Costs of and Bottlenecks in Zero-Emission Medium- and Heavy-Duty Vehicle Infrastructure Deployment

dunsky
Energy + Climate

EXECUTIVE SUMMARY

Dunsky Energy + Climate Advisors ("Dunsky") has conducted research to help Clean Energy Canada gain a better understanding of the **real costs** and **bottlenecks** to zero-emission (ZE) medium- and heavy-duty vehicle (MHDV) infrastructure deployment, with a focus on utility service upgrades. This information can play a vital role in informing actions taken by policymakers, utilities and fleets to improve the utility service upgrade process before we start seeing an even larger volume of service upgrade requests come in. Dunsky's engagement with six MHDV fleets and four utilities across Canada, as well as our complementary desktop research, have informed the insights found in this report, comprising:

1. An overview of utility service upgrades, including
   - The typical types of utility service upgrades required to support ZE MHDV charging
   - Key steps involved in obtaining a utility service upgrade
   - Ranges in costs associated with different levels of service requests, as well as an overview of the major drivers of these costs
   - Typical timelines for different levels of service requests
2. Early feet experiences with ZE MHDV infrastructure deployment and utility service upgrades, including a discussion of common fleet and utility-side bottlenecks
3. Recommendations on opportunities to alleviate some of the major costs and bottlenecks

Overview of Utility Service Upgrades

Types of Upgrades

Depending on the local conditions of the distribution grid, a given ZE MHDV charging infrastructure project may trigger **different types of infrastructure upgrades**, and thus very **different costs**. Figure ES1 provides an overview of the different types of equipment upgrades that may be required under different scenarios.

Costs

If a fleet can provide EV charging infrastructure onsite without requiring a new or upgraded electrical utility service connection under the applicable electrical code, then utilities may have no recourse for charging that specific customer for any incremental upstream system improvements;[1] those costs will ultimately be borne by the ratepayer via utility rates.

However, it is often the case when adding the relatively large loads associated with ZE MHDV charging that a new service upgrade is unavoidable. In this case, utilities will charge a fee to the customer for a new/upgraded service. Importantly, there are **different models** for how

This project was undertaken with the financial support of the Government of Canada.

Ce projet a été réalisé avec l'appui financier du gouvernement du Canada.

Canada

Commissioned by:

CLEAN ENERGY CANADA

utility service upgrade fees are structured, and therefore what costs customers will pay for the electrical service. The key takeaway is that **service upgrade fees comprise a very important part of the total cost** of implementing ZE MHDV charging infrastructure. They **vary by jurisdiction** and are **often unpredictable** and **non-linear**, often depending on the unique state of local distribution systems (e.g., the capacity of the upstream feeders and substations).

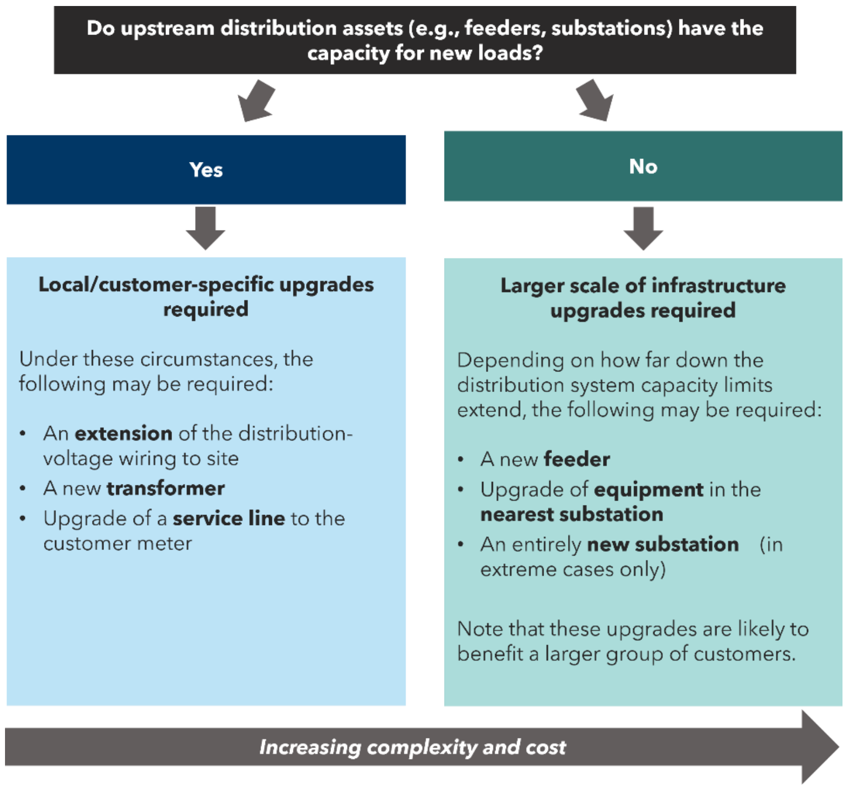

Figure ES1. Types of equipment upgrades that may be required under different scenarios[2]

As an illustrative example, the table below shows just how quickly electricity demand ramp-ups with ZE MHDV deployments. A fleet of **50 ZE medium-duty vehicles (MDVs)** charging overnight is expected to require at least **1 MW** of power. Meanwhile, a fleet of **50 ZE heavy-duty vehicles (HDVs)** could require up to **7.5 MW**. For reference, 1 MW of electrical capacity would be equivalent to the power consumption of 800 Canadian households for a year or a small Canadian town, whereas 7.5 MW would be equivalent to the consumption of 6,000 Canadian households or a large industrial complex.

Table ES1. Illustrative ZE MHDV fleet power demands for overnight depot charging

Vehicle Type	Charger Power Requirements (Overnight Depot Charging)	Total Power Demand for a Fleet of 50 Vehicles
MDVs (box trucks, urban delivery trucks)	20 - 50 kW	1 - 2.5 MW
HDVs (class 8 trucks, regional buses, transit buses)	50 - 150 kW	2.5 – 7.5 MW

[1] However, some utilities' terms of service include provisions providing the utility with some recourse to compensation if customers' loads increase substantially relative to e.g. the maximum loads that occurred during the first several years of connection.

[2] A useful diagram highlighting the various components of the distribution system can be found on: Florida Power & Light's website here.

While costs can range significantly from one site to another, we expect the following to be representative of utility service upgrade costs for different scales of site demand:

- **2-6 MW**: $200,000 to $1 million
- **7-20 MW**: $2 to $20 million
- **150 MW**: $50 million

Overall, we heard that utility upgrade costs vary significantly from one project to another and are driven by several parameters, including the total power requirements, the distance between the customer and the nearest transmission station, whether or not the utility needs to cross private property, the type of terrain being crossed, and the age of the existing infrastructure.

Customer Journey Process Map

The steps involved in upgrading a facility's electrical service will be fairly similar from the perspective of a fleet, regardless of which level of upgrade is needed. We mapped out an overview of the utility upgrade process, as well as typical fleet and utility roles at each step in Figure ES2. Note that the relative **length of each step** has been indicated through the **height of each row** (i.e., a taller row indicates a longer step). We have also indicated actions that fleets will likely be taking in parallel to deploy fleet-side infrastructure in italics.

Timelines

Under the right conditions, a minor utility service upgrade (e.g., one that solely requires a transformer upgrade or system extension to the customer) can be completed in approximately **six months**. However, major projects that require upgrades to the distribution system may require **upwards of two years**.

STEPS	FLEET ROLES	UTILITY ROLES
Online Request	Submit online request via utility website with preliminary project information (electrical engineer/contractor may be required to assess site capacity/load impacts)	Receive the application
Preliminary Design		Assign an internal designer for preliminary assessment and design
Detailed Design	Respond to data request from utility to support detailed design *Fleet responsible for detailed design of fleet-side infrastructure (i.e., all infrastructure behind the meter including panels, switchgear and EV chargers)*	Develop detailed design that outlines the infrastructure requirements needed to meet the service request
Connection Agreement	Property owner to sign offer outlining the scope and costs of the utility service upgrade	Develop the offer to connect, as well as terms and conditions and costs of the construction
Permitting and Other Dependencies	*Obtain necessary electrical and municipal permits and undergo any environmental assessments for fleet-side infrastructure, as needed, prior to construction*	Obtain necessary electrical and municipal permits and undergo any environmental assessments for utility-side infrastructure, as needed, prior to construction
Easements	Respond to easements from utility if utility-owned infrastructure needs to be installed on fleet property	Establish easements with any property owners whose land needs to be crossed to make the connection
Construction	*Fleet responsible for construction and deployment of fleet-side infrastructure (e.g., panels, switchgear and EV chargers)*	Procure major equipment and complete on-site construction (e.g., order transformers, lay feeder lines, construct substations, install meters)
Site Inspection	*Electrical safety inspection completed by relevant organization (e.g., ESA, Technical Safety BC) for fleet-owned infrastructure*	Electrical safety inspection completed by relevant organization for utility-owned infrastructure
Energization		Set up customer account, schedule and energize the connection

Figure ES2. The customer's journey to a utility service upgrade[3]

[3] Note that behind-the-meter refers to electrical infrastructure located beyond the meter on the customer side. Front-of-the-meter refers to infrastructure located on the utility side of the meter.

Canadian ZE MHDV Experience with Utility Service Upgrades

Current State of ZE MHDV Infrastructure Deployment

Dunsky's engagement with six MHDV fleets across Canada that are leading in the transition to ZE vehicle models suggests that leading MHDV fleets in Canada have deployed infrastructure to support **60-100+ ZEVs** per fleet. Fleets have installed electrical capacities ranging from **2 to 9 MW** to support this first phase of deployments. Overall, however, major utility service **upgrades have been limited** to date. Note that this scale of infrastructure deployment extends well beyond the level of ZE MHDV deployments to date as most fleets are **future-proofing** their facilities to support future ZEV deployments.

Many fleets are taking a **phased approach** to electrical infrastructure upgrades, with this being the first phase. For some fleets, this first phase has involved building facilities from the ground up to support near-term ZEV deployments. As service upgrades in these cases were made during the building construction stage, this translated to fewer bottlenecks overall. For other fleets, this first phase has involved relatively minor equipment upgrades on the utility or customer side (e.g., transformers, switchboards or switchgear).

Bottlenecks in the Process

Our engagement with fleets and utilities across Canada uncovered the following as common causes of bottlenecks in the utility service upgrade process:

- **Coordination** across a wide range of teams within the utility.
- Staff **capacity constraints** driven by an unprecedented volume of utility service upgrade requests across all sectors.
- Customer-side **data collection** to support utility requests (e.g., future demand estimates).
- **No special treatment** for fleet service upgrade requests.
- Few utilities make **system capacity maps** available to the public, necessitating back-and-forth between the utility and customer when determining whether system capacity is available to support the request.
- Reluctant property owners can slow down **easement negotiations**.
- **Supply chain constraints** leading to delays in the procurement of key pieces of equipment like transformers.

Looking Ahead: Recommendations for Improvements

Dunsky has developed a series of recommendations that can address bottlenecks to EV charging infrastructure deployment for MHDV fleets. In general, we have aimed to order these recommendations by relative level of impact/importance.

- Utility **tariffs should be revised** to ensure customers are not required to cover a disproportionate share of costs associated with **upstream system capacity increases** that currently place an undue burden on "first movers". Utilities should explore the possibility of ratebasing infrastructure upgrades such that individuals collectively pay for utility capacity increases as a means of cost recovery.

- Utilities should be given the regulatory authority to make **proactive investments** in transmission and distribution system upgrades. ZEV mandates and targets coming into effect make it clear that this load will materialize. Regulators should also consider mandating utilities to develop comprehensive plans of distribution investments needed under a range of MHDV electrification scenarios, including very rapid electrification.
- Appropriate mechanisms to enable **federal and provincial financial support** for utility-led transmission and distribution system upgrades should be identified. Investments should be pursued.
- Regulators should identify appropriate mechanisms to **prioritize beneficial electrification initiatives** like transportation electrification for expedited utility service connections.
- Utilities and their regulators should update rates to better reflect **real-time energy prices** and **marginal costs of demand** on distribution and transmission grids. **Demand-side management programs** should be expanded to optimize EV load flexibility to reduce costs/maximize value for the electric grid, including using passive measures, active managed charging, and vehicle-to-grid. Programs and rates should be structured to reward fleets that adopt strategies that maximize the flexibility of EV charging, resulting in improved economics for fleet owners and more rapid adoption of electric fleets versus the status quo.
- Electricity system operators should establish **regional standards for utility service connections** in provinces that are host to a patchwork of local distribution companies.
- Regulators should mandate utilities to provide better customer visibility into **infrastructure cost ranges**. Opportunities to standardize costs across regions should be explored.
- Regulators should mandate utilities to share **up-to-date system capacity maps**. Utilities should ensure that their internal processes are streamlined in such a way that timely and low-cost connections can be completed regardless of local capacity.
- The federal government should explore opportunities to allocate funding for **clean energy workforce** and supply chain development.
- Utilities should improve **internal capacity** around **transportation electrification solutions** through, for example, training for staff, development of educational resources for customers, and establishing networks of external consultants that can reliably support EV charging infrastructure assessments.

Table of Contents

1. Context

Dunsky Energy + Climate Advisors ("Dunsky") has conducted research to help Clean Energy Canada gain a better understanding of the real costs and bottlenecks to zero-emission (ZE) medium- and heavy-duty vehicle (MHDV) infrastructure deployment, with a focus on utility service upgrades. Early lessons learned from the early ZE MHDV deployments in the United States suggest that electrical service upgrades can be a significant source of delays in the transition to ZE MHDV flees. Through this project, Dunsky conducted desktop research, and engaged utilities and fleets across Canada to develop a better understanding of the utility service upgrade process and identify sources of ZE MHDV infrastructure deployment delays north of the border. In this report, we share lessons learned from this engagement, including:

1. An overview of utility service upgrades, including
   - The typical types of utility service upgrades required to support ZE MHDV charging
   - Key steps involved in obtaining a utility service upgrade
   - Ranges in costs associated with different levels of service requests, as well as an overview of the major drivers of these costs
   - Typical timelines for different levels of service requests
2. Early feet experiences with ZE MHDV infrastructure deployment and utility service upgrades, including a discussion of common fleet and utility-side bottlenecks
3. Recommendations on opportunities to alleviate some of the major costs and bottlenecks

This information can play a vital role in informing actions taken by policymakers, utilities and fleets to improve the utility service upgrade process before we start seeing an even larger volume of requests come in.

2. Approach

2.1 Overview

Dunsky engaged utilities and fleets as our primary method of data collection for this project. more details on our approach to utility and fleet engagement can be found in the sections below. Insights from utilities and fleets served to enhance our baseline understanding of the utility service upgrade process. To complement findings from the utility and fleet engagement, Dunsky leveraged existing work and conducted additional desktop research. In particular, this included a jurisdictional scan to identify action being taken in other provinces/states to improve the utility service upgrade process. We focused our scan on actions being taken in Canada and the United States but expanded our search to other jurisdictions, as needed.

2.2 Utility Engagement

Dunsky engaged three utilities found in Canada's most populous provinces that are home to the country's highest rates of EV adoption: BC Hydro, Hydro Quebec and Alectra. These regions are also host to important freight hubs, including ports and intermodal distribution centres. These utilities differ, however, in their ownership structure. While BC Hydro and Hydro Quebec are both provincially owned crown corporations responsible for power generation, transmission and distribution, Alectra is a municipally owned local distribution company that serves a range of municipalities in the Golden Horseshoe region, including Peel Region.

In addition to these three utilities, Dunsky also engaged PowerON Energy Solutions, a turnkey fleet EV charging solutions provider. Though PowerON is not a utility, its design team works closely with utilities across Canada, and the organization is in the unique position of being a subsidiary of Ontario's largest power generation company.

Table 1. Overview of organizations Dunsky engaged

Name	Organization Type	Region of Operation
BC Hydro	Provincial crown corporation responsible for electricity generation, transmission, and distribution	British Columbia
Hydro-Québec	Provincial crown corporation responsible for electricity generation, transmission, and distribution	Quebec
Alectra Utilities	Municipally-owned local distribution company	Ontario (Golden Horseshoe)
PowerON Energy Solutions	An Ontario Power Generation (OPG) subsidiary that provides turnkey fleet EV infrastructure support	Ontario-based (serves customers Canada-wide)

We leveraged insights from our engagement with utilities to map out key steps in the utility service upgrade process, as well as typical fleet and utility roles and responsibilities across each step. Note that a discussion of the typical timelines and costs associated with different levels of service upgrades will complement this figure in our final report for Clean Energy Canada. Given the complexity of the process, as well as the level of nuance associated with project timelines and costs, we excluded these metrics from the figure below.

2.3 Fleet Engagement

Dunsky developed a survey that was circulated to ten commercial fleets across Canada that have started to deploy ZE MHDVs. Dunsky was successful in engaging six fleets across a range of sectors and provinces in Canada (see Table 2). In some cases, a survey response was substituted with a 30-minute to 1-hour interview. Our questions were centered around better understanding the fleet's progress in deploying ZE MHDV infrastructure, whether utility service upgrades have been necessary, ranges in costs incurred, and bottlenecks faced during the process. A full list of survey questions can be found in Appendix B.

Table 2. Overview of fleets Dunsky engaged

Fleet Type	Location of ZE MHDV Deployments	Engagement Type
Retail freight and logistics	Ontario, Nova Scotia and British Columbia	Survey
Public school bus fleet	Maritimes	Survey
Public transit fleet	Ontario	Survey
For-hire freight and logistics	Quebec	Interview
Public transit fleet	Alberta	Interview
Tourism bus fleet	British Columbia	Interview

3. Overview of Utility Service Upgrades

3.1 Types of Utility Service Upgrades

Depending on the local conditions of the distribution grid, a given project may trigger different types of infrastructure upgrades, and thus very different costs. For example, at a particular site, there could be sufficient capacity on a utility distribution feeder and its upstream infrastructure to accommodate the required electrical capacity for new ZE MHDV infrastructure, but it would require a short extension of the distribution infrastructure to the site; in this case, the costs incurred due to this project would be limited to what some utilities refer to as a service extension and therefore be relatively modest (e.g., for the sake of illustration, a short extension might cost ~$5k-$20k).

However, the next ZE MHDV charging infrastructure project on that distribution feeder might result in aggregate peak demand that exceeds the capacity of the circuit, resulting in a need to increase the capacity of the feeder(s), substation, and/or other upstream electric utility distribution systems. In such cases, the costs associated with the ZE MHDV infrastructure project can be orders of magnitude higher depending on the nature of the necessary works. Figure 2 provides an overview of the different types of equipment upgrades that may be required under different scenarios. Notably, however, different customer service classes have different types of infrastructure on their side of the meter. For example, above a certain estimated demand, customers own the transformer. Below, they will use the utility transformer.

Utilities use varying terminology to refer to different types of utility service upgrades. For instance, BC Hydro uses the term "service extension" to refer to an extension of the distribution to the customer, and "system improvement" to refer to upgrades to the distribution system (see Figure 1 for a schematic diagram of these terms).

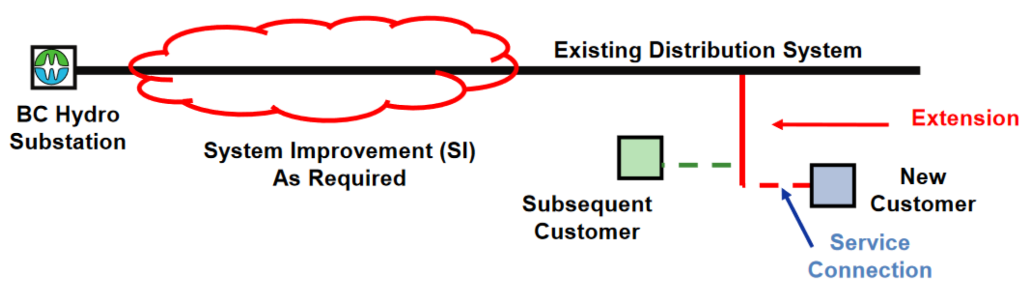

Figure 1. A comparison of service extensions and system improvements (Source: BC Hydro[4])

[4] BC Hydro, Distribution Extension Policy Workshop (2023).

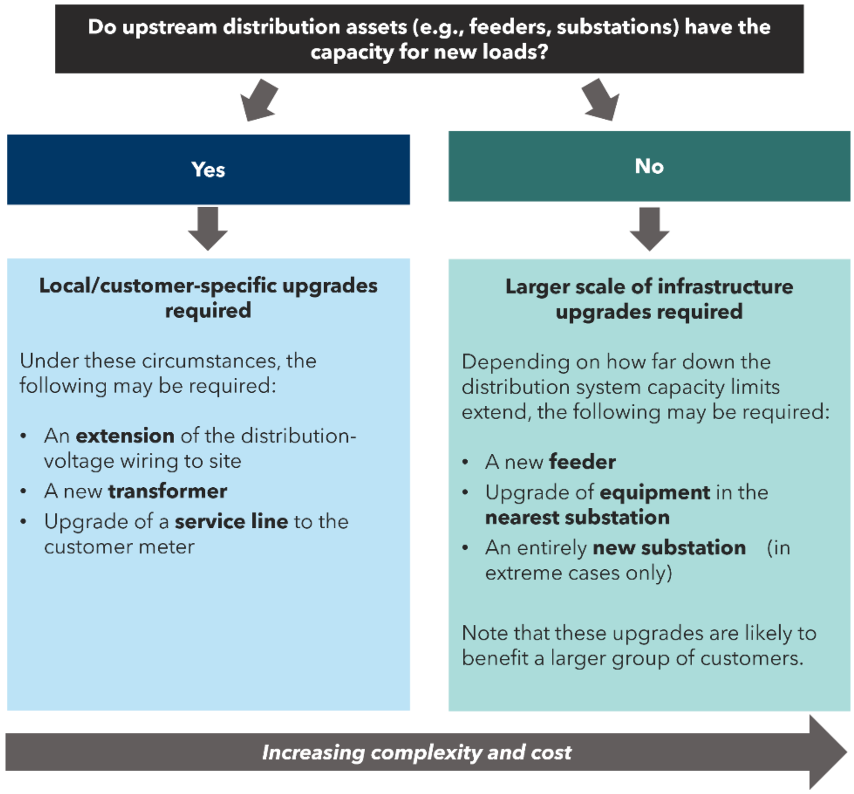

Figure 2. Types of equipment upgrades that may be required under different scenarios

3.2 Costs

3.2.1 Types of Capital Costs

Broadly, there are **two categories of capital costs** when adding new electrical loads to a site:

1. **Onsite costs** include the costs of infrastructure that is "downstream" of the electric utility service connection point. These costs can include electrical works (e.g., transformers, switchgear, site feeders, branch panels, branch circuits, EV supply equipment, etc.) communications equipment, civil works (e.g., cutting and repaving pavement to lay electrical conduit), etc.

   Typically, utility customers (i.e. facility owners/tenants) and their financiers pay these costs. However, government or ratepayer-funded programs may also provide cash contributions to such works (e.g., EV charging infrastructure incentives).
2. **Utility distribution system costs** include costs that are "upstream" of the electric utility service connection point. These costs consist of the incremental grid infrastructure upgrades necessitated by a new electrical load (e.g., ZE MHDV charging), which utilities must invest in to ensure that grids can reliably provide customers with power.

3.2.2 Cost Allocation

If a fleet can provide EV charging infrastructure onsite without requiring a new or upgraded electrical utility service connection under the applicable electrical code, then utilities may have no recourse for charging that specific customer for any incremental upstream system improvements;[5] those costs will ultimately be borne by the ratepayer via utility rates. For this reason, if possible, electrical engineers working on behalf of a facility owner will often seek to avoid triggering a service upgrade when adding EV charging infrastructure and/or other electrical loads.

However, it is often the case when adding the relatively large loads associated with ZE MHDV charging that a new service upgrade is unavoidable. In this case, utilities will charge a fee to the customer for a new/upgraded service. Importantly, there are **different models for how utility service upgrade fees are structured**, and therefore what costs customers will pay for the electrical service.

For example, different fee structures in use or under consideration by Canadian utilities include:

1. Charging the **actual costs** of the service upgrade associated with a project, **less the value of future revenues** received by the utility for customers' subsequent use of electricity. For example, a General Service[6] customer might pay the cost of the upgrade quoted by the utility, less a credit for the value of their future demand (e.g., $200/kW). Future demand values (kW) may be estimated; alternatively, customers may need to make a deposit for distribution system upgrades, that they can earn back if and when their own demand or neighbouring properties' demand materializes in a specified period of time (e.g., 5 to 10 years). For example, a customer would pay a deposit covering the full upgrade costs, but then receive repayment (e.g., $200/kW) for their demand and/or their neighbours' demand on that distribution feeder. This way of structuring utility service upgrade fees results in customers assuming the risk of whether loads at neighbouring properties will materialize.

   This way of structuring these fees can result in **highly unpredictable costs** for customers. Often, costs will be modest because no significant upgrades to the utility distribution system are necessary. However, certain customers can face significant costs if their project happens to trigger upstream investments; this can and does make some ZE MHDV charging infrastructure projects uneconomic.
2. **Average system improvement fees**. Alternately, the distribution system upgrade component of the fee can be structured as an average for all distribution system upgrade costs across a utility. This structure recognizes that all customers contribute towards the eventual need for distribution system improvements. Thus, all customers are allocated a portion of these costs proportional to their added load, with new services charged a standard $/kW proportional to the load they represent. However, customers are still charged the real cost of the extension to the distribution grid.
3. **Demand-based fees**. Building on #2 above, upgrade fees can be structured to normalize service connections into a simple average $/kW of new demand. This not only normalizes the average cost of distribution system upgrades but also normalizes between customers

[5] However, some utilities' terms of service include provisions providing the utility with some recourse to compensation if customers' loads increase substantially relative to e.g. the maximum loads that occurred during the first several years of connection.
[6] Most ZE MHDV charging sites would currently have a General Service utility rate, though some utilities are introducing special EV charging rates.

depending on the cost of the service extension to their site (which can be influenced by where distribution lines run, civil works, vagaries of construction, etc.).

The different ways of calculating service upgrade fees noted above are provided as illustrative examples, and may not encompass all the ways such fees are calculated. We are not aware of any comprehensive publicly accessible database of such fee structures. The key takeaway is that **service upgrade fees comprise a very important part of the total cost of implementing ZE MHDV charging infrastructure. They vary by jurisdiction and are often unpredictable and non-linear, often depending on the unique state of local distribution systems** (e.g., the capacity of the upstream feeders and substations).

Moreover, the design of utility service upgrade fees is in flux. We are aware of several utilities and regulatory commissions that are considering changes to the design of these fees, driven in no small part by the barriers they can impose on electrification projects (e.g., see the Ontario Energy Board's "Proposed Amendments to the Distribution System Code to Facilitate Connection of EV Charging Infrastructure", BC Hydro's Distribution Extension Policy engagements, etc.).

3.2.3 Typical Cost Ranges

While costs can range significantly from one site to another, we expect the following to be representative ranges of utility service upgrade costs for different scales of site demand:

- **2-6 MW**: $200,000 to $1 million
- **7-20 MW**: $2 to $20 million
- **150 MW**: $50 million

Dunsky has also obtained estimates from utilities on the cost of service upgrades typically required to support varying scales of direct current fast charging (DCFC) EV charger deployments along highways (see Table 3). Refer to Table 4 for illustrative ZE MHDV fleet power demands.

Table 3. Utility service upgrade cost range for different levels of DCFC deployment

No. DCFC Ports	Total Site Demand	Cost Estimate
4x150 kW	0.6 MW	$150,000 to $250,000
10x150 kW	1.5 MW	$150,000 to $250,000
10x1 MW	10 MW	$1M to $1.25M; up to $7.5M if upgrades to substation required
10x2 MW	20 MW	$2.5M to $7.5M assuming upgrades to substation or new substation required

We validated these cost ranges through our engagement with fleets who cited that electrical service upgrade costs were on the order of $500,000 to $2 million for sites requiring 2 to 9 MW in additional capacity. For one fleet, this included the cost of moving neighbouring customers to adjacent feeders to free up capacity on their main feeder. For other fleets, these ranges also include costs related to customer-owned equipment including transformers, substations, and switchgear. For reference, it's estimated that the cost to install a transformer would be on the order of $100,000-$150,000. There is some uncertainty around the distribution of utility-side versus customer-side costs within these estimates.

Though nominal in comparison to the typical total project costs, utilities may require a deposit to support site design work. One utility we heard from noted that this is typically in the range of $10,000. Once this deposit is made, electrical capacity is reserved for that customer.

3.2.4 Key Drivers of Costs

Overall, we heard that utility upgrade costs vary significantly from one project to another and are driven by several parameters, including:

- **Scale of upgrades required:** if upgrades to the distribution system are required to meet the customer's needs (i.e., upgrades to utility-owned transformers, lines, feeders or substations), costs are expected to be significantly higher. However, it depends on the utility tariff to what extent fleets bear the cost of these upstream improvements.
- **Power requirements:** customers requesting more power are more likely to trigger expensive equipment upgrades.
- **Length of line:** total cost may be driven by the distance between the customer and the nearest transmission station. Typically, the further away from the station, the costlier, as it increases the likelihood of crossing private property and may also require more trenching/boring to bury lines.
- **Crossing private property:** utilities must establish easements with property owners when they are required to install utility-owned infrastructure on private land. Private landowners typically ask for a portion of the value of land in the right-of-way that the utility needs to acquire.
- **Terrain type:** if wires need to be buried (e.g., to cross under a highway or through private property), project construction costs typically surge.
- **Age of existing infrastructure:** in some cases, the lifecycle of the current electrical infrastructure impacts the final cost borne by the customer. If the infrastructure is nearing the end of its life, the customer will only pay for the incremental cost of having a more powerful installation, not the full replacement cost.

The fleets we engaged cited the cost of equipment and labour as the biggest drivers of costs. Given that some of these deployments occurred during the COVID-19 pandemic, some costs may be inflated as a result of the supply chain constraints and labour shortages that were prevalent in the early years of the pandemic.

3.3 Customer Journey Process Map

The steps involved in upgrading a facility's electrical service will be fairly similar from the perspective of a fleet, regardless of which level of upgrade is needed. We mapped out an overview of the utility upgrade process, as well as typical fleet and utility roles at each step in Figure 3. Note that the **relative length** of each step has been indicated through the **height of each row** (i.e., a taller row indicates a longer step). We have also indicated actions that fleets will likely be taking in parallel to deploy **fleet-side infrastructure** in ***italics***.

STEPS	FLEET ROLES	UTILITY ROLES
Online Request	Submit online request via utility website with preliminary project information (electrical engineer/contractor may be required to assess site capacity/load impacts)	Receive the application
Preliminary Design		Assign an internal designer for preliminary assessment and design
Detailed Design	Respond to data request from utility to support detailed design *Fleet responsible for detailed design of fleet-side infrastructure (i.e., all infrastructure behind the meter including panels, switchgear and EV chargers)*	Develop detailed design that outlines the infrastructure requirements needed to meet the service request
Connection Agreement	Property owner to sign offer outlining the scope and costs of the utility service upgrade	Develop the offer to connect, as well as terms and conditions and costs of the construction
Permitting and Other Dependencies	*Obtain necessary electrical and municipal permits and undergo any environmental assessments for fleet-side infrastructure, as needed, prior to construction*	Obtain necessary electrical and municipal permits and undergo any environmental assessments for utility-side infrastructure, as needed, prior to construction
Easements	Respond to easements from utility if utility-owned infrastructure needs to be installed on fleet property	Establish easements with any property owners whose land needs to be crossed to make the connection
Construction	*Fleet responsible for construction and deployment of fleet-side infrastructure (e.g., panels, switchgear and EV chargers)*	Procure major equipment and complete on-site construction (e.g., order transformers, lay feeder lines, construct substations, install meters)
Site Inspection	*Electrical safety inspection completed by relevant organization (e.g., ESA, Technical Safety BC) for fleet-owned infrastructure*	Electrical safety inspection completed by relevant organization for utility-owned infrastructure
Energization		Set up customer account, schedule and energize the connection

Figure 3. The customer's journey to a utility service upgrade[7]

[7] Note that behind-the-meter refers to electrical infrastructure located beyond the meter on the customer side. Front-of-the-meter refers to infrastructure located on the utility side of the meter.

3.4 Timelines

The preliminary steps of online requests and preliminary design are standard across utilities and are expected to take between one to six months, depending on the number of customers in the queue at the utility.

The lengths of the next steps – detailed design, establishment of a connection agreement, permitting and other dependencies, and easements, as needed – will vary according to the extent of the upgrades necessary. For minor upgrades, we expect this next phase to take less than six months, but it may last up to two years for major projects that require upgrades to the distribution system. In general, permitting and other dependencies, as well as the establishment of easements, can be completed in tandem with the development of detailed designs.

Once this step is completed, the construction can be completed in as little as a couple of months for minor upgrades, but can last up to 18 months for larger-scale improvements to the distribution system. The final step, the energization, is straightforward and can be completed in two weeks.

Under the right conditions, **a minor utility service upgrade** (e.g., one that solely requires a transformer upgrade or system extension to the customer) **can be completed in approximately six months**.

4. Canadian ZE MHDV Experience with Utility Service Upgrades

4.1 Current State of ZE MHDV Infrastructure Deployment

Major utility service upgrades have been limited to date among commercial ZE MHDV fleets in Canada.

Overall, large-scale ZE MHDV infrastructure deployments in Canada have been limited to date. The utilities we spoke to – though within Canada's most populous and ZEV-supportive provinces – have limited experience supporting upgrade requests for MHDV fleets. This is consistent with the fact that, with the exception of transit and school bus fleets, the vast majority of MHDV fleets in Canada have only deployed ZEVs at the pilot scale.

Many fleets are taking a phased approach to electrical infrastructure upgrades.

The few fleets we engaged that have expanded beyond the pilot scale, or that are proactively building out infrastructure to support future expansion of ZEVs into their fleet, have phased their deployments such that they are only in the first phase of necessary infrastructure upgrades.

For some fleets, this first phase has involved building facilities from the ground up to support near-term ZEV deployments. As service upgrades in these cases were made during the building construction stage, this translated to fewer bottlenecks overall.

For other fleets, this first phase has involved relatively straightforward equipment upgrades on the utility or customer side. This has included transformer, as well as switchboard and switchgear upgrades.

Leading MHDV fleets in Canada have deployed infrastructure to support 60-100+ ZEVs per fleet.

Overall, the transit and school bus fleets we engaged were the furthest advanced with one fleet having built out infrastructure to support 60 ZE MHDVs and another having deployed 107 EV chargers. Notably, one fleet we engaged has future-proofed four sites to support an expansion of up to 100 ZE class 8 trucks. This scale of infrastructure deployment extends well beyond the level of ZE MHDV deployments to date as most fleets are future-proofing their facilities to support future ZEV deployments.

Fleets have installed electrical capacities ranging from 2 to 9 MW to support this first phase of 60-100+ ZE MHDVs.

As an illustrative example, the table below shows just how quickly electricity demand ramp-ups with ZE MHDV deployments. A fleet of 50 ZE medium-duty vehicles (MDVs) charging overnight is expected to require at least 1 MW of power. Meanwhile, a fleet of 50 ZE heavy-duty vehicles (HDVs) could require up to 7.5 MW. For reference, 1 MW of electrical capacity would be equivalent to the power consumption of 800 Canadian households for a year or a small Canadian town, whereas 7.5 MW would be equivalent to the consumption of 6,000 Canadian households or a large industrial complex.

Table 4. Illustrative ZE MHDV fleet power demands

Vehicle Type	Charger Power Requirements for Overnight Depot Charging	Total Power Demand for a Fleet of 50 Vehicles
MDVs (box trucks, urban delivery trucks)	20 - 50 kW	1 - 2.5 MW
HDVs (class 8 trucks, regional buses, transit buses)	50 - 150 kW	2.5 – 7.5 MW

4.2 Bottlenecks in the Process

Electrical service upgrade requests require coordination across a wide range of teams within the utility.

We heard that, to date, most service upgrade requests are led by an individual within the utility's distribution design team. The project manager is responsible for coordination across, in some cases, over a dozen internal departments, such as:

- Design
- Properties
- Integrated Planning
- Vegetation
- Civil
- Line Field Operations
- Key Accounts
- Drafting
- Environmental
- Metering
- Policy
- Indigenous Relations
- Safety
- Generation System Operations
- Finance
- Standards

In addition to internal stakeholders, the project manager must also coordinate with the client and its contractors, leading to an even more complex process. Designers leading this process are typically not specialized in project management. We heard from one utility that they plan to introduce dedicated project managers to reduce the burden on the design team and aid in streamlining the process.

Staff capacity constraints on the utility side can lead to bottlenecks.

Utilities are facing an unprecedented volume of service upgrade requests across all sectors. This is not only driven by the electrification of sectors like buildings and transportation as a means of reducing emissions but also by housing crises and population growth that are driving development. The high demand is leading to internal staff capacity constraints, especially of qualified and trained personnel, which is causing significant delays during service upgrade requests. This demand is placing constraints not just on teams leading the planning or design phase, but also on field-based teams responsible for poles, lines, metering, or electrical safety. We heard that, in response to these capacity constraints, some utilities are subcontracting their technical reviews to external consultants leading to long review periods.

Data collection on the customer side can drive delays.

Many fleet operators do not have experience with utility service upgrade requests. This lack of experience can cause delays as fleets are not well-versed in the type or quality of supporting documentation that they are required to bring to discussions with utilities. Furthermore, they may not realize how quickly or often they need to engage their utility in this process. Utilities we spoke to noted that experienced electrical engineers, contractors, or EVSE providers can go a long way in assisting fleets to assess the level of service needed before submitting an application to the utility. Support from experienced external organizations can help to avoid unnecessary over-design. Some utilities, such as BC Hydro, have already established guides for fleet customers seeking a service connection that provides tips and best practices for infrastructure planning. Another utility we spoke to is exploring the implementation of a fleet advisory program.

One utility we spoke to also noted that customer requests to change the project scope late in the process can result in significant delays, as this may require the utility to restart the process from the design phase or seek what are typically lengthy approvals for variances.

Fleet service upgrade requests do not receive special treatment over other connection requests.

All of the utilities we spoke to noted that fleet service upgrade requests are not treated any differently than other service requests. One utility noted that there are regulatory barriers to prioritizing decarbonization initiatives like transportation electrification requests. Specifically, utilities are mandated to treat all connection requests equally. Another utility noted that there are challenges in prioritizing a decarbonization initiative from one that, for example, will help alleviate housing constraints, as both of these initiatives serve the public interest.

Utilities are reluctant to publicly share system capacity maps as they can quickly become out of date.

Some groups are advocating for system capacity maps to be made publicly available as this would improve transparency and aid fleets and other organizations during the planning stage. However, utilities are reluctant to share these maps primarily because the system capacity is dynamic and can change quickly when new projects enter the pipeline. If capacity maps are not regularly updated, utilities fear this could lead to further confusion. Some utilities also expressed concern that these heatmaps could be used by large customers to proactively reserve capacity in strategic locations for future projects, thereby disadvantaging other customers.

Reluctant property owners can slow down easement negotiations.

Fleet customers seeking the connection of a new electrical service on a leased property typically need to ensure that they have an agreement in place with the property owner before proceeding with major installations. One such agreement is called an "easement" and is often required by utilities at the connection agreement stage. It requires sign-off from owners of any property that needs to be crossed to connect the customer to the nearest transmission line. Some property owners are reluctant to give the right-of-way to the utilities to install cables and other equipment on-site, fearing devaluation of their property or the repercussions of no longer being able to access a portion of the land. This reluctance from property owners can lengthen the easement negotiation period resulting in delays to service connections.

Supply chain constraints were the leading cause of infrastructure bottlenecks experienced to date by the fleets we engaged.

These supply chain constraints have affected multiple dimensions of the transition to ZE MHDVs. One fleet we engaged cited vehicle availability as the biggest bottleneck. Another two fleets reported delays in procuring behind-the-meter infrastructure and equipment, such as chargers, electrical panels and breakers. A fourth fleet cited on-site construction as a major bottleneck.

We also heard that some utilities have faced delays when ordering critical equipment, which can lead to delays in project construction. Transformers were cited as having especially long lead times taking up to a year to be delivered, whereas lead times were closer to 16 weeks pre-pandemic.

It's expected that some of these delays could be attributed to supply chain constraints caused by the COVID-19 pandemic.

5. Looking Ahead: Recommendations for Improvement

Dunsky has developed a series of recommendations that can address bottlenecks to EV charging infrastructure deployment for MHDV fleets. In general, we have aimed to order these recommendations by relative level of impact/importance. For each recommendation, we have identified:

- Examples of similar initiatives in place in other jurisdictions, where possible;
- The relative ease of implementation (i.e., level of effort – whether that be political or financial capital – that would need to go into its implementation); and
- The agency best suited to leading its implementation, and where applicable, other agencies that are well-suited to playing a supportive role.

Table 5. Recommended actions to address bottlenecks in utility service upgrades to support ZE MHDV infrastructure deployment

Recommendation *Example from Other Jurisdictions*	**Ease of Implemen-tation**	**Implementation Lead & Support(s)**		
		Utility	**Regulator or Prov. Gov't**	**Fed. Gov't**
Utility **tariffs should be revised** to ensure customers are not required to cover a disproportionate share of costs associated with **upstream system capacity increases** that currently place an undue burden on "first movers". Utilities should explore the possibility of ratebasing infrastructure upgrades such that individuals collectively pay for utility capacity increases as a means of cost recovery. Recent analysis in the United States shows that utility investment in electrical infrastructure upgrades to support fleet electrification can result in a net benefit for ratepayers.[8]	Low	Lead	Support	
Utilities should be given the regulatory authority to make **proactive investments** in transmission and distribution system upgrades. ZEV mandates and targets coming into effect make it clear that this load will materialize. Regulators should also consider mandating utilities	Low	Support	Lead	

[8] Pamela MacDougall, "Covering infrastructure costs to support commercial EV charging is worth it for utilities and ratepayers," *Utility Dive*, April 20, 2023.

Recommendation *Example from Other Jurisdictions*	**Ease of Implemen-tation**	**Implementation Lead & Support(s)**		
		Utility	**Regulator or Prov. Gov't**	**Fed. Gov't**
to develop comprehensive plans of distribution investments needed under a range of MHDV electrification scenarios, including very rapid electrification. *Examples: Through the Greenhouse Gas Reduction Regulation (GGRR), the B.C. Government allows utilities to ratebase "prescribed undertakings" that contribute to GHG emissions reductions, including the deployment of EV charging infrastructure.*[9] *Similarly, the Government of Quebec adopted a law – the Loi favorisant l'établissement d'un service public de recharge rapide pour véhicules électriques – that enables the utility to ratebase investments in public charging infrastructure.*[10]				
Appropriate mechanisms to enable **federal and provincial financial support** for utility-led transmission and distribution system upgrades should be identified. Investments should be pursued. *Example: MISO board approved $10.3 billion in long-range transmission portfolio to enable GHG emissions reductions.*[11]	Med		Co-Lead	Co-Lead
Regulators should identify appropriate mechanisms to **prioritize beneficial electrification initiatives** like transportation electrification for expedited utility service connections. *Example: Hydro Quebec must authorize any interconnection project requiring more than 5MW, based on technical criteria as well as economic, social and environmental benefits.*[12]	Low	Support	Lead	

[9] B.C. Government, "Greenhouse Gas Reduction Regulation." Accessed April 2024.
[10] Hydro Québec, "Le Circuit électrique va déployer 1600 bornes de recharge rapide au Québec sur 10 ans." Accessed April 2024
[11] MISO Energy, "MISO Board Approves $10.3B in Transmission Projects." Accessed April 2024.
[12] Government of Quebec, "Attribution responsable et durable de notre électricité." Accessed April 2024.

Recommendation *Example from Other Jurisdictions*	**Ease of Implemen-tation**	**Implementation Lead & Support(s)**		
		Utility	**Regulator or Prov. Gov't**	**Fed. Gov't**
Utilities and their regulators should update rates to better reflect **real-time energy prices** and **marginal costs of demand** on distribution and transmission grids. **Demand-side management** programs should be expanded to optimize EV load flexibility to reduce costs/maximize value for the electric grid, including using: • Passive measures (e.g., rates, programs that reward electrical designs for EV charging that result in the least contribution to coincident peak power demand, etc.) • Active managed charging (V1G) • Vehicle to grid (V2G) Programs and rates should be structured to reward fleets that adopt strategies that maximize the flexibility of EV charging, resulting in improved economics for fleet owners and more rapid adoption of electric fleets versus the status quo.	Med	Lead	Support	
Electricity system operators should establish **regional standards for utility service connections** in provinces that are host to a patchwork of local distribution companies. *Example: The Ontario Energy Board (OEB) has developed the EV Charging Connection Procedures, outlining the process that all local distribution companies in the province must follow for installing and connecting EV chargers.*[13]	High	Support	Lead	
Regulators should mandate utilities to provide better customer visibility into **infrastructure cost ranges**. Opportunities to standardize costs across regions should be explored.	Med	Support	Lead	
Regulators should mandate utilities to publicly share **up-to-date system capacity maps**. Utilities should ensure that their internal	Med	Support	Lead	

[13] Ontario Energy Board, Electric Vehicle Charging Connection Procedures (2023).

Recommendation *Example from Other Jurisdictions*	**Ease of Implemen-tation**	**Implementation Lead & Support(s)**		
		Utility	**Regulator or Prov. Gov't**	**Fed. Gov't**
processes are streamlined in such a way that timely and low-cost connections can be completed regardless of local capacity. *Example: The Federal Energy Regulatory Commission (FERC) recently finalized a rule requiring utilities to maintain publicly available system capacity maps (i.e., heatmaps).*[14]				
The federal government should explore opportunities to allocate funding for **clean energy workforce** and supply chain development.	Med			Lead
Utilities should allocate funding to improve **internal capacity** around **transportation electrification solutions** by, for example, hiring dedicated staff, offering training programs for staff, developing educational resources for customers (e.g., guides for fleets seeking a service upgrade), and establishing networks of external consultants that can reliably support EV charging infrastructure assessments.	High	Lead		

[14] Federal Energy Regulatory Commission, "Explainer on the Interconnection Final Rule." Accessed April 2024.

Appendix A

Building Electrical System Components

Note that this section draws on content that was recently developed for the Federation of Canadian Municipalities on Futureproofing Multifamily Buildings for EV Charging. While the context differs somewhat, many of the same principles apply.

Figure 4 and Figure 5 summarize the basic elements of electrical systems in more simple and complex buildings, respectively. Typical equipment includes:

- A main **electrical meter**. Additional utility meters, as well as non-utility sub-metering, may be installed in other portions of the building too.
- A **main transformer** reduces voltages from utility distribution system voltages (e.g., 25kV, 12.5kV, other voltages) to those used in building systems (e.g., 120/240V in small buildings; 277/480V or 347/600V in larger buildings). Utilities typically own the transformers in small buildings and many larger buildings too. Some large buildings get utility service connections at distribution system voltages and own their own transformers.
- **Switchgear**. In larger buildings, the electricity supply is first fed into switchgear comprised of electrical disconnect switches, fuses or circuit breakers used to control, protect and isolate electrical equipment. Switchgear distributes power to various **feeders** serving different parts of a building.
- Transformers may be located on these feeders to step down voltages to those used to supply equipment such as EV chargers (e.g., from 347/600V to 120/208V).
- Power is then delivered to various **branch panels**. For example, one or more branch panels will provide the source of electricity for EV charging in a fleet depot building.
- **Branch circuits** are distributed off from branch panels. A branch circuit is the portion of a wiring installation between the final overcurrent device (e.g., a circuit breaker) protecting the circuit and an outlet(s).
- An **outlet** is the point in a wiring installation at which current is taken to supply equipment like an EV charger. An outlet can be a receptacle at which equipment is plugged in. It can also be a junction box or enclosure at which equipment like an EV charger can be hardwired.

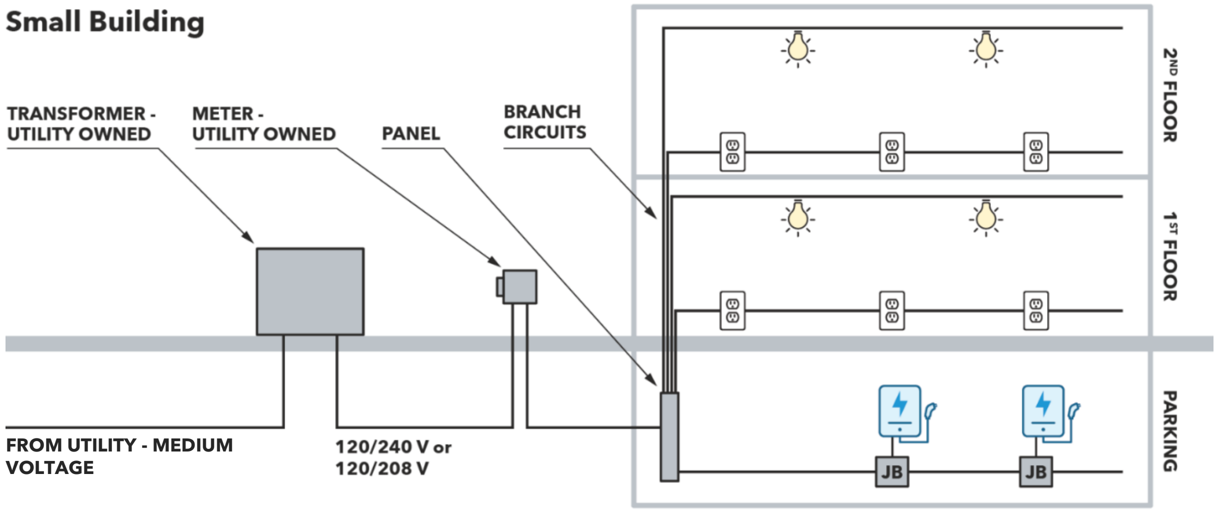

Figure 4. Electrical systems in a smaller building

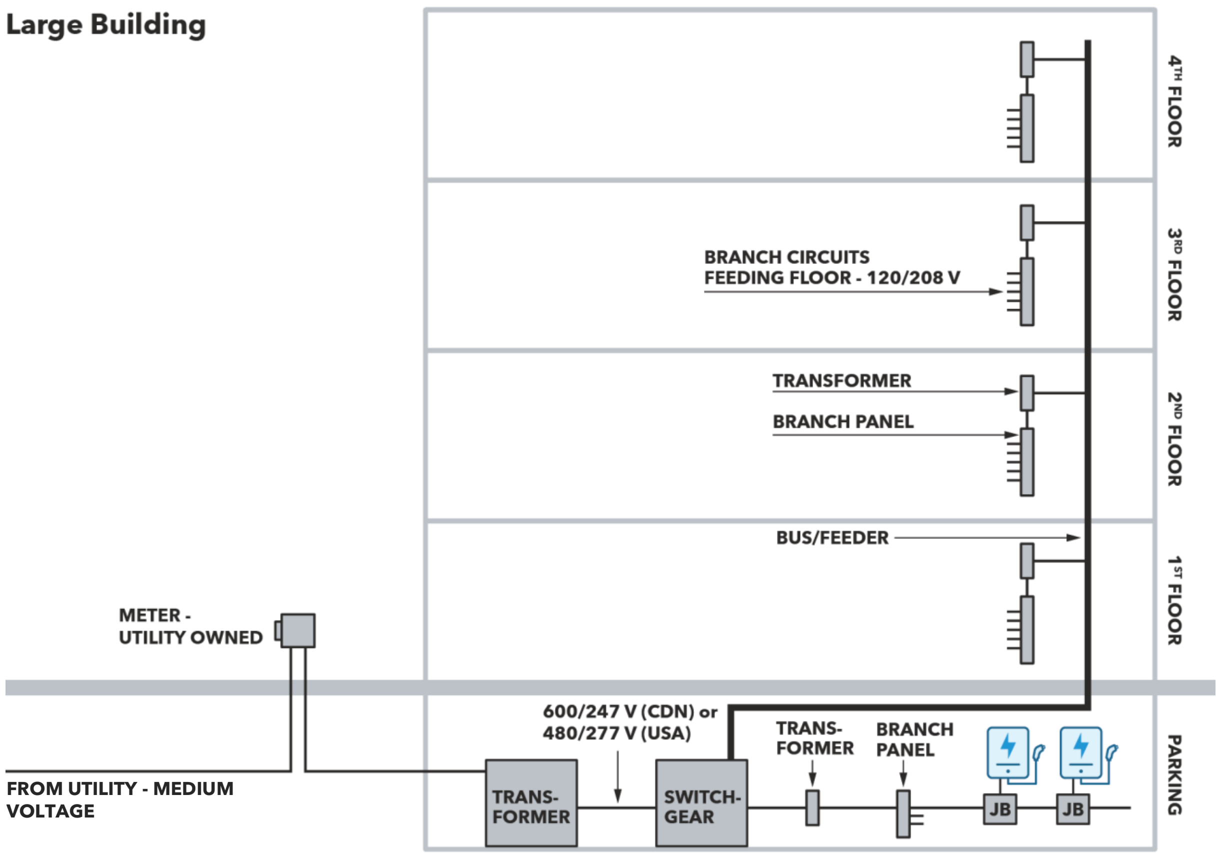

Figure 5. Electrical systems in a larger building

Appendix B

Fleet Survey Questions

Part 1: Electrical Connection Request Process

1. In your electrification journey, have you needed to request a new electrical service and/or upgrade your existing electrical service to support fleet charging?

a. Yes
b. No
c. Other

2. If not, how did you avoid an upgrade to your electrical service? Do you expect you'll need an upgrade in the future?

3. If yes, what stage are you at in the process?

a. Planning
b. Implementation
c. It's already complete
d. Other

4. Describe the scale of infrastructure upgrades you completed (e.g., number of EVs supported, type of electrical infrastructure installed).

5. If known, what level of capacity did you need to install (in MVA or MW, please indicate units)?

6. Was this upgrade a part of a phased approach to long-term fleet electrification?

a. Yes
b. No, it was to serve our immediate needs
c. Other

7. If yes, can you provide an overview of your phased approach?

8. Which utility supported your request?

9. Can you provide an overview of the major steps involved in the process of obtaining a new electrical service?

10. From the time you made the request to the time you completed the process, how long did this take?

11. Did you work with an experienced contractor or engineering team on the project?

a. Yes
b. No
c. Other

12. Did you explore the implementation of energy efficiency and other demand management measures (e.g., on-site storage or EV charging load management strategies) to reduce your facility's peak demand before pursuing this upgrade?

a. Yes
b. No
c. Other

13. What was the biggest bottleneck that you faced during the interconnection/upgrade process?

a. Preparing necessary documentation for utility

b. Receiving design and cost estimate from utility
c. Receiving rights/permission from property owner/manager
d. On-site construction
e. Other

14. What was the root cause of this bottleneck?
a. Lack of internal experience and knowledge around what the utility would need from our fleet to support the process
b. Delays on utility side
c. Supply chain constraints
d. Shortage of skilled workers
e. Other

Part 2: Costs

15. What magnitude of costs did you face to upgrade your facility's electrical connection (excluding EV charger hardware and installation)?
a. <$250,000
b. $250,000-$500,000
c. $500,000-$1M
d. $1-2M
e. $2-5M
f. $5-10M
g. >$10M

16. What was the biggest driver of these costs (e.g., what piece of equipment represented the largest share of costs)?

17. Did the utility ask you to cover any portion of the cost of infrastructure in front of the meter?
a. Yes
b. No
c. Other

18. If yes, what was their rationale for you covering those costs?

19. Are you aware of federal infrastructure programs for ZEMHDVs (either the Zero-Emissions Vehicle Infrastructure Program, the Canada Infrastructure Bank's Charging and Refuelling Program, or the Zero-Emissions Transit Fund)?
a. Yes
b. No
c. Other

20. Did you apply? Why/why not?

21. Were you successful in receiving funding from either of these programs to support your electrical infrastructure upgrades?
a. Yes, ZEVIP
b. Yes, ZETF
c. No
d. Other

22. If not, why not?

Part 3: Other

23. Would access to your local utility/distribution company's system capacity map be helpful for planning purposes?

- *a. Yes*
- *b. No*
- *c. Other*

24. Did you engage with other fleets before starting the process to gain insight into their experience?

- *a. Yes*
- *b. No*
- *c. Other*

"NO DISCLAIMERS" POLICY

This report was prepared by Dunsky Energy + Climate Advisors, an independent firm focused on the clean energy transition and committed to quality, integrity and unbiased analysis and counsel. Our findings and recommendations are based on the best information available at the time the work was conducted as well as our experts' professional judgment.
Dunsky is proud to stand by our work.

To support the mandate of Canada's Net-Zero Advisory Body related to research, this project was undertaken with the financial support of the Government of Canada. Funding was provided through the Environmental Damages Fund's Climate Action and Awareness Fund, administered by Environment and Climate Change Canada.