15 November 2017).
57 A general reduction in bid size to 1 MW has not been enacted, since it is considered to harm competition and reduce balancing responsible parties' incentive to make accurate forecasts (see Section 4.5.1 of BK6 BK6-15-159).

Figure 18 | Left: Regional distribution of residential grid charges spanning from more than 10 cents/kWh (orange) to less than 5 cents/kWh. Right: Most congested transmission lines of the German transmission grid. Source: Bundesnetzagentur (2017).



also traded in day-ahead instead of week-ahead auctions.

Before these reforms, the regulator could foster demand response as a source for primary and tertiary control power by allowing TSOs to auction 750 MW of "instantaneously" and "fast" interruptible load from the largest electricity consumers, respectively.[58] The underlying "ordinance of interruptible load agreements,"[59] or "AbLaV", was launched in 2013. By 2015, the cost of balancing power provided by interruptible loads had tripled to €27 million, which still constitutes only a small fraction of total balancing costs. So far there appear to be three prequalified providers of "instantaneously" and six providers of "fast" interruptible load, which together experienced 11 incidences of load interruption for 60 minutes on average.

In contrast to balancing power costs, total costs for transmission congestion management have increased from €129 million in 2011 to about €425 million in 2015. The lion's share of these costs is attributable to national and cross-border redispatch measures, which mostly stem from renewable feed-in management measures. These "EinsMan" measures are interventions to manage shortages in transmission capacity, during which TSOs and DSOs are allowed to curtail renewable generation units when curtailing conventional (nonrenewable) generation units is insufficient. In the broadest sense, the EinsMan measures can be interpreted as a regulatory response to VRE integration challenges. §2 of the RESA defines the physical dispatch priority of renewable generation units: TSOs have to warrant that each unit of renewably generated electricity is fed into the grid, even if this

58 The minimum and maximum bid sizes amount to 5 MW and 200 MW, respectively, and the duration of load interruption offered must last at least 15 minutes, up to 32 quarter-hours. Auctions are held weekly.
59 For details (German only), go to https://www.gesetze-im-internet.de/ablav_2016/BJNR198400016.html (last accessed 15 November 2017).

means that conventional plants have to ramp or shut down. However, since 2009, §14 of the RESA has defined the conditions under which TSOs are allowed to deviate from the renewable dispatch priority. According to §15 of the EEG, TSOs have to compensate each curtailed renewable energy generator for its lost profits, and since 2009, renewable curtailment costs have increased by more than 50 times, to about €315 million in 2015 (Bundesnetzagentur 2016). Interestingly, the largest year-to-year increase occurred between 2014 and 2015, when costs almost quadrupled, largely because of a sharp increase in curtailed wind energy (Bundesnetzagentur 2016).[60] This coincides with the 2014 amendment of RESA, which fixes the remuneration of VRE plant owners that are curtailed at 95 percent of lost revenues (TABLE 1). In general, other factors, such as the decommissioning of nuclear plants and delayed implementation of transmission capacity expansion projects, are mentioned as reasons for the significant increase in congestion management measures (Bundesnetzagentur 2016).

Finally, some regulatory adjustments to the mostly administratively determined transmission capacity expansion process have been made, particularly to speed it up. Past expansion targets have so far not been reached, which is increasingly seen as a problem for system reliability. The slow pace of expansion is behind the rapidly growing redispatch costs, which, as described above, constitute an increasing part of costs for remunerating curtailed wind generators in northern Germany and has already prompted questions about the distributional effects of the energy transition. However, the extent to which the delay in transmission construction actually hampers the further expansion of renewable capacity and whether this accounts for the higher costs are subjects of debate (Agora Energiewende 2013). Improving coordination processes among TSOs may yet yield cost savings and avoid construction of new transmission lines (Kunz and Zerrahn 2015). By giving the Federal Grid Agency many responsibilities in the grid expansion planning process, and thereby centralizing many decision steps (Section 2.1.5), the Grid Expansion Acceleration Act of 2011 and its subsequent amendment represent steps to quicken progress on removing bottlenecks in the German transmission grid.

3.1.3.2 Regional integration

In 2007, together with France, Belgium, Luxembourg, and the Netherlands, Germany established the Pentalateral Energy Forum to pursue regional cooperation with the aim of better integrating renewables (Handke 2018). A core achievement has been the implementation of flow-based market coupling, which replaced earlier explicit auctioning of cross-border transfer capacity. Additional top-down legislation was implemented by the EU to advance the Internal Energy Market, mainly by harmonizing market rules and expanding cross-country transmission through financial support and integrated planning tools. The overall governance approach is thus a combination of bottom-up regional and top-down EU-level (framework) elements, sometimes called differentiated integration.

Cooperation through the Pentalateral Energy Forum has been relatively effective in the past and will certainly continue to be an important element of regional market integration. A major factor in its success is the focus on technical aspects of market integration and policy planning and on alignment—by and large—of the broader climate and energy policies of the involved EU member states. However, integration with other member states whose policy priorities align less well is more challenging. Increasing export of power in times of high renewable production has led to loop flows and reduced power prices in neighboring countries—Poland, the Czech Republic, and Austria. Respective distributional implications have led to political controversies and have hampered further integration. Likewise, to reduce the threat to system stability posed by imports of Danish wind power, the responsible German TSO has reduced transfer capacities between the two countries. Germany is now facing infringement litigation for failing to ful-

60 Between 2014 and 2015, the amount of curtailed wind energy jumped from about 1.2 TWh/year to more than 4.1 TWh/year out of 4.7 TWh/year of total curtailed renewable energy (mostly in the Tennet and 50Hertz regions—i.e., northern control regions) (Bundesnetzagentur 2016). Corresponding costs almost quadrupled from about €83 to €315 million during this timeframe particularly due to a sharp increase in curtailed wind energy (Bundesnetzagentur 2016).

ly comply with the EU Third Energy Package regulation.[61] This development suggests that market integration eventually also requires policy integration and active management of distributional implications.

3.2 California

As discussed in Section 2.2, significant support for renewable electricity production in California dates to the 1980s, and until recently, renewable sources (primarily wind and biomass) have provided roughly 15 percent of supply. Renewable investment in the 2000s was focused at the distribution level, supported by the California Solar Initiative, which promoted rooftop solar, and other factors, such as rate structure (Borenstein 2017). This section discusses the second wave of utility-scale renewable investment in California, which began around 2010.

3.2.1 Renewable policy adjustments

TABLE 6 lists the major legislation and regulations directed at expanding utility-scale renewable electricity production. California-specific renewable policies have taken several forms, including modest feed-in tariff programs for targeted technologies, but the most effective policy has been the renewable portfolio standard (RPS) requirements placed on electricity retail suppliers. This mechanism has been applied in many US states. In general, an RPS requires that a fixed percentage of the energy sold to end users be procured from a generation source deemed renewable.[62] The California RPS was initially set at 20 percent in 2002 and has twice been adjusted upward. In the years immediately following 2002, utilities experienced some difficulty procuring sufficient energy, raising concerns about complying with the interim targets of the 2002 law. To ease short-term compliance burdens without relaxing the stringency of the ultimate goal, the CPUC adopted a 33 percent target but extended the 2017 deadline for compliance to 2020.

From 1997 to 2015, the focus of policymaking shifted from the regulatory arena, driven by the CPUC, to the legislative one. Originally conceived as an energy policy, by the late 2000s the RPS was seen as primarily a climate policy, to be integrated with an array of other policies also directed at GHG emissions. Assembly Bill 32, passed in 2006, established an emissions reduction goal for California but did not specify policies for achieving it. Initially, the CPUC took responsibility for implementing the renewable electricity strategy, but this created an ambiguous status for suppliers not subject to CPUC jurisdiction. In 2011, Senate Bill X resolved this ambiguity by imposing RPS requirements on municipal utilities and community choice aggregators as well as regulated utilities.

The RPS targets did not spur much new investment during the 2000s, but the more stringent requirements, combined with a smoother procurement process, have prompted substantial new capacity since 2010. FIGURE 19 illustrates the annual non-hydro renewable generation by technology type. During the last 6 years, solar PV has by far dominated the portfolio of new capacity additions, which is reflected in the relatively sharp increase in annual solar electricity generation. By 2016, the perception in policy circles was that reaching the 33 percent target would be relatively easy, and as California moved toward setting more aggressive GHG emissions goals for 2030, renewables in the electricity sector were identified as one path. Senate Bill 350 was originally designed for reducing petroleum emissions by 50 percent as well as setting a renewable electricity production target at 50 percent. However, the aggressive petroleum reduction goal met resistance, and the final bill focused on electricity production and energy efficiency as the two measures for reducing GHGs. In the same legislative session, Senate Bill 32 established an overall GHG emissions target of 40 percent below 1990 levels by 2030.

61 http://europa.eu/rapid/press-release_IP-18-4487_en.htm.
62 Qualifying renewables vary from state to state, as do the target levels and the penalties for noncompliance. In California, qualifying renewable energy sources include solar, wind, biomass, renewable gas, and small hydro but exclude large hydro facilities.

Table 6 | California renewable electricity policies, 1997–2015

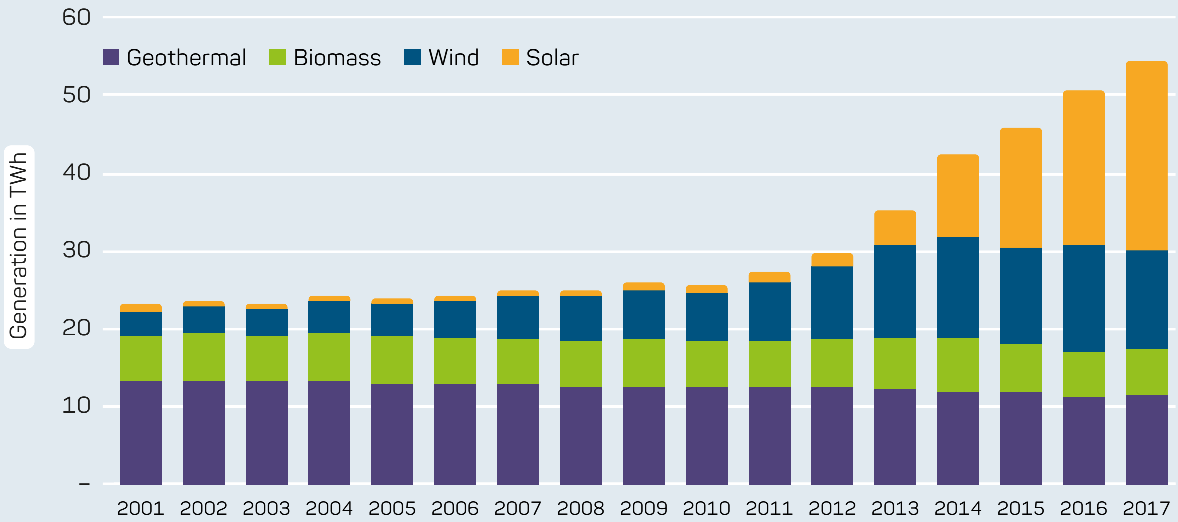
Policy	Effective Date	Description
Renewable energy program	1997 (SB 90, Sher)	Provided $340 million in 1998–2011 to renewable projects developed prior to 1996, as well as funding for distributed renewable projects.[63]
20 % by 2017 RPS	2002 (SB 1078, Sher)	Required utilities to procure 20% of retail sales of electricity from eligible renewable resources (excluding hydroelectric greater than 30 MW) by 2017[64]
1990 GHG emissions levels by 2020	2006 (AB 32, Nuñez-Pavley)	Directed California Air Resources Board to adopt policies to reduce GHG emissions to 1990 levels by 2020, resulting in industry-wide and sector-specific emissions policies, including statewide cap-and-trade system[65]
Emissions performance standard	2006 (SB 1368, Perata)	Prohibited development of or contracting with non-peaking resources above specified GHG emissions rates and criteria pollutants, effectively excluding coal[66]
33 % by 2020 RPS	2011 (SBX 2, Simitian)	Required utilities to procure 33% of retail sales of electricity from eligible renewable resources (excluding hydroelectric greater than 30 MW) by 2020[67]
Solar energy systems tax exclusion	2014 (SB 871, Budget)	Exempted value of new solar facility construction from certain property tax calculations[68]
250MW bio-energy feed-in tariff program	2012 (SB 1122, Rubio)	Required investor-owned utilities to procure 250 MW of eligible agricultural or forest bioenergy projects smaller than 3 MW.[69]
Renewable feed-in-tariff program, renewable market-adjusting tariff	2013 (CPUC, D. 12-05-035)	Provided fixed-price contract to small-scale renewable projects (<3 MW); closed to new participants in 2017[70]
50 % by 2030 RPS	2015 (SB 350, De León)	Required utilities to procure 50% of their retail sales of electricity from eligible renewable resources (excluding hydroelectric over 30MW) by 2030[71]

GHG = greenhouse gas; RPS = renewable portfolio standard.

California has added substantial generation from renewable sources in the past five years, but the 50 percent target entails nearly doubling current levels. Most recently, investment in renewable energy, as well as conventional capacity, has stalled because of the uncertainty created by the looming prospect of large-scale customer defection to CCAs (Section 2.2.2). Legislation proposed during 2017 that eventually did not pass would have established a state authority to reach power purchase agreements (PPAs) with new capacity and then assign the energy to the various electricity retail entities. Although such an outcome remains unlikely, the CPUC is exploring the prospect of some kind of centralized planning or procurement authority. It is not clear how such a model would interact with the current semi-liberalized retail sector.

63 https://energyarchive.ca.gov/renewables/existing_renewables/.
64 http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200120020SB1078.
65 http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32.
66 http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060SB1368.
67 http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201120121SB2.
68 http://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=RTC&division=1.&title=&part=0.5.&chapter=3.&article=.
69 http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201120120SB1122.
70 http://www.cpuc.ca.gov/General.aspx?id=6442452475.
71 http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

Figure 19 | California renewable energy production, 2001–2017.
Source: California Energy Commission.



3.2.2 Electricity wholesale market adjustments

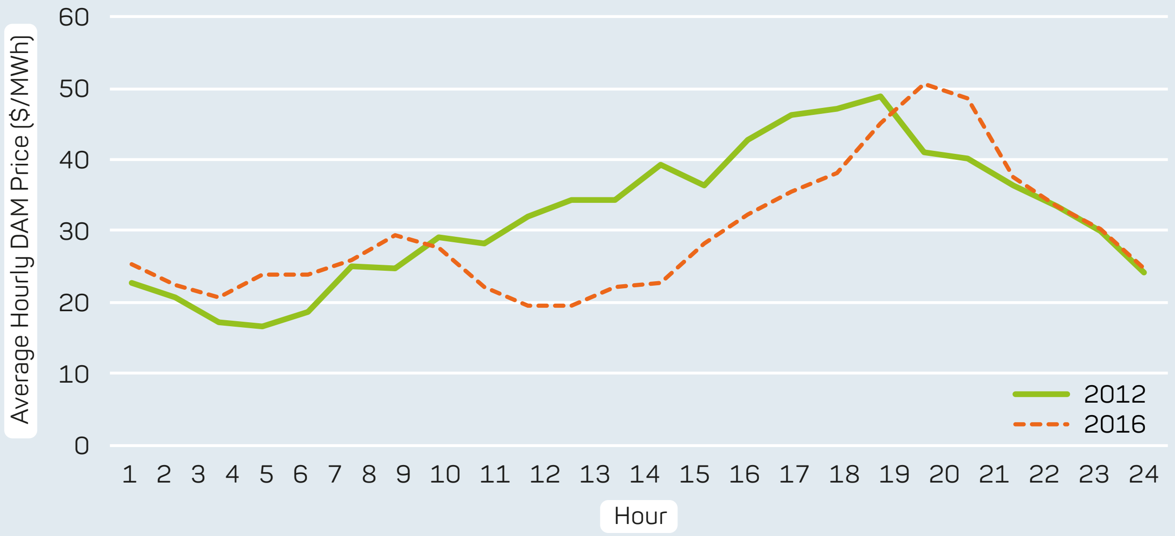
As a policy tool for promoting renewable investment, the RPS has an advantage over a feed-in tariff because the value of the production incentive is automatically adjusted down by market forces as production nears the renewable target. However, it also draws several criticisms. One is that a somewhat arbitrary target for renewable penetration (e.g., 20 or 33 percent) is unlikely to reflect the optimal balance of costs and benefits. Another criticism is that by emphasizing renewable energy as opposed to low-carbon energy, the RPS has threatened the economic viability of nuclear energy, another zero-carbon power source that currently provides 20 percent of US electricity supply. Further, since the RPS requirement is measured in generic MWh, the regulation places no premium on renewable energy that is produced in more valuable places or at more valuable times, and it fails to differentiate among the emissions intensities of the fossil generation sources that it might displace.

When the amounts of renewables produced under an RPS are relatively small, these factors have only minor consequences, but as the penetration of renewables has climbed above 20 percent, the incentive problems with the RPS mechanism are becoming apparent. The effects of the boom in solar investment are documented in Bushnell and Novan (2018). As illustrated in FIGURE 20, the hourly profile of electricity prices shifted dramatically between 2012 and 2016. The surge of midday solar production has meant that midday hours are now the lowest-priced periods in the California market. One implication is that additional solar capacity, which continues to dominate resource planning for compliance with higher RPS targets, will provide diminishing value to the system because production will increasingly be concentrated in hours of relatively low value. This will grow more extreme unless the electricity system evolves and that introduces widespread opportunities for battery storage (e.g., electric vehicles) and thermal storage (building space and water conditioning) become available.

3.2.3 Transmission system operation adjustments

Two significant changes to the management of transmission in the CAISO were implemented early in the second wave of renewable investment. The first was the adoption of locational marginal pricing in 2009, and the second was the reforms to the generation interconnection process, which better integrated transmission planning with resource planning (Section 2.2). Although the surge of solar production in the past five years has had a dramatic effect on the time profile of prices, the

Figure 20 | Hourly average prices in CAISO real-time market.
Source: Bushnell and Novan (2018).

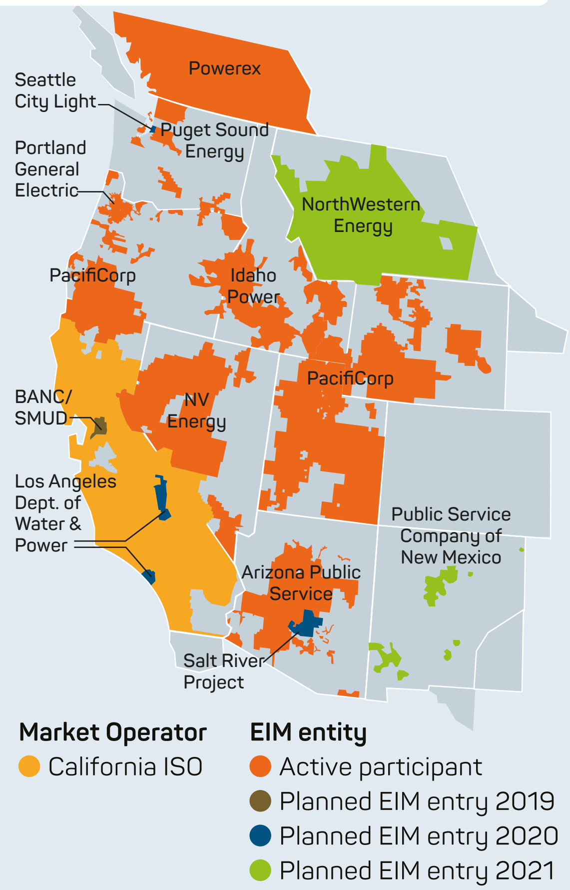


geographic profile of prices has not shifted significantly. Internal congestion in the CAISO market is still relatively modest.

However, growing concerns over the potential surplus of renewable energy, particularly during spring, have given momentum to initiatives designed to better integrate the California market with its neighboring control areas. The Energy Imbalance Market (EIM) is a real-time market with growing participation throughout the western United States, and it has extended market-based dispatch beyond the CAISO.

Unlike the CAISO's two-settlement market, the EIM manages only energy transactions. Management of local reserves and other reliability services remain the responsibility of the EIM entities. Each EIM entity submits a balanced schedule of supply and demand that forms the basis of a 15-minute and 5-minute day-of-reoptimization of resources based on supply offers and demand bids. Before the EIM was set up, it was difficult to adjust imports and exports from California after the day-ahead market and nearly impossible to adjust flows on less than a 15-minute basis. Although patterns of surplus energy that are predictable daily could be managed under the previous market regime, the

Figure 21 | Western Energy Imbalance Market (EIM) of the California Independent System Operator (CAISO). Source: CAISO.[72]



72 The Figure and further details can be found here: https://www.westerneim.com/Pages/About/default.aspx.

EIM increases California's ability to export surplus energy in short timeframes.

After FERC Order 1000, finalized in 2011, a third category providing justification for transmission investment was added: support for public policy requirements. Many transmission projects deemed necessary for accessing areas with large-scale renewable energy production could not qualify on their reliability or economic benefits alone; this category is intended to stimulate the transmission investments necessary to support state-level re-newable electricity targets.

4 Trends and future pathways

IN THIS SECTION WE CONSIDER CURRENT TRENDS AND POLICY OPTIONS IN GERMANY AND CALIFORNIA IN FIVE CATEGORIES: (1) ELECTRICITY PRICING MODELS AND REGIONAL MARKET INTEGRATION, (2) RENEWABLE PROCUREMENT MODELS, (3) RENEWABLE POLICY DESIGN, (4) DEMAND FLEXIBILITY AND RETAIL RATE DESIGN, AND (5) ELECTRIFICATION OF THE TRANSPORTATION, INDUSTRIAL, AND BUILDING SECTORS.

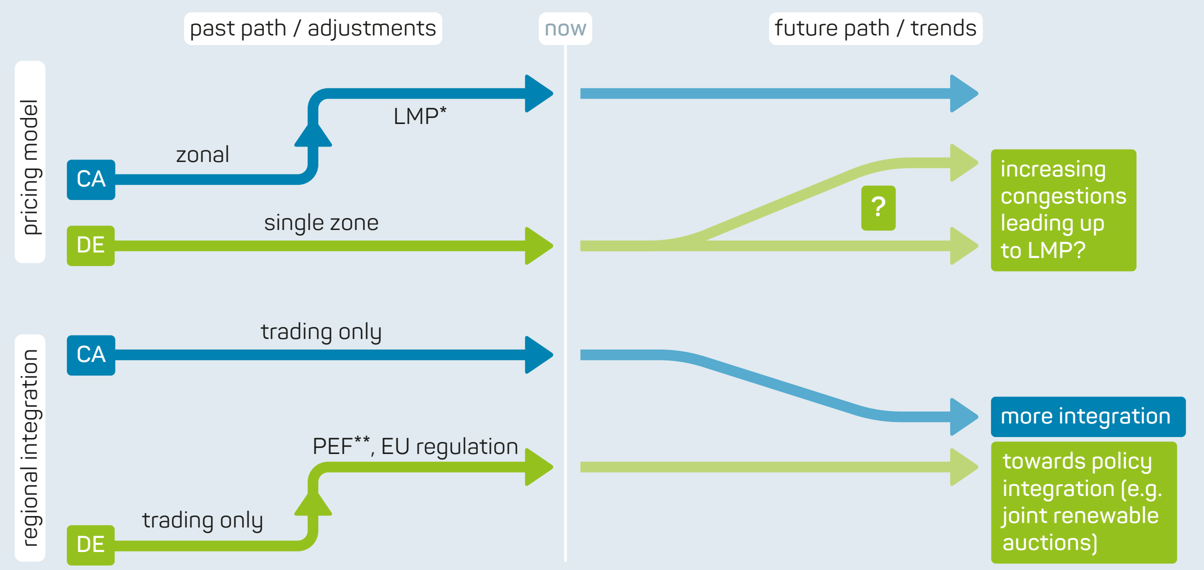
In most cases we find a convergence in policy pathways: either one jurisdiction is moving toward the approach pursued in the other, or both paths are leading toward a new model. Both outcomes suggest that pursuing deep decarbonization tends to bring initially different market and policy environments closer together—and thus may foreshadow how the next iteration of market and policy design may take shape.

4.1 Electricity pricing model and regional market integration

The support of large-scale renewable penetration almost certainly requires additional investment in network assets, given that existing networks evolved to serve a market where generation has been located with convenient access to fossil fuels, as opposed to renewable potential. The increasing demands on grid assets also increase the need for a more rational and efficient utilization of those assets. Even when transmission congestion is modest in the short run, the use of less granular pricing, such as zonal pricing, can lead to inefficiencies in the long run. Furthermore, market integration also raises the issue of policy integration to avoid reshuffling of generation resources to meet environmental policy constraints without meaningful overall emissions reductions, and to manage the distributional implications of increasing electricity trade with neighboring jurisdictions whose policy approaches may differ.

California experienced inefficiencies in the early 2000s, when gas generation expanded in relatively low cost locations along the California-Mexico border. These units were eligible to earn a Southern

Figure 22 | Electricity pricing model and regional market integration pathways



*Locational Marginal Pricing **Pentalateral Energy Forum

California zonal price under the state's zonal pricing scheme at the time, even though these investments induced significant intrazonal congestion between the border areas and end-use load. In response to these and other long-run stresses, California adopted full nodal locational marginal pricing in 2009. Given the existing capacity of the network, with full nodal pricing, resources in areas with substantial congestion will bear the short-run congestion costs of that location decision. LMP has provided both market participants and policymakers with an accurate and transparent signal about the locational value of various resources, as well as an efficient means of rationing the available transmission capacity. These pricing signals are more acute for generation sources, which receive site-specific LMP, than for customers, who pay zonal prices that are the average of all the customer nodes in a given zone. Nonetheless, transmission investment can disruptively alter pricing patterns and impose costs that create distributional considerations, which may not be politically acceptable in all venues.

In contrast to California, Germany has pursued the single price zone model and has even recently written this into law. Yet the problems and challenges of this model are increasing, as manifest in rising costs for balancing measures and curtailment of renewables, constraints on renewable deployment in regions with frequent congestion, and the recent split of the uniform German-Austrian price zone due to frequent congestion. Germany's primary response has been to introduce measures to accelerate grid expansion, but it has not kept pace with renewable expansion. In fact, the plans of the new government to increase the 2030 renewable target to 65 percent (up from 50 percent) seem to be on hold for this reason.

If that trend continues, introducing LMP might eventually be necessary, but policymakers in Germany voice two concerns about moving away from the historical legacy of a single price zone.[73] One is that addressing the congestion problem through a new strategy (local price signals) would take a long time and could disrupt grid expansion in the meantime. A second concern is that LMP would have distributional effects, raising prices considerably in some states of the country and lowering them others. In Germany's liberalized retail market, these price changes might be difficult to cushion because electricity rates are not regulated. From a political point of view, this is important because the country's federal system typically requires consent by all states for major legal reforms, such as would be required for the implementation of LMP.

Concerns about a transition to LMP are common but may be misplaced, based on the experience in California and elsewhere. By identifying and quantifying the costs of congestion, LMP helps improve and focus grid expansion rather than impede it. The only transmission investments that are discouraged are those that are more efficiently dealt with through pricing. The potential distributional effects are a concern, but several mechanisms can greatly mitigate their magnitude. First, customer prices can be aggregated to zonal or even countrywide averages of LMP. Such aggregation of pricing on the load side is not uncommon in LMP markets. Second, cost differences can be mitigated by the allocation of financial transmission rights, which provide a financial hedge that can at least partially offset the congestion costs revealed by LMP. Importantly, when LMP is efficiently implemented, it lowers the overall costs of network congestion, creating savings that can also be applied to offset distributional concerns.

The expanded availability of renewable electricity has also increased momentum toward geographic expansion and better integration of regional markets. Historically, both the German and the CAISO systems have operated as stand-alone electricity balancing areas. Trade between these markets and other neighboring balancing areas has always been limited by the "seams" issues common between electricity markets.

In both jurisdictions, renewable integration has also motivated better integration with neighboring markets. Germany took action relatively early, in 2007, by setting up the Pentalateral Energy Forum. In California, modeling efforts have demonstrated that solar production will likely face increasing

73 This information is based on conversations with senior policymakers.

curtailment during midday periods, absent more opportunities for exporting surplus energy.[74] Thus far, the regional expansion of market-based dispatch has been limited to a real-time Energy Imbalance Market.

In California, as in Germany, a central issue with regional expansion of the operation of the grid is governance. The California ISO is led by a state governing board, and it is understandably untenable for neighboring states to agree to such a governance structure. For their part, stakeholders in California worry that a regional governing body might not reflect California's commitment to decarbonization and might allow out-of-state fossil fuel resources to service California demand. Furthermore, with regionalization, the greater investment in renewables that is necessary to achieve California's commitments might occur outside the state, or regulatory authority of the transmission system might be ceded to federal agencies.

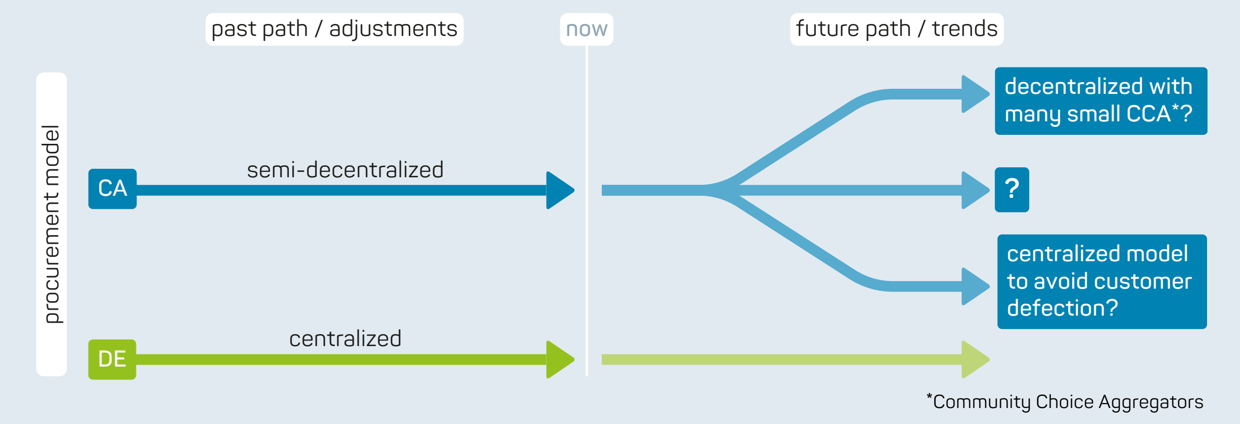
Conversely, from a climate perspective, an advantage to regionalization is that opening the grid to greater contribution from wind and solar resources from outside the state might help California reach its climate goals at less cost. A more extensive transmission reach and integrated operation on a larger geographic scale also may help reduce the cost intermittency of in-state renewable resources, just as is envisioned in Germany. Moreover, regionalization may provide a market venue for California's climate-oriented market push policies to influence a broader region.

While issues pertaining to regional integration of a day-ahead market are playing out in a visible way in California, the Energy Imbalance Market has been steadily expanding in a more subtle way across several western states. The EIM has volatile prices that signal the value of real-time changes in generation or consumption. Only a small fraction of total energy transactions flow through the EIM, but this has substantial value and indirectly provides many of the features that a coordinated day-ahead market would provide; some argue it has less risk of regional market rules that are unfriendly to renewables. Even absent formal ISO expansion, plans for a greatly expanded day-ahead EIM market are moving forward.

4.2 Renewable procurement model

The renewable procurement model is the organizational structure of regulation to deploy renewables. The two prototypical models are centralized procurement (single-buyer, typically a government agency) and decentralized procurement (multiple buyers, typically utilities under a renewable obligation). This issue has received little attention in recent years as a crucial aspect of renewable

Figure 23 | Renewable procurement



74 Investigating a Higher Renewables Portfolio Standard in California. E3 consulting. January 2014. https://www.ethree.com/wp-content/uploads/2017/01/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf

integration, even though it relates to the widely heralded "utility death spiral." Crucial aspects controlled through the procurement model are the financial (costs) and geographic distribution of renewable energy sources and the degree of fragmentation of regulation.

In Germany, renewables have from the beginning been centrally procured, with the TSOs acting as counterparties for respective PPAs. Overall support costs are pooled and passed on to all but the largest (industrial, energy-intensive) consumers by means of a uniform volumetric top-up levy as part of electricity rates. Furthermore, central procurement is now also used to counterbalance grid bottlenecks by limiting new capacity in congested areas.

In California, the long-term planning and procurement process informally and imperfectly played a role somewhat similar to the explicit central procurement in Germany. Long-term procurement applied only to the regulated IOUs, which until recently (with the advent of community choice aggregators) served the majority of customers in California. Furthermore, investment in distributed solar was completely uncoordinated and driven by inefficient retail pricing structures and net metering policies. This is now changing. The emergence of CCAs has diluted the influence of the procurement process to the point where it has been discontinued by the CPUC. In its place is a set of increasingly uncoordinated procurement decisions made by individual small retail entities.

Going forward, California can either try to adapt its renewable policies to a more decentralized electricity market environment or try to concentrate its procurement decisions through a new, more centralized procurement mechanism that again takes discretion out of the hands of individual retail providers.

In Germany, the lack of LMP implies that buyers and sellers have little disincentive to procure additional renewable energy in the already congested northern regions. The central procurement auction for the acquisition of renewable electricity supply has tried to offset these incentives by discounting energy purchased in such regions relative to that purchased elsewhere.[75] A centralized procurement auction could be designed to place higher value on the diversity of hourly output profiles from different sources rather than simply procuring the lowest-cost MWh of renewable energy. Although the centralized model offers many coordination advantages, it represents a retreat from competition, and as an administrative construct, it may be influenced by economic interests or slow to adjust to changing circumstances. If the procurement process is inefficient or inadequate, customers have no alternatives.

4.3 Renewable policy design

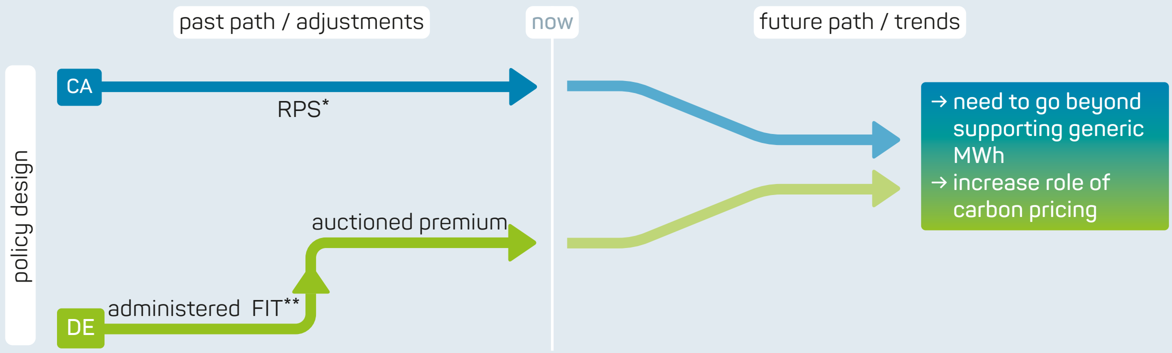
Policy design is an important factor for achieving renewable energy targets with high cost-effectiveness. With growing shares of renewables, system interactions become increasingly complex, and pricing to incentivize efficient dispatch and investment becomes more relevant.

Although Germany and California have been among the world's leaders in stimulating and procuring renewable electricity, the policy tools used to achieve these ends have been, up until now, very different. Whereas Germany's policy has evolved from administered FITs to auctioned premiums, California has relied largely on a RPS at the wholesale level and a host of mixed incentives to support distributed solar. In both cases, however, problems associated with integrating intermittent renewable supply into the electricity system have led to growing concerns about costs as well as the quality of the energy that is being acquired.

In Germany, increasing support costs for renewables, combined with the cost-ineffectiveness of policy to promote renewables, led to the adoption of competitive auctions for allocating support. These auctions replaced the first-come, first-served allocation at fixed price levels of the original feed-in tariff scheme. To some extent, this

75 It is not clear that these discounts are of the correct magnitude, but this example illustrates the potential (realized or not) for centralized procurement to overcome such distortions.

Figure 24 | Renewable policy designs



*Renewable Portfolio Standard **Feed-In Tariff

brought the German approach closer to California's RPS, in which renewable power purchase agreements are also typically procured through auctions. Moreover, the original PPAs in Germany paid producers a fixed price per kWh, independent of its market value at the time. Accordingly, they did not create adequate incentives to produce or invest efficiently. This began to change with the introduction of the sliding premium, a contract-for-difference with the monthly average technology-specific wholesale price as the strike price. However, the differential incentives created through the sliding premium are relatively small. In addition, in recent years, more frequent negative prices have led to a revision so that the premium is not paid in these hours. There is thus already a trend of paying renewable production according to its market value, even though steps in that direction are incremental. However, the potential inefficiencies that rising shares of renewables could introduce to the system under the current incentive structure will likely make more fundamental reforms necessary.

California has yet to confront the cost implications of its policies, in part because falling solar PV costs and natural gas prices have papered over inefficiencies. The concern in California is less about the cost of the power than about when it is being generated. The daytime availability of solar has reduced midday energy prices, reflecting the plunging value of the energy that is being procured. Policymakers speak of renewable curtailment, which is really the extreme manifestation of low-value power. In recent years, PPAs with renewable suppliers have stipulated that suppliers be paid for output even when they are curtailed.

Carbon pricing has been implemented in both jurisdictions, but carbon emissions reductions are a secondary aspect of the policy design rather than the primary driver, which is to build out renewable electricity capacity. The efficiency problems with the existing renewables support frameworks may force a reordering of these priorities.

By incorporating the cost of the carbon emissions of existing generation into the power prices, carbon pricing provides the most straightforward and efficient signal of the additional value provided, on an hourly basis, by low-carbon power, including renewables. In Germany (via the EU) and California (via the Western Climate Initiative), carbon pricing has been implemented via a cap-and-trade mechanism. The more effective are other policies, including renewables support policies, the lower the carbon price necessary to achieve the emissions cap, and thereby the carbon price signal is eroded. The two carbon markets have different approaches to support the carbon price by changing the supply of emissions allowances. California has a minimum price in the auction for newly issued emissions allowances, and the EU has recently introduced the market stability reserve mechanism, which delays the introduction of new emissions allowances and includes a provision for invalidation (cancellation) of allowances if the reserve grows large. Consequently, both programs have a safeguard against an outcome in which carbon prices might fall to low levels or zero, but investment in renewables nonetheless will suppress the carbon price over a large range of possible outcomes, and investments in renewables are guided primarily by renewable obligations rather than the carbon price.

4.4 Demand flexibility and retail rate design

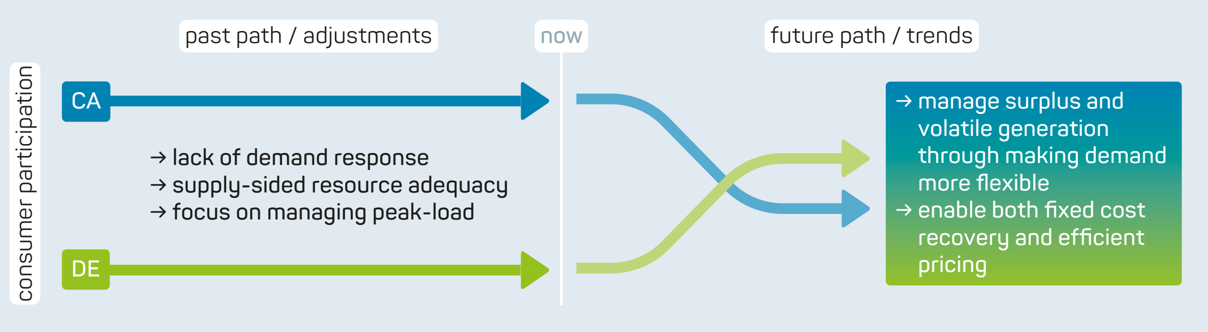
Successful integration of renewables requires the alignment of demand with the timing of renewable availability. Achieving this coordination involves the design of efficient and equitable wholesale and retail rates that enable both demand responsiveness to prices and the recovery of the fixed costs of electricity supply.

Activating demand to respond to supply and system conditions, generally referred to as demand-side management, can be achieved either through proactive use of automated systems in tandem with dynamic electricity prices (demand flexibility) or through temporary reactions triggered in response to a specific event, such as threats to grid reliability (demand response[76]). Demand flexibility refers to all measures and programs aiming to incentivize consumers' anticipation of price signals or other incentive-based mechanisms. Interruptible load contracts, which give grid operators the option to curb the demand of usually large consumers in specific situations, are one example of demand response.[77]

The activation of demand-side resources was not considered relevant to renewable energy policy until the integration challenges of VRE became evident. Regulators to date have focused primarily on managing peak electricity demand to complement the primary strategy of installing sufficient generation capacity and reserves to accommodate peak demand. With large-scale variable renewable generation, attention has shifted to managing surplus generation when renewable supplies are abundant and managing rapid changes in supply stemming from the variability. Accordingly, demand-side management and demand flexibility are becoming essential for increasing efficiency in low-carbon electricity markets.

Time-based pricing is for many economists a rather intuitive option to activate demand flexibility, since it gives consumers incentive to consume more when prices are low and vice versa. In theory, customers would ideally be exposed to accurately calculated wholesale electricity prices in real time. Although the potential of time-based pricing remains largely untapped, regulatory steps appear imminent. Smart meters, which would technically allow the implementation of real-time pricing programs, are being

Figure 25 | Enabeling consumer participation while assuring fixed cost recovery



76 Note that the terminology differs. In Germany, demand flexibility usually includes any measure (incentive based or not) that results in changes from usual consumption patterns (e.g., Connect Energy Economics 2015), whereas in the United States, such measures are often termed demand-side management. Moreover, FERC narrows the definition of demand response to consumption changes triggered solely by price signals, which is different from the use here.

77 Southern California Edison offers an interruptible load contract to its agricultural customers. See https://www.sce.com/wps/wcm/connect/bed771c5-9e2f-4246-a539-919248499b1d/AgriculturalPumpingFactSheet.pdf?MOD=AJPERES.

rolled out on a large scale in both Germany[78] and California.[79] In practice, however, full-fledged real-time pricing has not been widely implemented yet because of social acceptance problems: potentially high transaction costs and the fear of increasing electricity bills, volatility, and price spikes. Accordingly, real-time pricing is not available to most retail customers in either jurisdiction. Instead, time-of-use (TOU) rates, peak pricing, and peak-time rebate schemes are offered, particularly by California utilities, to almost all customer types. Simple TOU pricing is becoming the mandatory default for retail customers in California in 2020.[80]

The benefits of TOU pricing can be questioned, however. TOU rates are determined at least a year ahead and thus reflect only coarse fluctuations in electricity generation; they do not enable instantaneous response to resource scarcity on the grid. Nevertheless, in systems such as California's, where most VRE is generated from solar PV with relatively predictable output patterns, such rates may indeed represent a second-best alternative to real-time pricing.[81] Peak-pricing schemes—such as critical-peak pricing, under which customers face disproportionately high prices during several predetermined event days—are another approach. Although they perform relatively well in conventional markets, they may become increasingly inefficient with large-scale renewable supply because the allocative efficiency gains from introducing time-based pricing will mainly arise from reducing "underconsumption" during low-price periods rather than from reducing "overconsumption" during high-price periods (Gambardella et al. 2016). Therefore, the paradigm of designing policy to ensure reliability during a handful of peak hours will likely have to shift to one in which demand varies with renewable output.

We see three issues critical to tapping the large demand-side potential. The first is consumers' reluctance to adopt dynamic, time-based pricing schemes. Addressing this issue will require empirical insights about what psychological factors lead to misperceptions about the benefits and costs of time-based pricing; what role transaction costs play in tariff choice; how technological solutions, such as smart appliances, could help reduce such costs; and how electrification could increase the incentives for tariff switching (Section 4.5).

A second issue is the role for demand-response programs (e.g., rebate schemes, interruptible load contracts) in facilitating the transition toward widespread time-based retail pricing. Such programs would have to address the challenges of surplus generation, which could, for instance, be achieved through off-peak rebates for consumption increases during high wind or solar energy supply periods. If demand-response programs are supposed to help overcome acceptance problems for time-based pricing in all consumer segments, then such programs should be available for all types of customers. In Germany, demand-response programs are less prevalent than in California, and when they are introduced, they are usually targeted at large commercial or industrial customers.[82] California utilities and demand-response providers offer such programs to both residential and non-residential customers.[83]

The third issue regards the efficiency and equity aspects of retail rate design because of the conflicting goals of sending efficient price signals to

78 A mandatory smart meter roll-out was supposed to start in 2017 for customers with an annual consumption exceeding 10,000 kWh and is set to start in 2020 for customers consuming more than 6,000 kWh; a roll-out to smaller consumers is optional. See https://www.bmwi.de/Redaktion/EN/FAQ/Smart-Meters/faq-smart-meters.html.
79 CPUC reports that it authorized the three IOUs to install approximately 11.7 million new smart meters in total. For the whole Western Electricity Coordinating Council region, FERC reports that 60.6, 59.9, and 44.9 percent of residential, commercial, and industrial customers, respectively, are equipped with advanced meters. See http://www.cpuc.ca.gov/general.aspx?id=4853 and https://www.ferc.gov/legal/staff-reports/2018/DR-AM-Report2018.pdf?csrt=2906552758071829344.
80 https://www.utilitydive.com/news/as-california-leads-way-with-tou-rates-some-call-for-simpler-solutions/532436/.
81 Holland and Mansur (2006) illustrate how monthly adjusted flat rates, in contrast to annually determined rates, could capture a substantial portion of the potential efficiency gains under real-time pricing.
82 The German aggregator Next Kraftwerke, for instance, offers real-time pricing under its "proactive flexibility" product to large commercial and industrial consumers only. The "reactive flexibility" product, which consists of different demand-response programs, also focuses on this customer segment.
83 California utilities have to give third-party providers, such as Enernoc or EnergyHub, access to the customers of their service region. See http://www.cpuc.ca.gov/General.aspx?id=6306.

promote electricity use when resources are abundant and recovering system fixed costs. The time-varying energy costs captured in dynamic pricing constitute, on average, roughly half the costs reflected in prices in Californian rates and only about a quarter in German retail residential rates. The remaining shares consist of various taxes, levies, and grid and service costs that are typically recovered through volumetric ($/kWh) charges. This approach to recovering fixed costs dilutes the variation in the energy component that would be provided by time-based pricing, and hence weakens the incentive for consumers to consume electricity when resources are abundant.

The relatively high proportion of fixed-cost components in current electricity rates has general efficiency implications. Consumer rates can differ substantially from the actual social marginal costs of electricity (Borenstein and Bushnell 2018). In the German case, levies and taxes are a significantly larger component in electricity rates than in prices for gas or gasoline. This is seen to reduce the incentives of consumers to use electricity for transportation and heating and thus impede the electrification that would be needed for decarbonization of the economy (Section 4.5). Energy tax and levy reforms might therefore become necessary in the near term, at least in Germany (Agora Energiewende 2017).

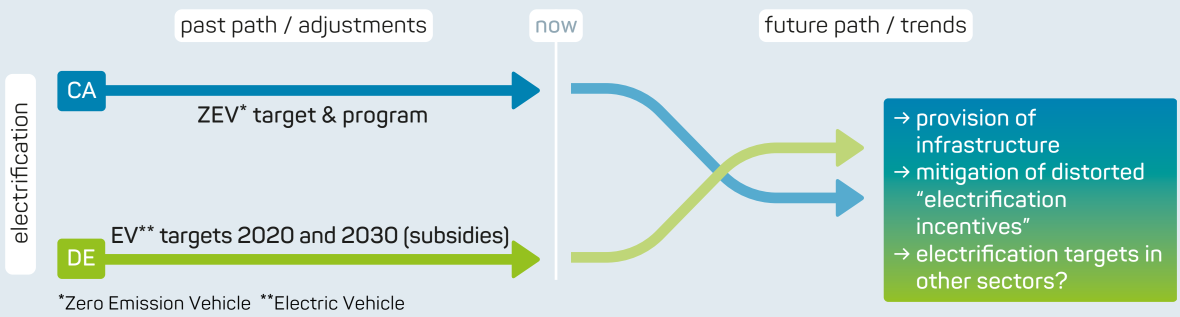
In combination with net metering rules, high fixed costs in electricity rates can raise distributional problems associated with integrating renewables. In California, the distributed solar business is well established, and retail prices are designed such that self-generation enables customers to avoid paying for the fixed costs of distribution and transmission networks. When the option to avoid grid-related costs had a similar effect in Germany, the regulator significantly reduced the possibility of avoiding fixed costs by incentivizing self-consumption of self-produced energy. Going forward, the economics of distributed energy in both markets will eventually depend on regulation, particularly for rate structure and net metering. With a large base of installed capacity, as well as an influential distributed solar industry, reforms to either rate structure or net-metering policies are meeting strong resistance in California. However, as distributed energy resources continue to spread, the shift of distribution costs onto conventional customers may also become untenable.

Two-part tariffs, already common in both markets, are a partial solution to the conflicts among efficient retail pricing, adverse distributional effects, and fixed-cost recovery. Specifically, balance among goals could be achieved by replacing volumetric charges with monthly or annual fees that cover the fixed costs contained in the fixed price components of current retail rates. In this way, price variations would be salient to consumers who are on time-based pricing, while allowing utilities to break even on their fixed costs. Two-part tariffs would further give both consumers and retailers the possibility of hedging risk related to bill changes or procurement costs (Borenstein 2007). Since self-generation decisions would be disconnected from potential savings in grid charges, two-part tariffs may also mitigate adverse distributional effects from net metering (Darghouth et al. 2016). By adjusting the monthly or annually fixed fees for different income groups in the residential sector, regulators and retailers have leverage to address the trade-off between efficiency and equity in rate design (Feldstein 1972).

4.5 Electrification

Every analysis of technological pathways and scenarios to achieving deep decarbonization assigns an important role to electrification of transportation, industry, and building energy use with zero or low-carbon electricity generation. This will likely involve a greatly expanded role for renewables as a share of total generation, and especially in absolute generation levels. The share of electricity in these sectors in Germany in 2050 is highly uncer-

Figure 26 | Mainstreaming electrification



tain[84] and may range between 20 and 85 percent in different scenarios (Ruhnau et al. 2019). In California, the direct and indirect (hydrogen) electricity share of total energy consumption is expected to grow from about 20 percent today to 25 percent by 2030 and to 50 to 70 percent by 2050, nearly tripling the size of the electricity sector.

California has taken dedicated action to electrify the transportation sector, which has the state's highest share of overall GHG emissions, 41 percent.[85] Notably, it has set a target of 1.5 million zero-emission vehicles (ZEVs) on the road by 2025, and it instituted a ZEV program that requires manufacturers to produce a certain number of such cars each year. Germany formulated its target in 2010—one million electric vehicles (including plug-in hybrids) by 2020—but the policy was never backed with dedicated action. Only recently have rebates on purchases been granted as a measure to advance ZEVs, but these rebates are insufficient for reaching the target.[86]

Notwithstanding the relatively modest progress Germany has made so far—the country is not on track to achieve its climate targets—electrification is increasingly high on the policy agenda. Electrification has received considerable attention under the keyword "sector coupling." Analogous to the Energiewende, there is now discussion of a Wärmewende (heating transition) and Verkehrswende (transportation transition), with calls for reforming energy taxes and the fixed-cost components of the retail electricity rate (E-Bridge, ZEW, & Clausthal, 2018).

As of yet, however, the only new legislation is an amendment that paves the way for using ZEVs to balance the grid. The 2016 amendment of the Energy Industry Act (EnWG, §14a) established so-called interruptible load to reduce distribution grid congestion. Distribution system operators can temporarily disconnect such loads to balance the grid, and in return, this load is offered special rates with reduced grid fees (E-Bridge, ZEW, & Clausthal, 2018). The building sector, however, has no electrification target similar to the ZEV target.

Electrification is a two-sided issue. On the one hand, it could change both load sizes and patterns, and a question is whether this makes integration of renewables easier. Electric vehicles have inherent storage capabilities, so when they draw electricity from the grid and when they deliver transportation services are not coincident. Hence, the ability of expanded demand to enhance the integration of renewables hinges on the potential for new load to be turned into renewable following load through, for example, time-based pricing. It is also a function of whether prices and technology

84 This may imply that final annual electricity consumption may almost double, from about 509 TWh in 2018 to about 900 TWH in 2050, or it may decrease to 462 TWh (Fraunhofer IWES 2015). The drivers of this high level of uncertainty are manifold, but three major factors appear to be the underlying CO2 emissions reduction goal, which may range from 80 to 95 percent compared with 1990 levels; the achievement of ambitious building efficiency goals; and the availability of biomass and carbon capture and sequestration technologies (Fraunhofer IWES 2015).
85 https://www.arb.ca.gov/cc/inventory/data/data.htm.
86 Regulation at the EU level—fleet standards for GHG emissions—creates incentives for electric vehicle production only indirectly, through so-called super credits for these vehicles.

can make the renewable following potential of the new load a reality.

On the other hand, electrification might be hampered by price wedges between electricity and other types of energy. For instance, if taxes (and fees) on electricity are high while taxes on gas are low, switching to ZEVs, heat pumps, or electric heaters would be insufficiently incentivized. Accordingly, electrification presumes a harmonization of energy taxes and rationalization of energy pricing.

5 Summary and conclusion

BOTH GERMANY AND CALIFORNIA HAVE SUBSTANTIALLY INCREASED THE SHARE OF RENEWABLES IN THEIR ELECTRICITY SUPPLY SINCE THE EARLY 2000S AND ARE ON TRACK FOR ACHIEVING THEIR LONG-TERM TARGETS FOR RENEWABLE GENERATION. MOREOVER, BOTH JURISDICTIONS HAVE RECENTLY DECIDED ON MORE AMBITIOUS TARGETS.

Germany reached this point by increasing policy cost-effectiveness and making markets more efficient; in California, reforms have been more incremental and were not necessarily driven by the increasing share of renewables. The common theme is that both places are trying to go where electricity systems have not gone before—an aspiration that will likely involve an iterative process of policy experimentation and problem discovery.

Which policy pathways will California and Germany pursue? Given that past pathways differed because of market conditions and historic circumstances, the convergence of pathways that we now observe in California and Germany suggests that both jurisdictions face similar challenges and are responding to them with similar policy choices. It also suggests that their pathways might be prototypical for energy transitions in general, and thus their experiences may provide evidence and lessons that are highly valuable for other jurisdictions.

Section 4 has shown that by and large, there is substantial convergence in five areas, even though one jurisdiction may be at a more advanced state of experimentation than the other. Transporting, balancing, and trading renewable electricity (Section 4.1) have become increasing concerns that call for market integration supported by locational marginal pricing. In Germany, the issue is primarily spatial: the lack of grid capacity to move electricity from where it is abundant in supply to where demand is greatest, In California, the issue is primarily temporal: integrating renewable resources when they are abundant. Both jurisdictions need to produce renewables more efficiently and therefore need policies that go beyond supporting generic production of any renewable electricity anywhere and at any time (Section 4.3).

Both California and Germany are moving toward demand flexibility to enable load to anticipate or follow generation of variable renewable energy (Section 4.4). How system-level fixed costs are recovered constitutes a major barrier to activating demand, and reforms may be needed to give users strong incentives to consume electricity when it is most abundant. Furthermore, the expected expansion of electricity use by other sectors has become a pertinent issue for deep decarbonization in both jurisdictions (Section 4.5).

The only major difference between California and Germany—and possibly a divergent pathway—relates to the procurement of renewables (Section 4.2): will California move to a more centralized model, similar to that in Germany, or will Germany put more emphasis on decentralized policy options, as observed in California, or will each continue with its current approach?

With that exception, Germany and California are converging on a new track—substantial reform of existing policies and new major legislation, combined with, ultimately, policy innovation. Accordingly, many important policy choices are still in the proposal stage. The eventual implementation of these policies will initiate a new round of market and policy design, which will once again push the frontier and generate new evidence on how even higher shares of renewables can be integrated.

Several questions are important from a long-term perspective. What role can carbon pricing play in decarbonizing the power sector? It is still an open issue whether, under what conditions, and with which designs carbon pricing can provide the primary impetus to full decarbonization, and whether such pricing can become politically acceptable. A related issue is whether companion policies to carbon pricing will become permanent or can eventually be phased out. Is there a potential transition from a policy mix to carbon pricing alone? Could a gradual infusion of price incentives into renewable policies ultimately lead to carbon pricing?

Finally, what is the appropriate long-term target? California recently adopted a 100 percent target for clean energy. The costs of increasing the share beyond 80 or 90 percent might rise sharply. The issue was discussed extensively in Germany, and the country decided to aim for 80 percent. The difference between the two targets might be a distraction in view of the expected rapid electrification and displacement of emissions from direct combustion of fossil fuels in other sectors. A near-term focus on complete or nearly complete decarbonization of the electricity sector deters from the need to focus on the pace of electrification and the opportunity to reduce the use of fossil fuels in other sectors. More generally, it is an open question whether such targets are actually useful and needed when the final aim of all policies is to reduce economywide GHG emissions. As shown by Germany's formulation of sector-specific targets in 2016,[87] when one sector gets too far out front in terms of decarbonization and costs, the consequence can be destabilizing and counterproductive to overall GHG reductions.

87 Also see https://media.rff.org/documents/Session_1_-_Pahle.pdf.

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