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October 30, 2018

B.C. Sustainable Energy Association
c/o William J. Andrews, Barrister & Solicitor
1958 Parkside Lane
North Vancouver, B.C.
V7G 1X5

Attention: Mr. William J. Andrews

Dear Mr. Andrews:

Re: FortisBC Inc. (FBC)

Project No. 1598973

2019-2022 Demand-Side Management (DSM) Expenditures Application (the Application)

Response to the B.C. Sustainable Energy Association and Sierra Club of British Columbia (BCSEA) Information Request (IR) No. 1

On August 2, 2018, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-179-18 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCSEA IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1.0 Topic: EfficiencyBC

Reference: MEMPR medial release, "New program makes saving energy more affordable" (https://news.gov.bc.ca/releases/2018EMPR0052-001891); EfficiencyBC website (https://efficiencybc.ca)

On September 28th, 2018, the Province announced a new energy efficiency program – EfficiencyBC – that "makes saving energy more affordable."

The EfficiencyBC website states:

> "About EfficiencyBC
>
> EfficiencyBC is BC's online hub for homeowners and businesses to access information, incentives and support to reduce energy use and greenhouse gas emissions in new and existing homes and buildings. EfficiencyBC is funded by the Province of British Columbia and the Government of Canada under the Low Carbon Economy Leadership Fund. EfficiencyBC incentives are administered by BC Hydro, FortisBC and BC Housing.
>
> EfficiencyBC resources include:
>
> - Easy to use incentive search tools for residential renovations, residential new construction, commercial renovations, and commercial new construction
> - Single application for EfficiencyBC, BC Hydro, FortisBC and local government residential renovation incentives
> - Information and answers to frequently asked questions on energy efficiency upgrades
> - Free Energy Coaching Services for homeowners and businesses undertaking renovations, including a phone and email hotline staffed by energy coaching specialists
> - Search tool to find registered EnerGuide Rating System energy advisors for residential renovations
> - Contractor directories to find registered contractors in your area
>
> Resources and support are available for the following building types in British Columbia:
>
> - Residential renovations and new construction
> - Commercial renovations and new construction (multi-unit residential buildings, commercial buildings, institutional buildings)

Energy Coach Service

The Energy Coach is a free coaching service for homeowners and commercial building owners and managers in B.C. Energy Coaches are trained energy efficiency specialists who provide building-science based information about the options and opportunities to improve the energy efficiency of your home or building. They are available to answer your questions at all stages of your energy improvement project. Energy Coach services are available for homeowners and commercial building owners or managers.

The Energy Coach, formerly known as the BC Home Energy Coach, has been expanded to include commercial building owners and managers in addition to homeowners.

Energy Coach services include:

- Access to Energy Coaches via a toll-free hotline and e-mail
- Information and advice about energy efficiency upgrades and incentives
- If needed, directing you to appropriate program representative

Please see our Privacy Page for full Energy Coach Terms of Use."

According to the EfficiencyBC website, incentives are offered in the residential and commercial sectors, for both new construction and renovations, for a wide variety of heating types and for many places in BC. Incentives cover a variety of items, including gas appliances, heat pumps, insulation, windows, doors, etc. Rebate amounts range from hundreds of dollars to at least tens of thousands of dollars.

1.1 Please explain FBC's understanding of the EfficiencyBC program, including the program's strategic objectives and its expected effects on DSM activities in BC and in FBC's service area.

Response:

FBC's understanding is that the strategic objectives of the EfficiencyBC program are to support the reduction of energy use in order to reduce greenhouse gas emissions in existing homes and buildings. EfficiencyBC offers are intended to integrate into FBC's existing DSM programs and will be administered through each program's existing application process. In terms of effects on FBC's DSM activities, EfficiencyBC's promotional efforts may drive additional awareness and participation in FBC's existing programs. FBC is unable to comment on EfficiencyBC's effect on DSM activities outside of FBC's service area.

1.1.1 Is EfficiencyBC intended to increase DSM energy savings above the levels planned by FBC and other BC utilities, or to help the utilities achieve planned savings levels?

Response:

As the DSM measures that are funded by FBC and EfficiencyBC are mutually exclusive, EfficiencyBC is not intended to increase DSM energy savings above the levels planned by FBC. FBC is unable to provide comment on other BC utilities.

1.1.2 Is EfficiencyBC intended to reach different potential DSM customers than are targeted by FBC and other BC utilities?

Response:

FBC's understanding is that EfficiencyBC incentives are targeted at customers with homes and buildings that are heated by natural gas, propane, and oil; whereas FBC provides DSM programs and offers for its customers' electrically heated homes and buildings and other electricity uses. FBC is unable to provide comment on other BC utilities.

1.1.3 Does EfficiencyBC have strategic objectives regarding the uptake of particular DSM measures (e.g. such as building envelope efficiency upgrades) or fuel type that are different than those of FBC or other BC utilities?

Response:

FBC's understanding is that EfficiencyBC's objectives encourage the following:

- Uptake of the highest efficiency natural gas equipment, such as the highest tier efficiency residential gas furnaces;

- Uptake of building envelope improvements such as high-performance windows and doors in natural gas heated homes;
- Commercial and institutional natural gas customers to implement custom natural gas saving energy efficiency measures that cannot be supported by FEI's Performance Program due to measure cost-effectiveness (eg. some high efficiency window, building envelope, and heat recovery projects); and
- Conversion of fossil fuel to electric heating equipment.

1.1.4 Does EfficiencyBC target any sector or sectors in particular (e.g. rental accommodations) in order to fill any perceived gaps in the coverage of current and planned DSM offerings by FBC and other BC utilities?

Response:

FBC's understanding is that EfficiencyBC's programs target the residential, commercial, and low income sectors, all of which are sectors that are already covered by FBC's current and planned DSM offerings. FBC is unable to provide comment on other BC utilities. Please also refer to the responses to BCSEA IRs 1.1.1, 1.1.1.1 and 1.1.1.2.

1.2 Please discuss how FBC's participation in EfficiencyBC affects the design and implementation of the 2019-2022 DSM plan?

Response:

To provide offer consistency across the province, FBC's participation in EfficiencyBC affected the design of the 2019-2022 DSM Plan as follows:

- Residential Home Renovation Rebate program:
  - Added incentives for windows and doors;
  - Increased incentives for heat pump measures; and
  - Collaborated with BC Hydro, FEI, and the Province to restructure the program's bonus offers.

There were no other impacts to the design and implementation of the 2019-2022 DSM Plan.

1.3 Please describe the levels and structure of the funding provided by the Province and the federal government under the Low Carbon Economy Leadership Fund. Does FBC receive such funding, or does the funding go directly to end-users in the form of incentives?

Response:

FBC is unable to comment on the funding levels and structure of the Low Carbon Economy Leadership Fund. The Province integrates provincial and federal funding through EfficiencyBC. EfficiencyBC incentives are integrated into FBC's existing programs and will be administered through each program's existing application process. As such, FBC administers and provides incentives on EfficiencyBC's behalf directly to the end user. FBC will recover administration costs and incentive funds from the Province on a quarterly basis.

1.4 Under the EfficiencyBC program, how much federal and provincial money is allocated to the FBC service area, or to the FBC and FortisBC Energy Inc. (natural gas) Shared Services Territory?

Response:

As EfficiencyBC is a Government of British Columbia initiative, FBC is unable to provide information regarding how federal and provincial money is allocated.

1.5 Please confirm, or otherwise explain, that, in theory, federal and provincial funding contributions toward FBC's DSM measures would not affect the TRC but would elevate the UCT and RIM.

Response:

The incentives, costs, and energy savings that stem from FBC and EfficiencyBC funding are mutually exclusive. As such, the TRC, UCT and RIM of FBC's DSM measures are not affected by EfficiencyBC funding.

1.6 Do the benefit/cost estimates in the Application reflect consideration of funding through EfficiencyBC?

Response:

Please refer to the response to BCSEA IR 1.1.5.

1.7 Would funding from the federal and provincial governments to FBC under EfficiencyBC be an example of what is referred to as "Partner Co-funding" in Table 1-1: DSM Portfolio Summary Results for 2017 in the FBC DSM 2017 Annual Report? [Exhibit B-1, Appendix E, pdf p.166]

Response:

The "Partner Co-funding" in the referenced table refers to federal and provincial funds, separate from EfficiencyBC funds, that were put towards FBC's Heat Pump Water Heater field study, and the installation of heat pumps in Indigenous communities as part of the Energy Conservation Assistance Program. As the funding related to EfficiencyBC is retained by the Province of British Columbia, it is not an example of "Partner Co-funding" as noted in the reference.

1.8 Does FBC anticipate being able to separate the savings consequences of (a) federal and provincial spending through EfficiencyBC and (b) FBC's DSM spending? If so, how? If not, how will FBC handle evaluation?

Response:

Please refer to the response to BCSEA IR 1.1.5.

1.9 Does federal and provincial funding through EfficiencyBC mean that FBC will be able to offer incentives for certain efficiency measures that would not otherwise meet benefit/cost objectives?

Response:

Federal and provincial funding through EfficiencyBC does not mean FBC will be able to offer incentives for efficiency measures that would not otherwise meet benefit/cost objectives. The cost-effective portfolio of measures that FBC offers customers is independent of EfficiencyBC programs and offers, although EfficiencyBC programs are integrated with FBC programs from an administrative standpoint for ease of customer access. The federal and provincial funding through EfficiencyBC does not impact the benefit and cost assumptions used in FBC's cost-effectiveness requirements under the DSM Regulation.

1.10 Can FBC confirm that the federal and provincial funding through EfficiencyBC is incremental to FBC's DSM spending, rather than being a mechanism for FBC to reduce its DSM spending?

Response:

Confirmed. Federal and provincial funding through EfficiencyBC is incremental to FBC's DSM spending, and is not a mechanism for FBC to reduce its DSM spending. EfficiencyBC only supports electrification offers in FBC's service territory, and does not currently support any electric DSM measures.

2.0 Topic: 2019-2022 DSM Plan Expenditures and Savings

Reference: Exhibit B-1, Appendix A: 2019-2022 DSM Plan, p.1, pdf p.39; Table 1-1: DSM Plan Expenditures & Savings, 2019-2022, pdf p.40

The Application states:

> "Overall, the 2019-2022 DSM Plan expenditures are 21 percent higher (at $43.3 million) than was contemplated by the pro-forma budgets provided in the 2016 LT DSM Plan ($35.7 million). Over half ($4.0 million) of the $7.6 million total increase in proposed DSM spending is allocated to lighting in the Industrial sector, largely to address agriculture process lighting in the emergent cannabis industry. Other large increases are from the addition of a Residential Customer Engagement Tool ($1.1 million), the Demand Response pilot ($1.0 million), and the DSM tracking tool ($0.6 million) under Supporting Initiatives. The program area sections that follow below provide more details on each of these items.
>
> The 2019-2022 DSM Plan energy savings are also 17 percent higher (130.3 GWh) compared to the 2016 LT DSM Plan forecast (111.6 GWh) due largely to the estimated savings from the proposed cannabis production projects in the industrial sector."

2.1 FBC explains a total of $6.7 million of the $7.6 million by which the Plan expenditures exceed the pro forma budgets in the Long-Term Plan. What accounts for the remaining $0.9 million difference?

Response:

As discussed, the budgets presented in the 2016 LT DSM Plan are pro forma. FBC only estimated expenditures in two categories: incentives and non-incentive (program) costs. The remaining $0.9 million difference is all attributable to additional non-incentive costs, such as an increase in innovative technology projects and codes and standards expenditures. After removing the additional $4.0 million in proposed DSM spending on lighting in the Industrial sector, the anticipated incentive spend for the 2019-2022 DSM Plan is within 1 percent of the incentives allocated in the 2016 LT DSM Plan.

2.2 Table 1-1 of the 2019-2022 DSM Plan provides LT DSM figures only at the whole plan level. Please provide a table comparing by program area the spending and estimated energy savings for the 2019-2022 DSM Plan and for the LT DSM Plan.

Response:

FBC estimated expenditures in the 2016 LT DSM Plan in two categories: incentives and non-incentive costs. The following table compares the 2016 LT DSM Plan to comparable categories for the 2019-2022 DSM plan. FBC did not estimate energy savings by program area in the 2016 LT DSM Plan.

Please note that due to a correction to the estimated savings in the Low Income program area, the total 2019-22 DSM Plan savings have increased. For further information, please refer to the errata filed concurrently with FBC's IR responses.

Table 1: Comparison of 2016 LT DSM Plan to 2019-2022 DSM Plan, Expenditures ($000s)

Year	2016 LT DSM Plan, 2019 dollars ($000s)			2019-2022 DSM Plan, 2019 dollars ($000s)		
	Incentives	Non-incentives	Total	Incentives	Non-incentives	Total
2019	4,644	3,456	8,100	5,920	4,985	10,905
2020	4,644	3,456	8,100	6,085	4,385	10,469
2021	5,450	3,750	9,200	6,309	4,537	10,846
2022	6,256	4,044	10,300	6,629	4,450	11,079
Total	**20,993**	**14,707**	**35,700**	**24,944**	**18,356**	**43,300**

Table 2: Comparison of 2016 LT DSM Plan to 2019-2022 DSM Plan, Savings (GWh)

Year	2016 LT DSM Plan, GWh	2019-2022 DSM Plan, GWh
2019	26.4	32.8
2020	26.4	32.3
2021	28.4	32.6
2022	30.4	33.3
Total	**111.6**	**131.0**

2.3 If the 2019-2022 DSM Plan has lower energy savings than the LT DSM Plan for one or more program areas, please provide a detailed explanation.

Response:

FBC did not estimate energy savings by program area in the 2016 LT DSM Plan. However, FBC estimates that approximately 24 GWh of electricity savings in the 2019-2022 DSM Plan will be from LED lighting installed in cannabis facilities. Deducting cannabis-related savings potential from the 2019-2022 DSM Plan leaves approximately 107 GWh of savings (five percent less) compared to the 2016 LT DSM Plan.

Please note that due to a correction to the estimated savings in the Low Income program area, the total 2019-22 DSM Plan savings have increased. For further information, please refer to the errata filed concurrently with FBC's IR responses.

2.4 FBC explains that the proposed savings are 17% higher than the LT DSM Plan "due largely to the estimated savings from the proposed cannabis production projects in the industrial sector." [underline added]

2.4.1 What portion of the increased savings is due to savings from the proposed cannabis production projects?

Response:

Please refer to the response to BCSEA IR 1.2.3 for additional details on savings estimates for the proposed cannabis production projects in the industrial sector.

2.4.2 Please describe the program areas in which the remaining increased savings are expected.

Response:

Forecast activity in cannabis production makes up more than 100 percent of the difference between the 2019-2022 DSM Plan and 2016 LT DSM Plan. Please refer to the response to BCSEA IR 1.2.3 for additional details on savings estimates.

3.0 Topic: Customer Engagement Tool

Reference: Exhibit B-1, Appendix A: 2019-2022 DSM Plan, p.1, pp.12-13, pdf p.50-51

The Application states:

> "... Other large increases are from the addition of a Residential Customer Engagement Tool ($1.1 million), the Demand Response pilot ($1.0 million), and the DSM tracking tool ($0.6 million) under Supporting Initiatives. The program area sections that follow below provide more details on each of these items." [p. 14, pdf p.19, underline added]

> "The Residential Customer Engagement Tool initiative plans to provide home energy reporting and other tools that will provide energy consumption analysis to customers, increase customer awareness of energy efficiency and conservation and foster conservation behaviours. The 2018 DSM Plan included this program under the Residential Behavioural program but, after further refinement and development, FBC determined this program would be more appropriately placed within the CEO program area for the 2019-2022 DSM Plan. This initiative is in partnership with FEI to develop an online portal where customers can access targeted energy conservation content and are aware of FBC's other DSM offers.
>
> Industry research on similar tools indicate electric savings for this type of initiative are approximately 2% of total participant electric consumption. However, since these savings are based on behavior changes and there is uncertainty on their relative magnitude, they cannot be effectively forecast at this time and have not been included in this DSM Plan. Once savings are realized, they will be reported in FBC's annual DSM reports to the British Columbia Utilities Commission." [pp.12-13, pdf pp.50-51]

3.1 FBC explains that $1.1 million of the budget increase (2019-2022 DSM Plan over LT DSM Plan) is from the addition of a Residential Customer Engagement Tool. What, if any, portion of the $1.1 million is one-time development costs?

Response:

FBC estimates that one-time development costs represent approximately 12 percent of the four year DSM Plan budget total for the Residential Customer Engagement Tool (CET). Please note that at the time of writing the procurement process has not been completed and the estimates are subject to change.

3.2 What is the expected ongoing annual cost for the Residential Customer Engagement Tool for the 2019-2022 period?

Response:

The expenditures listed in the DSM Plan for the CET are estimated based on RFP values from potential vendors and are subject to change pending the finalization of the agreement. Please see the table below that breaks down the estimates by one-time development costs in 2019 and ongoing annual costs across the 2019-2022 period. Please note that increased annual costs across the 2019-2022 period are based on forecast program growth. Please refer to the response to BCSEA IR 1.3.6 for more details on the forecast growth rates.

Projected CET Expenditures* (000s)			
Year	One-time Development Costs	Ongoing Annual Costs	Total
2019	$124	$157	$281
2020	$0	$203	$203
2021	$0	$254	$254
2022	$0	$321	$321
Total	**$124**	**$935**	**$1,059**

* $2019

3.3 If FBC continues to implement the Residential Customer Engagement Tool beyond 2022, would it expect the ongoing annual cost to be similar?

Response:

The expenditures listed in the DSM Plan for the CET are estimated based on RFP values from potential vendors. As such, those estimates are subject to change pending the selection of the vendor, contract negotiations, scope refinement and the finalization of the agreement. FBC assumes that, if the finalized values are in-line with what is in the current DSM Plan, then those costs would be similar beyond 2022 based on adjusted market rates and the number of customers engaged with CET, for example, the number of customers to receive mailed home energy reports and the frequency of the reports being mailed.

3.4 Please explain how costs for the Tool are shared between FEI and FBC.

Response:

Cost sharing percentages across FEI and FBC for the Residential CET vary by activity. For instance, since FEI and FBC each use their own customer information system, two extracts need to be built and sent to the CET vendor in order to create relevant and customized content for the CET. As such, the costs pertaining to building the data extract from the electric Customer Information System (CIS) are charged 100 percent to FBC, while costs pertaining to building the data extract from the gas CIS are charged 100 percent to FEI. Other costs that benefit both FEI and FBC customers equally, such as the portal and home energy reports, are expected to be allocated between FEI and FBC based on the number of customers of each company, with FEI's share at 88 percent and FBC's share at 12 percent.

3.4.1 How was the cost allocation between FBC and FEI determined?

Response:

Please refer to the response to BCSEA IR 1.3.4.

3.4.2 What are FEI's costs expected to be for the tool each year, for the 2019-2022 DSM Plan period?

Response:

Please refer to the table below that breaks out the FEI expenditures for the 2019-2022 DSM Plan period. For more information, please refer to page 45, Section 7.4.2 of the FEI DSM Plan, filed as Appendix A to its 2019-2022 DSM Expenditures Plan Application (Exhibit B-1).

	FEI Expenditures ($000's)				
Program	**2019**	**2020**	**2021**	**2022**	**2019-2022**
Residential Customer Engagement Tool	$ 2,434	$ 2,472	$ 3,019	$ 3,718	$ 11,643

3.5 FBC states its position that "since these savings are based on behavior changes and there is uncertainty on their relative magnitude, they cannot be effectively forecast at this time and have not been included in this DSM Plan." If savings cannot be effectively forecast, what was the basis of FBC's determination that the tool would be a good investment?

Response:

FBC believes that the determination of a good investment is not solely based on direct energy savings. Not all DSM expenditures result in direct energy savings, but are important to ensure energy conservation and DSM program information has a broad reach and that the DSM portfolio meets the adequacy requirements as stated in the DSM Regulation. Some of those expenditures, such as the CET and all other behavioral programs under the Conservation Education and Outreach Program Area (CEO), are focused on broader energy efficiency education and are also considered to be specified demand-side measures within the meaning of the DSM Regulation.

FBC expects the CET will reach residential customers with targeted energy conservation content that FBC has not normally been able to deliver through traditional communication outreach strategies. FBC plans to use this tool to increase customer literacy of their energy usage by providing details of their specific home energy consumption across appliance type and comparisons across similar buildings, and to provide customers with pathways to reduce their consumption, as well as directly link to residential rebate programs that encourage energy efficient appliance upgrades. FBC intends to leverage both the online portal and the home energy reports to drive behaviour change, increase DSM program participation, and improve customer satisfaction levels.

Furthermore, although FBC feels that not enough data exists to estimate savings in the DSM Plan, FBC believes that savings will be realized and plans to report those savings in future annual reports. Based on an industry review conducted by E Source (an energy industry analytics consultancy) the range of savings for CET programs falls within 1-3 percent.

3.5.1 Did FBC conduct any sort cost-benefit analysis of the Residential Customer Engagement Tool? If yes, please provide this analysis. If no, why not?

Response:

CEO initiatives, such as the CET, are considered to be a specified demand-side measure and therefore expenditures are evaluated as part of the DSM portfolio as a whole. FBC did conduct a high-level cost-benefit analysis for Home Energy Reports (HERs), which was included in the BC Conservation Potential Review (BC CPR). The analysis conducted at the time of the BC CPR was completed based on industry costs and savings estimates for HERs and did not incorporate costs with respect to the portal, rewards and development. Furthermore, the costing data did not include current estimates based on RFP responses that may be subject to change upon the selection of the vendor, scope refinements, and the finalization of the agreement. FBC plans to re-run the cost-benefit analysis once the measure values and program costs are finalized.

Please see also the table below from the BC CPR analysis that breaks down the TRC results from 2019-2022 by residential customer segment types.

Net Benefit/Cost Ratios

Measures	Service Territory	Customer Segment	Cost Test	End Use	2019	2020	2021	2022
Res | Home Energy Reports Elec -SI RET	FortisBC Electric | Southern Interior	R_Other Residential	Total Resource Cost Test	Whole Building	6.761088	6.797153	6.84442	6.896493
Res | Home Energy Reports Elec -SI RET	FortisBC Electric | Southern Interior	R_Single Family Attached/Row	Total Resource Cost Test	Whole Building	7.476078	7.518714	7.574605	7.636153
Res | Home Energy Reports Elec -SI RET	FortisBC Electric | Southern Interior	R_Single Family Detached	Total Resource Cost Test	Whole Building	8.457858	8.502756	8.561597	8.626423

3.5.2 Please explain how the expected savings based on behaviour changes due to the Residential Customer Engagement Tool relate to FBC's position in the 2017 Cost of Service and Rate Design Application that opportunities for future savings due to the Residential Conservation Rate have been largely exhausted.

Response:

FBC stated in the 2017 Cost of Service Analysis (COSA) and Rate Design Application (RDA) that a number of customers have expressed that their opportunities for conservation have been exhausted and, as such, the RCR is viewed as unfair and punitive. The Company has also stated that it believes that much of the more easily completed conservation measures driven by the impact of the Residential Conservation Rate (RCR) have likely been undertaken, and that the five-year timeframe for the full realization of RCR-driven conservation included in the original Residential Inclining Block Application is coming to an end.

FBC has not stated that no further conservation potential exists and in particular, regardless of the level or structure of the residential rate, the savings that accompany conservation will still provide an incentive to use less energy. To the extent that conservation opportunities exist for individual customers, the Residential CET will help those customers to identify them, and as stated will provide home energy reporting and other tools that can foster conservation behaviour.

3.6 Does FBC anticipate that the Residential Customer Engagement Tool will be made available to all of its residential customers?

Response:

The Residential CET will be made available to both FEI and FBC customers that have signed up to Account Online. FBC estimates that approximately 400 thousand residential customers across both FEI and FBC will have access to targeted energy conservation content in 2019. Among those, approximately 10 percent will be FBC customers. This number is expected to grow to approximately 675 thousand FEI/FBC customers by 2022 as more customers are signing up to Account Online. Access to this targeted energy conservation content will be made available through the online portal, which may include action plans, reward programs, seasonal tips, links to contractors, and other related content. Further to having access to the online portal, approximately 25 percent of those customers will be selected to receive home energy reports in proportion with that growth rate. This translates to approximately 90 thousand FEI

and 10 thousand FBC customers receiving home energy reports in 2019, growing to approximately 170 thousand in 2022.

3.7 Please describe FBC's expected methodology for determining the level of savings that can be attributed to the Residential Customer Engagement Tool.

Response:

The Residential CET savings are primarily based on behavior changes and the relative magnitude is uncertain. Once savings are realized, they will be reported in the DSM Annual Reports for the year in which they were realized. FBC expects that historical savings and other factors will be used in forecasting future CET savings.

4.0 Topic: Program Coordination with FEI

Reference: Exhibit B-1, Appendix A: 2019-2022 DSM Plan, p.3, p.5, p.9.

Regarding its Home Renovation program, FBC states that "By design, the program enables partnerships with BC Hydro, FEI, and all levels of government." [Section 2.1, Home Renovation, pdf p. 41]

Regarding its Rental Apartment Efficiency Program, FBC states that "FBC provides the Rental Apartment Efficiency Program in collaboration with FEI." [Section 2.6, pdf p. 43]

Regarding its Custom Program, FBC states that "The program is administered jointly with FEI, providing customers with a one-stop program in the FBC service territory to evaluate and implement building-scale energy efficiency projects." [Section 4.2, pdf p. 47]

4.1 Please explain how these programs that are implemented in partnerships between FBC and FEI are implemented and administered.

Response:

FEI and FBC jointly promote and administer the Home Renovation, Rental Apartment Efficiency and Custom programs in the following areas:

- Co-development of the program structure, process and procedures;
- Day-to-day administration of the program;
- Co-fund the development of marketing and communications pieces and cost share media buys in the combined FEI and FBC service territory;
- Co-fund and share program evaluation and survey results to monitor program health and to identify improvement opportunities;
- Share technological infrastructure including online application forms, databases, and websites; and
- Co-fund builder and energy advisor training with other program partners where applicable.

FEI and FBC continuously seek ways to integrate operational aspects of the program to streamline operations, reduce costs and add value for customers.

4.2 Please explain how cost allocations between FEI and FBC are determined.

Response:

Cost allocations between FEI and FBC vary by activity, and are proportionally divided by percentage based on customer counts in the companies' respective service territories. When allocating costs on a province-wide project that benefits FEI and FBC customers equally, 88 percent of the cost is allocated to FEI and 12 percent to FBC. When allocating costs in the shared service territory that mutually benefits FEI and FBC customers, the costs are divided equally.

4.3 Where certain end uses have efficient options with both electricity and natural gas, for example, electric heat pump water heaters and condensing natural gas demand water heaters, or condensing natural gas furnaces and electric heat pumps, how does FBC envision that programs would ensure that customers receive unbiased information regarding their fuel and technology choices?

Response:

FBC will provide practical information to help customers make the most appropriate choices for their individual circumstances. FBC will provide information relevant to building envelope, air tightness and energy-efficient electric technologies, while FEI will do the same with respect to energy efficient natural gas technologies. For more in-depth information on the climate impacts of different technologies and fuel choices, customers can speak to their FBC Energy Efficiency Representative, FBC Technical Advisor, or FEI Energy Solutions Manager.

4.4 Would the relative climate impacts of the different technologies factor into the information provided to customers?

Response:

Please refer to the response to BCSEA IR 1.4.3.

5.0 Topic: Commercial Program Expenditures and Savings.

Reference: Exhibit B, Appendix A: 2019-2022 DSM Plan, Table 4-1: Commercial Expenditures and Savings, 2019-2022, p.8, pdf p.46.

Table 4-1: Commercial Expenditures and Savings, 2019-2022

Program	Expenditures 2019 dollars (000s)					Energy savings (GWh)					TRC 2019-
	2019	2020	2021	2022	Total	2019	2020	2021	2022	Total	Ratio
Commercial Custom	$980	$963	$1,005	$1,095	$4,043	4.4	5.3	6.0	6.8	22.6	1.3
Commercial Prescriptive	$1,371	$1,218	$1,174	$1,057	$4,819	11.1	10.1	9.2	8.7	39.1	2.8
Labour and expenses	$828	$828	$828	$828	$3,312						
Total	**$3,178**	**$3,008**	**$3,006**	**$2,980**	**$12,173**	**15.5**	**15.5**	**15.3**	**15.5**	**61.8**	**2.0**

5.1 Please explain the reason for the annual decrease in the Commercial Prescriptive expenditures and savings.

Response:

Please refer to the response to BCUC IR 1.12.3.

5.2 Why are the proposed annual labour and expenses identical for each year, while the program Commercial Prescriptive budget is decreasing?

Response:

As described in the response to BCUC IR 1.12.3, the market potential for energy efficiency savings in the Commercial Program Area as a whole is decreasing due to the market transformation of some LED lighting technologies. FBC's Prescriptive Program plans to offset some of the loss in commercial lighting program participation by encouraging customers to increase participation in the Prescriptive Program's non-lighting energy efficiency incentives. In order to achieve those goals, FBC is proposing to maintain the current resources in the Commercial Program Area, but shift a portion of their focus from promoting efficient lighting offers to promoting other efficient non-lighting offers.

6.0 Topic: Low Income Program Area.

Reference: Exhibit B-1, Appendix A: 2019-2022 DSM Plan, pp.6-7, pdf pp. 44-45;

2018 DSM Expenditure Schedule proceeding, Exhibit B-2[1], FBC Responses to BCUC IR1, Appendix A – 2018 DSM Plan, Section A2 Residential Program Area, Table A2-1: Residential Program Expenditures & Savings, pdf p.33;

BCUC Order G-113-18.

The Application states:

> "Table 3-1 outlines the Low Income programs planned expenditures, energy savings and the Benefit/Cost ratio on a Total Resource Cost (TRC) basis. Overall, the Low Income Program Area continues to grow throughout the plan period." [pdf. p. 44]

Table 3-1: Low Income Expenditures and Savings, 2019-2022

Program	Expenditures 2019 dollars (000s)					Energy savings (GWh)				
	2019	2020	2021	2022	Total	2019	2020	2021	2022	Total
Self Install (ESK)	$74	$74	$74	$74	$296	0.2	0.2	0.2	0.2	1.0
Direct Install (ECAP)	$665	$687	$704	$726	$2,781	0.7	0.7	0.7	0.7	2.8
Social Housing Support										
Prescriptive Rebate	$15	$16	$18	$20	$68	0.1	0.1	0.1	0.1	0.4
Support	$26	$30	$35	$40	$130					
Labour and expenses	$64	$64	$64	$64	$254					
Program	**$843**	**$870**	**$894**	**$923**	**$3,530**	**1.0**	**1.0**	**1.0**	**1.1**	**4.1**

Table A2-1: Residential Program Expenditures & Savings from the FBC 2018 DSM expenditure schedule proceeding is reproduced for reference:

[1] https://www.bcuc.com/Documents/Proceedings/2017/DOC_50491_B-2_FBC-Responses-to-BCUC-IR1.pdf.

Table A2-1: Residential Program Expenditures & Savings

	Program	2017 Approved		2018 Plan		
		Savings, system MWh	Cost ($000s)	Savings, system MWh	Cost ($000s)	TRC, net B/C ratio
1	**Home Renovation**					
2	Home Renovation	364	206	1,203	300	1.1
3	Heat Pumps	781	253	395	167	0.9
4	Lighting	2,735	153	3,337	202	1.8
5	Appliances	126	71	215	159	2.1
6	Water Heating	17	28	38	25	1.8
7	**New Home**					
8	New Home	126	52	169	76	1.3
9	**Income Qualified & Rentals**					
10	Low Income	3,247	1,265	1,229	731	2.0
11	Rentals	0	0	306	53	3.4
12	**Customer Engagement Tools**	3,097	200	240	165	0.7
13	**Non-program specific expenses**		491		610	
14	**Total**	**10,493**	**2,718**	**7,132**	**2,486**	**1.4**

6.1 With reference to the 2017 Approved, and 2018 Plan, Savings and Cost for Income Qualified & Rentals, please explain why the 2019-2022 DSM savings that FBC proposes for its low income customers are so much lower than the 2017 Approved, and 2018 Plan, Savings and Cost for Income Qualified & Rentals shown in Table 2A-1 from the 2018 DSM expenditure schedule proceeding.

Response:

Please note that due to a correction to the estimated savings in the Low Income Direct Install program area, Low Income Program Area estimated savings (and total 2019-22 DSM Plan savings) have increased. For further information, please refer to the errata filed concurrently with FBC's IR responses. The following table shows that, once the savings that were omitted are added into the 2019-2022 DSM Plan pursuant to the errata, the savings are similar to the 2018 DSM Plan. Please refer to the 2018 DSM Plan proceeding for a discussion of the changes from 2017.

Low Income	Energy savings, system GWh				
Program	2018 Plan	2019	2020	2021	2022
Total	1,229	1,213	1,214	1,217	1,255

Savings relative to expenditure are showing a variance from the 2018 DSM Plan due to:

- The 2019 Plan participation rate for the Direct Install program has been adjusted to below 2018 Plan levels based on 2018 performance;

- Lighting measures in the Direct Install program are declining due to there being less opportunities than earlier years to upgrade lighting to LEDs and lighting measures are generally a low cost, high savings measure; and
- New programs such as the Support Program involve energy studies and energy conservation installation support, which are activities that have costs and do not have energy savings associated with them.

6.2 Given that the savings are less in each year of the 2019-2022 DSM Plan than were proposed in 2018, why are the costs in 2019-2022 more than the 2018 costs?

Response:

Please refer to the response to BCSEA IR 1.6.1.

6.3 In Order G-113-18 the BCUC accepted FBC's 2018 DSM expenditure schedule and stated on page 7 that "It is expected that FBC will provide an update on the effectiveness of its program outreach efforts in the next expenditure schedule filing with the BCUC." Has FBC provided such an update? If yes, please provide it. If not, why not?

Response:

FBC has not provided a specific update on the effectiveness of its Low Income program outreach efforts in the 2019-22 DSM Plan itself. FBC has provided an update on its outreach efforts and addressed the difficulties of determining their effectiveness in the short term in response to BCUC IR 1.11.3. FBC believes that a sustained approach to outreach activities is vital in building the participation levels in the Low Income programs and, as noted in Section 3.5 of the 2019-22 DSM Plan (Appendix A to the Application), is proposing to strengthen and build on the outreach activities that were started in 2018. FBC believes that the outreach activities in the 2019-22 DSM Plan will, over time, result in higher participation rates.

7.0 Topic: Potential Changes to Markets and Avoided Costs during the 2019-2022 Plan period.

Reference: Exhibit B-1, Application for Acceptance of DSM Expenditures for 2019-2022, p.1.

The Application states:

> "The LT DSM Plan was premised on a ramp up in DSM spending and savings, beginning in 2021, that would offset an average of 77 percent of FBC's forecast load growth annually over the LTERP's planning horizon. <u>In response to emerging customer activities</u>, the DSM Plan builds on and is an escalation of the target savings contemplated in the LT DSM Plan." [underline added]

7.1 Does FBC view it as possible that "emerging customer activities" could occur that are not anticipated in the four-year Plan period, and that could materially either increase or decrease the opportunity for cost-effective energy saving opportunities prior to its next LTERP and LT DSM Plan and 2023+ DSM Expenditure Schedule filings?

<u>Response:</u>

Yes, FBC believes it is possible that "emerging customer activities", additional to the cannabis production facilities contemplated in the current DSM expenditure schedule application filing, or changes to avoided costs, or other factors outside of FBC's control could occur and could materially either increase or decrease the opportunity for cost-effective energy saving opportunities prior to its next LTERP and LT DSM Plan and DSM expenditure schedule filings.

7.1.1 If yes, what process would FBC propose to use to adapt or alter its approved Plan?

<u>Response:</u>

FBC does not believe a specific process or mechanism is required. FBC's request for approval to roll over unspent expenditures is a recognition that the DSM Plan is subject to changes in market conditions, customer responses to programs, and other external factors that could impact the timing of program expenditures and is meant to give FBC flexibility to respond accordingly.

In addition, if there were changes during the period covered by the 2019-2022 DSM Plan that significantly impacted the opportunities or cost-effectiveness of its DSM programs, FBC would

review its level of expenditures in light of the changes and determine whether there was any need to file an amended expenditure schedule with the BCUC. Such a decision would depend on a variety of factors that would vary in the circumstances, including the amount of time and resources needed to plan and organize any new program, whether the new program could be implemented before the end of the term of the expenditure schedule, whether programs could be ramped up to accommodate any increase in funding, and whether changes to program design are necessary.

Please also refer to the response to BCUC IR 1.9.4.

7.1.2 Does FBC anticipate that BCUC approvals would be required?

Response:

Please refer to the responses to BCSEA IR 1.7.1.1 and BCUC IR 1.9.4.

7.2 Does FBC view it as possible that avoided costs could substantively change in a manner that is not anticipated in the four-year Plan period, and that could materially either increase or decrease the opportunity for cost-effective energy saving opportunities prior to its next LTERP and LT DSM Plan and 2023-2028 DSM Expenditure Schedule filings?

Response:

Please refer to the response to BCSEA IR 1.7.1.

FBC notes that the LRMC and DCE factors are, by their nature, long-run avoided costs and thus unlikely to fluctuate significantly in the short term. Additionally, the Company has committed to reviewing, and updating as necessary, both factors as part of the next LTERP process.

7.2.1 If yes, what process would FBC propose to use to adapt or alter its approved Plan?

Response:

Please refer to the response to BCSEA IR 1.7.1.1.

7.2.2 Does FBC anticipate that BCUC approvals would be required?

Response:

Please refer to the responses to BCSEA IR 1.7.1.1 and BCUC IR 1.9.4.

8.0 Topic: Heat Pumps

Reference: Exhibit B-1, Appendix A: 2019-2022 DSM Plan, section 2.2, Heat Pumps, p.4, pdf p.42;

Exhibit B-1, Appendix E, FBC DSM 2017 Annual Report, Subappendix C, Residential Heat Pumps Program Executive Summary, pdf p.195

Appendix A to the Application states:

> "Central and ductless heat pump incentive offers are consolidated within the Home Renovation program. With its temperate winters and hot summers, the FBC service area is an ideal climate for air source heat pumps (ASHP). Customers can upgrade electric heating systems to either central split (forced-air) or ductless mini-split (for customers with electric baseboard heating) air source heat pumps." [pdf p.42]

The March 2018 Final Report of the Evaluation of the FortisBC Residential Heat Pump Program states in the executive summary:

> "**Conclusion 5**: Current rebates, although reasonable, could be further optimized. While current participants indicated that rebate levels were adequate – and even suggested they might have bought heat pumps at lower rebate levels, feedback from surveyed contractors and nonparticipants4 suggests that current incentive levels may not be sufficient to drive a large increase in participation.5 Since staff are considering restructuring rebate offers, we recommend exploring tiered rebates that depend upon factors such as efficiency level or whether the heat pump is certified to operate in very cold climates. Tiered rebates would reward (i.e., be higher for) customers who installed more efficient equipment and are the most common type of rebates offered by many heat pump programs we reviewed during this evaluation." [pdf p.200, footnote numbers removed]

8.1 Please explain the heat pump incentive offers that FBC proposes will be available within its Home Renovation program.

<u>Response:</u>

FBC will offer incentives for central and ductless heat pumps under the Home Renovation Rebate partner program with utility partners and EfficiencyBC. Incentives have been aligned with the provincial offer, increased and structured into tiers to reward customers who install more efficient equipment. Heat pump tune ups will also be offered by FBC.

As an alternative to direct financial incentives, FBC may continue to offer heat pump loans for qualifying customers at a below market interest rate.

8.2 Will FBC offer tiered, or otherwise enhanced, rebates as recommended in the Evaluation?

Response:

Please refer to the response to BCSEA IR 1.8.1.

9.0 Topic: Commercial and Industrial Custom Program

Reference: Exhibit B-1, Appendix E, FBC DSM 2017 Annual Report, Subappendix D, Custom Business Efficiency Program Executive Summary, pdf p.201

The March 2018 Evaluation of the FortisBC Custom Business Efficiency Program (CBEP) states in the executive summary:

> **"1.3.2 Summary of Trade Ally Findings and Recommendations**
>
> The results of our limited interviews indicate a surprisingly low level of involvement with and awareness of CBEP among 17 companies identified as trade allies by FortisBC. Even though we reached out to the specific contact provided by FortisBC or spoke with individuals we were referred to by that contact, only a few trade allies were aware of any involvement with projects completed through CBEP. While trade allies who had completed applications for the program generally considered the paperwork and other administrative requirements to be reasonable, those who were aware of the program but had not participated perceived it to be complicated and cumbersome, and they were not certain of what kinds or sizes of projects would be eligible for the program.
>
> For most trade allies, the Business Direct Install (BDI) program was one with which they had more experience and found much easier to use and sell to their customers. The Commercial Products Program is seen as less generous in the level of rebates provided but easier to participate in than CBEP.
>
> Both these results and specific suggestions from some respondents indicate that <u>better communication with trade allies is needed</u> to explain the details of CBEP, including eligibility requirements and the participation process. In addition, several trade allies pointed out that customers are relatively uninformed regarding energy efficiency generally and FortisBC programs in particular. A more focused outreach program to address these concerns should be manageable for the limited number of trade allies involved." [pdf p.214, underline added]

9.1 Please explain the steps that FBC intends to implement to improve communication with trade allies for its Commercial Custom Program and its Industrial Custom Program.

<u>Response:</u>

Energy consultants, contractors, and distributors serve as the primary Trade Allies that support and engage customers in the Commercial and Industrial Custom Program. As Custom Programs typically require technical and engineering support, energy consultants are the primary Trade Ally that work with customers. FBC expects that the integration of the FBC and

FEI custom programs and additional direct communications with energy consultants will increase awareness of FBC Commercial and Industrial Custom Program offers.

Following feedback from the Custom Business Efficiency Program evaluation, FBC looked to leverage the strong awareness of the FEI Commercial Custom Design Program (FEI Performance Program) among customers, trade allies, and energy consultants and integrated the FBC Custom programs under the same brand. FBC and FEI will realize efficiencies through integrating and administering the custom offers jointly and by having FBC and FEI program staff present both natural gas and electric offers together when reaching out to trade allies that serve the FBC service territory.

FBC has also contacted the top participating energy consultants in the FEI Performance Program to make them aware of electric energy efficiency opportunities in the FBC service territory. There are currently five energy studies underway in 2018, with two others in development in the FBC service territory, compared to only one energy study completed in 2017.

10.0 Topic: Kelowna Demand Response Assessment

Reference: Exhibit B-1, Appendix A-1, Kelowna Demand Response Assessment, Phase 1: Screening Study, pdf p.64

Appendix A to the Application states:

> "FBC is considering Demand Response (DR), where electricity consumers reduce their load by responding to a signal from the utility at critical times, as a potential low-cost solution to defer system upgrades. A study conducted by Navigant identified 50-60 MW of DR potential across FBC's entire territory from the residential & commercial sectors. With this information, FBC has decided to conduct a DR screening study (Phase 1 and 2), and subject to the results, conduct a pilot to determine if DR can cost-effectively and reliably provide avoided capacity benefits in the Kelowna area." [p.2, pdf p.64]

10.1 Please provide the Navigant study referenced in the paragraph above.

Response:

The referenced Navigant Study is included as Attachment 10.1.

11.0 Topic: Kelowna Demand Response Assessment

Reference: Exhibit B-1, Appendix A-1, Kelowna Demand Response Assessment, Phase 1: Screening Study, p.3, pdf p.63 & 83

The executive summary of the enbala report states:

> "FBC Inc. (FBC or the Company) is investigating the potential use of Demand Response (DR) for mitigating both system peaks (winter and summer) and regional congestion within the Kelowna area. FBC has engaged Enbala to examine the potential for commercial, industrial and institutional sectors in the Kelowna area to provide sufficient DR capacity to provide capacity relief during grid peak times.... " [pdf p. 63]

The conclusions and recommendations of the enbala report state:

> "FBC's load projections, by necessity, are constantly adapting to new information. The rapid adoption of plug-in electric vehicles (PEV) and air conditioning units may pose a significant challenge on the electricity network, which not only impacts the peak load, but also impacts the load shape. Interestingly, both of these end-use technologies are loads that can be included in DR programs." [pdf p.83]

11.1 Did FBC consider whether to include an assessment of the potential for residential or small commercial customer Demand Response, such as through direct load control of air conditioning, to contribute to capacity relief in the Kelowna area? If yes, why did FBC determine not to include residential or small commercial DR in the assessment? If no, why not?

Response:

The Navigant DR study, a copy of which is provided in the response to BCSEA IR 1.10.1, shows a DR potential assessment of residential and small commercial customers. FBC notes the Navigant DR study was at a high-level, focused on winter peak mitigation and encompassed FBC's entire service area. Whereas the Enbala DR assessment was a detailed characterization of large Institutional, Commercial, and Industrial (ICI) customer base, including mapping the top 50 customers' detailed usage profiles against the backdrop of three years of the Kelowna area load profile. Furthermore, the Enbala study focused on summer peak mitigation as the Kelowna area bulk transformers' summer reliability threshold will be breached first. FBC intends to take a hands-on approach with the successful proponent for its proposed DR pilot, from recruiting ICI customers to learning all aspects of operating the DR pilot.

Typically, Residential and Small Commercial DR programs use the services of a third-party aggregator, which would restrict the Company's learning from a DR pilot focused on such mass market customers.

11.2 Will FBC investigate, in future assessments, the potential for residential or small commercial customer Demand Response, such as through direct load control of air conditioning, to contribute to capacity relief in the Kelowna area?

Response:

Please refer to the response to BCSEA IR 1.11.1.

FBC anticipates the scope of future DR assessments will include residential and small commercial end-uses such as air conditioning, whether by direct load control or other means such as smart thermostat set-point changes.

11.3 Will FBC investigate, in future assessments, the potential for residential or small commercial customer Demand Response, such as through direct load control of air conditioning, to contribute to capacity relief in other constrained areas of its service territory?

Response:

Please refer to the response to BCSEA IR 1.11.1.

FBC anticipates its proposed DR pilot will inform a business case on whether to pursue DR on a larger scale, including targeting both Kelowna and other constrained areas, for both summer and/or winter capacity relief as indicated in future DR assessments.

12.0 Topic: Kelowna Demand Response Assessment

Reference: Exhibit B-1, Appendix A-1, Kelowna Demand Response Assessment, Phase 1: Screening Study, p.5, pdf p.65; p.17, pdf p.77

The Kelowna Demand Response Assessment states:

> "The total load forecast for both summer and winter is shown in Figure 2 for the Kelowna area. This plot includes the overall reliable capacity of bulk supply substations, Lee Terminal and DG Bell together. Currently there is a narrow margin between the peak loads and reliability limit in summer, whereas winter contains significant additional capacity. Therefore, the study is focused on analyzing the summer peak periods only. <u>The forecast shown here is based on historical load drivers expected in the Kelowna area and does not include proposals for cannabis facilities or block-chain which may increase the load growth significantly</u>. Enbala has focused this study on the Kelowna area load as a proxy to represent peak demands system wide." [p.5, pdf p.65, underline added]

> "FortisBC is experiencing large potential uncertainty in load growth in the Kelowna region due to emergent cannabis production facilities and cryptocurrency miners. Given this uncertainty, <u>it is difficult for FBC to be certain that even 11 MVA of DR as identified in this study will be sufficient to avoid a capital upgrade</u>." [p.17, pdf p.77, underline added]

12.1 What steps will FBC take to minimize the capacity needs of emergent cannabis production facilities and cryptocurrency miners to mitigate the potential impact they may have on capital upgrade needs?

<u>Response:</u>

FBC offers both the Industrial Prescriptive and Custom Programs to new cannabis production and block-chain mining facilities. Upon identification of a potential new facility, FBC's Technical Advisors reach out to each new facility under development to discuss how FBC DSM programs can help optimize their energy savings, costs and capacity needs.

12.2 Will FBC develop comprehensive energy efficiency and demand response proposals for emergent cannabis production facilities and cryptocurrency miners to ensure that load impacts due to this market growth will be minimized? If yes, please describe FBC's expected approach to these emergent customers. If no, why not?

Response:

FBC currently has comprehensive energy efficiency offers for emergent cannabis production facilities through the Industrial Custom Program. As of October 15, 2018, five cannabis facilities have active applications in the Industrial Custom Program, primarily to encourage customer implementation of LED grow lights instead of standard efficiency grow lights, but also to investigate other energy efficiency opportunities.

Energy efficiency opportunities in block-chain mining are not well understood, and if cost-effective energy efficiency solutions for eligible block-chain mining customers emerge, FBC will consider providing offers under the FBC Industrial Program Area.

For a discussion of FBC's approach to cannabis and cryptocurrency demand response, please refer to the responses to BCUC IRs 1.13.3 and 1.18.6.

13.0 Topic: Innovative Technologies

Reference: Exhibit B-1, Appendix A, FBC 2019-2022 DSM Plan, section 9.3 Innovative Technologies, p.18-19, pdf p.56-57

Under the Innovative Technologies program, FBC states:

> "An example of a field study is to monitor cold climate heat pumps (CCHP). FBC has submitted a proposal to NRCan to co-fund a CCHP study, in collaboration with BC Hydro and BC Ministry of Energy and Mines."

13.1 If the study goes ahead, when does FBC anticipate receiving the results?

Response:

If the study goes ahead, FBC anticipates receiving the results in April 2020.

14.0 Topic: Electrification (fuel switching)

Reference: Exhibit B-1, Table 3-1: BC's Energy Objectives Met by FBC DSM Plan, p.5, pdf p.10

Regarding BC energy objective (h), to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia, FBC states:

> "FBC pursues electrification (fuel switching) measures pursuant to s. 18 of the CEA and s. 4 of the Greenhouse Gas Reduction (Clean Energy) Regulation. For example: FBC undertook construction of the Kootenay Electric Vehicle (EV) charging network and plans to pursue the construction of further EV charging facilities." [footnote omitted]

14.1 In addition to the Kootenay EV charging network, what low-carbon electrification (fuel switching) measures does FBC have underway or planned?

Response:

In addition to deploying direct current fast charging stations to support highway EV travel, FBC is also currently examining the use of incentives and/or rebates related to Level 2 charging infrastructure to support customers considering EV adoption.

FBC also currently administers the residential and commercial electrification offers on behalf of EfficiencyBC within the FBC service area. The budget to administer and provide incentives for the EfficiencyBC program are provided by the provincial and federal governments and not from FBC.

15.0 Topic: Market Potential, Incentive Levels

Reference: Exhibit B-1, Appendix B, BC Conservation Potential Review, Section 5, Market Potential

The Application states:

> "Market potential is a subset of economic potential that estimates the rate of adoption, over the planning horizon, of DSM measures using factors like equipment turnover (a function of a measure's lifetime), <u>simulated incentive levels</u>, consumer willingness to adopt efficient technologies, and marketing activities. Table 5-2 provides an overview of the approach used for each of the factors." [p.16, pdf p.21, underline added]

In Table 5-2, with reference to "Incentive Strategy," FBC states:

> "Set incentive levels on a levelized $ per kWh of savings basis, such that the simulated percentages of total spending from incentives versus non-incentive costs aligns with planned 2017 values across the sector." [p.17, pdf p.22]

The Navigant CPR Market Potential chapter says that the model estimated market potential based on incentive levels determined as follows:

> "1.1.5 Incentive Strategy
>
> Per FortisBC Electric's guidance, this study calculates measure-level incentives based on a levelized dollar-per-kWh of savings basis. A levelized dollar-per-kWh incentive represents the dollar amount provided for each discounted kWh of savings over a measure's lifetime. The discount rates used to find the present value of savings are consistent with those applied to discounted cash flows. Since a single incentive level is found for each sector10, the model bounds the actual incentive provided to each measure to be at least 25% of the incremental measure cost, and to not exceed more than 100% of the incremental measure cost. Section 1.1.8 discusses how the model calibration process informed the specified incentive percentage in more detail.
>
> [10] Navigant applied incentive percentages at the sector level, as opposed to the measure level, per the focus of this study's scope on sector-level market potential, rather than program-level potential. Actual program design would define incentive levels for each measure." [p. 11, pdf p. 98]

15.1 Please confirm, or otherwise explain, that the quoted explanation relates to deriving the estimate of market potential, not to setting incentive levels for specific programs.

Response:

Confirmed, the quoted explanation relates to deriving the estimate of market potential, not to setting incentive levels for specific programs.

15.2 What strategy or guidelines does FBC apply to setting actual incentive levels for DSM measures?

Response:

FBC sets incentive levels on a program-by-program basis. However, FBC generally uses the following guidelines to determine incentive levels for DSM measures:

- The lesser of:
  - Up to $0.25 per kWh of estimated annual savings (except in certain programs that require higher incentives, such as Low Income),
  - 50 percent of installed measure cost,
  - 100 percent of incremental costs for new products or new construction, or
  - The amount sufficient to achieve a two-year payback.

15.3 Does FBC maintain a guideline that incentives will not exceed 50% of the participant's cost of the measure?

Response:

FBC sets incentive levels on a program-by-program basis. When it is deemed appropriate, incentives may exceed 50 percent of the participant's cost of the measure.

16.0 Topic: Natural Change

Reference: Exhibit B-1, Appendix B, BC Conservation Potential Review, Section 5, Market Potential, 1.2.6 Adjustments for Natural Change

The Navigant report states:

> "As discussed in Section 2.3.2, Navigant estimated natural change to account for differences in end-use consumption in the Reference Case compared to the frozen EUI case. Natural change accounts for changes in consumption that are naturally occurring and are not the result of utility-sponsored programs or incentives." [pp. 27-28, pdf pp. 114-115, underline added]

16.1 Do changes in consumption due to FBC's Residential Conservation Rate (RCR) fall into the "natural change" category in the market potential modeling?

Response:

FBC believes that changes in consumption due to FBC's RCR fall into the "natural change" category. However, the results of the market potential study are presented in "gross terms and are not adjusted for natural change" (Appendix B to Exhibit B-1, p.28).

From the British Columbia Conservation Potential Review: Section 5: Market Potential (Appendix B to the Application (Exhibit B-1)):

- Since results in previous sections are in gross terms and are not adjusted for natural change, this section compares the results before and after adjustments for natural change; Market potential after adjustment for natural change is on average about 6% lower than potential before natural change by 2035 [p.28].

From the British Columbia Conservation Potential Review (Appendix A to the 2016 LT DSM Plan filed as part of the 2016 LTERP):

- Natural conservation is a well-established concept in DSM programs, and typically refers to actions taken by utility customers — in absence of utility-sponsored programs — to improve energy efficiency and reduce consumption. These actions are occurring naturally, with no influence from utilities or program administrators [p. 61 of 135];

- This study captures the effects of natural conservation as well as natural growth within the end-use intensities, and defines these effects as "natural change" [p. 61 of 135];

- Since Navigant estimates technical and economic potential based on the frozen EUI case, any missing consumption (i.e., positive natural change) is not included in the technical and economic results. Conversely, the model overestimates technical and economic potential when natural change is negative [p. 115 of 135];

The Navigant report states:

> "On average across the study period, the residential technical potential after adjusted natural change is roughly 5% lower than the potential prior to natural change." [p.29, pdf p.116]

16.2 Did Navigant's estimate of natural change for the residential sector assume that the RCR remains in place throughout the test period?

Response:

Navigant did not explicitly estimate the impact of the RCR on natural change for the residential sector. Please refer to the response to BCSEA IR 1.16.1 for more discussion on natural change.

17.0 Topic: Proposed Optional Time of Use Rates

Reference: FBC 2017 Cost of Service and Rate Design Application, Exhibit B-1, p.8

17.1 Please confirm that in its 2017 Cost of Service and Rate Design Application FBC seeks Commission approval of optional time of use rates, and that this proceeding is not yet concluded.

Response:

Confirmed. FBC is seeking approval to reintroduce optional Time of Use (TOU) rates for Residential customers in its 2017 COSA and RDA. The 2017 COSA and RDA regulatory process is still ongoing. For all other rate classes, the Company already has optional TOU rates in place, but is seeking approval to amend both the structure and pricing of those rates.

17.2 Please explain whether and how the 2019-2022 DSM Plan incorporates the possibility of approval of optional time of use rates.

Response:

FBC considers that optional TOU rates for residential customers, if approved, will send price signals to participating customers to shift their loads to lower cost, off-peak time periods. Since the status of TOU rates was unknown at the time, the 2019-2022 DSM Plan does not contain any enabling measures, (e.g., Electric Thermal Storage (ETS) units), however such measures could be contemplated in the future as part of a larger DR business case.

18.0 Topic: Benefit/Cost Measures

Reference: Exhibit B-1, Appendix A, 2019-2022 DSM Plan, Table 10-1: DSM Plan Benefit-Cost Tests, 2019-2022, p.21, pdf p.59

Table 10-1: DSM Plan Benefit-Cost Tests, 2019-2022

Program Area (Sector)	TRC	mTRC	UCT	PCT	RIM	TRC	Utility Cost
	Ratio	Ratio	Ratio	Ratio	Ratio	$/MWh	$/MWh
Total	**1.5**	**1.7**	**2.8**	**3.1**	**0.8**	**84.5**	**45.1**
Residential Program							
Home Renovation	2.2	2.4	4.2	4.3	0.8	77.2	39.7
New Home	2.2	2.4	3.9	4.0	1.0	92.0	52.4
Lighting	1.9	2.2	13.6	1.9	1.1	58.3	8.2
Rental Apartment	3.0	3.4	3.0	-	0.7	38.2	38.2
Total	**2.1**	**2.3**	**4.8**	**3.5**	**0.9**	**72.6**	**32.4**
Low Income Program							
Self Install	3.6	3.6	3.6	-	0.3	30.6	30.6
Direct Install	1.6	1.6	1.6	-	0.7	73.5	73.5
Social Housing Rebate Support							
Prescriptive Rebate Support	1.5	1.5	10.2	1.4	1.1	75.7	11.3
Total	**1.7**	**1.7**	**1.8**	**-**	**0.6**	**68.4**	**62.9**
Commercial Program							
Commercial Custom	1.3	1.5	4.7	1.9	0.8	92.5	25.2
Commercial Prescriptive	2.8	3.2	6.7	5.2	0.8	43.9	18.4
Total	**2.0**	**2.2**	**5.8**	**3.2**	**0.8**	**62.2**	**21.0**
Industrial Program							
Industrial Custom	1.8	2.1	5.1	2.3	1.0	58.7	21.2
Industrial Prescriptive	1.4	1.5	4.9	1.7	0.9	91.6	25.4
Total	**1.7**	**2.0**	**5.1**	**2.2**	**1.0**	**64.0**	**21.8**

18.1 Please define the measures TRC as $/MWh and Utility Cost as $/MWh.

Response:

'TRC as $/MWh' refers to the Total Resource Cost of the program (including customer costs, incentives, and non-incentive program costs) per MWh of energy savings. 'Utility Cost as $/MWh' refers to the Utility Cost of the program (including incentives and non-incentive program costs) per MWh of energy savings.

19.0 Topic: Low Income Program

Reference: FEI Annual review for 2019 Delivery Rates, Exhibit B-9, response to Undertaking No. 5, pdf pp. 6-7

In its response to Undertaking No. 5 in the FortisBC Energy Inc. (natural gas) Annual Review of 2019 Delivery Rates proceeding, FEI explained that:

> "2018 projected expenditures for the low income program area are below plan due to anticipated lower project completions in the Energy Conservation Assistance Program. This is due to a program delivery vendor transition that occurred during 2018 after the initial delivery vendor entered creditor protection early in the year.

19.1 Did the program delivery vendor transition affect FBC's implementation of the Energy Conservation Assistance Program?

Response:

Yes, the program delivery vendor transition affected FBC's implementation of the Energy Conservation Assistance Program (ECAP). FBC made best efforts to minimize impacts to the program and its participants. New contractors were engaged, trained on the program processes and specifications, and began scheduling jobs with program participants as quickly as possible. All customers that were mid-stream in program participation were preserved and the work is being completed by the new contractors. The initial vendor going into creditor protection was not expected and the main impact was a delay in customer project completions, which in turn has led to lower projected expenditures for the ECAP program in 2018.

19.2 What is the current status of FBC's ability to deliver ECAP for its customers?

Response:

Currently, FBC is focused on serving any customers that had projects mid-stream during the transition of program delivery vendors and also serving new customers that have recently applied to the ECAP. FBC has engaged two program delivery vendors to replace the one former vendor. This will reduce the wait times for customers that were mid-stream during the transition and also create greater capacity for future years. Both vendors are currently fully operational and actively scheduling work for ECAP participants.

Attachment 10.1

Demand Response Potential Assessment for FortisBC

FINAL REPORT

Prepared for:

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Reference No.: 180336
September 13, 2018

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DISCLAIMER

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EXECUTIVE SUMMARY

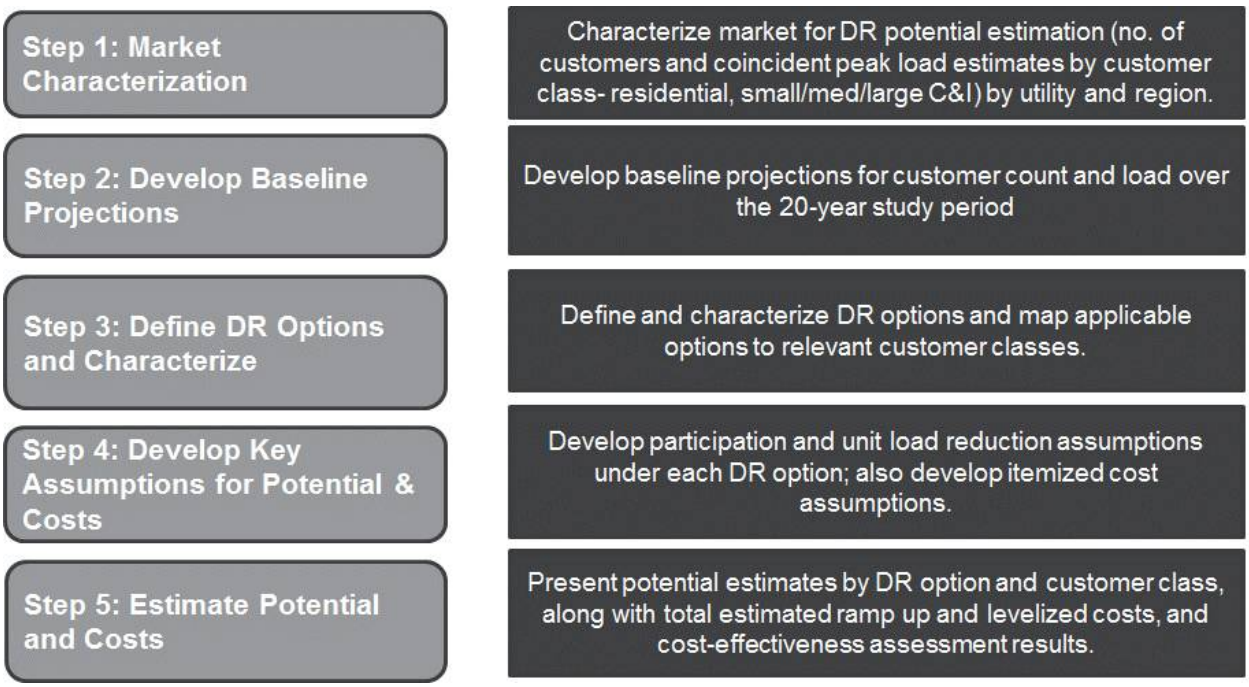
FortisBC engaged Navigant Consulting Ltd. (Navigant or the team) to prepare a demand response (DR) potential assessment for FortisBC's service territory over the 2018-2037 forecast period. The objective of this assessment was to estimate the potential for use of DR as a long-term capacity planning resource to reduce customer loads during winter peak periods.

Navigant worked with FortisBC to identify relevant DR program types in FortisBC's service territory and the applicability of these program types by customer segments and end-uses to realize winter peak load reductions. Navigant developed technical and market potential estimates for DR, estimated costs and conducted cost-effectiveness assessment of the different DR options.

Analysis Approach

Navigant developed FortisBC's demand response potential and cost estimates using a bottom-up analysis. The analysis utilizes primary data from FortisBC on customer load characteristics and latest available information from the industry on DR resource performance and costs. The DR potential analysis efforts provide input data to Navigant's Demand-Response Simulator (DRSim™) model, which calculates total DR potential across the FortisBC's service territory. Figure ES-1 below summarizes the DR potential estimation approach.

Figure ES-1. DR Potential Assessment Steps



Source: Navigant

Table ES-1 below represents the segmentation of customers by size for the DR potential assessment.

Table ES-1. Market Segmentation for DR Potential Assessment

Level	Description
Level 1: Sector	• Residential • Commercial and industrial (C&I)
Level 2: Customer Class	• Residential • C&I customers by size, based on maximum demand values: ○ **Small C&I:** <40 kW maximum demand (Small Commercial Service) ○ **Medium C&I:** ≥40 kW and <150 kW maximum demand (Commercial Service) ○ **Large C&I:** ≥150 kW maximum demand and <1 MW maximum demand. (Commercial Service, Large General Service) ○ **Extra-Large C&I:** >1 MW maximum demand (Large General Service)

Source: Navigant

The potential assessment considered three types of DR options: Direct Load Control (DLC), C&I Curtailment, and Time-Of-Use (TOU) rates, summarized below in Table ES-2.

Table ES-2. Summary of DR Options

DR Options	Characteristics of DR Options	Eligible Customer Classes	Targeted/Controllable End Uses
Direct Load Control (DLC) ✓ Thermostat ✓ Load control switch	Control of space heating/cooling load using a two-way communicating thermostat and of water heating load using a load control switch	• Residential • Small C&I • Medium C&I	• Electric space heating: central forced air furnaces, heat pumps, and baseboard heaters • Electric water heating
C&I Curtailment ✓ Manual ✓ Auto-DR-enabled	• Firm capacity reduction commitment • $/kW payment based on contracted capacity plus $/kWh payment based on energy reduction during an event	• Large C&I • Extra-Large C&I	Various load types including HVAC, lighting, refrigeration, and industrial process loads
✓ **TOU Rates**	Voluntary opt-in TOU rate offer[1]	All customer classes	All

Source: Navigant

[1] Opt-in implies that customers are offered a choice of enrolling in this rate and a certain percentage of customers opt-in and are placed on the TOU rate. Therefore the "TOU" rate considered in the analysis is an opt-in type of offer. The other type of rate offer is "default with opt-out" where customers would be defaulted to the rate (in this case TOU) and would have the choice to opt-out of the rate if they wanted to. Opt-out type of offer is not included in this analysis.

Baseline Peak Demand Projections

The baseline winter morning and evening peak demand projections serve as a foundation for the DR potential assessment. Analysis of FortisBC's system load identified the time periods during which the peak load falls as follows:

- **Winter months:** November-February
- **Morning peak period:** 7 a.m.-11 a.m.
- **Evening peak period:** 4 p.m.-8 p.m.
- **Day type:** Weekdays

This study assesses winter DR potential using the peak definition above. However, timing of the peak load is only one component of determining system needs – it is also necessary to consider resource availability. It may be the case that FortisBC has system capacity constraints over a period that is broader than this definition.

Navigant developed disaggregated peak demand projections by customer class and end-use based on the reference case sales forecast from Base Services (energy efficiency potential assessment), building type load profiles available from the Southern Interior[2] region of BC Hydro's service territory and publicly available end-use load shapes.

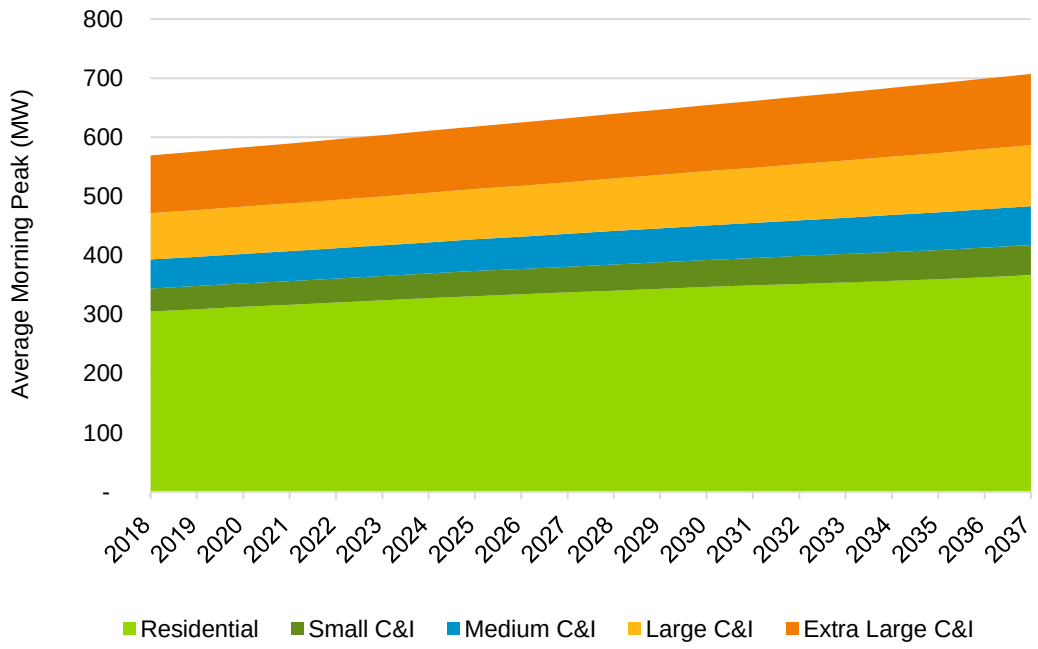
Figure ES-2 and Figure ES-3 show the winter morning and evening average peak demand projections by customer class. Note that these peak demand values represent the average demand over the 4-hour, multi month, peak period in the morning and the 4-hour, multi month, peak period in the evening, which results in these peak demand values being materially lower than the traditional, single hour system peak.

The average morning peak period demand is projected to steadily grow from 570 MW in 2018 to 707 MW in 2037. The average evening peak period demand is projected to steadily grow from 580 MW in 2018 to 703 MW in 2037[3]. Residential has the highest share of the peak demand (~50% share in morning and ~60% share in evening), followed by extra-large C&I (~17% share in morning and ~15% in evening). Large C&I customers have slightly lower share than extra-large (~15% share in morning and ~12% share in evening), while small and medium C&I customer classes each have less than 10% share in the peak demand.

[2] FortisBC and Navigant jointly agreed that the Southern Interior region was the best choice for consideration of load profiles given that FortisBC did not have load profiles available for its service territory.

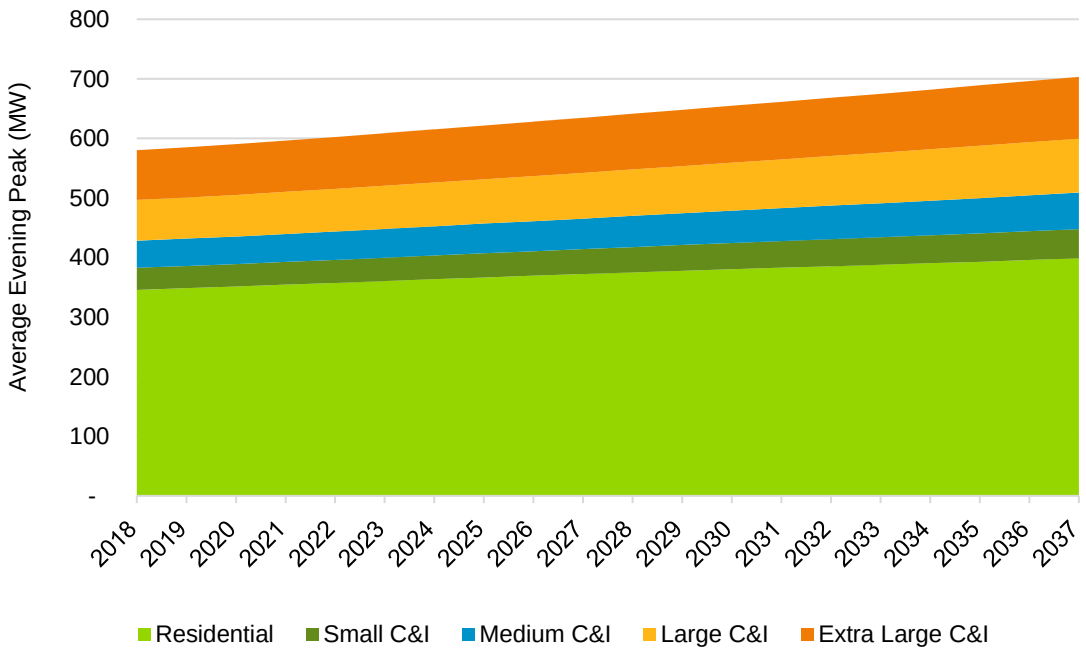
[3] FortisBC currently experiences a higher peak demand in the evening than in the morning. However, the average peak demand projections (averaging over the four morning or evening hours over multiple months) indicate that the average evening peak demand is expected to grow at a slightly lower rate than the average morning peak demand in future. The slowdown in the evening peak demand is driven by more efficient lighting and appliances entering the marketplace, which lead to lowered energy use from these end-uses in the evening. In addition, residential electric water and space heating have increasing end use intensities over time and result in higher morning peak than evening peak, since these loads are morning-heavy.

Figure ES-2. Winter Morning Peak Load Forecast by Customer Class (MW)



Source: Navigant

Figure ES-3. Winter Evening Peak Load Forecast by Customer Class (MW)



Source: Navigant

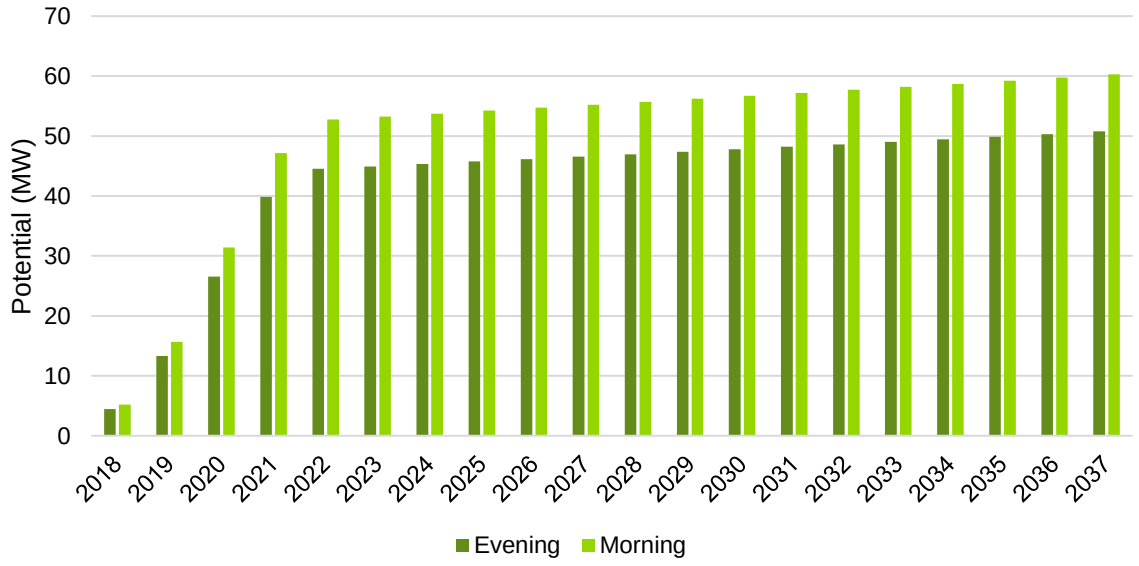
Next, we present DR market potential results by the different DR options and customer segments. The key variables for DR potential estimation are participation rates in the DR options and the amount of load

reduction that could be realized once customers are enrolled in a DR program through different types of control mechanisms, referred to as unit impact. The analysis also included itemized detailed cost assumptions for realizing the potential. The study estimated potential at three levels – technical potential (potential assuming 100% participation of eligible load), standalone market potential (independent potential estimates by DR option based on achievable market participation rates), and integrated market potential (which considers a portfolio of DR programs and considers interdependencies in program participation across the different DR options). The integrated market potential and cost results are discussed below[4].

DR Integrated Market Potential and Cost Results

Figure ES-4 and Figure ES-5 show the integrated market potential results in absolute MW values and as a "% of FortisBC's peak demand". Potential in the morning peak period is expected to increase from roughly 4 MW in 2018 to approximately 53 MW in 2022, based on an assumption that participation ramps up rapidly over five years. The potential then grows at a much slower rate over the next 15 years to reach 60 MW in 2037, which represents 8.5% reduction in FortisBC's average morning peak demand. The integrated evening potential is about 16% lower than the morning potential. It increases rapidly from around 4 MW in 2018 to approximately 45 MW in 2022. Beyond 2022, over the next 15 years, the evening grows steadily to reach ~50 MW in 2037, representing 7.2% of FortisBC's projected average evening peak demand.

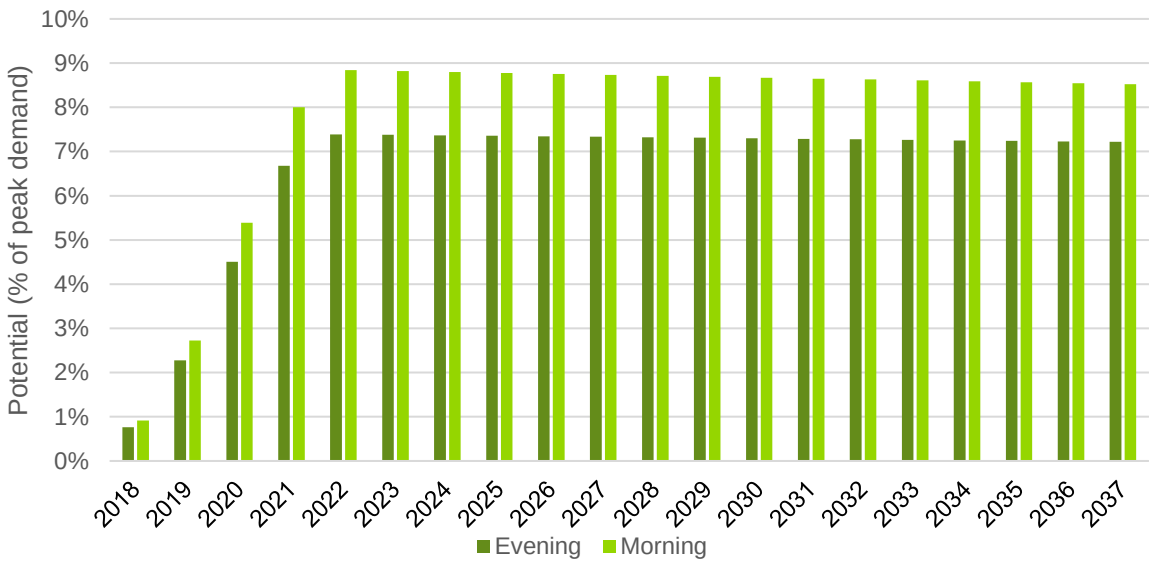
Figure ES-4. Integrated Market Potential – Morning vs. Evening



Source: Navigant Analysis

[4] Technical and standalone market potential results are described in Chapter 3.

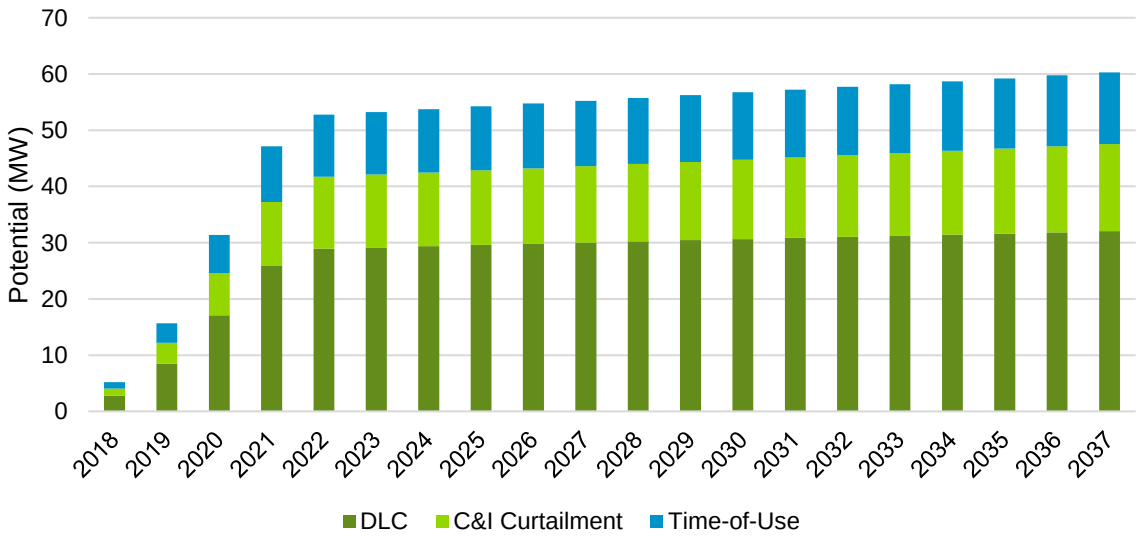
Figure ES-5. Integrated Market Potential – Morning vs. Evening



Source: Navigant Analysis

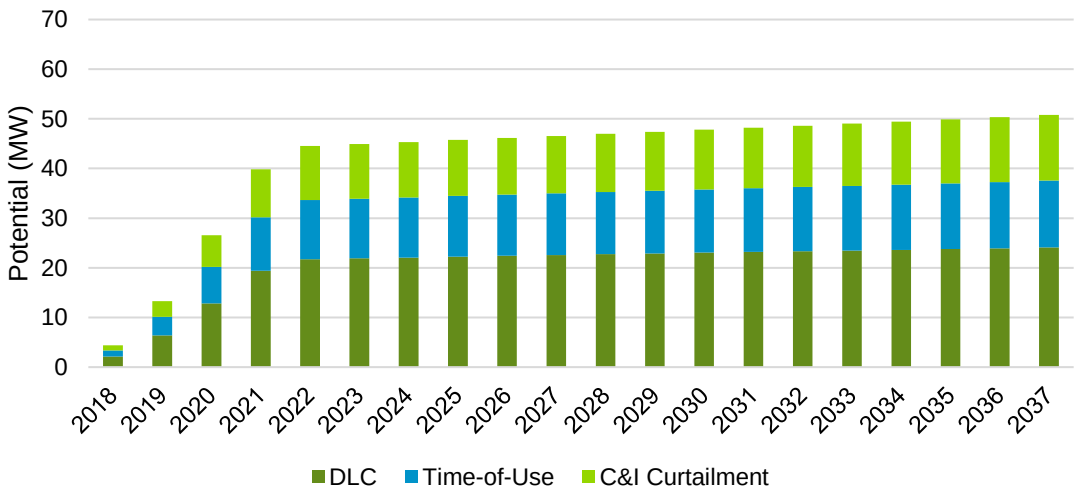
Figure ES-6 shows a breakdown of the integrated morning potential by DR option, and Figure ES-7 shows the breakdown of the evening potential by DR option. Of the three different DR options included in the analysis, DLC has highest contribution to the potential at approximately 55% share in morning and 50% share in evening, C&I Curtailment has approximately 25% share in both morning and evening peak periods. TOU constitutes the remaining 20% share in morning potential and 25% share in evening potential.

Figure ES-6. Integrated Market Potential by Option – Morning



Source: Navigant Analysis

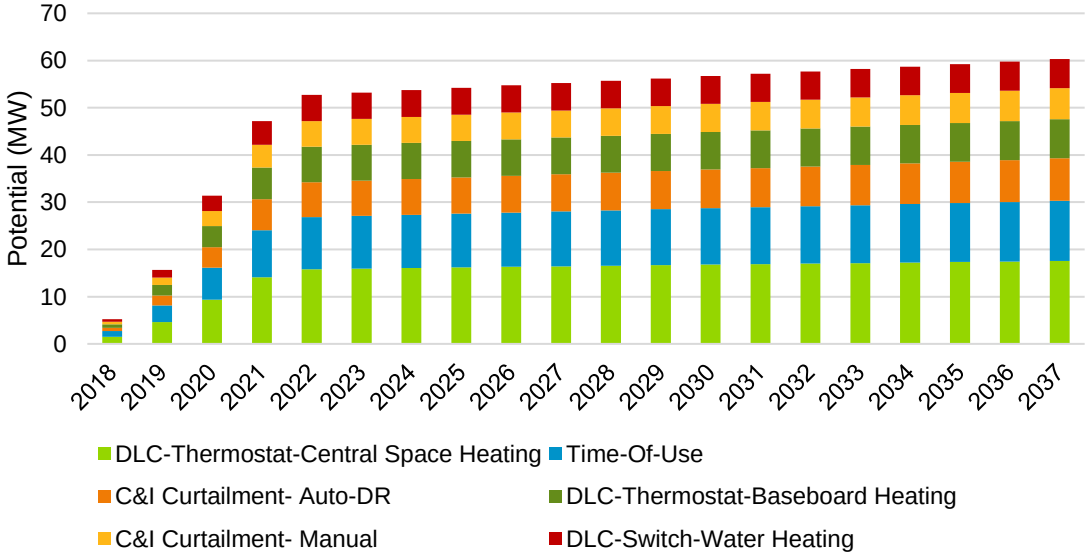
Figure ES-7. Integrated Market Potential by Option – Evening



Source: Navigant Analysis

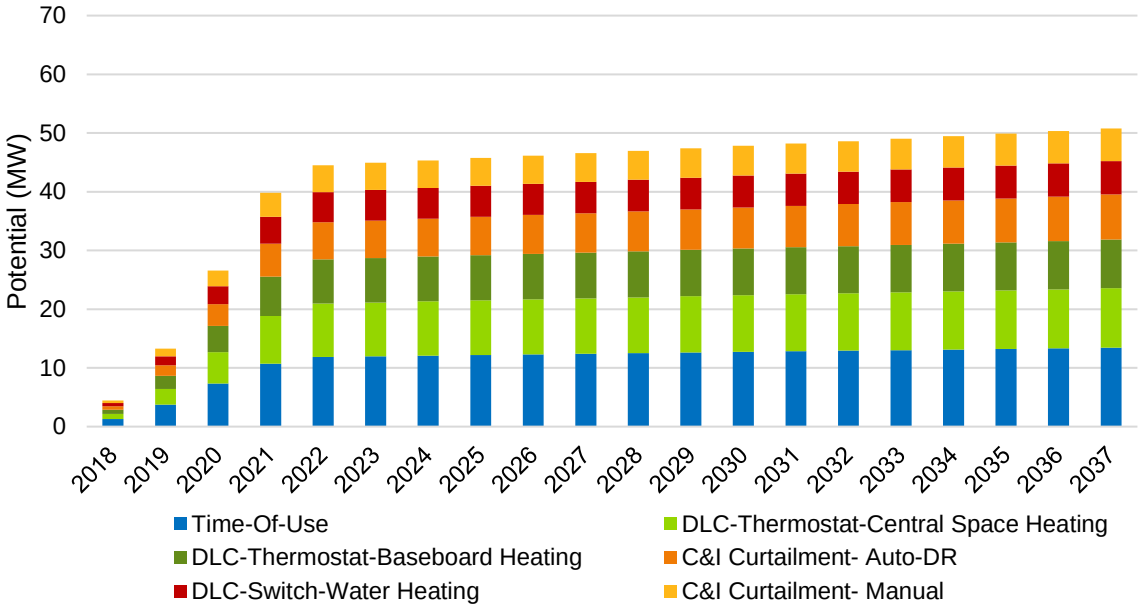
Figure ES-8 shows a breakdown of the integrated morning potential by DR sub-option, and Figure ES-9 shows the breakdown of the evening potential by DR sub-option. Thermostat based central space heating control is the highest contributor to morning peak demand reduction at 30% share, followed by TOU at 20% share. In the evening, however, TOU has higher potential than central space heating control due to a higher fraction of "other" enduse load types in the evening that could be affected by TOU. Central space heating control has 20% share in evening potential and TOU has 25% share in evening potential. Baseboard heating control has approximately 15% share in potential during both morning and evening peaks. Water heating control has 10% share in both periods. Under C&I Curtailment for large and extra-large customers, Auto-DR based C&I Curtailment has 15% share in both peak periods, while Manual Curtailment has lower contribution at approximately 10%.

Figure ES-8. Integrated DR Market Potential by Sub-Option – Morning



Source: Navigant Analysis

Figure ES-9. Integrated DR Market Potential by Sub-Option – Evening



Source: Navigant Analysis

If FortisBC were to pursue all of the cost-effective DR market potential, largely by using a third-party aggregator, Navigant estimates the total annual costs would escalate from approximately 3 million CAD in 2018 to roughly 8.5 million CAD in 2021. This represents all types of costs included in the analysis, fixed and variable, either incurred one-time or on a recurring basis. A large fraction of these costs is associated with marketing and recruiting new customers into the program during the ramp-up period and installing enabling technologies for demand reductions. Costs decline and remain steady beyond the initial program ramp-up period and then increase again at the end of the 10-year lifetime assumed for the DLC and C&I programs.

Table ES-3 shows the levelized costs by DR sub-option and customer class, calculated by dividing the NPV of the annual costs by the NPV of the annual potential estimates.[5] It shows the DR sub-options and customer class combinations arranged in increasing order of costs, TOU rate offers have lowest cost, except for small C&I customers, where TOU rates are significantly more expensive due to very low impacts. Thermostat-based central space heating control with highest potential costs around $106/kW-yr. Baseboard heating control from residential with second highest potential has a substantially higher cost at around $250/kW-yr. Space heating control costs for small and medium C&I customers costs are lower than those for residential. Manual curtailment for large and extra-large C&I customers costs roughly $150/kW-yr. Auto-DR curtailment costs approximately 33% more than manual curtailment, at around $200/kW-yr. levelized costs. However, it also delivers around 35% higher potential than manual curtailment. Switch-based electric water heating load control has relatively high costs, between $260/kW-yr. and $280/kW-yr. levelized costs.

[5] The average of the morning and evening peak potential values are used to calculate the NPV of annual megawatts for the levelized costs.

Table ES-3. Levelized Costs by DR Sub-Option

DR Sub-Option | Customer Class	Levelized Cost ($/kW-yr)	2037 Morning Potential (MW)
Time-Of-Use | Extra Large C&I	$12.6	0.8
Time-Of-Use | Large C&I	$12.8	0.7
Time-Of-Use | Medium C&I	$13.7	0.5
Time-Of-Use | Residential	$14.9	10.7
DLC-Thermostat-Central Space Heating | Medium C&I	$69.0	0.7
DLC-Thermostat-Central Space Heating | Small C&I	$94.7	1.7
DLC-Thermostat-Central Space Heating | Residential	$106.6	15.2
C&I Curtailment- Manual | Extra Large C&I	$149.3	3.7
C&I Curtailment- Manual | Large C&I	$149.6	2.9
C&I Curtailment- Auto-DR | Extra Large C&I	$205.2	4.7
C&I Curtailment- Auto-DR | Large C&I	$206.1	4.3
DLC-Thermostat-Baseboard Heating | Residential	$252.3	8.3
DLC-Switch-Water Heating | Small C&I	$257.0	0.2
DLC-Switch-Water Heating | Residential	$258.5	6
DLC-Switch-Water Heating | Medium C&I	$281.4	0.02
Time-Of-Use | Small C&I	$401.4	0.01

Source: Navigant Analysis

At the program level, all three DR options (DLC, C&I Curtailment, and TOU rates) are cost-effective under TRC (shown in Table ES-4). TOU rates have the highest benefit-to-cost ratios. DLC and C&I Curtailment have similar cost-effectiveness, as evidenced by the benefit-to-cost ratios.

Table ES-4. Benefit-Cost Ratios by DR Option

DR Option	TRC	UCT	PCT	RIM
DLC	1.3	1.2	2.0	1.2
C&I Curtailment	1.4	1.2	2.0	1.2
TOU	11.6	11.6	-	11.6

Source: Navigant Analysis

1. INTRODUCTION

FortisBC Inc. (FBC) engaged Navigant Consulting Ltd. (Navigant or the team) to prepare a demand response (DR) potential assessment for FortisBC's service territory over the 2018-2037 forecast period. The objective of this assessment was to estimate the potential for use of DR as a capacity resource to reduce customer loads during winter peak periods[6].

Navigant worked with FortisBC to identify relevant types of DR programs in FortisBC's service territory and the applicability of these program types by customer segments and end uses to realize winter peak demand reductions. The team developed technical and market potential estimates for the different DR program types at various levels of disaggregation along with high-level cost estimate FortisBC would incur to implement the portfolio of DR programs. Navigant also conducted a cost-effectiveness assessment of the DR program types included. The analysis was conducted using Navigant's proprietary DRSim™ model, customized for FortisBC.

FortisBC may use these results as input to its own demand-side management planning and long-term goals for peak demand reduction.

The remainder of this report is organized as follows:

- Section 2 describes the methodology and approach Navigant used to estimate DR potential, including market characterization and baseline peak demand projections for the DR potential assessment. It also describes the DR options considered in the analysis and their key characteristics.
- Section 3 presents the DR potential and cost-effectiveness results.
- Appendices A-D provide detailed input assumptions used for potential calculations and the cost-effectiveness assessment.

Navigant also provided FortisBC with an Excel-based inputs database that includes all data used to model the DR potential and cost estimates and an Excel-based results file that includes all potential and cost results from this analysis. In addition, the team delivered the Analytica-based DRSim model used for the analysis.

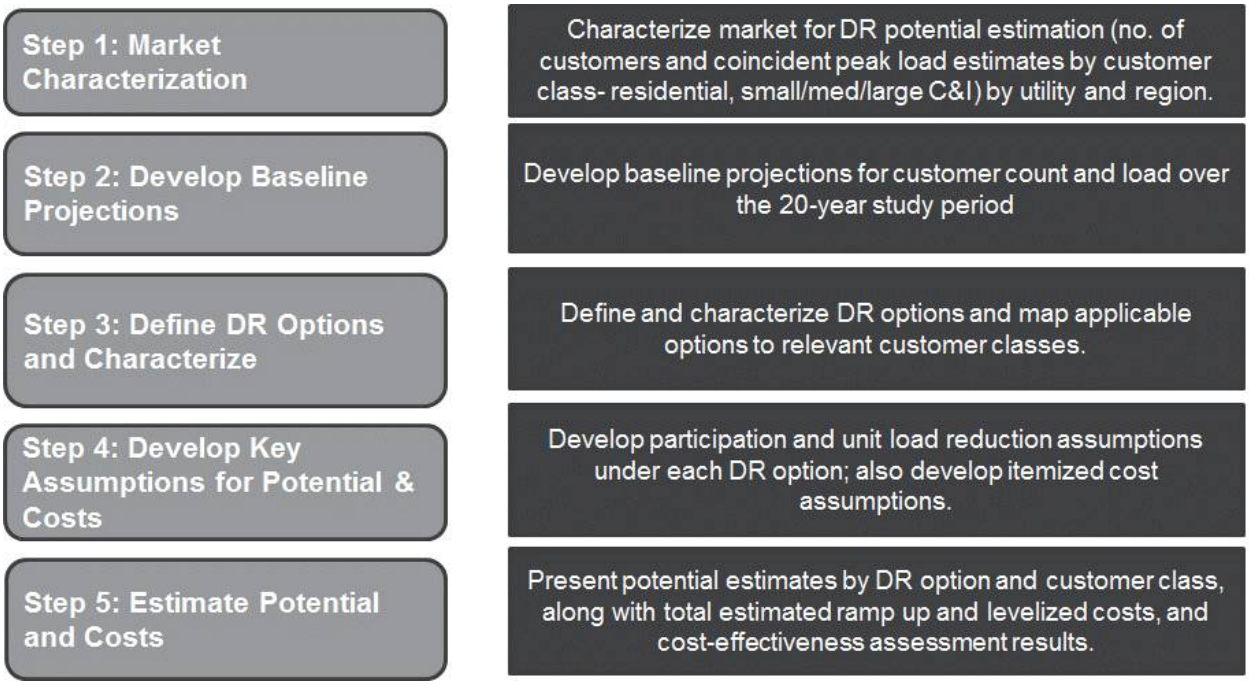
[6] Even though this study presents potential for winter peak reduction, some of the DR resources enrolled in the winter program could be utilized during summer peak periods. For e.g., water heating load could be controlled during both winter and summer. Also, curtailment of end-uses such as motors, industrial processes, motors/pumps could be undertaken during both winter and summer peak periods. Additionally, customers on TOU rates could be placed on these to achieve both winter and summer peak reductions.

2. DR POTENTIAL ASSESSMENT METHODOLOGY

This section describes the methodology Navigant employed to estimate energy and demand savings across FortisBC's service territory.

Navigant developed FortisBC's DR potential and cost estimates using a bottom-up analysis. The analysis utilized primary data from FortisBC and relevant secondary information sources as documented in the input workbook that accompanies this report. The team customized its DRSim model, which uses this data as inputs, for the study. The following subsections detail Navigant's DR potential and cost estimation methodology, as summarized below in Figure 2-1.

Figure 2-1. DR Potential Assessment Steps



Source: Navigant

2.1 Market Characterization for DR Potential Assessment

Market characterization is the first step in the DR potential assessment process. Table 2-1 shows the different levels of market segmentation. It is based on an examination of FortisBC's rate schedules, retail sales and demand data, and end-use load profiles as part of the broader energy efficiency potential study conducted by Navigant for FortisBC. The team finalized the market segmentation for the DR potential assessment in consultation with FortisBC.

Table 2-1. Market Segmentation for DR Potential Assessment

Level	Description
Level 1: Sector	• Residential • Commercial and industrial (C&I)
Level 2: Customer Class	• Residential • C&I customers by size, based on maximum demand values: ○ **Small C&I:** <40 kW maximum demand (Small Commercial Service) ○ **Medium C&I:** ≥40 kW and <150 kW maximum demand (Commercial Service) ○ **Large C&I:** ≥150 kW maximum demand and <1 MW maximum demand. (Commercial Service, Large General Service) ○ **Extra-Large C&I:** >1 MW maximum demand (Large General Service)

Source: Navigant

Navigant segmented the market for this assessment into the following levels, each of which is briefly described below.

Level 1: Sector
For the DR analysis, customers were first segmented into the residential and C&I sectors based on data provided by FortisBC. Non-residential customers were not differentiated by whether they were commercial or industrial customers—they were combined under the C&I sector.[7] The reason C&I customers were combined into one sector was because DR program offers did not vary by whether a customer was commercial or industrial; instead, it varied by customer size, as is discussed below.

Level 2: Customer Class
Next, Navigant segmented C&I customers into four different size categories (small, medium, large, and extra-large) based on their maximum demand values, following FortisBC's rate schedules (shown in Table 2-1). These size categories are also referred to as C&I customer class. The segmentation by size was necessary, as the type of DR program offer varied by customer size for C&I customers.

2.2 Baseline Projections for DR Potential Assessment

Navigant's next step after market segmentation was to develop baseline customer count and peak demand projections by customer class and segment over the 20-year potential assessment period (2018-2037). The team developed the baseline customer count and peak demand projections for the DR potential assessment at the following levels:

- Customer count by customer class
- Winter morning and evening peak demand projections by customer class and end use

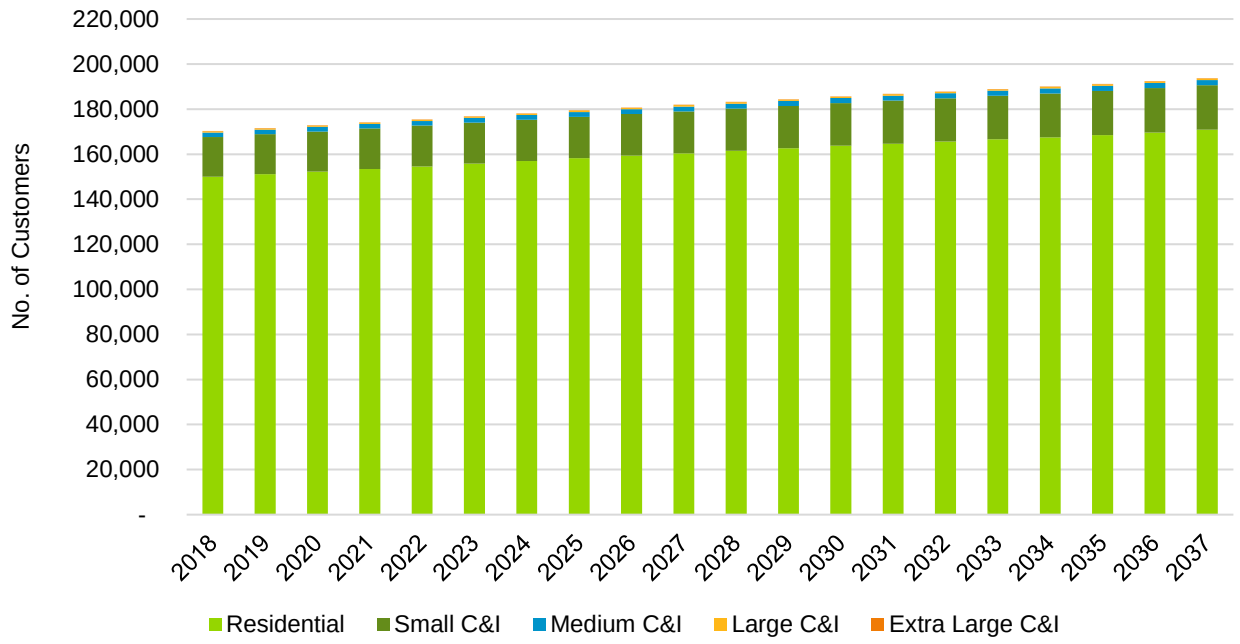
[7] Street lighting customers were excluded from the analysis because of public safety considerations. Additionally, there is no industry experience on controlling street lights for demand response.

2.2.1 Customer Count Projections

Navigant utilized customer sales and maximum demand information, along with customer rate schedules, to segment C&I customers into the four different customer classes—small, medium, large, and extra-large C&I customers (listed above in Table 2-1)—for the base year. This analysis maintained 2014 as the base year for this study because that was the selected year for the prior analysis Navigant conducted under Base Services[8] for FortisBC. FortisBC provided Navigant with customer count data for the base and forecasted years.[9]

Figure 2-2 shows the baseline customer count projections by customer class. In 2037, residential customers constitute approximately 88% of the total customers. Out of the total non-residential customers, small C&I customers are 86.6% of the total, followed by medium C&I at 10.2% share, large C&I at 3% share, and extra-large C&I at only 0.2% share.

Figure 2-2. Customer Count Projections for DR Potential Assessment[10]



Source: Navigant

[8] Navigant conducted an energy efficiency potential study for FortisBC that was completed prior to this study and was under the Base Services contract between FortisBC and Navigant. This is referred to as Base Services in this report.

[9] The commercial accounts forecast used the growth rates from the forecasted total area (million m^2 stock) for commercial customers and forecasted total energy use for industrial customers. These values were obtained from the reference case sales forecast from the Base Services energy efficiency potential study.

[10] The customer count projection data table associated with the figure is included in the Excel-based model input file provided to FortisBC.

2.2.2 Peak Demand Projections

This section describes the process that Navigant used to define the morning and evening peak periods and disaggregate bottom-up peak demand projections by customer class, segment, and end use for each period.

2.2.2.1 Peak Period Definition

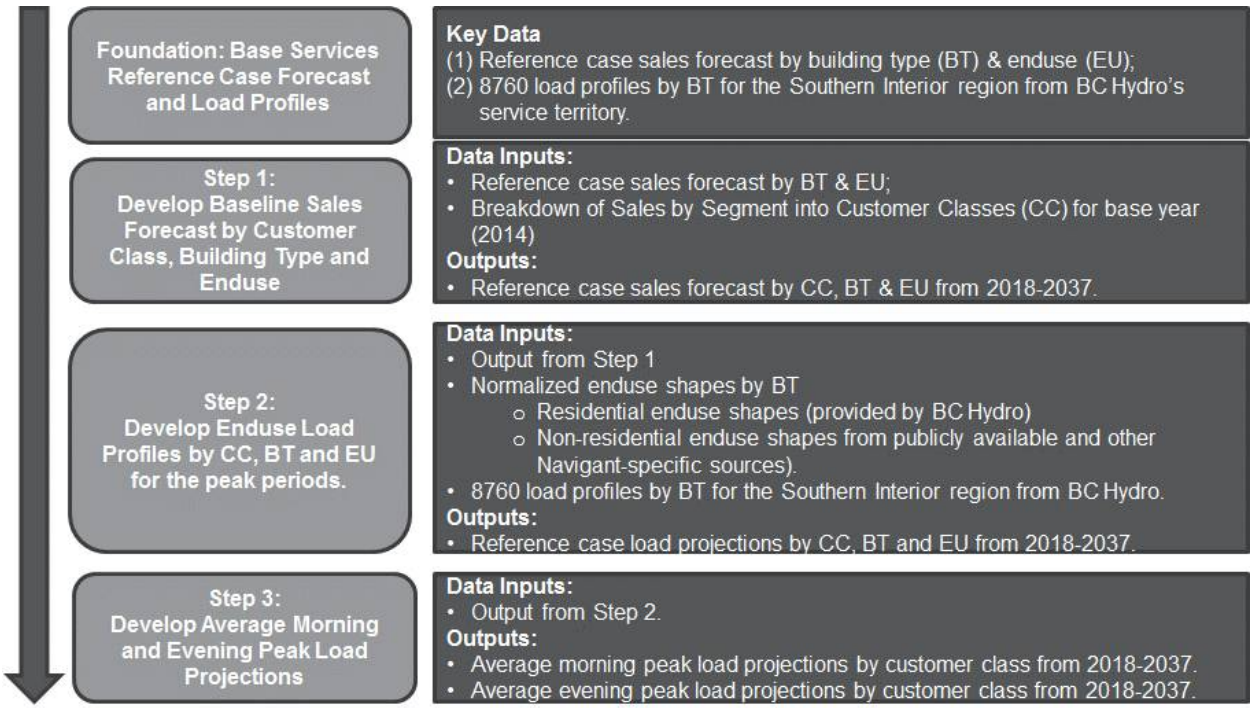
A key element in the DR potential analysis is the peak period definition, which the team based on an analysis of the hourly system load data. Navigant analyzed the historical hourly system load data provided by FortisBC over 2012-2016 and identified the peak period as follows:

- **Winter months:** November-February
- **Morning peak period:** 7 a.m.-11 a.m.
- **Evening peak period:** 4 p.m.-8 p.m.
- **Day type:** Weekdays

2.2.2.2 Peak Demand Projection Methodology

Figure 2-3 shows the step-by-step methodology Navigant used to develop winter morning and evening peak load projections by customer class and end use.

Figure 2-3. Peak Load Forecast Development Methodology



Source: Navigant

Table 2-2 lists the end uses for the residential and C&I customers included in the disaggregated peak demand projections for these customers.

Table 2-2. List of End Uses by Customer Class

Customer Class	End Uses
Residential	• Space Heating • Water Heating • Other (Lighting, Appliances, Electronics, Space Cooling, Other Misc.)
All Non-Residential Classes	• Lighting • HVAC Fans/Pumps • Space Heating • Water Heating • Refrigeration • Other[11] (Cooking, Office Equipment, Other Misc.) • Process and Other[12] Industrial (Compressed Air, Industrial Process, Material Transport, Process Compressors, Process Heat, Product Drying, Pumps.)

Source: Navigant

The steps below describe the approach for peak demand projections.

1. **Develop baseline sales projections by customer class, building type, and end use**

   The starting point for developing the peak load projections is the reference case sales forecast by customer class, segment, and end use. Navigant had developed the reference case sales forecast by segment and end use as part of Base Services. FortisBC provided Navigant with the sales breakdown by rate code as part of this analysis. The team combined this information with the reference case sales forecast from Base Services to project sales by customer class, segment, and end-use for FortisBC's service territory.

2. **Develop end-use load profiles by customer class and building type**

   Next, Navigant combined the 2014 sales by end use and building type, derived from the previous step, with end-use load shapes to develop **peak demand estimates** by building type and end-use for residential and commercial customers.

   The team obtained space heating and water heating end-use shapes for residential customers from FortisBC and used these shapes for FortisBC. For C&I customers, no end-use shape was available from FortisBC's or from FortisBC's service territory. Therefore, Navigant used a publicly available database of building profiles to obtain end-use shapes for non-residential customers.[13]

[11] This "Other" category is associated with commercial customers.

[12] The "Other" end-use loads with process loads are associated with the industrial customers.

[13] Navigant used weather-normalized end-use shapes from OpenEI, which is a publicly available database of load profiles for all TMY3 locations in the US. The database contains hourly load profile data for 16 commercial building types (based off the US Department of Energy (DOE) commercial reference building models). Open EI data is downloadable at: https://en.openei.org/community/blog/commercial-and-residential-hourly-load-data-now-available-openei

Using the FortisBC-provided residential end-use shapes and weather-normalized load profiles from Open EI for non-residential customers, Navigant developed **hourly load profiles** for the following end uses:

- Residential: space heating, water heating
- Non-residential: water heating, space heating, HVAC fans/pumps, refrigeration, lighting

For the remaining end uses, the team used the unitized shapes derived from the whole building load profiles for the Southern Interior region in FortisBC's service territory. FortisBC did not provide any load profiles specific to its service territory. The load profiles from the Southern Interior region of FortisBC's service territory were deemed to be the closest match to FortisBC's service territory characteristics based on discussions between FortisBC and Navigant.[14]

The residential space heating and water heating shapes from FortisBC were weather normalized. Also, the non-residential end-use shapes sourced from Open EI (which covers the weather sensitive end uses) were weather-normalized shapes. However, the profiles available from FortisBC for the Southern Interior region were not weather normalized; consequently, the derived load profiles for the remaining other end uses (primarily non-weather sensitive end uses) were not weather normalized. Given that weather-normalized building type load profiles were not available from either FortisBC or FortisBC and that only non-weather sensitive end uses were affected by this, Navigant assessed the approach followed in this study to develop projected end-use profiles by building type to be reasonable.

The 2014 unitized end-use profiles building segment were applied to the reference case sales forecast to project load profiles by customer class, building segment, and end use over the 2018-2037 forecast period.

3. **Develop average morning and evening peak load projections by customer class and end use**

   Using the morning and evening peak period definitions and the hourly load profiles by customer class, building type, and end use developed through the previous step, Navigant calculated the average morning and evening peak demand by customer class, building type, and end use over the 2018-2037 forecast period.

2.2.2.3 Peak Demand Projection Results

This section presents the morning and evening peak demand projection results, first by customer class and then within each customer class by end use.

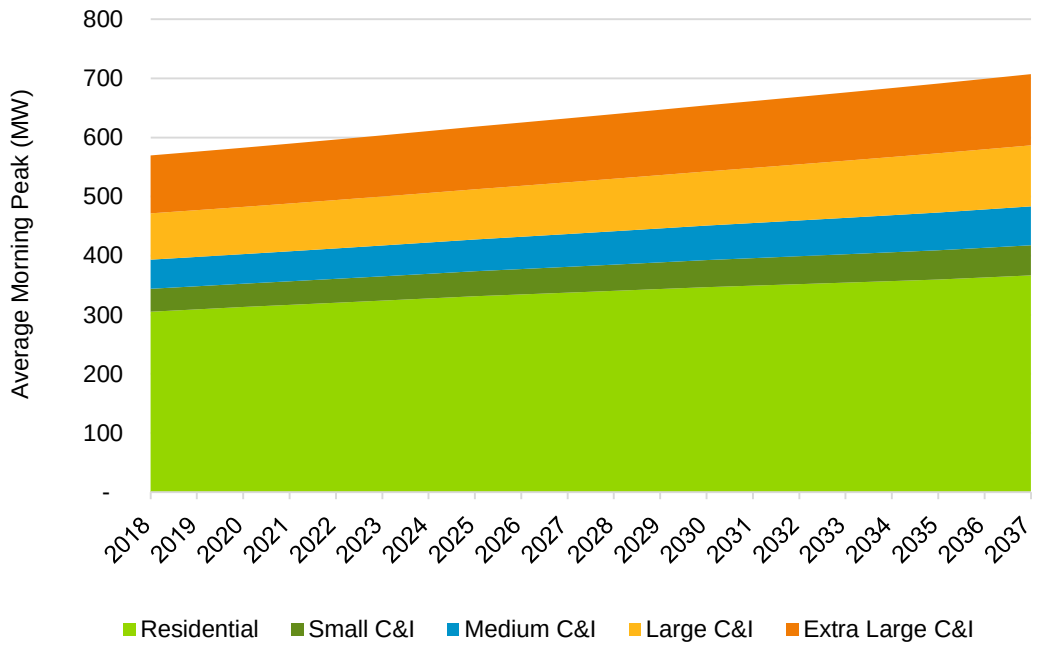
Peak Demand Projections by Customer Class

Figure 2-4 shows the winter morning average peak demand projections by customer class. The average morning peak period demand is projected to steadily grow from 570 MW in 2018 to 707 MW in 2037. Residential customers have the highest contribution to the peak at approximately 52% share of the morning peak demand in 2037. Extra-large C&I has about 17% share of the morning peak demand, even though these customers constitute only 0.2% of the total count. Large C&I share in morning peak demand

[14] FortisBC and Navigant jointly agreed that the Southern Interior region was the best choice for consideration of load profiles given that FortisBC did not have load profiles available for its service territory.

is slightly lower than extra-large, at 15%, while small and medium C&I share are 7% and 9% respectively in 2037.

Figure 2-4. Winter Morning Peak Load Forecast by Customer Class (MW)[15]



Source: Navigant

Figure 2-5 shows the winter evening average peak demand projections by customer class. The average evening peak period demand is projected to steadily grow from 580 MW in 2018 to 703 MW in 2037. The evening peak is 1%-2% greater than the morning peak till around 2030. Beyond 2030, the average morning peak is slightly higher than the evening peak demand. The difference is narrow—less than 1% between the morning and evening peak demand values. Residential customers have a slightly higher share of the evening peak than their share of the morning peak. Their share is approximately 60% of the evening peak demand. Extra-large C&I has around 15% share of the evening peak demand, followed by large C&I customers at 12% share. Medium C&I customers have 8% share, while small C&I customers have 6% share of the evening peak demand.

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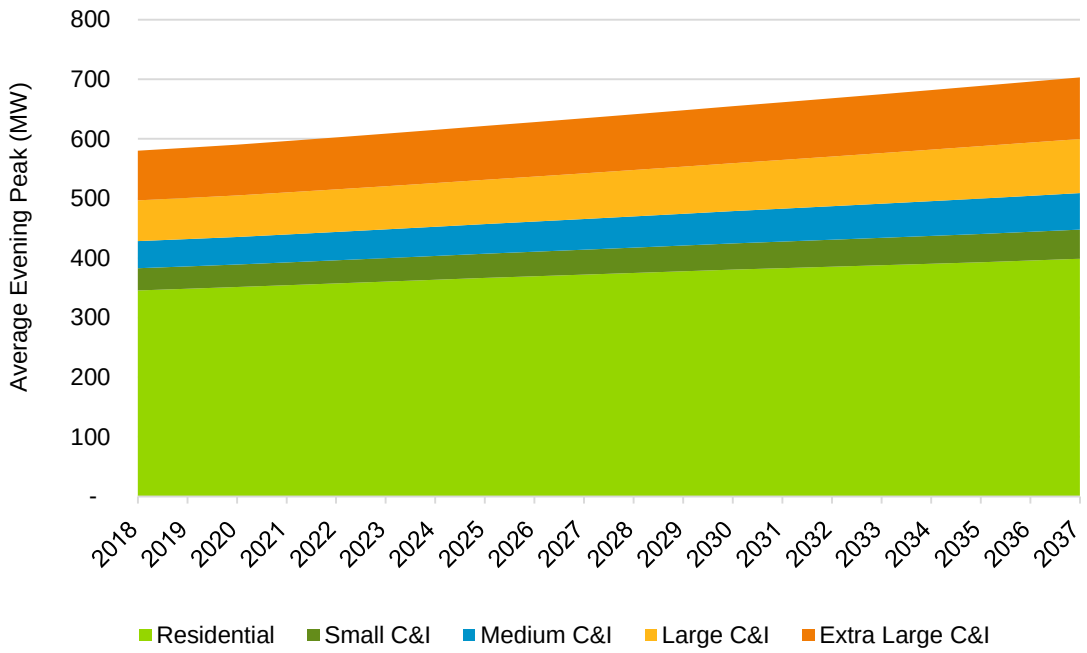
[15] The data table associated with this figure is included in the Excel-based model input file provided to FortisBC.

Figure 2-5. Winter Evening Peak Load Forecast by Customer Class (MW)[16]



Source: Navigant

Next, the team presents end-use breakdowns of the peak demand projections by customer class.

Residential Peak Demand Projections by End Use

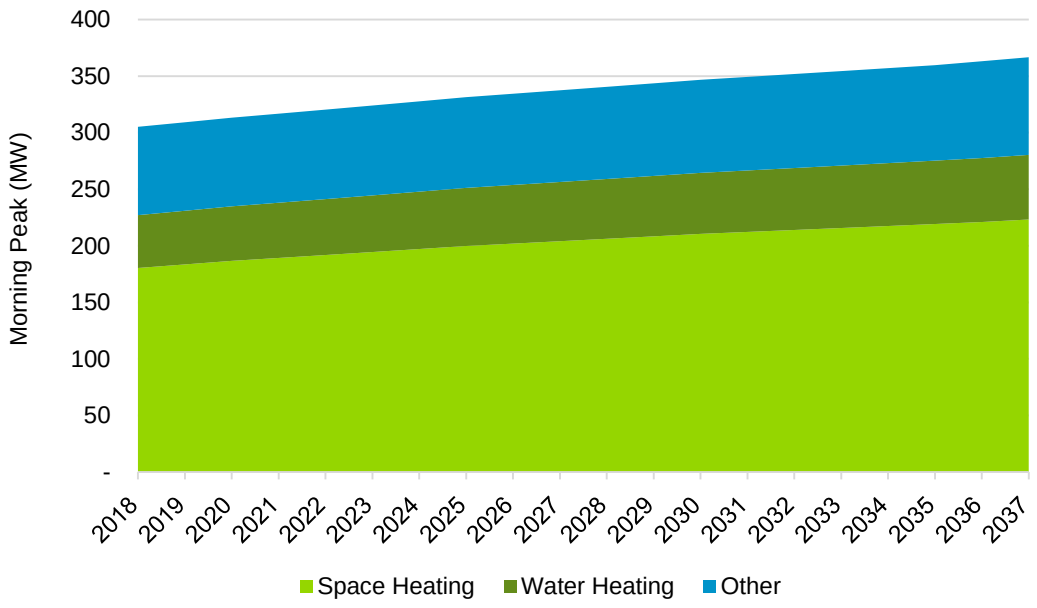
Figure 2-6 and Figure 2-7 show residential morning and evening peak demand projection by end use. The residential morning peak demand is projected to grow at an average annual rate of approximately 0.9% over the 20-year forecast period from 305 MW in 2018 to 367 MW in 2037. Residential space heating leads in the end-use mix with a 60% share, followed by other[17] end uses at an approximately 25% share. Electric water heating makes up the remaining 15%.

The evening peak demand is projected to grow at a slightly lower growth rate than the morning peak demand at an average 0.7% annually over the 20-year forecast period from 2018-2037. It grows from 346 MW in 2018 to 399 MW in 2037. The end-use mix in the evening load differs from the end-use mix in the morning load. While space heating has an approximately 60% share of the morning peak demand, it has a much lower share at roughly 35% of the evening peak demand. The share of the other end-use loads is substantially higher in the evening peak than in the morning peak. These other end uses, which include cooking e.g. electric ranges, have around 55% share of the evening peak demand. Electric water heating constitutes the remaining 10% share of the evening peak demand.

[16] The customer count projection data table associated with this figure is included in the Excel-based model input file provided to FortisBC.

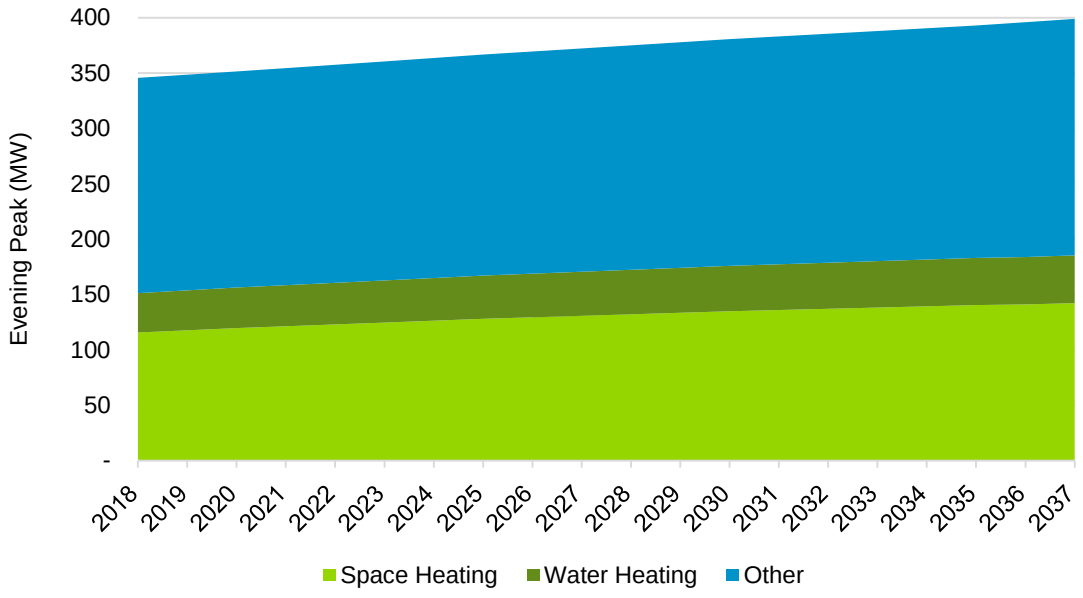
[17] Note that other end uses refers to any type of load other than electric space heating and water heating, as listed earlier in Table 2-2. It includes lighting, appliances, electronics, space cooling, and other miscellaneous end uses.

Figure 2-6. Residential Winter Morning Peak Load Forecast by End Use (MW)



Source: Navigant

Figure 2-7. Residential Winter Evening Peak Load Forecast by End Use (MW)



Source: Navigant

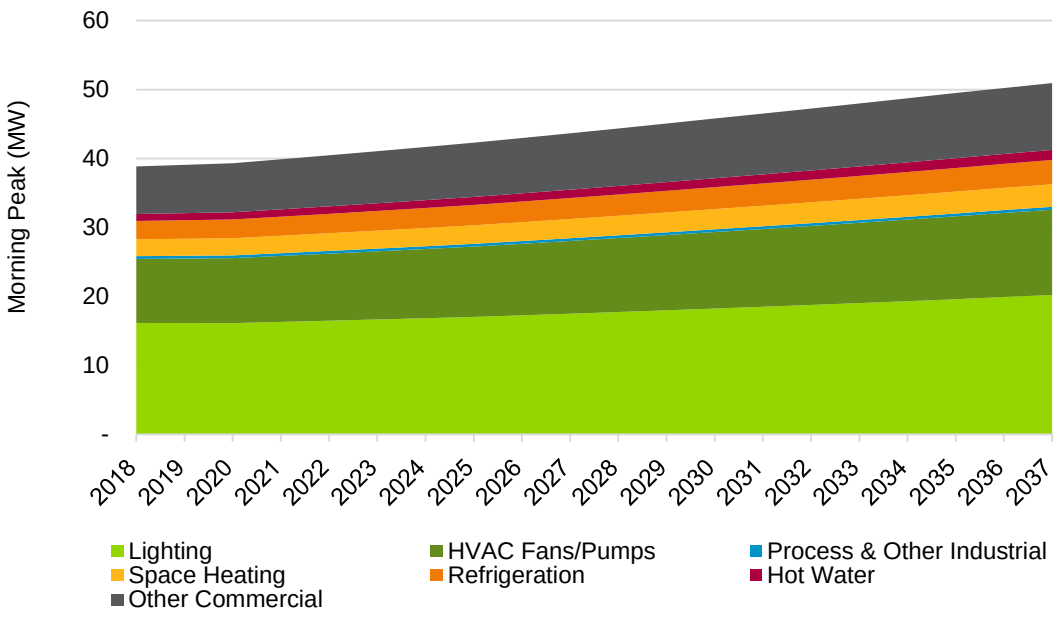
Small C&I Peak Demand Projections by End Use

Figure 2-8 and Figure 2-9 show the morning and evening peak demand projections for small C&I customers.

The morning peak demand for small C&I is projected to grow at an average annual rate of approximately 1.4% over the 20-year forecast period from 39 MW in 2018 to 51 MW in 2037. The average evening peak demand for small C&I is around 4% lower than the morning peak demand and is expected to grow from 37 MW in 2018 to 49 MW in 2037.

Lighting has the highest share of both morning and evening peak demand at approximately 40% share of the total demand. HVAC fans/pumps have about 25% share of the demand, space heating and refrigeration each have approximately 5% share, and electric water heating is at less than 5% share. The other[18] remaining loads constitute roughly 20% of the small C&I average peak demand.

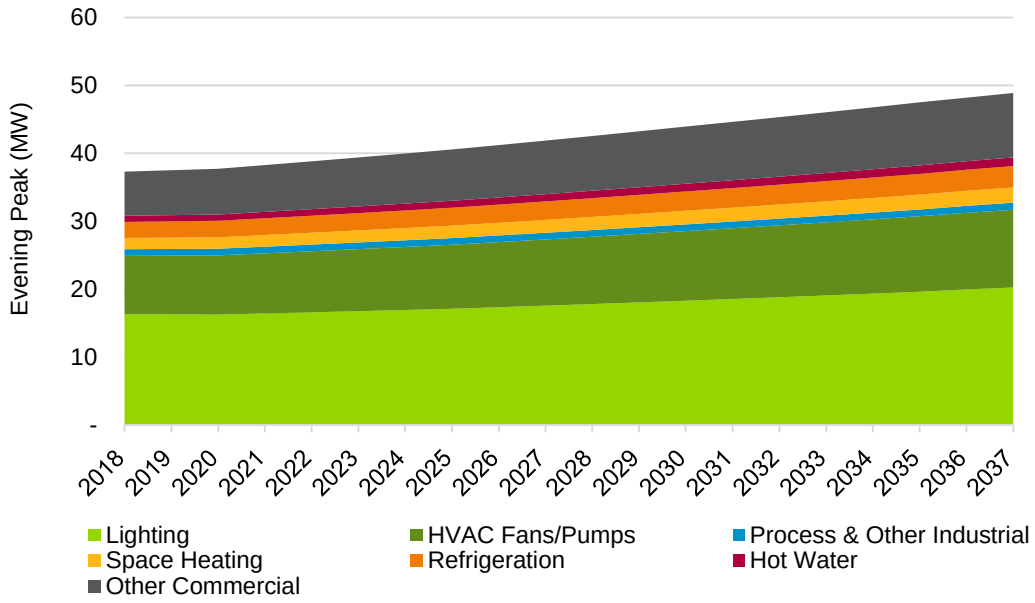
Figure 2-8. Small C&I Morning Peak Load Forecast by End Use (MW)



Source: Navigant

[18] Includes other industrial and commercial loads. Other industrial loads include compressed air, industrial process, material transport, process compressors, process heat, product drying, and pumps. Other commercial loads include cooking, office equipment, and other miscellaneous commercial loads.

Figure 2-9. Small C&I Evening Peak Load Forecast by End Use (MW)



Source: Navigant

Medium C&I Peak Demand Projections by End Use

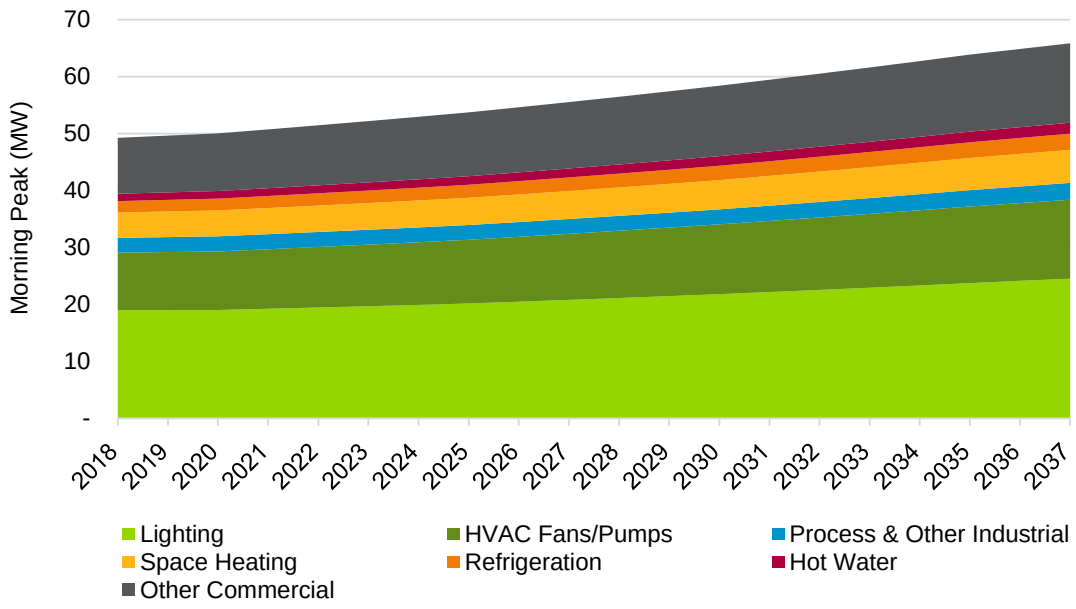
Figure 2-10 and Figure 2-11 show the morning and evening peak demand projections for medium C&I customers.

The morning peak demand for medium C&I is projected to grow at an average annual rate of roughly 1.5% over the 20-year forecast period from 49 MW in 2018 to 66 MW in 2037. The average evening peak demand for medium C&I is approximately 7% lower than the morning peak demand and is expected to grow from 46 MW in 2018 to 61 MW in 2037.

The end-use contributions to peak demand for medium C&I customers is similar to that for small C&I customers. Lighting has the highest share of both morning and evening peak demand at approximately 40% share of the total demand. HVAC fans/pumps have around 20% share of the demand, space heating ranges from 5% to 10% (slightly higher share in the morning), refrigeration is at roughly 5%, and electric water heating is at less than 5% share. The other[19] remaining loads constitute approximately 25% of the medium C&I average peak demand.

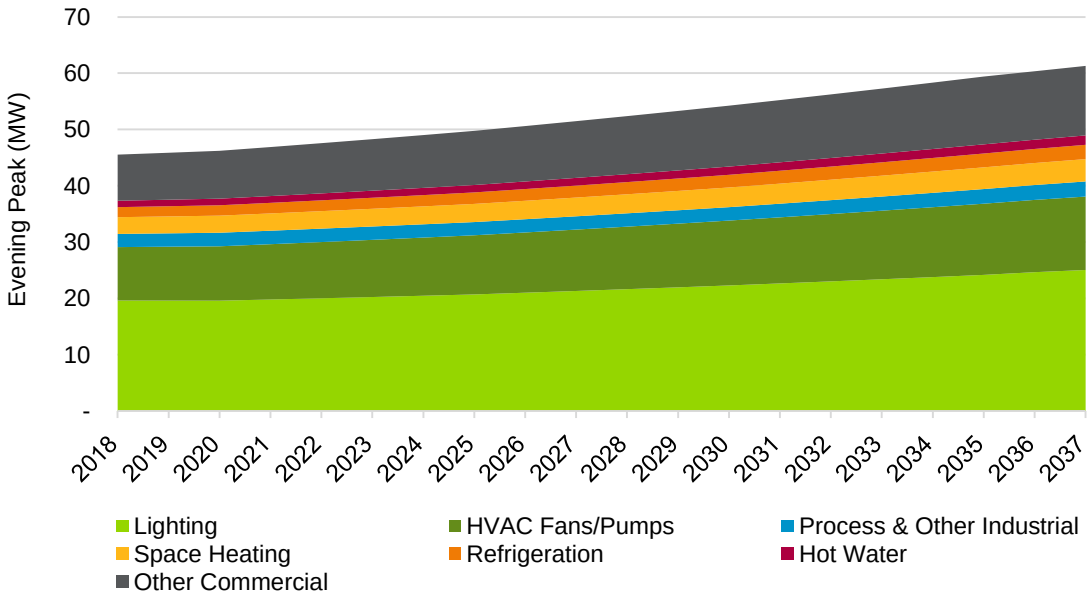
[19] Includes other industrial and commercial loads. Other industrial loads include compressed air, industrial process, material transport, process compressors, process heat, product drying, and pumps. Other commercial loads include cooking, office equipment, and other miscellaneous commercial loads.

Figure 2-10. Medium C&I Morning Peak Load Forecast by End Use (MW)



Source: Navigant

Figure 2-11. Medium C&I Evening Peak Load Forecast by End Use (MW)



Source: Navigant

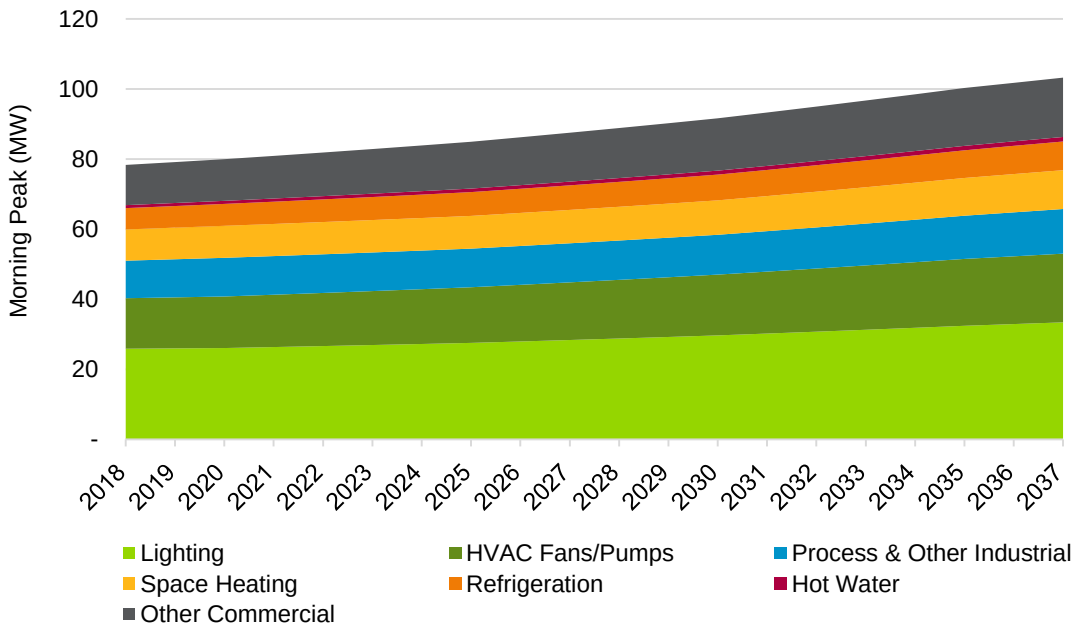
Large C&I Peak Demand Projections by End Use

Figure 2-12 and Figure 2-13 show the morning and evening peak demand projections for large C&I customers. The large C&I average morning peak demand is projected to grow at an average annual rate of approximately 1.5% over the 20-year forecast period from 78 MW in 2018 to 103 MW in 2037. The

average evening peak demand for large C&I is around 15% lower than the morning peak demand and is expected to grow from 68 MW in 2018 to 91 MW in 2037.

The end-use breakup of demand for these customers is different from those for small and medium C&I. The share of process and other industrial[20] load types is greater for large C&I at roughly 15% of the total peak demand, whereas for the small and medium C&I customers the share was at less than 5%. Lighting continues to lead at an approximately 35% contribution to the peak demand. HVAC fans/pumps have about 20% share, followed by space heating and refrigeration at 8%-10% each. Contribution from other commercial[21] loads is at around 15% of the peak demand.

Figure 2-12. Large C&I Morning Peak Load Forecast by End Use (MW)

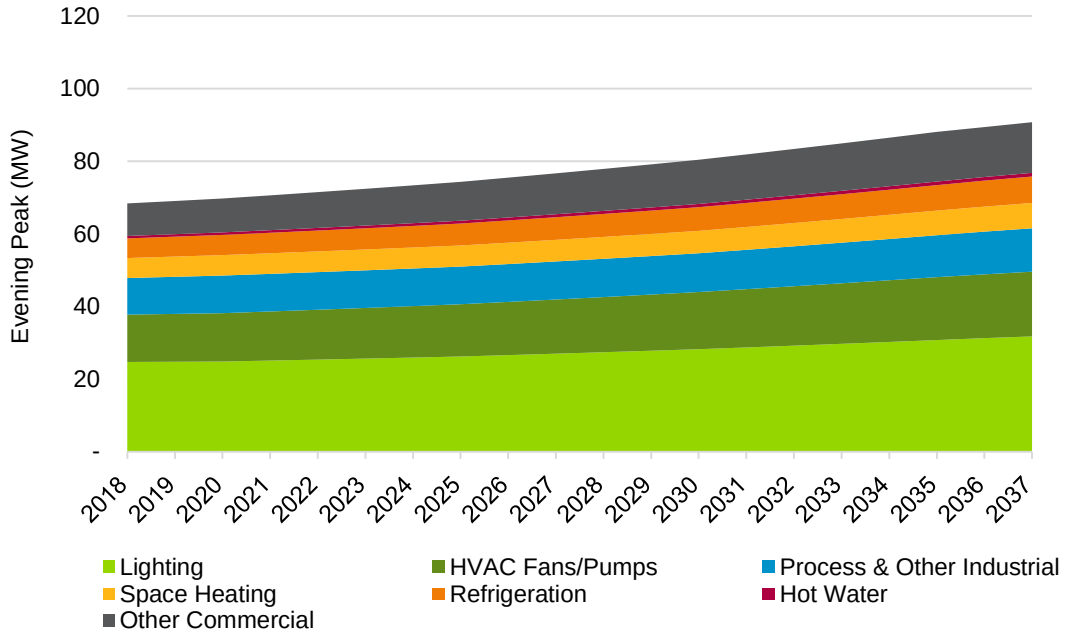


Source: Navigant

[20] The other industrial loads include compressed air, industrial process, material transport, process compressors, process heat, product drying, and pumps.

[21] This includes cooking, office equipment, and other miscellaneous types of commercial load.

Figure 2-13. Large C&I Evening Peak Load Forecast by End Use (MW)



Source: Navigant

Extra-Large C&I Peak Demand Projections by End Use

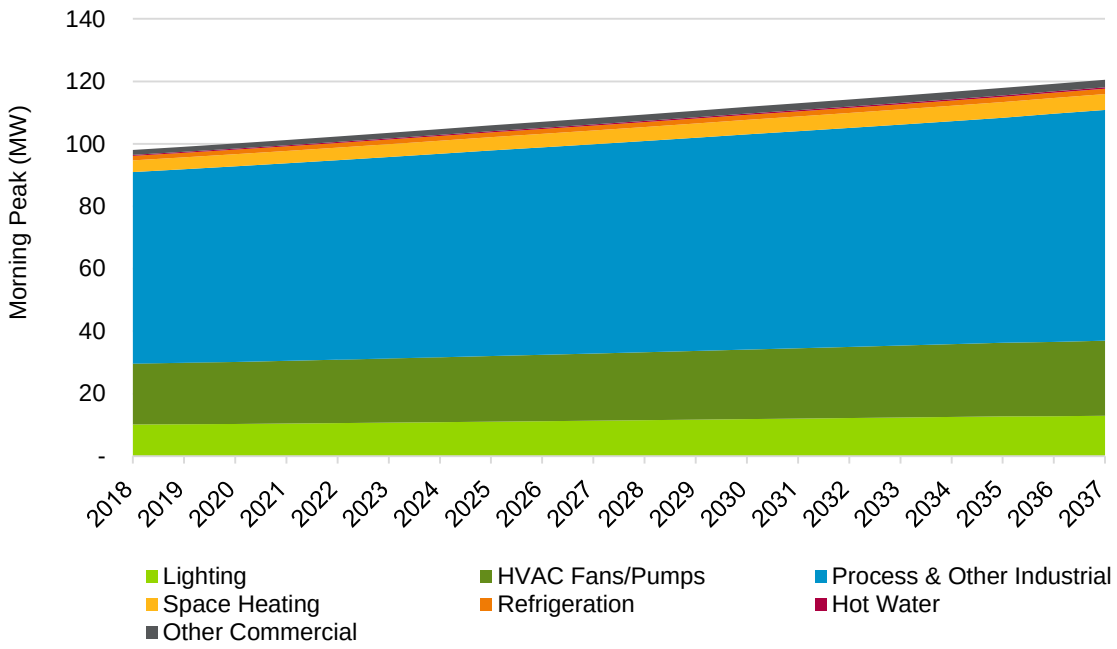
Figure 2-14 and Figure 2-15 show the morning and evening peak demand projections for extra-large C&I customers. For these customers, average morning peak demand is projected to grow at an average annual rate of approximately 1% over the 20-year forecast period from 98 MW in 2018 to 120 MW in 2037. The average evening peak demand for extra-large C&I is roughly 15% lower than the morning peak demand and is expected to grow from 83 MW in 2018 to 103 MW in 2037.

The end-use breakup of peak demand for these customers is significantly different from the other customer classes. Approximately 60% of the peak demand for these customers is from process and other industrial[22] end uses. HVAC fans/pumps' share is around 20%, while lighting's is 10%. Electric space heating and other commercial[23] each have less than 5% share of the peak demand.

[22] The other industrial loads include compressed air, industrial process, material transport, process compressors, process heat, product drying, and pumps.

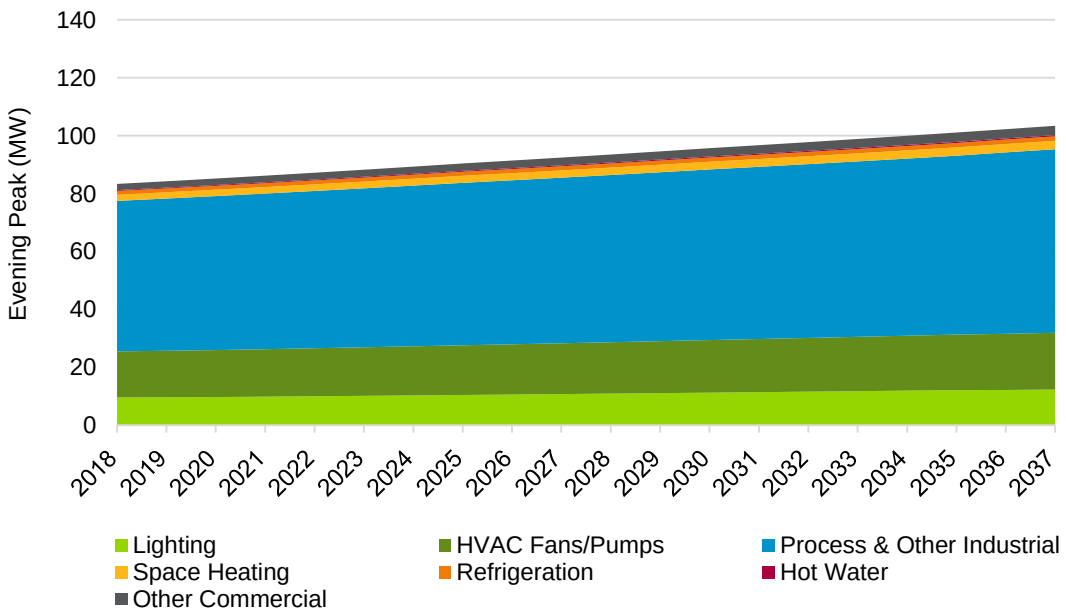
[23] This includes cooking, office equipment, and other miscellaneous types of commercial load.

Figure 2-14. Extra-Large C&I Morning Peak Load Forecast by End Use (MW)



Source: Navigant

Figure 2-15. Extra-Large C&I Evening Peak Load Forecast by End Use (MW)



Source: Navigant

2.3 DR Options Characterization

The next key step after baseline peak demand projections was to characterize the different types of DR options that could be utilized to curtail the peak demand.

Table 2-3Table 2-3 summarizes the DR options included in the analysis. These DR options are representative of the most commonly deployed DR programs in the industry. The two types of DR options Navigant considered for residential customers were direct load control (DLC) and time-of-use (TOU) rates. For small and medium C&I customers, the applicable options were DLC and dynamic pricing. For the large and extra-large C&I customers, the applicable DR options were C&I Curtailment and dynamic pricing. These different DR options are described in greater detail below.

Table 2-3. Summary of DR Options

DR Options	Characteristics of DR Options	Eligible Customer Classes	Targeted/Controllable End Uses
Direct Load Control (DLC) ✓ Thermostat ✓ Load control switch	Control of space heating/cooling load using a two-way communicating thermostat and of water heating load using a load control switch	• Residential • Small C&I • Medium C&I	• Electric space heating: central forced air furnaces, heat pumps, and baseboard heaters • Electric water heating
C&I Curtailment ✓ Manual ✓ Auto-DR-enabled	• Firm capacity reduction commitment • $/kW payment based on contracted capacity plus $/kWh payment based on energy reduction during an event	• Large C&I • Extra-Large C&I	Various load types including HVAC, lighting, refrigeration, and industrial process loads
✓ **TOU Rates**	Voluntary opt-in TOU rate offer	All customer classes	All

Source: Navigant

2.3.1 Direct Load Control

DLC involves FortisBC being able to directly control electric space heating load using smart thermostats. The potential assessment included smart thermostats for control of central forced air furnaces and heat pumps (referred to in the analysis as “central space heating”) and baseboard heaters.[24] In addition to

[24] This study uses information from BC Hydro’s baseboard pilot for assessing potential (Reference: “PCT Field Trial Research Report; RDH Building Science”).

space heating control, this analysis also considered electric water heating control via a load control switch.

There are two delivery models for DLC: Direct Install (DI) and Bring Your Own Thermostat (BYOT). In the DI approach, FortisBC would be responsible for installing the thermostat at the customer premises and bear all or a portion of the thermostat purchase and installation cost for DR enablement. In the BYOT approach, the customer purchases and installs their own thermostat and is subsequently enrolled in the DR program. Therefore, the purchase and installation costs of the thermostat are borne by the customer, which would consequently lower FortisBC's costs. This study considers a Direct Install implementation approach for DLC.

Table 2-4 describes the DLC program characteristics considered in this study.

Table 2-4. DLC Program Characteristics

Items	Description(s)
Program Name	Direct Load Control Program
Program Description	This program covers control of central electric space heaters (including furnaces and heat pumps) and baseboard heaters for residential customers and of central electric space heaters for small and medium C&I customers only.[25] The study assumes control of these different equipment types using a two-way communicating programmable thermostat, referred to as a smart thermostat. Baseboard heating control uses a line voltage thermostat.[26] Load reductions could be achieved either through a cycling strategy or a temperature setback strategy. Water heating control is through a load control switch that FortisBC could operate remotely to turn off the water heater during the peak demand period.
Purpose/Trigger	DLC events will be called primarily to meet capacity shortfalls during winter, triggered primarily by low day-ahead temperature forecast.
Key Program Design Parameters	• Events will be called during peak demand periods in winter. • Participants will not have any advance notification for DR events. However, they can choose to opt out of an event at any time during the event. • Average event duration is 4 hours and not more than one event is called in a day; also, calling events for more than two consecutive days may lead to customer dissatisfaction and disenrollment.
Participation Eligibility	• Residential customers with electric central space heating, baseboard heating, and electric water heating • Small and medium C&I customers with central electric space heating and electric water heating

[25] Baseboard heater control was not included in the analysis for small and medium C&I customers because the saturation of electric baseboard heaters is low for these customers.

[2626] Baseboard heating control experience is relatively less mature than control of furnaces and heat pumps and there is limited information available from the field. Navigant used unit impacts from BC Hydro's baseboard pilot to develop potential estimates.

Items	Description(s)
Dependent Technology and Metering	**Technology** • Space heating load is controlled using a two-way programmable communicating thermostat (PCT). ○ Baseboard heaters are controlled using a line voltage thermostat. • Electric water heaters are controlled using a load control switch. **Metering:** Standard meter (no interval meter required). The program can use data loggers on a sample of participants to record interval usage for purposes of measurement and verification.

Source: Navigant

2.3.2 C&I Curtailment

The C&I Curtailment program, as represented in this study, is the most commonly deployed program for large C&I customers in the industry. It involves a contract for a firm capacity reduction commitment from large and extra-large C&I customers. Under this option, FortisBC would typically enter into a turnkey implementation contract with a third-party DR service provider (commonly referred to as an aggregator) to deliver a certain fixed amount megawatt load reduction. However, FortisBC could also choose to internally administer the program without contracting out to a third-party DR service provider.

Under this program, customers have a firm load reduction commitment, and enrolled participants agree to curtail their demand to a pre-specified level. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (expressed as $/kW-year). Customers are paid to be on call even though actual load curtailments may not occur. The capacity payment level could vary with the load commitment level. In addition to the fixed capacity payment, participants typically receive a payment for energy reduction ($/kWh amount). Because it is a contractual arrangement for a specific level of load reduction, enrolled loads represent a firm resource. Once enrolled, participation during events is mandatory with penalty clauses. A specific site could curtail a variety of end-use loads depending on the types of business processes—either manually or automatically (Auto-DR-enabled). Auto-DR enablement can help provide greater reliability and higher predictability in load reductions.

Table 2-5 describes the C&I Curtailment program characteristics considered in this study.

Table 2-5. C&I Curtailment Program Characteristics

Items	Description(s)
Program Name	C&I Curtailment
Program Description	Typically, the program is administered by a third-party DR service provider. This is usually a turnkey contract, in which the vendor is responsible for a fixed amount of load reduction over the contract period. The common approach is for the utility to pay a pre-determined capacity payment ($/kW-yr.) based either on the nominated load reduction (if no event is called) or actual load reduction (if an event is called) to the third-party administering the program. In addition, the utility would pay the vendor for actual energy reduced during an event based on a specified $/kWh level in the contract. Participating sites enrolled in the program curtail a variety of end uses (e.g., HVAC, water heating, lighting, refrigeration, process loads) depending on the business type. Load curtailment can be manual and/or Auto-DR[27]-enabled. Participants may also shift load to backup generators during the DR event period.
Purpose/Trigger	DR events are likely to be called to help meet winter capacity shortfalls.
Key Program Design Parameters	• Events will be called during winter peak demand periods. • Average event duration assumed to be 4 hours. • Event notification is typically day-ahead and/or 1-2 hours ahead. • Average event duration is 4 hours and not more than one event is called in a day; also, calling events for more than two consecutive days may lead to customer dissatisfaction and disenrollment. • Annual maximum event hours set at 80-100 hours.
Participation Eligibility	All large and extra-large C&I customers
Dependent Technology and Metering	**Technology:** Manual DR requires a communication channel between the vendor and its customers, which might include SMS, email, or telephone. Auto-DR requires a building automation system, a load control device, or breakers on specific circuits. All control mechanisms must be able to receive an electronic signal from the program administrator and initiate the curtailment procedure without manual intervention. Auto-DR dispatches are called using an open communication protocol known as Open-ADR. For Auto-DR customers, the vendor installs an Open-ADR-compliant gateway at the participating site, which is then able to notify the building management system (BMS)/energy management system (EMS) or other control systems at the facility to run their pre-programed curtailment scripts. The vendor monitors energy reduction in real time and provides visual access to this demand data to the participant through a web-based software platform. This platform may be integrated for overall energy optimization, which may help realize energy efficiency benefits along with DR benefits. **Metering:** Interval meters.

Source: Navigant

2.3.3 Time-of-Use (TOU) Rates

TOU rates are the most commonly deployed form of time-varying rate offered in the industry. A TOU rate divides the day into time periods and provides a schedule of rates for each period. The peak period typically applies to weekdays only (weekends are usually entirely off-peak). The price differential between the peak and off-peak period usually follows the supply cost differential during the periods. TOU rates offer savings opportunities for customers by shifting their usage from peak to off-peak periods. The off-peak period price for customers on TOU rates is lower than the price on their otherwise applicable tariff.

The TOU potential assessment in this study assumes a 3:1 peak to off-peak price ratio for all customer classes. The selection of this price ratio for potential estimation was based on discussions with FortisBC on what the most likely future rate design is likely to be.
Table 2-6 describes the TOU characteristics considered in this study.

Table 2-6. TOU Characteristics

Items	Description(s)
Program Name	TOU rate
Program Description	Opt-in TOU rate offer to all customers with a 3:1 peak to off-peak price ratio.
Purpose/Trigger	Non-dispatchable and, therefore, no event/trigger.
Key Program Design Parameters	**Notification/response time:** Non-dispatchable; therefore, not applicable. **Event limits:** Non-dispatchable; therefore, not applicable.
Participation Eligibility	All customers
Dependent Technology and Metering	Interval meters required

Source: Navigant

2.4 Key Assumptions for DR Potential and Cost Estimation

The key variables for DR potential estimation are participation rates in the DR programs discussed above and the amount of load reduction that could be realized once customers are enrolled in a DR program through different types of control mechanisms, referred to as unit impact. (either expressed as “kW reduction per customer” or as “% reduction in enrolled load”). Additional parameters for potential estimation include DR event participation rates (expressed as “% of eligible customers”) or opt outs (expressed as “% of enrolled customers”), percentage of enrolled customers with enabling technology, and attrition rates of enrolled customers.

[27] Under Auto-DR, customer loads will be curtailed automatically via a building energy management control system (EMCS) in response to a signal from FortisBC. Auto-DR is a platform to automatically activate a pre-programmed load reduction strategy in response to a signal from a DR automation server (DRAS). Load is curtailed by the customer’s building management after being triggered by a signal that is sent from FortisBC’s control room to the vendor’s operations center and on to the customer’s facility. The customer always retains the ability to override the curtailment sequence in the event a site cannot participate in a specific DR dispatch. Auto-DR ensures higher reliability of response than manual curtailment.

Navigant calculated both the technical and market potential associated with implementing DR programs for this study.

Technical potential refers to the theoretical maximum potential under 100% participation of the eligible load. Navigant calculated technical potential by multiplying the eligible load/customers by the unit impact for each sub-option.

An important caveat is that, by definition, a technical potential calculation does not consider participation overlaps. **Technical potential across the various sub-options are not additive** and should not be added together to obtain a total technical potential. Therefore, the technical potential estimates for each DR sub-option should be considered independently. The technical potential calculation is summarized through Equation 2-1.

Equation 2-1. DR Technical Potential

$$\begin{aligned} &Technical\ Potential_{DR\ Sub\ Option,End\ Use,Year} \\ &\quad = Eligible\ Load_{DR\ Sub\ Option,Segment,End\ Use,Year} \\ &\quad * Unit\ Impact_{DR\ Sub\ Option,Segment,Year} \end{aligned}$$

Navigant calculated market potential by multiplying participation assumptions that are expected to be achievable by the technical potential estimates. Market potential also accounts for customer opt outs during DR events. The market technical potential calculation is summarized through Equation 2-2.

Equation 2-2. DR Market Potential

$$\begin{aligned} &Market\ Potential \\ &\quad = Technical\ Potential_{DR\ Sub\ Option,Segment,End\ Use,Year} \\ &\quad * Achievable\ Participation\ Rate_{DR\ Sub\ Option,Segment,Year} \\ &\quad * (1 - Event\ Opt\ Out\ Rate)_{DR\ Sub\ Option,Year} \end{aligned}$$

Market potential is calculated at two levels: standalone and integrated:

- Standalone market potential does not consider participation overlaps across multiple program offers to the same set of customers. Standalone market potential estimates simply apply anticipated achievable participation rates to the technical potential estimates to arrive at market potential estimates. Hence, potentials from individual programs offered to the same customer class are not additive.
- On the other hand, integrated market potential estimates account for participation overlaps through a program hierarchy, which avoids double counting of potential (discussed below in Section 2.4.1). Therefore, the potentials from multiple options offered to the same customer class are additive.

The potential results in Section 3 present both standalone and integrated market potential results for morning and evening peak periods.

In addition to the potential estimates, Navigant developed annual and levelized costs by DR options and sub-options and conducted a cost-effectiveness assessment of these options and sub-options.

Developing DR program annual and levelized costs involves itemizing the various cost components such as program development costs, equipment costs, participant marketing and recruitment costs, annual program administration costs, product lifetimes, discount rate, etc. Table 2-7 summarizes the key variables Navigant used to calculate DR potential and associated costs in this analysis.

Table 2-7. Key Variables for DR Potential and Cost Estimates

Key Variables	Description
Participation Rates	Percentage of eligible customers by program type and customer class
Unit Impacts	• Kilowatt (kW) reduction per device (for DLC) • Percentage of enrolled load (for C&I Curtailment, pricing, and behavioral)
Costs	• One-time fixed costs related to program development • One-time variable costs for customer recruitment and program marketing, equipment installation, and enablement • Recurring fixed and variable costs such as annual program admin. costs, customer incentives, O&M, etc.
Global Parameters	Program lifetime, discount rate, inflation rate, line losses, and avoided costs

Source: Navigant

The key variables for potential and cost assumptions and for benefit-cost assessment are further discussed below.

2.4.1 Participation Assumptions and Hierarchy

Navigant's development of potential and cost assumptions is based on its industry expertise in the area and relevant secondary sources of information such as publicly available DR potential studies and evaluation reports from other jurisdictions and DR program databases such as the Federal Energy Regulatory Commission (FERC) National DR Program Survey database.[28]

Appendix A presents detailed participation assumptions used for potential estimation in the study and presents detailed documentation for the basis of these assumptions. The participation assumptions are developed by customer class and DR option based on the most likely or achievable participation rates in these options. Table A-1 represents steady-state participation assumptions after the program is fully ramped up. Based on standard industry assumptions, Navigant assumes a 5-year S-shaped ramp for the DR options. Therefore, these steady participation values are assumed to be reached after a 5-year program ramp.

Navigant also accounted for participation overlaps among the different DR programs in estimating potential. Table 2-8 presents the participation hierarchy considered in this study, whereby achievable participation estimates are applied to eligible customers only. The participation hierarchy presented here

[28] http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp

is a well-tested approach, initially established in the *National Assessment of DR Potential Study*, conducted by FERC[29] and adopted in a number of other DR potential studies. The participation hierarchy helps avoid double counting of potential through common load participation across multiple programs and is necessary to arrive at an aggregate potential estimate for an entire portfolio of DR programs.

Table 2-8. Program Hierarchy to Account for Participation Overlaps

Customer Class	DR Options	Eligible Customers
Residential, Small C&I, Medium C&I	DLC	Customers with electric space heating and electric water heating
	TOU	Customers not enrolled in DLC
Large C&I, Extra-Large C&I	C&I Curtailment	Customers with various loads (HVAC, lighting, refrigeration, industrial process loads) enrolled in curtailment program types
	TOU	Customers not enrolled in C&I Curtailment

Source: Navigant

2.4.2 Unit Impact Assumptions

The unit impacts specify the amount of load that could be reduced during a DR event once customers are enrolled in a DR program. Unit impacts can be specified either directly as "kW reduction per participant" or as "% of enrolled load." The unit impact values assume a 4-hour event duration, and the values represent the average load reduction over the 4-hour event duration for the two dispatchable DR options: DLC and C&I curtailment.[30] TOU unit impacts are not differentiated by duration of the peak period in literature, and therefore the TOU unit impact assumptions are not specifically tied to a 4-hr. peak period in the TOU rates.[31]

Table B-1 presents the unit impact assumptions used for potential estimation and provides detailed documentation for the basis of these assumptions. This study utilized the latest available secondary sources of information for the unit impact values along with information from DR pilots conducted by other utilities in the area, e.g., FortisBC[32].

Unit impacts were developed by DR sub-option, as the unit impact values are tied to the end uses and type of control. For example, the load reductions associated with the manual HVAC control and Auto-DR HVAC control are different and are specified accordingly.

[29] https://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdfelow

[30] In terms of consecutive day event calling or frequency of events, this does not directly factor into the unit impact assumptions. However, industry experience suggests that calling events for more than two days in a row can lead to dissatisfaction and customer attrition. Therefore, the implicit assumption is that events are not called for more than two consecutive days.

[31] Existing studies on TOU impacts indicate that the peak to off-peak price ratio has the largest influence on load reduction. Duration of the peak period could have an effect on the average impact from the TOU rates, but that is not established in literature and is likely to be less significant than influence of peak to off-peak price ratio.

[32] Navigant used the BC Hydro baseboard pilot findings for baseboard control unit impacts, which was vetted by FortisBC.

2.4.3 Program Costs and Related Assumptions for Cost-Effectiveness

Navigant developed detailed itemized cost assumptions for each DR option to assess annual program costs and calculate levelized costs for each option. These cost calculations feed into the cost-effectiveness assessment of DR options. Appendix C presents detailed itemized cost assumptions used in this study and documents the basis for these assumptions.[33]

The cost assumptions fall into the following broad categories:

- **One-time fixed costs**, specified in terms of $/DR option, which include the program startup costs, including, for example, the software and IT infrastructure-related costs and associated labor time/costs (in terms of full-time equivalents or FTEs) incurred to set up the program.
- **One-time variable costs**, which include marketing/recruitment costs for new participants, metering costs, and all other costs associated with control and communications technologies to enable load reduction at participating sites. The enabling technology cost is specified either in terms of "$/new participant" on a per site basis or as "$/kW of enabled load reduction" on a participating load basis.
- **Annual fixed costs,** specified in terms of $/yr., which primarily includes FTE costs for annual program administration.
- **Annual variable costs,** which primarily includes customer incentives, specified either as a fixed monthly/annual incentive amount per participant ($/participant) or in terms of load and/or energy reduction ($/kW and/or $/kWh reduction). It also includes additional O&M costs that may be associated with servicing technology installed at customer premises.
- **Program delivery costs.** This is a fixed contracted payment for third-party delivery of DR programs and is specified as $/kW-yr.

Other than the itemized program costs, the other key variables related to the cost-effectiveness calculations in the model are the following:

- **Nominal discount rate** of 8.12%, used for net present value (NPV) calculations.
- **Inflation rate** of 2%, used to inflate the costs over the forecast period (2018-2037).
- **Program life**, assumed to be 10 years for DLC and C&I Curtailment and 20 years for TOU.
- **Derating factor**, used to derate the benefits from DR to bring it at par with generation resources. The derating factor is used to account for program design constraints, such as limitations on how often events can be called, annual maximum hours for which events can be called, window of hours during the day during which events can be called, and sometimes even on the number of days in a row that events may be called. The derating factor helps lower the benefits from DR so that a megawatt from DR is not considered at par as a megawatt from a generator, which does not have similar availability constraints and could potentially be available round the clock. Appendix D documents the derating factor assumptions used in this study. Note that the derating factor only affects the benefit calculations and *not* the megawatt potential estimates.
- **Avoided costs,** including both avoided generation capacity and transmission and distribution (T&D) capacity cost projections provided by FortisBC to calculate DR benefits. Appendix E presents the avoided costs used for calculating DR benefits. The benefits assessment does not

[33] Note that all costs are specified in CAD. Navigant assumed an exchange rate of 1 USD=1.4 CAD.

include avoided energy costs since the energy savings impacts from DR programs are likely to be insignificant.[34] The cost-effectiveness assessment was based on all five types of cost tests shown in Table 2-9, which represents how the different items are treated by the type of test.

Table 2-9. Treatment of Benefits and Costs by Type of Cost Test

Item	TRC[35]	UCT[36]	PCT[37]	RIM[38]	SCT[39]
Program Development Cost	Cost	Cost	N/A	Cost	Cost
Program Administrative Cost	Cost	Cost	N/A	Cost	Cost
Program Delivery Cost	Cost	Cost	N/A	Cost	Cost
Marketing and Recruitment Cost	Cost	Cost	N/A	Cost	Cost
Technology Enablement Cost	Cost	Cost	N/A	Cost	Cost
Operation and Maintenance (O&M) Cost	Cost	Cost	N/A	Cost	Cost
Incentives	Transfer	Cost	Benefit	Cost	Transfer
Avoided Generation Capacity Costs	Benefit	Benefit	N/A	Benefit	Benefit
Avoided T&D Capacity Costs	Benefit	Benefit	N/A	Benefit	Benefit
Avoided Energy Purchases	Benefit	Benefit	N/A	Benefit	Benefit
Participant Cost	Cost	N/A	Cost	N/A	Cost

Source: Navigant

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[3434] This is a standard practice across many other DR potential studies.

[35] Total Resource Cost Test

[36] Utility Cost Test

[37] Participant Cost Test

[38] Ratepayer Impact Measure Test

[39] Societal Cost Test

3. DR POTENTIAL RESULTS

This section presents DR potential and cost results based on the approach described in Section 2. Potential estimates include both winter morning and evening potential results.

This study estimated both technical and market potential results for DR. However, as described in Section 2, technical potential results are considered on a standalone basis for each DR sub-option and cannot be aggregated to provide a total potential. For DR, technical potential represents the theoretical maximum potential that estimates how much load reduction one could theoretically achieve if 100% of the eligible load is controllable through a DR technology in a program.[40]

Market potential is presented at two levels, as described previously in Section 2. These are standalone market potential and integrated market potential. The integrated market potential results are most representative of what FortisBC could aim to achieve through future DR programmatic activities. It accounts for participation overlaps across multiple DR options targeting the same customers and avoid double counting of DR potential by building in a participation hierarchy, described previously in Section 2.4.1.

This section presents analysis results in the following order:[41]

- **Section 3.1: Technical Potential Results**
  - Morning peak demand reduction by DR sub-option
  - Evening peak demand reduction by DR sub-option
  - Morning and evening technical potential by customer class and DR sub-option
- **Section 3.2: Standalone Market Potential Results**
  - Morning peak demand reduction by DR sub-option
  - Evening peak demand reduction by DR sub-option
  - Morning and evening standalone potential by customer class and DR sub-option
- **Section 3.3: Integrated Market Potential Results**
  - Aggregate Integrated Market Potential Results for Morning and Evening Peak Periods
  - Integrated Market Potential Results by DR Options and Sub-options
  - Integrated Market Potential by Customer Class
- **Section 3.3.5: Program Costs and Cost-Effectiveness Results**
  - Annual Program Costs under Integrated Market Potential
  - Levelized Costs by DR Sub-options
  - Benefit-to-Cost Ratios by DR Options and Sub-options for the different cost tests

[40] Note that unlike energy efficiency potential studies, DR potential assessment considers cost-effectiveness at the program level and not by individual technologies/measures. This is because DR measures/technologies do not exist without a program and, therefore the cost-effectiveness assessment for DR is conducted for individual programs and at the portfolio level.

[41] Detailed potential and cost results are included in the Excel-based results dashboards accompanying this report.

Navigant's analysis considered three DR options synonymous with DR programs: DLC, C&I Curtailment, and TOU. DLC and C&I Curtailment options were further broken down into sub-options based on the type of control technology. For example, DLC included both thermostat- and switch-based control and C&I Curtailment included manual and Auto-DR sub-options.

This section presents DR technical, standalone market, and integrated market potential results. It also includes annual DR program costs, levelized costs by DR option, and cost-effectiveness test results..

3.1 Technical Potential Results

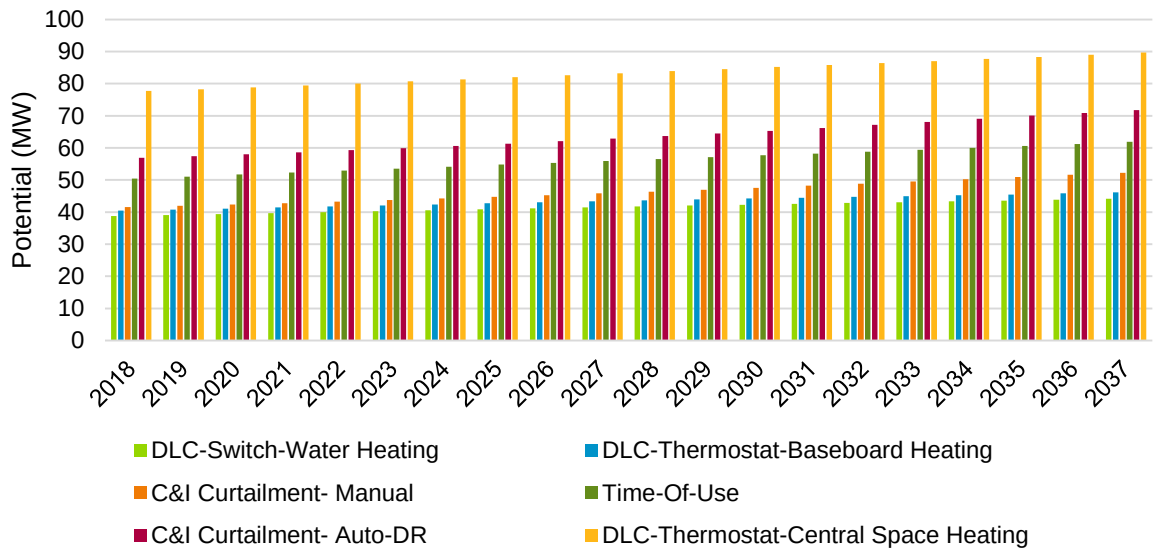
Technical potential results in this section are reported first by DR sub-option for morning and evening peak periods and then by customer class for morning and evening peak periods. Note that the growth in technical potential represents the growth in customer count and load since the unit impacts are assumed to remain unchanged over the 20-year forecast period. Technical potential assumes 100% participation of eligible customers/load and therefore participation is held constant at 100% over 2018-2037.

3.1.1 Technical Potential by DR Sub-Option

3.1.1.1 Morning Peak Period

Figure 3-1 shows the morning technical potential results by sub-option. Among the different sub-options included in the study, control of central space heating has the highest potential (grows from 78 MW in 2018 to 90 MW in 2037). Auto-DR-enabled curtailment potential from large and extra-large customers is next highest (Auto-DR grows from ~57 MW in 2018 to ~72 MW in 2037). The higher potential with Auto-DR is associated with larger amounts of unit impacts associated with Auto-DR-enabled curtailment versus manual curtailment. TOU rates with 100% participation across all customer classes could help realize a 50 MW morning peak reduction in 2018, with a steady growth to a 62 MW reduction in 2037. Potential from manual curtailment is approximately 70% of the potential from Auto-DR curtailment and grows from about 40 MW in 2018 to 52 MW in 2037. Control of baseboard heating for residential customers has the next highest potential. Switch-based control of electric water heating has the least technical potential (~39 MW in 2018 that grows to ~44 MW in 2037).

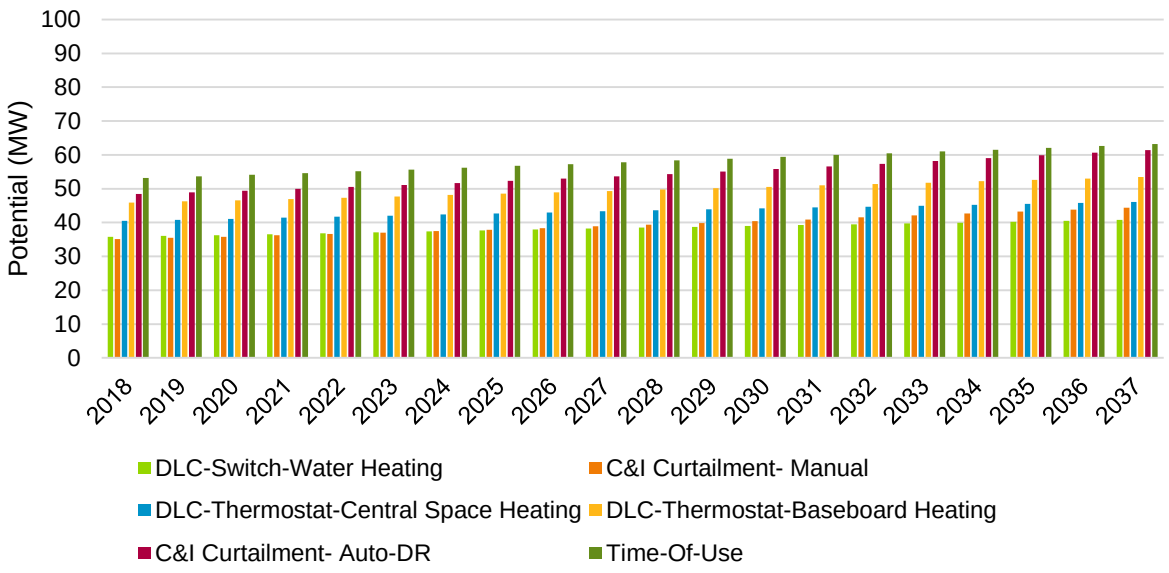
Figure 3-1. Technical DR Potential by Sub-Option – Morning



3.1.1.2 Evening Peak Period

Figure 3-2, which shows evening peak period DR potential by DR sub-option, has a different sub-option order in terms of highest to lowest potential values compared to the morning results. TOU rates have the largest evening technical potential (~53 MW in 2018 that grows to ~63 MW in 2037) and nearly the same technical potential in evening than morning. Auto-DR-enabled curtailment has the next highest potential (~48 MW in 2018 that grows to ~61 MW in 2037). For C&I Curtailment, the evening technical potential for both the manual and Auto-DR sub-options is roughly 85% of their morning technical potential because the end-use loads are lower in the evening than in the morning. DLC potential from control of central space heating (furnaces and heat pumps) has third highest technical potential growing from 46 MW in 2018 to 53 MW in 2037. The evening potential from central space heating control is approximately 60% of the morning potential due to lower space heating load in evening than morning. Evening potential from baseboard heating control is approximately 990% of the potential from central space heating control. We assumed same unit impacts for baseboard control for morning and evening and therefore the potential remains unchanged between the two periods. For electric water heating control, evening technical potential is approximately 92% of the morning technical potential and has the lowest potential among all DR sub—options.

Figure 3-2. Technical DR Potential by Sub-Option – Evening



3.1.2 Technical Potential by Customer Class

This section shows technical potential results by customer class and DR sub-options for the morning and evening peak periods.

3.1.2.1 Residential Technical Potential

Figure 3-3 shows the technical potential for residential customers in the morning peak period. Control of central electric furnaces and heat pumps has the highest technical potential (grows from ~49 MW in 2018 to ~56 MW in 2037), which represents 15% reduction in the residential morning peak demand. Potential from control of baseboard heating grows from ~41 MW in 2018 to ~46 MW in 2037, and represents approximately 13% reduction in residential peak demand. TOU rates for residential have the next highest technical potential among the sub-options. It could help realize roughly 35 MW of potential in 2018, increasing to close to 42 MW in 2037, if all customers were enrolled in TOU rates. The TOU technical potential in 2037 represents slightly greater than 10% reduction in residential peak demand. Control of electric water heaters through switches for residential customers has the least amount of technical potential (35 MW of morning peak reduction in 2018, increasing to around 39 MW in 2037).

Figure 3-3. Residential Technical Potential – Morning

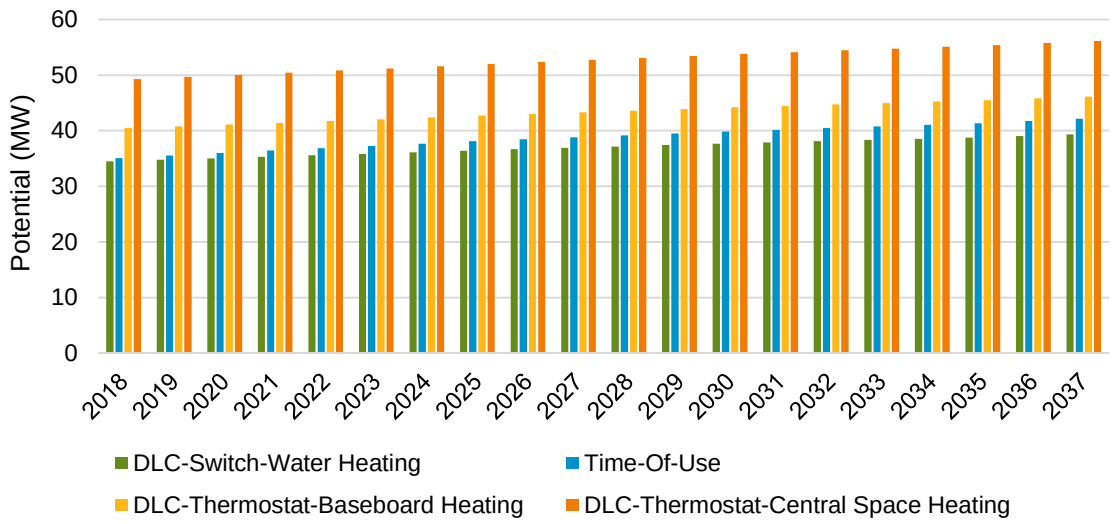
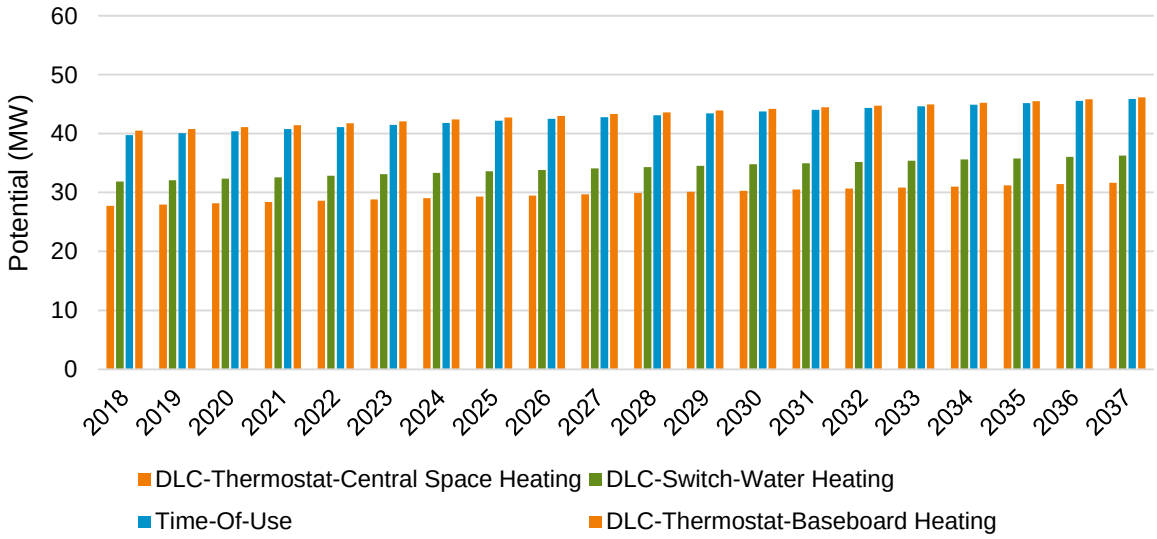


Figure 3-4 shows the residential technical potential for the evening period by sub-option, which follows a slightly different ordering of sub-options from the morning peak period, in terms of their relative potential estimates. Impacts from baseboard heating control are the highest and represent approximately 12% reduction in residential evening peak demand. TOU rates have second highest technical potential in the evening and have values very close to the baseboard heating potential values (growing from ~40 MW in 2018 to ~46 MW in 2037), representing 12% reduction in residential peak demand. Evening peak reduction potential from water heating control is around 86% of the morning peak reduction potential. Impacts from central space heating control in evening have the lowest technical potential among the residential DR sub-options and are estimated at approximately 80% of morning impacts (technical potential from central space heating control grows from ~28 MW in 2018 to ~32 MW in 2037), and represents 8% reduction in residential evening peak demand.

Figure 3-4. Residential Technical Potential – Evening



3.1.2.2 Small C&I Technical Potential

The small C&I customer class sub-options include control of central space heating, electric water heating, and TOU rates. Figure 3-5 shows the technical potential associated with these three sub-options. The highest technical potential for small C&I customers is from central space heating control (grows from ~21 MW in 2018 to ~24 MW in 2037). Control of electric water heating for these customers—if 100% of the customers were to participate—can provide only an approximately 4 MW reduction in morning peak in 2018 through 2037, representing 8% reduction in small C&I peak demand. TOU rates have low potential from small C&I due to the low level of TOU unit impact values for these customers.

Figure 3-5. Small C&I Technical Potential – Morning

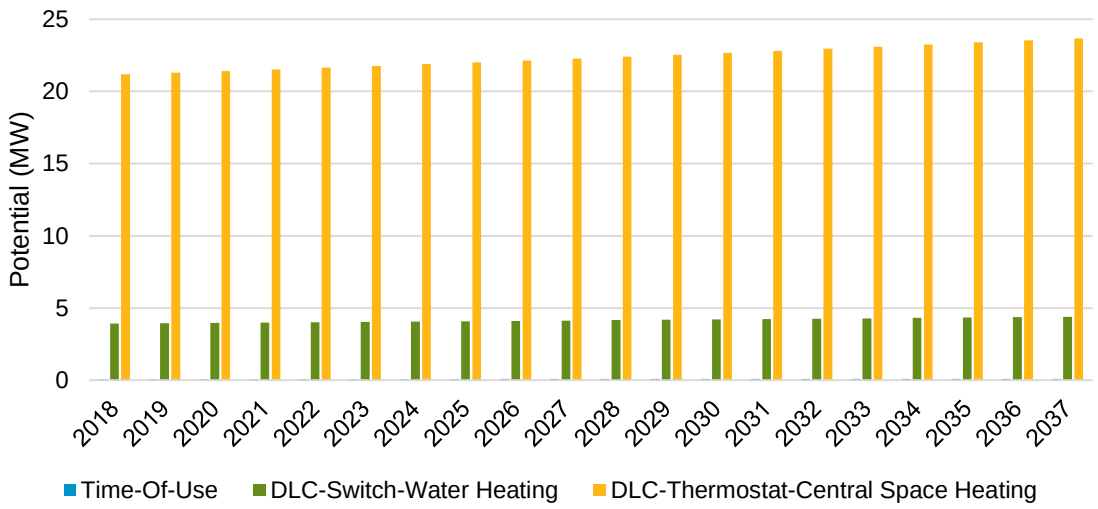
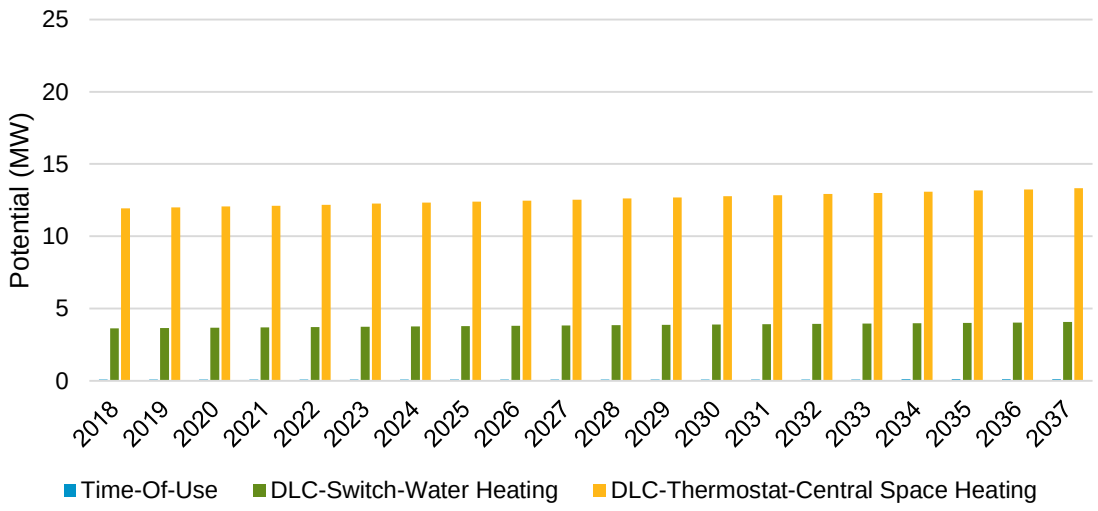


Figure 3-6 shows the small C&I technical potential for the evening period by sub-option, which follows the same ordering of sub-options as for the morning peak period. Impacts from central space heating control in evening are projected to be approximately 56% of morning impacts (technical potential from central space heating control grows from ~12 MW in 2018 to ~13 MW in 2037). Evening peak reduction potential from water heating control is around 92% of the morning peak reduction potential across the entire forecast period. Potential from TOU rates in evening is only slightly lower than morning potential.

Figure 3-6. Small C&I Technical Potential – Evening



3.1.2.3 Medium C&I Technical Potential

The sub-options for medium C&I customers are the same as those for small C&I customers. For these customers, as shown in Figure 3-7, control of electric space heating has the highest technical potential (grows from ~7 MW in 2018 to ~10 MW in 2037), which represents approximately 15% reduction in small C&I morning peak demand. TOU rates for medium C&I ranks second with around 3-4 MW of potential only, representing approximately 6% reduction in medium C&I peak demand. Control of electric water heating has lowest technical potential (less than 0.5 MW over the forecast period) due to very small contribution of electric water heating load in the total medium C&I peak demand.

Figure 3-7. Medium C&I Technical Potential – Morning

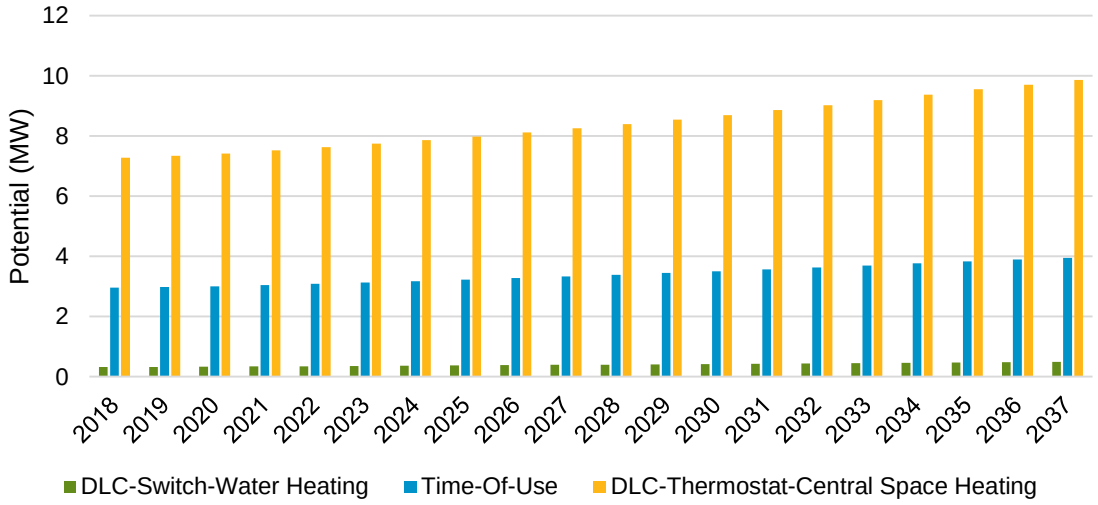
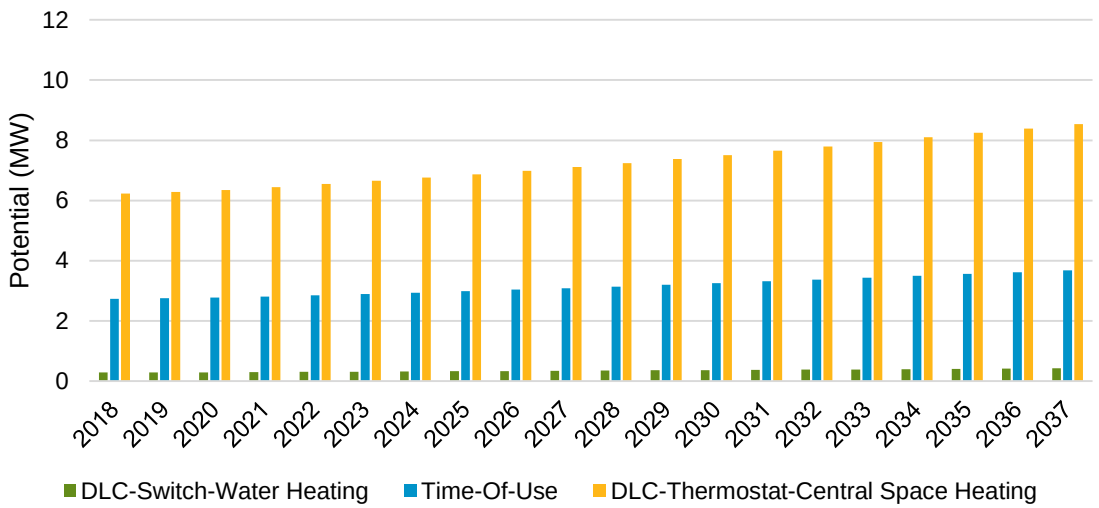


Figure 3-8 shows the medium C&I technical potential for the evening period by sub-option. Central space heating load reductions in evening are projected to be approximately 87% of morning impacts (technical

potential from central space heating control grows from ~6 MW in 2018 to ~9 MW in 2037), and represents 15% reduction in medium C&I evening peak demand. Impact from TOU rates in evening is approximately 7% lower than morning impacts due to lower evening peak demand from these customers than morning peak demand. Switch-based water heating load control offers almost the same potential in evening as in morning (again, less than 0.5 MW over the forecast period).

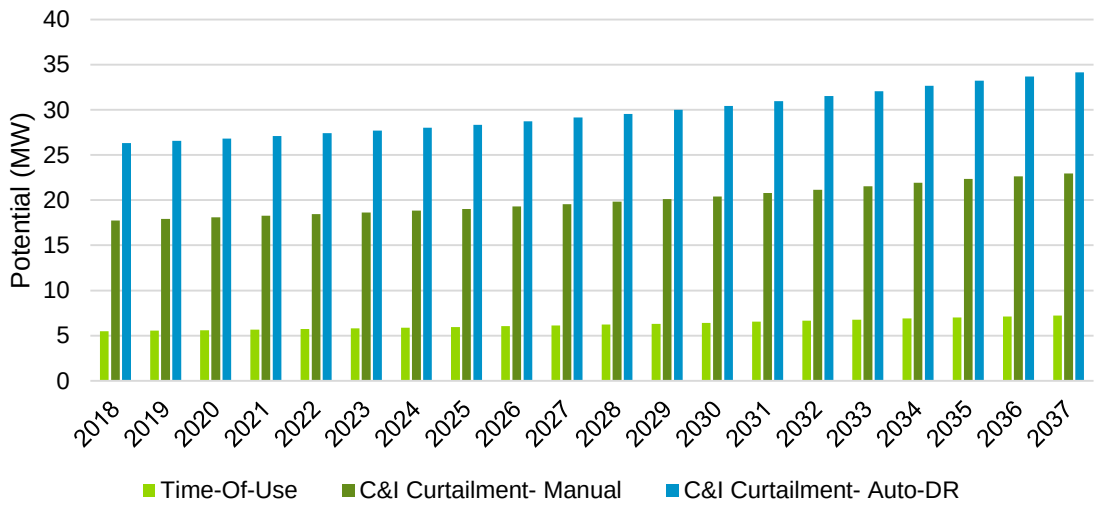
Figure 3-8. Medium C&I Technical Potential – Evening



3.1.2.4 Large C&I Technical Potential

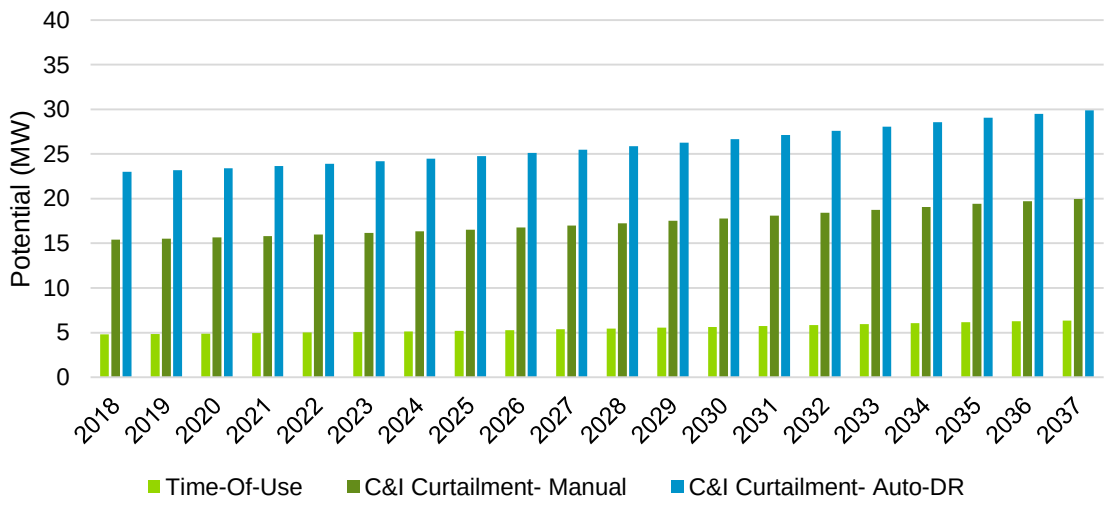
For large C&I customers, Auto-DR-enabled load curtailment offers the largest potential. For these customers, the morning technical potential grows only slightly from approximately 26 MW in 2018 to 34 MW in 2037 (shown below in Figure 3-9), which represents approximately 33% reduction in large C&I morning peak demand. Potential from manual curtailment is about 67% of the potential from Auto-DR-enabled curtailment (grows from ~18 MW in 2018 to ~23 MW in 2037), and represents approximately 22% reduction in large C&I peak demand. TOU rates have a much lower potential than the curtailment option. Technical potential from the TOU rate offer to these customers is estimated at approximately 5 MW in 2018, which grows to just about 7 MW in 2037 in the morning peak period, and represents approximately 7% reduction in medium C&I morning peak demand.

Figure 3-9. Large C&I Technical Potential – Morning (MW)



The ordering of the sub-options remains the same for evening peak reduction. Evening potential is approximately 12% lower than the morning potential for large C&I customers. Figure 3-10 shows the evening potential by DR sub-option for these customers. Auto-DR curtailment potential represents 25% reduction in large C&I evening peak demand, manual curtailment represents 17% reduction in peak demand, and TOU rates represent 7% reduction in peak demand.

Figure 3-10. Large C&I Technical Potential – Evening



3.1.2.5 Extra-Large C&I Technical Potential

The extra-large C&I technical potential is approximately 8% higher than the large C&I technical potential and follows the same order of sub-options in terms of their relative technical potential values. Figure 3-11 shows the morning technical potential by DR sub-option for extra-large C&I customers. Technical potential for Auto-DR-enabled C&I Curtailment for the morning peak period is projected to grow from

approximately 31 MW in 2018 to about 38 MW in 2037, representing 32% reduction in extra-large C&I peak demand. Potential from manual curtailment is roughly 22% lower than the potential from Auto-DR-enabled curtailment (manual curtailment potential grows from ~24 MW in 2018 to ~31 MW in 2037). Technical potential from TOU rates is substantially lower than the potential from the curtailment-based options—morning peak period technical potential from TOU rates is approximately 7 MW in 2018 and is expected to grow to around 8 MW in 2037, representing 7% reduction in peak demand.

Figure 3-11. Extra-Large C&I Technical Potential – Morning

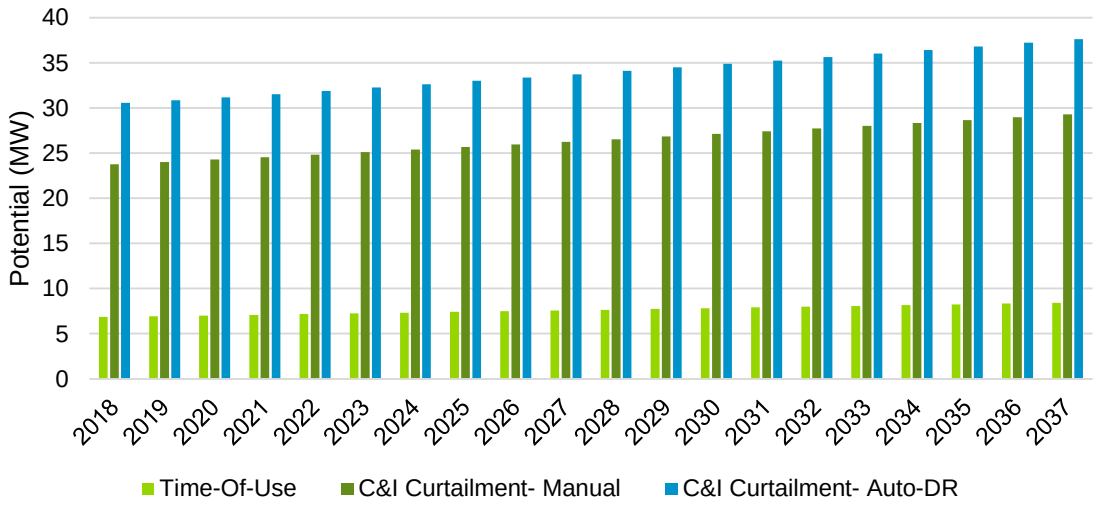
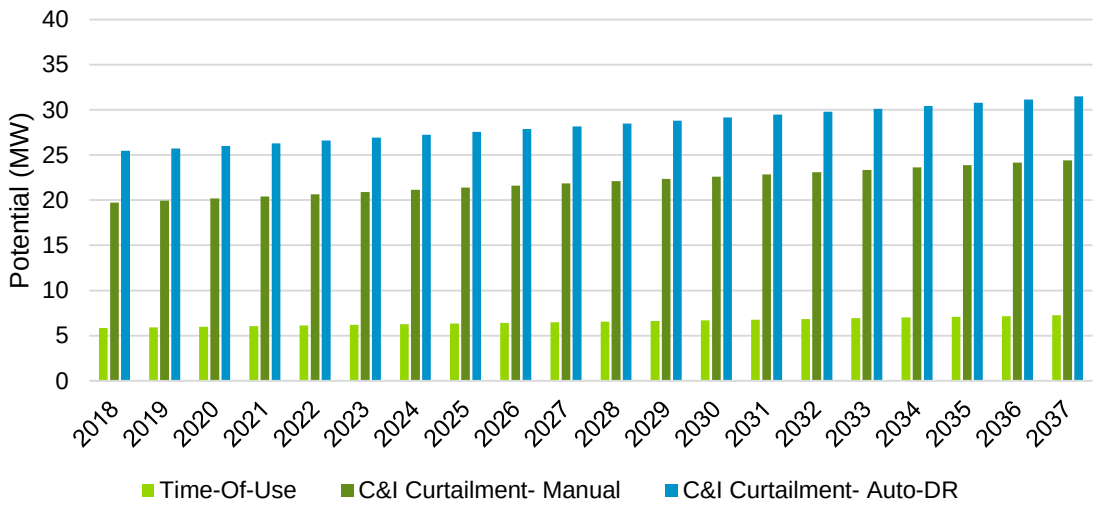


Figure 3-12 shows the evening technical potential by DR sub-option for extra-large C&I customers. Evening technical potential is approximately 83%-86% lower than morning technical potential but follows the same pattern as the morning results. A significant portion of the potential from extra-large customers comes through curtailment of process/other industrial loads, which do not change much between morning and evening peak periods; thus, potential remains roughly the same. Auto-DR curtailment represents approximately 30% reduction in extra-large C&I evening peak demand, manual curtailment represents 24% reduction in peak demand, and TOU rates represent 7% reduction in peak demand.

Figure 3-12. Extra-Large C&I Technical Potential – Evening



3.2 Standalone Market Potential Results

Standalone market potential results in this section are reported first by DR option for morning and evening peak periods and then by customer class and sub-option for morning and evening peak periods. As previously discussed, standalone market potential results do not consider participation hierarchy and there are likely overlaps in participation among the DR options offered to the same set of customers. Thus, the potential cannot be summed across the DR options.

3.2.1 Standalone Market Potential Results by DR Option

Figure 3-13 and Figure 3-14 show the standalone market potential results for the morning and evening peak periods, respectively.

DLC has the highest potential, followed by C&I Curtailment and TOU. DLC potential in the morning peak period grows rapidly from 3 MW in 2018 to 28 MW in 2022 during the program's ramp stage and subsequently to just over 32 MW in 2037. This represents approximately 4.5% reduction in FortisBC's total average morning peak demand. The DLC evening potential is lower— approximately 75% of the morning potential—because the end uses contributing toward DLC (space heating and water heating) have higher load during the morning peak period than during the evening peak period. The evening DLC potential represents ~3.5% reduction in the total average evening peak demand.

The C&I Curtailment potential is approximately 50% of the DLC potential. The C&I Curtailment potential in the morning peak period grows rapidly from 1 MW in 2018 to 13 MW in 2022, as the program ramps up over a 5-year period. From 2023 onward, the potential grows at a much slower rate to approximately 15 MW in 2037. The C&I Curtailment potential represents approximately 2% reduction in FortisBC's average morning peak demand. The evening peak period potential for C&I Curtailment is approximately 85% of the morning peak reduction potential due to lower C&I loads during the evening peak period and represents 2% reduction in evening peak demand.

TOU potential is approximately 40%-60% of the potential of DLC and nearly identical to C&I Curtailment. Like C&I Curtailment, the morning TOU potential grows from 1 MW in 2018 to around 14 MW in 2037, representing 2% reduction in the total average morning peak demand. Evening TOU potential is slightly greater than the morning potential and grows from approximately 1 MW to 15 MW from 2018 to 2037, representing ~2% reduction in evening peak demand.

Figure 3-13. Standalone Market Potential by DR Option – Morning

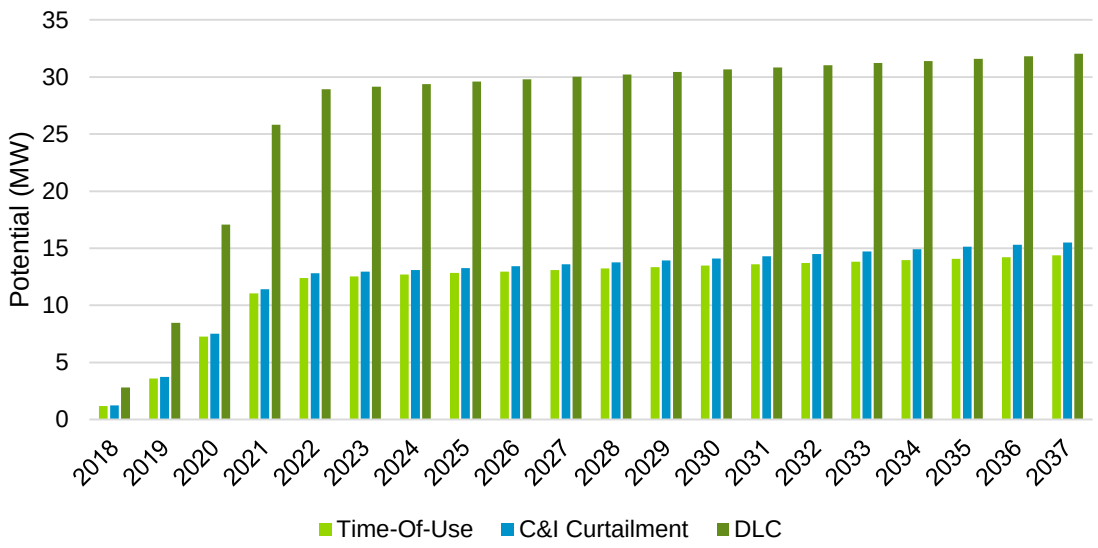
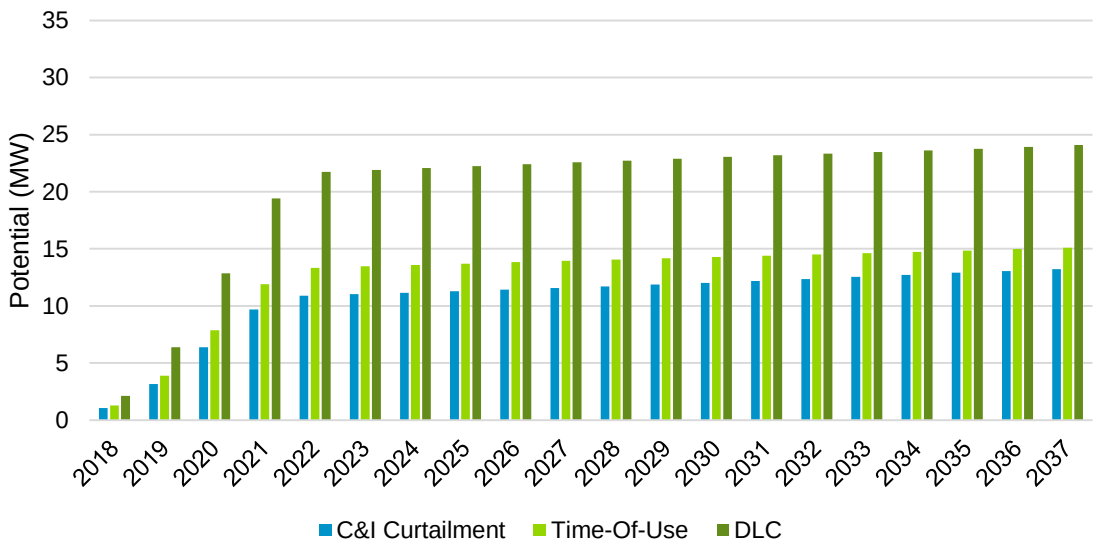


Figure 3-14. Standalone Market Potential by DR Option – Evening



3.2.2 Standalone Market Potential Results by DR Sub-Option

This section presents disaggregated standalone market potential results by DR sub-option. Figure 3-15 shows standalone market potential by DR sub-option for the morning peak period and Figure 3-16 shows results for the evening peak period.

The control of central space heating (furnaces and heat pumps) for residential and small and medium C&I customers is the greatest contributor to the morning potential. The control of central space heating potential is projected to grow from 2 MW in 2018 to 18 MW in 2037, with rapid growth during the first 5 years as the program ramps up. The space heating demand is lower during the evening peak period than the morning peak period; consequently, the evening potential is about 42% lower than the morning potential. The potential from central space heating control represents 2.5% of system morning peak reduction and 1.5% of system evening peak reduction.

TOU has the second highest morning potential and the greatest evening potential. As discussed previously, TOU morning potential starts close to 1 MW in 2018 and is expected to grow to 14 MW in 2037; the evening potential starts close to 1 MW and is projected to grow to 15 MW from 2018 to 2037. The TOU potential does not consider overlap in participation with the DLC program and C&I Curtailment programs; thus, it is not additive to the potential from these other two options. The TOU potential in both periods represents approximately 2% reduction in the system peak demand.

Of the total C&I Curtailment potential reported earlier, 58% of it is from Auto-DR and the remaining 42% is from manual curtailment. The Auto-DR curtailment potential is projected to grow from approximately 0.3 MW in 2018 to 9 MW in 2037, with rapid growth during the first 5 years as the C&I Curtailment program ramps up, and represents ~1.3% reduction in total morning peak demand. The evening potential is slightly lower at 85% of the morning potential because the curtailable loads from large and extra-large C&I customers have higher demand in the morning than in the evening. The evening potential from Auto-DR represents ~1% reduction in total evening peak demand. Manual curtailment potential grows from 0.2 MW in 2018 to 7 MW in 2037 in the morning period and has 15% lower potential in the evening, with 0.2 MW of potential in 2018 and 6 MW of potential in 2037. For both peak periods, manual curtailment potential represents slightly lower than 1% reduction in overall peak demand.

Potential from baseboard heating control in residential homes has almost equal to Auto-DR-curtailment potential, with projected growth from 1 MW in 2018 to 8 MW in 2037, representing ~1.2% reduction in overall peak demand. As observed earlier, water heating control potential has the smallest potential with 0.5 MW in 2018 growing to approximately 6 MW in 2037. Water heating control potential is almost equal to manual curtailment potential and represents approximately 0.8% reduction in overall peak demand.

Figure 3-15. Standalone DR Market Potential by Sub-Option – Morning

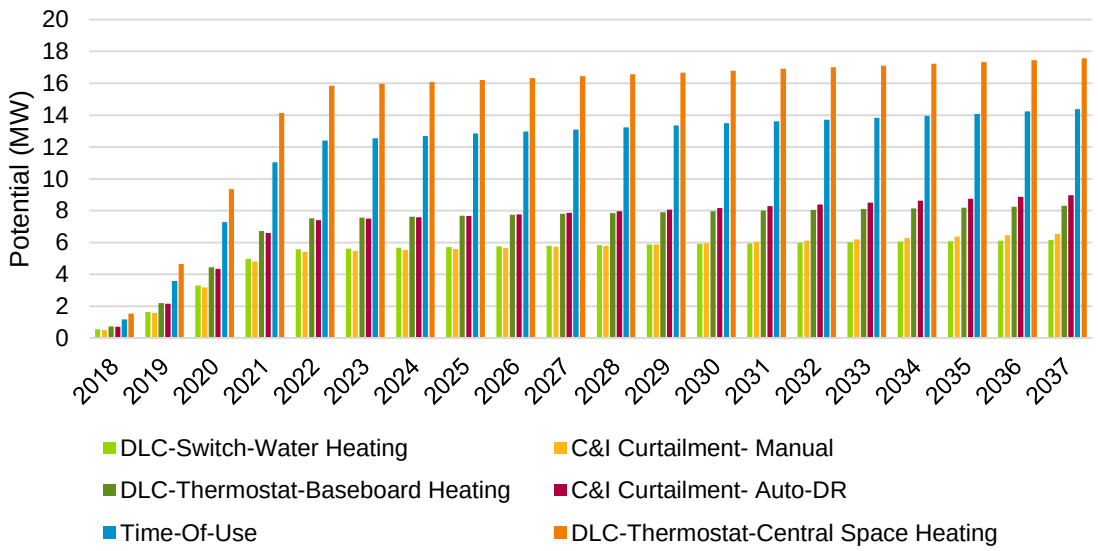
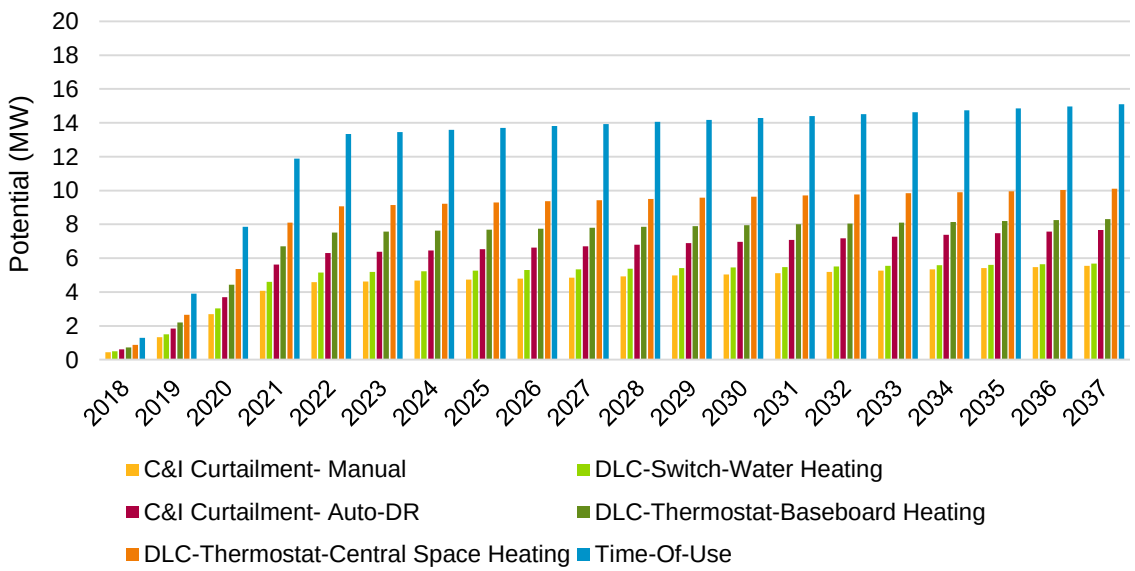


Figure 3-16. Standalone DR Market Potential by Sub-Option – Evening



3.2.3 Standalone Market Potential Results by Customer Class

This section discusses the standalone market potential by sub-option for each customer class during the morning and evening peak periods.

3.2.3.1 Residential Standalone Market Potential

Figure 3-17 and Figure 3-18 show the standalone morning and evening market potentials from residential customers.

Total DLC potential from residential is projected to grow from approximately 3 MW in 2018 to around 29 MW in 2037. The evening DLC potential is approximately 75% of the morning DLC potential since residential space heating demand is lower in the evening than in the morning. The residential DLC potential represents ~3-4% reduction in system demand for both morning and evening peak periods. The morning DLC potential is equivalent to 8% reduction in residential peak demand and the evening DLC potential translates to 5.6% of residential evening peak demand.

DLC potential from residential customers is substantially higher than TOU potential and is at 2 - 2.5 times the TOU potential for both peak periods. However, if we consider the potential by different DR sub-options, TOU rates have highest potential in evening and second highest potential in morning. On a standalone basis, TOU potential for morning peak reduction from residential is projected to grow from 1 MW in 2018 to 12 MW in 2037, and from 1 MW in 2018 to 13 MW in 2037 for evening peak reduction. The TOU potential represents slightly less than 2% reduction in system peak demand during both periods and ~3% reduction in residential peak demand.

Among the different end uses controlled in DLC, central space heating has the highest potential in the morning, followed by baseboard heating and then switch-water heating. However, in the evening, the potential from baseboard heating is almost equal to the potential from central space heaters (furnaces and heat pumps). Potential from water heating control is around 20% of the total potential from DLC for both peak periods.

Figure 3-17. Residential Standalone Market Potential – Morning

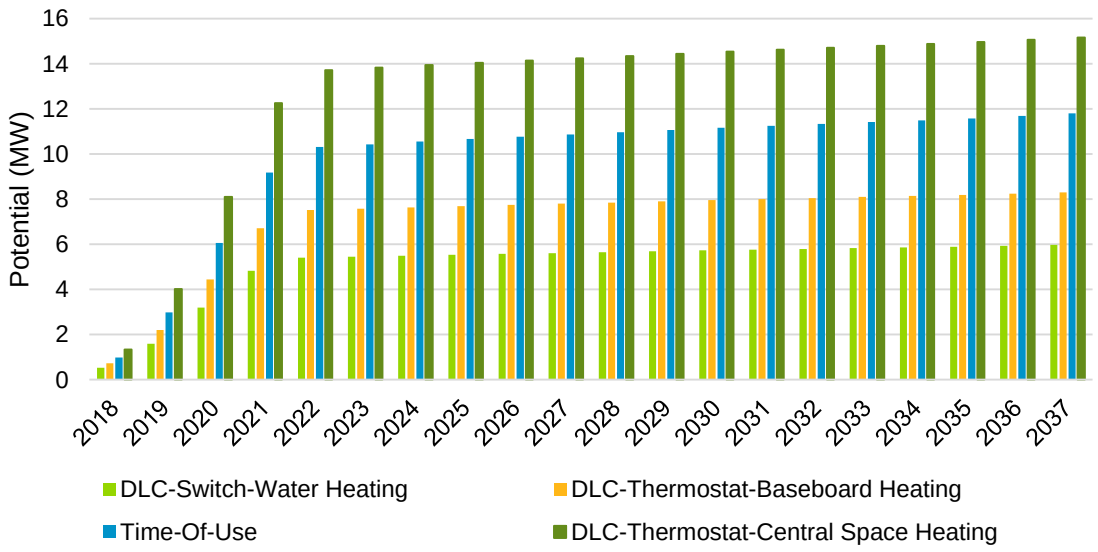
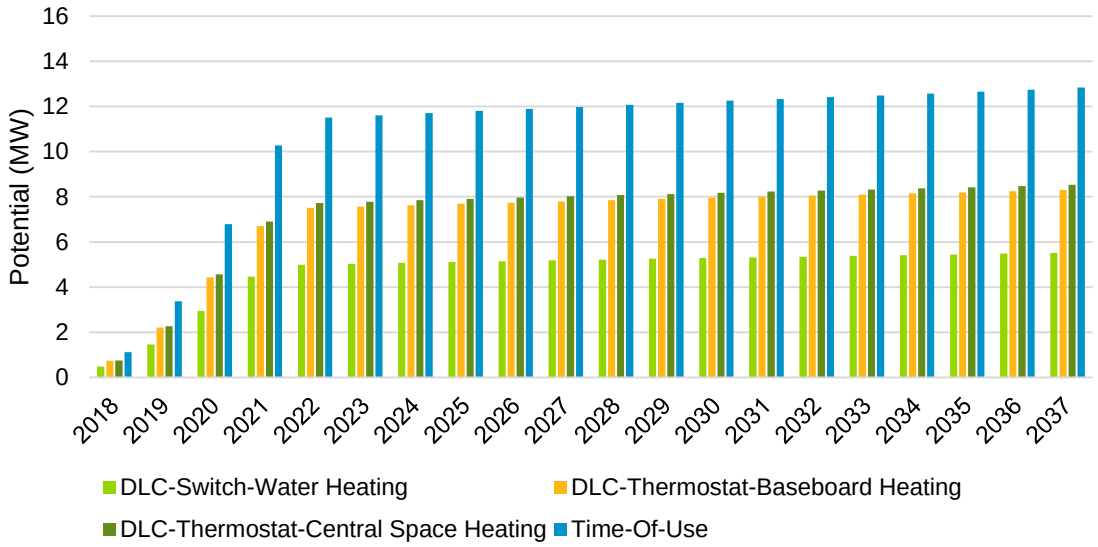


Figure 3-18. Residential Standalone Market Potential – Evening



3.2.3.2 Small C&I Standalone Market Potential

Figure 3-19 and Figure 3-20 show the standalone morning and evening market potentials from small C&I customers.

The small C&I DLC potential is substantially lower than the residential DLC potential at approximately 4%-6% of the residential potential. It is projected to grow from 0.1 MW-0.2 MW in 2018 to 1-2 MW in 2037 for the evening and morning peak periods, respectively. The evening DLC potential is about 60% of the morning DLC potential. Of the DLC potential for these customers, 86%-90% is through control of electric space heating for the evening and morning peak periods, respectively. TOU potential is insignificant for small C&I customers. The small C&I potential represents less than 0.5% reduction in system peak demand.

Figure 3-19. Small C&I Standalone Market Potential – Morning

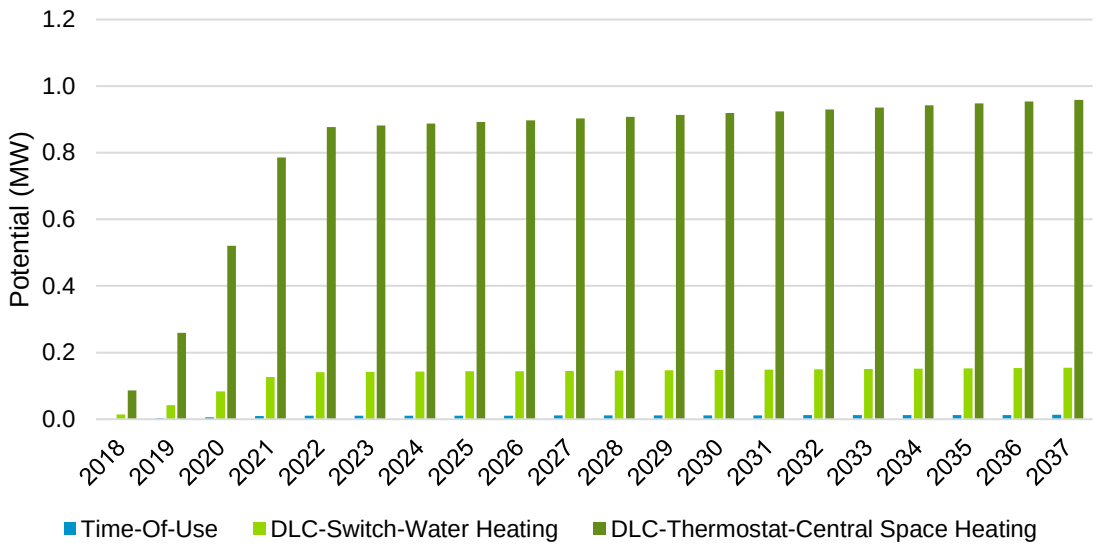
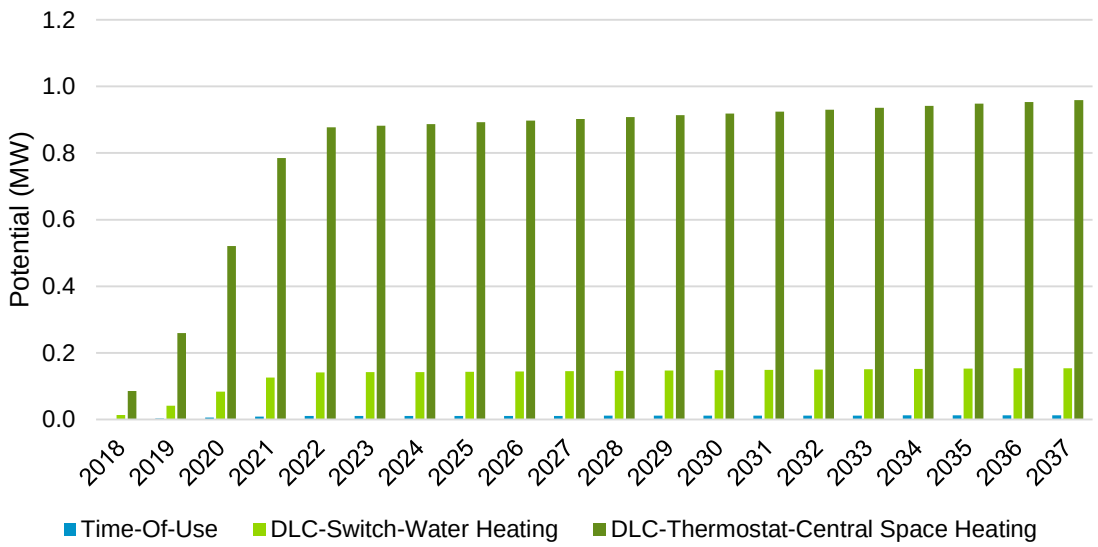


Figure 3-20. Small C&I Standalone Market Potential – Evening



3.2.3.3 Medium C&I Standalone Market Potential

Figure 3-21 and Figure 3-22 show the standalone morning and evening market potentials from medium C&I customers.

Medium C&I potential is lowest among all customer classes. It increases only from 0.06 MW to 0.8 MW for DLC during the morning peak period and from 0.05 MW to 0.6 MW in the evening, the majority of which comes from central space heating control. TOU potential from these customers is less than 0.7 MW in 2037 for both peak periods. The low potential levels from these customers are due to the relatively

small market size and peak demand from these customers when compared with the other customer classes.

Figure 3-21. Medium C&I Standalone Market Potential – Morning

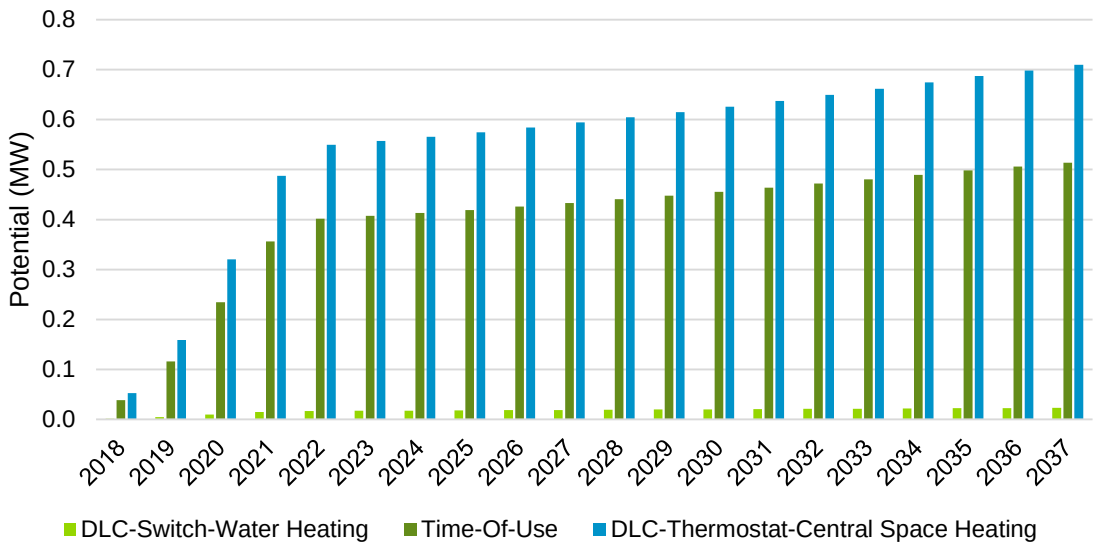
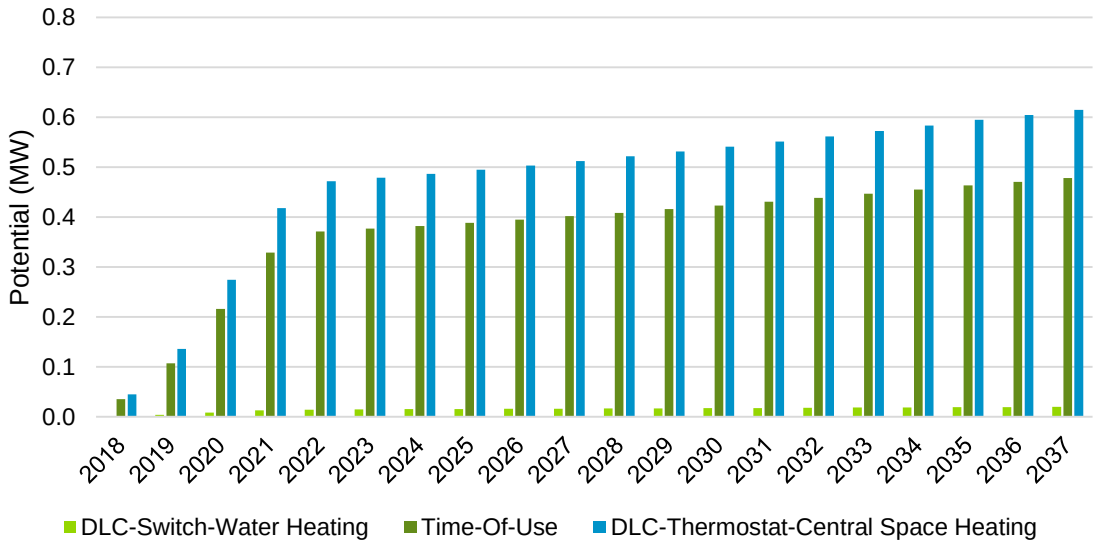


Figure 3-22. Medium C&I Standalone Market Potential – Evening



3.2.3.4 Large C&I Standalone Market Potential

Figure 3-23 and Figure 3-24 show the standalone market potential from large C&I customers for the morning and evening peak periods.

The total C&I Curtailment potential from these customers grows from approximately 0.5 MW to around 7 MW of morning and evening peak reduction over 2018-2037. As discussed previously, 60% (morning)

and 52% (evening) of this reduction is through Auto-DR curtailment and the remaining 40% (morning) and 48% (evening) from manual curtailment. C&I Curtailment potential is nearly equal for the evening and morning periods and represents approximately 1% reduction in the overall peak demand. TOU potential is substantially lower than the curtailment potential. When considered independently from C&I Curtailment, TOU potential is projected to grow from approximately 0.06 MW-0.07 MW in 2018 to 0.8 MW-0.9 MW in 2037 for the evening and morning peak periods, respectively. The TOU potential is insignificant at less than 0.1% reduction in overall peak demand.

Figure 3-23. Large C&I Standalone Market Potential – Morning

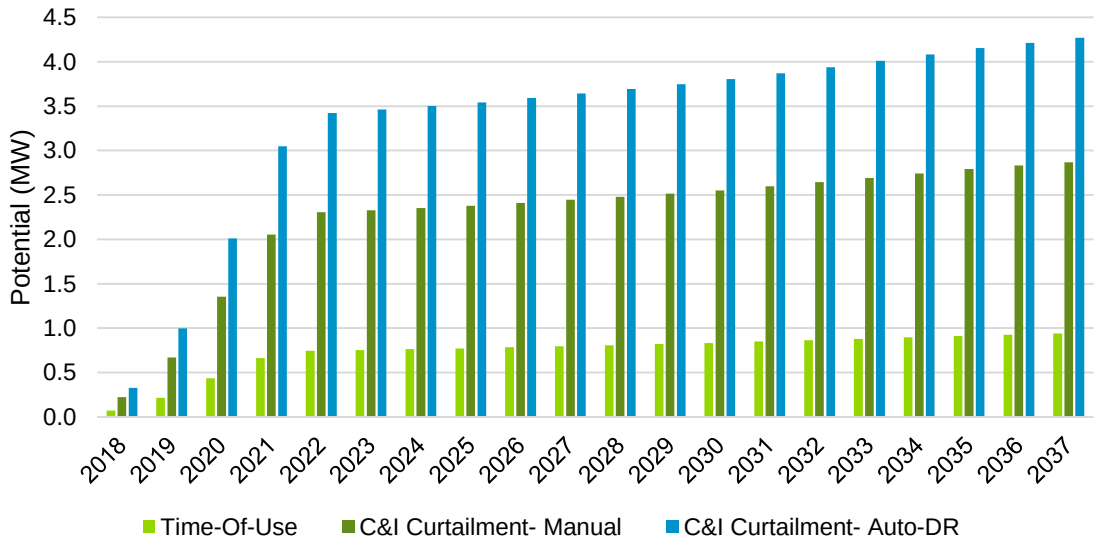
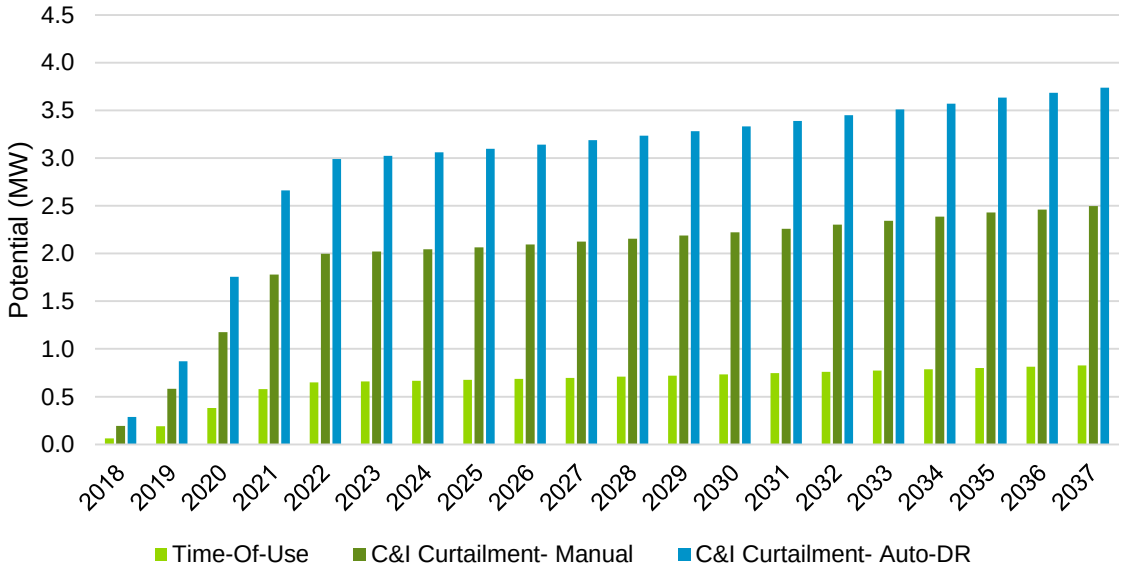


Figure 3-24. Large C&I Standalone Market Potential – Evening



3.2.3.5 Extra-Large C&I Standalone Market Potential

Figure 3-25 and Figure 3-26 show the standalone market potential from extra-large C&I customers for the morning and evening peak periods.

The potential levels from these customers are close in value to those observed from the large C&I customers and follow similar trends. The total C&I Curtailment potential from these customers is expected to grow to 7 MW-8 MW of peak reduction in 2037 for the evening and morning peak periods, respectively and represent ~1% reduction in system peak demand. TOU potential levels are almost the same as those for the large C&I customers and are projected to be just over 1 MW by 2037, which is at an insignificant 0.1% in terms of system peak demand reduction. There is little variation in the morning and evening potentials from these customers because the load for these customers remains fairly constant during these two periods.

Figure 3-25. Extra-Large C&I Standalone Market Potential – Morning

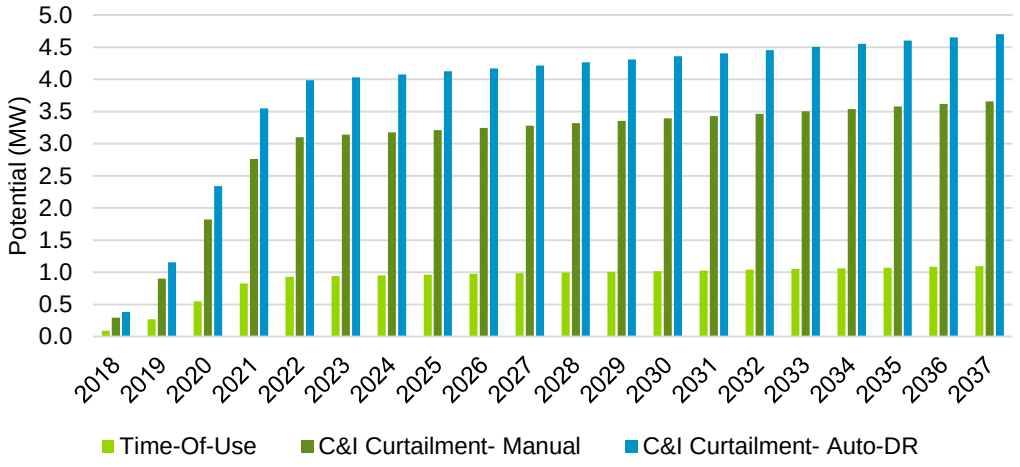
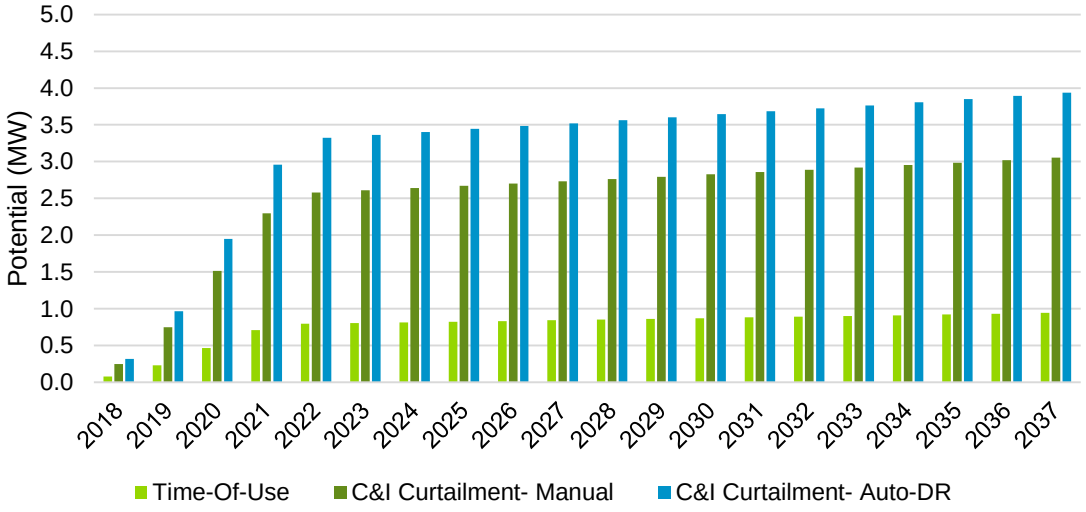


Figure 3-26. Extra-Large C&I Standalone Market Potential – Evening



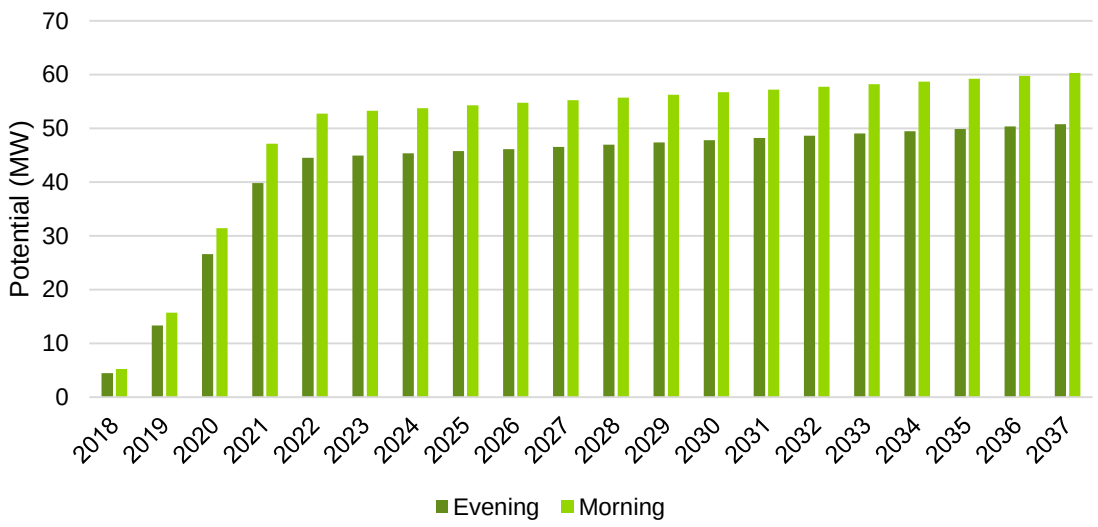
3.3 Integrated Market Potential Results

This section reports integrated market potential results. As discussed earlier, the integrated potential results consider participation hierarchy and overlaps in participation between DLC and TOU for residential, small and medium C&I customers, and between C&I Curtailment and TOU for large and extra-large C&I customers. Therefore, the potentials from DLC and C&I Curtailment are the same as those reported under the standalone results—only the TOU results vary. Because these potential results do not double count potential from the same set of customers, the potential results for all DR options are additive.

3.3.1 Total Morning and Evening Integrated Market Potential Results

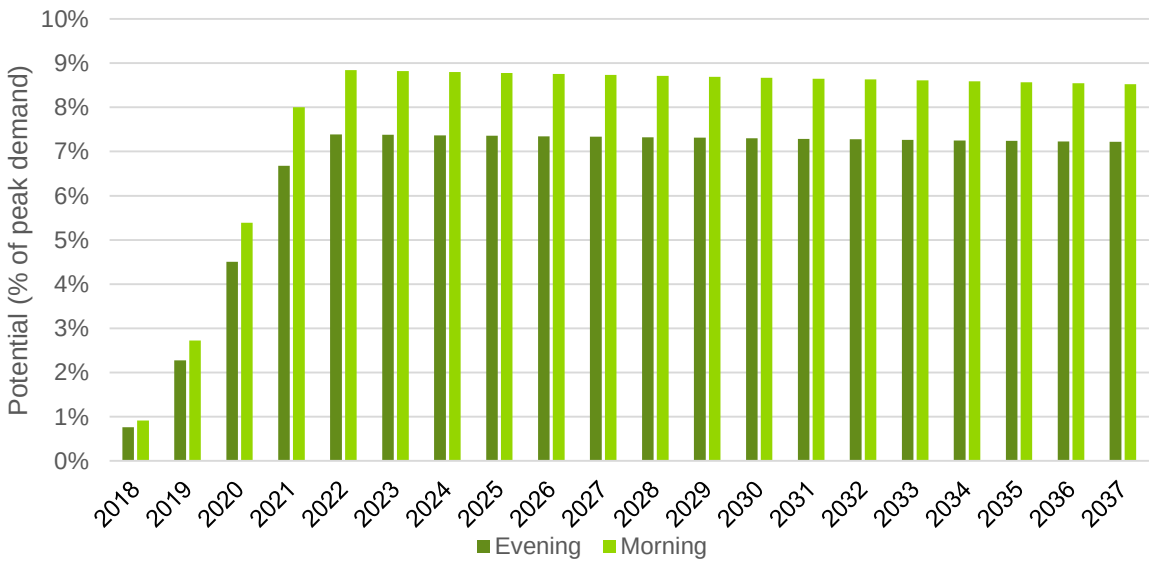
Figure 3-27 shows the integrated total potential for morning and evening in megawatts, and Figure 3-28 shows the potential as a percentage of morning and evening peak period loads. The market potential in the morning peak period ramps up rapidly up from roughly 4 MW in 2018 to approximately 53 MW in 2022.[42] The potential then grows at a much slower rate over the next 15 years to reach 60 MW in 2037, which represents 8.5% reduction in FortisBC's average morning peak demand. The integrated evening potential is about 16% lower than the morning potential. It increases rapidly from around 4 MW in 2018 to approximately 45 MW in 2022. Beyond 2022, over the next 15 years, the evening grows steadily to reach ~50 MW in 2037, representing 7.2% of FortisBC's projected average evening peak demand.

Figure 3-27. Integrated Market Potential – Morning vs. Evening



[42] Industry experience indicates that typically DR programs ramp over a 5-year period following a S-shaped curve, which is what is assumed in this study. FBC could choose to administer the non-pricing DR programs through a third-party aggregator, which is observed to be an increasing trend in the industry. In that case, the aggregator would be responsible for the program ramp up within the 5-year period.

Figure 3-28. Integrated Market Potential – Morning vs. Evening



3.3.2 Integrated Market Potential by DR Option

Figure 3-29 and Figure 3-30 shows the breakdown of the integrated morning potential by DR option, and Figure 3-30 shows the break of the evening potential by DR option. As is evident from previous discussions in Section 3.2, DLC has the most potential (~50%) in both peak periods. The potential values for DLC and C&I Curtailment remain unchanged in the integrated results from their values under the standalone potential results. Only TOU is affected because it is below these options in the hierarchy. The TOU potential decreases by approximately 10% in the integrated results when compared with the TOU potential estimates on a standalone basis, implying that considering participation overlaps with DLC and C&I Curtailment leads to a 10% erosion in TOU potential. TOU potential ranks second in the evening and third in the morning.

Figure 3-29. Integrated Market Potential by Option – Morning

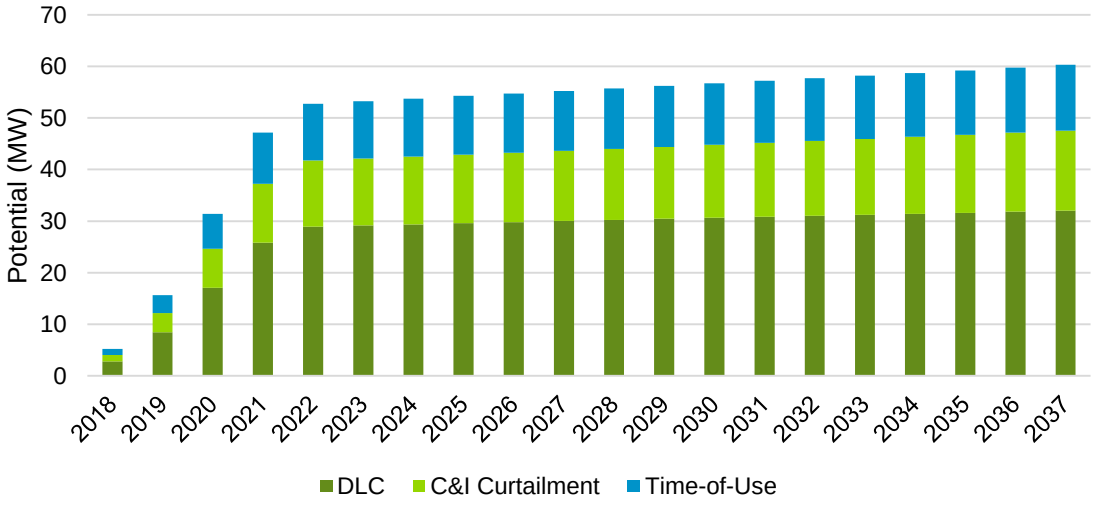
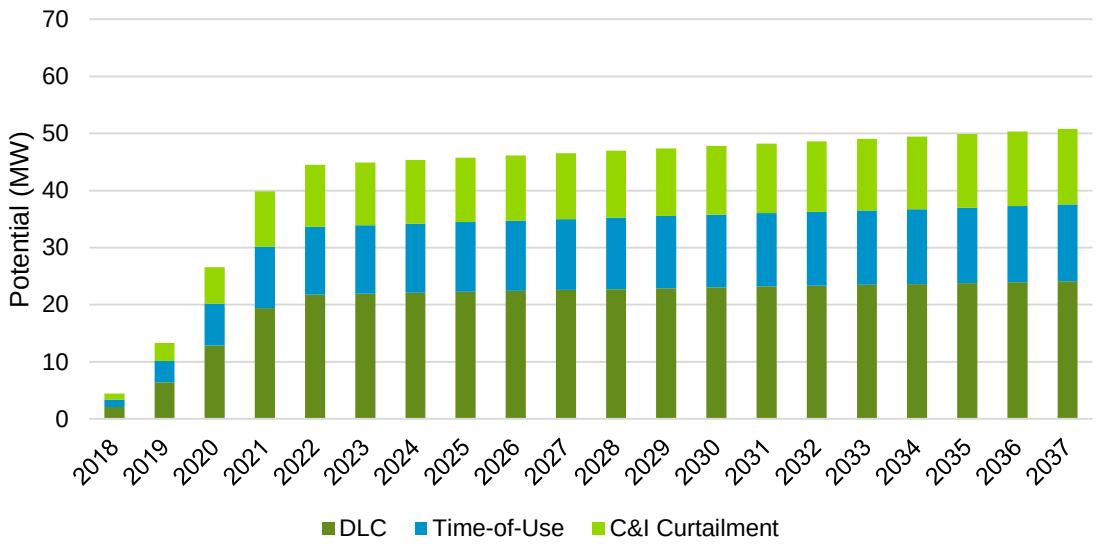


Figure 3-30. Integrated Market Potential by Option – Evening



3.3.3 Integrated Market Potential by DR Sub-Option

Figure 3-31 and Figure 3-32 show the integrated market potential by sub-option for the morning and evening peak periods, respectively. Thermostat based central space heating control is the highest contributor to morning peak demand reduction at 30% share, followed by TOU at 20% share. In the evening, however, TOU has higher potential than central space heating control due to a higher fraction of "other" enduse load types in the evening that could be affected by TOU. Central space heating control has 20% share in evening potential and TOU has 25% share in evening potential.
Baseboard heating control has approximately 15% share in potential during both morning and evening peaks. Water heating control has 10% share in both periods. Under C&I Curtailment for large and extra-large customers, Auto-DR based C&I Curtailment has 15% share in both peak periods, while Manual Curtailment has lower contribution at approximately 10%.

Figure 3-31. Integrated DR Market Potential by Sub-Option – Morning

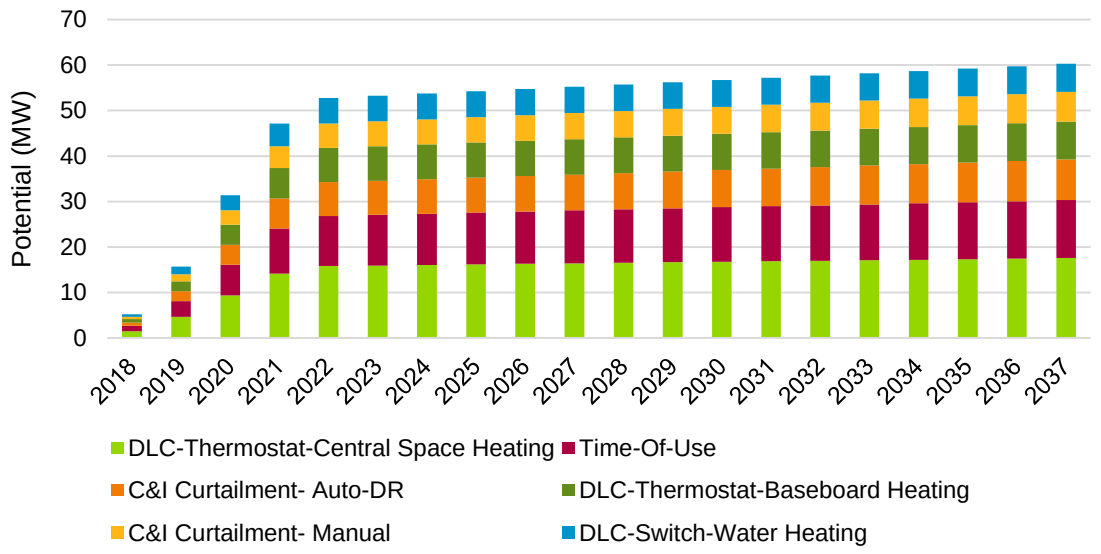
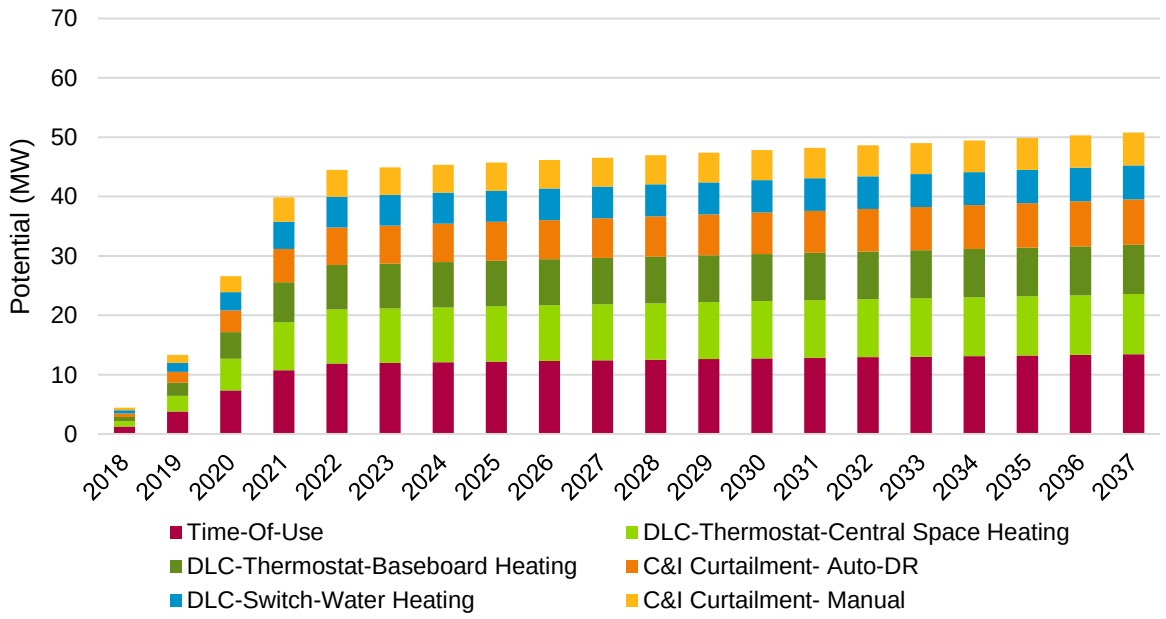


Figure 3-32. Integrated DR Market Potential by Sub-Option – Evening



3.3.4 Integrated Market Potential by Customer Class

Figure 3-33 and Figure 3-34 show the integrated market potential by customer class for the morning and evening peak periods, respectively. The potential values by customer class are slightly lower than those discussed under the standalone results due to the lower potential associated with TOU rates.

Residential customers have roughly two-thirds share of the total potential. The potential from residential customers grows rapidly from around 4 MW 2018 to approximately 36 MW in 2022 for morning peak

reduction. Beyond that, growth in potential is much slower and reaches 40 MW in 2037. The evening peak reduction potential from residential is about 15% lower than the morning peak reduction potential.

Large C&I and extra-large C&I customers have almost equal potentials at around 13%-15% each of the total. Potential from each of these two classes increases from less than 1 MW in 2018 to approximately 6 MW-9 MW in 2022 for morning peak reduction. The potential over the next 15 years for morning peak reduction grows to around 8 MW for large C&I and about 9 MW for extra-large C&I customers. The evening peak reduction potential from large C&I is approximately 13% lower than the morning peak reduction potential, while for the extra-large C&I customers, the evening potential is 17% lower. Small and medium C&I customers combined have roughly 5% of the morning total potential and less than 2% share of the evening total potential.

Figure 3-33. Integrated DR Market Potential by Customer Class – Morning

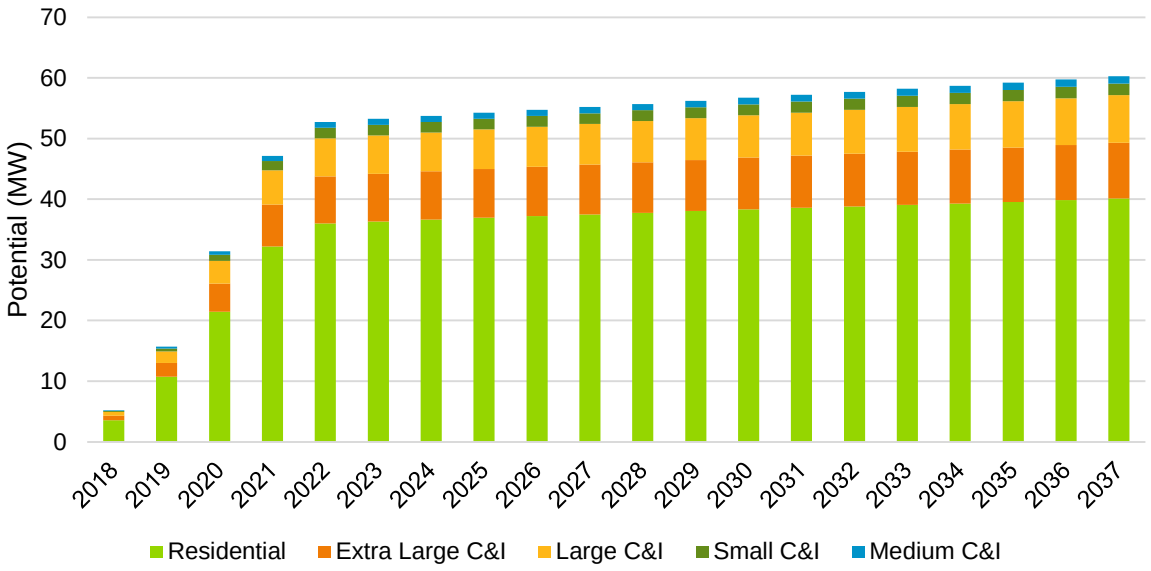
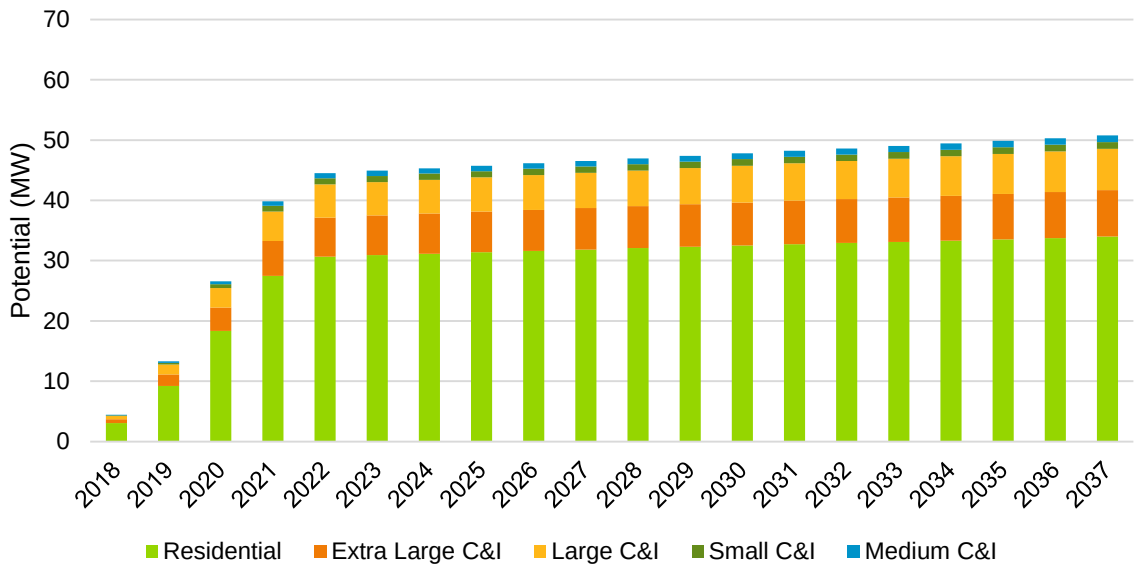


Figure 3-34. Integrated DR Market Potential by Customer Class – Evening



3.3.5 Snapback Effects

The previous discussions on potential estimates only included demand reductions during the DR event period. For DLC programs, typically, where the end-use load is being directly controlled either through a switch or a thermostat, a snapback effect is commonly observed after the DR event ends. This arises because customers may increase the thermostat set point temperature for electric space heating almost immediately after the event period to make up for the loss of heat in their homes during the DR event period. Impact evaluation of DLC programs typically include snapback estimates and provide insights on snapback effects from these studies.[43] Navigant's industry experience in this area indicates that for central furnaces and heat pumps, the morning snapback is typically lower than the evening snapback. In terms of absolute kilowatt values per device, the evening snapback magnitude may be the same or even greater than the DR evening peak demand reduction, while the morning snapback is likely to be considerably smaller in magnitude than the morning peak load reduction. This may be due to customers lowering temperature set points either manually or with programmable thermostats once they leave the home for work in the morning. Thus, the set-point to which the heat pumps must restore household temperature will be lower in the morning (when many participants are not at home) than in the evening (when many participants are in the home). The result is a very modest snapback in the morning, compared with that observed in the evening.

There are differences in snapback estimates between different types of space heating equipment. For example, for heat pumps, the snapback may be much more pronounced than for central furnaces. For a two-stage heat pump, the compressor operates above a certain ambient temperature to supply electric heat. But below that temperature, the compressor is no longer able to supply heat and the remaining heat is supplied by a resistance heating element, referred to as heat strip. Snapback could potentially be exacerbated because when the heat pump is cycled off for a curtailment event, the electric heat strips may then be more likely called into operation after the curtailment event. This is because the temperature

[43] The Navigant team for this study referred to impact evaluation studies conducted by Navigant to draw on insights related to snapback.

differential (current vs. desired) is now greater than it would be had the heat pump been operating normally during the time of the curtailment event and the heat strips come into action since the ambient temperature is too low for compressor operation. This could potentially lead to significantly higher electricity use during the post event period for customers with heat pump. This phenomenon is not firmly established and requires additional research. Evaluation of other DLC programs indicates that there is no net increase in electricity use for customers with heat pumps because even though the snapback may be quite pronounced immediately following the event, it is likely to last for a short period. Therefore, the average snapback magnitude over a post-event period that has the same duration as the event period is likely lower than the average event period impact, alleviating concerns related to net increase in electricity use for participants with space heating control.

Among the different types of electric space heating equipment, Navigant's evaluation experience indicates that the snapback effects from baseboard control are much more moderate than those observed for heat pumps and central furnaces.

In situations where customers might use gas and other supplemental fuels for heating, snapback effect could be mitigated by some of the other fuel types being used for heating during the event period.

For water heating load control, some pilots/programs observed greater snapback impacts than event period impacts in the evening. Although counter-intuitive, a reasonable explanation is that even when hot water is not being used, water heaters will suffer from modest stand-by losses to maintain the water set-point temperature. These stand-by losses tend to be quite small, and not coincident across households. However, all that standby consumption isn't averted, but merely shifted to the snapback period when the hot water tank is re-activated. That is, the stand-by consumption that would otherwise have been spread evenly over the event duration is aggregated into a single hour following the event, resulting in a substantially high snapback effect. However, the snapback is observed to last over a very short period. Some impact studies report the snapback during the one hour, 10-15 minutes following the DR event, to be almost double the average DR event period impact, say over 4-hr. event duration. However, the average snapback magnitude over the same duration as the event (for e.g., in this case 4 hrs.) is expected to be lower than the average impact during the 4-hr. event period, alleviating concerns related to net increase in electricity use due to snapback.

Table 3-1 below summarizes the assessment of snapback effect by the different DR sub-options.

Table 3-1. Assessment of Snapback Effect by DR Sub--Option[44]

DR Option/Sub-Option	End Use/Equipment Type	Whether snapback exists	Estimated Magnitude*	Notes*
DLC-Thermostat-Central Space Heating	Central Furnace	Yes	High in both morning and evening	• Snapback commonly observed; could be slightly higher in evening than in morning. ○ Snapback data from a winter DLC program in another jurisdiction with control of central furnaces indicates around 80%-90% snapback during morning and greater than 90% snapback during evening. ▪ Higher snapback during evening rather than morning is due to a larger fraction of customers being home after the evening control period than the percentage of at-home customers after the morning control period (a larger number of customers are likely to turn their heat up after the event period during evening than during morning, resulting in higher snapback during evening). ○ There is limited data available for snapback from baseboard heaters. Available information from a winter DLC program in another jurisdiction suggests approximately 30% or less snapback for baseboard heaters. • Customers with dual-fuel heating or multi—fuel heating likely to have lower snapback. • The snapback impact is likely to be influenced by the temperature offset during the event and the event duration. • Snapback likely to be lower for customers that can undertake preheating, e.g., those with ceramic brick furnaces with thermal storage.
DLC-Thermostat-Baseboard Heating	Baseboard Heaters	Yes	Low	

[44] Note that these snapback estimates are based on limited data availability and therefore FortisBC should conduct its own evaluation of programs/pilots to estimate snapback.

DR Option/Sub-Option	End Use/Equipment Type	Whether snapback exists	Estimated Magnitude*	Notes*
DLC- Thermostat-Heat Pumps	Heat Pumps	Yes	Low/Medium in morning; Medium in evening	• Snapback effect from heat pumps is less pronounced than that from central furnaces. • Likely to be higher in evening than morning. Available information from a winter DLC program in another jurisdiction show around 30%-40% snapback in morning and slightly greater than 60% snapback in the evening. ○ Higher snapback during evening than morning could be explained by the fact that more customers are home during evening than morning in the hours after the control period. • Customers with dual-fuel heating or multi—fuel heating likely to have lower snapback. • Snapback likely to be lower for customers that preheat prior to the event.
DLC-Switch-Water Heating	Water Heating	Yes	Medium/High in morning; High in evening	• Snapback impacts for winter water heating control could be significant. Water heaters experience high snapback over very short duration due to water heaters drawing additional power to make up for the standby losses. • Evaluation studies of similar programs show around 70%[45] snapback during the morning hours (during the first two hours immediately following the event) and greater than 150% snapback during the evening hours (average snapback during the first two hours immediately following the event). The snapback could be more than double the peak period impact in the hour immediately following the event. ○ The snapback value being greater than the peak period impact is possibly due to significant increase in water heater load in the hour immediately following the event period for the water heaters to make up for the standby losses that occurred during the control period, when they swing back into action.

[45] The percentage refers to the snapback as a percentage of average load reduction impacts during the peak period.

DR Option/Sub-Option	End Use/Equipment Type	Whether snapback exists	Estimated Magnitude*	Notes*
C&I Curtailment	HVAC	Yes	Low/Medium	Unlike DLC, existing impact evaluation studies for this program type do not report impacts at the end-use level and therefore snapback is not characterized by end-use. We summarize some general notes on snapback below based on the Navigant study team's industry expertise. • Little or no snapback might be observed for facilities with back-up generator or Behind-the-Meter (BTM) batteries, with ability to shift load during the peak period. • Also, snapback likely to be lower for facilities that preheat prior to the event.
	Water Heating	Yes	Low/Medium	
	Process	Yes	Variable	• Dependent on the type of process and whether the facility has back-up power sources such as generator or batteries. • Also for industries with process storage capabilities, such as 'pulp and paper' and cement plants, snapback may not be prominent since they are able to carry on with production processes during the event.
	Lighting	No	-	No snapback for lighting.
Time-Of-Use	All loads	Yes	Low – High	• "Snapback", as defined in the DR context, does not apply to TOU as it is not event-based. • The amount of load shifted from peak to off-peak periods depends on the peak to off-peak price differential and on the peak period duration, and on the type of facility.

* Estimated magnitude of snapback highly dependent on specific equipment type and program design (e.g., curtailment strategy, event duration, etc.).

3.3.6 Frequency/Repeatability

The program parameters presented earlier in Section 2.3 discuss how factors such as frequency/repeatability of events can influence potential estimation, especially those related to event opt-out rates and annual program participation (presented in Appendix D). If DR events are called more frequently, i.e. the number of events called within a day or within a specific timeframe increase, industry experience suggests that customers are likely to opt-out of event participation. In conjunction with higher event opt-out rates, customers are also likely to dis-enrol from DR programs, represented by the annual program attrition rates. The degree to which frequency/repeatability of events is likely to influence effective customer participation in a DR program is dependent on the type of customer, the type of controlled end-uses and how critical those are in terms of comfort/convenience and impact on facility/business operations. For example, increased frequency of space heating control for residential customers could have a higher impact than water heating control. Also, residential customers may be more sensitive to more frequent event calling than C&I customers. The impact of more frequent events may also depend on whether customers have alternate backup arrangements or storage devices to continue with their normal operations and not hamper their comfort/convenience. Therefore, customers with dual-fuel sources, with backup generators for power supply during DR events and those with some sort of storage may be more tolerant toward repeated event calling. There is insufficient field data on DR programs to help establish an empirical relationship between program parameters and effective program participation.

Table 3-2 below provides a qualitative assessment of the factors that are likely to influence DR program participation in response to an increased frequency of events. These observations are based on Navigant's industry experience in the area.

Table 3-2. Assessment of Frequency/Repeatability of Event Calling on DR Impacts

DR Option/Sub-Option	End Use/Equipment Type	Estimated Magnitude of Impacts from Increased Frequency*	Notes
DLC-Thermostat-Space Heating	Central Furnace, Heat Pumps, Baseboard Heaters	High[46]	• Customer fatigue/discomfort likely to be prominent for space heating loads. • Calling events for more three-four days in a row can lead to a high percentage of opt-outs and customers dropping of the program. • Effect will be lower for customers with multi—fuel heating as these customers are more tolerant toward more frequent event calling. • Effect will be lower for customers that are able to preheat and with central furnaces with storage (e.g. ceramic brick furnaces). • This is highly dependent on event duration, amount curtailed, and the incentive amount offered—with shorter events, smaller setpoint adjustments, and higher incentives, some of these limitations on customer response can be overcome or decreased.
DLC-Switch-Water Heating	Water Heating	Low/Medium[47]	• Likely to have relatively lower effect than space heating as customers often do not notice that their water heater is being controlled. • Therefore, customers are likely to be much more tolerant of their water heaters being frequently controlled than they would be for space heating.

[46] High refers to greater than an average of 5% annual program attrition. Note that there is insufficient empirical data to establish a functional relationship between frequency of events and customer attrition. The estimates are based on Navigant DR team's industry expertise.

[47] Low/medium would typically refer to an average annual attrition of 2%-5%. Note that there is insufficient empirical data to establish a functional relationship between frequency of events and customer attrition. The estimates are based on Navigant DR team's industry expertise.

DR Option/Sub-Option	End Use/Equipment Type	Estimated Magnitude of Impacts from Increased Frequency*	Notes
C&I Curtailment-Manual and Auto-DR	HVAC, Lighting, Water Heating, Process, etc.	Varies, depending on the type of facility and the end-uses being curtailed.	• Calling events for more than three/four days in a row likely to cause customer dissatisfaction and drop-outs. • Effect likely to be stronger for customers with a high percentage of HVAC load under control. • Also, more frequent event calling may have a stronger influence on facilities that primarily engage in manual curtailment as disruptions in operations may be more strongly felt in such cases. Facilities that engage in automated curtailment may experience less disruptions as only non-essential or non-critical loads may be pre-programmed to respond to DR events. • Effect will be lower for customers with back-up generators, batteries, and thermal storage devices. • For industrial facilities with process dominated loads, the effect of frequent event calling will depend on the process type and the types of loads being curtailed during DR events. For example, industries such as pulp and paper have “process storage” capability by way of which they can store intermediate products during their processing and shift loads out of the peak period. These types of facilities may be more tolerant toward more frequent event calling.
Time-Of-Use	All loads	Not applicable	TOU is not event based. Customers engage in load shifting/reduction in response to TOU peak to off-peak price differentials on a permanent basis.

3.4 Program Costs and Cost-Effectiveness Results

3.4.1 Program Costs

The potential analysis in this study also considered itemized costs for implementing the DR programs, as discussed previously in Section 2 and presented in the cost assumptions in Appendix C. Costs are considered for the portfolio of DR programs under the integrated market potential case.

If FortisBC were to pursue all of the cost-effective DR market potential, largely by using a third-party aggregator, Navigant estimates the total annual costs would escalate from approximately 3 million CAD in 2018 to roughly 8.5 million CAD in 2021. This represents all types of costs included in the analysis, fixed and variable, either incurred one-time or on a recurring basis. A large fraction of these costs is associated with marketing and recruiting new customers into the program during the ramp-up period and installing enabling technologies for demand reductions. Costs decline and remain steady beyond the initial program ramp-up period and then increase again at the end of the 10-year lifetime assumed for the DLC and C&I programs.

The DLC sub-options, which exhibit the highest levelized costs, have significant share of the total costs during the program ramp period. For C&I Curtailment, the costs represent the delivery costs for an aggregator-based program, plus Auto-DR enablement costs provided as incentives to the customers. In addition, FortisBC is assumed to incur one-time set up and annual administration costs for the C&I Curtailment program. TOU rates have less than 3% share of the estimated annual costs due to the relatively low costs associated with implementing rates.

3.4.2 Levelized Costs by DR Sub-Option

Table 3-3 shows the levelized costs by DR sub-option and customer class, calculated by dividing the NPV of the annual costs by the NPV of the annual potential estimates.[48] It shows the DR sub-options and customer class combinations arranged in increasing order of costs, . TOU rate offers have lowest cost, except for small C&I customers, where TOU rates are significantly more expensive due to very low impacts. Thermostat-based central space heating control with highest potential costs around $106/kW-yr. Baseboard heating control from residential with second highest potential has a substantially higher cost at around $250/kW-yr. . Space heating control costs for small and medium C&I customers costs are lower than those for residential. Manual curtailment for large and extra-large C&I customers costs roughly $150/kW-yr. Auto-DR curtailment costs approximately 33% more than manual curtailment, at around $200/kW-yr. levelized costs. However, it also delivers around 35% higher potential than manual curtailment. Switch-based electric water heating load control has relatively high costs, between $260/kW-yr. and $280/kW-yr. levelized costs.

[48] The average of the morning and evening peak potential values are used to calculate the NPV of annual megawatts for the levelized costs.

Table 3-3. Levelized Costs by DR Sub-Option

DR Sub-Option | Customer Class	Levelized Cost ($/kW-yr)	2037 Morning Potential (MW)
Time-Of-Use | Extra Large C&I	$12.6	0.8
Time-Of-Use | Large C&I	$12.8	0.7
Time-Of-Use | Medium C&I	$13.7	0.5
Time-Of-Use | Residential	$14.9	10.7
DLC-Thermostat-Central Space Heating | Medium C&I	$69.0	0.7
DLC-Thermostat-Central Space Heating | Small C&I	$94.7	1.7
DLC-Thermostat-Central Space Heating | Residential	$106.6	15.2
C&I Curtailment- Manual | Extra Large C&I	$149.3	3.7
C&I Curtailment- Manual | Large C&I	$149.6	2.9
C&I Curtailment- Auto-DR | Extra Large C&I	$205.2	4.7
C&I Curtailment- Auto-DR | Large C&I	$206.1	4.3
DLC-Thermostat-Baseboard Heating | Residential	$252.3	8.3
DLC-Switch-Water Heating | Small C&I	$257.0	0.2
DLC-Switch-Water Heating | Residential	$258.5	6
DLC-Switch-Water Heating | Medium C&I	$281.4	0.02
Time-Of-Use | Small C&I	$401.4	0.01

3.4.3 Cost-Effectiveness Assessment Results

DR program cost-effectiveness is considered at the program portfolio level. The program benefits calculations incorporate the derating factor discussed earlier in Section 2 and presented in Appendix D. Note that the derating factor only affects the benefits assessment from DR options and not the megawatt potential estimates.

Table 3-4 shows the benefit-cost ratios for the three DR options by the different cost tests included in the analysis. Note that the TRC and the SCT have the same ratio since they have the same discount rates and have the same categories of benefits and costs. The UCT and RIM tests have the same ratios since both tests treat benefits and costs for DR in the same manner.

All DR options have a benefit-cost ratio greater than 1. Under the Participant Cost Test (PCT), we assumed that the hassle cost associated with customer participation is half of the incentives and therefore the benefit-to-cost ratio is 2. Rate-based options like TOU do not have a specified incentive, and therefore the benefit-cost ratio calculation under PCT does not apply to rate-based options. For TOU, no customer hassle costs are considered, and customers are assumed to undertake behavioral changes in energy use in response to TOU. They may invest in control hardware such as timers for load shifting or invest in storage technologies to facilitate those behavioral shifts in energy use. However, since their response to the TOU rate is not specifically tied to these technologies these costs are not specifically accounted for in the participant costs under TOU.

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Table 3-4. Benefit-Cost Ratios by DR Option

DR Option	TRC	UCT	PCT	RIM	SCT
DLC	1.3	1.2	2.0	1.2	1.3
C&I Curtailment	1.4	1.2	2.0	1.2	1.4
TOU	11.6	11.6	-	11.6	11.6

Table 3-5 shows the benefit-cost ratios at the most granular level by customer class and DR sub-options. For residential customers, the benefit-cost ratio is less than 1 for switch-based water heating load control under all tests except the PCT. Thermostat-based space heating control for central space heating is cost-effective while baseboard heating control benefit-to-cost ratio is marginally less than at ~0.9. For small C&I customers, TOU and water heating control have ratios less than 1 under all tests except the PCT, whereas for medium C&I customers, only water heating load control has a less than 1 benefit-cost ratio. Based on field data from TOU pilots and programs, the percentage load reductions from TOU for small C&I customers is observed to be significantly lower than those for other customers, which lead to much lower benefit-cost ratios for these customers than those for the other customer classes.[49] For large and extra-large C&I customers, all DR sub-options have greater than 1 benefit-cost ratios.

[49] Small C&I customers might have little/no flexibility in their businesses to shift their energy use in response to rates. They also often lack awareness of these rates and their benefits, which in turn lead to low level of response to these rates.

Table 3-5. Benefit-Cost Ratios for Cost-Effectiveness Tests[50]

Customer Class	DR Sub-Option	TRC	UCT	PCT	RIM	SCT
Residential	DLC-Thermostat-Central Space Heating	2.36	2.01	2.00	2.01	2.36
	DLC-Thermostat-Baseboard Heating	0.91	0.85	2.00	0.85	0.91
	DLC-Switch-Water Heating	0.88	0.83	2.00	0.83	0.88
	Time-Of-Use	11.67	11.67	-	11.67	11.67
Small C&I	DLC-Thermostat-Central Space Heating	2.72	2.26	2.00	2.26	2.72
	DLC-Switch-Water Heating	0.89	0.83	2.00	0.83	0.89
	Time-Of-Use	0.44	0.44	-	0.44	0.44
Medium C&I	DLC-Thermostat-Central Space Heating	4.18	3.12	2.00	3.12	4.18
	DLC-Switch-Water Heating	0.81	0.77	2.00	0.77	0.81
	Time-Of-Use	12.75	12.75	-	12.75	12.75
Large C&I	C&I Curtailment-Manual	1.70	1.35	2.00	1.35	1.70
	C&I Curtailment-Auto-DR	1.23	1.04	2.00	1.04	1.23
	Time-Of-Use	13.61	13.61	-	13.61	13.61
Extra-Large C&I	C&I Curtailment-Manual	1.70	1.35	2.00	1.35	1.70
	C&I Curtailment-Auto-DR	1.23	1.05	2.00	1.05	1.23
	Time-Of-Use	13.77	13.77	-	13.77	13.77

[50] The DR sub-options by customer class with benefit-cost ratio less than 1 are shaded in pink.

4. CONCLUSIONS

The DR potential analysis in this report indicates the extent to which FortisBC could rely on curtailment of end-use loads at customer premises to help meet winter capacity shortfalls during the morning and evening peak periods.

The analysis results indicate that DR could help reduce approximately 7%-8.5% of the peak demand. However, FortisBC would need to consider a portfolio of different DR program types—DLC, C&I Curtailment, and TOU rates—targeted toward different customer classes to help realize this potential.

The integrated market potential in the morning peak period ramps up rapidly up from roughly 4 MW in 2018 to approximately 53 MW in 2022. The potential then grows at a much slower rate over the next 15 years to reach 60 MW in 2037, which represents 8.5% reduction in FortisBC's average morning peak demand. The integrated evening potential is about 16% lower than the morning potential. It increases rapidly from around 4 MW in 2018 to approximately 45 MW in 2022. Beyond 2022, over the next 15 years, the evening grows steadily to reach ~50 MW in 2037, representing 7.2% of FortisBC's projected average evening peak demand.

If FortisBC were to pursue the full DR Market Potential, the total annual costs are estimated to steeply increase from approximately 3 million CAD in 2018 to roughly 8.5 million CAD in 2021. A large fraction of these costs is associated with marketing and recruiting new customers into the program during the ramp-up period and installing enabling technologies for demand reductions. Costs decline and remain steady beyond the initial program ramp-up period and then increase again at the end of the 10-year lifetime assumed for the DLC and C&I programs. Beyond the program ramp-up stage, FortisBC would incur annual costs for maintaining these programs, which is expected to cost around 4.6 million CAD.

Of the three different DR options included in the analysis, DLC has highest contribution to the total integrated market potential ranging from 50%-55% of the total. C&I Curtailment share is approximately 25% of the total potential. TOU has ~20-25% share in total potential. Among the different control options within DLC, control of central space heating has around 30% share of morning potential and about 20% share of evening potential. Share from baseboard heating control is around 15%. Control of electric water heating has slightly less than 10% contribution to the total. Within C&I Curtailment, Auto-DR curtailment has roughly 15% share of the total potential, followed by approximately 10% from manual curtailment.

Residential customers have highest share of the potential at approximately 67% of the total, followed large C&I and extra-large C&I with around 15% share from each. Small and medium C&I customers combined have about 5% share of the total potential.

TOU rates are the lowest cost option[51], followed by DLC for space heating control and C&I Curtailment. Baseboard heating control and water heating control under DLC are more expensive than C&I Curtailment. At a portfolio level, all DR options are assessed to be cost-effective.

[51] Only exception is for small C&I customers who have very low unit impacts for TOU.

APPENDIX A. PARTICIPATION ASSUMPTIONS

Table A-1. Steady-State Participation Assumptions by DR Option, Customer Class, and Segment

DR Sub Option	Customer Class ↓	Winter DR Participation (% of eligible customers)	Assumptions Documentation
DLC-Switch-Water Heating	Residential	16%	Derived participation percentage for WH load control; assumed that only customers under SH control (central and baseboard) are enrolled for WH load control; this is based on the assumption that WH load control only for customers is not economic due to relatively small amount of load reduction. This is corroborated by discussions with vendors and field experience with programs.
DLC-Thermostat-Baseboard Heating	Residential	20%	Assumed lower percentage than central space heating participation since technology is less well--established
DLC-Thermostat-Central Space Heating	Residential	30%	Based on benchmarking with DLC programs; vendor field assessment from similar program offers
Time-Of-Use	Residential	28%	Opt-in average enrollment rate in residential TOU, based on Brattle Group's pricing program database (Ref: Demand Response Market Research for PGE, 2016).
DLC-Switch-Water Heating	Small C&I	4%	Derived participation percentage for WH load control; assumed that only customers under SH control are enrolled for WH load control; this is based on the assumption that WH load control only for customers is not economic due to relatively small amount of load reduction. This is corroborated by discussions with vendors and field experience with programs.
DLC-Thermostat-Central Space Heating	Small C&I	8%	Based on benchmarking and vendor assessments
Time-Of-Use	Small C&I	13%	Average opt-in enrollment rate for C&I TOU based on Brattle Group's Pricing Program Database (PacifiCorp Demand Response Potential Study; Vol 5; Class 1&3 Appendix; Feb, 2017)
DLC-Switch-Water Heating	Medium C&I	5%	Derived participation percentage for WH load control; assumed that only customers under SH control are enrolled for WH load control; this assumes that WH load control only for customers is not economic due to relatively small amount of load reduction. This is corroborated by discussions with vendors and field experience with programs.
DLC-Thermostat-Central Space Heating	Medium C&I	8%	Based on benchmarking and vendor assessments

DR Sub Option	Customer Class ↓	Winter DR Participation (% of eligible customers)	Assumptions Documentation
Time-Of-Use	Medium C&I	13%	Average opt-in enrollment rate for C&I TOU based on Brattle Group's Pricing Program Database (PacifiCorp Demand Response Potential Study; Vol 5; Class 1&3 Appendix; Feb 2017)
C&I Curtailment-Manual	Large C&I	13%	Assumed overall 25% program participation; half of the customers curtail manually, and the rest are Auto-DR enabled
C&I Curtailment-Auto-DR	Large C&I	13%	Assumed overall 25% program participation; half of the customers curtail manually, and the rest are Auto-DR enabled
Time-Of-Use	Large C&I	13%	Average opt-in enrollment rate for C&I TOU based on Brattle Group's Pricing Program Database (PacifiCorp Demand Response Potential Study; Vol 5; Class 1&3 Appendix; Feb 2017)
C&I Curtailment-Manual	Extra Large C&I	13%	Assumed overall 25% program participation; half of the customers curtail manually, and the rest are Auto-DR enabled
C&I Curtailment-Auto-DR	Extra Large C&I	13%	Assumed overall 25% program participation; half of the customers curtail manually, and the rest are Auto-DR enabled
Time-Of-Use	Extra Large C&I	13%	Average opt-in enrollment rate for C&I TOU based on Brattle Group's Pricing Program Database (PacifiCorp Demand Response Potential Study; Vol 5; Class 1&3 Appendix; Feb 2017)

APPENDIX B. UNIT IMPACT ASSUMPTIONS

Table B-1. Unit Impact Assumptions by DR Sub-Option, Customer Class, and Segment

DR Sub Option	Customer Class	End-use	Unit	Morning Peak	Evening Peak	Assumptions Basis
DLC-Switch-Water Heating	Residential	Hot Water	kW per participant	0.39	0.36	Reference: BCH 2016 Residential Hot Water DLC Curtailment Pilot; average morning and evening impacts are based on 4-hr. event duration.
DLC-Thermostat-Baseboard Heating	Residential	Baseboard Heating	kW per participant	1.00	1.00	BCH Pilot Data.
DLC-Thermostat-Central Space Heating	Residential	Central Space Heating	kW per participant	2.49	1.40	Reference: Navigant's Impact Evaluation of a winter DLC pilot for a Pacific Northwest U.S. utility. kW reductions are by equipment types, furnaces and heat pumps, for morning and evening. These are weighted by the equipment saturation to get the weighted average unit impact for ESH load.
Time-Of-Use	Residential	All	% enrolled load[52]	7.0%	7.0%	Assumes 3:1 peak to off-peak price ratio for TOU rates. Impact assumptions are sourced from The Brattle Group's Arc of Price Responsiveness (Ref: Demand Response Market Research for Portland General Electric: 2016 to 2035; prepared by The Brattle Group; January 2016).
DLC-Switch-Water Heating	Small C&I	Hot Water	kW per participant	0.39	0.36	Assumed to be the same as residential.
DLC-Thermostat-Central Space Heating	Small C&I	Central Space Heating	kW per participant	3.74	2.11	Assumed to be 1.5 times that of residential
Time-Of-Use	Small C&I	All	% enrolled load[53]	0.2%	0.2%	Assumes 3:1 peak to off-peak price ratio for TOU rates. Impact assumptions are sourced from The Brattle Group's Arc of Price Responsiveness (Ref: Demand Response Market Research for Portland General Electric: 2016 to 2035; prepared by The Brattle Group; January 2016).

[52] For TOU, the % unit impacts are applied to the total facility load and are not tied to a specific end-use, whereas for the DLC and C&I Curtailment sub-options, the unit impacts are tied to a specific end-use.

[53] *Ibid.*

DR Sub Option	Customer Class	End-use	Unit	Morning Peak	Evening Peak	Assumptions Basis
DLC-Switch-Water Heating	Medium C&I	Hot Water	% enrolled load	25%	25%	Reference: Grid Integration of Aggregate Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection; September 2013;
DLC-Thermostat-Central Space Heating	Medium C&I	Central Space Heating	% enrolled load	50%	50%	Reference: Grid Integration of Aggregate Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection; September 2013;
Time-Of-Use	Medium C&I	All	% enrolled load[54]	4.0%	4.0%	Assumes 3:1 peak to off-peak price ratio for TOU rates. Impact assumptions are sourced from The Brattle Group's Arc of Price Responsiveness (Ref: Demand Response Market Research for Portland General Electric: 2016 to 2035; prepared by The Brattle Group; January 2016).
C&I Curtailment-Manual	Large C&I	Hot Water	% enrolled load	25%	25%	Reference: Grid Integration of Aggregate Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection; September 2013;
C&I Curtailment-Manual	Large C&I	HVAC Fans/Pumps	% enrolled load	39%	39%	Reference: California Demand Response Potential Study Final Report, Phase 2 Results' Table G-17, HVAC End-use shed filters.
C&I Curtailment-Manual	Large C&I	Lighting	% enrolled load	22%	22%	Reference: California Demand Response Potential Study Final Report, Phase 2 Results' Table G-30, Commercial Lighting End-use shed filters.
C&I Curtailment-Manual	Large C&I	Other	% enrolled load	0%	0%	No curtailment estimates available for "other" commercial end-uses such as cooking, office equipment and other misc. loads.
C&I Curtailment-Manual	Large C&I	Refrigeration	% enrolled load	10%	10%	Reference: Grid Integration of Aggregate Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection; September 2013;
C&I Curtailment-Manual	Large C&I	Central Space Heating	% enrolled load	39%	39%	Reference: California Demand Response Potential Study Final Report, Phase 2 Results' Table G-17, HVAC End-use shed filters.
C&I Curtailment-Manual	Large C&I	Process/Other	% enrolled load	20%	20%	Reference: Assessment of Industrial Loads for Demand Response across U.S. Regions of the

[54] For TOU, the % unit impacts are applied to the total facility load and are not tied to a specific end-use, whereas for the DLC and C&I Curtailment sub-options, the unit impacts are tied to a specific end-use

DR Sub Option	Customer Class	End-use	Unit	Morning Peak	Evening Peak	Assumptions Basis
						Western Interconnect; Oak Ridge National Lab, 2013; assumed sheddability of 20% based on the low end of the sheddability values presented in the ORNL study;
C&I Curtailment-Auto-DR	Large C&I	Hot Water	% enrolled load	25%	25%	Reference: Grid Integration of Aggregate Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection; September 2013;
C&I Curtailment-Auto-DR	Large C&I	HVAC Fans/Pumps	% enrolled load	50%	50%	Reference: Grid Integration of Aggregate Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection; September 2013;
C&I Curtailment-Auto-DR	Large C&I	Lighting	% enrolled load	33%	33%	Reference: California Demand Response Potential Study Final Report, Phase 2 Results' Table G-30, Commercial Lighting End-use shed filters.
C&I Curtailment-Auto-DR	Large C&I	Other	% enrolled load	0%	0%	No curtailment estimates available for "other" commercial end-uses such as cooking, office equipment and other misc. loads.
C&I Curtailment-Auto-DR	Large C&I	Refrigeration	% enrolled load	55%	55%	Reference: California Demand Response Potential Study Phase 2 Final Study Results; 11/14/2016; Table G-43
C&I Curtailment-Auto-DR	Large C&I	Central Space Heating	% enrolled load	50%	50%	Reference: Grid Integration of Aggregate Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection; September 2013;
C&I Curtailment-Auto-DR	Large C&I	Process/Other	% enrolled load	24%	24%	Reference: Auto--DR enabled curtailment has potential to provide 20% higher sheddability than manual; based on data from California Demand Response Potential Study, Phase II Study Results.
Time-Of-Use	Large C&I	All	% enrolled load	4.5%	4.5%	Assumes 3:1 peak to off-peak price ratio for TOU rates. Impact assumptions are sourced from The Brattle Group's Arc of Price Responsiveness (Ref: Demand Response Market Research for Portland General Electric: 2016 to 2035; prepared by The Brattle Group; January 2016).
C&I Curtailment-Manual	Extra Large C&I	Hot Water	% enrolled load	25%	25%	Reference: Grid Integration of Aggregate Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection; September 2013;

DR Sub Option	Customer Class	End-use	Unit	Morning Peak	Evening Peak	Assumptions Basis
C&I Curtailment-Manual	Extra Large C&I	HVAC Fans/Pumps	% enrolled load	39%	39%	Reference: California Demand Response Potential Study Final Report, Phase 2 Results' Table G-17, HVAC End-use shed filters.
C&I Curtailment-Manual	Extra Large C&I	Lighting	% enrolled load	22%	22%	Reference: California Demand Response Potential Study Final Report, Phase 2 Results' Table G-30, Commercial Lighting End-use shed filters.
C&I Curtailment-Manual	Extra Large C&I	Other	% enrolled load	0%	0%	No curtailment estimates available for "other" commercial end-uses such as cooking, office equipment and other misc. loads.
C&I Curtailment-Manual	Extra Large C&I	Refrigeration	% enrolled load	10%	10%	Reference: Grid Integration of Aggregate Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection; September 2013;
C&I Curtailment-Manual	Extra Large C&I	Central Space Heating	% enrolled load	39%	39%	Reference: California Demand Response Potential Study Final Report, Phase 2 Results' Table G-17, HVAC End-use shed filters.
C&I Curtailment-Manual	Extra Large C&I	Process/Other	% enrolled load	20%	20%	Reference: Assessment of Industrial Loads for Demand Response across U.S. Regions of the Western Interconnect; Oak Ridge National Lab, 2013; assumed sheddability of 20% based on the low end of the sheddability values presented in the ORNL study;
C&I Curtailment-Auto-DR	Extra Large C&I	Hot Water	% enrolled load	25%	25%	Reference: Grid Integration of Aggregate Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection; September 2013;
C&I Curtailment-Auto-DR	Extra Large C&I	HVAC Fans/Pumps	% enrolled load	50%	50%	Reference: Grid Integration of Aggregate Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection; September 2013;
C&I Curtailment-Auto-DR	Extra Large C&I	Lighting	% enrolled load	33%	33%	Reference: California Demand Response Potential Study Final Report, Phase 2 Results' Table G-30, Commercial Lighting End-use shed filters.
C&I Curtailment-Auto-DR	Extra Large C&I	Other	% enrolled load	0%	0%	No curtailment estimates available for "other" commercial end-uses such as cooking, office equipment and other misc. loads.
C&I Curtailment-Auto-DR	Extra Large C&I	Refrigeration	% enrolled load	55%	55%	Reference: California Demand Response Potential Study Phase 2 Final Study Results; 11/14/2016; Table G-43

DR Sub Option	Customer Class	End-use	Unit	Morning Peak	Evening Peak	Assumptions Basis
C&I Curtailment-Auto-DR	Extra Large C&I	Central Space Heating	% enrolled load	50%	50%	Reference: Grid Integration of Aggregate Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection; September 2013;
C&I Curtailment-Auto-DR	Extra Large C&I	Process/Other	% enrolled load	24%	24%	Reference: Auto--DR enabled curtailment has potential to provide 20% higher sheddability than manual; based on data from California Demand Response Potential Study, Phase II Study Results.
Time-Of-Use	Extra Large C&I	All	% enrolled load	4.5%	4.5%	Assumes 3:1 peak to off-peak price ratio for TOU rates. Impact assumptions are sourced from The Brattle Group's Arc of Price Responsiveness (Ref: Demand Response Market Research for Portland General Electric: 2016 to 2035; prepared by The Brattle Group; January 2016).

APPENDIX C. COST ASSUMPTIONS [55]

Table C-1. Program Development Cost Assumptions by DR Sub-Option

DR Sub Option ↓	Customer Class ↓	Program Development Cost (one-time $)	Assumptions Documentation
DLC-Switch-Water Heating	Residential	$65,100	Assumed one-time cost of $250,000 for program development/mobilization for DLC-Central Space Heating and WH; considered an additional $100,000 for DLC-Baseboard heating upfront costs. The overall DLC program development cost is apportioned among the customer classes in the ratio of their 2037 potential.
DLC-Thermostat-Baseboard Heating	Residential	$90,650	Assumed one-time cost of $250,000 for program development/mobilization for DLC-Central Space Heating and WH; considered an additional $100,000 for DLC-Baseboard heating upfront costs. The overall DLC program development cost is apportioned among the customer classes in the ratio of their 2037 potential.
DLC-Thermostat-Central Space Heating	Residential	$165,550	Assumed one-time cost of $250,000 for program development/mobilization for DLC-Central Space Heating and WH; considered an additional $100,000 for DLC-Baseboard heating upfront costs. The overall DLC program development cost is apportioned among the customer classes in the ratio of their 2037 potential.
Time-Of-Use	Residential	$125,400	Assumed $150,000 is required to promote the TOU rate offering. This is distributed across the different customer classes in the ratio of their 2037 potential.
DLC-Switch-Water Heating	Small C&I	$1,750	Assumed one-time cost of $250,000 for program development/mobilization for DLC-Central Space Heating and WH; considered an additional $100,000 for DLC-Baseboard heating upfront costs. The overall DLC program development cost is apportioned among the customer classes in the ratio of their 2037 potential.
DLC-Thermostat-Baseboard Heating	Small C&I	$0	Not applicable
DLC-Thermostat-Central Space Heating	Small C&I	$18,550	Assumed one-time cost of $250,000 for program development/mobilization for DLC-Central Space Heating and WH; considered an additional $100,000 for DLC-Baseboard heating upfront costs. The overall DLC program development cost is apportioned among the customer classes in the ratio of their 2037 potential.

[55] Note that all costs are specified in CAD and assumed an exchange rate of 1 USD=1.4 CAD.

DR Sub Option ↓	Customer Class ↓	Program Development Cost (one-time $)	Assumptions Documentation
Time-Of-Use	Small C&I	$150	Assumed $150,000 is required to promote the TOU rate offering. This is distributed across the different customer classes in the ratio of their 2037 potential.
DLC-Switch-Water Heating	Medium C&I	$350	Assumed one-time cost of $250,000 for program development/mobilization for DLC-Central Space Heating and WH; considered an additional $100,000 for DLC-Baseboard heating upfront costs. The overall DLC program development cost is apportioned among the customer classes in the ratio of their 2037 potential.
DLC-Thermostat-Baseboard Heating	Medium C&I	$0	Not applicable
DLC-Thermostat-Central Space Heating	Medium C&I	$7,700	Assumed one-time cost of $250,000 for program development/mobilization for DLC-Central Space Heating and WH; considered an additional $100,000 for DLC-Baseboard heating upfront costs. The overall DLC program development cost is apportioned among the customer classes in the ratio of their 2037 potential.
Time-Of-Use	Medium C&I	$5,850	Assumed $150,000 is required to promote the TOU rate offering. This is distributed across the different customer classes in the ratio of their 2037 potential.
C&I Curtailment- Manual	Large C&I	$27,600	Assumed one FTE @$150,000 is required for upfront program costs. This is distributed across the customer classes in the ratio of their 2037 potential.
C&I Curtailment- Auto-DR	Large C&I	$41,250	Assumed one FTE @$150,000 is required for upfront program costs. This is distributed across the customer classes in the ratio of their 2037 potential.
Time-Of-Use	Large C&I	$8,250	Assumed $150,000 is required to promote the TOU rate offering. This is distributed across the different customer classes in the ratio of their 2037 potential.
C&I Curtailment- Manual	Extra Large C&I	$35,550	Assumed one FTE @$150,000 is required for upfront program costs. This is distributed across the customer classes in the ratio of their 2037 potential.
C&I Curtailment- Auto-DR	Extra Large C&I	$45,600	Assumed one FTE @$150,000 is required for upfront program costs. This is distributed across the customer classes in the ratio of their 2037 potential.
Time-Of-Use	Extra Large C&I	$10,350	Assumed $150,000 is required to promote the TOU rate offering. This is distributed across the different customer classes in the ratio of their 2037 potential.

Table C-2. Program Administration Cost Assumptions by DR Option

DR Sub Option ↓	Customer Class ↓	Program Admin Costs ($/yr.)	Assumptions Documentation
DLC-Switch-Water Heating	Residential	$65,100	Assumed $200,000 annual software licensing fee for a 10-year contract period; plus 1 FTE cost @$150,000 for program administration. Costs are distributed in the 2037 market potential ratios.
DLC-Thermostat-Baseboard Heating	Residential	$90,650	Assumed $200,000 annual software licensing fee for a 10-year contract period; plus 1 FTE cost @$150,000 for program administration. Costs are distributed in the 2037 market potential ratios.
DLC-Thermostat-Central Space Heating	Residential	$165,550	Assumed $200,000 annual software licensing fee for a 10-year contract period; plus 1 FTE cost @$150,000 for program administration. Costs are distributed in the 2037 market potential ratios.
Time-Of-Use	Residential	$62,700	Assumed 0.5 FTE @$150,000 is required to annually administer the rate. This is distributed across the different customer classes in the ratio of their 2037 potential.
DLC-Switch-Water Heating	Small C&I	$1,750	Assumed $200,000 annual software licensing fee for a 10-year contract period; plus 1 FTE cost @$150,000 for program administration. Costs are distributed in the 2037 market potential ratios.
DLC-Thermostat-Baseboard Heating	Small C&I	$0	Not applicable
DLC-Thermostat-Central Space Heating	Small C&I	$18,550	Assumed $200,000 annual software licensing fee for a 10-year contract period; plus 1 FTE cost @$150,000 for program administration. Costs are distributed in the 2037 market potential ratios.
Time-Of-Use	Small C&I	$75	Assumed 0.5 FTE @$150,000 is required to annually administer the rate. This is distributed across the different customer classes in the ratio of their 2037 potential.
DLC-Switch-Water Heating	Medium C&I	$350	Assumed $200,000 annual software licensing fee for a 10-year contract period; plus 1 FTE cost @$150,000 for program administration. Costs are distributed in the 2037 market potential ratios.
DLC-Thermostat-Baseboard Heating	Medium C&I	$0	Not applicable
DLC-Thermostat-Central Space Heating	Medium C&I	$7,700	Assumed $200,000 annual software licensing fee for a 10-year contract period; plus 1 FTE cost @$150,000 for program administration. Costs are distributed in the 2037 market potential ratios.

DR Sub Option ↓	Customer Class ↓	Program Admin Costs ($/yr.)	Assumptions Documentation
Time-Of-Use	Medium C&I	$2,925	Assumed 0.5 FTE @$150,000 is required to annually administer the rate. This is distributed across the different customer classes in the ratio of their 2037 potential.
C&I Curtailment-Manual	Large C&I	$27,600	Assumed 1 FTE annual admin. cost @$150,000. Cost is distributed in the ratio of 2037 potential.
C&I Curtailment-Auto-DR	Large C&I	$41,250	Assumed 1 FTE annual admin. cost @$150,000. Cost is distributed in the ratio of 2037 potential.
Time-Of-Use	Large C&I	$4,125	Assumed 0.5 FTE @$150,000 is required to annually administer the rate. This is distributed across the different customer classes in the ratio of their 2037 potential.
C&I Curtailment-Manual	Extra Large C&I	$35,550	Assumed 1 FTE annual admin. cost @$150,000. Cost is distributed in the ratio of 2037 potential.

Table C-3. Marketing and Recruitment Costs by DR Sub-Option

DR Sub Option ↓	Customer Class ↓	Marketing & Recruitment Costs ($/new participant)	Assumptions Documentation
DLC-Switch-Water Heating	Residential	$0	Assumed no additional cost for WH; sign-up incentive included under space heating. Participants under WH control are also controlled for SH.
DLC-Thermostat-Baseboard Heating	Residential	$100	Assumed same marketing and recruitment cost as for central furnace thermostat control participants
DLC-Thermostat-Central Space Heating	Residential	$100	Assumed a sign-up incentive of $70; this is based on vendor bid information for similar program in other jurisdictions. In addition, assumed $30 marketing costs.
Time-Of-Use	Residential	$10	This is a rate offering; so, costs are relatively low.
DLC-Switch-Water Heating	Small C&I	$0	Assumed no additional cost for WH; sign-up incentive included under space heating. Participants under WH control are also controlled for SH.
DLC-Thermostat-Baseboard Heating	Small C&I	$0	Not Applicable
DLC-Thermostat-Central Space Heating	Small C&I	$140	Assumed a sign-up incentive of $105; this is based on vendor bid information for similar program in another jurisdiction. 25% higher cost than residential. Also assumed $35 additional marketing costs.
Time-Of-Use	Small C&I	$15	
DLC-Switch-Water Heating	Medium C&I	$0	Assumed no additional cost for WH; sign-up incentive included under space heating. Participants under WH control are also controlled for SH.
DLC-Thermostat-Baseboard Heating	Medium C&I	$0	Not Applicable
DLC-Thermostat-Central Space Heating	Medium C&I	$220	Assumed a sign-up incentive of $175; this is based on vendor bid information for similar program in other jurisdictions. In addition, assumed 25% higher marketing cost than small C&I.
Time-Of-Use	Medium C&I	$20	
C&I Curtailment- Manual	Large C&I	$0	Rolled into third-party program delivery cost.
C&I Curtailment- Auto-DR	Large C&I	$0	Rolled into third-party program delivery cost.
Time-Of-Use	Large C&I	$50	
C&I Curtailment- Manual	Extra Large C&I	$0	Rolled into third-party program delivery cost.

Table C-4. Enabling Technology Costs by DR Sub-Option

DR Sub Option ↓	Customer Class ↓	Technology Enablement Costs	Cost Units	Assumptions Documentation
DLC-Switch-Water Heating	Residential	$290	$/new participant	$140 switch cost, plus $100 installation cost; Additional permit cost $50.
DLC-Thermostat-Baseboard Heating	Residential	$650	$/new participant	Assumed $350 thermostat cost for baseboard heaters, plus installation costs for 4 hours @75/hr. (based on 6/16 email with cost information from BCH)
DLC-Thermostat-Central Space Heating	Residential	$290	$/new participant	Assumed smart thermostat cost of $140, plus installation costs for 2 hours@$75/hr.
Time-Of-Use	Residential	$0	$/new participant	No enabling technology cost for TOU.
DLC-Switch-Water Heating	Small C&I	$290	$/new participant	Assumed same cost as residential.
DLC-Thermostat-Baseboard Heating	Small C&I	$0	$/new participant	Not Applicable
DLC-Thermostat-Central Space Heating	Small C&I	$363	$/new participant	Assumed to be approx. 25% higher cost than residential; assumed $140 smart thermostat cost (converted from $100 USD using 1.4 exchange rate), plus $150 installation cost for residential. Note that this study, however, assumed BYOT delivery for residential. The residential costs stated here are only for reference purposes to estimate the small C&I costs.
Time-Of-Use	Small C&I	$0	$/new participant	No enabling technology cost for TOU.
DLC-Switch-Water Heating	Medium C&I	$290	$/new participant	Assumed same cost as residential.
DLC-Thermostat-Baseboard Heating	Medium C&I	$0	$/new participant	Not Applicable
DLC-Thermostat-Central Space Heating	Medium C&I	$435	$/new participant	Assumed to be approx. 50% higher cost than residential; assumed $140 smart thermostat cost (converted from $100 USD using 1.4 exchange rate), plus $150 installation cost for residential. Note that this study, however, assumed BYOT delivery for residential. The residential costs stated here are only

DR Sub Option ↓	Customer Class ↓	Technology Enablement Costs	Cost Units	Assumptions Documentation
				for reference purposes to estimate the medium C&I costs.
Time-Of-Use	Medium C&I	$0	$/new participant	No enabling technology cost for TOU.
C&I Curtailment- Manual	Large C&I	$0	$/new kW	No tech enabling cost separately specified; rolled into program delivery cost
C&I Curtailment- Auto-DR	Large C&I	$280	$/new kW	Additional Auto-DR enablement cost, which is typically provided to the customer as a separate incentive.
Time-Of-Use	Large C&I	$0	$/new kW	No enabling technology cost for TOU.
C&I Curtailment- Manual	Extra Large C&I	$0	$/new kW	No tech enabling cost separately specified; rolled into program delivery cost

Table C-5. Program Delivery Costs by DR Sub-Option

DR Sub Option ↓	Customer Class ↓	Program Delivery Costs	Cost Units	Assumptions Documentation
C&I Curtailment- Manual	Large C&I	$56.00	$/kW	This is the delivery cost, excluding incentives, which is based on information from DR service providers.
C&I Curtailment- Auto-DR	Large C&I	$56.00	$/kW	This is the delivery cost, excluding incentives, which is based on information from DR service providers.
C&I Curtailment- Manual	Extra Large C&I	$56.00	$/kW	This is the delivery cost, excluding incentives, which is based on information from DR service providers.
C&I Curtailment- Auto-DR	Extra Large C&I	$56.00	$/kW	This is the delivery cost, excluding incentives, which is based on information from DR service providers.

Table C-6. O&M Costs by DR Sub-Option

DR Sub Option ↓	Customer Class ↓	O&M Costs ($/participant)	Assumptions Documentation
DLC-Switch-Water Heating	Residential	$14	Assumed 10% of equipment cost.
DLC-Thermostat-Baseboard Heating	Residential	$35	Approx. 10% of equipment cost.
DLC-Thermostat-Central Space Heating	Residential	$14	Assumed 10% of equipment cost.
DLC-Switch-Water Heating	Small C&I	$14	Assumed 10% of equipment cost.

DR Sub Option ↓	Customer Class ↓	O&M Costs ($/participant)	Assumptions Documentation
DLC-Thermostat-Central Space Heating	Small C&I	$18	Assumed 25% higher than residential costs.
DLC-Switch-Water Heating	Medium C&I	$14	Assumed 10% of equipment cost.
DLC-Thermostat-Central Space Heating	Medium C&I	$21	Assumed 50% higher than residential costs.

Table C-7. Incentive Costs by DR Sub-Option

DR Sub Option ↓	Customer Class ↓	$/yr.	$/kW-yr.	$/kWh	Basis for assumptions
DLC-Switch-Water Heating	Residential	$11	-	-	Based on benchmarking with similar programs and field data from vendors.
DLC-Thermostat-Baseboard Heating	Residential	$28	-	-	Per participant load reduction is half of that from central space heating control, so accordingly per participant incentive levels are also assumed to be half.
DLC-Thermostat-Central Space Heating	Residential	$56	-	-	Based on benchmarking with similar programs and field data from vendors.
Time-Of-Use	Residential	$0	-	-	Time-varying rate; so incentives don't apply.
DLC-Switch-Water Heating	Small C&I	$11	-	-	Based on benchmarking with similar programs and field data from vendors.
DLC-Thermostat-Central Space Heating	Small C&I	$84	-	-	Based on benchmarking with similar programs and field data from vendors.
Time-Of-Use	Small C&I	$0	-	-	Time-varying rate; so incentives don't apply.
DLC-Switch-Water Heating	Medium C&I	$11	-	-	Based on benchmarking with similar programs and field data from vendors.
DLC-Thermostat-Central Space Heating	Medium C&I	-	$35	-	Based on similar program experience and vendor quotes.
Time-Of-Use	Medium C&I	-	-	-	Time-varying rate; so incentives don't apply.
C&I Curtailment-Manual	Large C&I	-	$56	$0.140	Based on similar program experience and vendor quotes.
C&I Curtailment- Auto-DR	Large C&I	-	$56	$0.140	Based on similar program experience and vendor quotes.
Time-Of-Use	Large C&I	-	-	-	Time-varying rate; so incentives don't apply.

DR Sub Option ↓	Customer Class ↓	$/yr.	$/kW-yr.	$/kWh	Basis for assumptions
C&I Curtailment-Manual	Extra Large C&I	-	$56	$0.140	Based on similar program experience and vendor quotes.
C&I Curtailment- Auto-DR	Extra Large C&I	-	$56	$0.140	Based on similar program experience and vendor quotes.
Time-Of-Use	Extra Large C&I	-	-	-	Time-varying rate; so incentives don't apply.

APPENDIX D. DERATING FACTOR ASSUMPTIONS

Table D-1. Derating Factor Assumptions

DR Sub Option ↓	Customer Class ↓	Derating factor	Assumptions Documentation
DLC-Switch-Water Heating	Residential	80%	Technology-enabled direct load control programs are assumed to be derated by 20%. (Reference: Valuing Demand Response: International Best Practices, Case Studies, and Applications; prepared by the Brattle Group; January 2015).
DLC-Thermostat-Baseboard Heating	Residential	80%	Technology-enabled direct load control programs are assumed to be derated by 20%. (Reference: Valuing Demand Response: International Best Practices, Case Studies, and Applications; prepared by the Brattle Group; January 2015).
DLC-Thermostat-Central Space Heating	Residential	80%	Technology-enabled direct load control programs are assumed to be derated by 20%. (Reference: Valuing Demand Response: International Best Practices, Case Studies, and Applications; prepared by the Brattle Group; January 2015).
Time-Of-Use	Residential	65%	TOU derating factor assumption of 65% is from "Demand Response Market Research for Portland General Electric; by the Brattle Group, January 2016).
DLC-Switch-Water Heating	Small C&I	80%	Technology-enabled direct load control programs are assumed to be derated by 20%. (Reference: Valuing Demand Response: International Best Practices, Case Studies, and Applications; prepared by the Brattle Group; January 2015).
DLC-Thermostat-Central Space Heating	Small C&I	80%	Technology-enabled direct load control programs are assumed to be derated by 20%. (Reference: Valuing Demand Response: International Best Practices, Case Studies, and Applications; prepared by the Brattle Group; January 2015).
Time-Of-Use	Small C&I	65%	TOU derating factor assumption of 65% is from "Demand Response Market Research for Portland General Electric; by the Brattle Group, January 2016).
DLC-Switch-Water Heating	Medium C&I	80%	Technology-enabled direct load control programs are assumed to be derated by 20%. (Reference: Valuing Demand Response: International Best Practices, Case Studies, and Applications; prepared by the Brattle Group; January 2015).
DLC-Thermostat-Central Space Heating	Medium C&I	80%	Technology-enabled direct load control programs are assumed to be derated by 20%. (Reference: Valuing Demand Response: International Best Practices, Case Studies, and Applications; prepared by the Brattle Group; January 2015).
Time-Of-Use	Medium C&I	65%	TOU derating factor assumption of 65% is from "Demand Response Market Research for Portland General Electric; by the Brattle Group, January 2016).
C&I Curtailment- Manual	Large C&I	75%	Representative derate factor for DR programs (Reference: Valuing Demand Response: International Best Practices, Case Studies, and Applications; prepared by the Brattle Group; January 2015).
C&I Curtailment- Auto-DR	Large C&I	80%	Technology-enabled programs are assumed to be derated by 20%. (Reference: Valuing Demand Response: International Best Practices, Case Studies, and Applications; prepared by the Brattle Group; January 2015).

DR Sub Option ↓	Customer Class ↓	Derating factor	Assumptions Documentation
Time-Of-Use	Large C&I	65%	TOU derating factor assumption of 65% is from "Demand Response Market Research for Portland General Electric; by the Brattle Group, January 2016).
C&I Curtailment- Manual	Extra Large C&I	75%	Representative derate factor for DR programs (Reference: Valuing Demand Response: International Best Practices, Case Studies, and Applications; prepared by the Brattle Group; January 2015).
C&I Curtailment- Auto-DR	Extra Large C&I	80%	Technology-enabled programs are assumed to be derated by 20%. (Reference: Valuing Demand Response: International Best Practices, Case Studies, and Applications; prepared by the Brattle Group; January 2015).
Time-Of-Use	Extra Large C&I	65%	TOU derating factor assumption of 65% is from "Demand Response Market Research for Portland General Electric; by the Brattle Group, January 2016).

APPENDIX E. AVOIDED COST ASSUMPTIONS

Table E-1. Avoided Cost Projections (nominal CAD)

Year	Generation Capacity ($/kW-yr.)	T&D Capacity ($/kW-yr.)
2018	122.0	84.7
2019	124.5	86.4
2020	127.0	88.2
2021	129.5	89.9
2022	132.1	91.7
2023	134.7	93.6
2024	137.4	95.4
2025	140.2	97.3
2026	143.0	99.3
2027	145.9	101.3
2028	148.8	103.3
2029	151.7	105.4
2030	154.8	107.5
2031	157.9	109.6
2032	161.0	111.8
2033	164.3	114.1
2034	167.5	116.3
2035	170.9	118.7
2036	174.3	121.0
2037	177.8	123.5