Electrification, Decarbonization, and the Future Carbon-Free Grid: The Role of Energy Storage in the Electric Grid Infrastructure

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THIS article discusses the upcoming changes in the electricity industry including electrification, and the drive toward fossil-free generation, and the role of energy storage (ES) in electrification and the operation of a future electric grid without fossil fuels.

Though our discussion is primarily focused on the United States electricity system, the issues affecting the operation of future electric grids are global. While the United States is prototypical of other highly developed and energy-intensive countries, variations in renewable energy production and storage, end energy usage, market structure, and policy, among other factors, make each country somewhat unique.

I. INTRODUCTION

Climate change is driving policies around renewable energy portfolio standards (RPSs) and electrification of energy end use in the building, transportation, and industrial sectors [1]. If we address climate change as a critical

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challenge and understand the consequences of different policy and implementation decisions, then ES will play a pivotal role in the transformation of electric grid to become less carbon-intense and eventually carbon-free. This scenario requires integration of unprecedented amounts of renewables in the generation mix and the operation of the electric grid with intermittent resources on a scale that the current grid is not designed for [2]. The future system needs substantial capacity reserves, far more advanced energy management systems, and widely deployed ES through the system. Although substantial amounts of ES, primarily in the form of pumped hydro storage, has been a critical part of the asset mix for several decades, the amount of installed ES capacity is fairly small and amounts to roughly 15–30 min of ride through in most countries. In the United States, we have a system with about 850 GW of baseload and a 1250 GW summer peak [3], requiring a massive amount of ES to operate a carbon-free grid. Without sufficient augmentation of transmission capacity across the country, the need for large amount of localized ES is significant.

Recent large-scale blackouts and electric grid-related emergencies in California, Texas, and elsewhere have demonstrated two things clearly. First is that climate change is already having an impact on grid operations and resilience. The second is that high renewable penetration can lead to unforeseen common supply side and delivery infrastructure failures that far exceed conventional "$N-1$" (N minus 1, or, the condition arising when one asset in a fleet of assets fail) and "$N-2$" planning criteria. The industry lacks a framework, much less an accepted methodology, for identifying such failure modes and planning for them. It is reasonable to expect that such failures may become more frequent in coming years. Heat waves, forest fires, hurricanes, severe cold snaps, drought all need to be taken into account, including the downstream, secondary effects on social, economic, political, and ecological systems.

After a decade of early deployments, the role of ES today is well understood in the context of wholesale energy markets, where it provides energy and ancillary services and participates in capacity markets. It is increasingly well understood in terms of facilitating renewable integration and achieving high renewable penetration. ES is also becoming mainstream as a behind the meter (BTM) asset associated with distributed photovoltaic (PV) and electric vehicle (EV) charging and microgrids. ES as non-wire alternatives (NWAs) to conventional transmission and distribution (T&D) assets is beginning to be considered seriously by policy makers and system operators. Analytical tools, regulatory models, and integrated resource planning incorporating ES are at varying levels of development that mirror the growing maturity of ES in these different domains.

Since the passage of the American Reinvestment and Recovery Act (ARRA) in 2009, with its provisions for accelerating ES research and development and pilot project deployment, the energy and utilities (E&U) industry has come a long way in understanding how to apply and exploit ES in grid-tied applications [4]. All the market operators have developed protocols and market products tailored to ES in the energy, ancillary services, and capacity markets. Many states have announced mandates or goals for ES deployment as part of their broader goals for renewable energy development and several states have announced plans for moving toward fossil-free generation by the middle of the century [5]. In addition, some other states have also launched NWA initiatives that seek to replace investment in T&D assets with the development of distributed energy resources when cost–benefit analyses indicate a positive return on investment (ROI), with ES having a central role in these efforts.

Some states and locales have announced ambitious goals for rapid electrification of transportation and industrial sectors with a focus on de-carbonization. This is driven, of course, by the growing realization of the effects of climate change and the role for electrification as one of the main ways to mitigate climate change. The impact of high levels of electrification on the grid and on energy markets is not yet well understood, much less the role that ES will play in this transition. The impact of climate change on the grid and on energy supply is gaining visibility in terms of grid resilience. The impacts of climate change, including severe heat and weather, flooding, drought, wildfire, and more, on electric grid reliability and resilience are becoming increasingly severe. The impact of climate change on renewable production, load profiles, grid asset life, and reliability of the system still needs to be fully explored [6].

Local mandates at the state level for ES appear to have chosen target levels, in some cases by segment, without having done analytical homework to understand how much ES is needed or optimum and for what reasons. Some studies have focused on production cost simulations under high renewable penetration to answer the question of how much ES will be needed to support achievement of high renewable portfolio standards (RPSs) goals. This is a key question, admittedly, but not the only key question.

BTM ES is becoming mainstream as well as having the potential to provide many industry benefits.

1) Bolstering PV economics under different net metering tariffs.
2) Enhancing PV capabilities as back-up and/or resilience-related generation.
3) Helping to lower demand charges associated with air conditioners, EV charging, and other uses.
4) Leading to increased penetration of distributed generation (DG), which reduces energy sales and motivates T&D utilities to "decouple" rates from energy usage, leading ultimately to

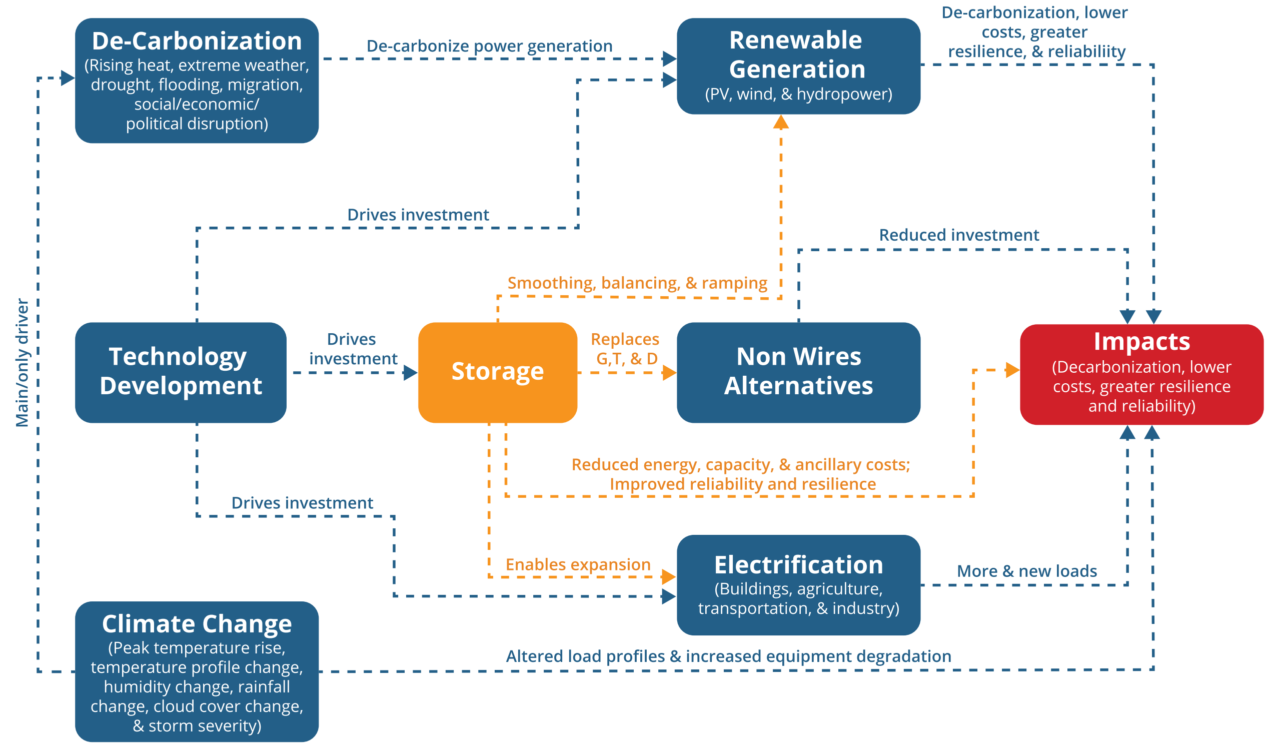

Fig. 1. ***High-level illustration of the primary drivers, linkages, and impacts of how energy storage can potentially integrate with broader clean energy goals.***

more reliance on demand or interconnection capacity charges.

Last, as a new and rapidly evolving grid asset, ES is still treated as a new and different category of generation, load, or transmission/distribution instead of as its own asset class, which complicates regulatory processes and impairs the smooth integration of ES into grid operations. ES should, in fact, be treated as a new and distinct asset class, but this innovation would also serve to further complicate regulatory processes, as new uses and rules are integrated.

All these points highlight the reality that electric grid is changing rapidly with mandates for cleaner generation, moves toward fossil-free generation, rapid growth EVs, and associated infrastructure needs, all built on aging T&D infrastructure, and requires ES including long duration and seasonal ES at scales that have not been thought about until now. Furthermore, ES technologies are evolving so fast that the overall role of ES in the future energy ecosystem is not currently well understood, much less quantified or planned.

II. BIG PICTURE

This is a good time to take a big picture view of ES in the broader context of climate change, electrification, renewables, and decarbonization. We can start to connect the dots and see how all these initiatives and effects inter-relate, and how ES fits into the new energy ecosystem. As shown in Fig. 1, the primary drivers and the pathways we can take to reach objective goals are highly linked.

Climate change is the primary driver behind decarbonization, but it also directly impacts the energy system. Changes in snow fall, rainfall, and snow melt directly impact hydroelectric seasonal capacity and increase risks to production. Altered water availability will also impact conventional (thermal, natural gas) generation that relies heavily on water for cooling. Higher temperatures have already impacted combustion turbine capacities in the United States Southwest, they have driven higher electricity demand for cooling, and as stated earlier, they are driving wildfires with severe impacts across all sectors. Higher ambient temperatures, especially overnight, coupled with higher utilization (higher/flatter loading profiles arising from electrification and NWAs) will have impacts on T&D asset life, especially transformers. For example, as shown in Fig. 2, equipment failures increase significantly with years in service. In light of the fact that most T&D equipment in many advanced countries is getting old, and this has significant impact on operational reliability. Changes in cloud cover patterns will affect PV production and changes in wind patterns will impact wind production. These issues have not gotten the level of attention needed.

Decarbonization drives both renewable penetration goals and electrification goals. Many studies have been performed on market and grid performance in regions with comparatively high levels of renewables integration in the grid. Very few

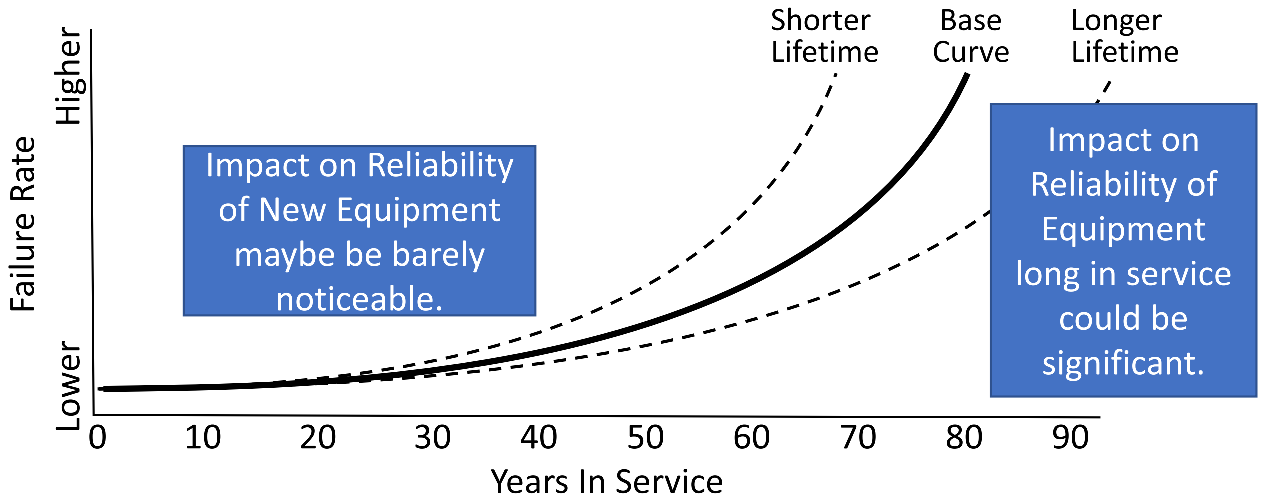

Fig. 2. *Because of the shape of typical failure-rate curves as a function of age, the impact is greater on older transformers and other equipment than newer.*

studies have been conducted that examine the impacts of large-scale electrification, and none that look at high electrification and high renewables in conjunction and the concomitant requirement for storage. Some believe that high electrification can be achieved without significant grid investment. They argue that a combination of smart charging that limits increased load to nighttime, along with switching building heating to heat pump technology, will keep winter loads lower than summer air conditioning loads and that questions around long-term grid investment are moot.

However, focused studies or observations of just parts of the electrification and climate change problem have shown that more, not less, demand will be placed on the grid in future. As a simple example, one mid-Atlantic utility reports that conversion of oil heating to heat pumps in areas without natural gas service have already turned it into a winter peaking utility again.

A more complex example shows that conversion of commercial and public fleet vehicle operations will require substantial new capacity in distribution stations and circuits. For instance, depots of medium-duty trucks can represent peak loads of 5–10 MW. No amount of distributed PV will supply that in dense areas. Relocating the fleet operations to remote areas with adequate space for PV is impractical operationally. ES can buffer some of the impact but not eliminate it. Grid investment is unavoidable if electrification of transportation sector is to be realized. If current projections were to become real, the peak demand on the grid will likely double in many urban areas.

Furthermore, studies of the impact of EV charging have tended to focus on electric cars and typically assume overnight charging at home, but not daytime charging during work hours in concentrated parking garages. And commercial fleets may electrify more often and more rapidly as a result of local mandates, corporate sustainability goals, and simple economics. Typical load forecasting approaches fail to deal with these issues. An example of the kind of analysis that is needed is shown in Fig. 3. Growing commercial acceptance of EVs, especially buses and medium duty vehicles, indicate the need robust charging infrastructure in commercial districts and city centers.

One goal of a non-wire alternatives (NWAs) approach is to increase T&D "utilization" (which had become increasingly "peakier" in past decades) and defer or avoid major T&D investments as a way to slow rate increases. However, one preliminary examination of an unintended consequence of this looked at the impact of higher utilization and higher ambient temperatures (especially evening/nighttime temperature profiles) on power transformers.

Power transformer ratings take into consideration the ability of the transformer to radiate heat from I2R losses (energy lost as heat due to resistance) and maintain internal temperatures within limits that do not degrade winding insulation. Of critical consideration is the likelihood, duration, and increased loading from "$N-1$" events when a transformer has to pick up the load of an adjacent unit that has failed due to lightning strike, equipment failure, or another cause. During these events, the transformer overheats for the duration of the outage and experiences some loss of life. The planned maximum loading of the transformer for normal and emergency conditions (i.e., its "rating") takes these things into account to manage expected loss of life. The ratings factor in the ability of the transformer to cool off, literally, at night when temperatures and loading are lower. But climate change increases nighttime temperatures, and electrification increases nighttime load along with levelizing daily load profiles, so the transformer

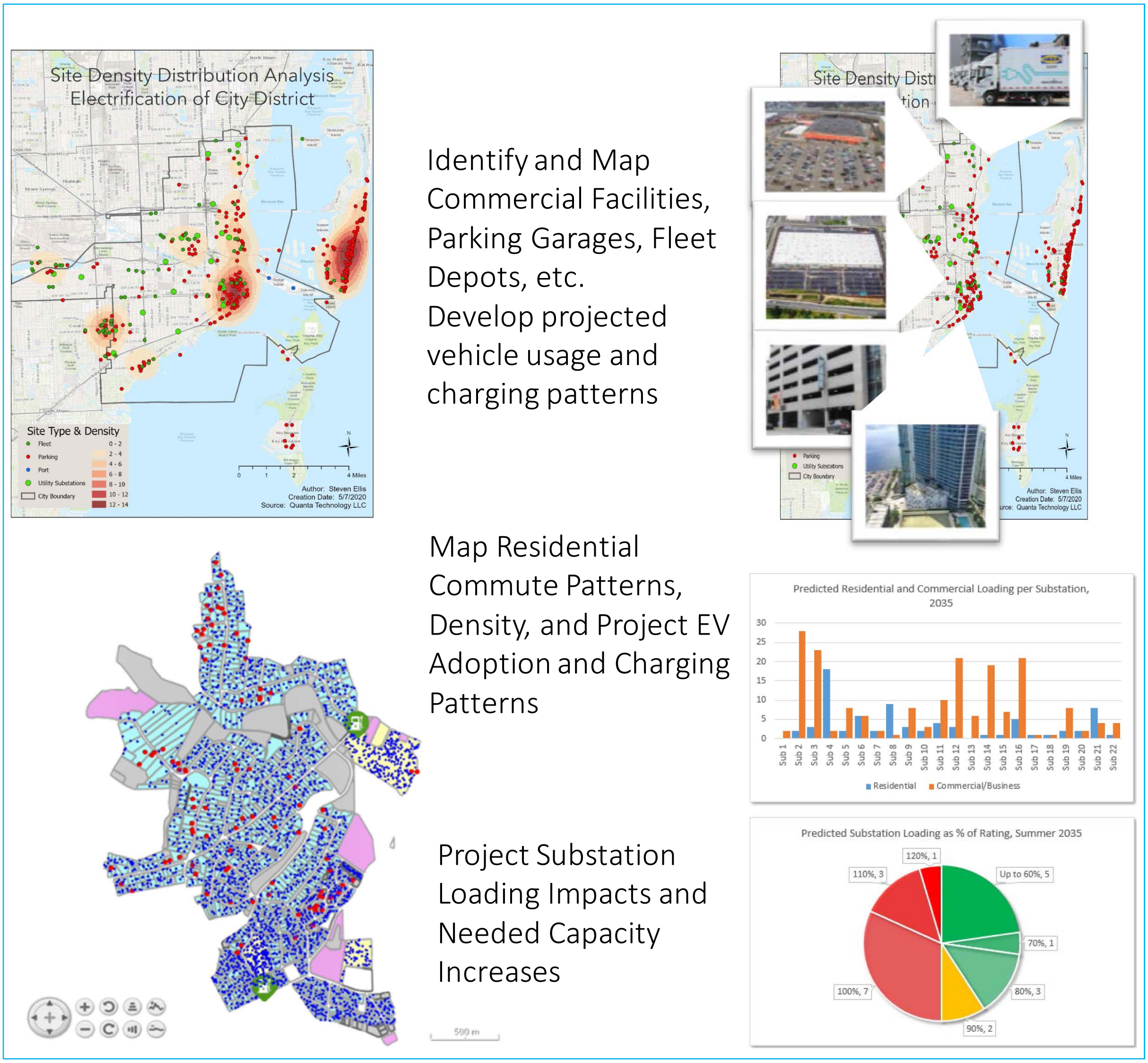

Fig. 3. ***Scenario model for electrification impact on load and capacity needs in Miami.***

cannot cool off nearly as much, especially under $N-1$ conditions.

The possible consequences of this include higher failure rates, shorter lifetimes, and accelerated replacement costs. Perhaps, utilities should change transformer rating practices given that a new transformer will be in service for 40 or 50 years and in effect install bigger units now in anticipation of climate change and electrification impacts in the future. Just how big a problem is this and what are the financial costs? We really do not have data and it is important to find out.

Another "disconnect" today is that many regions incorporate a "zero load growth" assumption into medium- and long-range planning, under the assumption that energy efficiency measures will offset new load from new appliances and other technologies. This has a good basis in fact—many utilities have seen negative growth in baseload in recent years, and distributed PV only increases this effect. Load growth is driven by "new businesses" (i.e., new construction or remodeling). Electrification throws that out the window, certainly in the case of energy consumption and almost certainly in the case of peak demand. DG may well mitigate this in less dense suburbs or rural areas, but a 40-story office tower with a 4-MW load today that converts to heat pumps and deploys EV chargers in the parking garage is not going to have 6 or 8 MW of PV on the roof, nor the distribution circuits designed to sustain these types of new loads.

Load forecasting is typically a statistical process that "looks backward" using a decade or more of historical data to forecast load in coming years. As such, it does a poor job of understanding technology change, end use change, adoption rates, impacts on load, and climate change. Load forecasts often force utilities, regulators, and stakeholders to argue over differences of a few percent or less arising from statistical models, and over (often subjective) assumptions about energy efficiency and PV adoption. But a further complication arises in forecasting around *weather adjustment* (the process of adjusting the prior year's peak load to a normalized view of peak temperature that would only be exceeded one year in ten). The entire focus is on the annual peak hour and not on the entire year's profile. How climate change should affect that forecasting of peak temperature, the annual load profile on a daily and seasonal basis, is an area of urgent concern but without consensus today. It is becoming difficult to predict future temperature patterns based on historic data, as dynamics of temperature changes has become more complicated.

It is becoming clear already that medium- to long-term forecasting has to incorporate technology adoption (building heat electrification and EV, but also multiple industrial applications), how that technology will be used by different end use sectors, along with expected changes in climate. Medium- to long-range electric T&D system planning is subject to greater uncertainty today than at any prior time, driven by policy decisions around renewable generation and electrification, and customer adoption rates driven by rapidly evolving technology costs.

III. WHAT IS THE BIG PICTURE FOR GRID ES?

Electricity without storage is "Just in Time" in that once produced, it must be consumed nearly instantaneously. The fuels or sources of electricity production (water behind a dam, gas in a storage tank, coal in a pile, etc.) could be stored of course, but storing generated electrical energy in the T&D system was not part of ac system engineering. Today, increased reliance on renewable energy and the difficulties in matching the timing of renewable production to consumption make a strong case for ES across time domains from seconds/minutes (for frequency regulation and balancing) through hours and days (diurnal cycles) to longer-term storage on a weekly and seasonal basis (renewable production profiles).

How do the challenges described above link to ES and the transformative changes that are coming in the electricity business? Considering the role of ES for other commodities (e.g., gas, grains, metals, finished goods of all kinds, and basic inventory needs), it is helpful to identify broad conclusions. First, the role/purpose of generic (not just ES) storage is threefold.

1) To enable goods produced at one point in time to be consumed at a later time.
2) To buffer volatility throughout the supply chain.
3) To mitigate disruptions throughout the supply chain to ensure delivery.

Ironically, in other industries, the focus of intense process improvement in the past decades has been on reducing inventory costs and achieving the kind of "just in time" production that the electric utility industry must live with. These roles/purposes have easily seen and understood analogs in the E&U sector, and the push for decarbonization increases the importance and criticality of these capabilities.

In other less regulated industries, the decisions about how much to store, where to store along the supply chain, and how much storage capacity is required are completely left to the market. But these industries are not regulated monopolies, and in most cases product substitution is readily available—either as a different store, different brand, or a different good that serves a similar purpose. Even a broad crop failure usually allows consumers to substitute other foods. The principal regulatory concerns around storage have involved scrutinizing commodities for market manipulation (e.g., metals) and monitoring levels of goods in storage to understand downstream market impacts for trading, or in extreme cases, for emergency measures. Some market transparency is provided around the level of goods in storage, as this affects future markets to varying degrees. Storage levels range from days (e.g., grocery store inventory of fresh vegetables, fruit, and meat) to a year or more for some commodities.

Some commodities do not suffer from losses or degradation in storage—gold being a prime example. Others (perishable food stocks) degrade over time. All commodities have some costs imposed associated with putting them in storage, maintaining them in storage, and removing them from storage. Electric energy is perhaps the extreme counterpoint to gold—almost all storage mediums associated with electric energy have charging and discharging (storing and retrieval) losses, sometimes quite high; and many storage mediums have self-discharge or operating costs that impose a degradation effect. Because all electrical ES technologies (save possibly capacitors) involve a transformation to electrochemical, physical, or other forms, there are significant conversion losses. By contrast, the E&U industry affords little or no product substitution (and electrification would further reduce that), and it has single monopolies in the "delivery" parts of the business. T&D has a unique market structure dependent upon single market operators in many regions. The E&U industry is also subject to highly regulated market protocols with barriers to independent innovation. Compared to unregulated sectors, the T&D part of the supply chain has little incentive to innovate and every reason to be risk-averse. On top of that, it is undergoing rapid change in supply technologies (renewables) and end use/consumption or target customers (electrification). Amid these changes, it has to learn to manage ES throughout the supply chain and across the space of planning, deployment, and operations.

The high cost (until recently) of ES, the novelty and high rate of technology development, the regulatory classification of it as generation, transmission, distribution, or load, and the general lack of familiarity in the industry with ES in an extremely standardized industry all remain as major obstacles. Given these challenges, it is amazing that ES has come as far as it has in the past decade.

The theme of this article should now be clear: we need to connect the dots and establish a much deeper understanding of what the electric power system will look like in a world of climate change, electric end use displacing fossil fuels in all sectors, and very high or total renewable generation. The role of governmental regulation—at federal, state, and local levels—cannot be ignored, as incentives and mandates will be required to drive multiple adoption trends. Most importantly, we need to understand the sweet spot for grid investment and ES adoption under different scenarios for which electrification, decarbonization, and renewable technologies prevail.

While most of our discussion has been primarily focused on North American electric power system, ES is front and center in addressing global challenges related to climate change and the need for rapid decarbonization of electricity and transportation sectors. Near-term global scenarios vary considerably. For example, in the case of advanced economies, electrification and grid modernization is highly policy-driven. Here, one has to take into consideration the need for utilization of existing infrastructure assets while ensuring decarbonization and electrification goals are met. For example, the delivery of electricity to enable rapid electrification transportation fleet is likely to require massive investments in the distribution infrastructure, which is already capacity constrained in most urban areas. From a policy and asset utilization perspective, addition of new renewable generation capacity, ES, and other new resources have to compete with the retirement and re-purposing of existing hydrocarbon infrastructure, which currently delivers nearly 60% of energy needs in many developed countries including the United States [7]. This creates competing policy priorities which have not been fully addressed. Major investments and grid upgrades do require societal consent and the development of equitable regulatory framework takes time.

Decarbonization of manufacturing industries is another area that is highly energy intensive, where most current energy use is either thermal or process gases such as hydrogen. Making manufacturing industries less carbon-intensive is a daunting task for new ES resources. For electrification at larger scales requires large-capacity, long-duration ES. Currently, existing long-duration ES options are either too costly or lack the policy or regulatory support to become commercially viable in the near term [8]. For example, hydrogen as a liquid fuel is an area that is getting considerable policy attention. Widespread use of hydrogen as an alternative fuel has the potential to reduce greenhouse gas emissions and to serve as bulk ES. Currently, hydrogen is managed as chemical, not as energy/fuel for power generation. Also, conversion technologies based on hydrogen fuels require large capital investments and large-scale capacity planning. There are longer-term technical barriers, as well as infrastructure challenges and regulatory hurdles to consider. Thermal ES is a potentially viable option if coupled with large-scale concentrated solar power has not proved to be commercially successful.

The case for ES in the developing economies is murkier. With weak electric grids, there is considerable policy discussion toward larger-scale adaption of distributed energy systems. This is considered as a potential option for the billion or more people in the developing world who are not connected to the electric grid [9]. For example, *IEEE Empower a Billon Lives* initiative highlights the centrality of renewables and ES for providing energy/electricity access [10]. While off-grid electric services are a potential option, off-grid solutions are costly and suboptimal as longer-term alternatives to grid-connected delivery models. Low-cost distributed energy delivery requires ES to provide reliable power. To improve energy access in developing countries requires a rethinking on the future electric grid infrastructure.

IV. KEY QUESTIONS

In order to develop that understanding, critical gaps in our analytical capabilities need to be addressed and filled. Key questions include as follows.

1) What is the impact of climate change on load, and how will that change over time?
2) What is the impact of electrification on load in different sectors and under different technology adoption scenarios?
3) What are the impacts on technology adoption and usage in terms of peak load, daily and annual profiles, the sensitivity of load to price over different time frames, and the impact of policy decisions?
4) How will load volatility change over different time periods? In particular, what are the uncertainties in medium- and longer-term load forecasts, and how do they correlate with uncertainties in underlying variables?
5) What is the optimum mix of ES deployment, renewable deployment/curtailment, and transmission expansion required to achieve carbon free goals?

These are forecasting and planning questions that cannot be answered by statistical analysis of historical data. Technology adoption models—the diffusion or “S” curve—that can incorporate multiple inputs (cost, temperature change, etc.) will be needed. These are familiar in other industries but have not been widely used in the E&U industry.

Given that these forecasting questions are where long-term planning starts, and seeing how contentious forecasting already is when wrapped into public review of planning and rate case decisions, it is obvious that rapid development of ES technologies is critical. When major investment decisions are on the table, having a consensus approach to the problem that recognizes all the important regional differences will be essential.

When discussing technology adoption in electrification scenarios, it is important to acknowledge the role of hydrogen fuel cells in transportation. Shifting some transportation electrification to hydrogen can change the location and amount of electric load—instead of charging, hydrolysis is the load. Whether and how hydrogen is transported factors into this. In colder climates, it could replace resistance heat backup for heat pumps, as well. It might also be the answer to the need for long-duration ES (LDES) which will likely continue on a growth trajectory as application and price considerations mature. Today, hydrogen from renewable energy costs about \$5-/kg [11] and appears too costly/difficult when considered "narrowly," but that could change when all the dots are connected. For deeper decarbonization of the grid, we also need advances in other LDES technologies including thermal and thermochemical ES [12].

A second broad topic is around scenarios for large-scale adoption of renewable generation. Many aspects of this topic are well explored, for example, assessing PV hosting capacity and determining how renewable penetration and volatility affect grid and market operations, transmission planning, and curtailment for wind farm development.

Key questions remain as follows.

1) What is the impact of climate change on different renewable technologies in different regions, whether grid-scale or distributed? Climate change forecasting as reported focuses on temperature, sea level, and severe weather, but cloud cover and wind speeds are also critical.
2) How does renewable production variability change? How will renewable forecast accuracy change? These answers have implications for amounts of operating reserves needed, and for how to incorporate "reasonable worst case" figures instead of means in planning.
3) How will T&D investment decisions and incentives factor into the relative adoption of different renewable technologies—PV versus wind, grid scale versus distributed, remote versus local? What are the "best" mixes given all costs and performance?

An example of this is how the construction of transmission to Competitive Renewable Energy Zones (CREZ), Texas, reduced interconnection costs, forecast curtailment, and stimulated/enabled wind development. Should states encourage utilities to build out PV hosting capacity to facilitate distributed PV deployment? Is this better than building transmission to remote wind farms? This is a complex question involving more than investment costs. How different ratepayers are affected, and how property taxes are distributed all come into play.

Answers to these questions are important inputs to the questions around ES planning. And some ES planning questions impact considerations of various renewables and how they will be used.

1) How do ES costs and business models impact adoption of different renewable technologies?
2) If ES were available on a "rental" basis instead of folded into development capital costs, does it change things favorably? Is a gas transmission pipeline storage model appropriate?
3) How does ES affect opportunities for production and investment tax credits?
4) How can ES assist in making production available at a later date—the daily, weekly, and annual, location-specific renewable profiles will affect the amount of ES needed and its economics (therefore, climate change impact and the technology adoption scenarios will be increasingly relevant).
5) When the role of ES is to buffer volatility in production and demand—clearly understanding how the total volatility of production varies with the adoption scenarios will be increasingly important.
6) The NWA movement has an implicit or explicit bias against long-term infrastructure investments in the T&D apparatus. Will this bias extend over to LDES such as pumped hydro (the only practical long-term storage technology today), and with what implications?

V. CONCLUSION

The value of ES in the E&U industry's grid system is certainly well-established and has been long appreciated. Traditionally, in a highly centralized generation infrastructure, ES has existed in the long trains loaded with coal that snake across the United States and coal stockpiles at power plants, in the stored nuclear fuels in reactors providing a year or more of fuel storage, in the caves and pipelines that hold natural gas, as well as the reservoirs of large hydropower systems. For transportation, energy is stored in gas and oil tanks at refineries, at distribution points, and in vehicles. Looking back even further, industries have relied on ES in the forests that served as sources for biomass generation. But now the world is changing dramatically, and efforts to decarbonize our energy system will make several of these traditional forms of ES obsolete. Until the time when storing wind or sunshine is feasible, it is increasingly important to find ways to mitigate their variability with new and ubiquitous forms of ES in our grid.

Dependence upon renewable energy will force the E&U industry to adopt some of the measures common in seasonal and weather dependent domains, such as agriculture. Rainwater and snowmelt must be stored somehow until needed for irrigation; commodities that are only produced one or two times a year must be stored along the supply chain until consumed. Orchards, vineyards, and truck farms have never been able to adopt the economics and management techniques of "Just in Time" production.

The engineers and operators of our electric grid have made substantial progress in recent years regarding the role of ES in securing an affordable and resilient electric system. In wholesale markets, where costs and benefits can be readily compared, we have seen the advancement of market-based ES solutions, in the form of battery systems of varying sizes. Additionally, advanced demonstration projects—largely conducted as public–private partnerships—have allowed us to learn much more about new technology integrations and applications across various use cases. Coupled with the continued decline in the overall cost of battery electric ES systems, we continue to see rapid growth in the acceptance and development of ES projects on the grid.

Interestingly, we are at a time when the past simply does not hold as a good indicator of what the future may hold. There are too many uncertainties including climate change, changing market and regulatory structures, decentralization of grid management and operations, and electrification of other infrastructures—most notably, transportation. The combined potential impacts of these factors lead to the conclusion that our current predictive capabilities are not as good as they need to be.

Ultimately, ES will be an essential part of the solution of a 21st-century resilient and secure electric system. For this to happen effectively, however, several knowledge and technology gaps must be addressed as follows.

1) New forecasting tools that can adequately help to predict contingencies under different possible scenarios involving electrification of vehicles, ambient temperatures, and other resource availability such as water for thermoelectric or nuclear plant cooling.
2) Continued reduction in technology costs, including systems integration and associated controls (not just batteries).
3) Development of ES solutions on multiple time scales, from seconds to seasons, including thermal and hydrogen-related technologies.
4) A supply chain and manufacturing infrastructure that can address the orders-of-magnitude increase needed for effective integration of ES technologies in our infrastructure.
5) Further understanding of system security and resiliency implications related to highly distributed ES solutions across our electric system and the tools to ensure that we maintain and enhance security, resilience, and reliability as we make this transition.
6) The development of appropriate computer models to drive simulations of integrated ES systems under a variety of grid scenarios.
7) A regulatory and market framework that recognizes ES as a distinct asset class, rather than as part of the existing generation-transmission-distribution-load framework.
8) The ancillary effects of employing ES as an NWA to infrastructure upgrades must be explored and addressed. For instance, increased capacity of transmission lines, distribution lines, and transformers can lead to further heating and lifetime effects of components.

The time is now to determine a path for new ES technologies to be an integral part of our future electric system. United States have adopted aggressive clean energy targets that require near-complete transitions to renewable-based infrastructures [13]. The electrification of the transportation sector will further enable this transition. Many countries are making similar policy transitions, with several European countries leading the way. Currently, the analytical, predictive, regulatory, and technology-based tools simply do not exist to achieve such targets, but these gaps can be addressed if we start now. We need to aggressively develop these tools and technologies in order to meet these aggressive clean energy objectives. In doing so, we will be developing a new technology base and growing new industries for the United States and the world. ■

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