City of Penticton Electric Utility

Electric Utility Master Plan

2020-2045

WO#: OPR102-005 – Master Plan

CIMA+ file number: K000426A
07-01-2021 – Review 0

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PROFESSIONAL
PROVINCE OF
W. N. NYGAARD
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BRITISH COLUMBIA
ENGINEER
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Executive Summary

The City of Penticton Electric Utility (CPEU) is a dynamic entity that is constantly changing and improving to meet the needs of its customers, operators, and owners both now and in the future. This Electrical Master Plan (EMP) provides a path forward for the electrical system so that it continues to serve its stakeholders well into the future. The EMP will be incorporated into the overall Integrated Infrastructure Master Plan (IMP).

The CPEU services 42 sq. km, that includes a population of 34,400, and over 18,800 customers as of 2019. To accomplish this, it uses four substations, approximately 368 km of overhead lines, 161 km of underground cables, 4,200 distribution poles, and 2,700 transformers.

The EMP has the following objectives:

- Study the impacts of present and future demand on the existing electrical system;
- Develop recommendations with priorities of necessary upgrades (projects) to meet forecasted demands to 2045; with emphasis given to the next five years;
- Develop cost estimates for each project;
- Establish an implementation timeline for the required upgrades;

Over the past several years, the CPEU has undergone a voltage conversion from 8 kV to 12 kV. This conversion program is now complete and has increased the distribution system capacity and flexibility. In addition, 90% of the transformers are less than 25 years old due to the conversion program. The CPEU has established inspection and maintenance cycles to proactively address emerging equipment issues.

In recent years, the CPEU has achieved reliability scores better than the CEA Canadian Composite with a System Average Interruption Duration Index (SAIDI) of 0.70 hours in 2019 compared to the CEA Canadian Composite of 8.38 hours. Also, the CPEU has a better SAIDI index than the North American average which, according to IEEE Std 1366-1998, is 1.50 hours. The SAIDI index measures the average duration of interrupted power for all customers served and is a benchmark for a utility's reliability.

There are trends that have implications for electric utilities across North America. These trends include the impacts of climate change, environmental policy, and transportation electrification. In addition, technology is rapidly evolving facilitating advancement in renewable energy, distributed energy resources (DERs) such as solar and battery energy storage systems, and smart grid technologies. These trends present both challenges and opportunities for electric utility owners and operators. The focus of the EMP is to study the impacts of future demand on the system and consider these emerging trends in the forecast scenarios.

A load forecast was developed to model the peak electrical demand based on historical load data, growth factors based on the 2019 Official Community Plan (OCP), and the impacts of electric vehicle demand. With the OCP medium population growth rate of 0.65% per year, overall growth due to population increase is small; however, the impacts of electric vehicle demand could be significant through the EMP study period. Other future unplanned or unanticipated loads, such as a new data centre or new developments could also have significant impacts on the system demand. It can take several years to plan and implement expansion projects such as substations, so it is important to consider these factors in a long-term EMP.

The load forecast provides information required for the update of the electrical system model. Extensive studies were done using CYME software to evaluate backup and contingency scenarios throughout the study period. Recommended capital upgrades were developed based on the results of the model (see Section 4 – Results & Recommendations).

The CPEU system is in very good condition. The replacement of poles and anchors from third party projects has improved the systems condition. Most recommended capital upgrade expenditures (see Appendix I) in this report are related to improving backup and increasing the capacity of the system due to an increase in Electric Vehicle (EV) penetration. This is essential to ensure reliable electricity supply to customers during peak loading times such as very cold winters or very hot summers. It also safeguards against potential substation or feeder outages. Continuing with cyclical and ongoing O&M programs ensures the electrical system's long-term health.

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1. REPORT SCOPE

1.1 TERMS OF REFERENCE

This document is for the sole purpose of delivering the requirements of the City of Penticton 2020-RFP-06 Electrical Engineering Services Section 2.2 Electrical Master Plan. The study focuses on the capacity of the system, the system reliability, and the forecasted impacts to the system with the addition of electric vehicles, renewables, and system growth.

1.2 PROJECT SCOPE

The City of Penticton Electric Utility (CPEU) has engaged Cima Canada Inc. (CIMA+) to develop a 25-year master plan for the electric utility. This report is based on information available from the City of Penticton Official Community Plan (OCP) Bylaw No. 2019-08, consultation with City staff, inputs from the previous 2015 Electrical Master Plan (EMP), and inputs from the City's ArcGIS system.

The report scope includes the following:

+ A study of the impacts of present and future demand on the existing electrical distribution system caused by meeting the vision of the OCP, new electric vehicle infrastructure, and DERs.
+ A list of recommendations with priorities of necessary upgrades to meet forecasted demands to 2045; with emphasis given to the next five years.
+ A project sheet for each recommended upgrade with CIMA+ opinion of probable cost – using the provided template.
+ A summary of recommended upgrade projects.
    - Priorities classified as high, medium, or low based on criticality;
    - Implementation timeline (e.g., 5-year, 10 year, and 25 year to 2045, with an emphasis given to the next five years); and
    - Opinion of probable cost for each project (assumed a 2% inflation rate).
+ An implementation plan and phasing strategy in coordination with the Integrated Infrastructure Master Plan (IMP).

1.3 LIST OF ABBREVIATIONS

APPA -	American Public Power Association
BESS -	Battery Energy Storage System
CAIDI -	Customer Average Interruption Frequency Index
CEA -	Canadian Electricity Association
COP -	City of Penticton
COR -	Certificate of Recognition
CPEU -	City of Penticton Electric Utility
CSA -	Canadian Standards Association
DER -	Distributed Energy Resource(s)
DSM -	Demand Side Management
EMP -	Electrical Master Plan
ERF -	Electrical Reserve Fund
EV -	Electric vehicle
FBC -	FortisBC
FCI -	Fault Circuit Indicator
GHG -	Greenhouse gas
IEEE -	Institute of Electrical and Electronics Engineers
IMP -	Integrated Infrastructure Master Plan
Li-ion -	Lithium-ion battery (LIB)
OCP -	Official Community Plan
PPA -	Power Purchase Agreement
PV -	Photovoltaic
RP3 -	Reliable Public Power Provider
SAIDI -	System Average Interruption Duration Index
SAIFI -	System Average Interruption Frequency Index
SCADA -	Supervisory control and data acquisition
VFI -	Vacuum Fault Indicator
ZEV -	Zero-emissions vehicle

2. INTRODUCTION

2.1 EXISTING ELECTRIC UTILITY SYSTEM

The CPEU is owned and operated by the City of Penticton and provides electrical service to 42 sq. km, that includes a population of 34,400, and over 18,800 residential, commercial, and industrial customers within City limits through medium voltage distribution and four substations (see Figure 1). Power is purchased from FBC at a wholesale rate and resold to CPEU customers at a retail rate. The revenue generated from electrical sales is used to cover the costs associated with running the utility as well as providing an annual dividend to the City which is used to fund general capital projects.

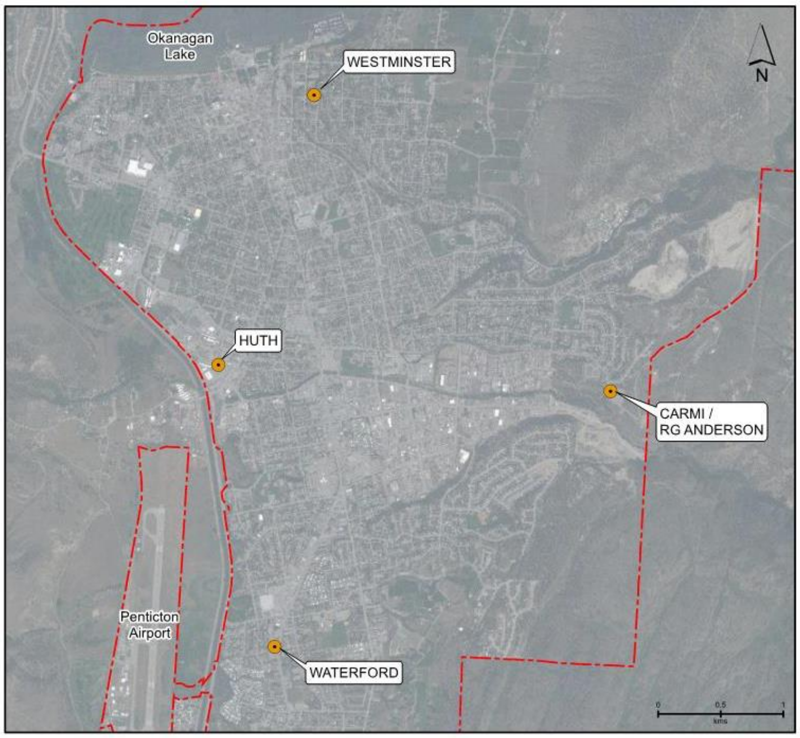

Figure 1: City of Penticton Substation Locations

CPEU presently operates eighteen 12 kV feeders. The City is supplied at 12 kV through a wholesale Power Purchase Agreement (PPA) from the four FBC substations shown above. There are four wholesale delivery points which are shown in Table 1 below.

Table 1: Wholesale Delivery Points

Delivery Point	Substation	Voltage
1	Carmi (RG Anderson)	12 kV
2	Huth	12 kV
3	Waterford	12 kV
4	Westminster	12 kV

To give a perspective of the utility's magnitude, the overhead system network spans approximately 368 km; the underground network is approximately 161 km; and there are approximately 4,100 poles with roughly 2,700 service transformers, both pole, and pad mount. The COP pole data identifies that all overhead poles have been inspected and/or tested in the past eight years. The existing CPEU pole standard is galvanized steel, and new pole line construction is apparent throughout the City.

There is little use of voltage support through line voltage regulation. Three phase ganged switches are utilized at normally open points between feeders. Capacitor banks (approximately one per feeder) of fixed capacity are installed on the system. Many of those capacitor banks are not in use as voltage support is not required on most feeders now that voltage conversion is complete. Considering that the electrical system is restricted to within the City's municipal boundaries, distribution lines are typically short enough in length such that voltage support will not be required. Presently, the only exception to this is with regards to the distribution line that travels North from the Westminster Substation towards Naramata.

2.1.1 ACHIEVEMENTS AND RECOGNITION

The CPEU has taken a proactive approach to energy efficiency and system reliability. Awards for these accomplishments include the FortisBC Efficiency in Action Award in 2016 and the 2016 Philips Environmental Awareness & Knowledge Recognition for CPEU's commitment to sustainability through use of LED streetlights.

The CPEU has completed multiple different projects to help the system be more sustainable and reliable. Of significant note is the completion of the 12 kV converstion of the distribution system. The first plan for this conversion was issued in 1995 with two substations and six feeders converted from 1995-2014 and the remaining two substations and twelve feeders converted from 2015-2020 with over $17 million invested in enhancing the grid. This has resulted in limiting the need for additional substations, or voltage regulators, based on the geographic location of the existing four FortisBC substations. In addition to improving the system capacity and reliability, the voltage conversion has also reduced significant line losses through the system making it more efficient.

Other projects and CPEU initiatives in recent years include:

+ Built a new SCADA system
+ Deployed field-controlled devices:
  - Switchgear
  - Voltage Regulators
  - Fault Circuit Indicators
+ Eliminated hazardous copper conductors
+ Eliminated all PCB's from the system
+ 1st department to fully deploy GIS
+ Rebuilt East Lane of Main Street
+ New Hospital supply and integration with SCADA
+ Eliminated a number of privately owned HV services – making the community safer.

2.1.2 FORTISBC GENERATION SUPPLY

Currently, the bulk of CPEU electricity is supplied by a wholesale PPA with FortisBC. This section covers how FBC supplies its customers with their electricity needs.

FBC generates 45% of its customers electricity from four hydroelectric generating stations. These four generating stations have an aggregate capacity of 225 MW. They provide 30% of the peak capacity needs of FBC (FortisBC, 2020):

+ Corra Linn
+ Upper Bonnington
+ Lower Bonnington
+ South Slocan

The remaining electricity comes through long-term and short-term power purchase contracts (FortisBC, 2020). Presently, there are six PPA's:

+ The Brilliant PPA;
+ The BC Hydro PPA;
+ Brilliant Expansion Capacity and Energy Purchase Agreement;
+ Several small power purchase contracts with certain independent power producers (less than 1% of energy supply requirements);
+ Spot market and contracted capacity purchases (approximately 12% of energy supply requirements); and
+ The WECA.

From these six PPA's, approximately 90% of FBC's energy requirements are from hydroelectric generating plants. More information regarding the above PPA's can be found in Appendix A.

2.2 RELIABLE PUBLIC POWER

The *American Public Power Association (APPA) – Reliable Public Power Provider* (RP3) application guide provides a useful reference to direct the operation of a utility in order to manage the performance to a nationally accepted set of criteria (American Public Power Association, 2017). A review of these criteria provides a benchmark that can help determine where the CPEU meets, exceeds, or is lacking compared to the guideline. The objective is to bring the utility's operation and planning to a state where it could achieve RP3 "gold level" with APPA (high proficiency in reliability, safety, work force development, and system improvement).

A potential benefit is for the COP to communicate excellent reliability to attract economic development with new businesses. The goal is not necessarily to apply for the status, but to use it as a reference for best practices by a municipal utility. This will allow the CPEU to benchmark their performance against other electrical utilities that have similar operating conditions. The recommendations in the guide are grouped into four categories:

1. Track and improve reliability
2. Create a culture of safety
3. Develop the work force
4. Improve the electrical system capacity

2.2.1 TRACK AND IMPROVE RELIABILITY

TRACK RELIABILITY

The electric utility industry uses several metrics to track and report on system reliability. Organizations such as the Canadian Electricity Association (CEA) benchmark these metrics. Industry standard service indices are defined below and capture the duration and frequency of outages:

SAIDI: System Average Interruption Duration Index

$$SAIDI = \frac{Total\ Customer\ Hours\ of\ Interruption}{Total\ Customers\ Served}$$

SAIFI: System Average Interruption Frequency Index

$$SAIFI = \frac{Total\ Customer\ Interruptions}{Total\ Customers\ Served}$$

CAIDI: Customer Average Interruption Frequency Index

$$CAIDI = \frac{Total\ Customer\ Hours\ of\ Interruption}{Total\ Customer\ Interruptions}$$

Index of Reliability: Per-unit annual customer hours of service available

$$Index\ of\ Reliability = \frac{8760\ hours - SAIDI}{8760\ hours}$$

The CPEU started tracking these reliability metrics in 2014. CPEU participates annually in the CEA surveys and the manager of CPEU participates as a member of the CEA's service continuity committee. Figure 2 below shows a comparison, of the CPEU's SAIDI Index, with the Canadian Electricity Association (CEA) Canadian Composite, BC Hydro (BC Hydro, 2019), and FortisBC (FortisBC, 2019). It is important to note that the nature of service areas, such as rural or urban, can have varied reliability profiles. The CPEU services mainly urban and suburban customers compared to many other Canadian utilities which have more rural customers. The CPEU's SAIDI Index, which measures the interruption duration for the average of all customers, was 0.70 hours in 2019.

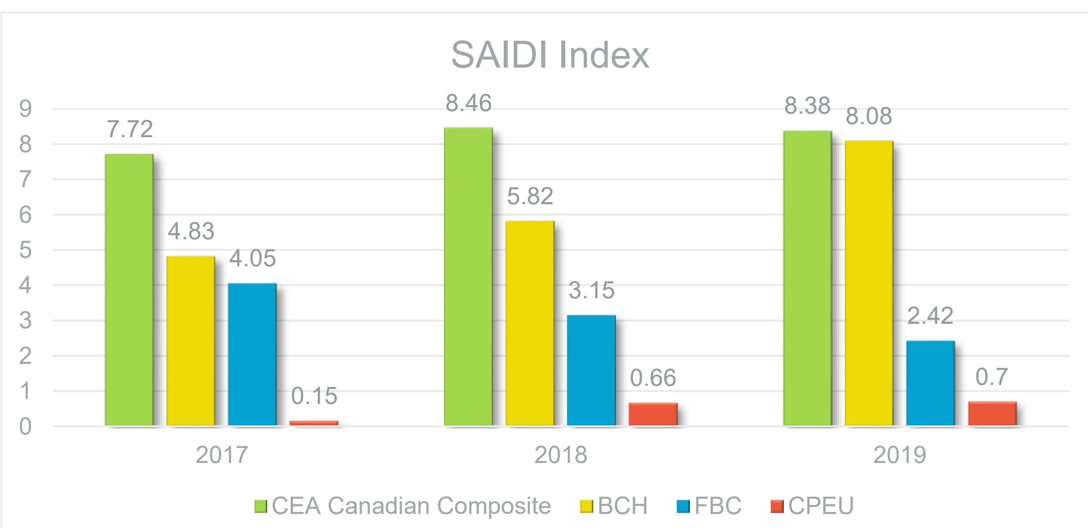

Figure 2: SAIDI Comparison between CEA Canadian Composite, BC Hydro, FortisBC, and CPEU

Reliability indices can be used as a marker to help improve the system's reliability. Methods for using the indices to improve the system:

- Worst performing circuit identification;
- Vegetation management;
- Distribution circuit inspection program;
- Overhead to underground conversion programs;
- Installation of animal/squirrel guards;
- Transformer load management;
- Underground cable replacements;
- System reinforcement for backup and contingency operation;
- Public communication and reporting;
- Other reliability improvements.

Other aspects of reliability scoring for the APPA include Mutual Aid, Disaster Planning, Physical Security, and Cyber Security.

IMPROVE RELIABILITY

The CPEU has recently improved their reliability by completing projects and deploying items such as:

- Replace #1/0 Cu with #477 AAL on Eckhardt Ave between Government St and Main St;
- Replace #4/0 ACSR on R12 with #477 AAL on Duncan Ave, Pine St, Ridgedale Ave, Debeck Rd, and Hudson St;
- Replace existing overhead conductor with #3/0 ACSR, and existing underground cable with #4/0 AL along Burnaby Ave and Dynes;
- Replace #3/0 ACSR along Westminster Ave W from Rigsby St to Power St and along Power St from Westminster Ave to Wade Ave with #477 AAL;
- Replace #4/0 ACSR along Main St from Industrial Ave to Dawson Ave with #477 AAL;
- Carmi Substation 13 kV Upgrade;
- Install #4/0 AL in conduit between R10 and R24;
- Replace Pad Switch 6-10 with 3 x 600 A and 1 x 200 A Switch;
- Fault Circuit Indicators (FCIs);
- Motor operated Vacuum Fault Interrupters (VFIs) switchgear; and
- Improvements to the SCADA network.

Through studying the system and consulting CPEU staff, there were some additional reliability improvements recommended:

- Complete Lawrence Ave loop;
- Underground Main St between Westminster Ave and Eckhardt Ave; and
- Replacement of Top Hat and Cobrahead LED streetlights.

These recommendations are outlined in Section 4 of this EMP.

2.2.2 SAFETY

Safety is the top priority for electric utilities. It is paramount to ensure the safety of the public and all the workers involved in the operation of the electric utility infrastructure. Safety encompasses all aspects of the organization, starting with a strong safety culture. Safety is incorporated into the planning process, and design practices include safety by design to eliminate or mitigate safety risks even before starting construction.

An annual review of the CPEU safety program and safety manual is recommended. Aspects of the safety review should include, but not be limited to, safety culture, safety meetings, enforcement, tailboards, safety equipment such as defibrillators and associated training, arc flash assessment and awareness, disaster preparedness, safe work practices, and safety index benchmarking. The COP's vision to move towards COR certification is in direct alignment with this target.

2.2.3 DEVELOP THE WORKFORCE

Workforce development is an important part of the APPA guide and includes Succession Planning and Recruitment, Employee Development and Recognition, Education, Participation and Service. While important to the operation of the utility, the elements of workforce development are beyond the scope of this report.

2.2.4 IMPROVE SYSTEM CAPACITY

The System Improvement component of the APPA guide encompasses Research & Development, System Maintenance and Betterment, and Financial Health. Specific elements within these categories include system losses, planning study, customer owned DERs, financial health policies and procedures. The CPEU has implemented various projects and programs as listed in the reliability section above – many of these grid enhancements also increase and improve the system capacity. This EMP is in direct alignment with the RP3 as it focuses on increasing reliability and system capacity while supporting safety and workforce development initiatives.

2.3 INDUSTRY TRENDS

The electric utility industry is facing many pressures and changes due to a combination of factors including climate change, technology advancement, and aging infrastructure. Policy makers and users are driving transitions to new forms of electrical energy use such as electric vehicles and emerging loads such as crypto mining facilities. Customers are increasingly generating their own electricity, for example, with roof-top solar. A portion of this customer generated electricity can be returned to the grid with net-metering. These factors have many implications for electric utility operators, such as the reverse flow of power, which is a fundamental shift in the way the power grid operates.

Key Forces	External Factors	Emerging Solutions
Climate Change Technology Advancement Aging Infrastructure	Transportation Electrification Customer Owned Generation Emerging Loads (i.e. data centres, crypto mining)	Renewable Energy: wind, solar, biomass, hydro Distributed Energy Resources (DERs) Smart Grid

RENEWABLE ENERGY AND DISTRIBUTED ENERGY RESOURCES

Due to the desires of the public, as a result of global challenges in relation to consumer energy consumption and generation fuel sources, renewable energy initiatives have been increasingly adopted and are becoming a societal norm. Renewable energy generation sources are fueled by natural sources or processes that can be replenished faster than it can be consumed. Commonly known renewable energy resources such as wind and solar photovoltaic (PV) are becoming increasingly common in the generation mix that is utilized to meet load demands from the grid. Some lesser known forms of renewable energy resources include geothermal, hydropower, and biofuel generation. The adoption of large-scale renewable energy generation exhibits its own operational and grid reliability and resiliency challenges. As such, the adoption of such sources into the transmission network are becoming increasingly complex to mitigate system failures.

Smaller scale renewable energy generation is often connected at the distribution level to facilitate supplying local loads. These form part of the evolving distribution network in conjunction with the adoption of DERs and smart grid technology with the goal of a sustainable energy future. DERs are defined as electricity-producing and storage resources or controllable loads (including EVs) that are directly connected to a local distribution system or connected to a host facility within the local distribution system. The adoption of DERs within the distribution grid yields unique challenges and benefits. Such benefits include reductions in line losses, reduction in infrastructure upgrade requirements, increased reliability and voltage profile improvement. Some challenges include bi-directional power flows and system characteristic changes. The adoption of DERs within distribution networks have been facilitated globally through green initiatives with many systems experiencing increasing penetration levels. This trend is expected to continue considering the challenges to such changes can be overcome using modern-day technology and methods.

One method of DER and renewable energy implementation that has gained a lot of attention is the use of microgrids. Microgrids are a cluster of local loads and DERs that can transition a small section of a network between grid and islanded modes seamlessly. The result is that local loads can be serviced without interruption even without the presence of an energy source from the wider electrical grid. Microgrids are beginning to emerge as a practice for increasing reliability metrics for utilities in addition to increasing resiliency of critical loads. Although microgrids are outside the scope of this report, they are a candidate for consideration should reliability and resiliency issues become apparent in the future.

Considering the widespread adoption of DERs and renewable generation within distribution networks, it has become prudent for utilities of all sizes to consider their overall potential effects when creating master plans such as this report. This ensures that industrial trends and shifts are present within planning metrics mitigating the occurrence of unexpected outcomes.

SMART GRID

With the challenges associated to the introduction of DERs, adaptable technologies and solutions are being increasingly adopted to mitigate risks and reinforce grid reliability and resiliency. The realization of this forms the basis of the concept of the smart grid. A smart grid can be defined as an electrical system that entails the fusion of advanced measurements, communications, controls, cyber systems, and energy storage to make delivery of electricity more efficient, reliable, and secure. There is not one aspect of a grid that marks it “smart”, it is the fusion of all the processes that lead to the automated operation of the grid that give the appearance of an intelligent system.

Smart grid technologies include, but are not limited to, the use of relays that can adjust their settings dynamically based on grid conditions, outage management systems including automatic switching, automated load and generation control, advanced fault detection and real-time pricing and demand responses. The introduction of such technologies allows for the increasing penetration of DERs to be managed in such a manner that the grid is not at a significant risk of failure.

Smart grid outage management systems have the capacity to identify faulted feeders and consumption points and then actively instruct switches throughout the network to open/close in a sequence that limits instability issues whilst re-energizing significant portions of affected customers in short time frames. This leads to an improvement in reliability metrics which demonstrate overall performance. Advanced outage management systems are being increasingly deployed with utilities globally, often through the existing SCADA (supervisory control and data acquisition) network, while achieving desirable outcomes.

Many utilities are deploying “smart capable” technologies throughout their networks to facilitate the potential transition to an automated grid. Many relays are available in the market that can be operated as a traditional relay or can be communicated with to achieve outcomes such as adapting settings in accordance with real-time grid conditions. While many of these relays have higher costs associated to them initially, their increased capabilities grant flexibility in future planning activities due to the removal of many protection infrastructure upgrade requirements when attempting to achieve smart grid characteristics.

The culmination of multiple smart grid technologies fused together is widely observed as being the solution to accommodating increasing DER penetration in distribution networks. This trend is expected to continue, meaning that potential risks associated with DER penetration may be exacerbated should the introduction of smart grid technologies be prolonged. One such way to facilitate this transition is through the replacement of aged infrastructure that has the capacity of operating seamlessly within a smart grid architecture.

The work identified in the EMP is foundational to address the capacity constraints within the network. The aforementioned projects are important for future consideration when system upgrades are planned as they will allow for a natural smart grid growth within the network. However, considering the current CPEU system reliability and planned projects there is not an immediate need for such upgrades and as a result they fall outside the scope of this report.

TRANSPORTATION ELECTRIFICATION

The electrification of transportation is growing rapidly and will have significant implications for electric utilities. Transportation electrification involves the transition of traditional gas- or diesel-powered engines to electrically powered motors. This transition is primarily driven by policy goals to reduce greenhouse gas (GHG) emissions; however, with the advancement of technologies such as lithium ion (Li-ion) batteries, electrified transportation is also becoming more attractive based on pure economics.

Transportation electrification encompasses passenger vehicles, fleet vehicles, busses, locomotives (trains), trucks (including commercial and freight), air transportation, recreational watercraft, cargo ships, bicycles (e-bikes), scooters, alternative transportation, and other forms of electrified transportation. Due to a combination of factors including costs, energy density, safety, and lifespan, lithium ion batteries are currently the main form of energy storage for transportation electrification. Other forms of electrical energy storage, such as hydrogen, are available and are under active development.

This study focuses on the potential impacts of increased electric vehicle usage within the City of Penticton for passenger transportation. The Province of British Columbia passed the Zero-Emission Vehicles Act (ZEV Act) on May 30, 2019 (British Columbia Government, 2019). The ZEV Act requires automakers to meet an escalating annual percentage of new light-duty ZEV sales and leases, reaching: 10% of light-duty vehicle sales by 2025, 30% by 2030, and 100% by 2040. This policy is expected to have significant impact on the adoption of EVs within the province and has implications for the electric utility as identified in this study.

This study does not investigate the impacts of other forms of transportation electrification that may occur within the City of Penticton, such as the electrification of busses, fleet vehicles, rail, air, or other forms of transportation electrification. At this time, we are not aware of COP initiatives to implement additional electrification measures; however, if the electrification of busses or fleet vehicles is being considered, we recommend a detailed electrification study be developed. This study should review the charging infrastructure requirements and impacts on the system demand at a feeder, substation and system level.

The impacts of hydrogen energy storage and associated hydrogen powered transportation is beyond the scope of this report. Hydrogen can be generated through various methods, including from natural gas and electrolysis.

DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY

Demand side management (DSM) is an approach to offsetting generation requirements by reducing the customer end use demand. DSM programs focus on changing the shape of the daily load curve to reduce the system demand (peak load in kVA) and energy efficiency programs focus on reducing total consumption (kWh). DSM and energy efficiency programs often go together as many energy efficiency initiatives also reduce system demand.

The 2007 BC Energy Plan set an ambitious conservation target of 50% of electricity demand growth and encouraged utilities to offer DSM programs to their customers (Province of British Columbia, 2020). This mandate was reaffirmed with the 2010 Clean Energy Act, which set a conservation target of 65% for new electricity demand growth for BC Hydro until 2020 (Queen's Printer, 2010).

FBC has a DSM program that extends to the CPEU customers and it includes both DSM and energy efficiency initiatives to reduce energy consumption for residential, low income, commercial, and industrial customers. Examples of the FBC DSM programs include lighting retrofits, appliance upgrades, energy efficiency renovation improvements, and temporary load curtailment. Additional information on FBC DSM and energy efficiency programs can be found on the FortisBC website[1].

Based on the FBC demand-side management 2019 annual report, FBC spent over $10 million on DSM initiatives and saved an estimated incremental 25,791 MWh (FortisBC, 2020), representing approximately 1% of the annual FBC energy consumption. These energy conservation initiatives impact the CPEU electrical demand and have been intrinsically factored into the load forecast model.

As a municipality and utility, the COP has also invested in its own energy efficiency programs. For example, the CPEU was an early adopter of LED street lighting and has received recognition for this achievement in sustainability. The peak shaving generator pilot program is another innovative example of implementing DSM.

In addition, there has been an announcement that BC will be incorporating a new standard, the BC Energy Step Code, in order to make buildings net-zero energy ready by 2032. As part of this, the BC Building Code will adopt the Step Code standards in intervals over the next several years (Energy Step Code, 2019). From a utility perspective, the Step Code will only effect new builds. With the COP predicting a small amount of new builds, the Step Code will not impact the CPEU in any significant manner.

With the advancement of smart grid technologies, the utility has increasing options and data available to pursue DSM initiatives. For example, many customers are installing smart thermostats, which could potentially be controlled by the utility for load curtailment. These approaches to DSM can be explored by CPEU as technologies mature and become more practical to implement.

[1] https://www.fortisbc.com/rebates-and-energy-savings

RESILIENCY

During recent years, utilities have been experiencing an increase in low-probability but high-impact events. Grid resilience is the ability to withstand major unprecedented events such as a major natural event or cybersecurity attack. A resiliency study involves an in-depth review of the City's electric utility infrastructure and develops recommendations to enhance the electric utility's resilience. While the EMP focuses on the capacity and reliability of the system, including the potential impacts of emerging disruptors such as electric vehicles, a resiliency study focuses on preparing the utility for unanticipated major impact events. For example, the Master Plan studied one lost element (N-1) scenario; whereas, a resiliency study aims to prepare the utility for cascading or simultaneous failures, such as a cyber-physical attack that could disable multiple elements in the system concurrently.

The resilience model encompasses four key areas:

+ Preparation: self-assessment, emergency planning, and scenario-threat impact models.
+ Mitigation: mitigation assessment, resource mitigation measures, power system restoration, and black-start resource planning.
+ Response: Impact assessment of major potential events and emergency management response plan development.
+ Recovery: Emerge, Manage, Communication, Collaboration.

Specific scenarios can be developed and assessed to mitigate the effects of rare but high impact events. Scenarios that may be considered specific to the CPEU may include fires, cyber security attacks, cyber-physical attacks, terrorism, solar flares, total loss of supply from FBC, and other low-probability high-impact events.

It is recommended CPEU undertake a resiliency study to guide the process of preparation, scenario analysis, and develop recommendations to enhance the distribution system.

3. METHODOLOGY

The approach to developing the CPEU EMP included three phases: (1) review of existing plans and information (background), (2) load forecast, (3) electrical system modelling.

REVIEW OF EXISTING PLANS AND INFORMATION (BACKGROUND)

The first phase of the CPEU EMP was to review the existing plans and information. To begin this phase, a review of the 2019 OCP was conducted, followed by a review of the inputs. The background review included:

+ OCP supporting documentation (e.g., land use changes);
+ Policy updates (e.g. net metering, energy efficiency, and electric vehicle adoption);
+ ArcGIS data update;
+ Historical feeder and system loading data from SCADA;
+ Billing history (peak demands and energy use confirmation);
+ Known land developments and major projects; and
+ Available population and economic forecasts.

Once these reviews were completed, an in-person kick-off meeting was scheduled with the CPEU staff. This meeting confirmed which DERs would be included in the study. The DERs confirmed were:

+ Solar (residential, new City-owned, existing City-owned);
+ Peak Shaving backup generators; and
+ Battery energy storage systems.

To ensure the model was including the correct inputs, key CPEU staff were consulted. Once confirmed that the model was complete, a review of demand limits, capacity criteria, and contractual limits between CPEU and FBC was assessed. Following the previously mentioned assessment, the CYME model was updated based on an extract from ArcGIS. The next step in this phase was reviewing the previous capital budget sheets to confirm their status. Asset management data supplied by the CPEU, including asset age and condition assessment information, was reviewed and incorporated into the study. Additionally, the Penticton Alternative Generation Study, and CPEU's reliability statistics were reviewed as inputs to the EMP.

LOAD FORECAST

The load forecast is a linear regression model that leverages the historical electric utility loads in combination with the OCP and development plans for the City. The load forecast update included the following steps:

+ Identified of known developments and major projects in coordination with the City Development Engineering Department and CPEU.
+ Collected, process, and synthesize historical feeder data from the CPEU SCADA system.
+ Determined regional growth factors from regional population and economic data.
+ Performed basic weather normalization analysis.
+ Performed a high-level review of the climate change impacts on future load projections.

- Performed two electric vehicle load forecast scenarios.
- Performed two load forecast scenario analysis for DERs based on the Penticton Generation Study report.
- Reviewed load forecast results with CPEU to confirm growth factors and results prior to beginning the CYME load allocation and modelling.

ELECTRICAL SYSTEM MODELLING

The CPEU network was modelled using CYME software, which is a power engineering analysis software package that is used extensively in the industry to model electrical network behaviours.

The following activities were completed to update, calibrate, and run the model:

- The CYME model was updated based on the latest system changes and configuration.
  - An updated extract from the City's ArcGIS platform was used to update the feeder configurations and conductor sizes.
  - Identify and determine 'locked' spot loads for the CYME model.
  - Develop a new 2020 CYME base model.
- Incorporated additional key generation sources into the CYME model based on the Generation Study report and discussion with CPEU.
- CYME load allocation.
- Calibrated the model and re-run the load allocation.
- Performed back-up and contingency analysis.
  - Include back-up analysis for the support from and the support of FBC lines along Naramata road.
- Developed CYME model scenario for future years to evaluate the system weaknesses.
  - Major projects were incorporated in the future year CYME scenarios such as the undergrounding of the Main St back alleys of downtown Penticton and other key projects as identified in the OCP.
- Identified the list of capital upgrades required based on the CYME model and back-up analysis. Found in Section 4.3.
- Validated the impact of recommended upgrades with the CYME model.

3.1 BACKGROUND

3.1.1 REVIEW EXISTING MODEL AND PLANS

In preparation for developing the master plan CYME models, we reviewed the existing model and budget plans. During this phase CIMA+ undertook the following activities:

- Reviewed demand limits, capacity criteria, and contract limits with CPEU and FBC.
- Reviewed the CYME model and validate with an updated extract from ArcGIS.
- Reviewed previous capital budget project sheets to confirm status.
- Reviewed CPEU's asset management and maintenance program data and results.
- Reviewed the Generation Study Report.
- Reviewed CPEU's reliability statistics.

3.1.1.1. CITY OF PENTICTON OFFICIAL COMMUNITY PLAN

In 2020, the City of Penticton has an approximate area of 42 square kilometers and an approximate population of 34,440 (City of Penticton, 2019). The City of Penticton has experienced slow but steady population growth for the last twenty years, and that trend is expected to continue. The Official Community Plan (OCP) outlines an anticipated medium population growth scenario of 0.65% per annum to the year 2046, at which time the forecasted population would be 41,900. The population growth would be largely in the 65+ age demographic with the under 64 age population demographics remaining relatively steady into the future. This growth would facilitate the need for approximately 4,450 new residences, as well as increased commercial and industrial floor space, over the 25-year forecast.

New housing projects will be diversified through the construction of infill, single detached homes, duplexes, townhomes, and apartments. Plans indicate the improvement of existing developed land to include more mixed use and multi-family residences. The bulk of high density residential and higher end commercial/office space will be directed downtown.

The EMP will address the forecasted load growth in all areas of the City, based on the OCP assumptions. Thus, ensuring the CPEU has the information required to accommodate the evolution of the City and can plan accordingly.

3.1.1.2. GENERATION STUDY

CIMA+ participated in the City of Penticton Generation Study (hereafter referred to as "The Generation Study") as part of the City Council power generation program as one of the 2020 initiatives. The Generation Study, led by Midgard Consulting, in 2019 to 2020 identifies potential new investment ideas that the COP could consider in order to reduce CPEU demand (and potentially energy) charges from FBC (Midgard Consulting Incorporated, 2019). This study was the first step in completing a high-level analysis to see which types of projects were worth pursuing by the COP.

For the final report, 17 generation alternatives were considered and discussed. Out of the 17 alternatives, only four alternatives passed the established screening thresholds. These four alternatives included:

+ Peak Shaving (Diesel)
+ Peak Shaving (Battery)
+ Solar – City Owned Rooftop (New Build)
+ Solar – City Owned Rooftop (Retrofit)

These results were presented to City Council and the Community Sustainability Advisory Committee. The COP was left with the following recommendations:

+ Pursue the Alternatives ranking in the TOP bin either as standalone projects or in combinations (e.g., Solar + Battery);
+ Pursue grant funding to offset development costs; and
+ Consider Electrical Reserve Fund (ERF) funding for next fiscal period to implement preferred Alternative(s).

For clarity, Table 2 below shows Table 35 from The Generation Study which has the results in three ranking categories: TOP, MIDDLE, and BOTTOM. The TOP bin is for the desirable outcomes. The MIDDLE bin is for marginally desirable outcomes. The BOTTOM bin is for undesirable outcomes. All outcomes (desirable / marginal/less desirable) were defined by The Generation Study ranking system to produce the above recommendations.

Table 2: Ranking and Recommended Action

Rank	Grant Funding Scenario	ERF Scenario	Recommended Action
TOP	7 Solar - City Owned Rooftop - New Build 12 Peak Shaving (Battery) 13 Peak Shaving (Diesel)	7 Solar - City Owned Rooftop - New Build 8 Solar - City Owned Rooftop - Retrofit 12 Peak Shaving (Battery) 13 Peak Shaving (Diesel)	Pursue
MIDDLE	3 Randolf Irrigation 8 Solar - City Owned Rooftop - Retrofit 10 Solar - Customer Net Metering - Rooftop	2 Penticton Creek (WTP) 3 Randolf Irrigation 10 Solar - Customer Net Metering - Rooftop 14 Geoexchange	Consider after Top Alternatives
BOTTOM	1 Greyback Dam 2 Penticton Creek (WTP) 4 Penticton Channel 9 Solar - City Owned Ground Mount 14 Geoexchange	1 Greyback Dam 4 Penticton Channel 9 Solar - City Owned Ground Mount	Do Not Assess Further

PEAK SHAVING (DIESEL AND BATTERY)

For the purposes of this EMP, it is noted that a pilot project, for Peak Shaving (Diesel), has already been initiated by the CPEU and is planned to be in place by 2021. Data will be collected and analyzed to monitor the effectiveness of the approach.

The Peak Shaving (Battery) alternative is being considered pending funding and potential grant opportunities.

SOLAR – CITY OWNED ROOFTOP

There were two options considered for siting new city owned rooftop solar:

1. Use existing City owned buildings; or
2. Install solar on a new building.

CIMA+ has been informed that the COP has no plans for a new building. Therefore, Option 2 likely will not be a reality for at least 10 or 15 years. However, there was interest to investigate the retrofit option of existing City-owned buildings. During the Generation Study, it was noted that structural enhancements are likely required and allocating space for panels on existing buildings is expected to be expensive and would require further investigation to pursue.

3.1.2 ELECTRIC UTILITY ASSET AGE AND CONDITION

While asset management and condition assessment are outside the scope of this report, it is important to consider the asset age and condition in the development of a holistic plan for the CPEU. The CPEU has established asset assessment and maintenance cycles, which are summarized in Table 3.

Table 3: Asset Management and Maintenance Cycles

ASSET	PERIOD	METHOD
Distribution Substation	Monthly	Visual Inspection
Distribution Substation	4 Year	Recloser refurbishment Protection Setting Review
Distribution Substation	2 Year	Substation Inspection and Cleaning
Distribution Substation Pot-head Risers	Annual	Infrared Thermographic Survey and Visual Inspection
Overhead Circuits and Connections	Annual	Infrared Thermographic Survey and Visual Inspection
Transformers (Polemount)	3 Years	Infrared Thermographic Survey and Visual Inspection
O/H Gang Switches	Annual	Infrared Thermographic Survey
O/H Gang Switches	5 Years	Preventative Maintenance
Poles and Structures	3 Years	Visual Inspection
Poles and Structures	8 Years	Wood Rot Test
Vegetation Management	3 years	Tree trimming / Brush clearing
Transformers (Padmount) – Single Phase	3 Years	Visual Inspection
Transformers (Padmount) – Three Phase	3 Years	Infrared Thermographic Survey and Visual Inspection
Padmount Switchgear and Junctions	3 Years	Infrared Thermographic Survey and Visual Inspection

3.1.2.1. DISTRIBUTION POLES

WOOD POLES

The CPEU has taken a proactive approach to the testing and replacement of wood poles; the testing uses specialized test equipment. Defective poles are identified for replacement and critical poles are replaced immediately with a high priority placed on those equipped with transformers, underground cable connections, or poles that have an additional public safety implication, such as those in proximity to schools or parks.

The average age of a wood pole in the system is 40 years, the average age for a non-wood pole is 15 years. There are approximately 1,292 wood poles (46%) which are greater than 40 years old. There are approximately 747 wood poles (27%) which are greater than 50 years old. Figure 3 below shows the age distribution of wood poles in the City of Penticton. A sustainment budget of $ 8,000 per pole on average to replace the aging wood poles with steel poles has been included in the budget summary. The timing of replacement should be based on the results of the routine condition assessment. Based on the Integrity Pole Inspection reports, 46 wood poles were marked for replacement in 2019 and eight poles were marked for replacement in 2018.

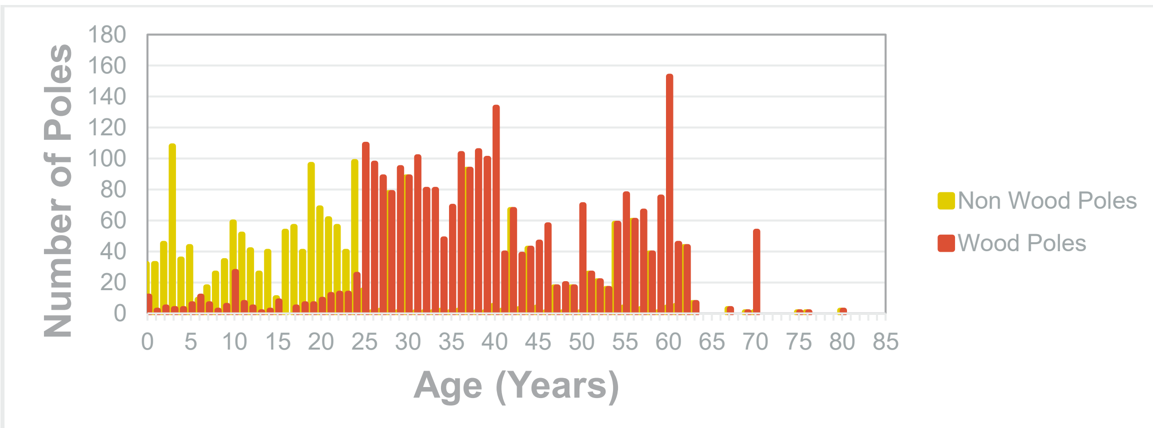

Figure 3: COP Pole Histogram

According to a study done for wood poles in British Columbia (BC Hydro, 2001), western red cedar poles have an average lifespan of 57 years (with a standard deviation of 15). While most poles have not reached their average lifespan, there are a number of poles that have slightly exceeded the average lifespan and as a result the annual number of required pole replacements is expected to increase in the coming years.

STEEL POLES

The COP has been installing steel distribution poles since 1993. The lifespan of these poles is anticipated to be around 60 to 80 years.

Maintenance is minimal on steel poles because they do not shrink so re-tightening hardware is not required. Also, steel retains its shape and strength and isn’t susceptible to cracking or damage by woodpeckers, insects, rot, or fires.

Steel poles do not require a test and treat program like wood poles, but it is recommended that they be inspected in the same 8-year cycle as wood poles. This is due to the potential for damage, most often from vehicles.

3.1.2.2. DISTRIBUTION TRANSFORMERS

The CPEU completed the replacement of 8 kV transformers with dual voltage (8 and 12 kV) transformers during its multi-decade voltage conversion program. The CPEU has taken a proactive approach over the past five years to help improve the safety of their customers by working with them to eliminate customer owned high voltage transformers. Most customers that owned these transformers were not aware of the maintenance and Technical Safety BC requirements. Reoccurring maintenance had not been completed. With CPEU taking over these assets, safety and reliability has been improved while reducing customer's liability.

Any remaining 8 kV transformers are customer owned and supplied by a 12 – 8 kV step-down transformer. Figure 4 below summarizes the age of the distribution transformers. The typical average lifespan of a distribution transformer is approximately 40 years depending on loading, number of faults, and other factors. Based on the GIS records, there are approximately 2,700 distribution transformers in the system with a small portion over 40 years old. Depending on the condition and loading, these older transformers may continue to operate for many years. The routine condition assessment should identify any transformers that require replacement. Overall, the transformer ages are very good compared to many North American electric utilities.

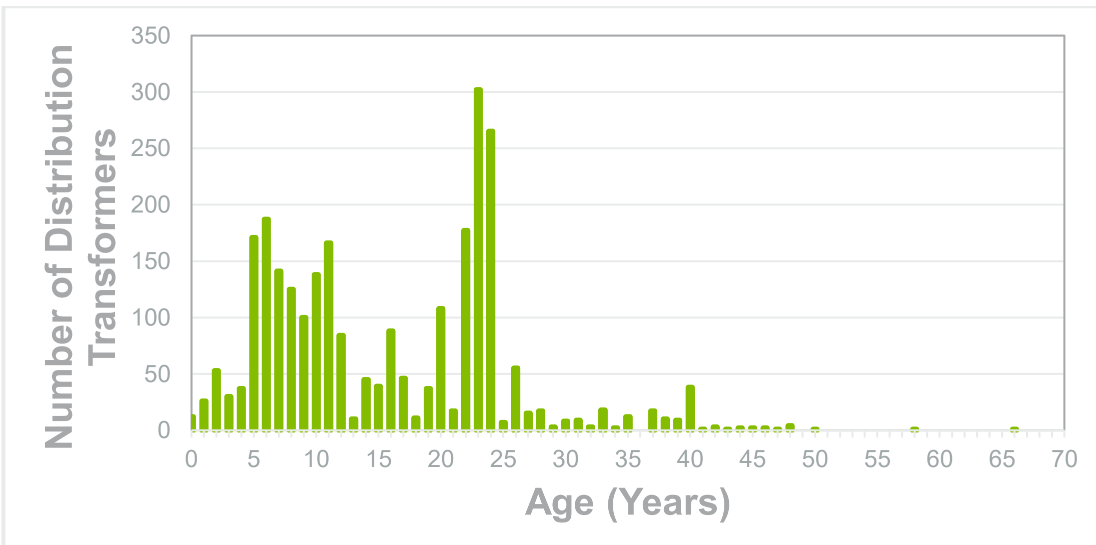

Figure 4: COP Transformer Histogram

3.1.2.3. UNDERGROUND CABLE

Underground cables manufactured before 1970 have a weak insulation design and cables manufactured from 1970 to 1981 were likely steam cured. These cables have a higher risk of failure due to a phenomenon called water treeing. In general, the lifespan of a cable depends on the normal loading limits and normal operating temperature. According to "Electrical Power

Equipment Maintenance and Testing" by Paul Gill, the normal lifespan of the cable insulation is approximately 30 years (Gill, 1997).

Utility experience is that underground cables installed in this time period begin to fail around 30 to 35 years old. Since the CPEU's underground system has operated at 8 kV on a 15 kV rated underground cable, the likelihood of cable insulation breakdown is lower than most utility's experiences.

What is Water Treeing?

Water trees are small discrete voids separated by insulation and they develop over a period of many years. The most dangerous water trees are those that initiate from imperfection between the insulation and the semiconducting shield. Excessive treeing has led to the premature failure of many polyethylene cables. Manufacturing processes have improved over time and reliability of newer cables are increasing.

Reference: Electric Power Distribution Handbook, T.A. Short, 2004, Chapter 3.7

The replacement of underground cables in an emergency condition can be expensive and time consuming, resulting in extended Customer outages. Many utilities have implemented cable injection and cable replacement programs. Cable injection is a process that can extend the life of cross-linked polyethylene (XLPE) cables that are at risk of failure from water treeing. In many cases, cable injection is not effective (for example, the injection process is blocked by any splices in the cable) and the only option is to replace the cable.

The following data was obtained from the GIS system for cables installed prior to 1990:

+ 840 m of 1C + 3C 750 MCM Al. Approximately 1% of the system cable.
+ 33.8 km of 1C + 3C #2 Cu. Approximately 20% of the system cable.

At the time of this report, operations have reported limited instances of cable failure. However, these cables are now more than 30 to 40 years old and are at higher risk of failure.

The cost of replacing the cables will vary greatly depending on the availability of usable conduit systems, accessibility for equipment, and other factors such the amount and type of landscaping, road, or sidewalk repair.

It is recommended that a cable replacement program be established to identify at risk cables and determine the course of action to ensure system reliability is maintained.

The options may include:

+ Complete cable replacement program;
+ Cable silicone injection program;
+ Replace only direct buried cables and run cables in conduit systems to failure where they can be effectively replaced on an emergency basis;
+ Run to failure or reevaluate after more cable failures occur in the future.

A proactive program can provide the following benefits over an emergency repair:

+ Less outage time (better reliability): In many cases, outages can be completely avoided through a planned replacement.
+ Lower cost due to planned work installation compared to overtime and unscheduled emergency work.
+ Lower cost when the replacement can be incorporated into other system upgrades and municipal projects.

The replacement program can evaluate the business case for each cable type based on risk of failure, reliability impact, and rejuvenation cost.

3.1.2.4. OVERHEAD CONDUCTOR

Many utilities have or are upgrading their ageing infrastructure to meet load requirements and improve system safety and service reliability. Utilities have experienced higher failures associated with old small copper conductors which have a direct impact on safety and reliability. Overhead copper conductors become brittle as they age, and the older #6 and #8 copper conductors are particularly prone to breaking due to their smaller size. Special operating procedures are also required when working with brittle copper overhead conductor. The CPEU has been replacing the hazardous copper circuits for the past several years and based on the GIS records, nearly all of #6 and #8 copper conductors have been replaced.

3.1.2.5. SUBSTATION CONDITION ASSESSMENT

Based on CPEU operating staff, the substation reclosers at the Huth and Waterford are approaching end of life. It is recommended that a condition assessment of each of the substations be performed. The condition assessment should include an assessment of the reclosers and a plan for replacement. The CPEU has recently received some substation refurbishment recommendations by others and these are provided in Appendix G for reference.

3.2 LOAD FORECAST

The first stage of updating the load forecast was to obtain the latest feeder data. Data was obtained for 2016 to 2019 from the SCADA system. Data collection had intervals of one minute in the years 2016, 2017, and 2018. In 2019 the data was recorded in intervals of 10 minutes. From this data, the average and peak demands were found for each feeder in both the summer and winter seasons. The seasons were divided into six-month periods, shown in Table 4 below.

Table 4: Summer and Winter Months

Summer	April	May	June	July	August	September
Winter	January	February	March	October	November	December

Furthermore, a check was made to ensure system load transfers were not included in the average or peak loads.

Distribution substations in Penticton have different ratings for summer and winter peaks. Emergency offloading of a substation during a peak time of year can result in feeders exceeding the normal, maximum demands. The seasonal peaks were compared to seasonal equipment ratings and expressed as a percentage of the seasonal capacity. The comparison revealed that most of the time, summer peak demand was a higher percentage of seasonal equipment ratings than winter peak demand.

The forecasted demand of the substations was generated from the average feeder forecasts. To account for non-coincident peaks, due to staggered feeder demand levels, a diversity factor was applied.

The next, and most fundamental, stage to developing the CPEU Electrical Distribution System Plan was to forecast the future peak load on the system. From the OCP, a load growth factor was developed per feeder based on the OCP forecasted population growth of 0.65% from 2020 to 2046.

In the City, there are going to be areas that grow at different rates than others; therefore, feeder demand will also grow at different rates. Using the OCP Growth and Infill Areas map below, feeders were assigned growth factors that aligned with the projected growth of the City. The 2019 OCP Growth and Infill Areas Map (Figure 5) was obtained from the OCP and a more legible version can be found in Appendix B.

Figure 5: 2019 OCP Growth and Infill Areas

3.2.1 WEATHER NORMALIZATION

Electrical demand has a strong correlation to weather. Weather varies over time seasonally and annually. The effect of weather variations can sometimes mask the underlying power consumption trend when studying the changes over time. The effect of weather can be normalized to better understand the overall system trends.

To evaluate the impacts of weather specific to the CPEU, 40 years of hourly weather data (from 1980 to 2020) was obtained from AccuWeather (AccuWeather, 2020) and was then compared to the system load. Historically, CPEU records peak demands between 4 and 6 p.m.; therefore, the 5 p.m. system data is shown in Figure 6 to illustrate the impact of temperature at a typical system peak hour.

CIMA+ determined that a 1-in-10 year weather scenario would provide enough flexibility in the system to be prepared for weather scenarios that are likely to occur in the future years. To find the temperature for a 1-in-10 year scenario, daily weather data was used to find the max/min temperature of each year. With the minimum and maximum temperatures of the previous 40 years, a winter and summer histogram was created. The resulting histograms in Figure 7 were used to derive a 1-in-10 year scenario at -21.5°C during the winter and 39°C during the summer.

Loads were weather normalized using this method for the years 2015 to 2020 as shown in Figure 8. The lower trend line in yellow indicates the demand normalized to 15°C, representing a mild day without heating or cooling loads. The middle trend in cyan shows the actual system demand at 5pm and the upper trend in green shows the 1-in-10 year weather adjusted values. The load forecast model was based off of the “Weather Adjusted” values seen in Figure 8 to ensure the infrastructure can handle the loads during colder and hotter years.

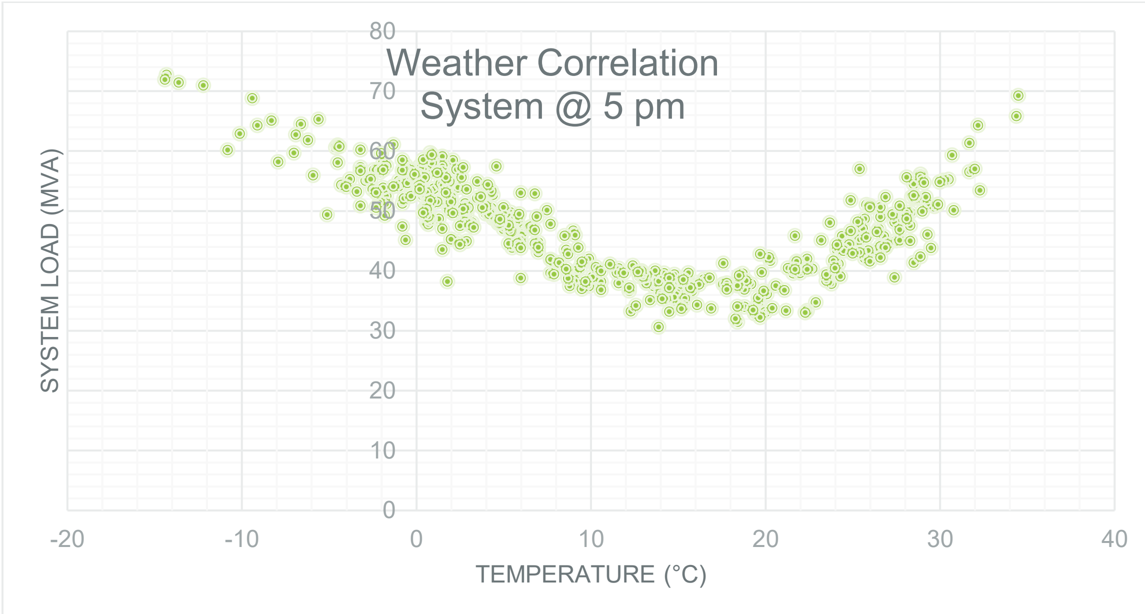

Figure 6: System Normalization Graph – System at 5pm

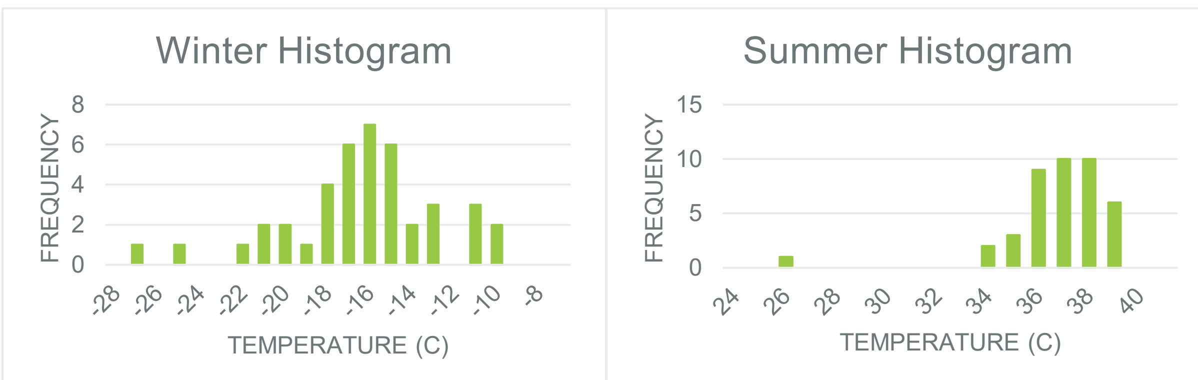

Figure 7: Winter and summer max/min temperatures for the previous 30 years.

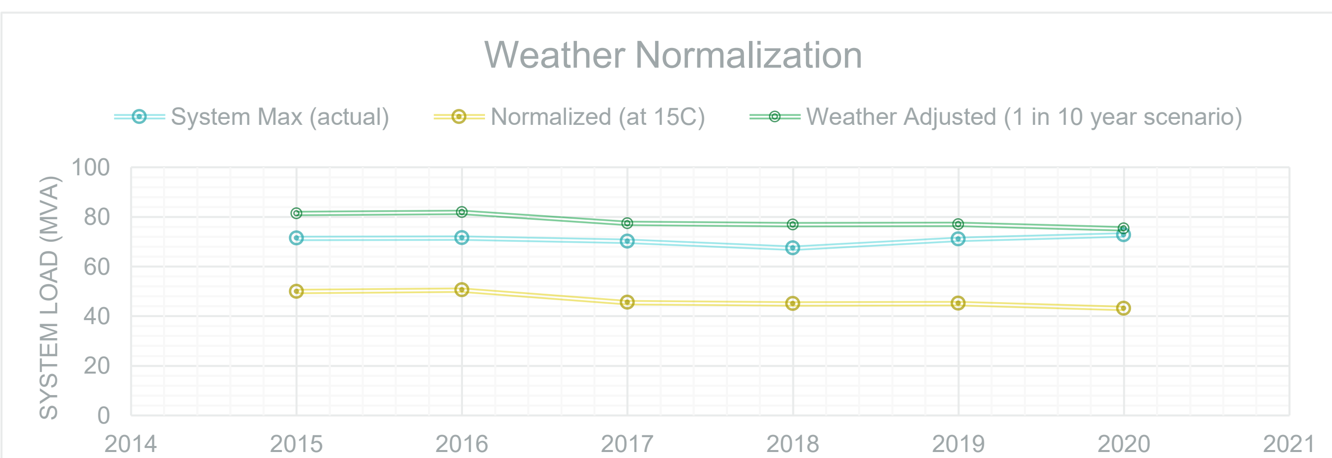

Figure 8: Weather normalized system data at 5pm.

3.2.2 IMPACTS OF CLIMATE CHANGE ON THE LOAD FORECAST

How could climate change impact the electrical system demand? Figure 9 and Figure 10, retrieved ClimateAtlas.ca (Prairie Climate Centre, 2020), depict projected changes in the average warmest maximum temperature and average coolest minimum temperature out to 2050. Based on the weather normalization function, a 2.5 °C increase in the maximum temperature could contribute 3.3 MVA of peak summer load while a 3.7 °C increase in the winter minimum temperature could reduce the winter peak by 4.4 MVA. Having noted this, the CPEU system substation capacity is more constrained during summer peaks verses winter peaks. The impact of this long term climate trend has been considered in the development of recommendations for reliability and capacity enhancements.

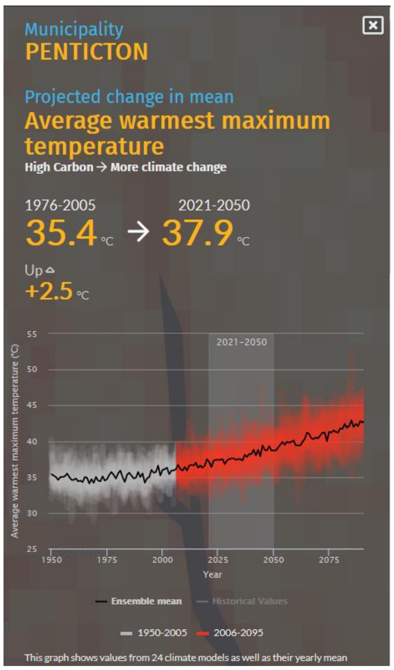

Figure 9 - Average warmest maximum temperature forecasted changes due to climate change.

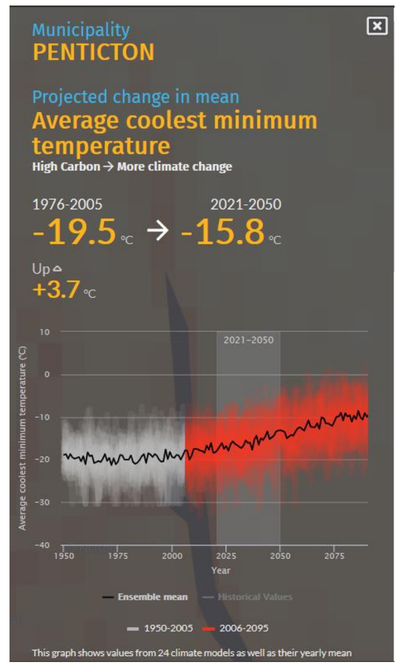

Figure 10 - Average coolest minimum temperature forecasted changes due to climate change.

3.2.3 ELECTRIC VEHICLE SCENARIOS

Electric vehicle adoption is increasing rapidly due to various factors including decreasing battery costs, BC government policy, increasing availability of charging infrastructure, and lower operating and maintenance costs of EVs compared to traditional vehicles. The Province of British Columbia passed the Zero-Emission Vehicles Act (ZEV Act) on 30 May 2019 that mandates 100% of light-duty vehicle sales be zero emission by 2040 (British Columbia Government, 2019). If the policy is implemented with no regulations of when and how EVs can charge, there will be significant implications for the CPEU system demand.

There are several factors that impact the demand contribution of Electric Vehicles (EV):

+ The quantity of EVs being charged on the system;
+ The nature of the charging systems (e.g., Level I, Level II, or Level III);
+ The allotted capacity of charging systems (e.g., outlet or smart charger controller);
+ The location of the charging infrastructure (residential neighborhood, commercial district, tourist district, highway supercharger, etc.);
+ The vehicle-use and charging patterns of the vehicle user (i.e. time of day and the charging stations energy demand); and/or
+ The ability of the CPEU to impact charging patterns (via policy or programs).

Different EV scenarios were modelled and focused on:

+ The forecasted quantity energy demand (of EVs being charged on the system); and
+ The average diversified peak demand contribution per EV (the impact of multiple EVs charging simultaneously on the utility's system).

The City of Richmond published an EV Technical Bulletin No. ENGINEERING-05 (City of Richmond, 2018) (hereafter referred to as the Technical Bulletin) that outlines the electrical requirements for EV chargers. This Technical Bulletin requires infrastructure to have the ability to supply 1.5 kVA at 90% diversity (1.35 kVA). This bulletin has become a reference for many BC municipalities and is used by Technical Safety BC for inspections of safe EV charger installations.

Other studies are available, for example, an IEEE article "Distribution Grid Impacts of Smart Electric Vehicle Charging From Different Perspectives" used a value of 1 kVA for a typical peak demand contribution per EV (E.Veldman, 2015). A detailed load research study could be conducted to develop values specific to the CPEU; however, the demand contribution identified in the Technical Bulletin of 1.35 kVA per EV is suitable for the purposes of this study and is more conservative than the 1 kVA per EV cited in the above IEEE study.

To establish an EV growth model for the CPEU load forecast, historical vehicle and EV adoption statistics in Canada, British Columbia, and Penticton were analyzed. Both registered vehicles and new sales of total vehicles and EVs in Canada, British Columbia, and Penticton were compared together to develop ratios for the forecast model. Since sales data for Penticton is not available, these ratios were used to predict EV sales in the region. Three scenarios were modelled.

Scenario 1: Base Case (No EVs)

This scenario is what the system would look like with no additional EVs being added to the City.

Scenario 2: Canada Energy Regulator Market Share Prediction

This scenario is based on an EV adoption forecast developed by the Canada Energy Regulator (Canada Energy Regulator, 2019). The market share percentage for light-duty vehicles (amount of EV sales vs amount of total vehicle sales) was compared to develop ratios and apply the forecast to the Penticton region. The Canada Energy Regulator forecast projects the following market share outlook for total EVs as a percentage of total vehicles:

- 2025 = 10% market share
- 2030 = 35% market share
- 2040 = 64% market share

Table 5 below shows the total amount of EVs on the road vs the market share penetration.

Table 5: Total EVs on the Road - Scenario 2

Year	2025	2030	2040
EV New Sales Penetration	10%	35%	64%
Total EVs (% of Total Penticton vehicles)	**612 (2.02%)**	**2,889 (9.22%)**	**14,421 (43.12%)**

Scenario 3: British Columbia ZEV Act (Mandated Policy)

Compared market share percentage for light-duty vehicles (amount of EV sales vs amount of total vehicle sales). Then used the BC mandated model of:

- 2025 = 10% market share
- 2030 = 30% market share
- 2040 = 100% market share

Table 6 shows the total amount of EVs on the road vs the market share penetration.

Table 6: Total EVs on the Road - Scenario 1

Year	2025	2030	2040
EV New Sales Penetration	10%	30%	100%
Total EVs (% of Total Penticton vehicles)	**751 (2.47%)**	**2,872 (9.16%)**	**17,118 (51.19%)**

Figures 9-12 show the impact of the three scenarios on each of the four CPEU substations. Penticton's EV penetration forecast scenario models are included in Appendix E.

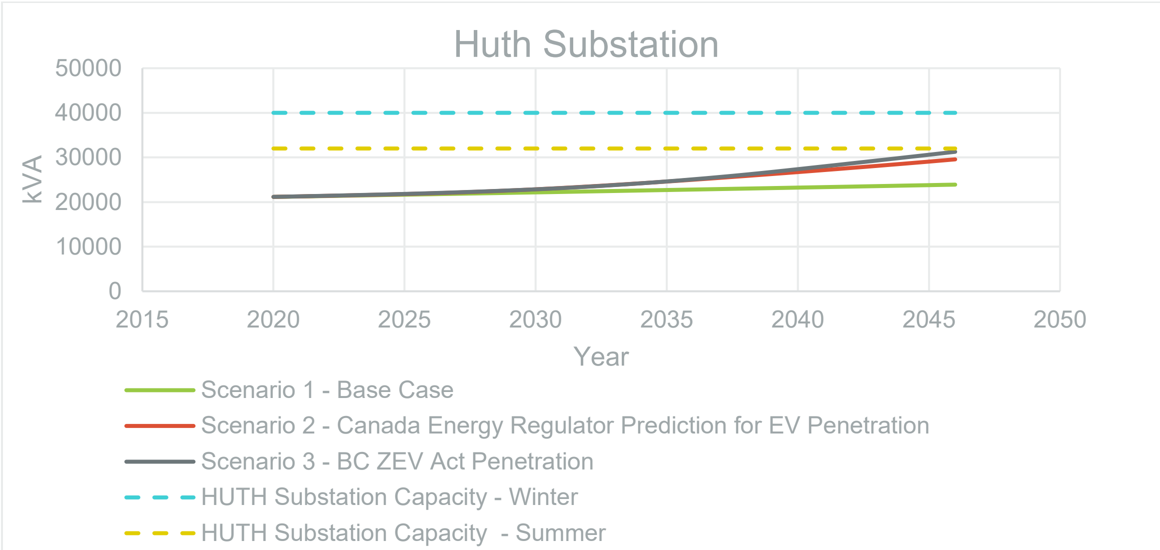

Figure 11: EV Penetration Comparison – Huth

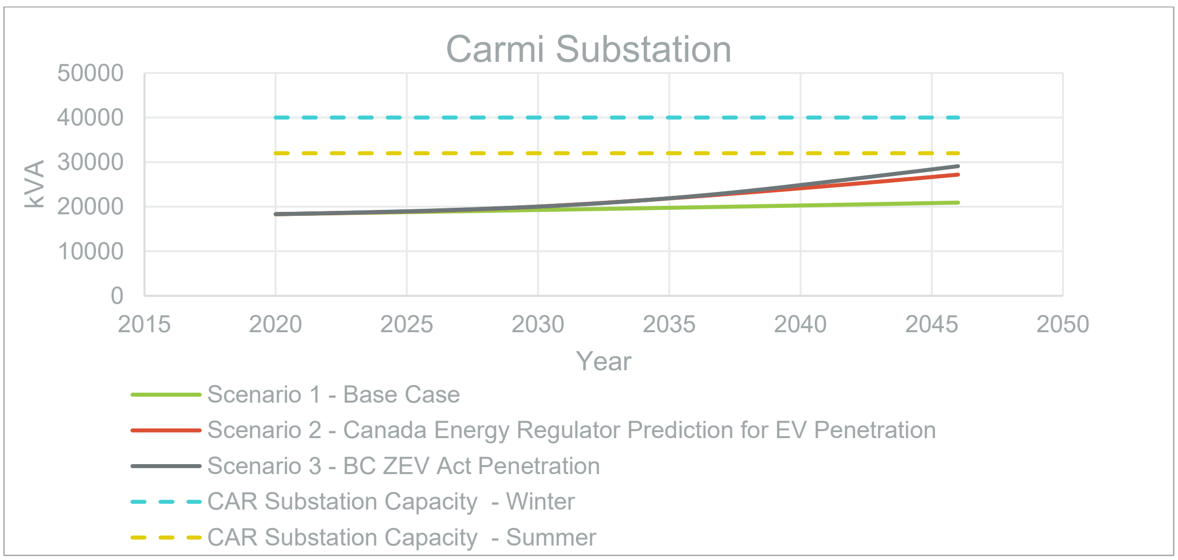

Figure 12: EV Penetration Comparison – Carmi

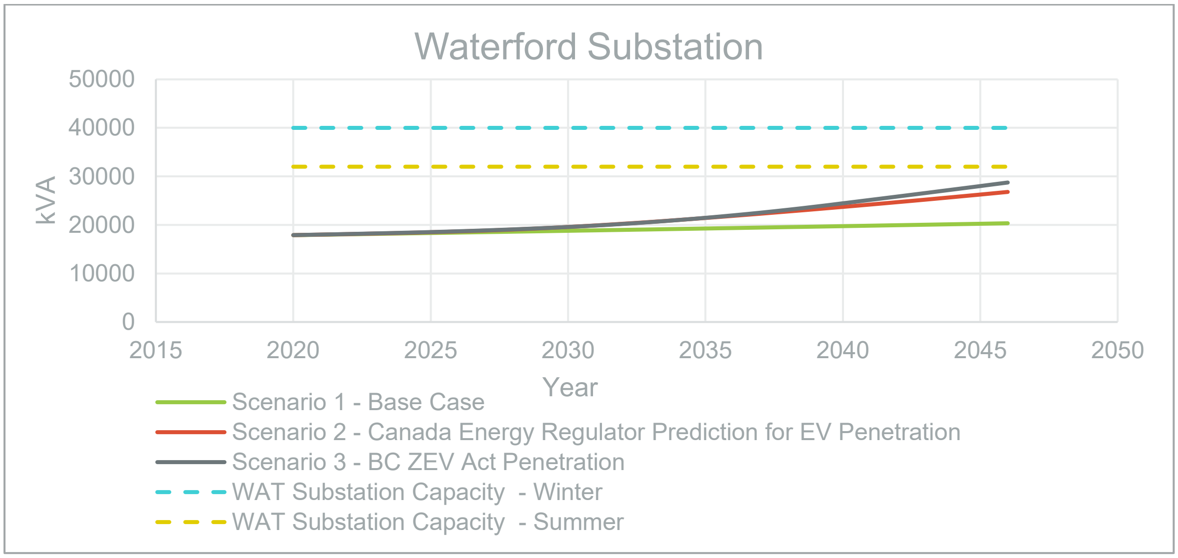

Figure 13: EV Penetration Comparison – Waterford

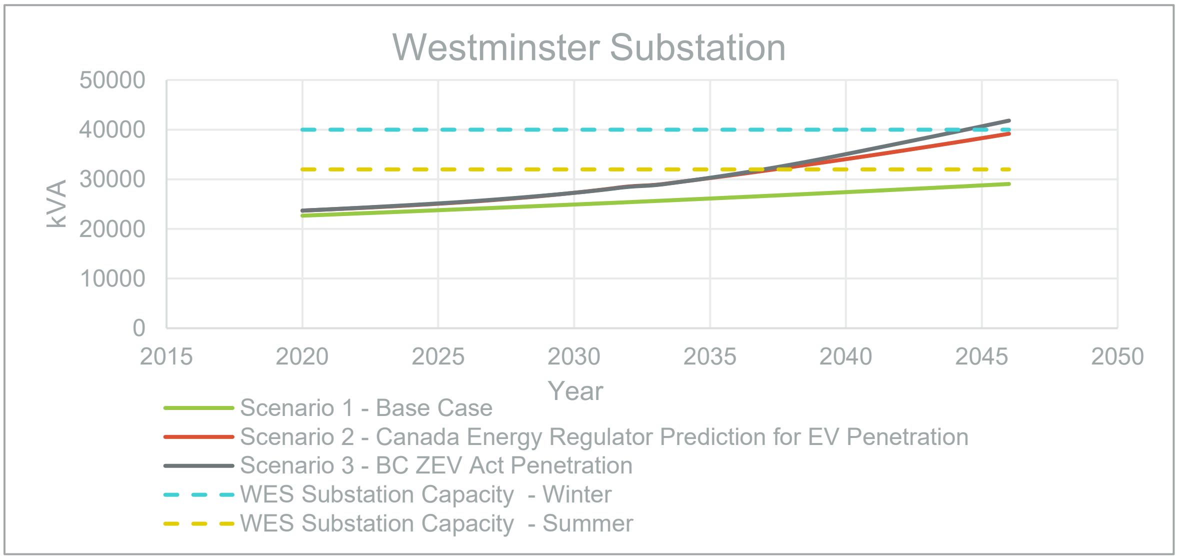

Figure 14: EV Penetration Comparison - Westminster

3.2.3.1. SUMMARY OF EV SCENARIOS

Based on the results above, EVs have the potential to significantly impact the utility. Capital planning budgets were based on Scenario 3 to ensure that CPEU is prepared for the potential grid implications of the BC ZEV Act.

3.2.4 DISTRIBUTED ENERGY RESOURCES

As part of the EMP, the impacts from three of the DERs in the Generation Study were considered. The sections below describe the different resources and how they were implemented in the forecast:

+ Solar
+ Energy Storage
+ Peak Shaving

3.2.4.1. SOLAR

Below are graphical representations of the effects of solar on the CPEU system peak. The graphs were produced using CPEU system peak and a simulated solar facility specific to Penticton in both winter and summer.

Figure 15 (summer) and Figure 16 (winter) illustrate a classic 'duckbill curve', based on a simulated 24 hour load profile, specific to the CPEU system. Initial solar generation will reduce the system peak slightly. The simulation indicates a 10% solar penetration would reduce peak demand by approximately 2%. As the quantity of solar generation increases, the marginal impact to peak demand reduction diminishes. For example, based on the 30% simulated solar penetration scenario, the summer system demand was reduced by approximately 3.5%.

The contribution to the system demand reduction is minimal and only in the summer months. During the winter months, the solar generation contribution to the peak demand is negligible. Currently the CPEU has a limited amount of connected solar generation. Industry experience indicates that most utilities can facilitate 20% or more inverter based connected generation sources, such as solar, without the need for investing in reverse power protection mechanisms or other system support devices (e.g., to address voltage or harmonic challenges). For the CPEU, 20% is approximately 14 MVA. The four alternatives that passed the screening thresholds in The Generation Study remain well below this amount.

For the purposes of distribution system capital planning, CIMA+ determined that the adoption of solar with the CPEU would have negligible impact on the capacity requirements at a feeder and substation level. It is recommended that this be re-evaluated if the level of inverter-based generation, such as solar / Battery Energy Storage System (BESS) / wind, increases near or beyond 20% of system demand.

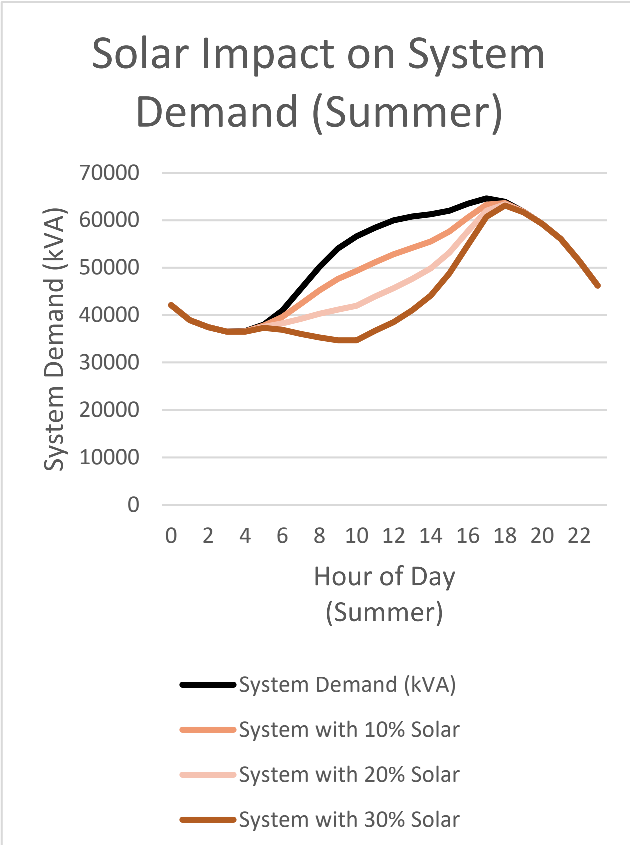

Figure 15: Solar Impact on System (Summer)

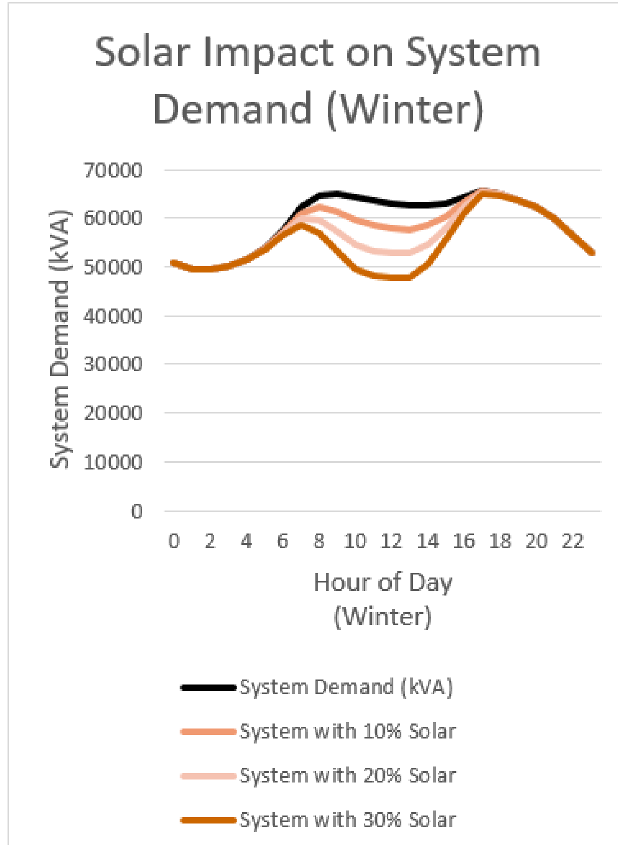

Figure 16: Solar Impact on System (Winter)

3.2.4.2. ENERGY STORAGE

One of the recommended outcomes from the Generation Study was the implementation of a BESS. As other types of variable renewable energy are added to the system, BESS becomes more valuable to the grid operation and reliability by shifting loads and distributed generation to or from demand heavy periods. For example, BESS can help shift daytime solar generation to supply evening peak loads. As electric vehicle adoption increases, BESS can also be used to shift the EV load curve and manage the overall system demand. Overall, a BESS facilitates a flatter load curve which puts less strain on the grid infrastructure and enables more efficient utilization of generation assets.

One of the main goals of a BESS is to reduce the system demand and the associated demand charges presently being paid to FBC. BESS projects can also attract grant funding as it supports a modern renewable power grid. Combined with grant funding, BESS can provide an attractive net financial benefit to CPEU.

A BESS project may be incorporated into the CPEU fiscal plan with a potential implementation as early as 2023 should funding be made available through the ERF and/or grant applications. The Generation Study considered grants worth up to $ 879,000. Although the installation could take place in many locations throughout the City, the City Yards location is proposed for the following reasons:

+ Accessibility (ease of maintenance)
+ Security
+ Available City owned land

One of the BESS options studied can be comprised of 2.5 MW / 5.0 MWh capacity with two (2) two-hour discharge cycles or 1.5 MW / 6 MWh capacity with two (2) four-hour discharge cycles. The load forecast includes an energy storage scenario with a 2.5 MW capacity being applied from 2024 onward based on the Generation Study results. The Generation Study preliminary analysis of the BESS indicates that up to approximately $4.5 million in FBC billing charges (both wire and power supply charges) could potentially be offset over a 20-year period. Note that this project has not been initiated by the CPEU at the time of preparing this report.

This project has many facets that are beneficial for both COP and the CPEU. One of the significant O&M advantages of this type of system is that it does not require additional fuel sources to maintain the system during operation; and should have a lifetime of approximately 20 years (up to 15-year warranty). It is a highly flexible type of system that will work well with Penticton's load profiles.

3.2.4.3. PEAK SHAVING

The CPEU is employing a pilot project to use existing City owned standby generator assets to reduce the utility's peak demand. The chosen unit for the pilot program is an 837 kW diesel generator stationed at the OK Pumping Station on Lakeshore drive. Long term, the pilot will utilize its one-hour-per-month generator standby tests (requirement) during high demand load times in the City. If timed well, there is a possibility that the main peak load on the system can be significantly reduced. If successful, the invoicing cycle of the utility will diminish the metered peak usage; which may reduce the demand portion of the City's purchasing costs for up to 6 months.

3.2.5 LOAD FORECAST RESULTS

An initial forecast without recommended system improvements is shown in Appendix C and highlights overloading feeders and substations in the CPEU system. Figures 17 through 20 show the initial forecast for each substation. Initial forecasts account for EV load growth and population load growth.

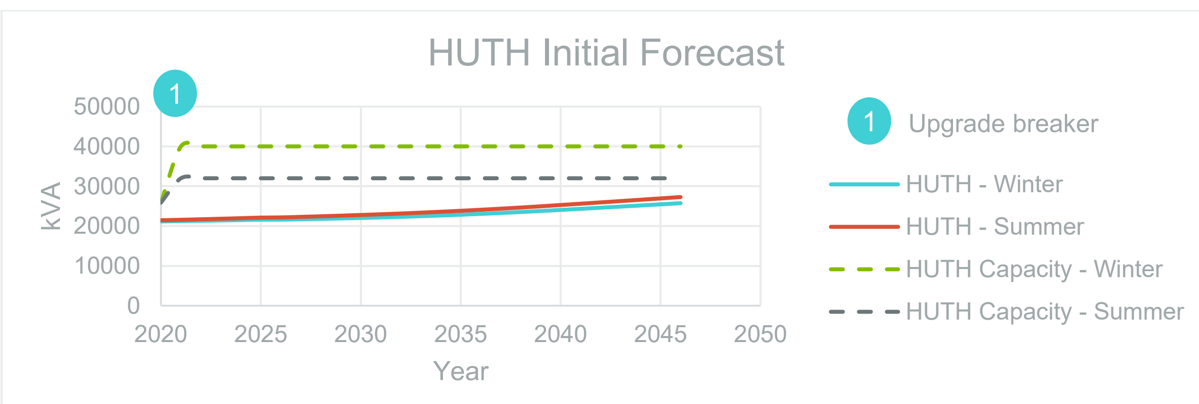

Figure 17: Huth - Initial Forecast

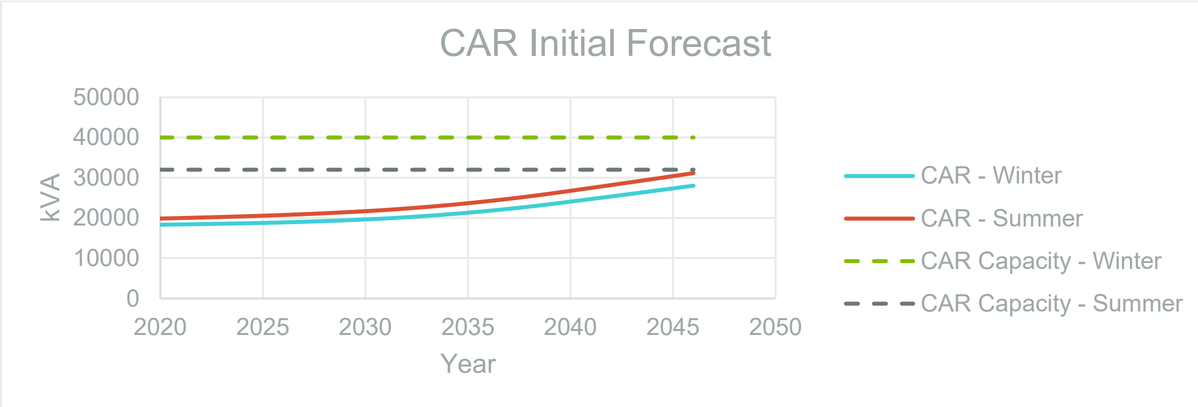

Figure 18: Carmi - Initial Forecast

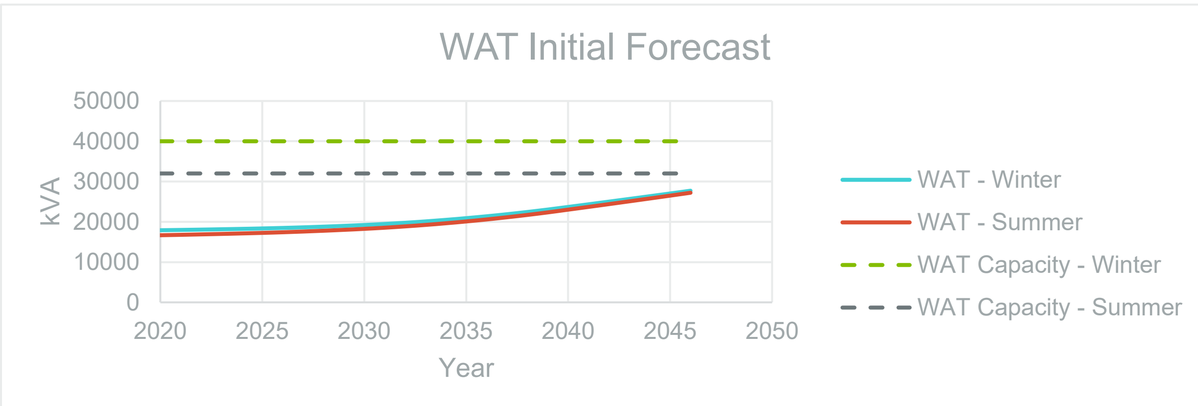

Figure 19: Waterford - Initial Forecast

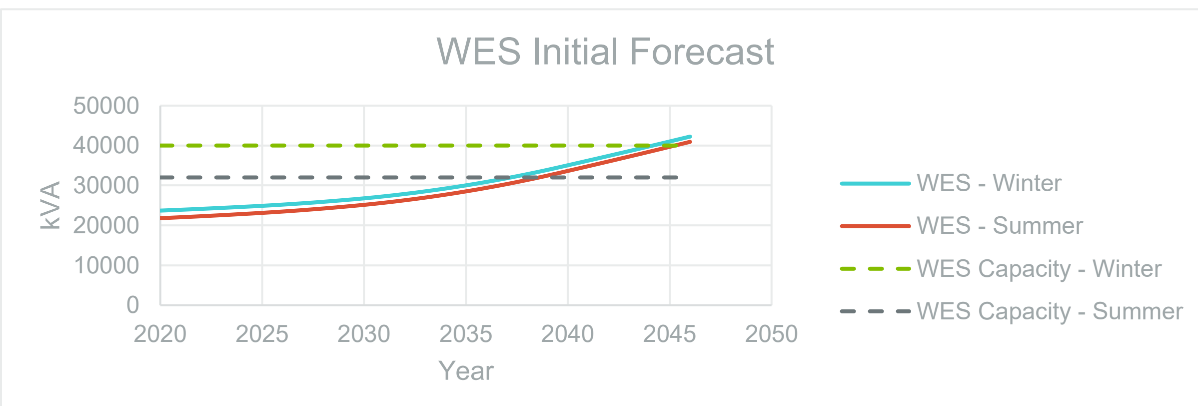

Figure 20: Westminster - Initial Forecast

Observations made of the initial forecasts are as follows:

1. Huth substation is currently running at 80% capacity because of limitations on the FBC breaker. The breaker will be addressed by FBC in Q4 of 2020.
2. Westminster reaches its summer capacity limit in 2038.
3. Westminster substation reaches its winter capacity in 2045.

CIMA+ recommends the load forecast be updated annually. Minor adjustments to the CYME model and system plan would also be done on an annual basis. A full master plan is recommended to be completed every five years.

3.3 ELECTRICAL SYSTEM MODELLING / CYME

The CPEU system model was based on the 2020 CYME model that was created during the 2015 masterplan plus the changes that have occurred since that time. The model also took into consideration the information available from the CPEU-Primary Single Line. Overhead conductors, underground cables, transformers, switches, and fuses were manually verified in the model.

3.3.1 SUBSTATION CAPACITY CRITERIA

CPEU nominal substation capacity is based on the wholesale power purchase agreement between CPEU and FBC. Each supply point has a specified contract demand limit (see Table 7). According to contractual terms, FBC is required to upgrade a supply point when the load on that supply point reaches 95% of the demand limit. During an emergency, such as a substation outage, the contract demand limits may be exceeded in order to provide backup for the affected feeders. FBC still retains the right to place an upper limit on the supply from each supply point, even during an emergency.

Table 7: Substation Demand Limits

Substation / Supply Point	Season	Demand Limit
Huth 12 kV	Summer	32 MVA
	Winter	40 MVA
Carmi 12 kV	Summer	32 MVA
	Winter	40 MVA
Waterford 12 kV	Summer	32 MVA
	Winter	40 MVA
Westminster 12 kV	Summer	32 MVA
	Winter	40 MVA

Currently, the system can handle N-1 conditions. N-1 is the condition with one failure or loss of one device on the system. Beyond year 10 in the Scenario 3 – BC ZEV Act forecast, the remaining substations and feeders approach their capacity limit in an N-1 backup scenario. By 2037, due to EV penetration and population growth, the substations cannot be backed up in an N-1 scenario. Under peak loading, the Westminster Substation will reach 80% of the summer capacity by 2038.

3.3.2 DISTRIBUTION CAPACITY CRITERIA

During normal operation, feeder loading is less than 80% of the 490 A nominal capacity of 750 MCM AL or the 648 A nominal capacity of 477 MCM, until the year 2037.

To simplify fuse coordination and inventory, the CPEU has standardized on the cables and conductors listed in Table 8. These will be used for all new construction and for rebuilds where a conductor replacement is warranted.

Table 8: Standard Cables and Conductors

Underground Cables			
Purpose	**Description**	**Nominal Ampacity**	**Emergency Ampacity**
Substation Egress	750 MCM CU XLPE 15 kV	605 A	735 A
Main Feeder	750 MCM AL XLPE 15 kV	490 A	595 A
Area Tap	4/0 AL XLPE 15 kV	245 A	295 A
Small Tap	#2 CU XLPE 15 kV	166 A	200 A
Overhead Conductors			
Purpose	**Description**	**Nominal Ampacity**	**Emergency Ampacity**
Main Feeder	Cosmos – 477 MCM AAL	648 A	735 A
Area Tap	Penguin – 4/0 ACSR	387 A	492 A
Small Tap	Sparrow - #2 ACSR	189 A	235 A

3.3.3 CABLE AND CONDUCTOR AMPACITY CRITERIA

Overhead conductors and underground cables must have the capacity to carry the peak summer and winter loads. A detailed list of references used for cable and conductor ratings is included in Appendix F.

During modelling the feeders were deemed to be overloaded when they exceeded 80% of their nominal rating during normal operation. The practice of limiting normal capacity to 80% provides some allowance for load transfers during backup or emergency conditions. During backup, feeders were deemed to be overloaded when they exceeded 100% of their emergency rating.

3.3.4 BACKUP CRITERIA

The distribution system is designed so that load can be transferred between feeders and substations to provide undisrupted supply during planned events and has the capacity to quickly transfer load to restore power during unplanned events.

If a substation or feeder fails through the failure of a normal supply point, then backup must be provided from an alternate source to the affected area as soon as practical. Backup criteria have been developed to create a way of measuring the electrical system's capability during outages.

During backup the upper limit (approximately 2000 A for the 12 kV substations) on any substation must not be exceeded and each feeder's emergency rating (approximately 650 A for 750 MCM CU egress cables) must not be exceeded. Feeder emergency ratings are limited by the maximum ampacity of the cable, conductor, switch, or elbow without causing long term damage. In many cases this is the egress cable from the substation, but in other cases it is a pad-mounted switch, elbow, cable, or conductor.

No more than four switching operations were used to back up any feeder. This ensures the backup of a feeder can be accomplished in a timely manner with as little complexity as possible. Substation backup scenarios were modelled to ensure substantial system capacity. The recent upgrade to a 12kV system enabled more feeders to be available for usage, as well as reduced amperage on cables.

3.3.5 MINIMUM AND MAXIMUM VOLTAGE LEVELS

The minimum and maximum voltage levels are based on the criteria specified by Canadian Standards Association (CSA) Standard CAN3-C235-83 (R2000) Preferred Voltage Levels for AC Systems, 0 to 50,000 V – Table 3 Recommended Voltage Variation Limits for Circuits up to 1000 V, at Service Entrances. Please see Table 9 and Table 10 below for voltage limits based upon a 120 V secondary voltage:

Table 9: Voltage Limits During Normal Operation

Line Type	Min. Voltage	Max. Voltage
3 Φ	115 V	128 V
1 Φ	113 V	128 V

Table 10: Voltage Limits During Emergency Operation

Line Type	Min. Voltage	Max. Voltage
3 Φ	113 V	130 V
1 Φ	109 V	130 V

These voltage levels should be checked periodically. That would ensure that the FBC tap changers are adequately addressing load changes to provide enough end-of-line voltage.

3.3.6 MODELLING

The main objective in modelling the distribution system, in a program such as CYME, as well as determining acceptable loading limits is to provide information about the capacity and limitations of the electrical distribution system. Decisions based on the best information available lead to an electrical distribution system that is aligned with good utility practices and effectively meets the needs of CPEU and its customers. The modelling approach is described below.

A base case model is developed to reflect the system's present operating conditions. Following this, criteria are developed and used to determine the strength of the electrical distribution system. This is done by completing a load flow study to ensure the electrical components are adequately rated and voltage levels are enough throughout the network. Substations or FBC supply points are checked for enough capacity and short circuit contributions.

Once the load flow is complete, it is important to then check system contingency conditions. This includes identifying backup scenarios of substations and their respective feeders. System voltage is re-analyzed during backup settings and cable / conductor ampacities are re-confirmed to ensure lifespan is not decreased and failures are not created during these events.

When system overload or under-voltage conditions are identified in the model, load was shifted between feeders to create a balanced system. When load shifting was not enough to avoid issues, infrastructure upgrade projects were identified. The process below describes how an upgrade was deemed necessary.

1. Allocate year 1 load (2020) to the model. Test the model for accuracy. Determine if there are any limits broken in the system. Solve for any conditions that are outside good utility operating practices.
2. Allocate year 5 load (2025) to the model. Determine exceeded limits into the planning criteria. Solve for the conditions outside good utility operating practices (planning criteria). Determine what year the failure occurs.
3. Run one year and five-year models for back up planning for feeders and substations. Determine failures and solutions.
4. Identify recommended solutions and estimate cost to +/-25%.
5. The recommended upgrades considered the following from least cost solution to highest cost solution:

- Load balancing
- Load swap to an alternative feeder
- Re-conductor (including overhead or underground rebuilds)
- Add new feeders / substation
- Voltage conversion

The above processes were completed with forecasted load and load transfers. Recommended system improvements to address system constraints that arise from load growth (OCP, EV):

- Split load between feeder R33 and R35;
- Underground feeders from Carmi Substation to Wiltse Blvd and Dartmouth Rd;
- Express feeder to Pineview Rd and Main St;
- Second transformer at Huth Substation; and
- Additional feeders at Huth Substation.

3.3.7 25 kV CONVERSION CONSIDERATIONS

The CPEU has recently completed an upgrade of the distribution system from 8 kV to 12 kV. This voltage conversion program was started in 1995 and completed in 2020. The conversion to 12 kV has significantly enhanced the system capacity and renewed the distribution infrastructure. As load grows, in particular due to electric vehicles, it is recommended that a 25 kV voltage conversion be evaluated as an input to the next electrical master plan update. The main driver for a 25 kV conversion would be to accommodate electric vehicle load in the long-term horizon and should be evaluated prior to expanding the Huth substation, planned for 2033. Items to consider when evaluating a 25 kV voltage conversion include the following:

- Purchasing 25/12 kV dual voltage rated distribution;
- Ensure all newly installed pole crossarms and insulators are sized to accommodate 25 kV conductor spacing;
- Purchasing 25 kV rated elbows (e.g., 200 A, 600 A);
- Purchasing 25 kV rated underground cable;
- Stocking of both 12 kV and 25 kV rated materials for a long period of time;
- The return to having a system with two different voltages at the same time and the subsequent reduction in flexibility until the entire system is converted to 25 kV;
- The option for CPEU to own their substations (transmission verses distribution rate structure);
- The role of FBC in the potential conversion program.

4. RESULTS & RECOMMENDATIONS

The completion of the conversion from 8 kV to 12 kV enabled a flexible and efficient back-up for the system for planned and unplanned events. It also provided additional capacity for new load, such as the Penticton Regional Hospital expansion. The system is, and will continue to be, capable of accepting renewable energy generation and supplying electric vehicle charging for the short-term future. As the system demand increases, in particular, with the growth of electric vehicles and other forms of transportation electrification, re-enforcement of certain aspects of the CPEU infrastructure will be required to maintain reliability and operability in the longer term.

Expected 25-yr annual capital expenditures are summarized in the Project Budget Sheet (see Appendix H). The associated project planning sheets are provided in Appendix I.

4.1 PROCESS

The CPEU has many stakeholders and priorities which vie for funding. Prioritization reflects the long-term vision for the system while taking short-term requirements from a wide variety of stakeholders into consideration. It maintains sufficient flexibility to respond to internal and external priority changes as they arise.

Items with the least flexibility and highest priority include investments required to fulfill duties under applicable Acts, Regulations, and Codes. Specifically:

Non-discretionary budget items include:

- Projects to accommodate new customers and load growth to meet the CPEU obligation to connect.
  - These costs are generally borne by the customer that caused the required upgrade.
- Projects to accommodate Municipal, Provincial, or Federal government projects.
  - An example would be a road or highway upgrade.
- Expenditures to satisfy regulatory initiatives, environmental risks, and safety risks.

Sustainment budget items include:

- Infrastructure renewal projects
- Upgrades to fleet vehicles or line crew tools
- Expenditures that if neglected will lead to a decline in system reliability.

Enhancement budget items include:

- Distribution automation
- Smart grid deployment
- Information technology
- Expenditures that enhance the system reliability and performance.

Expansion budget items:

- Green field developments i.e. expanding the footprint of the Distribution System
- Acquiring additional assets to expand the service area.

4.2 RECOMMENDATIONS, PRIORITIZATION, AND COST ESTIMATES

Investments in the system allow for predicted growth while maintaining or improving distribution system reliability. Based on the data collected, reviewed, and analyzed for this report. CIMA+ recommends the projects listed below and shown on the map in Figure 21.

Figure 21: Recommendations shown by location

1. Diesel Generation – Peak Shaving Pilot (UPG-1) (2021)
    a. The COP owns several diesel backup generators that are required to operate for one hour per month for maintenance purposes. This economically driven pilot project will implement control logic to deploy the generator at the time of the system peak with the goal of reducing the overall system demand. A reduction in peak demand reduces stress on the electrical infrastructure and reduces demand billing fees paid to FBC. The backup generator located at the OK Pumping Station has been selected for this pilot.
2. Complete Lawrence Ave Loop (UPG-2)(2021)
    a. With more developments being added to the Sendero Canyon, there has been a point of emphasis to improve the neighborhood's reliability and allow for neighbourhood growth. Currently, the neighborhood is fed radially. Any point of failure results in an outage with no backup. Completing a loop from Syer Rd would resolve this issue and improve the reliability. The loop would also help balance the load.
    b. Option A - Overhead and Underground (UPG-2-A) (Preferred option)
        i. Lower cost
    c. Option B - Underground only (UPG-2-B)
3. Energy Storage (UPG-3)(No year defined)
    a. Installing a BESS allows the CPEU flexibility in supporting their customers. A benefit of using a BESS is being able to charge the systems during off-peak hours and then use the system during peak loading times. This will effectively

reduce the demand charges from FBC. BESS can also be used to shift the EV load curve and manage the overall system demand. The feasibility of this project may be dependent on grant funding availability to ensure that economic drivers are validated.

4. Split load between feeder R33 and new feeder R35 (UPG-4)(2021)
    a. Driven by the system growth and EV load projections, additional support for feeder R33 is recommended to support during normal and backup situations. Off-loading part of feeder R33 onto the new R35 will allow both feeders to be more reliable and more readily available during an outage situation. This will also allow each feeder to be ready for load growth in the future.
5. Cable Replacement Program (UPG-5)(2021-2030)
    a. With approximately 20% of cables being 30 years or older, a replacement program should identify at risk cables and determine the course of action to ensure system reliability.
6. Resiliency Study (UPG-6)(2022)
    a. Utilities have been experiencing an increase in low probability but high impact events. This study would focus on preparation, mitigation, response, and recovery for such events.
7. 25 kV Conversion Study (UPG-7)(2025)
    a. To account for future load, this study could focus on the pros and cons of upgrading the system to 25 kV.
8. Underground feeders from Carmi Substation (Wiltse Rd and Dartmouth Rd) (UPG-8)(2026-2028)
    a. Based on long-term system growth and EV load projections, additional support to feeders R23 and R24 is required to support the system in a backup scenario by 2029. Bring five underground feeders, two to Wiltse Rd and three to Okanagan Ave E., from Carmi. The feeders will have the capacity to help Huth or Waterford during substation outages. Also, the new route would allow the CPEU to remove existing overhead lines from non-municipally owned land. This would reduce annual fees paid to FBC, which is $250 per pole.
    b. Option A involves going through private land (with an easement) with only underground infrastructure. (UPG-8-A) (Preferred option)
        i. Has the ability to serve a new industrial area without significant additional cost.
    c. Option B involves longer routes through City land with both a mix of underground and overhead infrastructure required. (UPG-8-B)
9. Carmi Substation: Express Feeder to Pineview Rd & Main St (UPG-9)(2029)
    a. Due to projected load growth and EV penetration, a new express feeder is recommended to better balance the system network and, in the case of an emergency, have the capacity to backup R23 and R24.The new feeder will reduce the load on feeder R10 and R24 during normal operation.
    b. Option A involves mostly overhead infrastructure. (UPG-9-A) (Preferred option)
        i. Lower cost

c. Option B involves only underground infrastructure. (UPG-9-B)

10. Underground Main St between Westminster Ave and Eckhardt Ave (UPG-10)(2028-2045)
    a. Main St alleys consist of old construction and aging infrastructure that are reaching their end of life. Clearances to buildings limit development options due to the overhead conductors. Underground cables eliminate the clearance issues and allows for greater flexibility in building design/construction. Underground cables would provide a safer, more reliable, and more aesthetic system. To help achieve this recommendation, new developments going in that area can assist in offsetting the cost.
11. Huth Substation Expansion: Second Transformer (UPG-11)(2033-2036)
    a. Due to projected load growth and EV penetration, system capacity needs to be increased. Increasing capacity at Huth Substation is the most beneficial as it can help all the current substations (Carmi, Westminster, and Waterford).
12. Huth Substation Feeder Expansion (UPG-12)(2033-2036)
    a. Necessary to make effective use of a second transformer at Huth Substation.
13. Top Hat Streetlight Replacement (UPG-13)(2036)
    a. LED Streetlights have an expected life expectancy of 20 years; therefore, the top hat streetlights should start being replaced in 2036 to avoid unexpected failures.
14. Cobrahead Streetlight Replacement (UPG-14)(2037)
    a. LED Streetlights have an expected life expectancy of 20 years; therefore, the cobrahead streetlights should start being replaced in 2037 to avoid unexpected failures.
15. Substation Condition Assessment
    a. The reclosers at substations Huth and Waterford are approaching end of life. The condition assessment should include an evaluation of the reclosers and a plan for replacement should be developed as required.
16. On-going CYME Model Update
    a. Addition of new feeders and new builds should be updated in the CYME model to keep an accurate representation of the CPEU distribution system.
    b. Implement the ArcGIS to CYME link to facilitate for efficient model updates as required.

4.3 FINAL LOAD FORECAST RESULTS

Figures 21 through 24 show the final load forecast for each substation once the recommendations have been implemented. Refer to Appendix D for the tabulated final load forecast. The final load forecast validates that over the next 25 years, with all recommended projects completed, the system will operate within its capacity without overloading.

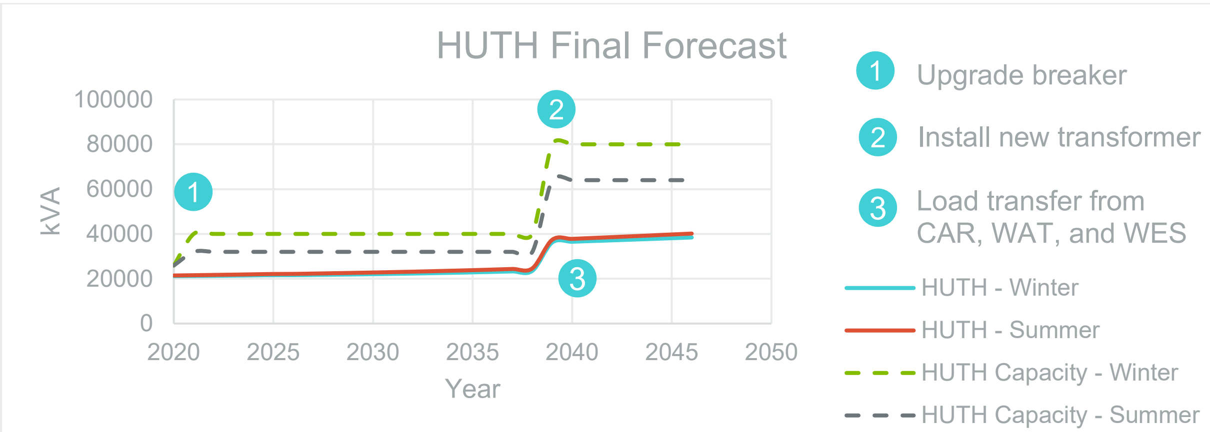

Figure 22: Huth - Final Forecast.

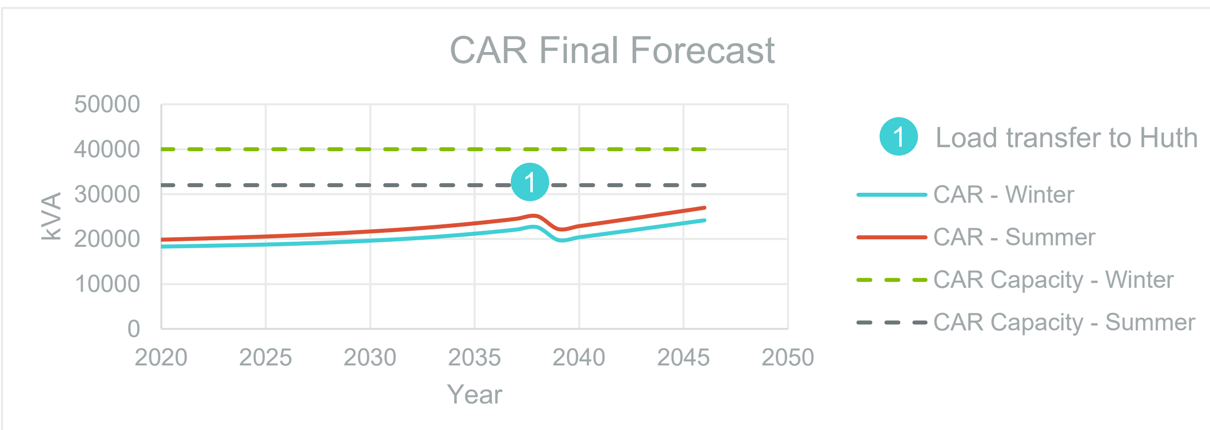

Figure 23: Carmi - Final Forecast.

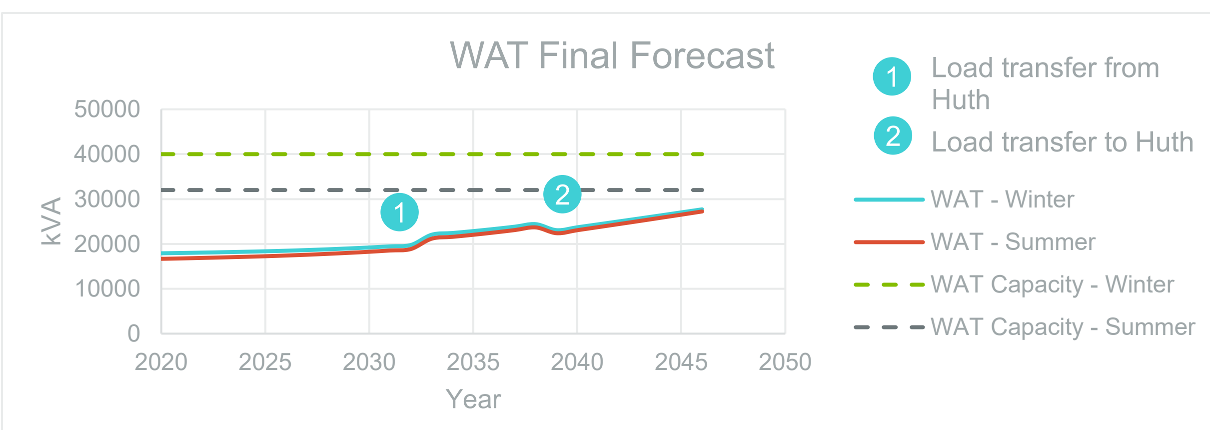

Figure 24: Waterford - Final Forecast.

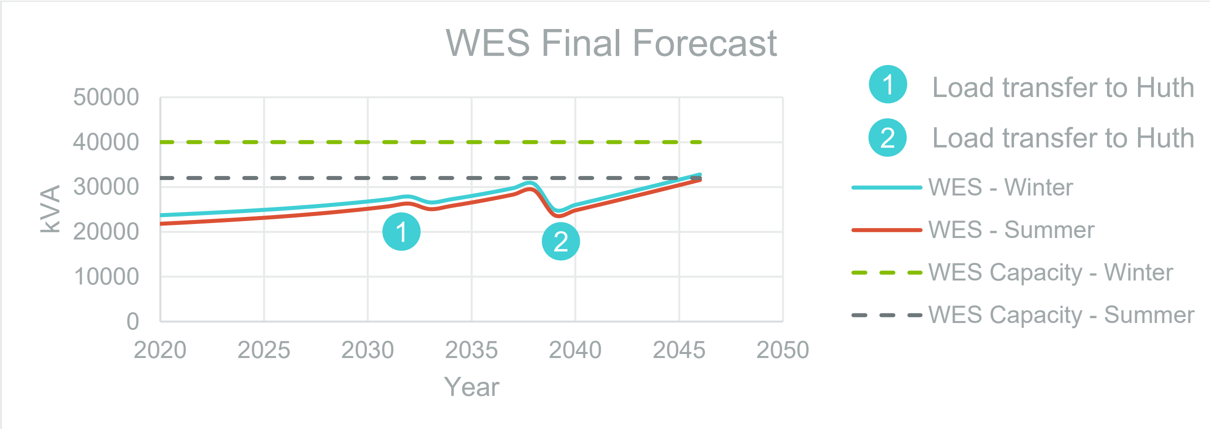

Figure 25: Westminster - Final Forecast.

Observations made of the final forecasts, assuming all upgrades are completed:

1. Summer loading at all substations approach capacity by 2045.
2. All substations will operate at an acceptable level up to and including the year 2045, if all recommended upgrades are completed.

4.4 PROJECT SHEETS, GIS LAYERS AND BUDGET SUMMARY

Table 11 below, shows the GIS layers that were created as part of this study.

Table 11: Project Sheets and GIS Layers

Project ID	Description	Cost Estimate
UPG-1	Diesel Generator – Peak Shaving (2021)	$ 25,000
UPG-2-A	Completing Loop at Lawrence Ave – UG & OH (2021)	$ 694,00
UPG-3	Energy Storage – BESS (No year defined)	$ 2,600,000
UPG-4	Splitting Load on R33 (2021)	$ 800,000
UPG-5	Cable Replacement Program (2021-2030)	$ 3,750,000
UPG-6	Resiliency Study (2022)	$ 30,000
UPG-7	25 kV Conversion Study (2025)	$ 50,000
UPG-8-A	Carmi Underground Feeders (2026-2028)	$ 6,100,000
UPG-9-A	Carmi Express to Pineview Rd and Main St – OH (2029)	$ 920,000
UPG-10	Undergrounding Main St (2028-2045)	$ 18,500,000
UPG-11	Upgrade Huth Capacity (2033-2036)	$ 12,100,000
UPG-12	Huth Feeder Expansion (2033-2036)	$ 5,300,000
UPG-13	Tophat Street Light Replacement (2036)	$ 275,000
UPG-14	Cobrahead Street Light Replacement (2037)	$ 840,000

Figure 26 below shows the CPEU capital investment based on the recommendations over the next 25 years.

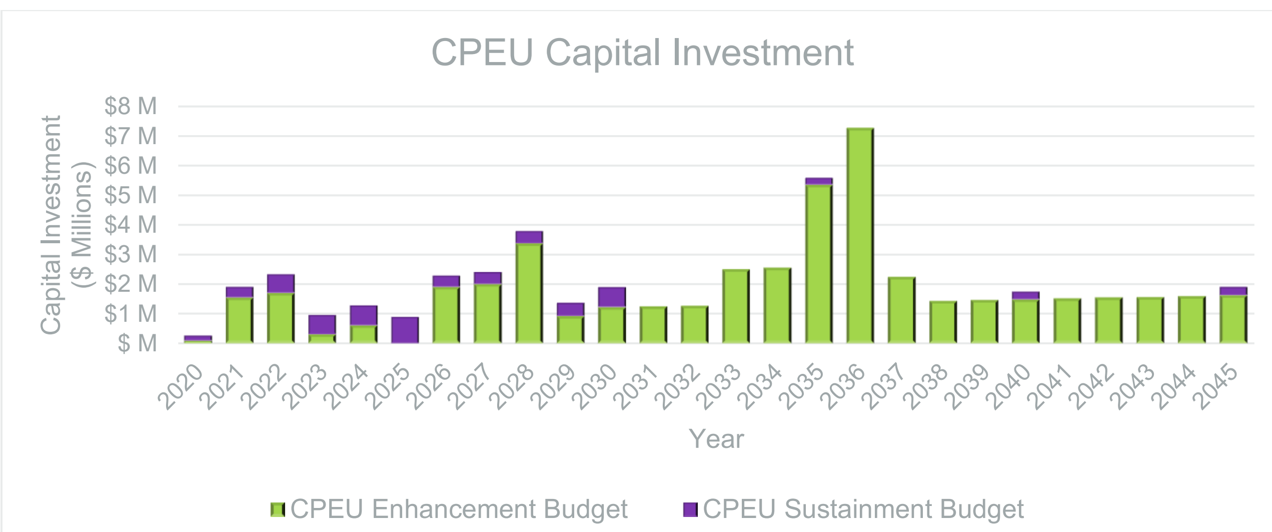

Figure 26: CPEU Capital Investment

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Appendix A
FBC Electricity Needs

FortisBC Inc.
An indirect subsidiary of Fortis Inc.

Annual Information Form
For the Year Ended December 31, 2019
Dated March 10, 2020

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All figures are expressed in Canadian dollars unless otherwise noted.

Except as otherwise stated, the information in this Annual Information Form is given as of December 31, 2019.

FORWARD-LOOKING INFORMATION

Certain statements contained in this Annual Information Form contain forward-looking information within the meaning of applicable securities laws in Canada ("forward-looking information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management. The forward-looking information in this Annual Information Form and the information incorporated herein by reference includes, but is not limited to, statements regarding: expectations regarding the scheduled rehabilitation and life extension of FBC's hydroelectric generation units, expectations regarding power output in the event that the CPA is terminated; expectations under take-or-pay contracts; expectations regarding the timing of the BCUC's decision on FBC's Multi-year Rate Plan ("MRP") Application; and the Corporation's expectation that compliance with environmental laws and regulations will not have a material effect on the Corporation's capital expenditures, earnings or competitive position.

The forecasts and projections that make up the forward-looking information are based on assumptions, which include but are not limited to: receipt of applicable regulatory approvals and requested rate orders; absence of administrative monetary penalties; the ability to continue to report under United States generally accepted accounting principles ("US GAAP") beyond the Canadian securities regulators exemption to the end of 2023 or earlier; absence of asset breakdown; absence of environmental damage and health and safety issues; absence of climate change impacts; absence of adverse weather conditions and natural disasters; ability to maintain and obtain applicable permits; the adequacy of the Corporation's existing insurance arrangements; no adverse effect of the Indigenous peoples' settlement process on the Corporation; the ability to maintain and renew collective bargaining agreements on acceptable terms; no material change in employee future benefit costs; the ability of the Corporation to attract and retain a skilled workforce; absence of information technology infrastructure failure; absence of cyber-security failure; continued electricity demand; the ability to arrange sufficient and cost effective financing; no material adverse rating actions by credit rating agencies; continued population growth and new housing starts; the availability of power supply; and no weather related demand loss or significant and sustained loss of precipitation over the headwaters of the Kootenay River system.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk (including the risk of imposition of administrative monetary penalties); continued reporting in accordance with US GAAP risk; asset breakdown, operation, maintenance, and expansion risk; environment, health and safety matters risk; climate change risk; weather and natural disasters risk; permits risk; underinsured and uninsured losses; risks related to Indigenous rights and engagement; labour relations risk; employee future benefits risk; human resources risk; information technology infrastructure risk; cyber-security risk; interest rates risk; impact of changes in economic conditions risk; capital resources and liquidity risk; competitiveness and commodity price risk; power purchase and capacity sale contracts risk; electricity supply and weather related risks; and other risks described in this Annual Information Form. For additional information with respect to these risk factors, reference should be made to the section entitled "Risk Factors" in this Annual Information Form, the section entitled "Business Risk Management" in the Corporation's Management Discussion & Analysis for the year ended December 31, 2019 and the other continuous disclosure materials filed from time to time on SEDAR at www.sedar.com, and which are incorporated herein by reference.

All forward-looking information in this Annual Information Form and the information incorporated herein by reference is qualified in its entirety by this cautionary statement and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

GLOSSARY

Except as otherwise defined, or unless the context otherwise requires, the following terms have the meanings set forth below.

"ARO" means asset retirement obligation;

"BC Hydro" means British Columbia Hydro and Power Authority, a British Columbia Crown corporation and electric utility serving the majority of British Columbia residents;

"BC Hydro PPA" means the 200 MW power purchase agreement between the Corporation and BC Hydro dated May 21, 2013;

"BCUC" means the British Columbia Utilities Commission;

"Board" means the Board of Directors of FBC;

"Brilliant Plant" means the 149 MW hydroelectric generating plant jointly owned by CPC and CBT through the Brilliant Power Corporation;

"Brilliant PPA" means the 149 MW power purchase agreement between the Corporation and Brilliant Power Corporation terminating in 2056;

"Canal Plant" means the Kootenay Canal Plant, a hydroelectric generating plant on the Kootenay River system owned by BC Hydro;

"CBT" means Columbia Basin Trust;

"COPE" or "MoveUP" means Canadian Office and Professional Employees Union Local 378, which operates as MoveUP;

"Corporation" or **"FBC"** means FortisBC Inc.;

"CPA" means the second amended and restated Canal Plant Agreement dated for reference November 15, 2011 among BC Hydro, the Corporation, Teck Metals Ltd., Brilliant Power Corporation, Brilliant Expansion Corporation and Waneta Expansion Power Corporation;

"CPC" means Columbia Power Corporation, a British Columbia Crown corporation;

"DBRS Morningstar" means DBRS Limited, which was acquired by Morningstar, Inc. on July 2, 2019;

"EMS" means environmental management system;

"Entitlement" means a generating facility's fixed annual entitlement of capacity and energy under the CPA;

"Entitlement Parties" means, collectively, Brilliant Power Corporation, Brilliant Expansion Power Corporation, Teck Metals Ltd., Waneta Expansion Power Corporation and FBC;

"FEI" means FortisBC Energy Inc.;

"Fortis" means Fortis Inc.;

"FortisBC Pacific" means FortisBC Pacific Holdings Inc.;

"**GHG**" means greenhouse gas;

"GWh" means a gigawatt hour, which is a measure of energy that is equal to 1,000,000,000 watts used over a one-hour period;

"IBEW" means International Brotherhood of Electrical Workers Union, Local 213;

"Moody's" means Moody's Investors Service;

"MW" means a megawatt, which is a measure for power that is equal to 1,000,000 watts;

"MWh" means a megawatt hour, which is a measure of energy that is equal to 1,000,000 watts used over a one-hour period;

"PBR" means the performance based rate setting methodology for regulation of public utilities;

"PCBs" means polychlorinated biphenyls;

"Powerex" means Powerex Corp.;

"Rate Base Assets" means all generation, transmission, distribution and other utility assets that are used or required to be used to provide service to utility customers, which are included in the calculation of the Corporation's revenue requirement for the applicable year and are subject to a regulated rate of return;

"UCA" or the "Act" means the *Utilities Commission Act* (British Columbia), as amended**;**

"WECA" means the capacity purchase agreement between Waneta Expansion Power Corporation and FBC made as of October 1, 2010.

1.0 CORPORATE STRUCTURE

1.1 NAME AND INCORPORATION

FBC was incorporated as West Kootenay Power and Light Corporation, Limited pursuant to the *West Kootenay Power and Light Corporation, Limited, Act 1897* (British Columbia), as amended. The Corporation's name was changed to "West Kootenay Power Ltd." on September 1, 1988, to "UtiliCorp Networks Canada (British Columbia) Ltd." on October 22, 2001, to "Aquila Networks Canada (British Columbia) Ltd." on May 31, 2002 and to "FortisBC Inc." on June 1, 2004.

FBC's head office is located at Suite 100, 1975 Springfield Road, Kelowna, British Columbia ("BC"), V1Y 7V7 and its registered office is located at 2500 – 700 West Georgia Street, Vancouver, BC, V7Y 1B3.

1.2 INTER-CORPORATE RELATIONSHIPS

The Corporation is an indirect, wholly-owned subsidiary of Fortis. Fortis is a leader in the North American electric and gas utility business, serving customers across Canada, the United States and the Caribbean.

2.0 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 THREE-YEAR HISTORY

Over the past three years, the Corporation's Rate Base Assets have grown by approximately 4 per cent. This growth reflects the Corporation's capital expenditures necessary to ensure the ability to provide service, public and employee safety and reliability of supply of electricity to the Corporation's customer base. Significant capital expenditures that have contributed to the increase in Rate Base Assets over the three-year period include the Kootenay Operations Centre, the Upper Bonnington Old Units Refurbishment and the Corra Linn Spillway Gate Replacement.

3.0 THE BUSINESS OF FORTISBC INC.

3.1 GENERAL

FBC is an integrated, regulated electric utility that owns hydroelectric generating plants, high voltage transmission lines, and a large network of distribution assets, all of which are located in the southern interior of BC. The Corporation has been in continuous operation since 1897.

As at December 31, 2019 FBC served, directly and indirectly, a diverse base of approximately 178,800 customers. Customers are comprised of residential, commercial, wholesale and industrial consumers of electricity located in the cities and rural regions of the southern interior of BC. The majority of FBC's customers are located in urban centres. In 2019, the Corporation sold 3,326 GWh of electricity to its customers, 587 GWh of which was purchased by FBC's six wholesale customers. The Corporation had a peak demand of 696 MW in 2019, 50 MW lower than the historical peak demand of 746 MW.

The Corporation's regulated generation assets consist of four hydroelectric generating plants on the Kootenay River with an aggregate capacity of 225 MW and an annual gross energy entitlement of approximately 1,609 GWh. FBC meets the remainder of its customers' energy and capacity requirements through a portfolio of long-term and short-term power purchase contracts, the costs of which are flowed through to customers. The Corporation's regulated transmission and distribution assets consist of approximately 7,300 kilometres of transmission and distribution power lines and 65 substations. With the exception of BC Hydro, FBC is the only integrated, regulated electric utility operating in BC. FBC also conducts a small amount of other activities relating primarily to the operation and management of third-party owned hydroelectric generation, transmission and distribution systems located within the FBC service area.

FBC operates in the southern interior of BC serving approximately 141,000 direct customers in communities including Kelowna, Oliver, Osoyoos, Trail, Castlegar, Creston and Rossland. In addition, FBC indirectly serves approximately 37,800 customers through the wholesale supply of power to municipal distributors in the communities of Summerland, Penticton, Grand Forks and Nelson, as well as to BC Hydro at two points. The service territory is primarily residential but also contains key industries served by FBC including lumber, pulp and paper, mining, agriculture and manufacturing.

The following table compares 2019 and 2018 regulated electricity revenue, electricity sales, and number of customers by customer class:

	Electricity Revenue				Electricity Sales				Customers (2)			
	2019		2018		2019		2018		2019		2018	
	$ millions	%	$ millions	%	GWh	%	GWh	%	#	%	#	%
Residential Service	177	49	181	51	1,289	39	1,326	41	122,465	87	120,291	87
Commercial (1)	98	27	96	27	978	29	978	29	18,505	13	18,238	13
Wholesale	48	13	47	13	587	18	572	18	6	0	6	0
Industrial	39	11	30	9	472	14	374	12	51	0	52	0
Total	**362**	**100**	**354**	**100**	**3,326**	**100**	**3,250**	**100**	**141,027**	**100**	**138,587**	**100**

Notes:

1. Commercial includes street light & irrigation customers.
2. Direct customers.

3.2 GENERATION AND POWER SUPPLY

FBC meets the electricity supply requirements of its customers through a mix of owned-generation and short-term and long-term power purchase contracts. The Corporation owns four regulated hydroelectric generating plants with an aggregate capacity of 225 MW, which provide approximately 45 per cent of the energy and 30 per cent of the peak capacity needs of FBC. The four hydroelectric generation plants are located on the Kootenay River and contain fifteen separate generating units. Generation assets represent approximately 14 per cent of the Corporation's Rate Base Assets. Under the CPA, as described below, these generating facilities are dispatched by BC Hydro in exchange for Entitlement. However, the generating units are required to be maintained and available for dispatch. Since 1998, eleven of fifteen FBC hydroelectric generation units have been subject to a life extension and upgrade program which substantially concluded in 2011. On January 20, 2017, the BCUC approved a complete rehabilitation and life extension of the remaining four units, which commenced in 2017. Three of these four units are substantially complete, with the project expected to be completed by 2021.

(a) Canal Plant Agreement

Plant	Capacity (MW)	Owners
Canal Plant	580	BC Hydro
Waneta Dam	493	BC Hydro (long term lease of 237 MW to Teck Metals Ltd.)
Waneta Expansion	335	Waneta Expansion Power Corporation (WEPC), an indirect, wholly-owned subsidiary of each of CPC and CBT
Kootenay River System (4 plants)	225	FBC
Brilliant Dam	149	Brilliant Power Corporation
Brilliant Expansion	120	Brilliant Expansion Power Corporation

FBC's four hydroelectric generating plants are governed by the CPA. The CPA is a multi-party agreement that enables the five separate owners and one lease holder of nine hydroelectric generating plants (having a combined capacity of approximately 1,900 MW and all located in relatively close proximity to each other) to coordinate the operation and dispatch of their generating plants. The plants and their respective capacity and owners are:

The CPA enables BC Hydro and the Entitlement Parties, through coordinated use of water flows, subject to the 1961 Columbia River Treaty between Canada and the United States, and coordinated operation of storage reservoirs and generating plants, to generate more power from their respective generating plants than they could if they operated independently. Under the CPA, BC Hydro determines the output of the plants such that all plants are operated as a coordinated whole. BC Hydro then takes into its system the power generated by all of the plants. In exchange, the Entitlement Parties are each contractually entitled to their Entitlements, which are based on 50-year historical water flows and the plants' generating capabilities. The Entitlement Parties receive their Entitlements irrespective of actual water flows to the Entitlement Parties' generating plants.

BC Hydro enjoys the benefits of the additional power generated through coordinated operation and optimal use of water flows. The Entitlement Parties benefit by knowing years in advance the amount of power that they will receive from their generating plants and therefore do not face hydrology variability in generation supply planning.

The Corporation, however, retains rights to its original water licenses and flows in perpetuity. Should the CPA be terminated, the output of the Corporation's Kootenay River system plants would, with the water and storage authorized under its existing licenses and on a long-term average, be approximately the same power output as the Corporation receives under the CPA. The CPA does not affect the Corporation's ownership of its physical generation assets. The Corporation continues to own and operate its four Kootenay River system generating plants, which are included in the Corporation's Rate Base Assets. The CPA continues in force until terminated by any of the parties by giving no less than five years' notice at any time on or after December 31, 2030.

(b) Power Purchase Agreements

The Corporation's electricity supply not supplied by its own generating plants is acquired through power purchase contracts consisting of the following:

(i) the Brilliant PPA;

(ii) the BC Hydro PPA;

(iii) Brilliant Expansion Capacity and Energy Purchase Agreement;

(iv) a number of small power purchase contracts with certain independent power producers;

(v) spot market and contracted capacity purchases; and

(vi) the WECA.

These power purchase contracts have been accepted by the BCUC and prudently incurred costs thereunder flow through to customers through electricity rates.

(i) Brilliant Power Purchase Agreement

The Brilliant Plant is a hydroelectric generating plant jointly owned by CPC and CBT through the Brilliant Power Corporation. The Brilliant Plant is allocated Entitlement energy of 985 GWh and capacity of 149 MW pursuant to the CPA. Under the Brilliant PPA, FBC has agreed to purchase from Brilliant Power Corporation, on a long-term basis (a) the Entitlement allocated to the Brilliant Plant and (b) after the expiration of the CPA, the actual electrical output generated by the Brilliant Plant. While the total Entitlement is 985 GWh, FBC does not purchase the approximately 60 GWh of regulated flow upgrade Entitlement under this agreement. However, FBC has entered into another agreement with CPC for this energy over a ten-year period as discussed below. The Brilliant PPA uses a take-or-pay contract structure which requires that FBC pay for the Brilliant Plant's Entitlement, irrespective of whether FBC actually takes it. FBC does not foresee any circumstances under which the Corporation would be required to pay for power that it does not require. During the first 30 years of the Brilliant PPA term, FBC pays to Brilliant Power Corporation an amount that covers the operation and maintenance costs of the Brilliant Plant and provides a return on capital, including original purchase costs, sustaining capital costs and any life extension investments. During the second 30 years of the Brilliant PPA term (commencing in 2026), an adjustment using a market price mechanism based on the depreciated value of the Brilliant Plant and then-prevailing operating costs will be made to the amounts payable by FBC. The Brilliant PPA provided FBC with approximately 25 per cent of its energy requirements in 2019.

(ii) Power Purchases from BC Hydro

FBC is a party to the BC Hydro PPA, which provides the Corporation with additional electricity for purposes of supplying its load requirements, up to a maximum demand of 200 MW. Energy bought pursuant to the BC Hydro PPA provided approximately 16 per cent of FBC's energy requirements in 2019. The current BC Hydro PPA was approved by the BCUC in May 2014 and expires on September 30, 2033. The current agreement replaced a previous power purchase agreement with BC Hydro that had been in place since 1993.

(iii) Brilliant Expansion Capacity and Energy Purchase Agreement

FBC has an agreement to purchase CPC's unused Entitlements from the Brilliant Plant and the Brilliant Expansion Plant, including the 60 GWh from the Brilliant Plant that is not included in the Brilliant Power Purchase Agreement. The agreement provided approximately 2 per cent of FBC's energy requirements in 2019. The agreement is for a ten- year period expiring at the end of 2027, and contains terms similar to those in a previous agreement which expired at the end of 2017.

(iv) Small Power Purchase Contracts

FBC has a number of small power purchase contracts with independent power producers, which collectively provided less than 1 per cent of the Corporation's energy supply requirements in 2019.

(v) Spot Market and Contracted Capacity Purchases

During 2019, the Corporation purchased capacity and energy from the market to meet its peak energy requirements and optimize its overall power supply portfolio. To facilitate market transactions going forward, FBC entered into the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex, which was approved by the BCUC in April 2015. The CEPSA is a master agreement that sets the terms and conditions for future market transactions entered into by FBC with Powerex. The CEPSA became effective May 1, 2015 and expires on September 30, 2022, as extended by the First Amending Agreement dated April 29, 2019. Spot market and contracted purchases provided approximately 12 per cent of the Corporation's energy supply requirements in 2019.

(vi) WECA

The Corporation entered into the WECA to purchase capacity from the Waneta Expansion Plant, a 335 MW hydroelectric generating facility owned by WEPC and situated adjacent to the existing Waneta Plant on the Pend d'Oreille River in BC. WECA allows FBC to purchase capacity over a 40-year period which commenced in April 2015. The WECA was accepted for filing as an energy supply contract by the BCUC in May 2012. The Waneta Expansion Plant was owned and operated by Waneta Expansion Limited Partnership, of which Fortis owned a 51 per cent interest, and a wholly-owned subsidiary of each of CPC and CBT owned the remaining interest. However, on April 16, 2019 Fortis sold its interest in the Waneta Expansion Plant to CPC and CBT.

3.3 OPERATIONS

(a) Transmission

FBC's transmission system is a high voltage system that operates at the 230 kV, 161 kV, 138 kV and 63 kV levels while transmitting electricity to customers directly connected to the transmission grid. The transmission system is highly integrated and operates synchronously with the BC Hydro system. It consists of approximately 1,300 kilometres of transmission lines and includes major substations throughout the service territory. FBC has 9 terminal transmission substations, the components of which include high voltage power transformers, power circuit breakers, high voltage switches, capacitor and reactor banks, protection and control systems, metering and monitoring systems, together with site infrastructures such as buildings and security systems. There are also 4 additional substations with generator step-up transformers associated with the four generating plants.

(b) Distribution

Electricity produced at generating plants is moved across transmission lines to terminal stations and transformers and then distributed at lower voltages to customers. FBC's distribution system is comprised of 52 distribution substations and approximately 6,000 kilometres of overhead and underground distribution lines. The FBC distribution system is being upgraded in a number of locations over several years in order to renew obsolete components at or near the end of their useful life, and to accommodate load growth that has caused load on the existing system to approach design capacity.

(c) Major Capital Projects

The Corporation plans and implements programs for sustaining and enhancing its regulated generation, transmission and distribution assets. Capital projects are typically identified as being one of two types: (a) "sustaining", which are directed at adequately maintaining asset condition and modernizing equipment; and (b) "growth" or "expansionary", which are primarily required to accommodate customer and load growth within the FBC service area. Developing the priorities for the transmission and distribution system involves an assessment of both asset condition and maintenance needs and system contingency analysis. The latter involves a modeling and simulation of system impacts following several possible and different system event scenarios.

3.4 OTHER OPERATIONS, ASSETS AND ACTIVITIES

(a) Other Operations

FBC carries out monitoring, control and real-time management of its generation, transmission and distribution facilities through its centralized system control centre. The control centre coordinates with BC Hydro to ensure that appropriate monitoring and control of transmission equipment is maintained twenty-four hours a day.

(b) Other Assets

Other assets of the Corporation include those supporting the ongoing maintenance and operation of the system, such as office and service buildings, transport and work equipment and other office and information technology assets.

(c) Other Activities

FBC's other activities are relatively small in comparison to its regulated electricity operations but provide an opportunity to leverage the utilization of FBC's utility operation, maintenance and management resources under service contracts to third parties. FBC provides certain operations, maintenance and management services relating to the Waneta Plant and the Brilliant Plant.

FortisBC Pacific, the direct parent of the Corporation, provides services of a similar nature with respect to the Brilliant Expansion Plant, Waneta Expansion Plant and Arrow Lakes Generating Station. FBC provides staff and material resources to FortisBC Pacific in order for it to carry out the services required under the contracts and charges FortisBC Pacific its cost plus a mark-up as compensation.

3.5 OTHER MATERIAL CORPORATE ISSUES

(a) Insurance

The Corporation, through Fortis, maintains insurance coverage including liability, all risk property, boiler and machinery, and directors' and officers' liability insurance for the benefit of the Corporation. The Corporation self-insures against the risk of damage to transmission and distribution poles, wires and related equipment. FBC also maintains insurance coverage that is required by provincial statute, which covers automobile liability, firefighting expense and non-owned aircraft liability. Management believes that the coverage, amounts and terms of the Corporation's insurance agreements are consistent with industry practices.

(b) Employees

The Corporation employed 538 employees as at December 31, 2019. The organized employees of FBC are represented by the IBEW and COPE unions. IBEW represents employees in specified occupations in the areas of generation and transmission and distribution. The term of the current collective agreement with the IBEW is February 1, 2018 to January 31, 2021.

There are two collective agreements between the Corporation and COPE, now referred to as MoveUP. The term of the first collective agreement with MoveUP, representing employees in specified occupations in the areas of administration and operations support, expired on December 31, 2019 and discussions with MoveUP continue. The term of the second collective agreement with COPE, representing customer service employees, is April 1, 2017 to March 31, 2022.

(c) Specialized Skills and Knowledge

The skills and knowledge needed to operate and maintain electrical generation, transmission and distribution systems are key to the Corporation’s success. These skills are currently available, and the Corporation has placed considerable focus in succession planning on ensuring that these skills are preserved as the Corporation’s workforce ages and retires.

(d) Intellectual Property

Fortis owns the trademark “FortisBC”, which it has licensed the Corporation to use. FBC owns the trademark “PowerSense”, which has been used in the promotion by the Corporation of energy efficiency and energy awareness programs.

(e) Real Property

Certain of the Corporation’s transmission and distribution facilities cross over land that is owned by the governments of Canada or BC. The Corporation believes it has obtained appropriate access rights from the relevant governments through Crown leases, statutory rights of way, land use permits, licenses of occupation and low voltage permits. Where transmission or distribution lines extend over waterways, various provincial and federal government bodies must approve the installation of those lines. Agreements and permits in this respect have been obtained from the appropriate government body.

The Corporation’s transmission and distribution lines at times also cross over or run parallel to lands owned by various railway companies. In these circumstances, appropriate access rights, generally referred to as crossing agreements, have been obtained from the relevant railway company. Some of the Corporation’s transmission and distribution lines are located on lands owned by other persons, including local governments, corporations, Indigenous peoples, and individuals. The Corporation believes it has obtained or is in the process of obtaining the rights to use these lands through working with the property owner to come to an agreement (such as statutory rights of way) permitting land usage.

If the Corporation becomes aware of a situation in which it has not acquired the requisite usage rights, it will attempt to come to an agreement to secure usage rights with the landowner. The Corporation has the power to expropriate land if necessary.

(f) Seasonality

FBC's operations generally produce lower net earnings in the third quarter due to the timing of power purchases. The higher net earnings in the first and fourth quarters are due to increased customer load as a result of cooler weather, while certain expenses such as depreciation, interest and operating expenses remain more evenly distributed throughout the fiscal year.

(g) Competition

BC’s traditional regulatory model does not support retail competition for customers, which would give customers the right to purchase electricity from suppliers other than the utility to which they are directly connected. FBC has a form of retail access for its wholesale and industrial customers supplied at transmission voltage. This retail access has not led to a loss of any of FBC’s wholesale or industrial customers.

4.0 REGULATION

4.1 OVERVIEW

Public utilities in BC, such as FBC, are subject to the regulatory jurisdiction of the BCUC. The UCA is the legislation that defines the scope of the BCUC's jurisdiction regarding the regulation of public utilities and the responsibilities of those public utilities. The BCUC’s primary responsibility is to establish just and reasonable utility rates, which include an opportunity for the public utilities to earn a fair return on the investments they have already made and will make in the future to provide customers with safe and reliable service.

4.2 RATE SETTING

The rate setting process generally has two main elements: revenue requirements and rate design.

The utility’s revenue requirements represent the total revenues that are necessary for the utility to recover prudent costs for providing the utility services, to recover prudent investment, and to earn a fair return on and of its investments. The cost of providing service includes energy costs, operating and maintenance expenses, depreciation expenses, taxes, financing costs and a return on equity. Rate base is the book value of utility plant in service (plant less accumulated depreciation and customer contributions in aid of construction) and utility deferred charges, plus an allowance for working capital invested in the business, and is the investment base to which a rate of return is applied. The return on rate base is established by determining the cost of individual components of the capital structure, including equity, and weighting such costs to determine an aggregate return on rate base. Both the capital structure and rate of return on equity are determined by the BCUC.

From 2014 to 2019, FBC operated under a PBR Plan. In March 2019, FBC filed an MRP Application for 2020 to 2024 with the BCUC that is similar to the 2014 to 2019 PBR Plan. In the MRP Application, FBC proposes a rate-setting framework that includes, among other items, the following: (1) a level of operation and maintenance expense per customer indexed for inflation; (2) a forecast approach to capital (rather than the formulaic approach adopted in the 2014 to 2019 PBR term); (3) a 50/50 sharing between customers and FBC of variances from the allowed ROE; (4) targeted incentives for power supply cost mitigation, supporting clean transportation and enhancing customer engagement; (5) an innovation fund recognizing the need to accelerate investment in clean energy innovation; and (6) the BCUC’s approval of updated depreciation rates and a number of service quality indicators designed to ensure FBC maintains service levels.

A decision on FBC’s MRP Application is expected by mid-2020. In the interim, the BCUC has approved FBC’s request for an interim rate increase of 1.0% over 2019 rates, effective January 1, 2020. Interim rates will remain in place pending a final decision by the BCUC on permanent rates.

When approved by the BCUC, FBC employs deferral accounts to address certain uncontrollable or non-routine items and to match costs incurred to the periods that the costs benefit. In its MRP Application, FBC has proposed a deferral account to flow through other variances in gross margin and in certain uncontrollable items.

After revenue requirements have been established, costs are allocated among different classes of energy users/customers and rates are designed to reflect the cost of providing services to each rate class. Before any rate can be put into effect, it must be filed with and approved by the BCUC.

In BC, the regulatory process for revenue requirement determination and rate design involves participation of interested parties, such as customer representatives, other public groups or private individuals.

4.3 KEY REGULATORY INFORMATION

Important regulatory information pertaining to decisions made by the BCUC with respect to FBC is summarized in the following table.

	2019	2018	2017	2016
Rate Base Assets ($ millions)	1,342	1,321	1,285	1,286
Deemed common equity component of total capital structure (%)	40.0	40.0	40.0	40.0
Allowed rate of return on common equity (%)	9.15	9.15	9.15	9.15

5.0 SAFETY AND ENVIRONMENTAL MATTERS

5.1 GENERAL

Canadian federal, provincial and municipal governments share jurisdiction over matters affecting safety and the environment. As a result, the Corporation is subject to provincial occupational health and safety legislation as well as federal, provincial and municipal requirements relating to the protection of the environment including, but not limited to, air, water, land, and natural resource protection, including fish and wildlife; the proper storage, transportation, discharge and disposal of hazardous and non-hazardous substances; and air emissions management. In addition, both the provincial and federal governments have environmental assessment legislation, which is designed to foster better natural resource and land-use planning through the identification and mitigation of potential environmental impacts of projects or undertakings prior to and after commencement.

5.2 ENVIRONMENTAL MANAGEMENT SYSTEM

The environmental risks associated with the Corporation's activities and operations are managed under the framework of an EMS. FBC has an EMS in place to manage the impact of its activities on the environment and the design of the EMS is consistent with the guidelines of ISO 14001:2015, an internationally recognized standard for EMS.

The Corporation's EMS includes an environmental policy, a summary of the environmental risks associated with the Corporation's business and operations, a summary of relevant environmental legislation, and an internal reporting process. The EMS also includes environmental training requirements for employees and contractors and reinforces environmental guidelines that serve to minimize the environmental impacts of FBC operations and comply with applicable environmental legislation. FBC has external audits of its EMS conducted on a regular cycle to ensure continued compliance with ISO 14001:2015 standards and legal requirements.

5.3 PERMITS, LICENCES AND APPROVALS

Various federal and provincial statutes require the Corporation to obtain and comply with specific permits, licenses and approvals in the course of its operations. Pursuant to the *Water Sustainability Act* (British Columbia), water rental rates apply to the use of water for power generation. Water rental rates in BC are levied on the basis of both total station capacity and on total station generation. The Corporation is able to recover water rental costs through rates.

5.4 ENVIRONMENTAL EXPENDITURES

The Corporation incurs environmental management and compliance related expenditures in connection with capital projects and in connection with ongoing operation and maintenance activities that are not reasonably quantifiable. The Corporation's cost of compliance with environmental laws and regulations did not have a material effect on the operating costs, capital expenditures, earnings or competitive position of the Corporation in 2019 and, based on current laws, facts and circumstances, is not expected to have a material effect on such matters in the future. Operating and capital costs associated with complying with environmental laws and regulations are generally recoverable by the Corporation through rates.

5.5 RELEASES

Federal, provincial and municipal environmental legislation regulate the release of substances into the environment through the regulation of discharges that have an adverse effect or a potentially adverse effect on the environment. FBC believes that the potential for spills, and resulting enforcement actions under existing environmental legislation, is reduced through the implementation of spill prevention, waste discharge authorizations, proper material handling, emergency response programs and spill response guidelines in conjunction with appropriate training. The potential for an adverse effect resulting from a spill is further reduced by the Corporation through the tracking of all incidents and potential incidents in an incident reporting database in order to facilitate continual learning and improvement.

5.6 HAZARDOUS SUBSTANCES

The Corporation manages hazardous substances used in its operations such as PCBs and herbicides. The Corporation has environmental management programs in place to deal with the hazardous substances including programs to deal with PCBs and herbicides:

(a) *PCBs* - Current management plans for PCBs focus on the identification, safe handling, transportation, storage and ultimate disposal of PCB containing equipment. As equipment becomes obsolete and is taken out of service, FBC disposes of it in an environmentally sound manner and in compliance with applicable laws. Federal PCB regulations specify deadlines for the elimination of PCB containing equipment. With the exception of pole-top transformers and their auxiliary equipment, PCB containing equipment having levels of PCBs greater than 500 ppm or those with PCB levels between 50 ppm and 500 ppm located in sensitive areas were removed from service by the end of 2009. FBC believes it is compliant with the PCB regulation. For certain substation auxiliary equipment FBC had been granted an extension to the Federal PCB regulation deadline to 2014 and had mitigated the PCB concern for the majority of this substation equipment at year end. However, the regulation was subsequently amended to extend the deadline for removal from service of such substation auxiliary equipment to December 31, 2025. All other electrical equipment with PCB levels greater than 50 ppm must be removed from service by December 31, 2025. FBC is taking the necessary steps to meet these compliance deadlines and will recover the associated costs through rates as approved by BCUC.

(b) *Herbicides* - The Corporation uses herbicides primarily for the control of incompatible vegetation on rights-of-way, along transmission and distribution lines and on station sites. The Corporation uses an integrated approach toward vegetation management using manual and mechanical cutting, natural competition from compatible vegetation, together with the selective use of herbicides. Patrols occur to monitor vegetation growth and assess appropriate maintenance activities. Site-specific conditions, including tree species, tree density, height, terrain, prevailing wind directions, and adjacent land uses, are considered by the Corporation in determining the appropriate overall vegetation management plan. Herbicides are applied in accordance with applicable federal and provincial legislation, which governs application, notification and reporting.

(c) *Other* - In addition, some facilities and products used in operational activities contain substances that are designated for special treatment under occupational health and safety legislation, such as asbestos, lead and mercury. The Corporation has exposure control plans in place to address situations when these kinds of substances are encountered or utilized. In addition, the Corporation has programs in place to manage the disposal of materials and products containing hazardous substances in accordance with regulatory requirements.

5.7 SITE INVESTIGATION AND REMEDIATION

Spills and leaks of substances may occur in the normal course of the Corporation's operations and may result in future clean-up costs being incurred in connection with these releases. The Corporation has from time to time, investigated sites for potential contamination and remediated sites where appropriate. It is possible that remediation costs could be incurred in future due to contamination at sites and the Corporation expects that costs incurred for site remediation would be recovered through rates.

5.8 AIR EMISSIONS MANAGEMENT AND POLICY

The Company has an emissions management program in place to track regulatory and policy changes, implement operational changes, and report compliance. The Corporation continues to report its GHG emissions for electricity imports pursuant to provincial GHG reporting regulation.

The BC government (the "Province") has enacted climate change legislation that frames BC's approach to reducing emissions and transitioning to a low-carbon economy. The *Climate Change Accountability Act* (formerly the *Greenhouse Gas Reduction Targets Act*) sets new legislated targets for reductions in GHG emissions. Under this Act, the Province is required to report publically on how it is preparing for climate change. Starting in 2020, the Province will report on the risks to BC from a changing climate, progress towards reducing those risks, and actions and plans to achieve that progress.

In late 2018, the Province released its provincial climate plan, entitled CleanBC. CleanBC was developed as a pathway to achieve the Province's legislated targets of reducing GHG emissions by 40% by 2030 based on 2007 levels and has two phases. The first phase highlights actions to achieve 75% of the 2030 target. The second phase, which began in 2019, will be developed over the course of 18 to 24 months and will describe and quantify additional reduction initiatives. CleanBC sets GHG emission reduction goals for the transportation, buildings, industrial and waste sectors. The actions proposed under each of these sectors fall into three categories: significantly improve efficiency, electrify some energy end-uses, and use low-carbon fuels. CleanBC recognizes the role of electrical infrastructure in achieving long-term GHG reductions and creating opportunities for the Corporation. For example, CleanBC emphasizes the role of electric vehicles and electrical vehicle charging infrastructure in reducing GHG emissions.

To date, the Province has not pursued a cap and trade approach to GHG emissions reduction. However, BC remains a participating jurisdiction in the Western Climate Initiative ("WCI") and if BC decides to participate in a WCI cap and trade program, the specific details will be defined in regulation. If implemented, the cap and trade program is expected to have a declining cap on emissions that all covered facilities must meet, either by reducing emissions internally or by purchasing allowances from other facilities for releases over the capped amount.

5.9 ASSET RETIREMENT OBLIGATIONS

During 2010, the Corporation obtained sufficient information to determine an estimate of the fair value and timing of the estimated future expenditures associated with the removal of PCB contaminated oil, as previously described in Section 5.6(a), from certain of its electrical equipment. As such, the Corporation has recorded an ARO of approximately $2 million as at December 31, 2019. The determination of the ARO depends upon management's best estimates relating to factors such as timing, amount and nature of future cash flows necessary to discharge the legal obligation and comply with existing legislation or regulations, as well as the use of a credit-adjusted risk-free rate for measurement purposes. There are uncertainties in estimating future asset retirement costs due to potential external events such as changing legislation or regulations and advances in remediation technologies. It is possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the Corporation's current assumptions. In addition, in order to remove certain PCB-contaminated oil, the ability to conduct maintenance outages in critical facilities may impact the timing of expenditures. The ARO may change from period to period because of the changes in the estimation of these uncertainties.

Excluding the ARO pertaining to PCBs, the nature, amount and timing of costs associated with land and other environmental remediation and/or removal of assets, cannot be reasonably estimated due to the nature of their operation; and applicable licences, permits and laws are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and to ensure the continued provision of service to customers. In the event that environmental issues are identified, or the applicable licences, permits, laws or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

5.10 EMERGENCY PREPAREDNESS AND SAFETY

FBC has detailed emergency preparedness plans in place to respond to natural disasters, accidents and emergencies, and regularly tests these plans in simulations involving employees and other emergency response organizations.

The Corporation is committed to monitoring and assessing its safety management system regularly. FBC incorporates safety performance measures into its employee compensation system, sets challenge levels and objectives for performance, and conducts safety and environmental audits regularly.

5.11 ELECTRO-MAGNETIC FIELDS

Electric and magnetic fields exist wherever electricity is used or transmitted, including electric power facilities such as transmission and distribution lines and within every building that has electrical service. Scientists and public health experts in North America and abroad are studying the possibility that exposure to electro-magnetic fields may cause health problems. FBC understands there is no conclusive evidence of any harm caused by exposure at levels normally found in Canadian living and working environments. Electro-magnetic fields are not currently regulated by the federal or provincial governments and the Corporation is unaware of any plans to regulate electro-magnetic fields.

6.0 RISK FACTORS

For more information with respect to risks and uncertainties to which the Corporation is subject, see the section entitled “Business Risk Management” in the Corporation’s Management Discussion & Analysis for the year ended December 31, 2019, which is filed on SEDAR at www.sedar.com, and is incorporated herein by reference.

7.0 CAPITAL STRUCTURE

FBC’s business requires the Corporation to have ongoing access to capital to allow it to build and maintain the electrical systems in its service territory. In order to ensure that this access to capital is maintained and in accordance with BCUC requirements, the Corporation currently targets a long-term capital structure that includes 40 per cent equity and 60 per cent debt. This capital structure excludes the effects of goodwill and other items that do not impact the deemed capital structure. The cost of capital for regulated utilities in BC is reviewed periodically which can result in a change in the equity component for the Corporation.

7.1 SHARE CAPITAL

The Corporation is authorized to issue 500,000,000 common shares with a par value of $100 each and 500,000,000 preferred shares with a par value of $25 each, of which 20,000 shares have been designated as Preferred Shares - Series 1, and 480,000 shares have been designated as Cumulative Redeemable Retractable Preferred Shares - Series 2. The issued and outstanding share capital of FBC as at December 31, 2019 consists of 2,191,510 common shares and no preferred shares. Fortis owns all of the issued common shares through its indirect wholly-owned subsidiary, FortisBC Pacific.

Holders of common shares of the Corporation are entitled to receive dividends as and when declared by the Board, subject to the rights of holders of the preferred shares, and are entitled to one vote per share on all matters to be voted on at all meetings of shareholders except those meetings at which only the holders of shares of another class or of a particular series are entitled to vote. Upon the liquidation, dissolution or winding-up of the Corporation, the holders of common shares are entitled to share rateably in the remaining assets available for distribution, after payment of liabilities and subject to the rights of the holders of the preferred shares. The common shares do not have exchange, conversion, redemption or retraction rights.

Preferred shares may be issued from time to time in one or more series, each series comprising the number of shares, designation, rights and restrictions determined by the Board. Preferred shares are entitled to priority over the common shares with respect to the payment of dividends and distributions of assets in the event of the liquidation, dissolution or winding-up of the Corporation. Except in respect of a meeting of holders of the preferred shares or of a particular series of the preferred shares, or except as may otherwise be provided in the rights attached to any series of preferred shares, holders of the preferred shares will not be entitled to vote at any meetings of shareholders.

7.2 DIVIDEND POLICY

The declaration and payment of dividends is at the discretion of the Board and will be influenced by ongoing capital structure management. In 2019, FBC paid $45 million in dividends, compared with $44 million in 2018 and $47 million in 2017.

Certain of the Corporation's debt covenants contain restrictions on the payment of dividends if consolidated debt exceeds 75 per cent of consolidated capitalization, if the dividends are not in the ordinary course of business or if the cumulative dividends paid since the date that certain debt instruments were issued exceeds thresholds based on the cumulative net earnings of the Corporation.

8.0 CREDIT RATINGS

The following table discloses the Corporation's credit ratings as at December 31, 2019.

Credit Ratings	DBRS Morningstar	Moody's
Unsecured Debentures	A (low), Stable Trend	Baa1, Stable Outlook
Secured Debentures	A (low), Stable Trend	-
Commercial Paper	R-1 (low), Stable Trent	-

In March 2019, DBRS Morningstar affirmed the long-term credit rating for FBC of A (low) for unsecured and secured debentures and R-1 (low) for commercial paper. In August 2019, Moody's affirmed the long term credit rating for FBC of Baa1 for unsecured debentures.

Ratings are not recommendations to purchase, hold, or sell debentures because ratings do not comment as to market price or suitability for a particular investor. The Corporation understands that ratings are based on, among other things, information furnished to the rating agencies by the Corporation and information obtained by the rating agencies from public sources. Ratings may be changed, suspended or withdrawn as a result of changes in, or unavailability of, that information.

Securities issued by FBC are rated by DBRS Morningstar and Moody's. FBC paid each of these agencies a maintenance fee to provide ratings during 2019 and 2018, but did not pay for or receive any other services from the agencies during those years. The ratings assigned to securities issued by FBC are reviewed by these agencies on an ongoing basis. Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. DBRS Morningstar rates debt instruments by rating categories ranging from AAA which represents the highest quality of securities, to D which represents the lowest quality of securities rated. Moody's rates debt instruments by rating categories ranging from Aaa which represents the highest quality of securities to C which represents the lowest quality of securities.

According to the DBRS Morningstar rating system, debt securities rated A are of good credit quality. Protection of interest and principal is still substantial, but the degree of strength is less than with AA related entities. Entities in the A category may be vulnerable to future events, but qualifying negative factors are considered manageable. "High" or "Low" are used to indicate the relative standing of a credit within a particular rating category. The lack of one of these designations indicates a rating which is essentially in the middle of the category.

According to the Moody's rating system, debt securities rated Baa are considered to be subject to moderate credit risk, are medium grade obligations and as such may possess certain speculative characteristics. Moody's applies numerical modifiers (1, 2 and 3) in each rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of its rating category.

9.0 MARKET FOR SECURITIES

None of the issued and outstanding shares of the Corporation or any of its debentures are listed on any exchange.

In November 2018, FBC established a commercial paper program under which it is authorized to issue up to $150 million in short-term notes.

10.0 DIRECTORS AND OFFICERS

10.1 DIRECTORS

The following table sets forth the name, province or state, and country of residence of each director of the Corporation, his or her respective position and office with the Corporation as at the date of filing of this Annual Information Form. In addition this table sets forth each director's principal occupation during the five preceding years, and the period during which he or she has served as a director of the Corporation, and when his or her term expires:

NAME AND RESIDENCE	TERM AS A DIRECTOR[(4)]	PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS
Tracey C. Ball[(1)] British Columbia, Canada	Commencing 2018. Term expires at the next annual general meeting.	Corporate Director.
Peter Blake[(1)] British Columbia, Canada	Commencing 2017. Term expires at the next annual general meeting.	Corporate Director. Additionally Chief Executive Officer of WesternOne Inc. to December 2018.
Roger A. Dall'Antonia British Columbia, Canada	Commencing 2017. Term expires at the next annual general meeting.	President & CEO of the Corporation and additionally of FortisBC Energy Inc. since December 2017; prior thereto Executive Vice President, Customer Service & Technology of the Corporation and additionally of FortisBC Energy Inc. since October 2016; prior thereto Executive Vice President, Customer Service & Regulatory Affairs of the Corporation and additionally of FortisBC Energy Inc.
David G. Hutchens[(1)] Arizona, USA	Commencing 2015. Term expires at the next annual general meeting.	Chief Operating Officer of Fortis since January 2020; Executive Vice President, Western Utility Operations of Fortis since January 2018; additionally and prior thereto President & Chief Executive Officer of UNS Energy Corporation ("UNS Energy").
K.M. Tracy Medve[(2)(3)] British Columbia, Canada	Commencing 2016. Term expires at the next annual general meeting.	President of KF Aerospace Group of Companies.

Name and Residence	**Term as a Director[(4)]**	**Principal Occupation for the Five Preceding Years**
Michael L. Mosher[(2)] Alberta, Canada	Commencing 2019. Term expires at the next annual general meeting.	President & CEO of FortisAlberta Inc. since September 2018; prior thereto President & CEO of Central Hudson Gas & Electric Corp. since April 2016; prior thereto Vice President, Regulatory Affairs of same.
Barry V. Perry[(2)] Newfoundland and Labrador, Canada	Commencing 2010. Term expires at the next annual general meeting.	President & CEO of Fortis.
Jocelyn H. Perry[(1)] Newfoundland and Labrador, Canada	Commencing 2019. Term expires at the next annual general meeting.	Chief Financial Officer of Fortis since June 2018; prior thereto President & CEO of Newfoundland Power Inc. since June 2017; prior thereto executive of Newfoundland Power Inc.
Christopher F. Scott[(2)] British Columbia, Canada	Commencing 2013. Term expires at the next annual general meeting.	Corporate Director; additionally Consultant to Indigenous Bands; additionally Owner/Operator of Premium Varietal Vineyard.
Janet P. Woodruff [(1)] British Columbia, Canada	Commencing 2013. Term expires at the next annual general meeting.	Corporate Director; additionally Consultant to June 2015.

Notes:

1. Member of the Audit Committee.
2. Member of the Governance Committee.
3. Chair of the Board.
4. The Articles of the Corporation provide that if the Corporation does not hold an annual general meeting in accordance with the *Business Corporations Act* (British Columbia), the Directors then in office shall be deemed to have been elected or appointed as Directors on the last day on which the annual general meeting could have been held pursuant to the *Business Corporations Act* (British Columbia), and they may hold office until other Directors are appointed or elected or until the day on which the next annual general meeting is held.

10.2 OFFICERS

The following table sets forth the name, province and country of residence of each executive officer of the Corporation, his or her respective position and office with the Corporation as at the date of filing of this Annual Information Form. In addition, this table sets forth each officer's principal occupation during the five preceding years:

NAME AND RESIDENCE	OFFICE HELD	PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS
Roger A. Dall'Antonia British Columbia, Canada	President & CEO	President & CEO of the Corporation and additionally of FortisBC Energy Inc. since December 2017; prior thereto Executive Vice President, Customer Service & Technology of the Corporation and additionally of FortisBC Energy Inc. since October 2016; prior thereto Executive Vice President, Customer Service & Regulatory Affairs of the Corporation and additionally of FortisBC Energy Inc.
Doyle Sam British Columbia, Canada	Executive Vice President, Operations & Engineering	Executive Vice President, Operations & Engineering of the Corporation and additionally of FortisBC Energy Inc.
Jody D. Drope British Columbia, Canada	Vice President, Human Resources & Environment, Health and Safety	Vice President, Human Resources & Environment, Health and Safety of the Corporation and additionally of FortisBC Energy Inc.
Michael A. Leclair British Columbia, Canada	Vice President, Major Projects	Vice President, Major Projects of the Corporation and additionally of FortisBC Energy Inc. since February 2018; prior thereto Director, Generation & Compression of the Corporation since August 2016; prior thereto Director, Generation of the Corporation.
Ian G. Lorimer British Columbia, Canada	Vice President, Finance & CFO	Vice President, Finance & CFO of the Corporation and additionally of FortisBC Energy Inc. since June 2015; prior thereto Vice President, Finance & CFO of FortisAlberta Inc.
Dawn M. Mehrer British Columbia, Canada	Vice President, Customer Service and Information Systems	Vice President, Customer Service and Information Systems of the Corporation and additionally of FortisBC Energy Inc. since February 2018; prior thereto Director, Customer Contact Centres of FortisBC Energy Inc.
Diane E. Roy British Columbia, Canada	Vice President, Regulatory Affairs	Vice President, Regulatory Affairs of the Corporation and additionally of FortisBC Energy Inc. since October 2016; prior thereto Director, Regulatory Services of the Corporation and additionally of FortisBC Energy Inc.

NAME AND RESIDENCE	OFFICE HELD	PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS
Douglas L. Stout British Columbia, Canada	Vice President, Market Development & External Relations	Vice President, Market Development & External Relations of the Corporation and additionally of FortisBC Energy Inc.
Dennis A. Swanson British Columbia, Canada	Vice President, Energy Supply & Resource Development	Vice President, Energy Supply & Resource Development of the Corporation and additionally of FortisBC Energy Inc. since August 2017; prior thereto Vice President, Energy Supply of the Corporation and additionally of FortisBC Energy Inc. since May 2016; prior thereto Vice President, Corporate Services of the Corporation and additionally of FortisBC Energy Inc.
Monic D. Pratch British Columbia, Canada	Corporate Secretary	Director, Governance & Corporate Compliance, Corporate Secretary & Senior Counsel of the Corporation and additionally of FortisBC Energy Inc. since August 2018; prior thereto Chief Privacy Officer, Corporate Secretary & Senior Counsel of the Corporation and additionally of FortisBC Energy Inc. since April 2017; prior thereto Chief Privacy Officer, Corporate Secretary & Counsel of the Corporation and additionally of FortisBC Energy Inc.
Debra G. Nelson British Columbia, Canada	Assistant Corporate Secretary	Assistant Corporate Secretary and Manager, Corporate Compliance and Secretariat of the Corporation and additionally of FortisBC Energy Inc.

10.3 CONFLICTS OF INTEREST

Other than as disclosed herein, to the knowledge of management of the Corporation, there are no existing or potential material conflicts of interest among the Corporation or a subsidiary of the Corporation and any director or officer of the Corporation or such subsidiary.

11.0 EXECUTIVE COMPENSATION

The Corporation's Statement of Executive Compensation is attached as Schedule "A".

12.0 SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The Corporation does not have a compensation plan under which securities of the Corporation are authorized for issuance. See "Executive Compensation – Share Based Awards" in Schedule "A" of this Annual Information Form for a description of the Fortis 2012 Stock Option Plan.

13.0 INDEBTEDNESS OF EXECUTIVE OFFICERS, DIRECTORS, AND EMPLOYEES

The following table sets forth details of the aggregate indebtedness of all executive officers, directors, and employees and former executive officers, directors and employees outstanding at the date of this Annual Information Form to the Corporation or any of its subsidiaries in connection with (i) the purchase of securities and (ii) all other indebtedness, other than routine indebtedness.

Aggregate Indebtedness ($)		
Purpose	**To the Corporation or its Subsidiaries**	**To Another Entity**
Share purchases	Nil	Nil
Other	Nil	Nil

14.0 INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer of the Corporation, or person or Corporation that beneficially owns, or controls or directs, directly or indirectly, more than 10 per cent of any class or series of the Corporation's outstanding voting securities, nor any associate of the foregoing persons, has or has had any material interest, direct or indirect, in any transaction within the three most recently completed financial years of the Corporation or during the current financial year of the Corporation that has materially affected or is reasonably expected by the Corporation to materially affect the Corporation.

For more information with respect to the Corporation's material transactions with related parties, see the section entitled "Related Party Transactions" in the Corporation's Management Discussion & Analysis for the year ended December 31, 2019, which is filed on SEDAR at www.sedar.com, and is incorporated herein by reference.

15.0 MATERIAL CONTRACTS

The following are the only material contracts, other than contracts entered into in the ordinary course of business and not required by applicable securities laws to be filed with a Canadian securities regulatory authority or those that were entered into before January 1, 2002, which have been entered into by the Corporation within the Corporation's most recently completed financial year, or before the most recently completed financial year but is still in effect:

- the trust indenture dated as of November 30, 2004 between the Corporation and Computershare Trust Corporation of Canada, as Trustee, as supplemented and amended from time to time;
- the CPA (see "The Business of FortisBC Inc. – Generation and Power Supply"); and
- the trust indenture dated as of May 27, 2009 between the Corporation and Computershare Trust Corporation of Canada, as Trustee, as supplemented and amended from time to time.

Copies of the above noted agreements are contained on SEDAR at www.sedar.com.

16.0 LEGAL PROCEEDINGS

There are no material legal proceedings filed by or against the Corporation at the date of this Annual Information Form.

17.0 TRANSFER AGENTS AND REGISTRARS

Computershare Trust Corporation of Canada is the registrar and transfer agent and trustee for the Corporation's debentures. Transfers of these securities may be effected at Computershare Trust Corporation of Canada's offices in the city of Vancouver, BC.

18.0 INTEREST OF EXPERTS

Deloitte LLP Chartered Accountants is the auditor of the Corporation and was appointed effective as at May 15, 2017 and each year thereafter. Deloitte LLP has prepared the audit report attached to the audited consolidated financial statements for the Corporation's financial year ended December 31, 2019. Deloitte LLP remains independent with respect of the Corporation within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of British Columbia.

19.0 ADDITIONAL INFORMATION

Additional financial information is also provided in the Corporation's financial statements for the financial year ended December 31, 2019, and management's discussion and analysis of such financial results. A copy of such documents and additional information relating the Corporation is contained on SEDAR at www.sedar.com. Such information is not incorporated by reference into this document unless specifically stated herein.

SCHEDULE "A" - EXECUTIVE COMPENSATION

A. COMPENSATION DISCUSSION AND ANALYSIS

It is the responsibility of the Governance Committee to review, recommend and administer the compensation policies in respect of the Corporation's executive officers. The Governance Committee's recommendations as to base salary, short term incentives and grants under the 2015 Performance Share Unit ("PSU") Plan and the 2015 Restricted Share Unit ("RSU") Plan are submitted to the Board of the Corporation for approval. Proposed grants to the Corporation's executive officers under the Fortis Stock Option Plan are submitted by the Corporation's Board to the Human Resources Committee of the Fortis Board of Directors for approval.

The Corporation's executive compensation program is designed to provide competitive levels of compensation, a significant portion of which is dependent upon individual and corporate performance and contribution to increasing shareholder value. The Governance Committee recognizes the need to provide a total compensation package that will attract and retain qualified and experienced executives as well as align the compensation level of each executive to that executive's level of responsibility.

The Corporation has a policy of compensating executive officers at approximately the median (50th percentile) of comparable Canadian commercial industrial companies. For clarity, this reference group does not include organizations in the financial service and broader public sectors. It does include organizations from the energy, mining and manufacturing sectors. Annually, the Governance Committee uses the compensation data from this reference group to compare each executive officer to corresponding positions within the reference group. This framework serves as a guide for the Governance Committee's deliberations. The actual total compensation and/or amount of each compensation component for an individual executive officer may be more or less than the median amount.

Total annual compensation for the executive officers is composed primarily of the following main components:

- annual base salary;
- annual incentive plan that provides the opportunity to each to earn a cash bonus;
- share-based awards that provide the opportunity to earn cash at the end of a three-year period (RSU Plan);
- share-based awards that provide the opportunity to earn cash based on performance metrics at the end of a three-year period (PSU Plan);
- option-based awards to purchase Fortis Common Shares; and
- pension arrangements.

Each of the components is discussed further in the following sections of this Schedule "A".

REPORT ON CORPORATE GOVERNANCE

Governance Committee

Specifically, the Governance Committee provides assistance to the Board by overseeing the Corporation's policy and performance in matters of corporate governance, including the nomination of Directors, matters of environment and safety, and matters of human resource management, including compensation of executive officers and the Corporation's pension plans.

With regards to executive compensation matters, the responsibilities of the Governance Committee include reviewing and making recommendations to the Board regarding:

- the adequacy and form of compensation of directors;
- the appointment and compensation of executive officers;
- the overall effectiveness of the senior management team including the CEO; and
- the development of policy for orderly succession to senior positions and targets used by the Corporation to measure performance for compensation purposes.

Total annual compensation for the executive officers involves a significant proportion that is at risk due to the use of short-term and long-term incentive components. For 2019, approximately 70 per cent of the President & Chief Executive Officer's total annual compensation was designed to be at risk. Approximately 50-55 per cent of other executive officers' total annual compensation was designed to be at risk. Total annual compensation includes both the cash compensation paid to the executive officers in the year and the target compensation for the medium-term and long-term incentive components.

Additionally, the Governance Committee believes that the Corporation's compensation regime appropriately takes into account the performance of the Corporation and the contribution of the President & CEO and other executive officers of the Corporation toward that performance.

The mandate of the Governance Committee includes making recommendations to the Board with respect to the governance and management of the pension plans and designating executive officers for purposes of participation in supplemental pension plans. In regards to non-union pension matters, the Governance Committee appoints the auditor for the pension plan financial statements. The Board establishes or terminates pension plans, is the fiduciary and administrator for the plans and approves the governance structure, major plan design changes and the mandate of the Governance Committee.

The Corporation recognizes the importance of appointing knowledgeable and experienced individuals to the Governance Committee. The Governance Committee composition includes members that have the necessary background and skills to provide effective oversight of corporate governance and executive compensation, including adherence with sound risk management principles.

To enable the Governance Committee to fulfill its mandate, all Governance Committee members have significant senior leadership and/or governance experience. More specifically, a majority of the membership of the Governance Committee has direct operational or functional experience overseeing compensation policies and practices at large organizations similar in complexity to FBC.

The members of the Governance Committee are Christopher F. Scott, Barry V. Perry, K. M. Tracy Medve and Michael L. Mosher. These directors are independent directors with the exception of Barry V. Perry, President & CEO of Fortis and Michael L. Mosher, President & CEO of FortisAlberta Inc.

In fulfilling its duties and responsibilities with respect to executive compensation, the Governance Committee seeks periodic input, advice, and recommendations from various sources, including the Board, executive officers, and external independent consultants. The Governance Committee retains discretion in its executive compensation decisions and is not bound by the input, advice, and/or recommendations received from the external independent consultant.

Compensation Review Framework

Annual Review

FBC monitors, reviews, and evaluates its executive compensation program annually to ensure that it provides reasonable compensation ranges at appropriate levels and remains competitive and effective.

As part of the annual review process, Fortis engages Korn Ferry Hay Group Limited ("Korn Ferry") its primary compensation consultant, to provide comparative analyses of market compensation data reflecting the pay levels and practices of Canadian commercial industrial companies. Using this data, a detailed review is prepared to analyze the Corporation's competitive compensation positioning against its peer group is undertaken. Korn Ferry provides Fortis and its subsidiaries' management preliminary recommendations on the basis of pay competitiveness, emerging market trends and best practices. In addition, the Corporation may from time to time engage Korn Ferry to provide specific analysis of its executive compensation components.

Management then takes into account the corporate performance against pre-determined objectives and together with the CEO recommends a set of new performance objectives for the following year. Individual performance reviews, incentive award payouts, and compensation adjustments, if any, are also determined at this stage. The CEO does not make recommendations to the Governance Committee with respect to his own compensation.

In the final step, the Governance Committee reviews the recommendations set forward by management and the compensation consultant prior to seeking approval from the Board regarding current year's compensation payouts and next year's performance objectives. The Governance Committee and the Board may exercise discretion when making compensation decisions in appropriate circumstances and make deviations from the prescribed incentive award formulas, if necessary.

Competitive Positioning

FBC does not measure performance against a particular reference group. However, as a general policy, FBC establishes base and incentive compensation targets so as to compensate executives and in particular, each person who served as the CEO or CFO during the most recently completed financial year and the most highly compensated executive officers of the Corporation during the most recently completed financial year (the "Named Executive Officers" or "NEOs"), at a level generally equivalent to the median of practice among a broad reference group of approximately 200 Canadian commercial industrial companies. This reference group, (The Commercial Industrial Comparator Group) is compiled by Korn Ferry. For clarity, this reference group does not include organizations in the financial service and broader public sectors. It does include organizations from the energy, mining and manufacturing sectors. This reference group is formally reviewed as part of the Fortis review of executive compensation policy.

Elements of Total Compensation

Total annual compensation for the executive officers involves a significant proportion that is at risk due to the use of short-term and long-term incentive components. The total annual compensation includes both the cash compensation paid to the executive officers in the year and an estimated compensation for the long-term incentive components.

The executive compensation regime is structured in a manner that recognizes the greater ability of the President & CEO to affect corporate performance by making a greater portion of that individual's compensation dependent upon corporate performance.

The elements of compensation of the NEOs and their respective compensation objectives are set out below:

Compensation Element *(Eligibility)*	**Description**	**Compensation Objectives**
Annual Base Salary and Annual Incentive		
Annual Base Salary *(all NEOs)*	Salary is a market-competitive, fixed level of compensation.	Attract and retain highly qualified executives. Motivate strong business performance.
Annual Incentive *(all NEOs)*	Combined with salary, the target level of annual incentive is intended to provide executives with a market-competitive total cash opportunity. Annual incentive payout depends on individual and corporate performance.	Attract and retain highly qualified executives. Motivate strong business performance. Compensation dependent on individual and corporate performance. Simple to communicate and administer.

Mid-term Equity Based Incentive		
Share-Based Awards (PSUs) *(all NEOs)*	Incentive is based on the Corporation's and Fortis' performance over a three-year period against predetermined measures. The amount of annual grant is determined as a specified percentage of the participant's annual base salary divided by the volume-weighted average price of Fortis' common shares for the five trading days immediately preceding the date of grant. The grant date is January 1 of each year. Cash payout upon completion of the three-year performance period, depending on Fortis' performance.	Align executive and shareholder interests. Attract and retain highly qualified executives. Encourage strong long-term business performance. Balance compensation for short and long-term strategic results. Compensation dependent on corporate performance. Encourages sustained long-term growth by linking a portion of compensation to long-term performance. Simple to communicate and administer.
Share Based Awards (RSUs) *(all NEOs)*	The amount of annual grant is determined as a specified percentage of the participant's annual base salary divided by the volume-weighted average price of Fortis' common shares for the five trading days immediately preceding the date of grant. The grant date is January 1 of each year. Cash payout upon completion of the three-year period.	Align executive and shareholder interests. Attract and retain highly qualified executives. Balance compensation for short and long-term strategic results. Simple to communicate and administer.
Long-term Equity Based Incentive		
Stock Options *(all NEOs)*	Annual equity grants are made in the form of stock options to purchase common shares of Fortis. Beginning in 2015, the amount of annual grant is determined as a specified percentage of the participant's annual base salary divided by the binomial valuation of Fortis' share price. Options vest over a 4-year period and expire after 10 years (2012 Stock Option Plan).	Align executive and shareholder interests. Attract and retain highly qualified executives. Encourage strong long-term business performance. Balance compensation for short and long-term strategic results. Simple to communicate and administer.

Pension Plans		
Registered Retirement Savings Plan ("RRSP") *(all NEOs)*	Contribution to a RRSP equal to 6.5 per cent of a member's base salary which is matched by the member up to the maximum annual contribution limit allowed by the Canada Revenue Agency.	Attract and retain highly qualified executives. Simple to communicate and administer.
Defined Contribution: Supplemental Employee Retirement Plan ("SRP" or "SERP") *(all NEOs)*	Accrual of 13 per cent of base salary and annual incentive in excess of the Canada Revenue Agency annual limit. At time of retirement, paid in one lump sum or in equal payments up to 15 years.	Attract and retain highly qualified executives. Simple to communicate and administer.

Annual Base Salary

Annual base salaries paid to the Corporation's NEOs are determined by the Board upon recommendation by the Governance Committee and are established annually by reference to the range of salaries paid by comparable Canadian commercial industrial companies and are targeted to the median of the comparator group.

Annual Incentive

NEOs participate in an annual incentive plan that provides for annual cash bonuses which are determined by way of an annual assessment of corporate and individual performance in relation to targets approved by the Board upon recommendation by the Governance Committee. The Corporation's annual earnings must reach a minimum threshold level before any payments are made. The objectives of the annual incentive plan are to reward achievement of short-term financial and operating performance and focus on key activities and achievements critical to the ongoing success of the Corporation.

Corporate performance is determined with reference to the performance of the Corporation relative to weighted targets in respect to financial, safety, customer satisfaction and regulatory performance. There were seven targets in 2019 which included (i) net earnings (30 per cent weighting); (ii) major capital projects (10 per cent weighting); (iii) cash flow (10 per cent weighting); (iv) an all injury frequency rate which measures how safely the Corporation operates (15 per cent weighting); (v) safety improvements (5 per cent weighting); (vi) customer service index which measures a customer survey score (15 per cent weighting); and (vii) field services score (15 per cent weighting). Net earnings are primarily based on regulated earnings which are representative of the achieved return on equity based on the allowed return on equity as approved by the BCUC.

Individual performance is determined with reference to individual contribution to corporate objectives, elements of which are subjective. For the President & CEO and each of the other NEOs, 70 per cent of the annual cash bonus is based on corporate targets and 30 per cent is based upon personal targets. At the discretion of the Board, executives may be awarded up to an additional 50 per cent of target incentive pay in recognition of exceptional performance contributions.

Medium and Long-Term Incentive Plan

Effective 2015, the Corporation has changed its medium and long-term incentive granting practices to provide a target long-term incentive ("LTI") value, expressed as a percentage of base salary, which is then granted in pre-determined proportions of PSUs, RSUs and stock options. The LTI value for the President & CEO was 150 per cent of his base salary. The Vice President, Finance & CFO was granted LTI having a market value at the time of grant equal to 60 per cent of his base salary. The Executive Vice President, Operations & Engineering was granted LTI having a market value at the time of grant equal to 70 per cent of his base salary. The LTI value is granted to all the executive officers through a combination of 50 per cent in PSUs, 25 per cent in RSUs and 25 per cent in stock options.

Share Based Awards

PSUs: Effective January 1, 2015, the Corporation adopted a PSU Plan. Each PSU represents a unit with an underlying value equivalent to the value of a Fortis common share. Grants of PSUs are determined as a specified percentage of the participant's annual base salary divided by the volume-weighted average trading price of Fortis common shares for the five trading days immediately preceding the date of the grant. Notional dividends are assumed to accrue to the holder of the PSU and to be reinvested on the quarterly dividend payment dates of the common shares. Payment is made three years after the grant in an amount of 0-200 per cent of the number of PSUs accumulated, including reinvestment of notional dividends, times the volume-weighted average trading price of Fortis common shares, as determined appropriate by the Governance Committee upon measurement of Fortis' performance, as compared to a comparable group of utility holding companies, over such three-year period against predetermined measures and the Corporation's performance over such three-year period against predetermined net income targets. Previous grants of PSUs are not taken into consideration when new PSUs are awarded.

RSUs: Effective January 1, 2015, the Corporation adopted a RSU Plan. Each RSU represents a unit with an underlying value equivalent to the value of a Fortis common share. Grants of RSUs and the accumulation of notional dividends are consistent with the PSU Plan. Payment will be made three years after the grant in an amount of the number of RSUs accumulated, including reinvestment of notional dividends, times the volume-weighted average trading price of Fortis common shares.

Option-Based Awards: Long-term incentives take the form of grants of options under a Fortis Stock Option Plan, pursuant to which options to acquire Fortis common shares may be granted to executive officers, in order to encourage increased share ownership to participants as an incentive to maximize shareholder value. Grants of options are dependent upon the optionee's salary.

In February 2019, the President & Chief Executive Officer of the Corporation was granted options entitling him to purchase that number of common shares of Fortis having a market value at the time of grant equal to 37.5 per cent of his base salary. The Chief Financial Officer of the Corporation was granted options entitling him to purchase that number of common shares of Fortis having a market value at the time of grant equal to 15.0 per cent of his base salary. The Executive Vice President, Operations & Engineering was granted options entitling the executive to purchase that number of common shares having a market value at the time of grant equal to 17.5 per cent of such executive's base salary. Previous grants of stock options are not taken into consideration when new options are awarded.

The stock option plan in place for 2019 was the 2012 Stock Option Plan. The 2012 Stock Option Plan became effective May 4, 2012. The exercise period of options granted under the 2012 Stock Option Plan is ten years from the date the option is granted, subject to any accelerated termination. In addition, options granted under the 2012 Stock Option Plan will vest and become exercisable at such time or times as may be determined by Fortis. Under the terms of this plan, all options granted, vesting rights, and financing provisions under previous plans continue to exist and remain in force as long as any options granted under former plans are outstanding. No consolidation of options granted previous to May 4, 2012 will be made into the 2012 Stock Option Plan and Fortis has ceased to grant options under previous stock option plans.

Pension Plans – see "Executive Compensation – Pension Plan Benefits".

Director Compensation

The Governance Committee reviews director compensation on a periodic basis by reviewing director fees paid by organization of similar size and complexity to FBC.

Director compensation is comprised solely of retainer fees. There are no compensation securities issued to Directors. In 2019, each director of the Corporation, other than the President & CEO who does not receive director compensation, was paid an annual retainer of $80,000. An additional annual retainer of $10,000 was paid to the Chair of the Audit Committee and an additional annual retainer of $6,000 was paid to the Chair of

Governance Committee. The Chair of the Board was paid an annual retainer of $115,000, inclusive of the basic annual director's retainer. The Corporation also paid an additional $1,250 in respect of travel time for directors that attended a group of meetings outside of their regional area of residence.

Directors of FBC also serve on the respective board of FEI, and the companies share the total board compensation costs proportionately.

The President & Chief Executive Officer receives no fees for his services as a director.

B. TABLE OF COMPENSATION

The following table sets forth information concerning the compensation earned for services rendered in respect of each of the individuals who served as the President & CEO, the Vice President, Finance & CFO and the Corporation's other most highly compensated executive officer during the most recently completed financial year. The table also details individual director compensation.

Name and position	Year	Salary or Retainer(1) ($)	Bonus(2) ($)	Committee or meeting fees(3) ($)	Value of all other compensation(4) ($)	Total Compensation (5)(6) ($)
Roger A. Dall'Antonia President & CEO	2019	575,000	695,000	-	170,953	1,440,953
Director(7) FortisBC Holdings Inc.	2018	500,000	525,000	-	130,462	1,155,462
Ian G. Lorimer Vice President, Finance &	2019	360,500	288,500	-	106,175	755,175
CFO FortisBC Energy Inc.	2018	330,000	190,737	-	100,156	620,893
Doyle Sam Executive Vice President,	2019	379,500	345,000	-	83,341	807,841
Operations & Engineering	2018	358,000	279,797	-	69,928	707,725
Peter Blake	2019	87,500	-	-	1,250	88,750
Director(8)	2018	70,000	-	-	2,500	72,500
Phonse Delaney	2019	29,538	-	-	2,500	32,038
Director(9)	2018	70,000	-	-	5,000	75,000

Name and position	Year	Salary or Retainer(1) ($)	Bonus(2) ($)	Committee or meeting fees(3) ($)	Value of all other compensation(4) ($)	Total Compensation (5)(6) ($)
Brenda Eaton	2019	22,500	-	-	1,250	23,750
Director(10)	2018	79,000	-	-	3,750	82,750
Ida J. Goodreau	2019	108,030	-	-	5,000	113,030
Director(11)	2018	105,000	-	-	5,000	110,000
David G. Hutchens	2019	80,000	-	-	5,000	85,000
Director(12)	2018	70,000	-	-	5,000	75,000
K.M. Tracy Medve	2019	80,000	-	-	3,750	83,750
Director	2018	70,000	-	-	3,750	73,750
Barry V. Perry	2019	80,000	-	-	3,750	83,750
Director(13)	2018	70,000	-	-	5,000	75,000
Tracey C. Ball	2019	80,000	-	-	5,000	85,000
Director	2018	52,500	-	-	2,500	55,000
Christopher F. Scott	2019	86,000	-	-	5,000	91,000
Director(14)	2018	75,000	-	-	5,000	80,000
Michael L. Mosher	2019	80,000	-	-	3,750	83,750
Director(15)	2018	-	-	-	-	-
Janet P. Woodruff	2019	80,000	-	-	1,250	81,250
Director	2018	70,000	-	-	2,500	72,500
Jocelyn H. Perry	2019	40,000	-	-	2,500	42,500
Director(16)	2018	-	-	-	-	-

Notes:

1. Represents the annual salary for the NEOs and the retainer paid to each of the Directors. See **Director Compensation** for a description of fees paid to Directors.
2. Represents performance bonus and amounts awarded under the Corporation's short-term non-equity incentive program in recognition of FEI and FBC's respective corporate performances and the individual's performance for the reported year and paid in the following year.
3. See **Director Compensation** for a description of retainers and other fees paid to Directors.
4. Includes, where applicable the aggregate of amounts paid by FEI or FBC for (i) payment in lieu of vacation, (ii) the dollar value of insurance premiums paid by the Corporation with respect to term life insurance, (iii) 10 per cent match by the Corporation on contributions made to purchase Fortis Common Shares through the Employee Share Purchase Plan (ESPP), (iv) interest benefit from ESPP loans, (v) Director travel reimbursement and (vi) all compensation paid or accrued to Named Executive Officers relating to defined contribution pension plans, including contributions to the Named Executive Officer's self-directed RRSP and SERP. See **Pension Plan Benefits**. Perquisites are not disclosed as they did not exceed the minimum disclosure threshold of the lesser of 10 per cent of the total annual salary of the Named Executive Officer.

5. Amounts reported represent amounts payable by FBC for Mr. Sam's service to FEI and FortisBC Holdings Inc. FEI proportionately reimburses FBC for Mr. Sam's service.
6. Amounts reported represent amounts paid by FEI for Mr. Dall'Antonia's and Mr. Lorimer's service to FBC and other FortisBC companies. FBC proportionately reimburses FEI for their services.
7. In addition to his role of President and CEO, Mr. Dall'Antonia also held the position of Director for which no additional compensation was earned or received.
8. Appointed Chair of Audit Committee in April 2019.
9. Mr. Delaney also held the position of Executive Vice President with Fortis for which Fortis provided executive compensation. Director to May 13, 2019.
10. Chair of the Audit Committee to March 30, 2019. Director to March 30, 2019.
11. Chair of the Board of Directors to December 9, 2019. Director to December 9, 2019.
12. Mr. Hutchens also held the position of President & CEO of UNS Energy for which UNS Energy provided executive compensation.
13. Mr. Perry also held the position of President & CEO of Fortis for which Fortis provided executive compensation.
14. Chair of the Governance Committee.
15. Appointed to the Board of Directors January 1, 2019.
16. Appointed to the Board of Directors July 1, 2019. Ms. Perry also held the position of Chief Financial Officer of Fortis for which Fortis provided executive compensation.

C. COMPENSATION SECURITIES

The following table sets forth details of the securities granted to each NEO in the most recently completed financial year. There are no compensation securities issued to Directors.

Name & Position	Type of compensation security	Number of compensation securities(1)	Date of grant	Issue or exercise price ($)(2)	Closing price of underlying security on date of grant ($)(3)	Closing price of underlying security at year end ($)(3)	Expiry Date
Roger A. Dall'Antonia President & CEO Director(4)	Stock Options	45,328	13-Feb-19	47.57	47.19	53.88	13-Feb-29
	PSUs	9,553	1-Jan-19	45.14	45.51	53.88	1-Jan-22
	RSUs	4,776	1-Jan-19	45.14	45.51	53.88	1-Jan-22
Ian G. Lorimer Vice President, Finance & CFO(5)	Stock Options	11,368	13-Feb-19	47.57	47.19	53.88	13-Feb-29
	PSUs	2,396	1-Jan-19	45.14	45.51	53.88	1-Jan-22
	RSUs	1,198	1-Jan-19	45.14	45.51	53.88	1-Jan-22
Doyle Sam Executive Vice President, Operations & Engineering(6)	Stock Options	13,964	13-Feb-19	47.57	47.19	53.88	13-Feb-29
	PSUs	2,942	1-Jan-19	45.14	45.51	53.88	1-Jan-22
	RSUs	1,471	1-Jan-19	45.14	45.51	53.88	1-Jan-22

Notes:
1. Each unit of stock option, PSU and RSU is equivalent to one common share of Fortis. The compensation securities granted in 2019 represent less than 1 per cent of the total number of common shares issued and outstanding of Fortis.
2. The exercise price for stock options and issue price for PSUs and RSUs is the volume weighted average price of the common shares of Fortis traded on the Toronto Stock Exchange (TSX) for the five trading days immediately preceding the date of grant.
3. Represents the closing price of Fortis Common Shares on the TSX on the applicable dates.
4. At December 31, 2019, Mr. Dall'Antonia held 148,388 unexercised stock options, of which 69,516 were fully vested. Options vest at a rate of 25 per cent, per year over the four-year period commencing on the first anniversary of the date of grant. Mr. Dall'Antonia also held 31,018 PSUs and RSUs. PSUs and RSUs vest upon the completion of the three-year period from the date of grant.
5. At December 31, 2019, Mr. Lorimer held 70,184 unexercised stock options, of which 44,107 were fully vested. Options vest at a rate of 25 per cent, per year over the four year period commencing on the first anniversary of the date of grant. Mr. Lorimer also held 10,990 PSUs and RSUs. PSUs and RSUs vest upon the completion of the three-year period from the date of grant.

6. At December 31, 2019, Mr. Sam held 54,484 unexercised stock options, of which 21,102 were fully vested. Options vest at a rate of 25 per cent, per year over the four-year period commencing on the first anniversary of the date of grant. Mr. Sam also held 13,849 PSUs and RSUs. PSUs and RSUs vest upon the completion of the three-year period from the date of grant.

The following table sets forth details of the securities exercised by each NEO in the most recently completed financial year.

<table>
<tr><th>Name & Position</th><th>Type of compensation security(1)(2)</th><th>Number of underlying securities exercised</th><th>Exercise price per security
($)</th><th>Date of exercise</th><th>Closing price per security on date of exercise
($)</th><th>Difference between exercise price and closing price on date of exercise
($)</th><th>Total value on exercise date
($)</th></tr>
<tr><td rowspan="2">Roger A. Dall'Antonia President & CEO Director(3)</td><td>RSUs</td><td>1,632</td><td>37.72</td><td>1-Jan-19</td><td>45.14</td><td>7.42</td><td>73,663</td></tr>
<tr><td>PSUs</td><td>3,264</td><td>37.72</td><td>1-Jan-19</td><td>45.14</td><td>7.42</td><td>149,388</td></tr>
<tr><td rowspan="3">Ian G. Lorimer Vice President, Finance & CFO</td><td>Stock Options</td><td>10,288</td><td>34.27</td><td>27-Mar-19</td><td>49.69</td><td>15.42</td><td>158,692</td></tr>
<tr><td>RSUs</td><td>1,110</td><td>37.72</td><td>1-Jan-19</td><td>45.14</td><td>7.42</td><td>50,103</td></tr>
<tr><td>PSUs</td><td>2,220</td><td>37.72</td><td>1-Jan-19</td><td>45.14</td><td>7.42</td><td>101,608</td></tr>
<tr><td rowspan="6">Doyle Sam Executive Vice President, Operations & Engineering</td><td rowspan="4">Stock Options</td><td>11,556</td><td>34.27</td><td>07-Mar-19</td><td>48.00</td><td>13.73</td><td>158,664</td></tr>
<tr><td>12,860</td><td>33.58</td><td>07-Mar-19</td><td>48.00</td><td>14.42</td><td>185,441</td></tr>
<tr><td>15,132</td><td>30.73</td><td>07-Mar-19</td><td>48.00</td><td>17.27</td><td>261,330</td></tr>
<tr><td>12,192</td><td>39.25</td><td>07-Mar-19</td><td>48.00</td><td>8.75</td><td>106,680</td></tr>
<tr><td>RSUs</td><td>1,715</td><td>37.72</td><td>1-Jan-19</td><td>45.14</td><td>7.42</td><td>77,416</td></tr>
<tr><td>PSUs</td><td>3,430</td><td>37.72</td><td>1-Jan-19</td><td>45.14</td><td>7.42</td><td>157,000</td></tr>
</table>

Notes:

1. PSUs represent the 2016 PSU values that were realized and paid in 2019 in respect of the three-year period. The value of the PSUs at the payment date is dependent on meeting the payment criteria and corporate performance.
2. RSUs awarded in 2016 vested January 1, 2019 and paid in early 2019.
3. Mr. Dall'Antonia did not exercise Stock Options in 2019.

D. PENSION PLAN BENEFITS

The following table sets forth the details of the defined contribution amounts and supplemental employee retirement plan for the respective NEOs.

Name	Accumulated value at start of year ($)	Compensatory ($)	Accumulated value at year end ($)[1]
Roger A. Dall'Antonia	445,829	116,500	577,129
Ian G. Lorimer	317,985	45,161	376,382
Doyle Sam	521,084	59,209	601,625

Note:

1. Includes non-compensatory amount, including regular investment earnings on contributions, which are not included as a separate column in the table above.

Each of Mr. Dall'Antonia, Mr. Lorimer and Mr. Sam participate in an RRSP which requires the NEO to contribute to a self-directed RRSP equal to 6.5 per cent of the individual's annual base salary and bonus which is matched by the corporation that employs them, up to the maximum contribution limit allowed by the Canada Revenue Agency. In 2019, the respective corporations that employ each of the NEOs contributed $13,250 for each of the NEO's participating in the executive RRSP arrangement.

In addition, Mr. Dall'Antonia, Mr. Lorimer and Mr. Sam participate in a defined contribution supplemental employee retirement plan (the "DC SERP"). The DC SERP provides for the accrual by the respective corporations who employ each of the NEOs of an amount equal to 13 per cent of the annual base salary and bonus paid to the NEO. This amount which is in excess of the maximum contribution limit allowed by the Canada Revenue Agency to an RRSP, is tracked in a notional account which accrues interest equal to the rate of a 10-year Government of Canada Bond plus a premium of 0 per cent to 3 per cent dependent upon years of service. At the time of retirement, the notional amounts accumulated under the DC SERP may be paid to the NEO in one lump sum or in equal payments up to 15 years.

E. TERMINATION AND CHANGE OF CONTROL BENEFITS

There are no contracts, agreements, plans or arrangements that provide for payments to Mr. Lorimer and Mr. Sam at, following or in connection with any termination. There is a written employment agreement between FEI and Mr. Dall'Antonia that sets out the terms of his employment and provides for certain benefits in the event that employment is terminated other than for cause. The terms of the agreements are based on competitive practices and include non-competition, non-solicitation and confidentiality provisions.

The table below sets out the key severance, termination and change of control provisions for Mr. Dall'Antonia.

	Retirement (early or normal)	Termination with Cause	Termination without cause	Change of Control
Annual base salary	Ceases on the termination date.	Ceases on the termination date.	Ceases on the termination date.	Ceases on the termination date.
Annual STI for applicable year	Target annual incentive for the fiscal year is pro-rated to the date of retirement.	Forfeited.	Target annual incentive for the fiscal year is pro-rated to the date of termination.	Target annual incentive for the fiscal year in which the termination date occurs (or if greater, the fiscal year immediately preceding the fiscal year in which the change of control occurs).
Cash severance	None.	None.	The greater of: A lump sum payment to one million five hundred thousand dollars ($1,500,000) or a lump sum payment equal to one and a half (1.5) times the sum of the base salary and target incentive for the fiscal year in which the termination date occurs.	A lump sum payment equal to one and a half (1.5) times the sum of the base salary and target incentive for the fiscal year in which the termination date occurs (or if greater, the fiscal year immediately preceding the fiscal year in which the change of control occurs).
Performance share units	Continue per normal schedule.	All PSUs are cancelled.	PSUs that have a payment date prior to the expiry of the notice period are paid. Other PSUs are cancelled.	All PSUs are redeemed at 100% on the date immediately before the change of control.
Restricted share units	Continue per normal schedule.	All RSUs are cancelled.	RSUs that have a payment date prior to the expiry of the notice period are paid. Other RSUs are cancelled.	All RSUs are redeemed at 100% on the date immediately before the change of control.
Stock Options	All unvested options continue to vest per normal schedule for two years after retirement, and all remaining unvested options after the second year vest immediately. Options expire on the original expiry date or three years from the date of retirement, whichever is earlier.	All vested and unvested options expire immediately and are forfeited on the termination date.	All unexercised options expire after 90 days from the termination date. All unvested options expire immediately and are forfeited.	All unvested options vest immediately and become exercisable.
Retirement benefits	Entitled to accrued pension and retiree health benefits.	Entitled to accrued pension.	Entitled to accrued pension and retiree health benefits.	Entitled to accrued pension and retiree health benefits.
Perquisites	Ceases immediately.	Ceases immediately.	Ceases immediately.	Ceases immediately.

The next table shows the estimated incremental amounts that would be paid to Mr. Dall'Antonia if his employment had been terminated on December 31, 2019.

	Retirement (early or normal)[1] ($)	Termination with Cause ($)	Termination without cause[2] ($)	Change of Control[3] ($)
Cash Severance	-	-	1,500,000	1,466,250
Annual Incentive	695,000	-	402,500	402,500
Restricted share units	-	-	-	557,085
Performance share units	-	-	-	1,114,170
Stock options	-	-	-	1,932,080

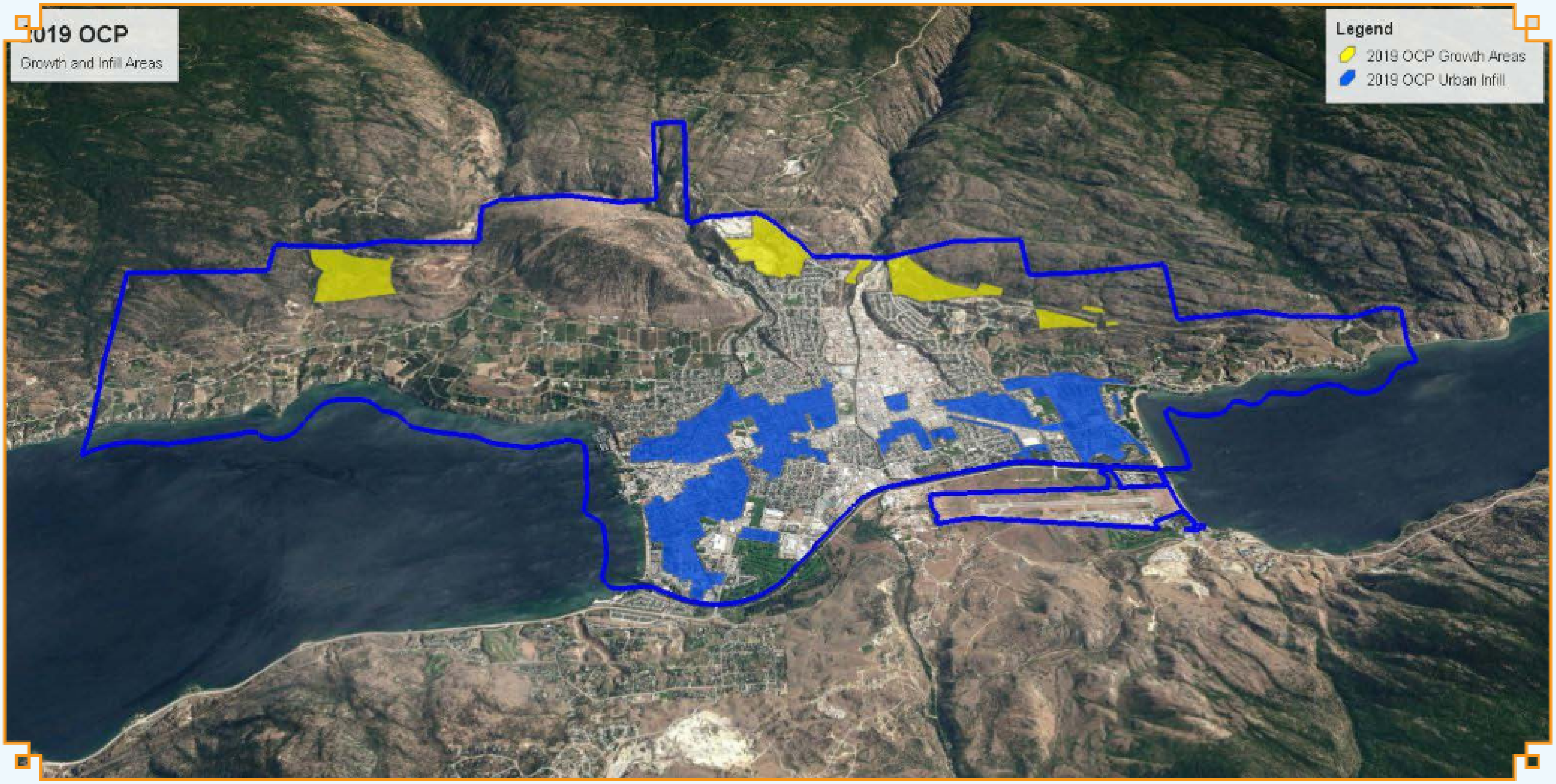
Notes:

1. PSUs continue to vest according to the normal schedule.
2. PSU payments depend on the notice period.
3. Market or payout value of share-based awards is the market value of outstanding PSUs and RSUs based on $53.88, the closing price of Fortis common shares on the TSX on December 31, 2019.

B

Appendix B
OCP Growth Map

2019 OCP Growth Areas and Infill Areas



C

Appendix C
Initial Load Forecast

Feeder	Capacity	Season	2016	2017	2018	2019		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	Expected Year 6-26 Growth
			Historical Loads					Forecasted Peak Loads (kVA) for Years 0-5						Forecasted Peak Loads (kVA) for Years 6-26																					
								Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	
R2	16806	Winter	1808	1856	4727	4392	Winter	4753	4770	4788	4807	4828	4851	4877	4908	4942	4981	5024	5075	5132	5198	5271	5352	5441	5538	5644	5758	5880	6004	6129	6254	6381	6509	6639	
							Total % Growth		0.35%	0.38%	0.41%	0.44%	0.47%	0.55%	0.63%	0.70%	0.78%	0.86%	1.00%	1.14%	1.27%	1.41%	1.54%	1.66%	1.79%	1.91%	2.02%	2.13%	2.10%	2.08%	2.05%	2.03%	2.01%	1.98%	
							% Capacity	28.28%	28.38%	28.49%	28.61%	28.73%	28.86%	29.02%	29.20%	29.41%	29.64%	29.90%	30.20%	30.54%	30.93%	31.36%	31.85%	32.38%	32.95%	33.58%	34.26%	34.99%	35.72%	36.47%	37.22%	37.97%	38.73%	39.50%	
	13444	Summer	2533	1866	5986	4456	Summer	5991	6023	6057	6092	6129	6167	6209	6256	6306	6361	6420	6487	6561	6643	6733	6831	6937	7051	7174	7305	7445	7586	7728	7871	8016	8162	8309	0.47%
							Total % Growth		0.53%	0.56%	0.58%	0.60%	0.62%	0.69%	0.75%	0.81%	0.87%	0.93%	1.04%	1.14%	1.25%	1.35%	1.45%	1.55%	1.65%	1.74%	1.83%	1.92%	1.90%	1.88%	1.86%	1.84%	1.82%	1.80%	
							% Capacity	44.56%	44.80%	45.05%	45.31%	45.58%	45.87%	46.18%	46.53%	46.91%	47.31%	47.76%	48.25%	48.80%	49.41%	50.08%	50.81%	51.60%	52.45%	53.36%	54.33%	55.37%	56.42%	57.48%	58.55%	59.62%	60.71%	61.80%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
							Load Transfers																												
R3	16806	Winter	4627	5448	4463	3937	Winter	3961	3975	3991	4009	4027	4048	4072	4100	4133	4169	4210	4258	4314	4377	4448	4527	4613	4708	4812	4923	5044	5165	5287	5411	5536	5661	5788	
							Total % Growth		0.36%	0.40%	0.43%	0.47%	0.51%	0.60%	0.70%	0.79%	0.88%	0.98%	1.14%	1.30%	1.46%	1.62%	1.77%	1.92%	2.06%	2.19%	2.32%	2.44%	2.41%	2.37%	2.34%	2.30%	2.27%	2.24%	
							% Capacity	23.57%	23.66%	23.75%	23.85%	23.97%	24.09%	24.23%	24.40%	24.59%	24.81%	25.05%	25.34%	25.67%	26.05%	26.47%	26.94%	27.45%	28.02%	28.63%	29.30%	30.01%	30.73%	31.46%	32.20%	32.94%	33.69%	34.44%	
	13444	Summer	4369	5113	2692	4172	Summer	4177	4201	4226	4252	4280	4310	4343	4381	4423	4469	4519	4577	4642	4715	4795	4884	4981	5086	5199	5321	5451	5583	5716	5850	5985	6121	6259	0.47%
							Total %Growth		0.56%	0.59%	0.62%	0.66%	0.69%	0.78%	0.87%	0.95%	1.04%	1.13%	1.28%	1.43%	1.57%	1.71%	1.85%	1.98%	2.11%	2.23%	2.34%	2.45%	2.42%	2.38%	2.34%	2.31%	2.28%	2.25%	
							% Capacity	31.07%	31.25%	31.43%	31.63%	31.83%	32.05%	32.30%	32.58%	32.89%	33.24%	33.61%	34.04%	34.53%	35.07%	35.67%	36.33%	37.05%	37.83%	38.67%	39.58%	40.55%	41.53%	42.51%	43.51%	44.52%	45.53%	46.55%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
							Load Transfers																												
R4	14500	Winter	5389	5415	5295	5077	Winter	5444	5463	5483	5504	5527	5552	5529	5544	5559	5574	5589	5604	5620	5635	5650	5666	5681	5697	5712	5728	5743	5759	5775	5791	5806	5822	5838	
							Total % Growth		0.34%	0.36%	0.39%	0.42%	0.44%	-0.41%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	
							% Capacity	37.55%	37.67%	37.81%	37.96%	38.12%	38.29%	38.13%	38.23%	38.34%	38.44%	38.55%	38.65%	38.76%	38.86%	38.97%	39.07%	39.18%	39.29%	39.39%	39.50%	39.61%	39.72%	39.83%	39.93%	40.04%	40.15%	40.26%	
	11600	Summer	4505	4979	5073	5640	Summer	5645	5676	5708	5741	5776	5813	5802	5829	5857	5885	5912	5940	5968	5997	6025	6053	6082	6111	6140	6169	6198	6227	6257	6286	6316	6346	6376	0.47%
							Total % Growth		0.54%	0.56%	0.59%	0.61%	0.63%	-0.18%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	
							% Capacity	48.67%	48.93%	49.20%	49.49%	49.79%	50.11%	50.02%	50.25%	50.49%	50.73%	50.97%	51.21%	51.45%	51.69%	51.94%	52.18%	52.43%	52.68%	52.93%	53.18%	53.43%	53.68%	53.94%	54.19%	54.45%	54.70%	54.96%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							Load Transfers																												
R5	16806	Winter	5498	4428	4045	4565	Winter	4592	4608	4626	4645	4665	4687	4675	4689	4704	4718	4733	4747	4762	4777	4792	4807	4822	4837	4852	4868	4883	4899	4914	4930	4946	4962	4978	
							Total % Growth		0.35%	0.38%	0.41%	0.44%	0.47%	-0.26%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	
							% Capacity	27.32%	27.42%	27.52%	27.64%	27.76%	27.89%	27.82%	27.90%	27.99%	28.08%	28.16%	28.25%	28.34%	28.42%	28.51%	28.60%	28.69%	28.78%	28.87%	28.96%	29.06%	29.15%	29.24%	29.34%	29.43%	29.53%	29.62%	
	13444	Summer	4559	4572	4788	3599	Summer	3604	3625	3647	3671	3696	3723	3715	3734	3754	3773	3792	3812	3832	3851	3872	3892	3912	3932	3953	3974	3995	4016	4037	4058	4080	4102	4123	0.47%
							Total %Growth		0.57%	0.61%	0.65%	0.69%	0.72%	-0.20%	0.51%	0.51%	0.51%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	
							% Capacity	26.81%	26.96%	27.13%	27.30%	27.49%	27.69%	27.63%	27.78%	27.92%	28.06%	28.21%	28.35%	28.50%	28.65%	28.80%	28.95%	29.10%	29.25%	29.40%	29.56%	29.71%	29.87%	30.03%	30.19%	30.35%	30.51%	30.67%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	13	15	16	18	20	21	23	25	27	29	31	33	35	37	40	42	44	47	50	52	55	
							Load Transfers																												
R6	16806	Winter	4909	4904	3544	3359	Winter	3380	3393	3407	3423	3440	3459	3443	3454	3465	3476	3488	3499	3510	3521	3533	3544	3556	3568	3580	3591	3603	3616	3628	3640	3652	3665	3677	
							Total % Growth		0.38%	0.42%	0.46%	0.50%	0.55%	-0.45%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.33%	0.33%	0.33%	0.33%	0.33%	0.33%	0.33%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	
							% Capacity	20.11%	20.19%	20.28%	20.37%	20.47%	20.58%	20.49%	20.56%	20.62%	20.69%	20.75%	20.82%	20.89%	20.95%	21.02%	21.09%	21.16%	21.23%	21.30%	21.37%	21.44%	21.51%	21.59%	21.66%	21.73%	21.81%	21.88%	
	13444	Summer	5696	4536	5211	2964	Summer	2969	2987	3006	3027	3049	3073	3062	3078	3094	3110	3127	3143	3160	3176	3193	3210	3227	3244	3262	3279	3297	3315	3332	3351	3369	3387	3406	0.47%
							Total % Growth		0.59%	0.64%	0.69%	0.73%	0.78%	-0.35%	0.52%	0.52%	0.52%	0.52%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.54%	0.54%	0.54%	0.54%	0.54%	0.54%	0.54%	0.55%	
							% Capacity	22.09%	22.22%	22.36%	22.51%	22.68%	22.85%	22.78%	22.89%	23.01%	23.13%	23.26%	23.38%	23.50%	23.63%	23.75%	23.88%	24.00%	24.13%	24.26%	24.39%	24.52%	24.65%	24.79%	24.92%	25.06%	25.19%	25.33%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	13	15	16	18	20	21	23	25	27	29	31	33	35	37	40	42	44	47	50	52	55	
							Load Transfers																												
R7 (Represents the new Huth Substation and feeders)	67222					0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
									#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
								0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	53778					0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.47%
									#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
								0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
								0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
														0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Huth 12kV	25900	Winter	20733	27951	17778	20431	Winter	21163	21238	21320	21409	21505	21608	21608	21703	21806	21917	22036	22169	22317	22480	22657	22850	23059	23283	23523	23780	24053	24329	24607	24888	25170	25455	25743	
							Total % Growth		0.35%	0.39%	0.42%	0.45%	0.48%	0.00%	0.44%	0.47%	0.51%	0.54%	0.61%	0.67%	0.73%	0.79%	0.85%	0.91%	0.97%	1.03%	1.09%	1.15%	1.15%	1.14%	1.14%	1.14%	1.13%	1.13%	
							% Capacity	81.71%	82.00%	82.32%	82.66%	83.03%	83.43%	83.43%	83.80%	84.19%	84.62%	85.08%	85.60%	86.17%	86.79%	87.48%	88.22%	89.03%	89.90%	90.82%	91.81%	92.87%	93.93%	95.01%	96.09%	97.18%	98.28%	99.39%	
	25900	Summer	19827	19214	20566	13365	Summer	21452	21571	21697	21830	21971	22120	22165	22305	22454	22611	22777	22958	23153	23363	23589	23831	24088	24361	24652	24958	25282	25609	25938	26270	26605	26942	27283	0.47%
							Total % Growth		0.55%	0.58%	0.61%	0.65%	0.68%	0.20%	0.63%	0.67%	0.70%	0.73%	0.79%	0.85%	0.91%	0.97%	1.02%	1.08%	1.14%	1.19%	1.24%	1.30%	1.29%	1.29%	1.28%	1.27%	1.27%	1.26%	
							% Capacity	82.83%	83.29%	83.77%	84.29%	84.83%	85.40%	85.58%	86.12%	86.69%	87.30%	87.94%	88.64%	89.39%	90.21%	91.08%	92.01%	93.00%	94.06%	95.18%	96.36%	97.62%	98.88%	100.15%	101.43%	102.72%	104.02%	105.34%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	27	45	70	103	143	190	129	167	213	267	330	407	500	608	731	870	1025	1197	1385	1590	1812	2037	2264	2493	2725	2959	3195	
							Load Transfers																												

R10	13611	Winter	3243	6623	6660	5773	Winter	5848	5906	5970	6038	6111	6190	6281	6386	6504	6635	6548	6658	6780	6915	7062	7223	7396	7583	7784	7998	8227	8458	8691	8926	9163	9403	9644	1.00%
							Total % Growth		1.00%	1.07%	1.14%	1.21%	1.28%	1.48%	1.66%	1.85%	2.02%	-1.31%	1.68%	1.83%	1.99%	2.13%	2.27%	2.40%	2.53%	2.65%	2.76%	2.86%	2.81%	2.75%	2.70%	2.66%	2.61%	2.57%	
							% Capacity	42.97%	43.39%	43.86%	44.36%	44.90%	45.48%	46.15%	46.92%	47.78%	48.75%	48.11%	48.92%	49.81%	50.80%	51.89%	53.06%	54.34%	55.71%	57.19%	58.76%	60.44%	62.14%	63.85%	65.58%	67.32%	69.08%	70.86%	
	10889	Summer	4090	6659	6600	6477	Summer	6886	6966	7052	7143	7239	7341	7456	7585	7727	7883	7821	7957	8104	8265	8439	8626	8827	9042	9270	9513	9771	10031	10293	10558	10826	11096	11369	
							Total %Growth		1.17%	1.23%	1.29%	1.35%	1.41%	1.57%	1.72%	1.88%	2.02%	-0.79%	1.73%	1.86%	1.98%	2.10%	2.22%	2.33%	2.43%	2.53%	2.62%	2.71%	2.66%	2.62%	2.57%	2.53%	2.50%	2.46%	
							% Capacity	63.24%	63.98%	64.76%	65.60%	66.48%	67.42%	68.48%	69.66%	70.96%	72.40%	71.83%	73.07%	74.43%	75.90%	77.50%	79.22%	81.06%	83.04%	85.13%	87.37%	89.73%	92.12%	94.53%	96.96%	99.42%	101.90%	104.41%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	17	29	45	66	91	122	164	220	288	370	233	292	363	446	542	650	771	905	1052	1212	1387	1563	1740	1920	2101	2283	2468	
							Load Transfers																												
R11	13611	Winter	6643	5298	5334	5054	Winter	6664	6675	6688	6702	6718	6735	6755	6780	6809	6843	6880	6925	6977	7036	7104	7179	7262	7353	7453	7561	7678	7795	7914	8034	8155	8277	8400	0.31%
							Total % Growth		0.17%	0.19%	0.21%	0.23%	0.25%	0.31%	0.37%	0.43%	0.49%	0.55%	0.65%	0.75%	0.85%	0.96%	1.06%	1.16%	1.26%	1.35%	1.45%	1.54%	1.53%	1.52%	1.51%	1.50%	1.50%	1.49%	
							% Capacity	48.96%	49.04%	49.14%	49.24%	49.35%	49.48%	49.63%	49.82%	50.03%	50.27%	50.55%	50.87%	51.26%	51.69%	52.19%	52.74%	53.35%	54.02%	54.76%	55.55%	56.41%	57.27%	58.14%	59.02%	59.91%	60.81%	61.71%	
	10889	Summer	6630	4564	4485	3949	Summer	3954	3970	3988	4007	4027	4049	4075	4105	4139	4177	4220	4270	4327	4392	4464	4545	4633	4730	4835	4948	5070	5194	5318	5443	5570	5697	5826	
							Total %Growth		0.40%	0.44%	0.47%	0.51%	0.55%	0.64%	0.73%	0.83%	0.92%	1.02%	1.18%	1.34%	1.50%	1.65%	1.80%	1.95%	2.09%	2.22%	2.35%	2.47%	2.43%	2.39%	2.36%	2.32%	2.29%	2.26%	
							% Capacity	36.32%	36.46%	36.62%	36.80%	36.98%	37.19%	37.42%	37.70%	38.01%	38.36%	38.75%	39.21%	39.74%	40.33%	41.00%	41.74%	42.55%	43.44%	44.40%	45.44%	46.56%	47.70%	48.84%	49.99%	51.15%	52.32%	53.50%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
							Load Transfers																												
R12	13611	Winter	6636	6626	6639	6663	Winter	6725	6736	6749	6763	6778	6795	6816	6841	6870	6904	6941	6986	7038	7098	7165	7240	7324	7415	7515	7623	7739	7857	7976	8096	8217	8339	8462	0.31%
							Total % Growth		0.17%	0.19%	0.21%	0.23%	0.25%	0.31%	0.37%	0.42%	0.48%	0.54%	0.64%	0.75%	0.85%	0.95%	1.05%	1.15%	1.25%	1.34%	1.44%	1.53%	1.52%	1.51%	1.50%	1.49%	1.49%	1.48%	
							% Capacity	49.41%	49.49%	49.58%	49.68%	49.80%	49.92%	50.08%	50.26%	50.48%	50.72%	51.00%	51.32%	51.71%	52.15%	52.64%	53.19%	53.81%	54.48%	55.21%	56.00%	56.86%	57.73%	58.60%	59.48%	60.37%	61.27%	62.17%	
	10889	Summer	6478	6588	6624	6656	Summer	6661	6686	6712	6739	6768	6799	6833	6872	6915	6962	7013	7071	7137	7211	7292	7382	7479	7585	7699	7821	7952	8084	8217	8352	8487	8624	8762	
							Total %Growth		0.37%	0.39%	0.41%	0.43%	0.45%	0.51%	0.56%	0.62%	0.68%	0.74%	0.83%	0.93%	1.03%	1.13%	1.22%	1.32%	1.41%	1.50%	1.59%	1.68%	1.66%	1.65%	1.64%	1.62%	1.61%	1.60%	
							% Capacity	61.18%	61.40%	61.64%	61.89%	62.16%	62.44%	62.76%	63.11%	63.50%	63.93%	64.40%	64.94%	65.55%	66.22%	66.97%	67.79%	68.69%	69.65%	70.70%	71.83%	73.03%	74.24%	75.47%	76.70%	77.95%	79.20%	80.47%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
							Load Transfers																												
R13	13611	Winter	6337	5111	2947	2182	Winter	2194	2200	2208	2217	2227	2239	2255	2275	2299	2327	2359	2399	2446	2500	2562	2632	2710	2797	2891	2994	3105	3218	3332	3446	3562	3679	3797	0.31%
							Total % Growth		0.28%	0.34%	0.41%	0.47%	0.54%	0.71%	0.88%	1.05%	1.22%	1.39%	1.68%	1.96%	2.23%	2.49%	2.73%	2.97%	3.18%	3.38%	3.56%	3.72%	3.62%	3.53%	3.44%	3.36%	3.28%	3.20%	
							% Capacity	16.12%	16.17%	16.22%	16.29%	16.36%	16.45%	16.57%	16.71%	16.89%	17.10%	17.33%	17.62%	17.97%	18.37%	18.83%	19.34%	19.91%	20.55%	21.24%	22.00%	22.82%	23.64%	24.48%	25.32%	26.17%	27.03%	27.89%	
	10889	Summer	5194	3441	4731	4100	Summer	5199	5219	5241	5264	5288	5314	5344	5378	5416	5458	5504	5558	5619	5688	5765	5849	5942	6043	6152	6269	6396	6523	6651	6781	6912	7043	7176	
							Total %Growth		0.38%	0.41%	0.44%	0.46%	0.49%	0.56%	0.63%	0.71%	0.78%	0.85%	0.98%	1.10%	1.23%	1.35%	1.47%	1.58%	1.70%	1.81%	1.91%	2.01%	1.99%	1.97%	1.95%	1.93%	1.91%	1.89%	
							% Capacity	47.75%	47.93%	48.13%	48.34%	48.56%	48.80%	49.07%	49.39%	49.74%	50.12%	50.55%	51.04%	51.61%	52.24%	52.94%	53.72%	54.57%	55.50%	56.50%	57.58%	58.74%	59.91%	61.08%	62.27%	63.47%	64.68%	65.90%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
							Load Transfers																												
R14	18000	Winter	0	0	0	0	Winter	0	0	0	0	0	0	0	0	0	0	233	292	363	446	542	650	771	905	1052	1212	1387	1563	1740	1920	2101	2283	2468	0.31%
							Total % Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	25.47%	24.37%	22.93%	21.41%	19.95%	18.60%	17.37%	16.26%	15.27%	14.38%	12.69%	11.37%	10.31%	9.43%	8.70%	8.08%	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.29%	1.62%	2.02%	2.48%	3.01%	3.61%	4.28%	5.03%	5.84%	6.73%	7.70%	8.68%	9.67%	10.66%	11.67%	12.69%	13.71%	
	14400	Summer	0	0	0	0	Summer	0	0	0	0	0	0	0	0	0	0	233	292	363	446	542	650	771	905	1052	1212	1387	1563	1740	1920	2101	2283	2468	
							Total %Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	25.47%	24.37%	22.93%	21.41%	19.95%	18.60%	17.37%	16.26%	15.27%	14.38%	12.69%	11.37%	10.31%	9.43%	8.70%	8.08%	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.62%	2.03%	2.52%	3.10%	3.76%	4.51%	5.35%	6.28%	7.30%	8.42%	9.63%	10.85%	12.08%	13.33%	14.59%	15.86%	17.14%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV											233	292	363	446	542	650	771	905	1052	1212	1387	1563	1740	1920	2101	2283	2468	
							Load Transfers																												
R15	16806	Winter	0	0	0	0	Winter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.31%
							Total % Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	13444	Summer	0	0	0	0	Summer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							Total %Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV																												
							Load Transfers																												
R16 (Future)	40000	Winter	0	0	0	0	Winter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.31%
							Total % Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	32000	Summer	0	0	0	0	Summer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							Total %Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV																												
							Load Transfers																												
Carmi 12kV	40000	Winter	20558	18749	20532	17337	Winter	18332	18406	18488	18578	18677	18783	18911	19060	19231	19424	19640	19895	20190	20525	20901	21319	21780	22285	22833	23427	24067	24713	25364	26022	26685	27355	28031	0.59%
							Total % Growth		0.41%	0.45%	0.49%	0.53%	0.57%	0.68%	0.79%	0.90%	1.00%	1.11%	1.30%	1.48%	1.66%	1.83%	2.00%	2.16%	2.32%	2.46%	2.60%	2.73%	2.68%	2.64%	2.59%	2.55%	2.51%	2.47%	
							% Capacity	45.83%	46.01%	46.22%	46.45%	46.69%	46.96%	47.28%	47.65%	48.08%	48.56%	49.10%	49.74%	50.47%	51.31%	52.25%	53.30%	54.45%	55.71%	57.08%	58.57%	60.17%	61.78%	63.41%	65.05%	66.71%	68.39%	70.08%	
	32000	Summer	20901	21501	21533	16688	Summer	19868	19991	20123	20263	20412	20570	20750	20952	21177	21425	21697	22009	22362	22757	23195	23676	24201	24771	25387	26050	26760	27476	28199	28929	29665	30408	31158	
							Total %Growth		0.62%	0.66%	0.70%	0.74%	0.77%	0.87%	0.97%	1.07%	1.17%	1.27%	1.44%	1.60%	1.77%	1.92%	2.07%	2.22%	2.36%	2.49%	2.61%	2.73%	2.68%	2.63%	2.59%	2.55%	2.50%	2.47%	
							% Capacity	62.09%	62.47%	62.88%	63.32%	63.79%	64.28%	64.84%	65.48%	66.18%	66.95%	67.80%	68.78%	69.88%	71.12%	72.48%	73.99%	75.63%	77.41%	79.34%	81.41%	83.62%	85.86%	88.12%	90.40%	92.70%	95.03%	97.37%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	33	56	87	128	177	236	318	426	559	717	901	1131	1406	1729	2099	2518	2986	3505	4075	4697	5373	6055	6743	7438	8140	8848	9563	
							Load Transfers																												

	16806	Winter	4752	4968	4399	6635	Winter	6685	6718	6754	6794	6836	6881	6934	6996	7065	7143	7229	7330	7446	7578	7724	7887	8065	8260	8472	8701	8947	9195	9445	9697	9952	10209	10468	
							Total % Growth		0.50%	0.54%	0.58%	0.62%	0.66%	0.77%	0.88%	0.99%	1.10%	1.21%	1.40%	1.58%	1.76%	1.94%	2.10%	2.26%	2.42%	2.56%	2.70%	2.83%	2.77%	2.72%	2.67%	2.63%	2.58%	2.54%	
							% Capacity	39.78%	39.98%	40.19%	40.42%	40.68%	40.94%	41.26%	41.63%	42.04%	42.50%	43.02%	43.62%	44.31%	45.09%	45.96%	46.93%	47.99%	49.15%	50.41%	51.77%	53.24%	54.71%	56.20%	57.70%	59.22%	60.75%	62.29%	
R21	13444	Summer	5464	5284	4787	5923	Summer	6314	6358	6406	6456	6510	6567	6632	6705	6787	6877	6975	7089	7217	7361	7521	7696	7888	8096	8321	8563	8822	9084	9348	9615	9883	10155	10428	0.59%
							Total %Growth		0.70%	0.75%	0.79%	0.83%	0.87%	0.99%	1.10%	1.22%	1.33%	1.43%	1.63%	1.81%	1.99%	2.17%	2.33%	2.49%	2.64%	2.78%	2.91%	3.03%	2.97%	2.91%	2.85%	2.80%	2.74%	2.69%	
							% Capacity	46.96%	47.29%	47.65%	48.02%	48.42%	48.85%	49.33%	49.87%	50.48%	51.15%	51.88%	52.73%	53.68%	54.75%	55.94%	57.24%	58.67%	60.22%	61.89%	63.69%	65.62%	67.57%	69.53%	71.51%	73.51%	75.53%	77.57%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	11	18	28	41	57	76	103	137	180	231	291	365	454	558	677	812	963	1131	1315	1515	1733	1953	2175	2399	2626	2854	3085	
							Load Transfers																												
	13611	Winter	1448	1474	2868	3839	Winter	3859	3869	3880	3893	3908	3924	3944	3967	3995	4028	4064	4107	4159	4217	4283	4358	4440	4530	4629	4736	4852	4968	5086	5205	5325	5446	5568	
							Total % Growth		0.26%	0.30%	0.34%	0.37%	0.41%	0.51%	0.61%	0.70%	0.80%	0.90%	1.07%	1.24%	1.41%	1.57%	1.73%	1.89%	2.03%	2.18%	2.31%	2.44%	2.41%	2.37%	2.34%	2.30%	2.27%	2.24%	
							% Capacity	28.35%	28.42%	28.51%	28.60%	28.71%	28.83%	28.97%	29.15%	29.35%	29.59%	29.86%	30.18%	30.55%	30.98%	31.47%	32.02%	32.62%	33.28%	34.01%	34.79%	35.64%	36.50%	37.37%	38.24%	39.12%	40.01%	40.91%	
R22	10889	Summer	1675	1757	4114	4258	Summer	4263	4283	4304	4326	4350	4375	4404	4438	4475	4517	4563	4616	4677	4745	4821	4906	4998	5098	5207	5324	5449	5576	5704	5833	5964	6095	6227	0.37%
							Total %Growth		0.45%	0.49%	0.52%	0.55%	0.58%	0.67%	0.76%	0.84%	0.93%	1.02%	1.17%	1.32%	1.46%	1.60%	1.74%	1.88%	2.01%	2.13%	2.25%	2.36%	2.33%	2.29%	2.26%	2.23%	2.20%	2.17%	
							% Capacity	39.15%	39.33%	39.52%	39.73%	39.95%	40.18%	40.45%	40.75%	41.10%	41.48%	41.90%	42.39%	42.95%	43.58%	44.28%	45.05%	45.90%	46.82%	47.82%	48.89%	50.05%	51.21%	52.39%	53.57%	54.77%	55.97%	57.19%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
							Load Transfers																												
	13611	Winter	5555	5381	3558	3989	Winter	4009	4019	4031	4045	4059	4075	4096	4120	4148	4180	4217	4261	4312	4371	4438	4512	4595	4685	4784	4891	5007	5124	5242	5361	5481	5603	5725	
							Total % Growth		0.26%	0.29%	0.33%	0.36%	0.40%	0.49%	0.59%	0.68%	0.78%	0.88%	1.04%	1.20%	1.37%	1.52%	1.68%	1.83%	1.97%	2.11%	2.24%	2.37%	2.34%	2.30%	2.27%	2.24%	2.21%	2.18%	
							% Capacity	29.45%	29.53%	29.62%	29.71%	29.82%	29.94%	30.09%	30.27%	30.48%	30.71%	30.98%	31.30%	31.68%	32.11%	32.60%	33.15%	33.76%	34.42%	35.15%	35.94%	36.79%	37.65%	38.51%	39.39%	40.27%	41.16%	42.06%	
R23	10889	Summer	5344	5270	3751	4025	Summer	4030	4049	4069	4090	4113	4138	4166	4199	4235	4276	4321	4373	4433	4501	4576	4659	4750	4850	4958	5074	5199	5325	5452	5580	5709	5840	5971	0.37%
							Total %Growth		0.46%	0.49%	0.53%	0.56%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.21%	1.37%	1.52%	1.67%	1.82%	1.96%	2.09%	2.22%	2.34%	2.46%	2.42%	2.39%	2.35%	2.32%	2.28%	2.25%	
							% Capacity	37.01%	37.18%	37.37%	37.56%	37.77%	38.00%	38.26%	38.56%	38.90%	39.27%	39.68%	40.16%	40.71%	41.33%	42.03%	42.79%	43.63%	44.54%	45.53%	46.60%	47.74%	48.90%	50.07%	51.24%	52.43%	53.63%	54.84%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
							Load Transfers																												
	13611	Winter	6662	6606	4238	3815	Winter	3846	3867	3890	3915	3943	3974	4010	4053	4103	4159	4222	4297	4384	4482	4594	4718	4854	5004	5167	5344	5534	5726	5920	6116	6313	6512	6713	
							Total % Growth		0.54%	0.60%	0.65%	0.71%	0.77%	0.92%	1.07%	1.22%	1.37%	1.52%	1.77%	2.02%	2.26%	2.48%	2.70%	2.90%	3.09%	3.26%	3.42%	3.56%	3.47%	3.39%	3.30%	3.23%	3.15%	3.09%	
							% Capacity	28.26%	28.41%	28.58%	28.77%	28.97%	29.19%	29.46%	29.78%	30.14%	30.56%	31.02%	31.57%	32.21%	32.93%	33.75%	34.66%	35.66%	36.76%	37.96%	39.26%	40.66%	42.07%	43.49%	44.93%	46.38%	47.85%	49.32%	
R24	10889	Summer	6661	5137	3261	2636	Summer	2645	2666	2690	2716	2744	2775	2813	2857	2907	2964	3028	3104	3192	3291	3404	3529	3666	3817	3982	4160	4351	4545	4740	4937	5136	5336	5539	0.59%
							Total %Growth		0.81%	0.89%	0.97%	1.05%	1.13%	1.35%	1.56%	1.77%	1.97%	2.16%	2.50%	2.83%	3.13%	3.41%	3.67%	3.91%	4.12%	4.30%	4.47%	4.61%	4.45%	4.30%	4.16%	4.03%	3.91%	3.79%	
							% Capacity	24.29%	24.48%	24.70%	24.94%	25.20%	25.49%	25.83%	26.23%	26.70%	27.22%	27.81%	28.50%	29.31%	30.23%	31.26%	32.41%	33.67%	35.06%	36.57%	38.20%	39.96%	41.74%	43.53%	45.34%	47.17%	49.01%	50.87%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	9	14	23	33	46	61	82	110	144	185	233	292	363	446	542	650	771	905	1052	1212	1387	1563	1740	1920	2101	2283	2468	
							Load Transfers																												
	40000	Winter	20134	20527	15734	14827	Winter	17909	17981	18062	18150	18247	18352	18478	18627	18797	18991	19207	19463	19760	20099	20479	20903	21370	21881	22438	23041	23692	24347	25009	25677	26351	27031	27716	
							Total % Growth		0.41%	0.45%	0.49%	0.53%	0.58%	0.69%	0.80%	0.92%	1.03%	1.14%	1.33%	1.53%	1.71%	1.89%	2.07%	2.23%	2.39%	2.55%	2.69%	2.82%	2.77%	2.72%	2.67%	2.62%	2.58%	2.54%	
							% Capacity	44.77%	44.95%	45.15%	45.38%	45.62%	45.88%	46.20%	46.57%	46.99%	47.48%	48.02%	48.66%	49.40%	50.25%	51.20%	52.26%	53.42%	54.70%	56.10%	57.60%	59.23%	60.87%	62.52%	64.19%	65.88%	67.58%	69.29%	
Waterford 12kV	32000	Summer	18988	17345	15824	14920	Summer	16670	16770	16878	16994	17119	17252	17407	17584	17783	18004	18249	18534	18860	19227	19636	20087	20583	21123	21708	22339	23017	23701	24391	25088	25790	26499	27215	0.51%
							Total %Growth		0.60%	0.64%	0.69%	0.73%	0.78%	0.90%	1.02%	1.13%	1.25%	1.36%	1.56%	1.76%	1.95%	2.13%	2.30%	2.47%	2.62%	2.77%	2.91%	3.04%	2.97%	2.91%	2.86%	2.80%	2.75%	2.70%	
							% Capacity	52.09%	52.41%	52.74%	53.11%	53.50%	53.91%	54.40%	54.95%	55.57%	56.26%	57.03%	57.92%	58.94%	60.08%	61.36%	62.77%	64.32%	66.01%	67.84%	69.81%	71.93%	74.07%	76.22%	78.40%	80.60%	82.81%	85.05%	
	Δ Load						Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							EV	30	51	79	115	160	213	288	385	505	648	814	1021	1270	1562	1896	2274	2697	3166	3681	4243	4853	5469	6091	6718	7352	7992	8637	
							Load Transfers																												

R31	13611	Winter	4383	1845		1000	Winter	1017	1031	1046	1062	1080	1100	1124	1151	1183	1220	1260	1308	1363	1426	1497	1576	1663	1758	1862	1974	2095	2217	2340	2464	2589	2716	2844	
							Total % Growth		1.33%	1.46%	1.58%	1.70%	1.82%	2.15%	2.47%	2.77%	3.06%	3.32%	3.80%	4.24%	4.63%	4.97%	5.27%	5.52%	5.72%	5.89%	6.02%	6.12%	5.82%	5.55%	5.31%	5.09%	4.89%	4.71%	
							% Capacity	7.47%	7.57%	7.68%	7.80%	7.94%	8.08%	8.26%	8.46%	8.69%	8.96%	9.26%	9.61%	10.02%	10.48%	11.00%	11.58%	12.22%	12.92%	13.68%	14.50%	15.39%	16.29%	17.19%	18.10%	19.02%	19.96%	20.89%	
	10889	Summer	5438	2564		1000	Summer	1005	1021	1038	1056	1076	1098	1124	1154	1188	1226	1269	1319	1377	1443	1516	1597	1687	1785	1891	2006	2129	2254	2380	2508	2636	2766	2897	1.17%
							Total %Growth		1.53%	1.66%	1.78%	1.90%	2.02%	2.35%	2.66%	2.96%	3.23%	3.49%	3.96%	4.38%	4.76%	5.09%	5.37%	5.60%	5.80%	5.95%	6.07%	6.16%	5.86%	5.59%	5.35%	5.12%	4.92%	4.74%	
							% Capacity	9.23%	9.37%	9.53%	9.70%	9.88%	10.08%	10.32%	10.60%	10.91%	11.26%	11.66%	12.12%	12.65%	13.25%	13.92%	14.67%	15.49%	16.39%	17.37%	18.42%	19.56%	20.70%	21.86%	23.03%	24.21%	25.40%	26.60%	
							Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Δ Load						EV	5	9	14	21	29	38	51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
							Load Transfers																												
R32	16806	Winter	4770	4744	5870	5753	Winter	6476	6498	6522	6547	6574	6603	6635	6671	6712	6756	6805	6862	6925	6997	7076	7163	7258	7361	7473	7593	7722	7851	7982	8114	8247	8382	8517	
							Total % Growth		0.34%	0.37%	0.39%	0.41%	0.43%	0.49%	0.55%	0.61%	0.67%	0.72%	0.83%	0.93%	1.03%	1.13%	1.23%	1.33%	1.42%	1.52%	1.61%	1.70%	1.68%	1.67%	1.65%	1.64%	1.63%	1.62%	
							% Capacity	38.53%	38.67%	38.81%	38.96%	39.12%	39.29%	39.48%	39.70%	39.94%	40.20%	40.49%	40.83%	41.21%	41.63%	42.10%	42.62%	43.19%	43.80%	44.47%	45.18%	45.95%	46.72%	47.50%	48.28%	49.08%	49.87%	50.68%	
	13444	Summer	6458	4634	4729	5516	Summer	6463	6499	6535	6574	6614	6655	6701	6751	6805	6863	6926	6996	7074	7160	7253	7354	7464	7582	7708	7843	7986	8131	8277	8424	8573	8723	8874	0.49%
							Total %Growth		0.54%	0.57%	0.59%	0.61%	0.63%	0.69%	0.74%	0.80%	0.86%	0.91%	1.01%	1.11%	1.21%	1.30%	1.40%	1.49%	1.58%	1.67%	1.75%	1.83%	1.81%	1.80%	1.78%	1.76%	1.75%	1.73%	
							% Capacity	48.07%	48.34%	48.61%	48.90%	49.19%	49.50%	49.84%	50.21%	50.62%	51.05%	51.52%	52.04%	52.62%	53.25%	53.95%	54.70%	55.52%	56.39%	57.33%	58.33%	59.40%	60.48%	61.57%	62.66%	63.77%	64.88%	66.00%	
							Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Δ Load						EV	5	9	14	21	29	38	51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
							Load Transfers																												
R33	14500	Winter	6469	6527	6271	4827	Winter	4920	4998	5082	5172	5267	5368	5482	5610	5752	5909	6080	6275	6495	6383	6577	6788	7015	7259	7519	7798	8093	8392	8694	9000	9308	9620	9936	
							Total % Growth		1.60%	1.68%	1.76%	1.84%	1.92%	2.13%	2.34%	2.53%	2.72%	2.89%	3.21%	3.50%	-1.72%	3.05%	3.20%	3.34%	3.47%	3.59%	3.70%	3.79%	3.69%	3.60%	3.51%	3.43%	3.35%	3.28%	
							% Capacity	33.93%	34.47%	35.05%	35.67%	36.32%	37.02%	37.81%	38.69%	39.67%	40.75%	41.93%	43.27%	44.79%	44.02%	45.36%	46.81%	48.38%	50.06%	51.86%	53.78%	55.82%	57.88%	59.96%	62.07%	64.20%	66.35%	68.52%	
	11600	Summer	6530	5979	6328	4327	Summer	4344	4424	4509	4599	4696	4798	4914	5044	5188	5346	5519	5717	5939	5830	6028	6242	6472	6720	6984	7267	7567	7870	8177	8488	8802	9119	9441	1.56%
							Total %Growth		1.83%	1.92%	2.01%	2.10%	2.18%	2.42%	2.64%	2.85%	3.05%	3.24%	3.58%	3.89%	-1.83%	3.39%	3.55%	3.69%	3.82%	3.94%	4.04%	4.13%	4.01%	3.90%	3.80%	3.70%	3.61%	3.52%	
							% Capacity	37.45%	38.13%	38.87%	39.65%	40.48%	41.36%	42.36%	43.48%	44.72%	46.09%	47.58%	49.28%	51.20%	50.26%	51.96%	53.81%	55.79%	57.93%	60.21%	62.64%	65.23%	67.85%	70.49%	73.17%	75.88%	78.62%	81.38%	
							Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Δ Load						EV	17	29	45	66	91	122	164	220	288	370	465	584	726	535	650	780	925	1085	1262	1455	1664	1875	2088	2303	2521	2740	2961	
							Load Transfers																												
R34	16806	Winter	6493	6523	6462	6492	Winter	6622	6705	6792	6884	6980	7082	7190	7308	7439	7581	7736	7910	8105	8321	8559	8818	9099	9402	9729	10079	10453	10830	11211	11595	11984	12376	12772	
							Total % Growth		1.25%	1.30%	1.35%	1.40%	1.45%	1.52%	1.65%	1.79%	1.91%	2.04%	2.26%	2.47%	2.67%	2.85%	3.03%	3.19%	3.34%	3.47%	3.60%	3.71%	3.61%	3.52%	3.43%	3.35%	3.27%	3.20%	
							% Capacity	39.40%	39.90%	40.41%	40.96%	41.54%	42.14%	42.78%	43.49%	44.27%	45.11%	46.03%	47.07%	48.23%	49.51%	50.93%	52.47%	54.14%	55.95%	57.89%	59.97%	62.20%	64.44%	66.71%	69.00%	71.31%	73.64%	76.00%	
	13444	Summer	6081	5817	6438	6189	Summer	6493	6587	6686	6790	6899	7013	7134	7266	7410	7567	7735	7925	8135	8366	8619	8894	9192	9512	9856	10224	10615	11011	11410	11814	12222	12634	13050	1.23%
							Total %Growth		1.45%	1.50%	1.56%	1.61%	1.66%	1.72%	1.86%	1.99%	2.11%	2.23%	2.45%	2.65%	2.84%	3.02%	3.19%	3.35%	3.49%	3.61%	3.73%	3.83%	3.73%	3.63%	3.54%	3.45%	3.37%	3.29%	
							% Capacity	48.29%	48.99%	49.73%	50.50%	51.31%	52.16%	53.06%	54.05%	55.12%	56.28%	57.54%	58.94%	60.51%	62.23%	64.11%	66.16%	68.37%	70.75%	73.31%	76.04%	78.95%	81.90%	84.87%	87.87%	90.90%	93.97%	97.06%	
							Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Δ Load						EV	14	24	38	55	76	101	137	183	240	308	388	486	605	744	903	1083	1284	1508	1753	2020	2311	2604	2900	3199	3501	3806	4113	
							Load Transfers																												
R35 (Future)	16806	Winter	0	0	0	0	Winter	0	0	0	0	0	0	0	0	0	0	0	0	0	357	433	520	617	724	841	970	1109	1250	1392	1536	1680	1827	1974	
							Total % Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	21.41%	19.95%	18.60%	17.37%	16.26%	15.27%	14.38%	12.69%	11.37%	10.31%	9.43%	8.70%	8.08%	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.12%	2.58%	3.09%	3.67%	4.31%	5.01%	5.77%	6.60%	7.44%	8.28%	9.14%	10.00%	10.87%	11.75%	
	13444	Summer	0	0	0	0	Summer	0	0	0	0	0	0	0	0	0	0	0	0	0	357	433	520	617	724	841	970	1109	1250	1392	1536	1680	1827	1974	1.000%
							Total %Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	21.41%	19.95%	18.60%	17.37%	16.26%	15.27%	14.38%	12.69%	11.37%	10.31%	9.43%	8.70%	8.08%	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.65%	3.22%	3.87%	4.59%	5.38%	6.26%	7.21%	8.25%	9.30%	10.35%	11.42%	12.50%	13.59%	14.68%	
							Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Δ Load						EV														357	433	520	617	724	841	970	1109	1250	1392	1536	1680	1827	1974	
							Load Transfers																												
R36	18000	Winter	1593	4449	4950	5172	Winter	5203	5221	5241	5263	5286	5311	5339	5372	5409	5450	5495	5547	5607	5675	5750	5833	5925	6024	6132	6248	6373	6499	6626	6754	6883	7013	7145	
							Total % Growth		0.36%	0.39%	0.41%	0.44%	0.47%	0.54%	0.61%	0.68%	0.76%	0.83%	0.96%	1.08%	1.20%	1.33%	1.45%	1.56%	1.68%	1.79%	1.90%	2.00%	1.98%	1.95%	1.93%	1.91%	1.89%	1.87%	
							% Capacity	28.90%	29.01%	29.12%	29.24%	29.37%	29.50%	29.66%	29.84%	30.05%	30.28%	30.53%	30.82%	31.15%	31.53%	31.95%	32.41%	32.91%	33.47%	34.06%	34.71%	35.40%	36.10%	36.81%	37.52%	38.24%	38.96%	39.69%	
	14400	Summer	1990	4583	4510	4017	Summer	4588	4614	4642	4671	4702	4734	4770	4811	4855	4904	4957	5018	5086	5162	5245	5337	5437	5545	5661	5786	5919	6054	6190	6327	6465	6605	6745	0.49%
							Total %Growth		0.57%	0.60%	0.63%	0.66%	0.69%	0.77%	0.85%	0.93%	1.01%	1.08%	1.22%	1.36%	1.49%	1.62%	1.75%	1.87%	1.98%	2.10%	2.21%	2.31%	2.28%	2.24%	2.21%	2.18%	2.16%	2.13%	
							% Capacity	31.86%	32.04%	32.24%	32.44%	32.65%	32.88%	33.13%	33.41%	33.72%	34.06%	34.43%	34.85%	35.32%	35.85%	36.43%	37.06%	37.75%	38.50%	39.31%	40.18%	41.11%	42.04%	42.98%	43.94%	44.90%	45.86%	46.84%	
							Developments	0	0	0	0	0	0																						
	Δ Load						EV	5	9	14	21	29	38	51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
							Load Transfers																												
Westminster 12kV	40000	Winter	21958	18526	18905	19000	Winter	23702	23913	24139	24378	24632	24901	25201	25537	25910	26322	26771	27286	27867	28515	29232	30020	30879	31810	32815	33896	35053	36221	37400	38591	39794	41008	42234	
							Total % Growth		0.89%	0.94%	0.99%	1.04%	1.09%	1.20%	1.33%	1.46%	1.59%	1.71%	1.92%	2.13%	2.33%	2.52%	2.69%	2.86%	3.02%	3.16%	3.29%	3.41%	3.33%	3.26%	3.18%	3.12%	3.05%	2.99%	
							% Capacity	59.26%	59.78%	60.35%	60.95%	61.58%	62.25%	63.00%	63.84%	64.78%	65.80%	66.93%	68.21%	69.67%	71.29%	73.08%	75.05%	77.20%	79.52%	82.04%	84.74%	87.63%	90.55%	93.50%	96.48%	99.48%	102.52%	105.58%	
	32000	Summer	27057	15817	18721	16672	Summer	21797	22036	22288	22556	22838	23135	23463	23827	24228	24666	25143	25683	26289	26961	27701	28510	29389	30340	31364	32461	33634	34819	36015	37223	38444	39677	40922	0.95%
							Total %Growth		1.09%	1.15%	1.20%	1.25%	1.30%	1.42%	1.55%	1.68%	1.81%	1.93%	2.15%	2.36%	2.56%	2.74%	2.92%	3.08%	3.23%	3.37%	3.50%	3.61%	3.52%	3.44%	3.36%	3.28%	3.21%	3.14%	
							% Capacity	68.12%	68.86%	69.65%	70.49%	71.37%	72.30%	73.32%	74.46%	75.71%	77.08%	78.57%	80.26%	82.15%	84.25%	86.57%	89.09%	91.84%	94.81%	98.01%	101.44%	105.11%	108.81%	112.55%	116.32%	120.14%	123.99%	127.88%	
							Developments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Δ Load						EV	48	80	125	182	253	337	455	609	799	1025	1289	1617	2011	2472	3002	3601	4271	5012	5828	6718	7684	8659	9644	10637	11641	12654	13676	
							Load Transfers																												
System	145900	Winter	70906	66206	64620	66450	Winter	67642	68003	68395	68818	69273	69760	70221	70829	71511	72268	73103	74070	75171	76409	77787	79307	80971	82782	84743	86856	89125	91415	93726	96058	98412	100788	103186	
							Total % Growth		0.53%	0.58%	0.62%	0.66%	0.70%	0.66%	0.87%	0.96%	1.06%	1.16%	1.32%	1.49%	1.65%	1.80%	1.95%	2.10%	2.24%	2.37%	2.49%	2.61%	2.57%	2.53%	2.49%	2.45%	2.41%	2.38%	
							% Capacity	46.36%	46.61%	46.88%	47.17%	47.48%	47.81%	48.13%	48.55%	49.01%	49.53%	50.11%	50.77%	51.52%	52.37%	53.32%	54.36%	55.50%	56.74%	58.08%	59.53%	61.09%	62.66%	64.24%	65.84%	67.45%	69.08%	70.72%	0.66%
	121900	Summer	63513	71498	66638	64600	Summer	66543	67027	67543	68091	68672	69286	69876	70613	71425	72314	73280	74379	75614	76985	78497	80151	81950	83897	85994	88244	90650	93079	95530	98004	100501	103021	105565	
							Total %Growth		0.73%	0.77%	0.81%	0.85%	0.89%	0.85%	1.05%	1.15%	1.24%	1.34%	1.50%	1.66%	1.81%	1.96%	2.11%	2.24%	2.38%	2.50%	2.62%	2.73%	2.68%	2.63%	2.59%	2.55%	2.51%	2.47%	
							% Capacity	54.59%	54.99%	55.41%	55.86%	56.33%	56.84%	57.32%	57.93%	58.59%	59.32%	60.12%	61.02%	62.03%	63.15%	64.39%	65.75%	67.23%	68.82%	70.54%	72.39%	74.36%	76.36%	78.37%	80.40%	82.45%	84.51%	86.60%	
							Developments	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	
	Δ Load						EV	138	232	362	528	733	975	1190	1586	2075	2657	3334	4177	5188	6371	7728	9263	10979	12880	14968	17248	19722	22220	24741	27287	29857	32452	35071	
							D.E.R.																												
							Load Transfers																												

D

Appendix D
Final Load Forecast

			Historical Loads					Forecasted Peak Loads (kVA) for Years 0-5						
								Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	
Feeder	Capacity	Season	2016	2017	2018	2019		2020	2021	2022	2023	2024	2025	Expected Base Growth Year 1-5
R2	16806	Winter	1808	1856	4727	4392	Winter	4753	4770	4788	4807	4828	4851	
							Total % Growth		0.35%	0.38%	0.41%	0.44%	0.47%	
							% Capacity	28.28%	28.38%	28.49%	28.61%	28.73%	28.86%	
	13444	Summer	2533	1866	5986	4456	Summer	5991	6023	6057	6092	6129	6167	0.47%
							Total % Growth		0.53%	0.56%	0.58%	0.60%	0.62%	
							% Capacity	44.56%	44.80%	45.05%	45.31%	45.58%	45.87%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	
							Load Transfers	0	0	0	0	0	0	
R3	16806	Winter	4627	5448	4463	3937	Winter	3961	3975	3991	4009	4027	4048	
							Total % Growth		0.36%	0.40%	0.43%	0.47%	0.51%	
							% Capacity	23.57%	23.66%	23.75%	23.85%	23.97%	24.09%	
	13444	Summer	4369	5113	2692	4172	Summer	4177	4201	4226	4252	4280	4310	0.47%
							Total %Growth		0.56%	0.59%	0.62%	0.66%	0.69%	
							% Capacity	31.07%	31.25%	31.43%	31.63%	31.83%	32.05%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	
							Load Transfers	0	0	0	0	0	0	
R4	14500	Winter	5389	5415	5295	5077	Winter	5444	5463	5483	5504	5527	5552	
							Total % Growth		0.34%	0.36%	0.39%	0.42%	0.44%	
							% Capacity	37.55%	37.67%	37.81%	37.96%	38.12%	38.29%	
	11600	Summer	4505	4979	5073	5640	Summer	5645	5676	5708	5741	5776	5813	0.47%
							Total % Growth		0.54%	0.56%	0.59%	0.61%	0.63%	
							% Capacity	48.67%	48.93%	49.20%	49.49%	49.79%	50.11%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	
							Load Transfers	0	0	0	0	0	0	
R5	16806	Winter	5498	4428	4045	4565	Winter	4592	4608	4626	4645	4665	4687	
							Total % Growth		0.35%	0.38%	0.41%	0.44%	0.47%	
							% Capacity	27.32%	27.42%	27.52%	27.64%	27.76%	27.89%	
	13444	Summer	4559	4572	4788	3599	Summer	3604	3625	3647	3671	3696	3723	0.47%
							Total %Growth		0.57%	0.61%	0.65%	0.69%	0.72%	
							% Capacity	26.81%	26.96%	27.13%	27.30%	27.49%	27.69%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	
							Load Transfers	0	0	0	0	0	0	
R6	16806	Winter	4909	4904	3544	3359	Winter	3380	3393	3407	3423	3440	3459	
							Total % Growth		0.38%	0.42%	0.46%	0.50%	0.55%	
							% Capacity	20.11%	20.19%	20.28%	20.37%	20.47%	20.58%	
	13444	Summer	5696	4536	5211	2964	Summer	2969	2987	3006	3027	3049	3073	0.47%
							Total % Growth		0.59%	0.64%	0.69%	0.73%	0.78%	
							% Capacity	22.09%	22.22%	22.36%	22.51%	22.68%	22.85%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	
							Load Transfers	0	0	0	0	0	0	
R7 (Represents the new Huth Substation and feeders)	67222					0		0	0	0	0	0	0	
									#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
								0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	53778					0		0	0	0	0	0	0	0.47%
									#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
								0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
								0	0	0	0	0	0	
								0	0	0	0	0	0	
Huth 12kV	25900	Winter	20733	27951	17778	20431	Winter	21163	21238	21320	21409	21505	21608	
							Total % Growth		0.35%	0.39%	0.42%	0.45%	0.48%	
							% Capacity	81.71%	82.00%	82.32%	82.66%	83.03%	83.43%	
	25900	Summer	19827	19214	20566	13365	Summer	21452	21571	21697	21830	21971	22120	0.49%
							Total % Growth		0.55%	0.58%	0.61%	0.65%	0.68%	
							% Capacity	82.83%	83.29%	83.77%	84.29%	84.83%	85.40%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	27	45	70	103	143	190	
							Load Transfers	0	0	0	0	0	0	

				Forecasted Peak Loads (kVA) for Years 6-26																					
				Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	
Feeder		Capacity	Season	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	Expected Year 6-26 Growth
R2	Winter	16806	Winter	4877	4908	4942	4981	5024	5075	5132	3198	3265	3341	3424	3516	3616	-75	31	139	248	358	468	580	693	
	Total % Growth			0.55%	0.63%	0.70%	0.78%	0.86%	1.00%	1.14%	-37.69%	2.12%	2.31%	2.50%	2.68%	2.84%	-102.09%	-141.44%	344.59%	78.25%	44.32%	31.01%	23.90%	19.47%	
	% Capacity			29.02%	29.20%	29.41%	29.64%	29.90%	30.20%	30.54%	19.03%	19.43%	19.88%	20.38%	20.92%	21.52%	-0.45%	0.19%	0.83%	1.47%	2.13%	2.79%	3.45%	4.13%	
	Summer	13444	Summer	6209	6256	6306	6361	6420	6487	6561	4643	4724	4812	4908	5013	5126	1447	1560	1673	1787	1903	2019	2137	2255	0.47%
	Total % Growth			0.69%	0.75%	0.81%	0.87%	0.93%	1.04%	1.14%	-29.23%	1.73%	1.87%	2.00%	2.13%	2.25%	-71.76%	7.75%	7.26%	6.83%	6.46%	6.12%	5.82%	5.55%	
	% Capacity			46.18%	46.53%	46.91%	47.31%	47.76%	48.25%	48.80%	34.54%	35.13%	35.79%	36.51%	37.29%	38.13%	10.77%	11.60%	12.44%	13.29%	14.15%	15.02%	15.89%	16.77%	
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EV			51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
	Load Transfers			0	0	0	0	0	0	0	-2000	0	0	0	0	0	-3800	0	0	0	0	0	0	0	
R3	Winter	16806	Winter	4072	4100	4133	4169	4210	4258	4314	4377	4448	4527	4613	4708	4812	4923	5044	5165	5287	5411	5536	5661	5788	
	Total % Growth			0.60%	0.70%	0.79%	0.88%	0.98%	1.14%	1.30%	1.46%	1.62%	1.77%	1.92%	2.06%	2.19%	2.32%	2.44%	2.41%	2.37%	2.34%	2.30%	2.27%	2.24%	
	% Capacity			24.23%	24.40%	24.59%	24.81%	25.05%	25.34%	25.67%	26.05%	26.47%	26.94%	27.45%	28.02%	28.63%	29.30%	30.01%	30.73%	31.46%	32.20%	32.94%	33.69%	34.44%	
	Summer	13444	Summer	4343	4381	4423	4469	4519	4577	4642	4715	4795	4884	4981	5086	5199	5321	5451	5583	5716	5850	5985	6121	6259	0.47%
	Total % Growth			0.78%	0.87%	0.95%	1.04%	1.13%	1.28%	1.43%	1.57%	1.71%	1.85%	1.98%	2.11%	2.23%	2.34%	2.45%	2.42%	2.38%	2.34%	2.31%	2.28%	2.25%	
	% Capacity			32.30%	32.58%	32.89%	33.24%	33.61%	34.04%	34.53%	35.07%	35.67%	36.33%	37.05%	37.83%	38.67%	39.58%	40.55%	41.53%	42.51%	43.51%	44.52%	45.53%	46.55%	
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EV			51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
R4	Winter	14500	Winter	5529	5544	5559	5574	5589	5604	5620	7635	7656	7677	7698	7719	7740	7761	7782	7803	7824	7846	7867	7889	7910	
	Total % Growth			-0.41%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	35.86%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	
	% Capacity			38.13%	38.23%	38.34%	38.44%	38.55%	38.65%	38.76%	52.66%	52.80%	52.94%	53.09%	53.23%	53.38%	53.52%	53.67%	53.81%	53.96%	54.11%	54.26%	54.40%	54.55%	
	Summer	11600	Summer	5802	5829	5857	5885	5912	5940	5968	7997	8034	8072	8111	8149	8187	8226	8265	8304	8343	8383	8422	8462	8502	0.47%
	Total % Growth			-0.18%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	33.98%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	
	% Capacity			50.02%	50.25%	50.49%	50.73%	50.97%	51.21%	51.45%	68.94%	69.26%	69.59%	69.92%	70.25%	70.58%	70.91%	71.25%	71.59%	71.92%	72.26%	72.61%	72.95%	73.29%	
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EV			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Load Transfers			0	0	0	0	0	0	0	2000	0	0	0	0	0	0	0	0	0	0	0	0	0	
R5	Winter	16806	Winter	4675	4689	4704	4718	4733	4747	4762	4777	4792	4807	4822	4837	4852	4868	4883	4899	4914	4930	4946	4962	4978	
	Total % Growth			-0.26%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	
	% Capacity			27.82%	27.90%	27.99%	28.08%	28.16%	28.25%	28.34%	28.42%	28.51%	28.60%	28.69%	28.78%	28.87%	28.96%	29.06%	29.15%	29.24%	29.34%	29.43%	29.53%	29.62%	
	Summer	13444	Summer	3715	3734	3754	3773	3792	3812	3832	3851	3872	3892	3912	3932	3953	3974	3995	4016	4037	4058	4080	4102	4123	0.47%
	Total %Growth			-0.20%	0.51%	0.51%	0.51%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	
	% Capacity			27.63%	27.78%	27.92%	28.06%	28.21%	28.35%	28.50%	28.65%	28.80%	28.95%	29.10%	29.25%	29.40%	29.56%	29.71%	29.87%	30.03%	30.19%	30.35%	30.51%	30.67%	
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EV			13	15	16	18	20	21	23	25	27	29	31	33	35	37	40	42	44	47	50	52	55	
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
R6	Winter	16806	Winter	3443	3454	3465	3476	3488	3499	3510	3521	3533	3544	3556	3568	3580	3591	3603	3616	3628	3640	3652	3665	3677	
	Total % Growth			-0.45%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.33%	0.33%	0.33%	0.33%	0.33%	0.33%	0.33%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	
	% Capacity			20.49%	20.56%	20.62%	20.69%	20.75%	20.82%	20.89%	20.95%	21.02%	21.09%	21.16%	21.23%	21.30%	21.37%	21.44%	21.51%	21.59%	21.66%	21.73%	21.81%	21.88%	
	Summer	13444	Summer	3062	3078	3094	3110	3127	3143	3160	3176	3193	3210	3227	3244	3262	3279	3297	3315	3332	3351	3369	3387	3406	0.47%
	Total % Growth			-0.35%	0.52%	0.52%	0.52%	0.52%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.54%	0.54%	0.54%	0.54%	0.54%	0.54%	0.54%	0.55%	
	% Capacity			22.78%	22.89%	23.01%	23.13%	23.26%	23.38%	23.50%	23.63%	23.75%	23.88%	24.00%	24.13%	24.26%	24.39%	24.52%	24.65%	24.79%	24.92%	25.06%	25.19%	25.33%	
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EV			13	15	16	18	20	21	23	25	27	29	31	33	35	37	40	42	44	47	50	52	55	
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
R7	Winter	67222	Winter	0	0	0	0	0	0	0	0	0	0	0	0	0	16800	16845	16891	16936	16982	17028	17074	17120	
	Total % Growth			#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	
	% Capacity			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	24.99%	25.06%	25.13%	25.19%	25.26%	25.33%	25.40%	25.47%	
	Summer	53778	Summer	0	0	0	0	0	0	0	0	0	0	0	0	0	16800	16879	16958	17038	17118	17199	17279	17361	0.47%
	Total % Growth			#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	
	% Capacity			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	31.24%	31.39%	31.53%	31.68%	31.83%	31.98%	32.13%	32.28%	
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EV			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0	0	0	16800	0	0	0	0	0	0	0	
Huth 12kV	Winter	40000	Winter	21608	21703	21806	21917	22036	22169	22317	22480	22657	22850	23059	23283	23523	36211	36518	36828	37139	37453	37770	38089	38410	
	Total % Growth			0.00%	0.44%	0.47%	0.51%	0.54%	0.61%	0.67%	0.73%	0.79%	0.85%	0.91%	0.97%	1.03%	53.94%	0.85%	0.85%	0.85%	0.85%	0.85%	0.84%	0.84%	
	% Capacity			54.02%	54.26%	54.51%	54.79%	55.09%	55.42%	55.79%	56.20%	56.64%	57.13%	57.65%	58.21%	58.81%	45.26%	45.65%	46.03%	46.42%	46.82%	47.21%	47.61%	48.01%	
	Summer	32000	Summer	22165	22305	22454	22611	22777	22958	23153	23363	23589	23831	24088	24361	24652	37415	37798	38183	38571	38962	39357	39754	40154	0.47%
	Total % Growth			0.20%	0.63%	0.67%	0.70%	0.73%	0.79%	0.85%	0.91%	0.97%	1.02%	1.08%	1.14%	1.19%	51.78%	1.02%	1.02%	1.02%	1.01%	1.01%	1.01%	1.01%	
	% Capacity			69.26%	69.70%	70.17%	70.66%	71.18%	71.74%	72.35%	73.01%	73.72%	74.47%	75.27%	76.13%	77.04%	58.46%	59.06%	59.66%	60.27%	60.88%	61.49%	62.12%	62.74%	
	Developments	Δ Load		0	0	0	0	0	0	0	2000	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EV			129	167	213	267	330	407	500	608	731	870	1025	1197	1385	1590	1812	2037	2264	2493	2725	2959	3195	
	Load Transfers			0	0	0	0	0	0	0	-2000	0	0	0	0	0	13000	0	0	0	0	0	0	0	

Feeder	Capacity	Season	Historical Loads					Forecasted Peak Loads (kVA) for Years 0-5						Expected Base Growth Year 1-5
								Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	
			2016	2017	2018	2019		2020	2021	2022	2023	2024	2025	
R10	13611	Winter	3243	6623	6660	5773	Winter	5848	5906	5970	6038	6111	6190	
							Total % Growth		1.00%	1.07%	1.14%	1.21%	1.28%	
							% Capacity	42.97%	43.39%	43.86%	44.36%	44.90%	45.48%	
	10889	Summer	4090	6659	6600	6477	Summer	6886	6966	7052	7143	7239	7341	1.00%
							Total %Growth		1.17%	1.23%	1.29%	1.35%	1.41%	
							% Capacity	63.24%	63.98%	64.76%	65.60%	66.48%	67.42%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	17	29	45	66	91	122	
							Load Transfers	0	0	0	0	0	0	
R11	13611	Winter	6643	5298	5334	5054	Winter	6664	6675	6688	6702	6718	6735	
							Total % Growth		0.17%	0.19%	0.21%	0.23%	0.25%	
							% Capacity	48.96%	49.04%	49.14%	49.24%	49.35%	49.48%	
	10889	Summer	6630	4564	4485	3949	Summer	3954	3970	3988	4007	4027	4049	0.31%
							Total %Growth		0.40%	0.44%	0.47%	0.51%	0.55%	
							% Capacity	36.32%	36.46%	36.62%	36.80%	36.98%	37.19%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	
							Load Transfers	0	0	0	0	0	0	
R12	13611	Winter	6636	6626	6639	6663	Winter	6725	6736	6749	6763	6778	6795	
							Total % Growth		0.17%	0.19%	0.21%	0.23%	0.25%	
							% Capacity	49.41%	49.49%	49.58%	49.68%	49.80%	49.92%	
	10889	Summer	6478	6588	6624	6656	Summer	6661	6686	6712	6739	6768	6799	0.31%
							Total %Growth		0.37%	0.39%	0.41%	0.43%	0.45%	
							% Capacity	61.18%	61.40%	61.64%	61.89%	62.16%	62.44%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	
							Load Transfers	0	0	0	0	0	0	
R13	13611	Winter	6337	5111	2947	2182	Winter	2194	2200	2208	2217	2227	2239	
							Total % Growth		0.28%	0.34%	0.41%	0.47%	0.54%	
							% Capacity	16.12%	16.17%	16.22%	16.29%	16.36%	16.45%	
	10889	Summer	5194	3441	4731	4100	Summer	5199	5219	5241	5264	5288	5314	0.31%
							Total %Growth		0.38%	0.41%	0.44%	0.46%	0.49%	
							% Capacity	47.75%	47.93%	48.13%	48.34%	48.56%	48.80%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	
							Load Transfers	0	0	0	0	0	0	
R14	18000	Winter	0	0	0	0	Winter	0	0	0	0	0	0	
							Total % Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	14400	Summer	0	0	0	0	Summer	0	0	0	0	0	0	0.31%
							Total %Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV							
							Load Transfers	0	0	0	0	0	0	
R15	16806	Winter	0	0	0	0	Winter	0	0	0	0	0	0	
							Total % Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	13444	Summer	0	0	0	0	Summer	0	0	0	0	0	0	0.31%
							Total %Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV							
							Load Transfers	0	0	0	0	0	0	
R16 (Future)	40000	Winter	0	0	0	0	Winter	0	0	0	0	0	0	
							Total % Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	32000	Summer	0	0	0	0	Summer	0	0	0	0	0	0	0.31%
							Total %Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV							
							Load Transfers	0	0	0	0	0	0	
Carmi 12kV	40000	Winter	20558	18749	20532	17337	Winter	18332	18406	18488	18578	18677	18783	
							Total % Growth		0.41%	0.45%	0.49%	0.53%	0.57%	
							% Capacity	45.83%	46.01%	46.22%	46.45%	46.69%	46.96%	
	32000	Summer	20901	21501	21533	16688	Summer	19868	19991	20123	20263	20412	20570	0.59%
							Total %Growth		0.62%	0.66%	0.70%	0.74%	0.77%	
							% Capacity	62.09%	62.47%	62.88%	63.32%	63.79%	64.28%	
	Δ Load						Developments				0	0	0	
							EV	33	56	87	128	177	236	
							Load Transfers				0	0	0	

Feeder		Capacity	Season	Forecasted Peak Loads (kVA) for Years 6-26										
				Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
				2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
R10	Winter	14500	Winter	6281	6386	6504	6635	2548	2626	2716	2818	2932	3060	3200
	Total % Growth			1.48%	1.66%	1.85%	2.02%	-61.60%	3.05%	3.42%	3.76%	4.07%	4.34%	4.58%
	% Capacity			46.15%	46.92%	47.78%	48.75%	18.72%	19.29%	19.95%	20.70%	21.54%	22.48%	23.51%
	Summer	11600	Summer	7456	7585	7727	7883	3821	3916	4024	4144	4276	4422	4580
	Total % Growth			1.57%	1.72%	1.88%	2.02%	-51.53%	2.49%	2.74%	2.98%	3.20%	3.40%	3.59%
	% Capacity			68.48%	69.66%	70.96%	72.40%	35.09%	35.97%	36.95%	38.06%	39.27%	40.61%	42.07%
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0
	EV			164	220	288	370	233	292	363	446	542	650	771
	Load Transfers			0	0	0	0	-4000	0	0	0	0	0	0
R11	Winter	14500	Winter	6755	6780	6809	6843	6880	6925	6977	7036	7104	7179	7262
	Total % Growth			0.31%	0.37%	0.43%	0.49%	0.55%	0.65%	0.75%	0.85%	0.96%	1.06%	1.16%
	% Capacity			49.63%	49.82%	50.03%	50.27%	50.55%	50.87%	51.26%	51.69%	52.19%	52.74%	53.35%
	Summer	11600	Summer	4075	4105	4139	4177	4220	4270	4327	4392	4464	4545	4633
	Total % Growth			0.64%	0.73%	0.83%	0.92%	1.02%	1.18%	1.34%	1.50%	1.65%	1.80%	1.95%
	% Capacity			37.42%	37.70%	38.01%	38.36%	38.75%	39.21%	39.74%	40.33%	41.00%	41.74%	42.55%
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0
	EV			51	69	90	116	145	182	227	279	339	406	482
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0
R12	Winter	13611	Winter	6816	6841	6870	6904	6941	6986	7038	7098	7165	7240	7324
	Total % Growth			0.31%	0.37%	0.42%	0.48%	0.54%	0.64%	0.75%	0.85%	0.95%	1.05%	1.15%
	% Capacity			50.08%	50.26%	50.48%	50.72%	51.00%	51.32%	51.71%	52.15%	52.64%	53.19%	53.81%
	Summer	10889	Summer	6833	6872	6915	6962	7013	7071	7137	7211	7292	7382	7479
	Total % Growth			0.51%	0.56%	0.62%	0.68%	0.74%	0.83%	0.93%	1.03%	1.13%	1.22%	1.32%
	% Capacity			62.76%	63.11%	63.50%	63.93%	64.40%	64.94%	65.55%	66.22%	66.97%	67.79%	68.69%
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0
	EV			51	69	90	116	145	182	227	279	339	406	482
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0
R13	Winter	13611	Winter	2255	2275	2299	2327	2359	2399	2446	2500	2562	2632	2710
	Total % Growth			0.71%	0.88%	1.05%	1.22%	1.39%	1.68%	1.96%	2.23%	2.49%	2.73%	2.97%
	% Capacity			16.57%	16.71%	16.89%	17.10%	17.33%	17.62%	17.97%	18.37%	18.83%	19.34%	19.91%
	Summer	10889	Summer	5344	5378	5416	5458	5504	5558	5619	5688	5765	5849	5942
	Total % Growth			0.56%	0.63%	0.71%	0.78%	0.85%	0.98%	1.10%	1.23%	1.35%	1.47%	1.58%
	% Capacity			49.07%	49.39%	49.74%	50.12%	50.55%	51.04%	51.61%	52.24%	52.94%	53.72%	54.57%
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0
	EV			51	69	90	116	145	182	227	279	339	406	482
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0
R14	Winter	18000	Winter	0	0	0	0	4233	4296	4372	4460	4560	4672	4798
	Total % Growth			#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	1.51%	1.76%	2.01%	2.24%	2.47%	2.68%
	% Capacity			0.00%	0.00%	0.00%	0.00%	23.51%	23.87%	24.29%	24.78%	25.33%	25.96%	26.65%
	Summer	14400	Summer	0	0	0	0	4233	4292	4363	4446	4542	4650	4771
	Total % Growth			#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	1.40%	1.66%	1.91%	2.15%	2.38%	2.60%
	% Capacity			0.00%	0.00%	0.00%	0.00%	29.39%	29.80%	30.30%	30.88%	31.54%	32.29%	33.13%
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0
	EV							233	292	363	446	542	650	771
	Load Transfers			0	0	0	0	4000	0	0	0	0	0	0
R15	Winter	16806	Winter	0	0	0	0	0	0	0	0	0	0	0
	Total % Growth			#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
	% Capacity			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Summer	13444	Summer	0	0	0	0	0	0	0	0	0	0	0
	Total % Growth			#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
	% Capacity			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0
	EV													
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0
R16 (Future)	Winter	40000	Winter	0	0	0	0	0	0	0	0	0	0	0
	Total % Growth			#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
	% Capacity			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Summer	32000	Summer	0	0	0	0	0	0	0	0	0	0	0
	Total % Growth			#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
	% Capacity			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0
	EV													
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0
Carmi 12kV	Winter	40000	Winter	18911	19060	19231	19424	19640	19871	20142	20453	20805	21199	21635
	Total % Growth			0.68%	0.79%	0.90%	1.00%	1.11%	1.18%	1.36%	1.54%	1.72%	1.89%	2.06%
	% Capacity			47.28%	47.65%	48.08%	48.56%	49.10%	49.68%	50.36%	51.13%	52.01%	53.00%	54.09%
	Summer	32000	Summer	20750	20952	21177	21425	21697	21974	22292	22651	23053	23497	23985
	Total % Growth			0.87%	0.97%	1.07%	1.17%	1.27%	1.28%	1.45%	1.61%	1.77%	1.93%	2.08%
	% Capacity			64.84%	65.48%	66.18%	66.95%	67.80%	68.67%	69.66%	70.78%	72.04%	73.43%	74.95%
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0
	EV			318	426	559	717	901	1131	1406	1729	2099	2518	2986
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0

Feeder		Forecasted Peak Loads (kVA) for Years 6-26 (cont.)										Expected Year 6-26 Growth
		Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	
		2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	
R10	Winter	3353	3520	3700	3895	4091	4289	4488	4690	4894	5099	
	Total % Growth	4.79%	4.97%	5.12%	5.25%	5.03%	4.84%	4.66%	4.49%	4.34%	4.20%	
	% Capacity	24.64%	25.86%	27.19%	28.61%	30.05%	31.51%	32.98%	34.46%	35.95%	37.46%	
	Summer	4753	4938	5138	5351	5567	5785	6005	6227	6451	6677	1.00%
	Total % Growth	3.76%	3.91%	4.04%	4.16%	4.03%	3.91%	3.80%	3.70%	3.60%	3.51%	
	% Capacity	43.65%	45.35%	47.18%	49.15%	51.13%	53.13%	55.15%	57.18%	59.24%	61.32%	
	Developments	0	0	0	0	0	0	0	0	0	0	
	EV	905	1052	1212	1387	1563	1740	1920	2101	2283	2468	
	Load Transfers	0	0	0	0	0	0	0	0	0	0	
R11	Winter	7353	7453	3561	3673	3786	3901	4016	4132	4250	4368	
	Total % Growth	1.26%	1.35%	-52.22%	3.15%	3.08%	3.02%	2.96%	2.90%	2.84%	2.79%	
	% Capacity	54.02%	54.76%	26.16%	26.99%	27.82%	28.66%	29.50%	30.36%	31.22%	32.09%	
	Summer	4730	4835	948	1058	1168	1280	1393	1507	1621	1737	0.31%
	Total % Growth	2.09%	2.22%	-80.39%	11.55%	10.45%	9.55%	8.80%	8.17%	7.62%	7.15%	
	% Capacity	43.44%	44.40%	8.71%	9.71%	10.73%	11.76%	12.79%	13.84%	14.89%	15.95%	
	Developments	0	0	0	0	0	0	0	0	0	0	
	EV	565	657	758	867	977	1088	1200	1313	1427	1542	
	Load Transfers	0	0	-4000	0	0	0	0	0	0	0	
R12	Winter	7415	7515	7623	7739	7857	7976	8096	8217	8339	8462	
	Total % Growth	1.25%	1.34%	1.44%	1.53%	1.52%	1.51%	1.50%	1.49%	1.49%	1.48%	
	% Capacity	54.48%	55.21%	56.00%	56.86%	57.73%	58.60%	59.48%	60.37%	61.27%	62.17%	
	Summer	7585	7699	7821	7952	8084	8217	8352	8487	8624	8762	0.31%
	Total % Growth	1.41%	1.50%	1.59%	1.68%	1.66%	1.65%	1.64%	1.62%	1.61%	1.60%	
	% Capacity	69.65%	70.70%	71.83%	73.03%	74.24%	75.47%	76.70%	77.95%	79.20%	80.47%	
	Developments	0	0	0	0	0	0	0	0	0	0	
	EV	565	657	758	867	977	1088	1200	1313	1427	1542	
	Load Transfers	0	0	0	0	0	0	0	0	0	0	
R13	Winter	2797	2891	2994	3105	3218	3332	3446	3562	3679	3797	
	Total % Growth	3.18%	3.38%	3.56%	3.72%	3.62%	3.53%	3.44%	3.36%	3.28%	3.20%	
	% Capacity	20.55%	21.24%	22.00%	22.82%	23.64%	24.48%	25.32%	26.17%	27.03%	27.89%	
	Summer	6043	6152	6269	6396	6523	6651	6781	6912	7043	7176	0.31%
	Total % Growth	1.70%	1.81%	1.91%	2.01%	1.99%	1.97%	1.95%	1.93%	1.91%	1.89%	
	% Capacity	55.50%	56.50%	57.58%	58.74%	59.91%	61.08%	62.27%	63.47%	64.68%	65.90%	
	Developments	0	0	0	0	0	0	0	0	0	0	
	EV	565	657	758	867	977	1088	1200	1313	1427	1542	
	Load Transfers	0	0	0	0	0	0	0	0	0	0	
R14	Winter	4936	5088	5253	5432	5613	5795	5979	6164	6352	6541	
	Total % Growth	2.89%	3.07%	3.25%	3.41%	3.32%	3.25%	3.17%	3.10%	3.04%	2.98%	
	% Capacity	27.42%	28.27%	29.18%	30.18%	31.18%	32.19%	33.22%	34.25%	35.29%	36.34%	
	Summer	4905	5052	5212	5387	5563	5740	5920	6101	6283	6468	0.31%
	Total % Growth	2.81%	3.00%	3.18%	3.34%	3.27%	3.19%	3.12%	3.06%	3.00%	2.94%	
	% Capacity	34.06%	35.08%	36.20%	37.41%	38.63%	39.86%	41.11%	42.37%	43.63%	44.92%	
	Developments	0	0	0	0	0	0	0	0	0	0	
	EV	905	1052	1212	1387	1563	1740	1920	2101	2283	2468	
	Load Transfers	0	0	0	0	0	0	0	0	0	0	
R15	Winter	0	0	0	0	0	0	0	0	0	0	
	Total % Growth	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
	% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Summer	0	0	0	0	0	0	0	0	0	0	0.31%
	Total % Growth	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
	% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Developments	0	0	0	0	0	0	0	0	0	0	
	EV											
	Load Transfers	0	0	0	0	0	0	0	0	0	0	
R16 (Future)	Winter	0	0	0	0	0	0	0	0	0	0	
	Total % Growth	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
	% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Summer	0	0	0	0	0	0	0	0	0	0	0.31%
	Total % Growth	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
	% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Developments	0	0	0	0	0	0	0	0	0	0	
	EV											
	Load Transfers	0	0	0	0	0	0	0	0	0	0	
Carmi 12kV	Winter	22115	22639	19786	20396	21012	21634	22261	22894	23533	24178	
	Total % Growth	2.22%	2.37%	-12.60%	3.08%	3.02%	2.96%	2.90%	2.84%	2.79%	2.74%	
	% Capacity	55.29%	56.60%	49.46%	50.99%	52.53%	54.08%	55.65%	57.24%	58.83%	60.45%	
	Summer	24518	25097	22220	22881	23548	24221	24900	25585	26276	26974	0.59%
	Total % Growth	2.22%	2.36%	-11.46%	2.97%	2.91%	2.86%	2.80%	2.75%	2.70%	2.66%	
	% Capacity	76.62%	78.43%	69.44%	71.50%	73.59%	75.69%	77.81%	79.95%	82.11%	84.29%	
	Developments	0	0	0	0	0	0	0	0	0	0	
	EV	3505	4075	4697	5373	6055	6743	7438	8140	8848	9563	
	Load Transfers	0	0	-4000	0	0	0	0	0	0	0	

Feeder	Capacity	Season	Historical Loads					Forecasted Peak Loads (kVA) for Years 0-5						Expected Base Growth Year 1-5
								Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	
			2016	2017	2018	2019		2020	2021	2022	2023	2024	2025	
R21	16806	Winter	4752	4968	4399	6635	Winter	6685	6718	6754	6794	6836	6881	0.59%
							Total % Growth		0.50%	0.54%	0.58%	0.62%	0.66%	
							% Capacity	39.78%	39.98%	40.19%	40.42%	40.68%	40.94%	
	13444	Summer	5464	5284	4787	5923	Summer	6314	6358	6406	6456	6510	6567	
							Total %Growth		0.70%	0.75%	0.79%	0.83%	0.87%	
							% Capacity	46.96%	47.29%	47.65%	48.02%	48.42%	48.85%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	11	18	28	41	57	76	
							Load Transfers	0	0	0	0	0	0	
R22	13611	Winter	1448	1474	2868	3839	Winter	3859	3869	3880	3893	3908	3924	0.37%
							Total % Growth		0.26%	0.30%	0.34%	0.37%	0.41%	
							% Capacity	28.35%	28.42%	28.51%	28.60%	28.71%	28.83%	
	10889	Summer	1675	1757	4114	4258	Summer	4263	4283	4304	4326	4350	4375	
							Total %Growth		0.45%	0.49%	0.52%	0.55%	0.58%	
							% Capacity	39.15%	39.33%	39.52%	39.73%	39.95%	40.18%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	
							Load Transfers	0	0	0	0	0	0	
R23	13611	Winter	5555	5381	3558	3989	Winter	4009	4019	4031	4045	4059	4075	0.37%
							Total % Growth		0.26%	0.29%	0.33%	0.36%	0.40%	
							% Capacity	29.45%	29.53%	29.62%	29.71%	29.82%	29.94%	
	10889	Summer	5344	5270	3751	4025	Summer	4030	4049	4069	4090	4113	4138	
							Total %Growth		0.46%	0.49%	0.53%	0.56%	0.60%	
							% Capacity	37.01%	37.18%	37.37%	37.56%	37.77%	38.00%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	
							Load Transfers	0	0	0	0	0	0	
R24	13611	Winter	6662	6606	4238	3815	Winter	3846	3867	3890	3915	3943	3974	0.59%
							Total % Growth		0.54%	0.60%	0.65%	0.71%	0.77%	
							% Capacity	28.26%	28.41%	28.58%	28.77%	28.97%	29.19%	
	10889	Summer	6661	5137	3261	2636	Summer	2645	2666	2690	2716	2744	2775	
							Total %Growth		0.81%	0.89%	0.97%	1.05%	1.13%	
							% Capacity	24.29%	24.48%	24.70%	24.94%	25.20%	25.49%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	9	14	23	33	46	61	
							Load Transfers	0	0	0	0	0	0	
Waterford 12kV	40000	Winter	20134	20527	15734	14827	Winter	17909	17981	18062	18150	18247	18352	0.51%
							Total % Growth		0.41%	0.45%	0.49%	0.53%	0.58%	
							% Capacity	44.77%	44.95%	45.15%	45.38%	45.62%	45.88%	
	32000	Summer	18988	17345	15824	14920	Summer	16670	16770	16878	16994	17119	17252	
							Total %Growth		0.60%	0.64%	0.69%	0.73%	0.78%	
							% Capacity	52.09%	52.41%	52.74%	53.11%	53.50%	53.91%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	30	51	79	115	160	213	
							Load Transfers	0	0	0	0	0	0	

Feeder		Capacity	Season	Forecasted Peak Loads (kVA) for Years 6-26									
				Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
				2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
R21	Winter	16806	Winter	6934	6996	7065	7143	7229	7330	7446	7578	7724	7887
	Total % Growth			0.77%	0.88%	0.99%	1.10%	1.21%	1.40%	1.58%	1.76%	1.94%	2.10%
	% Capacity			41.26%	41.63%	42.04%	42.50%	43.02%	43.62%	44.31%	45.09%	45.96%	46.93%
	Summer	13444	Summer	6632	6705	6787	6877	6975	7089	7217	7361	7521	7696
	Total % Growth			0.99%	1.10%	1.22%	1.33%	1.43%	1.63%	1.81%	1.99%	2.17%	2.33%
	% Capacity			49.33%	49.87%	50.48%	51.15%	51.88%	52.73%	53.68%	54.75%	55.94%	57.24%
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0
	EV			103	137	180	231	291	365	454	558	677	812
	Load Transfers			0	0	0	0	0	0	0	0	0	0
R22	Winter	13611	Winter	3944	3967	3995	4028	4064	4107	4159	6217	6287	6364
	Total % Growth			0.51%	0.61%	0.70%	0.80%	0.90%	1.07%	1.24%	49.50%	1.12%	1.23%
	% Capacity			28.97%	29.15%	29.35%	29.59%	29.86%	30.18%	30.55%	45.68%	46.19%	46.76%
	Summer	10889	Summer	4404	4438	4475	4517	4563	4616	4677	6745	6829	6920
	Total % Growth			0.67%	0.76%	0.84%	0.93%	1.02%	1.17%	1.32%	44.23%	1.24%	1.34%
	% Capacity			40.45%	40.75%	41.10%	41.48%	41.90%	42.39%	42.95%	61.95%	62.71%	63.55%
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0
	EV			51	69	90	116	145	182	227	279	339	406
	Load Transfers			0	0	0	0	0	0	0	2000	0	0
R23	Winter	16806	Winter	4096	4120	4148	4180	4217	4261	4312	4371	4438	4512
	Total % Growth			0.49%	0.59%	0.68%	0.78%	0.88%	1.04%	1.20%	1.37%	1.52%	1.68%
	% Capacity			30.09%	30.27%	30.48%	30.71%	30.98%	31.30%	31.68%	32.11%	32.60%	33.15%
	Summer	13444	Summer	4166	4199	4235	4276	4321	4373	4433	4501	4576	4659
	Total % Growth			0.69%	0.78%	0.87%	0.96%	1.05%	1.21%	1.37%	1.52%	1.67%	1.82%
	% Capacity			38.26%	38.56%	38.90%	39.27%	39.68%	40.16%	40.71%	41.33%	42.03%	42.79%
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0
	EV			51	69	90	116	145	182	227	279	339	406
	Load Transfers			0	0	0	0	0	0	0	0	0	0
R24	Winter	13611	Winter	4010	4053	4103	4159	4222	4297	4384	4482	4594	4718
	Total % Growth			0.92%	1.07%	1.22%	1.37%	1.52%	1.77%	2.02%	2.26%	2.48%	2.70%
	% Capacity			29.46%	29.78%	30.14%	30.56%	31.02%	31.57%	32.21%	32.93%	33.75%	34.66%
	Summer	10889	Summer	2813	2857	2907	2964	3028	3104	3192	3291	3404	3529
	Total % Growth			1.35%	1.56%	1.77%	1.97%	2.16%	2.50%	2.83%	3.13%	3.41%	3.67%
	% Capacity			25.83%	26.23%	26.70%	27.22%	27.81%	28.50%	29.31%	30.23%	31.26%	32.41%
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0
	EV			82	110	144	185	233	292	363	446	542	650
	Load Transfers			0	0	0	0	0	0	0	0	0	0
Waterford 12kV	Winter	40000	Winter	18478	18627	18797	18991	19207	19463	19760	22045	22429	22856
	Total % Growth			0.69%	0.80%	0.92%	1.03%	1.14%	1.33%	1.53%	11.56%	1.74%	1.90%
	% Capacity			46.20%	46.57%	46.99%	47.48%	48.02%	48.66%	49.40%	55.11%	56.07%	57.14%
	Summer	32000	Summer	17407	17584	17783	18004	18249	18534	18860	21159	21575	22034
	Total % Growth			0.90%	1.02%	1.13%	1.25%	1.36%	1.56%	1.76%	12.19%	1.97%	2.13%
	% Capacity			54.40%	54.95%	55.57%	56.26%	57.03%	57.92%	58.94%	66.12%	67.42%	68.86%
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0
	EV			288	385	505	648	814	1021	1270	1562	1896	2274
	Load Transfers			0	0	0	0	0	0	0	2000	0	0

Feeder		Forecasted Peak Loads (kVA) for Years 6-26 (cont.)											Expected Year 6-26 Growth
		Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	
		2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	
R21	Winter	8065	8260	8472	8701	8947	9195	9445	9697	9952	10209	10468	0.59%
	Total % Growth	2.26%	2.42%	2.56%	2.70%	2.83%	2.77%	2.72%	2.67%	2.63%	2.58%	2.54%	
	% Capacity	47.99%	49.15%	50.41%	51.77%	53.24%	54.71%	56.20%	57.70%	59.22%	60.75%	62.29%	
	Summer	7888	8096	8321	8563	8822	9084	9348	9615	9883	10155	10428	
	Total % Growth	2.49%	2.64%	2.78%	2.91%	3.03%	2.97%	2.91%	2.85%	2.80%	2.74%	2.69%	
	% Capacity	58.67%	60.22%	61.89%	63.69%	65.62%	67.57%	69.53%	71.51%	73.51%	75.53%	77.57%	
	Developments	0	0	0	0	0	0	0	0	0	0	0	
	EV	963	1131	1315	1515	1733	1953	2175	2399	2626	2854	3085	
	Load Transfers	0	0	0	0	0	0	0	0	0	0	0	
R22	Winter	6450	6544	6646	6756	6875	6995	7116	7239	7362	7486	7612	0.37%
	Total % Growth	1.34%	1.45%	1.56%	1.66%	1.76%	1.75%	1.73%	1.72%	1.70%	1.69%	1.68%	
	% Capacity	47.39%	48.08%	48.83%	49.64%	50.51%	51.39%	52.28%	53.18%	54.09%	55.00%	55.92%	
	Summer	7020	7128	7244	7368	7502	7636	7772	7908	8046	8185	8325	
	Total % Growth	1.44%	1.53%	1.63%	1.72%	1.81%	1.79%	1.78%	1.76%	1.74%	1.73%	1.71%	
	% Capacity	64.47%	65.46%	66.52%	67.67%	68.89%	70.13%	71.37%	72.63%	73.89%	75.17%	76.46%	
	Developments	0	0	0	0	0	0	0	0	0	0	0	
	EV	482	565	657	758	867	977	1088	1200	1313	1427	1542	
	Load Transfers	0	0	0	0	0	0	0	0	0	0	0	
R23	Winter	4595	4685	4784	4891	5007	5124	5242	5361	5481	5603	5725	0.37%
	Total % Growth	1.83%	1.97%	2.11%	2.24%	2.37%	2.34%	2.30%	2.27%	2.24%	2.21%	2.18%	
	% Capacity	33.76%	34.42%	35.15%	35.94%	36.79%	37.65%	38.51%	39.39%	40.27%	41.16%	42.06%	
	Summer	4750	4850	4958	5074	5199	5325	5452	5580	5709	5840	5971	
	Total % Growth	1.96%	2.09%	2.22%	2.34%	2.46%	2.42%	2.39%	2.35%	2.32%	2.28%	2.25%	
	% Capacity	43.63%	44.54%	45.53%	46.60%	47.74%	48.90%	50.07%	51.24%	52.43%	53.63%	54.84%	
	Developments	0	0	0	0	0	0	0	0	0	0	0	
	EV	482	565	657	758	867	977	1088	1200	1313	1427	1542	
	Load Transfers	0	0	0	0	0	0	0	0	0	0	0	
R24	Winter	4854	5004	5167	3344	3526	3711	3897	4084	4274	4465	4658	0.59%
	Total % Growth	2.90%	3.09%	3.26%	-35.29%	5.46%	5.23%	5.01%	4.82%	4.64%	4.47%	4.32%	
	% Capacity	35.66%	36.76%	37.96%	24.57%	25.91%	27.26%	28.63%	30.01%	31.40%	32.80%	34.22%	
	Summer	3666	3817	3982	2160	2339	2521	2704	2889	3076	3265	3455	
	Total % Growth	3.91%	4.12%	4.30%	-45.76%	8.33%	7.76%	7.27%	6.84%	6.46%	6.13%	5.83%	
	% Capacity	33.67%	35.06%	36.57%	19.83%	21.48%	23.15%	24.84%	26.54%	28.25%	29.98%	31.73%	
	Developments	0	0	0	0	0	0	0	0	0	0	0	
	EV	771	905	1052	1212	1387	1563	1740	1920	2101	2283	2468	
	Load Transfers	0	0	0	-2000	0	0	0	0	0	0	0	
Waterford 12kV	Winter	23326	23841	24402	23061	23707	24359	25016	25680	26349	27024	27706	0.51%
	Total % Growth	2.06%	2.21%	2.35%	-5.49%	2.80%	2.75%	2.70%	2.65%	2.61%	2.56%	2.52%	
	% Capacity	58.32%	59.60%	61.00%	57.65%	59.27%	60.90%	62.54%	64.20%	65.87%	67.56%	69.26%	
	Summer	22537	23084	23676	22382	23056	23736	24422	25114	25813	26517	27228	
	Total % Growth	2.28%	2.43%	2.57%	-5.47%	3.01%	2.95%	2.89%	2.83%	2.78%	2.73%	2.68%	
	% Capacity	70.43%	72.14%	73.99%	69.94%	72.05%	74.18%	76.32%	78.48%	80.66%	82.87%	85.09%	
	Developments	0	0	0	0	0	0	0	0	0	0	0	
	EV	2697	3166	3681	4243	4853	5469	6091	6718	7352	7992	8637	
	Load Transfers	0	0	0	-2000	0	0	0	0	0	0	0	

			Historical Loads					Forecasted Peak Loads (kVA) for Years 0-5						
								Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	
Feeder	Capacity	Season	2016	2017	2018	2019		2020	2021	2022	2023	2024	2025	Expected Base Growth Year 1-5
R31	13611	Winter	4383	1845		1000	Winter	1017	1031	1046	1062	1080	1100	1.17%
							Total % Growth		1.33%	1.46%	1.58%	1.70%	1.82%	
							% Capacity	7.47%	7.57%	7.68%	7.80%	7.94%	8.08%	
	10889	Summer	5438	2564		1000	Summer	1005	1021	1038	1056	1076	1098	
							Total %Growth		1.53%	1.66%	1.78%	1.90%	2.02%	
							% Capacity	9.23%	9.37%	9.53%	9.70%	9.88%	10.08%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	
							Load Transfers	0	0	0	0	0	0	
R32	16806	Winter	4770	4744	5870	5753	Winter	6476	6498	6522	6547	6574	6603	0.49%
							Total % Growth		0.34%	0.37%	0.39%	0.41%	0.43%	
							% Capacity	38.53%	38.67%	38.81%	38.96%	39.12%	39.29%	
	13444	Summer	6458	4634	4729	5516	Summer	6463	6499	6535	6574	6614	6655	
							Total %Growth		0.54%	0.57%	0.59%	0.61%	0.63%	
							% Capacity	48.07%	48.34%	48.61%	48.90%	49.19%	49.50%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	
							Load Transfers	0	0	0	0	0	0	
R33	14500	Winter	6469	6527	6271	4827	Winter	4920	4998	5082	5172	5267	5368	1.56%
							Total % Growth		1.60%	1.68%	1.76%	1.84%	1.92%	
							% Capacity	33.93%	34.47%	35.05%	35.67%	36.32%	37.02%	
	11600	Summer	6530	5979	6328	4327	Summer	4344	4424	4509	4599	4696	4798	
							Total %Growth		1.83%	1.92%	2.01%	2.10%	2.18%	
							% Capacity	37.45%	38.13%	38.87%	39.65%	40.48%	41.36%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	17	29	45	66	91	122	
							Load Transfers	0	0	0	0	0	0	
R34	16806	Winter	6493	6523	6462	6492	Winter	6622	6705	6792	6884	6980	7082	1.30%
							Total % Growth		1.25%	1.30%	1.35%	1.40%	1.45%	
							% Capacity	39.40%	39.90%	40.41%	40.96%	41.54%	42.14%	
	13444	Summer	6081	5817	6438	6189	Summer	6493	6587	6686	6790	6899	7013	
							Total %Growth		1.45%	1.50%	1.56%	1.61%	1.66%	
							% Capacity	48.29%	48.99%	49.73%	50.50%	51.31%	52.16%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	14	24	38	55	76	101	
							Load Transfers	0	0	0	0	0	0	
R35 (Future)	16806	Winter	0	0	0	0	Winter	0	0	0	0	0	0	0.650%
							Total % Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	13444	Summer	0	0	0	0	Summer	0	0	0	0	0	0	
							Total %Growth		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
							% Capacity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV							
							Load Transfers	0	0	0	0	0	0	
R36	18000	Winter	1593	4449	4950	5172	Winter	5203	5221	5241	5263	5286	5311	0.49%
							Total % Growth		0.36%	0.39%	0.41%	0.44%	0.47%	
							% Capacity	28.90%	29.01%	29.12%	29.24%	29.37%	29.50%	
	14400	Summer	1990	4583	4510	4017	Summer	4588	4614	4642	4671	4702	4734	
							Total %Growth		0.57%	0.60%	0.63%	0.66%	0.69%	
							% Capacity	31.86%	32.04%	32.24%	32.44%	32.65%	32.88%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	5	9	14	21	29	38	
							Load Transfers	0	0	0	0	0	0	
Westminster 12kV	40000	Winter	21958	18526	18905	19000	Winter	23702	23913	24139	24378	24632	24901	0.95%
							Total % Growth		0.89%	0.94%	0.99%	1.04%	1.09%	
							% Capacity	59.26%	59.78%	60.35%	60.95%	61.58%	62.25%	
	32000	Summer	27057	15817	18721	16672	Summer	21797	22036	22288	22556	22838	23135	
							Total %Growth		1.09%	1.15%	1.20%	1.25%	1.30%	
							% Capacity	68.12%	68.86%	69.65%	70.49%	71.37%	72.30%	
	Δ Load						Developments	0	0	0	0	0	0	
							EV	48	80	125	182	253	337	
							Load Transfers	0	0	0	0	0	0	
System	145900	Winter	70906	66206	64620	66450	Winter	67642	68253	68395	68818	70173	69760	0.66%
							Total % Growth		0.90%	0.21%	0.62%	1.97%	-0.59%	
							% Capacity	46.36%	46.78%	46.88%	47.17%	43.86%	47.81%	
	121900	Summer	63513	71498	66638	64600	Summer	66543	67277	67543	68091	69572	69286	
							Total %Growth		1.10%	0.39%	0.81%	2.18%	-0.41%	
							% Capacity	54.59%	55.19%	55.41%	55.86%	54.35%	56.84%	
	Δ Load						Developments	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	
							EV	138	232	362	528	733	975	
							D.E.R.	-	(300.0)	-	-	(1,080.0)	-	
							Load Transfers	0	0	0	0	0	0	

				Forecasted Peak Loads (kVA) for Years 6-26																					
				Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	
Feeder		Capacity	Season	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	Expected Year 6-26 Growth
R31	Winter	13611	Winter	1124	1151	1183	1220	1260	1308	1363	1426	1497	1576	1663	1758	1862	1974	2095	2217	2340	2464	2589	2716	2844	1.17%
	Total % Growth			2.15%	2.47%	2.77%	3.06%	3.32%	3.80%	4.24%	4.63%	4.97%	5.27%	5.52%	5.72%	5.89%	6.02%	6.12%	5.82%	5.55%	5.31%	5.09%	4.89%	4.71%	
	% Capacity			8.26%	8.46%	8.69%	8.96%	9.26%	9.61%	10.02%	10.48%	11.00%	11.58%	12.22%	12.92%	13.68%	14.50%	15.39%	16.29%	17.19%	18.10%	19.02%	19.96%	20.89%	
	Summer	10889	Summer	1124	1154	1188	1226	1269	1319	1377	1443	1516	1597	1687	1785	1891	2006	2129	2254	2380	2508	2636	2766	2897	
	Total % Growth			2.35%	2.66%	2.96%	3.23%	3.49%	3.96%	4.38%	4.76%	5.09%	5.37%	5.60%	5.80%	5.95%	6.07%	6.16%	5.86%	5.59%	5.35%	5.12%	4.92%	4.74%	
	% Capacity			10.32%	10.60%	10.91%	11.26%	11.66%	12.12%	12.65%	13.25%	13.92%	14.67%	15.49%	16.39%	17.37%	18.42%	19.56%	20.70%	21.86%	23.03%	24.21%	25.40%	26.60%	
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EV			51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
R32	Winter	16806	Winter	6635	6671	6712	6756	6805	6862	6925	6997	7076	7163	7258	7361	7473	2593	2707	2822	2939	3056	3175	3294	3415	0.49%
	Total % Growth			0.49%	0.55%	0.61%	0.67%	0.72%	0.83%	0.93%	1.03%	1.13%	1.23%	1.33%	1.42%	1.52%	-65.30%	4.41%	4.26%	4.12%	4.00%	3.88%	3.77%	3.66%	
	% Capacity			39.48%	39.70%	39.94%	40.20%	40.49%	40.83%	41.21%	41.63%	42.10%	42.62%	43.19%	43.80%	44.47%	15.43%	16.11%	16.79%	17.49%	18.19%	18.89%	19.60%	20.32%	
	Summer	13444	Summer	6701	6751	6805	6863	6926	6996	7074	7160	7253	7354	7464	7582	7708	2843	2962	3082	3204	3326	3450	3574	3700	
	Total % Growth			0.69%	0.74%	0.80%	0.86%	0.91%	1.01%	1.11%	1.21%	1.30%	1.40%	1.49%	1.58%	1.67%	-63.12%	4.19%	4.06%	3.94%	3.82%	3.71%	3.61%	3.52%	
	% Capacity			49.84%	50.21%	50.62%	51.05%	51.52%	52.04%	52.62%	53.25%	53.95%	54.70%	55.52%	56.39%	57.33%	21.14%	22.03%	22.93%	23.83%	24.74%	25.66%	26.58%	27.52%	
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EV			51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0	0	0	-5000	0	0	0	0	0	0	0	
R33	Winter	14500	Winter	5482	5610	5752	5909	6080	6275	6495	2383	2523	2678	2849	3036	3239	3459	3695	3934	4175	4419	4665	4914	5165	1.56%
	Total % Growth			2.13%	2.34%	2.53%	2.72%	2.89%	3.21%	3.50%	-63.31%	5.87%	6.15%	6.38%	6.56%	6.69%	6.78%	6.84%	6.47%	6.13%	5.84%	5.57%	5.33%	5.11%	
	% Capacity			37.81%	38.69%	39.67%	40.75%	41.93%	43.27%	44.79%	16.43%	17.40%	18.47%	19.65%	20.94%	22.34%	23.85%	25.48%	27.13%	28.80%	30.48%	32.17%	33.89%	35.62%	
	Summer	11600	Summer	4914	5044	5188	5346	5519	5717	5939	1830	1965	2115	2281	2463	2661	2876	3107	3341	3577	3816	4057	4300	4546	
	Total % Growth			2.42%	2.64%	2.85%	3.05%	3.24%	3.58%	3.89%	-69.18%	7.37%	7.65%	7.84%	7.97%	8.04%	8.06%	8.05%	7.52%	7.07%	6.67%	6.31%	6.00%	5.72%	
	% Capacity			42.36%	43.48%	44.72%	46.09%	47.58%	49.28%	51.20%	15.78%	16.94%	18.24%	19.67%	21.23%	22.94%	24.79%	26.79%	28.80%	30.84%	32.89%	34.97%	37.07%	39.19%	
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EV			164	220	288	370	465	584	726	535	650	780	925	1085	1262	1455	1664	1875	2088	2303	2521	2740	2961	
	Load Transfers			0	0	0	0	0	0	0	-4000	0	0	0	0	0	0	0	0	0	0	0	0	0	
R34	Winter	16806	Winter	7190	7308	7439	7581	7736	7910	8105	8321	8559	8818	9099	9402	9729	8079	8432	8788	9148	9512	9878	10249	10623	1.23%
	Total % Growth			1.52%	1.65%	1.79%	1.91%	2.04%	2.26%	2.47%	2.67%	2.85%	3.03%	3.19%	3.34%	3.47%	-16.96%	4.37%	4.23%	4.09%	3.97%	3.86%	3.75%	3.65%	
	% Capacity			42.78%	43.49%	44.27%	45.11%	46.03%	47.07%	48.23%	49.51%	50.93%	52.47%	54.14%	55.95%	57.89%	48.07%	50.17%	52.29%	54.44%	56.60%	58.78%	60.98%	63.21%	
	Summer	13444	Summer	7134	7266	7410	7567	7735	7925	8135	8366	8619	8894	9192	9512	9856	8224	8590	8961	9335	9713	10095	10481	10871	
	Total % Growth			1.72%	1.86%	1.99%	2.11%	2.23%	2.45%	2.65%	2.84%	3.02%	3.19%	3.35%	3.49%	3.61%	-16.56%	4.46%	4.31%	4.18%	4.05%	3.93%	3.82%	3.72%	
	% Capacity			53.06%	54.05%	55.12%	56.28%	57.54%	58.94%	60.51%	62.23%	64.11%	66.16%	68.37%	70.75%	73.31%	61.17%	63.90%	66.65%	69.44%	72.25%	75.09%	77.96%	80.86%	
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EV			137	183	240	308	388	486	605	744	903	1083	1284	1508	1753	2020	2311	2604	2900	3199	3501	3806	4113	
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0	0	0	-2000	0	0	0	0	0	0	0	
R35 (Future)	Winter	16806	Winter	0	0	0	0	0	0	0	4357	4465	4584	4713	4853	5004	5166	5339	5513	5690	5867	6047	6228	6411	1.000%
	Total % Growth			#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	2.49%	2.66%	2.82%	2.97%	3.11%	3.23%	3.35%	3.27%	3.20%	3.13%	3.06%	3.00%	2.94%	
	% Capacity			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	25.93%	26.57%	27.28%	28.05%	28.88%	29.78%	30.74%	31.77%	32.81%	33.86%	34.91%	35.98%	37.06%	38.15%	
	Summer	13444	Summer	0	0	0	0	0	0	0	4357	4473	4600	4738	4886	5045	5216	5398	5581	5767	5954	6143	6334	6527	
	Total %Growth			#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	2.67%	2.84%	2.99%	3.13%	3.26%	3.38%	3.49%	3.40%	3.32%	3.25%	3.17%	3.11%	3.04%	
	% Capacity			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	32.41%	33.27%	34.22%	35.24%	36.34%	37.53%	38.80%	40.15%	41.51%	42.89%	44.29%	45.69%	47.11%	48.55%	
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EV										357	433	520	617	724	841	970	1109	1250	1392	1536	1680	1827	1974	
	Load Transfers			0	0	0	0	0	0	0	4000	0	0	0	0	0	0	0	0	0	0	0	0	0	
R36	Winter	18000	Winter	5339	5372	5409	5450	5495	5547	5607	3675	3744	3822	3907	4001	4103	4213	4332	4452	4573	4695	4818	4943	5068	0.49%
	Total % Growth			0.54%	0.61%	0.68%	0.76%	0.83%	0.96%	1.08%	-34.46%	1.89%	2.07%	2.23%	2.39%	2.55%	2.69%	2.82%	2.77%	2.72%	2.67%	2.63%	2.58%	2.54%	
	% Capacity			29.66%	29.84%	30.05%	30.28%	30.53%	30.82%	31.15%	20.42%	20.80%	21.23%	21.71%	22.23%	22.79%	23.41%	24.07%	24.73%	25.41%	26.08%	26.77%	27.46%	28.16%	
	Summer	14400	Summer	4770	4811	4855	4904	4957	5018	5086	3162	3236	3317	3407	3505	3611	3726	3850	3974	4100	4227	4355	4484	4614	
	Total %Growth			0.77%	0.85%	0.93%	1.01%	1.08%	1.22%	1.36%	-37.83%	2.33%	2.53%	2.71%	2.88%	3.03%	3.18%	3.31%	3.24%	3.16%	3.09%	3.03%	2.96%	2.91%	
	% Capacity			33.13%	33.41%	33.72%	34.06%	34.43%	34.85%	35.32%	21.96%	22.47%	23.04%	23.66%	24.34%	25.08%	25.88%	26.73%	27.60%	28.47%	29.35%	30.24%	31.14%	32.04%	
	Developments	Δ Load																							
	EV			51	69	90	116	145	182	227	279	339	406	482	565	657	758	867	977	1088	1200	1313	1427	1542	
	Load Transfers			0	0	0	0	0	0	0	-2000	0	0	0	0	0	0	0	0	0	0	0	0	0	
Westminster 12kV	Winter	40000	Winter	25201	25537	25910	26322	26771	27286	27867	26559	27249	28008	28838	29740	30716	24920	26012	27114	28227	29351	30485	31630	32785	0.95%
	Total % Growth			1.20%	1.33%	1.46%	1.59%	1.71%	1.92%	2.13%	-4.69%	2.60%	2.79%	2.96%	3.13%	3.28%	-18.87%	4.38%	4.24%	4.10%	3.98%	3.86%	3.76%	3.65%	
	% Capacity			63.00%	63.84%	64.78%	65.80%	66.93%	68.21%	69.67%	66.40%	68.12%	70.02%	72.09%	74.35%	76.79%	62.30%	65.03%	67.79%	70.57%	73.38%	76.21%	79.07%	81.96%	
	Summer	32000	Summer	23463	23827	24228	24666	25143	25683	26289	25057	25766	26544	27391	28309	29299	23698	24790	25892	27005	28129	29264	30409	31566	
	Total % Growth			1.42%	1.55%	1.68%	1.81%	1.93%	2.15%	2.36%	-4.69%	2.83%	3.02%	3.19%	3.35%	3.50%	-19.12%	4.61%	4.45%	4.30%	4.16%	4.03%	3.92%	3.80%	
	% Capacity			73.32%	74.46%	75.71%	77.08%	78.57%	80.26%	82.15%	78.30%	80.52%	82.95%	85.60%	88.47%	91.56%	74.06%	77.47%	80.91%	84.39%	87.90%	91.45%	95.03%	98.65%	
	Developments	Δ Load		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EV			455	609	799	1025	1289	1617	2011	2472	3002	3601	4271	5012	5828	6718	7684	8659	9644	10637	11641	12654	13676	
	Load Transfers			0	0	0	0	0	0	0	-2000	0	0	0	0	0	-7000	0	0	0	0	0	0	0	
System	Winter	160000	Winter	70221	70829	71511	72268	73103	74050	75132	76342	77679	79158	80780	82549	84467	86718	88932	91167	93422	95697	97993	100310	102649	0.66%
	Total % Growth			0.66%	0.87%	0.96%	1.06%	1.16%	1.30%	1.46%	1.61%	1.75%	1.90%	2.05%	2.19%	2.32%	2.67%	2.55%	2.51%	2.47%	2.44%	2.40%	2.36%	2.33%	
	% Capacity			43.89%	44.27%	44.69%	45.17%	45.69%	46.28%	46.96%	47.71%	48.55%	49.47%	50.49%	51.59%	52.79%	54.20%	55.58%	56.98%	58.39%	59.81%	61.25%	62.69%	64.16%	
	Summer	128000	Summer	69876	70613	71425	72314	73280	74350	75555	76920	78382	79985	81733	83627	85672	88167	90509	92873	95258	97665	100095	102546	105020	
	Total % Growth			0.85%	1.05%	1.15%	1.24%	1.34%	1.46%	1.62%	1.81%	1.90%	2.05%	2.18%	2.32%	2.44%	2.91%	2.66%	2.61%	2.57%	2.53%	2.49%	2.45%	2.41%	
	% Capacity			54.59%	55.17%	55.80%	56.49%	57.25%	58.09%	59.03%	60.09%	61.24%	62.49%	63.85%	65.33%	66.93%	68.88%	70.71%	72.56%	74.42%	76.30%	78.20%	80.11%	82.05%	
	Developments	Δ Load		#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	
	EV			1190	1586	2075	2657	3334	4177	5188	6371	7728	9263	10979	12880	14968	17248	19722	22220	24741	27287	29857	32452	35071	
	D.E.R.			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Load Transfers			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	4	5	6	

E

Appendix E
Electric Vehicle Methodology

Market Share Prediction Method

Registered Canadian Cars	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	23,006,222	23,538,817	23,923,806	24,269,868	24,566,696	25,008,897	25,459,057	25,917,320	26,383,831	26,858,740	27,342,198
Canadian Vehicle Sales	-	1,890,387	1,939,517	1,983,745	2,076,945	2,035,832	1,961,298	1,232,126	2,000,110	2,019,111	2,038,292
BC Sales based on Canadian Sales & Population		255,202	261,835	267,806	280,388	274,837	264,775	166,337	270,015	272,580	275,169
PEN Sales based on Population		1,700	1,744	1,784	1,867	1,830	1,763	1,108	1,798	1,815	1,833
EV Market Share - Canada		0.28%	0.36%	0.56%	0.95%	2.17%	2.75%	4.9%	5.6%	6.0%	6.0%
EV Market Share - BC		0.29%	0.57%	0.67%	1.19%	3.07%	7.41%	7.90%	8.25%	8.75%	9.20%
EV Market Share - PEN		0.06%	0.11%	0.39%	0.48%	0.98%	2.00%	3.00%	4.00%	5.50%	7.00%
EV Sales based on Market Share	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Canada		5,356	7,072	11,060	19,645	44,175	53,931	60,403	112,006	121,147	122,298
BC		730	1,500	1,800	3,329	8,449	19,613	13,141	22,276	23,851	25,316
PEN	1	1	2	7	9	18	35	33	72	100	128
Total EVs based on Market Share	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Canada	6000	11,356	18,428	29,488	49,133	93,308	147,239	207,642	319,648	440,794	563,092
BC	970	1,700	3,200	5,000	8,329	16,778	36,391	49,532	71,808	95,659	120,974
PEN	1	2	4	11	20	38	73	107	178	278	407
EV Percentage of Total Cars (PEN)	0.00%	0.01%	0.01%	0.04%	0.07%	0.13%	0.25%	0.36%	0.60%	0.94%	1.36%
BC % Error	-	-	-	-							
Souther Interior % Erro	-	-	-	-							
Penticton Error	-	-	-	-							

Registered Canadian Cars	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	27,615,620	27,891,776	28,170,694	28,452,401	28,736,925	29,024,294	29,314,537	29,607,682	29,903,759	30,202,797	30,504,825
Canadian Vehicle Sales	2,057,656	2,077,204	2,096,937	2,116,858	2,136,968	2,157,269	2,177,763	2,198,452	2,219,337	2,240,421	2,261,705
BC Sales based on Canadian Sales & Population	277,784	280,422	283,087	285,776	288,491	291,231	293,998	296,791	299,611	302,457	305,330
PEN Sales based on Population	1,850	1,868	1,885	1,903	1,921	1,940	1,958	1,977	1,995	2,014	2,033
EV Market Share - Canada	6.5%	6.8%	7.0%	7.3%	7.5%	7.6%	7.7%	7.7%	7.8%	7.9%	7.0%
EV Market Share - BC	9.60%	10.00%	14.00%	18.00%	22.00%	26.00%	30.00%	37.00%	44.00%	51.00%	58.00%
EV Market Share - PEN	8.50%	10.00%	14.00%	18.00%	22.00%	26.00%	30.00%	37.00%	44.00%	51.00%	58.00%
EV Sales based on Market Share	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Canada	133,748	140,211	146,786	153,472	160,273	163,952	167,688	169,281	173,108	176,993	158,319
BC	26,667	28,042	39,632	51,440	63,468	75,720	88,199	109,813	131,829	154,253	177,092
PEN	157	187	264	343	423	504	587	731	878	1,027	1,179
Total EVs based on Market Share	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Canada	696,840	837,051	983,837	1,137,309	1,297,581	1,461,534	1,629,222	1,798,502	1,971,611	2,148,604	2,306,923
BC	147,641	175,684	215,316	266,755	330,223	405,943	494,143	603,956	735,784	890,037	1,067,129
PEN	564	751	1,015	1,357	1,780	2,284	2,872	3,603	4,481	5,508	6,688
EV Percentage of Total Cars (PEN)	1.87%	2.47%	3.32%	4.41%	5.75%	7.33%	9.16%	11.42%	14.11%	17.23%	20.79%
BC % Error											
Souther Interior % Erro											
Penticton Error											

Registered Canadian Cars	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
	30,809,873	31,117,972	31,429,151	31,743,443	32,060,877	32,381,486	32,705,301	33,032,354	33,362,677	33,696,304	34,033,267	34,373,600
Canadian Vehicle Sales	2,283,191	2,304,882	2,326,778	2,348,882	2,371,197	2,393,723	2,416,464	2,439,420	2,462,594	2,485,989	2,509,606	2,533,447
BC Sales based on Canadian Sales & Population	308,231	311,159	314,115	317,099	320,112	323,153	326,223	329,322	332,450	335,609	338,797	342,015
PEN Sales based on Population	2,053	2,072	2,092	2,112	2,132	2,152	2,173	2,193	2,214	2,235	2,256	2,278
EV Market Share - Canada	7.5%	7.6%	7.8%	7.8%	7.9%	8.0%	8.2%	8.4%	8.5%	8.6%	8.8%	9.0%
EV Market Share - BC	65.00%	72.00%	79.00%	86.00%	93.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
EV Market Share - PEN	65.00%	72.00%	79.00%	86.00%	93.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
EV Sales based on Market Share	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**
Canada	171,239	175,171	180,791	183,213	187,325	191,498	198,150	204,911	208,089	213,795	220,845	228,010
BC	200,350	224,034	248,151	272,705	297,704	323,153	326,223	329,322	332,450	335,609	338,797	342,015
PEN	1,334	1,492	1,653	1,816	1,983	2,152	2,173	2,193	2,214	2,235	2,256	2,278
Total EVs based on Market Share	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**
Canada	2,478,163	2,653,334	2,834,124	3,017,337	3,204,662	3,396,160	3,594,310	3,799,221	4,007,310	4,221,105	4,441,951	4,669,961
BC	1,267,479	1,491,513	1,739,664	2,012,369	2,310,073	2,633,226	2,959,448	3,288,770	3,621,220	3,956,829	4,295,626	4,637,641
PEN	8,022	9,514	11,167	12,983	14,966	17,118	19,290	21,484	23,698	25,933	28,189	30,467
EV Percentage of Total Cars (PEN)	24.78%	29.20%	34.05%	39.33%	45.04%	51.19%	57.31%	63.41%	69.50%	75.56%	81.60%	87.63%
BC % Error												
Souther Interior % Erro												
Penticton Error												

EV Load Distribution Throughout COP per Feeder (Market Share)

EV Diversity Factor: 0.9

EV Demand [kW]: 1.5

	Percentage of Load	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
R2	3.75%	0.1	0.1	0.2	0.6	1.0	1.9	3.7	5.4	9.0	14.1	20.6	28.5	38.0	51.4	68.7	90.1	115.6
R3	3.75%	0.1	0.1	0.2	0.6	1.0	1.9	3.7	5.4	9.0	14.1	20.6	28.5	38.0	51.4	68.7	90.1	115.6
R4	3.75%	0.1	0.1	0.2	0.6	1.0	1.9	3.7	5.4	9.0	14.1	20.6	28.5	38.0	51.4	68.7	90.1	115.6
R5	3.75%	0.1	0.1	0.2	0.6	1.0	1.9	3.7	5.4	9.0	14.1	20.6	28.5	38.0	51.4	68.7	90.1	115.6
R6	3.75%	0.1	0.1	0.2	0.6	1.0	1.9	3.7	5.4	9.0	14.1	20.6	28.5	38.0	51.4	68.7	90.1	115.6
R10	12.00%	0.2	0.3	0.6	1.8	3.2	6.2	11.9	17.3	28.9	45.1	65.9	91.3	121.6	164.4	219.9	288.3	370.0
R11	3.75%	0.1	0.1	0.2	0.6	1.0	1.9	3.7	5.4	9.0	14.1	20.6	28.5	38.0	51.4	68.7	90.1	115.6
R12	3.75%	0.1	0.1	0.2	0.6	1.0	1.9	3.7	5.4	9.0	14.1	20.6	28.5	38.0	51.4	68.7	90.1	115.6
R13	3.75%	0.1	0.1	0.2	0.6	1.0	1.9	3.7	5.4	9.0	14.1	20.6	28.5	38.0	51.4	68.7	90.1	115.6
R21	7.50%	0.1	0.2	0.4	1.1	2.0	3.8	7.4	10.8	18.1	28.2	41.2	57.1	76.0	102.7	137.4	180.2	231.3
R22	3.75%	0.1	0.1	0.2	0.6	1.0	1.9	3.7	5.4	9.0	14.1	20.6	28.5	38.0	51.4	68.7	90.1	115.6
R23	3.75%	0.1	0.1	0.2	0.6	1.0	1.9	3.7	5.4	9.0	14.1	20.6	28.5	38.0	51.4	68.7	90.1	115.6
R24	6.00%	0.1	0.2	0.3	0.9	1.6	3.1	5.9	8.6	14.5	22.5	32.9	45.7	60.8	82.2	109.9	144.2	185.0
R31	3.75%	0.1	0.1	0.2	0.6	1.0	1.9	3.7	5.4	9.0	14.1	20.6	28.5	38.0	51.4	68.7	90.1	115.6
R32	3.75%	0.1	0.1	0.2	0.6	1.0	1.9	3.7	5.4	9.0	14.1	20.6	28.5	38.0	51.4	68.7	90.1	115.6
R33	12.00%	0.2	0.3	0.6	1.8	3.2	6.2	11.9	17.3	28.9	45.1	65.9	91.3	121.6	164.4	219.9	288.3	370.0
R34	10.00%	0.1	0.3	0.5	1.5	2.7	5.1	9.9	14.4	24.1	37.6	54.9	76.1	101.3	137.0	183.2	240.3	308.4
R35																		
R36	3.75%	0.1	0.1	0.2	0.6	1.0	1.9	3.7	5.4	9.0	14.1	20.6	28.5	38.0	51.4	68.7	90.1	115.6

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
R2	145.4	182.4	226.8	278.9	338.6	406.1	481.6	565.3	657.3	757.6	866.6	976.6	1087.6	1199.7	1312.9	1427.1	1542.4
R3	145.4	182.4	226.8	278.9	338.6	406.1	481.6	565.3	657.3	757.6	866.6	976.6	1087.6	1199.7	1312.9	1427.1	1542.4
R4	145.4	182.4	226.8	278.9	338.6	406.1	481.6	565.3	657.3	757.6	866.6	976.6	1087.6	1199.7	1312.9	1427.1	1542.4
R5	145.4	182.4	226.8	278.9	338.6	406.1	481.6	565.3	657.3	757.6	866.6	976.6	1087.6	1199.7	1312.9	1427.1	1542.4
R6	145.4	182.4	226.8	278.9	338.6	406.1	481.6	565.3	657.3	757.6	866.6	976.6	1087.6	1199.7	1312.9	1427.1	1542.4
R10	465.2	583.7	725.9	892.3	1083.4	1299.6	1541.3	1809.0	2103.2	2424.4	2773.1	3125.1	3480.4	3839.1	4201.1	4566.7	4935.7
R11	145.4	182.4	226.8	278.9	338.6	406.1	481.6	565.3	657.3	757.6	866.6	976.6	1087.6	1199.7	1312.9	1427.1	1542.4
R12	145.4	182.4	226.8	278.9	338.6	406.1	481.6	565.3	657.3	757.6	866.6	976.6	1087.6	1199.7	1312.9	1427.1	1542.4
R13	145.4	182.4	226.8	278.9	338.6	406.1	481.6	565.3	657.3	757.6	866.6	976.6	1087.6	1199.7	1312.9	1427.1	1542.4
R21	290.7	364.8	453.7	557.7	677.1	812.2	963.3	1130.6	1314.5	1515.3	1733.2	1953.2	2175.2	2399.4	2625.7	2854.2	3084.8
R22	145.4	182.4	226.8	278.9	338.6	406.1	481.6	565.3	657.3	757.6	866.6	976.6	1087.6	1199.7	1312.9	1427.1	1542.4
R23	145.4	182.4	226.8	278.9	338.6	406.1	481.6	565.3	657.3	757.6	866.6	976.6	1087.6	1199.7	1312.9	1427.1	1542.4
R24	232.6	291.8	362.9	446.2	541.7	649.8	770.6	904.5	1051.6	1212.2	1386.5	1562.5	1740.2	1919.5	2100.6	2283.3	2467.8
R31	145.4	182.4	226.8	278.9	338.6	406.1	481.6	565.3	657.3	757.6	866.6	976.6	1087.6	1199.7	1312.9	1427.1	1542.4
R32	145.4	182.4	226.8	278.9	338.6	406.1	481.6	565.3	657.3	757.6	866.6	976.6	1087.6	1199.7	1312.9	1427.1	1542.4
R33	465.2	583.7	725.9	892.3	1083.4	1299.6	1541.3	1809.0	2103.2	2424.4	2773.1	3125.1	3480.4	3839.1	4201.1	4566.7	4935.7
R34	387.7	486.4	604.9	743.6	902.8	1083.0	1284.4	1507.5	1752.7	2020.4	2310.9	2604.2	2900.3	3199.2	3501.0	3805.6	4113.1
R35																	
R36	145.4	182.4	226.8	278.9	338.6	406.1	481.6	565.3	657.3	757.6	866.6	976.6	1087.6	1199.7	1312.9	1427.1	1542.4

F

Appendix F
COP Cable Ampacities

COP Cable & Conductor Ampacities

Underground Cables										
Cable Type and Ampacities					Equivalent Impedances					
Cable	Cable Type	Rated Voltage (kV)	Ampacity (Normal)	Ampacity (Emergency)	R_1 (Ω/km)	X_1 (Ω/km)	B_1 (µS/km)	R_0 (Ω/km)	X_0 (Ω/km)	B_0 (µS/km)
#2 CU	Stranded CN	15	166 (6)	200 (22)	0.7147	0.8013	53.45	0.7147	0.8013	53.45
4/0 AL	Stranded CN	15	245 (3)	295 (3)	0.3455	0.2312	78.23	0.4935	1.824	78.23
500MCM CU	Stranded CN	15	490 (3)	595 (3)	0.08929	0.2033	97.00	0.2373	1.796	97.00
750MCM AL	Stranded CN	15	490 (3)	595 (3)	0.09831	0.1902	115.9	0.2463	1.783	115.9
750MCM CU	Stranded CN	15	605 (24)	735 (25)	0.06037	0.1902	108.8	0.2084	1.783	108.8

Overhead Conductors										
Conductor Type and Ampacities					Equivalent Impedances					
Conductor	Code Name	Construction	Ampacity (Normal)	Ampacity (Emergency)	R_1 (Ω/km)	X_1 (Ω/km)	B_1 (µS/km)	R_0 (Ω/km)	X_0 (Ω/km)	B_0 (µS/km)
#6 CU	N/A	Solid	105 (15)	169 (20)	1.4816	0.9117	2.355	1.4816	0.9117	2.3550
#4 ACSR	Swan	6/1	143 (23)	175 (5)	1.45	1.0070	2.700	1.45	1.0070	2.7000
#4 CU	N/A	Solid	140 (9)	229 (19)	0.9768	0.8537	2.4206	0.9768	0.8537	2.4206
#2 ACSR	Sparrow	6/1	189 (9)	235 (5)	0.876	0.4590	3.7000	1.0540	2.0240	3.7000
#2 CU	N/A	Solid	194 (9)	297 (18)	0.6485	0.7949	25.6047	0.6485	0.7949	25.6047
1/0 ACSR	Bamboo	6/1 Poly	243 (9)	316 (5)	0.5369	0.4556	3.7598	0.8626	1.4167	1.6790
1/0 CU	N/A	7/1	265 (16)	412 (21)	0.3449	0.4538	3.7069	0.5970	1.3511	1.6665
3/0 ACSR	Mahogany	6/1 Poly	324 (9)	425 (5)	0.3393	0.4294	4.0301	0.5130	1.9167	1.5760
4/0 ACSR	Penguin	6/1	387 (10)	492 (5)	0.2697	0.4201	4.1214	0.4434	1.9074	1.5897
336 ACSR	Merlin	18/1	522 (9)	664 (5)	0.1696	0.3947	4.2115	0.4230	1.2838	1.7696
477 AAC	Cosmos	16	648 (17)	830 (5)	0.1212	0.3778	4.4463	0.2949	1.8651	1.6357

(1) CEC C22.1-09 2009

(2) BCH Distribution Standards Overhead Electrial ES43 Series 2002

(3) BCH ES53 Underground Electrical Distribution Standards 2009

(4) FBC Engineering Standard Overhead Conductor Ampacities Normal Ratings Thermal Capacity Conductors (MVA) July 2010

(5) FBC Engineering Standard Overhead Conductor Ampacities Emergency Ratings Thermal Capacity Conductors (MVA) July 2010

(6) BCH #1AL (3) x 120 [CEC #2CU (1)]/ 105 [CEC #1AL (1)]

(7) BCH #4/0AL (3) x 185 [CEC #2/0CU (1)]/ 185 [CEC #4/0AL (1)]

(8) BCH #4/0AL Emergency (3) x 185 [CEC #2/0CU (1)]/ 185 [CEC #4/0AL (1)]

(9) BCH (3) * 0.9 CEC Table 5A (1)

(10) BCH #3/0ACSR (2) x 0.9 CEC Table 5A (1) x 400 [CEC #4/0AL (1)]/ 335 [CEC #3/0AL (1)]

(11) BCH 500AL (3) x 325 [CEC 350CU (1)]/ 330 [CEC 500AL (1)]

(12) BCH 500MCMCU x 585 [CEC 1000MCMCU] / 395 [CEC 500MCMCU]

(13) BCH 500MCMCU Emergency x 585 [CEC 1000MCMCU] / 395 [CEC 500MCMCU]

(14) BCH 500AL Emergency (3) x 325 [CEC 350CU (1)]/ 330 [CEC 500AL (1)]

(15) BCH #4CU (2) x 0.9 CEC Table 5A (1) x 135 [CEC #6CU (1)]/ 180 [CEC #4CU (1)]

(16) BCH 2/0CU (2) x 0.9 CEC Table 5A (1) x 325 [CEC 1/0CU (1)]/ 370 [CEC 2/0CU (1)]

(17) FBC #477ACSR (5) x 0.9 CEC Table 5A (1) x 580 [BCH #336ACSR (2)]/496 [FBC #336ACSR (4)]

(18) FBC 1/0ACSR Emergency (5) x 240 [CEC #2CU (1)]/ 255 [CEC 1/0ACSR (1)]

(19) FBC #2AL Emergency (5) x 180 [CEC #4CU (1)]/185 [CEC #2AL (1)]

(20) FBC #4ACSR Emergency (5) x 135 [CEC #6CU (1)]/140 [CEC #4AL (1)]

(21) FBC 3/0AL Emergency (5) x 325 [CEC 1/0CU (1)]/ 335 [CEC 3/0AL (1)]

(22) BCH #1AL Emergency (3) x 120 [CEC #2CU (1)]/ 105 [CEC #1AL (1)]

(23) BCH #2ACSR (2) x 0.9 CEC Table 5A (1) x 140 [CEC #4AL (1)]/ 185 [CEC #2AL (1)]

(24) BCH 750MCMAL (3) x 500 [CEC 750MCMCU] / 405 [CEC 5750MCMAL]

(25) BCH 500MCMAL Emergency (3) x 500 [CEC 750MCMCU] (1) / 395 [CEC 750MCMAL (1)]

References:
City of Penticton Electrical Distribution System Plan 2012-2031
General Cable Electric Utility Catalogue R_0415
CYME

G

Appendix G
CPEU Substation Refurbishment Recommendations

Waterford:

4.0 RECOMMENDATIONS

- Monitor foundations for further sinking
- Consider budgeting for replacement of the McGraw Edison Type "ME" reclosers; the recloser is no longer manufactured and parts are not available or supported in the aftermarket
- WAT 24-0 breather check valve is missing, recommend installing a new check valve
- WAT 23-0 pole number 2 bushing insulation resistance to ground exhibits possible degradation, continue to monitor, recommend performing a diagnostic test using 10kV power factor test equipment
- SEL to return repaired SEL-351R relay (serial number 2000321128) to City of Penticton, when received it should be installed in the spare relay cabinet which the new spare relay was obtained from

Huth:

4.0 RECOMMENDATIONS

- Consider budgeting for replacement of the McGraw Edison Type "ME" reclosers; the recloser is no longer manufactured and parts are not available or supported in the aftermarket
- Compare R-3 contact resistance results to past test results to determine if further action is required
- Perform thermal infrared scan of R-3 to determine if a heating issue exists that warrants further investigation and repair
- Modify conduit installation for R-4 relay control cabinet

Westminster:

4.0 RECOMMENDATIONS

- Consider budgeting for replacement of the McGraw Edison Type "ME" reclosers; the recloser is no longer manufactured and parts are not available or supported in the aftermarket
- Compare 8R31 contact resistance results to previous records if available, consider corrective repairs if the recloser will be returned to service
- Perform SEL-351R BATT command test on 12R35
- Troubleshoot 12R31 SEL-351R close output and associated logic to identify cause of failed close test
- Check WES 12kV recloser SEL-351R battery voltages after equipment is returned to service

H

Appendix H
Budget Sheet

Annual Budget	YEAR					
	2020	2021	2022	2023	2024	2025
Sustainment						
Utility Master Plan / Load & Model Update	$ 175,000					$ 193,214
Huth and Waterford Assessment/Refurbishment		$ 51,000	$ 312,120	$ 318,362	$ 324,730	$ 331,224
UPG-5 Cable Replacement Program		$ 300,000	$ 314,868	$ 330,473	$ 346,851	$ 364,041
Sustainment Total Cost	$ 175,000	$ 351,000	$ 626,988	$ 648,835	$ 671,581	$ 888,479
Enhancement						
UPG-1 Diesel Generation - Peak Shaving	$ 85,000	$ 25,000				
UPG-2-A Completing loop at Lawrence Ave w UG & OH		$ 694,000				
UPG-3 Energy Storage			$ 1,700,000	$ 300,000	$ 600,000	
UPG-4 Splitting Load on R33		$ 800,000				
UPG-6 Resiliency Study			$ 30,000			
UPG-7 25 kV Conversion Study					$ 50,000	
UPG-8-A UG Carmi Feeders to Dartmouth & Wiltse						
UPG-9-A Carmi Express to Pineview Rd and Main St - OH						
UPG-10 Undergrounding Main St						
UPG-11 Upgrade Huth Capacity						
UPG-12 Huth Feeder Expansion						
UPG-13 Tophat Street Light Replacements						
UPG-14 Cobrahead Street Light Replacements						
Capital Planning Total Cost	$ 85,000	$ 1,519,000	$ 1,730,000	$ 300,000	$ 650,000	$ -

Annual Budget	Year				
	2026	2027	2028	2029	2030
Sustainment					
Utility Master Plan / Load & Model Update					$ 213,324
Huth and Waterford Assessment/Refurbishment					
UPG-5 Cable Replacement Program	$ 378,570	$ 397,682	$ 417,751	$ 438,821	$ 460,944
Sustainment Total Cost	$ 378,570	$ 397,682	$ 417,751	$ 438,821	$ 674,268
Enhancement					
UPG-1 Diesel Generation - Peak Shaving					
UPG-2-A Completing loop at Lawrence Ave w UG & OH					
UPG-3 Energy Storage					
UPG-4 Splitting Load on R33					
UPG-6 Resiliency Study					
UPG-7 25 kV Conversion Study					
UPG-8-A UG Carmi Feeders to Dartmouth & Wiltse	$ 1,900,000	$ 2,000,000	$ 2,200,000		
UPG-9-A Carmi Express to Pineview Rd and Main St - OH				$ 920,000	
UPG-10 Undergrounding Main St			$ 1,171,659		$ 1,218,994
UPG-11 Upgrade Huth Capacity					
UPG-12 Huth Feeder Expansion					
UPG-13 Tophat Street Light Replacements					
UPG-14 Cobrahead Street Light Replacements					
Capital Planning Total Cost	$ 1,900,000	$ 2,000,000	$ 3,371,659	$ 920,000	$ 1,218,994

Annual Budget	Year				
	2031	2032	2033	2034	2035
Sustainment					
Utility Master Plan / Load & Model Update					$ 235,527
Huth and Waterford Assessment/Refurbishment					
UPG-5 Cable Replacement Program					
Sustainment Total Cost	$ -	$ -	$ -	$ -	$ 235,527
Enhancement					
UPG-1 Diesel Generation - Peak Shaving					
UPG-2-A Completing loop at Lawrence Ave w UG & OH					
UPG-3 Energy Storage					
UPG-4 Splitting Load on R33					
UPG-6 Resiliency Study					
UPG-7 25 kV Conversion Study					
UPG-8-A UG Carmi Feeders to Dartmouth & Wiltse					
UPG-9-A Carmi Express to Pineview Rd and Main St - OH					
UPG-10 Undergrounding Main St	$ 1,243,374	$ 1,268,242			
UPG-11 Upgrade Huth Capacity			$ 1,300,000	$ 1,300,000	$ 4,000,000
UPG-12 Huth Feeder Expansion			$ 1,200,000	$ 1,250,000	$ 1,350,000
UPG-13 Tophat Street Light Replacements					
UPG-14 Cobrahead Street Light Replacements					
Capital Planning Total Cost	$ 1,243,374	$ 1,268,242	$ 2,500,000	$ 2,550,000	$ 5,350,000

Annual Budget	Year 2036	2037	2038	2039	2040
Sustainment					
Utility Master Plan / Load & Model Update					$ 260,041
Huth and Waterford Assessment/Refurbishment					
UPG-5 Cable Replacement Program					
Sustainment Total Cost	$ -	$ -	$ -	$ -	$ 260,041
Enhancement					
UPG-1 Diesel Generation - Peak Shaving					
UPG-2-A Completing loop at Lawrence Ave w UG & OH					
UPG-3 Energy Storage					
UPG-4 Splitting Load on R33					
UPG-6 Resiliency Study					
UPG-7 25 kV Conversion Study					
UPG-8-A UG Carmi Feeders to Dartmouth & Wiltse					
UPG-9-A Carmi Express to Pineview Rd and Main St - OH					
UPG-10 Undergrounding Main St		$ 1,400,241	$ 1,428,246	$ 1,456,811	$ 1,485,947
UPG-11 Upgrade Huth Capacity	$ 5,500,000				
UPG-12 Huth Feeder Expansion	$ 1,500,000				
UPG-13 Tophat Street Light Replacements	$ 275,000				
UPG-14 Cobrahead Street Light Replacements		$ 840,000			
Capital Planning Total Cost	$ 7,275,000	$ 2,240,241	$ 1,428,246	$ 1,456,811	$ 1,485,947

Annual Budget	Year 2041	2042	2043	2044	2045	Project Total
Sustainment						Sustainment
Utility Master Plan / Load & Model Update					$ 287,106	$ 1,364,212
Huth and Waterford Assessment/Refurbishment						$ 1,337,436
UPG-5 Cable Replacement Program						$ 3,750,000
Sustainment Total Cost	$ -	$ -	$ -	$ -	$ 287,106	$ 6,451,648
Enhancement						Enhancement
UPG-1 Diesel Generation - Peak Shaving						$ 110,000
UPG-2-A Completing loop at Lawrence Ave w UG & OH						$ 694,000
UPG-3 Energy Storage						$ 2,600,000
UPG-4 Splitting Load on R33						$ 800,000
UPG-6 Resiliency Study						$ 30,000
UPG-7 25 kV Conversion Study						$ 50,000
UPG-8-A UG Carmi Feeders to Dartmouth & Wiltse						$ 6,100,000
UPG-9-A Carmi Express to Pineview Rd and Main St - OH						$ 920,000
UPG-10 Undergrounding Main St	$ 1,515,666	$ 1,545,980	$ 1,556,899	$ 1,588,437	$ 1,619,501	$ 18,500,000
UPG-11 Upgrade Huth Capacity						$ 12,100,000
UPG-12 Huth Feeder Expansion						$ 5,300,000
UPG-13 Tophat Street Light Replacements						$ 275,000
UPG-14 Cobrahead Street Light Replacements						$ 840,000
Capital Planning Total Cost	$ 1,515,666	$ 1,545,980	$ 1,556,899	$ 1,588,437	$ 1,619,501	**$ 48,319,000**

Appendix I
Recommended Project Sheets

Project: UPG-1 Diesel Generation – Peak Shaving Pilot

Driver: Economics

Description: The generator will run once a month, during peak times, to shave the peak demand. The CPEU can use the existing generator, located at the OK Pumping Station, to reduce peak demand billing fees from FBC. During the pilot phase the generator will run as required to analyze the savings, then report on how much it needs to be run versus the mandatory 1-hr/month.

Planning Year: 2021

Category: Enhancement

Priority: ☐ High ☒ Medium ☐ Low

Capital Cost Estimate

Construction Cost Estimate	-	$ 17,756
Engineering	28%	$ 4,971
Subtotal	-	$ 22,727
Contingency	10%	$ 2,273
Total Capital Cost Estimate	-	$ 25,000

Notes: GST not included.

Project: UPG-2-A Completing Lawrence Ave Loop with Overhead Conductor and Underground Cable (Preferred option)

Driver: **Improved Reliability**

With more development being added to Sendero Canyon, there is a need for increased reliability.

Description: Currently, the neighborhood is fed radially. Any point of failure results in an outage with no backup. Completing a loop from Syer Rd would resolve this issue. The loop would also help balance the load. The north 550 m will be underground, followed by 875 m of overhead to the south, and the final 75 m will be underground.

Planning Year: 2021

Category: Enhancement

Priority: ☐ High ☐ Medium ☒ Low

Capital Cost Estimate

Construction Cost Estimate	-	$ 550,000
Engineering	5%	$ 28,000
Subtotal	-	$ 578,000
Contingency	20%	$ 116,000
Total Capital Cost Estimate	-	$ 694,000

Notes: GST not included. This option is preferred because of its lower cost.

Project: UPG-2-B Completing Lawrence Ave Loop with Underground Cable

Driver: **Improved Reliability**

With more developments being added to Sendero Canyon, the need for increased reliability is necessary.

Description: Currently, the neighborhood is fed radially. Any point of failure results in an outage with no backup. Completing a loop from Syer Rd would resolve this issue. The loop would also help balance the load. This feeder will be underground the entire route.

Planning Year: 2021

Category: Enhancement

Priority: ☐ High ☒ Medium ☐ Low

Capital Cost Estimate

Construction Cost Estimate	-	$ 950,000
Engineering	5%	$ 50,000
Subtotal	-	$ 1,000,000
Contingency	20%	$ 200,000
Total Capital Cost Estimate	-	$ 1,200,000

Notes: GST not included.

Project: UPG-3 Energy Storage

Driver: Economics

Description: Installing a BESS will allow the CPEU flexibility in supporting their customers. One of the most beneficial outcomes is being able to charge the BESS during off-peak hours and use the BESS to help with peak demands during high-load scenarios. This will help reduce demand peak charges seen from FortisBC as well as potentially take advantage of funding initiatives to be at the forefront in supporting a growing industry in green technologies. BESS can also be used to shift the EV load curve and manage the overall system demand.

Planning Year: No year defined until grant funding is available or decision on ERF is made

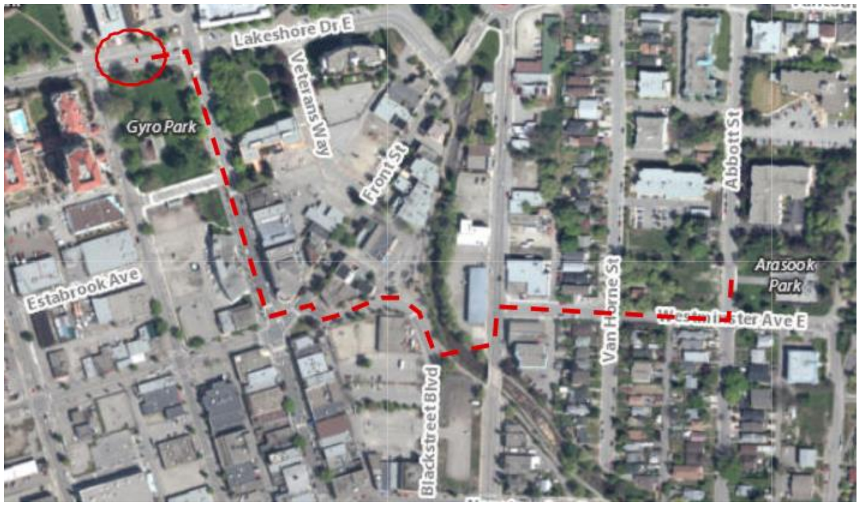
Category: Enhancement

Priority: ☐ High ☒ Medium ☐ Low

Capital Cost Estimate		
Construction Cost Estimate	-	$ 2,100,000
Engineering	5%	$ 100,000
Subtotal	-	$ 2,000,000
Contingency	20%	$ 400,000
Total Capital Cost Estimate	-	$ 2,600,000

Notes: GST not included.

Project: UPG-4 Split load between feeder R33 and R35



Driver: **Economics and Future Growth**

Due to the system growth and EV load projections, additional support for feeder R33 will be required to support the system in normal and backup situations.

Description: Install new underground cable from the Westminster substation to Lakeshore Dr W and Main St. The new cable can split load on R33 into two feeders, R33 & R35, which enables R33 to be more readily available in the case of an emergency outage at Huth substation. A 4x600A switch will need to be installed at Gyro Park.

Planning Year: 2021

Category: Sustainment / Enhancement

Priority: ☐ High ☒ Medium ☐ Low

Capital Cost Estimate

Construction Cost Estimate	-	$ 640,000
Engineering	5%	$ 30,000
Subtotal	-	$ 670,000
Contingency	20%	$ 130,000
Total Capital Cost Estimate	-	$ 800,000

Notes: GST not included.

Project: UPG-5 Cable Replacement Program

Driver: **Reliability**

Approximately 20% of underground cables are 30+ years old. These cables are at a higher risk of failure due to their age.

Description: Replace aging cables before the point of failure to avoid expensive, time consuming emergency replacements.

Planning Year: 2021-2030

Category: Sustainment

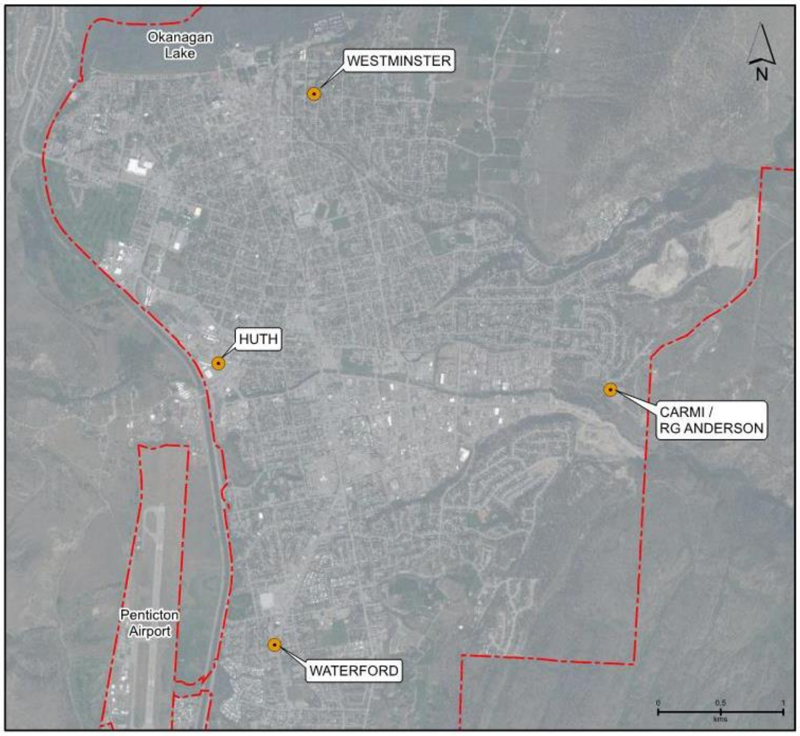
Priority: ☐ High ☒ Medium ☐ Low

2026-2028 Capital Cost Estimate

Construction Cost Estimate	-	$ 2,974,000
Engineering	10%	$ 296,000
Subtotal	-	$ 3,270,000
Contingency	15%	$ 480,000
Total Capital Cost Estimate	-	$ 3,750,000

Notes: GST not included.

Project: UPG-6 Resiliency Study



Driver: Reliability

Utilities have been experiencing an increase in low probability but high impact events.

Description: This study would focus on preparation, mitigation, response, and recovery for low probability but high impact events.

Planning Year: 2022

Category: Sustainment

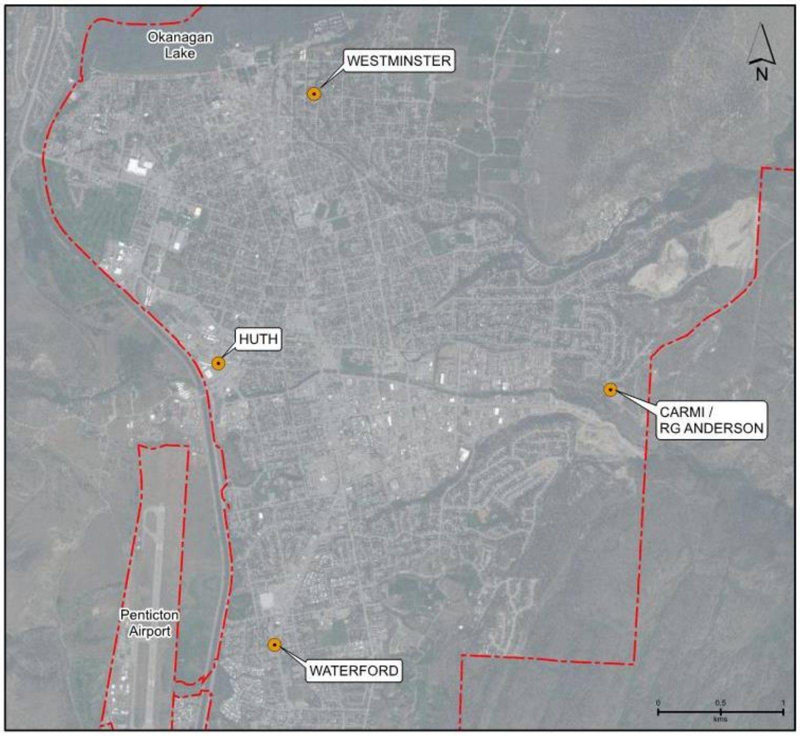
Priority: ☐ High ☒ Medium ☐ Low

2026-2028 Capital Cost Estimate

Construction Cost Estimate	-	$ -
Engineering	-	$ 30,000
Subtotal	-	$ -
Contingency	-	$ -
Total Capital Cost Estimate	-	$ 30,000

Notes: GST not included.

Project: UPG-7 25 kV Conversion Study



Driver: Reliability

Description: To account for future load, the purpose of the 25 kV conversion study is to investigate the pros and cons of upgrading to a 25 kV distribution system. This study should consider the operational, maintenance, and capital implications of converting the system compared to the next best alternatives.

Planning Year: 2024

Category: Sustainment

Priority: ☐ High ☐ Medium ☒ Low

2026-2028 Capital Cost Estimate

Construction Cost Estimate	-	$ -
Engineering	-	$ 50,000
Subtotal	-	$ -
Contingency	-	$ -
Total Capital Cost Estimate	-	$ 50,000

Notes: GST not included.

Project: UPG-8-A Underground feeders from Carmi Substation to Wiltse Blvd and Dartmouth Rd. (Preferred option)

Driver: Reliability & System Capacity

Based on long-term system growth and EV load projections, additional support to feeders R23 and R24 is required to support the system in a backup scenario.

Description: Bring five underground feeders, three to Wiltse Blvd and two to Dartmouth Rd and switch LB00019, from Carmi substation. Reroute R12 to initially follow the R13 route (Overhead). These feeders will allow for more robust backup options at the Waterford or Huth substation. The reliability of the substation would improve as the two new feeders would decrease the percentage of load on R10.

Planning Year: 2026-2028

Category: Enhancement

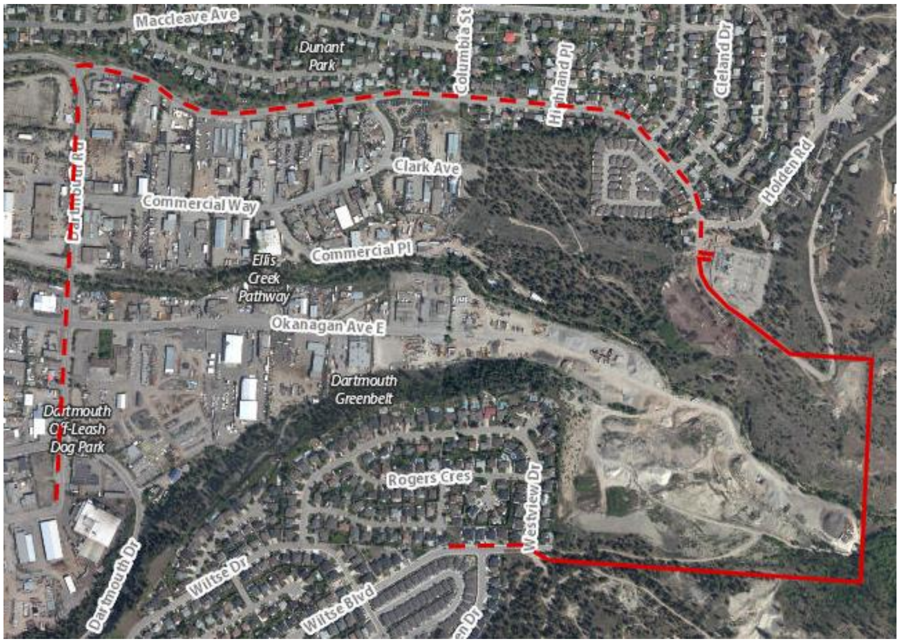
Priority: ☐ High ☒ Medium ☐ Low

2026-2028 Capital Cost Estimate

Construction Cost Estimate	-	$ 4,800,000
Engineering	5%	$ 240,000
Subtotal	-	$ 5,040,000
Contingency	20%	$ 1,060,000
Total Capital Cost Estimate	-	$ 6,100,000

Notes: GST not included. This is the preferred option because it would have the ability to serve a new industrial area without significant additional cost.

Project: UPG-8-B Underground feeders from Carmi Substation to Dartmouth Rd and Overhead feeders around to Wiltse Blvd.



Driver: **Reliability & System Capacity**

Based on long-term system growth and EV load projections, additional support to feeders R23 and R24 is required to support the system in a backup scenario.

Description: To achieve this, bring six feeders, two to Wiltse Blvd (Overhead) and the remaining four (Underground) to Dartmouth Rd and switch LB00019, from Carmi substation. This will allow for more robust backup options at the Waterford or Huth substation. The reliability of the substation would improve as the two new feeders would decrease the percentage of load on R10.

Planning Year: 2026-2028

Category: Enhancement

Priority: ☐ High ☒ Medium ☐ Low

Capital Cost Estimate

Construction Cost Estimate	-	$ 4,300,000
Engineering	5%	$ 215,000
Subtotal	-	$ 4,515,000
Contingency	20%	$ 885,000
Total Capital Cost Estimate	-	$ 5,400,000

Notes: GST not included.

Project: UPG-9-A Carmi Substation – Overhead Express Feeder to Pineview Rd and Main St. (Preferred option)

Driver: **Reliability & System Capacity**

Based on the long-term system growth and EV load projections, additional support for feeders R23 and R24 is required to support the system in a backup scenario.

Description: An overhead express feeder is proposed as shown in the figure. This proposed overhead feeder will be used to reduce the load on Carmi and Waterford. This feeder will better balance the network, and, in the case of an emergency, it will have the capacity to backup R23 or R24. This project needs UPG-5 to be completed prior to commencement.

Planning Year: 2029

Category: Enhancement

Priority: ☐ High ☒ Medium ☐ Low

Capital Cost Estimate

Construction Cost Estimate	-	$ 730,000
Engineering	5%	$ 30,000
Subtotal	-	$ 760,000
Contingency	20%	$ 160,000
Total Capital Cost Estimate	-	$ 920,000

Notes: GST not included. Green line indicates UPG-5. The red line indicates UPG-6-A. This option is preferred because of its lower cost.

Project: UPG-9-B Carmi Substation – Underground Express Feeder to Pineview Rd and Main St.

Driver: Reliability & System Capacity

Based on the long-term system growth and EV load projections, additional support for feeders R23 and R24 is required to support the system in a backup scenario

Description: An underground express feeder is proposed as shown in the figure. This proposed overhead feeder will be used to reduce the load on Carmi and Waterford. This feeder will better balance the network, and in the case of an emergency, it will have the capacity to backup R23 or R24. This project needs UPG-5 to be completed prior to commencement.

Planning Year: 2029

Category: Enhancement

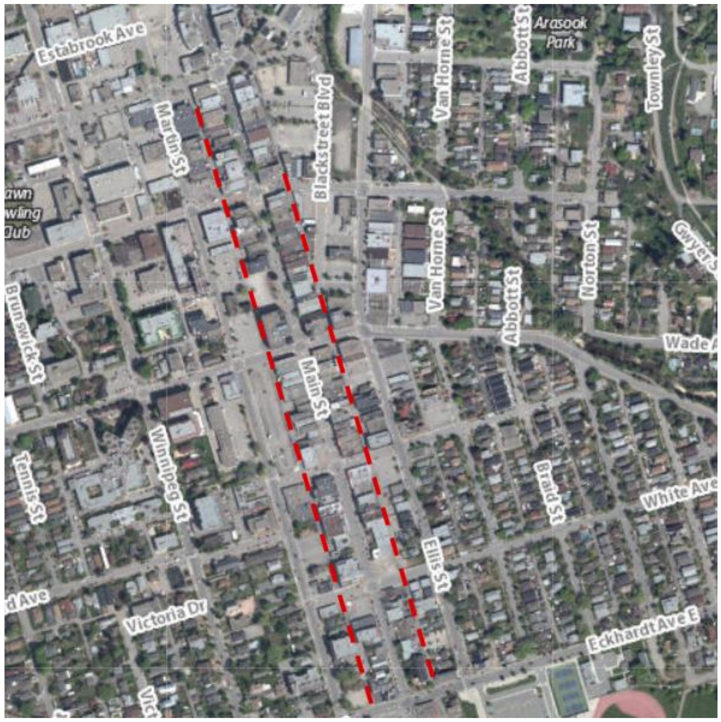
Priority: ☐ High ☒ Medium ☐ Low

Capital Cost Estimate

Construction Cost Estimate	-	$ 1,750,000
Engineering	10%	$ 175,000
Subtotal	-	$ 1,925,000
Contingency	20%	$ 375,000
Total Capital Cost Estimate	-	$ 2,300,000

Notes: GST not included. Green line indicates UPG-5. The red line is UPG-6-B.

Project: UPG-10 Main St. Overhead to Underground



Driver: Operations & Maintenance, Safety

Description: Main St. consists of old construction and aging infrastructure. Clearances to buildings limit development options due to the overhead conductors. Underground cables eliminate the clearance issues and allows for greater flexibility in building design / construction. Underground cables would provide a safer, more reliable, and more aesthetic system.

Planning Year: 2028-2045

Category: Enhancement

Priority: ☐ High ☐ Medium ☒ Low

2028-2045 Capital Cost Estimate

Construction Cost Estimate	-	$ 14,700,000
Engineering	5%	$ 740,000
Subtotal	-	$ 15,440,000
Contingency	20%	$ 3,060,000
Total Capital Cost Estimate	-	$ 18,500,000

Notes: GST not included.

Project: UPG-11 Huth Substation Expansion – Second Transformer

Driver: Reliability and System Growth

Based on the load forecast, there is not enough capacity to effectively back up substations in certain scenarios.

Description: Add a second transformer at Huth to allow for a far more robust backup option during any emergency.

Planning Year: 2033-2036

Category: Enhancement

Priority: ☐ High ☐ Medium ☒ Low

Capital Cost Estimate

Construction Cost Estimate	-	$ 9,400,000
Engineering	8%	$ 750,000
Subtotal	-	$ 10,150,000
Contingency	20%	$ 1,950,000
Total Capital Cost Estimate	-	$ 12,100,000

Notes: GST not included.

Project: UPG-12 Huth Substation Feeder Expansion

Driver: Reliability and System Growth

Description: Once UPG-8 is completed, there are not enough feeders to provide additional capacity to the system during load transfers and backup scenarios. To solve this issue, an additional four feeders should be added: two feeders heading North to offload Westminster, one East to feeder R11 and one feeder South to support Waterford.

Planning Year: 2033-2036

Category: Enhancement

Priority: ☐ High ☐ Medium ☒ Low

Capital Cost Estimate

Construction Cost Estimate	-	$ 4,100,000
Engineering	7%	$ 300,000
Subtotal	-	$ 4,400,000
Contingency	20%	$ 900,000
Total Capital Cost Estimate	-	$ 5,300,000

Notes: GST not included.

Project: UPG-13 Top Hat Street Light Replacements

Driver: Operations & Maintenance

Description: LED Streetlights have an expected lifespan of 20 years; therefore, the top hat streetlights should start being replaced in 2036 to avoid unexpected failures.

Planning Year: 2036

Category: Enhancement

Priority: ☐ High ☐ Medium ☒ Low

Capital Cost Estimate

Construction Cost Estimate	-	$ 210,000
Engineering	10%	$ 20,000
Subtotal	-	$ 230,000
Contingency	20%	$ 45,000
Total Capital Cost Estimate	-	$ 275,000

Notes: GST not included.

Project: UPG-14 Cobrahead Street Light Replacements

Driver: Operations & Maintenance

Description: LED Streetlights have an expected lifespan of 20 years; therefore, the cobrahead streetlights should start being replaced in 2037 to avoid unexpected failures.

Planning Year: 2037

Category: Enhancement

Priority: ☐ High ☐ Medium ☒ Low

Capital Cost Estimate

Construction Cost Estimate	-	$ 635,000
Engineering	10%	$ 60,000
Subtotal	-	$ 695,000
Contingency	20%	$ 145,000
Total Capital Cost Estimate	-	$ 840,000

Notes: GST not included.