

Transportation decarbonization

Bridging the disconnect: aligning utility planning with fleet electrification deployment in North America



Jacobs

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Executive summary

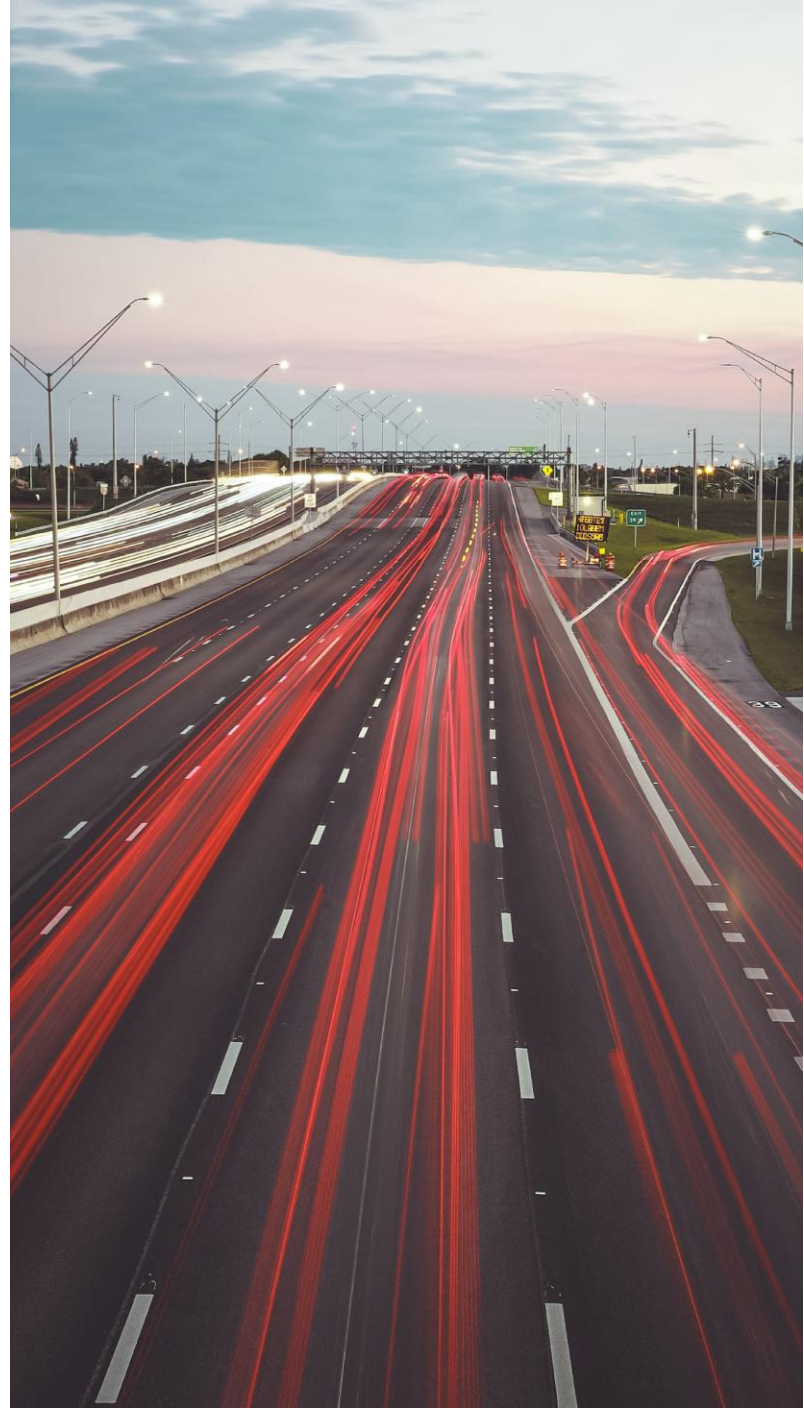
Fleet electrification is accelerating across transit agencies, school districts, ports and commercial operators, driven by sustainability commitments, regulatory mandates and increasingly favorable economics. Yet the success of this transition depends on a critical partner: utilities, which provide the power supply and grid capacity alongside infrastructure upgrades to energize high-power charging systems.

Utilities and fleets, however, operate on fundamentally different planning horizons. While utilities plan and invest in multi-year to multi-decade cycles, fleet operators often work within compressed timelines shaped by funding cycles, procurement schedules and operational needs. This mismatch creates persistent gaps between when fleets are ready to deploy electric vehicles and when utilities can deliver necessary infrastructure.

While the examples in this article are drawn primarily from North America, aligning utility planning with transportation electrification is an increasingly relevant challenge for transportation agencies, ports and fleet operators globally.

Compounding this challenge is a surge in grid demand from digital infrastructure such as data centers, which further tightens planning margins and heightens the importance of early, structured engagement. Without systematic coordination, electrification projects risk delays, added costs, stranded assets and missed opportunities for grid-optimized solutions.

This paper examines sector-specific electrification demands, highlights the systemic disconnect between fleet and utility planning processes



and proposes actionable strategies including joint planning models, shared forecasting tools, standardized engagement pathways and targeted policy reforms to harmonize infrastructure readiness with fleet deployment timelines and support scalable, efficient transportation decarbonization.

The good news is many of these challenges can be addressed through proactive planning, stronger utility collaboration, data sharing and integrated infrastructure strategies. Understanding where disconnect occurs is the first step toward closing it.

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Introduction

CONSERVATIVE SITE ENERGY DEMAND ESTIMATION BY SITE TYPE

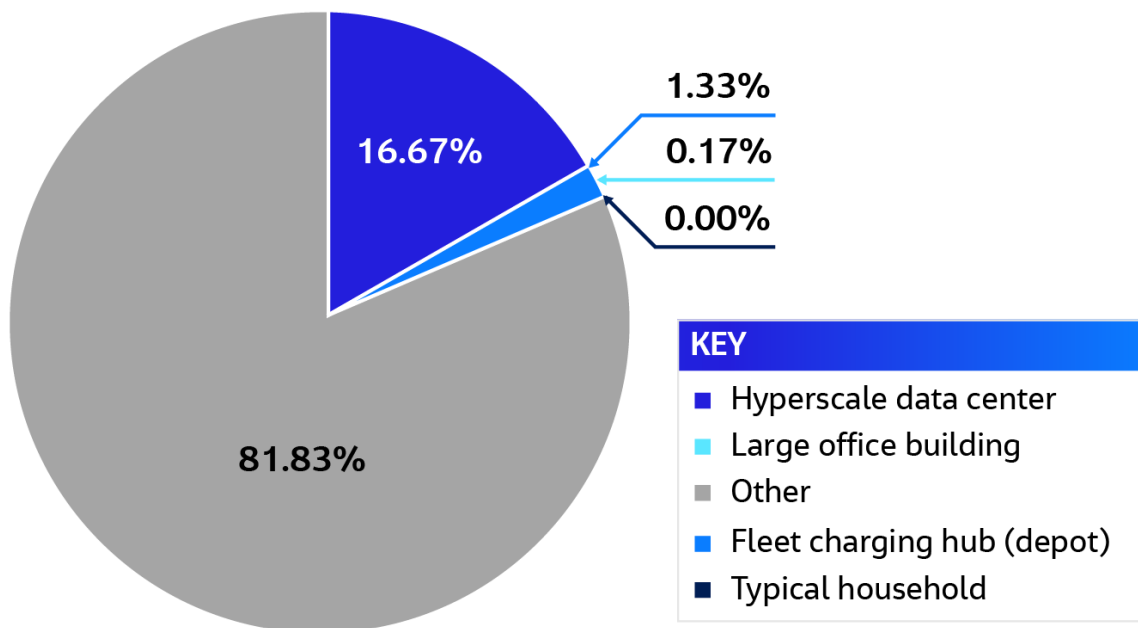


Figure 1: Typical Electrical Demand for a single site as a percentage of a typical city's electrical demand (Conservative Site Demand Estimation)¹

The transportation sector is undergoing a profound transformation as electrification accelerates across transit agencies, school bus fleets, ports and commercial operators. These efforts are driven by a combination of environmental imperatives, regulatory mandates and increasingly compelling business cases for electric propulsion. Lower total cost of ownership and improved operational efficiency as well as alignment with corporate sustainability goals are making electrification a strategic priority across industries.

At the same time, a new wave of demand is reshaping grid planning, driven by the rapid growth of data centers. As illustrated in Figure 1, a single hyperscale data center can account for a significant share of a typical city's electrical demand. While not all data centers operate at this scale, data centers of all sizes contribute to growing electricity demand and place additional requirements on grid capacity. When combined with other emerging loads, such as dedicated electric vehicle (EV) fleet charging hubs, these demands can place additional pressure

¹ Percentages represent the share of average daily electricity demand in a mid-sized U.S. metropolitan area (~14,000–20,000 Megawatt hours (MWh) per day). Site level demand values are expressed in MW and converted to daily energy (MWh/day) using typical operating assumptions. Sources include EIA, DOE/LBNL, NREL, PNNL, CALSTART and industry engineering studies.

on grid planning and infrastructure readiness. As more high-demand customers connect to the grid, coordination and long-term planning become increasingly important to maintain reliable service.

This growing demand highlights the need for closer alignment between transportation electrification efforts and utility planning.

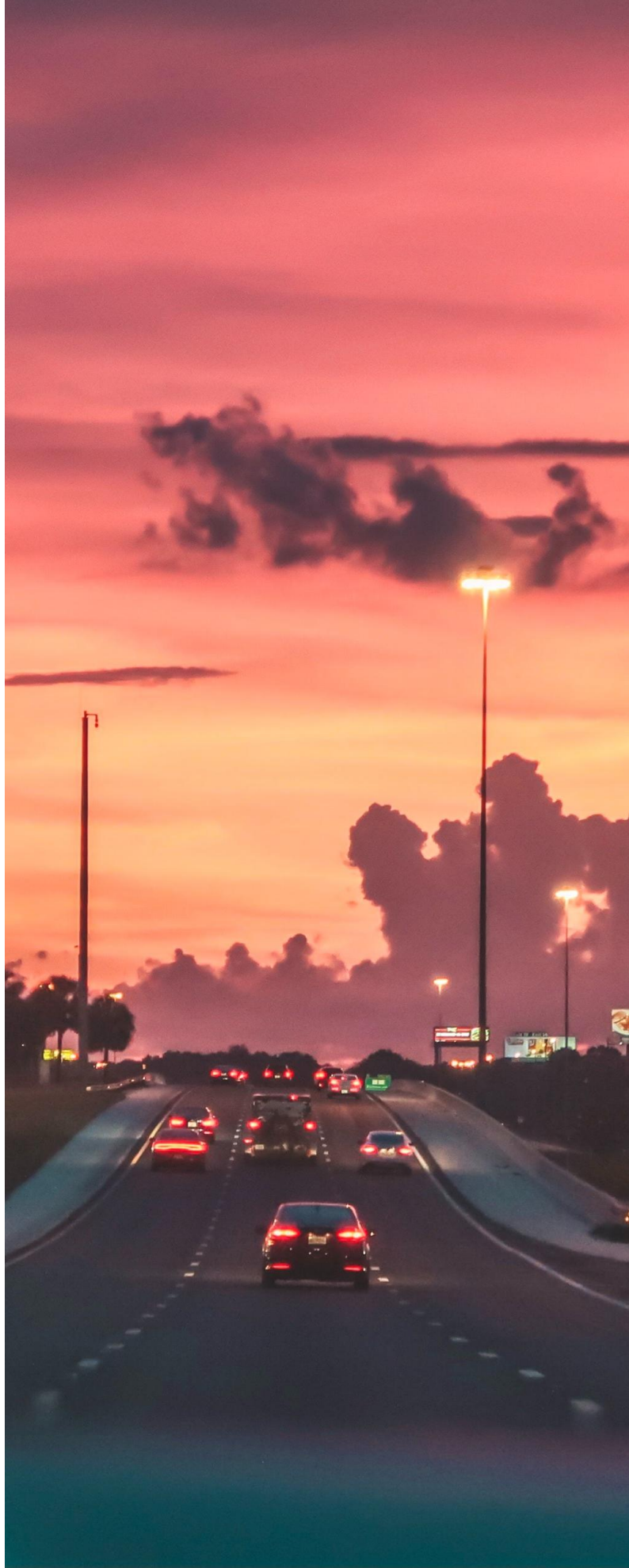
This transition exposes a critical structural challenge: utilities and fleets operate on fundamentally different planning horizons, priorities and data frameworks.

Utilities are responsible for grid reliability and long-term resource adequacy. As such, their planning cycles, regulatory processes and capital programs ultimately determine when and how new system loads can be served. New or unanticipated loads may require substantial infrastructure upgrades, including new substations, transformer replacements and integration of microgrids to meet the demand while maintaining grid resiliency and reliability.

Utilities must plan decades ahead, while fleets often work within compressed timelines of months or years dictated by funding cycles or operational needs. This misalignment creates a persistent gap between the pace of fleet deployment and the readiness of utility infrastructure to support new loads.

The consequences of this disconnect are significant and can include delayed projects, stranded assets and/or missed opportunities for optimization. Bridging this gap requires more than ad hoc coordination. It demands systemic alignment through shared planning tools, standardized engagement models and policy frameworks that incentivize collaboration.

This paper examines where utility and fleet planning cycles diverge, why those gaps create delays and additional costs and the practical strategies organizations can use to better align infrastructure readiness with fleet deployment timelines.



Sector-specific electrification demands

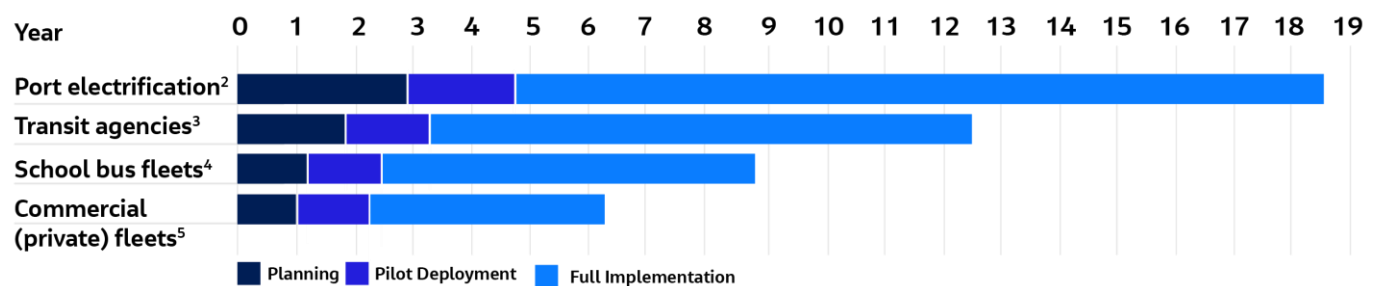


Figure 2: Comparable, general estimated timelines for fleet electrification between sectors (in years).

Electrification across transportation sectors presents diverse infrastructure challenges and energy demands. While fleets are moving toward zero-emission technologies, each sector follows a markedly different deployment trajectory driven by operational patterns, duty cycles, funding mechanisms and site constraints. These varying timelines (summarized in Figure 2, which compares typical electrification durations across transit, school bus, port and commercial fleets) underscore why utilities struggle to anticipate future load growth without early engagement. Understanding these distinct sector profiles is essential for aligning fleet deployment schedules with long-term utility planning processes. This section outlines the unique electrification characteristics of four key

sectors: **transit agencies, school bus operators, port authorities and commercial fleets.**

Transit agencies

Typical transit agency energy demand overwhelmingly occurs during early morning, late evening and overnight hours, as vehicles are in revenue service throughout the day. While service schedules vary by agency, most operate routes from approximately 6 a.m. to 10 p.m. (plus or minus a few hours on each end), with only limited downtime for maintenance or operator availability. This operational pattern results in concentrated charging demand during off-peak utility hours (typically using 50 kilowatt (kW) – 150kW direct

² Journal of Port Management, "Electrification of Marine Terminals: Timelines and Practices" (2023); May 2024 Port Electrification Handbook from Pacific Northwest National Lab

³ Planning & pilot: National Renewable Energy Laboratory (NREL), "Zero Emission Transit Bus Rollout: Feasibility to Deployment" (2023); Scale-up: APTA, "Best Practices for Transit Bus Fleet Decarbonization" (2024)

⁴ California Air Resources Board (CARB) and CALSTART timeline: "Electric School Bus Roll-Out Guide" (2022)

⁵ CALSTART, "Commercial Fleet Electrification: Deployment Guidebook" (2023)

current (DC) fast chargers in the depot), which can be beneficial from a grid management perspective.

However, a fully electrified transit fleet introduces a substantial and often vastly different load profile compared to traditional demand in surrounding areas. Additionally, if certain routes are overly taxing on the vehicle, the agency may need to supplement overnight charging with on-route opportunity charging (typically consisting of a 300kW – 600kW charging system). Without access to detailed grid capacity maps or load forecasts, fleet operators may struggle to plan charging infrastructure that aligns with local grid capabilities, increasing the risk of costly delays or underutilized assets.

Transit agencies also face financial constraints that limit their flexibility in infrastructure planning. With service revenue typically allocated to operating costs, major capital investments are often contingent on securing federal or local grant funding. Programs like the Federal Transit Administration (FTA) Low and No Emission Vehicle Program have catalyzed modernization efforts, enabling agencies to pursue electrification and alternative fuel technologies. However, these funding opportunities frequently require coordination with utilities during the application phase, even though utilities may lack access to critical fleet data such as deployment timelines, route details and charging schedules. This asymmetry in information sharing hinders proactive infrastructure planning and load management, making it difficult for utilities to allocate resources effectively or anticipate future demand. Bridging this gap will require the development of secure, standardized data-sharing frameworks that support mutual visibility and long-term planning, in addition to policy reform.

School bus fleets

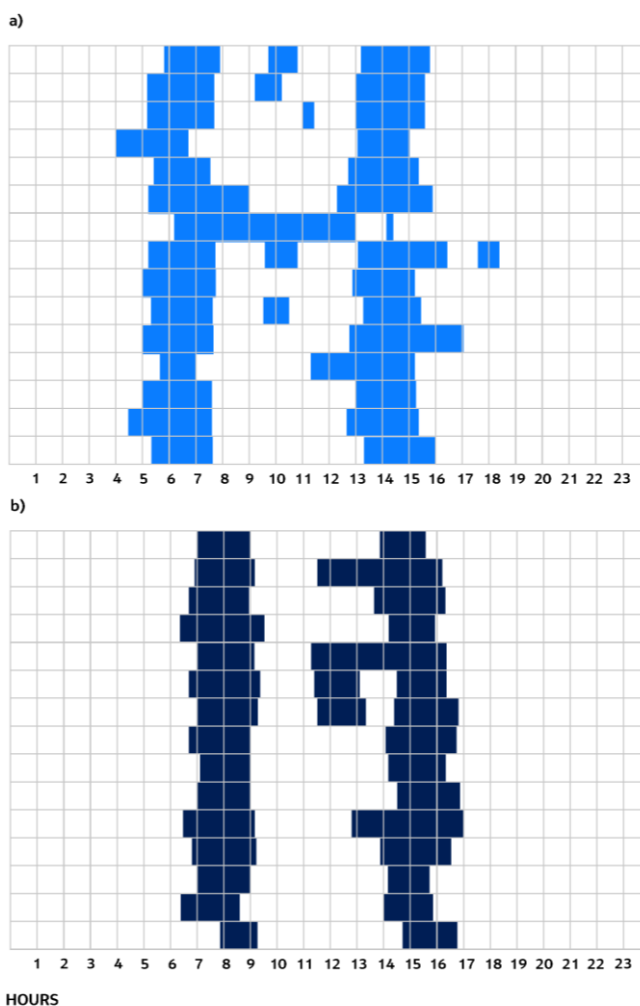


Figure 3: Samples of typical daily operating windows for two different school bus fleets. These fleets consistently run morning and afternoon shifts and are parked during midday and overnight⁶.

⁶ National Renewable Energy Laboratory (NREL). Electrifying Education: Insights into Charging Electric School Buses in the United States. NREL/PO-5400-87322, 2024. Available at: <https://www.nrel.gov/publications>

School bus fleet operations differ significantly from transit agencies, defined by predictable, low-duty cycles and pronounced seasonal variability. Most buses operate fixed morning and afternoon routes during the academic year, creating consistent midday and overnight charging windows and extended downtime during school breaks. This predictable profile offers strong flexibility for grid integration, including opportunities to align charging with off-peak hours and explore vehicle-to-grid (V2G) applications. Short route lengths and multiple daily charging windows also allow for lower-power infrastructure (typically 30–60 kW) and scalable depot-based installations. However, route changes between school years and the use of buses for field trips or extracurricular activities introduce uncertainty that can complicate long-term infrastructure planning.

Despite these operational advantages, many school districts and private contractors lack the technical expertise and internal capacity needed to plan and manage electrification projects. Engagement with utilities often begins late in the process, creating avoidable delays in interconnection studies and infrastructure upgrades. Many fleets engage with third-party consultants to provide specialized technical support and accelerate early planning; to ensure lasting benefits, districts may also need strategies to capture and internalize this knowledge over time.

School bus electrification is also shaped by unique capital and scheduling constraints. Infrastructure investments are frequently tied to grant funding, such as the Environmental Protection Agency (EPA) Clean School Bus Program, because operating budgets rarely support major capital projects. Construction and installation often must align with school breaks, further tightening deployment windows. Districts that allow drivers to take buses home at night face additional challenges in coordinating distributed charging, which may require multiple utility service areas or new metering strategies.

Ports

Port electrification is one of the most demanding transportation use cases because operations run continuously and major equipment often draws multi-megawatt loads at a single site (e.g., cranes, yard tractors and shore-power systems). Serving these concentrated, round-the-clock loads typically requires significant upgrades to local distribution infrastructure (such as new feeders, transformers, switchgear, etc.) and, at larger scales, entirely new substations or transmission reinforcements.

Port operations vary widely across the U.S. and may be managed by public authorities, private operators or hybrid arrangements. Facilities frequently span multiple utility service territories, adding complexity to interconnection planning, jurisdictional coordination and cost-allocation decisions. Electrified port equipment compounds these challenges: individual heavy-duty chargers commonly fall in the 150–350 kW range, while shore-power connections for vessels exceed those levels and can drive aggregated site demand into the multi-megawatt range.

Planning for port electrification also intersects with larger regional considerations, including freight corridor strategies and environmental mandates as well as federal and state funding programs. Despite the strategic role ports play in national decarbonization, few planning frameworks fully integrate port electrification requirements into regional grid modernization or long-term utility planning activities. As a result, utilities and port operators often lack shared tools to align timelines, forecast future load growth or optimize phased investment.

Emerging utility programs, such as recent initiatives by Xcel Energy, DTE Energy and National Grid, demonstrate promising models for collaboration, but ports require more comprehensive and sustained coordination mechanisms that reflect their operational intensity and grid impact. Closing this gap will require targeted policy support and cross-agency collaboration alongside planning tools that embed port electrification needs directly into broader grid investment and modernization strategies.

Delivery fleets

Delivery fleets span a wide range of operational models and duty cycles, creating highly varied electrification requirements. Last-mile delivery fleets often operate dynamic routes with minimal downtime, driving the need for fast, flexible charging solutions that balance speed with cost efficiency. By contrast, regional-haul fleets follow more predictable patterns but travel longer distances, leading to higher per-vehicle energy use and more complex charging needs. Charging can occur at centralized depots, drivers' homes or public corridors, requiring distributed infrastructure and smart charging software to manage load and reduce peak demand, while limiting exposure to demand charges.

Charger power levels vary significantly across fleet segments. Last-mile depots commonly deploy 50–100 kW chargers, regional-haul fleets often require 150–350 kW systems and megawatt-class charging for heavy-duty long-haul vehicles is emerging. These varied profiles complicate infrastructure planning and demand tailored solutions that reflect both operational requirements and local grid constraints.

Private commercial operators typically pursue electrification based on internal business cases and operational needs as well as corporate sustainability goals rather than using grant cycles to push electrification like public fleets. While this independence allows them to move quickly, it also compresses deployment timelines and frequently outpaces the ability of utilities to deliver the necessary infrastructure upgrades.

As a result, commercial fleet projects can encounter interconnection delays, uncertainty around long-term electricity costs and challenges of scaling initial deployments.

Utility fleet-advisory programs offer encouraging models for early engagement, but broader, more agile coordination frameworks are needed to support widespread commercial electrification. Closing this gap will require utilities to adopt faster planning processes and deploy tools that enable proactive collaboration with fast-moving private fleets.

Cross-sector themes

While each transportation sector faces distinct operational and infrastructure challenges, several common themes underscore the need for systemic coordination between fleets and utilities. These include the following:

- Benefits of electrification are shifting from incentives to economic value
- Operational understanding and load forecasting is required for success
- Operators need scalable and modular infrastructure solutions with a transition strategy
- Utility engagement is critical

Historically, major fleet electrification momentum has been driven by incentive programs such as the [Environmental Protection Agency \(EPA\) Clean School Bus Program](#), the [Low or No Emission Grant Program - 5339\(c\) | FTA](#) and [Clean Ports Grant Program](#). These initiatives were instrumental in catalyzing early adoption. However, the market is undergoing a fundamental shift: economic benefits, particularly lower total cost of ownership (TCO), are beginning to outshine external financial incentives and even environmental considerations. For many operators, electrification is now a business decision as much as a sustainability commitment.



Across all sectors, understanding the operational profile is critical to successful electrification.

Fleets must accurately assess current duty cycles and model future energy needs using robust load forecasting tools. However, most operators lack access to utility-grade models capable of predicting charging demand based on route schedules and vehicle mix as well as operational patterns. This gap limits the ability to anticipate costs and optimize infrastructure design, making electrification efforts a piecemeal compilation of stand-alone projects without overarching planning and direction.

Closely tied to forecasting is the need for scalable infrastructure planning. Full fleet conversion is rarely practical, or advisable, at the outset. Electric vehicles remain relatively new to the market and early deployments often reveal operational and maintenance pain points. Gradual scaling,

supported by modular charging solutions, allows fleets to adapt incrementally while minimizing stranded assets or other pain points. Unfortunately, many initial installations are designed for short-term needs, creating inefficiencies and requiring costly retrofits as adoption accelerates.

Finally, regardless of sector, engagement with utilities is imperative. External factors such as grid capacity and interconnection timelines play a decisive role in project success. “Right-sizing” refers to matching connected capacity, charger count and per-unit power to the fleet’s duty cycles and dwell times often via managed charging to limit simultaneous peak draw. Proactive coordination is essential to align infrastructure readiness with fleet deployment schedules and to unlock advanced strategies like managed charging and vehicle-to-grid integration. Understanding why this coordination remains challenging requires examining the different planning frameworks, constraints and decision-making processes that shape utility and fleet operations.

Divergent planning paradigms

While electrification requirements vary across transit, school bus, port and commercial fleet applications, a common challenge emerges across every sector: successful deployment depends on effective coordination between fleet operators and utilities. The following section examines why that coordination can be difficult, focusing on the different planning frameworks that shape utility and fleet decision-making.

Fleet electrification and utility infrastructure planning are both critical to achieving a zero-emissions future. Yet, these domains operate under fundamentally different planning paradigms each with distinct timelines, priorities and decision-making structures. This misalignment remains a significant barrier to effective coordination and timely infrastructure deployment.

Utility planning frameworks

Utility resource planning requires balancing immediate grid demands with long-term system needs. Most utilities plan 10–20 years ahead, supported by regulatory processes and significant capital investments programs. These processes are further complicated by federal and state regulatory requirements, which extend timelines and add complexity.

A cornerstone of utility planning is the Integrated Resource Plan (IRP), a long-term planning framework used to forecast future electricity demand and identify the investments needed to maintain reliable service. Whether through IRPs or similar planning processes, utilities rely on long-range forecasts to guide infrastructure decisions and resource allocation.

COMPARISON OF UTILITY AND FLEET ELECTRIFICATION PLANNING TIMELINES (MONTHS)

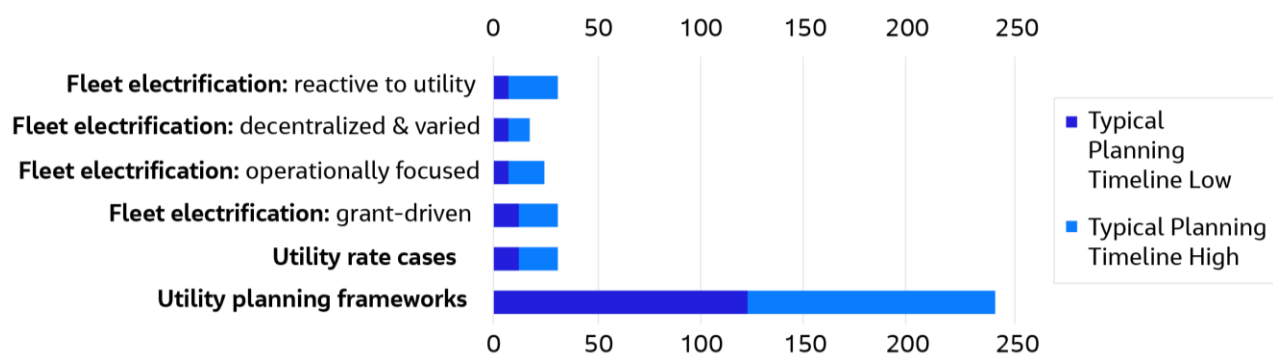


Figure 4: Utilities operate on multi-year planning cycles, while fleets deploy on 6–24-month timelines. This mismatch creates coordination challenges and delays in delivering the grid upgrades required for fleet electrification.

Utilities also manage rate-setting processes through formal regulatory proceedings, which can take 12–24 months. Rates must cover operational and maintenance costs as well as capital investments — all while providing a reasonable return on investment. Because these proceedings anticipate conditions years in advance, rate structures tend to be stable but lack flexibility to respond to emerging fleet needs. Regulatory oversight by Public Utility Commissions (PUCs) further reinforces this rigidity.

Major grid upgrades such as substation expansions, transformer replacements or new transmission pathways are executed through complex capital expenditure (CAPEX) projects. These projects often span several years, with design, permitting and regulatory approvals frequently requiring months or even years to complete.

Federal and state permitting requirements add further complexity, contributing to the long planning horizons utilities must navigate before new infrastructure can be brought into service.

Table 1: Utility and fleet planning timelines differ dramatically, with fleets operating on compressed schedules that often outpace the multi-year planning cycles utilities rely on — highlighting a central source of deployment misalignment.

Category	Typical planning timeline	Key drivers	Regulatory influence	Flexibility
Utility planning frameworks	10–20 years	Grid reliability, resource adequacy, cost recovery	High (PUCs, federal/state regulations)	Low — rigid and slow to adapt
Fleet electrification: grant-driven	12–24 months	Funding cycles, Notices of Funding opportunity (NOFO) deadlines	Moderate (government funding rules)	Medium — constrained by grant timelines
Fleet electrification: operationally focused	6–18 months	Operational efficiency, cost savings	Low	High — rapid decision-making
Fleet electrification: decentralized and varied	6–12 months	Local priorities, limited resources	Low	High — minimal technical resources but very flexible on schedule
Fleet electrification: reactive to utility	Variable (often delayed)	Utility incentives, grid capacity	Moderate	Low — dependent on utility actions

Despite advances in planning and forecasting, utilities can only plan using the information available at a given point in time. As a result, large-scale electrification projects may request power capacity on timelines that outpace existing utility planning and infrastructure readiness.

Fleet electrification planning

Fleet electrification planning operates on dramatically shorter timelines than utility planning. These strategies are shaped by operational priorities and funding opportunities rather than lengthy regulatory processes. Common approaches include:

- Grant-driven and time-sensitive
- Operationally focused
- Decentralized and varied
- Reactive to utility timelines

Grant-driven and time-sensitive

Public agencies (such as transit agencies and school bus fleets) often align planning with federal or state funding cycles. Notices of Funding Opportunity (NOFOs) typically allow 60 days for applications and awarded projects may require infrastructure readiness within 12–24 months. This creates compressed timelines and external dependencies that leave little room for iterative design or contingency planning. Agencies must also navigate procurement rules and environmental reviews, which can further constrain flexibility and increase the risk of delays if utility coordination is not initiated early. In some cases, operators may move quickly to secure available funding before fully evaluating site conditions, grid constraints or operational requirements, increasing the risk of delays and cost overruns later in the project lifecycle.

Operationally focused

Although operations are a focus across all sectors, private commercial fleets (such as last-mile delivery providers) survive and thrive by optimizing route coverage and vehicle uptime, alongside depot logistics. They face fewer regulatory constraints and rarely depend on government funding, enabling rapid planning and execution compared to utilities or grant-driven agencies. As a result, they can often move more quickly than public agencies, but rapid deployment may still be constrained by available grid capacity.



Decentralized and varied

Smaller, local operators often lack dedicated technical teams or programmatic strategies. Their planning tends to be less structured, making alignment with utility timelines more difficult. These organizations may rely on external consultants or vendor guidance, which can introduce inconsistencies in design standards and deployment schedules. Limited financial resources also mean these fleets are extremely sensitive to upfront costs, often opting for incremental electrification rather than large-scale transitions.

Reactive to utility timelines

Some fleets align deployment plans around anticipated utility upgrades, available grid capacity or incentive programs. While this approach can create opportunities for faster deployment, it can also result in project timelines that are highly dependent on external decisions and infrastructure readiness. Without early coordination, fleets may encounter unexpected grid constraints, delays and additional costs.

Utility coordination challenges

The differing planning approaches outlined above ultimately converge during project development, where fleet operators and utilities must coordinate infrastructure requirements, schedules and investment decisions. Despite growing electrification momentum, several systematic barriers continue to delay infrastructure readiness, increase costs and reduce overall project effectiveness. This section outlines the most common barriers to utility coordination across public and private fleet sectors, such as:

- Interconnection complexity and uncertainty
- Rate design and cost predictability
- Limited technical capacity and engagement models
- Regulatory and institutional barriers
- Data silos between fleet operators and utilities

Interconnection complexity and uncertainty

One of the most persistent barriers to timely fleet electrification is the complexity and opacity of utility interconnection processes. Fleet operators, particularly those deploying high-power charging infrastructure, frequently encounter unclear or inconsistent requirements that vary widely across utilities and jurisdictions. This lack of standardization creates uncertainty during critical planning phases. Figure 5 illustrates the typical flow for a fleet operator to request a new service. If there is a stumble at any one of these points, then the entire project could be severely impacted, both from schedule and budget standpoint.

Interconnection requirements typically involve multiple technical and regulatory steps, yet transparency around these processes remains limited. Fleet operators rarely receive clear guidance on key factors such as:

- **Transformer upgrade timelines:** Utilities may require significant equipment upgrades before energization, but projected timelines for these upgrades are often unavailable or subject to change.
- **Feeder capacity constraints:** Local distribution networks may lack sufficient capacity to support new loads, necessitating feeder enhancements that can add months, or even years, to deployment schedules
- **Permitting and inspection processes:** Jurisdictional differences in permitting requirements and inspection protocols introduce additional complexity, particularly for projects spanning multiple service territories.

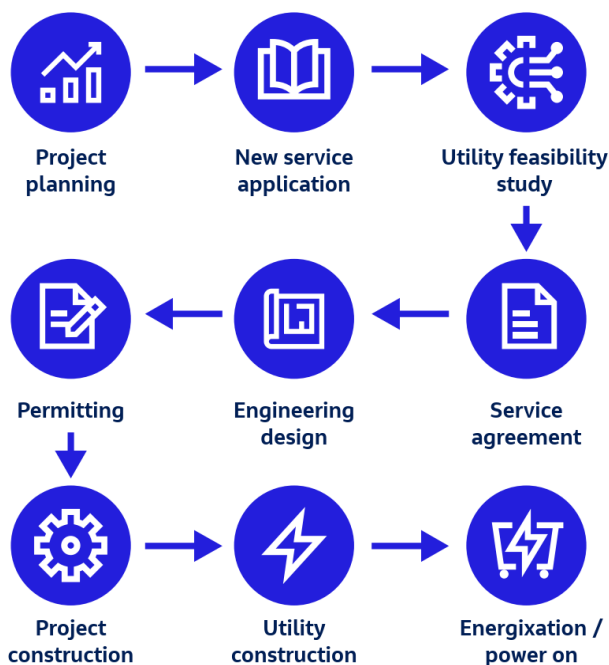


Figure 5: Typical steps to add or modify new service to a site.

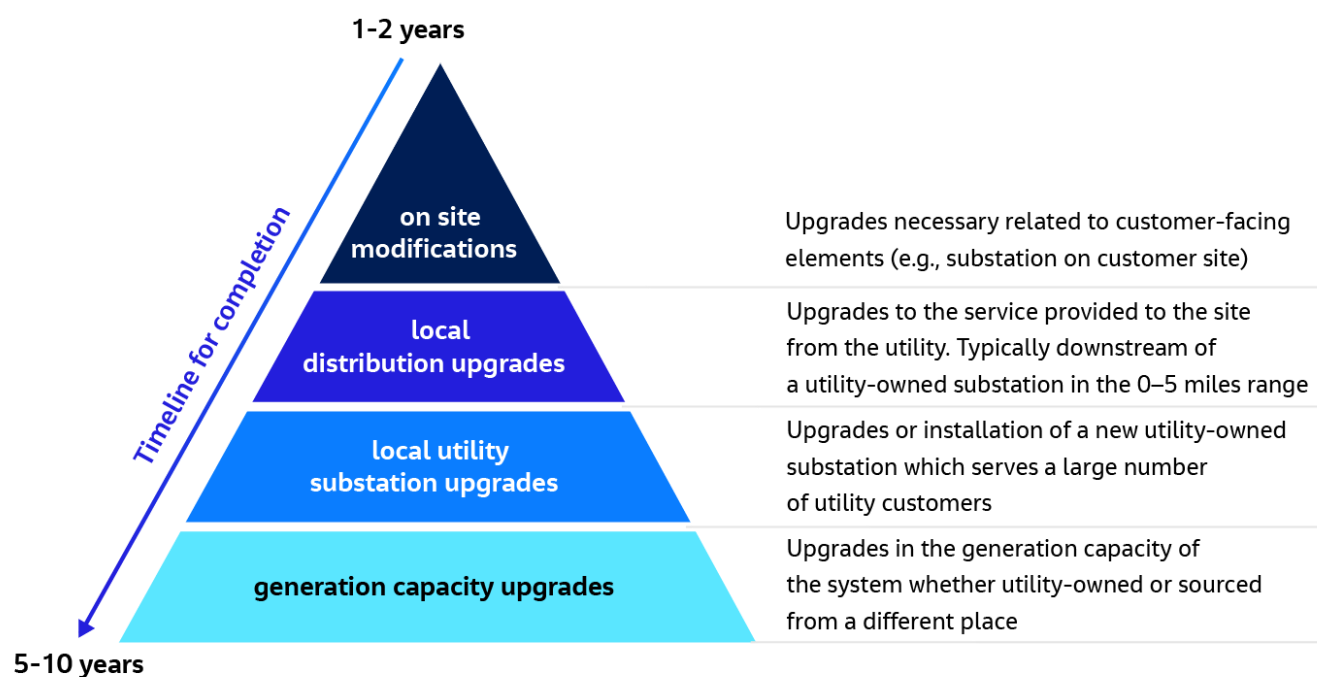


Figure 6: Electrification projects may trigger upgrades from fast customer-site work to lengthy distribution and substation improvements, extending timelines from 1–2 years up to 5–10.

These challenges are magnified for large-scale deployments, where upgrades to the local utility grid can impose substantial time and cost burdens. In some cases, interconnection studies reveal the need for major infrastructure investments, such as new substations or transmission pathways, that extend beyond the original scope of the fleet project. As shown in Figure 6, these additional investments can significantly extend project schedules. While on-site modifications may only take 1–2 years to complete, any major generation capacity upgrade investments can take up to 10 years.

Beyond standard utility connection requirements, projects can become more complex when fleet operators incorporate on-site energy generation or microgrid capabilities. Although, these technologies can improve resilience and energy performance, they often require additional technical reviews, power export controls and coordination with the utility to ensure wider grid stability.

While projects that combine vehicle charging with on-site energy systems typically require more detailed planning and coordination, many fleet operators continue to pursue these solutions because of the operational and economic benefits they can provide.

Onsite generation can reduce exposure to high demand charges, while storage smooths load spikes from fast charging and supports managed charging strategies. Microgrids provide resilience during outages (an increasingly important benefit for mission critical fleets such as transit, school transportation, ports and logistics hubs). For some operators, the combination of resilience, long-term cost savings, operational certainty and sustainability goals outweighs the additional interconnection steps.

Limited technical capacity and engagement models

Smaller fleets, such as school districts and rural transit agencies, often face significant barriers when engaging with utilities due to limited technical expertise and staffing capacity. These organizations may struggle to interpret utility requirements, navigate interconnection processes, or forecast future energy needs with the precision utilities required. At the same time, many smaller utility providers lack dedicated fleet advisory teams or standardized engagement protocols, which can result in inconsistent communication and missed opportunities for early collaboration.

Without clear points of contact or established processes, coordination can become inconsistent, leading to delays, misaligned expectations and under-optimized infrastructure investments.

Bridging this gap requires intentional capacity-building on both sides, along with the development of replicable engagement models that support smaller fleets in navigating the electrification journey.

Regulatory and institutional barriers

While there is accelerating momentum behind fleet electrification, regulatory and policy frameworks haven't kept pace with the operational realities of deploying electric vehicles at scale. Public Utility Commissions (PUCs), which govern utility planning and investment, often lack mechanisms that support early coordination with fleet operators or flexible interconnection models tailored to transportation electrification. This regulatory inertia can result in delayed infrastructure deployment and missed opportunities for strategic alignment. Compounding the issue, funding streams (whether federal, state or utility-based) are frequently siloed, making it difficult to synchronize investments in grid upgrades, charging infrastructure and vehicle procurement. These misalignments create friction in project execution and limit the scalability of electrification efforts.

Policy gaps further complicate the landscape. Key areas such as vehicle-to-grid (V2G) compensation, shared infrastructure models and multi-tenant charging sites remain underdeveloped or inconsistently addressed across jurisdictions. While recent federal grant programs have emphasized the importance of utility coordination during the application process, this engagement is often speculative. Utilities are asked to commit time and resources to planning efforts without assurance that the project will be funded or move forward. This uncertainty undermines efficient resource allocation and discourages deeper collaboration.

Data silos between fleet operators and utilities

A critical barrier to effective coordination between fleets and utilities is the absence of shared planning data and a common strategic framework.

This forces both fleets and utilities to make planning decisions using information that is incomplete, uncertain and continually evolving.

Yet the challenge is more than a lack of transparency — it's also the inherent uncertainty both sides must navigate. Fleet deployment plans, vehicle counts, charging needs and route assignments can shift frequently, while utilities must constantly manage evolving load forecasts and distributed energy resource adoption alongside broader system demands. Without secure, standardized mechanisms to exchange the most relevant and reliable information — however provisional — both parties are forced to plan with incomplete and rapidly changing inputs. As a result, coordination often remains project-by-project rather than supporting proactive investment, optimized load management and scalable system planning, making opportunities for efficiency, cost control and timely infrastructure delivery more difficult to realize.

The barriers outlined above make coordination more difficult, but the impacts extend beyond planning challenges alone. When utility infrastructure readiness and fleet deployment schedules are not effectively aligned, the consequences can be significant for project delivery, costs and operational performance.

Consequences of misalignment

Utility upgrade lag

Energization delay

Idle assets

Cost overruns

Lost user confidence

Figure 7: Misalignment between fleet deployment and utility infrastructure readiness can lead to delayed energization, idle assets, cost overruns and missed optimization opportunities, underscoring the importance of early coordination.

Utilities and fleets share the same goal — accelerating the decarbonization transition. However, misalignment between utility infrastructure readiness and fleet deployment schedules can have significant consequences for project delivery and fleet operations.

Common consequences include power supply bottlenecks, budget overruns, schedule delays and missed opportunities for optimization. For example, if a utility can't deliver the required power within the fleet's deployment window, charging infrastructure may sit idle, despite being purchased and installed, while warranty periods expire and vehicles remain inoperable.

When energization dates slip, fleets risk stranded assets, idle charging equipment and vehicles that cannot enter service as planned. Compressed rollout schedules leave little room to absorb these delays, increasing project risk and operational disruption.

Beyond cost and schedule impacts, lack of joint planning means fleets and utilities miss opportunities to implement advanced strategies like managed charging, vehicle-to-grid (V2G) integration or shared infrastructure, all of which can reduce grid stress and improve overall system efficiency.



Bridging strategies and best practices

Successfully aligning fleet electrification timelines with utility infrastructure readiness requires both structural coordination mechanisms and practical implementation tools. The following bridging strategies outline the system-level actions needed to enable long-term alignment, while the best practices provide tactical, repeatable steps that fleets, utilities and regulators can apply on

individual projects to reduce delays and improve predictability, supporting scalable electrification.

Bridging strategies

Bridging strategies focus on long-term actions needed to strengthen coordination and align planning efforts.

Establish fleet-utility electrification task forces

- Create recurring collaboration forums involving utilities, fleet operators, regulators and local agencies.
- Use these groups to align deployment schedules, identify grid impacts early and coordinate investment cycles.

Align federal, state and utility funding streams

- Synchronize charging infrastructure grants, grid upgrade funding and vehicle procurement timelines.
- Reduce friction caused by mismatched deadlines and eligibility rules across agencies.

Implement shared load forecasting & planning tools

- Integrate fleet operational data (routes, dwell times, charging windows) with utility system models.
- Support secure data sharing frameworks to protect sensitive information while enabling accurate grid impact analysis.

Invest in workforce development for utilities and fleets

- Expand technical training programs for charging infrastructure design, Distributed Energy Resources (DER) integration, grid modeling and interconnection processes.
- Support utilities in developing dedicated fleet electrification liaisons and advisory teams.

Strengthening regulatory support via public utility commissions (PUCs)

- Encourage PUCs to mandate early engagement between fleets and utilities.
- Streamline interconnection requirements, establish transportation aligned planning expectations and support flexible approaches to DER integration and managed charging.

Best practices

Best practices provide practical actions that can be applied at the project level to improve execution and reduce deployment risk.

Conduct early stage feasibility & pre application studies - Encourage fleets to consult utilities before site selection or vehicle procurement. - Identify constraints (transformer capacity, feeder limitations, need for substation upgrades) early to set realistic timelines.	Integrate DER planning (solar, storage, microgrids) early - Treat distributed energy resources and charging infrastructure as a single system design, not parallel tracks. - Minimize redesigns and avoid unexpected interconnection requirements.
Publish and maintain transparent hosting capacity maps - Utilities should provide regularly updated maps indicating feeder and substation capacity availability. - Fleets can use these maps to evaluate viable sites and reduce early-stage uncertainty.	Provide flexible EV specific rate designs & transparent cost modeling tools - Develop commercial EV rates that reflect fleet charging behavior (e.g., reduced demand charges, managed charging incentives, Time-of-Use (TOU) windows aligned to operations). - Offer user friendly cost modeling tools that allow fleets to simulate charging behaviors, compare rate options and forecast long term energy costs.
Standard interconnection processes - Use consistent checklists, application forms, timelines and study protocols to reduce ambiguity. - Improve transparency around expected durations, cost responsibilities and equipment lead times.	Develop standardized planning templates & utility engagement checklists Provide structured templates that enable fleets to assemble required data (load profiles, duty cycles, DER plans, site constraints). Use checklists to clarify what utilities need to initiate studies and avoid incomplete or inaccurate submissions.
Managing deployment for speed There are various levers that customers can utilize to accelerate the process such as setting up protection systems to prevent the export of power or deploying an open transition system versus closed transition. While utilizing these levers may have an impact on overall benefits, they allow for the acceleration of projects and can be revisited with the utility once the system is up and running.	Establish grid readiness key performance indicators (KPIs) - Track interconnection timelines, transformer availability, upgrade milestones and managed charging adoption rates. - Use KPIs to identify bottlenecks and increase accountability across stakeholders.
Build or leverage technical capacity for smaller fleets - Offer simplified planning guides, pre-scoped site assessment tools and advisory programs tailored to school districts, municipalities and small operators. - Leverage a consultant with a good working relationship with the utility as this work is more intensive up front but once complete requires minimal support moving forward.	

Conclusion

Fleet electrification is advancing rapidly across transit agencies, school districts, ports and commercial operators, but its success ultimately depends on the ability of utilities to deliver the power and infrastructure required to support these new loads. Successfully scaling fleet electrification will depend on stronger coordination between utilities and fleet operators to ensure infrastructure readiness keeps pace with vehicle deployment.

Sector-specific analyses highlight the diversity of fleet operating patterns, charging needs and infrastructure requirements. Transit agencies must manage high-demand overnight charging, school districts operate within predictable windows tied to academic calendars, ports face continuous multi-megawatt loads and commercial fleets navigate a wide range of duty cycles and site constraints. These differences underscore the need for flexible planning approaches that reflect the unique requirements of each sector while supporting effective coordination between fleets and utilities.

The strategies and best practices outlined in this paper provide a pathway to close this gap. Structural actions such as establishing fleet–utility task forces, sharing load-forecasting models, coordinating investment plans and strengthening regulatory support create the foundations for long-term alignment.

Practical measures such as early feasibility reviews, transparent interconnection processes, hosting capacity maps and standardized planning



templates can improve predictability and reduce deployment risk.

Ultimately, scaling fleet electrification requires moving from reactive, project-by-project coordination to proactive, systems-level planning.

By adopting these approaches, utilities and fleet operators can improve planning certainty and make more informed infrastructure investment decisions.

With deliberate coordination and clear communication, the industry can unlock a more resilient, reliable and scalable pathway to zero-emission transportation.

Appendix A - Glossary of utility and fleet planning terms

Advanced Metering Infrastructure (AMI) Smart metering systems that provide real-time or near real-time energy usage data, enabling improved grid visibility, load management and customer monitoring.

Baseload / Peak Demand Baseload refers to the minimum level of constant electricity demand on a grid. Peak demand refers to the highest load level over a specified time, often driving required grid capacity.

Capital Expenditure (CAPEX) Long-term infrastructure investments by utilities, such as substations, feeders, transformers and transmission lines, typically requiring regulatory approval and multi-year planning.

Certificate of Public Convenience and Necessity (CPCN) A regulatory authorization required in many states before a utility can build major new infrastructure, ensuring the project serves public need and follows proper siting requirements.

Demand Charges Fees based on a customer's highest level of power draw (kW) during a billing period, common in commercial electricity rates and a major cost factor for fleet charging operations.

Demand Side Management (DSM) Utility programs aimed at reducing or shifting electricity consumption through efficiency, load management, or customer incentives.

Distributed Energy Resources (DERs) Small scale, onsite energy systems such as solar PV, battery storage and microgrids that can supply power locally and interact with the utility grid.

Distribution System The lower voltage portion of the electric grid that delivers power from

substations to end use customers, including feeders, transformers and service lines.

Electric Vehicle Supply Equipment (EVSE) Charging infrastructure that delivers power to electric vehicles, including AC Level 2 chargers, DC fast chargers and megawatt class heavy-duty chargers.

Feeder Capacity The maximum allowable power flow on a distribution circuit (feeder). If electrification load exceeds available capacity, utility upgrades may be required.

Fleet Duty Cycle The operational pattern of a vehicle fleet, including run times, idle windows, dwell times and charging periods which are key inputs to fleet energy modeling.

Hosting Capacity The amount of incremental load or DER generation that a distribution circuit can support without requiring system upgrades, typically shown in utility hosting capacity maps.

Integrated Resource Plan (IRP) A long-term utility planning document (often 10–20 years) outlining future energy demand, resource mix and major infrastructure investments. Updated every 2–5 years in many states.

Interconnection The formal process through which new loads (such as charging depots) or DERs (such as solar or storage) are evaluated, approved and physically connected to the utility grid.

Islanding (Microgrid) The ability of a microgrid to operate independently from the main grid during outages. Requires careful utility review for safety and power quality coordination.



Load Forecasting The process of estimating future electricity demand using historical usage data, fleet duty cycles, weather, economic trends and anticipated electrification.

Managed Charging (Smart Charging) Control strategies that adjust EV charging rates or timing to reduce peak loads, minimize costs, or align charging with grid capacity.

Microgrid A localized energy system capable of operating with the grid or independently, integrating on-site generation, storage and controls for resilience or energy optimization.

Notice of Funding Opportunity (NOFO) Formal announcement for federal or state competitive grants with defined application windows, often influencing fleet deployment timelines.

Planning Templates / Engagement Checklists Standardized documents that enable fleets and utilities to exchange required technical data, streamline early engagement and reduce delays in interconnection studies.

Public Utility Commission (PUC) A state regulatory body responsible for overseeing utility rates, planning and infrastructure approvals and often governing interconnection rules.

Rate Case A formal regulatory proceeding in which a utility proposes changes to customer rates to recover costs of operations, maintenance and capital investments.

Resource Adequacy A utility's obligation to ensure enough generation and grid capacity exists to meet current and future electricity demand under all expected conditions.

Service Upgrade A utility improvement (e.g., transformer replacement, feeder extension) required to support higher electrical loads at a customer site.

Substation A major utility facility where voltage is transformed, circuits are sectionalized and distribution feeders originate. Often requires years to design, permit and build.

Time of Use (TOU) Rates Electricity prices that vary by time of day to encourage consumption during off-peak hours which are important for fleet charging economics.

Transmission System The high voltage portion of the electric grid that transports electricity over long distances from generation sources to substations.

Vehicle to Grid (V2G) Bidirectional power flow capability that allows EVs to discharge energy back onto the grid or into local facilities during peak periods or outages.

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About the author

William Lyddane is a transportation decarbonization leader with more than a decade of experience working with clients to plan and deliver the infrastructure systems needed for a more sustainable transportation future. His work focuses on the intersection of transportation, energy and the built environment, where successful decarbonization requires more than technology alone. By connecting long-term planning with operational realities, he supports organizations to move from vision to implementation.

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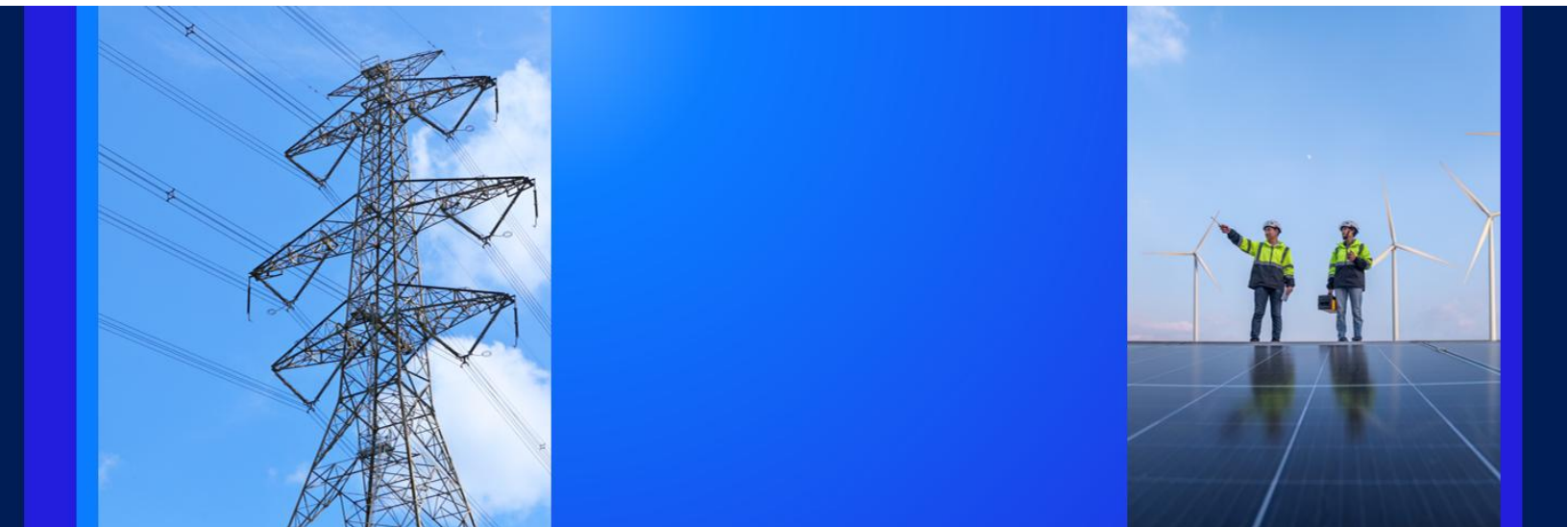
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William translates complex technical and operational considerations into actionable strategies, enabling organizations to turn ambitious goals into measurable outcomes that strengthen communities and keep the world moving.



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