A Brave New World

DEEP DE-CARBONIZATION OF ELECTRICITY GRIDS

J.P. Morgan
Our annual energy paper: the deep de-carbonization of electricity grids

October 19, 2015

A Brave New World

In our last few annual energy notes, we analyzed the individual components of the electricity grid: coal, nuclear, natural gas, wind, solar and energy storage. This year, we look at how they fit together in a system dominated by renewable energy, with a focus on cost and CO₂ emissions. The importance of understanding such systems is amplified by President Obama’s “Clean Power Plan”, a by-product of which will likely be greater use of renewable energy for electricity generation.

This year, we focus on Germany and its Energiewende plan (deep de-carbonization of the electricity grid in which 80% of demand is met by renewable energy), and on a California version we refer to as Caliwende. We compare these systems to the current electricity mix, and to a balanced system with a mix of renewable and nuclear energy. These charts summarize cost (Y-axis) and emission (X-axis) results:

Our primary conclusions:

• A critical part of any analysis of high-renewable systems is the cost of backup thermal power and/or storage needed to meet demand during periods of low renewable generation. These costs are substantial; as a result, levelized costs of wind and solar are not the right tools to use in assessing the total cost of a high-renewable system

• Emissions. High-renewable grids reduce CO₂ emissions by 65%-70% in Germany and 55%-60% in California vs. the current grid. Reason: backup thermal capacity is idle for much of the year

• Costs. High-renewable grid costs per MWh are 1.9x the current system in Germany, and 1.5x in California. Costs fall to 1.6x in Germany and 1.2x in California assuming long-run “learning curve” declines in wind, solar and storage costs, higher nuclear plant costs and higher natural gas fuel costs

• Storage. The cost of time-shifting surplus renewable generation via storage has fallen, but its cost, intermittent utilization and energy loss result in higher per MWh system costs when it is added

• Nuclear. Balanced systems with nuclear power have lower estimated costs and CO₂ emissions than high-renewable systems. However, there’s enormous uncertainty regarding the actual cost of nuclear power in the US and Europe, rendering balanced system assessments less reliable. Nuclear power is growing in Asia where plant costs are 20%-30% lower, but political, historical, economic, regulatory and cultural issues prevent these observations from being easily applied outside of Asia

• Location and comparability. Germany and California rank in the top 70th and 90th percentiles with respect to their potential wind and solar energy (see Appendix I). However, actual wind and solar energy productivity is higher in California (i.e., higher capacity factors), which is the primary reason that Energiewende is more expensive per MWh than Caliwende. Regions without high quality wind and solar irradiation may find that grids dominated by renewable energy are more costly
• **What-ifs.** National/cross-border grid expansion, storing electricity in electric car batteries, demand management and renewable energy overbuilding are often mentioned as ways of reducing the cost of high-renewable systems. However, each relies to some extent on conjecture, insufficient empirical support and/or incomplete assessments of related costs.

**Other implications of high-renewable systems:**

• **Transmission costs excluded.** We exclude investments in transmission infrastructure often required to accompany large amounts of renewable energy capacity, which could substantially increase the estimated cost of high-renewable systems. Wind capacity factors may also degrade with a large wind build-out since the most optimal sites are often developed first.

• **Other uncertainties.** As thermal power (gas, coal) is further relegated to a backup power role, there are uncertainties regarding how such high-cost, low-utilization assets will be financed and maintained by the private sector.

This paper gets into the weeds of hourly generation and intermittency. I found that it’s difficult to have a well-informed understanding of renewable systems without doing so. **My goal:** to give you a layman’s perspective of high-renewable systems while still adhering to the physical and engineering realities of electricity generation, stripped of the hyperbole which often accompanies the subject.

As always, our energy piece is overseen by Vaclav Smil, Distinguished Professor Emeritus in the Faculty of Environment at the University of Manitoba in Winnipeg and a Fellow of the Royal Society of Canada. His interdisciplinary research has included the studies of energy systems (resources, conversions, and impacts), environmental change (particularly global biogeochemical cycles), and the history of technical advances and interactions among energy, environment, food, economy, and population. He is the author of 37 books and more than four hundred papers on these subjects and has lectured widely in North America, Europe, and Asia. In 2010 Foreign Policy magazine listed him among the 100 most influential global thinkers. In 2015, he received the biennial OPEC award for research. He is also described by Bill Gates as his favorite author.

Michael Cembalest
J.P. Morgan Asset Management

**Why de-carbonize the electricity grid? Vaclav offers his opinion**

The impact of CO₂ emissions on the planet is not the purpose of this year’s energy paper. We are primarily focused on understanding the direct cost and emission implications of electricity systems with large amounts of renewable energy, the mechanics of energy storage, etc. However, I did ask Vaclav for his thoughts on the de-carbonization question. Here is his response:

“Underlying all of the recent moves toward renewable energy is the conviction that such a transition should be accelerated in order to avoid some of the worst consequences of rapid anthropogenic global warming. Combustion of fossil fuels is the single largest contributor to man-made emissions of CO₂ which, in turn, is the most important greenhouse gas released by human activities. While our computer models are not good enough to offer reliable predictions of many possible environmental, health, economic and political effects of global warming by 2050 (and even less so by 2100), we know that energy transitions are inherently protracted affairs and hence, acting as risk minimizers, we should proceed with the de-carbonization of our overwhelmingly carbon-based electricity supply – but we must also appraise the real costs of this shift. This report is a small contribution toward that goal.”
Table of contents

Introduction and comments from Vaclav on the goal of de-carbonization 1

Section 1: Germany
1a. Germany’s Energiewende Plan 4
1b. Germany renewable generation and electricity demand 5
1c. A comparison of Energiewende with Germany’s current electricity mix 6
1d. Exploring the energy storage dynamics of a renewable energy world 7
1e. Energiewende, with and without storage 8
1f. Is there a cheaper way to do it? A balanced system, with nuclear power 9
1g. Learning curves and possible cost changes in the future 11
1h. Concluding thoughts on Energiewende…is Germany the wrong test case? 12

Section 2: California
2a. Caliwende: California’s version of a high-renewable energy system 13
2b. California renewable generation and electricity demand 14
2c. A comparison of Caliwende with California’s current electricity mix and a balanced system 15

Conclusions and more what-ifs 16-17

Appendices 18-26
Appendix I How relevant are Germany and California to the rest of the world?
Appendix II Estimating the need for back-up thermal capacity in a high-renewable system
Appendix III Current and future costs per generation source
Appendix IV A cost-emissions preference curve for analyzing energy storage
Appendix V Nuclear power cost and future technology alternatives
Appendix VI Energy learning curves
Appendix VII What about storing energy in electric car batteries?
Appendix VIII The uncertain magic of demand management

Acknowledgements and Sources 27
Acronyms 28

Before we get started, a comment on cost. The cost of electricity generation is absorbed by ratepayers (users of electricity), shareholders of electricity generation/distribution companies, and taxpayers (via subsidies). In other words, electricity rates paid by households and businesses are not the only place to look when analyzing the total cost of electricity. In this paper, we look at overall cost (construction plus ongoing operational and maintenance expenses), excluding the benefit of subsidies. This concept is known as direct cost. There are also indirect costs related to environmental and health consequences of fossil fuels that direct costs do not include, and which are driving the push for deep de-carbonization of electricity grids. While direct costs exclude these exogenous costs, they are still useful in comparing different de-carbonization alternatives.
1a. Germany’s Energiewende Plan

Energiewende is an energy policy passed by the German government in 2011. On the demand side, the policy calls for a 25% reduction in electricity usage below 2008 levels by the year 2050. This is a large decline, and would bring German electricity consumption below 1985 levels and below a projection for 2050 that takes into account Germany’s demographics.

On the supply side, Energiewende aims to phase out nuclear power by 2022 and meet 80% of electricity demand via renewable energy. To do so, Energiewende envisages Germany’s wind generation growing by 3x and solar growing by 2x. With nuclear decommissioned, electricity demand unmet by renewable energy would most likely be met by thermal power: domestic coal and imported natural gas, the latter being better suited to ramping, and the former offering Germany more energy security.

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1 A 1980 publication by Öko-Institut coined the term Energiewende; “die Wende” means change or a turn, but in English the compound noun is usually translated as “energy transition”.

2 Some additional background on Energiewende. Germany’s transition to higher renewables began in 2000 with the passage of the Renewable Energies Law, which subsidized renewable electricity generation. All electricity generated by renewable energy became eligible for guaranteed fixed payments to producers, and the grid had to absorb all output even if coal, fuel oil, or natural gas plants had to be curtailed or shut down. The law had its desired effect: between 2000 and 2010, German renewable generation tripled to 17% of electricity generation.

The process is not without its detractors, given operational issues for German grid operators, and undermined economic viability of traditional utilities due to low returns realized on fossil fuel-based generation. Germany electricity consumers are already feeling the impact. In 2014, the average electricity price including taxes for German residential and industrial segments was EUR 298 per MWh (2nd highest of 28 European countries, behind Denmark) and EUR 203 per MWh (3rd highest in Europe), respectively. For comparison, the average price of US electricity is EUR 94 and 53 per MWh for residential and industrial sectors. Sources: Eurostat, EIA, JPMAM.
1b. Germany renewable generation and electricity demand

Let’s start with a sense for how Energiewende might work in practice using hourly generation data for January and June. The charts show hydroelectric and biomass power generation, plus wind and solar generation multiplied by 3x and 2x based on Energiewende targets (e.g., an expanded footprint of Germany’s existing wind and solar facilities). In January, there would be lot of wind but not much solar, and in June, less wind and more solar. Although hydro-electricity generation is variable, we assume that hydro and biomass are run at constant rates, functioning as a small amount of baseload power.

How would this electricity supply meet demand? The next charts superimpose 2014 German demand for electricity (“the load”), reduced by 25% as per the Energiewende plan. There are times of excess renewable generation (a surplus), and times when renewable generation is not enough to meet demand, in which case thermal power would be called upon to meet the gap. In January, supply-demand gaps occur during extended periods of wind variability, while in June, they are related to daily solar variability.

These are just two months in the year, as examples. Over the entire year, surpluses would be 47 TWh higher than the load, while deficits would be 107 TWh. As a result, we can draw two preliminary conclusions about Energiewende: (a) there would be substantial need for back-up power, and (b) energy storage of new renewables (wind and solar) would only partly mitigate the need for and use of backup thermal power, since the surpluses are smaller than the deficits.

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3 Hydropower (run-of-river and stored hydro) is 3% of total electricity generation in Germany. While hydro does have some dispatchable capacity, the impact on the broader electricity system is not very large.
1c. A comparison of Energiewende with Germany’s current electricity mix

To get a sense for the cost and CO₂ implications of Energiewende, we compare it to Germany’s current electricity generation mix:

<table>
<thead>
<tr>
<th>Installed capacity (GW)</th>
<th>Generation</th>
<th>Cost</th>
<th>CO₂ emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total</td>
<td>Wind</td>
<td>PV</td>
</tr>
<tr>
<td>Current; No Stor; Curr cost</td>
<td>120</td>
<td>24</td>
<td>25</td>
</tr>
<tr>
<td>Energiewende; No Stor; Curr cost</td>
<td>278</td>
<td>118</td>
<td>86</td>
</tr>
</tbody>
</table>

Source: Germany grid operators, JPMAM 2015.

Key findings regarding our assessment of Energiewende:

- **Backup power needs unchanged.** Germany’s need for thermal power (coal and natural gas) does not fall with Energiewende, since large renewable generation gaps result in the need for substantial backup capacity (see Appendix II), and also since nuclear power has been eliminated.

- **Emissions sharply reduced.** While there’s a lot of back-up thermal capacity required, for much of the year, these thermal plants are idle. Energiewende results in a 52% decline in natural gas generation vs. the current system, and a 63% decline in CO₂ emissions.

- **Cost almost double current system.** The direct cost of Energiewende, using today’s costs as a reference point, is 1.9x the current system. Compared to the current system, Energiewende reduces CO₂ emissions at a cost of $300 per metric ton.

Here are the underlying assumptions (we iterate the results using different cost assumptions later):

- **Renewable energy grid priority.** Baseload hydro and biomass get first preference on the grid, followed by wind and solar; any residual unmet demand is satisfied by thermal power split 50/50 between coal and natural gas (Germany’s current thermal power split is 82% coal/18% natural gas).

- **Capacity buffer.** We include a 20% capacity buffer for demand spikes or supply shortfalls.

- **Curtailment of excess generation.** When renewable energy generation is above demand, it is “curtailed”, which means that it is not used by the German grid. The next section considers storage.

- **Generation costs.** Generation costs are based on data from the Energy Information Administration, the National Renewable Energy Laboratory, the Electric Power Research Institute and other sources as described in Appendix III. All costs exclude subsidies, and are for projects delivered in 2016-2018.

- **Fuel costs.** We assume coal at $2 per MMBtu and natural gas at $10 per MMBtu based on a 5-year average of German gas import costs from its largest suppliers (Russia, Norway, Netherlands).

- **Cost measures: generation vs consumption.** “Cost per MWh-cons” is the cost of generating electricity consumed in Germany, while “cost per MWh-gen” is the cost of total electricity generated. There’s not a large difference between them; only 11% of generation is unused in the Energiewende scenario. Surplus electricity may have less economic value if surrounding areas experience a surge in renewable generation at the same time.
1d. Exploring the energy storage dynamics of a renewable energy world

One goal of energy storage: during periods of excess renewable generation, time-shift energy so as to avoid having to discard it, and therefore reduce the need for backup thermal generation. There are several approaches: gravitational energy (pumped hydro), pressure energy (compressed air), chemical energy (conventional, high temperature and “flow” batteries) and hydrogen. Pumped storage is the most common, accounting for over 95% of all energy stored in the US and around the world. There are substantial efforts underway to develop cost-effective storage alternatives, a topic we covered last year, but it is too early to assess their ultimate penetration rates.

Energy storage sounds great, but there are three constraints to keep in mind:

- **Account for energy loss.** Storing energy involves energy loss (energy that is stored and not recovered). In the case of pumped storage, for example, overall efficiency is around 80%. Existing and prototype chemical and hydrogen storage techniques experience similar energy losses as well, both instantaneous and over time (see chart, right).

- **Account for cost.** Gravitational and pressure energy storage systems are capital intensive, involving terrain management and engineering. As for utility-scale battery energy storage systems, they require commodity inputs (sodium, chromium, nickel, cadmium, zinc, lithium, etc.), protective housing and other materials. The broader point is that energy storage does not create energy, and simply shifts it in time. Costs include upfront capital costs, and ongoing operation and maintenance.

- **Account for scope.** A storage system is not an abstract holding pen for any imaginable renewable generation surplus, but one with predetermined capabilities to provide power and store it. When estimating cost, one must account for the storage reservoir (measured in MWh) and equipment which provides instantaneous power (measured in MW). In some approaches like lithium ion batteries, the power (MW)-to-energy (MWh) ratio is fixed. For others, they can be separate, as with hydrogen storage (hydrogen storage tanks can be sized independently and alter the power-to-energy ratio).
1e. **Energiewende**, with and without storage

Subject to the constraints from the prior page, we went in search of intelligent life in the storage universe by giving the following tools to imaginary Energiewende grid operators:

- **Storage types.** The ability to use pumped storage, zinc hybrid battery storage or hydrogen storage; we did not incorporate geographic limitations on feasible pumped storage sites
- **Power vs reservoir.** The ability to resize the storage system, both with respect to its instantaneous power (MW) and the energy it can store (MWh), subject to existing power-to-energy ratios
- **Storage operations.** The ability to draw on stored energy as soon as there is a renewable generation gap vs. demand, or to save some for a rainy day with the goal of mitigating the largest demand gaps of the year, in which case the need for backup thermal capacity could be diminished
- **Storage reservoir management.** The ability to run thermal plants to fill empty storage reservoirs, with the same goal as the prior one: to decrease the year’s largest demand gaps

Results: the best energy storage results reduced emissions by 8% and increased costs by 6%.

The chart shows system cost on the y-axis and CO₂ emissions on the x-axis. Energiewende without storage is shown (green circle), along with the best cost-emission storage tradeoffs we found. System costs rise with storage, since capital and operating costs of storage are higher than foregone natural gas fuel costs, and since no thermal capacity is taken offline. Is it still worth doing? Using a preference curve approach indicated by the dotted line (see Appendix IV) it might be, but this is a subjective conclusion.

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**The International Energy Agency on energy storage at current costs and performance**

From the International Energy Agency Technology Perspectives 2014 Factsheet: “Electricity storage is expected to play multiple roles in future energy systems, but it is unlikely to be a transformative force itself. At current costs and performance levels, particularly for high-power and high-energy applications, it falls short of delivering the conceptual flexibility potential when compared with competing options” (i.e., dispatchable natural gas).

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*Hydrogen is generally not used for utility-scale storage* due to its high cost and low round-trip efficiency, of around 40%. However, some academic papers note its theoretical potential for energy storage when large amounts of storage (MWh) are needed relative to power (MW), since with hydrogen storage, the two are essentially separate. Hydrogen is stored in separate tanks and can be sized independently of the electrolyzer and fuel cell.

**Why only battery storage, pumped storage and hydrogen storage?** Approaches like flywheels are designed for frequent, short-term applications (fluctuation suppression, regulation control, voltage stability, mitigating power oscillations) and are not relevant to a discussion of storing large amounts of excess renewable generation.
1f. Is there a cheaper way to do it? A balanced system, with nuclear power

Nuclear Power. For some, the discussion stops here, since they have scientific, financial, environmental or geopolitical objections. That said, we analyze a balanced system as well: Germany maintains the wind, solar, hydro and biomass it now has; relies on nuclear to meet 35% of demand by turning back on some of its idle plants; and uses a 50/50 natural gas/coal mix for the remainder. Balanced results are shown in the last row, along with no-storage and storage scenarios for Energiewende, and the current system.

The balanced system we analyzed achieves cost and CO2 reductions at a much lower cost per metric ton than Energiewende ... but only if EIA nuclear cost projections are accurate. In support of EIA data, Carnegie Mellon published a 2013 survey of 16 nuclear power industry practitioners in the Proceedings of the National Academy of Sciences. Their median cost estimates for nuclear plants developed in the Southeast US were pretty close to the most recent EIA projections.

However, EIA and Carnegie Mellon cost estimates may not reflect reality. The rising trend in OECD nuclear capital and operating costs is a topic we addressed last year. In the US, real costs per MWh for nuclear have risen by 19% annually since the 1970’s. Even in France, the country with the greatest reliance on nuclear power as a share of generation and whose centralized decision-making and regulatory structure are geared toward nuclear power, costs have been rising and priorities are shifting to renewable energy. Globally, nuclear power peaked as a share of electricity generation in 1995 at 18% and is now at 11%, primarily a reflection of slower development in the OECD.

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5 Even when nuclear power plants are not completed, as with the cancelled Levy County plant in Florida, they can become huge political and economic liabilities.

6 There are huge cost over-runs at Flamanville France and Olkiluoto (Finland), the first plants built in Europe in 20 years. In Finland, 50% cost over-runs and delivery delays of nine years resulted in the utility abandoning its option to apply for a second French Evolutionary Power Reactor (EPR). In February 2015, Areva asked the US Nuclear Regulatory Commission to suspend work on EPR design certification until further notice. The coup de grace: France now aims to reduce nuclear from 70% to 50% of its electricity mix and increase renewable energy.
In contrast to stagnation in the US and Europe, nuclear power is alive and well in Asia where 50 GW are under construction and where plant costs are lower. The World Nuclear Association cites nuclear construction costs in China and Korea that are 20%-30% below US and EU levels. KEPCO (S Kor.) is building 5.6 GW of nuclear in the UAE, scheduled for delivery in 2017 at $3,600 per kW, which is 35% below EIA cost assumptions for the US. Asian cost differentials vs. the US and Europe are apparently related to shorter lead times, shorter construction times and lower labor costs. The differences do not appear to reflect different nuclear technology, since almost all plants under construction worldwide are either boiling water reactors or pressurized water reactors.

Some of the cost difference, in our view, reflects a greater degree of collectivism in government energy policy in Asia relative to the US and Europe. Whatever the reasons, there are intense debates as to whether the nuclear standardization and cost structure in Asia could be replicated in the US or Europe without compromising regulatory and legal protocols. It may be possible, but we have little to base this on without more evidence of exactly why costs are so much lower in Asia.

The chart below shows nuclear plant construction starts worldwide since 1955. Over 80% of plants now under construction are in emerging economies. While balanced systems may offer cost and CO₂ emissions advantages vs. high-renewable systems, a grid with 35% of demand met by nuclear power appears to run counter to current government and voter preferences in the OECD.

Emerging economies account for most of the recent recovery in plant construction, global nuclear reactor starts

![chart showing nuclear plant construction starts worldwide since 1955](chart.png)

1g. Learning curves and possible cost changes in the future

Wind and solar costs fell sharply in recent decades, following established patterns of costs declining as installed capacity increases (see Appendix VI for more on learning curves). As a result, we consider scenarios in which costs decline further. The first is a favorable scenario for Energiewende, and incorporates the following assumptions (all of which are outlined in Appendix III):

- **Lower wind/solar costs.** Long-term technological road maps from the International Energy Agency assume 10% and 47% further declines in wind and solar capital costs, and similar declines in O&M costs.

- **Lower storage costs.** A 2015 Nature Climate Change Journal study projects 35% declines in capital and O&M costs for lithium batteries; we apply similar changes to zinc hybrid batteries. The National Renewable Energy Laboratory projects similar declines for hydrogen storage and round-trip efficiency rising from 44% to 61%, but in all candor we were not convinced by NREL’s rationale on either point.

- **Higher natural gas fuel costs.** We assume no change in natural gas or coal plant capital costs, but assume higher fuel costs in Germany of $13 per MMBtu; no change in coal prices.

- **Higher nuclear costs.** We assume that nuclear capital and fixed O&M costs are 25% higher than EIA estimates, reflecting increases in safety, spent fuel rod and decommissioning costs.

**Results: the cost gap partially closes.** If all of these changes took place, Energiewende’s cost vs. the current system falls from 1.9x to 1.6x, and the cost of CO₂ emission reductions vs. the current system falls from $300 to $200 per ton. The balanced system cost doesn’t change much and remains cheaper than Energiewende, since higher nuclear costs are offset by lower renewable costs. Storage still adds to net system cost, but at least the best results were inside our preference curve.

We added another point on the first chart to reflect the following premise. In the future, utilities may add storage as an independent business decision unrelated to high-renewable grids. The reasons: replace aging peaker plants, and/or avoid expensive upgrades to transmission lines. To explore the cost-emission consequences of this premise, we assume that in the future, utilities will have replaced 100% of their peaker plants with storage. This “pre-existing” storage outcome shows larger emissions declines at no incremental cost, since it’s a storage “free lunch”. While I am sympathetic to the logic, this sequence of events and the degree to which utilities make this transition is too uncertain to consider as a base case.

A final cost iteration in the second chart (Fut Cost 2) uses all the same assumptions with the exception of nuclear, whose costs are assumed to be 20% below current EIA levels. This would put nuclear costs only 5% above those in South Korea. The impact: a 10% decline in balanced system costs. What could drive such a decline in costs? Either greater standardization of the process by which plants reliant on current technology are approved and built, or a new approach to nuclear power, some of which are outlined in Appendix V (to be clear, we are likely decades away from commercialization of these alternatives).
1h. Concluding thoughts on Energiewende…is Germany the wrong test case?

Energiewende looks expensive, even when assuming future learning curve cost declines. Could the problem be that Germany is the wrong test case? Berlin and Frankfurt receive 20% less sunlight than Seattle, so Germany may not be the best place to explore solar power’s potential. And with regards to wind, German wind capacity factors are low despite its favorable wind conditions. Anyone who follows renewable energy will recognize that Germany’s wind and solar capacity factors in the chart (left) are very low. In the next section, we look at California, which as shown in the second chart, has done a better job harnessing its wind and solar resources.

With respect to wind and solar capacity factors, one would not pick Germany to lead the way in renewables. Percent

<table>
<thead>
<tr>
<th>Year</th>
<th>Wind</th>
<th>Solar</th>
</tr>
</thead>
<tbody>
<tr>
<td>1991</td>
<td>30%</td>
<td>5%</td>
</tr>
<tr>
<td>1994</td>
<td>25%</td>
<td>10%</td>
</tr>
<tr>
<td>1997</td>
<td>20%</td>
<td>15%</td>
</tr>
<tr>
<td>2000</td>
<td>15%</td>
<td>20%</td>
</tr>
<tr>
<td>2003</td>
<td>10%</td>
<td>25%</td>
</tr>
<tr>
<td>2006</td>
<td>5%</td>
<td>30%</td>
</tr>
<tr>
<td>2009</td>
<td>0%</td>
<td>30%</td>
</tr>
<tr>
<td>2012</td>
<td>0%</td>
<td>30%</td>
</tr>
</tbody>
</table>

Source: German Federal Ministry for Economic Affairs and Energy, 2014.

2014 capacity factors for wind and solar in Germany and California, Percent

<table>
<thead>
<tr>
<th>Capacity factors measure electricity generated relative to rated capacity assuming 24/7/365 production</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
</tr>
<tr>
<td>Solar PV</td>
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<table>
<thead>
<tr>
<th>Region</th>
<th>Wind</th>
<th>Solar PV</th>
</tr>
</thead>
<tbody>
<tr>
<td>GER</td>
<td>10%</td>
<td>15%</td>
</tr>
<tr>
<td>CAL</td>
<td>20%</td>
<td>25%</td>
</tr>
</tbody>
</table>

Source: Germany grid operators, CAISO, JPMAM, 2015.

Wind capacity factors in California are higher than in Germany, despite generally superior overall wind conditions in Germany according to National Renewable Energy Laboratory and IRENA Global data. This [link](#) shows wind speeds maps which compare the two regions.
2a. **Caliwende: California's version of a high-renewable energy system**

Using our framework for examining electricity grids, we examine California. California's renewable generation is rising, reflecting subsidies for wind and solar, declining solar module and installation costs, improving solar capacity factors from inverter efficiency and single/dual axis tracking panels, and a 33% Renewable Portfolio Standard target which was raised this year to 50% by the state legislature.

Here's where California stands today. In 2014, renewable energy represented 22% of in-state electricity generation. We also estimate that ~50% of its electricity imports derive from renewable energy as well, some of which is hydroelectric and wind power imported from the Pacific Northwest. If so, on a look-through basis, around a third of California's electricity use comes from renewable energy. With this backdrop, here’s what "Caliwende" (the counterpart to Energiewende) might look like:

- The share of California electricity demand met by renewable energy is the same as in Energiewende (80%). In California, this requires a 5x increase in wind and an 8x increase in solar
- We assume solar capacity growth will be mostly photovoltaic rather than concentrated solar thermal, given the predominance of the former and early-stage disappointments at the Ivanpah concentrated solar facility in the Mojave desert. Ivanpah, a bellweather project that the Dep’t of Energy describes as the world’s largest solar thermal plant in operation, has been generating 15% capacity factors that appear to be roughly half of initial projections
- California shutters the small amount of its remaining coal capacity (less than 200 MW)
- Following the closure of the San Onofre nuclear plant in 2013, California closes its last remaining nuclear power plant in Diablo Canyon (2.3 GW)
- California continues to import 27% of its electricity from neighboring states: surplus hydropower and wind power from the Pacific Northwest, and a combination of natural gas, nuclear, hydro and solar power from the Southwest
- Any shortfall in electricity supply is met by natural gas (and not coal)

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8 Our analysis of California covers the part of the state whose electricity is governed by the California Independent System Operator (CAISO). All references to “California” in this section refer to this region. CAISO region electricity generation is ~85% of total in-state California generation.

9 We used EIA data to compute capacity factors for Ivanpah. The other mystery about Ivanpah: why is it using so much natural gas? We found that Ivanpah concentrated solar thermal plants are using an amount of natural gas equal to ~20% (in energy terms) of its total solar generation. At the minimum, this suggests that fuel costs should be incorporated into levelized cost assumptions for concentrated solar thermal facilities. Ivanpah is only in year #2 of operations, so perhaps in 2-3 years, things will improve.

10 In January 2012, San Onofre Unit 2 suffered a small radioactive leak inside its containment shell, and the reactor was shut down per standard procedure. Investigators found wear and tear in 3,000 tubes in replacement steam generators that were installed in 2010 and 2011. The Nuclear Regulatory Commission ruled that the plant could not reopen until the causes were thoroughly investigated and repaired. Before various hearings could take place to determine the necessary steps for re-opening the plants, its owners (SoCal Edison) announced that it would close the plants permanently, a process which they project will cost $4.4 billion over 20 years.
2b. California renewable generation and electricity demand

The charts show January and June electricity generation based on Caliwende assumptions (i.e., current levels of hydro, biogas, biomass and geothermal, plus wind\(^{11}\) and solar generation multiplied by 5x and 8x, respectively), along with 2014 electricity demand. Assuming such a build-out, in June, California would get 91% of its electricity from renewable energy, a peak for the year. In January, however, only 52% would come from renewable energy (the low for the year). Aggregate surplus renewable generation would be 31 TWh, while aggregate renewable generation shortfalls vs. the load would be 66 TWh. As in Germany, backup thermal capacity would still be needed, even when assuming energy storage.

\(^{11}\) Assessments of high-renewable systems are sensitive to the year analyzed. For example, in the first half of 2015, US wind electricity generation fell by 6% even as installed capacity rose by 9% (perhaps a reflection of El Niño). Lower wind capacity factors would increase our estimated cost of a high-renewable system, which we based on 2014 data.
2c. **A comparison of Caliwende with California’s current electricity mix and a balanced system**

We compare Caliwende to the current system and to a balanced system which meets 35% of demand with nuclear and 40% with renewable energy. All cost assumptions are the same as in Germany, with the exception of natural gas, whose fuel cost we set at $5 per MMBtu to reflect its long-term US futures prices. The table shows capacity, generation, cost and emissions data when assuming current costs.

<table>
<thead>
<tr>
<th>Installed capacity (GW)</th>
<th>Generation</th>
<th>Cost</th>
<th>CO2 emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total</td>
<td>Wind</td>
<td>Solar</td>
</tr>
<tr>
<td>Current; No Stor; Curr cost</td>
<td>77</td>
<td>10</td>
<td>6</td>
</tr>
<tr>
<td>Caliwende; No Stor; Curr cost</td>
<td>128</td>
<td>29</td>
<td>39</td>
</tr>
<tr>
<td>Caliwende; Pump Stor - 2; Curr cost</td>
<td>128</td>
<td>29</td>
<td>39</td>
</tr>
<tr>
<td>Caliwende; Batt Stor - 2; Curr cost</td>
<td>128</td>
<td>29</td>
<td>39</td>
</tr>
<tr>
<td>Balanced; No Stor; Curr cost</td>
<td>84</td>
<td>12</td>
<td>12</td>
</tr>
</tbody>
</table>

Source: CAISO, JPMAM. 2015.

Caliwende’s cost premium over the current system (1.5x) is lower than in Germany (1.9x). The best battery and pumped storage scenarios we analyzed added to net system cost, but were well inside our preference curve. The balanced system came in at 1.2x the current system, with all the nuclear cost provisos and caveats described earlier.

**At current costs, high renewable case is more expensive than balanced but much closer than in Germany**

System cost, USD per MWh consumed

- **Caliwende** converges with balanced system assuming FUT COST 1; FUT COST 2 assumes lower nuclear costs

System cost, USD per MWh consumed

- **Caliwende** looks better when assuming the FUT COST 1 case. As a reminder, this is when solar and wind costs decline by 47% and 10%, hydrogen and battery storage capital costs decline by 40%-50%, hydrogen round-trip efficiency improves by almost half, nuclear costs rise by 25% and natural gas fuel costs rise from $5 to $8 per MMBtu. **If all assumptions are borne out (and to reiterate, this is a big “if”), the cost of Caliwende would converge with the balanced system, even when taking into account its embedded cost of backup thermal power.** Just as in Germany, storage adds to net system cost assuming that the high-renewable grid absorbs the expense of building it.

FUT COST 2 is shown as well. If nuclear power costs declined by 20% vs. current EIA estimates, the balanced system would once again be the preferred option from a cost-emissions perspective: it would cost around the same as California’s current system with less than half the CO₂ emissions.
Conclusions and more what-ifs

Germany and California are taking bold steps to de-carbonize the grid, which in most parts of the world, accounts for 40% of all CO₂ emissions. What does it all mean? Our analysis suggests the following regarding electricity systems with very high penetration of renewable energy:

- Intermittency greatly reduces the importance of wind and solar levelized cost when assessing high-renewable grids. The cost of backup thermal capacity and storage is an inextricable part of any analysis of a high renewable system. Academic and industry research has reached similar conclusions. A 2015 paper from the Potsdam Institute for Climate Impact Research notes that integration costs in systems with high levels of renewable energy can be up to 50% of generation costs, and that the largest single factor is the additional cost of backup thermal power.

- Energy storage reduces CO₂ emissions but its cost, utilization rate and energy loss must be accounted for. Even when assuming continued learning curves, storage adds to net system cost.

- The cost of a high-renewable system reflects potential renewable resources, and the efficiency with which these resources are harnessed. In Germany, even assuming future cost declines, it will be an expensive journey. In California, the economics of a high-renewable system are better given higher wind and solar capacity factors. However, it may be aggressive to extrapolate the spectacular decline in photovoltaic panel costs across other energy technologies. In addition, as shown in Appendix I, many countries do not have the solar resource of California or the wind resource of Germany.

- The CO₂ intensity of global electricity generation has declined over the last few years, but is simply back at the level it was at in 1995. A combination of a global recession which reduced peak energy demand, a shift in some jurisdictions away from coal towards natural gas and increased installation of wind and solar power explain the decline since 2007.

- Even in California, there are uncertainties to this Brave New World: California’s Independent System Operator gave a presentation in 2014 highlighting how the impacts from increasing renewable energy on the grid are still not fully understood. They mentioned voltage fluctuation due to upward/downward ramps, high voltage issues on distribution circuits, voltage/power regulation control issues, the greater number of operations and increased maintenance on voltage control, etc.
We often hear people referring to other what-ifs regarding high-renewable grids. Many rely on highly uncertain assumptions and conjecture, while others neglect related costs.

- Could **cross-border integration** of high-renewable grids reduce the need for backup power and its corresponding cost? That’s the next wave of renewable energy research. It would cost money to build these interconnections, but in theory, if wind and solar patterns are more divergent the larger the geographic area covered, the problem of renewable intermittency could simply be diversified away. Unfortunately, **new research on wind suggests that this theory has major limitations**. This remains a premise best proven empirically rather than by assumption.

- What about over-building renewable energy and storage so that the need for and cost of backup power is eliminated? The good news: it’s an emission-less system. The problem is that incremental solar, wind and energy storage costs would dwarf foregone costs of backup thermal power. Our models determined that a system in California with enough wind, solar and storage to eliminate backup power entirely would cost $280-$600 per MWh, which is 2.5x – 5.0x more expensive than Caliwende (depending on assumed storage system properties and costs). Bottom line: a renewable energy storage version of the Temple Granaries looks to be prohibitively expensive.

- Why not draw on electricity stored in electric car batteries (“car-to-grid”) to reduce storage costs? Another theoretical possibility that’s only worth discussing when we can determine the penetration rate of plug-in vehicles, the participation rate of drivers willing to share their battery with the grid and how much of it they would share, the cost of interconnections, and the cost of incentives required by drivers to have their expensive car batteries cycled more frequently. See Appendix VII.

- What about “**demand management**”? If demand could (somehow) be reconfigured to match up with variable renewable generation, unused surpluses and demand gaps would be smaller and system costs could decline. However, demand management is meant to deal with intraday supply-demand issues, not intermittency issues which span weeks and months. See Appendix VIII.

Deep de-carbonization of the electricity grid via renewable energy and without nuclear power can be done, but we should not underestimate the cost or speed of doing so in many parts of the world. At the minimum, the costs involved suggest that efforts to solve the nuclear cost-safety puzzle could yield large dividends in a post-carbon world. Such is the belief of the scientists, academics and environmentalists who still see a substantial role for nuclear power in the future (see Appendix V). See you next year.

Michael Cembalest
J.P. Morgan Asset Management

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12 The synchronization of regional wind patterns. A February 2015 paper from researchers at the MIT Joint Program on the Science and Policy of Global Change looked at wind, and found that the benefits of geographically broadening the wind-grid footprint were modest. “Aggregation of wind turbines mitigates intermittency to some extent, but in each ISO [Independent System Operator], there is a considerable fraction of time when there is less than 5% capacity [in use]. The hourly wind power time series show benefit of aggregation but the high and low wind events are lumped in time, thus indicating that intermittency is synchronized in each region”. They conclude that “an analytical consideration of the collective behavior of aggregated wind turbines shows that the benefit of aggregation saturates beyond a certain number of generating units asymptotically.” In other words, the benefit of aggregation falls rapidly due to correlation of wind patterns across areas within a given ISO. The authors found similar outcomes in Europe, where co-location benefits of wind and solar across regions were capped by their correlation. Gunturu (MIT) and Schlosser (MIT), *Applied Energy*, February 2015.
Appendix I: How relevant are Germany and California to the rest of the world?

To get a rough sense for potential renewable energy resources by country and US state, we created the chart below. The x-axis shows relative potential solar energy (kWh per meter-sq. per day), and the y-axis shows relative potential wind energy (kWh per meter-sq. per year). The bubble size is population. While Germany and California have an abundant natural resource to draw upon, other countries and states do not. Germany wind/solar patterns are similar to some US states (IL, OH, MI, IN, MN) and some large countries. California’s solar footprint is similar to much of the Mediterranean and Middle East.

To be clear, there’s a big difference between potential energy and deliverable electricity (one example being Germany’s low wind capacity factors despite a good wind resource). In addition, a given solar/ wind resource goes farther in countries with low population densities. Nevertheless, the contours of this chart are helpful when thinking about where high-renewable systems have the greatest potential impact.

Wind and Solar potential energy resources, and population: Countries and US States

Percentile of onshore WIND resource energy potential, measured in kWh per m-sq per year based on wind speed

Percentile of SOLAR resource energy potential, measured in kWh per m-sq per day based on direct normal irradiance

Source: National Renewable Energy Laboratory Resource Data Center (solar), Harvard University Cruft Laboratory at the Paulsen School of Engineering and Applied Science (wind); World Bank; OpenEI; JP Morgan Asset Management.

Bubble size = population; 85% of world population represented on chart. Highlighted: Germany and California.

Solar potential energy is based on “direct normal irradiance”, which effectively incorporates the benefits from photovoltaic dual-axis tracking systems. Harvard’s analysis of wind confines sites to those with capacity factors of at least 20%, and excludes urban and forested areas, and areas covered with water or ice. The real-life realities of siting wind farms are of course more complicated. A similar analysis from the National Renewable Energy Laboratory excludes National Park Service, Department of Defense and Federal lands; airfields and wetland areas; USDA grasslands; areas with slopes over 20%, etc. Almost 30% of windy US lands ended up being excluded by NREL, whose estimated MWh of US onshore wind potential was 35% below Harvard’s estimate.
Appendix II: Estimating the need for back-up thermal capacity in a high-renewable system

The thermal capacity required depends on the largest supply-demand gap of the year. As shown for Energiewende and Caliwende, at many times during the year the load is not met by renewable generation alone. The highest peak is the backup capacity need; note how close high-renewable thermal capacity requirements vs the current system. Backup thermal plants would be used less frequently than in the current system, which would reduce variable O&M and fuel costs and associated CO₂ emissions; but upfront capital and annual fixed O&M costs are around the same. When storage is assumed the concept is similar: backup thermal capacity is set at the peak amount of load not met by renewable generation plus available energy drawn from storage.

**Germany 2050 electricity demand gap under Energiewende**
Projected hourly load not met by wind, solar, hydro and biomass, gigawatts

**California electricity demand gap under Caliwende**
Projected hourly load not met by wind, solar, hydro, biogas, biomass and geothermal, gigawatts

Appendix III: Current and future costs per generation source

Current costs

- Current costs incorporate upfront capital costs per kW, annual fixed operating and maintenance (O&M) costs per kW, annual variable costs per kWh and annual fuel costs per kWh (when applicable). Costs exclude subsidies and are for projects now in the planning stage to be completed in 2-4 years.
- On solar PV, we use NREL data rather than EIA data. The EIA 2015 Annual Energy Outlook reports solar PV capital costs of $3,279 per kW for projects delivered in 2016. However, most industry estimates are MUCH lower, so we use the $2,250 estimate from NREL, derived from a bottom-up cost model which incorporates up-to-date cost figures for each component of a PV system.
- There is something important to understand about how PV solar costs are often quoted. Photovoltaic panels generate DC power which is converted to AC power through an inverter before it is transferred to the grid. To optimize costs, utility-scale solar projects are typically overbuilt by 25% or more relative to the rated AC output of the inverter; in other words, the DC capacity of the panels is 125%+ of its eventual AC output. As a result, computations of cost per MWh of AC output from solar PV electricity should reflect the degree to which DC capacity is overbuilt. You might read in the press that the cost of utility-scale solar PV is $1.8 per watt-DC; that’s equivalent to our assumption of $2,250 per kW-AC after accounting for AC-DC overbuilding. For more on this topic, see “Utility Scale Solar”, Lawrence Berkeley National Laboratory, September 2014, page 5: “AC or DC? AC Capacity Ratings Make More Sense for Utility-Scale Solar”.
- EIA wind costs are also higher than NREL, LBNL, IEA and Bloomberg New Energy Finance data; we use NREL for wind, whose estimates are similar to the rest.
- We do not model cost improvements in concentrated solar power; CSP does not play a role in our Germany analysis, is a small component of the California analysis, and is experiencing growing pains.
- For pumped storage and battery storage, capital costs are quoted per kWh. For hydrogen, fuel cell and electrolyzer costs are quoted per kW and tank storage costs are quoted per kWh.
- Battery capital costs are based on a zinc hybrid battery system now commercially available from Eos Energy Storage, and include the cost of the inverter and system interconnections. These costs are 30% below those cited in a March 2015 paper in Nature Climate Change Journal which tracks improvements in lithium ion batteries used in automobiles.
- Capital costs are amortized over 10 years for hydrogen storage, over 15 years for battery storage, over 20 years for wind/solar/hydro/biomass, over 30 years for natural gas, over 40 years for pumped storage, and over 40 years for nuclear, all at a 10% discount rate.
- On nuclear power, we assume it has baseload priority before renewable energy, and generates power based on a 95% capacity factor. We added decommissioning costs (which the EIA excludes) based on published data from Vermont Yankee and San Onofre plants.

Current costs: baseline for projects delivered in 2016-2018

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital (kW-AC) ($)</th>
<th>Capital (kW-h) ($)</th>
<th>Fixed O&amp;M (kW-y) ($)</th>
<th>Var O&amp;M (MWh) ($)</th>
<th>Fuel* Source</th>
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<td>Wind</td>
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<td>$0.00</td>
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<tr>
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<td>$3.27 / $5 (C)</td>
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</tr>
<tr>
<td>Nat gas combust turbine</td>
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</tr>
</tbody>
</table>

* Natural gas and coal fuel quoted in $/MMBtu; nuclear and biomass fuel quoted in $/MWh. G: Germany, C: California.
Future costs

- Long-term technological road maps from the International Energy Agency project 10% and 47% future declines in upfront capital and fixed O&M costs for wind and solar.

- For hydrogen storage, we use “future case” assumptions from NREL. They imply 55% declines in both upfront capital and fixed O&M costs, and an increase in round-trip efficiency from 43.9% to 60.9%. From our perspective, NREL future case assumptions on costs and round-trip efficiency are highly optimistic given the limited degree to which utilities now use hydrogen storage for surplus generation storage (see pie chart on page 7). For battery storage, we use long-term forecasts from the Nature Climate Change Journal paper cited on the prior page and applied their projected learning curves to zinc hybrid battery storage capital and O&M costs.

- In spite of what looks like a glut of natural gas in the US, we wanted to reflect the possibility that some combination of carbon taxes and/or increasing regulation around fracking could increase its price. As a result, we modeled $8 per MMBtu for the US in this scenario. In Germany, natural gas fuel prices are assumed to rise from $10 to $13 per MMBtu. Coal prices remain unchanged.

- We did not assume any changes to upfront capital or fixed O&M costs for natural gas.

- For nuclear power, in FUT COST 1, we used the upper end of median estimates from the Carnegie Mellon paper cited in Appendix V. FUT COST 2 is identical to FUT COST 1, with the exception of a 20% decline in nuclear capital and fixed O&M costs vs. EIA estimates. See Appendix V for details.

FUT COST 1: Renewable/storage progress, nuclear safety overhang and higher nat gas fuel cost

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Capital ($/kW-AC)</th>
<th>Capital ($/kWh)</th>
<th>Fixed O&amp;M ($/kW-y)</th>
<th>Var O&amp;M ($/MWh)</th>
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<td>$67.23</td>
<td>$0.00</td>
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</tr>
<tr>
<td>Geothermal</td>
<td>$2,448</td>
<td>$0</td>
<td>$112.85</td>
<td>$0.00</td>
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</tr>
<tr>
<td>Nat gas combined cycle</td>
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<td>$0</td>
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<td>$179.04</td>
<td>$13 (G) / $8 (C)</td>
<td>Carnegie Mellon University/PNAS, JPMAM</td>
</tr>
<tr>
<td>Hydro</td>
<td>$2,651</td>
<td>$0</td>
<td>$15.15</td>
<td>$5.76</td>
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<td>Biomass</td>
<td>$3,659</td>
<td>$0</td>
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<td>Pumped storage</td>
<td>$0</td>
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</tr>
</tbody>
</table>

* Natural gas and coal fuel quoted in $/MMBtu; nuclear and biomass fuel quoted in $/MWh. G: Germany, C: California.

Additional modeling assumptions:

- We assume Energiewende will rely on onshore wind rather than offshore wind, since in Germany, the latter is currently more than twice as expensive in terms of levelized cost per kWh.

- We modeled the natural gas stack as first calling on natural gas combined cycle (NGCC) plants for the first 70% of demand, and then advanced combustion turbines (NG CT) for the remainder, and for the buffer set aside for peaking needs. This is consistent with prior research designed to optimize the cost-emissions mix between the two. NG CT plants have lower capital and fixed O&M costs, but higher variable and fuel costs due to a higher heat rate. NGCC plants make sense for the first part of the natural gas stack, with NG CT reserved for peaking plants that are less frequently used.
Appendix IV: A cost-emissions preference curve for analyzing energy storage

Is it a good idea to build energy storage? To answer the question, we need a framework for analyzing what storage is supposed to do: some combination of lowering system costs and/or CO₂ emissions.

The chart below is a conceptual one, and shows cost per MWh on the y-axis and CO₂ emissions on the x-axis. Energiewende with no storage is shown at the intersection of its cost and emissions. If we can find a storage scenario that lowers costs AND emissions, that would be great (A). In our view, a storage scenario that entails a small increase in cost in exchange for a large emissions reduction would also be a good outcome (B); the same goes for a large cost decline accompanied by a small increase in emissions (C). What we are effectively describing is a preference curve for storage, where points below the curve have positive utility; the farther away from and below the curve, the better.

The shape of our curve implies our own implicit judgments on storage tradeoffs. Very high cost outcomes even when accompanied by large emissions reductions would fall above this curve (D), as would very low cost outcomes requiring very large increases in emissions (E). Everyone’s preference curve is different; those focused on global warming might have steeper preference curves, with a greater tolerance to accept higher costs in exchange for reduced CO₂ emissions. One thing is clear: assessing the benefits of energy storage is not simply an exercise in just minimizing cost or just minimizing emissions; both variables should be taken into account.

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14 Thanks to Max Cembalest (Wesleyan ‘18) for his insights on the ellipse mathematics and required theorems associated with preference curve applications to this project.
Appendix V: Nuclear power cost and future technology alternatives

Carnegie Mellon surveyed 16 nuclear industry participants regarding capital costs of large nuclear plants using existing technology, and of prototype small modular reactors. Note how wide the range of estimates is in the first chart; and these are just median estimates (the full range of the high and low estimates was even wider). These cost projections reflect the technology, regulatory, legal, environmental and political framework in which nuclear power is developed in the Southeastern United States. In other words, they are not a universal measure of nuclear power costs, since many of these items differ by jurisdiction. As explained earlier, nuclear power costs are 25%-30% lower in Asia.

Our FutCost1 estimate is meant to reflect possible cost increases in cost based on safety, spent fuel and containment issues raised by the accident in Fukushima. Our FutCost2 reflects decreases in cost due to possible standardization and streamlining of existing technology (along the lines of Asian costs), and/or an optimistic assessment of small modular reactors of the future (see below).

The future of nuclear power. The list of those who see nuclear power as a critical component of future grids is a long one. It includes the Clean Air Task Force, International Energy Agency, the Breakthrough Institute, climatologist/activist James Hansen of Columbia University, David Mackay of Cambridge, Robert Hargraves from Dartmouth, Ralph Moir from Lawrence Livermore National Laboratory, British environmentalist Mark Lynas, etc.). The industry itself is scrambling to find a better and cheaper way forward; the box shows nuclear technologies under development. But even if an economic and acceptable alternative emerges soon, how fast it could be scaled up to become more than a marginal contributor?

There’s enthusiasm in some circles for small modular reactors (SMRs). The idea: smaller design (10 MW to 100 MW capacity), factory-produced with higher levels of quality control, shipped to site by rail or barge. More than 20 companies are developing SMRs worldwide, with 3 in the US focused on “light water” SMRs. The problem: smaller units tend to have lower economies of scale, so it is not a foregone conclusion that SMRs would be cheaper than today’s plants. The same National Academy of Sciences paper cited earlier also looked at possible SMR costs; the low end of median projections for 45-225 MW SMRs ranged from $3,500 to $4,000 per kW, which is ~25% below EIA cost estimates for larger plants using current designs. To be clear however, the upper end of the median cost range was considerably higher, and even more tellingly, none of these units is under construction. It may be decades before we know just how much new nuclear power designs really cost.
Appendix VI: Energy learning curves

The first 3 charts show learning curves for solar, wind and storage; capital costs fell as capacity rose. In the case of wind, the learning curve was interrupted in 2004 by a period of rising costs for raw materials (steel, iron, copper, aluminum, fiberglass), energy and labor which led to rising turbine prices.

The next chart was produced in 2003 for the European Commission’s 2030 World Energy, Technology and Climate Outlook report. It’s a bit outdated, but does a good job conveying how analysts used historical data available at the time to project learning curve progress in the future.

Learning curves for power generation technologies
Total investment cost, 1999 EUR per kW, log scale

Appendix VII: What about storing energy in electric car batteries?

One of my associates (the resourceful Robert Hawkes), as part of our research, attended a Power Systems Modeling and De-carbonization conference. One topic: what if utilities access consumer-owned electric car batteries to store excess renewable energy and retrieve it when needed? I see why the idea is appealing: storage is expensive to build and maintain, so if part of the cost is absorbed by owners of electric cars who already purchase the battery as a sunk cost, storage would seem cheaper.

However, there are a lot of questions that would have to be addressed first, and which create a much more complex storage environment when compared to centralized versions:

- **Electric vehicle penetration.** We first need to assume substantial penetration of plug-in electric vehicles (PEV). US PEV penetration levels are around 0.7% today, so there’s a long way to go. Perhaps gasoline taxes, Federal incentives and declining battery costs can raise PEV ownership levels.

- **Interconnection buildout.** The electricity grid would need to be modified to allow broad-scale grid-interconnection of vehicles and net metering, with thousands of two-way charging points. The technology exists; this would simply be a question of who finances the scope of such a build-out.

- **Storing excess generation.** A lot of PEVs would have to be plugged in and NOT fully charged at times of excess renewable generation, whether it occurred during the day or night. The premise: a user-controlled application would allow drivers to specify the minimum charge they needed, so that even after being plugged in for hours, part of their battery would remain uncharged and available to the utility, which would charge it only at times of excess renewable generation. This would require a substantial mindset change by drivers, who would have to adjust to plugging in their cars and not getting a full charge overnight, based on their preferences and specifications.

- **Drawing on charged car batteries.** The same user-application would be used to control utility draws on charged batteries. During periods of low-renewable electricity generation, the utility could draw on each car battery down to the minimum charge level specified by the driver.

- **Incentives.** Two kinds of driver incentives would be needed: one to compensate the driver for the nuisance factor of never having a full tank and the risk of being stranded, and another incentive to compensate the driver for increased cycling of an expensive battery, which reduces its useful life.

While all of this is possible, it involves PEV penetration and behavioral changes whose related incentives are very hard to quantify. A lot more analysis (see box) would be needed before we could include grid-storage on electric car batteries as an option in our Energiewende or Caliwende cost-emissions models.

---

**What could grid storage in electric car batteries accomplish in our Caliwende scenario?**

California has ~24 million cars. Let’s assume PEV penetration via the Nissan Leaf, whose storage capacity is 24 kWh. Let’s also assume that 75% of Leaf drivers participate in grid integration, and are willing to share up to 33% of their car battery at any time with the grid. Now we can incorporate Nissan Leaf storage into the Caliwende scenario, in which 31 TWh of surplus renewable generation takes place during the year.

Based on these assumptions, we can estimate the subset of the 31 TWh of surplus generation that Nissan Leaf batteries could store during the year. With 10% PEV penetration, 10% of this surplus would be stored. At 25% PEV penetration, 23% of the surplus would be stored. At 50% PEV penetration, 40% of the surplus would be stored. At this 50% PEV penetration rate, Caliwende’s cost would decline from $129.2 per MWh to $123.7 per MWh, assuming no economic cost to achieve such driver participation. This 4% decline, using the FutCost1 set of assumptions, would still leave Caliwende more expensive than the balanced system.

Bottom line: high PEV penetration and high driver participation rates would be needed to materially reduce reliance on other energy storage approaches and on thermal generation, and still does not substantially alter the relative cost equation of high-renewable vs balanced systems.
Appendix VIII: The uncertain magic of demand management

The purpose of demand management: reconfigure demand so that it matches up better with renewable electricity generation. This would reduce the need for storage, since there is less surplus energy created in the first place. To do so, grid operators and policymakers have to convince industrial and residential users to shift electricity demand to conform to the contour of renewable generation occurring at that time. We wanted to get a sense for its potential, so we assumed that within every 72-hour period, load demand would be magically re-shaped to match the contours of wind and solar generation. The chart below shows these assumptions at work in California during May/June. As a reminder, demand management is conceived as means of addressing short-term diurnal intermittency of renewable energy rather than longer-term intermittency across weeks and months.

Our magical implementation of demand management may not be possible in the real world

In the charts below, we compare no-storage, storage, and demand management outcomes. The latter would result in meaningful CO₂ emission reductions vs. the no-storage case (19% in Germany and 33% in California vs. the no-storage case) and also modestly lower costs, since required backup thermal capacity declines and there is no assumed cost to reconfiguring consumer demand.

That said, cost-emissions benefits of our demand management scenarios are surely overstated. Incentives would be needed to get users to change demand patterns to this degree (if it could be done at all), which increases system cost by an amount we cannot quantify. Furthermore, most demand management approaches span hours rather than the three-day period we assume. As a result, our estimate is better than a best-case outcome, and loaded with conjecture.

The benefits of demand management as an alternative to storage, assuming it’s free (Germany)

System cost, USD per MWh consumed

<table>
<thead>
<tr>
<th>CO₂ emissions, million metric tonnes per year</th>
<th>$230</th>
<th>$210</th>
<th>$190</th>
<th>$170</th>
<th>$150</th>
<th>$130</th>
<th>$110</th>
<th>$90</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand management</td>
<td>Pumped storage</td>
<td>Hydrogen storage</td>
<td>No storage</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energiewende</td>
<td>Balanced</td>
<td>Current</td>
<td></td>
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<tr>
<td>System cost, USD per MWh consumed</td>
<td>$230</td>
<td>$210</td>
<td>$190</td>
<td>$170</td>
<td>$150</td>
<td>$130</td>
<td>$110</td>
<td>$90</td>
</tr>
</tbody>
</table>

Source: Germany grid operators, JPMAM. 2015.

The benefits of demand management as an alternative to storage, assuming it’s free (California)

System cost, USD per MWh consumed

<table>
<thead>
<tr>
<th>CO₂ emissions, million metric tonnes per year</th>
<th>$160</th>
<th>$150</th>
<th>$140</th>
<th>$130</th>
<th>$120</th>
<th>$110</th>
<th>$100</th>
<th>$90</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand management</td>
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<td>Hydrogen storage</td>
<td>No storage</td>
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<tr>
<td>Energiewende</td>
<td>Balanced</td>
<td>Current</td>
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<td>$100</td>
<td>$90</td>
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</table>

Source: CAISO, JPMAM. 2015.
Acknowledgements

This year’s paper was inspired by research undertaken by Armond Cohen, Executive Director and co-founder of the Clean Air Task Force, whose team has been analyzing different pathways to deep de-carbonization of power grids. The Clean Air Task Force believes that a diverse portfolio of technologies will likely be necessary; is concerned that the extent of backup thermal capacity required by systems with high-renewable energy penetration (even with storage) is underappreciated; and is concerned that not enough effort is being spent to support demonstration of advanced nuclear power given its equally compelling de-carbonization potential.

In addition to Vaclav, I would like to thank the following individuals who reviewed sections of this paper and provided feedback (any errors or omissions are my own): Armond Cohen and Stephen Brick at the Clean Air Task Force; Cory Budischak at Delaware Tech; Andrew Mills at Lawrence Berkeley National Labs; Mackay Miller, Donna Heimiller and Ran Fu at National Renewable Energy Laboratory; Jared Moore at Meridian Energy Policy; Jesse Jenkins at MIT; Haresh Kamath and Ben Kaun at the Electricity Power Research Institute; Ines Azevedo at Carnegie Mellon University; Sama Bilbao at Virginia Commonwealth University; Lion Hirth at Neon.

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Acronyms

CAISO: California independent system operator
CATF: Clean Air Task Force
CO₂: carbon dioxide
CHP: Combined heat and power
CSP: Concentrated solar power
DOE: US Department of Energy
EIA: US Energy Information Administration
EPA: US Environmental Protection Agency
EPR: Evolutionary Power Reactor
EPRI: Electric Power Research Institute
EUR: Euro
GW: Gigawatt
GWEC: Global Wind Energy Council
GWh: Gigawatt hour
IRENA: International Renewable Energy Agency
kW: Kilowatt
kWh: Kilowatt hour
IEA: International Energy Agency
JPMAM: J.P. Morgan Asset Management
JPS: Journal of Power Sources
LBNL: Lawrence Berkeley National Laboratory
LCOE: Levelized cost of energy
M-sq: Meters squared

MMbtu: Million British thermal units
MW: Megawatt
MWh: Megawatt hour
NG CT: Natural gas advanced combustion turbines
NGCC: Natural gas combined cycle
NREL: National Renewable Energy Laboratory
O&M: Operations and maintenance
OPEC: Organization of the Petroleum Exporting Countries
PEM: Proton exchange membrane
PEV: Plug-in electric vehicle
PNAS: Proceedings of the National Academy of Sciences
POLES: Prospective outlook on long-term energy systems
PV: Photovoltaic
SFC: Smart fuel cells
SMR: Small modular reactors
SoCal: Southern California
TW: Terawatt
TWh: Terawatt hour
UPMF: Université Pierre Mendès-France
USD: United States Dollar
USDA: US Department of Agriculture
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