Electrification and The Future of Electricity Markets

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Introduction

End-use electrification is one of the three pillars of deep decarbonization—fundamental strategies necessary to eliminate energy system carbon emissions. As a low-carbon strategy, electrification is only effective when paired with reductions in the emissions intensity of electricity generation. Thus, any discussion of electrification's role in reducing carbon emissions—either through direct electrification of end-uses but also fuel switching to electricity derived fuels—must include supply-demand interactions within the electricity system. This paper highlights what these interactions may look like in the transition to a very low carbon energy system in the U.S., and some potential implications for the future of the grid and wholesale electricity markets. The concepts are primarily illustrated using updated scenarios from the 2014 U.S. Deep Decarbonization Pathways Project technical report (See *Pathways to deep decarbonization in the United States 2014* in Further Reading).

Research in the United States indicates that reducing overall greenhouse gas emissions to 80% below 1990 levels by 2050 – a level adopted by the U.S. and other governments as compatible with international agreements to protect the climate – will require a 90%+ reduction in the average emissions intensity of electricity generation in the U.S. over the same time period. Three observations help explain the need for a disproportionally large reduction in emissions from electricity.

- First, electricity generation in a very low carbon energy system will need to grow significantly—from 4 petawatt-hours per year today to around 7 petawatt-hours per year in 2050, an increase of one petawatt-hour per decade. This growth is a necessary consequence of widespread electrification, even assuming rapid progress in energy efficiency.
- Second, because the carbon benefits of electrification are contingent on emissions reductions in electricity, the greater those reductions are, the more attractive and effective electrification will become as a carbon strategy. Put another way, because their combined effect on emissions is multiplicative, not linear, these strategies are mutually reinforcing.
- Finally, reducing emissions intensity in electricity is of moderate cost compared to alternatives in other sectors, and thus it makes economic sense from society's standpoint to reserve any remaining emissions budget for high marginal abatement cost applications in transportation and industry. Reducing emissions by less than 80% in these areas implies larger reductions in other areas, particularly electricity generation, if the overall emissions goal for the U.S. is to be met.

Accepting the premise that deep decarbonization requires profound changes in the electricity mix, three generation types are likely candidates: renewables, nuclear, and carbon capture and storage (CCS). We define renewables here broadly, but the primary focus is on wind and solar given that these two resources have the largest technical and economic potential. Between the three generation types, renewables have emerged as the front-runner and have made up most of the capacity added in the U.S. over the last 10 years. This trend is expected to continue, in part due to strong policy support on a regional basis. Even in prior deep decarbonization scenarios emphasizing nuclear and CCS, results suggest that renewables will still comprise a plurality of generation by mid-century.

Physical characteristics of highly electrified and highly renewable electricity systems

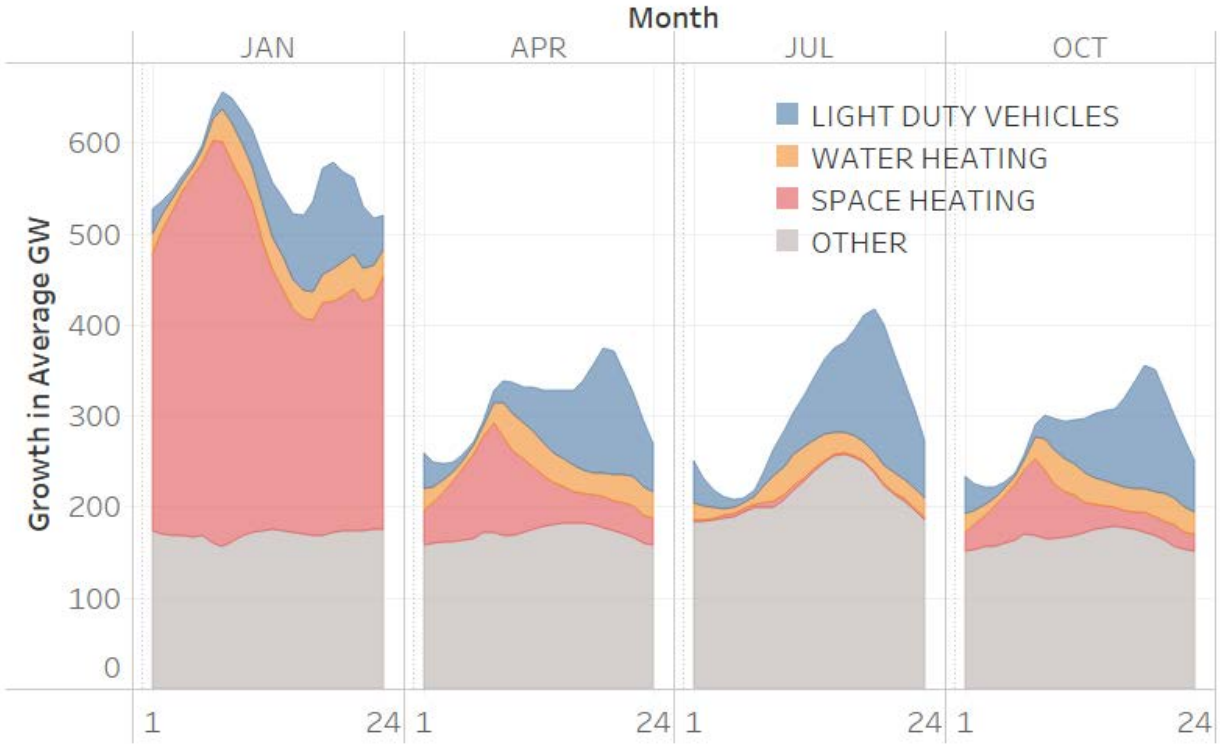
Given two premises – that deep decarbonization requires both high levels of electrification and a near complete decarbonization of electricity, and that the most likely method of electricity decarbonization is large deployments of renewable energy – some significant changes in the physical supply-demand dynamics of the future U.S. electricity system can be anticipated. In studies, these characteristics start to emerge when the penetrations of wind and solar exceed about 50% by energy, driven by the nature of both newly electrified loads and variable generation.

Newly electrified loads will be large but potentially flexible

The largest loads with the potential to be electrified are heating, electric vehicles, and in some cases, electric fuel production (for example, electrolysis of water to produce hydrogen). Figure 1 shows demand-side load growth between 2020 and 2050 in a high electrification scenario, broken down by end-use. A key feature of these loads is that heating, vehicles, and electric fuels all have inherent storage potential – thermal or chemical – that can be used to shift energy in time.

Electric fuel production is a non-firm load (meaning it can be curtailed) with a high operating-to-capital cost ratio that can shift vast amounts of energy seasonally. Heating and vehicle loads are fungible over much shorter timescales, but can still solve shorter time-scale energy imbalance, and critically, mitigate their own impact on the need for new system infrastructure build.

Figure 1 Month-hour average load growth from 2018 to 2050 in the U.S. DDPP High Renewables Scenario by end-use. Vehicle charging profile shown before flexible charging is applied.



New loads can have very high and unpredictable instantaneous demand

Electric vehicle rapid-charging has become a selling point for new electric vehicles, and as battery charge management continues to improve, public DC-charging of light-duty electric vehicles in the hundreds of kW or up to one MW for heavy duty transportation will be common. In terms of instantaneous demand, these power demands are more concentrated than all but large industrial loads and will have large locational impacts on transmission and distribution systems. Absent the development of real-time vehicle-grid communications, the exact timing of these loads will be difficult to predict.

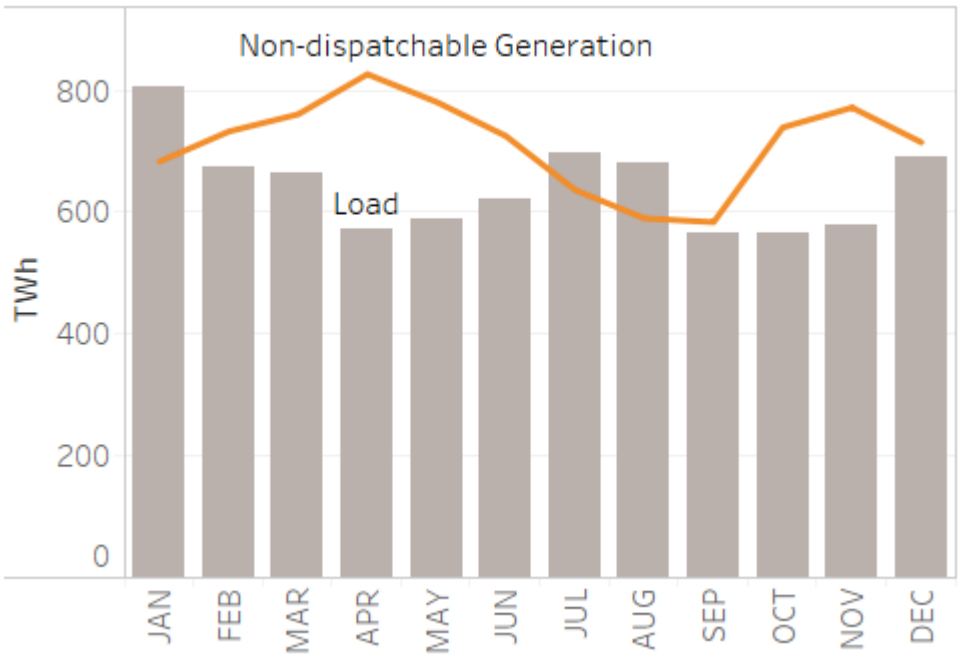
New loads will change seasonal load profiles of many utilities

For most of the U.S. today, summer electric loads are strongly temperature dependent above 65˚F due to air conditioning. But, below 65˚F, load today is only weakly coupled to temperature, except where electric heating is already common. If a much larger share of heating across the U.S. is electrified, load will have a strong dependence on temperature across the entire range, and many more utilities will find themselves with both summer and winter peaks. This is already evident in places like Florida with large air conditioning load but also infrequent cold snaps and high penetration of electric resistance heating.

Energy imbalance has a long timescale in high renewable systems

That the production patterns for wind and solar generally do not match load on a diurnal basis is a well-understood problem that can be addressed in many ways including generator ramping, load shifting, electricity trading, and energy storage. Less well understood is that in very high renewable systems, systemic over-generation will occur in some seasons and systemic energy deficit in other seasons. For the U.S., the former will occur in spring and fall, and the latter in summer and winter, as illustrated in Figure 2. Particularly in hydro-wind dominated systems, even longer timescale imbalance, including inter-annual, can also be observed.

Figure 2 Firm load vs. non-dispatchable generation in 2050 by month for the U.S. DDPP high-renewables scenario



Solving seasonal energy imbalance is arguably the main impediment to reaching aspirational 100% renewable energy goals called for by localities across the U.S. Seasonal energy imbalance is a multi-faceted challenge, and will require some mix of dispatchable generators, long duration storage, seasonal flexible load (e.g. electric fuel production), and overbuilding and curtailing renewables. Many of the most widely-discussed solutions for integrating wind and solar, for example flexible loads in buildings, flexible vehicle charging, and battery electric storage, will be ineffective for balancing on seasonal timescales. In the scenario shown in Figure 2, electric fuel production in spring and fall, plus limited thermal generation in summer and winter, are used to solve this imbalance, in addition to seasonal renewable curtailment.

Seasonal energy imbalance extends across a large geographic area

Regional coordination to increase the diversity of load and generation can be one of the most cost-effective ways to integrate renewables by reducing relative forecast errors, thermal ramping, and round-trip efficiency losses from storage. However, increased regional coordination will not greatly diminish the fundamental drivers of seasonal energy imbalance common to most of the U.S. For example, across North America, spring is characterized by low loads due to moderate temperatures, while solar insolation grows with the approach of the summer solstice, higher pressure differentials in temperate regions drive high winds, and spring snowmelt produces high hydro. Therefore, regional coordination (in the absence of a globally-connected grid) can only address seasonal imbalance to a degree.

Renewable curtailment occurs across many hours

Overgeneration-driven renewable curtailment occurs when non-dispatchable and must-run generation exceeds load, including storage. The quantity of curtailment that a system experiences is highly non-linear, and as the amount of solar and wind on the system approaches the levels required in deeply decarbonized systems, is projected to be significant, as shown in Figure 3.

Figure 3 Percentage of renewables curtailed without storage or flexible load for a simulated system in New York State. Renewable delivery respects a must-run requirement of nuclear, co-gen, and hydro (16% by energy). An RPS of greater than

100% implies that renewables are over-built to increase the amount of delivered renewables, with excess energy curtailed. This type of chart can be generated for other geographies with the exact pattern depending on load and renewable profiles.

RPS (%)											
130%	49%	45%	44%	45%	45%	47%	49%	53%	58%	64%	70%
120%	46%	42%	41%	41%	42%	44%	46%	50%	55%	62%	68%
110%	43%	39%	37%	37%	38%	40%	43%	47%	53%	59%	65%
100%	39%	35%	32%	32%	33%	36%	39%	44%	50%	56%	62%
90%	35%	30%	27%	27%	28%	31%	35%	40%	46%	52%	59%
80%	30%	26%	22%	21%	23%	26%	31%	36%	42%	48%	55%
70%	24%	20%	17%	16%	17%	21%	25%	31%	37%	43%	50%
60%	18%	14%	11%	10%	11%	15%	19%	25%	31%	37%	43%
50%	11%	9%	7%	6%	6%	9%	13%	18%	23%	29%	35%
40%	6%	4%	3%	2%	2%	3%	6%	10%	15%	20%	25%
30%	2%	1%	1%	0%	0%	1%	1%	3%	5%	9%	13%
20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%
10%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Solar Fraction	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Wind Fraction	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%	0%

Resources that provide flexibility can derive value from arbitraging between periods with and without curtailment; however, diminishing returns and a long-tailed distribution of hours with substantial curtailment make it certain that some amount of curtailment will always be economic. Ultimately the most cost-effective system design and the level of resulting curtailment will depend on the relative costs between adding additional renewable capacity versus adding resources that provide flexibility. The lower the cost of renewables and the higher the cost of flexible resources, such as energy storage, the higher the optimal level of curtailment.

The U.S. DDPP high renewable scenario, with 80%+ renewables by energy, results in curtailment in 20-40% percent of all hours, depending on location. Actual curtailment may be less than these levels due to new types of loads currently unanticipated that can take advantage of electricity that is zero cost at the margin, yet not eliminated given the large amount of curtailed energy concentrated in short periods of time and the difficulty of using intermittently available energy economically.

Wind and solar alone do not provide resource adequacy

Systems with high variable generation have large needs for dispatchable capacity, termed residual capacity, to provide reliability, frequently at times of the year when energy deficits make it more difficult for short duration storage to fill this need. Figure 4 below shows the residual capacity need in a 100% Eastern U.S. renewable scenario using a single year of data from 2011. In an ideal scenario, the net load (load minus renewables) would be zero, meaning that no residual capacity is needed. Instead, the residual capacity need at minimum is 60% of the gross load peak, indicating that a significant amount of flexible load or dispatchable generation is needed to maintain current reliability levels.

Figure 4 Capacity met with 100% renewables by energy in the Eastern Interconnection with different wind/solar compositions

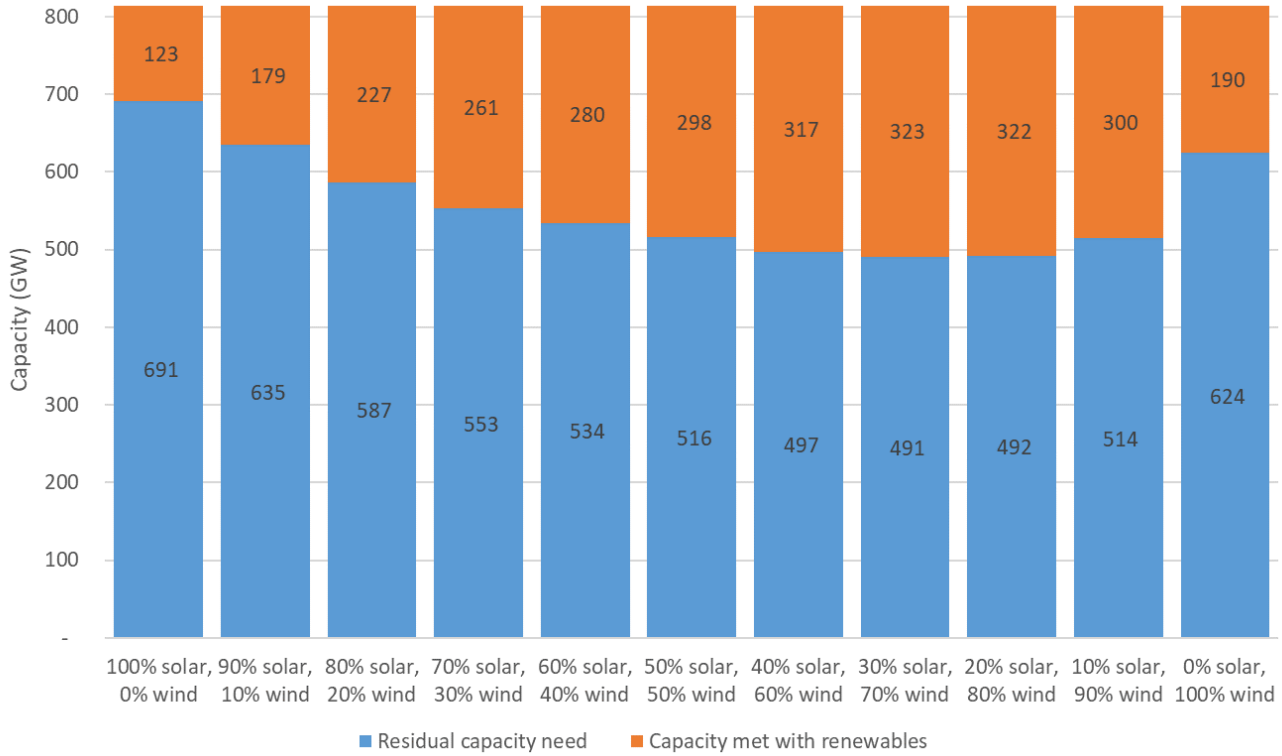


Illustration of this basic idea is well demonstrated in analysis of the effective load carrying capability (ELCC) of renewable generation, a concept that accounts for the outage rates of thermal generation and the probability distributions of renewable production, along with decades of historical weather conditions, that impact peak load. Large-scale electrification is likely to materially alter ELCC calculations due to heating load and other load shape changes.

The size and persistent nature of residual capacity requirements make it unlikely that imbalance in high renewables systems can be solved with load flexibility alone. As already noted, short-duration storage is not able to efficiently provide this capacity because it is energy-limited during peak seasons. These concepts are elaborated below in the discussion of the "21st century screening curve." While an ensemble of complementary resources will be helpful in reducing residual peak load, significant amounts of "persistent" balancing capacity, meaning those that aren't severely energy limited, will be required to match today's electric reliability.

Five existential questions for future low carbon electricity markets

While they seem to be technically feasible, highly renewable and high electrification electricity systems will be radically different from today's systems dominated by dispatchable thermal capacity and inflexible loads, not only in physical characteristics but in market behavior. In competitive electricity markets today, unit commitment and dispatch is handled by a security constrained economic dispatch where all generators are paid the nodal clearing price, may provide a diverse set of ancillary services, and depending on the market, may receive additional capacity payments. Limited out-of-market

payments are used to make whole those generators needed for reliability/stability but not competitive in the market.

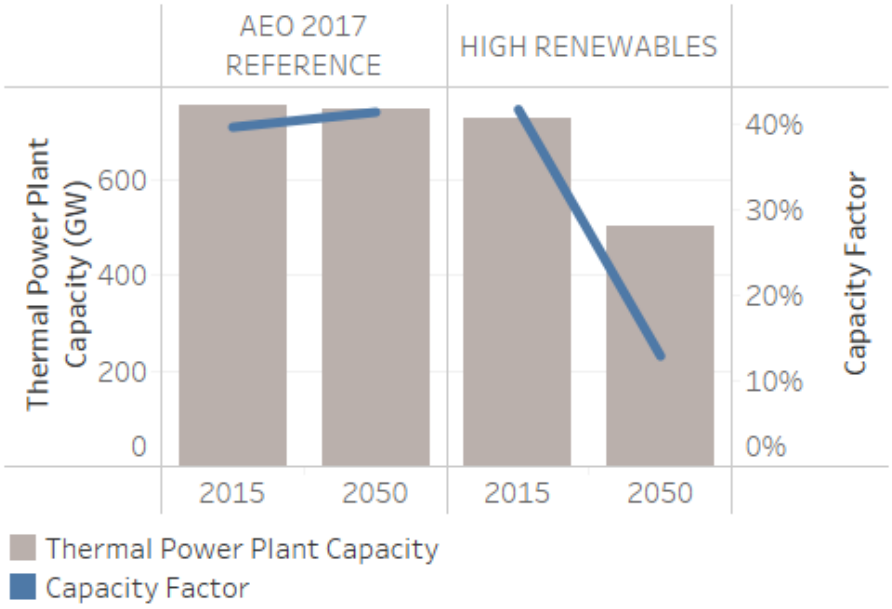
Market design is not agnostic to resource type. Each market rule, from lead-time for unit commitment decisions to qualifying for regulation markets, inherently embeds the technical characteristics of existing loads and resources. These markets were designed under a paradigm in which most generators are assumed to be dispatchable and have non-zero marginal cost, and where load is passive and far more difficult and costly to control than supply. These assumptions are flipped under a high renewable system paradigm in which almost all costs are fixed, supply is variable, and new technology enables unprecedented demand side flexibility. This leads to five basic issues that future market designs must address in order for high renewables, high electrification systems to succeed.

How will conventional power plants get paid?

As noted earlier, a significant quantity of residual capacity will be needed to maintain reliability in a high wind and solar system, but those generators, if not equipped with carbon capture, must operate at low capacity factors else carbon budgets be exceeded. Essentially, all fossil plants that cannot sequester carbon must transition to being peaker plants under deep decarbonization.

Figure 5 shows the capacity and utilization for fossil thermal power plants in the U.S. DDPP High Renewables scenario contrasted against the 2017 Annual Energy Outlook. Thermal capacity declines by 31% in the high renewables scenario, due to the resource adequacy provided by wind and solar (but offset somewhat by electrification). Capacity factors, on the other hand, decrease by 69%, to just over 10%, for the fossil thermal fleet.

Figure 5 Fossil thermal power plant capacity and utilization for the 2017 Annual Energy Outlook Reference scenario and the U.S. DDPP High Renewables Scenario.



What Figure 5 indicates is that the revenues earned by generators in an energy market will decline over time, even if all caps on market bids are removed. In jurisdictions with capacity markets, the difference

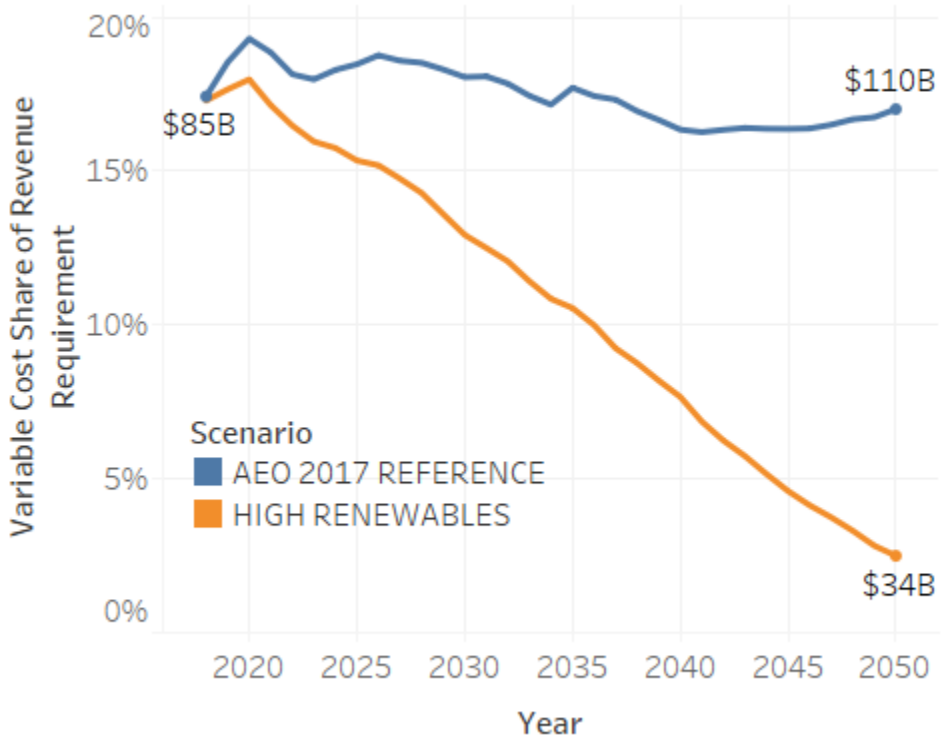
between gross and net cost of new entry (CONE) will decrease. This will present special challenges for energy-only markets such as ERCOT, with greater volatility likely as fixed costs must be recovered in fewer and fewer hours. Out-of-market payments may increase and new ancillary service products may be devised, trends that have already begun, but these are not likely to completely replace lost energy market revenues.

The importance of capacity markets will grow, and where they do exist these mechanisms will need to become more sophisticated regarding the types of products and characteristics of the resources that qualify. For instance, a six-hour battery that may provide capacity today may not contribute to reliability in a high wind and solar system where the binding constraint (say, in August) is the availability of energy. Here, concepts that have been long used in hydro-dominated systems, such as sustained peaking capability, may need to become an integral part of all markets. This is illustrated by the "21st century screening curve" in the final section.

How will fixed costs be allocated among electricity consumers?

Today, variable costs already make up a relatively small share of total electricity system costs (encompassing generation, transmission, and distribution), and their share of the total electricity revenue requirement is set to plummet in a high renewables scenario, as shown in Figure 6 using data from the U.S. DDPP scenarios. In the high renewables scenario only 2.5% of costs are variable by 2050, thus 97.5% of the revenue requirement must be collected regardless of how, when, or whether electricity gets used.

Figure 6 Variable costs as a share of the total U.S. electricity revenue requirement. This is created using generator fuel costs not market prices. In electricity markets where a marginal price is paid to all generators, a greater portion of fixed costs are recovered on a variable basis than shown.



It can be argued that many new electric loads, including electric fuel production, will be able to balance the system by consuming energy that is free at the margin. However, this ignores a serious cost allocation problem, namely that other market participants must pay for the renewable generator providing that marginally-free electricity at the price of a long-term power purchase agreement (PPA). Thus, if a direct access customer is not the PPA off-taker, they become a fixed-cost free rider and receive energy subsidized by other market participants. This could be desirable from a public policy perspective, for example to encourage zero carbon transportation using hydrogen generated from marginally-free electricity, but it raises legitimate concerns about cross-subsidies between customer classes.

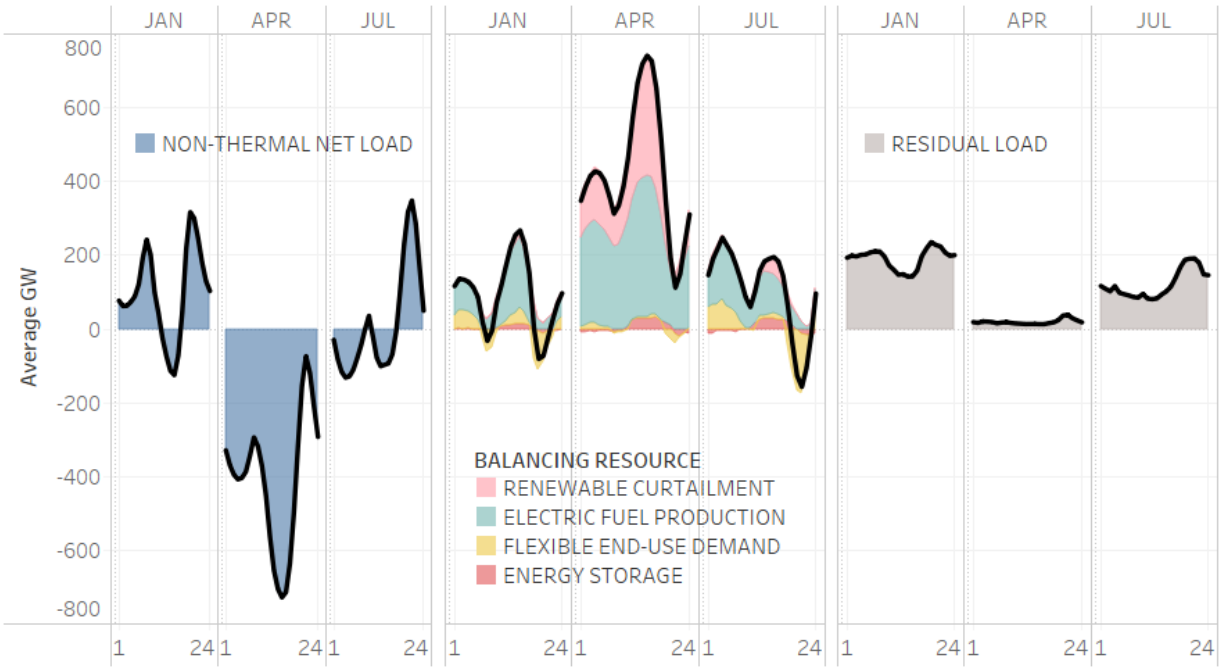
How can flexible load be induced to participate?

Flexible load has large potential to solve energy imbalance at low cost compared to many other solutions. Anticipated new electric loads have inherent flexibility, either as a function of their thermal storage (electric space and water heating) or chemical storage (electric vehicle batteries or hydrogen electrolysis), which can be leveraged to manage supply-demand imbalances.

The role flexible load could play in a future system is illustrated in Figure 7 showing average load for three simulated months in 2050 in a high renewables scenario. The first panel shows load net of all non-thermal generation technologies, including dispatchable hydro and nuclear. As seen, the average net load is frequently negative indicating a surplus of energy on the system. Unsurprisingly, given the seasonal features shown in Figure 2, the month of April has the greatest surplus energy. The second

panel shows the average hourly operation of different balancing solutions in each month. Balancing solutions above the x-axis effectively increase load and absorb surplus energy, while those below the x-axis reduce load. Electric fuel production plays a large role in reducing curtailment in the spring, and flexible end-use demand, including vehicle charging flexibility and flexible thermal loads, play a large role in reducing daily net load peaks. The final panel shows the residual net load (summing panel one with panel two) that in this scenario is met with thermal dispatchable generation. These three panels demonstrate the importance of flexible loads among the balancing solutions. In these scenarios energy storage plays a relatively small role because it does not have the storage duration to replicate the role of electric fuel production in seasonal balancing, and is more expensive than flexible load for solving diurnal imbalance.

Figure 7 Example of the magnitude of flexible demand that operates in a high renewables system taken from the U.S. DDPP High Renewables Scenario.



Conceptually, it is useful to divide flexible load into two types: short-duration, which is primarily traditional firm load made flexible through the use of control technology; and long-duration, which includes new non-firm loads with low marginal energy storage costs, for instance grid-scale electrolysis. The first type of flexible load can solve diurnal energy imbalance and reduce load at peak to avoid capital investments (i.e. substations, transmission lines, etc.). The second type of flexible load provides a productive use for excess energy during seasons with extensive over-generation, and allows for further renewable build at lower marginal curtailment by reducing energy deficits during other times of year. Ultimately for both types of flexible load, the goal is to flatten net load.

Short-duration and long-duration flexible load each face different barriers to adoption. Interruptible load for peak shaving is a mature market for large commercial and industrial applications; recently interruptible programs have expanded into small commercial and residential applications, with many small interruptible loads aggregated into large ones. More recent still are load shifting programs, which

are an important step past traditional demand response. For most customers, though, even given the necessary smart controls in demand equipment, the price signals sent do not have the temporal or spatial granularity to unlock the full cost-of-service reductions possible from utilizing flexible load.

The barriers to long-duration flexible load also include its exclusion from full participation in energy markets. Today the impact that price responsive flexible load has on the shape of load must be accounted for in load forecasts. This works fine when flexible load is marginal, but if very large non-firm flexible loads such as electric fuel production develop, symmetry between supply and demand in electricity markets will be critical for optimal outcomes, for two reasons. First, wind and solar vary enough day to day that a pre-arranged schedule will always be suboptimal. Second, the quantity of electric fuel production could be substantial and thus will have a systemic impact on markets.

How can developers be induced to make long-term investments given uncertain revenues?

Today most renewable generators are compensated through bilateral power purchase agreements (PPAs), which guarantee fixed volumetric rates over many years and insulate project developers from variable market prices. Few merchant non-dispatchable generators exist today, and it seems unlikely that merchant exposure is a robust model for future development given the long payback times for renewable generators, and the significant risk of curtailment and market price depression over the project lifetime. Thus, bilateral PPAs are likely to remain the dominant structure for paying renewable generators.

Technologies that provide balancing, such as energy storage or electric fuel production, face similar risks in energy markets due to unknown future patterns of renewable development and/or deployment of competing balancing resources. While risk is a normal part of the merchant electricity equation, the rapidity of changes on the supply side may produce so much uncertainty in long-term revenues that no project is 'bankable,' or deployment of balancing sub-optimally lags the build of variable generation.

How will future electricity system planning be conducted?

If reaching 2050 electricity emission rate targets consistent with deep decarbonization is the goal, it is necessary for the electricity system to go through several decades of unprecedented change. Widespread electrification will lead to load growth not seen in decades. Planning in a system dominated by variable generation is more complex because it introduces a temporal component into every planning problem. The timing and complementarity of the many different but necessary electricity investment decisions are critical, and many 20th century planning paradigms and tools are likely insufficient to address the challenges ahead.

Compounding the planning challenges, deregulation has decentralized planning by putting many planning activities in the hands of market participants. In current competitive markets, no stakeholder has visibility into all parts of the system, which will seriously hamper execution of an overall long-term vision. If uncertainty about policy, market rules, or timing of complementary resource deployment calls future revenue streams into question, then carbon targets may not be met, the cost of financing may increase, and sub-optimal development strategies pursued.

Electrification exacerbates planning challenges by involving sectors that have no strong links to electricity historically, notably transportation. As previously mentioned, transportation loads represent

significant energy, but perhaps even more important, may have very high and unpredictable instantaneous power demand. The new spatial planning challenge of developing transportation charging infrastructure in which the highest demand is located where the electricity grid best able to accommodate it is considerable.

Concepts for future market design

Given the challenges posed by rapid electrification and renewable build, markets will need to keep pace on several different fronts simultaneously. It can be argued that a vertically integrated, rather than deregulated, structure is best suited for coordinating the scope of electricity system changes brought about by deep decarbonization. But, this argument neglects functions that markets are better suited to accomplish, namely communicating information between participants and driving efficiency improvements. The challenge is thus how to get the best of both: flow of information and efficient operations from markets, and effective long-term planning from a central decision maker. Below are some concepts, challenges, and principles that such an optimal approach should consider.

Energy market compensates balancing services, with full symmetry between supply and demand side balancing

In a world with near-zero marginal cost for energy and uncontrollable supply, energy markets primarily become a place to compensate and schedule balancing services. As seen in Figure 7, these balancing services can take many forms including flexible end-uses, new non-firm loads, energy storage, thermal resources, and renewable curtailment. Such resource types would provide the bulk of balancing in a highly electrified, high variable generation system, but today these resources are not integrated into markets in a way that would allow them to operate in the way pictured.

In such a system, large loads would bid a demand curve in which different amounts of energy consumption would be offered at different prices, in a way that is completely analogous to how generators bid an energy supply curve today. For small customers, this could be done by an aggregator on their behalf that then sends control signals to building loads after considering a customer's expressed preferences.

One technical challenge when scheduling flexible load or energy storage is state of charge (SOC) constraints, which are not yet integrated into markets. Today most resources that track state-of-charge, such as hydro or energy storage, self-schedule generation, which works fine when those resource are marginal, when net-load is predictable and well understood by the scheduler, or when few competing balancing resources exist (no real need to exchange information). As supply becomes less flexible and the opportunity cost of not using newly electrified flexible loads mounts, markets have a critical role as a clearing house for balancing resources. It will be important for regional transmission operators (RTOs) to gain experience scheduling flexible loads at a small scale before balancing needs grow massive. The alternative is more reliance on conventional resources, which in the context of deep decarbonization could add significantly to cost or make carbon goals unattainable.

Capacity market must have multiple products that represent capacity of different time durations ("21st century screening curve")

Capacity markets serve two key functions in electricity today. The first is as a longer-term planning mechanism to ensure sufficient resources are built and maintained to meet expected loads, months or

years in advance. The second is as an operational tool to make sure sufficient resources are available in energy markets to cover forecast errors or meet expected and unexpected changes in net-load or generation. Under this definition, most ancillary service products can be categorized as near-term capacity markets.

In a highly electrified, highly variable electricity system all capacity markets will need to increase in sophistication. Ancillary service products must accommodate increased forecast error, more extreme generator ramping, and certain grid services provided today by conventional generation but not replicated by renewables such as primary frequency response. This is an area in which RTOs have been active in recent years and much progress has been made.

The changes necessary for long-term capacity markets are less well understood and debate still revolves around exactly what capabilities are necessary for future capacity and how much will be required. It is often assumed that a combination of wind, solar and 6-24 hours of energy storage will be sufficient to create a reliable low-cost decarbonized electricity system, but this does not stand up to serious scrutiny.

To illustrate these concepts, a new type of screening curve is presented here for systems with large amounts of inflexible supply that demonstrates the capacity required from balancing resources of different durations. Figure 8 shows the residual capacity over the modeled year 2050 for two cases, DOE's 2017 *Annual Energy Outlook* and the high renewables scenario from the U.S. DDPP. Residual capacity is calculated as gross load minus all zero-carbon resources (excluding bio-energy) and includes the impact of all flexible loads and energy storage.

This residual is instructive because it is the energy that must be met with either thermal resources or greater deployment of the zero carbon resources already in the system. The key question is what the characteristics for other resources must be to replace thermal and reduce emissions or cost. This question is approached by analyzing the residual capacity requirement, to understand the number of hours a given capacity must be maintained to ensure a reliable system. This result is shown in Figure 9. In the high renewables case, capacity resources had to be able to provide at least 422 GW for one hour, at least 376 GW for 10 hours, and at least 141 GW for 100 hours. The flatter these screening curves, the higher the likely capacity factors for residual resources, and the longer the duration, the more difficult it is for energy-constrained balancing resources, such as battery storage, to meet the need.

Figure 8 Residual capacity need across simulated 2050 scenarios. Residual capacity is equal to total load minus all zero-carbon resources, including nuclear and hydroelectricity. In the modeled scenarios, this residual was met with thermal resources.

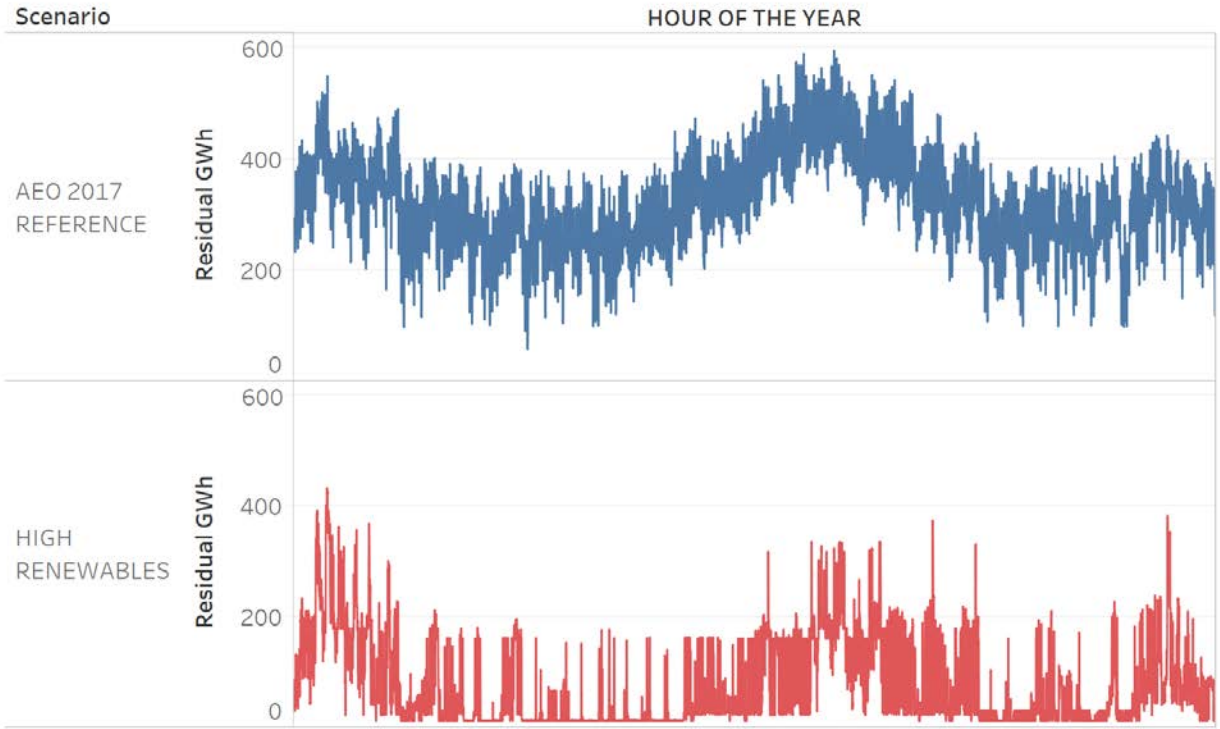
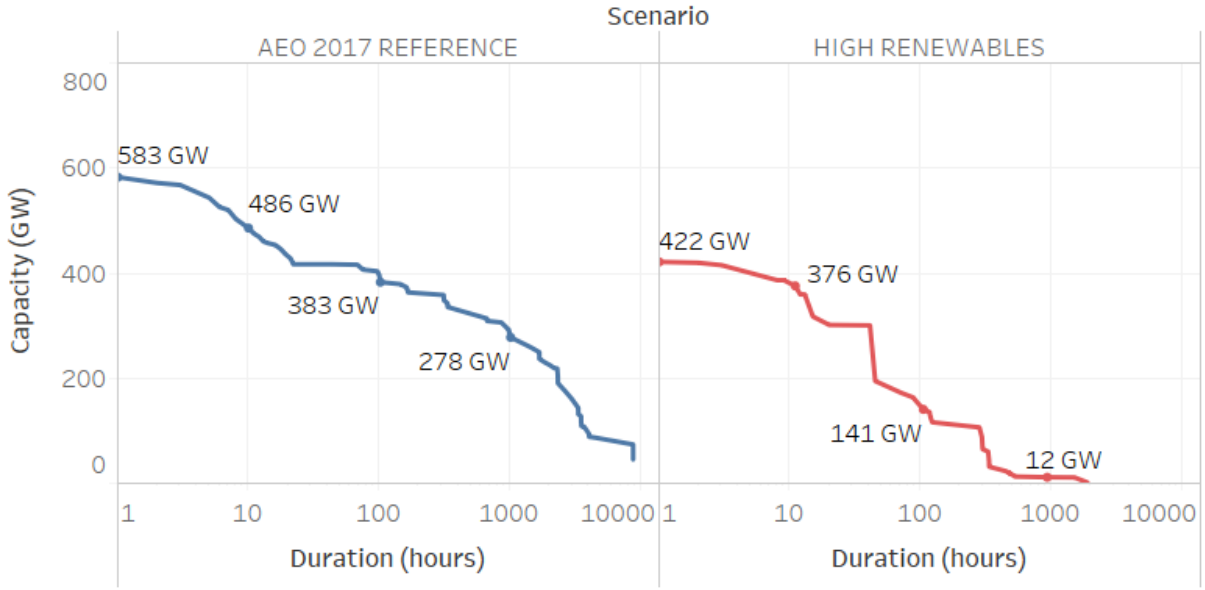


Figure 9 21st century screening curve showing the number of hours different amounts of capacity must be maintained for a reliable system. This curve was created using residual net load (gross load minus non-thermal resources) for the Annual Energy Outlook Reference scenario and the U.S. DDPP High Renewables Scenario by systematically counting the number of hours load stayed above a certain capacity level.



The most striking aspect of the curve is how little the shape of the curve changes between the two cases. Despite huge quantities of renewable generation, residual capacity needs with significant

duration remain a necessity for reliably operating the system. One important caveat is that this screening curve does not consider the need for long-duration storage resources to charge as well as discharge. Thus, a storage resource with 100 hours of duration may need 100 hours of charging after meeting a long duration event and may be unavailable for subsequent events it could theoretically have met if operated differently. The operation of such a resource to maintain system reliability and yet not be overly conservative is a large challenge for future system operators.

Caveats aside, Figure 9 demonstrates a critical challenge for the provision of long-term capacity in future markets. For markets today, the binding constraint is nearly always in the first six hours of peak duration because most generators are not energy limited. However, in future systems with sufficient load flexibility and short-duration storage, it is possible that longer duration constraints will become binding, and capacity markets will need to expand to specifically procure persistent balancing resources.

A new mechanism for allocating socialized fixed costs (renewable PPAs, grid electrolysis plants, energy storage systems) among energy consumers must be devised.

In the highly electrified, highly variable generation system in which 97.5% of all electricity costs are fixed, the question of how to allocate these costs among market participants will be critical. The question is made more difficult because cost allocation is as much a policy question as an economic one. Today, fixed costs are allocated using auctions and a combination of volumetric, capacity, and fixed charges. Figuring out how to fairly allocate fixed costs to loads using these mechanisms will be an important step in the overall development of decarbonized electricity systems.

As an example of the challenge, consider the options for allocating the cost of non-dispatchable renewable generation. As discussed previously, energy market prices will be insufficient to cover the costs of renewable generation if all generators bid their marginal cost, which is near zero. To purchase a renewable generator is essentially to pre-pay for the energy and the question is what mechanism will be used to allocate the cost of pre-paid energy between market participants. Three potential options include:

- No special cost allocation – renewable off-takers make or lose the spread between market prices and power purchase agreements and other loads benefit from merit order effects and potential curtailed energy
- Some or all loads must purchase pre-paid energy credits, equivalent to RECs today. This is similar to how many RPS mechanisms work today. The necessity for different types of loads to purchase RECs would be policy driven and market participants could trade RECs between themselves. Any loads not required to purchase credits are given an implicit subsidy paid for by other loads.
- Renewable costs are pooled and administered in the market as part of a charge analogous to a transmission access charge.

Risk must be pooled to attract long-term investment with reasonable financing

Mechanisms will be needed to pool the risks associated with many of the new technologies discussed, including large flexible loads and balancing resources. The basic issue comes back to uncertainty regarding future revenues, which will drive up the cost of financing or cause underinvestment when

measured against what is required for deep decarbonization. Mechanisms to address this issue must be developed, playing a role similar to the one played by PPAs for renewables.

Capital assets in energy have long lifetimes, depend on a long-term revenue stream, and aren't mobile between markets. Utilities and regulators have a large role to play in deep decarbonization by providing stability in future revenue streams for projects deemed optimal by long-term planning exercises. Market mechanisms, such as reverse auctions, should be employed within this framework to ensure the lowest cost solutions are built; regulators should maintain technology neutrality, defining the technical characteristics for generic new resources and allowing markets to respond.

The pace of change required in electricity to reach deep decarbonization by mid-century may very likely produce less optimal planning decisions than would otherwise happen under a slower transition. The main risk is that too many poor decisions may derail the entire exercise, driving up costs while missing the carbon goals. This highlights the need for expanded long-term planning.

Concluding Thoughts: An elevated role for planning is needed to ensure prudency and guide sequencing toward deep decarbonization goals

Establishing and frequently updating a clear roadmap to deep decarbonization in electricity is critical to ensure goals are met on time and at reasonable cost. In creating and administering such roadmaps, utilities and their regulators play an indispensable role, and must rise to the occasion for the enterprise to succeed. We conclude by offering some guiding principles for success over the coming decades:

- A key to future planning will be the efficient and transparent sharing of information between stakeholders, some of which have not coordinated historically.
- Regulators should strive to understand which changes will be best accomplished through markets and which through regulations.
- Delaying reaching 2050 goals is better than making poor decisions because it risks that the goals end up even further delayed and have a damping effect on the ambition of others. Deliberation must be properly balanced against urgency.
- All near-term decisions should always be viewed through the lens of long-term goals. This will help minimize carbon lock-in or stranded assets.
- Regulators have an important role to play in democratizing risk and in transforming markets by deploying novel technologies.

This paper raises many questions regarding markets and regulatory structures at large associated with a highly electrified electricity system with significant amounts of renewables. Due to the pace of change in technology and the speed at which those technologies need to be deployed, agility in planning and market design is paramount. This is perhaps the single most important concept for regulators and system planners in the coming decades: maintaining the ability to correct course quickly and frequently will be more valuable than the ability to perfectly follow a blueprint created years before.

Further reading:

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