Flexibility

The path to low-carbon, low-cost electricity grids

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A CPI Report

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Descriptors

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About CPI

Climate Policy Initiative works to improve the most important energy and land use policies around the world, with a particular focus on finance. An independent organization supported in part by a grant from the Open Society Foundations, CPI works in places that provide the most potential for policy impact including Brazil, China, Europe, India, Indonesia, and the United States.

Our work helps nations grow while addressing increasingly scarce resources and climate risk. This is a complex challenge in which policy plays a crucial role.

Executive summary

Wind and solar have become established resources for low-carbon electricity around the world. Cost declines for those technologies now allow us a tantalizing vision of the not-too-distant future where our electricity is supplied almost exclusively by renewables. However, to make this vision a reality, our grids need to add resources that can compensate for the intermittency of these technologies.

Electricity systems have always been managed 'flexibly'. Weather, work patterns, industry, or even sports schedules create predictable or unexpected drops or spikes in demand. Sudden system failures, such as power station or transmission outages, mean that backup generation has always been required to keep the lights on. Generally, suppliers have controlled generation from coal, gas or hydro plants to respond to whatever consumers demanded of the system.

Now that technology costs are competitive with fossil fuels, today's challenge in the energy systems transition has shifted towards integration of dispatchable low-carbon electricity sources into the system – at the lowest possible cost.

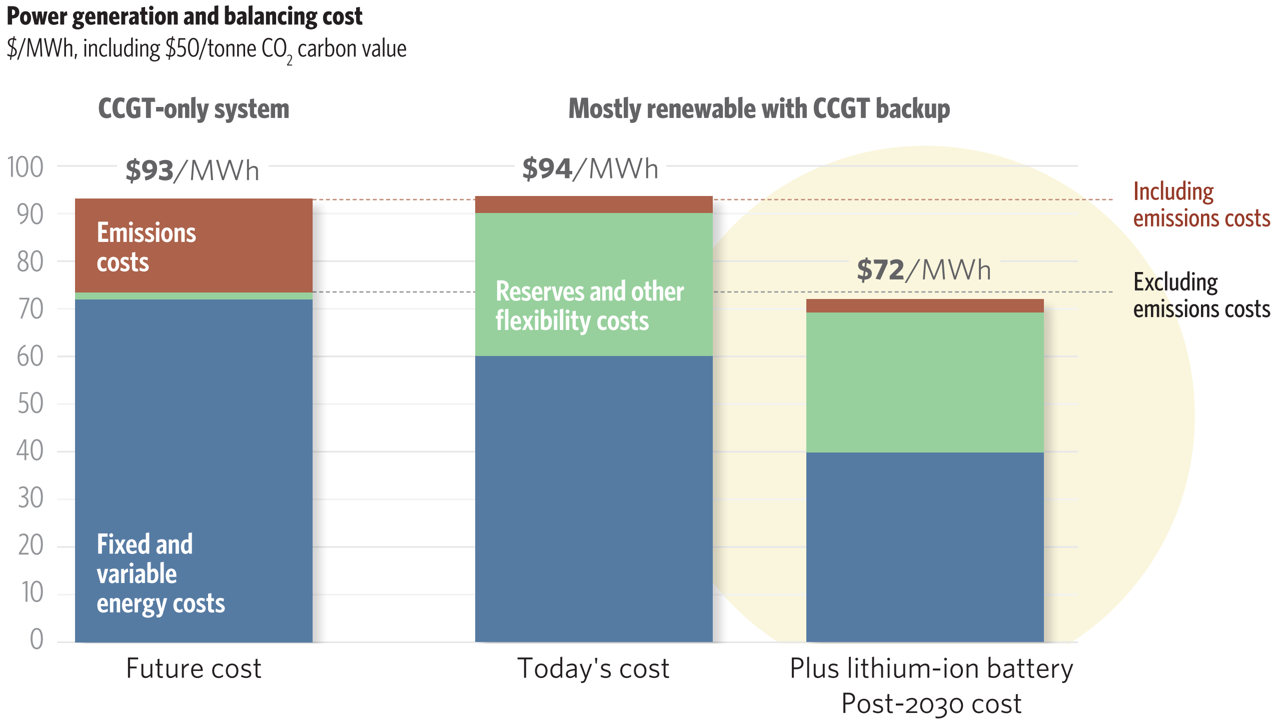
With this challenge at the heart of its roadmap to accelerate a shift towards an affordable, reliable, sustainable and modern energy system, in 2016 the Energy Transitions Commission (ETC) commissioned Climate Policy Initiative (CPI) to examine four areas:

1. What would be the maximum cost of an electricity system based entirely on renewable energy, including the cost of delivering flexibility, and how would that compare to fossil fuel- based options?
2. What technological and market-based options are available to provide this flexibility, how will costs develop, and which technology options should we prioritize for development?
3. How might flexibility needs and technology requirements vary as a function of regional differences?
4. What are the key policy and market design issues that need to be resolved?

The maximum cost of a near-total renewable energy-based system is cost competitive today compared with a gas-based system with a \$50/tonne carbon price - by 2030 it will be cost-competitive even without a carbon price.

In figure ES-1, our analysis shows that by 2030, a variable renewable energy system with a mix of batteries and gas for backup would be considerably less expensive than a system powered exclusively by natural gas. Such a system would have nearly 90% lower gas use and carbon emissions. When existing hydro and demand management potential is employed, carbon emissions and costs will fall further.

Figure ES-1: Total cost of generation from renewable and natural gas-based systems including flexibility



A wide range of technologies will be effective in meeting future flexibility needs, while a portfolio approach for technologies is likely to be the lowest cost. It turns out that flexibility is not a single product, but a series of needs largely differentiated by response time. Some flexibility response must be instantaneous, while other needs stretch over the course of a day – for example shifting excess solar generation during the day to serve evening demand for lighting. Yet another kind of flexibility shifts supply or demand over the year – shifting summer generation to meet winter heating demand. We analyzed a range of technologies and their fit and cost for each of the flexibility categories.

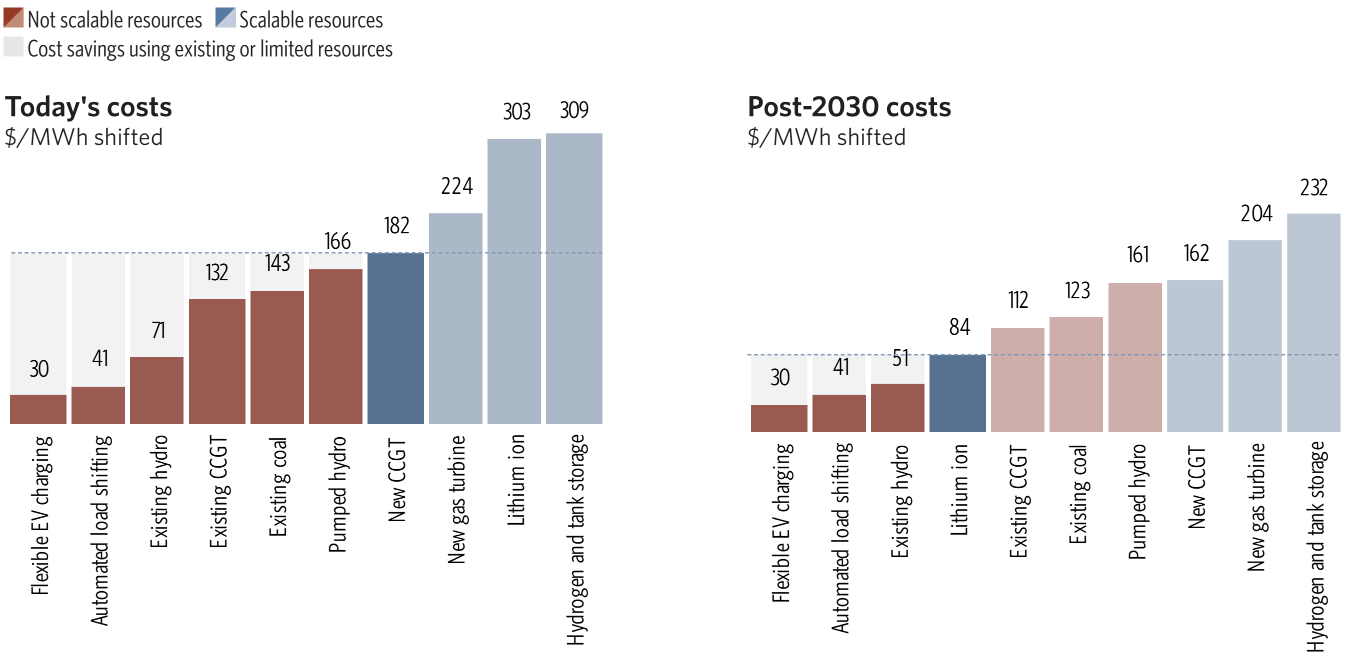
For each of the flexibility needs, we analysed the technologies that could have a good potential technical fit and ranked them by cost of serving that flexibility need. Figure ES-2 shows that ranking for one particular flexibility need – daily load shifting at a 30% load factor, which roughly equates to shifting 8 hours per day, each day of the year. The red columns below show that there are a number of technologies with low costs, but whose potential could be limited, for example by factors such as how many electric cars are sold and available to vary their charging pattern. The "lowest- cost scalable resource" is that technology that could be scaled up to meet any level of system needs. While our maximum cost analysis assumed that only the lowest-cost scalable resources is available, using the other options would significantly reduce costs. We also note that by 2030 the costs of batteries will fall to the point that this technology will be cheaper than a new combined cycle gas turbine (CCGT) for providing daily energy shifting. Thus, to minimize costs and enhance flexibility the system needs to pursue, develop and integrate a portfolio of technologies.

We evaluated flexibility needs in California, Germany, Maharashtra and the Nordic region and found significant differences, although all are reasonably well positioned for further renewable energy growth. California, Germany and the Nordic region all have different profiles in terms of resources, deployment rates of certain technologies and the potential for somewhat flat demand growth. Each are leaders in deployment of renewable energy and will be among the first to exceed 30%-50% or even higher shares of wind and solar. Our evaluation covered each flexibility need separately for each region.

As in figure ES-3 flexibility needs in each of these regions are reasonably covered for the near term, even at ambitious levels of renewable energy deployment at around 30%. The possible exception is ramping in

Figure ES-2: Ranking of technology costs to provide daily load shifting

Cost of daily shifting (30% capacity factor)

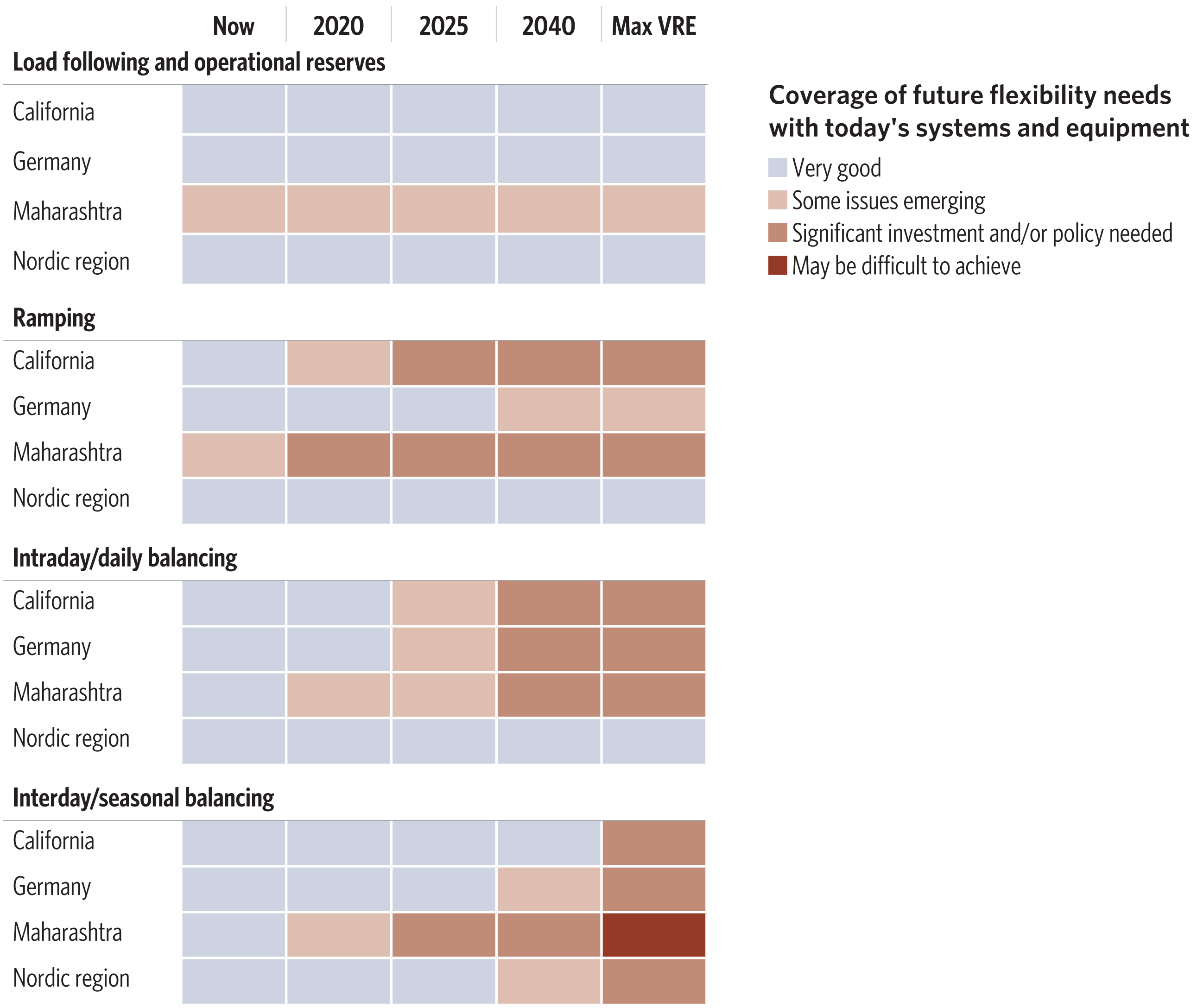


Maharashtra, where growing demand, rather than renewable energy supply, is straining the system.

After 10 years, the need for new flexibility sources grows across all regions, in line with continuing growth in renewable energy supply. In particular, interday and intraday balancing are expected to need additional support. Further out in time, a maximum variable renewable energy scenario approaching 100% of energy supply (in line with the total variable renewable energy system described above) would require significant investment with specific investments and resultant costs affected by the availability of hydroelectric supply, demand response and other flexibility resources in each region.

Policymakers need to begin significant changes to market and technology support now to ensure that low-cost flexibility is available in the future when it is needed. Even though many of the needs are several years in the future, developing and implementing new market designs and technological solutions will take time. If these market design, industry structure and technology development and implementation issues are addressed early, our analysis suggests that policymakers should be unconcerned about moving to levels of renewable energy deployment that are far higher than even the most ambitious plans in place today, including perhaps systems with nearly all energy generated by either reservoir hydro or variable renewable energy, where there is a moderate supply of hydroelectric supply available.

Figure ES-3: Daily and seasonal balancing needs will intensify in all regions



ES-4: Findings and recommendations for policymakers

FINDING	WHAT POLICYMAKERS SHOULD THINK ABOUT
Renewable energy ambition Solutions are available now on most systems to accommodate high proportions of renewable energy at a reasonable cost	• **Feel free to set ambitious renewable energy targets** to meet their low-carbon objectives. • **Focus on optimizing the costs of today's flexibility options**, while setting policy that will deliver increased flexibility capacity in time to meet targets for decarbonizing the power sector at the lowest possible cost.
Portfolio approach No single technology, market mechanism, or flexibility resource will be able to meet all flexibility requirements across all regions	• **Promote the development and cost reduction of several technologies and flexibility resources**, while creating markets and policy for cost-effective integration of these resources as they develop. • **Create solutions that can contribute to delivering the needed flexibility at a competitive cost including**: Using existing generation capacity differently; increasing demand side flexibility; increasing and optimizing new electrification; restructuring transmission and distribution; developing new roles for batteries; and building some new gas turbines as additional support.
Transition framework New policy, market and regulatory mechanisms are needed to cost effectively develop flexibility for a high variable renewable energy system	• **Focus planning and policy development on the transition path to a much higher variable renewable energy system**, while markets need to be configured to get the best output, lowest cost and lowest risk from both renewable energy and the evolving flexibility resources. • **Design markets with long-term signals for investment in the transition**; better signals to consumers; markets that differentiate between the supply of energy and flexibility; mechanisms that balance sources of renewable energy to reduce flexibility needs; and process and real-time and locational price signals to improve regional coordination.
Planning horizons Longer-term planning horizons are needed to develop new flexibility solutions and avoid lock-in of long-term solutions that do not align with transition goals	• **Create markets and policy that incentivise long-term innovation and balance this innovation against near-term objectives.** For example, there is a continued role for existing fossil fuel generation to ease the transition, while innovation policy and long-term planning is needed to access some of the lowest cost future resources.

Contents

Introduction

Renewable energy costs have declined precipitously over the past decade to the point where the cost of a kWh of energy generated from onshore wind and solar PV can compete with generation from conventional coal or natural gas power plants. Further cost reductions in the future will make renewable energy far more competitive than new fossil fuel generation in many cases.

However, a simple comparison of per kWh costs for renewables versus conventional generation does not tell the whole story, since traditional power plants, including gas, coal and especially hydroelectric generation, provide "flexibility" services that intermittent wind and solar generation cannot readily supply.

In nearly all power systems today operators schedule and dispatch coal, gas or reservoir-based hydro generation to ensure that electricity supply and demand are in balance every minute of every hour of every day. These "dispatchable" resources provide value to the system because their output can be adjusted to keep the system in equilibrium, subject to operational (and economic) constraints. While demand for flexibility generally follows fairly predictable patterns, flexibility must also provide contingencies for less predictable events such as plant or transmission failures.

While the more traditional fossil fuel and reservoir hydro generation of the supply side of the power system responds to fluctuations from the demand side, supply from renewables is difficult to adjust and often requires more flexibility to respond to variations in wind or solar output, increasing the system's overall flexibility needs. Fortunately, there are many options for providing flexibility services. Reservoir hydro, interconnection, demand management and generation from gas are currently cost-effective and widely used. In the future, other technologies such as battery storage will become increasingly economical. On the demand side in particular, there is potential for costs to fall as usage is increased, more capacity is developed and market and regulatory signals incentivise appropriate responses.

A system incorporating large amounts of intermittent renewable generation will have greater flexibility needs, but may not cost more. A central finding of this report is that in as little as two decades a system built from scratch, based on renewable energy with investment to support the additional flexibility needs could cost less per unit of energy delivered than a new gas system, even if all of the existing flexibility resources were suddenly unavailable. Employing flexibility inherent in existing hydro-electric plants, demand management, and sparing use of existing gas generation could reduce the additional flexibility costs by half or more, further improving the cost competitiveness of the renewables based system.

Few regions are currently building power systems from scratch, so how existing assets are used along the way to a high renewables future will affect the timing and size of total system costs.

Ensuring that the power system of the future has access to flexibility in sufficient quantities and at acceptable cost means addressing these key questions:

1. How much intermittent renewable energy can the system support without major changes, and when will new/alternative flexibility services be needed?
2. What flexibility services need to be replaced, and which ones will need to be developed?
3. How much will these services cost?
4. What can be done to reduce these costs and keep them low?

The answers will be regionally specific, but there are commonalties across geographies (and thus, across technology mixes) that can and should inform broader discussions of the global energy transition.

This report is a summary of analysis conducted on behalf of the Energy Transitions Commission, a consortium of organisations aiming to accelerate the shift towards a low-carbon energy system.

Section 1 begins with a generic analysis that compares the cost of a near-total intermittent renewable system (reliant to some degree on natural gas for flexibility) with the cost of an electricity system based entirely on gas-fired generation. We then expand this analysis to explore flexibility needs and solutions in more detail, incorporating regional particularities and presenting cost-curves for various flexibility resources beyond just natural gas; these regional and multi-resource analyses suggest the potential to provide flexibility at significantly less cost than the generic case of the near-total intermittent renewables system.

Section 2 sets out the major categories of flexibility that an electricity system requires to provide secure and reliable service.

Section 3 evaluates current and expected regional characteristics in four sample regions: California in the United States, Germany and the Nordic countries in Europe and Maharashtra state in India.

Section 4 explores the range of technologies and business processes that could be used to meet flexibility needs**.**

Finally, **Section 5** examines how technologies could be cost-effectively combined to meet flexibility needs and discusses the roles for policy, market design, and consumers (in particular, industry) in making this transition.

1. A starting point for evaluating flexibility options: the comparative cost of a near-total intermittent renewable energy system

Our analysis shows that building a completely new system today based only on solar and wind with limited amounts of gas to provide all flexibility and backup requirements, would cost about the same as building a completely new system that relied exclusively on gas, with a $50/tonne carbon price.

By 2030, the decline in the cost of wind, solar and lithium-ion batteries will make a variable renewable energy system supported by a combination of batteries and gas less expensive than a system based only on gas, even without a carbon price. Such a system would have nearly 80-90% lower gas use and carbon emissions.[1]

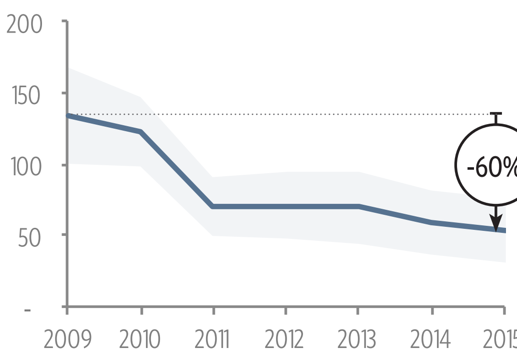
Overview

Our electricity systems did not have to be structured the way they are. Technology, industry structure, regulation, economics and finance have all developed over time as companies, suppliers, governments and consumers have worked with the supply options they had on hand to develop a system that met the needs of consumers and the economy. That consumers in many countries can expect to have almost any amount of energy available to them at the flick of a switch is a happy coincidence of the ready availability of fossil fuel generation. If the electricity systems had been built in a world without large amounts of coal, oil or gas to feed dispatchable generation, the system would have been designed very differently.

With carbon prices set to constrain the amount of flexibility available from fossil fuels at the same time as variable renewable energy increases demand for flexibility, the cost of creating a more dynamic system has become a pressing concern. In framing this concern, we start with the most costly case where a near-total renewables system would need to be built with only a limited recourse to fossil fuel generation as backup supply. We compare this system to an entirely new system that would be based on gas, the lowest cost form of new generation in many markets. This comparison is highly stylized and is intended to show the boundaries of the additional cost and provide some initial insight into how a low-carbon electricity system might look if it were based predominantly on variable renewable energy such as wind and solar. As we will discuss in subsequent sections, costs will not be anywhere near these levels in most regions as they can rely on flexible resources including hydroelectric generation, transmission and consumer flexibility.

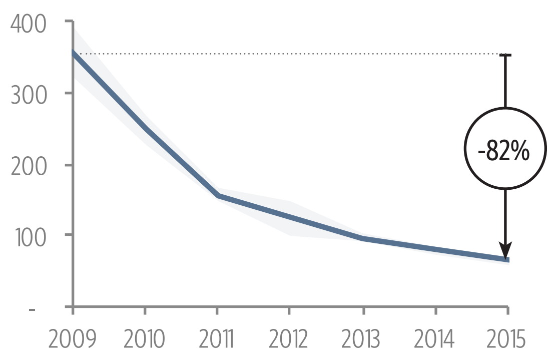
Figure 1.1: Levelized cost of variable renewable energy

Levelized cost of wind
$/MWh, unsubsidized



Recent bid prices:
$35/MWh onshore — USA, 2015
€72.5/MWh — Netherlands, July 2016

Levelized cost of utility-scale PV
$/MWh, unsubsidized



Recent bid prices:
$29.90/MWh — Dubai, May 2016
$29.10/MWh — Chile, August 2016
$24/MWh — Abu Dhabi, Sept 2016

Source: Lazard Levelized Cost of Energy 9.0 (2015), Grentech Media, Lawrency Berkeley National Lab
Note: USA 2015 wind bid price adjusted for production tax credit. According to LBL's 2015 Wind Technologies Market Report, 2015, USA PPA prices are as low as ~$20/MWh after PTC, plus an adjustment of $15/MWh levelised value of the PTC.

1 Emissions reduction based on 14% gas contribution in near-total renewables system for flexibility services.

Furthermore, this model represents a near-total variable renewable energy system that is unlikely to be achieved for several decades even in regions with the most aggressive deployment targets.

Levelized Cost of Energy (LCOE) — an incomplete metric

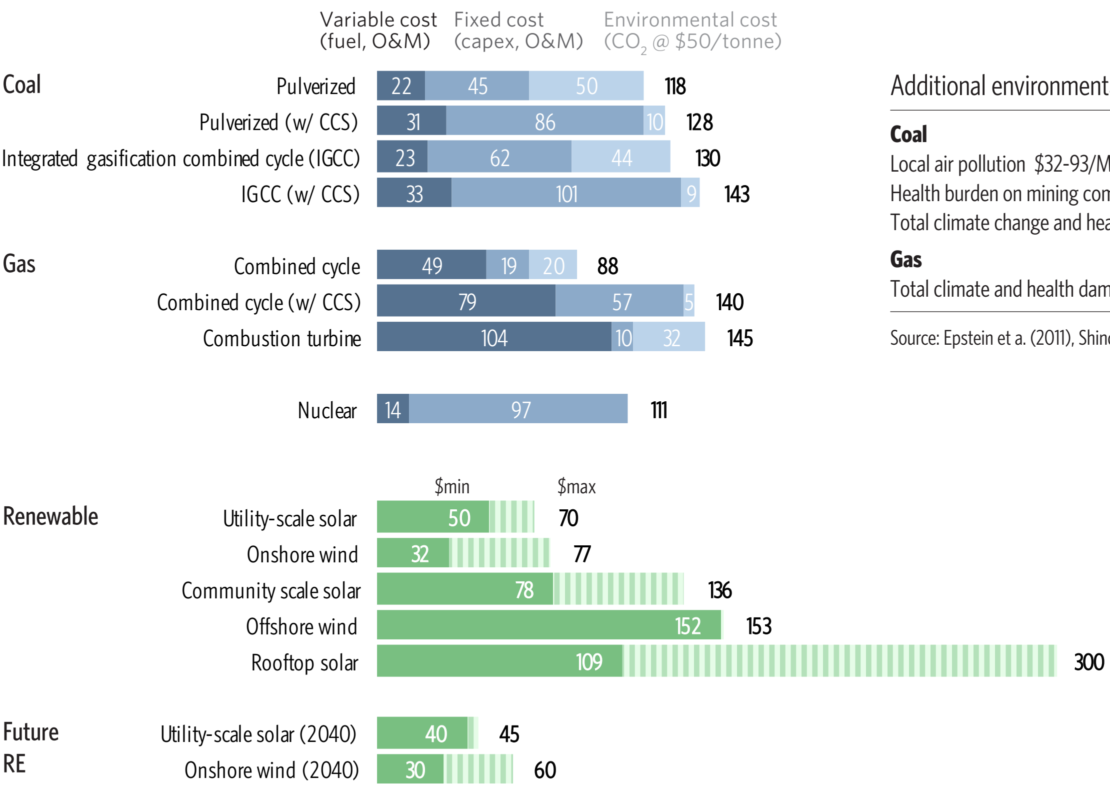
Cost profiles for wind and solar are different from coal- or gas-fired generation. Since there is no fuel to purchase and annual maintenance costs for wind turbines and PV systems are relatively low, the cost of energy is driven primarily by the initial investment and financing costs, while investors receive their return from revenue generated by selling energy over the project's life. Over the past few decades, the cost of equipment has fallen, while output efficiencies have improved. Financing costs have declined as investors perceive lower risks for investing in renewables, especially when assets are contracted over long terms. Levelised cost of energy (LCOE) is a calculation of the average price per unit of electricity that an investor must receive to meet all fixed and variable costs.

By this measure, the cost of onshore wind and utility-scale solar PV have fallen 60% and 82%, respectively, over the past six years (see Figure 1.1).

Figure 1.2 shows that wind and utility-scale solar are competitive with conventional coal and gas-fired generation in terms of LCOE, even without a carbon price. With a carbon price, wind and solar are significantly less expensive. Renewable energy costs are expected to decline further, making wind and solar even more competitive with new conventional generation.

Of course, much of the fossil fuel generating plant is already built, so in the near term an accurate comparison would include only variable and fixed operating costs, and not the initial capital investment. Even by this measure, however, renewable energy is becoming competitive, assuming moderate carbon prices. Over the longer term, existing plants will age, be retired or need increasing maintenance capex; in this timeframe, a cost comparison that includes capital expenditures makes sense.

Figure 1.2: Cost competitiveness of renewables vs fossil fuel generation ($/MWh)



Additional environmental costs of fossil generation

Coal
Local air pollution $32-93/MWh
Health burden on mining communities $44/MWh
Total climate change and health damages $140-340/MWh

Gas
Total climate and health damages $40-180/MWh

Source: Epstein et a. (2011), Shindell (2015)

Sources: CPI analysis, Black & Veatch (2013), Lazard (2015), BNEF (2015), IRENA (2016), Agora/Fraunhofer (2015)

Beyond LCOE — the true value of matching demand with supply

LCOE values do not include the costs of matching the timing of electricity supply from generation to the times that consumers request the energy, which is what we call flexibility.

In order to determine the flexibility that would be needed in a near-total intermittent renewables system, we have modelled a system with wind, solar and non-dispatchable run-of-river hydro renewable generation sized to provide output exactly equal to electricity demand in Germany over the course of a year.

In 2015, annual German electricity demand was 505TWh, so we have calculated the daily renewable energy output from variable renewable energy generation that can provide 505TWh over the course of a year. **Around 403TWh, or 80% of total annual renewable generation, is coincident with demand in the hour it is generated.**

In Figure 1.3, the black line corresponds to daily demand, which varied from 1.1TWh per day to 1.7TWh per day. The grey, dark blue, green and red areas map output to demand on a daily basis:

- grey shows those hours when renewable energy meets demand in the same hour as it was generated;
- dark blue represents the daily shortfall where there is not enough renewable supply to meet demand;
- green represents energy that could be used in the day it was generated, but not in the same hour. For instance, when an excess of solar power generated at midday could meet lighting needs in the evening; and
- red indicates energy that is produced in excess of that day's demand.

Overall, what this graph shows is that the red areas, which represent daily excess production, would equal the dark blue areas, which represent daily shortfalls of production. Combined, these two categories illustrate what shifting needs would be required beyond a 24-hour period in a near-total variable renewable energy system.

Daily shifting

In Figure 1.3, we can see that the system would experience its largest hourly shortfall of power - 62GW – on a cold, windless January day. Therefore, in our notional near-total variable renewable energy system, we have included the costs of providing 62GW of backup peaking capacity, including the fuel (see Figure 1.4).

On a mild day in late April, abundant daytime solar and wind production would exceed demand for several hours (see Figure 1.4); this would give rise to the year's peak intraday shifting opportunity, 364GWh that could be used later in the same day. We then sized battery and gas turbine capacity to meet this intraday shifting need at lowest cost. Over the course of the year, 50TWh (roughly 10% of total annual renewable generation) would be subject to intraday shifting.

Interday shifting

Longer-term shifting (outside of a single day) would be provided by combined cycle gas turbines (CCGTs) during the low periods and curtailment of renewables during high periods. Where the resource investments for longer-term shifting were deemed necessary to satisy peaking capacity or daily shifting needs, we included only the incremental cost fuel to serve interday shifting needs. Over the course of the year, 53TWh (roughly 10% of total annual renewable generation) would be subject to longer-term shifting.

Figure 1.3: Daily demand versus renewable energy production profile

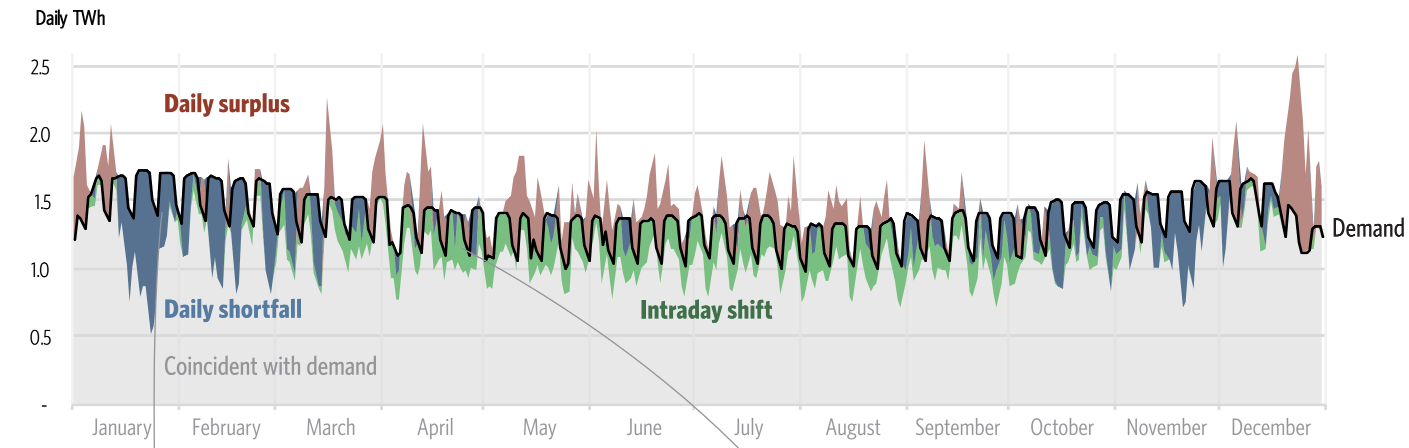
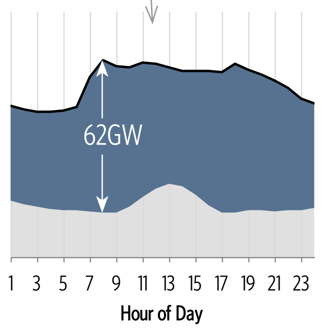


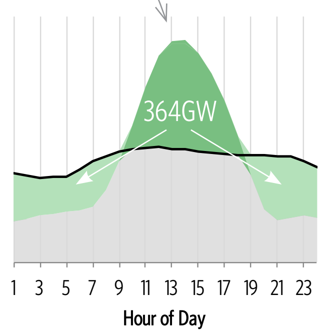
Figure 1.4: Intraday shifting requirement over the course of the year

Higher resolution sections of figure 1.3



Capacity need on biggest shortfall day

Backup peaking capacity is based on the largest difference between electricity demand and total renewable energy production, which in the model would have reached 62GW on a cold, windless January day.



Intraday shifting on highest shifting day

Daily storage capacity is based on the peak daily storage needs for a mild, sunny, windy day in late April where 364GWh of daytime energy production would need to be shifted to the night.

Total annual demand, renewable energy generation and daily and seasonal shifting	**TWh**	**(%)**
Renewable energy coincident with demand	403	(80%)
Intraday shift of renewable energy	50	(10%)
Interday/seasonal shift of renewable energy	53	(10%)
Total renewable energy generation	505	(100%)

Note: Seasonal shift is 53TWh based on sum of daily shortfall, or daily surplus

For this analysis we have looked only at resources that could be used in any region with supply-side investments (eg, are not dependent on how much industrial demand or electric vehicle charging there might be at scale). **Our estimate therefore represents a maximum cost for a generic system.**

The next step is to calculate the cost of the additional resources needed to balance our modelled system. In Figure 1.5 below, we compare the cost per MWh of meeting all demand in a system with a demand profile similar to Germany's today, where:

(a) all of the energy needs are met by a combined cycle gas turbine (CCGT), assuming today's costs. In the CCGT system, we adjusted output to match the system demand profile and scaled the size of the system to provide all of the flexibility required by the system. This includes sufficient capacity to meet peak demand, plus 5% to meet estimated reserve capacity needs for grid contingencies and short-term demand uncertainty. As the CCGTs in this case would be operated to meet demand hour by hour (and some of the capacity would be held in reserve for unexpected needs), the total system capacity would be operated at full capacity less of the time (ie, at a lower capacity factor) than a baseload power plant. **All told, this system delivers energy at $73/MWh.**

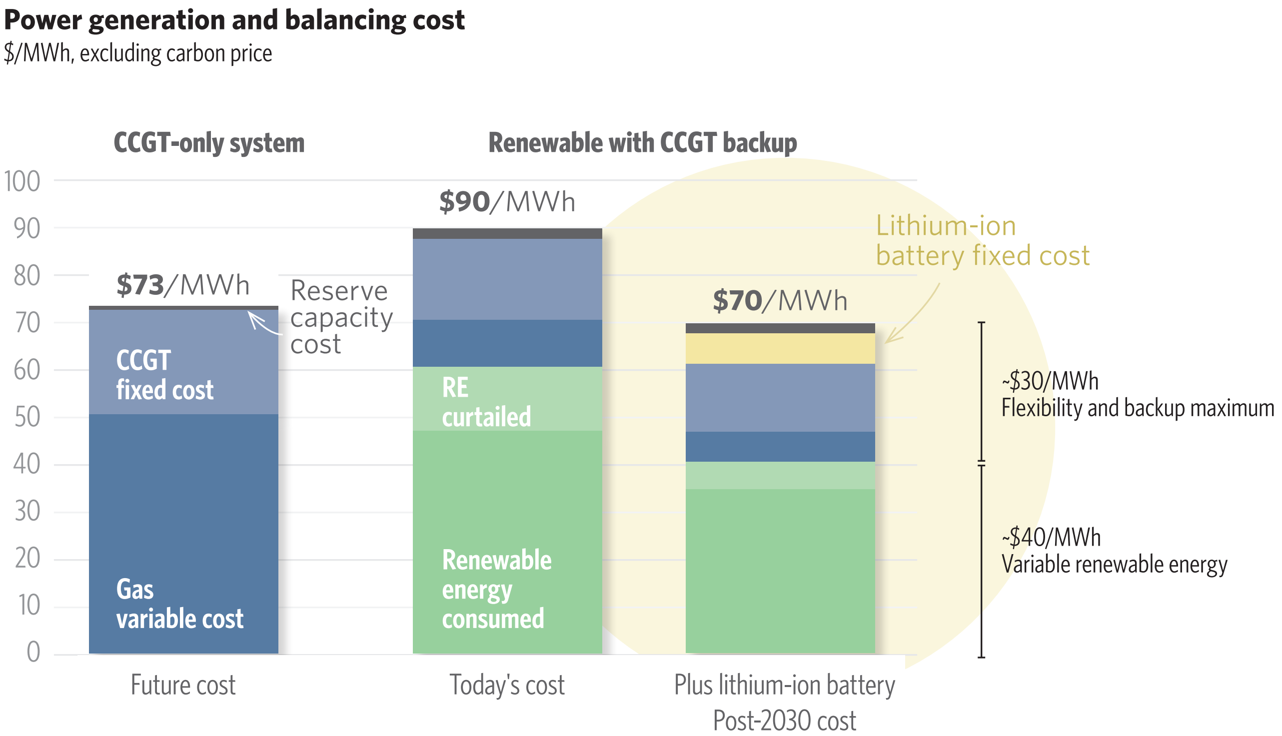
or

(b) the system is supplied almost entirely by intermittent renewable energy, with natural gas supplying some additional flexibility resources, assuming today's cost. In this system, flexibility services would be delivered by CCGTs running at low load factors, ie they are generating less than they are capable of producing. In this case, gas moves from providing 100% of energy in the scenario above to roughly 20%. Gas provides energy for those hours when there is not enough wind or solar energy on the system. During hours where there is excess renewable energy output, dumping excess renewable energy off the system—ie, curtailing wind or solar—would be the cheapest option. **At today's costs, this system delivers energy at around $90/MWh;**

or

(c) based on forecasts of steadily declining renewable energy and battery prices, we calculate costs for a post-2030 scenario, in which **batteries supply much of the flexibility, reducing gas use (down to roughly 13% of total energy) and curtailment of renewables by shifting renewable energy from times when production exceeds demand to times of energy shortfalls.** This renewables system will be cheaper than a gas-based system, assuming that the costs of the gas-based system rise in line with inflation, renewables fall in cost from $60/MWh today to $40/MWh post-2030 and lithium-ion battery storage costs $160/kW-year. **Total system costs in this scenario would be $70/MWh.**

Figure 1.5: Total cost of generation from renewables and CCGT-based systems including flexibility (no carbon price)



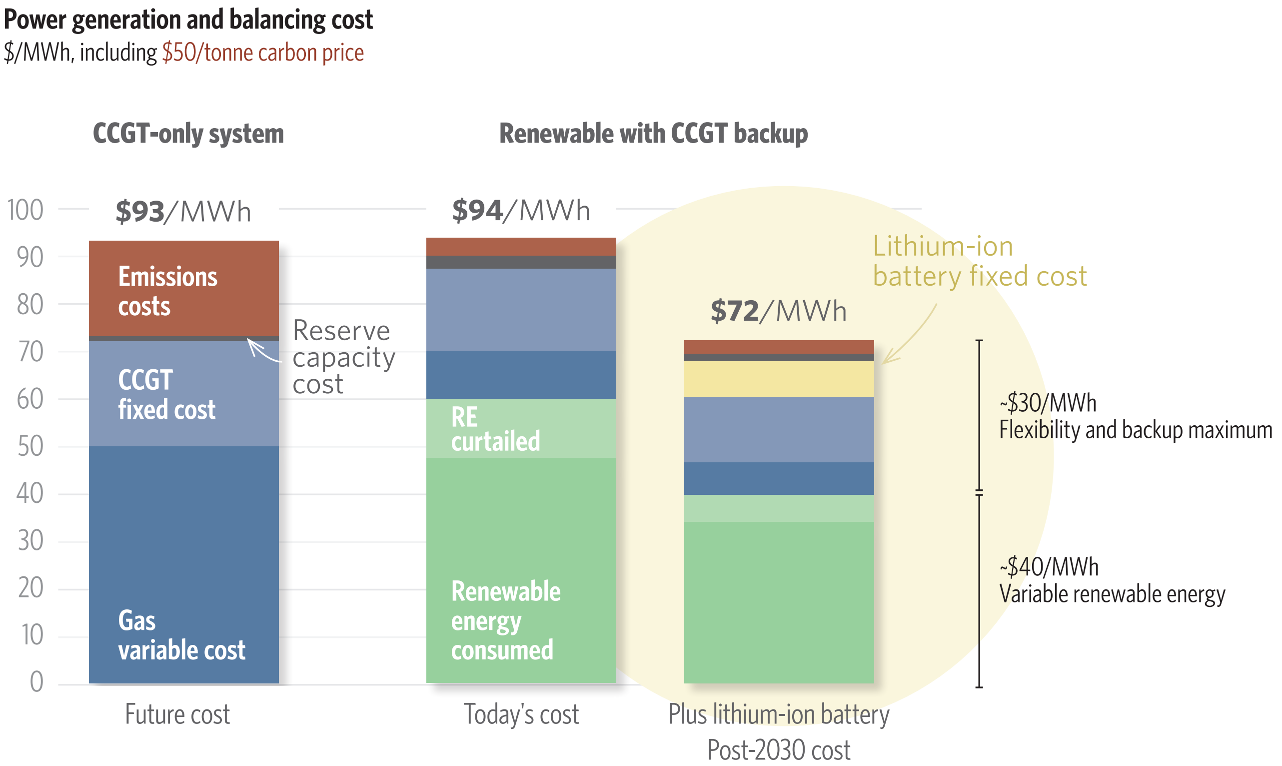
Addition of a carbon price makes renewable energy solutions even more cost competitive. Figure 1.6 shows that with today's technology and costs, a system almost entirely based on intermittent renewables would be cost competitive with a CCGT-based electricity system given a $50 per tonne price on carbon. With future (post-2030) technology advances, the renewables system will be more than 20% less expensive than the gas-based alternative.

Real world systems

There is no major electricity system in the world today that approaches the level of intermittent renewable energy set out in the discussion here. Even in future, there may never be a power system with 80% penetration of wind and solar, as other low-carbon generation sources (hydroelectric power with reservoir storage, nuclear, biofuels, or even fossil fuel generation with carbon capture and storage) can be expected to take on some of the generation burden. Integrating these technologies along with other low-cost but quantity-limited flexibility solutions on the demand side could significantly lower the flexibility costs associated with intermittent renewable energy, as we will see in sections 4 and 5.

In section 4 we examine four regions with aggressive goals for wind and solar power and assess their ability to provide sufficient flexibility in 2025 using existing hydro and fossil fuel generation. Save for the rapidly growing system in Maharashtra, the regions studied will all be able to derive sufficient flexibility from existing resources to cover all needs as they grow their intermittent renewable generation over the next decade. Further out, additional flexibility may be needed, but **our generic system cost model shows this to be economically feasible, even before considering low-cost sources of flexibility including existing hydro and thermal power plants and demand management**.

Figure 1.6: Total cost of generation from renewables and CCGT-based systems including flexibility (with a carbon price)



2. Defining the generic set of flexibility requirements: the six major types of flexibility needed to operate an electricity system

Electricity systems have always been dynamic to respond to fluctuations in supply and demand. There are many types of flexibility that enable the system to match energy supply and demand across seconds, hours, days and seasons.

The five major types of flexibility are:

1. *Spinning reserve and load following*
2. *Short-term reserve*
3. *Ramping*
4. *Daily (intraday) balancing*
5. *Seasonal (interday) balancing*

Each of these types of flexibility has a location-specific element, as flexibility may be needed in a specific part of the grid to address local mismatches between demand and supply.

Our analysis shows that as the penetration of variable renewable energy increases, flexibility needs in the shortest time horizons will grow slowly, while the increase in balancing energy needs on a daily or seasonal basis will be much more significant.

Overview

Modern electricity systems require continuous and instantaneous matching of electricity supply and demand. Failure to match supply and demand can severely reduce power quality, causing voltage levels to fall or frequencies to drift into ranges that can cause permanent damage to equipment such as pumps and motors. Mismatches can even overload transmission and distribution networks, causing power outages across the system. This matching needs to happen along a continuum of timescales, from second to second, month to month.

Electricity system operators and planners have many tools at their disposal to match supply and demand. To balance supply and demand on a second-to-second basis, electricity system operators often depend on power plants that can adjust their power output at a moment's notice, or in response to changing grid conditions. At longer intervals, more active management comes into play, including the ability to schedule and dispatch power plants and transmission lines, operate storage facilities, and call upon demand-side response. In general, resources that are available—and most suitable—for matching vary with timescale. Responsibility for flexibility planning, investments and operations also changes with matching timescale. System operators ensure the continuous match of supply and demand, for example, responding to an unexpected spike in demand or the loss of a transmission line by rapidly dispatching reserve supply.

Decisions with longer lead times are typically left to electricity markets or even long-term planning. For instance, scheduling power plants for tomorrow is often left to day-ahead electricity markets. Planning decisions on which plants should be built in three years is typically a matter for utilities, regulators and governments.

Figure 2.1 shows the types of flexibility needed in an electricity system in relation to timescales. Technical constraints and current market practices prevent solar and wind from providing some types of flexibility.[2] Technical and market remedies are available to an extent at additional cost.[3]

As will be discussed in section 4, in most geographies longer-term flexibility needs are likely to be more strongly affected by increased intermittent renewable generation. In most systems, the responsibility and mechanisms for dealing with shorter-term flexibility needs are more well developed, with system operators under strong mandates to maintain system balance. Responsibility for longer-term flexibility is usually more diffuse, with energy and financial markets as well as regulatory planning processes taking the place of reliability mandates.

2 Since solar and wind do not power rotating generators synchronised to the frequency of the AC grid, a high renewables system will have less system inertia to help control frequency. See NREL (2016), On the path to SunShot: Emerging Issues and Challenges in Integrating High Levels of Solar into the Electrical Generation and Transmission System.

3 Power electronics enable wind turbines to deliver synthetic inertia, harnessing the rotational forces on the rotor side of the inverter. Given suitable incentives, both wind and solar could provide primary frequency response. In addition, thermally powered turbines no longer needed for generation could be converted to synchronous condensers (ie, motors that spin freely without an attached load) to contribute inertial frequency response.

Figure 2.1: Power systems require multiple types of flexibility to manage variability and uncertainty

Increase in flexibility needed with growth of low-carbon power

		Type of flexibility	Renewables-based	Nuclear	Fossil fuels with CCS
Real-time operations	<1 min – 5 min	Spinning and load-following	**Low to moderate** Modest increases in forecast error with more variable generation	**Low** Low demand forecast errors	**Low** Low demand forecast errors
Real-time operations	5 min – 15 min	Short-term reserve			
Scheduling and forecasting	Hour	Ramping	**Moderate to high** Daily patterns (eg, sunset) lead to substantial ramping needs	**Low to moderate** Baseload nuclear has limited ramping capability	**Low to moderate** Baseload fossil fuels with CCS has limited ramping capability
Scheduling and forecasting	Day	Intraday / daily balancing	**Moderate to high** Misalignment between generation and load drives hourly over/under-production	**Moderate to high** Constant supply and variable demand creates need for daily energy shift	**Moderate** Following demand lowers capacity factor, and increases cost
Planning	Season – Year(s)	Interday / seasonal balancing	**Moderate to high** Dependent on resource mix, seasonality of renewable resource	**Low to moderate** Dependent on seasonality of demand and ability to operate plant seasonally	**Low to moderate** Following load lowers capacity factor, and increases cost substantially
			Primary focus of this analysis		

Figure 2.2 offers further descriptions of these flexibility needs. We also note that flexibility services are locational in nature. Not only "when" but "where" the flexibility is delivered matters, so the behaviour of transmission and distribution system operators as well as the presence and effectiveness of locational market signals must be considered.

Flexibility options are very much dependent on geographically determined resources, access to markets through interconnection and other locational factors. Local flexibility needs are determined by transmission and distribution constraints. **Distributed flexibility resources could be a valuable resource but face a number of barriers to providing services to the grid.** In particular, data exchange between distributed flexibility resources (such as batteries, electric vehicle chargers, small on-site generators) and grid operators can be challenging, given the variety of technologies, diffuse spread across an electricity system, and large number of assets that would need to be coordinated.

REAL-TIME OPERATIONS IN A HIGH RENEWABLES GRID

Real-time balancing needs

A stable grid must match supply and demand in real time. If consumption exceeds generation, frequency will drop; conversely, if generation outpaces consumption, frequency will increase. If frequency limits are exceeded in either direction, equipment on the grid may be damaged. To prevent damage to generators that could cause a prolonged blackout, the system operator may cut power to some customers or generators may disconnect from the system. Matching supply and demand in real-time is accomplished through both physical properties of the grid and contracted services. Viewed along a timeline of longer (slower) reaction times:

- **Instantaneously and automatically, the physical inertia of rotating generators on the grid** slows frequency changes. This can be provided by thermal or hydro power plants, by "synchronous condensers" (ie, large motors that spin freely without a load), provided as "synthetic inertia" by the power conversion equipment of wind farms, or synthesised by batteries, flywheels or supercapacitors that can deliver power in microseconds in response to grid conditions.
- **In a matter of only a few seconds, synchronous generators equipped with "governors"** stabilize frequency if they sense a change in grid conditions. Intermittent renewables (and baseload nuclear plants) are not typically equipped with governors, but power electronics can replicate their role. Fast-responding batteries can also provide this type of service.
- **In less than a minute, resources controlled by automatic generation control (AGC) signals** restore frequency to desired levels. Many short-term flexibility options—from demand-side controls to hydroelectric dams to battery energy storage—can be enabled to provide this type of response.

At times of high renewables output, conventional generators that provide these services are less likely to be online/operating.

Reactive power and voltage support

Reactive power, a form of power in alternating current systems that doesn't physically do work, is needed for certain types of loads, such as large electric motors to operate reliably, and to maintain the voltage level of the grid. When reactive power is lacking, voltage sinks, especially as distance from generation increases. Transmitting reactive power reduces the amount of real power that can be transmitted and may increase transmission losses. Reactive power can be supplied or absorbed by power plants (at the cost of reduced output of usable energy) as well as by devices on the transmission systems (eg, capacitors, reactors, static-VAR compensators). Given that intermittent renewables are often remotely located, their presence on the grid can increase demand for reactive power and voltage support. That said, modern power conversion technology used by most renewable power plants can produce both real and reactive power as needed.

On distribution systems, voltage is the primary power quality concern. Long distribution feeders typically result in large voltage drops, and utilities often install large capacitors along their distribution lines to support voltage levels (and provide reactive power). As the number of rooftop solar installations and distributed batteries increase, the injection of power at many points of the distribution system can change voltage levels, and distribution equipment that cannot dynamically adjust may complicate the problem. However, smart inverter technology paired with distributed energy storage can provide voltage support services to the distribution grid.

Black start services

Restoring grid service after an outage is a complicated, multi-stage process that begins with "black start" units—commonly hydro and gas turbines—that can start operations without the need for grid-delivered electricity. In turn, these black start units are used to energise the surrounding grid. In large systems, this process begins with multiple islanded grids, which are then synchronised to achieve full restoration. Using intermittent renewables can complicate the process; more and smaller islands must be energised and connected, and variability of supply can destabilise the grid during the sensitive restoration.

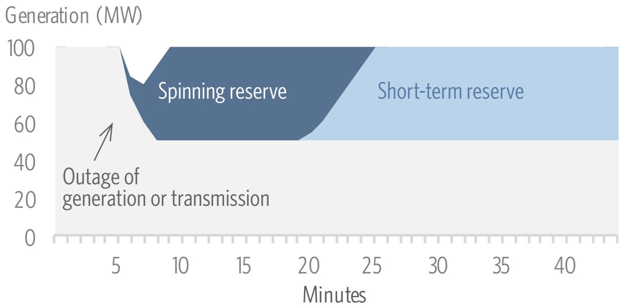
Figure 2.2: Types of flexibility

SPINNING & SHORT TERM RESERVES

Renewables may increase generation forecast uncertainty, but there are mitigating solutions to limit this risk

Energy sources (or consumption) that can be varied on a continuous basis to ensure that demand and supply are continuously in balance. Electricity production can change rapidly, for instance when a cloud passes over a solar power plant, or a major transmission line or power plant shuts down unexpectedly. Demand also changes suddenly, for instance, when an industrial electricity user turns on major equipment, or people switch on their kettle during a TV ad break. Matching demand and supply at these times requires sources that can be adjusted within seconds. **As intermittent wind and solar supplies a greater share of electricity demand, uncertainty and short-term variability of these resources will increase the need for fast-responding reserves.**

'Contingency-based' spinning and short-term reserves



POWER SYSTEM NEED

- Generation can come online quickly in case of unexpected generation / transmission outage
- Typically less than 5% of peak load

IMPLICATIONS FOR RENEWABLES BASED-SYSTEM

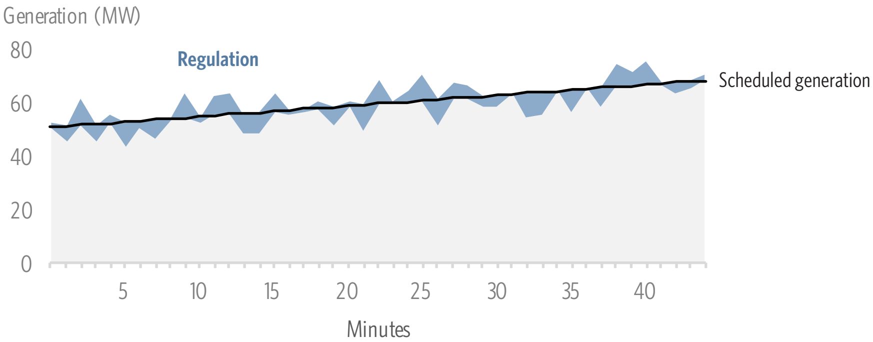
- Increased renewables unlikely to change largest contingency
- Often provided by excess headroom on operating generators, which could get pushed out of merit order by zero-marginal cost renewables

LOAD FOLLOWING

Renewables may increase generation forecast uncertainty, but mitigating solutions exist to limit this risk

Reserves must be in place to cover unexpected events whose impact can last many hours. Beyond the immediate load following adjustment, the system may need to replace lost capacity over a matter of many hours, while the system is rebalanced. When an event occurs, short-term reserve may be brought on line so that spinning reserve can be restored to enable load following.

Load-following 'regulation' reserves



POWER SYSTEM NEED

- Rapid changes in output to account for differences between predicted and actual generation or load
- Typically around 1% of peak load, often provided by hydro and pumped storage
- Often between 3-7% of renewable generation capacity to account for forecast uncertainty

IMPLICATIONS FOR RENEWABLES BASED-SYSTEM

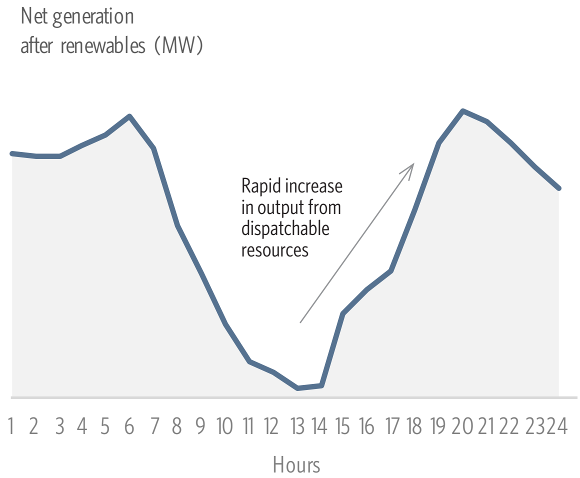
- Increased renewables may increase generation forecast uncertainty, although dynamic reserve requirements, improved forecasting, and shorter gate closure times can reduce the need for this option

RAMPING

Daily patterns of renewables-based generation will increase frequency and magnitude of ramping events

Energy supply must be able to ramp up or ramp down quickly enough. In many cases, it will not be a lack of capacity or energy supply that constrains the system, but the speed at which the output of that supply can be increased to meet rising demand (or decreased to accommodate sharp drops in demand). A classic case is where energy supply from solar decreases at sunset just as demand increases when consumers turn their lights on. Fast-ramping generation plants may be needed to balance supply and demand for several hours, even if the system has more cost-efficient capacity sized to meet peak (or minimum) load but requires more time to raise (or lower) output. Bringing on extra generators just to meet ramping needs can increase system costs.

Ramping



POWER SYSTEM NEED

- Level of output can increase quickly as load increases or variable generation decreases, typically over 1-3 hours
- Generally, ramping needs are predictable, as opposed to variations handled by regulating reserves
- Examples include ramping to accommodate a drop in PV output at sunset in solar-heavy systems

IMPLICATIONS FOR RENEWABLES BASED-SYSTEM

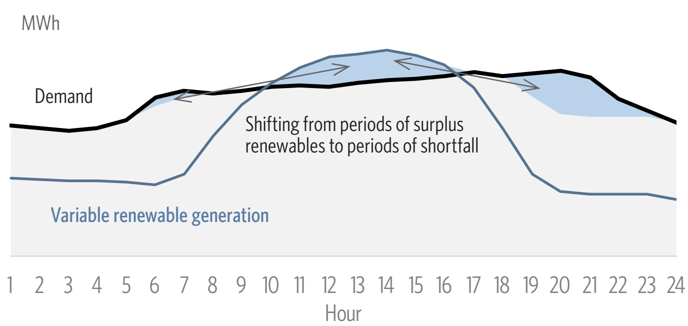
- Greater penetration of variable renewable energy will increase frequency and size of ramping events
- Some thermal generation technologies (particularly coal and nuclear) cannot ramp production quickly, while others (natural gas turbines) can ramp to full production in a matter of minutes

DAILY BALANCING (INTRADAY)

Renewables will increase misalignment between generation and load, increasing the need for shifting

Shifting the timing of energy production or consumption on a daily basis to enable supply to meet demand at all times. Energy use varies throughout the day in reasonably predictable patterns, as does some intermittent renewable generation. Depending on the country and its economy, electricity use can peak in late morning or in the evening when consumers come home from work. By comparison, demand at 3am can be low; in many systems, peak demand can be two or three times higher than off-peak demand. Production from low-carbon sources may be constant (for example, nuclear) or follow patterns that are similar to demand patterns. "Peak clipping", "valley filling" and "load shifting" are all terms that the electricity industry uses to describe techniques that align the daily patterns of energy supply and demand more closely.

Daily balancing and shifting



POWER SYSTEM NEED

- Timing of variable renewable generation may not exactly match timing of electricity consumption
- Some electricity consumption may be time-shifted to periods of surplus renewable energy or low demand
- Surplus electricity can be stored in batteries, pumped hydro, etc

IMPLICATIONS FOR RENEWABLES BASED-SYSTEM:

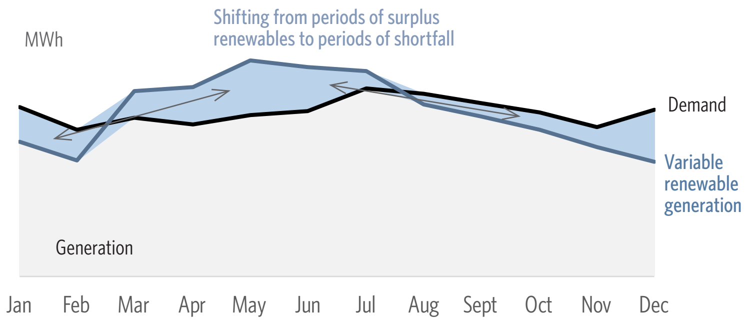
- Greater penetration of variable renewable energy will increase surplus generation and need for shifting
- Baseload thermal generation (nuclear, coal or gas) that remains online to serve other grid services (eg, reserves) can increase surplus generation and shifting required

SEASONAL BALANCING (INTERDAY)

At high levels of renewable penetration, seasonal shifting needs may increase in response to seasonality of resource

Energy supply may need to be adjusted to ensure that energy supply and demand balance across the year. Energy output and demand can vary over the course of the year, for instance from high hydro output during a rainy season, wind during a windy season and solar in the summer. Demand also may be seasonal depending on heating or air conditioning loads. Storage or shifting of energy for four to eight months or even across years is fundamentally different than shifting it between day and night.

Seasonal balancing (interday)



POWER SYSTEM NEED

- Rapid changes in output to account for differences between predicted and actual generation or load
- Typically around 1% of peak load, often provided by hydro and pumped storage
- Often between 3-7% of renewable generation capacity to account for forecast uncertainty

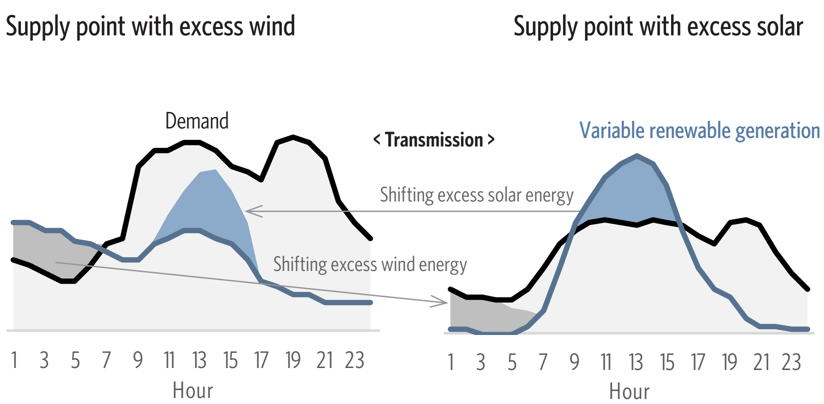
IMPLICATIONS FOR RENEWABLES BASED-SYSTEM

- Increased renewables may increase generation forecast uncertainty, although dynamic reserve requirements, improved forecasting, and shorter gate closure times can reduce the need for this option

LOCATIONAL FLEXIBILITY

Renewables place a greater emphasis on optimising transmission, distribution and the location of flexibility resources

All of these flexibility requirements have locational dimensions. Transmission or distribution can be as big a constraint as a lack of generating capacity. If generation or demand are concentrated spatially, transmission (or even distribution) could become constrained, preventing supply from matching demand in a particular location, even when adequate resources are available in aggregate. To prevent this, flexibility resources need to be distributed across the network; transmission may also need to be expanded to link generation, demand and flexibility more robustly.



POWER SYSTEM NEED

- Flexibility must be delivered to where it is needed as well as when
- Transmission and distribution can balance regional differences in electricity production and demand, but when differences become large, transmission can become constrained and expanding the grid could become expensive.
- Locating flexibility resources at strategic points in the grid can reduce the amount of flexibility that needs to be transported

IMPLICATIONS FOR RENEWABLES BASED-SYSTEM

- Distributed flexibility tools as well as those that can be located with renewable generation sources can have cost advantages
- Price signals need to offer locational differentiation to encourage flexibility to be developed in ways that minimise congestion, grid costs and losses

3. Comparing a broad set of options: technologies, business models and market signals to develop flexibility mechanisms

We analysed a range of technologies and their fit and cost for each of the flexibility categories. Today, the default technology to meet many of the flexibility needs would be new gas-fired generation (either jet-engine type "peaker" gas turbines, or more efficient combined cycle plants that also generate power from the resulting heat), often run infrequently to provide backup and capacity rather than energy. In the future, batteries will fall in cost and improve in performance to the point where they will become the default technology for many, but not all, flexibility services. The default option is the technology that is highly scalable at a reasonable cost and will be applied as a last resort once all the cheaper, but less scalable, options are exhausted.

Cheaper options include using existing hydroelectric generation (which is limited by location and rainfall), consumer demand management (which is limited by technology or behaviour), transmission to shift flexibility from one region to another, and using other existing generation. In many systems, these options could replace most or all of the need for new gas generation at low generation levels, even at the highest renewable energy penetration levels, often at a much lower cost.

There are many potential sources of flexibility within an electricity system. Historically, electricity systems have relied primarily on large, central station generating equipment such as hydroelectric, coal or gas fired power plants, which we refer to as **Supply-side measures.**

The regional analysis in section 4 shows that in the short to medium term a significant amount of flexibility should continue to be available from these plants. However, even before the recent expansion of variable renewable energy, operators realized that costs could be lowered by accessing several additional types of flexibility:

- **Demand-side measures** enable consumers to make their consumption more flexible and provide that flexibility back to the system, often in exchange for financial compensation or lower energy prices. An industrial customer, for instance, can reduce demand during periods of extreme demand peaks and help the system avoid using—or even having to build—new peaking plant. Residential and commercial consumers can participate as well. Markets have been developed over the last several decades to make this process more efficient, while automated control systems allow for more reliable and rapid response while aggregating ever smaller shifting opportunities. There is likely to be much more demand-side flexibility to tap, and much of this flexibility is low cost.
- **Conversion to other forms of energy** is a set of typically consumer-side options. Many electricity services, such as heat, or transportation, involve converting electricity to other forms of energy that can then be used as a way to store electricity. Storing heat, or making hydrogen or other energy intensive products are ways of converting energy and storing it to provide flexibility.
- **Direct electricity storage,** where electricity is stored and its use is transferred to other times of the day or week, is an increasingly popular option, due to the declining cost of batteries. However, other options have been used for some time, including pumped storage hydro.
- **Infrastructure**, especially transmission and distribution, can help access flexibility from other regions, or reduce overall flexibility needs if transmission is used to connect two regions that have uncorrelated electricity demand and flexibility needs.

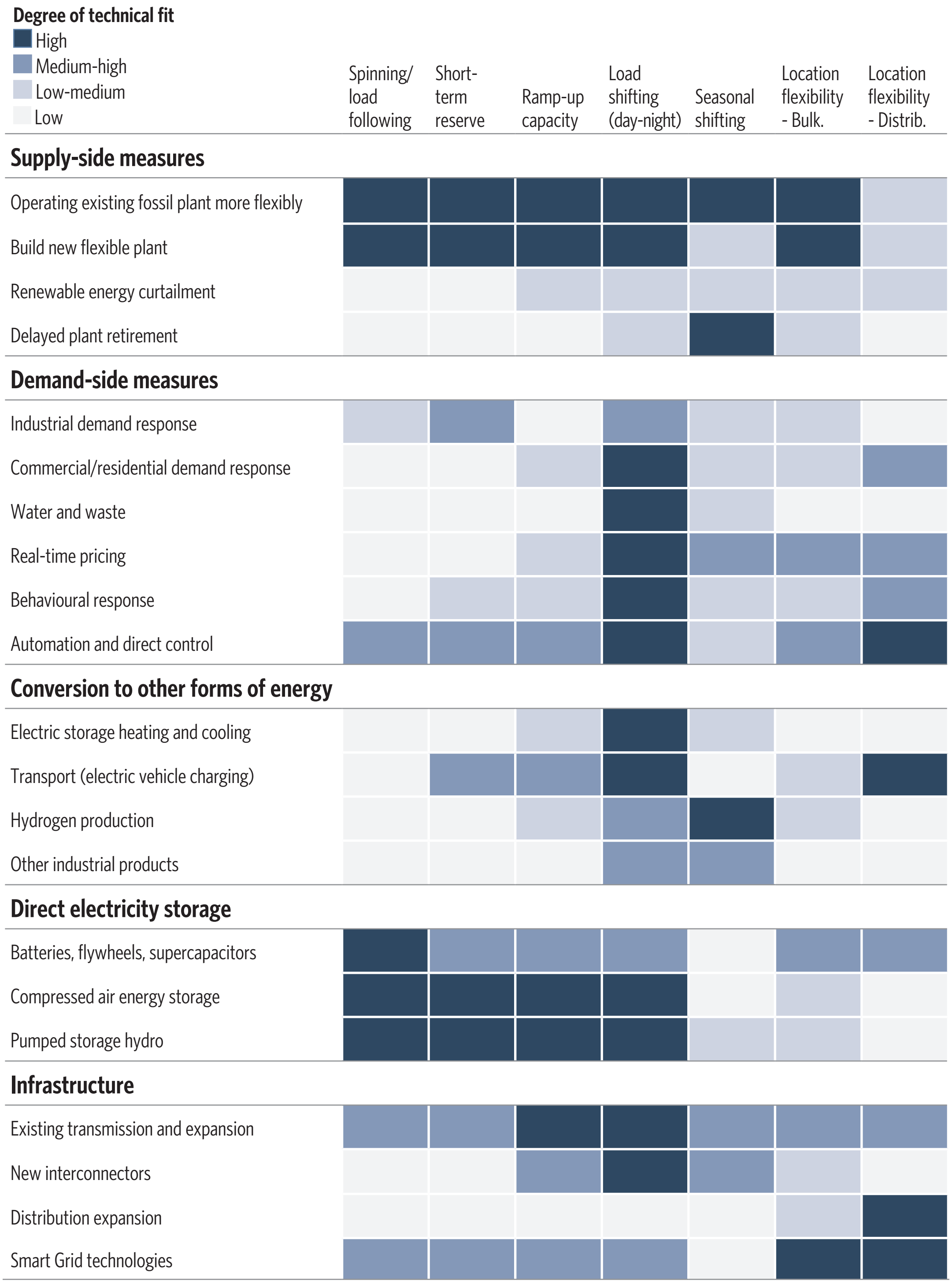
Table 3.1: Potential options in every category

SUPPLY-SIDE MEASURES	DEMAND-SIDE MEASURES	CONVERSION TO OTHER ENERGY FORMS	DIRECT ELECTRICITY STORAGE	INFRASTRUCTURE
Operating existing plants more flexibly Coal Gas Storage hydro Run-of-river hydro	**Industrial demand response** Steel industry Aluminum industry Chemicals Pulp and paper Cement Manufacturing	**Heat and thermal inertia** Storage heating Storage cooling CHP and district heating	**Batteries** Lithium ion Lead acid Zinc bromine flow Other flow batteries Lithium air Solid state Aqueous saltwater	**Existing infrastructure** Improved balancing and control
Build new flexible plant Flexible gas Hydro Concentrated solar Biomass Tidal or wave power	**Commercial & residential demand response** Heating Cooling Lighting Water heating Data centres Refrigeration Appliances & electronics	**Transport** Light vehicle charging Fleet LV charging Bus and rail	**Flywheels**	**New transmission** Intraregional reinforcement Interconnection and regional expansion
Renewable curtailment Existing utility-scale wind and solar New utility-scale wind and solar Distributed solar curtailment Improved forecasting	**Water and waste** Pumping Desalination **Real-time pricing** By sector	**Hydrogen production and similar** Hydrogen production and storage Synthetic fuels Fertiliser	**Supercapacitors**	**Transmission smart grid technologies** eg, Supervisory control and data acquisition (SCADA)
Delayed plant retirement Coal Gas	**Behavioural response** By sector	**Other industrial products** Production and storage of chemicals Steel Cement	**Pumped storage hydro** Pure pumped storage Mixed pump-reservoir storage	**New distribution** Reinforcement Active transmission elements (capacitors, management systems, etc)
	Automation/direct control Consumer aggregation Other by sector		**Compressed air energy storage**	**Distribution smart grid technologies** Control systems and automation

While these options all provide some types of flexibility, not all of them can provide every type of flexibility outlined in section 2. For example, the response time required to get an industrial plant to reduce demand can be longer than the few seconds allowed to provide the shortest-term reserves. Alternatively, many direct storage options are not built to store energy for the extended periods of time that would be needed to address seasonal flexibility needs.

Figure 3.1 compares the various flexibility options outlined above against the technical fit with each type of flexibility laid out in sections 2.

Figure 3.1: Matching flexibility types with application



How we evaluated the cost of flexibility from various sources

CPI estimated the cost of providing each type of flexibility from a key set of flexibility options in several steps.

1. We first modelled the fixed and variable costs of providing a specific type of flexibility and calculated a comparable figure (eg, $/MWh or $/kW-yr) for each option.
2. We then ranked these options from lowest to highest cost to compare the relative costs of each option.
3. The least-cost options were consistently demand-side flexibility or existing generation, which by definition are limited in their potential scale. The lowest-cost source of flexibility that is highly scalable and not dependent on a regional installed base is what we've termed the "lowest cost scalable resource", or the "default option" for building new flexibility.

We highlighted this "lowest-cost scalable resource" in our analysis to provide a benchmark: flexibility options with lower costs should be used to the greatest extent possible, while higher-cost resources are unlikely to be economic (as there will always be a cheaper, highly scalable resource at lower cost).

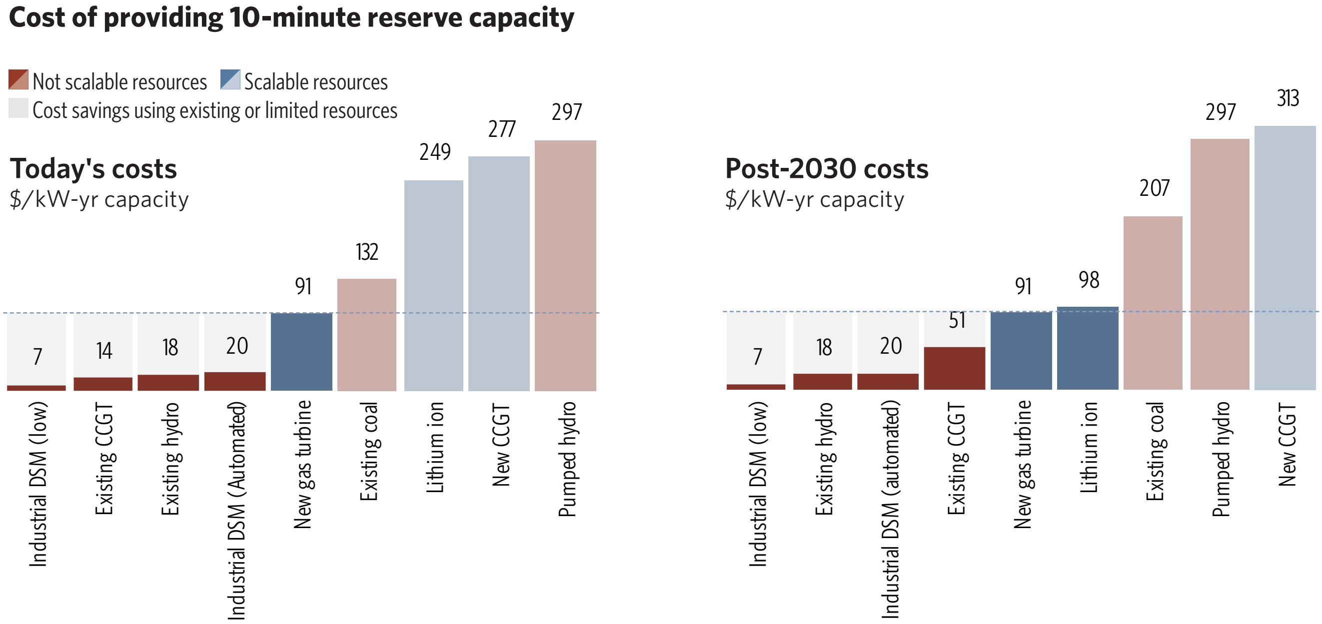
Detailed assumptions for this analysis are provided in Appendix 2, part 3.

Beyond pure technical fit, there is the question of economic suitability, which varies tremendously between options. Some have high capital costs and low variable costs, ie, if they shift a good deal of energy the lower cost per unit of energy shifted can justify the higher investment. Other options—those with low capital but high operating costs—might be more economic for reserve functions where the value is not in the energy provision, but the capacity, so that low capacity costs can become more important. In the following examples, we present metrics for evaluating the relative cost effectiveness of the various options to meet each of the flexibility needs.

3.1. Options to meet short-term reserves and load following

At the shortest timescale that flexibility is needed, system operators need to be able to call on capacity that can deliver power almost instantaneously. Moving slightly beyond this timeframe, there are short-term flexibility needs around frequency response, load following, and short-term reserves. As a proxy for these various types of reserves we have evaluated the relative economics of 10-minute reserve, that is, capacity that could be brought online within 10 minutes.

Figure 3.2: Short-term reserves: existing hydro and demand flexibility are low-cost options to replace reserves from fossil fuel-based plant



Sources: CPI analysis. Total fixed costs are allocated to plan capacity available within 10 minutes. "Unrecovered operating costs" based on operation time when variable renewables are on the margin — assumed to be negligible for today's cost, and 7% at minimum generation level in 2040, based on expected overgeneration. Includes $50/tonne carbon price.

Figure 3.3 shows that at today's cost a new gas turbine (GT) would be the marginal source of new capacity to meet new 10-minute reserve, but existing hydro, GTs, CCGTs or low-cost industrial demand-side management are all significantly cheaper, since no new capital outlay is required. In the future, lithium-ion batteries are expected to decline in cost to the point that they are competitive with building a new GT. In general, the short-term flexibility requirements are likely to have the lowest growth due to increasing variable renewable energy. Furthermore, batteries and gas turbines, which are cost effective measures for short-term reserve, are likely to contribute to ramping, daily balancing and seasonal balancing; by providing multiple flexibility services from the same asset, costs for these resources may be even lower.

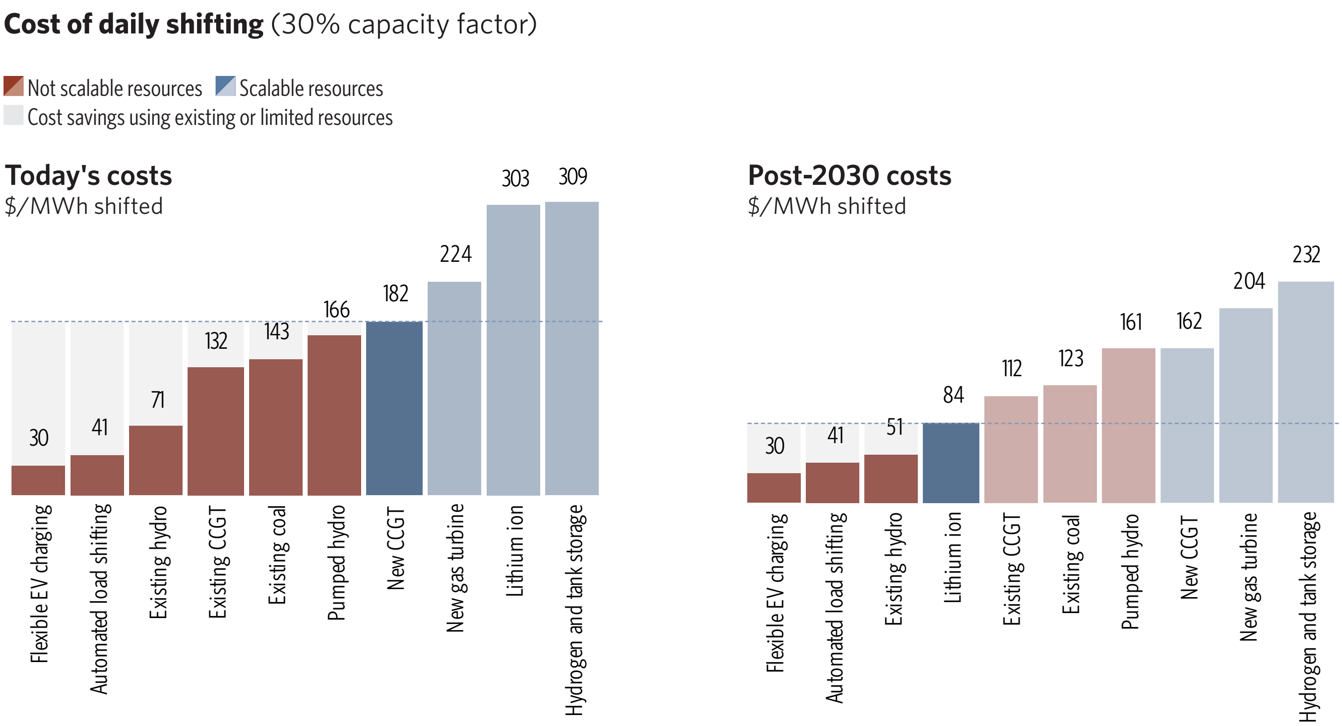
3.2. Options to meet intraday/daily load shifting requirements

In contrast, intraday shifting or daily load shifting is likely to be among the fastest growing flexibility requirements once renewable energy reaches 30-40% of total electricity supply. The economics of intraday flexibility options will depend on how often the option is needed. A certain base amount of shifting from day to night or night to day will be required every day for as much as 8 hours per day. The peak on a moderate day may require only 30 minutes of shifting, while more extreme days – hotter, colder or with more variable wind or solar energy supply – could need 2 hours of shifting of higher peaks, albeit far fewer times per year. Demand that follows a reasonably predictable annual pattern would justify building more efficient shifting capacity that might have a higher initial cost, although very occasional or less predictable shifting needs (high and lengthy peaks) may be met at lower cost by capacity with low capital costs even if it has higher variable costs or is limited by annual output.

Our analysis separates daily load shifting into the daily, long-duration shifting (ie, consistently used for multiple hours per day), represented by the 30% load factor chart (just under 8 hours a day every day), and the infrequent use represented by a 5% load factor (every day just over 1 hour a day, or about 8 hours per week).

In addition, not all options are directly comparable. Some – for instance, batteries – shift energy from one time of the day to another, with some energy lost in the process. Others, like GTs, only generate replacement energy. Shifting excess wind generation from one time to another with a battery requires only the cost of building and operating the battery. Providing the

Figure 3.3: On a typical day, flexible loads and existing resources are the most cost-effective options today for daily shifting, but future declines in lithium ion costs will yield cheaper alternatives



Sources: CPI analysis. Curtailment cost for renewable energy of $60/MWh for today's cost, $40/MWh for post-2030 costs. Shifting costs for storage technologies include losses valued at cost of curtailment of renewable energy. Includes $50/tonne carbon price.

equivalent shift of energy using a gas turbine, however, would require the system operator to curtail excess wind generation, and replace it with gas generation at a different time. **In this case, the cost of flexibility from the gas turbine includes both the cost of the gas turbine and the cost of the wind energy that is not used.**[4] For those options in the charts where a renewable **curtailment cost is included, it is valued at $50/MWh in 2030,** the expected future cost per MWh of renewable energy.

At a 30% load factor today, a new CCGT combined with curtailment of wind generation is the most economic option (Figure 3.3 on the previous page) for new shifting capability. Many other options are cheaper but limited in potential capacity, including existing CCGTs or coal plants, which are limited by existing capacity levels, and consumer load shifting. **Over the next 15 years we expect the cost of lithium ion batteries to fall to the point where batteries will be a cheaper option than all but existing hydro and consumer load shifting.**

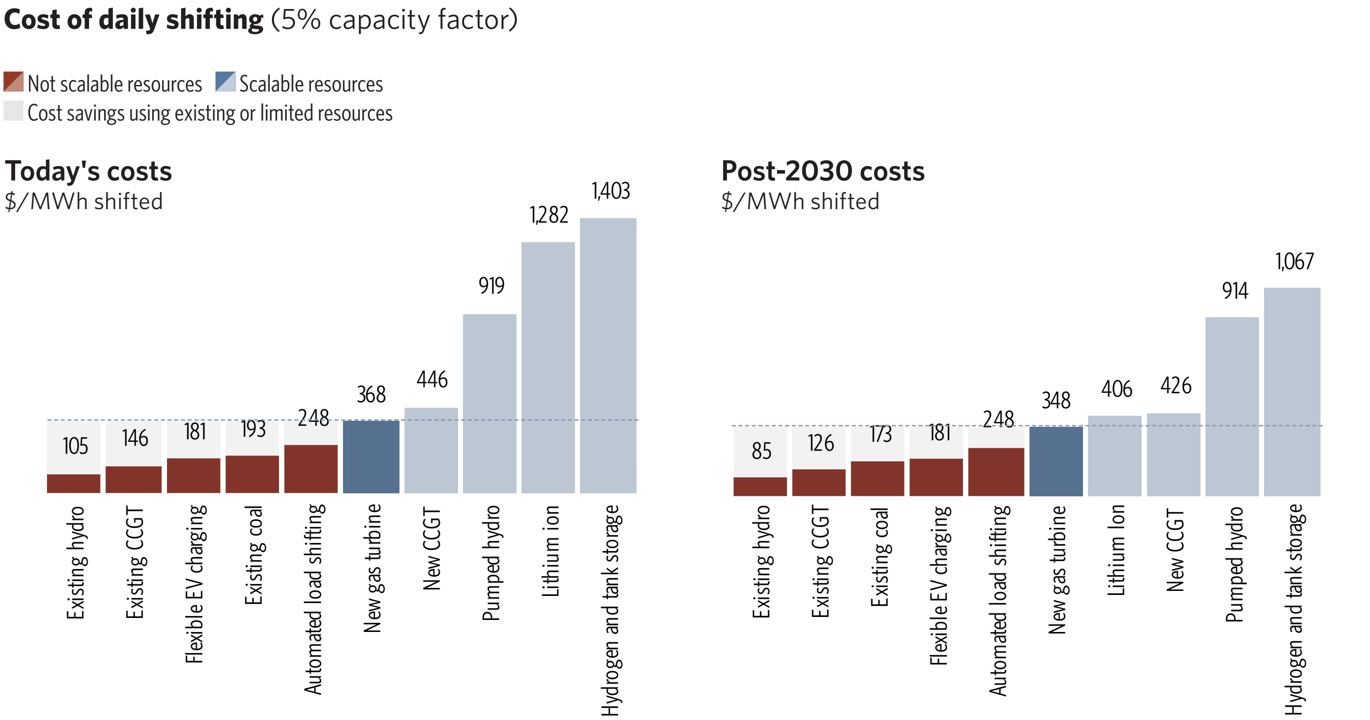
For more infrequent load shifting (Figure 3.4), gas turbines will continue to be the lowest-cost new-build option. Existing plant and demand response can contribute at a lower cost where they are available.

The 5% and 30% options are just two examples. Any given system will operate along a band of capacity factors determined by its needs. Thus, an optimised system will likely have a mix of GTs, batteries, a large amount of shiftable demand and access to existing resources. Systems with significant amounts of hydro and pumped storage will be able to depend on those resources for most or all of their shifting needs.

3.3. Options to meet interday/seasonal load shifting

The seasonal shifting required, for instance, to move energy from sunny summer months with a good deal of solar energy to darker winter months with high heating demand, or from windy winter months to wind-poor summer months with increased air conditioning demand, requires a different type of shifting with very different economics. Unlike daily shifting where the same storage capacity can be used for cycle after cycle, day after day, for seasonal shifting storage capacity might be used (ie, cycled) only once or twice a year. In some cases, seasonal shifting may be needed only every few years, for instance when a drought reduces hydroelectric generation.

Figure 3.4: Daily shifting (peak) needs may require gas generation by default, although cheaper shifting options exist



Sources: CPI analysis. Curtailment cost for renewable energy of $60/MWh for today's cost, $40/MWh for post-2030 costs. Shifting costs for storage technologies include losses valued at cost of curtailment of renewable energy. Includes $50/tonne carbon price.

4 Power costs are spread across fewer MWh, raising the cost of power that is used.

Seasonal shifting also requires large volumes of energy storage that will only be used once or twice per year. As a result, technologies such as batteries and pumped storage that are attractive for daily operation are very expensive for seasonal storage.[5]

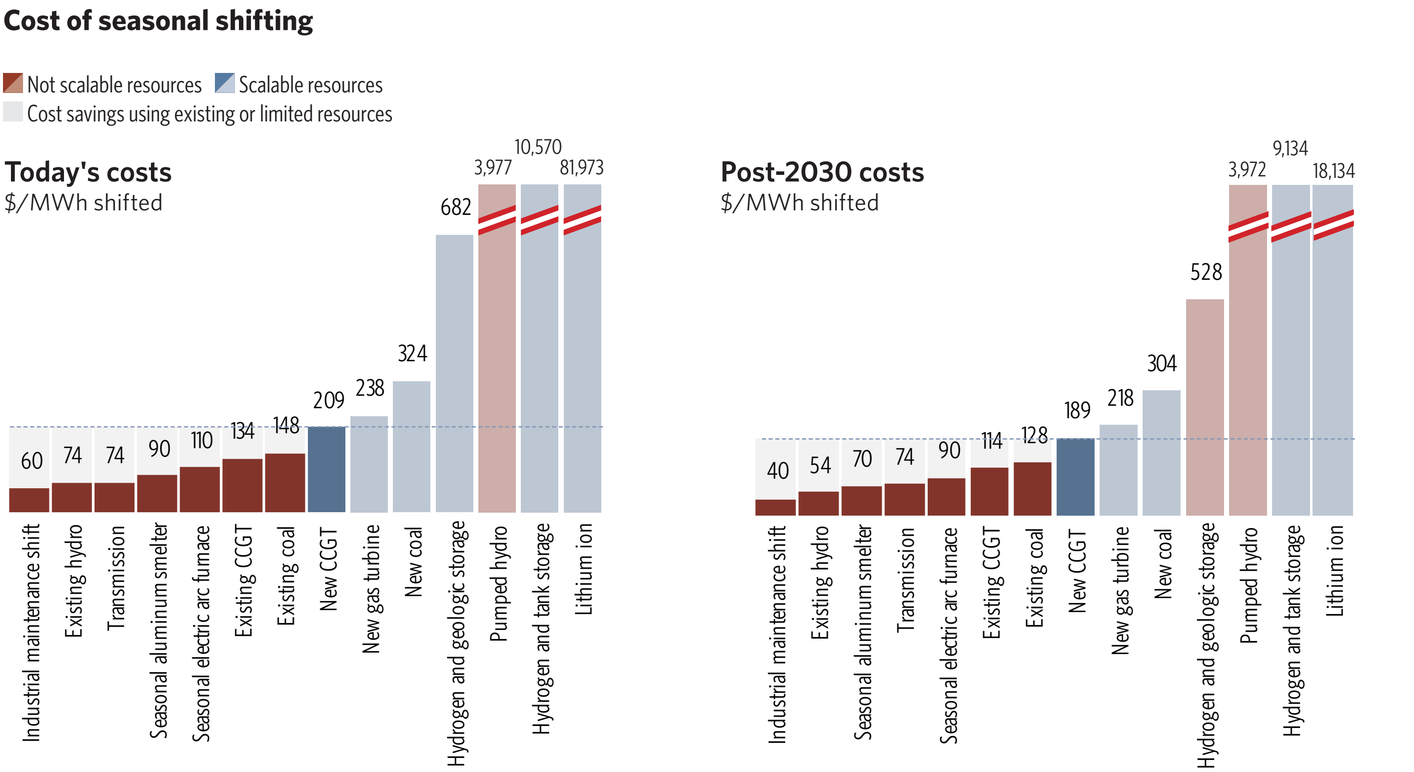
As in Figure 3.5, our analysis shows that a new gas CCGT used during periods of energy shortfall combined with curtailment of renewables during periods of excess energy will continue to be the most cost-effective source of new seasonal shifting. Once again, we note that there are many less expensive options whose availability will be region specific, including keeping existing plant available as seasonal back up, using hydro resources effectively and providing incentives to energy intensive industrial consumers to shift their annual operating, production and maintenance cycles to reduce energy demand during low resource months.

Beyond building new seasonal storage capabilities, many options exist to reduce the requirement in the first place. Using a mix of renewable energy sources with different seasonal patterns can reduce seasonal flexibility needs, though the benefits of such diversification will vary significantly from region to region. In many cases, output from hydroelectric power plants can be shifted to the weeks or months it is most needed, thereby meeting most of the seasonal flexibility needs. Creating a portfolio of options to meet daily flexibility can also help with seasonal challenges; for instance, flexibility options that contribute energy to the system will be more attractive during periods of low renewable resource, while pure shifting options will be more economic during periods of high renewable resource. Finally, building transmission systems can balance seasonality needs across regions. More significantly, transmission can help access additional seasonality capacity from other regions, such as using Nordic hydro resources to balance German seasonal electricity needs.

3.4. Integrating multiple flexibility options to minimize costs

Section 1 argued that the maximum cost of flexibility would be $30/MWh for a system where nearly all electricity was supplied by variable renewable energy with costs that we expect to see post-2030. In real

Figure 3.5: Seasonal shifting: seasonal storage requires 1-2 cycles of stored energy per year, leading to high costs for traditional storage technologies



Source: CPI Analysis. Curtailment cost for renewable energy of $60/MWh for today's costs, $40/MWh for post-2030 costs. Shifting costs for storage technologies include losses valued at cost of curtailment of renewable energy. Includes $50/tonne carbon price. Generation assumes 20% capacity factor. Storage assumes 1 cycle per year. Trasmission assumes 40% utilization and interconnected flexibility resources.

5 Pumped storage that is connected to a large existing reservoir may be more suitable for seasonal storage than facilities with only several hours of storage capacity.

OPTIMIZING INTERMITTENCY

Solar power output usually peaks, as one would expect, during the summer. Wind power is also seasonal. In Germany, for instance, wind output tends to peak in December and January, while in California it peaks in late spring or early summer and in India it peaks during the monsoon season.

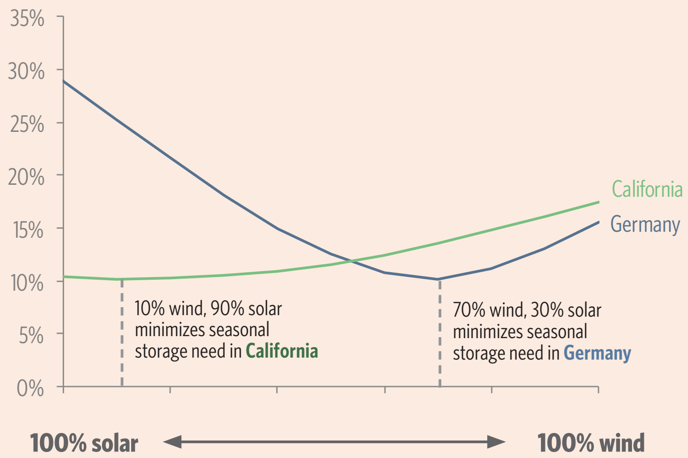
At the same time, demand follows predictable seasonal patterns, highest in summer in warm regions with higher air-conditioning demand and highest in winter where colder climates drive up heating demand. The amount of seasonal flexibility and long term shifting of demand or supply depends crucially on how these seasonal fluctuations fit together.

The chart on the right shows how the mix of variable renewable energy supply would affect the amount of seasonal storage required in California and Germany. A German energy system entirely dependent on solar generation would need the capacity to store just short of one-third of its annual energy output to meet seasonal needs. Conversely, **a mix of 70% wind and 30% solar would have the lowest seasonal storage capacity needs, requiring less than 10% of annual demand to be stored.**

In California, where both wind and solar energy are more closely aligned with seasonal demand patterns, the mix is less important, but higher levels of solar generally reduce storage needs.

For policymakers and market designers, particularly in countries with patterns similar to Germany, these patterns suggest that there will be economic benefit to the system to maintain a mix of diverse renewable energy supplies. Market mechanisms that offer price signals for different renewable energy technologies could optimize the available options for seasonal storage, and significantly reduce overall system costs. These concerns only become important at very high levels of variable renewable energy penetration, but are worthy of attention as renewable energy deployment increases.

Cumulative seasonal storage required for different shares of wind and solar
% of annual MWh



systems, we expect the costs to be much lower. The analysis assumed that no existing plant was already available to serve flexibility needs. Thus, any system with reservoir-based hydro will be able to meet some, if not all, flexibility needs at a quarter to half the costs outlined in section 1. Indeed, if there is enough hydro, the amount of wind and solar that will be built can fall, reducing the need for curtailment and cutting flexibility costs even further. Our modelling suggests that a nuclear-based system would have lower flexibility costs, particularly for seasonal flexibility, although nuclear requires significant flexibility to match near-constant output of energy from a reactor to demand that varies throughout the day. Transmission interconnections, which allow flexibility to be shared across regions, will reduce flexibility costs even further.

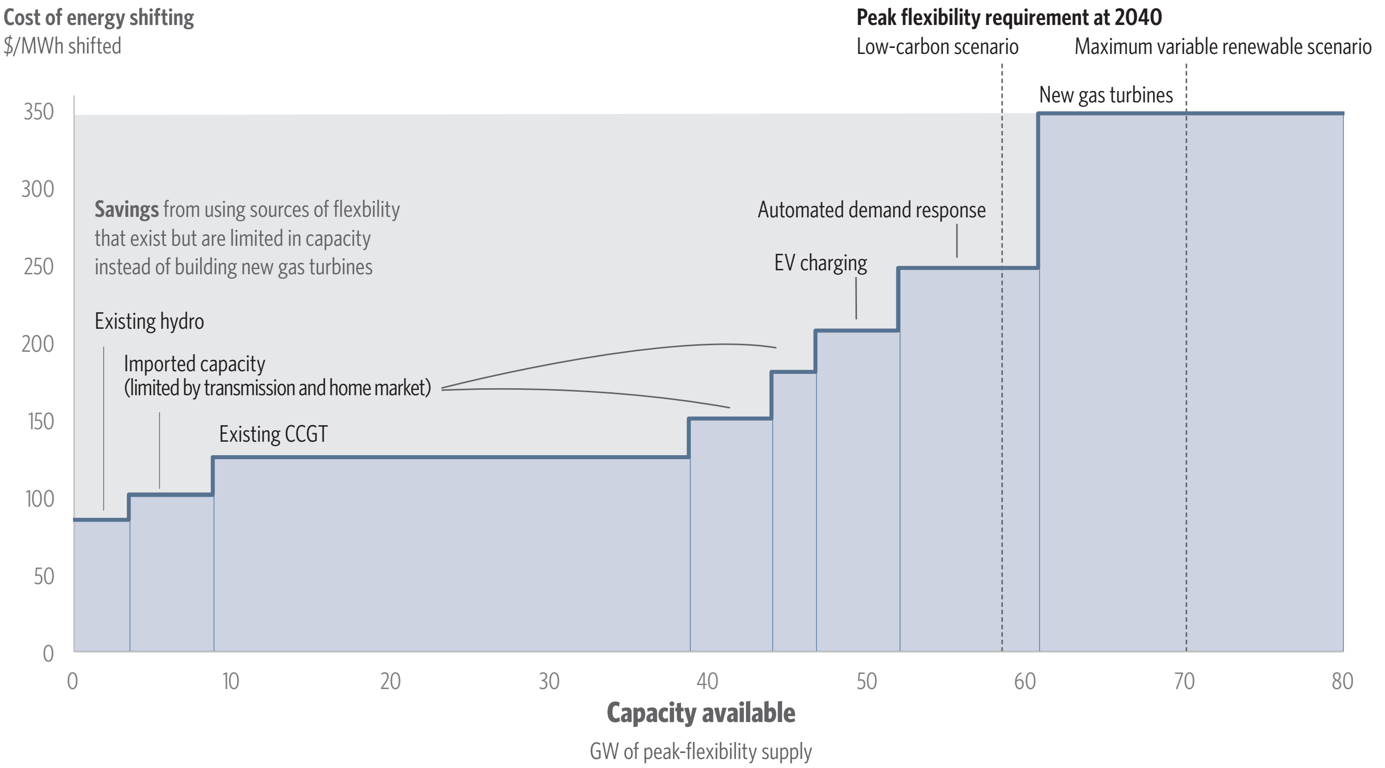
Furthermore, using existing gas plants, rather than building new ones, eliminates (at least in the short term) additional capital cost for new plant, leaving only maintenance, fuel and operating costs. In regions with a flexible gas fleet already in place, this can also cut costs for some flexibility needs by as much as half.

How much costs can fall below the generic analysis of figure 1.5 (in section 1) is very specific to a region, its demand pattern and weather, its consumers, hydroelectric resources and existing fossil fuel plant.

Calculating the cost savings is beyond the scope of this analysis and would require an integrated system model that simultaneously evaluates all flexibility needs and supply options.[6] Since we are addressing markets 25 years hence and levels of variable renewable energy generation that we are unlikely to see even in 25 years, such forecasts have enormous uncertainty. However, we can use one example to illustrate the potential to lower costs by accessing the lower cost, but limited potential, flexibility resources instead of the generic default options.

Figure 3.6 is based upon the need for daily peak flexibility in 2040 using California's system as an example. We have estimated how much of the various low-cost flexibility resources could be available at that time and at what cost. If no existing or demand-side flexibility was available, all 70GW of peak flexibility needs would be met by building a new gas turbine. The chart shows that there will be approximately 60GW of lower cost flexibility options, including existing hydro

Figure 3.6. Using the lowest-cost peak daily shifting options
Illustrative cost and supply of California peak daily shifting options in 2040



6 Similarly, calculating the emissions savings from different flexibility approaches would require detailed modelling that factors in a realistic fuel mix for the power sector and optimizes dispatch of those resources.

and CCGTs as well as demand response and electric vehicle charging. Using the lower-cost options first would reduce flexibility costs by almost one-half for the total renewable energy system, and almost 60% for the 2040 stretch low-carbon case, relative to meeting all peak intraday shifting using new GT power plants.

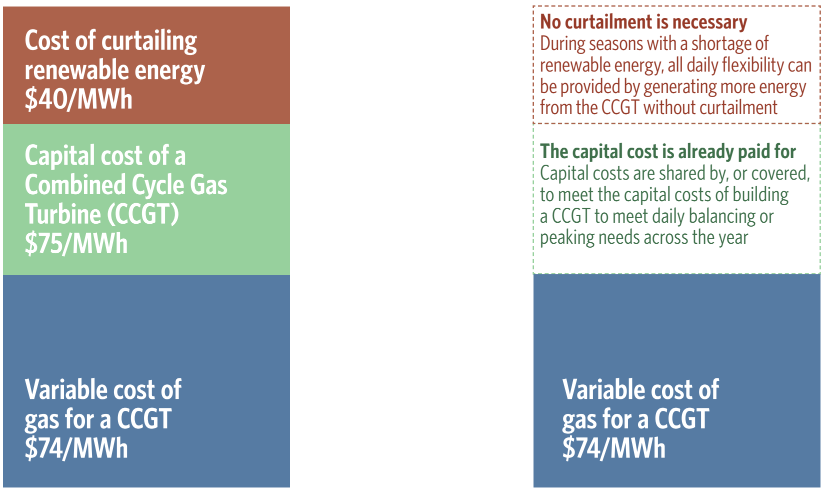
In this scenario, flexibility needed for daily 8-hour shifting could be 30% met by existing hydro resources, 10% by electric vehicle charging, 20% by demand shifting, and much of the remainder by imported hydro. However, the cost of imported hydro will depend on several variables, including home market demand, so we cannot be certain how that cost will compare with batteries, which are the lowest cost default option for 2040 daily shifting. With that set of assumptions, daily shifting would cost almost 30% less than the figures in section 1. Similarly, seasonal flexibility is also likely to be as little as half of the default cost, perhaps less. Note that the daily shifting needs described overleaf can be met through building very few, and perhaps no, new GTs, resulting in a large savings in capital costs.

3.5. Sharing flexibility options across different needs to lower costs

Another factor in lowering costs is the ability to use one asset to create more than one type of flexibility. For example, a system could build gas turbines or CCGTs to meet peak daily shifting needs, but once built, these resources could also be used to meet seasonal flexibility, as outlined below:

- CCGTs meet flexibility needs during seasons where there is a shortage of renewable energy, but batteries are used during seasons with excess renewable energy. Since the capital cost is already accounted for in meeting daily balancing needs, seasonal flexibility will only face the variable costs of existing CCGTs.
- During shortage seasons, there will be no need to curtail renewable energy, as more energy is needed for the system, so costs for seasonal balancing fall further.
- Thus, sharing costs between flexibility options is likely to reduce total costs and may also lead

Figure 3.7: Assets and technologies may serve more than one flexibility need, which will change the relative cost



Stand-alone cost of providing seasonal balancing with a CCGT when all daily balancing needs are met without CCGTs

Cost of providing seasonal balancing with a CCGT when CCGT capital and curtailment costs are avoided by using a CCGT 8 hours a day during low renewable seasons to meet both seasonal and daily flexibility needs in the winter to a different mix of flexibility options than meeting every need individually.

Our analysis of the maximum system flexibility costs (Figure 1.5) includes sharing of costs between intraday shifting and seasonal flexibility needs, assuming both are provided by the same gas-fired power plants plus curtailment of intermittent renewable energy. [7]

3.6. Summary of flexibility options

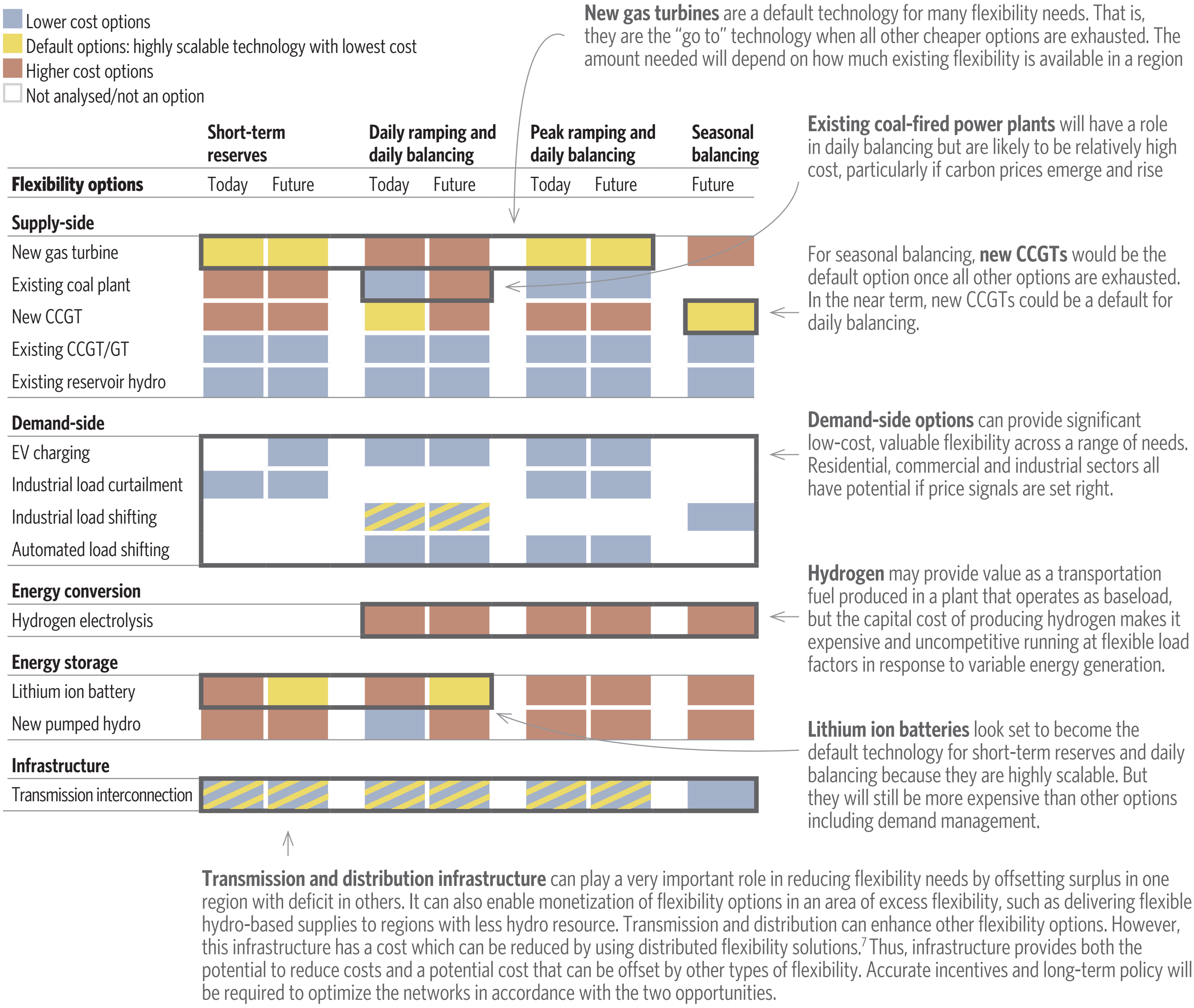
Figure 3.8 compares various technology options against specific flexibility needs, using costs today and in the future. Red denotes those options that are, or will be, uneconomic as a source of that type of flexibility.

Yellow denotes the default supply of that flexibility, that is, the lowest cost source of flexibility that can be developed to meet total needs when all cheaper sources are exhausted.

These technologies were used in our estimate of the maximum total renewable energy driven system cost including flexibility, as laid out in section 1. Green denotes low-cost options that will reduce the cost of overall flexibility and, therefore, should be developed to the greatest extent possible.

As in Figure 3.8, several important messages emerge about technologies and option selection.

Figure 3.8: Comparison of flexibility options



7 *Economics of Demand Flexibility* (Rocky Mountain Institute, 2015) estimates that distributed renewable generation combined with distributed flexibility resources such as batteries could reduce total infrastructure investment by $9bn annually in the US (around $27 per kW-year of peak demand reduction).

4. Evaluating flexibility needs in four regions: a brief look at California, Germany, Maharashtra and the Nordic countries

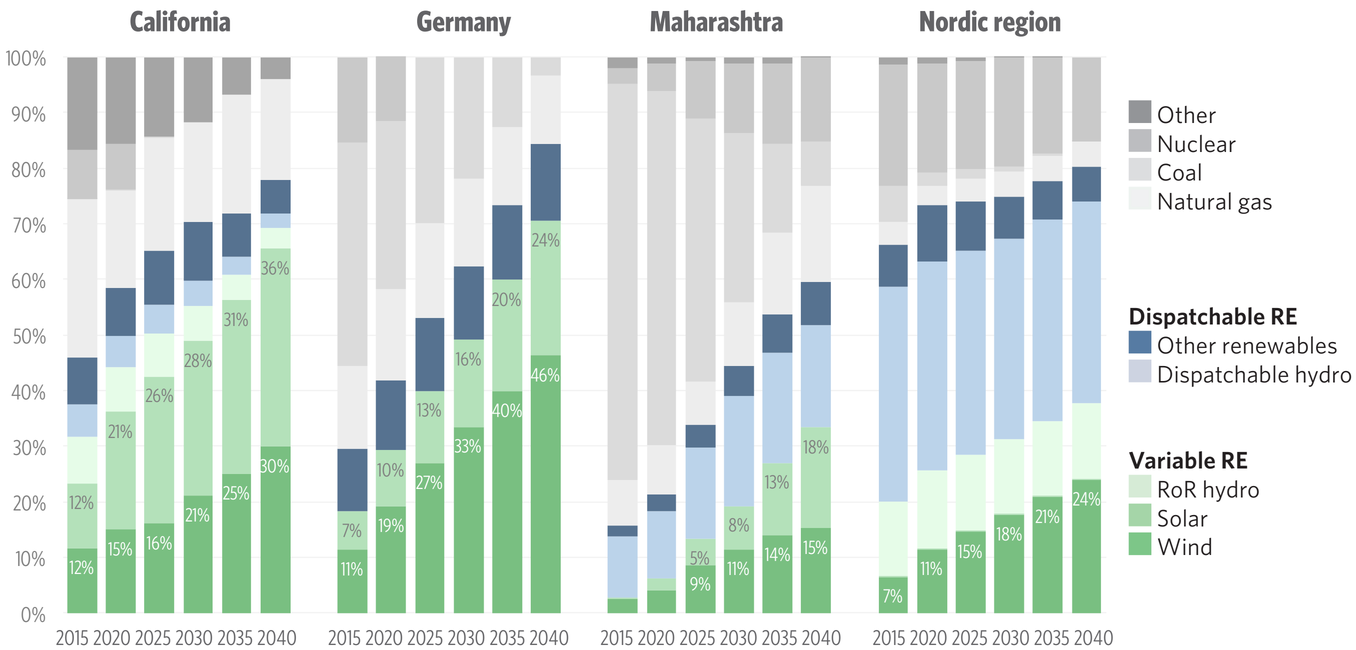
California, Germany and the Nordic region all differ in terms of access to resources and deployment rates of certain technologies. But they all have the potential for somewhat flat demand growth. Each region is a leader in the deployment of renewable energy and will be among the first to exceed 30%-50% or even higher shares of wind and solar. Maharashtra also has ambitious renewable energy deployment with aggressive renewables targets set by government (100GW of solar by 2022 as part of India's National Solar Mission goals) and high demand growth in a region where the grid has not yet been extended to provide energy access to all consumers. Maharashtra illustrates the challenges of managing flexibility alongside rapid growth rates for renewable energy in emerging markets.

Each region's experience will be invaluable in transferring knowledge to other regions. **In all of the regions we have studied, flexibility needs are reasonably covered for the near term, even at ambitious levels of deployment.** The possible exception is ramping in Maharashtra, where growing demand, rather than renewable energy supply, is straining the system. From 10 years onward, the need for new flexibility sources grows across all regions, in line with continuing growth in renewable energy supply. Interday and intraday balancing in particular are expected to need additional support, while a near-total variable renewable energy system would require significant investment, albeit one that is adjusted for hydroelectric supply, demand response and other available flexibility resources.

Flexibility requirements for an electricity system with a large share of intermittent renewable energy depend on several factors, including:

- Weather patterns and their impact on demand and renewable energy production.
- Consumer behaviour, equipment and economic activity.
- Hydroelectric power plant availability.
- Infrastructure and interconnections with neighbouring systems.
- Existing plant capabilities and retirement plans.
- Market structure.
- Economic development.
- Renewable energy ambitions.

Figure 4.1. Potential build-out of renewable energy in the four regions



Sources: California – E3 Pathways Scenarios (2016) – "Other" primarily combined heat and power (CHP); Germany – Nitsch Szenario (2013); Maharashtra – Based on India-wide projection from IEA as a proxy (2015); Nordic region – IEA Nordic Energy Technology Perspectives, Carbon Neutral Scenario (2016)

Table 4.1: Factors that influence flexibility requirements

Weather patterns	Regions with colder winters will have demand peaks in the winter; warm climates will have peaks in the summer. Temperature and weather variation will play an important role in setting electricity demand to which the supply must be adapted. To some extent, wind or solar resources may follow weather-correlated electricity demand, as is the case with solar energy and air conditioning needs. In other cases, there may be no relationship.
Consumer behaviour	Economies with a heavy industrial base will tend to have more constant energy demand, while consumer and service economy demand will tend to have greater variation throughout the day and year. Some consumers are more effectively incentivised (or in some cases, simply compelled) to adjust demand to changes in electricity prices or supply and are better able to provide flexibility to the grid.
Hydroelectric power plant	Existing reservoir-based hydro or pumped storage are among the lowest cost and most effective providers of flexibility services ranging from load following and reserves to seasonal flexibility. Systems with access to high levels of hydro should be able to absorb very high levels of renewables and have additional value in supplying seasonal flexibility. New reservoir hydro or pumped storage can be expensive, but there are site-specific opportunities for new cost-effective investments.
Infrastructure and interconnections	Flexibility from hydro or other sources can be exported to regions that are in short supply, provided the infrastructure, including transmission, is adequate. Transmission can also rationalize the supply of flexibility across a larger region.
Existing power plant and retirement	As renewable energy grows in most regions over the next 20 years, existing plant will be asked to provide more flexibility to the system. How these plants are operated, and at what rate they are retired, will be key factors.
Market structure	Market structure can make it easier to access flexibility, either from generators or consumers. Product design, gate closure times, eligibility requirements, and many other factors can influence the degree to which market participants on both the demand and supply side can develop/participate in solutions to provide more flexibility.
Economic development	Economic development can affect infrastructure as well as consumer characteristics. Rapidly developing countries will need to develop more flexibility in a system where demand is growing rapidly, which can be a challenge, as well as an opportunity to build greater flexibility into the system from the beginning.
Renewable energy production	The nature of the renewable energy supply itself is important, including how predictable the supply is, how coincident it is with demand, and how each of the potential sources are correlated in terms of generation. More important, current levels of intermittent renewable energy supply and the speed at which additional capacity is likely to be added will shape the costs of adding flexibility.

All four regions have ambitious renewable energy targets to help meet their decarbonisation goals. California and Germany are aiming for electricity systems with 60%-70% variable renewable energy by 2040, with total renewable energy closer to 80%. For its part, India (including Maharashtra) could see an electricity system with over 30% variable and 50% total renewables. And the Nordic region is likely to be nearly all low-carbon generation, with 80% from renewables and over 30% from variable renewables.

In addition, the four regions provide a good mix of the various factors affecting renewable energy integration. California is a summer peaking system driven by cooling loads, while Germany is a winter peaking system. Solar and wind generation are being deployed in large quantities in both systems, though capacity factors (ie, maximum potential generation), especially of solar, differ significantly by region. California and Germany have well diversified legacy systems, including access to hydro and nuclear, though the latter resource is slated for retirement in both systems. Well-developed energy markets are in place in both regions, though significant differences do exist, particularly with respect to demand response and locational pricing.

In Maharashtra, we find a very rapidly growing market with very ambitious renewable energy expansion plans, but relatively low penetrations to date. Some types of flexibility are already in short supply, as the power industry struggles to keep up with growing and shifting demand patterns. To some extent, consumers are already accustomed to providing flexibility services for themselves, for example with back-up diesel generation, so there may be opportunities to develop new models for providing reliable supply that rely less on central resources. Financing, markets and regulation are often more dynamic as well, offering potential opportunities for leap-frogging to new models.

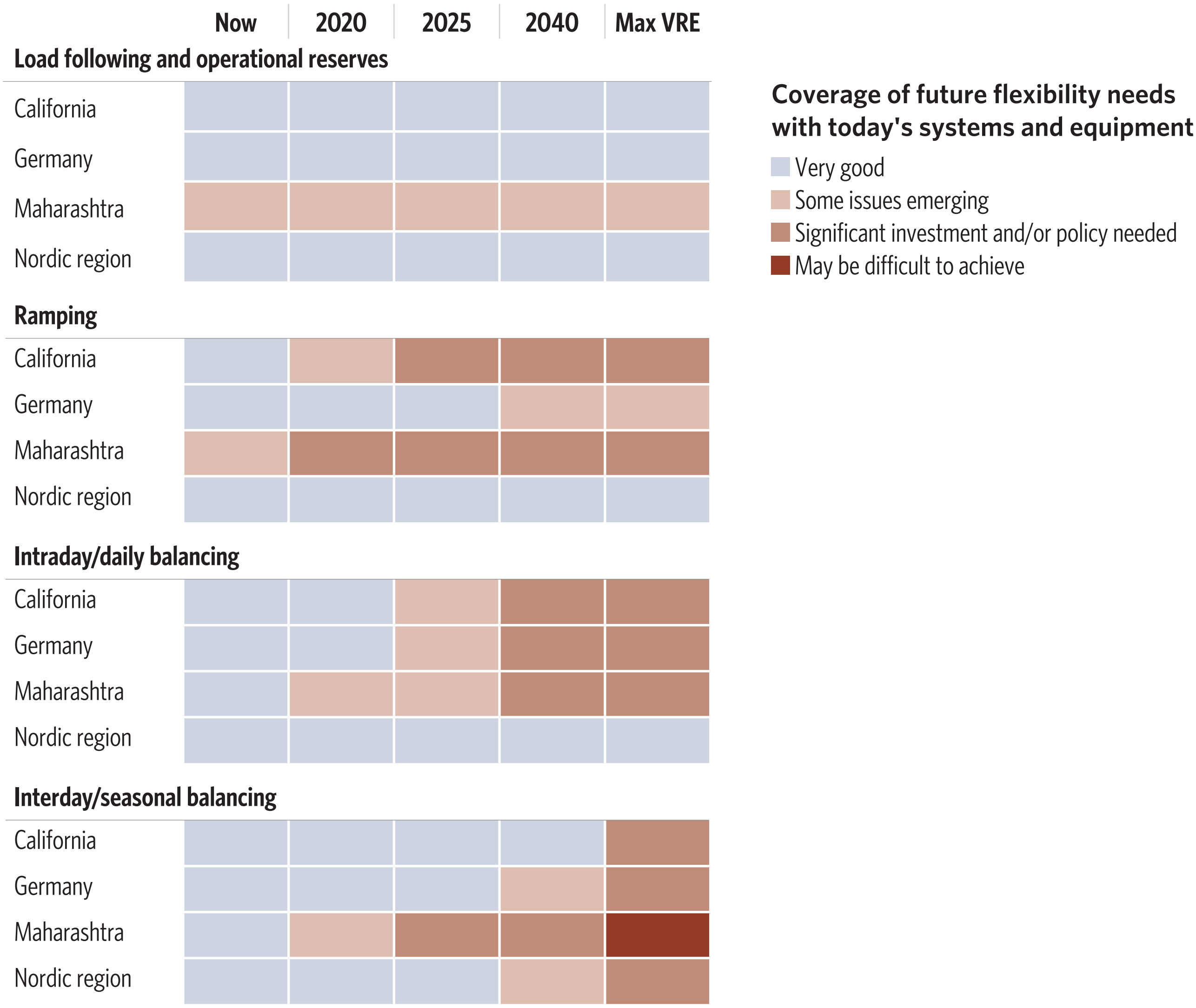
Finally, the Nordic system illustrates a different set of challenges. The key question is whether to use ample hydro resources to provide flexibility to surrounding systems, support the region's own wind generation, or decrease pressure on consumers to adapt their demand patterns. Beyond hydro, the Nordic system has other potential sources of flexibility, particularly in energy-intensive industries, but only if the economics prove attractive.

Figure 4.2. Key characteristics of selected regions relevant to variable renewable energy

	California	Germany	Maharashtra	Nordic region
Economic development	Advanced, diversified economy	Advanced, diversified economy	Emerging market still expanding energy access	Advanced, diversified economy
Renewable energy ambitions	High 50% RE by 2030	High 50% RE by 2030	Medium India-wide solar (100GW) and wind (60GW) missions by 2022, ~18% RE	High (hydro-based) Varies by country, supporting carbon-neutrality by 2050
Hydro capacity	Medium	Medium	Low	High
Interconnections	Med/high Southwestern coal, nuclear and solar, and northwestern hydro	High Continental Europe and Nordic countries	Medium Neighbouring states and transmission companies	Medium/high Continental Europe and future large expansions to UK and EU
Solar resource	High	Medium	High	Low
Demand profile (Dark is summer peaking)	Summer peak driven by high AC load	Winter peak driven by heating load	Flat load profile, daily ramps driven by residential and commercial lighting and AC	Winter peak driven by heating load
Seasonal patterns (Dark is summer peaking)	Wind and solar highest in spring / early summer	Wind peaks in winter driven by North sea storms, solar peaks in summer	Wind concentrated in May-Oct monsoon, solar consistent throughout year	Wind output peaks in winter
Market structure (Dark denotes competitive generation)	Regulated utilities with competitive wholesale market	Regulated transmission and distribution, competitive generation	Regulated retail with mix of regulated and competitive generation	Regulated transmission and distribution, competitive generation through Nord Pool
Existing plant capabilities (Dark is coal/gas based)	Flexible gas fleet	Significant lignite / coal generation low flexibility	Coal-based fleet	Hydro-based mix, with nuclear and thermal

As shown in Figure 4.3, in each of these regions flexibility needs are reasonably covered for the near term, even at ambitious levels of renewables deployment. The possible exception is ramping in Maharashtra, where growing demand, rather than renewable energy supply, is straining the system. From 10 years onward, the need for new flexibility sources grows across all regions, in line with continuing growth in renewable energy supply. In particular, interday and intraday balancing are expected to need additional support, while a maximum variable renewable energy scenario approaching 100% of energy supply would require significant investment, but adjusted for hydroelectric supply, demand response and other available flexibility resources.

Figure 4.3: Flexibility needs are well covered over the next 10 years in most regions, but daily and seasonal balancing will require more flexibility at very high renewable generation



4.1. California

4.1.1 OVERVIEW

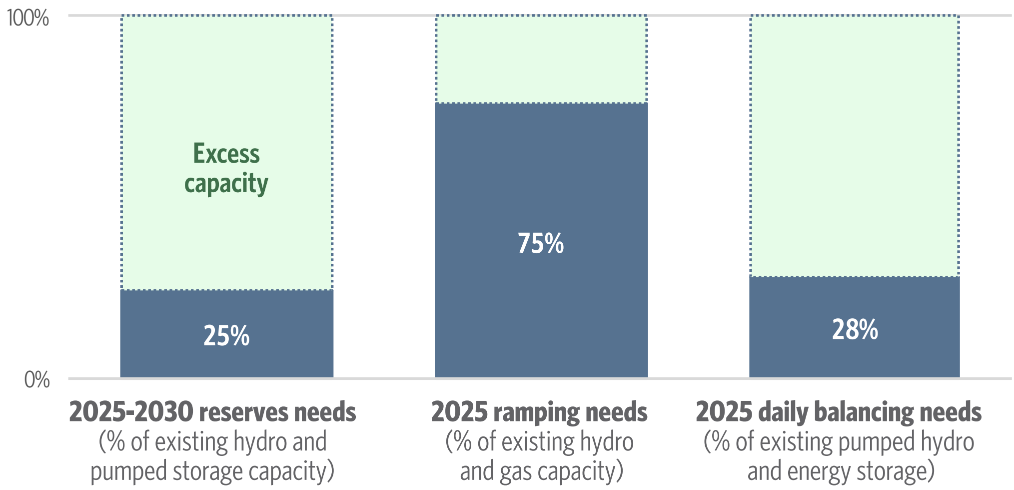
California is well covered by existing flexibility resources across all flexibility needs for the next 10 years. Ramping is the most pressing concern, while seasonal storage (not included in Figure 4.4) would have an impact only with much higher levels of variable renewables.

Of all the regions in this study, California is—and will likely remain—most dependent on solar to meet the generation needs of a low-carbon power sector. By 2040, utility- and residential-scale solar, is expected to supply 36% of the state's electricity, while wind at 30%, should constitute the second-largest resource. Integration of rooftop solar is a major concern, particularly with respect to ramping needs.

Table 4.2: Summary of factors affecting California's flexibility needs

Renewable energy goals	Currently, 24% of electricity in California is produced by intermittent renewables, with a nearly even split between solar and wind. Aggressive goals to reach 50% renewable energy by 2030 are likely to include an increase of wind and solar to 21% and 28%, respectively.
Demand growth and patterns	California has a peak summer demand of over 50GW. Summer peaking is a good fit for the state's abundant solar resources. Despite a rapidly growing population and economy, electricity demand has been growing at only 0.5% a year, but the growth rate is expected to nearly double for the next decade.[8]
Existing plant and retirements	In-state hydroelectric generation provides between 7-20% of annual electricity production, providing significant flexibility. Natural gas, nuclear and imports provide the bulk of the remaining generation, although the state's nuclear capacity is proposed for elimination in 2025.
Interconnections and imports	California imports significant quantities of hydroelectric generation from the northwest, and has interconnections to Nevada and Arizona. While the hydro provides additional flexibility, there are questions about how that value is shared.

Figure 4.4: Existing resources available to meet California's flexibility needs by 2025



8 *California Energy Demand 2016-2026, Revised Electricity Forecast*, California Energy Commission (2016).

4.1.2 LOAD FOLLOWING AND SPINNING RESERVES / SHORT-TERM RESERVES

The California Independent System Operator (CAISO) has responsibility for meeting short-term flexibility needs. Short-term reserve requirements are highly contingent on emergency events, such as the loss of a transmission line or power plant. Since neither power plant size nor individual transmission line size is likely to grow, demand for contingency reserves should stay flat. Control reserves (eg, voltage and frequency support) are expected to grow only slightly (5%) by 2030. Demand for load following reserves will likely see more significant—though still modest—growth (25%), as hour-ahead forecast errors increase.

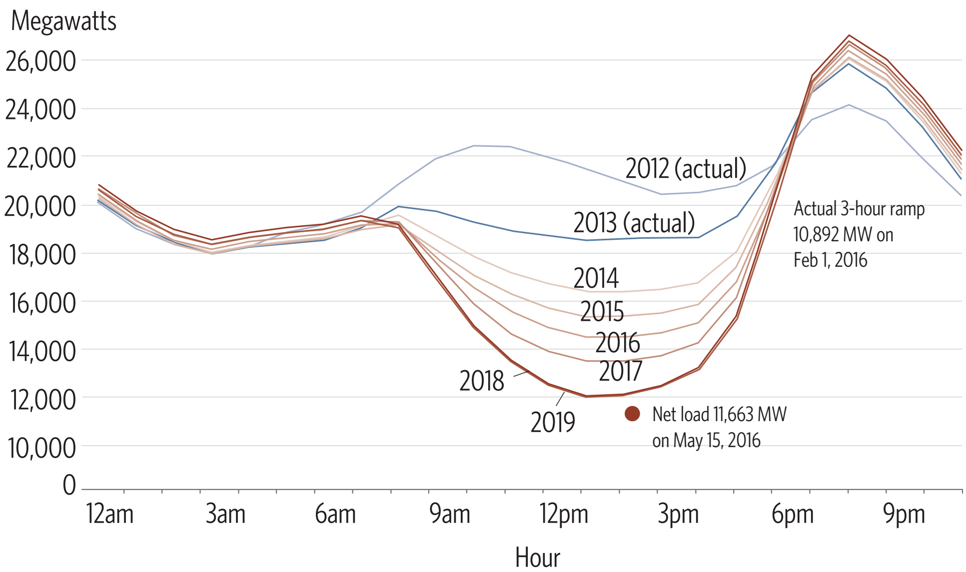
Along with existing suppliers of reserves, new types of resources (eg, storage, fast-responding demand, and even wind and solar equipped with the appropriate power electronics and controls) should be readily able to meet these flexibility needs. Just what mix will be most cost-effective is difficult to predict. What is certain is market structures will need to be updated to explicitly value all services (eg, compensation for provision of voltage support) at levels that reflect their flexibility ("all-source valuation").

4.1.3 RAMPING

Evening ramping is already emerging as a concern for California's system and is likely to be an ongoing challenge. Residual load in the Golden State peaks on spring and autumn evenings, when air conditioning is still in high use while solar generation goes offline. In summer, solar generation persists into the evening hours and is better correlated with load. The three-hour evening ramp, falling roughly between 5pm and 8pm, is currently 6GW on average days but could more than double by 2020, topping 13GW. On the most severe day in 2030, three-hour ramps could reach 60% of annual peak total load; by 2050, this figure could hit 80%. The prevalence of behind-the-meter residential solar, which today cannot be dispatched or even accurately measured by the system operator, increases the ramping uncertainty.

The ramping challenge is well illustrated by the "neck" of the so-called "duck curve."

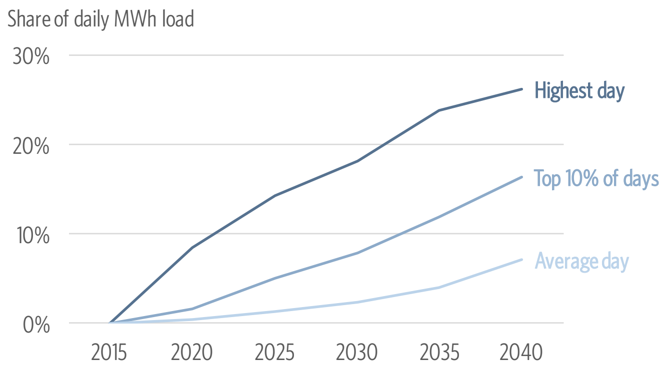
Figure 4.5: California's "duck" curve – net load predictions through 2019



What the Duck Curve Tells us about Managing a Green Grid, CAISO (2016)

4.1.4 DAILY BALANCING

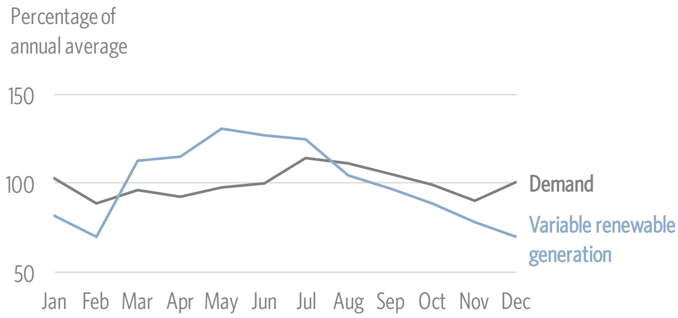
Figure 4.6: California daily energy shifting need



The projected deepening of the duck's "belly" illustrates another key flexibility concern—the increased likelihood of over-generation when solar output and "must-run" conventional generation combine to exceed demand at midday. Viewed from midday to evening, the residual load curve also neatly illustrates the relationship between the daily balancing and ramping challenges. As renewables provide more and more generation during the day, the pressure grows to reduce conventional generation to avoid curtailing carbon-free (and lowest-variable-cost) production. But this effort to displace conventional generation when there is ample renewable generation only steepens the ramp facing the system when solar goes offline. CPI analysis indicates that a California system could require a shift of 30% of daily energy demand (MWh) to avoid curtailment on the most challenging day by 2040; even an average day in the year can expect daily shifts exceeding 5% of daily energy demand.

4.1.5 SEASONAL BALANCING

Figure 4.7: California seasonal renewable resource and demand profile

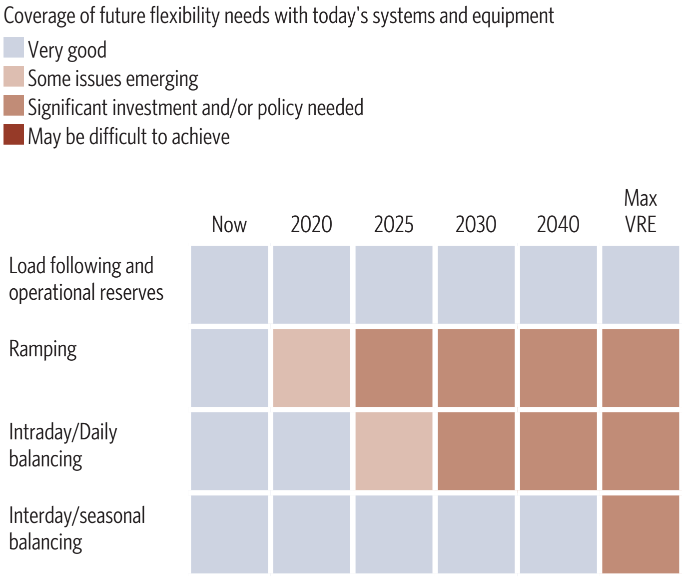


Energy production from wind and solar peak in California in May and June, but demand is highest from July through September. A system running solely on variable wind and solar would need to store spring renewable energy for fall and winter use (see figure 4.7). At levels of variable renewable energy expected by 2040, there will be few days where wind and solar output exceeds demand over the whole day, and in a strict sense there will be no need for seasonal shifts in energy. However, increasing levels of wind and solar will change seasonal patterns of energy needed from dispatchable sources. Only at very high levels of variable renewable energy would significant energy shifting from one time of year to another be required. Figure 4.13 shows how much seasonal storage California would need if all of its electricity were produced by wind, solar, or a combination of the two. The figure shows that at optimized shares of wind and solar, California would need seasonal storage equivalent to 10% of annual demand. By comparison, California currently produces 7-20% of its energy through in-state hydro, much of which can be used for seasonal storage.

California's solar and wind generation are seasonally correlated with output (in contrast to Germany's, as shown in figure 4.12), so optimization of the resource mix can do less to flatten the annual production profile.

4.1.6 INSTITUTIONAL ISSUES AND SUMMARY

Figure 4.8: Evaluation of California flexibility needs



Overall, the biggest issue facing California is the development of ramping capacity. This need will emerge in the short term and intensify. As shown in Figure 4.8, we believe that with the ongoing policy and technology developments, California is well covered for the load-following and contingency reserve requirements into the foreseeable future.

Intraday flexibility, or daily balancing, and interday flexibility, or seasonal balancing, are issues that California will face as it extends its renewable capacity, especially from the 2040s.

Many market, technology and regulatory solutions can help reduce the cost of all of these flexibility requirements, as we see in sections 3 and 5. California is pursuing a broad range of flexibility solutions, including system operation and market reforms, expanded storage and demand response mandates, and rate reform. However, many flexibility solutions, particularly for daily and seasonal balancing, may take decades to develop and deploy. The California Public Utility Commission (CPUC)'s Long Term Procurement Plan (LTPP) is a biannual undertaking that assesses system needs and makes procurement decisions looking out 10 years. While such medium-term planning is valuable, a complementary effort to plan over longer time horizons (and with broader geographical scope) is advisable.

Summary of institutional issues:

- **System/market operations**: California's utilities must demonstrate the procurement of generation capacity in excess of peak forecasted demand and identify resources by their level of flexibility. Since 2014, the system operator, CAISO has participated in an Energy Imbalance Market (EIM) that allows sharing of reserves with other balancing areas in the Western Interconnection. CAISO just introduced a flexible ramping product to remunerate resources that can provide "standby" ramping capacity; both generating and non-generating resources (eg, storage) are eligible to participate.
- **Storage and demand response:** As required by law, California's major utilities have begun procuring 1.3GW of storage, mostly at the transmission and distribution levels.[9] Eligible investments must contribute to the integration of renewable energy sources; grid optimization, including peak load reduction; or reduction of GHG emissions. California has also greatly expanded its DR efforts, introducing opportunities for wholesale market participation (the Demand Response Auction Mechanism, or DRAM) that will complement more traditional load-modifying DR contracted by utilities.
- **Tariffs:** In 2015, the CPUC adopted a major revision of retail rates that includes a requirement that utilities transition customers to default time-of-use rates by 2019. Properly designed time-varying rates should incentivize consumers to shift load to reduce ramping and daily balancing needs. In 2016, the CPUC reaffirmed net metering at the full retail rate for residential solar customers; however, net metering customers will be required to use the TOU rates.[10]

9 CPUC Decision Adopting Energy Storage Procurement Framework, R. 10-12-007, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M078/K929/78929853.pdf.

10 California's NEM 2.0 Decision Keeps Retail Rate for Rooftop Solar, Adds Time-of-Use, Greentech Media (November 2016): https://www.greentechmedia.com/articles/read/Californias-Net-Metering-2.0-Decision-Rooftop-Solar-to-Keep-Retail-Payme.

4.2. Germany

4.2.1 OVERVIEW

Germany is also well covered by existing flexibility resources across all flexibility needs for the next 10 years as variable renewable energy deployment increases. With wind as the primary renewable, ramping needs will be less steep than in California, but additional flexible resources will be required as variable renewables exceed 50% of generation after 2030.

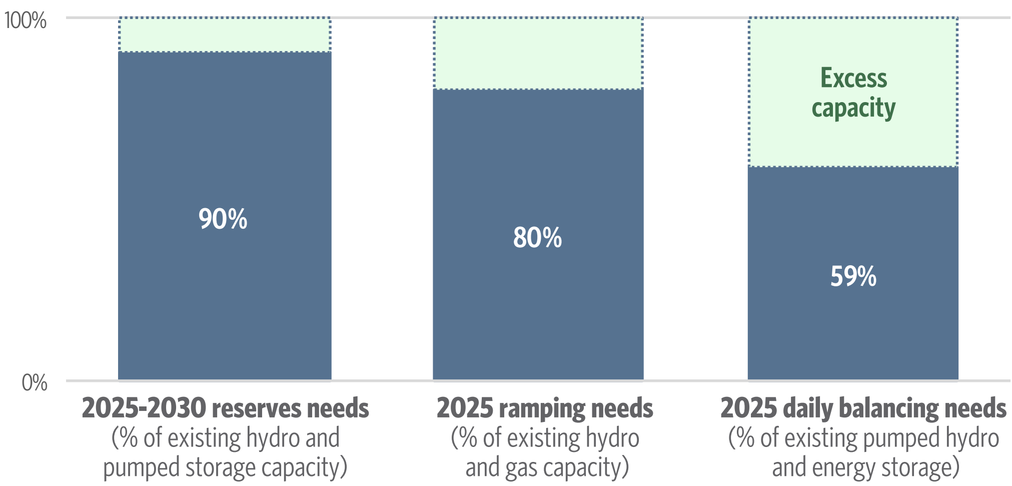
Daily balancing and seasonal shifting (not included in Figure 4.9) will also cause concern at high levels of variable renewables.

Transmission constraints have been exacerbated by oversupply caused by flat demand and the rapid deployment of renewables in a legacy system with ample capacity. The north of the country is home to a disproportionate share of onshore wind generation, and offshore projects are further taxing the grid in this region. Transmission from the north to load concentrations in the south and southwest is often congested, and proposals to expand north-south transmission using above-ground lines have been hampered by grassroots opposition. The 2015 Federal Requirement Plan Law (*Bundesbedarfsplangesetz*) contains measures to expand the transmission network, including a requirement that all new high voltage DC lines be subterranean.

Table 4.3: Summary of factors affecting Germany's flexibility needs

Renewable energy goals	In 2015, 18% of electricity in Germany was produced by intermittent renewables, with approximately 60% coming from wind and 40% from solar. Current law targets the generation of at least 55% of the country's electricity with renewables by 2035; wind generation will account for two-thirds of intermittent generation and solar the remainder.
Demand growth and patterns	Germany has a peak demand of more than 80GW. The winter peak is a good fit for a system that will become increasingly reliant on wind as its largest generation source. Germany's population is expected to decrease, and electricity demand is expected decline in absolute terms (by 6% from 2011 to 2030) even as its share of final energy consumption grows (from 21% in 2011 to 24% in 2030).[11]
Existing plant and retirements	Domestic hydroelectric generation provided under 3% of electricity production in 2015. Natural gas (9.5%), nuclear (14.2%) and coal (42.1%) accounted for just about all non-renewable generation in the same year. The country's nuclear phase-out is set to be completed by 2022.
Interconnections and imports	Germany has interconnections with Austria, Switzerland, the Czech Republic, Denmark, France, Luxembourg, the Netherlands, Poland and Sweden. As of 2012, interconnection capacity exceeded 20GW.[3] Germany is now unequivocally a net exporter of electricity; exports of surplus renewables, often at very low wholesale prices, have contributed significantly to this trade balance.[12]

Figure 4.9: Existing resources available to meet Germany's flexibility needs by 2025



11 *Entwicklung der Energiemärkte - Energiereferenzprognose, Projekt Nr. 57/12 des Bundesministeriums für Wirtschaft und Technologie*, EWI (2014).

12 *Report on the German Power System*, Agora (2015).

4.2.2 LOAD FOLLOWING AND SPINNING RESERVES / SHORT-TERM RESERVES

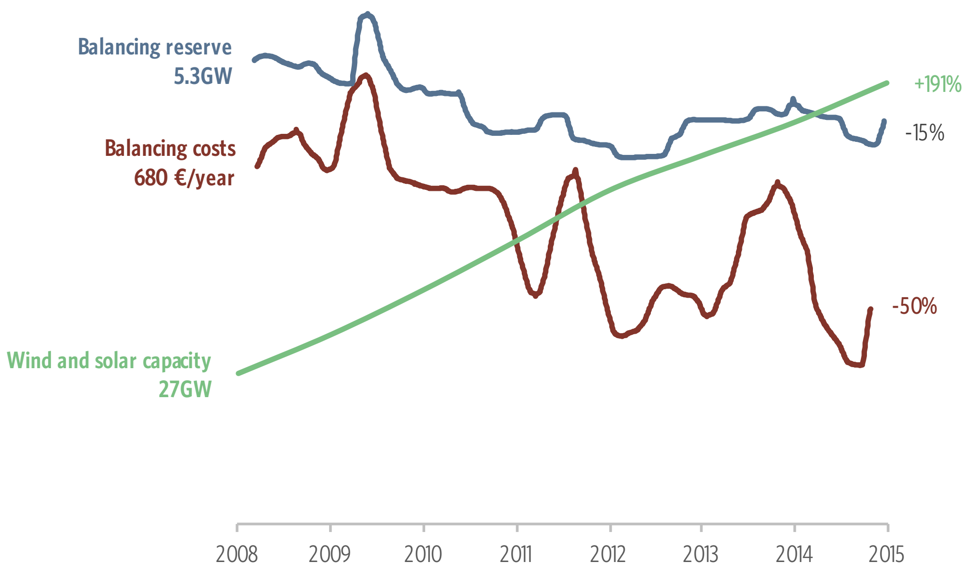
As in California, demand for voltage and frequency services (primary reserves) is not expected to grow, while secondary and tertiary ("minute") reserves—ie, joint load-following and contingency reserve categories distinguished by reaction time—will edge upward to accommodate the forecast errors that accompany variable generation. Prices for secondary and tertiary reserves have decreased markedly in recent years, in large part because of generation oversupply. [13]

In the long-term, new methodologies for handling reserves should help to limit increases in reserve needs. For instance, calculating reserves requirements dynamically based on system conditions and near-term forecast errors would yield much lower reserve requirements. Shorter lead times for procurement and more temporal granularity for procured amounts will, for instance, facilitate participation by renewables; such changes are currently under consideration by the Federal Network Agency (*Bundesnetzagentur*). The agency has also been authorized to pass through to balancing energy charges at least part of the procurement costs for reserves; previously these costs were spread across all users through network charges.

4.2.3 RAMPING

Solar is expected to supply less than one quarter of Germany's energy needs by 2040, but the energy produced will be during the daytime hours and especially in spring, summer and autumn months. As a result, Germany's ramping needs during some parts of the year will be similar to those in solar-rich regions like California. Currently, three-hour ramping needs on an average day in Germany hover around 20% of peak generation capacity but up to to 30% on the most challenging day. By 2040, three-hour ramps on an average day will climb to 40% of peak generation capacity, and soar to nearly 70% on the most challenging day.

Figure 4.10: Developments in German renewable capacity, balancing reserve volumes and balancing costs

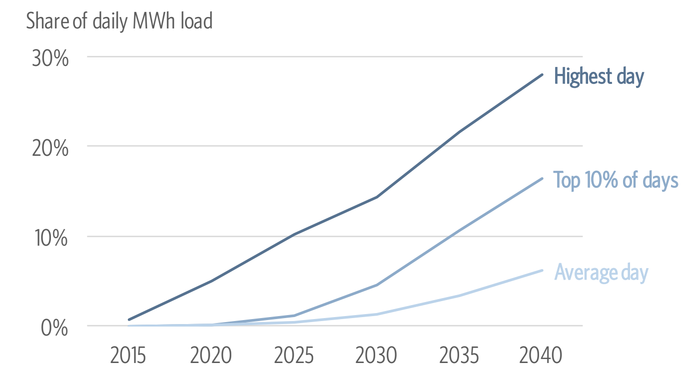


Source: Balancing Power and Variable Renewables: Three Links (Hirth and Ziegenhagen, 2015)

13 *Balancing Power and Variable Renewables: Three Links*, Renewable & Sustainable Energy Reviews, Lion Hirth and Inka Ziegenhagen (2015).

4.2.4 DAILY BALANCING

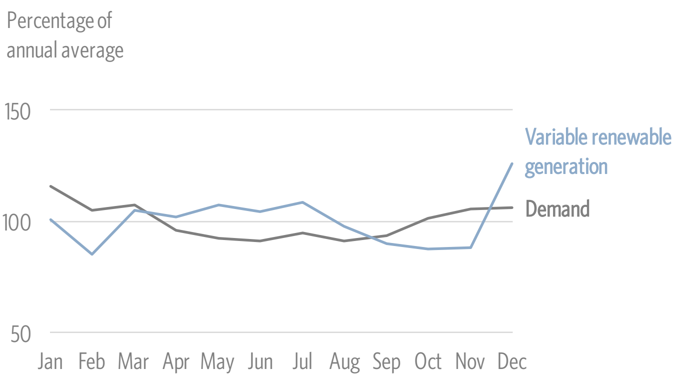
Figure 4.11: Germany's daily shifting needs over time



On sunny spring and summer days as well as on exceptionally windy winter ones, renewable generation will often exceed demand for multiple hours. On occasion, daily renewable generation will outstrip total daily demand, implying the potential, if not the need, for interday shifting. By 2030, surplus daily generation could reach 15GWh, against daily demand of 1.4TWh. By 2040, however, the daily surplus could well grow to over 250GWh, on the order of one-fifth of daily demand.

4.2.5 SEASONAL BALANCING

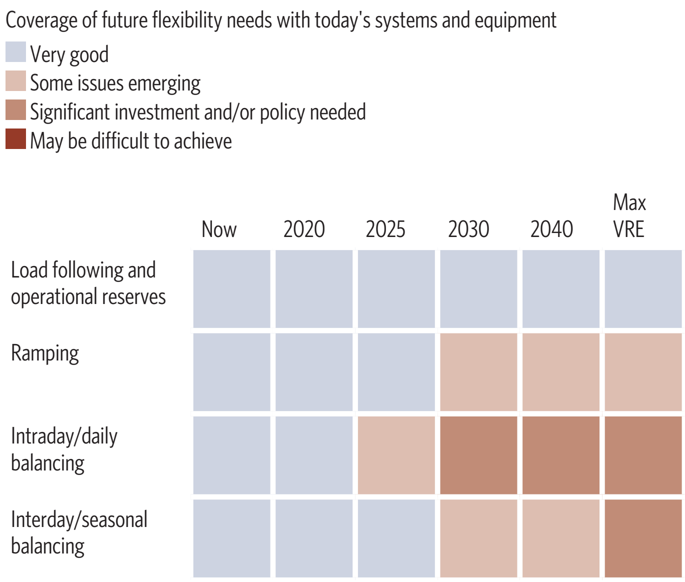
Figure 4.12: Germany seasonal renewable resource and demand profile



German power demand typically peaks on a December evening, driven by heating and lighting loads. This winter peak coincides with the shortest days of the year, when solar-dependent generation sources are least productive. Overall, Germany's low-carbon power system will rely primarily on wind generation, which is expected to deliver 46% of production in 2040, almost double the amount from solar. And while wind generation is not constant across the day, it does not predictably reduce to zero for extended stretches, as solar does during hours of darkness. As such, an optimized German portfolio of 30% solar and 70% wind resources has greater potential to provide consistent levels of generation throughout the year (see Optimizing Intermittency, page 30). Even at extremely high renewable penetrations (70%+), CPI analysis does not foresee month-long periods of overgeneration occuring in Germany.

4.2.6 INSTITUTIONAL ISSUES AND SUMMARY

Figure 4.13: Evaluation of Germany flexibility needs



The combination of increasing variable renewables (enjoying significant incentives and market privileges) and relatively inflexible legacy generation has depressed average wholesale power prices in recent years, even pushing them into negative territory for 64 hours in 2014 and 126 hours in 2015.[14] Increasingly often, German baseload plants "must run" even when it is uneconomic so that they can provide services (above all, reactive power) and reserves and be available for market participation when demand is required.[15] In turn, exports of power from Germany to its neighbours have risen to record highs.[16] To account for grid congestion and limit curtailment of renewables, German system operators must "redispatch" power, ordering conventional generators in the north to reduce output below contracted levels (and paying them for

14 *Die Energiewende im Stromsektor: Stand der Dinge 2015. Rückblick auf die wesentlichen Entwicklungen sowie Ausblick auf 2016*, Agora Energiewende (2016), https://www.agora-energiewende.de/fileadmin/Projekte/2016/Jahresauswertung_2016/Agora_Jahresauswertung_2015_web.pdf.

15 *Connect Energy Economics, The German Power Market 2.0, Session 2 (IEA Workshop: Renewables in the Mainstream): Adapting liberalised power markets - Minor tweak or major overhaul?* https://www.iea.org/media/workshops/2015/renewablesinthemainstream/S2P2Nicolosi.pdf.

16 *Stand der Dinge 2015*, Agora.

their lost margins over fuel costs) while contracting for increased generation in the south at higher prices.[17] In the first quarter of 2016, redispatched generation reached 4,560GWh, up from 2,860GWh in the same period the year before.[18] Despite redispatch, curtailment of renewables is increasing, rising to 1,511GWh in the first quarter of 2016 from 1,135GWh in the same period the year before.[19]

Summary of institutional issues:

- **System/market operations:** The law governing the electricity market (*Strommarktgesetz*) recognizes that scarcity prices well above the marginal cost of generation are necessary to bring about investment in resources that may operate for only a few hours a year. The law also allows price signals to be conveyed more effectively through charges for balancing energy, charges that are imposed on generators and distributors that have not secured sufficient supply in the energy-only day-ahead or intraday markets.
- **Storage and demand response:** Germany's interruptible load programs permit demand-side participation for up to half of the procurable total of 1.4GW.[20] However, minimum bid sizes and restrictions on the extent of aggregation effectively limit participation to large industrial consumers. German industry's technical DR potential has been estimated as high as 6.4GW (1-hour duration), but market reforms will be necessary to unleash this total (eg, industrial customers currently risk losing valuable network tariffs discounts by diverging from a flat load profile to provide DR).[21] Aggregation is stifled by non-standardized contracting requirements that serve to discourage participation by third parties.
- **Tariffs:** Consumers with annual usage in excess of 10,000kWh will be required to install smart meters by 2017; the cut-off will decline to 6,000kWh annually in 2020. Even the latter amount is well above normal German household consumption, which averages around 4,000kWh a year. However, where installation is not required based on annual consumption, utilities and owners of multi-family properties retain the option to install smart meters without consumer consent and pass along some of the costs to the end-users.

17 *Redispatch costs in the German power grid, Clean Energy Wire*, https://www.cleanenergywire.org/factsheets/re-dispatch-costs-german-power-grid.

18 *Quartalsbericht zu Netz- und Systemsicherheitsmaßnahmen. Erstes Quartal 2016*, http://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Allgemeines/Bundesnetzagentur/Publikationen/Berichte/2016/Quartalsbericht_Q1_2016.pdf?__blob=publicationFile&v=2.

19 Ibid.

20 *Mapping Demand Response in Europe 2015*, http://www.smartenergydemand.eu/?p=6533.

21 *Demand Response in Germany: Technical Potential, Benefits and Regulatory Challenges*, DIW Roundup 96, http://hayek.diw.de/documents/publikationen/73/diw_01.c.532827.de/diw_roundup_96_en.pdf.

4.3. Maharashtra

4.3.1 OVERVIEW

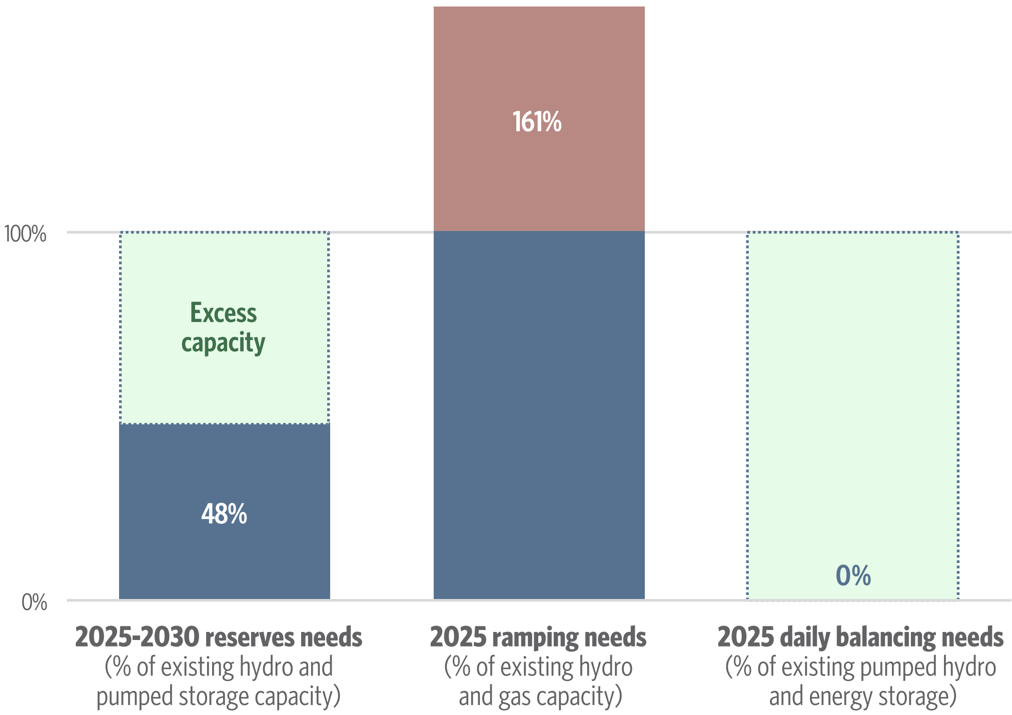
India's electric power system is growing rapidly—the IEA estimates over a fourfold increase in capacity between 2013 (1,193TWh) and 2050 (5,330TWh).

As of 2015, Maharashtra had approximately 7GW of installed renewable capacity, with wind contributing 4.4GW and solar 0.3GW. The state's policy calls for boosting renewables capacity to over 14GW by 2020, with almost all of the additions from solar.[26]

Table 4.4: Summary of factors affecting Maharashtra's flexibility needs

Renewable energy goals	As of 2015, Maharashtra's state-level Renewable Purchase Obligation requires load-serving entities to procure 9% of generation from renewables.[22] The government has set targets for 60GW of wind and 100GW of solar by 2020 which corresponds to an estimated 18% of energy from wind and solar.
Demand growth and patterns	For India as a whole, the IEA projects a five-fold increase in electricity demand from 792TWh in 2007 to 4,069TWh in 2050.[24] Maharashtra accounts for around 13% of the national total.[24] Demand will become increasingly peaky as AC and other commercial/residential loads grow.
Existing plant and retirements	Total installed capacity stood at 307GW as of October 2016; over 60% of this total was coal-fired, 8.2% from natural gas, 1.9% from nuclear, 14% from hydro, and just under 15% from other renewables.[25] Nearly 25% of capacity was non-utility owned, often by industry. Peak load in Maharashtra is around 18GW.
Interconnections and imports	The transmission grid is in significant need of expansion. As of 2010, transmission lines rated at 110kV amounted to only 12% of total generation capacity, a low percentage compared to more developed systems.[27]

Figure 4.14: Existing resources available to meet Maharashtra's flexibility needs by 2025



22 *Preliminary assessment of renewable energy grid integration in India*, Lawrence Berkeley National Laboratory (2016).

23 Energy Technology Perspectives (2016).

24 *Demand Side Management in India: An Overview of State Level Initiatives*, Prayas (2014).

25 Central Electric Authority, http://www.cea.nic.in/reports/monthly/installedcapacity/2016/installed_capacity-10.pdf

26 *Tentative State-wise break-up of Renewable Power target to be achieved by the year 2022*, Ministry of New and Renewable Energy, http://mnre.gov.in/file-manager/UserFiles/Tentative-State-wise-break-up-of-Renewable-Power-by-2022.pdf

27 *Technology Development Prospects for the Indian Power Sector*, International Energy Agency (2011).

To satisfy the 2-degree scenario in the IEA's 2016 Energy Technology Perspective, wind power will need to provide over 15% of generation in 2040.[28] Solar's fraction of generation will need to approach one-fifth of output. Currently, all non-hydro renewables contribute around 15% of capacity, but a lesser share of energy.

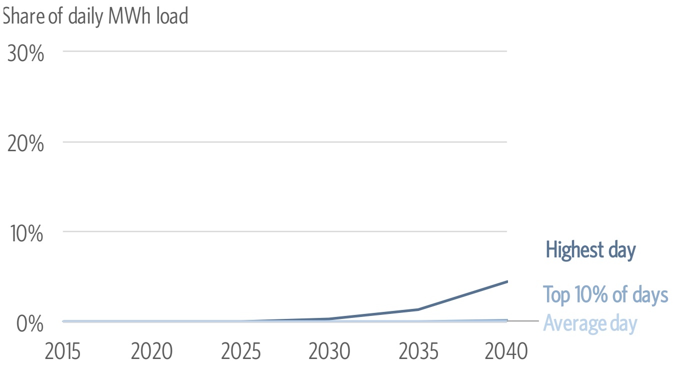
Compared with California or Germany, Maharashtra in 2040 will be relatively less reliant on variable sources of renewable electricity, but it will still confront significant flexibility challenges driven primarily by overall system growth.

4.3.2 LOAD FOLLOWING AND SPINNING RESERVES / SHORT-TERM RESERVES

The overall requirement for control reserves is increasing in line with rapidly growing peak load (reserve requirements are mandated nationally at 5% of peak load, however, many parts of the country regularly operate with less of a reserve margin than required).[29] In the near-term, microgrids and off-grid renewables may be employed to delay the larger investments that would be required for full-scale network development and integration; Maharashtra recently announced plans to heavily subsidise the deployment over the next five years of 200MWe of on-site solar systems as well as two microgrids in villages currently without grid connections.[30]

4.3.3 RAMPING

Figure 4.15: Maharashtra daily shifting need



Maharashtra's evening ramp (4pm to 6pm) exceeds 25% of peak demand on the most severe day of the year. This is expected to increase greatly to over 60% of peak demand by 2040, as Maharashtra increases afternoon and evening air-conditioning loads as solar generation increases.

4.3.4 DAILY BALANCING

Due to wind and solar making up only a small share of total energy production, intermittent renewables should not cause daily balance issues before 2040, and even by that time shifting needs should not exceed 5% of daily generation even on the worst days.

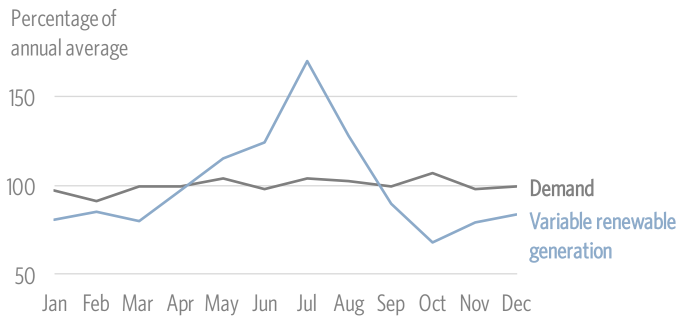
4.3.5 SEASONAL BALANCING

Wind generation in Maharashtra and India as a whole fluctuates dramatically with the seasons, spiking during the monsoon season (June through September) to levels two to five times higher (depending on region) than those achievable in winter (December through February). Summer output falls in the middle of these extremes. Within most days, wind generation is lowest at midday, rising into the afternoon and evening.

Solar output also varies with the seasons, albeit to a lesser degree than wind generation, peaking in summer months and bottoming out in winter; in Maharashtra, which lies in the west of the country, solar output in the monsoon season falls in between the winter-summer extremes.

Peak load in Maharashtra rises during summer afternoons, driven by demand for air conditioning. In a nationwide system with roughly twice as much wind as solar capacity (the likely scenario in the 2020s), net load (that is, minus renewables output) will track the overall summer load profile closely, but a shift toward solar in the generation mix will reduce net load while exacerbating the evening ramp-up. Relatively similar patterns are expected in the monsoon season under the same generation scenarios. In winter, however, when both wind and solar generation decline, net load is much closer to total load; in a more solar dependent system, the evening ramp is expected to be even steeper than in summer, as disproportionately impaired wind will be unable to compensate as solar goes offline at sundown.

Figure 4.16: Maharashtra seasonal resource and demand Profile



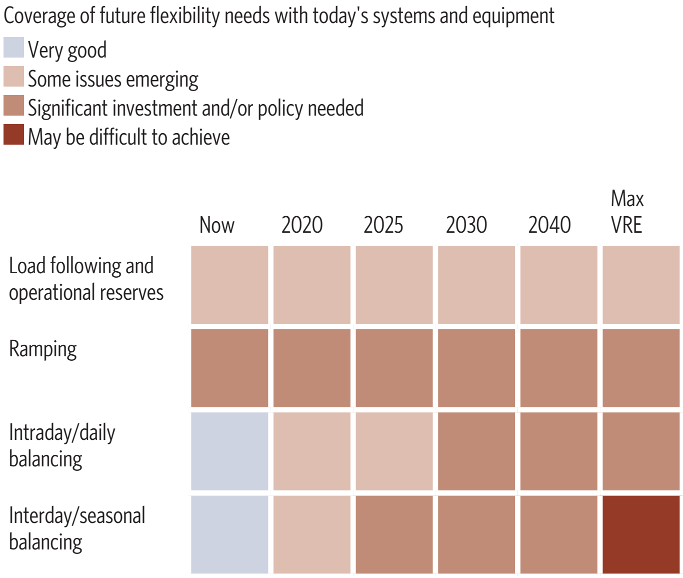
28 *Energy Technology Perspectives*, IEA (2016)

29 *Report of the Committee on Spinning Reserve*, Central Electricity Regulatory Commission (2015).

30 *Maharashtra approves off-grid power scheme*, Decentralized Energy (26 January 2016), http://www.decentralized-energy.com/articles/2016/01/maharashtra-approves-off-grid-power-scheme.html.

4.3.6 INSTITUTIONAL ISSUES AND SUMMARY

Figure 4.17: Evaluation of Maharashtra's flexibility needs

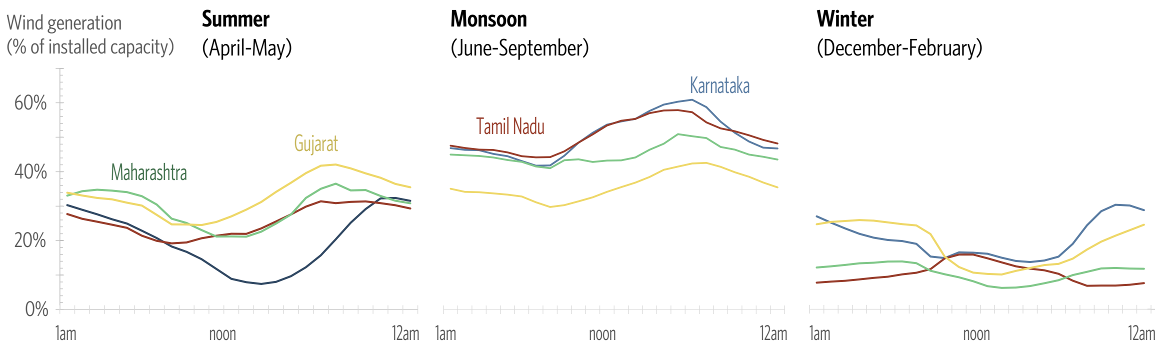


Across all time dimensions, Maharashtra needs to increase flexibility supplies to meet the demands of a growing system. Developing technical and institutional capacity to provide flexibility, while meeting growing demand and expanding energy access, will be challenging, especially given emerging-market investment challenges.

Alone among the regions studied, Maharashtra's most critical flexibility need will likely be seasonal. While planned curtailment will not be an issue at the renewable penetrations expected by 2040, winter reductions in solar and wind output (as well as of dispatchable hydro) will leave the system dependent on fossil-fuelled resources for months at a time. Ramping needs will also test the system, especially as Indian consumers become less tolerant of poor power quality and outages.

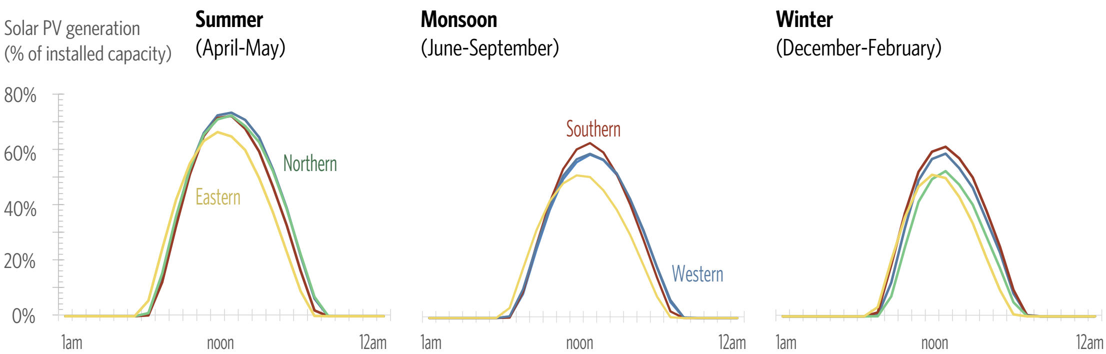
Regional diversity could partially alleviate these challenges, with Maharashtra (west) potentially exporting (solar) generation to the east and south during summer days and importing (wind) generation from the south during summer nights, but this will require significant upgrades to India's grid.

Figure 4.18: Average daily wind generation curve for key states in India by season (from LBNL)



Reproduced from: *Preliminary assessment of renewable energy grid integration in India*, LBNL (2016).

Figure 4.19: Average daily solar generation curve for each region in India (from LBNL)

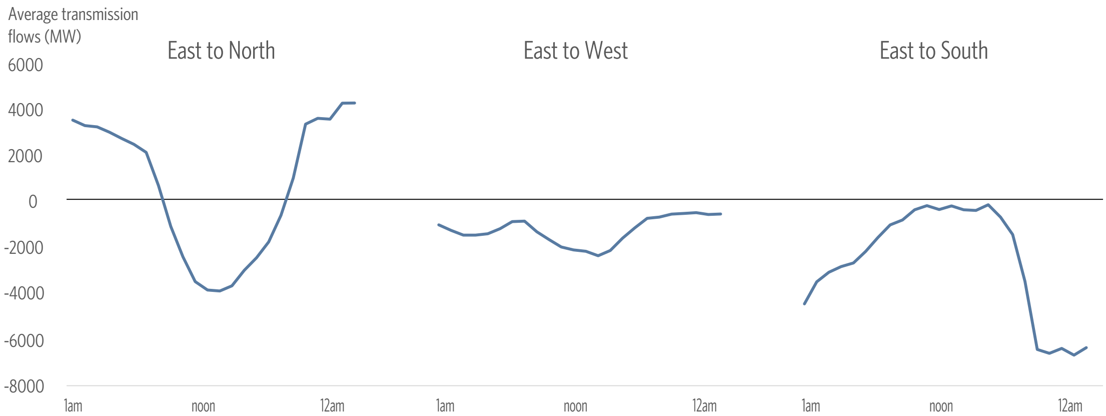


Reproduced from: *Preliminary assessment of renewable energy grid integration in India*, LBNL (2016).

Summary of institutional issues:

- **System/market operations:** For India's system operators, meeting annual load growth is a critical objective. Maharashtra has been relatively successful in maintaining the balance. In 2015-2016, the supply deficit was only 0.3%, compared to a national deficit of 2.1%.[31] For 2016-2017, a surplus has been forecast.
- **Storage and demand response:** The Maharashtra Electricity Regulatory Commission (MERC) has issued incentives and regulations to advance demand-side management.
- Accordingly, the state's distribution companies have implemented various offerings, including thermal storage and DR, but impacts have been small, in keeping with mostly pilot-scale activities. [32]
- **Tariffs:** Time-of-use pricing is required for high-voltage industrial consumers, and in that customer segment, the share of off-peak consumption in this sector has been steady in recent years. However, for low-voltage industrial customers facing time-of-use tariffs, the price differential has not prevented load from shifting to peak periods.

Figure 4.20: Estimated interchange between regions in India (from LBNL)



Source: *Preliminary assessment of renewable energy grid integration in India*, LBNL (2016).

31 *Load Generation Balance Report 2016-17*, Annex-VI(B), Government of India, Ministry of Power, Central Electricity Authority (2016).

32 *Demand Side Management in India: An Overview of State Level Initiatives*, Praya Energy Group (2015).

4.4. Nordic region

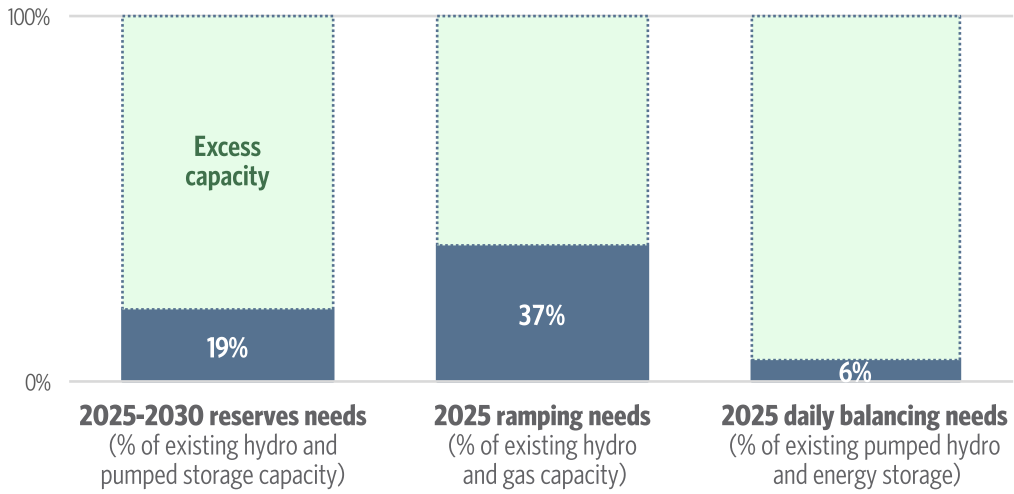
4.4.1 OVERVIEW

With vast hydropower capacity, the Nordic countries have sufficient flexible resources to meet flexibility needs in 10 years, and for many years into the future. How to use this surplus flexibility is an open question, though. Exporting this flexibility to other regions that are themselves short on flexibility could lower transition costs for Europe as a whole and provide rents to the owners (the citizenry of Norway and Sweden among them). On the flip side, the export of Nordic flexibility will likely raise prices for Nordic power consumers, at least those who do not adjust their behaviour to accept more variable pricing.

Table 4.5: Summary of factors affecting Nordic flexibility needs

Renewable energy goals	Denmark has targeted a 100% renewable electric power (and heating) supply by 2035. Norway already has a power system that is essentially 100% renewable. Sweden and Finland have a variety of goals for carbon reduction across energy sectors. The combined Nordic power sector goal is commensurate with an 80% renewables system by 2040.
Demand growth and patterns	Peak load in the Nordics occurs in winter and has approached 69GW in recent years. Demand growth has been flat or negative in recent years.
Existing plant and retirements	Nuclear plants located in Sweden and Finland supplied around 23% of Nordic generation in 2013.[33] The Nordic commitment to nuclear generation is uncertain, especially in Sweden, but a complete withdrawal is unlikely during the study timeframe. Nearly all of the region's fossil generation is located in Finland and Denmark; the latter country has a highly aggressive transition agenda, aiming for 100% renewable electricity generation by 2035, predominantly from wind. Norway's generation is almost completely sourced from hydro.
Interconnections and imports	As of 2013, the Nordics were a net importer of electricity to the tune of 2.1TWh annually. Germany has in recent years become a net exporter of electricity to the Nordics (in volume, not value). Interconnection capacity with neighbouring systems will increase by 50% by 2025.[34] In effect since 2014, coupling of the Nordic and Northwest European markets has allowed for more efficient allocation ('implicit auctioning') of interconnection capacity, but this also increases the exposure of the Nordic system to the Continent's more volatile pricing.

Figure 4.21: Share of existing resources needed to meet 2025 flexibility needs in the Nordic region



33 Nordic Energy Technology Perspectives, IEA/Norden (2016).

34 *Challenges and Opportunities for the Nordic Power System*, Statnett, Fingrid, Energinet.dk, and Svenska Kraftnät (2016).

4.4.2 LOAD FOLLOWING AND SPINNING RESERVES / SHORT-TERM RESERVES

Nordic energy markets are scheduled hourly, and as supply becomes more variable, this relatively low resolution dispatch will increasingly burden load-following reserves and contribute to the deterioration of frequency quality. However, with more accurate renewables forecasting, shorter dispatch intervals, and improved opportunities for DR to provide flexibility, the Nordics can free up reserves, which in turn would enable increased export of reservoir hydro energy.

During periods of low load on summer nights, wind, run-of-river generation, nuclear, and cheap imports may be sufficient to cover demand, allowing reservoir hydro to be conserved for winter. But with large-scale hydro offline, the system may be short of load-following flexibility, with down regulation especially becoming markedly more expensive.

4.4.3 RAMPING

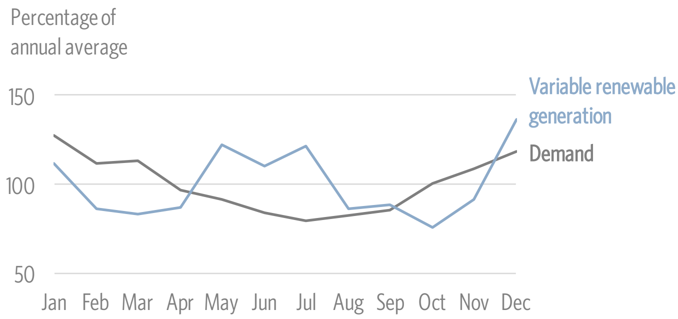
With solar practically absent from the resource mix, ramping is not expected to be a significant challenge, and is one that can easily be met by the large share of quickly dispatchable and easily rampable hydropower.

DAILY BALANCING

Daily balancing issues are not expected to be a concern. The absence of solar from the Nordic system reduces the overall need for daily balancing, while a prevalence of flexible hydro is available to meet within-day energy balancing needs. However, balancing across periods longer than a day are likely to be a greater concern at high penetrations of wind.

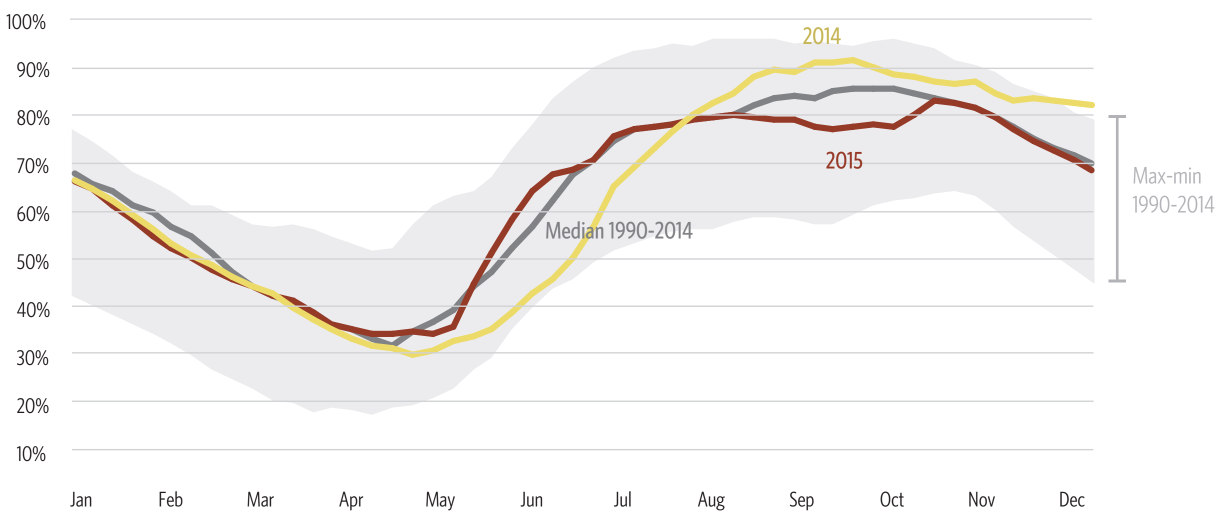
4.4.4 SEASONAL BALANCING

Figure 4.22: Nordic region seasonal resource and demand profile



Existing hydro resources can also cover future seasonal shifting needs, provided these resources are not committed to export or other flexibility services. Most obviously, hydro allows summer run-off waters to be stored for use during the high-demand summer season. To the extent that the Nordic countries can develop new seasonal shifting resources, say, in the form of excess capacity in energy-intensive industries, opportunities for value optimizing allocations of the region's hydro resources (both domestically and internationally) will increase.

Figure 4.23: Hydro reservoir levels in Norway

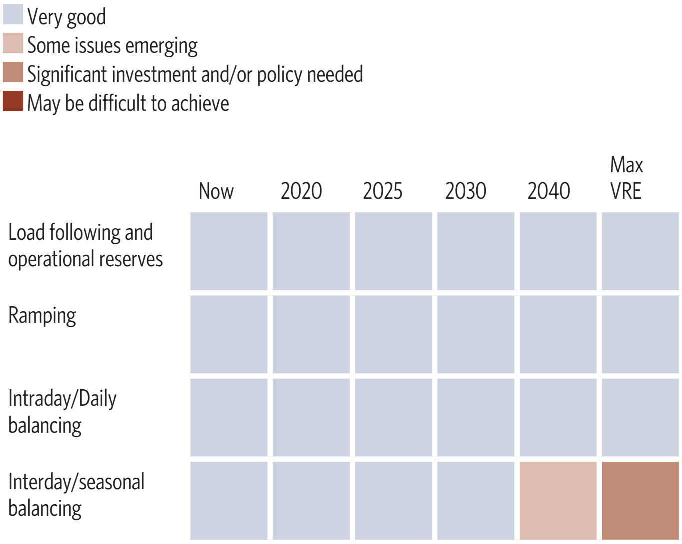


Reproduced from: Statnett, *Annual Report 2015*.

4.4.5 INSTITUTIONAL ISSUES AND SUMMARY

Figure 4.24: Evaluation of Nordic region flexibility needs

Coverage of future flexibility needs with today's systems and equipment



Regional power sector integration is well advanced in the Nordic region through the Nord Pool market and regional power system planning. The four Nordic TSOs recently identified their shared challenges for operations through to 2025, especially underscoring frequency and inertial response as concerns.[35]

- **System/market operations:** Norwegian capacity, which is nearly completely based on extremely low-cost and highly flexible hydro resources (30.9GW out of a total 32.9GW),[36] has the potential to export flexibility, although transmission bottlenecks from north to south are a concern. Hydro resources in Sweden are also extensive (16.2GW out of a total 38.3GW). In Denmark, the western half of the country is synchronously connected to the continent, while the eastern half is integrated into the Nordic system. Power demand in Finland outstrips domestic production consistently through the year.

- **Storage and demand response:** Norway's power-intensive industry is large, and household heating is also highly electrified; both could potentially provide greater DR. In Sweden, power-intensive industry is also a significant share of demand, but residential heating is not widely electrified and is instead heavily reliant on district heating. Power-intensive heavy industry is not a factor in the Danish system. Residential electric heating is rare, as fossil cogeneration is widespread; recent regulatory changes have encouraged retrofitting these cogeneration plants to produce heat by means of electricity, lowering their must-run levels as generators and allowing greater absorption of intermittent wind generation.37 In Finland, day-to-night price differentials are large, and nearly all residential consumers have both hourly meters and electric hot water heaters, providing significant potential for DR.

- **Tariffs:** Norway's smart meter deployment is not complete but is expected by 2020.[38] Smart meters are already widely installed in Sweden, but they provide daily metering only. As in Norway, smart meter deployment in Denmark is expected by the beginning of the next decade. Retail prices in Denmark are significantly higher than in the other Nordic counties. Alone in the region, Denmark experiences negative wholesale prices in the day-ahead (Elspot) market.[39] Retail prices in Finland are flat throughout the year; they are in line with, though slightly above, those in Sweden and Norway during the fall and winter but do not dip along with the latter in spring and summer.

35 *Challenges and Opportunities*, Statnett et al.
36 *Nordic Market Report 2014*, NordREG (2014).
37 *The Danish Experience with Integrating Variable Renewable Energy.* Study on behalf of Agora Energiewende (2015).
38 *Demand response in the Nordic electricity market*, Thema (2014).
39 *Nordic Market Report 2014*, NordREG (2014).

5. Conclusions: getting the markets, price signals, policy, technologies and institutions right in the short and long term

Flexibility is an essential enabler of a modern, decarbonised electricity system. While the need for greater flexibility is often cited as a key constraint on the amount of variable renewable energy that can be deployed in a grid, flexibility solutions are already available that can enable high levels of variable renewable energy at a reasonable cost, and new technologies are set to drive costs down further.

Most power systems have enough latent flexibility to support a continued rapid deployment of variable renewable energy over the next 10 years, so policymakers should feel free to set ambitious renewable energy targets without fear of insufficient system flexibility. In the long term, greater flexibility will be needed to meet low-carbon objectives and to accelerate a transition to a cleaner, more sustainable, and ultimately less expensive energy system.

However, this seemingly attractive future is not guaranteed. Inappropriately designed markets can significantly increase the investment risk, and therefore the financing cost, of renewable energy supplies and discourage investment in and development of new flexibility technologies and resources. Unfortunately, there are many aspects of current electricity market regulation and design that threaten both higher renewable energy financing costs and poor long-term incentives for flexibility. Meanwhile, it is not yet clear which of the various developing flexibility solutions will ultimately create the most value at the lowest cost. Choosing the wrong technology, or choosing no technology at all, could prevent a flexibility resource from developing, ultimately leading to a shortage of flexibility when and where it is needed. In other words, without careful guidance, the path to low-carbon electricity system could be longer, costlier, and messier than it should be.

Thus, while policymakers should feel comfortable about accelerating their renewable energy deployment plans over the next five to 10 years, they should simultaneously be charting a course to redesign electricity markets and regulation, industry structure, pricing, and technology development to create a smooth transition pathway to a low-carbon, low-cost electricity system beyond that.

In addition to ambitious clean energy deployment plans, doing so will require a portfolio approach for developing flexibility options, a new industry and market structure and a framework for a cost-effective and low-risk transition to the new markets and industry structure. All of this will require planning horizons that extend beyond the time it takes to build a new power plant and indeed long enough to enable envisioning and planning for the utility industry of the future.

Table 5.1. Key findings and recommendations for policymakers

FINDING	WHAT POLICYMAKERS SHOULD THINK ABOUT
Renewable energy ambition Solutions are available now on most systems to accommodate high proportions of renewable energy at a reasonable cost	• **Feel free to set ambitious renewable energy targets** to meet their low-carbon objectives. • **Focus on optimising the costs of today's flexibility options**, while setting policy that will deliver increased flexibility capacity in time to meet targets for decarbonising the power sector at the lowest possible cost.
Portfolio approach No single technology, market mechanism, or flexibility resource will be able to meet all flexibility requirements across all regions	• **Promote the development and cost reduction of several technologies and flexibility resources**, while creating markets and policy for cost-effective integration of these resources as they develop. • **Create solutions that can contribute to delivering the needed flexibility at a competitive cost include**: Using existing generation capacity differently; increasing demand side flexibility; increasing and optimizing new electrification; restructuring transmission and distribution; developing new roles for batteries; and building some new gas turbines as additional support.
Transition framework New policy, market and regulatory mechanisms are needed to cost effectively develop flexibility for a high variable renewable energy system	• **Focus planning and policy development on the transition path to a much higher variable renewable energy system**, while markets need to be configured to get the best output, lowest cost and lowest risk from both renewable energy and the evolving flexibility resources. • **Design markets with long-term signals for investment in the transition**; better signals to consumers; markets that differentiate between the supply of energy and flexibility; mechanisms that balance sources of renewable energy to reduce flexibility needs; and real-time and locational price signals to improve regional coordination.
Planning horizons Longer-term planning horizons are needed to develop new flexibility solutions and avoid lock-in of long-term solutions that do not align with transition goals	• **Create markets and policy that incentivise long-term innovation and balance this innovation against near-term objectives.** For example, there is a continued role for existing fossil fuel generation to ease the transition, while innovation policy and long-term planning is needed to access some of the lowest cost future resources.

Renewable accleration & framework
There are numerous policy actions that have been successful in accelerating the deployment of renewable energy and other low carbon electricity sources. The choice of these mechanisms is beyond the scope of this paper. For developing a portfolio approach and transition framework to build the flexible electricity system that can incorporate these higher levels of clean energy there are four main levers that policymakers can use: 1) industry structure (eg, encouraging new business models/platforms); 2) market design (to make sure markets for flexibility services are sending appropriate signals for efficient investment and operation of flexible assets); 3) technology programmes (to ensure that promising flexibility technologies come down in cost); 4) system planning (to prioritise investments and avoid locking in a more expensive pathway for system transition).

The portfolio approach

Section 1 presented the case for developing an entirely renewable energy-based system that ignored both existing generation and the flexibility that consumers can provide. The reality is that we begin from a point where there is existing generation in place and consumers can adjust their demand. Both of these existing assets can be critical to lowering the cost of the transition and the longer-term solution. As we will discuss later, developing demand-side flexibility solutions is likely to be particularly effective. Some of these demand-side solutions will involve electrifying energy uses that currently depend on fossil fuels, but many others can be developed for existing uses. Additionally, as variable renewable energy deployment increases, existing generation options will increasingly be valued for the flexibility they offer, rather than the energy they supply. Markets will need to change to reflect this difference and to reward investment and operational practices that follow this need.

Table 5.2: A portfolio approach to flexibility

FINDING	RECOMMENDATION	POLICY LEVER
Existing generation, including fossil fuels and hydro, is a critical resource.	Operate and incentivize existing generation to support variable energy, rather than forcing variable renewable energy to fit into existing supply incentive models.	**Market design**
Demand-side flexibility is an attractive and low-cost resource across all flexibility needs.	Develop better markets, market signals, increased awareness and technology to reach the full potential across all consumers.	
Electrification of additional services can significantly increase consumer flexibility and add value beyond energy efficiency and decarbonisation.	Implement well-structured demand-side signals to unlock full value.	
Transmission and distribution can reduce total flexibility needs, enabling diversification, broadened access to low-cost resources and sharing of reserves.	Optimise transmission and distribution by supporting better locational energy pricing signals and new investment.	
Batteries will become increasingly cost competitive, while reducing carbon emissions.	Support deployment to reduce costs and improve integration as costs drop.	**Technology support**
Gas turbines provide a default source of flexibility across several types of needs.	Carefully balance new build, existing plant and developing new flexibility options.	

Beyond the demand side and existing generation, system operators and policymakers will need to explore the trade-offs, benefits and integration of a range of flexibility supply options, including what today look to be the three largest and most attractive options: transmission and distribution to share the value of flexibility more widely, battery and/or storage technology development, and new, low load factor but highly flexible gas turbines used as an ultimate backup. These three are the most obvious today, but each needs a degree of continued technology development; decision-makers should also keep abreast of other options on the horizon that could provide even more value.

Table 5.3. Examples of technology support policies in flexibility

POLICY LEVER	IMPACTS	EXAMPLES
Technology support	Bring down the cost of multiple flexibility options in time to meet renewable ambitions Enable learning by doing and economies of scale Reduce perceived technology risk through demonstration	Germany: 50MW/year "Innovation Auctions" in 2018-2020 included in latest Renewables Law to support technologies that provide flexibility Maharashtra: On-site generation and microgrid incentives California: 1.3GW Energy Storage Mandate

New market designs and a transition framework

Technologies will not be deployed without the appropriate incentives or price signals, and even if they are deployed, poor price signals can create confusion, poor integration and higher costs. Since consumer flexibility is a key element to achieving the lowest costs, providing appropriate signals to consumers is likely to be the starting point. Locational signals, including locational marginal pricing, will also be an important step for both consumers and suppliers of flexibility. Meanwhile, we need to ensure that price signals focus on delivering flexibility to the system but do so without increasing costs and risks needlessly elsewhere in the system, for example, by imposing risks and costs on suppliers that are unable to provide (and profit from) value in response.

Table 5.4: New markets designs and a transition framework for flexibility

FINDING	RECOMMENDATION	POLICY LEVER
Electricity markets need to provide **better long-term and short-term signals to consumers,** who have been undervalued.	Develop short-term signals to encourage changed use patterns; long-term signals to encourage investment.	**Market design**
Markets must provide consumers and suppliers **better signals about where flexibility is needed**.	Implement location pricing and other tools to deliver incentives to consumers and suppliers for investment, operation and process change.	
Markets need to **differentiate signals between core renewable energy supply and flexibility**.	Avoid flexibility price signals for intermittent renewables to offer flexibility they do not have, as it will increase risk, raise capital costs and energy costs.	
A mix of renewable energy technologies with different generation profiles is likely to reduce flexibility requirements.	Design market signals and planning processes which account for the value of supply diversification and provide incentives accordingly.	**System planning & market design**
Institutional coordination, between regions and value chain segments, can remove barriers to cost-effective management of flexibility.	Expand markets regionally and vertically.	

As with technology development, there are many good examples of policy development that are moving in the right direction, improving coordination and pricing signals, as in the table below. However, significantly more progress is needed in designing new industry structures and regulation based around the characteristics of the future system, rather than developed as a series of incremental changes to the old systems.

Table 5.5: Examples of market design and industry structure flexibility solutions

POLICY LEVER	IMPACTS	EXAMPLES
Industry structure	Mitigate flexibility needs by integrating regional markets Unlock demand-side flexibility through coordination of distribution/transmission Develop new business models and corporate structures to respond to the new requirements of a flexible system	Nordic region/Germany: Coupling of day-ahead markets in northwest Europe since 2014 enables efficient use of interconnectors between Nordic region and continental Europe (implicit auctioning) New York: Reforming the Energy Vision (REV)
Market design	Drive efficient operations and investment Develop appropriate market signals to encourage shifts/behavioural change Ensure technical adequacy at lowest cost Place operating risks with parties best placed to manage	California: Flexible Ramping Capacity, Demand Response Auction Mechanism Maharashtra: Time of Day (ToD) tariff for large energy consumers

Longer-term planning horizons

Most electricity system flexibility planning revolves around how long it takes to plan for, approve and build a new power plant, typically a gas turbine, to provide that flexibility. A 10-year time horizon is typical. Developing new technologies or demand-side management resources at a cost and scale that could replace the supply side technologies might take more time. A demand-side programme that would be large and successful could easily be undermined if a series of new gas turbines were scheduled to enter the system before the demand-side programme and its technology were able to reach scale. Thus a 10-year horizon could lock in the gas turbine or supply-side technologies. Careful planning with a longer-term horizon will be required to nurture new options while ensuring that a delay in developing these new options does not risk creating shortages and higher costs.

Table 5.6: Planning for flexibility

FINDING	RECOMMENDATION	POLICY LEVER
Current planning horizons may miss long-term flexibility resource opportunities, as these horizons are built around building the current set of supply-side flexibility options and thus may lock these options	Encourage long-term planning to unlock low-cost options, focused on steady development of demand-side resources and new technology.	**System planning**
Continued fossil fuel generation is essential for a smooth transition, but in the long term, fossil fuel generation can be mostly replaced.	Policy should avoid wasting valuable existing assets, but also guard against new assets that will either be stranded or lock in emissions.	
Industrial electrification may have significant long-term potential, but it is less explored, so the opportunity is not yet clear.	Need to assess how electrification will stack up against carbon capture, biofuels or other carbon abatement measures, and what further research is needed to clarify the opportunities.	**System planning and technology support**

There are few examples of effective long-term system planning practices to draw from, particularly when it comes to the type of cross-sector planning that industrial and transport electrification may require. For example, California—a region with aggressive decarbonization goals—undertakes a variety of long-term multi-decade planning exercises, typically to set policy goals and strategy for the state. However, these are often not integrated with more granular power system planning, where trade-offs between various investments are weighed against one another, usually with a shorter time horizon.

Table 5.7: Examples of planning approaches in the power sector

POLICY LEVER	IMPACTS	EXAMPLES
System planning	Identify long-term resource needs; balance with short-term constraints Prioritise investments and incentivise long-term innovation Set goals and procurement targets to minimise system costs Avoid lock-in	California: Long-term procurement planning (typically 10 years) Maharashtra/India: national energy planning is well developed but has short time horizon (Five-Year Plans)

PRIORITY FLEXIBILITY OPTIONS

The cost reducing role of consumer flexibility options

Demand-side flexibility consistently ranks among the lowest-cost options for providing all types of system flexibility. As a consequence, demand-side resources should be among the first flexibility options deployed to meet growing flexibility needs, and should be deployed to their maximum extent. If the demand-side potential is realized, most regions may require only modest additional resources to satisfy flexibility needs. Accurate estimates will require detailed system-specific analysis that includes the entire range of flexibility options and addresses the timing of both renewable energy builds and existing plant retirements.

Figure 3.6 showed that consumer-based flexibility options—that is demand-side options—will almost always provide relatively low-cost flexibility to the system, so the focus of every system should be on developing the technology, market signals and behavioural patterns that can increase this type of flexibility to the fullest extent.

Table 5.8 identifies the various forecasting, market design, business model, technology and infrastructure requirement that need to be developed to maximize this potential. Market design, in particular, needs careful evaluation, as many current markets evolved to optimize the dispatch of fossil fuel-based generation in the context of decelerating demand growth. In particular, new market designs should serve to ensure that demand-side flexibility is available and used when it is most valuable.

Table 5.8: Enabling factors for demand-side flexibility

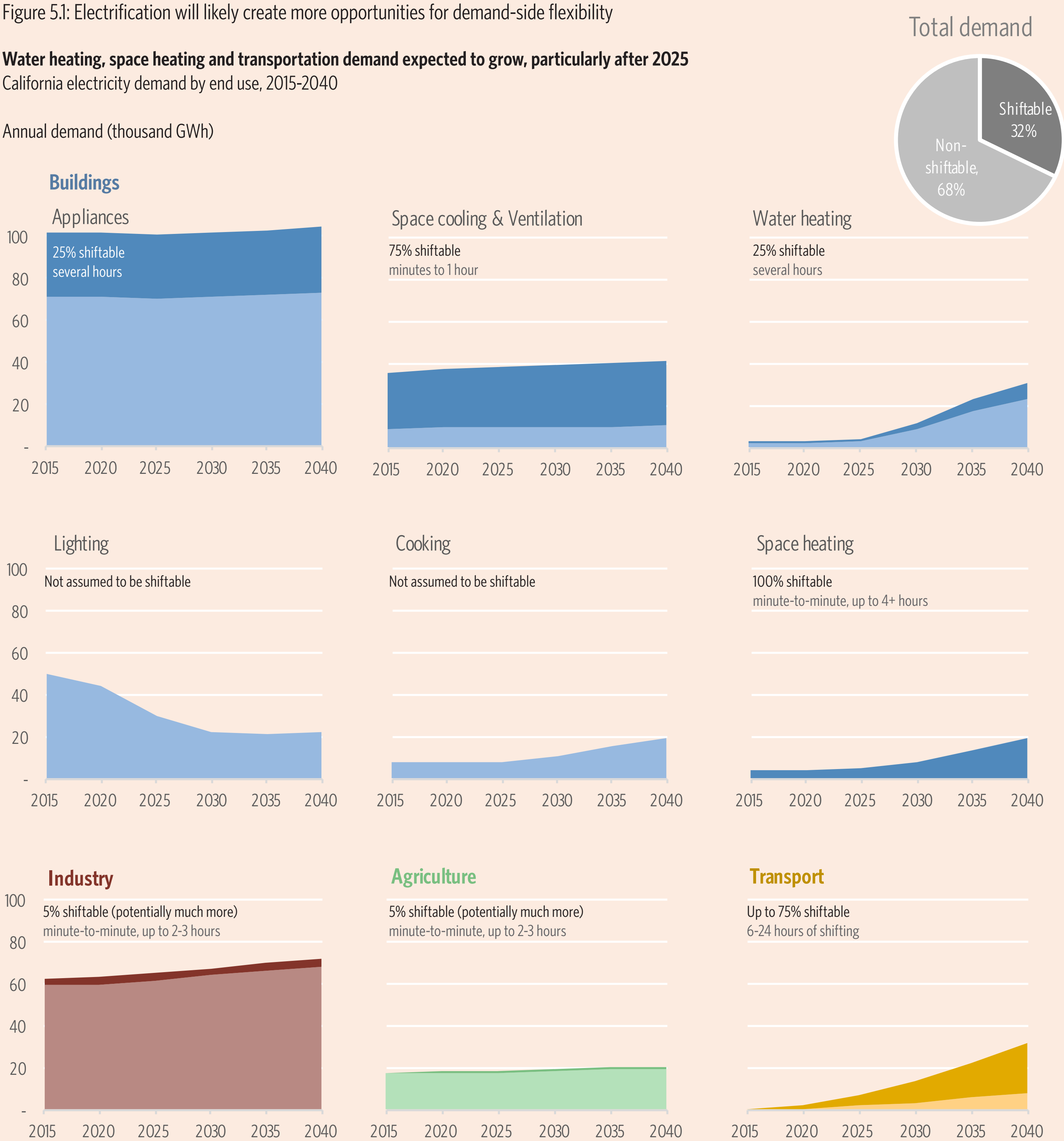
	ROLE	EXAMPLES	CURRENT STATUS
Supply and demand forecasting	Provide advance information to flexibility suppliers and operators	Renewable energy supply forecast Weather and demand forecast	Accuracy and advance timing steadily improving, substantially reducing short-term reserve costs
Market design and flexibility service pricing	Provide short-term incentives to respond to flexibility needs and long-term incentives to develop new response capacity	5-minute energy markets Capacity markets Long-term contracts for reserve Long-term contracts for flexible supply Annual flexibility auctions Transmission rights	Many examples in place, but most do not yet provide optimum allocation of incentives
Consumer aggregators	Aggregate market to consumers to reduce transaction costs and improve reach and scope	Energy service companies Utilities and municipalities Consumer aggregators	Many examples in development, but much greater potential once market design and price signals become more focused
Response and control technology	Enable aggregators to access flexibility potential of consumers and respond to market signals	Automated control systems Internet and broadband based communications Integration and trading platforms and software	Technology is available, but great potential to refine and expand as incentives and systems improve
Metering data and analysis	Consumer end-use metering to enable control, measurement and payment	Smart meters End-use meters End-use analysis software Integration software	Smart meter/end-use meter roll-out is underway in many geographies, but there is room for improvement in the adoption and cost performance of end-use metering
Consumer infrastructure	Infrastructure that will allow consumers energy demand to be more flexible	Fast electric vehicle chargers to increase EV response Building insulation to increase heat demand shifting Appliance control systems for remote response	Build-out is ongoing, but lack of incentives means development is slow

PRIORITY FLEXIBILITY OPTIONS

Using increased electrification to increase consumer flexibility

Increasing electrification—of transport, buildings and even industry—promises improved energy productivity, higher quality services, and carbon emissions reductions, all the more so when the additional electricity is generated by low-carbon resources. Most of the new electricity demand expected from greater electrification will be inherently flexible: electric vehicles incorporate batteries that can be charged when renewable energy is available, while well-insulated buildings can store heat or stay cool for hours at a time without more energy, thereby enabling electricity demand to shift with electricity system needs.

Figure 5.1: Electrification will likely create more opportunities for demand-side flexibility

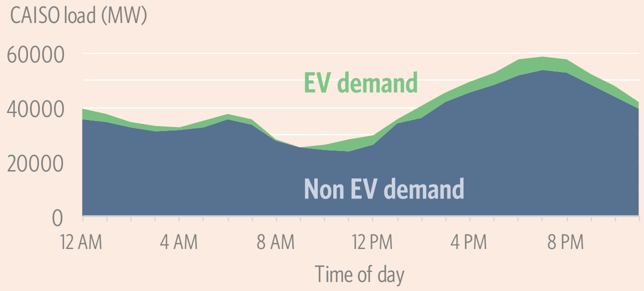


Source: CPI analysis: Shiftable shares based on Birrer et. al. (2015). Oak Ridge National Lab (2013) and interviews with industry experts.

PRIORITY FLEXIBILITY OPTIONS

While additional electricity demand for vehicles and heating can, in principle, create additional flexibility for the system, accessing this flexibility will require appropriate technology, markets mechanisms and business models. Failure to do so could increase the amount of flexibility demanded by the system. In an unconstrained system, that is, one without flexibility market signals, electric vehicle owners will be prone to come home and plug in their cars to charge overnight.40 In a solar heavy system, such as California, the additional demand will come at the same time as solar production falls and consumers switch on their lights.

Figure 5.2: Projected CAISO demand with 23% EV penetration and 2031 RE penetration goals with uncontrolled EV charging



CAISO demand with 23% EV penetration and optimized charging

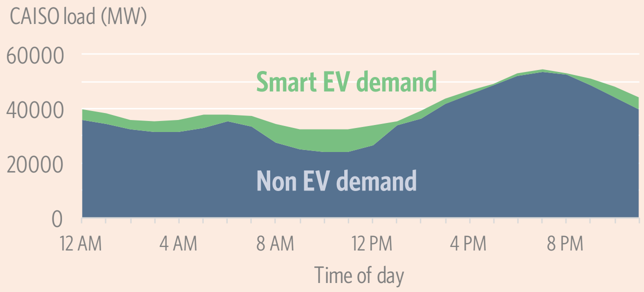


Figure 5.2, from the Rocky Mountain Institute study *Electric Vehicles as Distributed Energy Resources*, shows the impact that electric vehicles would have in a world with and without flexibility enhancing measures such as pricing and fast chargers (to concentrate charging during periods of low demand or high solar generation). In the case without any policy, the difference between peak demand and the lowest demand in a day, one key measure of the flexibility needed, increases by 20-25%, while with appropriate markets and investment, this difference will decrease by 15-20%.

Electricity provides only a quarter of the energy used in global industry, a sector responsible for approximately 30% of total carbon dioxide emissions.[41]

Electrification of industrial processes can play a vital role in decarbonisation strategies. Above all, as industry switches from direct consumption of fossil fuels to electricity increasingly produced by renewables, sector emissions will decline.[42] And, in turn, greater industrial electricity demand will serve to increase low-cost, demand-side provision of flexibility. This virtuous cycle could boost renewable generation while reducing system costs in the power sector.

Some industrial electrification pathways are already well established. In the steel industry, for instance, electric arc furnaces (EAF) can raise electricity consumption 2.4 fold compared to basic oxygen furnaces, while significantly reducing total energy consumption per unit output. EAF already account for one-quarter of global steel production; as they require scrap steel, however, further shifting to this process is limited by recycling potential.

A major technical hurdle hindering industrial electrification is the widespread need for high-temperature process heating. Whether they produce basic metals, chemicals, non-ferrous metals, or even pulp and paper, many industries require large quantities of medium- (100°C to 400°C) and high-temperature (above 400°C) heat to carry out key functions. Current commercial heat pumps top out at 100°C.[43] Increasing the maximum heat output of such pumps to 140°C could double their potential; other electric technologies such as induction heating and microwaves as well as non-electric but renewable solar furnaces could also help satisfy industrial demand for process without reliance on fossil fuels.[44] Advances in electro-refining and electrowinning could have an even more "disruptive" impact in industries that rely on smelting processes, as could hydrogen electrolysis in the chemicals sector.

Unamortized investments in existing asset bases, workforce knowledge, and the inertia of legacy business practices will undoubtedly produce headwinds against industrial electrification. Detailed analyses of industrial electrification potential are needed to quantify stand-alone value propositions as well as system-wide benefits incorporating carbon impacts.

40 *Electric Vehicles as Distributed Energy Resources*, RMI (2016).

41 *Renewable energies for manufacturing industries*, IEA (2015). http://www.iea.org/media/workshops/2015/cop21/otherevents/4DecPhilibert.pdf.

42 Only vast deterioration in overall energy productivity could negate this benefit. Not only is this unlikely given the efficiency of many established electric processes, but of course industry could prioritize for conversion those processes promising the most improved emissions profiles.

43 *Renewable energies for manufacturing industries*, EDF (2015), https://www.iea.org/media/workshops/2015/renewablesinmanufacturing/Session4Speaker1CrocombetteEdF.pdf.

44 Ibid., 21-29, and *Renewable energies*, Philbert.

PRIORITY FLEXIBILITY OPTIONS

Optimizing transmission and distribution

As the electricity system evolves to incorporate a greater share of variable renewable energy, transmission and distribution power flow patterns will likely change significantly. This presents a challenge, both with regard to optimizing the usage of existing infrastructure, as well as facilitating investment in new transmission and distribution infrastructure that reliably moves power from where it is generated to where it is consumed. There are a variety of factors that impact the needs for additional transmission infrastructure, and these factors vary significantly from one region to the next. For instance, the distance between the best renewable resources and demand centres, the robustness of the existing grid, the extent to which renewable build-out occurs on the transmission versus distribution grid, and opportunities to export or import power to or from other markets to create greater value overall.

However, there are some common issues encountered in developing this infrastructure, as well as principles for developing and deploying transmission and distribution at lowest cost to the system, as outlined in table 5.9 below.

Table 5.9: Planning and policy can be used to optimise investment and use of T&D infrastructure

	TRANSMISSION INFRASTRUCTURE	DISTRIBUTION INFRASTRUCTURE
Compensation	• Locational marginal pricing to quantify value of grid constraints • Policies and instruments that enable and reduce the risk related to investments in transmission capacity • Regulated return on investment for projects with broad social benefit but marginal project economics	• Traditionally thought of as a natural monopoly compensated through a regulated return on investment (typically through retail rates) • Distributed generation and flexibility resources could offset need for distribution upgrades, if given appropriate market signals (eg, tariffs for flexible load or battery energy storage, value of solar tariffs, or locational distribution pricing)
Planning	• Transmission and interconnection planning needs to account for expected mix and location of electricity generators • Scenario analysis is useful to identify projects that have value across a range of possible future scenarios • Cost and value of new transmission should be compared with other options (eg, changing the location of generation, utilizing flexibility resources to reduce transmission infrastructure need)	• Distribution planning increasingly faced with integration of distributed generation and flexibility resources; needs to be used to identify distribution upgrades that have the most value in range of scenarios
Barriers	• Regional coordination challenges • Local resistance to transmission projects	• Regulatory models for distribution favour utility investment over use of third-party capital for investment in distributed energy resources • Limited information flow between resources and network operators • Utilising distributed energy resources to offset distribution investments requires managing a large number of "endpoints," increasing operational complexity

Summary: Creating the pathway to flexible, low-cost, low-carbon power systems

Building a more flexible, low-cost grid based primarily on renewable energy faces a number of implementation challenges.

- In the near term, many electricity markets will remain ill-designed for valuing flexibility attributes or services and, moreover, for encouraging flexibility from consumers. Modifying markets to better value flexibility services, while broadening participation in these markets to include the demand side will help make electricity systems more dynamic and flexible while keeping costs low.
- In the medium term (10-15 years), electricity systems will begin to see more dramatic changes as greater renewable energy shares reduce fossil-based generation. Changes will be needed in how remaining fossil plants are compensated so that they can remain available to provide flexibility (if and when they are indeed the lowest-cost sources of system flexibility). At the same time, greater electrification of transportation and heat will bring new opportunities and expand the potential for demand-side flexibility, if provided the right market signals.
- In the long term, it will be critical to support innovation, deployment and learning-by-doing in new power system technologies, particularly energy storage. Today's relatively short-term planning horizons do a poor job of capturing the needs of a system that will likely be radically different in 25-30 years. Robust planning and scenario analysis can identify which flexibility investments have value in a variety of future scenarios, as opposed to those that may be made obsolete through changing technology and evolving system needs.

This study has provided a survey of how flexibility needs will evolve, as well as a broad comparison of potential options to meet these flexibility needs. It is clear that flexibility needs vary from one region to another, and that institutional, policy and market contexts can also be quite different by geography. One clear area for deeper analysis is in working with stakeholders in key regions to identify flexibility needs and chart a course for energy system transition.

Moreover, our analysis compares only a handful of flexibility options. In truth, there are dozens of battery technologies, hundreds of demand-side flexibility applications, and countless ways to operate existing electricity generation more flexibly, and many of these options merit deeper exploration and analysis.

Transitioning our energy system from a primarily fossil-based system to one based on renewable energy sources like wind and solar is a complex and long-term task. Flexibility is the key enabler of this transition. A more flexible dynamic electricity grid will allow us to stretch well beyond current renewable energy targets in many regions, ushering in a sustainable future.

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7. Appendix 2: Modelling assumptions and sources

Part 1 – Illustrative cost of renewables-based system

Energy and flexibility needs

This illustrative example is based on the renewable resource profile and expected demand profile in Germany. Germany load profiles and renewable resource profile data from the data archive of Paul Frederick Bach (compiled from Germany's Transmission System Operators), Fraunhofer and EEX.

Renewables profile is based on expected mix of wind and solar in 2040, scaled such that variable renewable energy produces 100% of energy needed over the course of the year. Demand profile based on historical German demand profile, plus incremental heating and EV charging load by 2030.

Time mismatch of energy production and energy consumption is taken into account to calculate storage/shifting, curtailment, and dispatchable generation capacity needs.

	GAS-ONLY CASE	RENEWABLES-BASED WITH GAS FLEXIBILITY	RENEWABLES-BASED WITH GAS AND LITHIUM ION FLEXIBILITY
Demand-coincident energy	505TWh produced at variable cost of energy from CCGT	403TWh produced at LCOE of renewable energy ($60/MWh today, $40/MWh future)	403TWh produced at LCOE of renewable energy ($60/MWh today, $40/MWh future)
Storage / Shifting	N/A	N/A	Storage sized to meet average day shifting need (21GW, 136GWh) 33 TWh shifted annually
Overproduction of energy	N/A	102TWh curtailed, cost is LCOE of renewable energy ($60/MWh today, $40/MWh future)	69TWh curtailed, cost is LCOE of renewable energy ($60/MWh today, $40/MWh future)
Underproduction of energy	N/A	102TWh produced at variable cost of energy from CCGT	69 Wh produced at variable cost of energy from CCGT
Capacity on worst shortfall day	Peak hourly demand (81GW)—met by CCGT capacity at annualized fixed cost	Peak hourly "net demand" after renewable energy (62GW)—met by CCGT capacity at annualized fixed cost	Peak hourly "net demand" after renewable energy (62GW) - first met by storage (21GW), which reduces amount of CCGT capacity (50GW) needed
Reserves	3% contingency reserve, 2% demand uncertainty - total 4GW, met by additional CCGT capacity	3% contingency reserve, 5% RE production uncertainty - total 10GW, met by additional CCGT capacity	3% contingency reserve, 5% RE production uncertainty - total 10GW, met by additional battery capacity with 2 hours (20GWh) of storage

Calculation of Daily/Intraday Balancing Needs

INTRADAY BALANCING PROVIDED BY:	GAS ONLY (WITH NO CARBON PRICE)	A MIX OF GAS AND STORAGE (WITH NO CARBON PRICE)
CCGT		
Capacity	62GW	50GW
Energy generated	50TWh	17TWh
Capacity cost per year	140 $/kW-yr	140 $/kW-yr
Variable cost	50 $/MWh	50 $/MWh
Total cost	11.2 $bn	7.8 $bn
Lithium-ion battery		
Capacity		21GW x 136GWh
Energy shifted	-	33TWh
Capacity cost per year	-	160 USD/kW-yr
Variable cost (losses)	-	3.2 $/ MWh
Total cost	-	3.5 $bn
Total	11.2 $bn	11.3 $bn
Cost per MWh shifted	225 $/MWh	229 $/MWh
Cost per MWh of total load (505TWh)	**22.1 $/MWh**	**22.5 $/MWh**

Calculation of Seasonal/Interday Balancing Needs

	CCGT TO PROVIDE INTERDAY/SEASONAL BALANCING (WITH NO CARBON PRICE)
CCGT	
Capacity	62GW
Energy generated	53TWh
Capacity cost per year	Counted under intraday balancing
Variable cost	50 $/MWh
Total cost	2.6 $bn
Cost per MWh shifted	50 $/MWh
Cost per MWh of total load (505 TWh)	**5.2 $/MWh**

Supply and flexibility options

VARIABLE RENEWABLE ENERGY PRODUCTION:

- Cost based on midrange of today's cost and future estimates: $60/MWh today, $40/MWh future estimate (Lazard, BNEF)

LITHIUM-ION BATTERY:

- Not expected to be economic replacement of CCGT capacity at today's costs, so not modeled in today's cost scenario
- Future cost of $150/kWh based on BNEF, Navigant and RMI forecasts.
- Current O&M estimate of $58/kW-yr expected to remain
- Fixed costs annualized over lifetime of equipment (with 10% discount rate), approximately $160/kW-yr for shifting battery, and $100/kW-yr for reserves battery
- Future cycle life assumed to improve to 10,000 cycles (high end of today's product warranties – eg, Sonnen)
- 8% losses assumed based on current technologies, at cost of renewable energy production

CCGT:

- Capital cost of $1230/kW, fixed O&M of $6.31/kW-yr, variable O&M of $3.67/MWh (Black and Veatch)
- Fuel cost of $4.70/MMBtu—based on IEA WEO 2020 US estimate (and assumed here to be a generic midrange between low-cost US gas and high cost Asian and European gas) – no difference assumed between current and future scenarios
- Emissions intensity calculated at 0.357 tonnes/MWh, valued (where applicable) at $50/tonne.
- Fixed costs annualized at 10% discount rate

Part 2 – Calculation of flexibility needs

Flexibility needs were calculated for each region based on regionally specific resource profiles for wind and solar, as well as historical demand profiles (and expected changes to demand profiles with greater electrification of vehicles and heating). Net demand profiles were calculated on an hourly basis by subtracting estimated variable renewable energy production (based on estimated market share from region-specific low carbon scenarios).

Specifically, the following metrics were calculated for each region:

- Ramping: Maximum 3-hour change in net demand each day (GW)
- Daily balancing: Non-coincident renewable energy production (GWh) that could be shifted and used within the day
- Seasonal balancing: Non-coincident renewable energy production (GWh) that cannot be used within the same day

Key data sources are listed below.

California

RESERVES

- CAISO, 2015 Annual Report on Market Issues and Performance, https://caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf
- GE, CAISO Frequency Response Study, 2011, https://www.caiso.com/Documents/Report-FrequencyResponseStudy.pdf
- NREL, Low-Carbon Grid Study, 2015

RAMPING, DAILY BALANCING, SEASONAL BALANCING

- CPI analysis
- Load profile and renewable resource profile data from CAISO
- Renewable energy share from E3, Pathways Straightline Scenario
- Electrification potential by end-use from E3, Pathways Straightline Scenario

Germany

RESERVES:

- DENA, Ancillary Services Study 2030, 2014

RAMPING, DAILY BALANCING, SEASONAL BALANCING:

- CPI analysis
- Load profile and renewable resource profile data from Paul Frederick Bach, Fraunhofer and EEX
- Renewable energy share from Nitsch, Szenario 2013
- Electrification potential by end-use from Nitsch, Szenario 2013 and GROKO-II Scenario (2014)

Maharashtra

RESERVES:

- Central Electricity Regulatory Commission, Committee on Spinning Reserves, September 2015, http://www.cercind.gov.in/2015/orders/Annexure-%20SpinningReseves.pdf

RAMPING, DAILY BALANCING, SEASONAL BALANCING:

- CPI analysis
- Load profile and renewable resource profile data from Maharashtra Load Dispatch Centre
- Renewable energy share from IEA, Energy Technology Perspectives, 2015, 2 Degrees Scenario
- Electrification potential by end-use from IEA, Energy Technology Perspectives, 2015, 2 Degrees Scenario

Nordic region

RESERVES:

- Smart Energy Demand Coalition (SEDC), Mapping Demand Response in Europe Today 2015 (2015)
- THEMA Consulting Group, Capacity adequacy in the Nordic electricity market (2015).
- ENTSO-E, Nordic Systems Operation Workshop (10 December 2014).

RAMPING, DAILY BALANCING, SEASONAL BALANCING:

- CPI analysis
- Load profile and renewable resource profile data from Nord Pool
- Renewable energy share from IEA, Nordic Energy Technology Perspectives, 2016, Carbon-Neutral Scenario
- Electrification potential by end-use from IEA, Nordic Energy Technology Perspectives, 2016, Carbon-Neutral Scenario

Part 3 – Supply Stacks: Key Cost Assumptions

FLEXIBILITY OPTION	CAPEX ($/KW)	FIXED O&M ($/KW-YR)	VARIABLE O&M ($/ MWH)	FUEL COST ($/MMBTU) [FUEL INFLATION]	HEAT RATE (BTU/KWH)	CO2 EMISSIONS (TONNES / MWH)	LIFETIME (YRS)
Supply Side							
New GT	651	5.3	29.9	4.70 [5%]	10,390	0.553	20
New CCGT	1230	6.31	3.67	4.70 [5%]	6,705	0.357	20
Existing CCGT	0	6.31	3.67	4.70 [5%]	6,705	0.357	20
Existing Coal	0	23.0	3.71	2.00 [0%]	9,000	0.880	20
Existing reservoir hydro	0	15.0	3.00	0	0	0	40
Demand side							
EV charging	500	5.00	0	0	0	0	10
Industrial load curtailment	10	5.00	250.00 (opp. cost)	0	0	0	10
Commercial/ residential automated load shift	300	30.00 (including customer incentive)	0	0	0	0	10
Conversion							
Hydrogen electrolysis + combustion (current)	2008	22.00	0	58% losses valued at LCOE of RE	0	0	20
Hydrogen electrolysis + combustion (post-2030)	1448	22.00	0	58% losses valued at LCOE of RE	0	0	20
Additional cost for tank-based storage	19/kWh						
Additional cost for geologic storage	0.30/kWh						
Energy storage							
Lithium ion (current)	700/kWh	58.00	0	8% losses valued at LCOE of RE	0	0	5,000 cycles (or 20 yrs)
Lithium ion (post-2030)	150/kWh	58.00	0	8% losses valued at LCOE of RE	0	0	10,000 cycles (or 20 yrs)
New pumped hydro	3000	15.00	0	25% losses valued at LCOE of RE	0	0	40
Infrastructure							
New transmission	1200	15	0	0	0	0	40

Key operating assumptions

10-minute reserve capacity

- All costs based on capacity available within 10 minutes. Because of startup and ramping times only 50% of CCGT capacity, and 20% of coal capacity were assumed to be available within 10 minutes. All other flexibility options are sufficiently fast-starting or fast ramping to be fully available within 10 minutes.
- Because CCGT and coal generation must remain online to provide to-minute reserves, costs include "unrecovered operating costs"—operating costs during periods of expected RE surplus—of approximately 7% of annual operating costs at minimum generation levels.
- Otherwise costs only include fixed costs (eg, no fuel, startup, redispatching costs included)

Peak daily shifting

- All resources compared on a 5% capacity factor basis (ie, 438 full load hours per year).
- Generation-only resources assumed to include cost of curtailment of equivalent MWh (eg, at times of renewable energy over-production), at an assumed $60/MWh today, $40/MWh future.
- Storage resources assumed to include storage losses, valued at $60/MWh today, $40/MWh future.

Regular daily shifting

- All resources compared on a 30% capacity factor basis (ie, 2,628 full load hours per year, or 7.2 hours per day).
- Generation-only resources assumed to include cost of curtailment of equivalent MWh (ie, at times of renewable energy over-production), at an assumed $60/MWh today, $40/MWh future.
- Storage resources assumed to include storage losses, valued at $60/MWh today, $40/MWh future.
- Storage resources assumed to cycle daily, and sized to have sufficient hours of storage to deliver power for up to 8 hours per day.

Seasonal shifting

- Seasonal shifting assumes 20% capacity factor for generation resources.
- Storage resources assumed to perform 1 cycle per year.
- Transmission assumed 40% utilization factor (bi-directional), and availability of flexible resources through interconnection to provide (or absorb) energy.
- Industrial maintenance shift assumed to only include the cost of seasonal curtailment of excess energy (as maintenance shift only assumed to reduce energy consumption in high season)
- Seasonal electric arc furnace and aluminum smelter include cost of equipment, cost of increased equipment failure rates (aluminum smelting pots), and cost of fixed labor costs, as well as cost of seasonal curtailment of excess energy production (as operating seasonally only reduces energy consumption in high season).