2023 TECHNICAL REPORT

Zero-Emission Planning and Grid Assessment for the Port of Los Angeles

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Final Report, June 2023

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ABSTRACT

Ports, including the Port of Los Angeles (POLA), are aiming to reduce greenhouse gas emissions and local air-quality impacts. However, electrification of cargo handling equipment (CHE) at ports poses technical challenges. In a project jointly funded by the Los Angeles Department of Water and Power (LADWP) and POLA, the project team assessed the extent of current electrification efforts with six POLA container terminal operators, and identified cost-effective CHE electrification opportunities that will be applicable to all the terminal operators using CHE at POLA. The emphasis of the work was a complete review of land-side equipment, including terminal tractors (UTRs), forklifts, top loaders, empty container handlers, non-road vehicles, rubber-tired gantry (RTG) cranes, and wharf cranes. The team then studied the impacts on the existing electric grid infrastructure if all ZE CHE were powered by electricity. Upgrades to the LADWP grid infrastructure required to meet the new electrification loads were also identified. The team then developed a roadmap for LADWP and POLA to meet ZE CHE goals by 2030 and 2035, assuming all ZE CHE is powered by electricity. The study also conducted a preliminary assessment of using hydrogen as a fuel to meet the net ZE targets while minimizing grid impacts.

Keywords

Air quality
Electrification
Hydrogen
Ports
Seaports
Zero-emission

EXECUTIVE SUMMARY

Deliverable Number: 3002025783

Product Type: Technical Report

Product Title: Zero-Emission Planning and Grid Assessment for the Port of Los Angeles

Primary Audience: Utility personnel involved in system planning, distribution engineering and transportation; Port Authority personnel, and environmental engineers

Secondary Audience: Port Terminal Operators, other governmental agencies personnel, such as the California Air Resources Board (CARB) and Air Quality Management Districts (AQMDs)

KEY RESEARCH QUESTION

Ports, including POLA, are aiming to reduce greenhouse gas (GHG) emissions and local air-quality impacts. However, electrification of cargo handling equipment (CHE) at ports poses technical challenges. Lithium-ion battery technology costs are currently high, and technology availability is limited. Demonstrations of new electric technologies at the ports are in process, but widespread adoption has not yet been achieved. Complying with regulatory requirements and responding to local resolutions, including a mandate for zero-emission (ZE) CHE by 2030 at POLA, places challenges. POLA needs to maintain its competitiveness, while overcoming technical complexities and ensuring response and compliance. Another important topic this project addresses is the need to understand the grid impact of supplying the ZE (electric) CHE equipment.

RESEARCH OVERVIEW

In a project jointly funded by the Los Angeles Department of Water and Power (LADWP) and POLA, the project team assessed the extent of current electrification efforts with six POLA container terminal operators, and identified cost-effective CHE electrification opportunities that will be applicable to all the terminal operators using CHE at POLA. The emphasis of the work was a complete review of land-side equipment, including terminal tractors (UTRs), forklifts, top loaders, empty container handlers, non-road vehicles, rubber-tired gantry (RTG) cranes, and wharf cranes. The team then studied the impacts on the existing electric grid infrastructure if all ZE CHE were powered by electricity. Upgrades to the LADWP grid infrastructure required to meet the new electrification loads were also identified. The team then developed a roadmap for LADWP and POLA to meet ZE CHE goals by 2030 and 2035, assuming all ZE CHE is powered by electricity. The study also conducted a preliminary assessment of using hydrogen as a fuel to meet the net ZE targets while minimizing grid impacts.

KEY FINDINGS

- The terminal tractors (UTRs), top handlers, forklifts, RTG cranes, and straddle carriers offer the highest electrification potential opportunity for POLA, accounting for nearly 88% of the total container CHE inventory of the six terminals visited.
- CHE at POLA accounts for nearly 15% of CO_2 emissions, 5% of NOx emissions, 38% of CO emissions, and approximately 5% of all diesel-related pollutants of the total port emissions.
- The POLA tenant CHE charging loads significantly increase the POLA area distribution system loading, requiring significant distribution system upgrades. Original (2021 COVID-19 impacted, conservative) load models predict distribution loading increases of 277 MW with unmanaged charging, or 133 MW with managed charging. Updated (2022, less COVID-19 impacted, less conservative) load models predict increases of 191 MW (unmanaged) or 128 MW (managed). These reflect 108–230% of the RS-Q Bank B existing peak load of 119 MW in 2021.
- Peak demand of CHE can be significantly reduced with an optimal charging solution implemented at the terminal operator locations.
- In the grid impact analysis with load models from either original (2021 COVID-19 impacted, conservative) modeling or updated (2022, less COVID-19 impacted, less conservative) modeling, no overvoltages were observed in any of the analyzed future electrification scenarios. Only limited undervoltages were observed in 100% unmanaged charging scenarios. Significant receiving station (RS-Q) bank and circuit overloads were observed in the future electrification scenarios. The updated load models resulted in considerably less overloads than the original load models, highlighting the importance and uncertainty with the port and CHE load modeling.
- Analysis of energy storage as a mitigation measure found that energy storage is not an economically viable solution for the terminal operators to reduce their CHE peak loads, given the current energy storage costs and the rate structures available to the operators. However, this may change as energy storage costs decrease or if different rate structures are available.
- The future substation (RS-Q) upgrades that LADWP plans are insufficient alone to accommodate the future electrification scenarios with either original or updated load models. A new receiving station and significant circuit-level upgrades would be required to accommodate some of the scenarios analyzed in the report.
- The grid impact and mitigation assessment has demonstrated a clear value in managing the POLA tenant CHE charging loads to reduce the peak loads that they may cause. The unmanaged charging scenarios (in which CHE is charged as soon and as much as possible) resulted in significantly greater grid impacts, requiring considerably more expensive grid upgrades compared to the managed charging scenarios.

WHY THIS MATTERS

Potential benefits to POLA include enhanced regulatory compliance, equipment lifecycle cost savings, improved CHE productivity, and enhanced employee safety, health, and satisfaction. Potential benefits to surrounding communities include improved air quality (i.e., reduced NO_x, SO_x, and particulate emissions from CHE and ships at marine ports), thereby reducing local human-health impacts. Potential benefits to the broader area include decarbonization via reduced GHG emissions to achieve climate change mitigation goals. Potential benefits to LADWP, EPRI members, and the broader utility community include proactively supporting current and future port electrifications, meeting broad electrification and sustainability targets, quantifying characteristics and needs of port electrification projects, and enabling strategic and cost-effective investment by identifying load mitigation solutions to prioritize grid upgrades.

HOW TO APPLY RESULTS

LADWP and POLA can directly use the information in this report to identify cost-effective CHE electrification opportunities, identify LADWP grid infrastructure upgrades required to meet the new electrification loads, and develop a roadmap to meet ZE CHE goals by 2030 and 2035, assuming all ZE CHE is powered by electricity. The conclusions and recommendations section includes project accomplishments, key findings, and the roadmap.

LEARNING AND ENGAGEMENT OPPORTUNITIES

A complementary study is planned to understand the emission impacts with hydrogen fuel cells supporting CHE use.

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PROGRAMS:

- Electrification Program (P199)
- Distribution Operations and Planning (P200)
- Energy Storage (P94)
- Electric Transportation (P18)

ACRONYMS AND ABBREVIATIONS

AMP	Alternative Maritime Power®
CARB	California Air Resources Board
CHE	cargo handling equipment
CH4	methane
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
DEFT	Dynamic Energy Forecasting Tool
DOE	U.S. Department of Energy
DPM	diesel particulate matter
DS	distribution station
DSS	distribution system simulator
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FMS	Fenix Marine Services
GIS	geographic information system
H2	hydrogen
HC	hydrocarbons
hp	horsepower
ICE	internal combustion engine
IS	industrial station
ICTF	Intermodal Containers Transfer Facility
kVA	kilovolt-amp

kvar	kilovolt-amp reactive
MVAR	megavolt-amp reactive
kW	kilowatt
kWh	kilowatt hour
LADWP	Los Angeles Department of Water and Power
LEAF	low energy adaptive fuel
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LTC	load tap changer
MMBtu	million British thermal units
MV	medium voltage
MW	megawatt
NAICS	North American Industry Classification System
NO_x	nitrogen oxides
N_2O	nitrous oxide
NZE	near zero emission
OEM	original equipment manufacturer
PF	power factor
POLA	Port of Los Angeles
PM	particulate matter
PM_{10}	particulate matter (10 micrometers and smaller)
$PM_{2.5}$	particulate matter (2.5 micrometers and smaller)
pu	per unit
PV	photovoltaics

QSTS	quasi-static time-series
RMG	rail-mounted gantry (crane)
RNG	renewable natural gas
RS	receiving station
RS-C	receiving station “C”
RS-Q	receiving station “Q”
RTG	rubber-tired gantry (crane)
SCADA	supervisory control and data acquisition
SO_x	sulfur oxides
SO_2	sulfur dioxide
STS	ship-to-shore
TSHD	trailing suction hopper dredge
UP	Union Pacific
UTR	utility tractor rig
WBCT	West Basin Container Terminal
YTI	Yusen Terminals
ZE	zero emission
ZECAP	Zero Emissions for California Ports

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1 INTRODUCTION

This section describes the motivation for this study, the challenges the Port of Los Angeles (POLA) faces, the purpose of this study, project tasks, potential benefits of the project for various stakeholders, and relevant regulatory and policy initiatives. The section also describes the potential applications for electrification in U.S. marine ports, as well as the scope of this study. Also included are descriptions of cargo handling equipment (CHE), challenges with converting these to alternative fuels or electricity, summaries of past POLA efforts in this regard, a list of the largest providers of cargo handling services (according to the North American Industry Classification System [NAICS]), and available models of electrical equipment relevant to port electrification.

Motivation for this Study

Today, the United States is served by publicly and privately owned marine facilities located in approximately 360 commercial sea and river ports. These marine ports rely in large part on specialized diesel-fueled and gasoline-engine-fueled CHE that handles various types of cargo. In 2008, EPRI provided POLA a resource guide on CHE, including available electric equipment, the general costs and benefits of electrification, and contact information for electric equipment manufacturers [1].

A key driver is reducing greenhouse gas (i.e., carbon dioxide [CO_2]) emissions. In recent years, air-quality concerns associated with nitrogen oxides (NO_x), sulfur oxides (SO_x), and particulate emissions at marine ports have become a widely discussed issue facing cargo handling. While economic growth is necessary for economic health and global competitiveness, the pollution emitted is growing as well.

Responding to these concerns, the California Air Resources Board (CARB) has issued a regulation, and the Los Angeles City Council and Long Beach City Council have issued resolutions related to marine port emissions. As major motivators of this project, these developments are summarized below.

Electrification of CHE is a near-term option that can provide broad-based benefits to marine ports, including potential emissions reductions, lifecycle cost savings, improved employee health and safety, and improved productivity.

With these motivations, POLA and the Los Angeles Department of Water and Power (LADWP) engaged with EPRI to perform this Port of Los Angeles Electrification Planning and Assessment project. The project team has been conducting this project over the course of 2022 and early 2023.

Summary of Challenges POLA Faces

POLA faces the following challenges:

- Electrification at ports is not without its technical challenges. Lithium-ion (Li-ion) battery technology—with all of its variants—boasts high energy densities, long life, and resilience to rapid charge and discharge cycles. However, technology costs are currently high, and technology availability is limited. Demonstrations of new electric technologies at the ports are in process, but widespread adoption has not yet been achieved.
- Complying with regulatory requirements and responding to local resolutions places challenges on POLA.
- POLA needs to maintain its competitiveness while overcoming technical complexities and ensuring response and compliance.

Purpose and Objectives of this Study

The purpose of this study is to assess the extent of current electrification efforts, as well as understand the electrification pathway to meet the zero-emission (ZE) mandate (ZE CHE by 2030)[1] at POLA [2,3,4]. This study addresses the many aspects of ports that can be considered for electrification. The emphasis of the work is a complete review of land-side equipment, including terminal tractors, forklifts, top loaders, empty container handlers, non-road vehicles, rubber-tired gantry (RTG) cranes, and wharf cranes. The study was jointly funded by the LADWP and POLA and was prepared by EPRI.

The objectives of this study are as follows:

- To assess the extent of current electrification efforts with six container terminal operators
- To identify cost-effective CHE electrification and hydrogen fuel cell opportunities at POLA
- To study impacts to existing electric grid infrastructure if all ZE CHE were powered by electricity and/or hydrogen fuel cell
- To identify the LADWP grid infrastructure upgrades required to meet the new electrification and/or hydrogen fuel cell loads
- To develop a roadmap for LADWP and POLA to meet ZE CHE goals by 2030 and 2035, assuming all ZE CHE is powered by electricity and/or hydrogen fuel cell

[1] 2017 CAAP cites NZE for CHE by 2030: https://cleanairactionplan.org/2017-clean-air-action-plan-update/#.

Disclaimers

The study team would like to add the following study disclaimers:

- This study is based on the following assumption: all existing nonelectric and fossil-fueled CHE is converted to ZE CHE via electric power and/ or hydrogen fuel cell. In other words, the scope of alternative technologies examined was limited to battery-electric, grid-electric technologies and hydrogen fuel cell technologies.
- The CHE electric loads have been developed using the best information about port terminal CHE inventories and operations and about the electric alternatives available at the time of this study.
- The team recommends that the study be revisited in the 2–3-year timeframe to update the findings by verifying whether the assumption that all ZE CHE will be powered by electricity is valid in 2024 or 2025 and applying updated costs, availability of electrification technologies, information of POLA tenant electrification strategies, and so on.
- This study acknowledges that no POLA container terminal operator shared specific plans to meet ZE CHE goals by 2030 or 2035, nor did they share anticipated electric charging schedules, as most ZE CHE is still in prototype phase. Therefore, this study assumes all CHE listed in the 2021 POLA Air Emissions Inventory will be converted to ZE CHE via electric power and/or hydrogen fuel cell. This study also utilized a 2021 Pacific Merchant Shipping Association report, *Electrification of California Ports*, as a reference to develop ZE CHE electric charging schedules.

Project Tasks

This study consists of the following analyses:

- Existing CHE inventory analysis
- Electric demand, energy, and emissions analysis for the existing CHE inventory (which are currently powered by diesel, gasoline, liquefied petroleum gas [LPG], or liquefied natural gas [LNG] fuel) and for ZE CHE, assuming all existing CHE were powered by electricity and/ or hydrogen fuel cell
- Electric grid impact analysis if all existing CHE were powered by electricity and/or hydrogen fuel cell to become ZE CHE
- Electric grid mitigation analysis for electric-powered and/ or hydrogen fuel cell ZE CHE

As a part of the study, the LADWP, EPRI, and POLA staff conducted a site visit from March 30 to April 1, 2022 and met with six terminal operators located in POLA. The inventory information provided by the terminal operators (or POLA tenants) is used in the above analyses. Additionally, the 2021 Air Emissions Inventory was used to cross-check the inventory that was collected from the six terminal operators. However, no terminal operator shared plans to meet

ZE CHE goals by 2030 and 2035, as most ZE CHE is currently in prototype phase. Therefore, this study assumes all existing CHE will be converted to electric power and/or hydrogen fuel cell to meet ZE CHE goals in 2030 and 2035.

The tasks and deliverables of this project are listed in Table 1 (with the relevant section numbers in this report).

Table 1. Project tasks and deliverables

Task #	Task Description	Deliverables	Section in this Report
1	Initial Discussion and Roadmap	Kickoff presentation slides for LADWP and POLA and briefing presentation for port operators/tenants Electrification guide that includes a 13-year roadmap (2022–2035) for port operations and expansion	1
2	Site Visit and Data Collection	Preliminary equipment inventory database of the port operators in three days	2
3	Inventory of CHE and Other Port Equipment	Final detailed inventory database and preliminary slides on the various CHE and other port equipment	2
4	Characterization of Energy Requirements and Emissions Reduction for Port Operations	Individual equipment annual energy usage, load shape characterization, load shape under planned and unplanned usage, cumulative energy and kW demand characteristics, and overall site emissions reduction potential	3, 4
5	Characterization of Electric Equipment Charging Options	Report on equipment charging solutions, both current (if any) and future recommendations based on utility rates, availability of equipment, timing of operation, most cost-effective charging strategy, and other parameters	4
6	Grid Data Collection	Documentation of data provided for grid modeling and any data cleaning necessary for modeling	Appendix B
7	Grid Model Development	Time-series OpenDSS model of the LADWP distribution system in the POLA area, including any assumptions and a snapshot CYME model along with the time-series profiles	5
8	Grid Impact Assessment	Summary of capacity and energy deliverability of existing assets pre-electrification and identification of assets overloaded due to new electrification and/or hydrogen fuel cell load	6
9	Mitigation Alternative Assessment	Summary of feasible mitigation solutions	7

Table 1 (continued). Project tasks and deliverables

Task #		Task Description	Deliverables	Section in this Report
10		Performance of Techno-Economic Analysis of Mitigation Solutions	Draft report on cost-benefit analysis for each of the identified port equipment (on a per unit basis)	8
11		Reporting and Technology/Knowledge Transfer	Develop project key findings, conclusions, and recommended next steps	9

Potential Benefits of the Project

Potential benefits to POLA tenants include the following:

- **Regulatory compliance.** Electric and/or hydrogen fuel cell CHE and shore-power systems help POLA tenants comply with CARB regulations and respond to relevant local resolutions.
- **Lifecycle cost savings.** Higher capital costs—vehicles, infrastructure, batteries, and hydrogen fuel cells—can be offset by lower fuel and maintenance costs over the equipment lifecycle.
- **Enhanced employee safety, health, and satisfaction.** Employees like the quiet, emission-free, vibration-free operation of electric CHE.
- **Improved productivity.** In some applications, electric and hydrogen fuel cell CHE outperforms diesel- and gasoline-powered equipment, enhancing productivity.

Potential benefits to surrounding communities include the following:

- **Improved local air quality.** Reduced NO_x, SO_x, and particulate emissions from CHE and ships at marine ports improves local air quality, thereby reducing local human-health impacts.

Potential benefits to the broader area include the following:

- **Decarbonization.** Reduced greenhouse gas (e.g., CO_2) emissions helps achieve decarbonization and climate change mitigation goals. Reduced air pollutants from diesel- and gasoline-powered vehicles help improve the health of port workers and the local community.

Potential benefits to LADWP, EPRI members, and the broader utility community include the following:

- Provide customer- and grid-specific processes, considerations, and analytics to proactively support current and future port electrifications
- Meet broad electrification and sustainability targets by proactively planning for future electrification and hydrogen fuel cell scenarios
- Quantify port load characteristics, energy, and peak demand; charging infrastructure needs; and forecasts of future port electrification and/or hydrogen fuel cell loads
- Enable strategic and cost-effective investment by identifying load mitigation solutions to prioritize grid upgrades

Background on Regulatory and Policy Initiatives

This subsection summarizes climate goals for the State of California, CARB at-berth ship regulation, Los Angeles City Council and Long Beach City Council resolutions, and a U.S. Environmental Protection Agency (EPA) shore power assessment.

Electrification and/or Hydrogen Fuel Cell Guide: 13-Year Roadmap for POLA

Table 2 from the 2021 POLA Emissions Inventory shows estimates of CHE emissions of CO_2, NO_x, CO, hydrocarbons (HC), and diesel-related pollutants at POLA in 2021 for various pollutant types [5].

Table 2. CHE emissions at POLA for calendar year 2021 [5]

Terminal Type	PM_{10} tons	$PM_{2.5}$ tons	DPM tons	NO_x tons	SO_x tons	CO tons	HC tons	CO_2e tonnes
Auto	0.0	0.0	0.0	0.0	0.0	0.2	0.0	5
Break-Bulk	0.4	0.4	0.4	28.2	0.1	24.9	3.2	8364
Container	5.8	5.4	4.4	370.7	1.9	717.9	79.8	169,063
Cruise	0.0	0.0	0.0	0.1	0.0	0.6	0.0	48
Dry Bulk	0.1	0.1	0.1	7.1	0.0	6.5	0.6	454
Liquid	0.0	0.0	0.0	0.1	0.0	0.2	0.1	49
Other	0.2	0.2	0.2	8.0	0.1	29.5	1.8	6856
Total	**6.5**	**6.0**	**5.0**	**414.2**	**2.0**	**779.8**	**85.5**	**184,837**

Table 3 shows the team’s proposed 13-year roadmap (2022–2035) for POLA.

Table 3. Electrification and/or Hydrogen Fuel Cell guide: The team's proposed 13-year roadmap (2022–2035) for POLA operations and expansion

Timeline	CHE Equipment	Recommendations
2022–2025	Convert 50% of the existing nonelectric CHE equipment to electric and/or hydrogen fuel cell in the following categories: 1. Utility tractor rigs (UTRs) – Several electric and/or hydrogen fuel cell options exist from Kalmar Ottawa, Orange EV, Capacity, and Autocar. 2. Forklifts – Electric and/or hydrogen fuel cell forklifts are available in all lifting capacities from 5000 lb to 80,000 lb. 3. RTG cranes – Several manufacturers have electric-powered RTG cranes. 4. Top handlers – This technology is currently demonstrated at POLA. 5. Straddle carriers – A hybrid option currently exists that uses both electric- and diesel-based technology. These five categories represent nearly 88% of the CHE inventory in the six container terminals.	Optimal charging is possible that can help reduce the peak demand by up to 50%.
2025–2030	Convert the remaining 50% of the five categories (UTRs, forklifts, RTGs, top handlers, and straddle carriers) of the fossil-fuel-based CHE inventory to electric and/or hydrogen fuel cell. Other nonelectric, ZE options could also be considered to meet the 100% ZE port regulations, such as hydrogen fuel cell equipment. In the interim, terminal operators may also investigate other low-carbon fuel solutions, such as LNG or renewable natural gas (RNG) technology solutions.	The cost of energy storage solutions may decrease, enabling reduction at each of the terminals. The energy storage solution could be co-owned by POLA and LADWP.
2030–2035	Some technologies, such as yard sweepers and cone vehicles, still do not have an electric and/or hydrogen fuel cell equivalent. They may become available after 2035.	Vehicle-to-grid options could be available in 10 years that could potentially help with demand reduction. The integration of more renewable generation could help reduce the growing electric demand.

In order to achieve 100% ZE for the ports, the CHE could be phased out of fossil fuel technologies and phased into electric and/or hydrogen fuel cell technologies. Although not all the CHE technologies have an electric and/or hydrogen fuel cell equivalent technology that exists today, many of the current technologies have at least one or more available battery-electric or hydrogen fuel cell technology equivalents. These technologies are currently demonstrated at some of the container terminals at POLA.

California Air Resources Board "At-Berth" Ship Regulation

Building on 2007 regulation, a CARB rule adds new vessel categories (e.g., auto carriers and tanker vessels) that must control pollutant emissions (NO_x, SO_x, particulate emissions, reactive organic gases, and greenhouse gases) from their auxiliary engines and boilers while docked in an expanded set of California ports and terminals. The new rule took effect January 1, 2023, but is being phased in from 2023 to 2027 for various vessel types. Under the rule, all vessels at a regulated California port must use either shore power or a CARB-approved control technology to control emissions [6, 7].

Los Angeles City Council: Zero-Emission Ports by 2030

In November, 2021, the Los Angeles City Council adopted a resolution that calls for all ships that dock at the ports of Los Angeles and Long Beach to be ZE ships by 2030. This regulation comes on the heels of record numbers of ships idling offshore of these ports, which increased local pollution levels from shipping. According to one report, "the 2030 deadline is likely to prove overly ambitious with the greenest of pledges from top carriers thus far saying they'll have their first zero emissions ships running this decade, but by no means entire fleets ready in eight years' time" [8]. While the city has no regulatory authority over maritime activities, the resolution places pressure on shippers to adopt emissions-reducing technologies [9].

Long Beach City Council Adopts "Ship It Zero" Resolution

In June 2022, the Long Beach City Council passed a "Ship It Zero" resolution that calls for shippers using the San Pedro Port Complex (which encompasses POLA and the Port of Long Beach) to use ZE ships by 2030. Following a similar resolution by the LA City Council, this resolution unites the nation's two largest ports in this commitment [10]. The port complex handles over 275 million metric tons of cargo each year.

The Green Shipping Challenge

The United States and Norway organized the Green Shipping Challenge at the 27th Conference of the Parties to the United Nations Framework Convention on Climate Change (COP27) [11]. This challenge encourages governments, ports, and companies to prepare commitments to increase the transition to green shipping.

U.S. EPA Shore Power Assessment

In 2017, the U.S. EPA published a technology assessment of shore power technology at U.S. ports. Although not a regulatory action, the report characterizes technical and operational aspects of installed shore power systems. Interested parties can use a companion calculator tool to estimate the potential for reduction of air pollutant emissions at U.S. ports “to help evaluate potential shore power projects for grant applications, and for reporting emission reductions from grant projects” [12].

Decarbonization Through Electrification of Port Equipment

Some electrification of U.S. port equipment has occurred. U.S. ports began converting large ship-to-shore (STS) cranes from diesel to electric in the 1970s and continued until the few remaining diesel cranes became a rarity. In addition, new marine terminals throughout the country are either installing shore power for ships or planning for its future installation. At the other end of the spectrum, improving battery and battery-charging technologies are seeing increasing application in smaller port equipment, such as forklifts and passenger vehicles.

Port-related equipment, ranging from small forklifts to cranes and even the ships themselves, has traditionally been fueled by diesel fuel at ports around the world. Increasingly, alternatives to this fuel have been utilized. Electricity is one alternative to diesel fuel that can typically be cost-effectively incorporated into port equipment, substantially reducing pollutant emissions. Several U.S. ports have employed an electrification strategy for port equipment, including CHE and ships, as one of many means to reduce emissions. Electric power and/or hydrogen fuel cell can be utilized in a variety of port applications, including the following:

- **CHE.** Diesel-fueled CHE can be replaced with electric-powered and/or hydrogen fuel cell equipment. CHE (e.g., cranes and forklifts) used to load and unload goods and perform other functions around terminal yards may be electric and/or hydrogen fuel cell powered.
- **Ship power at berth.** When ships are at berth, STS power (i.e., shore-side electricity) can be used instead of ships’ auxiliary engines. Infrastructure on some ships and at some terminals enables ships to “cold iron” or plug into shore power while in port, instead of using diesel power generators to supply ship power. A ship equipped for shore power, at a terminal so equipped, can turn off its diesel auxiliary engines while at a berth. Substantial emission reductions can be achieved through cold ironing. These include over one ton of NO_x per ship per day, in addition to particulate matter (PM) reductions.
- **On-Road and Off-Road Transportation.** A wide variety of on-road and off-road transportation activities are relevant to ports. On-road vehicles include diesel- and gasoline-powered trucks, truck refrigeration units, and others. Off-road vehicles include various railroad vehicles as well as port facility construction and dredging equipment. All of these forms of transportation are beyond the scope of this project. EPRI has initiated a relevant companion project to this one called *Fleet Electrification Planning and Assessment* [13].

Cargo Handling Equipment

Descriptions of CHE Types

Much of the activity involving land-side CHE is related to general cargo, which may include bundles, coils, rolls, pallets, and marine containers. Depending on configuration, container terminals at ports use a combination of cranes, forklifts, top loaders, and yard tractors to move containers to and from ships. In general, the land-side equipment used at container terminals consists of yard tractors, forklifts, top and side handlers, front loaders, and gantry cranes. Table 4 summarizes port CHE and associated key decarbonization approaches. Appendix A of this report contains more information on alternate fuel deployments and development of CHE.

Table 4. Summary descriptions of primary CHE

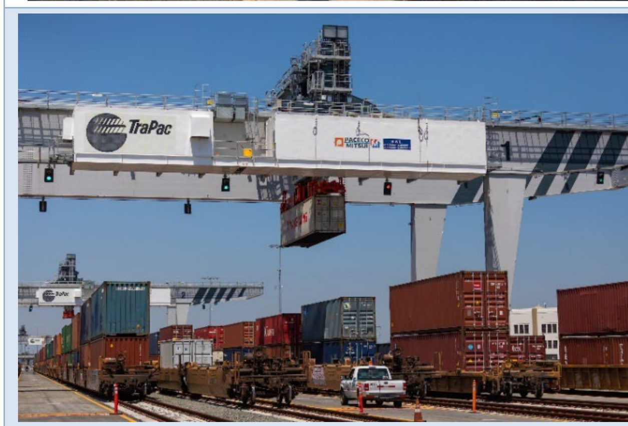
	A **rubber-tired gantry crane** (RTG) straddles stacks of shipping containers. It moves containers and consolidates stacks as containers are loaded onto trucks. **Fuel**: Shore power electric options, including electric and hybrid drive systems, are currently replacing the diesel fuel traditionally used for this equipment.
	A **rail-mounted gantry crane** (RMG) straddles stacks of shipping containers. It moves containers and consolidates stacks as containers are loaded onto railcars. **Fuel:** Shore power electric options are currently replacing the diesel fuel traditionally used for this equipment.

Table 4 (continued). Summary descriptions of primary CHE

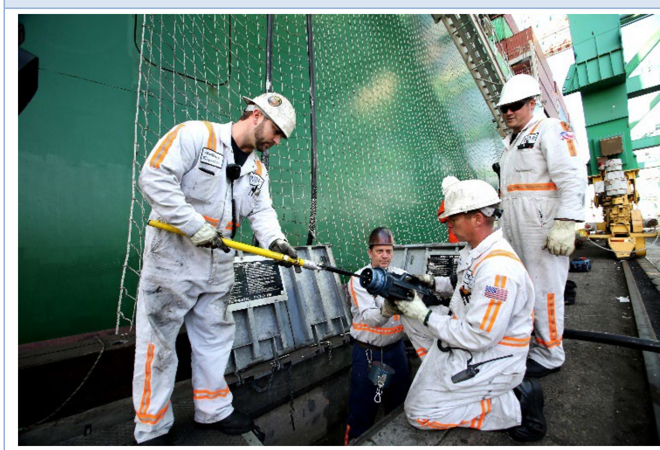
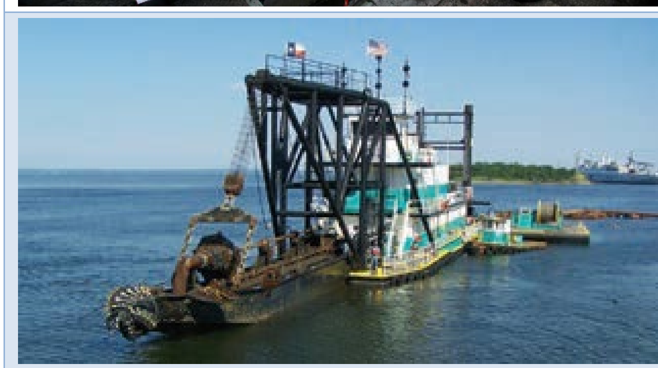
	A **straddle carrier** (aka saddle truck) straddles a container and lifts it from the top. It can stack up to four containers and can move containers without the assistance of cranes or forklifts [14]. **Fuel:** Diesel, electric, and hybrid models are available.
	A **top handler**, also known as a top pick, is a commonly used off-road port vehicle. It has an overhead boom for loading containers weighing up to 100,000 lb onto trucks and trains, unloading them, and stacking them on terminals between pickups and deliveries [15]. **Fuel**: Traditionally driven by diesel fuel, top handlers are becoming more available in battery-electric and H_2-based electric fuel cell models.
	**Shore power** or cold ironing (aka Alternative Maritime Power® [AMP] at POLA) is the process of providing shoreside electrical power to a ship at berth while its main and auxiliary engines are turned off. It permits emergency equipment, refrigeration, cooling, heating, lighting, and other equipment to receive continuous electrical power during ship loading and unloading. **Fuel:** Shore power electric options are currently replacing fossil fuel used by cruise and cargo ships.
	A **dredge** uses scooping or suction devices to deepen harbors and waterways, restore beaches or wetlands, and dig in other underwater applications near ports.

Table 4 (continued). Summary descriptions of primary CHE

	A **yard tractor**, or terminal tractor, is another commonly used non-road vehicle (similar to a semi-tractor) that moves semitrailers and containers within a port, cargo yard, warehouse facility, or intermodal facility. **Fuel**: Traditionally driven by diesel fuel, tractors currently have a few low-carbon fuel options, such as battery electric, H_2-based electric fuel cells, compressed natural gas (CNG), and LNG.
	A **forklift** (or lift truck) is a common piece of equipment at ports of all sizes. It is used for both container and non-container handling activities. Forklifts may be equipped with cushion tires for use inside or on flat surfaces or with pneumatic tires for use outside or on rough terrain. **Fuel**: Forklifts are commonly available in gas, diesel, and LPG. Electric options include battery-electric and H_2-based fuel cell options.
	A **refrigerated cargo container** maintains the cargo in a container at a prescribed temperature to preserve the cargo. It is stacked to form "reefer" racks while awaiting ground transfer. **Fuel:** Traditionally diesel is used to run the diesel-driven compressor, but shore power and H_2-based fuel cell options are now available.

The following resources provide additional information on port CHE:

- In November 2015, CARB published a technology assessment that describes various types of CHE and assesses the potential for alternative fuel and electric technologies [16].
- In September 2019, POLA and the Port of Long Beach published a feasibility assessment for CHE as part of the San Pedro Bay Ports Clean Air Action Plan. The report assesses CHE commercial availability, technical viability, operational feasibility, infrastructure availability, and economic workability. The key findings of this report are summarized in the following subsection [17].
- In March 2022, Argonne National Laboratory published a summary of various types of CHE and developed a table that shows fuel types available for each type of CHE [14].

  RTG Crane. The electric feed for an electric RTG can be arranged in various ways, including an overhead busbar system (e.g., Konecranes in Spain at the MSC Terminal VLC) [18] or a cable-reel system in which the electric cable is attached to the crane [19,20]. Hybrid electric RTGs, such as the Kalmar Hybrid RTG solutions [21], have been demonstrated at several ports and have been adopted on a widespread basis at terminals such as the Hugh K. Leatherman Terminal in South Carolina, which installed six hybrid RTGs from ZPMC [22]. This hybrid crane uses Li-ion batteries to store energy for crane power and run 100% on electric battery power. It uses diesel fuel only to recharge the batteries, which significantly reduces diesel engine idling time. The batteries are expected to reduce fuel consumption by about 70%, compared to conventional diesel port cranes.

POLA 2019 Assessment of CHE

In September 2019, POLA and the Port of Long Beach published a feasibility assessment for CHE fuel/technologies as part of the San Pedro Bay Ports Clean Air Action Plan. The assessment determined that four types of CHE (i.e., yard tractors, top handlers, RTG cranes, and large-capacity forklifts) are responsible for over 85% of total pollutant emissions at the ports, so the study focused on these four CHE types. The study examined five parameters to assess the feasibility of fuel/technologies (battery electric or grid electric, hydrogen fuel cell, advanced diesel internal combustion engine (ICE), advanced natural gas/propane, and hybrid electric) for CHE at the ports.

The 2019 POLA project team used two of the five parameters (commercial availability and technical viability) to initially screen the fuel/technologies for feasibility to power large numbers of CHE by 2021. This process eliminated top handlers and large-capacity forklifts. The lack of these types of CHE that are commercially available and technically viable is a significant challenge to broad-based adoption of alternative fuels and electricity at the ports.

The POLA team then assessed the remaining two CHE types (yard tractors and RTG cranes) using the remaining three parameters (operational feasibility, infrastructure availability, and economic workability). The team concluded the following:

- For yard tractors, multiple original equipment manufacturers (OEMs) offer pre- or early-commercial battery-electric and natural gas ICE technology options. Fuel cell, hybrid-electric, and diesel ICE technologies do not meet the study's screening criteria.
- Grid-electric and hybrid-electric RTG cranes are fully commercial products. Fuel cell and diesel ICE technologies do not meet the study's screening criteria.
- Based on these evaluations, the team estimated the relative degree to which the CHE types can achieve the five criteria by 2021 (in order of likelihood):
  - Diesel hybrid-electric RTG cranes
  - Grid-electric RTG cranes
  - Natural gas ICE yard tractors
  - Battery-electric yard tractors
- Regarding yard tractors, the team emphasized the challenging need for OEMs to improve cost-effectiveness by reducing the costs of onboard energy storage systems (batteries or natural gas tanks) and by realizing greater economies of scale through higher-volume manufacturing.
- The POLA team emphasized the challenge of implementing a gradual process of transitioning CHE to the new technologies. A parallel challenge is advancement of, and coordination with, expanding fueling and charging infrastructures [17].

Summary of POLA CHE Demonstration Projects

Appendix B of the POLA CHE assessment contains a summary of recent POLA projects to demonstrate alternative fuel-powered and electric-powered CHE [17]. The following are summaries of these projects:

- **ZE yard tractor demonstrations.** As of 2018, about 16 ZE yard tractor demonstrations were underway or planned at San Pedro Bay terminals. Within a few years of that time, these projects were expected to demonstrate approximately 111 battery-electric yard tractors and two hydrogen fuel cell yard tractors. At that time, ZE battery-electric yard tractors were perceived as pre-commercial vehicles, and their demonstration was expected to yield valuable lessons learned.
- **Near-zero-emission (NZE) yard tractor demonstrations.** As of 2018, 22 NZE LNG-fueled yard tractors were planned for demonstration at the San Pedro Bay terminals over the following two years, with initial deployments planned for mid-2019. To enable these demonstrations, the host marine terminal operators had been working with natural gas infrastructure providers to obtain access to on-site LNG fueling. In the decade prior to 2018, the ports had deployed at least 17 LNG yard tractors (in warehouse and logistics applications, rather than moving containers at the terminals), demonstrating they are proven alternatives to

conventional yard tractors. Like their ZE counterparts, the NZE LNG-fueled yard tractors were perceived as pre-commercial vehicles at that time, and their demonstration was expected to yield valuable lessons learned.

- **ZE top handler demonstrations.** According to the report, these vehicles present greater challenges than yard tractors in ZE and ZNE architectures. Although nine battery-electric top handlers were scheduled for demonstration at San Pedro Bay terminals in 2019 or 2020, product builds and deployment were delayed.
- **ZE RTG crane demonstrations.** As of 2018, the San Pedro Bay terminals operated 13 NZE hybrid-electric RTG cranes. The report concluded that due to the commercial maturity of these vehicles, further demonstration was not needed. At the same time, no grid-electric RTG cranes were operating—not due to lack of commercial maturity, but due to site-specific (e.g., electricity infrastructure) challenges. To address these challenges, the Port of Long Beach initiated a demonstration of nine grid-electric RTG cranes with funding from the California Energy Commission, augmented by the U.S. EPA Diesel Emissions Reduction Act. The port is working with Southern California Edison, SSA Marine, and others.
- **ZE large-capacity forklift demonstrations.** As of 2018, at least 12 battery-electric, larger-capacity forklifts were scheduled for demonstration at the ports [17].

Cargo Handling Equipment Companies

According to the NAICS Association (NAICS code 488320, which provides stevedoring and other marine cargo-handling services), the following are the top-ten businesses by annual sales in the marine cargo-handling category (complete profiles on each of these are available at the NAICS Association website [23]):

- Carrix Inc
- Port of Portland
- Frs Capital Corp.
- APM Terminals North Amer Inc.
- Ports America Inc.
- Cooper/T Smith Stevedoring Inc.
- Virginia Intl Terminals LLC
- San Diego Unified Port Dst.
- Port of Houston Authority
- Amports Inc.

EPRI has compiled a list of electric equipment models for CHE equipment from various manufacturers (see Table 5).

Table 5. List of electric equipment models for CHE equipment

<table>
<tr><th>Automatic Stacking Cranes</th><th>Electric Wharf Cranes</th><th>Forklifts</th><th>Loaders</th><th>Top Handler</th><th>Yard Tractor</th></tr>
<tr><td>Kalmar</td><td>Mitsubishi</td><td>Hyster</td><td>JLG Lift</td><td>Taylor</td><td>BYD</td></tr>
<tr><td rowspan="9">- ASC 4+
- ASC 5.0</td><td>- 50T
- 60T
- 7820-7</td><td>- N40FR
- N40XMR2</td><td>- GS2646</td><td rowspan="9">- ZLC</td><td rowspan="9">- 8Y</td></tr>
<tr><td>Mitsui/Paceco</td><td>Kalmar</td><td>Skyjack</td></tr>
<tr><td>- 70T</td><td>- DCS160-12</td><td rowspan="7">- 3226
- 3291
- SJIH 4740</td></tr>
<tr><td>ZMPC</td><td>Mitsubishi</td></tr>
<tr><td rowspan="5">- J111A00-8, 9
- J481A
- ZP-10020000148, 149, 150, 151
- ZP-2073-10, 11, 12</td><td>- EP16KT
- FB16KT
- FB16NT</td></tr>
<tr><td>Nissan</td></tr>
<tr><td>- CK1B1L15S
- CSP01L15S
- MCJ1B1L15S</td></tr>
<tr><td>Raymond Pacer</td></tr>
<tr><td>- R30-C30TT</td></tr>
</table>

2 POLA OVERVIEW

This section provides overview information on the POLA. This includes the port's daily operating and terminal operation schedules, the layout of the port, and an inventory of CHE at the port.

Operating Schedules

Daily Operating Schedules

The typical first work shift at POLA is 8 hours, typically from 8 a.m. to 5 p.m. with a 1-hr lunch break, per a west coast collective-bargaining agreement. Most terminals require some second-shift work for vessels, gate, and rail service. The second shift is typically 8 hours, from 6 p.m. to 3 a.m. with a 1-hr lunch break. The third shift, also known as "hoot shift," is typically 5 hours, from 3 a.m. to 8 a.m., but is rarely used for terminal work other than rail shunting and equipment maintenance.

Terminal Operations and Grid Peak Demand

Electrical grid peak demand hours (i.e., when overall demand for electrical power is highest) are typically as follows:

- Summer: 10:00 a.m. to 8:00 p.m. during weekdays
- Winter: 7:00 a.m. to 11:00 a.m. and 5:00 p.m. to 9:00 p.m.

Figure 1 illustrates the relationship between terminal operating hours and peak grid power demand periods. Terminal operations overlap with both summer and winter peak grid demand hours. Hence, conversion to electric- and battery-powered CHE will increase the burden on the electrical power grid during peak hours. In addition, the most opportune recharge periods for battery-powered equipment are during shift breaks and the third shift, when not used. However, if all the tenants choose the third shift to charge their equipment, the peak demand for the ports may increase. Mitigation solutions are needed in this situation The deployment of hydrogen fuel cell-powered CHE would mitigate load on electrical power grid.

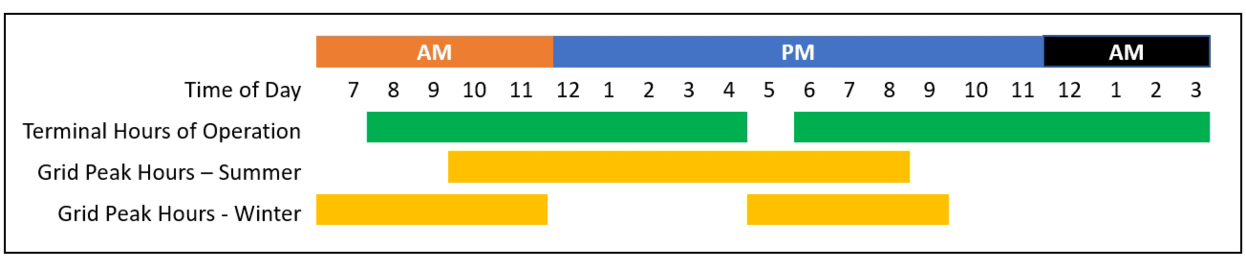


Figure 1. Terminal operating hours compared to peak electrical grid hours

Port Layout

Figure 2 shows an aerial view of the vast POLA. Figure 3 illustrates the general layout of the port.

Figure 2. Aerial image of the entire POLA

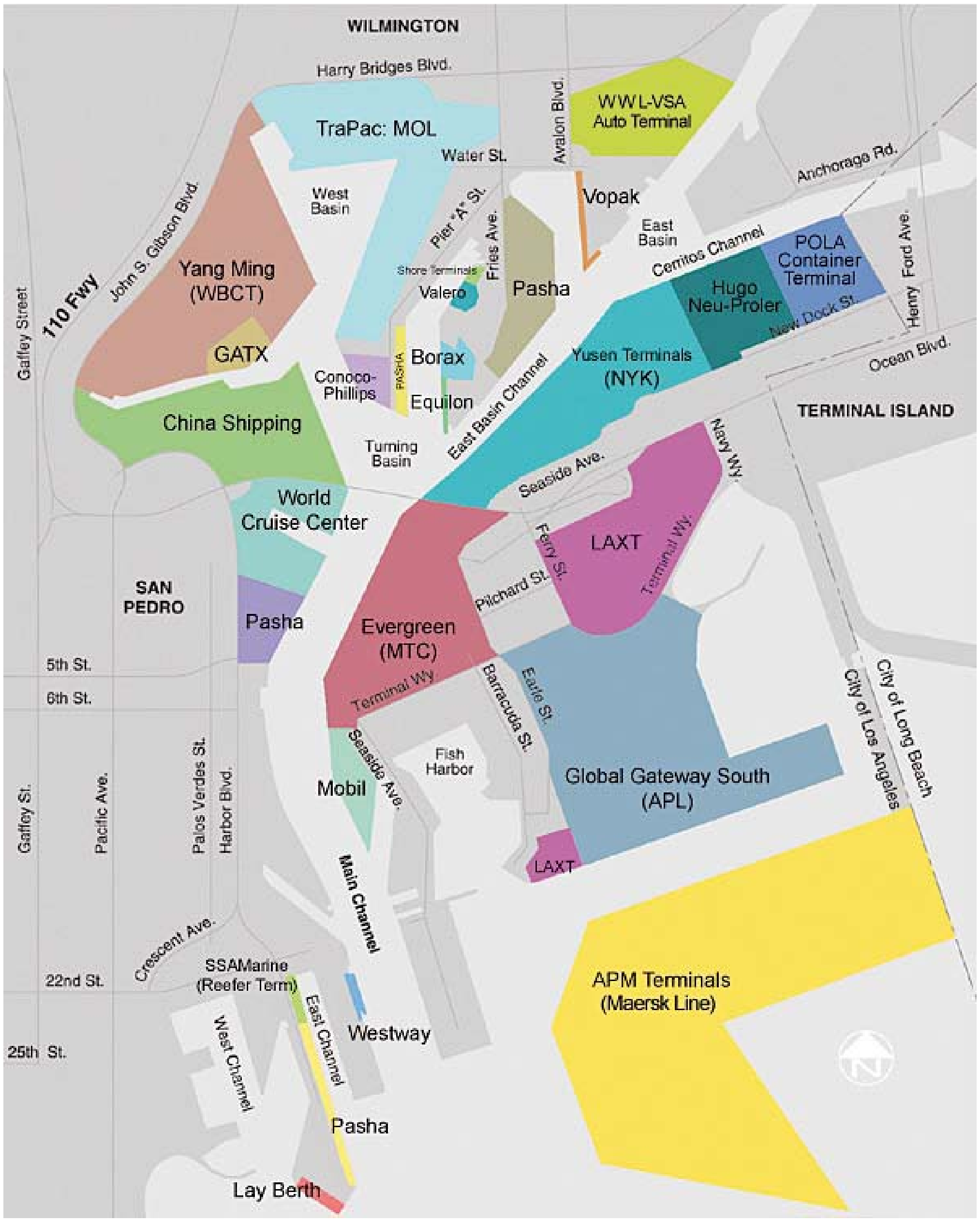


Figure 3. POLA map showing the various terminals[2]

[2] Note that Evergreen on the map is the location of Everport, FMS was formerly known as Global Gateway South, and WBCT consists of Yang Ming and China Shipping.

POLA consists of several terminals. The six largest container terminals at the port were selected for this study. These terminals represent about 85% of the CHE used in all the container terminals at POLA. They are as follows:

- APM Terminals Pacific (APM)
- Everport Terminal Services
- Fenix Marine Services (FMS)
- TraPac
- West Basin Container Terminal (WBCT)
- Yusen Terminals (YTI)

Site Visits

LADWP, EPRI, and POLA staff visited all six POLA container terminals from March 30 and April 1, 2022, and met with each container terminal operator. The following types of equipment were inventoried during the site visit:

- CHE, including terminal tractors (UTRs), top loaders, side loaders, cranes, and so on. These are currently mostly fueled, though some electric equipment currently exists in the terminals.
- Shore power or AMP technologies, which use shore-side electricity in place of the auxiliary engines of berthed ships.
- Truck refrigeration units or reefer units.
- Diesel, propane, and other fossil-fuel land-side equipment with electric equipment, such as forklifts, sweepers, and man lifts.

Size, capacity, operational hours, fuel usage, equipment horsepower, quantities, vintage, work schedule, and break hours were some of the information documented. This information was used to calculate fuel and emissions offset through electrification and the electric consumption profile in each electrification scenario.

Existing CHE Inventory for the Six POLA Terminals

The detailed inventory of existing CHE of the six terminal operators, for all container terminal operators, is summarized in Table 6. The inventory includes more than 1600 pieces of equipment in total. The equipment uses diesel, gasoline, propane, LNG, and electricity. This inventory was verified against the 2021 POLA Emissions Inventory and the inventory of all the container terminal operators and was found to be within an acceptable error margin of less than 3%.

The CHE category includes equipment that moves cargo (e.g., containers, general cargo, and bulk cargo) to and from marine vessels, railcars, and on-road trucks [24]. The equipment is typically operated at marine terminals or at rail yards and not on public roadways. Due to the diversity of cargo handled by the port's terminals, there is a wide range of equipment types. Most CHE can be classified into one of the following equipment types:

- Cone vehicles
- Forklifts
- RTG cranes
- Side picks
- Sweepers
- Straddle carriers
- Top handlers
- Yard tractors (UTRs)
- Others, such as bulldozers, material handlers, and rail pushers

CHE are used at container, dry bulk, break bulk, liquid bulk, auto, and cruise terminals, as well as at Union Pacific's (UP's) Intermodal Containers Transfer Facility (ICTF) and smaller facilities located within port boundaries. The inventory documented at the six container terminals visited during the site visit shows that the following are the top-five CHE equipment types (*nonelectric*) used at these terminals:

1. Terminal tractors (or UTRs): 859 (52%)
2. Top handlers: 223 (14%)
3. Forklifts: 130 (8%)
4. RTGs/hybrid RTGs: 116 (7%)
5. Straddle carriers/hybrid straddle carriers: 110 (7%)

Collectively, the top-five CHE equipment types listed here account for 1438 pieces of equipment by count, or 88% of the total inventory, for the six container terminal operators.

The population distribution of the 1930 pieces of equipment inventoried at the port for calendar year 2021, according to the *Port of Los Angeles Inventory of Air Emissions 2021* report, is shown in Figure 4 The hybrid and conventional RTG crane counts were included in the "RTG crane" category. The hybrid and conventional straddle carrier counts were included in the "straddle carrier" category. This is similar to the distribution noticed in the inventory documented by the site visit of the six container terminals for this study.

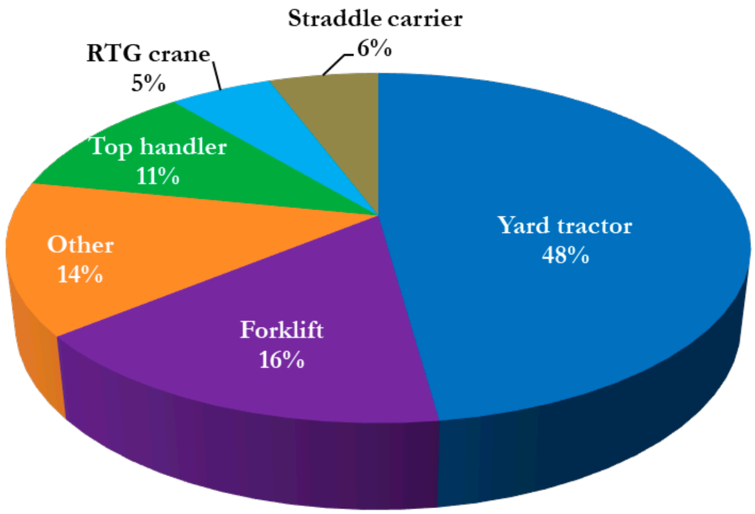


Figure 4. 2021 CHE count distribution by equipment type in POLA [25]

The yard trucks are not counted toward the emission inventory analysis by POLA. However, a large number of yard trucks are employed by the terminal operators. A total of 880 yard trucks are accounted for in the inventory data gathered from the six terminal operators (see Table 6). Note that yard trucks *were* included in other aspects of the overall analysis, including charging profiles, electricity cost estimates, and so on.

Table 6. Inventory of the existing CHE of the six container terminals at POLA

Equipment Count at Six Container Terminals	Total Count	Terminal 1	Terminal 2	Terminal 3	Terminal 4	Terminal 5	Terminal 6
Equipment by Engine & Fuel Type							
Diesel Total	***1234***						
Bulldozer	0						
Cone vehicle	29	8		7			14
Forklift	52	4	4	9	5		30
Hybrid RTG	21						21
Hybrid straddle carrier	82	12					70
Man lift	10	7		3			
RTG	95	0	12	27	21	14	21
Side pick	9	6	3				
Straddle carriers	28	28					0
Sweeper	7	1	1	1	1	1	2

Table 6 (continued). Inventory of the existing CHE of the six container terminals at POLA

Equipment Count at Six Container Terminals	Total Count	Terminal 1	Terminal 2	Terminal 3	Terminal 4	Terminal 5	Terminal 6
Top handler	223	11	24	51	41	33	63
Yard trucks	880	69	107	164	174	138	228
Yard tractor UTR	678	37	112	199	30	120	180
Electric Total	***141***						
Automatic stacking crane	29	29					0
Crane (RMG)	3	3					
Electric wharf crane	79	10	8	16	15	11	19
Forklift	2					2	
Top handler	2		2				
Yard tractor UTR	26	2	4				20
LNG Total	***22***						
Yard tractor UTR	22		22				
LPG Total	***237***						
Forklift	78	10	8	25	8	22	5
Yard tractor UTR	***159***				***159***		
Total	**1634***	**237**	**307**	**502**	**454**	**341**	**673**

**Note: The total count does not include the yard trucks because they are not considered to be a type of CHE.*

3 EMISSIONS CHARACTERIZATION

This section covers the methodology used to calculate CHE emissions and the results of these calculations.

Emissions Calculation Methodology

The emissions calculation methodology used to estimate CHE emissions is consistent with CARB's latest methodology for estimating emissions from CHE [24]. The basic equation used to estimate CHE emissions is as follows:

$$\boldsymbol{E = Power \times Activity \times LF \times EF \times FCF \times CF} \qquad \text{Eq. 1}$$

Where:

E = Emissions (grams/year)

Power = Maximum rated power of the engine (hp or kW)

Activity = Equipment's engine activity (hour/year)

LF = Load factor, which is the ratio of average load used during normal operations to full load at maximum rated horsepower (dimensionless)

EF = Emission factor (grams of pollutant per unit of work [g/hp-hour or g/kW-hour])

FCF = Fuel correction factors, used to adjust EF associated with a base fuel to the fuel used to reflect changes in fuel properties that have occurred over time (dimensionless)

CF = Control factor to reflect changes in emissions due to installation of emission reduction technologies not originally reflected in the emission factors (dimensionless)

The emission factor is a function of the zero-hour emission rate by fuel type (diesel, propane, or LNG), CHE engine type (off-road or on-road), CHE engine model year (in the absence of any malfunction or tampering of engine components that can change emissions), deterioration rate, and cumulative hours. The deterioration rate reflects the fact that the engine's zero-hour emission rates change as the equipment is used, due to wear of various engine parts or reduced efficiency of emission control devices. The cumulative hours reflect the CHE engine's total operating hours.

The emission factor is calculated as follows:

$$\boldsymbol{EF} = \boldsymbol{ZH} + (\boldsymbol{DR} \times \boldsymbol{Cumulative\ Hours}) \qquad \text{Eq. 2}$$

Where:

EF = Emission factor (g/hp-hour or g/kW-hour)

ZH = Zero-hour emission rate by fuel type by CHE engine type for a given horsepower category and model year (g/hp-hour or g/kW-hour)

DR = Deterioration rate, which is the rate of change of emissions as a function of CHE engine age (g/hp-hour^2 or g/kW-hour^2)

Cumulative hours = Number of hours the CHE engine has been in use and calculated as annual operating hours times age of the CHE engine (hours)

Emissions factors in this analysis vary based on engine type, model year, and engine power using 2020 CHE inventory data from the *2020 Port of Los Angeles Inventory of Air Emissions* (see Table 5.1 in the report) and emissions factors from the *San Pedro Bay Ports Emissions Inventory Methodology Report, Version 2 – 2021* (see Appendix B in that report). The team applied the methodology using the CHE inventory in Table 6.

Emissions Calculation Results

The resulting annual emissions are charted in Figure 5.

The following values are computed:

- Pollutants
  - PM, PM_{10}, $PM_{2.5}$, diesel particulate matter (DPM), NO_x, SO_2, HC, CO
- Greenhouse gases
  - CO_2, CH_4, N_2O

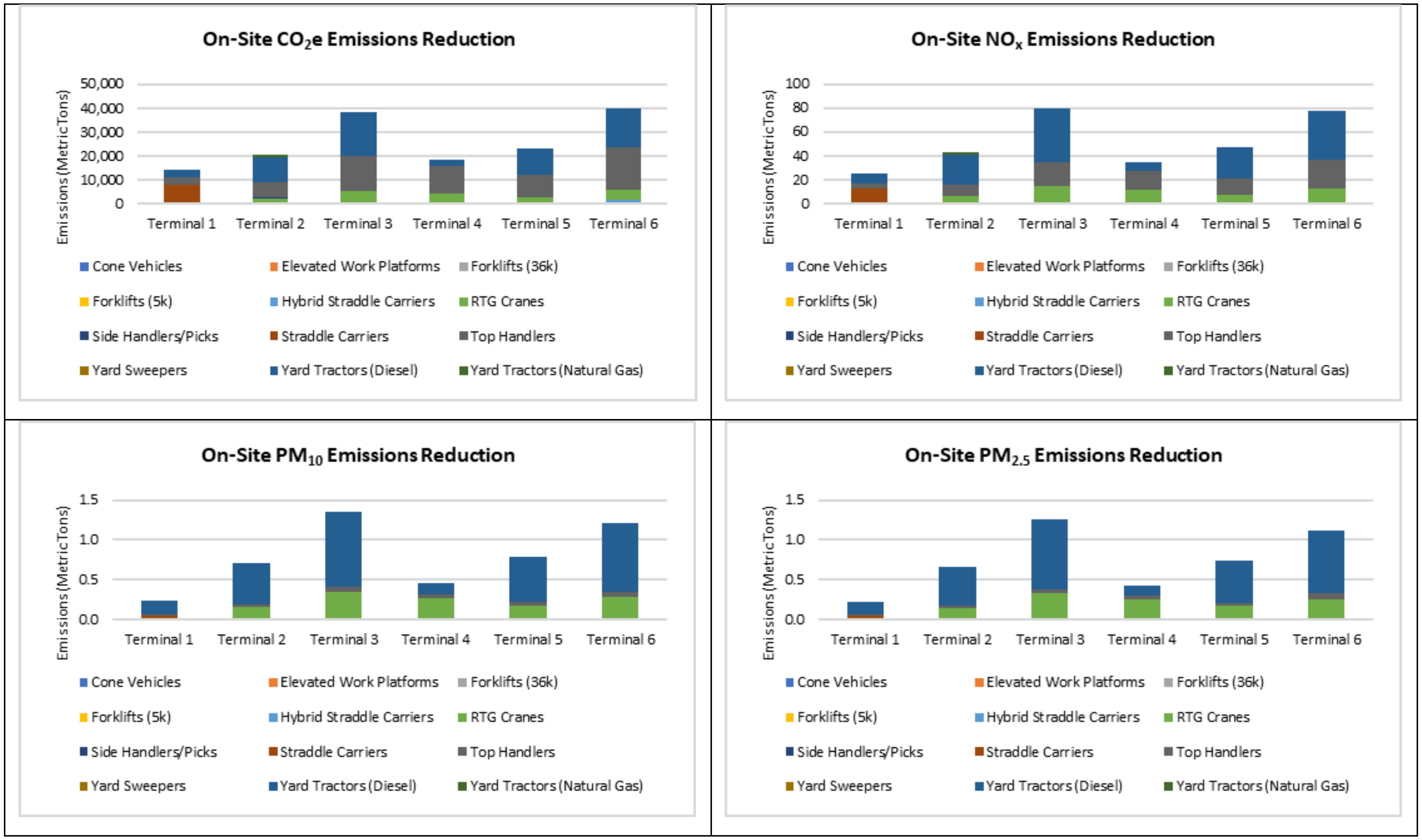


Figure 5. Annual emissions reduction for the six terminals based on 100% conversion of CHE loads from fossil fuel to electric (scope 1 emissions)

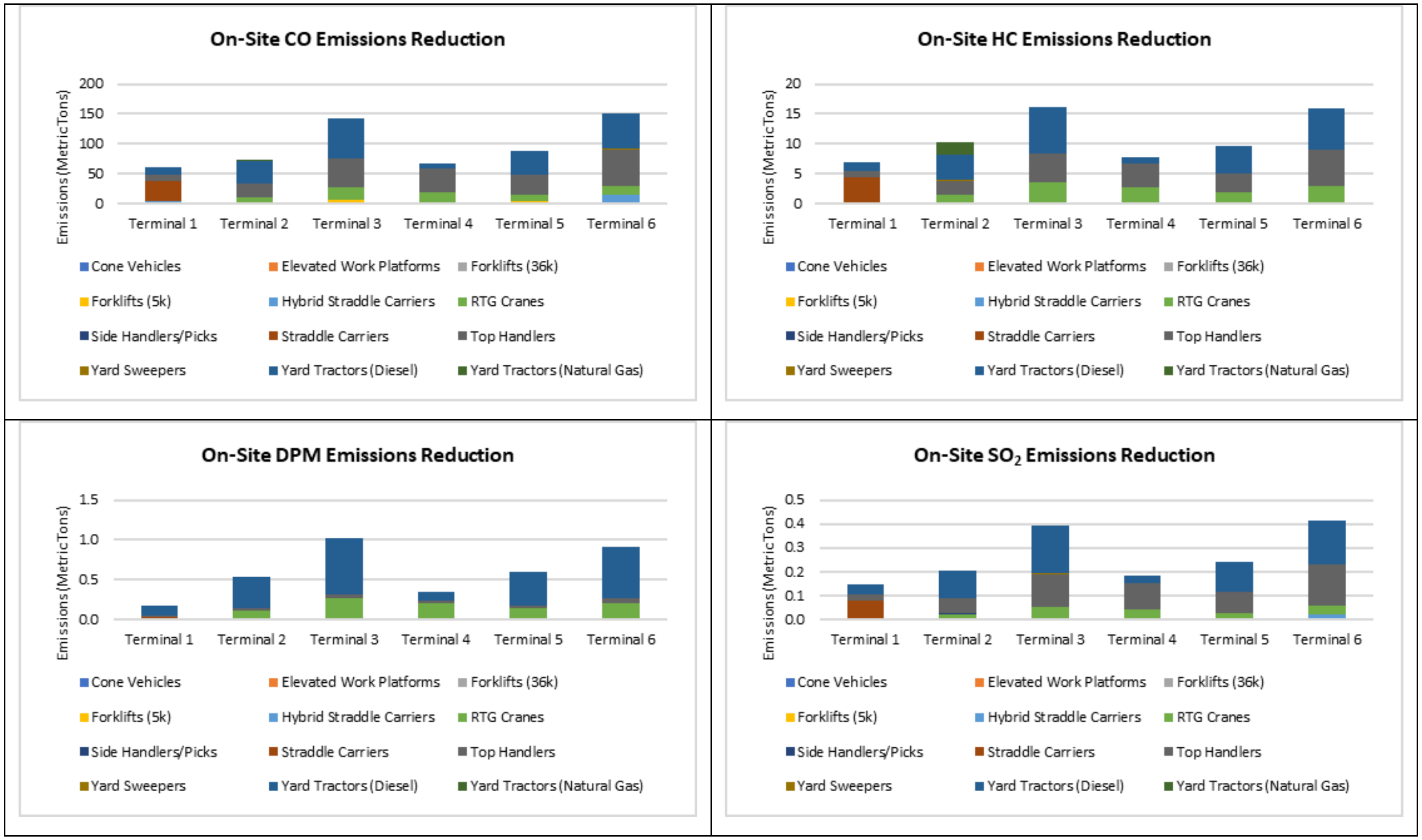


Figure 5 (continued). Annual emissions reduction for the six terminals based on 100% conversion of CHE loads from fossil fuel to electric (scope 1 emissions)

Table 7 shows the emissions reduction potential for 100% electrification computed in this electrification study for all CHE in the six container terminals.

Table 7. Emissions reduction potential for 100% electrification scenarios for the CHE at the six terminals

Emission Type	PM_{10}	$PM_{2.5}$	DPM	NO_x	SO_2	CO	HC	CO_{2e}
	Metric tons	Metric tons	Metric tons	Metric tons	Metric tons	Metric tons	Metric tons	Metric tons
CHE from the inventory from the six terminals	4.8	4.4	3.6	307	1.6	582	67	154,958
Container terminals (2021 POLA Emissions Inventory)	6.4	6.0	4.8	409	2.1	791	88	169,063

4 TENANT ELECTRIFICATION MODELING

This section describes the use and modification of the Dynamic Energy Forecasting Tool (DEFT) [26] and its ability to model changes to electric load profiles associated with converting port terminal CHE to ZE alternatives.

Introduction

The DEFT is a simulation tool for port CHE that uses electric equipment technical specifications, the number of each type of fueled equipment that will be replaced with an electric alternative, port shift schedules, electric tariff information, and baseline electric load data to estimate changes to a port terminal's peak electric load, electricity costs, fuel use, and associated emissions. EPRI originally developed the DEFT as open-source, python-based software for the Port of Long Beach with funding from the California Energy Commission, and it can be used or adapted by anyone. The tool is available at github [27].

The DEFT can be used in many ways to address a wide range of questions relating to the costs and technical details of the transition from fueled CHE to ZE equipment. This case study models the electricity consumption of a set of POLA terminal operators as they convert their CHE roster to electric alternatives.

The base DEFT tool implements a direct simulation of each individual piece of CHE, when it is being operated, when it is being charged, and how the state of charge of on-board batteries evolves in response to use and charging. The base DEFT tool can be used to do the following:

- Apply simple, managed charging strategies
- Model opportunity charging during mid-shift breaks
- Invoke other software to optimally size an energy storage system to help reduce peak electricity loads along with managed charging

For this analysis, the project team modified the base DEFT tool from its direct simulation approach to an optimization-based approach that does not differentiate between individual pieces of equipment; rather, it differentiates only between different equipment types. The team implemented this simplification due to the following:

- The intent of the analysis, which is to estimate peak electric loads during the busiest days when all equipment is operated identically
- The computational limitations of optimization

Managed Charging

For managed charging, the optimization objective considered is minimizing the peak electric load from all CHE, including existing electric equipment (e.g., STS gantry cranes). This results in the best-case scenario for the terminal, which would not be attainable under practical circumstances. For example, the state of charge of on-board batteries is brought down to zero at the end of some shifts. In reality, some buffer is needed to account for uncertainty and avoid stranding equipment in the yard.

Unmanaged Charging

For unmanaged charging, an otherwise identical optimization objective is maximizing the integral of vehicles' states of charge. This means that equipment is charged as soon and as much as possible, which is what would occur if a controller did not manage the chargers.

Zero-Emission Equipment

The modeled cases explore the replacement of a set of fueled CHE with electric alternatives. Table 8 shows the numbers of each type of equipment for each of six terminal operators to be replaced. In the table, equipment labeled as electric is currently electric and does not need to be replaced in this analysis.

Table 8. Inventory of current fuel type for each equipment type to be replaced with electric alternatives

Equipment Segments	Current Fuel	Electric Demand (kW)	Terminal-1 Inventory	Terminal-2 Inventory	Terminal-3 Inventory	Terminal-4 Inventory	Terminal-5 Inventory	Terminal-6 Inventory	Non-Container Terminals Inventory
UTRs	Diesel	200	37	112	199	30	120	180	55
Top Handlers	Diesel	400	11	24	51	41	33	63	5
RTG Cranes	Diesel	80	0	12	27	21	14	0	5
Gantry Cranes (STS)[3]	Diesel	400	0	0	0	0	0	0	
Automatic Stacking Cranes	Diesel	100	0	0	0	0	0	0	
Straddle Carriers	Diesel	400	28	0	0	0	0	0	
Forklift 80K	Diesel	50			1				49
Cone Vehicle	Diesel	10	8	0	7	0	0	14	6
Fuel Trucks	Diesel	50	2	2	4	6	3	0	
Side Handlers/ Side Pick	Diesel	400	6	3	0	0	0	0	4
Elevated work platform	Diesel	6.5	7	0		0	0	0	
Other diesel, electric, gasoline, LNG, LPG, hydrogen, and hybrid equipment	Diesel	N/A	2	0	0	0	0	0	

[3]STS = ship-to-shore

Table 8 (continued). Inventory of current fuel type for each equipment type to be replaced with electric alternatives

Equipment Segments	Current Fuel	Electric Demand (kW)	Terminal-1 Inventory	Terminal-2 Inventory	Terminal-3 Inventory	Terminal-4 Inventory	Terminal-5 Inventory	Terminal-6 Inventory	Non-Container Terminals Inventory
Shuttle Buses	Diesel	450	3	3	4	4	4	9	
Automatic Rail Mounted Gantry	Diesel	200					0		
Elevated Rail Mounted Gantry	Diesel	200					0		
Material Handler	Diesel	7.5							12
Skid Steer Loader	Diesel	10							5
Telehandler	Diesel	6.5							7
Loader	Diesel	12.8							14
Yard Sweeper	Diesel/Gasoline	10	1	1	1	1	1	2	3
Hybrid Straddle Carrier	Diesel/Hybrid	400	12	0	0	0	0	70	0
Yard Trucks	Diesel/LPG	19	69	107	164	174	138	228	10
Forklift	Diesel/Propane	7.5						25	
Forklifts 36K	Diesel/Propane	50	4	4	8	5	0	5	2
Man Lift	Diesel/Gasoline	6.5	0	0	3	0			7
Electric Top Handlers	Electric	400	0	2	0	0	0	0	
Electric Wharf Crane	Electric	400	10	8	16	15	11	19	8

Table 8 (continued). Inventory of current fuel type for each equipment type to be replaced with electric alternatives

Equipment Segments	Current Fuel	Electric Demand (kW)	Terminal-1 Inventory	Terminal-2 Inventory	Terminal-3 Inventory	Terminal-4 Inventory	Terminal-5 Inventory	Terminal-6 Inventory	Non-Container Terminals Inventory
Electric Automatic Stacking Cranes	Electric	100	29	0	0	0	0	0	0
Electric Forklift	Electric	7.5	0	0	0	0	2	0	28
Reefer	Electric	6	1076	0	702	0	0	4	0
AMP	Electric	2500	10	7	4	1.3333333	0	5	0
Electric Automatic Rail Mounted Gantry	Electric	950	3	0	0	0	0	0	0
Electric Loader	Electric	12.8	0	0	0		0	0	2
Electric UTRs	Electric	200	0	4	0		0	20	0
Electric Shuttle bus	Electric	450	0	0	0		0	9	0
EV Chargers	Electric	19	3	0	0		0	100	0
Electric Man Lift	Electric	6.5	0	0	0		0	0	3
Hybrid RTG Cranes	Electric/Hybrid	80	0	0	0	0	0	21	1
LNG UTRs	LNG	200	0	22	0	0	0	0	
LPG UTRs	LPG/LNG	200				159			
Forklifts 5K	Propane	7.5	10	8	25	8	22	5	111

Battery-powered equipment draws more power between shifts, while grid-powered equipment draws power during shifts. Since demand charges may represent a large part of each terminal operator's total bills, mitigating the increase in peak power draw from the entire terminal can help limit the electricity cost increases due to implementing electric equipment. This can be done via the following:

- Selecting chargers with appropriate power levels
- Implementing smart managed charging
- Balancing grid-powered and battery-powered equipment purchases

Terminal Schedule

All terminals are assumed to operate under the same shift schedule, as follows:

- First shift: 8 a.m. to 5 p.m.
- Second shift: 6 p.m. to 3 a.m.

The project team did not consider heterogeneity between terminal operations except for the consideration of different equipment inventories at each terminal. In reality, some terminals may have different CHE electric load profile shapes due to differences in scheduling, charging operations, and so on that are not captured in this analysis.

In addition to the two main shifts, a third swing shift can operate at the port. However, the team used the two-shift schedule for the purposes of this analysis.

During the busiest days, all ZE equipment is used during all shifts. The busiest day sets the peak electric load for charging battery-powered equipment and directly powering grid-connected equipment. It is possible to differentiate average days from busy days, where the average-day results are used to estimate fuel-use reduction, energy-charge increases, and so on, while the busy-day results are used to estimate peak-load increases, demand-charge increases, and so on. However, this project focuses on grid-upgrade needs. Current conditions indicate that most days will fairly closely resemble the busy-day schedule. Hence, the team modeled only busy days.

One potential strategy is to over-procure battery-powered equipment, keeping some in reserve during shifts to charge while the others work. This would allow a fleet of battery-powered equipment to survive a more demanding schedule without running out of stored energy, because any piece can be swapped for a charged vehicle during meal breaks or between shifts. However, since every shift utilizes all of the available equipment in this analysis, each piece of battery-powered equipment must be able to survive the shift schedule on its own.

CHE is unavailable for charging during the entire 8 hours of each shift and will be charged during meal breaks (noon to 1 p.m. and 9 p.m. to 10 p.m.) and the time between the first and second shifts. CHE operators take an additional 2-hr break during each shift, but this analysis assumes that the equipment cannot charge during these breaks.

Tariff

For the purposes of this assessment, the team assumed that all port terminals are billed for electricity according to the LADWP A-3 (A) tariff. This tariff applies time-of-day energy prices, which are highest from 1 p.m. to 5 p.m. in the afternoon and highest in the summer months. Additionally, the team applied the following stacking demand charges:

- An all-hours facilities demand charge of $5.98/kW-mo applies to every hour of the year
- A $9.7/kW-mo demand charge applies to summer weekdays from 1 p.m. to 5 p.m.
- A $3.3/kW-mo applies to summer months during low-peak hours on weekdays from 10 a.m. to 8 p.m., excluding the hours of 1 p.m. to 5 p.m.
- A $4.3/kW-mo demand charge applies to winter high-peak hours on weekdays from 1 p.m. to 5 p.m.

This tariff strongly penalizes power use during summer afternoons through both demand and energy charges, although an all-hours demand charge applies to peak power use, regardless of the time of day.

Data Availability

The following data, which was not available in this analysis, could contribute to a more sophisticated understanding of ZE CHE electricity usage:

- **Charging-power profiles for each battery-powered equipment model.** The current analysis assumes rectangular charging profiles when vehicles are plugged in without a managed charging system. In reality, charging power is rectangular only until the vehicle's battery reaches a threshold state of charge, after which charging power diminishes.
- **Tenant electric demand interval data.** Each tenant has an incentive to minimize its own peak electric usage due to tenant-specific demand charges and the possibility of paying for grid upgrades. While the tenants' electricity use is likely highly coincident with each other due to their similar shift schedules, some differences in timing are likely. This analysis lacks demand data for individual tenants, so the analysis cannot model each tenant operating individually. Instead, this analysis models only the CHE, neglecting other on-site loads (e.g., bulk material handling equipment, building loads, and so on).

- **Well-understood operating characteristics of ZE equipment.** How many hours of on-shift use can a full charge support? What options for charger power, battery size, and so on are available, and do the real-world performance data match the specifications? These and similar questions represent a large amount of uncertainty in this analysis. POLA compiled the ZE equipment specs used in this analysis by leveraging publicly available information and experience with pilot projects.

Load Shape Results

Figure 6 shows the unmanaged and optimal (managed) results for all POLA terminals as a whole. The results are shown hourly around the clock for the maximum demand day. The contribution to the peak load from each of the 36 CHE types are color-coded. The various types of CHE are listed in the legend.

In the unmanaged scenario, the instantaneous peak demand (with all chargers concurrently operating at maximum power) is 450 MW (not shown).[4] This number assumes no diversity in plug-in timing, assuming instead that each equipment operator perfectly follows the schedule and plugs in as soon as they can. Also in the unmanaged scenario, the hourly average peak demand (with all chargers concurrently operating at maximum power but some finishing within the hour) is 298 MW. This number is lower than the instantaneous peak demand because it is averaged across an hour and not all equipment will be charging for the entire hour. Note that maximum charging demand occurs in hours 3, 12, 17, and 22. These are the hours immediately after the vehicles plug in, so all vehicles will need at least some charging energy during these hours.

In the optimal (managed) scenario, the lowest possible peak demand (perfect managed charging) is 142 MW. Note the following:

- The “baseline” cranes are (1) not charged, but instead are powered directly from the grid, and (2) are powered only during the shifts.
- The primary reduction in peak charging demand in the managed scenario occurs by charging more equipment during hours 3–7 (3 a.m. to 7 a.m.). This is the period when the port is typically not operating. Charging of the remaining (non-crane) CHE is distributed across these hours, in addition to hours 3, 12, 17, and 22, thus reducing the overall peak demand.

Hence, implementing perfect managed charging could reduce the peak electricity consumption from CHE by about one-half.

[4] This is not shown in plots because it is simply the sum of all chargers’ maximum power consumptions and never shows up in an hourly charging profile. The team does not expect this amount to ever be realized due to at least some heterogeneity between plug-in times for the equipment and so on.

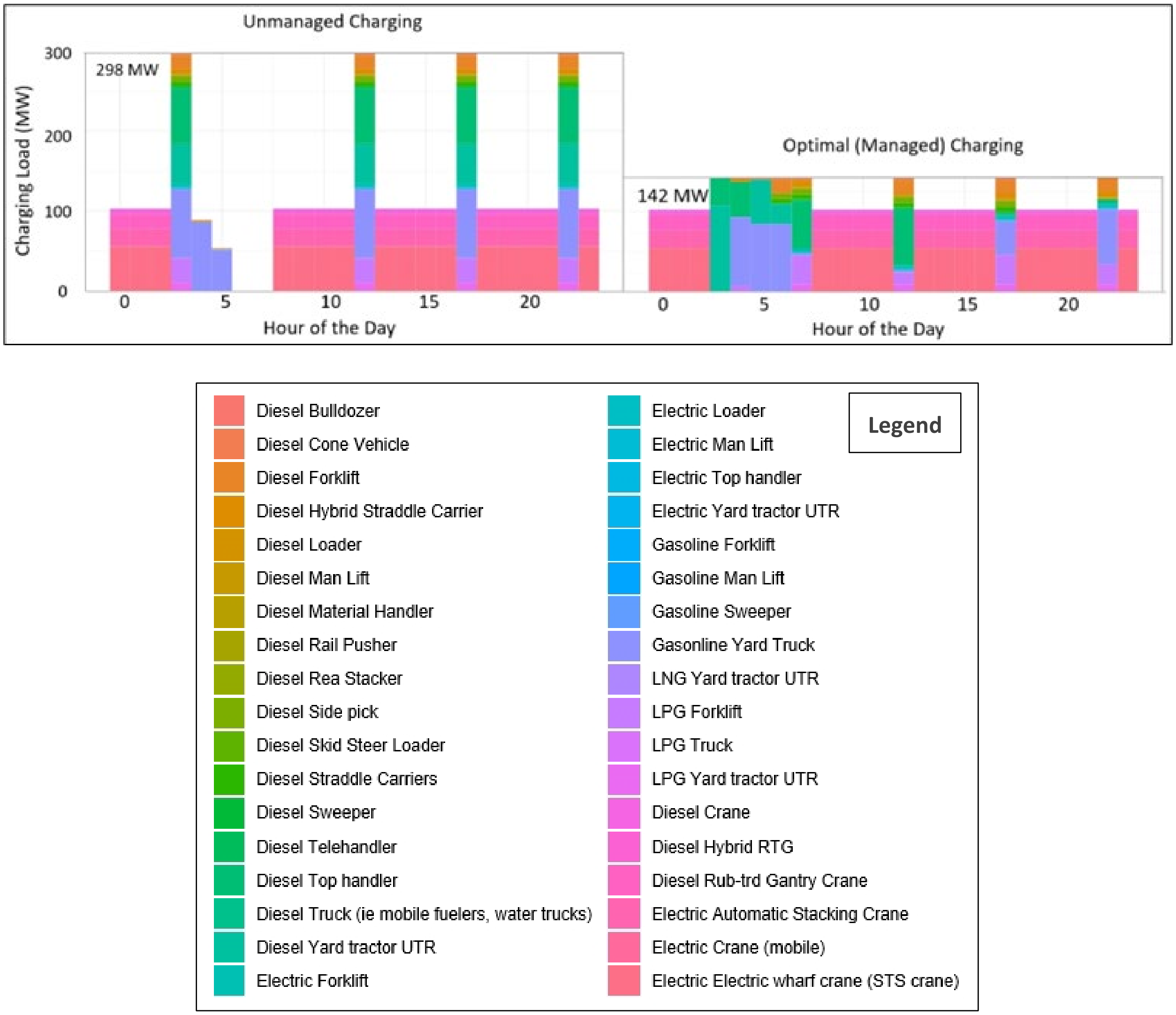


Figure 6. Unmanaged and optimal (managed) charging for all POLA terminals as a whole

Figure 7 shows the unmanaged and optimal (managed) charging for the total of the six POLA terminals (as opposed to all POLA terminals shown in Figure 6).

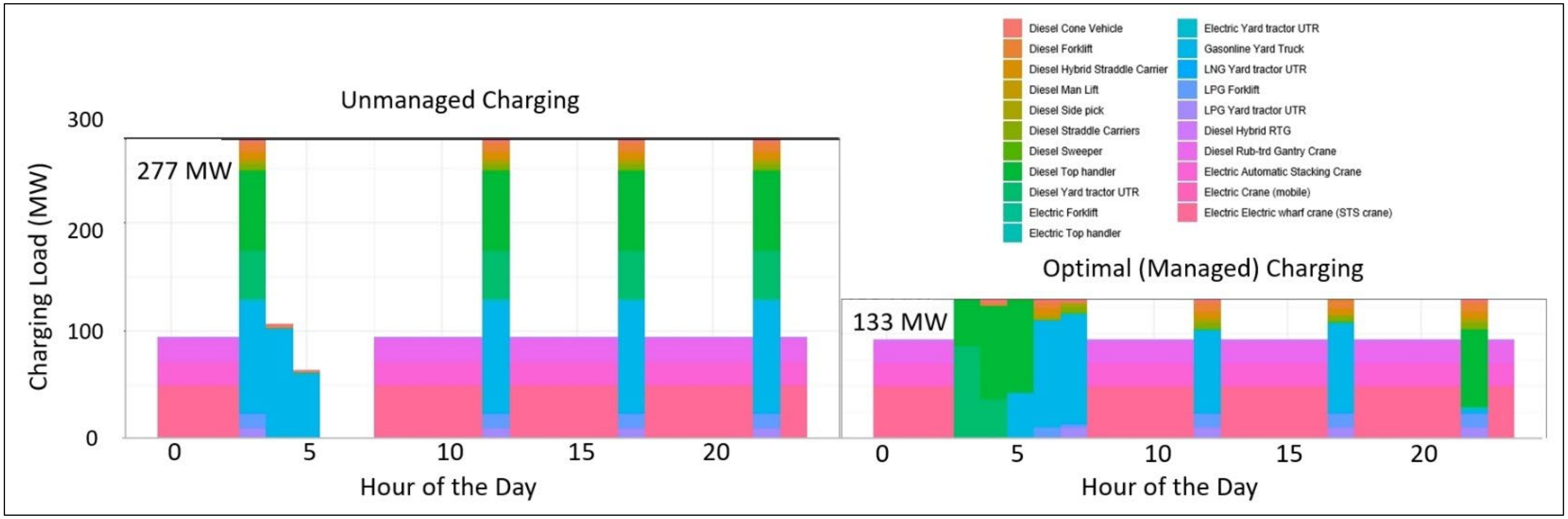


Figure 7. Unmanaged and optimal (managed) charging for the total of the six POLA terminals

Figures 8 through 13 display similar results for each of the individual six terminals. Each of the terminals displays similar results—peak demand reduction via shifting charging to 3 a.m. to 7 a.m.—except Terminal-6. The peak electric load at Terminal-6 is set by the STS gantry cranes and other grid-powered equipment, rather than by battery charging load. These grid-powered loads cannot be mitigated through managed charging, so the managed charging case is nearly the same as the unmanaged charging case.

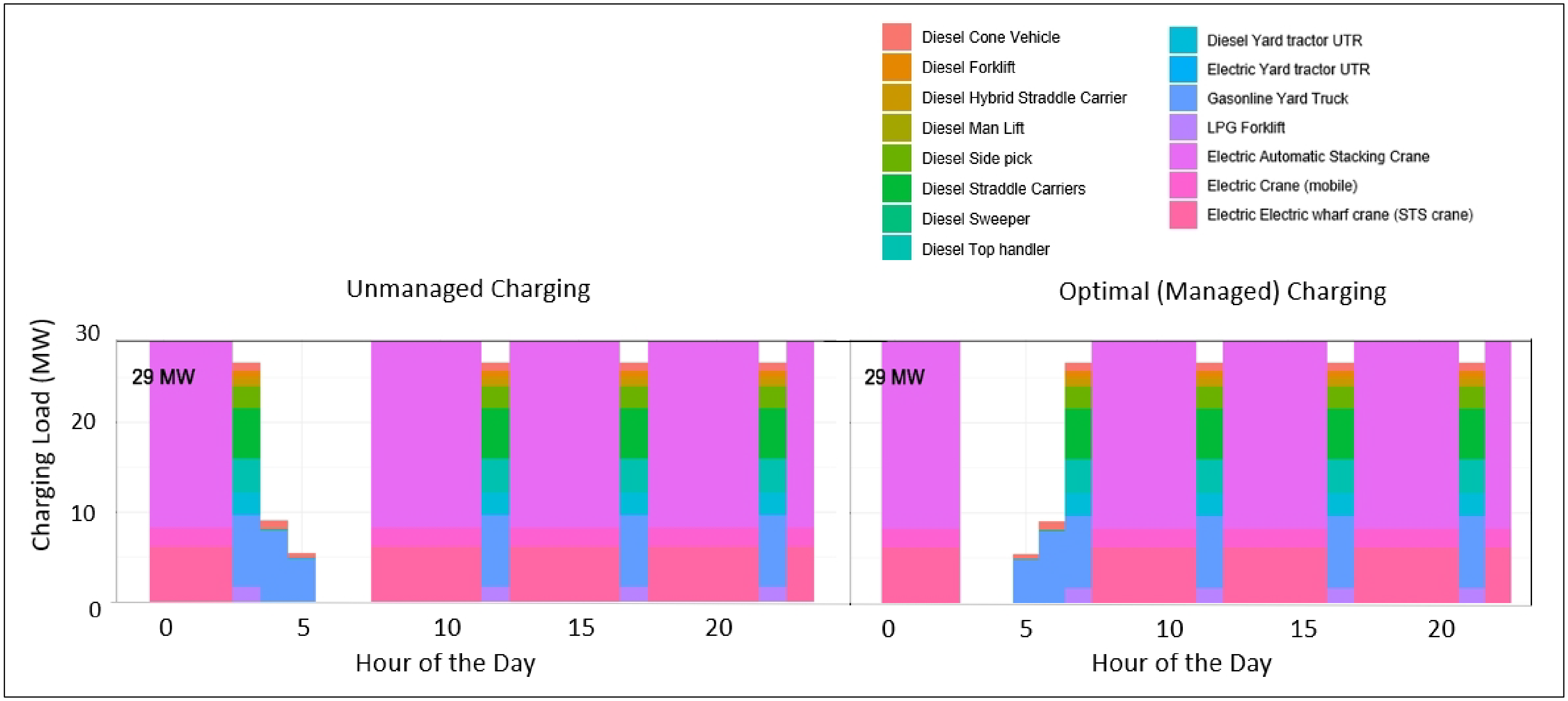


Figure 8. Unmanaged and optimal (managed) charging for Terminal-1

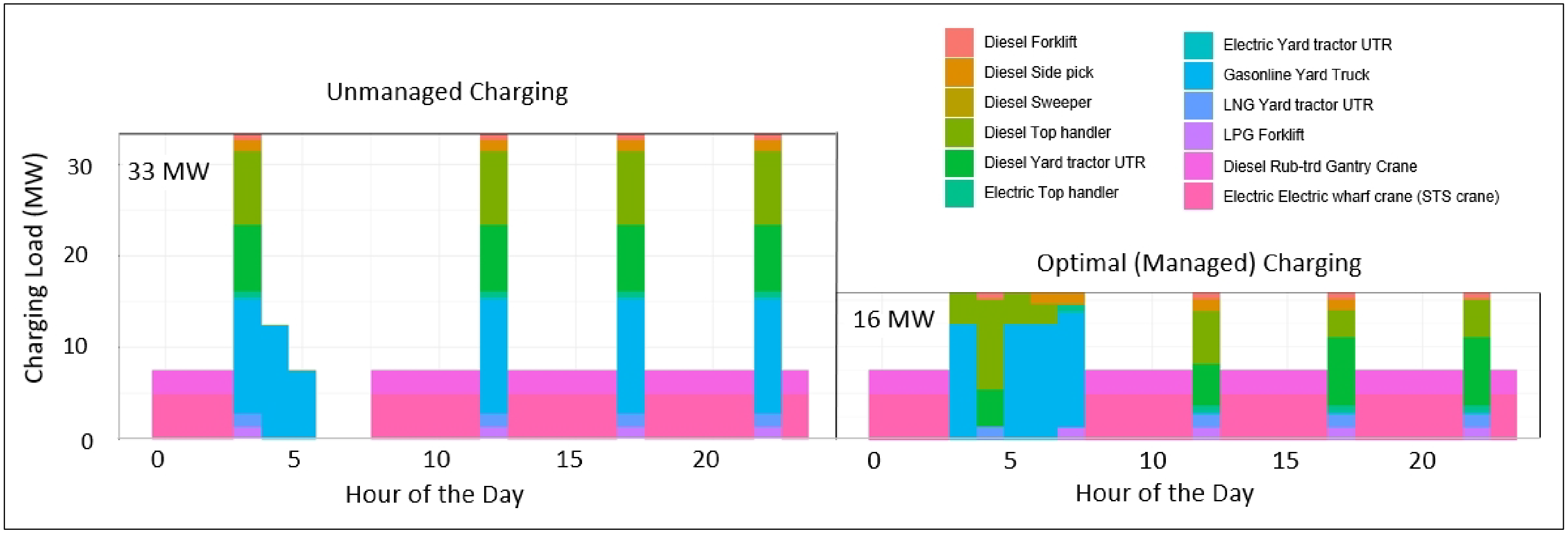


Figure 9. Unmanaged and optimal (managed) charging for Terminal-2

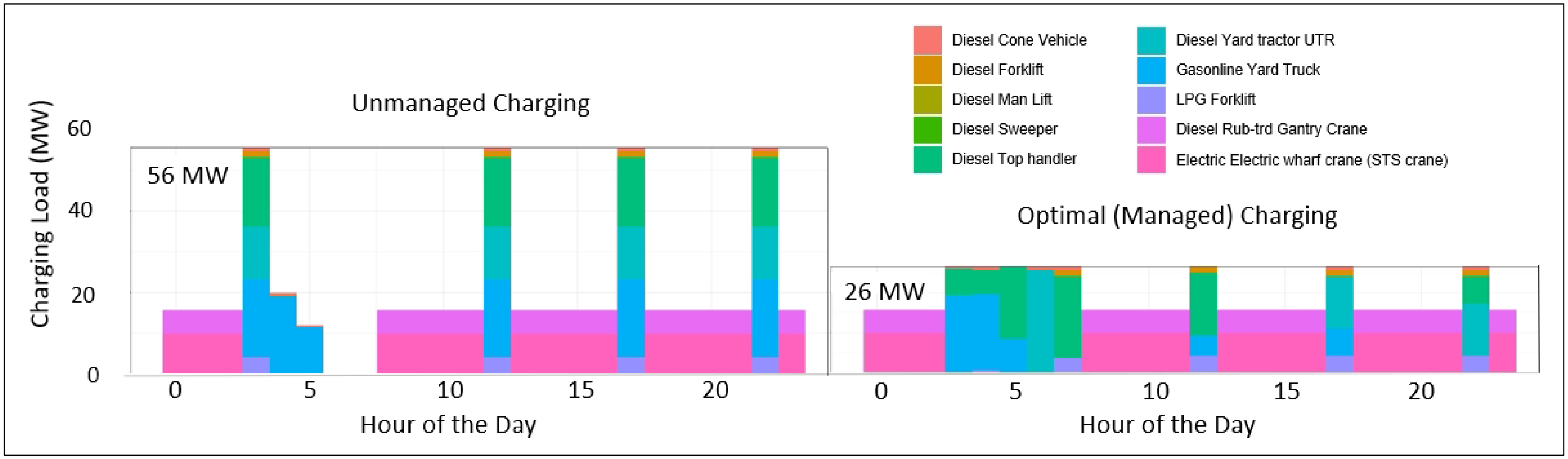


Figure 10. Unmanaged and optimal (managed) charging for Terminal-3

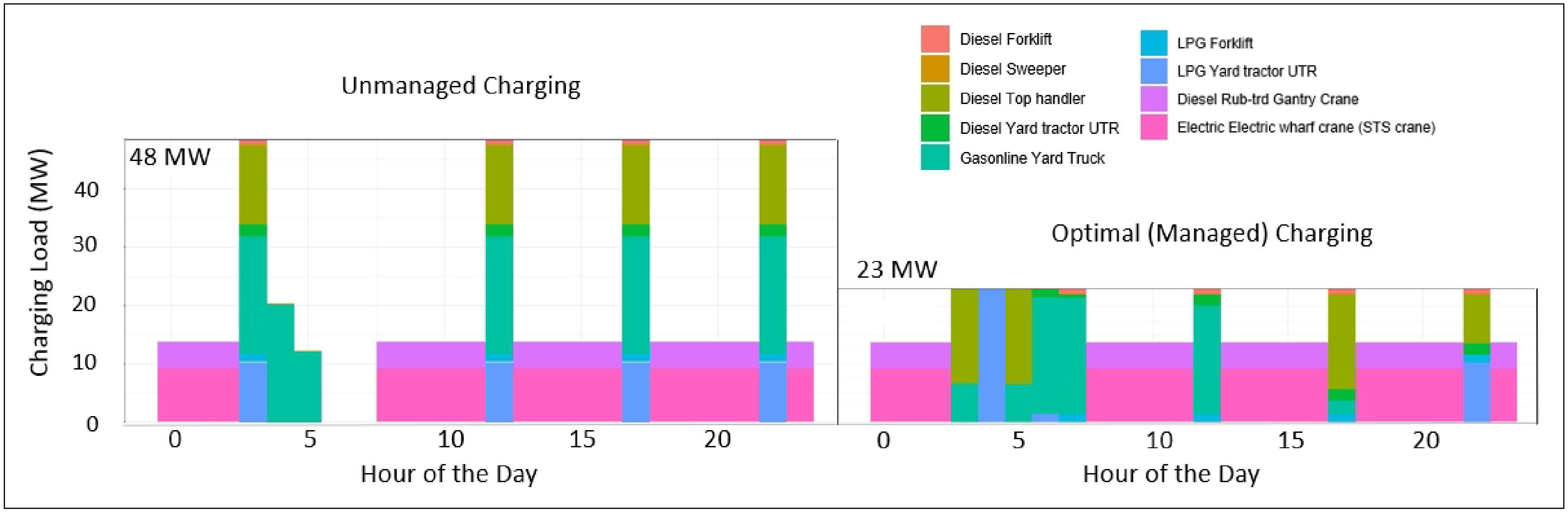


Figure 11. Unmanaged and optimal (managed) charging for Terminal-4

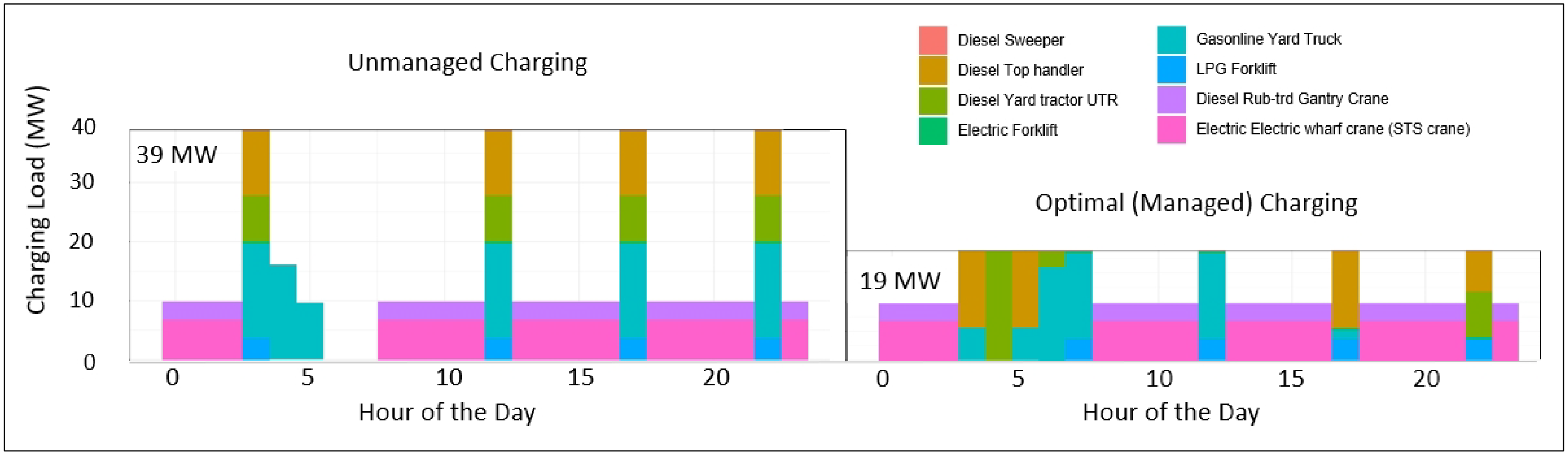


Figure 12. Unmanaged and optimal (managed) charging for Terminal-5

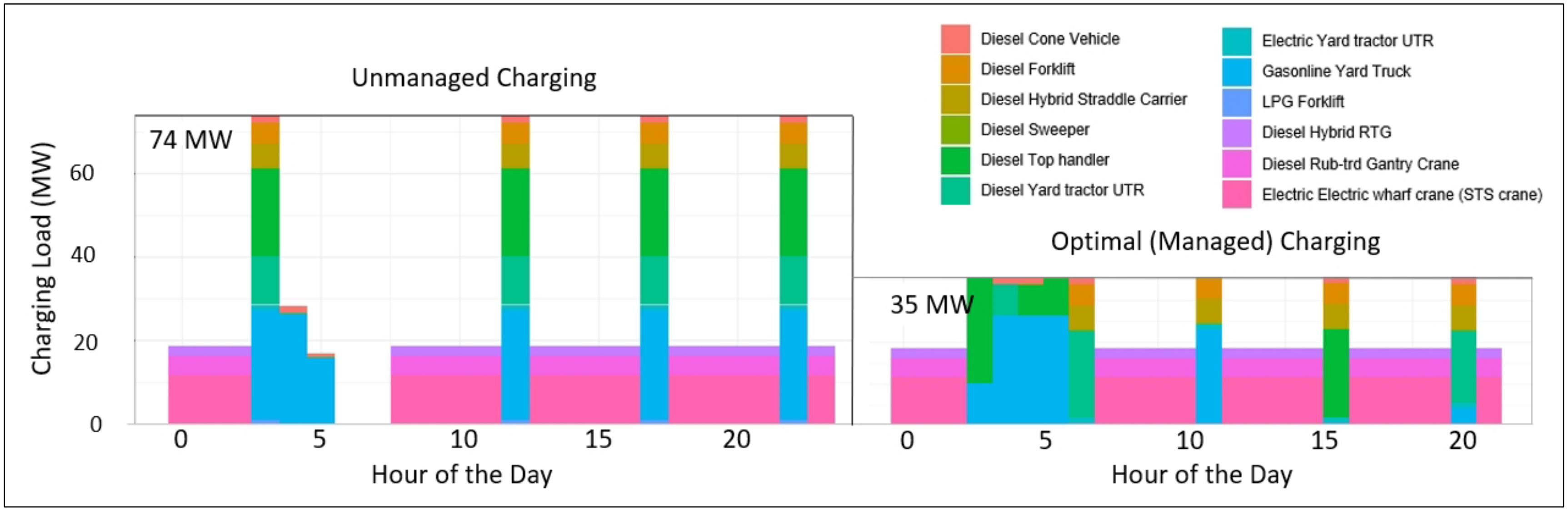


Figure 13. Unmanaged and optimal (managed) charging for Terminal-6

Electric Demand Results

To calculate the electric demand for the various CHE types, information is needed on kW and charging time for each CHE type. This also assumes that all existing CHE is converted to electric-powered ZE CHE. Table 9 shows the assumptions used for kW and charging time for each type of CHE. Using this data, Table 10 shows the electric demand for the various types of CHE in the six container terminals. Peak demand is estimated from the CHE electricity-use profiles alone (not including other demand on-site). This estimate also assumes the full utilization of CHE for both the managed and unmanaged cases.

Energy Results

To calculate the annual energy use of each terminal in the various scenarios, the project team used the load shapes using EPRI's modified DEFT tool. The LADWP A-3 rates, Large Commercial and Multi-Family Service (34.5 kV), were used for the annual electric utility bill analysis [28]. The total amount of electricity in kWh used by electric CHE over a year is estimated from the unmanaged profiles. These profiles represent complete utilization of the fleet of CHE, putting an upper bound on the total energy use from CHE. The port may see lower utilization some of the time, resulting in lower electricity use. Table 11 provides the results of this analysis.

Table 9. CHE inventory used in the electric demand modeling

Equipment by Fuel Type	Count	Source	Charging Power (kW)	Charging Time (hour)	Durability (hour)
DIESEL					
Yard Tractor (UTR)	737	Battery	200	1.3	16
Top Handler	205	Battery	400	2.5	12
Forklift	100	Battery	200	1.25	6
RTG Crane	86	Grid	216	0	0
Hybrid Straddle Carrier	82	Battery	100	2.5	12
Straddle Carriers	28	Battery	200	2	8
Truck (i.e., mobile fuelers, water trucks)	24	Battery	116	5.6	25
Cone Vehicle	21	Battery	116	5.6	16
Man Lift	20	Battery	15	2	15
Side Pick	18	Battery	400	2.5	10
Hybrid RTG	16	Grid	116	0	0
Loader	14	Battery	65	1.08	18
Material Handler	12	Battery	200	3	15

Table 9 (continued). CHE inventory used in the electric demand modeling

Equipment by Fuel Type	Count	Source	Charging Power (kW)	Charging Time (hour)	Durability (hour)
DIESEL, continued					
Crane	7	Grid	716	0	0
Telehandler	7	Battery	400	2.71	12
Sweeper	6	Battery	116	5.6	16
Skid Steer Loader	5	Battery	65	1.08	11
Bulldozer	3	Battery	200	1.25	6
Reach Stacker	1	Battery	200	3	11
Rail Pusher	1	Battery	15	5	22
GASOLINE					
Yard Truck	731	Battery	116	5.6	16
Forklift	6	Battery	200	1.25	6
Sweeper	3	Battery	116	5.6	16
Man Lift	1	Battery	15	2	15
ELECTRIC					
Wharf Crane (STS crane)	88	Grid	616	0	0
Automatic Stacking Crane	29	Grid	716	0	0
Forklift	28	Battery	200	1.25	6
Yard Tractor (UTR)	5	Battery	200	1.3	16
Man Lift	5	Battery	15	2	15
Crane (mobile)	3	Grid	716	0	0
Top Handler	2	Battery	400	2.5	12
Loader	2	Battery	65	1.08	18
LNG					
Yard Tractor (UTR)	22	Battery	200	1.3	16
LPG					
Forklift	180	Battery	200	1.25	6
Yard Tractor (UTR)	158	Battery	200	1.3	16
Truck	1	Battery	116	5.6	25

Table 10. Electric demand estimates for the 50% and 100% electrification scenarios for the container terminals and all POLA terminals

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
POLA Tenants	Current Connected Load			Current Aggregated Transformer Nameplate of ISs Supplying the Tenant[4]	Incremental Future Connected Load[5]		Total Future Connected Load[6]		Incremental Future Diversified Peak Demand[7]				Demand Factor[8]			
	Total[1]	AMP + Reefer Load[2]	Other Loads[3]		50% by 2025	100% by 2030	50% by 2025	100% by 2030	50% by 2025 – Unmngd	100% by 2030 – Unmngd	50% by 2025 – Managed	100% by 2030 – Managed	50% by 2025 – Unmngd	100% by 2030 – Unmngd	50% by 2025 – Managed	100% by 2030 – Managed
	MW	MW	MW	MVA	MW	MW	MW	MW	MW	MW	MW	MW				
Terminal-1	63.76	31.45	32.31	26.25	16.69	33.37	80.45	97.13	14.5	29	14.5	29	0.87	0.87	0.87	0.87
Terminal-2	22.30	17.50	4.8	17.25	21.16	42.31	43.46	64.61	16.5	33	8	16	0.78	0.78	0.38	0.38
Terminal-3	20.61	14.21	6.4	15.00	34.11	68.21	54.72	88.83	28	56	13	26	0.82	0.82	0.38	0.38
Terminal-4	6.00	-	6.0	22.50	30.80	61.61	36.8	67.61	24	48	11.5	23	0.78	0.78	0.37	0.37
Terminal-5	4.42	-	4.42	21.00	21.53	43.07	25.95	47.48	19.5	39	9.5	19	0.91	0.91	0.44	0.44
Terminal-6	31.75	12.52	19.23	55.00	49.11	98.22	80.86	129.97	37	74	17.5	35	0.75	0.75	0.35	0.36
Other Non-Container Terminals	3.54	-	-	-	9.54	19.07	-	22.61	-	-	-	-	-	-	-	-
Six Terminal Total	**148.8**	**75.7**	**73.2**	**157**	**173.4**	**346.8**	**322.2**	**495.6**	**138.5**	**277**	**66.5**	**133**	**0.79**	**0.80**	**0.21**	**0.38**
POLA (ALL Terminals)	**152.4**	-	-	**157**	**182.9**	**365.9**	**322.2**	**518.2**	**149**	**298**	**71**	**142**	**0.81**	**0.81**	**0.39**	**0.39**

Notes and assumptions:

1. Established based on the terminal inventory. Includes the AMP and reefer loads.
2. Assumes 2.5 MW/AMP connector, 6 kW/reefer.
3. Calculated as column B minus column C.
4. Excludes ISs marked as dedicated for AMP loads.
5. Calculated based on the equipment inventory and assumed kW demand by equipment type. These incremental future loads do not include AMP or reefer loads.
6. Sum of the total current connected load (column B) and the future connected load (column F or G).
7. The peak demand of the CHE load profiles established with the DEFT tool.
8. Calculated with incremental future diversified peak demand (columns J–M) / incremental future connected load (columns F–G).

Table 11. Electric energy and electric utility bill estimates for 50% and 100% electrification (container terminals and all POLA terminals)[5]

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
POLA Tenants	Current Connected Load			Current Aggregated Transformer Nameplate of ISs Supplying the Tenant[4]	Incremental Future Connected Load[5]		Total Future Connected Load[6]		Incremental Future Diversified Peak Demand[7]				Total Annual CHE Energy Use[8]	Total Annual CHE Electric Utility Bill Estimate	Total Annual CHE Electric Utility Bill Estimate
	Total[1]	AMP + Reefer Load[2]	Other Loads[3]		50% by 2025	100% by 2030	50% by 2025	100% by 2030	50% by 2025 – Unmngd	100% by 2030 – Unmngd	50% by 2025 – Managed	100% by 2030 – Managed	100% by 2030	100% by 2030 – Unmngd	100% by 2030 – Managed
	MW	MW	MW	MVA	MW	MW	MW	MW	MW	MW	MW	MW	MWh	million $	million $
Terminal-1	63.76	31.45	32.31	26.25	16.69	33.37	80.45	97.13	14.5	29	14.5	29	213,957	20.62	20.62
Terminal-2	22.30	17.50	4.8	17.25	21.16	42.31	43.46	64.61	16.5	33	8	16	99,945	10.83	8.49
Terminal-3	20.61	14.21	6.4	15.00	34.11	68.21	54.72	88.83	28	56	13	26	184,413	19.62	15.81
Terminal-4	6.00	-	6.0	22.50	30.80	61.61	36.8	67.61	24	48	11.5	23	162,997	17.26	13.83
Terminal-5	4.42	-	4.42	21.00	21.53	43.07	25.95	47.48	19.5	39	9.5	19	123,477	13.21	10.54
Terminal-6	31.75	12.52	19.23	55.00	49.11	98.22	80.86	129.97	37	74	17.5	35	233,594	25.04	19.99

Notes and assumptions:

1. Established based on the terminal inventory. Includes the AMP and reefer loads.
2. Assumes 2.5 MW/AMP connector, 6 kW/reefer.
3. Calculated as column B minus column C.
4. Excludes ISs marked as dedicated for AMP loads
5. Calculated based on the equipment inventory and assumed kW demand by equipment type. These incremental future loads do not include AMP or reefer loads.
6. Sum of the total current connected load (column B) and the future connected load (column F or G).
7. The peak demand of the CHE load profiles established with the DEFT tool.
8. Annual electric energy of the new CHE loads that are converted 100% from fossil fuel to electric (AMP and reefer loads are not included)

.

[5] Note that columns B–M in this table are repeated from Table 11 for convenience.

Conclusions

The conclusions of the tenant electrification modeling are the following:

- Implementing perfect managed charging could reduce the peak electricity consumption from CHE by about one-half on a two-shift schedule.
- Achieving this would be impractically difficult in any real implementation but demonstrates the potential value of managing the CHE charging to reduce the peak demands.
- The uncertain data inputs to this analysis result in uncertain outputs, which impact the grid analysis.

5 GRID MODEL DEVELOPMENT

At the time of this assessment, LADWP was conducting an ongoing initiative to develop models for its entire electric distribution system. However, this effort did not yet have a model available for the RS-Q area. Therefore, it was necessary to develop such a model. This section describes the process of developing a model of the electric distribution grid in the area including and surrounding POLA. The various steps of model development are described. The various assumptions necessary for the model development are also included in this section. Appendix B of this report summarizes the data received from LADWP for this task.

Based on geographic information system (GIS) data, station drawings, maps, supervisory control and data acquisition (SCADA) measurements, and various other data sources received from LADWP, EPRI developed a detailed grid model using OpenDSS software. The model represents the 34.5-kV level of the RS-Q area, including but not limited to the following aspects: RS-Q transformer banks, 34.5-kV circuits, distribution stations (DSs), industrial stations (ISs), and capacitor banks. The model was calibrated for yearly 8760-hour, quasi-static time-series (QSTS) simulations based on existing system conditions. By modifying this model to represent selected future scenarios, the model was used to conduct the grid impacts analysis presented in sections 6 and 9 and the grid mitigation assessment presented in sections 7 and 10.

Grid Model Development Process

At a high level, the team conducted the following steps for grid model development:

- The team translated the GIS data into the OpenDSS[6] model format for all circuits.
- The team addressed numerous issues in the GIS data (e.g., missing or bad parameter values, and so on) that led to some elements not being properly converted or similar.
- The team addressed connectivity issues for all circuits separately. This step involved a large amount of manual work and some iterations with LADWP.
- Based on station one-line drawings, the team modeled the receiving station “Q” (RS-Q), including the following components:
  - Transformer banks and load tap changers (LTCs)
  - Capacitor banks
  - Circuit-to-RS bank connectivity
  - Load-balancing reactors

[6] Developed by EPRI, OpenDSS is an electric power distribution system simulator (DSS) designed to support distributed energy resource grid integration and grid modernization.

- Based on one-line drawings, the team modeled DSs supplied by RS-Q (DS3, DS89, DS118, DS119, DS120, DS121, and DS214), including the following aspects:
  - 34.5-kV capacitor banks
  - A lumped load representing the DS loads
  - Circuit-to-DS connectivity
- Based on GIS data, PDF maps, and several other data sources provided, the team modeled the relevant aspects of the ISs, including the following:
  - The team added a static load to each transformer.
  - The team represented circuit-to-IS connectivity.
- The team implemented a compiled OpenDSS model of all circuits supplied by RS-Q, including the following steps:
  - The team compiled all circuits.
  - The team modeled tie points between circuits with correct switch statuses.
- The team addressed all connectivity issues in the model based on extensive communication with LADWP. This step was particularly labor-intensive because some of the connectivity information was not easily available in GIS or other data sources received from LADWP. While extensive effort was invested in this step, the connectivity of elements in the overall model is subject to some uncertainty given the data limitations.
- The team modeled cogeneration facilities (solar photovoltaic [PV] systems[7]) at ISs.
- The team implemented snapshot load models for each DS, IS, and transformer. This involved the following steps:
  - Assume a power factor (PF) of 0.90 for loads. Capacitor banks are modeled separately.
  - To model the DS loads, the team performed the following:
    - Modeled DS loads with a single load without a transformer; only the 34.5-kV side was modeled.
    - Assuming a PF of 0.90, kW values for the loads were calculated from the kVA values "2021 Coincidental Demand at RS Peak [MVA]" in the "CKT & Bank demand" sheet of the "Bank B Load Analysis rev1.xlsx" spreadsheet.
  - For IS loads, the team performed the following:
    - The team modeled IS transformers in GIS and added each transformer load.
    - The team did not model IS transformers not in GIS, but the team did add a load to each such IS. The team relied on various maps and other data sources to identify the locations of ISs that were not in the GIS data. This step was highly time-consuming.

[7] All cogeneration facilities modeled were PVs except for two fuel cell generating facilities.

- The team derived kW values for the loads as follows:
  - If available, the team used the kW value from the “Original KW” column of the “Bank B Load Analysis rev1.xlsx” file.
  - If this value was blank, the team instead used the value in the column “Demand KW.”
  - If the resulting kW value was zero, the team assumed 30% loading of the transformer nameplate.
- The team scaled the static loads to establish a realistic current peak load scenario and the RS-Q level. The scaling involved several iterations with LADWP but is not discussed here because the static load modeling is not used in this assessment. For this assessment, the team applied a time-series load modeling approach. This approach is discussed separately in a later section.

- The team modeled cable/conductor upgrades that LADWP specified.
- The team validated the RS-Q area model with the static load models for the following aspects:
  - Isolated elements and numerous other modeling issues
  - Power flow convergence
  - RS-level loading
  - Voltage profile and voltages
  - Overloads
  - Losses
- The following is an overview of the model with the static load model:
  - Devices = 13,951
  - Buses = 13,105
  - Nodes = 39,316
  - Maximum voltage = 1.04 pu
  - Minimum voltage = 0.99 pu
  - Total active power: 128.12 MW
  - Total reactive power: -5.18 MVAR
  - Total active losses: 0.97 MW (0.76%)
  - Total reactive losses: 0.72 MVAR

Figure 14 shows an overview of the model layout (left) and a voltage profile for a static load flow (right).

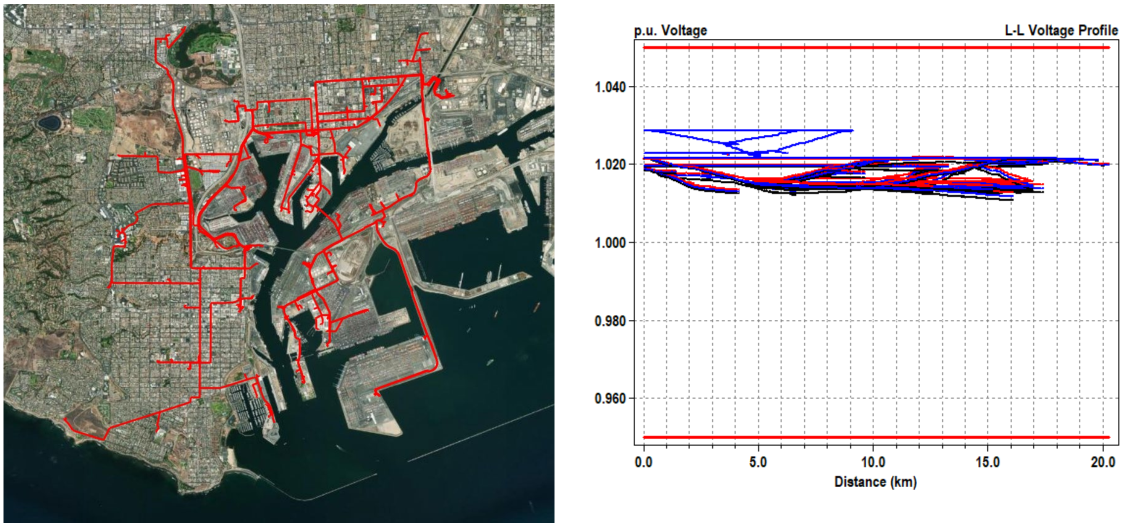


Figure 14. Overview of the developed RS-Q OpenDSS model (layout on the left, voltage profile on the right)

- The team converted the RS-Q OpenDSS model into CYME, which was provided to LADWP. The CYME model was not used in this assessment but is described in more detail in Appendix C.
- The team modeled capacitor switching controls with the following steps:
  - The team modeled local controls that attempt to maintain the RS-Q bank secondary reactive power flow between +10 MVAR inductive and -5 MVAR capacitive.
  - The team assumed a "switching priority order" for the capacitors.
  - In practice, the capacitors are not locally controlled but operated manually by a control center operator. The control model is intended to reasonably mimic this operating principle.
- The team removed the circuits VLPED1, VLRPEDA, VLRPEDB, VLRPEDC, VLRPEDD, and VLRPEDE from the RS-Q model because of excessive uncertainty in their models. In particular, the element connectivity was highly uncertain for these circuits. The team modeled the load on these circuits at their connection points with the upstream circuits HAR-PED F, HAR-PED G, and HAR-PED H. This change is expected to have a minimal impact on the lines on RS-Q bank C lines upstream of the VLR lines. Moreover, this change plays no role for this project, which focuses on the RS-Q bank B that supplies the POLA area.
- The team refined ampacity and impedance models of overhead lines and underground cables based on updated circuit-specific ampacities and series impedance parameters that LADWP provided. Figure 15 shows the updated circuit-specific line ampacities.

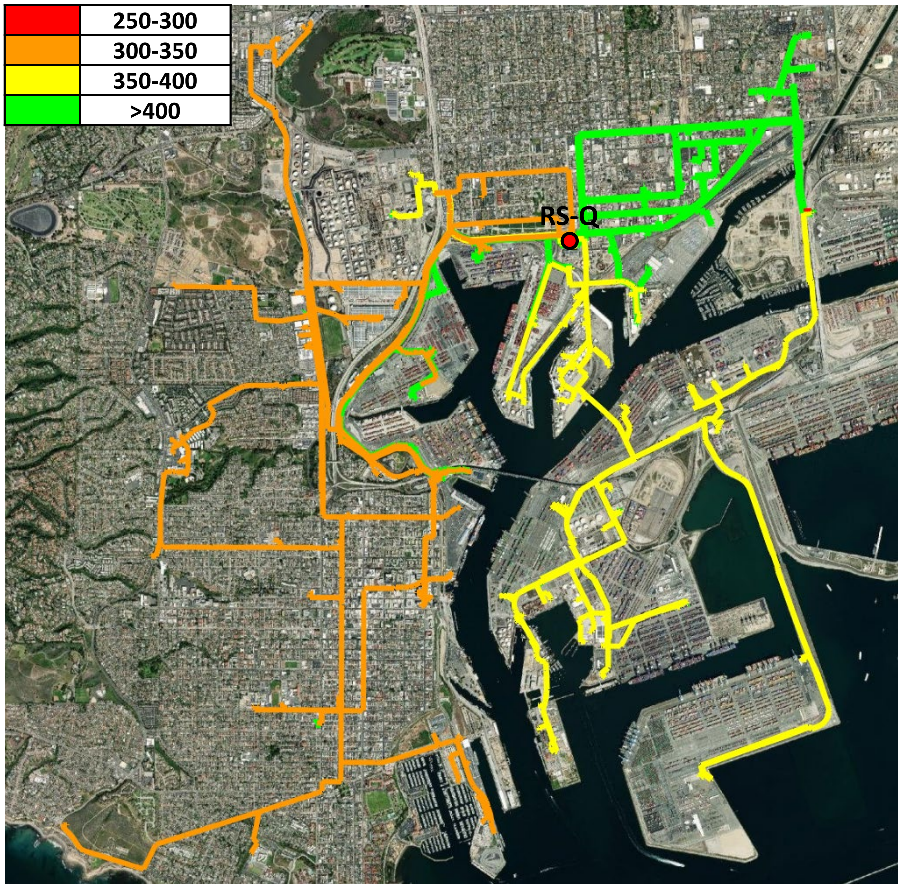


Figure 15. Updated circuit-specific line ampacities that LADWP provided

Time-Series Load Modeling Approach and Validation

The grid impact and infrastructure upgrade analyses presented in sections 6 and 7 applied a QSTS simulation that required establishing time-series load models for the existing loads in the RS-Q area.[8] A series of conversations with LADWP personnel enabled identification of a satisfactory modeling approach. The time-series load modeling was not trivial due to the looped/meshed nature of the RS-Q area grid and various data issues. The team addressed numerous issues in the LADWP SCADA system data to enable its use for the load modeling. Before fixing the issues, applying the circuit-specific SCADA data resulted in ±20 MW or ±20% errors at the RS-Q bank B level.

Figure 16 illustrates the RS-Q total load (banks A, B, C for 1/2018–9/2021). The total peak load of about 166.6 MW is significantly higher than the 99th percentile loading of 137.9 MW.

[8] The time-series load modeling discussed here represents the existing system conditions. The modeling of future loading conditions inside and outside the POLA area is discussed separately in section 6.

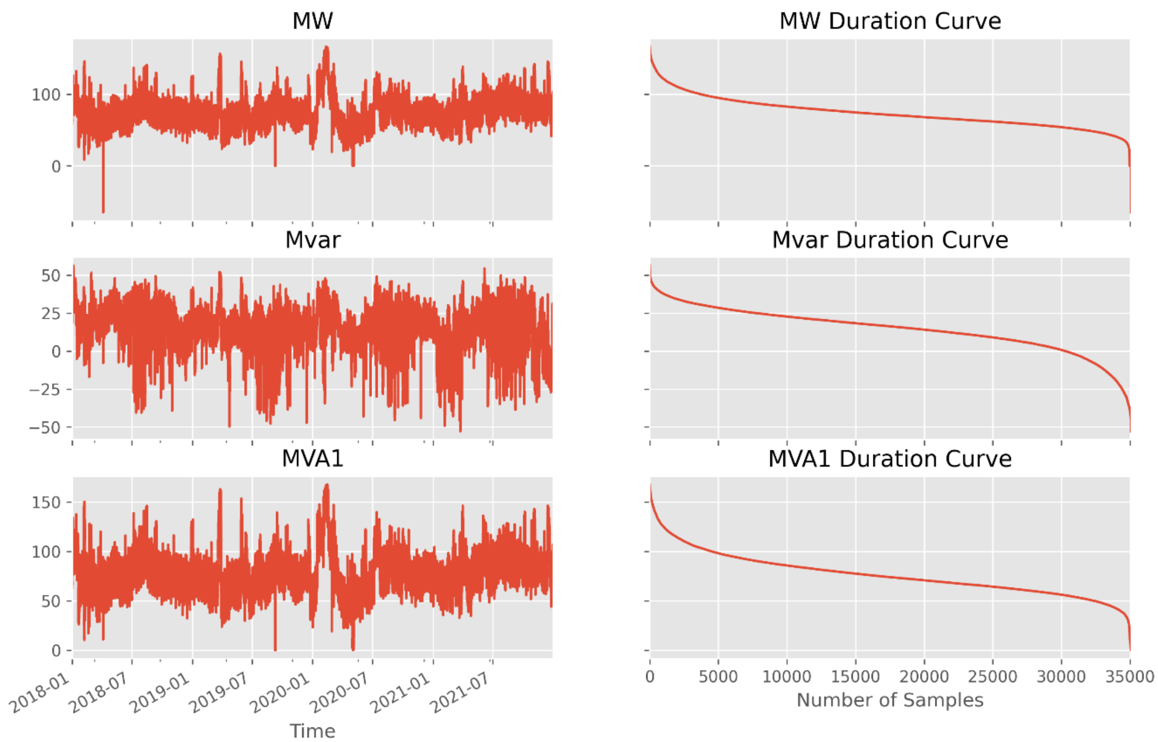


Figure 16. RS-Q total (banks A + B + C) load

The bank A load profile was "spiky," with a peak load of about 95.3 MW, but a 90th percentile at only 9.1 MW (see Figure 17). There seems to be considerable cogeneration and reverse power flow at times. Note that bank A supplies only a large refinery. Bank A is not a focus in this project because the bank is dedicated to supplying the refinery.

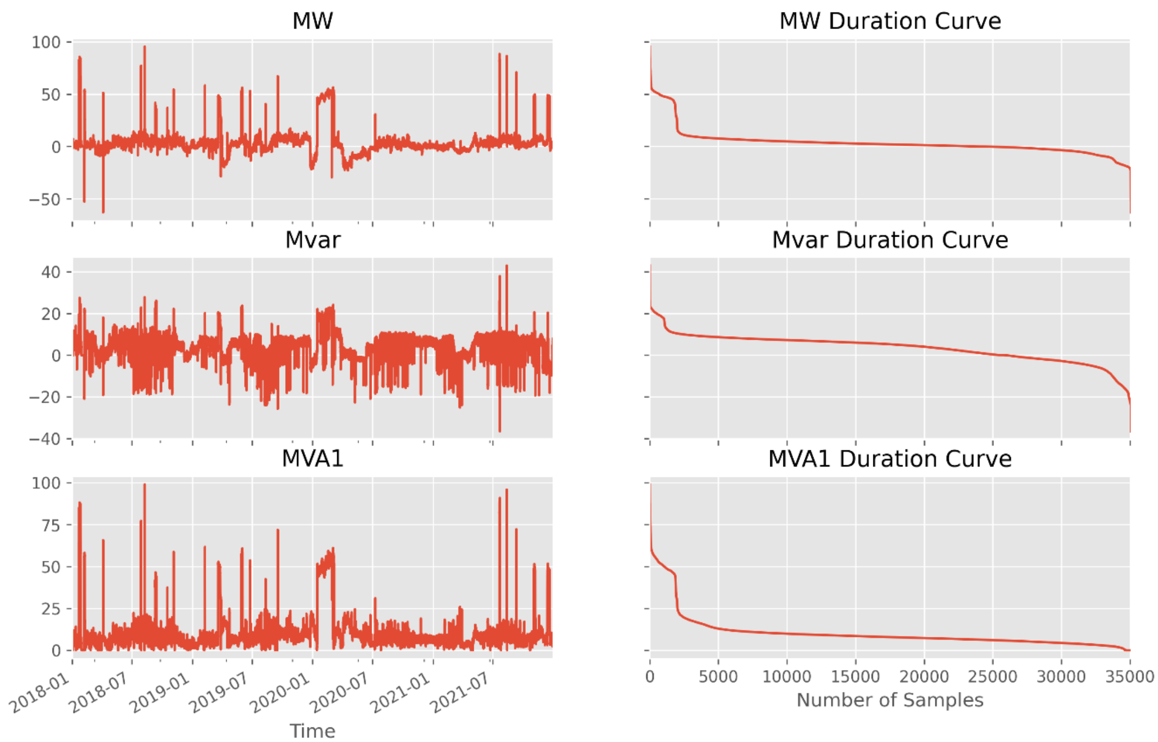


Figure 17. RS-Q bank A total load

The bank C load profile was also “spiky,” with a peak load of about 96.8 MW, but a 90th percentile of only 17.8 MW (see Figure 18). There seems to be considerable cogeneration and reverse power flow on this bank at times. Similar to bank A, bank C supplies only a large refinery. Bank C is not a focus in this project because the bank is dedicated to supplying the refinery.

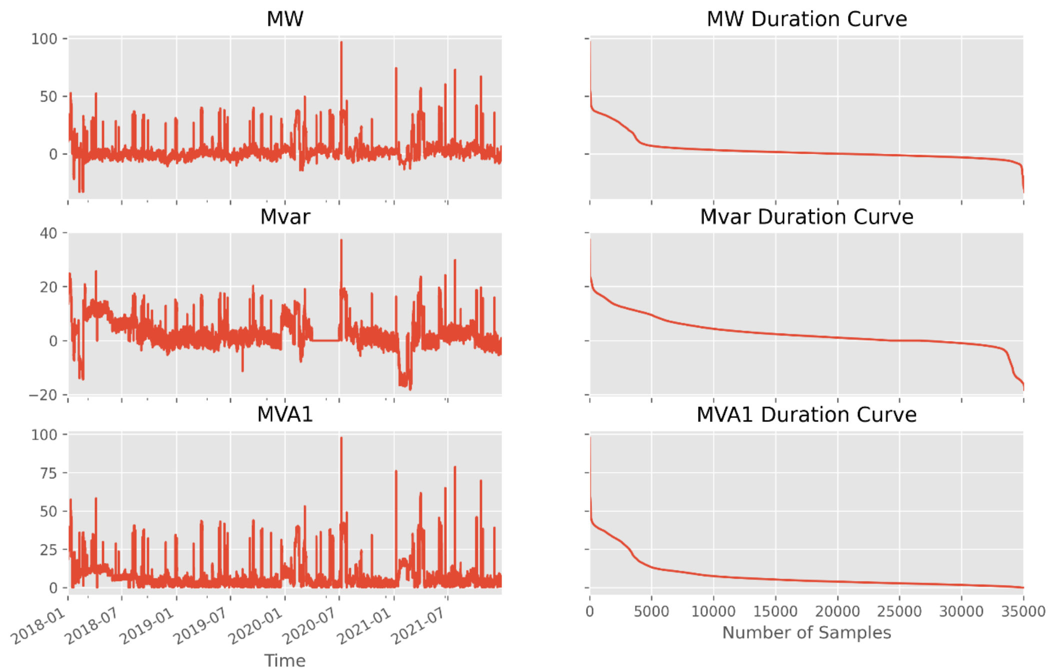


Figure 18. RS-Q bank C total load

Figure 19 illustrates bank B load. This project focuses on the RS-Q bank B.

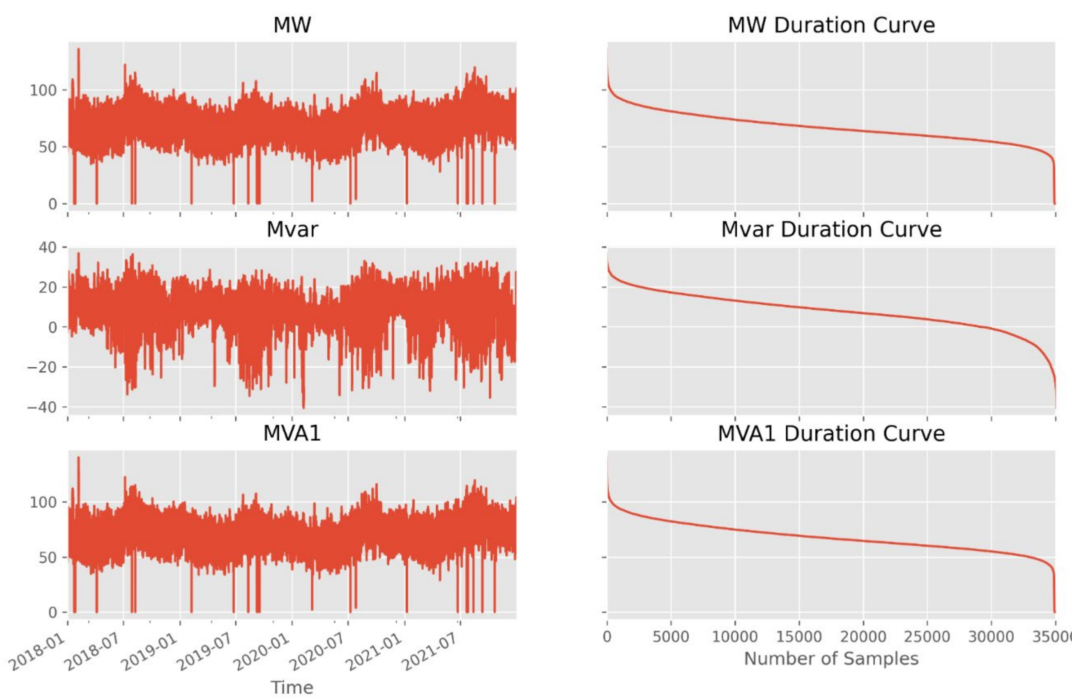


Figure 19. RS-Q bank B total load

The team performed the QSTS modeling using the most recent data from the year 2021. Note that the loading data during this period may have been impacted by the pandemic.

The team used the following approach to conduct the final time-series load modeling:

- The team assumed a PF of 0.9 for all existing loads.
- The team modeled all loads supplied by RS-Q bank A and bank C with bank-specific load profiles created from SCADA data for 2021. To do this, the team did the following:
  - Manually removed all the data points with abnormal behavior in the SCADA data of each bank
  - Represented short periods of removed data with previous samples, and represented a few longer periods with data from a previous day
  - Created a normalized load profile for each bank by dividing the MW values by the aggregated MW of all loads served by the bank
  - Applied appropriate normalized load profile for each load
- The team modeled all loads served by RS-Q bank B with DS/IS/circuit-specific load profiles created from SCADA data for 2021. To do this, the team did the following:
  - Processed the bank B/DS/IS/circuit SCADA data for bad and missing data points
  - Created kW load profiles for DS3, DS89, DS119, and DS121 based on the SCADA DS data
  - Created kW load profiles for IS-3185, IS-4301, IS-4798, and IS-5210 based on SCADA IS bank and/or circuit data[9]
  - Created circuit-specific kW load profiles based on SCADA measurements from both ends of each circuit
  - Scaled the circuit-specific kW load profiles to match the aggregated RS-Q bank B kW data (DS + IS + circuits) with the RS-Q bank B kW SCADA data
  - Created a normalized 8760-hour PV generation profile based on 12- x 24-hour profiles (i.e., one day at hourly resolution for each month) received from LADWP (see Figure 20)[10]
  - Estimated the PV generation on each circuit by multiplying the normalized PV generation profile by the aggregated PV nameplate on each circuit (see Figure 21 for the entire RS-Q area)[11]

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[9] Due to various data-quality issues, SCADA data from the IS transformer banks and/or circuits was used.

[10] In future studies, it is recommended to represent the PV generation in more detail using field measurement data or another approach.

[11] The PV AC kW rating was modeled based on the kW rating that LADWP provided. PV AC kW generation was directly modeled by multiplying the AC kW rating by the normalized generation profile, and hence the PV DC rating was not necessary.

– Created circuit-native load MW profiles by adding the estimated PV MW generation per circuit to each circuit's net load MW profile[12]

– Created circuit-specific normalized load profiles for each circuit by normalizing the scaled circuit-specific kW profiles by the total kW of all loads on the circuit

– Applied the correct DS/IS/circuit load profiles for each load served by RS-Q bank B

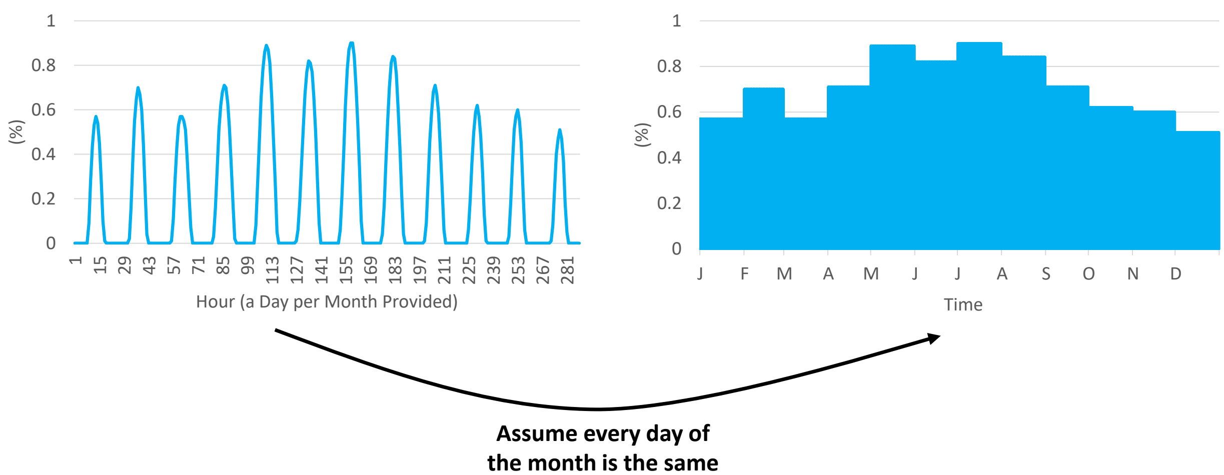


Figure 20. Conversion from a 12- x 24-hour PV generation profile to an 8760-hour yearly profile

[12] To do this, it was necessary to consider daylight saving time in the load and PV generation profiles. This step is subject to error.

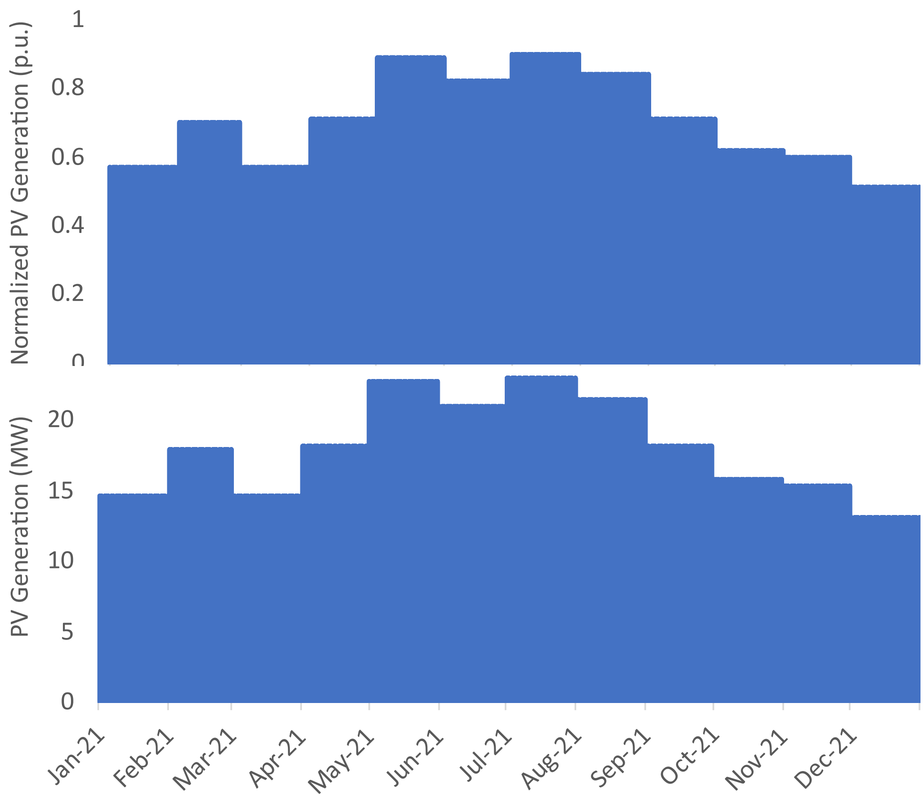


Figure 21. Normalized PV generation profile (top) and MW PV generation profile (bottom)

- The team validated the load modeling by performing the following:
  - Running a QSTS simulation with the created load profiles
  - Comparing the simulated versus measured values for RS-Q banks, DSs, ISs, and circuits

With the refined circuit-specific load models, the simulated and measured loads match closely for the RS-Q banks, DSs, and ISs. This is expected for the following reasons:

- First, the measured data is directly applied to model the RS-Q bank A and C loads, as well as the bank B loads at DSs and ISs.
- Second, RS-Q bank B level loading matches due to the scaling applied for the bank B circuit load profiles.

The simulated and measured loading at the ends of the circuits also match reasonably well for the circuits. The remaining discrepancy between the simulated and measured circuit-level loading is attributed to numerous issues in the SCADA data applied for the time-series load modeling and any inaccuracies in the circuit model.

Future Recommendations

Via the grid model development process discussed in this section, the team identified several potential areas for improvement for the LADWP distribution system data. At the time of this assessment, LADWP has an initiative to develop models for its entire distribution system. This initiative may address some of the recommended future improvements. The key recommendations are as follows:

- **Address discrepancies in GIS data.** The existing GIS data was observed to have missing components and missing, erroneous, or outdated component attributes. In particular, the following GIS data attributes were observed to have errors and/or gaps: voltage levels, line lengths, conductor/cable types, connectivity of elements (caused by small distances between asset coordinates), and switch statuses.
- **Complement GIS data.** The existing GIS data (received by EPRI) did not include some critical information required for model development. For example, a significant amount of RS, DS, and IS information, including critical data such as location and transformer capacity, was not available from GIS and hence was manually processed from maps, station drawings, and various other documents. Similarly, the GIS data did not include cogeneration facilities or their grid connections. Limitations were also observed in the available overhead line and underground cable impedance parameters.
- **Address issues in RS/DS/IS/circuit SCADA data.** Various issues were identified in the RS/DS/IS/circuit SCADA data. For example, some of the measured quantities were not available or suffered from poor quality.
- **Integrate customer load data.** Customer-level load data was not available for this assessment. Given the meshed nature of the LADWP 34.5-kV system, accurate circuit-level loading was observed to be important. This could be made more practical by either addressing the SCADA data issues discussed above and/or by integrating customer data available from MV-Web or other sources into the grid models LADWP is currently developing.
- **Collect PV measurement data.** No PV field measurements were available for this assessment. Given the high penetration of PV on some of the circuits, accurate PV modeling is becoming increasingly important. This could be supported by having easy access to PV field measurement data from the distribution system area.

6 GRID IMPACT ANALYSIS

This section analyzes the grid impacts of future RS-Q scenarios representing POLA tenant CHE loads and RS-wide load growth. While the RS-Q grid upgrades currently planned by LADWP are represented, no other grid upgrades are considered in this section. Future RS-Q area grid infrastructure considered by LADWP, along with other grid infrastructure upgrades required to mitigate the grid impacts for the future scenarios, are analyzed separately in section 7. This section briefly introduces the scenarios analyzed and then presents the results of the grid impact analysis. Appendix D contains detailed results on the grid impact analysis.

Overview of the Analyzed Scenarios

The team analyzed grid impacts for the seven scenarios summarized in Table 12. Scenario 1 (existing system conditions) represents the existing distribution system conditions (in 2021) for the RS-Q area grid model introduced in section 5. Scenario 1 does not include any future POLA tenant CHE loads, RS-Q-level load growth, or grid upgrades currently planned by LADWP. Scenarios 2–7 correspond to six future scenarios representing the following:

- Future spot loads in the RS-Q area
- RS-Q-wide load growth (2025 versus 2030 versus 2035)
- POLA tenant CHE loads
  - Load levels 50% by 2025 versus 100% by 2030 and beyond
  - Charging scheme: Unmanaged versus managed
- RS-Q grid upgrades currently planned by LADWP

These aspects are discussed in more detail in the subsections following Table 12. The team also studied two scenarios where CHE is powered by hydrogen fuel cell and the results are shown in section 8, herein (see subsection Hydrogen Fuel Cell Scenarios).

Table 12. Grid impact analysis scenarios

Scenario	1: Existing System Conditions (2021)	2: 50% Electrification by 2025 – Unmanaged	3: 50% Electrification by 2025 – Managed	4: 100% Electrification by 2030 – Unmanaged	5: 100% Electrification by 2030 – Managed	6: 100% Electrification by 2035 – Unmanaged	7: 100% Electrification by 2035 – Managed
Include Future RS-Q Spot Loads	No	Yes	Yes	Yes	Yes	Yes	Yes
RS-Q Bank B Forecast Peak Load (MW)[13]	119.0	141.9	141.9	156.5	156.5	162.0	162.0
OpenDSS Growth Multiplier (pu)[14]	1.000	1.125	1.125	1.225	1.225	1.260	1.260
POLA Tenant CHE Load Level (%)	0	50	50	100	100	100	100
POLA Tenant CHE Load Profile	None	Unmanaged	Managed	Unmanaged	Managed	Unmanaged	Managed
Includes Upgrades Currently Planned By LADWP	No	Yes	Yes	Yes	Yes	Yes	Yes

Future RS-Q Spot Loads

Based on extensive discussions with LADWP, it was decided to represent for this assessment only one future spot load in the RS-Q area, excluding the POLA container terminal CHE loads and the other loads represented in section 7. The spot load, which was interconnected in May

[13] The RSQ bank B load forecast does not include POLA CHE loads or other loads represented in section 7.

[14] The growth multipliers of scenarios 2–4 are somewhat lower than the percentage load growth of each scenario over scenario 1 due to the added spot load, losses, and other non-linearities.

2022,[15] is served by the HAR-TER 1 circuit. The spot load location is shown in Figure 22. The spot load was modeled with a demand of about 2.7 MW and a PF of 0.86. The load was assumed to follow the HAR-TER 1 circuit load profile established as a part of the model development discussed in section 5.

During the course of this assessment, LADWP received additional future customer service requests. It is recommended to revisit this assessment in about two years as additional loads are added to the RS-Q area and as new service requests are received.

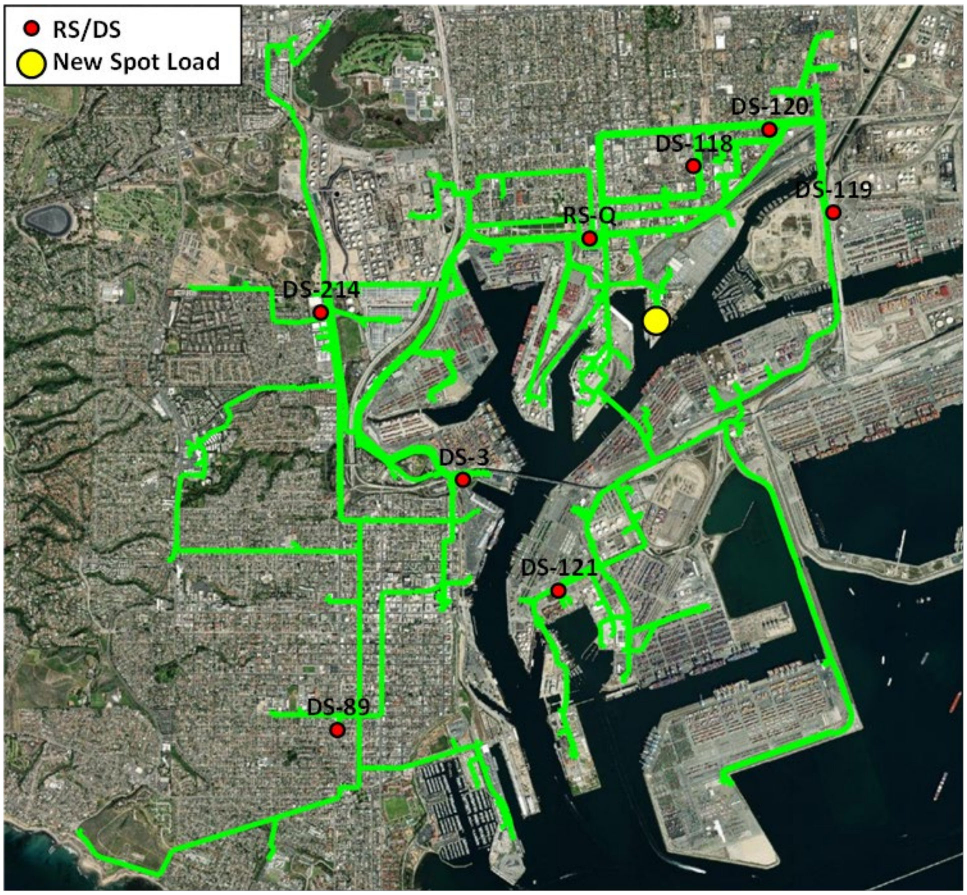


Figure 22. Future RS-Q spot loads outside the POLA area

RS-Q Load Growth Excluding POLA Container Terminals

It was necessary to represent other future load growth in the RS-Q area beyond the single spot load discussed above and the POLA tenant CHE loads discussed below. To do so, the LADWP distribution planning team provided a load forecast for the RS-Q area. The forecast projected that RS-Q bank A and C loads would remain at their existing levels or slightly decrease in the future. Hence, the loads served by banks A and C were modeled to follow their existing

[15] Although this spot load was connected in 2022, it was considered as a future load given that the non-CHE loads were modeled using LADWP SCADA measurements from 2021.

conditions (discussed in section 5) in scenarios 1–7. The forecast projected the RS-Q bank B load to grow considerably. The load growth on RS-Q bank B was represented by uniformly scaling all the loads served by bank B (except the POLA tenant CHE loads) based on the bank-level forecast listed in Table 12. The load growth was modeled in OpenDSS with the growth multipliers listed in Table 12.

POLA Tenant CHE Loads

Scenarios 2–7 apply the *hourly* POLA tenant CHE load profiles presented in section 4 in the following manner:

- **Scenario 2: 50% Electrification by 2025 – Unmanaged.** The load profiles of the 100% unmanaged electrification scenario were divided by two.
- **Scenario 3: 50% Electrification by 2025 – Managed.** The load profiles of the 100% managed electrification scenario were divided by two.
- **Scenario 4: 100% Electrification by 2030 – Unmanaged.** The team directly applied the load profiles of the 100% unmanaged electrification scenario.
- **Scenario 5: 100% Electrification by 2030 – Managed.** The team directly applied the load profiles of the 100% managed electrification scenario.
- **Scenario 6: 100% Electrification by 2035 – Unmanaged.** This is identical to scenario 4, in which the team directly applied the load profiles of the 100% unmanaged electrification scenario.
- **Scenario 7: 100% Electrification by 2035 – Managed.** This is identical to scenario 5, in which the team directly applied the load profiles of the 100% managed electrification scenario.

Note that the CHE load profiles are identical for scenarios 4 and 6 and for scenarios 5 and 7.

To model the reactive power of the CHE loads, all grid-connected (non-battery-operated) equipment was assumed to have a PF of 0.90, and all battery-operated equipment (charging) was assumed to have a PF of 1.00. Based on this assumption, the CHE reactive power load profile, Q_t, of tenant i at time t was calculated from the total active power of the tenant's grid-connected equipment, $P_{i,t}$, with: $Q_{i,t} = P_t\sqrt{\frac{1}{PF^2-1}}$.

The aggregated active and reactive power load profiles of all tenants over three days for the 100% and 50% electrification scenarios with unmanaged and managed charging are illustrated in Figure 23. The active power load profiles of each tenant are shown in section 4.

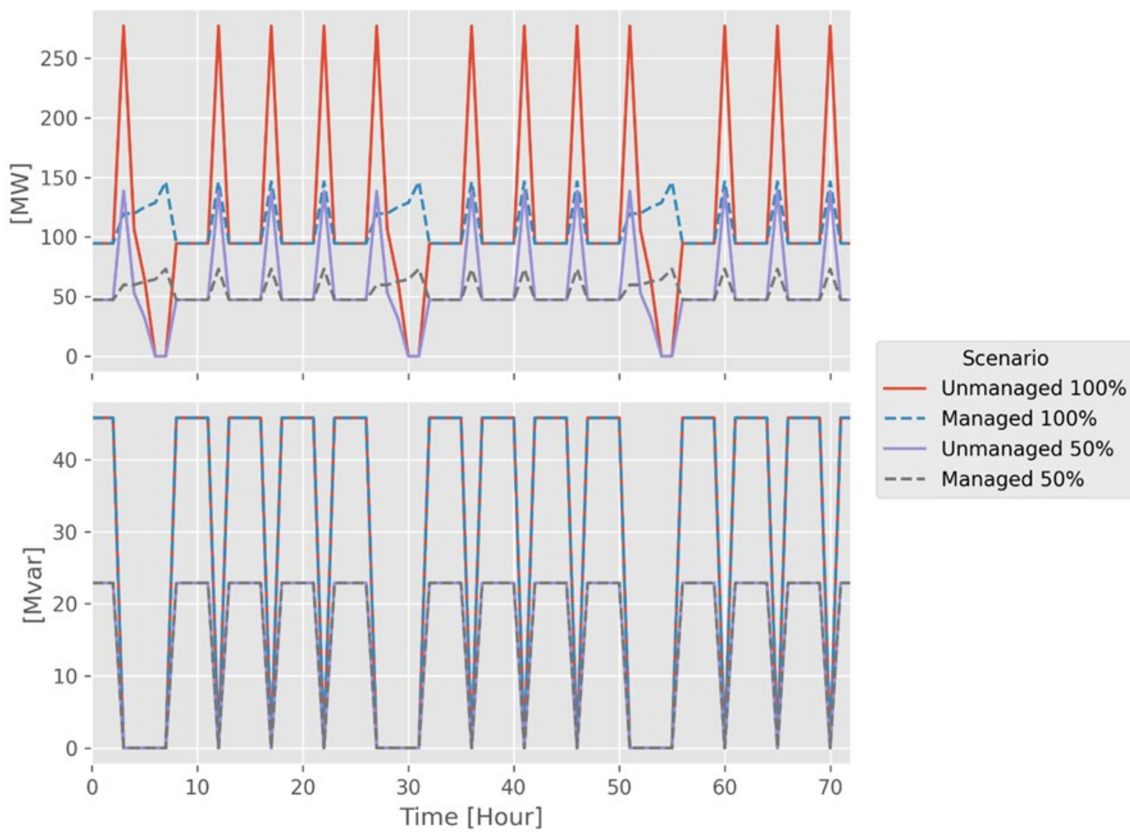


Figure 23. Total CHE load of all tenants over three days

In each of scenarios 2–7, the CHE load profiles of each tenant were equally divided among all the transformer banks of all the ISs serving each tenant.[16] Note that this assumption was necessary as more precise locations of the future tenant CHE chargers or their connections to the LADWP grid were not available for this assessment. The ISs, transformer banks, circuits supplying the transformer, POLA area, and the share of overall tenant CHE load profile assigned to each transformer are listed in Table 13. Note that four of the six tenants (APM, Everport, FMS, and YTI) are located on Terminal Island, Trapac is located on the Wilmington side, and WBCT is located in part on the Wilmington side and in part on the San Pedro side. The three grid areas, the LADWP RS-Q and DSs, and the tenant CHE locations are illustrated in Figure 24.

The CHE loads were connected on the 34.5-kV side of each transformer bank. In practice, new ISs, IS transformers, and/or tenant-side grid upgrades would be required to accommodate the CHE charging loads. However, these were not analyzed in this assessment.

It is recommended to revisit this assessment as additional information on the tenant charger locations and grid connections, charge management strategies, and so on becomes available.

[16] ISs dedicated to serving AMP loads were ignored (i.e., no CHE loads were assumed to be connected at their locations).

Table 13. POLA tenant grid locations

POLA Tenant	Industrial Station	Transformer Bank	Connected to LADWP Circuit	POLA Area	Share of Tenant CHE Load
Terminal-1	2192	01	HAR PED 1	Wilmington	1/7
		02	HAR PED 1		
	4185	01	HAR PED 1	Wilmington	
		02	HAR PED 1		
	5349	01	HAR PED 9	Wilmington	
		02	HAR-TER 1		
	5357	01[17]	HAR-TER 1	Wilmington	
Terminal-2	2010	01	FRD-TER 1	Terminal Island	1/4
	2188	01	HAR-TER 1	Terminal Island	
		02	HAR-TER 1		
	3722	01	HAR-TER 1	Terminal Island	
Terminal-3	3124	01	FRD-TER 1	Terminal Island	1/3
		02	FRD-TER 1		
	3125	01	TER PED 1	Terminal Island	
Terminal-4	4124	01	HAR-SP 3	San Pedro	1/4
	4130	01	HAR PED 1		
	2262	01	HAR PED 1	Wilmington	
		02	HAR-GAF 1		
Terminal-5	2641	01	HUG PED 1	Terminal Island	1/4
	2645	01	FRD-TER 1	Terminal Island	
		02	FRD-TER 1		
	4144	01	HAR PED 9	Terminal Island	
Terminal-6	4036	01	HUG PED 1	Terminal Island	1/8
		02	HUG PED 1		
		03	HUG PED 1		
	4048	01	FRD-TER 1	Terminal Island	
		02	FRD-TER 1		
		03	FRD-TER 1		
	4061	01	FRD-TER 1	Terminal Island	
		02	FRD-TER 1		

[17] The GIS data had no transformers for IS-5349 and IS-5357, so the loads were modeled at the IS locations.

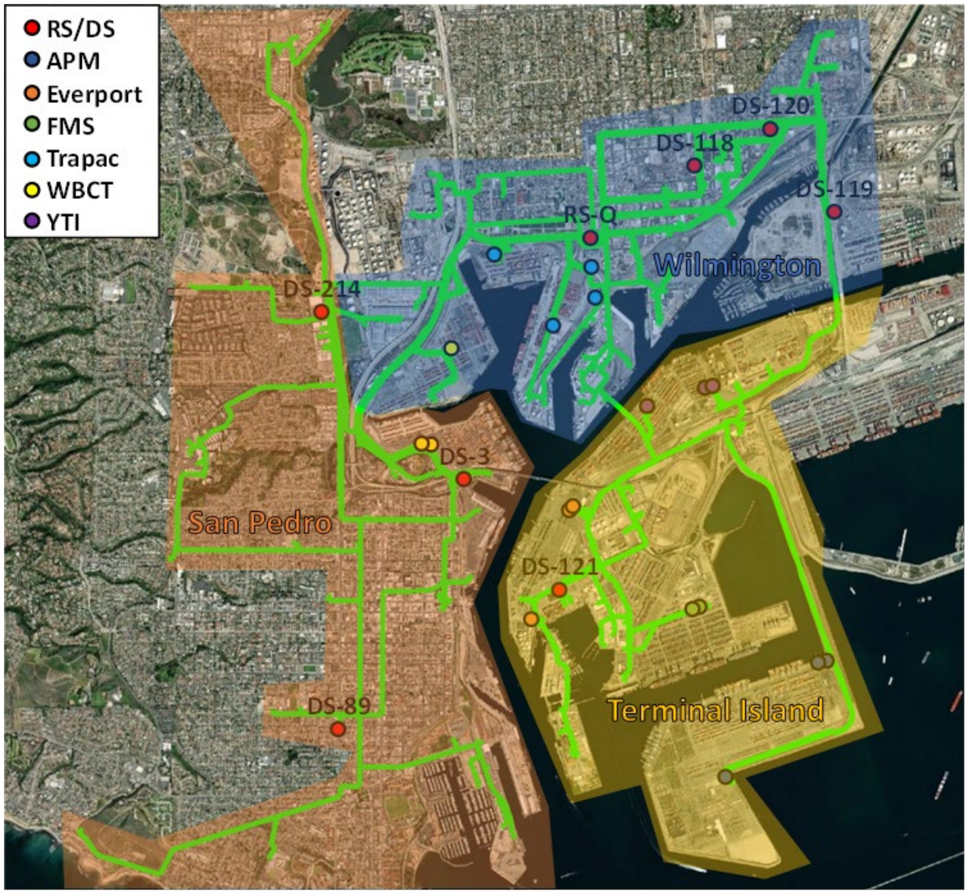


Figure 24. The three grid areas, locations of LADWP RS-Q and DSs, and the six POLA tenants

Future Upgrades Planned by LADWP

Scenarios 2–4 consider RS-Q conductor upgrades planned by LADWP. The upgrades, which were documented in the "RS-Q Cable Conductor Upgrades.pdf" document provided by LADWP, consisted of the following upgrades to circuits HAR-GAF 1 and GAF PED 1:

- For the HAR-GAF 1, some 1000-3C GAS and 750-3C GAS line sections were removed and replaced with 1000-3C EPR type.
- For the GAF PED 1 circuit, approximately 3098 ft (944 m) of 3/0 and 1/0 line sections were replaced with 477 ACSR.

These upgrades are expected to be online in 2023, and hence they were considered in the future scenarios 2–7, but not in scenario 1, which represents the existing system conditions.

Grid Impacts for the Analyzed Scenarios

This subsection presents the results for the grid impacts for the analyzed scenarios. The grid impacts were analyzed with the OpenDSS model presented in section 5 using yearly 8760-hr QSTS simulations for each of the seven scenarios. As discussed in section 5, this assessment focused only on the 34.5-kV level. The 4.8-kV level, POLA tenant side, and others were not analyzed.

RS-Q Bank Loading

The team first analyzed the impact of the CHE charging load on the RS-Q bank loading. Figure 25 shows the RS-Q banks A, B, and C peak loads for the seven analyzed scenarios. The continuous rating of each of the existing RS-Q banks A, B, and C is 160 MVA.

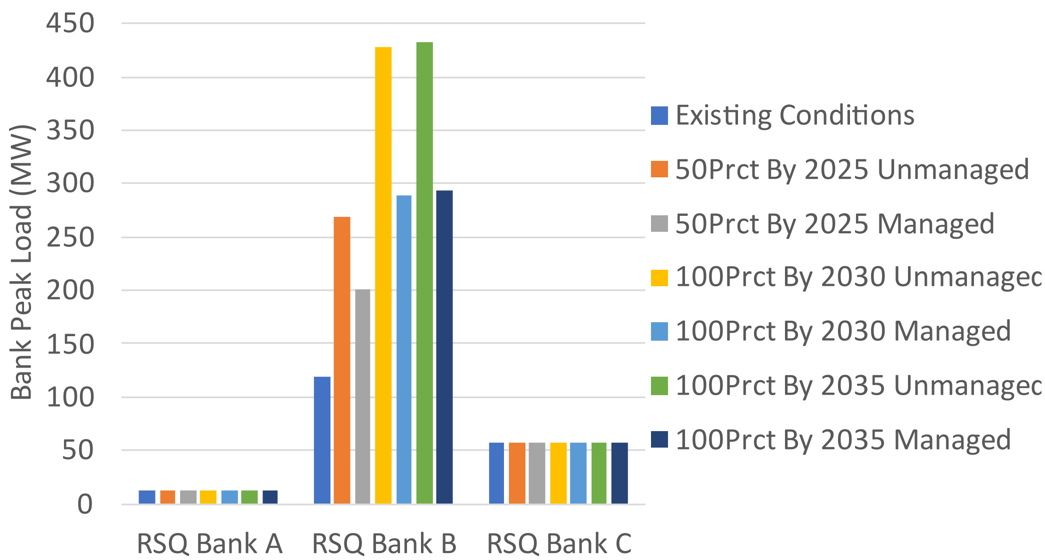


Figure 25. RS-Q bank peak loads for the analyzed scenarios

As expected, banks A and C loads are identical for all the scenarios for the following three reasons:

- No new spot loads were assumed to be served by banks A and C.
- No bank-level load growth was represented for the banks.
- The CHE loads are exclusively served by bank B.

Bank B peak loads are significantly higher in scenarios 2–7 compared to scenario 1 (existing conditions). This is caused by the CHE loads, the future spot load served by bank B, and the bank-level load growth. In the existing condition, the bank peak load was about 119 MW, which is below the bank continuous, 4-hr, and 2-hr ratings of 160 MVA, 176 MVA, and 192 MVA, respectively. In all other scenarios, the peak loads were much higher than in scenario 1. Moreover, 100% electrification resulted in much higher peak loads than 50% electrification, and unmanaged charging caused higher peaks than managed charging.

Table 14 lists the bank B peak loads and the number of additional 160-MVA RS-Q banks required in addition to the existing banks A, B, and C. Based on this analysis, *at least one additional bank is required at RS-Q to accommodate any of the future scenarios analyzed*. Moreover, *at least two additional RS-Q banks would be required to accommodate the two 100% unmanaged electrification scenarios*. Based on input received from LADWP, RS-Q can accommodate only one additional transformer bank—bank D, which is currently being considered by LADWP and is evaluated in section 7. Beyond that, a new RS would be required. Clearly, there seems to be considerable value in managing the CHE charging loads to reduce the charging coincidence and reduce the charging peak loads. The impact of adding an additional RS-Q bank in the future as planned by LADWP is evaluated in section 7. It should also be noted that various reliability considerations were out of the scope of this study. For example, reliability considerations for configuration and protection of large loads or customer stations, network stations, three-point lines, and so on were out of the scope of this study.

Table 14. Bank peak loads and the minimum number of additional RS-Q banks required

Scenario	Bank B Peak Demand (MW)	Number of Additional 160-MVA Banks Required[18]
Scenario 1: Existing system conditions (2021)	119	0
Scenario 2: 50% electrification by 2025 – unmanaged	269	1
Scenario 3: 50% electrification by 2025 – managed	201	1
Scenario 4: 100% electrification by 2030 – unmanaged	428	2
Scenario 5: 100% electrification by 2030 – managed	289	1
Scenario 6: 100% electrification by 2035 – unmanaged	432	2
Scenario 7: 100% electrification by 2035 – managed	293	1

Figure 26 shows RS-Q bank B load duration curves[19] for the analyzed scenarios. The projected load growth (represented as a percentage increase) has increased the bank loading over the course of the entire year in all the future scenarios. The managed CHE charging considerably increased the bank loading over the course of the entire year, but the unmanaged charging

[18] These numbers are calculated based on the bank B peak demand, assuming 160-MVA capacity for the existing and new banks and that no load is shifted from bank B to bank A or C. The RS-Q bank D planned by LADWP is not considered here but is assessed in section 7.

[19] The load duration curve presents the loads over a period of time, sorted in descending order. The load duration curve is useful in illustrating the frequency with which a given load value is exceeded.

resulted in very high peak loads for about 18% of the time. The loading is much higher in the 100% electrification scenarios, compared to the 50% electrification scenarios. The results are nearly identical between the 2030 and 2035 scenarios.

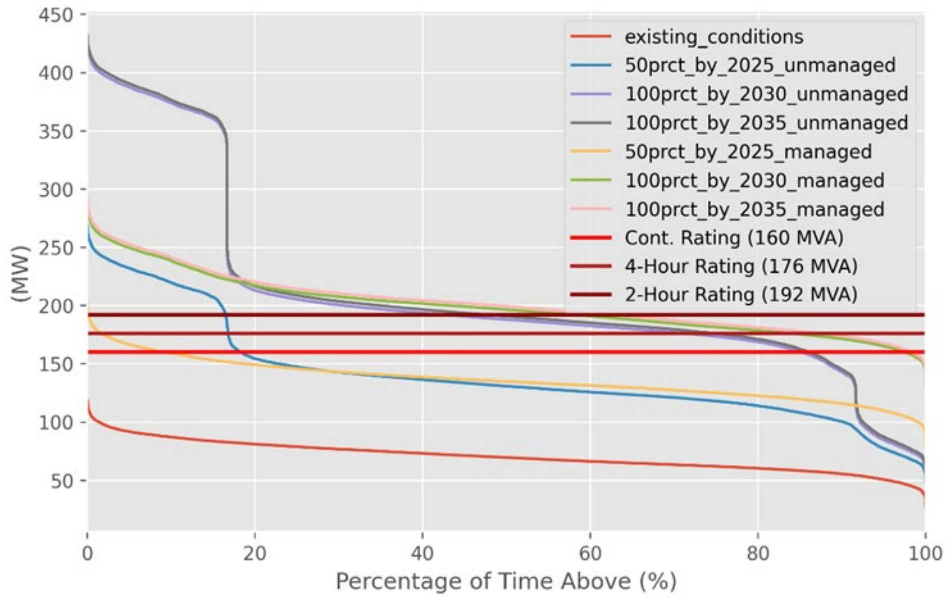


Figure 26. RS-Q bank B load duration curves for the analyzed scenarios

The bank continuous rating of 160 MVA is exceeded as follows:

- About 10% of the year with 50% managed charging
- About 18% of the year with 50% unmanaged charging
- About 85% of the year with 100% unmanaged charging
- About 95% of the year with 100% managed charging

These results further suggest the following:

- Existing bank B is nearly, but not completely, capable of accommodating the 50% managed charging scenario. A new RS-Q bank would be required to accommodate this scenario.
- Depending on the future scenario, one or two additional RS-Q banks are required to accommodate the future loads considered here.
- The additional bank D planned by LADWP provides sufficient capacity to accommodate the 50% electrification scenarios and the 100% managed charging scenarios, but not the 100% unmanaged charging scenarios. The planned bank D is analyzed in further detail in section 7.[20]

[20] The scenarios analyzed in section 6 do not consider some of the future loads considered in section 7.

Figure 27 shows the correlation of the aggregated total CHE load of all the six tenants with the RS-Q bank B existing load over the year. Each red dot in the plots corresponds to the aggregated total CHE load of the six tenants (*y*-axis) and the corresponding RS-Q bank B load (*x*-axis) at a given hour of the year (there are 8760 red dots in each of the four plots). As evident from the figure, the CHE charging loads are not correlated with the bank B existing load, which is expected, as the CHE charging loads are modeled to follow identical patterns over the course of the year. However, the peak CHE charging load coincides with high existing bank loading. This means that *CHE charging increases the bank B peak load nearly by the CHE peak load*. In other words, there is very limited diversity between the CHE peak load and the bank B existing peak load.

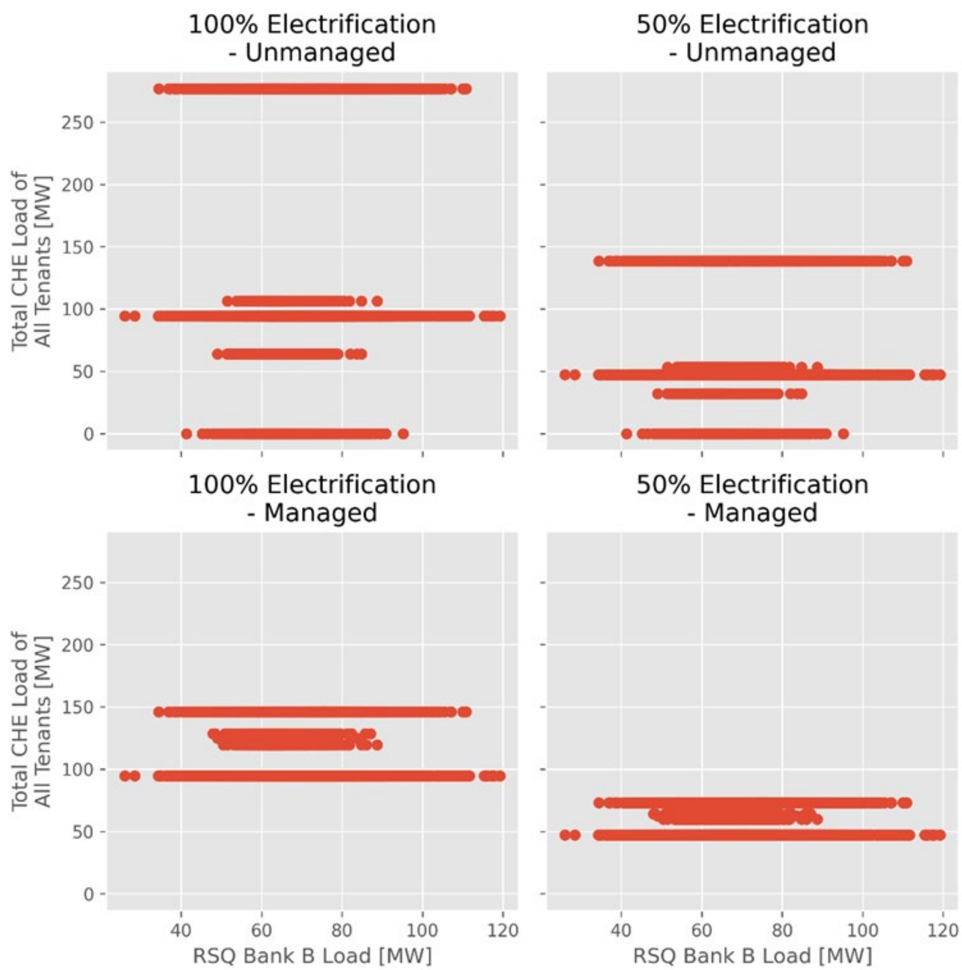


Figure 27. Total CHE load of all tenants versus RS-Q bank B existing load

Grid Area Loading

This subsection shows the loading for the three grid areas (San Pedro, Terminal Island, and Wilmington) illustrated in Figure 24. Note that RS-Q is located in Wilmington, whereas only one of the six POLA container terminals (Trapac) is fully located in Wilmington and another one

(WBCT) is partially located in Wilmington. Therefore, much of the future CHE loads are served by circuits transporting power from RS-Q in Wilmington to the tenants on Terminal Island and to some extent in San Pedro. This is expected to require a number of additional circuits from Wilmington to the two other areas.

To analyze the requirements for the tie-lines between the areas, the team analyzed the demand in the three areas. The demand in the three areas was calculated as follows:

- Terminal Island demand was calculated as a sum of the power flows of circuits FRD-TER 1, FRD PED 2, HAR-TER 1, and HAR PED 9 at the boundary between Wilmington and Terminal Island.
- Similarly, San Pedro demand was calculated as a sum of the power flows of circuits HAR-GAF 1, HAR PED 1, HAR-SP1, HAR-SP 2, and HAR-SP 3 at the boundary between Wilmington and San Pedro.
- Wilmington demand was calculated by subtracting Terminal Island and San Pedro demands from the RS-Q bank B demand.

Figure 28 lists the peak demands in the three grid areas for the seven scenarios analyzed. The red lines indicate the total capacity of the existing tie-lines between Wilmington and Terminal Island (about 88 MW) and between Wilmington and San Pedro (about 103 MW).[21] As expected, the future electrification scenarios significantly increased the peak demand of the Terminal Island area, but less so the peak demands of the San Pedro and Wilmington areas. All future scenarios exceed the total tie-line capacity to Terminal Island, requiring additional circuits between Wilmington and Terminal Island.

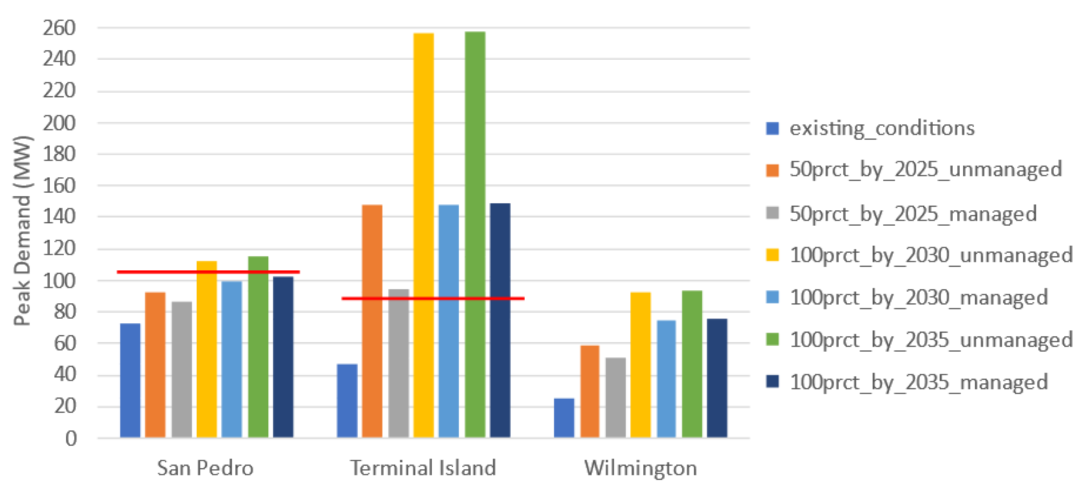


Figure 28. Peak demand of the three grid areas

[21] The capacity was calculated by adding the capacities of the individual tie-lines calculated from the rated ampacity of the circuit, I_{normal}, with: $P_{normal} = \sqrt{3}(34.5\ kV)(I_{normal})(0.98)$. This calculation assumes PF = 0.98 and nominal voltage.

Figure 29 shows the maximum power flows (over the year) and the remaining capacity[22] for the tie-lines at the area boundaries. As expected, all the tie-lines have remaining capacity in scenario 1 (existing conditions). *In the future scenarios, many of the lines to Terminal Island ("TI" in the figure) run out of capacity, whereas many of the lines to San Pedro ("SP" in the figure) still have capacity remaining*.

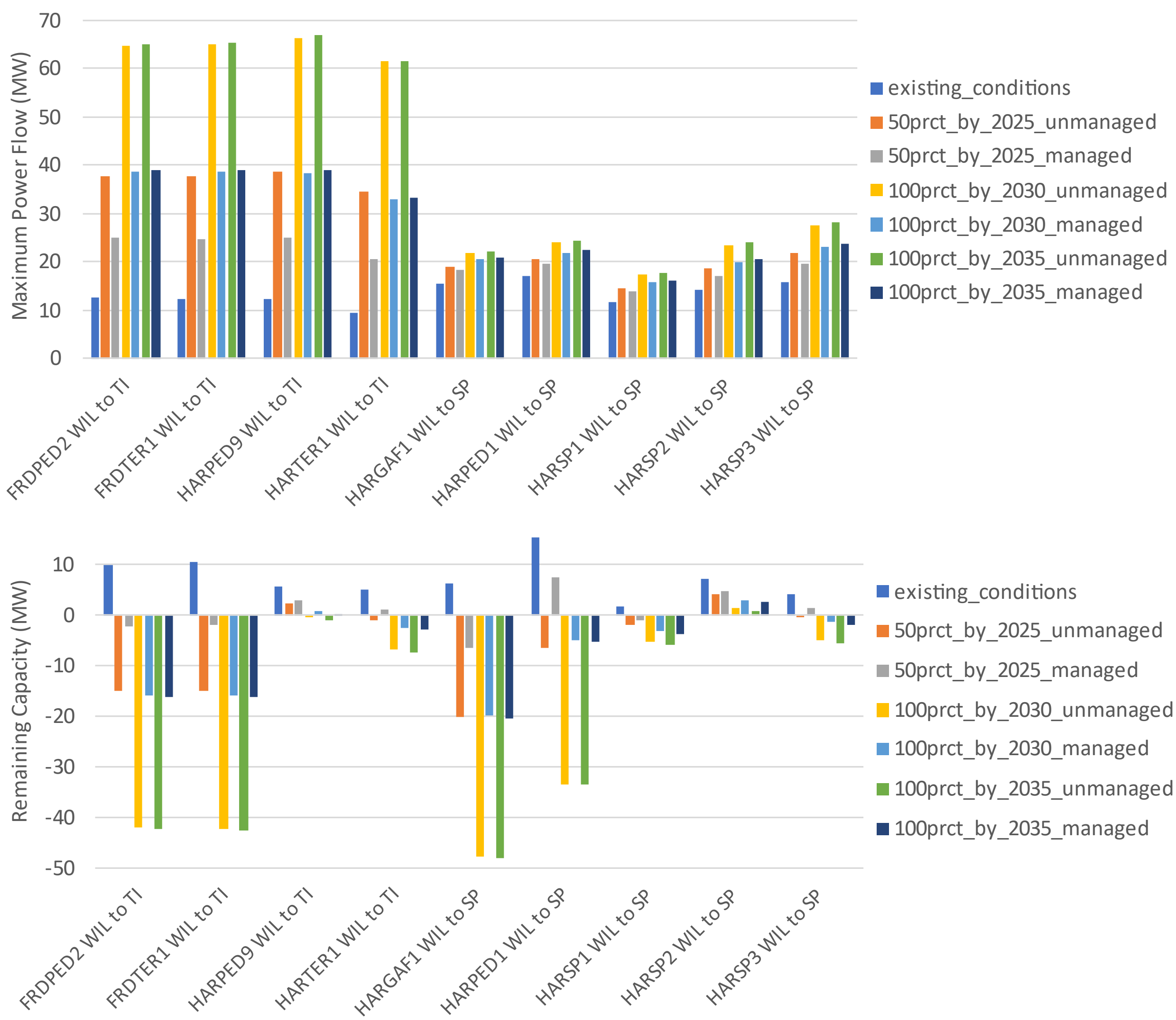


Figure 29. Maximum power flows (top) and remaining capacity (bottom) on the tie-lines at the area boundaries

Table 15 lists the minimum number of additional 400-amp circuits required from Wilmington to Terminal Island and San Pedro in the seven analyzed scenarios. To accommodate the load in the future scenarios, at least one to eight lines and zero to one additional lines are required from Wilmington to Terminal Island and San Pedro, respectively. More lines are likely required in the

[22] The remaining capacity was calculated by subtracting the maximum power flow from the calculated line capacity.

100% electrification scenarios as compared to the 50% electrification scenarios. More lines are also likely required in the unmanaged charging versus the managed charging scenarios. Fewer lines are required to San Pedro, given that more CHE loads are added in Terminal Island.[23] The numbers listed in Table 15 represent the minimum number of new 400-amp lines. In practice, the number of lines required may be higher due to the following reasons:

- Some of the circuits transferring power from Wilmington to Terminal Island and San Pedro also supply loads on the Wilmington side that consume the circuit capacity. The overloads and circuit-level loading are analyzed in more detail in the following sections.
- This simple analysis assumes that powers are perfectly balanced between the circuits. In practice, there is a varying degree of loading unbalance between the circuits. Note that the meshed nature of the RS-Q 34.5-kV system makes it challenging to balance the loading between the circuits. The grid upgrades required are analyzed in more detail in section 7.

Table 15. Minimum number of new 400-amp lines required from Wilmington to Terminal Island and San Pedro

Scenario	Minimum Number of New 400-amp Lines Required from Wilmington to	
	Terminal Island	San Pedro
Existing conditions	0	0
50% by 2025 – unmanaged	3	0
50% by 2025 – managed	1	0
100% by 2030 – unmanaged	8	1
100% by 2030 – managed	3	0
100% by 2035 – unmanaged	8	1
100% by 2035 – managed	3	0

To provide additional detail on the area loading, Figure 30 shows the load duration curves for the three areas. In an ideal case, the existing tie-lines to Terminal Island may be able to accommodate the 50% managed charging, but additional lines to Terminal Island would be required in all other scenarios. Moreover, in an ideal case, no additional lines to San Pedro may be required. The simplifications of this analysis discussed above should be noted. Overloads and circuit-level loading are analyzed in more detail in the following sections.

[23] The grid impact assessment presented in this section does not represent the Outer Harbor Cruise Facility, which is considered in the grid mitigation analysis presented in section 7.

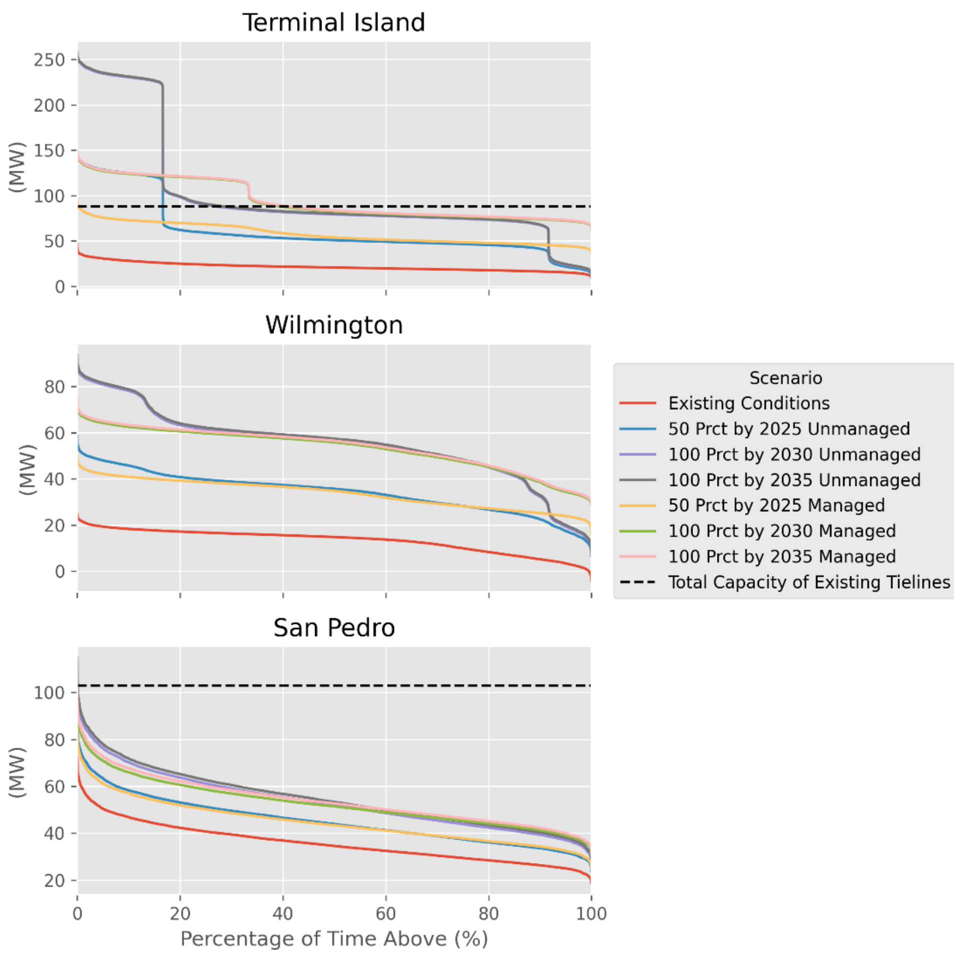


Figure 30. Load duration curves of the three grid areas

Overloads

This subsection presents the overload analysis on the RS-Q area circuits.

The number of overloaded elements (out of a total of about 13,951 circuit model elements), the number of hours with at least one overload, and the maximum overload (as a percentage of the equipment normal ratings) are illustrated in Figure 31. The following key observations can be made:

- As expected, there are practically no overloads in the existing conditions scenario. The overloads seen for the scenario are for two IS transformers that were overloaded for a few hours over the year up to about 120% of their nameplate rating. These overloads are expected to be caused by inaccuracies in the load modeling and can be ignored.
- There are drastic overloads in all the future scenarios analyzed. Clearly, considerable grid-side mitigation measures are required in all the scenarios analyzed.

- Compared to managed charging, unmanaged charging considerably increases the scope, duration, and magnitude of overloads.
- Compared to 50% electrification, 100% electrification results in about twice the overload scope, duration, and magnitude.
- The results are similar between 2030 and 2035. The minor differences are caused by the additional bank B level load growth modeled in the 2035 scenarios, compared to the 2030 scenarios.

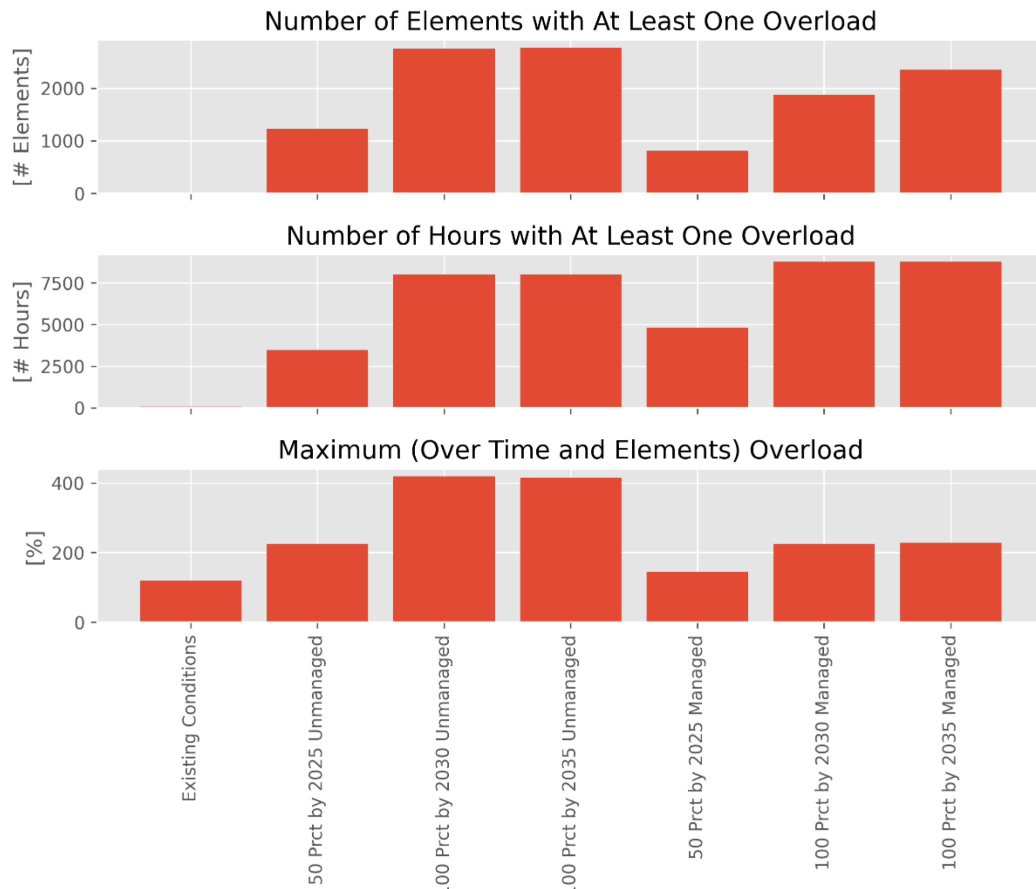


Figure 31. Summary of overloads in the RS-Q area

Figure 32 and Figure 33 visualize the overload locations for scenarios 2 and 3 and for scenarios 3 and 4, respectively. Similar maps for all scenarios are shown in appendix D. *Many of the lines serving the POLA container terminals become overloaded. Unmanaged charging results in considerably more overloaded lines compared to managed charging. Similarly, 100% electrification led to considerably more overloads, compared to 50% electrification.*

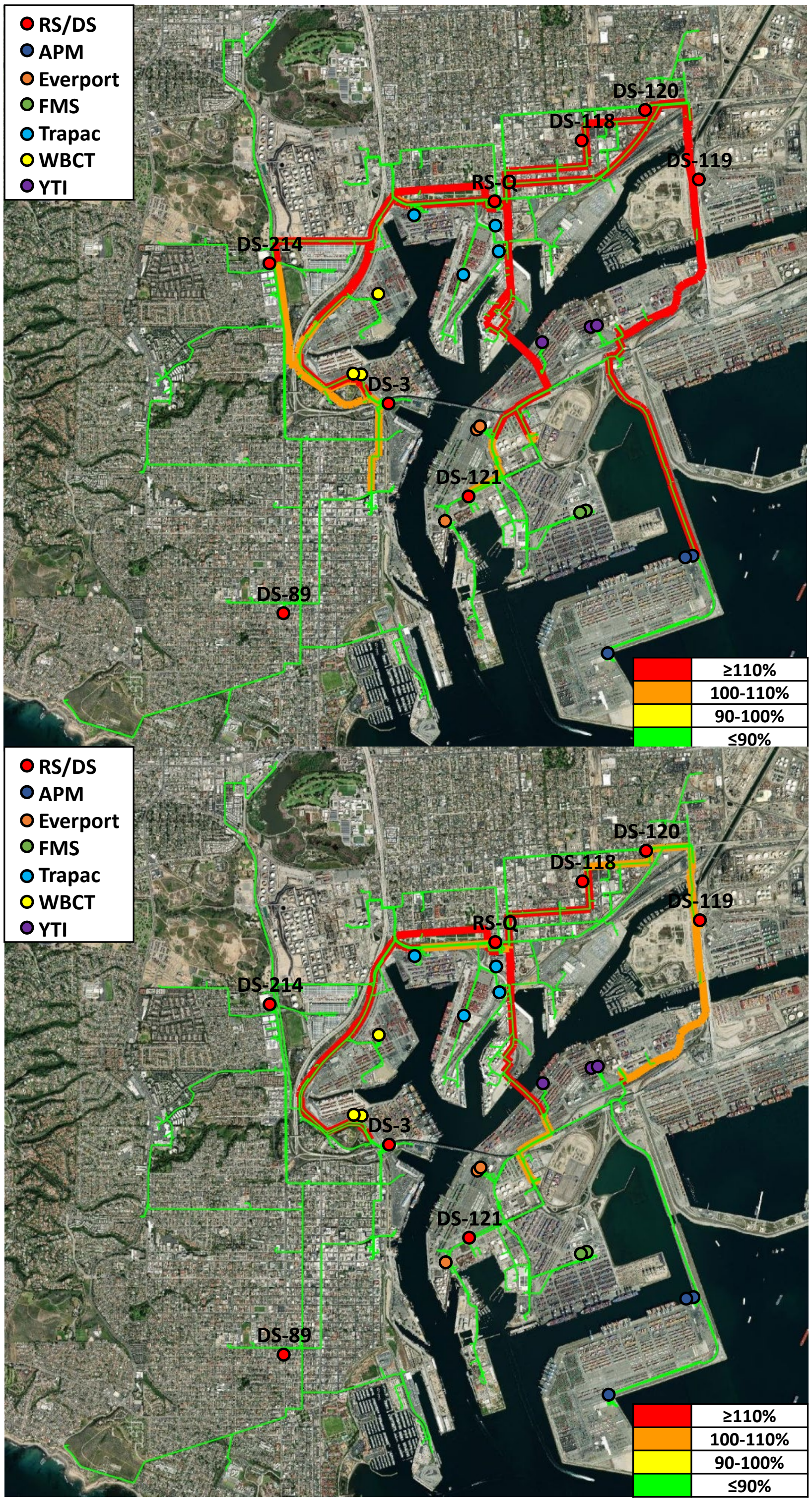
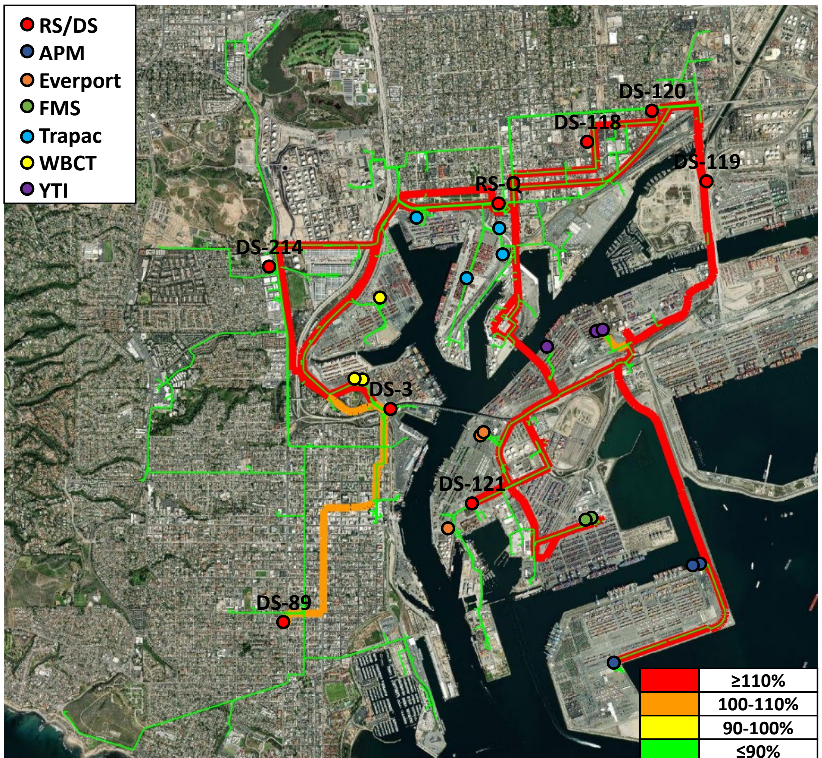


Figure 32. Circuit overloads for scenario 2 (50% electrification by 2025 – unmanaged; top) and scenario 3 (50% electrification by 2025 – managed; bottom)



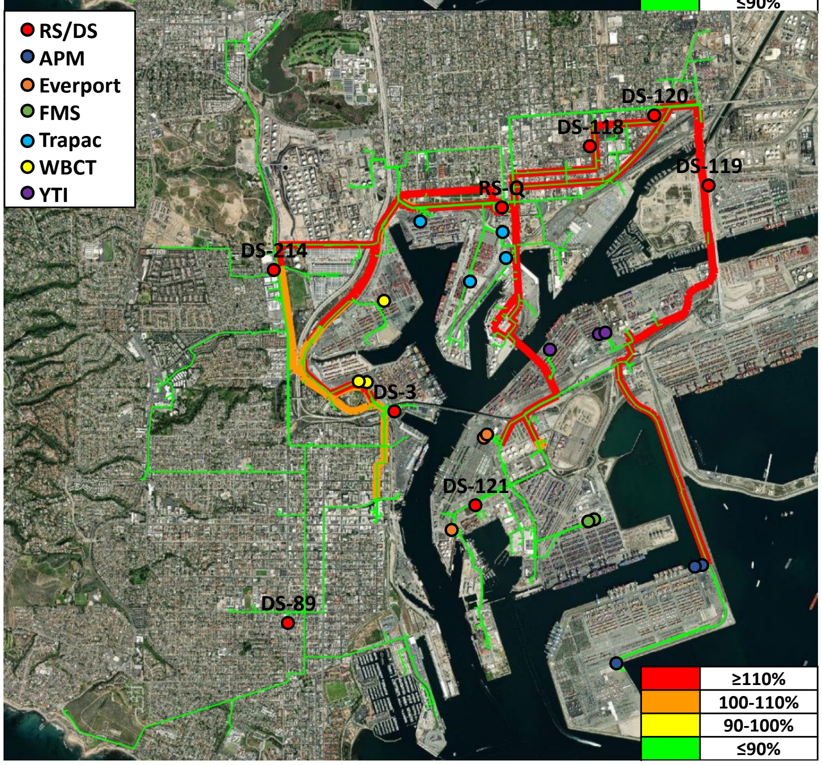


Figure 33. Circuit overloads for scenario 4 (100% electrification by 2030 – unmanaged; top) and scenario 5 (100% electrification by 2030 – managed; bottom)

Figure 34 shows the peak power and peak current at the “sending end” of each of the 25 circuits in the RS-Q model for five of the scenarios. The peak power and current are considerably higher for the 100% electrification scenarios compared to 50% electrification. The peak power and current are also considerably higher for the unmanaged scenarios compared to the managed scenarios. Note that Figure 35 shows the total length of all lines overloaded at some time instance for the seven scenarios. As discussed above, there are no overloaded lines in the existing conditions scenario. However, depending on the future scenario, 15.5–37.5 mi (24.9–60.4 km) of the RS-Q lines become overloaded. This corresponds to 12–31% of all the RS-Q lines in the OpenDSS model.[24]

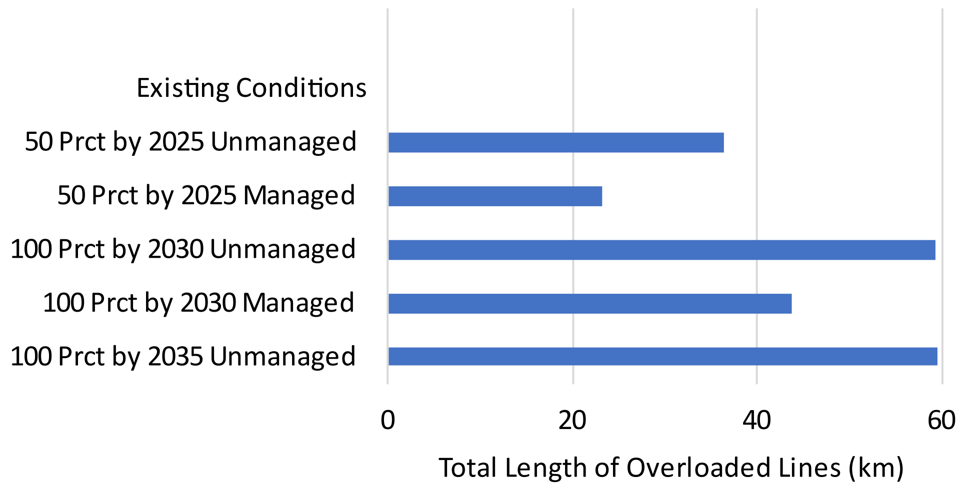


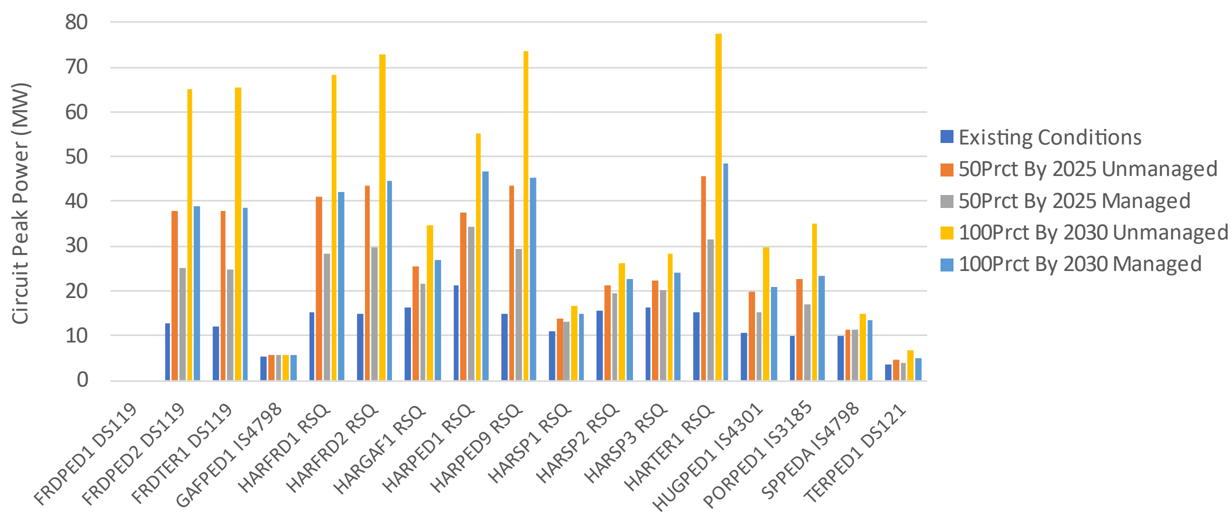
Figure 34. Total length of all lines overloaded at some time instance for the seven scenarios

Figure 35 shows the peak power and peak current at the sending end[25] of each of the 25 circuits in the RS-Q model for five of the scenarios.[26] The peak power and current are considerably higher for the 100% electrification scenarios compared to 50% electrification. The peak power and current are also considerably higher for the unmanaged scenarios compared to the managed scenarios. Note that Figure 35 shows the peak power and current at the sending end of each circuit. Depending on the circuit, the highest power or current may occur at another location of the circuit.

[24] The total length of all lines in the RS-Q OpenDSS model is about 119.2 mi (191.9 km).

[25] The sending end locations are listed next to the circuit name in Figure 34.

[26] The 2035 scenarios are not shown, as their results are nearly identical to the 2030 scenarios.



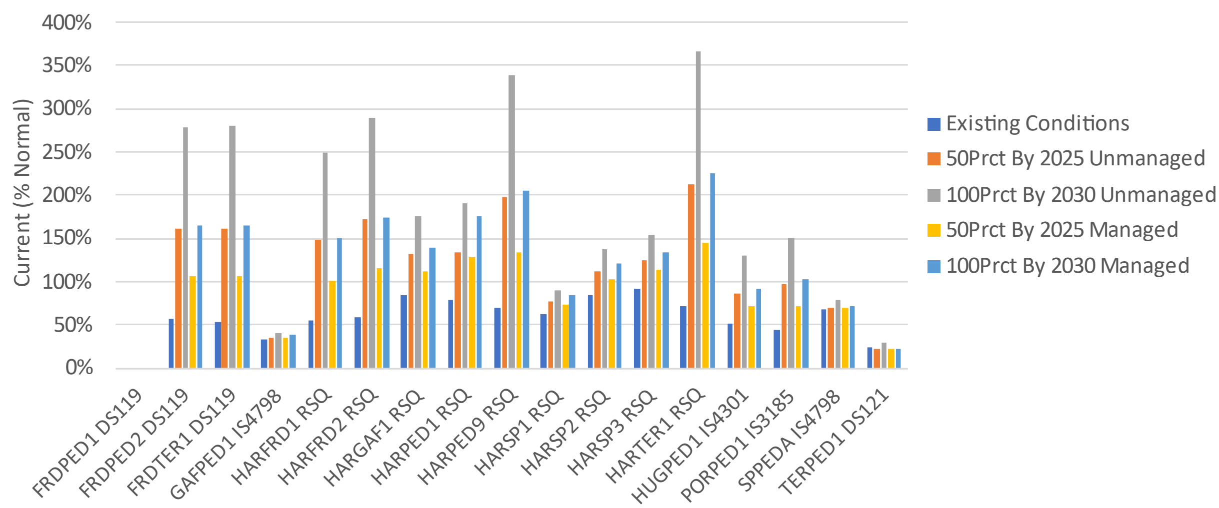


Figure 35. Peak power (top) and peak current (bottom) at the sending end of each circuit

The maximum MVA overloads over the circuit normal and emergency ratings for each of the 17 circuits and seven scenarios are listed in Table 16 and Table 17, respectively. The values in the table correspond to the maximum loading (as percentage of the element normal rating) over the year and over all the elements of a given circuit. Overload values listed as “0” correspond to maximum loading below 100% of the normal rating. The following observations can be made:

- There are no overloads in scenario 1 (existing conditions).
- In the future scenarios, the maximum loading exceeds the normal rating for 10–13 circuits, depending on the scenario.
- In the future scenarios, the maximum loading exceeds 150% and 200% of the normal rating for 0–11 and 0–6 circuits, respectively.
- Some circuits experience much higher overloads than others.

- The overloads are higher with 100% electrification scenarios compared to 50% electrification scenarios. Similarly, the overloads are higher with unmanaged charging compared to managed charging.
- Some new circuits may be required to accommodate the 50% electrification scenarios analyzed. Several new circuits may be required to accommodate the 100% electrification scenarios analyzed. The required grid mitigation measures are analyzed in section 7.

Table 16. Maximum MVA overloads over normal ratings[27] for each circuit and scenario, and the number of circuits overloaded 0 MVA, 10 MVA, and 20 MVA above the line normal ampere rating

Circuit	Existing Conditions	50 Prct by 2025 Unmanaged	100 Prct by 2030 Unmanaged	100 Prct by 2035 Unmanaged	50 Prct by 2025 Managed	100 Prct by 2030 Managed	100 Prct by 2035 Managed
FRDPED1	0	0	0	0	0	0	0
FRDPED2	0	14	42	43	1	15	16
FRDTER1	0	29	74	74	8	29	29
GAFPED1	0	0	0	0	0	0	0
HARFRD1	0	13	40	41	0	14	14
HARFRD2	0	18	47	47	4	18	19
HARGAF1	0	6	15	16	2	7	8
HARPED1	0	9	26	27	8	22	23
HARPED9	0	21	52	53	7	23	24
HARSP1	0	0	0	0	0	0	0
HARSP2	0	2	7	8	1	4	5
HARSP3	0	5	10	12	3	6	7
HARTER1	0	24	57	57	10	27	27
HUGPED1	0	0	14	15	0	0	0
PORPED1	0	0	12	12	0	0	0
SPPEDA	0	0	0	0	0	0	0
TERPED1	0	0	3	3	0	0	0
# Circuits Over NormAmps	0	10	13	13	10	11	11
# Circuits 10 MVA Over NormAmps	0	6	11	11	0	7	7
# Circuits 20 MVA Over NormAmps	0	3	7	7	0	4	4

[27] The table values represent the maximum (over all the lines of a given circuit and the 8760 hrs of the year) MVA overload, where the MVA overload (of a given line and time instance) is calculated with: $\mathrm{MVAOverLoad} = \frac{\sqrt{3}\times 34.500\times I_{OverNormalRating}}{1000}$, and $I_{OverNormalRating}$ is the line amperes over the line normal ampere rating.

Table 17. Maximum MVA overloads over emergency ratings[28] for each circuit and scenario, and the number of circuits overloaded 0 MVA, 10 MVA, and 20 MVA above the line emergency ampere

Circuit	Existing Conditions	50 Prct by 2025 Unmanaged	100 Prct by 2030 Unmanaged	100 Prct by 2035 Unmanaged	50 Prct by 2025 Managed	100 Prct by 2030 Managed	100 Prct by 2035 Managed
FRDPED1	0	0	0	0	0	0	0
FRDPED2	0	8	36	37	0	9	10
FRDTER1	0	23	69	68	2	23	23
GAFPED1	0	0	0	0	0	0	0
HARFRD1	0	9	36	37	0	10	10
HARFRD2	0	14	43	43	0	14	15
HARGAF1	0	3	12	13	0	4	5
HARPED1	0	5	22	23	4	18	19
HARPED9	0	18	49	50	4	20	20
HARSP1	0	0	0	0	0	0	0
HARSP2	0	0	4	5	0	1	1
HARSP3	0	2	7	8	0	3	4
HARTER1	0	22	54	54	7	24	25
HUGPED1	0	0	8	9	0	0	0
PORPED1	0	0	6	7	0	0	0
SPPEDA	0	0	0	0	0	0	0
TERPED1	0	0	0	0	0	0	0
# Circuits Over EmergAmps	0	9	12	12	4	10	10
# Circuits 10 MVA Over EmergAmps	0	4	8	8	0	5	6
# Circuits 20 MVA Over EmergAmps	0	2	7	7	0	2	3

[28] The table values represent the maximum (over all the lines of a given circuit and the 8760 hrs of the year) MVA overload, where the MVA overload (of a given line and time instance) is calculated with: $\mathrm{MVAOverLoad} = \frac{\sqrt{3}\times 34.500\times I_{OverNormalRating}}{1000}$, and $I_{OverNormalRating}$ is the line amperes over the line normal ampere rating.

Voltage Impacts

This subsection summarizes the voltage impacts for the analyzed scenarios. Appendix D presents additional analysis. No overvoltages[29] took place in any of the scenarios.[30] This is expected given that load growth is not expected to increase the system voltages. As no overvoltages took place, this subsection focuses on undervoltages. Figure 36 summarizes the minimum voltage (of any bus at any time during the year), the maximum number of buses with undervoltages at any time during the year, and the number of hours that undervoltages were experienced. The following observations can be made:

- *There are no undervoltages in scenario 1 (existing conditions) in the 50% electrification (unmanaged or managed) scenarios or in the 100% electrification (managed) scenarios.*
- *In the 100% unmanaged charging scenarios, there are negligible undervoltages*. Undervoltages were experienced down to about 0.934 pu for up to four buses (out of about 14,000 total buses) and for up to 15 hrs (out of 8760 hrs of the year).[31]

[29] Overvoltages and undervoltages were defined as voltages above 1.05 pu and below 0.95 pu of the nominal, respectively.

[30] This excludes minor overvoltages at the tertiary bus of RS-Q bank B, which can be ignored.

[31] Not more than four buses experienced undervoltages in any of the scenarios. All the undervoltages occurred at the secondary buses of IS transformers and are likely caused by inaccuracies in the load modeling and hence should be ignored. No undervoltages took place at the 34.5-kV level.

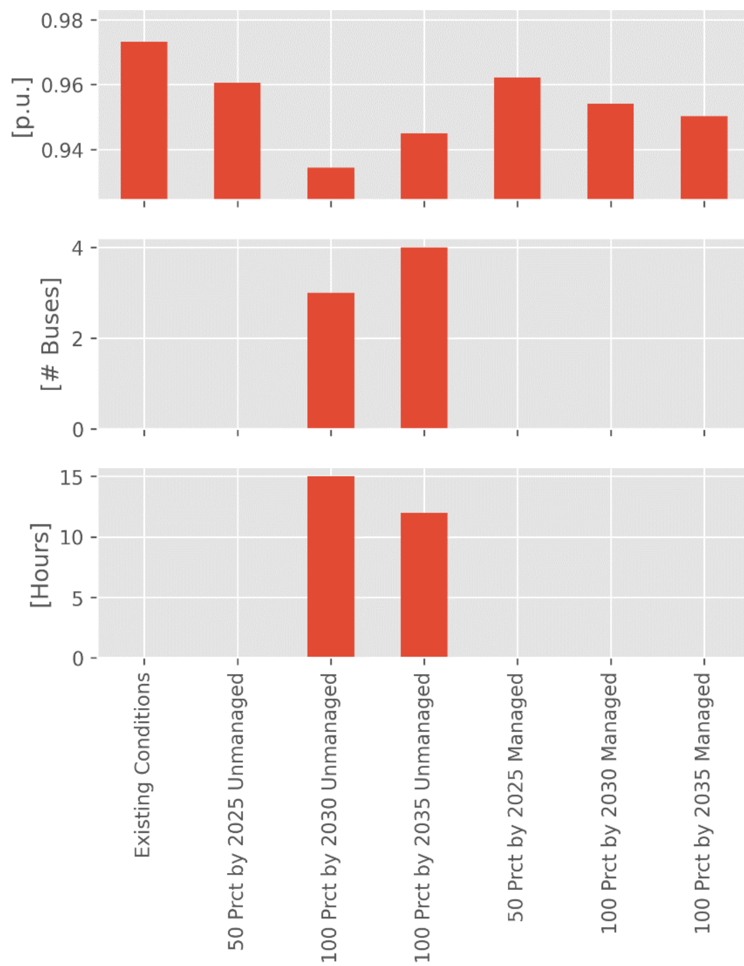


Figure 36. Summary of undervoltages [32]

Figure 37 shows the minimum voltages at the locations where the POLA tenant CHE equipment loads are added. The results for the 2035 scenarios are nearly identical to the 2030 scenarios, and hence they are not shown here. All the minimum voltages are above 0.95 pu.

[32] As this assessment focuses on the 34.5-kV level, this plot ignores undervoltages at low-voltage buses (defined here as buses with a nominal voltage less than 1.0 kV).

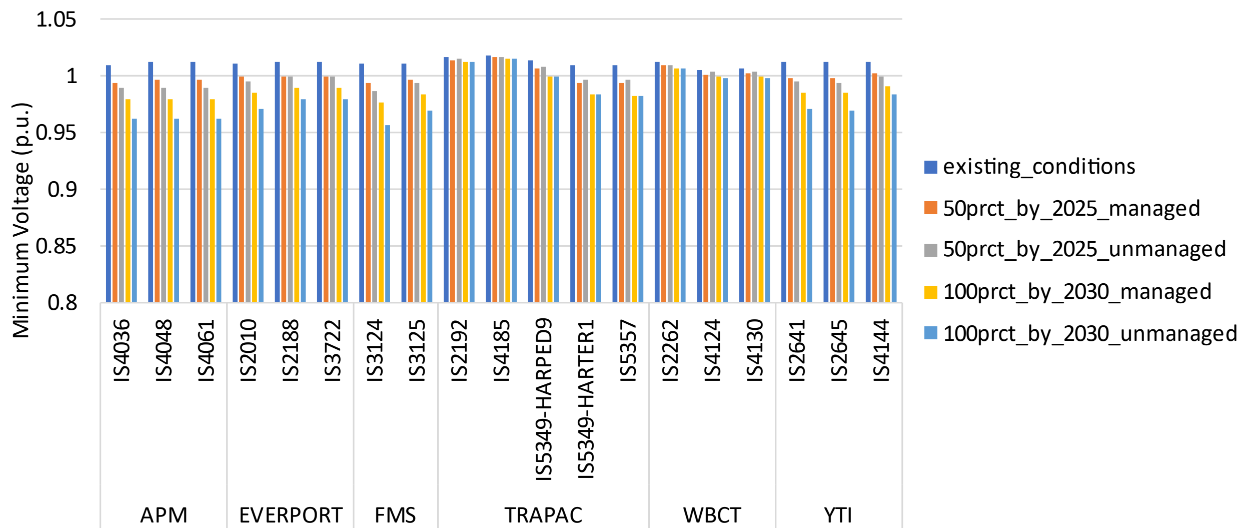


Figure 37. Minimum voltages at the tenant CHE connection points

Conclusions

- This section reports the results of analysis of grid impacts for seven scenarios. Scenario 1 represents the existing system conditions, whereas scenarios 2–7 represent future system conditions with future spot loads in the RS-Q area, RS-Q-wide load growth, POLA tenant CHE electrification, and RS-Q upgrades currently planned by LADWP. The team performed annual 8760-hr QSTS simulations using OpenDSS to obtain a detailed view of the electrification impacts in the RS-Q grid area.
- All the analyzed future electrification scenarios would require one additional 160-MVA transformer bank at the RS-Q. Moreover, the 100% unmanaged CHE charging scenarios would require two additional 160-MVA RS-Q transformer banks. The RS-Q bank D planned by LADWP would be able to accommodate the 50% unmanaged or managed electrification scenarios. However, to accommodate 100% electrification with unmanaged charging, either a second additional RS-Q bank would be required, or the peak loads of the POLA tenant CHE charging loads would need to be managed. As RS-Q cannot accommodate another transformer bank beyond bank D, a new RS would be required.
- The peak load of the POLA tenant CHE charging loads coincides with high existing loading times at the RS-Q bank B. Hence, CHE charging increases the bank B peak load nearly by the CHE peak load.
- Of the six POLA container terminals, four are located in the Terminal Island area, one in the Wilmington area, and one partially in the San Pedro area and partially in the Wilmington area. Hence, the future electrification scenarios significantly increased the peak demand of the Terminal Island area, but less so the peak demands of the San Pedro and Wilmington areas. All future scenarios exceeded the total tie-line capacity to Terminal Island, requiring additional circuits between Wilmington and Terminal Island. The existing tie-lines to Terminal Island run out of capacity in the future scenarios. Depending on the future

scenario, at least between one and six additional lines between Wilmington and Terminal Island are required. Some additional lines between Wilmington and San Pedro may also be required.

- Many of the lines serving the POLA container terminals become overloaded. Unmanaged charging resulted in considerably more overloaded lines compared to the managed charging. Similarly, the 100% electrification led to considerably more overloads compared to 50% electrification. In addition to the lines between the three RS-Q grid areas, a considerable number of additional lines may also be required within each of the three areas, depending on the electrification scenario.
- No overvoltages were observed in any of the analyzed scenarios. There are no undervoltages in scenario 1 (existing conditions), in the 50% electrification (unmanaged or managed) scenarios, or in the 100% electrification managed scenarios. In the 100% unmanaged charging scenarios, there are very limited undervoltages.

Section 7 presents an assessment of grid-side mitigation measures required to address the grid impacts identified in this section.

7 MITIGATION SOLUTIONS

Overview

This section presents the analysis of POLA tenant-side and LADWP grid-side mitigation measures to address the grid impacts analyzed in section 6. First, the viability of using energy storage to reduce the CHE peak loads is analyzed. Then, grid-side mitigation measures are assessed.

Energy Storage as a Mitigation Solution

This analysis considered the impact of energy storage on charging profiles and tenant rates. The analysis was considered and analyzed separately from the grid-side mitigation measures. Changes to grid-side mitigation measures were not considered, and storage versus grid-side measures were not optimized.

Individual terminal operators can use energy storage to offset their peak net load and reduce the demand charges they pay to the utility. The storage may also charge during off-peak times and discharge during on-peak times, lowering energy charges. This mode of operation may reduce the peak net load for each terminal individually, but might not reduce the peak load from all terminals efficiently if the terminals' net loads do not peak at the same time. This mode of operation is driven by lowering the demand and energy charges for each terminal individually. If the savings from reduced demand charges over the life of the storage system are enough to cover the costs of the storage, terminal operators would have an incentive to install the storage on their own. Footprint area may be highly important for the terminal operators, and the costs of footprint area are not considered in this analysis.

The team used EPRI's Distributed Energy Resources Value Estimation Tool (DER-VET™)[33] to optimally size an energy storage system for each of the terminal operator's CHE electric loads (not considering other demand on-site). Under the LADWP A-3 tariff, energy storage that costs $800/kW + $250/kWh could not recover its costs over an assumed 10-year lifetime through bill savings. The DER-VET optimization considers all components of the terminal operators' electricity bills, along with the costs of energy storage, to determine the size (both power capacity and energy capacity) of energy storage that minimizes the present value of these costs over the life of the storage. The optimal size was 0 kW and 0 kWh, indicating that the storage cannot recover its costs through bill savings at any size when it is operated perfectly.

To contextualize this result, consider a hypothetical energy storage system that is operated such that it reduces each demand charge in the A3 tariff every month of the year by its power capacity. If successful, it would save a terminal operator about $158/year per kW of energy storage power capacity. With a discount rate of 7%, no rate increases, and a life of 10 years, the

[33] DER-VET is available at: www.der-vet.com.

present value of the avoided demand charges is $1100/kW. To minimize the cost of the energy storage system, assuming 1 hr of storage, the total cost of the system, expressed in $/kW is $800/kW + 1 kWh/kW x $250/kWh = $1050/kW ~ $1100/kW, a conservative assessment. This would seem to imply a breakeven cost-benefit. However, the assumption that all monthly demand charges would be avoided over 10 years is highly unlikely to be achievable with only 1 hr of storage. Even with a 4-hr storage system, meeting this assumption would remain challenging, requiring almost perfect load control, and so on. With the above assumptions, the cost of a 4-hr system is about $1800, which is greater than the maximum savings achievable of $1100/kW. It is also interesting to note that managed charging versus unmanaged charging actually increases the difficulty of avoiding all of the demand charges, since managed charging flattens the load shape. Hence, for energy storage to be cost-effective, either the cost of storage needs to decrease significantly, the applicable electric demand charge needs to increase significantly, or some combination.

It would also be possible for the storage system to shift energy from low-price periods (for charging) to high-price periods (for discharging), but this does not offset utility distribution upgrade needs and comes at the cost of additional battery degradation and shorter life.

It would be possible to design a storage system directly for grid impact mitigation instead of demand charge management, which might have a different outcome. This should be considered for future work when more data is available.

Future Upgrades Considered by LADWP

This subsection presents LADWP's future RS-Q area grid infrastructure upgrade plans,[34] its modeling, and the grid impacts of the upgrade plans. These upgrade plans are considered as a baseline beyond which the additional grid infrastructure upgrades to mitigate all grid impacts are identified.

Modeling of the Future Grid Infrastructure Upgrade Plans by LADWP

The plans considered in this assessment consisted of the RS-Q expansion and circuit extensions described below.

[34] LADWP described the upgrades in email exchanges and in the document "Preliminary Work for RS-Q System Extension to San Pedro Outer Harbor [09132022_signed].pdf" that LADWP shared with EPRI.

New Spot Loads

The team modeled two new spot loads in the San Pedro Outer Harbor area identified in LADWP's future grid upgrade plans. A new load at berths 45–50 was modeled with rated load of 40,000 kW, and a new load at berths 56–71 was modeled with rated load of 20,000 kW. Both loads were assumed to follow the RS-Q bank B load profile in 2021.[35] Note that these two loads are not considered in the grid impact assessment presented in section 6.

In this assessment, no additional future loads were considered beyond the two loads introduced above and the future spot load and RS-Q bank B level load growth described in the grid model development in section 5 of this report. The team recommends revisiting this assessment in a couple of years when LADWP gains additional information on future loads in the RS-Q grid area.

RS-Q Expansion

To accommodate future load growth in the area, LADWP is planning to expand RS-Q. The scope of the RS-Q expansion plans includes equipping a 138-kV transformer bank position, installing a 160-MVA transformer bank, and constructing a new 34.5-kV rack with ten 34.5-kV line positions. LADWP expects the RS-Q expansion to be in service to accept electrification loads after 2027. *However, this subsection assumes that the expansion is already available for the 50% electrification scenarios by 2025 because the scenarios require an additional RS-Q transformer bank*.

The team represented the RS-Q expansion in the OpenDSS model with a new 160-MVA transformer bank, similar to the existing RS-Q transformer banks.

RS-Q Circuit Extensions

LADWP plans to extend the circuits from RS-Q to support the proposed electrical demands that the Los Angeles Harbor Department identified. The scope of the circuit extension plans considered here consist of five new 34.5-kV circuits from the RS-Q to DS-3 and San Pedro Outer Harbor area corresponding to berths 45–72. The San Pedro Outer Harbor area and POLA berth locations are illustrated in Figure 38.

[35] This assumption was made to represent a worst-case scenario, where the new loads coincide perfectly with the existing RS-Q bank B loads.

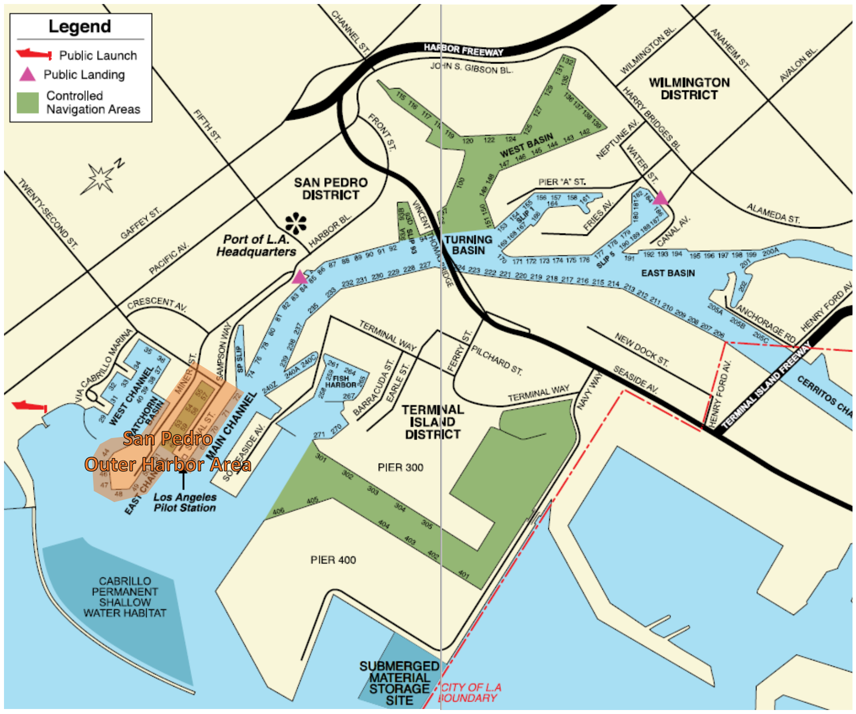


Figure 38. San Pedro Outer Harbor Area and POLA berth numbers [29]

LADWP expects the five new circuits from RS-Q to DS-3 to require about 50,000 ft (about 15,240 m) of new cables. LADWP further expects the five new circuits from RS-Q to berths 45–72 to require an additional 140,000 ft (about 42,672 m) of cable. The circuit upgrades are illustrated on a map in Figure 39 and with simplified circuit one-line drawings in Figure 40.

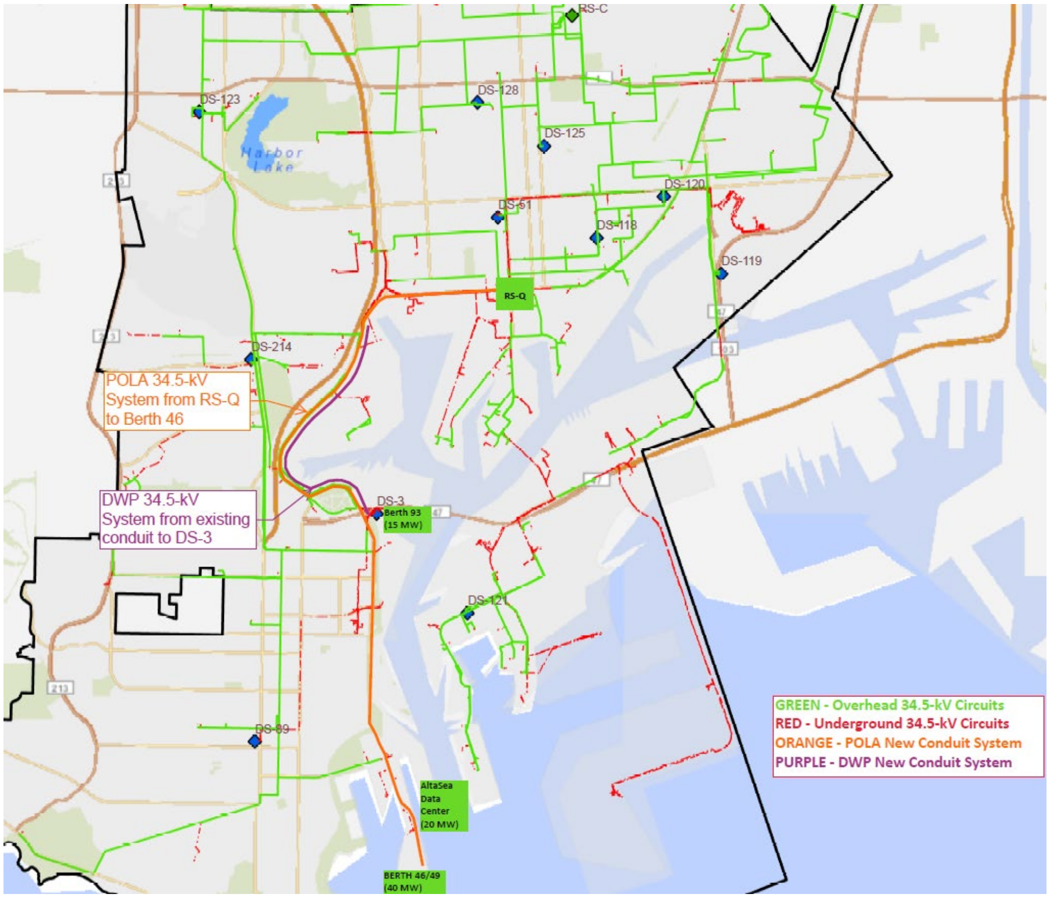


Figure 39. Map overview of the proposed path for the new circuits

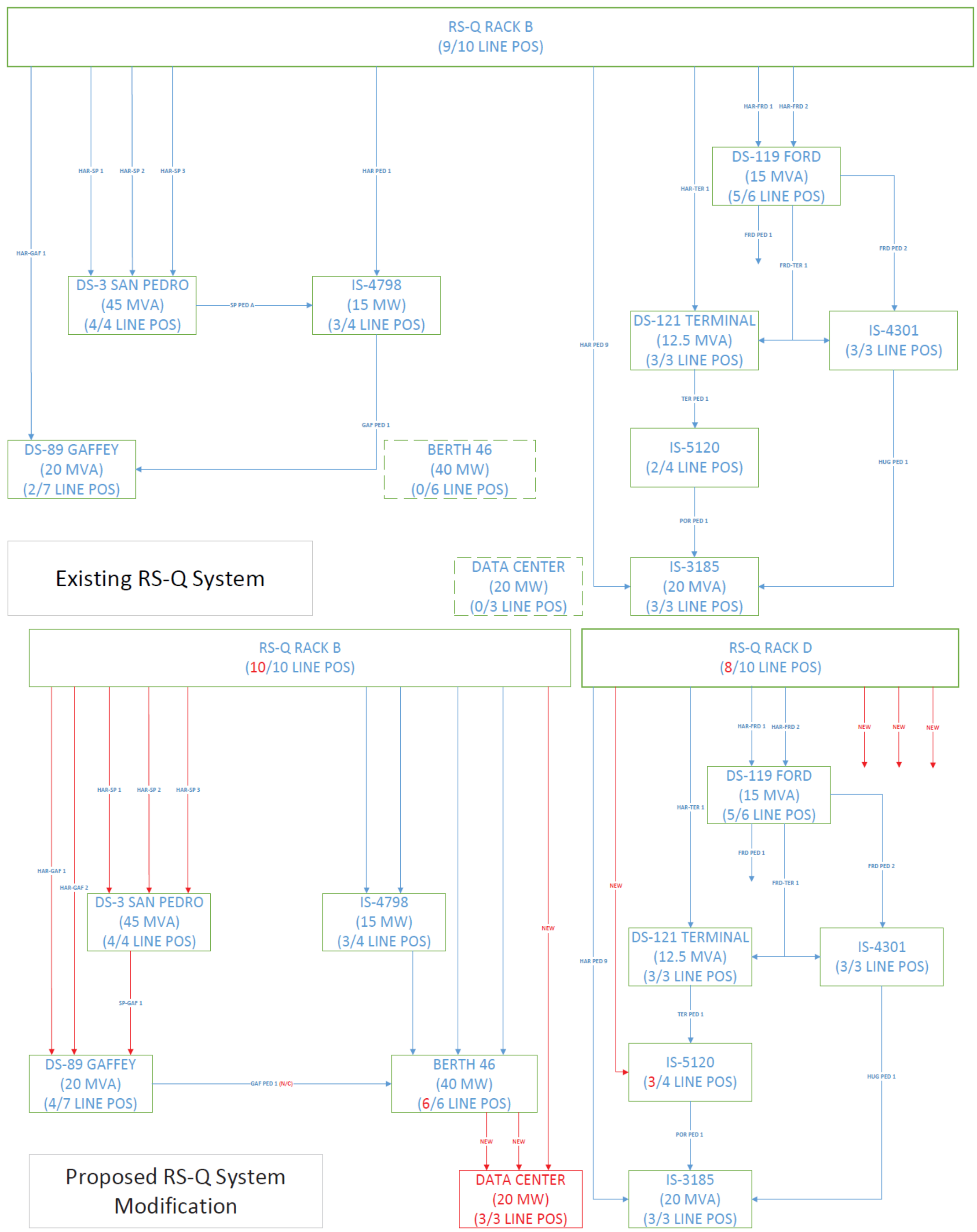


Figure 40. One-line diagrams of the existing and proposed RS-Q system configuration[36]

[36] In the original plan received from LADWP, the circuits were connected to rack B and rack D in opposite order, where, for example, HAR-SP 1 was supplied by rack D and HAR-FRD 1 by rack B. This study is based on the earlier connectivity. The updated circuit-to-rack connectivity shown here would change bank B and bank D loading with one another but is not expected to cause other changes to the results shown in this report.

The team represented the circuit extensions in the OpenDSS model as follows. First, HAR-GAF 1, HAR-SP 1, HAR-SP 2, HAR-SP 3, and HAR PED 1 circuits were transferred from RS-Q bank B to bank D. Second, new lines were added to the model as listed in Table 18. The line type of 1000_3C_CU_EPR, along with normal rating of 400 amps, was assumed for all the modeled lines.

Table 18. New lines modeled based on LADWP's preliminary future plans

Line Name[37]	From	To	Assumed Length (ft [m])[38]
HAR-GAF 2	RS-Q bank D	DS-89	28,000 (8400)
SP-GAF 1	DS-3	DS-89	11,000 (3500)
"HAR-IS4798"	RS-Q bank D	IS-4798	16,000 (4900)
"HAR-CT 1"	RS-Q bank D	Berths 45–50	29,000 (8700)
"HAR-CT 2"	RS-Q bank D	Berths 45–50	29,000 (8700)
"HAR-AS 1"	RS-Q bank D	Berths 56–71	27,000 (8100)
"CT-AS 1"	Berths 45–50	Berths 56–71	6600 (2000)
"CT-AS 2"	Berths 45–50	Berths 56–71	6600 (2000)
"HAR-IS5120"	RS-Q bank B	IS-5120	22,000 (6700)

Grid Impacts of LADWP's Future Grid Infrastructure Upgrade Plans

The team analyzed the grid impacts of LADWP's future grid infrastructure plans for the seven electrification scenarios.

RS-Q Bank Loading

Figure 41 shows the RS-Q bank peak loads for the seven analyzed scenarios with the future upgrades planned by LADWP. Note that bank D has been included. The addition of bank D and the move of some of the circuits from bank B to bank D has considerably reduced bank B peak loads compared to Figure 25 (before any grid infrastructure upgrades). *Banks B and D are both overloaded in all future scenarios except 50% managed electrification*. Hence, it is not possible to mitigate the overloads of banks B or D by moving circuits from one of the banks to the other.

Note that it might be possible to mitigate (some of) these overloads by moving circuits from banks B and D to banks A and C. However, banks A and C, which each serve a large refinery, experience occasional high load spikes close to the bank ratings, as illustrated in Figure 17 and

[37] EPRI defined the line names in quotation marks for the purposes of this assessment. Line names without quotation marks are defined in the LADWP plans.

[38] The lengths were roughly estimated with Google Maps based on the existing and/or proposed line paths.

Figure 18. Note that these high load spikes of banks A and C are not reflected in the grid model and this assessment, as is evident from Figure 25 and Figure 41. Moreover, as LADWP indicated, it may not be possible to move circuits from banks B and D to banks A and C for contractual reasons.

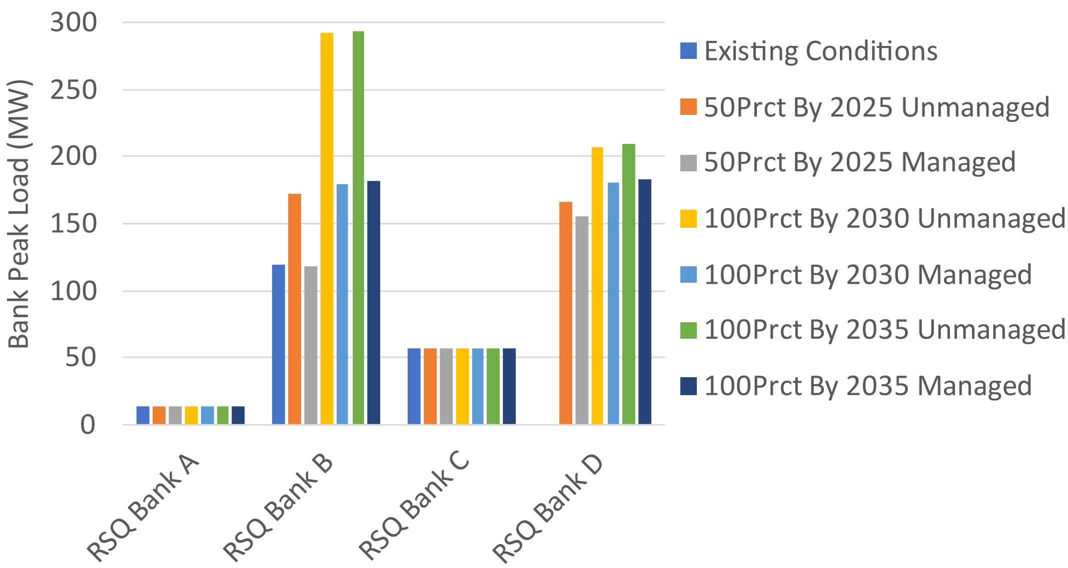


Figure 41. RS-Q bank peak loads for the analyzed scenarios with the future upgrades planned by LADWP

Table 19 lists the peak loads of the individual banks, total of banks B and D, and total of all banks. As expected, banks A and C peak loads are identical for all scenarios, but banks B and D peak loads increase considerably in the future electrification scenarios.[39] Table 19 also lists the number of new 160-MVA banks required, assuming perfect load balancing between the existing banks B and D or between all four banks.

[39] Bank D is not considered in scenario 1 (existing conditions).

Table 19. RS-Q bank peak loads and the number of additional RS-Q banks required

Scenario	Peak Load of Banks (MW)[40]						Number of New 160-MVA Banks Required with Perfect Load Balancing Between Existing[41]	
	A	B	C	D	B + D	All Banks	Banks B and D	All Banks
Existing Conditions	13.2	119.3	57.4	0.0	119.3	143.1	0	0
50% by 2025 – Unmanaged	13.2	172.2	57.4	166.3	319.9	341.3	0	0
50% by 2025 – Managed	13.2	117.5	57.4	155.7	252.6	274.0	0	0
100% by 2030 – Unmanaged	13.2	291.8	57.4	206.5	476.9	498.5	1	1
100% by 2030 – Managed	13.2	179.2	57.4	180.6	339.3	360.9	1	0
100% by 2035 – Unmanaged	13.2	293.6	57.4	209.3	481.0	502.7	2	1
100% by 2035 – Managed	13.2	181.3	57.4	183.4	343.3	365.1	1	0

The following observations can be made:

- The peak of the sum of banks B and D load is somewhat less than the sum of the peak loads of the individual banks B and D due to the non-coincidence of the bank peak loads. The same applies for the peak of the sum of all banks versus the sum of the peaks of individual banks.

[40] Column "B+D" is calculated by adding the yearly (8760-hour) load profiles of Bank B and D and taking the maximum over the year. Similarly, column "All Banks" is calculated by adding the yearly (8760-hour) load profiles of all banks (A+B+C+D) and taking the maximum over the year. Note that the value of column "B+D" is less than the sum of columns "B" and "D" because the bank peak loads do not occur at the same time. For the same reason, column "All Banks" is less than the sum of the columns "A", "B", "C" and "D".

[41] These numbers are calculated based on the peak loads of bank B + D or all banks, assuming 160-MVA capacity for the existing and new banks.

- Proper balancing of loads between banks B and D allows accommodating the 50% electrification scenarios, assuming no load growth beyond what is considered here. A new bank in addition to bank D would be required to accommodate the 100% electrification scenarios. As discussed before, this would require a new RS, as RS-Q can accommodate only four banks.
- Proper balancing of loads between all four banks allows accommodating the 50% electrification and 100% managed electrification scenarios, assuming no load growth beyond what is considered here and the peak loads considered here.
- *The 100% unmanaged electrification scenarios require an additional bank beyond the planned bank D*. This is the case even if: 1) the loads were perfectly balanced among all four banks, 2) banks A and C peak loads are the ones considered here (see discussion above), and 3) there is no load growth beyond what is represented here.

Next, this subsection focuses on required grid infrastructure upgrades, assuming that a sufficient amount of RS-Q bank capacity is provided in some way.

RS-Q Grid Area Loading

Figure 42 lists the peak demands in the three grid areas for the seven scenarios analyzed. The red lines indicate the total capacity of the tie-lines (includes the existing tie-lines and the tie-lines planned by LADWP) between Wilmington and Terminal Island (about 111 MW) and between Wilmington and San Pedro (about 218 MW).[42] As expected, the future electrification scenarios significantly increased the peak demand of the Terminal Island area, but less so the peak demands of the San Pedro and Wilmington areas. With the future upgrades that LADWP plans, there is more than enough capacity to San Pedro in all the scenarios. However, there is insufficient capacity to Terminal Island in all future scenarios except the 50% managed electrification. These results suggest that no further tie-lines may be needed to San Pedro. These results also suggest that additional tie-lines to Terminal Island will be required and the number of lines will vary considerably based on the electrification scenario.

[42] The capacity was calculated by adding the capacities of the individual tie-lines calculated from the rated ampacity of the circuit, I_{normal}, with: $P_{normal} = \sqrt{3}(34.5\ kV)(I_{normal})(0.98)$. This calculation assumes PF = 0.98 and nominal voltage.

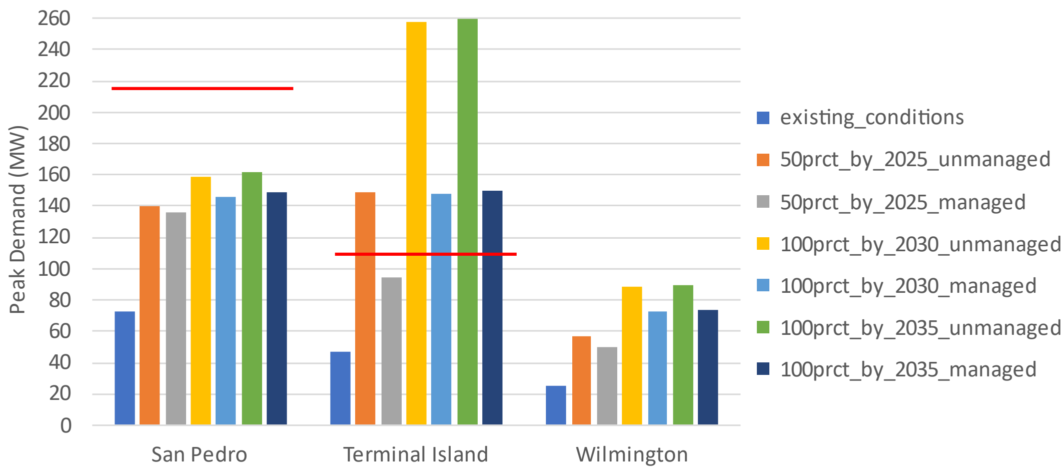


Figure 42. Peak demand of the three grid areas with the future upgrades that LADWP plans. The red lines indicate the aggregated capacity of the existing tie-lines (not considering any available spare positions).

Table 20 lists the minimum number of new 400-amp lines required from Wilmington to Terminal Island and San Pedro beyond the existing lines and the future lines planned by LADWP considered in this section. With the new lines that LADWP plans, no further lines from Wilmington to San Pedro may be needed. However, at least zero to seven additional lines will be required from Wilmington to Terminal Island, depending on the future electrification scenario. The reader should note the caveats related to this simple type of calculation as discussed above Table 15. Line upgrade requirements are analyzed in more detail later in this section.

It should also be noted that the simple analysis here does not consider practical limitations for constructing additional circuits. In particular, the existing directional bore between Wilmington and San Pedro has only three spare conduits for running new circuits. After these conduits have been utilized, an additional directional bore would be required. Moreover, the RS-Q existing (and planned new rack) have limited circuit positions beyond which a new RS would be required. Due to these practical limits, the 100% unmanaged electrification scenarios, which would require seven additional circuits to Terminal Island, would require a new RS.

Table 20. Minimum number of new 400-amp lines required from Wilmington to Terminal Island and San Pedro

Scenario	Minimum Number of New 400-amp Lines Required from Wilmington to	
	Terminal Island	San Pedro
Existing conditions	0	0
50% by 2025 – unmanaged	2	0
50% by 2025 – managed	0	0
100% by 2030 – unmanaged	7	0
100 by 2030 – managed	2	0
100 by 2035 – unmanaged	7	0
100 – by 2035 – managed	2	0

Figure 43 shows the maximum power flows (over the year) and the remaining capacity[43] for the tie-lines at the area boundaries. Note the future lines planned represented here (HARGAF2, HARIS4798, HARCT1, HARCT2, HARAS1, and HARIS5120).

[43] The remaining capacity was calculated by subtracting the maximum power flow from the calculated line capacity.

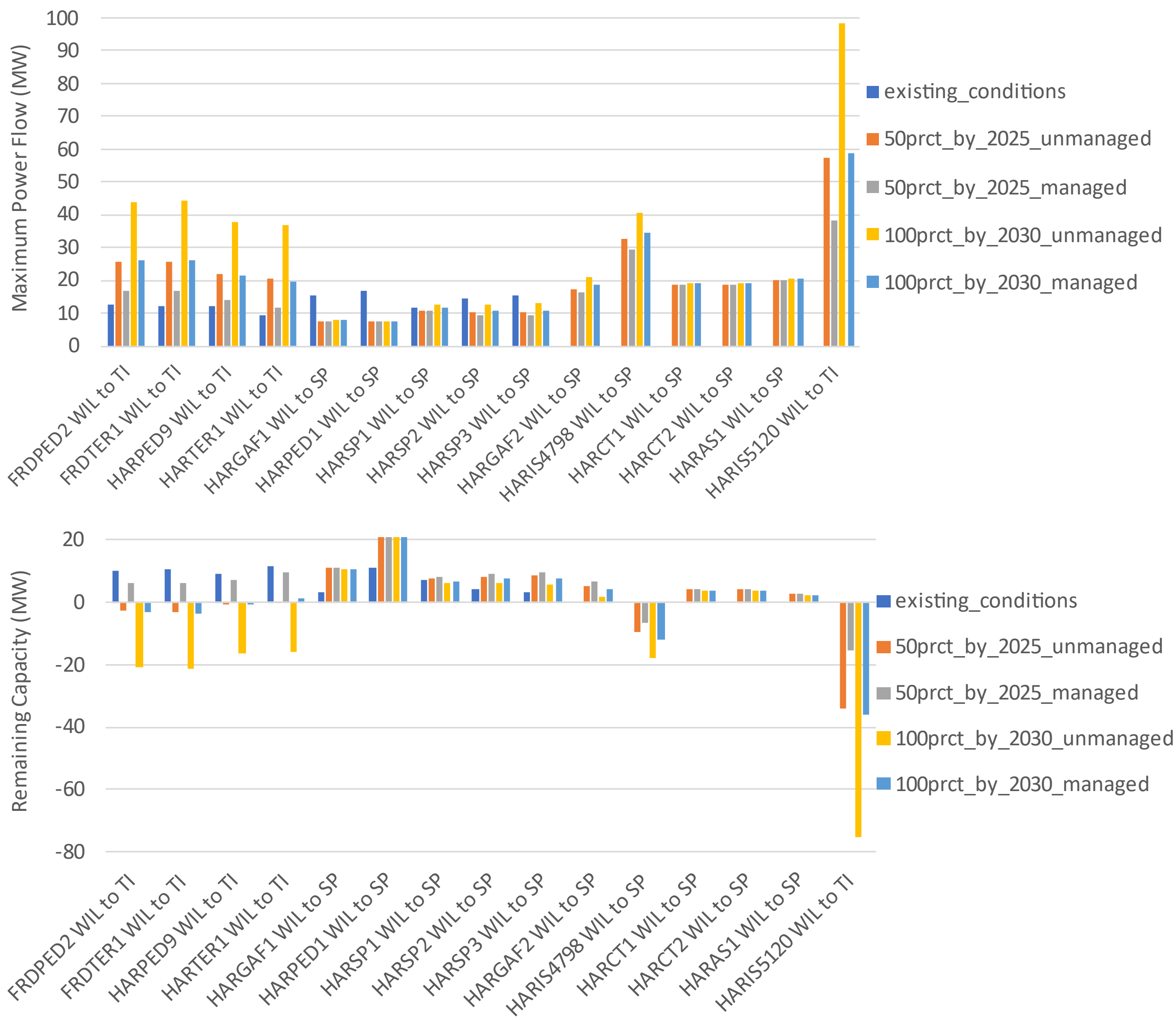


Figure 43. Maximum power flows (top) and remaining capacity (bottom) on the tie-lines at the area boundaries—future lines planned by LADWP included

All the tie-lines to San Pedro, except HARIS4798, have remaining capacity. The overload on HARIS4798 could be mitigated by balancing the loading between the circuits. The new tie-line to Terminal Island, HARIS5120, has unrealistically high power flow that skews the loading of the other tie-lines to Terminal Island. This in turn, skews all other grid impacts, and hence the impacts with the future infrastructure upgrades planned by LADWP alone are not analyzed further.

The following subsections evaluate approaches to mitigating the grid impacts, including the overloads on HARIS4798 and HARIS5120 circuits, with additional grid infrastructure upgrades.

Additional Grid Infrastructure Upgrades Required

As shown in the previous subsection, the future upgrades planned by LADWP are not sufficient to mitigate all the grid impacts in the analyzed future electrification scenarios. This subsection analyzes the additional grid infrastructure upgrades required to mitigate grid impacts that LADWP's planned future upgrades do not address. In particular, the team analyzed additional grid infrastructure upgrades required to accommodate 50% electrification by 2025 with managed charging or unmanaged charging. The other scenarios are not analyzed for the following reasons:

- No grid infrastructure upgrades are required for the existing conditions scenario.
- As discussed previously, all the 100% electrification scenarios would require one to two additional transformer banks. Based on feedback from LADWP, it is infeasible to add additional transformer banks at RS-Q, and hence a new RS would be required to accommodate any of the 100% electrification scenarios. It was out of the scope of this assessment to evaluate a new RS and the associated grid changes. The team recommends revisiting this assessment in a couple of years as additional information on the POLA tenant electrification strategies and other RS-Q area load growth becomes available.

The following subsections identify the additional grid infrastructure upgrades first for 50% electrification with managed charging and then for 50% electrification with unmanaged charging. This order was applied given that the managed charging requires fewer upgrades. The assessment focuses on the circuit upgrades, assuming that sufficient RS-Q bank capacity is available.

It is important to emphasize that the additional grid infrastructure upgrades were identified based on high-level analysis. All new lines are assumed to have the type of 1000_3C_CU_EPR and the normal rating of 400 amps. The results presented here are intended to illustrate the scope of the required grid infrastructure upgrades as opposed to recommending the least-cost technically viable grid infrastructure upgrades. Moreover, it was out of the scope of this assessment to evaluate or consider optimal line/cable routing, emergency operating conditions, protection considerations, ratings of new circuits, availability of DS/IS line positions, and various other practical considerations.

50% Electrification by 2025 with Managed Charging

The analysis presented previously indicated that it may be possible to accommodate scenario 3 (50% electrification by 2025 with managed charging) with no additional circuits (beyond the ones already planned by LADWP) by appropriately balancing the loading between circuits and particularly between the tie-lines from Wilmington to Terminal Island. However, it turned out to be quite challenging to mitigate all overloads at all QSTS time instances.

The following changes were observed to mitigate nearly all overloads:

- De-energize circuit SP PED A[44]
- Adjust the reactance of the HAR-TER 1 reactor at RS-Q from about 1.31 ohms to 1.6 ohms
- Adjust the reactance of the HAR PED 9 reactor at RS-Q from about 1.31 ohms to 1.2 ohms
- Add a load-balancing reactor with reactance of 0.9 ohms at the head of the new circuit HARIS5120 (the circuit added from RS-Q bank B to IS-5120)
- Transfer the CHE loads at IS-5349 from HAR PED 9 and HAR-TER 1 to HAR PED 1
- Add a short line section to mitigate overloads on a short section of FRD-TER 1, as illustrated in Figure 44

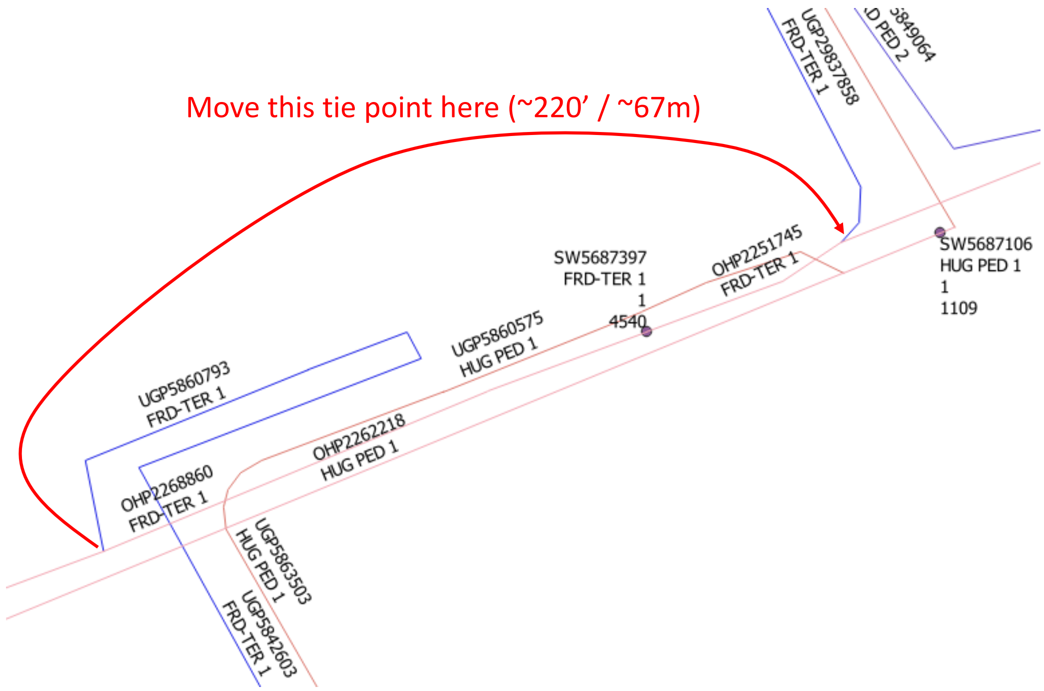


Figure 44. Grid infrastructure upgrade to mitigate overloads on a short line section of FRD-TER 1 near IS-4301

The upgrades described above addressed practically all the overloads in this scenario. However, the following negligible overloads remained in the QSTS simulation:

- RS-Q bank D transformer experienced negligible overloads up to about 104.5% during 5 hrs of the year.
- Three load-serving transformers were slightly overloaded. This is likely caused by inaccuracies in the load modeling.

[44] Based on the information received from LADWP, it was not clear if this was already included in LADWP's future plans. De-energizing this short circuit improved load balancing between the existing and the new circuits.

- HARIS5120 was overloaded up to 101.7% during 1 hr.
- A few HAR PED 9 lines were overloaded up to 100.7% during 30 hrs of the year.

These overloads are negligible and well within the overall accuracy of this assessment. Moreover, it may be possible to mitigate the remaining overloads by better load balancing between the circuits.

All the voltages were well within the ANSI range for this scenario.

To summarize, *these results suggest that it is possible to accommodate 50% electrification by 2025 with managed charging with relatively minor load-balancing measures such as the ones listed here*.

50% Electrification by 2025 with Unmanaged Charging

Based on Table 20, at least two additional lines from Wilmington to Terminal Island are expected to be required to accommodate this scenario. The following upgrades were identified for this scenario:

- De-energize circuit SP PED A.[45]
- Add a load-balancing reactor with reactance of 0.90 ohms at the head of HARIS5120 (the circuit added from RS-Q bank B to IS-5120) at RS-Q.
- Add a second approximately 4.16-mi (22,000-ft, or 6700-m) circuit from RS-Q bank B to IS-5120 "HARIS5120L2." Add a load-balancing reactor at the head of the circuit at RS-Q with reactance of 0.90 ohms.
- Transfer all FMS CHE loads to IS-5120 served by HARIS5120 and HARIS5120L2.
- Add an approximately 2.49-mi (13,100-ft, or 4000-m) circuit from RS-Q bank B to IS-4301. Add a load-balancing reactor at the head of the circuit at RS-Q with reactance of 1.55 ohms.
- Add an approximately 1.99-mi (10,500-ft, or 3200-m) circuit from IS-4301 to IS-4048. Transfer all the existing and CHE loads at IS-4048 to the circuit.
- Add an approximately 0.43-mi (2,300-ft, or 700-m) circuit from RS-Q bank B to the underground line section "UGP29380074," and transfer the HAR PED 9 west of the section to the new circuit. This upgrade is illustrated in Figure 45.[46]
- Add a short line section to mitigate overloads on a short section of FRD-TER 1, as illustrated in Figure 44. Transfer IS-5349 and IS-5357 loads to the new line section.

[45] Based on the information received from LADWP, it was not clear if this was already included in LADWP's future plans. De-energizing this short circuit improved load balancing between the existing and the new circuits.

[46] In practice, this upgrade would be challenging to implement due to bridge crossing.

- Adjust the reactance of two existing load-balancing reactors as follows:
  - HAR PED 9: 1.15 ohms
  - HAR-TER 1: 1.6 ohms

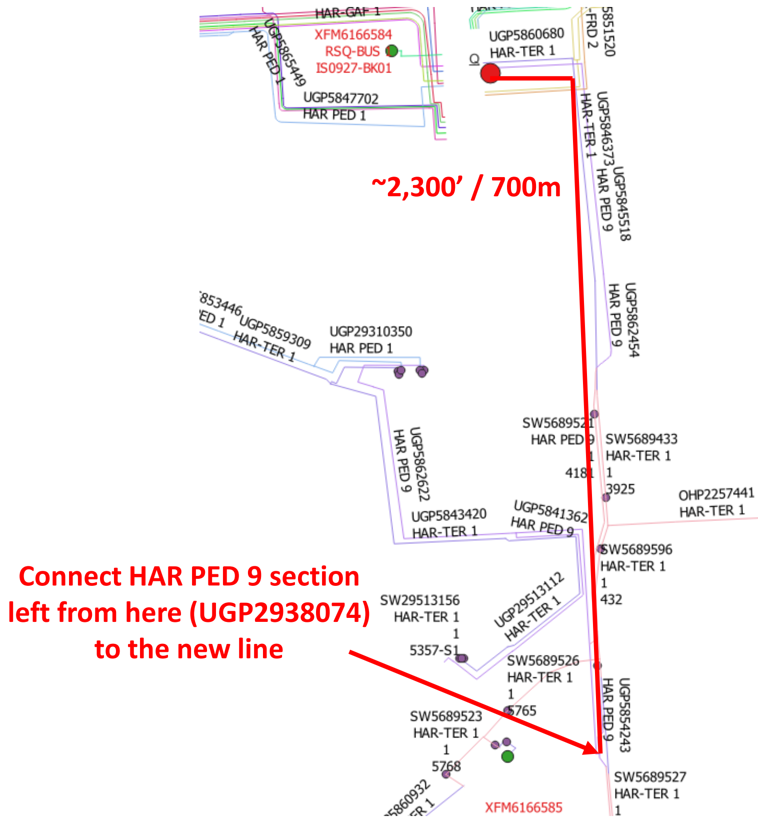


Figure 45. Grid infrastructure upgrade to mitigate overloads on HAR PED 9 and HAR-TER 1

The upgrades described above addressed practically all the overloads in this scenario. However, the following negligible overloads still remained in the QSTS simulation:

- RS-Q bank D transformer experienced negligible overloads of up to about 104.9% during 5 hrs of the year.
- Three load-serving transformers were slightly overloaded. This is likely caused by inaccuracies in the load modeling.
- Four circuits experienced negligible overloads as follows:
  - HARIS4301: about 101% of normal, 1 hr of the year
  - HARIS5120: about 101% of normal, 1 hr of the year
  - HARIS5120L2: about 101% of normal, 1 hr of the year
  - HAR PED 9: about 101% of normal, 72 hrs of the year

These overloads are negligible and well within the overall accuracy of this assessment. Moreover, it may be possible to mitigate these remaining overloads by better balancing the loads between the RS-Q banks and circuits, and/or with other no-cost or low-cost measures.

All the 34.5-kV-level voltages were within the ANSI range for this scenario.

To summarize, these results suggest that *it is possible to accommodate 50% electrification by 2025 with unmanaged charging with upgrades that consist of two new tie-lines from Wilmington to Terminal Island along with other circuit upgrades requiring about 9.13 mi (48,230 ft, or 14,700 m) of new line sections and three new load-balancing reactors at RS-Q. Additionally, switching operations and other relatively minor upgrades are required*.

Conclusions

- Given the current energy storage costs and LADWP rate structures, energy storage was not found to be an economically viable solution to reduce the CHE peak loads. This may change as energy storage costs decrease or under different rate structures.
- The future RS-Q upgrades that LADWP plans are not sufficient alone to mitigate all the grid impacts from the considered future electrification scenarios.
- Proper balancing of loads between banks B and D allows accommodating the 50% electrification scenarios, assuming no load growth beyond what is considered here. A new bank in addition to bank D would be required to accommodate the 100% electrification scenarios. Alternatively, proper balancing of loads between all four RS-Q banks allows accommodating the 50% electrification and 100% managed electrification scenarios, but not the 100% unmanaged electrification scenarios. A new RS would likely be required to accommodate the 100% electrification scenarios, given that RS-Q cannot accommodate more than four banks.
- The future upgrades that LADWP plans provide sufficient grid capacity in the San Pedro area. However, depending on the future electrification scenario, up to seven new tie-lines from RS-Q in Wilmington to Terminal Island will be required.
- It is possible to accommodate 50% electrification by 2025 with managed charging with relatively minor load-balancing measures in addition to the future upgrades planned by LADWP.[47] Accommodating the 50% electrification by 2025 with unmanaged charging requires at least two new tie-lines from Wilmington to Terminal Island along with other circuit upgrades requiring about 9.13 mi (48,230 ft, or 14,700 m) of new line sections and three new load-balancing reactors at RS-Q. Additionally, switching operations and other relatively minor upgrades are required.

[47] As illustrated in Figure 25, it would be possible to accommodate this scenario without the added Outer Harbor loads and without the new RS-Q rack D, provided that ~40 MW of load can be transferred from RS-Q bank B to banks A and C. As illustrated in Table 20, it would be possible to accommodate this scenario with the added Outer Harbor loads without the new RS-Q rack D, provided that ~115 MW of load can be transferred from RS-Q bank B to banks A and C.

8 TENANT ZERO-EMISSION MODELING – UPDATE

In addition to the methods and results presented in sections 4–7, another round of simulations was conducted using a different suite of technical specifications based on different estimations of the quickly evolving field of electric CHE. These estimates came from manufacturer data sheets as much as possible or other sources where needed. Additionally, two additional parameters were included for each piece of equipment, a utilization factor and a historical annual activity hours field. The utilization factor represents the proportion of the total inventory that is in use at any given point in time as opposed to being out of use due to maintenance or other causes. The historical annual activity hours field represents on average how many hours per year that equipment type was actually operated in the past. This analysis makes the assumption that all equipment in the inventory, except that undergoing maintenance, is used for the duration of every shift to estimate peak electric loads in both the managed and unmanaged charging scenarios. This conservative assumption ensures that the grid analysis is given electric loading data that represents the busiest times and is less likely to be exceeded in practice. However, the annual activity hours are used to scale total annual energy use results and associated electricity bills down. Because of data limitations in some CHE areas, the equipment inventory has also been updated. Managed/unmanaged charging approaches, terminal schedules, and others considered in this updated analysis were identical to those in the initial analysis. The deployment of hydrogen fuel cell-powered CHE would mitigate load on electrical power grid (see Table 30).

Updated Technical Specifications

The updated inventory and technical specifications for the updated analysis are shown in Table 21.

Table 21. Updated inventory and technical specifications

Equipment	Source	Annual Activity (hr) 1	Charging Power (kW)	Charging Time (hr)	Durability (hr)	Utilization Factor (%) (Assumed)	Terminal 1	Terminal 2	Terminal 3	Terminal 4	Terminal 5	Terminal 6
DIESEL EQUIPMENT												
Diesel Cone Vehicle	Battery	1196	150	0.8148	9.2	0.85	8	0	7	0	0	14
Diesel Forklift	Battery	507	86	2.9716	8	0.85	4	4	9	5	0	30
Diesel Hybrid Straddle Carrier	Battery	2142	600	0.0556	4	0.85	12	0	0	0	0	70
Diesel Man Lift	Battery	167	6.5	2.8718	8	0.85	7	0	3	0	0	0
Diesel Side Pick	Battery	533	400	2.7778	18	0.85	6	3	0	0	0	0
Diesel Straddle Carriers	Battery	5256	600	0.0556	4	0.85	28	0	0	0	0	0
Diesel Sweeper	Battery	396	150	1.5556	11	0.85	1	1	1	1	1	2
Diesel Top Handler	Battery	2419	400	2.7778	18	0.85	11	24	51	41	33	63
Diesel Truck (Yard Trucks)	Battery	685	150	0.7259	6.6	0.85	69	107	164	174	138	228
Diesel Yard Tractor UTR	Battery	2038	120	1.9352	10	0.85	37	112	199	30	120	180
Diesel Hybrid RTG	Grid	2541	506			0.9	0	0	0	0	0	21
Diesel RTG Crane	Grid	2517	484.705			0.9	0	12	27	21	14	21

Table 21 (continued). Updated inventory and technical specifications

Equipment	Source	Annual Activity (hr) 1	Charging Power (kW)	Charging Time (hr)	Durability (hr)	Utilization Factor (%) (Assumed)	Terminal 1	Terminal 2	Terminal 3	Terminal 4	Terminal 5	Terminal 6
DIESEL EQUIPMENT												
LNG Yard Tractor UTR	Battery	1085	120	2.0093	10	0.85	0	22	0	0	0	0
LPG Forklift	Battery	387	48	3.2778	9	0.85	10	8	25	8	22	5
LPG Yard Tractor UTR	Battery	1663	120	1.9352	10	0.85	0	0	0	159	0	0
ELECTRIC EQUIPMENT												
Electric Automatic Stacking Crane	Grid	2151	700			0.9	29	0	0	0	0	0
Electric Crane (Automated RMG Cranes)	Grid	975	950			0.9	3	0	0	0	0	0
Electric Wharf Crane (STS)	Grid	1627	910			0.8	10	8	16	15	11	19

In the process of developing these updated technical specifications, some alterations needed to be made to ensure feasibility in the modeling. This arose because some of the new battery-powered equipment specifications either had too high a charging time or too low a durability to be able to get through concurrent shifts without running out of stored energy. The operations modeling is done in optimization and requires that a feasible solution exist, so the durability of this equipment was artificially increased until a feasible solution existed.

Durability is the number of on-shift hours a fully charged vehicle can operate before running out of charge. Charging time is the number of hours it takes to charge the vehicle from 0% to 100%. This analysis calculates the upper limit on charging time that allows vehicles to survive the shift schedule without running out of charge. Managed charging strategies may throttle charging below this value at some times of day.

There are two shifts per day, each with a 1-hr meal break in the middle, separated by a 1-hr shift transition. Battery equipment must be able to go through both shifts without running out of charge, recharging only during the three 1-hr breaks. The 5-hr period after shift 2 and before the beginning of shift 1 must be able to restore the equipment to full charge for the next cycle. Each shift segment is 4 hrs long, so a full charge must support at least 4 hrs of operating time. At very long durabilities, the limiting factor becomes how much energy can be delivered to the battery during all 8 hrs of off-shift time in a day. This energy must at least replace the amount lost during the 16 working hours. If all these conditions are met, then the equipment may feasibly survive the shift schedule.

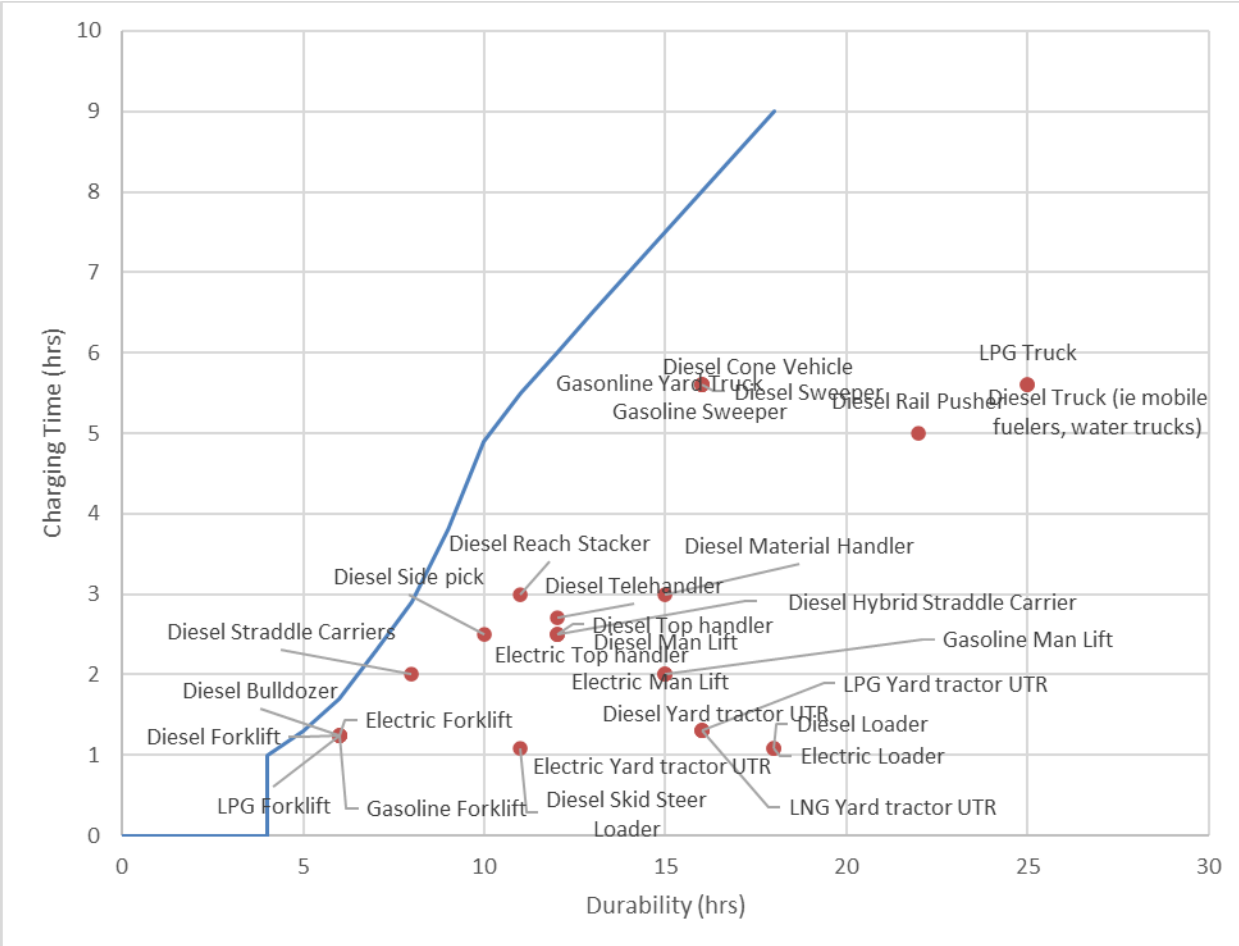


Figure 46. All equipment in the initial assessment could survive a busy shift schedule; the blue line shows the maximum feasible charging-time-to-durability ratio

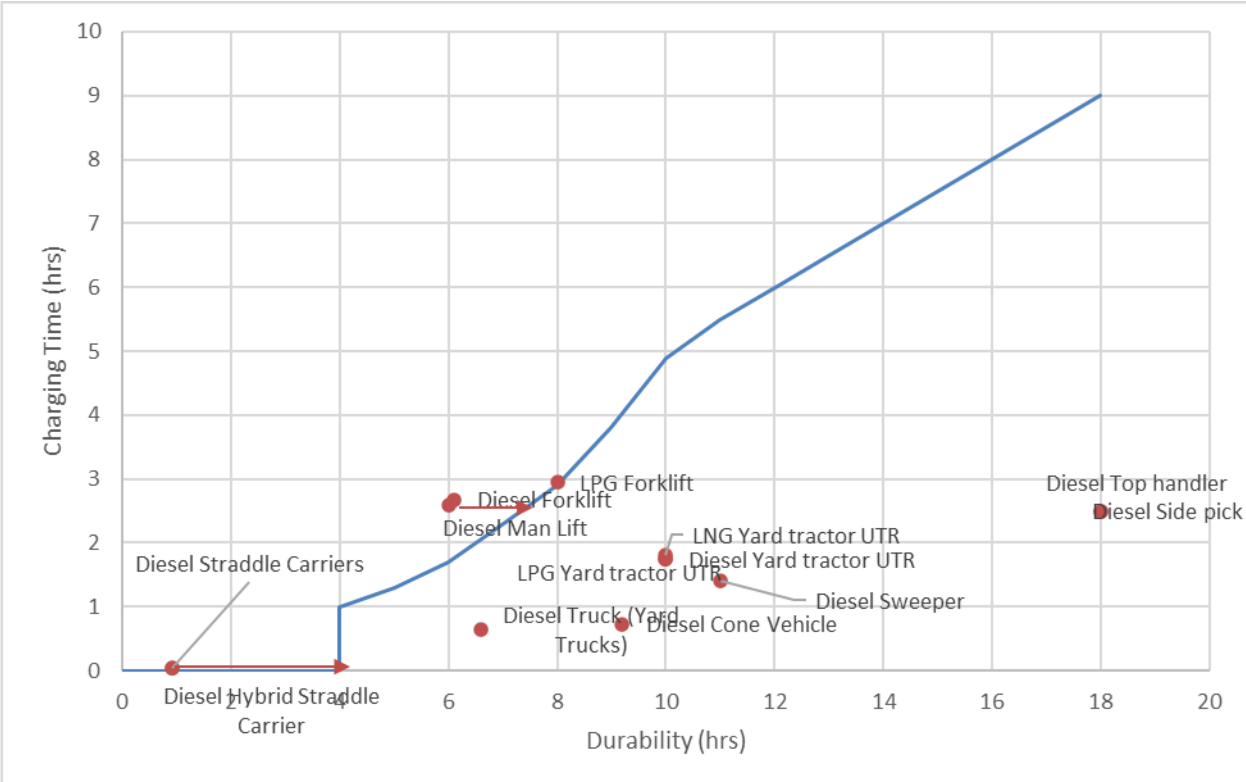


Figure 47. New technical specifications require some adjustment to durability (shown as red arrows); the blue line shows the maximum feasible charging-time-to-durability ratio

Load Shape Results

For the six terminals involved in this study, their overall CHE electric load estimate is shown in Figures 48 through 54 for both managed and unmanaged cases.

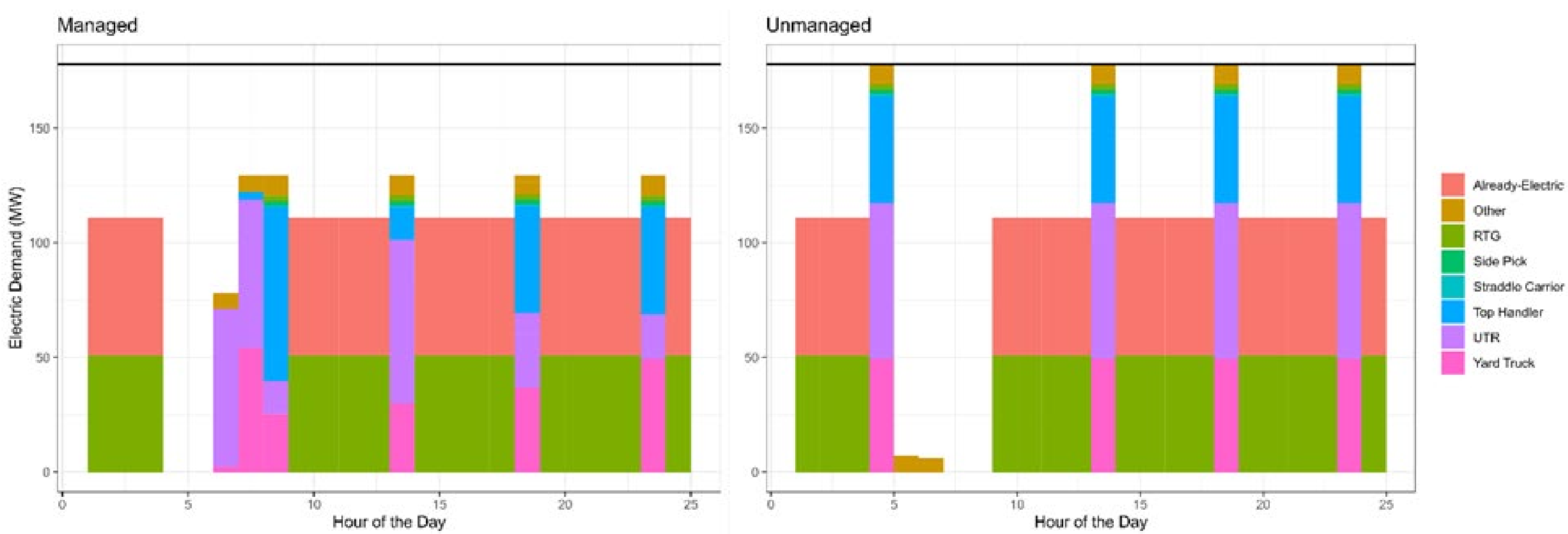


Figure 48. Six terminals' CHE updated load estimate

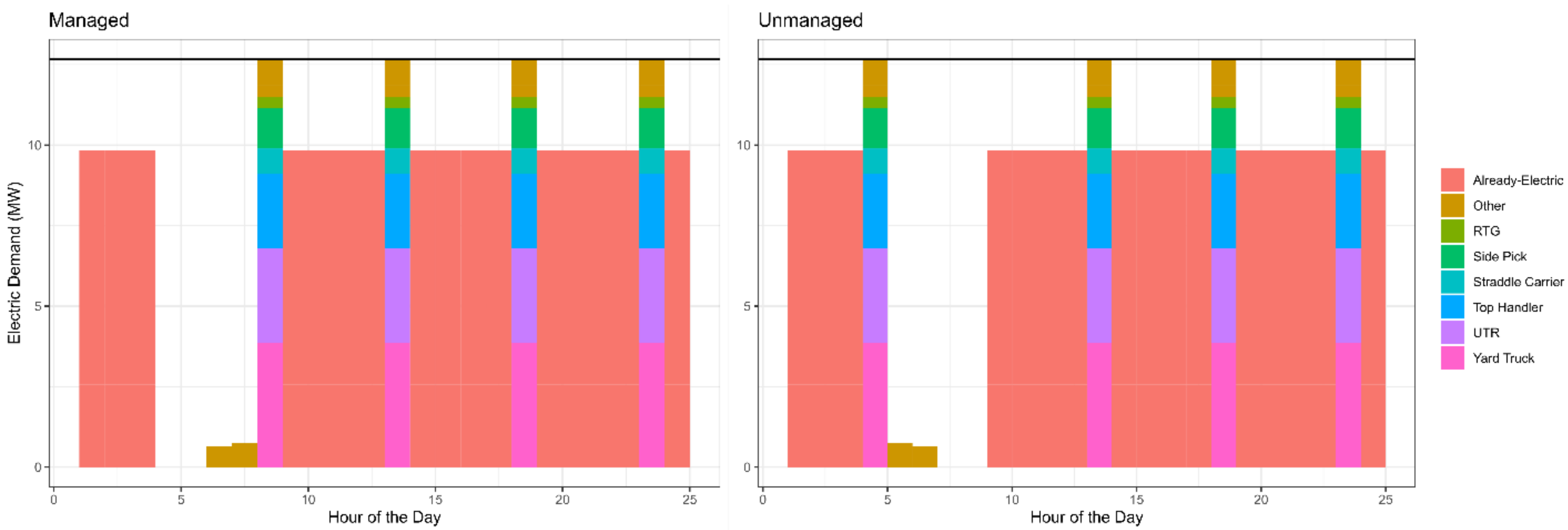


Figure 49. Terminal-1 CHE updated load estimate

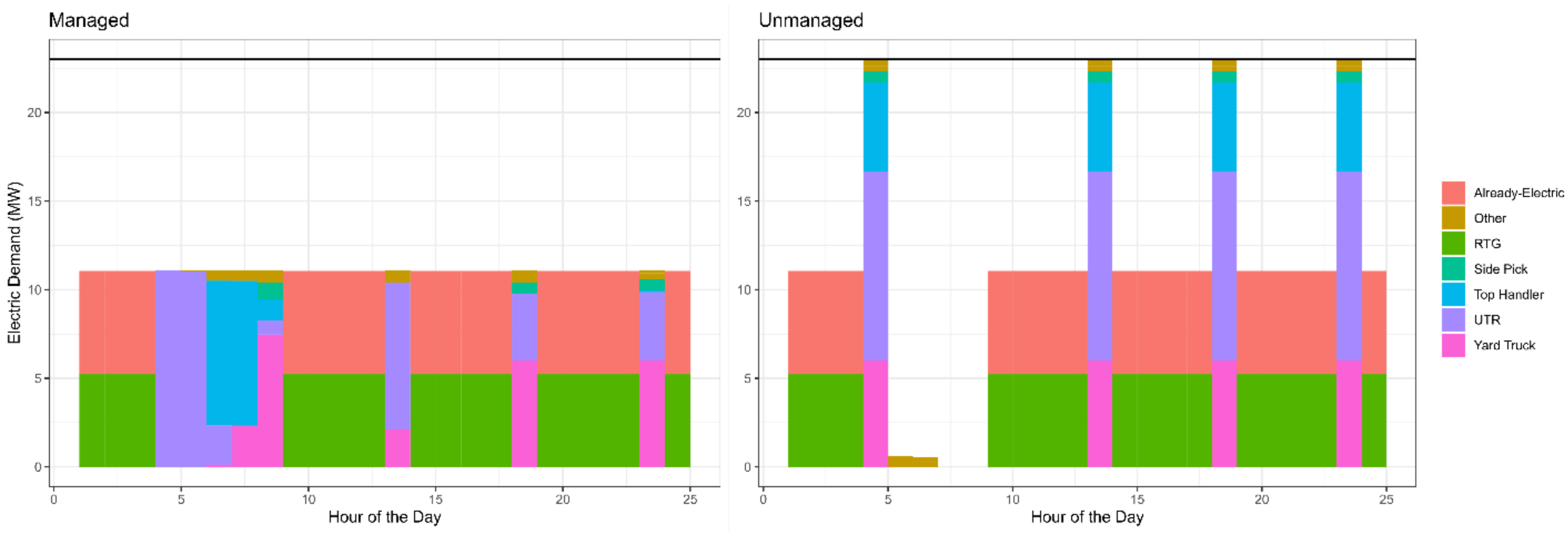


Figure 50. Terminal-2 CHE updated load estimate

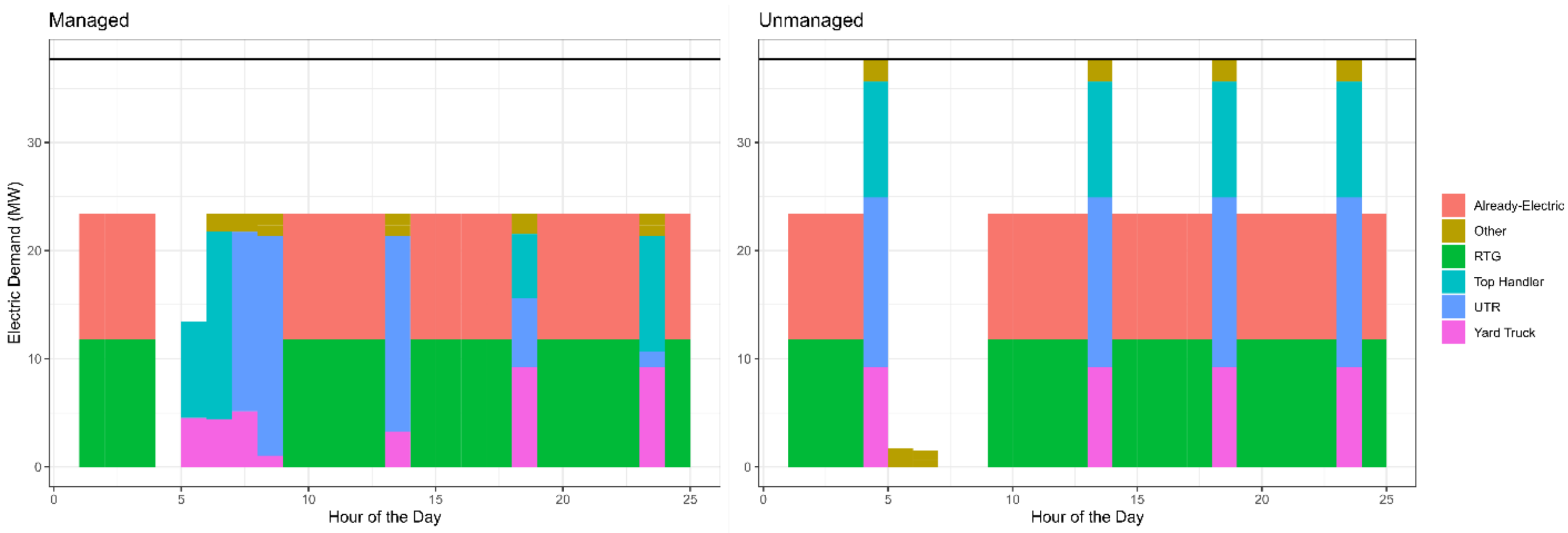


Figure 51. Terminal-3 CHE updated load estimate

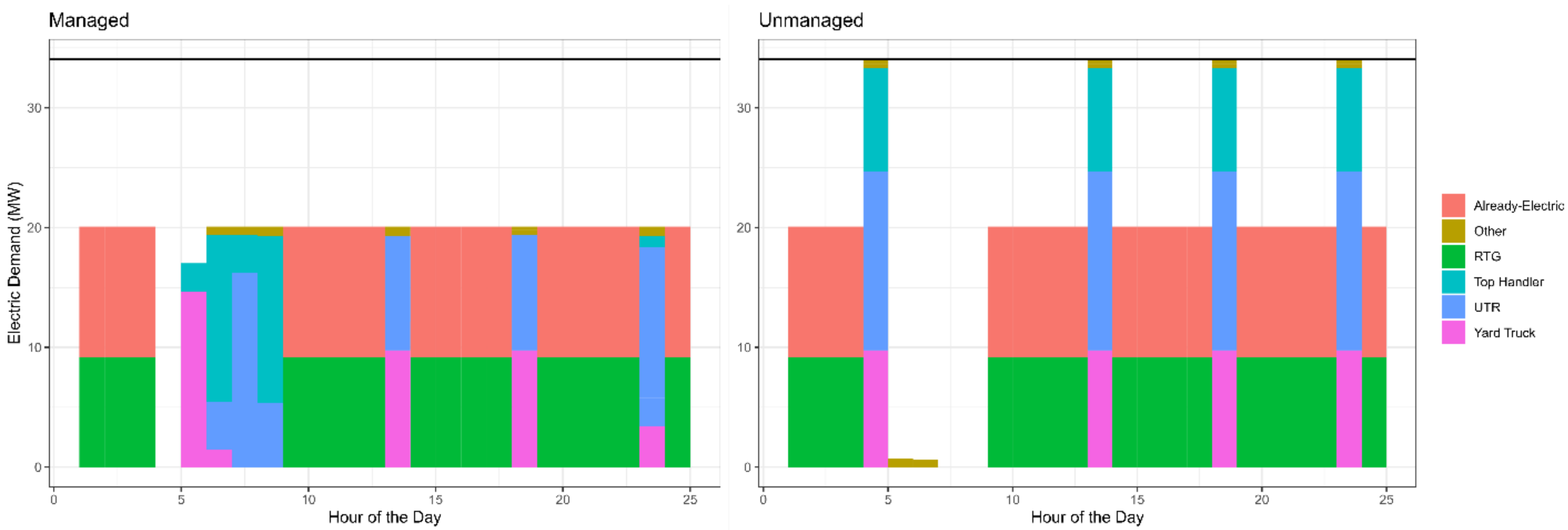


Figure 52. Terminal-4 CHE updated load estimate

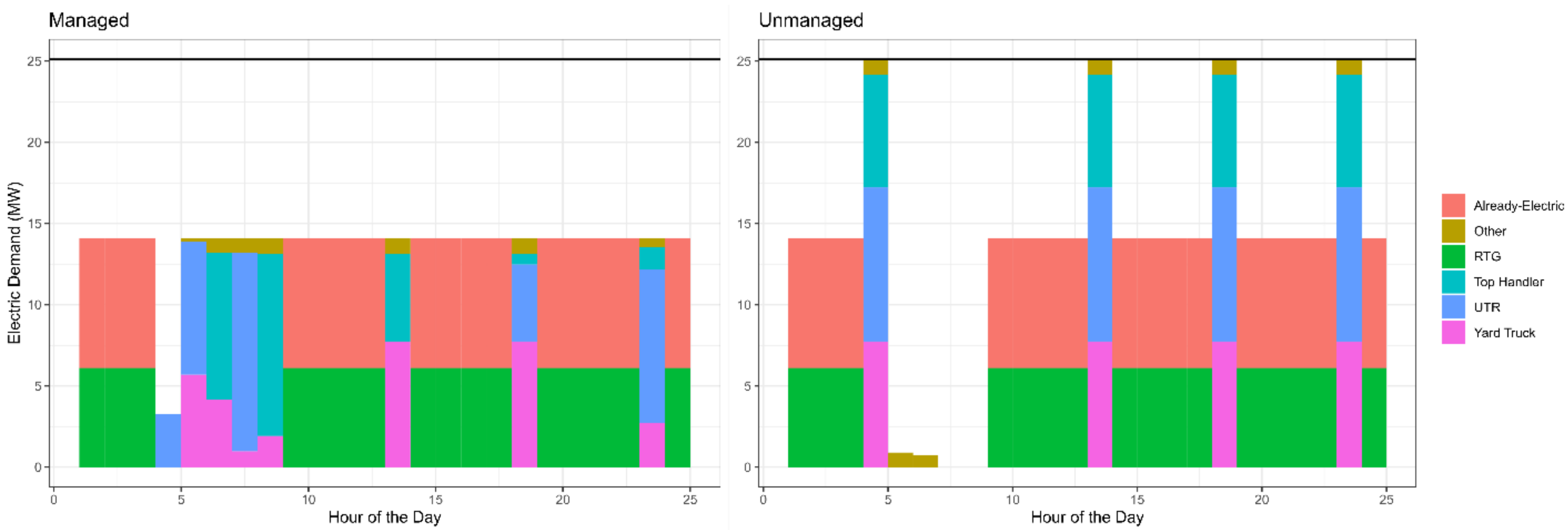


Figure 53. Terminal-5 CHE updated load estimate

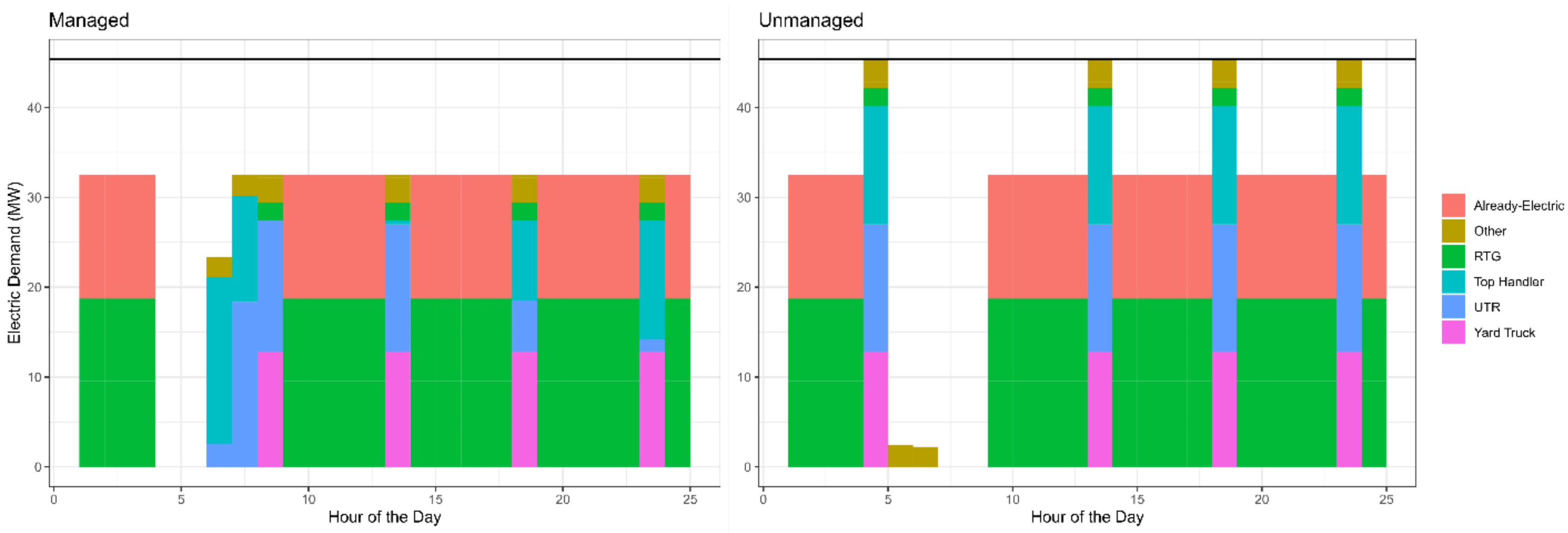


Figure 54. Terminal-6 CHE updated load estimate

Electric Demand Results

In the electric demand estimation, two scenarios were considered: 1) a low-utilization scenario and 2) a high-utilization scenario.

1. Low Utilization: In this scenario, the annual activity hours (actual) based on the 2021 POLA air emissions survey data was used. The results for the low utilization are provided in Table 22, below.

Table 22. Low-utilization scenario results

	Incremental Future Connected Load				Total Future Connected Load				Incremental Future Diversified Peak Demand			
POLA Tenants	50% by 2025		100% by 2030		50% by 2025		100% by 2030		50% by 2025 – Unmngd	100% by 2030 – Unmngd	50% by 2025 – Managed	100% by 2030 – Managed
	Battery (MW)	Grid (MW)	Battery (MW)	Grid (MW)	Battery (MW)	Grid (MW)	Battery (MW)	Grid (MW)	MW	MW	MW	MW
Terminal-1	11.93	0.00	23.87	0.00	12.12	41.34	24.06	41.34	9.18	9.18	9.18	9.18
Terminal-2	5.85	1.31	11.70	2.61	6.91	13.72	12.76	15.02	3.16	6.32	2.79	3.88
Terminal-3	10.45	2.94	20.90	5.88	10.45	26.70	20.90	29.64	5.78	11.19	5.78	8.32
Terminal-4	8.66	2.29	17.33	4.58	8.66	27.44	17.33	29.72	5.02	9.17	5.02	7.52
Terminal-5	6.78	1.53	13.56	3.05	6.81	18.59	13.59	20.12	3.56	7.15	3.60	4.94
Terminal-6	19.86	4.70	39.71	9.40	21.78	33.28	41.63	37.98	7.91	13.01	7.91	11.96
Six Terminals Total	**63.53**	**12.76**	**127.06**	**25.52**	**66.73**	**161.06**	**130.27**	**173.82**	**34.61**	**56.02**	**34.28**	**45.80**
Non-Container Terminals	2.29	0.66	4.58	1.32	2.67	6.48	4.96	7.14	1.77	1.89	1.51	1.76
POLA (ALL Terminals)	**65.82**	**13.42**	**131.64**	**26.84**	**69.40**	**167.55**	**135.22**	**180.96**	**36.38**	**57.91**	**35.79**	**47.56**

2. High Utilization: In this scenario, the equipment was assumed to operate at higher utilization (16 hrs per day) throughout the year. The results for the high-utilization scenario are provided in Table 23, below.

Table 23. High-utilization scenario results

	Incremental Future Connected Load				Total Future Connected Load				Incremental Future Diversified Peak Demand			
POLA Tenants	50% by 2025		100% by 2030		50% by 2025		100% by 2030		50% by 2025 – Unmngd	100% by 2030 – Unmngd	50% by 2025 – Managed	100% by 2030 – Managed
	Battery (MW)	Grid (MW)	Battery (MW)	Grid (MW)	Battery (MW)	Grid (MW)	Battery (MW)	Grid (MW)	MW	MW	MW	MW
Terminal-1	20.21	0.00	40.42	0.00	20.40	41.34	40.61	41.34	28.06	28.04	28.06	28.04
Terminal-2	18.22	2.62	36.43	5.23	19.28	15.03	37.50	17.64	11.36	22.67	8.34	10.95
Terminal-3	30.03	5.89	60.07	11.78	30.03	29.64	60.07	35.53	18.66	37.23	17.37	23.14
Terminal-4	27.54	4.58	55.09	9.16	27.54	29.73	55.09	34.31	16.88	33.62	15.35	19.83
Terminal-5	20.68	3.05	41.36	6.11	20.71	20.12	41.39	23.18	12.22	24.83	11.02	13.96
Terminal-6	53.95	9.36	107.91	18.72	55.87	37.94	109.83	47.31	23.03	45.04	23.03	32.31
Six Terminals Total	**170.64**	**25.50**	**341.27**	**51.01**	**173.84**	**173.81**	**344.48**	**199.31**	**110.22**	**191.44**	**103.17**	**128.23**
Non-Container Terminals	9.46	1.32	18.91	2.64	9.84	7.14	19.29	8.46	5.38	9.77	5.04	6.54
POLA (ALL Terminals)	**180.09**	**26.82**	**360.18**	**53.64**	**183.68**	**180.95**	**363.77**	**207.77**	**115.60**	**201.21**	**108.20**	**134.77**

Energy Results

To calculate the annual energy use of each terminal in the above scenarios, the project team used the load shapes using EPRI's modified DEFT tool. The LADWP commercial EV A-3 rates, applicable to general service from the 34.5-kV system, were used for the annual electric utility bill analysis. The total amount of electricity in kWh used by electric CHE over a year is estimated from the unmanaged profiles. These profiles represent complete utilization of the fleet of CHE, putting an upper bound on the total energy use from CHE. The port may see lower utilization some of the time, resulting in lower electricity use. Table 24 through Table 26 provide the results of this analysis. Scenarios where CHE is powered by hydrogen fuel cell were also studied, and results are shown below (see subsection Hydrogen Fuel Cell Scenarios).

Table 24. Energy estimates from low-utilization scenario

	Incremental Future Diversified Peak Demand				Total Approx. Annual CHE Energy Use Estimate		Total Annual CHE Energy Use Estimate from DEFT				Total Annual CHE Electric Utility Bill Estimate			
POLA Tenants	50% by 2025 – Unmngd	100% by 2030 – Unmngd	50% by 2025 – Managed	100% by 2030 – Managed	50% by 2025 – Unmngd	100% by 2030 – Unmngd	50% by 2025 – Unmanaged	100% by 2030 – Unmanaged	50% by 2025 – Managed	100% by 2030 – Managed	50% by 2025 – Unmngd	50% by 2025 Managed	100% by 2030 – Unmngd	100% by 2030 – Managed
	MW	MW	MW	MW	GWh	GWh	GWh	GWh	GWh	GWh	million $	million $	million $	million $
Terminal-1	9.18	9.18	9.18	9.18	31.72	63.45	56.23	58.81	56.23	58.81	11.01	11.02	11.47	11.50
Terminal-2	3.16	6.32	2.79	3.88	16.38	32.76	20.69	31.91	20.69	31.33	4.08	3.97	6.45	5.82
Terminal-3	5.78	11.19	5.78	8.32	33.02	66.04	41.99	65.02	41.99	65.02	8.15	8.13	12.87	12.26
Terminal-4	5.02	9.17	5.02	7.52	27.67	55.33	36.00	54.25	36.00	54.25	7.02	6.99	10.81	10.22
Terminal-5	3.56	7.15	3.60	4.94	19.82	39.65	25.92	38.88	26.23	38.88	5.05	5.02	7.77	7.29
Terminal-6	7.91	13.01	7.91	11.96	47.14	94.28	55.75	89.00	55.75	89.00	10.77	10.83	17.43	16.88
Six Terminals Total	**34.61**	**56.02**	**34.28**	**45.80**	**175.76**	**351.51**	**236.58**	**337.87**	**236.89**	**337.29**	**46.08**	**45.96**	**66.80**	**63.97**
Non-Container Terminals	1.77	1.89	1.51	1.76	10.83	21.66	15.09	20.60	14.78	21.18	2.71	3.08	3.72	4.51
POLA (ALL Terminals)	**36.38**	**57.91**	**35.79**	**47.56**	**186.59**	**373.17**	**251.67**	**358.47**	**251.67**	**358.47**	**48.79**	**49.04**	**70.52**	**68.48**

Table 25. Energy estimates from high-utilization scenario

	Incremental Future Diversified Peak Demand				Total Approx. Annual CHE Energy Use Estimate		Total Annual CHE Energy Use Estimate from DEFT				Total Annual CHE Electric Utility Bill Estimate			
POLA Tenants	50% by 2025 – Unmngd	100% by 2030 – Unmngd	50% by 2025 – Managed	100% by 2030 – Managed	50% by 2025 – Unmngd	100% by 2030 – Unmngd	50% by 2025 – Unmanaged	100% by 2030 – Unmanaged	50% by 2025 – Managed	100% by 2030 – Managed	50% by 2025 – Unmngd	50% by 2025 Managed	100% by 2030 – Unmngd	100% by 2030 – Managed
	MW	MW	MW	MW	GWh	GWh	GWh	GWh	GWh	GWh	million $	million $	million $	million $
Terminal-1	28.06	28.04	28.06	28.04	91.85	183.71	173.69	183.19	173.69	183.19	32.27	32.33	33.98	34.09
Terminal-2	11.36	22.67	8.34	10.95	48.70	97.39	66.30	98.69	66.30	97.03	12.34	12.16	18.51	17.42
Terminal-3	18.66	37.23	17.37	23.14	94.77	189.53	130.52	193.00	130.52	193.00	24.17	24.22	36.01	35.07
Terminal-4	16.88	33.62	15.35	19.83	82.34	164.68	115.62	167.47	115.62	167.47	21.43	21.45	31.30	30.35
Terminal-5	12.22	24.83	11.02	13.96	58.92	117.83	82.75	119.69	83.06	119.69	15.34	15.31	22.39	21.62
Terminal-6	23.03	45.04	23.03	32.31	131.96	263.92	169.43	258.08	169.43	258.08	31.33	31.54	48.00	47.26
Six Terminals Total	**110.22**	**191.44**	**103.17**	**128.23**	**508.53**	**1017.07**	**738.31**	**1020.12**	**738.62**	**1018.46**	**136.88**	**137.01**	**190.19**	**185.81**
Non-Container Terminals	5.38	9.77	5.04	6.54	40.18	80.36	56.24	77.43	55.93	79.09	10.07	10.82	13.85	14.98
POLA (ALL Terminals)	**115.60**	**201.21**	**108.20**	**134.77**	**548.71**	**1097.43**	**794.55**	**1097.55**	**794.55**	**1097.55**	**146.95**	**147.83**	**204.04**	**200.79**

Table 26. Summary of energy and electricity bill estimates from low- and high-utilization scenarios

Scenario	Incremental Diversified Power Demand – Low Utilization (MW)	Incremental Diversified Power Demand – High Utilization (MW)	Annual Energy Consumption – Low Utilization (GWh)	Annual Energy Consumption – High Utilization (GWh)	Annual Electric Bill Estimate – Low Utilization ($M)	Annual Electric Bill Estimate – High Utilization ($M)
50% Electrified by 2025 – Unmanaged	36	116	252	795	49	147
50% Electrified by 2025 – Managed	36	108	252	795	49	148
100% Electrified by 2030 – Unmanaged	59	201	358	1098	71	204
100% Electrified by 2030 – Managed	48	135	358	1098	68	201

Hydrogen Fuel Cell Scenarios

In order to understand the impacts of hydrogen fuel cell on the electric demand for POLA, two simplified scenarios were considered. The two scenarios are as follows:

1. Hydrogen Fuel Cell CHE scenario A:

   All CHE is converted to hydrogen fuel cell, including busses, shuttle, and sweeper. However, the STS and RMG cranes and all equipment at China Shipping (WBCT) will remain electrified.

   In this scenario, hydrogen is used for straddle carriers, forklifts, top handlers, man lifts, vehicles (sweeper, trucks, UTRs), cranes (RTG), and side picks at the TraPac, Everport, Fenix, Yusen, and APM terminals. WBCT (China Shipping) will remain electrified.

2. Hydrogen Fuel Cell CHE scenario B:

   All CHE to go to hydrogen fuel cell conversion. The UTR, busses, shuttle, sweeper, and cranes (RTG, STS, and RMG) are to remain electric, as well as all equipment at China Shipping (WBCT).

   In this scenario, hydrogen is used for straddle carriers, forklifts, top handlers, man lifts, and side picks at all terminals except WBCT.

A simplified demand analysis was conducted using the available inventory of the equipment and the nameplate information.

The hydrogen fuel cell CHE scenario results are shown below along with all electrification and high-utilization scenarios to compare the electric demand variation in the hydrogen scenario with respect to the all-electric scenario.

1. 100% electrification with high equipment-utilization scenario

Table 27. 100% electrification by 2030 with high equipment-utilization scenario

	Incremental Future Connected Load				Total Future Connected Load				Incremental Future Diversified Peak Demand			
POLA Tenants	**50% by 2025**		**100% by 2030**		**50% by 2025**		**100% by 2030**		**50% by 2025 – Unmngd**	**100% by 2030 – Unmngd**	**50% by 2025 – Managed**	**100% by 2030 – Managed**
	Battery (MW)	**Grid (MW)**	**Battery (MW)**	**Grid (MW)**	**Battery (MW)**	**Grid (MW)**	**Battery (MW)**	**Grid (MW)**	**MW**	**MW**	**MW**	**MW**
Terminal-1	20.21	0.00	40.42	0.00	20.40	41.34	40.61	41.34	28.06	28.04	28.06	28.04
Terminal-2	18.22	2.62	36.43	5.23	19.28	15.03	37.50	17.64	11.36	22.67	8.34	10.95
Terminal-3	30.03	5.89	60.07	11.78	30.03	29.64	60.07	35.53	18.66	37.23	17.37	23.14
Terminal-4	27.54	4.58	55.09	9.16	27.54	29.73	55.09	34.31	16.88	33.62	15.35	19.83
Terminal-5	20.68	3.05	41.36	6.11	20.71	20.12	41.39	23.18	12.22	24.83	11.02	13.96
Terminal-6	53.95	9.36	107.91	18.72	55.87	37.94	109.83	47.31	23.03	45.04	23.03	32.31
Six Terminals Total	**170.64**	**25.50**	**341.27**	**51.01**	**173.84**	**173.81**	**344.48**	**199.31**	**110.22**	**191.44**	**103.17**	**128.23**
Non-Container Terminals	9.46	1.32	18.91	2.64	9.84	7.14	19.29	8.46	5.38	9.77	5.04	6.54
POLA (ALL Terminals)	**180.09**	**26.82**	**360.18**	**53.64**	**183.68**	**180.95**	**363.77**	**207.77**	**115.60**	**201.21**	**108.20**	**134.77**

Notes and assumptions:

1. Connected load is the aggregated nameplate rating of all the electric equipment. It is typically much higher than the electric supply capacity since not all electric equipment of all customers is used simultaneously.
2. Established based on the terminal inventory. Includes the AMP and reefer loads.
3. Assumes 2.5-MW/AMP connector, 6 kW/reefer at 0.5 demand factor. This also includes the maximum AMP loads that can be connected per terminal at a given time.
4. Other loads are calculated as columns (B + C) minus column D (other loads include CHE loads, including yard trucks, cone vehicles, and sweepers, but not the building loads).
5. Actual measured data from each terminal obtained from LADWP meter data.
6. Excludes ISs marked as dedicated for AMP loads.
7. Calculated based on the equipment inventory and assumed kW demand by equipment type. These incremental future loads do not include AMP or reefer loads.
8. Sum of the total current connected load (columns B + C) and the incremental future connected load (columns [H + I] or [J + K]).
9. The peak demand of the CHE load profiles based on the DEFT tool simulation.
10. Approximate annual electric energy of the new CHE loads that are converted 100% from fossil fuel to electric (AMP and reefer loads are not included).
11. Calculated using DEFT tool with high utilization (utilization factor assumptions are provided in the "Load Estimator" tab Column R).
12. Calculated using *only* CHE loads under the LADWP EVA3 tariff. This would be the annual cost of powering electric CHE without any discounts or individually negotiated rates.

*Rounding errors in calculations can lead to slight variations in the numbers.

**High-utilization scenario: This scenario was calculated using an 80–90% utilization rate of the CHE equipment based on the guidance received from LAHD.

2. Hydrogen Fuel Cell CHE scenario A

The results from the hydrogen fuel cell CHE scenario A are summarized in Table 28, below. It can be seen that hydrogen scenario A significantly reduces the electric demand compared to the all-electric scenario. This is because most of the CHE equipment will be converted to hydrogen fuel cell and it eliminates the need for chargers, which are required for the battery electric equipment. The existing electric equipment at the terminals is not converted to hydrogen fuel cell.

Table 28. High-utilization electric demand under hydrogen fuel cell CHE scenario A

	Incremental Future Connected Load		Total Future Connected Load		Incremental Future Diversified Peak Demand	
POLA Tenants	**100% by 2030**		**100% by 2030**		**100% by 2030 – Unmngd**	**100% by 2030 – Managed**
	Battery (MW)	**Grid (MW)**	**Battery (MW)**	**Grid (MW)**	**MW**	**MW**
Terminal-1	0.00	0.00	0.19	41.34	5.83	5.83
Terminal-2	0.00	0.00	1.06	12.41	3.06	1.88
Terminal-3	0.00	0.00	0.00	23.75	5.26	3.91
Terminal-4	55.09	9.16	55.09	34.31	17.42	14.29
Terminal-5	0.00	0.00	0.03	17.07	3.63	2.51
Terminal-6	0.00	0.00	1.92	28.58	4.98	4.58
Six Terminals Total	**55.09**	**9.16**	**58.29**	**157.46**	**40.19**	**33.00**
Non-Container Terminals	0.00	0.00	0.38	5.82	0.97	0.90
POLA (ALL Terminals)	**55.09**	**9.16**	**58.67**	**163.29**	**41.16**	**33.90**

3. Hydrogen fuel cell CHE scenario B

The results from hydrogen fuel cell CHE scenario B are summarized in Table 29, below. It can be seen that hydrogen scenario B significantly reduces the electric demand compared to the all-electric scenario. This is because most of the CHE equipment will be converted to hydrogen fuel cell and it eliminates the need for chargers, which are required for the battery electric equipment. The existing electric equipment at the terminals is not converted to hydrogen fuel cell. The hydrogen fuel cell CHE scenario B has higher electric demand because the UTR, busses, shuttle, sweeper, and cranes (RTG, STS, and RMG), as well as all equipment at China Shipping (WBCT), are to remain electric and not be converted to hydrogen fuel cell.

Table 29. High-utilization electric demand under hydrogen fuel cell CHE scenario B

	Incremental Future Connected Load		Total Future Connected Load		Incremental Future Diversified Peak Demand	
POLA Tenants	100% by 2030		100% by 2030		100% by 2030 – Unmngd	100% by 2030 – Managed
	Battery (MW)	Grid (MW)	Battery (MW)	Grid (MW)	MW	MW
Terminal-1	4.70	0.00	4.89	41.34	15.82	15.82
Terminal-2	12.99	5.23	14.06	17.64	13.03	6.29
Terminal-3	20.12	11.78	20.12	35.53	21.68	13.47
Terminal-4	55.09	9.16	55.09	34.31	33.62	19.83
Terminal-5	11.65	6.11	11.67	23.18	13.40	7.54
Terminal-6	21.24	18.72	23.16	47.31	20.20	14.49
Six Terminals Total	**125.79**	**51.01**	**128.99**	**199.31**	**117.75**	**77.44**
Non-Container Terminals	6.43	2.64	6.81	8.46	5.38	3.60
POLA (ALL Terminals)	**132.22**	**53.64**	**135.80**	**207.77**	**123.13**	**81.04**

Conclusions

The simplified hydrogen fuel cell CHE scenarios A and B show significant electric demand reduction compared to the all-electric, high-utilization scenario. Scenario A shows at least 74% reduction in the incremental future diversified peak demand compared to the all-electric, high-utilization case, and scenario B at least 38% reduction.

Table 30. Comparison of the hydrogen scenario electric demand with the all-electric, high-utilization scenario for incremental future diversified peak demand (for the six terminals)

Scenarios	100% by 2030 – Unmanaged (MW)	Variation Compared to All-Electric Scenario	100% by 2030 –Managed (MW)	Variation Compared to All Electric Scenario
High Utilization and Full Electrification	191.44		128.23	
Hydrogen Scenario A	40.19	-79.05%	33.00	-74.26%
Hydrogen Scenario B	117.75	-38.49%	77.44	-39.60%

The conclusions of the tenant zero emission modeling are the following:

- Implementing perfect managed charging could reduce the peak electricity consumption from CHE by about 29% on a two-shift schedule.
- Achieving this would be impractically difficult in any real implementation, but demonstrates the potential value of managing the CHE charging to reduce the peak demands.
- The uncertain data inputs to this analysis result in uncertain outputs, which impact the grid analysis.
- A simplified analysis of two hydrogen fuel cell CHE scenarios shows that there is a tremendous potential to lower the electric peak demand, by as much as 79% in scenario A and 38% in scenario B when compared to all-electrification scenarios by 2030. Detailed analysis needs to be conducted to understand the grid impacts of the hydrogen fuel cells.
- For hydrogen scenario A, there will not be a need for a second bank installation (even with an unmanaged charging profile). For hydrogen scenario B, there may be a need for a new RS-Q bank under an unmanaged scenario.
- The hydrogen scenarios assume the majority of hydrogen will be imported to the site. The pumping and importing electricity requirements are yet unknown and should be further investigated to determine actual feasibility and any electric load they may require.
- It is recommended that LADWP and POLA pursue a more in-depth analysis of hydrogen technology maturity, resource availability, equipment and vehicle availability at scale, and the hydrogen storage and pumping infrastructure required to be in place to ensure reliability and redundancy to maintain critical port terminal operations.

9 GRID IMPACT ANALYSIS – UPDATED LOAD MODELS

This section extends the grid impact analysis presented in section 6 by applying different assumptions on the POLA tenant CHE loads and the RS-Q other loads. In particular, this section presents the grid impact analysis results for the seven scenarios introduced in section 6 applying the assumptions in section 6 with the following two modifications: 1) RS-Q loads were modeled with 2022 SCADA measurements, and 2) POLA tenant CHE loads were modeled with updated equipment inventory and assumptions. An overview of these two modifications is provided in the two following subsections.

RS-Q Load Modeling Using 2022 SCADA Measurements

In this subsection, the RS-Q (non-CHE loads) were modeled based on LADWP circuit SCADA measurements from 2022, whereas 2021 SCADA data was used in sections 5–7. Load data from 2022 were expected to reflect normal operation better than 2021 data, which were impacted by the global COVID-19 pandemic. In addition, the 2022 bank and circuit measurements were more consistent with each other, leading to reduced uncertainty in the overall load model.

The team used the same approach discussed in section 5 to create the 2022 load shapes, with a few differences as follows:

- kW load profiles for DS-3, DS-89, DS-119, DS-121, IS-4301, and IS-4798 were created using the sum of circuit measurements feeding each DS or IS, rather than SCADA DS or IS bank measurements, as was done in section 5.
- Due to missing data for all measurements at IS-3185 and IS-5120 for most of 2022, it was impossible to directly create accurate load shapes for those stations and the circuits that connect to them, namely POR-PED 1, HUG-PED 1, HAR-PED 9, and TER-PED 1. Therefore, a single load shape was created to represent all of these circuit and IS loads using the sum of the measurements entering the area, including the following:
  - HAR-PED 9 leaving RS-Q
  - TER-PED 1 leaving DS-121
  - HUG-PED 1 leaving IS-4301
- The area load shape was then allocated to each circuit and IS proportionally based on each IS or circuit’s peak load calculated during the first few weeks of January, when measurement data was available. Thus, each load shape in the area follows the same shape with different magnitudes. Due to the incomplete measurement data, the loads in this area are subject to increased uncertainty.
- Since circuit and bank measurements matched more closely than in 2021, it was not necessary to scale the circuit kW load profiles to match the RS-Q bank B kW SCADA data.

The created load models were validated by comparing the simulated and measured loads at bank B and at one end of each circuit. The loading matches well at bank B and at all San Pedro circuits, and reasonably well for the circuits at Terminal Island. The remaining discrepancy between the simulated and measured circuit-level loading is attributed to issues in the SCADA data discussed above and any inaccuracies in the circuit model.

It is worth noting that the RS-Q bank B peak load modeled with the 2022 SCADA measurements is 122.2 MW, which is slightly higher than the peak load of 119.0 MW modeled with the 2021 SCADA measurements in section 6. This slight difference in the RS-Q bank B peak load and the differences between the 2021 and 2022 load profile should be considered when comparing results between sections 6 and 8 and between sections 7 and 9.

CHE Load Profiles

The analysis presented in this subsection also applies POLA tenant CHE charging load profiles that were modeled with updated tenant equipment inventory and assumptions. A detailed discussion of the updated inventory and other assumptions can be found in section 8. A brief overview of the updated CHE load models is provided as follows.

Figure 55 compares the aggregated CHE load profiles of all six tenants with unmanaged and managed charging and with 50% and 100% CHE electrification levels. The updated assumptions have resulted in considerably lower total CHE active and reactive power loads. The reduced CHE loads are expected to result in fewer grid impacts in sections 8 and 9 compared to sections 6 and 7.

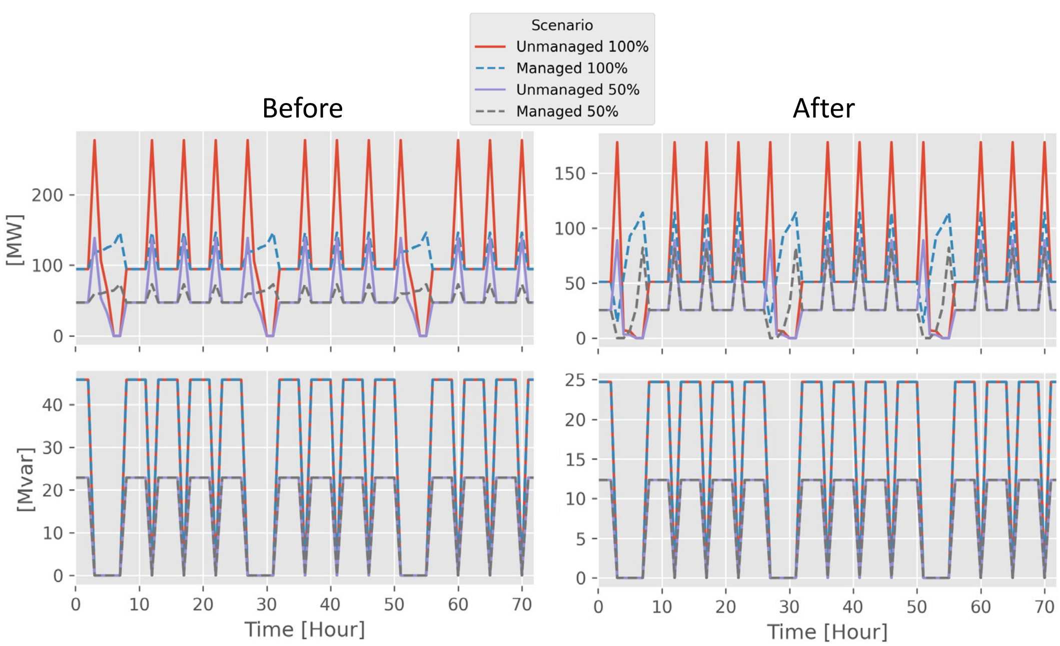


Figure 55. Total CHE load of the six tenants over three days

Table 31 compares the CHE peak MW and MVAR loads before and after updating the load models. The updated CHE load models resulted in considerably lower peak values in all cases except the 50% managed electrification scenario.

Table 31. Peak MW and MVAR of the total CHE loads before and after updating the load models

Scenario	Peak MW		Peak MVAR	
	Before	After	Before	After
MW unmanaged 50%	138	89	23	12
MW managed 50%	73	82	23	12
MW unmanaged 100%	277	178	46	25
MW managed 100%	146	114	46	25

Identically to section 6, the results presented in this subsection do not consider any future grid upgrades and consider only the single future spot load identified in section 6. Also identically to section 6, the grid impact analysis presented in this subsection was conducted with the OpenDSS model presented in section 5 using yearly 8760-hr QSTS simulations for each of the seven scenarios. As discussed in sections 5 and 6, this assessment focused only on the 34.5-kV level. The 4.8-kV level, POLA tenant side, and so on were not analyzed. The following subsections discuss the grid impact analysis results for the RS-Q banks, the three grid areas, overloads, and voltages.

RS-Q Bank Loading

Figure 56 compares the RS-Q banks A, B, and C peak loads before and after updating the CHE and RS-Q load models. As expected, the bank peak loads have considerably reduced.

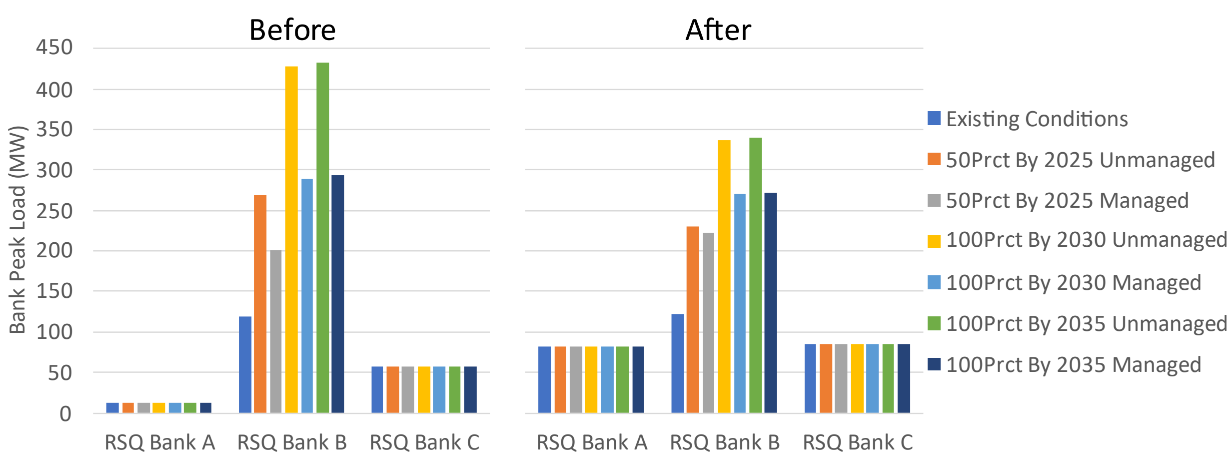


Figure 56. RS-Q bank peak loads for the analyzed scenarios before (left) and after (right) updating the CHE and RS-Q load models

Table 32 lists the bank B peak loads and the number of additional 160-MVA RS-Q banks required in addition to the existing banks A, B, and C before and after updating the load models. While the bank peak loads have considerably reduced after updating the load models, the number of additional RS-Q banks has not changed.

Table 32. Bank peak loads and the number of additional RS-Q banks required before and after updating the load models

Scenario	Before Updating the Load Models		After Updating the Load Models	
	Bank B Peak Demand (MW)	Number of Additional 160-MVA Banks Required[48]	Bank B Peak Demand (MW)	Number of Additional 160-MVA Banks Required[48]
Scenario 1: Existing System Conditions (2021)	119	0	122	0
Scenario 2: 50% Electrification by 2025 – Unmanaged	269	1	230	1
Scenario 3: 50% Electrification by 2025 – Managed	201	1	222	1
Scenario 4: 100% Electrification by 2030 – Unmanaged	428	2	337	2
Scenario 5: 100% Electrification by 2030 – Managed	289	1	270	1
Scenario 6: 100% Electrification by 2035 – Unmanaged	432	2	340	2
Scenario 7: 100% Electrification by 2035 – Managed	293	1	272	1

Figure 57 shows RS-Q bank B load duration curves[49] for the analyzed scenarios before and after updating the load models. The updated load models resulted in the load duration curves shifting lower on the *y*-axis, but the general shapes of the curves are quite similar to the earlier curves.

[48] These numbers are calculated based on the bank B peak demand, assuming 160-MVA capacity for the existing and new banks and that no load is shifted from bank B to bank A or C.

[49] The load duration curve presents the loads over a period of time, sorted in descending order. The load duration curve is useful in illustrating the frequency with which a given load value is exceeded.

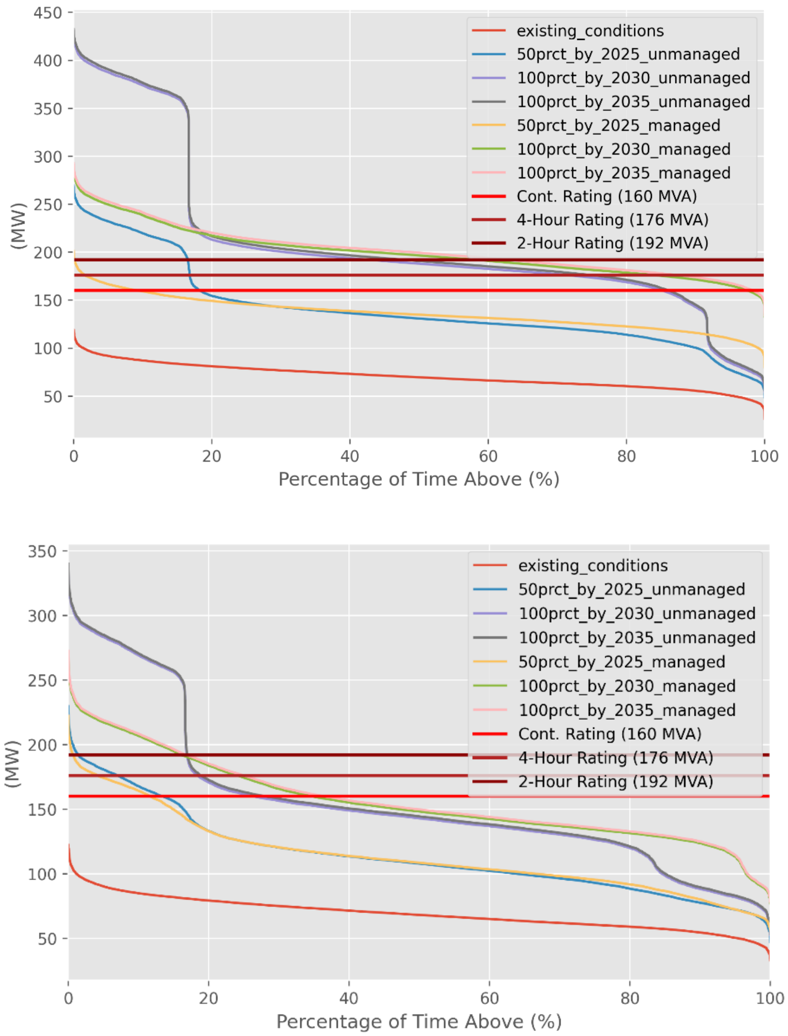


Figure 57. RS-Q bank B load duration curves for the analyzed scenarios before (top) and after (bottom) adjusting the load models

Figure 58 correlates the aggregated total CHE load of all tenants with the RS-Q bank B existing load over the year after the load models have been updated. Figure 27 shows the respective results before updating the load models. As before the load models were updated, the peak CHE charging load coincides with high existing bank loading, which means that CHE charging increases the bank B peak load nearly by the CHE peak load. In other words, there is very limited diversity between the CHE peak load and the bank B existing peak load.

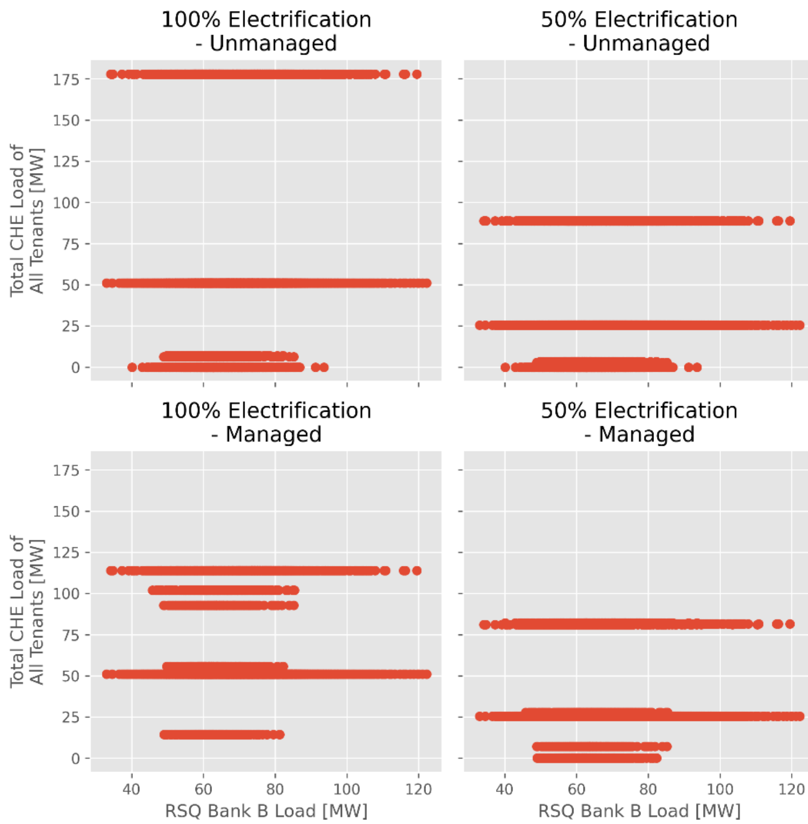


Figure 58. Total CHE load of all tenants versus RS-Q bank B existing load

Grid Area Loading

This subsection shows the loading for the three grid areas (San Pedro, Terminal Island, and Wilmington) illustrated in Figure 24. Figure 59 shows the peak demands in the three grid areas for the seven scenarios analyzed. The red lines indicate the total capacity of the existing tie-lines between Wilmington and Terminal Island (about 88 MW) and between Wilmington and San Pedro (about 103 MW).[50] The following conclusions are similar to the ones reached before updating the load models:

- The future electrification scenarios significantly increased the peak demand of the Terminal Island area, but less so the peak demands of the San Pedro and Wilmington areas.
- All future scenarios exceed the total tie-line capacity to Terminal Island, requiring additional circuits between Wilmington and Terminal Island.

[50] The capacity was calculated by adding the capacities of the individual tie-lines calculated from the rated ampacity of the circuit, I_{normal}, with: $P_{normal} = \sqrt{3}(34.5\ kV)(I_{normal})$(0.98). This calculation assumes PF = 0.98 and nominal voltage.

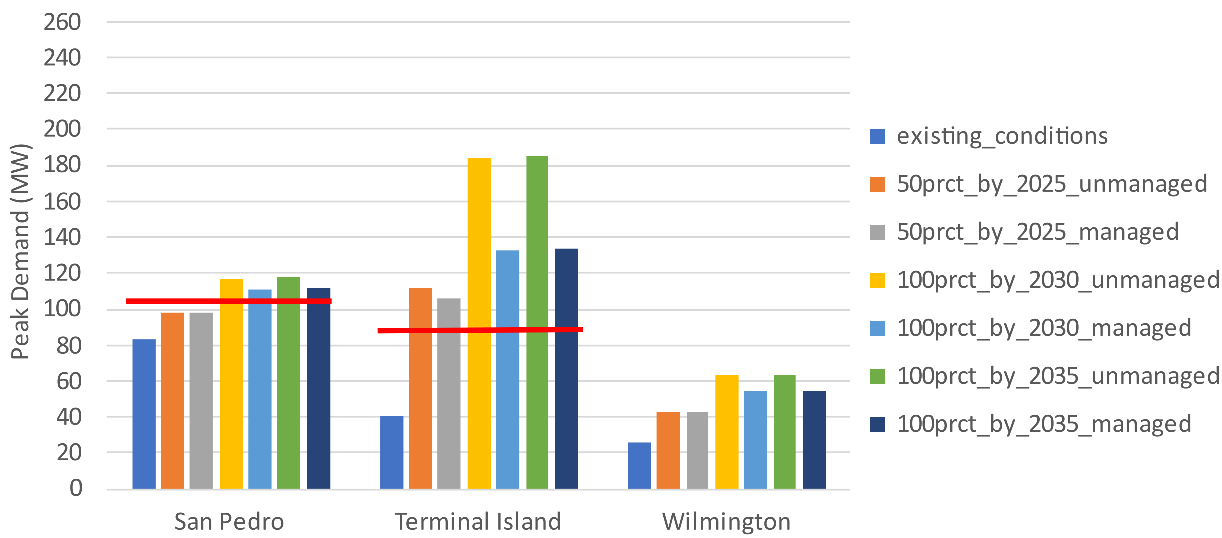


Figure 59. Peak demand of the three grid areas (the red lines indicate the approximate total power transfer capacity from Wilmington to either San Pedro or Terminal Island)

Table 33 lists the minimum number of additional 400-amp circuits required from Wilmington to Terminal Island and to San Pedro in the seven analyzed scenarios. To accommodate the load in the future scenarios, at least one to five lines and zero to one additional lines are required from Wilmington to Terminal Island and San Pedro, respectively. Fewer lines are required to San Pedro given that more CHE loads are added in Terminal Island. The numbers listed in Table 33 represent the minimum number of new 400-amp lines. In practice, the number of lines required may be higher due to the following reasons:

- Some of the circuits transferring power from Wilmington to Terminal Island and San Pedro also supply loads on the Wilmington side that consume the circuit capacity. The overloads and circuit-level loading are analyzed in more detail in the following sections.
- This simple analysis assumes that powers are perfectly balanced between the circuits. In practice, there is a varying degree of loading unbalance between the circuits. Note that the meshed nature of the RS-Q 34.5-kV system makes it challenging to balance the loading between the circuits. The grid upgrades required are analyzed in more detail in section 10.

Table 33. Minimum number of new 400-amp lines required from Wilmington to Terminal Island and San Pedro

Scenario	Minimum Number of New 400-amp Lines Required from Wilmington to	
	Terminal Island	San Pedro
Existing conditions	0	0
50% by 2025 – unmanaged	1	0
50% by 2025 – managed	1	0
100% by 2030 – unmanaged	5	1
100% by 2030 – managed	2	1
100% by 2035 – unmanaged	5	1
100% by 2035 – managed	2	1

Overloads

Figure 60 shows the total length of all lines overloaded at some time instance for the seven scenarios. Depending on the future scenario, 15.5–37.5 mi (24.9–60.4 km) of the RS-Q lines become overloaded. This corresponds to 12–31% of all the RS-Q lines in the OpenDSS model.

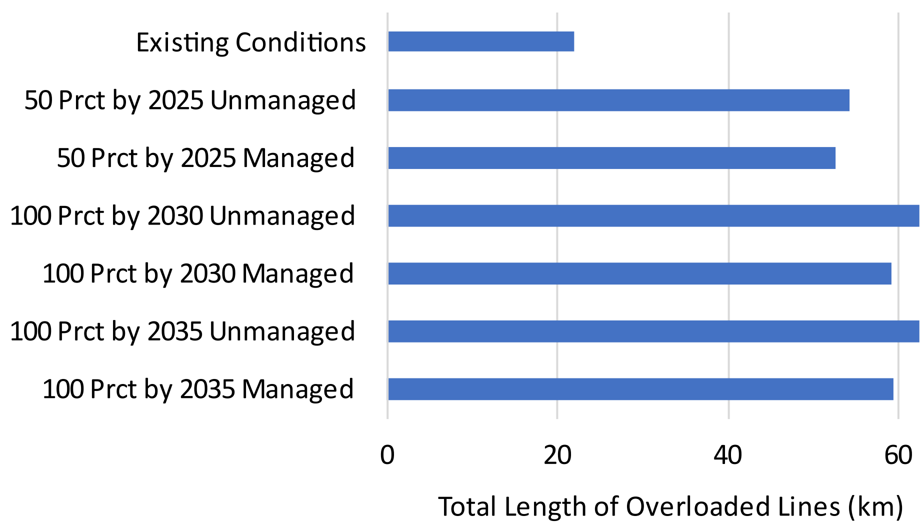
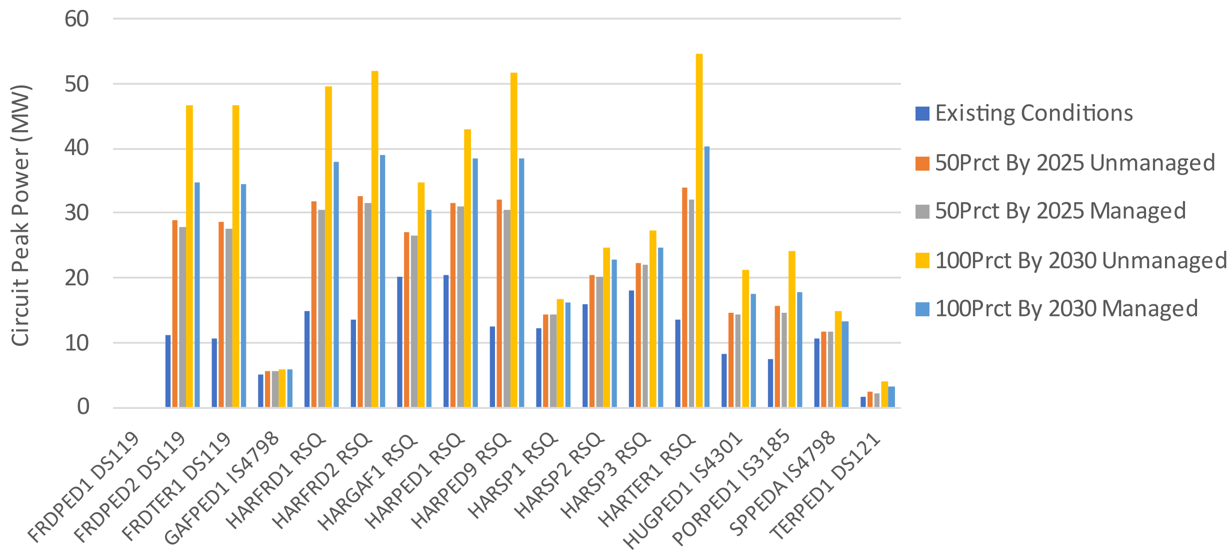


Figure 60. Total length of all lines overloaded at some time instance for the seven scenarios

Figure 61 shows the peak power and peak current at the sending end[51] of each of the 17 circuits in the RS-Q model for five of the scenarios.[52] The peak power and current are considerably higher for the 100% electrification scenarios compared to 50% electrification scenarios. The peak power and current are also considerably higher for the unmanaged scenarios compared to the managed scenarios. Note that Figure 61 shows the peak power and current at the sending end of each circuit. Depending on the circuit, the highest power or current may occur at another location of the circuit.

[51] The sending end locations are listed next to the circuit name in Figure 34.

[52] The circuits dedicated to supplying the two refineries (HAR PED A, HAR PED B, HAR PED C, HAR PED D, HAR PED E, HAR PED F, HAR PED G, HAR PED H) are not shown, as they are not of interest to this study. The 2035 scenarios are not shown, as their results are nearly identical to the 2030 scenarios.



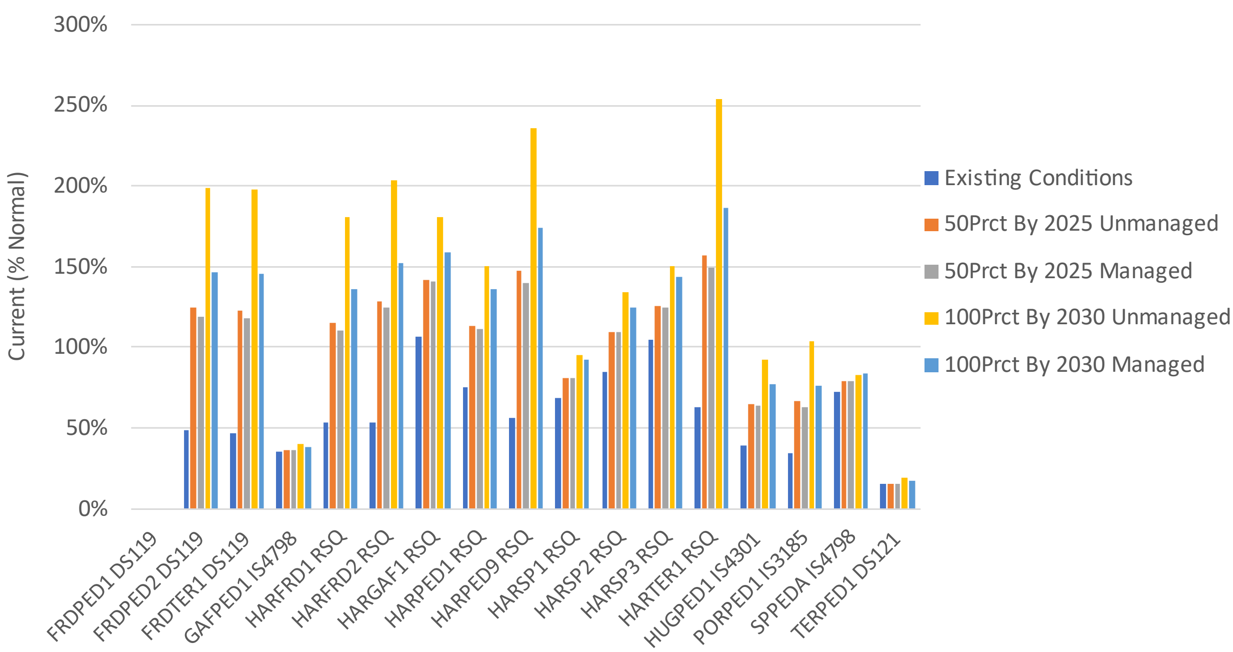


Figure 61. Peak power (top) and peak current (bottom) at the sending end of each circuit

The maximum MVA overloads over the normal and emergency ratings for each of the 17 circuits and 7 scenarios are listed in Table 34 and Table 35, respectively. Values listed as “0” correspond to maximum loading below 100% of the normal rating (Table 34) and emergency rating (Table 35). The following observations can be made:

- Only two circuits (HAR-GAF 1 and HAR-SP 3) are overloaded in scenario 1 (existing conditions).

- Depending on the future scenarios, the maximum loading exceeds the following:
  - 100% of the normal rating for 10–11 circuits
  - 150% of the normal rating for 0–11 circuits
  - 200% of the normal rating for 0–6 circuits
- Some circuits (e.g., FRD-TER 1 and HAR PED 9) experience much higher overloads than others.
- The overloads are higher with 100% electrification scenarios compared to 50% electrification scenarios. Similarly, the overloads are higher with unmanaged charging compared to managed charging.
- Some new circuits may be required to accommodate the 50% electrification scenarios analyzed. Several new circuits may be required to accommodate the 100% electrification scenarios analyzed. The required grid mitigation measures are analyzed in section 10.

Table 34. Maximum MVA overloads over normal ratings[53] for each circuit and scenario, and the number of circuits overloaded 0 MVA, 10 MVA, and 20 MVA above the line normal ampere rating

Circuit	Existing Conditions	50 Prct by 2025 Unmanaged	100 Prct by 2030 Unmanaged	100 Prct by 2035 Unmanaged	50 Prct by 2025 Managed	100 Prct by 2030 Managed	100 Prct by 2035 Managed
FRDPED1	0	0	0	0	0	0	0
FRDPED2	0	6	23	23	4	11	11
FRDTER1	0	16	45	45	14	25	25
GAFPED1	0	0	0	0	0	0	0
HARFRD1	0	4	22	22	3	10	10
HARFRD2	0	7	26	26	6	13	13
HARGAF1	1	8	15	16	8	11	12
HARPED1	0	4	14	15	3	10	11
HARPED9	0	10	29	30	9	16	16
HARSP1	0	0	1	1	0	0	0
HARSP2	0	2	7	7	2	5	5
HARSP3	1	5	10	10	5	8	8
HARTER1	0	12	33	33	11	18	19
HUGPED1	0	0	0	0	0	0	0
PORPED1	0	0	0	0	0	0	0
SPPEDA	0	0	0	0	0	0	0
TERPED1	0	0	0	0	0	0	0
# Circuits Over NormAmps	2	10	11	11	10	11	11
# Circuits 10 MVA Over NormAmps	0	3	8	9	2	7	7
# Circuits 20 MVA Over NormAmps	0	0	6	6	0	1	1

[53] The table values represent the maximum (over all the lines of a given circuit and the 8760 hrs of the year) MVA overload, where the MVA overload (of a given line and time instance) is calculated with: $\mathrm{MVAOverLoad} = \frac{\sqrt{3}\times 34.500\times I_{OverNormalRating}}{1000}$, and $I_{OverNormalRating}$ is the line amperes over the line normal ampere rating.

Table 35. Maximum MVA overloads over emergency ratings[54] for each circuit and scenario, and the number of circuits overloaded 0 MVA, 10 MVA, and 20 MVA above the line emergency ampere rating

Circuit	Existing Conditions	50 Prct by 2025 Unmanaged	100 Prct by 2030 Unmanaged	100 Prct by 2035 Unmanaged	50 Prct by 2025 Managed	100 Prct by 2030 Managed	100 Prct by 2035 Managed
FRDPED1	0	0	0	0	0	0	0
FRDPED2	0	0	17	18	0	5	6
FRDTER1	0	11	39	40	8	19	19
GAFPED1	0	0	0	0	0	0	0
HARFRD1	0	0	18	18	0	6	6
HARFRD2	0	3	22	22	2	9	9
HARGAF1	0	5	12	13	5	8	9
HARPED1	0	0	10	11	0	6	7
HARPED9	0	7	26	26	5	13	13
HARSP1	0	0	0	0	0	0	0
HARSP2	0	0	3	4	0	2	2
HARSP3	0	2	7	7	2	5	5
HARTER1	0	10	30	31	8	16	16
HUGPED1	0	0	0	0	0	0	0
PORPED1	0	0	0	0	0	0	0
SPPEDA	0	0	0	0	0	0	0
TERPED1	0	0	0	0	0	0	0
# Circuits Over EmergAmps	0	7	10	10	6	10	10
# Circuits 10 MVA Over EmergAmps	0	1	8	8	0	3	3
# Circuits 20 MVA Over EmergAmps	0	0	4	4	0	0	0

[54] The table values represent the maximum (over all the lines of a given circuit and the 8760 hrs of the year) MVA overload, where the MVA overload (of a given line and time instance) is calculated with: $\mathrm{MVAOverLoad} = \frac{\sqrt{3} \times 34.500 \times I_{OverNormalRating}}{1000}$, and $I_{OverNormalRating}$ is the line amperes over the line normal ampere rating.

Voltage Impacts

As this assessment focuses on the 34.5-kV level, only the 34.5-kV-level voltage impacts were analyzed. At the 34.5-kV level, no undervoltages[55] and no overvoltages[56] were experienced in any of the analyzed scenarios.

Figure 62 shows the minimum voltages at the locations where the POLA tenant CHE equipment loads are added. The results for the 2035 scenarios are nearly identical to the 2030 scenarios, and hence they are not shown here. All the minimum voltages are well above 0.95 pu.

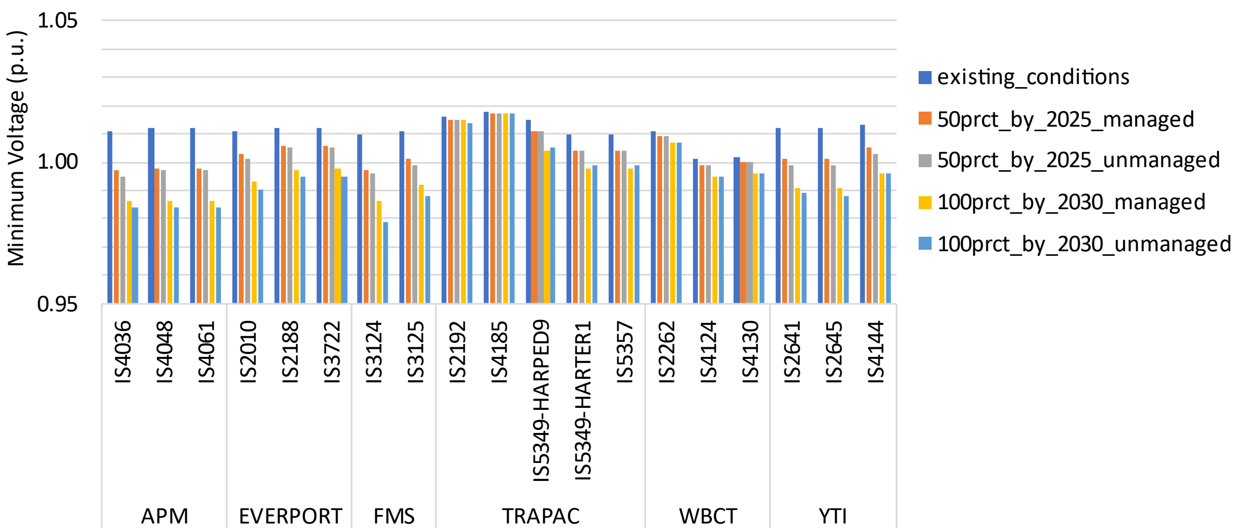


Figure 62. Minimum voltages at the tenant CHE connection points

[55] In all the scenarios, the secondary buses of two IS transformers experienced undervoltages. The undervoltages at these two buses are likely caused by inaccuracies in the load modeling and thus can be ignored. Voltages at all other buses in all scenarios and at all times were above 0.95 pu.

[56] One IS bus on circuit HAR PED D experienced overvoltages, but this is caused by inaccuracies in the circuit load modeling, and thus these overvoltages can be ignored.

10 MITIGATION SOLUTIONS – UPDATED LOAD MODELS

This section extends the grid mitigation analysis presented in section 7 with the updated RS-Q load and POLA tenant CHE load models analogous to how section 9 extends the grid impact analysis in section 6. First, the grid impacts of LADWP's future grid infrastructure upgrade plans are analyzed. Then, additional grid infrastructure upgrades required to address the grid impacts are analyzed. Last, the viability of using energy storage to reduce the CHE peak loads is analyzed.

Grid Impacts of LADWP's Future Grid Infrastructure Upgrade Plans

This subsection presents the grid impacts of LADWP's future grid infrastructure plans for the seven electrification scenarios.

RS-Q Bank Loading

Figure 63 shows the RS-Q bank peak loads for the seven analyzed scenarios with the future upgrades planned by LADWP. The following observations can be made:

- The updated load models have resulted in considerably lower bank B and bank D peak loads, which can be seen by comparing Figure 63 to Figure 41.
- In the 50% (managed and unmanaged) electrification scenarios, bank D is slightly overloaded, but other banks have plenty of capacity.
- In the 100% managed electrification scenarios, bank D is overloaded, but bank B is not.
- Banks B and D are overloaded in the 100% unmanaged electrification scenarios.

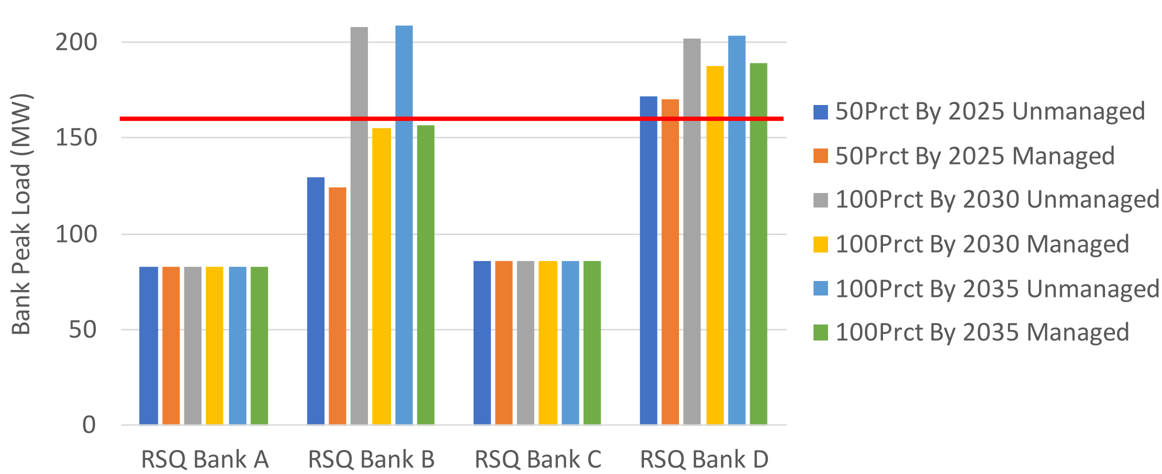


Figure 63. RS-Q bank peak loads for the analyzed scenarios with the future upgrades planned by LADWP

Table 36 lists the peak loads of the individual banks, total of banks B and D, and total of all banks. Table 36 also lists the number of new 160-MVA banks required, assuming perfect load balancing between the existing banks B and D or between all four banks. The following observations can be made:

- As expected, banks A and C peak loads are identical for all scenarios, but banks B and D peak loads increase considerably in the future electrification scenarios.
- The peak of the sum of banks B and D load is somewhat less than the sum of the peak loads of the individual banks B and D due to the non-coincidence of the bank peak loads. The same applies for the peak of the sum of all banks versus the sum of the peaks of individual banks.
- Perfect balancing of loads between banks B and D allows accommodating the 50% electrification scenarios, assuming no load growth beyond what is considered here. A new bank in addition to bank D would be required to accommodate the 100% electrification scenarios, which would trigger requiring an RS.
- Perfect balancing of loads between all four banks allows accommodating all the future electrification scenarios, assuming no load growth beyond what is considered here and the peak loads considered here.

Table 36. RS-Q bank peak loads and the number of additional RS-Q banks required

Scenario	Peak Load of Banks (MW)						Number of New 160-MVA Banks Required with Perfect Load Balancing Between Existing[57]	
	A	B	C	D	B + D	All Banks	Banks B and D	All Banks[58]
50% by 2025 – Unmanaged	82.6	129.8	85.6	171.9	289.4	352.5	0	0
50% by 2025 – Managed	82.6	124.0	85.6	170.4	282.1	345.2	0	0
100% by 2030 – Unmanaged	82.6	207.8	85.6	202.1	396.0	454.6	1	0

[57] These numbers are calculated based on the peak loads of banks B + D or all banks, assuming 160-MVA capacity for the existing and new banks.

[58] It is important to note that banks A and C, which each serve a large refinery, experience occasional high load spikes, as discussed in section 5. Moreover, as LADWP indicated, it may not be possible to move circuits from banks B and D to banks A and C for contractual reasons.

Table 36 (continued). RS-Q bank peak loads and the number of additional RS-Q banks required

100% by 2030 – Managed	**82.6**	**155.3**	**85.6**	**187.9**	**329.5**	**388.3**	**1**	**0**
100% by 2035 – Unmanaged	82.6	208.9	85.6	203.6	398.4	456.2	1	0
100% by 2035 – Managed	82.6	156.3	85.6	189.4	331.8	389.9	1	0

Table 37 illustrates the amount of peak load that would need to be moved from RS-Q banks B and D to banks A and C to keep banks B and D loads below their 160-MVA limit.

Table 37. Peak load that needs to be moved from RS-Q banks B and D to banks A and C to keep banks B and D loads below the 160-MVA limit[59]

Scenario	From Bank B to Banks A and C	From Bank D to Banks A and C	From Banks B and D to Banks A and C
50% by 2025 – Unmanaged	0	12	0
50% by 2025 – Managed	48	43	76
100% by 2030 – Unmanaged	49	44	79
100% by 2030 – Managed	0	11	0
100% by 2035 – Unmanaged	0	28	10
100% by 2035 – Managed	0	30	12

The remainder of this section focuses on required grid infrastructure upgrades, assuming that a sufficient amount of RS-Q bank capacity is provided in some way.

RS-Q Grid Area Loading

Figure 64 lists the peak demands in the three grid areas for the six future scenarios analyzed. The red lines indicate the total capacity of the tie-lines (includes the existing tie-lines and the tie-lines planned by LADWP) between Wilmington and Terminal Island (about 111 MW) and between Wilmington and San Pedro (about 218 MW).[60] As expected, the future electrification scenarios significantly increased the peak demand of the Terminal Island area, but less so the peak demands of the San Pedro and Wilmington areas. With the future upgrades that LADWP plans, there is more than enough capacity to San Pedro in all the scenarios. However, there is

[59] These values are calculated as a difference of the banks B and/or D peak MW loads and the 160-MVA loading limit.

[60] The capacity was calculated by adding the capacities of the individual tie-lines calculated from the rated ampacity of the circuit, I_{normal}, with: $P_{normal} = \sqrt{3}(34.5\ kV)(I_{normal})(0.98)$. This calculation assumes PF = 0.98 and nominal voltage.

insufficient capacity to Terminal Island in all future scenarios except the 50% managed electrification. In the 50% unmanaged charging scenario, there is almost enough tie-line capacity with the additional capacity required well within the accuracy of this assessment. These results suggest that no further tie-lines may be needed to San Pedro. These results also suggest that additional tie-lines to Terminal Island will be required at least in the 100% electrification scenarios, and the number of lines will vary considerably based on the electrification scenario.

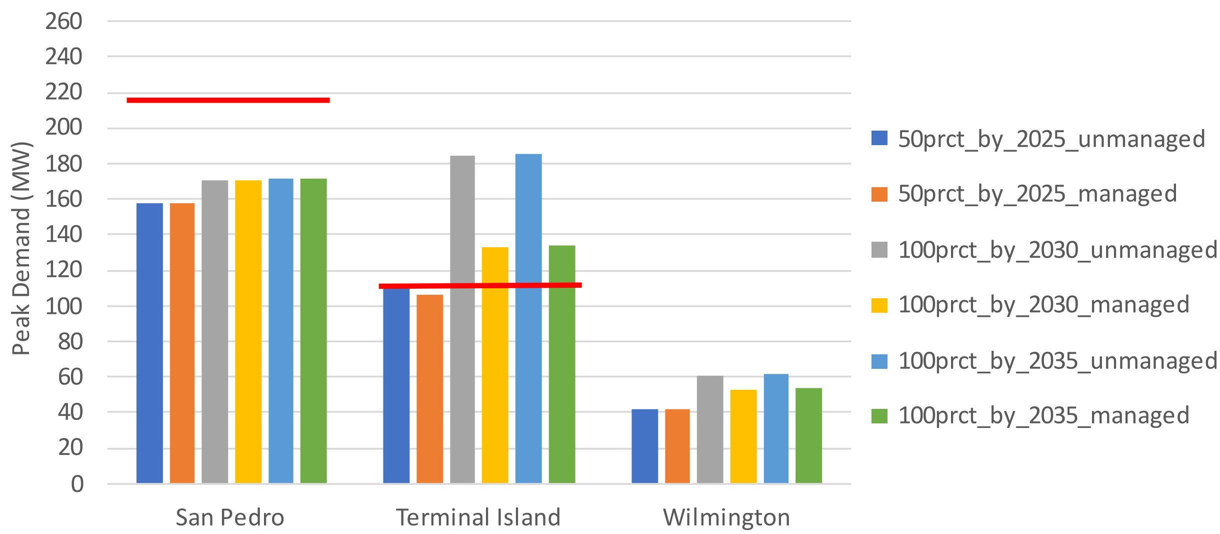


Figure 64. Peak demand of the three grid areas with the future upgrades that LADWP plans

Table 38 lists the minimum number of new 400-amp lines required from Wilmington to Terminal Island and San Pedro beyond the existing lines and the future lines planned by LADWP considered in this section. With the new lines that LADWP plans, no further lines from Wilmington to San Pedro may be needed. However, at least zero to four additional lines will be required from Wilmington to Terminal Island, depending on the future electrification scenario. The reader should note the caveats related to this simple type of calculations as discussed above in Table 15. Line upgrade requirements are analyzed in more detail later in this section.

Table 38. Minimum number of new 400-amp lines required from Wilmington to Terminal Island and San Pedro

Scenario	Minimum Number of New 400-amp Lines Required from Wilmington to	
	Terminal Island	San Pedro
50% by 2025 – unmanaged	1	0
50% by 2025 – managed	0	0
100% by 2030 – unmanaged	4	0
100% by 2030 – managed	1	0
100% by 2035 – unmanaged	4	0
100% by 2035 – managed	1	0

Overloads

Table 39 shows the maximum power flows (over the year) and the remaining capacity[61] for the tie-lines at the area boundaries. Note the future lines planned represented here (HARGAF2, HARIS4798, HARCT1, HARCT2, HARAS1, and HARIS5120).

All the tie-lines to San Pedro, except HARIS4798, have remaining capacity. The overload on HARIS4798 could be mitigated by balancing the loading between the circuits. The new tie-line to Terminal Island, HARIS5120, has unrealistically high power flow that skews the loading of the other tie-lines to Terminal Island. This in turn skews all other grid impacts, and hence the impacts with the future infrastructure upgrades planned by LADWP alone are not analyzed further.

The following subsections evaluate approaches to mitigating the grid impacts, including the overloads on HARIS4798 and HARIS5120 circuits, with additional grid infrastructure upgrades.

[61] The remaining capacity was calculated by subtracting the maximum power flow from the calculated line capacity.

Table 39. Maximum MVA overloads over normal ratings[62] for each circuit and scenario, and the number of circuits overloaded 0 MVA, 10 MVA, and 20 MVA above the line normal ampere rating

	50 Prct by 2025 Unmanaged	100 Prct by 2030 Unmanaged	100 Prct by 2035 Unmanaged	50 Prct by 2025 Managed	100 Prct by 2030 Managed	100 Prct by 2035 Managed
FRDPED1	0	0	0	0	0	0
FRDPED2	0	9	9	0	1	1
FRDTER1	9	32	33	7	16	16
GAFPED1	0	0	0	0	0	0
HARAS1	0	0	0	0	0	0
HARCT1	0	0	0	0	0	0
HARCT2	0	0	0	0	0	0
HARFRD1	0	8	8	0	0	0
HARFRD2	0	11	11	0	2	3
HARGAF1	0	0	0	0	0	0
HARGAF2	0	0	0	0	0	0
HARIS4798	8	14	15	8	12	12
HARIS5120	17	43	44	15	25	25
HARPED1	0	0	0	0	0	0
HARPED9	0	9	10	0	2	2
HARSP1	0	0	0	0	0	0
HARSP2	0	0	0	0	0	0
HARSP3	0	0	0	0	0	0
HARTER1	2	16	16	1	6	6
HUGPED1	0	9	9	0	1	1
PORPED1	0	0	0	0	0	0
SPGAF1	0	0	0	0	0	0
SPPEDA	12	14	15	12	15	15
TERPED1	3	23	23	1	8	8
# Circuits Over NormAmps	5	9	9	5	9	9
# Circuits 10 MVA Over NormAmps	2	6	6	2	3	3
# Circuits 20 MVA Over NormAmps	0	2	2	0	1	1

[62] The table values represent the maximum (over all the lines of a given circuit and the 8760 hrs of the year) MVA overload, where the MVA overload (of a given line and time instance) is calculated with: $\text{MVAOverLoad} = \frac{\sqrt{3}\times 34.500\times I_{OverNormalRating}}{1000}$, and $I_{OverNormalRating}$ is the line amperes over the line normal ampere rating.

Additional Grid Infrastructure Upgrades Required

As shown in the previous subsection, the future upgrades planned by LADWP are not sufficient to mitigate all the grid impacts in the analyzed future electrification scenarios. This subsection analyzes the additional grid infrastructure upgrades required to mitigate grid impacts that LADWP's planned future upgrades do not address. In particular, the team analyzed additional grid infrastructure upgrades required to accommodate 50% electrification by 2025 with managed charging or unmanaged charging. The other scenarios are not analyzed for the following reasons:

- No grid infrastructure upgrades are required for the existing conditions scenario.
- As discussed previously, all the 100% electrification scenarios would require rebalancing loads between all four transformer banks at RS-Q. It was out of the scope of this assessment to assess redistributing major parts of load between banks, as those changes would require contingency analysis to avoid impacts on reliability. The team recommends revisiting this assessment in a couple of years as additional information on the POLA tenant electrification strategies and other RS-Q area load growth becomes available.

The following subsections identify the additional grid infrastructure upgrades first for 50% electrification with managed charging and then for 50% electrification with unmanaged charging. This order was applied given that the managed charging requires less upgrades. The assessment focuses on the circuit upgrades, assuming that sufficient RS-Q bank capacity is available.

It is important to emphasize that the additional grid infrastructure upgrades were identified based on high-level analysis. All new lines are assumed to have the type of 1000_3C_CU_EPR and the normal rating of 400 amps. The results presented here are intended to illustrate the scope of the required grid infrastructure upgrades as opposed to recommending the least-cost technically viable grid infrastructure upgrades. Moreover, it was out of the scope of this assessment to evaluate or consider optimal line/cable routing, emergency operating conditions, protection considerations, ratings of new circuits, and various other practical considerations.

50% Electrification by 2025 with Managed Charging

The analysis presented previously indicated that it may be possible to accommodate scenario 3 (50% electrification by 2025 with managed charging) with no additional circuits (beyond the ones already planned by LADWP) by appropriately balancing the loading between circuits and, in particular, between the tie-lines from Wilmington to Terminal Island. However, it turned out to be quite challenging to mitigate all overloads at all QSTS time instances, as loads peak in different areas at different times of day and in different seasons. Therefore, one new line is proposed to mitigate overloads, assuming perfect, continuous load balancing will be impossible.

The following changes were observed to mitigate nearly all overloads:

- Add a load-balancing reactor with reactance of 0.9 ohms at the head of the new circuit HARIS5120 (the circuit added from RS-Q bank B to IS-5120).
- Add a load-balancing reactor with reactance of 2 ohms at the head of the new circuit HARIS4798 (the circuit added from RS-Q bank D to IS-4798).
- Add a second approximately 22,000-ft (6700-m) circuit from RS-Q bank B to IS-5120 "HARIS5120L2."
- Add a load-balancing reactor at the head of the circuit at RS-Q with reactance of 0.9 ohms.
- Transfer load at IS-4061 from FRD-TER 1 to HUG-PED 1.

The upgrades described above addressed practically all the overloads in this scenario. However, the following negligible overloads remained in the QSTS simulation:

- RS-Q bank D transformer experienced overloads of up to about 109% during 12 hrs of the year.
- Six load-serving transformers were overloaded. This is likely caused by inaccuracies in the load modeling.
- About 500 ft (150 m) of HAR-TER 1 lines were overloaded up to 101.5% for 4 hrs.
- About 300 ft (90 m) of TER-PED 1 lines were overloaded up to 100.5% for 2 hrs.

These overloads are well within the overall accuracy of this assessment and hence can be ignored. Moreover, it may be possible to mitigate the remaining overloads by better load balancing between the circuits and between banks B and D.

All the voltages were well within the ANSI range for this scenario.

To summarize, *these results suggest that it is possible to accommodate 50% electrification by 2025 with managed charging with one new tie-line from Wilmington to Terminal Island, along with minor load-balancing measures such as the ones listed here*.

50% Electrification by 2025 with Unmanaged Charging

Based on Table 20, at least one additional line from Wilmington to Terminal Island is expected to be required to accommodate this scenario. The following upgrades were identified for this scenario:

- Add a load-balancing reactor with reactance of 2 ohms at the head of the new circuit HARIS4798 (the circuit added from RS-Q bank D to IS-4798).
- Add a load-balancing reactor with reactance of 1.2 ohms at the head of HARIS5120 (the circuit added from RS-Q bank B to IS-5120) at RS-Q.

- Add a second approximately 22,000-ft (6700-m) circuit from RS-Q bank B to IS-5120 "HARIS5120L2." Add a load-balancing reactor at the head of the circuit at RS-Q with reactance of 1.2 ohms.
- Increase the reactance of the existing load-balancing reactor at HAR-TER 1 to 1.4 ohms.
- Transfer the CHE loads at IS-5349 from HAR PED 9 and HAR-TER 1 to HAR PED 1.
- Transfer load at IS-4061 from FRD-TER 1 to HUG-PED 1.
- Add a short line section to mitigate overloads on a short section of FRD-TER 1, as illustrated in Figure 65.

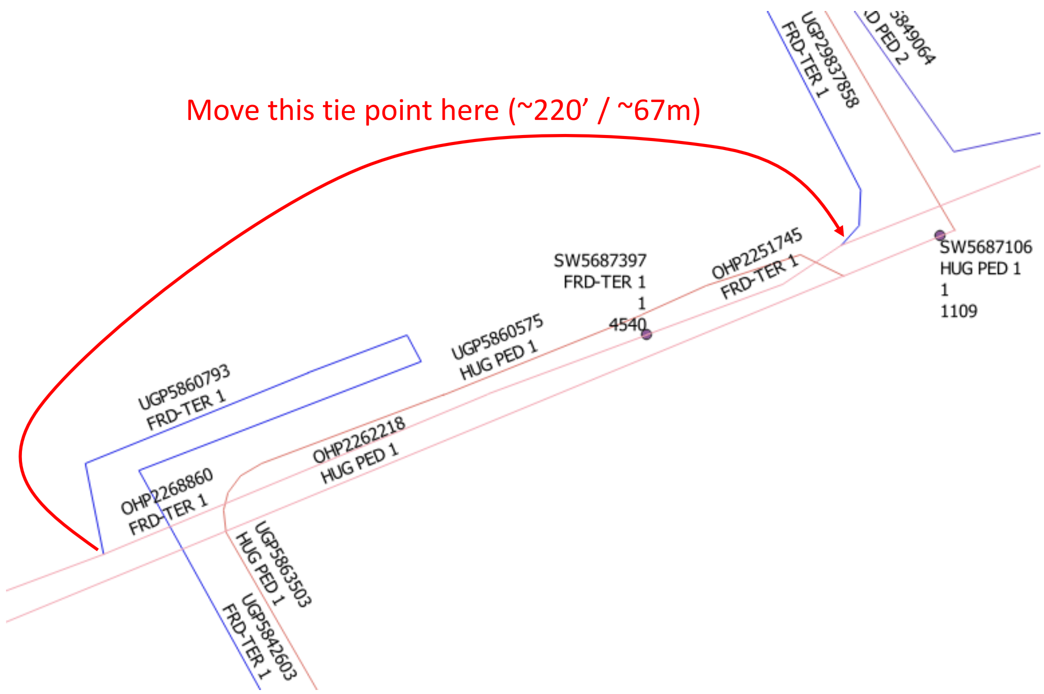


Figure 65. Grid infrastructure upgrade to mitigate overloads on a short line section of FRD-TER 1 near IS-4301

The upgrades described above addressed practically all the overloads in this scenario. However, the following negligible overloads still remained in the QSTS simulation:

- RS-Q bank D transformer experienced overloads of up to about 111.95% during 13 hrs of the year.
- Six load-serving transformers were overloaded. This is likely caused by inaccuracies in the load modeling.
- Two circuits experienced negligible overloads as follows:
  - TER-PED 1 1: up to 101.5% of normal, 4 hrs of the year
  - HAR-TER 1: about 101.9% of normal, 8 hrs of the year

These overloads are well within the overall accuracy of this assessment and hence can be ignored. Moreover, it may be possible to mitigate these remaining overloads by better balancing the loads between the RS-Q banks and circuits and/or with other no-cost or low-cost measures.

All the 34.5-kV-level voltages were within the ANSI range for this scenario.

To summarize, *these results suggest that it is possible to accommodate 50% electrification by 2025 with unmanaged charging with upgrades that consist of one new tie-line from Wilmington to Terminal Island along with switching operations and other relatively minor load-balancing measures*.

Energy Storage as a Mitigation Solution

As the results previously shown in this section indicate, a new RS may be needed to accommodate some of the analyzed future electrification scenarios. As constructing a new RS would be both very expensive and require a long lead time, it would be desirable to avoid the need for a new RS. This subsection analyzes avoiding the need for a new RS with a centralized energy storage system located at or near RS-Q, where the storage reduces the RS-Q bank peak loads and hence offsets the need for a new RS. To avoid the need for a new RS, the storage system would need to mitigate the overloads of banks B and D.[63]

Table 40 lists the power and energy capacities required and the corresponding cost estimates of an energy storage system mitigating the overloads of bank B, bank D, banks B and D separately (sum of bank B and bank D), and banks B and D jointly with perfect load balancing between the banks. The following observations can be made:

- To avoid the need for a new RS in the 50% electrification scenarios, a $13 million to $14 million energy storage system would be required without balancing banks B and D loads. With perfect load balancing between the banks, no energy storage system would be required.
- To avoid the need for a new RS in the 100% managed electrification scenarios, a $47 million to $52 million energy storage system would be required without balancing banks B and D loads. With perfect load balancing, the cost of the required storage system would be only $10 million to $12 million.
- To avoid the need for a new RS in the 100% unmanaged electrification scenarios, the energy storage system cost would be over $80 million even with perfect load balancing between banks B and D.
- Hydrogen fuel cell CHE scenarios studied in section 8 also indicate a new RS will not be required when ZE CHE is hydrogen fuel cell-powered.

[63] This analysis assumes that no load is transferred to banks A and C.

Table 40. Power and energy capacities required and the corresponding cost estimates of an energy storage system mitigating bank B, bank D, and banks B and D overloads[64]

RS-Q Bank Overloads Mitigated	Scenario	Peak Load (MW)	Load Limit (MW)	Minimum Storage Power Capacity (MW)	Minimum Storage Energy Capacity (MWh)	Energy Storage Cost Estimate (million $)
Bank B	50% by 2025 – unmanaged	130	160	0	0	0
	100% by 2030 – unmanaged	208	160	48	48	50
	100% by 2035 – unmanaged	209	160	49	49	51
	50% by 2025 – managed	124	160	0	0	0
	100% by 2030 – managed	155	160	0	0	0
	100% by 2035 – managed	156	160	0	0	0
Bank D	50% by 2025 – unmanaged	172	160	12	19	14
	100% by 2030 – unmanaged	202	160	42	128	66
	100% by 2035 – unmanaged	204	160	44	145	71
	50% by 2025 – managed	170	160	10	18	13
	100% by 2030 – managed	188	160	28	99	47
	100% by 2035 – managed	189	160	29	112	52

[64] The results for "Bank B" and "Bank D" indicate the storage requirements and associated costs for mitigating the overloads of the two banks separately, without any circuit/load transfers between the banks. The results for "Bank B and D Separately" indicate the storage requirements if loads were balanced for both banks B and D but separately, without any circuit/load transfers between the banks. Finally, the results for "Banks B and D Jointly with Perfect Load Balancing" indicate the storage requirements if loads were perfectly balanced between banks B and D.

Table 40 (continued). Power and energy capacities required and the corresponding cost estimates of an energy storage system mitigating bank B, bank D, and banks B and D overloads

RS-Q Bank Overloads Mitigated	Scenario	Peak Load (MW)	Load Limit (MW)	Minimum Storage Power Capacity (MW)	Minimum Storage Energy Capacity (MWh)	Energy Storage Cost Estimate (million $)
Banks B and D Separately	50% by 2025 – unmanaged	N/A	N/A	12	19	14
	100% by 2030 – unmanaged	N/A	N/A	90	176	116
	100% by 2035 – unmanaged	N/A	N/A	93	194	122
	50% by 2025 – managed	N/A	N/A	10	18	13
	100% by 2030 – managed	N/A	N/A	28	99	47
	100% by 2035 – managed	N/A	N/A	29	112	52
Banks B and D Jointly with Perfect Load Balancing	50% by 2025 – unmanaged	289	320	0	0	0
	100% by 2030 – unmanaged	396	320	76	76	80
	100% by 2035 – unmanaged	398	320	78	78	82
	50% by 2025 – managed	282	320	0	0	–
	100% by 2030 – managed	330	320	10	10	10
	100% by 2035 – managed	332	320	12	12	12

Conclusions

- The future RS-Q upgrades that LADWP plans are not sufficient alone to mitigate all the grid impacts from the considered future electrification scenarios. However, hydrogen fuel cell CHE scenarios studied in section 8 suggest that no new additional upgrades may be required when ZE CHE is hydrogen cell-powered.
- Proper balancing of loads between banks B and D allows accommodating the 50% electrification scenarios, assuming no load growth beyond what is considered here. A new bank in addition to bank D would be required to accommodate the 100% electrification scenarios. Alternatively, proper balancing of loads between all four RS-Q banks allows accommodating all of the 50% electrification and 100% electrification scenarios.

- The future upgrades that LADWP plans provide sufficient grid capacity in the San Pedro area. However, zero to four new tie-lines from RS-Q in Wilmington to Terminal Island will be required depending on the future electrification scenario.
- It is possible to accommodate 50% electrification by 2025 with managed or unmanaged charging with one new tie-line from Wilmington to Terminal Island in addition to the future upgrades planned by LADWP. Additional switching operations and other relatively minor upgrades are required.
- The power and energy requirements and cost of an energy storage system located at RS-Q to mitigate the RS-Q bank overloads were analyzed. The storage capacity requirements and cost could be reduced by proper balancing of loads between banks B and D. Combined with good load balancing between RS-Q banks B and D, energy storage may be a viable option to provide sufficient bank capacity in all scenarios except 100% unmanaged electrification.

11 COST-BENEFIT ANALYSIS OF MITIGATION SOLUTIONS

Overview

The goal of this task is to conduct a cost-benefit analysis for each type of electric-powered CHE technology, with simple payback and lifetime savings. These technologies are emerging, and hence their costs are changing relatively rapidly or are unavailable. Battery costs are continuing to decrease, which will reduce the costs of these technologies. Due to this rapidly changing and/or limited information, the project team is not able to perform this task at this time. However, this important task is recommended for future work.

Based on capital costs alone, the costs of electric technologies are higher than the fossil-fuel-based technologies. However, several grants are available through federal and state government agencies to help offset the capital costs and increase the market adoption of these electric technologies. This section lists some of these grants.

Grant Opportunities

The Green Shipping Challenge encourages governments, ports, and companies to prepare commitments to increase the transition to green shipping [11].

Major takeaways from the United States' commitment specific to port technologies include the following:

- The U.S. Inflation Reduction Act of 2022 includes a new $3 billion rebate and grant program at the U.S. EPA to provide funding for ZE port equipment or technology [30].
- The U.S. Department of Transportation announced more than $703 million to fund 41 projects in 22 states and one territory that will improve port facilities through the Maritime Administration's Port Infrastructure Development Program [31].

Other grant opportunities for port improvements with electrification include the following:

- Port Infrastructure Development Grants (PIDP) [32]
  - This is a grant program administered by the U.S. Maritime Administration (MARAD).
  - Funds for the PIDP are awarded to projects that improve the safety and reliability of the movement of goods into and out of a port.
  - For FY2022, the Infrastructure and Jobs Act appropriated $450 million to the PIDP.

- The U.S. EPA Diesel Emissions Reduction Act (DERA) grant [33]
  - A total of 180 grants have been awarded for port projects, totaling $171 million.
  - This covers projects involving loading and unloading of passengers and/or cargo from ships, ferries, and other vessels, railyards, and other goods movement facilities.
- California-specific grants
  - Electrify America's California Zero Emission Vehicle Investment Program includes $25 million for ZE infrastructure at ports [34].
  - The State of California will spend $2.3 billion on seaport-related improvements [35].
  - CARB has Low Carbon Transportation Investments and Air Quality Improvement Program (AQIP) Grant Solicitations [36].

Mitigation Solution Costs

This subsection provides high-level cost estimates for the technically feasible mitigation solutions.

Table 41 lists high-level cost-range estimates for the RS-Q area upgrades identified by LADWP that are introduced in section 7. The total cost of these upgrades is estimated to be $165.7 million to $194.5 million. It is important to reiterate that LADWP identified these upgrades to facilitate new loads expected in the Outer Harbor area (see section 7). In particular, LADWP did not design these upgrades to accommodate the POLA tenant CHE electrification. The upgrades identified by LADWP alone are insufficient to accommodate any of the future electrification scenarios as shown with the original load models in section 7 and with the updated load models in section 10.

Table 41. High-level cost-range estimates for upgrades identified by LADWP

LADWP Upgrade	Estimated Cost Range ($M)
34.5-kV Cable Cost (LADWP System)	10.7–12.5
34.5-kV Cable Cost (POLA System)	30–45
Conduit Design	100–112
New Rack at RS-Q	25
Total	165.7–194.5

Table 42 lists high-level cost estimates for the additional grid infrastructure upgrades required as identified by EPRI. Given the lack of detailed cost breakdown of upgrades not currently planned by LADWP, these cost-range estimates represent only new lines and line sections priced at a rough cost estimate of $150–$175 per foot. In particular, these cost-range estimates do not include: 1) load transfers between circuits, 2) changing the reactances of the existing RS-Q load-balancing reactors, 3) adding new reactors at RS-Q, or 4) conduit design. As seen in Table 41 for the upgrades identified by LADWP, conduit design could significantly increase the overall costs. Note that Table 42 does not list cost estimates for additional upgrades for scenarios 4–7, as a new RS or effective balancing of loads between all four banks would be required. Even if it were possible to accommodate some of these scenarios without a new RS, the scenarios are expected to require much more extensive upgrades compared to scenario 2.

Table 42. High-level cost-range estimates for the additional grid infrastructure upgrades required, as identified by EPRI

Scenario	Load Models Applied	Total Length of New Lines and Line Sections (ft [m])	Estimated Cost Range ($M)
Scenario 1: Existing system conditions (2021)	Original	None	0
	Revisited	None	0
Scenario 2: 50% Electrification by 2025 – Unmanaged	Original	48,230 (14,700)	7.23–8.44
	Revisited	21,980 (6700)	3.30–3.85
Scenario 3: 50% Electrification by 2025 – Managed	Original	220	0.03–0.04
	Revisited	21,980 (6700)	3.30–3.85
Scenario 4: 100% Electrification by 2030 – Unmanaged	Original	Not identified[65]	N/A
	Revisited	Not identified[66]	N/A
Scenario 5: 100% Electrification by 2030 – Managed	Original	Not identified [34]	N/A
	Revisited	Not identified [34]	N/A
Scenario 6: 100% Electrification by 2035 – Unmanaged	Original	Not identified [33]	N/A
	Revisited	Not identified [34]	N/A
Scenario 7: 100% Electrification by 2035 – Managed	Original	Not identified [34]	N/A
	Revisited	Not identified[66] [34]	N/A

Using energy storage to avoid the need for a new RS-Q is analyzed in section 10. For convenience, the energy storage cost estimates are relisted in Table 43. Without load balancing between RS-Q banks B and D, the storage cost would be $13 million to $122 million, depending on the future electrification scenario. With perfect load balancing between RS-Q banks B and D, the required storage costs would be reduced to $0 to $82 million, depending on the future electrification scenario. Note that these costs are for a centralized storage system at RS-Q applied for reducing the bank peak loads and thus avoiding the need for a new RS. Such a centralized storage system is not expected to reduce the need for any circuit upgrades. As additional information about the POLA tenant electrification strategies becomes available, it is recommended to evaluate energy storage for reducing the peak demands of the tenant CHE charging loads and thus reducing the need for additional circuit upgrades.

[65] A new RS would likely be required to accommodate this scenario.

[66] Either a new RS or effective balancing of circuits/loads between all four RS-Q banks would be required to accommodate this scenario.

Table 43. High-level energy storage cost estimates to mitigate the need for a new RS

Scenario	Energy Storage Cost Estimate (million $)			
	Bank B	Bank D	Banks B and D Separately	Banks B and D Jointly with Perfect Load Balancing
Scenario 2: 50% Electrification by 2025 – Unmanaged	0	14	14	0
50% by 2025 – Managed	0	13	13	0
Scenario 3: 50% Electrification by 2025 – Managed	50	66	116	80
100% by 2030 – Managed	0	47	47	10
Scenario 4: 100% Electrification by 2030 – Unmanaged	51	71	122	82
100% by 2035 – Managed	0	52	52	12

12 CONCLUSIONS AND RECOMMENDATIONS

This section summarizes the accomplishments of this study, its key findings, and recommended next steps.

Accomplishments

This study accomplished the following:

- The team provided customer- and grid-specific processes, considerations, and analytics to proactively support current and future port electrifications.
- The team helped POLA meet broad electrification and sustainability targets by proactively planning for future electrification scenarios.
- The team quantified port load characteristics, energy, and peak demand, charging infrastructure needs, and forecasts of future port electrification loads.
- The team identified technologies available for port electrification.
- The team developed a detailed time-series model for the LADWP RS-Q distribution system area.
- The team quantified the distribution grid impacts for several future electrification scenarios.
- The team identified grid infrastructure upgrades required to mitigate the considered future electrification scenarios.
- The team enabled strategic and cost-effective investment by identifying load mitigation solutions.
- The team supported strategic and cost-effective investment plans for future upgrades, phased charge management plans, and grid availability to support current and future port electrification efforts.

Key Findings

Following are the key findings of this study:

- CHE accounts for slightly more than 1900 pieces of equipment in POLA. Most of the CHE is used within the container terminals. The six container terminals visited for the electrification study account for 85% of all the CHE used in POLA (about 1600 pieces).
- The terminal tractors (UTRs), top handlers, forklifts, RTG cranes, and straddle carriers offer the highest electrification potential opportunity for POLA, accounting for nearly 88% of the total container CHE inventory of the six terminals visited.
- CHE at POLA accounts for nearly 15% of CO_2 emissions, 5% of NO_x emissions, 38% of CO emissions, and approximately 5% of all diesel-related pollutants of the total port emissions.

- In a 50% electrification scenario that aims to replace 50% of the existing CHE stock with electric equivalent technologies, the incremental future *connected load* for the six terminals visited at POLA is estimated to be about 173 MW, and it doubles in the 100% electrification scenario to about 346 MW. However, the incremental *diversified peak demand* for the six terminals is about 139 MW in the 50% electrification scenario under unmanaged charging conditions. With optimal charging conditions, the peak demand for the same scenario decreases to 67 MW, a reduction of up to 50%. Similarly, in the 100% electrification scenario, the incremental *diversified peak demand* for the six terminals is about 277 MW under unmanaged charging conditions. With optimal charging conditions, the peak demand for the same scenario decreases to 133 MW, a reduction of up to 50%. This shows that the peak demand can be significantly reduced with optimal charging solution implemented at the terminal operator locations.
- The total energy consumption for the six terminals under 100% electrification is about 1,018,000 MWh if the terminals operate their equipment according to a busy schedule where most equipment is operated in each shift.
- Grid impacts and mitigation measures were both assessed with two models for the port area loads and the POLA tenant CHE charging loads. The “original load models” represent the 2021 port area loading (impacted by the COVID-19 pandemic) and more conservative assumptions on the CHE charging loads. The “updated load models” represent the 2022 port area loads (less impacted by the COVID-19 pandemic) and less conservative models for the CHE charging loads.
- In the grid impact analysis with either the original or updated load models, no overvoltages were observed in any of the analyzed future electrification scenarios. Only limited undervoltages were observed in 100% unmanaged charging scenarios. Significant RS-Q bank and circuit overloads were observed in the future electrification scenarios. The updated load models resulted in considerably less overloads than the original load models, highlighting the importance and uncertainty with the port and CHE load modeling.
- Analysis of energy storage as a mitigation measure found that energy storage is not an economically viable solution to reduce the CHE peak loads, given the current energy storage costs and the rate structures available to terminal operators. However, this may change as energy storage costs decrease or if different rate structures are available.
- Analysis of grid-side mitigation measures found the following:
  - The future RS-Q upgrades that LADWP plans are insufficient alone to accommodate the future electrification scenarios with either original or updated load models.
  - The RS-Q bank that LADWP plans was found to accommodate the 50% electrification scenarios. However, a new RS would be required to accommodate the 100% electrification scenarios.

- With the original load models, the future upgrade plans by LADWP along with relatively minor load-balancing measures may be sufficient to accommodate the 50% electrification by 2025 with managed charging. However, with the updated load models, it seems that a new 22,000-ft (6700-m) circuit will be required.
- With the original load models, accommodating the 50% electrification by 2025 with unmanaged charging would require at least two new tie-lines from Wilmington to Terminal Island, along with other circuit upgrades with about 9.13 mi (48,230 ft [14,700 m]) of new line sections. Additionally, three new load-balancing reactors at RS-Q, switching operations, and other relatively minor upgrades would be required. With the updated load models, it may be possible to accommodate this scenario with just one new tie-line from Wilmington to Terminal Island.

- The grid impact and mitigation assessment has demonstrated a clear value in managing the POLA tenant CHE charging loads to reduce the peak loads that they may cause. The unmanaged charging scenarios resulted in significantly greater grid impacts, requiring considerably more expensive grid upgrades compared to the managed charging scenarios.

Roadmap to Meet ZE CHE Goals by 2030 and 2035 (Assuming All ZE CHE is Powered with Electricity and/or Hydrogen Fuel Cell)

CHE at POLA accounts for nearly 15% of CO_2 emissions, 5% of NO_x emissions, 38% of CO emissions, and approximately 5% of all diesel-related pollutants (see Table 44).[67]

In order to achieve 100% ZE for the ports, the CHE could be phased out of fossil fuel technologies and phased into electric and/or hydrogen fuel cell technologies. Although not all the CHE technologies have an electric equivalent technology that exists today, many of the current technologies have at least one available battery-electric or hydrogen fuel cell technology equivalent. These technologies are currently demonstrated at some of the container terminals in POLA. The impact of hydrogen technologies on electric power consumption is negligible and so can be used to offset the need for grid upgrades, mitigation measures, and so on that would have been necessitated by electric technologies and can lower the electricity bills of terminal operators. However, these hydrogen technologies have their own costs and their own requirements, such as their hydrogen supply. The costs and technical implications of hydrogen technologies outside of their ability to offset electric power are not included in this report.

[67] Source: POLA, Inventory of Air Emissions 2021.

Table 44. Maritime industry-related 2021 emissions comparison by source category

	PM_{10} tons	$PM_{2.5}$ tons	DPM tons	NO_x tons	SO_x tons	CO tons	HC tons	CO_{2e} tons
2021								
Ocean-going vessels	127	117	83	5956	248	605	255	504,842
Harbor craft	15	15	15	565	1	112	29	53,521
Cargo handling equipment	6	6	5	414	2	780	86	184,837
Locomotives	27	25	27	751	1	187	42	65,216
Heavy-duty vehicles	6	6	6	1042	4	356	52	444,814
Total	**182**	**168**	**136**	**8729**	**255**	**2040**	**464**	**1,253,229**

Table 45 shows a 13-year roadmap (2022–2035) proposed for the port operations.

- A simplified analysis of two hydrogen fuel cell scenarios show that there is a tremendous potential to lower the electric peak demand, as much as 82% in scenario A and 55% in scenario B when compared to all-electrification scenarios by 2030. Detailed analysis needs to be conducted to understand the grid impacts of the hydrogen fuel cells.
- Implementing hydrogen fueling (scenarios A and B) reduces the 100% electrification demand by 327 MW in scenario A and by 215 MW in scenario B, and there won't be a need for a second bank installation (even with an unmanaged charging profile). As discussed in chapter 8, the RS-Q expansion and rack D installation will be required with or without hydrogen scenarios.
- The study assumes the hydrogen will be imported to the site and the pumping and importing electricity requirements are negligible.

Table 45. Electrification and/or Hydrogen Fuel Cell Guide: 13-year roadmap (2022–2035) for port operations and expansion

Timeline	CHE Equipment	Recommendations
2022–2025	Convert 50% of the existing nonelectric CHE equipment to electric and/or hydrogen fuel cell in the following categories: • UTRs – Several electric and/or hydrogen fuel cell options exist from Kalmar Ottawa, Orange EV, Capacity, and Autocar. • Forklifts – Electric forklifts are available in all lifting capacities from 5000 to 80,000 lb (2200 to 36,000 kg). • RTG cranes – Several manufacturers have electric-powered RTG cranes. • Top handlers – This electric technology is currently demonstrated at POLA. • Straddle carriers – A hybrid option currently exists that uses both electric- and diesel-based technology. These five categories represent nearly 88% of the CHE inventory in the six container terminals	• Evaluate approaches to manage charging to reduce the peak demand by up to 50% and/or to diversify the CHE charging times between terminal operators. • Managed charging also has an advantage of extending the battery life of battery-operated CHE equipment as it prevents overheating of batteries. • Complete the RS-Q expansion, new lines to San Pedro, and switching circuits between RS-Q banks B and D planned by LADWP. • Evaluate the possibility of reducing RS-Q banks B and D loading by switching some circuits to be served from RS-Q banks A and C. RS-Q banks A and C have capacity, but contractual issues may limit utilizing the banks for new loads. • As additional information on the terminal ZE strategies and CHE equipment charging becomes available, identify the additional grid infrastructure upgrades required beyond the current upgrades planned by LADWP. • Evaluate incentives for the terminal operators to reduce their CHE charging peak demands through either managed charging and/or the use of energy storage. • Evaluate if reducing energy storage costs and other aspects may make utility-owned energy storage as an economically feasible solution to either defer or avoid some of the grid infrastructure upgrades required.

Table 45 (continued). Electrification guide: 13-year roadmap (2022–2035) for port operations and expansion

Timeline	CHE Equipment	Recommendations
2025–2030	• Convert the remaining 50% of the five categories (UTRs, forklifts, RTGs, top handlers, and straddle carriers) of the fossil-fuel-based CHE inventory to electric. • Other nonelectric, ZE options could also be considered to meet the 100% ZE port regulations, such as hydrogen fuel cell equipment, which does not impact electricity use by the terminal operators.	• As additional information on the terminal ZE strategies and CHE equipment charging becomes available, identify the additional grid infrastructure upgrades required. In particular, evaluate the need for a new RS in the port area. • Consider implementing incentives for the terminal operators to reduce their CHE charging peak demands and/or to diversify the CHE charging times between terminal operators. • Evaluate if reducing energy storage costs makes storage a viable solution for terminal operators to reduce their individual peak loads caused by CHE charging through either managed charging or the use of energy storage. Evaluate if reducing energy storage costs and other aspects may make utility-owned energy storage an economically feasible solution to either defer or avoid some of the grid infrastructure upgrades required. • Hydrogen fuel cell technology could be utilized for CHE to meet the ZE mandates and it has the potential to reduce the electric demand requirements in the short term. • It is possible to accommodate 50% electrification by 2025 with managed or unmanaged charging with one new tie-line from Wilmington to Terminal Island in addition to the future upgrades planned by LADWP. Additional switching operations and other relatively minor upgrades are required. • Perfect balancing of loads between banks B and D allows accommodating the 50% electrification scenarios, assuming no load growth beyond what is considered here. A new bank in addition to bank D would be required to accommodate the 100% electrification scenarios, which would trigger requiring an RS.
2030–2035	Some technologies still do not have an electric and/or hydrogen fuel cell equivalent, such as yard sweepers, cone vehicles, and so on. They may become available after 2035.	Vehicle-to-grid options could be available in 10 years that could potentially help with demand reduction. More renewable integrations could help meet the growing electric demand.

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A ALTERNATE FUEL DEPLOYMENTS AND DEVELOPMENT OF CHE

This appendix provides additional information on alternate fuel deployments and development of CHE.

Forklifts

At the ProMat 2019 conference, Toyota Material Handling unveiled a three-wheeled fuel cell forklift that was planned for production later in 2019 [37].

As of the end of 2018, over 20,000 hydrogen fuel cell forklifts were in place in warehouses, stores, and manufacturing facilities throughout the United States. Hydrogen-powered forklifts offer rapid refueling, improved performance, and ZE compared to their conventional counterparts. Use of hydrogen in forklifts is steadily increasing as more ports and other establishments implement climate goals [38].

Yard Tractors

In March 2021, GTI was preparing to launch a fuel cell pilot program called Zero Emissions for California Ports (ZECAP) with yard tractors. Project partner TraPac is working in conjunction with the manufacturer of the yard tractor, Capacity of Texas trucks, and the power systems manufacturer, Ballard Power Systems. CARB funded this project [39].

In Europe, a yard tractor manufacturer, Terberg, planned to introduce a fuel-cell-based yard tractor in the summer of 2020 [40].

Top Loaders and RTGs

Through the California Climate Investment program, several pilot demonstrations of fuel cell hybrid top loaders and RTGs were successfully completed by spring 2020 at POLA and the Port of Long Beach. Hyster-Yale built the top loader, which integrated fuel cell engines from Nuvera. WAVE provided the wireless charging for the hybrid battery operation [41].

Refrigerated Containers (Reefers)

In 2013, demonstrations of hydrogen fuel-cell-powered refrigerated containers for use at sea and land were conducted. This multi-year U.S. DOE-funded project was completed at the end of 2016 [42].

In 2020, the port of Marseille in France successfully integrated use of fuel cell energy for reefer containers. Helion provided the H_2 solution for green generators to power the reefer units for the major shipping and logistic provider, CMA CGM, which is the second largest reefer carrier in the world [43].

Dredges

A few pilots have been underway to use low-carbon alternate fuels for dredge equipment at ports. Royal IHC is developing a hydrogen-fueled trailing suction hopper dredge (TSHD) and testing it in the Netherlands. Royal IHC is exploring a new type of vessel referred to as a low energy adaptive fuel (LEAF) hopper in an innovation partnership with the Rijkswaterstaat. The latter is part of the Dutch Ministry of Infrastructure and Water Management and is responsible for the design, construction, management, and maintenance of the main infrastructure facilities in the Netherlands. The exploration phase began at the beginning of 2019, with the aim of developing a vessel that can be operational in 2024 [44].

B LADWP DATA RECEIVED FOR THE GRID MODEL DEVELOPMENT TASK

The EPRI project team received numerous types of data from LADWP to aid grid model development. This data is summarized in this appendix.

GIS Data Received

The GIS data received consisted of 129 GIS files in various formats. The data originated from data accessible via Esri software.[68] The team used QGIS software[69] to read in the GIS data and explore it. Figure 66 shows an overview of the GIS data received.

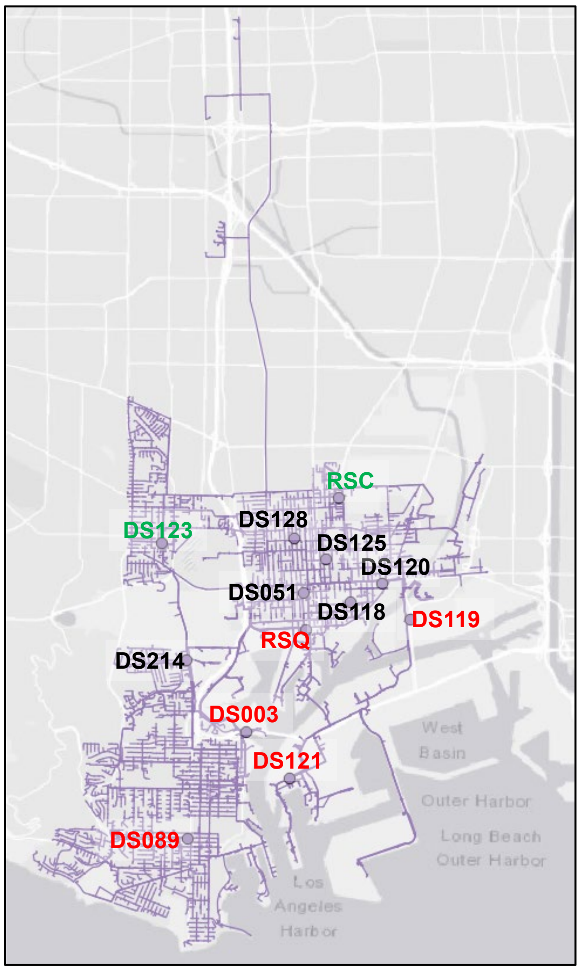

Figure 66. Overview of the GIS data received, highlighting the locations of the RSs and DSs

[68] Esri is commercially available GIS software.

[69] QGIS is an open-source desktop GIS application that supports various data manipulations of geospatial data.

The GIS data contained the entire area served by LADWP's RS-Q and most of the area served by the utility's RS-C. This report focuses on RS-Q because it is the only RS that serves POLA. Although the team converted both the RS-C and RS-Q data into the EPRI OpenDSS[70] format, only the RS-Q area is applied in this project.

Both 34.5-kV and 4.8-kV distribution-level voltages were included in the GIS data. This project modeled and analyzed only the 34.5-kV level that supplies all the POLA container terminals and other large loads.

One-Line Drawings Received

LADWP provided the team with numerous one-line wiring and operating diagrams (see Table 46) as follows:

- RS-Q
- RS-C
- The DSs served by RS-Q (DS3, DS89, DS119, and DS121)
- The DSs served by RS-C (DS51, DS123, DS125, and DS128)
- Numerous ISs in the RS-Q area

Table 46. List of the receiving station and distribution station drawings received

Station ID	Station Type	Station Drawings	Source (RS from GIS)
DS3	Distribution	d3ea1.pdf d3edr1.pdf	RS-Q
DS51	Distribution	d51ea1.pdf d51edr1.pdf	RS-C
DS89	Distribution	d89ea1.pdf d89ed1.pdf	RS-Q
DS118	Distribution	d118ed1.pdf	RS-Q
DS119	Distribution	d119ea1.pdf d119ed1.pdf	RS-Q
DS120	Distribution	d120ed1.pdf	RS-Q
DS121	Distribution	d121ea1.pdf d121ed1.pdf	RS-Q

[70] Developed by EPRI, OpenDSS is an electric power DSS designed to support distributed energy resource grid integration and grid modernization.

Table 46 (continued). List of the receiving station and distribution station drawings received

Station ID	Station Type	Station Drawings	Source (RS from GIS)
DS123	Distribution	d123ea1.pdf d123ed1.pdf	RS-C
DS125	Distribution	d125ed1.pdf	RS-C
DS128	Distribution	d128ed1.pdf	RS-C
DS214	Distribution	d214ed1.pdf	RS-Q
RS-C	Receiving	r3ea1.pdf (RS-C) r3ed1.pdf (RS-C)	N/A
RS-Q	Receiving	r17ea1.pdf (RS-Q) r17ed1.pdf (RS-Q)	N/A

Maps Received

LADWP provided the team with numerous maps and system layout drawings (see Table 47).

Table 47. List and description of maps and system layout drawings received

Map or System Layout Filename	Description
612.pdf	These files are maps titled "cogeneration." Their purpose was not specified.
613.pdf	
614.pdf	
619.pdf	
620.pdf	
624.pdf	
625.pdf	
Bulk overview.pdf	Bulk system overview of RS-Q, RS-C, HAL RS, and HAR-GS.
POLA Area Map.pdf	POLA area map with LADWP RS, DS, and tenant locations marked.
RSQ.pdf	These files are topological drawings of the respective system area.
RSQ_section A&C overview.pdf	
RSQ_section A.pdf	
RSQ_section B overview.pdf	
RSQ_section B.pdf	
RSQ_section C.pdf	

Table 47 (continued). List and description of maps and system layout drawings received

Map or System Layout Filename	Description
Confidential_CEII_RS-Q DSD System One Line.pdf	This is a one-line diagram of the entire RS-Q area.
Power System Diagram.JPG	

The team used these maps to support the grid modeling in the following ways:

- Identifying the locations of ISs
- Validating selected aspects of the GIS data converted into OpenDSS

Load Data Received

LADWP granted the team access to the utility's MV-WEB web portal that hosts customer load data. This data was eventually not applied for this project due to various data availability and quality issues.

LADWP also provided various other load data sources that the team used for the load modeling. These data sources include the "RS-HAL-C-Q.xlsx" spreadsheet and the "RS-Q_BANKS_CKTS_SCADA_READS.accdb" Microsoft Access database. The "RS-HAL-C-Q.xlsx" spreadsheet contained the circuit-level loading data, which the team applied for the load modeling. The Access database consists of load data for various RS-Q area banks, DSs, and circuits. In the following tables and content, the measurement fields and time periods are listed:

- DSBANK_TBL
  - RS-Q Sect: B, Bank: 20, DS: 3, 89, 119, 121
  - Fields: MW, MVAR, MVA
  - Jan 1 2018 12:00AM through Dec 31, 2021 11:00PM
- RSBANK_TBL
  - RS-Q Bank: A, B, C, TOTAL
  - Fields: MW, MVAR, MVA1, total_cogen_mw, MVA
  - Jan 1 2018 12:00AM through Dec 31, 2021 11:00PM
- RSCircuits_Tbl
  - RS-Q section: A, B, C
  - Circuit code: HAR PED A,HAR PED B,HAR PED C,HAR PED D,HAR PED E,FRD PED 1,FRD PED 2,FRD-TER 1,GAF PED 1,HAR PED 1,HAR PED 9,HAR-FRD 1,HAR-FRD 2,HAR-GAF 1,HAR-SP 2,HAR-SP 3,HAR-TER 1,HAR-WIL C,HUG PED 1,POR PED 1,SP PED A,TER PED 1,HAR PED 5,HAR PED F,HAR PED G,HAR PED H,VLR PED A

- Fields: Sending_Amps, Receiving_Amps, IS_Amps
- Jan 1 2018 12:00AM through Dec 27, 2021 11:00PM

Other Data Received

The team also received the following documents containing grid or related data:

- **Bank B Load Analysis rev1.xlsx.** This spreadsheet contains the LADWP Port Load Study that includes the peak demands (kW) for the ISs in the POLA area. The team used this spreadsheet to assign a baseline load for each IS. The baseline values are scaled with time-series load profiles separately. It includes the following:
  - **Bank B IS demands sheet.** For 167 ISs, it lists the circuit, kW old, original kW, demand kW, BK1-4 capacity, total transformer size, and others.
  - **IS1 sheet.** For 5665 ISs, it contains many different attributes.
  - **Summary sheet.** This table lists the circuit, POLA area, IS, total transformer rating, sum of demand kW, and sum of original kW.
- **Complete Port Load Calculations.pdf.** This document contained part of the spreadsheet listed above, and hence the team did not need to use it.
- **POLA's LOAD Analysis_01-30-20.pdf.** This document contained part of the spreadsheet listed above, and hence the team did not need to use it.
- **RS-Q Cable Conductor Upgrades.pdf.** This document describes distribution upgrades, which the team reflected in the grid model.
- **POLA billing 01_01_2020 to 04_01_2022.xlsx.** This spreadsheet document lists POLA tenant meter IDs and related information. The team did not apply this document.
- **Tenant_mapping.xlsx.** EPRI created this spreadsheet to map MV-WEB meters, SP ID, IS equipment (e.g., transformers), and others, and used it for load modeling. The spreadsheet contains the following information:
  - **Meter_IS_mismatches.** This is a summary of the mismatches the team identified based on other sheets.
  - **MV-WEB_Meters.** This is meter info taken from MV-WEB. The team manually created the column "Tenant Info Found," summarizing whether a matching address was found in the "Tenant_meters" sheet.
  - **Tenant_meters.** Most columns in this sheet are copied from the different sheets in "Terminal Operators.xlsx." The team manually created columns "Meter ID in MV-Web" and "Notes on MV-Web Meter Match" by trying to match addresses between MV-WEB and the addresses on this sheet.
  - **Tenant_meters_raw.** This is a temporary sheet that can be ignored.

- **Terminal operator list.** The team created this sheet from a sheet with the same name in the "Terminal Operators.xlsx."
- **IS_Numbers_in_GIS.** This is a list of IS numbers the team obtained from the GIS data based on the IS attribute in the transformers layer. The column "GIS IS has SP IDs" checks if the IS name is found in the "Tenant_meters" sheet.
- **GIS_IS.** This is a temporary sheet that can be ignored.
- **GIS_xfmrs.** This sheet contains the transformers attribute layer that the team obtained from the GIS data. This data is used for identifying the IS numbers in the GIS based on the sheet "GIS_IS."

C CONVERSION OF THE OPENDSS MODEL TO CYME

The team converted the RS-Q OpenDSS model into CYME, which was provided to LADWP. This appendix briefly introduces the CYME model. The CYME model was not used in the overall assessment.

- The team validated the CYME model against the OpenDSS model for the following aspects:
  - Total load
  - Voltage profile
  - Line loading
- The team provided the CYME to LADWP, but it was not used in this project. Figure 67 shows an overview of the developed CYME model, Figure 68 shows the CYME model voltage profile, and Table 48 shows the CYME model loading.

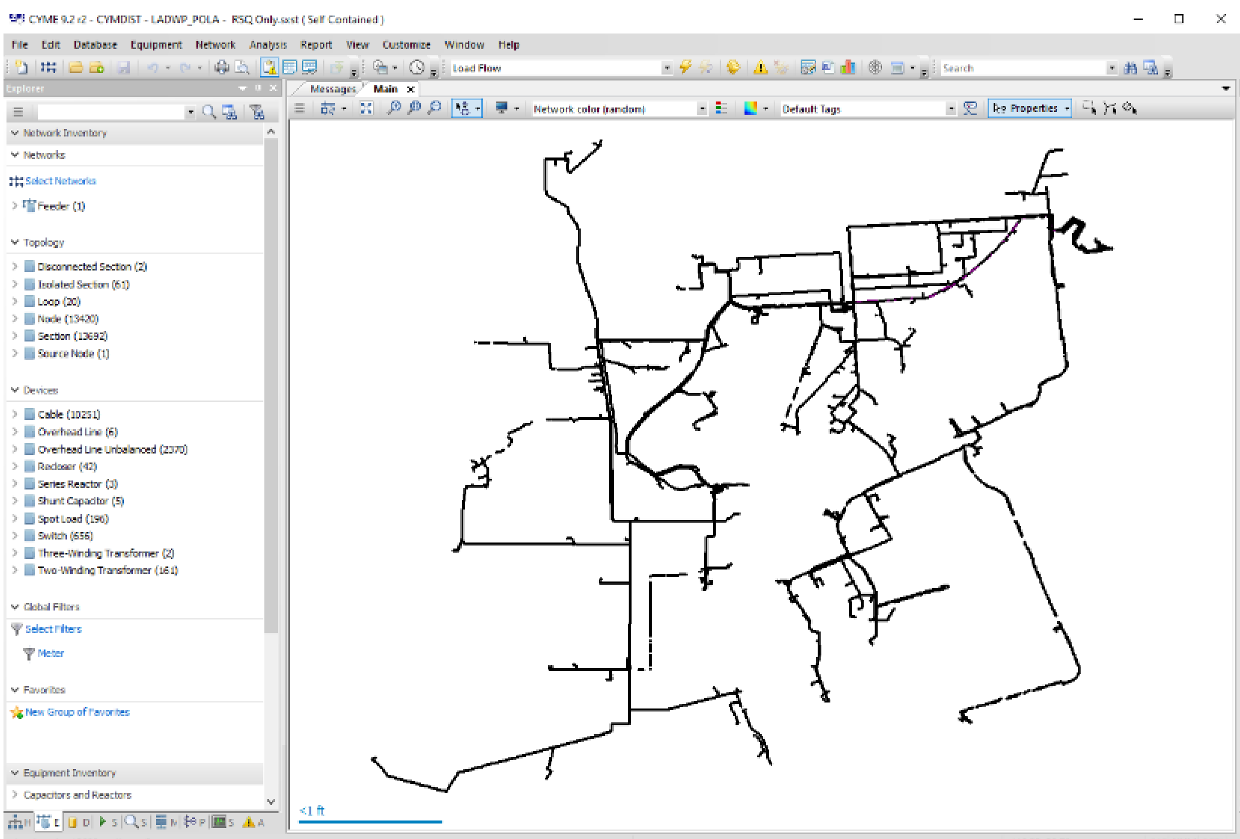

Figure 67. Overview of the developed RS-Q area in the CYME model

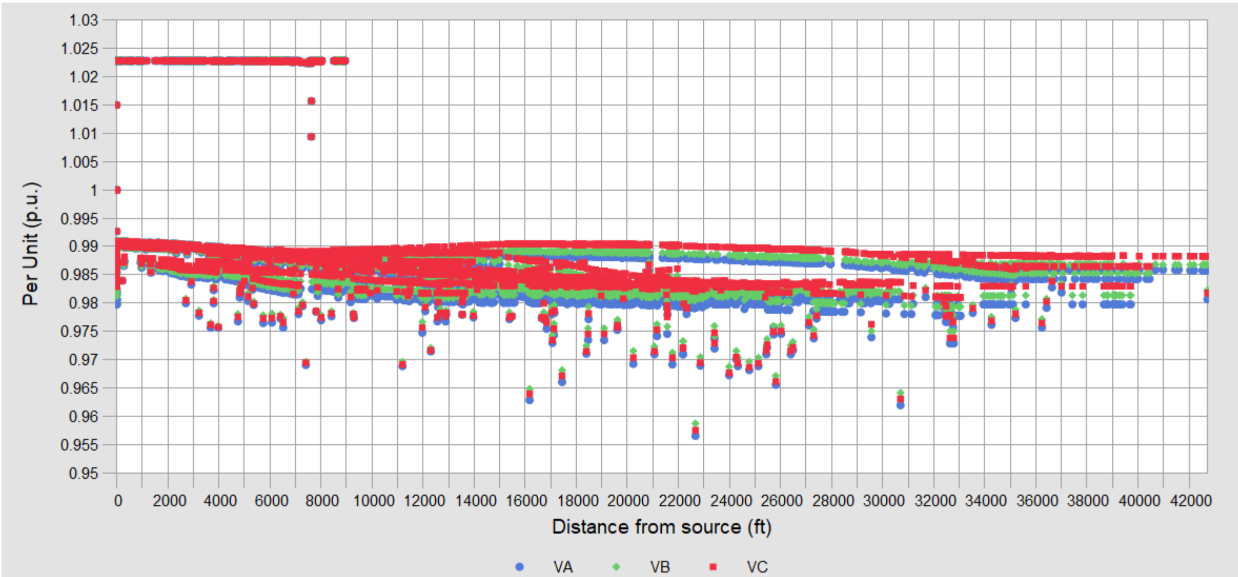

Figure 68. CYME model voltage profile

Table 48. CYME model loading

Total Summary	kW	kvar	kVA	PF (%)
Sources (swing)	128,095.29	-770.96	128,097.61	-100.00
Generators	0.00	0.00	0.00	0.00
Total Generation	128,095.29	-770.96	128,097.61	-100.00
Load read (non-adjusted)	215,416.28	104,330.86	239,351.42	90.00
Load used (adjusted)	127,095.60	61,555.21	141,217.34	90.00
Shunt capacitors (adjusted)	0.00	-64,699.99	64,699.99	0.00
Shunt reactors (adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	127,095.60	-3144.78	127,134.50	-99.97
Cable capacitance	0.00	-12,841.50	12,841.50	0.00
Line capacitance	-0.00	-425.52	425.52	0.00
Total Shunt Capacitance	0.00	-13,267.02	13,267.02	0.00
Line losses	328.85	1412.62	1450.39	22.67
Cable losses	278.52	414.61	499.47	55.76
Transformer load losses	395.10	13,232.37	13,238.17	2.96
Transformer no-load losses	0.00	0.00	0.00	0.00
Other losses	-0.00	581.04	581.04	0.00
Total Losses	999.47	15,640.62	15,672.53	6.38

D DETAILED RESULTS OF THE GRID IMPACT ANALYSIS

This appendix contains the detailed results of the grid impact analysis.

Circuit Overload Maps

Circuit overloads for the six future scenarios are illustrated on maps in Figure 69 through Figure 74. Scenario 1 (existing conditions) had no (line) overloads and hence is not shown here.

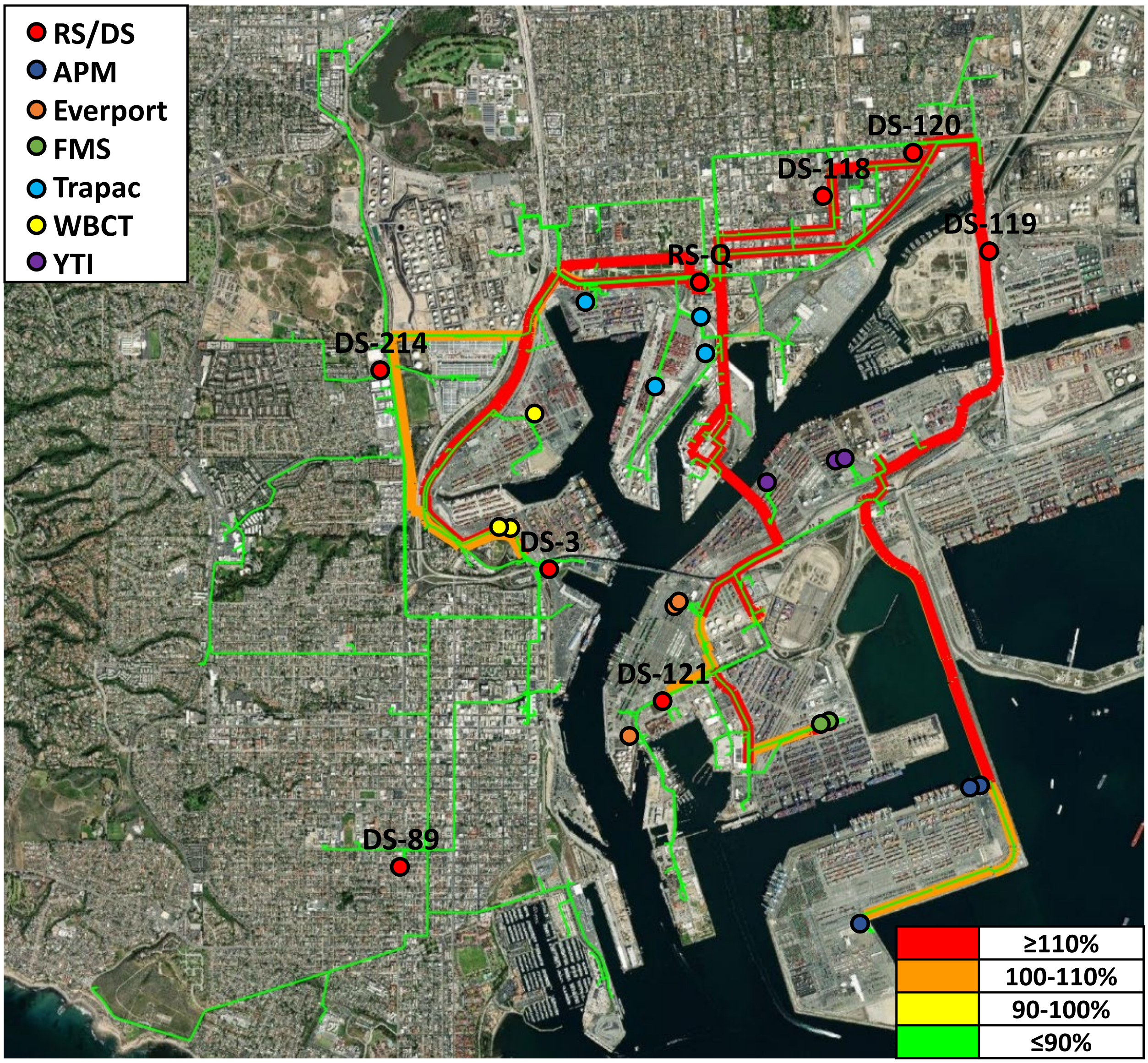

Figure 69. Circuit overloads – 50% electrification by 2025 unmanaged

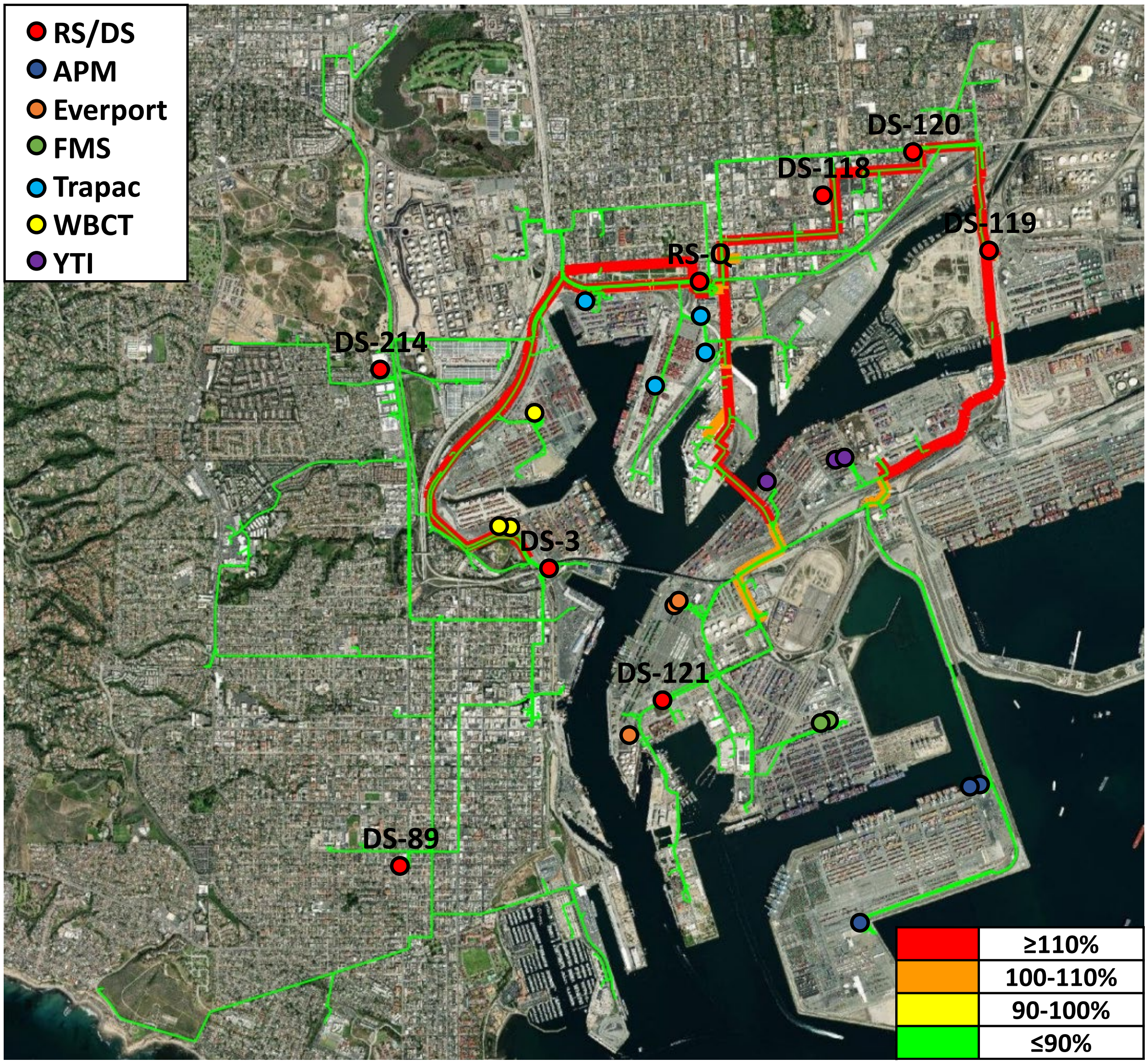

Figure 70. Circuit overloads – 50% electrification by 2025 managed

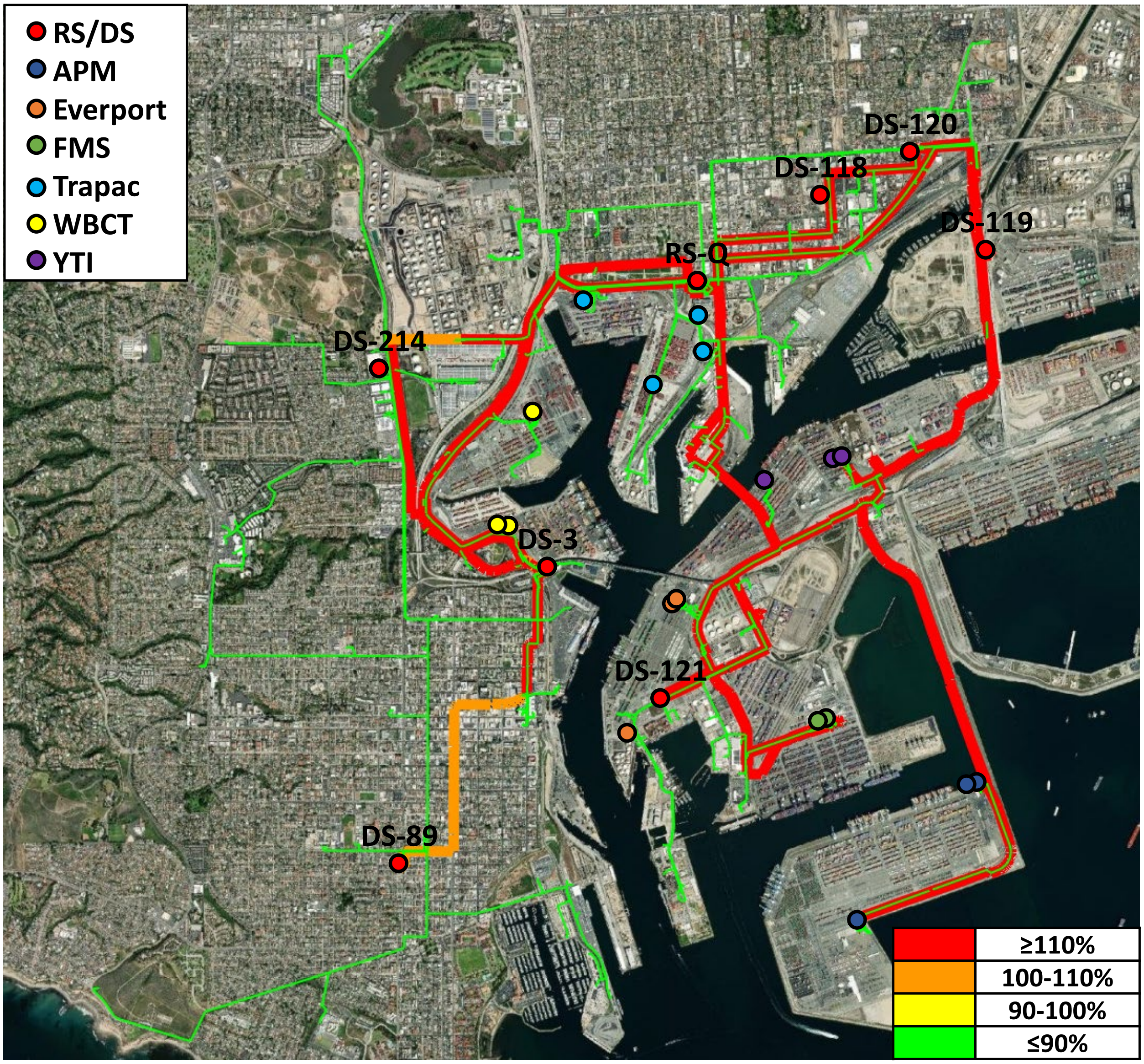

Figure 71. Circuit overloads – 100% electrification by 2030 unmanaged

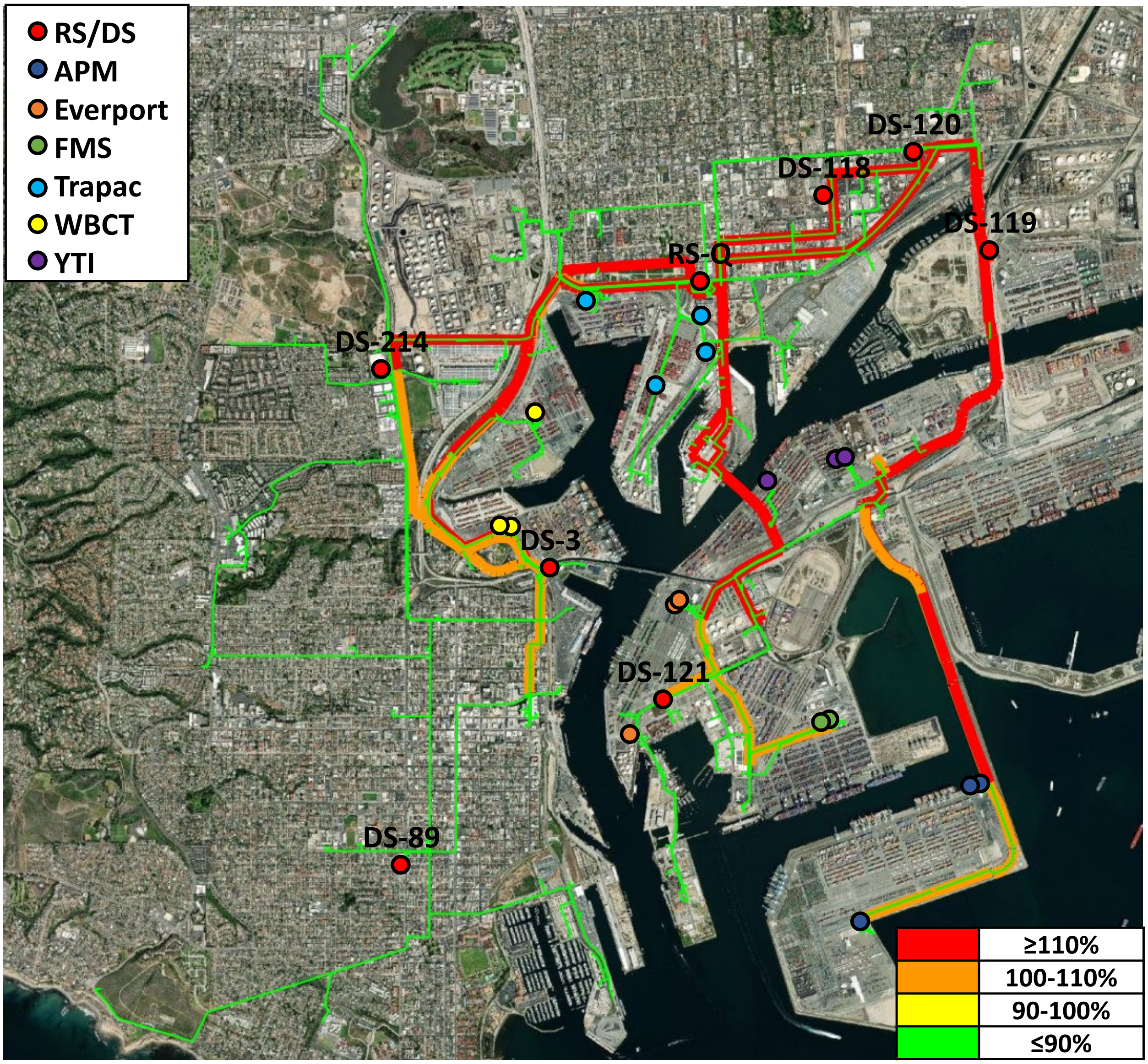

Figure 72. Circuit overloads – 100% electrification by 2030 managed

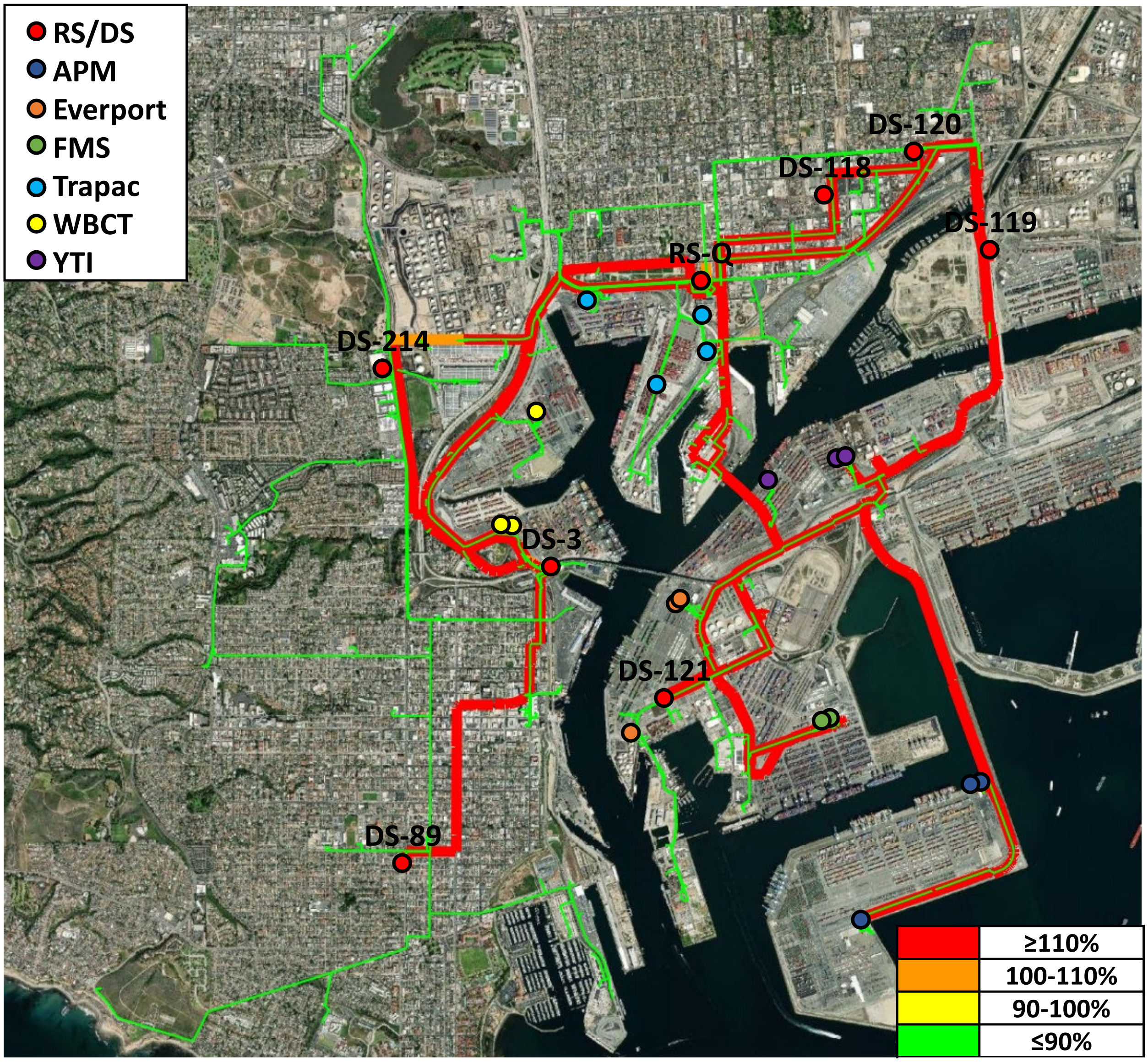

Figure 73. Circuit overloads – 100% electrification by 2035 unmanaged

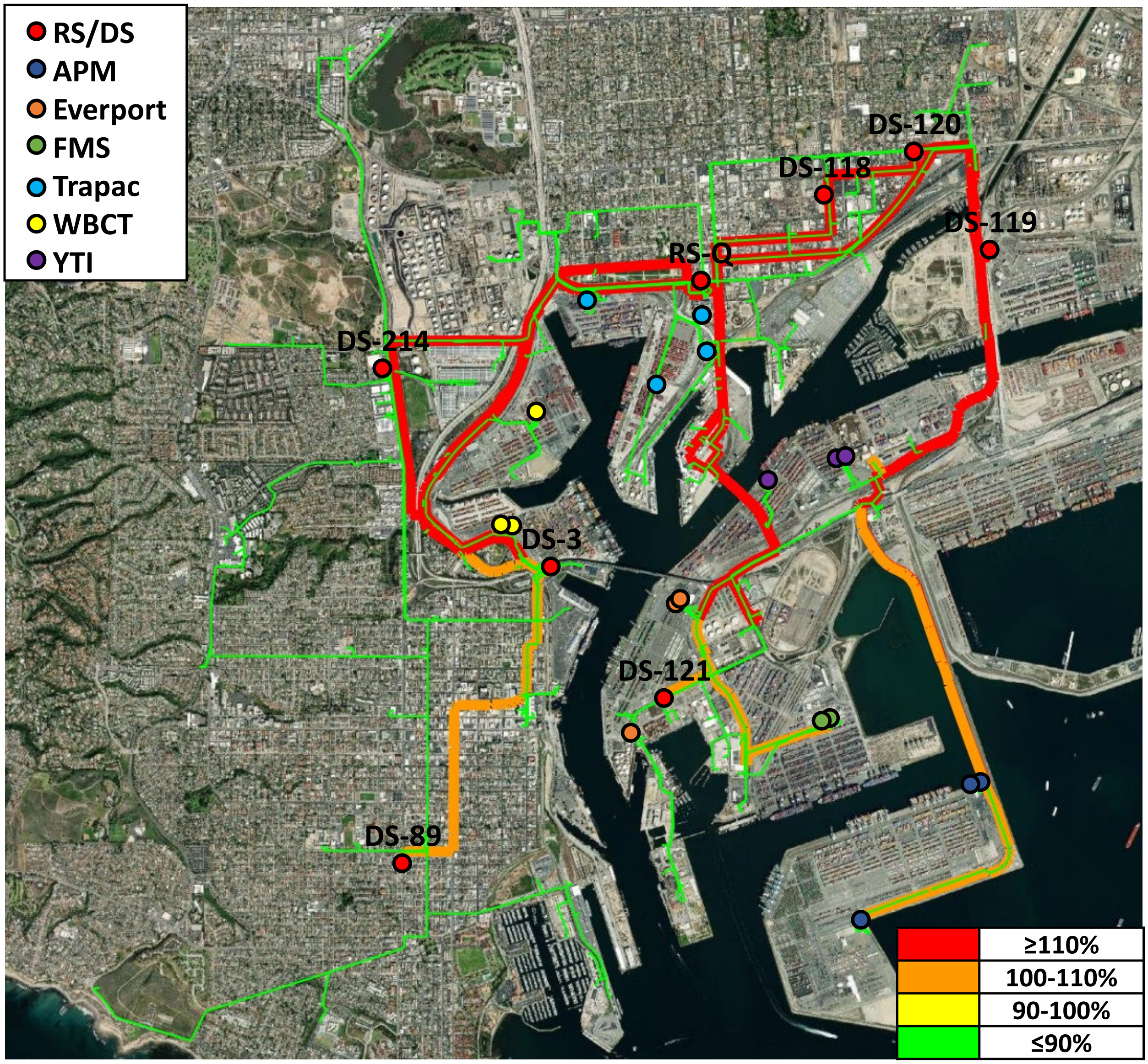

Figure 74. Circuit overloads – 100% electrification by 2035 managed

Number of Overloaded Elements and the Maximum Percentage Overload Over the Year

The number of overloaded elements and the maximum percentage overload over the year for the six future scenarios are shown in Figure 75 through Figure 80. Scenario 1 (existing conditions) had no overloads and hence is not shown here.

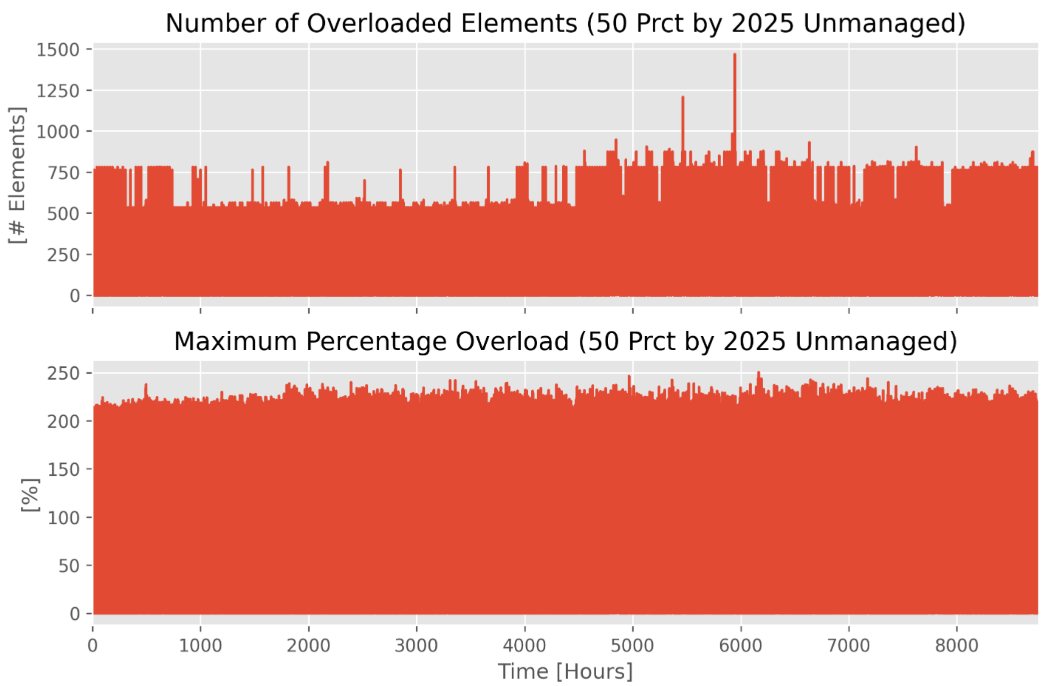

Figure 75. Number of overloaded elements and the maximum percentage overload over time for scenario 2 (50% electrification by 2025 – unmanaged)

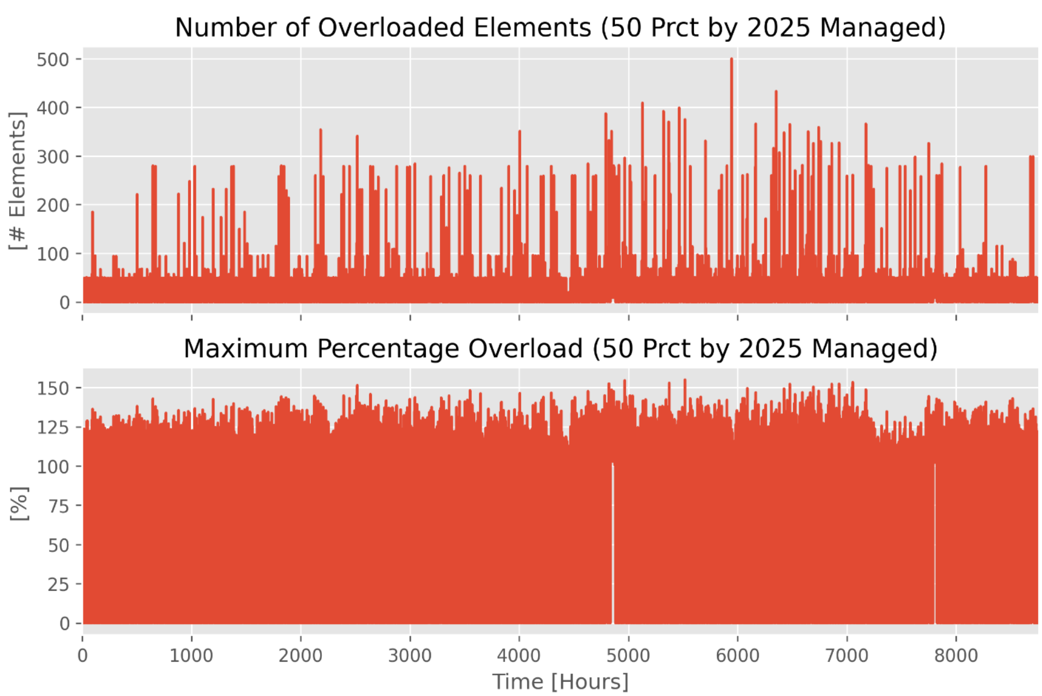

Figure 76. Number of overloaded elements and the maximum percentage overload over time for scenario 3 (50% electrification by 2025 – managed)

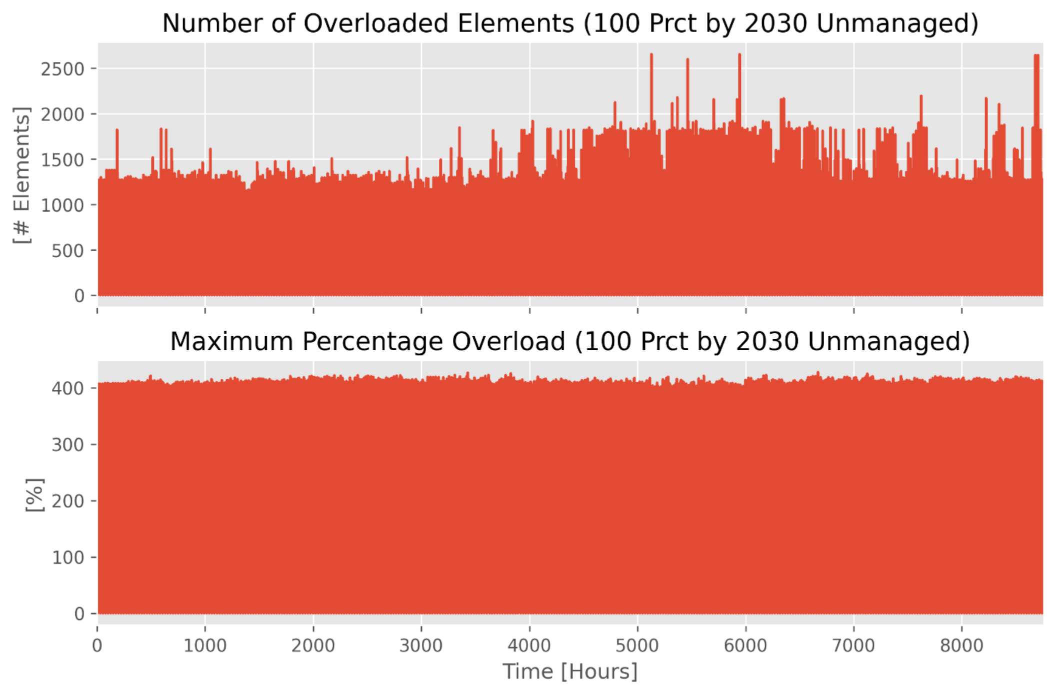

Figure 77. Number of overloaded elements and the maximum percentage overload over time for scenario 4 (100% electrification by 2030 – unmanaged)

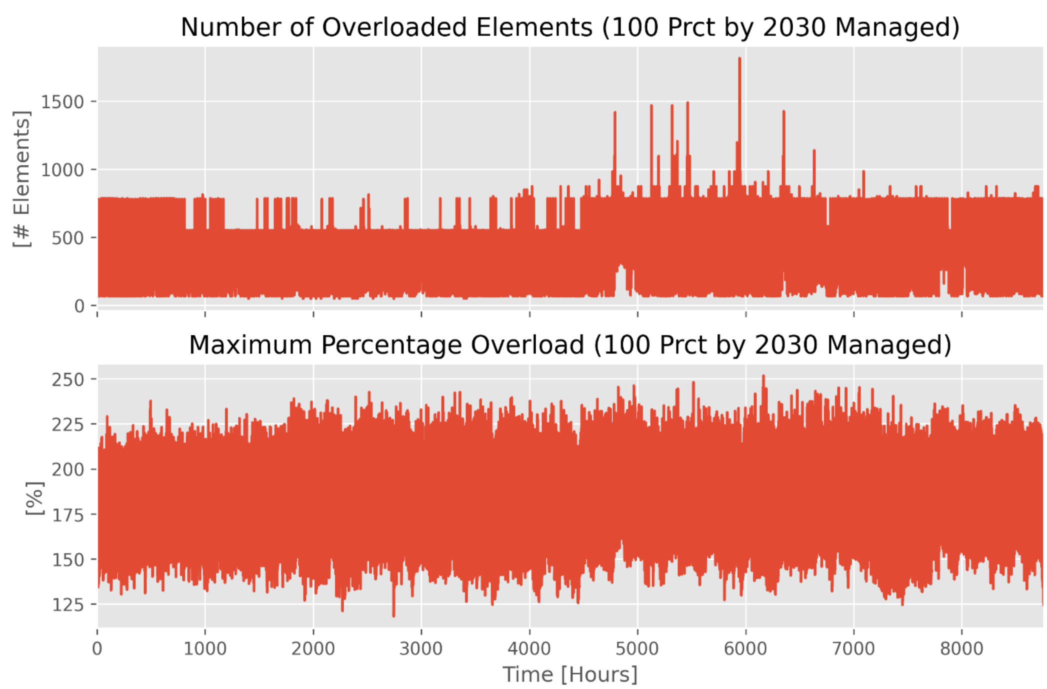

Figure 78. Number of overloaded elements and the maximum percentage overload over time for scenario 5 (100% electrification by 2030 – managed)

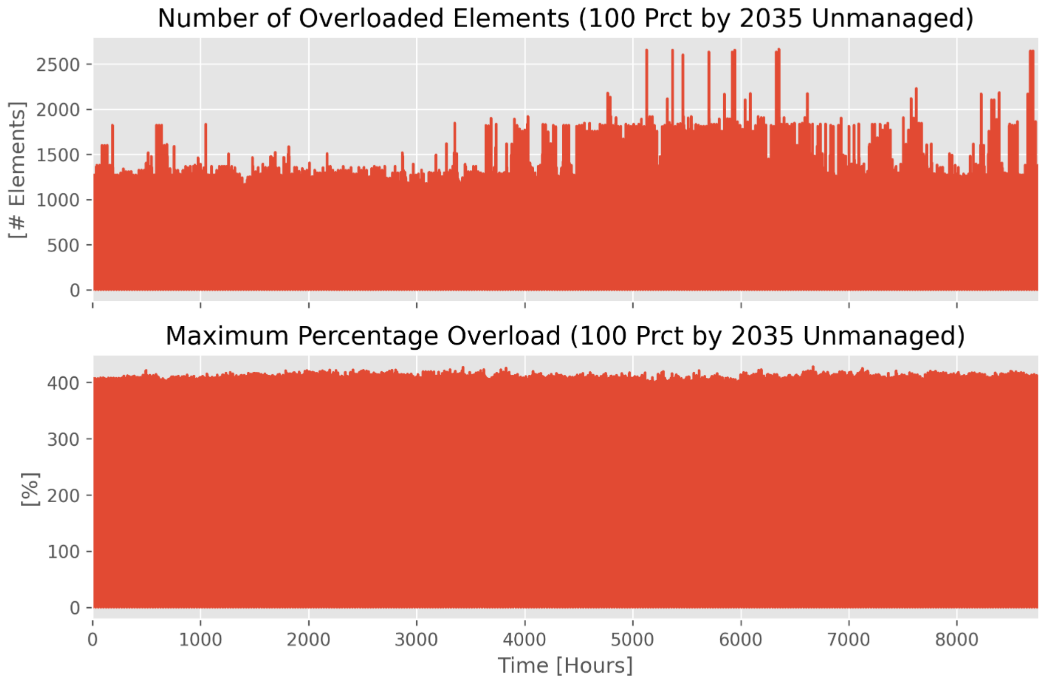

Figure 79. Number of overloaded elements and the maximum percentage overload over time for scenario 6 (100% electrification by 2035 – unmanaged)

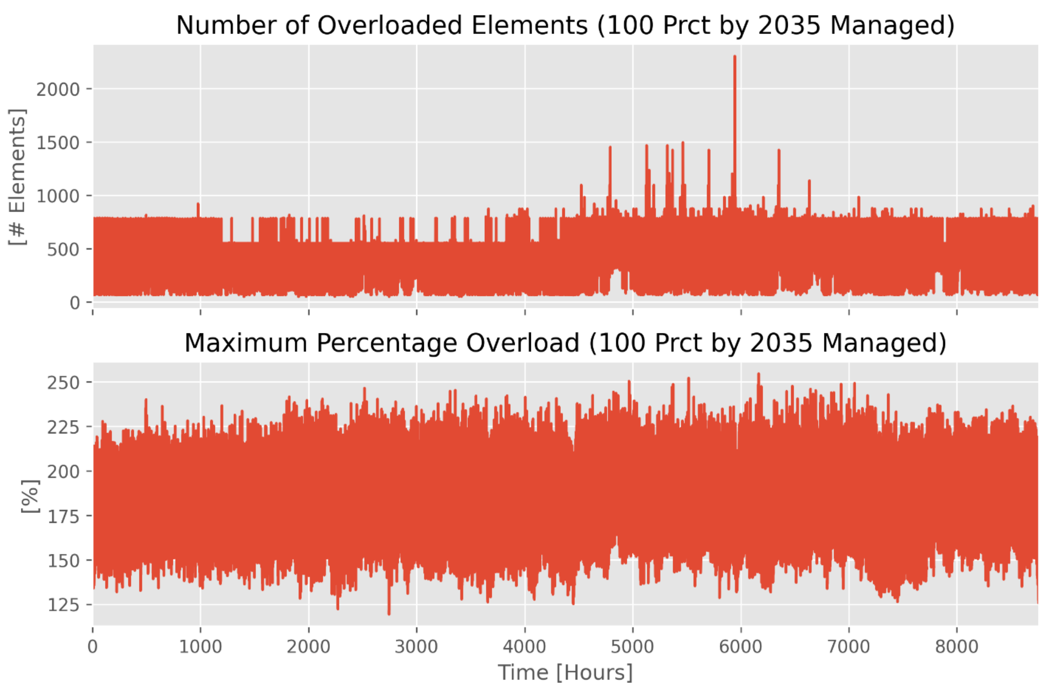

Figure 80. Number of overloaded elements and the maximum percentage overload over time for scenario 7 (100% electrification by 2035 – managed)

Maximum and Minimum Medium Voltages Over the Year

Figure 81 through Figure 87 show the maximum and minimum MVs of MV buses over the year for the seven analyzed scenarios. For these figures, MVs are defined as nominal voltages above 1 kV. The maximum voltages above 1.05 pu are caused by the RS-Q bank B tertiary bus. All other medium-voltage and low-voltage buses had voltages below 1.05 pu. Hence, the overvoltages in these figures can be ignored.

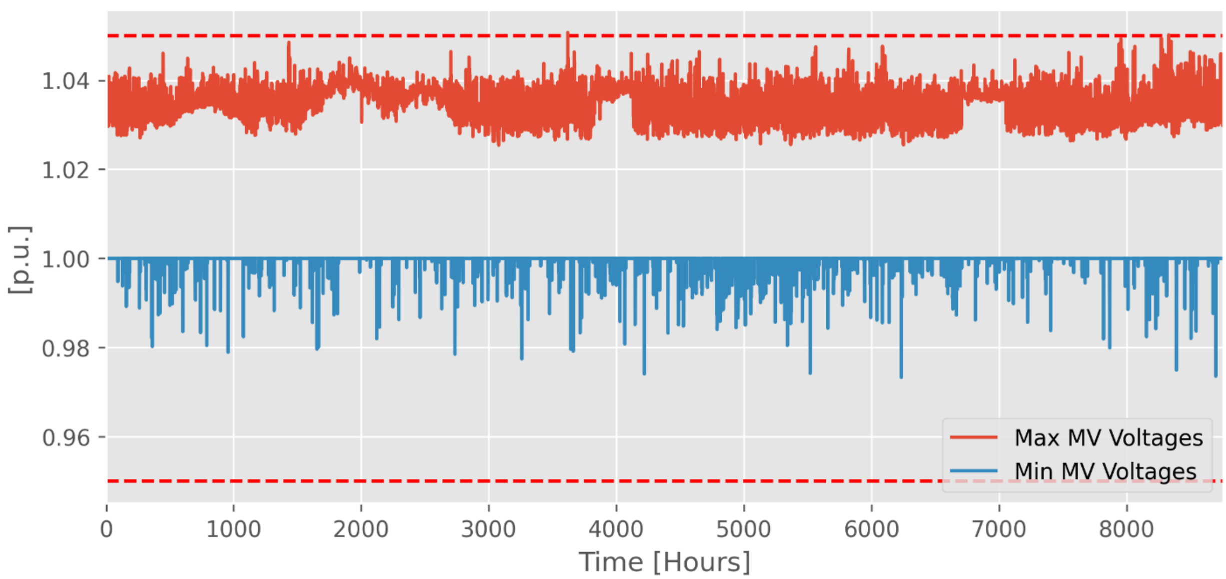

Figure 81. Maximum and minimum medium voltages for scenario 1 (existing conditions)

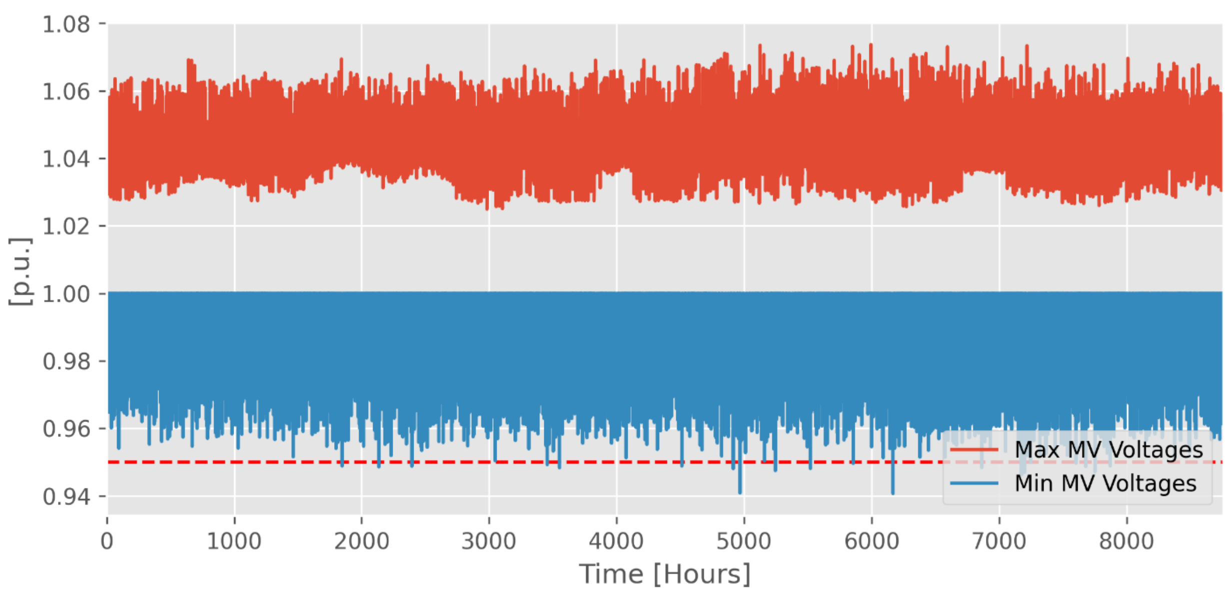

Figure 82. Maximum and minimum medium voltages for scenario 2 (50% electrification by 2025 – unmanaged)

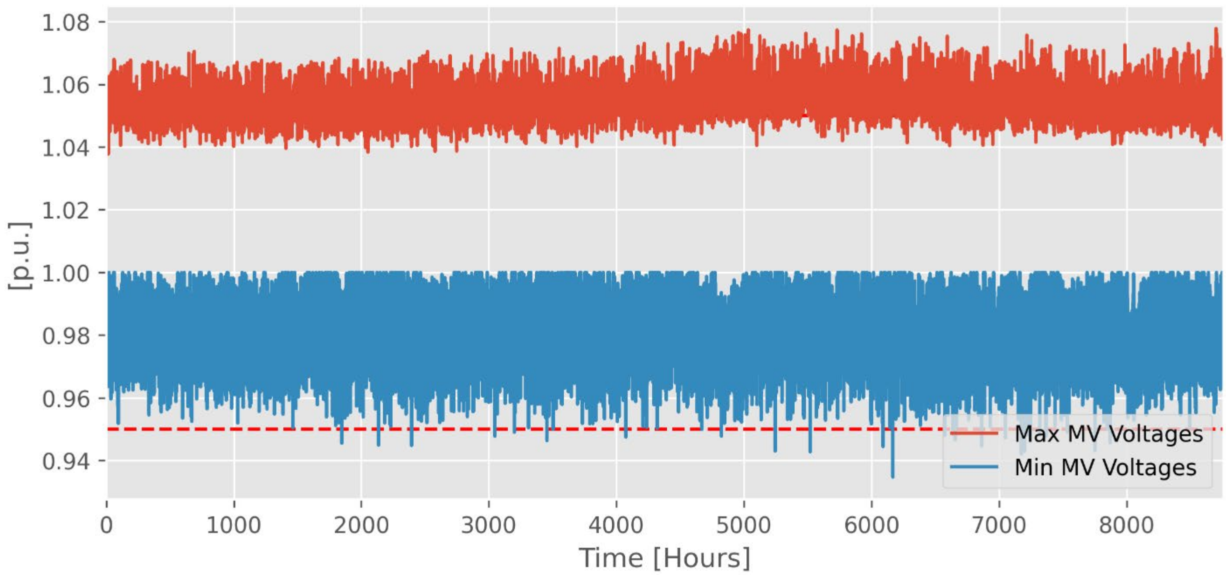

Figure 83. Maximum and minimum medium voltages for scenario 3 (50% electrification by 2025 – managed)

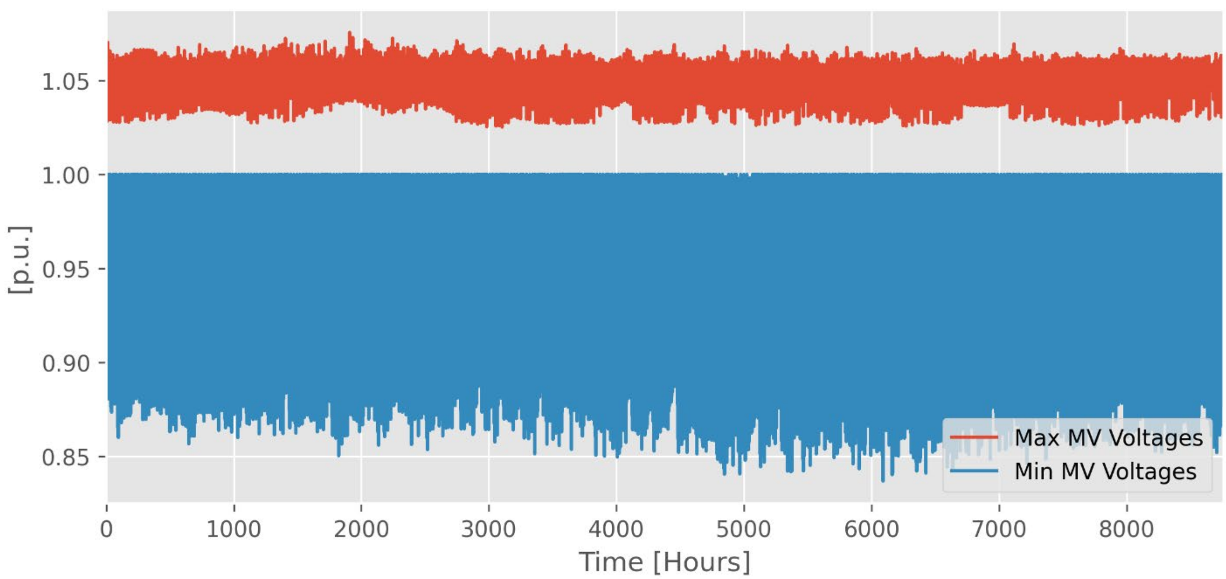

Figure 84. Maximum and minimum medium voltages for scenario 4 (100% electrification by 2030 – unmanaged)

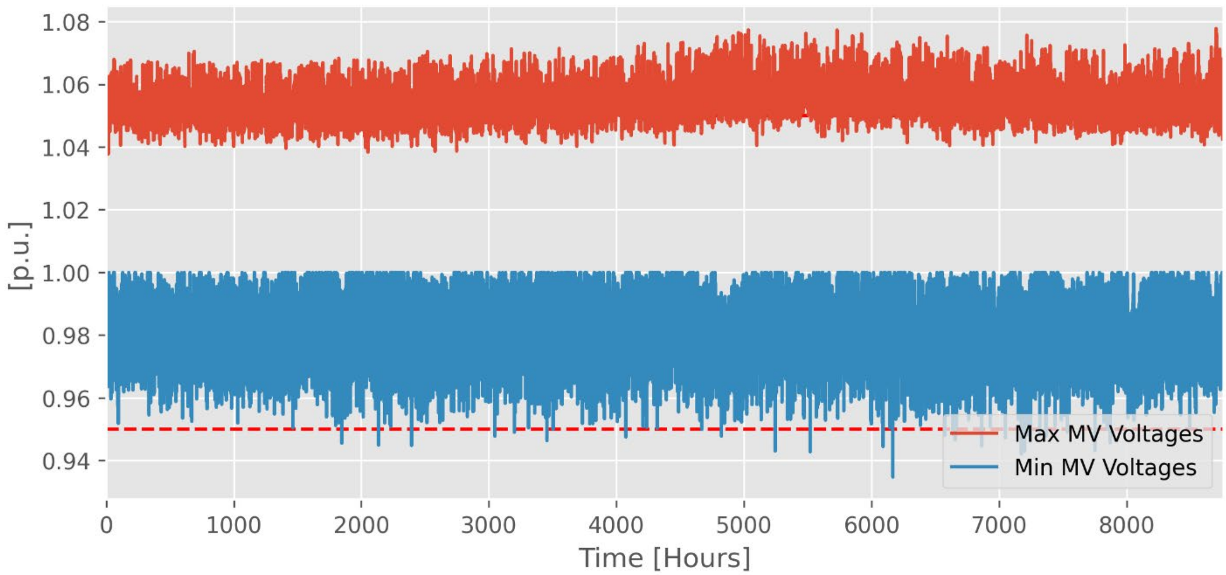

Figure 85. Maximum and minimum medium voltages for scenario 5 (100% electrification by 2030 – managed)

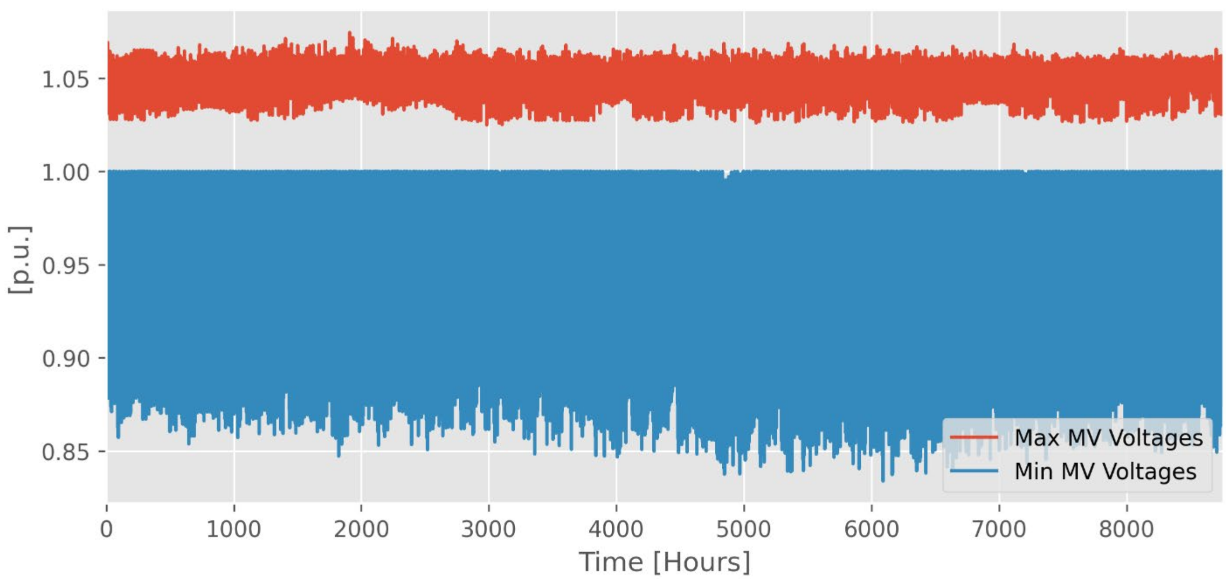

Figure 86. Maximum and minimum medium voltages for scenario 6 (100% electrification by 2035 – unmanaged)

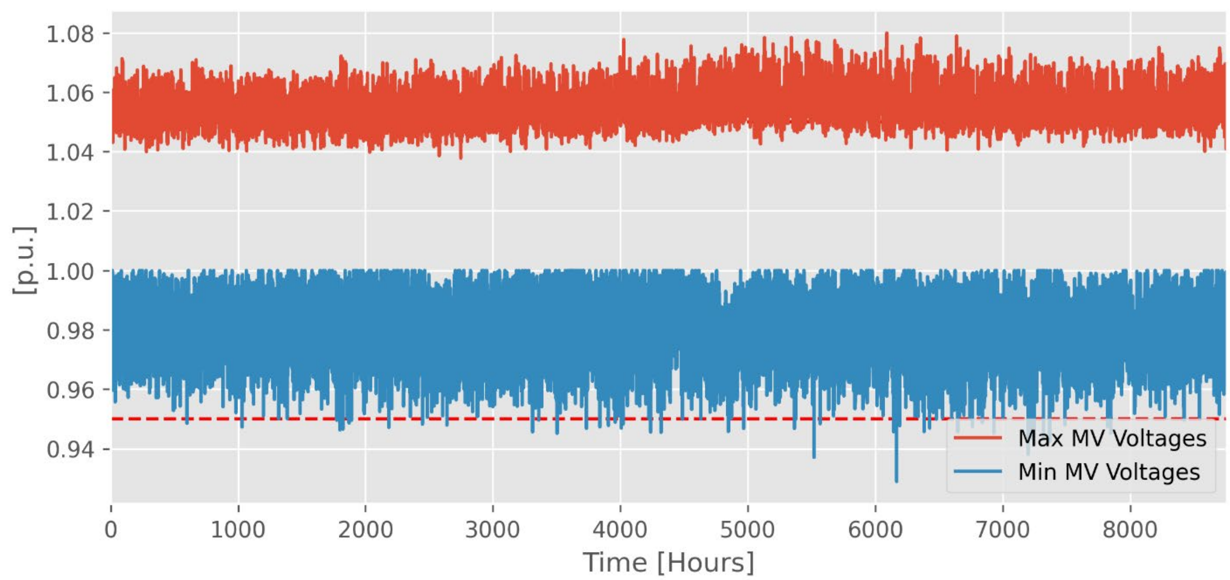

Figure 87. Maximum and minimum medium voltages for scenario 7 (100% electrification by 2035 – managed)

About EPRI

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