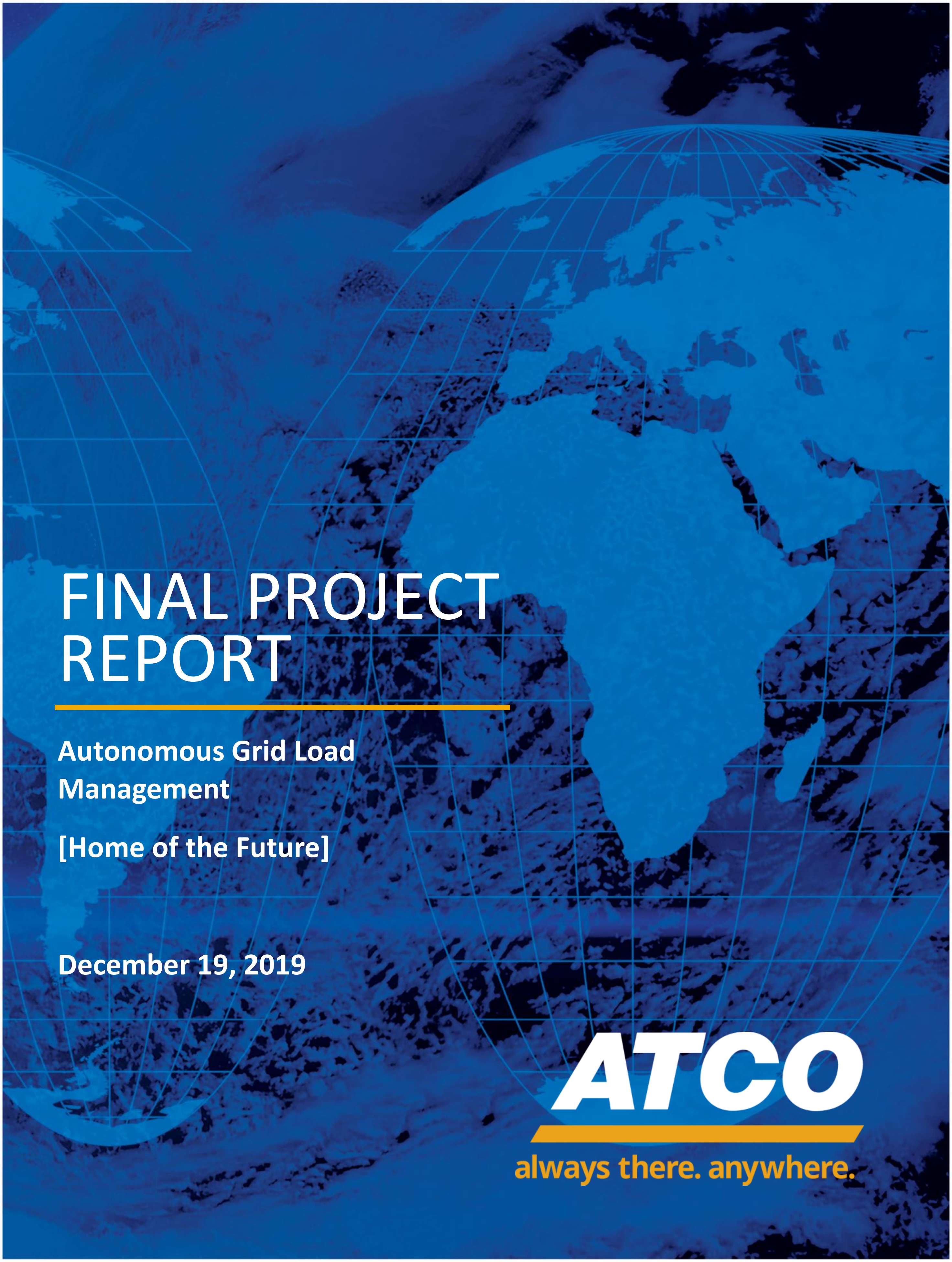

FINAL PROJECT REPORT

Autonomous Grid Load Management

[Home of the Future]

December 19, 2019

ATCO

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ABSTRACT

The purpose of the Home of the Future project is to validate the effectiveness of a non-wires alternative (NWA) at the grid's edge to manage and orchestrate electric demand at the distribution level, namely distributed energy resources (DERs) such as electric vehicle (EV) chargers, electric water heater tanks or other energy-intensive equipment behind the meter. The project includes assessing business impacts compared to traditional capital infrastructure upgrades.

Our grid orchestration engine is based upon a novel approach — “engineered price signal” that monetizes the utility’s costs of managing capital, asset depreciation and operations and maintenance (O&M). Our grid orchestration engine effectively uses demand-side management combined with an engineered price signal through direct connection into DER assets to reduce utility system cost.

The aggregated peak load of the secondary distribution circuit transformer is reduced anywhere between 11% and 41% based on levels of EV penetration. The tangible outcome of reducing peak load at specific times is avoiding transformer hot-spot temperature (HST), reducing loss of asset life from 62% to 100% depending on the percentage of EV homeowners subscribing to the utility’s engineered price signal for EV charging curtailment control.

TEAM

MEMBER	ROLE
François Blouin	Business sponsor and leadership execution
Aatif Baskanderi	Product owner — stakeholder engagement, commercial strategist
Karen Wei	Project manager
Andrew Moss, Anmol Arora (Co-op student)	Backend Software development for Database, DER Communications and DSO Price Signal Algorithm implementation
Mohammed Al-Saffar (PhD Student)	Supporting development of algorithms to predict transformer and other asset life impacts based on operation as well as GHG modeling
Mario Perron (Consultant)	DSO price signal algorithm development and Homeowner Dashboard Development
Chris Stoklosa	DSO dashboard visualization
Jeff Reading	Fund development and partnerships

PARTNERS

MEMBER	ROLE
Alberta Innovates	Project funder
SAIT	Testing partner and prototype site
Lethbridge Electric Utility	Testing partner and pilot site

CONTENTS

LIST OF ABBREVIATIONS

AMI	Advanced Metering Infrastructure
API	Application Program Interface
CSA	Canadian Standards Association
DER	Distributed Energy Resource
DFO	Distribution Facility Owner
DSO	Distribution System Operator
EV	Electric Vehicle
GHG	Greenhouse Gas
HoF	Home of the Future
HST	Hottest Spot Temperature (transformer)
IoT	Internet of Things
LEU	Lethbridge Electric Utility
MW	Megawatt (power or demand)
MWh	Megawatt-Hour (energy or consumption)
NWA	Non-Wires Alternative
O&M	Operations and Maintenance
TOU	Time-of-Use

DISCLAIMER

EXECUTIVE SUMMARY

Innovations being deployed closer to the end-user, whether residential, commercial or industrial are redefining the way we manage energy. Instead of utilities managing the grid with traditional, static “energy profiles” of such end-users, new distributed energy resource (DER) technologies enable a much more dynamic, heterogeneous energy mix to be tamed: electric vehicle (EV) chargers, solar panels, connected hot water tanks, etc. These innovations are pushing utilities out of their traditional role to adopt smarter grid features, which are becoming mandatory for today’s system planning, operations and modulated energy rates.

The purpose of the Home of the Future project is to validate the cost-benefit of a non-wire alternative (NWA) software solution for the utility that leverages sensors prevalent in the grid, Internet of things (IoT) and data analytics. The solution manages and orchestrates electric demand of DERs at the neighbourhood level, such as EV chargers, electric water heater tanks or other energy intensive equipment “behind-the-meter” that end-users are adopting. The goal of the energy orchestration is to assess and optimize the business impact compared to traditional capital infrastructure upgrades required to integrate such DERs onto the electricity grid.

Our intelligent near-real-time decision making system (i.e. the “orchestration engine”) is based upon a novel approach: “engineered price signal” that monetizes the utility’s costs of managing capital, asset depreciation and operations and maintenance (O&M), which is increased when DERs are introduced onto their grid. The orchestration engine advances traditional approaches of managing electrical demand on the grid by combining it with the new engineered price signal that directly connects into DER assets. The result is shifting the demand of DERs that relieves a burden on utility assets to reduce their loss of life, hence enabling a more cost-effective and resilient grid that can handle the deployment of large electric demand DERs, such as EVs.

The new engineered price signal used in our new approach includes numerous components to assist in effective decision making, such as: real-time energy pricing, neighbourhood circuit load, individual home load, weather, EV charging demand, grid emissions, and customer behavior data. Our software-based NWA integrates physical asset control and a utility economic model that benefits utility investments, which is currently not found in the market. We have developed the software, built the knowledge base, deployed the technology, conducted advanced simulations and collected evidence through a small-scale pilot in Lethbridge to prove the potential applications of NWA and to assess the significance of its impact in displacing cost of traditional approaches, all whilst saving money for customers and lowering overall system cost. The key results achieved through this project are listed in Table 1.

# OF EV HOUSEHOLDS PARTICIPATING OUT OF 16 HOMES (%)	REDUCTION TO PEAK LOAD (%)	REDUCTION TO TRANSFORMER LOSS OF LIFE (%)	ANNUAL CO_2 kg PER TRANSFORMER REDUCTION
1 EV participation (6 %)	11%	62%	0
2 EV participation (13%)	21%	91%	40
3 EV participation (19%)	29%	98%	110
4 EV participation (25%)	35%	99%	120
5 EV participation (31%)	41%	100%	220

Table 1: Results summary for 16 homes connected to the same 50 kVA transformer; similar outcomes for 13 homes on a 34.5 kVA transformer

The aggregated peak load of the neighbourhood distribution circuit transformer is reduced anywhere between 11% and 41%, based on the percentage of residential customers with EVs subscribing to the project’s new autonomous demand response approach. The tangible outcome of reducing the peak load at specific times is to avoid transformer hot-spot temperature (HST), which reduces loss of life of the asset between 62% and up to 100%, depending on the percentage of residential customers with EVs subscribing to the approach. In addition, we have been able to simulate the impact on GHG emission reduction by synchronizing our load control with the Alberta grid generation mix of today and a lower carbon mix in 2030. See section for detailed results analyses.

The Home of the Future project was developed and tested at the neighbourhood distribution network level, also referred to as the secondary circuit. The same asset optimization problem is exacerbated when we look at the circuit level connecting thousands of customers. Asset life extension – or transformer loss of life due to continuous overload conditions – will trigger significant capital investments to support the future of not only home EV charging, but further electrification of the home. For example, EPCOR has conducted an initial cost study of the impact of residential EV charging on their grid. They estimate that $5.8B in capital expenditure will be required to mitigate peak demand if no control of EV charging is implemented. See Appendix H: EPCOR Charging Study for more details.

The Home of the Future has a unique value proposition for emerging challenges faced by utilities in the new energy world when it comes to rate design, communication and orchestration. Our go-to-market strategy is to partner with new entrants in the energy industry, such as third-party aggregation platforms, which can assist with communication management and interoperability. We can also partner with EV charger hardware vendors that hold the relationship with homeowners. Both platform and hardware vendors lack a clear and compelling value proposition to incorporate grid orchestration to solve asset optimization issues for their utility customers due to the lack of market signal to inform their smart grid controls. Our product complements and enhances the demand response ecosystem for all actors. ATCO is well positioned to develop the smart grid orchestration solution based on our unique, complementary insights in supply and demand management across the grid and understanding of energy value streams.

In conclusion, our control system can be applied to energy flow control and grid congestion management to dynamically orchestrating DERs to protect utility assets, reduce cost associated to over-provisioning and enable capital deferral of the invested assets. The evolution of the product caused by engaging customers with a design-thinking approach enabled us to move from a technologically innovative solution that was not solving a large enough problem to developing a solution that established new value flows in a blue ocean market (ie new market not exploited or non-existent) to help distribution utilities find a position in the new energy world. Both EPCOR and ENMAX have expressed interest in such product.

To Probe Further . . .

Utility controlled, behind-the-meter loads such as EV charging stations will require more visibility for utilities to geographically identify service areas at risk and offer load management solutions (similar issues for any DERs). A potential strategy to bring situational awareness could be to request mandatory registration when an EV or EV charger is purchased, this will greatly facilitate grid planning and especially demand side management.

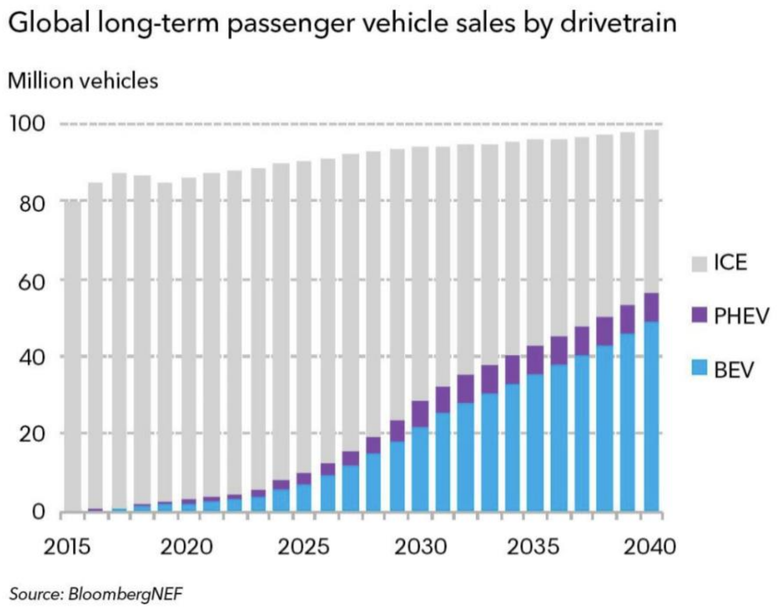
Furthermore, to ensure adequate participation, some form of incentives and or revenue sharing business model could prove necessary; however, these are still in their infancy. Revenue sharing aside, behavioural components such as GHG emission reduction can be leveraged to solve both the environmental and grid asset optimization problems. Establishing closer communication between distribution utilities, residential/commercial/industrial demand customers and other market participants will be key to ensure optimal use of new DERs, in conjunction with existing regulated facilities.

Unfortunately, monetization of energy orchestration remains an unclear value proposition in the eyes of the regulator. Given this “wait and see” attitude, utilities risk being outplayed by emerging energy service companies (ESCOs) that may not have the patience to wait for regulation to change and instead could build up relationships with utility customers and more aggressively offer new business models to disrupt the utilities.

Controlling or influencing energy demand will be one of the most valuable businesses in the future and a motivation to evolve traditional DFOs (Distribution Facility Owner) into a DSO (Distribution System Operator) in the Utility of the Future.

1.0 INTRODUCTION

Along with many other countries, Canada is witnessing a shift in electricity energy usage. Efficiency is flattening or declining the general demand of traditional loads while there is a significant increase of new electric loads and grid-edge technologies that are impacting the electricity distribution network. In particular, the market is seeing exponential growth in the customer adoption of electric vehicles (EVs) – see Figure 1 as they demonstrate consistent cost reductions and improved diversity, resulting in increasing market share over time. There is also growth in solar PV installations for localized energy generation and use of electric water heaters by residential users.



Source: BloombergNEF

Figure 1: By 2040, we expect that 57% of all passenger vehicle sales, and over 30% of the global passenger vehicle fleet, will be electric. Electric Vehicle Outlook 2019, Bloomberg NEF (New Energy Finance)

Of all distributed energy resources (DERs), there is great concern by Distribution Facility Owners (DFOs) regarding the impact of EV charging infrastructure on the grid as EVs continue to penetrate the market. While Level 1 charging using a standard 120-volt power outlet typically demands 1.4 to 1.9 kW to charge a vehicle, this 5 – 7 km of range per hour of charging is being pushed out of the market by Level 2 charging. The 240-volt Level 2 chargers typically demand 7.2 kW and 30 Amp to enable charging at a rate of 15 – 30 km of range per hour. Level 2 chargers are also becoming much more accessible to the market: with prices dropping to the hundreds of dollars, they are easily ordered online and installed by most electricians without any notification to the DFO. As reference, the average home electricity demand is approximately 3 – 4 kW; hence, the addition of a charging electric vehicle can almost triple the typical residential customer's electricity demand.

DFOs plan their systems based on a typical electricity demand profile for each home. This involves designing, procuring and installing the infrastructure required for safe, reliable and affordable electricity distribution to customers. Residential customers are placed on a secondary circuit, which is a transformer typically designed to service anywhere from a few to over a dozen homes. However, with the introduction of EVs, there is a threat to the planned lifespan and reliability of existing assets, along with the optimization of assets to be installed. Customer-driven trends moving the sector toward further electrification, which can impact the traditional approach to DFO network design and management. Trends are also moving toward greater intelligence through the Internet of Things (IoT), which enables associated demand-side response mechanisms that can use a control system approach to balance the grid more dynamically at the distribution level (instead of the traditional transmission level) to more efficiently manage the deployment of DERs being connected to the grid, such as EVs, solar PV, battery storage and heat pumps, among others. Statista suggests that the global smart home market is forecast to reach a value of more than USD 40 billion by 2020. Markets and Markets suggests that the global smart home market will be valued at USD 137.91 billion by 2023, growing at a rate of 13.61% between 2017 and 2023. Business Wire suggests that the global smart home market will cross 3.9 million units, growing at a rate of 5.4% during the forecast period 2016 – 2022. McKinsey & Company surveyed approximately 3,000 households for their views on the connected home —revealing distinct customer segments, emerging opportunities and key issues to tackle to unlock growth. There is a significant and growing market need.

Technologies that integrate home automation, micro-generation, electric vehicles, energy storage and grid demand response into a single management control system, and that also feature a dashboard with benefits for both grid operators and residential customers, do not exist. This project developed a novel smart integrated control system that addresses a significant technology gap and is a potential game-changing solution for DFOs and the electricity ecosystem. Current solutions rely on power purchasing decisions based on accessible market factors for third parties. However, there are DFO economics that are not considered and are therefore either neglected or, worse, have issues exacerbated by existing technologies in the market. Traditional behind-the-meter installations of DERs without intelligently designed systems result in inefficient use of these cleaner technologies. Such approaches are not capitalizing on the untapped opportunities of leveraging IoT and smart-grid tools to build a better connection between the residential customer and the DFO that can ultimately solve problems for both parties. There is a market opportunity for a control system that integrates DERs with the smart grid to optimize their use through DFO-residential customer cooperation. Numerous challenges must be overcome, including involving residential customers who typically have not engaged in the DFO ecosystem, understanding the usage profiles of EVs, reconciling user behaviour with orchestration of demands and analyzing the dynamic impact of such orchestration on both the DSO and residential customers. Overcoming these challenges will not only assist with residential customers, but will also provide a stepping-stone into the new energy world.

1.1 NEW ENERGY WORLD

The United Nations Sustainable Development Goals adopted by Canada and 192 other countries include ensuring access to affordable, reliable, sustainable and modern energy for all by building a resilient, sustainable future for our users and communities with innovative energy solutions. These goals, coupled with disruptive market trends such as digitalization, democratization and decarbonization of energy, are changing the role of the utility. Figure 2 illustrates a futuristic view of the potential energy ecosystem in which the grid is now fully bidirectional, evolving from 1 to many relationships towards many-to-many in term of both electrons, data and the transaction. A new energy provisioning paradigm will emerge, with prosumers (producers and consumers), hyperconnected assets, people, buildings, businesses

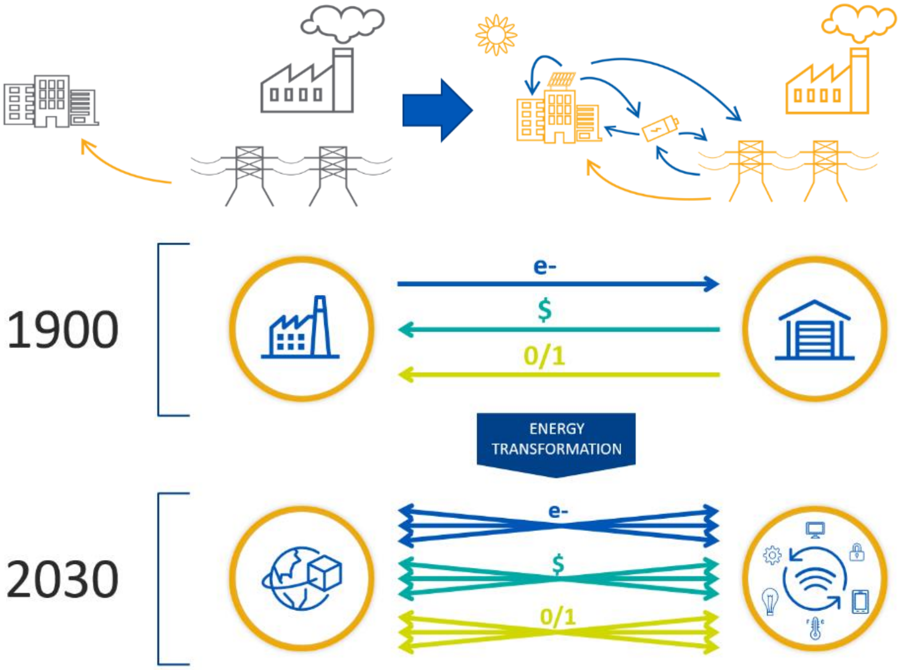


Figure 2: The traditional and new world energy transition

The traditional utility is changing as energy and economics flows face significant changes. ATCO therefore designed the New Energy World innovation roadmap by synthesizing market research and, most importantly, through peer review with subject-matter experts across Canada – see Figure 3.

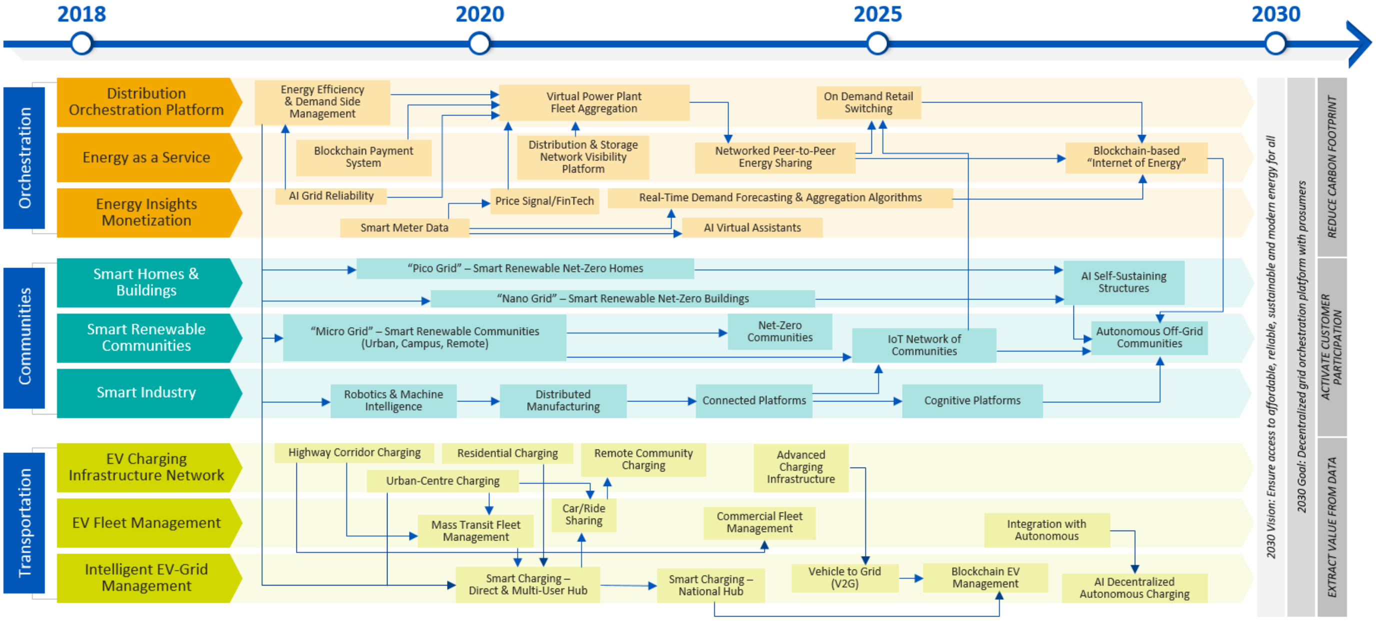


Figure 3: ATCO's "New Energy World" Innovation Roadmap

The Home of the Future was identified as a foundational building block of orchestration integrating numerous capabilities such as energy monitoring analytics, load control and price signals that can be leveraged to further assist in developing commercial and industrial applications. This also reflects the evolving business model of the utility. With more IoT devices facilitating a smart-connecting electricity system, new actors are emerging. The existing role of the DFO owning distribution wires will evolve towards Distribution System Operators (DSO) as we transition to virtual power plants, micro-grids and community aggregation within an intelligent distribution grid – see Figure 4. The grid will become an order of magnitude more complex to manage heterogeneous devices in the New Energy World. The ability to manage this complexity enables new value and new methods of using the grid, hence forming a new business model for the future utility as a grid orchestrator.

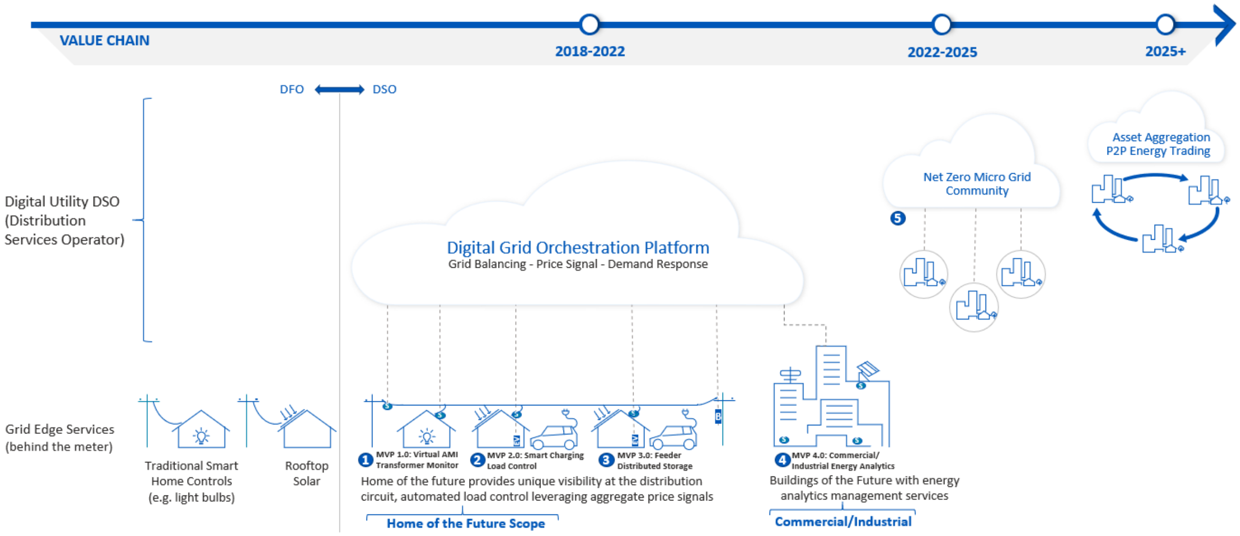


Figure 4: ATCO's Evolution to Grid Orchestrator

1.2 HOME OF THE FUTURE PROJECT

ATCO convened a partnership of predominantly Canadian organizations to work on the Home of the Future project. SAIT provided access to its net-zero energy Green Building Technologies (GBT) Lab and Demonstration Centre to test this project and support the development of trades that advance budding innovative solutions to market. Mitacs was used to work with leading researchers to design a novel system to coordinate energy management systems for the smart grid. AddEnergie provided EV charging station infrastructure, user interface knowledge, EV demand response and real-time grid demand monitoring. Aquanta provided the sensor and controller system for electric water heaters and associated communications interface. Eyedro provided the home electricity monitor to enable visibility of the home load. The Alberta Electric System Operator was also involved to listen and learn about potential code, regulatory and policy changes to consider that would support market uptake. ATCO led the technical design, software platform and algorithm development, and integration and commissioning of the solution, which included the holistic energy ecosystem platform (solar PV, storage, EV, electricity management and customer portal).

The original objective of this project was to address a technology gap that exists in high-performance homes. The largest barrier is the technological fragmentation of the smart-home ecosystem in which consumers need to install multiple networking devices and have numerous apps to run their smart homes. The sector has developed controllers that manage home operations and renewables; however, a smart control system that integrates these functions and includes electric vehicles, energy storage and an ability to feed back to the grid — and which uses smart controls that help with knowing when to use the grid, storage and renewables — has yet to be developed. The ATCO Home of the Future project developed an intelligent integrated control system that manages home energy flow, energy flow to and from the grid and to and from storage.

1.3 PROJECT PIVOTS

Through the customer discovery and validation process early in the project, ATCO confirmed that Alberta homeowners' current willingness to pay for DERs and energy management systems is much lower than the original business assumptions. The project made a pivot (Pivot #1) to engage DSOs as a primary customers as a value proposition became apparent through the discovery process. As a result of the findings from DSO customer engagement sessions following the first pivot, the project's focus shifted from developing a home-centric product to a multi-sided business model that will also include products for DSOs and energy retailers. However, it was still not economical for DSOs to invest in the full-fledged original solution. With Pivot #2, the project focused on developing a cloud-based DSO orchestration platform to allow visibility and control of home loads that will offer cost savings to DSOs, retailers and residential customers. A change in the overall system components to make it more software than hardware dependent, tapping into hardware that already exists in the target market, resulted in a smaller capital investment to make it more commercially viable while ultimately solving the issue for both residential customers and DSOs. The resulting project established a unique set of objectives for the pilot to validate.

2.0 PROJECT OBJECTIVES

The purpose of the Home of the Future project is to validate the effectiveness of a Non-Wire Alternative (NWA) solution at the grid-edge to manage and orchestrate new electric load at the distribution level, namely DERs (EV charging stations and hot water tanks) behind the meter, and to assess the business impact compared to traditional capital infrastructure upgrades – see Figure 5. NWAs are essentially active and dynamic software control systems and advanced analytics that provide energy flow control to defer or replace the need for traditional poles and wires distribution projects. This is typically done at lower total resource cost, by implementing demand-side management and congestion control to maximize existing asset use.

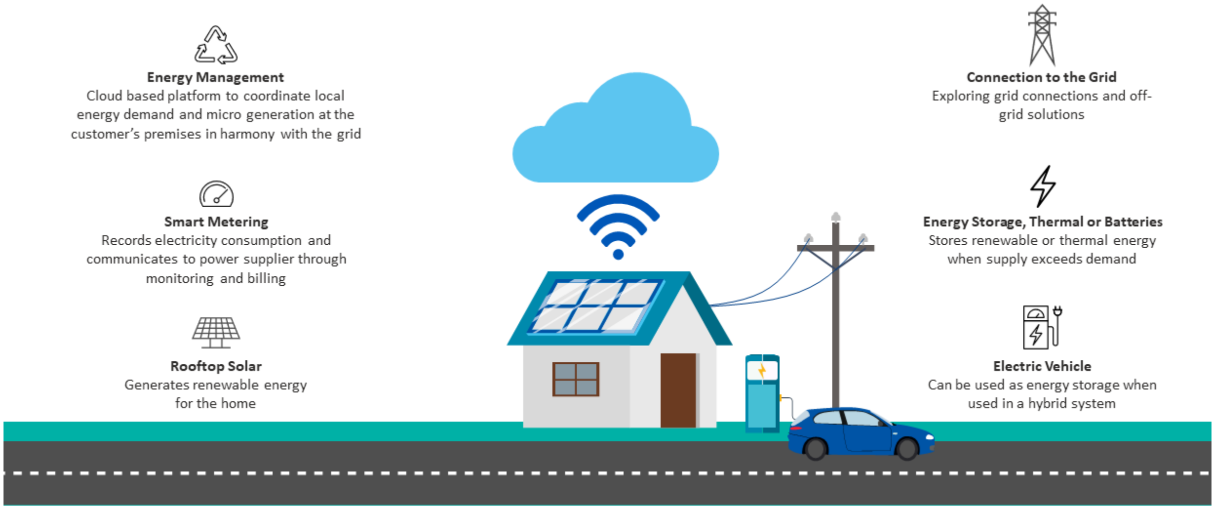


Figure 5: ATCO Home of the Future — Intelligent Energy Orchestration

In addition, a multi-sided business model approach was developed to serve multiple stakeholders in the residential electricity value-chain system as depicted on Figure 6.

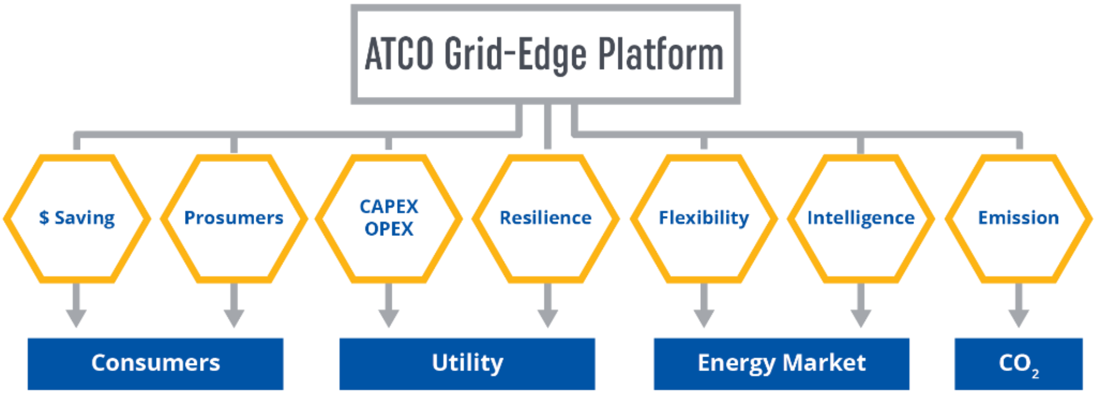


Figure 6: ATCO's Grid-Edge Platform multi-sided business model

ATCO has developed a software-based energy flow control and congestion management tool similar to how telecommunications networks are architected. The core innovative capability of our approach is a solution that provides benefits throughout the energy value chain. By understanding and optimizing the impact on the distribution grid, utilities and residential customers can be rewarded as active participants with increased reliability and potential additional incentives provided by the DSO as a shared investment saving program.

As the market trend of EV penetration continues, residential EV charging could force DSOs to reinvest in operational infrastructure, wherein justification to the regulator to increase capacity might not always be accepted or cheap, or could force the DSO to adjust its resource management to focus on residential neighbourhoods that they could previously “set-and-forget” assets with a typical expected lifetime based on lower demands.

For DSOs, this project aims to:

- Understand the impact of EVs and large loads on the residential distribution grid assets;
- Develop situational awareness of energy consumption within the home as well as aggregate utility level;
- Develop a platform to control residential loads to minimize their impact on distribution grid assets;
- Develop an automated decision-making engine to allow optimization of utility infrastructure resources through demand-side management;
- Enable a new way for utilities to communicate with homeowners and the grid to improve energy security and grid stability;
- Integrate control systems that better manage the implementation of grid-intensive activities that customers wish to add to their homes to ensure maximum grid performance for all; and
- Establish the Utility of the Future by evolving the role of utilities and their ability to leverage distributed energy resources for the benefit of the utility grid, while providing value to customers.

For residential customers, this project aims to:

- Provide awareness of home electricity demands, particularly large EV demand, to facilitate transparency and greater agency in their home energy management; and
- Leverage smart charging to allow a larger number of EV charging stations to be coordinated to ensure grid resiliency.

For energy generators and retailers, this project aims to:

- Provide visibility into energy usage of residential customers in aggregate to inform energy procurement; and
- Enable more transparency of residential energy usage for residential customers to limit negative engagements with retailers.

A potential multi-sided business model, shown in Figure 7, whereby a profit-sharing model to incentivize customer participation that is funded by distribution and generation/retail utilities benefiting from the proposed grid-edge load management platform through capital investments savings.

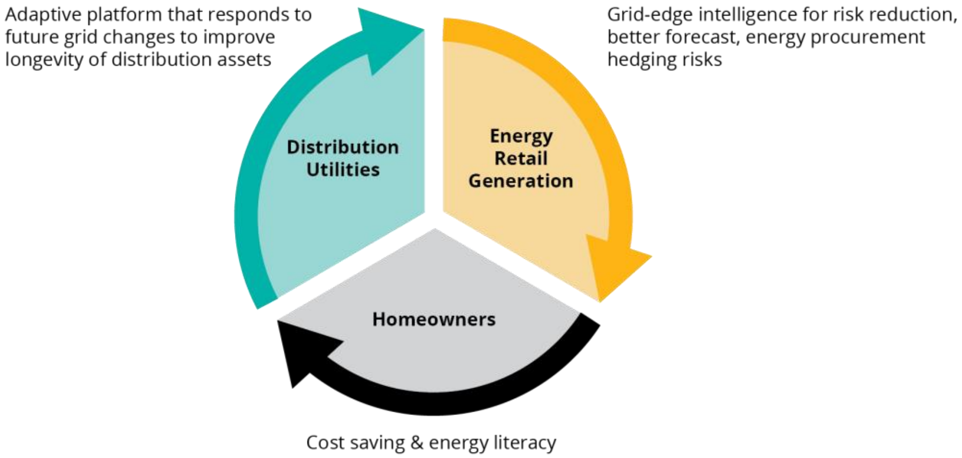


Figure 7: ATCO's Home of the Future Multi-Sided Business Model

2.1 HIGH-LEVEL DESIGN

The Home of the Future uses data analytics and situational awareness to deliver energy orchestration through more interactive data exchanges between the distribution network, consumers and orchestration platform. The pilot project aggregates individual smart meter data or sensors in the breaker panel and within IoT technologies in the home to establish the architecture of a secondary distribution circuit that is typically found in a residential neighbourhood. The core differentiating value proposition is the engineered price signal dispatch that optimizes decisions based on a multitude of factors such as weather, carbon intensity, residential load and aggregate load at the neighbourhood's transformer.

The project aims to validate the operations of the Home of the Future orchestration engine seen below on Figure 8. This engine can acquire data from multiple sources, including EV demand, home load and distribution circuit load to deploy informed demand-side management control decisions to the EV charger. The goals of the solution include:

- Developing a smart integrated controls platform that uses IoT technologies (protocols, software and sensors) to combine benefits of EVs, solar generation and electric hot water tanks with the ability to strategically shed or shift loads to optimize energy consumption from the electrical grid;
- Strong customer participation and incentives through real-time behavioural dashboard, and home portals that make energy visible and incentivize conservation;
- Growth of a home smart "pico" grid combining real-time control via edge devices deployed to residential homes with the power of cloud computing to coordinate decisions across a fleet of distributed energy resources. This allows the aggregated DERs to act as a virtual power plant, replacing the need for traditional and inefficient reserve generation capabilities used today; and
- Software development to leverage machine learning to make recommendations and/or automate scheduling and dispatching of a residential customer's power demand from the grid or optimize their usage through demand-response signals, providing grid stability and feeder-line cost deferral.

Project objectives also included connecting into existing IoT technologies prevalent on the grid without the need to add additional expensive hardware.

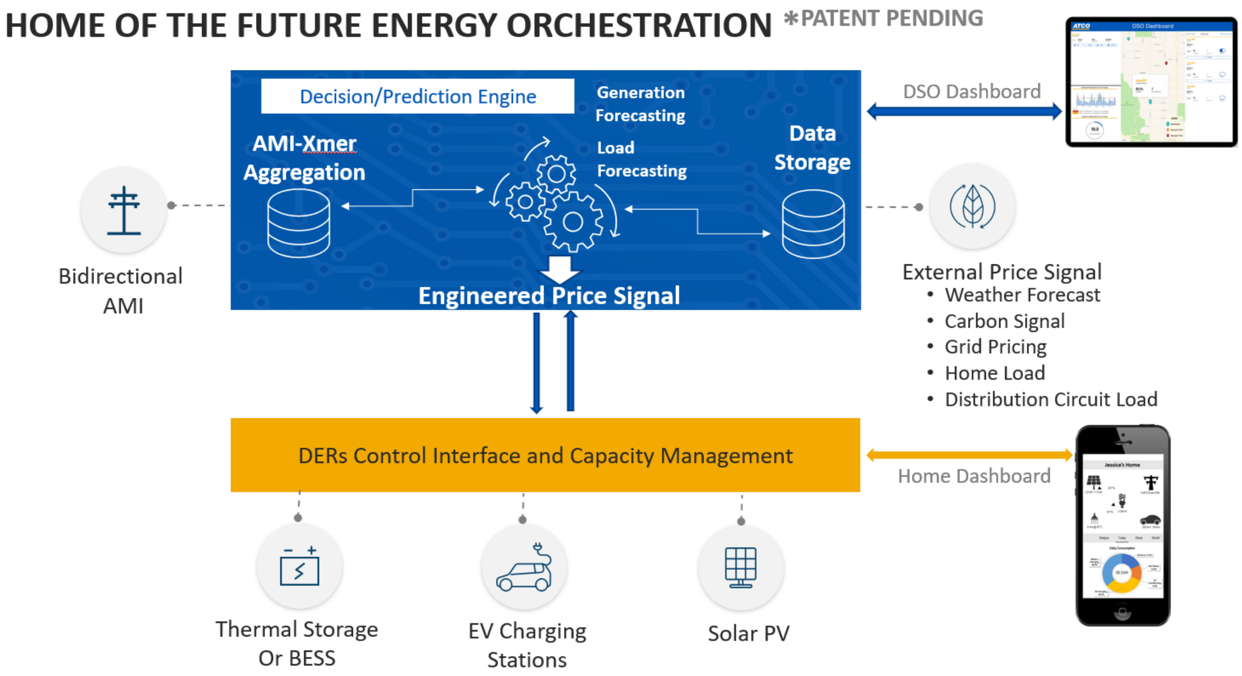


*Figure 8: ATCO Home of the Future Orchestration Engine (*Patent Pending)*

3.0 METHODOLOGY

The project methodology was divided into 6 phases as follows.

- **Phase 1**: Data collection, visualization, customer discovery and value proposition development.
- **Phase 2**: High-level system design, hardware installation and lab setup at SAIT.
- **Phase 3**: Establish DSO-to-home-DER communication and manual control dispatch capability.
- **Phase 4**: Automated DER dispatch and dynamic price signals.
- **Phase 5**: Pilot deployment and field testing with AMI data integration.
- **Phase 6**: Commercialization — conducting market research and business model development.

Phase 1: Data Collection, Visualization, Customer Discovery & Value Proposition Development

In Phase 1, the initial step was to understand and model home energy usage, determine base load and new additional EV load, identify patterns, and how load forecasting can be modelled. ATCO had installed smart meters with load disaggregation in six employees' homes and collected data for 12 months prior to starting this project. We developed and trained a machine learning model to determine if it was possible to accurately predict and forecast individual home energy consumption. We also created our initial business model canvas, customer survey and customer discovery sessions to validate our initial hypotheses. A few pivots were necessary as we gathered more evidence, conducted primary research and further validated our hypotheses. The initial business model canvas is included in Appendix E: Business Model. The final value proposition is discussed in the Project Results and Outcomes section.

Technical Objectives for Phase 1

- Data acquisition of DER energy flows (solar, storage, EV) and dashboard portal; and
- Initial machine learning (home user behavioural learning).

Metrics

- Hardware equipment installed and continuously operational for three months with base energy management coordination functionality enabled.

Home load forecasting model

Figure 9 below is a home load forecast output predicted from a long short-term memory (LSTM) model trained with 12 months of data from a single home. LSTM is artificial recurrent neural network architecture for deep learning. The goal of LSTM is sequence prediction (i.e., time-series forecasting).

When evaluating the performance of a time-series forecast there are two sets of error measures: training and testing. Training error is calculated by running the model on data it has already trained on. This is used for parameter optimization and is not sufficient for evaluating the performance of the model.

In order to evaluate the performance of our model under testing, we use the root mean-squared error (RMSE) to measure the error for time-series forecasting. The RMSE is in the same units as the target variable (kWh). The expectation is that the prediction can and will deviate ±1 RMSE value. In our testing, with a new set of data, the testing error measures was 'rmse': 0.439 for a model trained with a single home of 12 months of historical data. As can be seen in Figure 9, this level of error enabled the general trend of the electricity use to be captured by the prediction model but not all of the details. A more frequent model re-training and or creation of multiple models that would separate week days vs weekend and seasonality change should be explored further to reduce the prediction error.

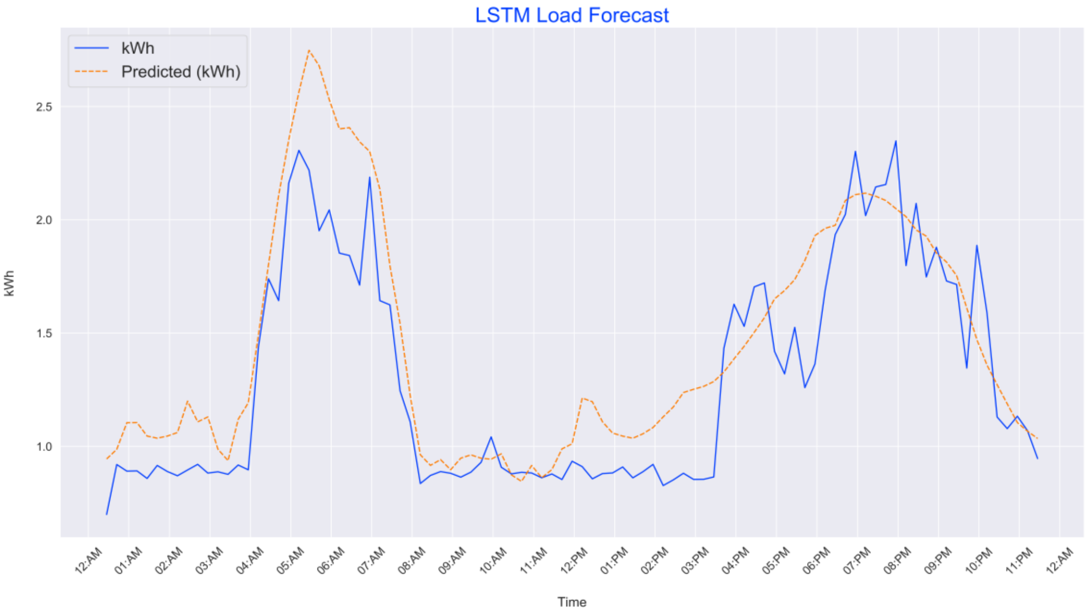


Figure 9: LSTM Model Load Forecasting After Training the Model with 12-month data for a Single Home

In Figure 10 below, we trained the model with data from a group of six homes instead of an individual home to determine if we can save processing power/time by training an aggregate data set as opposed to a single individual home. The prediction error was too high to be a reliable approach. The testing error was 'rmse': 0.781

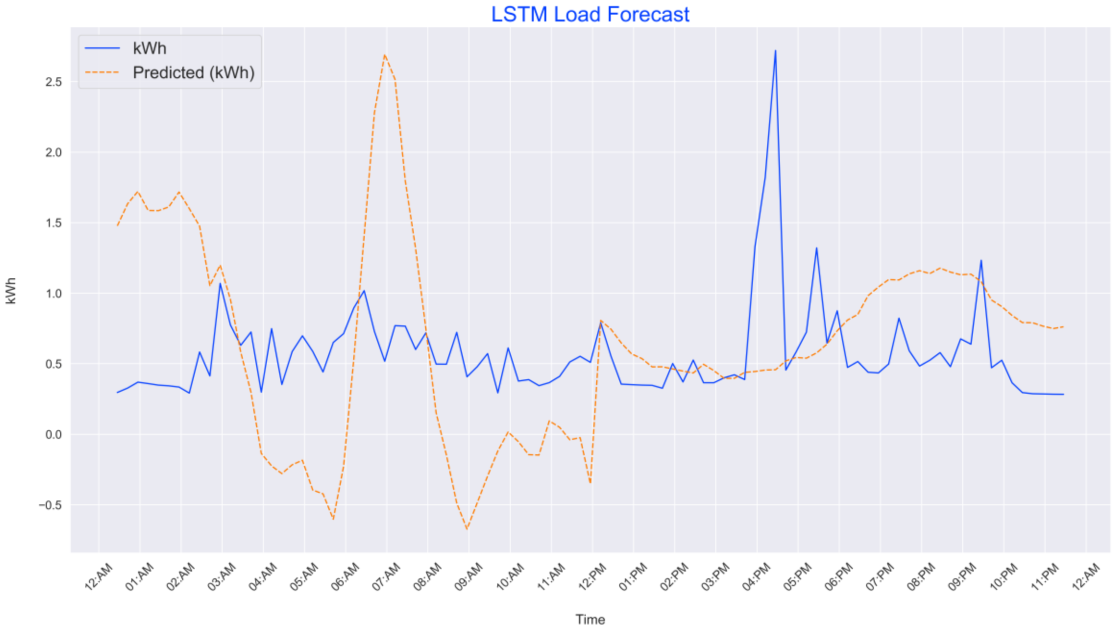


Figure 10: LSTM Model Forecasting After Training the Model with Aggregate Data from Six Homes

Phase 2: High-Level System Design, Hardware Installation & Lab Setup at SAIT

The focus of Phase 2 was to develop the initial minimum viable product (MVP) software and hardware architecture, setup the lab environment, integrate API with all DERs to be controlled and establish initial software communication through API. A capital-light methodology for devising this solution was to deploy it on existing hardware solutions to mitigate expensive development costs that would be put toward the software intelligence. For the hardware, we selected proven technologies in the market that have API communication capabilities such that our software can use their functions.

Technical Objectives for Phase 2

- Use Internet of Things technologies (protocols, software and sensors) to combine the benefits of traditional solar generation and storage.

Metrics

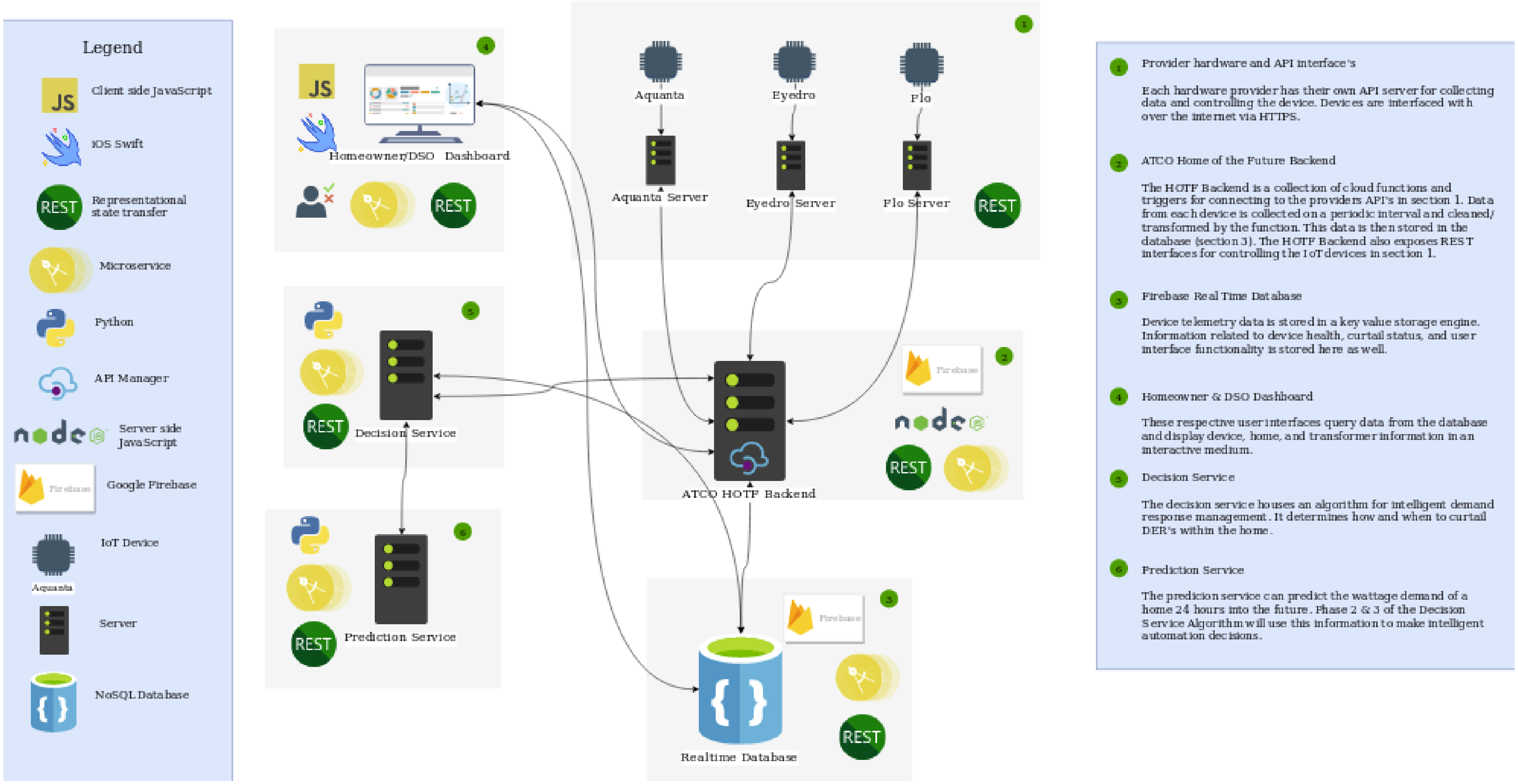
- Hardware equipment installed and continuously operational for three months with base energy management coordination functionality enabled.

The following hardware components were selected.

- AddEnergie FLO X5: A home Level-2 EV charger;
- Aquanta Smart Water Heater Controller — An after-market sensor and controller that can be installed on electric resistive hot-water heaters; and
- Eyedro WiFi EYEFI.4 and Wired EHEM1 — An electricity monitor designed for residential circuit panels to gather energy usage data. The Eyedro was used as a substitute to utility-provided AMI smart meters to minimize integration time.

For the software and data analytics infrastructure, we opted for a cloud-based approach leveraging API to control DERs behind the meter. The technical implementation of grid-edge services and DSO orchestration has been structured as a collection of distributed microservices as shown on Figure 11 and **Error! Reference source not found.**. Each IoT device is encapsulated by its own service, containing custom business logic, control architecture and data storage. The orchestration and control of these devices takes place via HTTPS requests between ATCO's custom server infrastructure and the device's exposed APIs.

For this implementation, ATCO chose the Google cloud for server infrastructure. Specifically, the Firebase subset of products is being employed. Firebase is Google's mobile application platform focused on rapid application development. It is an all-in-one management and development suite for applications. Functionality for analytics, databases, messaging, crash reporting and automatic scaling are inherent in Firebase deployments. Of the multiple product offerings by Firebase, the HoF (Home of the Future) project employed Cloud Functions and the Real Time Database. A cloud function is a compute product for creating event-driven applications. With cloud functions, the developer creates single-purpose functions that are triggered by events emitted externally via HTTPS requests or internally via cloud infrastructure and services. Code runs in a fully managed environment without the need for explicit hardware allocation. The Firebase Real Time Database is the flagship NoSQL cloud database offered by Google. Data is synced across all clients in real time and remains available when the application is offline. The Real Time Database stores data in a JSON key value structure in a schema-less fashion. This is a highly simple storage solution that emphasizes performance, scalability and ease of integration with applications and clients that use the data.



1 Provider hardware and API interface's

Each hardware provider has their own API server for collecting data and controlling the device. Devices are interfaced with over the internet via HTTPS.

2 ATCO Home of the Future Backend

The HOTF Backend is a collection of cloud functions and triggers for connecting to the providers API's in section 1. Data from each device is collected on a periodic interval and cleaned/transformed by the function. This data is then stored in the database (section 3). The HOTF Backend also exposes REST interfaces for controlling the IoT devices in section 1.

3 Firebase Real Time Database

Device telemetry data is stored in a key value storage engine. Information related to device health, curtail status, and user interface functionality is stored here as well.

4 Homeowner & DSO Dashboard

These respective user interfaces query data from the database and display device, home, and transformer information in an interactive medium.

5 Decision Service

The decision service houses an algorithm for intelligent demand response management. It determines how and when to curtail DER's within the home.

6 Prediction Service

The prediction service can predict the wattage demand of a home 24 hours into the future. Phase 2 & 3 of the Decision Service Algorithm will use this information to make intelligent automation decisions.

Figure 11: ATCO Home of the Future System Architecture Diagram

Phase 3: Establish DSO-to-Home DER Communication & Manual Control Dispatch Capability

In phase 3 we established the DER registration and data collection database infrastructure onto ATCO's orchestration platform and enabled data exchange communication between the home owners' meter and ATCO's cloud-based infrastructure. A lab environment was configured at SAIT to allow initial manual dispatching and communication testing. A test plan was developed to ensure DER control and curtailment were well synchronize and accurate.

Technical Objectives for Phase 3

- Development of DSO demand-response server communication protocol between DERs in home and DSO dispatch center; and
- Establish smart integrated controls platform that integrates cloud computing and communications to coordinate with PV solar and DERs at the home.

Metrics

- SAIT home platform prototype proven to control DERs from cloud-based commands.

Error! Reference source not found. shows the overall cloud based system architecture and the communication path between the DERs under control and the orchestration engine where curtailment decision are made (firebase real time DB).

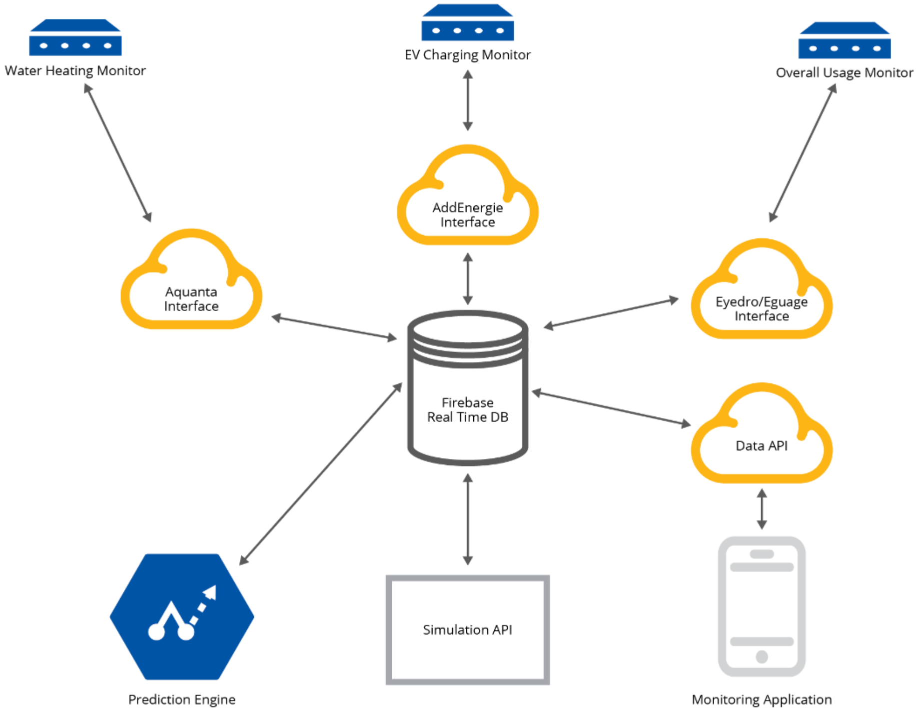


Figure 12: ATCO Home of the Future software and hardware Infrastructure

On Figure 13, we show a more detailed representation of the DERS hardware under control, namely EV charging station from addenergie, electric hot water tank controller from Aquanta, aenergy monitoring sensors (emulating smart meters) from eyedro.

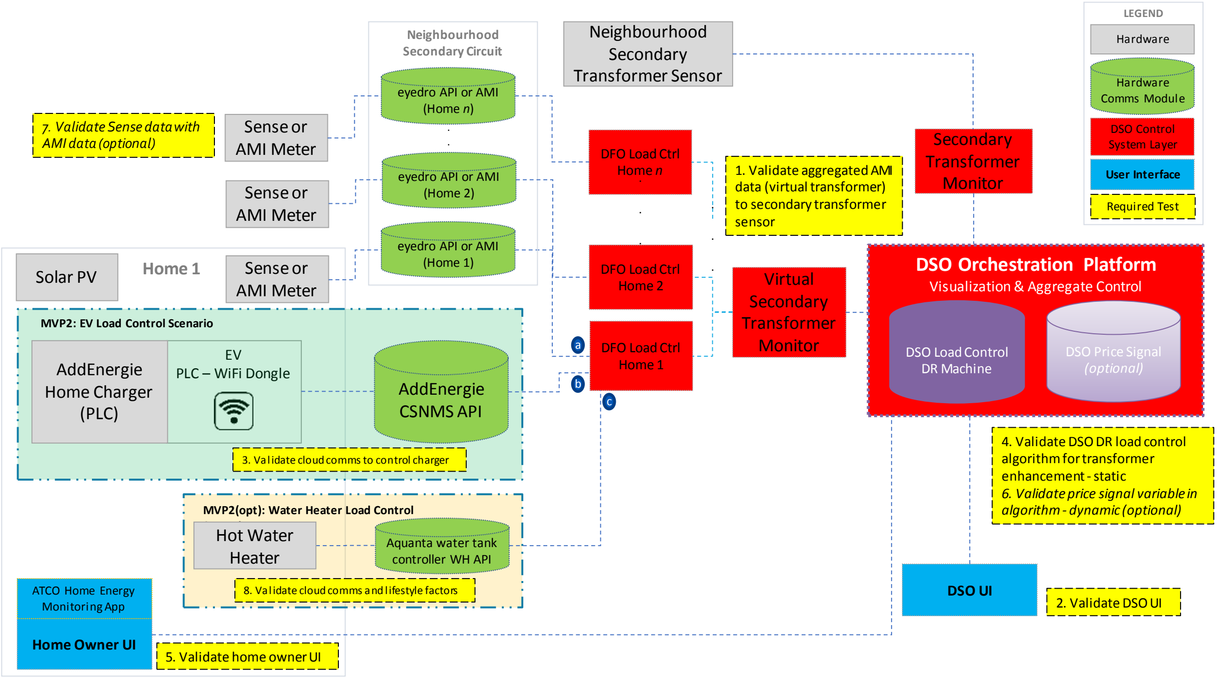


Figure 13: ATCO Home of the Future DERs under control Block Diagram

Manual dispatch and communication testing were conducted by turning devices on or off using the web-based API and following a prescribed test plan. (see Appendix F: Software Testing for more details).

Phase 4: Automated DERs Dispatch & Dynamic Price Signals

We created and implemented an autonomous energy flows orchestration platform, comprising a rules engine, price signals and DER dispatch control. The automated orchestration platform collected real-time data and made decisions automatically on which DERs to shed/load control, thus reducing peak demand to protect and eliminate distribution circuit overload (and minimize asset loss of life). One of the novelties of this project is a multi-factor dynamic price signal aimed at extending utility asset life at the secondary distribution circuit level by preventing continuous overload. We developed and implemented tailored algorithms that were enabled by a rules engine and informed by a series of real-time data points queried from limited data sources.

Technical Objectives for Phase 4

- Develop a smart integrated controls platform that:
  - Provides the ability to strategically shed or shift loads to optimize DSO transformer loading and/or energy consumption from the electrical grid; and
  - Integrates cloud computing and communications to control, load shift and throttle home EV charging and thermal storage according to demand-response (DR) signal.

Metrics

- ATCO installs prototype system at SAIT (EV charging station and water heater system) that allows for automated scheduling and dispatch through demand-response signals to optimize transformer loading and energy consumption from the grid. Prototype system is used successfully for 60 events requested over 14 days.

In our Home of the Future project, data sources included:

- In-house connected sensors:
    - Total, aggregated home energy consumption;
    - Water heater energy consumption; and
    - EV charger energy consumption; and
- External feeds:
    - Energy market price;
    - Grid carbon mix (i.e., % of renewables vs. fossil generation);
    - Real-time transformer energy load and capacity nameplate; and
    - EV state of charge (estimates).

The rules engine will dispatch an engineered price signal according to the following two main principles.

- When the transformer loading reaches warning state, a 'meritocratic' dispatch occurs whereby, load is curtailed proportional to each individual home consumption to meet available secondary circuit capacity to achieve a normal transformer loading.
- When the transformer reaches overload state, a 'egalitarian' dispatch occurs whereby, load is curtailed equally, independent of individual home load to meet available secondary distribution circuit available capacity until transformer operates in normal zone.

The software components were primarily focused on API data exchange communications and algorithm design. The algorithm design approach consists of a state machine and a decision rules engine that determines which DER to shed or load to control and when (state dependent). The operational state of the transformer (normal, warning, overload) is determined by the overall grid transformer capacity to handle energy demand and its effect on asset longevity.

One of the key components of smart grid DER integration is that the pricing and reliability information known at the grid system or utility level must be transmitted and translated into load-reducing actions at the customer sites. Engineered price signals are dynamic and temporary based on factors such as near real-time load data, asset data and others. The approach to developing a unique price signal is different than those commonly found today in the market of smart energy technologies, which is noted below as the Classic Price Signal.

The Classic Price Signal relies on the price of energy consumption in kWh defined by the retailer and, if applicable, established time-of-use rates. The delivery charges, also known as the transmission and distribution charges, consist of fixed and variable components that the utility manages and passes through to the residential customer via their energy bill from their retailer. These charges are designed to essentially remunerate the DSO for their cost of maintaining a safe, reliable and accessible network to provide energy. Such costs include asset design, ownership and management, which was previously somewhat predictable. However, the emergence of DERs challenges these assets and can disrupt the designed life on the network based on their energy demand and not necessarily consumption.

The Classic Price Signal found in the industry today does not account for these costs upon the DSO, so ATCO devised an Engineered Price Signal that incorporates the economic impact of large loads to DSO assets to inform demand-side management in an economic and acceptable manner: it manages asset life for the utility while not negatively affecting the lifestyle of the residential customer.

The Engineered Price Signal can be broken into three evolutionary steps: 1) the basic Engineered Price Signal only focuses on the home load and transformer load; 2) the full Engineered Price Signal adds factors such as EV load, energy pricing, hot water temperature, solar production and carbon intensity; and 3) the Predictive Price Signal incorporates machine learning to forecast all these factors to pre-determine smart-grid actions and proactively manage situations. With the current state of EV deployment and understanding of energy usage profiles, we decided not to fully pursue the Predictive Price Signal within this pilot project as it is not solving a significant enough problem to make it a viable investment, but we have made some incremental analysis and development in this field.

Equation 1summarizes the different approach of price signals. Figure 14 illustrates the key parameters we used in ATCO engineered price signal, which is essentially the evolution of the classic price signal.

Price Signal Functions

Classic Price Signal = function of (Energy price, Time of Use)

Basic Engineered Price Signal = function of (Transformer Load, Home Load)

Full Engineered Price Signal = function of (Transformer Load, Home Load, EV Charge, Hot Water Thank Temp, Price of Energy, Carbon Intensity, Solar Production)

Equation 1: Grid Price Signal Functions

The price signal reflects the various methodologies a utility would be interested in pursuing, including the current price-driven algorithms that exist, the emerging incentive– or event-driven approaches and, finally, the new infrastructure resilience approach this project is incorporating; see Figure 14.

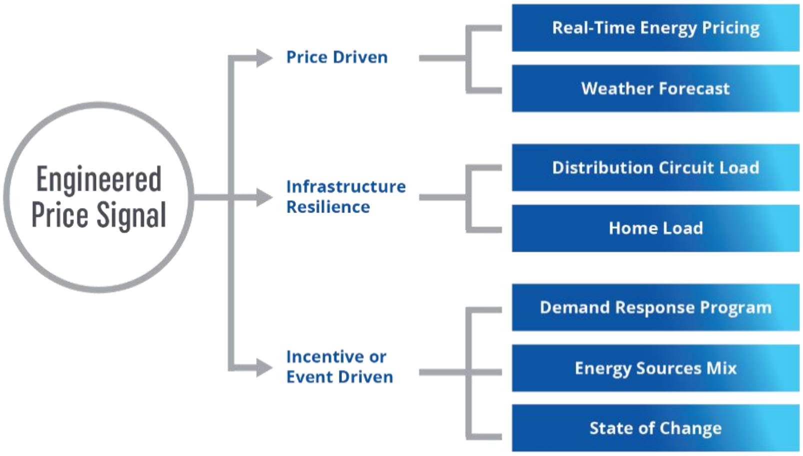


Figure 14: Home of the Future Engineered Price Signal

Phase 5: Pilot Deployment & Field Testing with AMI Data Integration

Phase 5's focus was on pilot deployment and associated logistics, customer opt-in and live DER orchestration in Lethbridge with 9 homes under control and management (+7 virtual homes used in modeling and simulations). We also conducted, as a complementary exercise, a series of hybrid simulations where we injected real Lethbridge pilot data into a computer simulation to further analyze performance impact and cost-benefits of infrastructure resilience; this involved applying DER orchestration for EV smart charging to manage secondary distribution circuit overload conditions under a wide range of scenarios to further validate the operational range impact.

Technical Objectives for Phase 5

- Development of AMI aggregation system to provide DSO visibility to the loading on secondary transformers supplying homeowners.
- Software development to leverage communication technologies, artificial intelligence/machine learning to provide automatic DSO control of DER load consumption.
- Enable the integration of EV charging stations and manage the distribution grid implications for charging at home by extending asset life span and/or cost deferral.

Metrics

- In an interested DSO's jurisdiction, installation of DERs — solar PV, EV charger and thermal storage (if available) — at a home, operating with control from the DSO Energy Management System (EMS) for four weeks.
- Confirm that the AMI aggregation system provides accurate data for transformer loading compared to transformer-installed sensor data.
- DSO EMS will automatically schedule and dispatch homeowners' DERs (EV charger and thermal storage) using desired price signals for a four-week duration based upon real-time AMI-collected data.

Figure 15 below summarizes the pilot deployment timeline. Figure 16 illustrates the Lethbridge pilot deployment infrastructure and communication with ATCO orchestration platform

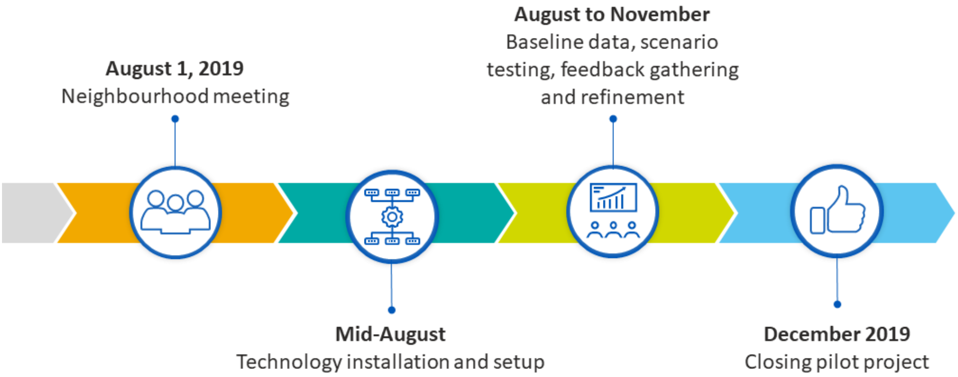


Figure 15: Phase 5 Pilot Installation/Deployment/Operation Schedule

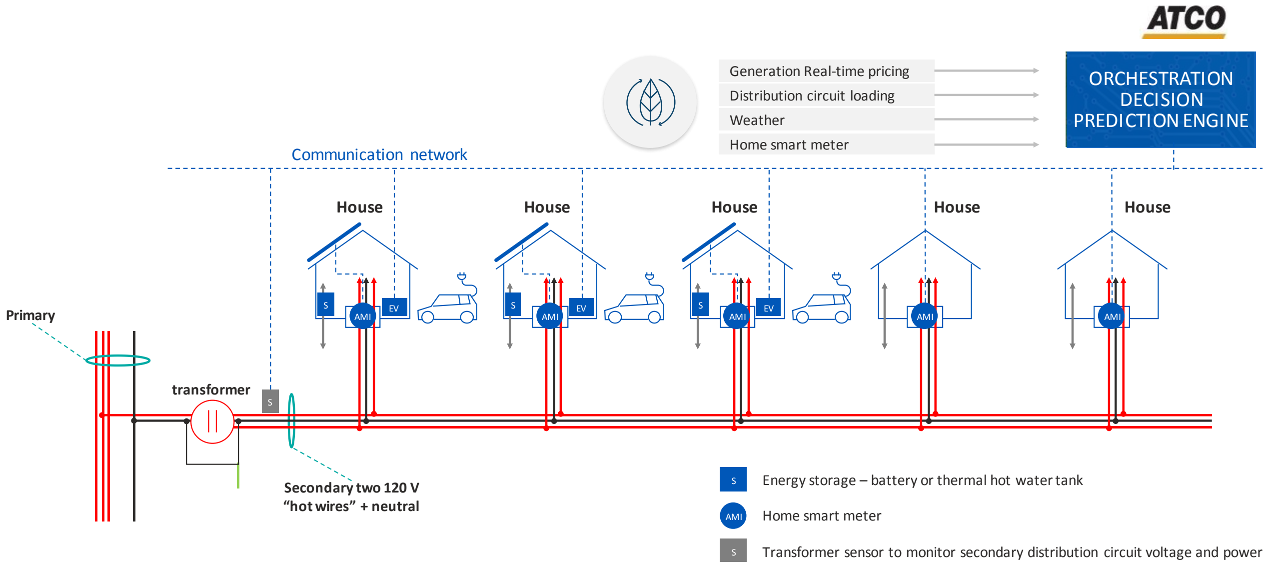


Figure 16: ATCO Home of the Future Overview Pilot Diagram in Lethbridge

Hybrid Simulations

As mentioned earlier, in addition to the live pilot deployment, we also developed simulation models to validate our DER orchestration algorithm to measure its long-term impact on infrastructure resiliency. The approach for infrastructure resiliency was chosen to focus on the lifespan of the secondary transformers servicing the neighborhoods, which is typically a "run to fail" for utilities. The run-to-fail approach is challenged by major disruptions in electricity demand than previously designed for; hence, this project will target transformer lifespan optimization.

The key variable is the transformer overheating due to being overloaded, which is exemplified by the hottest spot temperature (HST). The hottest spot temperature (HST) is the sum of all these two deltas, i) the top oil temperature rise over the ambient temperature, ii) the winding hot spot temperature rise over the top oil temperature, and the ambient temperature. This approach is utilized to determine the ageing acceleration level of the insulation as a result of the thermal behavior of a distribution transformer.

Thus, HST examines the effect of demand response on the ageing characteristics of a distribution transformer. The reference HST is 110°C for a typical transformer with a 20-year life span when an upgraded winding insulation type of 65°C average winding rise is used. If a non-upgraded winding insulation type of 55°C average winding rise is used then the reference HST is 95°C. The winding rise is an accumulative process, it is calculated by summing up the above 3 terms(top oil temperature rise, winding hot spot temperature rise, and the ambient temperature) over every time period (one hour or one minute as in our project). HST calculation itself doesn't take the average. The objective is to measures the continuous and accumulative effect of the real-time load on the transformer over time. This information plays an important role to estimate the transformer ageing and eventually its lifespan.

Phase 6: Commercialization — Establish Business Model, Conduct Market Research & Customer Discovery to Identify Entry & Scale Markets

The last phase of our project methodology, Phase 6, focused principally on product development, product-market fit and commercialization. We consolidated all the customer discovery learnings from the previous phases, and identified relevant commercial opportunities to deploy at a large scale should ATCO decides to pursue this opportunity further. We conducted several meetings with Lethbridge Electric Utility, town halls with homeowners, phone calls and research in social media, among other resources. It should be noted that customer discovery and product market-fit was conducted at each phase as an iterative process (not only in Phase 6), and learnings were consolidated in Phase 6. This is discussed further in the Commercialization section.

Technical Objectives for Phase 6

- Validation of the benefits to DSOs of distributed energy architecture that will reduce the need for new generation, transmission and distribution assets.
- Validation of benefits to homeowners and retailers.
- Development of commercialization strategies for deploying the multi-sided business model within Alberta, targeting DSOs, energy retailers and homeowners.
- Development of commercialization strategy for deployment in other jurisdictions.

Metrics

- Development and attraction of highly qualified people at ATCO.
- Business models developed and tested at pitch sessions.
- Achieving a single letter of intent for the product in any of the Alberta markets (DSO, energy retailer or homeowner) or an external market.

4.0 PROJECT RESULTS & OUTCOMES

The Home of the Future DER orchestration engine algorithm pilot deployment and hybrid simulations have produced very significant results that show that our algorithm could be used as a viable non-wires alternative and a foundational component for smart grid modernization. The simulations incorporated real pilot data injected into a simulator to study a broader range of deployment scenarios.

We demonstrated, through the live pilot in Lethbridge as well as modelling and simulations, significant improvements in terms of peak-load reduction, resulting in asset life improvement of the secondary distribution circuit transformer, capital investment deferral and GHG emissions reduction. More details on these results are provided in the following sections.

4.1 PILOT OPERATIONAL CONFIGURATIONS

Test layout: a typical rural transformer of 50 kVA would have between 13 and 16 homes connected to it and a typical urban transformer of 37 kVA would have 13 homes connected. Since only nine real homes were deployed in the Lethbridge pilot, four and seven virtual homes were included in the analysis to represent typical transformer deployments in rural and urban areas.

The nine real homes included four homes with EVs, two of which also have solar and a third has an electric hot water tank and electric baseboard heating. The remaining fivehomes were instrumented with smart meters to capture their baseload but had neither EVs nor electric hot-water tanks. Below is a list of each home and the equipment they had on site.

Lethbridge homes Pilot Configuration

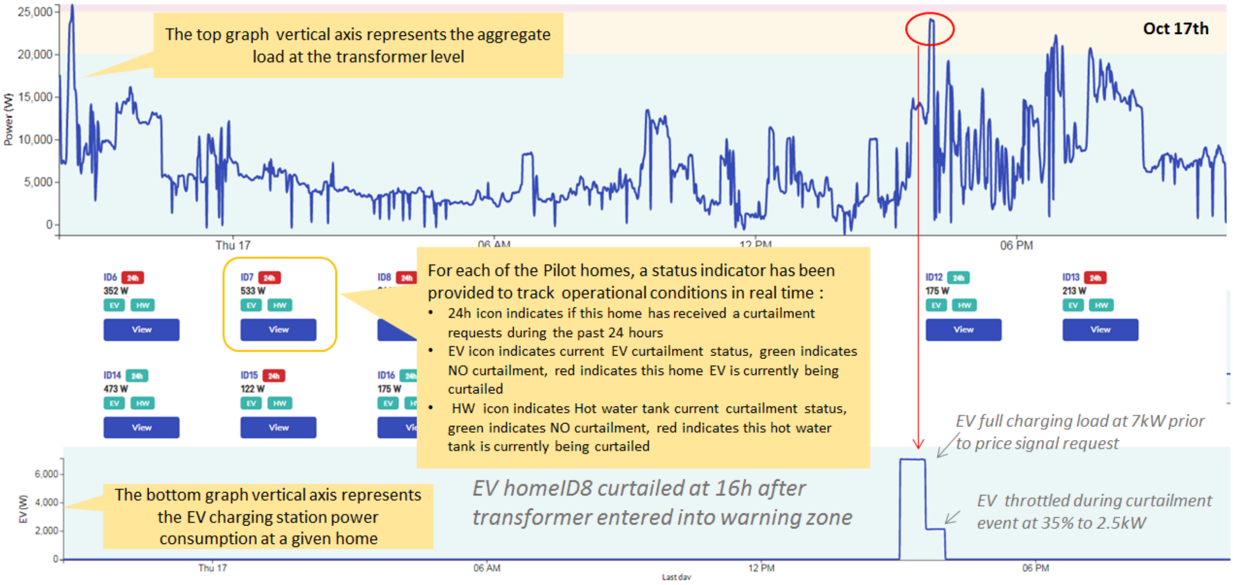
- Home ID 6: smart meter, EV, Solar PV
- Home ID 7: smart meter, EV
- Home ID 8: smart meter, EV, Solar PV
- Home ID 9: smart meter, EV, electric hot water tank
- Home ID 10: smart meter only
- Home ID 11: smart meter only
- Home ID 12: smart meter only
- Home ID 13: smart meter only
- Home ID 14: smart meter only

In order to emulate more precisely the characteristics of a full active 16-home neighbourhood on a 50 kVA transformer and 13 homes on 37.5 kVA, we developed a simulator in which we injected real traffic load collected from the nine Lethbridge pilot homes, complemented with a set of additional virtual homes. For the four and seven virtual homes, we replicated a subset of the real Lethbridge pilot homes to compute and model different transformer load conditions This will be discussed in the next section. A probability distribution function for EV arrival time and charge time was used. More details can be found in Appendix G: Modelling Parameters.

4.2 OPERATIONAL PILOT & DSO DASHBOARD RESULTS

The results in this section are from the operational pilot that took place from August to November 2019 in Lethbridge. One of the tools that was developed, the DSO dashboard, has been very useful for analyzing and monitoring performance and behaviour of the system at the secondary distribution circuit transformer at the aggregate level.

The purpose of the DSO dashboard is to provide live visualization of the whole system behaviour and performance from the utility perspective. We created a web application that extracts data from our cloud platform, in real time, and creates a visualization dashboard to allow observations of the pilot deployment and display the load shifting/curtailment events, etc. Figure 17 is an illustration of the DSO dashboard and provides info on how to read the different levels of information. The top portion indicates the aggregate power consumption at the transformer level, that is, the sum of all homes. The bottom graph is a zoomed in view on one home EV charging station power consumption that is being dispatch according to the algorithm monitoring the transformer loading conditions



The top graph vertical axis represents the aggregate load at the transformer level

For each of the Pilot homes, a status indicator has been provided to track operational conditions in real time :

- 24h icon indicates if this home has received a curtailment requests during the past 24 hours
- EV icon indicates current EV curtailment status, green indicates NO curtailment, red indicates this home EV is currently being curtailed
- HW icon indicates Hot water tank current curtailment status, green indicates NO curtailment, red indicates this hot water tank is currently being curtailed

EV full charging load at 7kW prior to price signal request

The bottom graph vertical axis represents the EV charging station power consumption at a given home

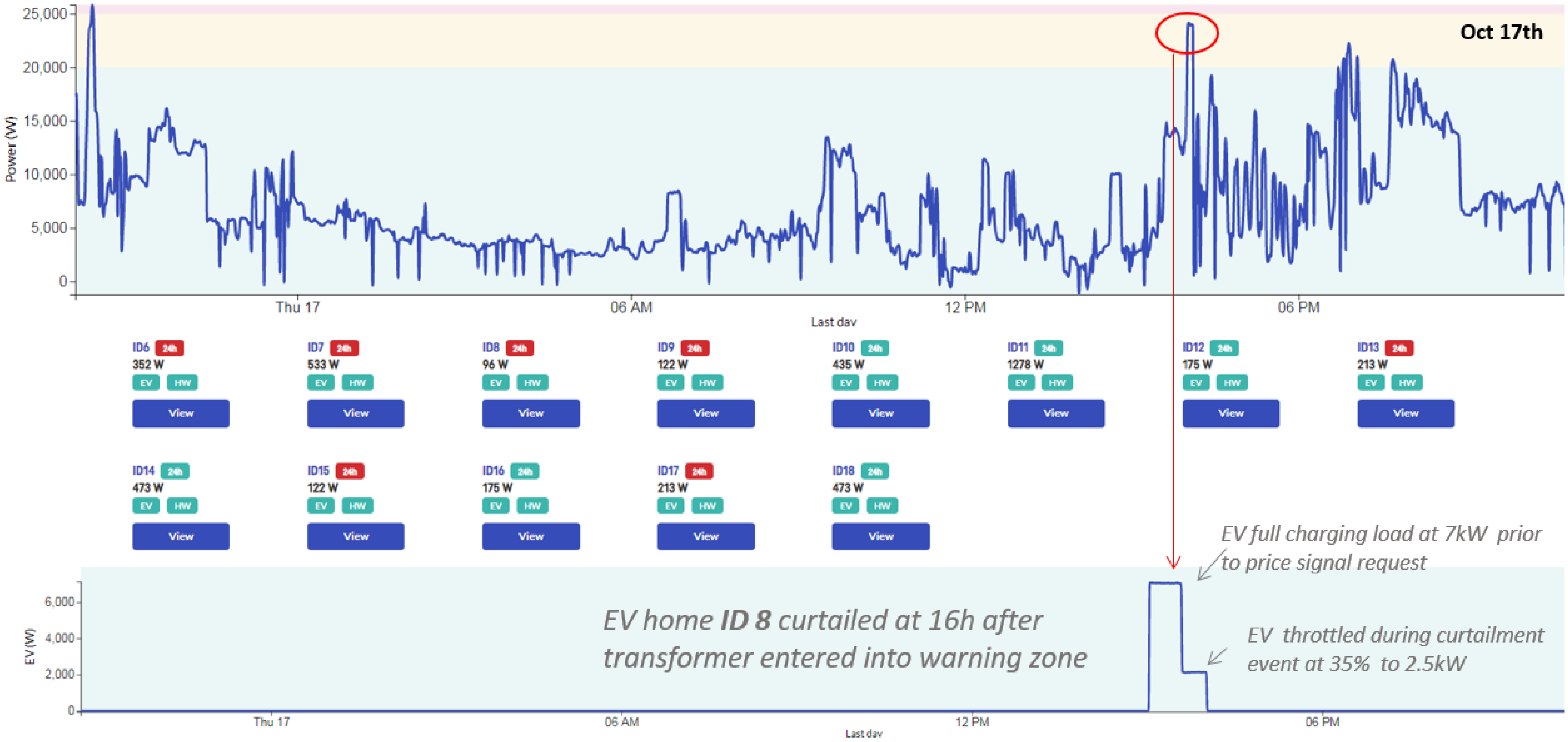
EV homeID8 curtailed at 16h after transformer entered into warning zone

EV throttled during curtailment event at 35% to 2.5kW

Figure 17 DSO dashboard- how to read the info

Our orchestration algorithm was configured to operate in three states: i) normal (below 20 kW — green zone); ii) warning (between 20 kW and 25 kW — yellow zone); and iii) overload (above 25 kW — red zone), representing the transformer's real-time health status. We configured these thresholds to create more dispatching and curtailment events to allow accelerated data capture and performance validation.

We developed a rules engine that assesses the state of the system and issues curtailment orders to one or many EV chargers in order to shift the load later when the system enters Warning or Overload status. Rules-engine decisions are made dynamically every five minutes. The following excerpts show examples of some interesting observations captured from the Lethbridge pilot.



Oct 17th

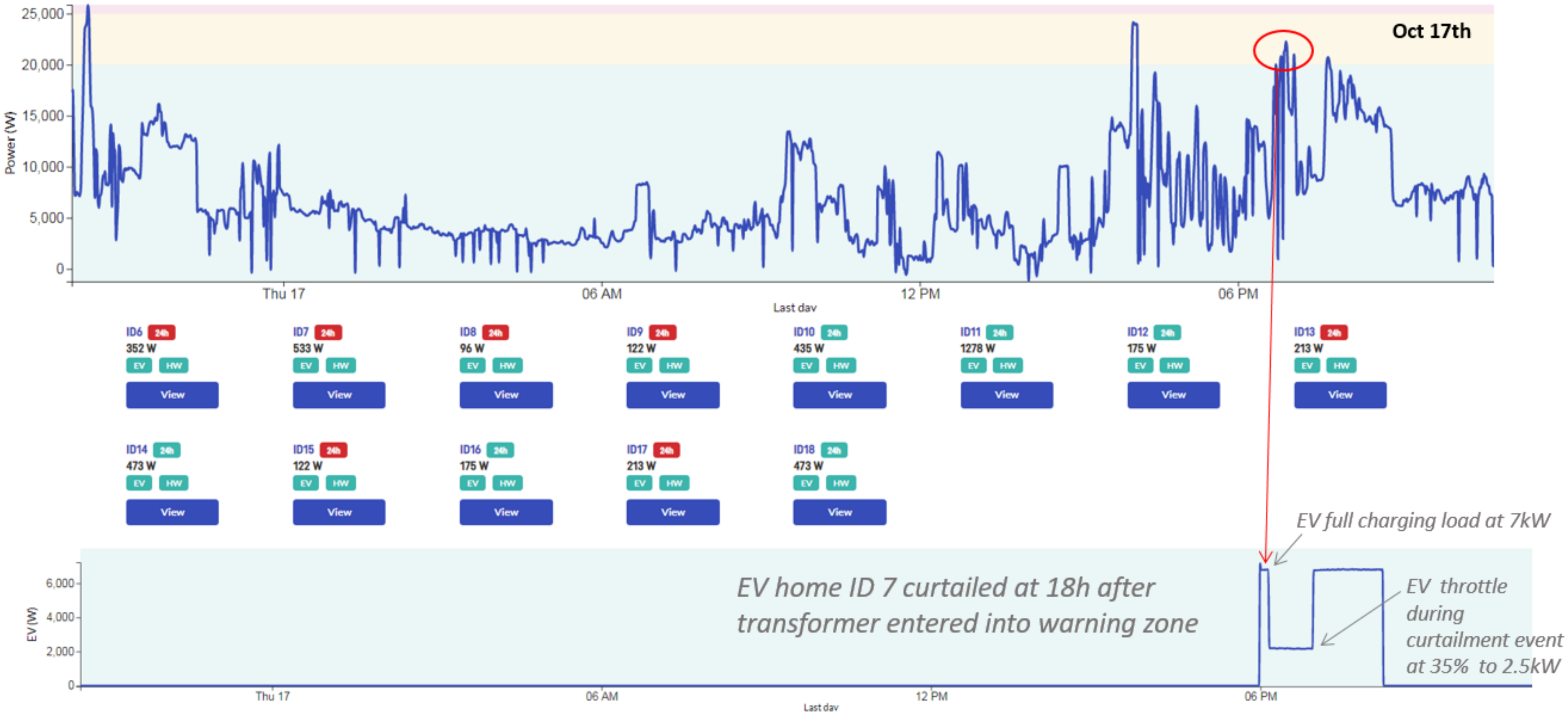
EV full charging load at 7kW prior to price signal request

*EV home **ID 8** curtailed at 16h after transformer entered into warning zone*

EV throttled during curtailment event at 35% to 2.5kW

Figure 18: DSO Dashboard screenshot on October 17, 2019, for the system as a whole (top) and with EV charger consumption for homeID8 (below).

Figure 18 top graph shows the aggregate load at the secondary distribution circuit transformer for a 24 hour period. Each individual home status is indicated underneath with a red box 24hr box indicating if that home has been curtailed in the past 24 hours, the green box indicates the current status of the EV charging station and hot water tank. The bottom graph shows the EV charging load for one of the curtailed homes during a DER-dispatched event. The transformer entered a warning zone at around 1600 hours on October 17, 2019. The engineered price signal dispatched curtailment events to a set of specific homes. We configured the algorithm to not fully curtail 100% of the EV charging but to let it charge at a rate of 35% of the full load (as a safety measure during the pilot). It should be noted that peak load does not always occur at the same time each day. We observed during September and October that multiple peak load events occurred. On the graph above and below, peak events occurred at both around 1600 h and 1900 h, demonstrating the purpose and value of a dynamic and adaptive algorithm versus fixed static time of use.



EV full charging load at 7kW

EV home ID 7 curtailed at 18h after transformer entered into warning zone

EV throttle during curtailment event at 35% to 2.5kW

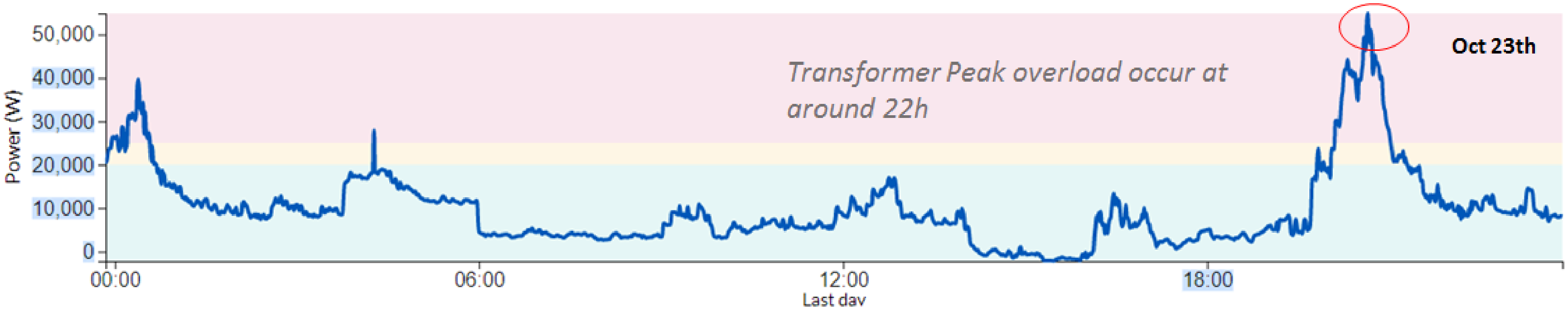
Figure 19: DSO Dashboard screenshot on October 17, 2019, for EV homeID7.

In Figure 19 above, our orchestration algorithm dispatched a second curtailment event at approximately 1900 h (first curtailment at 1600h for Home ID8 in the above Figure 18), to throttle down homeID7 as the transformer was back in overload condition. It is worth noting that once the transformer has returned into a normal state, top graph green zone at 2000 h, the orchestration engine had automatically released the EV charging station out of a curtailment and return to 7kW full charge.

Multiple curtailment events were issued on EV home ID 9 from 18h until midnight after transformer entered into warning and overload zone multiple times

Figure 20: DSO Dashboard screenshot on October 18, 2019, for EV HomeID9.

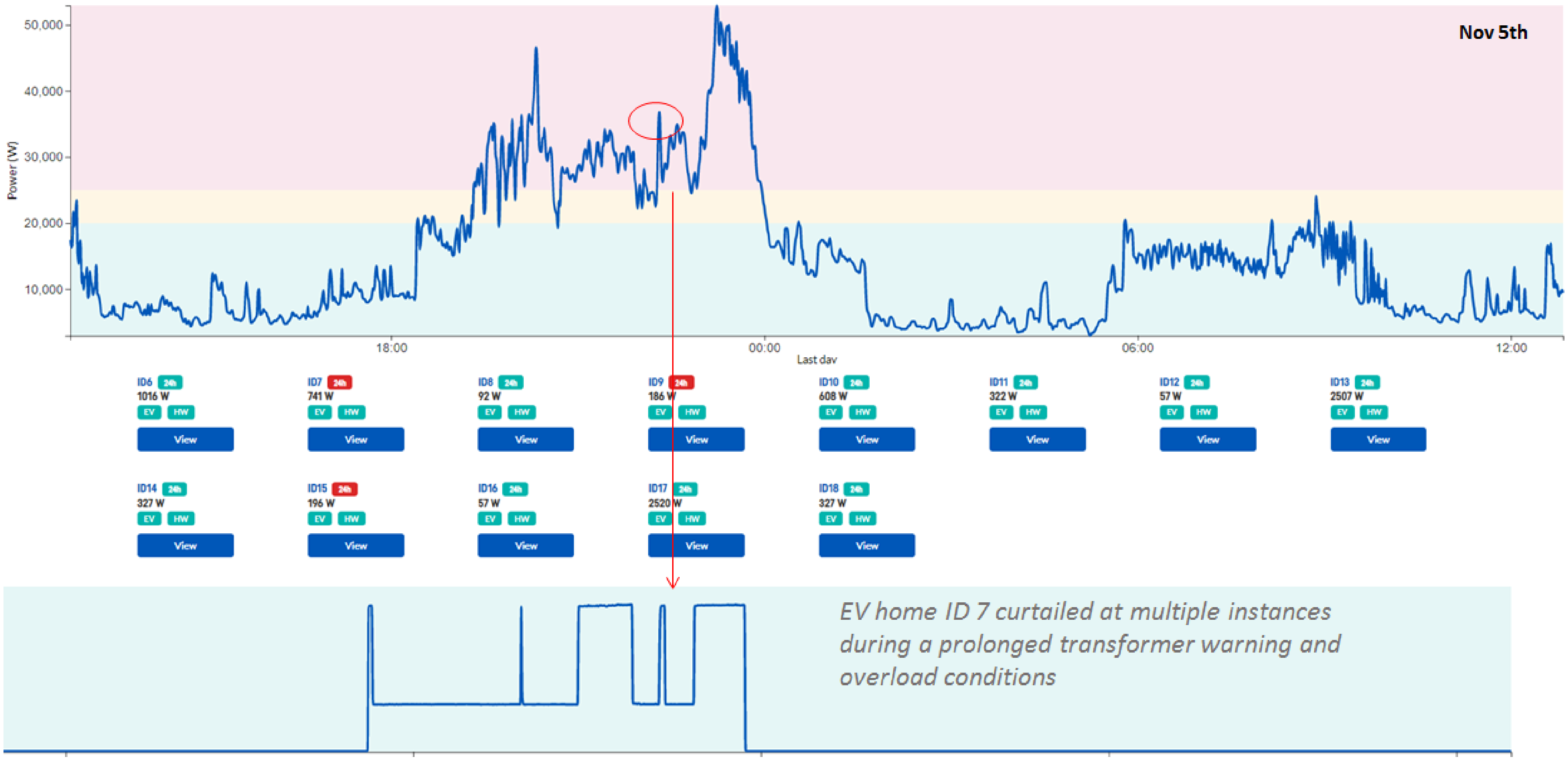
Figure 20 shows that the algorithm conducted multiple curtailments events and adapted to the continuous transformer warning and overload conditions that persisted longer than usual. The bottom graph shows multiple curtailment events back to back, with a short period back into full EV charging mode, then back into curtailment mode at 35%. The adaptive nature of our algorithm has an objective to not issue curtailments if not required, contrary to the traditional fixed static time-of-use approach. This is an interesting example illustrating the multiple polling request to resume from curtailment but because the transformer was still in a prolonged warning and/or overloaded zone, the curtailment has been re-issued continuously. Note that all of this management was done automatically without intervention of the Lethbridge utility.



Transformer Peak overload occur at around 22h

Figure 21: DSO Dashboard showing transformer loading on October 23, 2019.

Figure 21 shows that peak events do not always occur at the expected 1800 h – 2000 h time due to various factors, such as weekdays versus weekends, weather, etc. On this particular day, the peak was achieved at around 2200 h.



EV home ID 7 curtailed at multiple instances during a prolonged transformer warning and overload conditions

Figure 22: DSO Dashboard screenshot on November 5, 2019.

Figure 22 illustrates the EV 7 being curtailed at multiple instances. We observed that a bug existed in our algorithm; an additional curtailment event should have been issued at around 2300 h, but it did not happen. This is a good example of the impact of uncontrolled charging at peak load. We will look into more details in the next section as we modelled and simulated various combinations of EVs charging versus their participation as a dispatched load.

4.3 OPERATIONAL PILOT LOAD DISAGGREGATION RESULTS

In this section, we highlight some further observations derived from the operational pilot, where we focused our attention into the key contributors of peak demand and more behind-the-meter analyses.

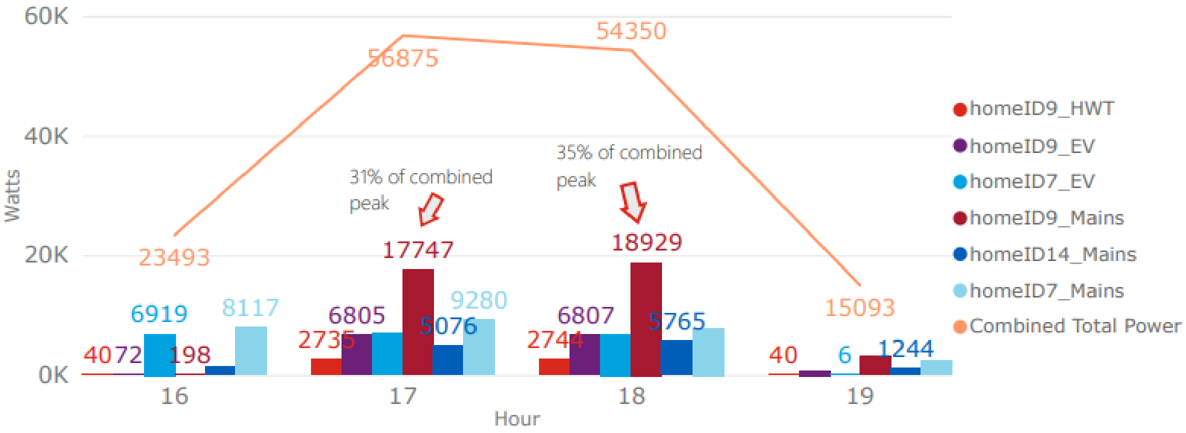
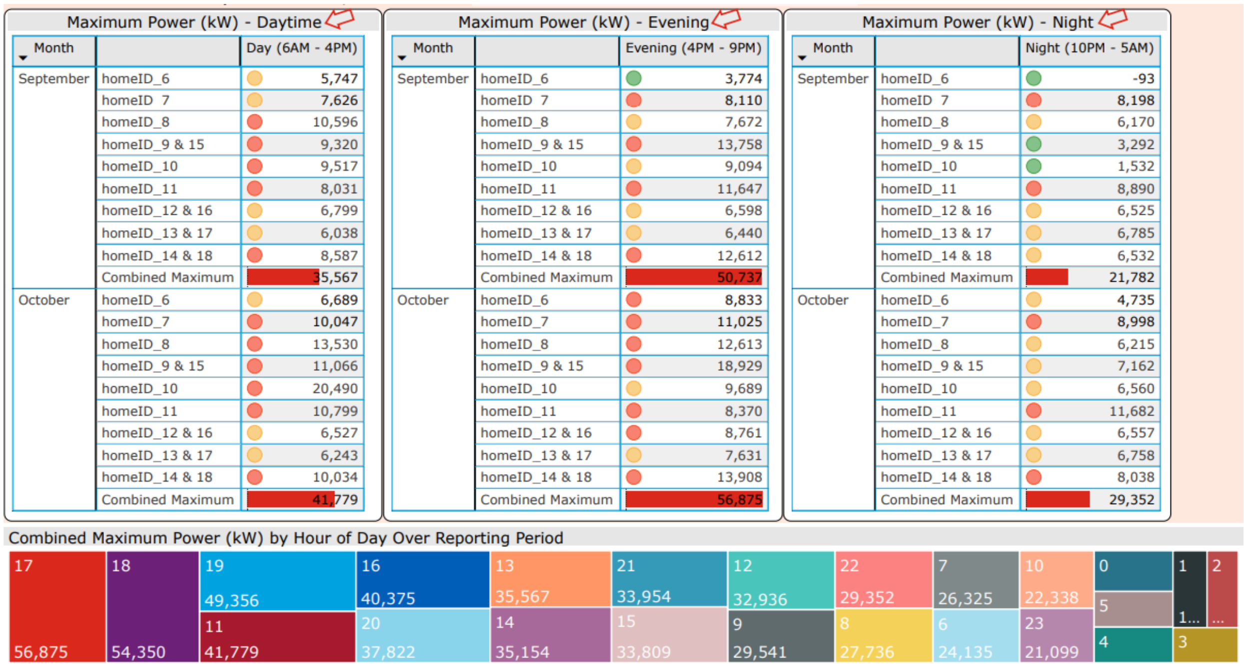


Figure 23: Consumption of Lethbridge Pilot Homes October 22, 2019, from 1600 h to 1900 h during peak power consumption event

In Figure 23 above shows an example of a peak period recorded between 17h and 18h on Oct 22nd , homeID9 exhibits the highest peak power usage on that day. For homeID9, this maximum was reached within the hour of 1800. At the period of peak power, homeID9 represented 31% of the combined total peak for all homes on this transformer at this hour. EV and HWT usage represented 54% of homeID9's load. Of note, homeID7 at these peak hours is also charging an EV that accounts for nearly all the home's energy consumption.



Maximum Power (kW) - Daytime

Month		Day (6AM - 4PM)
September	homeID_6	● 5,747
	homeID 7	● 7,626
	homeID_8	● 10,596
	homeID_9 & 15	● 9,320
	homeID_10	● 9,517
	homeID_11	● 8,031
	homeID_12 & 16	● 6,799
	homeID_13 & 17	● 6,038
	homeID_14 & 18	● 8,587
	Combined Maximum	35,567
October	homeID_6	● 6,689
	homeID_7	● 10,047
	homeID_8	● 13,530
	homeID_9 & 15	● 11,066
	homeID_10	● 20,490
	homeID_11	● 10,799
	homeID_12 & 16	● 6,527
	homeID_13 & 17	● 6,243
	homeID_14 & 18	● 10,034
	Combined Maximum	41,779

Maximum Power (kW) - Evening

Month		Evening (4PM - 9PM)
September	homeID_6	● 3,774
	homeID 7	● 8,110
	homeID_8	● 7,672
	homeID_9 & 15	● 13,758
	homeID_10	● 9,094
	homeID_11	● 11,647
	homeID_12 & 16	● 6,598
	homeID_13 & 17	● 6,440
	homeID_14 & 18	● 12,612
	Combined Maximum	50,737
October	homeID_6	● 8,833
	homeID_7	● 11,025
	homeID_8	● 12,613
	homeID_9 & 15	● 18,929
	homeID_10	● 9,689
	homeID_11	● 8,370
	homeID_12 & 16	● 8,761
	homeID_13 & 17	● 7,631
	homeID_14 & 18	● 13,908
	Combined Maximum	56,875

Maximum Power (kW) - Night

Month		Night (10PM - 5AM)
September	homeID_6	● -93
	homeID 7	● 8,198
	homeID_8	● 6,170
	homeID_9 & 15	● 3,292
	homeID_10	● 1,532
	homeID_11	● 8,890
	homeID_12 & 16	● 6,525
	homeID_13 & 17	● 6,785
	homeID_14 & 18	● 6,532
	Combined Maximum	21,782
October	homeID_6	● 4,735
	homeID_7	● 8,998
	homeID_8	● 6,215
	homeID_9 & 15	● 7,162
	homeID_10	● 6,560
	homeID_11	● 11,682
	homeID_12 & 16	● 6,557
	homeID_13 & 17	● 6,758
	homeID_14 & 18	● 8,038
	Combined Maximum	29,352

Combined Maximum Power (kW) by Hour of Day Over Reporting Period

Figure 24: Maximum power consumption of Lethbridge pilot homes during September and October 2019

Figure 24 top graph indicates the maximum power consumption for each of the individual homes participating in our operational pilot during September and October, as well as the aggregate total load at the transformer level. It is worth noting that the evening time achieved the highest peak load compared to the day time and during the night. Note that the largest single home load came from a net zero home, which has generated lots of questions. Home ID 9 is a net zero home that has the lowest base load BUT because of some high efficiency equipment such as a hot water tank with heat pump, and EV charging station, it creates very high peak demand when the equipment turns on. Although home ID9 exhibits the highest peak, it is also the one with the lowest baseload of 84W. The bottom part of the Figure 24 indicates the aggregate combined load of each home, at the transformer level by the hour of the day.

In Figure 25 below, we conducted home load disaggregation to understand the main contribution of a peak load event and determine the largest contributors, whether EV charging stations or electric hot-water tanks. The time scale of this figure is from 1711h to 1821h on October 22, 2019h.

- homeID7, homeID9 and homeID15 EV chargers had been running at ~6,800W for about an hour prior to peak at 1759h.
- homeID8's EV charger was charging at ~1,100W before and after the peak at 1759h.
- homeID9 and homeID15's hot-water tanks cycled at ~2,700 W for 10 – 20 minutes before and after the peak.
- The sum of the above events at 1759 h is 21,660 W or 36% of the combined total mains measurements for that minute.
- The sum of the above events at 1747 h is 27,128 W or 86% of the combined total mains measurements for that minute.

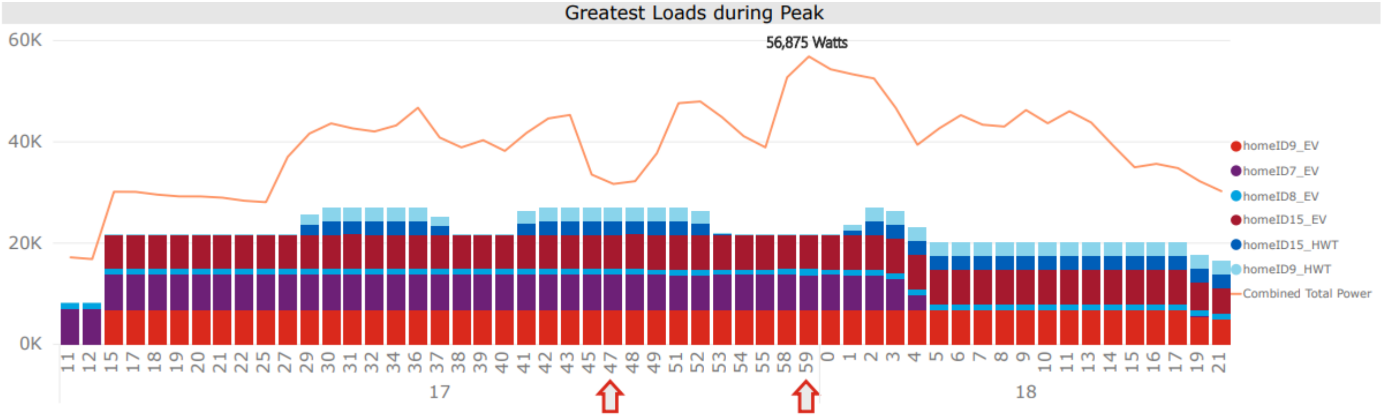


Figure 25: Pilot Home Load Disaggregation October 22, 2019, during peak event period. The horizontal axis shows the minutes of the hour between 17h and 18h from 17h11 to 18h21.

In Figure 26 below, we noted the impact of curtailment dispatch events at three distinct times that provided significant peak demand reduction, namely at ~1829 h, 1920 h and 1951 h on October 23. The scenario in the graph suggests that curtailment requests are sent often or proactively during peak hours, and immediately if a threshold is sensed. The curtailments at 1829 h reduce the load of 19.873 kW by 34% and at 1951 h the load of 20.842 kW is reduced by 11.235 kW (54%).

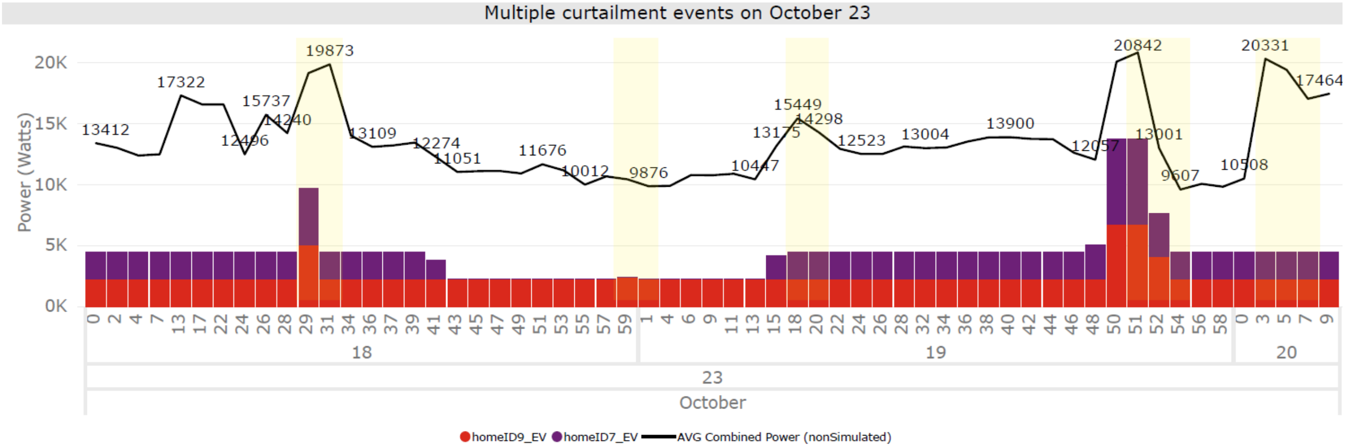


Figure 26: Analysis of peak load reduction during curtailment events October 23, 2019

Figure 27: Analysis of curtailment vs. no curtailment impact of peak, average, min/max and first /second quartile (box plot)

In summary, the live pilot results have demonstrated the operation of our adaptive energy orchestration management and achieve between 34% to 54%% peak demand reduction during our 2 months of operation. In the next section we will discuss further results achieved through modeling and simulations

4.4 SIMULATION RESULTS

In the previous edition, we demonstrated, through the live pilot in Lethbridge, significant improvements in terms of peak-load reduction. In section 4.5 and 4.6, we will focus our analysis and results from our simulator. Table 2 below depicts the peak load observed for a range of 1 to 5 EV chargers connected on a transformer, 49kW up to 74kW when un-controlled (first row in the table), and the resulting reduction by implementing our autonomous energy orchestration platform which is set up to simulate the reduction in peak load when 1 EV charger (row 2) to 5 EV chargers (row 6) are controlled. The peak load was reduced from 11% to 42% as the number of controlled EV chargers increased.

PEAK LOAD (WATT)	1 EV	2 EV	3 EV	4 EV	5 EV
0/5 EVs Controlled	49,368	55,507	62,042	67,786	74,321
1/5 EVs Controlled	44,113	49,368	55,903	62,438	68,973
2/5 EVs Controlled	—	44,113	50,647	57,175	63,710
3/5 EVs Controlled	—	—	44,113	50,640	57,175
4/5 EVs Controlled	—	—	—	44,113	50,648
5/5 EVs Controlled	—	—	—	—	44,113
BENEFIT	**11%**	**21%**	**29%**	**35%**	**41%**

Table 2: Table of results showing peak load variation, as a function of the number of charging EVs connected to a 50 kVA transformer with a total of 16 homes. 1 to 5 charging EVs and 3 homes with electric hot-water tanks.

On Table 3 below, we report the annual loss of life as we increase the number of EV chargers connected to a single transformer (first row of the table). By controlling 1-5 EV chargers through our orchestration platform, we are able to improve the asset life of the secondary distribution circuit transformer. The impact on asset cost depreciation or capital deferral has been estimated at around $20K per transformer. As an indicator, a medium city such as Edmonton has around 40K transformers that could potentially be impacted in the medium-long term.

ANNUAL LIFE REDUCTION (YEARS)	1 EV	2 EV	3 EV	4 EV	5 EV
0/5 EVs Controlled	0.021	0.087	0.496	0.966	3.456
1/5 EVs Controlled	0.008	0.021	0.113	0.321	1.477
2/5 EVs Controlled	—	0.008	0.039	0.160	0.856
3/5 EVs Controlled	—	—	0.008	0.029	0.154
4/5 EVs Controlled	—	—	—	0.008	0.032
5/5 EVs Controlled	—	—	—	—	0.008
BENEFIT	**62%**	**91%**	**98%**	**99%**	**100%**

Table 3: Table of results showing Loss of Life due to Overloading as a function of the number of charging EVs connected to a 50kVA transformer with a total of 16 homes. 1 to 5 charging EVs and 3 homes with electric hot water tanks.

Table 4 provides the summary results for GHG emissions reduction and illustrates how controlling 1-5 EV chargers through our orchestration platform, enables CO2e savings. More details on these results are provided in the following sections.

ANNUAL CO_2E (KG)	1 EV	2 EV	3 EV	4 EV	5 EV
0/5 EVs Controlled	118,790	120,640	124,280	126,130	129,780
1/5 EVs Controlled	118,780	120,630	124,270	126,130	129,770
2/5 EVs Controlled	—	120,600	124,240	126,090	129,740
3/5 EVs Controlled	—	—	124,170	126,030	129,670
4/5 EVs Controlled	—	—	—	126,000	129,650
5/5 EVs Controlled	—	—	—	—	129,570
CO_2e SAVINGS	**10**	**40**	**110**	**130**	**210**

Table 4: Table of results showing emissions reduction as a function of the number of charging EVs connected to a 50 kVA transformer with a total of 16 homes. 1 to 5 charging EVs and 3 homes with electric hot-water tanks.

4.5 HYBRID MODELLING & SIMULATION RESULTS

In this section, we discuss the results of our hybrid modelling and simulations. The purpose of conducting modelling and simulation was to explore and analyze a larger set of scenarios and boundary conditions to quantify, more precisely, the operational performance conditions and limitations. In addition, the simulation tool was essential to assisting with optimizing and fine-tuning our control system algorithm, as well as testing a few different algorithms' performance. For the modelling, we simulated 16 homes on a 50 kVA transformer. We injected real data extracted from operational pilot data into the simulator to represent the base load. On top of this we injected the following loads: i) EV charging load based upon different scenarios of customer participation (e.g., number of customers who agreed to have a utility control the price signal to manage and throttle their EV charger); and ii) hot-water tank energy consumption profile, data also from the operational pilot.

- Xmer size: 50 KVA, 25 kV
- P.F: 0.9
- Ambient temp °C: Lethbridge temperature over 12-months
- No of consumers: 16
- No of EVs: 5
- The EV variable distributions such as; the time of arrival and the state of charge (SOC%) are based on the probability density function (PDF)

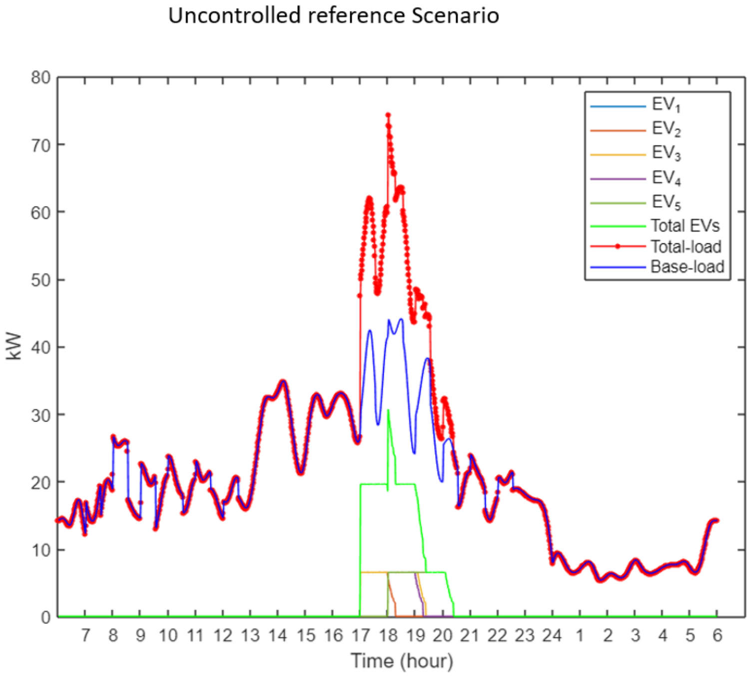


Figure 28: Peak demand baseline scenario with no EV control

In Figure 27, a baseline scenario was developed to illustrate the impact of uncontrolled EV charging stations. We developed a simulator in Matlab that is using the baseload power consumption of each individual pilot home in Lethbridge; we separated and subtracted the total load with EV load to allow accurate modeling and simulations for a variety of EV loads when added to a home baseload. The uncontrolled reference scenario on Figure 27 shows the baseload in blue, then we added each EV charging load, EV1-5, the sum of all EVs is depicted in green. The resulting total transformer load is shown in red.

In Table 5 below, we describe the operational conditions and associated modelling results of the baseline scenario — that is, all EV chargers uncontrolled. The annual life reduction indicates the loss of life transformer assets will experience when under continuous overload conditions. The annual life reduction of a given transformer, calculated by the HST algorithm, is a function of:

- The number of EV chargers connected to that transformer;
- The number of electric hot-water tanks connected to that transformer;
- The baseload of all homes connected to that transformer;
- The temperature of the transformer; and
- A number of additional parameters defined by the hot-spot temperature model.

	1 EV	2 EV	3 EV	4 EV	5 EV
ANNUAL LIFE REDUCTION					
1 EWH	0.012	0.053	0.302	0.55	1.888
2 EWH	0.016	0.061	0.351	0.82	3.305
3 EWH	0.021	0.087	0.496	0.966	3.456
LOAD MAX (WATT)					
1 EWH	47,793	54,322	60,857	65,506	72,041
2 EWH	49,368	54,716	61,251	67,786	74,321
3 EWH	49,368	55,507	62,042	67,786	74,321

Table 5: Modelling Results for Baseline Scenario — All EV Chargers Uncontrolled.

Table 5 shows the peak load variation as well as the loss of life due to overloading as a function of the number of EVs connected to a 50 kVA transformer. The baseload of each home has been extracted from the operational pilot database. For the annual life reduction there is a significant impact on the transformer life reduction when you move from 4 EVs to 5 EVs with the number of electric water heaters having less of an impact. It is important to note that due to the probability distribution of arrival time and charging duration, the statistical multiplexing of multiple sources is terms of peak load is resulting in a flattening of the peak load as you move above 4 EVs on the same transformer

In this study, two algorithms were developed to study performance objectives goals in terms of power system reliability, GHG emission and different implementation complexity (processing power).

- **Peak Shifting (PS) Algorithm:** This algorithm shifts the EV charging demands from the peak period (typically from 4:30 – 7:30 p.m.) to the earliest time when the transformer returned into a normal operating zone, typically between 8 p.m. and 6 a.m. In fact, this algorithm seeks the time that is closest to 8 p.m. as manageable to ensure that EVs are charged at the earliest time possible. Moreover, the shifted EV demands should not exceed the transformer limit.
- **Optimal Time Shifting (OTS) Algorithm**: To achieve three objectives — peak load shaving, balanced load over 24 hours and low GHG emission — an optimized model needs to be established. In this optimization model, the time constraint is from 8 p.m. – 6 a.m., and its objective function guarantees a minimum kW sum of the EV charging demands and the home base loads; this sum also accomplishes a minimum GHG emission at the same time.

In the first scenario below, in Figure 29 only one EV is controlled (shaded blue); each of the other four EVs on that transformer are uncontrolled. In this scenario we observed a transformer peak reduction of 7% from the baseline scenario, representing a peak reduction from 74.3 kW in Figure 29 to 68.9 kW which has resulted in a reduction of loss of life of 57% (from 3.46 years to 1.47 years). In this scenario, no significant difference has been observed between the two algorithms (Peak Shifting (PS) Algorithm and Optimal Time Shifting (OTS) Algorithm) from a peak reduction. Even though only 1 EV was being controlled, the OTS Algorithm moved the charging to the 1:30-3:00 am time zone versus 8:30pm for the PS algorithm. The reason being that PS algorithm shifts the load to the earliest available period when the transformer is in normal state (ie not overloaded), while the OTS algorithm shifts the load to the lowest transformer utilisation based upon historical data, in this case at 1:30am.

Scenario 1: 6% Participation, 1 EV Curtailed

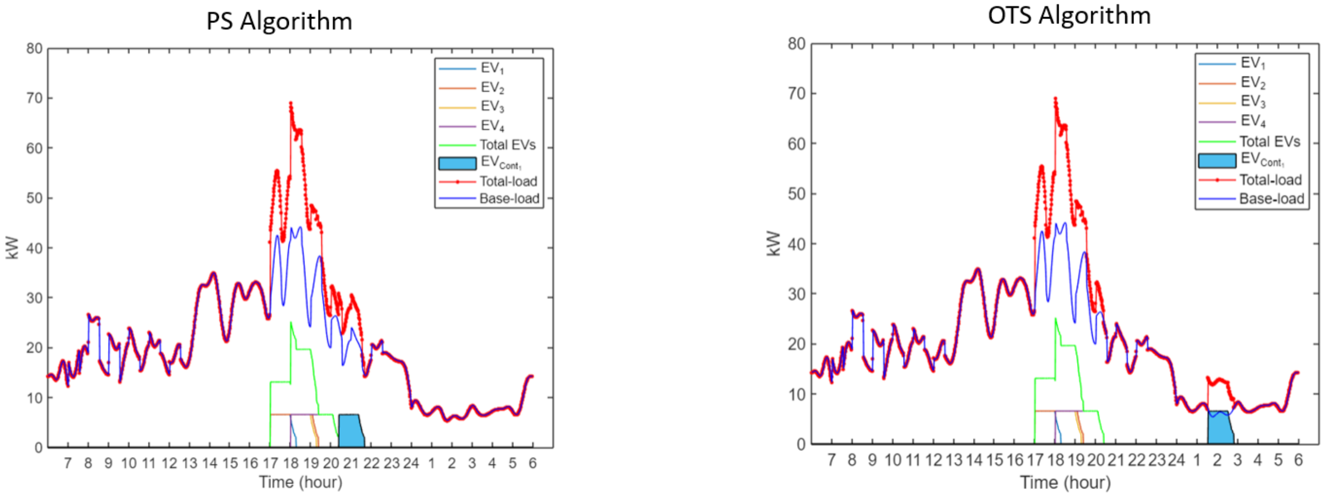


Figure 29: Modelling Results for Scenario 1 — One EV Charger Controlled

In Scenario 2 shown in Figure 30 below, two EV chargers are controlled; the remaining three EV chargers on that transformer are uncontrolled. In this scenario we observed a transformer peak reduction of 14% from the baseline scenario, representing a reduction from 74.32 kW to 63.7 kW, which has resulted in a reduction of loss of life by 75% (from 3.456 years to 0.856 years). Similar to Scenario 1, we see the OTS Algorithm has shifted the EV load at a different time; it reduces the width of the peak load period centered at 18h. Also, the OTS Algorithm considers the GHG emissions associated with the electricity grid generation mix, which varies on an hourly basis. We will further analyse the impact on GHG emission in the next section.

Scenario 2: 13% Participation, 2 EVs Curtailed

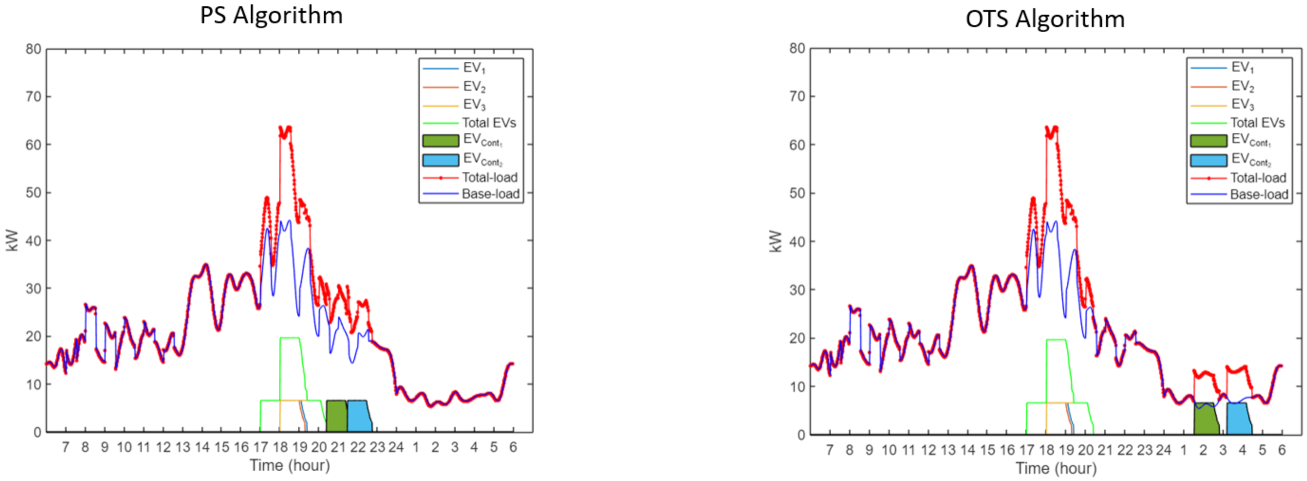
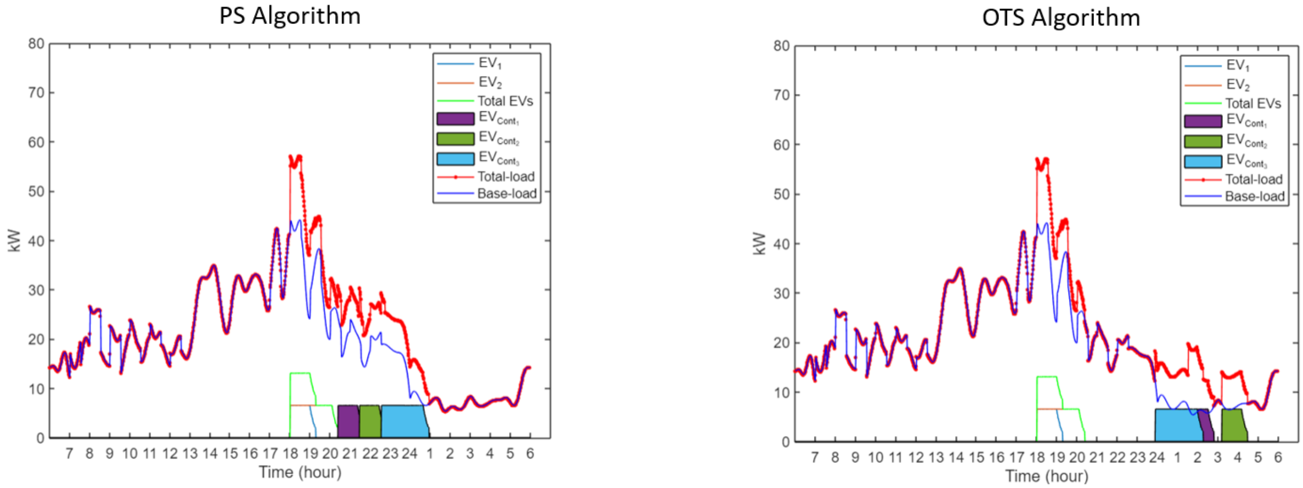


Figure 30: Modelling Results for Scenario 2 — Two EV Chargers Controlled

In Scenario 3 in Figure 31, three EV chargers are controlled (19% customer participation); the remaining two EV chargers on that transformer are uncontrolled. In this scenario we observed a transformer peak reduction of 23% from the baseline scenario, representing a reduction from 74.3 kW to 57.18 kW, which has resulted in a reduction of loss of life of 96% (from 3.456 years to 0.155 years). In terms of load shifting, the PS and OTS Algorithm produced similar results in peak load reduction to Scenario 2, but OTS has shifted EV loads at the lowest demand period in the middle of the night and smoothed out the overall demand on the grid, which will have further impact on GHG emissions. This will be discussed further in the next section.

Scenario 3: 19% Participation, 3 EVs Curtailed

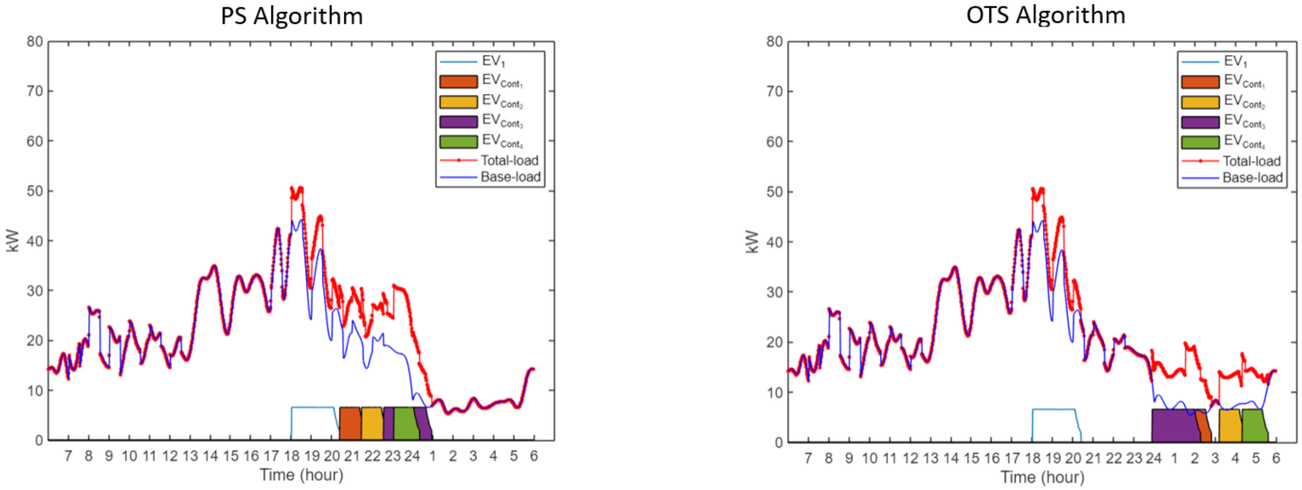

PS Algorithm

OTS Algorithm

Figure 31: Modelling Results for Scenario 3 — Three EV Chargers Controlled

In Scenario 4 in Figure 32, four EV chargers are controlled (25% customer participation); the remaining EV charger on that transformer is uncontrolled. In this scenario, we observed a transformer peak reduction of 32% from the baseline scenario, representing a reduction from 74.32 kW to 50.65 kW, which has resulted in a reduction of loss of life of 99% (from 3.456 years to 0.0318 years). Again, the PS and OTS exhibit both similar peak load reduction, with OTS further smoothing out the overall demand on the grid.

Scenario 4: 25% Participation, 4 EVs Curtailed


PS Algorithm

OTS Algorithm

Figure 32: Modelling Results for Scenario 4 — Four EV Chargers Controlled

In the last scenario, Scenario 5 in Figure 33, all five EVs are controlled (33% customer participation). In this scenario, we observed a transformer peak reduction of 41% from the baseline scenario, representing a reduction from 74.32 kW to 44.11 kW, which has resulted in a reduction of loss of life of 100% (from 3.456 years to 0.008 years).

Scenario 5: 31% Participation, 5 EVs Curtailed

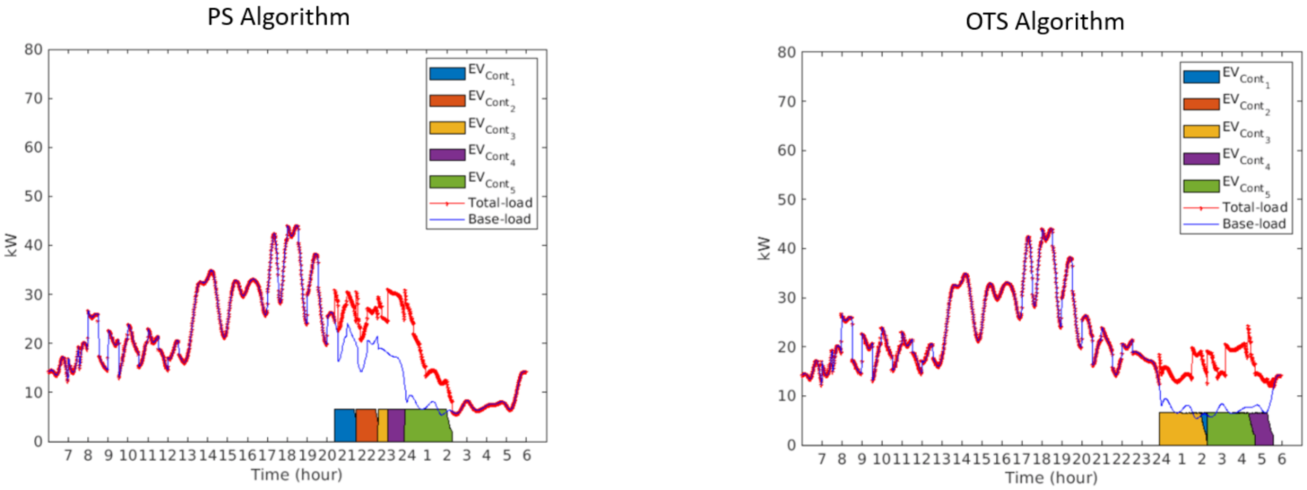


Figure 33: Modelling Results for Scenario 5 — Five EV Chargers Controlled

The most interesting learning from modelling the two algorithms is that, at first glance, the Optimal Time Shifting method has limited incremental benefit over the Peak Shifting method from of peak load reduction. This saves on complexity as OTS requires machine learning to track the lowest demand moment to shift the load, whereas PS is a logic controller. The PS method is also a more democratic approach in that it does not force a shift in charging to a set time but enables it whenever the system can handle it effectively. However two important observations: OTS shifts the EV charging to the lowest grid load window, thus the overall transformer load is even smoother and the duration of the remaining peak period is further reduced. We also anticipate that OTS algorithm will be more effective at the circuit level where hundreds of transformers are aggregated. More research needs to be done of the overall system benefits of the OTS versus PS upstream of the secondary transformer, as PS only considers the single transformer and not the entire system.

4.6 AMI AGGREGATION VERSUS TRANSFORMER SENSOR

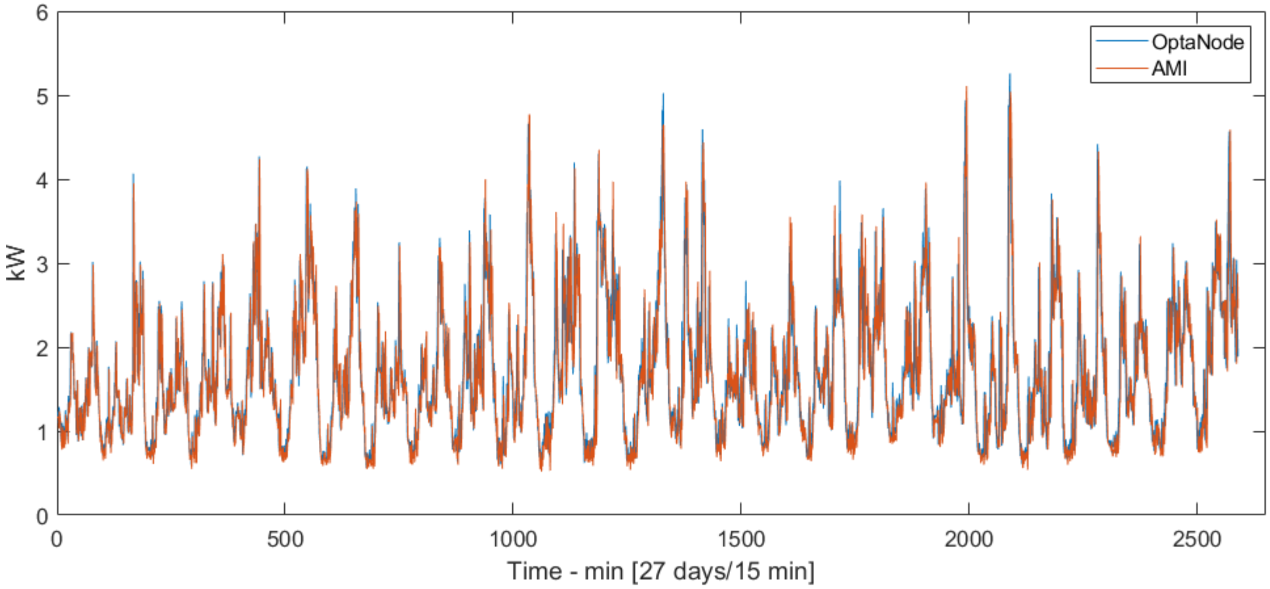


Figure 34: Comparison of Aggregated Utility AMI data to the OptaNode Transformer Sensor data

In this pilot project, we wanted to validate that the aggregated kW measurements from the home meters are very close to the transformer kW measurement; we used the mean squared error (MSE) calculation. MSE basically measures the average of the squared errors. It determines how far the data is from the average value from one data sample to another. For this pilot project, the MSE is 0.204.

Transfomer_OptaNode (monthly energy)	= 4392.4 kWh
AMI (monthly energy)	= 4311.8 kWh

Conclusions: The AMI aggregation error is extremely low and it is a very reliable proxy to infer transformer loading with less than 1.8% on a total monthly kWh.

5.0 LESSONS LEARNED & OUTCOMES OF RESULTS

5.1 KEY LESSONS LEARNED

Dashboard Development Pivot

The team decided to take a Minimum Viable Product (MVP) approach to developing the Home of the Future dashboard by quickly developing a functional mock-up for use in customer feedback discussions while leveraging some existing Pason Power dashboard capabilities to demonstrate the integration efforts at SAIT. This also served to de-couple the two efforts, allowing both the customer feedback and integration efforts to be worked in parallel.

Using the MVP dashboard approach, the team was able to gather valuable insight from customer groups prior to investing heavy development efforts without determining the key use cases. For example, gathering feedback from current and potential EV customers helped us to better understand how the EV charging use case can be incorporated into the dashboard and the energy storage optimization strategy, which will prove valuable as part of the next phase of development.

Integration of the Eguana Storage System & Pasons' Energy Management System at SAIT

The team encountered some unexpected challenges during the procurement and installation at the SAIT home, and this slowed progress as a result.

- Attempting to integrate with the existing eGauge meters resulted in additional troubleshooting and complications due to existing meter assumptions and configurations and issues with older firmware running on the devices. Installing a separate meter (as will be expected for a typical home installation) would help to streamline the installation and configuration process.
- The team encountered issues using a VPN connection to access the SAIT Energy Storage System site controller PC due to the network security firewall. This could be a common occurrence depending on the network security settings at a home if we intend to use Wi-Fi or the wired home internet. As a result, we plan to update our remote communication methods to be more firewall friendly to ensure that remote support can be provided if necessary.
- Issues were encountered when installing the Eguana Residential AC battery system that required support from the Eguana technical team. These issues stemmed from inexperience in installing the equipment and unclear installation details regarding system communication cable installation. As a result, we plan to ensure that training for installers of the Home of the Future system includes the proper installation details for the Eguana energy storage system.
- SAIT demand loads are different than a common residential setting. It took longer than expected to understand this variance.
- Despite the many talents of the project team, dealing with emerging technologies and training installers on new technologies took longer than expected.

Large Partnership

There were some challenges for the project team to learn to work with each other given the many partners (e.g., interaction between partners and associated schedule processes, partnership agreements, operational role descriptions, information communication). This resulted in the three-month schedule delay and required more active project management monitoring, as well as more frequent communication between key project members to bring the project back on schedule.

Intellectual Property Ownership

This project presented challenges in determining intellectual property ownership between the main partners.

SAIT Home Lab Communication Infrastructure

The team encountered some unexpected challenges setting up DERs at the SAIT Green Home building when setting up the DERs for remote communication/control. This slowed progress as a result. The SAIT lab has not been designed as a home simulator but instead as a commercial building; many adjustments in terms of available loads to reflect a home consumption were not easily configurable, and equipment installation was not designed for home operating voltage and capacity. In addition, the lab is not very digital, has limited Wi-Fi and is not very programmable.

API/Data Access Challenges

- Hardware providers for this project are mostly startups and new entrants to the IoT market. Some of our providers have been highly amenable to customizing their product to our use case. However, some providers were not able to implement the advertised functionality of their product. Avoiding these issues requires thorough vetting of providers, their product and, most importantly, their API capabilities before partnering.
- AddEnergie provided/published very limited API/data access. For example, we cannot see feedback from an EV charging unit when the curtailment is issued. Without a previously implemented workaround developed at our SAIT testing facilities, this information would not be readily accessible.

Machine Learning Model Challenges

- The use of machine learning, particularly neural networks, requires a tremendous amount of training data. This can lead to implementation challenges as optimizations may take months to come to fruition.
- The results of a machine-learning model are stochastic by nature. Their results should be evaluated with error in mind.
- Furthermore, machine-learning models are computationally intensive to train. Incorporating training, testing and prediction into real-time software is a software engineering challenge in and of itself.
- The machine-learning model was a good predictor of the behaviour of a single home. However, the model did not predict well for a neighbourhood of homes.

Software Architecture

Choose optimal tools for software development, maintainability, scalability, longevity, etc. More thought/decision-making process is required to choose optimal architecture at the beginning of a project that can work for the whole lifespan of the project/product.

Technical Capacity

Making custom software products on the cutting edge of innovation is new for ATCO. Opportunities and challenges related to software development, machine learning and IoT are not fully understood by the organization.

Data Privacy

- The project team could not use utility’s AMI data, and developed a workaround using alternative equipment while gathering anonymized data to fill the knowledge gap.
- Future considerations for data access and storage are needed for when this product/service is rolled out commercially.

Stakeholder Engagement

- Providing technology as an incentive for EV owners was successful.
- Providing technology as an incentive for other homeowners also garnered significant interest to enable participation.
- Designing a pilot participation agreement and being transparent about the requirements to participate while keeping users accountable was successful.

DSO Engagement

A better understanding is required of what the DSO is seeking to support their day-to-day operations, maintenance, etc. This includes integration into existing systems and non-intrusive dashboards.

Curtailment Duration

- The curtailment duration was originally set for four hours. Upon reviewing pilot data, the project team noted that peak periods do not last for four consecutive hours. The curtailment duration was reduced and changed to be adaptive by the system. Real-time operating conditions are fed into the decision rules engine, then further curtailment requests are issued as necessary.
- The ultimate goal is to issue the least amount of curtailment to minimize potential impact on customers.

Technical Training

- Feedback from pilot participants indicated that they were not fully satisfied with the configuration of the hardware devices during the installation process.
- Future considerations for technology schools such as NAIT and SAIT include building training programs in the area of Applied IOT in Energy Management for Clean Technologies, which could help address the knowledge gap.

Pivots

Pivoting the scope to integrate DFOs will help mitigate emerging grid-resilience challenges. This also mitigated the market risk of residential customer adoption and willingness to pay for the initial value proposition. The result of the pivot was to create new economic value streams for utilities that were not previously used.

Knowledge & Guidance for Development of Opportunities for Market Entry

Customer engagement sessions, collaboration with Brookfield and other market definition efforts fostered an understanding of potential market entry strategies. Pivoting the scope to integrate DFOs will open new market directions and these need to be further defined.

Optimized Business Model Developed in Consultation with Stakeholders

Seven potential business models have been defined and must be reviewed and verified for commercial deployment.

Demonstrated GHG Benefits to Alberta from Project & Future Project Plans

Indicate how the provincial GHG emissions based on the hourly generation mix can be used as a price signal to reduce carbon emissions of the Home of the Future during peak hours.

5.2 OUTCOME OF RESULTS

Attraction of New Skills

The project has attracted new skills (software/data scientist). Two new interns and one new contractor were hired.

Development of Future Skills

A full stack software developer, data scientist and digital control system engineer are required.

6.0 PROJECT BENEFITS & IMPACTS

The benefits of the Home of the Future include those outlined below.

- It will address a technology gap. There are many barriers preventing mass-market smart-home adoption and greater integration of smart-grid solutions. A large barrier is the technological fragmentation of the smart-home ecosystem, in which consumers need multiple networking devices, apps and more to build and run their smart homes. Some aggregators are appearing in the market to provide this service to utilities, but none have effectively developed the dynamic value proposition that incorporates utility asset management. The ATCO Home of the Future project addresses this gap.
- The sector has developed a controller that manages home operations and renewables; however, the smart control system that integrates these functions — and also includes EVs, storage and an ability to feedback to the grid, and which uses smart controls that help with knowing when to use the grid, storage and renewables — has yet to be developed. This project has developed a smart integrated control system that manages home energy flow to and from the grid.
- As a large-scale innovation leader in Alberta, ATCO intends to be able to deploy and scale the solution not just in Canada but globally, particularly in Australia where we are pursuing multiple energy innovation initiatives.
- This product can integrate region-specific grid emission factors, based upon local energy mix that enables visibility and management of emissions within the smart grid to help meet climate change goals.
- This product positions Alberta to deploy and scale virtual power plants in a modular and flexible fashion as the grid is moving toward a decentralized architecture.

Benefits to Alberta

- This solution is adaptable, scalable and repeatable across the residential sector in Alberta.
- The platform can perform in all jurisdictions with AMI due to the plug-and-play simplicity.
- It will reduce residential electric load demand, reducing CO_2 emissions from the residential housing sector and associated electricity generation.
- The platform will improve energy security and supply, which represents an effective climate-change adaption feature.
- Widespread adoption of ATCO Homes of the Future will have a positive GDP effect and mitigate rate increase and capital investments deferral by utility resulting in lower electric utility ratepayers price increases.
- The solution will enhance energy literacy for homeowners.
- Jobs will be created in smart buildings, energy efficiency and energy management systems.
- It will help reduce electrical bills in jurisdiction that have implemented a residential demand charge rate when a peak load is exceeded, such as Lethbridge Utility.
- Residential customers will be empowered by ecosystem controls and flexible energy management options through this visible energy system.

6.1 GHG EMISSION REDUCTIONS

The Home of the Future algorithm influences adoption and facilitate integration of clean technologies such as EV charging stations. The integration of DERs enabled by the Home of the Future orchestration platform allows for greater use of greenhouse gas (GHG) mitigation features in the smart grid. The expected GHG benefits are achieved by reducing peak demand, shifting load to times of lower grid emissions, thereby reducing the need to run fossil gas peaker plants. Provincial GHG emissions based on the hourly generation mix can be used as a price signal to reduce carbon emissions of the Home of the Future during peak hours. The product creates more value out of demand-side management as it incorporates a multi-stakeholder multi-factor optimization, peak demand at the distribution level, peak demand at the overall generation capacity and synchronizing demand with high renewable production.

The conversion and normalization of 1 kWh of EV charging into GHG emissions is calculated according to the block diagram in Figure 35. In Alberta, while wind and hydro have no direct emissions, coal-fired electricity production resulted in 985 grams of carbon dioxide equivalent for every kilowatt hour (g CO2e/kWh) of energy in 2018, compared to 293 g CO2e/kWh for co-generation, 413 g CO2e/kWh for combined cycle, and 577 g CO2e/kWh for simple cycle processes[1], and 16.5 g CO2e/kWh for the biomass. The net intertie emissions estimate is based off the British Columbia grid emissions intensity, predominantly hydro as well as other sources, being the majority energy imports to Alberta.

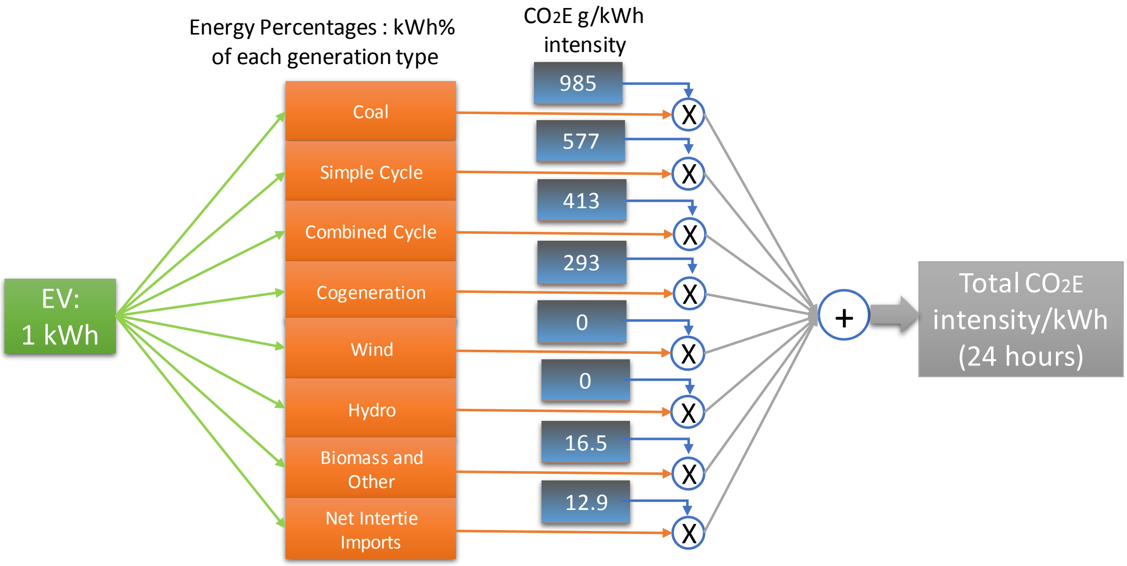


Figure 35: Calculation process to convert 1 kWh of EV charging demand into greenhouse gas (GHG) emission.

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[1] https://www.nationalobserver.com/2019/02/20/news/albertas-ndp-government-says-emissions-reductions-prove-carbon-pricing-works?fbclid=IwAR2GazM_h4sjPBJ1haaEBZ8F-b2g8oGCjnYfqYsDmL3KOBUDStu4EP8nXks

In order to calculate the typical hourly emissions intensity profile over a day in 2017, we obtained the AESO hourly metered volumes data[2] for all types of generators supplying the Alberta grid. In Table 6, we averaged the metered volumes data for each hour in a day.

Time(h)	Coal	Simple Cycle	Combined Cycle	Cogeneration	Wind	Hydro	Biomass and Other	Net Intertie Imports
1	3772.973	53.44	675.35	1182.925	540.796	152.934	57.359	58.805
2	3693.44	51.979	661.662	1186.093	533.147	151.383	57.925	65.347
3	3657.123	51.737	656.734	1186.557	521.461	154.051	58.249	70.603
4	3664.362	51.434	657.823	1186.647	516.404	156.596	58.584	73.648
5	3736.871	52.341	670.557	1197.946	513.228	164.521	59.123	63.933
6	3922.5	58.455	711.572	1211.138	502.994	181.377	58.952	34.597
7	4153.542	82.036	788.946	1223.79	479.761	242.82	58.437	-25.498
8	4335.877	102.21	852.359	1239.141	448.473	256.159	57.784	-33.989
9	4444.898	116.728	880.964	1241.359	434.566	252.159	57.314	-22.088
10	4487.808	132.485	885.141	1237.395	438.252	252.629	57.257	21.065
11	4507.389	147.192	890.955	1236.057	442.587	254.225	57.38	49.59
12	4507.338	156.222	888.838	1225.737	450.144	251.964	57.476	73.79
13	4499.545	157.527	881.123	1217.772	464.275	251.913	57.326	89.502
14	4477.177	158.752	877.036	1214.617	472.371	253.177	57.12	103.46
15	4465.599	159.228	873.964	1209.509	489.395	256.27	56.841	104.694
16	4473.419	162.773	873.671	1209.093	501.132	262.431	57.234	103.056
17	4486.934	168.79	879.584	1211	514.413	266.356	57.269	91.329
18	4476.195	165.799	892.219	1211.871	523.162	273.416	56.898	58.746
19	4467.817	157.368	898.18	1212.865	533.446	272.961	56.662	7.045
20	4453.386	142.898	896.859	1217.578	541.383	261.06	56.515	-12.076
21	4378.171	129.09	883.728	1216.284	552.35	241.249	56.314	-2.206
22	4241.243	105.069	850.949	1205.356	558.883	222.554	56.425	-6.662
23	4067.129	75.207	766.102	1195.94	557.611	178.764	57.009	27.115
24	3893.856	58.901	706.569	1186.85	545.728	158.985	57.207	50.735

Table 6 Average MW generation mix over 12 months for every hour

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[2] https://www.aeso.ca/market/market-and-system-reporting/data-requests/hourly-metered-volumes-by-generation-type

Then we needed to determine the ratio of individual generation sources for a given hour over 12 months. This is shown in Table 7.

Time(h)	Coal	Simple Cycle	Combined Cycle	Cogeneration	Wind	Hydro	Biomass and Other	Net Intertie Imports
1	0.581	0.008	0.104	0.182	0.083	0.024	0.009	0.009
2	0.577	0.008	0.103	0.185	0.083	0.024	0.009	0.01
3	0.575	0.008	0.103	0.187	0.082	0.024	0.009	0.011
4	0.576	0.008	0.103	0.186	0.081	0.025	0.009	0.012
5	0.579	0.008	0.104	0.185	0.079	0.025	0.009	0.01
6	0.587	0.009	0.106	0.181	0.075	0.027	0.009	0.005
7	0.593	0.012	0.113	0.175	0.069	0.035	0.008	-0.004
8	0.597	0.014	0.117	0.171	0.062	0.035	0.008	-0.005
9	0.6	0.016	0.119	0.168	0.059	0.034	0.008	-0.003
10	0.597	0.018	0.118	0.165	0.058	0.034	0.008	0.003
11	0.594	0.019	0.117	0.163	0.058	0.034	0.008	0.007
12	0.592	0.021	0.117	0.161	0.059	0.033	0.008	0.01
13	0.591	0.021	0.116	0.16	0.061	0.033	0.008	0.012
14	0.588	0.021	0.115	0.16	0.062	0.033	0.008	0.014
15	0.586	0.021	0.115	0.159	0.064	0.034	0.007	0.014
16	0.585	0.021	0.114	0.158	0.066	0.034	0.007	0.013
17	0.585	0.022	0.115	0.158	0.067	0.035	0.007	0.012
18	0.584	0.022	0.117	0.158	0.068	0.036	0.007	0.008
19	0.587	0.021	0.118	0.159	0.07	0.036	0.007	0.001
20	0.589	0.019	0.119	0.161	0.072	0.035	0.007	-0.002
21	0.587	0.017	0.119	0.163	0.074	0.032	0.008	0
22	0.586	0.015	0.118	0.167	0.077	0.031	0.008	-0.001
23	0.587	0.011	0.111	0.173	0.081	0.026	0.008	0.004
24	0.585	0.009	0.106	0.178	0.082	0.024	0.009	0.008

Table 7 Ratio of individual Generation sources for a given hour percentages over 12 months by the hour

The CO_2 emissions intensity profile, shown in Table 8, was calculated by multiplying the hourly generation mix of the multiple generation sources in Table 7 by the respective weighted emissions of each source from Figure 35 and included in Table 8 for reference.

	Coal	Simple Cycle	Combined Cycle	Cogeneration	Wind	Hydro	Biomass and Other	Net Intertie Imports
Intensity g CO_2e/kWh Time (h)	985	577	413	293	12	4	18	12.9
1	572.227	4.748	42.947	53.367	0.999	0.094	0.159	0.117
2	568.357	4.686	42.691	54.293	0.999	0.095	0.163	0.132
3	566.705	4.696	42.67	54.694	0.984	0.097	0.165	0.143
4	567.025	4.662	42.68	54.621	0.974	0.098	0.166	0.149
5	569.917	4.676	42.88	54.347	0.954	0.102	0.165	0.128
6	578.255	5.048	43.983	53.111	0.903	0.109	0.159	0.067
7	584.143	6.758	46.522	51.196	0.822	0.139	0.15	-0.047
8	588.431	8.125	48.501	50.023	0.741	0.141	0.143	-0.06
9	591.181	9.094	49.128	49.112	0.704	0.136	0.139	-0.038
10	588.455	10.176	48.664	48.263	0.7	0.135	0.137	0.036
11	585.308	11.196	48.51	47.745	0.7	0.134	0.136	0.084
12	583.292	11.843	48.228	47.184	0.71	0.132	0.136	0.125
13	581.712	11.93	47.763	46.831	0.731	0.132	0.135	0.152
14	579.221	12.031	47.574	46.742	0.745	0.133	0.135	0.175
15	577.587	12.064	47.396	46.535	0.771	0.135	0.134	0.177
16	576.531	12.289	47.211	46.353	0.787	0.137	0.135	0.174
17	575.797	12.688	47.327	46.227	0.804	0.139	0.134	0.153
18	575.722	12.492	48.116	46.365	0.82	0.143	0.134	0.099
19	578.57	11.938	48.768	46.72	0.842	0.144	0.134	0.012
20	580.42	10.91	49.011	47.204	0.86	0.138	0.135	-0.021
21	578.472	9.991	48.958	47.803	0.889	0.129	0.136	-0.004
22	577.513	8.381	48.583	48.822	0.927	0.123	0.14	-0.012
23	578.512	6.266	45.69	50.602	0.966	0.103	0.148	0.051
24	575.994	5.104	43.823	52.223	0.983	0.096	0.155	0.098

Table 8 Total emission for every specific source for every hour grams of CO2E g/kWh intensity for every generation type.

The hourly emissions for each generation type were then add together to create the hourly emissions. This is shown in Table 9.

Time(h)	Aggregate genmeration mix CO_2E g/kWh (2017 data)
1	674.658
2	671.415
3	670.154
4	670.375
5	673.167
6	681.635
7	689.684
8	696.046
9	699.456
10	696.566
11	693.814
12	691.649
13	689.386
14	686.756
15	684.8
16	683.617
17	683.27
18	683.89
19	687.127
20	688.657
21	686.375
22	684.478
23	682.339
24	678.477

Table 9 The 2017 aggregated generation mix CO2e g/kWh intensity for every hour of the day

For illustration purposes, the hourly GHG emissions profile is plotted in Figure 36. Using the AESO 2019 Long-term Outlook, a similar process was used to determine the GHG emissions profile for 2030, which is also plotted in Figure 36.

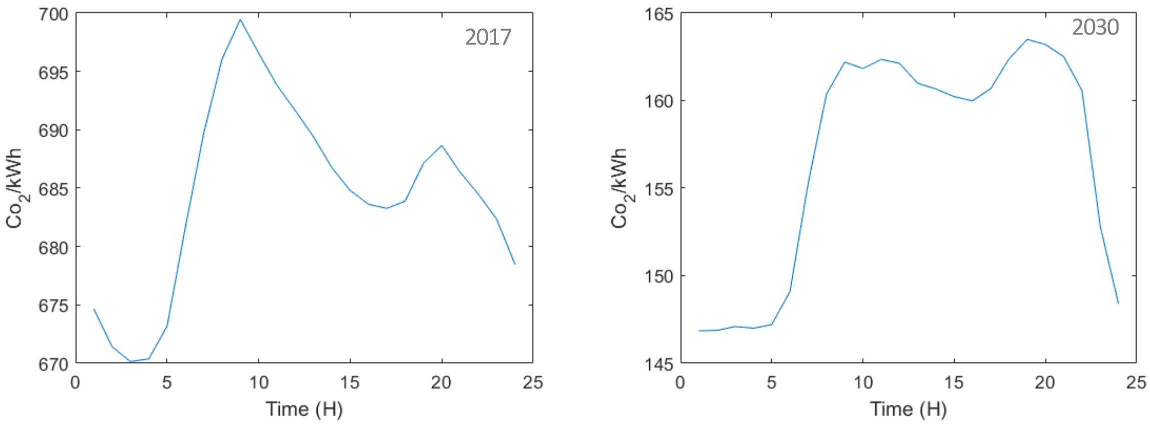


Figure 36: Alberta grid emission intensity (AESO, 2017, 2030). Generation MWh mix based on AESO 2017 hourly metered volumes and 2019 Long Term Outlook.

To calculate the intensity at the transformer level, we calculated the transformer kW demand over the 24 hours (19-day average from Lethbridge pilot data) as shown in Figure 37. We used the transformer demand profile with the respective 24-hour daily average CO2e g/kWh intensity to calculate a 24-hour emissions profile for the transformer that can be cumulated to show the total daily emissions. This daily result is multiplied by 365 days of the year to find the annual CO2e emissions as shown in Table 10.

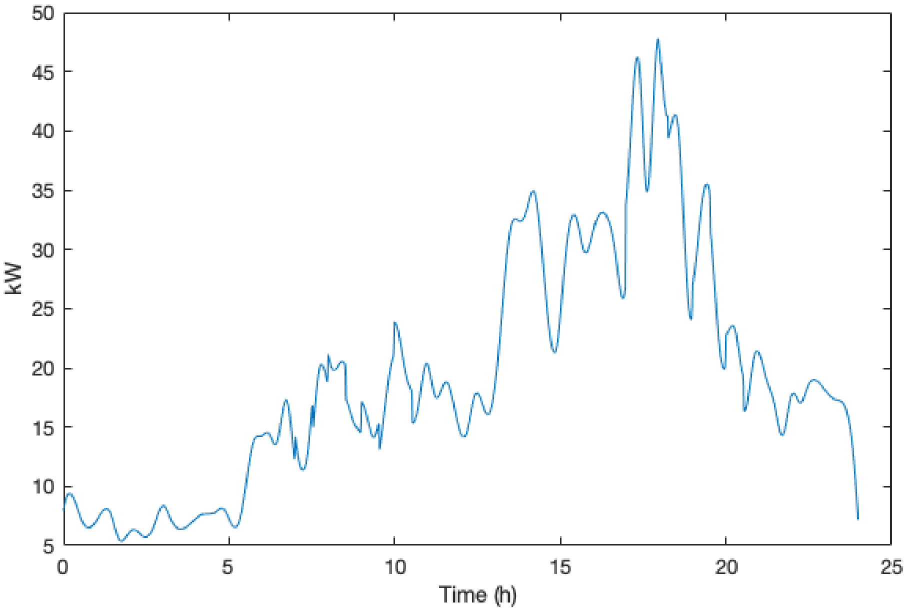


Figure 37 Aggregate transformer load - total load of {baseload(80% max of 19 days) + 1 EV + 1 Hot water tank

The GHG emission results of the controlled EV chargers by the two algorithms — the Peak Shifting (PS) algorithm and the Optimal Time Shifting (OTS) algorithm — for a transformer serving 16 homes with varying number of EV chargers are shown in Table 10 for 2017 grid emissions. As the emissions intensity varies throughout the day due to the variety of generation sources supplying the grid and measured on an hourly basis, the demand caused by the specific time of charging an EV has varying emissions correspondingly. The GHG emission results of the uncontrolled scenario are shown in the first row of each table, where the rest of the rows represent the number of participating EV chargers being controlled. The number of EV owners connected to the transformer circuit is represented by each column, whereas each row exhibits the respective ratio of EV chargers that are participating in the shifting algorithm.

ANNUAL CO_2e (kg)	1 EV	2 EV	3 EV	4 EV	5 EV
PS ALGORITHM					
0/5 EVs Controlled	113,960	115,810	119,450	121,310	124,960
1/5 EVs Controlled	114,000	115,850	119,490	121,350	124,990
2/5 EVs Controlled	—	115,860	119,500	121,360	125,000
3/5 EVs Controlled	—	—	119,500	121,360	125,000
4/5 EVs Controlled	—	—	—	121,360	125,000
5/5 EVs Controlled	—	—	—	—	124,990
CO_2e Savings (kg)	**-40**	**-50**	**-50**	**-50**	**-30**
OTS ALGORITHM					
0/5 EVs Controlled	113,960	115,810	119,450	121,310	124,960
1/5 EVs Controlled	113,960	115,800	119,440	121,300	124,950
2/5 EVs Controlled	—	115,770	119,410	121,270	124,910
3/5 EVs Controlled	—	—	119,340	121,200	124,850
4/5 EVs Controlled	—	—	—	121,180	124,830
5/5 EVs Controlled	—	—	—	—	124,740
CO_2e Savings (kg)	**0**	**40**	**110**	**130**	**220**

Table 10: 2017 GHG emission results, CO_2 kg per year per transformer serving 16 homes on a 50kVA transformer, of the controlled EV chargers by the two algorithms; the Peak Shifting (PS) algorithm and the Optimal Time Shifting (OTS) algorithm, based upon Alberta grid energy mixed 2017.

The most interesting finding is that one of our EV charger dispatching algorithms, the simple PS, is in fact augmenting the CO_2e emission due to the fact that the shifting is out of synch with the grid emission intensity. Our second algorithm, OTS, in contrast is synchronized with grid emission intensity and therefore achieving positive emission reduction. Note that the CO_2e emission results are shown for only one transformer serving five EV charges for a total 16 homes.

Table 11 below illustrates the annual GHG emissions and savings for the projected grid in 2030 for one transformer based on the projected energy generation mix from AESO's 2019 Long Term Plan. It is interesting to note that with the OTS algorithm, we demonstrated 220 kg of savings in 2017 and, with a lower carbon intensity grid in 2030, we were able to save 282 kg per transformer for 5 EV chargers under control. Therefore, we can conclude that even as the GHG emissions intensity factor of the Alberta grid is decreasing through the changes in generation mix in2030, the Home of the Future orchestration platform can still provide comparable GHG emission reduction improvements. Note, as a reference, a medium size city such as Edmonton as ~ 40K transformers therefore the CO2e savings would be scaled accordingly.

ANNUAL CO_2e (kg)	1 EV	2 EV	3 EV	4 EV	5 EV
PS ALGORITHM — FORECAST 2030					
0/5 EVs Controlled	26,488	26,925	27,789	28,230	29,097
1/5 EVs Controlled	26,497	26,935	27,798	28,239	29,105
2/5 EVs Controlled	—	26,937	27,801	28,242	29,107
3/5 EVs Controlled	—	—	27,791	28,232	29,097
4/5 EVs Controlled	—	—	—	28,228	29,092
5/5 EVs Controlled	—	—	—	—	29,070
CO_2e Savings (kg)	**-9**	**-12**	**-2**	**2**	**27**
OTS ALGORITHM — FORECAST 2030					
0/5 EVs Controlled	26,488	26,925	27,789	28,230	29,097
1/5 EVs Controlled	26,454	26,891	27,755	28,196	29,062
2/5 EVs Controlled	—	26,851	27,715	28,156	29,022
3/5 EVs Controlled	—	—	27,632	28,073	28,940
4/5 EVs Controlled	—	—	—	28,033	28,900
5/5 EVs Controlled	—	—	—	—	28,815
CO_2e Savings (kg)	**34**	**74**	**157**	**197**	**282**

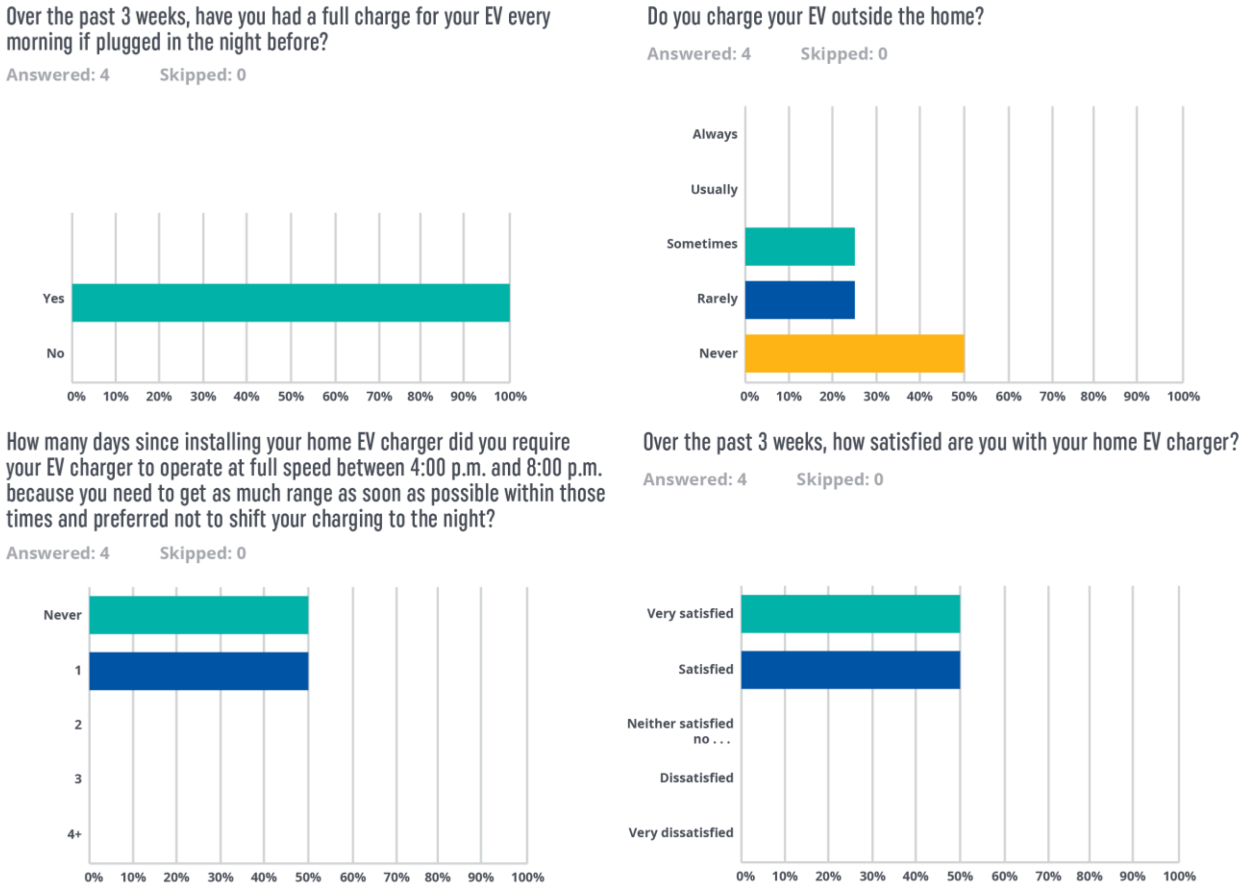
Table 11: 2030 GHG emission results, CO2 kg per year per transformer serving 16 homes on a 50kVA transformer, of the controlled EVs by the two algorithms; the Peak Shifting (PS) algorithm and the Optimal Time Shifting (OTS) algorithm, based upon Alberta grid energy mixed 2030.

Generally, it can be concluded that, with the current initiatives to increase EV deployment in the Alberta distribution grid, a greater reduction of GHG emissions can be achieved depending on the EV charging time dispatch algorithm and active generators. Two algorithms, PS and OTS, were developed to reduce the transformer peak load and expand its lifespan. To evaluate the benefits of these algorithms in terms of GHG emission reduction, the PS algorithm has almost no clear reduction in GHG emission and sometimes the GHG emissions increase with this algorithm. On the other hand, the OTS algorithm, when controlling five EV chargers (with one electric water heater) the emissions are annually reduced by 220 kg per year per transformer in 2017 and by 282 kg in 2030. While this exhibits a current view within the pilot project, we would also like to note that future research would need to be completed based on the impact of shifting a significant amount of EV chargers and their corresponding load to late night and the associated generation mix required to supply such demand.

Residents of the ATCO Home of the Future will have unprecedented visibility into their energy usage, and the ability to determine in real time as well as in aggregate the consequences of changes in their decision making. When these environmentally responsible practices can have their respective impacts measured, consumers will be more likely to adopt habits that decrease utility costs, which have positive environmental impacts.

6.2 TECHNICAL BENEFITS

The primary technical benefit of the project was a new approach to smart grid integration of DERs that created a new value stream for demand-side management. The technology reconciles the increased penetration of EVs, other DERs and integrated control systems while reducing the costs of grid upgrades to support an increase of intermittent renewables. The communication channels to multiple devices through API communication in a technology-agnostic modular approach is an emerging field by the few aggregators in the market. However, the integration into utility asset management is a new value that mitigates the technical risks of greater penetration of EVs onto any grid. A unique angle for utilities that creates new value is the incorporation of a “Homeowner Dashboard” that establishes a relationship between the DSO and residential customer that was not present before. The dashboard provides a level of knowledge and transparency into the residential customer’s electrical system, which promoted a behaviour of ownership and partnership with the utility to help solve a shared problem. It is also the platform that empowers residential customers to have authority in the system’s actions to not intrude on their lives, such as through the opt-out option in curtailment events. While no residential customers used the opt out, the option provides security for the homeowner. This illustrated the benefit for both parties of integrating user behaviours with technical demand-side management considerations. Figure 38 below illustrates the results that were collected through a customer survey after the Lethbridge pilot with the home owners participating in the pilot.



Over the past 3 weeks, have you had a full charge for your EV every morning if plugged in the night before?

Do you charge your EV outside the home?

How many days since installing your home EV charger did you require your EV charger to operate at full speed between 4:00 p.m. and 8:00 p.m. because you need to get as much range as soon as possible within those times and preferred not to shift your charging to the night?

Over the past 3 weeks, how satisfied are you with your home EV charger?

Figure 38: Residential Customer Survey Results on EVs

Integrating functionality for existing advanced metering infrastructure is critical to reduce the need for additional behind-the-meter sensors for home load measurement. It also alleviates the need for the transformer sensor as this technology's solution aggregates the AMI load data from each home to estimate the transformer load and load-based asset issues that would arise due to peak load, which would decrease asset life and reduce capital efficiency. Pilot efforts at SAIT have improved our understanding of the size and scale of renewable generation and storage. More time dedicated to observing and analyzing the data from pilot operations observation would be beneficial to further define the solution for commercial delivery. The benchmarks achieved from the pilot project enable monitoring of near-real-time energy profiles of homes and neighbourhoods via the transformer. This technical advancement of integrating home and transformer data as a tool for dynamic demand response — which incorporates asset management considerations through an intelligent state-machine algorithm — is the largest technical benefit of the Home of the Future product. This technical advancement also applies to other demand-side management applications, which can further enable the deployment of microgrids and virtual powerplants on a smart grid.

6.3 COMMERCIALIZATION STRATEGY

The initial business models developed for this product ranged due to the value propositions for various customers. Through consultation with stakeholders early in the project, a number of potential business models were identified (see Appendix E: Business Model, for early value proposition iterations), with portions of each either adopted or dropped. These business models included the following.

Key Customer Segment: Homeowners

Homeowner pays for full ownership of solar + storage + energy management system (EMS)

- Components adopted: homeowner pays for ownership of EV charger and electric water heater, which are penetrating the market organically. This business model will not be constrained by deploying new hardware, but will optimize the value of existing hardware to homeowners.

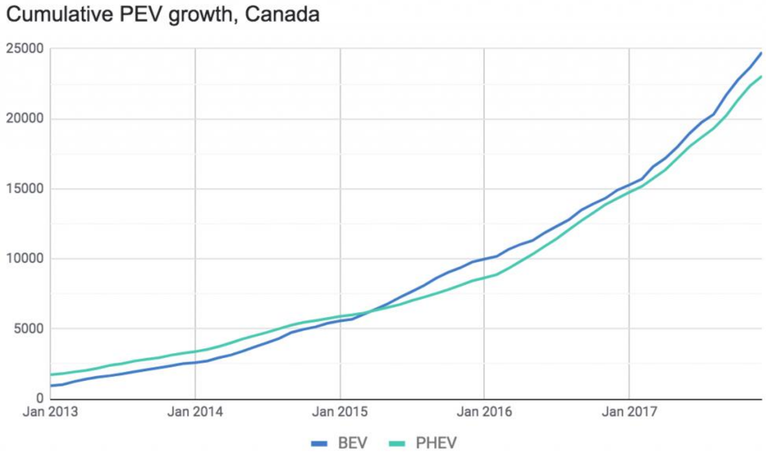


Figure 39: EV Growth in Canada

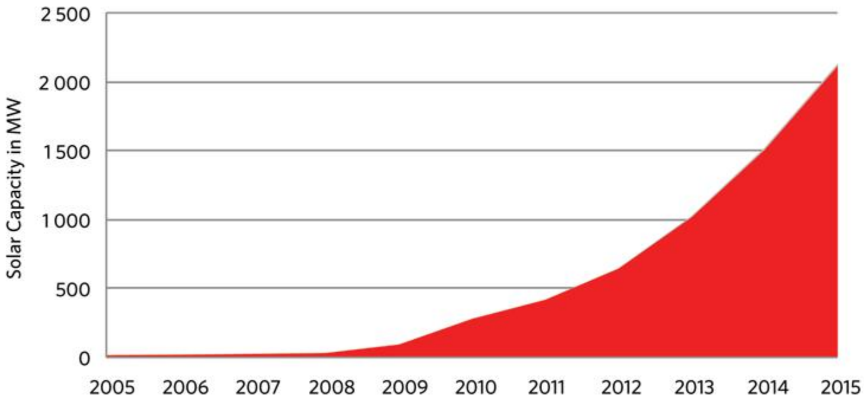


Figure 40: Installed solar capacity growth in Canada

Key Customer Segment: Technology Vendors

Solar + storage + EV charger distributors and installers wholesale purchase EMS as value-add to solar + EMS

- Given the value proposition to utilities to own more of the customer relationship, ATCO decided to focus on the utility rather than the hardware vendors. Also, the platform connects multiple technologies from different vendors in an agnostic method. However, vendors are used as a market channel to help their customers capture more value from their hardware.

Key Customer Segment: Home Builders

Home builders incorporate solar + storage + EMS or EMS alone into new homes as incremental add-on

- Components adopted: offer value proposition to home builders as a differentiating factor in the market and value-add to their customers.

Key Customer Segment: Energy Retailers

Energy retailers wholesale purchase product to sell to homes at discount to gather customer data

- Consumption foresight in aggregate can inform energy trading. Furthermore, for full-chain electricity utilities that include retail, the product can inform system design and associated quality improvement initiatives.

Key Customer Segment: DSO

Utility owns solar + storage + EMS assets and leases to homeowner for monthly fee with EMS for risk management and control (solar + storage as a service)

- Valuation for utilities established to determine incentive design.
- Utility invests in Property Assessed Clean Energy (PACE) program and services solar + storage installation and EMS sales.
    - Financing component not being considered in this business given pivot to focus on organic market adoption of existing hardware, thus reducing the large capital investment requirement.
- DSO rate-bases produced as NWA and value-add to AMI asset to enable the DER market.
    - Meetings with ATCO’s regulatory team identified strong potential for the solution to be rate-based as an NWA, as it results in savings to the ratepayer over time due to asset life optimization.

Furthermore, through pivots, we were able to focus our value proposition to solve an emerging problem for DSOs, and were able to highlight an opportunity for utilities to build a stronger relationship with residential customers through more active engagement. For electricity systems with a joint distribution utility and retailer, this provides a commercial option for recommending new products to residential customers. Home developers are very interested as a major trend in both residential electric water heaters and solar, as well as emerging electric vehicles. The ability to optimize home solar into the home load rather than send excess to the grid is of interest to reduce overall home emissions profiles.

The commercial strategy for DSOs, the primary customer, is a business model that monetizes asset optimization through demand-side management that is flexible and modular to adopt future DERs as they arise on the distribution grid. Utilities are not actively involved, except where emerging regulation enables a new marketplace (e.g., capacity market). The utility carries the burden of O&M and customer satisfaction, where customer satisfaction is being met by third parties, resulting in less reliance on the grid and O&M costs that are not articulated into an operational price signal that is useful in these systems. These third-party startups typically build solutions based on market prices and rates, but current energy economics and rate design are not necessarily keeping up with DER disruption on the grid. Even ToU (Time of Use) rates are based on an old grid and are not responsive to major technology shifts. The Alberta Utilities Commission has acknowledged this through the recent DER inquiry, where they are working with utilities across Alberta, including ATCO, to understand the impact of DER and new energy technologies on the grid. As a DSO, there is a drive to not cause rate shock and to meet the needs of the end user. DSOs are starting to gather general situational awareness of load monitoring to predict asset issues, even without the ability to control the load. Companies like UtiliSmart are deploying such offerings on top of AMI systems, but lack prediction and disaggregation to understand the impact of large loads like EVs. The Home of the Future product is a behavioural software-based demand-side management product offering this at a cheaper cost than large asset replacement. The commercial strategy of this grid orchestration product is to first deploy to residential customers and run autonomously. The pathway is to commercialize the knowledge and capabilities developed into further residential and commercial applications, including microgrids and EV fleet management.

Microgrids

It was announced at the HOMER International Microgrid Conference 2019 in Cambridge, MA, USA, in October 2019 that the future of microgrids is to go beyond the solar and storage supply-demand fit to integrate load management for further optimization. There are currently limited microgrid offerings that incorporate load management, as most operate under a traditional utility approach, just with DERs — i.e., supply the demand as effectively as possible without integrating load management. Microgrid developers such as Schneider and ABB are starting to explore load prediction, but not many vendors incorporate load management.

EV Fleets

Utilities are concerned with the emergence of EV fleets and the affect on the grid. While fleet management systems are prevalent in the market, most of them do not incorporate power systems design and grid interconnection. The future of the smart charging algorithm in this product can be used to orchestrate fleet EVs to optimize infrastructure usage and grid interconnection considerations for the DSO such that commercial customers can capture the environmental and economic benefits of EVs.

7.0 PROJECT COMMUNICATIONS & MEDIA

Conferences/Industry Discussions

- Jeanie Chin and Jeff Reading presented at the annual Energy Efficiency Alberta conference in Calgary in May 2018. The session was well attended, attracting over 100 people.
- Francois Blouin presented this project at the Electric Mobility Canada Conference in May 2018 and 2019 to an audience of 125 people composed of attendees from utilities, municipalities and EV manufacturers.
- Francois Blouin and the team presented to Yukon Electric in June 2019 to explore commercialization opportunities.
- ATCO hosted a customer event at Spruce Meadows in June 2019, with an exhibition booth to present the potential application and benefits of ATCO's Home of the Future to 100 guests.
- Jeff Reading included the project in a presentation to the Oldman Watershed Council in Lethbridge (100 people) in June 2019.
- The project was presented at the:
  - Hydro Quebec Smart Home conference in October 2019 to 50 people;
  - SPARK conference in Edmonton in October 2019 to 75 people; and
  - IEEE Grid Modernization conference in November 2019 to 60 people.

Public Communications

- Lethbridge Community Engagement sessions were held on August 1, 2019, and Dec 11 2019.
- The ATCO Communications Team developed an infographic that was shared internally to very positive results. The infographic has since been converted to a PowerPoint format as well, which makes it suitable for presentations and circulation. Visuals of these communications pieces are in Appendix A: Presentation Image.
  - Stakeholder engagement with Lethbridge Electric Utility and homeowners in Lethbridge for pilot project.
  - Public announcement of pilot project tentatively is targeted for the launch of an electric vehicle fast charger in Lethbridge.
  - EPCOR/ENMAX discussions took place at various events including conferences and in-person meetings in 2019.

8.0 NEXT STEPS

The next steps for the Home of the Future can be split into technical design and commercial application pathways with the residential sector and then commercial and industrial customers. For technical design, the aim is to further optimize the charging algorithm code and establish an architecture that is scalable to connect many FLO EV chargers through an API, given that this is the technology our solution integrates with and it has a large market share in Canada. To gain scale, we will then aim to integrate other residential EV charger vendors, starting with ChargePoint, which has a large market share in the United States.

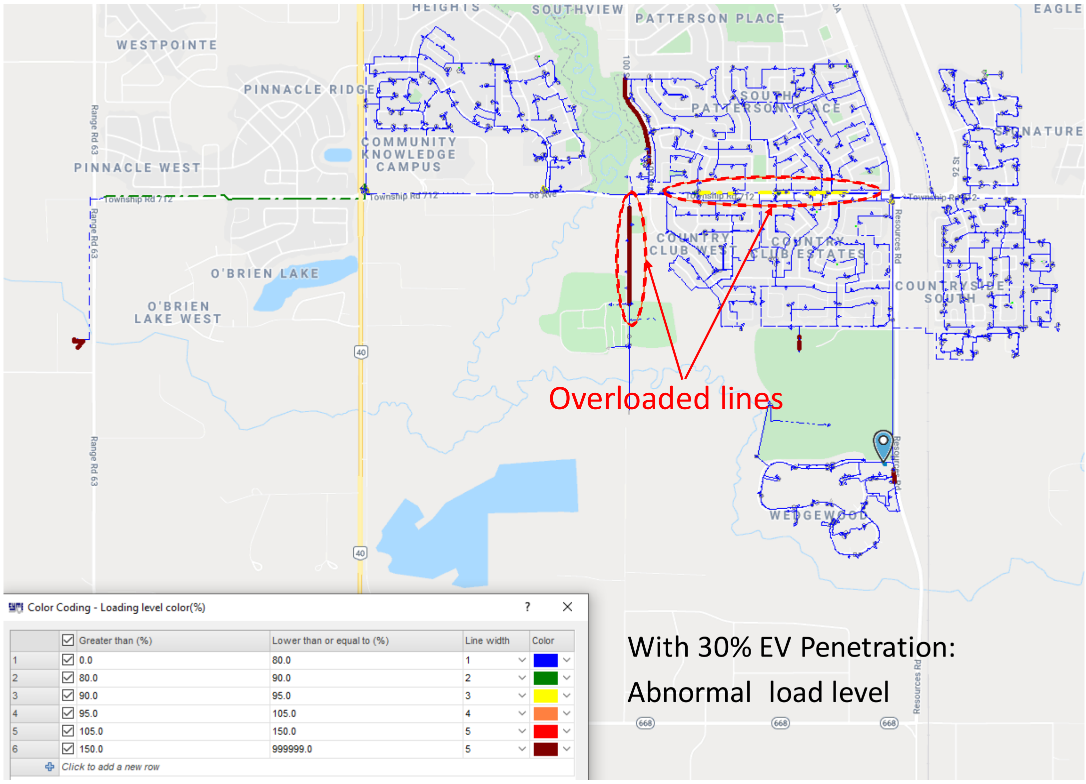
Aside from EVs, the next major technology to integrate is the electric hot-water tanks. The aim is to scale with Aquanta, which is currently integrated but an after-market solution. As smart water heaters are becoming more prevalent, our next target is to incorporate Rheem electric hot-water tanks given their large market size and built-in solution. The final target home technology is smart thermostats that have a connection to electric baseboard heating and air conditioning. This would enable us to connect to the three largest home electricity demand users with a flexibility envelope with the homeowner that could leverage automated decision making. We also aim to do more research to understand the overall grid effects of residential demand side management upstream from the secondary circuit to enhance the value proposition to DSOs.

The same algorithms developed in the Home of the Future also are valuable to commercial and industrial customers, given their existing demand-charges market and energy demand routines. We will also explore integrating the Home of the Future algorithms and technology communications for microgrid management. The initial target will be the ATCO off-grid solar and storage microgrid for diesel reduction in Fort Chipewyan, Alberta. The expansion to commercial and industrial customers is a longer-term plan, as it will require numerous diverse technologies to be integrated and customer value understood, which is a competitive market.

The next steps include:

- Exploring the prospective move to larger-scale deployment/commercialization;
- Energy Efficiency Alberta discussion to use the system to gather information on energy usage; and
- Further DFO discussions (EPCOR, ENMAX).

The Home of the Future project was developed and tested at the secondary distribution network level. The same problem is exacerbated when we look at the circuit level connecting thousands of customers. Asset life extension — or transformer loss of life due to continuous overload conditions — will trigger significant capital investments to support the future of not only home EV charging, but further electrification of the home as well. We have conducted some initial analysis in the City of Grande Prairie to estimate the impact; it confirms our previous results that significant overload is expected if no smart EV charging/EV control orchestration is implemented, as illustrated in Figure 41.



Overloaded lines

With 30% EV Penetration:
Abnormal load level

Color Coding - Loading level color(%)

	☑ Greater than (%)	Lower than or equal to (%)	Line width	Color
1	☑ 0.0	80.0	1	🟦
2	☑ 80.0	90.0	2	🟩
3	☑ 90.0	95.0	3	🟨
4	☑ 95.0	105.0	4	🟧
5	☑ 105.0	150.0	5	🟥
6	☑ 150.0	999999.0	5	🟫
✚	Click to add a new row			

Figure 41: Initial power flow analysis at the feeder level in Grande-Prairies with 30% penetration EVs

9.0 CONCLUSIONS

The learnings throughout this project have been critical in helping accelerate our path to a solution for both the Home of the Future and other products we aim to develop. The customer discovery approach helped us avoid a pitfall of designing a solution that no one was willing to pay for. Through iterations of validating stages of our idea and re-designing, we shifted from a space of designing a technology that sounded good in theory to one that users actually cared about. This was exemplified by EPCOR, a customer group we engaged early on in product development that was severely critical of our idea, enthusiastically asking the first question of “When can I buy this?” after our presentation at the 2019 IEEE PES Grid Modernization Workshop.

Through iterations of our idea, we were driven to design a product with a multi-sided business model focusing on DSOs as the primary customer while also providing a value proposition to residential customers and energy retailers and generators. The final result is a product that creates a quasi-ancillary services market, which does not currently exist, by monetizing the benefits of demand-side management for utilities through asset management. Where rate design lags in response to the dynamic changes on the electricity grid and customer connection to the DSO further separates, the Home of the Future engineered price signal provides that bridge to both customer behaviour and asset economics to save utilities and ratepayers money over the lifetime of assets by mitigating the risk of early asset replacement while maintaining residential customers’ lifestyles.

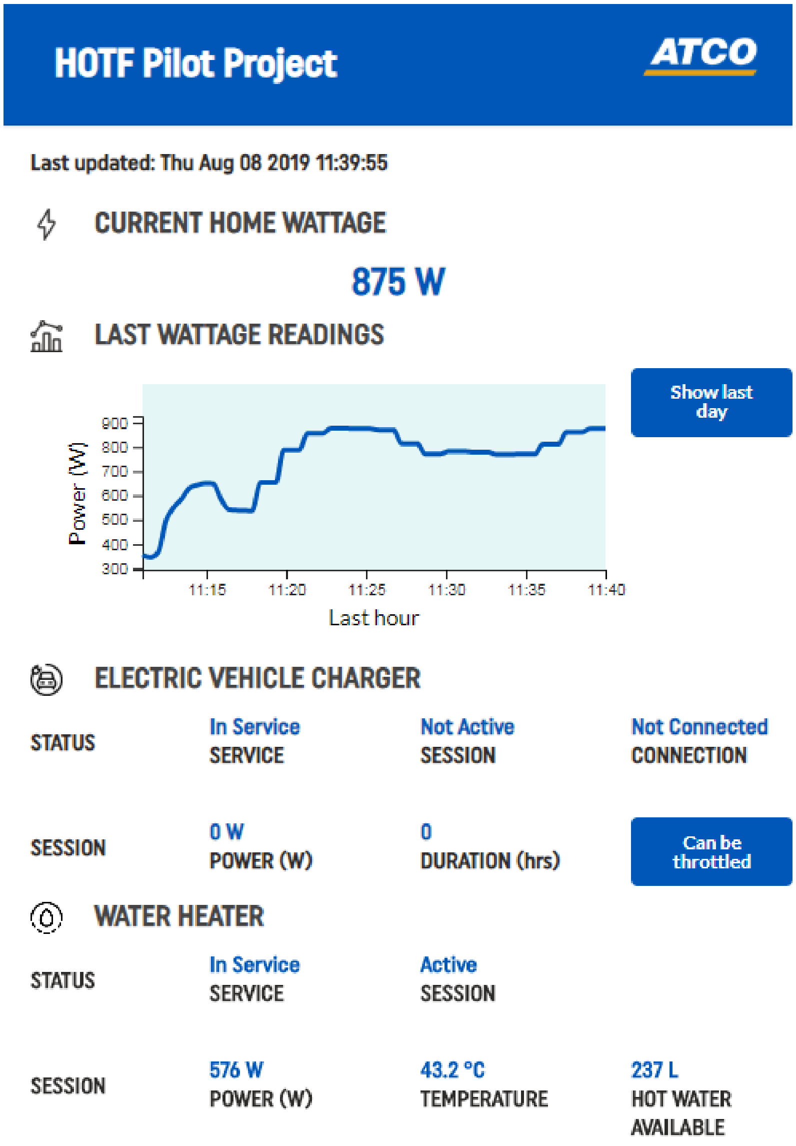
While the current solution focused on EVs, with the next version targeting electric hot-water tanks, the architecture is designed to be modular. The future of an array of grid-edge technologies drives us to be technology agnostic with the ability to add new devices in the future to leverage the IoT economy, especially as open communications interfaces such as APIs are coupled with such technologies. This ancillary services market is not only relevant to residential customers but can be applied similarly to commercial and industrial customers as a future market.

In conclusion, the evolution of the product caused by engaging customers with a design-thinking approach enabled us to move from a technologically innovative solution that was not solving a large enough problem to developing a solution that established new value flows in a blue ocean market (ie new market not exploited or non-existent) to help DSOs find a position in the new energy world. Both EPCOR and Enmax have expressed interest in such a product.

APPENDIX A: PRESENTATION IMAGE

Marketing and public image used in multiple presentations, events describing the vision of an integrated utility and behind the meter energy orchestration system.

APPENDIX B: DASHBOARD SCREENSHOTS



HOTF Pilot Project

Last updated: Thu Aug 08 2019 11:39:55

CURRENT HOME WATTAGE

875 W

LAST WATTAGE READINGS

ELECTRIC VEHICLE CHARGER

STATUS	In Service SERVICE	Not Active SESSION	Not Connected CONNECTION
SESSION	0 W POWER (W)	0 DURATION (hrs)	Can be throttled

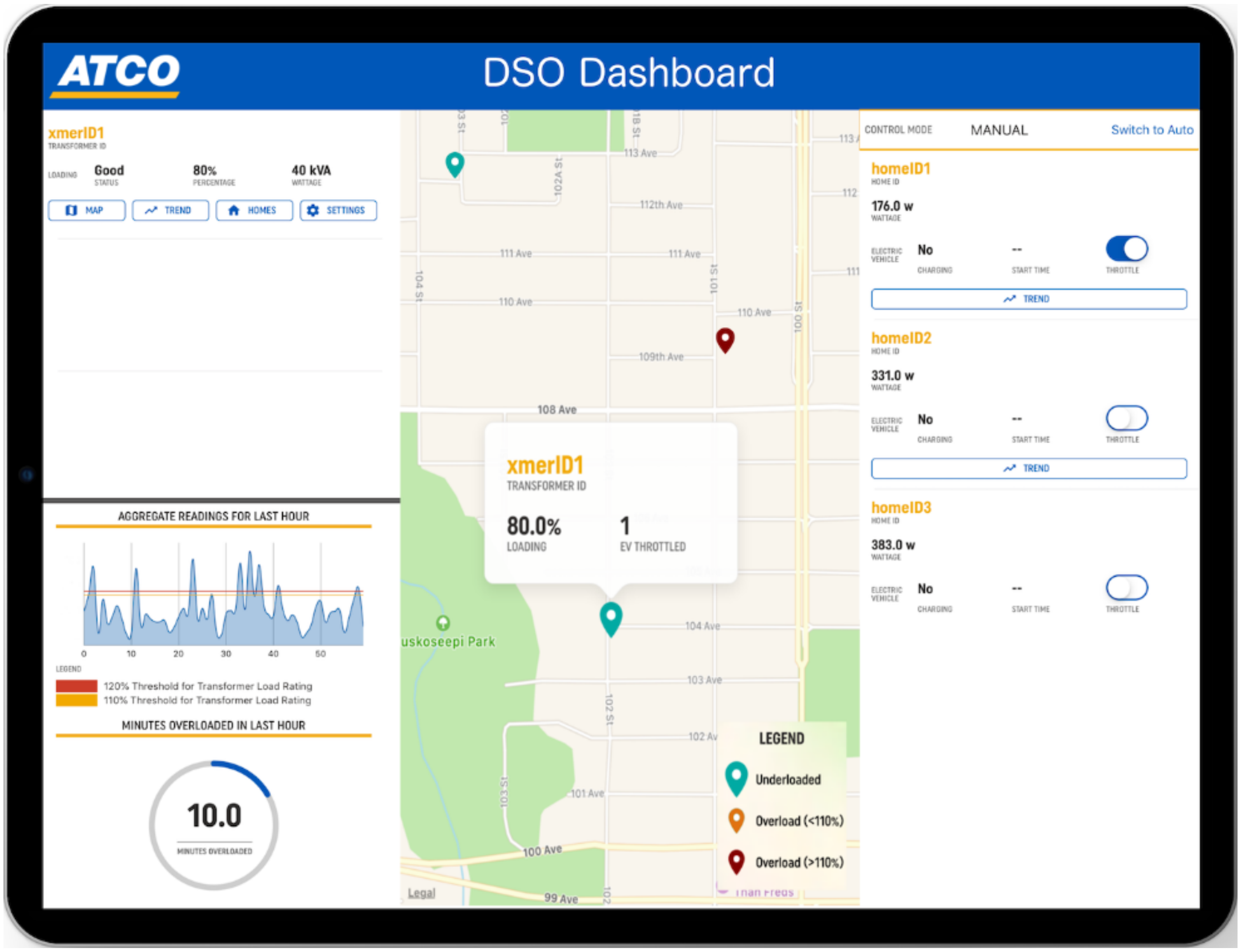
WATER HEATER

STATUS	In Service SERVICE	Active SESSION	
SESSION	576 W POWER (W)	43.2 °C TEMPERATURE	237 L HOT WATER AVAILABLE

Figure 42: Homeowner Dashboard Screenshot

DSO Dashboard Screenshot

- View the transformer location
- Provides basic transformer information
- View the last 60 minutes of aggregate readings for a specific transformer
- Quickly see how often the transformer was overloaded
- View high-level aggregate information of each home that contributes to loading on a specific transformer
- See instantaneous wattage reading
- See if EV charging in progress, when started, and ability to remotely throttle
- Auto mode system handles throttling individual house load based on ATCO produced algorithm



xmerID1
TRANSFORMER ID
LOADING Good STATUS 80% PERCENTAGE 40 kVA WATTAGE

10.0 MINUTES OVERLOADED

xmerID1 TRANSFORMER ID
80.0% LOADING
1 EV THROTTLED

CONTROL MODE MANUAL

homeID1 HOME ID
176.0 w WATTAGE
ELECTRIC VEHICLE No CHARGING -- START TIME THROTTLE ●

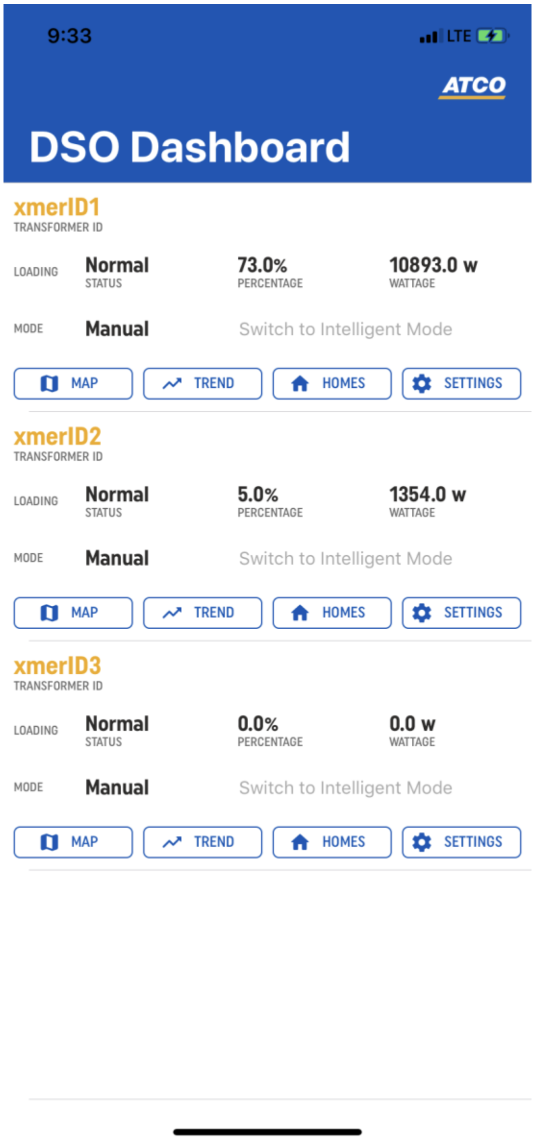
homeID2 HOME ID
331.0 w WATTAGE
ELECTRIC VEHICLE No CHARGING -- START TIME THROTTLE ○

homeID3 HOME ID
383.0 w WATTAGE
ELECTRIC VEHICLE No CHARGING -- START TIME THROTTLE ○

Figure 43: Possible iPad representation of the DSO dashboard.

DSO Dashboard — Main View

Below is the main screen seen when launching the mobile application. This screen is intended to provide a quick overview of the loading on each transformer being monitored. From this screen an app user can drill in deeper to view things such as the physical location of the transformer (on a map), the aggregate loading on the transformer, a view of all homes contributing to the loading and a settings page that is transformer specific.



DSO Dashboard

xmerID1
TRANSFORMER ID
LOADING Normal STATUS 73.0% PERCENTAGE 10893.0 w WATTAGE
MODE Manual Switch to Intelligent Mode

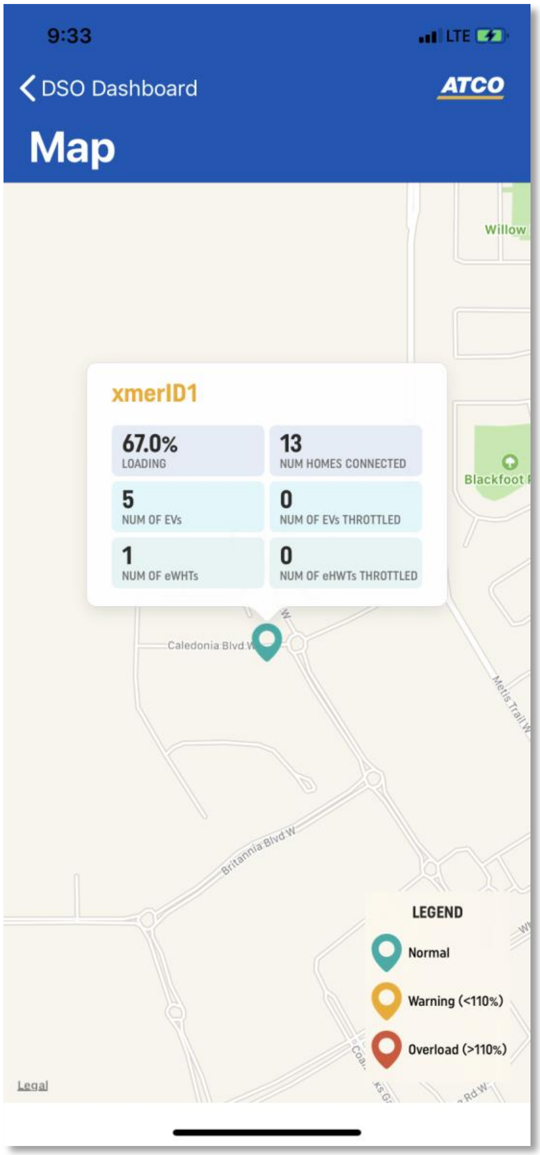
xmerID2
TRANSFORMER ID
LOADING Normal STATUS 5.0% PERCENTAGE 1354.0 w WATTAGE
MODE Manual Switch to Intelligent Mode

xmerID3
TRANSFORMER ID
LOADING Normal STATUS 0.0% PERCENTAGE 0.0 w WATTAGE
MODE Manual Switch to Intelligent Mode

Figure 44: DSO Dashboard Main Screen

DSO Dashboard — Geographical View

The geographical view displays the physical location of a transformer. The map pin colour changes depending on the loading of the transformer and tapping on the transformer pin displays an overview of how many homes are connected and contributing to the transformer's total loading.



9:33

DSO Dashboard

Map

xmerID1

67.0% LOADING	13 NUM HOMES CONNECTED
5 NUM OF EVs	0 NUM OF EVs THROTTLED
1 NUM OF eWHTs	0 NUM OF eHWTs THROTTLED

LEGEND

Normal

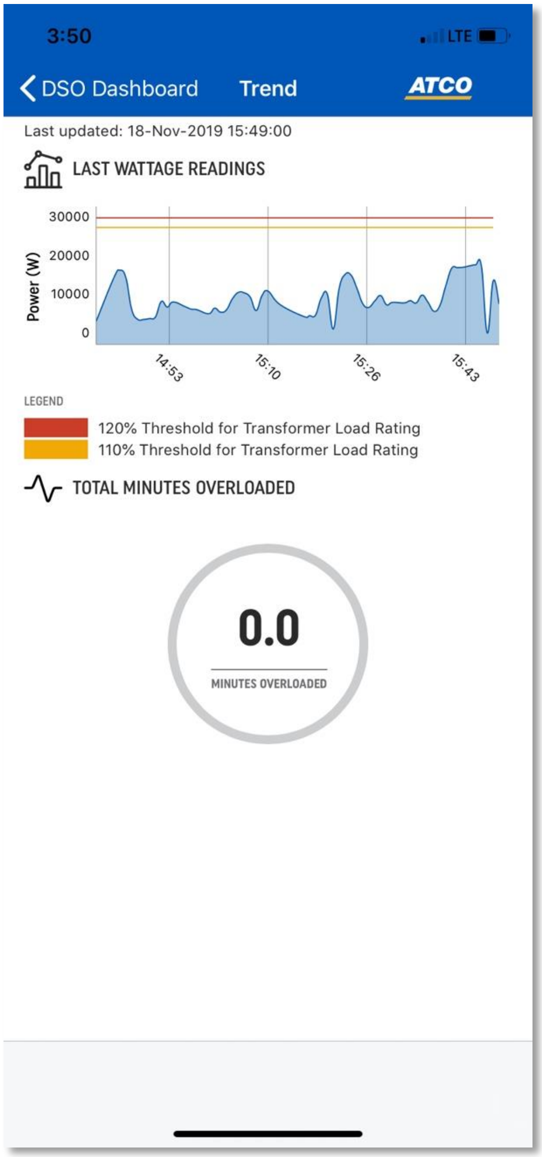
Warning (<110%)

Overload (>110%)

Figure 45: DSO Dashboard Map

DSO Dashboard — Transformer Aggregate Readings View

Quickly view the last 60 minutes of loading on a single transformer, as well as the total minutes the transformer was overloaded.

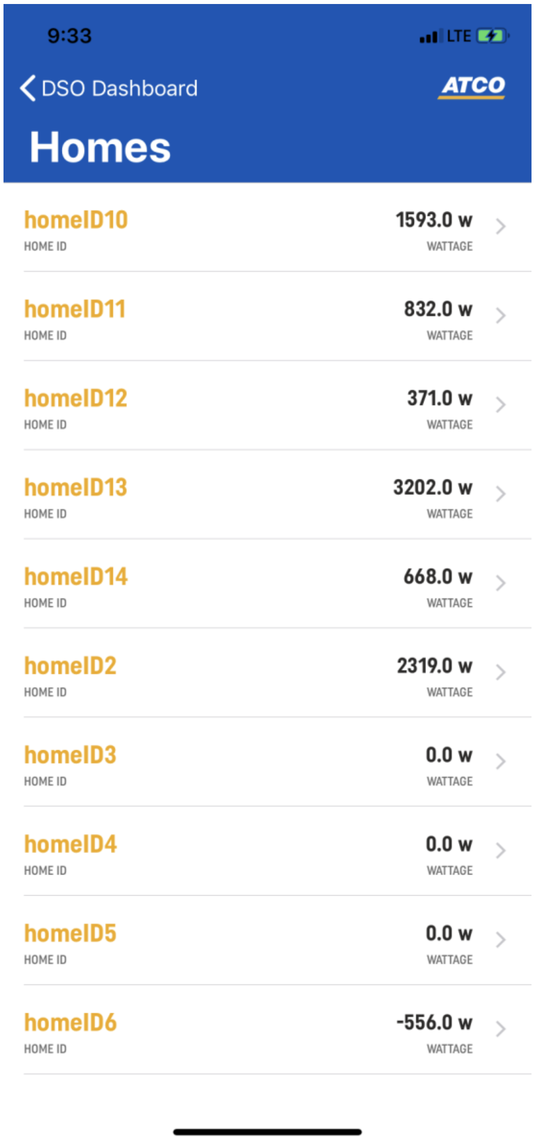


Last updated: 18-Nov-2019 15:49:00

Figure 46: DSO Dashboard Transformer Aggregate Display

DSO Dashboard — Homes View

Tapping on the Homes button from the main transformer dashboard displays a quick glance of all the homes contributing to the total transformer loading.



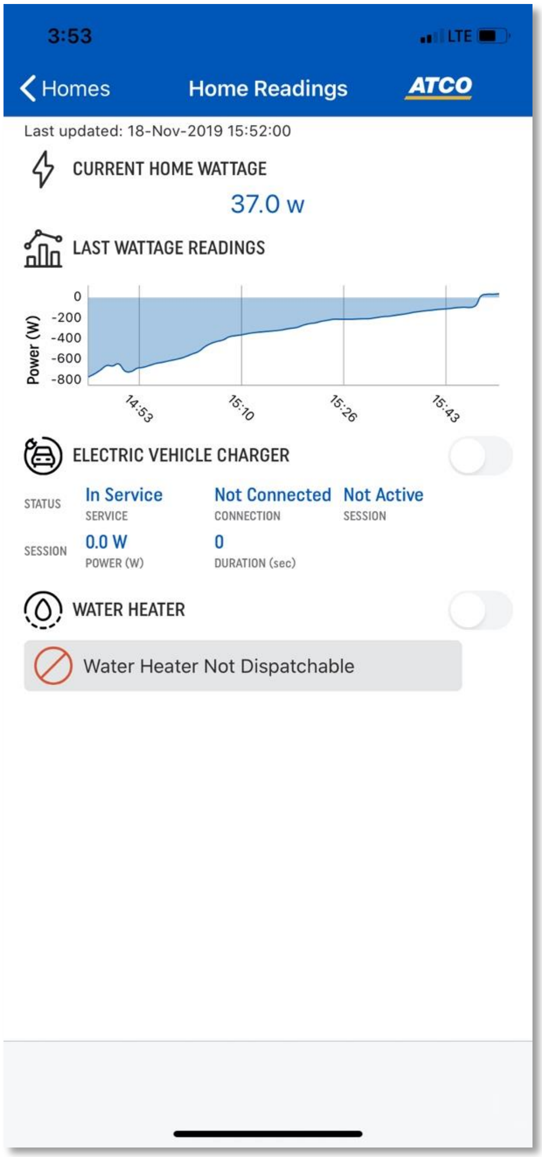
Homes

HOME ID	WATTAGE
homeID10	1593.0 w
homeID11	832.0 w
homeID12	371.0 w
homeID13	3202.0 w
homeID14	668.0 w
homeID2	2319.0 w
homeID3	0.0 w
homeID4	0.0 w
homeID5	0.0 w
homeID6	-556.0 w

Figure 47: DSO Dashboard Homes List

DSO Dashboard — Single Home View

Tapping on an individual home from the Homes view displays the current loading, last 60 minutes of aggregate readings and current loading caused from an EV or water heater. If the EV or water heater are active, the app user can also choose to throttle them on demand.



Home Readings

Last updated: 18-Nov-2019 15:52:00

CURRENT HOME WATTAGE

37.0 w

LAST WATTAGE READINGS

ELECTRIC VEHICLE CHARGER

STATUS	In Service SERVICE	Not Connected CONNECTION	Not Active SESSION
SESSION	0.0 W POWER (W)	0 DURATION (sec)	

WATER HEATER

Water Heater Not Dispatchable

Figure 48: DSO Dashboard Single Home View

APPENDIX C: LETHBRIDGE COMMUNITY ENGAGEMENT

Lethbridge Community Engagement Meetings

HOME OF
THE FUTURE

A Smart Renewable Home
and Energy Ecosystem Platform

ATCO Home of the Future
Pilot Project Neighbourhood
Meeting

Thursday, August 1, 2019

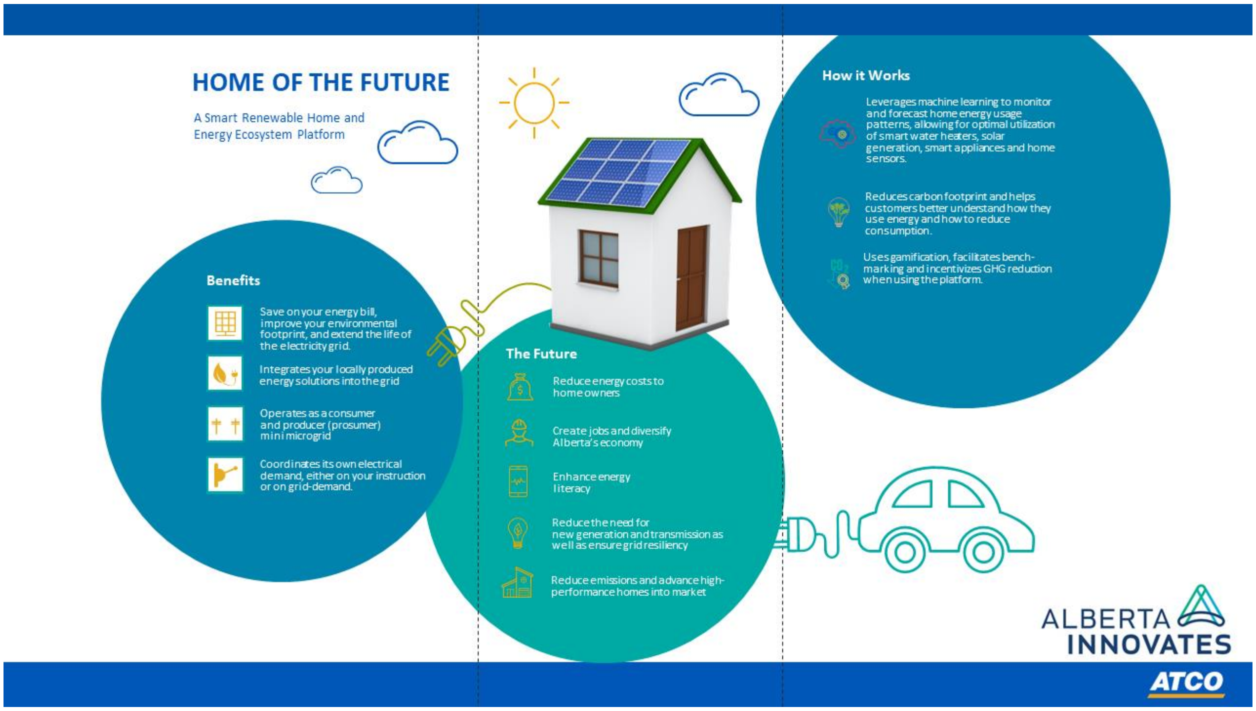
6:30 P.M. – 8:00 P.M.

Lethbridge Public Library - The Crossings
Branch: Friends Place

Light refreshments will be served.

Figure 49: Lethbridge Community Engagement Meeting Notices

Residential Customer Engagement Brochure



HOME OF THE FUTURE

A Smart Renewable Home and
Energy Ecosystem Platform

Benefits

- Save on your energy bill, improve your environmental footprint, and extend the life of the electricity grid.
- Integrates your locally produced energy solutions into the grid
- Operates as a consumer and producer (prosumer) mini microgrid
- Coordinates its own electrical demand, either on your instruction or on grid-demand.

The Future

- Reduce energy costs to home owners
- Create jobs and diversify Alberta's economy
- Enhance energy literacy
- Reduce the need for new generation and transmission as well as ensure grid resiliency
- Reduce emissions and advance high-performance homes into market

How it Works

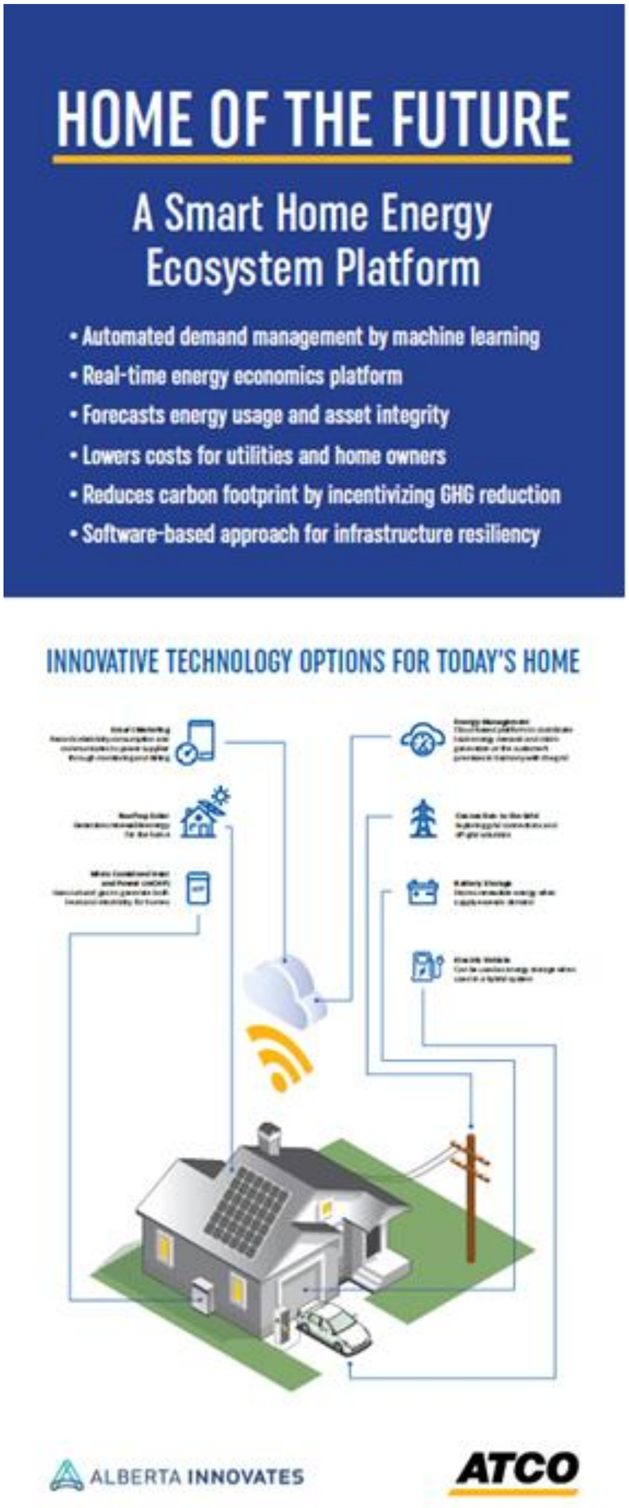
- Leverages machine learning to monitor and forecast home energy usage patterns, allowing for optimal utilization of smart water heaters, solar generation, smart appliances and home sensors.
- Reduces carbon footprint and helps customers better understand how they use energy and how to reduce consumption.
- Uses gamification, facilitates bench-marking and incentivizes GHG reduction when using the platform.

ALBERTA INNOVATES

ATCO

Figure 50: ATCO Home of the Future Residential Customer Engagement Banner

Home of the future event banner



HOME OF THE FUTURE

A Smart Home Energy Ecosystem Platform

- Automated demand management by machine learning
- Real-time energy economics platform
- Forecasts energy usage and asset integrity
- Lowers costs for utilities and home owners
- Reduces carbon footprint by incentivizing GHG reduction
- Software-based approach for infrastructure resiliency

INNOVATIVE TECHNOLOGY OPTIONS FOR TODAY'S HOME

APPENDIX D: ENGINEERED PRICE SIGNAL

ENGINEERED PRICE SIGNAL FOR ENERGY MANAGEMENT AND ALGORITHM DEVELOPMENT

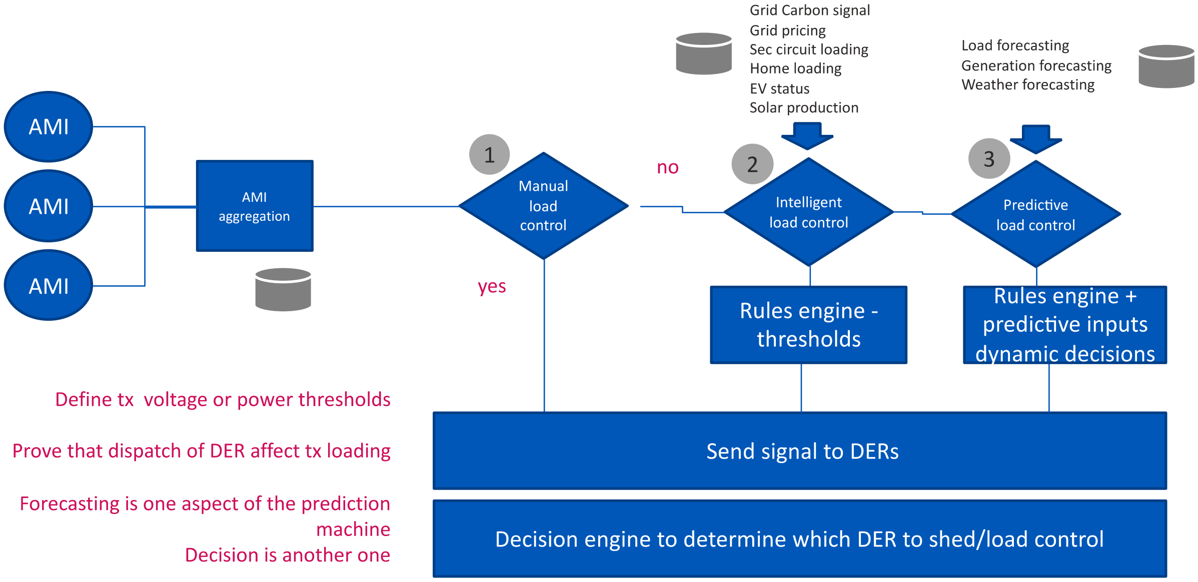
Purpose & Background

Decision engine to determine which DER to shed/load control, which can be defined as short-term modifications in customer end-use electric loads in response to:

- Grid energy pricing signal;
- Grid carbon signal;
- Secondary circuit loading;
- Home loading;
- EV charging status;
- Water heater status; or
- Solar production.

One of the key components of DER is that the pricing and reliability information known at the grid system or utility level must be transmitted and translated into load-reducing actions at the end-user sites.

Engineered prices are dynamic and temporary. They are driven by factors such as load forecasting, generation forecasting and/or weather forecasting.



Define tx voltage or power thresholds

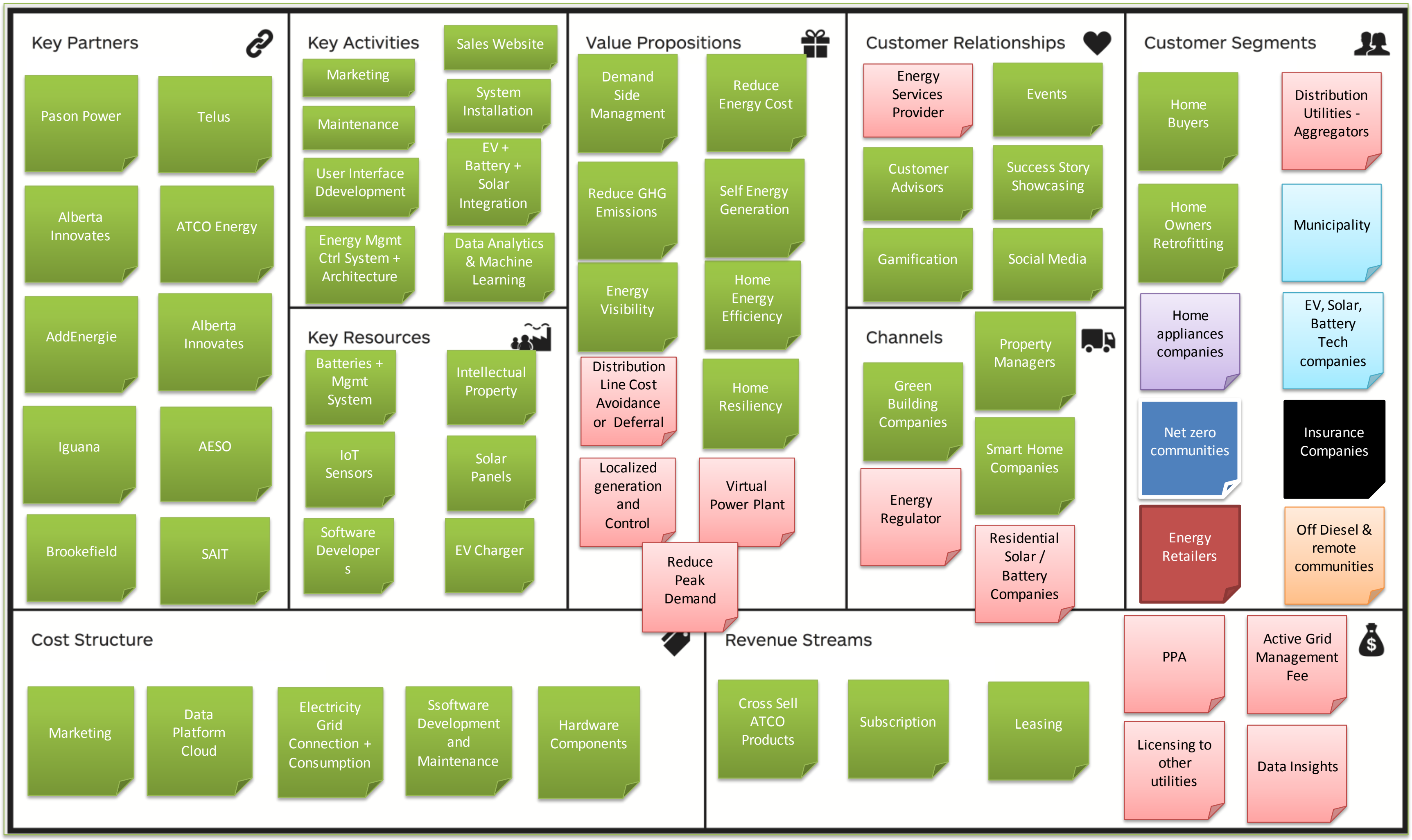
Prove that dispatch of DER affect tx loading

Forecasting is one aspect of the prediction machine
Decision is another one

Figure 51: High level overview of the engineered price signal conceptual implementation

APPENDIX E: BUSINESS MODEL

INITIAL BUSINESS MODEL CANVAS



Key Partners

- Pason Power
- Telus
- Alberta Innovates
- ATCO Energy
- AddEnergie
- Alberta Innovates
- Iguana
- AESO
- Brookefield
- SAIT

Key Activities

- Sales Website
- Marketing
- System Installation
- Maintenance
- EV + Battery + Solar Integration
- User Interface Ddevelopment
- Energy Mgmt Ctrl System + Architecture
- Data Analytics & Machine Learning

Key Resources

- Batteries + Mgmt System
- Intellectual Property
- IoT Sensors
- Solar Panels
- Software Developers
- EV Charger

Value Propositions

- Demand Side Managment
- Reduce Energy Cost
- Reduce GHG Emissions
- Self Energy Generation
- Energy Visibility
- Home Energy Efficiency
- Distribution Line Cost Avoidance or Deferral
- Home Resiliency
- Localized generation and Control
- Virtual Power Plant
- Reduce Peak Demand

Customer Relationships

- Energy Services Provider
- Events
- Customer Advisors
- Success Story Showcasing
- Gamification
- Social Media

Channels

- Property Managers
- Green Building Companies
- Smart Home Companies
- Energy Regulator
- Residential Solar / Battery Companies

Customer Segments

- Home Buyers
- Distribution Utilities - Aggregators
- Home Owners Retrofitting
- Municipality
- Home appliances companies
- EV, Solar, Battery Tech companies
- Net zero communities
- Insurance Companies
- Energy Retailers
- Off Diesel & remote communities

Cost Structure

- Marketing
- Data Platform Cloud
- Electricity Grid Connection + Consumption
- Ssoftware Development and Maintenance
- Hardware Components

Revenue Streams

- Cross Sell ATCO Products
- Subscription
- Leasing
- PPA
- Active Grid Management Fee
- Licensing to other utilities
- Data Insights

	MVP Implementation Features		VALUE PROPOSITION - HOME OWNER
5	Dynamic: DFO Aggregation of HoF as Virtual Power plant to dispatch on demand groups of HoF DERs	High D	5. Allows homeowners to serve their neighbours who do not have HoF where they capture social value as helping neighbours keep down their energy bills + mitigate power issues and/or revenue from the retailer or DFO. Potential Value Add: MEDIUM ($10/month ongoing) - Participating in community events and personally knowing neighbourhood.
4	Dynamic: critical peak load shedding with generation forecast prediction machine (AI) with external signal (i.e. weather)	High D	4. Aside from real-time incentives, greater intelligence to know when in the future home owners can capture value. Potential Value Add: LOW (<$1/month ongoing) - Weather channel and other tools that can tell homeowners expected sunshine, even though not exact.
3	Dynamic: external grid price signal when grid pricing are high or severely stressed	High D	3. Connected to grid to enable real-time incentives, which will allow for greater gamification and more freedom to capture value. Potential Value Add: HIGH ($20/month ongoing) - Rebates-as-a-service or similar incentive for ecommerce site for products and services that improve home comfort. (i.e. beyond the bill incentive)
2	Static: time of use, local pre-programmed time set load shedding, load shifting and smart EV charging rate throttling	Normal	2. Optimization of DER to ensure capturing max revenue for ToU and mitigating need to invest in home upgrades for EV. If programmed by retailer, can include flat, non-real time incentives, aside from energy cost savings. Potential Value Add: MEDIUM ($50-100 one-time and $10/month ongoing) - Smart EMS incremental cost
1	Static rule base (local solar PV-storage charge/discharge threshold based upon demand-storage level to balance self production vs export vs storage)	Normal	1. Optimization of DER to ensure capturing max renewable energy while servicing need that can reduce energy bill. Potential Value Add: LOW (<$30 one-time and $10/month ongoing) – Basic EMS cost
A	Dynamic: synchronization of grid renewable production with DER load shedding or load shifting or EV charging	Normal	A. Allows homeowners to feel good about being environmentally friendly. Potential Value Add: LOW ($5/month ongoing) – Cost of green energy premium to purchase or invest in other ways to feel good about social impact, such as charitable investments.
B	Operate as a pico grid and provide power during outages	Outage	B. Allows homeowners to feel confident of having power during an outage. Potential Value Add: LOW (risk ranking of $100 one-time inconvenience) - Cost of inconvenience with outages, that typically are not long enough to cause significant damage or lifestyle pains in the home.

	MVP Implementation Features		**VALUE PROPOSITION - DISTRIBUTION FACILITY OWNER**
5	Dynamic: DFO Aggregation of HoF as Virtual Power plant to dispatch on demand groups of HoF DERs	High D	5. Allows DFO to leverage single or multiple HoF DERs to balance an entire secondary circuit and potentially other topology levels to meet demand and reduce stress on circuits. *Potential Value Add: KEY QUESTIONS: How much money would you save in infrastructure investments if you could orchestrate DERs to serve neighbourhoods? Where else in the topology could they serve?*
4	Dynamic: critical peak load shedding with generation forecast prediction machine (AI) with external signal (i.e. weather)	High D	4. Aside from real-time incentives, greater forecasting intelligence to optimize DER scheduling for predicted grid balancing issues. *Potential Value Add: KEY QUESTIONS: When it comes to managing your protection systems and grid integrity, what are critical criteria you look to control in the grid and what predictive aspects could be of greatest value?*
3	Dynamic: external grid price signal when grid pricing are high or severely stressed	High D	3. Connect DFO to home to enable real-time management, which will allow for greater stability on grid during stress times. *Potential Value Add: KEY QUESTIONS: What problem are you solving by being able to have real-time control of DERs, such as battery utilization, solar utilization, or EV charging? What scenarios should be managed in real-time and cannot be programmed?*
2	Static: time of use, local pre-programmed time set load shedding, load shifting and smart EV charging rate throttling	Normal	2. Optimization of DER to ensure working at peak stress times on system and exporting to grid at pre-programmed times to reduce stress on secondary circuit, if programmed by DFO. *Potential Value Add: KEY QUESTIONS: What problem are you solving if you could directly schedule the DER EMS from the DFO before it is installed? What scenarios would you program for in the home?*
1	Static rule base (local solar PV-storage charge/discharge threshold based upon demand-storage level to balance self production vs export vs storage)	Normal	1. Optimization of DER to behind the meter maximize internal generation and demand balance to mitigate need for infrastructure investment, but may not meet emerging load needs of EV and export to grid at rules of home owner, not DFO. *Potential Value Add: KEY QUESTIONS: What issues do traditional EMS systems solve for more DERs in homes? What do those problems cost if they occur? What are the constraints of their capabilities in terms of managing the DERs effectively to mitigate grid issues? How do you currently deal with a significant load increase on the grid from a home (example: secondary suite) and what does it cost?*
A	Dynamic: synchronization of grid renewable production with DER load shedding or load shifting or EV charging	Normal	A. Enables DFO to balance voltage on grid with awareness and control of DERs, as well and manage peak load on transformer and secondary circuits through battery orchestration. *Potential Value Add: KEY QUESTIONS: What is the value of using localized DERs to service a neighbourhood over outside generation? Where do issues occur in the system under DER EMS different scenario?*
B	Operate as a pico grid and provide power during outages	Outage	B. Enables homes to serve themselves and potentially others on secondary circuit or neighbouring transformers during outages when they occur. *Potential Value Add: KEY QUESTIONS: What is the value of localized generation for a single home and/or multiple homes to serve critical loads on a secondary circuit during an outage.*

APPENDIX F: SOFTWARE TESTING

SOFTWARE PLATFORM TEST PLAN

Manual Load Control Testing

below is the manual demand response software test plan use to validate the initial set of functionality that we later automated.

TEST #	TEST NAME	PRECONDITION	EXPECTED RESULT
EV CHARGER GROUP			
1	Get EV charger status	EV is connected to charger	Is EV charging? [True, False]
2	Get EV charger status	EV is NOT connected	Is EV connected? [True, False]
3	Get EV charger status	FLO is not reachable	Error message
4	Start curtailing	EV charger is connected and evChargerFlag is False	EV charger is curtailed
5	Start curtailing	EV charger is connected and evChargerFlag is True	EV charger is NOT curtailed
6	Start curtailing	EV charger is NOT connected	Error message
7	Stop curtailing	EV charger is curtailed	Curtailing stops
WATER HEATER GROUP			
1	Get heater status	Heater is heating	Is Heater ON? [True, False]
2	Get heater status	Heater is NOT heating	Is Heater ON? [True, False]
3	Get heater status	Heater is NOT connected	Error message
4	Start curtailing	Heater is connected	Water heater is curtailed
5	Start curtailing	Heater is NOT connected	Error message
6	Stop curtailing	Water heater is curtailed	Curtailing stops
TRANSFORMER GROUP			
1	Get transformer status	Transformer is connected	Returns transformer load
2	Get transformer status	Transformer is NOT connected	Error message

Table 12: Sample Manual Demand Response Test Plan

Intelligent autonomous Load Control Testing

Automated price signals are similar but reduce facilities staff labour through a centralized control system with pre-programmed strategies. Intelligent load control enables remotely generated event initiation signals to control loads directly or to initiate pre-programmed rule-based strategies at the site. In the second phase, we develop tailored algorithms, enabled by a rules engine and informed by a series of real-time data points queried from limited data sources.

eA/B Testing Switch

OptimizeRetailer = GridPricing + 25% < average market price paid by Retailer
OptimizeLifestyle = Allocate available energy in a round robin manner

OptimizeGreen = Grid renewable energy mix > +25% than average grid energy mix

Functional Test Groups

Functional testing is a quality assurance (QA) process and a type of black-box testing that bases its test cases on the specifications of the software component under test. Functions are tested by feeding them input and examining the output, and internal program structure is rarely considered (unlike white-box testing). Functional testing is conducted to evaluate the compliance of a system or component with specified functional requirements. Functional testing usually describes what the system does.

Functional testing is executed using the system simulator. Test data is created from scratch to specifically support each test case. This data is loaded by the simulator before each execution of a test case and expected results are verified either manually or automatically (when feasible).

TEST #	TEST GROUP/NAME	PRECONDITION	EXPECTED RESULT
CONNECTIVITY GROUP			
1	Get connectivity status	EV charger, water heater and transformer are connected	Nominal status for all 3 devices
2	Get connectivity status	Only water heater and transformer are connected	Error message
3	Get connectivity status	Only EV charger and transformer are connected	Error message
4	Get connectivity status	Only EV charger and water heater are connected	Error message
PROTECT SECONDARY CIRCUIT OVERLOAD GROUP			
1	Very high transformer overload (>MaxTrans)	Transformer load is very high and at least one EV is connected to charger (and charging) and at least one water heater is heating	All EV stop charging, and all heaters stop heating
2	Moderately high transformer overload (>WarnTrans and <MaxTrans)	Transformer load is moderately high and at least one EV is connected to charger (and charging) and at least one water heater is heating	All EV stop charging, and all heaters continue heating
3	Nominal transformer load (<WarnTrans)	Transformer load is nominal and at least one EV is connected to charger (and charging) and at least one water heater is heating	All EV still charging, and all heaters still heating
ENERGY PRICE OPTIMIZATION GROUP			
1	Delay EV charging and water heating to lower energy price (GridPricing + GridCarbon > LowestPrice)	Transformer load is nominal and at least one EV is connected to charger (and charging) and/or at least one water heater is heating	All EV stop charging, all water heaters stop heating
2	Restart EV charging at lower energy price (GridPricing + GridCarbon <= LowestPrice)	Transformer load is nominal and at least one EV is connected to charger (and NOT charging)	All EV start charging
3	Restart water heating at lower energy price (GridPricing + GridCarbon <= LowestPrice)	Transformer load is nominal and at least one water heater is NOT heating at nominal temperature (<WaterTemp)	All water heaters start heating

Table 13: Functional Testing Plan

Integration Test Groups

Integration testing is the phase in software testing in which individual software modules are combined and tested as a group. Integration testing is conducted to evaluate the compliance of a system or component with specified functional requirements. Integration testing takes as its input modules that have been already tested, groups them in larger aggregates, applies tests defined in an integration test plan to those aggregates and delivers as its output the integrated system ready for complete system testing.

Integration testing is executed using the system simulator. Test data is either created from scratch or by extraction from real data flows to support each test case. This data is loaded by the simulator before each execution of a test case and expected results are verified either manually or automatically (when feasible).

TEST #	TEST GROUP/NAME	PRECONDITION	EXPECTED RESULT
STATE TRANSITIONS INTEGRATION GROUP			
1	Normal -> Warning	Total for homes connected to the same transformer Trans + 10% < WarnTrans AND Total for all homes >= GenerationMax **then** Total for homes connected to the same transformer Trans < MaxTrans and Trans + 10% >= WarnTrans OR Total for all homes >= GenerationMax	System in Warning state
2	Warning -> Overload	Total for homes connected to the same transformer Trans < MaxTrans and Trans + 10% >= WarnTrans OR Total for all homes >= GenerationMax **then** Total for homes connected to the same transformer (Trans) >= MaxTrans	System in Overload state
3	Overload -> Warning	Total for homes connected to the same transformer (Trans) >= MaxTrans **then** Total for homes connected to the same transformer Trans < MaxTrans and Trans + 10% >= WarnTrans OR Total for all homes >= GenerationMax	System in Warning state
4	Warning -> Normal	Total for homes connected to the same transformer Trans < MaxTrans and Trans + 10% >= WarnTrans OR Total for all homes >= GenerationMax **then** Total for homes connected to the same transformer Trans + 10% < WarnTrans AND Total for all homes >= GenerationMax	System in Normal state
5	Normal -> Overload	Total for homes connected to the same transformer Trans + 10% < WarnTrans AND Total for all homes >= GenerationMax **then** Total for homes connected to the same transformer (Trans) >= MaxTrans	System in Overload state
6	Overload -> Normal	Total for homes connected to the same transformer (Trans) >= MaxTrans **then** Total for homes connected to the same transformer Trans + 10% < WarnTrans AND Total for all homes >= GenerationMax	System in Normal state
A/B SWITCH GROUP			
1	Retailer optimization	Normal state, A/B Switch set to OptimizeRetailer and we have enough energy for all the home requirements	Shift water heaters and EV chargers to a more favourable time when price is lower than a certain threshold during the next 24 hours
2	Lifestyle optimization	Normal state, A/B Switch set to OptimizeLifestyle and we have enough energy for all the home requirements	Allocate available energy in round robin manner (15 minutes slots)

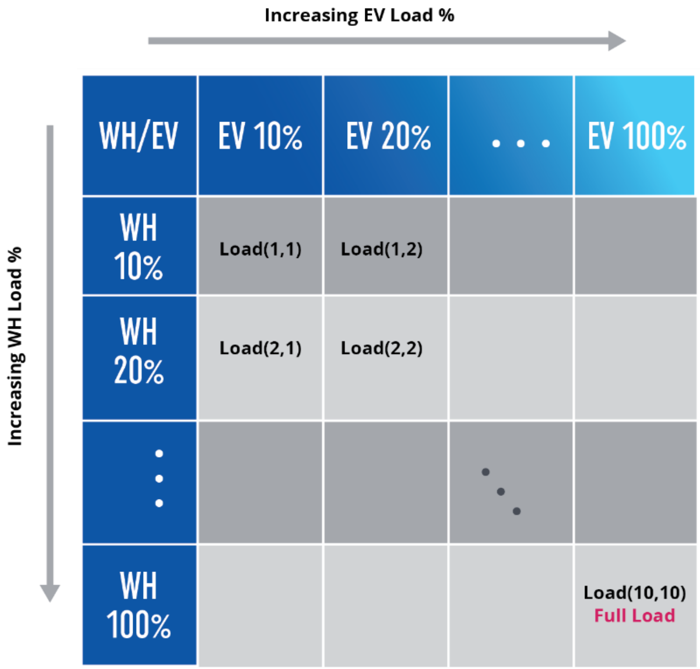
TEST #	TEST GROUP/NAME	PRECONDITION	EXPECTED RESULT
3	Green optimization	Normal state, A/B Switch set to OptimizeGreen and we have enough energy for all the home requirements	Allocate available energy in round robin when the grid carbon mix is higher than a pre-defined threshold during the next 24 hours

Table 14: Functional Testing Plan

Performance Test Groups

Performance testing is in general a testing practice performed to determine how a system performs in terms of responsiveness and stability under a particular workload. It can also serve to investigate, measure, validate or verify other quality attributes of the system, such as scalability, reliability and resource usage.

Performance testing is executed using the system simulator. Since we do not have a complete beta test site with 123-16 homes under the same transformer we will need to aggregate/extrapolate actual data sets in order to run credible performance tests. This matrix below may help for general overview about which region in the matrix we need to worry about.



WH/EV	EV 10%	EV 20%	. . .	EV 100%
WH 10%	Load(1,1)	Load(1,2)		
WH 20%	Load(2,1)	Load(2,2)		
⋮			⋱	
WH 100%				Load(10,10) Full Load

1. The percentage in the matrix means the number of the customers that may use the load (Load = WH + EV) under one transformer.
2. This matrix can be 3D if we consider the normal load profile along the day (except the WH and EV) by adding this load to it.

TEST #	TEST GROUP/NAME	PRECONDITION	EXPECTED RESULT
FULL LOAD (PEAK)			
1	Generate test dataset for 16 homes with both EV charger and Hot water heater at 100%	Total for homes connected to the same transformer (Trans) >= MaxTrans	System in Overload state
2	Generate test dataset for 16 homes with both EV charger and Hot water heater at 100%	Total for homes connected to the same transformer Trans < MaxTrans and Trans + 10% >= WarnTrans OR Total for all homes >= GenerationMax	System in Warning state
3	Generate test dataset for 16 homes with both EV charger and Hot water heater at 100%	Total for homes connected to the same transformer Trans + 10% < WarnTrans AND Total for all homes >= GenerationMax	System in Normal state

Table 15: Performance simulation model examples

Acceptance Test Groups

Acceptance testing is a level of software testing where a system is tested for acceptability. The purpose of this test is to evaluate the system's compliance with business requirements and assess whether it is acceptable for delivery. Acceptance testing is ideally conducted using “real life” datasets.

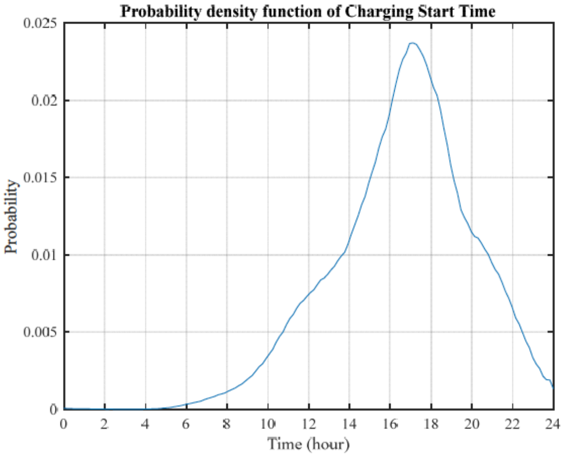
TEST #	TEST GROUP/NAME	PRECONDITION	EXPECTED RESULT
SITUATIONAL AWARENESS			
1	DSO needs to maintain an accurate view of the micro-grid in real time	DSO Dashboard displays a detailed, updated view of every home / every transformer at 1-minute intervals	Goal achieved over a 24 hours period (observed by sampling)
2	DSO wants to get visibility into the customer energy use	HOTF database contains up to the minute data on several key components of customer energy consumption	DSO can mine the database to derive insight
RIGHTSIZING INFRASTRUCTURE			
3	No need to retrofit existing infrastructure	HOTF helps DSO absorb new energy demands (mostly EV chargers) by intelligently managing the load	A group of homes (micro-grid) can handle a growth from 0% EV owners to 100% EV owner without upgrading infrastructure
4	Not over-provision new installation	HOTF helps DSO deploy rightsized micro-grid by intelligently managing the load	A group of new homes can be handled with rightsized installation
CUSTOMER RATES			
5	DSO wants to avoid being forced to raise customer rates as much as possible	HOTF helps DSO maintain a lower cost structure by intelligently managing energy demand (i.e. shifting load to less expensive periods)	Energy acquisition cost is lowered by X% with HOTF
WEATHER PREDICTION			
6	N/A		
EQUIPMENT MORTGAGE LIFE			
7	DSO wants to be able to mortgage its equipment over long period with confidence (i.e. the equipment will not need to be replaced prematurely)	HOTF database contains up to the minute data on several key components of customer energy consumption	DSO can mine the database to derive insight on the optimal size of the micro-grid for a new series of homes
COMPLIANCE TARGETS			

TEST #	TEST GROUP/NAME	PRECONDITION	EXPECTED RESULT
8	Deliver within CSA voltage limits (min. 110/220 V to max. 125/250 V)	Testing has to be conducted in a continuous manner and for a minimum of 1-year worth of data (so as to cover all year-round conditions)	Limits are respected

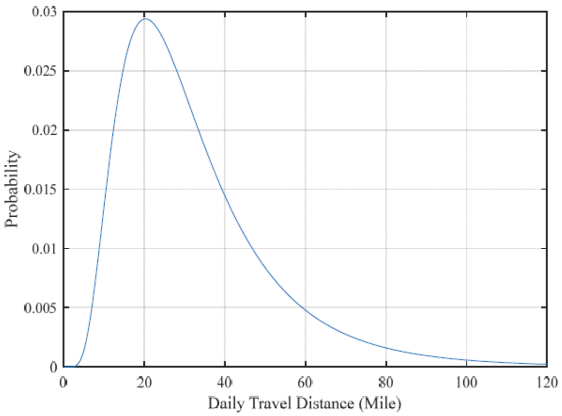
Table 16: Acceptance testing use cases

APPENDIX G: MODELLING PARAMETERS

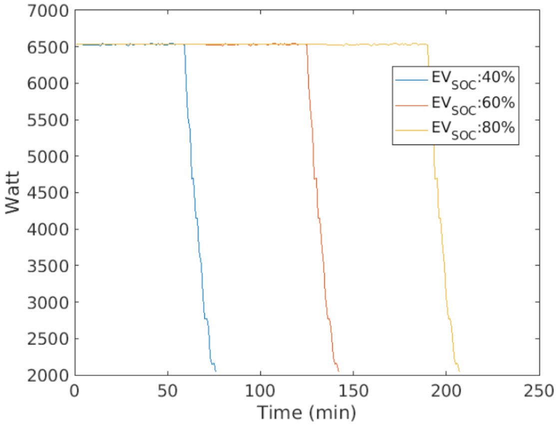
Source: Alberta Power Industry Consortium Project 2017A-3 Impact of Electric Vehicles on Residential Secondary Distribution Systems Final Report; Project Leader: Wilsun Xu Project Team Members: Dawit Fekadu and Pooya Bagheri, Department of Electrical & Computer Engineering, University of Alberta, Edmonton, AB, March 2018



Time of arrival probability

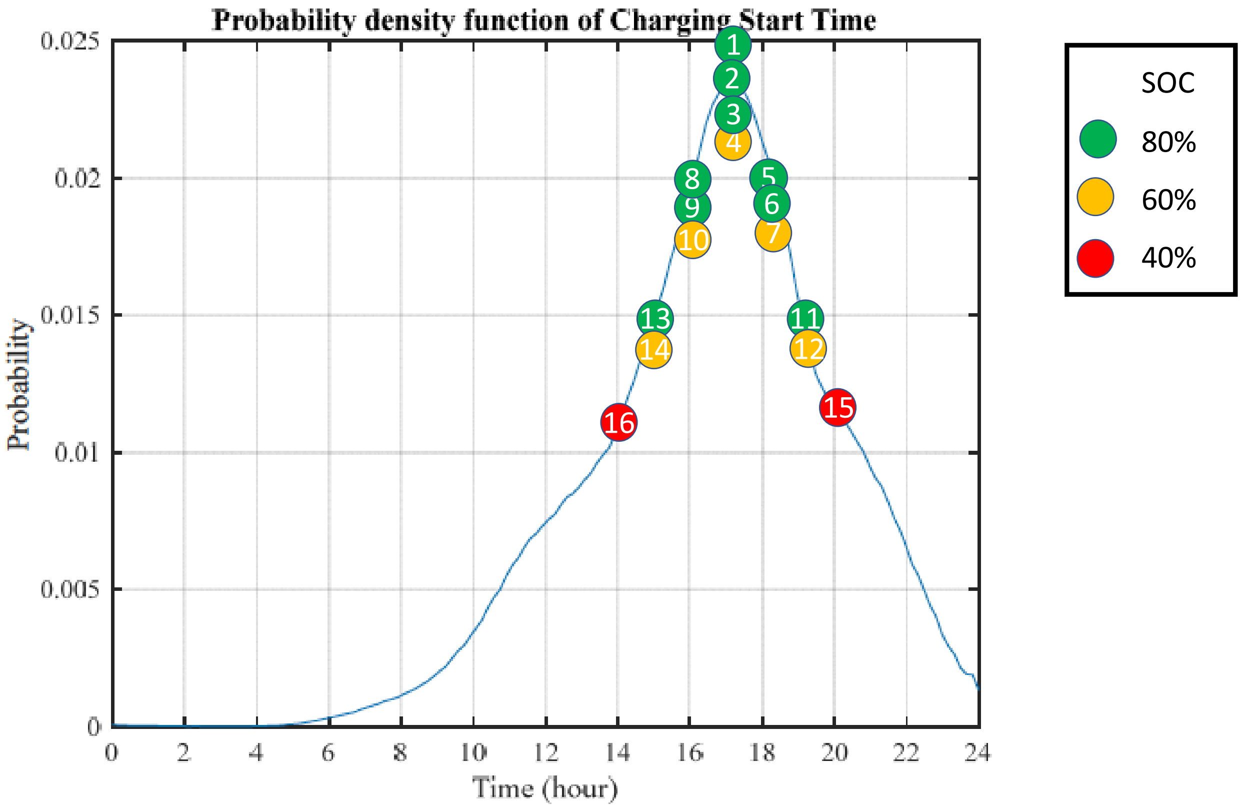


Travelling Distance probability



SOC% based on the travelling

The probability distribution of time of arrival of 16 EVs and the probability distribution EV SOC's



APPENDIX H: EPCOR CHARGING STUDY

EPCOR System

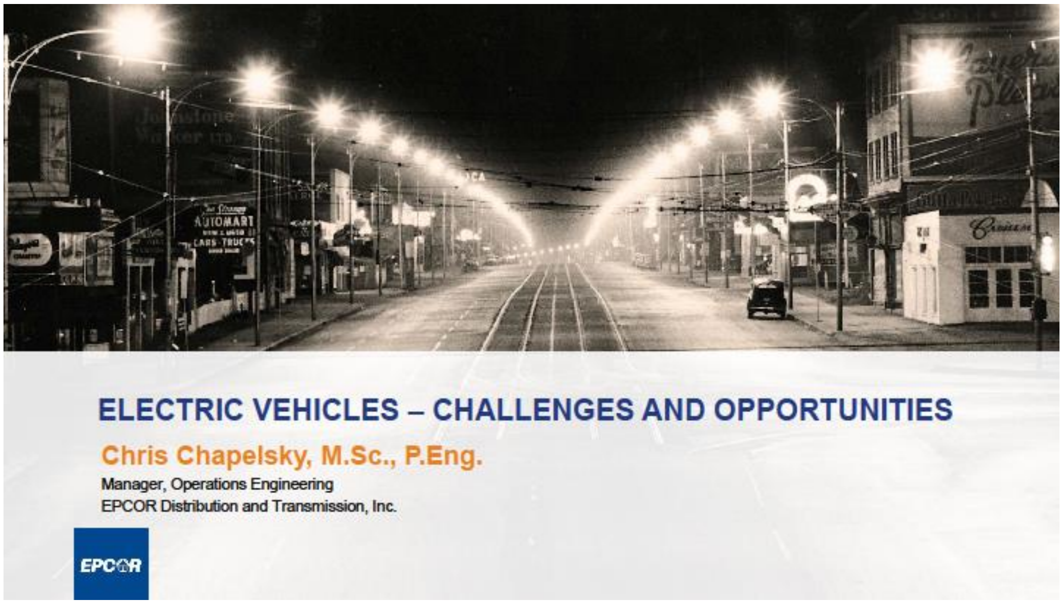
- 400,000+ customers
- 289 distribution circuits
- 25 kV, 15 kV and 5 kV primary voltages
- Longest 15 kV circuit: 7.6 km
- Longest 25 kV circuit: 15.2 km
- 1,000 – 8,000 customers per circuit
- “99%” urban

The estimated cost for the upgrade per circuit is $20 million. The cost estimate for the complete upgrade of EPCOR’s grid is as follows.

- Total cost to upgrade the 289 circuits (@ $20 million each) = $5.78 billion
- Average cost per customer for upgrade = $14,450

In 10 hours, 2.5 MW can transfer. 10 hours × 2.5 MW = 25 MWh. If the SLA guarantees 20 kWh minimum transfer between 8:00 p.m. and 6:00 a.m. (10 hours off peak period), it means 25MWh / 20kWh = 1,250 vehicles per circuit.

Considering 289 circuits, this means it would be sufficient to guarantee 20 kWh of transfer for 361,250 EVs. The controlled charging would completely recharge 1,250 EVs per circuit in less than 10 hours and avoid the $20 million capital investment per circuit.



ELECTRIC VEHICLES – CHALLENGES AND OPPORTUNITIES

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