2024 White Paper

Interim Service Solutions and Timely Grid Connections for Large Transportation Electrification Projects

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EXECUTIVE SUMMARY

Transportation Electrification (TE) projects create unique challenges for the utility industry in providing timely electric service to its customers. This is especially true for fleet customers with Medium and Heavy Duty (MHD) trucks and/or those requiring the charging of large numbers of light-duty vehicles. The timing mismatch between the lead time required for customers to procure electric vehicles (EVs) and install customer-owned ("behind-the-meter [BTM]") charging infrastructure, and the time required for utilities to provide electric service for the new load is quickly becoming an issue as fleet electrification and large public charging depots scale in size and number. In other words, fleet EVs may show up far more quickly than the traditional utility timeline that is required to provide power needed to sites to charge the vehicles. Thus, OEMs and customers are reporting postponement or cancellation of EV deployments due to the inability to receive utility electric service in a timely manner.

This research was launched to assess interim service solutions to bridge this timeline mismatch. However, researching interim solutions led us to naturally extend the research into solutions related to processes and procedures that may accelerate interconnections and reduce the need for interim solutions. The information in this white paper is based on interviews with utilities, fleets, OEMs, service providers, and other stakeholders in the TE industry. The feedback from these interviews and other observations have been condensed into this report highlighting underlying factors impacting service connection timeliness, best practices, and recommendations to minimize the impact of utility service capacity on the deployment of EVs.

Large TE projects have several attributes that are different from traditional utility customer projects. These arise from the fact that for over a century, utility processes and planning have been based on electric load associated with a building structure. With TE, the equipment consuming the electric power is mobile—enabling a shorter procurement and delivery process—and is ready for service when it arrives, which creates unique challenges for providing timely utility service.

Three key attributes of TE projects are summarized below. The first is the underlying topic of this white paper, while the second and third are attributes that impact the ability to address the first.

TIMELINE FOR TE PROJECTS

EVs have relatively short procurement lead times and the customer's charging infrastructure can typically be installed much faster than utility service upgrades. As a result, a gap of 12-18 months between customer readiness and utility capacity installations is not uncommon. This leads to postponement or cancellation of fleet deployment of EVs, especially in the medium/heavy-duty markets.

ENERGY DENSITY OF TE LOAD ADDITIONS

There is no precedent for the load increases at existing sites that can be encountered with large TE projects. Load increases of 5-10x with no change in customer footprint are common, with load increases of up to 100x occurring in certain use cases. Historically, load additions at existing customer sites are incremental to the site requirements. In contrast, TE projects are usually transformative to the site power needs and associated utility service.

UNCERTAINTY AND VARIABILITY OF TE LOAD CHARACTERISTICS

Utility planning and service processes are based on years of experience and understanding of customer load types for building-related loads (residential, commercial, and industrial). As a result, load estimates and projections can be done with relatively high confidence based on known parameters and the influence of weather conditions and/or predictable customer operational schedules. However, TE loads are much more uncertain and variable. This uncertainty arises from the immature state of the market.

The deployment of large TE projects—especially in the MHD space—varies greatly across the country for multiple reasons, especially with differences in regulatory and policy environments. As such, there is not a unified sense of urgency across the utility industry to address the timeline issue as there is from the OEMs and fleets that are trying to sell and deploy trucks. Furthermore, the need to address the timeline issue is a function of project scale. In this context, scale can mean either the number of projects in a given geography, or the size of projects in terms of maximum kW load. When projects are few or the size is small, existing utility processes are generally sufficient or the response can be custom in nature. However, when the number of projects that are above certain power thresholds (typically 500 kW-1 MW) reaches a critical level, utility processes are stressed, and customer service issues are exacerbated. As a result of this dynamic, utilities that have not reached a critical level may lack a sense of urgency. While areas with a lot of activity, such as California, must assess strategies in organization, processes, and programs to alleviate these issues.

Interim solutions include options on both the utility and customer side of the meter. To date, the customer side of the meter has seen the most activity, driven by the realities of operating early EVs when electric service from the utility is not ready. The most common customer side solutions include:

- **Utilizing spare electric capacity within the customer facility to power temporary EV chargers.** This enables customers to charge enough vehicles to begin their deployment plan, even though the charging location and EVSE equipment are not permanent.

Solutions to address the timeline mismatch can fall into one of two categories:

1. Develop and deploy interim solutions. This provides a bridge to enable the customer to begin deployment of vehicles and operate until full electric service can be provided.
2. Improve customer and/or utility processes to shorten the project timeline to a suitable schedule, and thus eliminate the need for an interim solution.

- **Distributed energy resources.** Deployment of on-site generation has been utilized by customers to power EV charging when utility capacity is unavailable. This includes traditional natural gas or diesel generators, as well as newer technologies such as fuel cells. Energy storage (ES) also provides an opportunity to manage load requirements within existing available capacity, however storage is generally more costly. Solar may be paired with storage to provide additional benefit depending on the location.

On the utility side of the meter, the most promising interim solutions include:

- **Provision of a construction service for short-term power needs.** A construction service is common for interim power needs at building construction projects. For these customers, there is an understanding that interim power is needed at the site as soon as possible, and that it will be needed until permanent service is available. This same paradigm can be applied to TE projects. In many cases, providing a 480V construction service will be the only interim solution needed.
- **Distributed energy resources.** As on the customer side of the meter, DERs can be utilized to provide interim capacity until full service can be supplied. Applying DER on the utility side may enable optimization across multiple customers and utility-based programs may be able to be deployed more economically than by the customer. The number of DER products available is growing as manufacturers target solutions for TE projects. These include traditional distributed generation (DG), such as diesel or natural gas, as well as ES, renewable generation, and fuel cells.

While it is important to develop and deploy interim power solutions, the ideal scenario is to not need an interim solution. For this reason, planning and service connection processes should be reviewed for improvement and innovation opportunities. A complicating factor in improving service timelines is that both customer and utility practice tend to be conservative in load estimation and determining available capacity. When combined, these practices can create longer timelines than might be needed otherwise.

From a customer perspective a good understanding of actual vehicle duty cycles is needed to determine realistic estimates for power, energy, and load profiles. In addition, the application of a Charge Management System (CMS) to limit capacity requirements should be an expectation on large projects. These methods can reduce the load request from the customer, which will tend to reduce project timelines with everything else being equal.

"The ideal scenario is to not need an interim solution."

From the utility perspective, conservative practices can apply to determining the total power rating for a circuit/substation and the available capacity. Many/most utilities base available capacity on "worst case" scenarios with the assumption that maximum customer load is coincident with the circuit/substation peak regardless of the customer's actual load profile. Additionally, utilities often do not consider or trust customer CMS solutions to limit load and therefore base availability on the contingency scenario of the CMS failure.

Utilities that are encountering a large number of TE projects, such as SCE and PG&E, are recognizing that traditional conservative practices for determining available capacity will not be sufficient to meet TE needs, driving unnecessary (and unsustainable) costs into the electrification transition and risking higher-than-needed customer rate increases. Innovation in new programs that incorporate seasonal, or time-of-day capacity ratings can dramatically improve timelines for customer projects, even if it only meets partial power requirements. Additional benefits can be obtained by incorporating utility signals directly to customer CMS solutions to communicate and verify capacity and load interaction.

This symbiotic relationship between customer load requests and capacity planning emphasizes the importance of the customer engagement processes for utilities. The nature of TE projects requires close collaboration between utility and customer to evaluate load requirements, power thresholds that would lead to upgrades on each side of the meter, charge management strategies, and when necessary, the determination of minimum viable power (MVP) requirements for an interim solution.

This collaboration is an objective of the advisory/consultation services offered by utilities. The following is a summary of best practices and recommendations included in the document:

Best Practices

- A large food distributor identifies existing spare capacity within their facility (switchgear and transformers) and deploys temporary/portable EV chargers where this capacity is available. This allows the deployment of early trucks, even if limited in number. As utility service is established, these chargers are moved to another site and the same process is used.
- At least one west coast utility has a proposed program to supply ES on the utility side of the meter for temporary capacity constraints.
- Multiple utilities have regulated and/or un-regulated programs to deploy DG for resiliency purposes. Typically, these are diesel or natural gas generators. While not originally designed for interim service, these programs have the opportunity to be utilized for this purpose.
- A G&T utility for cooperatives is assessing the provision of mobile substations and DER equipment that can be shared across the cooperative customers it serves. The program is still in development; however this principle is applicable to other utilities.
- PG&E has launched a new pilot program called Flexible Service Connection which allows customers with controllable loads to connect to the grid without waiting for a service upgrade. This bridge solution sends day ahead hourly capacity signals to a fleet customer's charge management system (CMS). The CMS then automatically limits load levels to the capacity thresholds communicated by the utility. Since most capacity constraints on the distribution system are due to relatively few hours/days during the year, this program enables customers to move forward with projects sooner than would otherwise be possible under the condition they can limit load during the few hours of the year when capacity is constrained.
- Southern California Edison's Load Control Management Systems (LCMS) program allows customer side software to be used to limit load based on capacity information from the utility. This enables customers to move forward with projects that otherwise would have been delayed. The load may be limited during certain seasons and hours; however, it can provide the customer flexibility to use full capacity at other times.
- Transformer availability and lead time issues
  - Several utilities are seeking to secure manufacturing capacity through direct engagement with manufacturers and/or reserving manufacturing capacity in advance of need.
  - One Southern municipal utility will install an available transformer of a smaller size as an interim measure. This allows the customer to energize and begin using power for initial EV charging until the appropriate transformer can be installed that provides full power capabilities.
  - Customer supplied transformers ("Bring your own transformer") can improve timelines in some situations. This is most commonly accomplished through a primary voltage delivery, however some customers have a willingness to reserve manufacturing capacity.
- One global last mile delivery company employs a tiered strategy to optimize existing electrical capacity when prioritizing deployment locations:
  - First, locations with spare transformer capacity are identified and deployment begins at a level that will not exceed this capacity.
  - Next, sites that have available line/circuit capacity from the utility are identified, and vehicle deployments are planned that do not exceed the available capacity.
  - Finally, projects that will exceed available utility capacity are identified, and generally prioritized last. If business needs dictate a higher priority, then distributed resources and active energy management may be deployed to address the capacity shortfall.
  - Across all these categories, communication is initiated with the utility to address long-term capacity requirements.

RECOMMENDATIONS

- The provision of "construction service" should be the default assumption for larger TE projects or any TE project requiring long lead times. Customer engagement processes should communicate this option. The standard expectation should be for a 480V, 400A construction service. This recommendation is a "quick hit" that can be implemented immediately.
- Develop common templates for a 480V, 400A service connection that is compatible with most utility service provisions. Share and communicate this template with customers, engineering firms, permitting agencies, and other stakeholders. Developing these templates are in the scope of EPRI's GridFAST workstream within the EVs2Scale2030 initiative.
- A database and processes to capture information from completed TE deployments should be created. Over time, this database will enable the establishment of "rules of thumb" load projections to assist with planning, and determination of which project metrics are necessary to predict load patterns. This will require data collaboration with fleets for key project parameters (number and type of trucks, number and type of chargers, dwell time, etc.) and load data from utilities, with customer consent (kW, kWh, load profile).
- The determination of a site MVP level should become standard practice. The MVP is the minimum power level required to enable a customer to begin vehicle deployment. An MVP will assist a fleet in determining viable customer side options and enable the utility to better evaluate interim service solutions.
- Utility adoption of available capacity ratings that incorporate customer load profiles with seasonal and/or time-of-day ratings. This requires circuit/substation metering to provide this data. Utilities that do not currently have this metering capability should create programs to do so.
- Customer engagement processes for TE projects should communicate available utility capacity thresholds (transformer, circuit, substation) and timelines required for construction if these thresholds are exceeded. While some utilities do this, it is not standard practice across the industry.
- Customer engagement processes should be relationship-based, not transactional. Engagement for TE projects requires discussion of things such as customer load estimation, energy management, deployment schedules, MVP, and interim power needs, that are difficult to accomplish without utility representatives that are well versed in fleet electrification projects.
- Utility Load Request templates should be updated to include additional information for TE projects, or a separate TE load sheet created. Existing load sheets used by utilities, with few exceptions, are not sufficient to capture TE load parameters. EPRI's GridFAST project will facilitate these updates.

FRAMING THE ISSUE

Electric load growth from the deployment of new technologies is not new. The electric utility industry was created to provide power to new technologies, beginning with electric light over a century ago. The post-World War II boom in electric appliances for the home, the large-scale adoption of central air conditioning in the last half of the 20th century, and the rise of computers, the internet, and data centers are examples of technology-driven load growth that utilities now serve.

The utility and transportation industries are now in the early stages of a new chapter in load growth created by TE. In some ways, this load growth is similar to that seen from the technologies listed above. However, as TE begins to scale, fundamental differences between providing utility service to previous technologies and the charging of EVs is impacting the customer service experience, especially for TE deployments by MHD fleets and large light-duty charging locations. Three of these differences are key to this white paper.

1. **Timeline for Transportation Electrification Projects**. EVs ordered by customers (including Class 8 trucks) can have lead times of as little as 4–6 months. In many cases, the customer charging infrastructure can be installed during this same period, or shortly thereafter. As a result, a customer can be ready for MW+ service from its electric utility supplier in a much shorter time period than traditional MW level loads. For TE, the load is mobile and drives to the site, meaning large TE loads can show up anywhere on the grid. The customer infrastructure for this load is typically the EVSE only and other electrical equipment, which requires much less construction time than needed for a commercial building of similar electric load.

   While the customer may be ready for electric service in 6–12 months, utility lead times for MW+ service capacity is typically quoted as 18–24 months or longer. Depending on the requested load level, lead times of 3–5 years are not uncommon if substation upgrades or line extensions with rights-of-way are required. This disconnect in lead times is affecting the adoption of EVs by fleets. Multiple truck OEMs, dealerships, and fleet customers have attested to the fact that orders/deployments are being postponed or cancelled due to the inability to get utility capacity in a timely manner. This is increasingly positioning electric utilities as a barrier to EV adoption in the fleet market. Policy drivers such as ACT (in multiple states) and ACF (in California), which promote or require EV adoption by fleets, will escalate this issue.

2. **Energy Density of Load Additions to "Brownfield" Sites.** There is no historical precedent to the electric load increases that will occur at existing customer locations due to TE. While new building expansions, HVAC, or industrial processes can add significant power requirements to an existing site, the order of magnitude that will be seen at many fleet locations is much greater. Load increases of 5–10x will be common, and some locations will be much more. For example:

   - **Distribution/logistics centers:** Electric power requirements at these locations today are commonly measured in the low 100's of kW. Many have only a small office area, with high-bay lighting and large fans in the distribution/logistics warehouse. It will not be uncommon for a 200 kW site to become 1–2 MW or greater when MHD trucks are electrified.
   - **Truck stops:** Similar to distribution centers, a typical truck stop today may have an electrical load of 200-300 kW. While future electrical load for a truck stop serving electric class 8 vehicles is subject to various assumptions, a common estimate by the trucking industry is that a typical site may be 20 MW. This is a power increase of 50–100x without a change in the footprint of the site.

   Since current planning and engineering processes were not created with TE in mind, existing site load increases of this magnitude are unprecedented in the utility industry. Processes to manage load additions at existing customer sites are based on incremental load increases, whereas TE projects are usually transformative in size. Characteristics highlighting the differences between incremental and transformative load additions are shown in Table 1.

INCREMENTAL LOAD INCREASES	TRANSFORMATIVE LOAD INCREASES
The existing site load is larger than the load addition	The new load is greater than existing site load
Existing site power is available for interim power needs	Existing site power is not suitable for interim power needs
Typically on-site work is the only upgrade required	Often off-site, long duration upgrades are required

Table 1.

> *“Processes to manage load additions at existing customer sites are based on incremental load increases, whereas TE projects are usually transformative in size.”*

3. **Uncertainty of Load Characteristics for TE Projects.** Utility planning, engineering, and service processes have evolved over decades of experience with customer load characteristics and profiles for building-related loads (residential, commercial, industrial). While forecasting must estimate the number and timing of customer additions, the load shapes of these customers are well understood based on many years of observation and documentation. Traditional load shapes and maximum load requirements are influenced primarily by HVAC loads, which are predicated on temperature and humidity patterns, or industrial process schedules, which usually follow predictable patterns. As such, utilities are very good at estimating capacity requirements for different load types. For example, the load requirement for a 100,000 square foot office building in Charlotte, NC, can be predicted with confidence. The electric load of a grocery store in Dallas, TX, can also be estimated accurately based on known factors, such as square footage, the type of HVAC, and the amount of refrigeration equipment.

   In contrast, there is relatively little load history for large TE deployments, especially in fleet applications. Some TE applications, such as Tesla Supercharger sites, are approaching more predictable load requirements based on the number of charging pedestals and the maximum charger rating. However, fleet electrification projects have many variables which make load estimation more difficult, especially given the lack of history available.

   An example of this difficulty can be seen by comparing the load estimation of an HVAC installation to that of an MHD vehicle deployment. If two similar and adjacent customers each install the same 100-ton chiller, the maximum load from those chillers will be very similar. The number of shifts operated by each business will impact the total energy consumed, however, the maximum kW demand will be influenced by the same weather factors.

   In contrast, two similar and adjacent fleet customers could deploy the exact same EV truck and their load shapes and maximum power requirements vary greatly. For example, one customer running trucks during a single daytime shift with overnight dwell hours may create a load of 20 kW per truck, with the maximum load occurring overnight. Another customer using the same truck in a “slip seat” fashion (multiple shifts) may create a load of 250 kW per truck during afternoon peak hours. Over time, enough experience will be obtained to do a better job of estimating maximum power requirements and load shapes. However, the number of variables impacting kW load will still likely be more than with historical building loads. A list of critical data points in estimating fleet load requirements includes:

   - Vehicle type
   - EVSE charging power
   - EVSE: EV ratio
   - Dwell time
   - Daily miles traveled
   - Battery size

To improve load estimates, it is crucial that the industry capture as many data points from deployments as possible to determine which factors are most relevant in predicting load requirements. The hypothesis of this white paper is that there are 4–5 characteristics which enable “rule of thumb” load estimation. The list above may include those parameters, but there may be others that are just as important. At this point, not enough data has been captured or disseminated.

RECOMMENDATION

A database and processes to capture information from completed TE deployments should be created. Over time, this database will enable the establishment of “rules of thumb” load projections to assist with planning, and determination of which project metrics are necessary to predict load patterns. This will require data collaboration with fleets for key project parameters (# and type of trucks, # and type of chargers, dwell time, etc.) and load data from utilities, with customer consent (kW, kWh, load profile).

One result of this uncertainty in load characteristics is that conservative engineering and planning assumptions are made by both utility and customer representatives. This can lead to available capacity estimates and project scope requirements that compound the timeline issues discussed earlier by overstating the anticipated charging load and understating the available utility capacity. Conservative assumptions have served the utility industry well in providing a reliable grid. However, these assumptions are based on the experiences and service requirements of "building" based loads and may be ill-suited in meeting the needs of a new type of customer class-electrified transportation.

DEVELOPING SOLUTIONS

Opportunities to address the timeline gap or "mismatch" between customer readiness and the utility's ability to provide electric service fall into two basic categories, which are discussed in more detail in the following sections.

1. Interim power solutions. If timelines to final electric service cannot be reduced to an acceptable level, then interim power solutions can be used to bridge the gap or to reduce load levels such that timely service connection can occur.
2. Improve or change planning and service connection processes. If process changes can reduce utility lead time to an acceptable level, then projects can proceed in a timelier manner. This topic will be covered in much more detail by the GridFAST workstream within EPRI's EVs2Scale 2030 program. GridFAST will include solutions and tools that expand on the recommendations listed in this report. In addition, the EPRI eRoadMAP that has already been deployed under the EVs2Scale program provides granular load estimation to improve utility planning processes.

The timeline gap becomes more of an issue as the TE industry scales. "Scale" related to TE can have two aspects:

- The number of projects in a given area
- The size of projects in MW

The number of projects affects the processes used to manage new service requests. When TE projects are few and unique in nature, utilities tend to manage these in an individual, custom manner. A designated individual within the utility takes ownership of the project and guides it through the utility to completion. As the number of projects grow, this "personality" driven response must give way to "process" driven responses. When this happens, TE projects can overwhelm processes that were not designed with the unique attributes of TE in mind. To reinforce the escalation in scale, at the time of this report there are over 1000 active projects in queue in the state of California. This transition between person- and process-driven response to large TE projects is a critical time for utilities and cannot be taken for granted.

As more fleets deploy EVs, the size of projects is growing larger. This is especially true with the deployment of medium/heavy-duty trucks. Early TE projects were dominated by public charging depots with a dozen or less chargers and tended to be less than 1 MW in size. With fleet and MHD deployments, TE projects above 1 MW are the norm, and projects more than 10 MW are not uncommon. Timelines for projects of this size can vary greatly and are very dependent on many factors, such as distribution circuit voltage, distance from substation, utility capacity planning and engineering practices, and other local factors. As such, these provide both the opportunity for improvements and the risk of negative customer experiences.

The process of developing solutions should recognize a few general principles related to meeting service requests:

- Smaller load requests can be met more timely than large load requests. Therefore, reducing load requirements tends to improve project timeliness.
- On-site upgrades (transformers, protective equipment) can usually be completed in a timelier manner than off-site (feeder, substation) grid upgrades. Therefore, designing projects that avoid off-site upgrades improves timeliness.
- When the timeline mismatch cannot be resolved, then interim solutions are required. Interim solutions may adjust the project size or scope to improve service timelines, utilize short-term service provisions, or include the installation of temporary assets for alternative power capacity (i.e., DER).

In addition, it is important to remember that other means of creating additional feeder/substation capacity may also be of value and should be part of the planning process. This includes temporary or permanent load switching from one feeder/substation to another, thus increasing available capacity for the TE project. Also, since feeder capacity is normally limited by the highest loaded phase of the circuit, balancing single phase load between phases may also increase available capacity. It is assumed that these options are evaluated along with the other items discussed in this white paper.

INTERIM SOLUTIONS

Ideally, interim power solutions would not be needed. Timelines for customers and utilities would align with permanent service in place when the customer needs it. However, even if best practices relative to utility planning and service connections are followed, that will not be the case in many situations. The premise of interim solutions is that full power requirements are typically not needed when the first vehicles arrive on a TE project. EV deployments generally occur in stages for a variety of reasons, which creates the opportunity for interim solutions to be beneficial in meeting near-term and/or partial load requirements. In some situations, interim solutions could become part of a permanent installation that reduces the long-term capacity needed for the site.

The delivery of interim power solutions is dependent on the establishment of a power level that can be supplied in a timely manner, while still providing enough value to enable the customer to begin their EV deployment. This can be thought of as the MVP for a site. This level will vary based on the specifics of a project, however based on conversations with OEMs and fleets, power levels as low as 200-300 kW can provide enough benefit to bridge the gap until full utility service can be established. This power level enables the use of several DCFC to charge 3-10 trucks depending on the duty cycle.

Interim charging solutions can be applied to either side of the utility meter. Some solutions are available to customers without involvement from the utility. Other solutions can be supplied by the utility. These options include, but are not limited to:

Customer-Side/BTM Options

- Utilization of available electrical capacity within the facility with temporary chargers
- Distributed Energy Resources (DER)

RECOMMENDATION

The determination of a site Minimum Viable Power (MVP) level should become standard practice. The MVP is the minimum power level required to enable a customer to begin vehicle deployment. An MVP will assist a fleet in determining viable customer side options and enable the utility to better evaluate interim service solutions.

Utility-Side Options

- Temporary or Construction service for partial capacity
- Distributed Energy Resources (DER)

Customer-Side Interim Solutions

Utilization of Available Capacity

Just as there is normally some level of available capacity on the utility electric grid, there may also be available electric capacity on customer switchgear and electrical equipment. While the source location of this capacity may not be ideal for charging vehicles, it may be suitable on a temporary basis. Several EVSE companies and service providers are developing mobile/portable chargers that can be more easily deployed than permanent solutions (see Appendix). These utilize common electrical connectors to facilitate the installation of wiring to a suitable point for the EVSE. A number of fleets have already used this solution as a bridge to full power requirements from a new/upgraded utility service connection. This rarely will be capable of providing full deployment needs; however, it enables initial delivery of multiple trucks to begin a deployment. As an added benefit, it provides the opportunity for site personnel and drivers to begin adapting to EVs sooner than would be possible otherwise, and before large numbers of vehicles arrive.

Before implementing this solution, communication should occur with the utility providing existing electric service. While utility construction is not needed for the customer-side connections, available service capacity from the utility needs to be confirmed. Utility service sizing is normally based on the actual load of a facility, not the potential load based on customer equipment ratings. Therefore, utility transformers or other equipment could have less available capacity than what is available on customer equipment.

Best Practice

- A large food distributor identifies existing spare capacity within their facility (switchgear and transformers) and deploys temporary/portable EV chargers where this capacity is available. This allows the deployment of early trucks, even if limited in number. As utility service is established, these chargers are moved to another site and the same process used.

Distributed Energy Resources (DER)

DER options include distributed generation (DG) and/or energy storage (ES). DG may be used as a supplement to, or as an alternative to power supplied by the utility, while ES can be used to reduce maximum load requirements to a level that can be more easily served by the utility or to optimize on-site generation.

The most common DG options include combustion engines (natural gas, diesel), renewables (solar), and fuel cells (natural gas, hydrogen). Combustion engines are usually the most economical and simplest to deploy, however there may be issues with the optics of charging EVs with fossil fueled generators and permitting of these solutions may not be possible in some locations. While the "optics" of a diesel or natural gas generator may not be ideal, it should be noted that in many situations the emissions from a diesel/NG generator supplying energy to an EV is less than the emissions from a similar internal combustion vehicle. This is due to the higher efficiency of electric drivetrains compared to ICE and the higher efficiency of a stationary combustion engine vs. an ICE engine in a vehicle. Fuel cells can be deployed in a similar manner to combustion engines. While more expensive, they may have emission benefits that allow them to be permitted in more locations than combustion.

Renewable generation can also provide power for EV deployments, but its use in interim solutions may be limited. The intermittent nature of solar, construction timelines, and additional interconnection requirements complicate their use for interim purposes, but doesn't rule them out entirely, especially if paired with ES.

ES is a viable option from a technical perspective; however, it is currently more costly than traditional DG solutions. As companies develop mobile ES solutions targeting the interim service need, business models will likely emerge to improve the economics. In addition, depending on rate tariffs and utility capacity, ES may also provide benefit for the permanent service solution beyond the interim need.

DER may also be coupled directly with chargers as a packaged interim solution. Products that package DCFC with generation, storage, and/or service equipment (transformer, switchgear) on a mobile/portable platform are becoming more common.

Other considerations when evaluating DER as an interim solution include:

- **Off-Grid vs. Grid Connected.** A recent off-grid depot installation in California demonstrates that DER solutions can be standalone systems that do not connect to grid infrastructure, even on a multi-MW scale. For these systems, utility infrastructure is not required (although utility communication is still important.) This may create benefits from ease of installation and operation; however, it may increase risk from a reliability standpoint. Grid-connected DER solutions may create additional interconnection requirements from the utility that could offset some of the expected timeline benefit.
- **Permanent vs. Temporary.** In the context of this document, the focus is on temporary installations for interim power needs. However, when considering DER it is prudent to consider if there is value in designing for long-term needs. This may increase costs excessively or may not be feasible for physical site reasons. In other situations, the interim service value may justify a permanent DER installation that would not be economical otherwise. In extreme situations, utility capacity limitations may be such that permanent DER will be required to meet load requirements.
- **Resiliency.** DER, especially distributed generation, is often deployed for resiliency needs regardless of interim service requirements. If existing DG is already on site, it may also support interim power needs. If existing DER is not on site, its deployment for interim power can become part of site resiliency plans.
- **Electricity Cost.** In areas with high electric rates, (including demand charges), DER may reduce utility costs through rate optimization. DER may enable customers to participate in time-of-use and/or load management programs. In some cases, electricity supplied by the DER may be at a lower cost than using a utility as the primary energy source.

- **Ownership Model.** If the DER is designed as an interim solution, the customer may not want to own the equipment unless it can also be used at other sites. Therefore, leasing models or 3rd party service offerings may be attractive.
- **Sustainability Objectives.** DER solutions can support sustainability objectives through enabling or optimizing the use of renewable energy. The "optics" of the type of DER used may also be a consideration, especially when fossil fueled DG is deployed. Even though emissions may be lower than supplied by the local grid, perception still must be managed.

There are many DER products designed to facilitate EV charging and more products are constantly coming to the market. The Appendix contains a list of many of these companies and products. It is not intended to be an exhaustive list as new products continue to be introduced.

Utility-Side Solutions

Construction (or Temporary) Service Delivery

It is a common practice for utilities to provide a construction service delivery to customers for a new building. This is true for everything from single-family homes to large industrial sites, and is based on the understanding that due to the duration of the construction project; power will be needed before the site is ready for permanent electric service. Since TE projects typically don't involve a building structure, the practice has been for customers to not ask for, nor the utility to offer a construction service. If timelines aligned, this practice would not come into question. However, for reasons noted earlier in this document, the TE customer is usually ready for power well before it can be provided by the utility.

When considering new building construction, the paradigm is that permanent electric service will be delivered in 1–2 years or more, depending on the building type. In addition, the expectation (from the utility and customer) is that a construction service will be provided asap to assist the project in moving forward. Applying this same paradigm to a large TE project creates the expectation (from the utility and customer) that the permanent service may take 1–2 years, and a construction service to provide initial site needs will be installed asap. Most utilities target installation of construction services in as short a timeframe as 1–3 months, although it can vary based on site factors and permitting. For commercial buildings, construction service at 480 volts is common, which is the same voltage typically needed by TE projects.

Customer costs for the provision of a construction service are subject to individual utility practices. Customer contribution-in-aid of construction (CIAC) processes will apply, which could range from zero to the full cost of installation and removal depending on project circumstances. Even with CIAC, the customer may find the value of a construction service worthwhile to provide interim power for charging. This option allows the customer to make the decision based on project needs.

RECOMMENDATION

- The provision of "construction service" should be the default assumption for larger TE projects or any TE project requiring long lead times. Customer engagement processes should communicate this option. The standard expectation should be for a 480V, 400A service. This recommendation is a "quick hit" that can be implemented immediately.
- Develop common templates for a 480V, 400A service connection that is compatible with most utility service provisions. Share and communicate this template with customers, engineering firms, permitting agencies, and other stakeholders. Developing these templates are in the scope of EPRI's GridFAST workstream within the EVs2Scale2030 initiative.

Adoption of this paradigm by utilities and TE customers could alleviate many of the issues being faced by OEMs and fleet customers in early deployments. Additionally, common designs for a 480V, 400A construction service for TE locations could improve this process as utilities and customers would know what to expect beforehand.

Distributed Energy Resources (DER)

The DER options discussed earlier for customer-side application also apply to the utility side of the meter. In addition to the application of the DER for the specific customer need, a potential benefit for utility side application is the sharing of the value across multiple customers. In addition to the types of DER mentioned earlier, utility side applications could include portable transformers and substations to provide short-term grid capacity.

Utility installed DER may be supplied as a value-added service to customers on a fee basis, or it can be used as a "non-wires" solution instead of more costly upgrades to feeders or substations.

Several utilities have existing services for onsite generation through regulated tariffs or unregulated products. Historically, these have been offered for backup power and resiliency purposes. However, these programs could be adapted for use to provide interim power.

Best Practices

- At least one west coast utility has a proposed program to supply ES on the utility side of the meter for temporary capacity constraints.
- Multiple utilities have regulated and/or unregulated programs to deploy DG for resiliency purposes. Typically, these are diesel or natural gas generators. While not originally designed for interim service, these programs have the opportunity to be utilized for this purpose.
- A G&T utility for cooperatives is assessing the provision of mobile substations and DER equipment that can be shared across the cooperative customers it serves. The program is still in development; however, this principle is applicable to other utilities.

PLANNING AND SERVICE CONNECTION PROCESSES

For the purposes of this document, "planning" refers to utility processes related to evaluating and addressing capacity needs on the distribution and transmission system. This includes determining available load capacity on circuits and equipment, forecasting when upgrades are needed to increase capacity, and creating plans for those upgrades.

Service connection processes refer to all engagements with the customer, including receiving a connection request, evaluating service requirements, customer contract provisions, service delivery engineering design, construction, and energization.

Planning processes are informed by knowledge of customer activity but are focused on utility operations and resource needs. Service connection processes require close coordination with the customer and are dependent on both utility and customer input. The interaction between utility and customer planning can create opportunities for innovation to reduce timelines, or it can have a compounding affect that complicates service planning and increases timelines. Figure 1 visualizes this interaction.

The potential for a timely service connection is represented by the red/green spectrum; red indicating a worse situation, and green something better. At a fundamental level, the timeline to provide electric service is a factor of how much load (kW) the customer requests, and how much capacity (kW) is available from the utility. The higher the load request from the customer, the more it tends to push the timeline to the "red" end of the spectrum. A lower load request tends to move the timeline toward the "green". From the utility perspective, the lower the available capacity, the more likely the timeline is to be in the "red". If there is a lot of capacity, the timeline has a better likelihood of being in the "green". If timelines are to be improved, this dynamic emphasizes the need for customer and utility collaboration to optimize a solution. However, current procedures in the industry (customer and utility) create the situation where projects are often "in the red".

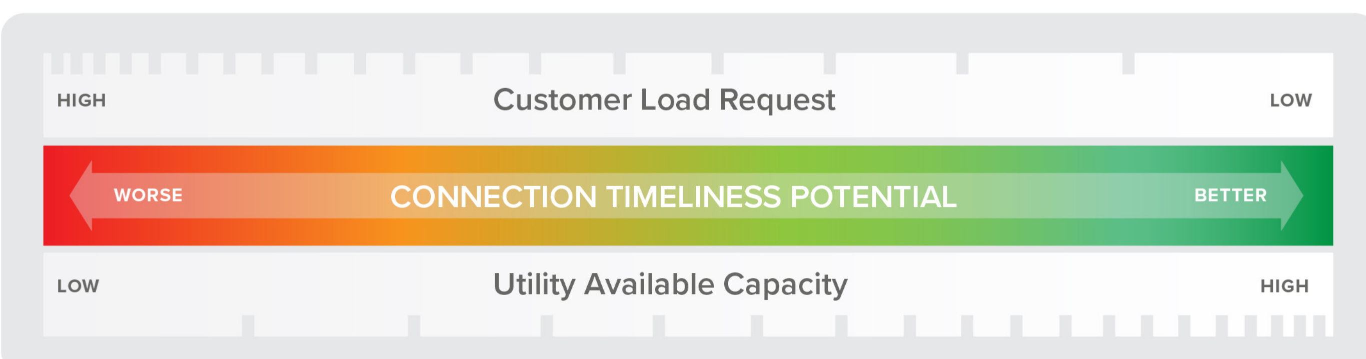

Figure 1.

How does this look in practice? As noted earlier in this document, there is limited experience in determining the load requirements for large EV deployments. As a result, fleet operators, electricians, engineers, and other customer personnel often overestimate the load requirements. Estimates may be based on the charging power of the EVSE or the charging power capability of the vehicle, with the assumption that all vehicles are charging at the same time. This may be based on applications of code requirements or desiring to be ready for "worst case" scenarios.

Given the early stage of the TE industry, many fleet customers are not accustomed to working with utilities and are unfamiliar with principles such as load diversity and charging curves for EVs. In addition, there may be an awareness of charge management in principle, however the impact of charge management on load requirements is not well understood in practice. Ideally, charge management implementation should reduce customer load levels and provide flexibility to optimize charging to available utility capacity, which can improve connection timelines. Examples of different methods of customer load request calculations and the potential impact on project planning are shown on the connection timeline spectrum (Figure 2).

Often, the starting point for a customer load request is the far-left end of the spectrum. Movement toward the green side of the spectrum is dependent on education, experience, and service offerings/programs.

In a similar manner, different approaches for determining available capacity have significant impact on the utility side of the spectrum. The same uncertainty in load characteristics present on the customer side can also influence utility personnel to assume worst case in load planning. It is not uncommon for utility personnel to do their own load calculations regardless of the estimate provided by the customer. In many cases, this reduces the load requirement as utilities understand concepts such as load diversity better than most customers. However, in some cases utilities take a more conservative approach and assume a worst-case scenario that is higher than customer estimates. Once a customer load estimate is determined, the utility must then evaluate the available capacity rating for the site. As with load estimation, there are different approaches to determining available capacity. Most utilities apply very conservative practices to this calculation. The most common practice is to base available capacity on the single highest annual load interval on the circuit/substation regardless of the time of the day or season that it occurs. To better understand this concept, let's assume a scenario:

- A fleet customer is deploying EV trucks that will operate during the day and charge overnight. Maximum power needed will be 2000 kW between the hours of 9:00 p.m. and 6:00 a.m. During other hours the customer will have a load of 200 kW.
- The distribution circuit serving this customer has a total rated capacity of 10 MW. The peak load on the circuit is currently 9 MW and occurs at 4:00 p.m. in the Summer. The maximum overnight load on the circuit between 9:00 p.m. and 6:00 a.m. is 6 MW.

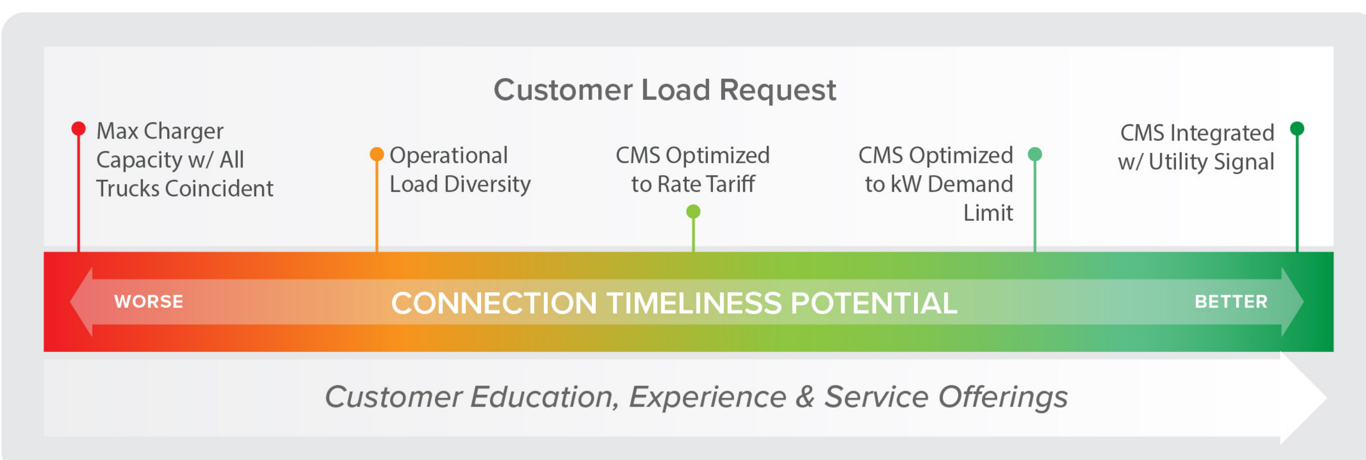

Figure 2.

In this example, the utility compares the maximum customer load (2 MW) to the minimum available capacity (1 MW) and determines that there is insufficient capacity on the circuit and an upgrade is required. However, if actual customer and circuit load profiles were utilized in the evaluation, it would indicate that sufficient capacity is available. At the time of circuit peak there is 1 MW available and customer load is 200 kW. At the time of customer maximum load of 2 MW, there is 4 MW of capacity available. This “worst case” scenario of assuming maximum customer load is coincident with circuit/substation peak is a common practice for utilities. Some utilities are beginning to use seasonal and time-of-day available capacity, however it is not yet common.

In addition to the load profile issue described in the previous example, there are also myriad ways of determining total capacity of a circuit/substation. Some utilities limit capacity ratings to a percentage of nameplate (e.g., 80%) as part of contingency planning. Utilities may have different winter/summer ratings based on the impact of outside temperature on equipment cooling. All these planning and engineering practices can impact project timelines based on their influence on available capacity calculations. Utility planning practices are understandably conservative in nature. The potential negative consequences of overloading grid infrastructure usually outweigh the incremental costs to increase system capacity. In addition, performance metrics related to reliability are used to measure success of individuals, departments, and utilities. Poor performance in reliability is also a major factor in customer satisfaction, which impacts utilities on multiple fronts. It has been said that engineers are conservative people, utility engineers are conservative engineers, and utility planning engineers are conservative utility engineers. These practices have served the utility industry well, however the nature of large TE projects will be a challenge to these practices. Some utilities are beginning to be more granular in their capacity planning, considering the season, month, or time-of-day of circuit peak. A few utilities are now capturing annual 8760 hourly load data as part of their planning process.

Furthermore, often there is a reluctance by utilities to recognize or “trust” the ability of a customer to limit load via a CMS, even when doing so would improve available capacity. As these practices are applied to the connection timeline spectrum, the impact on shifting projects in the direction of red or green can be seen in Figure 3. Today, most utilities operate on the red end of the spectrum. Therefore, moving in the green direction will require changes in planning and engineering practices. The willingness for utilities to move in this direction is currently dictated by the scale of fleet EV deployments occurring in their territory. For those with little activity, there is not a sense of urgency to adjust. However, for those utilities with a lot of activity (e.g., California, New York), there is recognition that meeting customer TE objectives through “business as usual” is not feasible. In other words, meeting customer needs with historical processes is not possible. The impact on timelines and service costs are too great.

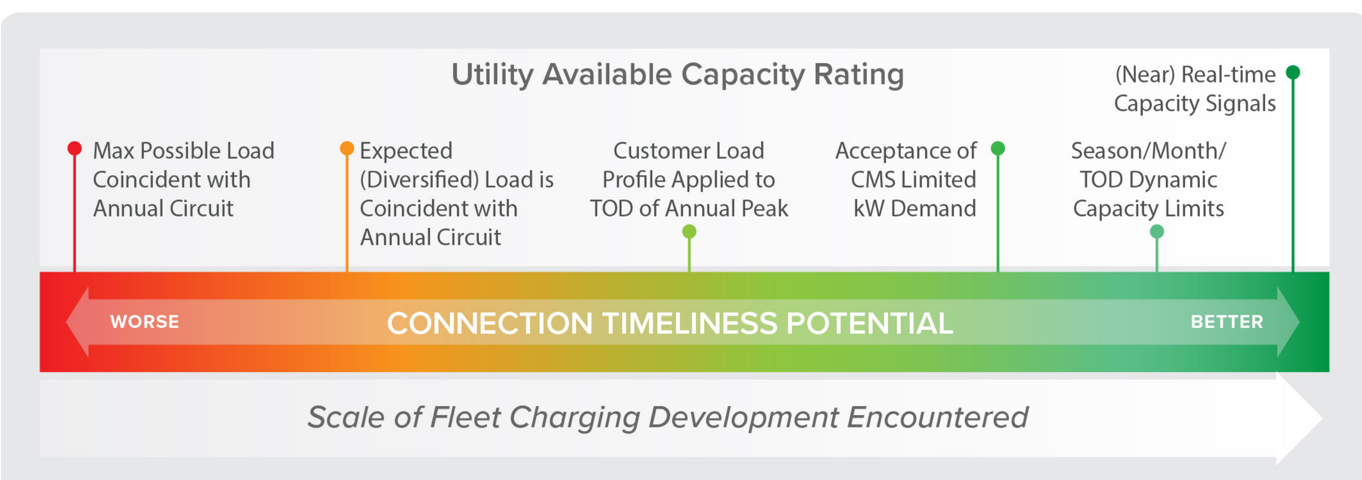

Figure 3.

While California utilities, such as PG&E and SCE, are now innovation leaders in the planning space, it required a lot of catching up as the scale (number and size) of projects moved quickly. For utilities not yet seeing this scale, there is the opportunity to prepare in advance for changes that may be needed in planning and service processes. However, without the direct push from actual customer projects, a sense of urgency is lacking within most utilities.

The symbiotic relationship between customer load requests and capacity planning emphasizes the importance of customer engagement processes for utilities. The nature of large TE projects requires evaluation of customer load requirements, load thresholds that lead to upgrades on both sides of the meter, charge management strategies, and interim solution options.

Best Practices (Utility)

- PG&E has launched a new pilot program called Flexible Service Connection which allows customers with controllable loads to connect to the grid without waiting for a service upgrade. This bridge solution sends day ahead hourly capacity signals to a fleet customer's charge management system (CMS). The CMS then automatically limits load levels to the capacity thresholds communicated by the utility. Since most capacity constraints on the distribution system are due to relatively few hours/days during the year, this program enables customers to move forward with projects sooner than would otherwise be possible under the condition they can limit load during the few hours of the year when capacity is constrained.
- Southern California Edison's Load Control Management Systems (LCMS) program allows customer side software to be used to limit load based on capacity information from the utility. This enables customers to move forward with projects that otherwise would have been delayed. The load may be limited during certain seasons and hours; however, it can provide the customer flexibility to use full capacity at other times.
- **Transformer availability and lead time issues**
  - Several utilities are seeking to secure manufacturing capacity through direct engagement with manufacturers and/or reserving capacity in advance of need.
  - One Southern municipal utility will install an available transformer of a smaller size as an interim measure. This allows the customer to energize and begin using power for initial EV charging until the appropriate transformer can be installed that provides full power capabilities.
  - Customer supplied transformers ("bring your own transformer") can improve timelines in some situations. This is most commonly accomplished through a primary voltage delivery, however some customers have a willingness to reserve manufacturing capacity.

Best Practices (Customer)

- One global last mile delivery company employs a tiered strategy to optimize existing electrical capacity when prioritizing deployment locations.
  - First, locations with spare transformer capacity are identified and deployment begins at a level that will not exceed this capacity.
  - Next, sites that have available line/circuit capacity from the utility are identified, and vehicle deployments are planned that do not exceed the available capacity.
  - Finally, projects that will exceed available utility capacity are identified, and generally prioritized last. If business needs dictate a higher priority, then distributed resources and active energy management may be deployed to address the capacity shortfall.
  - Across all these categories, communication is initiated with the utility to address long-term capacity requirements.

RECOMMENDATIONS

- Utility adoption of available capacity ratings that incorporate customer load profiles with seasonal and/or time-of-day ratings. This requires circuit/substation metering to provide this data. Utilities that do not currently have this metering capability should create programs to do so.
- Customer engagement processes for TE projects should communicate available utility capacity thresholds (transformer, circuit, substation) and timelines required for construction if these thresholds are exceeded. While some utilities do this, it is not standard practice across the industry.
- Customer engagement processes should be relationship-based, not transactional. Engagement for TE projects requires discussion of things such as customer load estimation, energy management, deployment schedules, MVP, and interim power needs, that are difficult to accomplish without utility representatives that are well versed in fleet electrification projects.
- Utility Load Request templates should be updated to include additional information for TE projects, or a separate TE load sheet created. Existing load sheets used by utilities, with few exceptions, are not sufficient to capture TE load parameters. EPRI's GridFAST project will facilitate these updates.

OTHER OBSERVATIONS

Throughout the research on interim power solutions, topics were encountered, or observations made that were not directly related to interim power solutions, but that do relate to the broader topic of improved utility/customer engagement on TE projects.

Customer Knowledge/Experience Level. The differences between traditional building related service requests and TE projects have been noted earlier. One area that wasn't discussed is the knowledge level and/or resources available to the customer. Companies implementing new building construction typically have a construction manager, project managers, and personnel with experience in engaging with utilities. However, many TE projects are being implemented by fleet managers or operations personnel with minimal experience in facility management and no previous need for electric utility engagement. In addition, since existing facility load may be minimal, many fleet companies do not have internal staff available that understand utilities and electric service parameters such as power and energy.

These factors reinforce the importance of pilots and early customer deployments. Pilots help customers (and utilities) identify gaps in their current knowledge and operational processes that must be addressed to enable successful scaled deployments.

Utility Program Design. Many utilities have, or are developing, TE programs which can include "make ready" funding, fleet advisory services, or other components designed for customer electrification. While these can provide many benefits, they can also have unintended consequences that can complicate efforts to provide timely service.

- Make Ready programs typically provide funding for a specific scope of work tied to near-term vehicle deployment. As noted earlier, TE projects often are deployed in phases. Efficient project planning often takes into consideration the long-term site plans so "pre-work" can be done for future phases. For example, laying additional conduit in the ground so digging is not required again during the next phase. However, make ready programs often limit the ability to do this type of work. The program only covers the scope needed for immediate load needs, so plans may not be approved which include site readiness for future phases. As utilities recognize the value in optimizing total project cost on the utility side, programs should recognize the same benefits on the customer side.
- Utility service request processes can be designed with the assumption that TE projects will be participating in utility programs. However, for various reasons a customer may decide to implement a project without participating in the available utility programs. If processes are designed based on program participation and a customer does not participate, it can leave the customer in limbo. One engineering firm commented that they felt "orphaned" when they attempted to implement a project without the utility program. The project didn't "fit" within processes, causing a multi-month delay in utility response.

Customer Communication Processes. The unique nature of large TE projects discussed throughout this document highlights the need for targeted and clear customer engagement between utility representatives and the customer. Opportunities and risk areas in this regard include:

- **Assigned and Unassigned Customers (those with Key Account Managers).** Due to their limited electrical load, very few fleets are considered key accounts today. The exceptions are the largest fleets which also have facilities that are large loads in their own right (e.g., Pepsico, Walmart, FedEx, etc.) However, as these customers deploy electric MHD vehicles, they will rise to an electric load level that would typically have an assigned Key Account Manager. As a result, customers adding large TE loads are often navigating utility processes without an Account Manager, which would enable better communication and negotiation of project parameters. Therefore, these projects don't get the "head start" that most larger customers have and must navigate "mass market" processes not designed for their needs.
- **Knowledgeable Single-Point-of-Contact (SPOC).** Closely related to the previous bullet is the feedback received from customers regarding projects that have gone well. A consistent comment being that the customer had a SPOC who was knowledgeable in engineering aspects of electric service, while also understanding rate tariffs and contracting processes. All utilities may not have the ability to provide a SPOC with this experience, but it should be considered where possible. The importance of this person is highlighted by the fact in many situations the utility SPOC will know much more about EV's and customer side requirements, than the customer contact will know about utility processes and requirements. Therefore, the utility representative can have the single biggest impact on overall project planning.
- **Communication and Transparency.** While most companies believe they communicate well and are transparent, feedback from customers with early TE projects is often the opposite. The needs of TE projects, especially regarding timelines, increases the impact for customers if communication channels are not open and transparent.
- **Utility Processes are Typically Triggered by a Formal Service Request.** Informal and exploratory conversations are not always encouraged. While the slogan "call early and often" is frequently cited, the message from some utilities is, "until you submit a service request, we won't do anything." This can be influenced by of the amount of activity being seen by a utility. Those utilities with very few projects are generally more receptive and desirous for customers to call early (they are still operating in "person" mode), while utilities with a lot of activity may not have the resources to manage the exploratory conversations, (they are operating in "process" mode.)
- **Load Information Desired from Customer.** Another inconsistency among utilities is the amount of information desired regarding customer plans. Some customers are told, "I only want to know what you need now", while other utilities want to know long-term plans. Hopefully, a discussion of full deployment plans is becoming the norm, but not all customers are hearing this.
- **Utility Contracting Practices.** As a rule, customers are expected to adjust to utility contracting practices instead of the utility adapting to customer practices. While there may be valid reasons for this historically, the nature of TE and the pace of adoption by customers served by multiple utilities around the country are bringing these practices to the forefront. Most large fleets with multiple facilities are accustomed to working with providers under a Master Services Agreement (MSA), which covers the general terms and conditions of the service relationship, and Statements of Work (SOW) which are amended to the MSA based on the requirements for a specific project. This framework can assist in getting a project started in a timely manner since many of the legal and risk aspects only have to be negotiated once. This framework is the norm for all of their suppliers except the utility.

Authorities Having Jurisdiction (AHJs). Addressing issues with AHJs is not within the scope of this document, however it would be remiss not to mention them briefly. For some (many?) projects the limiting factors in the timeline are things that are the responsibility of AHJs. This includes construction permits, electrical permits, rights-of-way, and other requirements as needed from governmental agencies. As all industry stakeholders seek to improve planning and timelines for TE projects, it will be crucial to seek ways to improve processes involving AHJs.

Policy-Regulatory Issues. This whitepaper does not address policy or regulatory strategies. However, it is recognized that the ability to provide timely service, including interim power, can be impacted by policy and regulations. The role of PUCs and Commissions in supporting the development of innovative utility planning and load forecasting strategies is crucial to enable utilities to better prepare for the scale of grid upgrades necessary to support transportation electrification.

APPENDIX A: DER COMPANIES AND PRODUCTS

Note: This list is not intended to be comprehensive and is not an "approved" or "vetted" product list. It is included to provide a sampling of the companies and products in the market to help the reader understand the breadth of products that may support interim power solutions.

Energy Storage

COMPANY	PRODUCT(S) [ENERGY/POWER/SIZE]	TECHNOLOGY TYPE (INSTALL LOCATION)
BP Pulse	Inrush (Mobile, Containerized, and Surface Mount Charging Solutions)	Battery Energy Storage (BTM)
Caterpillar	Various Generation and Energy Storage products	Battery Energy Storage (Utility, BTM, off-grid)
Designwerk	Mega Charger Integrated energy storage and EVSE [2,100 kW/1,800 kWh]	Battery Energy Storage (BTM)
Eaton	Various Energy Storage products	Battery Energy Storage (BTM)
ElectricFish	350 Squared Integrated storage and EVSE [400 kWh storage, 350 kW charging]	Battery Energy Storage (BTM, Utility)
EV Edison	Mobile Charging Hubs Integrated energy storage and EVSE	Battery Energy Storage (BTM, off-grid)
EVESCO	Containerized Battery Energy Storage Systems (BESS)	Battery Energy Storage (off-grid)
Generac	Various generation, solar, and battery storage products	Battery Energy Storage (BTM)
Hitachi Energy	eMobility Solutions (e-mesh™ PowerStore™) [30 kW-multi MW]	Battery Energy Storage (BTM, Utility)
Innoversa	PROMIS mobile energy storage Mobile Platforms	Battery Energy Storage (BTM, off-grid)
Joule	Zeus Power Cabinet, Atlas Energy Storage [170 kWh-5 MWh +]	Battery Energy Storage (BTM)
Lightning eMotors	Lightning Mobile Integrated storage and EVSE [19.2 kW AC, 80 kW DCFC/210-420 kWh (storage)]	Battery Energy Storage (off-grid)
Moxion Power	MP-75 [24-40 kW continuous, 24-75 kW max)/530 kWh usable energy]	Battery Energy Storage (off-grid)
Nomad Power	Traveler [2.0 MWh; 1,000 kW AC/1,993 kWh DC] Voyager [1.3 MWh; 500 kW AC/1,328 kWh DC] Rover [660 kWh; 250 kW AC/664 kWh DC] Pathfinder [220 kWh; 200 kW AC/220 kWh DC]	Battery Energy Storage (off-grid)
Northvolt	Voltpack Mobile [281 kWh installed capacity] Volthub Grid [275 kW max load power (peak shave)] Voltrack [170 kW peak power output, 140 kW continuous/175 kWh usable energy capacity]	Battery Energy Storage (BTM, Utility)
Paired Power	PairTree Solar Canopy and storage [4.6 kW solar/42.4 kWh battery]	Solar and Battery Energy Storage (off-grid)
Portable Electric	Voltstack® Mobile EV Charger Integrated energy storage and EVSE [27 kW continuous, 34 kW peak/80 kWh]	Battery Energy Storage (Off-grid)
Power Edison	TerraCharge™ Battery storage trailer [2-5 MWh] Power Conversion trailer [1 MW+]	Battery Energy Storage (Utility, Off-grid)

Energy Storage (continued)

COMPANY	PRODUCT(S) [ENERGY/POWER/SIZE]	TECHNOLOGY TYPE (INSTALL LOCATION)
Sunbelt Rentals	Various generation, storage, and portable EVSE products	Battery Energy Storage (Off-grid)
Tesla	Megapack [3.9 MWh per unit] Powerwall 3 [11.5 kW on-grid; 11.5 kW backup/ 13.5 kWh]	Battery Energy Storage (BTM)
Veloce	VPort™ [40 kW, 80 kW, 120 kW/78 kWh up to 468 kWh]	Battery Energy Storage (BTM)
Xos	Xos Hub, Mobile Charging Solution Battery integrated with EVSE [280 kWh]	Battery Energy Storage (BTM, off-grid)
ZincFive	Nickel-Zinc (NiZn) Batteries BC Series UPS Battery Cabinets [38-46 kWh storage] UPStealth® 2 [0.5-3.6 kW] Monobloc Batteries [8-12 kW]	Battery Energy Storage (BTM)
ZOOZ Power	ZOOZTER™-100	Flywheel Energy Storage (BTM)

Solar

COMPANY	PRODUCT(S) [ENERGY/POWER/SIZE]	TECHNOLOGY TYPE (INSTALL LOCATION)
Beam	EV ARC™ 2020 [5.76 kW, 4.4 kW solar/20, 30, 40 kWh]	Solar Canopy, Storage, EV (off-grid)
Blue Arc EV	Power Cube™ [19.2 kWh Level 2, 25-150 kWh DCFC; 5-10 kWh solar]	Solar, Storage, EV (BTM, off-grid)
BoxPower	Solar Powered EV Charging Stations (Off) [3.5 kW solar/7.6-30.4 kWh battery]	Solar, Storage, EV (off-grid)
Yotta Energy	REV Integrated solar, storage, and EVSE [50-300 kWh]	Solar-Powered EV Charging (off-grid)

Generation

COMPANY	PRODUCT(S) [ENERGY/POWER/SIZE]	TECHNOLOGY TYPE (INSTALL LOCATION)
Caterpillar	Various Generation and Energy Storage products	Generation (Utility, BTM, off-grid)
Cummins	Various Generation products	Generation (Utility, BTM, off-grid)
Generac	Various Generation and Energy Storage products	Generation (BTM, off-grid)
Larson Electronics	Temporary EV Charging Station [30-350 kW] Integrated Diesel/NG gensets with EVSE	Generator with EV Charging (BTM)
L Charge USA	Fixed and Mobile systems Integrated generation w/ EVSE	Generation w/ EV Charging (BTM, off-grid)
Mainspring Energy	Linear Generator [230 kW (AC inverters)-25 MW/acre]	Generation(Utility, BTM, off-grid)
Momentum Groups	Commercial Mobile EV Charging Stations Integrated generation with EVSE, green/renewable propane	Generator with EV Charging (off-grid)
Mullen	Power Up – Mobile EV Charging Truck On-board propane/ NG generator [120 kW]	Mobile generation (off-grid)
Pioneer eMobility	e-Boost Mobile propane fuel [30-300 kW]	Generation w/ EV Charging (off-grid)
Renewable Innovations	MPG – Hydrogen Mobile Power Generator Integrated generation and EVSE [80 kW Fuel cell, 180 kWh ES, 180 kW EVSE]	Generation w/ EV Charging-Fuel Cell (off-grid)
Sunbelt Rentals	Various generation, storage, and portable EVSE products	Generation(off-grid)
US Energy	Volt Vault Containerized Natural Gas generator and EV Charging	Generation w/ EV Charging (off-grid)

About EPRI

Founded in 1972, EPRI is the world's preeminent independent, non-profit energy research and development organization, with offices around the world. EPRI's trusted experts collaborate with more than 450 companies in 45 countries, driving innovation to ensure the public has clean, safe, reliable, affordable, and equitable access to electricity across the globe. Together, we are shaping the future of energy.

EPRI PREPARED THIS REPORT.

EPRI CONTACT

LIZ HUNT, *Principal Team Lead, Transportation*
650.855.2130, lhunt@epri.com

For more information, contact:

EPRI Customer Assistance Center
800.313.3774 • askepri@epri.com

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EPRI

3420 Hillview Avenue, Palo Alto, California 94304-1338 USA • 650.855.2121 • www.epri.com