REFERENCE:

Appendix 2.1, page 25 of 40

PREAMBLE TO IR (IF ANY):

At slide 25, MH states:
"What we're focused on today:
- Developing new products and services based on market perception study results for renewable natural gas.
- Completing evaluation studies for Electric Vehicle (EV) and Demand Response (DR) to identify feasible products and services (e.g., rate products) that could be offered by Manitoba Hydro's electric grid."

QUESTION:

Please provide the evaluation studies for EV and DR if available, otherwise, please outline the scope (including targeted customer classes) and deliverables of these studies, and the timeline for completion.

RATIONALE FOR QUESTION:

To better understand MH's plans regarding demand response, and Electric Vehicles.

RESPONSE:

Manitoba Hydro engaged Dunsky Energy + Consulting Advisors to complete market potential studies related to Electric Vehicles (Attachment 1) and Demand Response (Attachment 2 & 3). Manitoba Hydro is still currently developing a strategy to further explore Manitoba Hydro's role in these technologies and the scope, scale and deliverables have not been finalized.

Manitoba Hydro

EFFICIENCY MANITOBA

Electric Vehicle Adoption

Final Report

dunsky Energy + Climate

July 5, 2022

dunsky
Energy + Climate

EXPERTISE

- Buildings + Industry
- Energy
- Mobility

SERVICES

- **Quantify** Opportunities
- **Design** Strategies
- **Evaluate** Performance

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EXPERTISE

Buildings + Industry

Energy

Mobility

SERVICES

Quantify Opportunities

Design Strategies

Evaluate Performance

GOVERNMENTS | **UTILITIES** | **CORPORATE + NON-PROFIT**

Table of Contents

1. Introduction

1. Introduction

Overview

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EVA modeling will estimate potential for:

- Light Duty Vehicles (LDVs)
- Medium Duty Vehicles (MDVs)
- Heavy Duty Vehicles (HDVs)
- Buses

Alternate approach for “Other” vehicles:

- Forklifts
- Agricultural vehicles
- Construction vehicles
- Off-road vehicles
- Motorcycles
- Micro-mobility

1. Introduction

Overview

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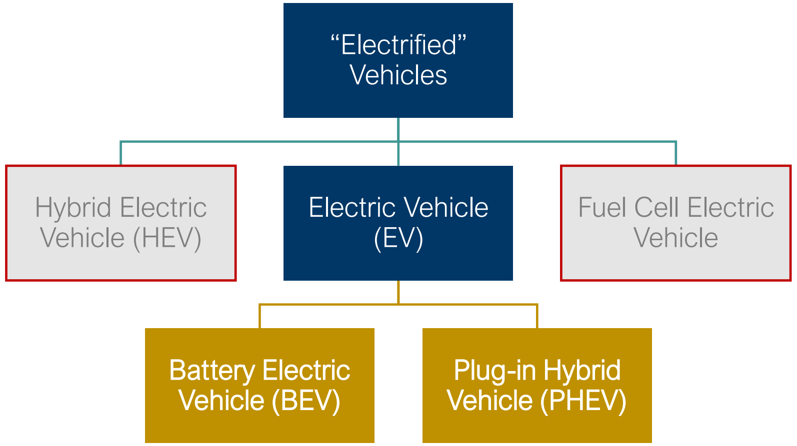
The study considers plug-in EVs, specifically:

- **Battery Electric Vehicles (BEVs):** “pure” electric vehicles that have only an electric powertrain and that plug in to charge (e.g., Tesla Model 3, Chevy Bolt, Nissan Leaf)
- **Plug-in Hybrid Electric Vehicles (PHEVs):** hybrid vehicles that can plug in to charge and operate in electric mode for short distances (e.g. 30 to 80 km), but that also include a combustion powertrain for longer trips. (e.g., Chevy Volt, Toyota Prius Prime)



The following are excluded from the analysis:

- **Hybrid Electric Vehicles (HEVs)** that do not plug in to charge and are considered internal combustion engine (ICE) vehicles.
- **Fuel Cell Electric Vehicles (FCEVs)** (i.e., hydrogen vehicles): market assumed to be small within the timeframe of the study for all vehicle segments

Chevrolet Bolt, a BEV with 417 km of range.

Toyota Prius Prime, a PHEV with 40 km of EV range

1. Introduction

Overview: Characterize Vehicle Segments

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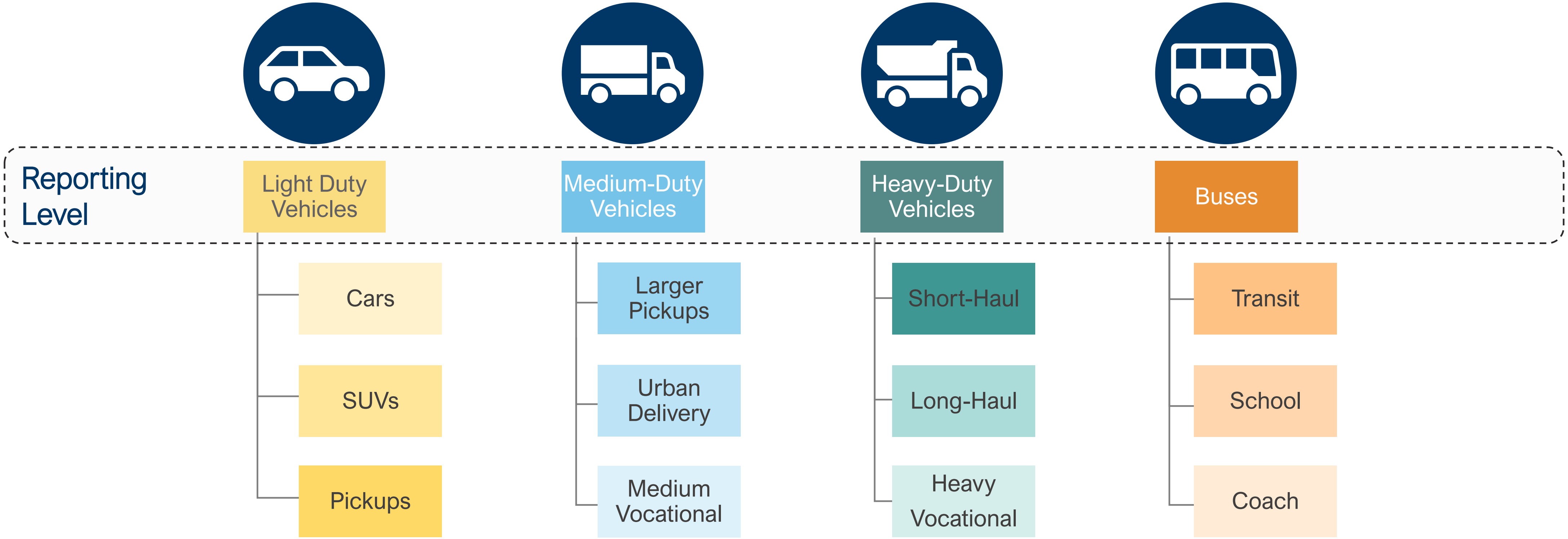
While multiple vehicle classification systems exist, for the purpose of this study, we break down the on-road vehicle market into four key segments that share common characteristics:



1. Introduction

Overview: Vehicle Market

Approximately 900,000 vehicles on the road in Manitoba

- 83% of vehicles for passenger/personal light-duty vehicles (LDVs)
- LDVs make up 89% of vehicles of vehicles on the road, with the remaining 11% being medium-and heavy-duty vehicles (MHDVs)

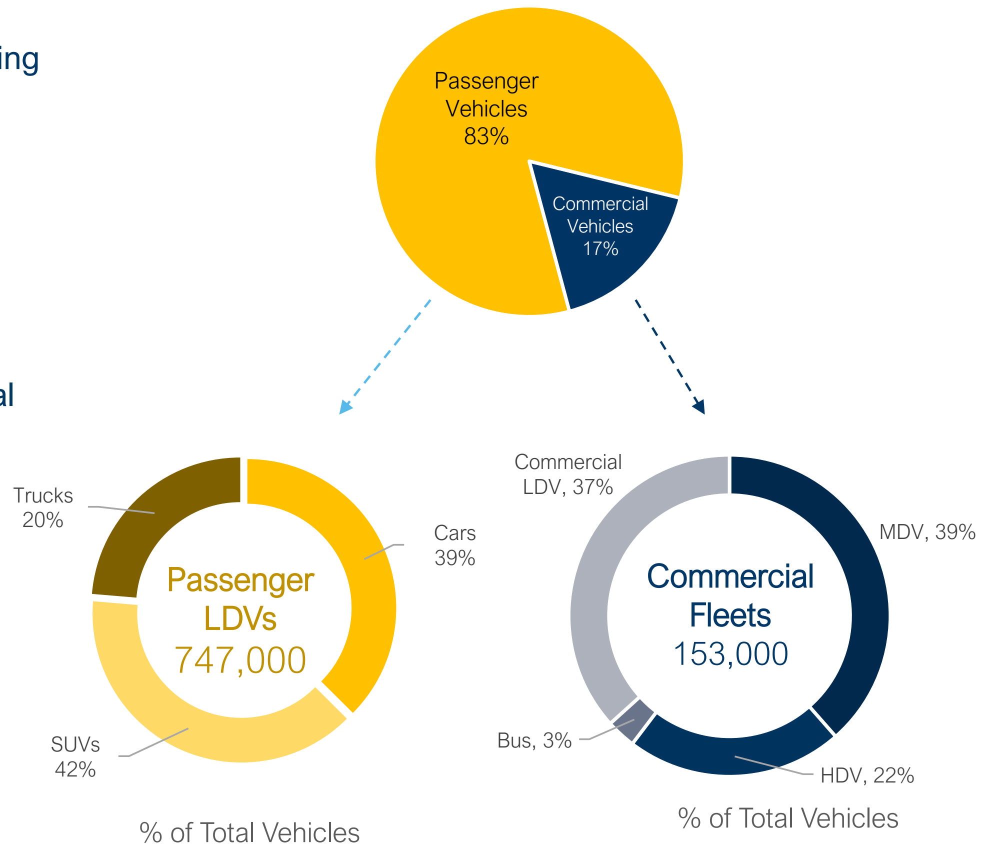
43,000 new LDVs registered annually

- Majority (93%) of LDVs predominantly passenger/personal use, with the remaining being commercial/institutional fleets
- SUVs and Trucks make up 84% of new vehicle sales in-line with historical trends of increasing customer interest in larger vehicles

6,000 new MHDVs estimated registered annually

- Medium-Duty Vehicles make up nearly 70% of vehicles in the segment

Total Registered Vehicles (2020)

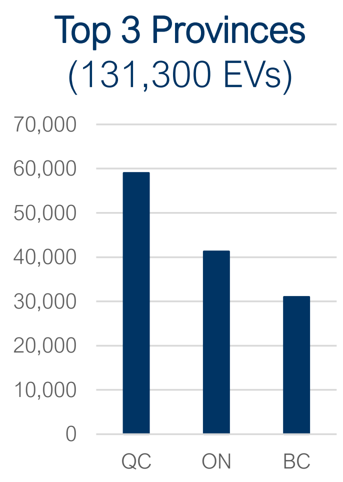


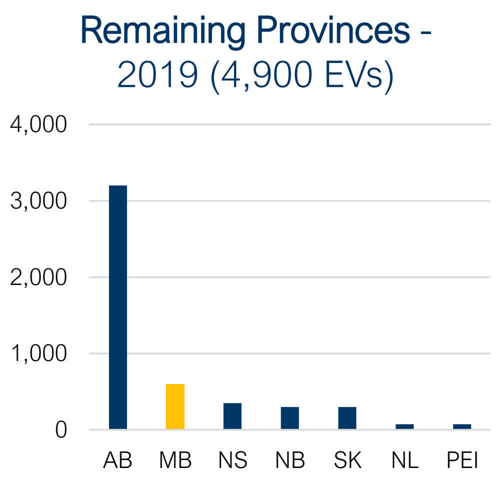
1. Introduction

Overview: Electric Vehicle Market

EV Adoption in Manitoba significantly lags behind Canada's three biggest markets (QC, ON, BC)

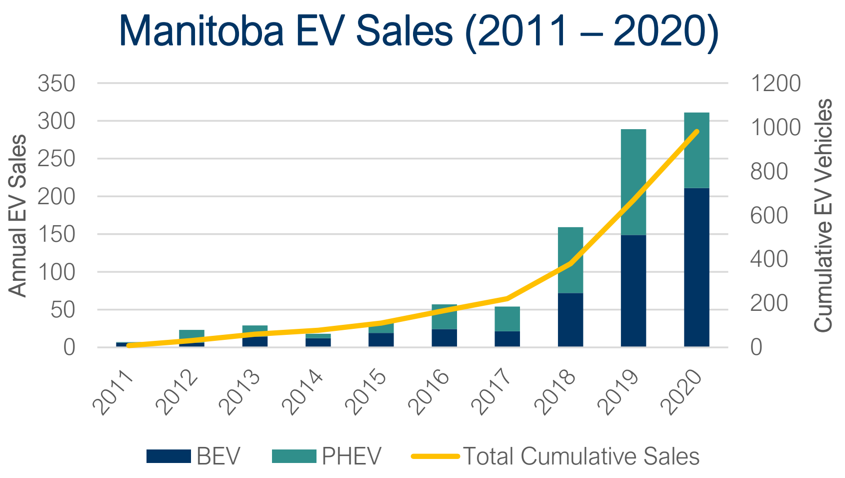
- Approximately 1,000 EVs registered (2020) in the province
- EVs represent 0.7% of new vehicle sales (2020)





In Manitoba, EVs adoption increased starting in 2018

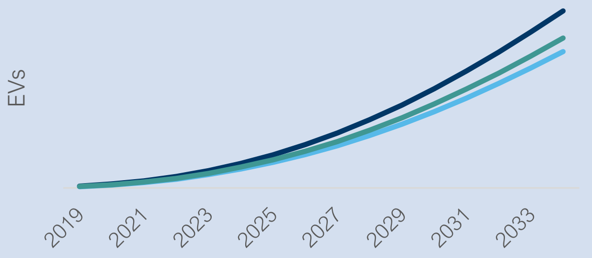
- A significant increase in uptake observed in 2019 (coincident with federal ZEV incentives)
- Increasing share of BEVs over the last 3 years (45% in 2018 up to 68% in 2020)
- Limited uptake of EVs within the Medium and Heavy-Duty Vehicle (MHDV) segment



Overview: Approach

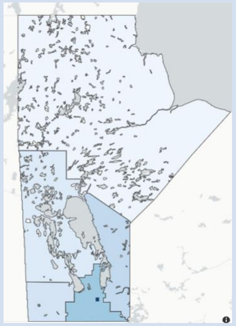
The study follows the following three steps to assess the potential for and impacts of EVs within Manitoba. Key aspects of the study approach are highlighted throughout the report.

Forecast EV Adoption



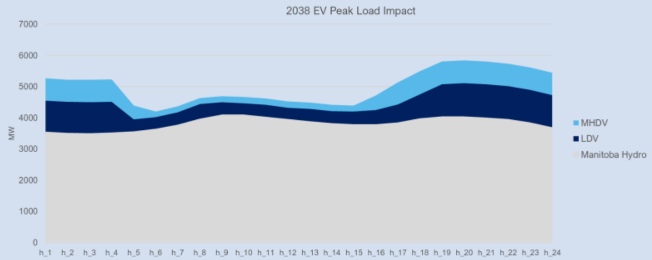
Using Dunsky's Electric Vehicle Adoption (EVA) model, forecast EV uptake within Manitoba under various scenarios reflecting different policy, program and technology conditions.

Develop Regional Projections



Estimate EV adoption across 6 regions in Manitoba based on high-impact factors likely to influence regional variation in EV adoption.

Assess Load Impacts



Assess the energy (GWh) and peak demand (MW) impacts associated with EV charging loads

1. Introduction

Overview: Scenarios

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For both LDVs and MHDVS, three scenarios were investigated:

1. Low Growth
2. Medium Growth
3. High Growth

And for each scenario, we project:

a) Annual EV adoption

b) Electricity load impact and peak demand impact

c) Hourly load peak impacts during both winter and summer (for 2038)

Finally, we summarize the winter hourly load impact (for 2038)

Note: A **dashboard** tool will be provided with Final Results to allow users to toggle between years.

1. Introduction

Study Scope

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- **Study Period:** 2023/24 – 2037/38 (15 years)
- **Geographic Scope:** Province-wide, with breakdown of results into 6 zones
- **Study Goal:** Develop robust projections of electric vehicle (EV) adoption in Manitoba to understand:
  - Uptake (# vehicles)
  - Energy consumption (kW.h)
  - Hourly demand (kW)
  - Emission reduction (tCO_{2eq})

1. Introduction

EVA Model

The study leverages Dunsky's Electric Vehicle Adoption (EVA) Model to forecast the uptake of EVs.

EVA powered by dunsky

TECHNICAL

Assess the maximum theoretical potential for deployment
- Market size and composition by vehicle class (e.g. cars, trucks, buses)
- Model availability for each vehicle powertrain (e.g. ICE, PHEV, BEV)

ECONOMIC

Calculate unconstrained economic potential uptake
- Incremental purchase cost of PHEV/BEV over ICE vehicles
- Total Cost of Ownership (TCO) (personal) or Internal Rate of Return (IRR) (commercial) based on operational and fuel costs

CONSTRAINTS

Account for jurisdiction-specific barriers and constraints
- Range anxiety or range requirements
- Public charging coverage, availability, and charging time
- Home charging access

MARKET

Incorporate market dynamics and non-quantifiable market constraints
- Use of technology diffusion theory to determine rate of adoption
- Market competition between vehicles types (PHEV vs. BEV)

2. Provincial Summary

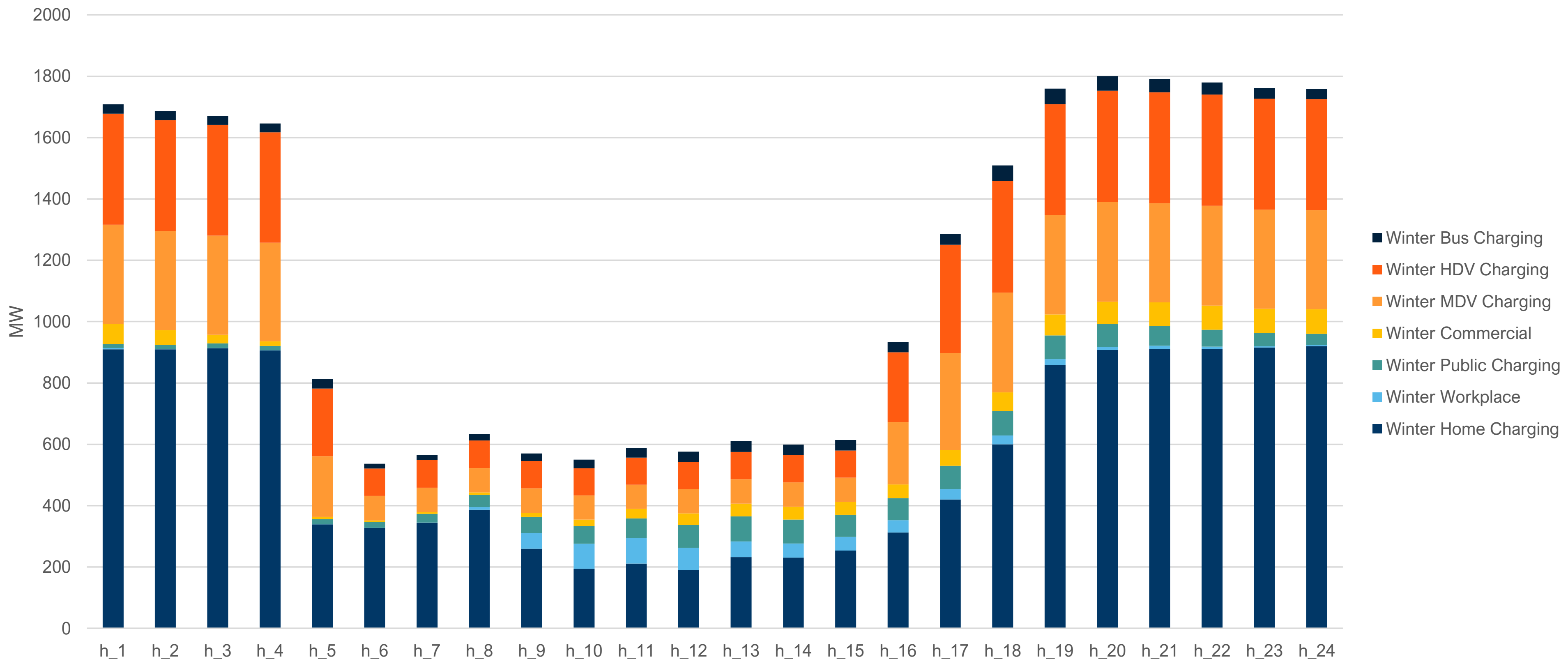
2.1 Load Impact Summary

2.2 Load Management

2. Provincial Summary

Load Impact Summary (2038)

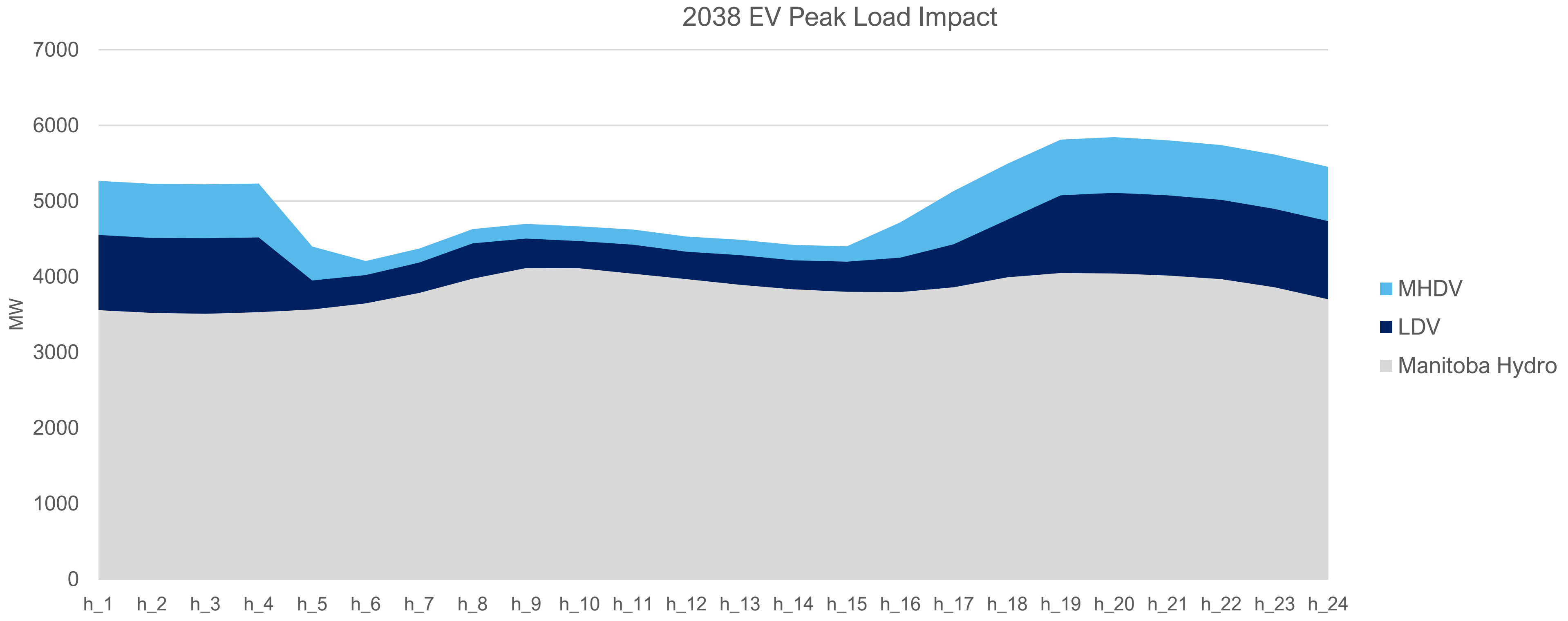
In 2038, if unmanaged, LDV home charging will be the primary driver of demand among EVs.



2. Provincial Summary

Load Impact Summary (2038)

If unmanaged, EVs could increase system peak loads by approximately 45% in 2038, relative to current peak load. The High Growth Scenarios for LDVs and MHDVs would result in Manitoba's electricity load peaking at 8pm on a winter day.



2. Provincial Summary

Key Consideration: Load Management

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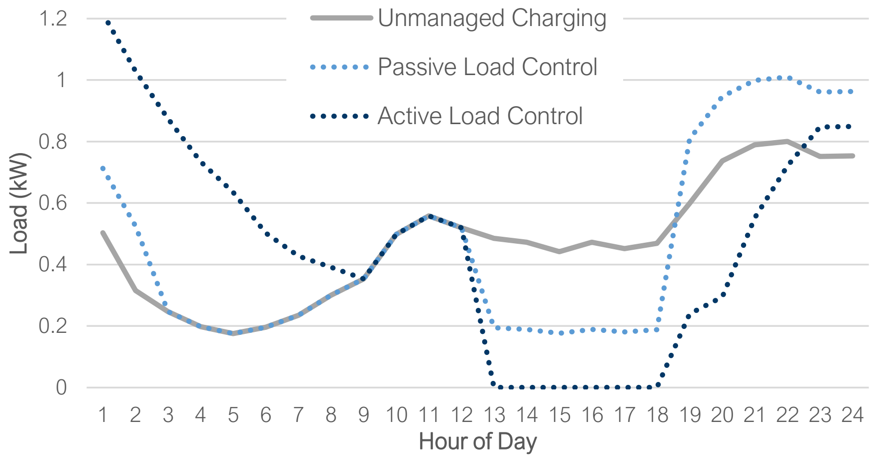
The inherent flexibility of EV charging loads means that they can be controlled, managed and potentially leveraged as Distributed Energy Resources (DERs) to reduce the peak demand impacts and bring additional system value

- Vehicles are usually connected to a charger much longer than required to obtain a full charge, therefore charging loads can be reduced or delayed with minimal disruption to drivers.
- Several EV load management strategies can be employed to shift charging loads from peak to off-peak hours, however generally they can be grouped into two categories

Illustration of the Impacts of Load Management



Strategies	Description	Examples	Impact
Passive Load Management	Rely on customer behavior and response to information, price signals or incentive from the utility	• Whole-home or EV-specific Time-of-Use (TOU) rates • Compensation for off-peak charging (e.g., "Smart Reward" program) • Utility guidance to EV drivers on setting a charge schedule	• Less certainty about customer response • Typically lower implementation costs • Risk of creating secondary peak with snapback
Active Load Management	Utility can manage charging loads through direct control, preset control strategies or other mechanisms	• Control via smart EVSE (e.g. Flo X5, ChargePoint Home, JuiceBox Pro) • Control via EV telematics (e.g. PG&E BMW Charge Forward pilot)	• Greater control over peak impacts, with ability to avoid snapback • Can help accommodate variable renewables

Key Consideration: Load Management

Managed Charging programs offer an opportunity to alleviate peak impacts of EV's

- Typically only personal LDVs are considered for these programs due to a lower drive cycles and longer overnight charging periods

Managed charging programs could be considered, including **education and awareness campaigns**, **charging control using EV telematics**, or **Smart Charging programs**

- Each program type varies with respect to level of effort, peak reduction impacts, and technology certainty

Managed Charging Program	Utility Cost/Level of Effort	Peak Load Reduction Impacts	Technology certainty
Education and Awareness Campaign	**Low**	**Low**	**High**
Charging Control Using EV Telematics	**Mid**	**High**	**Low**
Charging Control Using Smart Chargers	**High**	**High**	**High**

Education and awareness: EV drivers can be encouraged to purchase smart chargers, programming them to charge overnight and reduce evening peaks. There is uncertainty around customer response/degree of peak shifting. In addition, shifts will be 'blocky', as all EV owners will be given the same targeted time period to charging. This risks creating a secondary peak.

Telematics: Charging can be controlled through direct communication with vehicle telematics using a Demand Response Management System (DRMS). To-date, the communications protocols are not standardized between manufacturers; impact will depend on technological standardization moving forward.

Smart Chargers: Utilities can incentivize smart charger purchases with the expectation that participants will be willing to participate in a managed charging program in the future. Smart chargers are typically controlled through a utility DRMS.

3. Light Duty Vehicles

3.1 Provincial Scenarios
3.2 Regional Impacts

Forecasted EV Adoption Overview

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The EVA model was applied to forecast EV adoption using the following approach:

1. **Market Characterization:** Divide the market into vehicle segments (as depicted earlier), develop representative characteristics for each segment and collect data on annual vehicle sales, fleet size and other key market inputs.

2. **Model Calibration:** Using historical inputs on vehicle sales, energy prices, vehicle costs, incentive programs and infrastructure deployment to benchmark the model to historical adoption and calibrate key model parameters to local market conditions.

3. **Scenario Analysis:** Forecast service territory-wide EV adoption under scenarios reflecting different program/policy interventions (e.g. infrastructure deployment, incentives) as well as market and technology conditions (e.g. battery costs, energy prices).

3. Light Duty Vehicles

LDV Scenarios

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	Scenario 1 Low Growth	Scenario 2 Medium Growth	Scenario 3 High Growth
Description	Business-as-usual, without additional activities to promote uptake.	Additional investment in infrastructure and incentives increases uptake.	Most aggressive, with additional investment in infrastructure and incentives.
Key Assumption 1: Expansion of public charging infrastructure	Limited *DCFC: 100 Sites (200 ports)* *Public L2: 1,000 Sites (4,000 ports)*	Moderate *DCFC: 280 Sites (1,100 ports)* *Public L2: 1,250 Sites (8,500 ports)*	Significant *DCFC: 600 Sites (2,400 ports)* *Public L2: 1,900 Sites (19,000 ports)*
Key Assumption 2: Vehicle incentives	**BEVs:** $5,000 **PHEVs:** $3,750 *(Ramped down + phased-out by 2023)*	**BEVs:** $5,000 **PHEVs:** $3,750 *(Ramped down + phased-out by 2026)*	**BEVs:** $10,000 **PHEVs:** $5,000 *(Ramped down + phased-out by 2030)*
Key Assumption 3: Existing building charging infrastructure retrofits	Limited *15% of multi-unit buildings with access to charging by 2038*	Moderate *40% of multi-unit buildings with access to charging by 2038*	Significant *90% of multi-unit buildings with access to charging by 2038*

Note: The Federal government aims to achieve 100% Zero Emission Vehicle (ZEV) market share by 2035.
While uncertainties around the specific mechanisms and pathways to achieving this target exist, it does signal continued investments and supporting programs/policies to support EV uptake.

3. Light Duty Vehicles

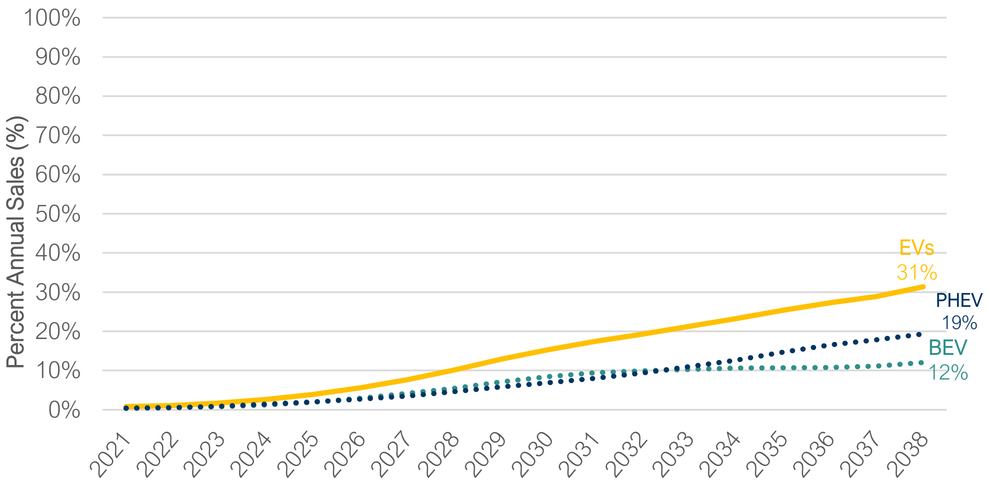
Low Growth Scenario

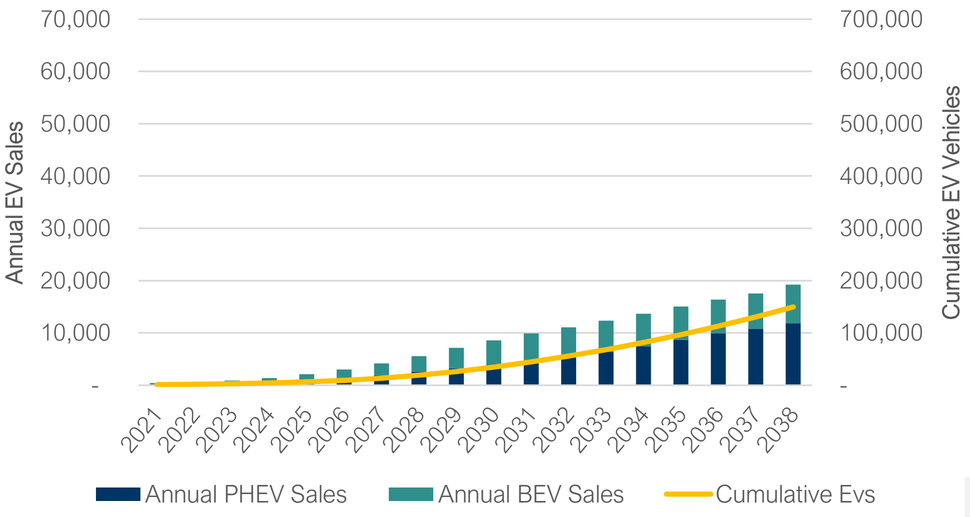
Policy/Program Interventions

Vehicle Incentives	Public DCFC (by 2038)	Public / Workplace Level 2 (by 2038)	Home Charging Access in MURBs (by 2038)
Current federal incentives (phased-out by 2023)	100 Sites (200 Ports)	1,000 Sites (4,000 ports)	15%

Under the Low Scenario, Manitoba will experience very modest growth in EV uptake.

- By 2038, a total of **149,000 EVs** of the 979,000 LDVs are forecasted to be on the road within Manitoba
- EV adoption is expected to **fall significantly short of federal 2035 ZEV targets (100%),** reaching only 25% of new sales by 2035
- Despite the growth in overall EV uptake, the **market share shifts towards PHEVs by 2033** as public infrastructure deployment in this scenario is insufficient to meet needs of BEV drivers.





3. Light Duty Vehicles

Low Growth Scenario

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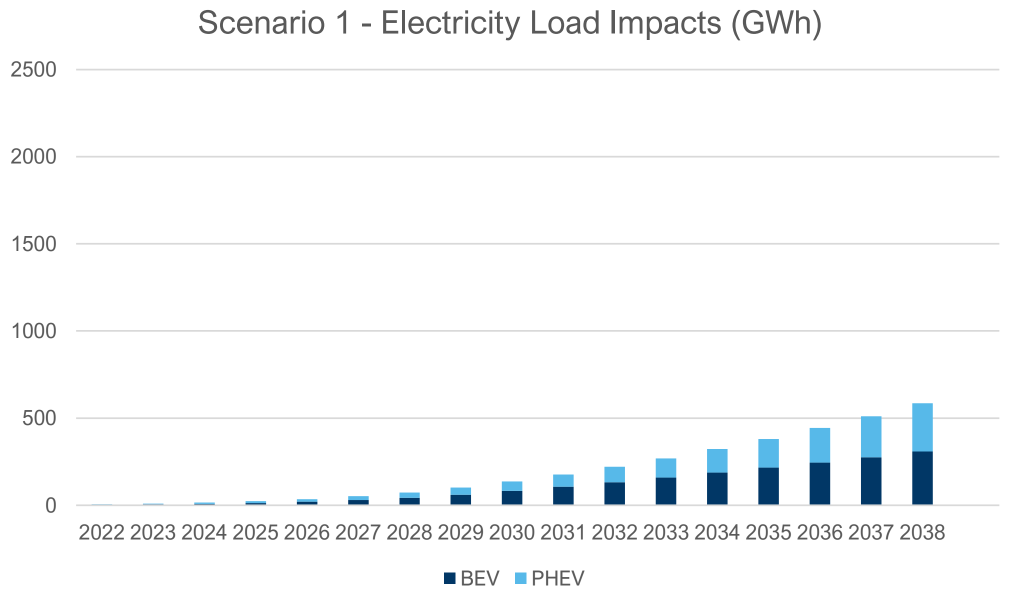
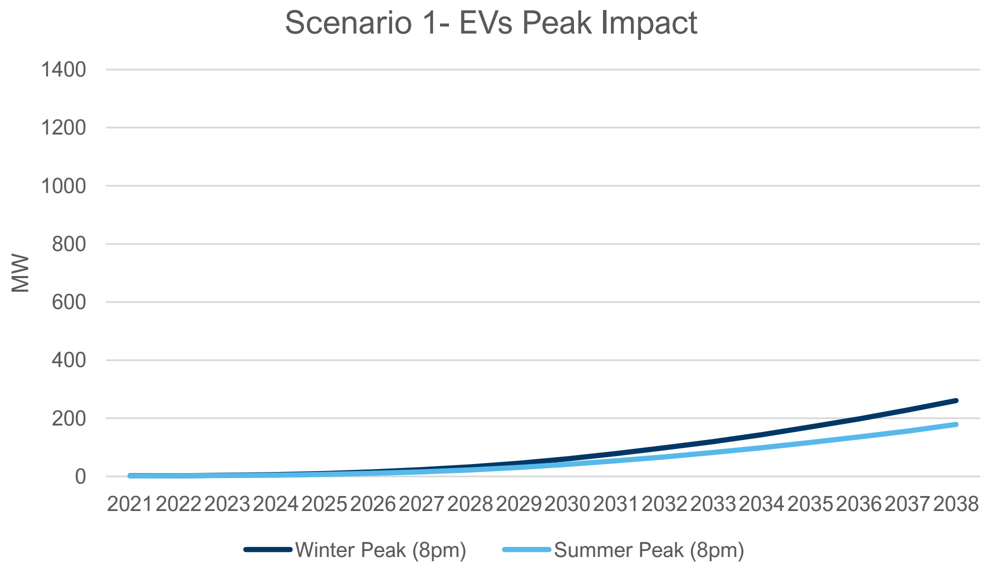
Under the Low Scenario, Manitoba will experience some electricity load impacts (590 GWh by 2038)

By 2038, EVs will contribute 260 MW to peak demand in the winter at 8PM





3. Light Duty Vehicles

Low Growth Scenario (2038)

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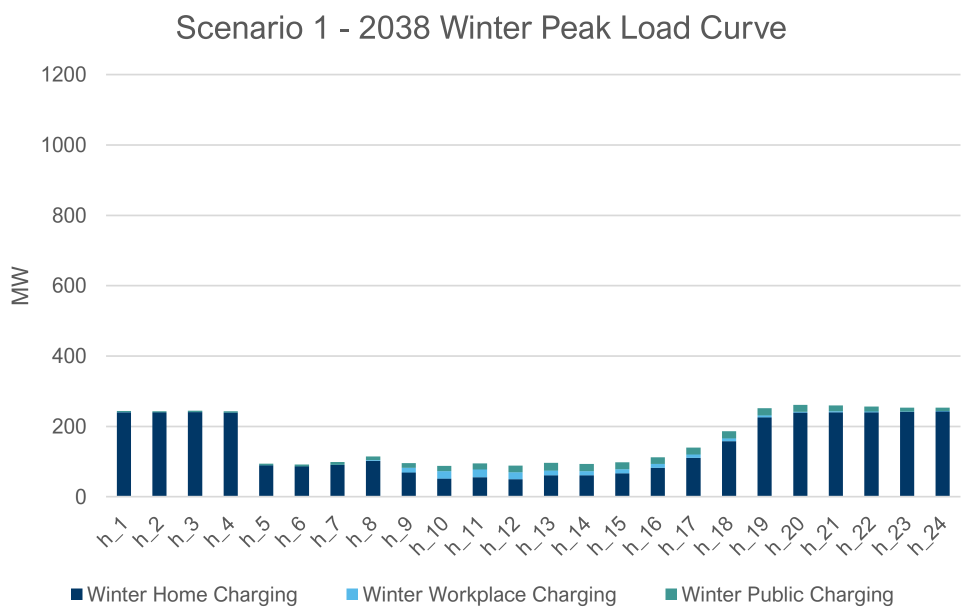
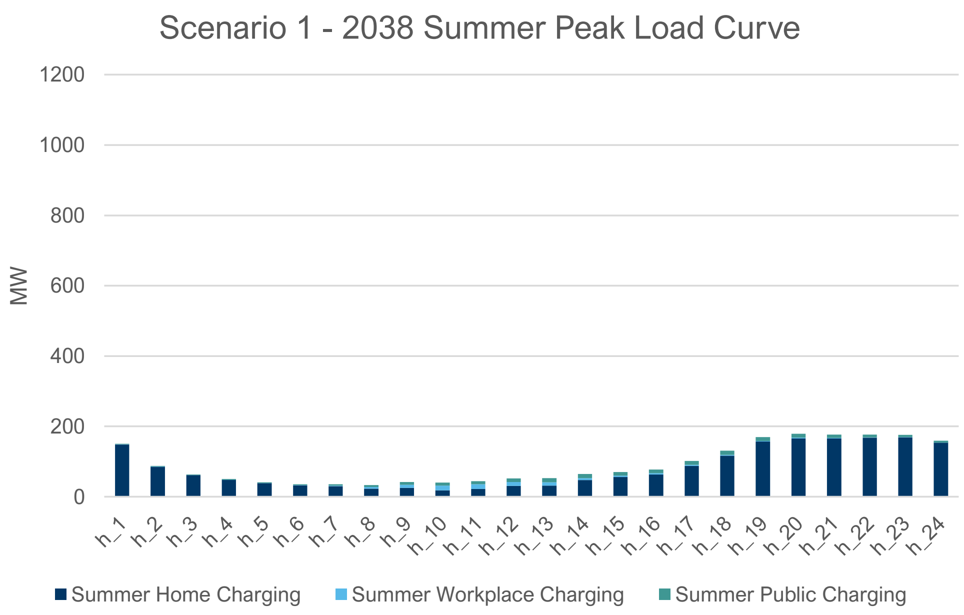
Home charging will impact winter peak MW's the most significantly

Peak hour will be 8pm for winter and 8pm for summer





3. Light Duty Vehicles

Medium Growth Scenario

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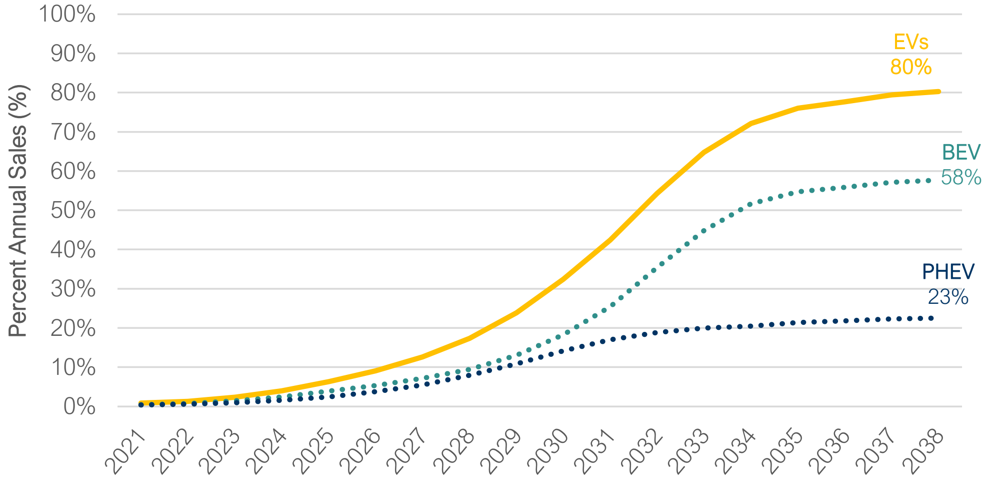
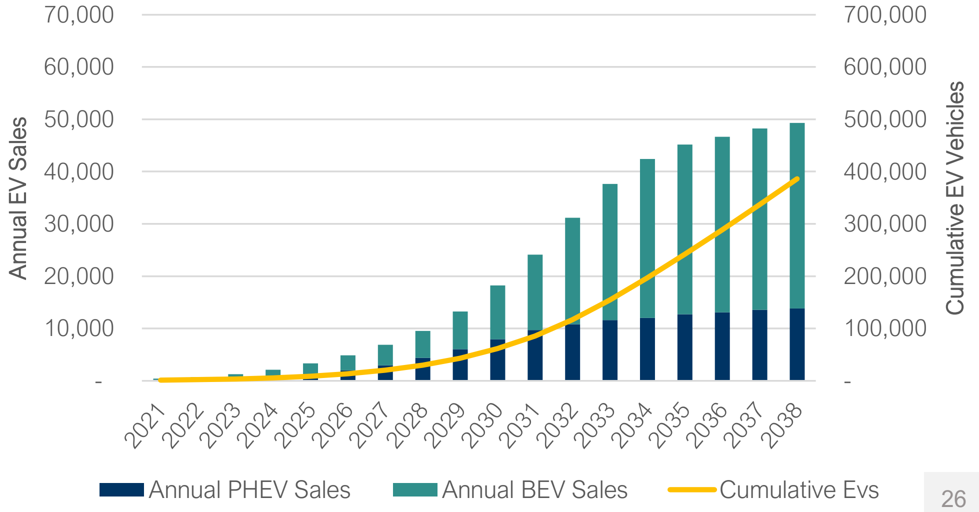
Policy/Program Interventions

Vehicle Incentives	Public DCFC (by 2038)	Public / Workplace Level 2 (by 2038)	Home Charging Access in MURBs (by 2038)
Current federal incentives (phased-out by 2026)	280 Sites (1,100 Ports)	1,250 Sites (8,500 ports)	40%

Expanding current EV support efforts will increase EV adoption and BEV market share in Manitoba; however, Manitoba will still likely fall short of Federal ZEV targets.

- By 2038, a total of **386,000 EVs** of the 979,000 LDVs are forecasted to be on the road within Manitoba
- EV adoption is expected to **fall short of the federal 2035 ZEV target** (100%), reaching only 76% of new sales by 2035.
- The increased deployment of local infrastructure **maintains the historical growth of BEV market share**, with BEVs representing ~60 % of all EVs on the road by 2038.





3. Light Duty Vehicles

Medium Growth Scenario

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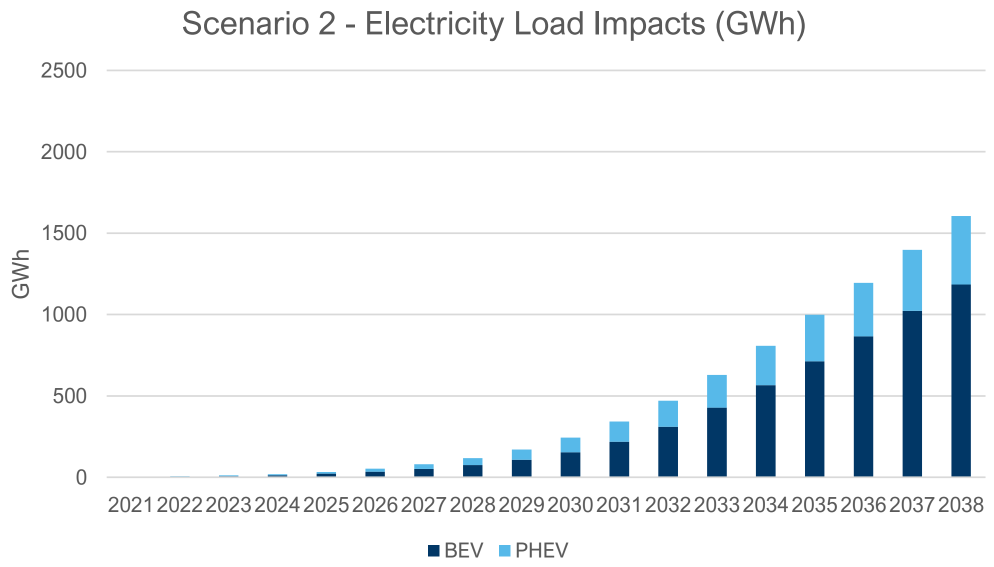
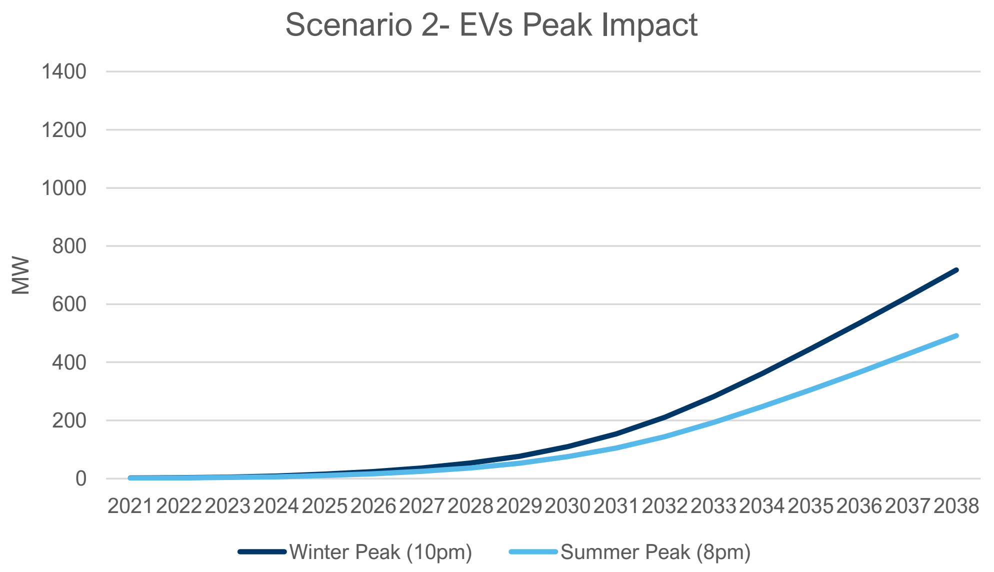
Under the Medium Scenario, Manitoba will experience moderate electricity load impacts (1000 GWh by 2038)

By 2038, EVs will contribute to 570 MW peak demand in the winter at 10PM



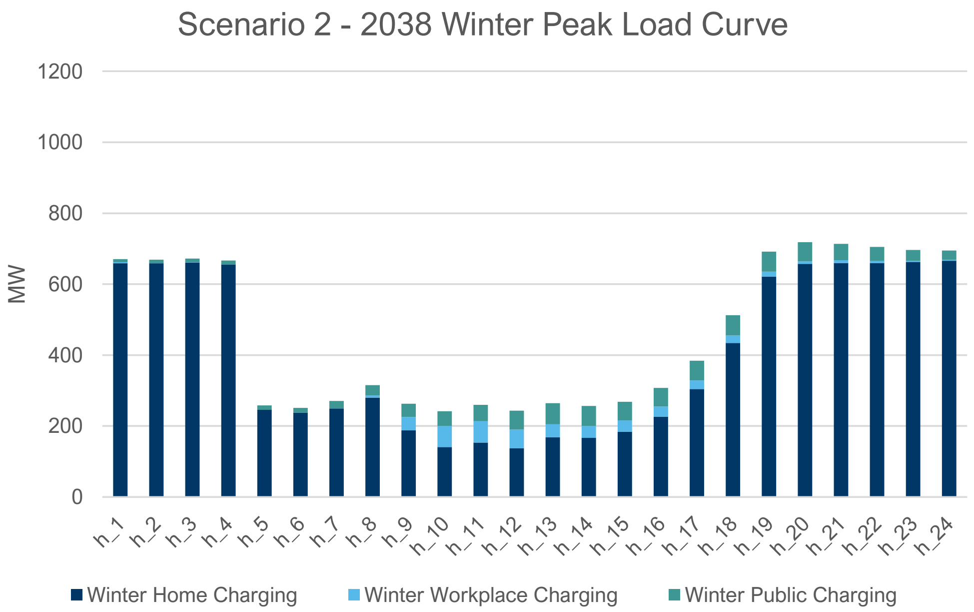


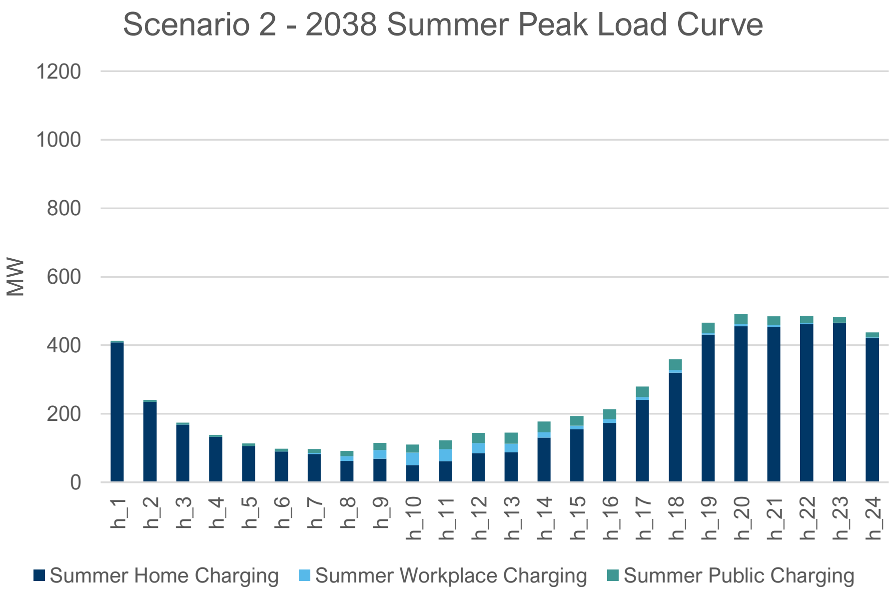
3. Light Duty Vehicles

Medium Growth Scenario (2038)

Home charging will impact winter peak MW's the most significantly

Peak hour will be 8pm for winter and 8pm for summer





3. Light Duty Vehicles

High Growth Scenario

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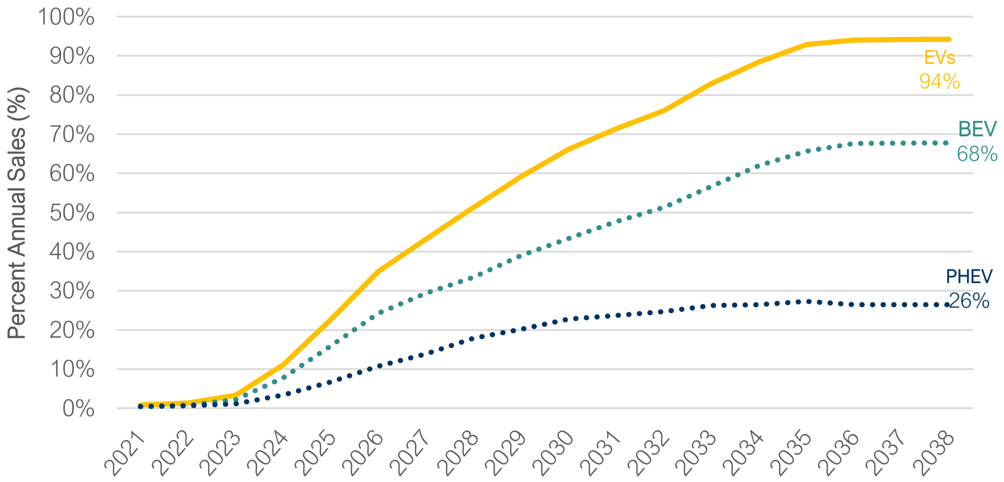
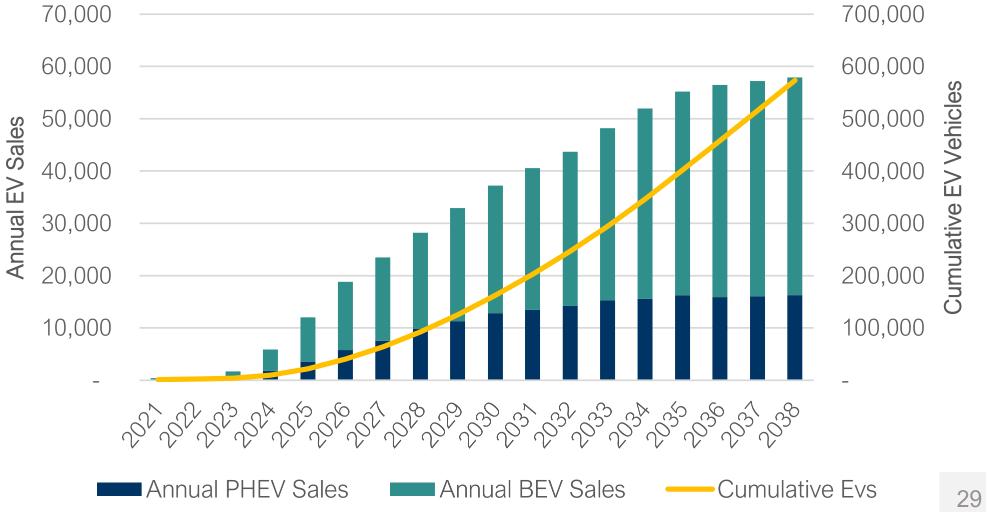
Policy/Program Interventions

Vehicle Incentives	Public DCFC (by 2038)	Public / Workplace Level 2 (by 2038)	Home Charging Access in MURBs (by 2038)
Extended federal incentive + top-up (phased-out by 2030	600 Sites (2,400 Ports)	1,900 Sites (19,000 ports)	90%

Aggressive expansion of public charging coupled with increased incentives, high EV local availability, and actions to increase home charging in MURBs would put Manitoba on trajectory to hit ZEV targets

- By 2038, a total of **573,000 EVs** of the 979,000 LDVs are forecasted to be on the road within Manitoba
- EV adoption in Manitoba would be expected to be close to meeting **the 2035 Federal ZEV Target of 100% of sales.**





3. Light Duty Vehicles

High Growth Scenario

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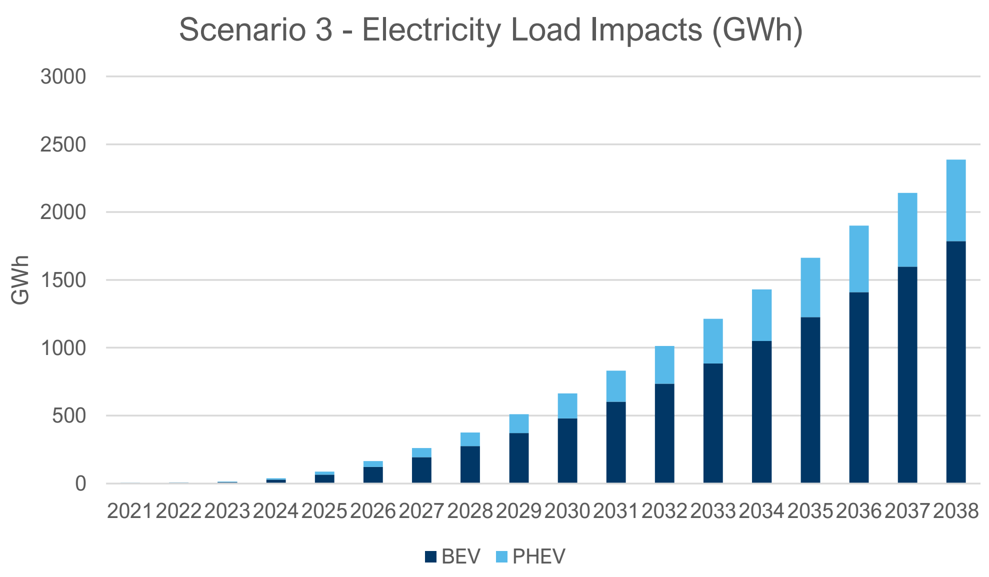
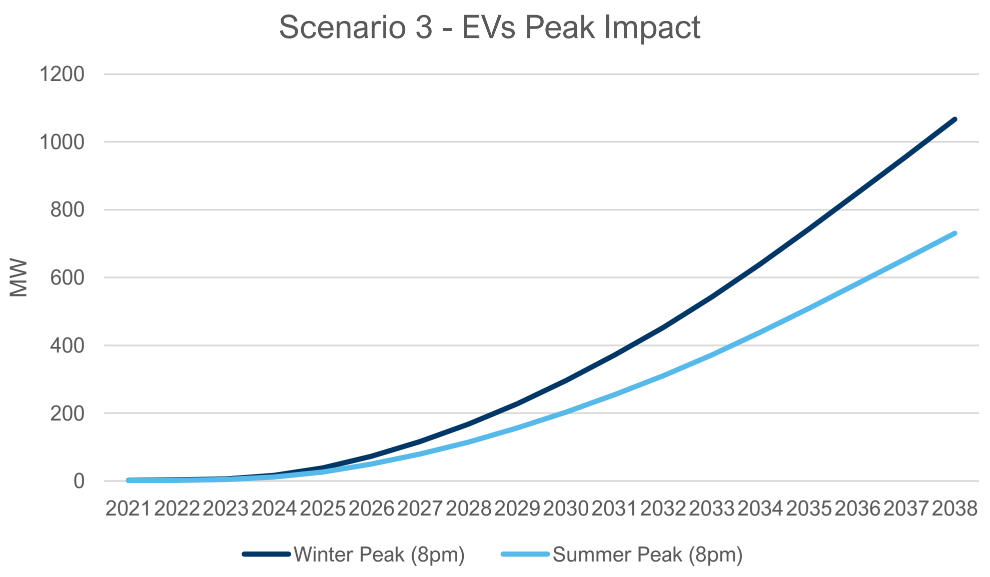
Under the High Scenario, Manitoba will experience high electricity load impacts (2400 GWh by 2038)

By 2038, EVs will contribute to 1,100 MW peak demand in the winter at 8PM





3. Light Duty Vehicles

High Growth Scenario (2038)

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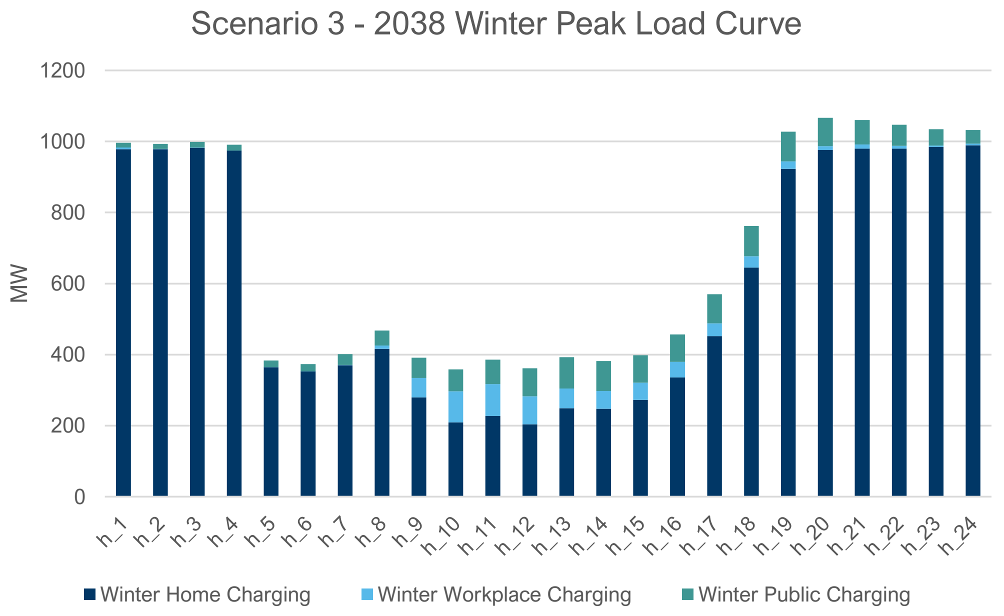
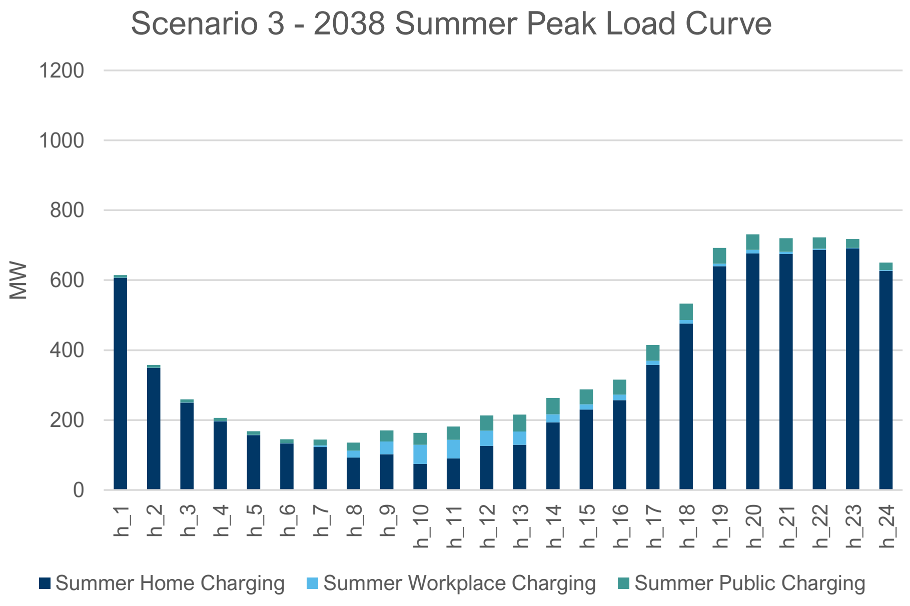
Home charging will impact winter peak MW's the most significantly

Peak hour will be 8pm for winter and 8pm for summer





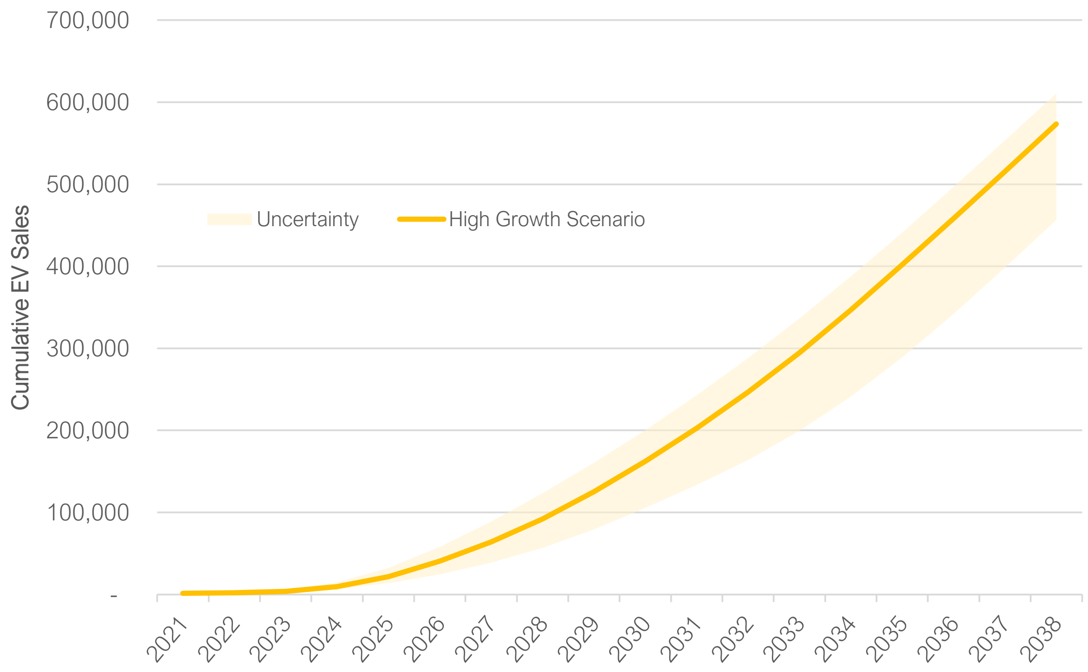
3. Light Duty Vehicles

Impacts of Uncertainty

Several key market and technology conditions will have an impact on the trajectory of EV adoption. For example, under the high growth scenario:

573,000 EVs on the road by 2038
(456k – 610k EVs)

- Uncertainty around key factors could impact adoption upwards or downwards by as much as 25%.
- Dunsky's base case battery cost forecast is most conservative in early years due to uncertainty around the timing of achieving economies of scale for battery production and tends towards a more optimistic battery cost forecast in the 2030's when the market is expected to be well-established.
- The increasing uncertainty around the absolute number of EVs on the road over time largely reflects the underlying uncertainty around total vehicle sales (ICE and EVs) in the province in the future.



3. Light Duty Vehicles

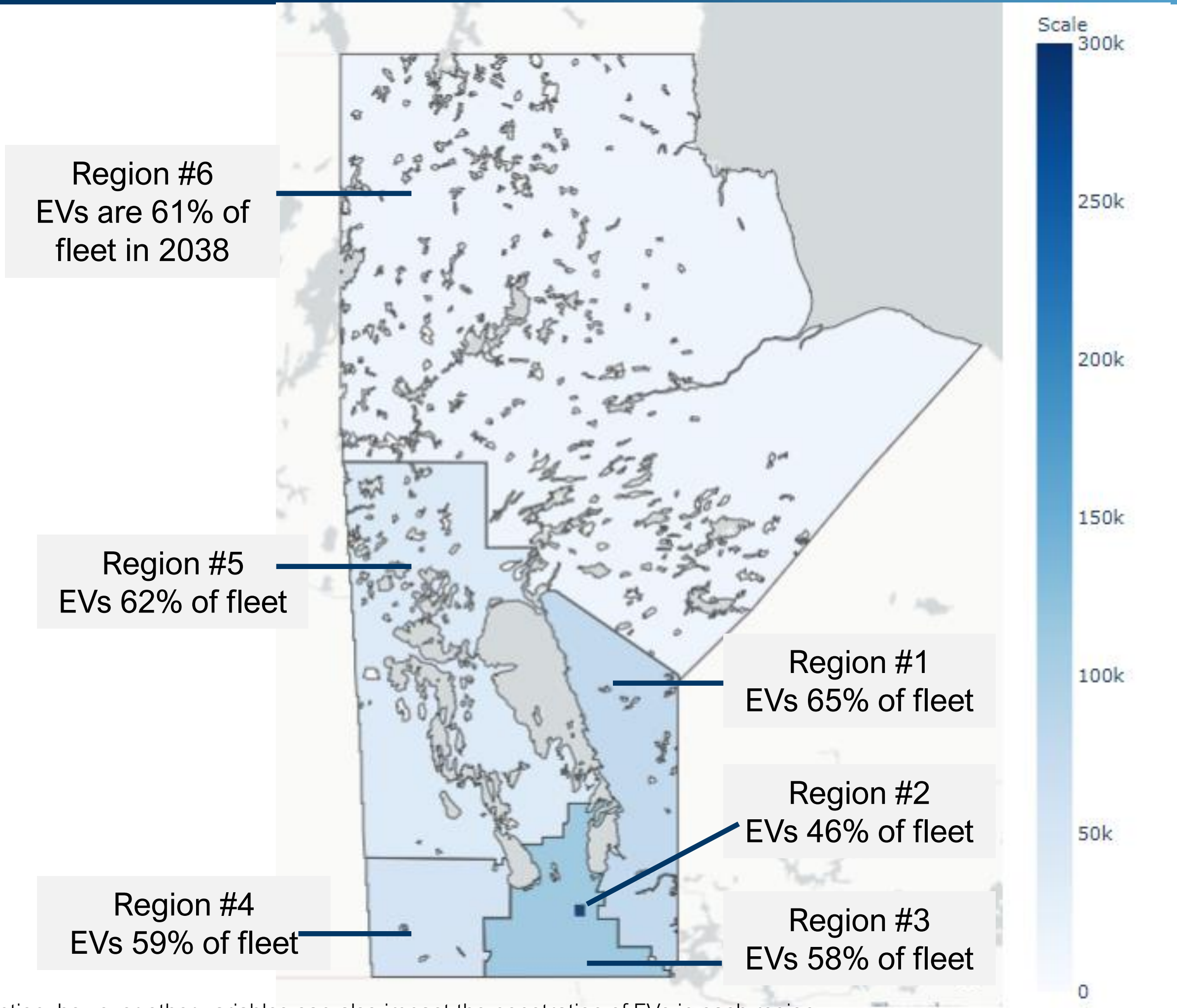
Regional Disaggregation

The province-wide adoption forecast is disaggregated into 6 regions to estimate the geographic distribution of EV adoption within the province, based on five high-impact factors most likely to influence regional variation in EV uptake*

- Number of vehicles
- Historic EV sales
- Housing composition
- Income levels
- Driving distance

Regional variations in passenger EV uptake are a function of:

- The distribution of passenger vehicles across the province (higher populations = more cumulative EVs)
- Other regional differences in income levels, housing composition and typical driving distances across the province - among other factors – that will impact local penetration of EVs.



*The factors highlighted above are believed to be key determinants of assessing local EV adoption, however other variables can also impact the penetration of EVs in each region.

3. Light Duty Vehicles

Regional – High Growth Scenario EV Consumption

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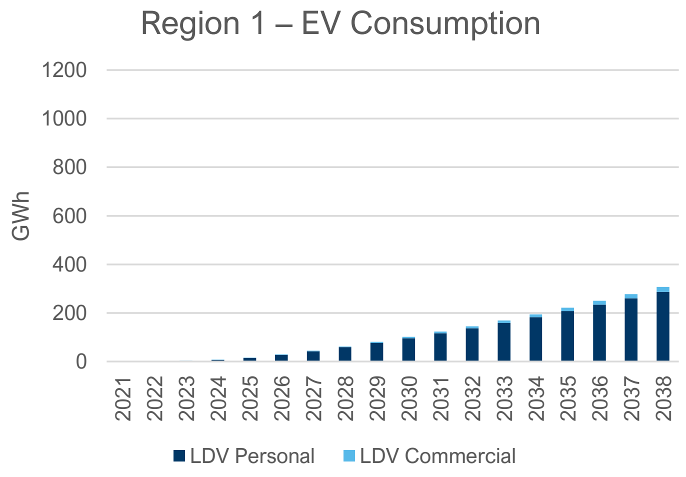
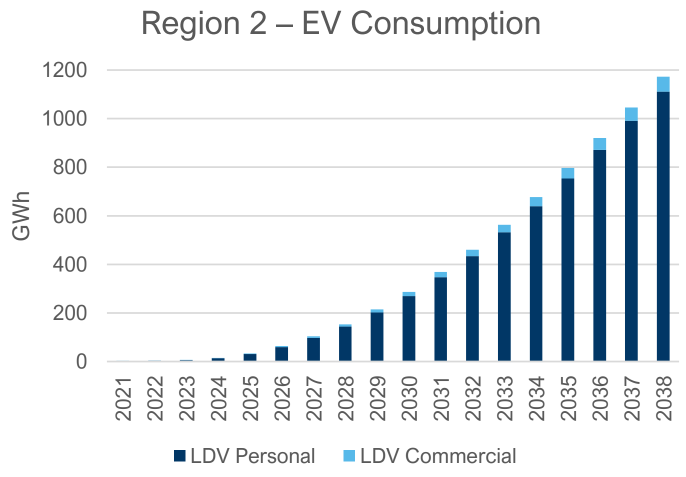
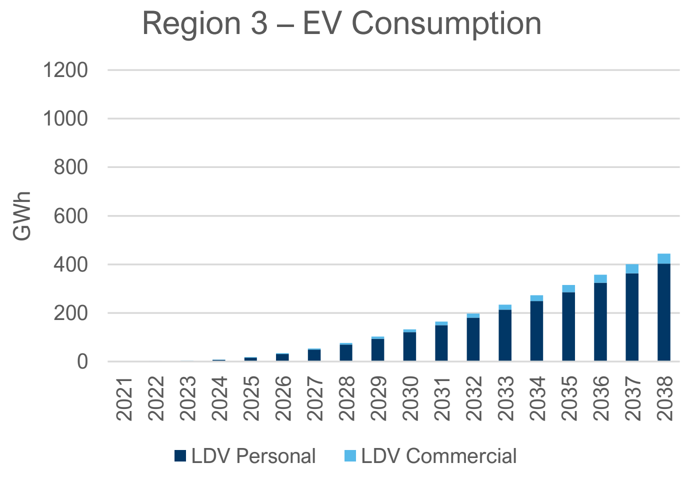
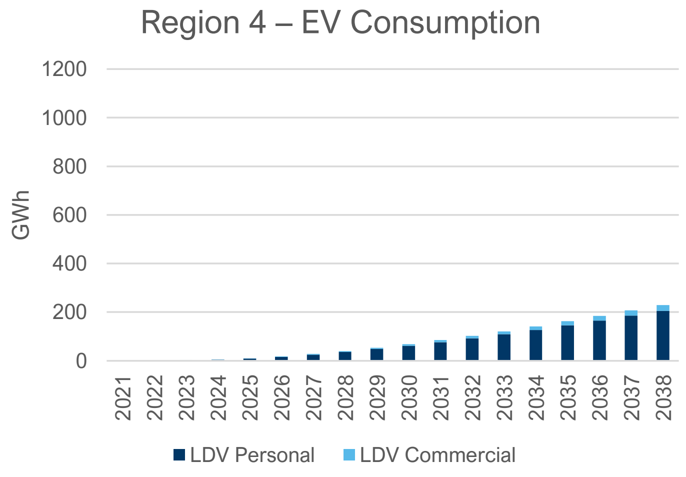
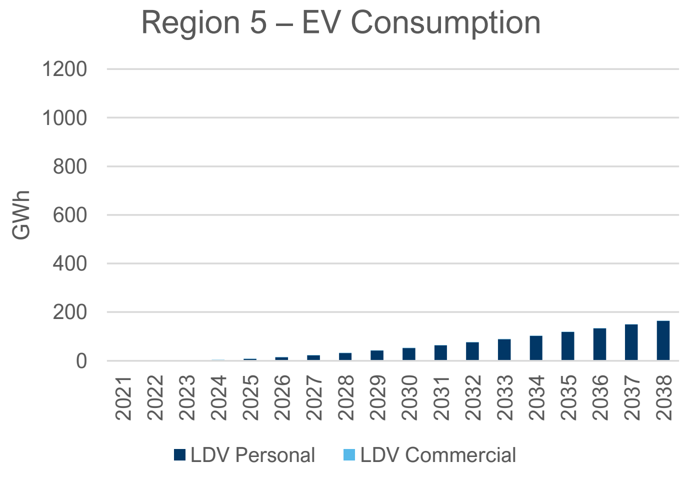
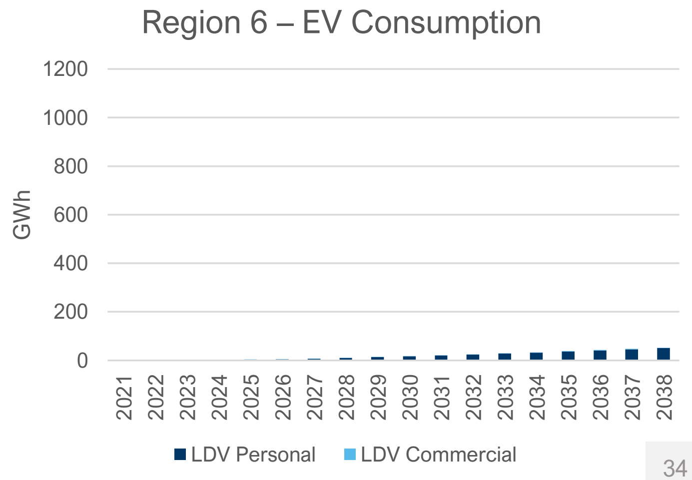






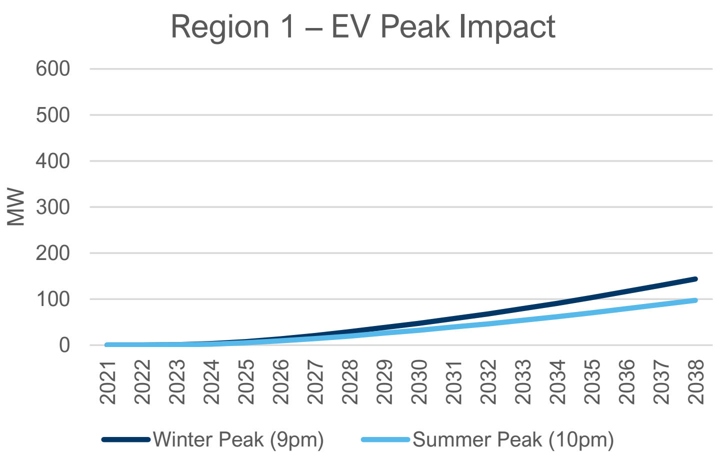


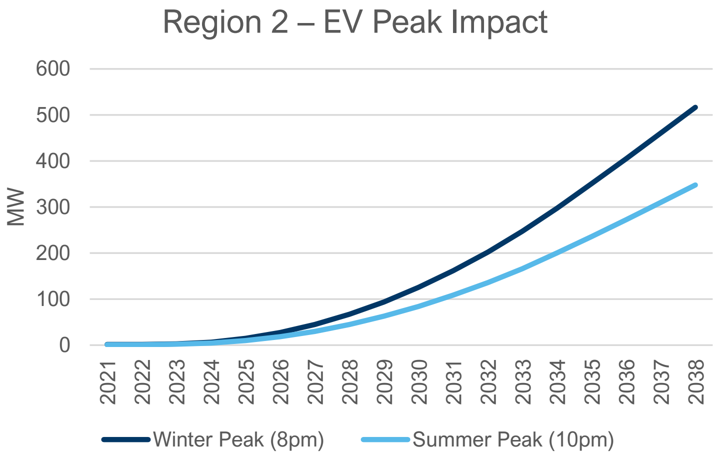


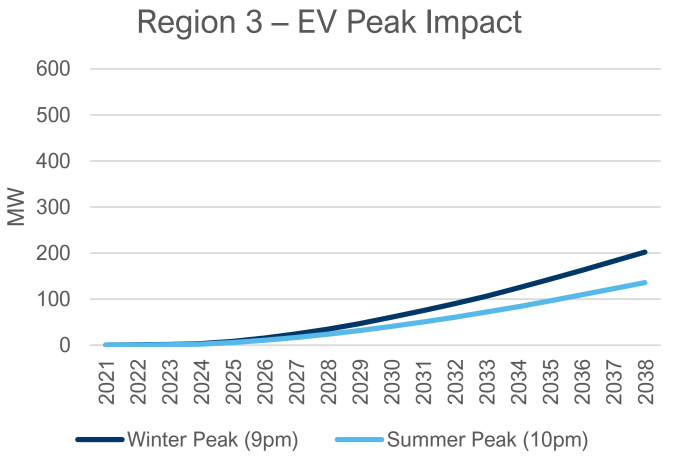


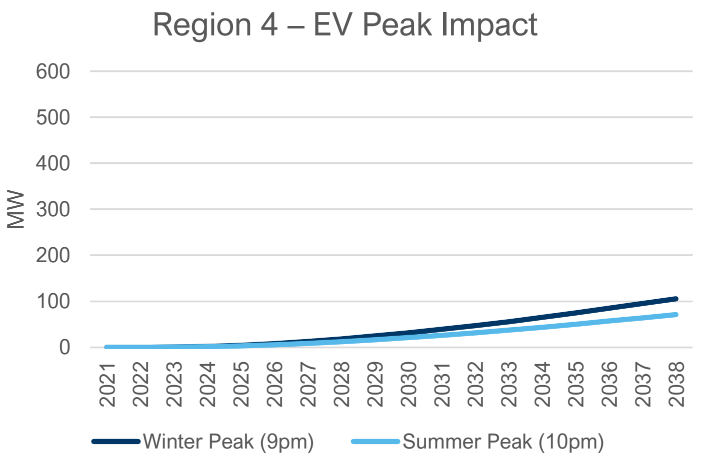
3. Light Duty Vehicles

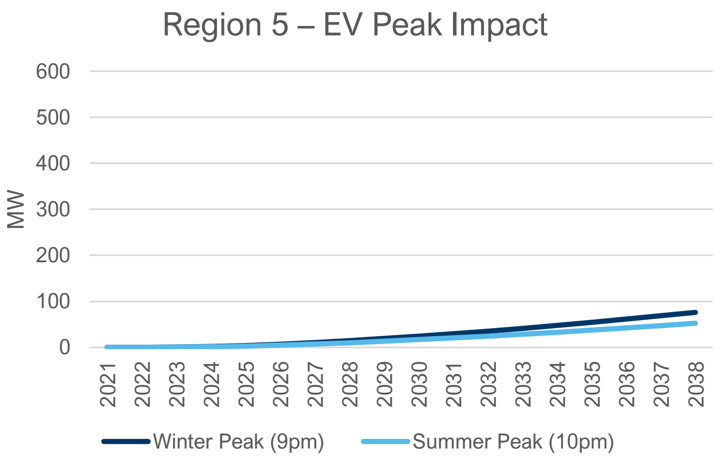
Regional – High Growth Scenario EV Peak Impact

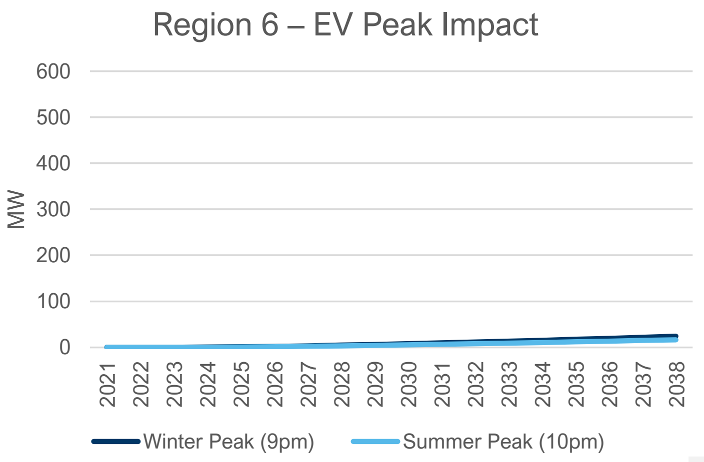






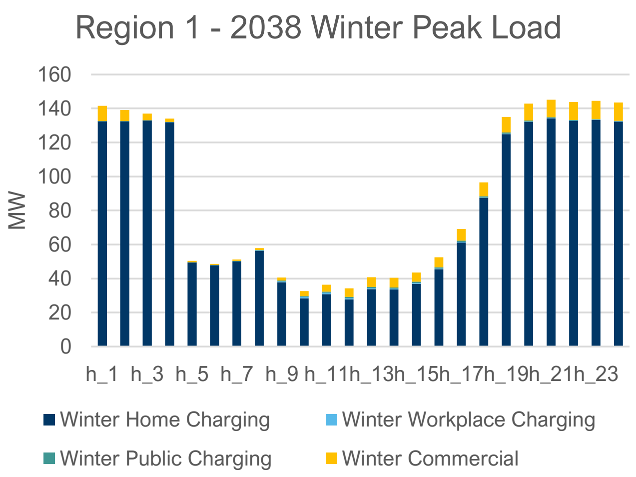


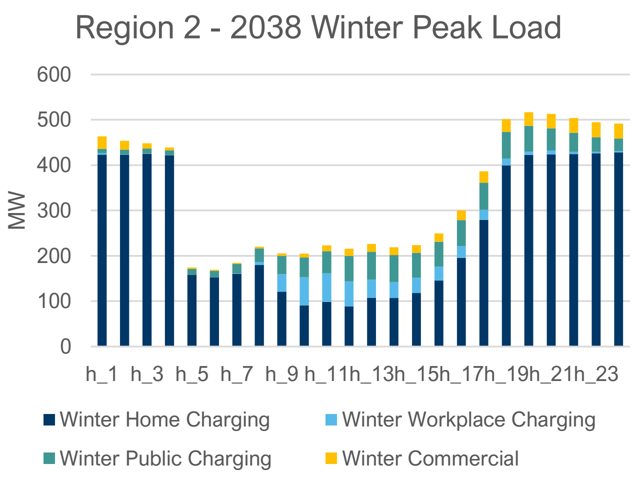


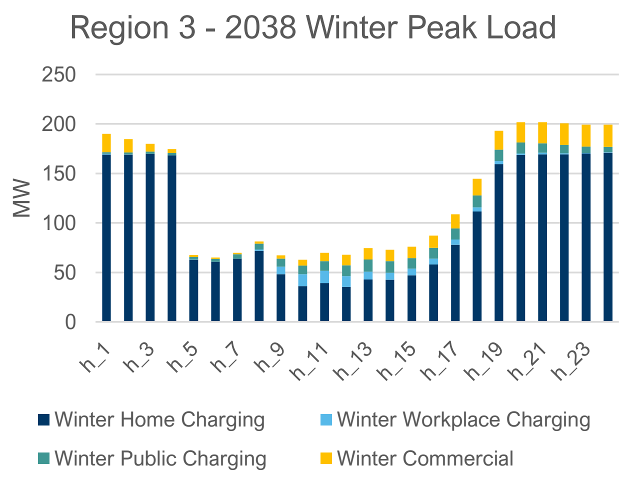


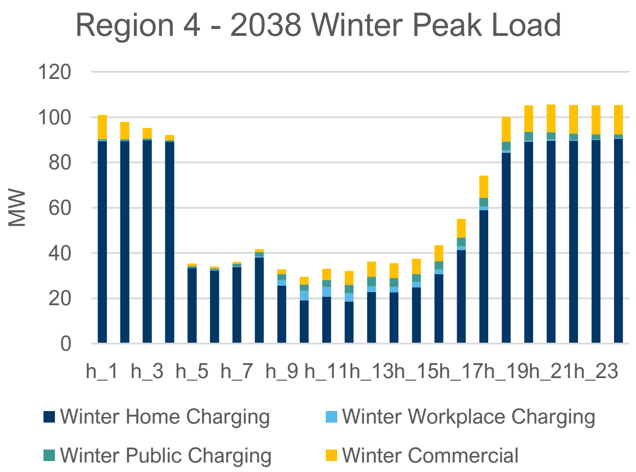
3. Light Duty Vehicles

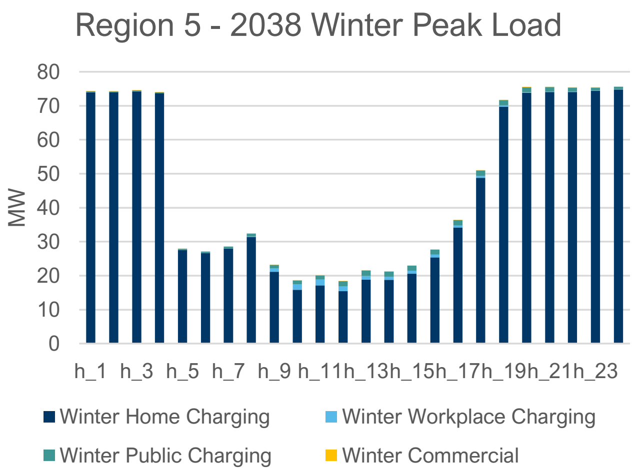
Regional – High Growth Scenario EV Peak Impact

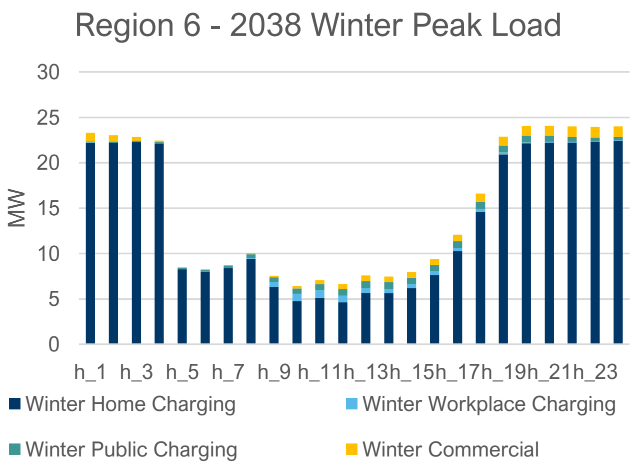












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4. Medium & Heavy Duty Vehicles

4.1 Provincial Scenarios
4.2 Regional Impacts

4. Medium & Heavy Duty Vehicles

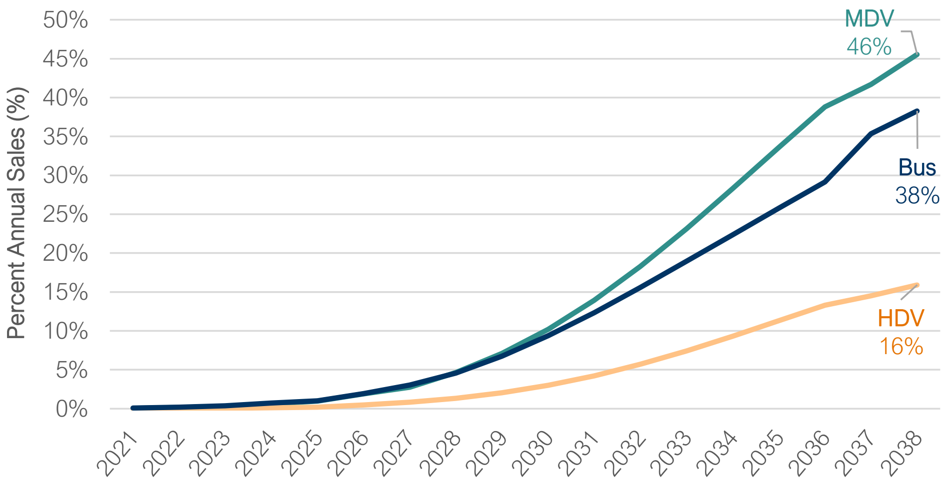
Scenarios

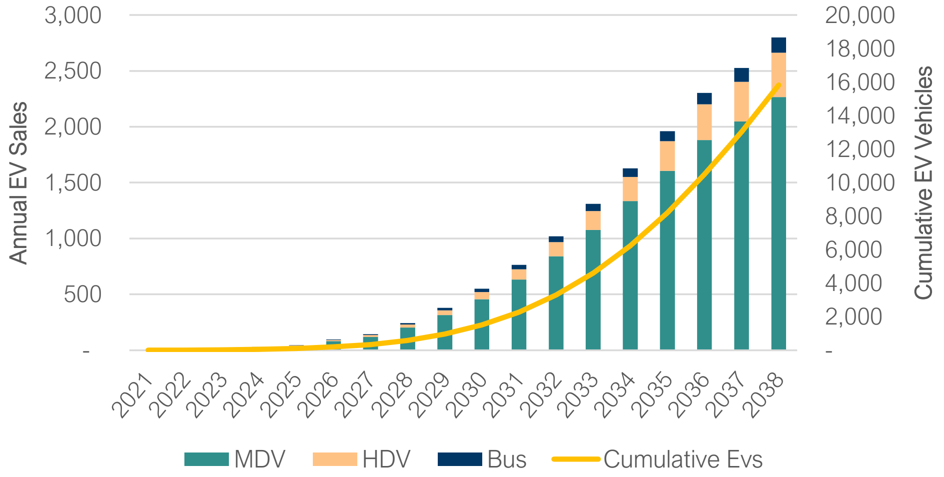
	Scenario 1 Low Growth	Scenario 2 Medium Growth	Scenario 3 High Growth
Description	Business-as-usual, without additional activities to promote uptake.	Additional investment in infrastructure and incentives increases uptake.	Most aggressive, with additional investment in infrastructure and incentives.
Key Assumption 1: **Charging power for long haul segments**	Up to 350 kW charging (Varies by vehicle segment)	Up to 1 MW charging (Varies by vehicle segment)	Up to 2 MW charging (Varies by vehicle segment)
Key Assumption 2: **Vehicle incentives**	None	25% of incremental cost, up to $75k (Ramped down + phased-out by 2026)	50% of incremental cost, up to $150k (Ramped down + phased-out by 2035)
Key Assumption 3: **Public procurement targets**	None	100% of new transit and school buses by 2030	100% of new transit and school buses by 2025

Low Growth Scenario

Under the Low Scenario, Manitoba will experience varying growth in EV uptake for different vehicle segments.

- MDV trucks will lead the MHDV market **(46% annual sales by 2038)** – this market segment is largely comprised of urban delivery vehicles that benefit from a strong business case for electrification thanks to consistent daily usage with high overall annual driving distances
- The bus segment is expected to be slightly less promising, reaching **38% annual sales by 2038**
- The HDV truck segment is expected to observe the lowest EV demand **(16% annual sales by 2038)** due to a portion of the HDV truck market focused on either long-haul or other vocational applications (e.g., dump trucks) with greater technical challenges (i.e., range requirements)



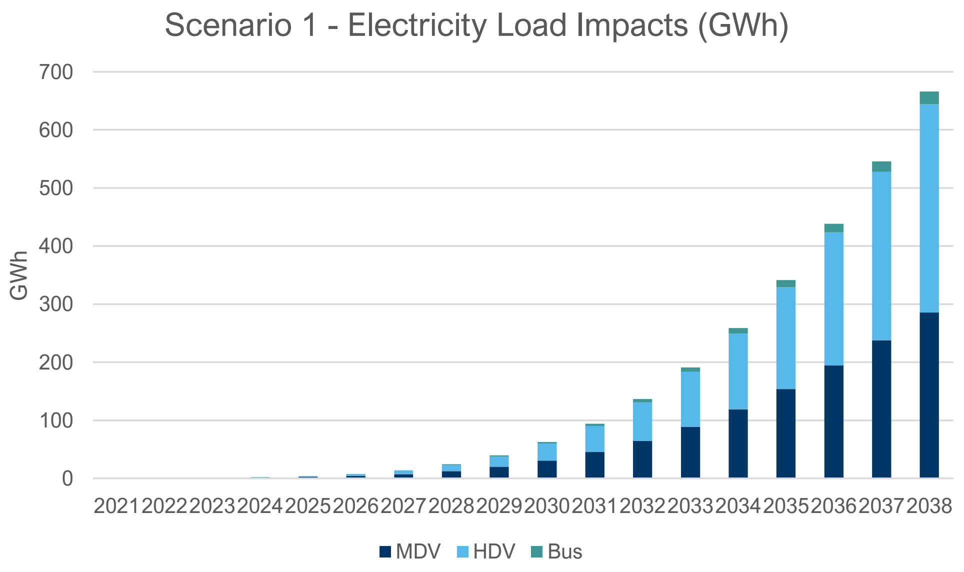


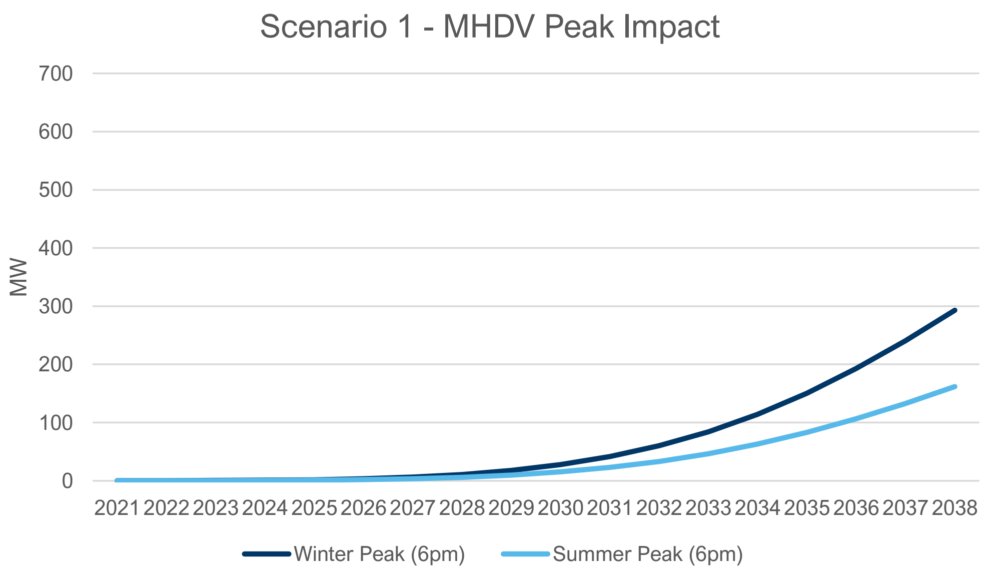
4. Medium & Heavy Duty Vehicles

Low Growth Scenario

Under the Low Scenario, Manitoba will experience some MHDV electricity load impacts (670 GWh by 2038)

By 2038, MHDVs will contribute 300 MW to peak demand in the winter at 6PM





4. Medium & Heavy Duty Vehicles

Low Growth Scenario (2038)

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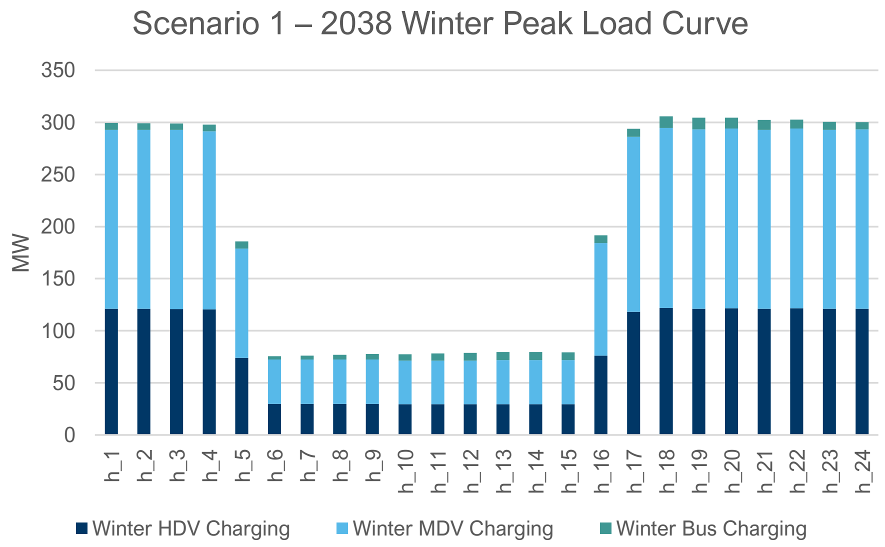
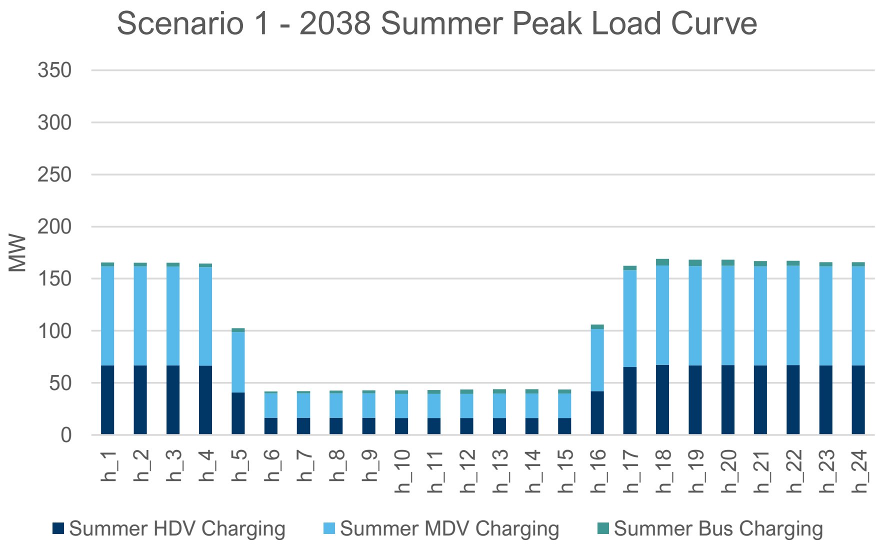
MHDV charging will impact winter peak MW's the most significantly

Peak hour will be 6pm for winter and 6pm for summer





4. Medium & Heavy Duty Vehicles

Medium Growth Scenario

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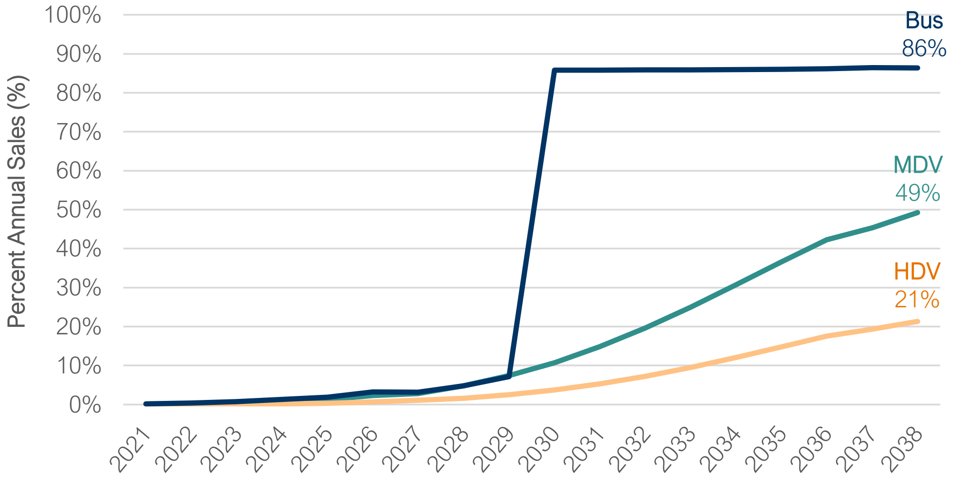
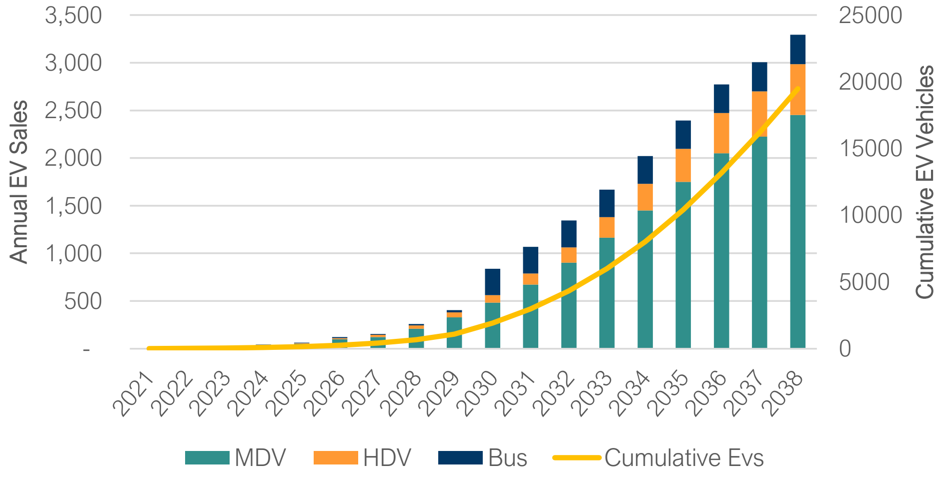
Under the Medium Scenario, Manitoba will experience modest growth in EV uptake.

- Vehicle incentives for MHDV segments improve the economics across all vehicle segments
- In this scenario, we also see the impact of setting “100% EV” procurement targets for transit and bus fleets, showing a sudden jump in market share in 2030 while the remaining bus segments (primarily coach buses) progress with a more natural growth in demand
- HDV trucks improve by over 30% relative to the Low Growth Scenario, partly thanks to the deployment of 1MW fast charging infrastructure that can enable long-haul trucking





4. Medium & Heavy Duty Vehicles

Medium Growth Scenario

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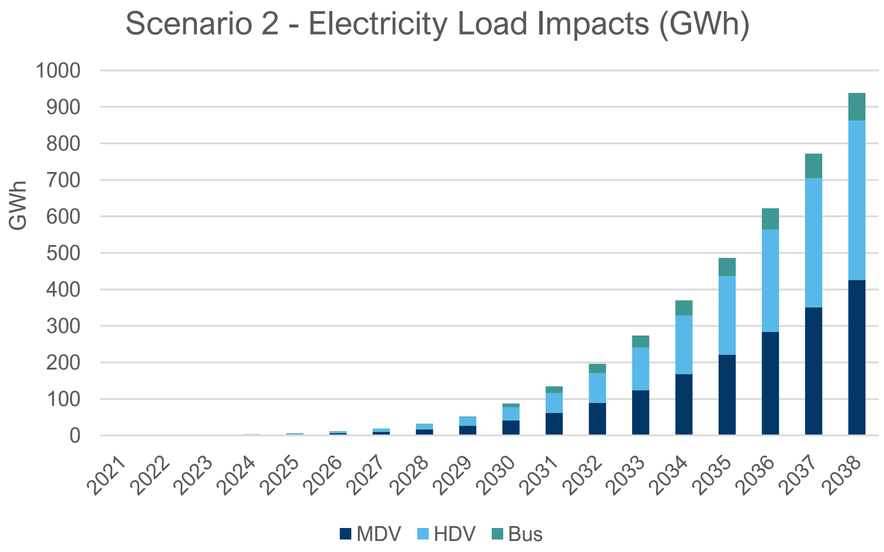
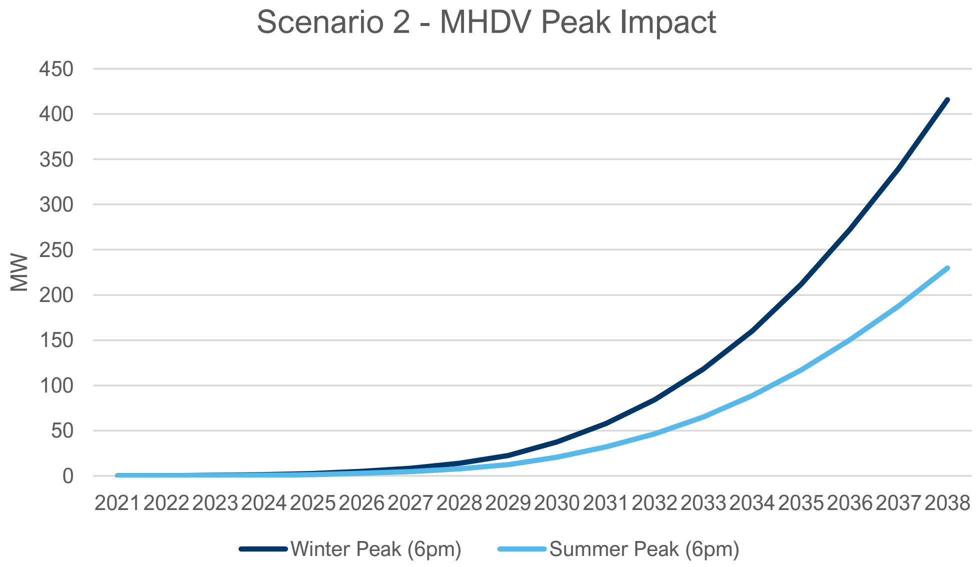
Under the Medium Scenario, Manitoba will experience high electricity load impacts (980 GWh by 2038)

By 2038, MHDVs will contribute 420 MW to peak demand in the winter at 6PM



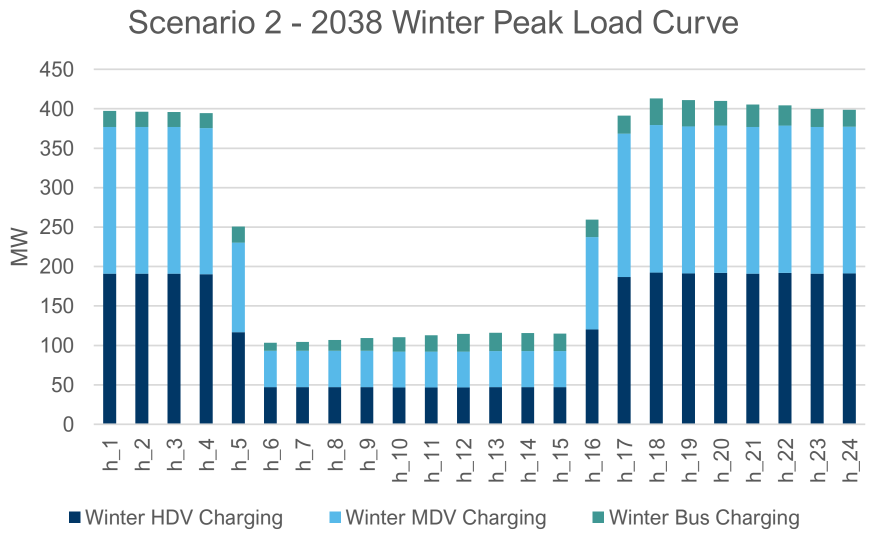


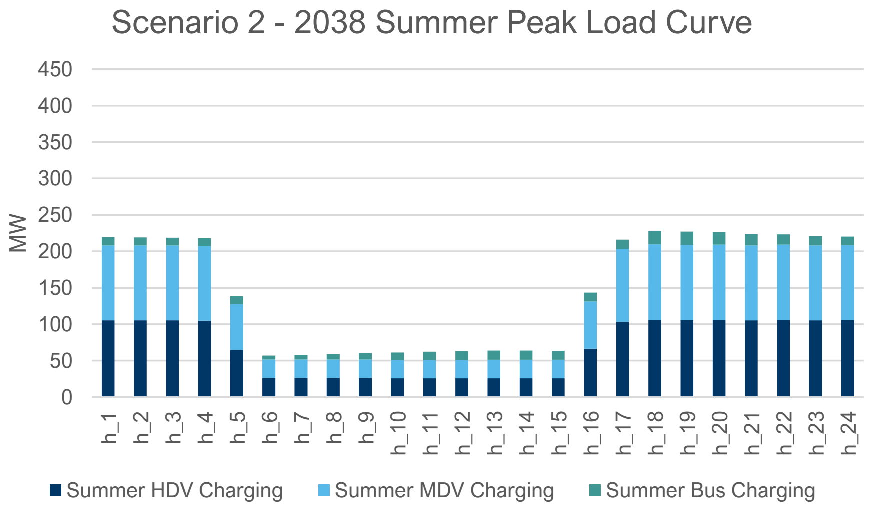
4. Medium & Heavy Duty Vehicles

Medium Growth Scenario

MDV charging will impact winter peak MW's the most significantly

Peak hour will be 6pm for winter and 6pm for summer





4. Medium & Heavy Duty Vehicles

High Growth Scenario

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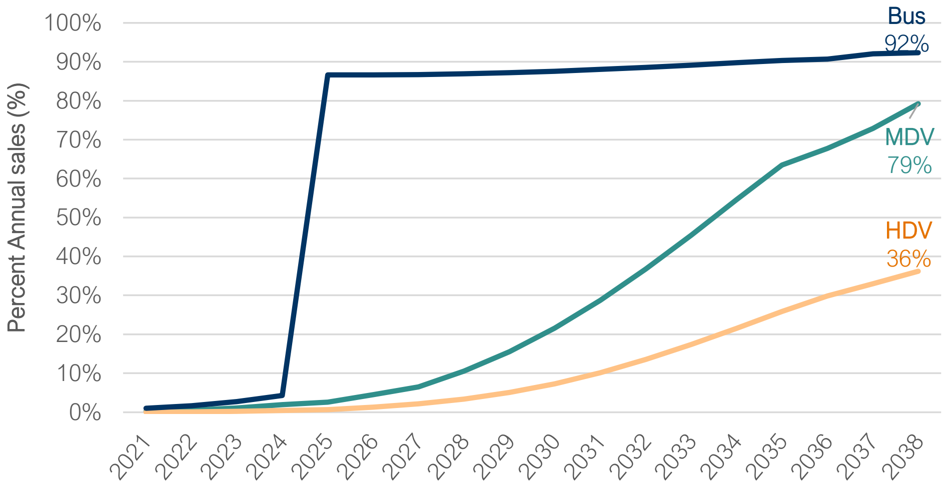
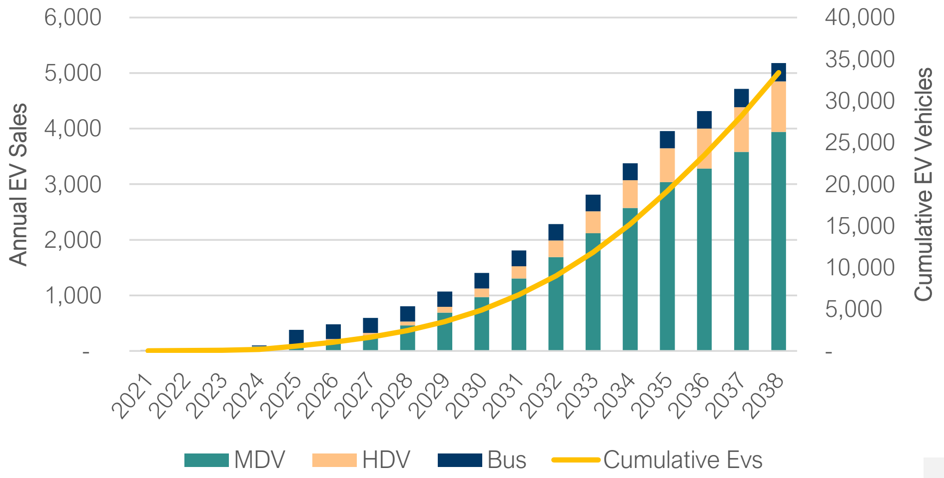
An aggressive policy push to electrify MHDVs fleet, particularly through government procurement mandates for buses could significantly change the market trajectory

- While the incremental incentives modeled in this scenario increase EV adoption across all three segments, the more prominent feature of this scenario is the impact of setting "100% EV" procurement targets for transit and bus fleets, showing a sudden jump in market share in 2025 while the remaining bus segments (primarily coach buses) progress with a more natural growth in demand.





4. Medium & Heavy Duty Vehicles

High Growth Scenario

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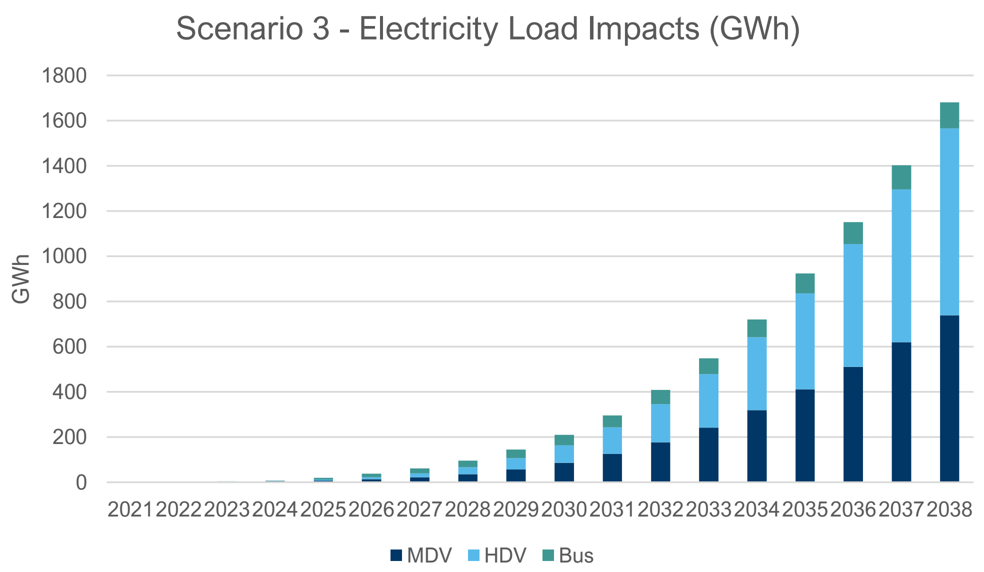
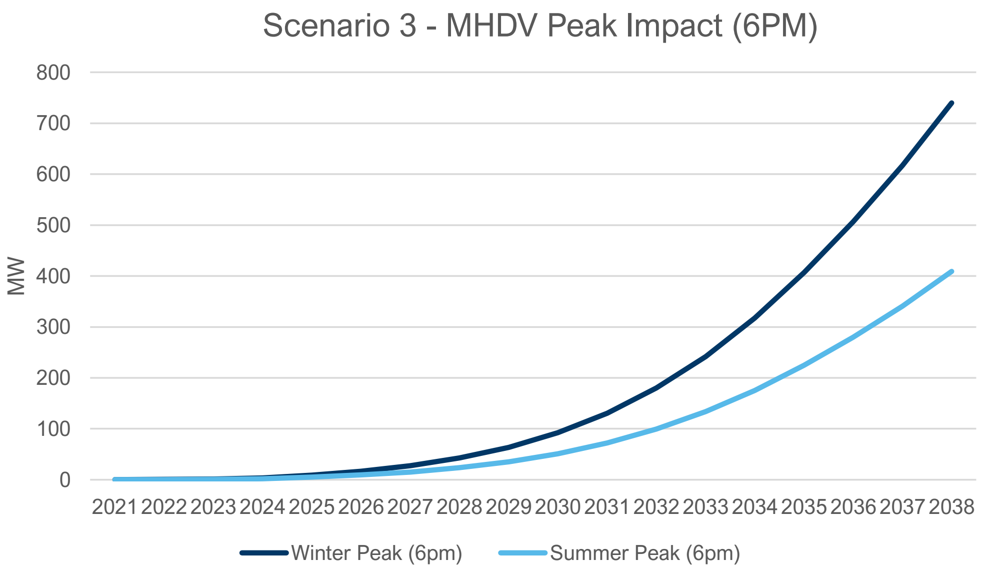
Under the High Scenario, Manitoba will experience high electricity load impacts (1775 GWh)

By 2038, MHDVs will contribute 800 MW to peak demand in the winter at 6PM



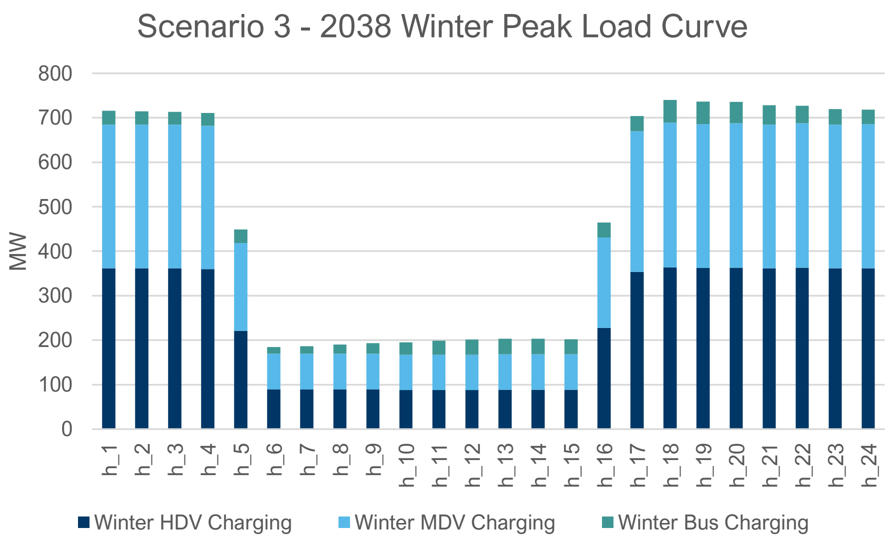


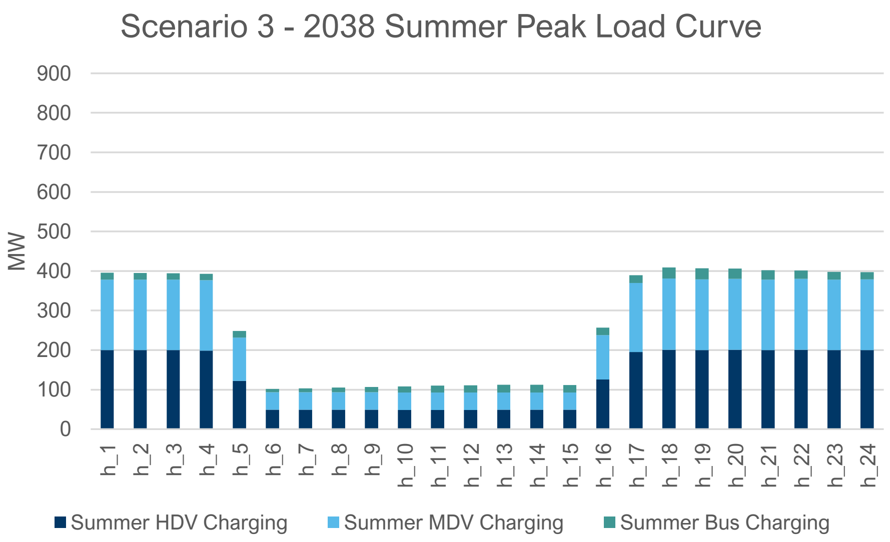
4. Medium & Heavy Duty Vehicles

High Growth Scenario

MDV charging will impact winter peak MW's the most significantly, but bus load impacts have become more aggressive than the previous two scenarios

Peak hour will be 6pm for winter and 6pm for summer





4. Medium & Heavy Duty Vehicles

Regional Disaggregation

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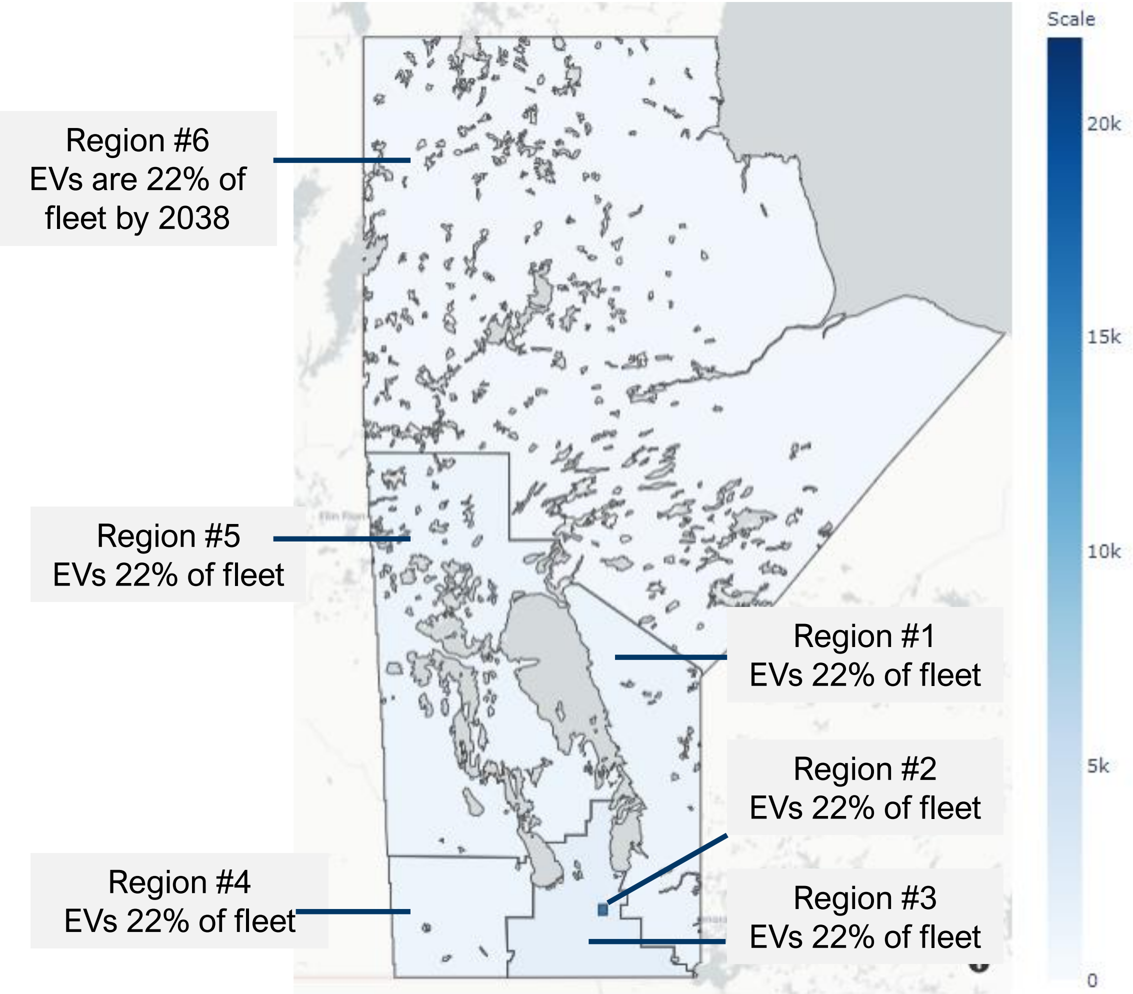
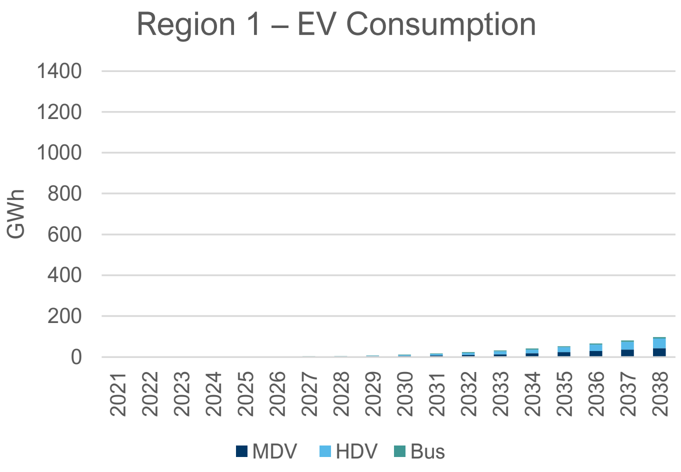
For commercial fleets, no differences in market penetration across regions was assumed, and results were disaggregated using number of registered vehicles in each area.

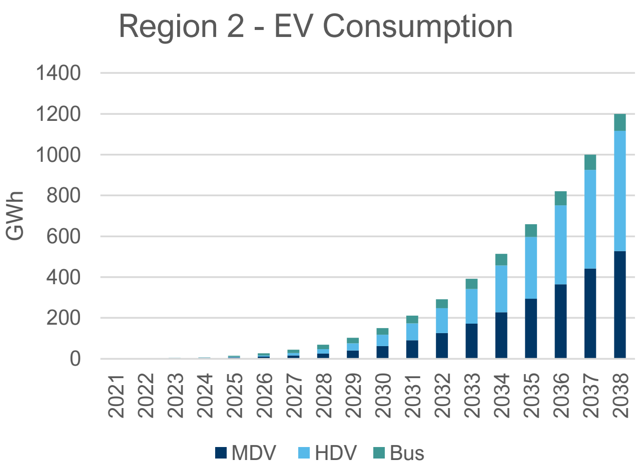
- Winnipeg holds the greatest MHDV market, approximately 70% of the MHDV total vehicle fleet – resulting in the highest penetration of EVs by 2038

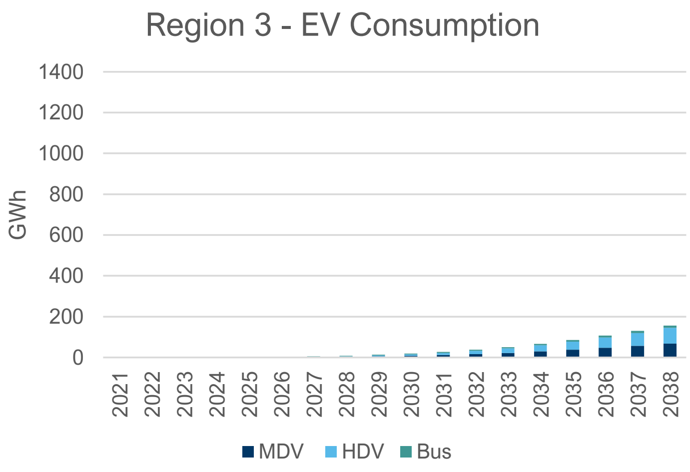


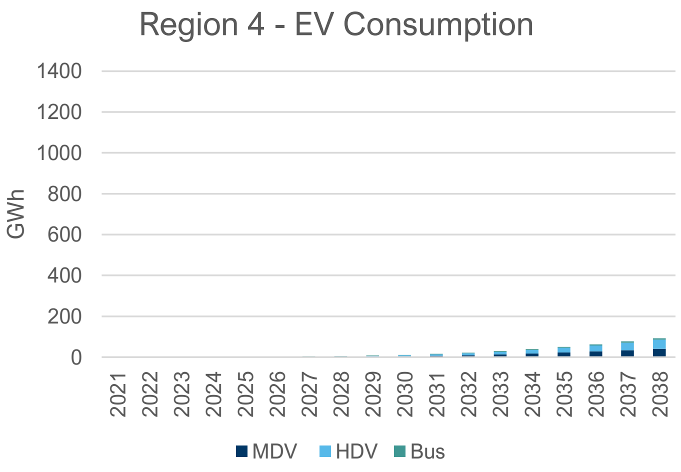
4. Medium & Heavy Duty Vehicles

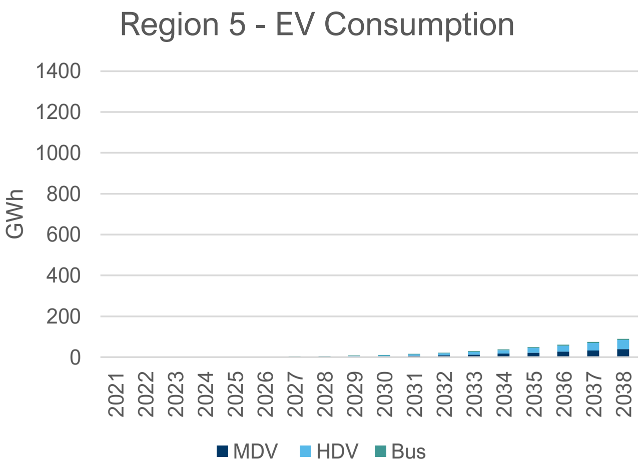
Regional Disaggregation – Consumption Scenario 3

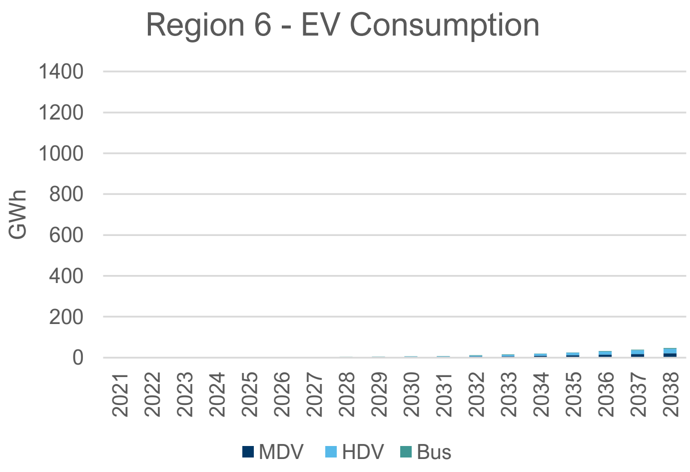






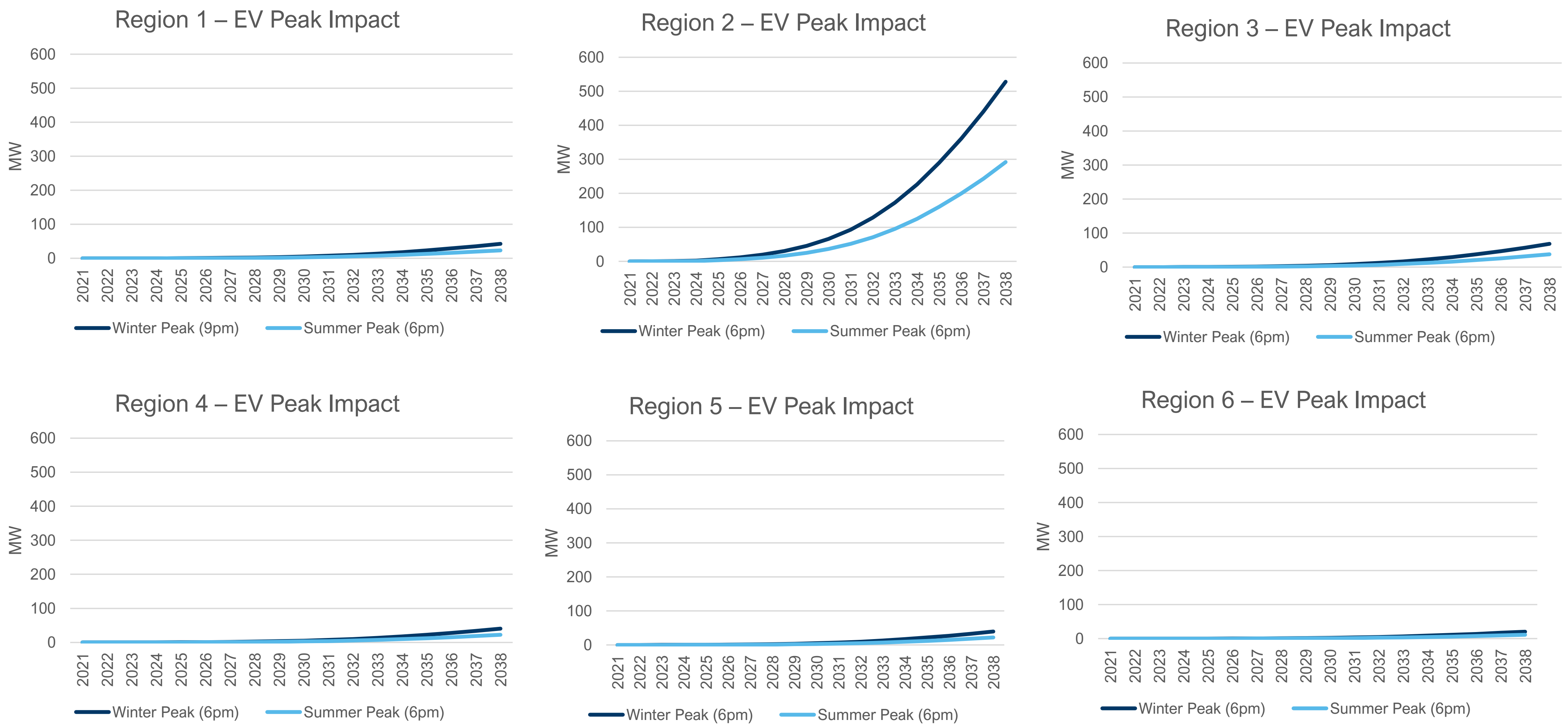






4. Medium & Heavy Duty Vehicles

Regional Disaggregation – Peak Impact (Scenario 3)



4. Medium & Heavy Duty Vehicles

Regional Disaggregation – Peak Impact (Scenario 3)

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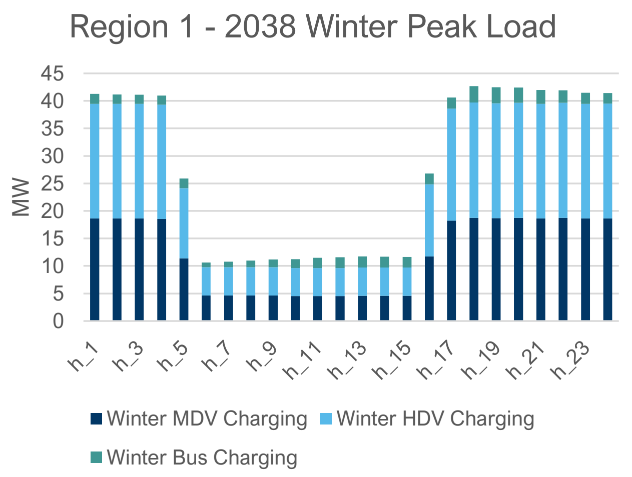

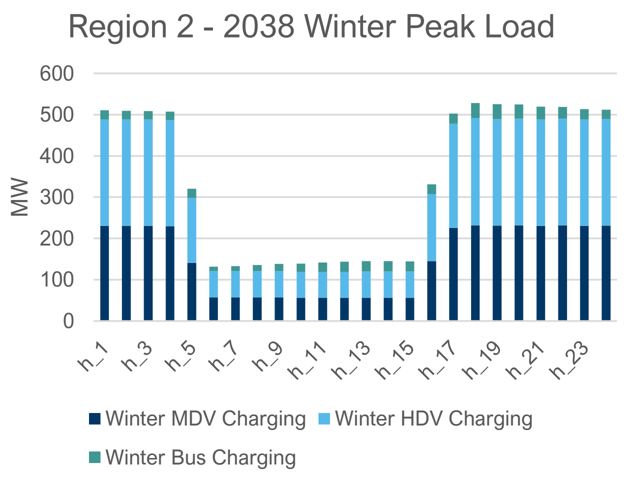

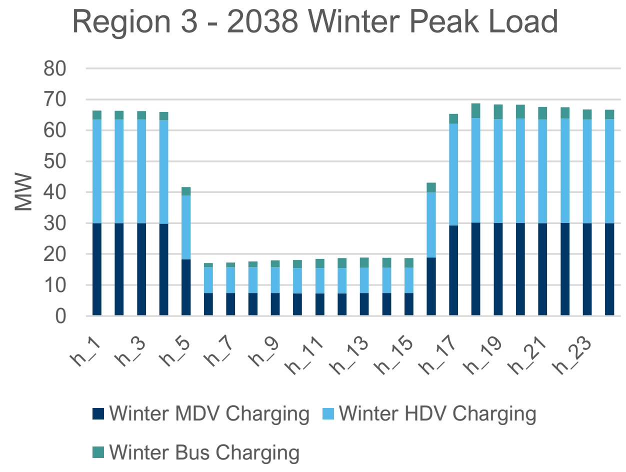

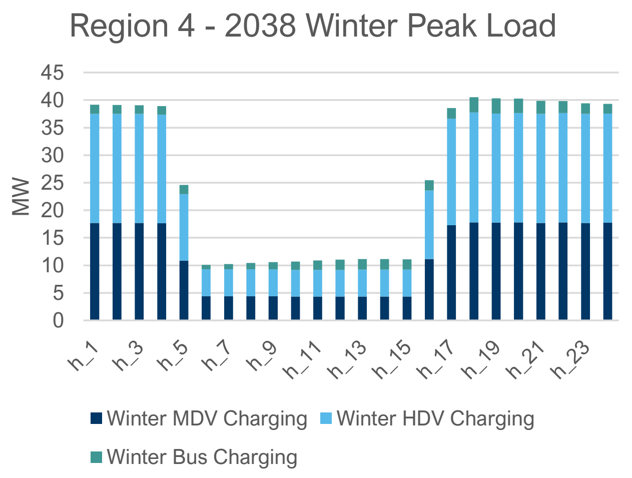

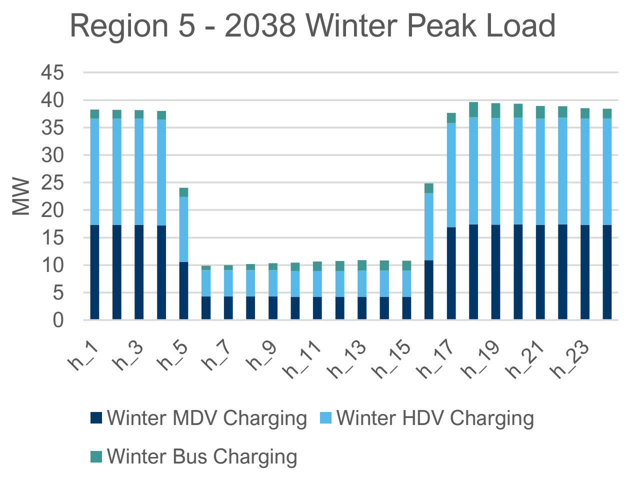

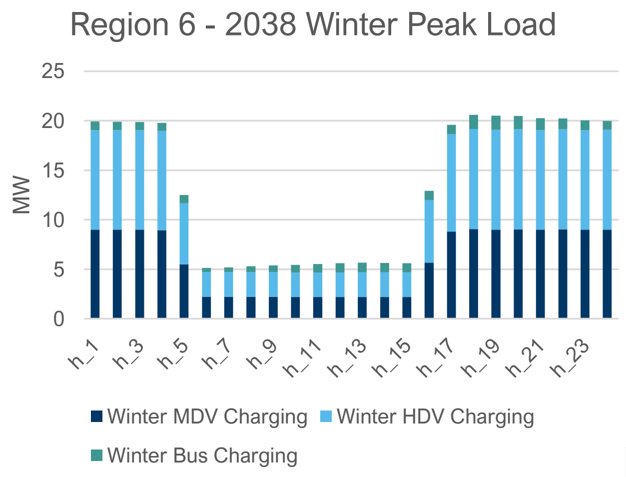

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5. Other Vehicles

5.1 Forklifts
5.2 Agricultural Vehicles
5.3 Construction Vehicles
5.4 Off-Road Vehicles
5.5 Motorcycles
5.6 Micro-Mobility

5. Other Vehicle

Specialty use vehicles: Categories

Selected based on potential load impact, likelihood of being cost-effective, and likely availability, five vehicle types are studied:

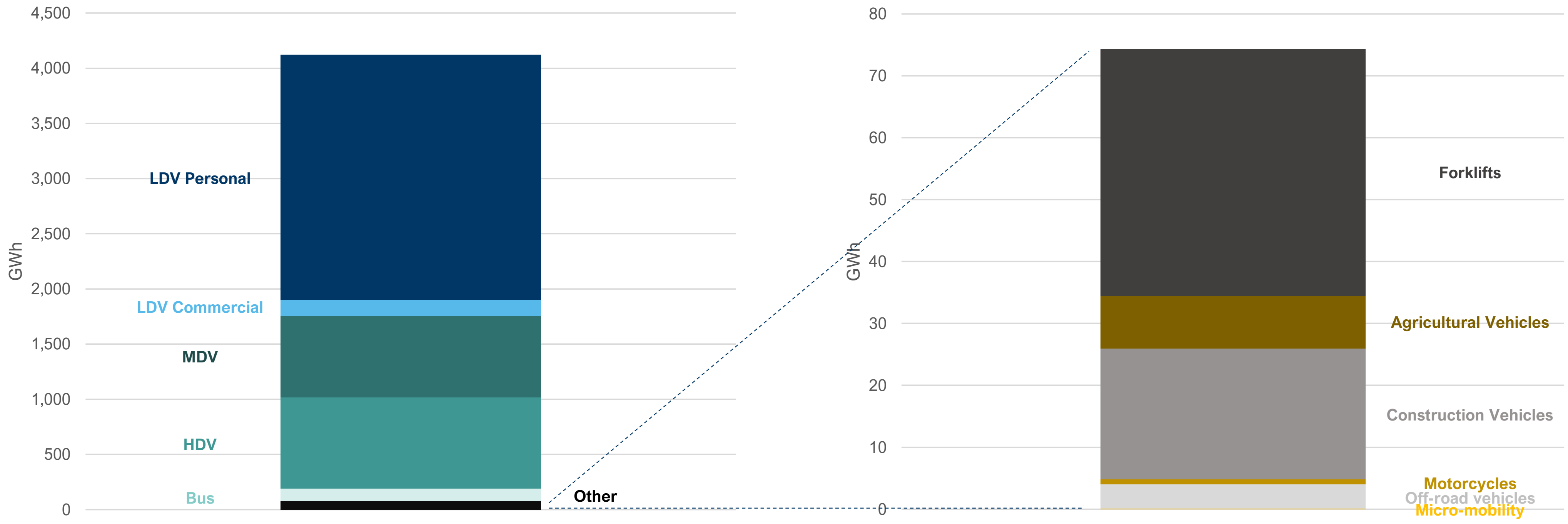
- **Forklifts**
- **Agricultural vehicles** (i.e., small- to-medium-sized tractors)
- **Construction vehicles** (e.g., compact loader, backhoe, excavators)
- **Off-road vehicles** (e.g., all-terrain vehicles, dirt bikes, skidoos)
- **Motorcycles**

Note: Most vehicles currently have limited commercial availability; professional judgement used to estimate time to market.

5 .Other Vehicles

Total Relative Consumption (2038 – Scenarios 3)

Energy requirements are significantly greater for the LDV and MHDV segments than for Other vehicles, with Other vehicles accounting for only 1.8% of increased consumption due to EVs in 2038.



5 .Other Vehicles

Forklifts

Forklifts have the **greatest short-term opportunity for electrification.** The North American forklift industry has seen **consistently high sales of electric** models (60+% since 2009) There is an ongoing shift from lead-acid (~50% of market in 2019) to lithium-ion (forecasting ~50% of market by 2028).

BENEFITS

1. **Many models available**: Long history in market allows for a long list of available electric options
2. **Environmental benefits:** No local emissions, no fluid waste requiring disposal, and recyclable batteries
3. **Reduced operator fatigue:** Less noise and smoother motion

ISSUES

a. **Higher up front cost**: Lithium-ion models have a higher upfront cost, though their total cost of ownership is positive

b. **Older models had limitations**: Lead-acid batteries permit fewer charge cycles, take longer to charge (and cool), bleed energy, and are limited in their operating conditions

Class 1	Class 2	Class 3
Electric Counterbalanced	Electric Narrow Aisle	Electric Motorized Hand Trucks

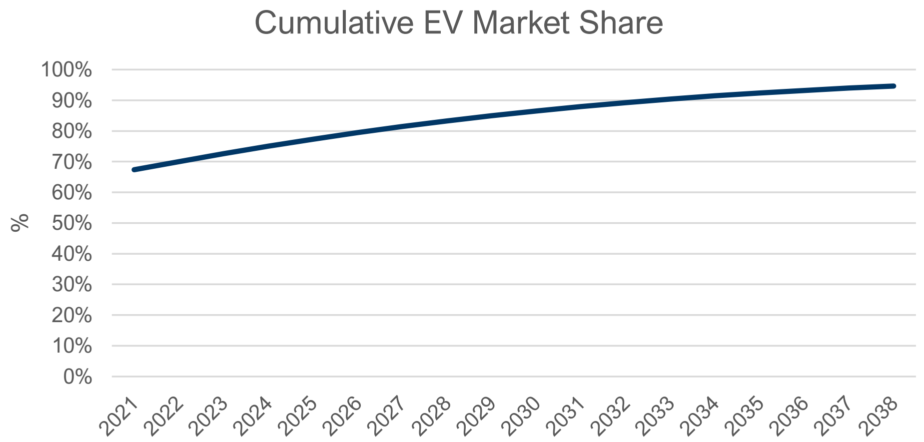
Three of the five main forklift classes are electric

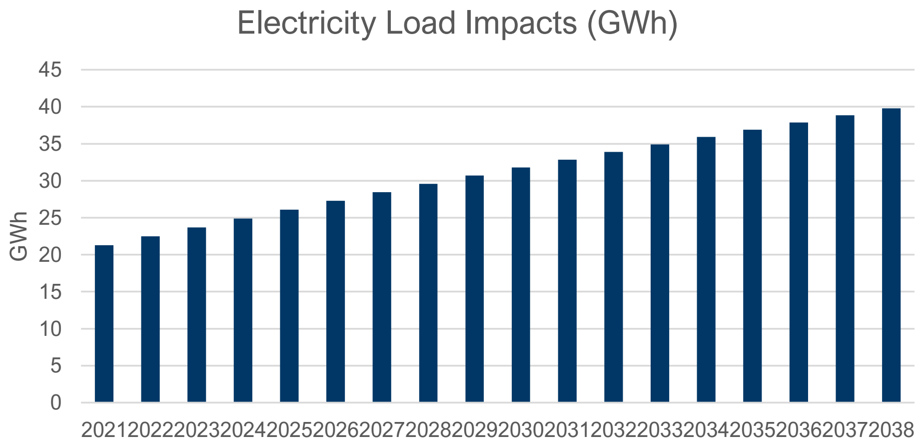
Depicts Hyster-Yale forklift models

Forklifts are anticipated to have the **greatest electricity load impact of all the Other Vehicles**.

5 .Other Vehicles

Forklifts





Relative to the impact of the LDV and MHDV forecasts, the forklift electricity load impact (GWh) in 2038 will represent approximately **1% of the additional consumption** associated with EVs.

- As such, for the purposes of this study, the demand impact of electrifying forklifts will not be determined on an hourly demand basis.

5 .Other Vehicles

Agricultural vehicles

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Low opportunity for electrification due to **limited number of models** currently in production. Tractors will begin to electrify in this segment, specifically **smaller two-wheel-drive tractors** (<100 hp). Larger vehicles (e.g., combines, harvesters, balers) are unlikely to have significant uptake during this study period.

BENEFITS

1. **Competitive total cost of ownership**: e-Tractors are already cost competitive on a TCO basis with ICE tractors
2. **Increased reliability**: Fewer moving parts means fewer things going wrong. Reliability is critical during finite windows when tasks must occur (e.g., sowing, harvesting)

ISSUES

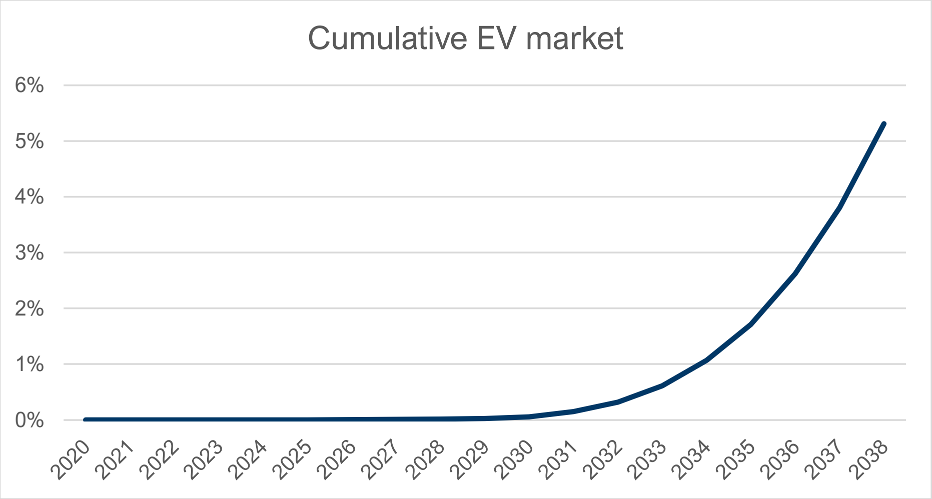
a. **Limited model availability**: Options are limited to tractors
b. **High power-to-weight ratios**: Energy intensive tasks (e.g., tilling, hauling) require significant hourly consumption
c. **Limited annual usage**: Vehicles typically average 200 – 400 hours of annual usage

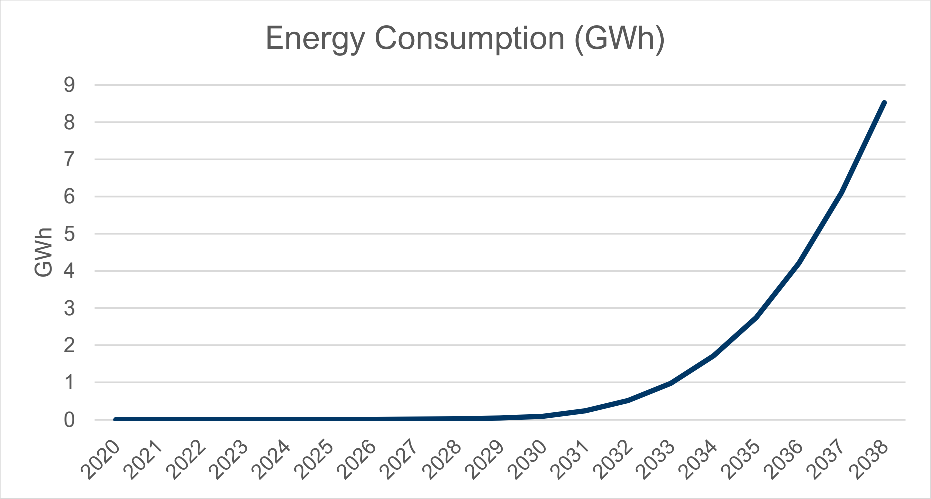
Solectrac, 60kWh electric tractor

The electric tractor market today is still small, representing **far less than 1% of tractors globally**.

5 .Other Vehicles

Agricultural vehicles





Relative to the impact of the LDV and MHDV forecasts, the agricultural vehicle electricity load impact (GWh) in 2038 will represent approximately **0.2% of the additional consumption** associated with EVs.

- As such, for the purposes of this study, the demand impact of electrifying agricultural vehicles was not determined on an hourly demand basis.

5 .Other Vehicles

Construction vehicles

A **limited number of models** are currently in production (either commercially or as prototypes). **Compact machines** will be the first movers (e.g., excavators, wheel loaders, and backhoes).

BENEFITS

1. **Reduced noise:** Lengthen possible work day, reduce on-site accidents, and improve worker comfort
2. **Reduced site air pollution:** Improved worker experience
3. **Equivalent performance:** Similar specs to diesel equivalents, with reduced run time (no need to idle)

ISSUES

a. **Limited model availability:** Challenges with battery storage, charging cycles, and power output for larger models
b. **Higher upfront cost**
c. **Charging infrastructure required:** Many vehicles on a site can lead to significant localized charging demands

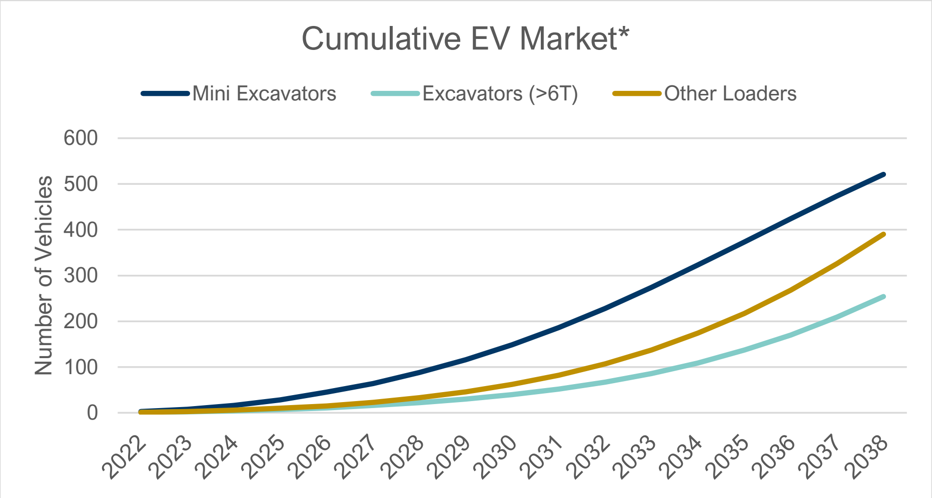
Campaign from Volvo promoting the quieter electric engine.

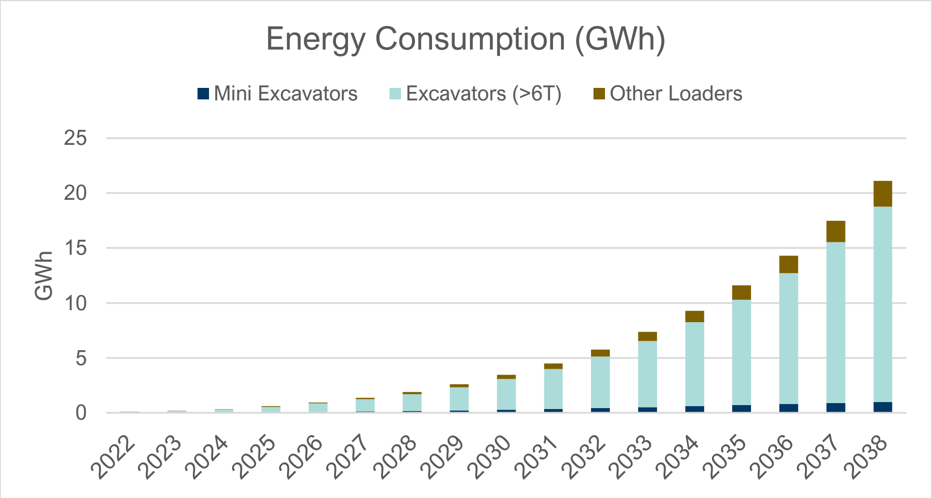
Volvo CE was the first construction equipment manufacturer to commit to an electric future for its compact machine range.

Local regulations and mandates, especially in Europe, are beginning to **drive demand** (E.g., Oslo, Norway plans to completely ban emissions and diesel vehicles from construction sites by 2030).

5 .Other Vehicles

Construction vehicles





Relative to the impact of the LDV and MHDV forecasts, the construction vehicle electricity load impact (GWh) in 2038 will represent approximately **0.5% of the additional consumption** associated with EVs.

- As such, for the purposes of this study, the demand impact of electrifying construction vehicle was not determined on an hourly demand basis.

* Note that Market Share of EVs of the construction vehicle segments was not determined. Due to data availability limitations, a forecast of EV vehicles was used instead of determining likely uptake based on the total market of construction vehicles.

5 .Other Vehicles

Motorcycles

While a more feasible vehicle segment to electrify, adoption levels remain low in Canada.

BENEFITS

1. **Reduced noise:** Can improve driver experience
2. **Instant torque and minimal maintenance:** Most models have ample amounts of torque and require low operation and maintenance costs

ISSUES

a. **Limited model availability:** Options are still limited compared to ICE motorcycles

b. **Higher upfront costs:** Higher upfront costs than more widely available ICE bikes

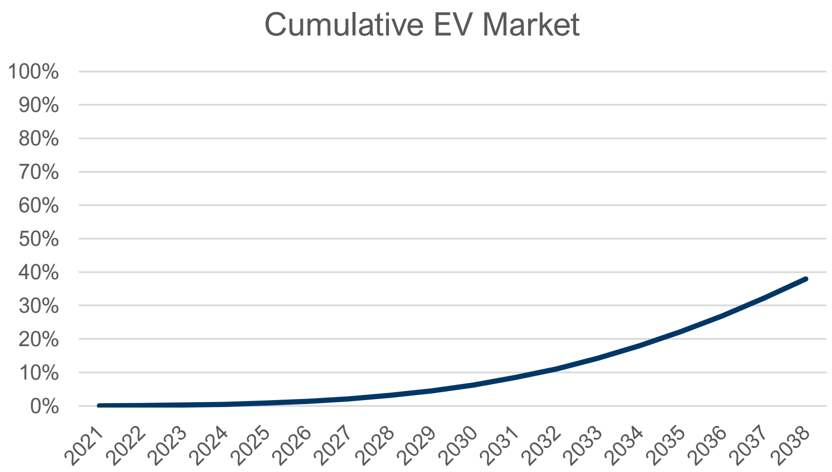
SR Zero Electric Motorcycle

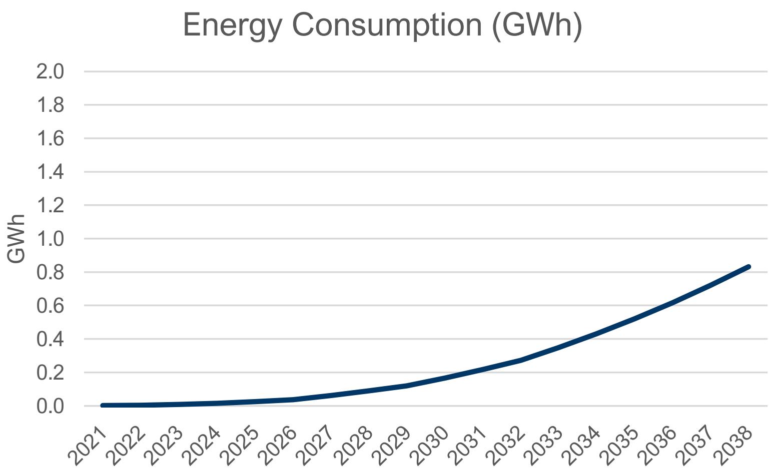
The electric motorcycle market in Manitoba is currently very small; **less than 0.2% of annual sales**.

5 .Other Vehicles

Motorcycles

There are approximately 24,000 Motorcycles registered in the province, about 0.05% registrations compared to personal LDV vehicles





Relative to the impact of the LDV and MHDV forecasts, the motorcycle electricity load impact (GWh) in 2038 will represent approximately **0.02% of the additional consumption** associated with EVs.

- As such, for the purposes of this study, the demand impact of electrifying motorcycles was not determined on an hourly demand basis.

5 .Other Vehicles

Off-Road Vehicles

Off-road vehicle refer to any motorized vehicle used for recreational travel on trails, non-highway roads, and cross-country travel over natural terrain. A significant portion of the market is made up of snowmobiles and ATVs.

BENEFITS

1. **Reduced noise:** Can improve driver experience
2. **Instant torque and minimal maintenance:** Most models have ample amounts of torque and require low operation and maintenance costs

ISSUES

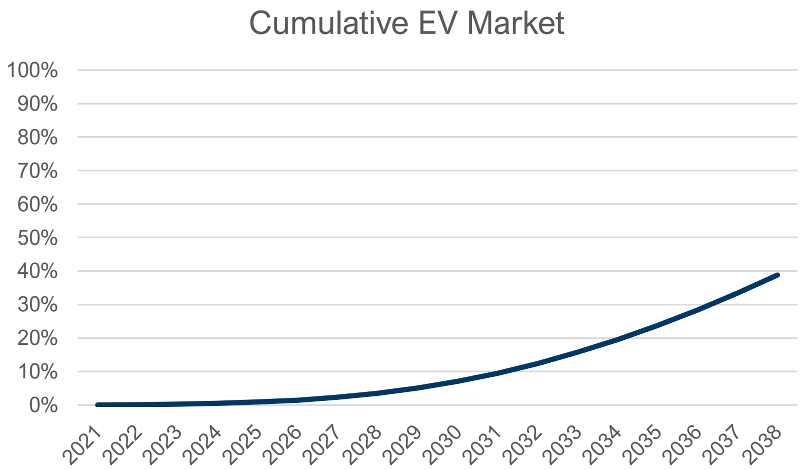
a. **Limited model availability:** Options are still limited
b. **Lack of rural charging stations**: While most charging will be at home, desire for chargers at staging areas
c. **Higher upfront costs:** Higher upfront costs than more widely available ICE models

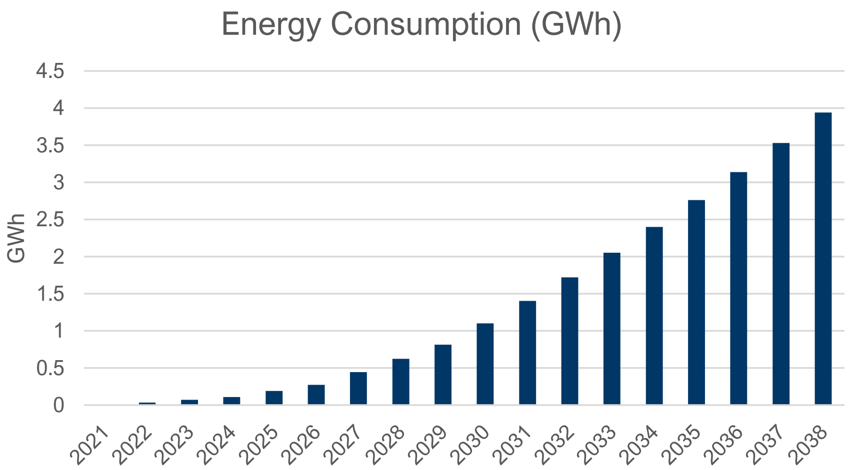
Taiga Electric Snowmobile

Electric off-road vehicles represent a very small portion of the current market; **less than 0.01% of annual sales.**

5 .Other Vehicles

Off-Road Vehicles





Relative to the impact of the LDV and MHDV forecasts, the off-road load impact (GWh) in 2038 will represent approximately **0.1% of the additional consumption** associated with EVs.

- As such, for the purposes of this study, the demand impact of electrifying motorcycles was not determined on an hourly demand basis.

5 .Other Vehicles

Micromobility

Micromobility is transportation using lightweight electric vehicles such as e-bicycles or e-scooters.

BENEFITS

1. **Reduced vehicle traffic and congestion:** Can reduce number of personal LDV trips
2. **Affordability:** While more expensive than non-motorized counterparts, offers a more affordable commuter option than a vehicle

ISSUES

a. **Legality and regulations on e-scooters:** Can't ride e-scooters on roads*

b. **Higher upfront costs than non-motorized versions:** Higher upfront costs than an average bike or scooter

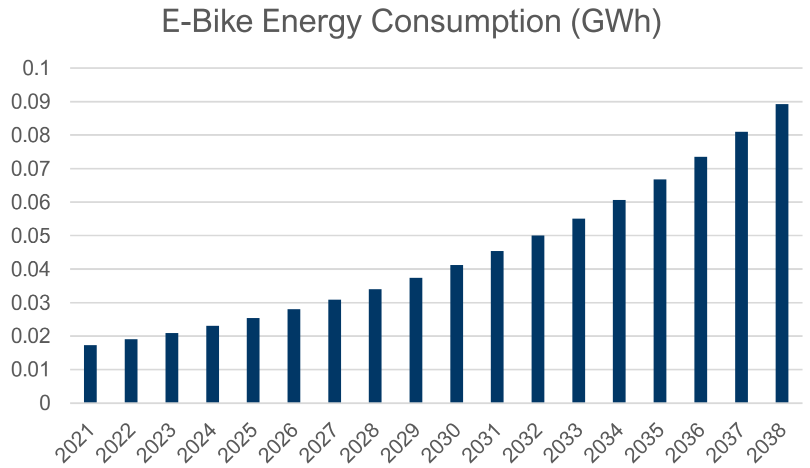
c. **Parking and storage**: Higher user concerns for secure parking and storage options

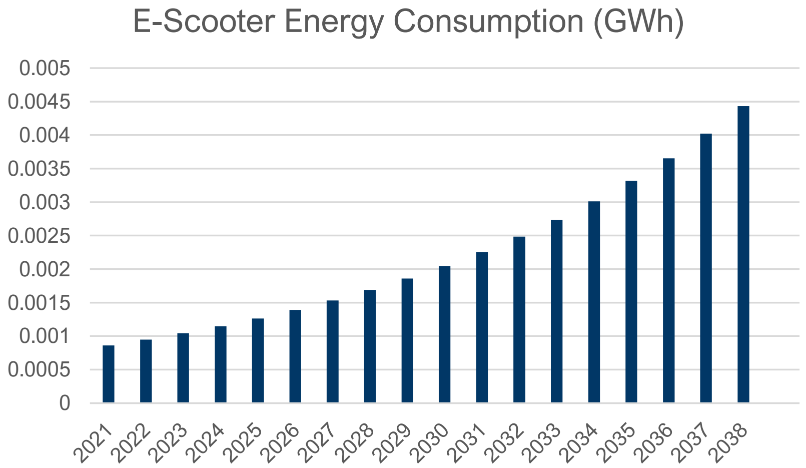
Aventon's Commuter Electric Bike

*Provincial amendments/proposed legislation are being considered by the province, such as Bill 21, that may accelerate micromobility pilots and adoption of e-bikes and e-scooters in the coming years.

5 .Other Vehicles

Micromobility





Relative to the impact of the LDV and MHDV forecasts, the micromobility load impact (GWh) in 2038 will represent approximately **0.0025% of the additional consumption** associated with EVs.

- As such, for the purposes of this study, the demand impact of electrifying motorcycles was not determined on an hourly demand basis.

6. GHG Emissions

6. GHG Emissions

GHG Emissions

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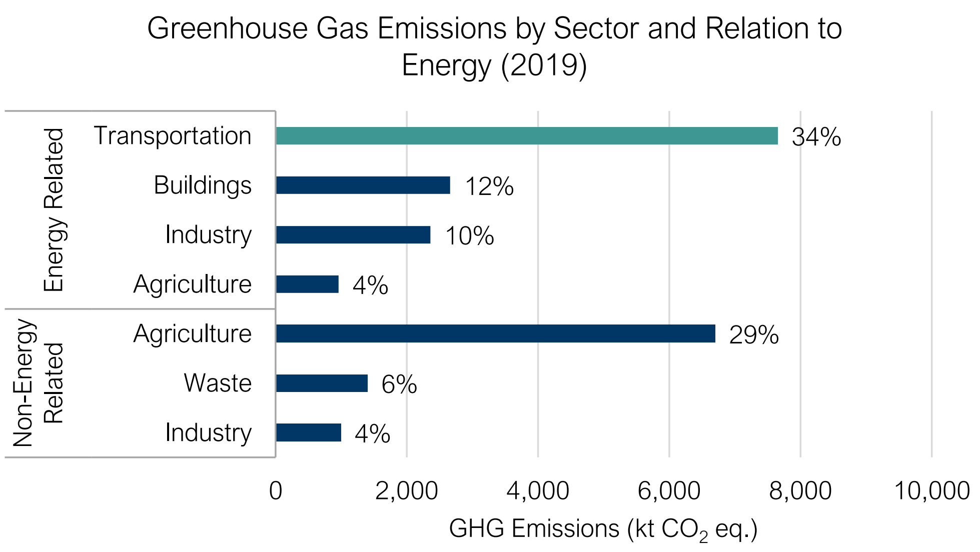
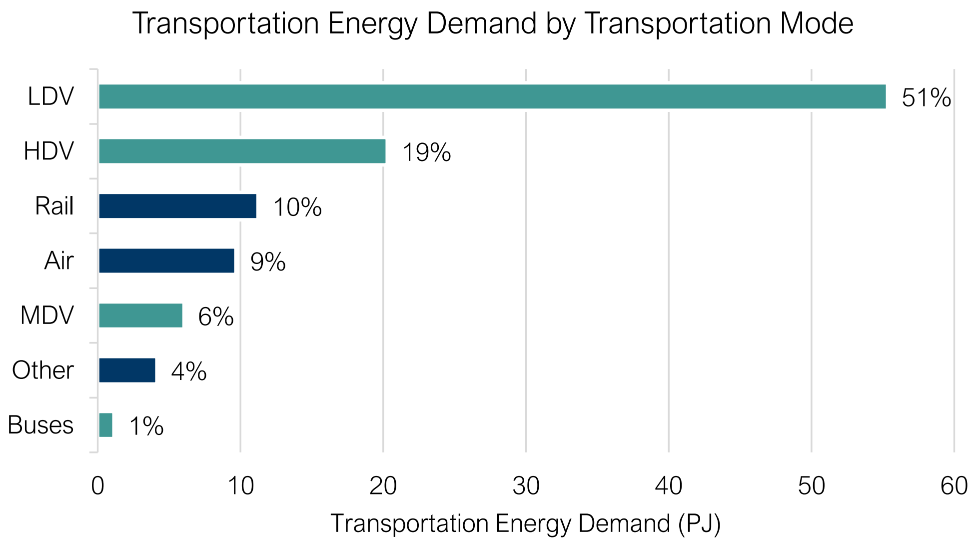
- **In 2019, Transportation represented 34% of the province's overall emissions (~ 7650 kt CO_2 eq.)**
- **Approximately 77% of energy use comes from on road transportation**





Source: Environment Canada. (2021). *National Inventory Report 1990-2019: Greenhouse Gas Sources and Sinks in Canada (Table A11–14).*
Source: Natural Resources Canada. (2020). *Comprehensive Energy Use Database (CEUD).*

6. GHG Emissions

GHG Emissions – Scenario Outputs

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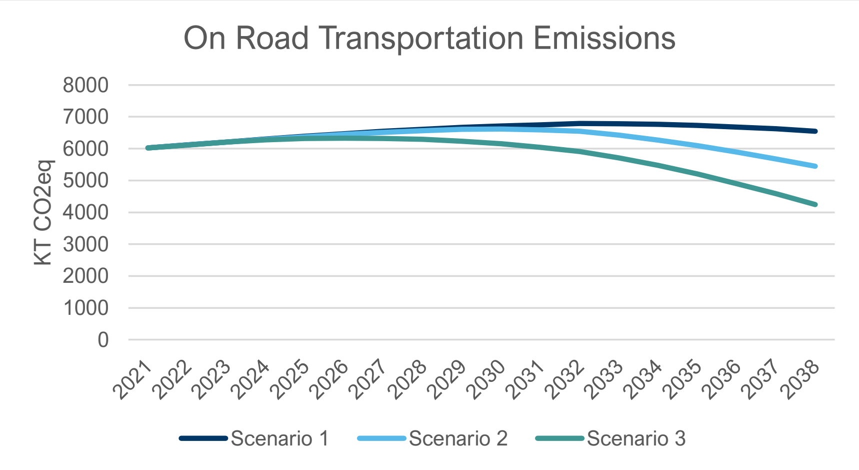
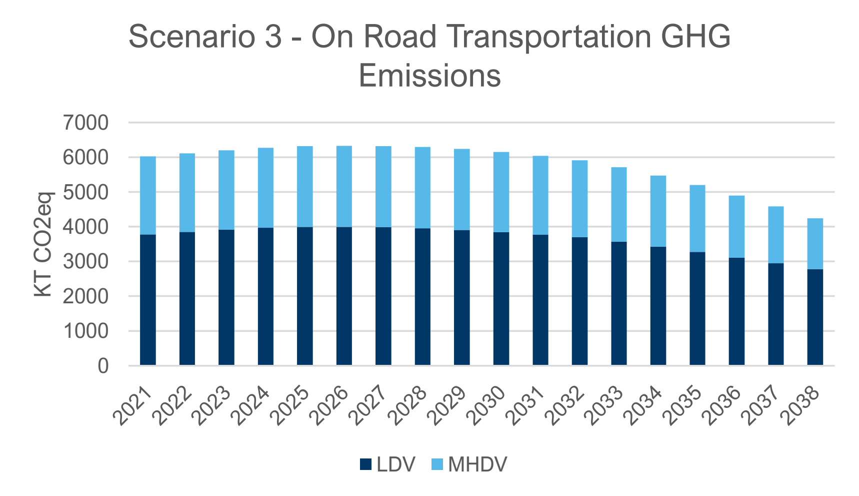
- **A key factor to reducing on road GHG emissions is the adoption of electric vehicles**
- **Scenario 3, the highest level of EV adoption modelled, leads to an additional reduction of 2,300 kt CO2eq emissions by 2038 (compared to scenario 1)**
- **Approximately 60% of emissions come from LDVs and 40% from MHDVs**



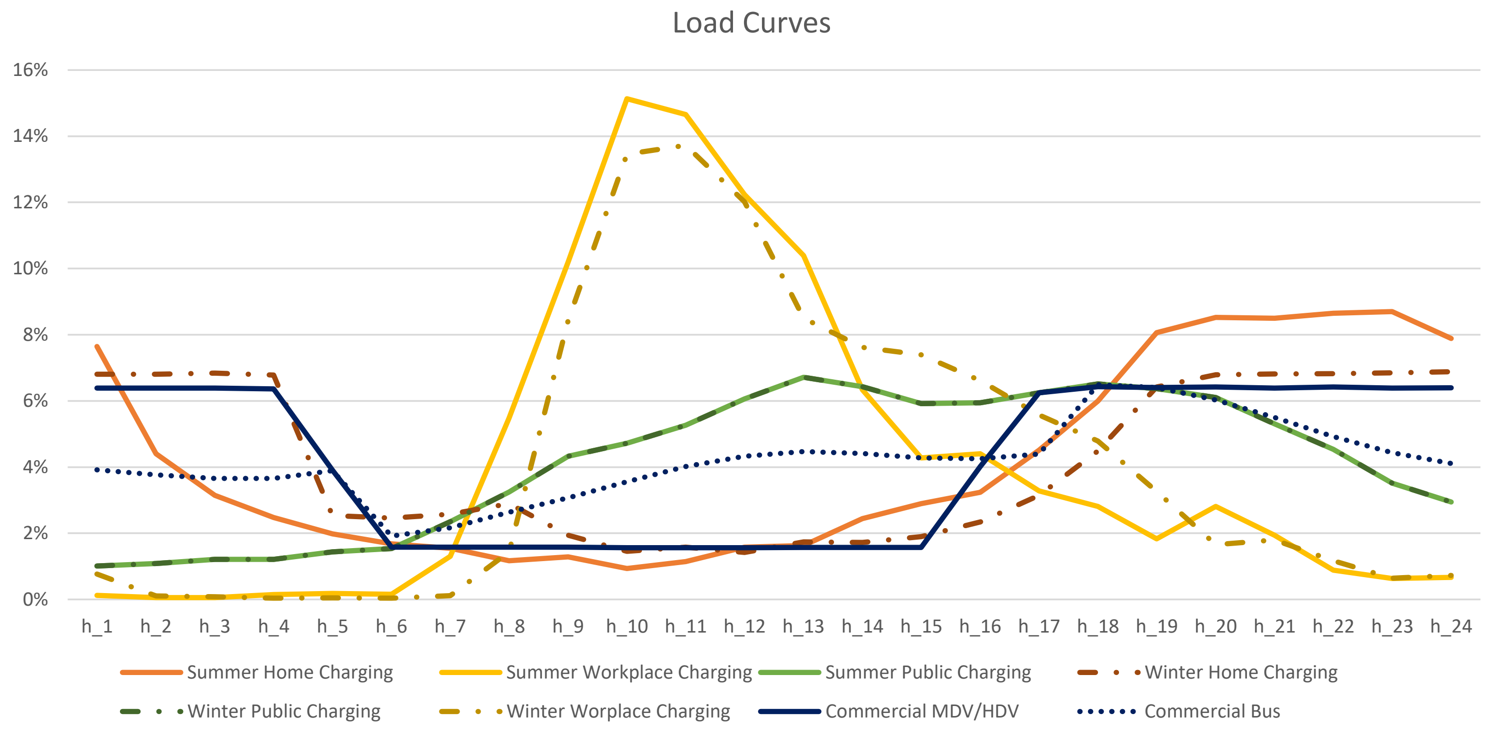


Appendix

Appendix

Normalized Load Curves

The normalized load curves below outline the anticipated hourly load by charging type for both summer and winter conditions. These curves are used to project hourly load.



Appendix

EVA Model: Methodology Overview

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EVA projects market adoption based on four key factors:

TECHNICAL

Assess the maximum theoretical potential for deployment
- Market size and composition by vehicle class (e.g. cars, SUVs, pickups)
- Model availability for each vehicle powertrain (e.g. ICE, PHEV, BEV)

ECONOMIC

Calculate unconstrained economic potential uptake
- Incremental purchase cost of PHEV/EV over ICE vehicles
- Total Cost of Ownership (TCO) (personal) or Internal Rate of Return (IRR) (commercial) based on operational and fuel costs

CONSTRAINTS

Account for jurisdiction-specific barriers and constraints
- Range anxiety or range requirements
- Public charging coverage, availability, and charging time
- Home charging access, others

MARKET

Incorporate market dynamics and non-quantifiable market constraints
- Use of technology diffusion theory to determine rate of adoption
- Market competition between vehicles types (PHEV vs. BEV)

Appendix

EVA Model: Technical

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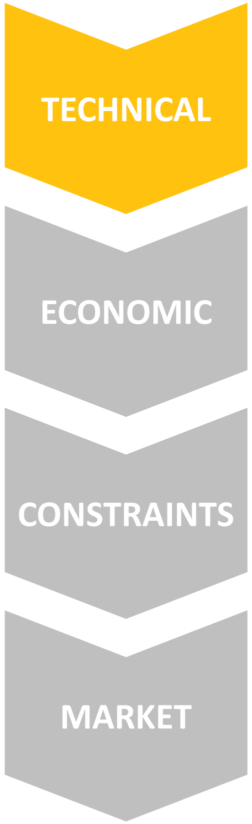


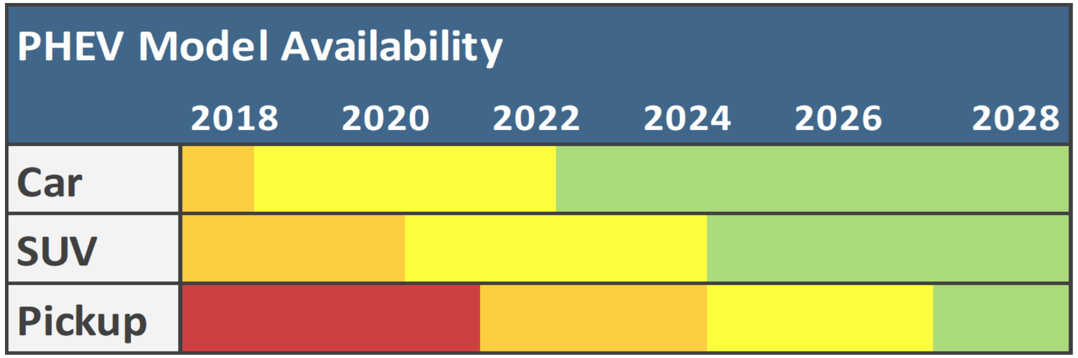
Assess the maximum theoretical potential for deployment

The model breaks down vehicles by segments (i.e. cars, SUVs, trucks, etc.) and powertrain (ICE, PHEV, BEV) with each class-powertrain being represented by an ***average*** vehicle option

Annual sales for each vehicle class represents 100% of attainable market

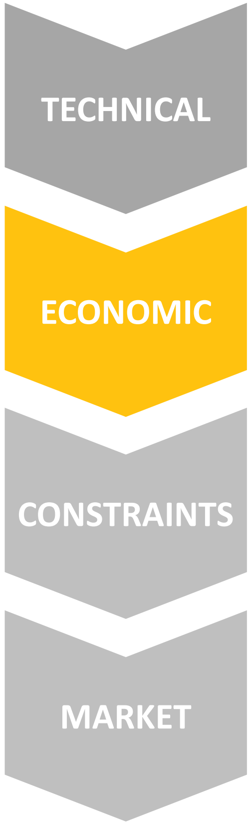
- Capture growth in forecasted vehicle sales and changing trends between vehicle segments

Model availability for each vehicle powertrain in each vehicle class is key



Appendix

EVA Model: Economic



Calculate unconstrained economic potential uptake

For each vehicle class and powertrain, vehicle cost is assessed bottom-up:

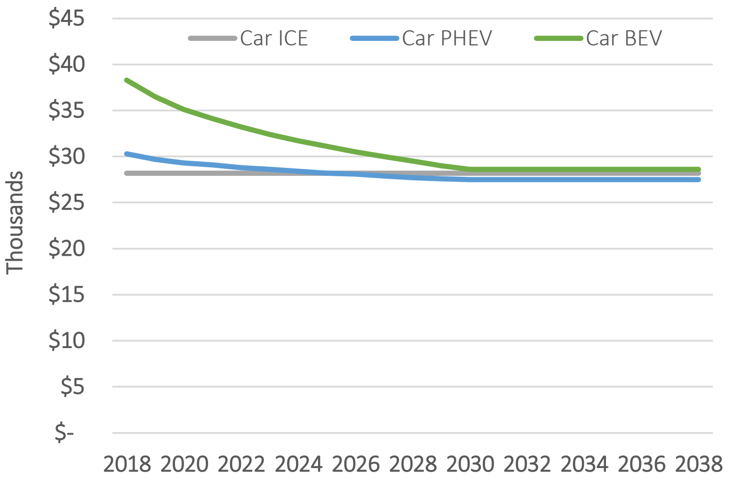
- Baseline vehicle cost
- ICE Powertrain cost
- Electric Powertrain Cost
- Battery Cost – based on BNEF and EIA forecasts[1]

For each vehicle class, Total Cost of Ownership (TCO) is based on

- Incremental Upfront cost of PHEV/BEV over ICE
- Lifetime operational cost savings incremental to ICE

Estimate unconstrained economic market potential based on identified willingness-to-pay from survey and research results

Sample EV cost decline scenario based on BNEF battery cost forecast



[1]Bloomberg New Energy Finance “EV Outlook 2018” and U.S. Energy Information Administration “Annual Energy Outlook 2018”

Appendix

EVA Model: Constraints

Account for jurisdiction-specific barriers and constraints

Market Constraining Factors include:

- Range anxiety: Capture the portion of the market that is constrained by the limited range of BEVs (does not apply to PHEVs)
- Home Charging Availability:
  - Given the importance of access to charging at home, EV adoption is constrained to the portion of the market where charging stations can readily be installed.
    - Building type (i.e. single-family vs. multi-family)
    - Percentage of each building type with access to charging (or driveways/dedicated parking)
  - Constraint can be reduced over time through targeted incentive programs and building code changes.

Appendix

EVA Model: Constraints

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TECHNICAL

ECONOMIC

CONSTRAINTS

MARKET

… *(cont'd)* Account for jurisdiction-specific barriers and constraints

Public Charging constraints are captured in two ways:

- **Coverage** captures the geographical coverage of charging infrastructure by contrasting the number of stations deployed to the required number of stations regionally considering:
  - *Number of stations required along key **highway corridors** across the region to alleviate charging barriers for potential EV adopters based on highway lengths and typical station spacing.*
  - *Number of stations required in **population clusters** (defined as population centers with > 10,000 people) to achieve at least one charging station per cluster and ensure that drivers have access to a charger within a reasonable radial distance.*
- **Charging Availability** captures the availability and power of charging ports and corresponding charging time
  - *Captured as EVs per Port ratio (for L2 and DCFC)*
  - *"Ideal" ratio calculated based on*
    - Population density in key population centers across the region
    - EV Density in key population centers across the region
    - Annual average temperatures
    - Home charging access
  - *Dynamic relationship with EVs of the road*

Station

Port

Appendix

EVA Model: Market

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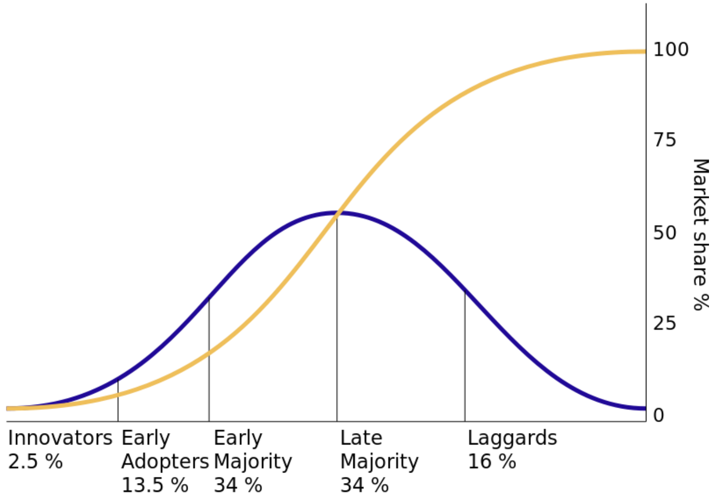
- TECHNICAL
- ECONOMIC
- CONSTRAINTS
- **MARKET**

Incorporate market dynamics and non-quantifiable market constraints

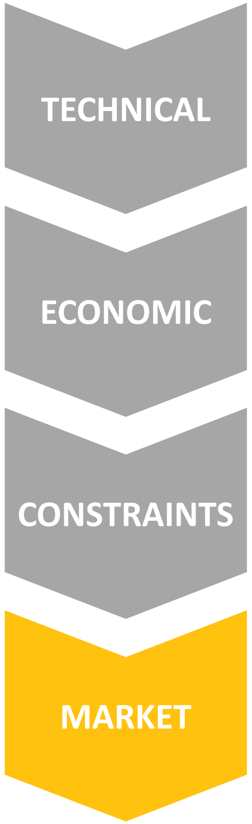
Estimate rate of market adoption using technology diffusion theory

- Captures the degree to which the market adopts new innovative technologies over time
- Accounts for the demographics and composition of market through segmenting potential adopters into five categories that vary by motivation for adoption (environmental, economic, etc.), willingness to take risks, technology understanding and other factors.
- Accounts for social interactions and public awareness (or lack of) and impact of programs on increasing awareness.



Appendix

EVA Model: Market



… *(cont'd)* Incorporate market dynamics and non-quantifiable market constraints

PHEVs and BEVs are assumed to compete for the same market

- After comparing technical, economic, constrained and market potential of both technologies, a probabilistic function is used to assume a portion of the market will not be rational and will adopt the inferior of the two options, considering historical trends in the market.
- Certain policies/programs can have the effect of shifting the market from one technology to the other without necessarily impacting overall EV market share.

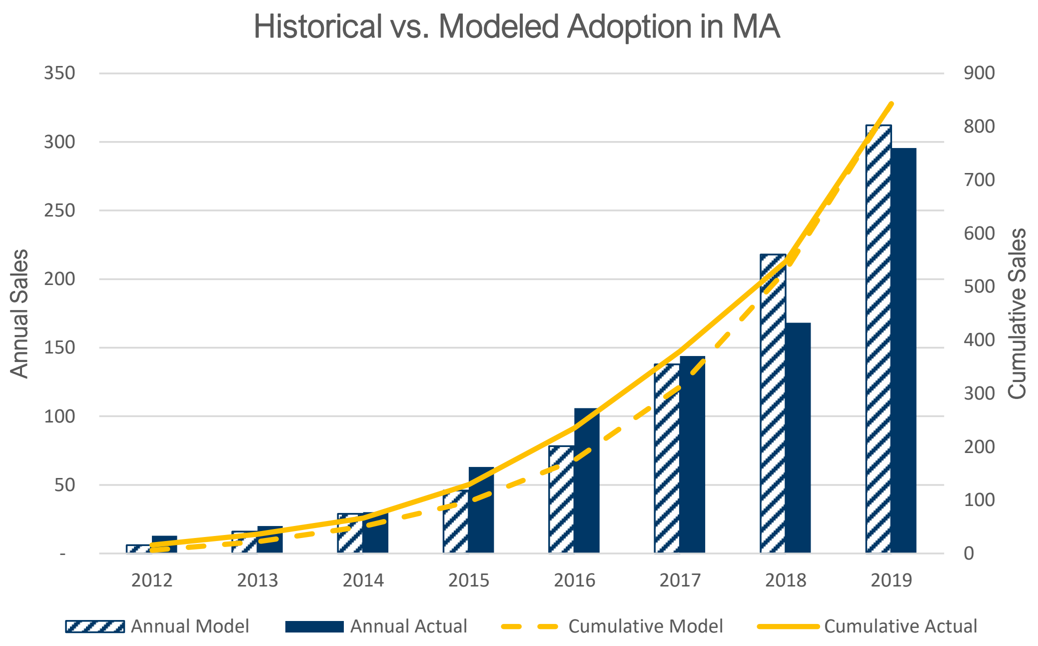
Appendix

EVA Model: Calibration

To capture the characteristics of the local market, historical inputs on vehicle sales, energy prices, vehicle costs, incentive programs and infrastructure deployment are used to benchmark the model to historical adoption in the jurisdiction and calibrate key model parameters to local market conditions, including:

- Technology diffusion (the rate at which a new technology spreads in a given market/jurisdiction),
- Optimal public charging availability levels (captured through an "optimal" EV/port ratio for Level 2 and DCFC infrastructure),
- The relative weighting of upfront costs versus TCO that customers consider in purchase decisions,
- Coefficient of competition between BEVs and PHEVs

Key parameters are adjusted to obtain the closest fit between actual and modeled cumulative adoption as week as representative trends of annual adoption and year-to-year growth



Appendix

EVA Model: Passenger Vehicles vs. Commercial Fleets

Consideration and treatment of key barriers in the model for personal vehicles and commercial fleets reflects key differences in decision-making between the segments.

Barrier	Personal LDV	Commercial LDV	Commercial MHDV
Technical	Base vehicle assumed to be **gasoline ICEV**		Base vehicle assumed to be **diesel ICEV**
Economic	Upfront cost and Total Cost of Ownership (TCO)	Based **on Internal Rate of Return (IRR)** of the vehicle's upfront and operational costs over its lifetime.	
Constraints	• Range Anxiety • Charging Time • Public Charging Coverage • Public Charging Availability • Home Charging Access	• Range Requirement • Charging Time Requirement • Public Charging Coverage	• Range Requirement • Charging Time Requirement
Market	**Competition** between PHEV and BEVs		**No competition** between PHEVs and BEVs (i.e. all assumed to be BEVs)

* The study does not model commercial light-duty vehicle segment distinctly. The analysis of light-duty vehicles focuses on the personal vehicle market (the majority light-duty vehicle market) and assumes that the commercial vehicle market follows a similar trajectory,

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Manitoba Hydro Demand Response Market Potential Study

Volume I – Report

Prepared for:

Manitoba Hydro

Efficiency Manitoba

Submitted to:

Efficiency Manitoba

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About Dunsky

Founded in 2004, Dunsky supports leading governments, utilities, corporations and non-profits across North America in their efforts to **accelerate the clean energy transition**, effectively and responsibly.

Working across buildings, industry, energy and mobility, we support our clients through three key services: we **quantify** opportunities (technical, economic, market); **design** go-to-market strategies (plans, programs, policies); and **evaluate** performance (with a view to continuous improvement).

Dunsky is proudly Canadian, with offices and staff in Montreal, Toronto, Vancouver, Ottawa and Halifax.

Contents

List of Figures

List of Tables

List of Acronyms

DLC	Direct load control
C&I	Commercial and industrial
CPP	Critical peak pricing
DR	Demand response
DSM	Demand side management
MPS	Market potential study
DROP	Dunsky's Demand Response Optimization Potential (DROP) model
PACT	Program administrator cost test

Executive Summary

The demand response (DR) study assesses the potential for peak-hour demand savings for possible future DR programs operated by Manitoba Hydro.[1] This includes DR program potential from equipment paired with controls, load curtailment strategies applied in industrial and commercial facilities, and dynamic rates, all of which are assessed based on their ability to reduce loads during the Manitoba Hydro system-wide winter peak demand hours. The study covers the fifteen years spanning fiscal years 2023/24 to 2037/38. For brevity, fiscal years are referred to by the starting year (e.g., 2023/24 is referred to as 2023).

DR potential is assessed using Dunsky's Demand Response Optimized Potential (DROP) model, which determines potential demand reductions during Manitoba Hydro's peak. Achievable potential is assessed under **three** scenarios corresponding to varied DR program approaches and levels of investment. Figure E-1 provides descriptions of each scenario. Further details on the specific program scenarios and their parameters are presented in Volume II.

Figure E-1. Demand Reduction Achievable Scenario Descriptions

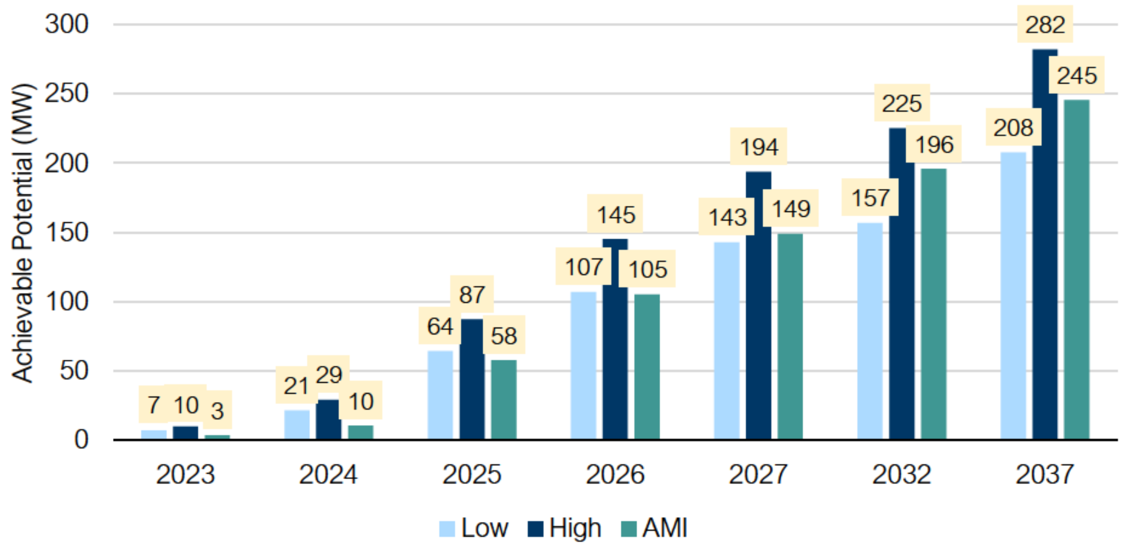
Low	Applies **standard incentives**, in-line with the measure-specific incentive levels seen in other jurisdictions that have established DR programs.
High	Tests the ability to **expand participation by increasing incentives** while maintaining cost-effectiveness.
AMI	Considers the availability of **advanced meter infrastructure** (AMI)**-enabled dynamic rates** in the residential and commercial sectors in combination with 'Low scenario' level incentives for other, non-rate measure types.

DR Program Results

Across the three scenarios, DR peak savings reduction potential is estimated to range between 208 and 282 MW in 2037 as shown in Figure E-2**Error! Reference source not found.**.

Figure E-2. DR Achievable Potential by Scenario and Year

[1] In all cases in this report, the annual peak demand refers to the hour in the year that exhibits the highest system peak demand in MW. It is assessed on a system-wide basis, not accounting for local constraints across the transmission and distribution system.



Under the Low scenario, DR peak savings reduction potential is estimated to grow from 7 MW in 2023 to 208 MW in 2037, which represents approximately 0.2% of Manitoba Hydro's peak demand in 2023, 3.5% in 2037. Both the High and AMI scenarios show an increase in achievable potential over the Low scenario levels, reaching 282 MW and 245 MW in 2037, respectively, which represents 4.7% and 4.1% of Manitoba Hydro's system-wide peak demand in that year.

At a high-level, the scenario analysis indicates that substantial peak savings can be achieved through implementation of demand response programs in Manitoba Hydro's service territory. The savings that can be achieved vary according to program strategy, which also has implications for cost-effectiveness as described in the sections that follow.

Table E-1 summarizes the achievable potential in 2027 for each of the achievable scenarios, as well as the annual program costs and the average supply cost. Annual costs increase over the study period programs grow, reaching $15.3 million in 2037 under the Low scenario and $34.0 million under the High scenario. Without accounting for any AMI infrastructure costs, program spending is $12.4 M under the AMI scenario in 2037. Over the course of the study period, avoided capacity costs vary between $119/kW and $153/kW. These results indicate that DR program peak reductions are often more cost-effective than procuring additional peak capacity. These avoided cost values are system-wide, however – actual avoided costs will vary by time and location on Manitoba Hydro's grid.

Table E-1. DR Potential and Annual Spending in 2037 by Scenario

Scenarios	Low	High	AMI
Achievable Potential	208 MW	282 MW	245 MW
Portfolio Annual Spending	$15.3 million	$34.0 million	$12.4 million*
Average Supply Cost	$90/kW	$134/kW	$32/kW

*Not accounting for any investment in AMI infrastructure.

Key Takeaways

Based on the findings in this study, the following key takeaways emerge:

There is significant opportunity to reduce Manitoba Hydro's peak loads using demand response.

Under the programs modeled for this study, the achievable peak load reduction in Manitoba Hydro's service territory could reach between 208 MW and 282 MW (Low to High scenario range) in 2037, representing up to 4.7% of projected system-wide peak load in that year.

Programs could achieve significant peak savings by focusing efforts on a limited number of measures with high potential and high cost-effectiveness.

Interruptible rates for large C&I customers and C&I manual curtailment programs could be promising initial program offerings. Both program types offer high potential savings and positive cost-effectiveness. As a next step, the potential found in the C&I sectors should be verified, however. Because Manitoba Hydro customer-specific industrial and commercial data was limited, conservative assumptions from other jurisdictions informed potential estimates. Customer peak load reduction potential and willingness to-participate in DR programs should be assessed as part of the program design process.

Over time, evening peak loads are expected to increase as a result of DER adoption. Growing EV charging loads will increase evening peaks, but managed EV charging programs can shift charging overnight and will be an important addition to Manitoba Hydro's DR portfolio in the later years of the study. These programs will take time to ramp up, as Manitoba Hydro will need to invest in smart charging equipment as customers adopt vehicles to secure their participation in smart charging programs.

A residential DLC program that features Wi-Fi thermostats is another high potential area for initial DR offerings. These programs can be Bring Your Own Device (BYOD), which leverage existing customer equipment, or use a direct-install program approach, where utilities purchase and install the equipment required to achieve savings in customer homes and businesses. BYOD programs are less expensive for the utility but are limited by existing market uptake of relevant measures. Leveraging measures that have been installed through other program offerings – for example, by programs designed to capture efficiency savings – can maximize BYOD opportunities. Initial modeling finds that WiFi thermostat cost-effectiveness is limited when only considering efficiency savings, however, indicating that efficiency program investments in thermostats may also be limited.[2] Coordinating efficiency and demand response programs would ensure that WiFi thermostats will generate both energy and peak demand savings, maximizing the benefits of these measures and improving cost-effectiveness. Residential water heaters can also be offered through a residential DLC program. This measure has high achievable potential under all scenarios, and the ability to reduce the load for several hours without impacting the participant's level of comfort.

If AMI is installed in Manitoba, it could be leveraged to achieve highly cost-effective savings through dynamic rates programs.

If AMI infrastructure becomes available in Manitoba Hydro's service territory, dynamic rates will offer highly cost-effective DR opportunities. Dynamic rates are limited in their deployment, however, because they can

---

[2] WiFi thermostats were modeled in the Efficiency Manitoba Market Potential Study, conducted in parallel to the Manitoba Hydro DR Potential study.

lead to new peaks. They should be combined with other, adaptable measure types that can be used at multiple times of the day and staggered to offset the peak-shifting impacts of rates. Interruptible rate, C&I curtailment, and residential DLC programs would complement a dynamic rate program, offering considerable achievable savings that are adaptable and cost-effective.

The results in this study are in-line with results from similar studies in other winter-peaking jurisdictions.

Table E-2 below benchmarks the achievable DR potential in this study against results in other relevant winter-peaking jurisdictions. Overall, these results show that the results are approximately in-line with the savings estimated elsewhere. Generally speaking, jurisdictions with higher avoided costs are expected to have greater savings potential. Higher avoided costs result in larger benefits associated with each kilowatt saved, improving cost-effectiveness. Results are highly dependent on the characteristics of customer loads, however, so comparisons between jurisdictions should be treated with a high degree of uncertainty; results are especially sensitive to the load patterns of C&I customers, given their potential to vary considerably by jurisdiction.

Table E-2. Benchmarking the Achievable DR Potential to Other Winter-Peaking Jurisdictions

	Manitoba (Study Published in 2022)	PEI (Study Published in 2021)	Newfoundland & Labrador (Study Published in 2020)	Pudget Sound Energy (Study Published in 2017)
Portion of Peak Load	3.5% - 4.7% (2037)	3.1% - 8.8% (2030)	10.4% - 12.0% (2034)	3.7% (2037)
Avoided Costs	≈$150 / kW	≈$203 / kW	≈$430 / kW	≈$290 / kW

Overall, the results of this study indicate that there is considerable demand response program potential in Manitoba Hydro's service territory. As a next step, Manitoba Hydro-specific program strategies can be developed through detailed program design.

1. Overview

1.1 Introduction

The following report presents the results of the electric demand response (DR) potential analysis conducted on behalf of Manitoba Hydro. The demand response (DR) study assesses the potential for peak-hour demand savings for DR programs operated by Manitoba Hydro.[3] This includes DR program potential from equipment paired with controls, load curtailment strategies applied in industrial and commercial facilities, and dynamic rates, which are assessed based on their ability to reduce loads during the Manitoba Hydro system-wide winter peak demand hours. The study covers the fifteen years spanning fiscal years 2023/24 to 2037/38. For brevity, fiscal years are referred to by the starting year (e.g., 2023/24 is referred to as 2023).

This report is structured into two volumes. This volume (Volume I) focuses on presenting the study results, while Volume II presents the study's supporting data, inputs, and methodological approach specific to the DR analysis. This study was conducted in conjunction with the 2023/38 Efficiency Manitoba Demand Side Management Market Potential Study (MPS), which is documented in a separate report, and the DR analysis leverages many inputs and assumptions from the MPS. For common inputs and assumptions shared with the MPS, please refer to the MPS report.

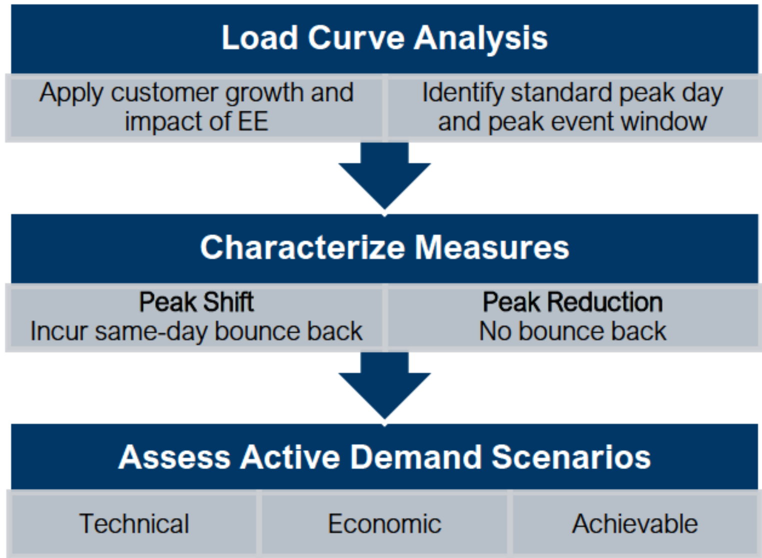
1.2 Approach

DR potential is assessed using Dunsky's Demand Response Optimized Potential (DROP) model, which determines potential demand reductions during Manitoba Hydro's peak. The strength of DROP resides in its consideration of two specific qualities of DR that differentiate it from conventional energy efficiency potential assessments: the dependency of DR savings on interactions among measures and the load curve, and the fact that many DR measures offer little to no direct economic benefits to customers. A more detailed description of the DROP model and methodology can be found in Volume II.

Figure 1-1 presents an overview of the steps applied to assess the DR potential in this study.

[3] In all cases in this report, the annual peak demand refers to the hour in the year that exhibits the highest system peak demand in MW. It is assessed on a system-wide basis, not accounting for local constraints across the transmission and distribution system.

Figure 1-1. DR Potential Assessment Approach



The first step in the analysis is to develop a develop a standard peak day load curve adjusted to account for projected load growth and DSM program impacts over the study period.[4] Establishing a standard peak day curve allows the model to assess each measure's net reduction of the annual peak, considering that the new annual peak may occur on a different day or hour than the initial peak due to the way that DR measures alter the utility load curve. This load analysis is described in more detail in the 'Load Analysis' section that follows.

The standard peak day utility load curve is used to characterize measures and to assess measure-specific peak demand reduction potential. The shape of the curve has an important impact on the measures pursued and how much DR potential can be captured by those measures. The optimizer function is used to quantify this DR potential, considering interactions among measures and with the curve to determine the overall net impact on annual peak demand. The box on the following page provides a description of each type of potential calculated as part of the study – technical, economic, and achievable.

[4] Impacts from the Efficiency Manitoba Market Potential Study, conducted in parallel to the Manitoba Hydro DR Potential study, were included in the load growth projections. This included forecasted impacts from energy efficiency, fuel switching, behind-the-meter solar PV, and electric vehicles.

Technical, Economic, and Achievable DR Potential

Technical potential is estimated as the total possible coincident peak load reduction for each individual measure multiplied by the saturation of the measure or opportunity in each market segment.

Economic potential is estimated as the net demand reduction possible from each individual measure when assessed against the utility load curve. It accounts for the difference between the utility peak load before and after the measure is applied, examining the 24-hour peak day curve and the 8,760 annual hourly curve and accounting for individual measure bounce-back impacts or peak time shift impacts.

Depending on the shape of the peak day curve these impacts may create new peaks. For example, a load curve with a relatively high/distinct peak over a few hours (a) offers more opportunity to reduce and shift load without creating a new peak whereas a flatter curve (b) requires targeted measures and can limit DR potential.


(a)


(b)

The measures are then screened against the Program Administrator Cost Test (PACT), and only those that pass the threshold are retained for inclusion in the achievable potential scenarios.[5]

Achievable potential is assessed under three scenarios by applying mixes of cost-effective measures under varying program designs, giving priority to the most cost-effective measures first. The DR potential is assessed for each year, accounting for existing programs from previous years as well as new measures or programs starting in that year. Unlike many efficiency measures, the DR peak savings only persist as long as the program is active. For the new programs, ramp-up factors are applied to account for the time required to recruit participants.

To ensure that the combined achievable potential results are truly additive in their ability to reduce annual peak loads, combinations of programs are assessed against the hourly load curve to capture inter-program interactions that could affect the net impact of each program.

[5] Only measures that pass the screening threshold of 1.0 are included in the achievable potential.

The technical and economic potential represent a significant portion of the overall load; however, this potential is not considered to be additive across all measures since some measures can target the same end use. For example, the same cooling load can be targeted by a smart thermostat used to control a central HVAC system or by an energy storage device. For this reason, technical and economic potential results are largely theoretical and of less practical use for understanding DR potential in a given jurisdiction. This report therefore focuses on the achievable potential results. Additional information on the technical and economic potential is provided in Volume II.

1.3 Achievable Scenarios

Achievable potential is assessed under **three** scenarios corresponding to varied DR program approaches and levels of investment. Figure 1-2 provides descriptions of each scenario. Further details on the specific program scenarios and their parameters are presented in Volume II.

Figure 1-2. Demand Reduction Achievable Scenario Descriptions

Low	Applies **standard incentives**, in-line with the measure-specific incentive levels seen in other jurisdictions that have established DR programs.
High	Tests the ability to **expand participation by increasing incentives** while maintaining cost-effectiveness.
AMI	Considers the availability of **advanced meter infrastructure (AMI)-enabled dynamic rates** in the residential and commercial sectors in combination with 'Low scenario' level incentives for other, non-rate measure types.

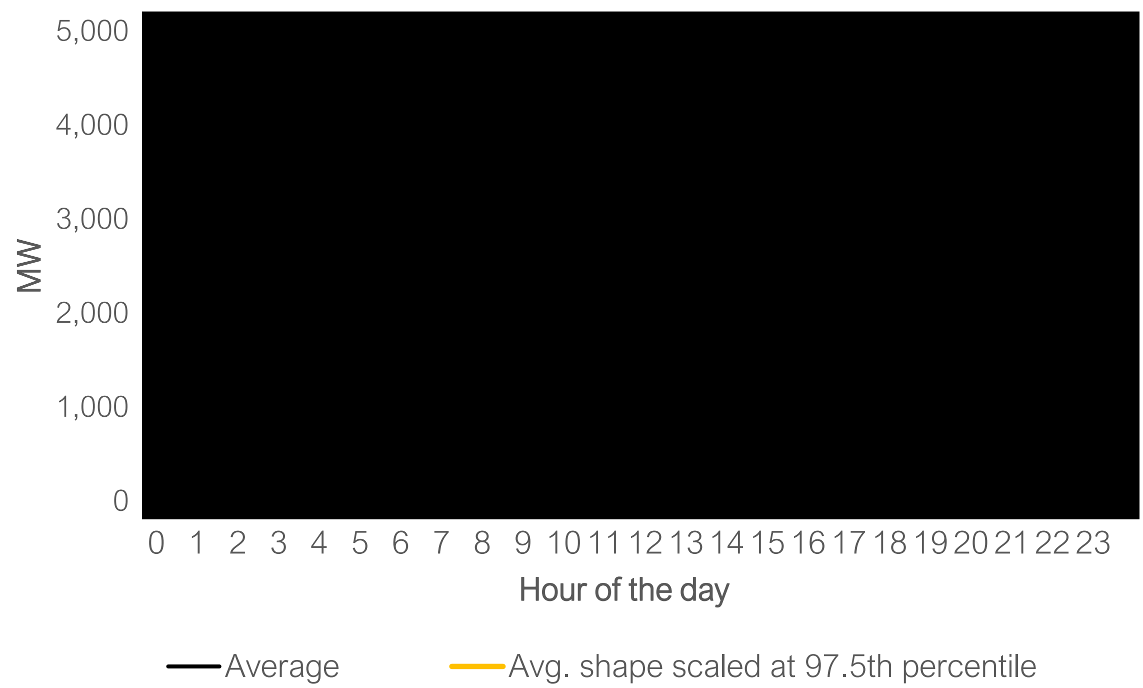
The Low scenario provides an indication of the DR potential Manitoba Hydro could achieve using incentive levels that are commonly seen in programs in other jurisdictions. The High scenario provides an indication of how much additional potential Manitoba Hydro could achieve, above-and-beyond Low scenario levels, through increasing incentive spending while maintaining cost-effectiveness.

Finally, the advanced meter infrastructure (AMI) scenario provides an indication of how leveraging AMI for DR purposes could impact achievable DR potential and cost-effectiveness by adding dynamic rates to the existing Low scenario program portfolio. The study assumes that AMI deployment would begin in 2025/26 after the completion of a successful pilot program and development of deployment strategy in 2023/24 and 2024/25. The AMI rollout is then assumed to occur over three years in equal increments with 33% of the customer base receiving AMI equipment per year.

1.4 Load Curve Analysis

The first step in the DR potential analysis is to define the 24-hour **standard peak day load curve.** Using historical Manitoba Hydro hourly load data, the standard peak day load curve for the province-wide electric system is defined by averaging the load shape of the top ten peak days in each of the six years of historical hourly load data provided. For each year, the ten highest peak days are isolated, generating a sample pool of sixty peak days. Through statistical analysis of these peak days, the average MW value is calculated for each hour of the day across all sample days. Collectively, the average hourly values establish the shape of the load curve (black line, Figure 1-3). This study aims to assess the impacts that can be achieved against the *largest* peaks seen on the system, however. Across all hourly MW values, the value in the 97.5th percentile is calculated.[6] The average load curve shape is then scaled to hit this value (yellow line, Figure 1-3), generating the standard peak day curve.

Figure 1-3. Load Shape Analysis with Percentile Distribution and Scaled Average Shape (MW)



For this study, the load curve analysis shows peaks in the morning and evening. At the beginning of the study, the peak hour (i.e., the hour with the highest load during the 24-hour standard peak day) is from 8:00 to 8:59. The analysis finds that **Manitoba Hydro's system has a relatively flat load curve with an morning peak as well as a second peak in the evening**, which is not uncommon in winter-peaking jurisdictions with a significant penetration of electric heating. The duration and steepness of the peak curve indicate that measures with significant bounce-back or pre-charge effects close to the peak will likely have limited potential to reduce the annual peak as they risk creating new peaks by shifting load from one hour to another. In addition, the shape of Manitoba Hydro's peak day load curve suggests that targeting DR measures that can be used to address an evening and/or morning peak would be beneficial for the province.

Over the course of the study period, however, the peak hour is expected to shift due to the impact of forecasted distributed energy resource (DER) adoption on the system load curve shape and magnitude

[6] This study aims to assess the potential for demand savings against a representative peak value. Therefore, the largest value was not taken in order to avoid capturing infrequent, non-typical peaks.

including measures adopted via DSM programs (e.g., energy efficiency, fuel switching, and distributed generation) and electric vehicle adoption.

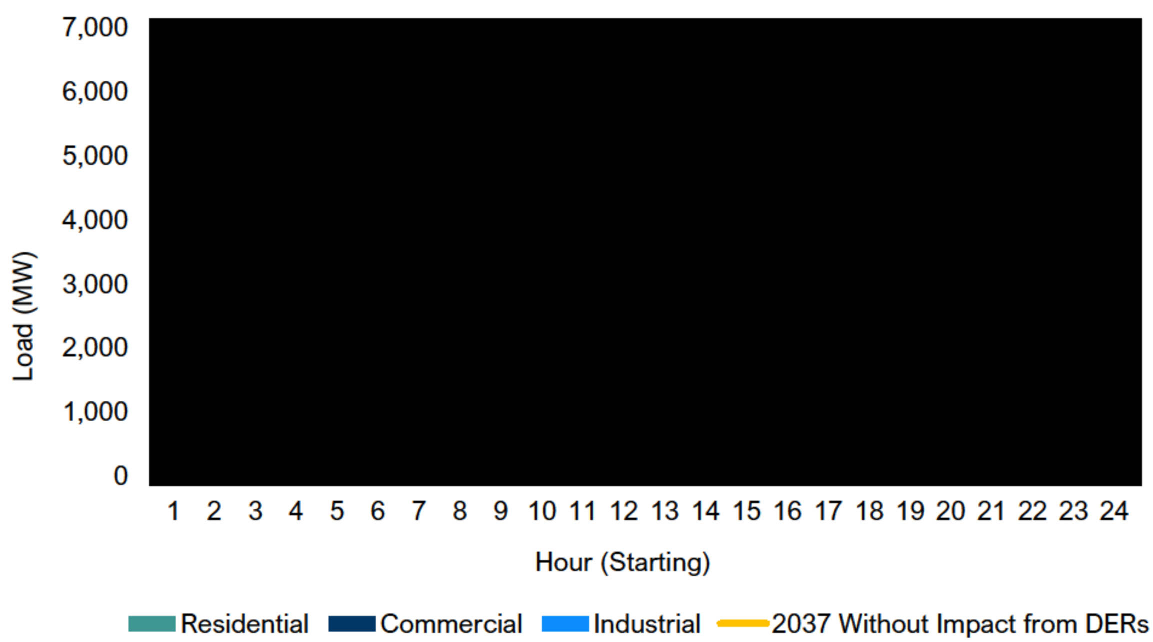
As the study progresses, these DERs increase the evening peak relative to the morning peak, shifting the peak hour from 19:00 to 19:59. The evening peak is first forecasted to supersede the morning peak in the year 2029, then continue to grow through to the end of the study period. However, it should be noted that load forecasting is inherently uncertain; because the morning and evening peaks are already close in magnitude, the evening peak could surpass the morning peak in earlier (or later) than projected.

The table below **Error! Reference source not found.** provides the peak forecast and peak hour for a selection of years, while the figure below includes the forecasted 2037 load curve, which is characterized by a higher evening peak.

Table 1-1. Peak Forecast and Peak Hour by Study Year

Year	Peak Forecast (MW)	Peak Hour
2023	4,087	8:00-8:59
2027	4,198	8:00-8:59
2033	4,981	19:00-19:59
2037	6,006	19:00-19:59

Figure 1-4. Load Curve by Sector in the year 2037 Before and After Considering Impacts from DERs



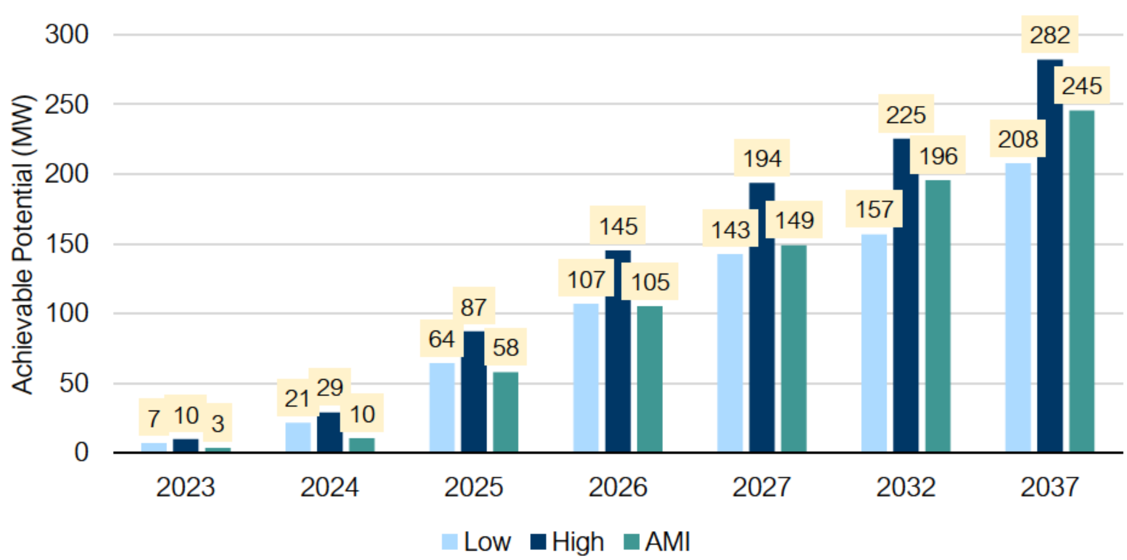
2. Results

The following section presents the achievable potential results for each modeled scenario. These results represent the combined peak load reduction from all cost-effective programs assessed against the standard peak day load curve, accounting for interactions among measures and ramp-up schedules for new programs. A description of each measure and program along with the measure's technical and economic potentials in each market segment are provided in Volume II.

2.1 Achievable Potential

Across the three scenarios, DR peak savings reduction potential is estimated to range between 208 to 282 MW in 2037 as shown in Figure 2-1.

Figure 2-1. DR Achievable Potential by Scenario and Year



Under the Low scenario, DR peak savings reduction potential is estimated to grow from 7 MW in 2023 to 208 MW in 2037, which represents approximately 0.2% of Manitoba Hydro's peak demand in 2023, 3.5% in 2037. Both the High and AMI scenarios show an increase in achievable potential over the Low scenario levels, reaching 282 MW and 245 MW in 2037, respectively, which represents 4.7% and 4.1% of Manitoba Hydro's system-wide peak demand in that year.

At a high-level, the scenario analysis indicates that substantial peak savings can be achieved through implementation of demand response programs in Manitoba Hydro's service territory. The savings that can be achieved vary according to program strategy, which also has implications for cost-effectiveness as described in the sections that follow.

2.1.1 Low Scenario

The Low scenario is designed to align with the programs, measure mixes, and incentive levels commonly seen in established DR programs in other jurisdictions.

Figure 2-2 shows how the 208 MW of achievable potential in 2037 under the Low scenario breaks down among the programs. In 2037, 94% of potential comes from three programs – residential Direct Load Control (DLC), interruptible rates, and manual Commercial and Industrial (C&I) curtailment programs. Potential from the remaining programs is limited primarily due to the relatively low avoided capacity costs, which limits the cost-effectiveness of several measures.

Peak demand reduction potential estimated for the interruptible rate program carries a higher degree of uncertainty as compared to other programs as the program is dependent on the willingness and ability of a small subset of Manitoba Hydro's largest customers to generate peak savings. Given high per customer potential, a single additional participant can lead to considerably higher savings while each customer not willing to participate can significantly reduce potential savings. The assumptions used in this analysis, including participation rates and curtailable demand at peak by industrial type and align with the performance seen in similar programs in other jurisdictions (see the detailed result workbook for more detail). However, to validate these findings for the Manitoba context, direct engagement with large customers would be required, which was outside the scope of this analysis.

Figure 2-2. DR Low Scenario Achievable Potential, 2037 – Breakdown by Program

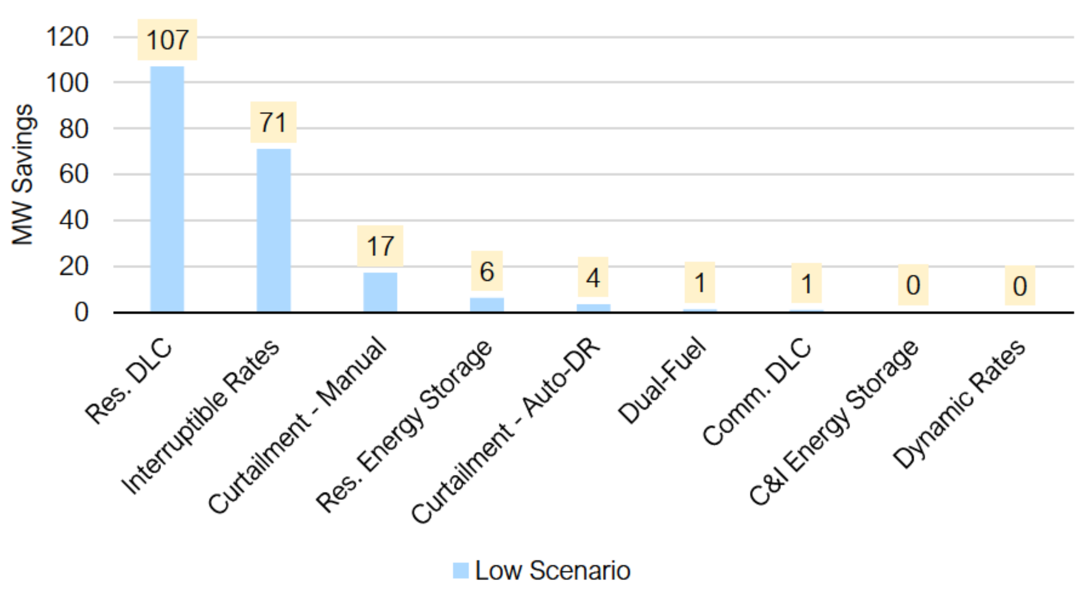


Table 2-1 shows the achievable potential measure-level savings in 2037 and the program associated with each measure.

Table 2-1. DR Low Scenario – Top Measures, 2037

Measures	Program	Achievable Potential 2037 (MW)
Interruptible Rates	Interruptible Rates	71
Electric Vehicle Smart Charger Control	Residential DLC	51
Wi-Fi Thermostat Connected to Central Heat	Residential DLC	23
C&I Manual Curtailment	Curtailment - Manual	18
Resistance Storage Water Heater	Residential DLC	18
BYOD Wi-Fi Thermostat Connected to Baseboards	Residential DLC	7
BYOD Wi-Fi Thermostat Connected to Central Heat	Residential DLC	5
Thermal Energy Storage	Residential Energy Storage	5
C&I Auto-DR Curtailment	Curtailment – Auto-DR	2
Battery Energy Storage	Residential Energy Storage	1
All Other Measures	N/A	5
Total*	N/A	**208**

*Total may not sum due to rounding.

The savings from the programs with the largest potential, interruptible rates, residential DLC, and C&I manual curtailment, are primarily a result of a limited number of measures:

- The **interruptible rate program** consists of a single measure: interruptible rates that target large C&I customers. Unlike Manitoba Hydro's current large industrial curtailable load program, which is designed to provide load reductions to support reliability (for example, during emergency events and to maintain reserve levels) and called very infrequently, the interruptible rate program is designed to reduce loads during peak events many times throughout the year.

- In the **residential DLC program**, residential electric vehicle (EV) smart charger controls, residential sector Wi-Fi thermostats (whether through a Bring Your Own Device (BYOD) or direct-install program approaches), and storage water heaters provide 98% of program potential in 2037. [7,8] EV adoption is forecasted to increase considerably in the later years of the study period, driving additional peak loads *and* additional opportunities for DR programs to address these loads. In the absence of a managed charging program, charging is assumed to happen in the early evening, increasing peak demand at this time. The EV smart charger

[7] BYOD programs leverage existing customer equipment, such as Wi-Fi thermostats, to achieve DR savings. Under direct install programs, utilities purchase and install the equipment required to achieve savings in customer homes and businesses. Although BYOD programs are less expensive for utilities, they are limited by existing market uptake of relevant measures. Leveraging measures that have been installed through other program offerings – for example, by programs designed to capture efficiency savings – can maximize BYOD opportunities.

[8] Most Wi-Fi thermostat potential is for central heating systems, although thermostats connected to baseboard heaters also show considerable potential under the Low scenario. Although there are many baseboard heaters in Manitoba, the DR potential is limited by relatively limited cost-effectiveness. Additionally, baseboard thermostat manufacturers are less established than central system thermostat manufacturers, adding a degree of uncertainty around the technology availability and capability.

control measure is designed to address this peak, shifting charging overnight. Other key measures – notably thermostats and storage water heaters – will remain important in addressing the non-EV related peaks that will continue to exist in the morning and in the early evening. As more efforts are deployed to provide WiFi thermostats through EE programs, leveraging the potential of these installed WiFi thermostats shows promising opportunities in the future

- The C&I curtailment programs (both manual and auto-DR) are technology-agnostic, meaning customers may reduce loads using the equipment that they prefer, whether through lighting, HVAC, or other devices.[9] The potential is greatest for manual C&I curtailment opportunities as they are more cost-effective. These measures do not require utility investment in customer-sited equipment, instead leveraging customer building management systems to reduce program costs in comparison to auto-DR approaches.

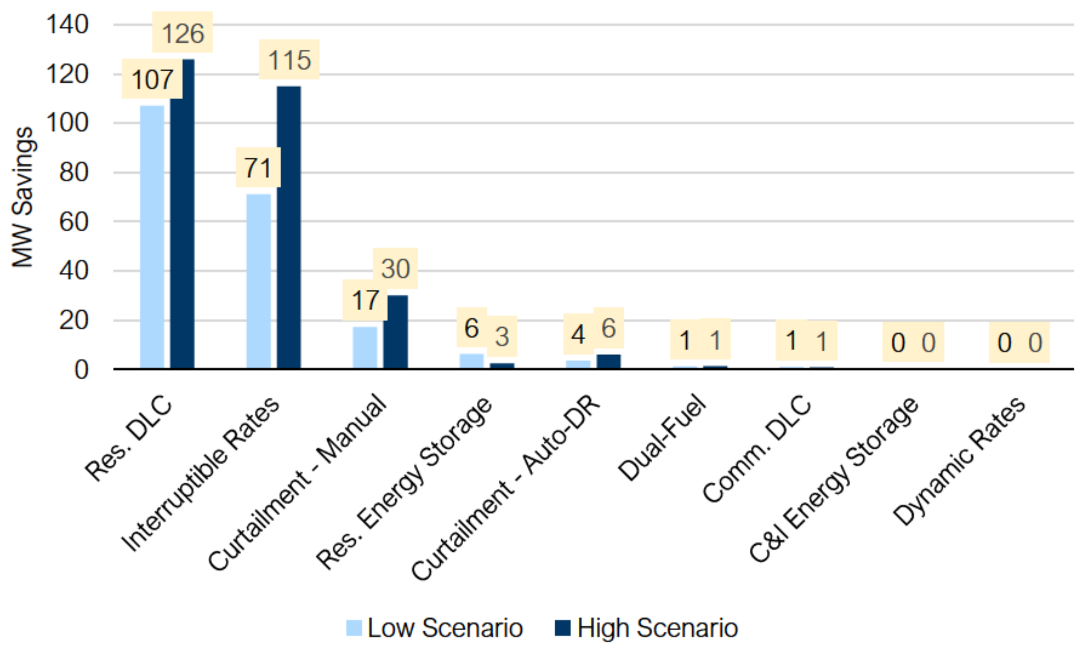
2.1.2 High Scenario

The High scenario explores the degree to which additional savings can be achieved through increased incentives while maintaining program cost-effectiveness.

In 2037, the High scenario has a portfolio-wide achievable potential increase of 36% over the Low scenario. The interruptible rates and curtailment programs show the most growth relative to the Low scenario results (Figure 2-3Figure 2-3). This indicates that these programs offer the greatest opportunities to increase incentives and drive additional participation while remaining cost-effective. For other programs, increased incentives do not result in a notable increase in potential. This indicates that the additional potential that *could* be captured by those measures can instead be captured using more cost-effective opportunities, or that other non-financial factors may be limiting potential (for example, measures with significant bounce-back may lead to a new peak if adoption is increased). In either case, incentive dollars would be better spent on other measure types.

[9] Under a manual curtailment program, C&I customers reduce demand in response to a utility notification. Under an auto-DR curtailment program, utilities reduce loads that have been pre-approved by the customer by communicating directly with customers' Building Automation Systems with no intervention required from the customer at the time of the event. An auto-DR approach requires utility investment in communication and controls equipment, increasing program costs.

Figure 2-3. DR Low and High Scenario Achievable Potential, 2037 – Breakdown by Program



The top 10 measures under the High scenario are mostly consistent with the Low scenario as presented in Table 2-2. However, almost all measures show higher potential due to increased participation resulting from higher customer incentives.

Table 2-2. DR High Scenario – Top Measures, 2037

Measures	Program	Achievable Potential 2037 (MW)
Interruptible Rates	Interruptible Rates	115
Electric Vehicle Smart Charger Control	Residential DLC	58
Wi-Fi Thermostat Connected to Central Heat	Residential DLC	41
C&I Manual Curtailment	Curtailment - Manual	32
Resistance Storage Water Heater	Residential DLC	19
BYOD Wi-Fi Thermostat Connected to Central Heat	Residential DLC	6
C&I Auto-DR Curtailment	Curtailment – Auto-DR	4
Battery Energy Storage	Residential Energy Storage	2
Thermal Energy Storage	Residential Energy Storage	1
Residential Dual Fuel System	Dual Fuel System	1
All Other Measures	N/A	8
Total*	N/A	**270**

*Total may not sum due to rounding.

Between the Low and High scenarios, the largest increases in potential are for the **interruptible rate, residential DLC central heat Wi-Fi thermostat, and C&I curtailment** programs. Increased incentives allow these programs to capture additional potential by generating greater participation. Increased incentives only marginally increase savings from other measure types, such as storage water heaters, thermal energy storage, and residential battery energy storage systems. In this case, the potential that would have been captured by these measures is instead being captured by more cost-effective opportunities.

2.1.3 AMI Scenario

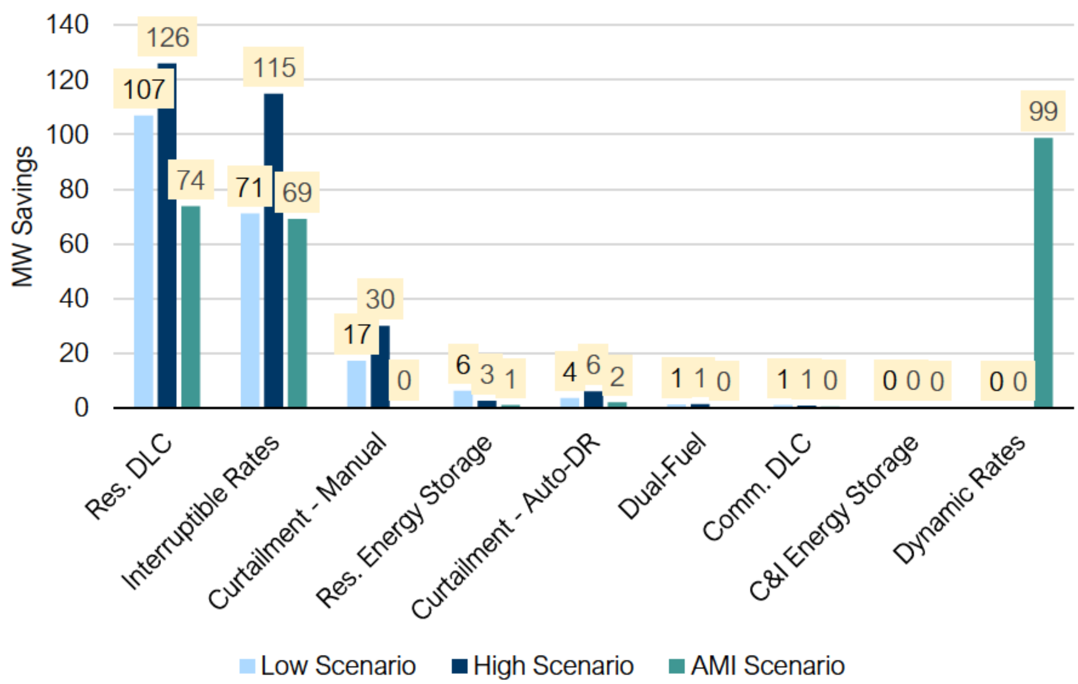
Under the AMI scenario, AMI-enabled dynamic rates in the residential and commercial sectors are modeled in combination with Low scenario incentives for other, non-rate measure types. The dynamic rate that was modeled was a two-tier Critical Peak Pricing (CPP) rate with a 4:1 peak-to-off-peak ratio.[10] This rate was applied across all residential and commercial customers. Other rate types such as Time-of-Use or Peak Time Rebates could achieve similar potential savings but would require different designs (e.g. different peak-to-off-peak pricing).

Compared to the Low scenario, the AMI scenario results in an additional 38 MW of peak load reduction in 2037. Comparing the AMI scenario to the Low and High scenarios (Figure 2-4), potential in the residential DLC, interruptible rate, and curtailment programs is reduced as dynamic rates offer alternate cost-effective opportunities to capture savings. Because rates generally have the same design for all

[10] Critical Peak Pricing is a rate structure designed to reduce load during peak times. Contrary to a Time-of-Use rate, on-peak times only refer to a limited number of peak periods per year. During these peak periods, rates are higher than during off-peak periods – 4x higher, under the rate design used in this study.

participating customers, program peak savings occur over the same period.[11] This contrasts with DLC or curtailment programs where the potential can be staggered over time across various groupings of customers. This characteristic of rates means that their deployment can actually lead to new peaks if not carefully designed, limiting their application. Complementary programs such as DLC or curtailment can be used in combination with rates to offset peak-shifting impacts, maximizing their use.

Figure 2-4. DR Low, High, and AMI Scenario Achievable Potential, 2037 – Breakdown by Program



The achievable potential for the top 10 measures under the AMI scenario is provided in Table 2-3. Under the AMI scenario, dynamic rates become the second and fourth most important measures as a result of their high cost-effectiveness.

Table 2-3. DR AMI Scenario – Top Measures, 2037

Measures	Program	Achievable Potential 2037 (MW)
Interruptible Rates	Interruptible Rates	69
Residential Critical Peak Pricing (CPP) Rates	Dynamic Rates	58
Electric Vehicle Smart Charger Control	Residential DLC	44
Commercial Critical Peak Pricing (CPP) Rates	Dynamic Rates	41

[11] Key rate design parameters include the duration and timing of peak periods, and the ratio between on-peak and off-peak rates.

Wi-Fi Thermostat Connected to Central Heat	Residential DLC	15
Resistance Storage Water Heater	Residential DLC	10
BYOD Wi-Fi Thermostat Connected to Central Heat	Residential DLC	3
C&I Auto-DR Curtailment	Curtailment – Auto-DR	2
Battery Energy Storage	Residential Energy Storage	1
Wi-Fi Thermostat	Commercial DLC	<1
All Other Measures	N/A	1
Total*	N/A	245

*Total may not sum due to rounding.

Under the AMI scenarios, rates provide cost-effective opportunities to reduce peak demand, capturing a portion of the potential associated with other measure types under the Low and High scenarios. Other measures do remain important, offering opportunities to offset dynamic rate peak-shifting impacts.

2.2 Results by Zone

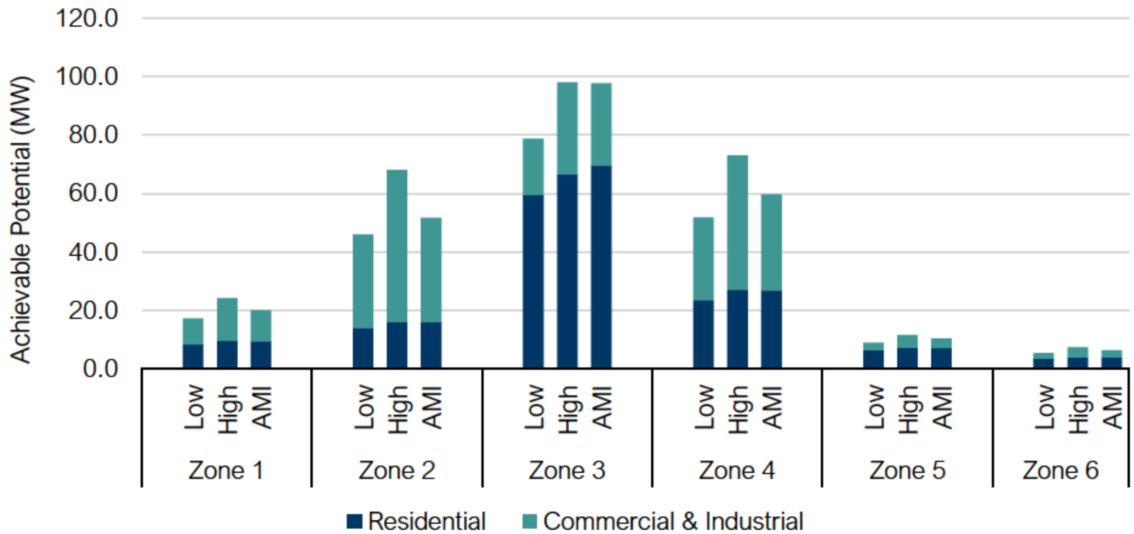
In addition to system-wide savings, potential results are further broken down by Manitoba Hydro's six load zones, listed in Table 2-4 below.

Table 2-4. Manitoba Hydro Load Zones

Zone	Zone Name
1	Northwest
2	West
3	Winnipeg
4	South Central
5	Easy
6	Northeast

The DR results are pro-rated by customer counts to develop estimates by zone. The results by zone and sector are shown in Figure 2-5 below.

Figure 2-5. DR Potential by Manitoba Hydro Load Zone



Considering the share of savings by sector, residential programs are estimated to play a large role in Zone 3 (Winnipeg) due to the high penetration of single and multi-family buildings. C&I programs that target industrial and large commercial customer appear to have the most significant impact in Zone 2 (West) and Zone 3 (Winnipeg). These results do not consider variation in per customer load patterns between zones, however, so actual results – in particular for C&I customers – may vary.

2.3 Portfolio Metrics

Figure 2-6 below provides the program costs for each scenario, broken down between upfront start-up costs and annual operational costs. Upfront costs include set-up costs for programs, costs associated with new participants, and equipment purchase costs and incentives. Annual operational costs cover administration and customer participation or performance incentives. By 2037, program spending is $15.3 M under the Low scenario and $34.0 M under the High scenario. Without accounting for any AMI infrastructure costs, program spending is $12.4 M under the AMI scenario in 2037.

Figure 2-6. DR Program Costs

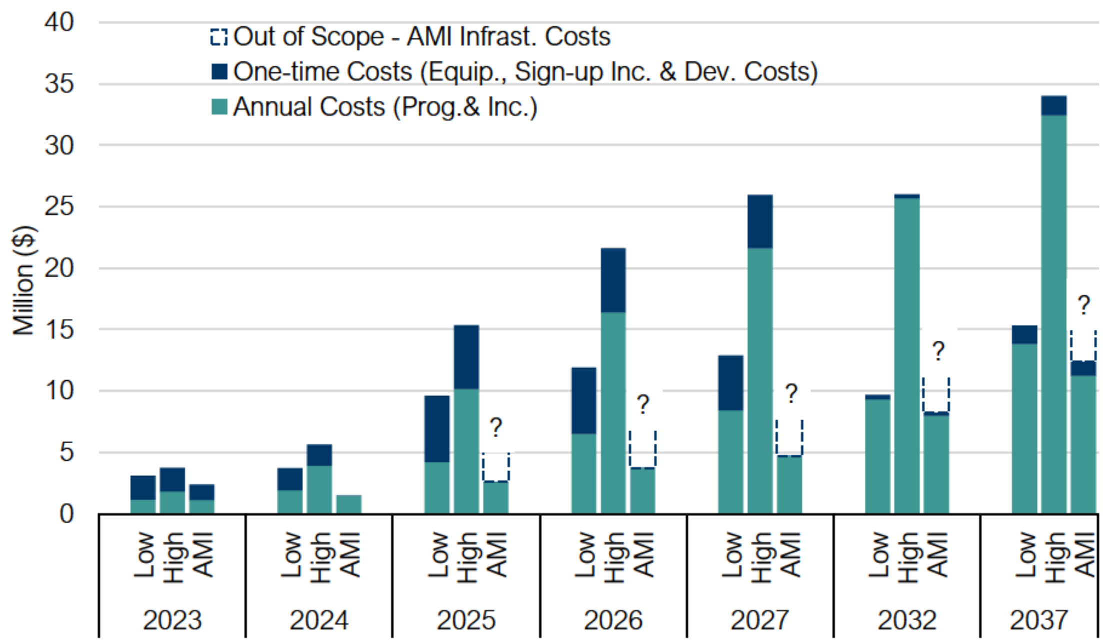


Table 2-5 presents the Total Resource Cost (TRC) test cost-effectiveness results for each program and scenario in 2037. Overall, these results indicate that although the High scenario offers greater peak reduction potential, some of the High scenario programs with the greatest potential – including interruptible rates and manual curtailment – have lower cost-effectiveness than under the Low and the AMI scenarios as a result of their inclusion of less cost-effective measure opportunities. The AMI Scenario maintains the highest benefit-cost ratio, driven mainly by low-cost dynamic rate measures. Again, these costs do not account for AMI investment; if a portion of AMI costs are attributed to DR programs, this cost-effectiveness will decrease.

Table 2-5. TRC Results by Program and Scenario in 2037

Program	Low	High	AMI
Interruptible Rates	2.7	1.0	2.9
Residential DLC	1.1	1.3	1.3
C&I Manual Curtailment	2.1	1.3	N/A
Residential Energy Storage	0.4	0.6	0.7
C&I Curtailment - Auto-DR	0.5	0.7	0.5
Dual Fuel Program	0.3	1.2	N/A
Commercial DLC	0.3	0.6	0.3
C&I Energy Storage	0.1	0.3	0.1
Dynamic Rates	N/A	N/A	6.6

Finally, Table 2-6 below includes the average portfolio-wide costs per kW saved by scenario. Costs shown are average values once programs reach full deployment, from 2027 onwards.

Table 2-6. Average Portfolio-Wide Costs by Scenario Once Programs Reach Full Deployment (2027 onwards)

Scenario	Average Portfolio-Wide Cost ($/kW)
Low	$90
High	$134
AMI	$32

Over the course of the study period, avoided capacity costs vary between $119/kW and $153/kW. These results indicate that DR program peak reductions are often more cost-effective than procuring additional peak capacity. These avoided cost values are system-wide, however – actual avoided costs will vary by time and location on Manitoba Hydro's grid.

3. Key Takeaways

Based on the findings in this study, the following key takeaways emerge:

There is significant opportunity to reduce Manitoba Hydro's peak loads using demand response.

Under the programs modeled for this study, the achievable peak load reduction in Manitoba Hydro's service territory could reach between 208 MW and 282 MW (Low to High scenario range) in 2037, representing up to 4.7% of projected system-wide peak load in that year (Table 3-1).

The Low scenario is designed to align with the measure mixes and incentive levels commonly seen in DR programs in other jurisdictions. Under this scenario, DR programs are estimated to achieve 7 MW of peak demand savings in 2023 and 208 MW in 2037. Program spending required to achieve these savings is projected to be $3.1 M in 2023 and $15.3 M in 2037.

The High scenario estimates the additional savings that could be achieved with the same measure mix as the Low scenario but increased incentives. Under this scenario, DR programs are estimated to achieve 10 MW of peak demand savings in 2023 and 282 MW in 2037, with projected annual program spending requirements of $3.7 M in 2023 and $34.0 M in 2037.

The AMI scenario provides an indication of how leveraging AMI for DR could impact the achievable DR potential and cost-effectiveness by enabling dynamic rates. Under this scenario, DR programs are estimated to achieve 3.5 MW of peak demand savings in 2023 and 245 MW in 2037, with projected annual program spending requirements of $2.4 M in 2023 and $12.4 M in 2037.

Table 3-1. DR Potential and Annual Spending in 2037 by Scenario

Scenarios	Low	High	AMI
Achievable Potential	208 MW	282 MW	245 MW
Achievable Potential as Percent of Peak Load	3.5%	4.7%	4.1%
Portfolio Annual Spending	$15.3 million	$34.0 million	$12.4 million

Programs could achieve significant peak savings by focusing efforts on a limited number of measures with high potential and high cost-effectiveness.

Interruptible rates for large C&I customers and C&I manual curtailment programs could be promising initial program offerings. Both program types offer high potential savings and positive cost-effectiveness. As a next step, the potential found in the C&I sectors should be verified, however. Because Manitoba Hydro customer-specific industrial and commercial data was limited, conservative assumptions from other jurisdictions informed potential estimates. Customer peak load reduction potential and willingness to-participate in DR programs should be assessed as part of the program design process.

Over time, evening peak loads are expected to increase as a result of DER adoption. Growing EV charging loads will increase evening peaks, but managed EV charging programs can shift charging overnight and will be an important addition to Manitoba Hydro's DR portfolio in the later years of the study. These programs will take time to ramp up, as Manitoba Hydro will need to invest in smart charging equipment as customers adopt vehicles to secure their participation in smart charging programs.

A residential DLC program that features Wi-Fi thermostats is another high potential area for initial DR offerings. These programs can be Bring Your Own Device (BYOD), which leverage existing customer equipment, or use a direct-install program approach, where utilities purchase and install the equipment required to achieve savings in customer homes and businesses. BYOD programs are less expensive for the utility but are limited by existing market uptake of relevant measures. Leveraging measures that have been installed through other program offerings – for example, by programs designed to capture efficiency savings – can maximize BYOD opportunities. Initial modeling finds that WiFi thermostat cost-effectiveness is limited when only considering efficiency savings, however, indicating that efficiency program investments in thermostats may also be limited.[12] Coordinating efficiency and demand response programs would ensure that WiFi thermostats will generate both energy and peak demand savings, maximizing the benefits of these measures and improving cost-effectiveness. Residential water heaters can also be offered through a residential DLC program. This measure has high achievable potential under all scenarios, and the ability to reduce the load for several hours without impacting the participant's level of comfort.

If AMI is installed in Manitoba, it could be leveraged to achieve highly cost-effective savings through dynamic rates programs.

If AMI infrastructure becomes available in Manitoba Hydro's service territory, dynamic rates will offer highly cost-effective DR opportunities. Dynamic rates are limited in their deployment, however, because they can lead to new peaks. They should be combined with other, adaptable measure types that can be used at multiple times of the day and staggered to offset the peak-shifting impacts of rates. Interruptible rate, C&I curtailment, and residential DLC programs would complement a dynamic rate program, offering considerable achievable savings that are adaptable and cost-effective.

The results in this study are in-line with results from similar studies in other winter-peaking jurisdictions.

Table 3-2 below benchmarks the achievable DR potential in this study against results in other relevant winter-peaking jurisdictions. Overall, these results show that the results are approximately in-line with the savings estimated elsewhere. Generally speaking, jurisdictions with higher avoided costs are expected to have greater savings potential. Higher avoided costs result in larger benefits associated with each kilowatt saved, improving cost-effectiveness. Results are highly dependent on the characteristics of customer loads, however, so comparisons between jurisdictions should be treated with a high degree of uncertainty; results are especially sensitive to the load patterns of C&I customers, given their potential to vary considerably by jurisdiction.

Table 3-2. Benchmarking the Achievable DR Potential to Other Winter-Peaking Jurisdictions

[12] WiFi thermostats were modeled in the Efficiency Manitoba Market Potential Study, conducted in parallel to the Manitoba Hydro DR Potential study.

	Manitoba (Study Published in 2022)	PEI (Study Published in 2021)	Newfoundland & Labrador (Study Published in 2020)	Pudget Sound Energy (Study Published in 2017)
Portion of Peak Load	3.5% - 4.7% (2037)	3.1% - 8.8% (2030)	10.4% - 12.0% (2034)	3.7% (2037)
Avoided Costs	≈$150 / kW	≈$203 / kW	≈$430 / kW	≈$290 / kW

Overall, the results of this study indicate that there is considerable demand response program potential in Manitoba Hydro's service territory. As a next step, Manitoba Hydro-specific program strategies can be developed through detailed program design.

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Energy + Climate

Manitoba Hydro Electric Demand Response Potential Study

Volume II – Appendix

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About Dunsky

Founded in 2004, Dunsky supports leading governments, utilities, corporations and non-profits across North America in their efforts to **accelerate the clean energy transition**, effectively and responsibly.

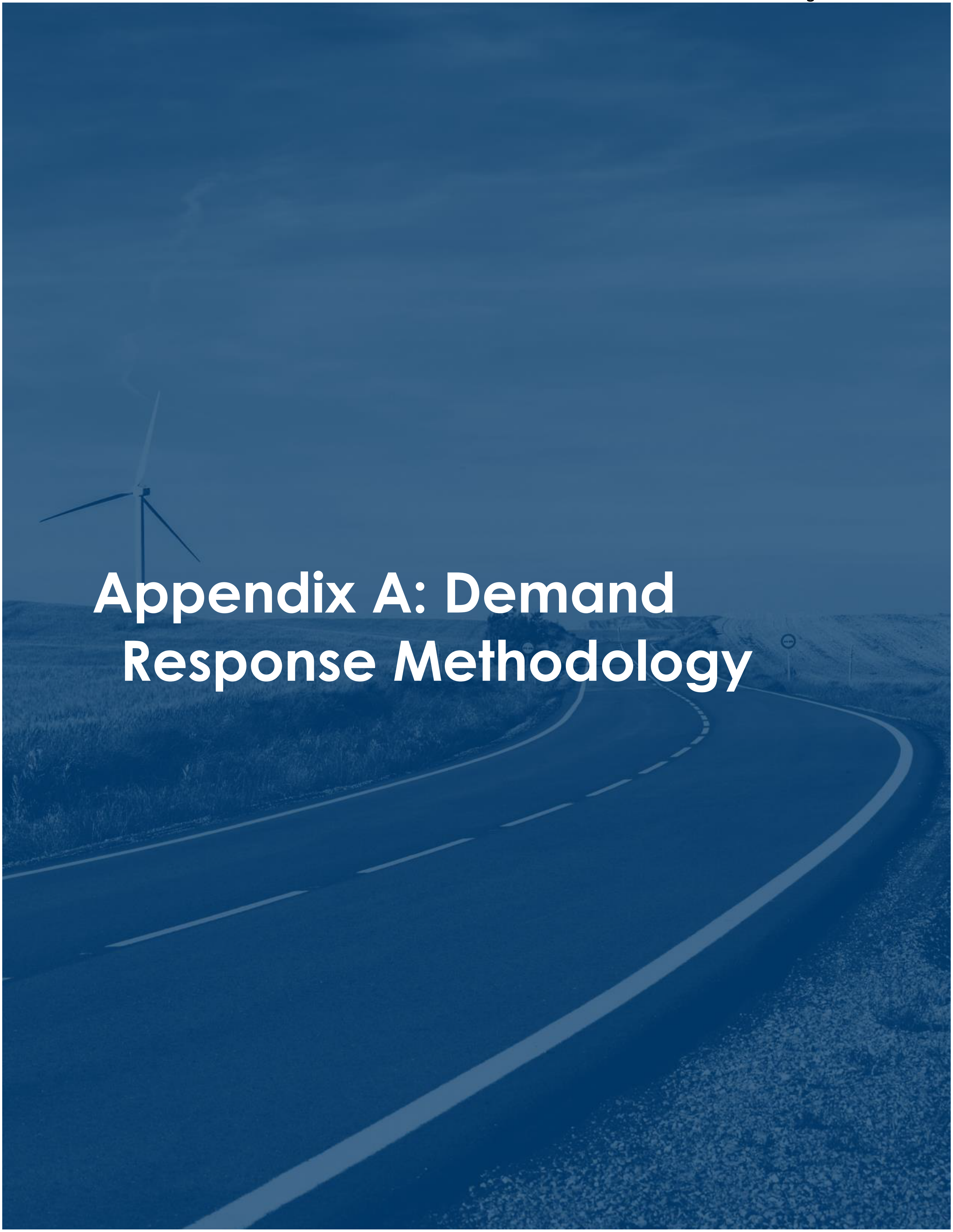
Working across buildings, industry, energy and mobility, we support our clients through three key services: we **quantify** opportunities (technical, economic, market); **design** go-to-market strategies (plans, programs, policies); and **evaluate** performance (with a view to continuous improvement).

Dunsky is proudly Canadian, with offices and staff in Montreal, Toronto, Vancouver, Ottawa and Halifax.

Table of Contents

List of Figures

List of Tables



Appendix A: Demand Response Methodology

A. Demand Response Methodology

A.1 Overview

The following appendix documents the modeling approach employed for assessing technical, economic, and achievable electric demand response (DR) potential. The approach employs Dunsky's Demand Response Optimized Potential (DROP) model to assess the peak-hour demand savings for electric demand response programs. The appendix begins with a general discussion of Dunsky's modeling approach and then provides details on the specific assumptions and inputs made in this study.

The strength of Dunsky's approach to analyzing DR potential resides in its considerations for two specific qualities of DR that differentiate it from conventional energy efficiency potential assessments.

DR Potential is Time-Sensitive

- DR measures are often subject to constraints based on when and for how long the responding electric loads can be reduced.
- DR measures may incur significant "bounce-back" effects (caused by shifting loads to another time) creating new peaks that limit overall achievable potential.
- DR measures impact one another by modifying the overall system load shape. Thus, the entire pool of measures must be assessed concurrently to capture these interactive effects and provide a true estimate of the aggregated achievable potential impact on the system peak.

Many DR Measures Offer Little to No Direct Economic Benefits to Customers

- Participants must receive an incentive over and above simply covering the incremental cost associated with installing the DR equipment.[1]
- Incentives can be based on an annual payment basis, a rebate/reduced rate based on a participant agreement to curtail load, or through time-dependent rates that send a price signal encouraging load reduction during anticipated system peak hours.
- Savings are expected to persist for only as long as programs remain active.

DROP accounts for both of these considerations, accounting for measure constraints and interactions when optimizing DR program potential and factoring in the costs of recruiting and retaining customers into program budgets. Figure A-1 presents an overview of the analysis steps applied to assess DR potential. For each step, system-specific inputs are identified and incorporated into the model.

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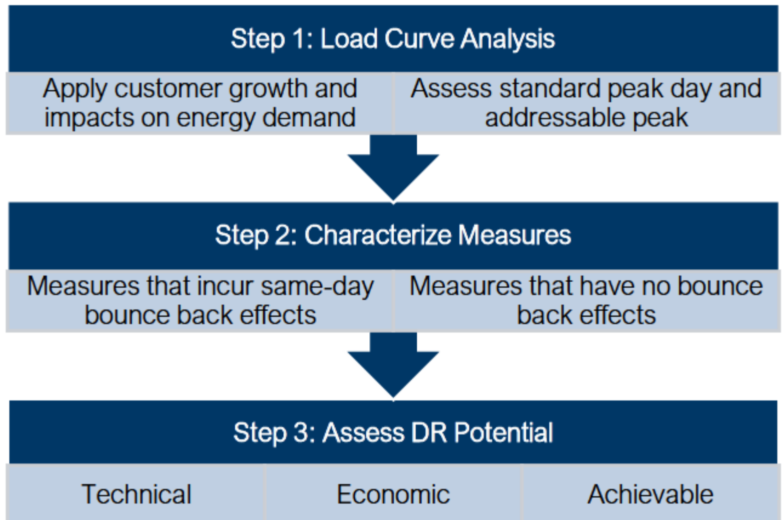
[1] This study did not account for reductions in customer peak demand charges that may arise from DR program participation. Since DR events are typically called for a small number of days each month at times that may not be coincident to the customer's billed peak demand, the impact on commercial monthly peak demand charges is assumed to be minimal.

Figure A-1. Demand Response Potential Assessment Steps



Across all steps of the analysis, the DR potential study uses inputs that are aligned with the Efficiency Manitoba DSM Market Potential Study wherever relevant.

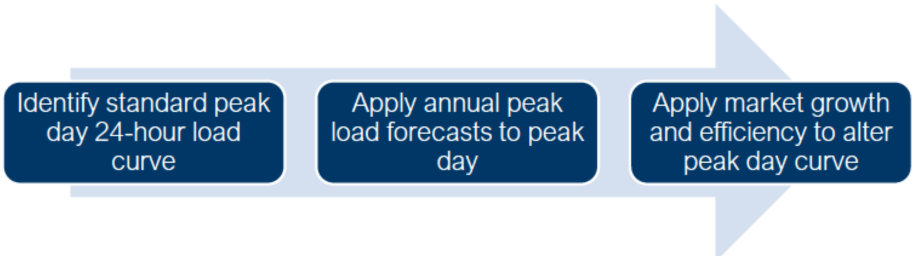
The remainder of this appendix describes each of the DR potential assessment steps in detail.

A.2 Load Curve Analysis

The first modeling step is to define the baseline load forecast and determine the key parameters of the utility load curve that influence the DR potential. The process begins by conducting a statistical analysis of historical utility data to determine the 24-hour load curve for the “standard peak day” (described below) against which DR measure impacts are assessed. The utility peak demand forecast period is then applied to adjust the amplitude of the standard peak day curve over the study period.[2] Finally, relative market sector growth factors and impacts from other DSM programs (e.g., efficiency, fuel switching, and distributed generation programs) or other modeled customer-driven load impacts (e.g., EV adoption) are applied to further adjust the peak day load curve.[2]

[2] This study employs the baseline peak demand forecast developed for the Efficiency Manitoba DSM Market Potential Study.

Figure A-2. Load Curve Analysis Tasks

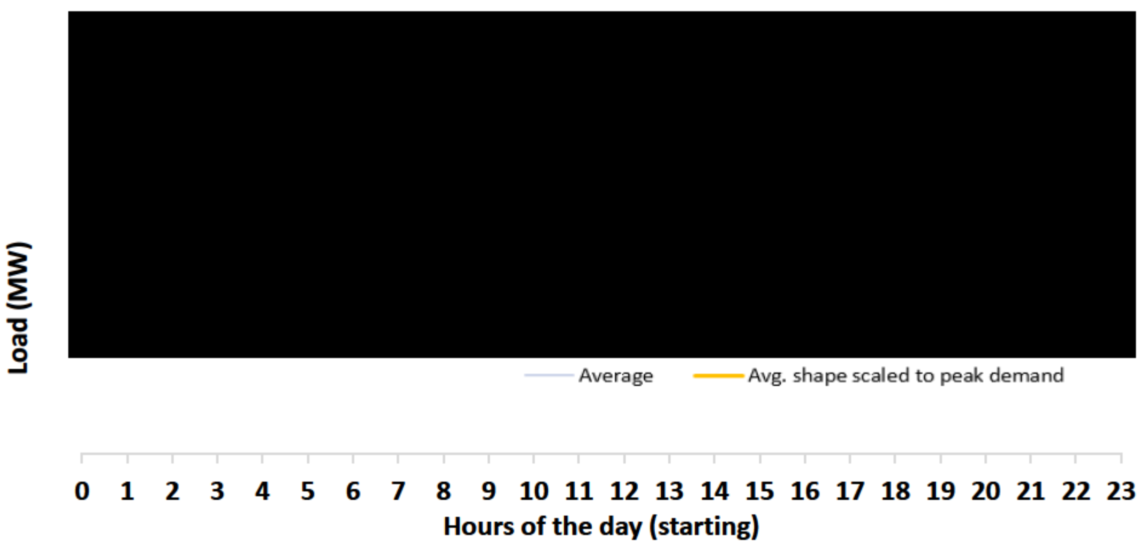


Once complete, the load curve analysis provides a tool that can assess the individual measure and combined program impacts against a valid utility peak baseline curve that evolves to reflect market changes over the study period.

A.2.1 Identify Standard Peak Day

The **standard peak day** is assessed through an analysis of historical hourly annual load curves.[3] For each year, a sample of the peak days is identified (e.g. top 10 peak demand days in each year where historical data is available) and a pool of peak days is established. From this, the average peak day shape is established from the pool of peak day hourly shapes. The standard peak day load curve is then defined by raising the average peak day load curve such that the peak moment matches the projected annual peak demand (keeping the shape consistent with the average curve), as shown in Figure A-3.

Figure A-3. Example of a Standard Peak Day Curve



Note: Each blue shading area represents a 10-percentile gradient.

[3] For details on the data used to establish the standard peak day for this study, please see the description of study inputs for the DROP model in Section A.5.1.

From the standard peak day curve, a DR window is identified which represents the period that captures the highest demand hours. These are assessed against the historical annual curves to ensure that 90% of DR peak events within a given year fall within the defined DR windows. These are used to characterize certain DR measures, to provide guidance on which hours to target customer-driven curtailment periods, and to create pre-charge/reduction/re-charge curves for equipment control measures, as described in the next step.

A.3 Measure Characterization

DR measure characterization draws on Dunsky's database of specific demand reducing measures developed from a review of commonly applied approaches in DR programs across North America, as well as other emerging opportunities such as battery storage.[4] Measures are characterized with respect to the local customer load profiles, and the technical and economic DR potentials are assessed for each measure.[5]

Figure A-4. DR Measure Characterization Tasks

Once complete, the measure-specific economic potential is loaded into the model to assess the achievable potential scenarios when all interactive load curve effects are considered.

A.3.1 Measure Specific Model Inputs

Measures are developed covering all customer segments and end-uses, and can be broadly categorized into three groups:

- **Type 1 DR Measures (typically constrained by demand bounce-back and/or pre-charging):**
    - These measures exhibit notable pre-charging or bounce-back demand profiles within the same day as the DR event is called. This can create new peaks outside of the DR window and may lead to significant interaction effects among measures when their combined impact on the utility peak day curve is assessed.
    - Typically, Type 1 measures can only be engaged for a limited number of hours before causing participant discomfort or inconvenience. This is reflected in the DR measure

[4] A detailed list of measures applied in this study are provided in the detailed results workbook.
[5] When local customer demand profiles are not available, profiles from similar jurisdictions are used.

load curves developed for each measure-segment combination. (example: direct load control of a residential water heater)

- **Type 2 DR Measures (unconstrained by load curve):**
  - These measures do not exhibit a demand bounce-back and are therefore not constrained by the addressable peak.
  - Some of them can be engaged at any time, for an extended duration. (example: back-up generator at a commercial facility)
- **Dynamic Rates:**
  - Dynamic rates vary according to the time of day. The rates align with on-peak and off-peak periods that may be adjusted by day (e.g. weekend vs. weekday) or seasonally. Rather than be engaged by the utility in response to a specific DR event, dynamic rates are designed to adjust consumer behaviour (and demand) across time. Dynamic rates require advanced metering infrastructure. The study advanced metering assumptions are outlined in the call-out box below.

Advanced Metering Infrastructure

Advanced metering infrastructure (AMI) is the key piece of enabling infrastructure for DR measures – particularly time-varying rate (TVR) measures such as time-of-use (TOU) rates and critical peak pricing (CPP).

Currently, AMI deployment in Manitoba Hydro's territory is negligible with only 102 AMI customer meters installed on the system. However, Manitoba Hydro is currently developing a business case for AMI with a target of being finalized by early fiscal 2022/23. Manitoba Hydro's current expectation is to have an AMI pilot in place as early as the mid of fiscal 2022/23. Subject to the success of the pilot project, Manitoba Hydro will consider plans for a mass rollout.

Since there are no definitive plans for AMI deployment, Dunsky incorporated differentiated AMI deployment assumptions in the three achievable scenarios modeled for DR to capture this uncertainty.

Achievable potential was assessed under several scenarios (Low, High, and AMI), each reflecting varying program conditions. For the Low and High scenarios, Dunsky did not assume that any AMI was deployed for the duration of the study period. Under these scenarios, TVR measures are not available for achievable DR potential.

For the AMI scenario, Dunsky assumed that AMI deployment would begin in 2025/26 after the completion of a successful pilot program and development of deployment strategy in 2023/24 and 2024/25. The AMI rollout is then assumed to occur over three years in equal increments with 33% of the customer base receiving AMI equipment per year[1]. Under this assumption, the applicable markets for TVR measures grew each year with 33% of the population having AMI by the beginning of 2026/27 and all customers having AMI by the beginning of 2028/29.

AMI Deployment Scenario Assumptions

Scenario	AMI Assumption	Impact
Low, High	Assume AMI is not deployed for the duration of the study period.	TVR and other AMI-enabled measures are not included in achievable potential.
AMI	Assume AMI is deployed and available to all Manitoba Hydro customers starting in 2026/27 and covering all customers by the beginning of 2028/29.	TVR and other AMI enable measures are offered beginning in 2026/27.

1. This aligns with other utility AMI deployment strategies observed in Canada such as the one currently being undertaken by NB Power. See NB Power's project timeline in their Project Status Report for the AMI Project (pg. 3).

Dunsky's existing library of applicable DR measure characterizations was applied and adjusted to reflect hourly end-use energy profiles for each applicable segment. Key metrics of the characterization are:

1. **Load Shape:** Each measure characterization relies on a defined 24-hour load shape both before and after the demand response event. The load shapes are based on the population of measures within each market segment and are defined as the average aggregate load in each hour across the segment.

2. **Effective Useful Life (EUL):** Effective useful life of the installed equipment/control device. For behavioural measures with no equipment, a one-year EUL is applied.

3. **Costs:** At the measure level, the costs include the initial cost of the installed equipment (i.e. controls devices and telemetry) and the annual operational cost (program administration, customer incentives, etc.).

4. **Constraints:** Some measures are subject to specific constraints such as the number of hours per day or year, the maximum number of events per year, and event durations.

Once the measures are adapted to the utility customer load profiles and markets, the technical and economic potentials are assessed for each measure independently as outlined below. Because these are assessed independently (i.e., not considering interactions among measures), the technical and economic potentials are not considered to be additive but instead provide important measure characterization inputs to assess the collective achievable potential when measures are analyzed together in step 3.

A.3.2 Technical Potential (Measure Specific)

The technical potential represents a theoretical assessment of the total universe of controllable loads that could be applicable to a DR program. It is defined as the technically feasible load (kW) impact for each DR measure considering the impact on the controlled equipment power draw coincident with the utility annual peak.

More specifically, the technical potential is calculated from the maximum hourly load impact during a DR event multiplied by the applicable market of the given measure. It is important to note that the technical potential assessment does not consider the utility load curve constraints, such as the impact that shifting load to another hour may have on the overall annual peak.

A.3.3 Economic Potential (Measure Specific)

Economic potential is defined as the total load impacts that pass standard cost-effectiveness testing. Measures are screened using the Program Administrator Cost Test (PACT) test at a benefit-cost ratio threshold of 1, considering installation and baseline incentive costs[6,7]. Any measure that fell below the benefit-cost threshold was not be retained for further consideration in the model. For measures that passed cost-effectiveness screening, program incentives were then be set as a fixed portion of the avoided costs net of measure costs (e.g. 50%) or at the level that maximizes the cost-effectiveness test value for the measure in question.

Table A-1. DR Benefits and Costs Included in Determination of the PACT

Benefits	Costs
Avoided Capacity Costs	Controls equipment installation Controls equipment Operations and Maintenance (O&M) (if required) Annual incentives ($/ participant) & peak reduction incentives ($/kW contracted) Program costs (Development fees, fixed fees, $/participant)

[6] In some cases, customer incentives are *not* treated as a pass-through cost for DR programs, unlike how they are typically treated for efficiency programs. This is because they typically do not cover a portion of the customers' own equipment incremental costs (i.e. customers typically have no direct equipment costs, unlike in efficiency programs where the incentives provided cover a portion of the participant's incremental costs for the efficiency upgrade), but are instead a participation incentive.
[7] The avoided costs used for the DR study will be the same as those used across all elements of the DSM potential study.

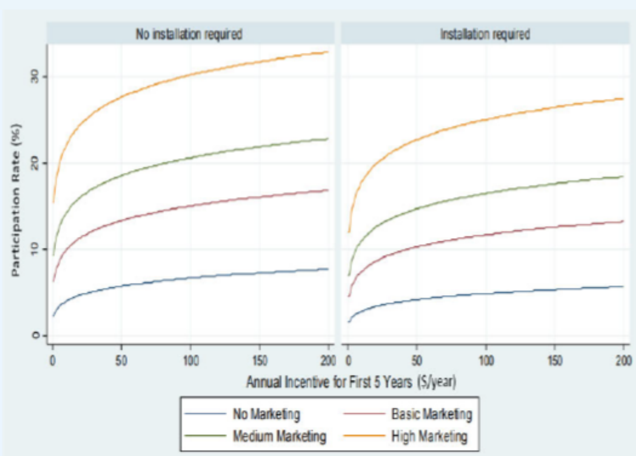
A.4 Assess Achievable Potential

The achievable potential is determined through an optimization process that considers market adoption constraints, individual measure constraints, and the combined inter-measure impacts on the utility load curve. First, for those measures that passed cost-effectiveness screening, the study team assessed the market potential for each measure individually. Next, the measures were combined to assess the market potential across each scenario, considering interactions among all measures and the utility load curve. Each of these steps are described in detail below.

Individual Measure Market: The market for a given DR program or measure may be constrained either by the impact on the load curve, or by the expected participation (or adoption) among utility customers. In the first case, the optimization process described under the 'Assess Technical Potential' section above determines the number of devices needed to achieve the measure's maximum impact on the utility peak load. This is the point where adding any further participation will have little to no further peak load reduction benefits. In the second case, the model determines the expected maximum program participation based on the incentive offered and the program strategy used by applying DR program propensity curves (developed by the Lawrence Berkeley National Laboratory[8] and described in the call-out box below). The model assesses the results from both market sizing approaches, then constrains the market (i.e. the maximum number of participants for each measure) to the lower of the two.

Demand Response Propensity Curves

For each measure, the propensity curve methodology, as developed by the Lawrence Berkeley National Laboratory to assess market adoption under various program conditions, is applied. The curves represent achievable enrollment rates as a function of incentive levels, marketing strategy, number of DR calls per year, and the need for controls equipment. Their development is based on empirical studies, calibrated to actual enrollment from utility customer data. The image below illustrates the residential propensity curves - specific curves are available for each sector.



[8] Lawrence Berkeley National Laboratory, March 2017. 2025 California Demand Study Potential Study, Phase 2 Appendix F. Retrieved at: http://www.cpuc.ca.gov/General.aspx?id=10622

Scenario Market Potential: Once the individual measure market sizes had been established, all measures were combined in a scenario assessment (described further in the section that follows). For this assessment, the study team assessed achievable potential under three program design scenarios, Low, High, and AMI. For each scenario, measures were applied in groups in order starting with the least flexible/most constrained measures and progressing to the measures/groups that are less and less constrained, as per the order outlined below.

1. **Dynamic Rates:** Before applying dispatchable DR technologies, the impact of dynamic rates is assessed, and the load curve is adjusted. The study team then applied subsequent DR measures to the adjusted peak day curve. Adjustments may have increased potential for some measures, or decreased potential for others. For this analysis, dynamic rates were only applied in the AMI scenario.

2. **Load Control and Curtailment Measures:** Next, direct control of connected loads such as water heaters and thermostats, along with customer controlled shut-off or ramp down of commercial or industrial loads are applied. These measures are typically constrained to specific times of day based on the utility peak load curve and the measure load shape (e.g. turning off residential water heaters at midday may be feasible but will deliver little to no savings as there is minimal hot water demand at that hour). Again, the study team created a new aggregate utility peak-day load curve that accounts for achievable load control peak reductions and bounce-back effects.

3. **Unconstrained Measures:** Finally, the team applied the remaining peak reduction measures that have no constraints on the duration, frequency, or timing of their application. These measures can typically be engaged as needed and have potential that is not impacted by the shape of the utility load curve.

A.4.1 DR Programs and Scenarios

Scenarios are developed to assess the impact various measure combinations and program parameters. For example, one scenario may assess the achievable potential of the impact of applying residential BYOD smart thermostat control and industrial curtailment, while another may assess the combined potential from direct install DLC equipment and industrial curtailment. This approach recognizes that there can be various strategies to access the DR potentials from the same pool of equipment (i.e. offering two measures for residential water heating DLC exert a reduction in residential water heating peak demand, thereby reducing or eliminating the potential from one or both water heater measures). The scenarios are assembled from logical combinations of programs and measures designed to test various strategies to maximize the achievable peak load reduction. Two of the scenarios included in this study have the same program measure mix but vary in the incentive level provided for each measure type (Low and High). A third scenario also includes dynamic rates in the program measure mix (AMI). These scenarios are outlined in the figure below.

Figure A-5. Achievable Potential Scenarios

Low	• Applies incentives that are in-line with other jurisdictions
High	• Applies enhanced incentives above low levels
AMI	• Applies dynamic rates to residential & commercial sectors as AMI becomes available alongside Low scenario incentives

Dunsky has developed a set of best-in-class program archetypes based on a review of programs in other jurisdictions. For each program, development, marketing, and operating costs are estimated and applicable measures are mapped to the corresponding program, applying key features from the program archetypes, and taking into account current programs offered by the utility.

The model first determines the achievable DR potential of the combined measures within all programs, and then assesses the program level cost-effectiveness, summing all program and measure costs, as well as applicable measure benefits. A specific program lifetime is assumed for each program, except where the program is based on control devices with a longer EUL, in which case the program is assumed to cover the entire device life. In cases where DR device EULs are shorter than the program lifetime, preparticipation / re-installation costs are applied. This approach allows the model to fairly assess the costs and benefits of the program for an ongoing program. Additional information about the programs can be found in the Inputs and Assumptions section.

New measure and program ramp-up: Where applicable, new programs and measures can be ramped up accounting for the time needed to enroll customers and install controls equipment to reach the full achievable potential. Ramp-up trajectories are applied to the achievable potential markets after all interactive effects (i.e. new peaks created or program interactions that affect the net impact of any other program) have been assessed. It is assumed that new or expanded programs or measures take time to reach full participation and roll out and are deployed following an s-curve deployment.

Based on these steps the Achievable DR potential for each measure, program, and scenario is developed, along with an appropriate assessment of the measure, program, and scenario level cost-effectiveness.

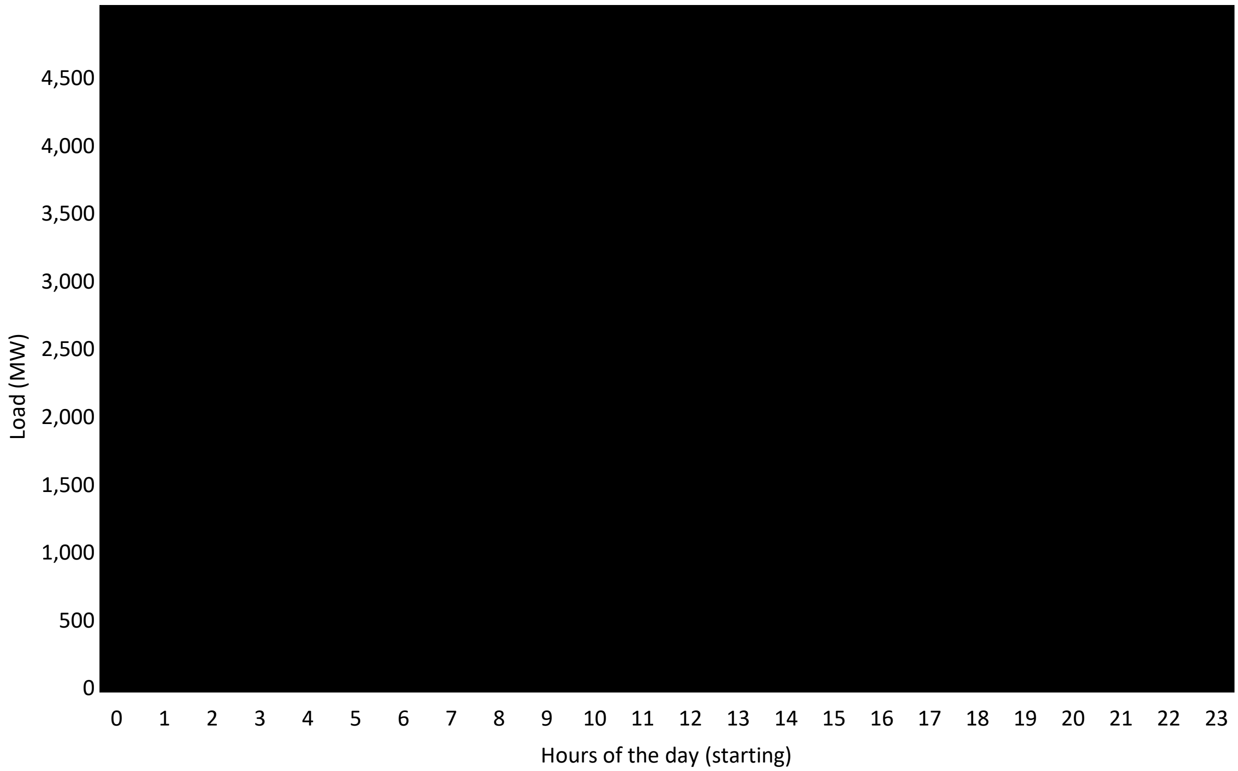
A.5 Inputs and Assumptions

In addition to the data described in this appendix, and the overarching data shared between all study components, several other inputs were used in the demand response potential assessment.

A.5.1 Standard Peak Day

Manitoba Hydro provided Dunsky with hourly historical load data. The data covered April 1st, 2015 to March 31st, 2021 (52,560 data points). This historical data was used to create standard peak days for the system.

Figure A-6. Standard Peak Day (at the meter) – Manitoba Hydro



[redacted]

A.5.2 End-Use Breakdowns

Dunsky developed end-use load curves for each market sector and end-use and where relevant, for individual segments. **Note that these breakdowns are for the electric consumption only, not the whole building (all fuel) energy use**. The load shapes were used to:

1. Assess standard peak day adjustments for DR addressable peak.
2. Characterize measures when local load curves were not available.
3. Benchmark savings when calibrating the model.

The end-use load curves were developed from the following sources:

- US Department of Energy (US DOE) published load curves, taken from buildings in the Massachusetts climate zones, and adjusted to account for heating energy sources.
- Engineered load profiles and Dunsky's in-house developed sample consumption profiles.

In this study, the industrial sector was grouped into one segment “Manufacturing / Industrial”. The segment was modeled using one industrial end-use (included under “Other”). Industrials were evaluated using Dunsky’s internal datasets.

Using this breakdown, an annual (hourly – 8670 hours) building energy consumption simulation from the US DOE (*Commercial Reference Buildings & Building America House Simulation Protocols*) allowed for the recreation of the end-use breakdown for a standard peak day. The figure below presents the end-use and sector breakdown of the electric system.

Figure A-7. Standard Peak Day – Sector Breakdown

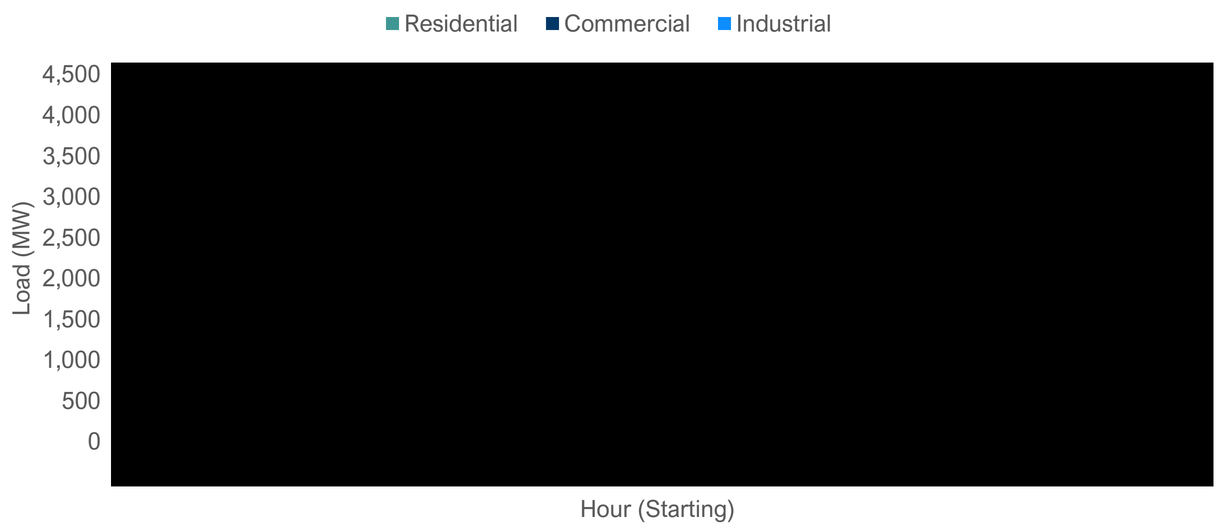
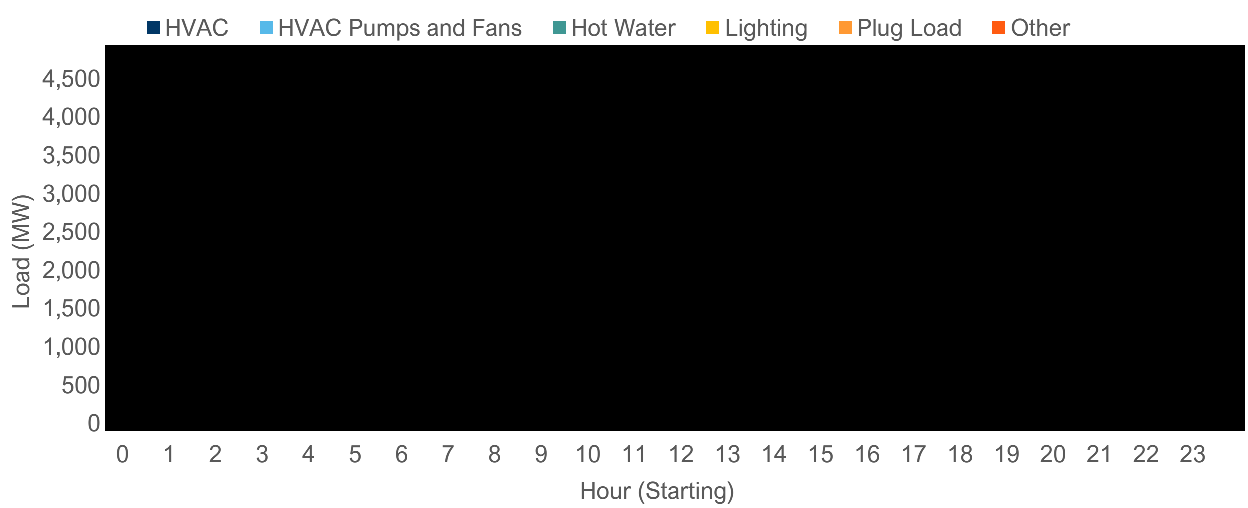


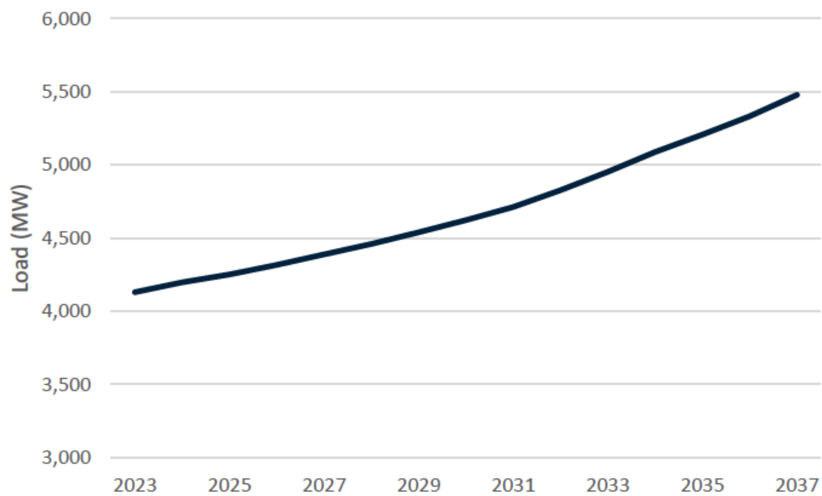
Figure A-8. Standard Peak Day – End-use Breakdown



A.5.3 Future impacts

The standard peak day was forecasted using the same peak demand forecast as the rest of the potential study. It is presented in the figure below.

Figure A-9. Manitoba Hydro Load Forecasting (Before EE/FS/DG/EV Impacts)



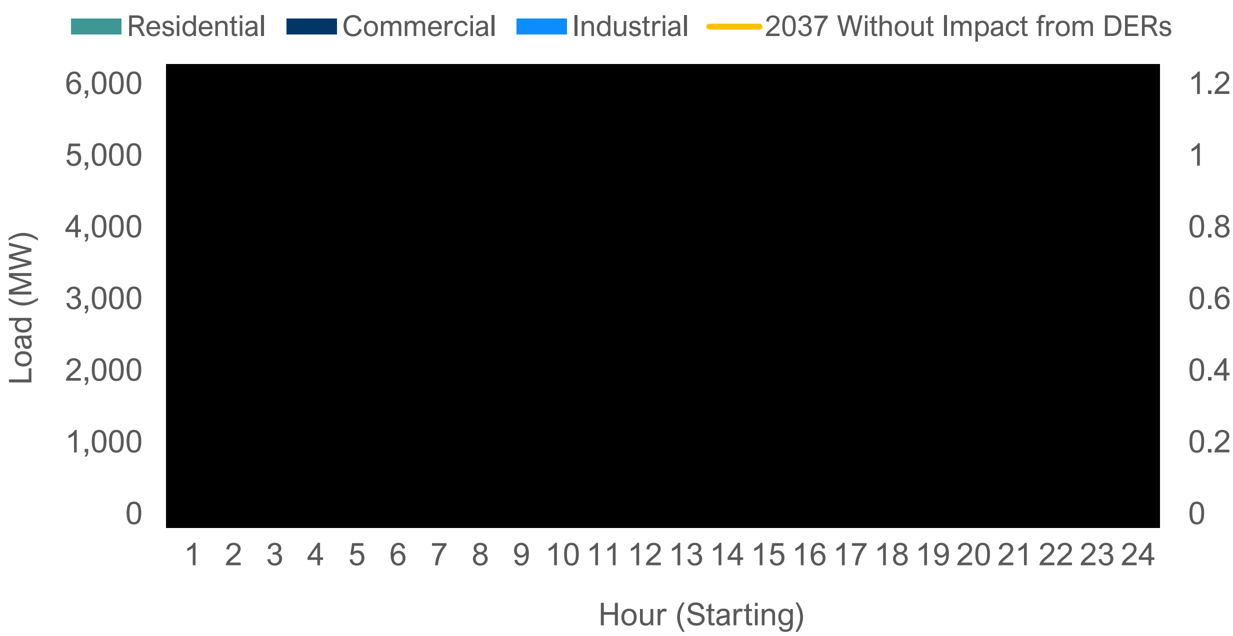
Impacts from the Efficiency Manitoba Market Potential Study, conducted in parallel to the Manitoba Hydro DR Potential study, were included in the load growth projections. Specifically, results for energy efficiency, fuel switching, distributed generation, and EV forecasts were combined with the load forecast to have a better grasp of the future load shape. These loads are collectively referred to as Distributed Energy Resources (DERs).

Table A-2. Impact of Energy Efficiency, Fuel Switching, Distributed Generation and EV on Key Demand Response Factors (2037)

Season	Average hourly reduction	Peak reduction	Peak-to-average difference
Winter	436 MW	190 MW	246 MW

When considering load growth with forecasted impacts of other study components as shown in the table above, the combined effects have implications for the magnitude and shape of the load curve in winter, as shown in Figure A-10. The yellow line indicates what the forecast was expected to be prior to consideration of DER impacts; the stacked graph indicates the forecast considering DER impacts (the forecast used to assess DR potential).

Figure A-10. Evolution of the Standard Peak Day, 2037



Overall, by 2037, the net impact of DERs is a shift in peak hour from the morning to the afternoon. Specifically, the impact by DER type in 2037 is:

- **Energy efficiency and fuel-switching[9]:** 1,227 MW of reduction in 2037
- **Solar PV[9]:** up to 117 MW of reduction (at time of peak system production)
- **EV[10]:** up to 1,056 MW of increase (at the time of peak charging loads)

These results demonstrate how DSM measures offered by Efficiency Manitoba combined with solar adoption could decrease demand, while EV adoption and unmanaged charging could increase demand, particularly in the evening and morning hours.

A.5.4 Measures

To assess the DR potential in the jurisdiction, Dunsky characterized over 25 demand reducing measures, based on commonly applied approaches in DR programs across North America, and emerging opportunities such as battery storage. Measures were selected to ensure meaningful potential when targeting Manitoba's peak (e.g., no summer-only measures, cost-effective in other jurisdictions, etc.). As defined in this appendix, the measures are covering all customer segments and can be categorized into two groups: Type 1 (constrained by the addressable peak) and type 2 (unconstrained by the addressable peak). Measures of all types have the following key metrics:

- Load shape of the measure
- Constraints

[9] These results correspond to the BAU+ scenario.
[10] These results correspond to the Max scenario.

- Measure Effective Useful Life (EUL)
- Costs

Dunsky applied our existing library of applicable DR measure characterizations and adjusted them to reflect end-use energy use profiles in Manitoba's climate. Each measure was evaluated independently for each segment of the study. The following tables provide an overview of each measure characterization and approach.

Table A-3. Residential Demand Response Measures

Measure	DR Strategy	Enabling Device	Market Size	Initial Cost	CE Test
Clothes Dryer - DLC	Appliance shut off during event	Smart Plug	Number of non-smart clothes dryers in the jurisdiction	Smart Plug	Fail
Clothes Dryer - BYOD	Appliance shut off during event	Smart Appliance	Number of smart clothes dryers in the jurisdiction	Incentive upon program inscription	Fail
Clothes Washer - DLC	Appliance shut off during event	Smart Plug	Number of non-smart clothes washers in the jurisdiction	Smart Plug	Fail
Clothes Washer - BYOD	Appliance shut off during event	Smart Appliance	Number of smart clothes washers in the jurisdiction	Incentive upon program inscription	Fail
Dishwasher - DLC	Appliance shut off during event	Smart Plug	Number of smart dishwashers in the jurisdiction	Smart Plug	Fail
Dishwasher - BYOD	Appliance shut off during event	Smart Appliance	Number of smart dishwashers in the jurisdiction	Incentive upon program inscription	Fail
Hot Tubs – Timer or Smart Switch – DLC	Postponing filtering and cleaning work of the pump	Timer Switch or Smart Switch	Number of non-smart hot tubs/spas in the jurisdiction	Timer or Smart Switch	Pass
Resistance Storage Water Heater - DLC	Appliance shut off during event	Smart Switch	Non-smart electric water heater (excl. heat pump water heater)	Smart Switch	Pass
Heat Pump Storage Water Heater – BYOD	Appliance shut off during event	Smart Heat Pump Water Heater	Smart heat pump water heater	Incentive upon program inscription	Pass
Central Heat (Furnace & Air-Source Heat Pump) – DLC	Temperature setback (including pre-heating strategies)	Wi-Fi Thermostat	Households with central furnace or ASHP with manual or programmable thermostat	Installation of a WiFi thermostat	Pass
Central Heat (Furnace & Air-Source Heat Pump) – BYOD	Temperature setback (including pre-heating strategies)	Wi-Fi Thermostat	Households with central furnace or ASHP with Wi-Fi Thermostat	Incentive upon program inscription	Pass
Baseboards Heat – DLC	Temperature setback (including pre-heating strategies)	Wi-Fi Thermostat	Households with baseboards and with manual or programmable thermostat	Installation of a WiFi thermostat	Pass
Baseboards Heat – BYOD	Temperature setback (including pre-heating strategies)	Wi-Fi Thermostat	Households with baseboards and with Wi-Fi Thermostat	Incentive upon program inscription	Pass

Measure	DR Strategy	Enabling Device	Market Size	Initial Cost	CE Test
Ductless HP – DLC	Temperature setback (including pre-heating strategies)	Wi-Fi Thermostat	Households with a Ductless HP	Installation of a WiFi thermostat	Pass
Ductless HP – BYOD	Temperature setback (including pre-heating strategies)	Wi-Fi Thermostat	Households with a Ductless HP connected to a smart thermostat	Incentive upon program inscription	Pass
Dual-Fuel - DLC	Main electric heating is turned off and a gas/oil backup is turned on	Automatic Switch	Households with an existing central gas/oil backup	Automatic Switch	Pass
Thermal Storage (Central) - DLC	Thermal Energy Storage (TES) discharges during event	Smart Switch	Households with a central heating system being replace (end of life)	Full cost of the combined heating-storage unit	Pass
Thermal Storage (Local) - DLC	Thermal Energy Storage (TES) discharges during event	Smart Switch	Households with baseboard heating	Full cost of the storage unit	Pass
Battery Energy Storage – With Solar - BYOD	Battery discharges during event and extra power is send back into the grid	Battery	Households with solar panels and battery	Incentive upon program inscription	Pass
Battery Energy Storage – Without Solar - BYOD	Battery discharges during event to cover the house loads only	Battery	All households with a battery, excluding households with solar panels	Incentive upon program inscription	Pass
Electrical Vehicle (EV)	Shut off during event	Smart Electric Vehicle Supply Equipment (EVSE) or Smart Plug (such as FloCarma Plug)	Number of EVs in the jurisdiction x % charged at home	Smart EVSE or Smart Plug	Pass
Dynamic Rates	Critical Peak Pricing (CPP) during peak windows	AMI Infrastructure	All households	None	Pass

Table A-4. Non-Residential Demand Response Measures

Measure	DR Strategy	Enabling Device	Market Size	Initial Cost	CE Test
Commercial Refrigeration	Refrigeration loads shed	Auto-DR	Refrigeration load per building with low-temperature cases x number of buildings (Food Sales only)	Automated demand response	Pass
Resistance Storage Water Heater - DLC	Appliance shut off during event	Smart Switch	Non-smart electric water heaters (excl. heat pump water heater)	Smart Switch	Pass (only food sales and food services)
WiFi Thermostat – DLC	Temperature setback (including pre-cooling strategies)	Wi-Fi Thermostat	Small C&I buildings with central heating and with manual or programmable thermostat	Wi-Fi Thermostat	Pass
WiFi Thermostat – BYOD	Temperature setback (including pre-cooling strategies)	Wi-Fi Thermostat	Small C&I buildings with central heating and with Wi-Fi thermostat	Incentive upon program inscription	Pass
Medium & Large C&I – HVAC Curtailment	HVAC demand curtailment (fresh airflow reduction, temperature adjustment, etc.)	Manual, BAS	All medium & large C&I buildings, excluding large industrials under interruptible rates	None	Pass
Medium & Large C&I – HVAC Curtailment (Auto-DR)	HVAC demand curtailment (fresh airflow reduction, temperature adjustment, etc.)	Auto-DR	All medium & large C&I buildings, excluding large industrials under interruptible rates	Auto-DR system	Pass
Dual-Fuel - DLC	Main electric heating is turned off and a gas/oil backup is turned on	Smart Switch	Small C&I buildings with an existing central gas/oil backup	Smart Switch	Pass
Thermal Storage (central) - DLC	Thermal Energy Storage (TES) discharges during event	Smart Switch	Small C&I buildings with a central heating system being replace (end of life)	Full cost of the combined heating-storage unit	Pass
Medium & Large C&I – Lighting Curtailment	Turning off and/or dimming some of the fixtures	Manual, BAS	All large-sized C&I buildings	None	Pass
Medium & Large C&I – Lighting Curtailment (Auto-DR)	Turning off and/or dimming some of the fixtures	Manual, BAS or Auto-DR	All large-sized C&I buildings	Auto-DR system	Pass
Electrical Vehicle (EV)	Shut off during event	Smart Electric Vehicle Supply Equipment (EVSE) or Smart Plug	Number of EVs in the jurisdiction x % charged at the office or at public charging station	Smart EVSE or Smart Plug	Fail

Measure	DR Strategy	Enabling Device	Market Size	Initial Cost	CE Test
Battery Energy Storage – With Solar	Battery discharges during event and extra power is send back into the grid	Battery	C&I buildings with solar panels and battery	None	Pass
Battery Energy Storage – Without Solar	Battery discharges during event to cover the building loads only	Battery	C&I buildings with a battery, excluding households with solar panels	None	Pass
Medium & Large C&I – Other	Turning off or reducing some devices, appliances or processes	Manual, BAS	All medium-sized C&I buildings	None	Pass
Medium & Large C&I – Other (Auto-DR)	Turning off or reducing some devices, appliances or processes	Auto-DR	All medium-sized C&I buildings	Auto-DR system	Pass
Backup Generator (Gas)	Use of emergency generator during event	Manual, BAS or Auto-DR	Number of gas emergency generator in the jurisdiction	Costs of EPA stationary nonemergency compliance	Pass
Large Industrial Interruptible Rate	Load shifting or with no intraday rebound	Manual, BAS	All large-sized Industrial buildings	None	Pass
Dynamic Rates	Critical Peak Pricing (CPP) during peak windows	AMI Infrastructure	All small and medium C&I customers	None	Pass

A.5.5 Programs

The table below presents the program costs for each major program type applied in the DR potential model, which were developed based on a jurisdictional scan from existing DR programs. Program costs account for program development (set up), annual management costs, and customer engagement costs. These are added over and above any equipment installation and customer incentive costs to assess the overall program cost-effectiveness. To assess cost-effectiveness, programs costs are evaluated over nine years to recoup development and initial costs. In some cases, a program's constituent measures may be cost-effective, but the program may not pass cost-effectiveness testing due to the additional program costs. Under those scenarios, the measures in the underperforming program are eliminated from the achievable potential measure mix, and the DR potential steps are recalculated to reassess the potential and cost-effectiveness of each measure and program.

Table A-5. DR Program Administration Costs Applied in Study[11] (excluding DR equipment costs)

[11] Costs were estimated through a jurisdictional scan of programs costs from existing DR programs.

Program Name	Development Costs	Program Fixed Annual Costs	Other Costs ($/customers) for marketing, IT, admin
Residential DLC	$200,000	$100,000	$40
Commercial DLC	$200,000	$100,000	$40
Residential Energy Storage	$100,000	$100,000	$30
C&I Curtailment	$75,000	$75,000	$20
C&I Curtailment - Auto-DR	$200,000	$150,000	$25
C&I Energy Storage	$100,000	$75,000	$30
Dual Fuel Program	$100,000	$100,000	$25
Interruptible Rates	$75,000	$75,000	$0
Dynamic Rates	$300,000	$300,000	$5

New programs were assumed to be deployed using a ramp-up rate over five years, except for the Dynamic Rates program which was deployed over three years. Since Manitoba does not have any DR program currently in place, all programs are assumed to be new programs and are deployed following the deployment rates below.

Table A-6. New DR Program Ramp-up Rates – Cumulative Deployment

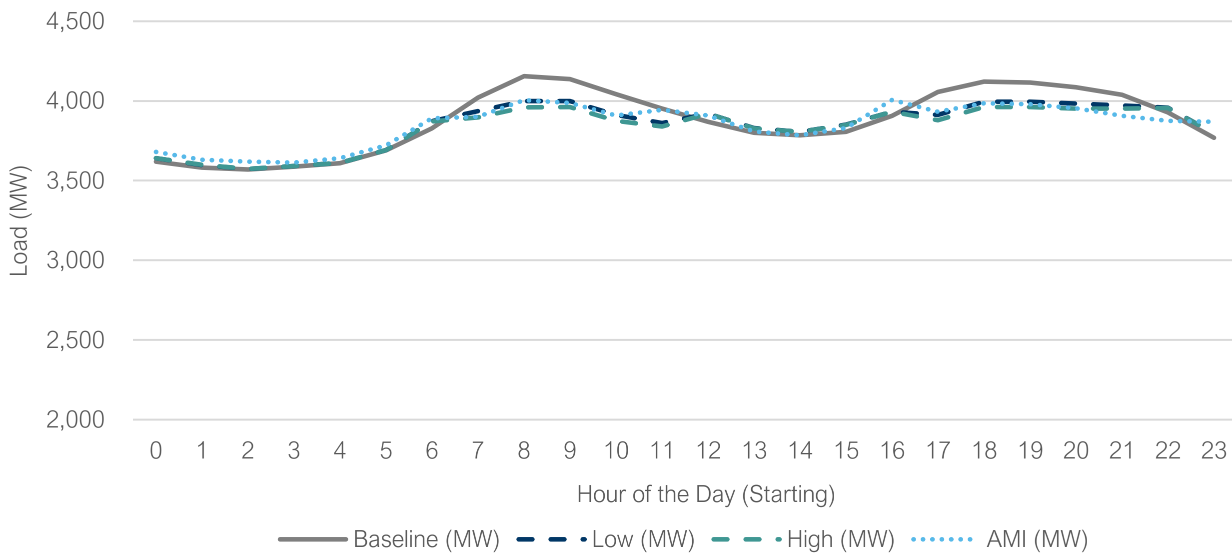
Year	New DR Programs (excl. Dynamic Rates)	Dynamic Rates Programs (AMI)
Year 1 (2023)	5%	0%
Year 2 (2024)	15%	0%

Year 3 (2025)	45%	33%
Year 4 (2026)	75%	66%
Year 5 (2027)	100%	100%

B. Peak Load Shape Impacts

Figure A-11 shows the impacts assessed for each scenario on the standard winter peak day in 2027, when all programs are at full deployment but prior to significant load growth from EVs. The assessment reveals the importance of targeting not only the peak hour, but the full duration of both peak windows; programs that only target limited hours in either the morning or afternoon could shift loads into hours that also have high demand, limiting their potential.

Figure A-11 Scenario Impact on Baseline Standard Peak Day Load Shape (2027) [12]



Under each scenario, achievable potential is calculating by assessing the difference in magnitude of the highest point on the baseline load curve and the highest point on the scenario curve across any hour, **not necessarily aligned with the baseline peak hour**. A more detailed optimization and program design may be able to somewhat further reduce load at the new peak hour, but that level of analysis was beyond the scope of this study.

[12] The baseline standard peak day load curve (grey line above) shows the forecasted load prior to any impacts from DR programs, but accounting for DER impacts forecasted by the Efficiency Manitoba Market Potential Study. This baseline standard peak day curve is equivalent to the stacked graph shown in Figure A-10 but for the year 2027.