C O N F E R E N C E   R E P O R T

MEETING THE RENEWABLES INTERMITTENCY CHALLENGE

ENERGY CENTER
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THE ENERGY VALUE CHAIN.

Introduction

The UNC Energy Center and the Kenan Institute of Private Enterprise hosted an April 13-14, 2018 conference on 'Meeting the Renewables Intermittency Challenge.' This introduction provides background on the event and focuses on the reasons why it was convened.

The last decade has seen more attention devoted to decarbonizing the electricity grid. Much of this effort has revolved around wind and solar generation. Public policy has supported their development through mandates (Renewable Portfolio Standards) and federal tax credits. In the space of a decade, these policies have achieved much of what they targeted. Wind and solar power now provide appreciable portions of generating capacity in many states; in California they can represent 67% of generation during the middle of the day. Wind/solar project costs have also come down as a result of manufacturing economies of scale and more efficient project design/installation. This progress has fostered a narrative to the effect that wind/solar will soon be more cost effective than fossil fuel plants. Reports of 'Levelized Costs of Electricity' by the Energy Information Administration and the Lazard bank appear to support these claims.

The fine print of these reports indicates that they disregard significant cost factors in their analysis – specifically those costs associated with the 'intermittency' of wind and solar. Intermittency here means the fact that wind and solar only produce electricity when nature cooperates. As a result, the amount of electricity they generate varies from zero to full capacity, depending upon conditions. This means other arrangements, including backup generation, must be added to assure customers receive uninterrupted, high quality power. The aforementioned reports make no effort to reflect these costs in their analysis. As a result, the public discussion takes place without a full disclosure of the costs of continuing to drive wind/solar penetration. This conference was convened in part to investigate these 'all-in' costs, and to determine whether the current narrative of ever declining renewables' costs is valid.

Wind and solar power offer important benefits beyond what they cost. They represent zero carbon, non-depletable power sources with arguable less environmental risk than fossil fuels. Consequently, there will be ongoing incentives to add wind/solar power so long as their all-in costs are not prohibitive. To this end the conference also sought to identify the lowest cost 'pathway' for increasing wind/solar penetration. Here again, there is a dominant public narrative - that battery storage, specifically lithium ion battery storage, is both the answer to renewables intermittency and a great means for upgrading the electricity grid. We wondered if this indeed is the case. Specifically, we wanted to learn a) whether battery storage truly is a cost-effective answer to wind/solar intermittency issues and b) whether there might be other options that work better than today's batteries.

The conference convened senior executives from major utilities and renewables companies along with consultants and academics. Their answers, reported without attribution, follow.

Executive Summary

On April 13-14, 2018 the UNC Energy Center, in cooperation with the Kenan Institute of Private Enterprise hosted a conference to explore the challenges posed by Wind/Solar intermittency and the means available to best address these issues. This was an Aspen Institute-style event, i.e. invitation-only, no publicity and no attribution of any comments to speakers/participants.

The event had three specific objectives: 1) to measure accurately the 'all-in' costs of wind and solar power; 2) to identify the lowest cost path for integrating more renewable generation into the electricity grid; and 3) to determine whether technology innovations on the horizon will materially alter this outlook. What follows below is the Conference Report compiled under these rules.

Summary of Key Findings:

The All-In Cost of Wind/Solar Power + Storage

- Wind/solar power have achieved impressive unit cost reductions and have potential to achieve more in this regard. Public policies, e.g. tax benefits and RPSs, have enabled them to achieve at-scale manufacturing and other efficiencies. This has and will allow wind/solar to make a significant contribution to the U.S. electricity sector. Once installed, they provide almost zero marginal cost power with zero carbon.
- In specific situations/locales, cost reductions are enabling wind/solar + storage to displace new-build natural gas peaking capacity; they also can provide other 'value to the grid,' e.g. frequency regulation.
- That said, the popular narrative around wind/solar leaves out the considerable costs of intermittency and grid integration. As such, it gives an incomplete and inaccurate impression of their ability to accomplish grid de-carbonization.
- These intermittency/integration costs come in several forms. The most common are: 1) second/minute voltage and frequency variations affecting power quality, 2) variations in power generated during the course of the day, 3) inability to follow the average load curve, 4) inability to 'ramp' up and down as demand varies, and 5) the generation of surplus power when demand is lacking. Over and above these issues is the macro challenge of wind/solar meeting demand when their production is impacted by time of day, weather and seasonality.
- To accommodate these issues, utilities and grid operators incur many costs which are hard to aggregate. Some costs materialize in the way they have to operate existing plants. For example, less flexible base load nuclear and fossil fuel plants must be cycled or idled to accommodate surplus solar/wind. Other costs include new investments to stabilize the grid and power quality, e.g. battery storage, sub-station upgrades and fast-start natural gas plants. Integration costs such as these are not captured in Renewable Power Purchase Agreements and thus are borne by the power rate structure. Still other costs are harder to spot. Existing plants capable of providing base load power may be forced into an inefficient peak-provider role. Depreciated plants with remaining life may be retired early. This is especially noteworthy when the plants in question are zero-carbon nuclear facilities. Wind/solar may also be built in less than optimal locations for connecting to the grid.
- The diffused and indirect nature of renewables' intermittency costs impedes an accurate assessment of their impact. Still, attempts at quantification show them to be significant. One utility's estimate shows them approaching $11/MWH at 20% renewables penetration. These costs also increase in a non-linear fashion as penetration rises.
- There is not yet a consensus on the level of renewables integration costs or how they increase over time. Studies done at one of the national laboratories suggest renewables could reach 30% of generating capacity in one specific market with 'minimal system changes.' What exactly that means is not spelled out as no economics are offered, and the report goes on to detail the added investments and redesigns required to go to higher wind/solar penetration. These discrepant views reflect differences between those tasked with operating an existing system reliably and those advocating for the future. The different perspectives are expressed in terms of different levels of risk embedded in projections and the seamlessness or not of effecting change. Still, there is little doubt that renewables integration costs exist, are material and increase with higher penetration levels.
- One reason that renewables show this cost profile is that today's electric grid was not designed with them in mind; rather, it was designed around large scale, base load coal, gas and nuclear plants. Many of these are inflexible, i.e. costly to stop and re-start. Conceivably, a different grid, one built to anticipate renewables intermittency and featuring much more storage, would show smaller incremental integration costs when adding more wind/solar. That said, today's grid is what it is, leading to material and increasing wind/solar integration costs. Moreover, a grid originally designed to accommodate a high renewables presence likely would show higher average electricity costs.

- The Kenan Institute of Private Enterprise (KIPE) sponsored a research project into the 'all-in costs' of driving wind/ solar plus storage into baseload generation. The project used a 650 MW Combined Cycle Natural Gas plant (CCNG) as its reference case. It then replaced this plant's yearly output with combinations of solar/wind and storage to produce an equivalent amount of electricity and have it predictably available through the year. The results demonstrate the high costs of having to solve renewables intermittency over extended time periods and seasons. The models solve for the carbon tax which will provide the wind/solar + storage projects with wholesale prices sufficient to generate a 10.5% leveraged Return on Equity. The resulting carbon taxes ranged from $151/ton for combining wind/solar and storage to over $300/ton for just solar + storage.
- The KIPE study was critiqued for focusing on replacing the power of a given plant as opposed to designing generation to meet demand load 'which varies all the time.' This perspective ignores the relatively constant base load that forms the foundation of the demand curve; it also is rooted in the idea that relatively constant demand can be met by different mixes of intermittent generation and storage. However, the KIPE study focuses not on the technical feasibility of doing this but what it costs, and it suggests that meeting an increment of relatively constant demand by combining wind/solar and battery storage will be very expensive.
- Widely quoted studies of the 'Levelized Costs of Renewable Power' (LCOEs) leave out intermittency costs, and thus are incomplete and misleading. Wind and solar cost estimates are also typically presented without reference to where they are located. Today's wind and solar projects are largely distributed in locations characterized by superior wind and solar resources and low cost land. This has occurred even when adopting these locations incurs higher transmission costs (not reflected in LCOEs). Consequently, it may be said that reported LCOEs tend to reflect the best wind/solar resources with no debits for higher cost transmission. These studies also may not reflect the largest scale solar/wind projects whose greater efficiency would be an offsetting factor.
- Quoted LCOEs also benefit from low capital costs. These costs account for ~1/3 of project costs. Renewables developers have benefitted from low equity costs driven by tax credits and low debt costs available in an abnormally low interest rate environment. These conditions have encouraged capital market appetite for renewables projects. However, future project costs of capital are unlikely to match the low levels of the recent past and may be materially higher. Rising interest rates will affect the LCOEs of all new generation. The effect on wind/solar will be more pronounced as their LCOEs are not weighted by ongoing fuel costs.
- Finally, solar costs have benefited from declining panel prices driven by Chinese manufacturing overcapacity. However, other factors continue to affect panel pricing, both up and down. Tariffs have interrupted the steady decline in costs, and recent changes in Chinese domestic support have resulted in reports of both solar industry rationalization and an oversupply scenario that is reducing pricing once again. For all the reasons cited, the direction and pace of future wind/solar LCOEs is uncertain, and will reflect the tug/pull of technology advances and manufacturing economies vs. diminishing returns/reversion effects from these other factors.

The Lowest Cost Pathway for Renewables Integration

- The conference did not engage in a detailed, apples-to-apples comparison to identify a low cost seriatim of integration options. Nonetheless, the conference materials do allow for the construction of a rough low cost integration pathway.
- Wide Area Energy Markets (WAEM) would appear to be at the top of the list. This action is an organizational step and involves little new capital. Rather it works with existing assets and infrastructure, bringing enhanced forecasting, planning and coordination. Typically the expanded area also accomplishes some renewables diversification, i.e. bringing different mixes of wind/solar + storage under a new coordinating body. WAEM forecasting and planning functions also help with long term intermittency issues by calibrating the amounts of flexible base load power needed to address renewables average weather-related and seasonality issues. This makes WAEMs relatively unique; other mitigating options tend to address shorter term intermittency.

- Compressed air and pumped storage hydro come next on the list. As noted below, these forms of storage are multiples more economic than battery storage for high capacity, long duration applications. Moreover, they can retain their potential to generate electricity for longer periods without material losses. As such they are well suited to address daily, weekly, and even some weather-related and seasonal intermittency. They come second on the list because they do involve capital expenditures along with siting and environmental issues.

- Renewable Power Curtailment comes third in the seriatim. This is so for two reasons: 1) the marginal cost of curtailment is negligible and 2) curtailment is a readily available option for addressing surplus power issues. It does nothing however for shortfalls of various types. Planned curtailment could deliver other benefits; it can create a reserve of renewable power that with planning and forecasting can be used to follow load and address ramping issues. This comes at the cost of denying the underlying renewables project a portion of its potential return. Curtailment in its various forms has been less studied and should receive more consideration going forward.

- Time of Use pricing can also be a low cost option. This occurs when the utility has customers (typically Commercial and Industrial, C/I) who will respond to pricing and the incentives also make economic sense for the utility. If time of day pricing is pursued, there will be periods of the day where electrical costs are quite low (<2 c kwh) and sophisticated C/I customers could identify commercial processes that take advantage of the low cost power created by high generation/low usage conditions. Such win/win situations exist but may be limited in scope and scale.

- Renewables diversification can be an attractive option where both the wind and solar projects show economic returns. The combination of wind/solar then accomplishes some muting of the mismatches between a single form of non-dispatchable power and the load curve. This gain can be partly or fully offset by the fact that adding even a diversified pool of renewable resources intensifies other, longer term intermittency issues.

- Despite noteworthy cost improvements and prospects for more, battery storage does not appear to provide a remedy for longer duration renewables intermittency issues. Today's technology, lithium ion battery storage, can effectively compensate for second/minute and some hourly intermittency. It is not cost effective for day-to-day, weekly, or seasonal intermittency. The technology prospects suggest this will continue to be the case for the foreseeable future.

- Mandates for storage, micro-grids and distributed energy resources are high cost alternatives due to the fact that they foster unintended consequences and impede the ability of utilities and ISO/RTOs to perform their integrating functions. Capital must then be spent to try to offset the unintended consequences created by decreeing these targeted outcomes.

- There is much to be learned about the optimal mix of options. Combining options is important because none by itself offers a broadly applicable solution; in many cases the mix will depend on local circumstances. California's experiment will provide useful learnings. For example, it may reveal that micro-grids can be efficient solutions in certain markets and that unconstrained growth of roof top solar will be difficult to manage. However, California's unique climate conditions, access to imported power and other local factors mean that its energy policies may not be broadly applicable.

- That many integration options exist is a positive for wind/solar penetration. It means that some mix likely is cost effective to some degree on a location by location basis. As utilities and ISO/RTOs learn more and options progress technically, more wind/solar penetration will be possible on a cost-effective, stable grid basis.

Prospects & Recommendations

- Near term growth in wind/solar plus storage capacity should continue at a robust pace. This will be driven by cost competition, customer demand (especially Industrial/Commercial firms), remaining mandates and the desire to grandfather projects as tax subsidies are phased down. Growth will also be assisted by favorable capital market conditions.

- Renewables financing costs face three potential headwinds: 1) phasedown of federal tax credits; 2) tax reform's lower rates, which reduce the value of tax credits and 3) a rising interest rate environment. That said, the renewables financing market has achieved considerable maturity. Various intermediaries now provide hedge products and connections with private equity, such that good investor appetite exists for renewables' equity and debt. Major utilities are also emerging as both primary and secondary market project investors. Utilities' interest in buying out existing projects will likely grow as initial PPA expirations approach.

- Wind/solar growth prospects post-2020 are less clear. Penetration will continue but the rate and ultimate extent are in question. The costs of intermittency are becoming more obvious. Diminishing returns, tariffs, rising interest rates and subsidy reductions raise questions about whether wind/solar and storage LCOEs will continue to decline and if so, at what rate. The unsuitability of wind/solar + storage as base load capacity will also be increasingly obvious.

These prospects suggest a number of 'go-forward' conclusions:

1. Since today's wind/solar + storage alone cannot accomplish grid de-carbonization at an acceptable cost, policy should embrace hybrid solutions optimized by location.

2. To achieve hybrid de-carbonization, energy policy needs to contemplate a broad mix of electricity generation. Natural gas plays a particularly important role here because of its ability to compensate for the non-dispatchable nature of wind/solar. California's reliance on natural gas to stabilize its grid testifies to this conclusion.

3. Because of natural gas' ability to compensate for wind/solar intermittency, serious efforts should be made to further de-carbonize natural gas. Recent developments in Carbon Capture/Sequestration (CCS) technology may offer promise here. These technologies may in some locations prove as or more economic than battery storage while offering a more comprehensive solution to the suite of intermittency issues.

4. Environmental restrictions adopted for Compressed air and Pumped Hydro (CA/PH) storage should be reviewed with an eye to facilitating renewed development of such projects. CA/PH projects could have great synergy with wind/solar generation and can offer specific customers fully renewable power. Current CA/PH siting regulations were adopted before the climate change issue was well defined. As such, they may have tilted excessively in the direction of safety. Improved technologies may also be available for these projects, addressing some concerns that shaped regulations. We note with emphasis that no serious effort of this sort is under way, and hope that a better recognition of CA/PH's synergy with wind/solar will stimulate the needed regulatory review.

5. Care should be taken before allowing renewables penetration to force retirement of existing nuclear capacity. Carbon taxes, capacity credits and other pricing mechanisms are recommended to put appropriate value on these facilities base load reliability and zero carbon production

6. Grid de-carbonization advocates should not oppose new natural gas pipeline construction. Quick starting natural gas plants have emerged as the natural companion of wind/solar. These plants not only compensate for short/medium term renewables intermittency but can operate in base load fashion under extreme conditions. Cost effective natural gas supplies for these plants are an essential ingredient of hybrid de-carbonization. Today's low cost of U.S. natural gas helps utilities and customers absorb the costs of renewables intermittency by offsetting some of these costs in wholesale and retail prices.

7. Hybrid de-carbonization will require technology advances for all elements of the solution. Public policy should encourage technology competitions among renewables, natural gas, storage, CCS and nuclear.

8. Finally, under the hybrid de-carbonization approach the need for continued Renewable Portfolio Standards (RPS) should be reconsidered. Their primary role was to enable renewables technology and manufacturing to be proven at scale. This has been accomplished. With intermittency and integration costs now evident and increasing, and with unanticipated consequences evident, the moment may have arrived for allowing wind/solar + storage projects to stand on their own economic feet. Doing so will also allow those responsible for power quality and grid stability to weigh all factors before promoting further penetration.

The All-In Unsubsidized Cost of Renewable Power

A recent Energy Information Administration (EIA) report on the Levelized Cost of Electricity by fuel source (LCOE) contained the following footnote:

> *"Duty cycle refers to the typical utilization or dispatch of a plant to serve base, intermediate, or peak load. Plants using wind, solar, or other intermittently available resources are not dispatched and do not necessarily follow a duty cycle based on load conditions...*
>
> *A related factor is the capacity value, which depends on both the existing capacity mix and load characteristics in a region.*
>
> *Since load must be balanced on a continuous basis, units whose output can*
>
> *be varied to follow demand (dispatchable technologies) generally have more value to a system than less flexible units (non-dispatchable technologies), or those whose operation is tied to the availability of an intermittent resource. The LCOE values for dispatchable and non-dispatchable technologies are listed separately in the tables, because caution should be used when comparing them to one another."*

Unpacking EIA's carefully worded caveat sheds light about what their LCOEs do and don't measure. In plain English, EIA is saying that wind/solar power is not 'dispatchable.' As such, their LCOEs are not comparable to dispatchable power, e.g. fossil fuel and hydro. Finally, EIA's LCOEs compare only the costs of power when generated and delivered to the grid. This means two things: 1) the LCOEs of renewable power leave out the costs of connecting and integrating into the grid and 2) they also leave out the costs associated with compensating for their non-dispatchable nature.

Widespread use of this reporting methodology has allowed renewables advocates to tout wind and solar as increasingly competitive with traditional, dispatchable power sources. Is this really the case?

To find out, this conference on 'Meeting the Renewables Intermittency Challenge' focused on defining the 'All-in unsubsidized cost of Renewable power', i.e. its unit costs when the costs of compensating for its non-dispatchable nature are included. The conference findings appear below. This begins with a discussion of the nature of the renewables intermittency challenge:

The Renewables Intermittency Challenge

- Renewables intermittency, defined as the unplanned variations in power generated by wind/solar capacity, is rooted in generating electricity only when nature cooperates. Everyone can envision that solar farms don't produce power at night nor wind farms on a calm day. Less well known are the various other forms of intermittency, of which we shall highlight four.
- The first type of intermittency is the second-minute to minute fluctuations that occurs as solar intensity varies, clouds role by and the wind gusts and then calms. Normal grid operations are characterized by constant, though small fluctuations in voltage and frequency. Both must be managed on a second-by-second basis to maintain power quality. Normal fluctuations are typically compensated by making small adjustments to power generated by 'on-line' plants. With renewable power in the picture, a step-change occurs in real-time power fluctuations (see Exhibit 1). This in turn requires bigger and more frequent tuning of on-line plants and the occasional start-up or shutdown of existing 'peaker' capacity. This problem intensifies as renewables penetration deepens.
- A second type of intermittency is the mismatch between average renewable power generation and the average electricity demand curve on a daily basis. Exhibit 2 shows one variation of this phenomena, an average demand curve; it begins in the morning as a ramp off low nighttime demand, peaks and then declines in the middle of the day, re-ramps to an early evening peak and then subsides to low nighttime demand. Overlaying this curve is average electricity generated by a solar farm. The solar farm produces nothing at night, ramps with demand in the morning but continues to rise after the morning peak, reaches its peak during low afternoon demand, and then begins to decline even as demand grows with customers returning home, cooking dinner and turning on lights, heat, or A/C. Thus, the second intermittency challenge is one of backing up renewable power supplies when they are either unlikely or unable to supply. This can mean mandating a power plant capable of base load generation to operate in a part-time, on demand mode, i.e. inefficiently in terms of costs

- The third intermittency challenge concerns power generations' ability to match the rate of change in the increase or decrease of power demand during the day. This is known as the 'ramping challenge.' Differences in the velocity of 'demand ramps' can occur from one day to the next (see Exhibit 3). On an especially hot day, A/C demand can rise rapidly leading to a sharply increasing call on the grid. Solar and wind farms are going to produce what nature allows them to produce at that time. Their ability to follow a demand ramp is purely a function of whether nature is cooperating at that time. Fossil fuel plants, with their ability to deliver 'dispatchable power' can plan for specific demand ramps in the knowledge that they don't depend on nature to cooperate with the plan. This makes for more efficient asset utilization. Utilities can also make forecasts about renewable power being available for ramping, but must have backup plans in case nature doesn't cooperate. This requires a layer of redundancy and potential use of more inefficient plants to meet unexpected supply shortfalls.

- The fourth mismatch is what to do with the 'surplus' solar power during solar's afternoon generation peak or wind's nighttime peak. Leaving storage aside for the moment, electricity once generated has to flow. If customers don't need the renewable power nature has generated, other 'dispatchable' power typically must be cut. This can involve curtailment or shutdown of fossil fuel or nuclear plants; such actions are expensive and not easily reversed (see Exhibit 4). An alternative is to 'dump' power into neighboring markets, which amounts to exporting the problem. An argument can be made that since renewable power exhibits zero marginal cost, consumers are advantaged by having wind/solar flowing and other plants curtailed. This argument must be weighed against the manning, fuel and other expenses involved in shutdown and re-start of fossil fuel and nuclear plants.

- The fifth form of renewables intermittency expresses itself as low capacity factors. Over the course of a year solar farms can generally be counted on to generate only 20-25% of their nameplate capacity. For wind farms that figure might be 40-45%. This contrasts with Combined Cycle Natural Gas (CCNG) plants producing 85% of nameplate capacity and nuclear over 90%. The lower renewables capacity factors are a function of their intermittency. Solar doesn't produce anything at night and produces less than nameplate capacity as a function of sun intensity, time of day, weather and seasonality (summer/winter). Wind velocities vary from strong to still depending on time of day, weather and season. Rough patterns exist from historical statistics, but each year will show variations. These low capacity factors and hard to predict variability mean that renewables are ill-suited to provide base load generation. Moreover, the more renewable power is added to the grid, the more the grid will struggle to accommodate either large amounts of surplus power and/or will have to maintain large reserves of dispatachable power to compensate for weather and seasonal fluctuations.

- Collectively coping with these forms of renewables intermittency imposes a host of costs on integrated utilities, transmission & distribution utilities and independent system operators. To understand the All-In costs of renewables power, these 'system costs' must be tabulated and reflected. Also, if wind and solar are to provide more zero carbon electricity in the future, these costs must be reduced as much as possible.

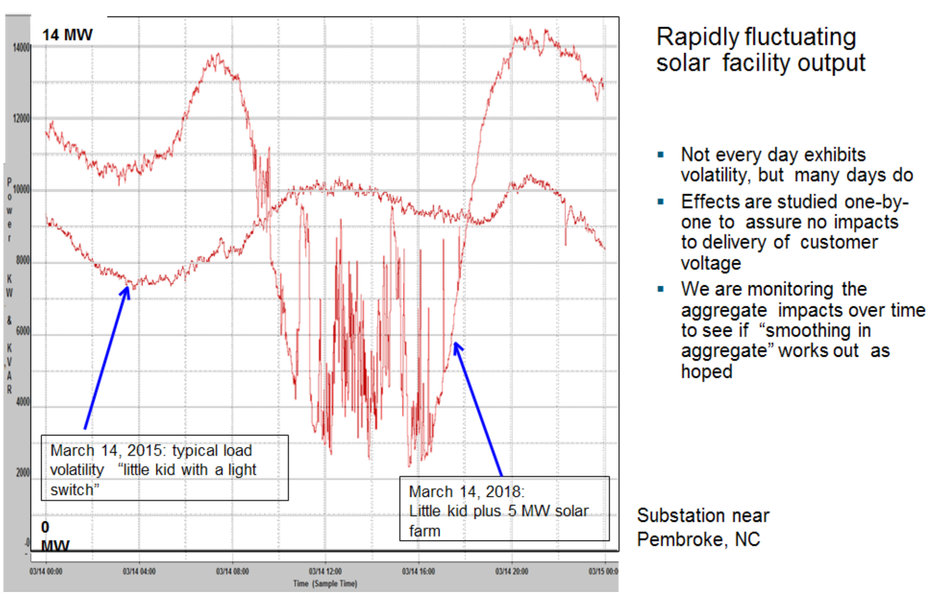


Exhibit 1: Intermittency Challenge One: Increased net load volatility sub-hourly/minute intermittency

The challenge

- Solar pushes the generating fleet's "net load" below the system's "**Lowest Reliability Operating Level**," the minimum required amount of conventional generation to operate

Today's solution

- Move excess generation off-system to western NC pumped storage plants, dump power, or curtail solar generation. Emergency last resort: curtail nuclear.

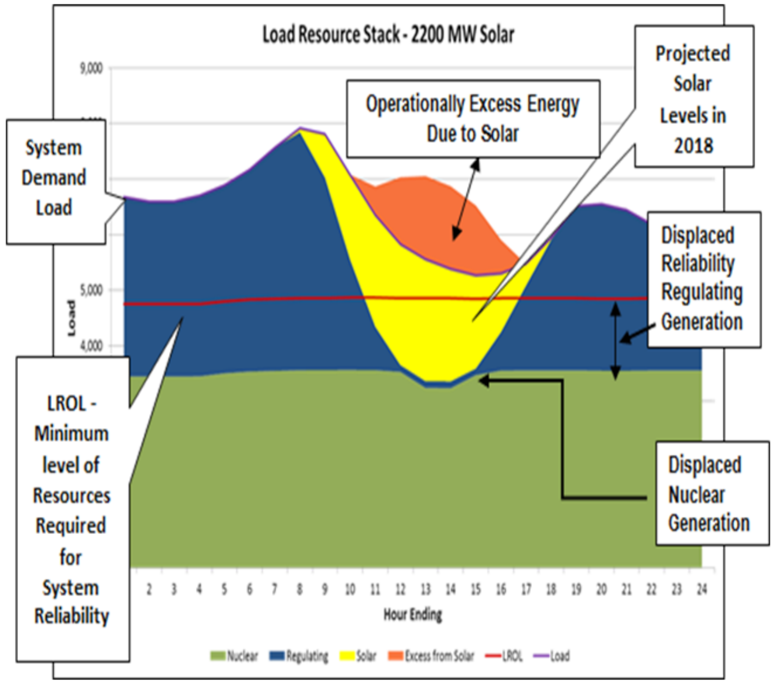
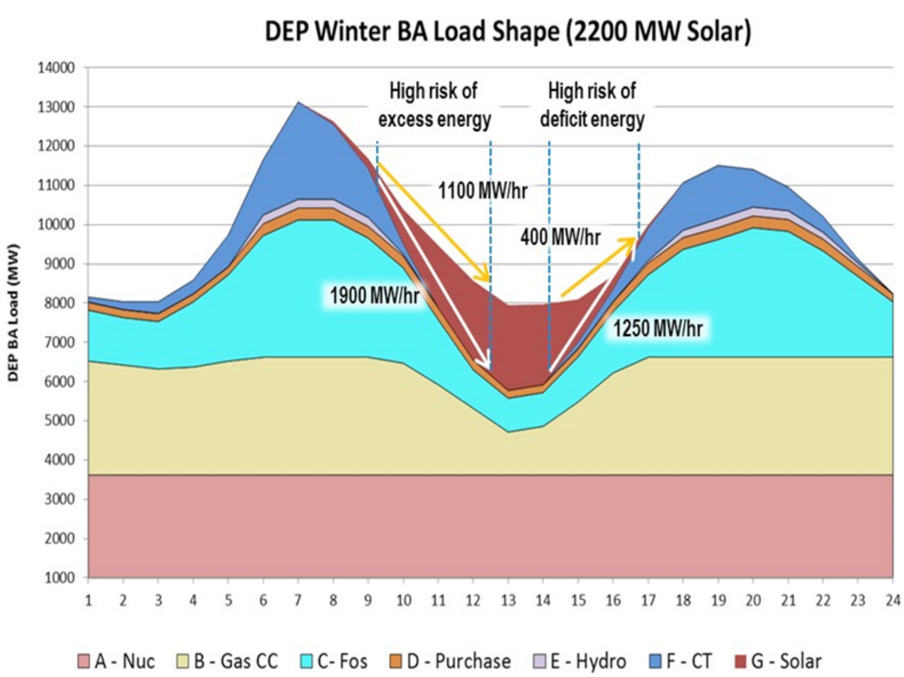


Exhibit 2: Intermittency Challenge Two: Excess Energy Sub-weekly/daily intermittency



The challenge

- Solar generation morning & afternoon ramping is <u>additive</u> to normal load ramping; generating fleet not designed to ramp beyond a certain rate of change.

Today's solution

- Closely timed coordination with pumped storage plants in western NC, when available.
- Turn on gas generation earlier in the afternoon to be ready for the up- ramp.

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Exhibit 3: Intermittency Challenge Three: Ramping sub-weekly/daily intermittency

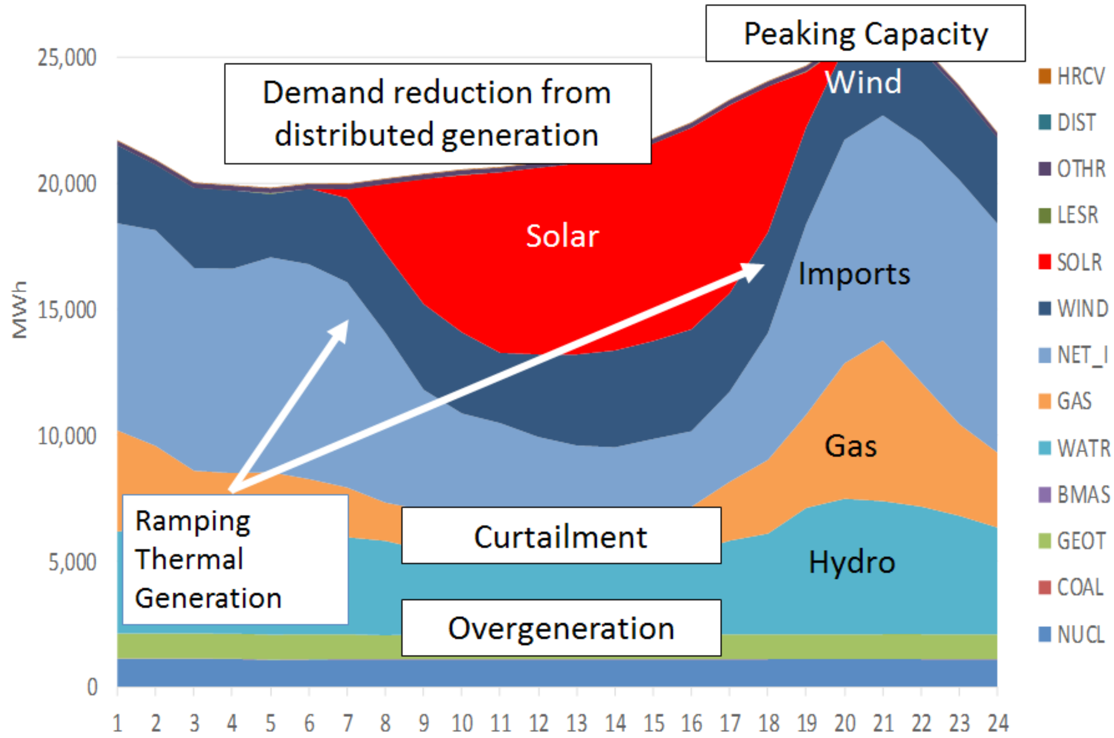


Exhibit 4: Cost Effective Renewables Integration Challenges

Renewable Power Cost Trends and LCOE Estimates

- Today the unit cost of some wind & solar power is competitive with the lowest cost fossil fuel plants. Wind power is generating electricity at $30-60 MW/H while utility scale solar is producing power at $42-56 MW/H (see Exhibit 5). Individual power auction results show even lower figures ($25-40 MW/H). These figures reflect the cost of power only when these facilities are producing and do not include any of the intermittency and system integration costs discussed above.
- Renewable electricity LCOEs cited in most studies roughly reflects the following split: 1/3 the investment costs of the land and equipment, 1/3 cost of capital, and the remainder distributed across installation costs and maintenance. These unit costs for wind/solar have declined rapidly in the last five years (see Exhibit 6). These trends reflect manufacturing economies of scale and improvements in facilities design & development.
- The costs of intermittency are significant and are not reflected in these LCOE estimates. The widely quoted Lazard studies of LCOEs contains the following note: "Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission or congestion costs or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets, emissions control systems)." The extensive list of items omitted testifies to the incompleteness of studies conducted on this basis.
- Moreover, intermittency costs tend to accelerate as the degree of renewables penetration increases. One utility estimates the costs of solar power integration at $3.50/MWH at 10% penetration and $11/MWH at 20% (see Exhibit 7). Leaving the acceleration of these costs out means that the public messaging of declining Renewable Power costs can best be described as incomplete and more accurately as misleading.

- These LCOE studies have an added problem in that they do not reflect cost variations rooted in differences in the quality and availability of wind and solar resources by location. All wind and solar is location specific. Yet, the cost differentials associated with, for example, solar in Arizona versus Minnesota are not disclosed. Thus, the LCOE studies imply that the costs displayed are generally available when in fact the map of wind/solar installations demonstrates their economics are dependent on locational conditions (see Exhibit 8).

- Leaving aside intermittency and grid integration costs, the renewables industry anticipates continued cost declines. Using $60/MWH as a 2017 benchmark, the Department of Energy has outlined a cost reduction pathway to reduce this figure by 50%. Cost reduction contributions come from lower panel prices, reduced O&M, longer project life with reduced degradation and an improved balance of system hardware and soft costs (see Exhibit 9).

- It should be emphasized that the DOE figures are targets with the actual cost reductions still to be achieved. They also don't take into account various production risks, diminishing returns and headwinds. Wind and solar manufacturing economies of scale give signs of slowing. Panel prices have fallen in recent years under the influence of Chinese spare capacity. A combination of new tariffs and Chinese government forced rationalizations has reversed this trend. The DOE figures also don't consider such factors as the potential for land costs to increase as the best wind/solar sites are occupied, for environmental costs to increase and for the cost of capital to go up in a rising interest rate environment. For these reasons, predictions of steadily declining wind and solar LCOEs should be viewed with caution.

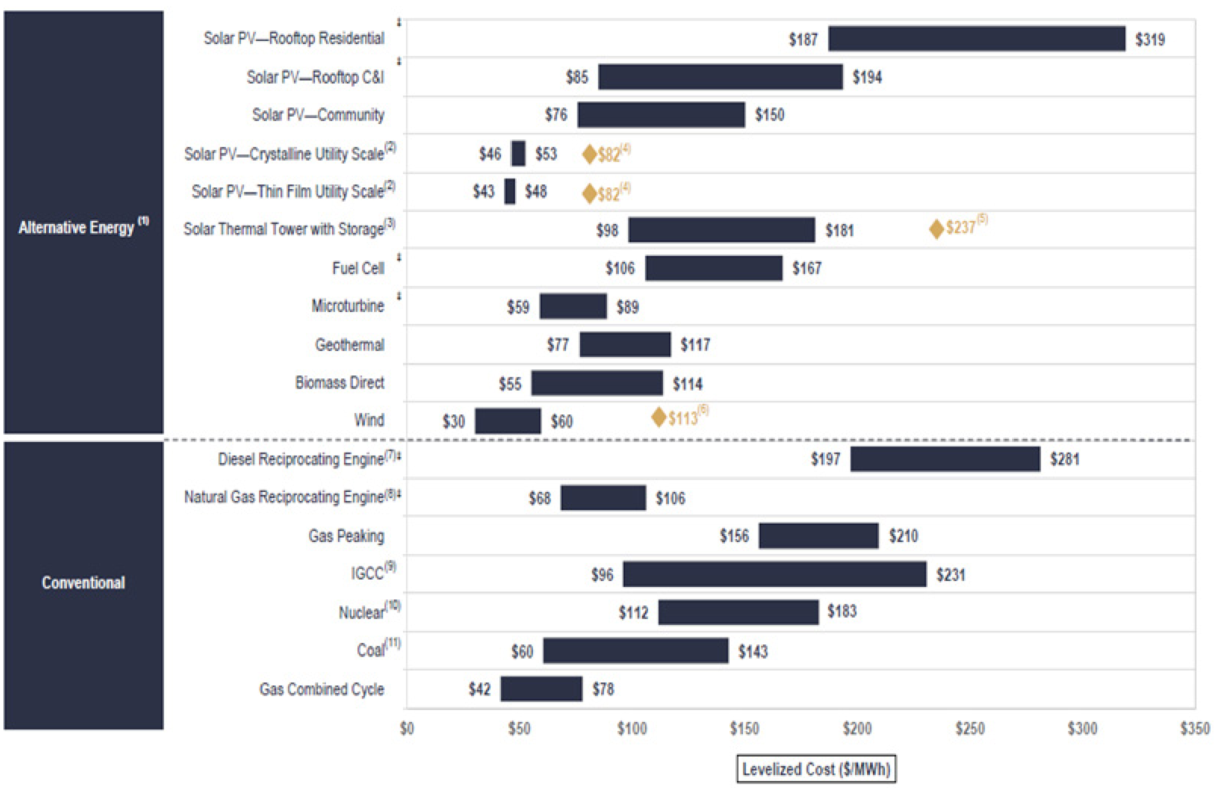


Exhibit 5: Unsubsidized Levelized Cost of Energy Comparison

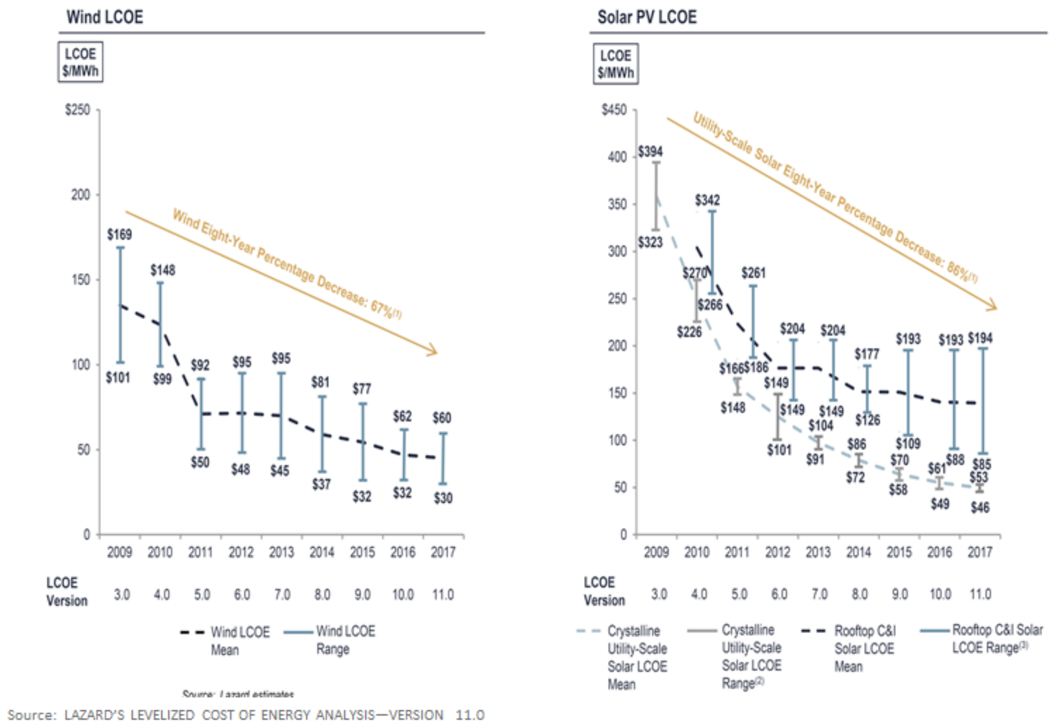
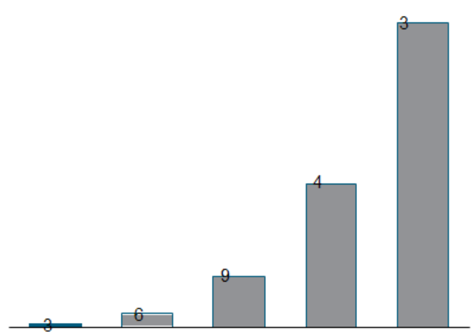


Exhibit 6: Unsubsidized Levelized Cost of Energy: Wind & Solar PV (Historical)

ANNUAL SOLAR INTEGRATION COSTS ($ millions)



Solar MWac:	**700**	**1,700**	**3,400**	**5,100**	**6,800**
Penetration*:	**2%**	**5%**	**10%**	**15%**	**20%**
Cost ($/MWh):	**$1.00**	**$2.00**	**$3.50**	**$7.00**	**$11.00**

*MW solar to Total Peak MW

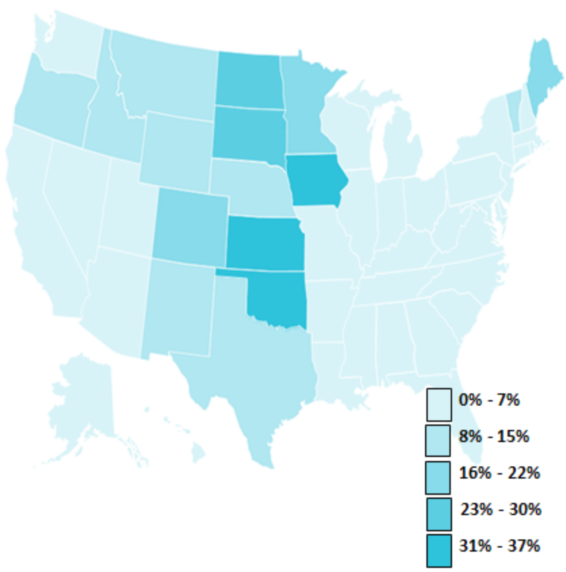
KEY FINDINGS

- Increased fuel costs related to dispatch order changes
- Excess energy becomes a problem at higher penetrations
- Planning and regulating reserves increase as solar penetration increases
- Plant cycling increases, especially CTs

Exhibit 7: Generation Integration Cost Estimates

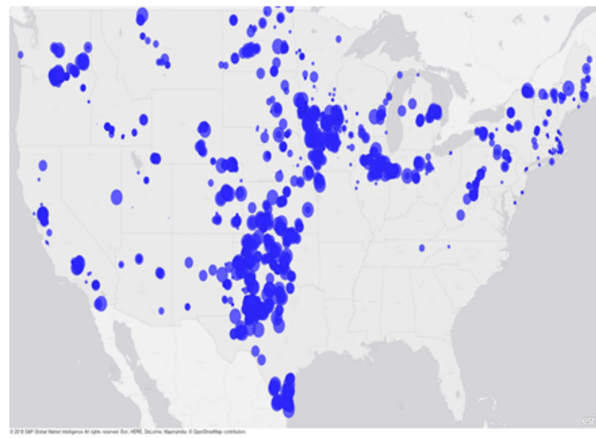
Renewable Resource Penetration: Location Matters

Wind Energy Share of Electric Generation by State (2017)



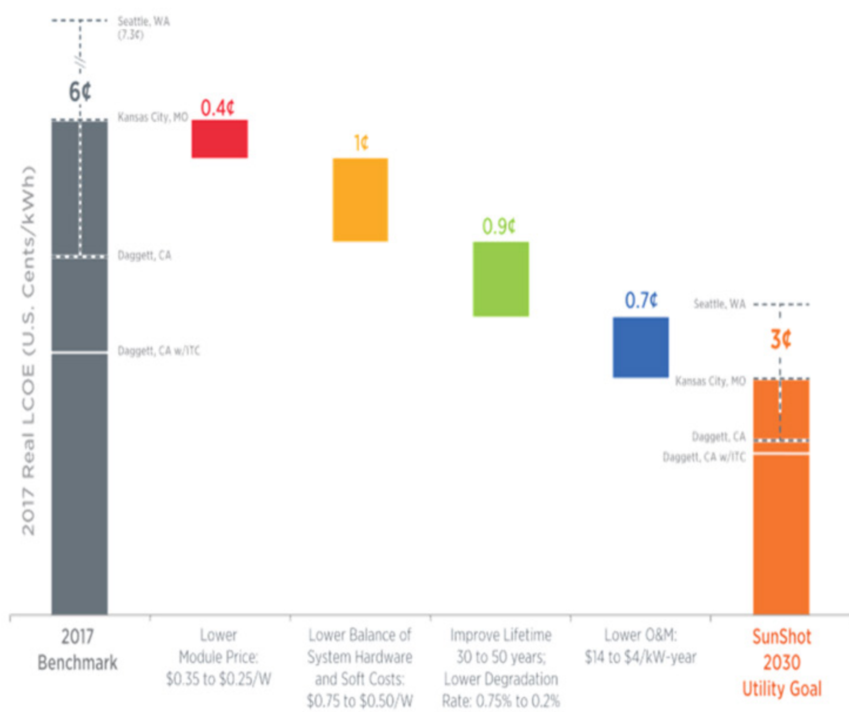
Source: EIA, Electric Power Monthly, Tables: 1.3.A, 1.14.B (February 2018)

Location of the Existing U.S. Wind Fleet



Source: S&P Global (Retrieved Apr. 2018)

Exhibit 8: Renewable Resource Penetration: Location Matters



100 $MW_{(DC)}$ One-Axis Tracking Systems With 1,860 $kWh_{(AC)}/kW_{(DC)}$ First-Year Performance.; Includes 5 Year MACRS. Horizontal Lines

Exhibit 9: DOE Solar Energy Technology Office Cost Pathway

Is Battery Storage the Remedy for Intermittency?

- Electricity storage is often cited as the solution for renewables intermittency. This discussion needs to take place in the context of costs and the different types of intermittency. Presently different types of storage show large differences in costs, with battery storage far from the most cost-efficient. Storage costs have evolved to the point where they offer cost-effective solutions for certain types of intermittency. However, other forms of intermittency have no cost-effective storage solution.
- Battery electricity storage costs have declined significantly in recent years (see Exhibit 10). This decline has allowed battery storage to become cost competitive with natural gas 'peaker' plants in addressing intermittency variations of up to two hours. Thus, battery storage is starting to be applied as a solution to intermittency issues with durations from seconds to several hours. Storage practitioners foresee battery cost-effectiveness extending to 4 hour discharge in the next several years (see Exhibit 11). These cost declines will be driven by the development of electric vehicles, which use of Lithium Ion Batteries will drive manufacturing costs down the experience curve.
- Thus, Lithium Ion Battery storage can provide cost effective solutions for short term peaking and intermittency issues. Industry experts also note batteries can provide a range of other 'value services' including frequency response, spinning reserve and flexible ramping.
- That said, battery storage does not offer a cost-effective solution to other intermittency challenges. Addressing renewables intermittency involves transferring generated power across days, weeks and months. To put this in perspective, its ultimate challenge would be to store surplus summer solar power for use in winter. Battery storage is not remotely close to economic for addressing this type of base load power issue. Improved manufacturing economics will not address this challenge. Consequently, most utilities are only deploying battery storage to smooth out short term grid stability issues, much of which are caused by increasing amounts of intermittent power.
- Claims which assert that battery storage is now rendering renewable power cost competitive with fossil fuels thus ignore these limitations and are misleading (see Exhibit 13 for an example).
- Pumped hydro and compressed air storage appear to offer much more economic storage options than batteries. This possibility will be discussed more fully in the 'Lowest Cost Pathway for Integrating More Renewables' section below.

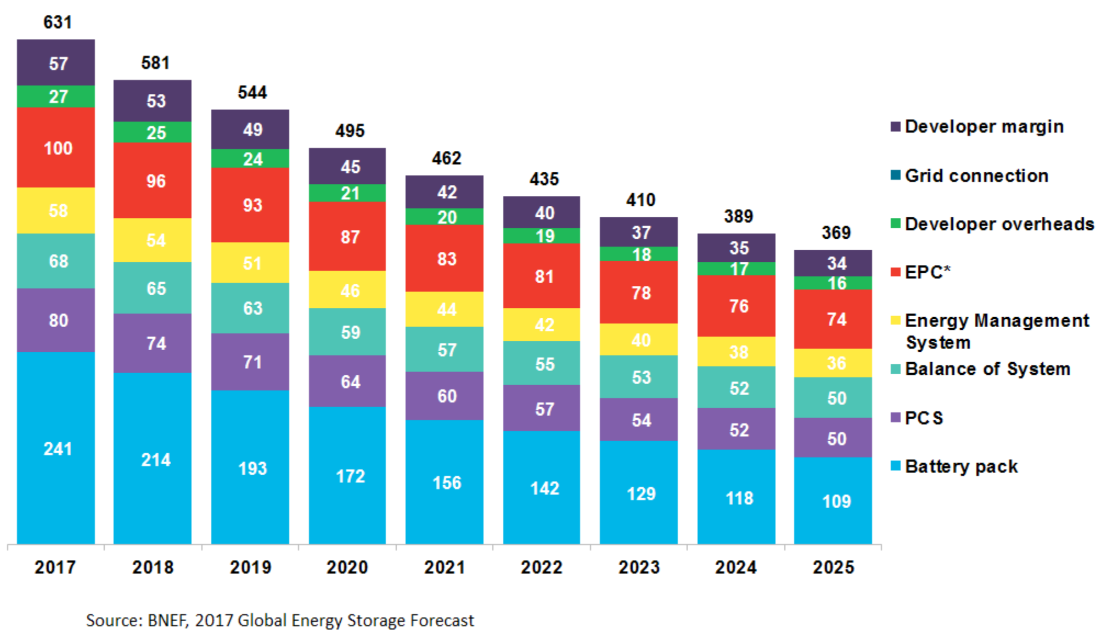


Exhibit 10: forecasted Battery Energy Storage System Price Trends

- Lithium Ion Batteries
- 20-500MW: Peaker to a combined cycle facility
- Can be deployed in <12 months
  - Sized to customer needs
  - No emissions; no air or water permits
- 10-20 year project life
- Economic Discharge duration:
  - 30min - 4 hours

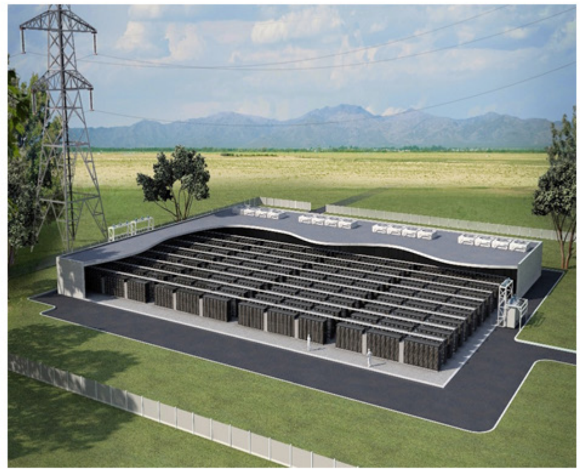


Exhibit 11: Forecasted Battery Energy Storage System Price Trends

Storage: Faster To Respond To System Needs

<u>Spec</u>	<u>LM 6000</u>	<u>Battery</u>
Size *(MW/MWh)*	50	50/100MWh
Start up Time *(Seconds)*	300	**<1**
Ramp Rate *(MW/min)*	50	**3,000**
Regulation Up	*50*	***3,000***
Regulation Down	*NA*	***-3,000***
System Availability	95%+	95%+
Failure to Start	~2%	**<1%**
Discharge Duration	**Unlimited**	2hrs
System Life	**25 year**	20 Years

Exhibit 12: Comparison-LM6000 vs. 50MW Battery

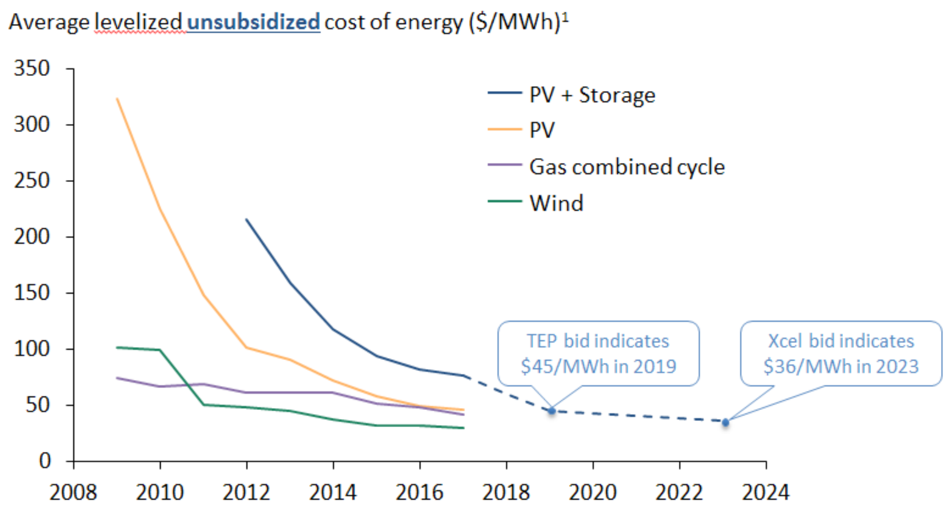


Exhibit 13: Assumptions about Intermittency Go Away When Talking Storage

The Challenge of Base Load Generation

- To decarbonizing the grid by themselves, wind/solar + storage must address the question of providing economic base load generation. This means using wind/solar + storage to meet all electricity demand load on a 24/7, 365 basis with reserve capacity to address demand/supply contingencies (e.g. planned and unplanned outages, severe weather, etc.).
- Fossil fuel plants, nuclear and hydro meet these requirements with high service factors, predictable output and planned downtime. Thus, the constant portion of the load curve can be met by generating capacity that is large scale, consistently available and largely insensitive to external factors like weather or seasonality.
- For reasons cite above, intermittent wind and solar power is ill-suited to meet base load power requirements, and battery storage is not an economic solution.
- To gain a picture of the economic challenge involved, the Kenan Institute of Private Enterprise commissioned a study by four Kenan Scholars on "Measuring Renewable Energy as Base Load Power." Their report used a 650 MW CCNG plant as a reference case. It then examined mixtures of solar, wind and storage to fill the footprint offered by the CCNG plant. The study identified a wholesale power price that provided the CCNG plant with a leveraged 10.5% Return on Equity. It then identified the carbon tax in each of the solar/wind/storage cases that provided a wholesale price high enough to give the renewable power cases a similar return.
- The results from this study are shown in Exhibit 14. The required carbon taxes for the wind/solar + storage solutions come in at $151/ton to almost $400/ton. Huge increases in capital requirements drive these economics. Equally interesting, the most economic solution combines Solar with CCNG and a $75/ton carbon tax.
- Exhibit 15 explains this result. To provide base load power wind/solar + storage must greatly overbuild capacity in order to generate enough surplus power to store for later periods of calm and low light. The fact that the amount of surplus power to be generated and stored cannot be predicted with precision simply adds to the overbuild requirement, i.e. hard to predict power must be overbuilt to generate a hard to predict surplus to be stored for a hard to predict later requirement. Exhibit 15 shows the days throughout the year where even with overbuilding of both renewable generation and storage, the resulting capacity does not fully meet load.
- This study provides a preview of what awaits markets which try to drive wind/solar into base load generation. The costs of doing so will be very high, and the carbon taxes most likely to be introduced will not overcome this. The current practice in some markets of diffusing/de-emphasizing the costs of driving renewables into base load will not obscure their large impacts on wholesale and retail prices.

- The perfect solution to grid de-carbonization is not apparent. However, the best approach currently available would dedicate nuclear and hydro to base load and employ fast start/CCNG plants to combine with wind/solar + storage. This hybrid solution offers the best balance of low electricity costs, low carbon footprint, reliable, high quality power and shareholder returns.

	NGCC	NGCC with Carbon Tax	Solar and NGCC	Solar and Storage	Wind and Storage	Solar, Wind and Storgae
Scenario	1	1	2	3	4	5
AC System Size NGCC (MW)	650	650	650	-	-	-
AC System Size Solar (MW)	-	-	650	2,958	-	845
AC System Size Wind (MW)	-	-	-	-	2,625	2,065
Total Annual MWh	4,839,900	4,839,900	4,839,900	6,738,381	12,392,152	11,671,720
Battery Capacity, MWh	-	-	-	10,250	6,550	2,410
Acreage	30	30	5,460	24,843	22,053	24,443
Wholesale Rate, $/MWh	**$47.1**	**$88.4**	**$88.4**	**$181.0**	**$135.9**	**$99.0**
Carbon Tax ($/MWh)	N/A	$41.3	$41.3	$133.9	$88.7	$51.9
Carbon Tax ($/ton)	N/A	$75.0	$75.0	$389.6	$258.2	$151.0
Capital Expenditure	$702,000,000	$702,000,000	$1,630,200,000	$7,720,641,000	$5,811,379,774	$5,075,501,108
Annual O&M + Fuel Cost	$110,627,806	$110,627,806	$116,087,806	$101,718,000	$363,743,664	$272,621,604
Debt	$280,800,000	$280,800,000	$652,080,000	$3,088,256,400	$2,324,551,909	$2,030,200,443
Equity	$421,200,000	$421,200,000	$978,120,000	$4,632,384,600	$3,486,827,864	$3,045,300,665
ROE	10.50%	13.24%	10.50%	10.50%	10.50%	10.51%

Exhibit 14: Wind/Solar & Storage as Base Load Power

Exhibit 15: Periods of Unserved Demand

The following tables illustrates the projected periods of unserved baseload demand for scenarios 3, 4, and 5. Battery storage is significantly leveraged in the energy modeling to provide baseload power during non-productive periods, reducing the number of unserved hours significantly. Nevertheless, approximately 15% of annual hours do not meet the 650MW baseload demand hurdle with the application of large scale battery storage. These periods of shortfall are relatively unpredictable over the long term but are seasonally influenced.

Sum of Days Mon	1	2	3	4	5	6	7	8	9	10	11	12
1	5,213.21	17,700.61	19,009.22	16,811.75	30,440.60	29,460.49	28,344.91	16,364.36	27,421.10	18,300.52	18,165.95	14,843.94
2	17,363.92	14,381.52	13,600.82	27,203.94	30,438.45	10,458.38	15,554.45	23,576.52	3,803.11	11,270.88	18,328.80	4,799.18
3	8,215.80	20,328.66	23,685.96	29,549.01	30,764.47	17,975.03	18,328.40	21,426.01	8,671.58	13,292.50	19,767.12	12,308.30
4	12,034.57	10,273.92	26,654.77	29,199.75	26,836.87	30,397.87	21,844.58	16,154.32	28,319.02	15,420.30	15,350.17	4,010.30
5	18,022.66	2,199.68	12,905.75	13,240.52	29,990.83	29,635.19	31,159.78	26,238.15	26,544.33	4,840.91	20,797.24	7,101.77
6	11,302.96	9,261.36	7,822.74	30,127.93	20,693.04	32,211.28	30,973.26	22,545.57	27,979.85	12,031.03	2,634.62	16,339.57
7	4,207.06	19,421.81	24,310.81	28,852.28	28,112.99	26,324.43	29,395.49	17,624.66	22,950.54	21,386.27	8,377.37	5,041.34
8	2,130.19	12,509.49	27,252.62	22,847.07	27,414.10	24,136.34	25,139.47	18,309.23	27,292.77	22,022.07	19,822.95	14,608.93
9	5,034.43	21,665.89	27,187.14	7,430.32	19,542.69	28,385.27	30,490.21	9,531.74	26,812.01	23,016.36	19,898.05	15,160.72
10	12,425.35	7,568.52	25,799.48	18,756.00	29,628.75	29,720.90	25,881.13	12,815.21	23,311.39	15,953.11	19,533.60	14,917.83
11	17,607.71	5,604.74	17,129.13	19,258.85	29,682.86	16,618.46	17,337.62	18,050.80	22,037.90	23,949.43	18,954.23	15,147.65
12	18,146.48	23,925.73	7,057.57	12,932.56	26,672.79	23,881.92	25,356.92	15,723.20	13,989.33	23,872.59	12,708.70	15,152.73
13	18,561.30	23,766.66	25,367.49	30,325.57	29,620.74	27,049.60	26,925.56	18,917.60	25,823.00	23,398.19	2,828.15	10,750.49
14	18,370.23	11,607.73	28,061.85	29,657.90	30,847.59	12,869.71	29,406.78	21,986.84	24,206.80	22,678.24	7,083.57	12,053.50
15	2,961.84	23,676.93	27,682.24	28,944.99	11,726.85	21,787.67	25,589.21	26,678.00	22,324.58	22,578.32	3,065.57	2,201.32
16	15,506.90	2,791.75	19,062.52	8,544.83	12,927.19	22,646.59	27,293.40	18,480.99	14,868.20	18,449.97	12,490.72	7,875.20
17	2,646.06	19,311.02	17,341.15	30,903.65	4,555.22	29,991.84	22,070.46	21,883.17	19,620.48	19,275.23	12,025.44	15,677.34
18	19,040.97	22,270.32	11,783.10	29,786.12	24,890.97	28,866.22	11,324.00	14,836.95	16,392.69	10,539.64	3,442.22	16,351.86
19	19,709.77	3,011.59	20,554.21	28,772.27	30,988.44	30,111.31	22,794.62	18,983.94	11,094.79	13,049.97	2,653.06	7,236.61
20	8,548.41	25,087.47	17,740.84	23,114.32	26,594.93	9,400.25	26,295.59	20,163.72	4,251.31	21,102.40	7,640.70	16,450.04
21	19,109.86	13,350.39	27,180.95	16,218.19	14,777.38	32,283.01	28,796.34	26,443.73	12,865.18	16,604.20	18,027.14	2,215.40
22	2,182.82	21,850.13	28,926.77	9,375.64	22,233.24	28,320.86	23,526.02	21,550.81	11,240.38	11,908.08	18,152.64	12,831.87
23	6,727.53	16,619.25	10,270.27	24,892.93	21,699.60	20,730.29	10,755.63	23,554.73	12,602.77	16,896.13	17,754.36	6,728.86
24	20,182.10	8,341.29	4,201.76	25,416.63	30,737.83	26,716.83	19,030.31	18,869.93	23,185.17	11,307.60	18,057.59	15,816.00
25	16,533.60	24,268.55	6,864.21	26,847.60	27,351.57	19,351.44	16,239.07	27,599.25	6,339.53	6,759.58	18,223.42	11,716.56
26	15,244.66	24,881.62	17,083.47	14,672.98	22,331.81	27,360.11	24,821.26	26,928.10	18,337.12	2,300.33	17,649.48	2,190.22
27	4,695.58	4,169.57	28,848.90	21,302.23	27,444.12	29,944.78	25,847.05	26,517.12	16,929.46	6,486.71	4,068.61	15,744.44
28	4,426.79	25,224.25	29,093.33	6,573.29	9,307.92	30,456.83	15,307.16	23,242.38	21,148.23	13,209.44	17,517.38	11,476.16
29	20,248.39		29,354.08	31,582.15	16,996.63	23,219.65	15,739.42	25,744.89	7,877.96	20,503.94	17,420.31	5,831.89
30	20,581.67		17,790.18	31,707.20	30,714.63	18,410.80	24,068.66	26,669.29	6,683.86	19,937.99	16,003.00	3,180.86
31	18,721.89		12,288.34		24,844.25		18,803.87	23,454.17		17,794.90		16,742.81

Daily Baseload Demand = 15600
Yellow: Slightly Below Baseload - 21 days
Red: Significantly Below Baseload -102 days

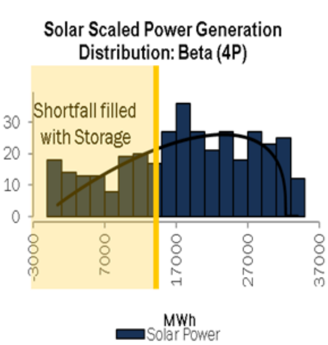
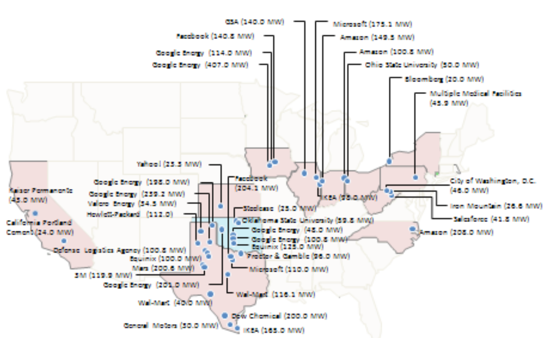


Exhibit 15: Periods of Unserved Demand

The Outlook for Capital Costs & Financing

- The immediate outlook for Renewable power financing is positive. This applies to both equity and debt financing. The outlook beyond 2020 is harder to predict.
- The capital markets are impressed with wind/solar/storage cost reductions and expect continued progress. They also are impressed with the appetite of major corporate clients to conclude Power Purchase Agreements (PPAs) with renewables providers (see Exhibit 16).
- These developments have attracted large scale funding from private equity sources, who consider high single digit but predictable returns attractive. Achieving these returns has been assisted by the banking community that has developed a variety of hedged contract structures that appeal to capital market investors (see Exhibit 17) Banks are also seeing a reduced percentage of projects being driven by Renewable Portfolio Standards (RPS) as opposed to those representing responses to customer demand (see Exhibit 18).
- The capital markets anticipate a substantial pipeline of wind and solar projects as tax subsidies phase down between now and 2022. Renewables developers will front-run the phase down, pushing projects through the pipeline to be grandfathered.
- Tax equity appetite remains adequate-to-good for the moment despite the recent Tax Reform Act's lowering of corporate tax rates. The change in bonus depreciation rules for utilities is a partial offset. The tax-appetite outlook beyond 2020 is less clear as wind/solar subsidy phase-down is completed (see Exhibit 19).
- As 2022 approaches, smaller renewable developers may face strong financing headwinds from the combination of subsidy phase-down and higher interest rates. The capital markets then anticipate an increased pace of utility project development plus acquisitions. Existing projects approaching the end of their initial PPAs may proves especially attractive to utilities interested in meeting RPSs and adding assets to their rate base. Many utilities already own substantial wind/solar businesses and continue to look for ways to grow in a low electricity demand growth environment (see Exhibit 20).

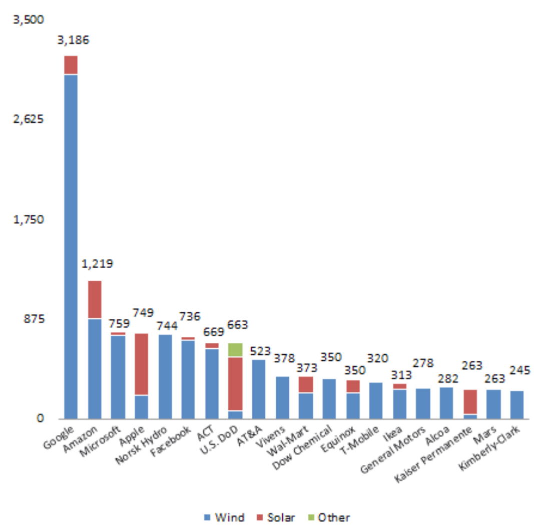
Executed Corporate PPAs By Company



Source: American Wind Energy Association

Global Corporate PPA Owner

- Top 20 Owners as of February 2018 (MW)



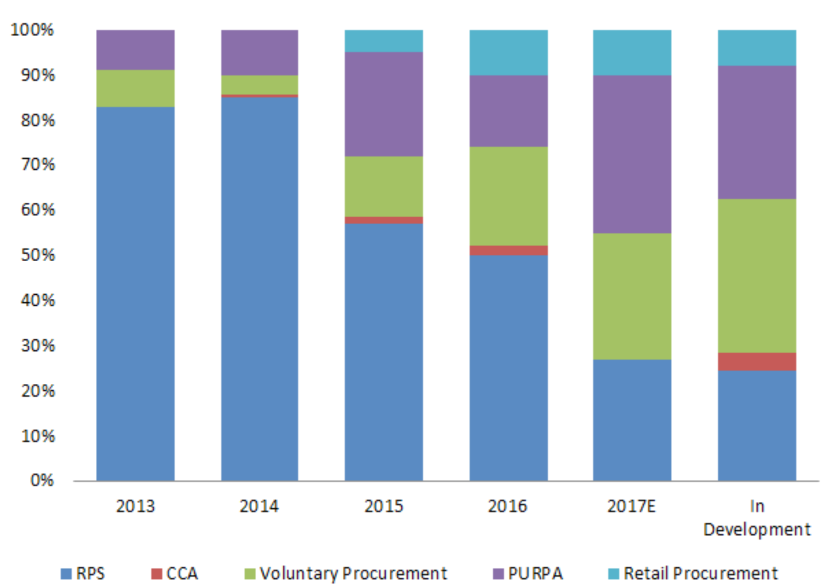
Source: Company Filings, BNEF Corporate PPA Tracker

Exhibit 16: Continuing Trend of Corporate PPAs

	Utility PPA	Corporate PPA	Bank Hedge	Proxy Revenue Swap
Volume	• As-generated, with payment per MWh • Fixed volume (not common)	• As-generated, with payment per MWh • Fixed volume	• Fixed volume using a 12x24 Shape based on P99 expected production • Use of tracking account	• As-generated , with fixed payment per month
Tenor	• 15 – 30 years	• 10 – 20 years	• 10 – 12 years	• 10 years
Pricing Structure	• Flat price per MWh or annual escalating price	• Flat price per MWh or annual escalating price	• Highly customizable; ability to use call and put options to shape risk exposure	• Fixed payment amount (akin to capacity payment subject to facility performance)
Common Markets	• Applies to all markets, including organized ISOs and physical systems	• ERCOT • SPP • MISO • PJM	• ERCOT • SPP • MISO	• ERCOT • SPP • MISO

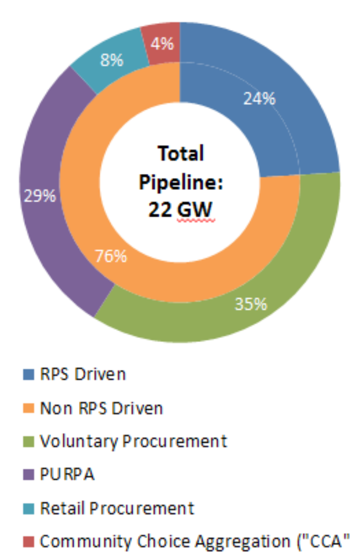
Exhibit 17: Renewable Off-Take Structures

Share of Utility Solar by Primary Driver (%)



Source: U.S. Utility PV Market Tracker

U.S. Utility PV Pipeline



Source: GTM Research U.S. Utility Solar Service

Exhibit 18: Mandates No Longer the Key Driver of Growth

Key Considerations

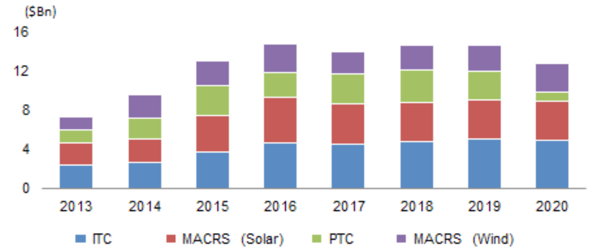
1 • Projected need for tax equity expected to hold constant
   – Size of market may exceed $14Bn per year for next four years as new solar and wind development continues

2 • Corporate tax policy will impact tax equity financing for marginal projects
   – Reduction to corporate taxes will reduce future tax expenses and tax equity appetite
   – One-time 10% tax on repatriated profits could increase tax appetite
   – Change in bonus depreciation rules for utilities will increase tax appetite

3 • End of year safe-harbor qualification push mean substantial greenfield pipeline
   – Developers have safe-harbored viable projects to keep optionality of the full PTC benefit for future development

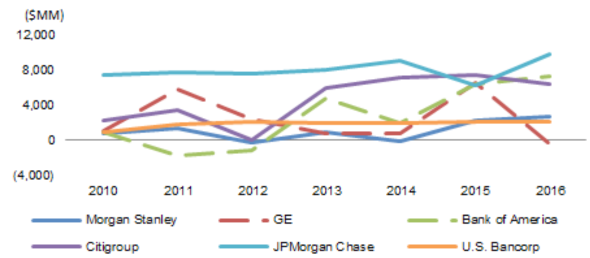
4 • Increase in tax efficient strategic buyers for new build projects
   – Utilities increasingly active in new build developments with financing synergies by funding construction and monetizing tax credits on balance sheet

Projected Need for Third-Party Solar and Wind Tax Equity Finance



Source: Bloomberg New Energy Finance

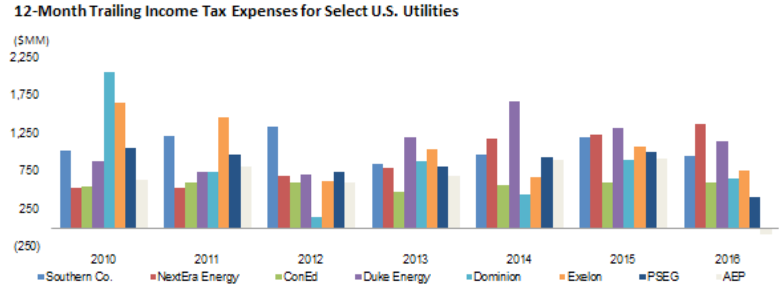
12-Month Trailing Income Tax Expenses for Large Tax Equity Investors



Source: Bloomberg New Energy Finance, Bloomberg LP, Capital IQ

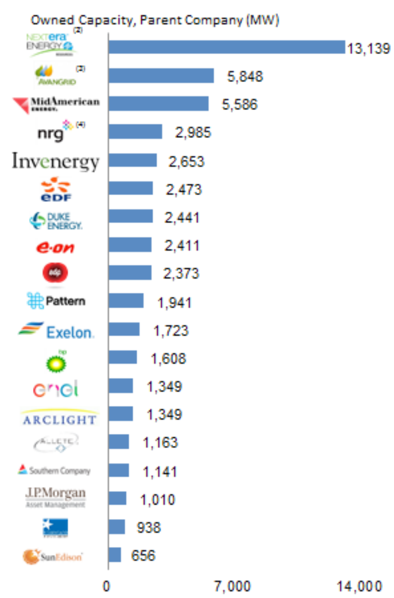
Exhibit 19: Key Themes in Tax Equity Market

12-Month Trailing Income Tax Expenses for Select U.S. Utilities



Source: BNEF, Company Filings, Capital IQ

Top Owners of U.S. Wind Assets [1]



MW Adjusted for Partial Ownership Stakes

Source: SNL Energy, Company Filings, Investor Presentations

Key Takeaways

- U.S. strategics and European strategics continue to hold the largest portfolios of wind
- Ownership fragmented across companies, with only NextEra owning more than 10% of installed capacity

Utilities Building To Monetize Tax Credits

- In August 2016, Iowa Utilities Board Approves $3.6Bn MidAmerican Wind Farm
  – MidAmerican to develop Wind XI which will add 2,000 MW of wind generation in Iowa
  – Approval helps MidAmerican take full advantage of recently extended federal wind production tax credit
- In September 2016, Xcel Energy reaches agreement on massive Rush Creek Wind Project
  – Development of $1Bn wind project in Colorado totaling 600 MW, owned and operated entirely by Xcel
  – Xcel to accelerate construction to claim the full $443MM under federal tax credits

1. Includes wind asset holdings of all subsidiaries that flow up through parent, both regulated and unregulated
2. Includes NextEra Energy and NextEra Energy Partners
3. Includes Iberdrola and Avangrid
4. Includes NRG and NRG Yield

Exhibit 20: U.S. Utility Scale Wind Ownership

What is The Lowest Cost Pathway for Integrating More Renewables into the Grid?

Wind/Solar + Storage have an important role to play in electricity generation; virtually every forecast of future energy supply/demand sees a growing role for these power sources. They will be important for countries like China and India, with vast populations, growing economies and a dearth of domestic oil & gas. Their growth in OECD countries is a signal of determination to restrain the growth of Greenhouse Gas emissions. Developing countries will look to Wind/Solar + Storage to help them avoid overdependence on imported fossil fuels. Yet, Wind/Solar + Storage face cost challenges. These are laid out in the first section of this report.

Accordingly, the conference asked a second question: given renewable powers' several desirable features (often not reflected in prices), what is the lowest cost pathway for integrating more Wind/Solar + Storage into the Grid? For many reasons it is hard to foresee how deeply wind/solar may ultimately penetrate. Cost, technological developments (or lack thereof), public policy and unforeseen events all will exert influence. What is unarguable is that identifying and following a lowest cost pathway will facilitate more penetration by these zero carbon electricity sources. To this topic we now turn.

Current Practices, Problems & Options

- A general consensus exists that renewables' grid integration requires some combination of six components: 1) Electricity Storage; 2) Renewables Diversification; 3) Wide Area Energy Markets; 4) Integrated Systems Planning/ Forecasting; 5) Demand Management; and 6) Use of Flexible Natural Gas Generation. Exhibit 21 illustrates this view.
- Although not part of this consensus, an argument can be made for curtailing renewable power as a low cost part of this pathway. Indeed, this argument can be presented in the form of 'planned curtailment.' When using planned curtailment, system operators purposely plan to use renewable power at levels below their capacity. This tends to avoid over-generation and can leave low cost renewable power available for backup and ramping. Exhibit 22 illustrates this view, which will be discussed further below.
- The relative merit of these options is not just a function of their direct costs. It is also a function of their ability to work with little friction in today's market and regulatory structures. This requires a look at those current practices and problems which present obstacles to a low cost integration of more renewable power.
- The U.S. presents a highly fractured electricity market, with different jurisdictions, regulatory authorities, Independent Operating Systems (ISOs), mandates & subsidies and pricing systems. These seem to operate in a seemingly crazy-quilt fashion. The resulting balkanized market makes implementation of a single 'best-practice' national approach impractical for now.
- The most important market fracture lies between markets where electricity generation has been deregulated versus those which retain fully integrated but regulated utilities. Power deregulation was adopted to employ competition to drive down wholesale prices and benefit consumers with lower cost power. Often this was achieved via auctions where companies bid competitively to supply power. Typically the auctions are structured so that the lowest power price bid must be accepted. When supply is abundant, providers have incentives to bid aggressively, all the way down to breakeven with variable costs. Thus, deregulated electricity markets have evolved to where auction results see bids down towards and even below producer marginal cost.
- Consequently, deregulated power markets do a poor job reflecting both the full costs of supply and a variety of 'system' benefits offered by different power sources. Reliability and resiliency often are not reflected in prices. Neither is power quality or an externality like low/zero carbon. Finally, deregulated market structured to produce cutthroat competition do a poor job of promoting capital formation. The long list of bankrupt merchant power firms, e.g. Calpine, Dynegy, testifies to this outcome. In short, deregulated power is not well suited to implement public policies of change. Their price structures don't incentivize things other than lowest short-term cost and they don't provide the capital producers need to finance change.

- The entry of wind/solar, often on the backs of RPS, intensifies these problems. Wind/solar have low to negligible marginal cost. As noted, they also cannot provide dispatchable power. Consequently, renewables operators feel they must bid aggressively in market auctions. The alternative is to see a portion of their already low capacity forced to be idle. In the case of wind power, it also means foregoing part of the available tax subsidy. These conditions have resulted in renewable power being bid into auctions at zero or even negative clearing prices. When this happens, it has forced curtailment and cycling of base load plants. In severe cases it has incentivized the retirement of coal, nuclear and gas plants before the end of their economic lives.

- This problem is less acute in regulated markets. There pricing recognizes full average production costs, the value of reserve capacity and a return on shareholder capital. In regulated markets renewables intermittency problems are more a function of RPS mandates forcing utilities to grants developers PPAs and then not recognizing the resulting costs of intermittency and grid integration in retail pricing.

- Wide Area Energy Markets (WAEMs) have been a major contributor to mitigating renewables integration costs. Integrating bigger electricity markets mutes power volatility by diversifying supply sources, transmission options and sources of demand. Independent System Operators like CAISO and ERCOT and even bigger Regional Transmission Organizations (RTOs) (PJM & MISO) have proven adept at moving power around within their markets, channeling surpluses to deficit areas and generally coordinating supply and demand to smooth out local mismatches. As such they have played a major role in demonstrating how power volatility stemming from growing renewables can be offset by connecting and coordinating markets over a bigger geographical footprint.

That said, the full potential of WAEMs is handicapped by the following:

- Regulated and De-Regulated market boundaries don't coincide with those of ISO/RTOs. Consequently, the latter have to address the power outputs incentivized by very different pricing systems

- ISO/RTOs generally cannot require utilities to make investments consistent with improved regional coordination. Those decisions lie mostly with the utility companies and state regulatory authorities. ISO/RTOs have no taxing authority and generally rely on their members for funding to improve the regional grid.

- RPS tend to work against Wide Area coordination. Generally speaking, RPS tend to produce Power Purchase Agreements drawn up without much consideration of transmission and integration costs. RPS also are set at the state level. This can result in large disparities in renewable power supplies from different locales within a ISO/RTO. System operators can give advice to state governments about the grid implications of their RPS policies, but the ultimate outcomes result from state government decisions.

- As a result of these factors, the potential of WAEMs to mitigate renewables intermittency, while considerable, encounters limits. It can be one, and perhaps the most economic, among several components of a low cost pathway for renewables integration; it is not the definitive solution.

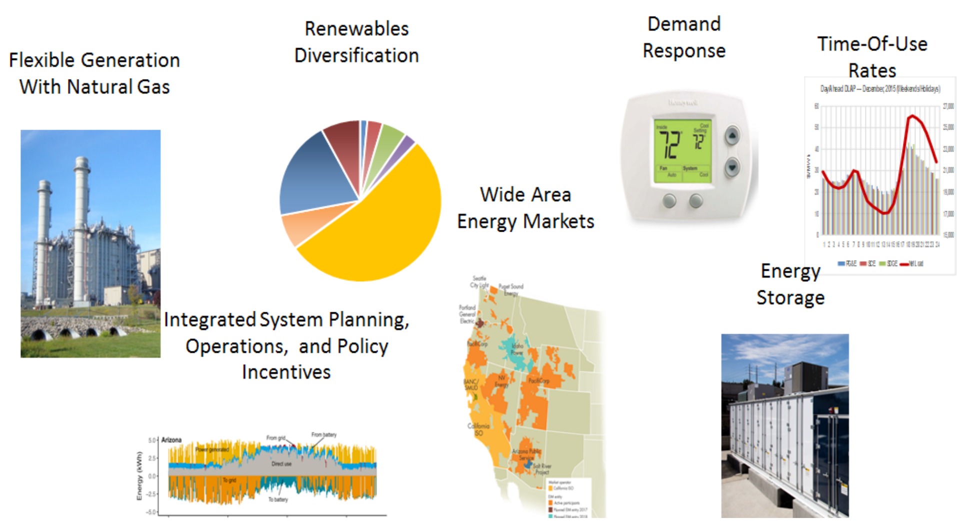
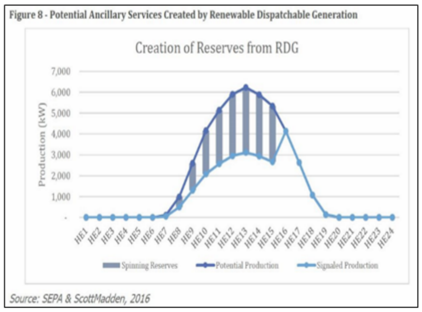


Exhibit 21: Some Pathways for Lowering the Cost of Renewables Integration

"Too often, curtailment is automatically viewed negatively. We wanted to explore a thoughtful approach to curtailment that might actually produce more flexible operations and better results for all parties involved."

Chris Vlahoplus, Clean Tech and Sustainability Practice Leader at ScottMadden.



"You're not curtailing; you're turning the power into ancillary services that create a new value stream for the grid, and customers (get) the benefit."

John Sterling, Senior Director at SEPA

Exhibit 22: Changing Solar PPAs Could Turn Curtailed Power into Dispatchable Resources

Option 1 – Electricity Storage

- Electricity storage has long been seen as the remedy for renewables intermittency. If surplus renewable power can be cost-effectively stored and then dispatched on call, renewable power becomes very attractive, offering almost zero marginal cost power and zero carbon emissions.
- Battery storage, principally lithium battery-based, is the most often cited form of such storage. Batteries however, have long been problematic as a systemic answer to renewables intermittency. Basic manufacturing costs were high. Batteries also are prone to charge losses, deterioration over time, and a variety of operating challenges. For example, they need to be kept sufficiently cooled, which consumes energy. This last point can be especially challenging in hot locations which often are also the most attractive sites for solar power. For all of these reasons, battery storage has not been economically attractive until very recently.
- Lithium-ion battery (LIBs) manufacturing costs have declined markedly in recent years (see Exhibit 23). This decline has been fostered by widespread use of these batteries in phones and portable devices, the growing demand for electricity storage and larger scale introduction of electric vehicles (EVs). Further cost declines are anticipated, driven by the vast expansion of EV fleets expected worldwide.
- As noted, this progress has enabled LIBs to render cost competitive storage versus reliance on short-term fossil fuel peaking capacity. Exhibit 24 shows how LIBs are today competitive within a two hour discharge window. They also can offer other value to the grid, e.g. frequency and voltage regulation. They do, however, need recharging after discharge, which compares unfavorably with natural gas plants that can remain online.
- Exhibit 25 suggests that LIBs' costs may continue to improve to the point where they approach competitiveness within a four hour discharge window. Even with these efficiency gains, they remain uncompetitive for longer term storage.
- This forecast sees global manufacturing of LIBs as a one-way path to efficiency gains. This outlook is at risk of ignoring other cost pressures as demand rises, e.g. inflation in materials inputs such as lithium.

- The outlook for a major technology breakthrough on battery storage is not positive. The leading contender, flow batteries, faces serious issues as regards longer term storage – exactly the frontier on which LIBs are challenged.
- More fundamentally, battery storage is far less cost effective than other forms of electricity storage. Exhibit 26 compares the relative efficiency of LIBs and other batteries versus two older forms of storage: Compressed Air (CA) and Pumped Storage Hydro (PH). This chart underscores how dramatically these other forms of storage outperform LIBs.
- Compressed Air and Pumped Hydro have been neglected for some time. The original wave of these projects coincided with the growth of the U.S. nuclear industry in the 1960-70s. Economics and safety favor nuclear plants staying online; this can result in electricity surpluses. CA/PH storage provided a means to avoid having to recycle other plants to avoid surpluses, and it enjoyed favorable economics by diverting power output from off-peak to higher pricing. As nuclear's growth faded and environmental regulations intensified, CA and PH projects dried up.
- Several of today's renewables intermittency issues are similar to those which fostered CA/PH projects, e.g. the need to store surplus power and to do this economically for time periods longer than a few hours. These conditions suggest a hybrid approach to electricity storage could be one of the most cost effective steps on the pathway to deeper renewables integration. LIBs can address short term and some hourly intermittency issues and provide power quality help. CA/PH projects can offer longer term storage, i.e. daily and possibly longer.
- It is encouraging that two Southeastern U.S. utilities are revisiting CA/PH as part of their integration plans for renewable power. This progress also suggests that renewables advocates should revisit the environmental conditions previously placed around these projects. It may be that in the light of CA/PH support for zero-carbon power, some adjustment to these regulations is warranted.

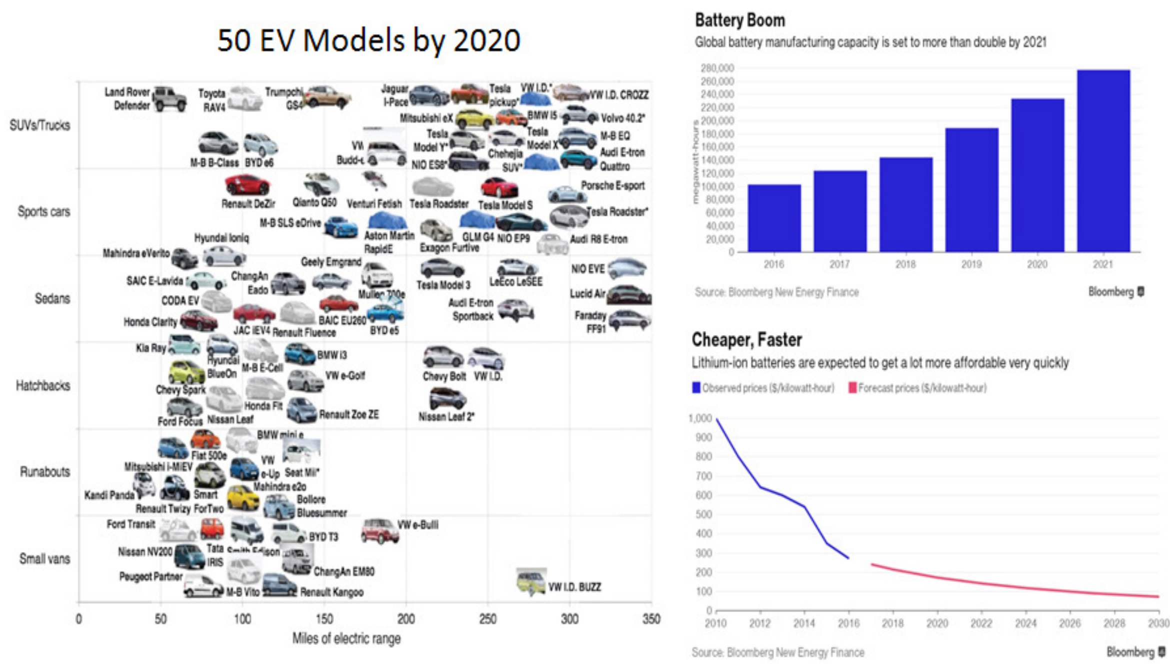


Exhibit 23: LI-ION Battery: cost Driver=EVS

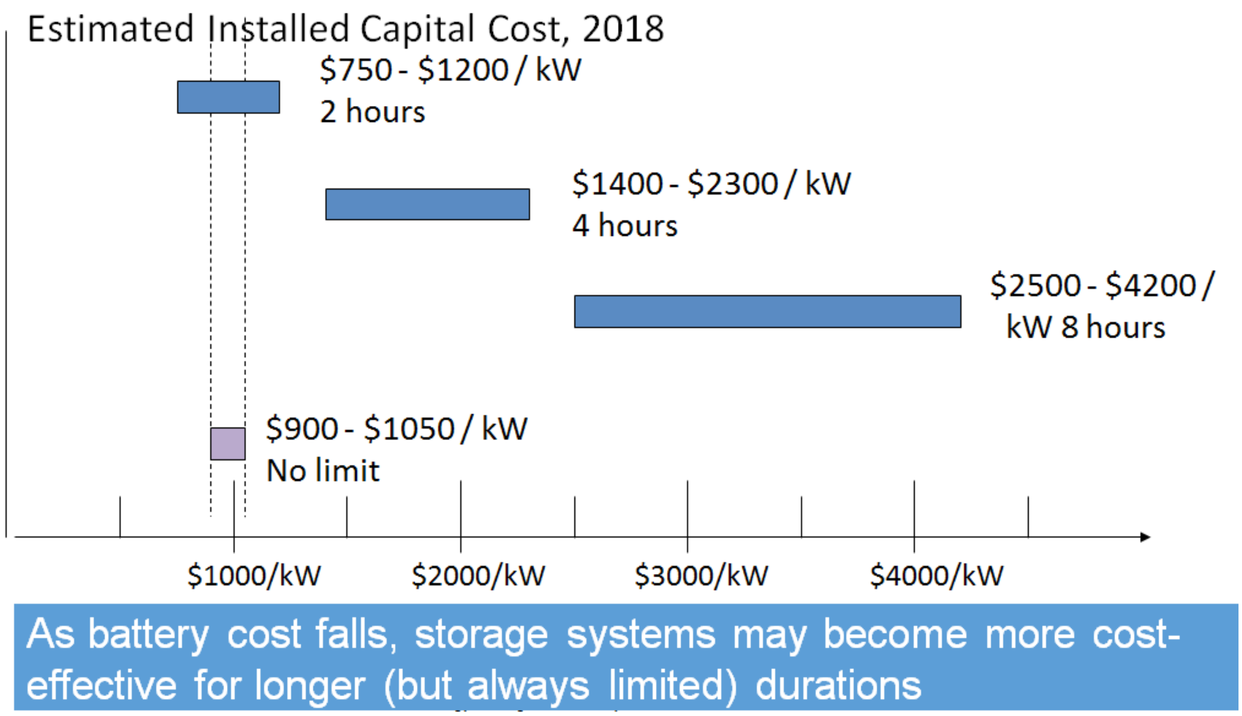


Exhibit 24: Lithium Ion Batteries vs. Open-Cycle Gas Turbines

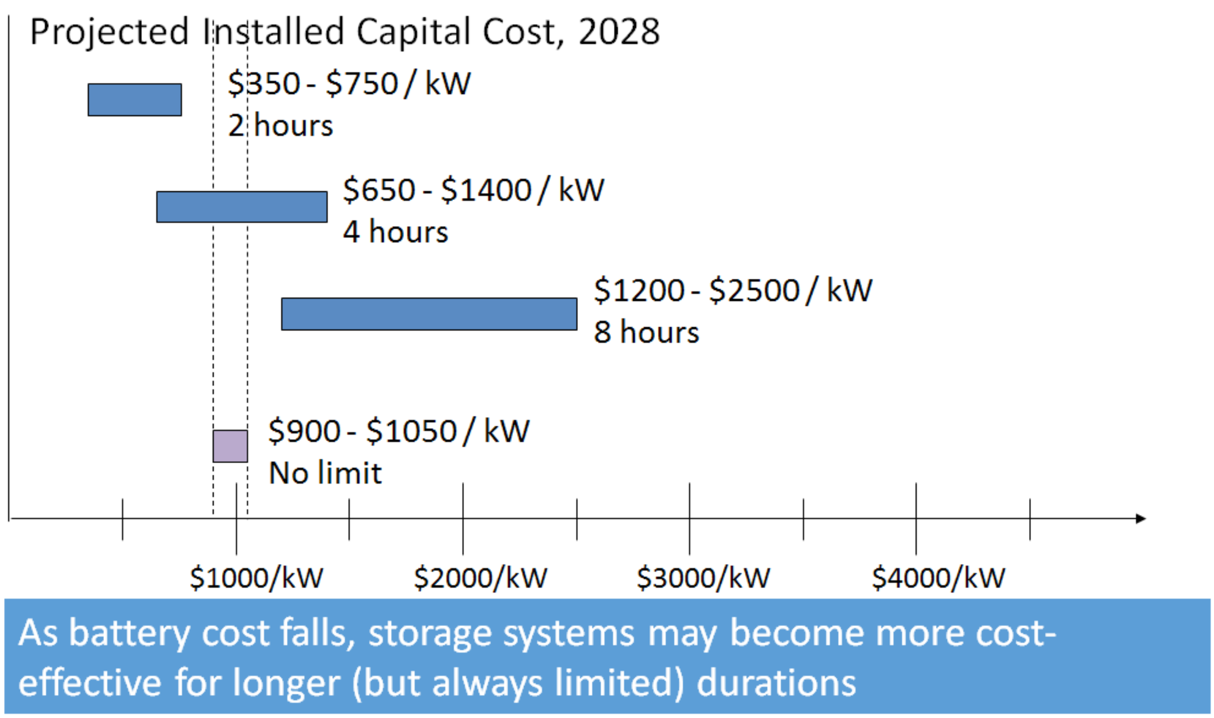


Exhibit 25: Lithium Ion Batteries vs. Open-Cycle Gas Turbines

$$ESOI = \frac{\eta D \lambda}{CTG}$$

where

$\eta = efficiency$

$D = depth\ of\ discharge$

$\lambda = cycle\ life$

$$CTG = \frac{Cradle\ to\ gate\ embodied\ energy(MJ)}{Storage\ capacity(MJ)}$$

2013. On the importance of reducing the energetic and material demands of electrical energy storage. Energy and Environmental Science, DOI: 10.1039/c3ee24040a.

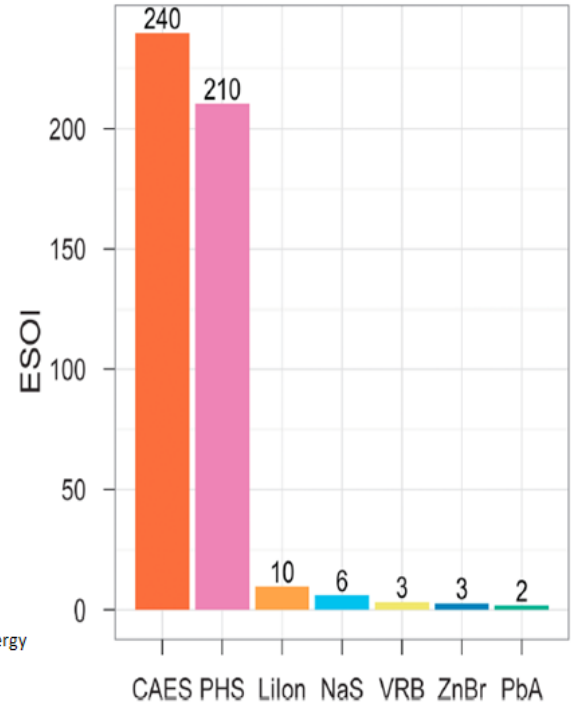
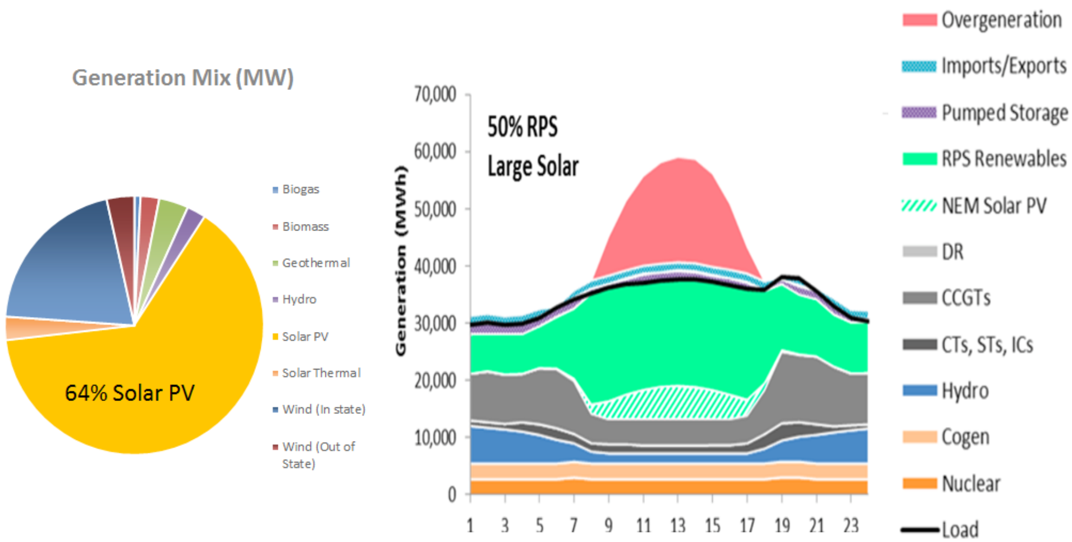


Exhibit 26: Energy Storage is Energy Intensive

Option 2: Renewables Diversification

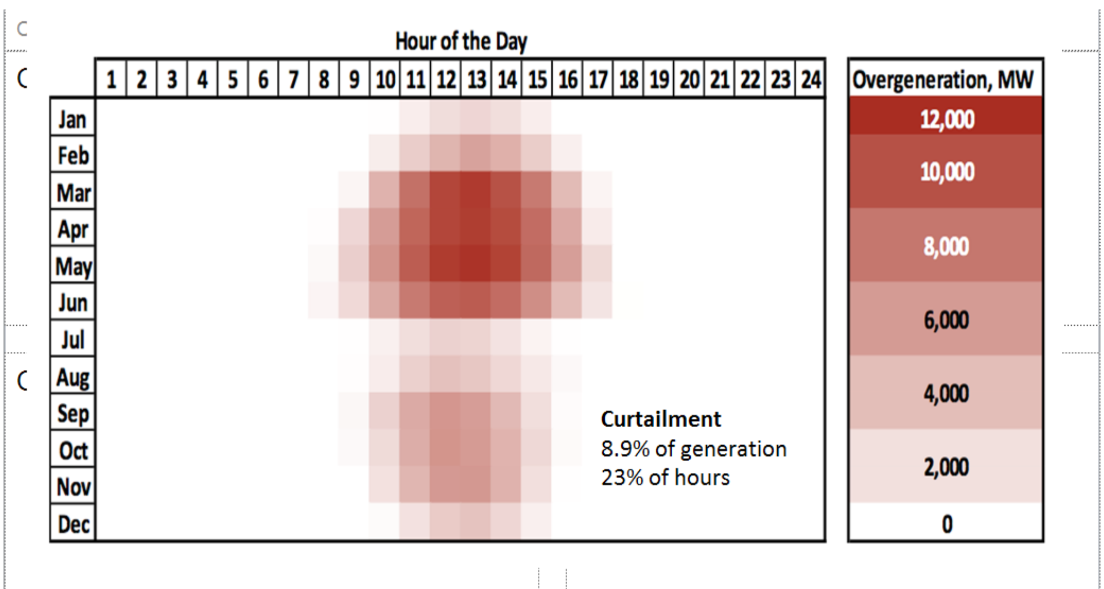
- Wind and solar tend to maximize production at different times. Solar provides peak power during the middle of daytime. Wind tends to maximize output at night. Consequently, a balanced portfolio of wind and solar tends to produce a less volatile average production output. Other forms of renewable power, e.g. hydro, can produce steadily or operate like hydro storage. Consequently, a diversified portfolio of renewable power sources can minimize intermittency issues.
- Overreliance on one form of renewable power intensifies the intermittency challenges. This is especially the case with solar, whose production curve varies from zero power at night to high peaks on summer mid-days. Exhibit 27 illustrates this problem in California and measures the impact in terms of forced curtailment, i.e. a decision not to produce power that would otherwise be available.
- Exhibit 28 and Exhibit 29 illustrate how rebalancing California's portfolio could result in a material (~50%) reduction in power curtailments.
- Overreliance on one renewable power source can be an unwelcome by-product of RPS. Typically RPS rely on PPAs given at 'avoided cost.' Prevailing definitions of avoided cost generally consider neither renewables integration costs nor the issue of diversifying the type of renewables incentivized. To the extent mandates require power to be built but don't mandate a balance of renewable type, they invite an overreliance issue.
- The challenge in renewables diversification is that many locations are blessed with a single economic renewable option. This is visible when observing the wind project concentrations in Exhibit 8 and those for solar in Exhibit 30.
- Long distance transmission lines can enable renewables diversification to proceed. Typically this will involve bringing low cost wind to balance solar dominated areas, although the opposite is occurring in ERCOT. These projects will be driven by economics, as the investment is for transmission lines which are neither subsidized nor mandated by RPS. Permitting and environmental challenges associated with building long distance transmission are limiting factors here.

- Diversifying renewables within a WAEM can be a lower cost option. This approach allows different renewables projects to be sited where most economic and relies on the ISO/RTO to forecast, coordinate and reallocate power as it is generated. This approach likely minimizes the amount of new capital required to accomplish diversification.
- For reasons cited above, RPS may be poorly suited as a low cost means of implementing deeper renewable power penetration. Originally adopted to encourage wind and solar manufacturing to reach scale, RPS can fairly be said to have accomplished this goal. Meanwhile, RPS don't recognize the intermittency and integration issues and encourage overreliance on a single renewable power source. Reconsideration of RPS targets and usage should be considered.



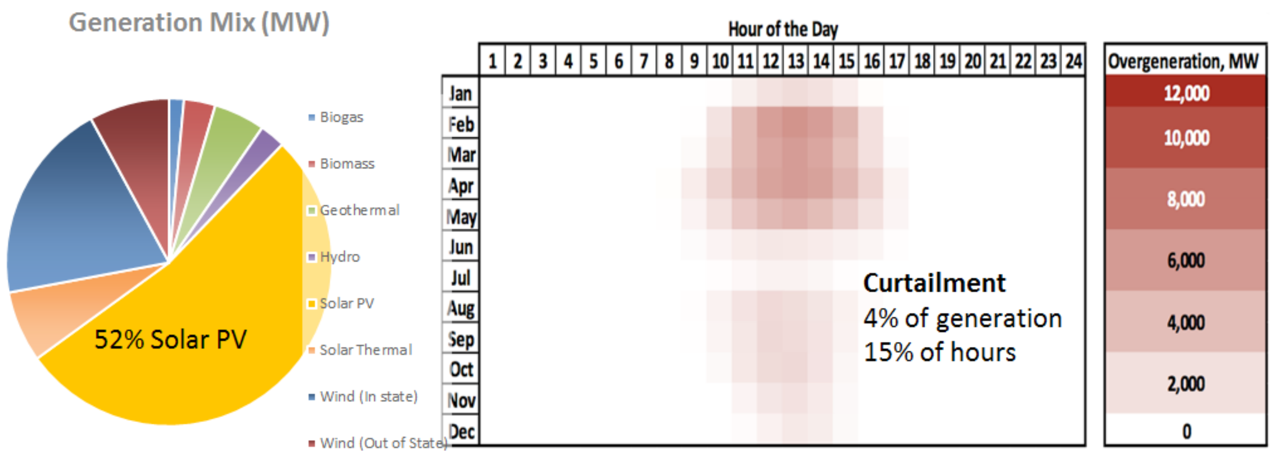
Source: E3 Investigating a Higher Renewables Portfolio Standard in California , 2014

Exhibit 27: Overgeneration on a Solar Dominated Grid (50% Renewable)



Source: E3 Investigating a Higher Renewables Portfolio Standard in California , 2014

Exhibit 28: Solar Dominated Grid Leads to Large Curtailment

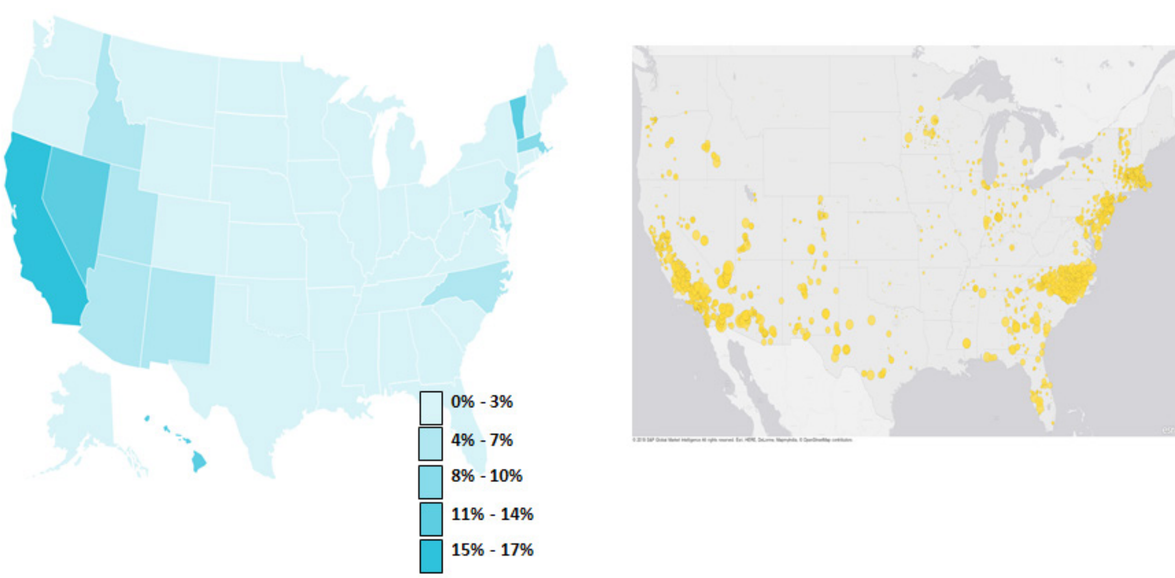


Source: E3 Investigating a Higher Renewables Portfolio Standard in California , 2014

Exhibit 29: Diverse Renewable Portfolio Reduces Curtailment by 50%

Solar Energy Share of Electric Generation by State (2017)

Location of the Existing U.S. Solar Fleet



Source: EIA, Electric Power Monthly, Tables: 1.3.A, 1.17.B, 1.18.B (February 2018)

Source: S&P Global (Retrieved Apr. 2018)

Exhibit 30: Renewable Resource Penetration-Location Matters

Option 3: Curtailment and Planned Curtailment

- Curtailment of wind/solar power is generally viewed negatively. This view is understandable given their low marginal cost. Economists and regulators are reluctant to deprive consumers of such low cost power when it is available. Note in Exhibit 27 and Exhibit 28 that curtailment is used as the definition of 'system costs.'
- Wind/solar's marginal cost is not however, the end of the economic discussion. A full cost analysis would also consider the costs of system disruptions, e.g. the costs of cycling down and restarting base load plants. Measured against those disruptions, curtailing wind/solar may be the lower cost option all-in.
- Because the marginal cost of wind/solar is negligible, their direct 'cost of curtailment' is also negligible. Their 'opportunity cost' of curtailment is the chance to provide consumers with low or zero cost power. Thus, the economics of renewables curtailment would weigh the cost of a) supplying the customer with base and intermediate load electricity with wind/solar curtailed versus b) supplying via wind/solar and cycling the base/intermediate load plant.
- An example will illustrate this case. Assume a CCNG plant is supplying power at $0.02/kwh in terms of marginal cost. Assume also that solar can supply power for zero cost and that shut down and re-start of the CCNG plant will cost $0.05/kwh over the period in question. In this case, the consumer can have $0.02/kwh power + zero cost of curtailment of the solar farm or zero cost solar power and $0.05/kwh costs for re-cycling the CCNG plant. Given these assumptions, curtailing the solar farm is more economic.
- The example suggests that the economics of wind/solar curtailment can be complex. If for example, surplus solar just puts a natural gas plant into 'spinning reserve,' major re-cycle costs may be avoided. The economics may then favor re-cycling the CCNG plant.
- The point here is that curtailment may be the low cost option under specific circumstances. Curtailment should not be ruled out by regulations or pricing. ISO/RTOs and utilities should have a chance to weigh the economic tradeoffs and the technical option to trigger wind/solar curtailment when that makes sense.
- It should be noted while curtailment can address some intra-day intermittency issues, it does little or nothing for supply shortfalls due to weather or seasonality.
- Planned curtailment has been brought forth in response criticisms that never curtailing wind/solar results in negative unintended consequences, e.g. dumping solar, idling nuclear plants. Various practitioners (see Scott Madden quote in Exhibit 21) have argued that curtailment is sometimes a positive course of action. These observers also see planned curtailment as creating possibilities for wind/solar to provide additional value to the grid.
- Exhibit 31 makes exactly this case. Here planned curtailment is offered as a way for solar farms to provide ramping support and load following characteristics that also avoid charging customers peak prices.
- The issue with planned curtailment is whether wind/solar projects can afford the revenue give-up from planning to produce at less than capacity. Many wind/solar projects do not offer robust returns; often these are single digit leveraged returns with aggressive 'back-end' assumptions on power prices. In the case of wind, their tax subsidy is tied to physical production; this means curtailing wind directly depresses project output and returns after-tax.
- That said, if the planned curtailment is accurately targeted to give up production whose revenue yield will be close to zero or even negative, the economic case for planned curtailment can be compelling.
- In sum, curtailment of renewable power can be a low cost response to intermittency issues at specific times and in specific places. Again depending upon location, this may even make planned curtailment a low cost step that adds flexibility and resiliency to the grid. Curtailment deserves more study and more consideration as a means for accommodating more wind/solar on the grid

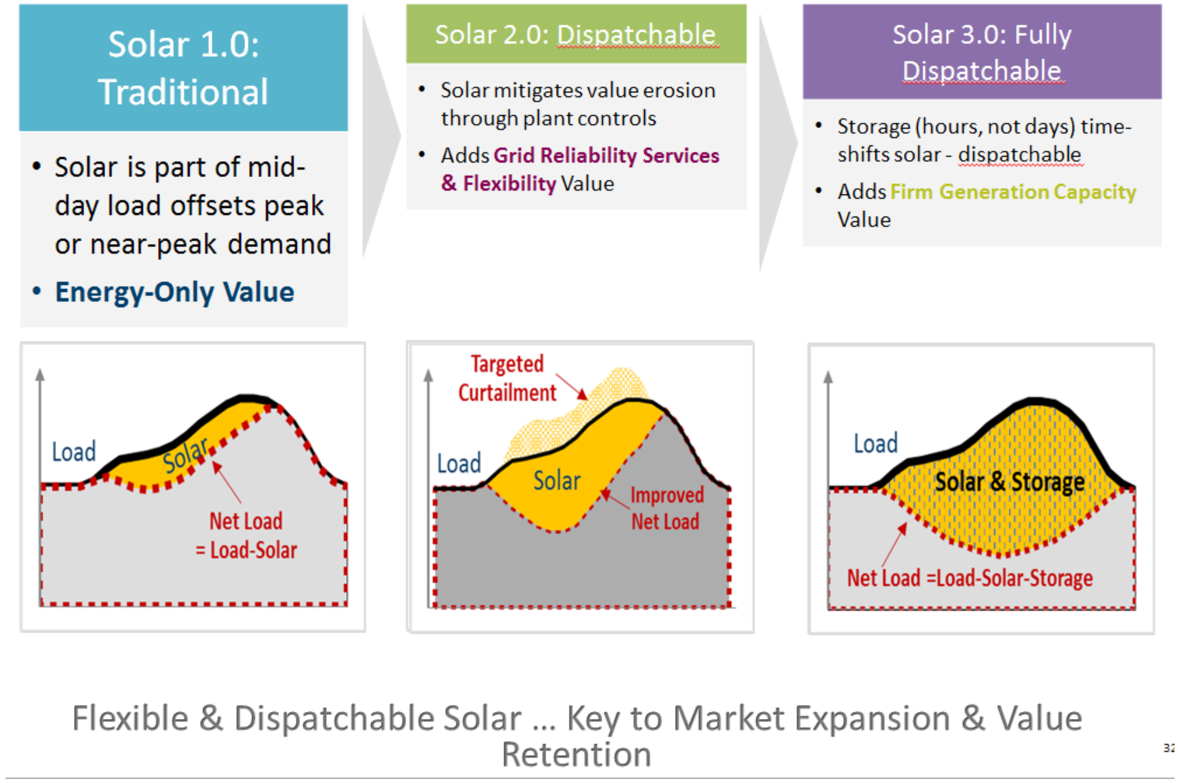


Exhibit 31: Better Integration and Scale Through Flexibility

Option 4: Regional grid integration, planning/forecasting, smart grid investment

- The section above on Current Problems, Practices and Options discussed the value provided by WAEMs in addressing renewables intermittency. Expanding these areas can be the lowest cost means of enabling more renewables integration.
- WAEMs accomplish this result in a variety of ways. First, they accomplish some renewables diversification without forcing it via mandates. It happens naturally as a function of wrapping a larger coordinating and integrating body around an existing base of wind, solar and storage assets. From there, WAEMs foster renewables integration via organizational means rather than by spending capital. Their forecasting, planning and coordinating roles harvest optimizations that more balkanized operations miss.
- This assessment is supported by recent studies comparing 'selling to the grid' with various use/store/curtailment options (see Exhibit 32 and Exhibit 33). While the level of benefit various with location, sales to the grid consistently comes in as the best option. These results testify to the benefits of using better forecasting/coordination/planning before allocating capital to address intermittency.
- Two areas of the country, the Great Plains states and the Southeast, don't have ISO/RTO organizations. A third, ERCOT, is 'its own' RTO. These areas contain large amounts of the country's wind and solar power and possess resources for further development. As their renewables saturation issues intensify, merging with or joining a neighboring ISO/RTO may offer a low cost means of sustaining renewable power growth.
- A hidden benefit of WAEMs is their ability to collect and analyze data over an expansive grid area. Over time this data collection in conjunction with dedicated planning/forecasting should bring more precision to assessments of renewables intermittency issues and the reserves of dispatchable power needed to assure grid stability. These assessments may better determine how best to combine wind/solar with different kinds of storage, NG peaking capacity and various base load plants.

- Smart grid investments can fortify these WAEM capabilities with better data, shortened response times and automated adjustments. Whether these benefits justify the capital expended will be case and location specific.
- A particular benefit of enhanced data analysis will be defining the optimal mix of wind/solar with rapid-start natural gas power. Several conference attendees note that low cost natural gas is a synergistic companion for renewable power. Better analytics may help define the optimal mix of wind/solar/storage with natural gas and the price risk which utilities may incur with this diversified generation set.
- Utility mergers can accomplish much the same planning/coordination benefits of ISO/RTOs, while also enhancing the ability of power suppliers to integrate system planning into their capital programs.
- With all the benefits WAEMs bring, they do relatively little to address the longer term intermittency issues, i.e. weather and seasonality related

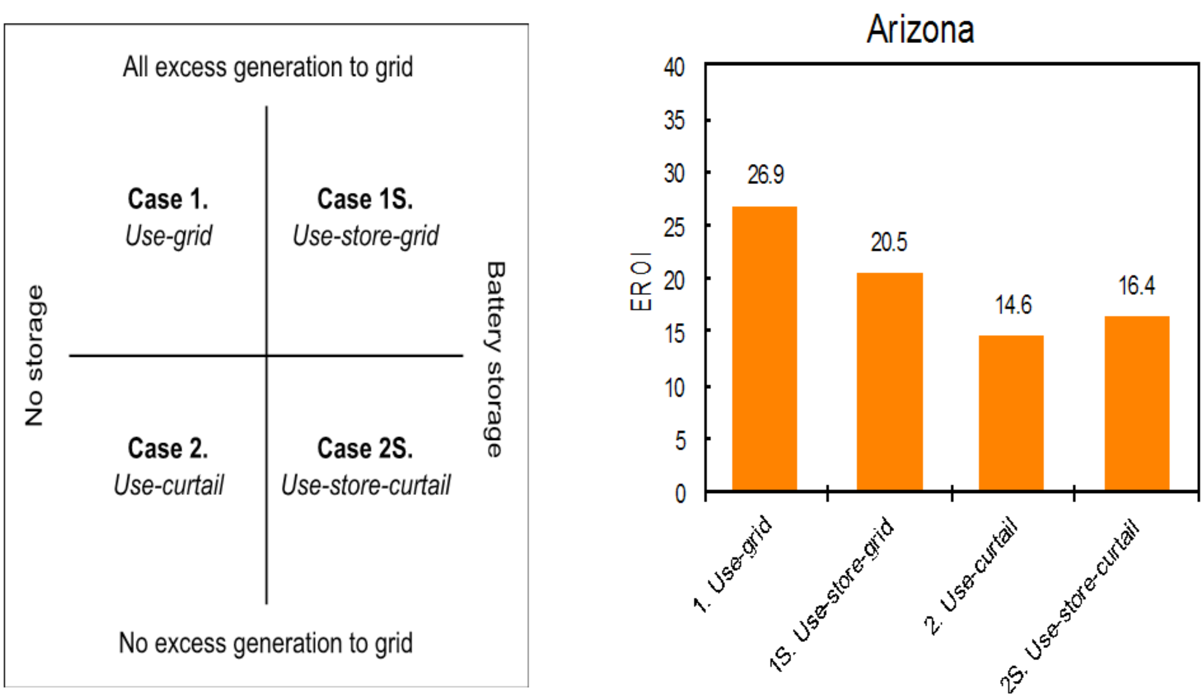


Exhibit 32: Selling Overgeneration to the Grid is the Best Choice

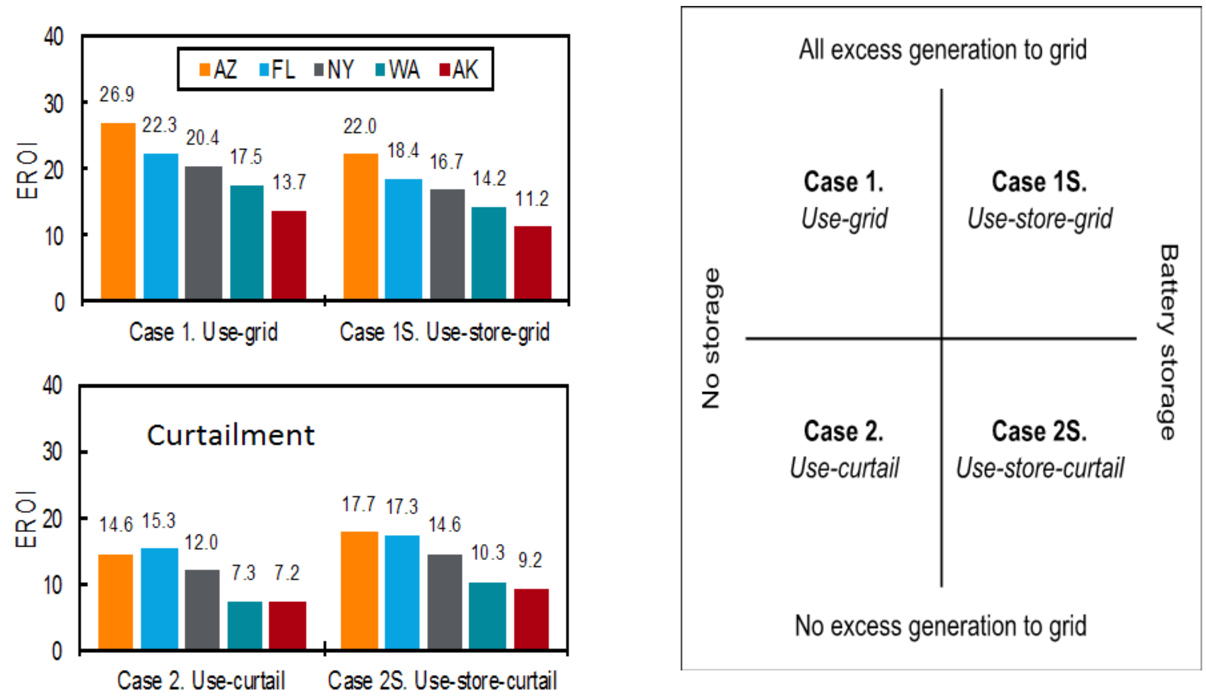


Exhibit 33: Value Strongly Dependent on Geography and the Possibility to Export Excess Generation to the Grid

Option 5: Demand Management and Time of Use Pricing

- One vision for the electric grid of the future would see WAEMs running smart grids and using both demand management and time of use pricing to manage intermittency. In this vision there would be renewables diversification and regional coordination to smooth out supply volatility combined with customers smoothing their demand and ISO/RTOs having options to dial down specific customer use as needed.
- The challenges to realizing this vision are several. Time of use pricing depends on customers responding to incentives. There has now been considerable experimentation with this approach. These trials have generally shown retail customers to be insensitive to its incentives. Commercial/Industrial (C/I) customers are more responsive. These results suggest some interesting but limited potential for this pricing approach.
- Demand management depends upon the customer voluntarily surrendering control over its usage, usually in return for some price incentive. It also requires installation of network means to reach into homes and businesses behind the meter. If this intrusion is based on small individual impacts, e.g. turning up A/C temperatures by 2 degrees, it needs to be widespread in application. Once again, C/I customers may be more willing to engage in such arrangements as opposed to retail consumers.
- Both Demand Management and Time of Use Pricing primarily affect intra-day intermittency issues, e.g. short term supply volatility, ramping, and surplus renewable generation. They are less impactful on weather and seasonality issues.
- Time of Use Pricing is a potentially low cost measure which utilities and ISO/RTOs should develop as renewables penetration continues. Demand Management involves more spending and is thus a higher cost option. Its economics may be favorable in site-specific cases and its potential for overcoming customer resistance remains to be seen.

Option 6: Rapid Start Natural Gas and Carbon Capture/Sequestration

- As noted, rapid start natural gas plants have been a major enabler of renewables growth. These plants compensate for renewables inability to load follow, addressing both shortfall and ramping issues. Because these plants can also operate in base and intermediate load mode if called upon, they also address renewables' longer term volatility issues. Exhibit 34 speaks to these points.
- Natural gas plants have also played a role in softening the economic impact of renewables penetration. CCNG plants have higher efficiency ratios than other fossil fuel plants. This fact has combined with the low natural gas prices to put downward pressure on wholesale power prices. Wind and especially solar plant economics are not low cost on an all-in basis. Without the muting effect of natural gas plants, renewables penetration would be driving wholesale and retail prices higher, engendering a different level of political resistance to their entry.
- Of course, the issue with natural gas is that it is not carbon free. A 650 MW CCNG plant produces about 2.1 million tons of CO2 annually versus wind/solar which directly produce none. For this reason there has been periodic interest in equipping natural gas plants with means to capture their CO2 emissions. The concentrated CO2 is then to be directed to some economic use or stored underground (Sequestration). Success in this effort would render not just natural gas but potentially coal generation to be very low carbon, and would restore utilities' ability to balance its generation mix on a more traditional economic basis.
- The experience with CCS to date has been disappointing. Existing carbon capture technologies are expensive. Attempts to combine these with economic deployments into chemicals or Enhanced Oil Recovery (EOR) have not looked attractive. Southern Company's attempt to build a CCS-equipped 'clean coal' plant (the Kemper project) incurred big overruns and was abandoned. Meanwhile, scientists and environmental groups have pointed to a number of concerns regarding storing large amounts of CO2 underground, i.e. its ability to leak upwards out of subterranean storage and contaminate drinking water.
- Post-mortems of the Kemper project suggest that project management issues were a large, if not the largest contributor to its cost overruns ($7.5 billion vs. $2.4 billion original estimate). This result and similar issues at recent new nuclear projects suggest that utility project execution capabilities are the principal challenge to deploying new plant technologies. The Kemper project used gasification technologies at high heat similar to those used in refining. It is possible that utilities considering CCS installations may need to import project management techniques practiced by refiners.
- Past failures have discouraged the utility industry generally from considering CCS in their plans. This is especially the case with merchant power producers. Already challenged on economics, these producers are reluctant to take the capital risk involved in attempting CCS installation.
- New CCS technologies have recently been developed. These appear to use the captured CO2 to generate additional electricity before having to dispose of the gas. Whether these technologies can alter the disappointing results experienced to date is not known. Several of these technologies are now at the demonstration plant stage, which should provide more reliable results to evaluate.
- The emergence of the new technologies has sparked interest at the U.S. government level. There the Department of Energy has encouraged the National Petroleum Council to undertake a new study of CCS applications and potential. This study in conjunction with the demo plants now underway should go some distance towards educating utilities on 'new' CCS as an option.
- Widespread adoption of CCS would be a game-changer. At a minimum it would enable utilities to marry renewables and natural gas as a reliable but flexible zero carbon generation mix. However, the inherent economic challenges associated with CCS imply that it faces a considerable development path, one probably associated with limited initial deployments in specific locations.

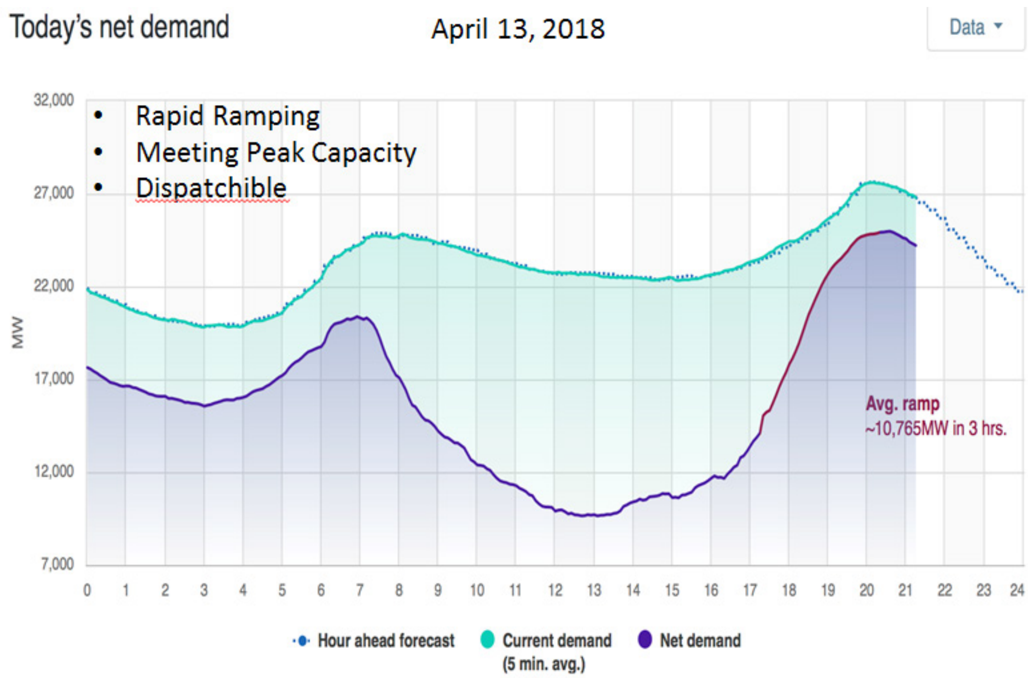


Exhibit 34: Natural Gas-The Unsung Hero of Renewable Generation

The California Experiment

- No state in the U.S. is as dedicated to realizing the low carbon electrification solution as California. The rest of the country will benefit from learning about the possibilities and costs of this 'California experiment.' Exhibit 35 illustrates the California vision.
- California has enacted the most aggressive RPS in the country. Exhibit 36 and Exhibit 37 illustrate its pathway and the GHG progress realized to date. California's RPS is backed by a host of more focused mandates covering among other things storage and distributed power. The most recent of these mandates will require solar panel installation on all new home construction.
- In the California vision, electrification of vehicle transportation and of buildings will put battery storage capacity at many distributed sites. This will allow for storage of surplus solar capacity and off-peak re-charging. In this vision, centralized utilities become less critical as generators and integrators – more complementary than fundamental. Exhibit 38 offers a depiction of this vision in action.
- This vision prioritizes de-carbonization and electrification more than any other U.S. location. In California electricity costs are a secondary concern. As a result, California's mandates will drive not only renewable generation but storage, micro-grids, differentiated pricing and distributed generation towards their limiting factors – technical and/or economic. This may go far towards identifying the best ways to integrate these elements of the renewables pathway as well as their relative costs.
- California is also going to demonstrate the synergies available between growing renewables on the grid and the adoption of electric vehicles. More than any other state, California will use policy to drive adoption of EVs. The state has used pollution concerns to drive the adoption of the nation's most aggressive CAFÉ standards and buttressed this with fuel taxes raising gasoline prices ~$1/gallon above the national average. As a result, EV fleets will probably grow faster in California than elsewhere. The rest of the country can harvest all these learnings as local conditions allow.

- That said, certain aspects of the California experiment limit its relevance to other locations. For starters, the state has a temperate climate. Even in portions of the southern part of the state, A/C use is not widespread. This both flattens load and, by limiting electricity usage, allows consumers to better tolerate high electricity prices. More fundamentally, much of California's economy is not especially sensitive to high electricity costs. High tech, media, agriculture, tourism and government are leading economic sectors. Energy intensive manufacturing is now limited in the state. California imports such goods and much of its energy from other locations. Unsurprisingly, these other locations are more concerned with energy costs in general and electricity prices in particular.
- California's generation mix points to other issues. Exhibit 39 shows California's electricity generation profile just before mid-day March 5, 2018. There are several things to note. First, there is a large percentage of renewable power in overall generation, i.e. ~60%. Second, wind and solar constitute ~87% of this renewables supply. Third, solar constitutes 88% of the wind/solar combination. Finally, California natural gas provides 24% of generation and imported power another 14%.
- These facts testify to other unique aspects of the California experiment. One must note the significant role played by natural gas in accommodating the high penetration of intermittent power. This pertains both to the state's own natural gas plants and a significant portion of its power imports. Second, the predominance of solar means that California is prone to excess generation around mid-day. Often it has solved this problem by dumping power into neighboring states to the distress of their utilities. This predominance of solar also means that the state's effective percentage of renewable power varies widely. This reflects not only solar's non-availability at night but all of the volatility inherent in weather and seasonality. Caution should thus be applied to high-level date touting California's degree of renewables penetration.
- California also has a particular way of accommodating the costs of renewables integration. While electricity generation occurs on a merchant basis, transmission and distribution remain regulated utilities. Firms such as Socal Edison and PG&E no longer generate electricity, but are tasked with working with CAISO to assure grid stability and reliability. As such, California assigns these regulated utilities the task of investing to help achieve its policy goals. It then awards the T&D utilities rate base prices that generate adequate returns on these investments. The result of all this is a large gap between California's wholesale and retail electricity prices. The former frequently come in at less than \$0.10/kwh while the latter often exceed \$0.40/kwh for high usage customers.
- This combination of unique characteristics and high electricity prices will temper the enthusiasm of other areas to regard California as the 'energy model of the future.' Moreover, the state's extensive and cross-cutting set of mandates raise costs in multiple ways. Outcomes are required irrespective of costs incurred or optimization alternatives that later become evident. Implementation is hampered by the sheer volume of mandates and the potential for new rules to complicate existing practices. For these reasons, California's experiment will be most valuable to other locations in terms of revealing 'what happens if' certain outcomes are attempted, e.g. EV adoption with high renewables penetration. The resulting lessons will be some combination of what is attractive and what not to replicate.

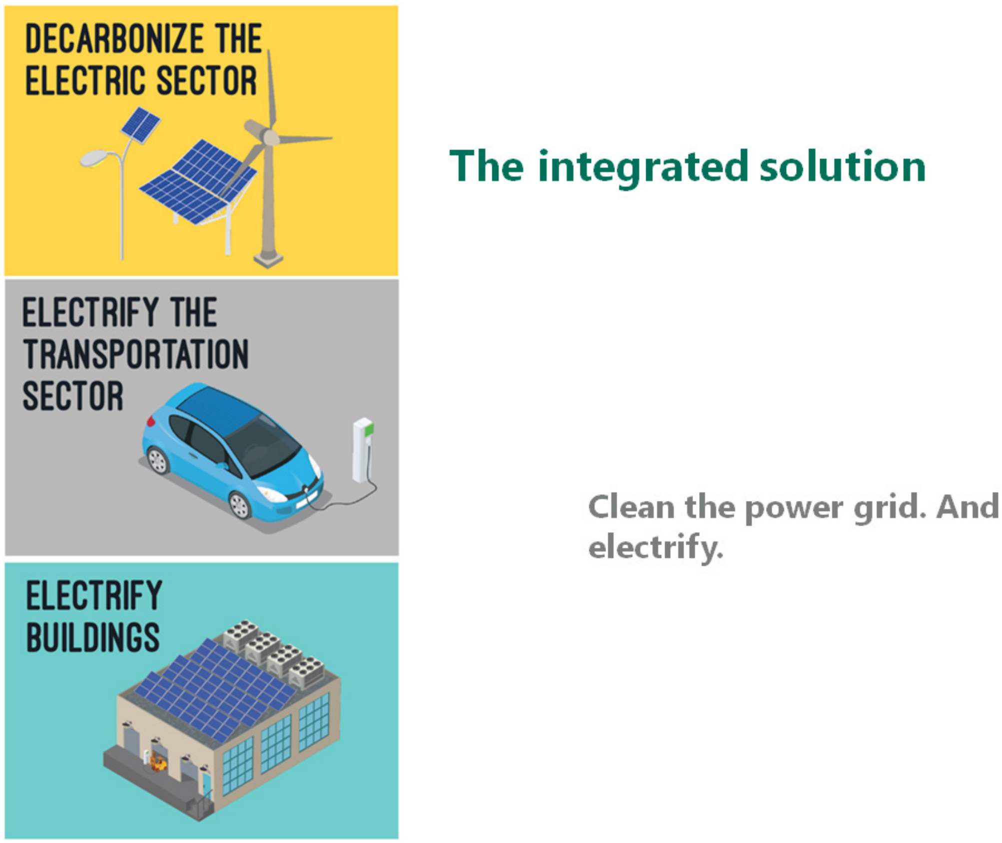


Exhibit 35: The Integrated Solution

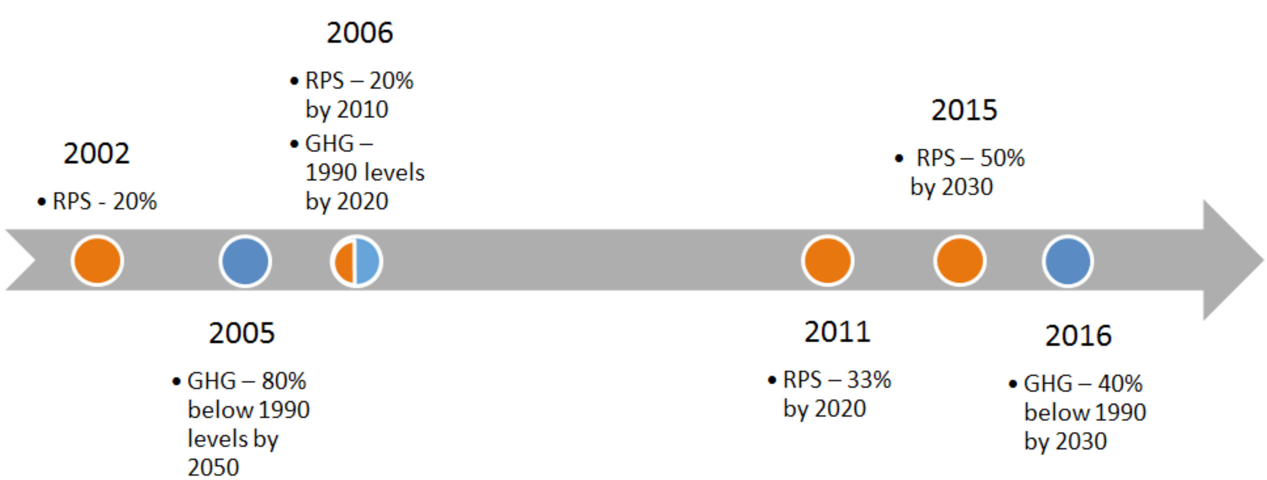


Exhibit 36: Integrated Solution

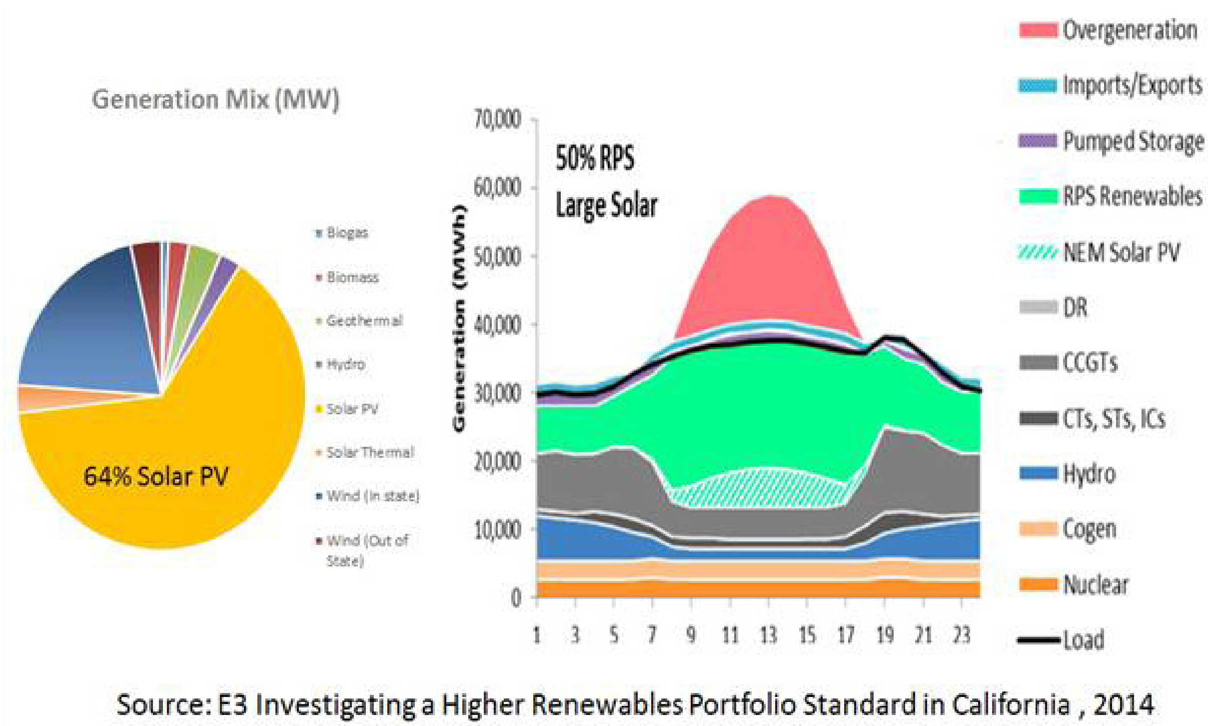


Exhibit 37: Overgeneration on a Solar Dominated Grid (50% Renewable)

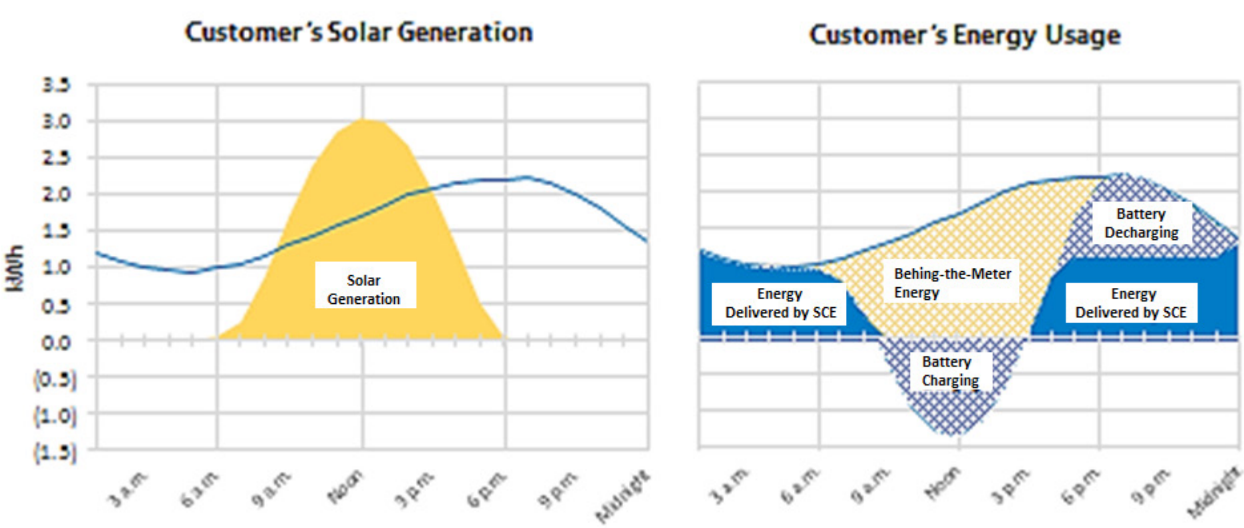


Exhibit 38: Customer Installs a Solar Panel w/ Storage

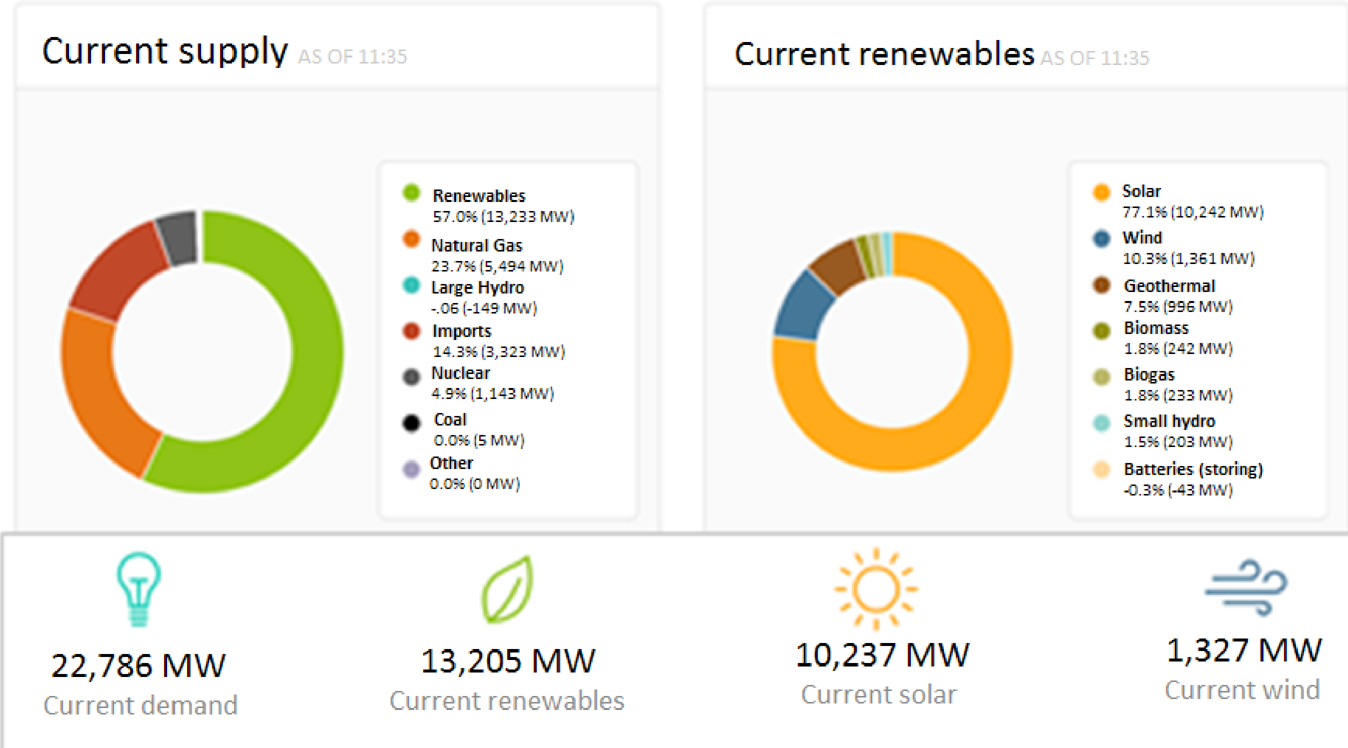


Exhibit 39: California Power Generation Mix March 5, 2018

Implications

- The conference established that the current narrative about wind/solar + storage is incomplete and in that sense, misleading. The difference between reported LCOEs and true 'all-in' costs is not trivial. As data presented indicates, renewables intermittency and integration costs are substantial, e.g. ~$0.11/kwh at 20% penetration. They also increase in a non-linear fashion with growing penetration.

- Moreover, public policy has made these costs difficult to identify and aggregate. The use of mandates (e.g. RPS) results in integration challenges materializing outside of generation, e.g. in Transmission/Distribution and/or ISO/RTOs. These costs tend to be absorbed in these sectors, disappearing into retail prices without a specific marker tying them to renewables integration. There also are unintended consequences, e.g. surplus solar, which cannibalize the returns of existing plants and cause retirements before the end of economic life.

- There are more than a few means available to mitigate the rising costs of renewables intermittency. Some, such as WAEMs, compressed air and pumped hydro storage, and planned curtailment look attractive in specific locations and applications. Some battery storage is attractive for addressing short-term intermittency issues. These opportunities deserve to be pursued to enable more zero carbon generation to operate at lower all-in cost. None of these options is a total fix and most have serious limitations of an economic or locational nature.

- The all-in cost of wind/solar plus storage appears especially unattractive when viewed as a source of base load generation. The consequences of overbuilding wind/solar become especially obvious when evaluated in this role. This conclusion clearly points to the need for hybrid solutions to accomplish a stable, economic and decarbonized grid. Wind/solar + battery storage alone will not achieve this goal at a reasonable cost.

- These results also suggest that the need for continued RPS should be reconsidered. Their primary role was to enable renewables technology and manufacturing to be proven at scale. This has been accomplished. With intermittency and integration costs now evident and increasing, and with unanticipated consequences evident, the moment may have arrived for allowing wind/solar + storage projects to stand on their own economic feet. Doing so will also allow those responsible for power quality and grid stability to weigh these factors before promoting further penetration.

- The case against doing away with RPS is that current economics don't put a value on the zero carbon nature of wind and solar. This is a valid point. It argues for the phase out of RPS to be combined with the introduction of a national carbon pricing regime.

- Since wind/solar + storage cannot accomplish grid de-carbonization at an acceptable cost, energy policy needs to contemplate a significant presence of other forms of generation. Natural gas plays a particularly important role here because of its ability to compensate for the non-dispatchable nature of wind/solar. California's reliance on natural gas to stability its grid even as it dumps solar power into neighboring states testifies to this conclusion.

- Because of natural gas' ability to compensate for wind/solar intermittency, serious efforts should be made to further de-carbonize natural gas. Recent developments in Carbon Capture/Sequestration technology may offer promise here. These technologies may prove as or more economic than battery storage while offering a more comprehensive solution to the suite of intermittency issues.

- Finally, environmental restrictions adopted for CA/PH storage and nuclear power should be reviewed with an eye to facilitating renewed development of projects. Current regulations were adopted before the climate change issue was well defined. As such, they may have tilted excessively in the direction of safety. Improved technologies may also be available for these projects which address some concerns that shaped regulations. We note with emphasis that no serious effort of this sort is presently under way, and hope that a better recognition of wind/solar's limitations and all-in costs will stimulate the needed regulatory review.

Conference Program

Friday Morning AM	
8:30	Convene, Welcome, Purpose of the Conference
8:45	Opening Address: What is the Vision for Renewables
9:30	Discussion of Achievable Targets & Key Issues/Assumptions Panel Discussion
10:00	BREAK
10:20	What is the Renewables Intermittency Challenge?
10:45	Overview of the challenges facing deeper Renewables
11:30	Which technical/operating problems are most challenging?
Friday Afternoon PM	
12:15	LUNCH & ADDRESS Natural Gas Power Plant Carbon Capture/Sequestration
1:45	Transition to 'Costs & Economics'
2:00	What has driven Wind/Solar/Storage production costs declines, and are the gains extendable?
2:45	"Is there a Wall out there as DERs approach base load?" Report on "Unsubsidized Cost of Base Load Solar?
3:30	BREAK
3:50	Current Power Pricing Models: Problems & Possible Solutions for Renewables Integration
4:30	Summing Up: Areas of Consensus, Principal Disagreements, Issues for Reflection

Saturday Morning AM Possible Solutions Going-Forward	
8:30	Continental Breakfast & Convene
9:00	Potential Technology Breakthroughs
9:45	Altered Regulatory and Pricing Models Regional grid management Shifting from IPP to Regulated models
10:30	BREAK
10:50	Discussion: What is the lowest cost path To manage Renewables intermittency, and How much will it Cost?
11:30	Capital Formation & Financing Renewables Integration: Coming changes & implications
Saturday Afternoon PM	
12:15	LUNCH & ADDRESS Panel Report on Key Issues, Learnings & Recommendations
1:15	SUMMING UP & Preview of Conference Report
1:30	ADJOURN

Notes on Attendees, Source material and Exhibits

This conference report is a product of materials presented at the conference on April 13-14, 2018. Those present were drawn from major utilities, renewable power developers, regulators, banks, other energy companies, and the Kenan-Flagler Business School faculty and students.

The speakers and attendees all acted under 'Chatham House Rules.' Their comments and presentations were encouraged to be candid based on assurances that no press or media were involved and that the subsequent Conference Report would contain no attributions to any specific speaker.

Consequently, this report contains no references or citations pertaining to individual speakers. The exhibits contained herein were presented at the conference. They are offered here stripped of any reference to the speaker who presented them, and are included with the permission of that speaker.

Inquiries as to specific material presented herein may be directed to the relevant speaker who may or may not respond at their own discretion.

Glossary of Technical Terms

- **Base Load Demand & Generation**: Refers to electricity demand that is constant and therefore is most efficiently met by generation capacity that can remain constantly online.
- **Carbon Capture/Sequestration**: Describes various processes by which Carbon Dioxide (CO2) that otherwise would be emitted into the atmosphere is capture and segregated before being released. The CO2 thus captured is then stored (sequestered) in a leak-proof environment, typically underground.
- **Compressed Air Storage:** Electricity is stored by using it to compress air into a defined space. The resulting pressurized air, upon release, can be later used to drive a turbine, generating electricity to then meet demand load.
- **Curtailment**: This involves taking deliberate action not to produce power that would otherwise be available, and usually pertains to available wind/solar power.
- **Dispatchable Power**: Refers to electricity generation that can be produced and transmitted 'on demand,' i.e. in response to a unanticipated increase in demand or decline in other supply.
- **Enhanced Oil Recovery**: The amount of discovered oil reserves that can be produced is enhanced by flooding the reservoir with water or C02. Other forms of EOR including using chemicals to improve reservoir permeability or to scrub free oil molecules adhered to rock.
- **Frequency Response**: A measure of power quality, it concerns the phase and magnitude of electricity output as a function of variations in the frequency of power input into the system.
- **ISO/RTO**: Independent System Operators and Regional Transmission Organizations are coordinating bodies who work to manage supply/demand and power quality across multiple utilities and jurisdictions. ISOs tend to be smaller units, many times limited to a single state whereas RTOs typically encompass multiple states. Both are regulated by FERC.
- **Levelized Cost of Electricity:** The average total cost of electricity for a particular plant or form of generation, calculated by dividing the costs to build and operate a plant over its economic life by its total output. Typically the answer is expressed in terms of $ per kilowatt or megawatt hour.
- **Leveraged Return on Equity**: A project investment return where the portion financed by debt is excluded from upfront capital costs and where interest and principal repayments are included in the cash flows. The result is an IRR calculated on equity invested.
- **Peaker Plants**: These generating plants may be idle except for when the demand load 'peaks' at which time they are started and brought online to meet demand.
- **Power Purchase Agreement:** A contract typically executed between an independent power producer and a transmission/distribution company (TDC). The contract specifies terms under which the TDC will purchase power from the producer, including volume, duration and pricing parameters. These agreements are critical to independent producers obtaining financing.
- **Pumped Hydro Storage**: Electricity is stored by using low value off-peak power to pump water to a higher elevation. When electricity is needed to meet peak demand, the stored water is released to run via gravity down through turbines, generating electricity.
- **Renewables Intermittency**: Refers to the characteristic of certain types of electricity generation, e.g. wind & solar, whereby their production varies with natural conditions as opposed to in response to human direction/customer demand.
- **Renewable Portfolio Standards:** Mandates, typically created at the state level, requiring electricity generating companies to reach a defined percentage of generating capacity provided from renewable sources, usually wind and solar, e.g. the State of North Carolina requires Duke Energy to obtain X% of power generated by wind/solar by Y date.

- **Spinning Reserve**: Refers to extra power capacity from plants which are already connected to the grid. Typically this is accomplished by increasing the torque applied to the turbine's rotor.
- **Time of Use Pricing:** The utility selling power to Consumer, Industrial and retail customers offers electricity prices that vary by time of day. The objective is to provide incentives for customers to use power in periods of low demand load, forego electricity use in high load periods and cut overall usage. This can smooth out the load curve and/or shifts load to times of day when the power company anticipates having surplus generation.
- **Wide Area Energy Markets**: Refers to markets encompassing multiple states and utilities, where electricity demand and supply are managed by an ISO/RTO whose jurisdiction covers those states and suppliers.

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