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May 31, 2019

Delivered by Email, RESS & Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street,
Suite 2701
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: OEB File No. EB-2018-0219
PUC Distribution Inc. Application for 2019 ICM/IRM Rates
Responses to Interrogatories Related to ICM and Confidential Filing

Pursuant to Procedural Order No. 1 dated April 4, 2019 and the letter from the Ontario Energy Board ("**Board**") dated May 15, 2019, please find enclosed PUC Distribution Inc.'s ("**PUC**") Responses to Interrogatories for ICM related questions.

In addition, a response to the subsequent question by the School Energy Coalition about the potential impacts of Bill C-97 has been included as part of the response to SEC-16 in the attached.

As part of the Responses to Interrogatories, PUC is filing in confidence the following documents:

1. Appendix 9 - Letter of Intent between PUC and Energizing, LLC (now named Infrastructure Energy LLC ("**IE**");

2. Appendix 11 - Amendment to Letter of Intent in No. 1 above;

3. Appendix 13 - Current working draft version of the main Project Agreement which will be between PUC and Project Co. (SSG, Inc.); and

4. Appendix 12 - Schedule to Project Agreement in No. 3 above (collectively, the "**Documents**").

PUC is filing the Documents in confidence pursuant to the Ontario Energy Board's (the "**Board**") Practice Direction on Confidential Filings (the "**Practice Direction**").

Section 17 of the *Freedom of Information and Protection of Privacy Act,* R.S.O. 1990, c.F.31 ("**FIPPA**") is discussed in the Board's Practice Direction. Subsection 17(1) of FIPPA provides:

> "17 (1) A head shall refuse to disclose a record that reveals a trade secret or scientific, technical, commercial, financial or labour relations information, supplied in confidence implicitly or explicitly, where the disclosure could reasonably be expected to,
>
> (a) prejudice significantly the competitive position or interfere significantly with the contractual or other negotiations of a person, group of persons, or organization;
>
> (b) result in similar information no longer being supplied to the institution where it is in the public interest that similar information continue to be so supplied;
>
> (c) result in undue loss or gain to any person, group, committee or financial institution or agency; or
>
> (d) reveal information supplied to or the report of a conciliation officer, mediator, labour relations officer or other person appointed to resolve a labour relations dispute. R.S.O. 1990, c. F.31, s. 17 (1); 2002, c. 18, Sched. K, s. 6; 2017, c. 8, Sched. 13, s. 2."

IE engages in competitive business activities, including the development of smart grid initiatives across North America. The information contained in the Documents are consistently treated in a confidential manner. The Documents themselves cost a considerable amount of money to draft and develop and disclosure of the Documents on the public record would allow the IE's competitors, such as Siemens, GE, Eaton, and Schneider Electric, to gain access to such valuable confidential information and could reasonably be expected to prejudice the economic interest of, significantly prejudice the competitive position of, cause undue financial loss to, and be injurious to the financial interest of IE. The information in the Documents could be used to apply to similar construction or services projects as well as future potential smart grid projects or P3 type works with LDCs or others, allowing competitors to have a competitive advantage in such future potential projects.

PUC is prepared to provide unredacted copies of the Documents to parties' counsel and experts or consultants provided that they have executed the Board's form of Declaration and Undertaking with respect to confidentiality and that they comply with the Practice Direction, subject to PUC's right to object to the Board's acceptance of a Declaration and Undertaking from any person.

In keeping with the requirements of the Practice Direction, PUC is filing two confidential unredacted versions of the Documents in hard copy only. The unredacted versions of the documents have been placed in a sealed envelope marked "Confidential". These documents are marked “Confidential” and printed on yellow paper. PUC requests that the unredacted documents be kept confidential.

Should you have any questions or require further information, please do not hesitate to contact me.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Per:

Original signed by John A. D. Vellone

John A. D. Vellone

cc: Intervenors of Records in EB-2018-0219

PUC Distribution Inc.

EB-2018-0219

Responses to Interrogatories

Filed: May 31, 2019

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PUC DISTRIBUTION INC.
ICM INTERROGATORY RESPONSES

Ontario Energy Board Staff Interrogatories

Incremental Capital Module

Staff-22

Reference 1: EB-2018-0219, Appendix 11, Page 10
Reference 2: EB-2018-0219, Appendix D, Navigant Report #1, Page 1

Preamble:

PUC Distribution notes that the scope of the Sault Smart Grid (SSG) Project involves the coordinated rapid implementation of a combination of well understood and proven smart grid technologies.

Reference 2 notes that the overall system design, architecture and components are comparable with Distribution Automation (DA) and Voltage/VAR Optimization (VVO) systems that Navigant has reviewed or analyzed throughout the U.S. and Canada.

The main difference between this project and other similar "smart grid" projects is the proposed coverage of PUC Distribution's service territory. Navigant notes that relative to PUC Distribution's service territory, the proposed feeder coverage for DA and VVO, 84% and 68% respectively, is higher than many other systems Navigant has encountered.

Questions:

(a) Please explain why PUC Distribution has not made on-going investments into its system over time, such like other distributors, to incorporate the components being asked for in this ICM.

(b) Please explain how this project meets the criteria for ICM funding, if the majority of other distributors have been making these investments over time through their respective capital budgets.

(c) Please explain whether PUC Distribution had considered implementing smart grid features as part of its capital budgets over a longer period of time, i.e. a phased-in approach rather than a community-wide implementation over a two-year period. If so, please provide details of options considered.

Response:

(a) The assumption implied in this question is not correct. PUC system capital investments over time have been primarily directed towards aged/end of life infrastructure renewal (poles, conductors, stations), and regulatory requirements such as smart meters, IESO P&C programs and customer demand requirements. PUC introduced our first voltage regulators on a few remote feeders in just the past couple years to address specific local power quality needs. Efforts to make limited capital budgets go as far as practical for aged asset replacement in a limited customer growth environment has focused on maintaining existing service and reliability with only some relatively small incremental new technology additions to replaced equipment except where mandated. PUC Distribution utilizes the system renewal assessment methodology for asset evaluation and prioritization to prioritize and select capital project needs (refer to Figure 8 of DSP).

(b) This project is discrete, incremental and material. It will add significant additional new distribution automation equipment assets and associated technology to the PUC distribution system. The functional asset category of distribution feeder voltage control is not in use now so these would be new incremental assets. The 12.5 kV distribution network currently does not have any automated switching or self-healing circuits. The new incremental capital investment and new assets for this project period meets the intent of the ICM funding criteria in our understanding.

(c) As part of the Project review PUC considered and presented some project timeframe options in our ICM application. [Please refer to ICM Application (page 38-43) Part 7. Prudence - options discussed]. The selected two-year project option with NRCan funding provides the least cost (net) solution and provides the benefits to customers at the earliest practical date so that rates and customer benefits has the closest alignment. The most significant impact of extending the project time period over 10 years lies in the loss of the NRCan funding which has a limited eligibility period. The options considered a 10 year - no CPI cost escalation and a 10 year - with 2% CPI NPV analysis. The estimated NPV impact with a 5% discount rate of the lost funding and a ten-year project period with an assumed 2% CPI yielded a negative variance of over $6.M [$28,845,895 - $22,582,046] to our customers excluding lost benefits realized from the project.

Staff-23

Reference: EB-2018-0219, ICM Application, Page 5

Preamble:

The following is an excerpt from the ICM Application:

> The total capital cost of the SSG Project is estimated to be $34,389,046, with 22% of the SSG Project ($7,655,053) to be in service by December 31, 2019 (Phase 1) with the remaining 78% ($26,733,992) to be in service by December 31, 2020 (Phase 2). Incremental funding for Phase 2 of the SSG Project will be requested by way of a 2020 ICM application.

Questions:

(a) It is unclear which aspects of the SSG Project are included in each of Phase 1 and Phase 2 of the proposed ICM project. Please split the scope of the SSG Project into its respective phases and explain what benefits customers can expect to receive solely from Phase 1 given that it is only a portion of the SSG project.

(b) How did PUC Distribution determine which components would make up Phase 1 and Phase 2 of the SSG Project as outlined in part (a)?

(c) PUC Distribution notes that Phase 1 is expected to be in-service by December 31, 2019. Has PUC Distribution begun any work on this project to date? If not, how feasible is a 2019 in-service date?

Response:

(a) The Phase 1 of the project is based on an estimated assets/capital in-service at the end of 2019. The project schedule assumed completion of some of the make-ready work in poles, underground high voltage cables and associated civil works that will be in-service at the end of the year. There are no savings benefits from the project until systems are in-service at end of 2020. Benefits to customers will be only those related to any aged assets replaced or new assets put in-service but not the majority of those benefits anticipated with the completion of the SSG project.

(b) The components were based on anticipated works complete and in-service at that point in time for the project as of December 31, 2019.

(c) Some of the 30% design engineering works completed identified some of the make-ready work that can be executed quickly once project approval is received. The project approval date would potentially have an impact on amount of make-ready work that can be completed and put in-service in 2019.

Staff-24

Reference: EB-2018-0219, ICM Application, Page 40

Preamble:

At the above reference, PUC Distribution notes that "the direct savings due to improved energy efficiency through voltage regulation cannot be fully realized until the entire SSG Project is in-service".

(a) When Phase 1 is completed, will any of the components of the SSG Project be functional or is completion of Phase 2 required in order for the SSG Project to come into service as a whole?

(b) In the event that Phase 2 cannot be carried out, for example if government funding is not continued, which aspects of Phase 1 can be brought into service?

(c) What benefits would customers receive if only Phase 1 was implemented? Are there savings included in the bill impacts provided that arise from the implementation of Phase 1 only? If so, how were these determined? If such savings have not been determined, please provide the bill impacts if only Phase 1 was successfully implemented.

Response:

(a) Some components of the project will become partly functional as they are installed and commissioned. As example a new installed switch will be live and available for manual operation before it is fully remotely operable.

(b) Phase 2 is just a continuation of the project in time not function from the first year to the second. This relates strictly to the how PUC Distribution has described the project in to the ICM module framework for the capital assets that have been put in service over each year of the project.

(c) Phase 1 of the project is based on an estimated assets/capital in-service at the end of 2019. Benefits to customers will be only those related to any aged assets replaced or new assets put in-service but not the majority of those benefits anticipated with the completion of the SSG project. There are no bill impact savings estimated at the end of 2019 (Phase 1). Savings were included in bill impact analysis once the entire project was completed and in-service.

Staff-25

Reference: EB-2017-0071, 2018 Cost of Service Distribution System Plan (DSP), Pages 107-109

Preamble:

The following is an excerpt from the reference above:

> ...PUC Distribution has implemented a number of smart grid features on its network, during the previous years, such as smart meters, digital protection systems, voltage regulators and remote-controlled substation switchgear to facilitate automation, but because all of these projects involved replacement of old infrastructure at the end of its service life with new assets, these were included in the System Renewal category as it was the primary driver.

Table 26 provides the following forecasted System Renewal budgets for 2018-2022 respectively: $3.761M, $6.906M, $3.296M, $4.533M, and $7.093M.

Questions:

(a) How much of the System Renewal budgets for 2018-2022 is to fund smart grid work as described in the quote above? Please provide a breakdown by year of expenditures for smart grid related work included in the 2018-2022 budgets.

(b) It is not clear if amounts embedded in the System Renewal category of the DSP coincide with work that is being proposed in this ICM. Are the components of the SSG Project different from the smart grid aspects of the System Renewal budgets? If so, how do they differ?

(c) Are the smart grid aspects of the System Renewal activities being shifted from the DSP to the SSG Project? If so, please explain which components are to be shifted.

(d) Why is the paced replacement, as set out in the DSP, being replaced with a two-year project?

(e) Has PUC Distribution considered filing an updated and consolidated DSP with its ICM application that takes into consideration the proposed SSG Project and how it interacts with other aspects of the DSP?

Response:

(a) The following list reflects incremental smart grid investments during the current DSP period that were included in the System Renewal category due to the fact that the subject infrastructure was at the end of its service life and therefore renewal was the primary driver:

- Engineering and minor software/hardware additions associated with enhanced feeder protection capable of DER support as part of Substation 16 rebuild in 2019, Sub 1, 11 & 20 relay replacements in 2020-2021 and Sub 22 build (Sub 4/5/17 replacement) in 2022
- Advanced SCADA communications for 3 recloser radio replacements in 2019

The incremental capital investments as it relates to 'smart-grid capability' for the period 2018-2022 and associated with Table 26 of the DSP is as follows:

Year	**2018**	**2019**	**2020**	**2021**	**2022**
Total Capital Investment for Renewal (per DSP Table 26)	$3.761M	$6.906M	$3.296M	$4.533M	$7.093M
Capital Investments attributable to 'smart-grid'	$0	$12k	$13.5k	$13.5k	$9k

(b) The amounts for smart grid features embedded in the DSP are different (i.e.: not coincident) with the amounts proposed in the SSG project. The SSG Project will add new to PUC asset groups or categories of voltage control and distribution automation equipment assets and associated technology to a significant level not present in the current distribution system. PUC only has 3 feeders that utilize distribution circuit voltage regulators with traditional feeder voltage profile controls that were installed in the past couple years to address local power quality needs. The 3 distribution reclosers currently in service are limited in use and operate in traditional radial application on 3 feeders. The new SSG project design adds Volt/VAR optimization control (voltage regulators and capacitors) to all selected distribution feeders with bell weather AMI smart meter based feedback. New distribution automation (reclosers and switches) will be introduced to feeders for zoned self-healing restoration capability.

(c) No, the smart-grid aspects embedded in the System Renewal category of the DSP are not being shifted to the SSG project. PUC Distribution confirmed this also in its response to 1-Staff-6 in EB-2017-0071.

(d) The paced replacement in the DSP is not "being replaced" with this two-year project. The System Renewal asset needs for the DSP remain the same and are mainly addressing aging assets and need for renewal and rehabilitation. The SSG Project is a discrete, incremental and material addition of substantial new asset groups or categories and a major step improvement towards customer energy savings and reliability improvement that exceeds the potential in the DSP. As well the Advanced Distribution Management System will provide much more operational awareness and monitoring capability and allow expansion as needed with future additions and growing complexities and challenges emerging for LDC system operations.

(e) Recognizing that the SSG Project has a significant level of detailed engineering design to work through, then following with the construction period running to the end of at least 2020, the optimization of newly developed operations and maintenance processes and procedures, it was PUC's view that it was premature to review and revise the DSP with this ICM application especially given as described above the DSP and SSG do not have an overlap of assets to any large extent. Once the project is complete and we enter SSG performance monitoring and full operational control in to 2021 the timing for a 2022 DSP review is considered as the best fit. This will align with preparation and submission of a cost of service application and renewed asset management plan and DSP for 2023-2027.

Staff-26

Reference: None

Questions:

(a) Are there any lower priority projects in the DSP, which are included in the existing capital budget, which may be lower priority than the SSG Project?

(b) Has PUC Distribution considered deferring lower priority projects included in its existing base capital budget envelope to create adequate headroom to implement the SSG Project, or some of its parts?

  i. If yes, please describe in detail the results of this consideration.
  ii. If no, why not?

(c) Does PUC Distribution's base capital (non-ICM) budget also include programs slated to include DA, VVO, substation upgrades, and integration and enhancement of Advanced Metering Infrastructure (AMI)?

  i. If yes, do the ICM line items represent an expansion of the programs already included in the base capital budget?

Response:

(a) No.

(b) PUC Distribution prepared its DSP with the last Cost of Service (COS) application without any substantial Smart Grid initiatives. The DSP priorities remain unchanged and continue to be the basis of our capital planning recognizing individual specific project priority is reviewed on an on-going basis and specifically at each annual budget cycle during the five-year DSP planning period. The DSP did not address system service categories such as smart grid given the status of asset condition renewal requirements and pending the outcome of the NRCan Smart Grid application. The ICM for the Smart Grid project is a discrete, incremental and material capital addition exceeding normal asset system renewal budget levels which is the intent of this application.

(c) PUC Distribution base capital budget does not include programs that are duplicative of the Smart Grid Project components for DA, VVO, and the AMI integration nor is it expansive to programs in the DSP.

Staff-27

Reference: EB-2018-0219, ICM Application, Page 23

Preamble:

The scope of DA requires the addition of electrical switching equipment, e.g. reclosers and switches. These are common elements of an electric distribution system and should routinely be replaced by electricity distributors as required in an on-going basis.

Questions:

(a) Does PUC Distribution have capital already allocated for the purposes of replacing and maintaining these types of equipment?

(b) If yes to (a), please explain why PUC Distribution is not funding this portion of the proposed SSG Project scope using this existing capital.

(c) If yes to (a), please explain why this is eligible for ICM treatment given that, as per ICM guidelines, ICM funding is not available for projects that are more related to recurring capital programs for replacements or refurbishments (i.e. business as usual projects).

Response:

(a) No. PUC does not currently have any capital program allocated for replacement of reclosers and distribution switches in the DSP.

(b) N/A

(c) N/A

Staff-28

Reference: EB-2018-0219, ICM Application, Pages 22-27

Preamble:

PUC Distribution presents three distinct components for the scope of the project: VVM, DA and AMI integration.

Questions:

(a) Please provide a project costs breakdown that separates the total project costs into the three separate components.

(b) Does the scope of each of the three components rely on each other? Is PUC Distribution able to implement each of the three components as standalone projects?

(c) Has PUC Distribution assessed the benefits and OM&A costs of each of the three components individually?

(d) If yes to (c), please provide the analysis. If no, please explain how PUC Distribution decided that a project that combined all three components was the most prudent option.

(e) Would Natural Resources Canada (NRCan) funding be provided if only a portion of the ICM is approved? How would the amount of funding be determined if this is the case?

(f) How would the amount of NRCan funding be affected if the ICM is approved but the PUC-funded portion is less than requested in this application? Would the amount of NRCan funding be decreased or remain the same? Is there an opportunity to obtain increased NRCan funding?

(g) If only Phase 1 of the SSG Project is approved, is the NRCan funding for Phase 1 still available or is it contingent on OEB approval of both Phase 1 and Phase 2?

Response:

(a) Project breakdown by major system based on 30% engineering design is:

- VVM $15.96M
- DA $14.66M
- AMI $ 3.77M

(Note- ratio and cost allocation to systems was estimated from project descriptions to support fixed asset categories and estimates in the rate design calculations. Detailed design may alter ratio of costs within committed project total of $34.4M.)

(b) The scope of the major project elements are interrelated. VVM and DA both rely on the integrated communication and control elements of the AMI integration implementation as well as project integrated project management, engineering, planning, scheduling, construction and commissioning.

(c) The benefits of VVM and DA have been estimated from the perspective of the VVM energy savings and DA reliability improvements. OM&A costs of the project have not been estimated individually for the project components.

(d) Project benefit estimating information is outlined in Appendix H of the ICM application. There is not an OM&A cost analysis based on the individual components of the project. OM&A and life cycle costs are part of the overall smart grid system preliminary design review. These engineering design reviews included an estimated impact of new assets and systems on operations and maintenance with staff augmentation identified for a field crew as well as FTE addition in engineering and IT. O&M costs going forward with the new system are further discussed in the ICM application with descriptive background starting at page 28 line 6.

(e) The Contribution Agreement (Appendix 1) with NRCan has a "true up" provision based on a percentage of the total costs. PUC Distribution has not confirmed how a partial project scope that was a result of only a portion of the ICM being approved would be treated but would anticipate that basis would be proportional in value assuming all the elements of the project were retained and the project was substantially as submitted under the program. PUC Distribution primary concern is that if the project was substantially altered in scope that there may be some risk to the funding and/or Contribution Agreement (Appendix 1).

(f) The NRCan Contribution Agreement (Appendix 1) criteria for the funding is the lesser of 25% or $11,807,000 of the total costs respecting the project cost eligibility requirements. PUC Distribution final overall costs for the project will impact the funding accordingly.

(g) There is not a Phase 1 and Phase 2 with respect to the project from the perspective of the NRCan Contribution Agreement (Appendix 1). This was only used in PUC Distribution's application to try and reflect the rate regulated treatment of capital assets in service over the 2-year project period.

<u>Staff-29</u>

<u>Reference</u>: EB-2018-0219, ICM Application, Pages 5 and 38

<u>Preamble:</u>

PUC Distribution notes that the NRCan funding requires projects to be completed by March 31, 2022.

<u>Questions:</u>

(a) Please provide the NRCan contribution agreement and any other documents related to the NRCan funding.

(b) Under what terms can the NRCan funding be revoked or cancelled? Does PUC Distribution have plans for these scenarios?

(c) Is PUC Distribution under any obligation to pay back the NRCan funding it receives?

(d) In the event of delays and shifting of in-service dates, would PUC Distribution still be eligible to receive NRCan funding?

(e) What if the in-service date is delayed past the March 31, 2022 NRCan deadline?

<u>Response:</u>

(a) Please see attached a copy of the Contribution Agreement (Appendix 1) and a copy of the NRCan Application (Appendix 3).

For clarity, the NRCan program funding is available until March 31, **<u>2022</u>**, however, as shown in Appendix 1, the relevant NRCan funding under the specific Contribution Agreement issued in connection with the SSG project is available until March 31, **<u>2021</u>**.

(b) The Contribution Agreement (Appendix 1) outlines the nature of the risk of funding being revoked or cancelled which would in general involve a major element of default. PUC Distribution does not have any plans to cause a default.

(c) The Contribution Agreement (Appendix 1) has provision for repayment to Canada for a five-year period for profit from the project in ratio to the contribution.

(d) Assuming PUC Distribution was successful in its application to NRCan to extend project expenditure period past the March 31, 2021 date in the Contribution Agreement (Appendix 1), delays and shifting of in-service dates could be accommodated. With respect to the ICM application in-service dates are more related to capital in-service requirements of the utility rate base process.

(e) The NRCan funding need was projected in the Contribution Agreement (Appendix 1) to cover through to March 31, 2021 based on the project schedule. If delays require extension PUC would need to apply for such potentially up to the Program end date in 2022. If the in-service date is delayed past March 31, 2022 the expenditures beyond that date would not be eligible under the program funding.

Staff-30

Reference**:** EB-2018-0219, ICM Application, Page 38

Preamble:

PUC Distribution states that the SSG project is structured to be completed over two years, with the majority of the funding to take place in Phase 2.

Question:

Has PUC Distribution considered implementation to take place over three years, with the in-service date to take place in 2022, but before the March 31 deadline? This would allow PUC Distribution to split the project costs and request funding in the third year, which would mitigate the impact on rates. If this option was not considered, why not?

Response:

No. Customers will not see any rate benefits until the project is completed. In addition, the NRCan Contribution Agreement (Appendix 1) has a deadline of March 31, 2021 which makes this approach impossible. PUC Distribution worked closely with project developer Infrastructure Energy, LLC (IE) and Engineering, Procurement and Construction (EPC) contractor Black & Veatch to finalize an optimal build schedule for SSG. Also in considering options for the project timeline PUC Distribution was cognizant of the hard date deadline of the NRCan program and that the risk of schedule delay that resulted in expenditures not being eligible for contribution funding by planning a schedule running through to March 31, 2022 was not an option we felt was prudent. The project implementation schedule delivers economic benefits to PUC customers upon commissioning of the project, and any delays in project schedule would cause the EPC contractor to be onsite for one additional year, causing an increase in Project costs and have a negative impact on rates. The two-year schedule seemed to best achieve the positive customer benefits with an efficient, timely schedule, optimized with the project developer from financing and construction perspective, balancing risks and benefits and was ultimately selected.

Staff-31

Reference: EB-2018-0219, ICM Application, Page 14
EB-2018-0219, ICM Application, Appendix I
EB-2018-0219, ICM Application, Appendix D

Preamble:

PUC Distribution states that the SSG Project is being developed through a Special Purpose Vehicle called SSG Inc. and will be initially funded through the North American Grid Modernization Fund (Fund), currently managed by Stonepeak Infrastructure Partners (Stonepeak) and Infrastructure Energy LLC (IE).

Appendix I identifies six entities as part of the organization of the SSG Project.

Question:

(a) Please confirm that Stonepeak and/or IE, a private equity investment firm, contributed the funds that make up the Fund.

(b) Please confirm that Energizing Co (ECo), an energy infrastructure development company based in California, formed IE with Stonepeak and that IE is essentially a project financing platform for ECo's grid modernization projects.

i. What is the role of ECo in the SSG Project? Please explain why it is not included in the organizational structure in Appendix I.
ii. Will PUC Distribution pay ECo monthly payments for the duration of the Project (as referenced in the Navigant Report, Appendix D)? If so, what is the purpose of such payments and what are the amounts of the payments?

(c) Please provide all documents related to the establishment of SSG Inc., including information related to its officers, directors, governance structure as well as all agreements entered into by SSG Inc. with the Fund, Stonepeak, ECo and/or IE.

(d) Please provide all documents related to agreements between PUC Distribution and the Fund, Stonepeak, ECo and/or IE.

(e) Please elaborate on the organizational structure of the Project as noted in Appendix I and how Project funding flows to each company involved.

(f) Please explain why PUC Distribution chose to proceed with the organizational and financing structure as described in part (e). Why is this arrangement preferable to PUC Distribution securing loans and hiring consultants and contractors directly?

(g) Please explain what alternatives, if any, PUC Distribution considered for the development and financing of the SSG Project, in addition to the arrangement with SSG Inc., the Fund, Stonepeak, ECo and/or IE. Please provide details of alternatives considered.

Response:

(a) Stonepeak is no longer involved in the project. The project will be financed through a combination of long-term project finance debt and equity. The equity capital shall consist of (1) institutional investment funds managed by a joint-venture consisting of Diode Ventures LLC (an affiliate of Black & Veatch) and Alma Global Infrastructure LLC and (2) IE as the original developer.

(b) Energizing, LLC (aka 'Energizing Co.' or 'ECo') changed its name to Infrastructure Energy, LLC (IE). It is the same entity.

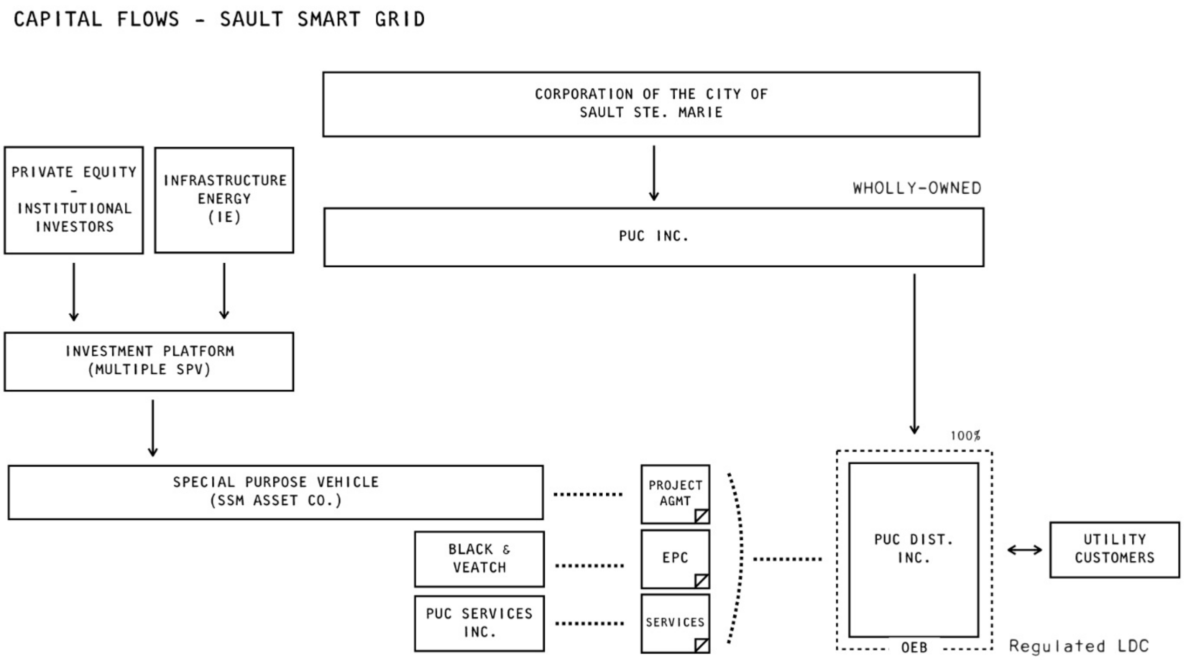
i. ECo was not included in the organizational structure, as it is the same entity as IE.
ii. No. PUC Distribution will make monthly payments directly to SPV SSG Inc. as will be detailed in the proposed Project Agreement (Appendix 12 & 13) between SSG, Inc. and PUC Distribution.

(c) SSG, Inc. has not been formed. It is intended to be a special purpose vehicle (SPV) formed at financial close of the Project, as is customary for projects of this type.

(d) Attached please find documents related to PUC Distribution and Eco/IE including four Letter of Intent related documents and amendments over the project feasibility period. In addition current working draft version of the main Project Agreement & Schedule 1 Definitions which will be between PUC Distribution and Project Co (SSG).

i. LOI PUCD & Eco 2013 (Appendix 9) – filed in confidence.
ii. ATP Letter 2014 (Appendix 10)
iii. Amendment 2015 (Appendix 11) – filed in confidence.
iv. Amendment 2016 (Appendix 14)
v. Project Agreement v15 20190419 (Appendix 13) – filed in confidence.
vi. Schedule 1 20190419 (Appendix 12) – filed in confidence.

(e) Please see below (i) additional information on the organizational structure of the Project, and (ii) a description of how Project funding flows to each company involved.



(i) A description of the organizational role of each company involved in the Project, as follows;

- PUC Distribution, Regulated Local Distribution Company and project proponent,
- Infrastructure Energy, Project development partner,
- Diode Ventures and Alma Global, Project investment partner,
- Black & Veatch, Project engineering, procurement and construction (EPC) partner,
- PUC Services, Project service provider (Services) partner, and
- SSG, Inc., special purpose vehicle (SPV) holding project assets during term of project.

(ii) A description of Project funding flows to each company involved, as follows:

- Infrastructure Energy provided funding for Pre-Feasibility Phase of Project, including finalization of Letter of Intent (2014) and presentation to Corporation of the City of Sault Ste. Marie City Council for Project Support Resolution (2014) passed unanimously, as well as funding for Pre-Feasibility Study for Sault Smart Grid project (Project). PUC subsequently provided Project Authority to Proceed (2014) based on results of Pre-Feasibility Study.

- Infrastructure Energy provided funding for Governance Approvals and Due Diligence Phase of Project, including PUC Board Sub-Committee Review and Recommendation (2015), Navigant Independent Business Case Review (2015), and Navigant Independent Project Cost Review (2015) [see ICM Appendix D,E].

- Corporation of the City of Sault Ste. Marie provided funding for Navigant Second Business Case Review (Appendix 7) for Corporation of City of Sault Ste. Marie (2016) which was considered in light of their efforts in socio-economic impacts to City and also as shareholder. Final Shareholder Approval Resolution (2018) (Appendix 8) for PUC Distribution to pursue project subject to key conditions.

    - Final Shareholder Approval Resolution (Appendix 8)
    - SSM Navigant Report (Appendix 7)

- All parties funding legal costs of negotiation of Project Agreement (PA), and two drop down contracts, the Design-Build Agreement (DBA) and Services Agreement (SA).

- Following satisfaction of final Conditions Precedent of PUC Board Approval and Shareholder Approval Resolution (Appendix 8), including NRCan approval and execution of Contribution Agreement (CA) (Appendix 1), and OEB regulatory approval, all Project documents are to be executed at Close of Financing (CoF), concurrent with formation of the special purpose vehicle SSG, Inc., and funding of all Project costs into SPV by Diode Ventures and Alma Global, and NRCan contributions through PUC Distribution.

- Project construction commences at CoF, subject to schedule and budget guarantees provided by EPC contractor, Black & Veatch. BV is funded directly by payments from SSG, Inc. during construction.

- Project payments will begin at Initial Operational Capability (IOC) of Project. At Full Operational Capability (FOC) of Project, title for assets of Project will be transferred to PUC Distribution from SPV. Benefits in increased distribution asset efficiency, reliability and resilience will commence in part concurrent with IOC, with full benefits delivered at FOC.

  Project payments will continue on a monthly basis throughout the term of the Project, over 25 years. Project payments were negotiated directly by PUC with project development partner Infrastructure Energy to ensure reduction in overall bills for PUC customers.

(f) The organizational and financing structure described in part (e) was selected by PUC over traditional methods of securing loans and hiring consultants and contractors directly. PUC Distribution elected to consider this approach for a number of reasons. One of the significant factors was that the project conceptual approach, significant data analysis, early design engineering and third-party vetting, review and comment was conducted at the cost and risk of the developer Infrastructure Energy (formerly Energizing Co.). PUC Distribution would have been unable to assign available resources (people or budget) to have undertaken the significant level of engineering analysis to scope and justify, including independent consultant review, such a project at the expense level involved. It has allowed PUC Distribution to conceive and propose a community-scale smart grid project integrating a number of smart grid systems that will mutually reinforce each other and offer increasing returns to scale – over a compressed timeline of two years to implementation with mitigated financial and performance risk via risk transfer to project developer, financial and technical partners. PUC Distribution efforts consisted of staff time to support data requests and a lot of review and discussion of engineering analysis and reports to achieve a successful outcome and had no cost risk should the project evaluation result in a “no go” decision by PUC. A key additional factor of the proposed two-year project vs. the traditional approach over a longer time frame is not having all customers paying through rates but delay benefits for some of those customers over that longer period. PUC did not incur external costs until the project achieved a viable status in the sole determination of PUC at which point costs for mostly legal and regulatory support became needed. PUC Distribution analyzed using traditional procurement methodology and found that it would have required a substantially slower smart grid system deployment, increasing risk exposure for budget, schedule and system performance. The selected approach benefits PUC and most importantly customers, by having a complex project developed, constructed and financed on a turnkey and de-risked basis. PUC customers paying for benefits received more closely aligns with costs rather than a longer, slower implementation where all customers are paying but only some receive available benefit.

(g) During the Pre-Feasibility Phase, PUC Distribution and risk-sharing developer partner Infrastructure Energy assessed a number of different SSG technology architectures and financial arrangements to arrive at the final project architecture and financing strategies. Strategy also includes integrating arrangement of external government financing from Natural Resources Canada (NRCan).

Staff-32

Reference: EB-2018-0219, ICM Application, Page 36

Preamble:

PUC Distribution indicates that the Fund mentioned in the question above funded the Leidos Report.

Question:

(a) Does PUC Distribution expect to receive any additional funding from the Fund, Stonepeak and/or IE?

(b) Is PUC Distribution or SSG Inc. expected to repay the Fund, Stonepeak and/or IE for its initial capital contribution for the Leidos Report?

Response:

(a) PUC Distribution has not and will not receive any funding directly from the SSG Development Consortium.

(b) PUC Distribution is not expected to repay SSG Development Consortium for its initial capital contribution for the Leidos Report.

Staff-33

Reference: EB-2018-0219, ICM Application, Pages 57-58

Preamble:

The reference provides the following quote: "[PUC President and CEO Rob] Brewer said that PUC is almost positive that they will be receiving $14,340,000 in federal and provincial government funding to subsidize the project[...]" PUC Distribution clarified in the same reference that the funding expected from NRCan is $11,807,000.

Question:

Please explain why the amount of federal funding PUC Distribution expected to receive changed from $14,340,000 to $11,807,000.

Response:

Note that the quote above refers to 'federal and provincial government funding'.

PUC Distribution had been initially anticipating provincial funding for the project but in application review it was determined LDC's were not eligible under the provincial program.

Staff-34

Reference: EB-2018-0219, ICM Application, Page 14

Preamble:

PUC Distribution indicates that it has chosen Black & Veatch (B&V) to act as the Engineering Procurement and Construction (EPC) contractor on the SSG project.

Questions:

(a) Please explain how B&V was chosen to be the EPC contractor and what processes PUC Distribution used to make its selection.

(b) Were other EPC contractors considered? If not, why not?

(c) If other EPC contractors were considered, please provide quotes submitted by other contractors. If response to this interrogatory involves confidential information, PUC Distribution should file redacted documents on the public record and request confidential treatment for the unredacted versions.

(d) Please clarify if PUC Distribution will be paying a one-time lump sum to B&V upon completion of the project, or if there is some type of monthly payment arrangement.

(e) If there is a monthly payment arrangement, has this amount been determined? If yes, how?

Response:

(a) There was a thorough process undertaken by development partner IE to select an EPC partner for the project. Criteria included a financial wherewithal to provide meaningful risk transfer, and experience in similarly large-scale power engineering projects in North America, and particularly with other LDCs in the Ontario market.

(b) Yes. IE considered two other comparably ranked North American engineering firms with similar EPC qualifications.

(c) EPC proposals were made by the three North American engineering firms directly to IE, not to PUC Distribution. The confidential and proprietary proposals that were submitted to IE by different engineering firms are not in scope of this ICM proceeding.

The SSG was developed on a collaborative basis with PUC resulting in a turn-key project proposal that included technical, financial and risk transfer elements aligned with OEB directives on LDC smart grid initiatives.

(d) No. PUC will not be making lump sum payment to B&V upon completion of project. See response to Staff-31 (e).
(e) No. There is no monthly payment directly to B&V. See response to Staff-31 (e).

Staff-35

Reference: EB-2018-0219, ICM Application, Page 30

Preamble:

The application notes that payment for the SSG Project will financed over a twenty-five year term through long term debt financing.

Question:

(a) Please provide details of the long-term debt financing, including sources of financing, terms and rates of repayment and provide all documents related to the financing. How does this financing fit in the payment structures to B&V noted above?

(b) Has PUC Distribution secured the debt financing, or is it pending OEB approval of both Phases 1 and 2 of the SSG project?

Response:

(a) PUC is not responsible for securing the long-term debt financing. The Project is turn-key, with monthly payments made directly from PUC to SSG as required in the Project Agreement (Appendix 12 & 13). See response to Staff-31 (e).

(b) PUC is not responsible for securing the debt financing. PUC Board approval requires OEB regulatory approval before execution of Project Agreement (Appendix 12 & 13). See response to Staff-31 (e).

Staff-36

Reference 1: EB-2018-0219, ICM Application, Page 14

Reference 2: EB-2018-0219, Appendix J

Preamble:

The Application states that "BV assumes the risk of project completion and performance of design..." It also states that "the risk of cost overruns will be borne by the developer and their EPC contractor."

Appendix J has several references to PM4 Change Management and in several locations, e.g. under the CYME Integration Workshop, states that: "any required scope changes will be input into the task PM4 Change Management."

Questions:

(a) Please reconcile how PUC Distribution expects no risks in bearing cost overruns if there is PM4 Change Management.

(b) Is there a contingency amount included in the Project estimate?

(c) If yes to (b), please indicate how much.

(d) How does PUC Distribution plan to manage possible scope changes?

Response:

(a) The Project is turn-key as outlined in the Project Agreement (Appendix 12 & 13) between PUC and SSG. Any cost overruns would be borne by SSG. PUC Distribution would approve any changes to Project scope under PM4 Change Management regime.

(b) There is no contingency in the turn-key Project Agreement (Appendix 12 & 13) between PUC and SSG. PUC Distribution did include a contingency in its own portion of the project cost estimate of $1.64M included in the ICM application.

(c) 10% on $1.64M or ~$164,000.

(d) PUC Distribution will be managing scope changes in regular project management process. (project scope, project budget, total budget vs value added, risk, etc.)

Staff-37

Reference: EB-2018-0219, ICM Application, Page 5

Preamble:

PUC Distribution has indicated that the total capital cost of the smart grid projected is estimated to be $34,389,046.

Questions:

(a) Please confirm if this total project cost is based on a firm price secured from B&V.

(b) If the answer to (a) is no, and PUC Distribution is yet to confirm a final price, what is the amount of variance expected?

(c) How will any variance in pricing be addressed?

Response:

(a) Project is turn-key as outlined in the Project Agreement (Appendix 12 & 13) between PUC and SSG plus PUC Distribution’s own costs.

(b) See answer to Staff-36 (c)

(c) There is no variance in pricing under the terms of the Project Agreement (Appendix 12 & 13) between PUC and SSG.

Staff-38

Reference 1: OEB 2017 Yearbook of Electricity Distributors

Reference 2: EB-2018-0219, Appendix D, Navigant Report #1, Page 33

Preamble:

The OEB's 2017 Yearbook of Electricity Distributors indicates that PUC Distribution has 284 square km of rural service area and 58 square km of urban service area.

The Navigant Report notes that: "Radial circuits connected to a single substation may not be able to transfer un-faulted sections to another feeder."

Questions:

(a) Feeders are generally sparser in rural areas with less tie points between feeders when compared to feeders in urban areas. Given that the majority of PUC Distribution's service area is rural, please provide a discussion on whether PUC Distribution has sufficient tie points between feeders in its distribution system to allow for load transfers in the event of faults. What percentage of feeders would be able to support load transfers?

(b) Please confirm if PUC Distribution's feeders, especially those within PUC Distribution's rural service areas, are radial. If so, please explain how PUC Distribution intends to leverage load transfers as part of the DA system to improve reliability.

(c) Please indicate whether PUC Distribution's feeders have sufficient capacity to accommodate short-term load transfers in the event of faults.

(d) Please indicate the impact on reliability PUC Distribution expects to have through load transfers in the event of faults as part of DA.

Response:

(a) Although the majority of the PUC Distribution system is classified as rural, it has a physical architecture within that territory that makes it highly conducive to looping. This is because many of the roads in the rural service territory are laid out in a grid pattern and the power lines follow these roads. Of the total circuit length in the service territory, ~10% have no opportunity for looping. All distribution feeders have potential for at least partial zone load transfer capability. Tie points have been identified in preliminary engineering design creating 83 zones on 40 feeders. Additional engineering is required to look at remaining 8 feeders in areas that were undergoing voltage conversion and load configuration changes during last evaluation. Faulted circuit indicators (FCI's) are included in scope for more rural, radial locations.

(b) All PUC Distribution circuits operate as radial circuits from an electrical protection perspective. As discussed in (a) above the remote end of feeder lengths in the more rural areas amount to about 11% by circuit length from a non-transferrable delivery option. Analysis of the balance of the system provides the opportunity for leverage DA in to improved reliability.

(c) Preliminary engineering confirmed feeders for upgrade with sufficient capacity for short-term load transfers. Review identified some locations where re-conductoring was recommended for the reliability improvement as well as improved losses. These will be subject to further review at detailed design and stages.

(d) Load transfer design typically results in reliability improvements of between 25% and 50%. Preliminary engineering design and analysis work arrived at improvements of 37% on SAIFI, 46% on SAIDI and 16% on CAIDI which in subsequent Navigant review were considered reasonable. The impact on reliability through load transfers is discussed in Appendix H of the ICM Application.

Staff-39

Reference: None

Questions:

(a) Please provide a table showing the number of interruptions by cause code for each of the years 2013 to 2017.

(b) If available, please also provide the number of interruptions by cause code for individual feeders for each of the years 2013 to 2017.

(c) How long does it currently take for PUC Distribution's field crews to locate faults? Please provide longest, shortest and average times.

Response:

(a) Please see the chart below outlining the number of interruptions by cause code for each of the years 2013 to 2017:

OEB Cause Code	Outage Description	2013	2014	2015	2016	2017
0	Unknown/Other	19	26	4	4	11
1	Scheduled	320	387	404	281	195
2	Loss of Supply	2	0	0	1	0
3	Tree Contacts	54	32	34	24	43
4	Lightning	10	4	1	2	6
5	Defective Equipment	104	191	203	186	144
6	Adverse Weather	7	16	55	28	38
7	Adverse Environment	0	0	0	1	1
8	Human Element	3	0	0	2	1
9	Foreign Interference	42	54	23	29	31
	Total	**561**	**710**	**724**	**558**	**470**

(b) PUC does not track the number of interruptions by cause code for individual feeders, in a database which can be systematically analyzed, and therefore data for the years 2013 to 2017 is not available.

(c) PUC does not track and therefore cannot report on the longest, shortest and average times that it takes for field crews to locate faults. There are many factors that can impact the length of time that it takes field crews to locate faults. Some of the factors include:

- proximity of the fault to the PUC Service Centre,
- when the fault occurs (regular business hours vs. after hours),
- underground vs. overhead system fault,
- location of field crews during fault occurrence

High level order of magnitude estimates for crews to locate faults generally range from 30 minutes for the shortest timeframe up to several hours for the longest.

Staff-40

Reference: EB-2018-0219, ICM Application, Page 11

Preamble:

The bulk of the annual net benefit to customers as shown in Table 1 in the ICM application is calculated using the estimated 2.7% reduction in energy consumption.

Questions:

(a) How likely is it that PUC Distribution will achieve a 2.7% reduction on energy consumption?

(b) Has the entire VVO implementation been analysed for the expected benefit per feeder based on the real load characteristics of each feeder? If so, please provide this information.

Response:

(a) There is a high likelihood of achieving 2.7% reduction based on design subject to conditions on the grid and external factors.

(b) Preliminary engineering analysis using software load flow analysis on 8 stations (32 feeders) in detail to support benefit analysis. Please refer to Appendix C, section 6 VVM Benefits in information provided in Leidos report submitted with ICM Application.

Staff-41

Reference 1: EB-2018-0219, ICM Application, Page 11

Preamble:

In Table 1, PUC Distribution assumes a 2.7% reduction in energy consumption.

The reduced energy consumption would have the added benefit of reducing the charge customers pay for volumetric distribution rates. However, not all of PUC Distribution's rate classes are billed on a kWh basis – Residential customers are on a fixed basis while certain other rate classes are billed on a kW basis.

Question:

In light of this, please explain how costs savings in distribution charges are expected to be allocated fairly across all rate classes.

Response:

The cost savings are not primarily in respect of distribution charges. The savings in energy consumption generates savings on other elements of the total bill that are billed on a kWh basis.

Staff-42

Reference: EB-2018-0219, ICM Application, Pages 5 and 11

Preamble:

The ICM application states that reduced energy consumption is a benefit of the smart grid project that will help lower customers' bills.

Currently, PUC Distribution recovers a portion of its revenue requirement through volumetric rates in all rate classes. The only change in the near future, is the transition to fully fixed rates for residential customers – the remainder of PUC Distribution's rate classes are expected to continue to have volumetric distribution rates.

Questions:

(a) What is the impact of the reduced energy consumption as a result of the SSG project on the amount of revenue PUC Distribution recovers through its volumetric rates?

(b) Has PUC Distribution performed an analysis on the potential in shortfall of revenue resulting from the reduced energy consumption? If yes, please provide the analysis.

(c) If the reduced energy consumption is expected to result in a shortfall of revenue for PUC Distribution, how does PUC Distribution expect to make up the shortfall?

Response:

(a) The impact of the reduced energy consumption of 2.7% as a result of the SSG project is estimated to be $241,491 annually using the current rate structure. The annual reduction falls to $174,542 at current rates as of May 1, 2020 when residential rates are fully fixed. See part (b) below for the analysis which utilizes data from the 2018 COS rate application.

(b)

PUC Distribution Inc. Analysis of Approved Distribution Revenue (including SSG consumption reduction)

Residential	2018 Approved Consumption	2018 Approved Rates (CoS)	2018 Annualized Revenue	% Energy Reduction	Vol. Energy Reduction	Projected Billing Determinants	Current Appoved Rates	Projected Revenue	Variance including SSG Energy Reduction
Customers	29,816	$24.41	$8,733,556.73			29,816	$24.41	$8,733,557	$0
kWh	288,323,799	$0.0086	$2,479,584.68	2.7%	7,784,743	280,539,057	$0.0086	$2,412,636	-$66,949
			$11,213,141.41					$11,146,193	-$66,949
General Service <50 kW									
Customers	3,431	$20.73	$853,436.90			3,431	$20.73	$853,437	$0
kWh	92,411,463	$0.0248	$2,291,804.29	2.7%	2,495,110	89,916,354	$0.0248	$2,229,926	-$61,879
			$3,145,241.19					$3,083,362	-$61,879
General Service 50 to 4,999 kW									
Customers	357	$114.46	$490,591.79			357	$114.46	$490,592	$0
kWh	244,620,598			2.7%	6,604,756	238,015,842			
Transformer Credit			($82,800.00)	2.7%		($2,236)		($80,564)	$2,236
kW	614,743	$6.7295	$4,136,912.35	2.7%	16,598	598,145	$6.7295	$4,025,216	-$111,697
			$4,544,704.14					$4,435,243	-$109,461
Sentinel Lights									
Customers	354	$3.55	$15,100.69			354	$3.55	$15,101	$0
kWh	209,800			2.7%	5,665	204,136			
kW	593	$33.1502	$19,641.98	2.7%	16	577	$33.1502	$19,112	-$530
			$34,742.68					$34,212	-$530
Street Lights									
Customers	8,070	$1.37	$132,670.80			8,070	$1.37	$132,671	$0
kWh	2,398,221			2.7%	64,752	2,333,469			
kW	7,030	$8.9284	$62,767.54	2.7%	190	6,840	$8.9284	$61,073	-$1,695
			$195,438.34					$193,744	-$1,695
USL									
Customers	22	$12.69	$3,328.30			22	$12.69	$3,328	$0
kWh	944,731	$0.0383	$36,183.21	2.7%	25,508	919,224	$0.0383	$35,206	-$977
			$39,511.51					$38,534.56	-$977
Total									
Customer/Connections	42,050					42,050			
kWh	628,908,614		$19,172,779.27			$611,928,082		$18,931,289	($241,491)
kW from applicable classes	622,366					605,562			

(c) PUC's distribution revenue will only be partially under the approved amount in 2020, with the full effects of the SSG commencing in 2021 and continuing in 2022 until PUC's next CoS rate application which is scheduled to be effective May 1, 2023. Any amount of the shortfall that cannot be made up through cost efficiencies will result in a slight reduction in return on equity until PUC's next rebasing.

Staff-43

Reference: EB-2018-0219, ICM Application, Page 12, Table 2

Preamble:

The bill impact for a typical residential customer consuming 750 kWh per month is shown in Table 2 to be an increase of $1.08, or 1.00% of the total bill.

Questions:

(a) If the full implementation of the SSG project results in a bill increase for typical residential customers, please explain how this reconciles with PUC Distribution's policy of "no net bill increase."

(b) Please explain how PUC Distribution generated the bill impacts in Table 2.

(c) Please provide a table showing the customer bill impacts after the full implementation of Phase 1 and Phase 2 of the SSG project, excluding any benefits associated with the SSG project.

Response:

(a) As noted on page 11, line 9 of the ICM Application there is an overall benefit to the customers in PUC Distribution's service territory. However, with any change to rates, the effect on specific customers will vary. Table 2 of ICM Application includes examples of bill impacts at various consumption levels once the full SSG Project is included in rates.

(b) The bill impacts were calculated by comparing:

i) the proposed rates from the ICM request at various consumption levels, excluding any increase due to the SSG (i.e. removing the Phase 1 revenue) to

ii) the proposed rates from the ICM request plus the effect of the full SSG project at consumption levels 2.7% less for RTSR Network charge, Wholesale Market Service Charge, Rural and Remote Rate Protection and energy charge (ie reduced consumption due to the SSG project). See the following example of a 750 kWh customer. This same method was used for the other listed consumption levels.

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION							
RPP / Non-RPP:	RPP							
Consumption	750	kWh	Consumption Decrease %		2.70%	Proposed consumption	730	
Demand	-	kW						
Current Loss Factor	1.0481							
Proposed/Approved Loss Factor	1.0481							
	Proposed			Proposed - ICM			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 28.17	1	$ 28.17	$ 28.17	1	$ 28.17	$ -	0.00%
Distribution Volumetric Rate	$ 0.0043	750	$ 3.23	$ 0.0043	730	$ 3.14	$ (0.09)	-2.70%
Fixed Rate Riders	$ (1.35)	1	$ (1.35)	$ (1.35)	1	$ (1.35)	$ -	0.00%
ICM - Fixed	$ -	1	$ -	$ 3.06	1	$ 3.06	$ 3.06	
Volumetric Rate Riders	$ 0.0007	750	$ -	$ 0.0007	730	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 30.05**			**$ 33.01**	**$ 2.97**	**9.88%**
Line Losses on Cost of Power	$ 0.0820	36	$ 2.96	$ 0.0820	35	$ 2.88	$ (0.08)	-2.71%
Total Deferral/Variance Account Rate Riders	($0.0067)	750	$ -	-$ 0.0067	730	$ -	$ -	
CBR Class B Rate Riders	$ -	750	$ -	$ -	730	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ -	730	$ -	$ -	
Low Voltage Service Charge	$ -	750	$ -		730	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	-$ 0.0004	750	$ (0.30)	-$ 0.0004	730	$ (0.29)	$ 0.01	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.27**			**$ 36.17**	**$ 2.90**	**8.71%**
RTSR - Network	$ 0.0059	786	$ 4.64	$ 0.0059	765	$ 4.51	$ (0.13)	-2.70%
RTSR - Connection and/or Line and Transformation Connection	$ -	786	$ -	$ -	765	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 37.91**			**$ 40.68**	**$ 2.77**	**7.31%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	786	$ 2.67	$ 0.0034	765	$ 2.60	$ (0.07)	-2.70%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	786	$ 0.39	$ 0.0005	765	$ 0.38	$ (0.01)	-2.70%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ -		$ -			$ -	$ -	
TOU - Off Peak	$ 0.0650	488	$ 31.69	$ 0.0650	474	$ 30.83	$ (0.86)	-2.70%
TOU - Mid Peak	$ 0.0940	128	$ 11.99	$ 0.0940	124	$ 11.66	$ (0.32)	-2.70%
TOU - On Peak	$ 0.1320	135	$ 17.82	$ 0.1320	131	$ 17.34	$ (0.48)	-2.70%
Total Bill on TOU (before Taxes)			**$ 102.72**			**$ 103.75**	**$ 1.03**	**1.00%**
HST	13%		$ 13.35	13%		$ 13.49	$ 0.13	1.00%
8% Rebate	8%		$ (8.22)	8%		$ (8.30)	$ (0.08)	
Total Bill on TOU			**$ 107.86**			**$ 108.94**	**$ 1.08**	**1.00%**
			$ 107.86			$ 108.94	$ 1.08	1.00%

(c) The following table was calculated based on the example above without taking in to account the projected reduction in consumption as a result of the SSG project. PUC Distribution does not agree that this is an appropriate methodology as it would incent LDCs not to make any system improvements that would reduce consumption and thus reduce total bill for customers.

Bill Impacts - Full Implementation of SSG without considering consumption reductions

Class	Consumption (kWh)	Consumption (kW)	Total Bill Increase/Decrease	Total Bill Impact %
Residential	750	0	$3.21	2.98%
Residential	1,130	0	$3.21	2.17%
Residential	2,000	0	$3.21	1.34%
GS<50	2,000	0	$7.20	2.62%
GS<50	2,250	0	$7.84	2.56%
GS<50	3,000	0	$9.74	2.43%
GS>50	19,740	55	$53.40	1.60%
GS>50	57,220	145	$120.15	1.29%
GS>50	142,465	452	$347.84	1.45%
GS>50	169,620	468	$359.70	1.30%

Staff-44

Reference: EB-2018-0219, Appendix D, Navigant Report #1, Pages 35-36

Preamble:

The following is an excerpt from the Navigant Report:

> The effect of reduction in voltage levels is largely dependent on the type of end-use equipment. Resistive and inductive loads will react differently to reductions in voltage, as will loads with and without a thermal cycle. For example, lighting fixtures behave as simple resistive load. A decrease in voltage translates proportionally to a reduction in the current flowing through the wire filament, dimming the light. In contract, a water heater, through a resistive load, has a thermal cycle. That is, it[s] behavior is dependent on a time-variant cycle. At lower voltages, a water heater will run at a lower power rating and, hence, will take longer to heat water to a specified temperature and use more energy.

As the Navigant Report notes, the amount of benefit from Conservation Voltage Regulation as part of VVO is largely dependent on the type of load.

Questions:

(a) Please confirm that certain types of load would use more energy as a result of lowered voltage, e.g. water heaters.

(b) Given that the types of loads can vary between customers, and between customers of different rate classes, please explain how the energy reduction from VVO is expected to benefit all customers fairly.

(c) Please explain how the “no net bill increase” commitment would be achieved if the anticipated benefits of the SSG Project are not realized. How does PUC Distribution intend to address such a scenario? How does PUC Distribution intend to address potential rate increases if the benefits of the Project are not realized?

Response:

(a) No. A resistive load like a water heater would only be considered to use more energy if environmental loss factors from heat storage were factored, otherwise the energy consumption remains exactly the same.

(b) All customers benefit fairly as the savings are proportional to usage.

(c) A scenario whereby SSG Project benefits are not realized is unlikely in our view. PUC Distribution system modelling completed in preliminary engineering work to support critical project design assumptions were able to provide confidence in comparison to industry savings achieved in public reports and verified by Navigant and Black & Veatch. PUC Distribution will continue refinement of the VVO systems over time to fine tune for savings as technology continues to evolve in this area.

Staff-45

Reference**:** EB-2018-0219, Appendix E, Navigant Report #2, Page 9

Preamble:

The following is an excerpt from the Navigant Report:

> [Navigant] note[s] that the proposed feeder coverage for DA and VVM – 84% and 68% is higher than many other systems Navigant has encountered [...] This coverage should maximize the total amount of benefits that can be achieved by DA and VVM on PUC's distribution system, though it may not represent the optimal economic level of VVM and DA.

Questions:

(a) In light of Navigant's comments above, has PUC Distribution evaluated the option of a smaller scaled project with the intent of achieving greater economic efficiency?

(b) If yes to (a), please provide the evaluation/report.

(c) If no to (a), please explain why not.

Response:

(a) Yes. Alternative project scope/scale were evaluated in preliminary engineering and are referenced within the application. The optimal economic scale project, if meaning by cost/benefit ratio would be that which is referenced above. This included the derived reliability benefit included in the cost/ benefit ratio referenced in the Navigant report. However, the project was not achieving the neutral bill impact objective of PUC Distribution. Balancing criteria such as optimal economic level, neutral bill impact and an equitable treatment objective of those who pay receiving benefit was still a remaining challenge. This was also prior to the NRCan smart grid program.

(b) This analysis was conducted as part of the preliminary design assessment by Leidos in Appendix C of the ICM Application.

(c) N/A

Staff-46

Reference: EB-2018-0219, ICM Application, Page 23

Preamble:

The ICM application notes that the DA system "provide(s) a capability to locate and isolate a fault, and restore power to the entire upstream section of the feeder and as much of the downstream feeder as possible."

Questions:

(a) Please indicate if PUC Distribution currently performs protection coordination studies on its distribution feeders.

(b) If yes to (a), please explain what additional benefits the DA system is expected to provide in isolating faults given that electrical protective equipment, along with protection coordination studies, already work to isolate faults.

(c) Please explain in what way this is considered a smart grid technology given that protection coordination is a common element of the electricity distribution system.

(d) Please indicate whether PUC Distribution currently employs sectionalizing equipment, e.g. reclosers, along feeders to minimize the number of customers experiencing sustained outages.

(e) If yes to (d), please provide the percentage of PUC Distribution feeders that currently benefit from sectionalizing equipment.

Response:

(a) PUC conducts protection coordination studies on a case by case basis as system changes or enhancements occur.

(b) Conducting traditional coordination studies and employing time co-ordination of protective devices allow for opportunities to improve coordination thus reducing potential upstream customer interruptions. The additional benefits of DA primarily come from the ability of the system to automatically self heal by transferring some of the downstream and/or upstream load to an available adjacent circuit immediately. This can then add value by reducing the duration of impact to more customers than would be possible with traditional non self-healing protection schemes.

(c) This is a ‘smart-grid’ solution in that it employs, through automation, a set of operational instructions and decisions. The system essentially issues a set of operating instructions to automatically reroute to an alternate circuit when a primary circuit fails.

(d) PUC Distribution currently employs a limited quantity of sectionalizing equipment (3 reclosers, 4 sectionalizers), primarily along its few radial circuits which reach far into the rural parts of the service territory. These are primarily in areas where access is poor, corridors are heavily treed and exposure to high winds occur frequently.

(e) PUC does employ reclosers installed on our feeders in our distribution system. PUC currently has 3 reclosers on 3 distribution feeders out of a total of 53 feeders representing 5.7% coverage.

Staff-47

Reference: EB-2018-0219, ICM Application, Page 23

Questions:

(a) Please provide PUC Distribution's Distribution Operating Maps.

(b) Please explain to what extent PUC Distribution is able to restore to sectionalized feeder segments by operating existing tie switches. What percentage of feeders have this capability, and are those feeders located in urban or rural sections?

Response:

(a) PUC Distribution's 34.5kV Sub-transmission System diagram and 15kV Primary Electrical Distribution System diagram has been provided in the attached Operating Maps (Appendix 15).

(b) As illustrated in the diagrams provided in response to question Staff47(a), a significant portion of PUC's 34.5kV sub-transmission system and 12.5kV distribution system are loop fed systems with the redundancy of another circuit being available for manual load transfers when outages occur. All of PUC's urban feeders are currently capable of being restored to adjacent feeder segments via manually operating existing tie switches. Approximately 25% of PUC's rural feeders and 89% of all feeders have this capability.

Staff-48

Reference: EB-2018-0219, ICM Application, Page 23

Preamble:

The ICM application notes that the scope of VVO includes phase balancing of feeders.

Questions:

(a) Please explain why PUC Distribution has not performed phase balancing already as a normal part of its system planning work.

(b) If phase balancing work has already been completed, please confirm whether any work already completed has been removed from the Project scope.

Response:

(a) PUC reviews phase balancing of circuits on an 'as required' basis for example when circuit expansions, new customer connections or renewal projects occur. If material, sustained imbalances are identified, they are corrected accordingly.

(b) Any phase rebalancing previously completed is excluded from the SSG Project phase rebalancing scope.

Staff-49

Reference: EB-2018-0219, ICM Application, Page 23

Preamble:

System losses can be reduced by increasing conductor sizes and having adequately sized conductors for loads and load transfers. Larger conductors also help reduce voltage drop along the feeder.

Questions:

(a) Does PUC Distribution currently review conductor sizes as a method of minimizing system losses and voltage drops?

(b) If yes to (a), what work has PUC Distribution already completed to reduce line losses in this way?

(c) N/A

Response:

(a) Yes, PUC does review conductor sizes. PUC employs standardized conductor sizes with the objective being to balance system losses, improve voltage drop and minimize installation/replacement costs. Improvements over the past ten years have generally been focused in areas of the distribution system containing 'restricted conductor'. The primary objectives are to improve safety and infrastructure renewal with secondary benefits of loss reduction and voltage regulation.

(b) Figures 17 and 18 in PUC Distribution's Asset Management Plan, submitted in the 2018 COS Rate Application EB-2017-0071, illustrate progress towards eliminating three phase and single phase restricted conductor. In addition, conductor is replaced through PUC's voltage conversion program which also serves to reduce losses and voltage drop. Reconductoring is considered as part of the smart grid project but is incremental to work planned in the DSP.

(c) N/A

Staff-50

Reference 1: EB-2018-0219, Appendix D, Navigant Report #1, Page 17

Reference 2: EB-2018-0219, ICM Application, Page 34

Preamble:

The ICM Model includes an entry for an ICM project expected to take place in 2020 for the substation 16 upgrade. The Navigant Report further elaborates on substation upgrades as part of the scope of the SSG project.

Questions:

(a) Please indicate if costs related to substation upgrades have been included in this ICM request.

(b) If so, please indicate the amounts, the specific substations, and the scope of the upgrades.

(c) Were substation upgrades already part of the DSP and capital budget but their upgrading is now being ‘accelerated’, as indicated in Navigant Report, Appendix D, page 1)?

(d) Please confirm that any substation upgrades already included in PUC Distribution’s capital budget have not been included in this ICM request.

Response:

(a) No, the costs related to the substation upgrades have not been included in this ICM request.

(b) N/A

(c) Substations upgrades were used in long term asset management plans but are not being ‘accelerated’ from the DSP. The Navigant report reviewed an early project scope/scale that included addressing some older substations. Substation renewals were removed from scope to improve project economics (reference ICM Application Appendix F - Timeline).

(d) PUC Distribution confirms that any substation upgrades already included in PUC Distribution’s capital budget have not been included in this ICM request.

Staff-51

Reference: EB-2018-0219, ICM Application, Page 33, Table 8

Preamble:

In Table 8 of the ICM application, there is an entry indicating that the $3,300,000 substation 16 rebuild, which was included in the DSP, has been rescheduled to 2020 and increased by $300,000.

Questions:

(a) Please explain why the substation 16 rebuild was delayed given that it was identified as a high priority project in the DSP.

(b) Please explain why the cost has increased by $300,000 and whether the increase is caused by accelerating the upgrade to accommodate the SSG Project.

(c) Please provide the capital work that was planned for 2019 per the DSP amount at the time of filing and the current plan for those projects.

Response:

(a) The Sub 16 station rebuilt continues to be a high priority. The schedule was revised so that the project engineering which commenced in 2018, continued into 2019 and correspondingly, the project construction stage was rescheduled from 2019 to 2020. The primary reason for the revised plan was to take into consideration the SSG project which proposes voltage regulators at Sub 16. This is incremental and not included in the original station design. Therefore the Sub 16 project timing was adjusted to produce the lowest cost integration with the SSG project.

(b) There has been no increase in the total multi-year project budget for Sub 16 from what was included in the DSP. The $300,000 is attributable to the underspend in engineering in 2018 which is being reflected in the costs in 2020 as described in the answer to Staff-51(a).

(c) The current capital work plan is unchanged from the work plan submitted in the DSP filing with the exception of Substation 16, for which the procurement and construction was moved from 2018-2019 to 2019-2020.

Staff-52

Reference 1: EB-2017-0071, 2018 Cost of Service Application, Exhibit 1, Page 16
Reference 2: EB-2017-0071, 2018 Cost of Service Application, Appendix 11 – Customer Engagement Survey, Page 27
Reference 3**:** EB-2018-0219, Appendix C, Leidos Report, Utility Distribution Microgrid: AMI Integration

Preamble:

As part of its 2018 cost of service application, PUC Distribution noted that it implemented automated and upgraded phone systems and the Atlas system. References one and two above describe these systems as tools to provide customers with automated notifications and outage information.

The Leidos Report in reference three above mentions, among other things, the following three areas: Automated Outage Reporting, Enhance CSR Toolset with AMI data and Enhance Customer Toolset with AMI data.

Questions:

(a) Please elaborate on how the systems mentioned in the 2018 Cost of Service application and the areas described in the Leidos Report differ in scope.

(b) Have any of the functionalities described in the Leidos Report already been implemented?

(c) If yes to (b), please confirm that any costs associated with the functionalities described in (b) have been removed from the SSG Project

Response:

(a) The upgraded phone system referenced in the 2018 COS, EB-2017-0071, allowed for more external calls to be handled through additional lines, department phone number filters, messaging and a call queuing system for Customer Care staff. The Atlas system referred to in the 2018 COS - "*is essentially 3 separate systems; a geographic information system (GIS), PUC's customer information database and an Interactive Voice Response system (auto dialer). When work involving service interruption to customers is being planned, PUC staff will identify which area will be affected by the interruption. The electric or water meters in the identified area will be cross referenced with the PUC customer database and a call list will be compiled. That list will be used by the auto dialer to notify the affected customers*. (sourced from PUC website).

The new systems proposed in the SSG Project are completely different from the Atlas System and will improve efficiency and customer service with the new Outage Management System integrating and providing additional data available in reporting and information availability during events.

(b) No, new functionalities have not yet been implemented.

(c) N/A

Staff-53

Reference 1**:** EB-2018-0219, Appendix C, Leidos Report, Utility Distribution Microgrid: AMI Integration, Section 4.2.4
Reference 2**:** EB-2018-0219, Appendix K, Project Cost Estimate

Preamble:

Section 4.2.4 of Appendix C states that: "[the Enhanced CSR/Customer Toolset] project is in motion at PUC and a 2015 CIS/CC upgrade is already planned to provide many of the required features and functionality."

The project cost estimate in Appendix K includes a line item for "AMI/OMS/CIS" with a unit cost of $1,275,000 and installation costs of $637,500.

Questions:

(a) Please indicate which functionalities have already been implemented for enhancing the CIS and CSR systems as part of the 2015 upgrade.

(b) Please indicate what further improvements to the CIS and CSR systems are expected to be carried out as part of the SSG Project.

(c) Please explain why the work described in (b) was not performed during the 2015 CIS/CC upgrade.

(d) Please provide a breakdown of the "AMI/OMS/CIS" cost in Appendix K and show the individual costs of the CIS portion.

(e) Please confirm that the costs in (d) excludes any work that has already been performed in the 2015 upgrade, as described in (a).

Response:

(a) The previous CIS upgrade addressed the challenges of a very old, unsupported version of software that was becoming increasingly problematic for IT operations and users. The functionalities achieved such as a more current operating platform, user interface improvements, user security and encryption provide a capability to consider some of the new additional enhancements planned for the SSG project.

(b) The CIS upgrades proposed in the project are related to integration of features from the new Outage Management System (OMS) to bring more real time status on operations to Customer Care clerks for customer service related to planned and unplanned outages. This will include AMI information drawn from customer smart meters with time and location to support customer communications.

(c) Other needed projects were determined to have higher priority so the 2015 upgrade did not include an OMS.

(d) PUC Distribution does not have this detail of cost breakdown from the SSG contractor.

(e) There are no costs in the ICM for work done in the 2015 upgrade.

Staff-54

Reference: EB-2017-0071, 2018 Cost of Service Application, Appendix 5 – Customer Satisfaction Survey, Pages 5, 17, 41, 44, 46

Preamble:

The following are UtilityPulse Customer Satisfaction Survey results filed as part of PUC Distribution's 2018 Cost of Service application:

> 91% of respondents indicated "strongly + somewhat agree" that PUC Distribution "provides consistent, reliable electricity."
>
> 90% of respondents indicated "strongly + somewhat agree" that PUC Distribution "quickly handles outages and restores power."
>
> 55% of respondents indicated that they are not willing to pay more to reduce the number of outages or the duration of outages.
>
> The majority of respondents indicated that they are not willing to pay more to: add automation and technology to reduce outage time, invest in technology to deal with cyber security issues or add a proactive outage management system.
>
> 67% of respondents indicated that "better prices/lower rates" as one of the most important things PUC Distribution can do to improve service.

Questions:

In light of the customer feedback listed above, please discuss why PUC Distribution is proposing to spend additional capital on the following areas:

- Reliability improvements
- Addition of automation and technology
- Addition of a proactive outage management system
- Additional technology to deal with cyber security issues

Response:

PUC Distribution understands and is fully aware of our customers sensitivity to cost and price. This factor was clearly the intent of our zero bill increase objective. This project and ICM is all about delivering on the expectations of our customers. The number one issue to customers has remained as the cost of electricity and this project impacts that directly by lowering customer energy use. The next most common issue has been to improve or maintain reliability along with improved communication. These are also outcomes expected from this project.

Staff-55

Reference: EB-2018-0219, Appendix D, Navigant Report #1, Page 1

Preamble:

The Navigant Report notes that the smart grid project includes "an extensive 3-year community engagement process for community outreach and stakeholder education." At various references, it is noted that customer engagement will be done in the first three years of the project.

Questions:

(a) Please describe the engagement activities undertaken to date with respect to the SSG Project?

(b) Did customer engagement as part of PUC Distribution's most recent DSP solicit customer feedback on the proposed SSG Project and the associated impacts?

(c) Given the dates of the Leidos and Navigant Reports, which are 2014 and 2015 respectively, please explain why PUC Distribution did not begin its customer engagement on the proposed Project prior to filing this application, rather than after the Project is in-service.

Response:

(a) Please see PUC Distributions 2018 COS Rate Application EB-2017-0071, Exhibit 1, Appendix 9 & 10 for a description of customer engagement activities regarding this project.

(b) The Customer Engagement Overview in the 2018 COS Rate Application EB-2017-0071 has a number of specific areas and results that served to shape and support the proposed direction for the project.

(c) Timing of the 2018 COS Rate Application and DSP engagement efforts supported the SSG project direction and scope in preparation of the application.

Staff-56

Reference: EB-2017-0071, 2018 Cost of Service Application DSP, Pages 22 and 59

Preamble:

The DSP indicates that PUC Distribution connected a new 7MW/7MWh energy storage facility in the fall of 2017 which provides "dynamic Volt/VAR control."

Questions:

(a) Given that this new energy storage facility was connected after the Leidos and Navigant Reports, does the new energy storage facility duplicate any of the proposed benefits from the VVO component of the SSG Project?

(b) If yes to (a), please explain whether PUC Distribution has considered changing the scope of VVO to avoid duplication of efforts and spending capital on benefits which can already be achieved through the energy storage facility.

Response:

(a) The 7MW/MWh facility referenced in the DSP (EB-2017-0071) is connected to PUC's system at the sub-transmission level at St. Mary's Transmission Station TS1. The energy storage facility is privately owned and operated under direct contract with the IESO. The purpose of the energy storage facility is to provide Volt/VAR support at the bulk transmission system level and does not duplicate the VVO benefits proposed in the SSG project which will regulate Volt/VAR at the distribution feeder level.

(b) Given the answer to question Staff-56(a), this question is not applicable.

Staff-57

Reference 1: EB-2017-0071, 2018 Cost of Service Application DSP, Page 98
Reference 2: EB-2018-0219, ICM Application, Pages 24-25

Preamble:

The following is an excerpt from the DSP:

> Keeping in view the customer's preference for low electricity prices, no investments are proposed in this DSP for smart grid initiatives or pilot projects to provide additional data access and visibility from the current level at this time.

The ICM application mentions that the AMI Integration portion of the Project will include: Data Analytics and Performance Reporting, Enhanced CSR/Customer Toolset, Improved Voltage Measurement Granularity and Data Analytics and Performance Reporting.

Questions:

(a) Please confirm whether the scope of AMI Integration includes the type of functionality to "provide additional data access and visibility" as described in the DSP.

(b) If yes to (a), please explain why PUC Distribution did not change the Project scope to reduce project costs of AMI Integration, consistent with the DSP and customer preferences that PUC Distribution has already identified.

(c) Does any part of the "investments planned under System Renewal" as described in the DSP coincide with the project in this application?

(d) If yes to (c), please explain how the project in this application meets the ICM criteria of being discrete and outside of the Rate Base.

(e) If no to (c), please explain how the smart grid work described in the DSP is distinct from this smart grid project.

Response:

(a) PUC Distribution confirms the scope of AMI Integration includes the type of functionality to "provide additional data access and visibility" as described in the DSP in PUC Distribution's 2018 COS Rate Application EB-2017-0071. However, with the SSG Project, this is being achieved with no net bill increase.

(b) N/A

(c) No

(d) N/A

(e) Please refer to Section 4.1.8 of the DSP submitted in PUC Distribution's 2018 COS Rate Application EB-2017-0071. Also, please refer to Staff-25 (b).

Staff-58

Reference 1: EB-2018-0219, ICM Application, Page 7
Reference 2: EB-2018-0219, Appendix H, Page 3

Preamble:

The ICM application notes that, following the Navigant Reviews, PUC Distribution modified the scope of the SSG Project from the scope laid out in the Leidos Preliminary Design Reports and Navigant Reports. On page 7, the application states that "following the Navigant Reviews, PUC Distribution concluded that it needed to de-scope the smart grid project to lower costs."

On page 3 of Appendix H, the application notes that as part of the scope change, work was scaled from 8 to 12 DS's, and from 32 to 48 feeders.

Questions:

(a) Please provide a list of all the changes between the original scope evaluated by Leidos and Navigant and the current scope of the SSG Project proposed in this application.

(b) Please reconcile the scope additions listed in Appendix H with the statement that "PUC Distribution concluded that it needed to de-scope the smart grid project to lower costs."

(c) In increasing the scope to include more DS's and feeders, what are the marginal costs and benefits of the additional DS's and feeders?

Response:

(a) Major scope changes from the Leidos Report and Navigant review included:

- removal of the stations;
- optimizing VVO and DA coverage; and
- scaling up with the availability of the NRCan funding.

(b) The scope additions were applied to reflect the provision of benefits to all customers reflecting their cost contribution while also maintaining the zero net bill objective.

(c) By increasing scope to include more DS's and feeders, PUC Distribution ensured that all of its customers start to benefit from the zero net bill objective.

Staff-59

Reference: EB-2018-0219, Appendix J – General Assumptions

Preamble:

Under the General Assumptions section in Appendix J, the document notes that:

> This Design and Construction Specification document includes the PUC's required 35% reduction in cost. The corresponding reduction in benefits has not been calculated and is not included.

Questions:

(a) Please explain whether or not the project benefits presented in this application reflect the updated project scope which includes the 35% reduction in cost.

(b) If the response to part (a) is negative, please provide an updated estimate of project benefits that reflects the reduction in cost.

Response:

(a) Yes the projected energy benefits in the application reflect the full system VVO and the reliability benefits have been adjusted so that the current project scope reflects the project cost.

(b) N/A

Staff-60

Reference 1: EB-2018-0219, Appendix J, Footnote 3

Preamble:

Footnote 3 in Appendix J indicates that GIS integration is no longer required for the SSG Project.

Questions:

(a) Please explain the original intended purpose and benefit of GIS Integration.

(b) Please indicate whether there will be repeated entry of GIS data into both the existing GIS system and the new ADMS systems now that GIS integration is not included.

(c) If yes to (b), please indicate the impact this will have on OM&A expenses.

Response:

(a) The original purpose and benefit was to explore operating efficiencies and cost savings of the GIS and ADMS Integration.

(b) Yes there will be repeated entry of GIS data into both the existing GIS and the new ADMS systems.

(c) There is no impact on OM&A expenses as the current SCADA and GIS systems processes currently require entering data into both systems.

Staff-61

Reference: EB-2018-0219, ICM Application, Page 11, Table 1

Preamble:

The application notes in Table 1 that the annual projected reliability benefit of the SSG project is $2,550,000.

Question:

Please provide the methodology and data PUC Distribution used to arrive at this number.

Response:

Please refer to Appendix H in the original ICM Application. Specifically, page 2 of 5.

Staff-62

Reference 1: EB-2018-0219, ICM Application, Page 11, Table 1
Reference 2: EB-2017-0071, 2018 Cost of Service Application, Exhibit 2, Page 49

Preamble:

Table 1 of the ICM application indicates that there is an expected annual benefit of $342,708 for "reduced future capital expenditures due to SSG implementation."

In its 2018 cost of service application, PUC Distribution provided its forecasted annual expenditures for 2019-2022 in four categories: System Access, System Renewal, System Service and General Plant. System Service expenditures is expected to be minimal for PUC Distribution as it is experiencing a period of reduction in system load. The bulk of capital expenditures set out in the can be attributed to System Access and System Renewal. System Access relates to "must do" projects for PUC Distribution to fulfill its statutory, regulatory and other obligations to provide customers with access to its distribution system. System Renewal relates to "both reactive expenditures for replacement of the assets that have failed in service, as well as proactive replacement of assets where the risk of an assets' failure in service is unacceptable."

Question:

Given that PUC Distribution is expected to continue spending on System Access and System Renewal projects, please indicate what types of projects that were part of the cost of service application could be deferred or not required as a result of SSG implementation that would result in the annual benefit of $342,708.

Response:

None of the projects identified in PUC Distribution's COS Rate Application EB-2017-0071 could be deferred or eliminated as a result of the SSG Project that would result in an annual benefit of $342,708. The amount of $342,708 reflect potential future capital savings associated with using substation power transformers with integral voltage regulation as opposed to standalone units to achieve VVO. Please refer to Appendix G, item g, page 60 of the originally filed ICM Application.

Staff-63

Reference: EB-2018-0219, ICM Application, Page 13

Question:

As specified in the DA section of the application, the SSG Project improves reliability by locating and isolating faults, and rapidly restoring power to customers on faulted feeders. While this reduces the duration of outages, please explain how the SSG Project will help to reduce the number of interruptions, both sustained and momentary.

Response:

The number of interruptions is reduced via planned or automated outage switching. The number of unplanned momentary interruptions will see no change but the sustained outages to a portion of the customers will be reduced via the DA.

Staff-64

Reference: EB-2018-0219, ICM Application, Page 10

Questions:

(a) Please explain how the benefit to cost ratio of 1.1:1 from a billing perspective is determined? Please explain the calculation and assumptions made.

(b) Please explain what is meant by "the ratio results is 1.4:1" in the cited reference.

i. How does reliability factor into the ratio?
ii. Please explain how the ratio is calculated and the assumptions made

Response:

(a) Please refer to the ICM Application, Appendix 11, page 11, Table 1 to reference the benefit to cost values. The benefit to cost ratio is calculated by dividing the $2,061,069 by $1,855,452 which equals 1.1:1.

(b) Please refer to the ICM Application, Appendix 11, page 11, Table 1 to reference the benefit to cost values. The benefit to cost ratio is calculated by dividing the $2,755,617 by $1,855,452 which equals 1.4:1.

i. Reliability is included in the numerator in the calculation in (b).
ii. Please see above (a) and (b).

Staff-65

Reference: EB-2018-0219, Appendix H, Page 4

Preamble:

The net benefits calculation starts with PUC Distribution's cost of power, reduced by 34.5kV customers from its 2018 cost of service application. Using the 2017 and 2018 cost of power reported in RRR and assuming all other figures in the net benefits calculation remains the same, OEB staff has calculated the revised net benefits to be as follows:

	2018 CoS	2017 RRR	2018 RRR
4705-Power Purchased	$ 71,366,511	$ 68,428,558	$ 61,672,851
4708-Charges-WMS	$ 2,372,973	$ 2,620,200	$ 2,253,664
4714-Charges-NW	$ 3,769,244	$ 3,797,613	$ 3,844,116
4716-Charges-CN	$ -	$ -	$ -
4730-Rural Rate Assistance	$ 197,748	N/A	N/A
4750-Low Voltage		$ -	$ -
4751 - Smart Metering Entity charge	$ 18,950	$ 322,910	$ 238,211
Total COP	$ 77,725,426	$ 75,169,281	$ 68,008,842
GS>50kW for 34.5kV	$ (4,847,999)		
Adjusted COP	$ 72,877,427	$ 75,169,281	$ 68,008,842
	2.7%	2.7%	2.7%
Projected COP Savings	$ 1,967,691	$ 2,029,571	$ 1,836,239
Difference from 2018 CoS COP Savings		$ (61,880)	$ 131,452
Net benefit to customers	$ 205,067	$ 266,947	$ 73,615

The above calculation based on 2017 and 2018 RRR cost of power did not remove the cost of power for 34.5kV customers.

Question:

If the adjustment to remove cost of power for 34.5kV customers is made, please explain whether the net benefits to customers would be further reduced and become possibly negative. Please explain how potentially negative net benefits correlate "no net bill increase" objective.

<u>Response:</u>

Please find below an update of the OEB provided chart which includes the GS>50kW for 34.5kV in 2017 and 2018. As can be seen, the net benefit is affected by the GS>50kW for 34.5kV. PUC believes the best method of estimating customer savings is utilizing the weather normalized load forecast approved in the recent 2018 COS Rate Application EB-2017-0071 rather than the results of individual years. It should also be noted that as the price of energy rises in the future, the savings to customers will also rise. In addition, the benefit of increased reliability is not included in the savings calculations below.

	2018 CoS	2017 RRR	2018 RRR
4705-Power Purchased	$71,366,511	$68,428,558	$61,672,851
4708-Charges-WMS	$2,372,973	$2,620,200	$2,253,664
4714-Charges-NW	$3,769,244	$3,797,613	$3,844,116
4716-Charges-Cn			
4730-Rural Rate Assistance	$197,748		
4750-Low Voltage			
4751-Smart Metering Entity Charge	$18,950	$322,910	$238,211
Total COP	$77,725,426	$75,169,281	$68,008,842
GS>50kW for 34.5kV	($4,847,999)	($5,034,460)	($4,582,157)
Adjusted COP	$72,877,427	$70,134,821	$63,426,685
	2.70%	2.70%	2.70%
Projected COP Savings	$1,967,691	$1,893,640	$1,712,521
Difference from 2018 CoS COP Savings		$74,050	$255,170
Net benefit to customers	$205,617	$131,567	($49,553)

Staff-66

Reference: EB-2018-0219, Appendix J

Preamble:

Appendix J notes the use of Bellwether meters to report voltage and other data. For VVO, there is a need for Bellwether meter voltage readings at, or close to, the end of the feeder.

Questions:

(a) OEB staff notes that alternate end of feeder locations can be created during abnormal configurations i.e. when a faulted feeder is sectionalized and load from the non-faulted section is transferred to another feeder. Please confirm that alternate end of feeder locations must still be kept within CSA voltage limits and whether PUC Distribution has accounted for this aspect of design.

(b) How does this impact the number of voltage readings that are required of the AMI system and can this system accommodate the frequency of readings required (more than hourly) by the VVO application?

Response:

(a) PUC Distribution confirms that alternate end of feeder locations will be kept within CSA voltage limits.

(b) The frequency of voltage readings required for VVO control will be tuned during commissioning and monitored on the actual voltage readings from the smart meters.

Staff-67

Reference: EB-2018-0219, Appendix C, Utility Distribution Microgrid: AMI Integration, Section 4.3.3

Preamble:

Section 4.3.3 of Appendix C states that the SSG Project will need to improve the granularity of voltage measurement readings to an hourly frequency.

Questions:

(a) Given that voltage fluctuates and is affected by customer electricity consumption at any given time, are hourly voltage readings sufficient to maintain voltages within CSA limits during the hour between voltage readings?

(b) Does PUC Distribution have any contingencies or protections in place within its VVO control schema to address any risks described in (a)?

(c) Will any of contingency/protection techniques described in (b) affect the expected benefits of VVO?

Response:

(a) The frequency of voltage readings required for VVO control will be tuned during commissioning and monitored on the actual voltage readings from the smart meters.

(b) Yes, PUC Distribution has contingencies and protections in place within its VVO control schema to address risks described in (a).

(c) No, the contingencies will not affect the benefits of VVO.

Staff-68

Reference: EB-2018-0219, Appendix C - Utility Distribution Microgrid: AMI Integration, Section 4.4.5

Preamble:

In the Leidos Report on AMI Integration, section 4.4.5 notes that: “data analytics will be performed from Leidos datacenters in the USA.” The analytics platform will consume customer information and store this data in the USA.

Question:

Please explain how PUC Distribution will address the differences in privacy laws between Canada and the USA and concerns about data privacy associated with sending customer data to the USA.

Response:

Data privacy will be addressed through contractual requirements and updates to PUC Distribution’s Conditions of Service as needed.

ICM Model

Staff-69

Reference: EB-2018-0219, ICM Model, Tab 1 – Information Sheet

Question:

Please provide an updated ICM Model with the IPI applicable to 2019 applications (i.e. 1.50%).

Response:

PUC Distribution has attached an updated ICM Model with the IPI applicable to 2019 applications (Appendix 2).

Staff-70

Reference 1: EB-2018-0219, ICM Model, Tab 6 – Rev_Requ_Check
Reference 2: EB-2017-0071, 2018 Cost of Service Application, Revenue Requirement Workform (RRWF)

Preamble:

OEB staff is unable to reconcile the OM&A expenses of $11,543,633, as filed in the ICM Model, to PUC Distribution's RRWF from its 2018 cost of service proceeding which indicates a figure of $11,474,633.

Question:

Please explain this discrepancy.

Response:

The amount of $11,474,633 does not include LEAP funding of $24,000 and taxes other than income taxes of $45,000. As per page 14 of the approved Settlement Proposal and the PUC_2018 Settlement_Rev_Reqt_Work_Form Tab 4 and Tab 5 (see highlighted cells below), total controllable expenses are $11,543,633.

Utility Income

Line No.	Particulars		Per Board Decision
	Operating Revenues:		
1	Distribution Revenue (at Proposed Rates)		$19,190,366
2	Other Revenue	(1)	$2,698,600
3	Total Operating Revenues		$21,888,966
	Operating Expenses:		
4	OM+A Expenses		$11,474,633
5	Depreciation/Amortization		$3,780,329
6	Property taxes		$45,000
7	Capital taxes		$ -
8	Other expense		$24,000
9	Subtotal (lines 4 to 8)		$15,323,962
10	Deemed Interest Expense		$2,390,597
11	Total Expenses (lines 9 to 10)		$17,714,559
12	**Utility income before income taxes**		$4,174,407
13	Income taxes (grossed-up)		$586,716
14	**Utility net income**		$3,587,691

Consumers Council of Canada Interrogatories

CCC-1

Reference: Ex. Manager's Summary, p. 16

Question:

Please provide the application that was submitted to NRCan and any additional documentation provided to NRCan in support of the Application. On what basis did NRCan choose to support the SSG project? Please provide all correspondence between NRCan and PUC Distribution regarding this project.

Response:

Please see attached the application and the Contribution Agreement (Appendix 1) and NRCan Application (Appendix 3) submitted to NRCan. PUC Distribution is not aware of the basis of NRCan's decision in choosing to support the SSG project.

CCC-2

Reference: ICM Application, p. 5

Question:

Is PUC, through this Application guaranteeing that the implementation of the Sault Smart Grid Project (SSG Project) will result in “no net bill increases”? If so, how? At what point will the project result in no net bill increases? How is the concept of “no net bill increases” to be assessed. Does the concept of “no net bill increases” apply to all customer rate classes? If not, please explain.

Response:

PUC Distribution is not guaranteeing that the implementation of the SSG Project will result in “no net bill increases”. Please refer to the ICM Application, Appendix 11, page 12, Table 2: Customer Bill Impacts which outlines at what consumptions rate classes will result in no net bill increases.

Please refer to Staff-43 (a) for an explanation of the “no net bill increase” concept.

CCC-3

Reference: ICM Application, p. 5

Question:

Did other Ontario LDCs apply for funding through this program? If, so, how many of those LDCs secured funding? Please provide a list of any other successful applicants and the nature of their arrangements with NRCan.

Response:

PUC Distribution does not have knowledge of who applied to the NRCan Program.

CCC-4

Reference: ICM Application, p. 5

Question:

How was the $11.8 million amount for NRCan funding arrived at? If the NRCan funding is dependent upon OEB approval for the SSG project, when will the project begin?

Response:

Please refer to Staff-28 (f) which details how the NRCan funding amount was arrived at. The project will begin as soon as the OEB approval is granted.

CCC-5

Reference: ICM Application, p. 7

Question:

The evidence states that in the first quarter of 2014 the City of Sault Ste. Marie Council passed a resolution supporting the concept of developing a smart grid in PUC Distribution's service area. Please provide a copy of that initial resolution and all materials provided to the City Council at that time. When did the City Council last review this project and what were the overall project costs submitted at that time?

Response:

Resolution: [http://saultstemarie.ca/Cityweb/media/City-Clerk/Council-Agendas/2014/2014_01_20_MINUTES.pdf?ext=.pdf]

Presentation: [http://saultstemarie.ca/Cityweb/media/City-Clerk/Council-Agendas/2014/2014_01_20_AGENDA.pdf?ext=.pdf]

Presentation to City Council were about development in Sault Ste. Marie were much broader than the specific PUC Distribution smart grid project. The ICM application relates specifically to the PUC Distribution smart grid project and does not encompass the vision of the potential developments in Sault Ste. Marie. This project and project costs were not specifically presented to city council.

CCC-6

Reference: ICM Application, p. 12

Question:

Please explain how the Customer Bill Impacts were calculated? Please include all assumptions. Please provide a 10-year forecast of the Customer Bill Impacts for each of the rate classes and consumption levels provided in Table 2.

Response:

The bill impacts were calculated by comparing:

i) the proposed rates from the ICM request at various consumption levels, excluding any increase due to the SSG (i.e. removing the Phase 1 revenue) to

ii) the proposed rates from the ICM request plus the effect of the full SSG project at consumption levels 2.7% less for RTSR Network charge, Wholesale Market Service Charge, Rural and Remote Rate Protection and energy charge (i.e. reduced consumption due to the SSG project). See the following example of a 750 kWh customer. This same method was used for the other listed consumption levels.

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION							
RPP / Non-RPP:	RPP							
Consumption	**750**	**kWh**	**Consumption Decrease %**	2.70%	**Proposed consumption**		**730**	
Demand	**-**	**kW**						
Current Loss Factor	**1.0481**							
Proposed/Approved Loss Factor	**1.0481**							
	Proposed			**Proposed - ICM**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 28.17**	1	$ 28.17	$ 28.17	1	$ 28.17	$ -	0.00%
Distribution Volumetric Rate	**$ 0.0043**	750	$ 3.23	$ 0.0043	730	$ 3.14	$ (0.09)	-2.70%
Fixed Rate Riders	**$ (1.35)**	1	$ (1.35)	$ (1.35)	1	$ (1.35)	$ -	0.00%
ICM - Fixed	**$ -**	1	$ -	$ 3.06	1	$ 3.06	$ 3.06	
Volumetric Rate Riders	**$ 0.0007**	750	$ -	$ 0.0007	730	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 30.05**			**$ 33.01**	**$ 2.97**	**9.88%**
Line Losses on Cost of Power	**$ 0.0820**	36	$ 2.96	$ 0.0820	35	$ 2.88	$ (0.08)	-2.71%
Total Deferral/Variance Account Rate Riders	**($0.0067)**	750	$ -	-$ 0.0067	730	$ -	$ -	
CBR Class B Rate Riders	**$ -**	750	$ -	$ -	730	$ -	$ -	
GA Rate Riders	**$ -**	750	$ -	$ -	730	$ -	$ -	
Low Voltage Service Charge	**$ -**	750	$ -		730	$ -	$ -	
Smart Meter Entity Charge (if applicable)	**$ 0.57**	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	**$ -**	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	**-$ 0.0004**	750	$ (0.30)	-$ 0.0004	730	$ (0.29)	$ 0.01	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.27**			**$ 36.17**	**$ 2.90**	**8.71%**
RTSR - Network	**$ 0.0059**	786	$ 4.64	$ 0.0059	765	$ 4.51	$ (0.13)	-2.70%
RTSR - Connection and/or Line and Transformation Connection	**$ -**	786	$ -	$ -	765	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 37.91**			**$ 40.68**	**$ 2.77**	**7.31%**
Wholesale Market Service Charge (WMSC)	**$ 0.0034**	786	$ 2.67	$ 0.0034	765	$ 2.60	$ (0.07)	-2.70%
Rural and Remote Rate Protection (RRRP)	**$ 0.0005**	786	$ 0.39	$ 0.0005	765	$ 0.38	$ (0.01)	-2.70%
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)	**$ -**		$ -			$ -	$ -	
TOU - Off Peak	**$ 0.0650**	488	$ 31.69	$ 0.0650	474	$ 30.83	$ (0.86)	-2.70%
TOU - Mid Peak	**$ 0.0940**	128	$ 11.99	$ 0.0940	124	$ 11.66	$ (0.32)	-2.70%
TOU - On Peak	**$ 0.1320**	135	$ 17.82	$ 0.1320	131	$ 17.34	$ (0.48)	-2.70%
Total Bill on TOU (before Taxes)			**$ 102.72**			**$ 103.75**	**$ 1.03**	**1.00%**
HST	13%		$ 13.35	13%		$ 13.49	$ 0.13	1.00%
8% Rebate	8%		$ (8.22)	8%		$ (8.30)	$ (0.08)	
Total Bill on TOU			**$ 107.86**			**$ 108.94**	**$ 1.08**	**1.00%**
			$ 107.86			$ 108.94	$ 1.08	1.00%

PUC is unable to provide the requested 10-year bill comparisons as it is not possible to predict such items as the timing of COS rebasings, future load forecasts, future cost allocations, regulated rate design, regulated interest rates, rates of return, etc.

The main driver effecting PUC rates is the capital cost of the SSG project. PUC has provided cost comparisons that include the entire increase to the rate base and the resulting consumption savings as a result of the SSG. Please refer to ICM Application, Page 12, Table 2 for customer bill impacts. Since the SSG is included in its entirety in theses comparisons, it is not expected to effect rate changes in future years.

CCC-7

Reference: ICM Application, p. 13

Question:

The evidence states that if the OEB does not approve this ICM, PUC Distribution would not proceed with the SSG Project and any NRCan funding would be forfeited. How much has been spent on the project to date? In the event the OEB does not approve the ICM project, how will the costs be recovered?

Response:

To date, PUC Distribution has spent $535,118 on the SSG project. In the event the OEB does not approve the ICM project, expenditures that can support future capital projects will be recovered through rates. Some expenditures will not be recovered.

CCC-8

Reference: ICM Application, p. 14

Question:

Please describe the North American Grid Modernization Fund and its mandate. How will the SSG Project be "initially funded" through this fund? Please provide a more detailed description of the contractual relationships among SSG Inc., the North American Grid Modernization Fund, Stonepeak Infrastructure Partners, Infrastructure Energy LLC, Black & Veatch and PUC Distribution Inc.

Response:

Please refer to Staff-31 for a description of the organizational structure of the project and funding flows to each company involved.

CCC-9

Reference: ICM Application, p. 15

Question:

Please explain why Voltage/VAR Optimization, Distribution Automation, and AMI integration are not normal distribution initiatives. Why should expenditures on these initiatives qualify as a discrete ICM project?

Response:

Please refer to page 10, lines 7-18 of the ICM Application and also the Options Analysis in Section 7 - Prudence of the ICM Application beginning on page 38.

CCC-10

Reference: ICM Application, p. 28

Question:

The total capital cost of the SSG project is estimated to be $34.4 million. The evidence states that the risk of cost overruns will be borne by the developer and their EPC contractor. If there are cost savings related to the project who will benefit from those savings?

Response:

The SSG project is a fixed price turn key style project with PUC Distribution in which any savings to be had in implementation of the project, will be the benefit of the EPC contractor. If there are costs overruns, this will be borne by the EPC contractor.

CCC-11

Reference: ICM Application, p. 28

Question:

Please provide a list of all factors that could delay the in-service date of the SSG project? How confident is PUC Distribution that the project will be in service in December 2019?

Response:

Factors that could delay the in-service date of the SSG project include:

- Approval processes;
- Weather; and
- Unforeseen system operating constraints.

PUC Distribution is confident that a substantial portion of the SSG capital expenditures can be in service for December 31, 2019.

CCC-12

Reference: ICM Application, p. 35

Question:

Please describe all customer engagement activities PUC Distribution undertook regarding this project. Please provide all materials related to that customer engagement.

Response:

Please refer to Staff-55 and PUC Distribution's 2018 COS EB-2017-0071 – Exhibit 1, Appendix 9 and 10 for a description and all materials related to customer engagement activities regarding this project.

CCC-13

Reference: ICM Application, pp. 36-37

Question:

PUC Distribution has provided a list of benefits to its customers arising from the SSG project. Please quantify, to the extent, possible, those benefits.

Response:

Please refer to the ICM Application, Appendix 11, page 11, Table 1 – Customer Benefit Summary and the ICM Application, Appendix 11, Appendix H, page 61 – Project Benefit Estimate for quantitative analysis of the benefits to customers arising from the SSG project.

CCC-14

Reference: ICM Application, p. 38

Question:

Please explain to what extent the NRCan funding is dependent upon a two-year project development term. If the OEB directed the project to be undertaken over a longer period of time how would this impact the NRCan funding. To what extent is the project viable without the NRCan funding?

Response:

The NRCan Funding is defined within the signed Contribution Agreement (Appendix 1). Please refer to Staff-22 (c) for discussion on the selected two-year project term and the impact of extending the project over a longer time period. Without NRCan funding, PUC Distribution would not achieve the net zero bill target and would not proceed with the project.

<u>CCC-15</u>

Reference: ICM Application, p. 38

Question:

Please provide the estimated annual savings, in detail, for PUC Distribution's ratepayers in 2019 and 2020.

Response:

PUC Distribution ratepayers will not incur savings in 2019. For savings in 2020-2021, please refer to the ICM Application, Appendix 11, page 11, Table 1 – Customer Benefit Summary and the ICM Application, Appendix 11, Appendix H, page 61 – Project Benefit Estimate for quantitative analysis of the benefits to customers arising from the SSG project.

CCC-16

Reference: None

Question:

Please provide a detailed list of PUC Distribution's actual capital expenditures for the period 2009-2019

Response:

Following are the Capital Projects Tables, Appendix 2-A from PUC Distribution's 2013 COS Rate Application EB-2012-0162 and Appendix 2-AA from PUC Distribution's 2018 COS Rate Application EB-2017-0071.

File Number:	EB-2012-0162
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-A
Capital Projects Table

PROJECTS	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
TRANSMISSION							
Reconstruct GLPT Line	209,134						
Transmission station equipment	15,308	325,804					
Sub-Total	224,442	325,804	0	0	0	0	0
RECONSTRUCT MANHOLES							
Reconstruct undersized manholes/vault	73,460					161,164	159,833
Sub-Total	73,460	0	0	0	0	161,164	159,833
ROAD RECONSTRUCTION							
New road reconstruction	12,204						
Sub-Total	12,204	0	0	0	0	0	0
LAND & EASEMENTS							
Easement purchases	1,215	1,071	2,259	10,909	5,539		
Land purchases							
Sub-Total	1,215	1,071	2,259	10,909	5,539	0	0
LINES & SWITCHES							
Misc. Lines and Switches	502,842	772,751	1,270,548				
Sub-Total	502,842	772,751	1,270,548	0	0	0	0
METERS							
Upgrade Wholesale Meters	65,150	81,885		10,495	37,058		
Wholesale Metering Points	81,873	70,635	72,189	137,654	1,282,316		
Meter Installations						322,327	319,666
Sub-Total	147,023	152,520	72,189	148,149	1,319,374	322,327	319,666
INSTALL UNDERGROUND SERVICES							
New Subdivision Underground Distribution	270,694	602,805	268,633	103,321	105,480		
Sub-Total	270,694	602,805	268,633	103,321	105,480	0	0
REPLACE WOOD POLES							
Replace wood poles	366,778	396,043	614,650	904,749	1,165,055	537,212	799,166
Sub-Total	366,778	396,043	614,650	904,749	1,165,055	537,212	799,166
NEW SERVICES							
Install Service - Customer demand	922,868	1,137,668	1,714,670	2,294,967	2,114,198	648,953	643,595
Install Commercial Services							
Extend 35kV to Starwood SSM2 & SSM3					4,028,633		
Sub-Total	922,868	1,137,668	1,714,670	2,294,967	6,142,831	648,953	643,595

VOLTAGE CONVERSION							
Reconstruct Substation 10						2,847,226	
Voltage Conversion Programs							1,763,492
Sub-Total						2,847,226	1,763,492
UPGRADES							
Transporation Corridor	30,003						
Replace porcelain side-post insulators			111,353	110,127	111,111	214,885	213,111
Replace restricted wire			59,808	102,034	132,735	537,212	532,777
Install reclosures and/or FCI's		3,829	58,066	13,876			
Replace failure defective ceramic disconnects						214,885	213,111
Install Substation 15 Transformer				561,776			
Underground Cables Remediation Program						537,212	958,998
Replace distribution switches and padmount gear				220,339	114,915	107,442	106,555
Extend 35 kV to POD Generating Group							
PCB Removal Program						161,164	159,833
Sub-Total	30,003	3,829	229,227	1,008,152	358,761	1,772,800	2,184,385
CONSERVATION							
Demand Side Mangement Program	50,812	2,684					
Sub-Total	50,812	2,684	0	0	0	0	0
RELOCATE POLE LINES							
Relocate pole lines - Hudson Street	7,441						
Sub-Total	7,441	0	0	0	0	0	0
SUBSTATIONS							
Convert to 12 kV - Sub 5	437,969	337,521					
Upgrade Sub Relays	43,007						
Purchase Substation Grounding Devices	9,500		34,382	101,491			
Improvements at Substation 18	62,046	210,046		212,599			
Replace substation switches and breakers				1,543	4,918	139,675	530,000
Replace underground station cables						537,212	319,666
Station Equipment	117,711	82,652	397,223				988,415
Replace SCADA system				46,498	41,856		266,389
Convert to 12 kV in Sub 17			419,712	131,379			
TS1 upgrades and repairs							
Replace 12 kV breakers				71,041	1,838		
Replace cables at Sub 11				160	7,555		
Install transfer-trip at TS1				961	112,430		
Upgrade sub 19 switching				11,103			
Purchase transformer for Sub 13				253,267			
Convert to 12 kV in the Sub 14 area					122,777		
Sub-Total	670,233	630,219	851,317	830,042	291,374	676,887	2,104,470
NEW BUILDINGS							
New Service Centre						23,000,000	
Sub-Total	0	0	0	0	0	23,000,000	0
MISCELLANEOUS CAPITAL WORKS	266,979	216,090	367,238	504,823	178,358		
Adjustment to actual 2012 expenditures as per settlement						-355,398	
Total	**3,546,994**	**4,241,484**	**5,390,731**	**5,805,112**	**9,566,772**	**29,611,171**	**7,974,607**

File Number:	EB-2017-0071
Exhibit:	2
Tab:	
Schedule:	
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Appendix 2-AA
Capital Projects Table

Projects	2013 Board Approved	2013	2014	2015	2016	2017 Bridge Year	2017	2018 Test Year
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
New Services & Subdivisions								
Land Rights (Formally known as Account 1906)			3,411		1,736	1,057	5,268	1,138
Buildings								
Transformer Station Equipment >50 kV		10,633		14,422		5,143		5,541
Distribution Station Equipment <50 kV			41		468	104	524	113
Poles, Towers & Fixtures	799,166	256,877	401,663	184,799	274,915	229,541	95,521	247,298
Overhead Conductors & Devices		64,863	200,363	70,055	101,891	89,737	93,696	96,679
Underground Conduit		114,781	177,913	39,290	37,655	75,874	85,536	81,744
Underground Conductors & Devices		107,784	171,551	209,801	94,176	119,734	142,631	128,997
Line Transformers		238,554	367,159	418,565	279,567	267,636	216,824	288,341
Services (Overhead & Underground)	643,595	810,182	527,136	357,901	347,857	419,376	365,987	451,820
Meters		799	76	10,431	1,376	2,603	15,530	2,805
Sub-Total	**1,442,761**	**1,604,473**	**1,849,313**	**1,305,264**	**1,139,641**	**1,210,805**	**1,021,517**	**1,304,476**
Joint Use								
Poles, Towers & Fixtures		1,132,205	1,010,215	74,737	35,201	86,257	105,436	123,906
Overhead Conductors & Devices		114,063	66,940		28,982	8,042	37,263	11,552
Line Transformers		19,507	10,386	-4,856	8,696	1,292		1,856
Sub-Total	**0**	**1,265,775**	**1,087,540**	**69,881**	**72,879**	**95,590**	**142,699**	**137,313**
Meters								
Transformer Station Equipment >50 kV					529	220		146
Line Transformers					11,410	4,740	12,473	3,157
Services (Overhead & Underground)			561			233		155
Meters	319,666	229,274	139,712	42,513	82,277	205,105	76,378	136,601
Sub-Total	**319,666**	**229,274**	**140,273**	**42,513**	**94,217**	**210,298**	**88,851**	**140,060**
City Projects								
Poles, Towers & Fixtures			41,491	63,781	15,328	19,709	62,878	22,649
Overhead Conductors & Devices			8,524	24,949	11,466	7,344	90,909	8,440
Underground Conduit		12,345	78,700	120,026	86,962	48,705	9,373	55,971
Underground Conductors & Devices		213,579	348,298	379,454	41,381	160,597	2,585	184,556
Line Transformers			10,421	-1,654	-3,118	923		1,061
Services (Overhead & Underground)			10,198		180	1,696		1,949
Sub-Total	**0**	**225,924**	**497,632**	**586,556**	**152,198**	**238,975**	**165,745**	**274,627**
Distribution Overhead Renewal								
Land Rights (Formally known as Account 1906)			3,387			450		483
Distribution Station Equipment <50 kV			224		-96,685	-12,806		-13,752
Poles, Towers & Fixtures		166,342	631,378	644,093	355,614	238,631	409,840	256,256
Overhead Conductors & Devices		84,447	187,156	310,734	210,691	105,284	83,344	113,061
Underground Conduit		48,061	515		850	6,562		7,047
Underground Conductors & Devices			18,303	32,261	15,357	8,752		9,398
Line Transformers		30,758	122,900	40,144	128,906	42,844	60,225	46,008
Services (Overhead & Underground)					1,465	195		209
Meters		13,967				1,854		1,991
System Supervisor Equipment		1,154				153		165
Sub-Total	**0**	**344,730**	**963,864**	**1,027,231**	**616,199**	**391,918**	**553,409**	**420,865**
Distribution Underground Renewal								
Land Rights (Formally known as Account 1906)					4,740	940		
Poles, Towers & Fixtures		106	6,556	2,026	21,084	5,905	1,319	
Overhead Conductors & Devices		923		2,060	226	636	7,594	
Underground Conduit		50,542	17,968	128,515	86,025	56,141		
Underground Conductors & Devices	159,833	14,008	43,641.17	145,481.57	149,431.11	69,928	39,074	
Line Transformers			9,389.49	117,080.24	114,162.51	47,728	607	
Services (Overhead & Underground)		1,726				342		
Sub-Total	**159,833**	**67,304**	**77,555**	**395,164**	**375,669**	**181,621**	**48,594**	**0**
Forced Overhead Renewal								
Poles, Towers & Fixtures		174,753	145,135	107,906	155,818	177,116	265,935	190,818
Overhead Conductors & Devices		70,826	28,380	30,341	42,914	52,339	55,720	56,388
Underground Conduit				46	2,390	740		797
Underground Conductors & Devices				1,075	3,834	1,490		1,605
Line Transformers		40,398	8,804	40,494	72,397	49,192	99,164	52,998
Services (Overhead & Underground)		1,572	3,662			1,588	781	1,711
Meters		12,886	1,300			4,305		4,638
Sub-Total	**0**	**300,434**	**187,280**	**179,862**	**277,353**	**286,770**	**421,600**	**308,955**
Forced Underground Renewal								
Overhead Conductors & Devices					2,011	1,299		1,575
Underground Conductors & Devices					23,637	15,271	92,560	18,509
Line Transformers	958,998			132,840	236,062	238,336	306,023	288,871
Sub-Total	**958,998**	**0**	**0**	**132,840**	**261,710**	**254,906**	**398,583**	**308,955**
Restricted Wire Replacement								
Poles, Towers & Fixtures	532,777	166,908	23,679	130,895	372,010	274,814	400,224	418,175
Overhead Conductors & Devices		195,224	59,650	90,998	371,776	284,386	408,070	432,741
Line Transformers		15,436	12,128	36,009	133,426	78,066	81,726	118,790
Sub-Total	**532,777**	**377,568**	**95,458**	**257,902**	**877,211**	**637,266**	**890,020**	**969,706**

School Energy Coalition (SEC) Interrogatories

SEC-1

Reference: None

Question:

SEC is interested in better understanding the rate impacts of the proposed ICM projects. For a typical school in the GS>50 kW class with 100kW of monthly demand, please confirm:

(a) The annual total of monthly fixed charges and volumetric charges at proposed 2019 rates, excluding the ICM riders, is $9,548.16 ($115.66 monthly fixed charge plus $6.802/kW demand charge).

(b) At that level, for a customer with those characteristics, only Hydro One, Toronto Hydro, Algoma Power and Canadian Niagara Power would have higher rates in 2019.

(c) The Applicant is proposing to increase the charges for that customer for the ICM projects by $250.44 in 2019 ($3.03 monthly fixed plus $0.1784/kW demand), a 2.62% incremental increase.

(d) The Applicant is proposing to increase the charges for that customer for the ICM projects by a further $1,163.76 in 2020 ($14.08 monthly fixed plus $0.8290/kW demand, bringing the total two year increase – not including the normal IRM increase – to 14.81%.

Response:

(a) PUC Distribution confirms the annual total of monthly fixed charges and volumetric charges at proposed 2019 rates is $9,548.16.

GS>50 kW class	100	kW	
	Proposed		
	Rate ($)	Volume	Charge ($)
Monthly Service Charge	$ 115.66	1	$ 115.66
Distribution Volumetric Rate	$ 6.8002	100	$ 680.02
			$ 795.68

$795.68 monthly x 12 months = $9,548.16

(b) Not confirmed - PUC Distribution rates include transformation connection costs which are not included in most other LDC distribution charges, but instead are recovered as part of the RTSR. This skews a comparison of distribution charges, as shown in Appendix B of the Board approved settlement in EB-2017-0071. PUC distribution customers pay $0 for Tx Connection charges because those costs are accounted for in distribution rates.

(c) Please see response below.

(d) Please see response below.

The following bill impact was calculated by comparing:

i) the proposed rates from the ICM request at various consumption levels, excluding any increase due to the SSG (i.e. removing the Phase 1 revenue) to
ii) the proposed rates from the ICM request plus the effect of the full SSG project at consumption levels 2.7% less for RTSR Network charge, Wholesale Market Service Charge, Rural and Remote Rate Protection and energy charge (i.e. reduced consumption due to the SSG project).

This comparison provides the impact to a 100 kW customer upon full implementation of the SSG including the increase to distribution rates and the energy and other related savings.

Customer Class:	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION				
RPP / Non-RPP:	Non-RPP (Other)				
Consumption	46,000 kWh	Consumption Decrease %	2.70%	Proposed consumption	97 Kw
Demand	100 kW			Proposed consumption	44,758 KwH
Current Loss Factor	1.0481				
Proposed/Approved Loss Factor	1.0481				

	Proposed			Proposed - ICM			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 115.66	1	$ 115.66	$ 115.66	1	$ 115.66	$ -	0.00%
Distribution Volumetric Rate	$ 6.8002	100	$ 680.02	$ 6.8002	97	$ 661.66	$ (18.36)	-2.70%
RRRP Credit	$ -	100	$ -		97	$ -	$ -	
DRP Adjustment	$ -	100	$ -		97	$ -	$ -	
Fixed Rate Riders	$ (4.74)	1	$ (4.74)	$ (4.74)	1	$ (4.74)	$ -	0.00%
ICM Fixed	$ -	1	$ -	$ 11.16	1	$ 11.16	$ 11.16	
ICM Variable	$ -	100	$ -	$ 0.6563	97	$ 63.86	$ 63.86	
Volumetric Rate Riders	-$ 0.0927	100	$ -	-$ 0.0927	97	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 790.94**			**$ 847.60**	**$ 56.66**	**7.16%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 2.6185	100	$ -	-$ 2.6185	97	$ -	$ -	
CBR Class B Rate Riders	$ -	100	$ -	$ -	97	$ -	$ -	
GA Rate Riders	$ 0.0026	46,000	$ -	$ 0.0026	44,758	$ -	$ -	
Low Voltage Service Charge	$ -	100	$ -		97	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	-$ 0.0004	46,000	$ (18.40)	-$ 0.0004	44,758	$ (17.90)	$ 0.50	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 772.54**			**$ 829.70**	**$ 57.16**	**7.40%**
RTSR - Network	$ 2.2323	100	$ 223.23	$ 2.2323	97	$ 217.20	$ (6.03)	-2.70%
RTSR - Connection and/or Line and Transformation Connection	$ -	100	$ -	$ -	97	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 995.77**			**$ 1,046.90**	**$ 51.13**	**5.13%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	48,213	$ 163.92	$ 0.0034	46,911	$ 159.50	$ (4.43)	-2.70%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	48,213	$ 24.11	$ 0.0005	46,911	$ 23.46	$ (0.65)	-2.70%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)			$ -			$ -	$ -	
TOU - Off Peak	$ 0.0650	-	$ -	$ 0.0650	-	$ -	$ -	
TOU - Mid Peak	$ 0.0940	-	$ -	$ 0.0940	-	$ -	$ -	
TOU - On Peak	$ 0.1320	-	$ -	$ 0.1320	-	$ -	$ -	
Non-RPP Retailer Avg. Price	$ 0.1101	100	$ 11.01	$ 0.1101	97	$ 10.71	$ (0.30)	-2.70%
Average IESO Wholesale Market Price	$ 0.1101	48,213	$ 5,308.21	$ 0.1101	46,911	$ 5,164.89	$ (143.32)	-2.70%
Total Bill on TOU (before Taxes)			**$ 6,492.26**			**$ 6,394.99**	**$ (97.27)**	**-1.50%**
HST	13%		$ 843.99	13%		$ 831.35	$ (12.64)	-1.50%
Total Bill on TOU			**$ 7,336.25**			**$ 7,226.34**	**$ (109.91)**	**-1.50%**

SEC-2

Reference: None

Question:

Please confirm that, for a residential customer, the rate increase proposed for the ICM projects, over 2019 and 2020, is $56.28 per year, over and above any IRM increases in those years.

Response:

Below is the total bill impact for a residential customer consuming 750 kWhs per month which includes the full rate increase due to the SSG.

The bill impact was calculated by comparing:

i) the proposed rates from the ICM request, excluding any increase due to the SSG (i.e. removing the Phase 1 revenue) to
ii) the proposed rates from the ICM request plus the effect of the full SSG project at consumption levels 2.7% less for RTSR Network charge, Wholesale Market Service Charge, Rural and Remote Rate Protection and energy charge (i.e. reduced consumption due to the SSG project).

The annual increase to distribution charges for a residential customer is $36.68 ($3.06*12). As per the bill impact calculation below, it is expected that the SSG will result in a consumption reduction of 2.7%. The overall bill increase for a residential 750 kWh customer would be $1.08 per month or $12.97 annually.

A residential customer consuming 1,130 kWhs per month would have a distribution charge increase of $36.68 as per above, but would as a result of reduced consumption, experience no change in their total bill.

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION							
RPP / Non-RPP:	RPP							
Consumption	750	kWh	Consumption Decrease %	2.70%	Proposed consumption		730	
Demand	-	kW						
Current Loss Factor	1.0481							
Proposed/Approved Loss Factor	1.0481							

	Proposed			Proposed - ICM			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 28.17	1	$ 28.17	$ 28.17	1	$ 28.17	$ -	0.00%
Distribution Volumetric Rate	$ 0.0043	750	$ 3.23	$ 0.0043	730	$ 3.14	$ (0.09)	-2.70%
Fixed Rate Riders	$ (1.35)	1	$ (1.35)	$ (1.35)	1	$ (1.35)	$ -	0.00%
ICM - Fixed	$ -	1	$ -	$ 3.06	1	$ 3.06	$ 3.06	
Volumetric Rate Riders	$ 0.0007	750	$ -	$ 0.0007	730	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 30.05**			**$ 33.01**	**$ 2.97**	**9.88%**
Line Losses on Cost of Power	$ 0.0820	36	$ 2.96	$ 0.0820	35	$ 2.88	$ (0.08)	-2.71%
Total Deferral/Variance Account Rate Riders	($0.0067)	750	$ -	-$ 0.0067	730	$ -	$ -	
CBR Class B Rate Riders	$ -	750	$ -	$ -	730	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ -	730	$ -	$ -	
Low Voltage Service Charge	$ -	750	$ -		730	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	-$ 0.0004	750	$ (0.30)	-$ 0.0004	730	$ (0.29)	$ 0.01	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.27**			**$ 36.17**	**$ 2.90**	**8.71%**
RTSR - Network	$ 0.0059	786	$ 4.64	$ 0.0059	765	$ 4.51	$ (0.13)	-2.70%
RTSR - Connection and/or Line and Transformation Connection	$ -	786	$ -	$ -	765	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 37.91**			**$ 40.68**	**$ 2.77**	**7.31%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	786	$ 2.67	$ 0.0034	765	$ 2.60	$ (0.07)	-2.70%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	786	$ 0.39	$ 0.0005	765	$ 0.38	$ (0.01)	-2.70%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ -		$ -			$ -	$ -	
TOU - Off Peak	$ 0.0650	488	$ 31.69	$ 0.0650	474	$ 30.83	$ (0.86)	-2.70%
TOU - Mid Peak	$ 0.0940	128	$ 11.99	$ 0.0940	124	$ 11.66	$ (0.32)	-2.70%
TOU - On Peak	$ 0.1320	135	$ 17.82	$ 0.1320	131	$ 17.34	$ (0.48)	-2.70%
Total Bill on TOU (before Taxes)			**$ 102.72**			**$ 103.75**	**$ 1.03**	**1.00%**
HST	13%		$ 13.35	13%		$ 13.49	$ 0.13	1.00%
8% Rebate	8%		$ (8.22)	8%		$ (8.30)	$ (0.08)	
Total Bill on TOU			**$ 107.86**			**$ 108.94**	**$ 1.08**	**1.00%**
			$ 107.86			$ 108.94	$ 1.08	1.00%

SEC-3

Reference: None

Question:

Please confirm that the net increase in rate base being proposed for the ICM projects is $22,582,045, which is a 24.29% increase in the net fixed assets of the Applicant (currently $92,962,876 – ICM Model, Tab 6) over two years. Please confirm that the Applicant has never in its history increased its net fixed assets by that much over any two year period. Please advise if the Applicant is aware of any electricity distributor in the Province of Ontario that has ever increased its net fixed assets by 24.29% or more over any two year period. If the Applicant is aware of any examples, please provide details.

Response:

The net increase to rate base as a result of the SSG is $22,582,046 ($34,389,046 cost less $11,807,000 funding).

PUC's net fixed assets as per the ICM Model, Tab 6 (Appendix 2) are $92,962,876.

The proposed increase to rate base due to the SSG is 24.29% of the current rate base.

As per the audited financial statements for the years 2011, 2012 and 2013, PUC increased its net fixed assets by $39,179,097 (92.65%) from 2011 to 2013 mainly as a result of the installation of smart meters and the construction of a new building.

PUC is unable to confirm nor deny that any other electricity distributor in the Province of Ontario has ever increased its net fixed assets by 24.29% or more.

SEC-4

Reference: Application, p. 5

Question:

Please file a copy of the application to NRCan for funding (if it is anything more than Appendix A), and the Contribution Agreement dated December 2018.

Response:

Please see Attached NRCan Application and Contribution Agreement (Appendix 1 & 3).

SEC-5

Reference: Application, p. 7, 42

Question:

Please confirm that the Preliminary Design Reports, the Navigant Report #1, and the Navigant Report #2, were reviews related to a project that is materially different from the Smart Grid Program being proposed in this Application. Please specify what evidentiary conclusions the Applicant believes the Board can reach from reviewing these three documents. Please confirm that neither Leidos nor Navigant has been asked to review the project current being proposed to the Board for approval.

Response:

The Preliminary Design Reports, Navigant Report #1 and the Navigant Report #2 provide relevant review and supporting background to the current project.

The Preliminary Design Reports provide supporting evidence of the engineering analysis of the cost and benefit for the project components. Navigant's reports provide a review of the reasonableness of the cost and benefit projections.

The adjusted scope of the current project has not been reviewed by a third party.

SEC-6

Reference: Application, p. 8, 33

Question:

Please provide a detailed list of all projects in the DSP filed in EB-2017-0071 that will be altered, amended, rescheduled, or cancelled as a result of the Smart Grid proposal. For each such project, please provide details of any changes in timing, cost, and other relevant factors.

Response:

No projects in the DSP change as a result of the Smart Grid proposal.

SEC-7

Reference: Application, p. 9

Question:

Please provide, for a typical Residential, GS<50, and GS>50 customer, a comparison of bills each year from 2019 to 2028 both with and without the expenditures on the ICM Projects. Please provide details of all assumptions, and provide all calculations in Excel format.

Response:

PUC is unable to provide the requested bill comparisons as it is not possible to predict such items as the timing of COS rebasings, future load forecasts, future cost allocations, regulated rate design, regulated interest rates, rates of return, etc.

The main driver effecting PUC rates is the capital cost of the SSG project. PUC has provided cost comparisons that include the entire increase to the rate base and the resulting consumption savings as a result of the SSG. Please refer to ICM Application, Page 12, Table 2 for customer bill impacts. Since the SSG is included in its entirety in theses comparisons, it is not expected to effect rate changes in future years.

SEC-8

Reference: Application p. 10

Questions:

SEC is seeking to understand how the proposed SSG Project is "innovative". To assist the Board in that regard:

(a) Please provide details of all components of the SurvalentONE product suite that are included in the SSG Project, and the purpose and cost of each. For each of those components (e.g. OMS, VVR, IVR, ADMS, etc.), please provide details on the other Ontario electricity distributors that are using that component already.

(b) Please provide details of all components of the SSG Project that are station refurbishments or replacements, feeder refurbishments or replacements, pole replacements, or any similar distribution infrastructure activity that has been carried out by the Applicant in the past, and the cost of each.

(c) Please provide details of all components of the SSG Project that are not included in (a) or (b) above, the purpose and cost of each, and the way in which each such component is innovative.

Response:

(a) It is planned that the Distribution Management (DMS) and Outage Management System (OMS) components of the SurvalentONE product suite are included in the SSG project. Integral to the DMS component are Fault Location, Isolation & Service Restoration (FLISR) and Volt/Var Optimization (VVO). This is premised on the preliminary scope of work prepared by Leidos in Appendix C of the ICM Application and will be confirmed/finalized during the detailed engineering phase by Black & Veatch. As this is a fixed price turn-key project, PUC does not have the details of the cost of each component. PUC is not aware of what components are in use among other Ontario electricity distributors.

(b) Please refer to the ICM Application, Appendix 11, page 26, Table 3: Summary of Equipment to be Installed/Modified and the ICM Application, Appendix 11, page 27, Table 4: Equipment Quantities, of the ICM application, for details of components that will comprise the SSG Project. The only material component of the SSG Project, that would be similar to any distribution infrastructure activity that has been carried out by PUC in the past, are pole replacements. Other components of the SSG Project, such as

VVO and DA, have not been carried out at all or to any substantial degree in the past. As this is a fixed price project, PUC does not have SSG Project component costs.

(c) All substantial components of the SSG Project are included in a) or b) above.

The innovative part of this project is that performing all the work at once, as part of a larger project, a no net bill increase can be achieved while driving significant improvements in overall distribution system operations. It is also innovative in that by bundling it together, PUC qualified for significant federal funding, thereby reducing the total cost of these improvements for ratepayers.

SEC-9

Reference: Application p. 10

Question:

Please provide a list of all assets that the Applicant expects to take out of service prior to the end of their useful life as a result of the SSG Project, and the forecast net book value of each at that time. Please provide details on the accounting treatment of those assets when they are taken out of service.

Response:

Although a detailed analysis of remaining book value of assets was not prepared during the 30% design phase of the smart grid project, a preliminary review indicated that the majority of assets to be replaced are beyond their useful life.

SEC-10

Reference: Application, p. 10, 59, 62

Question:

SEC is seeking to better understand the "performance risk transfer" referred to. In this regard:

(a) Please explain in detail the purpose of SSG Inc., and confirm that it will be owned by Infrastructure Energy LLC (IE) and Stonepeak Infrastructure Partners (SPIP), and not by the Applicant.

(b) Please provide a copy of all agreements between the Applicant and SSG Inc.

(c) Please describe the role of IE in the SSG Project, and the extent to which the Applicant is relying on IE to cover the risks of the project that would otherwise be borne by the Applicant and its customers or shareholders.

(d) Please provide a copy of all agreements between SSG Inc. and IE relating directly or indirectly to the SSG Project.

(e) Please describe the role of SPIP in the SSG Project, and the extent to which the Applicant is relying on SPIP to cover the risks of the project that would otherwise be borne by the Applicant and its customers or shareholders.

(f) Please provide a copy of all agreements between SSG Inc. and SPIP (or the North American Grid Modernization Fund) relating directly or indirectly to the SSG Project.

(g) Please describe the role of Black & Veatch in the SSG Project, and the extent to which the Applicant is relying on Black & Veatch to cover the risks of the project that would otherwise be borne by the Applicant and its customers or shareholders.

(h) Please provide a copy of all agreements between Black & Veatch and SSG Inc. relating directly or indirectly to the SSG Project, including but not limited to the "Prime Contract" attached as Attachment 16.1 to Appendix J, but not included in the Application.

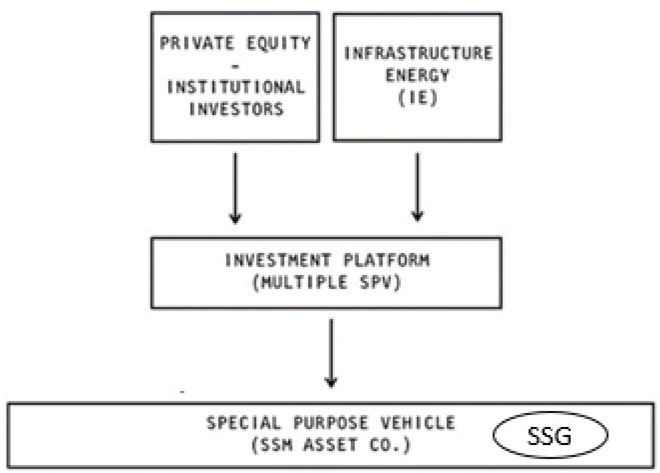
(i) With respect to each of SSG Inc., IE, SPIP, and Black & Veatch that is accepting any financial or contractual risk with respect to the SSG Project, please provide their latest audited financial statements, or other similar evidence of their financial ability to protect the Applicant, its customers and its shareholders from risk.

(j) Please provide a detailed description of what happens if the SSG Project is over budget, or performs worse than anticipated after implementation, to show who bears the cost or other risks associated with that result.

(k) Please explain why the SSG Project and the North American Grid Modernization Fund are not listed on the SPIP website as among of their active projects.

Response:

(a) SSG has not been formed. It is intended to be a special purpose vehicle (SPV) formed at financial close of the Project, as is customary for projects of this type. Stonepeak (SPIP) is no longer involved in the project. The project will be financed through a combination of long-term project finance debt and equity. The equity capital shall consist of (1) institutional investment funds managed by a joint-venture consisting of Diode Ventures LLC (an affiliate of Black & Veatch) and Alma Global Infrastructure LLC (together, the 'Investment JV') and (2) IE through contribution of its development assets to the SPV as in-kind equity participation.



(b) The current draft Project Agreement attached. Appendix 12 & 13.

(c) As lead developer partner IE has already provided all funding for Pre-Feasibility Phase of Project, Governance Approvals and Due Diligence Phase of Project, as well as commissioning the Navigant Independent Business Case Review (2015), and Navigant Independent Project Cost Review (2015). All parties are currently funding their own legal costs of negotiation related to the Project Agreement (PA) between PUC Distribution Inc., and the yet to be formed SSG, Inc., as well as the two drop down contracts, (i) the EPC Design-Build Agreement (DBA) and, (ii) Services

Agreement (SA). The latter two agreements will not be finalized until OEB regulatory approval is obtained. Project risk will be transferred to EPC Contractor and Service Provider via the two drop down contracts. Following financial close, IE will bear no further development risk on the project as its role as developer partner will be concluded.

(d) SSG Inc. will be formed at financial close of project, and as such formation documents relative to IE do not currently exist.

(e) SPIP is no longer involved with the project. Under the P3 financing structure, project construction risk will be transferred to EPC partner, and project performance risk will be transferred to Service Provider. Investment JV does not bear project risk at any time during the term of the SSG Project.

(f) SSG Inc. will be formed at financial close of project, and as such formation documents relative to the Investment JV do not currently exist.

(g) Black & Veatch ("B&V") as the EPC Contractor will have risk for the EPC design, procurement & construction for the turn key project delivery, and as such will bear Construction Phase schedule and budget risk for the SSG Project, to be defined through the PA and drop-down DBA.

(h) DBA will be drafted and executed following OEB regulatory approval, and will be substantially based on key terms and conditions excerpted from PA.

(i) SSG Inc. as SPV will bear no risk relative to the SSG Project. IE, as lead developer partner has already borne all of the development risks of the SSG Project and will bear no additional risks following financial close. B&V as EPC Contractor will bear Construction Phase schedule and budget risk for the SSG Project, to be defined through the PA and drop-down DBA. PUC Services as Service Provider will bear performance risk to be defined through the PA and drop-down SA.

(j) The project estimate includes the turn-key fixed price contract between PUC Distribution and SSG Inc. plus an estimate for the direct costs of PUC Distribution with a 10% (~$164k) contingency on PUC direct costs included. Design performance is part of the obligations through contracted risk transfer to the EPC contractor B&V.

(k) Please refer to (a) above.

<u>SEC-11</u>

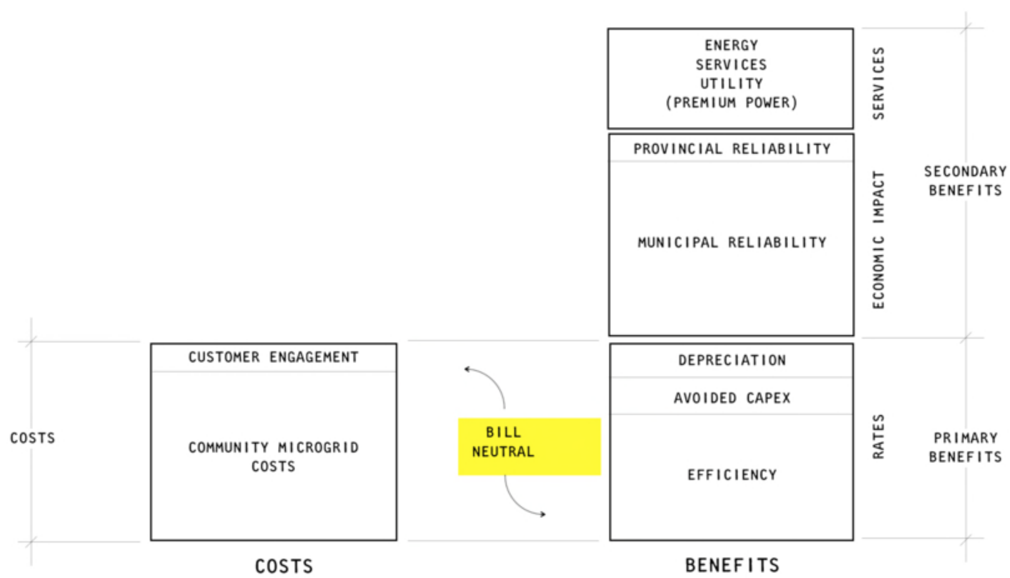
<u>Reference:</u> Application, p. 11

<u>Preamble:</u>

The schematic below is taken from the website of IE, and is intended to show the costs and benefits of a project like the SSG Project.

<u>Question:</u>

For each of the components of costs and benefits listed on the schematic, please provide the dollar amount associated with it for the SSG Project, and a reference in the Application to the support for that dollar amount.



<u>Response:</u>

PUC Distribution cannot comment on the application and interpretation of the illustration from IE website but has provided the values requested that were available for the project.

Costs:/ Benefits:	Reference to Table 1 of ICM Application
$34,389,046	Total Costs [2 year ICM Project]
$2,061,069	Efficiency [Customer & Loss savings]
$ 342,708	Avoided CAPEX [Capital savings estimate]

$ 755,171 Depreciation

$2,550,000 Reliability

~$2,000,000 Provincial Reliability [not referenced in ICM benefit other than in early review and Navigant Reports]

No value was calculated for potential benefits for service providers.

SEC-12

Reference: Application, p. 18

Question:

Please explain why the information being provided to the Board is still conceptual, if the expectation is that all or part of the SSG Project will be in-service before the end of 2019.

Response:

The ICM Application for the SSG Project includes an estimate of assets that will be in service at the end of 2019. This is based on availability of preliminary engineering work to date and forecast work that could be completed post OEB approval.

SEC-13

Reference: Application, p. 24

Question:

Please explain how the IVR is related to the smart grid, and is innovative.

Response:

PUC Distribution would not represent that the IVR application is innovative. Rather, the SSG project is innovative because performing all the work at once, as part of a larger project, a no net bill increase can be achieved while driving significant improvements in overall distribution system operations. It is also innovative in that by bundling it together, PUC qualified for significant federal funding, thereby reducing the total cost of these improvements for ratepayers.

SEC-14

Reference: Application, p. 24

Question:

Please confirm that the SCADA, AMI, and CIS are existing systems, not part of the SSG Project.

Response:

SCADA, AMI and CIS are existing systems. The SSG Project will include an upgraded SCADA platform (ADMS) and integration of AMI and CIS systems.

SEC-15

Reference: Application, p. 28, 58

Preamble:

Attached to these interrogatories is a story dated July 7, 2018, in Soo Today, which describes the SSG Project:

Questions:

(a) The story states that $14.3 million would be received in "federal and provincial support".
   i. Please confirm that this figure was communicated by the Applicant to City Council.
   ii. Please explain the change from $14.3 million to $11.8 million in the Application.
   iii. Please confirm that no provincial support is applied for or expected.

(b) The story refers to "calculations released by the energy utility". Please provide those calculations, and reconcile them with the figures in this Application.

(c) The story says engineering work will begin in the fall, with construction starting in the spring of 2019. Please confirm that these will both be later, and advise what the current schedule is.

Response:

(a) PUC Distribution can confirm this was communicated to City Council.
   i. Please refer to Staff-33 for an explanation of the change in funding.
   ii. PUC Distribution confirms that no provincial support is applied for or expected.

(b) PUC Distribution is uncertain of the calculations being referred to in the article.

(c) Preliminary engineering began in the spring of 2019 for a portion of the project. Construction will commence upon OEB Approval of this ICM Application.

SEC-16

Reference: Application, p. 30

Question:

Please extend Table 6 to include 2019, 2020, 2021, and 2022, and to include the forecast expenditures on the SSG Project in both 2019 and 2020.

Response:

The table below provides the calculation for depreciation and CCA for the capital expenditures of $5,026,797 in 2019 and $17,555,248 to complete the SSG in 2020. The CCA for the computer software is 100% in year one (1) of the expenditure; however to avoid double counting that benefit, PUC has spread the benefit over the three (3) remaining years until the next cost of service rebasing.

Calculation of Depreciation and Capital Cost Allowance
Pre Bill C 97 substantially enacted - in year of acquisition - no 1/2 year rule

YEAR 1

	Cost of Addition	Contributed Capital	Net Addition	# Years	Deprec Rate	Deprec Exp	CCA Class	CCA Rate (Class 47 @ 8%)	CCA	CCA For 2019 IRM	Undeprec Capital Cost 2020	CCA Rate	2020 CCA	Undeprec Capital Cost 2021	CCA Rate	2021 CCA	Undeprec Capital Cost 2021	CCA Rate	2022 CCA
1820 DS Equipment	$0	$0	$0	40	2.50%	$0	47	8%	$0		$0	8%	$0	$0	8%	$0	$0	8%	$0
1830 Poles & Fixtures	$1,929,153	$662,348	$1,266,805	45	2.20%	$27,870	47	8%	$101,344	$101,344	$1,165,461	8%	$93,237	$1,072,224	8%	$85,778	$986,446	8%	$78,916
1835 OH Conductors & Devices	$1,523,016	$522,906	$1,000,109	60	1.67%	$16,702	47	8%	$80,009	$80,009	$920,101	8%	$73,608	$846,493	8%	$67,719	$778,773	8%	$62,302
1840 UG Conduit/Civil	$162,455	$55,777	$106,678	50	2.00%	$2,134	47	8%	$8,534	$8,534	$98,144	8%	$7,852	$90,293	8%	$7,223	$83,069	8%	$6,646
1845 UG conductors & Devices	$0	$0	$0	40	2.50%	$0	47	8%	$0	$0	$0	8%	$0	$0	8%	$0	$0	8%	$0
1850 Line Transformers	$0	$0	$0	40	2.50%	$0	47	8%	$0	$0	$0	8%	$0	$0	8%	$0	$0	8%	$0
1920 Computer S/W	$1,158,085	$397,612	$760,473	5	20.00%	$152,095	12	100%	$760,473	$190,118	$570,354	100%	$190,118	$380,236	100%	$190,118	$190,118	100%	$190,118
1980 System Supervisory Equipment	$2,882,345	$989,613	$1,892,732	20	5.00%	$94,637	47	8%	$151,419	$151,419	$1,741,313	8%	$139,305	$1,602,008	8%	$128,161	$1,473,847	8%	$117,908
In Service Dec. 31, 2019	$7,655,053	$2,628,256	$5,026,797			$293,436			$1,101,779	$531,424			$504,120	$3,991,254		$479,000	$3,512,254		$455,889

Acct 1920 - CCA is 100% in year 1, benefit spread over 4 years for ICM

$492,608 4 year average CCA Phase 1

YEAR 2

	Cost of Addition	Contributed Capital	Net Addition	# Years	Deprec Rate	Deprec Exp	CCA Class					CCA Rate (Class 47 @ 8% plus 50%)	2020 CCA	Undeprec Capital Cost 2021	CCA Rate	2021 CCA	Undeprec Capital Cost 2021	CCA Rate	2022 CCA
1820 DS Equipment	954,428	$327,690	626,738	40	2.50%	15,668	47					8%	50,139	576,599	8%	46,128	530,471	8%	42,438
1830 Poles & Fixtures	-	$0	-	45	2.20%	-	47					8%	-	-	8%	-	-	8%	-
1835 OH Conductors & Devices	6,092,063	$2,091,625	4,000,438	60	1.67%	66,807	47					8%	320,035	3,680,403	8%	294,432	3,385,971	8%	270,878
1840 UG Conduit/Civil	40,614	$13,944	26,670	50	2.00%	533	47					8%	2,134	24,536	8%	1,963	22,573	8%	1,806
1845 UG conductors & Devices	406,138	$139,442	266,696	40	2.50%	6,667	47					8%	21,336	245,360	8%	19,629	225,732	8%	18,059
1850 Line Transformers	18,134,134	$6,226,102	11,908,032	40	2.50%	297,701	47					8%	952,643	10,955,389	8%	876,431	10,078,958	8%	806,317
1920 Computer S/W	386,028	$132,537	253,491	5	20.00%	50,698	12					100%	84,497	168,994	100%	84,497	84,497	100%	84,497
1980 System Supervisory Equipment	720,587	$247,403	473,183	20	5.00%	23,659	47					8%	37,855	435,329	8%	34,826	400,502	8%	32,040
Added to Service during 2020	26,733,992	9,178,744	17,555,248			461,735							1,468,638	16,086,611		1,357,906	14,728,704		1,256,034

Acct 1920 - CCA is 100% in year 1, benefit spread over 3 years for ICM

$1,360,859 3 year average CCA Phase 2

It is PUC’s understanding that Bill C-97, which is not yet law, includes an Accelerated Investment Incentive which will affect PUC’s CCA calculations. The incentive allows a write off of a larger share of the costs of newly acquired capital assets in the year of investment or the asset becoming available for use. The accelerated investment incentive is composed of two elements:

i) A 50% increase in the available CCA deduction for assets acquired after November 20, 2018 that become available for use before 2024, and
ii) The suspension of the CCA half-year rule for assets acquired after November 20, 2018 that become available for use before 2028.

The incentives are available only in the year of acquisition, the CCA deductions will revert to the current level in years beyond the year of acquisition.

The following table calculates the CCA deductions for phase 1 for the years 2019 to 2022 and for phase 2 for the years 2020 to 2022. The CCA for Phase 1 additions in 2019 is based on total assets put in service in 2019 (no half year rule) at a CCA rate increased by 50% (from 8% to 12%). Subsequent years for Phase 1 additions are based on the undepreciated capital cost of the Phase 1 additions (Phase 1 additions less 2019 CCA) at the normal CCA rate (8%). The CCA for Phase 2 additions in 2020 is based on total assets put in service in 2020 (no half year rule) at a CCA rate increased by 50% (from 8% to 12%). Subsequent years for Phase 2 additions are based on the undepreciated capital cost of the Phase 2 additions (Phase 2 additions less 2020 CCA) at the normal CCA rate (8%).

Since the incentive is only available in the year of acquisition, inflating year one CCA, PUC has included the four (4) year average CCA for the 2019 IRM and the three (3) year average for the total effect on rates.

Calculation of Depreciation and Capital Cost Allowance
Bill C 97 substantially enacted - in year of acquisition - add 50% to deprec rate & no 1/2 year rule

YEAR 1

	Cost of Addition	Contributed Capital	Net Addition	# Years	Deprec Rate	Deprec Exp	CCA Class	CCA Rate (Class 47 @ 8% plus 50%)	CCA	CCA For 2019 IRM	Undeprec Capital Cost 2020	CCA Rate	2020 CCA	Undeprec Capital Cost 2021	CCA Rate	2021 CCA	Undeprec Capital Cost 2021	CCA Rate	2022 CCA
1820 DS Equipment	$0	$0	$0	40	2.50%	$0	47	12%	$0		$0	8%	$0	$0	8%	$0	$0	8%	$0
1830 Poles & Fixtures	$1,929,153	$662,348	$1,266,805	45	2.20%	$27,870	47	12%	$152,017	$152,017	$1,114,789	8%	$89,183	$1,025,606	8%	$82,048	$943,557	8%	$75,485
1835 OH Conductors & Devices	$1,523,016	$522,906	$1,000,109	60	1.67%	$16,702	47	12%	$120,013	$120,013	$880,096	8%	$70,408	$809,689	8%	$64,775	$744,913	8%	$59,593
1840 UG Conduit/Civil	$162,455	$55,777	$106,678	50	2.00%	$2,134	47	12%	$12,801	$12,801	$93,877	8%	$7,510	$86,367	8%	$6,909	$79,457	8%	$6,357
1845 UG conductors & Devices	$0	$0	$0	40	2.50%	$0	47	12%	$0	$0	$0	8%	$0	$0	8%	$0	$0	8%	$0
1850 Line Transformers	$0	$0	$0	40	2.50%	$0	47	12%	$0	$0	$0	8%	$0	$0	8%	$0	$0	8%	$0
1920 Computer S/W	$1,158,085	$397,612	$760,473	5	20.00%	$152,095	12	100%	$760,473	$190,118	$570,354	100%	$190,118	$380,236	100%	$190,118	$190,118	100%	$190,118
1980 System Supervisory Equipment	$2,882,345	$989,613	$1,892,732	20	5.00%	$94,637	47	12%	$227,128	$227,128	$1,665,604	8%	$133,248	$1,532,356	8%	$122,588	$1,409,767	8%	$112,781
In Service Dec. 31, 2019	$7,655,053	$2,628,256	$5,026,797			$293,436			$1,272,432	$702,077			$490,467	$3,834,253		$466,439	$3,367,813		$444,334

Acct 1920 - CCA is 100% in year 1, benefit spread over 4 years for ICM

$525,829 4 year average CCA Phase 1

YEAR 2

	Cost of Addition	Contributed Capital	Net Addition	# Years	Deprec Rate	Deprec Exp	CCA Class					CCA Rate (Class 47 @ 8% plus 50%)	2020 CCA	Undeprec Capital Cost 2021	CCA Rate	2021 CCA	Undeprec Capital Cost 2021	CCA Rate	2022 CCA
1820 DS Equipment	954,428	$327,690	626,738	40	2.50%	15,668	47					12%	75,209	551,530	8%	44,122	507,407	8%	40,593
1830 Poles & Fixtures	-	$0	-	45	2.20%	-	47					12%	-	-	8%	-	-	8%	-
1835 OH Conductors & Devices	6,092,063	$2,091,625	4,000,438	60	1.67%	66,807	47					12%	480,053	3,520,386	8%	281,631	3,238,755	8%	259,100
1840 UG Conduit/Civil	40,614	$13,944	26,670	50	2.00%	533	47					12%	3,200	23,469	8%	1,878	21,592	8%	1,727
1845 UG conductors & Devices	406,138	$139,442	266,696	40	2.50%	6,667	47					12%	32,004	234,693	8%	18,775	215,917	8%	17,273
1850 Line Transformers	18,134,134	$6,226,102	11,908,032	40	2.50%	297,701	47					12%	1,428,964	10,479,068	8%	838,325	9,640,742	8%	771,259
1920 Computer S/W	386,028	$132,537	253,491	5	20.00%	50,698	12					100%	84,497	168,994	100%	84,497	84,497	100%	84,497
1980 System Supervisory Equipment	720,587	$247,403	473,183	20	5.00%	23,659	47					12%	56,782	416,401	8%	33,312	383,089	8%	30,647
Added to Service during 2020	26,733,992	9,178,744	17,555,248			461,735							2,160,708	15,394,540		1,302,541	14,092,000		1,205,097

Acct 1920 - CCA is 100% in year 1, benefit spread over 3 years for ICM

$1,556,115 3 year average CCA Phase 2

4 year average - Bill C 97 substantially enacted per above	$525,829
included in Sheet 10b 2019 Capital Module per above	$531,424
difference not material.	$5,695

SEC-17

Reference: Application, p. 35

Question:

Please provide details on how the Applicant proposes to report, to both customers and to the Board, on the extent to which the "key deliverables" of lowering energy use and system losses have been achieved.

Response:

PUC Distribution intends to monitor "key deliverables" of the project and will communicate the success of the project with its customers. PUC Distribution will report these deliverables to the Board is requested. Current OEB reporting includes system energy use and sales to calculate system losses.

SEC-18

Reference: Application, p. 35

Question:

Please confirm that the Applicant intends to use savings from "operational and capital program efficiencies" not to reduce rates, but for additional OM&A and capital spending "supporting asset management and cost control solutions".

Response:

PUC Distribution intends to use the savings from "operational and capital program efficiencies" to mitigate cost pressures from additional OM&A requirements related new program and regulatory requirements.

SEC-19

Reference: Application p. 37

Question:

Please explain why, if this project is in part intended to enhance economic development opportunities in Sault Ste. Marie, “there are no new customers or load growth as a result of the SSG Project”.

Response:

The SSG Project will support new customer load which has high reliability and power quality requirements. However, at this stage in the process, its it too early to create reliable forecasts of specific customer or load growth.

SEC-20

Reference: Application, p. 40

Question:

If there are no savings due to improved efficiency in 2019, why is any of the project being treated as in-service in 2019.

Response:

OEB accounting procedures treat capital assets in-service at year end as fixed assets. The plan for the project includes some assets being in service as of December 31, 2019.

SEC-21

Reference: Application, p. 42

Question:

Please provide a detailed calculation of the costs of the SSG Project that are primarily related to "upgrade PUC Distribution's grid to the industry standard", and costs that are to be incurred to implement leading edge or innovative technologies beyond industry standard.

Response:

PUC Distribution has not completed a cost breakdown calculation of these two categories proposed in this question. The reference on page 42 of the ICM Application refers to a future industry standard for LDC's to address the challenges and complexities of DER, electric vehicles etc.

SEC-22

Reference: Application, p. 11, 42

Question:

Please confirm that IE and the Applicant prepared the calculations in Table 1, and they have not been reviewed by any independent third party. Please provide the full calculations behind the figures in Table 1, and all assumptions used in generating those figures (except to the extent those calculations and assumptions are in Appendix H).

Response:

The Table 1 referenced above has been prepared by PUC Distribution as described in Appendix H. Further description of calculations and references follow.

Table 1: Customer Benefit Summary

Cost of Power - estimate from 2018 CoS rate application less 35 kV customers	$72,877,427	1
Projected consumption due to SSG implementation	2.70%	2
Projected customer savings	$1,967,691	
System Loss Reduction due to SSG implementation	$93,378	3
	$2,061,069	
Additional Revenue request due to increased SSG asset base	$1,877,976	4
Benefit of reduced future capital expenditures due to SSG implementation	($342,708)	5
Operating Efficiency benefit due to SSG implementation	($30,816)	6
Additional O & M expenses due to SSG implentation	$351,000	7
	$1,855,452	
Annual Net benefit to customers	**$205,617**	
Annual projected reliability benefit	$2,550,000	8
Total projected benefit to customers due to implementation of SSG	$2,755,617	

1. Cost of Power spreadsheet – see Appendix 4
2. Estimated $ saved on 2.7% energy at average cost of power price – see Appendix 4
3. Estimated $ on 2.6% energy saved on system losses (2.6% reduced losses - ICM Application Appendix D Navigant Report Table 8) – see Appendix 4
4. Total revenue request based on populating the ICM with the total project parameters
5. see answer to Staff-62

6. Operating savings from reduced truck rolls & less patrol time to find outages - Leidos estimate used the pre DA and post DA outage response time improvements to arrive at crew hour cost savings ~$33.5k. PUC adjusted to 90% as the more conservative value shown.

7. O&M for new operations staff for new assets/ equipment [Supv (IT/Eng) & Field crew]

	Hourly Rate	Benefits	Total Hourly	Annual Hours	Annual Cost	#	Total Cost
Supervisor	$55	25%	$68.75	2,080	$143,000	1	$143,000
Hourly Staff	$40	25%	$50.00	2,080	$104,000	2	$208,000
							$351,000

8. Leidos engineering work arrived at estimated reliability minutes on each distribution feeder with planned DA and applied $ using industry methods for an initial estimate. PUC Distribution adjusted feeders to current system design to arrive at the $2.55M figure as described in Appendix H. Methodology and $/customer minutes were reviewed by Navigant in reports provided in ICM application for reasonableness and also commented on in Appendix 7 page 11.

SEC-23

Reference: Application, p. 59

Question:

Please confirm that the Developer referred to is IE or an affiliate of IE. If not confirmed, please advise who is the Developer. With respect to IE:

(a) Please confirm that IE is a new name for Energizing Co., the previously named promoter of the project. If that is not confirmed, please describe the relationship between IE and Energizing Co., if any.

(b) Please provide a list of all other projects completed by IE, including size, location, nature of project, and other details sufficient for the Board and parties to understand the expertise being provided by IE.

Response:

(a) Energizing, LLC (aka 'Energizing Co.' or 'ECo') changed its name to Infrastructure Energy, LLC (IE). It is the same entity.

(b) Please see below for IE and Appendix 16 for B&V.

<table>
<tr><td>Team Member 1:</td><td colspan="3">Glen Martin</td></tr>
<tr><td>Organization:</td><td>Infrastructure Energy</td><td>Role in Project:</td><td>Smart Grid Developer</td></tr>
<tr><td colspan="4">Expertise and Experience:</td></tr>
<tr><td colspan="4">Glen Martin, CEO and Principal, Infrastructure Energy

As Principal of IE, Glen serves as the project developer, coordinating project P3 financing, and key design and construction services.

Glen has over 25 years experience from project development and infrastructure finance in the fields of aerospace, advanced technology and renewable energy, notably with project design and development for the International Space Station and leading positions at Boeing and Rolls Royce. He previously founded Pod Generating Group, developing a 60MW solar photovoltaic project, and was co-founder of ProtoStar Limited, a satellite operator that acquired and launched two satellites into geostationary orbit. Glen holds a Bachelor of Technology in Aerospace Engineering from Ryerson University in Toronto and an MBA from the University of Southern California in Los Angeles, California.</td></tr>
<tr><td>Team Member 2:</td><td colspan="3">Jim Ross</td></tr>
<tr><td>Organization:</td><td>Infrastructure Energy</td><td>Role in Project:</td><td>Operations and Technology Manager</td></tr>
<tr><td colspan="4">Expertise and Experience:</td></tr>
<tr><td colspan="4">Jim Ross, Senior Advisor, Infrastructure Energy

As manager for operations and technology, Jim is responsible for the selection and oversight of the Design and Construction of the SSG thru the Prime Contractor team at B&V, and other suppliers.

Jim oversees the development of Infrastructure Energy's multiple project management teams. He has over 20 years' experience in operations and project management. In 2002, Jim served as the Managing Principal of Ascertane, a business and technology consulting firm, and was previously the Director of Operations for Jackson Labs Technologies. Jim holds a BBA with a concentration in Corporate Finance from Western Michigan University.</td></tr>
</table>

SEC-24

Reference: Application, p. 60

Question:

Please provide a complete list of all "capital asset replacement deferrals" expected as a result of the SSG Project, whether or not within the DSP timeframe.

Response:

No capital asset replacement deferrals are expected during the current (2018-2022) DSP timeframe. Beyond 2022, the capital plan savings is expected to be achieved through reduced distribution station rebuilds. The power transformer renewal with integral voltage regulation may also provide savings. The benefit of those reduced capital expenditures due to SSG implementation is estimated at $342,708 as shown in Table 1 of the ICM Application on page 11.

SEC-25

Reference: Appendix H

Questions:

With respect to the Revised Scope and Benefits Estimate dated November, 2018:

(a) Please confirm that this document was prepared by internal staff of the Applicant, with the assistance of IE, and has not been reviewed by any independent third party.

(b) p. 1. Please confirm that Leidos estimated the CVR at 0.5, and that was changed by the Applicant to 0.9. Please recalculate the cost/benefit analysis of the project using 0.5 instead of 0.9.

(c) p. 2. Please provide a full list of "project scope changes", the "approximation adjustment" applied to each one, and the dollar impact on the cost/benefit analysis of each of those adjustments.

(d) Please provide all of the original spreadsheets underlying the calculations set out in this memo.

Response:

(a) PUC Distribution confirms that this document was prepared by internal staff.

(b) PUC Distribution confirms that Leidos estimated the CVR at 0.5 and that was changed by PUC Distribution to 0.9. A CVR of 0.5 is too conservative (refer to VECC-42). PUC Distribution recalculated the benefit/cost analysis of the project using 0.5 instead of 0.9 and ratio resulted in 0.64:1.

(c) Initial project scope and benefit/cost analysis is described in the Navigant Report #1. The project analysis indicated a positive benefit/cost ratio with all benefits included (provincial, transmission, reliability, bill, etc.). From a customer bill perspective alone, it did not meet PUC Distribution objectives and therefore project costs were considered too high versus benefits achieved. Therefore, descoping of the project was determined to be necessary and all substation renewal work was removed which represented about 49% of project costs. Also, additional scope reductions included examining reduction in DA coverage to meet benefit/cost objectives. At this point, the project was still not meeting objectives. External funding sources were being explored which ultimately led to the NRCan Smart Grid Program application. The potential for government funding allowed increasing system coverage for VVO so that all customers could benefit from energy savings. This became the scope of the current SSG Application.

(d) Spreadsheet attached (Appendix 4).

SEC-26

Reference: Appendix J

Question:

Please explain what “Scope will be finalized by Black & Veatch during the formal engineering phase to reflect a not-to-exceed agreement price” means, and when that scope finalization is expected to occur.

Response:

The project scope is developed from a 30% engineering design level analysis. Detailed engineering and value-added engineering will determine the final detailed project scope of work at the fixed price of the contract subject to PUC Distribution review and approval.

SEC-27

Reference: Appendix J, p. 517 of pdf

Question:

Please confirm that the items listed in section 4 on this page will be additional costs of the SSG Project. Please provide the forecasted amount of each of these costs, and the method by which the Applicant intends to recover them from customers. Please identify whether any of these costs will be borne by the EPC Contractor or the Developer.

Response:

These items, if required, are additional costs of the SSG Contract but are included in the SSG Project ICM Application. Please see Appendix K – Project Cost Estimate (page 9 of 10) for detailed costs of these items. These costs will be borne by PUC Distribution.

SEC-28

Reference: Appendix J, p. 517-8 of pdf

Question:

Please confirm that the Applicant has not yet done an analysis to identify "the impacts of the UDM on the PUC's organization and processes". If any work has been done in this area, please provide copies of all documents containing any component of this analysis. Please confirm the costs of any changes set out in Table 20 on page 518 of the pdf are not included in the ICM total provided to the Board. Please provide the forecasted amount of each of these costs, and the method by which the Applicant intends to recover them from customers. Please identify whether any of these costs will be borne by the EPC Contractor or the Developer.

Response:

PUC Distribution has not performed a complete analysis to identify "the impacts of the USM on the PUC's organization and processes." Preliminary analysis has been completed to identify ongoing operating cost impacts as identified in the ICM Application under "D. Revenue Requirement" (page 28 of 65). PUC Distribution confirms the costs of any changes required arising from the list in Table 20 are not included in the ICM Application. There is no forecasted amount for each of these costs. These costs will be borne by PUC Distribution as apart of current operating costs.

SEC-29

Reference: Appendix K, p. 64

Question:

Please add a column to this table showing the dollar amount of each line item that will be paid to or retained by the Applicant to cover internal costs associated with the SSG Project.

Response:

The estimated direct costs for PUC Distribution in addition to the contract with SSG are included in the full project estimate in Appendix K. The breakout of these costs from Appendix K page 9 have been added as a column as requested in the figure below.

2019/20 Smart Grid Project				
			Project Installation	SEC-29 Estimate
VVM (excludes AMI, SCADA, Comm, etc.)	***Qty***	**$Unit/Ea**		***(App K pg 9)***
DS with new LTC's (incremental)	2	60,000	120,000	
40 feeders				
> Bus/Padmount /Feeder/ VReg's/	44	210,000	9,240,000	
> feeder balancing Caps	6	8,250	49,500	
> feeder balancing VRegs	6	94,300	565,800	
			9,975,300	
Engineering		See Estim	3,205,800	
			13,181,100	
Project Mgmt/ Ext'l Commissioning Review		See Estim	1,645,550	$ 515,200
Regulatory/ Financial/ Legal		See Estim	1,132,830	$ 176,250
VVM			**15,959,480**	
DA (excludes AMI, SCADA, Comm, etc.)				
Generally staying with the ~80% system coverage				
Will likely be value added engineering changes				
in the detailed design phase of project.				
34.5 kV TT (10DS and TS?)	6	53,000	318,000	
Reclosers	38	84,000	3,192,000	
SW's(pole)	40	64,000	2,560,000	
2 way padmount SW's	3	114,000	342,000	
4 way padmount SW's	4	124,000	496,000	
OH FCI's	32	7,200	230,400	
UG FCI's	37	6,200	229,400	
Poles (added qty for adjacent lift/siting issues)	90	11,500	1,035,000	
			8,402,800	
Engineering		See Estim	3,456,800	
			11,859,600	
Project Mgmt/ Ext'l Commissioning Review		See Estim	1,501,250	$ 515,200
Regulatory/ Financial/ Legal		See Estim	1,298,610	$ 153,750
DA			**14,659,460**	
AMI Integration, SCADA, OMS, CIS, Comm, etc.)				
All IT H/W, S/W, SCADA, OMS, GIS, communication				
type work combined in to central sub-project.				
34.5 kV TT SW	14	35,000	490,000	
FLIR SW	1	450,000	450,000	
AMI/OMS/CIS	1	1,275,000	637,500	
			1,577,500	
Engineering		See Estim	1,337,400	$ 130,000
			2,914,900	
Project Mgmt/ Ext'l Commissioning Review		See Estim	523,800	$ 105,000
Regulatory/ Financial/ Legal		See Estim	331,560	$ 45,000
AMI			**3,770,260**	
Project Estimate Total System			**34,389,200**	$ 1,640,400
				4.8%

Construction	*Engineering*	*Reg/Fin/Legal*	*Project Mgmt*
19,955,600	*8,000,000*	*2,763,000*	*3,670,600*
58.0%	*23.3%*	*8.0%*	*10.7%*
34,389,200			

SEC-30

Reference: Appendix K, Revised Scope & Cost Estimate

Question:

Please confirm that no independent review of the project costs set forth in this memo has been done. If a review has been done, please provide a copy.

Response:

PUC Distribution confirms that this document has not had an independent review. The Estimate and methodology described in Appendix K referenced above was developed internally by PUC Distribution. As discussed in the application the check of reasonableness of the project costs as reviewed by Navigant (Appendix E) was used as a base for the project unit costs. PUC used the base costs and considered CPI and cost/project risk from Navigant report and PUC staff perspective along with changes in scope to the final project planned arrive at a check of the final estimate. Cross checks for construction, engineering, regulatory and project management were also reviewed although data available on P3 projects was not as common as traditional construction.

SEC-31

Reference: Appendix K, Revised Scope & Cost Estimate, p. 8

Question:

Please provide details of the amounts to be paid to IE, totaling $4,793,000, with a detailed justification for each.

Response:

As this is a fixed price turn key project, PUC Distribution does not have the details of the cost of each component.

SEC-32

Reference: Appendix K, Revised Scope & Cost Estimate, p. 9

Question:

Please provide details on the costs to be retained by the Applicant listed here, including the basis for weekly rates, the time involvement, and all other assumptions used in the calculations, and how the amount going to the Applicant is being accounted for in the ICM cost and customer impacts.

Response:

This is the portion of the project estimate of PUC Distribution costs that will be in addition to the contract. Rates and hours represent PUC Distributions internal project estimate developed for the overall project management (labour, equipment, & applicable overheads) with the scope of work listed in Appendix K page 10, for this function. The two-year project and ICM is based on the total capital costs for the project. See also SEC-29.

Vulnerable Energy Consumers Coalition (VECC) Interrogatories

VECC-1

Reference: None

Questions :

(a) Please provide the number of sustained outages per year for the years 2010 to 2018. Please provide the duration (interruption hours) of sustained outages per year for the years 2010 to 2018.

(b) Please provide the number of momentary outages per year for the years 2010 to 2018.

(c) Please provide the annual reduced interruption frequency and duration projections resulting from the SSG Project.

(d) Please provide the annual reduced interruption frequency and duration projections resulting from the SSG Project.

Response:

(a) The following tables illustrated the number of sustained outages per year for the years 2010 to 2018.

Year	Number of Sustained Outages
2010	390
2011	500
2012	504
2013	561
2014	710
2015	724
2016	558
2017	470
2018	352

Note: The data in the above table includes all outage causes.

(b) The following table illustrates the duration (interruption hours) of sustained outages per year for the years 2010 to 2018.

Year	Customer Hours of Interruptions
2010	69,287
2011	277,647
2012	54,264
2013	87,737
2014	39,660
2015	111,858
2016	84,824
2017	65,952
2018	78,699

Note: The data in the above table includes all outage causes.

(c) PUC Distribution does not separately track or record the number of momentary outages.

(d) The annual reduced interruption frequency and duration projections (refer to Appendix 7 page 11) resulting from the SSG Project are:

- SAIFI reduced by 37%
- SAIDI reduced by 46%
- CAIDI reduced by 16%

VECC-2

Reference: None

Question:

Please provide the number of severe/major weather events per year since 2010.

Response:

The following table illustrates the number of severe/major weather events per year since 2010.

Year	Number of Major Weather Events
2012	0
2013	3
2014	0
2015	2
2016	2
2017	2
2018	3

Note: Data on major events is not available for 2010 and 2011.

VECC-3

Reference: ICM Application Page 6

Preamble:

The total capital cost of the SSG Project is estimated to be $34,389,046, with 22% of the SSG Project ($7,655,053) to be in service by December 31, 2019 ("Phase 1") with the remaining 78% ($26,733,992) to be in service by December 31, 2020 ("Phase 2"). Incremental funding for Phase 2 of the SSG Project will be requested by way of a 2020 ICM application.

Questions:

(a) Please provide a cost estimate and scope of work for Phase 1 and Phase 2 and explain how the project phases were determined.

(b) If the project was implemented over three years instead of two years, please explain how the project could be broken down into three work phases and provide an estimate of costs for each phase.

Response:

(a) Please refer Staff-23 (a) and (b).

(b) Please refer to Staff-30.

VECC-4

Reference: ICM Application Page 6

Question:

Please confirm the Minister's Directive issued on November 23, 2010 is the key driver for this project.

Response:

The key drivers for this project are the benefits to both customers directly in energy savings and reliability but also the equally important aspect of the advanced distribution management system that will improve operational awareness, control and facilitate continuous improvement in distribution system management for new loads, DER and asset management.

VECC-5

Reference: ICM Application Page 6

Preamble:

The evidence states "From the third quarter of 2013 to the first quarter of 2014, PUC Distribution and its project partners collected data and conducted preliminary analyses with respect to the development of a smart grid project."

Questions:

(a) Please explain the type of data that PUC and its project partners collected.

(b) Please describe the quality of the data collected including accuracy, completeness, consistency, and comprehensiveness.

(c) Please discuss how the smart grid project responds to any data quality issues.

Response:

(a) Type of data PUC Distribution and its project partners collected includes:

- GIS system network data for all distribution feeders such as conductor size, circuit configuration and phasing, transformer connection and location;
- Outage statistic data for 2009-2012;
- Smart meter energy consumption by specific meter and location;
- Smart meter voltage data.

(b) Data sets were reviewed in detail to develop a typical nominal annual year data set. Normalizing meter data and reliability data to create a quality, consistent and comprehensive base for forecasts. Energy analysis by feeder and in total was checked and normalized to the 2018 COS load forecast data (EB-2017-0071) for benefit estimates from the preliminary engineering results and were also benchmarked to industry reports.

(c) Data quality issues have been reasonably addressed in project planning and scope.

VECC-6

Reference: ICM Application Page 7

Questions

(a) Please provide a copy of the City of Sault Ste. Marie City Council resolution passed in the first quarter of 2014 along with a copy of the report to City Council supporting the concept of developing a smart grid in PUC's service area.

(b) Please provide any subsequent reports to City Council and City Council resolutions related to the smart grid project.

Response:

(a) Resolution: [http://saultstemarie.ca/Cityweb/media/City-Clerk/Council-Agendas/2014/2014_01_20_MINUTES.pdf?ext=.pdf]

Presentation: [http://saultstemarie.ca/Cityweb/media/City-Clerk/Council-Agendas/2014/2014_01_20_AGENDA.pdf?ext=.pdf]

(b) Presentation above to City Council about development in Sault Ste. Marie were much broader than the specific PUC Distribution smart grid project. The ICM application relates specifically to the PUC Distribution smart grid project and does not encompass the vision of the potential developments in Sault Ste. Marie. This project and project costs were not specifically presented to city council in 2014.

VECC-7

Reference: ICM Application Page 7

Questions :

(a) Please confirm the costs for Leidos Engineering LLC and Navigant Consulting Inc. are included in the Project Cost Estimate at Appendix K.

(b) Please provide the cost of the work undertaken by Leidos Engineering LLC

(c) Please provide the cost of the work undertaken by Navigant Consulting Inc.

Response:

The answer to questions (a) (b) and (c) above is as follows:

As this is a fixed price turn key project, PUC Distribution does not have the details of the cost of each component.

VECC-8

Reference: ICM Application Page 7

Questions :

(a) Please show how PUC de-scoped the SSG Project and lowered costs.

(b) Please itemize all scope changes.

(c) Please discuss if the changes in scope in the Sault Smart Grid Project required City Council approval. If yes, please provide the council resolution.

Response:

(a) Initial project scope and benefit/cost analysis is described in the Navigant Report #1. The project analysis indicated a positive benefit/cost ratio with all benefits included (provincial, transmission, reliability, bill, etc.). From a customer bill perspective alone, it did not meet PUC Distribution objectives and therefore project costs were considered too high versus benefits achieved. Therefore, descoping of the project was determined to be necessary and all substation renewal work was removed which represented about 49% of project costs. Also, additional scope reductions included examining reduction in DA coverage to meet benefit/cost objectives. At this point, the project was still not meeting objectives. External funding sources were being explored which ultimately led to the NRCan Smart Grid Program. The potential for government funding allowed increasing system coverage for VVO so that all customers could benefit from energy savings. This became the scope of the current SSG Application.

(b) Please refer to (a) above which outlines the scope changes in the SSG Project.

(c) Changes in scope did not require City Council approval.

VECC-9

Reference: ICM Application Page 8

Preamble:

PUC indicates the Sault Smart Grid (SSG) Project was not included in PUC Distribution's latest Distribution System Plan (EB-2017-0071) filed on March 29, 2018.

Questions:

(a) Please provide a list of investments in the latest DSP that qualify as smart grid investments.

(b) Please provide a description and breakdown of PUC's smart grid investments undertaken since 2010.

(c) Please identify capital projects in the DSP that could be deferred as a result of approval and implementation of the SSG Project.

Response:

(a) The following list reflects smart grid investments during the current DSP period that were included in the System Renewal category due to the fact that the subject infrastructure was at the end of its service life and therefore renewal was the primary driver:

- Engineering and minor software/hardware additions associated with enhanced feeder protection capable of DER support as part of Substation 16 rebuild in 2019, Sub 1, 11 & 20 relay replacements in 2020-2021 and Sub 22 build (Sub 4/5/17 replacement) in 2022
- Advanced SCADA communications for 3 recloser radio replacements in 2019

The capital investments as it relates to 'smart-grid capability' for the period 2018-2022 and associated with Table 26 of the DSP is as follows:

Year	2018	2019	2020	2021	2022
Total Capital Investment for Renewal (per DSP Table 26)	$3.761M	$6.906M	$3.296M	$4.533M	$7.093M

Capital Investments attributable to 'smart-grid'	$0	$12k	$13.5k	$13.5k	$9k

(b) Prior to 2018, PUC Distribution does not have a separate breakdown of smart-grid investments but all costs are integrated with System Renewal which is the primary driver.

(c) During the DSP period there are no capital projects that could be deferred as a result of the SSG Project as there is no duplication.

VECC-10

Reference: ICM Application Page 8

Preamble:

PUC explains that it has been exploring an innovative and large scale system smart grid project for a few years that could provide significant benefit to our customers. The project would include elements for distribution automation, voltage control and improved customer care and outage management capabilities.

Questions:

(a) Please explain why PUC chose to undertake a large scale smart grid strategy rapidly versus smaller scale investments over time. Please discuss the advantages to this approach.

(b) Please compare the status of PUC's existing elements related to distribution automation, voltage control, customer care and outage management capabilities compared to what will be available through the SSG project.

Response:

(a) Please refer to Staff-22 (c) for an explanation as to why PUC Distribution chose to undertake the large scale smart grid strategy.

(b) Status of PUC Distribution's existing elements:

- PUC Distribution utilizes Survalent SCADA System to control its TS's and sub-transmission network;
- PUC introduced our first voltage regulators on a few remote feeders in just the past couple years to address specific local power quality needs;
- The 12.5 kV distribution network currently does not have any automated switching or self-healing circuits;
- Substations utilize breaker reclose but there is no voltage control;
- There is no voltage control on PUC Distribution's distribution network;
- The 3 distribution reclosers currently in service are limited in use and operate in traditional radial application on 3 feeders;
- There is no outage management system although PUC Distribution has brought some smart meter data to operations and customer care for outage notification via email.

VECC-11

Reference: ICM Application Page 10

Preamble:

The evidence states "Overall the project returns a positive benefit to cost ratio of 1.1:1 for customers from a billing perspective and with assuming only a 25% value for reliability, a 1.4:1 ratio results for the project. Customer reliability improvements are also calculated and projected as $2.55M annually to provide additional non-bill benefit to customers.

Questions:

(a) Please explain the basis to assume a 25% value for reliability.

(b) Please explain how the 1.4:1 ratio was determined and provide the calculation.

Response:

(a) The 25% value for reliability was for illustrative purposes only. PUC Distribution is not aware of any regulatory precedent being set on how to value reliability versus customer benefit in an approved rate process but there are reports that provide methodology on how the reliability value is calculated. In the Navigant report in Appendix 7 Navigant cites source for reliability value calculations used on page11.

(b) Please refer to Staff-64 (b) for an explanation and calculation on the 1.4:1 ratio.

VECC-12

Reference: ICM Application Page 10

Preamble:

PUC indicates the SSG Project is an innovative initiative. If successful, the SSG Project could become a model for Canadian cities that wish to deploy grid modernization and community-scale smart grids rapidly, accelerating the benefits to customers while minimizing both costs and risks.

Question:

Please summarize any research PUC undertook in Canada and Ontario specifically, regarding what other utilities are doing or not doing with respect to smart grid implementation and how the SSG Project compares and could be used as a model.

Response:

PUC Distribution follows and participates in various industry associations, such as the Electricity Distribution Association (EDA), Utilities Standards Forum (USF), IESO Smart Grid Forum, etc. The innovative part of the project is that by doing all the things at once, as part of a larger project PUC Distribution can achieve no net bill increase while driving significant improvements in overall distribution system operations. It is also innovative in that by bundling it together PUC Distribution qualified for significant federal funding, thereby reducing the total cost of these improvements for ratepayers.

VECC-13

Reference: ICM Application Page 11 Table 1 & Page 12

Questions:

(a) Please provide the calculation of $93,378 in system loss reduction.

(b) Please provide the calculation of $2.55M annually in reliability improvements.

(c) Please provide the calculation that underpins the estimated 25 year net-present value of the customer reliability benefit of over $40 million.

Response:

(a) The VVO will save 2.6% on the system losses which has been estimated as 11.87 cents multiplied by the estimated system losses.

(b) Please refer to Appendix H in the original ICM Application. Specifically page 2 of 5.

(c) The reference to $40M was incorrect. Correct calculation of the $2.55M and 25 years would be ~$35M. (5% discount rate)

The $2.55M figure was estimated as follows: (refer also to SEC-22)

- Initial Leidos analysis on 39 feeders, (excluded 4kV customers and Sub#10 which was under construction & Sub#20) using SAIFI, SAIDI values in report achieved estimated savings of $2.34M
- Voltage conversion work has now moved more customers on to the 12.5 kV system and Sub#20 back in service and new Sub#10 is in service (added about 20% more customers to feeders to be covered by DA.
- A conservative addition of ~10% additional customer savings was rounded to the $2.55M figure.

VECC-14

Reference: None

Preamble:

The evidence states "With this approach, the SSG Project will increase the efficiency of the entire distribution grid, reducing electrical energy delivery requirements from the transmission grid, greenhouse gas emissions, and reducing total costs to consumers."

Question:

Please quantify the annual greenhouse gas emission savings.

Response:

The estimated greenhouse gas emission savings through generation and loss savings of the reduced energy use is 2,804 t[1]. This number was provided in the NRCan Application.

[1] Project direct and indirect kWh reduction estimates were converted to tCO2 reduction estimates using an Ontario Power Generation Inc. (OPG) sponsored report, *GHG Emissions Associated with Various Methods of Power Generation in Ontario*, developed by Intrinsik Corp., October 2016.

VECC-15

Reference: ICM Application Page 12 Table 2

Questions :

(a) Please provide complete bill impact calculations in 2019 and 2020 for residential customers at the low, average and high consumption levels resulting from implementation of the SSG Project in 2019 and 2020.

(b) Has PUC consulted directly with low income seniors and other vulnerable customers on the SSG Project? If yes, when? Please discuss the outcome of these consultations. If not, please provide PUC's plan to consult with residential/vulnerable customers on the SSG Project.

(c) Please explain how low volume residential customers have the ability to lower energy use as a result of the SSG Project.

Response:

(a) The following bill impacts were calculated by comparing:

(i) the proposed rates from the ICM request, excluding any increase due to the SSG (i.e. removing the Phase 1 revenue) to
(ii) the proposed rates from the ICM request plus the effect of the full SSG project at consumption levels 2.7% less for RTSR Network charge, Wholesale Market Service Charge, Rural and Remote Rate Protection and energy charge (i.e. reduced consumption due to the SSG project).

The annual increase to distribution charges for a residential customer is $36.68 ($3.06*12). As per the bill impact calculation below, conservatively, it is expected that the SSG will result in a consumption reduction of 2.7%. The table below summarizes the effect to residential customers at various consumption levels. Detailed calculations for each consumption level follow the summary.

Consumption Level (KWhs)	$ Change per Month	% Change
400 kWhs	$2.07	2.92%
750 kWhs	$1.08	1.00%
806 kWhs	$0.92	0.81%
1,130 kWhs	$0.00	$0.0%
2,000 kWhs	($2.47)	(1.03%)
3,000 kWhs	($5.31)	(1.54%)

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION							
RPP / Non-RPP:	RPP							
Consumption	400	kWh	Consumption Decrease %			Proposed consumption	389	
Demand	-	kW	2.70%					
Current Loss Factor	1.0481							
Proposed/Approved Loss Factor	1.0481							

	Proposed			Proposed - ICM			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 28.17	1	$ 28.17	$ 28.17	1	$ 28.17	$ -	0.00%
Distribution Volumetric Rate	$ 0.0043	400	$ 1.72	$ 0.0043	389	$ 1.67	$ (0.05)	-2.70%
Fixed Rate Riders	$ (1.35)	1	$ (1.35)	$ (1.35)	1	$ (1.35)	$ -	0.00%
ICM - Fixed	$ -	1	$ -	$ 3.06	1	$ 3.06	$ 3.06	
Volumetric Rate Riders	$ 0.0007	400	$ -	$ 0.0007	389	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 28.54**			**$ 31.55**	**$ 3.01**	**10.55%**
Line Losses on Cost of Power	$ 0.0820	19	$ 1.58	$ 0.0820	19	$ 1.53	$ (0.04)	-2.71%
Total Deferral/Variance Account Rate Riders	($0.0067)	400	$ -	-$ 0.0067	389	$ -	$ -	
CBR Class B Rate Riders	$ -	400	$ -	$ -	389	$ -	$ -	
GA Rate Riders	$ -	400	$ -	$ -	389	$ -	$ -	
Low Voltage Service Charge	$ -	400	$ -		389	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	-$ 0.0004	400	$ (0.16)	-$ 0.0004	389	$ (0.16)	$ 0.00	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 30.53**			**$ 33.50**	**$ 2.97**	**9.73%**
RTSR - Network	$ 0.0059	419	$ 2.47	$ 0.0059	408	$ 2.41	$ (0.07)	-2.70%
RTSR - Connection and/or Line and Transformation Connection	$ -	419	$ -	$ -	408	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 33.00**			**$ 35.91**	**$ 2.90**	**8.80%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	419	$ 1.43	$ 0.0034	408	$ 1.39	$ (0.04)	-2.70%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	419	$ 0.21	$ 0.0005	408	$ 0.20	$ (0.01)	-2.70%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ -		$ -			$ -	$ -	
TOU - Off Peak	$ 0.0650	260	$ 16.90	$ 0.0650	253	$ 16.44	$ (0.46)	-2.70%
TOU - Mid Peak	$ 0.0940	68	$ 6.39	$ 0.0940	66	$ 6.22	$ (0.17)	-2.70%
TOU - On Peak	$ 0.1320	72	$ 9.50	$ 0.1320	70	$ 9.25	$ (0.26)	-2.70%
Total Bill on TOU (before Taxes)			**$ 67.68**			**$ 69.66**	**$ 1.98**	**2.92%**
HST	13%		$ 8.80	13%		$ 9.06	$ 0.26	2.92%
8% Rebate	8%		$ (5.41)	8%		$ (5.57)	$ (0.16)	
Total Bill on TOU			**$ 71.07**			**$ 73.14**	**$ 2.07**	**2.92%**

Customer Class: RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP: RPP
Consumption: 750 kWh | Consumption Decrease %: 2.70% | Proposed consumption: 730
Demand: - kW
Current Loss Factor: 1.0481
Proposed/Approved Loss Factor: 1.0481

	Proposed			Proposed - ICM			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 28.17	1	$ 28.17	$ 28.17	1	$ 28.17	$ -	0.00%
Distribution Volumetric Rate	$ 0.0043	750	$ 3.23	$ 0.0043	730	$ 3.14	$ (0.09)	-2.70%
Fixed Rate Riders	$ (1.35)	1	$ (1.35)	$ (1.35)	1	$ (1.35)	$ -	0.00%
ICM - Fixed	$ -	1	$ -	$ 3.06	1	$ 3.06	$ 3.06	
Volumetric Rate Riders	$ 0.0007	750	$ -	$ 0.0007	730	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 30.05**			**$ 33.01**	**$ 2.97**	**9.88%**
Line Losses on Cost of Power	$ 0.0820	36	$ 2.96	$ 0.0820	35	$ 2.88	$ (0.08)	-2.71%
Total Deferral/Variance Account Rate Riders	($0.0067)	750	$ -	-$ 0.0067	730	$ -	$ -	
CBR Class B Rate Riders	$ -	750	$ -	$ -	730	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ -	730	$ -	$ -	
Low Voltage Service Charge	$ -	750	$ -		730	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	-$ 0.0004	750	$ (0.30)	-$ 0.0004	730	$ (0.29)	$ 0.01	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.27**			**$ 36.17**	**$ 2.90**	**8.71%**
RTSR - Network	$ 0.0059	786	$ 4.64	$ 0.0059	765	$ 4.51	$ (0.13)	-2.70%
RTSR - Connection and/or Line and Transformation Connection	$ -	786	$ -	$ -	765	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 37.91**			**$ 40.68**	**$ 2.77**	**7.31%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	786	$ 2.67	$ 0.0034	765	$ 2.60	$ (0.07)	-2.70%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	786	$ 0.39	$ 0.0005	765	$ 0.38	$ (0.01)	-2.70%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ -		$ -			$ -	$ -	
TOU - Off Peak	$ 0.0650	488	$ 31.69	$ 0.0650	474	$ 30.83	$ (0.86)	-2.70%
TOU - Mid Peak	$ 0.0940	128	$ 11.99	$ 0.0940	124	$ 11.66	$ (0.32)	-2.70%
TOU - On Peak	$ 0.1320	135	$ 17.82	$ 0.1320	131	$ 17.34	$ (0.48)	-2.70%
Total Bill on TOU (before Taxes)			**$ 102.72**			**$ 103.75**	**$ 1.03**	**1.00%**
HST	13%		$ 13.35	13%		$ 13.49	$ 0.13	1.00%
8% Rebate	8%		$ (8.22)	8%		$ (8.30)	$ (0.08)	
Total Bill on TOU			**$ 107.86**			**$ 108.94**	**$ 1.08**	**1.00%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION			
RPP / Non-RPP:	RPP			
Consumption	806 kWh	Consumption Decrease %	Proposed consumption	784
Demand	- kW	2.70%		
Current Loss Factor	1.0481			
Proposed/Approved Loss Factor	1.0481			

	Proposed			Proposed - ICM			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 28.17	1	$ 28.17	$ 28.17	1	$ 28.17	$ -	0.00%
Distribution Volumetric Rate	$ 0.0043	806	$ 3.47	$ 0.0043	784	$ 3.37	$ (0.09)	-2.70%
Fixed Rate Riders	$ (1.35)	1	$ (1.35)	$ (1.35)	1	$ (1.35)	$ -	0.00%
ICM - Fixed	$ -	1	$ -	$ 3.06	1	$ 3.06	$ 3.06	
Volumetric Rate Riders	$ 0.0007	806	$ -	$ 0.0007	784	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 30.29**			**$ 33.25**	**$ 2.96**	**9.78%**
Line Losses on Cost of Power	$ 0.0820	39	$ 3.18	$ 0.0820	38	$ 3.09	$ (0.09)	-2.71%
Total Deferral/Variance Account Rate Riders	($0.0067)	806	$ -	-$ 0.0067	784	$ -	$ -	
CBR Class B Rate Riders	$ -	806	$ -	$ -	784	$ -	$ -	
GA Rate Riders	$ -	806	$ -	$ -	784	$ -	$ -	
Low Voltage Service Charge	$ -	806	$ -		784	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	-$ 0.0004	806	$ (0.32)	-$ 0.0004	784	$ (0.31)	$ 0.01	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.71**			**$ 36.60**	**$ 2.89**	**8.56%**
RTSR - Network	$ 0.0059	845	$ 4.98	$ 0.0059	822	$ 4.85	$ (0.13)	-2.70%
RTSR - Connection and/or Line and Transformation Connection	$ -	845	$ -	$ -	822	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 38.70**			**$ 41.45**	**$ 2.75**	**7.11%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	845	$ 2.87	$ 0.0034	822	$ 2.79	$ (0.08)	-2.70%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	845	$ 0.42	$ 0.0005	822	$ 0.41	$ (0.01)	-2.70%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ -		$ -			$ -	$ -	
TOU - Off Peak	$ 0.0650	524	$ 34.05	$ 0.0650	510	$ 33.13	$ (0.92)	-2.70%
TOU - Mid Peak	$ 0.0940	137	$ 12.88	$ 0.0940	133	$ 12.53	$ (0.35)	-2.70%
TOU - On Peak	$ 0.1320	145	$ 19.15	$ 0.1320	141	$ 18.63	$ (0.52)	-2.70%
Total Bill on TOU (before Taxes)			**$ 108.33**			**$ 109.20**	**$ 0.88**	**0.81%**
HST	13%		$ 14.08	13%		$ 14.20	$ 0.11	0.81%
8% Rebate	8%		$ (8.67)	8%		$ (8.74)	$ (0.07)	
Total Bill on TOU			**$ 113.74**			**$ 114.66**	**$ 0.92**	**0.81%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION								
RPP / Non-RPP:	RPP								
Consumption	1,130	kWh	Consumption Decrease %			Proposed consumption		1,099	
Demand	-	kW		2.70%					
Current Loss Factor	1.0481								
Proposed/Approved Loss Factor	1.0481								

	Proposed			Proposed - ICM			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 28.17	1	$ 28.17	$ 28.17	1	$ 28.17	$ -	0.00%
Distribution Volumetric Rate	$ 0.0043	1130	$ 4.86	$ 0.0043	1,099	$ 4.73	$ (0.13)	-2.70%
Fixed Rate Riders	$ (1.35)	1	$ (1.35)	$ (1.35)	1	$ (1.35)	$ -	0.00%
ICM - Fixed	$ -	1	$ -	$ 3.06	1	$ 3.06	$ 3.06	
Volumetric Rate Riders	$ 0.0007	1130	$ -	$ 0.0007	1099	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 31.68**			**$ 34.60**	**$ 2.93**	**9.23%**
Line Losses on Cost of Power	$ 0.0820	54	$ 4.46	$ 0.0820	53	$ 4.34	$ (0.12)	-2.71%
Total Deferral/Variance Account Rate Riders	($0.0067)	1,130	$ -	-$ 0.0067	1,099	$ -	$ -	
CBR Class B Rate Riders	$ -	1,130	$ -	$ -	1,099	$ -	$ -	
GA Rate Riders	$ -	1,130	$ -	$ -	1,099	$ -	$ -	
Low Voltage Service Charge	$ -	1,130	$ -		1,099	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	-$ 0.0004	1,130	$ (0.45)	-$ 0.0004	1,099	$ (0.44)	$ 0.01	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 36.25**			**$ 39.07**	**$ 2.82**	**7.77%**
RTSR - Network	$ 0.0059	1,184	$ 6.99	$ 0.0059	1,152	$ 6.80	$ (0.19)	-2.70%
RTSR - Connection and/or Line and Transformation Connection	$ -	1,184	$ -	$ -	1,152	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 43.24**			**$ 45.87**	**$ 2.63**	**6.08%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	1,184	$ 4.03	$ 0.0034	1,152	$ 3.92	$ (0.11)	-2.70%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	1,184	$ 0.59	$ 0.0005	1,152	$ 0.58	$ (0.02)	-2.70%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ -		$ -			$ -	$ -	
TOU - Off Peak	$ 0.0650	735	$ 47.74	$ 0.0650	715	$ 46.45	$ (1.29)	-2.70%
TOU - Mid Peak	$ 0.0940	192	$ 18.06	$ 0.0940	187	$ 17.57	$ (0.49)	-2.70%
TOU - On Peak	$ 0.1320	203	$ 26.85	$ 0.1320	198	$ 26.12	$ (0.72)	-2.70%
Total Bill on TOU (before Taxes)			**$ 140.76**			**$ 140.76**	**$ 0.00**	**0.00%**
HST	13%		$ 18.30	13%		$ 18.30	$ 0.00	0.00%
8% Rebate	8%		$ (11.26)	8%		$ (11.26)	$ (0.00)	
Total Bill on TOU			**$ 147.80**			**$ 147.80**	**$ 0.00**	**0.00%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION			
RPP / Non-RPP:	RPP			
Consumption	2,000	kWh	Consumption Decrease %	Proposed consumption 1,946
Demand	-	kW	2.70%	
Current Loss Factor	1.0481			
Proposed/Approved Loss Factor	1.0481			

	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Proposed - ICM Rate ($)	Proposed - ICM Volume	Proposed - ICM Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	$ 28.17	1	$ 28.17	$ 28.17	1	$ 28.17	$ -	0.00%
Distribution Volumetric Rate	$ 0.0043	2000	$ 8.60	$ 0.0043	1,946	$ 8.37	$ (0.23)	-2.70%
Fixed Rate Riders	$ (1.35)	1	$ (1.35)	$ (1.35)	1	$ (1.35)	$ -	0.00%
ICM - Fixed	$ -	1	$ -	$ 3.06	1	$ 3.06	$ 3.06	
Volumetric Rate Riders	$ 0.0007	2000	$ -	$ 0.0007	1946	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 35.42**			**$ 38.24**	**$ 2.82**	**7.97%**
Line Losses on Cost of Power	$ 0.0820	96	$ 7.89	$ 0.0820	94	$ 7.67	$ (0.21)	-2.71%
Total Deferral/Variance Account Rate Riders	($0.0067)	2,000	$ -	-$ 0.0067	1,946	$ -	$ -	
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	1,946	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ -	1,946	$ -	$ -	
Low Voltage Service Charge	$ -	2,000	$ -		1,946	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	-$ 0.0004	2,000	$ (0.80)	-$ 0.0004	1,946	$ (0.78)	$ 0.02	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 43.08**			**$ 45.71**	**$ 2.63**	**6.11%**
RTSR - Network	$ 0.0059	2,096	$ 12.37	$ 0.0059	2,040	$ 12.03	$ (0.33)	-2.70%
RTSR - Connection and/or Line and Transformation Connection	$ -	2,096	$ -	$ -	2,040	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 55.45**			**$ 57.74**	**$ 2.30**	**4.14%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,096	$ 7.13	$ 0.0034	2,040	$ 6.93	$ (0.19)	-2.70%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,096	$ 1.05	$ 0.0005	2,040	$ 1.02	$ (0.03)	-2.70%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ -		$ -			$ -	$ -	
TOU - Off Peak	$ 0.0650	1,300	$ 84.50	$ 0.0650	1,265	$ 82.22	$ (2.28)	-2.70%
TOU - Mid Peak	$ 0.0940	340	$ 31.96	$ 0.0940	331	$ 31.10	$ (0.86)	-2.70%
TOU - On Peak	$ 0.1320	360	$ 47.52	$ 0.1320	350	$ 46.24	$ (1.28)	-2.70%
Total Bill on TOU (before Taxes)			**$ 227.85**			**$ 225.50**	**$ (2.35)**	**-1.03%**
HST	13%		$ 29.62	13%		$ 29.32	$ (0.31)	-1.03%
8% Rebate	8%		$ (18.23)	8%		$ (18.04)	$ 0.19	
Total Bill on TOU			**$ 239.24**			**$ 236.78**	**$ (2.47)**	**-1.03%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION								
RPP / Non-RPP:	RPP								
Consumption	3,000	kWh	Consumption Decrease %			Proposed consumption		2,919	
Demand	-	kW		2.70%					
Current Loss Factor	1.0481								
Proposed/Approved Loss Factor	1.0481								

	Proposed			Proposed - ICM			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 28.17	1	$ 28.17	$ 28.17	1	$ 28.17	$ -	0.00%
Distribution Volumetric Rate	$ 0.0043	3000	$ 12.90	$ 0.0043	2,919	$ 12.55	$ (0.35)	-2.70%
Fixed Rate Riders	$ (1.35)	1	$ (1.35)	$ (1.35)	1	$ (1.35)	$ -	0.00%
ICM - Fixed	$ -	1	$ -	$ 3.06	1	$ 3.06	$ 3.06	
Volumetric Rate Riders	$ 0.0007	3000	$ -	$ 0.0007	2919	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 39.72**			**$ 42.43**	**$ 2.71**	**6.82%**
Line Losses on Cost of Power	$ 0.0820	144	$ 11.83	$ 0.0820	140	$ 11.51	$ (0.32)	-2.71%
Total Deferral/Variance Account Rate Riders	($0.0067)	3,000	$ -	-$ 0.0067	2,919	$ -	$ -	
CBR Class B Rate Riders	$ -	3,000	$ -	$ -	2,919	$ -	$ -	
GA Rate Riders	$ -	3,000	$ -	$ -	2,919	$ -	$ -	
Low Voltage Service Charge	$ -	3,000	$ -		2,919	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	-$ 0.0004	3,000	$ (1.20)	-$ 0.0004	2,919	$ (1.17)	$ 0.03	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 50.92**			**$ 53.34**	**$ 2.42**	**4.75%**
RTSR - Network	$ 0.0059	3,144	$ 18.55	$ 0.0059	3,059	$ 18.05	$ (0.50)	-2.70%
RTSR - Connection and/or Line and Transformation Connection	$ -	3,144	$ -	$ -	3,059	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 69.47**			**$ 71.39**	**$ 1.92**	**2.76%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	3,144	$ 10.69	$ 0.0034	3,059	$ 10.40	$ (0.29)	-2.70%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	3,144	$ 1.57	$ 0.0005	3,059	$ 1.53	$ (0.04)	-2.70%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ -		$ -			$ -	$ -	
TOU - Off Peak	$ 0.0650	1,950	$ 126.75	$ 0.0650	1,897	$ 123.33	$ (3.42)	-2.70%
TOU - Mid Peak	$ 0.0940	510	$ 47.94	$ 0.0940	496	$ 46.65	$ (1.29)	-2.70%
TOU - On Peak	$ 0.1320	540	$ 71.28	$ 0.1320	525	$ 69.36	$ (1.92)	-2.70%
Total Bill on TOU (before Taxes)			**$ 327.96**			**$ 322.90**	**$ (5.05)**	**-1.54%**
HST	13%		$ 42.63	13%		$ 41.98	$ (0.66)	-1.54%
8% Rebate	8%		$ (26.24)	8%		$ (25.83)	$ 0.40	
Total Bill on TOU			**$ 344.35**			**$ 339.05**	**$ (5.31)**	**-1.54%**

(b) Please see Staff-55 for customer engagement details.

(c) The VVO system lowers energy use for all customers by the lower voltage and the nature of their energy use equipment and devices. Low volume residential customers will generally receive the same proportional benefits.

VECC-16

Reference: ICM Application Page 13

Preamble:

PUC states "The system and data available will also support PUC Distribution decision making to make better long term asset management decisions and forecasting capital requirements with the continuing operating and financial challenges of aging infrastructure renewal.

Question:

Please explain how the system and data available will support PUC's decision making to make better long term asset management decisions and forecasting capital requirements.

Response:

An advanced distribution management system that monitors trends and retains data on asset performance will support decisions to be made on current condition, mitigation including intervention on current events, and extend asset life performance. The system will support asset condition data that will inform forecasting capital replacement requirements.

VECC-17

Reference: ICM Application Page 13

Question :

Please provide the actual ROE for 2018.

Response:

PUC Distribution's ROE for 2018 was 4.25%.

VECC-18

Reference: ICM Application Page 13

Preamble:

PUC states "In the event that the OEB does not approve this ICM, PUC Distribution would not proceed with the SSG Project and any NRCan funding would be forfeited."

Question:

Are there any elements of the SSG Project that PUC would incorporate into its capital plans and future DSP planning if the ICM was not approved? Please explain.

Response:

In the event the SSG Project ICM is not approved, it is undetermined at this time if elements of the SSG Project will be incorporated into future DSP plans. Elements of the SSG Project would be re-assessed in order to address any smart grid directives and as part of an overall asset management evaluation process.

VECC-19

Reference: ICM Application Page 14

Preamble:

The evidence states "PUC Distribution includes, throughout this ICM and in the Appendices attached hereto, comprehensive evidence which supports the need for the SSG Project."

Question:

Please describe the most pressing/immediate need for the project.

Response:

LDCs are required to improve situational awareness and operational control of their distribution systems to accommodate increasingly complex demands such as DERs, EVs, etc. Federal funding to support the PUC Distribution smart grid has a time limited availability.

Customers have indicated their primary need is to reduce the cost of their electricity bill while also asking for improved or maintained reliability, increased communication and access to outage information without increasing cost. Balancing these competing priorities above can be successfully delivered with the SSG Project.

VECC-20

Reference: ICM Application Page 14

Preamble:

Black & Veatch ("BV") has been selected to act as the EPC contractor on the SSG Project.

Questions:

(a) Please discuss the process PUC followed to select Black & Veatch.

(b) Please discuss when the scope will be finalized by Black & Veatch as part of the formal engineering phase.

(c) Please provide the not-to-exceed agreement price.

Response:

(a) PUC Distribution did not select Black & Veatch to act as the EPC contractor on the SSG Project. See also Staff-34

(b) The final scope will be finalized when detailed engineering is complete for the project. Detailed engineering will not commence until after this project is approved by the OEB.

(c) As this is a fixed price turn key project, PUC Distribution does not have the details of the cost of the EPC contract.

VECC-21

Reference: ICM Application Page 15

Preamble:

The key components of the SSG project are as follows:

- Voltage / VAR Optimization ("VVO")
- Distribution Automation ("DA")
- AMI Integration

Questions:

(a) Please rank the priority of the above three components.

(b) For each component, please summarize the problem that is being solved.

Response:

(a) The AMI Integration portion of the project, which includes the ADMS platform is a prerequisite for the other project components. The VVO provides the primary system benefit through the lower voltage and energy savings. The DA provides the opportunity to optimize savings from the VVO system and to gain additional energy saving benefits as well as reliability benefits. Unbundling the project would require a review of benefits that could be achieved in a different project scope.

(b) Please see (a) above which summarizes the problem being solved for each component.

VECC-22

Reference: ICM Application Page 22

Question:

Please provide the timing of the detailed design phase of the project.

Response:

Detailed engineering will be carried out over the first ten months of the project once approved by the OEB.

VECC-23

Reference: ICM Application Page 27 Table 4

Question :

Please provide the total proposed equipment quantities to be installed as a percentage of PUC's total existing asset quantities.

Response:

The following table quantifies the total proposed equipment quantities to be installed as a percentage of the PUCs total existing asset quantities. Please note that where 'N/A' is shown it indicates the existing installed asset quantity (i.e.: before the smart-grid project) is zero.

Equipment Description	Existing Equipment Installed (Quantity)	Proposed Equipment to Install (Quantity)	Total (Quantity)	Increase (%)
15kV pole top switches w/controller	0	35-40	40	N/A
15kV pole top recloser w/controller	3	35-40	43	1333%
15kV 2-way pad mount switches w/controller	0	4-8	8	N/A
15kV 4-way pad mount switches w/controller	0	4-8	8	N/A
3 phase O/H FCI	0	~30	30	N/A
3 phase U/G FCI	0	~20	20	N/A
Substation Regulators w/controller	0	~48	48	N/A
Line Regulators w/controller	0	3-5	5	N/A
Capacitors	5	2-4	9	80%
3 phase O/H FCI - auto transfer	0	~15	15	N/A
SpeedNet 900 MHz radios	12	~45	57	375%
SpeedNet repeaters	2	~12	14	600%
SpeedNet 900 MHz gateway radios	2	~10	12	500%

VECC-24

Reference: Appendix K

Questions:

(a) Please provide the date of the Project Cost Estimate.

(b) Was the project Cost Estimate reviewed by an independent third party?

(c) Please identify any expenditures that would otherwise be included in PUC's capital or operating budgets.

(d) Please provide a breakdown of the costs to date related to the SSG Project.

(e) Please provide a breakdown of costs by party.

(f) Please provide the contingency for the project.

(g) Please provide the contingency for Phase 1 and Phase 2.

(h) Please provide the key milestones for the project.

Response:

(a) The date of the Project Cost Estimate is January 1, 2019.

(b) The Project Cost Estimate was not reviewed by an independent third party.

(c) There are no expenditures that would otherwise be included in PUC Distributions capital or operating budgets.

(d) The total cost as of March 31, 2019 for PUC Distribution for the SSG Project is $535,118 as detailed in the chart below.

	Costs
Labour & Expenses	$199,428
External Engineering & Legal	$335,690
Total	**$535,118**

(e) PUC Distribution does not have information on developer costs incurred to date.

(f) PUC Distribution has a contingency on its portion of the project which is approximately $164,000.

(g) PUC Distribution has not completed this calculation.

(h) Please refer to Appendix F – Smart Grid Initiatives, History & Timeline and Appendix J – Project Specification and Scope Documents in the ICM Application.

VECC-25

Reference: ICM Application Appendix C Leidos Engineering LLC. Report, Utility Distribution Microgrid AMI Integration, Page 16

Preamble:

The Leidos' report states that for a UDM to be successful, clear internal metrics and reports will be required that track performance of the UDM, identify operational issues or inefficiencies and provide supporting detail for design, build and operational stages. Ultimately, any operating organization will need a data driven set of metrics to optimize and ensure maximum value from the UDM for both internal and external users, customers, and stakeholders.

Question:

(a) Please provide the internal performance metrics that will be used to track the project and optimize and ensure maximum value.

Response:

Although not all project performance metrics have been developed the initial set planned are indicated in the table below.

Metrics	Project Title:
GHG Emission Reductions and other Environmental Benefits	**Process indicators-VVM:** Reduced energy losses from GHG emitting supply (kWh); reduced customer energy consumption (kWh) **Impact indicators-VVM:** Tons CO_2e avoided from reduced energy losses and reduced customer consumption **Process indicators-DA:** # of truck rolls avoided; reduced energy losses from GHG emitting supply (kWh), resulting from re-conductoring and phase-balancing **Impact indicators-DA:** Tons CO_2e avoided from reduced vehicle emissions and reduced energy losses
Improved Asset Utilization and Increased Efficiency	**Process indicators-VVM:** Reduced peak demand on utility assets (kW); Reduced nee d for grid reserve capacity (kW); Increased load factor on certain assets; Reduced energy losses (kWh) **Impact indicators-VVM:** \$ savings from deferred system upgrades; \$ reduced utility demand charges; \$ energy savings to customers **Process indicators-DA:** # of truck rolls avoided (vehicle miles); reduced overtime (OT hours); # of customer minutes with outages avoided (minutes)

	Impact indicators-DA: O&M savings due to reduced truck rolls and overtime;
Increased Reliability and Resiliency	**Process indicators-VVM:** None **Impact indicators-VVM:** None **Process indicators-DA:** # of events Fault Location, Isolation and Restoration responded to; # customer calls/complaints avoided due to fewer outages **Impact indicators-DA:** $ revenue loss avoided from outages avoided; customer average interruption duration index (CAIDI) for customers served by the project; customer minute interruptions avoided
Increased System Flexibility and Renewable Energy Penetration	**Process indicators-VVM:** # of feeders with VVM installed and operational **Impact indicators-VVM:** # of voltage actions taken annually to improve grid efficiency and mitigate renewable intermittency **Process indicators-DA:** # of feeders integrated into Fault Location, Isolation and Restoration (FLIR) system **Impact indicators-DA:** % of feeders with automation
Cyber Security	**Process indicators-VVM:** Best practices developed or applied on system communications with AMI (qualitative indicator) **Impact indicators-VVM:** Real-time issue identification and reaction to cyber security threats **Process indicators-DA:** best practices developed or adhered to **Impact indicators-DA:** real-time issue identification and reaction to cyber security threats
Economic and Social Benefits	**Process indicators-VVM:** # jobs to implement system and highly qualified personnel trained, business case established/documented for VVM (Project) **Impact indicators-VVM:** Reduced customer charges due to improved (flatter, lower) voltage profile across the feeder (project); reduced customer charges or off-set increases to customer charges due to the lower demand charges and energy saved at the system level **Process indicators-DA:** # jobs to implement system and created to monitor the system; # customer jobs created due to higher reliability/resiliency **Impact indicators-DA:** $ customer value (e.g. avoided revenue loss) from avoided outages

VECC-26

Reference: ICM Application Appendix C

Question:

Please discuss the current involvement and role of Leidos Engineering LLC in the SSG Project.

Response:

Leidos no longer has a current role or involvement in the SSG Project.

VECC-27

Reference: ICM Application Appendix D Navigant Report #1: Review of Business Case for Smart Grid Project for PUC Distribution, Page 1

Preamble:

The Report indicates Energizing Company (ECo) is proposing to assist PUC with the implementation of a Utility Distribution Micro_grid (UDM).

Questions:

(a) Please explain the relationship between ECo and PUC and the other parties listed in the SSG Project Organizational Chart at Appendix I.

(b) Please provide a breakdown of the costs ECo is currently responsible for.

Response:

(a) Stonepeak is no longer involved in the project. The project will be financed through a combination of long-term project finance debt and equity. The equity capital shall consist of (1) institutional investment funds managed by a joint-venture consisting of Diode Ventures LLC (an affiliate of Black & Veatch) and Alma Global Infrastructure LLC and (2) IE as the original developer.

- Energizing, LLC (aka 'Energizing Co.' or 'ECo') changed its name to Infrastructure Energy, LLC (IE). It is the same entity. Infrastructure Energy, Project development partner;

- PUC Distribution, Regulated Local Distribution Company and project proponent;

- Diode Ventures and Alma Global, Project investment partner;

- Black & Veatch, Project engineering, procurement and construction (EPC) partner, and

- SSG, Inc., special purpose vehicle (SPV) holding project assets during term of project.

(b) ECo/IE are responsible for prefeasibility phase, including preliminary engineering work, governance and due diligence, review reports by Navigant. Each party is responsible for their own legal costs of negotiation of agreements.

VECC-28

Reference: ICM Application Appendix D Navigant Report #1: Review of Business Case for Smart Grid Project for PUC Distribution, Page 9

Preamble:

The Navigant Report #1 states, "The overall system design, architecture and system components are comparable with DA and VVM systems that Navigant has reviewed or analyzed throughout the U.S. and Canada. We note the proposed feeder coverage for DA and VVM – 84% and 68% – is higher than many other systems Navigant has encountered. We understand that one of PUC's goals was to ensure that the benefits of the system were shared across the community to the extent possible. This coverage should maximize the total amount of benefits that can be achieved by DA and VVM on PUC's distribution system, though it may not represent the optimal economic level of VVM and DA."

Questions:

(a) Please provide the feeder coverage typically encountered by Navigant.

(b) Please discuss the likelihood that some feeder locations are expected to be upgraded or targeted for reliability improvements over the next few years and may produce lower than expected economic benefits.

(c) Has PUC selected worst performing feeders for DA?

Response:

(a) Navigant has reported that VVO and phase balancing solutions can likely be deployed on 30% of feeders in Ontario (reference to the Navigant 2017 report to the Ministry of Energy – Considerations for Deploying In-Front-of-the-Meter Conservation Technologies in Ontario).

(b) PUC Distribution does not have any work in the current DSP that is expected to materially change benefits projected in this ICM Application.

(c) Outage performance was one of the criteria applied in the selection of the DA solution along with circuit configuration, load transfer capacity and cost.

VECC-29

Reference: ICM Application Appendix D Navigant Report #1: Review of Business Case for Smart Grid Project for PUC Distribution, Page 20

Preamble:

Navigant indicates "As part of the proposed project, PUC will make a fixed monthly payment to ECo for the operating period of the contract. This contractual arrangements include a *performance management strategy* intended to ensure that the performance of the UDM system meets all contract expectations and design specifications. Under this arrangement for example, if the DA system, intended to locate, isolate, and restore faults automatically, fails to restore power to an un-faulted zone within 5minutes, the monthly payment could reflect a financial penalty for failing to meet performance standards.

Question:

Please discuss if any contractual agreements for the SSG Project include financial penalties for failing to meet performance standards.

Response:

The draft contract agreement includes performance standards metrics and potential financial penalty for non performance.

VECC-30

Reference: ICM Application Appendix D Navigant Report #1: Review of Business Case for Smart Grid Project for PUC Distribution, Page 25

Preamble:
Navigant states "Leidos reduced the level of potential reliability improvement, as measured by SAIFI and SAIDI, from a theoretical reference of approximately 70% to estimates of 50% for feeders equipped with DA. Navigant agrees with the theoretical improvement in reliability predicted by Leidos' methodology. However, Navigant has found that actual improvement in reliability statistics are sometimes lower than predictions due to a variety of factors such as inaccurate historic reliability data, failure of the FLIR to detect or isolate all interruption, or future improvements on distribution feeders. The latter may include enhanced reliability improvement programs such as enhanced trimming, replacement of deteriorated equipment, and enhanced protection systems.

Question:

Please explain how PUC has considered Navigant's finding that actual improvement in reliability statistics are sometimes lower than predictions and how this impacts the reliability benefit calculation.

Response:

PUC Distribution agrees with Navigant comments and has considered potential for actual reliability improvement performance to be difference from theoretical. Leidos adjustments of 70% to 50% were apart of this discussion. In addition, PUC Distribution proposed a conservative 25% valuation of calculated reliability benefits in benefit estimates.

VECC-31

Reference: ICM Application Appendix D Navigant Report #1: Review of Business Case for Smart Grid Project for PUC Distribution, Page 27

Preamble:

Navigant indicates it did not independently confirm the level of reliability improvements or energy reduction.

Question:

How has PUC independently confirmed the level of reliability improvements and energy reductions?

Response:

As indicated in the Navigant Report cited above:

"Based on the technical review summarized above, Navigant concludes the UDM project is technically sound, designed and configured consistent with current utility practices. The project as designed will produce improved reliability and energy savings for PUC, its customers and will lower provincial power costs. **Navigant did not independently confirm the level of reliability improvements or energy reduction** but agrees with the methods applied by Leidos to predict reliability outcomes and energy savings.[24]"

[24] Navigant did not obtain or review PUC historic reliability data or conduct independent analysis of PUC's distribution system.

Although Navigant indicated they did not independently confirm the level of reliability improvements or energy reduction, PUC Distribution has confidence in the accuracy of the historic reliability and energy data used for the analysis. The reliability results are consistent with the range of results reported in industry publications including Navigant Report for California Energy Commission Research published as the Value of Distribution Automation in 2009.

VECC-32

Reference: ICM Application Appendix D Navigant Report #1: Review of Business Case for Smart Grid Project for PUC Distribution, Page 27

Preamble:

Navigant notes "Leidos was not able to cite other LDC's where it has designed and implemented a system of comparable scope (i.e. level of coverage). Similarly, both Leidos commentary and Navigant's review of prior Survalent experience in DA and VVM systems suggest that the proposed UDM project is more comprehensive than other projects reviewed both in terms of the level of coverage and project size relative to the size of PUC's distribution system. Navigant does not view the project scope as unreasonable and acknowledges that Leidos has the background and capability to perform requisite engineering and design of the UDM. Rather, we offer these observations both to reinforce the comprehensive nature of the project and to acknowledge the potential for cost overages, scheduling issues and lower than expected benefits for some segments of the system."

Question:

In the context of PUC's proposed change management process, please discuss the potential impact on the project if there are significant cost overages, scheduling issues and delays and lower than expected benefits for some segments of the system.

Response:

PUC Distribution notes there is no impact on the project for cost overages, scheduling issues and delays as this is a turn-key fixed price contract. PUC Distribution does expect some variance in benefits over different segments of the system, but overall system average is reasonable.

VECC-33

Reference: ICM Application Appendix D Navigant Report #1: Review of Business Case for Smart Grid Project for PUC Distribution, Page 28 Table 3

Question:

Please provide an updated Table showing the distribution of SSG Project costs by project features.

Response:

Table 3 cited above is no longer the structure of the intended project as there are no longer substation upgrades included in the scope of the project. The current estimated costs of the three major components of the system are outlined in Appendix K in the ICM Application and are estimated at DA – 43%, UDM – 46% and AMI – 11%.

VECC-34

Reference: ICM Application Appendix D Navigant Report #1: Review of Business Case for Smart Grid Project for PUC Distribution, Page 29

Questions:

(a) Please provide the latest cost and % of total SSG project costs for the following categories:

- Engineering
- System integration of AMI, VVM and DA Systems
- Total design

(b) Project Management and Control

Please provide industry averages for total design, project management and system integration costs.

Response:

(a) The latest breakdown of cost and percentage of the total SSG Project is located in Appendix K of the ICM Application. Engineering including Total Design percentages have increased due to the removal of the major capital assets in the substation upgrades. These are estimated at 23% of the project. System Integration has not been estimated on a standalone basis. Project Management and Control is at 10.7%.

(b) PUC Distribution does not have any references to cite for industry averages for total design, project management and system integration costs.

VECC-35

Reference: ICM Application Appendix D Navigant Report #1: Review of Business Case for Smart Grid Project for PUC Distribution, Page 30

Preamble:

At Page 30, Navigant indicates any unscheduled work, and corresponding costs, will be a responsibility of PUC.

Question:

Please discuss PUC's proposed treatment of unscheduled costs.

Response:

PUC Distribution expects that any unscheduled (any required work outside of the maintenance plan) costs will become a normal operating cost within PUC Distribution.

VECC-36

Reference: ICM Application Page 38

Preamble:

PUC provides 3 options regarding the SSG Project. NRCan Funding requires projects to be completed by March 31, 2022.

Questions:

(a) Did PUC consider pursuing and developing the project over 3 years and have the project in-service by December 31, 2021. If not, why not?

(b) Please provide the impact of implementing the project over three years instead of two years.

Response:

(a) Please refer to Staff-30 for consideration of pursuing this project over 3 years

(b) Please refer to (a).

VECC-37

Reference: ICM Application Page 42

Preamble:

PUC states "….in keeping with good utility practice, the SSG would likely still need to occur at some point in the future in order to upgrade PUC Distribution's grid to the industry standard.

Question:

Please define the industry standard referred to above.

Response:

Please refer to SEC-21.

VECC-38

Reference: None

Question:

Please provide PUC's most reliable check on the assumptions and impacts estimated for the two (2) year project.

Response:

PUC Distribution's most reliable check on the assumptions and impacted estimated for the two-year project is the team diligence in review of all these elements of the project:

- Detailed review in historical outage data and review;
- Detailed review of smart meter energy use;
- GIS network data to support Leidos load flow modelling;
- Navigant due diligence review reports of estimated impacts/benefits/costs; and
- Review of industry information and reports.

VECC-39

Reference: ICM Application Appendix D Navigant Report #2: Review of Project Costs for Smart Grid Project, Page 8

Preamble:

The Navigant report states "From the standpoint of the business case review, PUC could choose an alternative approach rather than pursue the ECo proposal.

Question:

Please discuss if PUC considered any alternative approaches such as implementing only portions of the capabilities proposed by Eco.

Response:

PUC Distribution did consider the alternative approaches suggested by Navigant in Navigant Report #1. Specific formal options were evaluated and described in ICM Application Section 7 – Prudence. Balancing criteria such as optimal economic level, neutral bill impact and an equitable treatment objective of those who pay receiving benefit were additional considerations in selecting the project presented for approval.

VECC-40

Reference: Appendix J

Preamble:

The Design and Construction Specifications document indicates integration with PUC's existing Geographic Information System (GIS) was originally planned, but based upon discussions with PUC staff and Survalent, the approach was changed so that GIS integration is no longer required.

Question:

Please explain why GIS integration is no longer required.

Response:

During the preliminary development stages of the SSG project, consideration was given to using GIS rather than SCADA as a central element in the control system design. After more detailed review, it was determined that the SCADA software was the better solution.

VECC-41

Reference: None

Question:

Please discuss if PUC will make the substation investments regardless of the implementation of the SSG Project.

Response:

In accordance with the DSP and the corresponding substation health indices identified as part of the Asset Management Plan, PUC plans to continue making substation investments regardless of the implementation of the SSG Project. In the event the SSG Project is not approved smart grid elements of the SSG Project would be re-assessed in order to address any smart grid directives and as part of an overall asset management evaluation process.

VECC-42

Reference: ICM Application Appendix H Page 1

Preamble:

The CVR factor is a proportionality variable that relates reductions in electricity demand to voltage reductions. Preliminary work looked at a CVR and savings factors of 0.5 (1.5%) and 0.7 (2.1%). Industry reports and Navigant suggested these may be overly conservative. In the end, PUC selected a CVR = 0.9 (2.7% savings) as an assumption to apply as a system or project average that is applied to the project energy savings estimate.

Questions:

(a) Please confirm that if the original CVRs are used, the Customer Benefit Summary on Page 11 (Table 1) does not result in a net benefit to customers.

(b) Please discuss PUC's confidence level in the selected CVR = 0.9 (2.7% savings).

(c) Please provide references to the industry reports that PUC relies on to conclude the original CVRs may be overly conservative and explain why.

Response:

(a) PUC Distribution confirms if the original CVRs are used, the Customer Benefit Summary does not result in a net benefit to customers.

(b) There is a high likelihood of achieving 2.7% reduction based on design subject to conditions on the grid and external factors. The PUC Distribution project includes use of AMI data which help to maximize energy savings.

(c) References to the industry reports include:

- Navigant Report ICM Application Appendix D - comment on page 36 "notably conservative" with respect to CVR of 0.5. Also Navigant cites PNNL report on page 34 (noted below).
- Navigant Report for Ministry of Energy 2017 – Considerations for Deploying In-Front-of-the-Meter Conservation Technologies in Ontario Page 159 – "The average voltage reduction of these studies is approximately 2.7%/the average CVR factor was 0.91." (Appendix 5)
- Pacific Northwest National Laboratory 2010 – Evaluation of CVR on a National Level – Section 5 Concluding Remarks (#4) – *When extrapolated to a national level it can be seen that a complete deployment of CVR, 100% of distribution feeders, provides a 3.04% reduction in annual energy consumption. (Appendix 6)*

VECC-43

Reference: ICM Application Appendix H Page 1

Preamble:

Reliability savings estimates very pretty widely in industry studies but in the Navigant Community Microgrid Business Case Review report (May 2016) the Leidos values were considered reasonable based on industry data.

Question:

(a) Please provide the Navigant Community Microgrid Business Case Review report (May 2016).

Response:

Please see attached Navigant Community Microgrid Business Case Review report (Appendix 7).

VECC-44

Reference: ICM Application Appendix H Page 1

Preamble**:**

Looking at a complete year of feeder outage data, Leidos estimates the reliability benefits as follows:

- SAIFI reduced by 37%
- SAIDI reduced by 46%
- CAIDI reduced by 16%

Questions:

(a) Please provide the page reference in the Leidos reports in Appendix C for these estimates.

(b) Please provide the analysis that underpins these reliability benefits.

(c) Did Leidos estimate a reduction in MAIFI? If yes, please provide.

(d) Please explain how these estimates translate into an annual projected reliability benefit of $2,550,000 and provide all assumptions and calculations.

Response:

(a) Please refer to page 11 of the Navigant Community Microgrid Business Case Review report attached as Appendix 7 for reference to the Leidos report estimates.

(b) The analysis is described in the Leidos Report #2 – Utility Distribution Microgrid: Distribution Automation in the ICM Application. This data was reviewed by Navigant in the report attached and mentioned above.

(c) Leidos did not estimate a reduction in MAIFI.

(d) Please see VECC-13 (c) and SEC-22.

APPENDIX 1
COPY OF CONTRIBUTION AGREEMENT

DEPARTMENT OF NATURAL RESOURCES

RENEWABLE ENERGY AND SMART GRID DEPLOYMENT PROGRAMS

SMART GRID DEPLOYMENT PROGRAM

REPAYABLE CONTRIBUTION AGREEMENT

THIS AGREEMENT is made in duplicate

BETWEEN:

HER MAJESTY THE QUEEN IN RIGHT OF CANADA ("Canada"), represented by the Minister of Natural Resources,

AND:

PUC DISTRIBUTION INC., a corporation, incorporated under the laws of Ontario (the "Proponent").

WHEREAS Canada wishes to encourage the adoption of the Smart Grid Deployment Program ("the Program");

WHEREAS the Proponent has submitted to the Minister a Proposal for the funding of a Project called **"SAULT SMART GRID (SSG)"** which qualifies for support under the Program;

WHEREAS Canada and the Proponent agree that in order for the Proponent to develop and implement the Project as described in Schedule A (Statement of Work), the Proponent will require financial assistance from Canada;

WHEREAS Canada is willing to provide financial assistance toward the Eligible Expenditures of the Project, in the manner and upon the terms and conditions hereinafter set forth;

AND WHEREAS, to the extent the Proponent derives any Profit from the Project, the Proponent agrees to repay Canada for its financial assistance pursuant to this Agreement;

NOW, THEREFORE, Canada and the Proponent agree as follows:

1. INTERPRETATION

1.1 In this Agreement:

"Agreement" means this Agreement and the attached Schedules A, B, C, D and E;

"Claim Period" means the period to which each advance payment or payment claim pertains as set out in Schedule C (Reports), Section 1;

"Completion Date" means the date that the Proponent shall complete the Project as specified in the ***Conduct of Project Article***;

"Contribution" means the funding provided by the Minister under this Agreement;

"Eligible Expenditures" means any expenditures Incurred by the Proponent, as set out in Schedule B (Budget and Eligible Expenditures), within the Eligible Expenditure Period in accordance with the terms and conditions of this Agreement; however, any Eligible Expenditures Incurred by the Proponent before this Agreement is signed by both Parties are limited to twenty (20) percent of the Contribution from the date the Proponent has been informed that the Project has been approved;

"Eligible Expenditure Period" means the period of September 5, 2018 to March 31, 2021

"Fiscal Year" means the period beginning on April 1st of any year and ending on March 31st in the next year;

"Fixed Asset" means a tangible non-current asset, including buildings and equipment, acquired not for sale but for use for the Project during the Eligible Expenditure Period;

"Incurred" means, in relation to an Eligible Expenditure, such Eligible Expenditure or a portion thereof that is owing and due by the end of each Claim Period;

"Incurred and Paid" means, in relation to an Eligible Expenditure, that the Proponent has paid for the said Eligible Expenditure;

"Intellectual Property" means any Intellectual Property right recognized by the law, including any intellectual property right protected through legislation including governing patents, copyright, trade-marks, and industrial designs;

"Interest Rate" means the Bank Rate, as defined in the *Interest and Administrative Charges Regulations*, in effect on the due date, plus 300 basis points, compounded monthly. The Interest Rate for any given month can be found at: http://www.tpsgc-pwgsc.gc.ca/recgen/txt/taux-rates-eng.html;

"Minister" means the Minister of Natural Resources and includes any duly authorized officers or representatives;

"Party" means either the Proponent or Canada;

"Profit" means in relation to the Project, the net income of the Proponent received from any product or Intellectual Property directly derived from the Project, but in no event shall include any return on rate base earned by the Proponent, all of which is as determined whether using Generally Accepted Accounting Principles (GAAP) or International Financial Reporting Standards (IFRS);

"Project" means the Project described in Schedule A (Statement of Work);

"Proposal" means a written Proposal signed by the Proponent on March 3, 2018, as amended from time to time by mutual consent of the Parties, including at least a background, purpose, work description, results expected, and a budget, which is accepted by the Minister for the Project;

"Rate Adjustment" means the revision of the delivery and regulatory rates to be approved by the Ontario Energy Board;

"Rate Base" means the value of investments on which a public utility is permitted to earn a specified rate of return, in accordance with rules set by a regulatory agency;

"Total Government Funding" means cash contributions provided by the federal government and other contributions from the provincial/territorial and municipal governments toward the Total Project Costs; and,

"Total Project Costs" means the Contribution and other verifiable cash or in-kind contributions either received or contributed by the Proponent and directly attributable to the Project from June 13, 2018 to March 31, 2022

1.2 The following schedules are attached to and made part of this Agreement:

a) Schedule A (Statement of Work);
b) Schedule B (Budget and Eligible Expenditures);
c) Schedule C (Reports);
d) Schedule D (Certification of Eligible Expenditures Incurred and Paid); and,
e) Schedule E (Proposal).

1.3 In case of conflict between any provision in the main body of this Agreement and a provision in a schedule attached hereto, the provision in the main body of this Agreement shall take precedence.

1.4 Grammatical variations of the above-defined terms have similar meanings. Words importing the singular number only shall include the plural and vice versa.

2. REPRESENTATIONS AND WARRANTIES

2.1 The Proponent represents and warrants that all factual matters contained in the Proposal and all supporting material submitted are true and accurate in all material respects, and that all estimates, forecasts and other related matters involving judgement were prepared in good faith and to the best of its ability, skill and judgement.

2.2 The Proponent represents and warrants that it is duly incorporated or registered and validly existing in good standing under the laws of Ontario and has the power and authority to carry on its business, to hold property, and undertakes to take all necessary action to maintain itself in good standing and preserve its legal capacity during the term of this Agreement.

2.3 The Proponent represents and warrants that the signatory to this Agreement has been duly authorized to execute and deliver this Agreement on its behalf.

2.4 The Proponent represents and warrants that the execution, delivery, and performance of this Agreement have been duly authorized and when executed and delivered will constitute a legal, valid, and binding obligation of the Proponent enforceable in accordance with its terms.

2.5 The Proponent represents and warrants that it has not, nor has any person offered or promised to any official or employee of Her Majesty the Queen in Right of Canada, for or with a view to obtaining this Agreement any bribe, gift or other inducement and it has not nor has any person on its behalf employed any person to solicit this Agreement for a commission, fee or any other consideration dependent upon the execution of this Agreement.

3. COMING INTO FORCE

3.1 This Agreement comes into force when signed by the Parties.

3.2 Except as otherwise provided in the articles below, this Agreement will terminate on the later of:

a) the date the Proponent has met, to the satisfaction of the Minister, all the obligations to repay the Contribution as described in the ***Repayment of Contribution Article*** of this Agreement; or,

b) the date on which the Proponent paid to the Minister all amounts due under this Agreement.

3.3 The Proponent undertakes to receive approval from the Ontario Energy Board for the required Rate Adjustment by March 31, 2019.

3.4 Notwithstanding Article 12 (Default) of this Agreement, Canada reserves the right to terminate this Agreement upon thirty (30) days' written notice to the Proponent in the event that the Proponent has not complied with paragraph 3.3 above. Upon thirty (30) days of this Agreement's termination, in accordance with this paragraph, the Proponent shall reimburse the Minister the amount of the Contribution disbursed. Any such amount is a debt due to Her Majesty in Right of Canada and is recoverable as such.

3.5 The following clauses shall survive the termination of this Agreement for an additional 5 years:

a) Repayment of Contribution Article;
b) Accounts and Audits Article;
c) Intellectual Property Article;
d) Indemnity Article;
e) Default Article;
f) Reports Article; and
g) Dispute Resolution Article

4. CONDUCT OF PROJECT

4.1 The Proponent shall carry out the Project promptly, diligently and in a professional manner and in accordance with the terms and conditions of this Agreement.

4.2 The Proponent shall complete the Project by March 31, 2021 unless terminated earlier pursuant to the provisions of this Agreement.

4.3 The Proponent shall comply with all applicable federal, provincial and municipal laws in relation to the Project.

4.4 The Parties are satisfied that any legal duty to consult with Aboriginal groups affected by the Project, and where appropriate, to accommodate Aboriginal group's concerns has been met and continues

to be met. If as a result of changes to the nature or scope of the Project Canada determines that a legal duty to consult is triggered, the Proponent agrees that all of Canada's obligations pursuant to this Agreement will be suspended from the moment that Canada informs the Proponent that a legal duty to consult arises.
In the event that a legal duty to consult arises, the Proponent agrees that:

a) Canada will withhold any payment of the Contribution toward Eligible Expenditures until Canada is satisfied that any legal duty to consult with, and where appropriate, to accommodate Aboriginal groups has been met and continues to be met;
b) if, as a result of such changes to the Project, Canada determines that further consultation is required, the Proponent will work with Canada to ensure that the legal duty to consult, and where appropriate, to accommodate Aboriginal groups, is met and continues to be met to Canada's satisfaction; and
c) it will consult with Aboriginal groups that might be affected by the changes to the Project, explain the Project to them, including Canada's role, and will provide a report to Canada, which will include:
    i) a list of all Aboriginal groups contacted;
    ii) a summary of all communications to date with the Aboriginal groups, indicating which groups support or object to the Project, and whether their positions are final, preliminary or conditional in nature;
    iii) a summary of any issues or concerns that the Aboriginal groups have raised and an indication of how the Proponent has addressed or proposes to address those issues or concerns; and
    iv) any other information Canada may deem appropriate.

5. ENVIRONMENT

5.1 The Proponent represents and warrants that the Project is not a designated project under the Canadian Environmental Assessment Act, 2012 and that it is under no obligation or prohibition, nor is it subject to or threatened by any actions, suits or proceedings, including those arising out of the Canadian Environmental Assessment Act, 2012 which could or would prevent compliance with this Agreement and undertakes to advise the Minister forthwith of any such occurrence during the term of this Agreement.

5.2 Notwithstanding any other provision of this Agreement, if during the Eligible Expenditure Period, a change that would trigger a reassessment of the Project under the *Canadian Environmental Assessment Act, 2012* is proposed for, or made to the Project, the Parties agree that Canada's obligation under this Agreement shall be suspended until an environmental effects evaluation is completed and Canada determines that the Project as modified is unlikely to result in any significant adverse environmental effects.

5.3 The Proponent shall provide any information requested by Canada to satisfy Canada's obligation under the Canadian Environmental Assessment Act, 2012 as a result of the Project.
5.4 The Proponent shall comply with all conditions arising out of an environmental effects evaluation in respect of the Project in accordance with the provisions of the Canadian Environmental Assessment Act, 2012 including any such conditions requiring the implementation of mitigation measures and any follow up program.

6. CONTRIBUTIONS

6.1 Notwithstanding any other provision of this Agreement, the Contribution shall not in any circumstances exceed the lesser of:

a) Twenty Five percent (25%) of Total Project Costs incurred; or
b) Eleven Million Eight Hundred Seven Thousand Dollars ($11,807,000).

6.2 The Fiscal Year allocations for the Contribution are as follows:

2018-2019	Six Million Six Hundred Fifty Three Thousand Dollars ($6,653,000)
2019-2020	Three Million Eight Hundred Sixty Five Thousand Six Hundred Ten Dollars ($3,865,610)
2020-2021	One Million Two Hundred Eighty Eight Thousand Three Hundred Ninety Dollars ($1,288,390)

Any reallocation of the Contribution amounts in whole or in part from one Fiscal Year to another shall require a written amendment signed by the Parties.

6.3 In order to be eligible to receive payment for any remaining portion of the Contribution as described herein, the Proponent must submit its final claim for payment on or before June 30, 2021.

6.4 The Minister will not contribute to any Eligible Expenditure Incurred by the Proponent prior to or after the Eligible Expenditure Period.

6.5 If by the Completion Date, the Total Government Funding as set out in Schedule B (Budget and Eligible Expenditures), the Proponent has received exceeds One Hundred percent (100%) of the Total Project Costs incurred, the Minister may require the Proponent to reimburse such excess back to Canada.

6.6 The Proponent represents that no other federal, provincial, territorial or municipal government assistance, other than those described below and listed in Schedule B (Budget and Eligible Expenditures), has been or will be provided in respect of the Total Project Costs incurred:

Canada (NRCan): Eleven Million Eight Hundred Seven Thousand Dollars ($11,807,000)
Other Federal: No Dollars ($0)
Provincial: Five Hundred Thousand Dollars ($500,000)
Territorial: No Dollars ($0)
Municipal: No Dollars ($0)
Total Government Funding: Twelve Million Three Hundred Thousand Dollars ($12,307,000)

The Proponent shall advise the Minister promptly of any change in the Total Government Funding listed above during the term of this Agreement.

6.7 Within ninety (90) days after the Completion Date, the Proponent shall provide the Minister with a declaration as to the total amount of contributions or payments, including Total Government Funding, received by the Proponent.

7. METHOD OF PAYMENT

7.1 Subject to the terms and conditions of this Agreement, Canada shall make the Contribution toward the Eligible Expenditures Incurred for which the goods have been received or the services have been rendered.

7.2 Subject to the terms and conditions of this Agreement, Canada shall make the Contribution toward the Eligible Expenditures Incurred for which the goods have not been received or for which the services have not been rendered, provided that:

a) For equipment, materials, or products, or contracting services related to the purchase of equipment, materials, or products:

i) Any claim for an Eligible Expenditure greater than $100,000, is supported by proper documentation which includes, but is not limited to a signed contract, a payment schedule showing milestone payment due dates, and invoice(s) due by said Claim Period;

ii) Any claim for an Eligible Expenditure of up to $100,000, is supported by proper documentation which includes, but is not limited to a purchase order, and an invoice(s) due by said Claim Period;

b) For Eligible Expenditures that are not described in paragraph a) above:

i) Any claim for an Eligible Expenditure greater than $50,000, is supported by proper documentation which includes, but is not limited to a signed contract or purchase order, showing payment due dates, and invoice(s) due by said Claim Period, and is subject to Canada's approval to reimburse the Eligible Expenditure before the goods or services pertaining to said Eligible Expenditure are received or rendered;

ii) Any claim for an Eligible Expenditure of up to $50,000, is supported by proper documentation which includes, but is not limited to a signed contract or purchase order, and an invoice(s) that is due by said Claim Period.

For greater clarity, the amounts described herein include the total cost of the Eligible Expenditure, and not the amount of any individual invoice related to said Eligible Expenditure.

7.3 The Minister shall withhold twenty five (25%) from each payment until the Proponent has:

a) completed the Project to the satisfaction of the Minister;

b) submitted a final report documenting the completion of the Project as set out in Schedule C (Reports) have been received and approved by the Minister and the Minister has approved said report;

c) certified, in the manner set out in Schedule D (Certification of Eligible Expenditures Incurred and Paid), that the Proponent has Incurred and Paid all claims for the payment of Eligible Expenditures of the Project;

d) submitted and the Minister has received and approved a final statement of Eligible Expenditures Incurred and Paid in respect of the Project; and,

e) submitted a technical performance report, completed to the satisfaction of the Minister as set out in Schedule C (Reports).

7.4 In addition to paragraph 7.3 above, from January 1, 2019, Canada will withhold one hundred (100) per cent of the Contribution until the Ontario Energy Board has approved the required Rate Adjustment for the Project and the Proponent has provided a copy of said approval to the Minister.

7.5 In order to receive payment of Eligible Expenditures, the Proponent shall submit claims for payment, as set out in Schedule C (Reports). All claims must be submitted no later than **thirty (30) days** after the end of each quarter, except the claim for the final payment.

7.6 Notwithstanding the ***Amendments Article***, following receipt of a written request from the Proponent in accordance with the ***Notices Article***, the Minister may approve in writing at its sole discretion an extension to submit any claim or any report required to be submitted in accordance with this Agreement.

7.7 Where for any reason the Minister determines that the amount of the Contribution disbursed exceeds the amount to which the Proponent is entitled or the Proponent is not entitled to the Contribution, the Proponent must repay to Canada no later than thirty (30) days from the date of the Minister's notice, the amount of the overpayment or the amount of the Contribution disbursed. If the amount is not repaid by its due date, interest accrues at the Interest Rate for the period beginning on the due date and ending on the day before the day on which repayment to Canada is received. Any such amount is a debt due to Her Majesty in Right of Canada and is recoverable as such.

7.8 Without limiting the scope of the set-off rights provided for under the Financial Administration Act, it is understood that the Minister may set off against any amount that may be payable to the Proponent pursuant to this Agreement, any amounts owed and past due by the Proponent to Her Majesty the Queen in Right of Canada under any legislation or contribution agreements and the Proponent shall declare to the Minister all amounts outstanding in that respect when making any claim under this Agreement.

8. REPAYMENT OF CONTRIBUTION

8.1 For a period of **5 years** commencing on the day immediately following the Completion Date, the Proponent shall pay to Canada annually the Profit arising from the Project in the same ratio as that of Canada's Contribution to the Total Project Costs, except that Canada's share shall not exceed its Contribution.

8.2 The Proponent shall submit financial reports and payments to Canada as described in Schedule C (Reports), for the period set out in the paragraph above.

8.3 The Proponent agrees that all considerations to be received by the Proponent in respect of the licensing, selling, marketing or commercialization of the Intellectual Property arising in the course of the Project to non-arms' length parties shall be deemed to be that which would be established in bona fide arm's length transactions between the Parties.

8.4 The Proponent shall pay to Canada interest at the Interest Rate on any payment that is overdue from the date such amount becomes overdue and ending on the day before the day on which repayment to Canada is received.

9. ACCOUNTS AND AUDITS

9.1 Prior to the Completion Date of the Project and for five (5) years after the termination of this Agreement, as described in the ***Coming Into Force Article***, the Proponent shall, at its own expense:

a) keep proper and accurate books, accounts, and records of its revenue received and expenses Incurred and Paid in connection with the Project and shall keep its invoices, receipts, and vouchers relating thereto;

b) keep proper and accurate records relating to the environmental impact (if any) of the Project;

c) keep proper and accurate records of all data, analyses, and other scientific or technical assessments and reports, and any and all information relating to the outputs and outcomes of the Project;

d) on demand, make available to the Minister such books, accounts, records, invoices, receipts, and vouchers referred to above and permit the Minister to examine and audit and take copies and extracts from such documents;

e) allow the Minister, at the Minister's own expense and discretion, to conduct a technical audit to verify that the proposed measures outlined in Schedule A (Statement of Work) were implemented in accordance with this Agreement; and

f) allow the Minister, at the Minister's own expense and discretion, to conduct an audit to verify the accuracy of reports submitted under Schedule C (Reports).

9.2 In respect of Eligible Expenditures related to professional, scientific and contracting services outlined in Schedule B (Budget and Eligible Expenditures), Canada's auditors may, acting reasonably, request that the Proponent's books, accounts and records be supplemented by information from the books, accounts and records of the subcontractors engaged by the Proponent having contracts in excess of twenty (20) percent of the Contribution for the purposes of the Project. The Proponent will use commercially reasonable efforts to obtain such information as is reasonably requested by Canada's auditors from the Proponent's subcontractors, subject to and to the extent permitted by terms of the applicable contracts and, in particular, the audit provisions of such contracts.

10. INTELLECTUAL PROPERTY

10.1 All Intellectual Property that arises in the course of the Project shall vest in the Proponent, or be licensed to the Proponent in the event that a Proponent's subcontractor retains title to such Intellectual Property.

10.2 The Proponent shall supply to Canada the reports and documents described in Schedule C (Reports) or as otherwise required by the Minister under the ***Reports Article***, and the Proponent hereby grants to Canada a non-exclusive, irrevocable, world-wide, free and royalty-free license in perpetuity to use, modify, and, subject to the Access to Information Act, make publicly available such reports and documents for non-commercial governmental purposes.

11. INDEMNITY

11.1 Neither Canada, nor its employees, officers and agents, will have any liability in respect of claims of any nature, including claims for injury or damages, made by any person involved in the activities of the Project or as a result of or arising out of this Agreement, and the Proponent will indemnify and save harmless Canada, its employees, officers and agents, in respect of such claims.

12. DEFAULT

12.1 The Minister may declare that an event of default has occurred if:

a) the Proponent becomes insolvent or is adjudged or declared bankrupt or if it goes into receivership or takes the benefit of any statute from time to time in force relating to bankrupt or insolvent debtors;

b) an order is made which is not being contested or appealed by the Proponent or a resolution is passed for the winding up of the Proponent or it is dissolved;

c) in the opinion of the Minister, there has been a misrepresentation or breach of warranty under the ***Representations and Warranties Article***;

d) in the opinion of the Minister, acting reasonably, a material adverse change in risk affecting the fulfilment of the terms and conditions of this Agreement has occurred;

e) any term, condition or undertaking in this Agreement is not complied with, including, without limitation, any of those in the ***Conduct of Project Article, the Environment Article or Method of Payment Article,*** and any such defect has not been cured by or remedied by the Proponent within thirty (30) days of written notice of such defect having been provided to the Proponent; or,

f) the Proponent neglects or fails to pay the Minister any amount due in accordance with this Agreement.

12.2 If the Minister declares that an event of default has occurred, in addition to all other remedies provided under contract law, the Minister may exercise one or more of the following remedies:

a) suspend any obligation of Canada to contribute or continue to contribute to the Eligible Expenditures of the Project or a part of the Project, including any obligation to pay any amount owing prior to the date of such suspension;

b) terminate any obligation of Canada to contribute or continue to contribute to the Eligible Expenditures, including any obligation to pay any amount owing prior to the date of such termination;

c) terminate this Agreement; or

d) direct the Proponent to repay all or part of the Contribution which has been paid to the Proponent, together with interest from the date of demand at the Interest Rate, with the exception of an event of default listed in Paragraph 12.1(d). Any such amount is a debt due to Her Majesty in Right of Canada and is recoverable as such.

For greater clarity, all above remedies are cumulative.

12.3 The fact that the Minister does not exercise a remedy that the Minister is entitled to exercise under this Agreement will not constitute a waiver of such right and any partial exercise of a right will not prevent the Minister in any way from later exercising any other right or remedy under this Agreement or other applicable law.

13. ACCESS

13.1 The Proponent shall provide the Minister or Minister's representatives, during the Eligible Expenditure Period and for a period of five (5) years after the Completion Date, reasonable access to any premises where the Project takes place to assess the Project's progress or any element thereof subject to providing reasonable notice and complying with the Proponent's safety requirements for such access.

14. REPORTS

14.1 The Proponent shall submit Project reports satisfactory to the Minister in accordance with the provisions of Schedule C (Reports) or as otherwise requested by the Minister.

15. DISPOSITION OF ASSETS

15.1 If, prior to the Completion Date of the Project and for five (5) years thereafter, the Proponent sells, leases or otherwise disposes of any Fixed Asset excluding Intellectual Property, where the cost of the Fixed Asset is part of the Eligible Expenditures under the Project to which Canada has contributed under this Agreement and where the proceeds of the sale, lease or other disposition are not applied to acquire assets in replacement of the Fixed Asset, the Proponent shall immediately notify the Minister in writing of such sale, lease or disposition and, if the Minister so requires, the Proponent shall share with Canada the proceeds of the sale, lease or any other disposition in the same ratio as that of Canada's Contribution to the purchase of the Fixed Asset by the Proponent, except that Canada's share shall not exceed the Contribution.

16. SUBCONTRACTS

16.1 The Proponent shall not subcontract all or any part of the Project except as provided in the Proposal or as otherwise set forth below. The Proponent shall advise the Minister of any other new contract, not originally included in the Proposal, the Proponent enters into with a third party to undertake work on the Project where the estimate of the cost of the work to be performed exceeds twenty (20) percent of the Contribution. The notice shall include a description of the extent and nature of the contracted work, the identity of the contractor, and the estimated cost of the contracted work. For greater certainty, for the purposes of this Article, there is no privity of contract between Canada and any of the Proponent's subcontractors; as such, the selection and amendment of any of the Proponent's subcontractors as may be listed in the Proposal is the sole responsibility of the Proponent and is not subject to the Minister's consent.

17. LEGAL RELATIONSHIP

17.1 Nothing contained in this Agreement shall create the relationship of principal and agent, employer and employee, partnership or joint venture between the Parties.

17.2 The Proponent shall not make any representation that:

a) the Proponent is an agent of Canada; or,
b) could reasonably lead any member of the public to believe that the Proponent or its contractors are agents of Canada.

18. ACKNOWLEDGEMENT

18.1 The Proponent shall acknowledge the financial support of Canada in all public information produced as part of the Project.

18.2 The Proponent will seek prior written consent of the Minister for any public acknowledgement of the financial support of Canada to this Project through news releases, public displays, and public and media events.

18.3 Except for releases of information required to comply with securities regulations or other laws, where media announcements and public events relating to this Project are to be made by a Party, the Party shall use commercially reasonable efforts to give to the other a three (3) weeks prior written notice of any media announcement or public event and a reasonable opportunity to review and comment thereon.

18.4 The Proponent acknowledges that the Proponent's name, the amount awarded, and the general nature of the activities supported under this Agreement may be made publicly available by the Government of Canada.

19. TIME OF ESSENCE

19.1 Time is of the essence with respect to all provisions of this Agreement that specify a time for performance.

20. MEMBERS OF PARLIAMENT

20.1 No Member of the House of Commons or Senate shall be admitted to any share or part of this Agreement or to any benefit arising therefrom that is not otherwise available to the general public.

21. CONFLICT OF INTEREST

21.1 It is a term of this Agreement that all current or former public servants to whom the federal *Values and Ethics Code* for the Public Sector, federal *Policy on Conflict of Interest and Post-Employment*, or *NRCan Values and Ethics Code* applies shall comply with the Codes or Policy, as applicable.

21.2 If any individual working for the Proponent formerly provided consultancy services to the Minister that are related to this Agreement, particularly any services associated with developing the Agreement or developing the Project which is the subject of this Agreement, the Proponent is considered to be in a real, perceived, or potential conflict of interest situation.

21.3 If a conflict of interest situation arises during the Agreement, the Proponent shall notify the Minister, in the manner prescribed in the ***Notices Article***. Upon request, the Proponent shall notify the Minister of all reasonable steps taken to identify, avoid, prevent, and where it exists, resolve any conflict of interest situation.

21.4 The Minister may investigate a real, perceived, or potential conflict of interest and take such steps and measures as the Minister considers appropriate, including without limitation: informing the Proponent that it is in a conflict of interest situation; requesting specific actions be taken to correct the situation; requiring the Proponent to withdraw any individual from participation in the Project for reasons of conflict of interest; suspending payments under the Agreement; or terminating the Agreement.

22. FORCE MAJEURE

22.1 The Parties shall not be in default or in breach of this Agreement due to any delay or failure to meet any of their obligations caused by or arising from any event beyond their reasonable control and without their fault or negligence, including any act of God or other cause which delays or frustrates the performance of this Agreement (a "force majeure event"). If a force majeure event frustrates the performance of this Agreement, Canada will only be liable for its proportionate share of the Eligible Expenditures Incurred and Paid to the date of the occurrence of the event.

22.2 The performance of the obligation affected by a "force majeure event" as set out above shall be delayed by the length of time over which the event lasted. However, should the interruption continue for more than thirty (30) days, this Agreement may be terminated by Canada.

22.3 Should either Party claim the existence of a "force majeure event" as above, prompt notice thereof shall be given to the other Party and the Party claiming the existence of a "force majeure event" shall have the obligation to provide reasonable satisfactory evidence of the existence of such event and use its best efforts to mitigate any damages to the other Party.

23. CONFIDENTIALITY

23.1 Except as otherwise provided in this Article, Canada agrees that this Agreement and all financial, commercial, scientific and technical information concerning the Project, other than that contained in the reports described in Sections 2 and 3 of Schedule C (Reports) that are submitted to the Minister under the *Reports Article,* which is made available or disclosed to Canada by the Proponent (the "Confidential Information") shall be kept confidential and shall not be disclosed to any third party.

23.2 Notwithstanding the foregoing, the above paragraph will not apply to any Confidential Information if:

a) it was in the public domain at the time of disclosure to Canada, or thereafter becomes part of the public domain through no fault of Canada;
b) it is later received from a third party having the legal right to disclose it;
c) it is required by the *Access to Information Act* (Canada) to be disclosed;
d) it becomes available to Canada on a non-confidential basis provided that the source of the Confidential Information is not and was not bound by a confidentiality agreement with the Proponent to hold that Confidential Information confidential; or
e) the Proponent and any third party affected by the disclosure consents to that disclosure.

23.3 The Proponent shall use commercially reasonable efforts to make the reports it submits to Canada pursuant to *Reports Article* accurate and complete. However, the Proponent makes no representation or warranty as to the accuracy or completeness of such reports or any other Confidential Information that it provides to Canada, and neither the Proponent, nor anyone representing the Proponent, shall have any liability for any errors or omissions or for any damages resulting from the use of such reports or such Confidential Information.

24. GOVERNING LAW

24.1 This Agreement shall be interpreted in accordance with the applicable federal laws and the laws in force in the Province of Ontario.

25. ASSIGNMENT

25.1 No benefit arising from this Agreement shall be assigned in whole or in part by the Proponent without the prior written consent of the Minister and any assignment made without that consent is void and of no effect.

26. NOTICES

26.1 The claims for payment, requests, reports, notices, repayments and information referred to in this Agreement shall be sent in writing or by any method of telecommunication and, unless notice to the contrary is given, shall be addressed to the Party concerned at the following address:

To Canada:

André Bernier
Senior Director, Renewable and Electrical Energy Division
Smart Grid Deployment Program
Natural Resources Canada
580 Booth Street, 17-B7-3
Ottawa, Ontario K1A 0E4
Telephone: (343) 292-6183
Fax: (613) 995-8343
E-mail: nrcan.sg-ri.rncan@canada.ca

To the Recipient:

Kevin D Bell
Vice President, Business Development
PUC Distribution Inc.
500 Second Line East
Sault Ste. Marie, Ontario P6A 6P2
Telephone: (705) 759-6515
Fax: (705) 759-6596
E-mail: kevin.bell@ssmpuc.com

26.2 Requests, notices and documents are deemed to have been received, if sent by registered mail, when the postal receipt is acknowledged by the other Party; by facsimile or electronic mail, when transmitted and receipt is confirmed; and by messenger or specialized courier agency, when delivered.

26.3 The Minister and the Proponent agree to notify each other in writing if the above contact information changes. This requirement will not cause an Amendment.

27. AMENDMENTS

27.1 No amendment of this Agreement or waiver of any of its terms and conditions shall be deemed valid unless effected by a written amendment signed by the Parties.

28. DISPUTE RESOLUTION

28.1 If a dispute arises concerning the application or interpretation of this Agreement, the Parties will attempt to resolve the matter through good faith negotiation, and may, if necessary and the Parties consent in writing, resolve the matter through mediation by a mutually acceptable mediator.

29. APPROPRIATION

29.1 The payment of monies by Canada under this Agreement is subject to there being an appropriation by Parliament for the Fiscal Year in which the payment of monies is to be made.

29.2 Notwithstanding any other provision of this Agreement, Canada may reduce or cancel the Contribution to the Project upon written notice to the Proponent in the event that the funding levels for the Department of Natural Resources are changed by Parliament during the term of this Agreement. In the event that Canada reduces or cancels the Contribution, the Parties agree to amend the Project and the Eligible Expenditures of the Project, namely this Agreement, to take into account the reduction or cancellation of the Contribution.

30. LOBBYING ACT

30.1 The Proponent shall ensure that any person lobbying on behalf of the Proponent is registered pursuant to the Lobbying Act and that the fees paid to the lobbyist are not to be related to the value of the Contribution.

31. SUCCESSORS AND ASSIGNS

31.1 This Agreement shall inure to the benefit of and be binding on the Parties and their respective representatives, successors and assigns.

32. OFFICIAL LANGUAGES/LANGUES OFFICIELLES

32.1 This Agreement is drawn in English at the request of the Parties. Les Parties ont convenu que le présent Accord soit rédigé en anglais.

32.2 All public information documents related to the Project prepared or paid for in whole or in part by Canada must be made available in both official languages, when the Department of Natural Resources judges that this is required under the *Official Languages Act.* Tout document d'information publique préparé ou payé en tout ou en partie par le Canada ayant trait au Projet doit être offert dans les deux langues officielles, lorsque le Ministère des ressources naturelles le juge pertinent, conformément à la Loi sur les langues officielles.

33. COUNTERPART SIGNATURE

33.1 This Agreement (and any amendments) may be signed in counterparts including facsimile, PDF and other electronic copies, each of which when taken together, will constitute one instrument.

34. SEVERABILITY

34.1 Any provision of this Agreement prohibited by law or otherwise ineffective, will be ineffective only to the extent of such prohibition or ineffectiveness and will be severable without invalidating or otherwise affecting the remaining provisions of the Agreement. The Parties agree to negotiate in good faith a substitute provision which most nearly reflects the Parties' intent in entering into this Agreement.

35. ENTIRE AGREEMENT

35.1 This Agreement constitutes the entire Agreement between the Parties with respect to the subject matter of this Agreement and supersedes all previous negotiations, communications, and other agreements, whether written or verbal between the Parties.

IN WITNESS THEREOF, this Agreement is duly executed on behalf of **Her Majesty the Queen in Right of Canada** by an officer duly authorized by the Minister of Natural Resources and on behalf of the **Proponent**, by an officer duly authorized on its behalf.

HER MAJESTY THE QUEEN IN RIGHT OF CANADA

Date

Jay Khosla
Assistant Deputy Minister
Energy Sector

PUC DISTRIBUTION INC.

Dec 11, 2018
Date

Robert Brewer
President, CEO

SCHEDULE A

To the Agreement between

HER MAJESTY THE QUEEN IN RIGHT OF CANADA

And

PUC DISTRIBUTION INC.

STATEMENT OF WORK

Project Title:	**Sault Smart Grid**
PROJECT OBJECTIVE:	The objective of this Project is to deploy a community-scale smart grid (Sault Smart Grid) in Sault Ste. Marie, Ontario. Using a public private partnership model, the Project will modernize the utility's distribution system infrastructure and deliver customer and community benefits improve the reliability, efficiency, and resiliency of the local grid; provide a platform for renewable energy applications; and reduce greenhouse gas emissions. This Project is intended to cover 100% of the PUC service area while remaining bill neutral for customers.
PROJECT DESCRIPTION:	The project will modernize the utility's distribution system infrastructure by deploying new, state-of-the-art smart grid technologies and leveraging existing smart meter AMI infrastructure. The key components of the Project are: • Advanced Distribution Management System (ADMS); • Outage Management System (OMS); • Fault Detection Isolation Restoration (FDIR) • Volt/VAR Management (VVM); and • Auto-transfer applications. The Project will be financed as a Public-Private-Partnership (P3) contract in order to minimize risk and lower cost to the Proponent. The North American Grid Modernization Fund (one of the sources of funds) will flow through a Special Purpose Vehicle named Sault Smart Grid Inc. (SSG Inc), with financial contributions from Stonepeak Infrastructure Partners (SPIP) and project development from Infrastructure Energy. As is common under P3 arrangements, upon completion and commissioning of the Project, the asset title will be transferred to the Proponent from SSG Inc. Repayment to SSG Inc. will be monthly payments over a 25-year term through a purchase agreement between the Proponent and SSG Inc.
BENEFITS:	**<u>Benefits to Canada/Canadians</u>** This Project will result in reduced electricity costs to consumers from more efficient usage, as well as increased reliability and enhanced power quality. Additionally, the region will benefit from reduced load on the grid. Customers will also benefit from an enhanced utility energy service offering resulting from smart grid implementation. Finally the project will result in job creation and new economic opportunities for the community, as the improvements in grid quality are anticipated to be attractive to a range of industries associated with Canada's clean energy sector (eg. electronics manufacturing, e-commerce, telecommunication services and data centres.). **<u>Benefits to Stakeholders:</u>** Stakeholders will benefit from a reduction in distribution, transmission and generation costs, as well as a more reliable and resilient grid. This will enable utilities to broaden their service offering to clients, and ensure that the community's grid is well-positioned to accommodate new distributed energy resources including renewables, to support smart cities and community economic development.

PROJECT TASKS:

Task Number	Task	Description	Outputs
1	**Engineering and design (Complete by Dec. 2019).**	- Design system integration (IVR, CIS, CYME, AMI) - Design the following: OMS system; upgrade to Survalent SCADA; lab facility; site specific DA design; field area network substation communication - Determine Project technical and IT requirements - Initiate protocol for required permits - Identify and prepare training for business process and organizational changes	- Project design and engineering complete - Local municipal permits obtained - Business process changes identified; train-the-trainer materials complete
2	**Procurement** **(Complete by Dec. 2020)**	- Purchase major materials and equipment including for the following systems: ADMS/OMS;VVO;RF;DA;IVR; Server hardware - Purchase minor materials and equipment - Stage major systems and test using lab facilities - Prepare equipment for field - Perform training identified in training plan	- Major and minor materials and equipment procured and verified - Lab testing plan complete - Training logs delivered
3	**Construction & installation** **(Complete by March 2021)**	- Undertake PUC Line construction - Construct test system - Perform cut-overs from test to development system, and from development to production system - Perform ene-to-end testing - Go live for IVR system. - Install communications equipment at substations & in field - Install field DA equipment	- Cut-over plans complete - Testing including field testing plans complete - Go-live plan complete
4	**Project Management** **(Complete by March 2021)**	- Project management and oversight provided by PUC, including management of change orders and relationships between financier, developer, EPC and vendors - IE to manage project, select vendors, ensure cash flow, manage closing costs, and manage lifecycle costs - PUC and IE to ensure project coordination between PUC and IE	- Status reports provided - Financial statements provided

PERFORMANCE INFORMATION:

Key Performance Indicators:	
1. GHG emissions reductions	Reduction in greenhouse gas emissions Reduced energy losses from GHG emitting supply (kWh)

2. Improved asset utilization and increased efficiency	Reduction in peak demand on utility assets
	Reduction in energy losses
	$ savings from deferred system upgrades
	$ energy savings to customers

3. Increased reliability and resiliency	# events Fault Location, Isolation and Restoration responded to # customer calls/complaints avoided due to fewer outages $ revenue loss avoided from outages avoided

SCHEDULE B

To the Agreement between

HER MAJESTY THE QUEEN IN RIGHT OF CANADA

And

PUC DISTRIBUTION INC.

BUDGET AND ELIGIBLE EXPENDITURES

1. Subject to the limitations set out in the ***Contributions Article***, Eligible Expenditures shall be approved in accordance with Treasury Board Guidelines associated with the execution of the various Activities as described in Schedule A (Statement of Work).

Approved Budget ($)	**2018-19**	**2019-20**	**2020-21**	**TOTAL ($)**
The Program (NRCan Contribution)	$6,653,000.00	$3,865,610.00	$1,288,390.00	$11,807,000.00
ELIGIBLE EXPENDITURES				
Salaries and Benefits	$0.00	$0.00	$0.00	**$0.00**
Overhead	$0.00	$0.00	$0.00	**$0.00**
Professional, Scientific &	$13,306,000.00	$26,912,000.00	$7,396,000.00	**$47,614,000.00**
Travel, including Meals and Accomodations	$0.00	$0.00	$0.00	**$0.00**
Equipment and Products	$0.00	$0.00	$0.00	**$0.00**
Other Expenses	$0.00	$0.00	$0.00	**$0.00**
Total by Fiscal Year:	**$13,306,000.00**	**$26,912,000.00**	**$7,396,000.00**	
			Total Eligible Expenditures	**$47,614,000.00**

INELIGIBLE COSTS				
INELIGIBLE EXPENDITURES	**2018-19**	**2019-20**	**2020-21**	**TOTAL ($)**
Incurred before Eligible Expenditure period (between June 13, 2018 and August 28, 2018)	$300,000.00	-	-	$300,000.00
Ineligible Overhead Expenditures	-	$0.00	$0.00	$0.00
			Total Ineligible Expenditures	**$300,000.00**
IN-KIND COSTS				

Source of Contributions:	**Percentage (%)**	**Cash ($)**	**In-Kind ($)**	**Total ($)**
The Program (NRCan Contribution)	**25%**	11,807,000	N/A	**11,807,000**
The Proponent	**74%**	35,607,000	0	**35,607,000**
Other Canadian Governments (Provincial, territorial, or municipal)	**1%**	500,000	0	**500,000**
TOTAL	**100%**	**$47,914,000**	**$0**	**$47,914,000**

In accordance with the departmental GST/PST/HST certification form, the reimbursable Provincial Sales Tax, the Goods and Services Tax and the Harmonized Sales Tax costs must be net of any tax rebate to which the Proponent is entitled.

NOTE: the following limitations apply to the approved budget above:

1. In-kind costs are those contributions of goods or services provided by the Proponent or other contributors that are considered towards Total Project Costs; however; they are not eligible for reimbursement.

2. Overhead is limited to 15% of total Eligible Expenditures, up to a maximum of $1,000,000.

3. Travel expenditures, including meals and accommodations are to be based on National Joint Council Rates.

4. "Other expenses" include the following:
   a. Field supplies and materials;
   b. Printing services and translation
   c. Data collection services, including processing, analysis and management;
   d. Facility expenses for seminars, conference room rentals, etc. (excluding hospitality);
   e. License fees and permits; and
   f. Field testing services.

2. Notwithstanding the ***Amendments Article***, provided the Contribution for any given Fiscal Year is not exceeded, the Proponent may adjust any cost allocated by Eligible Expenditure as listed above by up to twenty percent (20%) of that cost without providing notice to Canada. At the time of submitting a claim for payment, the Proponent must provide Canada with a revised budget.

The Proponent may submit a written request to Canada to make an adjustment greater than twenty percent (20%). The request must include a revised budget. This request is subject to the approval in writing by Canada's representative identified in the ***Notices Article***.

SCHEDULE C

To the Agreement between

HER MAJESTY THE QUEEN IN RIGHT OF CANADA

And

PUC DISTRIBUTION INC.

REPORTS

1. Payment of Claims:

The Proponent shall provide the following documentation when submitting each claim for payment no later than **thirty (30) days after the end of each quarter (the "Claim Period")**, as set out in the ***Method of Payment Article***:

i) a financial report signed by the Chief Financial Officer or Duly Authorized Officer of the organization which outlines Eligible Expenditures Incurred;

ii) an updated Project budget forecast for the upcoming quarter; and

iii) a brief update on Project activities over the quarter

The Program will provide templates for the requirements listed above.

Subject to the terms and conditions of this Agreement, if the Proponent cannot submit a claim for payment on or before March 31 of a Fiscal Year, the Proponent shall, **no later than April 5**, provide the Minister with a signed statement of anticipated Eligible Expenditures Incurred up to March 31, in order for the Minister to establish a Payable at Year-End.

2. On-going Progress/Technical Reports:

The Proponent shall submit on an annual basis, at the end of each fiscal year, a brief update on the project activities performed to date. The report must be provided with the fourth quarter invoice, no later than **thirty (30) days after the end of the fourth quarter**.

3. Final Reports (Financial and Progress/Technical):

The Proponent shall submit, **no later than June 30, 2022**:

i) a financial report that shall demonstrate how the Contribution was spent, including the receipt of goods and/or services being funded by Canada;

ii) a final narrative report to describe how its activities have contributed to the achievement of the objectives, the benefits, and the key performance measures of the Project as described in Schedule A (Statement of Work), including the results of the Project in comparison to the original outputs and work plan; and

iii) a certification, in the manner set out in Schedule D (Certification of Eligible Expenditures Incurred and Paid), that the claims for payment of Eligible Expenditures of the Project have been Incurred and Paid by the Proponent.

iv) a financial declaration as to whether the Proponent received contributions or payments in respect of the Project in addition to, or from sources other than, those named in the Proposal.

4. Technical Performance Report/Holdback Performance Audit:

Six months following the Project Completion date, or the date which the Project is deemed operational, the Proponent shall provide an invoice for the hold-back release along with a technical performance report. The report will provide the results of the three performance indicators identified in the Proposal, including the greenhouse gas emissions reductions, and an explanation on the methodology for calculating each of those indicators.

5. Revenue reporting

For five (5) years following the completion of the Project, the Proponent must submit a report indicating the revenues received as a result of the Project. Where no revenue has been received, a nil report is required. The Program will provide the Proponent with a template for the revenue report. The Proponent shall provide this report no later than 30 days following the anniversary of the Project Completion date.

SCHEDULE D

To the Agreement between

HER MAJESTY THE QUEEN IN RIGHT OF CANADA

And

PUC DISTRIBUTION INC

CERTIFICATION OF ELIGIBLE EXPENDITURES INCURRED AND PAID

1. Pursuant to the ***Method of Payment Article*** of this Agreement, the Proponent must submit, no later than June 30, 2021, the following certification in writing on company letterhead and signed by the duly authorized officer as follows.

"All claims for payment submitted to Canada for the reimbursement of Eligible Expenditures of the Project have been Incurred and Paid by PUC DISTBRIBUTION INC ("the Proponent") as of the date of this certification by the undersigned and all supporting documents to this effect have been kept in our records and will be made available to the Minister upon request."

In accordance with the Contributions Article, the Proponent, as of the date of this certification by the undersigned has reported all contributions and payments, including Total Government Funding, received by the Proponent.

"I______________ an officer of PUC DISTRIBUTION INC, duly authorized on behalf of the Proponent hereby represent and warrant that the above noted declarations are true and accurate. I understand that if, in the opinion of the Minister, there has been a misrepresentation or a breach of this warranty, the Minister could place the Proponent in default of the terms, conditions or obligations of the Agreement, and may exercise the Minister's right to terminate this Agreement, and direct the Proponent to repay forthwith all or any part of the monies paid by Canada pursuant to this Agreement."

Date: ________________ **Signature:** ________________________

Title: ____________________________

SCHEDULE E

To the Agreement between

HER MAJESTY THE QUEEN IN RIGHT OF CANADA

And

PUC DISTRIBUTION INC.

PROPOSAL DATED MARCH 3, 2018

APPENDIX 2
PUC DISTRIBUTION 2019 CAPITAL MODULE ACM MODEL

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Note: Depending on the selections made below, certain worksheets in this workbook will be hidden.

Utility Name	PUC Distribution Inc.
Assigned EB Number	EB-2018-0219
Name of Contact and Title	Andrew Belsito, Rates and Regulatory Affairs Officer
Phone Number	705-759-3009
Email Address	andrew.belsito@ssmpuc.com
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	**Price-Cap IR**
Rate Year	**2019**
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which PUC Distribution Inc. is applying:	**1**
PUC Distribution Inc. is applying for:	**ICM Approval**
Last Rebasing Year:	**2018**
The most recent complete year for which actual billing and load data exists	**2017**
Current IPI	**1.50%**
Strech Factor Assigned to Middle Cohort	**III**
Stretch Factor Value	**0.30%**
Price Cap Index	**1.20%**

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

PUC Distribution Inc.

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **6**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 4,999 KW
4	SENTINEL LIGHTING
5	STREET LIGHTING
6	UNMETERED SCATTERED LOAD

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

PUC Distribution Inc.

Input the billing determinants associated with PUC Distribution Inc.'s Revenues Based on 2018 Board-Approved Distribution Demand. Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

		2018 Board-Approved Distribution Demand			Current Approved Distribution Rates		
Rate Class	**Units**	**Billed Customers or Connections**	**Billed kWh**	**Billed kW (if applicable)**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**
RESIDENTIAL	$/kWh	29,816	288,323,799		24.41	0.0086	0.0000
GENERAL SERVICE LESS THAN 50 kW	$/kWh	3,431	92,411,463		20.73	0.0248	0.0000
GENERAL SERVICE 50 TO 4,999 KW	$/kW	357	244,620,598	614,743	114.46	0.0000	6.7295
SENTINEL LIGHTING	$/kW	354	209,800	593	3.55	0.0000	33.1502
STREET LIGHTING	$/kW	8,070	2,398,221	7,030	1.37	0.0000	8.9284
UNMETERED SCATTERED LOAD	$/kWh	22	944,731		12.69	0.0383	0.0000

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

PUC Distribution Inc.

Calculation of pro forma 2018 Revenues. No input required.

Rate Class	2018 Board-Approved Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
Total	**0**	**0**	**0**	**D**	**E**	**F**	**0**	**0**	**0**	**0**	**K = G / J**	**L = H / J**	**M = I / J**	**0.0%**
RESIDENTIAL	29,816	288,323,799		24.41	0.0086	0.0000	8,733,703	2,479,585	0	11,213,287	77.9%	22.1%	0.0%	58.2%
GENERAL SERVICE LESS THAN 50 kW	3,431	92,411,463		20.73	0.0248	0.0000	853,496	2,291,804	0	3,145,300	27.1%	72.9%	0.0%	16.3%
GENERAL SERVICE 50 TO 4,999 KW	357	244,620,598	614,743	114.46	0.0000	6.7295	490,347	0	4,136,913	4,627,260	10.6%	0.0%	89.4%	24.0%
SENTINEL LIGHTING	354	209,800	593	3.55	0.0000	33.1502	15,080	0	19,658	34,738	43.4%	0.0%	56.6%	0.2%
STREET LIGHTING	8,070	2,398,221	7,030	1.37	0.0000	8.9284	132,671	0	62,767	195,437	67.9%	0.0%	32.1%	1.0%
UNMETERED SCATTERED LOAD	22	944,731		12.69	0.0383	0.0000	3,350	36,183	0	39,533	8.5%	91.5%	0.0%	0.2%
Total	**42,050**	**628,908,612**	**622,366**				**10,228,646**	**4,807,572**	**4,219,338**	**19,255,556**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Applicants Rate Base

Last COS Rebasing: 2018

Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	106,264,141	A			
Add: CWIP Re-based Opening	$	-	B			
Re-based Capital Additions	$	5,358,355	C			
Re-based Capital Disposals	$	-	D			
Re-based Capital Retirements	$	-	E			
Deduct: CWIP Re-based Closing	-$	420,179	F			
Gross Fixed Assets - Re-based Closing	$	111,202,317	G			
Average Gross Fixed Assets				$	108,733,229	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	13,880,189	I			
Re-based Depreciation Expense	$	3,780,329	J			
Re-based Disposals			K			
Re-based Retirements			L			
Accumulated Depreciation - Re-based Closing	$	17,660,518	M			
Average Accumulated Depreciation				$	15,770,354	N = (I + M) / 2
Average Net Fixed Assets				**$**	**92,962,876**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	89,269,060	P			
Working Capital Allowance Rate		7.5%	Q			
Working Capital Allowance				**$**	**6,695,180**	R = P * Q
Rate Base				**$**	**99,658,055**	S = O + R
Return on Rate Base						
Deemed ShortTerm Debt %		4.00%	T	$	3,986,322	W = S * T
Deemed Long Term Debt %		56.00%	U	$	55,808,511	X = S * U
Deemed Equity %		40.00%	V	$	39,863,222	Y = S * V
Short Term Interest		2.29%	Z	$	91,287	AC = W * Z
Long Term Interest		4.12%	AA	$	2,299,311	AD = X * AA
Return on Equity		9.00%	AB	$	3,587,690	AE = Y * AB
Return on Rate Base				**$**	**5,978,287**	AF = AC + AD + AE
Distribution Expenses						
OM&A Expenses	$	11,543,633	AG			
Amortization	$	3,780,329	AH			
Ontario Capital Tax	$	-	AI			
Grossed Up Taxes/PILs	$	586,716	AJ			
Low Voltage	$	-	AK			
Transformer Allowance	$	82,800	AL			
	$	-	AM			
	$	-	AN			
	$	-	AO			
				$	**15,993,478**	AP = SUM (AG : AO)
Revenue Offsets						
Specific Service Charges	-$	2,698,600	AQ			
Late Payment Charges			AR			
Other Distribution Income			AS			
Other Income and Deductions			AT	**-$**	**2,698,600**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**19,273,165**	AV = AF + AP + AU
Rate Classes Revenue						
Rate Classes Revenue - Total (Sheet 5)				$	19,255,556	AW

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
PUC Distribution Inc.

Input the billing determinants associated with PUC Distribution Inc.'s Revenues Based on 2017 Actual Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

	2017 Actual Distribution Demand			Current Approved Distribution Rates										
Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
Total	0	0	0	D	E	F	0	0	0	0	$K = G / J_{total}$	$L = H / J_{total}$	$M = I / J_{total}$	0.0%
RESIDENTIAL	29,729	282,820,547		24.41	0.0086	0.0000	8,708,219	2,432,257	0	11,140,475	45.5%	12.7%	0.0%	58.3%
GENERAL SERVICE LESS THAN 50 kW	3,417	91,035,995		20.73	0.0248	0.0000	850,013	2,257,693	0	3,107,706	4.4%	11.8%	0.0%	16.3%
GENERAL SERVICE 50 TO 4,999 KW	361	245,166,376	610,764	114.46	0.0000	6.7295	495,841	0	4,110,136	4,605,977	2.6%	0.0%	21.5%	24.1%
SENTINEL LIGHTING	361	213,661	619	3.55	0.0000	33.1502	15,379	0	20,520	35,899	0.1%	0.0%	0.1%	0.2%
STREET LIGHTING	8,070	2,398,221	7,030	1.37	0.0000	8.9284	132,671	0	62,767	195,437	0.7%	0.0%	0.3%	1.0%
UNMETERED SCATTERED LOAD	21	907,713		12.69	0.0383	0.0000	3,198	34,765	0	37,963	0.0%	0.2%	0.0%	0.2%
Total	**41,959**	**622,542,513**	**618,413**				**10,205,320**	**4,724,715**	**4,193,423**	**19,123,457**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
PUC Distribution Inc.

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

Rate Class	Current OEB-Approved Base Rates			2018 Board-Approved Distribution Demand										
	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
Total	A	B	C	D	E	F	0	0	0	0	$L = G / J_{total}$	$M = H / J_{total}$	$N = I / J_{total}$	0.0%
RESIDENTIAL	24.41	0.0086	0.0000	29,816	288,323,799		8,733,703	2,479,585	0	11,213,287	45.36%	12.88%	0.00%	58.2%
GENERAL SERVICE LESS THAN 50 kW	20.73	0.0248	0.0000	3,431	92,411,463		853,496	2,291,804	0	3,145,300	4.43%	11.90%	0.00%	16.3%
GENERAL SERVICE 50 TO 4,999 KW	114.46	0.0000	6.7295	357	244,620,598	614,743	490,347	0	4,136,913	4,627,260	2.55%	0.00%	21.48%	24.0%
SENTINEL LIGHTING	3.55	0.0000	33.1502	354	209,800	593	15,080	0	19,658	34,738	0.08%	0.00%	0.10%	0.2%
STREET LIGHTING	1.37	0.0000	8.9284	8,070	2,398,221	7,030	132,671	0	62,767	195,437	0.69%	0.00%	0.33%	1.0%
UNMETERED SCATTERED LOAD	12.69	0.0383	0.0000	22	944,731		3,350	36,183	0	39,533	0.02%	0.19%	0.00%	0.2%
Total							**10,228,646**	**4,807,572**	**4,219,338**	**19,255,556**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

PUC Distribution Inc.

No Input Required.

Final Materiality Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2018**	
Price Cap IR Year in which Application is made		**1**	n
Price Cap Index		**1.20%**	PCI
Growth Factor Calculation			
Revenues Based on 2018 Board-Approved Distribution Demand		**$19,255,556**	
Revenues Based on 2017 Actual Distribution Demand		**$19,123,457**	
Growth Factor		**0.69%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	106,264,141	
Add: CWIP Opening	$	-	
Capital Additions	$	5,358,355	
Capital Disposals	$	-	
Capital Retirements	$	-	
Deduct: CWIP Closing	-$	420,179	
Gross Fixed Assets - Closing	$	111,202,317	
Average Gross Fixed Assets	$	108,733,229	
Accumulated Depreciation - Opening	$	13,880,189	
Depreciation Expense	$	3,780,329	
Disposals	$	-	
Retirements	$	-	
Accumulated Depreciation - Closing	$	17,660,518	
Average Accumulated Depreciation	$	15,770,354	
Average Net Fixed Assets	$	92,962,876	
Working Capital Allowance			
Working Capital Allowance Base	$	89,269,060	
Working Capital Allowance Rate		8%	
Working Capital Allowance	$	6,695,180	
Rate Base	**$**	**99,658,055**	RB
Depreciation	**$**	**3,780,329**	d

Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)

Price Cap IR Year 2019	**160%**
Price Cap IR Year 2020	**161%**
Price Cap IR Year 2021	**162%**
Price Cap IR Year 2022	**163%**
Price Cap IR Year 2023	**164%**
Price Cap IR Year 2024	**165%**
Price Cap IR Year 2025	**166%**
Price Cap IR Year 2026	**167%**
Price Cap IR Year 2027	**168%**
Price Cap IR Year 2028	**169%**

Threshold CAPEX — $Threshold\ Value \times d$

Price Cap IR Year 2019	**$**	**6,050,926**
Price Cap IR Year 2020	**$**	**6,086,867**
Price Cap IR Year 2021	**$**	**6,123,490**
Price Cap IR Year 2022	**$**	**6,160,809**
Price Cap IR Year 2023	**$**	**6,198,837**
Price Cap IR Year 2024	**$**	**6,237,587**
Price Cap IR Year 2025	**$**	**6,277,072**
Price Cap IR Year 2026	**$**	**6,317,308**
Price Cap IR Year 2027	**$**	**6,358,307**
Price Cap IR Year 2028	**$**	**6,400,086**

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
PUC Distribution Inc.

Identify ALL Proposed ACM projects and related CAPEX costs in the relevant years

	Cost of Service	Price Cap IR				Price Cap IR (Deferred Rebasing)					
	Test Year 2018	Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Year 6 2024	Year 7 2025	Year 8 2026	Year 9 2027	Year 10 2028
Distribution System Plan CAPEX	$ 5,358,355	$ 10,302,600	$ 26,600,104	$ 6,196,546	$ 8,708,176						
Materiality Threshold		$ 6,050,926	$ 6,086,867	$ 6,123,490	$ 6,160,809	$ 6,198,837	$ 6,237,587	$ 6,277,072	$ 6,317,308	$ 6,317,308	$ 6,317,308
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ 4,251,674	$ 20,513,237	$ 73,056	$ 2,547,367	$ -	$ -	$ -	$ -	$ -	$ -

Project Descriptions:	Type	Test Year 2018	Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Year 6 2024	Year 7 2025	Year 8 2026	Year 9 2027	Year 10 2028	Total
Sault Smart Grid	New ICM		$ 5,026,797.00	$ 17,555,248.00									**$ 22,582,045**
Substation 16	New ICM			$ 3,600,000		$ 3,300,000							**$ 6,900,000**
													$ -
													$ -
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Total Cost of ACM/ICM Projects		$ -	$ 5,026,797	$ 21,155,248	$ -	$ 3,300,000	$ -	$ -	$ -	$ -	$ -	$ -	**$ 29,482,045**
Maximum Allowed Incremental Capital			$ 4,251,674	$ 20,513,237	$ -	$ 2,547,367	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,312,278

	Test Year 2018	Price Cap IR Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022
Distribution System Plan CAPEX	$ 5,358,355	$ 10,302,600	$ 26,600,104	$ 6,196,546	$ 8,708,176
Materiality Threshold		$ 6,050,926	$ 6,086,867	$ 6,123,490	$ 6,160,809
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ 4,251,674	$ 20,513,237	$ 73,056	$ 2,547,367

		Test Year	Year 1			Year 2			Year 3			Year 4		
		2018	2019			2020			2021			2022		
Project Descriptions:	**Type**		**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**
Sault Smart Grid	New ICM		**$ 5,026,797**	$ 293,436	$ 531,424	**$ 17,555,248**	$ 461,735	$ 1,468,638	$ -			$ -		
Substation 16	New ICM		$ -	$ -	$ -	**$ 3,600,000**	$ 72,000	$ 288,000	$ -			**$ 3,300,000**		
			$ -			$ -			$ -			$ -		
			$ -			$ -			$ -			$ -		
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			$ -			$ -			$ -			$ -		
			$ -			$ -			$ -			$ -		
Total Cost of ACM/ICM Projects			$ 5,026,797	$ 293,436	$ 531,424	$ 21,155,248	$ 533,735	$ 1,756,638	$ -	$ -	$ -	$ 3,300,000	$ -	$ -

Price Cap IR (Deferred Rebasing) (if necessary)

Price Cap IR

		Year 5 2023	Year 6 2024	Year 7 2025	Year 8 2026
Distribution System Plan CAPEX		$ -	$ -	$ -	$ -
Materiality Threshold		$ 6,198,837	$ 6,237,587	$ 6,277,072	$ 6,317,308
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -	$ -	$ -

		Year 5 2023			Year 6 2024			Year 7 2025			Year 8 2026		
Project Descriptions:	**Type**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**
Sault Smart Grid	New ICM	$ -			$ -	$ -		$ -			$ -		
Substation 16	New ICM	$ -			$ -	$ -		$ -			$ -		
		$ -			$ -			$ -			$ -		
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		$ -			$ -			$ -			$ -		
Total Cost of ACM/ICM Projects		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Price Cap IR (Deferred Rebasing) (if necessary)

Price Cap IR

		Year 9 2027	Year 10 2028
Distribution System Plan CAPEX		$ -	$ -
Materiality Threshold		$ 6,317,308	$ 6,317,308
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -

		Year 9 2027			Year 10 2028		
Project Descriptions:	**Type**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**
Sault Smart Grid	New ICM	$ -			$ -		
Substation 16	New ICM	$ -			$ -		
		$ -			$ -		
		$ -			$ -		
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Total Cost ofACM/ICM Projects		$ -	$ -	$ -	$ -	$ -	$ -

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
PUC Distribution Inc.

Incremental Capital Adjustment **Rate Year:** 2019

Current Revenue Requirement

Current Revenue Requirement - Total		$	19,273,165	A

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim		Eligible for ACM/ICM (Prorated Amount) *(from Sheet 10b)*		
Amount of Capital Projects Claimed	$ 5,026,797	$	4,251,674	B
Depreciation Expense	$ 293,436	$	248,189	C
CCA	$ 531,424	$	449,479	V

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$	4,251,674	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$	248,189	C
Incremental Capital to be included in Rate Base (average NBV in year)			$	4,127,580	D = B - C/2
	% of capital structure				
Deemed Short-Term Debt	4.0%	E	$	165,103	G = D * E
Deemed Long-Term Debt	56.0%	F	$	2,311,445	H = D * F
	Rate (%)				
Short-Term Interest	2.29%	I	$	3,781	K = G * I
Long-Term Interest	4.12%	J	$	95,232	L = H * J
Return on Rate Base - Interest			$	99,012	M = K + L
	% of capital structure				
Deemed Equity %	40.00%	N	$	1,651,032	P = D * N
	Rate (%)				
Return on Rate Base -Equity	9.00%	O	$	148,593	Q = P * O
Return on Rate Base - Total			$	247,605	R = M + Q

Amortization Expense

Amortization Expense - Incremental	C	$	248,189	S

Grossed up Taxes/PILs

Regulatory Taxable Income		O	$	148,593	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$	248,189	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$	449,479	V
Incremental Taxable Income			-$	52,698	W = T + U - V
Current Tax Rate	26.5%	X			
Taxes/PILs Before Gross Up			-$	13,965	Y = W * X
Grossed-Up Taxes/PILs			-$	19,000	Z = Y / (1 - X)

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$	247,605	AA
Amortization Expense - Total	S	$	248,189	AB
Grossed-Up Taxes/PILs	Z	-$	19,000	AC
Incremental Revenue Requirement		$	476,794	AD = AA + AB + AC

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	Col C * Col I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M

APPENDIX 3
COPY OF SMART GRID PROPOSAL-NRCan APPLICATION

Department of Natural Resources Canada

Green Infrastructure Phase II

Smart Grid Demonstration and Deployment Program

Project Proposal

CONFIDENTIAL WHEN COMPLETED[1]

Notes

1. Review the "Smart Grid Demonstration and Deployment Program Applicant Guide" (also referred to as the Applicant Guide) before completing the Proposal template.

2. Review *both* the Word and Excel application templates before filling out each section. All relevant information must be included in the Proposal Word and Excel files.

3. Incomplete proposals will not be accepted. Proposals that do not follow the templates will not be accepted.

4. Word limit maximums must be respected.

5. Unless otherwise specified, the "proposed project" or the "project" or the "proposal" in this template refers to the proposed project submitted to the Smart Grid Demonstration and Deployment Program (also referred to as the Smart Grid Program or the Program).

6. The completed proposal must be submitted by e-mail as Word and Excel files for processing (a pdf copy may be submitted in addition to the Word file for the purposes of including a signature). Additional supporting material required can be provided in any format. Printed and mailed versions of the proposal and attestations will be accepted, but electronic versions are preferred.

7. Proposals must be submitted by **23:59 EST, March 4, 2018**. **Late submissions will not be accepted.** It is the applicant's responsibility to retain proof of the time the complete proposal package was sent to NRCan. This may be required in the event that NRCan does not receive the complete proposal package by the deadline for reasons that are beyond the control of the sender.

   Email address for submission: nrcan.innovation.rncan@canada.ca

[1] Except for Section 1

Smart Grid Program - Project Unique ID (to be filled in by Program):

Section 1: Non-Confidential Applicant Information and Project Summary

1.1 Applicant Information	
Organization:	PUC Distribution Inc. (PUC, or the PUC)
Applicant Type (private/investor-owned utility or public utility/operator or government/agency):	Provincially regulated Local Distribution Company (LDC) and a 100% owned subsidiary of PUC Inc., which is wholly owned by the Corporation of the City of Sault Ste. Marie.
Contact Name:	Kevin D. Bell, P.Eng., VP, Customer Engagement & Business Development
Project Manager:	Kevin D. Bell, P.Eng., VP, Customer Engagement & Business Development
Mailing Address:	PUC Distribution Inc. 500 Second Line East Sault Ste. Marie, ON P6B 4K1
Email Address:	kevin.bell@ssmpuc.com
Phone Number:	(705) 759-6515

1.2 Project Information Summary	
Project Title:	Sault Smart Grid (SSG)
Project Location(s):	*(Address, City, Province/Territory)* The project will cover the licensed service territory of PUC Distribution Inc., which includes Prince Township, Batchewana First Nation – Rankin Location and the City of Sault Ste. Marie. The project is based at 500 Second Line East, Sault Ste. Marie, ON
Project Start Date:	*(No earlier then April 1st, 2018)* Between 24.APR.2018 and 1.NOV 2018
Project End Date:	*(No later than March 31, 2022)* Between 24.APR.2020 and 1.NOV 2020)
Total Project Cost ($):	$47,230,000

Smart Grid Program - Project Unique ID (to be filled in by Program):

Funding Requested from Smart Grid Program ($):	$11,807,410	
Project Type Designation (Demonstration/ Deployment/Hybrid):	Deployment	
[Deployment projects only] **Will the deployment project reduce GHG emissions as a project outcome?**		YES Please indicate one: *Yes / No*

Smart Grid Program - Project Unique ID (to be filled in by Program):

1.2 Project Description Summary *Please note: this information could be used on NRCan's public facing website. Keep the information brief, non-technical, and non-confidential.*
Problem Statement (150 words maximum)
What issue or problem is this project trying to address? In what context is this project being introduced? Canadian communities and the electrical utilities that serve them are faced with rapidly evolving challenges in providing clean, reliable and resilient power service. The needs for utilities to reduce greenhouse gas emissions, improve asset efficiency, enhance reliability, enable renewable generation and electric vehicle integration, all while ensuring their systems are cyber-secure and promote economic development and diversification of their local economies is a substantial challenge. These challenges present an opportunity during replacement of aging electricity distribution infrastructure to incorporate emerging technologies and systems using new and innovative financing models that will support meeting or exceeding aggressive carbon reduction goals at Federal and Provincial levels. Our utility is proposing the creation of a community-scale smart grid that covers the entire service territory of PUC Distribution, benefiting our customers with an integrated and intelligent distribution management platform that will allow us to integrate smart energy technologies now and into the future.
Project Summary (150 words maximum)
Provide a brief, high-level summary of this project. PUC intends to establish a community-scale smart grid in Sault Ste. Marie, Ontario, the Sault Smart Grid (SSG). The innovative SSG is characterized by substantially improved efficiency, reliability, and resilience of the local distribution grid. The project will benefit from its broad impact and integration of complementary smart grid technologies, including; distribution automation (DA), Voltage/VAR management (VVM), and the enhancement of the existing advanced metering infrastructure (AMI). PUC will also engage directly with the community promoting understanding of the benefits of the new low-carbon electricity distribution system. The SSG will be financed under an innovative public-private partnership (P3) strategy that minimizes risk and lowers costs. The project advances reliability and efficiency benefits for customers, provides an enabling platform for renewable energy and smart grid technology applications, and expands customer opportunities to take advantage of enhanced energy services and solutions.
Benefit to Canadians and Stakeholders (150 words maximum)
Describe how this project benefits Canadians and project stakeholders. The SSG project provides a number of benefits for Canadians and Stakeholders. Electricity customers will see direct savings in their bills due to improved efficiency. The increased reliability and resilience of the new system architecture allows the utility and the province to defer or eliminate certain capital expenditures across the distribution, transmission and generating sectors. The region will benefit from reduced load on the transmission grid through both peak shaving and reduced overall load. The community benefits from increased reliability and enhanced power quality. The utility will be able to offer premium and enhanced energy services to its customers, adding system intelligence on both sides of the meter. Finally, the system will generate new economic opportunities for a Northern community evolving towards a diversified smart energy and information, communications and technology (ICT)

economy.

Note: Information beyond this point is considered confidential and will not be released without your permission.

Section 2: Project Overview

2.1 Project Objective (150 words maximum)

State the project's objective(s).

The Sault Smart Grid project (SSG) provides a community-scale smart grid enabling plan for the PUC electrical distribution service area. The project will increase the efficiency of the distribution grid, reducing electrical energy delivery requirements from the transmission grid, and thus reducing greenhouse gas emissions, and reducing costs to the consumers. The project also improves reliability and resiliency with self-healing networks and integrated system data management systems for normal outage planning and especially addressing situational weather events with enhanced outage management capability. The project provides an enabling platform for renewable energy and technology integration, and customer opportunities in energy services and solutions, supporting Federal and Provincial objectives and LDC license requirements.

The SSG brings together world leading engineering and project management from Black & Veatch, and innovative public – private (P3) financing through Infrastructure energy and Stonepeak Partners, ensuring the community gets the best possible project, while minimizing risk to ratepayers.

2.2 Project Description (800 words maximum)

Describe what the project is, how the work will be carried out and how it will be implemented and operationalized. Is this project a demonstration, deployment or a combination of the two (hybrid)? Does the project involve the regulator, system operator or customers? Please explain. Note: a Statement of Work is required in Section 3.1. NRCan reserves the right to make the final decision on project type.

Project Form and Scope:

The project is a deployment of a community-scale smart grid system that covers the local distribution utility service area. The project will be developed by Infrastructure Energy, through a special purpose vehicle, known as SSG Inc. The SSG project employs Black & Veatch as prime contractor to perform all phases of design, build, and validation. The developer assumes the risk of project completion and performance, with PUC accepting transfer of asset title at commissioning. The project is completed on the distributer's side of the meter with no requirement for direct involvement from the customers, improving the performance of the local distribution utility's system. The provincial regulator is involved in approval of rate adjustments to the PUCs customers.

The project covers the following scope of work:

- Feasibility and Preliminary Engineering
- Detailed Engineering and Design
- Advanced Metering Infrastructure System(AMI) Integration
- Communications Systems

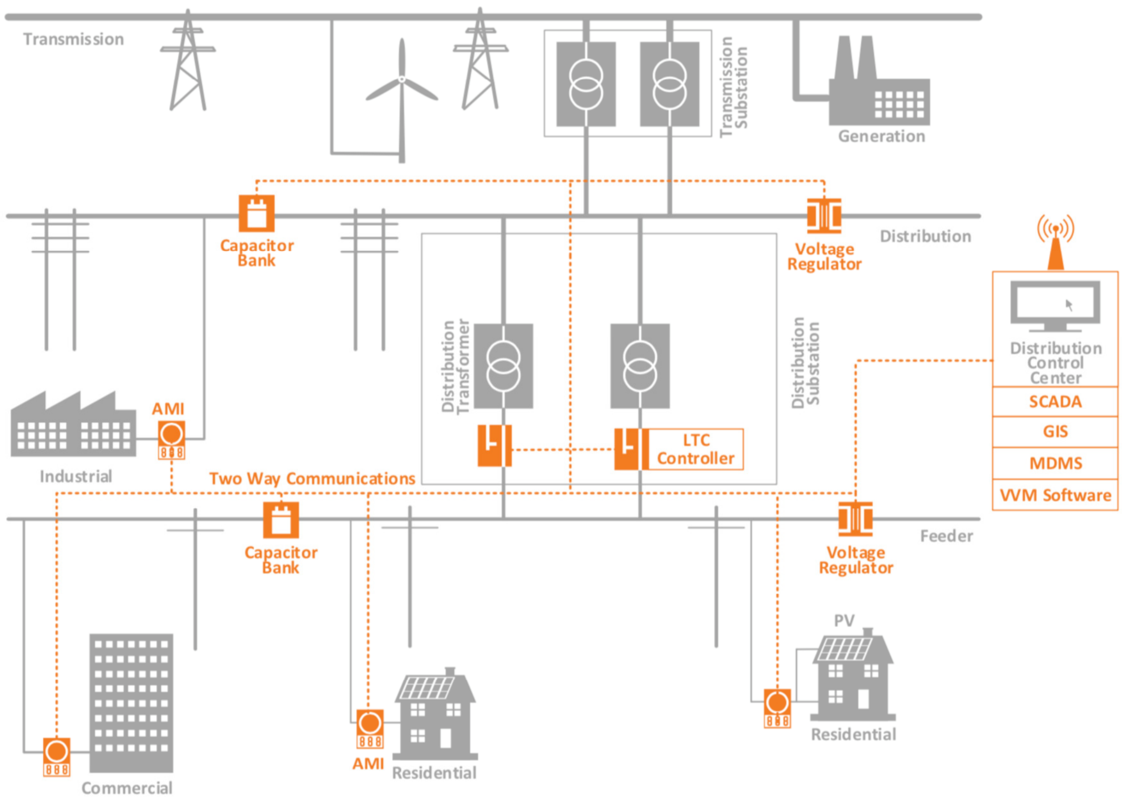
- Distribution Automation Systems(DA)
- Voltage /VAR Management Systems(VVM)
- Line Regulators
- Project Management
- Financing
- Closing Costs (legal, accounting, regulatory support)
- Stakeholder Engagement

Initially, for the construction phase, the project's source of funds will be the North American Grid Modernization Fund. Managers of the fund include Stonepeak Infrastructure Partners and Infrastructure Energy. The SSG project funds for this project will be flowed through a special purpose vehicle called Sault Smart Grid Inc.(SSG Inc.)

At construction completion and commissioning, the asset title will be transferred to PUC Distribution Inc. Repayment to SSG Inc. will be by monthly payments over a 25-year term through the purchase agreement between PUC and SSG Inc.

Description of Tasks:

The SSG Project for PUC is at its core, a project to modernize the utility's distribution system infrastructure and deliver customer and community benefits. The project deploys a strong foundation of state-of-the-art smart grid technologies and systems to support the goals of enhancing resiliency and reliability, improving outage management, leveraging existing smart meter AMI infrastructure and reducing energy consumption. The key components of the SSG are a new advanced distribution management system(ADMS) and outage management system(OMS), which will enhance reliability by implementing two distribution automation(DA) applications to improve outage management and reliability, fault detection isolation restoration(FDIR) and an auto- transfer scheme (see Figure 2.2-1). A third DA application, Volt/VAR management(VVM), will be implemented to optimize the distribution grid and reduce energy consumption behind the meter (See Figure 2.2-2).

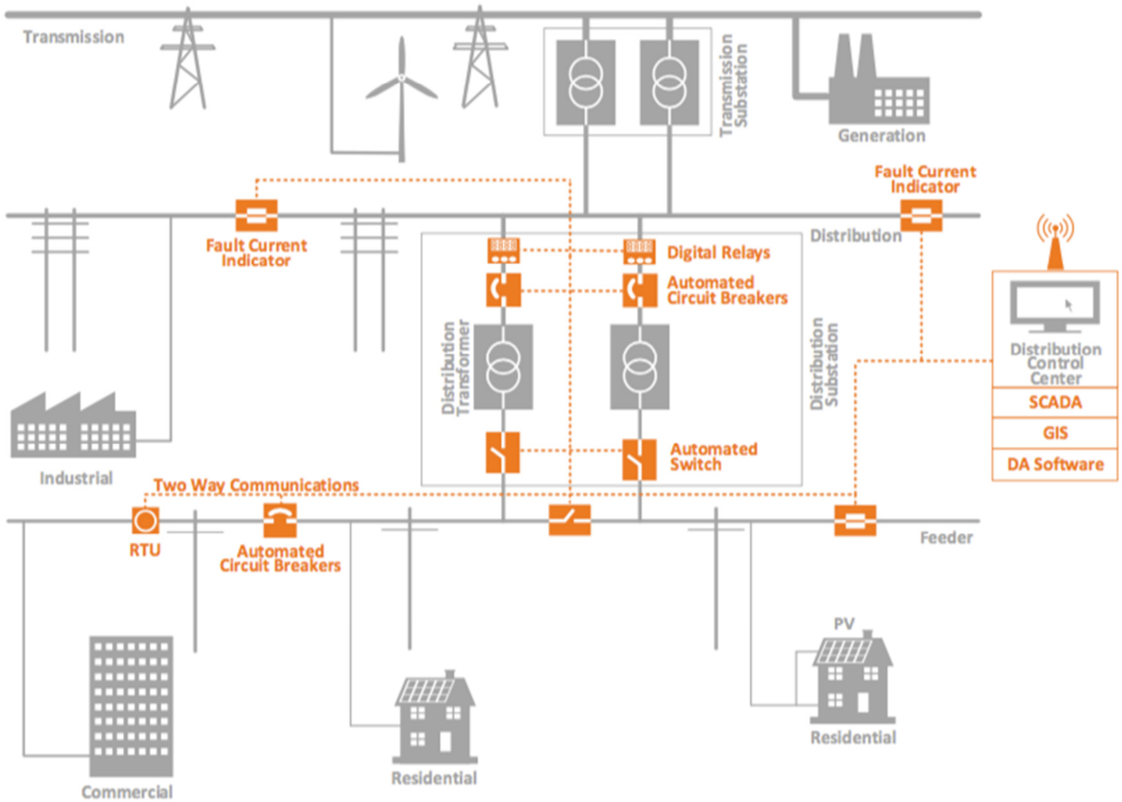


Source: Navigant

Figure 2.2-1 Voltage Volt-Ampere Reactivity (VAR) Management (VVM) System

SSG will provide for design, procurement, installation, testing, commissioning, and training on the following set of technologies and applications:

- ADMS software that includes integrated FDIR, VVM, and auto-transfer applications.
- OMS software that is tightly integrated with the new ADMS provide outage management functions.
- SCADA-enabled line distribution equipment such as reclosers, switches, and faulted circuit indicators support FDIR.
- SCADA-enabled voltage regulators and capacitors support VVM.
- Fault Circuit Indicators support an auto-transfer scheme on 34.5kV sub-transmission system.
- Field area networks collect the data and provide control in support of the three DA applications, which will integrate into existing PUC communication networks.
- Integration with PUC's existing customer information system, advanced metering infrastructure, and Engineering distribution system model



Source: Navigant

Figure 2.2-2 Distributed Automation (DA) System

SSG provides state of the art technology that is standards-based, which positions PUC to deploy and/or accommodate new distributed energy resources such as photovoltaics, energy storage (batteries), cogeneration, and electric vehicles and support smart cities and other community economic development activities. The project will develop design and construction work packages specifying the equipment and system integration to complete the design, procurement, installation, testing, commissioning, and training requirements.

Energy Issues Addressed:

The SSG directly enables:

- Grid monitoring and automation through the deployment of a network of SCADA enabled sensors and automated controls for fault detection isolation restoration, distribution automation and Volt/VAR management; and
- Data management and communications through the communications network tied into PUC's customer information systems and advanced metering infrastructure, including advanced distribution management system and outage management system.

The project enhances customer engagement by enabling consumers to either directly, or through other providers such as energy services utilities, adopt systems behind the meter, to communicate and coordinate with PUC's smart grid. The project will enable the integration of the following technologies and systems:

- Demand Management – providing data available to behind the meter systems, which allow for better energy management of load and distributed generation and storage;
- Electric Vehicle Integration – increased distribution system efficiency and resiliency in the project supports adoption of electric vehicles by the community within the capacity of the local distribution grid;
- Nested Microgrids – the project enables the development of microgrid systems for campus and individual building-scale microgrid systems;
- Energy Storage - the project's intelligence system better allows the distribution grid to integrate energy storage at utility and neighbourhood-scale; and
- Distributed Energy Resource Management – increasing the robustness and flexibility of the distribution grid enables integration of additional distributed generation and energy storage solutions, behind the meter.

2.3 Project Relevance to Smart Grid Program (300 words maximum)

Explain how the project aligns with the Program's Objectives and Scope (Sections 3 and 4 of the Applicants' Guide, respectively). Does the project contribute to GHG reductions, job creation and the development of Smart Grids in Canada? Note: deployment projects must reduce GHG emissions as a project outcome.

The project directly, and indirectly supports the following six results expected by NRCan:

- Reduced GHG emissions: Direct measurement of energy efficiency improvements may also be expressed as GHG emissions savings. Improved reliability and resiliency can be calculated to have a GHG emission effect through reduced service truck rolls for maintenance, repair, and replacement activity;
- Improved asset utilization and efficiency through energy use reduction and reduction of maintenance, repair, and replacement of equipment;
- Increased reliability and resiliency through reduced interruption frequency and duration, and more rapid recovery in the face of severe weather events and other causes of power outage;
- Increased system flexibility and renewable energy penetration –the project enables additional penetration of renewable generation;
- Cyber-security features are embedded within all key systems to be deployed as part of the SSG project, and the supporting communications networks will be hardened as they are built out and

integrated; and

- Enhanced socio-economic benefits are delivered by the project, and will be quantified by the Corporation of the City of Sault Ste. Marie for consideration during its approval of the project as sole shareholder.

The project provides additional community economic development benefits. An independent assessment was conducted by the City of Sault Ste. Marie in 2017, which calculated both the direct jobs and the business opportunities created by the SSG. The jobs are shown in table 2.3.

The project additionally has the ability to produce broader Canadian benefits, as the developers and financiers can produce similar benefits for other communities, including a near term pipeline plan of projects which can be executed in the next 5 years.

Business Component	Permanent Direct (net)	Construction Phase (2 Yr)	Indirect	Notes
SSG	5	60	102	SSG net job creation (PUC 2/18)
Enabled Business (CENEX, ESU)	135	45	111	SSM City Analysis for CENEX North NOC and ESU. Revised downward to JAN.2018 ESU estimates
Total	140	105	213	Sum: 458

Table 2.3 Jobs Impact for Sault Smart Grid

2.4 Project History (300 words maximum)

Describe past work that the proposed project builds upon. Provide references to the results and conclusions of past work that has been used in developing this project proposal. If any previous work was government-funded, please identify the funding programs. If this proposal is for a specific component of a larger, multi-component project, please explain the role of the proposed work and its relationship to the non-Program funded components.

PUC Distribution has one of the largest percentages of renewable energy generation penetration connected to our distribution utility network as ratio of system load of any LDC in Ontario with over 60MW of solar generation embedded in our network. In addition PUC receives almost all of its energy from renewable sources when considering the local transmission connected generation mix of hydroelectric and wind power in the region. The Sault Ste. Marie Economic Development Corporation has used the phrase “the alternative energy capital of North America” to describe our community. PUC has actively supported this evolution and continues to explore new technology and applications for our LDC and our community.

In this light, PUC has been exploring a comprehensive smart grid project in Sault Ste. Marie for over four years in collaboration with Infrastructure Energy LLC (IE). The project scope has varied over that period but has evolved to our current proposed SSG project that has exciting possibilities for not only our customers but also our community. The project concept has been brought before City Council on at least 3 occasions and has received support via council resolution. Engineering consultant work funded through IE by Leidos Engineering (now by B&V) has supported preliminary design and cost-benefit projections based on a 30% design level. Navigant Consulting Ltd was retained to review the system assumptions and projections and supported the general benefits projected to customers, the PUC and the Province in terms of energy savings. The largest benefit in the “value” assessment was in improved reliability but was not used directly in the PUC’s customer energy savings projections and financial cost/benefit analysis.

The project has the commitment of the North American Grid Modernization Fund, with a $274M commitment from Stonepeak partners.

Smart Grid Program - Project Unique ID (to be filled in by Program):

2.5 Core Team Members

List all key members of the project core team and describe the individual's contribution to the proposed project and the experience and expertise they would bring to it. Refer to similar projects in which each person has been involved. Please identify the Project Manager and provide sufficient information on all key team members for reviewers to be able to assess whether the team provides the necessary management, engineering, research and technical capacity, capability and expertise to do the proposed work. Refer to Section 3.1 and 3.2 in the Excel file if relevant.

<table>
<tr><td>Project Manager:</td><td colspan="3">Kevin Bell</td></tr>
<tr><td>Organization:</td><td>PUC Distribution Inc.</td><td>Role in Project:</td><td>SSG Project Manager for PUC.</td></tr>
<tr><td colspan="4">Expertise and Experience:</td></tr>
<tr><td colspan="4">Kevin D. Bell, P.Eng. VP, Customer Engagement & Business Development for PUC

Kevin serves as the project manager for the PUC, representing PUC in the all aspects of the Smart Grid Project. Kevin has over 35 years of management and engineering experience in generation, transmission and distribution utility operations with PUC and Great Lakes Power. Projects that Kevin has worked on include engineering and project management roles in all aspects of utility infrastructure including hydro generation, transmission station and line construction and most recently to integrate into the PUC service grid include the Sault Ste. Marie Solar Park, which was the second largest photo-voltaic plant in Canada when built in 2011. Kevin has a Bachelors of Engineering and Management from McMaster University.</td></tr>
<tr><td>Team Member 1:</td><td colspan="3">Glen Martin</td></tr>
<tr><td>Organization:</td><td>Infrastructure Energy</td><td>Role in Project:</td><td>Smart Grid Developer</td></tr>
<tr><td colspan="4">Expertise and Experience:</td></tr>
<tr><td colspan="4">Glen Martin, CEO and Principal, Infrastructure Energy

As Principal of IE, Glen serves as the project developer, coordinating project P3 financing, and key design and construction services.

Glen has over 25 years experience from project development and infrastructure finance in the fields of aerospace, advanced technology and renewable energy, notably with project design and development for the International Space Station and leading positions at Boeing and Rolls Royce. He previously founded Pod Generating Group, developing a 60MW solar photovoltaic project, and was co-founder of ProtoStar Limited, a satellite operator that acquired and launched two satellites into geostationary orbit. Glen holds a Bachelor of Technology in Aerospace Engineering from Ryerson University in Toronto and an MBA from the University of Southern California in Los Angeles, California.</td></tr>
</table>

Team Member 2:	Jim Ross		
Organization:	Infrastructure Energy	**Role in Project:**	Operations and Technology Manager
Expertise and Experience:			
Jim Ross, Senior Advisor, Infrastructure Energy As manager for operations and technology, Jim is responsible for the selection and oversight of the Design and Construction of the SSG thru the Prime Contractor team at B&V, and other suppliers. Jim oversees the development of Infrastructure Energy’s multiple project management teams. He has over 20 years’ experience in operations and project management. In 2002, Jim served as the Managing Principal of Ascertane, a business and technology consulting firm, and was previously the Director of Operations for Jackson Labs Technologies. Jim holds a BBA with a concentration in Corporate Finance from Western Michigan University.			
Team Member 3:	Gary Johnson		
Organization:	Black & Veatch	**Role in Project:**	Prime Contractor
Expertise and Experience:			
Gary Johnson, Regional Manager, Black & Veatch As prime contractor for the SSG, Gary is responsible for the B&V design, construction, and verification activities. Gary Johnson is the Regional Manager for Black & Veatch where he quarterbacks telecommunications, automation, microgrid and District Energy activities with utilities. An Electrical Engineer, Gary worked for Schlumberger mapping the geology of oil wells in West Africa. Following his MBA, Gary has held various sales, marketing and business development positions including Marketing Manager for Schlumberger's Electricity Metering Division, Director of Schlumberger's Utility Services Group and Business Development roles with Ontario Hydro and Bayly Communications.			
Team Member 4:	Luke Taylor		
Organization:	Stonepeak Partners	**Role in Project:**	Financier
Expertise and Experience:			
Luke Taylor, Senior Managing Director, Stonepeak Partners Luke Taylor coordinates project financing from Stonepeak Partners. Luke is a Senior Managing Director with Stonepeak Infrastructure Partners. Luke has been investing in infrastructure for over 14 years and sits on the board of Paradigm Energy Partners and is a former			

director of the Carlsbad Desalination Project and Northstar Renewable Power. Prior to joining Stonepeak, Luke was a Senior Vice President with Macquarie Capital based in New York. Luke has a Bachelor of Commerce and a Master of Business (Distinction) from the University of Otago (New Zealand).			
Team Member 5:	Craig Rizzo		
Organization:	Energrid	**Role in Project:**	Technology Advisor
Expertise and Experience:			
Craig Rizzo, CEO and Founder, EnerGrid Group, LLC Role: Lead Project Delivery Advisor As Lead Project Delivery Advisor, Craig is responsible for ensuring that PUC requirements are well defined and the technology integration design and contractor implementation plan will deliver the intended benefits to PUC, the community and the Province. Craig has 25 years of experience in strategic planning, design and implementation of complex systems, risk management and team leadership in the defense and commercial energy sectors. He has led the concept development, client engagement, pricing, solution architecture, and technical implementation of over 20 smart grid, microgrid and distributed energy projects with value of over $150M. Craig holds a Bachelor of Science in Operations Research from the U.S. Air Force Academy and a Master of Science in Operations Research, with a focus on artificial intelligence systems, from the Air Force Institute of Technology in Dayton, OH.			

<Add rows for team members as required>

As described in Section 7.7 of the Applicant Guide, please indicate the number of women and staff who identify as minorities within the electricity sector anticipated to be employed by this project by the Direct or Ultimate Recipient should this proposal be accepted.

Number of women and staff who identify as a minority in the electricity sector expected to be employed by this project by the Direct or Ultimate Recipient:	PUC Services Inc. is an equal opportunity employer. As a matter of practice, the PUC does not target hiring, or record employment data by sex, sexual orientation, or ethnicity. Thus we cannot guarantee any specific number of hires by sex or ethnicity. We would work with contracted parties to raise awareness and encourage efforts in this area for the project. As a Northern Ontario community we have a very robust indigenous population which is well represented in our own workforce.

Smart Grid Program - Project Unique ID (to be filled in by Program):

2.6 Contributions from the Applicant and Project Partners

List all partners (companies or organizations), including the applicant, and explain the nature of each organization's role in, and contribution to, the project. What values does each bring to the project? How will they interact with each other, what legal understandings are expected? Refer to Section 3.1 and 3.2 in the Excel file if relevant. Include letters of support if relevant. In the case where this Application is completed by a potential Initial Recipient such as a provincial government department or agency, please indicate who would be the project lead or Ultimate Recipient. (Refer to Section 7.8 of the Applicant Guide for Recipient Types).

Applicant: **Project Lead? ☒**	**PUC Distribution Inc. (PUC)** **Project Lead and Direct Recipient**

Note: In this box, enter the name of the eligible recipient who would sign the agreement with Natural Resources Canada. If that eligible recipient is also the project lead, please indicate by checking the box in the above cell. If that eligible recipient is not the project lead, please list the project lead as "Partner 1" and indicate that they are project lead by checking the box.

<Explain the nature of the organization's role and their contribution to the project>

PUC is the local electrical distribution company for Sault. Ste. Marie and surrounding areas. As the local utility, PUC is the project leader. PUC will contract the SSG to IE as the developer, using B&V as the prime contractor. PUC is responsible for approval of design and construction of the SSG. In addition PUC employees will be involved in some powerline trade work directly on the distribution circuits as well as engineering and operations roles. Upon construction completion, PUC will assume ownership and operation of the SSG.

PUC is a private company registered under the Ontario Business Corporations Act and is wholly owned by the Corporation of the City of Sault Ste. Marie. PUC Inc. has one subsidiary: PUC Distribution Inc., which distributes electricity to residences and businesses within the boundaries of the City of Sault Ste. Marie as well as parts of Prince Township, Dennis Township and the Batchewana First Nation Rankin Reserve. PUC Distribution Inc. is a provincially regulated Local Distribution Company (LDC) and must comply with requirements issued by the Ontario Energy Board (OEB) with respect to provision of services. As a participant in the Ontario electricity market, PUC Distribution Inc. must comply with the rules of the Independent Electricity System Operator (IESO). As an LDC, the company must adhere to Regulation 22/04 of the Electricity Act.

Note: Also in the local distribution utility family of companies is PUC Services Inc. a utility services company operating as a wholly owned municipal corporation of the Corporation of the City of Sault Ste. Marie. PUC Services Inc. manages the assets and business of PUC Distribution Inc., manages City's Public Utilities Commission water treatment and water distribution system assets and operates the City's two wastewater treatment plants under multi-year contracts. PUC Services Inc. also provides billing and customer care services and manages the operations of Espanola Regional Hydro under multi-year contracts. Water and wastewater services are also provided to several communities and organizations in the Algoma District.

Smart Grid Program - Project Unique ID (to be filled in by Program):

Partner 1 Name: **Project Lead?** ☐	Infrastructure Energy (IE)

<Explain the nature of the organization's role and their contribution to the project>

IE serves as the project developer for the SSG. IE arranges P3 financing, assumes and mitigates project risk during design thru verification phases, and manages the selection and oversight of the prime contractor and the system design and construction.

Through unique use of public-private partnership (P3) in the utility infrastructure sector, IE delivers community microgrid projects that are on-time and on-budget, advancing the timeline on the resilience, reliability and efficiency benefits.

Partner 2 Name:	Black and Veatch (B&V)

<Explain the nature of the organization's role and their contribution to the project>

B&V serves as the prime contractor for the SSG. B&V is responsible for system design, construction, integration and testing.

With our Canadian head office located in the GTA, Black & Veatch is an employee-owned, global leader in building critical human infrastructure in Electricity, Water, Telecommunications and Government Services. Since 1915, we have helped our clients improve the lives of people in over 100 countries through consulting, engineering, construction, operations and program management. With over 12,000 professionals, our revenues in 2016 were US$3 billion. Black & Veatch brings together the foundation of all smart functions—the convergence of physical infrastructure, communications and analytics—to infuse intelligence into the grid infrastructure and the communities they support.

Black & Veatch is leader in planning, design and implementation of essential city systems and their integration to achieve Smart City benefits. We enjoy top rankings across these major areas:
No. 1 .... Telecom
No. 2 .... Power
No. 5 .... Water Supply
No. 9 .... Sewer/Wastewater
No. 15 .... Overall Design Firm
Engineering News Record, 2017 Rankings

Partner 3 Name:	North American Grid Modernization Fund

<Explain the nature of the organization's role and their contribution to the project>

Finance source for development of project. The fund will finance an SPV for project development. The fund consists of contributions from:

- o Stonepeak Infrastructure Partners(SPIP)–financial source
- o Infrastructure Energy(IE)–project developer

Partner 4 Name:	Stonepeak Partners

<Explain the nature of the organization's role and their contribution to the project>

Stonepeak Partners serves as the primary project financing source, contributing to the project Special Purpose vehicle.

Stonepeak Infrastructure Partners is a North America focused private equity firm with a conservative yet opportunistic approach to infrastructure investing. Stonepeak invests in businesses comprised of hard assets with leading market positions primarily in the following sectors: Energy, Power & Renewables, Transportation, Utilities, Water & Communications. Founded in 2011 and headquartered in New York, Stonepeak manages $7.3 billion of capital for its investors (as of December 31, 2016).

Stonepeak's Operating Partners and Senior Advisors, who help drive value for the firm both in the due diligence process and during post-acquisition operations, are seasoned industry veterans and include multiple former chief executives of publicly listed companies.

Partner 5 Name:	Energrid Group LLC

<Explain the nature of the organization's role and their contribution to the project>

EnerGrid serves as a subcontractor to Black and Veatch, and is responsible for providing project advisory services that address the complexities of a highly integrated solution and mitigate technology, schedule and delivery risks by ensuring that solution designs and project delivery plans align with utility requirements and account for changes during implementation.

Established in 2016, EnerGrid is a smart grid and distributed energy consulting and project development firm, focused on promoting the technologies, business models and stakeholder engagement programs needed to realize a clean energy economy.

<Add partners as required>

Section 3: Project Statement of Work and Budget Overview

Use the Excel workbook "Smart Grid Proposal SOW and Budget Template.xlsx" from the Applicant package to complete **Section 3.1 Statement of Work** and **Section 3.2 Budget Overview**. The full proposal submission should include: the completed workbook (.xlsx file) and the signed proposal template (.docx file).

See attached File 180302 PUC SSG SOW and Budget rD rev1.xlsx.

3.3 Project Financing and Business Case for Funding Assistance (300 words maximum)

Provide a business case for the level of government funding requested. For deployment projects, please indicate how government funding for this project addresses market gaps. Consider questions such as: What is the financial ability of the applicant to fund the project? Is the co-funding to be provided by partners and other orders of government in place? Proponents are advised that NRCan will carry out financial due diligence on the applicant and the project business plan prior to commencing the negotiation of a contribution agreement.

The SSG project is intended to cover the maximum amount of the PUC service area while maintaining a bill neutral effect for the PUC customers. The SSG can achieve 100% coverage while remaining bill neutral with both the P3 funding arranged by the Infrastructure Energy, and the contribution from NRCan. By achieving complete coverage of the PUC service area, customers in all areas served by the PUC will have access to the efficiency, resiliency, and reliability that the SSG project will bring to Sault Ste. Marie. By providing for the entire service area, we maximize the ability of both present customers, and future development growth prospects to maximize their ability to participate in the evolving clean energy and distributed generation based energy economy.

Without the NRCan funding, the project would be limited to a subset of the service area with the greatest effect, thus maintaining a bill neutral state (see table 3.3). The reduction of scope would also eliminate the advantages to mitigation of aging infrastructure issues to approximately 30% of the distribution system, eliminating additional savings to the PUC and their customers.

The funding from Stonepeak Partners, thru Infrastructure Energy and the North American Grid Modernization Fund is in place.

Service	% PUC Service Area w/out NRCan Funding	% PUC Service Area with NRCan Funding
Distribution Automation (Resiliency and Reliability)	**84%**	**100%**
Volt/VAR Management (Efficiency)	**68%**	**100%**

Table 3.3 – Coverage Effect of Sault Smart Grid with and without NRCan funding

Smart Grid Program - Project Unique ID (to be filled in by Program):

3.4 Funding Requests from Other Organizations (300 words maximum)

Has this proposal been submitted to other funding organizations (including other levels of government)?	Yes ☒ No ☐

If yes:

1. *Provide the organization name(s) and contact information.*
2. *Describe the stage of approval under those organizations' proposal processes.*
3. *If applicable, describe how this proposal submitted to NRCan differs from the proposal submitted to the other organizations.*

Note: As part of its due diligence process, NRCan may contact these other potential funders. If you do not want NRCan to contact these organizations, provide your reasoning below.

The PUC has not submitted this project proposal to any other funding organization beyond the project developer who is providing project financing, and the NRCan application.

The developer, Infrastructure Energy (IE), has submitted an application for grant and/or loan funding for a combination of an independent Energy Services Company, a network operations centre, and portions of this project, to the Province of Ontario's Northern Ontario Heritage Fund (NOHFC).

Contact Information:

Glen Vine, Manager – Program Services
R/E NOHFC Application 8430069
Northern Ontario Heritage Fund Corporation
Suite 200, Roberta Bondar Place, 70 Foster Drive
Sault Ste. Marie, ON P6A 6V8
Tel: 705-945-6739
Cell: 705-941-8569

The NOHFC has completed due diligence on the application, and is in final decision-making stage.

The application differs from the focus of the NRCan application, as the NOHFC, by charter, cannot make grants to a publicly owned utility, nor fund utility infrastructure. The application by IE focuses primarily on "behind the meter" commercial products that can be offered to consumers in addition to, and by connection to the SSG.

Section 4: Impact of Proposed Project

The Smart Grid program impacts will be evaluated under six metrics:

- GHG emission reductions and other environmental benefits;
- Economic and social benefits;
- Improved asset utilization and increased efficiency;
- Increased reliability and resiliency;
- Increased system flexibility and renewable energy penetration; and
- Cybersecurity.

These six metrics cover a broad range of possible Smart Grid applications. Definitions, examples for each metric and additional evaluation details are included in **Section 10** of the Applicant Guide.

Please specify the order of the metrics from most relevant to least relevant for your project. The top three metrics will be used to rank submitted proposals, but applicants are encouraged to provide information on all six metrics in Sections 4.1 – 4.6[2] if applicable. **Deployment projects must list GHG Emission Reductions in the top three metrics.**

Order of Metrics by Relevance to Proposed Project (from most relevant to least relevant)
1. GHG Emission Reductions *[mandatory for deployment projects]*
2. Improved asset utilization and increased efficiency
3. Increased reliability and resiliency
4. Increased system flexibility and renewable energy penetration
5. Economic and social benefits
6. Cyber security

The metrics need to be quantified, justified and supported by indicators. Indicators are specific measures of project outputs, or results, which contribute to a given metric. Since many Smart Grid improvements are enabling technologies or preventive measures, applicants are asked to distinguish between process indicators and impact indicators:

- Process Indicators relate to what is being implemented or built and would measure an output; and

[2] Include both direct benefits for the grid and broader benefits as appropriate.

Smart Grid Program - Project Unique ID (to be filled in by Program):

- Impact Indicators relate to the results delivered from what has been built or implemented.

For example, a Conservation Voltage Reduction project using Advanced Metering Infrastructure could contribute to GHG emission reductions. In this case, a process metric could be 'energy saved from a GHG emitting supply' and an impact indicator could be 'tons CO_2e avoided from a given emitting electricity generator'. In addition, indicators should state whether they have project level or system level effects.

Proposed indicators for all six metric areas should be included in the summary table below. Examples of the six metric summary tables are included in Section 10.7 of the Applicant Guide.

SSG Project Volt-VAr Management (VVM) and Distribution Automation (DA)

Metrics	Project Title:
GHG Emission Reductions and other Environmental Benefits	**Process indicators-VVM:** Reduced energy losses from GHG emitting supply (kWh); reduced customer energy consumption (kWh) **Impact indicators-VVM:** Tons CO_2e avoided from reduced energy losses and reduced customer consumption **Process indicators-DA:** # of truck rolls avoided; reduced energy losses from GHG emitting supply (kWh), resulting from re-conductoring and phase-balancing **Impact indicators-DA:** Tons CO_2e avoided from reduced vehicle emissions and reduced energy losses
Improved Asset Utilization and Increased Efficiency	**Process indicators-VVM:** Reduced peak demand on utility assets (kW); Reduced need for grid reserve capacity (kW); Increased load factor on certain assets; Reduced energy losses (kWh) **Impact indicators-VVM:** $ savings from deferred system upgrades; $ reduced utility demand charges; $ energy savings to customers **Process indicators-DA:** # of truck rolls avoided (vehicle miles); reduced overtime (OT hours); # of customer minutes with outages avoided (minutes) **Impact indicators-DA:** O&M savings due to reduced truck rolls and overtime;
Increased Reliability and Resiliency	**Process indicators-VVM:** None **Impact indicators-VVM:** None **Process indicators-DA:** # of events Fault Location, Isolation and Restoration responded to; # customer calls/complaints avoided due to fewer outages **Impact indicators-DA:** $ revenue loss avoided from outages avoided; customer average interruption duration index (CAIDI) for customers served by the project; customer minute interruptions avoided
Increased System Flexibility and Renewable Energy	**Process indicators-VVM:** # of feeders with VVM installed and operational **Impact indicators-VVM:** # of voltage actions taken annually to improve grid efficiency and mitigate renewable intermittency

Penetration	**Process indicators-DA:** # of feeders integrated into Fault Location, Isolation and Restoration (FLIR) system **Impact indicators-DA:** % of feeders with automation
Cyber Security	**Process indicators-VVM:** Best practices developed or applied on system communications with AMI (qualitative indicator) **Impact indicators-VVM:** Real-time issue identification and reaction to cyber security threats **Process indicators-DA:** best practices developed or adhered to **Impact indicators-DA:** real-time issue identification and reaction to cyber security threats
Economic and Social Benefits	**Process indicators-VVM:** # jobs to implement system and highly qualified personnel trained, business case established/documented for VVM (Project) **Impact indicators-VVM:** Reduced customer charges due to improved (flatter, lower) voltage profile across the feeder (project); reduced customer charges or off-set increases to customer charges due to the lower demand charges and energy saved at the system level **Process indicators-DA:** # jobs to implement system and created to monitor the system; # customer jobs created due to higher reliability/resiliency **Impact indicators-DA:** $ customer value (e.g. avoided revenue loss) from avoided outages

4.1 GHG Emission Reductions and other Environmental Benefits (500 words maximum not including table)

Describe how the proposed smart grid system would result in GHG reductions in Canada, and, if applicable, internationally. Please see Section 10.1 of the Applicant Guide. Specify if emission reductions are direct (realised upon project completion), or indirect (facilitated or enabled with activities following project completion). What are the proposed process and impact indicators?

Describe the baseline scenario for the GHG reductions calculation and provide justification for why that is the most appropriate choice of baseline. When choosing a baseline, please consider standard industry practices, existing technologies to be replaced or displaced, and industry trends.

For demonstration projects: Describe the scale for the first projected commercial implementation of the technology and quantify the estimated annual GHG reductions that would result at this scale. In the case of demonstration projects assume GHG reductions from a commercial roll out of the technology in the Canadian context.

Smart Grid Program - Project Unique ID (to be filled in by Program):

Does the project contribute to other environmental benefits? Please describe and supply process and impact indicators.

In addition to answering the questions above, please complete the following table:

	Annually in 2030	**Cumulative by 2030**
Direct Canadian GHG Savings (tCO_2)	**2,804 t**	**22,532 t**
Indirect Canadian GHG Savings (tCO_2)	**232,227 t**	**1,535,882 t**
Indirect International GHG Savings (tCO_2)	**NA**	**NA**

The integrated smart grid solutions will provide both direct and indirect GHG emissions reductions in Canada.

The VVM system will directly reduce GHGs[3] by applying power factor optimization and Conservation Voltage Reduction(CVR) techniques, reducing the amount of real power consumed and subsequent thermal losses. Distribution line losses can typically be reduced up to 5%. CVR will be used to flatten voltage profiles and lower voltage across distribution feeders while staying within specified ANSI voltage limits. This can reduce overall system demand by up to 1% for every 1% voltage reduction, and has the dual benefit of reducing the overall customer energy consumption and reducing the amount of utility power needed to meet customer needs. We estimate a 1.5% reduction in customer energy use.

DA implementation will directly reduce GHG emissions in two ways. The first is reducing the number of utility service truck rolls for routine O&M and during outage response. Automating functions that currently require field crews to conduct on-site monitoring, maintenance and repair will reduce labour costs, truck rolls, vehicle-miles traveled and replacement part costs. The second is re-conductoring and phase-rebalancing that will be done prior to DA system deployment – this will further reduce energy losses from GHG emitting supplies (calculations used Ontario Electrical Generation GhG/KWh).

Indirect GHG emissions reductions in Canada will occur through two primary mechanisms. First, PUC's increased voltage monitoring and management capabilities coupled with grid automation will enable higher penetrations of intermittent distributed renewable energy systems and energy storage. We expect both utility and customer-owned distributed renewable deployments to increase through 2030,

[3] Project direct and indirect kWh reduction estimates were converted to tCO2 reduction estimates using an Ontario Power Generation Inc. (OPG) sponsored report, *GHG Emissions Associated with Various Methods of Power Generation in Ontario,* developed by Intrinsik Corp., October 2016.

based on lower technology, installation and service costs. Second, the innovative pairing of integrated utility smart grid solutions with a P3 project finance structure will be replicated with other Canadian municipal utilities. Indirect Canadian GHG savings estimates are based on Infrastructure Energy's current pipeline of 12 utility projects throughout Canada, with estimated benefits to roughly 1,500,000 utility customers.

Comparison baselines for GHG reductions attributable to VVM and DA/OMS reflect current PUC operating practices. For VVM, the baseline will be established by estimating distribution system losses using substation and AMI system voltage measurements. Actual loss reduction depends on the CVR factor, which can only be estimated (not calculated) prior to system deployment. After system commissioning, the actual CVR factor will be calculated using system data. For customer kWh savings, the current baseline represents estimated C/I/R loads at the aggregate feeder level. Following VVM system commissioning, automated performance analytics will be established to calculate annual system losses and customer energy consumption savings following the same methodology used for baseline calculations. For the DA/OMS system, the baseline reflects average system reliability performance (CAIDI and SAIDI) without grid automation for a 3-year period. Following system commissioning, a new 3-5 year average will be calculated annually for comparison to current-year CAIDI/SAIDI numbers. A second performance baseline will also be used that reflects what current year SAIDI/CAIDI numbers would be in the absence of the DA/OMS system. Customer minute interruptions avoided will be used to support these figures.

4.2 Economic and Social Benefits (300 words maximum)

Please identify the economic and/or social impacts that would be expected. Please see Section 10.2 of the Applicant Guide. For example, does the project involve any of the following:

- *Highly Qualified Personnel (HQP) trained during the project*
- *Employment generated for the duration of the project*
- *Creation of temporary and permanent jobs after the project*
- *Direct economic value added impact for Canada*
- *Inclusion of women and minority groups in project*

Does the project support indigenous communities or include indigenous groups in the project or project development?	*Please explain if applicable.* The SSG project benefits the service customers of PUC Distribution Inc. The customer service territory of PUC includes the indigenous community of Batchewana First Nation – Rankin Location. Indigenous Community support consists of the same improvement to community service that all of the PUC service area will receive.

Please provide relevant process and impact indicators, and describe how you expect the project to have an economic and social impact.

The SSG will produce economic and social benefits through three mechanisms, 1) job creation, 2) community engagement and 3) customer benefits - lower energy costs, improved grid reliability, prosumer facilitation and economic development support.

We anticipate creating near and long-term local jobs, including HQP positions, to support design, installation, commissioning, operation and maintenance. We will create a net 65 additional direct jobs. Additionally, we expect indirect job creation through the enablement of distributed renewables, smart homes and facility energy management systems. City Socio-economic analysis estimates an additional 393 jobs in Sault. Ste. Marie.

Community engagement is key SSG deliverable. PUC and IE have allocated funding for an extended 3-year community engagement period. This engagement is essential for customers to understand how to maximize their realization of systems benefits, both as customers and as a community.

Customer satisfaction is the third and most important benefit. Customer billing will see direct savings of at least 1.5% reduced energy use and mitigation of future increases. Increased system resiliency will allow PUC to defer capital expenditures across the distribution system, lowering customer rates.

SSG will improve the economic attractiveness of the community as a place to live and establish new businesses. We expect the grid benefits to be very attractive to industries requiring uninterrupted and high quality power, such as electronics manufacturing, e-commerce, telecommunication services, data centres, multi-modal shipping, and distribution hubs – the industries of Canada's emerging clean energy economy.

Community socio-economic benefits will also be explored through collaboration with the Sault Ste. Marie Innovation Centre (SSMIC) and Sault Ste. Marie Economic Development Corporation (SSMEDC), as directed in resolution by City Council to assess all anticipated primary and secondary socio-economic community benefits. This shall include of how other ongoing and planned Smart City initiatives (e.g. Community Geomatics Centre) can work together with the SSG.

4.2.1 Knowledge Dissemination (250 words maximum)

As the project is developed, it is important that there is a clear plan that allows for a transfer of the knowledge gained from this project to interested receptors. While confidential information is to be respected, it is required to note how the knowledge gained from this project is distributed/transferred to external parties. Please briefly describe the knowledge dissemination plan at the end of this project.

The SSG is particularly innovative as it is being developed with one of Canada's smaller utilities, in a community that is considered one of the "hub cities" of Northern Ontario, proving a model for financing and building substantial improvements to local distribution grids. SSG is a model for Canadian cities that wish to deploy grid modernization and community-scale smart grids rapidly, accelerating the benefits to customers while minimizing the risk and costs.

The project concept has been presented to leading members of the Canadian smart grid sector including Ontario Ministry of Energy staff responsible for the long term energy plan (LTEP) and smart grid policy. Further, the P3 financing and community-scale smart grid strategy for utilities has been presented at a number of conferences by project team, including the MaRS (Micro)grids Today conference, the SSMIC Energy Innovation conference, the Electricity Distributers Association (EDA) Energy Business Innovation Conference (EBIC), the Gowlings Energy Innovator Roundtable, and the Los Angeles Business Council (LABC) Sustainability Summit.

SSG best practices and lessons learned will be further disseminated through the following channels during project execution and following completion:

1. Documentation of project in case studies, releasable to other utilities
2. Publications in industry journals, websites, etc.
3. Direct sharing of knowledge from utility to utility at industry conferences and other events
4. Sharing of project concepts, lessons learned on team-member websites, etc.
5. Carrying forward of lessons learned by vendors, project developer, financier to other Canadian and international utilities

4.2.2 Receptor Capacity and Market Opportunity (250 words maximum)

Describe the target audience of this project and the market opportunity at project completion. Identify any potential direct customers for the technology, their position in the value chain, planned approach for the uptake, and opportunity for export of technology. Please reference engagement of relevant stakeholders such as regulators and system operators.

The SSG project focuses on smart grid technologies that improve efficiency, reliability, and resilience at the distribution utility scale. While all customers of a distribution utility would benefit, the target market is the electrical distribution utility. The local distribution utility will be the logical champion of smart grid systems, as they are first to feel the effects of the emerging energy market, as issues of distributed generation and electric vehicle load, as well as provincial and federal direction, as would be seen in long term energy plans and performance and smart grid scorecards. Benefits of the SSG project plan include the P3 financing, which can lower the cost, reduce risk, and decrease time to completion for the utility.

The utility scale project and P3 financing are developed in detail for each utilities unique configuration and set of energy consumer needs. At present Infrastructure Energy and the North American Grid Modernization Fund are developing projects across Canada and the United States.

4.2.3 Technology Advancement (250 words maximum not including table)

Describe the technical impact should the project be successful within 5 years of project completion. Does the technology itself address a significant gap that will lead to a needed technical advancement to meet other objectives (such as environmental and/or economic objectives)? Will there be new codes and standards developed, policies implemented as a result of this project? Please supply indicators, describe how the project will meet these targets, and the technical impact of meeting these targets.

The SSG project employs established, market proven technologies (TRL 9). The innovation of the project lies primarily in the utility wide scope, and the cost and risk reduction benefits of the P3 financing. We feel that as the leader in utility scale smart grid, Sault Ste. Marie will provide the “proof of concept” that will enable other distribution utilities to fully and quickly embrace smart grid modernization. At present the developer partner (IE) has identified a 4 year pipeline of 12 projects in Canada, valued at more than $650M, and providing smart grid modernization to more than 3 million Canadians.

Technology Readiness Levels[4]		
TRL at start of project	9	**Description:**
TRL at end of project	9	**Description:**
	Target Value at Project Completion	
Number of patents	**0**	
Number of licences	**0**	
Number of codes, standards, policies or regulations impacted	**0**	
<Applicant defined indicator 1>	**n/a**	
<Applicant defined indicator 2>	**n/a**	

<Add rows as needed>

[4] As described in Section 11 of the Applicant Guide

4.3 Improved Asset Utilization and Increased Efficiency (300 words maximum)

Describe how the proposed project would improve asset utilization and efficiency. Provide relevant process and impact indicators. Describe how each of the improvements/benefits you have listed would be quantified and reported to NRCan, and provide a justification for why the quantification process is representative of changes. Please consider existing standards and industry practices. Please see Section 10.3 of the Applicant Guide.

The PUC Smart Grid Project deploys hardware and software components fundamental to an advanced distribution management system (ADMS). Automated switching and intelligent controls will enable automated grid reconfiguration. Grid sensors coupled with data collection, integration and analysis tools will enable asset monitoring, condition-based maintenance and system planning improvements. These tools, integrated with PUCs sophisticated GIS platform, will improve customer service and utility work management processes. Combined, these hardware, software and procedural innovations will contribute significantly to improved asset utilization and utility operating efficiencies.

VVM quantification:

Process Indicators (PIs):

Reduced peak demand on utility assets (kW) - collect peak demand data from substation sensors. Calculate baseline using prior 5 years SCADA data. Calculate PI as the difference.

Reduced need for grid reserve capacity (kW) – aggregate of previous metric across all PUC feeders.

Increased load factor on certain assets – flattening the feeder voltage profile and lowering substation voltage allows more energy to be delivered. Compare 5-year average historic load factor per feeder to new load factor with VVM deployed.

Reduced energy losses (kWh) – use measured CVR factor and SCADA data within power flow model to calculate loss reductions. Baseline - average of model results for previous 3 years.

Impact Indicators (IIs):

$ savings from deferred system upgrades – deferments to PUC capital upgrade plan based on annually quantified PIs, per feeder/asset.

$ reduced utility demand charges – estimated kW reduction times PUCs average demand charges.

$ energy savings to customers – customer tariff rate times estimated annual kWh reduction.

DA Quantification:

Process Indicators:

# of truck rolls avoided – automated feeder reconfiguring reduces vehicle miles during normal operations and outage conditions. Vehicle mile savings are estimated based on feeder length and reconfiguration zones.

Reduced overtime – directly tied to reduced truck rolls/km travelled during off-hours.

# of customer minutes with outages avoided – calculate outage minutes avoided resulting from feeder auto-reconfiguration and return-to-service enabled by DA. Per feeder, per outage. Aggregate annually across distribution system.

Impact Indicators:

O&M savings due to reduced truck rolls and overtime – apply PUC annual rates to estimated vehicle mile and overtime savings.

4.4 Increased Reliability and Resiliency (300 words maximum)

Describe how the proposed project increases the reliability and resiliency of the system. Provide relevant process and impact indicators. What planning, infrastructure, operations and communications steps are in place? Does your project consider historical weather and incident data or do you use forecasted data? Does the project comply with NERC, IEEE or other reliability standards? Please see Section 10.4 of the Applicant Guide.

The DA system will be installed on PUCs 12.5 kV system, with a source-transfer scheme applied to the 34.5 kV system. The integrated solution provides hardware and software to enable monitoring and control; FLIR; auto-transfer and real-time power flow capabilities. The system will automatically identify system fault locations and reconfigure as needed to isolate faults and restore service to the maximum number of customers. This will reduce total customer outage minutes and improve reliability performance, in particular for critical community services and businesses that rely on enhanced reliability. Long term, the integrated solution will further enable distributed energy resource deployment, improving resiliency to system-wide events.

The project team has conducted feasibility assessments and developed a 30% design for the integrated solution set. These plans relied on detailed reviews of PUC outage information dating back to 2007. Based on historic performance, substations and feeders were prioritized and recloser/switch locations identified. Reconfiguration studies were performed using the CYME distribution power-flow model to verify switch locations and settings. Project costs and benefits were then estimated.

PUC has a plan in place for operating and business process changes that will occur to help maximize DA system value. The SSG also delivers an extensive 3-year community engagement process for community outreach and stakeholder education to communicate all expected benefits, including reliability and resiliency.

As mentioned, the project design leveraged historic incident data to develop the DA design and auto-transfer schemes. Historic, weather-normalized incident data will also serve as a performance baseline for the reliability metrics identified in this proposal.

FCIs shall be compatible with IEEE Std 495™-2007. Customers on un-faulted zones will be re-energized within five minutes such that outage duration will not be counted towards sustained outages as defined in IEEE 1366.

4.5 Increased System Flexibility and Renewable Energy Penetration (300 words maximum)

Describe how the proposed project will improve flexibility and increase renewable energy penetration. Provide relevant process and impact indicators, and justify your selection. Please see Section 10.5 of the Applicant Guide.

The ability of distribution systems to adequately control voltage is one of the factors limiting renewable penetration on distribution feeders. Additionally, the variations in apparent load caused by the wind and solar variability may cause more frequent cycling of electromechanical devices used for voltage control and shorten both operating life and maintenance intervals. Thus, it is important to pursue technologies to both mitigate intermittency (e.g. distributed storage) and to implement voltage monitoring and control solutions that increase the renewable capacity that distributions systems can accommodate.

Systems with more generation and storage options will be more flexible than systems with fewer options. The PUC smart grid solution deployment will facilitate more distributed generation and storage options, thus enabling a more flexible distribution system. The continued growth of plug-in electric vehicles will place additional strain on distribution systems, but managed properly through VVM and DA could become valuable grid assets to help mitigate grid operational challenges.

The advanced VVM system will improve overall distribution system performance and enable greater renewable penetration by the following:

- Maintaining acceptable voltage across feeders;
- Improving grid efficiency;
- Enabling operator monitoring and control functionality;
- Coordinating all grid operating devices;
- Allowing operator override.

The DA system will also contribute to system flexibility by allowing DERs including PV and energy storage to stay grid-connected and energized during an outage when feeder reconfiguration is able to isolate the outage and restore power to portions of the feeder.

Process and Impact will measure both the extent of the VVM and DA deployments and the number of voltage control actions taken over time. As renewable generation and storage penetrations increase, this impact indicator should also increase.

4.6 Cybersecurity (300 words maximum)

Describe how the project improves or considers cyber security and data privacy. Provide relevant process and impact indicators, and reference appropriate standards and tools as described in Section 10.6 of the Applicant Guide.

With respect to cyber security, the Ontario Energy Board (OEB) indicated in 2017 that it expects every licensed transmitter and distributor to manage its business in a manner that achieves the reliability, security and privacy protection obligations that are set out in its license and related regulatory requirements.

PUC follows the OEB recommended Ontario Cyber Security Framework, issued December 6 2017, which leverages the well established Cyber Security Framework created by the National Institute of Standards and Technology (NIST) in the United States. The NIST Framework for improving Critical Infrastructure Security is a set of industry standards and best practices to help organizations manage cybersecurity risks. It has been adopted by the electric power utilities in the US and Canada as a guide for improving security and reducing risk in our critical infrastructure.

The Distribution Automation (DA) program outlined in this application supports the Ontario Cyber Security Framework by contributing a more resilient grid designed using industry standard best practices and protocols as outlined in the NIST framework. Black & Veatch is highly qualified in Cybersecurity as an approved partner, and one of only a few vendor-agnostic partners, with the NIST's National Cybersecurity Center of Excellence, which accelerates the adoption of secure technologies.

Security and risk management is comprised of four main elements (see table 4.6):

- People
- Process
- Technology
- Governance

The DA program is an application of technology that supports PUC's Security and Risk Management strategy and policies.

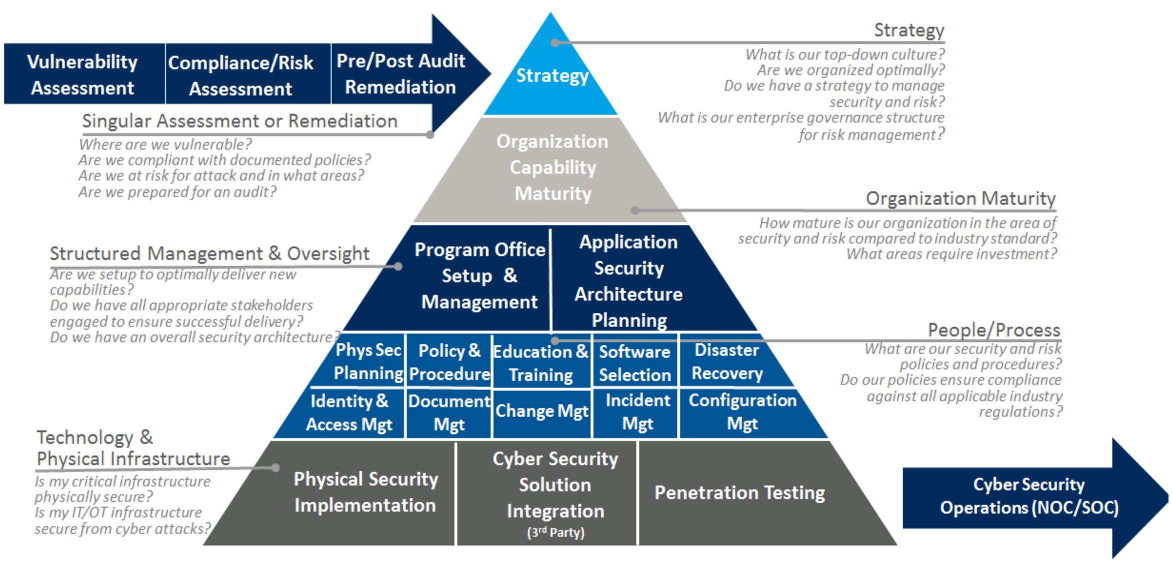


Table 4.6 – Cyber Security – Risk and Resiliance Capabilities (B&V Design)

Smart Grid Program - Project Unique ID (to be filled in by Program):

Section 5: Project Risk and Preliminary Due Diligence

5.1 Project Risk and Risk Mitigation Strategy

Provide a review of the project risks in terms of technical risk, business risk and other risks (environmental review, permitting, etc.). The project will be evaluated based on how well the risks have been identified and on the risk mitigation strategy. It is understood that projects carry risk, which is why government funding is required as part of a risk mitigation strategy. What is needed is for the applicant to show that they understand the risks at various stages of the project development and that there is a well thought out plan to execute the project in such a manner that risk is mitigated to a reasonable degree.

Type of Risk:	Choose an item.[5] Technical	Estimate Likelihood:	Choose an item.[6] Medium	Residual Risk to Project	Low
<Risk Name and Description> Technology Risk to the project completion due to the underlying technology proving unworkable or inadequate		<Enter mitigation measures> 1. PUC is protected by transferring risk via an EPC wrap 2. B&V is a proven world leader in EPC projects for utilities, including smart grid technologies 3. System Architecture has been validated by a third party (Navigant Consulting) 4. Components and their technologies are all commercially available and market proven (COTS). 5. Independent certification before transfer to PUC.		<Describe residual risk if medium or high>	

[5] Financial – e.g. project funding issues; Market – e.g. market environment, product entry; Technical – e.g. equipment failure; Regulatory – e.g. environmental approvals, permitting issues.

[6] Likelihood – Low – unlikely to occur <5%; Medium – moderately likely to occur ~25%; High – very likely to occur > 50%.

Smart Grid Program - Project Unique ID (to be filled in by Program):

Type of Risk:	Regulatory	Estimate Likelihood:	Low	Residual Risk to Project	Low
<Risk Name and Description> Regulation and Approval Risk that the provincial authority (OEB) will not approve and/or credit the full value of the project to PUC		<Enter mitigation measures> 1. The smart grid project aligns with Ontario Provincial Long Term Energy Plan (2013 & 2017) 2. PUC has consulted with OEB with positive feedback for inclusion in timely application approval (ACM method) 3. Project helps PUC achieve "in front of meter" LTEP efficiency goals for 2015-2020 4. PUC and the SSG project meet OEB Distributor Scorecard criteria 5. SSG project closes with bill neutral impact to residential customers		<Describe residual risk if medium or high>	
Type of Risk:	Budget	Estimate Likelihood:	Low	Residual Risk to Project	Low
<Risk Name and Description> Construction costs Risk of cost over run		<Enter mitigation measures> 1. EPC contractor is under a fixed price contract (risk transferred to B&V) 2. Contract includes a formal change control process with controls supported by PUC approvals 3. Design approval and vetting process is in place 4. B&V is a proven world leader in EPC projects for utilities, including smart grid technologies 5. COTS components		<Describe residual risk if medium or high>	

Smart Grid Program - Project Unique ID (to be filled in by Program):

Type of Risk:	Schedule	Estimate Likelihood:	Low	Residual Risk to Project	Low
<Risk Name and Description> Construction schedule Risk of schedule over run		<Enter mitigation measures> 1. EPC contractor is liquidated damages clauses 2. Contract includes a formal change control process with controls supported by PUC approvals 3. Design approval and vetting process is in place 4. B&V is a proven world leader in EPC projects for utilities, including smart grid technologies 5. COTS components		<Describe residual risk if medium or high>	
Type of Risk:	**Performance**	**Estimate Likelihood:**	**Low**	**Residual Risk to Project**	**Low**
<Risk Name and Description> System Performance as Designed System as designed may not achieve expected performance		<Enter mitigation measures> 1. PUC is protected by transferring risk via an EPC wrap including liquidated damages 2. B&V is a proven world leader in EPC projects for utilities, including smart grid technologies 3. System Architecture has been validated by a third party (Navigant Consulting) 4. Components and their technologies are all commercially available and market proven (COTS). 5. Independent system test and verification before transfer to PUC.		<Describe residual risk if medium or high>	

Smart Grid Program - Project Unique ID (to be filled in by Program):

Type of Risk:	Performance	Estimate Likelihood:	Low	Residual Risk to Project	Low
<Risk Name and Description> System Performance in operation System operations as part of the LDC distribution grid may not achieve expected performance		<Enter mitigation measures> 1. PUC is protected by transferring risk via an EPC wrap including liquidated damages 2. B&V is a proven world leader in EPC projects for utilities, including smart grid technologies 3. System Architecture has been validated by a third party (Navigant Consulting) 4. Components and their technologies are all commercially available and market proven (COTS). 5. Independent system test and verification before transfer to PUC.		<Describe residual risk if medium or high>	
Type of Risk:	Performance	Estimate Likelihood:	Low	Residual Risk to Project	Low
<Risk Name and Description> Operations / Maintenance & Life Cycle System operations, maintenance, and life cycle performance and cost does not meet expectations		<Enter mitigation measures> 1. System Architecture has been validated by a third party (Navigant Consulting) 2. Components and their technologies are all commercially available and market proven (COTS). 3. Independent certification before transfer to PUC. 4. PUC is a cost efficient distribution grid operator. PUC has amongst the lowest residential LDC rates Ontario 5. PUC cost variances are subject to periodic OEB review for rate adjustments		<Describe residual risk if medium or high>	

Smart Grid Program - Project Unique ID (to be filled in by Program):

<table>
<tr><td>Type of Risk:</td><td>Financial</td><td>Estimate Likelihood:</td><td>Low</td><td>Residual Risk to Project</td><td>Low</td></tr>
<tr><td colspan="2"><Risk Name and Description>

Cost of Money

Risk that cost of money an cost of operations will exceed expectations

Risk that the project will adversely affect the debt ratio of the utility</td><td colspan="2"><Enter mitigation measures>

1. PUC has a guaranteed price for the system
2. P3 financing contractually stipulated payments.
3. PUC debt structure is unaffected
4. Funding is available thru NAGMF with commitments from Stonepeak Partners.
5. PUC is a cost efficient distribution grid operator. PUC has amongst the lowest residential LDC rates Ontario
6. PUC cost variances are subject to periodic OEB review for rate adjustments</td><td colspan="2"><Describe residual risk if medium or high></td></tr>
<tr><td>Type of Risk:</td><td>Benefits</td><td>Estimate Likelihood:</td><td>Low</td><td>Residual Risk to Project</td><td>Low</td></tr>
<tr><td colspan="2"><Risk Name and Description>

Anticipated Project Benefits

Risk that benefits to interested parties do not materialize to timeline plans (Note that if the project was carried out organically by PUC, deployment would be incremental and take up to 7 years to achieve first benefits

1. Savings to Customer not realized timely manner
2. Provincial regulator (OEB) does not achieve smart grid, efficiency, reliability, and resiliency gains to 2015-2020 schedule
3. Federal government does not see expected GHG reductions in 2018-2025</td><td colspan="2"><Enter mitigation measures>

1. Use of developer, P3 financing, and EPC with validated system architecture speeds up 100% deployment to 2020
2. By deploying the system grid wide at one time, a synergy of benefits occurs, increasing likelihood of complimentary benefits (distributed generation and electric vehicle penetration)</td><td colspan="2"><Describe residual risk if medium or high></td></tr>
</table>

<Add rows as necessary>

5.2 Federal Environmental Assessment Required (300 words maximum)

Is this project a designated project under the *Canadian Environmental Assessment Act 2012*? *See Section 7.7 of the Applicant Guide for more details.*	Yes ☐ No ☒

If this project is considered a designated project under the Canadian Environmental Assessment Act 2012[7]*, please describe the activities undertaken to complete the environmental assessment, the remaining steps required and the anticipated completion date. Please also consider activities relevant to a Federal Environmental Assessment in Section 5.1 of the proposal (Project Risk and Mitigation Strategy).*

The SSG field modifications are completely located on PUC distribution poles and equipment located in existing facilities, stations and approved road rights of way under PUCs licenced service area. The SSG will not require any federal EAR.

5.3 Project Location on Federal Lands (300 words maximum)

Will this project be carried out on Federal lands?	Yes ☐ No ☒

Under Sections 67 and 68 of the Canadian Environmental Assessment Act 2012, NRCan is required to assess whether projects carried out on Federal Lands it intends to fund are likely to cause significant adverse environmental effects. If so, an environmental assessment may be required. Identify which portions of the project (if any) will be carried out on federal lands, and the specific activities (including but not limited to site preparation, construction, installation, modification, operation, decommissioning or abandonment) that will occur at those sites. Identify any other federal government involvement in your project such as funding from other federal departments or agencies, federal permits or licenses as appropriate. Also identify any provincial or territorial environmental assessment requirements, permits, certificate of authorizations, etc. as appropriate.

The SSG field modifications are completely located on PUC distribution poles and equipment located in existing facilities, stations and approved road rights of way under PUCs licenced service area. The SSG will not require any location on Federal Lands.

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[7] To determine if the project is a designated project under CEAA 2012, please refer to the Act and any Regulations made under the Act. More Information and downloadable documents are available at: http://laws-lois.justice.gc.ca/eng/acts/C-15.21/

Smart Grid Program - Project Unique ID (to be filled in by Program):

5.4 Indigenous Consultation (300 words maximum)

Will this project require Indigenous Consultation?	Yes ☐ No ☒

NRCan has a duty to consult with Indigenous groups when a contemplated Crown conduct, such as the provision of funding or the issuance of permits, may have adverse impact on existing or potential Aboriginal or Treaty rights. In order to assess Consultation requirements, and using the Aboriginal and Treaty Rights Information System (http://sidait-atris.aadnc-aandc.gc.ca/atris_online/home-accueil.aspx), identify the Indigenous groups that may be impacted by your project. Also identify any Indigenous groups you have interacted with on your project and describe the type and frequency of interactions. If you have not interacted with any Indigenous groups, please explain why.

The customer service territory of PUC includes the indigenous community of Batchewana First Nation – Rankin Location. PUCs distribution system is interconnected and fully integrated with the City and the BFN community. PUC's poles and equipment are located on FN road rights-of-way and the SSG will have no adverse impact on FN lands. PUC has long and cooperative relationship with the FN community and in addition to electric service provides water supply and distribution in the same road rights-of-way.

The SSG field modifications are completely located on PUC distribution poles and equipment located in existing facilities, stations and approved road rights of way. The SSG requires no modification of service or equipment to any customer. Because there is no impact to customer facilities or equipment with this project, there have been no consultations with indigenous groups.

Smart Grid Program - Project Unique ID (to be filled in by Program):

Section 6: Applicant's Attestations

By submitting this project proposal, the Applicant:

1. Attests that it is legally registered or incorporated in Canada.

2. Attests that the information provided is true and accurate to the best of their knowledge.

3. Understands that any costs incurred for the submission of the project proposals are at the Applicant's own risk.

4. NRCan reserves the right to alter the currently envisaged process, and deadlines, or to cancel the request for proposals at its sole discretion.

5. Understands that project funding decisions will only be made following receipt, review, selection of project proposals, and the successful completion of due diligence.

6. Understands and acknowledges that no liability and no commitment or obligation exists on the part of NRCan to make a financial contribution to the project until a written contribution agreement is signed by both parties.

7. Attests that it is the owner of all information - proprietary, confidential or otherwise - provided as part of the proposal submission, or, if the information belongs to another party, that it has obtained written consent to disclose the information to NRCan.

8. Understands that federal reviewers are bound by the requirements of the *Access to Information Act* and the *Privacy Act* regarding the treatment of confidential information.

9. NRCan may share this proposal and any other information provided as supplemental material as part of this response with other funding entities in effort to better support projects in Canada. Please indicate which of the following you consent to having your proposal shared with:

a) Other Departments across the Government of Canada ☒ **Yes** ☐ **No**

b) Provincial, and Territorial governments ☒ **Yes** ☐ **No**

c) Municipal Governments ☒ **Yes** ☐ **No**

d) The not-for-profit sector such as the Sustainable Development Technology Canada and the Green Municipal Fund ☒ **Yes** ☐ **No**.

Please sign below to confirm having read and understood the statements above.

___________ ______________________ **Name of Duly Authorized Officer for Applicant:** **Title: V.P. Customer Engagement & Business Development**	2018-03-03 Date

Section 7: Applicant Checklist and Program Mandatory Criteria

Criteria	Applicant	FOR PROGRAM USE ONLY	
	Checklist	Pass/Fail	Comment
Eligible Applicant:	☒		
Eligible Activities:	☒		
Project Timing:	☒		
Funding Criteria:	☒		
Fits Program Scope:	☒		
All sections of the Proposal Word document completed and attached:	☒		
All sections of the Proposal Excel file completed and attached:	☒		
All other relevant files attached (e.g. letters of support):	☒		
Signed Attestation:	☒		
Overall Assessment:			

FOR PROGRAM USE ONLY	Checklist Completed by:
Name:	
Signature:	
Name:	
Signature:	
Name:	
Signature:	

Smart Grid Program - Project Unique ID (to be filled in by Program):

ATTACHMENT 1

Letter of Commitment from City of Sault Ste. Marie

APPENDIX 4
COST OF POWER ANALYSIS

Bill Impact Analysis

2018 CoS Rate Application Loss Factor 1.0481 ***Allocation by Efficiency Benefit***

	Total Base Revenue Requirement	Class %	Number of Customers	2018 Test Year Weather Normal kWh (Load Forecast)	Class %	kW	2018 Test Year Weather Normal (kWh w/LF)	Class %	Reduce GS>50kW for 34.5kV (no VVM kwh)	LV Feeder Energy Consumption Base for VVM	Class %	Reduce GS>50kW for 34.5kV (no VVM kW)	LV Feeder kW	per customer/ month	
Res	$ 11,226,807	58.50%	29,816	288,323,799	45.85%		302,192,174	45.85%		302,192,174	49.23%			845	806
GS<50	$ 3,149,458	16.41%	3431	92,411,463	14.69%		96,856,454	14.69%		96,856,454	15.78%			2,352	2245
GS>50	$ 4,544,464	23.68%	357	244,620,598	38.90%	614,743	256,386,849	38.90%	(41,597,434)	214,789,415	34.99%	(98,669)	516,074	50,138	57101
Sent lights	$ 34,742	0.18%	354	209,800	0.03%	593	219,891	0.03%					593		
Street lights	$ 195,345	1.02%	8070	2,398,221	0.38%	7,030	2,513,575	0.38%					7,030		
USL	$ 39,551	0.21%	22	944,731	0.15%		990,173	0.15%							
	$ 19,190,367	100.00%		628,908,612	100%		659,159,116	100%		613,838,043	100%				
									-16.2%			-16.1%			

Note : Using consumption (adjusted for no 35kV loads) plus losses as simplified estimation for CVR savings.

Leidos/I.E. spreadsheet calculates all seperately (consumption, feeder loss, & demand)

ENTER VALUES			
	CVR factor	0.9	
	Voltage Savings	3.0	volts
	Energy Savings	2.7	%
		Estim Energy Savings (kWh)	Estim Energy Savings per Month (kWh)
Res		8,159,189	679,932
GS<50		2,615,124	217,927
GS>50		5,799,314	483,276
		16,573,627	1,381,136

Cost of Power Analysis

	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU		GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Cost of Power (COP*)	$77,725,426	$35,945,091	$11,467,389	$29,880,767	$0		$0	$0	$288,889	$25,865	$117,425
(*) gross w/loss factor		46.25%	14.75%	38.44%	0.00%		0.00%	0.00%	0.37%	0.03%	0.15%
Reduce GS>50kW for 34.5kV (no VVM)				($4,847,999.19)							
COP to VVM cust's	$72,877,427	$35,945,091	$11,467,389	$25,032,768					$288,889	$25,865	$117,425
2.7%	100.00%	49.32%	15.74%	34.35%					0.40%	0.04%	0.16%
Estim Energy Savings /Yr	$1,967,691	$970,517	$309,620	$675,885					$7,800	$698	$3,170
per month	$163,974	$80,876	$25,802	$56,324					$650	$58	$264
per kWh	$ 0.1187										
2.6% Reduced System Losses	$93,378										
Losses per month	$7,782	$3,838	$1,224	$2,673					$31	$3	$13
TOTAL Savings per Mth	$171,756	$84,715	$27,026	$58,997					$681	$61	$277
		ANNUAL	$2,061,069								
Revenue Requirement from ICM			$ 1,877,976								

Calculation of Revenue Requirement to Rate Classes and Fixed/Variable Rates

	(A) Rev Allocation (from above)	(B) Net Rev Requirement from above	(C) Class Revenue (A X B)	(D)	(E) Class Revenue including Transf Allow (C + D)		(F) Fixed % (2018 CoS)	(G) Variable % (2018 CoS)	(H) Fixed + Var % (F + G)	(I) Fixed $ (E x F)	(J) Var $ (E x G)		(K) Total (I + J)	(L) Customers (2018 CoS)	(M) kWhs (2018 CoS)	(N) kWs (2018 CoS)	(O) Fixed Rate (I/L/12)	(P) Var Rate (J/M)
Res	49.23%	1,877,976	924,527		924,527		77.40%	22.60%	100.00%	715,584	208,943		924,527	29,816	302,192,174		2.00	0.000691
GS<50	15.78%	1,877,976	296,323		296,323		26.80%	73.20%	100.00%	79,414	216,908		296,323	3,431	96,856,454		1.93	0.002239
GS>50	34.99%	1,877,976	657,127		657,127		12.80%	87.20%	100.00%	84,112	573,014		657,127	357	214,789,415	614,743	19.63	0.932120
Sent lights			-		-		42.10%	57.90%	100.00%	-	-		-	354		593	-	0.000000
Street lights			-		-		67.70%	32.30%	100.00%	-	-		-	8070		7,030	-	0.000000
USL			-		-		8.80%	91.20%	100.00%	-	-		-	22			-	#DIV/0!
	100.00%		1,877,976	-	1,877,976					879,110	998,866		1,877,976		613,838,043			

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2012_2013 Consumption Analysis by DS, Feeder and Customer Class - Note: will be scaled to 2018 COS for Benefit Calculation

2018 Cost of Service Estimated kWh - note lower consumption factors

>>- 2013 actuals in study data, 2018 COS adjusted for removing 34.5kV loads, conservation program, 2018 weather normalized forecast

>> Note: DS10 now in service - now supplies DS14 (retired) and part of DS4 loads

													628,204,369
		29,789	3,443	353							310,650,128	98,856,928	218,697,313
					annual consumption			load factor					
					329,484,605	95,139,400	258,275,777	0.70	0.70	0.75			713,607,514
total		29130	3249	323				53,732	15,515	39,311	345,596,402	99,791,717	268,219,395

		consumption						demand			billing consumption		
Feeder	subst	resident	comm <50kW	comm >50kW	residential	small commercial	large commercial	residential	small commercial	large commercial	residential	small commercial	large commercial
	#	#	#	#	kWh	kWh	kWh	kW	kW	kW	kWh	kWh	kWh
1-11	1	0	58	8	-	1,698,395	6,396,923	-	276.97	974	-	1,781,446	6,643,205
1-12	1	324	53	13	3,664,710	1,551,982	10,395,000	597.64	253.10	1582	3,843,915	1,627,873	10,795,208
1-13	1	38	53	13	429,812	1,551,982	10,395,000	70.09	253.10	1582	450,829	1,627,873	10,795,208
1-14	1	561	106	1	6,345,378	3,103,963	799,615	1,034.80	506.19	122	6,655,667	3,255,747	830,401
2-13	2	637	184	7	7,205,001	5,388,012	5,597,308	1,174.98	878.67	852	7,557,326	5,651,485	5,812,804
2-14	2	64	15	16	723,893	439,240	12,793,847	118.05	71.63	1947	759,292	460,719	13,286,410
2-15	2	1093	57	8	12,362,742	1,669,112	6,396,923	2,016.10	272.20	974	12,967,280	1,750,732	6,643,205
2-16	2	583	32	6	6,594,216	937,045	4,797,692	1,075.38	152.81	730	6,916,674	982,867	4,982,404
4-02	4	558	22	1	6,311,446	644,219	799,615	1,029.26	105.06	122	6,620,075	675,721	830,401
4-04	4	459	7	1	5,191,673	204,979	799,615	846.65	33.43	122	5,445,546	215,002	830,401
4-11	4	241	56	13	2,725,911	1,639,830	10,395,000	444.54	267.42	1582	2,859,208	1,720,017	10,795,208
4-12	4	532	58	4	6,017,364	1,698,395	3,198,462	981.31	276.97	487	6,311,613	1,781,446	3,321,602
5-01	5	0	0	0	-	-	-	-	-	0	-	-	-
5-02	5	81	8	0	916,178	234,261	-	149.41	38.20	0	960,979	245,717	-
5-05	5	27	3	0	305,393	87,848	-	49.80	14.33	0	320,326	92,144	-
11-11	11	377	46	5	4,264,185	1,347,003	3,998,077	695.40	219.67	609	4,472,703	1,412,871	4,152,003
11-12	11	1323	81	2	14,964,234	2,371,896	1,599,231	2,440.35	386.81	243	15,695,985	2,487,882	1,660,801
11-13	11	752	31	5	8,505,747	907,763	3,998,077	1,387.11	148.04	609	8,921,678	952,152	4,152,003
11-14	11	673	42	6	7,612,192	1,229,872	4,797,692	1,241.39	200.57	730	7,984,428	1,290,013	4,982,404
12-11	12	961	36	1	10,869,712	1,054,176	799,615	1,772.62	171.91	122	11,401,241	1,105,725	830,401
12-12	12	868	3	2	9,817,804	87,848	1,599,231	1,601.08	14.33	243	10,297,895	92,144	1,660,801
12-13	12	781	53	10	8,833,762	1,551,982	7,996,154	1,440.60	253.10	1217	9,265,733	1,627,873	8,304,006
12-14	12	442	10	11	4,999,389	292,827	8,795,770	815.29	47.75	1339	5,243,859	307,146	9,134,407
13-01	13	1005	72	4	11,367,389	2,108,352	3,198,462	1,853.78	343.83	487	11,923,254	2,211,451	3,321,602
13-02	13	1257	84	3	14,217,719	2,459,744	2,398,846	2,318.61	401.13	365	14,912,965	2,580,026	2,491,202
13-03	13	1196	111	7	13,527,758	3,250,377	5,597,308	2,206.09	530.07	852	14,189,265	3,409,320	5,812,804
13-04	13	634	79	2	7,171,069	2,313,331	1,599,231	1,169.45	377.26	243	7,521,734	2,426,453	1,660,801
14-03	14	312	24	2	3,528,980	702,784	1,599,231	575.50	114.61	243	3,701,547	737,150	1,660,801
14-04	14	262	26	2	2,963,439	761,349	1,599,231	483.27	124.16	243	3,108,351	798,579	1,660,801
14-05	14	91	12	5	1,029,286	351,392	3,998,077	167.85	57.30	609	1,079,618	368,575	4,152,003
14-06	14	227	17	1	2,567,559	497,805	799,615	418.71	81.18	122	2,693,113	522,148	830,401
15-01	15	0	47	6	-	1,376,286	4,797,692	-	224.44	730	-	1,443,586	4,982,404
15-02	15	21	77	2	237,528	2,254,766	1,599,231	38.74	367.70	243	249,143	2,365,024	1,660,801
15-03	15	382	214	4	4,320,739	6,266,492	3,198,462	704.62	1,021.93	487	4,532,023	6,572,923	3,321,602
15-04	15	171	77	3	1,934,153	2,254,766	2,398,846	315.42	367.70	365	2,028,733	2,365,024	2,491,202
16-01	16	438	142	7	4,954,145	4,158,139	5,597,308	807.92	678.10	852	5,196,403	4,361,472	5,812,804
16-02	16	497	132	18	5,621,485	3,865,313	14,393,077	916.75	630.35	2191	5,896,375	4,054,326	14,947,211
16-03	16	398	69	7	4,501,712	2,020,504	5,597,308	734.13	329.50	852	4,721,846	2,119,307	5,812,804
16-04	16	602	76	5	6,809,122	2,225,483	3,998,077	1,110.42	362.93	609	7,142,088	2,334,309	4,152,003
18-01	18	1001	102	2	11,322,145	2,986,833	1,599,231	1,846.40	487.09	243	11,875,798	3,132,889	1,660,801
18-02	18	833	44	2	9,421,925	1,288,438	1,599,231	1,536.52	210.12	243	9,882,657	1,351,442	1,660,801
18-03	18	494	5	0	5,587,552	146,413	-	911.21	23.88	0	5,860,783	153,573	-
18-04	18	830	102	2	9,387,993	2,986,833	1,599,231	1,530.98	487.09	243	9,847,065	3,132,889	1,660,801
19-01	19	14	1	1	158,352	29,283	799,615	25.82	4.78	122	166,095	30,715	830,401
19-02	19	742	76	7	8,392,639	2,225,483	5,597,308	1,368.66	362.93	852	8,803,039	2,334,309	5,812,804
19-03	19	643	147	23	7,272,866	4,304,553	18,391,154	1,186.05	701.98	2799	7,628,510	4,515,045	19,099,214
19-04	19	969	57	4	10,960,198	1,669,112	3,198,462	1,787.38	272.20	487	11,496,152	1,750,732	3,321,602
20-01	20	334	26	8	3,777,819	761,349	6,396,923	616.08	124.16	974	3,962,554	798,579	6,643,205
20-02	20	608	74	8	6,876,987	2,166,918	6,396,923	1,121.49	353.38	974	7,213,272	2,272,880	6,643,205
20-03	20	112	97	17	1,266,813	2,840,419	13,593,462	206.59	463.21	2069	1,328,761	2,979,316	14,116,810
20-04	20	892	39	14	10,089,264	1,142,024	11,194,616	1,645.35	186.24	1704	10,582,629	1,197,869	11,625,608
21-01	21	639	44	6	7,227,623	1,288,438	4,797,692	1,178.67	210.12	730	7,581,054	1,351,442	4,982,404
21-02	21	1183	109	2	13,380,717	3,191,811	1,599,231	2,182.11	520.52	243	14,035,034	3,347,891	1,660,801
21-03	21	740	24	1	8,370,017	702,784	799,615	1,364.97	114.61	122	8,779,311	737,150	830,401
21-04	21	228	29	9	2,578,870	849,197	7,196,539	420.56	138.49	1095	2,704,977	890,723	7,473,605

APPENDIX 5
NAVIGANT REPORT ON CONSIDERATIONS FOR DEPLOYING IN-FRONT-OF-THE-METER CONSERVATION TECHNOLOGIES IN ONTARIO

Considerations for Deploying In-Front-of-the-Meter Conservation Technologies in Ontario

Final Report

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Alectra
Avangrid
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BC Hydro
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Customer First
DVI Grid Solutions
Electricity Distributors Association
Entegrus
Enwin Utilities
Grid 20/20
Guelph Hydro Electric Systems
Hydro One Networks
Hydro Ottawa
Independent Electricity System Operator
KVAR Energy Savings
Northwest Power & Conservation Council
Ontario Energy Board
Pacific Gas and Electric
Southern California Edison
Thunder Bay Hydro
Toronto Hydro
Tucson Electric Power
Varantec
Veridian Connections

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EXECUTIVE SUMMARY

Introduction and Objectives

North America's electricity sector is undergoing a significant transformation, and utilities are exploring how various emerging intelligent grid technologies can be effectively integrated into networks to increase their efficiency and flexibility.

In-front-of-the-meter conservation (IFMC) technologies that are deployed on the distribution system resulting in electricity savings and peak demand reductions primarily for end users behind the meter are a potential element of this transformation. IFMC technologies have the added benefit of providing distribution network operators with increased communication and automation capabilities.

The Ministry of Energy (the Ministry) engaged Navigant Consulting Ltd. (Navigant) to[1]:

1. Identify market-ready IFMC technologies and evaluate their appropriateness for deployment in Ontario;
2. Estimate the technical and economic potential for electricity and peak demand reductions resulting from IFMC technology deployment in Ontario;
3. Identify and provide insight into how and why other jurisdictions have deployed IFMC technologies, as well as the barriers faced and the cost-recovery mechanisms used;
4. Provide a perspective on Ontario-specific factors that impede IFMC technology deployment; and,
5. Assess and compare three IFMC cost-recovery mechanisms; a conservation approach[2], a distribution-rates approach[3], and a hybrid approach.

Key Findings

The following six key findings were identified during study completion.

Key Finding	Description
A number of IFMC technologies have been tested and proven effective, and are available to be deployed in Ontario	Several successful pilot projects undertaken by North American utilities have demonstrated the viability of certain IFMC technologies, specifically, Volt/VAR Optimization (VVO) and phase balancing. These pilots reduce the technology risk associated with IFMC technologies and position Ontario's local distribution companies (LDCs) to benefit from lessons learned. These pilot projects have also demonstrated that the energy and demand

[1] Additionally, Navigant was retained to develop best practice evaluation, measurement, and verification (EM&V) methodologies that can be used to accurately assess the impacts and effectiveness of IFMC deployments. The findings of this complementary study are provided in a supplemental report entitled "IFMC – Best Practice EM&V Methodologies for Ontario".

[2] Under the conservation approach, a distributor would seek recovery of either a portion or all the project's capital costs and on-going operating and maintenance expenses through CDM budgets managed by the Independent Electricity System Operator.

[3] Under the distribution-rates approach, a distributor would apply to the Ontario Energy Board for approval to recover the project's capital investment and on-going operating expenses through distribution rates.

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Key Finding	Description
	savings impacts of IFMC deployments can be accurately evaluated using well-developed evaluation, measurement and verification processes. Ontario's LDCs are currently able to deploy both VVO and phase balancing on their networks, as there are no prerequisite system upgrades necessary to integrate these IFMC technologies.
A significant level of economically viable IFMC potential exists in Ontario	It is estimated that VVO and phase balancing solutions can be deployed on approximately 30% of Ontario's distribution feeders cost-effectively. The same estimate suggests that if all cost-effective IFMC is deployed Ontario could realize an average annual peak demand reduction of 185 megawatts, an average annual electricity consumption reduction of 1,130 gigawatt-hours, and an average annual line loss reduction of 180 gigawatt-hours. Combined, these savings represent approximately 18% of Ontario's 2015-2020 seven terawatt-hour (TWh) conservation and demand management (CDM) target. The net present value of deploying all cost-effective VVO and phase balancing projects is $235 million and $54 million, respectively. Both values are represented in 2017 dollars. A variety of feeder-specific factors affect the costs of deploying and the energy savings potential of IFMC technologies. To appropriately account for these factors, the modelling completed in support of the potential estimate considered costs and impacts across 15-prototypical feeders that reflect the realities of Ontario's various distribution networks. The levelized unit energy cost (LUEC) for IFMC deployment across these 15-feeders range from $0.052/kWh - $0.19/kWh[4].
Non-technical barriers are the primary inhibitor of IFMC deployment	As there have been a number of successful VVO and phase balancing pilots in North America, technological barriers are not the main adoption limiter in Ontario. The main barriers to IFMC deployment in Ontario are financial, cultural, and regulatory.
IFMC projects can be financially supported through either the distribution rates approach or conservation approach. However, key	*Conservation Approach:* Ontario's Conservation and Demand Management Framework, administered by the Independent Electricity System Operator (IESO), financially supports all aspects of customer facing energy efficiency and conservation programming. This includes funding of the incentives paid to participants for undertaking an approved energy efficiency project or installing an eligible efficient technology.

[4] The light rural 4.16kV feeder analysis resulted in an anomaly LUEC of $0.443/kWh. 14 of the 15 feeders demonstrated LUEC's between $0.052/kWh - $0.19/kWh.

Key Finding	Description
differences between the two options exists	Currently, the definition of CDM explicitly excludes any investments or measures that increase the efficiency of a utilities distribution system from incentive eligibility. For IFMC to be eligible for CDM incentives, the definition of CDM requires amendment. Further, a determination on whether IFMC investments should be considered as measures (which receive incentives) or programs (which receive full cost recovery) would be necessary. *Distribution Rates Approach*: The Ontario Energy Board (OEB) allows LDCs to recover the costs of IFMC deployments – provided the investments are backed by a strong business case – as part of approved distribution system plans or as part of individual one-off applications. To-date, this allowance has resulted in a very limited number of IFMC technology deployments. There are four primary differences between the two funding models: 1. The timeframe over which the costs are recovered from customers: costs will either be recovered over the lifetime of the asset or over the course of a CDM framework period; 2. Which customers pay: costs will either be socialized over all Ontario rate-payers or only to those customers within a specific LDC service territory; 3. The post-deployment evaluation, measurement, and verification requirements: projects funded through CDM require rigourous post-installation assessments whereas distribution-rates supported investments do not; and ultimately, 4. The ability of the funding model to effectively encourage LDC investment in IFMC technologies: to-date, the distribution rates approach does not appear to have an affect on encouraging IFMC investments. Integrating IFMC with CDM may be effective in stimulating uptake.
A hybrid approach to IFMC project financing, that combines the benefits of the distribution rate and conservation approach, is the option most likely to create an LDC response	Through the project, a third cost recovery model was identified - a hybrid model that blends the conservation and distribution-rates approaches. Under this hybrid model, cost-recovery of IFMC projects would be achieved through distribution rates, however, LDCs would be eligible to claim end-user savings from these projects towards their CDM targets. The value in this approach is that it leverages existing project financing channels while at the same time offering LDCs a viable financial motivation to pursue IFMC projects. LDCs would be provided with an additional option to achieve their 2015-2020 CDM targets and, if achieved, be eligible to receive associated CDM performance incentives. If an LDC achieves its CDM target, the

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Key Finding	Description
	end-of-framework performance incentives could be pro-rated to the portion of the target met through CDM-funded activities. This would eliminate any cross-subsidization concerns. It is understood that this incentive may not provide significant motivation to LDCs who are either already on-track to meet targets or who would still be unable to reach targets through the implementation of an IFMC project. A second key limitation to this approach is that although the OEB may be able to consider multiple benefit streams during decision making, traditionally their sole focus has remained on the distribution system benefits a project is anticipated to generate. Since IFMC cost-effectiveness is highly-driven by its transmission and generation benefits, non-consideration of these benefits may limit the achievable potential for IFMC investment in Ontario. To address this limitation, a variation to the hybrid approach, that accounts for IFMC related transmission and generation benefits, has been considered. Inclusion of these benefits may result in a greater number of IFMC projects being deemed cost-effective by the OEB.
A phased approach to IFMC deployment will address concerns over the underlying technology, overcome non-technical barriers, and provide the feedback necessary to support an efficient full-scale deployment	A phased approach to IFMC technology deployment, similar to processes used by other jurisdictions, can assist in mitigating the range of barriers that currently inhibit LDC investment in IFMC technologies. A phased deployment is intended to: 1. Demonstrate the technology in the Ontario (or LDC specific) context; 2. Help establish a clear path to capital cost recovery and reduce the financial barriers to deployment; 3. Help ensure IFMC investments are effectively integrated into LDC distribution system operations to maximize the value of the deployment. Regardless of the technology being deployed or the cost recovery mechanism used to financially support the investment, this phased approach to IFMC integration should be followed. In addition to addressing the key barriers in Ontario, this IFMC deployment strategy can help facilitate effective evaluation and ensure the validity of investments prior to aggressive rollout.

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IFMC Technologies

A technology scan identified all IFMC technologies that could contribute towards Ontario's provincial CDM objectives. To characterize the opportunity offered by these technologies, each was assessed against the following three key criteria:

1. *Technology Maturity* – Has the technology been proven through comprehensive pilot testing?
2. *Technology Value Proposition* – Is a primary benefit of the technology end-user energy and demand savings?
3. *Distribution-Level Deployment* – Is the technology deployed "in-front-of-the-meter" (i.e., on the distribution system)?

Based on this scan, two IFMC technology categories were identified as having potential for cost-effective deployment in Ontario:

1. Volt-VAR[5] Optimization (VVO); and,
2. Line Loss Identification and Mitigation (LLIM).

VVO

VVO is a technology solution that offers utilities real-time control of voltage and reactive power levels on distribution feeders and provides the following benefits:

- Improved LDC visibility of distribution circuit loadings, voltage, and power factor;
- Tighter voltage control;
- Power factor improvement; and,
- End-user electricity and peak demand savings.

Pilots undertaken across North America have shown that VVO can reduce electricity consumption and peak demand by between 1 and 3%[6].

LLIM

The LLIM category includes two technology solutions that target reductions in both *technical* and *non-technical* line losses.[7]

1) <u>Phase Balancing</u>: Phase balancing is a common utility practice that distributes load evenly across all three phases of a feeder to minimize technical line losses. Traditional approaches to phase balancing involve manually identifying and re-arranging feeders by "swapping" individual loads or laterals from one phase to another phase. Advanced phase balancing incorporates grid analytics and sensors to more accurately identify phase imbalance such that it can be corrected on a proactive rather than reactive basis. Although advanced phase balancing can remotely identify where feeder balancing is required, a manual process is still required to correct the issue.

[5] Volt- VAR Optimization, or Volt/Volt-Ampere Reactive Optimization uses sensors, equipment and software to tighten control of voltage and current fluctuations, which results in lower line losses and conservation benefits for end-users behind the meter.

[6] Various sources, including the Navigant Research reports described in Table 4.

[7] Technical losses are inherent to the distribution system and include heat dissipation from conductors and transformer losses, amongst others factors. Non-technical losses occur as a result of theft, metering inaccuracies, and unmetered electricity.

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2) Electricity Theft Identification and Mitigation: Electricity theft is the dominant component of non-technical line losses. Other minor contributors include faulty meters and unmetered loads. Detection and mitigation of theft reduces peak demand as well as electricity consumption on a circuit. Advanced methods for theft detection, which includes the use of monitoring devices, sensors and grid analytics to identify the occurrence, have been proven highly effective in identifying electricity theft on a utilities network.

Economic Potential in Ontario

To estimate the economic electricity and demand savings potential of IFMC deployments in Ontario, a cost-benefit analysis (CBA) was completed. The CBA results reflect deployment of the three technologies listed above (VVO, phase balancing and electricity theft identification and mitigation) across 15 prototypical Ontario distribution feeders. The CBA considered the following cost and benefits:

- Costs – all investments required to establish IFMC capability (e.g., distribution assets/equipment, replacement of assets/equipment over time, management systems, sensors, communications costs, ongoing operation and maintenance costs, etc.); and
- Benefits – the value of all benefits resulting from IFMC deployment (e.g., avoided generation costs, transmission and distribution system capacity improvements, etc.)

To ensure results accuracy, efforts were undertaken to validate that the costs and benefits inputs used in the CBA were appropriate for the Ontario context.

Once inputs were determined, results for each of the 15 prototypical feeders were extrapolated to estimate their aggregate impact across all of Ontario's approximately 10,000 feeders.

Table 1 shows the aggregate province-wide peak, electricity and line loss savings resulting from deployment of all three high-potential IFMC technologies. *Technical potential* is the "technically feasible" savings of IFMC technologies based on deployment across 100 percent of Ontario's approximately 10,000 feeders, regardless of cost-effectiveness. *Economic potential* is the savings potential for cost-effective IFMC technology deployment. As previously described, it was determined that IFMC technologies can be cost-effectively deployed on approximately 30 percent of Ontario's distribution feeders.

Table 1: Technical and Economic Potential Impacts (in 2018)

Impact	Technical Potential	Economic Potential	*Econ. as a % Tech.*
Peak (MW)	337	184	*55%*
Electricity (GWh)	2,148	1,128	*53%*
Line Losses (GWh)	282	181	*64%*

Source: Navigant analysis

Barriers to Deployment

Barriers to IFMC deployment in Ontario were identified through primary research. Specifically, through interviews and surveys with eight non-Ontario jurisdictions that have deployed IFMC technologies, 11 Ontario LDCs, two Ontario government agencies and three IFMC technology vendors. As described

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below, results of the research identified non-technical barriers – including financial, regulatory and cultural – as the primary inhibitors of IFMC investment in Ontario.

Financial: LDC capital budgets are limited and used for priority projects that are needed to maintain distribution system reliability. Discretionary projects, such as IFMC investments, that improve network efficiency and reduce line losses, are not given priority. LDCs emphasized the need for non-distribution rate funding to support IFMC deployments. All non-Ontario utility IFMC pilot projects had leveraged external funding sources (i.e., federal and state funds) and did not require significant distribution rate funding. However, larger scale IFMC projects that are being undertaken in non-Ontario jurisdictions will be funded solely through distribution rates.

Regulatory: Current regulatory policy does not incentivize LDCs to identify and implement innovative solutions to system/capacity constraints. LDCs earn a regulated rate of return on their invested capital, such that the greater the investment, the greater the LDCs return. This condition does not incentivize LDCs to consider innovative lower-cost technology solutions. Additionally, because of allowable minimum operations thresholds (e.g., for line losses), LDCs are not motivated to proactively/aggressively address distribution system performance issues, such as line losses or voltage irregularities.

Cultural: IFMC technologies have the potential to disrupt long-standing network operating practices. Thus, LDCs have shown reluctance to deploy IFMC technologies without first conducting their own IFMC pilots. This is the case even when other jurisdictions have reported positive results from their IFMC projects.

IFMC Cost-Recovery Mechanisms

Three IFMC funding options were explored: a conservation approach, a distribution rates approach and a hybrid approach. Descriptions of each option are provided below.

Conservation Approach: Under this approach, an LDC would seek recovery of all, or a portion of the capital investment and on-going operating and maintenance expenses associated with an IFMC project through IESO managed CDM budgets. Changes to the existing conservation first framework and overarching policies and directives would be required for this approach to be viable.

For the conservation approach to be effective, LDCs would likely require an "incentive" equal to 100 percent of the project's cost.[8] In order to facilitate this level of funding, IFMC projects would need to be considered a "program", where the participant recovers all costs, rather than a "measure".

Distribution Rates: Under this approach, an LDC would seek approval for recovery of the capital investment and on-going operating and maintenance expenses from the OEB through their distribution rate applications. An LDC would need to demonstrate that the IFMC investment is cost-effective, or – in a situation where a system upgrade is required – the least-cost alternative. The up-front investment would be capitalized and included in the LDC's regulated asset base. The on-going operating and maintenance

8 A distributor would not likely consider utilizing conservation budgets if an incentive equal to 100% of the project's cost was not offered. This is due to the fact that while customers can monetize the value of the non-incentivized portion of the investment associated with energy efficiency upgrades through on-going bill reductions, an electricity distributor does not have a similar mechanism to monetize the residual value. If an incentive less than 100% of project costs was provided, the LDC would be required to apply to the OEB for cost recovery of the balance of the investment.

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costs would be included as part of the LDC's recoverable operating, maintenance, and administrative costs.

Hybrid Approach: Under the hybrid model, cost-recovery of IFMC projects would be through distribution rates, however, LDCs would be eligible to claim end-user savings driven through these projects against their CDM targets. If LDCs meet their CDM targets they are eligible for performance incentives, however, to avoid issues of cross-subsidization, the incentive would be pro-rated to the portion of the target met through CDM-funded activities. Note: As projects funded through the hybrid approach would be eligible to claim CDM savings, rigourous post-installation assessments will be required.

Table 2 provides a comparison of these three possible funding models.

Table 2: Comparison of Conservation and Distribution-Rates Funding Approaches

	Conservation Approach	Distribution Rates Approach	Hybrid Approach
Implementation Approach			
Implementer	IESO	OEB	OEB & IESO
Upfront Investment by:	IESO/LDC	LDC	LDC
Cost-Recovery Period:	Within the current CDM framework (~3 years if funded through 2015-2020 budgets)	~10 to 15 years (depending on asset life)	~10 to 15 years (depending on asset life)
Cost Recovered from:	All Ontario electricity customers	Limited to an LDC's customers	Limited to an LDC's customers
Cost-Benefit Analysis			
Cost-Effectiveness:	• Program Administrator Cost (PAC) • Total Resource Cost (TRC)	• Net Present Value (NPV)	• Net Present Value (NPV) • Program Administrator Cost (PAC) • Total Resource Cost (TRC)
Recoverable Costs:	• Capital investment	• Financing costs • Capital investment • Operating and maintenance costs	• Financing costs • Capital investment • Operating and maintenance costs
Benefits Considered:	• Avoided Distribution, Transmission, and Generation Capacity • Avoided Energy Generation • Non-Energy Benefits (NEB)	• Avoided Distribution Capacity (The OEB has discretion to consider benefits outside of those that accrue to the LDCs' distribution system)	• Avoided Distribution Capacity (The OEB has discretion to consider benefits outside of those that accrue to the LDCs' distribution system) • For purposes of allowing the LDC to claim IFMC end-user savings towards CDM targets, project cost effectiveness for the TRC and PAC tests are likely to be required.

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Comparing the Conservation and Distribution Rates Approaches to Cost Recovery

Significant differences between the two funding approaches exists in terms of:

1. **The project approval process:** The approval process for IFMC projects under the conservation approach would be less onerous, as approval of conservation and demand management plans is not subject to full regulatory oversight.

2. **The timeframe over which the costs are recovered from customers**: Under the conservation approach, project costs would be recovered over a condensed period through CDM funding (approximately 3 years if funded through the current 2015-2020 Conservation First Framework). Under the distribution rates approach, costs would be recovered through the rate of return over the useful life of the assets (approximately 10-15 years).

3. **Which customers pay:** Under the conservation approach, costs are socialized over all of Ontario's electricity customers. Under the distribution rates approach, costs are socialized over the implementing LDC's customers alone.

4. **The post-deployment evaluation, measurement, and verification requirements**: Projects funded through CDM require rigourous post-installation assessments, whereas distribution-rates supported investments do not.

5. **The ability of the funding model to effectively encourage LDC investment in IFMC technologies:** To-date, the distribution rates approach has had minimal affect on encouraging IFMC investments. Integrating IFMC with CDM may be effective in stimulating uptake.

Both funding approaches have unique benefits and limitations. If either were available to distributors, in theory they could identify the funding mechanism that is best aligned to a given project's primary goals. As an example, if the primary purpose of the project is to offset a costlier traditional system investment, a distribution rates approach could be used. If the primary purpose is to provide electricity and demand savings to end-use customers, a conservation approach is appropriate. However, in practice, if distributors could choose between these two cost-recovery mechanisms, LDCs would be unlikely to pursue the rigourous distribution rates approach.

Hybrid Approach to IFMC Project Cost Recovery

A hybrid approach to IFMC cost recovery considers a blending of the CDM and distribution-rates options. Specifically, under the hybrid model, cost-recovery of IFMC projects would be achieved through distribution rates, however, LDCs would be eligible to claim end-user savings driven through these projects against their CDM targets. If LDCs meet their CDM targets using IFMC projects, their performance incentive would be pro-rated to the portion of their target they met through CDM-funded projects.

The value in this approach is that it leverages existing project financing channels while at the same time offering LDCs a viable financial motivation to pursue IFMC projects. Specifically, under this model, LDCs would be provided with an additional tool to achieve their 2015-2020 CDM targets and, if targets are achieved, LDCs could receive associated CDM performance incentives. This incentive would only encourage some LDCs, and not to those LDCs who are either already on-track to meet target or who would still be unable to reach targets through the implementation of an IFMC project.

However, the hybrid approach has a number of benefits over the singular conservation or distribution rates approach, including:

1. No changes to current regulatory policy are required, and only minor changes to the CDM framework are required to enable the hybrid approach. Consequently, the model can be implemented expeditiously.
2. Actively promotes IFMC as a conservation resource, however, ensures that an LDC's CDM budgets remain focused on encouraging end-use customers to adopt energy efficiency in their homes or place of business.
3. Introduces the concept of considering IFMC project benefits outside of those delivered to the LDC's distribution system. When assessing LDC capital project applications, the OEB has traditionally considered only the avoided distribution capacity benefits the investment generates. Integrating IFMC with CDM may allow for a wider-range of benefits to be considered, including, but not limited to, avoided transmission and generation. Valuing additional benefits will have a direct impact on the number of projects that are deemed cost-effective to pursue.
4. The financial motivation from 2015-2020 CDM performance incentives may incentivize LDCs to act quickly to implement IFMC projects. Specifically, LDCs that can meet their 2015-2020 CDM target through an IFMC project.
5. The hybrid approach is sustainable, as it does not rely on funding from a time limited Framework. The incentive of the CDM targets, while only in place during the current framework, will help to kick start LDC investments in IFMC projects.

This approach uses a cost allocation mechanism to allocate the portion of the project's cost associated with upstream system benefits to all Ontario ratepayers and allocates distribution system benefit costs to local ratepayers. For example, if 75 percent of a project's benefits are attributed to local distribution benefits, then 75 percent of costs would be recovered from the LDC's rate-base. The cost-allocation mechanism would allow the remaining 25 percent of costs to be recovered from all other provincial ratepayers, through a rate-rider or other appropriate option, since these benefits accrue to the broader system.

Strategic Approach to IFMC Deployment

A strategic IFMC deployment strategy can help facilitate effective evaluation and give LDCs confidence in the technologies prior to aggressive rollout. Below, and as shown in Figure 1, a strategic approach to IFMC deployment in Ontario has been developed. Following this approach will help mitigate the barriers to IFMC technology investments in Ontario and ensure IFMC investments are effectively integrated into LDC system operations.

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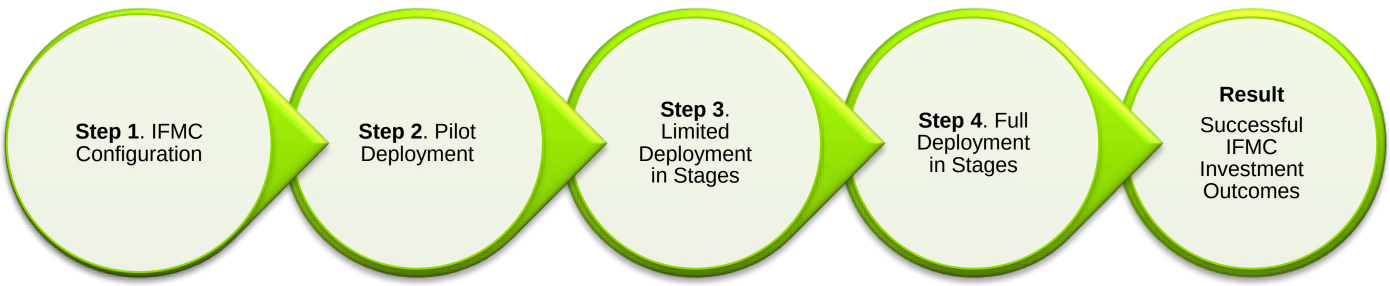
Figure 1. Recommended IFMC Deployment Strategy



The strategic approach to IFMC deployment recommends LDCs undertake additional IFMC pilots, for those LDCs who have no experience with these technologies. Additional IFMC pilots are needed as each utility's experience deploying an IFMC project will be unique. This individuality results from the diversified mix of infrastructure, human resources, internal culture and distribution management systems in each LDC. The strategic approach to IFMC deployment considers these LDC differences and by following this deployment strategy, LDCs will be able to achieve the best outcomes for their IFMC investment.

Regardless of the technology being deployed or the funding strategy used to financially support the investment, this strategic approach to IFMC deployment should be followed.

Step 1: IFMC Configuration

During the IFMC configuration phase, the following activities should occur between the LDC and IFMC technology vendor:

1. **Project initiation meeting:** to ensure that key LDC stakeholders in the IFMC project are engaged in the decision-making processes.
2. **Requirements workshop:** LDCs should conduct workshops with key utility stakeholders and the selected IFMC vendor to ensure answers to the utilities main questions related to the technologies deployment and functionality are answered.
3. **Design document:** LDCs should require the selected IFMC vendor to develop a design document that provides specific detail on the technologies characteristics including, but not limited to, hardware and software specifications, strategy for integration of the product within the LDCs' distribution management system, key engineering questions that require clarification before deployment as well as the anticipated impact that the IFMC investment will have on system operations.
4. **Software configuration:** IFMC software integration is critical to project success and must be addressed at the outset of projects.
5. **Interface development:** The IFMC's interface refers to the actual on-screen graphical user interface (GUI) that LDC staff will use to activate the technologies capabilities. Development of the interface should occur concurrently with the software integration activity.

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Step 2: Pilot Deployment

The goal of the Step 2 is to test the IFMC solution at a single location on the LDC's distribution system. As an example, for a pilot VVO installation, the technology should be deployed on a single substation transformer and its associated feeders. The IFMC pilot location should not have any planned construction or changes to the substation and feeder setup during the pilot period as this will impact pilot results. Additionally, the LDC should choose a location that is reflective of the conditions where IFMC will have the highest benefits.

Following deployment, the LDC should operate and observe the IFMC solution on the single controlled location.

Step 3: Limited Deployment in Stages

This step expands the IFMC deployment to additional locations on the LDC's network. Using the previous VVO example, this stage could incorporate additional transformers in the pilot substation and additional adjacent substations. The goal of this phase is to expand the configuration of the VVO solution to test the technology on more feeders and substations.

By targeting different feeders and substations in this step, the LDC will be able to further validate the technology and its impacts.

Step 4: Full Deployment in Stages

The goal of this step is to achieve more cost-effective IFMC deployment in stages. The previous steps will have given the LDC experience with the technology and answered any substantive questions that the LDC may have had about integration with their systems.

In step 4, the LDC would identify the areas of their distribution system that would benefit most from cost-effective IFMC deployment and begin deploying the technology to these points over time.

Evaluating Results

Following Steps 2-4, the LDC should engage an independent evaluator to assess the impacts of the IFMC technology across its service territory. The evaluation of the results can then be used to compare the forecasted outcomes, defined in the design document from step 1, with the LDC results to identify any deviations from expectations identified.

The methods used to assess project success after each step should be consistent with those defined in the EM&V best-practices report developed to complement this study entitled "IFMC – Best Practice EM&V Methodologies for Ontario". Application of these evaluation processes will ensure the energy and demand savings impacts, as well as cost-effectiveness, of each IFMC project are accurately determined.

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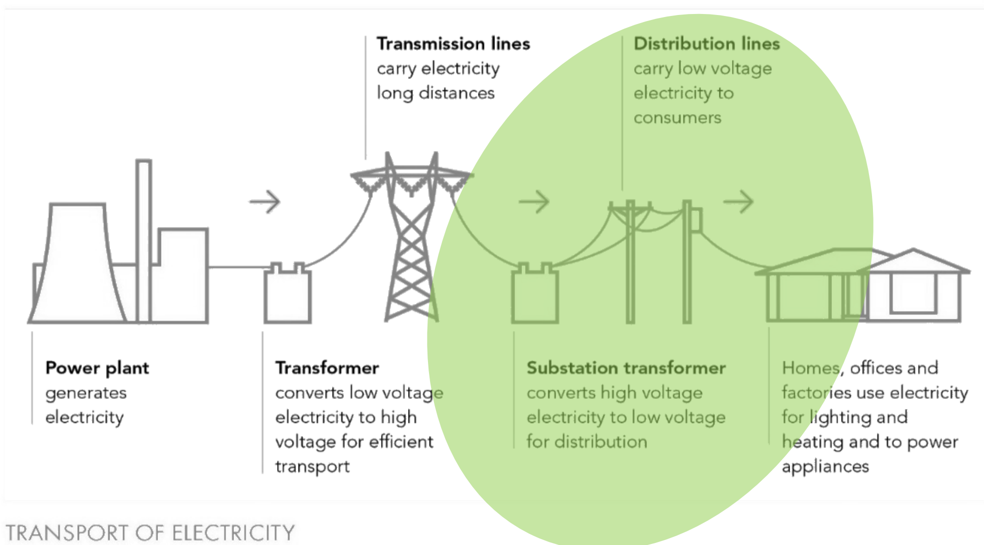
1. INTRODUCTION

North America's electricity sector is undergoing a significant transformation, and utilities are exploring how various emerging intelligent grid technologies can be effectively integrated into networks to increase their efficiency and flexibility.

In-front-of-the-meter conservation (IFMC) technologies that are deployed on the distribution system resulting in electricity savings and peak demand reductions primarily for end users behind the meter are a potential element of this transformation. IFMC technologies have the added benefit of providing distribution network operators with increased communication and automation capabilities.

Using a traditional generation model, the highlighted portion of Figure 2 demonstrates where in the electricity delivery process IFMC technologies can be integrated. Examples of IFMC technologies that can be effectively deployed at this stage of the electricity distribution sequence include volt/volt-ampere reactive (Volt/VAR) optimization (VVO) and line loss identification and mitigation (LLIM).

Figure 2. IFMC Technology Integration Points



IFMC technology deployments that provide LDCs with increased communications and automation capabilities are part of the emerging smart grid. The importance of intelligent grid infrastructure continues to grow as the sector shifts from the traditional hub-and-spoke generation model to one that places higher priority on providing end-user power through various smaller, clean, and localized sources referred to as distributed energy resources (DER).

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1.1 Project Objectives

The Ministry of Energy (the Ministry) engaged Navigant Consulting Ltd. (Navigant) to:

1. Identify market-ready IFMC technologies and evaluate their appropriateness for deployment in Ontario;
2. Estimate the technical and economic potential for electricity and peak demand reductions resulting from IFMC technology deployment in Ontario;
3. Identify and provide insight into how and why other jurisdictions have deployed IFMC technologies, as well as the barriers faced and the cost-recovery mechanisms used;
4. Provide a perspective on Ontario-specific factors that impede IFMC technology deployment; and,
5. Assess and compare three IFMC cost-recovery mechanisms; a conservation approach[9], a distribution-rates approach[10], and a hybrid approach.

This report presents IFMC-related findings and consists of the following seven sections:

- **Section 2** establishes the definition of IFMC technologies and provides detail on the process used to scope the study to the technologies identified (VVO and LLIM).
- **Section 3** discusses the jurisdictional review conducted that provides insight into the lessons learned by other jurisdictions that have actively engaged IFMC technologies.
- **Section 4** describes the findings of the primary research efforts undertaken with Ontario's IFMC stakeholders to identify barriers to IFMC technology deployment.
- **Section 5** details the cost-benefit analysis and technology potential approach and results.
- **Section 6** discusses the various cost-recovery mechanisms that could support IFMC deployments in Ontario.
- **Section 7** highlights the key findings of the IFMC study.

The information provided in Sections 2 through 6.5 are supplemented by the following appendices:

- Appendix A : Excel Results Databooks (provided in a separate file)
  - This file includes detail on the CBAs completed to demonstrate IFMC impacts in Ontario
- Appendix B: Detailed IFMC CBA Results
- Appendix C: Excluded IFMC Technology Descriptions
- Appendix D: Grid+ (Analytica) Model Overview and Input Assumption Detail
- Appendix E: Ontario Stakeholders Interview Process
- Appendix F: Non-Ontario Jurisdictional Review (Incremental Findings)

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9 Under the conservation approach, a distributor would seek recovery of either a portion or all the project's capital costs and on-going operating and maintenance expenses through CDM budgets managed by the Independent Electricity System Operator.

10 Under the distribution-rates approach, a distributor would apply to the Ontario Energy Board for approval to recover the project's capital investment and on-going operating expenses through distribution rates.

2. IFMC TECHNOLOGIES OVERVIEW

2.1 Introduction and Objectives

A technological scan was completed to identify all IFMC technologies that have the potential for deployment in Ontario. Following identification, detailed descriptions of each IFMC technology were developed.

The primary objectives of the technology scan included the following:

1. Identify all distribution-level technologies that could be considered IFMC technologies based on their ability to drive end-user electricity savings and demand reductions.
2. Provide the information necessary on each identified technology to determine which should be fully characterized and modeled through this project.
3. Through the technology characterization process, provide the detail necessary on the various available technologies to inform and frame the definition for IFMC.

2.2 Key Findings and Observations

As described below, two key findings were identified through completion of the IFMC technology scan. Following this section, the methodology used to complete the technology scan is described and associated findings provided.

Key Finding 1: Several IFMC technologies have been tested and proven effective.

Several successful pilot projects, undertaken by North American utilities, have demonstrated the viability of certain IFMC technologies, specifically, VVO and phase balancing. These pilots have been used to test IFMC technologies and position Ontario LDCs to benefit from lessons learned.

Key Finding 2: IFMC technologies can leverage Ontario's smart/interval meters.

Numerous technologies are available to LDCs for the purposes of facilitating VVO. However, the most effective technologies use advanced metering infrastructure (AMI) data to optimize controlled voltage set points and, therefore, maximize impacts. Technologies that do not leverage AMI data must conservatively estimate endpoint voltages to determine voltage reduction availability.

2.3 IFMC Technology Identification Methodology

The methodology used to identify the final set of IFMC technologies included in the study is outlined below.

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2.3.1 Framing IFMC Eligibility Parameters

The decision to further explore technologies was based on their alignment with the guiding principles presented in Table 3. These guiding principles were developed in order to ensure that the project focused on the technology types that offer the highest potential for Ontario's LDCs.

Table 3. Guiding Principles for IFMC Technology Identification

Guiding Principle	Description
Technology Maturity	To be considered, the technology must have been proven to deliver end-user conservation benefits through pilots or full deployment projects.
Technology Value Proposition	A primary benefit of the technology must be end-user electricity and demand savings.
Deployed at the Distribution System Level[11]	All technologies must be deployed on the distribution system and not either behind the customer meter or on the transmission system.

2.3.2 Key Sources of Input

In identifying and describing the IFMC technology solutions, several publicly available and confidential reports were leveraged, as well as Navigant's internal IFMC subject matter experts (SMEs). The complete listing of source material is provided in Table 4.

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[11] IFMC technologies are defined as distribution technologies deployed on the distribution system that result in electricity savings and peak demand reductions primarily for end-users BTM. Therefore, transmission system investments that provide similar efficiency benefits at the bulk system level are not considered within this report.

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Table 4. Key Sources of Input for IFMC Technology

Source Type	Description	Sources
Navigant Research Reports	Technology research, case studies, and projections	• ***Distribution and Substation Automation*****:** Distribution Substation Automation, Feeder Automation, and Transformer Automation: Global Market Analysis and Forecasts • ***Grid Edge Intelligence for DER Integration*****:** Operational IT/OT, Distributed Monitoring and Control, and Communications Networks: Global Market Analysis and Forecasts • ***Utility Analytics*****:** Use Cases, Platforms, and Services: Global Market Analysis and Forecasts
Technology Vendor Material	Information on specific equipment for technology solutions	• kVAR Energy Controller: http://www.kvar.com/ • Gridco Systems 21mpower Solution: http://gridcosystems.com/applications/vvocvr/ • Dvi EDGE: http://dvigridsolutions.com/products/ • dTechs epmMeter Suite solution : http ://www.dtechsepm.com/our-product
Case Studies/ White Papers	Research on technologies research, case studies, and industry studies	• Northeast Energy Efficiency Alliance (NEEA): *Long-Term Monitoring and Tracking Distribution Efficiency* http://neea.org/docs/default-source/reports/long-term-monitoring-and-tracking-distribution-efficiency.pdf?sfvrsn=5 • NEMA: *Volt/VAR Optimization Improves Grid Efficiency* https://www.nema.org/Policy/Energy/Smartgrid/Documents/VoltVAR-Optimazation-Improves%20Grid-Efficiency.pdf
Subject Matter Experts	Individual expertise within Navigant's Energy Practice	• Erik Gilbert, Director (Grid Modernization) • Larry Gelbien, Director (Operations and Performance Excellence) • Omar Dickenson, Associate Director (Operations and Performance Excellence) • Thomas Wells, Managing Consultant (Operations and Performance Excellence)

2.4 Selected IFMC Technologies Overview

The study was scoped to Volt-Ampere Reactive (Volt/VAR) Optimization (VVO) and Line Loss Identification and Mitigation (LLIM) technologies. A high-level summary of these technologies is provided in Table 5 below. Detailed descriptions of each of these technology types, including a discussion of how each meet identified IFMC guiding principles, follow Table 5.

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Table 5. IFMC Technologies

IFMC Technology Solution	Description
Volt/VAR Optimization (VVO)	• Integrates distributed, communicating grid sensors and controls with optimizing software algorithms to achieve the following: ○ Improved visibility of distribution circuit loadings, voltage, and power factor ○ Tighter voltage control ○ Electricity savings ○ Demand reduction ○ Power factor improvement ○ Saves 1%-3% on electricity and peak depending on feeder characteristics[12]
Line Loss Identification and Mitigation (LLIM)	As outlined below, two forms of line loss were considered: electricity theft identification and mitigation and phase balancing. **Electricity theft identification and mitigation:** • This solution includes both identification of theft and enforcement. Any enforcement activities after identification would follow LDC procedures. • Ontario's Smart Grid Roadmap[13] identified that Ontario's deployment of AMI lead to a three percent reduction of electricity theft. Any additional reductions would be incremental to this value. **Phase balancing:** • When the three phases of the distribution system are equally loaded, technical line losses are minimized. • Phase balancing is a manual process that involves moving customer loads from one phase of power to another.

2.4.1 Volt/VAR Optimization (VVO)

Voltage optimization technologies have been used in the electricity sector for many years. However, technological advancements now allow voltage optimization to be done in real-time on a distribution feeder or group of feeders to optimize power delivery on a systemic (rather than individual) and forward-looking (i.e., predictive rather than reactive) basis.

These advanced VVO projects typically achieve the following benefits simultaneously: improved LDC visibility of distribution circuit loadings, voltage, and power factor; tighter voltage control; power factor improvement; and end-user electricity and peak demand savings.

Pilot projects undertaken across North America have shown that VVO can reduce end-user electricity consumption and peak demand requirements by 1%-3%,[14] depending on feeder characteristics (e.g., feeder loading, baseline voltage level, feeder health, and mix of end-use customers). Total savings are also dependent on the base condition of the distribution system (such as the currently installed number of

[12] Various sources, including those demonstrated in Table 4.

[13] https://www.ontarioenergyreport.ca/pdfs/Navigant-Smart-Grid-Assessment-and-Roadmap-Final-Report-.pdf

[14] Various sources, including those demonstrated in Table 4.

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voltage regulators, capacitor banks, and other power factor correction devices) and the Volt/VAR control strategy of the VVO system.

For example, an LDC's decision to implement a conservation voltage reduction (CVR[15]) scheme could have less impact than if a more advanced VVO strategy that leverages real-time AMI[16] readings and variable cap banks is implemented. Generally speaking, VVO – or decentralized VVO – relies on a LDC's Distribution Management System (DMS) to monitor and determine optimal voltage settings based on the information provided from the substation. CVR – or centralized VVO – does not consider end-use customer voltage and, as a result, often requires LDCs to design and operate their systems in a conservative manner to accommodate worst case scenarios on a feeder (i.e., customers on a feeder whose current voltage is close to minimum allowable thresholds).

Figure 3 identifies the equipment required to implement highly advanced VVO on a distribution system.

Figure 3. Equipment Requirements for VVO[17]

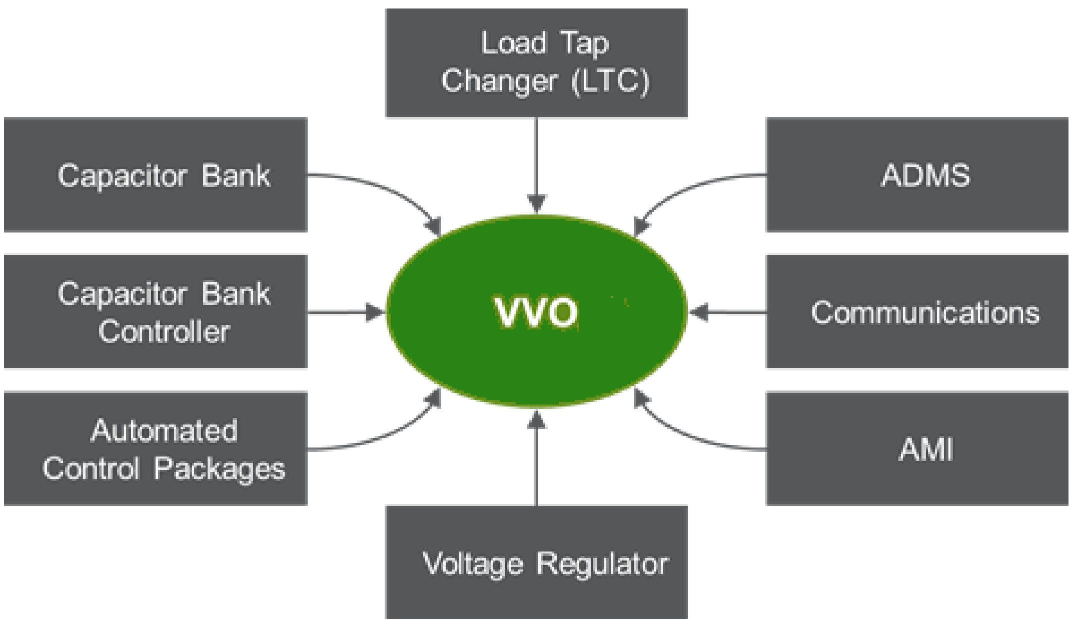

Table 6 provides a description of the technologies identified in Figure 3. Given their need to interact with a utilities distribution system communications infrastructure, the list of technologies for VVO is more comprehensive than the technologies necessary for a CVR strategy. This has a corresponding impact on the costs of deployment. The technologies necessary only for CVR are indicated in the second column of the following table.

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[15] CVR refers to reducing average voltage levels to lower the aggregate power demand of end-use loads and sustaining the lower demand levels over time with the aim of reducing electricity consumption.

[16] AMI refers to the entirety of the infrastructure that facilitates time-of-use billing, including but not limited to: smart meters, the meter data management and repository, and supporting communications infrastructure. Ontario currently has the AMI infrastructure required to facilitate advanced VVO.

[17] ADMS stands for advanced distribution management systems and AMI stands for advanced metering infrastructure.

Table 6. Description of Equipment Required for VVO/CVR

Equipment Required for VVO	Required for CVR	Description
Load Tap Changer (LTC)	Both capable of providing CVR functionality; could use both or either one	Adjusts voltage levels on transformers at substations; as feeder loads increase, LTCs can increase voltage outputs to account for the larger voltage drop along the feeder. LTCs can be centrally and digitally controlled. The LTC regulates voltage on all three phases and has an impact on all customers fed by the substation. The LTC is limited to coarse voltage control.
Voltage Regulator		Adjusts voltages at the substation or, more typically, along distribution feeders to regulate and lower downstream voltage levels.
Capacitor Bank (switched or fixed)	Yes	Compensates for reactive power and lowers voltage along the distribution feeders: provides voltage support; reduces the total amount of power required; can be remotely controlled/automated and interfaced with a distribution management system. Capacitor banks impact both upstream and downstream voltage and requires careful coordination.
Capacitor Bank Controller	No	Improves operational effectiveness through a reduction of system losses when integrated into a Volt/VAR system.
Automated Control Packages (*Controllers*)	No	Integrates the control of field devices (e.g. voltage regulators and capacitor banks) with LDC interfaces and communication systems. Controllers can be programmed to switch capacitors in or out of service automatically depending on the voltage level and power factor, or in response to a command from an operator or other control system. Controllers may also use more complex software algorithms to coordinate its operation with other devices or systems to perform different operations. The control software may be built into the controller, or may reside in a central computer.
Advanced Distribution Management System (ADMS)	No	A central computer and software that analyzes distribution power flow and makes decisions about switching capacitor banks and adjusting LTCs and voltage regulator set-points; also used for automated feeder switching, fault identification, and equipment health monitoring; can include VVO algorithm.
Communications	No	Connect sensors to information processors, and information processors to the control devices that regulate voltage and power factor.
AMI	No	When available, voltage readings from the meters are often used to support VVO.

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2.4.1.1 VVO Components

Figure 4 demonstrates how the LTC can adjust the voltage at the beginning (head) of the feeder (i.e., the substation (S/S)) to keep the voltage profile within the acceptable range of 110V to 127V. Characteristically of all distribution systems, feeder line connections (i.e., customer loads), after the LTC, are subject to voltage declines. The M represents the metering of the power supplied by the substation.

Figure 4. Hypothetical Feeder Voltage Profile with an LTC[18]

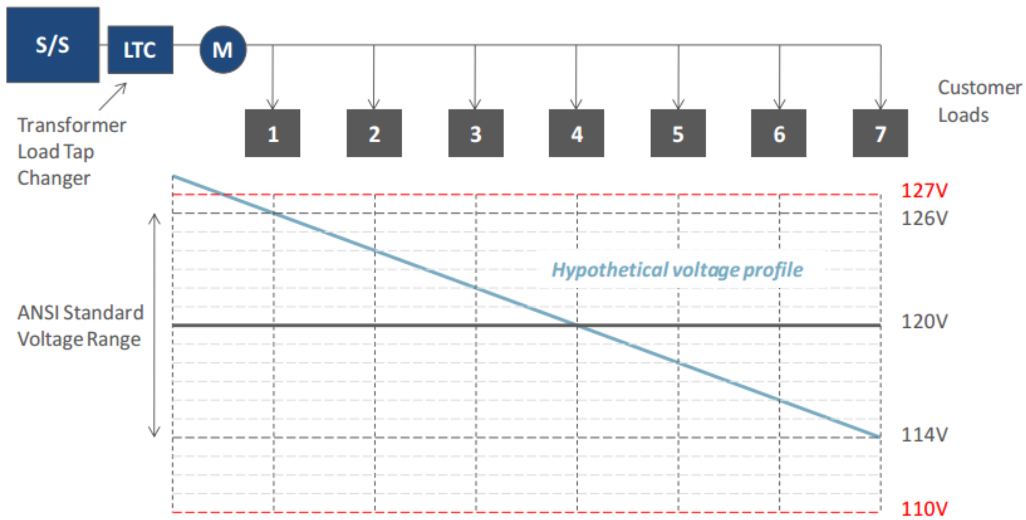


Figure 5 illustrates how a voltage regulator placed strategically on a feeder line adds an additional control point to increase or decrease the end of line (EOL) voltage levels, depending on the desired effect. In this figure, the voltage regulator is placed between customers 4 and 5. As demonstrated, installation of the voltage regulator increases the voltage and allows for the voltage decrease which facilitates the CVR effect. The effect of CVR is shown as the dashed line.

[18] US Department of Energy (DOE). December 2012: https://www.smartgrid.gov/files/VVO_Report_-_Final.pdf

Figure 5. Hypothetical Feeder Voltage Profile with an LTC and Voltage Regulator[19]

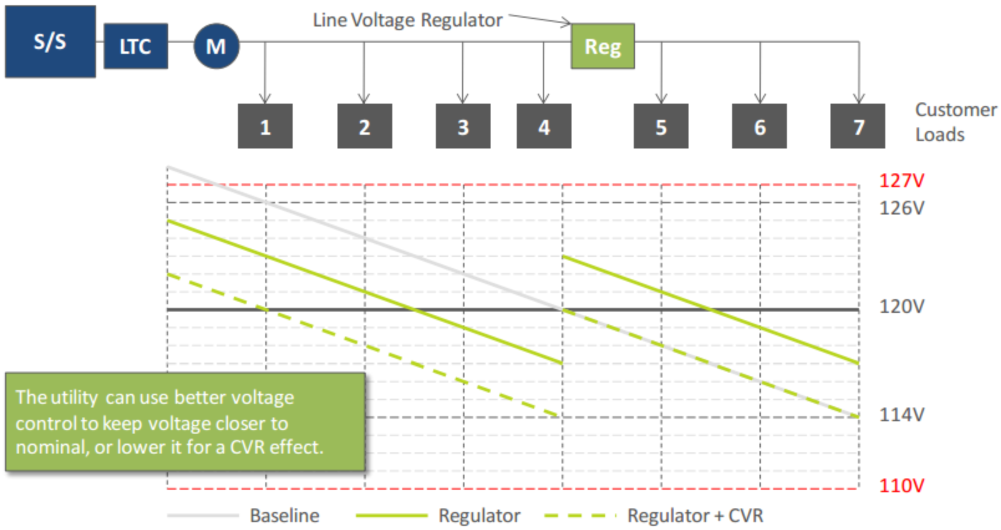
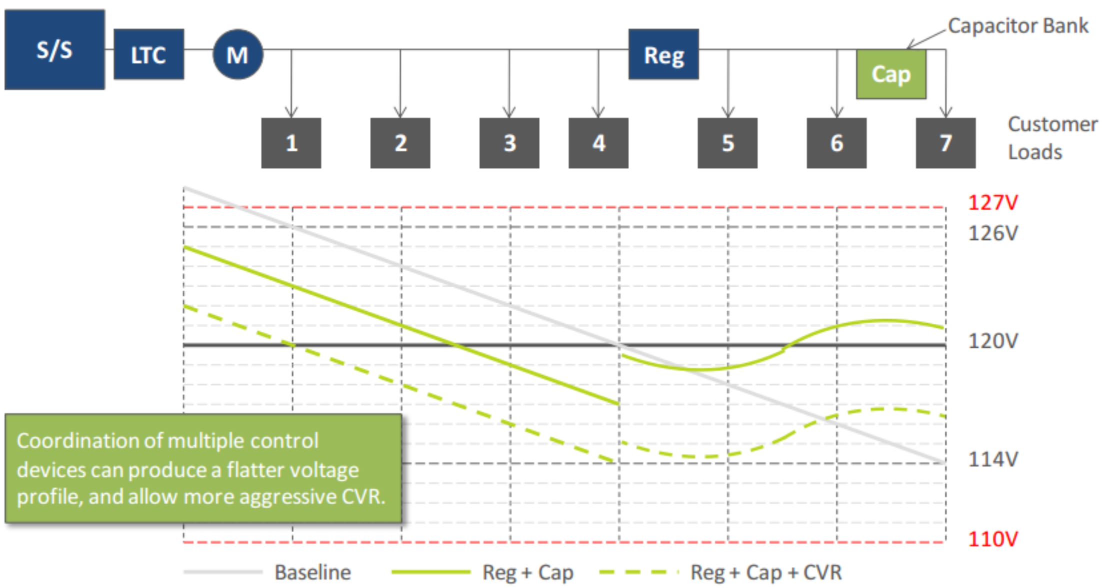


Figure 6 shows the feeder voltage profile if a capacitor bank is added between customers 6 and 7. The capacitor bank is applied for voltage support and not voltage control, and leads to increase in voltage of about 3V.

Figure 6. Hypothetical Feeder Voltage Profile with LTC, Voltage Regulator, and Capacitor Bank[20]



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[19] Ibid

[20] US Department of Energy (DOE). December 2012: https://www.smartgrid.gov/files/VVO_Report_-_Final.pdf

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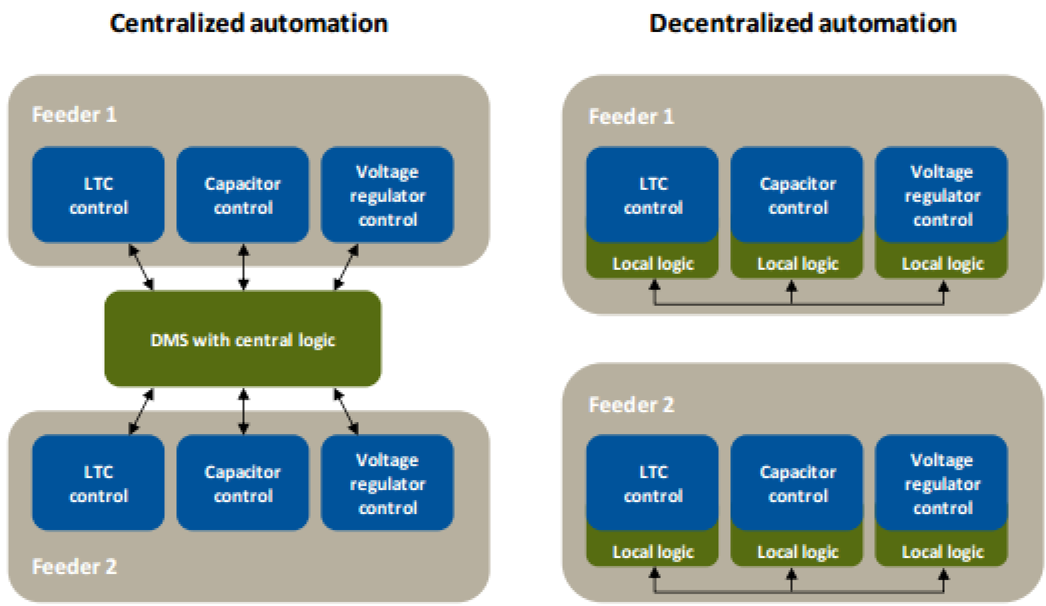
2.4.1.2 Centralized (CVR) vs. Decentralized (VVO) Implementation

As demonstrated in Figure 7, VVO can be implemented by LDCs using either a centralized or decentralized strategy. Generally speaking, decentralized VVO relies on a LDC's Distribution Management System (DMS) to monitor and determine optimal voltage settings based on the information provided from the substation. Centralized VVO – or CVR – does not consider end-use customer voltage and, as a result, often requires LDCs to design and operate their systems in a conservative manner to accommodate worst case scenarios on a feeder (i.e., customers on a feeder whose current voltage is close to minimum allowable thresholds).

Decentralized VVO leverages end-use customer voltage data available through AMI to optimize network voltage settings. Consequently, decentralized voltage regulation can result in greater end-use energy savings, but has higher implementation costs in jurisdictions that do not have AMI deployed.

Figure 7. Centralized vs. Decentralized VVO[21]

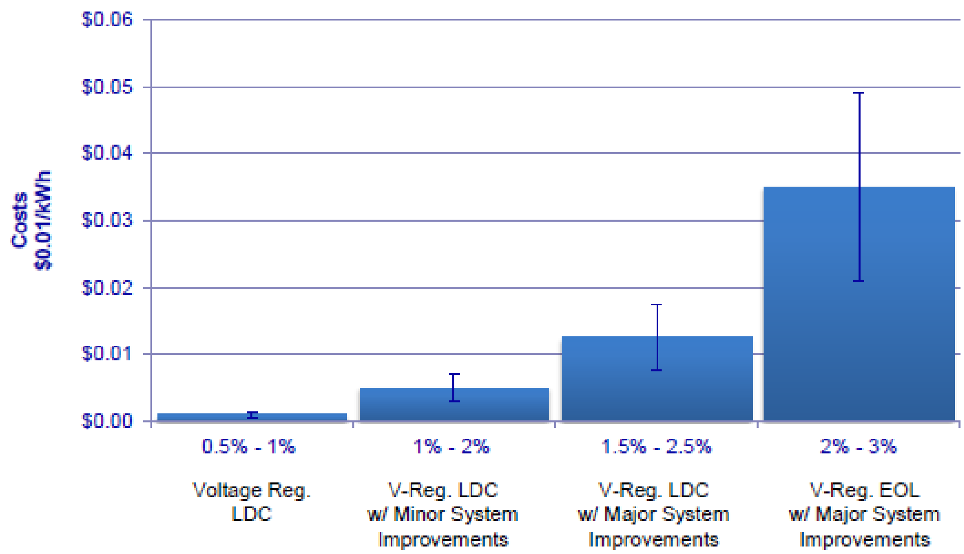


2.4.1.3 VVO Deployment Cost Trend

Figure 8, obtained from a Northeast Energy Efficiency Alliance (NEEA) report from 2007, shows the differences in costs and potential savings between different VVO technology options.

[21] US Department of Energy (DOE). December 2012: https://www.smartgrid.gov/files/VVO_Report_-_Final.pdf

Figure 8. Cost and Savings Comparison[22]



Overall costs of VVO deployments have dropped since 2007 as more vendors have entered the market and technological advancements have been made. Since individual VVO component costs have decreased, the cost-effectiveness of the highest potential technologies has increased since 2007.

Asset-specific costs are included as part of the CBA analysis in Section 5. In order to ensure accurate and up-to-date data, cost inputs from Navigant SMEs were used and data was collected from previous client engagements to support the model. Appendix D provides a detailed description of the main data sources used to determine CBA cost inputs.

2.4.2 LLIM

Line losses is the difference between the amount of electricity delivered to the distribution system and the amount of electricity customers consume. Line losses are the result of distribution system inefficiencies and naturally occurring losses from transporting electricity.

It is cost-prohibitive and not technically feasible to perform detailed measurement of all line losses that occur in an LDC distribution system because of the size and complexity of these systems. Therefore, LDCs generally perform post-fact analysis of annual metered consumption and electricity supplied or use benchmarking analyses to determine the magnitude of their line losses.

[22] "Major Findings from a DOE-Sponsored National Assessment of Conservation Voltage Reduction (CVR)." http://grouper.ieee.org/groups/td/dist/da/doc/Major%20Findings%20from%20a%20DOE-Sponsored%20National%20Assessment%20of%20Conservation%20Voltage%20Reduction%20(CVR)%20-%20Ronald%20Willoughby.pdf

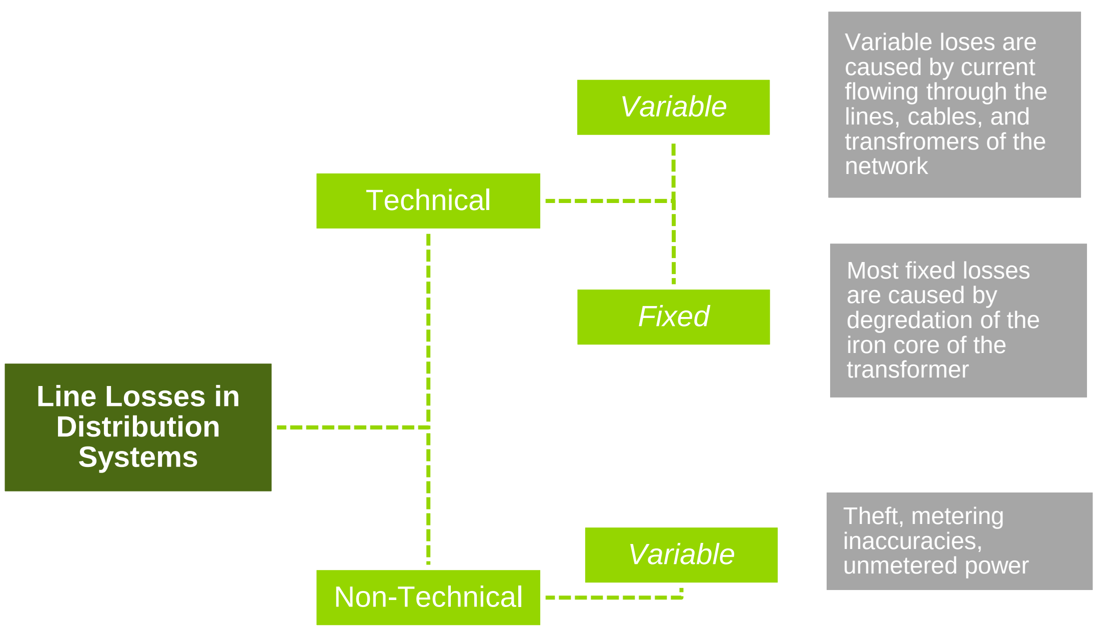
In Ontario, the costs of line losses are passed through to all Ontario ratepayers. Line loss studies are completed by LDCs using historical data to determine an average line loss factor. Once the line loss factor has been developed and approved by the OEB, it is added to customer bills as a volumetric cost (i,e, the line loss factor is multiplied by a customers' electricity consumption). The cost-savings impacts of IFMC measures that target line losses will not be immediately seen by customers because historical data is used to inform line loss factor calculations.

There are two types of distribution line losses:

1. **Technical line losses** on distribution systems are primarily caused by heat dissipation resulting from current passing through conductors and from magnetic losses in transformers. Technical losses are classified as either variable or fixed (as shown in Figure 9) and are inherent to the distribution of electricity and cannot be fully eliminated.
2. **Non-technical line losses** occur as a result of theft, metering inaccuracies, and unmetered electricity (e.g., situations where electricity use is estimated because metering is uneconomic such as street lights). Non-technical losses are difficult to identify and measure using traditional power system analysis technologies and tools.

Figure 9 shows the different types of line losses on a distribution system.

Figure 9. Distribution System Line Losses



Source: Navigant

Two forms of LLIM are explored in this study: electricity theft identification and phase balancing,

Electricity Theft Identification

Electricity theft is non-technical line loss that normally occurs at the end-user meter level and is the result of individuals tampering with meters and meter seals, bypassing meters, or damaging and removing

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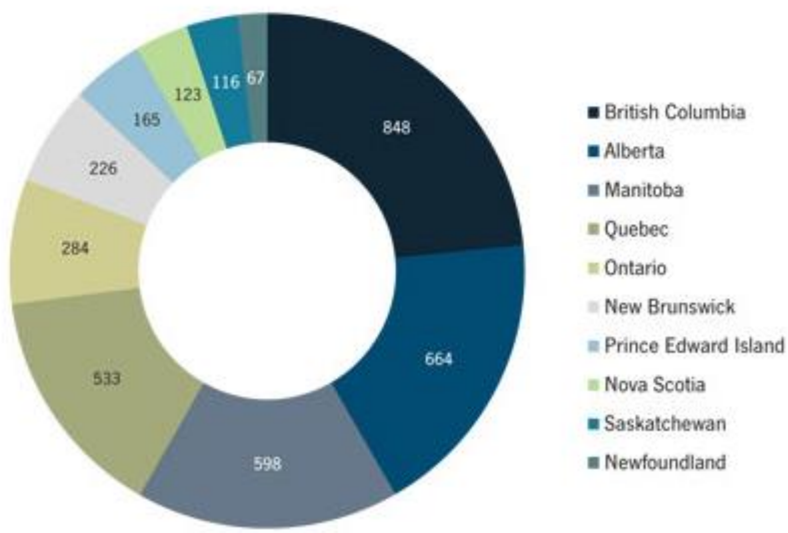
meters. Theft can also occur through illegally tapping into bare wires or underground cables at the transformers or through illegal terminal taps on the low side of the transformer.

Electricity theft mitigation can be achieved by either installing mobile technologies that can be placed on specific transformers to identify theft or permanent installations of meters between the feeder and the customer.

Based on recent research, the majority of stolen electricity in Canada is being used to power illegal marijuana growing operations. Research by GTM Research and the Royal Canadian Mounted Police estimated the number of marijuana grow operations in each province as demonstrated in Figure 10. This research suggests that Ontario has the fifth highest level of marijuana growing operations in Canada.

Figure 10. Estimated Marijuana Grow Operations by Province



Source: GTM Research and the Royal Canadian Mounted Police

Electricity theft reduction includes both identifying theft and enforcement. As there are presently no technologies that allow for automated correction of theft, any enforcement activities need to be performed by the LDC using their procedures.

Reports for Canada estimate economic loss from theft to be in the $500 million range.[23] Since line loss costs are passed to customers in Ontario, reducing electricity theft will lower costs for paying customers. This reduction in electricity theft is also likely to lower the peak demand for energy use.

An emerging method of identifying electricity theft uses sensors deployed in-front of the meter. These sensors can be located at centralized points on the distribution system to monitor electricity flow in real-time, and compare with smart meter data to identify anomalies. This can be less costly than the alternative method of metering each transformer station, because the centrally located sensors each

[23] https://www.greentechmedia.com/articles/read/pot-growers-costing-canada-500-million-in-power-theft

monitor more customers. Further, sensors can be installed permanently and work with mobile devices to better pinpoint potential non-technical losses such as electricity theft.

In addition, smart meter data can be analyzed specifically to help detect theft by correlating electricity use to time of day and weather to detect abnormal readings. For example, a vendor has developed a proprietary meter data analysis software algorithm that is used to both report problematic or abnormal electrical load patterns.[24]

Figure 11 identifies the equipment required to implement advanced electricity theft detection.

Figure 11. Equipment Required for Electricity Theft Detection

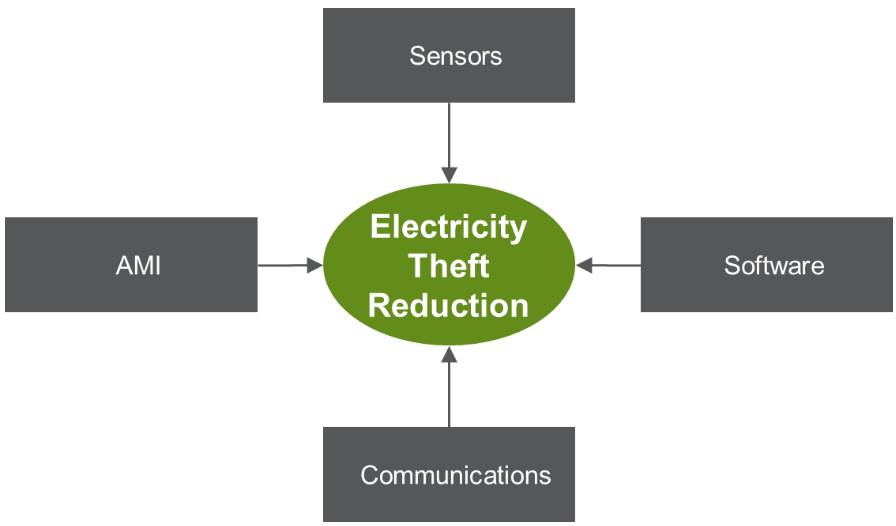


Table 7 provides a brief description of the equipment required to implement advanced electricity theft identification.

[24] http://www.dtechsepm.com/our-product

Table 7. Description of Equipment Required for Electricity Theft Detection

Equipment Required	Description
Sensors	Sensors are used to detect the location of electricity loss in the distribution system.
Software	Software works with the sensors or controls to monitor and improve grid performance by preventing line loss and isolate and restore detected faults.
Communications	Connecting sensors to an information processor can control devices that regulate voltage and power factor.
AMI	Customer meters and the advanced metering infrastructure (AMI) can be used to identify abnormal load profiles and determine line losses by subtracting known loads from the total electricity delivered.

Phase Balancing

Both Ontario's transmission and distribution (T&D) systems transmit electric power in three-phases. To optimize grid performance in a three-phase system, the peak demand for voltage should be equally distributed across all three phases. If an equal amount is not carried by each phase, then the phases are in a state of imbalance, which leads to greater technical line loses. Phase balancing is the process of equally distributing peak demand for voltage across all three phases of the distribution system.

Phase imbalance is a variable technical line loss. As defined above, variable technical losses are dependent on the magnitude of current and represent 60 to 75 percent of technical losses in Ontario. Other factors such as length of distribution lines and power factor also contribute to variable technical line losses. [25,26]

The level of imbalance and the amount of line loss is related to the extent of phase imbalance that can vary significantly between feeders. Phase balancing can be a cost-effective investment when a feeder is highly unbalanced (e.g. feeders with greater than 20% phase imbalance). Phase balancing requires physically altering the distribution system either with phase swaps (i.e., shifting customers load from one phase of power to another) or installing compensators.

In general, the cost of correcting phase imbalance depends on the level of imbalance because the greater the imbalance, the longer it will take to correct. There is value in LDCs pursuing phase balancing for highly imbalanced feeders, even if system-wide phase balancing is not cost-effective.[27,28]

Phase imbalance mitigation techniques fall into two categories:

1. Manually rearrange feeders or redistribute loads in such a way that the system becomes more balanced.
2. Install compensators (power quality conditioners such as reactor or capacitor banks) to compensate for phase imbalances.

[25] http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2007-0681/Exhibit%20A/Tab_15_Schedule_3_Distribution_Line_Losses_Study.pdf
[26] http://electrical-engineering-portal.com/total-losses-in-power-distribution-and-transmission-lines-1
[27] http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2007-0681/Exhibit%20A/Tab_15_Schedule_3_Distribution_Line_Losses_Study.pdf
[28] http://electrical-engineering-portal.com/total-losses-in-power-distribution-and-transmission-lines-1

Traditional methods of detecting phase imbalance are through customer complaints and detection during maintenance. Grid analytics, including the use of AMI data, and advanced technologies can be used to increase the effectiveness of a phase balancing through faster and more accurate identification of imbalances. These technologies can also mitigate future phase imbalances in areas of load growth.

AMI data is not necessary for advanced phase balancing initiatives, however, it can contribute to identifying the optimal phase balancing solution. Customers identified, through AMI data, as drawing from the highly loaded phase can be switched to a lesser loaded phase, creating equally distributed peak demand across the feeder line.

Figure 12 identifies the equipment required to implement phase balancing.

Figure 12. Requirements for Advanced Phase Balancing

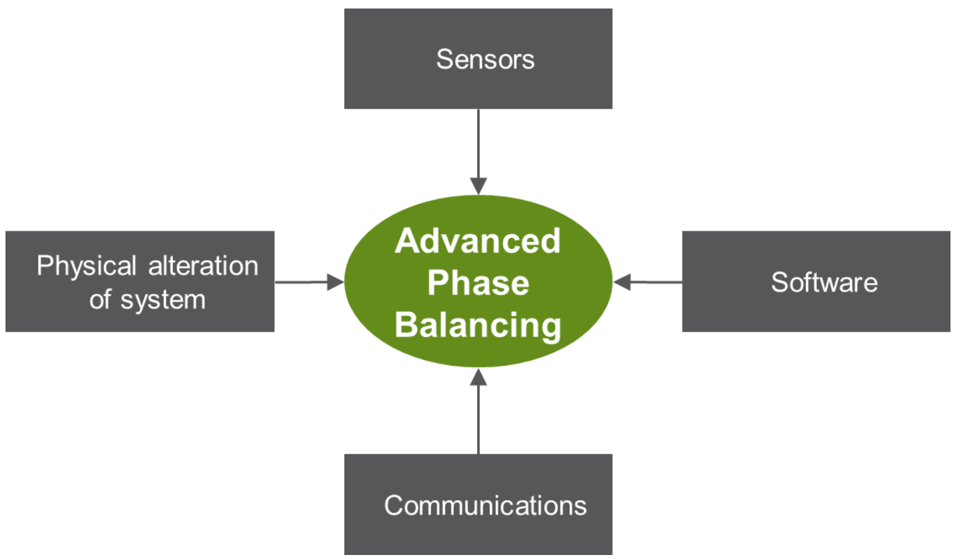


Table 8. Description of Equipment Required for Advanced Phase Balancing

Equipment Required	Description
Sensors	Sensors are used to detect where a phase imbalance is occurring and to identify areas with the highest potential benefit of phase balancing activities.
Software	Software works with distributed and communicating sensors and performs analytics to determine what mitigation techniques should be conducted to balance phases.
Communications	Connection of sensors to information processors to control devices that provide automated regulation of voltage and power factor.

2.5 Current Readiness of Ontario's Distribution Systems to Accept IFMC

Currently, Ontario's distribution system is able to accept and integrate all identified IFMC technologies in this study (i.e., VVO, Phase Balancing and Electricity Theft). This is because the incremental

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technologies required to enable IFMC deployment on a LDC's distribution system are "bolt-on" and there are no prerequisite system upgrades for integrating IFMC technologies.

As demonstrated throughout Section 2, a variety of technologies are required to enable each IFMC solution. Each LDC in Ontario will have already made investments in different technologies, some of which enable VVO or LLIM. Thus, the costs incurred by each LDC to implement any IFMC project will vary based on the current level of "intelligence" built into each LDC's distribution system. The cost-benefit analysis undertaken in this study is conservative and assumes LDC have not made investments in any of the technologies identified in Table 6, Table 7, and Table 8 that enable the IFMC solutions studied.

In Ontario, many LDCs have already installed certain equipment that are likely to facilitate highly-effective IFMC deployments. As an example, Ontario's smart meter and AMI infrastructure are two of the critical investments required to optimize phase balancing, electricity theft detection and VVO deployments.

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3. JURISDICTIONAL REVIEW

3.1 Introduction and Objectives

The purpose of the jurisdictional review is to identify and aggregate the lessons learned by other jurisdictions in the United States and Canada that have deployed IFMC technologies.

The jurisdictional review focused on identifying the following:

1. Motivations for IFMC deployment.
2. The strengths and weaknesses of each IFMC technology deployed and the deployment strategy used.
3. Barriers that have affected deployment of IFMC and how these barriers were overcome.
4. The impacts, costs, and benefits of the IFMC deployment.
5. Best practices and lessons learned from each IFMC deployment.
6. Effective implementation and communication strategies that have been used to gain IFMC acceptance by the public, regulators and utilities.
7. The cost recovery mechanisms used for IFMC deployments and the success of these mechanisms in achieving the IFMC deployment objectives.

3.2 Key Findings and Observations

Described below are the key findings of the jurisdictional review.

Key Finding 1: Non-technical barriers, including financial, cultural, and regulatory barriers, are the primary inhibitors of IFMC investment.

The jurisdictional review found that non-technical barriers are the most significant factor inhibiting utility interest and investment in IFMC technologies. While the biggest barrier is financial, specifically how to recovery costs, regulatory and cultural barriers also significantly limit IFMC deployment.

Key Finding 2: Current utility cost recovery mechanisms dis-incent IFMC deployments that tend to be lower cost than traditional infrastructure upgrades.

Current regulated cost recovery mechanisms encourage utilities to pursue capital intensive distribution system projects, rather than lower cost alternatives to address identified system needs. This is because utilities are able to earn a regulated rate of return on investments made on their distribution system.

Key Finding 3: Utilities that have piloted IFMC technologies in the United States have all received third-party funding to support their initial IFMC deployment.

Utilities in the United States that piloted IFMC technologies all received state or federal funds to financially support their pilots. In interviews these jurisdictions indicated that their initial IFMC pilot deployments would not have taken place without this support.

Key Finding 4: Changing government policies creates uncertainty for LDCs to invest in new technologies, including IFMC.

Utilities are hesitant to invest in IFMC technologies because the utility's ability to recovery costs may change as a result federal and local government policies. Change in the federal or local government may lead to a change in priorities and prevent IFMC cost recovery even if initial approval for the project was granted by the regulator under a previous administration.

Key Finding 5: IFMC pilots are the first step for IFMC deployment, however, successful IFMC pilots alone are not effective in influencing wide-scale rollout.

Utilities are reluctant to deploy IFMC technology without first conducting their own pilot projects, even if other jurisdictions are reporting positive results from their IFMC programs. Individual IFMC pilots are needed as each utility's experience deploying an IFMC project will be unique. This individuality results from the diversified mix of infrastructure, human resources, internal culture and distribution management systems in each LDC. However, even following successful pilots, utilities still face regulatory and financial uncertainty that inhibit further engagement.

3.3 Defining the Targeted Group for Stakeholder Input

Eight non-Ontario utilities were identified for review based on their experience with IFMC technologies. Following identification, telephone interviews were scheduled with each utility.

3.3.1 Non-Ontario Interview Process: Telephone Surveying

Interviews with the following non-Ontario jurisdictions were conducted to gain a deeper insight into their perspectives on IFMC technology. The list of jurisdictions consisted primarily of utilities, but also included a regional power council (Northwest Power and Conservation Council). Information on the state of IFMC projects were provided by utility staff involved in distribution system planning and operations.

Note that due to scheduling constraints, not all interviews could be completed before submission of the final report to the Ministry of Energy. Thus, any incremental findings from the few interviews conducted post-submission are discussed in Appendix F.

Table 9. Final List of Non-Ontario Jurisdictions for In-Depth Investigation

Entity	IFMC Projects Deployed
BC Hydro	VVO, Electricity theft mitigation
Pacific Gas and Electric	VVO
Southern California Edison	VVO
Northwest Power and Conservation Council	VVO
Avista	VVO
Eversource	VVO

Entity	IFMC Projects Deployed
Avangrid	VVO
Idaho Power	VVO

3.4 IFMC Projects Across Jurisdictions

Many jurisdictions in North America are aware of IFMC technologies (particularly VVO) and the benefits they can offer their distribution systems. More than 75 percent of interviewees mentioned that the primary motivation for investing in IFMC projects was the achievable electricity and peak demand savings that would benefit the customer behind the meter. They were confident that VVO, for example, could achieve approximately one to two percent electricity savings under a system-wide deployment, with savings varying from feeder to feeder.

Based on the interviews conducted, it is evident that there is significant interest in IFMC technologies; however, most utilities are still exploring the potential and benefits of these technologies. That is, they are evaluating or have recently evaluated the potential benefits for their distribution systems through pilot projects. Based on responses provided by interviewees, it was observed that the level of interest and cost recovery mechanisms for these projects varied from jurisdiction to jurisdiction. Additionally, the main IFMC technology that utilities were deploying and evaluating was VVO.

3.5 Regulatory and Policy Motivations

In many jurisdictions across North America, regulators and policymakers have encouraged their utilities to improve the efficiency of their distribution systems. For example, in the state of Washington the *Energy Independence Act*, 2006 requires that utilities with more than 25,000 customers "pursue all available conservation that is cost-effective, reliable, and feasible."[29] Policies that specifically target IFMC technologies have also been implemented in some states; for example in California, Senate Bill 350 (effective as of October 2015) suggests that VVO may be one of the technologies through which California can achieve a doubling in energy efficiency-driven conservation by 2030[30].

3.5.1 Impact of Jurisdictional Policy and Regulatory Factors

Regulators approve utility infrastructure projects that are cost-effective and in the best interests of customers. In many jurisdictions in the United States and in Canada, there is growing awareness among regulators and utilities alike that IFMC technologies, particularly VVO, present cost-effective opportunities. Thus, regulators are encouraging utilities to pursue cost-effective IFMC projects, for the benefit of the customer.

Conservation potential studies have been a key driver in giving utilities and regulators confidence in IFMC technologies. One example of a conservation potential study that demonstrated IFMC value was conducted by the Northwest Power and Conservation Council (Council) and reported in their Seventh

[29] Section 19.285.040(1) of Revised Code of Washington

[30] California Energy Commission (2015). Available here: http://www.energy.ca.gov/sb350/

Power Plan (2016). In this plan, the Council identified 215 average megawatts (aMW) of conservation potential,[31] much of which was achievable through VVO.[32]

As a result, utilities are increasingly interested in conducting IFMC pilots to test their potential to deliver electricity savings. However, many utilities still state that they cannot adequately recover the costs of IFMC deployments, which discourages them from deploying IFMC beyond the pilot stage. See Section 3.6 for more detail.

3.6 IFMC Project Funding

As part of the jurisdictional review, interviewees were asked what cost recovery mechanisms they used to fund IFMC technology deployments. The majority of respondents stated that part of the funding was provided through a government grant (such as through the American Recovery and Reinvestment Act or state funds), and the remainder of costs were recovered through their distribution rates. None of the utilities interviewed had deployed VVO or other IFMC technologies on a wide scale across their distribution system; the funding mechanisms they discussed were used for pilot projects.

The utilities interviewed stated that their IFMC pilot deployments would not have been financially viable without external funding. As in Ontario, many utilities in the United States lack the financial incentives to pursue IFMC technologies—they are not adequately financially rewarded for mitigating line losses or increasing the efficiency of their distribution system and so are less motivated to make the necessary distribution system investments. This is a direct result of the ability of these utilities to pass on the costs of system inefficiencies to their customers.

Approximately half of the utilities interviewed had successfully completed IFMC pilot projects and had submitted (or were in the process of submitting) applications to their regulator to increase IFMC deployment. However, these utilities mentioned that it could still be challenging for them to receive IFMC project funding, despite successfully completing pilot projects, because of barriers that hinder IFMC deployment (see Section 3.7 for more detail on these barriers), and technical challenges (e.g. successfully integrating IFMC into the utility's DMS).

3.6.1 The Role of Conservation and Demand Management

No respondents funded their IFMC pilots or deployment using conservation or demand side management (DSM) budgets. IFMC investments had to compete with other potential distribution capital projects in their rate applications submitted to their regulators. Some respondents said they would be interested in seeing IFMC technologies funded through conservation programs. One respondent mentioned that they were currently in discussions with their regulator in order to explore the potential for using conservation or energy efficiency (EE) funds to finance IFMC projects.

Conversely, another respondent expressed concern over using conservation funds. They said there could be conflicts with conservation program managers regarding the purpose of conservation funds and were uncertain about whether customers would find it appropriate to have conservation funds used for IFMC

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[31] An average megawatt is a unit of energy output that is equal to the energy produced by the continuous operation of one megawatt of capacity over a year.

[32] Source: https://www.nwcouncil.org/energy/powerplan/7/plan/

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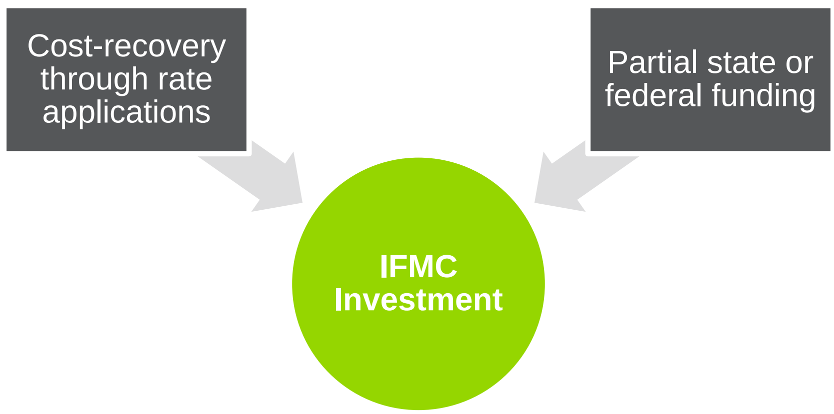
investments. The uncertainty around customer support for using DSM funds to finance IFMC investments was based on the respondents understanding of their market. Specifically, within their region, year-over-year there is a significant level of customer up-take in DSM programs. If these programs were scaled-back, or eliminated, they felt as though some form a backlash may occur.

Figure 13 shows the typical funding model for a prototypical non-Ontario jurisdiction. Note that while this is not reflective of all utilities investigated as part of this jurisdictional review, it does reflect how the majority of non-Ontario utilities have funded IFMC pilot projects.

Figure 13: IFMC Funding for a prototypical non-Ontario jurisdiction



3.7 Barriers to Deployment

Respondents described a variety of barriers to IFMC deployment. However, certain barriers were universal. The primary barriers identified are listed below in order of decreasing significance:

Financial Barriers

- A lack of financial incentives reduces the motivation for utilities to pursue IFMC deployments.
- Many utilities have limited capital budgets, which can make it challenging to allocate resources to IFMC investments.

Regulatory Barriers

- Many regulators have not created a framework for utilities that rewards/penalizes them for managing distribution system efficiency.
- Utilities are uncertain whether they will be able to recovery costs for IFMC even if there is initial project approval (due to the changing nature of government policies).

Cultural Barriers

- Utility staff will require training to engage with IFMC technologies, which is often considered prohibitive to deployment.
- Distribution engineers are reluctant to admit that their distribution system needs upgrading/ improvements.
- Reluctance to change long-standing system operating practices.

Technology Barriers

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- Data management: implementing IFMC technology could result in a significant increase in the amount of data that the utility must manage.
- Communications and controls networks will need to be upgraded to facilitate the IFMC technology (i.e., potentially cost-prohibitive AMI deployments).

For more than 75 percent of the interviewees, financial and/or regulatory barriers were considered the most significant barriers to IFMC deployment. However, there was one utility that described technology barriers as the most significant. This demonstrates that circumstances can differ between utilities, and that utilities must consider all potential barriers in their distribution system when evaluating IFMC projects. The prioritized list of barriers above describes the barriers of the majority of utilities interviewed.

An additional barrier that utilities identified was the pace of technological advancement of IFMC technologies. One utility mentioned that they were satisfied with the results of their VVO pilot, and would like to increase VVO deployment. However, the utility was cautious about deploying too quickly as VVO (and perhaps other IFMC technologies) is currently experiencing technological advancements very quickly. The utility indicating that they intend to deploy the technology slowly so that it can capture the benefits of these technological advances. Although this barrier was only raised by one utility, it will likely impact other utilities as well.

3.8 EM&V Lessons Learned

Based on research conducted, all jurisdictions understand the importance of a robust EM&V approach to verify the technology benefits. Strong EM&V processes can effectively validate the impacts and benefits of a new technology, addressing one of the key non-technical barriers to IFMC deployment. After a utility has conducted a robust EM&V for an initial deployment, they and their regulators gain confidence in the technologies and would likely expand deployment to other cost-effective areas of their distribution system.

Utilities also conducted EM&V strategically by evaluating the technology through pilot projects in their own service territory. This was done primarily because:

- Utilities and regulators prefer to take a low-risk approach when installing a new technology on distribution systems. The existing culture influences utilities to first rigorously evaluate a new technology on a test-basis before installing the technology across their system; and
- Distribution system characteristics (such as asset life, quantity of voltage regulation devices on feeders, loads served, etc.) can vary significantly between utilities and feeders. As a result, utilities believe it is more appropriate to evaluate the technology on their own feeders to accurately understand the cost-effectiveness of implementing IFMC technology across their distribution systems. Thus, even if other jurisdictions are reporting positive results from their EM&V programs, utilities are reluctant to deploy the technology without conducting their own pilot programs.

Deploying IFMC technologies through pilots and conducting rigorous EM&V processes allows utilities to learn key lessons from initial deployments. For example, during the EM&V process for a VVO pilot, one utility learned that VVO technologies should be responsive to system configuration changes (e.g. circuits being switched between buses) to maximize benefits. The lessons learned from pilot projects can improve the quality of larger scale IFMC deployments.

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4. IFMC TECHNOLOGY DEPLOYMENT BARRIERS

4.1 Introduction and Objectives

This section describes the key barriers to IFMC technology deployment in Ontario. The deployment barriers were identified through primary and secondary research. In order to effectively capture potential IFMC technology deployment barriers, stakeholder investigations focused on the following:

1. The extent to which LDCs have conducted investigations to explore IFMC potential in their service territories;
2. How current regulatory or policy frameworks promote or inhibit LDC interest in IFMC;
3. Key technical and non-technical barriers that currently impede IFMC deployment; and
4. How a distribution rate or CDM approach can be effective in encouraging IFMC investment.

4.2 Key Findings and Observations

The following are key findings consistent across all LDCs, vendors and government agencies.

Key Finding 1: Non-technical barriers, which include financial, regulatory and cultural barriers, are the primary inhibitor of IFMC deployment.

Non-technical barriers are the most significant factor inhibiting LDC interest and investment in IFMC projects. While the most limiting non-technical barrier is financial, the regulatory and cultural barriers are significant inhibitors of IFMC deployment in Ontario.

Key Finding 2: Current LDC cost recovery mechanisms dis-incent lower cost IFMC alternatives.

Current regulatory policy encourages LDCs to pursue capital intensive distribution system projects, rather than lower cost IFMC alternatives to address identified system needs (note that IFMC alternatives are not lower cost in all cases). This is a result of current OEB cost recovery mechanisms that allow LDCs to earn a prescriptive rate of return on investments made on their network.

Key Finding 3: LDC capital budgets are limited and reserved for priority projects.

LDCs have limited capital budgets that are dedicated to projects that are necessary to maintain distribution system reliability. Non-critical projects, such as IFMC investments, that improve network efficiency and reduce line losses, are not given priority over system reliability.

Key Finding 4: The complexity of deploying IFMC technologies presents challenges.

LDCs are concerned about the challenges of integrating IFMC into their distribution management systems. Challenges include integrating IFMC into existing SCADA and IT infrastructure, measuring the benefits of IFMC and appropriately training staff.

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Key Finding 5: Internal LDC cultural factors/resistance to change poses a significant challenge to IFMC integration.

Some LDCs view IFMC technologies as novel and unproven in a real-world context. As a result, they are less motivated to invest in the technologies. Additionally, LDCs are reluctant to alter long-standing network operating practices.

Key Finding 6: If IFMC technologies are funded through distribution rates and also considered as a CDM eligible measure, LDCs may have to answer to multiple government agencies.

As the CDM program and rate applications are administered by two different authorities in Ontario (the IESO and OEB, respectively), LDCs would potentially have to answer to both authorities regarding distribution system plans. This could complicate approvals processes if the requirements of both authorities vary.

Key Finding 7: In the absence of other funding, all stakeholders were receptive towards the idea of utilizing CDM dollars to fund IFMC pilot projects.

All stakeholders were supportive of using CDM funds to support *pilot projects.* Not all stakeholders were receptive towards the idea of using CDM dollars to fund wide-scale IFMC deployments. For example, LDCs are concerned that IFMC investments, if funded through a CDM approach, will displace dollars from customer-facing energy efficiency initiatives.

4.2.1 Technical vs. Non-Technical Barriers

Barriers to IFMC technology deployment can be classified into two categories; ***technical barriers*** — those related to the technical characteristics of distribution circuits and IFMC technologies —, and ***non-technical barriers*** — those related to financial, regulatory, and cultural barriers.

1. **Technical barriers** are intrinsic to the distribution system and the IFMC technologies (e.g., suitability of IFMC on highly loaded urban feeders vs. long rural feeders). Since technical barriers are inherent to the distribution system, no action, policy, or IFMC initiative will mitigate these barriers.

2. **Non-technical barriers** impact a LDC's ability to plan and deploy cost-effective IFMC technologies. They include regulatory, financial, and cultural barriers.

4.3 IFMC Deployment Limitations Identification Methodology

To identify both technical and non-technical barriers from all necessary perspectives, primary research was completed with the following entities:

- The OEB
- The IESO (both CDM and system operations)
- The Electricity Distributors Association
- Representatives from 11 separate LDCs
- Four IFMC technology vendors

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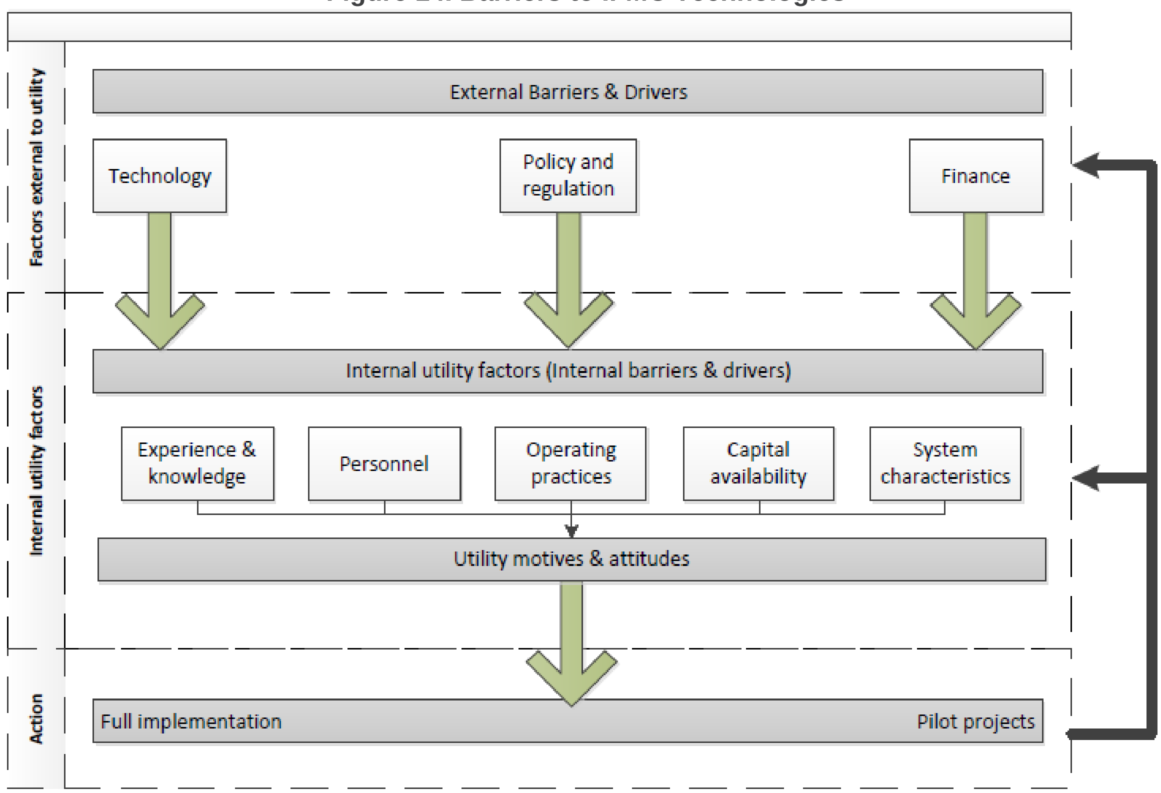
The primary research identified the range of barriers that inhibit IFMC deployment in Ontario, with a focus on financial, regulatory, and cultural factors. Figure 14 shows a disaggregated perspective of deployment barriers. This figure also shows the primary lines of questioning posed to interviewees.

Figure 14. Barriers to IFMC Technologies



In addition to discussions with Ontario's LDCs, government agencies and vendors, the jurisdictional review also explored the barriers to adoption and how these barriers were overcome (as described in Section 3). This approach provides a comprehensive understanding of the potential barriers to IFMC deployment in Ontario.

4.4 IFMC Deployments Barriers (Technical and Non-Technical)

4.4.1 Ontario Perspective

The following sections demonstrate the range of feedback received from Ontario's LDCs, government agencies, and technology vendors. Each stakeholder group's feedback has been divided into the following categories to isolate the most critical information:

- **Current Perspectives:** Provides an overview of current opinions, or perspectives of IFMC technologies and general feedback on IFMC potential in Ontario.
- **Barriers to Deployment:** Describes the barriers each stakeholder believes requires addressing in order to deploy cost-effective IFMC in Ontario.

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- **IFMC Funding Mechanisms:** Provides an overview of stakeholder feedback on how IFMC project costs could be recovered in Ontario.

4.4.1.1 Current Perspectives: LDCs

The key themes observed through information collected from LDCs are summarized below. The remainder of this section provides greater detail and quantitative data collected on the current perspectives of LDCs interviewed.

- **IFMC Awareness:** All LDCs involved in the study are aware of IFMC technologies, and more than 75% indicated that they are very familiar with IFMC technologies.
- **IFMC Research Conducted:** Almost 80% of LDCs had already conducted initial or significant research into the potential and costs of IFMC deployment in their service territory.
- **IFMC Cost-Effectiveness:** More than 75% of LDCs believe that IFMC technologies, particularly VVO, present cost-effective opportunities.

This section discusses the LDCs' overall understanding of IFMC technologies. The results inform how familiar LDCs are with IFMC technologies, and the general potential for deployment they believe exists within the province. It is important to note that the survey was sent to CDM managers at the LDC's CDM department, therefore the responses are likely specific to IFMC as relevant to the CDM Framework (assuming the CDM manager completed the survey as opposed to sending it to a colleague in another department).

As shown in Figure 15 below, all respondents ranked their familiarity with IFMC technologies as 5 or above, where a score of 10 is "highly familiar" and a score of 1 is "not at all familiar". This indicates that all survey respondents are aware of IFMC technologies. The majority (66%) responded with a score of 7 or higher, indicating that most LDCs are highly familiar with IFMC technologies. Additionally, during telephone interviews, some LDCs mentioned that they had been internally discussing how they can incorporate IFMC technologies into their future distribution system plans.

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Figure 15: With 10 being highly familiar and 1 being not at all familiar, how familiar are you with In Front of the Meter Conservation (IFMC) technologies?

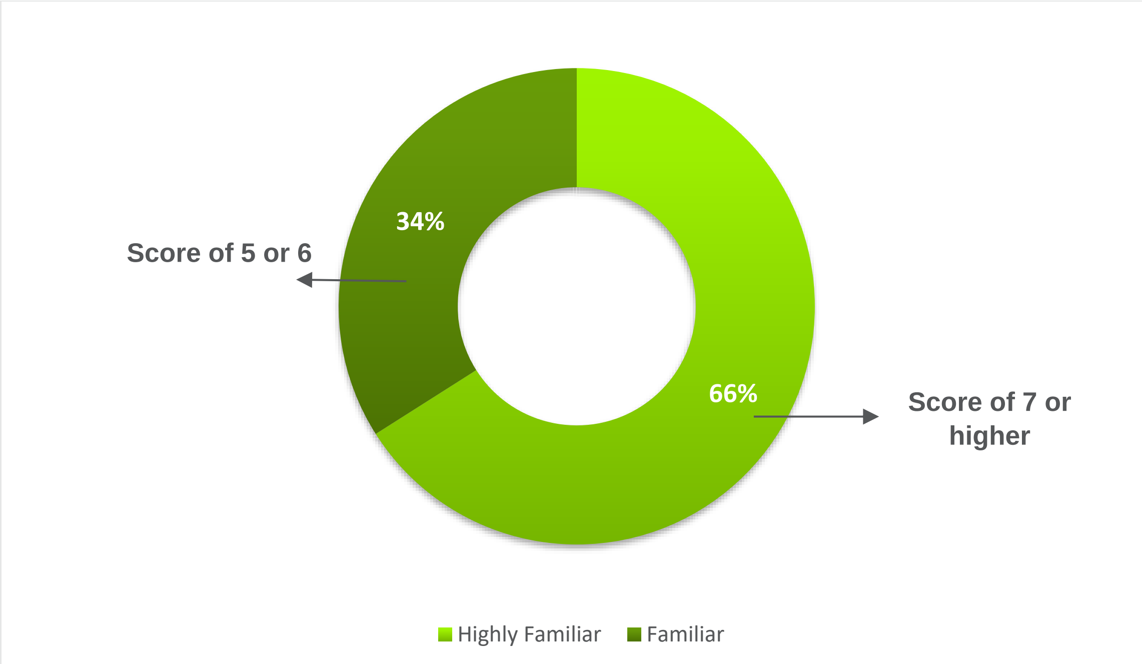

Figure 16 shows that 78 percent of participants had conducted initial (67%) or significant (11%) research to investigate IFMC potential and costs in their service territory. This result further substantiates the fact that the majority of LDCs are interested in IFMC technology and its potential impact on their distribution systems. Interestingly, 22% of LDCs said they were *not* interested in pursuing investments in IFMC technologies. Section 4, which describes barriers to IFMC deployment, will provide more information as to why this might be the case. Participants indicated that they had conducted research in the following areas:

- The potential for VVO in their service territory. A few LDCs are currently implementing pilot projects with vendors of VVO technology.
- The potential for line sensors and other technologies that leverage existing AMI communications networks.
- The potential for line loss management through phase balancing, voltage regulation and distribution transformer monitoring (among other technologies).

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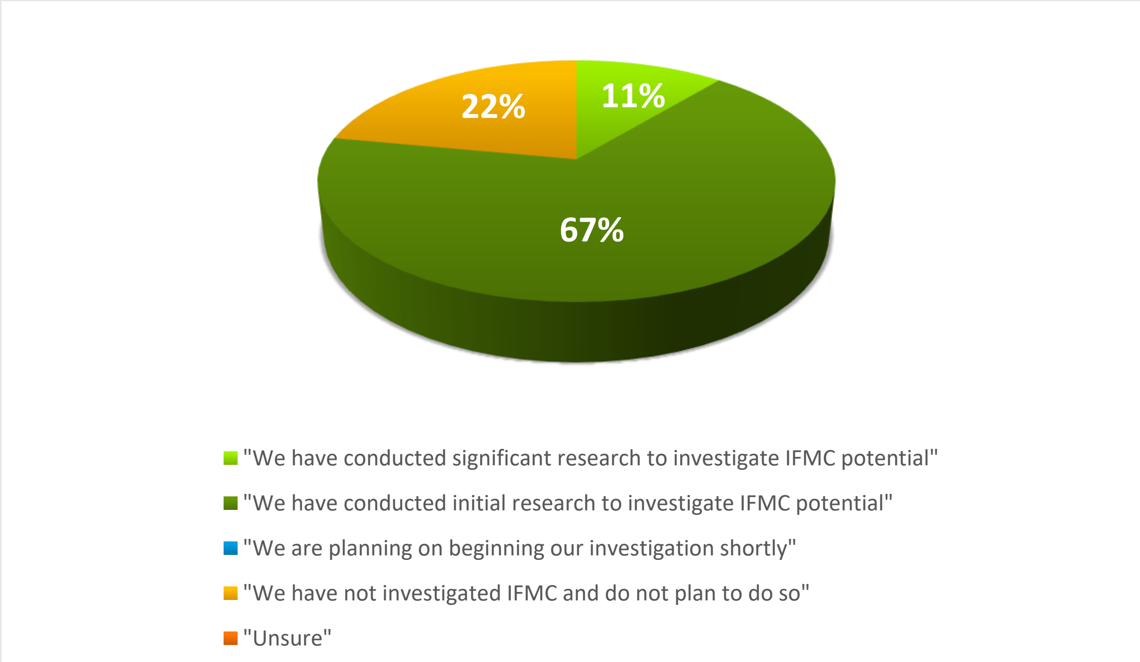
Figure 16: To what extent has your organization conducted research to investigate In Front of the Meter Conservation (IFMC) potential and costs in your service territory?



As the majority of LDCs (78%) have conducted at least initial research to investigate IFMC potential, it is evident that LDCs are interested in learning more about IFMC technologies. They are aware that implementing IFMC can be complex, but also mentioned that the attractiveness of IFMC increases considerably when the technologies provide system reliability benefits as well. One LDC is in the process of releasing a request for interest (RFI) to expand their knowledge of the technologies available in the market and how the technologies could benefit their distribution system.

As shown in Figure 17, most participants (78%) gave a score of 6 or higher when asked about the level of potential they see for cost-effective IFMC deployment in their service territory, where a score of 10 indicates “very high potential” and a score of 1 indicates “very low potential”. This shows that the majority of participants believe cost-effective opportunities exist for IFMC deployment. Further, it suggests that LDCs have seen positive results from their research and in a few cases, pilot projects.

Nearly half the participants said that technologies that dynamically reduce voltage (i.e., VVO) are the primary type of cost-effective IFMC technology. Participants were confident VVO technology would allow them to reduce feeder voltages to the low end of the regulated voltage band without causing system issues. LDCs also mentioned that there is potential to decrease line losses through transformer management and electricity theft mitigation.

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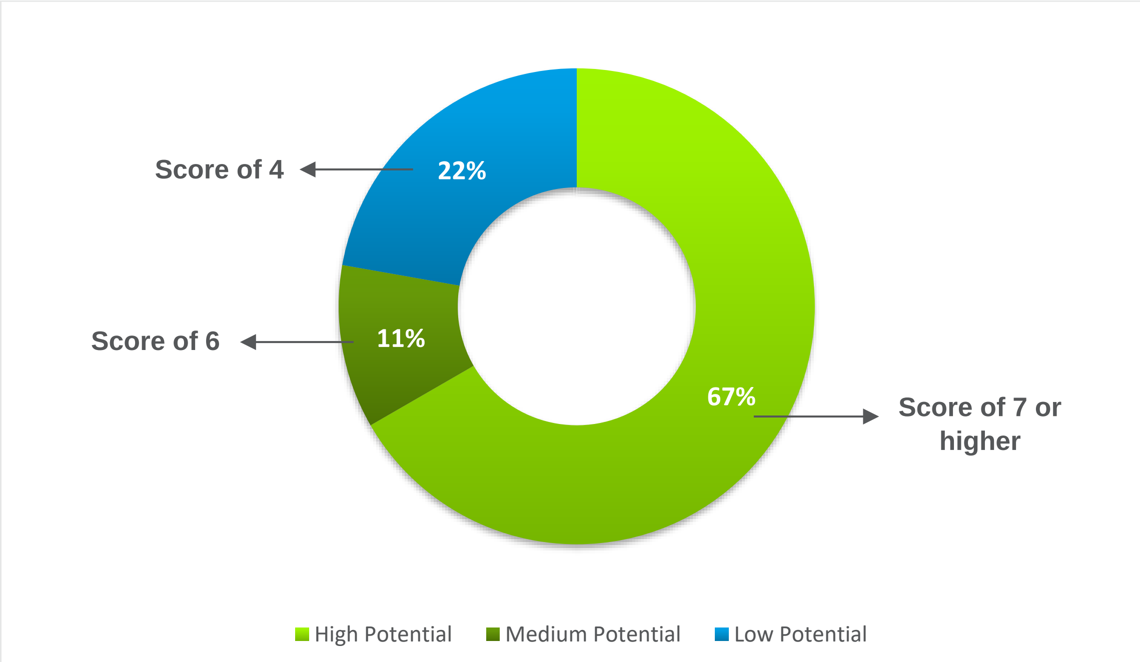
Figure 17: With 10 indicating very high potential and 1 indicating very low potential, what level of potential do you see for cost-effective In Front of the Meter Conservation (IFMC) technology deployment in your service territory?



Overall, LDCs see potential for IFMC technology in Ontario. LDCs are relatively familiar with IFMC technologies and see benefit particularly in dynamically managing voltage and reactive power flow (VVO).

4.4.1.2 Current Perspectives: Vendors

Several vendors offer commercially viable IFMC technology solutions. Their IFMC technologies generally include software, sensors and advanced grid analytics that give LDCs greater insight and data into the conditions and operations of their distribution systems. Vendors identified that they have worked with utilities internationally (including California, Virginia, Mexico, Germany and Ontario) to pilot and evaluate the benefits of their IFMC technology solutions. Vendors believe IFMC technologies have a strong value proposition in Ontario, and described the following value drivers:

- **Primary Value Driver:** Electricity and Peak Demand Savings.
- **Secondary Value Drivers:**
  - **Increased Reliability:** IFMC technologies can improve voltage stability and power quality on the distribution system.
  - **DER Integration Support:** IFMC technologies can help integrate more DER (solar, wind, electric vehicles), by mitigating reliability issues and other challenges as the number of DERs connected to the grid increases.
  - **Leverage Existing Infrastructure:** Several IFMC technologies build on existing distribution system infrastructure (such as the AMI) to enhance their value proposition.

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- **Greenhouse Gas Reductions:** Reductions in electricity and peak demand offset electricity generated from fossil fuels and result in greenhouse gas reductions.

4.4.1.3 Current Perspectives: Government Agencies

The government stakeholders had different levels of familiarity with IFMC technology solutions and had different concerns about implementation in Ontario. One stakeholder said that they had not yet been approached by LDCs regarding IFMC projects, but indicated that they are receptive to IFMC investments included in a rate application, as long as it has a strong business case. The agency also mentioned that LDCs would find IFMC investments more appealing if funding did not come from distribution rates, as the distribution rate application process is rigorous.

On the other hand, another agency said that IFMC technologies should not be included as a CDM resource. In their opinion CDM funds should only be used to support customer-facing conservation and energy efficiency programs. The agency believed that supporting IFMC projects with CDM funds would create considerable criticism from customers, as it takes away from the customer's ability participate in conservation initiatives.

4.4.1.4 Barriers to Deployment: LDCs

This section describes the barriers to IFMC deployment in Ontario identified by LDCs. The barriers are listed below in order of decreasing significance.

Financial Barriers

- All LDCs have limited capital budgets which are dedicated to projects needed to maintain distribution system reliability. Discretionary projects, such as IFMC investments that improve network efficiency and reduce line losses, are not given priority.

Regulatory Barriers

- Current regulatory policy encourages LDCs to pursue capitally intensive distribution system projects, rather than lower cost alternatives to address identified system needs. This is a result of current OEB cost recovery mechanisms, which allow LDCs to earn a regulated rate of return on distribution infrastructure investments.

Cultural Barriers

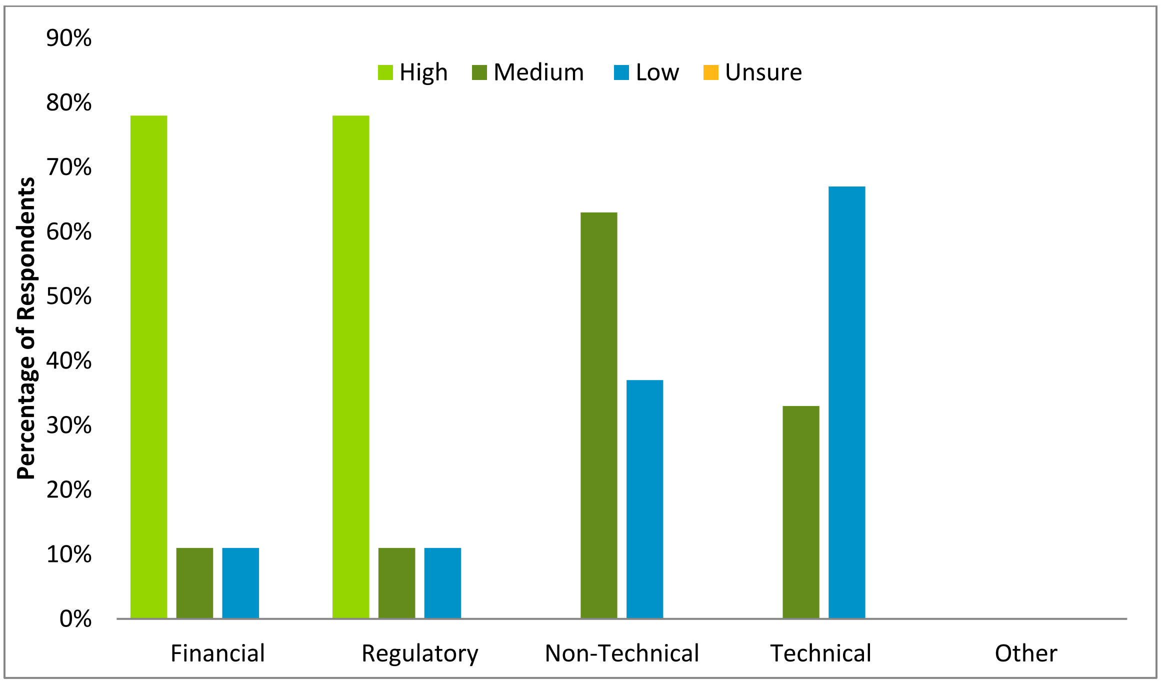
- More than half the LDCs in the study are reluctant to alter long-standing network operating practices.
- All LDCs are concerned that if IFMC investments are funded through the CDM framework these projects will displace funding for customer-facing energy-efficiency programs.

Technology Barriers

- Approximately half the LDCs in the study are concerned that IFMC technologies are a novelty and unproven in a real-world context.
- More than half the LDCs in the study are concerned about the challenges of integrating IFMC into their distribution management systems and the associated training required.

It is important to note that, although possible, respondents did not mention any other barriers. **Error! Reference source not found.** Figure 18 shows LDC responses on the significance of each barrier. LDCs identified financial[33] and regulatory[34] barriers as very significant. In the commentary provided by the LDCs, the main concerns were that LDCs do not have an appropriate method of cost recovery for investments in IFMC technologies in the existing regulatory framework. LDCs cannot access CDM funds to support these projects, and some LDCs believe that cost recovery through OEB rates is not guaranteed and risky. This is mainly due to the fact that LDCs interested in deploying IFMC technologies in their service territory are still in the process of developing a business case for IFMC technologies that they can present to the OEB; as expected, a strong business case is necessary for the OEB to grant approval of an IFMC project.

Figure 18: To what extent do you believe the following barriers inhibit your organization's ability to deploy cost-effective In Front of the Meter Conservation (IFMC) technologies in your service territory?



Additionally, LDCs identified that IFMC technologies may be capable of deferring poles and wires projects. However, this can also dis-incent some LDCs from pursuing these technologies as it means a reduction in their revenue stream; LDCs earn a greater return on more capital-intensive projects in the current regulatory framework. Further, there is currently no financial incentive for LDCs to reduce line losses beyond thresholds set by the OEB. IFMC technologies will compete with traditional wires projects for funding from an LDC operations budget, and the traditional investments are often seen as more important to maintain system reliability.

[33] **Financial Barriers:** Availability of funds or recovery mechanisms for IFMC investments

[34] **Regulatory (or policy) Barriers:** External regulatory or policy restrictions that prevent a LDC from deploying IFMC

Non-technical (cultural) barriers[35] are the next most significant barrier, with 63 percent of participants rating it “medium” significance. The primary barriers discussed by LDCs in this category are the perception of IFMC technologies. There are two aspects to perception influencing this rating:

- **Customer perception:** If IFMC technologies are funded through the CDM approach, LDCs are concerned that this would displace dollars from customer-facing energy efficiency (CDM) initiatives. They realize it will be challenging for LDCs to demonstrate to *all* customers how IFMC technologies, such as VVO, are reducing their electricity bills.
- **LDC perception:** Many LDCs are concerned that IFMC technologies are a novelty and unproven in a real-world context. While IFMC technologies have been implemented by several different utilities in the United States and demonstrated positive results, they are still relatively new in Canada, and thus LDCs are uncertain of the benefits.

Technical barriers[36] were the least significant barriers to IFMC deployment, with 67 percent of LDCs rating it as low significance. Importantly, no respondents considered it a barrier with high significance. There were two types of technical barriers that LDCs were concerned about:

- **Integrating IFMC technologies:** LDCs believe it will be challenging to effectively integrate IFMC technologies into their existing distribution systems. SCADA, IT and cybersecurity are examples of areas that might need upgrades to coordinate with IFMC technologies.
- **Measuring benefits:** Benefits from implementing IFMC technologies can be difficult to measure. LDCs said that they may have to rely on theoretical calculations rather than measured benefits to determine the impacts of IFMC technologies.

4.4.1.5 Barriers to Deployment: Vendors

This section describes the barriers vendors identified for IFMC deployment in Ontario. A summary of the barriers to deploying IFMC technologies that vendors face is listed below in order of decreasing significance.

Financial Barriers

- Energy efficiency initiatives such as IFMC result in revenue erosion for the LDC. LDCs may need financial incentives or a clear cost recovery mechanism to pursue IFMC investments.

Regulatory Barriers

- Vendors believe regulations need to change to give LDCs an effective cost-recovery mechanism and sufficient financial motivation to pursue distribution system efficiencies.

Cultural Barriers

- Vendors believe some LDCs are reluctant to mitigate technical and non-technical line losses as their regulator allows them to pass these costs on to consumers.

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[35] **Non-Technical Barriers:** Organizational culture, level of IFMC specific knowledge, perception, or internal resources that inhibit IFMC deployment.

[36] **Technical Barriers:** Characteristics of a LDC’s distribution system that inhibit the successful deployment of IFMC. For example, feeder voltage levels currently at the low end of the allowable range, presence of a significant number of long rural feeders, lack the technology platform to incorporate line loss sensors, etc.

Technical Barriers

- Vendors stated that some LDCs will need to work together to deploy IFMC technologies in areas where their distribution systems overlap (i.e. with Hydro One).
- A considerable amount of work and effort is required to develop LDC-specific IFMC deployment plans.

Vendors said that the most significant barrier in Ontario and other jurisdiction is the cost-recovery mechanism for LDCs who invest in IFMC technologies. Vendors believe the solution to this problem is changing regulation to make it easier for LDCs to recover costs, and encourage LDCs to proactively pursue efficiencies on their distribution systems.

Vendors stated that Ontario's distribution system is technically capable of incorporating IFMC technologies. Technical barriers were ranked as the lowest of all the barrier types. Examples of technical barriers include:

- **LDC cooperation:** In Ontario, certain voltage regulating equipment on the transmission side of the transformer stations (such as LTCs) is controlled by Hydro One. Thus, LDCs will need to effectively cooperate with Hydro One to deploy certain IFMC technologies.
- **LDC deployment plans for IFMC:** As IFMC technologies are relatively new in Ontario, there is additional work for LDCs to create deployment plans for IFMC technology. This could make IFMC less desirable compared to tried and tested infrastructure options.

4.4.1.6 Barriers to Deployment: Government Agencies

This section describes the barriers to IFMC deployment identified by government agencies. A summary of these barriers, in order of decreasing significance, is provided below.

Financial Barriers

- Government agencies will require LDCs to develop strong business cases to support IFMC technology deployment. IFMC projects will need to demonstrate that they are cost-effective and competitive against other distribution investment projects the LDC could pursue to fulfill a defined need.

Regulatory Barriers

- LDCs are not incentivized to pursue lower cost IFMC projects when distribution system upgrades are required; the current regulatory framework gives LDCs a greater financial return on projects that require higher capital investments.

Cultural Barriers

- It is the responsibility of LDCs and regulators to ensure customers are aware of investments made by LDCs that help reduce customer bills. For IFMC investments, LDCs and/or regulators would need to develop a communications plan to inform customers that these investments are being made for their benefit.

Technical Barriers

- There is a range of distribution system configurations and staff capabilities within Ontario's LDCs. Some LDCs have advanced distribution systems and would be able to successfully manage the added complexities of IFMC, while other LDCs may not.

Government agencies also ranked financial and regulatory barriers as the most significant barriers to IFMC deployment. Cultural and technical barriers are also important and must be addressed, but will have less of an impact on IFMC deployment.

One stakeholder also brought up the concern about the potential impact of voltage reduction from VVO technologies on the IESO's transmission and distribution system-wide voltage reduction control action[37]. This concern was raised with a vendor of VVO technology, who agreed that widespread deployment of VVO would limit the total demand reduction yield available to the IESO through its voltage reduction program.

However, the vendor mentioned that VVO has the potential to enhance the IESO's visibility into the distribution system, by better quantifying and locating the potential for demand voltage reduction, as well as understanding the service voltage impacts to consumers. Recently, an IESO-LDC Interoperability Standing Committee was created in order to facilitate data sharing around the joint operation of Ontario's grid. Issues such as the impact of VVO on the IESO's voltage regulation program can be efficiently explored during these sessions[38].

4.4.1.7 Cost Recovery Mechanisms: LDCs

This section provides an overview of LDC feedback on cost recovery mechanisms for IFMC projects in Ontario. LDCs were asked about how the cost recovery mechanism (i.e. through the CDM budgets or distribution rate applications) would affect their plans for deploying IFMC technology.

CDM Approach

- LDCs believe that if costs are recovered through CDM budgets, the current CDM methods of evaluation and reporting and cost-effectiveness tools will need to be revised for IFMC technologies.
- LDCs also expressed concerns about IFMC projects reducing the funding for customer facing energy efficiency programs, and customer's perception of using CDM budgets for IFMC projects.
- However, the majority of LDCs are comfortable with recovering IFMC project costs through the CDM budgets.

Distribution Rates Approach

- LDCs stated that regulatory barriers are the main factors limiting them from including IFMC technologies in their distribution system plans (DSPs).

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[37] The IESO has a voltage reduction program in place that, when activated, works to reduce grid voltage during periods of high demand. This program is only activated in emergency situations. Note that the IESO also has a mandatory voltage reduction test every 18 months where they reduce grid voltage by 3% and 5% every 18 months to simulate emergency actions and to measure the load reduction resulting from the tests. Source: http://www.ieso.ca/corporate-ieso/media/news-releases/2016/08/ieso-to-conduct-routine-voltage-reduction-test

[38] http://www.ieso.ca/sector-participants/ieso-news/2017/02/first-meeting-of-the-grid-ldc-interoperability-standing-committee---march-9.

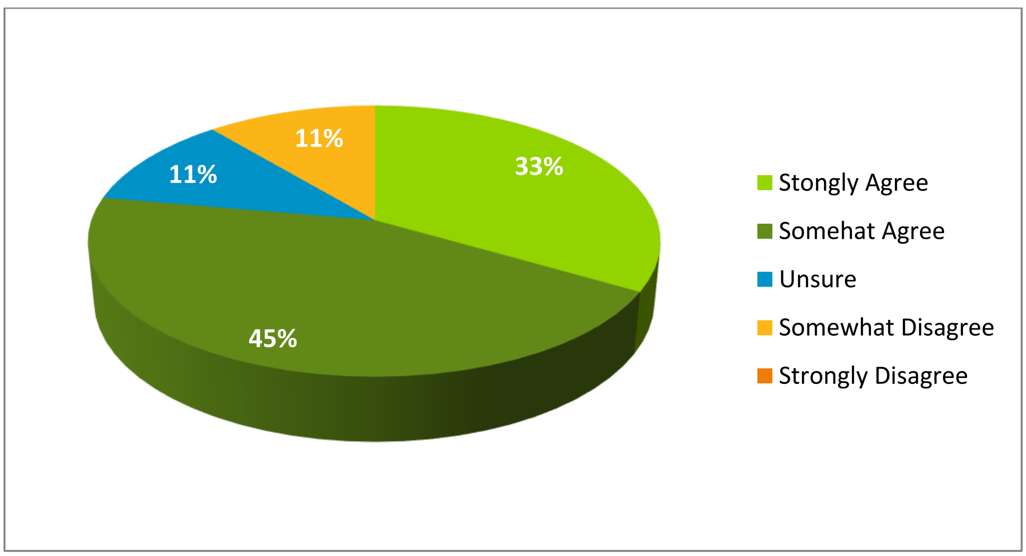
- To supplement their distribution rates applications, LDCs want more information on any existing IFMC applications and their corresponding financial benefits/risks, customer benefits/risks, success factors, lessons learned, etc.

Figure 19 demonstrates that the majority of participants (78 percent) either “somewhat agree” or “strongly agree” that IFMC investments could be appropriately funded through CDM efforts. While 11 percent of LDCs said that they “somewhat disagree” with funding through a CDM framework, no LDC was strongly against the idea. This suggests that LDCs would be comfortable with exploring the potential to use CDM budgets to fund IFMC projects.

Some LDCs said that IFMC technologies produce the same types of benefits as CDM programs as they provide reductions in electricity consumption for the end user. Further, they said that IFMC are more similar to the Behind-the-Meter (BTM) CDM energy efficiency initiatives and are capable of contributing to an LDC’s CDM target in a similar way.

Additionally, funding IFMC projects through the CDM approach would eliminate the need for IFMC investments to compete with other poles and wires projects. Removing the requirement of IFMC projects to compete with other distribution infrastructure projects would increase the chance of IFMC deployments in the province. However, if funding is provided through the CDM approach, significant care will need to be taken to ensure IFMC projects are a prudent investment for an LDC to take on their distribution system. That is, LDCs will need to take steps to ensure IFMC projects provide more benefits to customers behind-the-meter than other behind-the-meter programs that could be funded through the CDM budget.

Figure 19: To what extent do you agree with the following statement: “My organization’s In Front of the Meter Conservation (IFMC) investments could appropriately be funded in a similar way to my organization’s Conservation and Demand Management (CDM) efforts.”



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LDCs had different opinions about the degree of funding for IFMC projects that should be provided through CDM. One LDC mentioned that they would prefer to have IFMC technologies completely funded through their CDM budgets. Another LDC said that they would prefer to have at least the capital and O&M costs of IFMC projects funded through their CDM budgets in order to make the investment 'worthwhile'. More than 75 percent of LDCs interviewed believed IFMC technologies have a greater chance of being implemented if funded, in whole or in part, through CDM initiatives.

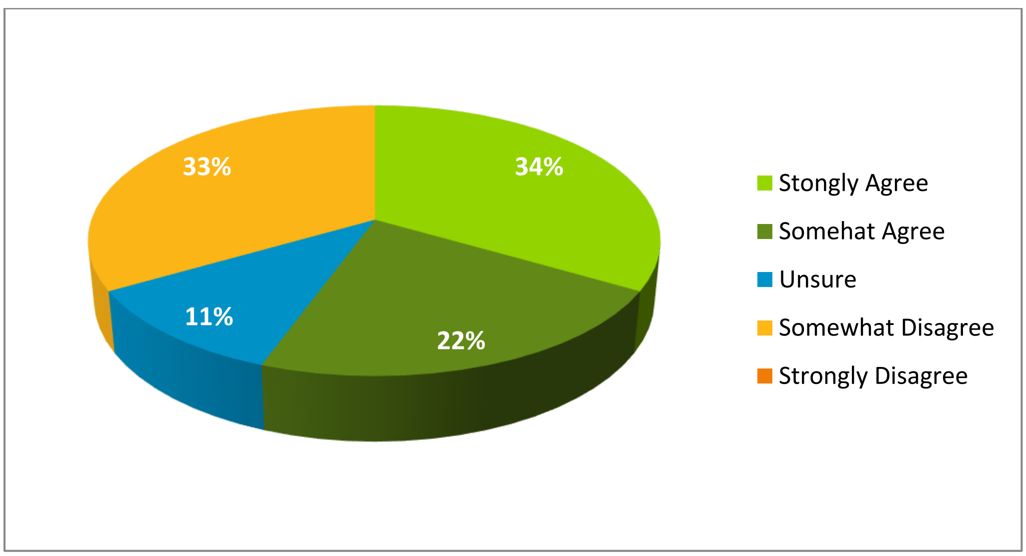
While most LDCs agreed that CDM budgets could be an appropriate source of funding for IFMC investments, responses were mixed about whether IFMC projects should be held to a similar, rigorous evaluation and reporting standard as used in the existing 2015-2020 Conservation First Framework (CFF). As shown in Figure 20, 33 percent of participants believed a different evaluation and reporting standard should be used for IFMC technologies. Several participants stated that achievable potential studies would be more complex with IFMC technologies, as compared to conservation initiatives BTM, due to IFMC technologies being implemented on the feeder level. LDCs provided reasons such as:

- *"Accurately modeling the impacts of a program at the feeder will be more challenging due to the variations in customer behavior, and number of customers involved."*
- *"An accurate distribution system model would be required, and would need to be regularly maintained for pre-and post-conditions."*

One LDC argued the opposite of the opinions above. They believed *"achievable potential studies for IFMC technologies may be more reasonable with a higher degree of certainty…due to the lack of dependency on the end user/customer in the implementation of energy savings technology."*

There are mixed opinions on an appropriate evaluation and reporting standard for IFMC technologies. Based on LDC responses it can be inferred that while elements of the evaluation methods for the existing CDM programs may be used, LDCs feel that revisions may need to be made to accurately evaluate and report on the performance of IFMC projects.

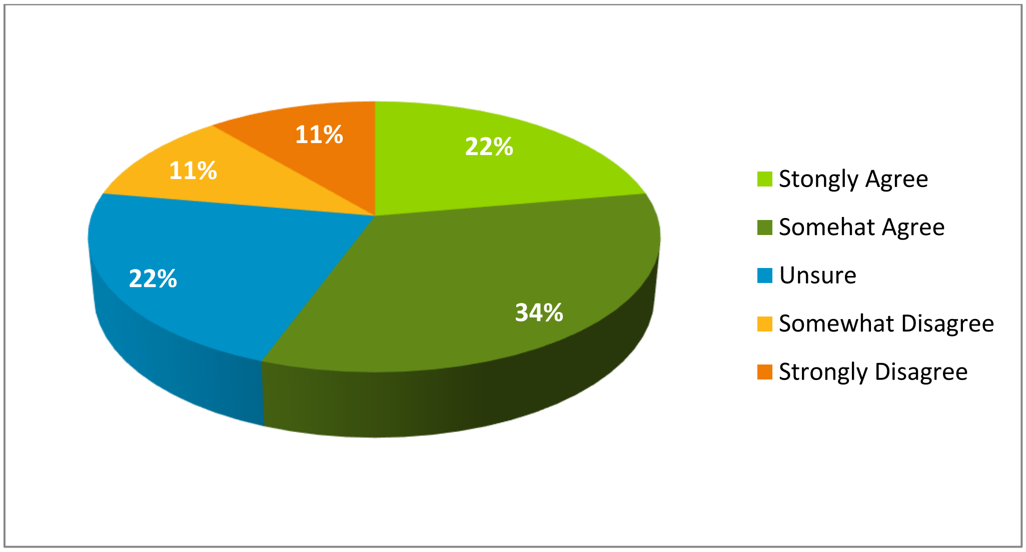
Figure 20: To what extent do you agree with the following statement: "In Front of the Meter Conservation (IFMC) projects funded through a CDM approach could be accurately held to a similarly rigorous evaluation and reporting standard



LDCs were also asked about any factors that should be considered when developing cost-effectiveness tools or adjusting the current cost-effectiveness tools to accurately evaluate IFMC investments. There was no clear consensus between LDCs on the factors requiring consideration. However, about a quarter of the LDCs interviewed indicated that the existing cost-effectiveness tools would need to be modified to make them appropriate for IFMC technologies.

Figure 21 shows the results of questions posed to LDCs on whether they are interested in prioritizing IFMC investments in their DSPs. The results show that 56 percent of participants indicated that they would be interested in doing so, with 22 percent saying they were very interested. This shows that LDCs are confident in the benefits IFMC technologies can bring, and may be willing to undertake IFMC investments even if they cannot receive funding through CDM budgets.

Figure 21: To what extent do you agree with the following:
"My organization is interested in prioritizing In Front of the Meter Conservation (IFMC) investments in our distribution system plans."



When asked whether LDCs had already prioritized IFMC investments, more than 75 percent of LDCs responded that they have not yet included them in their DSPs. LDCs mentioned that their priority is in ensuring existing infrastructure is functioning as required. Some LDCs perceive IFMC technologies as advanced technologies that allow utilities to go "above and beyond" their existing capabilities/ requirements, but are not necessary to achieve the current operations standards.

Through their responses, it was evident that LDCs were uncertain if they would be able to include IFMC investments in their distribution rate applications and the lack of certainty on how these investments would be viewed by their regulator was a key barrier.

One LDC stated that the governing authorities in Ontario must be in agreement whether IFMC technologies are conservation or grid activities. According to the LDC, "*VVO and [LLIM] can improve the efficiency of the grid and help reduce customer bills; however, the LDC receives no regulatory support for this activity and is already strapped for maintaining existing infrastructure health and reach to new customers.*"[39] Another participant believed that, while the OEB may approve small-scale pilots, it will likely be very challenging for LDCs to gain approval for wide-scale deployments of the technology on their grid.

To improve an LDC's ability to prepare rate applications that include IFMC investments, LDCs requested:

- Clear direction from the OEB on how to treat IFMC investments, and
- More information, perhaps developed by a third-party consultant or think tank (i.e. not a government agency), on any existing IFMC applications, any lessons learned by other jurisdictions and how to develop an effective business case for IFMC projects.

Determining the appropriate cost recovery mechanism for IFMC investments is a complex issue. As the CDM program and rate applications are administered by two different authorities in Ontario, LDCs would potentially have to answer to two different authorities regarding distribution system plans. One participant indicated that if this happens, it could be challenging to ensure the requirements set by both authorities are equivalent and appropriate.

4.4.1.8 Funding Mechanisms: Vendors

Vendors stated that in certain jurisdictions in United States and Canada, IFMC technologies have been used in conjunction with CDM programs to meet CDM targets. That is, IFMC technologies have been funded through rate applications or grants from regional/federal organizations, but were allowed to contribute to the utility's CDM targets. It is important to note that the ability to count IFMC savings towards CDM targets was mentioned by vendors. This statement could not be validated during discussions with any of the eight non-Ontario utilities interviewed through this project or during extensive secondary research efforts. However, there is no industry best practice for funding these technologies, and different jurisdictions have taken different approaches. Some utilities have used a rate rider[40] to recover costs, while others are piloting or implementing the technology through specific VVO programs/external funding mechanisms.

[39] VVC (Volt/VAR Controls) is another name for VVO (Volt/VAR Optimization). LLD/P is an acronym that refers to addressing line losses on the grid.

[40] A rate rider is a temporary additional rate applied to the total of all charges, before taxes. Amounts received from the rate rider are used to adjust any differences between the actual cost and the approved rate for providing service.

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When asked whether IFMC projects should be funded through the CDM program or a rates-based approach in Ontario, one vendor mentioned that at least for VVO, a hybrid approach to funding should be implemented. They suggested that "*investments in voltage control equipment and communications should be funded through the normal rate base process*," while "*VVO software and services should be funded through provincial CDM programs."* In their perspective, it is appropriate for any physical distribution system assets to be funded through the rates-based approach. However, in general, vendors are interested in any funding mechanism that could support IFMC deployment, and in their experience, IFMC projects rarely progress without third-party support.

It is also important to note that, as mentioned in Section 4.4.1.5, IFMC technologies are distribution system energy efficiency initiatives that can result in revenue erosion for the LDC. Thus, without an adequate financial incentive that encourages LDCs to pursue energy efficiency initiatives, LDCs are less motivated. Financial incentives could theoretically be provided through either funding mechanism: the CDM approach, a rates-based approach or a combined approach.

4.4.1.9 Funding Mechanisms: Government Agencies

As mentioned in previous sections, one agency was firmly against the CDM approach even if the primary motivation for IFMC technologies was to produce electricity savings and peak demand reductions for customers BTM. In their opinion, IFMC technologies should only be funded through distribution rate applications, and that there should be more stringent minimum performance efficiency standards for LDCs in Ontario. Creating such standards would incentivize LDCs to pursue IFMC opportunities instead of potentially more expensive poles and wires projects.

In October 2014, the OEB released a report entitled "*Renewed Regulatory Framework for Electricity: A Performance-Based Approach*". The framework was designed to "support the cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for customers"[41]. To facilitate this goal, several complementary initiatives and policies were introduced, including electricity LDC scorecards[42]. These scorecards must be completed annually by all of Ontario's LDCs.

LDC scorecards contain a number of metrics that allow both the OEB as well as an LDC's customers insight into the financial and operational performance of the LDC. Should a distribution-rates approach to IFMC project funding be taken, there is an opportunity to integrate minimum performance efficiency standards into LDC scorecards.

Another government agency was supportive of IFMC projects being funded through the CDM budget. They were also receptive of funding the projects through the rate base, however, the agency noted that IFMC projects would have to present a strong business case. Additionally, the agency noted that applications submitted for approval through the rate base are more rigorously evaluated than CDM project applications submitted to the IESO. This means a distribution rates approach will take longer for IFMC projects to be approved, and IFMC applications might have a lower success rate.

[41] http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/Report_Renewed_Regulatory_Framework_RRFE_20121018.pdf

[42] http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Electricity+Distributor+Scorecards

However, all government agencies were receptive towards the idea of utilizing CDM dollars to fund IFMC pilot projects, in the absence of other funding being available. Both government agencies understand the value of IFMC and believe it should be engaged by LDCs (as necessary) to improve the distribution system and to promote affordability.

4.4.2 Comparison between Ontario and Non-Ontario Jurisdictions

The following sections discuss how perspectives, barriers and funding mechanisms compare between stakeholders in Ontario and those in jurisdictions outside of Ontario. Section 3 provides additional information on perspectives from non-Ontario jurisdictions on barriers and cost recovery mechanisms for IFMC technology deployment.

4.4.2.1 Current Perspectives: Comparison

There are many similarities between stakeholders in Ontario and those in jurisdictions outside of the province. The majority of utilities, both in and outside Ontario, see significant potential for IFMC technologies, and are interested in enhancing their distribution systems through them. In the United States, a large number of utilities have already conducted pilot programs with IFMC technologies (particularly VVO) and have verified it achieves savings under specific grid conditions. Although IFMC technologies are relatively new in Ontario, the success in the United States should give Ontario LDCs more confidence in the capabilities of these technologies. However, for IFMC technologies to gain noticeable traction, financial and regulatory barriers will need to be addressed.

4.4.2.2 Barriers to Deployment: Comparison

For both Ontario and jurisdictions outside of Ontario, financial and regulatory barriers are the most significant barriers to deployment. This was the opinion of more than 75 percent of the LDCs, vendors and government stakeholders interviewed. The most significant barrier, which is both a financial and regulatory barrier, was the LDC understanding of the cost recovery mechanism for IFMC deployments. As IFMC deployments are distribution system energy efficiency investments, they result in revenue erosion for LDCs. Without a cost recovery mechanism or financial incentives to improve the efficiency of the distribution system, LDCs are not motivated to pursue IFMC investments.

Stakeholders in both jurisdictions also identified similar technical and organizational barriers that could affect IFMC deployment. Utilities outside Ontario have conducted and evaluated IFMC pilot projects and highlighted some of the technical concerns Ontario LDCs raised. One of the key technical concerns was the large volume of data that needs to be managed for successful IFMC projects. To address this, non-Ontario utilities stated that all utilities will need to ensure they have the appropriate infrastructure to manage this influx of data and upgrade other systems to complement IFMC technologies as needed. Additionally, the appropriate staff will also need to be trained.

By combining the opinions of stakeholders inside and outside of Ontario, it is evident that financial and regulatory barriers are the most significant and influential barriers to IFMC deployment in North America. Technical, cultural and technical barriers also play a key role, but can be addressed more easily by LDCs looking to deploy IFMC technology.

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4.4.2.3 Funding: Comparison

Utilities in other jurisdictions funded IFMC (pilot) projects through rate applications supplemented with an external state or federal subsidy Similar to Ontario, other jurisdictions also discussed the possibility and appropriateness of using CDM funds to support IFMC projects. Similar concerns about using CDM funds were echoed by both regions, with the primary issue being customer dissatisfaction against the usage of funds that have traditionally been allocated for energy efficiency or conservation programs BTM.

In Ontario, only one agency was firmly against CDM funds being used to support non-customer-facing conservation or energy efficiency initiatives. The majority of Ontario stakeholders were open to discussing the appropriateness of funding through a CDM approach. On the other hand, in non-Ontario jurisdictions, all stakeholders interviewed were open to the idea of using CDM funds (note: interviews were not completed with any non-Ontario government agency). Certain non-Ontario utilities mentioned that they were in the process of discussing with their regulators how to better use CDM funds to serve customers in their service territories and that including IFMC technologies is one of the options being considered.

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5. IFMC TECHNOLOGY POTENTIAL AND COST-BENEFIT ANALYSIS

5.1 Introduction and Objectives

This section provides results on the technical and economic potential for IFMC deployment in Ontario. It begins by summarizing the key findings and observations from the cost-benefit analysis (CBA), and by providing an overview of the computational model used, the CBA framework, and identifies the key inputs and assumptions used in the analysis.

The objectives of the technology potential and CBA section are:

1. Provide an overview of the CBA methodology;
2. Provide a description of key modelling assumptions including costs and benefit inputs;
3. Determine costs, benefits, and net present value for each IFMC technology; and
4. Determine the associated peak, electricity, and line loss reduction impacts from IFMC deployment.

5.2 Key Findings and Observations

Deployment of IFMC technologies across Ontario has the potential to reduce distribution peak demand, electricity consumption, and line losses significantly. **Error! Reference source not found.** Table 10 shows the peak, electricity, and line loss impacts across all IFCM technologies –including VVO, phase balancing, and electricity theft– in 2018 and 2037 (the first and last years of the study period).

Table 10: Summary of Economic and Technical Potential Impacts

Reduction Impact	Technical Potential		Economic Potential	
	2018	***2037***	***2018***	***2037***
Peak (MW)	337	355	184	194
Electricity (GWh)	2,148	2,266	1,128	1,190
Line Losses (GWh)	282	298	181	191
PV Benefits (2017 $M)	$2,169		$1,175	
PV Costs (2017 $M)	$2,817		$885	
NPV (2017 $M)	**($648)**		**$289**	

Source: Navigant analysis

This analysis is based on the assessment of IFMC costs and benefits for 15 prototypical Ontario feeders. The results for these 15 feeders are then extrapolated to Ontario's 10,000 feeders to determine province-wide costs and benefits. As part of the analysis, province-wide savings potential for peak demand, electricity consumption, and line losses are also determined. *Technical* savings potential reflects the impact of IFMC deployment across all of Ontario's 10,000 distribution feeders, while *economic* savings potential only reflects the impacts from feeders for which IFMC investments result in a cost-benefit ratio greater than one

The technical peak demand reduction impact is 337 MW in 2018 increasing to 355 MW by 2037. The small increase over time is a result of a slight increase in the provincial load forecast. As the provincial load increases over time, so does the resulting IFMC impact. A peak demand impact in the range of 337 to 355 MW is equivalent to approximately 1.6percent of the 2015 distribution system peak demand in Ontario.[43] The technical electricity consumption reduction impact is 2,148 GWh in 2018 and 2,266 GWh in 2037 (equivalent to 1.8 percent of the 2015 distribution electricity consumption), and the technical line losses reduction impact is 282 GWh in 2018 and 298 GWh in 2037 (equivalent to 5.9percent of 2015 line losses).

The economic potential results show that more than half of the peak, electricity, and line loss impacts are cost-effective with a cost-benefit ratio greater than one. Approximately 55 percent of the technical peak demand impacts are determined to be economic (e.g., 184 MW out of 337 MW during 2018, and 194 MW out of 355 MW in 2035). Similarly, 53 percent of electricity consumption impacts and 64 percent of line loss impacts are determined to be economic.

5.3 CBA Methodology

This section provides an overview of the Grid+ computational model, the CBA framework, and the key inputs and assumptions used in the analysis.

5.3.1 Computational Model

Navigant's Grid+ is a grid modernization CBA tool developed using the *Analytica* software platform. Grid+ has been used to evaluate investment business cases for distribution and transmission utilities, project developers, and industry groups. In 2015, the Grid+ model was used to develop the CBA supporting the Ministry's *Smart Grid Assessment and Roadmap* (2014). Appendix D.1 provides a more detailed description of the Grid+ model.

Grid+ is based on the CBA framework developed by the Electric Power Research Institute (EPRI) in 2010, for which Navigant was a key contributor.[44] The EPRI framework later informed the CBA methodology developed by Navigant for the US DOE for the evaluation of its 99 Smart Grid Investment Grant projects as part of the American Recovery and Reinvestment Act grant funding (note: several VVO projects received funding through this grant).

To evaluate the costs and benefits of IFMC technologies in Ontario, Navigant customized the Grid+ model to reflect Ontario-specific grid characteristics of distribution networks in the province. This customization process is described in detailed over the next several sections.

[43] Thorough this section, reductions in peak demand and electricity consumption are compared to 2015 historicals. 2015 is used as the reference point because it is the last year of OEB published data related to distribution-level peak demand and electricity consumption.

[44] EPRI, US. Methodological approach for estimating the benefits and costs of smart grid demonstration projects. Palo Alto: US EPRI, 2010.

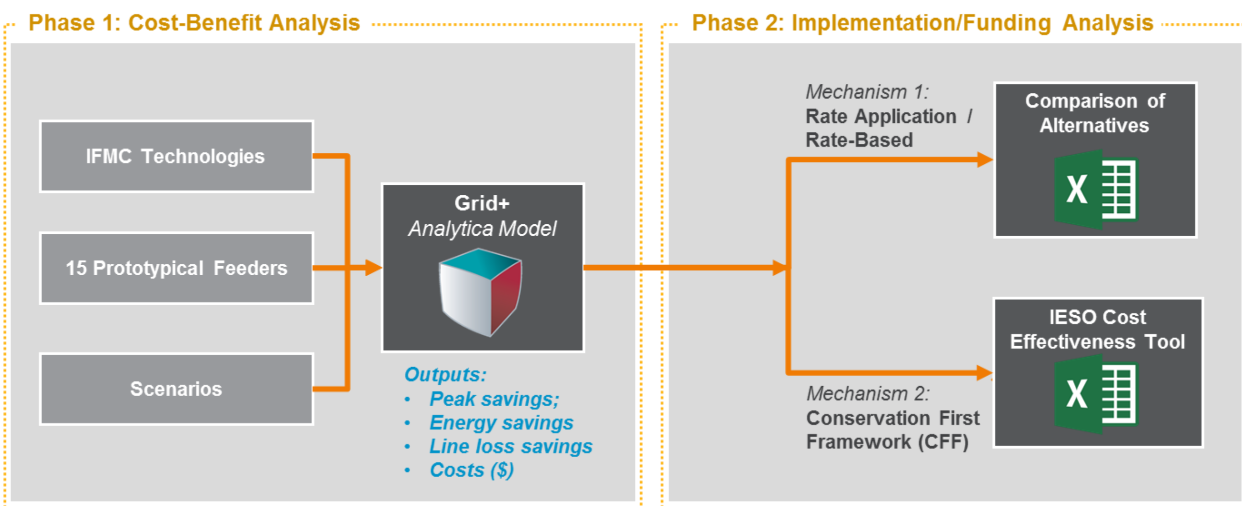
5.3.2 CBA Approach and Model Structure

The CBA approach was conducted in two phases, as illustrated by Figure 22, and described below:

- **Phase 1:** The IFMC CBA was developed using the Grid+ model.
- **Phase 2:** The IFMC technologies were evaluated based on two implementation mechanisms: funding through a CDM approach and funding through a distribution rate approach.

Figure 22 illustrates Phase 1 and Phase 2. Sections 5.5 through 5.6.4 present the findings of Phase 1, including cost and benefits, and peak, electricity and line loss savings. Section 6 focuses on Phase 2 and presents the results of the evaluation of IFMC through the distribution rates and CDM funding mechanisms.

Figure 22. CBA Process (Phase 1 and Phase 2)



Source: Navigant

The structure of the Phase 1 IFMC CBA is based on an analysis of 15 prototypical Ontario feeders, which are discussed in Section 5.4.1. The profiles and characteristics of these 15 prototypical feeders are representative of all distribution system feeders across Ontario. Results for these 15 prototypical feeders are extrapolated to the entire province to determine province-wide benefits and costs, and the corresponding peak demand, electricity, and line loss savings attributed to IFMC.

The overall structure of the CBA in relation to the prototypical feeders is summarized by these five steps:

- **Step 1:** Develop profile for 15 prototypical Ontario feeders
- **Step 2:** Estimate fraction of Ontario feeders represented by prototypical feeders
- **Step 3:** Perform CBA for each prototypical feeder
- **Step 4:** Demonstrate impacts for each prototypical feeder
- **Step 5:** Extrapolate results to entire province

This prototypical feeder approach described above was used for two of the three IFMC technologies; VVO and phase balancing. This approach was not used for electricity theft detection primarily because of

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a lack of available information that could be used to support a detailed analysis performed at the feeder level.[45] The analysis for theft detection was performed at the provincial level to determine system-wide costs and benefits of theft detection.

5.3.3 Key CBA Inputs

Navigant has conducted significant research and utilized a variety of public resources along with internal SME expertise to determine the inputs and assumptions for the CBA model. Additionally, a literature review was conducted and more information was collected from stakeholders being interviewed as part of the jurisdictional scan. This was to ensure that the most up-to-date information was feed as inputs into the IFMC CBA. Three main types of inputs feed into the CBA model:

- **Global inputs:** These inputs include all physical grid/network characteristics required by the model. It includes all the system-wide and feeder-level characteristics such as the number of feeders, annual electricity consumption per prototypical feeder and average peak demand per prototypical feeder. It enables the analysis to capture the most relevant distribution system characteristics required for scenario analyses. See Appendix D for a more detailed description of how the global inputs were determined and used by the CBA model.
- **Cost inputs:** These inputs include all the costs of implementing the IFMC technologies. Asset-specific costs (capital, maintenance, replacement, etc.) and program implementation costs are included as part of the CBA analysis. As the deployment of IFMC is leading-edge in Ontario, Ontario-specific data is limited. Navigant has leveraged cost inputs from its SMEs as well as data collected from previous client engagements (vetted by utilities) to feed into the model. See Appendix D for a description of the main sources used to determine the cost inputs.
- **Benefit inputs:** These inputs include impact parameters assumptions regarding peak, electricity, and line loss reductions established for each IFMC technology (i.e. voltage and peak reduction). See Appendix D for a description of the assumptions and literature review to determine benefit inputs.
- **Financial parameters and study period:** The analysis uses an inflation factor of 2% and a discount rate of 4%, consistent with the IESO's CDM guidelines; the study period is from 2017 to 2037.

5.4 Distribution Feeder Classifications

This section describes the approach used to develop the set of 15 prototypical Ontario feeders and their corresponding characteristics. These prototypical feeders are the cornerstone of the technology potential and CBA. The characteristics of these prototypical feeders are the underlying parameters and variables that drive all costs and benefits.

Section 5.4.1 below describes the various local grid conditions that characterize each prototypical feeder. Conditions such as voltage level, feeder loading and population density directly affect the percentage of Ontario feeders that each prototypical feeder represents. Conditions such as DER penetration, avoided

[45] It is difficult to suggest that electricity theft or illegal activity might be more prevalent on certain feeders than others as there is no evidence to suggest any sort of correlation between theft and prototypical feeders, voltage levels, population density, or feeder loading.

costs, and demand forecast will be applied to all prototypical feeders evenly (e.g., for DER penetration, each feeder will be modeled under a "High" and "Base" case penetration scenario).

5.4.1 Prototypical Ontario Feeders

The development of the 15 prototypical feeders is based on three fundamental local grid conditions: voltage level, feeder loading, and population density. While there are other important feeder conditions, such as feeder health, voltage level, feeder loading and population density are used to ensure that the 15 prototypical feeders capture most potential grid conditions in Ontario. Further, these feeder conditions are used to ensure that a single prototypical feeder does not represent more than 15% of all Ontario feeders.

- **Voltage level:** Four distribution-level voltage classes were used in the study: 4.16 kV, 12.47 kV, 27.6 kV, and 44.4 kV. There are other voltage classes in Ontario (e.g., 13.8 kV, 22 kV, etc.), however, the costs and benefits for these voltage classes do not to vary materially relative to the four main voltage classes. It is important to recognize that several Ontario utilities are currently undergoing infrastructure renewal projects to phasing out 4.16 kV feeders and replace them with 12.47 kV or 27.6 kV feeders. While this does not impact individual cost-benefit results for a given prototypical feeder, province-wide results will be affected by the changing mix of feeders.
- **Feeder loading**: Thermal rating is a measure of the maximum electrical load a feeder can carry (or supply) – in other words, thermal rating refers to a feeder's maximum capacity. Feeder loading describes the loading levels of a particular feeder relative to the feeder's thermal capacity. For example, 4.16 kV feeders have a thermal rating of approximately 3.0 MW. Feeders with peak demand higher than 80% of thermal rating are categorized as heavy, feeders between 40% to 80% are categorized as moderate, and feeders lower than 40% are categorized as light.
- **Population Density:** Population density describes the relative geographic location and population served by a feeder. For example, a feeder may be located and serve customers in an urban, suburban, or rural area. Whether a feeder serves a predominantly urban or rural area influences the mix of customers served (e.g., residential, commercial, and industrial customers). The customer mix may in turn impact the behavior of that feeder should a utility decided to make an investment in an IFMC technology like VVO. The peak and electricity reduction impact of VVO on a particular feeder are affected by a number of characteristics; one of which is the mix of customers and end-use equipment served by that feeder. This concept is explained in detail in Appendix D.

The following sources were used to determine the percentage of feeders by voltage class and population density (Table 11) and subsequently, the 15 prototypical feeders in Ontario (Table 12):

- **An LDC Survey** conducted as part of the O*ntario Smart Grid Assessment and Roadmap* study informed the estimate of total feeders in the province. Feeders in the survey represented 70% of all Ontario customers, and the results were extrapolated to estimate the total number of feeders in the province. 19 Ontario LDCs, representing 70% of Ontario customers, participated in the survey, including some of the largest LDCs as well as smaller, rural LDCs. See Appendix D.2 for the full list of LDCs.
- **Hydro One and Toronto Hydro** feeder data was used to disaggregate Ontario's approximate 10,000 feeders into distinct voltage classes; 4.16 kV, 12,47 kV, 27.6 kV and 44 kV. It is assumed that Hydro One and Toronto Hydro are representative of Ontario as they have the two largest distribution networks (in terms of number of feeders) and serve urban, suburban and rural territories. Navigant also reviewed publicly available documents from other LDCs including DSPs

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(Toronto Hydro, Hydro Ottawa, and formerly Horizon Utilities) to inform Navigant's estimate of the number of feeders by voltage class in Ontario. See Appendix D for specific feeder data from Toronto Hydro. Hydro One data is not included in this report because that data was provided to Navigant confidentially.

- **Statistics Canada** population data for Ontario was used to inform the number of feeders expected to be found in urban, suburban, and rural territories. Initially, it was assumed that there is a 1:1 relationship between number of feeders and population served (i.e., 1% of feeders in Ontario would serve 1% of Ontario's population). This relationship was modified based on an analysis of specific feeder data from Hydro One and Toronto Hydro.

Table 11 shows the approximate number of feeders by voltage class and population density in Ontario.

Table 11. Feeders by Voltage Class and Population Density

Feeder Voltage Class	Urban	Suburban	Rural	Percentage of Feeders by Voltage Class
4.16 kV[46]	16%	29%	5%	**50%**
12.47 kV	10%	15%	5%	**30%**
27.6 kV	5%	5%	5%	**15%**
44.4 kV	0%	0%	5%	**5%**
Percentage of Feeders by Population Region	**31%**	**49%**	**20%**	**100%**

Source: Navigant

Table 12 shows the list of prototypical feeders and the fraction of Ontario feeders that they represent. As noted previously, the development of these 15 prototypical feeders was done to ensure that no single feeder represents more than 15% of all Ontario feeders and that the most common and realistic feeder conditions are captured.

Table 11, public resources, and Navigant SME knowledge was used to develop the fraction of feeders assigned to each prototypical feeder.

To determine the relative loading of feeders in Ontario, Hydro One's publicly available list of station capacities was examined. Based on a review of Hydro One station capacities, the percentage of stations that are heavily loaded is estimated. This estimate is in turn used as a proxy to determine the number of heavily loaded feeders in the province (e.g., feeders with a peak demand higher than 80% of thermal capacity). This exercise was conducted for the 4.16 kV, 12.47 kV and 27.6 kV voltage classes. It was not needed for the 44 kV feeders as it is assumed that the vast majority of 44 kV feeders are lightly loaded.

Similarly, estimates of the percentage of moderately and lightly loaded feeders in Hydro One's service territory was used to inform the percentage of moderately and lightly loaded feeders in the province. Based on this analysis, approximately 5% of feeders are determined to be heavily loaded, 57% are moderately loaded, and 38% are lightly loaded.

[46] Several Ontario utilities are currently undergoing infrastructure renewal projects to phasing out 4.16 kV feeders and replace them with 12.47 kV or 27.6 kV feeders.

Appendix C provides qualitative descriptions of the 15 prototypical feeders including estimated peak demand, annual electricity consumption, and likely locations across the province.

Table 12. List of Ontario Prototypical Feeders

Prototypical Feeder	Classification	Fraction of all Ontario Feeders (%)	Number of Feeders
Feeder 1	4.16 kV - Heavy Urban	1%	102
Feeder 2	4.16 kV - Moderate Urban	15%	1,524
Feeder 3	4.16 kV - Heavy Suburban	1%	102
Feeder 4	4.16 kV - Moderate Suburban	15%	1,524
Feeder 5	4.16 kV - Light Suburban	13%	1,321
Feeder 6	4.16 kV - Light Rural	5%	508
Feeder 7	12.47 kV - Moderate Urban	10%	1,016
Feeder 8	12.47 kV - Heavy Suburban	3%	305
Feeder 9	12.47 kV - Moderate Suburban	7%	711
Feeder 10	12.47 kV - Light Suburban	5%	508
Feeder 11	12.47 kV - Light Rural	5%	508
Feeder 12	27.6 kV - Moderate Urban	5%	508
Feeder 13	27.6 kV - Moderate Suburban	5%	508
Feeder 14	27.6 kV - Light Rural	5%	508
Feeder 15	44.4 kV - Light Rural	5%	508
	Total	**100%**	**10,159**

Source: Navigant

5.4.2 Scenarios

As explained in the previous section, three feeder conditions—voltage levels, feeder loading, and population density—were used to develop the 15 prototypical feeders. To analyze cost-benefit results under different system-wide conditions, three additional conditions were considered: DER penetration, avoided costs, and demand forecast.

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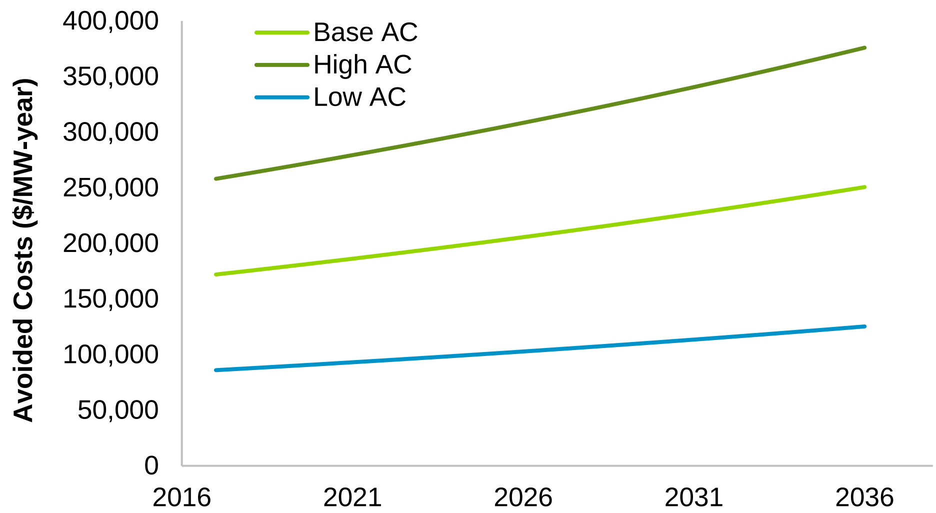
- **DER penetration** *(Base or High DER)****:*** DER penetration refers to the number of electricity customers on a particular feeder that adopt intermittent DER resources such as solar photovoltaic (PV) systems. As noted in previous sections, part of the value proposition for VVO adoption is the ability to enable DER integration as a result of improved control over voltage and reactive power (VAR) levels. This is true at relatively low or medium levels of DER penetration, however at higher penetration levels above 15%, DER penetration negatively affects the impacts of VVO. The high DER scenario represents a scenario where DER penetration reaches 25% of customers by 2037 (the final year of the study).[47] The base DER scenario assumes that DER penetration stays under 15% for the entire study period. The significance of DER penetration is the impact it has on the effectiveness of VVO to reduce peak demand and electricity consumption. At approximately 15% DER penetration, the reduction impact of VVO on peak demand and electricity consumption begins deteriorating and declines quickly as DER penetration passes 20%.
- **Avoided costs** *(High, Base, and Low)***:** Avoided costs refer to the costs of electricity generation ($/MWh), generation capacity ($/MW-year), transmission capacity ($/MW-year), and distribution capacity ($/MW-year) that may be avoided as a result of reductions in electricity demand, line losses, and peak demand. The base avoided costs scenario represent the avoided costs used in the IESO's CE tool.[48] The high avoided costs scenario represents a 50% increase relative to the base avoided costs scenario, and the low avoided costs scenario represents a 50% decrease. The significance of varying avoided costs is to reflect different scenarios where the costs of generation, transmission, and distribution capacity may be higher or lower than the average reflected in the IESO's CE tool.

Figure 23 shows the forecasts of the base, high, and low avoided costs scenarios.

[47] The High DER scenarios assumes an initial DER penetration of 1.0% in 2017 and growth of 1.0% per year from 2018 through 2024, 1.5% from 2025 to 2032, and 1.0% from 2033 to 2035.

[48] Avoided Cost assumptions were used from the IESO's CDM Energy Efficiency CE tool. Available here: http://www.ieso.ca/sector-participants/conservation-delivery-and-tools/ldc-toolkit

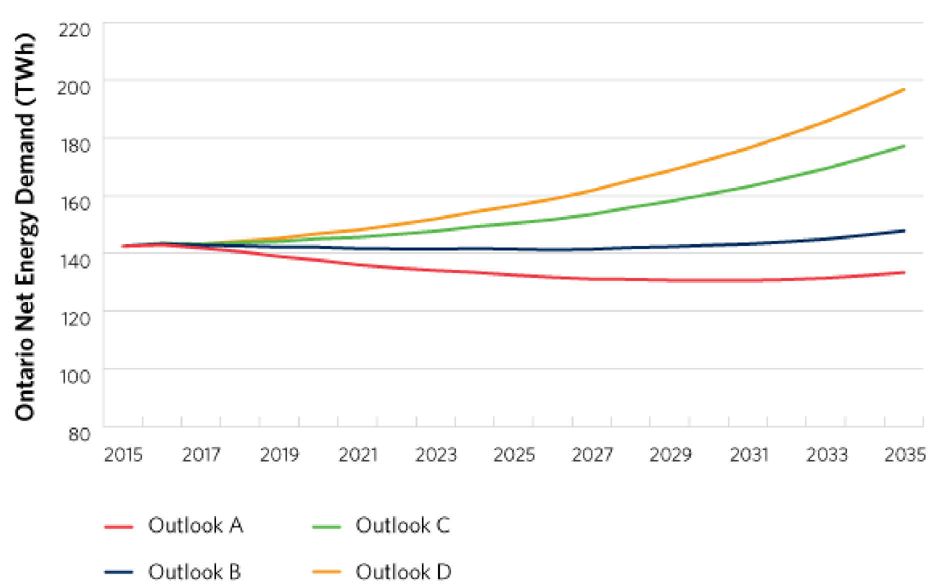
Figure 23. Avoided Cost Forecast (Base, High, and Low)



Source: Navigant analysis of IESO's CDM CE tool

Demand forecast *(OPO-B and OPO-D)***:** The IESO's Ontario Planning Outlook (OPO) provides a 10-year review (2005-2015) and a 20-year outlook (2016-2035) for Ontario's electricity system. In the OPO, the IESO considers a range of demand growth forecasts for Ontario's peak demand and electricity consumption which are represented by four different OPO outlooks. Two of the OPO outlooks were used in this analysis: Outlooks B and D. Figure 24 shows the four different outlooks, including Outlooks B and D.

Figure 24. OPO forecast of Ontario's Net Electricity Demand



Source: IESO OPO

Based on these three system-wide conditions, eight different scenarios were established. These eight system-wide scenarios reflect a combination of the DER penetration, avoided costs, and demand forecast conditions described above. Table 13 summarizes the underlying assumptions for each of the eight system-wide scenarios.

The cost-benefit results and impacts presented in Sections 5.5 and 5.6.4 are reflective of Scenario 1, while Section 5.6.4 shows the results for the remaining scenarios. Scenario 1 was selected as the "base" scenario (for which detailed results are presented) because it is based on the IESO's baseline avoided costs, a baseline level of DER penetration, and OPO outlook B – which forecasts Ontario electricity demand most aligned with recent historical demand levels.

Table 13. Scenario Descriptions

Scenario #	Avoided Costs	DER Penetration	OPO Outlook
1	**Base**	**Base**	**B**
2	Base	High	B
3	High	Base	B
4	Low	Base	B
5	High	High	B
6	Low	High	B
7	Base	Base	D
8	High	Base	D

Source: Navigant

5.5 CBA Results

This section summarizes the total costs and benefits of implementing IFMC based on Scenario 1. Cost and benefits results are presented by IFMC technology, and then broken down by prototypical feeder.

5.5.1 Cost-Benefit Results

The IFMC CBA covers four categories of benefits and five categories of costs. These benefit and cost categories are listed below and descriptions are provided in Table 14. The benefit categories were developed from the IESO CE tool and the cost categories were developed from Navigant's Grid+ model.

Each of these four benefit categories relate to a particular grid impact. For example, an IFMC technology that reduces peak demand will have associated benefits resulting from avoided generation capacity, avoided transmission capacity, and avoided distribution capacity. Similarly, an IFMC technology that reduces electricity consumption and/or line losses will have an associate benefit resulting from avoided energy generation.

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Table 14. Description of Benefit and Cost Categories

Cost-Benefit Categories	Description
Benefit Categories	
Avoided Gen. Capacity	Avoided cost (capital and O&M) of building additional generation capacity as a result of reduced peak demand
Avoided Energy Generation	Avoided cost (capital and O&M) of building additional transmission infrastructure as a result of reduced peak demand
Avoided Trans. Capacity	Avoided cost (capital and O&M) of building additional distribution infrastructure as a result of reduced peak demand
Avoided Dist. Capacity	Avoided energy generation costs result from reduced electricity consumption and/or line losses. They account for variable generation costs, including the cost of fuel and variable O&M for power plants
Cost Categories	
Asset Maintenance Costs	Asset maintenance costs represent annual O&M costs associated with the installed equipment
Asset Replacement Costs	Asset replacement costs reflect costs from equipment that need to be replaced once the useful life has been reached
Asset First Costs	Asset first costs represent initial, upfront equipment costs. These include installation and integration costs
System Startup Cost	System startup costs represent overhead costs –such as engineering, and planning– associated with rolling out an IFMC technology
System Operations Cost	System operations costs represent overhead costs –such as engineering, and planning– associated with rolling out an IFMC technology and the corresponding annual O&M

Source: Navigant

There are a few important considerations for the cost and benefit results. These considerations will affect the costs and benefits of deployment:

- **EM&V activity:** Early IFMC pilot projects are expected to require EM&V of IFMC impacts to validate expected impacts. For example, EM&V activity for VVO generally entails an on-off cycling approach requiring the system to be *turned off* for a certain period of time before being *turned on* again and so on. On-off cycling would ultimately result in a reduction of electricity consumption and line loss savings, and potentially a reduction in peak demand savings.

- **Peak and energy forecasts:** IFMC technology impacts on peak demand, electricity and line loss savings are, generally, directly proportional to projected levels of peak demand and electricity consumptions. For example, a feeder experiencing annual load growth of 2% per year will result in higher savings (and higher benefits) than a feeder experiencing 0.5% load growth. Consequently, for the analysis the peak and electricity forecasts should represent the most likely view of the future. To inform the baseline forecast of peak and electricity, 2016 OPO scenarios were chosen to represent projected load growth for the 15 prototypical feeders. Scenario B of the OPO is used as the underlying demand and electricity forecast used for Scenario 1 to ensure that estimates are conservative.

- **Accrual of benefits:** The analysis assumes technology deployment in 2017 which is the first year of the analysis period. As a result, technology capital costs are also incurred in 2017. Impacts, however, are assumed to materialize one year after the deployment of the technology, in 2018. This delay in the accrual of impacts, and the associated benefits, is more realistic than the assumption of first-year accrual of benefits and is consistent with the approach used by the IESO's CE tool.

- **Feeder- and system-level analysis:** As explained previously, the prototypical feeder approach was followed for VVO and phase balancing, while electricity theft detection was analyzed at the Ontario-wide level.

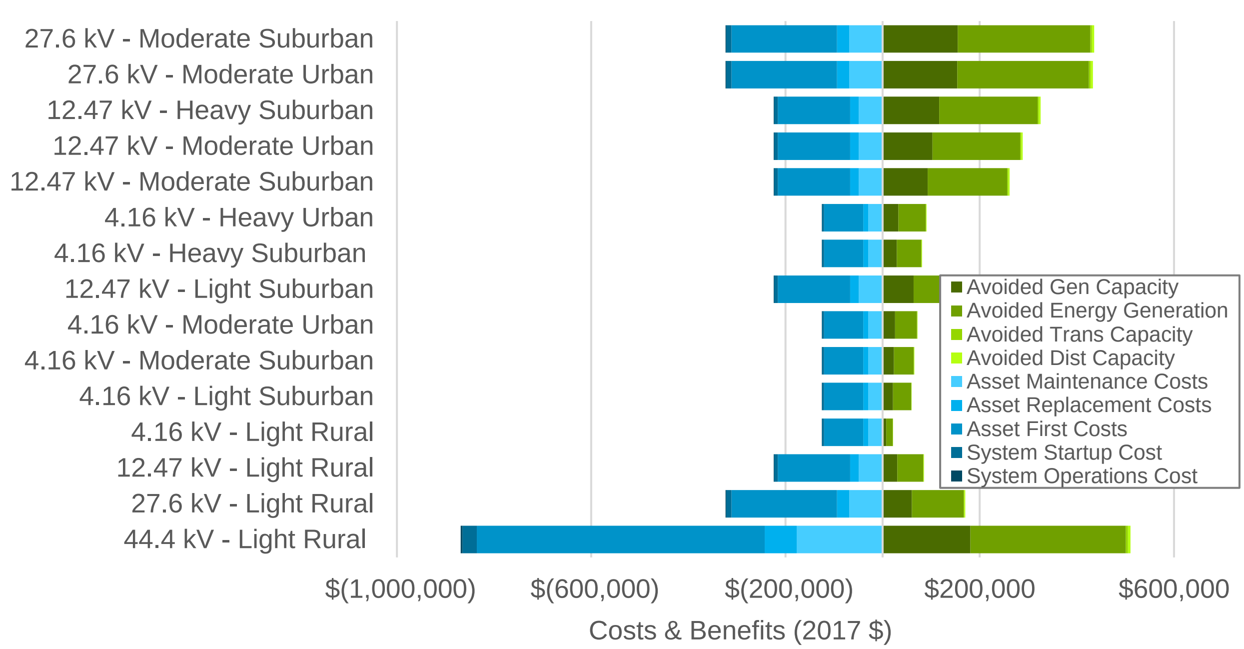
5.5.1.1 VVO

As described in Section 2.4.1, VVO provides integrated, real-time control of voltage and reactive power levels on a distribution feeder or group of feeders. The purpose of VVO is to optimize power delivery on a systemic (rather than individual), and forward-looking (i.e., predictive rather than reactive) basis. VVO implementations typically achieve the following benefits simultaneously:

- Improved LDC visibility of distribution circuit loadings, voltage, and power factor,
- Tighter voltage control,
- Power factor improvement, and
- End-user electricity and peak demand savings.

Figure 25 shows the costs and benefits of implementing VVO on all 15 prototypical feeders, shown in order of declining net present value (NPV). Figure 26 shows the corresponding net present value for all 15 prototypical feeders, also in order of declining NPV. The data used to generate these figures are in Table 39 and Table 40 of Appendix B.1.

Figure 25. Costs and Benefits by Feeder (2017$) – VVO



Source: Navigant

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The benefits and costs vary significantly by feeder based on the unique characteristics of each feeder. Feeder characteristics have a significant impact on the NPV of VVO by feeder type, with NPVs ranging from $110,000 for the 27.6 kV moderate suburban feeder down to $(360,000) for the 44 kV light rural. Only five of the 15 prototypical feeders have a positive NPV. These five feeders represent cost-effective deployments of VVO and account for approximately 3,000 feeders across Ontario, equivalent to 30% of all feeders.

As illustrated by Figure 25, avoided energy generation is the largest benefit category. Avoided energy benefits account for 63% of total benefits on average across all feeders. Avoided generation capacity benefits account for 35% of benefits, and avoided transmission and distribution capacity account for 1% of benefits each. Asset first costs and asset replacement costs account for a combined 74% of costs. Asset maintenance costs account for 22%, and system startup and operations costs account for the remaining 4%.

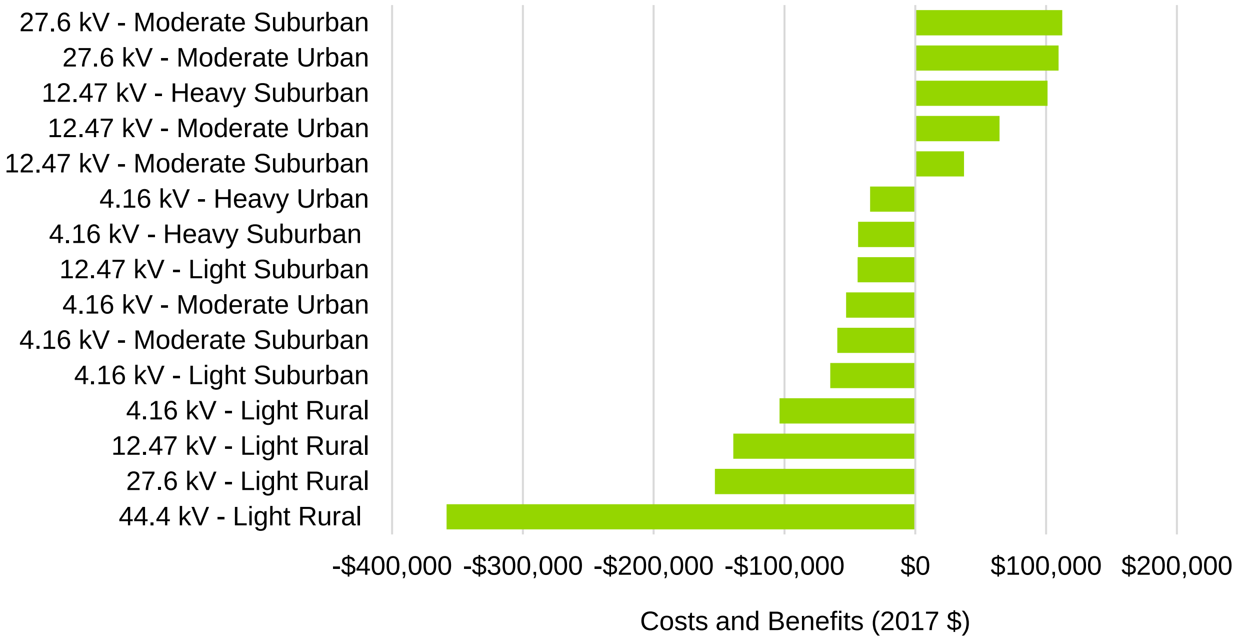
The costs of deploying VVO are not affected by population density (e.g., urban vs. rural) or feeder loading (e.g., heavy vs. light feeders). Costs only vary based on the voltage class of the feeders—for example, total costs for 4.16 kV feeders have the lowest cost, while 44 kV feeders have the highest costs.

Benefits, on the other hand, are dependent on several factors. Benefits are largely proportional to peak demand and electricity consumption by feeder, however benefits are also affected by feeder loading levels. For example, a feeder carrying a larger load compared to another feeder will most likely result in higher reductions in peak demand and electricity consumption. At the same time, lighter feeders may also result in a higher impact compared to heavier feeders. Since light feeders experience lower demand across the entire length of the line, they result in a relatively flatter voltage profile – along the main line – from the transformer to the EOL. As a result of the flatter voltage profile, light feeders have relatively more headroom to lower voltage at the transformer – and in turn, may result in higher impacts. In contrast, the voltage profile of heavy feeder declines rapidly as a result of higher demand. This results in less headroom for voltage reduction and in lower peak and electricity savings.

As seen in Figure 26, the top performing feeders with highest NPV tend to be moderately or highly loaded and are the 12.47 kV and 27.6 kV voltage levels. These feeders are the most cost-effective primarily because the peak, electricity, and line loss savings delivered is higher than any lightly loaded feeders. VVO deployment on these feeders delivers benefits ranging from $260,000 to $440,000, and costs ranging from $225,000 to $325,000.

The lowest performing feeders are the 4.16 kV, 44 kV, and lightly loaded feeders. These feeders have a negative NPV and are not cost-effective. Lightly loaded feeders deliver lower benefits as a result of the relatively small customer load carried by those feeders.

Figure 26. NPV by Feeder (2017$) – VVO



Source: Navigant

Table 15 below shows two variations of the Levelized Unit Electricity Cost (LUEC) for VVO on a feeder-level. The LUEC is a key metric used to evaluate and compare different generation or DSM resources on a level playing field. The LUEC compares the costs of resources on a *per-kilowatt* basis ($/kW) or a *per-kilowatt hour* basis ($/kWh). The components of each LUEC are:

LUEC ($/kWh):

- Benefits (kWh): Net present value of energy consumption reduction and line loss reduction benefits.
- Costs: Total project costs (including purchasing, installation, operations and maintenance).

LUEC ($/kW):

- Benefits (kW): Net present value of peak demand reductions.
- Costs: Total project costs (including purchasing, installation, operations and maintenance).

The five feeders with the lowest LUECs ($/kWh and $/kW) are highlighted green in Table 15 below. These are the only feeders that have an NPV greater than zero, and are thus the only cost-effective feeders. While these cost-effective feeders are not on par with CDM programs, they are still lower than most other costs of generation, including solar, wind, nuclear, and certain forms of hydro.[49]

[49] Ontario Planning Outlook. August 2016. *Module 4: Supply Outlook*. Available at: http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook

Table 15: LUEC by Feeder for VVO

Prototypical Feeder	LUEC ($/kWh)	LUEC ($/kW)
4.16kV - Heavy Urban	$0.105	$777
4.16 kV - Moderate Urban	$0.131	$984
4.16 kV - Heavy Suburban	$0.117	$866
4.16 kV - Moderate Suburban	$0.144	$1,087
4.16 kV - Light Suburban	$0.157	$1,188
4.16 kV - Light Rural	$0.443	$3,352
12.47 kV - Moderate Urban	$0.059	$441
12.47 kV - Heavy Suburban	$0.052	$388
12.47 kV - Moderate Suburban	$0.065	$487
12.47 kV - Light Suburban	$0.094	$710
12.47 kV - Light Rural	$0.198	$1,502
27.6 kV - Moderate Urban	$0.056	$424
27.6 kV - Moderate Suburban	$0.056	$422
27.6 kV - Light Rural	$0.143	$1,084
44.4 kV - Light Rural	$0.128	$970

Source: Navigant analysis

5.5.1.2 Electricity Theft

Figure 27 shows the costs, benefits, and NPV of implementing electricity theft detection across the province. The data used to generate these figure is Table 39 of Appendix B.1.

The analysis for theft detection is analyzed at the provincial level. Costs and benefits are estimated at approximately $130 million and $200 million, respectively, resulting in a negative NPV of ($65 million). Theft detection is not cost-effective primarily because of the relatively small—and secondary—*conservation* impact of detecting and mitigating electricity theft. This study estimates that electricity theft represents approximately 1.0% of electricity consumption, however, the conservation impact of theft detection is anticipated to much lower at only 0.1%. The analysis and methodology used to determine these impacts are described in Appendix D.4 and are summarized below.

In most cases, electricity theft in Ontario is driven by illegal marijuana growing operations. While detection of these operations results may result in a relatively significant reduction in energy consumption—particularly because of their energy-intensive nature—only a fraction of that reduction in load will actually result in a conservation impact. The reason for this is that demand for illegal substances is relatively inelastic so while a particular operation may be shut down, other operations will carry the lost production.

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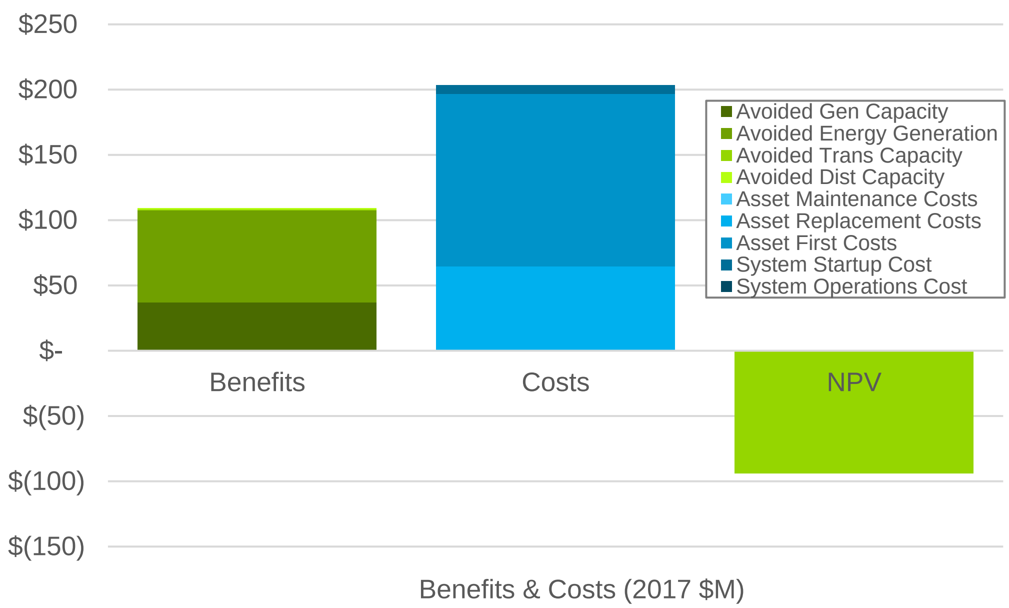
Ultimately, this results in a simple transfer of electricity theft from one operation to others.[50] As a result, the conservation impact is limited to the degree that efficiencies and economies of scale are achieved in these operations. This is likely to change over time as Canada develops its implementation plans for the legalization of marijuana.

This analysis is based on the assumption that utilities will target all feeders in the province for detection of electricity theft. At the provincial-level, the analysis shows that theft detection for purposes of conservation (e.g., peak, electricity, and line loss savings) is not cost-effective. However, these results may be different at an individual feeder level or if other benefits are included, such as increased volumetric sales.

As illustrated by Figure 27, avoided energy generation accounts for the majority of benefits; approximately 64% of the total benefits. Avoided generation capacity accounts for 34% of benefits, and avoided transmission and distribution capacity account for 1% each. Avoided energy generation is the largest benefit because the primary impact of theft detection is a reduction in energy consumption. Asset first costs and asset replacement costs account for 97% of total costs. System start-up costs account for the remaining 3% of costs. Since electricity theft detection does not require any annual ongoing costs, asset maintenance costs and system operations costs are zero.

Figure 27. System Costs, Benefits, and NPV (2017$M) – Electricity Theft Detection[51]



Source: Navigant

[50] Whether this transfer of electricity demand is to electricity-paying or non-paying customers is irrelevant. This is because the transferred load will show up in either a utility's line loss factor (if the customer is non-paying) or as part of regular consumption (if the customer is a paying-customer).

[51] Conservation impacts from theft detection are assumed to accrue for a duration of five years. This is an analysis assumption used to illustrate that all illegal activity will, in due time, be identified (e.g., absent electricity theft detection activity by utilities, policing will also identify those instances of illegal activity). By extension, this also assumes that new instances of theft will occur in the future, and that those new instances will, in-turn, be targeted for detection. In reality, electricity theft can be expected to subside and over time phase out completely. However, in the absence of substantive evidence to build those assumption, this analysis assumes a recurring cycle of costs and benefits every 5-year period.

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Table 16 shows two variations of the LUEC for electricity theft on a system level. The LUEC metrics are relatively high for electricity theft (compared to cost-effective VVO feeders), reaffirming that implementing this IFMC technology on a system-wide scale is not cost-effective.

Table 16: LUEC for Electricity Theft

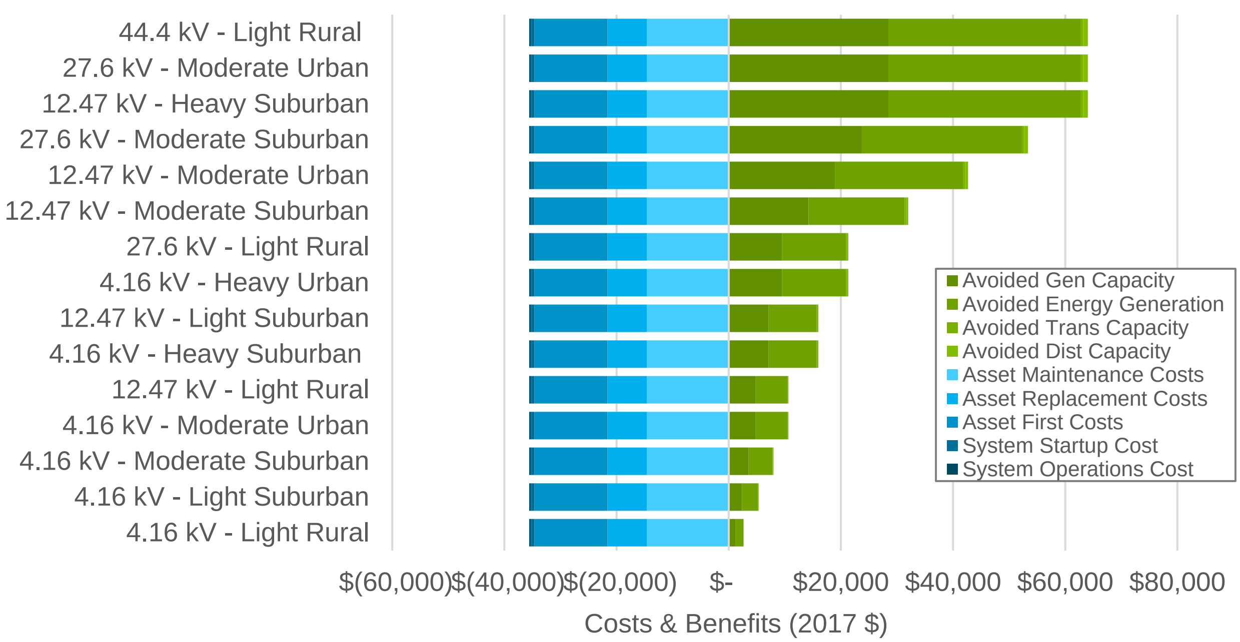
IFMC Technology	LUEC ($/kWh)	LUEC ($/kW)
Electricity Theft	$0.140	$1,093

Source: Navigant analysis

5.5.1.3 Phase Balancing

Figure 28 shows the costs and benefits of implementing phase balancing on all 15 prototypical feeders, shown in order of declining NPV. Figure 29 shows the corresponding net present value for all 15 prototypical feeders, also in order of declining NPV. The data used to generate this figure are in Table 39 and Table 40 of Appendix B.1.

Figure 28. Costs and Benefits by Feeder (2017$) – Phase Balancing



Source: Navigant

While the benefits vary significantly based on the characteristics of each prototypical feeder, the costs are the same across all feeders. Benefits vary drastically across feeders primarily in proportion to their load. The impact of phase balancing is a relatively small reduction in line losses as result of a more evenly distribution of load across phases. The impact of phase balancing is estimated as a 5% reduction in distribution line losses across all prototypical feeders. This impact will also vary based on the length of a feeder (e.g., the main line), the number of laterals –and length of those laterals–, and the degree of phase

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imbalance. [52] For example, higher voltage feeders such as the 27.6 kV and 44 kV feeders have much longer lines than most 12.47 kV or 4.16 kV feeders. Lower voltages could also be expected to be made up of a larger number of laterals.

The costs of implementing phase balancing are assumed to be constant across all feeders because deployment costs are not expected to be dependent on any of these feeder characteristics (e.g., line length, number of laterals, etc.). For example, any software analytics costs and equipment-related costs (such as meters and sensors) are largely independent of feeder voltage, population density, or feeder loading. Similarly, the costs of utility crew labor needed implement phase balancing (e.g., manually changing lateral X or customer Y from phase A to phase B) will also not vary drastically across feeders. This is because the number of phase transfers required to balance the phases of a feeder is generally limited. The analysis and methodology used to determine these impacts and costs are described in Appendix D.

As seen in Figure 29, five of the 15 prototypical feeders have a positive NPV. These five feeders represent cost-effective deployments of phase balancing and account for approximately 2,800 feeders across Ontario, equivalent to 28% of all feeders. The top performing feeders with highest NPV are the moderate and heavy 12.47 kV and 27.6 kV feeders, and the light 44 kV feeders. These feeders are the most cost-effective because the absolute magnitude of their line losses (in GWh instead of percentages) are the highest across all other feeders. Since these feeders have a larger amount of line losses, a 5% reduction in losses from phase balancing will result in a large amount of GWh of avoided losses, which in turn will result in higher benefits. These feeders range in NPV from $7,000 to $30,000.

The lowest performing feeders are the all of the 4.16 kV feeders and some of the lightly loaded 12.47 kV feeders. These feeders have a negative NPV and are not cost-effective largely because the line loss savings achieved through phase balancing are relatively small (in proportion to the feeder load) and do not justify the costs required.

As illustrated by Figure 28, avoided energy generation is the largest benefit category. Avoided energy benefits account for 53% of total benefits on average across all feeder. Avoided generation capacity benefits account for 44% of benefits, and avoided transmission and distribution capacity account for 1% of benefits each. Asset first costs and asset replacement costs account for a combined 56% of costs. Asset maintenance costs account for 41%, and system startup and operations costs account for the remaining 3%. Maintenance costs make up a significant fraction of all costs because of the magnitude of line crew manual work associated with implementing phase balancing.

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[52] A lateral refers to any section of a feeder that originates at the main line.

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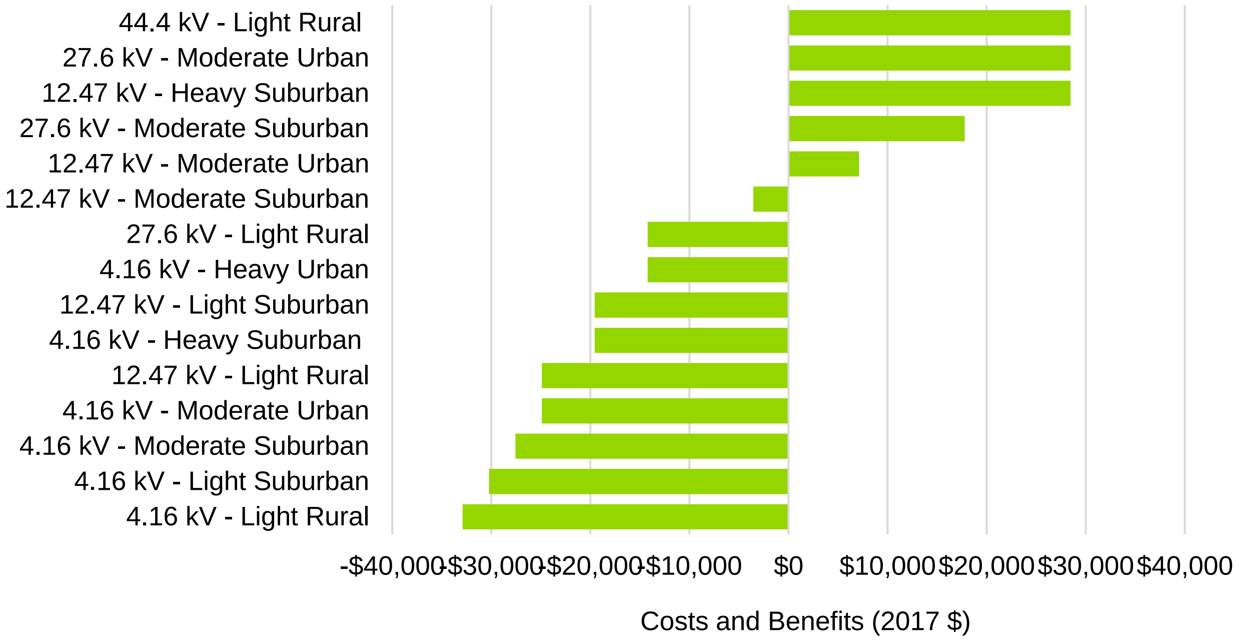
Figure 29. NPV by Feeder (2017$) – Phase Balancing



Source: Navigant

Table 17 below shows two variations of the LUEC for phase balancing on a feeder-level. The five feeders with the lowest LUECs ($/kWh and $/kW) are highlighted green. These are the only feeders that have an NPV greater than zero, and are thus the only cost-effective feeders. As highlighted for the cost-effective VVO feeders, phase balancing can also be a lower-cost alternative compared to some traditional and renewables generation sources.

Table 17: LUEC by Feeder for Phase Balancing

Prototypical Feeder	LUEC ($/kWh)	LUEC ($/kW)
4.16kV - Heavy Urban	$0.148	$756
4.16 kV - Moderate Urban	$0.295	$1,512
4.16 kV - Heavy Suburban	$0.197	$1,008
4.16 kV - Moderate Suburban	$0.394	$2,017
4.16 kV - Light Suburban	$0.590	$3,025
4.16 kV - Light Rural	$1.181	$6,050
12.47 kV - Moderate Urban	$0.074	$378
12.47 kV - Heavy Suburban	$0.049	$252
12.47 kV - Moderate Suburban	$0.098	$504
12.47 kV - Light Suburban	$0.197	$1,008
12.47 kV - Light Rural	$0.295	$1,512
27.6 kV - Moderate Urban	$0.049	$252
27.6 kV - Moderate Suburban	$0.059	$302
27.6 kV - Light Rural	$0.148	$756
44.4 kV - Light Rural	$0.049	$252

Source: Navigant

5.6 Technology Impacts

This section presents technical and economic potential results for the entire province based on Scenario 1. Scenario 1 assumes base avoided cost, base DER penetration and OPO Outlook B, which were further discussed in Section 5.4.2. Results are presented in peak demand reduction (MW/year), electricity consumption reduction (GWh/year) and line loss reduction (GWh/year), first by IFMC technology and then disaggregated by prototypical feeder cluster.

Figure 30 illustrates the difference between technical, economic, and achievable savings potential. Technical potential reflect peak, electricity, and line loss reductions across all of Ontario's approximately 10,000 feeders. Economic potential is a subset of technical potential and considers the total costs and benefits of IFMC deployment. Economic potential reflects the impact from feeders with a cost-benefit ratio greater than 1.0.

Achievable potential – which is not calculated as part of this analysis - considers market adoption barriers such as financial, regulatory, and cultural barriers and is intended to represent an expected level of IFMC adoption. Section 6 focuses on existing and potential IFMC cost-recovery mechanisms which may ultimately impact the level of achievable potential in Ontario.

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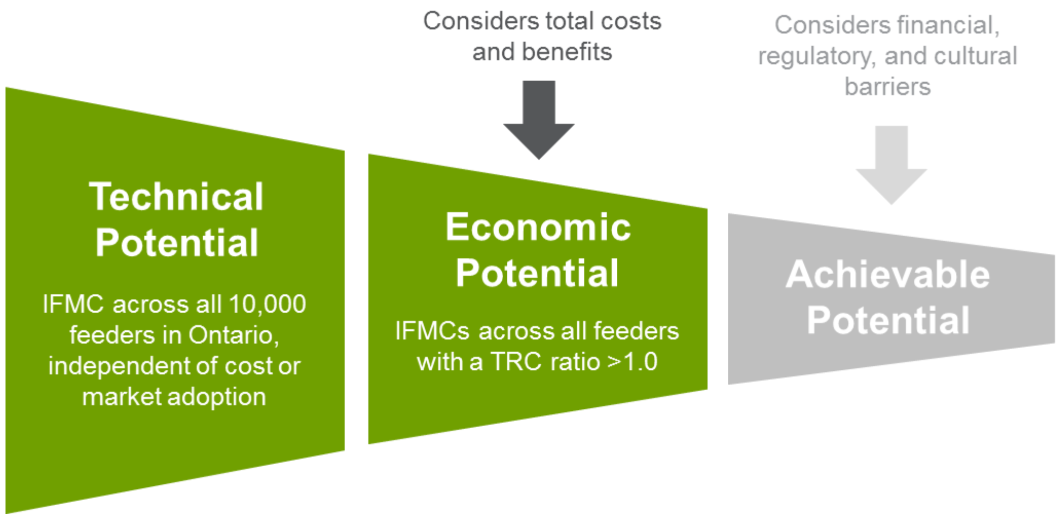
Figure 30. Technical, Economic & Achievable Potential



Source: Navigant

5.6.1 Technical Potential Results

Technical potential is defined as the total peak, electricity, and line loss reductions that could be achieved from a full deployment of IFMC technologies across all 10,000 Ontario feeders. This assumes that all IFMC technologies are installed regardless of cost, cost-effectiveness, or market acceptance.

Table 18 summarizes the technical peak, electricity, and line loss impacts across all IFMC technologies in 2018 and 2037. The peak demand reduction is 337 MW in 2018 increasing to 355 MW in 2037. The electricity consumption reduction is 2,148 GWh in 2018 increasing to 2,266 GWh in 2037, and the line loss reduction is 282 GWh in 2018 increasing to 298 GWh in 2037.

Table 18: Summary of Technical Potential Results

Reduction Impact	Technical Potential	
	2018	***2037***
Peak (MW)	337	355
Electricity (GWh)	2,148	2,266
Line Losses (GWh)	282	298

Source: Navigant analysis

The following sections present these technical potential impacts disaggregated by IFMC technology and prototypical feeder.

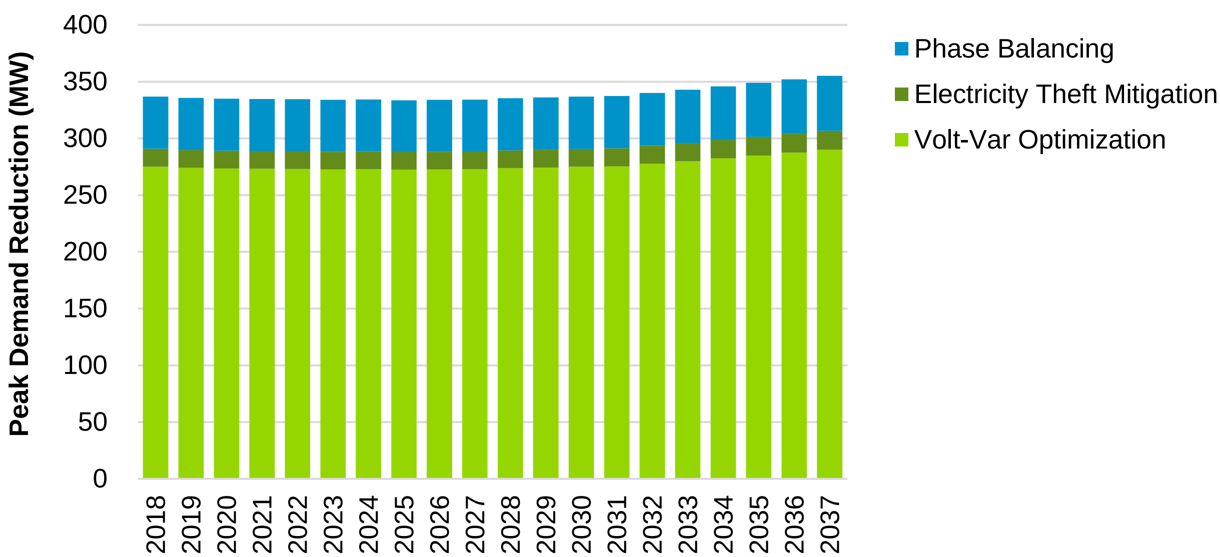
5.6.1.1 Results by IFMC Technology

Peak Demand Reduction Results

Figure 31 shows technical peak demand reduction by IFMC technology. The data used to generate this figure is in Table 41 of Appendix B.1. The technical potential peak demand reduction from all IFMC technologies, across all prototypical feeders, is 337 MW in 2018 increasing to 355 MW by 2037. This slight increase in peak demand is proportional to the load growth projected in the Scenario B of the OPO forecast.

Averaged from 2018 to 2037, this impact represents a peak demand reduction of approximately 1.6% relative to 2015 distribution system peak levels.[53] VVO contributes approximately 82% of the peak demand reduction on average over the study period. The peak demand reduction from VVO alone is 275 MW in 2018, increasing to 290 MW by 2037. Theft detection and phase balancing contribute 5% and 14%, respectively.

Figure 31. Technical Peak Demand Reduction by IFMC Technology (MW/year)



Source: Navigant

Electricity Consumption Reduction Results

Figure 32 shows technical electricity consumption reduction by IFMC technology. The data used to generate this figure is in Table 42 of Appendix B.1. The technical electricity consumption reduction from all IFMC technologies across all prototypical feeders is approximately 2,150 GWh in 2018, increasing to 2,270 GWh by 2037. Averaged from 2018 to 2037, this represents an electricity consumption reduction of approximately 1.8% relative to 2015 distribution system consumption levels.[54] VVO contributes approximately 94% of the electricity consumption reduction on average over the study period. The electricity consumption reduction from VVO alone is 2,020 GWh in 2018, increasing to 2,130 GWh by 2037. Theft detection contributes the remaining 6%. Phase balancing does not result in a reduction in electricity consumption, rather a reduction in line losses.

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[53] The distribution system peak demand in Ontario is estimated at 20,500 MW (for 2015), which represents approximately 90% of the provincial system peak. The other 10% of the system peak is attributed to the transmission system (e.g., transmission-connected load). 2015 is used as the reference point because it is the last year of OEB published data related to distribution-level peak demand and electricity consumption.

[54] The distribution electricity consumption in Ontario is approximately at 125,000 GWh, or 125 TWh (for 2015).

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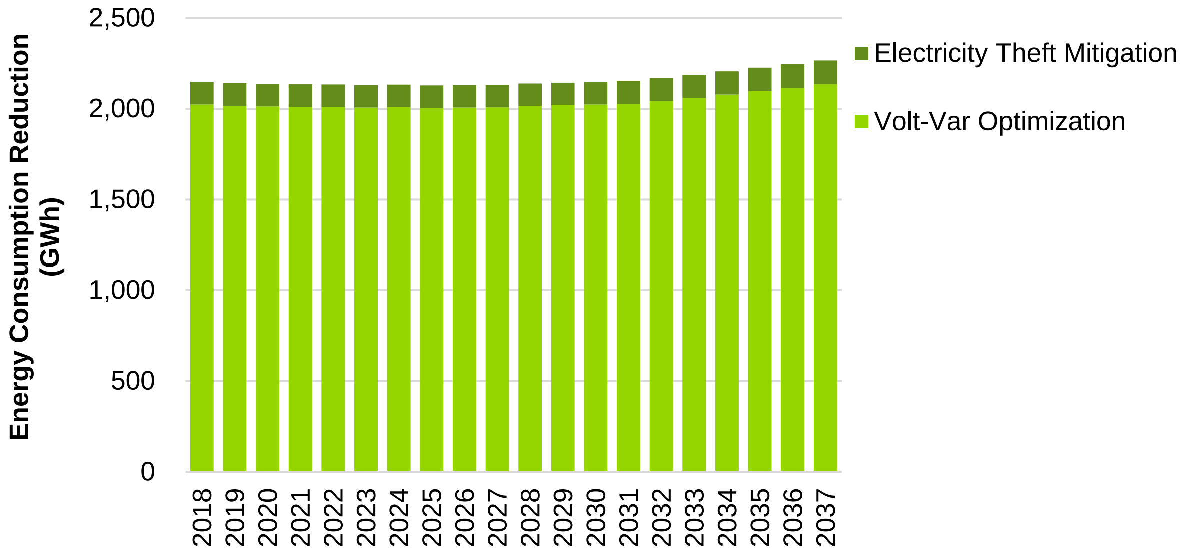
Figure 32. Technical Electricity Consumption Reduction by IFMC Technology (GWh/year)



Source: Navigant

Line Loss Reduction Results

Figure 33 shows technical line loss reduction by IFMC technology. The data used to generate this figure is in Table 43 of Appendix B.1. The technical line loss reduction from all IFMC technologies, across all prototypical feeders, is approximately 280 GWh in 2018, increasing to 300 GWh by 2037. Averaged from 2018 to 2037, this represents a line loss reduction of approximately 5.9% across the distribution system. Unlike with peak and electricity reductions, VVO only contributes a small amount of the total avoided line losses. VVO contributes 15% of the line loss reduction, while phase balancing contributes 84%. Theft detection contributes only 1.0%. The line loss reduction from phase balancing alone is 240 GWh in 2018 increasing to 250 GWh by 2037.

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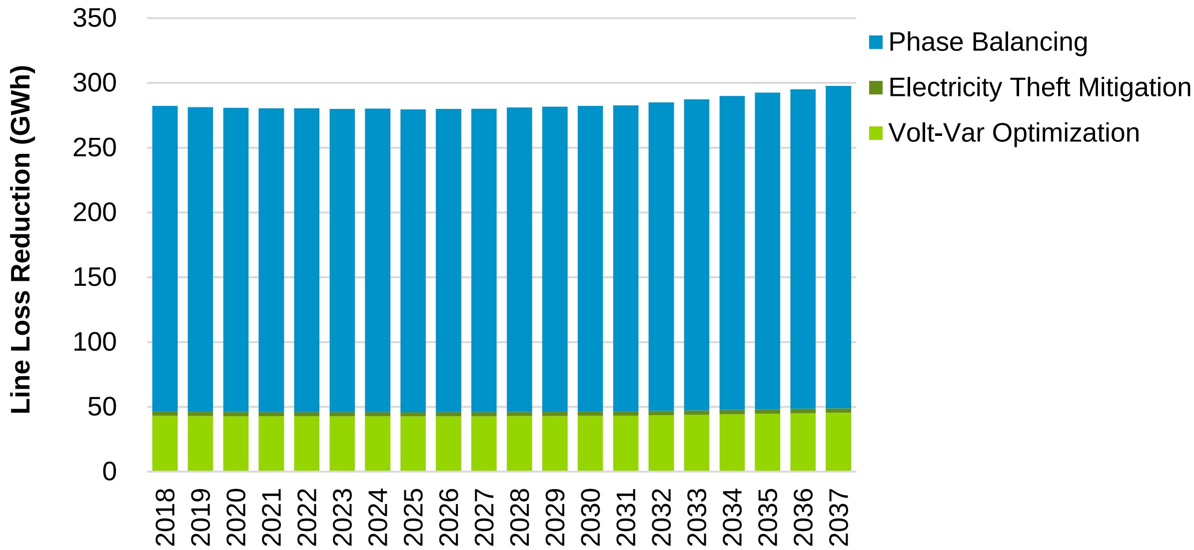
Figure 33. Technical Line Loss Reduction by IFMC Technology (GWh/year)



Source: Navigant

5.6.1.2 Results by IFMC Technology and Feeder Cluster

This section presents peak, electricity, and line loss impacts by IFMC technology and disaggregated by prototypical feeder cluster. A *feeder cluster* is defined as the total number of feeders in Ontario represented by a given prototypical feeder. For example, prototypical feeder #1 (4.16 kV - Heavy Urban) represents 102 feeders or 1% of the total number of feeders in Ontario. The peak demand impact from the prototypical feeder #1 cluster reflects the combined impact across all 102 feeders.

Note that electricity theft detection was not analyzed at the feeder level rather at the system level. Electricity theft detection impacts are presented in the previous section and are not included in this section.

Feeder Cluster Results for Volt/VAR Optimization

Figure 34 shows technical peak demand reduction for VVO by prototypical feeder cluster. The data used to generate this figure is in Table 44 of Appendix B.1. For this study all the costs are assumed to be accrued in 2017, and benefits are assumed to begin accruing in 2018 until 2037.

Peak Demand Reduction Results

The technical peak demand reduction for VVO across all feeders is 275 MW in 2018, increasing to 290 MW by 2037. Averaged from 2018 to 2037, this represents a peak demand reduction of approximately 1.3% relative to 2015 distribution system peak levels. The 12.47 kV and 27.6 kV feeder contribute the most to the overall impact, at 39% and 29% of the total peak demand reduction, respectively. Coincidentally, the 12.47 kV and 27.6 kV feeders are the most cost-effective feeders for VVO deployment. The 4.16 kV feeders contribute 17%, and the 44 kV feeders contribute 14%.

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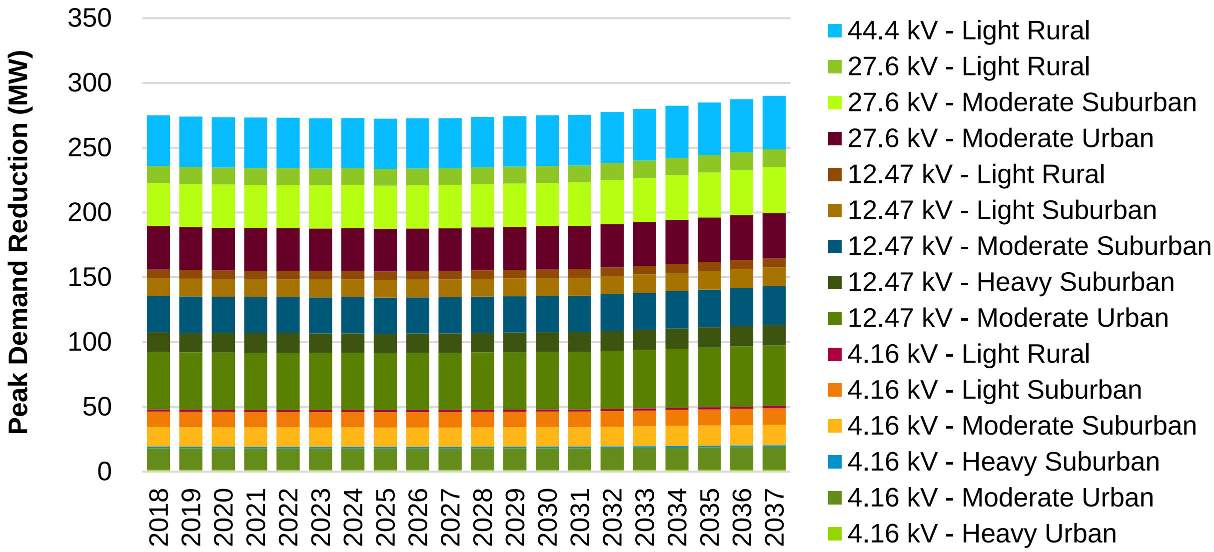
Figure 34. Technical Peak Demand Reduction by Feeder Cluster (MW/year) – VVO

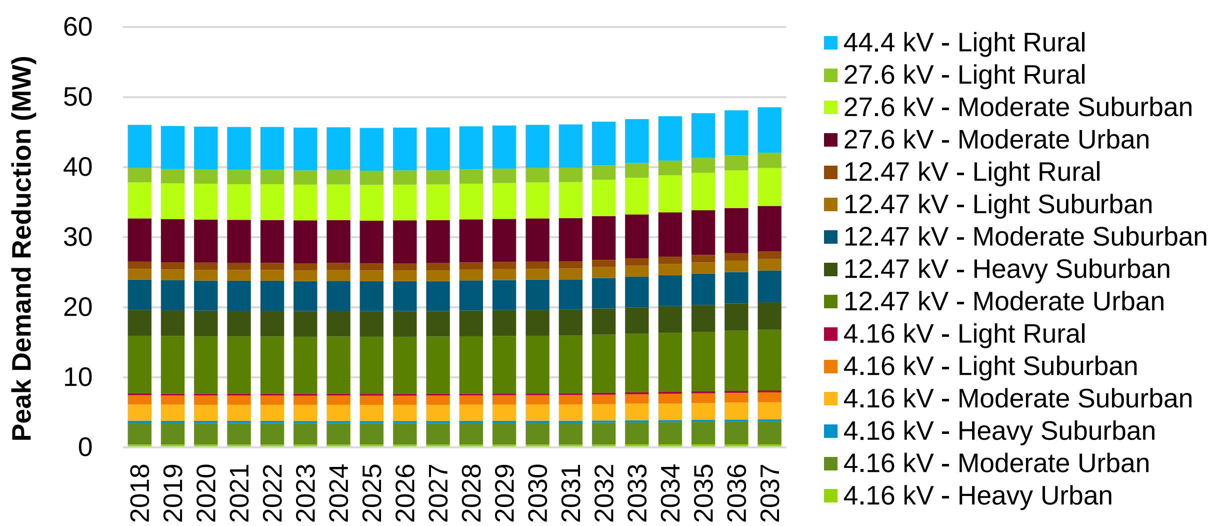


Source: Navigant

Electricity Consumption Reduction Results

Figure 35 shows technical electricity consumption reduction by prototypical feeder cluster. The data used to generate this figure is in Table 45 of Appendix B.1. The technical electricity consumption reduction for VVO across all feeders is 2,020 GWh in 2018, increasing to 2,130 GWh by 2037. Averaged from 2018 to 2037, this represents an electricity consumption reduction of approximately 1.6% relative to 2015 distribution electricity consumption. The breakdown of electricity consumption reduction across feeders is proportional to the peak demand impact having the 12.47 kV and 27.6 kV feeders contribute the most to the overall electricity consumption reduction.

Figure 35. Technical Electricity Consumption Reduction by Feeder Cluster (GWh/year) – VVO



Source: Navigant

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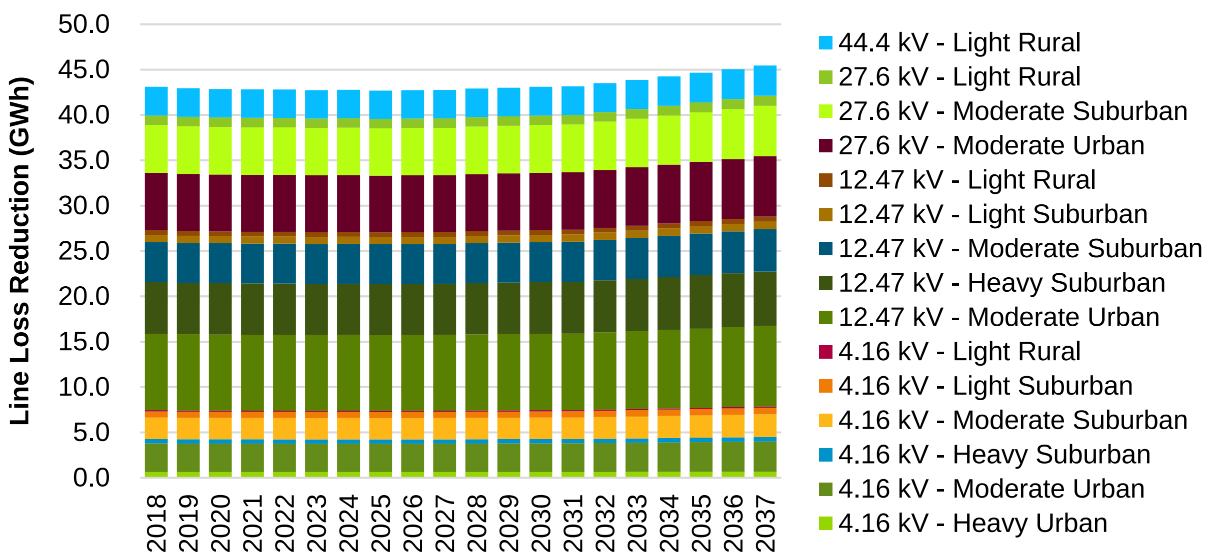
Line Loss Reduction Results

Figure 36 shows technical line loss reduction by prototypical feeder cluster. The data used to generate this figure is in Table 46 of Appendix B.1. The technical line loss reduction for VVO across all feeders is 43 GWh in 2018, increasing to 45 GWh by 2037. Averaged from 2018 to 2037, this represents a line loss reduction of approximately 0.9% across the distribution system. The breakdown of line loss reduction across feeders is proportional to the peak demand impact.

Figure 36. Technical Line Loss Reduction by Feeder Cluster (GWh/year) – VVO



Source: Navigant

Feeder Cluster Results for Phase Balancing

Peak Demand Reduction Results

Figure 37 shows technical peak demand reduction for phase balancing by prototypical feeder cluster. The data used to generate this figure is in Table 44 of Appendix B.1.

The technical peak demand reduction for phase balancing across all feeders is 46 MW in 2018, increasing to 49 MW by 2037. Averaged from 2018 to 2037, this represents a peak demand reduction of approximately 0.2% relative to 2015 distribution system peak levels. The 12.47 kV and 27.6 kV feeder contribute the most to the overall impact, at 41% and 29% of the total peak demand reduction, respectively. The 4.16 kV feeders contribute 17%, and the 44 kV feeders contribute 13%. The most cost-effective feeders are the moderate and heavy 12.47 kV and 27.6 kV feeders, and the 44 kV feeders.

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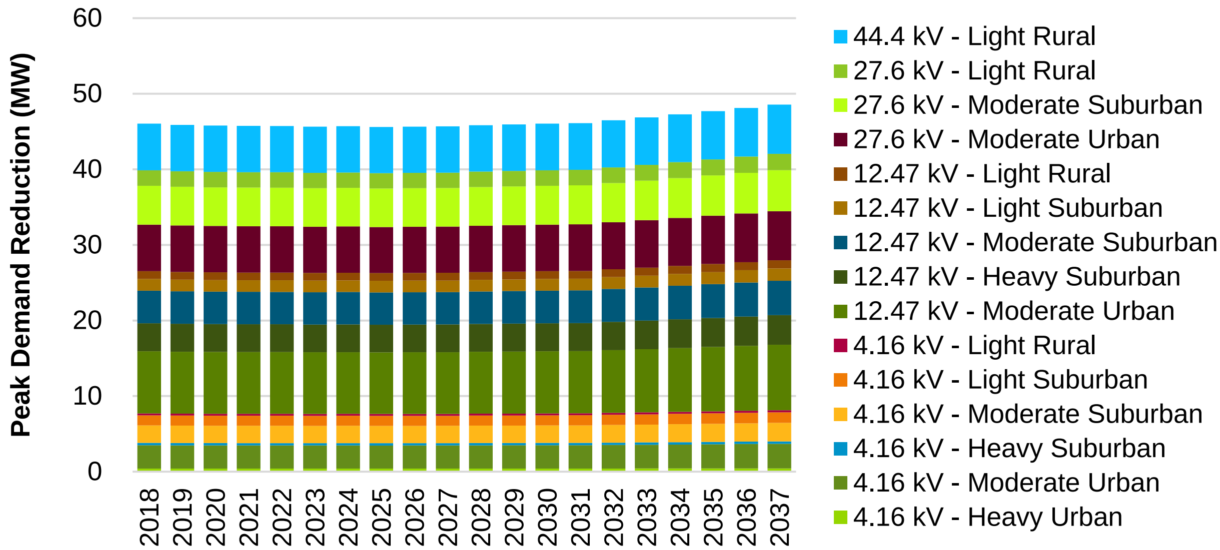
Figure 37. Technical Peak Demand Reduction by Feeder Cluster (MW/year) – Phase Balancing



Source: Navigant

Electricity Consumption Reduction Results

The electricity consumption reduction figure has been omitted from the phase balancing feeder results because phase balancing does not result in reduction in customer electricity consumption, only a reduction in line losses.

Line Loss Reduction Results

Figure 38 shows technical line loss reduction by prototypical feeder cluster. The data used to generate this figure is in Table 46 of Appendix B.1. The technical line loss reduction for phase balancing across all feeders is 240 GWh in 2018, increasing to 250 GWh by 2037. Averaged from 2018 to 2037, this represents a line loss reduction of 5.0% across the distribution system. The breakdown of line loss reduction across feeders is proportional to the peak demand impact.

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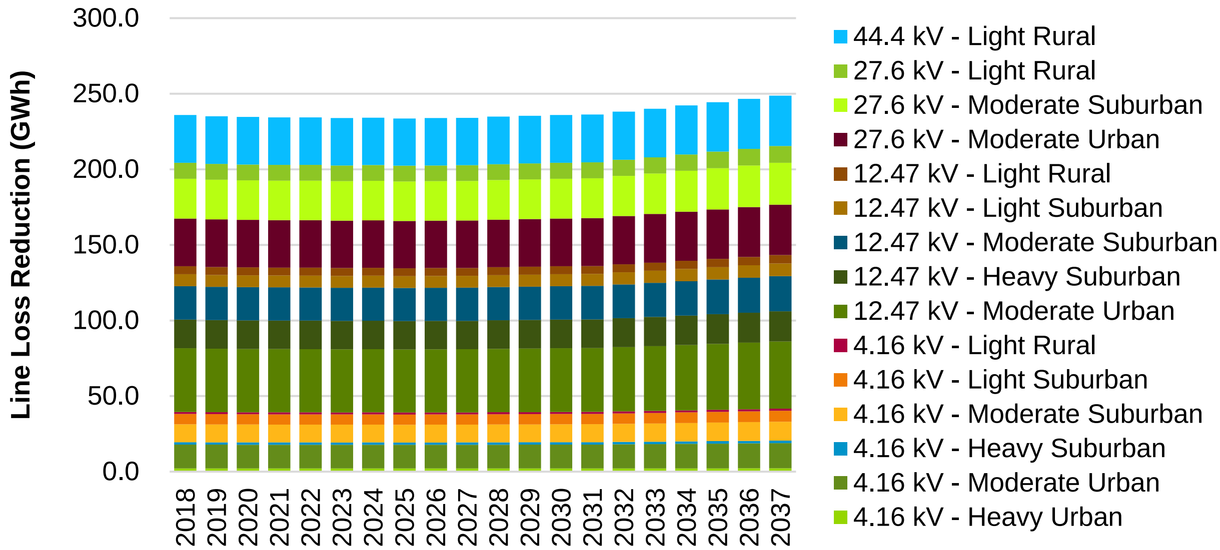
Figure 38. Technical Line Loss Reduction by Feeder Cluster (GWh/year) – Phase Balancing



Source: Navigant

5.6.2 Economic Potential Results

Economic potential is a subset of technical potential, using the same assumptions for IFMC deployment and impacts as in technical potential, but including only those prototypical feeder clusters that have a cost-benefit ratio of greater than or equal to 1.0.

As highlighted in previous sections, approximately 30% of all feeders are cost-effective for VVO deployment, while 28% are cost-effective for phase balancing. Electricity theft is not cost-effective at the system level so the economic results do not reflect any peak, electricity, or line loss impacts from theft detection.

Table 19 summarizes the economic peak, electricity, and line loss impacts across all IFMC technologies in 2018 and 2037. The peak demand reduction is 184 MW in 2018 increasing to 194 MW in 2037. The electricity consumption reduction is 1,128 GWh in 2018 increasing to 1,190 GWh in 2037, and the line loss reduction is 181 GWh in 2018 increasing to 191 GWh in 2037.

Table 19: Summary of Economic Potential Results

Reduction Impact	Economic Potential		*Econ. as % of Tech.*
	2018	***2037***	
Peak (MW)	184	194	*55%*
Electricity (GWh)	1,128	1,190	*53%*
Line Losses (GWh)	181	191	*64%*

Source: Navigant analysis

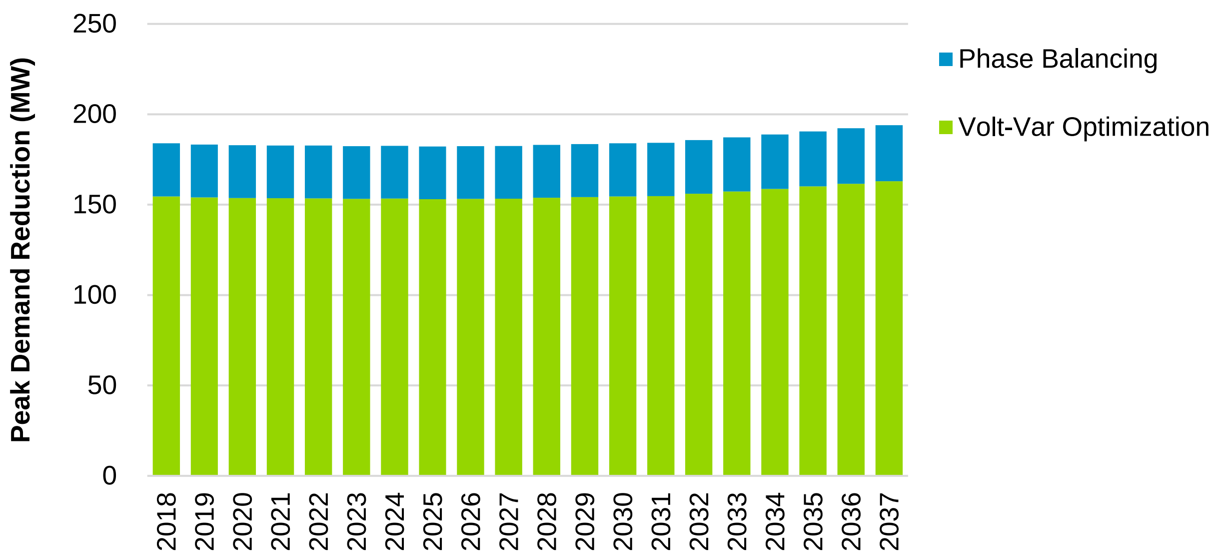
The following sections present these economic potential impacts disaggregated by IFMC technology and prototypical feeder.

5.6.2.1 Results by IFMC Technology

Peak Demand Reduction Results
Figure 39 shows economic peak demand reduction by IFMC technology. The data used to generate this figure is in Table 47 of Appendix B.1. The economic potential peak demand reduction from all IFMC technologies is 185 MW in 2018, increasing to 195 MW by 2037. While only 30% and 28% of feeders are cost-effective for VVO and phase balancing, 55% of the technical peak demand reduction is determined to be economic.[55]

Averaged from 2018 to 2037, this economic peak demand reduction represents a peak demand reduction of approximately 0.9% relative to 2015 distribution system peak levels.[56] VVO contributes approximately 84% of the peak demand reduction over the study period, while phase balancing contributes 16%. Electricity theft is not cost-effective at the system level so it does not contribute to peak demand reductions.

Figure 39. Economic Peak Demand Reduction by IFMC Technology (MW/year)



Source: Navigant

Electricity Consumption Reduction Results
Figure 40 shows economic electricity consumption reduction by IFMC technology. The data used to generate this figure is in Table 48 of Appendix B.1. The economic electricity consumption reduction from all IFMC technologies is approximately 1,130 GWh in 2018, increasing to 1,190 GWh by 2037. On average across the study period, 53% of the technical electricity consumption reduction is determined to be economic. Averaged from 2018 to 2037, this represents an electricity consumption reduction of

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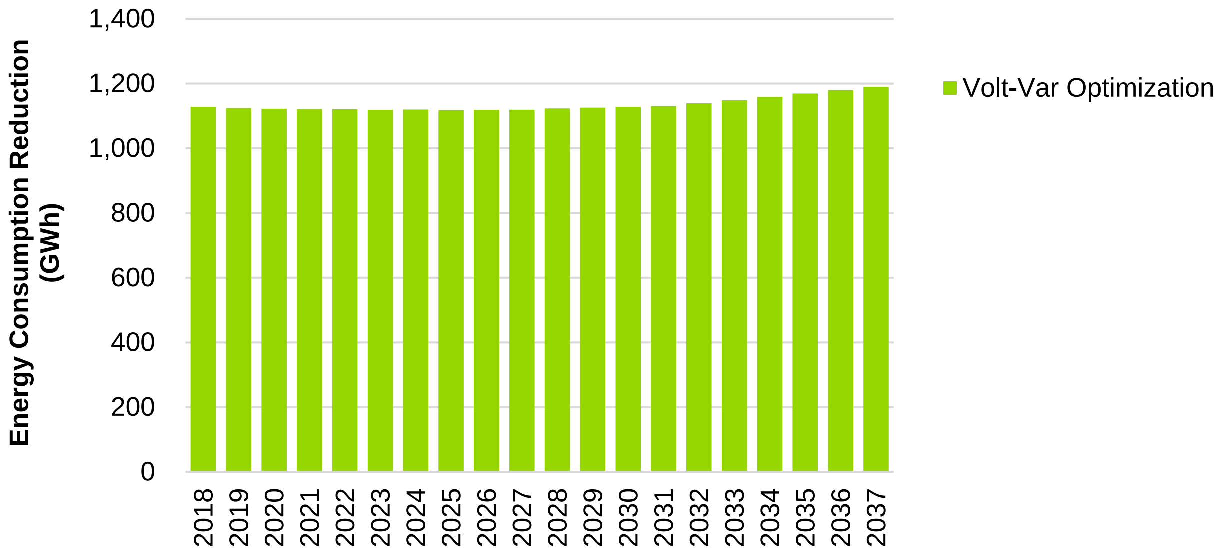
[55] For example, the 2018 technical peak demand reduction was estimated at 340 MW, however only 55% (or 185 MW) is determined to be economic

[56] The 2015 distribution system peak demand in Ontario is estimated at 20,500 MW, which represents approximately 90% of the provincial system peak. The other 10% of the system peak is attributed to the transmission system (e.g., transmission-connected load).

approximately 0.9% relative to 2015 distribution system consumption levels.[57] VVO contributes 100% of the electricity consumption reduction. Phase balancing does not result in a reduction in electricity consumption, rather a reduction in line losses, and theft detection is not economic.

Figure 40. Economic Electricity Consumption Reduction by IFMC Technology (GWh/year)



Source: Navigant

Line Loss Reduction Results

Figure 41 shows economic line loss reduction by IFMC technology. The data used to generate this figure is in Table 49 of Appendix B.1. The economic line loss reduction from all IFMC technologies is approximately 180 GWh in 2018, increasing to 190 GWh by 2037. On average over the study period, 64% of the technical line loss reduction is determined to be economic. Averaged from 2018 to 2037, this represents a line loss reduction of approximately 3.8% across the distribution system. VVO contributes 17% of the line loss reduction, while phase balancing contributes 83%.

[57] The 2015 distribution electricity consumption in Ontario is approximately at 125,000 GWh, or 125 TWh.

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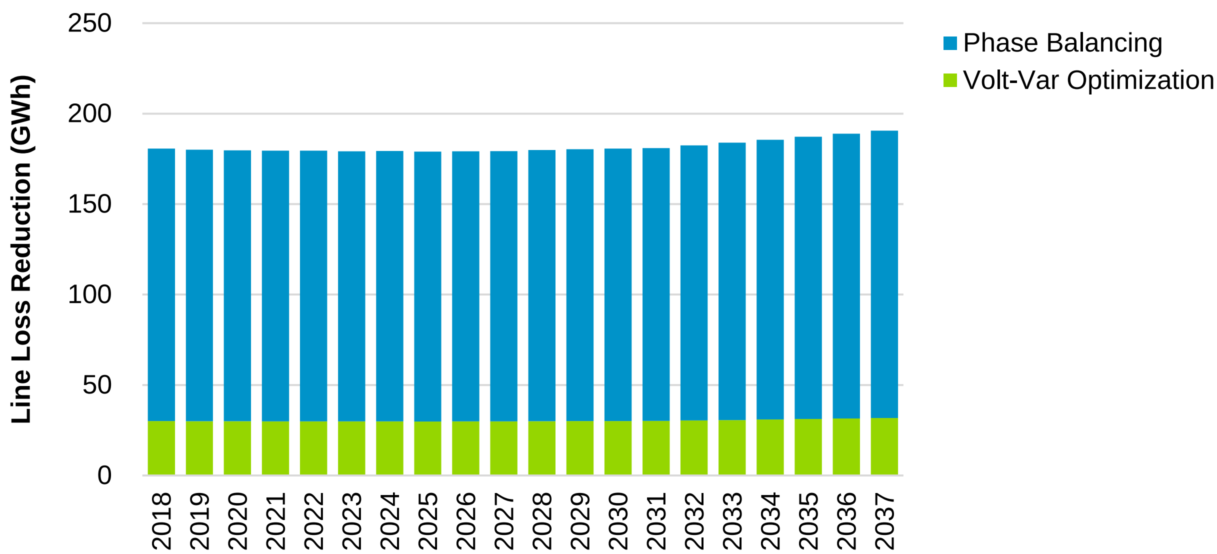
Figure 41. Economic Line Loss Reduction by IFMC Technology (GWh/year)



Source: Navigant

5.6.2.2 Results by IFMC Technology and Feeder Cluster

This section presents peak, electricity, and line loss impacts by IFMC technology and disaggregated by prototypical feeder cluster.

Feeder Cluster Results for Volt/VAR Optimization

Peak Demand Reduction Results

Figure 42 shows economic peak demand reduction for VVO for the five prototypical feeder clusters that were economical. The data used to generate this figure is in Table 50 of Appendix B.1.

The economic peak demand reduction for VVO across all cost-effective feeders is 155 MW in 2018 increasing to 163 MW by 2037. Averaged from 2018 to 2037, this represents a peak demand reduction of approximately 0.8% relative to 2015 distribution system peak levels. Only five of the 15 prototypical feeders are economic. Of them, the 12.47 kV feeders contribute 53% of the peak impact while the 27.6 kV feeders contribute 47%. Of the 12.47 kV feeders, the moderate urban feeders are the most impactful feeders contributing 29% of the overall peak reduction.

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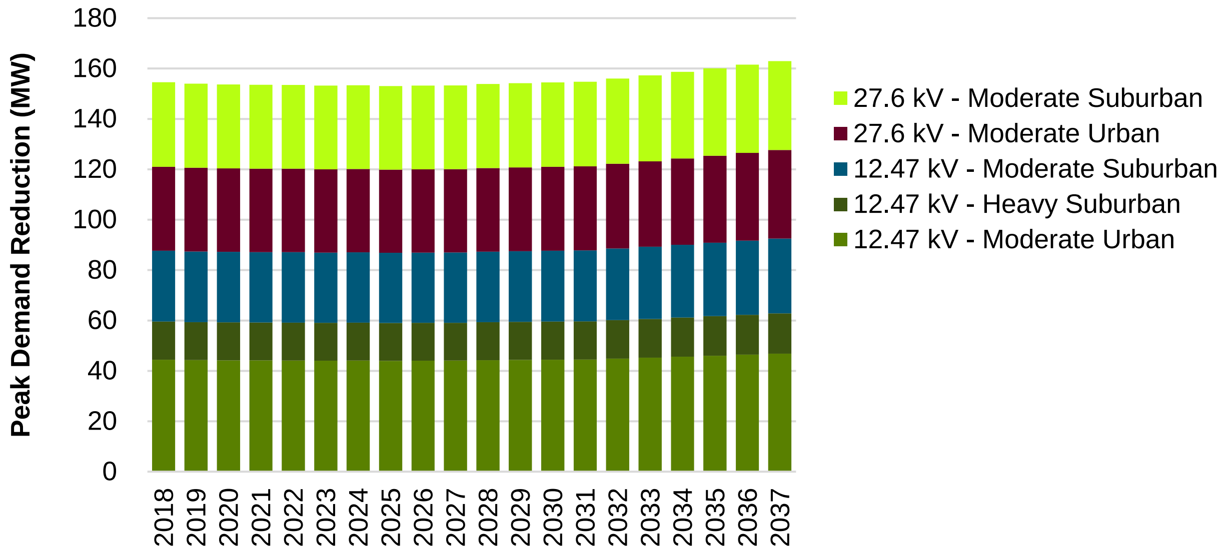
Figure 42. Economic Peak Demand Reduction by Feeder Cluster (MW/year) – VVO

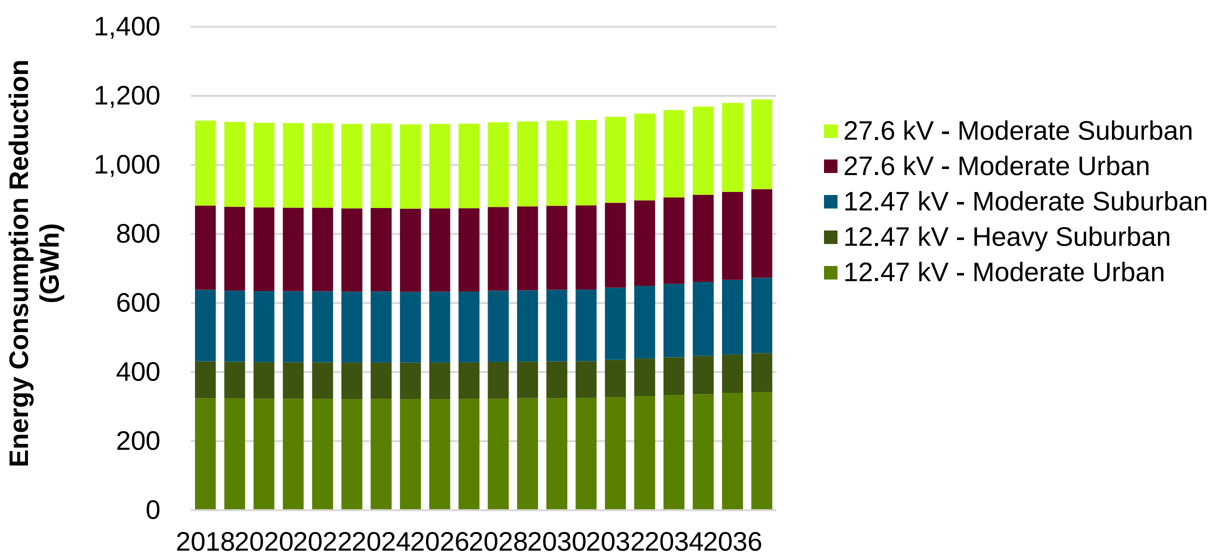


Source: Navigant

Electricity Consumption Reduction Results

Figure 43 shows economic electricity consumption reduction for the five prototypical feeder clusters that were economical. The data used to generate this figure is in Table 51 of Appendix B.1. The economic electricity consumption reduction for VVO across all feeders is 1,130 GWh in 2018, increasing to 1,190 GWh by 2037. Averaged from 2018 to 2037, this represents an electricity consumption reduction of approximately 0.9% relative to 2015 distribution system consumption levels. The breakdown of electricity consumption reduction across feeders is proportional to the peak demand impact.

Figure 43. Economic Electricity Consumption Reduction by Feeder Cluster (GWh/year) – VVO

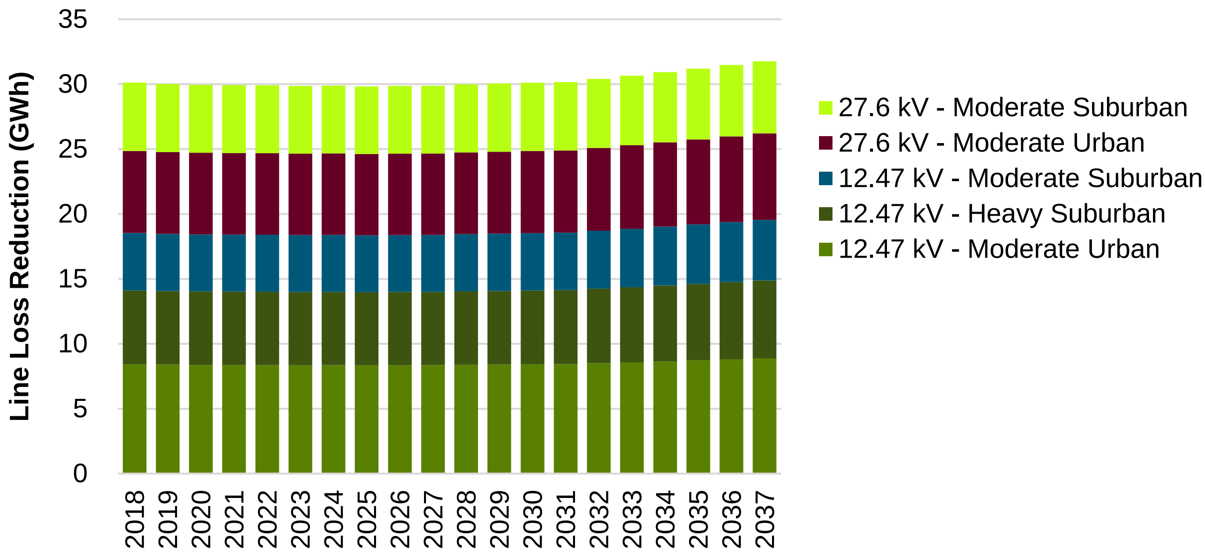


Source: Navigant

Line Loss Reduction Results

Figure 44 shows economic line loss reduction for the five prototypical feeder clusters that were economical. The data used to generate this figure is in Table 52 of Appendix B.1. The economic line loss reduction for VVO across all feeders is 30 GWh in 2018, increasing to 32 GWh by 2037. Averaged from 2018 to 2037, this represents a line loss reduction of approximately 0.6% across the distribution system. The breakdown of line loss reduction across feeders is proportional to the peak demand impact.

Figure 44. Economic Line Loss Reduction by Feeder Cluster (GWh/year) – VVO



Source: Navigant

Feeder Cluster Results for Phase Balancing

Peak Demand Reduction Results

Figure 45 shows economic peak demand reduction for phase balancing for the five prototypical feeder clusters that were economical. The data used to generate this figure is in Table 50 of Appendix B.1.

The economic peak demand reduction for phase balancing across all cost-effective feeders is 29 MW in 2018 increasing to 31 MW by 2037. Averaged from 2018 to 2037, this represents a peak demand reduction of approximately 0.1% relative to 2015 distribution system peak levels. Only five of the 15 prototypical feeders are economic. Of them, the 12.47 kV feeders contribute 41% of the peak impact, the 27.6 kV feeders contribute 47%, and the 44 kV contribute 21%. Of all cost-effective feeders, the moderate urban 12.47 kV and 26.7 kV feeders are the most impactful feeders contributing 28% and 21% of the overall peak reduction, respectively.

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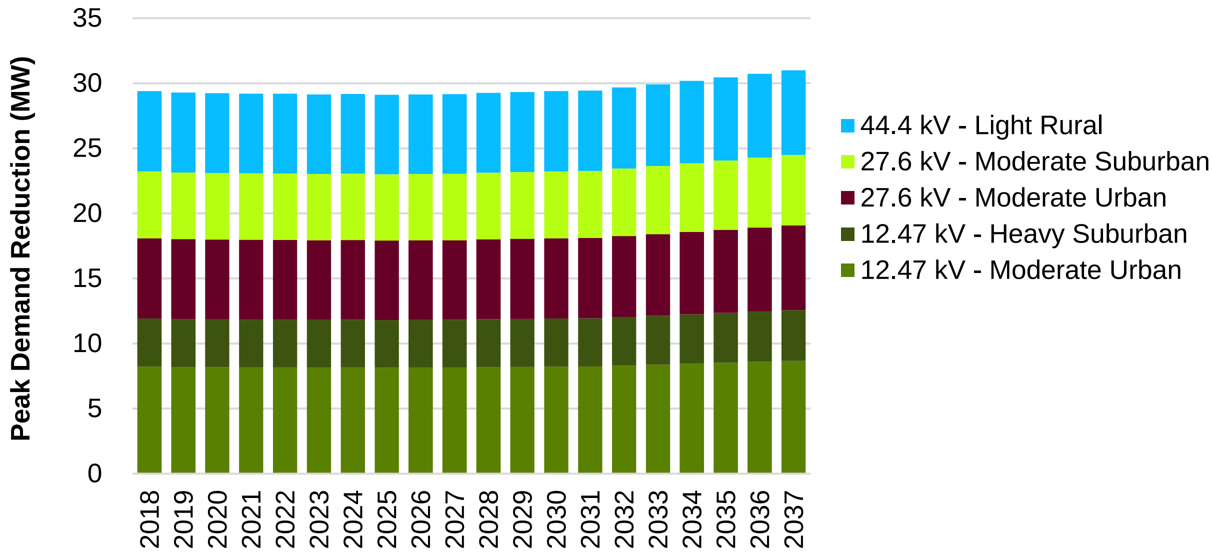
Figure 45. Economic Peak Demand Reduction by Feeder Cluster (MW/year) – Phase Balancing



Source: Navigant

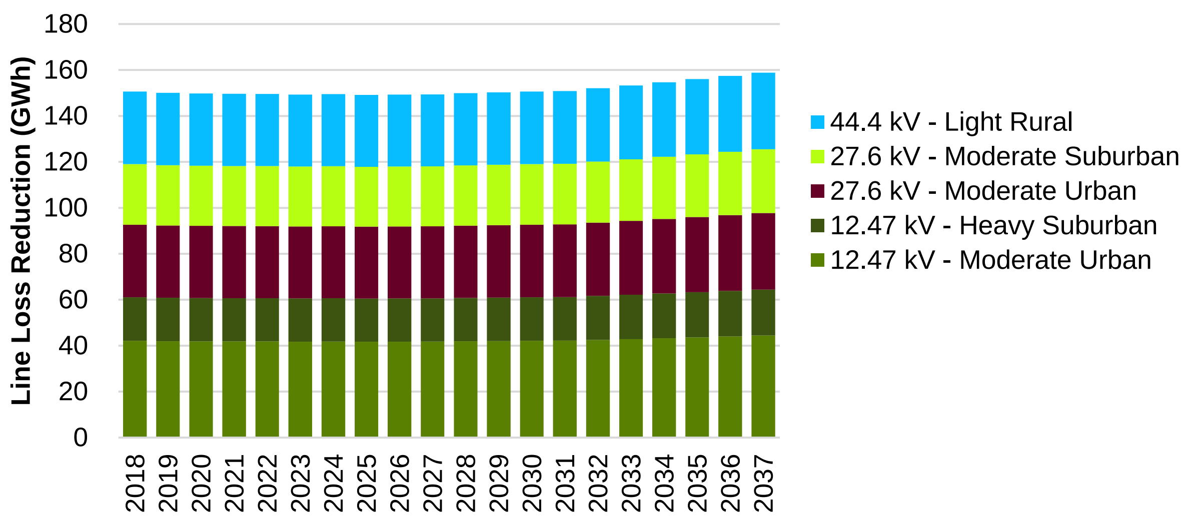
Electricity Consumption Reduction Results

The electricity consumption reduction figure has been omitted from the phase balancing feeder results because phase balancing does not result in a reduction in customer electricity consumption, rather only a reduction in line losses.

Line Loss Reduction Results

Figure 46 shows economic line loss reduction for the five prototypical feeder clusters that were economical. The data used to generate this figure is in Table 52 of Appendix B.1. The economic line loss reduction for phase balancing across all feeders is 151 GWh in 2018, increasing to 158 GWh by 2037. Averaged from 2018 to 2037, this represents a line loss reduction of 3.1% across the distribution system. The breakdown of line loss reduction across feeders is proportional to the peak demand impact.

Figure 46. Economic Line Loss Reduction by Feeder Cluster (GWh/year) – Phase Balancing



Source: Navigant

5.6.3 Results by IFMC Penetration Levels

This section presents the peak, electricity, and line loss impacts from IFMC technologies based on five IFMC penetration levels. Each of these penetration levels demonstrates different levels of distribution system deployment of IFMC technologies; including 5%, 10%, 25%, 50% and 75% of all feeders in the province.

The most critical assumption used to develop estimates of peak, electricity, and line loss impacts at various penetration levels is that the most cost-effective feeders for IFMC technologies will be targeted first (e.g., the low hanging fruit), followed by slightly less cost-effective feeders. The least cost-effective feeders would be the last set of feeders targeted for deployment. In reality, only the cost-effective feeders should be targeted. Cost-effectiveness is assessed based on the cost-benefit ratio of each prototypical feeder.

The analysis of electricity theft was performed at the system level so its results are not assessed by penetration level and have been omitted from this section.

5.6.3.1 Results for Volt/VAR Optimization

Table 20 shows the list of prototypical feeders ranked by VVO cost-benefit ratio, as well as the number of feeders per cluster. The top five feeders are cost-effective with cost-benefit ratios between 1.45 and 1.17, while the other 10 feeders are not cost-effective with cost-benefit ratios between 0.80 and 0.17. The B/C ratio less than 1.0 are highlighted red and those with a ratio of greater than 1 are in green. This table also shows the peak, electricity, and line loss reduction impacts for each feeder cluster in 2018.

The most attractive feeders for VVO deployment are feeders with the highest cost-benefit ratio; for example, the 12.47 kV and 26.7 kV moderate and heavy feeders. Once all of the cost-effective feeder clusters are deployed, the least non-cost-effective feeders would be targeted next; including the lightly loaded 12.47 kV/27.6 kV urban and suburban feeders, and most of the 4.16 kV feeders. The last set of feeder clusters targeted for deployment would be the rural and lightly loaded feeders, which consistently rank as the least cost-effective. In reality, only the cost-effective feeders should be targeted. However, for purposes of this analysis the following sets of figures show peak, electricity, and line loss results assuming all feeders are deployed in descending order of cost-benefit ratio.

Table 20. Ranking for Prototypical Feeders by Cost-Benefit Ratio - VVO

Rank	Ranked Feeders by Cost-Benefit Ratio	Feeders per Cluster	Benefit-Cost Ratio	Cluster Peak Reduction (MW)	Cluster Electricity Reduction (GWh)	Cluster Line Loss Reduction (GWh)
1	12.47 kV - Heavy Suburban	305	1.45	15	106	6
2	27.6 kV - Moderate Suburban	508	1.35	34	246	5
3	27.6 kV - Moderate Urban	508	1.34	33	244	6
4	12.47 kV - Moderate Urban	1,016	1.29	44	325	8
5	12.47 kV - Moderate Suburban	711	1.17	28	207	4
6	12.47 kV - Light Suburban	508	0.80	14	104	1
7	4.16 kV - Heavy Urban	102	0.72	1	10	1
8	4.16 kV - Heavy Suburban	102	0.65	1	9	0
9	44.4 kV - Light Rural	508	0.59	39	292	3
10	4.16 kV - Moderate Urban	1,524	0.58	17	122	3
11	27.6 kV - Light Rural	508	0.53	13	97	1
12	4.16 kV - Moderate Suburban	1,524	0.52	15	111	2
13	4.16 kV - Light Suburban	1,321	0.48	12	90	1
14	12.47 kV - Light Rural	508	0.38	7	49	1
15	4.16 kV - Light Rural	508	0.17	2	12	0

Source: Navigant analysis

Figure 47 shows resulting peak demand reduction by penetration level based on the deployment strategy outlined above. The vertical line at 30% penetration denotes the boundary of economic and non-economic feeder deployments. This figure shows that deployment to the most attractive 25% of feeders will capture approximately half of the total impact (approximately 49%).

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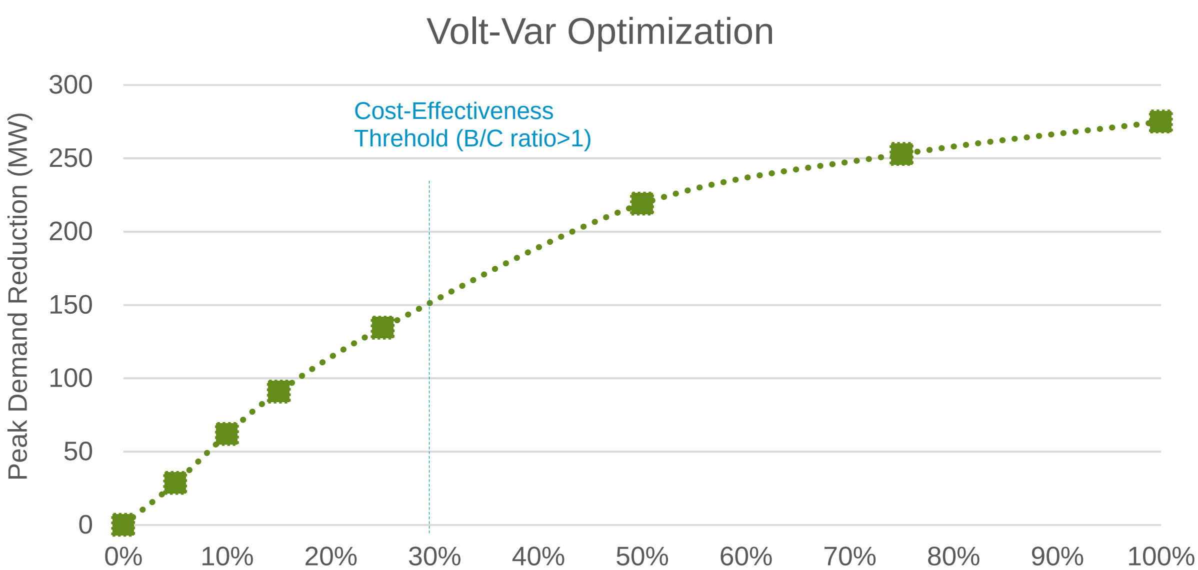
Figure 47. Peak Demand Reductions by Penetration Level (MW) – VVO



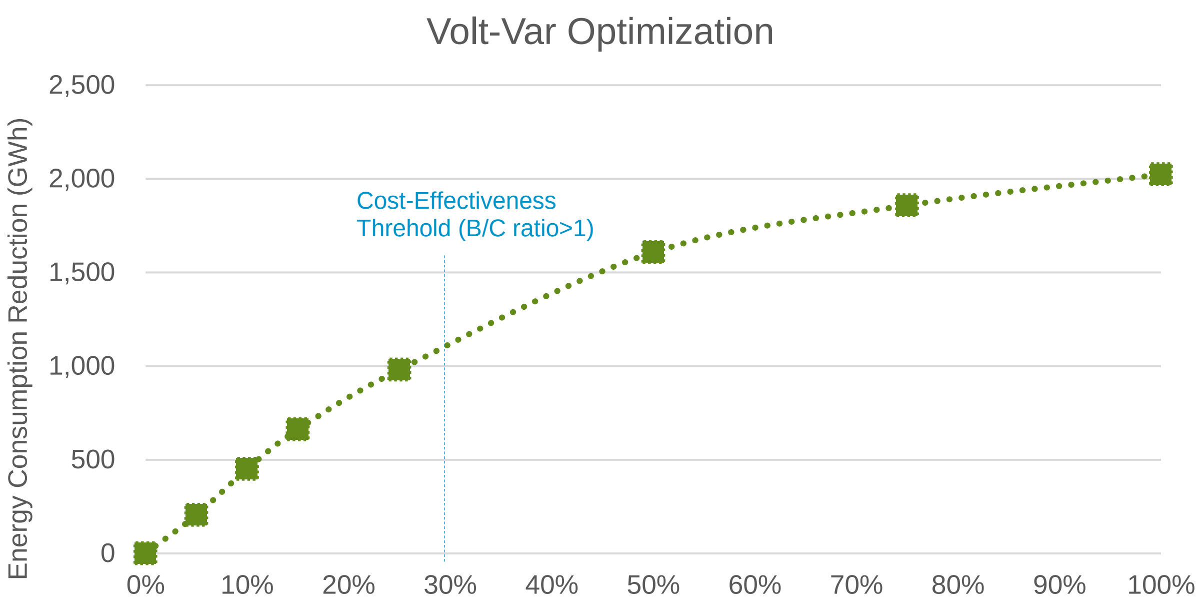
Source: Navigant

The graph also shows that the most economic feeders are also the most impactful feeder in terms of achieving reductions in peak demand. For example, deployment to the first 25% of feeders (e.g., the most attractive feeders) results in a peak demand reduction of 134 MW. In contrast, the last 25% of feeders (e.g., the least attractive feeders) result in a peak demand reduction of only 22 MW.[58] In general, the impact of additional deployment decreases at higher penetration levels. In other words, a feeder in the top 25% will, on average, achieve a peak reduction of approximately 53 kW (e.g., 134 MW divided by 2,500 feeders), whereas as feeder in the bottom 25% will only achieve a peak reduction of only 9 kW (e.g., 22 MW divided by 2,500 feeders).

The following two figures—Figure 48, and Figure 49—show the associated electricity and line loss reduction impacts from VVO at various penetration levels. The electricity and line loss deployment curves exhibit the same shape as the peak reduction curve. The electricity and line loss reduction curves shows that at a 25% penetration 980 GWh of electricity savings and 27 GWh of line loss savings are achieved.

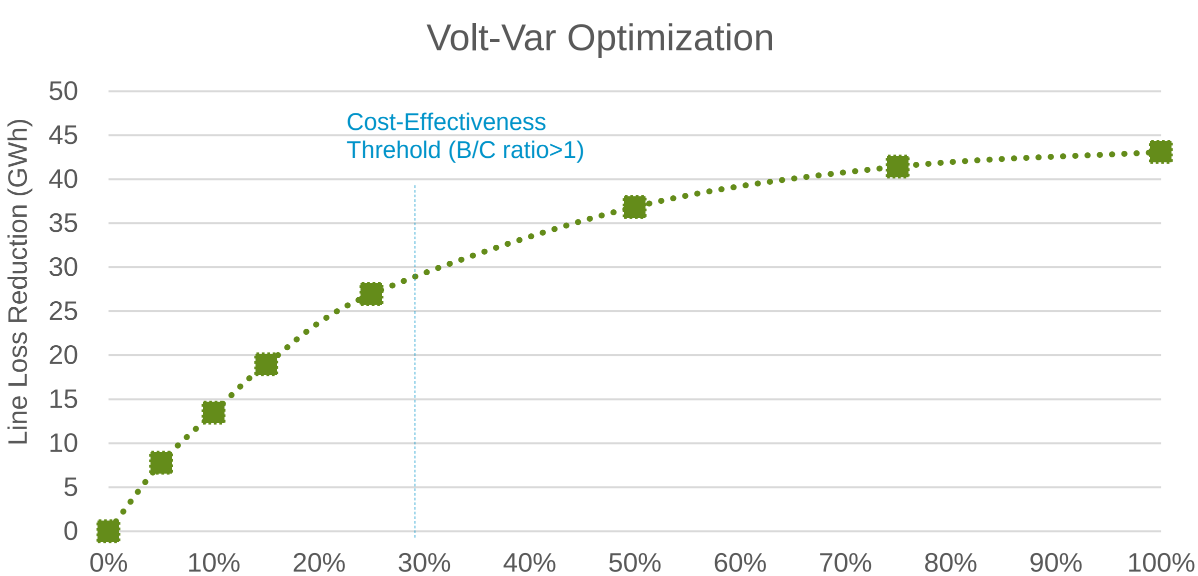
[58] The last 25% of feeders increase the cumulative peak demand by 22 MW from 253 MW to 275 MW.

Figure 48. Electricity Consumption Reductions by Penetration Level (GWh) – VVO



Source: Navigant

Figure 49. Line Loss Reductions by Penetration Level (GWh) – VVO



Source: Navigant

5.6.3.2 Results for Phase Balancing

Table 21 shows the list of prototypical feeders ranked by phase balancing cost-benefit ratio, as well as the number of feeders per cluster. The top five feeders are cost-effective with cost-benefit ratios between 1.80 and 1.20, while the other 10 feeders are not cost-effective with cost-benefit ratios between 0.90 and

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0.08. This table also shows the peak, electricity, and line loss reduction impacts for each feeder cluster in 2018.

The most attractive feeders for phase balancing deployment are feeders with the highest cost-benefit ratio including a selected group of the 12.47 kV and 26.7 kV—particularly some of the moderate and heavy feeders—as well as the 44 kV light rural feeders. Once all of the cost-effective feeder clusters are deployed, the least non-cost-effective feeders are targeted next. This includes most of the moderate and lightly loaded 12.47 kV and 27.6 kV feeders, and all of the heavy 4.16 kV feeders. The last set of feeder clusters targeted for deployment would be moderate and light 4.16 kV feeders.

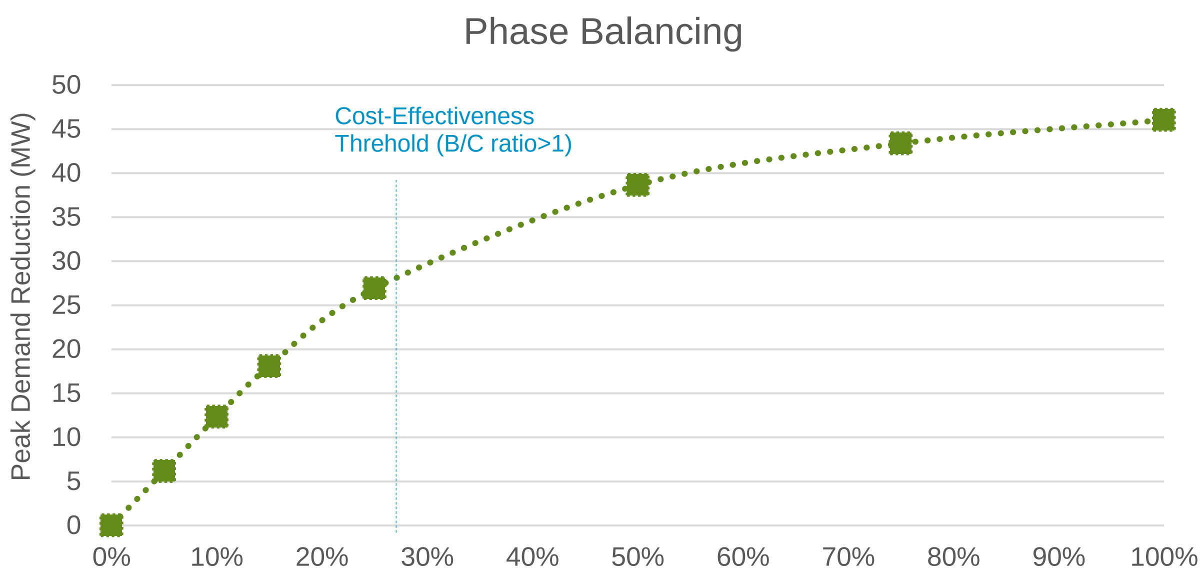
Table 21. Ranking for Prototypical Feeders by Cost-Benefit Ratio – Phase Balancing

Rank	Ranked Feeders by Cost-Benefit Ratio	Feeders per Cluster	Cost-Benefit Ratio	Cluster Peak Reduction (MW)	Cluster Electricity Reduction (GWh)	Cluster Line Loss Reduction (GWh)
1	12.47 kV - Heavy Suburban	305	1.80	4	0	19
2	27.6 kV - Moderate Urban	508	1.80	6	0	32
3	44.4 kV - Light Rural	508	1.80	6	0	32
4	27.6 kV - Moderate Suburban	508	1.50	5	0	26
5	12.47 kV - Moderate Urban	1,016	1.20	8	0	42
6	12.47 kV - Moderate Suburban	711	0.90	4	0	22
7	4.16 kV - Heavy Urban	102	0.60	0	0	2
8	27.6 kV - Light Rural	508	0.60	2	0	11
9	4.16 kV - Heavy Suburban	102	0.45	0	0	2
10	12.47 kV - Light Suburban	508	0.45	2	0	8
11	4.16 kV - Moderate Urban	1,524	0.30	3	0	16
12	12.47 kV - Light Rural	508	0.30	1	0	5
13	4.16 kV - Moderate Suburban	1,524	0.23	2	0	12
14	4.16 kV - Light Suburban	1,321	0.15	1	0	7
15	4.16 kV - Light Rural	508	0.08	0	0	1

Source: Navigant analysis

Figure 50 shows resulting peak demand reduction by penetration level based on the deployment strategy outlined above. The vertical line at 28% penetration denotes the boundary of economic and non-economic feeder deployments. Compared with the peak deployment curve for VVO, the phase balancing curve is slightly more aggressive. VVO deployment to the 25% most attractive feeders captures 49% of the peak impact. Phase balancing deployment to the 25% most attractive feeders captures a relatively higher proportion of the overall impacts, closer to 59%.

Figure 50. Peak Demand Reductions by Penetration Level (MW) – Phase Balancing



Source: Navigant

Deployment to the first 25% of feeders (e.g., the most attractive feeders) results in a peak demand reduction of 27 MW. The last 25% of feeders (e.g., the least attractive feeders) result in a peak demand reduction of only 3 MW.[59]

Figure 51 show the line loss reduction impacts from phase balancing at various penetration levels. Note that electricity reduction impacts are not presented because phase balancing does not reduce electricity consumption. The line loss reduction deployment curve exhibits the same shape as the peak reduction curve and shows that at a 25% penetration 138 GWh of line loss savings are achieved, which is equivalent to 59% of the maximum achievable reduction of 236 GWh.

[59] The last 25% of feeder increase the cumulative peak demand by 3 MW from 43 MW to 46 MW.

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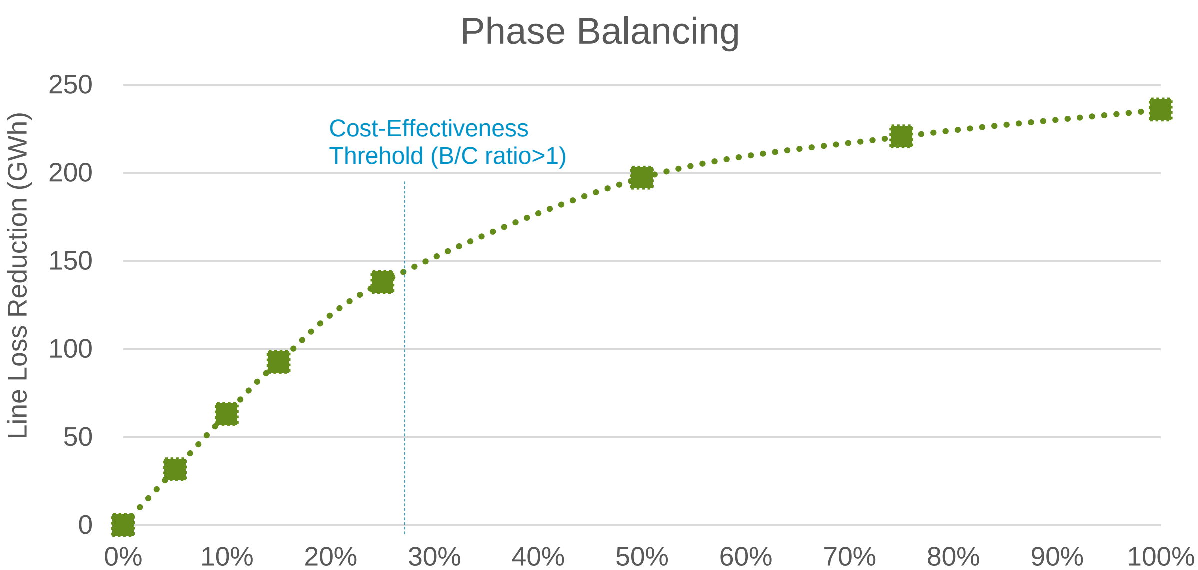
Figure 51. Line Loss Reductions by Penetration Level (GWh) – Phase Balancing



Source: Navigant

5.6.4 Associated Impact of IFMC on Customer Electricity Bills

One of the associated impacts of certain IFMC technologies can be a reduction in end-user electricity bills; whether a residential, commercial, or industrial customer. For example, assuming VVO deployment on a certain feeder results in a 2% reduction in electricity consumption, customers served by this feeder will see a corresponding reduction in their electricity bill. A residential customer consuming an average of 750 kWh per month would see their consumption decrease by 15 kWh down to 735 kWh per month (equivalent to a 2% reduction). For a Hydro One customer (*Residential – Urban (UR)*), this translates to a 1.6% reduction in their electricity bill. [60]

VVO is the only IFMC technology that can cause a reduction in customer's electricity bills. VVO lower voltage levels which in turn reduce electricity and peak demand from end-users. Phase balancing and electricity theft detection do not have no direct impact on a customer's electricity bill because they do no reduce end-use consumption or demand, only line losses.

Based on the analysis presented in Appendix D, reductions in electricity consumption from VVO vary from anywhere 0.8% to 2.5%. Using this range of impacts, the associated bill reductions for a 750 kWh per month, Hydro One customer vary from 0.6% to 2.0%. Although a customer's electricity bill impact will ultimately be dependent on the customer's tariff structure (e.g., based on the customer's distributor or whether a customer is general service, Class B, or Class A), the impact on electricity bills is not expected to vary significantly relative to these impacts.

[60] Using the OEB's residential bill calculator (as of April 2017), a Hydro One residential UR customer consuming 750 kWh per month pays an electricity bill of $136.10 before taxes and before the 8% HST provincial rebate. Based on a consumption of 735 kWh per month, the electricity bill decreases to $133.91, equivalent to a 1.6% reduction.

5.7 Scenario Results Potential

This section presents the technical and economic peak, electricity, and line loss impacts across all IFMC technologies and prototypical feeders based on all eight scenarios defined in Section 5.4.2. While the previous sections provided detailed results for Scenario 1 (based on base avoided cost, base DER penetration, and OPO-B), this section presents high-level results for the remaining scenarios in order to identify the impact of each of the three key variables that make up each scenario (e.g., avoided costs, DER penetration, and OPO scenarios). Scenarios 2 through 8 represent variations of Scenario 1 by adjusting one, two, or all three scenario variables. Detailed results for these scenarios, such as those presented in Sections 5.5 and 5.6, can be found in Appendix B.1.

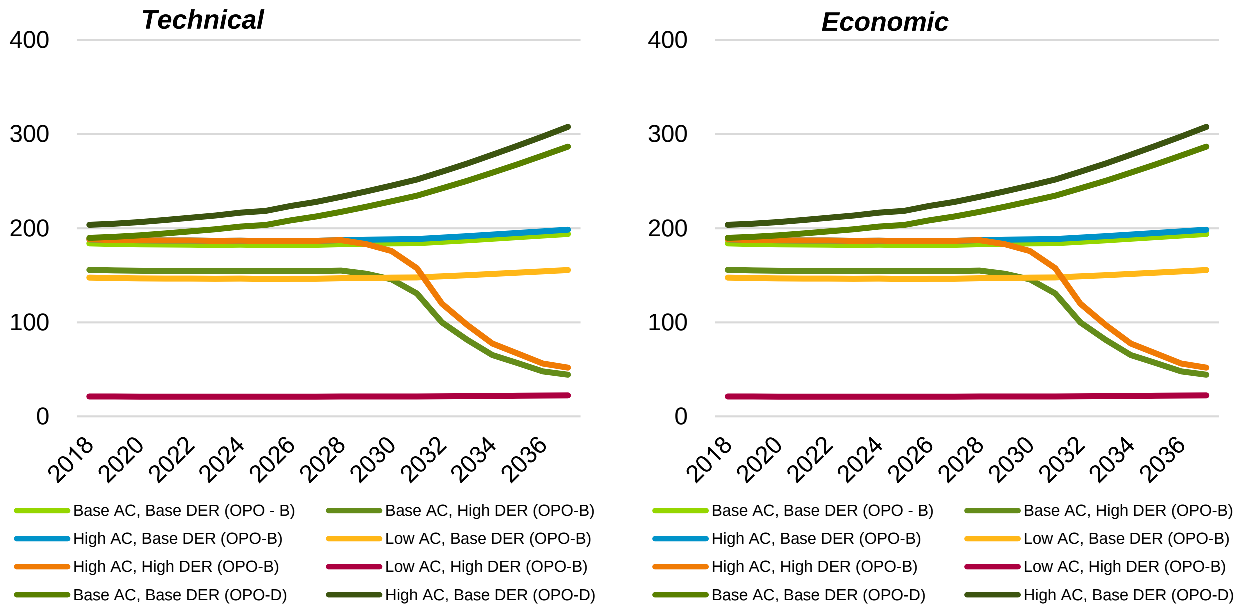
The key takeaways and considerations associated with each scenario are also summarized here:

- **High DER:** The inclusion of the high DER forecast results in a declining peak, electricity, and line loss reduction for VVO. Phase balancing and electricity theft are not affected by higher DER penetration. Technical potential is not affected; however, economic potential is lower for VVO.
- **High/low avoided costs:** Technical potential is not affected by changes in avoided costs because technical potential is independent of the magnitude of costs and benefits. Economic potential is, however, affected by higher avoided costs. Using higher avoided costs results in a higher magnitude of benefits attributed to VVO and phase balancing, which in turn may result in previously non-cost-effective feeder being deemed cost-effective. For example, a 1 MW reduction from VVO is attributed a higher magnitude of benefits (or is *worth* more) based on higher avoided costs than base avoided costs. Similarly, lower avoided costs may result in lower economic potential.
- **OPO Scenario D:** The growth forecast of Scenario D (2.0%) of the OPO is higher than Scenario B (0.2%). The higher growth forecast results in a higher peak, electricity, and line loss impact from all three IFMCs (VVO, phase balancing, and electricity theft detection).

Figure 52 shows technical and economic peak demand reduction by scenario. The data used to generate this figure can be found in Appendix B.1. The technical peak demand results show only three different peak reduction curves; however, this is because several scenarios result in the same technical peak demand reduction and therefore overlap. Only two variables impact technical peak demand reduction; DER penetration and the demand forecast.

- The yellow curve, which represents Scenario 1 and any other scenario based on the “base” level of DER penetration and based on the OPO-B load forecast, increases slightly from approximately 340 MW in 2018 to 355 MW in 2037.
- The red curve, which reflects any of the scenarios that are based on a high-level of DER penetration, shows a significant decrease in peak beginning in 2028 down to 94 MW in 2037. As DER penetration increases, the effectiveness of VVO to reduce peak (as well as electricity, and line losses) declines.
- The green curve, which reflects any of the scenarios that are based on the OPO-D load forecast, shows a significant increase in peak up to 513 MW in 2037. Over time, as the load on a feeder increases, so does the resulting peak reduction, electricity consumption reduction, and line loss reduction.

Figure 52. Technical and Economic Peak Demand Reduction by Scenario (MW)



Source: Navigant

The economic peak demand results show a much more complex set of results, however several trends that were identified in the technical peak demand graphs hold true. Specifically, the declining peak impact over time as a result of higher DER penetration, or increasing peak impact as a result of a more aggressive load forecast.

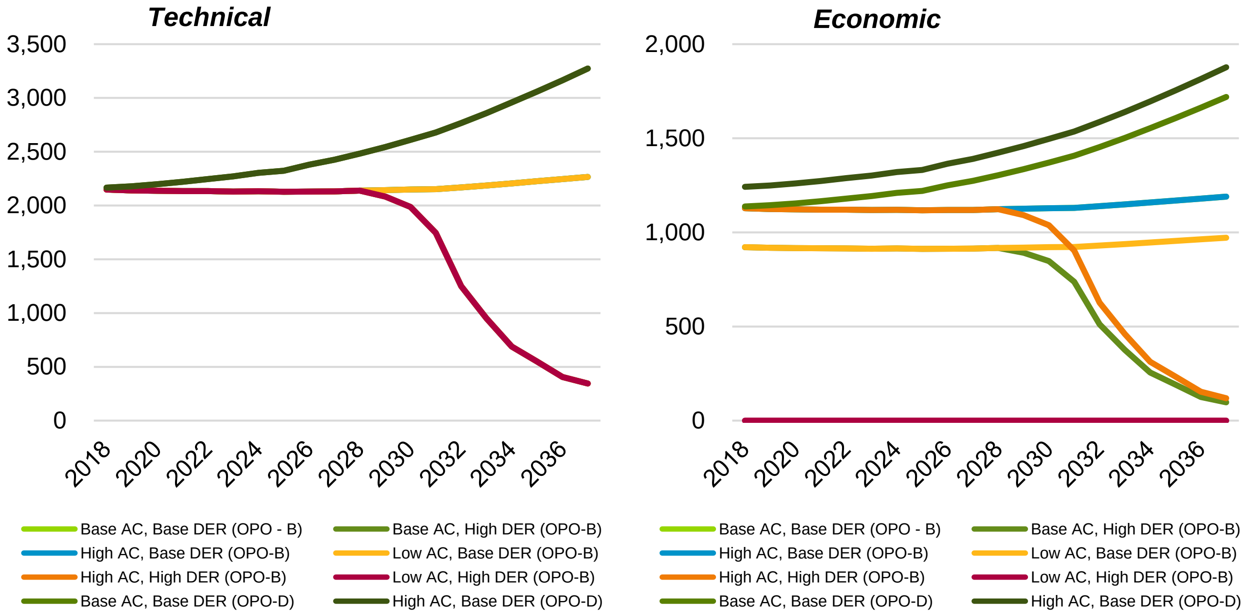
Some of the differences between technical and economic potential curves are a result of low and high avoided costs which either decrease or increase the economic potential, relative to the *baseline* avoided costs. Further, high DER penetration and OPO-D load forecast have significant impacts on the cost-effectiveness of VVO and LLIM.

For example:

- Based on the *baseline* level of avoided costs VVO is economic on 30% of all feeders, which captures more than half of the total peak demand reduction potential.
    - The use of low avoided costs decreases the fraction of cost-effective VVO deployment.
    - In contrast, the use of high avoided costs increases the fraction of cost-effective VVO.
    - High DER penetration results in lower economic benefits since VVO results in a declining peak demand impact beyond 2028.
    - On the other hand, the high load growth of the OPO-D forecast increases the cost-effectiveness of VVO.
- Based on *baseline* level of avoided costs, phase balancing is economic on 28% of all feeders, which captures more than half of the total peak demand reduction.
    - While phase balancing is not affected by the level of DER penetration, the economics are more attractive based on the OPO-D forecast.

Figure 53 shows technical and economic electricity consumption reduction by scenario. The data used to generate this figure can be found in Appendix B.1. These results show the same characteristics as the peak demand results presented above, including the impact of high DER penetration, the OPO-D forecast, and high and low avoided costs on the economics of VVO and phase balancing.

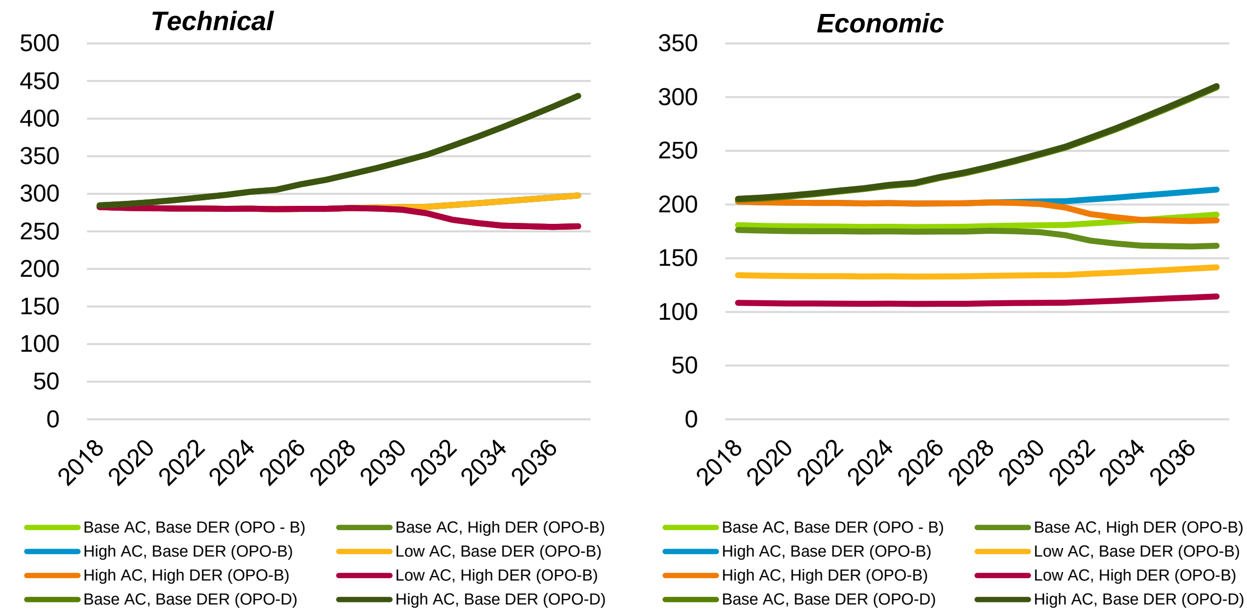
Figure 53. Technical and Economic Electricity Consumption Reduction by Scenario (GWh/year)



Source: Navigant

Figure 54 shows technical and economic line loss reduction by scenario. The data used to generate this figure can be found in Appendix B.1. Similar to the peak and electricity reduction impacts, the same characteristics and themes are seen. One important difference is that since the phase balancing contributes the most to the line loss impacts and is not affected by a high level of DER penetration, the overall reduction in line loss impacts observed beyond 2020 is minimal –relative to the peak and electricity reduction impacts.

Figure 54. Technical and Economic Line Loss Reduction by Scenario (GWh/year)



Source: Navigant

Table 22 provides a detailed description of each individual scenario highlighting the key differences relative to Scenario 1 as well as describing the key drivers of results.

Table 22. Summary of Results by Scenario

Scenario	Key Takeaways and Considerations
Base AC, Base DER (OPO - B)	This scenario (Scenario 1) was used for the all results presented in previous section.
Base AC, High DER (OPO-B)	This scenario is based on the same assumptions as Scenario 1 with the exception of a high DER penetration. The high DER scenario results in decrease in the effectiveness and cos-effectiveness of VVO to reduced peak, electricity, and line losses. As a result, the technical and economic peak, electricity, and line losses reduce significantly in magnitude beginning in 2028. The high DER scenario does not impact theft detection or phase balancing results. The high DER also scenario results in a lower fraction of feeders being cost-effective for VVO; 23% of feeders.
High AC, Base DER (OPO-B)	This scenario is based on the same assumptions as Scenario 1 however with higher avoided costs. Technical potential results are not affected. However, higher avoided costs means that the benefits of VVO, phase balancing and electricity theft are proportionally higher (e.g., 50% higher). More feeders are cost-effective for phase balancing; 35% of feeder. Despite high avoided costs, the same number of VVO feeders are cost-effective. Theft detection (at the system level) remains cost-effective.

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Scenario	Key Takeaways and Considerations
Low AC, Base DER (OPO-B)	This scenario is based on the same assumptions as Scenario 1 however with lower avoided costs. Technical potential results are not affected. However, lower avoided costs decrease the magnitude of the benefits from VVO, phase balancing and electricity theft. Less feeders are cost-effective for VVO (23% of feeders) and phase balancing deployment (18% of feeders). Electricity theft detection remains not cost-effective.
High AC, High DER (OPO-B)	This scenario is based on the same load growth forecast as Scenario 1; however, with higher avoided costs, and higher DER penetration. Technical potential results for phase balancing results are not affected; however, the high DER penetration decreases the technical potential for VVO as penetration increases over time. High DER penetration decreases the fraction of cost-effective VVO feeders, however the high avoided costs offset the impact – result in no change relative to Scenario 1; 30% of VVO feeders are cost-effective. Higher avoided costs increase the number of cost-effective phase balancing feeders (35% of feeders). Theft detection (at the system level) remains cost-effective.
Low AC, High DER (OPO-B)	This scenario is based on the same load growth forecast as Scenario 1; however, with lower avoided costs, and higher DER penetration. Phase balancing technical potential results are not affected; however high DER penetration decreases the VVO technical potential over time. Low avoided costs and high DER penetration both contribute to significant reduction in the fraction of cost-effective VVO feeders; no feeders are cost-effective. Low avoided costs decrease the fraction of cost-effective phase balancing feeders; 18% of feeders. Theft detection (at the system level) remains not cost-effective.
Base AC, Base DER (OPO-D)	This scenario is based on the same assumptions as Scenario 1 however with the OPO-D load growth forecast. Technical potential results for VVO, phase balancing and electricity theft detection increases proportionally. Despite an increase in benefits, the VVO economic potential remains unchanged, while phase balancing economic potential increases to 35% of feeders. Theft detection (at the system level) remains not cost-effective.
High AC, Base DER (OPO-D)	This scenario is based on the OPO-D load growth forecast with higher avoided costs. The higher load growth forecast increases the technical potential for VVO, phase balancing and theft detection. Economic potential increases for VVO and phase balancing as a result of higher avoided costs and higher load forecast; for both technologies, economic potential increases to 35% of feeders. Theft detection (at the system level) remains cost-effective.

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6. OPTIONS TO SUPPORT IFMC DEPLOYMENT

6.1 Introduction and Objectives

Theoretically, Ontario LDCs could obtain funding for IFMC projects through three different cost-recovery mechanisms; (1) funding through CDM budgets, (2) funding through distribution-rates, or (3) a hybrid approach. The conservation funding approach uses the criteria and practices for evaluating conservation programs set out by the IESO through the Conservation First Framework (CFF), and the distribution-rates funding approach uses the criteria and practices set out by the OEB for capital investments or system upgrades. The hybrid approach blends both the CDM and distribution rates approach to financially support IFMC investments.

The objective of this section is to identify the key characteristics, differences, and trade-offs between the various cost-recovery mechanisms to identify their appropriateness and effectiveness at encouraging IFMC deployment in Ontario. While Section 5 focused on technical and economic potential, this section focuses on achievable potential and considers the impact of existing (and potential) cost-recovery mechanisms on the level of achievable IFMC potential in Ontario

This section begins with a brief description of the CDM and distribution-rates funding approaches, and then analyzes the cost-benefit captured by each approach. The section concludes by identifying the key differences between the approaches, and identifying a hybrid alternative which may be more affective at encouraging adoption.

6.2 Key Findings & Observations

There are five primary differences between the conservation and the distribution-rates cost-recovery mechanisms:

1. **The project approval process -** The approval process for IFMC projects under the conservation approach would be less onerous, as approval of conservation and demand management plans is not subject to full regulatory oversight. However, related evaluation, measurement, and verification requirements for projects that are funded through conservation budgets would likely be more complex.

2. **The timeframe over which the costs are recovered from customers** - Under the conservation approach, project costs would be recovered over a condensed period (~3 years if funded through the current 2015-2020 framework). Under the distribution rates approach, costs would be recovered over the useful life of the assets (~10-15 years).

3. **Which customers pay** - Under the conservation approach, costs are socialized over all of Ontario's electricity customers. Under the distribution rates approach, costs are recovered from the implementing LDC's customers alone.

4. **The post-deployment evaluation, measurement, and verification requirements** - Projects funded through CDM require rigourous post-installation assessments whereas distribution-rates supported investments do not.

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5. **The ability of the funding model to effectively encourage LDC investment in IFMC technologies** - To-date, the distribution rates approach has had minimal affect on encouraging IFMC investments. Integrating IFMC with CDM may be effective in stimulating uptake.

An alternative cost-recovery mechanism combines the benefits of the conservation approach and the distribution rate approach; the *hybrid* approach. In this hybrid approach, cost-recovery of IFMC projects would be achieved through distribution rates, however, LDCs would be eligible to claim conservation savings driven against their CDM targets. This approach leverages traditional project financing channels (e.g., through a regulatory processes), while at the same time offering LDCs a viable financial motivation to pursue IFMC projects – in addition to performance incentives should an LDC meet their CDM targets.

A key limitation to this approach is inherent to the distribution rates approach –and the underlying regulatory process. Generally, LDC investments in the distribution system must be justified based exclusively on local distribution benefits. Should a project result in upstream benefits in transmission and generation, those benefits are not considered part of the overall business case. Since IFMC investments are partly driven by transmission and generation benefits, this approach may significantly limit the achievable potential for IFMC investment. For example, a VVO project which may on-the-whole be cost-effective (supported by transmission and generation benefits), may not be deemed economic if only distribution benefits are considered.

To address this limitation, a variation to the hybrid approach enables LDCs to consider upstream transmission and generation benefits in the evaluation of IFMC projects. This would ensure that any cost-effective IFMC projects will be determined to be economic. However, since cost-recovery of investments is through local distribution rates, this results in a situation where all IFMC costs would recovered locally even if upstream benefits are significant.

This hybrid approach also introduces a *cost-allocation mechanism* that would enable LDCs to allocate the portion of cost associated with upstream system benefits to Ontario ratepayers, while only allocating costs to local ratepayers in proportion to local benefits. This mechanism would enable a fair allocation of costs across local and all Ontario ratepayers (e.g., in proportion to benefits), and would be critical at encouraging IFMC deployment.

6.3 Conservation and Demand Management (CDM) Funding Approach

Funding of IFMC deployment through the CDM approach is based on the 2015-2020 Conservation First Framework. If IFMC technologies were to be included in the definition of CDM, a LDC would be required to develop a project with a proposed budget, timeline, and expected energy savings much like any other CDM program. Under the CDM funding approach, a LDC would seek recovery of a portion or all of the capital investment associated with the project and on-going operating and maintenance expenses from the IESO through the CDM budget.

The objective of this section is to evaluate the cost-effectiveness of an IFMC investment using the standard cost-effectiveness metrics used by the IESO to evaluate CDM programs. Specifically, this section explores:

1. The cost-effectiveness metrics most appropriate for evaluating IFMC technologies; and
2. The funding options (and implications) available through the CDM budget.

Under the conservation approach, project costs would be recovered over the length of the conservation period. The current CFF lasts over a period of 6 years (3.5 years remaining), and the government will be deciding on frameworks for the post-2020 period. If CDM funds are used to subsidize IFMC project costs (in part or in full), it means that IFMC project costs would be socialized over all electricity customers in the province.

While certain benefits of IFMC deployment produce value for all customers in the province (e.g. avoided generation and transmission costs), other benefits are localized (e.g. avoided distribution costs). Thus, if IFMC deployment is fully funded through the CDM approach, all costs would be socialized over all electricity customers in the province**,** but certain customers will benefit more than others. Note that all CDM cost-effectiveness tests include all system-wide benefits; including benefits from avoided distribution and transmission costs, which are based on provincial averages rather than local grid conditions, and generation capacity.

Table 23 summarizes the key components of the conservation cost-recovery mechanism for IFMC deployments. Two cost-effective tests that are commonly used to assess many types of CDM programs have been outlined: Total Resource Cost (TRC) and Program Administrator Cost (PAC). However, for the remainder of this section, quantitative results will only be provided for the TRC test. This is because the PAC test does not provide a holistic view of all costs required to deploy IFMC technologies, for the following reasons:

- The PAC test's most significant cost component is "incentive cost", which depends on the type of CDM program being administered[61]. For traditional, customer-facing behind-the-meter CDM programs, incentives are provided by the program administrator (LDC) to end-use customers. However, since IFMC technologies do not involve customers, the incentive payment is a transfer of funds from the IESO to an LDC. This means that the PAC test is applied from the perspective of the CDM provider (IESO), and not the LDC. As there has not been any decision to date on what an appropriate incentive mechanism for IFMC technologies would be, it would not be appropriate to assume an incentive payment and subsequently calculate PAC metrics.
- The PAC test does not consider the capital costs required to deploy IFMC as one of its cost components. Thus, it does not capture a significant cost component involved in IFMC deployment.
- The PAC test considers all benefits (avoided generation, transmission & distribution capacity and avoided energy generation). However, the only benefit seen by the LDC implementing IFMC technology is the avoided distribution capacity cost. Thus, the PAC test would present IFMC more favorably than what is seen by the LDC.

[61] Incentive Costs are costs that include cash incentives, payments for demand response services, upstream incentives, payments for studies, and in-kind contributions that the program administrator provides to participating customers, contractors, and trade allies to encourage the implementation of CDM by offsetting the incremental cost of efficiency.

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Table 23: Summary of Conservation Funding Mechanism

Implementation Approach	
Implementer	IESO
Upfront Investment by:	IESO and LDC
Cost-Recovery Period:	~3 years (prior to 2020)
Cost Recovered from:	All Ontario electricity customers
Cost-Benefit Analysis Structure	
Cost-Effectiveness:	• Program Administrator Cost (PAC) • Program Administrator Cost (PAC)
Recoverable Costs:	• Financing costs (currently not eligible but may be granted) • Capital investment • Operating and maintenance cost
Benefits Considered:	• Avoided Distribution, Transmission, and Generation Capacity • Avoided Energy Generation • Non-Energy Benefits (NEB)

6.3.1 Analysis of Conservation Funding Approach

Using the IESO's CDM cost-effectiveness tool, TRC metrics can be calculated for each IFMC technology. This section will discuss the results of the TRC test, and its implications for IFMC deployment. Table 24 describes the benefit and cost components of the TRC test.

Table 24. Benefit and Cost Components of the TRC test

Benefit Components	Cost Components
• **Avoided supply-side resource costs:** these are the avoided costs of energy generation, generation capacity, transmission capacity and distribution capacity.	• **Participant Costs**: These are the incremental capital and O&M costs incurred by the program participant to implement the CDM measure. • **Program Costs:** These are the costs related to the program design, implementation, marketing, evaluation and administration, including of fixed overhead costs.

In the context of IFMC, participant costs refer to all the project-related costs (asset first, asset maintenance, asset replacement, system startup and system operations costs). On the other hand, the largest component of program costs will likely be a Detailed Engineering Study that needs to take place prior to deploying the respective IFMC technology, and the cost of EM&V post-installation. These factors make IFMC projects similar to the projects in the Save on Energy Process and Systems Upgrades Program. Thus, program costs are assumed to be approximately 5% of the participant (project-related) costs of deploying IFMC technology.

Cost-Effectiveness Results by IFMC Technology
The following tables show the system-wide (all feeders in the province) cost-effectiveness results for each IFMC technology based on Scenario 1 of the CBA.

Table 25. System-wide TRC Metrics by Technology

IFMC Technology	Benefits ($M)	Costs ($M)	TRC	Net Benefits ($M)
VVO	2,078.7	2,355.4	0.88	-276.7
Electricity Theft	123.7	213.5	0.58	-89.7
Phase Balancing	278.3	381.7	0.73	-103.3

Source: Navigant analysis

The TRC test considers all benefits and costs of implementing IFMC technologies, and can provide a clear indication of whether an IFMC technology is cost-effective (TRC > 1). According to the TRC test, none of the technologies are cost-effective on a system-wide scale. As discussed in Section 5, the costs and benefits of IFMC technologies are heavily dependent on individual feeder conditions. There could be a strong economic case to strategically deploy VVO and phase balancing on specific feeders in the province. Cost-effectiveness results on a feeder level are shown in Table 26 for VVO and Table 27 for phase balancing.

On the other hand, it is sufficient to analyze electricity theft on a system-wide scale as the benefits and costs will not vary on a prototypical feeder level. That is, there is no evidence to suggest that prototypical feeder X will experience more theft (and thus more benefits from deploying theft mitigation technology) than prototypical feeder Y. Similarly, the cost of mitigating theft will not vary between prototypical feeders. (See Appendix D.3 and D.4 for more information on the benefit and cost inputs for each IFMC technology).

As shown in Table 26, there are five prototypical feeders that are cost-effective for VVO according to all metrics used. The cost-effective feeders are generally moderately loaded, serving urban or suburban population densities and in the 12.47 kV or 27.6 kV voltage classes.

The TRC metric produces similar results to the cost-benefit ratio from the Grid+ model (table of results shown in Appendix D.1). This is expected as both use the IESO's avoided costs tables in order to measure benefits. However, even though the TRC metric considers program costs when the Analytica model does not, the non-energy benefit adder means the TRC test produces higher cost-benefit ratios. Nonetheless, both the TRC and the Grid+ CBA results screen the same prototypical feeders as being cost-effective.

Table 26. Feeder-Level CE Metrics for VVO

Prototypical Feeder	TRC
4.16kV - Heavy Urban	0.77
4.16 kV - Moderate Urban	0.61
4.16 kV - Heavy Suburban	0.69
4.16 kV - Moderate Suburban	0.55
4.16 kV - Light Suburban	0.51
4.16 kV - Light Rural	0.18
12.47 kV - Moderate Urban	1.41
12.47 kV - Heavy Suburban	1.59
12.47 kV - Moderate Suburban	1.28
12.47 kV - Light Suburban	0.88
12.47 kV - Light Rural	0.42
27.6 kV - Moderate Urban	1.49
27.6 kV - Moderate Suburban	1.49
27.6 kV - Light Rural	0.58
44.4 kV - Light Rural	0.66

Source: Navigant analysis

Similar to VVO, there are five prototypical feeders that are cost-effective for phase balancing according to all the metrics used (shown in Table 27). The cost of correcting phase imbalances depends on the level of imbalance and the number of phase swaps that need to take place, but these do not depend on voltage class or population density. Thus, it has been assumed that the costs of correcting phase imbalances do not vary between prototypical feeders.

As a result, the difference in benefits (due to the quantity of line loss reduction) between prototypical feeders is the prime driver of cost-effectiveness. The five cost-effective feeders will experience greater absolute line loss reductions (as a result of having higher electricity consumption) than the non-cost-effective feeders. Once again, both the TRC and the Grid+ CBA results screen the same prototypical feeders as being cost-effective.

Table 27. Feeder-Level CE Metrics for Phase Balancing

Prototypical Feeder	TRC
4.16kV - Heavy Urban	0.65
4.16 kV - Moderate Urban	0.33
4.16 kV - Heavy Suburban	0.49
4.16 kV - Moderate Suburban	0.24
4.16 kV - Light Suburban	0.16
4.16 kV - Light Rural	0.08
12.47 kV - Moderate Urban	1.30
12.47 kV - Heavy Suburban	1.95
12.47 kV - Moderate Suburban	0.98
12.47 kV - Light Suburban	0.49
12.47 kV - Light Rural	0.33
27.6 kV - Moderate Urban	1.95
27.6 kV - Moderate Suburban	1.63
27.6 kV - Light Rural	0.65
44.4 kV - Light Rural	1.95

Source: Navigant analysis

The TRC test indicated that five prototypical feeders are cost-effective for both VVO and phase balancing, as demonstrated by the CBA results in Section 5. While this means VVO and phase balancing can be cost-effective from a project-perspective, it does not necessarily mean that LDCs will be interested in pursuing IFMC projects. The achievable potential of IFMC (e.g., the expected level of IFMC adoption) will depend on the magnitude of funding (or incentives) provided to LDCs through CDM.

Table 28 describes two cost-recovery variations based on the CDM funding approach; the first option (CDM with Partial Incentive) is based on LDCs recovering IFMC costs through CDM funds while the remaining costs are recovered from distribution rates, and the second option (CDM with Full Funding) is based on full cost-recovery through CDM funds.

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Table 28: Comparison of CDM Cost-Recovery Options

		CDM with Partial Incentive	CDM with Full Funding
Option		**(1)**	**(2)**
TRC	Costs	All Costs	All Costs
	Benefits	All Benefits + NEB	All Benefits + NEB
UCT	Costs	**All Costs – Incent.**	**No Costs**
	Benefits	**Dx.**	**Dx.**
Technical Potential		Approx. 2 TWh	
Economic Potential		Approx. 1 TWh	
Achievable Potential		**Low**	**High**

Source: Navigant analysis

Option 1: CDM with Partial Incentive – In this option, LDCs receive an incentive payment from the IESO that covers a portion of their IFMC project costs. As only part of the project costs will be covered through CDM, an LDC must recover the remaining costs through distribution rates as part of an application to the OEB. Since an LDC is required to go to two governing authorities – the IESO and the OEB– for the same IFMC project, this option introduces a complex process unattractive to LDCs. Furthermore, the IESO must determine an appropriate incentive level or mechanism for IFMC technologies.

To illustrate this dual-funding approach from an LDC's perspective, the Utility Cost Test (UCT) – which considers benefits and costs as seen by a LDC – is also presented in Table 28. While the UCT is not an official cost-effectiveness test under the IESO's CDM cost-effectiveness guide, it helps explain the financial motivation for LDCs to pursue IFMC projects. The UCT demonstrates that an LDC can only claim distribution benefits in their rate application to the OEB. The costs are made up of all project costs less the value of the (capital) incentive payment provided by the IESO. Since the magnitude of distribution benefits is a relatively small component of total IFMC benefits (as explained in Section 5 only 1% of benefits), the B/C ratio under the UCT will always be less than one. Thus, the achievable potential under Option 1 is low.

Option 2: CDM with Full Funding - In Option 2, all project costs for the LDC are recovered through CDM funds. This would mean a LDC only needs to submit one application to the IESO, making the approval process more streamlined for all parties involved. The UC test is also always greater than 1 under this option, as a LDC need not recover any costs through the OEB. However, pursuing Option 2 will mean a significant portion of CDM funds will need to be allocated for IFMC technologies. This will move funds away from customer-facing CDM programs, which is a concern for both LDCs and government entities.

It is also important to note that if IFMC projects receive CDM funds, LDCs will be able to count the peak demand and energy savings achieved to their CDM targets under the conservation framework. Consequently, some LDCs might meet or exceed their CDM target, making them eligible for a performance incentive. LDCs that expect to reach or achieve their CDM target would be particularly interested in the CDM approach, as they have the highest chance of receiving a performance incentive.

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6.4 Distribution Rates Funding Approach

The second funding mechanism considers the regulatory process LDCs currently follow in order to obtain approval for capital investments. With this approach, a LDC is required to justify that an IFMC investment is cost-effective, or –in a situation where a system upgrade is required– the *least-costly* alternative.

Under this approach, a LDC would seek recovery of the capital investment associated with a project and on-going operating and maintenance expenses from the OEB through distribution rates. Experience to-date, however, illustrates that this approach has not encouraged IFMC deployment.

The objective of this section on the rate-based approach is to demonstrate the business case for an IFMC investment as an LDC would present it to the OEB. Specifically, this section explores how an LDC could demonstrate that the IFMC technology is cost-effective:

1. Based on a comparison of the present value of costs and benefits – analogous to the analysis presented in Section 5; or,
2. Based on how the costs of the IFMC technology compare against the cost of an alternative solution in the case where a system upgrade is required (e.g., re-conductoring, upgrading a feeder, or building a secondary feeder).

Table 29 summarizes the key findings for the distribution-rates approach. Under this approach, project costs would be recovered over the useful life of the assets (e.g., 10 to 15 years) whereas with the CDM approach, costs –which may vary based on the level of incentive funding received– would be recovered over the CFF timeline. Another important point of comparison is that with distribution rates, costs are recovered from the LDC's rate base, whereas with the CDM approach costs are socialized over all Ontario ratepayers. Another critical aspect of the distribution rates approach is that, traditionally, only distribution-level benefits (e.g., avoided distribution capacity) are captured as part of an LDC's evaluation of projects. The OEB may have discretion to consider upstream benefits such as avoided generation and transmission capacity, however, this is not the norm.

A final point of consideration is related to the level of recoverable costs of IFMC projects. Up-front investment would be capitalized and included in the LDCs' regulated asset base, which they can earn a rate of return on. On-going Operating and Maintenance (O&M) would be expenses and included in the LDC's overall Operating, Maintenance, and Administrative (OM&A) costs.

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Table 29: Summary of Distribution Rates Funding

Implementation Approach	
Implementer	Ontario Energy Board
Upfront Investment by:	LDC
Cost-Recovery Period:	~10 to 15 years
Cost Recovered from:	(depending on asset life)
Cost-Benefit Analysis Structure	
Cost-Effectiveness:	• Net Present Value (NPV)
Recoverable Costs:	• Financing costs • Capital investment • Operating and maintenance costs
Benefits Considered:	• Avoided Distribution Capacity (OEB has discretion to consider other benefits)

As described above, an LDC may pursue cost-recovery of IFMC projects through distribution rates based on two scenarios; (1) based on the overall NPV of the IFMC investment, or (2) based on a comparison of the costs of various alternatives (in the case where a system upgrade is required).

There is a critical distinction between these two scenarios. The first scenario is analogous to the CBA performed in the previous section for the deployment of VVO, theft detection, and phase balancing – however, only considering distribution benefits, and not upstream benefits. The second scenario, rather than assessing the avoided costs from IFMC investments, the investments are compared to other alternative investments. In this scenario, the regulator –in the interest of ratepayers– would only approve the least-cost investment. IFMC technologies will, in effect, be evaluated like any other non-wires alternative (NWA), which may defer or avoid a traditional transmission and distribution (T&D) investment.

The following two sections illustrate the analysis based on these two scenarios.

6.4.1 Distribution Rates Approach based on Overall NPV

The key distinction between the evaluation of IFMC investments for cost-recovery through distribution rates and the evaluation in Section 5 is that, traditionally, only distribution benefits are considered in an LDC's rate application. Section 5 results are include all system-wide benefits: avoided generation, transmission, and distribution capacity, and avoided energy generation.

Table 30 compares both sets of B/C ratios for VVO deployment. The first column shows the Section 5 B/C ratios, and the second column shows B/C ratios with only distribution benefits. Since distribution benefits account for 1% of total benefits, in the second column none of the 15 prototypical feeders are cost-effective.[62]

While these results are based on average distribution avoided costs from the IESO's CDM tool (and may not be reflective of higher-value opportunities), this demonstrates that limiting the benefits to distribution

[62] On average, avoided energy generation accounts for 63% of the total VVO benefits. Avoided generation capacity accounts for 36% of benefits, while avoided transmission and distribution capacity account for 1% each.

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system only, significantly lowers the B/C ratio of VVO. Since LDCs cannot account for upstream generation and transmission benefits in their rate applications, adoption of VVO is likely to be limited.

Similar results are found for phase balancing and electricity theft detection.

Table 30. B/C Ratios for VVO by Prototypical Feeder – System-Wide vs. Dist. Benefits

Rank	Ranked Feeders by Cost-Benefit Ratio	System-Wide *B/C ratio*	Dist.-Benefits *B/C ratio*
1	12.47 kV - Heavy Suburban	1.80	0.02
2	27.6 kV - Moderate Urban	1.80	0.01
3	44.4 kV - Light Rural	1.80	0.01
4	27.6 kV - Moderate Suburban	1.50	0.01
5	12.47 kV - Moderate Urban	1.20	0.01
6	12.47 kV - Moderate Suburban	0.90	0.01
7	4.16 kV - Heavy Urban	0.60	0.01
8	27.6 kV - Light Rural	0.60	0.01
9	4.16 kV - Heavy Suburban	0.45	0.01
10	12.47 kV - Light Suburban	0.45	0.01
11	4.16 kV - Moderate Urban	0.30	0.01
12	12.47 kV - Light Rural	0.30	0.01
13	4.16 kV - Moderate Suburban	0.23	0.01
14	4.16 kV - Light Suburban	0.15	0.01
15	4.16 kV - Light Rural	0.08	0.00

Source: Navigant analysis

This illustrates a critical barrier to IFMC adoption in Ontario. Much like many smart grid investment, IFMC technologies result in diffuse benefits and concentrated costs. Benefits accrue across all segments of the electricity sector (e.g., generation, transmission, distribution, and customers), however all costs are concentrated and carried by one segment; distribution (e.g., LDCs). For example, on average across all 15 prototypical feeders, avoided energy generation accounts for 63% of the total VVO benefits. Avoided generation capacity accounts for 36% of benefits, and avoided transmission and distribution capacity account for 1% each, respectively. While only 37% of benefits accrue upstream of the distribution system (generation plus transmission), LDCs are burdened with the full cost of VVO deployment. This misalignment of costs and benefits limits the ability of LDCs to build a comprehensive business case for IFMC technologies because there are limited opportunities to capture benefits outside of the distribution segment.

Section 7 presents a hybrid approach to cost-recovery addresses the challenge of misalignment between costs and benefits.

6.4.2 Distribution Rates Approach based on Comparison of Alternatives

The analysis presented in this section is based on the second scenario for funding of IFMC through distribution rates. This scenario compares of IFMC investment costs with the costs of alternative distribution upgrades. Much like the previous scenario, this scenario considers only distribution benefits, however, is based on the potential for an IFMC technology to defer a distribution investment.

The key challenge faced by each of the three IFMC technologies evaluated in this report (VVO, phase balancing, and theft detection) is that the premise for the comparison of alternatives is based on the ability of an IFMC technology to reduce peak demand and therefore potentially defer distribution upgrades for some period of time. Table 31 shows the peak demand reduction impacts of these three technologies. Appendix D describes the assumptions underlying these impact factors. Of the three technologies, only VVO has potential to result in a meaningful reduction in peak demand.

VVO peak demand reductions vary between 0.6% to 1.9% based on the prototypical feeder analysis. The impacts of phase balancing and theft detection are negligible and cannot result in the deferral of distribution investments. As a result, this section focuses on the potential use of VVO to defer infrastructure investments.

Table 31. Peak Demand Reduction Impacts by IFMC Technology

IFMC	Peak Demand Reduction (%)
VVO	0.6% to 1.9% [63]
Phase Balancing	Negligible [64]
Theft Detection	0.07% [65]

To evaluate the rate-based approach for VVO, this section is divided into three steps:

1. **Forecast Need for Capacity:** This step uses the growth rates from OPO Scenarios B and D to determine when, in the future, each of the prototypical feeder may require an upgrade.
2. **Deferral Period:** This step assumes a hypothetical VVO deployment and determines the resulting deferral period using the reductions in peak demand from VVO deployment.
3. **Comparison of Alternatives:** This step compares the cost of VVO deployment with the costs of investing in distribution upgrades.

6.4.2.1 Forecast Need for Capacity

The cumulative annual growth rate (CAGR, %) underlying OPO Scenarios B and D are equivalent to 0.2% and 2.0% respectively per year. OPO-B leads to 4.1% increase in peak load over a 20-year period for any feeder. An increase of this magnitude is unlikely to trigger the need for capacity upgrades for any of the prototypical feeders. Recognizing that the Scenario B growth rate is for provincial-level and not the feeder-level, the analysis includes a list of hypothetical feeder-level growth scenarios. These growth scenarios are assumed to more closely resemble real scenarios in areas of the province where significant growth is projected in the short and long term.

[63] Peak reduction impact varies by prototypical feeder. See Appendix D for more information.

[64] Peak reduction impact is indirectly determined based on a 5%-line loss reduction (e.g., 5% multiplied by the line loss factor). See Appendix D for more information.

[65] Peak reduction impact is based on reduction in electricity consumption of 0.10% and a load factor of 70%. See Appendix D for more information.

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To illustrate various growth scenarios, the analysis will focus on a hypothetical, heavy 4.16 kV feeder under various load growth projects; 1%, 2% (aligned with OPO-D), 3% and 4% per year. Heavily loaded feeders, independent of voltage class, are ideal candidates because they are more likely to be upgraded when significant load growth is projected. Although a voltage class of 4.16kV is selected for this analysis, any other voltage class will result in similar results.

Table 32 shows the peak demand forecast based on a Year 0 peak of 2.75 MW. The second half of this table shows the year in which a feeder upgrade would be required based on a maximum thermal capacity of 3.00 MW. For example, based on the 1% scenario this feeder would reach maximum capacity and require an upgrade in Year 8. Based on the 2% scenario, an upgrade would be required in Year 4, and based on the 3% and 4% scenarios an upgrade would be required in Year 2.

Table 32. Load Growth Scenarios for Heavy 4.16 kV Feeder

	Growth Rate (%)	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Peak Demand Forecast (MW)										
1% Scenario	**1.00%**	2.75	2.78	2.81	2.83	2.86	2.89	2.92	2.95	2.98
2% Scenario	**2.00%**	2.75	2.81	2.86	2.92	2.98	3.04	3.10	3.16	3.22
3% Scenario	**3.00%**	2.75	2.83	2.92	3.00	3.10	3.19	3.28	3.38	3.48
4% Scenario	**4.00%**	2.75	2.86	2.97	3.09	3.22	3.35	3.48	3.62	3.76
Upgrade Required (1 = Yes)										
1% Scenario										1
2% Scenario						1	1	1	1	1
3% Scenario				1	1	1	1	1	1	1
4% Scenario				1	1	1	1	1	1	1

Source: Navigant

6.4.2.2 Deferral Period

This section determines the deferral period obtained from the deployment of VVO on the 4.16 kV feeder. Figure 55 shows an illustration of the impact of VVO based on the 2% load growth scenario, and assuming a peak demand reduction of 2%. In this example, VVO is deployed in Year 0 and forecasted peak is reduced by 2% in Year 1. This scenario leads to a 1-year deferral period for feeder capacity. Deploying VVO on this feeder pushes out the need for feeder capacity from Year 4 (as determined in the previous section) to Year 5.

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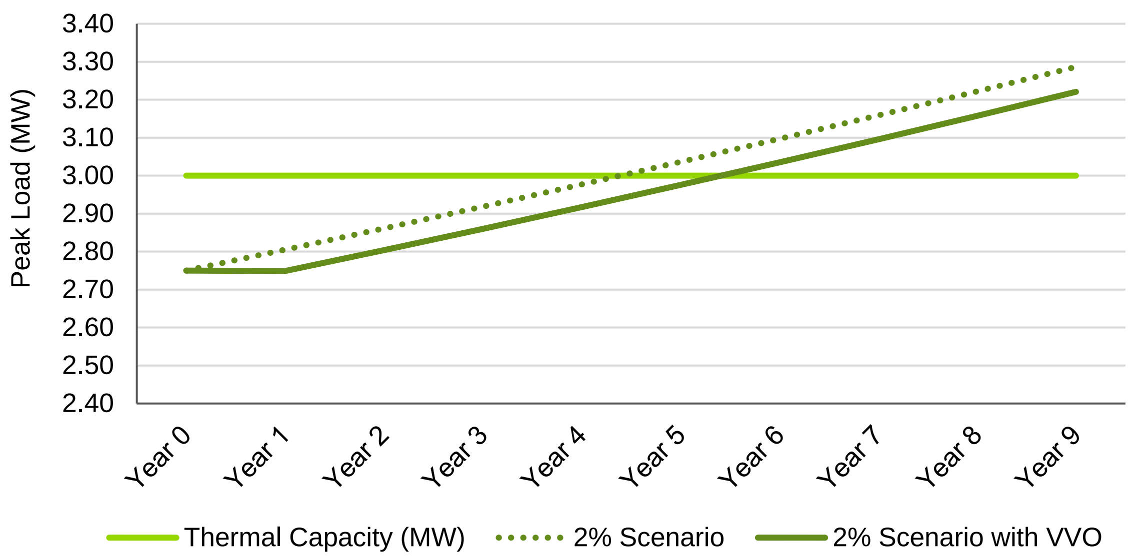
Figure 55. Illustrative Load Forecast for 4.16kV Feeders



Source: Navigant

Table 33 shows the impact of varying the peak reduction impact of VVO on the deferral period. Based on a relatively small peak reduction of 1% on two of the growth scenario (the 2% and 4% scenarios) does not result a deferral of capacity upgrades. Based on a 4% peak demand reduction, two growth scenarios (the 2% and 3% scenarios) extend the deferral period by one additional year to a total of two years. This analysis shows that in most situations and scenarios, VVO will result in a deferral period between zero and two years, however, the most likely deferral period is one year.

High growth feeders are likely to result in shorter deferral periods than low growth feeders, since high growth will reach maximum capacity faster than low growth feeders. This is illustrated by the 4% growth scenario which in three out of four the peak reduction scenario do not result in any deferral period.

Table 33. Sensitivity of Deferral Period to VVO Peak Impact and Load Growth Scenarios (Years)

Scenario	VVO Peak Reduction (%) Impact			
	1%	***2%***	***3%***	***4%***
1% Scenario	1	1	1	1
2% Scenario	0	1	1	2
3% Scenario	1	1	1	2
4% Scenario	0	0	0	1

Source: Navigant

6.4.2.3 Comparison of Alternatives

To evaluate the rate-based approach for VVO, the total costs of VVO deployment were compared with the present-value of the deferral costs of upgrading the 4.16 kV feeder. Table 34 below presents this comparison of costs.

The costs of deploying VVO on one 4.16 kV feeder were estimated at approximately $125,000 –as presented in Table 34. The feeder upgrade costs are assumed to vary from $50,000 to $400,000 per kilometer of distribution line (*$ per km* is a common metric used to measure and benchmark line upgrade costs). Common overhead feeder costs for low voltage levels such as 4.16 kV can range wildly, and may cost up to approximately $500,000 per kilometer – however costs of this magnitude are far from common and unlikely to be widespread across Ontario.[66] Based on a feeder length of 10 km, the total upgrade costs range from $500,000 to $4,000,000.

The "net benefit" columns in Table 34 show the net-benefit (or cost) of a feeder upgrade. This column is calculated by netting the costs of VVO deployment with costs of upgrading a feeder assuming a deferral period of one or two years. For example, based on feeder upgrade costs of $50,000 per kilometer, VVO is not cost-effective for a deferral period of one or two years (result in net-cost of $70,000 and 20,000 respectively).

Based on feeder upgrade costs of $100,000 per km, VVO is not cost-effective if it results in a deferral period of one year (with a net-cost of $20,000). However, VVO is cost-effective based on a two-year deferral period (with a net-benefit of $80,000). Based on upgrade costs of $200,000 per kilometer or higher, VVO is cost-effective in either a one-year or two-year deferral period.

VVO is the more expensive alternative when the technology defers upgrades for a one year period and when feeder upgrades cost between $50,000 to $100,000 per kilometer. VVO is the least cost alternative when feeder upgrade costs higher than $100,000 per kilometer based on a two year deferral period. Across most distribution networks, feeder upgrade costs higher than $200,000 per km are very limited and only a small fraction of all Ontario feeders are likely to fall in this category

Higher feeder upgrade costs and longer deferral periods result in VVO investments being the least-expensive alternative.

Table 34. Rate-Based Approach – Comparison of IFMC and Feeder Upgrade for 4.16kV Feeders

Net Benefit based on Deferral Period			Feeder Upgrade Costs		
Voltage	**1 Year**	**2 Years**	**Overnight Cost** *(2017$)*	**Assumed Length** *(km)*	**Assumed Costs** *($/km)*
4.16 kV	($70,000)	($20,000)	500,000	10	$50,000
	($20,000)	$80,000	1,000,000		$100,000
	$90,000	$280,000	2,000,000		$200,000
	$200,000	$480,000	3,000,000		$300,000
	$300,000	$690,000	4,000,000		$400,000

Source: Navigant analysis

Table 35 illustrates the same comparison as in Table 34, however, Table 35 is based on estimates of feeder upgrade costs for the 12,47 kV, 27.6 kV, and 44.4 kV feeders. The 4.16 kV example is based on

[66] Costs may be higher for higher voltages, and may be two to five times higher for underground lines.
Energy & Environmental Economics. 2000. *Costing Methodology for Electric Distribution System Planning*.

feeder upgrade costs of $300,000 per kilometer. Upgrade costs for the 12.47 kV, 27.6 kV, and 44.4 kV vary between $400,000 and $600,000 per kilometer.

For all scenarios in Table 35, VVO is the least cost alternative when compared to feeder upgrades. This is because upgrades to the larger feeders are more costly.

Table 35. Rate-Based Approach: Comparison of IFMC and Feeder Upgrade for All Feeders

	NPV (Years of Deferral)		Feeder Upgrade Costs		
Voltage	**1 Year**	**2 Years**	**Overnight Cost** *(2017$)*	**Assumed Length** *(km)*	**Assumed Costs** *($/km)*
4.16 kV	$200,000	$480,000	$3,000,000	10	$300,000
12.47 kV	$630,000	$1,400,000	$8,000,000	20	$400,000
27.6 kV	$1,280,000	$2,720,000	$15,000,000	30	$500,000
44.4 kV	$2,350,000	$5,220,000	$30,000,000	50	$600,000

Source: Navigant analysis

It is important to recognize that the upgrade costs used in this section are illustrative, and do not reflect a provincial average. Defining a provincial average of upgrade costs is complex and runs the risk of oversimplifying the wide variety of grid conditions in the province. Upgrade costs can vary significantly by current loading levels, population/customer density, customer demographics, projected load growth, and several other location-specific factors. Similarly, typical distribution upgrade costs may also include or be affected by underground/overhead line breakdown, extent and reach of laterals, substation-related costs, and transformers, or other miscellaneous equipment.

This exercise demonstrates that there are likely opportunities where VVO deployment may be a cost-effective alternative to expensive investments in feeder upgrades or other distribution infrastructure. However, these grid conditions are likely limited in Ontario.

6.5 Comparison of Conservation and Distribution Rates Cost-Recovery

The conservation approach and the distribution rates approach have unique benefits and limitations. The conservation approach provides LDCs a streamlined approval process for IFMC technologies with a relatively shorter cost-recovery period. However, funding of IFMC projects through CDM would divert funds from customer-facing energy efficiency programs, and –given the magnitude of IFMC project costs– CDM funds might decrease materially should the CDM approach provide full funding for IFMC.

Comparatively, funding through distribution rates might encourage LDCs to pursue IFMC opportunities where costly distribution capacity upgrades might be deferred or avoided. However, experience to date demonstrates that this currently funding opportunity does not provide adequate motivation for LDCs to pursue IFMC. Another key challenge faced by the distribution rates approach is that projects must be justified on the basis of local benefits alone (e.g., local distribution benefits). Because of this, upstream benefits –including generation and transmission benefits– may not be included in an IFMC business case. In turn, projects that are cost-effective based on their broader system benefits but not when only local distribution benefits are considered, will not materialize.

In addition to these, there are five primary differences between the two funding models:

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1. **The project approval process -** The approval process for IFMC projects under the conservation approach is not subject to the full regulatory oversight required for the distribution rates approach
2. **The timeframe over which the costs are recovered from customers -** Costs will either be recovered over the lifetime of the asset or over the course of a CDM framework period;
3. **Which customers pay -** Costs will either be socialized over all Ontario rate-payers or customers in a specific LDC service territory;
4. **The post-deployment EM&V -** Projects funded through CDM require rigourous post-installation assessments whereas distribution-rates supported investments do not; and ultimately,
5. **The ability of the funding model to effectively encourage LDC investment in IFMC technologies -** To-date, the distribution rates approach has had minimal affect on encouraging IFMC investments. Integrating IFMC with CDM may be effective in stimulating uptake.

Table 36 compares the conservation approach and the distribution rates approach. This table shows the costs and benefits included in the cost-tests required for each approach. Although the UCT is not required by the IESO, it is included in this table to illustrate an LDC's financial motivation to pursue an IFMC project. The UCT and NPV rows are highlighted blue to highlight that the level of achievable potential is directly associated with these two tests.

The partial incentive option (i.e., an incentive less than 100% of project costs) of the conservation approach is not expected to result in IFMC adoption. Under the full funding conservation approach, since all project costs are guaranteed to be covered this approach could result in a higher level of adoption. Finally, unless the OEB considers the full range of benefit delivered through an IFMC project, the distribution rates approach would require LDCs to justify IFMC investments based exclusively on distribution benefits. As a result, only a small number of IFMC projects would be cost-effective resulting in low achievable potential.

Table 36: Comparison of Conservation and Distribution Rates Cost-Recovery

		Conservation Approach		Distribution Rates
		Partial Incentive	*Full Funding*	
Options		**(1)**	**(2)**	**(3)**
IESO-required Cost-Test				
TRC	Costs	All Costs	All Costs	–
	Benefits	All Benefits + NEB	All Benefits + NEB	–
UCT	Costs	**All Costs – Incent.**	**No Costs**	–
	Benefits	**Dx.**	**Dx.**	–
OEB-required Cost-Test				
NPV	Costs	–	–	**All Costs**
	Benefits	–	–	**Only Dx**
Technical Potential		Approx. 2 TWh		
Economic Potential		Approx. 1 TWh		
Achievable Potential		**Low**	**High**	**Very Low**

Source: Navigant analysis

6.6 A Hybrid Approach to IFMC Project Cost Recovery

A third option was developed that blends the conservation and distribution rates approaches (e.g., a hybrid option). There are two variations of the hybrid model. The first is based on the existing regulatory process used by LDCs to recovery costs associated with infrastructure investments. The second enables LDCs to capture upstream system benefits (e.g., transmission and generation benefits). This approach uses a cost allocation mechanism to allocate the portion of the project's cost associated with upstream system benefits to all Ontario ratepayers and allocates distribution system benefit costs to local ratepayers[67].

- **Hybrid Approach #1:** Status Quo Hybrid

  This hybrid option blends the conservation and distribution rates approaches. Under this hybrid model, cost-recovery of IFMC would be achieved through distribution rates, however, LDCs would be eligible to claim end-user savings driven through these projects against their CDM targets. While this change would enable LDCs to purse IFMC as a CDM option, cost-effective IFMC projects would be severely limited because projects would need to be justified based exclusively on local distribution benefits.

- **Hybrid Approach #2:** Enhanced Hybrid

  This hybrid option is based on the *Status Quo Hybrid*, however this approach enables LDCs to capture and incorporate broader system benefits (e.g., upstream of distribution) in the assessment of distribution investments. This approach also introduces a *cost-allocation mechanism* which would enable LDCs to recover IFMC costs in proportion to the breakdown of benefits. For example, if 75% of the benefits are attributed to local distribution benefits, then 75% of costs would be recovered from local customers. The cost-allocation mechanism would enable the remaining 25% of costs to be recovered from all other provincial ratepayers because 25% of benefits account for broader system-wide benefits. This approach enables a significant level of IFMC adoption because LDCs could justify IFMC projects based on both local distribution benefits and broader benefits.

Table 37 compares the two variations of the hybrid approach against the conservation and distribution rates approaches. Since the enhanced hybrid approach enables LDCs to justify IFMC investments based only distribution benefits and broader system benefits, it is expected to result in the very high level of adoption and achievable potential.

[67] Neither hybrid option has been vetted by Ontario's regulator or been scrutinized by the OEB.

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Table 37: Comparison of Conservation, Distribution Rates, and Hybrid Approach

		Conservation Approach		Dist. Rates	Hybrid	
		Partial Incentive	*Full Funding*	*Status Quo*	*Status Quo Hybrid*	*Enhanced Hybrid*
Options		**(1)**	**(2)**	**(3)**	**(4)**	**(5)**
IESO-required Cost-Test						
TRC	Costs	All Costs	All Costs	–	–	–
	Benefits	All Benefits + NEB	All Benefits + NEB	–	–	–
UCT	Costs	**All Costs – Incent.**	**No Costs**	–	–	–
	Benefits	**Dx.**	**Dx.**	–	–	–
OEB-required Cost-Test						
NPV	Costs	–	–	**All Costs**	**All Costs**	**All Costs ** **
	Benefits	–	–	**Only Dx**	**Only Dx ***	**All Benefits ** **
Technical Potential		Approx. 2 TWh				
Economic Potential		Approx. 1 TWh				
Achievable Potential		**Low**	**High**	**Very Low**	**Low**	**High**

Source: Navigant analysis
** Should an LDC exceed their CDM goals, they would be eligible for performance incentive benefits*
*** Cost-recovery across local and provincial ratepayers is proportional to distribution of benefits between local and broader benefits*

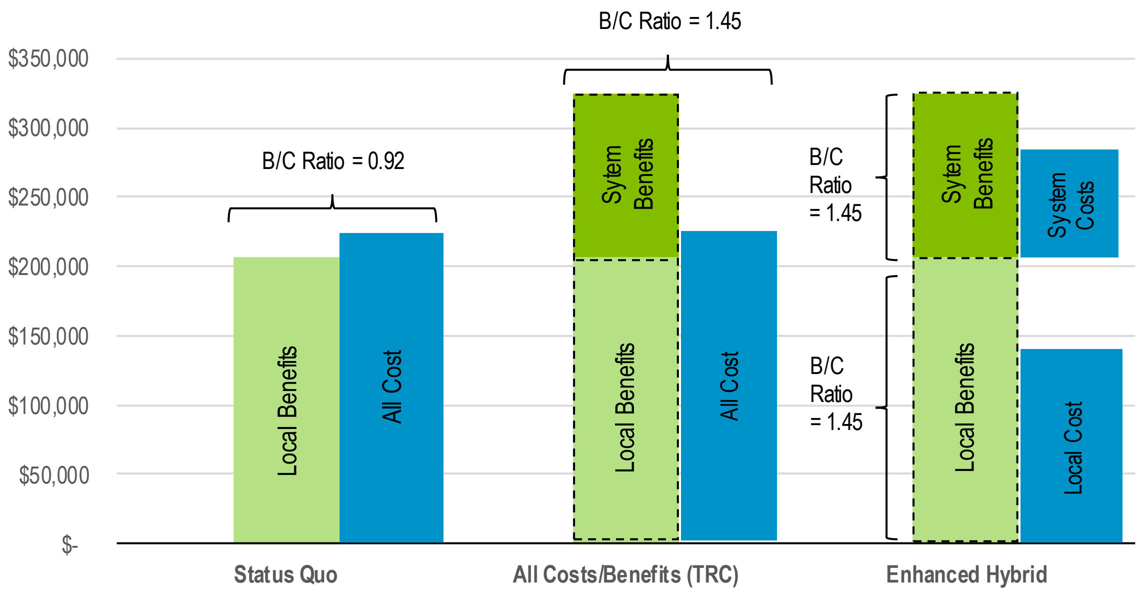
The significance of the enhanced hybrid option is that this cost-allocation mechanism helps breaks down regulatory and financial barriers. This approach enables LDCs to allocate the portion of cost associated with upstream system benefits to Ontario ratepayers, while only allocating costs to local ratepayers in proportion to local benefits. Enabling this alignment of benefits and costs across local and all Ontario ratepayers is critical at encouraging IFMC deployment. Disproportionately allocating costs on local ratepayers would have the opposite effect on LDCs and would significantly limit the magnitude of achievable potential.

An example of an existing cost-allocation mechanisms used in Ontario's electricity sector is the Renewable Generation Connection charge. The Renewable Generation Connection charge allocates costs incurred by distributors to connect distributed renewable generation to all Ontario ratepayers.

As an example, Figure 56 shows the costs and benefits for one 12.47 kV, heavy suburban feeder with VVO. Total benefits are approximately $325 million with $205 million of local benefits (63%), and $120 million of system benefits (37%), while total costs are $225 million. The NPV of VVO deployment on this feeder is $100 million. The first column illustrates the status quo approach to distribution rates with only local benefits being captured in the business case. Based exclusively on local benefits, the investment in VVO is not cost-effective with a B/C ratio of 0.92, and the project would not materialize.

The second column shows the overall costs and benefits from the TRC perspective. This illustrates that from a holistic perspective considering both local and system benefits, the VVO investment is in fact cost-effective with a B/C ratio of 1.45. The third column shows the proposed hybrid approach incorporating an enhanced distribution-rate approach. This approach would introduce a *cost-allocation mechanism* enabling costs to be recovered from local and provincial ratepayers in proportion to the breakdown of benefits. Since 63% of benefits accrue locally, the same proportion of costs (63%) would be recovered through distribution rates. Since the remaining 37% accrue represent upstream system benefits, 37% of costs would become part of the "cost-allocation mechanism" and be socialized across all ratepayers.

Figure 56. Illustrative Hybrid Approach (Status Hybrid, and Enhanced Hybrid) - VVO



Source: Navigant

7. CONCLUSIONS BASED ON KEY FINDINGS

The analysis in the previous sections have shown that IFMC projects could be financially supported through either the conservation approach, distribution rates approach or a hybrid approach. A summary of the three approaches is provided below.

Conservation Approach: Under this approach, an LDC would seek recovery of all, or a portion of the capital investment and on-going operating and maintenance expenses associated with an IFMC project through IESO managed CDM budgets. Changes to the existing conservation first framework and overarching policies and directives would be required for this approach to be viable.

For the conservation approach to be effective, LDCs would understandably require an "incentive" equal to 100% of the project's cost. This is due to the fact that while customers can monetize the value of the non-incentivized portion of the investment associated with energy efficiency upgrades through on-going bill reductions, an electricity distributor does not have a similar mechanism to monetize the residual value. If an incentive less than 100% of project costs was provided, the LDC would be required to apply to the OEB for cost recovery of the balance of the investment. As conservation and demand management initiatives do not normally offer an incentive that covers 100% of project costs, IFMC investments would likely need to be considered as a "program" and not a "measure". As a program, under the current CDM framework an LDC can recover all associated costs.

Distribution Rates: Under this approach, an LDC would seek approval for recovery of the capital investment and on-going operating and maintenance expenses from the OEB through their distribution rates. An LDC would need to justify that the IFMC investment is cost-effective, or – in a situation where a system upgrade is required – the least-cost alternative. The up-front investment would be capitalized and included in the LDC's regulated asset base. The on-going operating and maintenance costs would be accounted for as expenses and included as part of the LDC's recoverable operating, maintenance, and administrative costs.

Hybrid Approach: Under the hybrid model, cost-recovery of IFMC projects would be achieved through distribution rates, however, LDCs would be eligible to claim end-user savings driven through these projects against their CDM targets. Note: As projects funded through the hybrid approach would be eligible to claim CDM savings, rigourous post-installation assessments will be required.

Table 38 provides a comparison of these three possible funding models.

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Table 38: Comparison of Conservation and Distribution-Rates Funding Approaches

	Conservation Approach	Distribution Rates Approach	Hybrid Approach
Implementation Approach			
Implementer	IESO	OEB	OEB & IESO
Upfront Investment by:	IESO/LDC	LDC	LDC
Cost-Recovery Period:	Within the current CDM period (~3 years if funded through 2015-2020 budgets)	~10 to 15 years (depending on asset life)	~10 to 15 years (depending on asset life)
Cost Recovered from:	All Ontario electricity customers	Limited to an LDC's customers	Limited to an LDC's customers
Cost-Benefit Analysis			
Cost-Effectiveness:	• Program Administrator Cost • Total Resource Cost	• Net Present Value	• Net Present Value • Program Administrator Cost (PAC) • Total Resource Cost (TRC)
Recoverable Costs:	• Capital investment	• Financing costs • Capital investment • Operating and maintenance costs	• Financing costs • Capital investment • Operating and maintenance costs
Benefits Considered:	• Avoided Distribution, Transmission, and Generation Capacity • Avoided Energy Generation • Non-Energy Benefits (NEB)	• Avoided Distribution Capacity (The OEB has discretion to consider benefits outside of those that accrue to the LDCs' distribution system)	• Avoided Distribution Capacity (The OEB has discretion to consider benefits outside of those that accrue to the LDCs' distribution system) • For purposes of allowing the LDC to claim IFMC end-user savings towards CDM targets, project cost effectiveness for the TRC and PAC perspectives are likely to be required.

Source: Navigant

Comparing the Conservation and Distribution Rates Approaches to Cost Recovery

Significant differences between the two funding approaches exists in terms of:

1. **The project approval process:** The approval process for IFMC projects under the conservation approach would be less onerous, as approval of conservation and demand management plans is not subject to full regulatory oversight.

2. **The timeframe over which the costs are recovered from customers**: Under the conservation approach, project costs would be recovered over a condensed period (~3 years if funded through the current 2015-2020 framework). Under the distribution rates approach, costs would be recovered over the useful life of the assets (~10-15 years).

3. **Which customers pay:** Under the conservation approach, costs are socialized over all of Ontario's electricity customers. Under the distribution rates approach, costs are socialized over the implementing LDC's customers alone.

4. **The post-deployment evaluation, measurement, and verification requirements:** Projects funded through CDM require rigourous post-installation assessments whereas distribution-rates supported investments do not.

5. **The ability of the funding model to effectively encourage LDC investment in IFMC technologies:** To-date, the distribution rates approach has had minimal affect on encouraging IFMC investments. Integrating IFMC with CDM may be effective in stimulating uptake.

Both funding approaches have unique benefits and limitations. If either were available to distributors, in theory they could identify the funding mechanism that is best aligned to a given project's primary goals. As an example, if the primary purpose of the project is to offset a costlier traditional system investment, a distribution rates approach could be used. If the primary purpose is to provide electricity and demand savings to end-use customers, a conservation approach is appropriate.

Hybrid Approach to IFMC Project Cost Recovery

A hybrid approach to IFMC cost recovery considers a blending of the CDM and distribution-rates options. Specifically, under the hybrid model, cost-recovery of IFMC projects would be achieved through distribution rates, however, LDCs would be eligible to claim end-user savings driven through these projects against their CDM targets. If LDCs meet their CDM targets using IFMC projects, their performance incentive would be pro-rated to the portion of their target they met through CDM-funded projects.

The value in this approach is that it leverages existing project financing channels while at the same time offering LDCs a viable financial motivation to pursue IFMC projects. Specifically, under this model, LDCs would be provided with an additional tool to achieve their 2015-2020 CDM targets and, if targets are achieved, LDCs could receive associated CDM performance incentives. This incentive would only encourage some LDCs, and not to those LDCs who are either already on-track to meet target or who would still be unable to reach targets through the implementation of an IFMC project.

However, the hybrid approach has a number of benefits over the singular conservation or distribution rates approach, including:

1. No changes to current regulatory policy are required, and only minor changes to the CDM framework are required to enable the hybrid approach. Consequently, the model can be implemented expeditiously.
2. Actively promotes IFMC as a conservation resource, however, ensures that an LDC's CDM budgets remain focused on encouraging end-use customers to adopt energy efficiency in their homes or place of business.
3. Introduces the concept of considering IFMC project benefits outside of those delivered to the LDC's distribution system. When assessing LDC capital project applications, the OEB has traditionally considered only the avoided distribution capacity benefits the investment generates. Integrating IFMC with CDM may allow for a wider-range of benefits to be considered, including, but not limited to, avoided transmission and generation. Valuing additional benefits will have a direct impact on the number of projects that are deemed cost-effective to pursue.
4. The financial motivation from 2015-2020 CDM performance incentives may incentivize LDCs to act quickly to implement IFMC projects. Specifically, LDCs that can meet their 2015-2020 CDM target through an IFMC project.

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5. The hybrid approach is sustainable, as it does not rely on funding from a time limited Framework. The incentive of the CDM targets, while only in place during the current framework, will help to kick start LDC investments in IFMC projects.

A key limitation to this approach is that although the OEB may have the ability to consider multiple benefit streams during decision making, traditionally their sole focus has remained on the distribution system benefits a project is anticipated to generate. Since IFMC technology cost-effectiveness is driven by its transmission and generation benefits, this approach may significantly limit the achievable potential for IFMC investment in Ontario.

To address this limitation, a variation to the hybrid approach, which provides for inclusion of transmission and generation benefits, has been considered. This variation *(“Enhanced Hybrid Approach”)* introduces a *“cost-allocation mechanism”* which would enable LDCs to recover IFMC costs in proportion to the breakdown of benefits. For example, if 75% of the benefits are attributed to local distribution benefits, then 75% of costs would be recovered from local customers. The cost-allocation mechanism would enable the remaining 25% of costs to be recovered from all other provincial ratepayers because 25% of benefits account for broader system-wide benefits. This approach enables a significant level of IFMC adoption because LDCs could justify IFMC projects based on both local distribution benefits and broader benefits.

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APPENDIX A. EXCEL RESULTS DATABOOKS

Please refer to the attached Excel databooks for CBA results on each of the IFMC technologies evaluated.

APPENDIX B. DETAILED IFMC CBA RESULTS

B.1 Supporting Tables

The following abbreviations have been used in the subsequent tables for each IFMC technology:

- VVO: Volt/VAR Optimization
- ETM: Electricity Theft Mitigation
- PB: Phase Balancing

Feeder-level results for ETM are not included because the ETM study is only reported at the provincial level.

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Table 39. Benefits and Costs by Category by Feeder (2017 $)

IFMC	Selected Feeder	Avoided Gen Capacity	Avoided Energy Generation	Avoided Trans Capacity	Avoided Dist Capacity	Asset Maintenance Costs	Asset Replacement Costs	Asset First Costs	System Startup Cost	System Operations Cost
VVO	4.16 kV - Heavy Urban	$32,480	$56,233	$726	$978	$29,264	$10,647	$80,507	$4,025	$585
VVO	4.16 kV - Moderate Urban	$25,643	$45,148	$581	$773	$29,264	$10,647	$80,507	$4,025	$585
VVO	4.16 kV - Heavy Suburban	$29,122	$50,662	$654	$877	$29,264	$10,647	$80,507	$4,025	$585
VVO	4.16 kV - Moderate Suburban	$23,201	$40,934	$527	$700	$29,264	$10,647	$80,507	$4,025	$585
VVO	4.16 kV - Light Suburban	$21,227	$37,691	$485	$641	$29,264	$10,647	$80,507	$4,025	$585
VVO	4.16 kV - Light Rural	$7,527	$13,345	$172	$227	$29,264	$10,647	$80,507	$4,025	$585
VVO	12.47 kV - Moderate Urban	$102,573	$180,593	$2,326	$3,094	$48,960	$18,009	$148,807	$7,440	$979
VVO	12.47 kV - Heavy Suburban	$116,490	$202,646	$2,616	$3,509	$48,960	$18,009	$148,807	$7,440	$979
VVO	12.47 kV - Moderate Suburban	$92,804	$163,735	$2,108	$2,800	$48,960	$18,009	$148,807	$7,440	$979
VVO	12.47 kV - Light Suburban	$63,682	$113,073	$1,454	$1,923	$48,960	$18,009	$148,807	$7,440	$979
VVO	12.47 kV - Light Rural	$30,107	$53,379	$687	$909	$48,960	$18,009	$148,807	$7,440	$979
VVO	27.6 kV - Moderate Urban	$153,859	$270,889	$3,489	$4,641	$68,657	$25,371	$217,107	$10,855	$1,373
VVO	27.6 kV - Moderate Suburban	$154,674	$272,891	$3,513	$4,667	$68,657	$25,371	$217,107	$10,855	$1,373
VVO	27.6 kV - Light Rural	$60,215	$106,758	$1,373	$1,818	$68,657	$25,371	$217,107	$10,855	$1,373
VVO	44.4 kV - Light Rural	$180,645	$320,273	$4,119	$5,453	$176,991	$65,861	$592,757	$29,638	$3,540
PB	4.16 kV - Heavy Urban	$9,490	$11,416	$160	$277	$14,590	$7,036	$13,000	$650	$292
PB	4.16 kV - Moderate Urban	$4,745	$5,708	$80	$138	$14,590	$7,036	$13,000	$650	$292
PB	4.16 kV - Heavy Suburban	$7,118	$8,562	$120	$208	$14,590	$7,036	$13,000	$650	$292
PB	4.16 kV - Moderate Suburban	$3,559	$4,281	$60	$104	$14,590	$7,036	$13,000	$650	$292
PB	4.16 kV - Light Suburban	$2,373	$2,854	$40	$69	$14,590	$7,036	$13,000	$650	$292
PB	4.16 kV - Light Rural	$1,186	$1,427	$20	$35	$14,590	$7,036	$13,000	$650	$292
PB	12.47 kV - Moderate Urban	$18,980	$22,831	$320	$553	$14,590	$7,036	$13,000	$650	$292
PB	12.47 kV - Heavy Suburban	$28,470	$34,247	$480	$830	$14,590	$7,036	$13,000	$650	$292
PB	12.47 kV - Moderate Suburban	$14,235	$17,123	$240	$415	$14,590	$7,036	$13,000	$650	$292
PB	12.47 kV - Light Suburban	$7,118	$8,562	$120	$208	$14,590	$7,036	$13,000	$650	$292
PB	12.47 kV - Light Rural	$4,745	$5,708	$80	$138	$14,590	$7,036	$13,000	$650	$292
PB	27.6 kV - Moderate Urban	$28,470	$34,247	$480	$830	$14,590	$7,036	$13,000	$650	$292
PB	27.6 kV - Moderate Suburban	$23,725	$28,539	$400	$692	$14,590	$7,036	$13,000	$650	$292
PB	27.6 kV - Light Rural	$9,490	$11,416	$160	$277	$14,590	$7,036	$13,000	$650	$292
PB	44.4 kV - Light Rural	$28,470	$34,247	$480	$830	$14,590	$7,036	$13,000	$650	$292

Source: Navigant

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Table 40. Benefits and Costs by Feeder (2017 $)

IFMC	Selected Feeder	Benefits	Costs	NPV	Cost-Benefit Ratio
VVO	4.16 kV - Heavy Urban	$90,417	$125,028	-$34,611	0.72
VVO	4.16 kV - Moderate Urban	$72,146	$125,028	-$52,882	0.58
VVO	4.16 kV - Heavy Suburban	$81,315	$125,028	-$43,713	0.65
VVO	4.16 kV - Moderate Suburban	$65,362	$125,028	-$59,667	0.52
VVO	4.16 kV - Light Suburban	$60,044	$125,028	-$64,985	0.48
VVO	4.16 kV - Light Rural	$21,270	$125,028	-$103,758	0.17
VVO	12.47 kV - Moderate Urban	$288,585	$224,196	$64,389	1.29
VVO	12.47 kV - Heavy Suburban	$325,261	$224,196	$101,065	1.45
VVO	12.47 kV - Moderate Suburban	$261,447	$224,196	$37,250	1.17
VVO	12.47 kV - Light Suburban	$180,132	$224,196	-$44,065	0.80
VVO	12.47 kV - Light Rural	$85,082	$224,196	-$139,115	0.38
VVO	27.6 kV - Moderate Urban	$432,878	$323,364	$109,514	1.34
VVO	27.6 kV - Moderate Suburban	$435,745	$323,364	$112,381	1.35
VVO	27.6 kV - Light Rural	$170,163	$323,364	-$153,201	0.53
VVO	44.4 kV - Light Rural	$510,490	$868,787	-$358,297	0.59
PB	4.16 kV - Heavy Urban	$21,342	$35,568	-$14,226	0.60
PB	4.16 kV - Moderate Urban	$10,671	$35,568	-$24,897	0.30
PB	4.16 kV - Heavy Suburban	$16,007	$35,568	-$19,562	0.45
PB	4.16 kV - Moderate Suburban	$8,003	$35,568	-$27,565	0.23
PB	4.16 kV - Light Suburban	$5,336	$35,568	-$30,233	0.15
PB	4.16 kV - Light Rural	$2,668	$35,568	-$32,900	0.08
PB	12.47 kV - Moderate Urban	$42,685	$35,568	$7,116	1.20
PB	12.47 kV - Heavy Suburban	$64,027	$35,568	$28,459	1.80
PB	12.47 kV - Moderate Suburban	$32,013	$35,568	-$3,555	0.90
PB	12.47 kV - Light Suburban	$16,007	$35,568	-$19,562	0.45
PB	12.47 kV - Light Rural	$10,671	$35,568	-$24,897	0.30
PB	27.6 kV - Moderate Urban	$64,027	$35,568	$28,459	1.80
PB	27.6 kV - Moderate Suburban	$53,356	$35,568	$17,787	1.50
PB	27.6 kV - Light Rural	$21,342	$35,568	-$14,226	0.60
PB	44.4 kV - Light Rural	$64,027	$35,568	$28,459	1.80

Source: Navigant

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Table 41. Technical Peak Demand Reduction by IFMC Technology (MW)

IFMC	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
VVO	275	274	274	273	273	273	273	272	273	273	274	274	275	275	278	280	282	285	287	290
ETM	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	17	17
PB	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	47	47	48	48	49

Source: Navigant

Table 42. Technical Energy Consumption Reduction by IFMC Technology (GWh)

IFMC	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
VVO	2,024	2,016	2,013	2,010	2,010	2,006	2,009	2,004	2,006	2,007	2,015	2,019	2,024	2,027	2,043	2,060	2,078	2,096	2,115	2,134
ETM	125	124	124	124	124	124	124	124	124	124	124	124	125	125	126	127	128	129	130	132
PB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Source: Navigant

Table 43. Technical Line Loss Reduction by IFMC Technology (GWh)

IFMC	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
VVO	43	43	43	43	43	43	43	43	43	43	43	43	43	43	44	44	44	45	45	45
ETM	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PB	236	235	235	234	234	234	234	234	234	234	235	235	236	236	238	240	242	244	247	249

Source: Navigant

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Table 44. Technical Peak Demand Reduction by Feeder Cluster (MW)

IFMC	Feeder	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
VVO	4.16 kV - Heavy Urban	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5
VVO	4.16 kV - Moderate Urban	16.7	16.6	16.6	16.6	16.5	16.5	16.5	16.5	16.5	16.5	16.6	16.6	16.7	16.7	16.8	17.0	17.1	17.3	17.4	17.6
VVO	4.16 kV - Heavy Suburban	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
VVO	4.16 kV - Moderate Suburban	15.1	15.0	15.0	15.0	15.0	14.9	15.0	14.9	14.9	15.0	15.0	15.0	15.1	15.1	15.2	15.3	15.5	15.6	15.8	15.9
VVO	4.16 kV - Light Suburban	12.0	11.9	11.9	11.9	11.9	11.9	11.9	11.8	11.9	11.9	11.9	11.9	12.0	12.0	12.1	12.2	12.3	12.4	12.5	12.6
VVO	4.16 kV - Light Rural	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7
VVO	12.47 kV - Moderate Urban	44.4	44.3	44.2	44.1	44.1	44.1	44.1	44.0	44.1	44.1	44.2	44.3	44.4	44.5	44.9	45.2	45.6	46.0	46.4	46.9
VVO	12.47 kV - Heavy Suburban	15.1	15.1	15.1	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.1	15.1	15.1	15.2	15.3	15.4	15.5	15.7	15.8	16.0
VVO	12.47 kV - Moderate Suburban	28.1	28.0	28.0	28.0	28.0	27.9	27.9	27.9	27.9	27.9	28.0	28.1	28.1	28.2	28.4	28.6	28.9	29.2	29.4	29.7
VVO	12.47 kV - Light Suburban	13.8	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.8	13.8	13.8	13.9	14.0	14.2	14.3	14.4	14.5
VVO	12.47 kV - Light Rural	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.6	6.6	6.7	6.8	6.8	6.9
VVO	27.6 kV - Moderate Urban	33.3	33.2	33.1	33.1	33.1	33.0	33.1	33.0	33.0	33.1	33.2	33.3	33.3	33.4	33.6	33.9	34.2	34.5	34.8	35.1
VVO	27.6 kV - Moderate Suburban	33.5	33.4	33.3	33.3	33.3	33.2	33.3	33.2	33.2	33.2	33.4	33.4	33.5	33.5	33.8	34.1	34.4	34.7	35.0	35.3
VVO	27.6 kV - Light Rural	13.0	13.0	13.0	13.0	13.0	12.9	12.9	12.9	12.9	12.9	13.0	13.0	13.0	13.1	13.2	13.3	13.4	13.5	13.6	13.8
VVO	44.4 kV - Light Rural	39.1	39.0	38.9	38.9	38.9	38.8	38.8	38.8	38.8	38.8	39.0	39.0	39.1	39.2	39.5	39.8	40.2	40.5	40.9	41.3
PB	4.16 kV - Heavy Urban	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
PB	4.16 kV - Moderate Urban	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.3
PB	4.16 kV - Heavy Suburban	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
PB	4.16 kV - Moderate Suburban	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4
PB	4.16 kV - Light Suburban	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4
PB	4.16 kV - Light Rural	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
PB	12.47 kV - Moderate Urban	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.1	8.2	8.2	8.2	8.2	8.2	8.2	8.3	8.4	8.4	8.5	8.6	8.7
PB	12.47 kV - Heavy Suburban	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.8	3.8	3.8	3.9	3.9
PB	12.47 kV - Moderate Suburban	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.6
PB	12.47 kV - Light Suburban	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6
PB	12.47 kV - Light Rural	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1
PB	27.6 kV - Moderate Urban	6.2	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.2	6.2	6.2	6.2	6.3	6.3	6.4	6.4	6.5
PB	27.6 kV - Moderate Suburban	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.2	5.2	5.3	5.3	5.4	5.4
PB	27.6 kV - Light Rural	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2
PB	44.4 kV - Light Rural	6.2	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.2	6.2	6.2	6.2	6.3	6.3	6.4	6.4	6.5

Source: Navigant

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Table 45. Technical Energy Consumption Reduction by Feeder Cluster (GWh)

IFMC	Feeder	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
VVO	4.16 kV - Heavy Urban	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
VVO	4.16 kV - Moderate Urban	122	121	121	121	121	121	121	121	121	121	121	122	122	122	123	124	125	126	127	128
VVO	4.16 kV - Heavy Suburban	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
VVO	4.16 kV - Moderate Suburban	111	111	110	110	110	110	110	110	110	110	110	111	111	111	112	113	114	115	116	117
VVO	4.16 kV - Light Suburban	90	89	89	89	89	89	89	89	89	89	89	90	90	90	91	91	92	93	94	95
VVO	4.16 kV - Light Rural	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	13	13	13	13
VVO	12.47 kV - Moderate Urban	325	324	323	323	323	322	322	322	322	322	323	324	325	325	328	331	334	336	339	343
VVO	12.47 kV - Heavy Suburban	106	106	106	106	106	106	106	105	106	106	106	106	106	107	108	108	109	110	111	112
VVO	12.47 kV - Moderate Suburban	207	206	206	206	206	205	206	205	205	205	206	207	207	207	209	211	213	215	216	218
VVO	12.47 kV - Light Suburban	104	103	103	103	103	103	103	103	103	103	103	103	104	104	105	105	106	107	108	109
VVO	12.47 kV - Light Rural	49	49	48	48	48	48	48	48	48	48	49	49	49	49	49	50	50	50	51	51
VVO	27.6 kV - Moderate Urban	244	243	242	242	242	242	242	241	242	242	243	243	244	244	246	248	250	252	255	257
VVO	27.6 kV - Moderate Suburban	246	246	245	245	245	244	245	244	244	245	245	246	246	247	249	251	253	255	258	260
VVO	27.6 kV - Light Rural	97	97	97	97	97	97	97	97	97	97	97	97	97	98	98	99	100	101	102	103
VVO	44.4 kV - Light Rural	292	291	291	290	290	290	290	290	290	290	291	292	292	293	295	298	300	303	306	308
PB	4.16 kV - Heavy Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Moderate Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Heavy Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Moderate Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Moderate Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Heavy Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Moderate Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	27.6 kV - Moderate Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	27.6 kV - Moderate Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	27.6 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	44.4 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Source: Navigant

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Table 46. Technical Line Loss Reduction by Feeder Cluster (GWh)

IFMC	Feeder	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
VVO	4.16 kV - Heavy Urban	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7
VVO	4.16 kV - Moderate Urban	3.2	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2	3.2	3.2	3.3	3.3	3.3
VVO	4.16 kV - Heavy Suburban	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
VVO	4.16 kV - Moderate Suburban	2.4	2.4	2.4	2.4	2.4	2.3	2.4	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5
VVO	4.16 kV - Light Suburban	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
VVO	4.16 kV - Light Rural	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
VVO	12.47 kV - Moderate Urban	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.3	8.4	8.4	8.4	8.4	8.4	8.4	8.5	8.6	8.7	8.7	8.8	8.9
VVO	12.47 kV - Heavy Suburban	5.7	5.7	5.7	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.7	5.7	5.7	5.7	5.7	5.8	5.8	5.9	5.9	6.0
VVO	12.47 kV - Moderate Suburban	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.6	4.6	4.7
VVO	12.47 kV - Light Suburban	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
VVO	12.47 kV - Light Rural	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6
VVO	27.6 kV - Moderate Urban	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.4	6.4	6.5	6.5	6.6	6.7
VVO	27.6 kV - Moderate Suburban	5.3	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3	5.3	5.4	5.4	5.5	5.5	5.6
VVO	27.6 kV - Light Rural	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
VVO	44.4 kV - Light Rural	3.2	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2	3.2	3.2	3.3	3.3	3.3
PB	4.16 kV - Heavy Urban	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2
PB	4.16 kV - Moderate Urban	15.8	15.7	15.7	15.7	15.7	15.7	15.7	15.6	15.7	15.7	15.7	15.8	15.8	15.8	15.9	16.1	16.2	16.4	16.5	16.7
PB	4.16 kV - Heavy Suburban	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7
PB	4.16 kV - Moderate Suburban	11.8	11.8	11.8	11.8	11.8	11.7	11.8	11.7	11.7	11.8	11.8	11.8	11.8	11.9	12.0	12.1	12.2	12.3	12.4	12.5
PB	4.16 kV - Light Suburban	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.9	6.9	7.0	7.0	7.1	7.2	7.2
PB	4.16 kV - Light Rural	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4
PB	12.47 kV - Moderate Urban	42.1	42.0	41.9	41.9	41.8	41.8	41.8	41.7	41.8	41.8	41.9	42.0	42.1	42.2	42.5	42.9	43.3	43.6	44.0	44.4
PB	12.47 kV - Heavy Suburban	19.0	18.9	18.9	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.9	18.9	19.0	19.0	19.1	19.3	19.5	19.6	19.8	20.0
PB	12.47 kV - Moderate Suburban	22.1	22.0	22.0	22.0	22.0	21.9	22.0	21.9	21.9	21.9	22.0	22.1	22.1	22.1	22.3	22.5	22.7	22.9	23.1	23.3
PB	12.47 kV - Light Suburban	7.9	7.9	7.9	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.9	7.9	7.9	7.9	8.0	8.0	8.1	8.2	8.3	8.3
PB	12.47 kV - Light Rural	5.3	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3	5.3	5.4	5.4	5.5	5.5	5.6
PB	27.6 kV - Moderate Urban	31.6	31.5	31.4	31.4	31.4	31.3	31.4	31.3	31.3	31.3	31.5	31.5	31.6	31.6	31.9	32.2	32.4	32.7	33.0	33.3
PB	27.6 kV - Moderate Suburban	26.3	26.2	26.2	26.2	26.2	26.1	26.1	26.1	26.1	26.1	26.2	26.3	26.3	26.4	26.6	26.8	27.0	27.3	27.5	27.8
PB	27.6 kV - Light Rural	10.5	10.5	10.5	10.5	10.5	10.4	10.5	10.4	10.4	10.4	10.5	10.5	10.5	10.5	10.6	10.7	10.8	10.9	11.0	11.1
PB	44.4 kV - Light Rural	31.6	31.5	31.4	31.4	31.4	31.3	31.4	31.3	31.3	31.3	31.5	31.5	31.6	31.6	31.9	32.2	32.4	32.7	33.0	33.3

Source: Navigant

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Table 47. Economic Peak Demand Reduction by IFMC Technology – Ontario-Wide (MW)

IFMC	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
VVO	155	154	154	154	153	153	153	153	153	153	154	154	155	155	156	157	159	160	162	163
ETM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	29	29	29	29	29	29	29	29	29	29	29	29	29	29	30	30	30	30	31	31

Source: Navigant

Table 48. Economic Energy Consumption Reduction by IFMC Technology – Ontario-Wide (GWh)

IFMC	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
VVO	1,128	1,124	1,122	1,121	1,121	1,119	1,120	1,118	1,119	1,119	1,123	1,126	1,128	1,130	1,139	1,148	1,159	1,169	1,179	1,190
ETM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Source: Navigant

Table 49. Economic Line Loss Reduction by IFMC Technology – Ontario-Wide (GWh)

IFMC	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
VVO	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	31	31	31	31	32
ETM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	151	150	150	150	150	149	149	149	149	149	150	150	151	151	152	153	155	156	157	159

Source: Navigant

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Table 50. Economic Peak Demand Reduction by Feeder Cluster (MW)

IFMC	Feeder	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
VVO	4.16 kV - Heavy Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Moderate Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Heavy Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Moderate Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	12.47 kV - Moderate Urban	44	44	44	44	44	44	44	44	44	44	44	44	44	44	45	45	46	46	46	47
VVO	12.47 kV - Heavy Suburban	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	16	16	16	16
VVO	12.47 kV - Moderate Suburban	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	29	29	29	29	30
VVO	12.47 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	12.47 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	27.6 kV - Moderate Urban	33	33	33	33	33	33	33	33	33	33	33	33	33	33	34	34	34	35	35	35
VVO	27.6 kV - Moderate Suburban	34	33	33	33	33	33	33	33	33	33	33	33	33	34	34	34	34	35	35	35
VVO	27.6 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	44.4 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Heavy Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Moderate Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Heavy Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Moderate Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Moderate Urban	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	9	9	9
PB	12.47 kV - Heavy Suburban	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
PB	12.47 kV - Moderate Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	27.6 kV - Moderate Urban	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7
PB	27.6 kV - Moderate Suburban	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
PB	27.6 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	44.4 kV - Light Rural	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7

Source: Navigant

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Table 51. Economic Energy Consumption Reduction by Feeder Cluster (GWh)

IFMC	Feeder	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
VVO	4.16 kV - Heavy Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Moderate Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Heavy Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Moderate Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	12.47 kV - Moderate Urban	325	324	323	323	323	322	322	322	322	322	323	324	325	325	328	331	334	336	339	343
VVO	12.47 kV - Heavy Suburban	106	106	106	106	106	106	106	105	106	106	106	106	106	107	108	108	109	110	111	112
VVO	12.47 kV - Moderate Suburban	207	206	206	206	206	205	206	205	205	205	206	207	207	207	209	211	213	215	216	218
VVO	12.47 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	12.47 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	27.6 kV - Moderate Urban	244	243	242	242	242	242	242	241	242	242	243	243	244	244	246	248	250	252	255	257
VVO	27.6 kV - Moderate Suburban	246	246	245	245	245	244	245	244	244	245	245	246	246	247	249	251	253	255	258	260
VVO	27.6 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	44.4 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Heavy Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Moderate Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Heavy Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Moderate Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Moderate Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Heavy Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Moderate Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	27.6 kV - Moderate Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	27.6 kV - Moderate Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	27.6 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	44.4 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Source: Navigant

Table 52. Economic Line Loss Reduction by Feeder Cluster (GWh)

IFMC	Feeder	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
VVO	4.16 kV - Heavy Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Moderate Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Heavy Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Moderate Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	4.16 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	12.47 kV - Moderate Urban	8	8	8	8	8	8	8	8	8	8	8	8	8	8	9	9	9	9	9	9
VVO	12.47 kV - Heavy Suburban	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
VVO	12.47 kV - Moderate Suburban	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5	5	5
VVO	12.47 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	12.47 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	27.6 kV - Moderate Urban	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7
VVO	27.6 kV - Moderate Suburban	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	6	6
VVO	27.6 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VVO	44.4 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Heavy Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Moderate Urban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Heavy Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Moderate Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	4.16 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Moderate Urban	42	42	42	42	42	42	42	42	42	42	42	42	42	42	43	43	43	44	44	44
PB	12.47 kV - Heavy Suburban	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	20	20	20
PB	12.47 kV - Moderate Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Light Suburban	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	12.47 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	27.6 kV - Moderate Urban	32	31	31	31	31	31	31	31	31	31	31	32	32	32	32	32	32	33	33	33
PB	27.6 kV - Moderate Suburban	26	26	26	26	26	26	26	26	26	26	26	26	26	26	27	27	27	27	28	28
PB	27.6 kV - Light Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PB	44.4 kV - Light Rural	32	31	31	31	31	31	31	31	31	31	31	32	32	32	32	32	32	33	33	33

Source: Navigant

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Table 53. Peak Demand Reduction by IFMC Penetration Level (MW)

Use Case	Deployment Level	Peak Demand Reduction (MW)
Volt/VAR Optimization	0%	0
Volt/VAR Optimization	5%	29
Volt/VAR Optimization	10%	62
Volt/VAR Optimization	15%	91
Volt/VAR Optimization	25%	134
Volt/VAR Optimization	50%	219
Volt/VAR Optimization	75%	253
Volt/VAR Optimization	100%	275
Phase Balancing	0%	0
Phase Balancing	5%	6
Phase Balancing	10%	12
Phase Balancing	15%	18
Phase Balancing	25%	27
Phase Balancing	50%	39
Phase Balancing	75%	43
Phase Balancing	100%	46

Source: Navigant

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Table 54. Energy Consumption Reduction by IFMC Penetration Level (GWh)

Use Case	Deployment Level	Peak Demand Reduction (MW)
Volt/VAR Optimization	0%	0
Volt/VAR Optimization	5%	205
Volt/VAR Optimization	10%	450
Volt/VAR Optimization	15%	662
Volt/VAR Optimization	25%	980
Volt/VAR Optimization	50%	1,608
Volt/VAR Optimization	75%	1,858
Volt/VAR Optimization	100%	2,024
Phase Balancing	0%	0
Phase Balancing	5%	0
Phase Balancing	10%	0
Phase Balancing	15%	0
Phase Balancing	25%	0
Phase Balancing	50%	0
Phase Balancing	75%	0
Phase Balancing	100%	0

Source: Navigant

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Table 55. Line Loss Reduction by IFMC Penetration Level (GWh)

Use Case	Deployment Level	Peak Demand Reduction (MW)
Volt/VAR Optimization	0%	0
Volt/VAR Optimization	5%	8
Volt/VAR Optimization	10%	13
Volt/VAR Optimization	15%	19
Volt/VAR Optimization	25%	27
Volt/VAR Optimization	50%	37
Volt/VAR Optimization	75%	41
Volt/VAR Optimization	100%	43
Phase Balancing	0%	0
Phase Balancing	5%	32
Phase Balancing	10%	63
Phase Balancing	15%	93
Phase Balancing	25%	138
Phase Balancing	50%	197
Phase Balancing	75%	221
Phase Balancing	100%	236

Source: Navigant

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APPENDIX C. EXCLUDED IFMC TECHNOLOGY DESCRIPTIONS

The technologies listed below were originally considered for inclusion within the definition of IFMC; however, they were ultimately excluded from further analysis based on the outcomes of the consultation process. Below, descriptions of these excluded technologies are provided as well as the rationale for their elimination from further assessment.

C.1 Emerging Technologies

Smart Urban Low Voltage Networks

Smart Urban Low Voltage Networks is a new solid-state switching technology for use on the low voltage network. The devices developed for this technology solution are retrofitted to existing low voltage plants, and the system provides previously unavailable remote switching, visibility and reconfiguration of the low voltage network. Benefits could include reduced losses, increased capacity headroom and early visibility of emerging loading or power quality issues.

The equipment required for this technology solution includes: smart low voltage switches and software to model the low voltage network using low voltage connectivity models.

Rationale for Exclusion*:* Due to the emerging nature of this technology solution, there is no data available to support its potential impact on line losses. Also, equipment upgrades and retrofits do not fit within the definition of IFMC.

Soft Normal Open Points (SNOPS)

SNOPS is an emerging technology that enables effective meshing of circuits and hence provides the potential for reduced variable losses due to improved load sharing (subject to reasonable matching of circuit reactance). SNOPs have a potential application on both 11kV and low voltage networks.

Rationale for Exclusion: SNOPS are primarily recommended for optimal system integration of DERs, however with further secondary research the technology was found to not often realize significant electricity and demand savings.

C.2 Electricity Savings is a Secondary Benefit

Load Transfer

Primarily, load transfer is implemented in order to prevent equipment from damaging overloading situations and to extend its useful life. This technology solution can also reduce line losses by reducing the current, which also allows for deferred investments of upgrades to overloaded/heavily loaded infrastructure. Load transfer is common practice for summer or winter load switching, but new technology is allowing for more real-time and sophisticated load transfer.

The equipment required to perform load transfer includes: sensors, software, communications, smart switches, and AMI.

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Rationale for Exclusion: Load transfer was excluded as a result of the "value stack of benefits" it facilitates. Specifically, electricity and peak demand savings are minor compared to the high value of increasing equipment life or deferring investment that load transfer provides. Load transfer could be considered a free-rider in this case. In some cases, there is little incentive within the LDC to undertake the analysis to complete load transfer due to the simplicity of upgrading substation equipment as needed. Funding a portion of load transfer activities (including advanced equipment or analysis software) with CDM funds could encourage more implementation of load transfer which could significantly decrease rate increases from equipment upgrades. However, since the main objective is extending useful life, load transfer was not considered eligible as an IFMC technology.

C.3 Individual Equipment

Conductor Replacement

Newer conductors allow for less line losses, especially when the conductor is correctly sized for the system (incorrectly sized conductors are commonly seen as a reason for less than optimum Volt/VAR control). Proper conductor sizing in combination with optimized loading can prevent resistive losses and save electricity. The primary driver for conductor replacement is reliability in system design, rather than energy efficiency.

Rationale for Exclusion: The rationale for excluding conductor replacement in the IFMC analysis is that equipment upgrades and retrofits do not fit within the definition of IFMC technology. Specifically, conductor replacement is primarily undertaken to improve reliability, not produce electricity and demand impacts.

Efficient Distribution Transformers Installation

Innovations in materials and manufacturing make modern products up to 60 percent more efficient than older units. Newer, more efficient transformers allow for optimization of manufactured goods for environmental concerns. Besides benefits to the environment, efficient transformers deliver significant savings in operating costs.

Rationale for Exclusion: The rationale for excluding efficient transformers in this study is that equipment upgrades and retrofits do not fit within the definition of IFMC technology.

Capacitor Bank with Control Installation

Adding capacitor banks with controls could improve power factor and reduce line losses. Utilities are able to reduce VAR flow by deploying distribution capacitors with automated capacitor bank controls.

Rationale for Exclusion: The rationale for excluding capacitor banks with controls in the IFMC analysis is that that equipment upgrades and retrofits do not fit within the definition of IFMC technology.

Inductor Installation

In the niche case when there is too much reactive power, inductors could be used to counteract those conditions to correct power factor.

Rationale for Exclusion: The rationale for excluding inductor installation in the IFMC analysis is that equipment upgrades and retrofits do not fit within the definition of IFMC technology.

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C.4 Behind the Meter/Customer Side Technologies

Onsite Power Factor Correction Devices

Power factor correction devices work BTM to help correct power factor and are based on the individual demands of the customer's load. Most generally reclaim, store and provide power for inductive motor loads that would otherwise lower the power factor. These devices have been implemented at large industrial facilities and have been shown to save electricity depending on the amount of power factor correction. Some utilities in the US incentivize customers to install these devices and also help with proper sizing and installation. However, for the following reasons, power factor correction devices do not fit within the definition of IFMC:

1. Rate designs – such as Ontario's – that bill large customers separately for kVA demand already inherently incentivize those customers to install power factor correction devices. I.e., these devices reduce kVA demand and therefore customers can see bill reductions via their installation.
2. Power factor correction devices are – primarily – installed BTM.
3. Sizing of the power correction device is dependent on the specific load type and amount of reactive load of the customer. Proper sizing requires measurement of customer electricity use, historical information on electricity billing, and specific configuration to meet their needs. There are not a one size fits all solutions that utilities could easily deploy.
4. Many industrial facilities have already installed these devices to meet their own conservation goals and electricity savings.

Rationale for Exclusion*:* LDCs may wish to consider adopting power factor correction devices as an CDM eligible measure. Further investigation would be required.

Smart Demand Response (Smart DR)

Smart DR utilizes distributed, communicating sensors/controls and cloud-based software to achieve more reliable, tailored demand response and reduced burden or inconvenience to participating customers. It also provides the LDC with a granular ability to tailor load drops to LDC needs with respect to event timing and frequency, geographic distribution, and amount of reduction. Smart DR also provides participating customers with enhanced ability to tailor their responses to events by restricting response to specific individual loads, and imposing rules for how they participate, including times of day, and permissible temperature variance from thermostat set-point before being released.

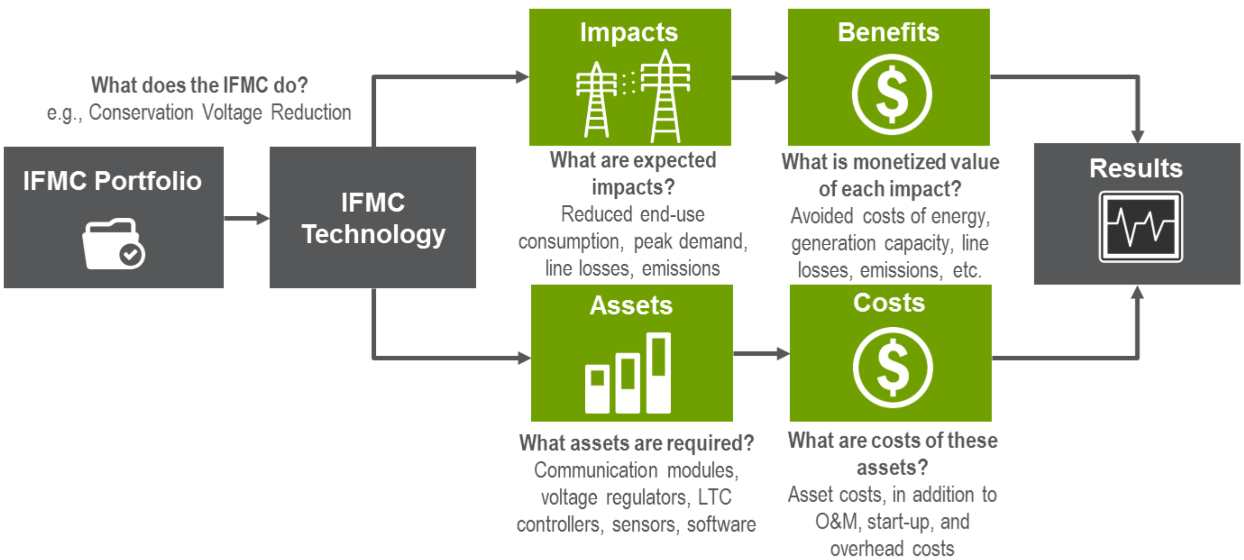
Rationale for Exclusion: The rationale for not including Smart DR in the IFMC study is because it impacts customer operations, which means it does not fall under the definition of IFMC technology.

APPENDIX D. GRID+ (ANALYTICA) MODEL OVERVIEW AND INPUT ASSUMPTION DETAIL

D.1 CBA Framework

Figure 57 presents a high level overview of the CBA framework underlying Navigant's Grid+ platform, using CVR as an illustrative example. The CBA framework considers what IFMC functionality the investment provides, what assets and collections of assets that functionality requires, how those assets physically impact the distribution system, and what benefits or value can be placed on these impacts.

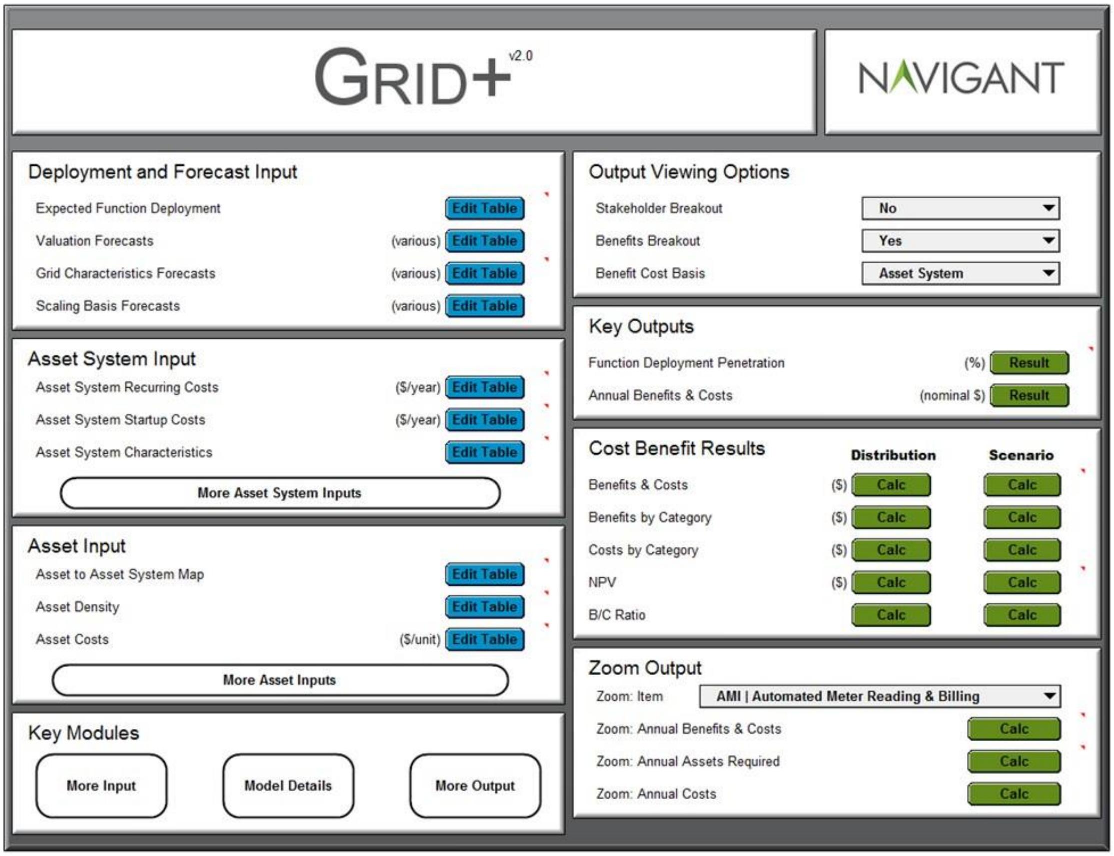
Figure 57. Cost-Benefit Analysis (CBA) Framework



Source: Navigant

Figure 58 shows the basic Grid+ dashboard design as an illustrative example of Grid+ BCA User Interface.

Figure 58. Basic Grid+TM Dashboard UI



Source: Navigant

D.2 Prototypical Feeder Analysis

LDC Survey

The following table provides the list of LDCs that provided Navigant with data on the total number of feeders in their service territory.

Table 56. LDC Data on Feeders and Customers in their Service Territory

LDC	Total No. of Feeders	No. of Customers
Hydro One Networks Inc.	3,200	1,257,016
Toronto Hydro-Electric System Limited	1,647	758,311
Hydro Ottawa Limited	865	323,919
Horizon Utilities Corporation	463	241,986
PowerStream Inc.	199	358,772
Greater Sudbury Hydro Inc.	136	47,298
Waterloo North Hydro Inc.	81	55,416
Guelph Hydro Electric Systems Inc.	62	53,789
London Hydro Inc.	53	153,947
Erie Thames Powerlines Corporation	45	18,434
Midland Power Utility Corporation	26	7,096
Wellington North Power Inc.	21	3,725
Brantford Power Inc.	18	39,127
Festival Hydro Inc.	18	20,556
Whitby Hydro Electric Corporation	13	41,798
Essex Powerlines Corporation	12	28,892
Kenora Hydro Electric Corporation Ltd.	6	5,569
*Other LDCs**	*3,294*	*1,639,088*
Total	10,159	5,054,739

*The number of feeders for Other LDCs was estimated by Navigant using customer count data from the OEB's LDC yearbook (2015)

Literature Review – Feeder Data

The following table provides feeder data by voltage class for Toronto Hydro.

Table 57. Feeder Data by Voltage Class for Toronto Hydro

	Toronto Hydro	
Voltage Class	**Feeders (% of Total)**	**Number of Feeders**
4.16	41%	674
12.5	42%	686
27.6	17%	286
44	0%	0

Source: Distribution Asset Condition Assessment for Toronto Hydro. Available at: https://www.torontohydro.com/sites/electricsystem/Documents/2008EDR/D1_T08_S09_ASSET_CONDITION_ASSESSMENTAPPA_V00.pdf

Prototypical Feeder Descriptions

The following table provides descriptions for each of the 15 prototypical feeders.

Table 58. Prototypical Feeder Descriptions

Feeder	Classification	Description
Feeder 1	4.16 kV - Heavy Urban	Feeder #1 is a 4.16 kV feeder found in Urban areas of Ontario. This feeder is heavily loaded with an average peak demand of approximately 2 MW and annual electricity consumption of 11 GWh. Feeder #1 would typically be found in urban areas such as the City of Toronto and City of Ottawa.
Feeder 2	4.16 kV - Moderate Urban	Feeder #2 is a 4.16 kV feeder found in Urban areas of Ontario. This feeder is moderately loaded with an average peak demand of approximately 1 MW and annual electricity consumption of 5 GWh. Feeder #2 would typically be found in urban areas such as the City of Toronto and City of Ottawa.
Feeder 3	4.16 kV - Heavy Suburban	Feeder #3 is a 4.16 kV feeder found in Suburban areas of Ontario. This feeder is heavily loaded with an average peak demand of approximately 1.5 MW and annual electricity consumption of 8 GWh. Feeder #3 would typically be found in the suburban areas of the Greater Toronto Area, Hamilton, and London.
Feeder 4	4.16 kV - Moderate Suburban	Feeder #4 is a 4.16 kV feeder found in Suburban areas of Ontario. This feeder is moderately loaded with an average peak demand of approximately 0.75 MW and annual electricity consumption of 4 GWh. Feeder #4 would typically be found in suburban areas of the Greater Toronto Area, Hamilton, London, Kingston and Peterborough.
Feeder 5	4.16 kV - Light Suburban	Feeder #5 is a 4.16 kV feeder found in Suburban areas of Ontario. This feeder is lightly loaded with an average peak demand of approximately 0.5 MW and annual electricity consumption of 3 GWh. Feeder #5 would typically be found in certain pockets of the Greater Toronto Area or less populated suburban areas such as Orangeville, Orillia and Bradford.
Feeder 6	4.16 kV - Light Rural	Feeder #6 is a 4.16 kV feeder found in rural areas of Ontario. This feeder is lightly loaded with an average peak demand of approximately 0.25 MW and annual electricity consumption of 1 GWh. Feeder #6 would typically be found in the rural areas of Northern Ontario and the Bruce Peninsula.
Feeder 7	12.47 kV - Moderate Urban	Feeder #7 is a 12.47 kV feeder found in urban areas of Ontario. This feeder is moderately loaded with an average peak demand of approximately 4 MW and annual electricity consumption of 22 GWh. Feeder #7 would typically be found in urban areas such as the City of Toronto and City of Ottawa.
Feeder 8	12.47 kV - Heavy Suburban	Feeder #8 is a 12.47 kV feeder found in suburban areas of Ontario. This feeder is heavily loaded with an average peak demand of approximately 4 MW and annual electricity consumption of 22 GWh. Feeder #8 would typically be found in urban areas such as the City of Toronto and City of Ottawa.
Feeder 9	12.47 kV - Moderate Suburban	Feeder #9 is a 12.47 kV feeder found in suburban areas of Ontario. This feeder is moderately loaded with an average peak demand of approximately 3 MW and annual electricity consumption of 16 GWh. Feeder #9 would typically be found in suburban areas of the Greater Toronto Area, Hamilton, London, Kingston and Peterborough.
Feeder 10	12.47 kV - Light Suburban	Feeder #10 is a 12.47 kV feeder found in suburban areas of Ontario. This feeder is lightly loaded with an average peak demand of approximately 1.5 MW and annual electricity consumption of 8 GWh. Feeder #10 would typically be found in certain pockets of the Greater Toronto Area or less populated suburban areas such as Orangeville, Orillia and Bradford.
Feeder 11	12.47 kV - Light Rural	Feeder #11 is a 12.47 kV feeder found in rural areas of Ontario. This feeder is lightly loaded with an average peak demand of approximately 1 MW and annual electricity consumption of 5 GWh. Feeder #11 would typically be found in the rural areas of Northern Ontario and the Bruce Peninsula.

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Feeder	Classification	Description
Feeder 12	27.6 kV - Moderate Urban	Feeder #12 is a 27.6 kV feeder found in urban areas of Ontario. This feeder is moderately loaded with an average peak demand of approximately 6 MW and annual electricity consumption of 33 GWh. Feeder #12 would typically be found in urban areas such as the City of Toronto and City of Ottawa.
Feeder 13	27.6 kV - Moderate Suburban	Feeder #13 is a 27.6 kV feeder found in suburban areas of Ontario. This feeder is moderately loaded with an average peak demand of approximately 5 MW and annual electricity consumption of 27 GWh. Feeder #13 would typically be found in suburban areas of the Greater Toronto Area, Hamilton, London, Kingston and Peterborough.
Feeder 14	27.6 kV - Light Rural	Feeder #14 is a 27.6 kV feeder found in rural areas of Ontario. This feeder is lightly loaded with an average peak demand of approximately 2 MW and annual electricity consumption of 11 GWh. Feeder #14 would typically be found in the rural areas of Northern Ontario and the Bruce Peninsula.
Feeder 15	44.4 kV - Light Rural	Feeder #15 is a 44 kV feeder found in rural areas of Ontario. This feeder is lightly loaded with an average peak demand of approximately 6 MW and annual electricity consumption of 33 GWh. Feeder #15 would typically be found in the rural areas of Northern Ontario and the Bruce Peninsula.

Source: Navigant

Prototypical Feeder Characteristics
The following tables provide a summary of the main prototypical feeder characteristics.

Table 59. Prototypical Feeder Characteristics

Feeder	Classification	Annual Electricity Consumption (MWh)	Average Peak Demand (MW)	Distribution Line Losses (%)
Feeder 1	4.16 kV - Heavy Urban	10,993	2	3.9%
Feeder 2	4.16 kV - Moderate Urban	5,496	1	3.9%
Feeder 3	4.16 kV - Heavy Suburban	8,245	1.5	3.9%
Feeder 4	4.16 kV - Moderate Suburban	4,122	0.75	3.9%
Feeder 5	4.16 kV - Light Suburban	2,748	0.5	3.9%
Feeder 6	4.16 kV - Light Rural	1,374	0.25	3.9%
Feeder 7	12.47 kV - Moderate Urban	21,986	4	3.9%
Feeder 8	12.47 kV - Heavy Suburban	32,978	6	3.9%
Feeder 9	12.47 kV - Moderate Suburban	16,489	3	3.9%
Feeder 10	12.47 kV - Light Suburban	8,245	1.5	3.9%
Feeder 11	12.47 kV - Light Rural	5,496	1	3.9%
Feeder 12	27.6 kV - Moderate Urban	32,978	6	3.9%
Feeder 13	27.6 kV - Moderate Suburban	27,482	5	3.9%
Feeder 14	27.6 kV - Light Rural	10,993	2	3.9%
Feeder 15	44.4 kV - Light Rural	32,978	6	3.9%

Annual electricity consumption and average peak demand values were cross-referenced with data from the OEB's LDC yearbook (2015) to ensure that Navigant's estimates are consistent with the distribution system-wide electricity consumption and peak demand in the province.

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The table below shows the estimated average line length for an individual feeder by voltage class. Values in the table were determined through discussions with Navigant SMEs. These values were used in conjunction with asset scaling factors to determine the number of certain assets per feeder. Asset scaling factor data can be found in the results spreadsheets listed in Appendix B.

Table 60. Prototypical Feeder Line Length by Voltage Class

Feeder Voltage Class	Distribution Line Length/feeder (km)
4.16 kV	10
12.47 kV	20
27.6 kV	30
44.4 kV	85

D.3 Cost Inputs

Volt/VAR Optimization
To develop a list of assets and the associated costs required for the implementation of VVO, the team reviewed previous VVO business cases developed by Navigant for various utilities and industry groups, as well as developed and vetted based on Navigant's internal SMEs. These engagements are listed below.

- BPA Regional Smart Grid Assessment (2011, 2014, 2016)[68]
- Smart Grid Great Britain Smart Grid Assessment (2014)[69]
- Eversource Grid Modernization Plan – Appendix 8 (Cost-Benefit Analysis) (2015)[70]
- *[Confidential - Canadian LDC]* Business Case Analysis (2015, 2016)
- *[Confidential – US Midwest LDC]* Business Model (2017)

Each individual VVO deployment is unique. The hardware and software required to implement VVO vary based on feeder characteristics such as line length, voltage level, and feeder "health". Poor feeder health can, in fact, make a feeder cost-prohibitive for VVO. Distribution infrastructure such as substation or feeders that are in poor condition or *under built* may often require additional preparation such as distribution capacity upgrades, reconductoring, or additional capacitor banks to correct power factor issues. Because each grid condition is different, the hardware and software used in this analysis intend to reflect an average deployment of VVO which includes the assets listed below. The deployment characteristics of each asset, capital costs, and operations and maintenance (O&M) costs associated with these assets can be found in the Excel databooks.

- CVR/VVO Control Software - App

[68] BPA 2015. Smart Grid. *Smart Grid Regional Business Case*. Available here: https://www.bpa.gov/projects/initiatives/smartgrid/pages/default.aspx

[69] SGGB 2014. *Making smart choices for smart grid development*. Available here: Link

[70] Eversource 2015. *Eversource Grid Modernization Plan*. Appendix 7: Navigant Cost-Benefit Analysis. Available here: http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=15-122%2fInitial_Filing_Petition.pdf

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- Capacitor Bank (Distribution)
- Capacitor Bank Dispatchable/Automated Controller
- Load Tap Changer Controller
- Multi-Purpose Distribution Circuit Sensor (e.g., Temperature, Volt, VAR, Current)
- Two-way Communications Infrastructure - Distribution SCADA
- Two-way Communications Infrastructure - Multi-Purpose Distribution Network
- Voltage Regulator
- Voltage Regulator Controller

Descriptions of these assets and their role in VVO can be found in Section 2.4.1. An important distinction between this asset list and Section 2.4.1 is related to the need for an ADMS and AMI equipment. An ADMS may incorporates the capabilities to implement VVO, however, these capabilities can also provide by a stand-alone CVR/VVO software system. Utilities with an ADMS in place may or may not need to procure a CVR/VVO system – depending on whether VVO capabilities are *built-in* – while utilities without an ADMS will require a CVR/VVO systems. This analysis conservatively assumes that most utilities will need a CVR/VVO systems. Since AMI has been widely adopted across Ontario, this analysis does not account for costs associated with *bell-weather* smart meters or AMI communication equipment.

Figure 59 shows the breakdown of VVO cost based on the technical potential scenario with deployment across Ontario's 10,000 feeders. This cost breakdown shows that 80% of costs are from hardware components which includes capacitor banks, capacitor bank controllers, voltage regulators, voltage regulator controllers, and load tap changer controllers. The remining 20% of costs are from sensors (multi-purpose distribution circuit sensors – 10%), communications infrastructure (SCADA and distribution network equipment – 6%), and software systems (CVR/VVO control software – 4%). This figure shows the breakdown system-wide VVO costs, however, this breakdown of costs may vary based on prototypical feeder. This is highlighted in Section 5.5 which describes that VVO costs vary based on voltage levels with 4.16kV feeders having the lowest costs while 44kV feeder have the highest.

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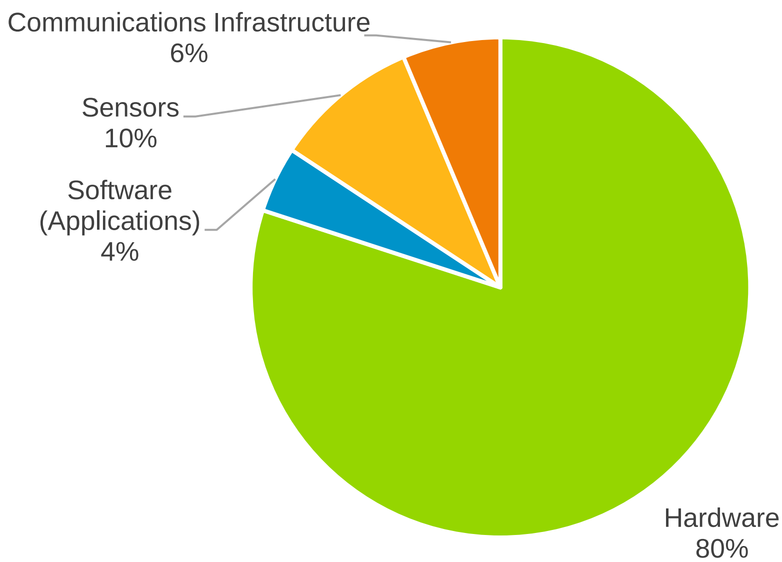
Figure 59: Breakdown of VVO Costs (%) – System Wide



Source: Navigant analysis

Table 61 shows the breakdown of VVO cost by asset and cost-category.

Table 61: Breakdown of VVO Costs (2017 $M) -System Wide

Selected Assets	Costs (2017 $M)
Capacitor Bank (Distribution)	$287
Capacitor Bank Dispatchable/Automated Controller	$416
Load Tap Changer Controller	$24
Voltage Regulator	$650
Voltage Regulator Controller	$425
Hardware	**$1,802**
Multi-Purpose Distribution Circuit Sensor (e.g., Temperature, Volt, VAR, Current)	$212
Sensors	**$212**
Two-way Communications Infrastructure - Distribution SCADA	$27
Two-way Communications Infrastructure - Multi-Purpose Distribution Network	$116
Communications	**$143**
CVR/VVO Control Software - App	$96
Software	**$96**
Total	**$2,253**

Source: Navigant analysis

Electricity Theft Detection

To develop a list of assets and the associated costs required for the implementation of electricity theft mitigation technology, the team reviewed available public literature, contacted vendors developing products to address this issue, and vetted the results with internal Navigant SMEs. There are three main

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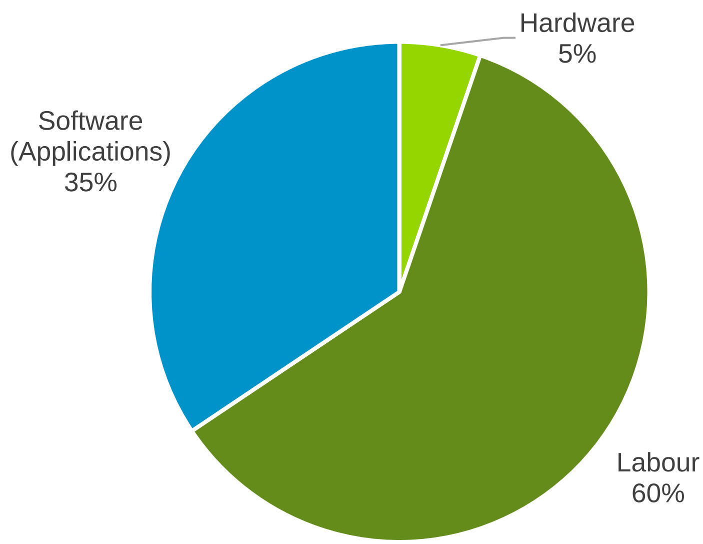
cost components related to electricity theft mitigation – as listed below. The capital and O&M costs associated with these cost components can be found in the Excel databooks.

- **Labor Costs:** This covers the costs of labor required to identify and address electricity theft incidents. Processes such as SCADA/AMI analysis, feeder onsite inspection, meter installation and retrieval, post-installation analysis, admin and other costs were considered in developing this estimate.
- **Meters:** This covers the capital cost of deploying a meter at a site suspected for conducting electricity theft to confirm existence of theft.
- **Software and Sensors**: This covers the cost of deploying smart sensors and grid analytics software to provide real-time data and improve the detection of theft on the distribution system.

Descriptions of these costs components and their role in electricity theft detection can be found in Section 2.4.2

Figure 60 shows the breakdown of electricity theft detection costs. Since the analysis for electricity theft detection was performed at the system level – rather than at the feeder-level, as was the case for VVO and phase balancing – costs are not reported by prototypical feeder. This figure shows that 60% of costs are associated with labor costs. The remaining 40% of costs in divided among software costs (software and sensors – 35%), and hardware (meters – 5%). Software and sensors are not reported separately because electricity theft detections solutions from vendors are offered to utilities as a single technology solution package.

Figure 60: Breakdown of Electricity Theft Detection Costs (%) – System Wide



Source: Navigant analysis

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Table 62 shows the breakdown of electricity theft detection costs by cost-category.

Table 62: Breakdown of Electricity Theft Detection Costs (2017 $M) – System Wide

Selected Assets	Costs (2017 $M)
Labor	$123
Software	$70
Hardware	$11
Total	**$203**

Source: Navigant analysis

Phase Balancing

The complete costs associated with these assets can be found in the Excel databooks.

To develop a list of assets and the associated costs required for correcting phase imbalances on the distribution system, the team reviewed available public literature, contacted vendors developing products to address this issue and vetted the results with internal Navigant SMEs. The following public sources were reviewed to determine cost input estimates for both electricity theft and phase balancing:

- "New BC Hydro devices save millions of dollars from cannabis-growing power thieves" (Article)[71]
- BC Hydro Financial Statements[72]
- Hydro One Line Loss Study by Kinetrics (2007)[73]
- "Large Scale Phase Balancing of LV Networks using the AMM infrastructure" (research paper)[74]
- Report of Consolidated Edison Company of New York, Inc. on Electric System Line Losses[75]

There are two main cost components related to correcting phase imbalances – as listed below. The capital and O&M costs associated with these cost components can be found in the Excel databooks.

- **Labor Costs:** This covers the costs of labor required to identify and address phase imbalances. Processes such as SCADA/AMI analysis, load-swapping to balance phase phases, post-balancing analysis, admin and other costs.
- **Software and Sensors:** This covers the cost of deploying smart sensors and grid analytics software to provide real-time data and improve the detection of phase imbalances on the distribution system.

[71] Vancouver Sun Article. Available here: http://vancouversun.com/news/local-news/new-b-c-hydro-devices-saves-millions-of-dollars-from-cannabis-growing-power-thieves

[72] BC Hydro Financial Statements. Available here: https://www.bchydro.com/about/accountability_reports/openness_accountability.html

[73] Hydro One 2007 (Kinetrics). 2007 Line Loss Study. Available here: http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2007-0681/Exhibit%20A/Tab_15_Schedule_3_Distribution_Line_Losses_Study.pdf

[74] CIRED Research Paper, 21st International Conference on Electricity Distribution. Available here: http://www.cired.net/publications/cired2011/part1/papers/CIRED2011_0808_final.pdf

[75] Case 08-E-0751. Available here: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/FCFC9542CC5BE76085257FE300543D5E?OpenDocument

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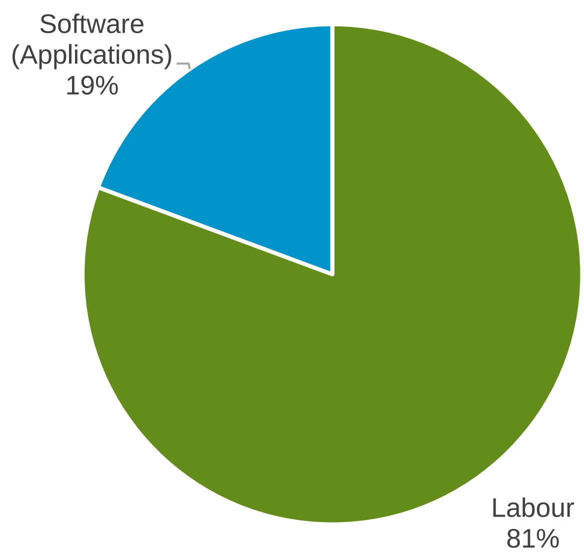
Figure 61 shows the breakdown of phase balancing costs based on the technical potential scenario with deployment across Ontario's 10,000 feeders. This cost breakdown shows that 81% of costs are associated with labor costs. The remaining 19% of costs are from software costs. The breakdown of costs does not vary based on prototypical feeder because – as described in 5.5 – labor and software costs are not expected to be dependent on voltage levels, population density, or feeder loading.

Figure 61: Breakdown of Phase Balancing Costs (%) – System Wide



Source: Navigant analysis

Table 63 shows the breakdown of phase balancing cost by cost-category.

Table 63: Breakdown of Phase Balancing Costs (2017 $M) – System Wide

Selected Assets	Costs (2017 $M)
Labor	$291
Software	$70
Total	**$361**

Source: Navigant analysis

D.4 Benefit Inputs

This section describes the assumption and inputs used to determine peak, electricity, and line loss impacts for each of the IFMC technologies; Volt/VAR optimization, theft reduction, and phase balancing.

Volt/VAR Optimization

To assign electricity and peak demand impacts to each of the prototypical feeder, the team performed a review of recent VVO literature. Table 64 lists twelve individual studies or pilot projects included as part of Navigant's review of VVO literature. In addition to these VVO projects, Navigant's review of VVO literature also included several confidential studies performed for VVO deployments at US utilities. For confidential purposes, these studies have not been included.

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In some cases, many of these resources include collection of multiple feeder or substation results. Navigant's review of these resources focused primarily on the reduction in voltage from implementing VVO (or CVR) and the observed CVR factor. The CVR factor is a measure of the effectiveness of reductions in voltage reductions to result in reductions in electricity consumption. The CVR factor is calculated by dividing the change in electricity consumption by the change in voltage.

The average voltage reduction across these studies is approximately 2.7%. The lowest voltage reduction is 0.9% (NEEA DEI) and the highest voltage reduction is 4.7% (Utilidata). To calculate the simple average of voltage reductions, any voltage reduction reported in "volts" were adjusted to percentages (%) by assuming a baseline end-use voltage of 120 V. For example, a 1.2 V reduction is equivalent to a 1% voltage reduction (e.g., 1.2 V divided by 120 V).

The average CVR factor across these studies is 0.91. The lowest CVR factor is 0.10 (Hydro-Quebec) and the highest CVR factor is 2.4 (Thomas Wilson, IEEE).

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Table 64. Literature Review of VVO Projects

Study	Year	Location	Test Circuits	Test Conditions	Voltage Reduction	CVR Factor
EPRI GA Power Peak-Time Voltage Reduction	2014	Southeastern US	5 substations	Alternate daily between normal and CVR voltage mode, summer 2012 and summer 2013	1.2% - 3.1%	0.3 - 2.0
EPRI AL Power CVR Tests	2014	Southeastern US	1 rural circuit, 1 urban circuit	Alternate daily between normal and CVR voltage mode, summer 2013	2.7% - 3.6%	0.4 - 0.7
EPRI SMUD CVR Tests	2015	Northern California	14 substations	Alternate daily between normal and CVR voltage mode, summer 2013	1.7%	0.6
EPRI Green Circuits (field trial results)	2010	Primarily Southeastern US	9 circuits at 4 utilities	Alternate daily between normal voltage mode, CVR mode for periods of 11-24 months	2% - 4%	0.6 - 0.8
NEEA DEI (load research project)	2007	Pacific Northwest	395 randomly selected residential customers at 11 utilities	Alternate daily between normal voltage mode, CVR mode for 24 months	4.3%	0.6
NEEA DEI (pilot demonstration project)	2007	Pacific Northwest	31 feeders at 6 utilities	Alternate daily between normal voltage mode, CVR mode for 24 months	0.9% - 3.6%	0.4 - 0.9
Hydro-Quebec IEEE PES conference paper	2008	Quebec, Canada	Residential	Summer	Unknown	0.7
				Winter		0.1
			Commercial	Summer		1
				Winter		0.8
			Small Industrial	Summer		0.1
				Winter		0.1
Thomas Wilson IEEE conference paper	2010	Spokane, WA (Avista)	2 feeders at 1 substation	Alternate daily between normal mode, CVR mode for 12 months	1.2V - 1.5V	2.0 - 2.4
		Canada (Hydro Ottawa)	2 feeders at 1 substation	Alternate daily between normal mode, CVR mode for 3 months	3.5V - 3.8V	1.9 - 2.3
Utilidata Murray State demonstration project	2011	Kentucky	1 university substation	Alternate daily between normal mode, CVR mode for 6 months	4.7%	1
Navigant Avista IVVC pilot project evaluation	2014	Spokane and Pullman, WA	25 feeders at 19 substations	Alternate daily between normal mode, CVR mode for 3 months	1.9% - 2.0%	0.7 - 0.9
PNNL CVR National Potential Study	2010	Southeastern US	10 modeled feeders for southeast region	Simulation modeling	2.5% - 5.9%	0.7
Triplett and Kufel Study	2012	New York state	3 substations	Winter - Alternating voltage settings w/ LDC	1.8% - 2.1%	0.8
				Sumer - Alternating voltage settings w/ LDC	2% - 2.6%	

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It is important to note that these studies represent only a small subset of feeders and substations. Many of these studies may also have selected feeders based on attractive grid characteristics for proof-of-concept purposes. Because of this, these results should not be assumed to be “across-the-board” potential voltage reduction and CVR factors applicable to an entire jurisdiction (e.g., across all of Ontario).

Navigant used the aggregated results of this literature review to inform the voltage reduction and CVR factors determined for each of the 15 prototypical feeders. The team assigned voltage reductions according to the feeder loading characteristics of the feeder, and CVR factors according to the population density of the feeder. Table 65 shows the voltage reductions and CVR factor assignments.

Feeder loading was determined to be an appropriate proxy for voltage reduction because the loading levels of a feeder impact the ability of a utility to lower voltage on that line. For example, a lightly loaded feeder may have a voltage profile –along the length of the feeder– that is relatively flat and that does not reduce significantly from the substation transformer to the end of the line. Based on this, a utility may be able to reduce voltage levels on this feeder by a good amount. In other words, lightly loaded feeders may have significant headroom to reduce voltage. In contrast, a heavily loaded feeder may have a voltage profile that decreases significantly from the substation to the end of the line. As a result, heavily loaded feeder has limited headroom for voltage reductions. Based on these characteristics, Navigant assigned voltage reduction varying from 1.3% for heavily loaded feeders to 2.9% for lightly loaded feeders.

Navigant assigned CVR factors according to population density. Population density is an appropriate proxy for CVR factors because the mix of end-use equipment found BTM generally vary by urban, suburban and rural locations. Different types of equipment will react differently to reductions in voltage. Resistive, inductive, and capacitive loads will behave differently when power is supplied closer to the lower end of the voltage range. Similarly, constant-power loads or loads with and without a thermal cycle will also behave differently. In general, resistive loads are better at reducing electricity consumption in response to voltage reductions than inductive or capacitive loads. A common example of a resistive load is an incandescent light bulb. A decrease in voltage translates proportionally to a reduction in the current flowing through the filament of the bulb, in turn dimming the light bulb. In general, suburban feeders are expected to result in a higher CVR factor than urban and rural feeders. This is because of their relatively higher proportion of residential loads which, more often than not, are made up of a higher proportion of resistive loads. Based on these characteristics, Navigant assigned CVR factors varying from 0.60 for rural feeders to 0.85 for suburban feeders.

As shown in Table 65, voltage reduction (by feeder loading) and CVR factor (by population density) are multiplied together to assign electricity reduction impacts by feeder type. The voltage reductions or CVR factor based on voltage levels (e.g., 4.16kV) were not varied.

Table 65. VVO Electricity Reduction Impacts

Feeder Loading		Population Density		
		Urban	Suburban	Rural
CVR factor → *Voltage Reduction (%) ↓*		***0.70***	***0.85***	***0.60***
Heavy	***1.3%***	0.9%	1.1%	0.8%
Moderate	***2.1%***	1.5%	1.8%	1.3%
Light	***2.9%***	2.0%	2.5%	1.8%

Source: Navigant analysis

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Electricity reduction estimates by feeder were used to estimate the corresponding peak demand reductions. To estimate peak demand reduction, a multiplying factor of 0.75 to the electricity reduction estimates was applied. This multiplier is also referred to as a $CVR_{Energy\text{-}to\text{-}Peak}$ factor, which can be estimated using measurements of CVR_{Energy} factors and a CVR_{Peak} factors. Reporting of CVR_{Peak} is relatively limited so utilities or evaluators generally only measure and report the CVR_{Energy} factor, which is often simply referred to as the CVR factor. A $CVR_{Energy\text{-}to\text{-}Peak}$ factor of 1.0 means that the percent reductions in energy and peak demand are the same.

The team used a 0.75 factor for Ontario because it expects reductions in peak demand to be lower than reductions in electricity. The primary reason for this is that Ontario is a predominantly summer-peaking jurisdiction. As such, during peak demand periods the space cooling load, made up largely of residential air conditioning (AC) units, is at its highest point. In turn, since much of the AC load is driven by fan motors which do not behave favorably to reductions in voltage, the peak demand reductions during the summer season are expected to be lower than the annual average. In theory, each prototypical feeder will have a unique load composition and hence will react differently during peak seasons. However, for the purposes of this analysis, the evaluation team has assumed a common assumption for all prototypical feeders.

Table 66 show the resulting peak demand reductions assignments by applying a 0.75 factor to the electricity impacts.

Table 66. VVO Peak Reduction Impacts

Feeder Loading	Population Density		
	Urban	Suburban	Rural
Heavy	0.7%	0.8%	0.6%
Moderate	1.1%	1.3%	0.9%
Light	1.5%	1.9%	1.3%

Source: Navigant analysis

Electricity Theft

Navigant developed estimates for the following three parameters in order to estimate peak and electricity reduction impacts of electricity theft detection:

A. Non-technical losses as percent of consumption (A%)
B. Electricity theft as percent of non-technical losses (B%)
C. Electricity reduction as a result theft detection (C%)

The peak and electricity reduction impacts are determined by multiplying A, B, and C. The evaluation team estimates that electricity theft represents approximately 1.0% of electricity consumption; however, the conservation impact of theft is anticipated to much lower at 0.1%. The following sections describe the methodology used to determine these values.

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Non-Technical Losses as a Percentage of Consumption (A%)

Hydro One's most recent line loss studies (2007, 2011) estimate the percentage of non-technical losses as a percent of electricity consumption.[76, 77] The Kinetrics 2007 study estimated non-technical losses at 1.2%, while the Navigant 2011 estimated them at 2.3%, for an average of 1.8%. Based on the last five years of OEB LDC Yearbook data (2011-2015), Hydro One's line losses have averaged approximately 6%. Therefore, non-technical losses (1.8%) as a percent of total line losses (6%) are approximately 30%. Since, Hydro One's line losses are generally higher than the provincial average, applying this estimate to the provincial average of 3.9% results in an estimate of Ontario-wide non-technical losses of 1.2% (e.g., 30% * 3.9%)

Electricity Theft as a Percentage of Non-Technical Losses (B%)

Non-technical losses occur as a result of electricity theft, faulty meters (both smart and mechanical), metering inaccuracies, and unmetered electricity (e.g., electricity that is not metered but estimated such as street lighting loads). While it is inherently impossible to estimate the what fraction of non-technical losses is a result of theft since –by definition– electricity theft is "undetected" load, there is general agreement among utilities and industry groups that electricity theft is the dominant component of non-technical losses.

In contrast, losses incurred by faulty meters or metering inaccuracies breakdown are quite rare, and more easily detected. This is because customers themselves may be able to identify changes in month-to-month consumption and report them to the LDC. Theft, however, is undetected load so month-to-month changes in consumption are not detected as readily. Based on this, Navigant estimates that approximately 80% of non-technical losses are a result of electricity theft.

Electricity Reduction as a Result of Theft Detection (C%)

Estimating the expected reduction in electricity consumption as a result of theft detection is the most complex component of the analysis. As explained in Section 2.4 (Technology Review), marijuana grow operations are generally understood to make up the largest component of electricity theft. Based on this, detection of this sort of activity results in incarceration meaning the amount of electricity consumed will, in theory, reduce to zero. In this particular case, detection of electricity theft will result in some reduction in electricity and peak demand. However, this also assumes that demand for illegal substances will also decrease. In reality, demand for illegal substances will remain the same, and by extension supply should as well. This means that, while a particular marijuana operation may be detected and eliminated, other operations will increase production. Those other operations may be electricity-paying or non-paying customers. However, whether they are paying or non-paying does will not impact overall electricity consumption. Rather, they will only affect whether their electricity consumption shows up in a LDC's line losses estimate (as non-technical line losses) or as regular consumption. To this extent, detection of electricity theft will result in no electricity or peak reduction impact.[78]

The electricity conservation aspect of theft detection is related to a secondary impact of theft detection. As theft detection activity escalates, more and more illegal operations are detected and drowned out. In

[76] Hydro One 2007 (Kinetrics). 2007 Line Loss Study. Available here: http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2007-0681/Exhibit%20A/Tab_15_Schedule_3_Distribution_Line_Losses_Study.pdf

[77] Hydro One 2011 (Navigant). 2011 Line Loss Study. Available here: http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2013-0416%20Dx%20Rates/Exhibit%20G/G1-08-02%20Attachment%201.pdf

[78] While Regardless, theft detection is an activity that utilities (in cooperation with police) will engage in to reduce non-technical loses, increase electricity sales (as limited as may be), and to identify illegal activity.

this process, economic theory dictates that production efficiencies and economies of scale will be created thereby decreasing electricity consumption on a per unit basis. In really, this effect will take time and will be situation-specific. While speculative, this is likely to result in some (however negligible) electricity and peak savings. Based on this analysis, we assume that deployment of theft detection technology to all of Ontario will result in 10% reduction in electricity demand.

Calculation of Electricity and Peak Impacts

Based on these three parameters, Table 67 shows that the estimated electricity consumption reduction from theft detection is 0.1%. The peak demand reduction of 0.07% is estimated assuming a flat load profile for marijuana operations and based on a load factor of 70% (representative of Ontario).

Table 67. Theft Reduction Peak Reduction Impacts

Parameter		Value
Non-technical losses as a percentage of consumption	(A%)	1.2%
Electricity theft as a percentage of non-technical losses	(B%)	80%
Theft as percentage of total consumption	*A x B*	*1.0%*
Electricity reduction as a result of theft detection	(C%)	10%
Electricity Consumption Reduction	A x B x C	**0.1%**
Load Factor		70%
Peak Demand Reduction		**0.07%**

Source: Navigant analysis

Phase Balancing

Navigant estimated that phase imbalances represent approximately 5% of total line losses. The following section describes the methodology used to determine this values.

Phase Imbalance as a Percentage of Total Line Losses

A phase imbalance is an example of a variable technical line loss. Variable technical losses are dependent on the magnitude of current; other factors that contribute to variable technical losses are the length of distribution lines and power factor (ratio of real power to apparent power). The amount of imbalance can vary significantly between feeders and the amount of line loss is related to the amount of phase imbalance.

A line loss study done by Kinetrics for Hydro One[79] determined that 24MWh of savings from correcting phase imbalances was achievable per feeder balanced. In this study, approximately 500 feeders were analyzed. As the average electricity consumption per Hydro One feeder is 8GWh and total line losses are approximately 6% of that[80] (REFERENCE – LDC yearbook), a 5%-line loss reduction was achieved (i.e., 6% of 8GWh = 480 MWh, 24MWh/480MWh = 5%). If almost all of the phase imbalance was corrected in the Kinetrics study, which is certainly possible, this would mean that the phase imbalance constituted 5%

[79] Hydro One 2007 (Kinetrics). 2007 Line Loss Study. Available here: http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2007-0681/Exhibit%20A/Tab_15_Schedule_3_Distribution_Line_Losses_Study.pdf

[80] OEB LDC Yearbook (2015). Available here: http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Reporting+and+Record+Keeping+Requirements/Yearbook+of+Distributors

of total line losses. This is a conservative estimate to determine the savings from correcting phase imbalances (i.e., if the feeder was still unbalanced after correction, there is still potential for electricity savings).

Navigant extrapolated this 5% value and applied it uniformly to all the prototypical feeders in this study. From a comprehensive literature review, Navigant did not identify any singular factor that would considerably make one prototypical feeder more prone to phase imbalances than another prototypical feeder. One could argue that phase imbalances as a proportion of variable, technical line losses shrinks as feeders increase in length. While this could be true, longer feeders are often at higher voltages, which increases line losses relative to shorter feeders at lower voltages. Thus, we determined a uniform assumption regarding phase imbalances as a percentage of line losses was most appropriate for the purposes of this study. It is also important to note that a reduction in line losses results in both electricity loss reduction and peak demand loss reduction.

APPENDIX E. ONTARIO STAKEHOLDERS INTERVIEW PROCESS

Defining the targeted group for stakeholder input

To identify both technical and non-technical barriers from all necessary perspectives, primary and secondary research was completed with the entities described in below. The objective of these research efforts was to ensure a comprehensive understanding of the various factors influencing IFMC projects from the standpoint of all relevant Ontario stakeholders was obtained.

Table 68. Ontario Entities Included in the IFMC Barriers Investigation

Entity	Rationale for Inclusion
The OEB	Discussions with the OEB provided clarity on the current mechanisms available to LDCs for purposes of funding IFMC projects (from both a CDM and rate-based perspective). Additionally, discussions were used to gain an understanding of the OEB's position on supporting IFMC projects proposed by LDCs.
The IESO	As the provincial administrator of CDM, the IESO was questioned on how IFMC fits within the current definition of CDM as well as the appropriateness of funding IFMC projects through CDM budgets in the future (non-technical barrier). Additionally, members of the IESO's systems operations team were interviewed to gain an understanding of any perceived transmission system management issues that could emerge if a significant number of IFMC projects were undertaken by LDCs (technical barrier).
The Electricity Distributor Association (EDA)	The EDA is an advocate for LDCs whose mandate includes assisting electricity LDCs achieve operating objectives. Given their role, they provided a valuable provincial perspective on the issue of IFMC as both a CDM and traditional power system planning resource.
Ontario LDCs	LDCs are the ultimate implementer of IFMC technologies and consequently it was necessary to gain their perspectives on the complete range of technical and non-technical barriers that could impact related investment decisions. To ensure a comprehensive perspective was obtained, primary research was completed with representative from 30 LDCs. The cross section of LDCs selected for interview was reflective of the following key LDC characteristics: size (in terms of geography and number of customers), regional diversification and current levels of IFMC engagement. Through the interview process, an accurate portrayal of all LDC perspectives was obtained. Of note: All LDCs invited to take part in this primary research responded positively to the request. This response in itself suggests a high level of LDC interest in IFMC.
IFMC Technology Vendors	IFMC vendors were interviewed to gain their insight on the potential for IFMC technology deployment in Ontario, to appreciate the extent to which they have worked with Ontario's LDC to explore IFMC technical potential, and to gain an understanding of their experiences deploying their proprietary technologies in other North American jurisdictions.

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Ontario LDC Interview Process: Telephone and Email Surveying

Two forms of primary research were completed with Ontario's LDC community: telephone/in-person interviews and email surveys. Through this research effort, the perspectives of 30 LDCs were collected. The findings of this research have been used to inform all aspects of this Section 4.

Table 69. LDC Primary Research Overview

Primary Research Method	Participating LDCs	Description of Implementation
Telephone/In-person Interview	• Enwin Utilities (telephone) • Hydro One (in-person) • Toronto Hydro (two interviews: one in-person and one telephone)	Invitations were sent to appropriate staff at each organization requesting their participation in the interview process. Each interview lasted, on average, 1.25 hours.
Online Survey	• Alectra • Cornerstone Hydro Electric Concepts (representing 15 separate LDCs)[81] • Customer First (representing six separate LDCs)[82] • Entegrus • Guelph Hydro • Ottawa Hydro • Thunder Bay Hydro • Veridian Connections	Invitations were sent to appropriate staff at each organization requesting their participation in the online survey process. Each survey, on average, required 35 minutes to complete. The online survey completed by LDCs is confidential and is not included in this report.

[81] Cornerstone Hydro Electric Concepts represents: Centre Wellington Hydro, COLLUS PowerStream, InnPower, Lakefront Utilities, Lakeland Power, Midland Power, Niagara-on-the-Lake Hydro, Orangeville Hydro, Orillia Power, Ottawa River Power, Renfrew Hydro, Rideau St. Lawrence Distribution, Wasaga Distribution, Wellington North Power and West Coast Huron Energy.

[82] Customer First represents: Espanola Regional Hydro Distribution Corporation, Greater Sudbury Hydro Inc., Newmarket-Tay Distribution Ltd., Northern Ontario Wires Inc., PUC Distribution Inc. and St. Thomas Energy Inc.

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Ontario Agency Interview Process: Telephone Surveying

Two forms of primary research were completed with Ontario's sector agencies, telephone/in-person interviews and email surveys. The findings of this research have been used to inform all aspects of this Section 4.

Table 70. Ontario Agency Primary Research Overview

Primary Research Method	Participating Agency	Description of Implementation
Telephone/In-person Interview	• IESO (two interviews: one in-person and one telephone) • OEB	Invitations were sent to appropriate staff at each organization requesting their participation in the interview process. Each interview lasted, on average, 1.15 hours.
Online Survey	• EDA	An invitation was sent to the EDA requesting their participation in the online survey process. The online survey completed by the EDA is confidential and is not included in this report.

Ontario Vendor Interview Process: Telephone and Email Surveying

Two forms of primary research were completed with IFMC technology vendors, telephone interviews and email surveys. The findings of this research have been used to inform all aspects of this Section 4.

Table 71. Vendor Primary Research Overview

Primary Research Method	Participating Vendor	Description of Implementation
Telephone Interview	• DVI	An invitation was sent to appropriate staff at DVI requesting their participation in the interview process. This interview lasted approximately 1 hour.
Online Survey	• Grid 20/20 • Varantec • kVar	Invitations were sent to appropriate staff at each organization requesting their participation in the online survey process. Each survey, on average, required 35 minutes to complete. The online survey completed by vendors is confidential and is not included in this report.

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APPENDIX F. NON-ONTARIO JURISDICTIONAL REVIEW (INCREMENTAL FINDINGS)

Due to interview scheduling constraints, not all non-Ontario interviews could be completed before submission of the final report to the Ministry of Energy. Thus, the findings from the few interviews conducted post-submission are discussed in this appendix.

F.1 Regulatory and Policy Motivations

As mentioned in Section 3.5, regulators are generally supportive towards and encourage initiatives that improve the EE of their distribution system, such as IFMC technologies. This was also evident from the utilities' responses during the final set of interviews. However, there are instances where regulators are not as concerned about EE as an important target. For example, in one jurisdiction, EE and conservation are not a priority for both the regulator and utility as the electricity price is very low. However, the utility still had plans to deploy VVO technology throughout their distribution system. This is an example of an (uncommon) scenario where regulatory pressure was not needed for the utility to pursue IFMC (VVO) deployment. The reasoning behind this is explained in Section F.2 below.

Impact of Jurisdictional Policy and Regulatory Factors

Findings from the final set of interviews are consistent with the explanations in Section 3.5.

F.2 Investment Motivations and Funding Models

While some utilities are interested in IFMC technologies for the energy and peak demand reductions they provide, others are pursuing them to upgrade their distribution system as and when needed. This is especially the case for VVO. One utility had recently developed plans to implement VVO across all feeders on their distribution system in a phased approach, but were only doing so because many of their assets are at end of life. The utility believes the myriad benefits from VVO and similar technologies will make it commonplace in the "LDC of the future." Other utilities that had piloted VVO projects also believed that this technology is currently the most optimal way to regulate voltage on the grid.

Another utility had been piloting and implementing VVO technology on select substations and feeders since 1996. The utility's initial, primary motivation was the achievable peak demand reduction, but more recently the focus has shifted to energy conservation. However, this utility was also only implementing VVO when certain substations or feeders were in need of an upgrade; they did not actively deploy VVO on assets within their distribution system unless they were at capacity or reached the end of their life. In other words, VVO was utilized as a supplementary technology to capital investments that had to be made on the distribution system.

The Role of CDM

The majority of the findings from the final set of interviews are consistent with the explanations in Section 3. As most utilities pursued IFMC investments primarily through their rate applications, they had not adequately considered the possibility of having the investments funded through CDM programs.

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F.3 Barriers to Adoption

The findings from the final set of interviews are mostly consistent with the explanations in Section 3.7. The only additional insight gained was that technology barriers, described by most utilities as perhaps the weakest type of barrier to IFMC deployment, were significant during one utility's VVO pilot. The utility mentioned that they had significant problems with integrating the IT infrastructure and running software algorithms necessary to effectively deploy VVO technology. This shows that from a technology perspective, even though VVO has demonstrated positive results in several jurisdictions, it can be considerably challenging for a distributor to successfully implement the system and produce desirable results.

Furthermore, the utility mentioned that it was important to be aware of the fact that a pilot VVO project could be very different from grid-scale VVO deployment. That is, distributors will need to carefully design an implementation plan if they are to successfully deploy VVO on their grid.

F.4 EM&V Lessons Learned

The findings from the final set of interviews are consistent with the explanations found in the supplemental report entitled "IFMC – Best Practice EM&V Methodologies for Ontario".

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APPENDIX 6
PACIFIC NORTHWEST NATIONAL LABORATORY- EVALUATION OF CONSERVATION VOLTAGE REDUCTION (CVR) ON A NATIONAL LEVEL

U.S. DEPARTMENT OF
ENERGY

PNNL-19596

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

Evaluation of Conservation Voltage Reduction (CVR) on a National Level

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July 2010

Pacific Northwest
NATIONAL LABORATORY

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Executive Summary

This report has developed an estimate of the benefits of Conservation Voltage Reduction (CVR) for individual distribution feeder types, as well as an extrapolation of the benefits on a national level. Simulations were conducted using the GridLAB-D simulation environment, developed at the Pacific Northwest National Laboratory (PNNL), as well as the Taxonomy of Prototypical Feeders developed under the Modern Grid Initiative (MGI), now the Modern Grid Strategy (MGS). Based on the results of this report there are seven high level conclusions:

1) The analysis of CVR, as well as other smart grid technologies, requires the use of time-series simulations.
2) The behavior of end use loads is more complicated than generally acknowledged. Voltage dependent multi-state models must be used to accurately represent the effects of CVR.
3) CVR provides peak load reduction and annual energy reduction of approximately 0.5%-4% depending on the specific feeder.
4) When extrapolated to a national level, it can be seen that a complete deployment of CVR, 100% of distribution feeders, provides a 3.04% reduction in annual energy consumption.
5) If deployed only on high value distribution feeders, 40% of distribution feeders, the annual energy consumption is still reduced by 2.4%.
6) In a practical deployment of CVR heavily loaded, higher voltage feeders should be targeted.
7) Loss reduction is not a significant benefit of CVR.

1. Introduction

Conservation Voltage Reduction (CVR) is a reduction of energy consumption resulting from a reduction of feeder voltage. While there have been numerous CVR systems deployed in North America, there has been little substantive analytic analysis of the effect; the majority of the published results are based on empirical field measurements. As a result, it is difficult to extrapolate how this technology will behave on the various types of distribution feeders found throughout the nation.

To ensure that the results of this report can be reproduced by other researchers, all of the tools, models, and materials used are openly available at [http://sourceforge.net/projects/gridlab-d/]. In order to prevent showing bias to any particular commercial vendor, the method of CVR selected was from a twenty year old academic publication. While this method of CVR does not represent the current state of the art, it does contain the fundamental elements that are used in current commercial CVR schemes. The majority of CVR schemes contain two fundamental components: reactive power compensation and voltage optimization. Reactive power compensation is achieved through the operation of shunt capacitors in order to maintain the power factor at the substation transformer within a prescribed band. Voltage optimization is achieved through the operation of substation voltage regulators in order to regulate the voltage at specific End of Line (EOL) points within a prescribed range. In this way the peak load is reduced and the annual energy consumption is reduced.

Through detailed time-series simulations conducted in GridLAB-D, the effectiveness of CVR can be examined on each of the 24 Prototypical Feeders. The weighting factors developed in [1] are then used to extrapolate these results to a national level. This methodology allows for the operational impact of CVR to be analyzed from the device level to the national level.

The remainder of this report is divided into five additional sections. Section 2 discusses the level of complexity which must be included in simulations in order to effectively evaluate CVR, while Section 3 examines the simulation results of the 24 Prototypical Feeders. Section 4 extrapolates the individual feeder results of Section 3 in order to develop a national level estimate of the benefits of CVR and Section 5 contains the concluding remarks. Section 6 is an appendix which contains multiple analysis plots for each of the 24 Prototypical Feeders.

2. Modeling Principles

In order to effectively model CVR, as well as most distribution level behaviors, it is necessary to perform time series simulations. Examining the peak load behavior and inferring behavior for the rest of the year is not adequate. For the analysis of CVR presented in this report simulations were performed with a one (1) minute time step for an entire year (8760 hours).

Additionally, standard power flow solutions are insufficient for analyzing the effects of CVR. Many loads within distribution systems cannot be defined as simple constant impedance, constant current, and constant power loads (ZIP). Many are thermostatically controlled, provide constant mechanical power, or draw a constant amount of energy over different time periods. To properly understand the effects of voltage reduction on the distribution system, such loads must be properly modeled. Additionally, standard distribution solvers ignore the effects of residential transformers (typically split-phase or center-tapped) and the cabling that connects the consumer to the transformer. While omitting these components may be acceptable for traditional capacity planning studies, when studying the effects of voltage reduction, they must be included. This section will discuss the level of detail which was used for determining the impacts of CVR on the various prototypical distribution feeders.

2.1. Taxonomy of Prototypical Distribution Feeders

As part of the 2008 MGI efforts, a Taxonomy of Prototypical Distribution Feeders was developed [1]. The feeders within this taxonomy were designed to provide researchers with an openly available set of distribution feeder models which are representative of those seen in the continental United States. Because climate and energy consumption are closely coupled, the prototypical feeders were divided into five climate regions based on the U.S DOE handbook (1980) providing design guidance for energy-efficient small office buildings [2].

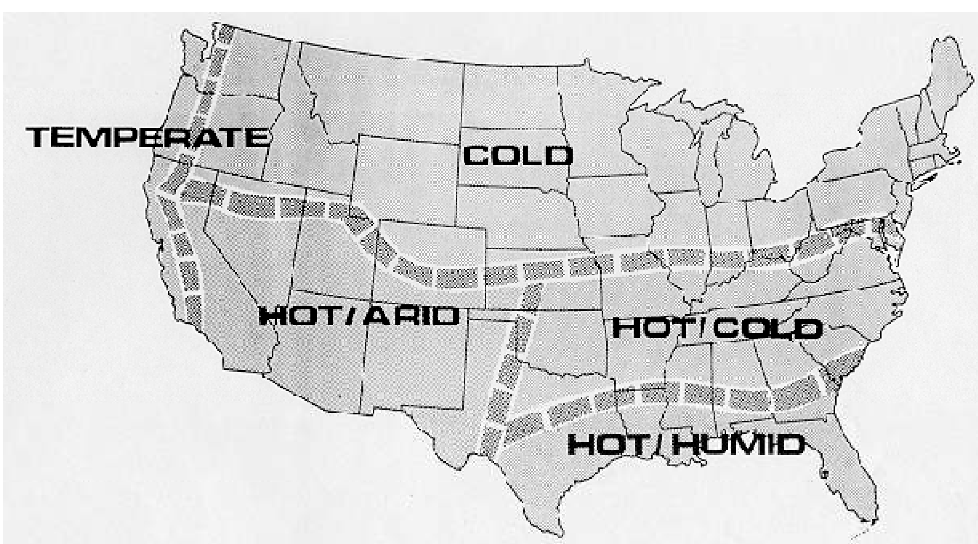


Figure 2.1: Climate Zones Used for Development of Prototypical Feeders

Within each of the climate zones, there are a set of feeders that are approximations of the types of feeders that are seen within that zone. Table 2.1 gives a summary of the 24 prototypical feeders, including feeder name, base voltage, peak load, and a qualitative description. The peak loading used for the CVR analysis is slightly different than the original values from the 2008 report; this difference will be discussed in further sections.

Table 2.1: Summary of Prototypical Feeders

Feeder	Base kV	Peak MVA	Description
R1-12.47-1	12.5	5.4	Moderate suburban and rural
R1-12.47-2	12.47	4.3	Moderate suburban and light rural
R1-12.47-3	12.47	2.4	Small urban center
R1-12.47-4	12.47	1.8	Heavy suburban
R1-25.00-1	24.9	4.9	Light rural
R2-12.47-1	12.47	2.3	Light urban
R2-12.47-2	12.47	6.7	Moderate suburban
R2-12.47-3	12.47	6.7	Light suburban
R2-25.00-1	24.9	4.8	Moderate urban
R2-35.00-1	34.5	21.3	Light rural
R3-12.47-1	12.47	6.9	Heavy urban
R3-12.47-2	12.47	11.6	Moderate urban
R3-12.47-3	12.47	4.0	Heavy suburban
R4-12.47-1	13.8	9.4	Heavy urban with rural spur
R4-12.47-2	12.5	6.7	Light suburban and moderate urban
R4-25.00-1	24.9	2.1	Light rural
R5-12.47-1	13.8	1.0	Heavy suburban and moderate urban
R5-12.47-2	12.47	10.8	Moderate suburban and heavy urban
R5-12.47-3	13.8	4.2	Moderate rural
R5-12.47-4	12.47	4.8	Moderate suburban and urban
R5-12.47-5	12.47	6.2	Moderate suburban and light urban
R5-25.00-1	22.9	8.5	Heavy suburban and moderate urban
R5-35.00-1	34.5	9.3	Moderate suburban and light urban
GC-12.47-1	12.47	12.1	Single large commercial or industrial

The original prototypical feeders were modeled in detail from the substation to the end use point of interconnection, but did not include detailed load models. To use these feeders for an accurate analytic assessment of CVR, it was necessary to include detailed end use load models.

2.2. Determination of Load Type

Load information in the original feeder models was fairly limited. The original models contained a small amount of information on commercial loads and no information on residential loads. Loads were defined as static spot loads, where blocks of individual commercial and residential loads were summed to a single peak spot load on the primary system (no secondary voltage loads were defined). To more accurately classify the loads, Google Earth© images of the feeders were located and the physical dimensions of the feeder overlaid. The loads provided by the original model were then manually classified by the type of building found at that location, and were broken into nine different load types via visual inspection. These were classified as Residential 1-6, Commercial 1-2, and Industrial. Brief descriptions are provided in Table 2.2. Each load classification describes the properties of the load in that area, and the details that describe each type of load will be further described in Section 2.4 Population of Loads.

Table 2.2: End Use Load Classifications

Load Class	Description
Residential 1	Pre-1980 <2000 sqft.
Residential 2	Post-1980 <2000 sqft.
Residential 3	Pre-1980 >2000 sqft.
Residential 4	Post-1980 >2000 sqft.
Residential 5	Mobile Homes
Residential 6	Apartment Complex
Commercial 1	>35 kVA
Commercial 2	<35 kVA
Industrial	All Industrial

By defining each building as older or newer, and larger or smaller, approximate physical properties for those homes could be assumed. These were then used to define multiple building models at each load location, depending upon the type of building that was found through observation in Google Earth©. Defining these properties gives insight into the benefits of voltage reduction not only at a single given load level, but as a function of seasonal and daily variations in load. Once again, while a particular building model at that location does not accurately represent a specific building in reality, the aggregate of the distribution of the buildings should approximate the response of all of the real buildings. Within each building, appliance loads were also modeled, as will be seen in the following sections.

2.3. Load Models

Once each of the points of interconnection were classified in accordance with Table 2.2, it was necessary to fully represent the load. Because of the complexity of end use load behavior, load models can be divided into two distinct classes: those without thermal cycles and those with thermal cycles. Loads without thermal cycles consume energy in a time-invariant manner, with the exception of voltage variations. Specifically, there is no control feedback loop. As an example, a light bulb will consume energy when turned on, as a function of voltage, in a fixed manner. In contrast, a load with a thermal cycle, such as a hot water heater, will have a varying duty cycle dependent on the supply voltage. For example, if the supply voltage is lowered, the hot water heater will draw less instantaneous power, but it must remain on for a longer period in order to heat the same mass of water.

Sections 2.3.1 and 2.3.2 will discuss loads without thermal cycles while Section 2.3.3 will discuss loads with thermal cycles. Section 2.3.4 will then discuss how these were combined to form complete load models for individual Residential, Commercial, and Industrial Customers.

2.3.1. Loads without Thermal Cycles

The traditional method for modeling a load without a thermal cycle is to use a ZIP model. The ZIP model is a load which is composed of time-invariant constant impedance (Z), constant current (I), and constant power (P) elements. Figure 2.2 shows the circuit representation of the ZIP model.

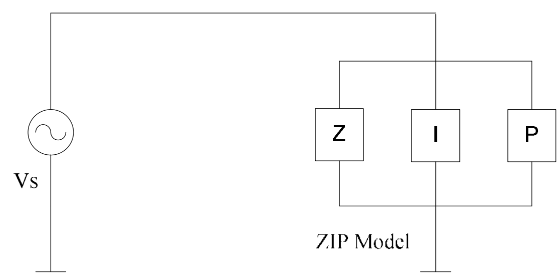


Figure 2.2: The Traditional ZIP Load Model

The total real power consumed by a ZIP load at a given voltage is shown in (2.1), and (2.2) gives the reactive power consumption. The values of the constants within (2.1) and (2.2) are limited by the constraint of (2.3)

$$P_i = \frac{V_a^2}{V_n^2} \cdot S_n \cdot Z_{\%} \cdot cos(Z_\theta) + \frac{V_a}{V_n} \cdot S_n \cdot I_{\%} \cdot cos(I_\theta) + S_n . P_{\%} \cdot cos(P_\theta) \tag{2.1}$$

$$Q_i = \frac{V_a^2}{V_n^2} \cdot S_n \cdot Z_{\%} \cdot sin(Z_\theta) + \frac{V_a}{V_n} \cdot S_n \cdot I_{\%} \cdot sin(I_\theta) + S_n . P_{\%} \cdot sin(P_\theta) \tag{2.2}$$

$$1 = Z_{\%} + I_{\%} + P_{\%} \tag{2.3}$$

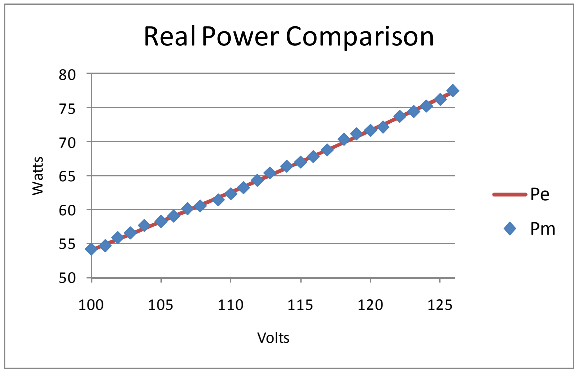
where:

P_i: Real power consumption of the i^{th} load
Q_i: Reactive power consumption of the i^{th} load
V_a: Actual terminal voltage
V_n: Nominal terminal voltage
S_n: Apparent power consumption at nominal voltage
$Z_{\%}$: Fraction of load that is constant impedance
$I_{\%}$: Fraction of load that is constant current
$P_{\%}$: Fraction of load that is constant power
Z_θ: Phase angle of the constant impedance component
I_θ: Phase angle of the constant current component
P_θ: Phase angle of the constant power component

In (2.1) and (2.2), there are six (6) constants that define the voltage dependent behavior of the ZIP load: $Z_{\%}$, $I_{\%}$, $P_{\%}$, Z_θ, I_θ, and P_θ. Because CVR changes the voltage of a feeder, it is critical to understand how typical end use loads will respond to changes in voltage. Specifically, what are the six constants that accurately reflect various end use loads? For loads such as a heating element, it is clear that the load is 100% Z, but for more complicated loads such as a Liquid Crystal Display (LCD) or Compact Florescent Light (CFL), the proper ratios are not as apparent. In an attempt to determine accurate ZIP models, a number of common household end use appliances were operated over a voltage range from 100V to 126V and their power consumption recorded. A constrained least squares fit was then used to determine the proper ZIP values, for both real power and power factor, that give the proper voltage dependency for the loads.

The following subsections contain plots of the real and reactive power consumption, P_m and Q_m respectively, for various end use loads while operated between 100V and 126V. The plots will also contain a red line indicating the voltage response curve using the fitted ZIP values, P_e and Q_e. In addition to the plots, the values for the six (6) fundamental ZIP values will be given for each load. These values are the numbers that will be used to model these loads in the prototypical feeders. While the following subsections do not contain a comprehensive list of loads, they provide a representative sample of the types of loads that are found in residences.

2.3.1.1. Incandescent Light Bulb (70W)



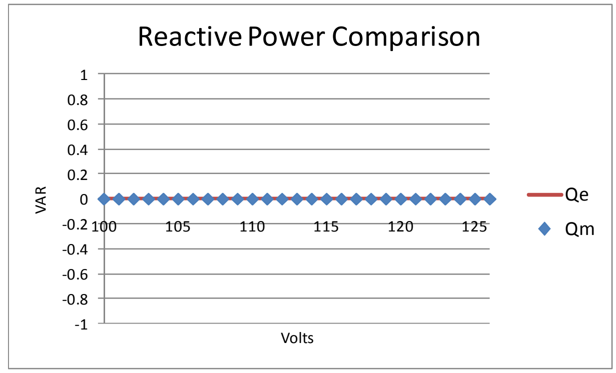
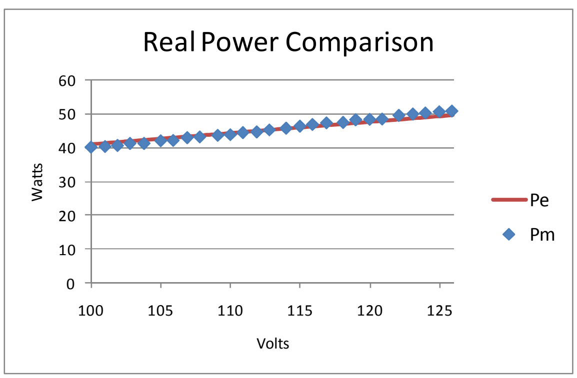


Figure 2.3: Voltage Dependent Energy Consumption of a 70W Incandescent Light Bulb

	ZIP Values					
	Z-%	I-%	P-%	Z-pf	I- pf	P-pf
Incandescent 75W	57.11%	42.57%	0.32%	1.00	-1.00	1.00

2.3.1.2. Magnavox Television (Cathode Ray Tube)



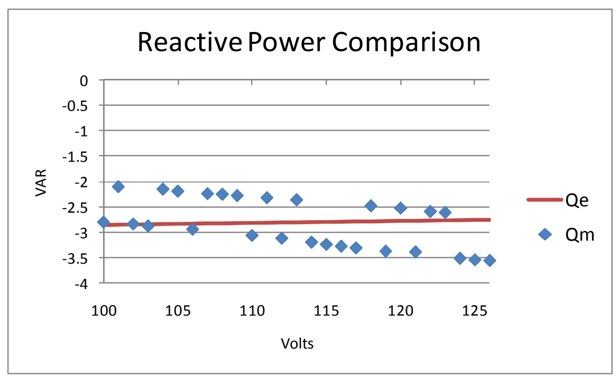
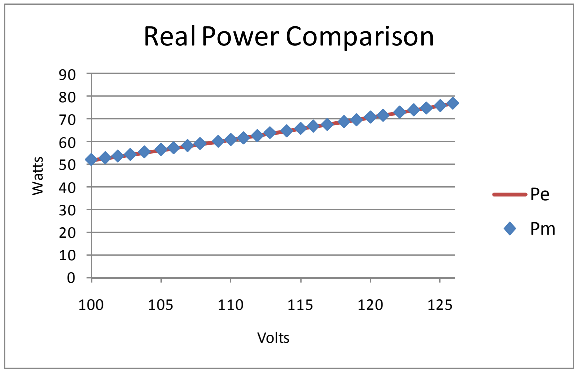


Figure 2.4: Voltage Dependent Energy Consumption of a CRT Television

	ZIP Values					
	Z-%	I-%	P-%	Z-pf	I- pf	P-pf
TV-Magnavox CRT	0.15%	82.66%	17.19%	-0.99	1.00	-0.92

2.3.1.3. Oscillating Fan



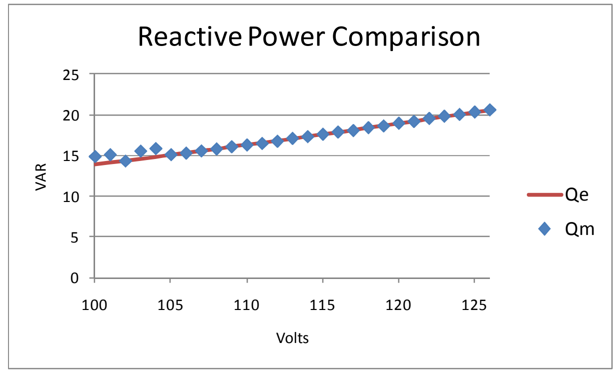
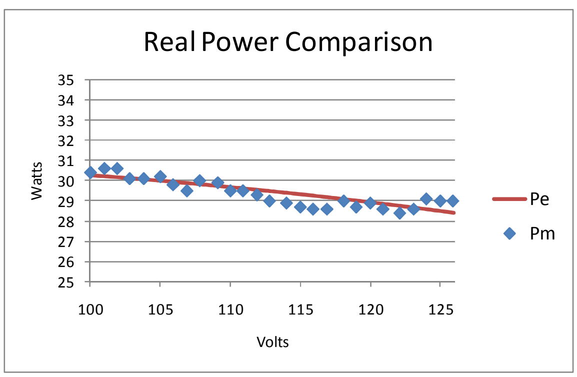


Figure 2.5: Voltage Dependent Energy Consumption of an Oscillating Fan

	ZIP Values					
	Z-%	I-%	P-%	Z-pf	I- pf	P-pf
Oscillating Fan	73.32%	25.34%	1.35%	0.97	0.95	-1.00

2.3.1.4. Liquid Crystal Display (LCD) – Dell



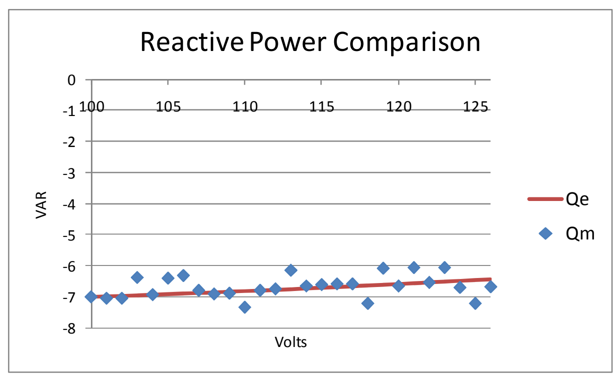


Figure 2.6: Voltage Dependent Energy Consumption of a Dell LCD

	ZIP Values					
	Z-%	I-%	P-%	Z-pf	I- pf	P-pf
LCD - Dell	-40.70%	46.29%	94.41%	-0.97	-0.98	-0.97

2.3.1.5. Plasma TV – Sony

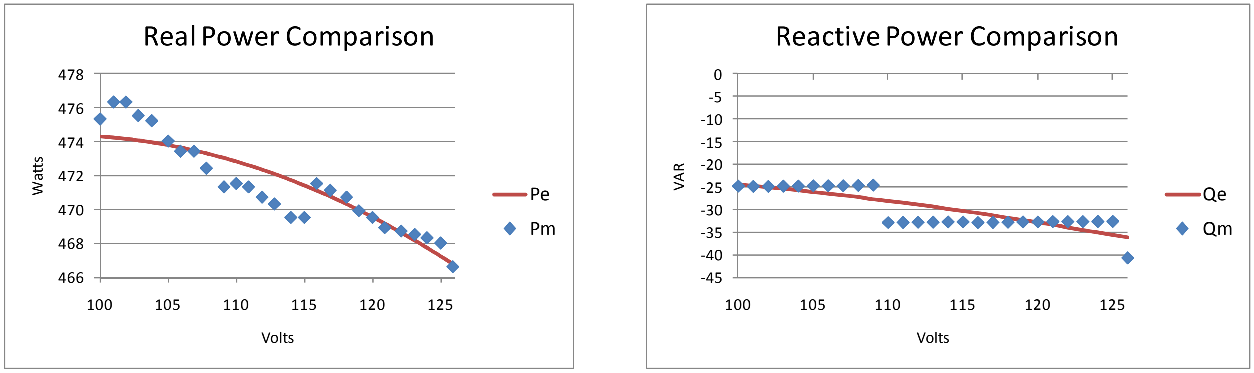


Figure 2.7: Voltage Dependent Energy Consumption of a Sony Plasma

	ZIP Values					
	Z-%	I-%	P-%	Z-pf	I- pf	P-pf
Plasma - Sony	-32.07%	48.36%	83.71%	0.85	0.91	-0.99

2.3.1.6. Liquid Crystal Display (LCD) - Clarity TV

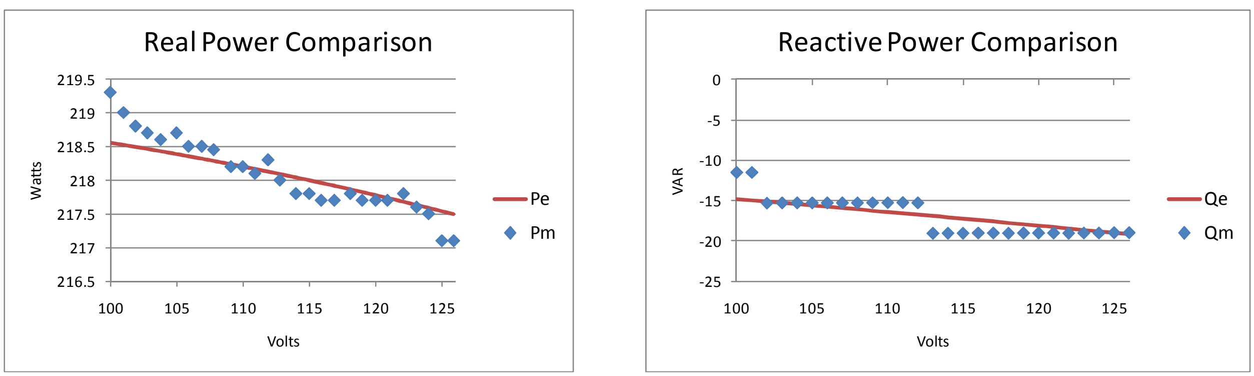
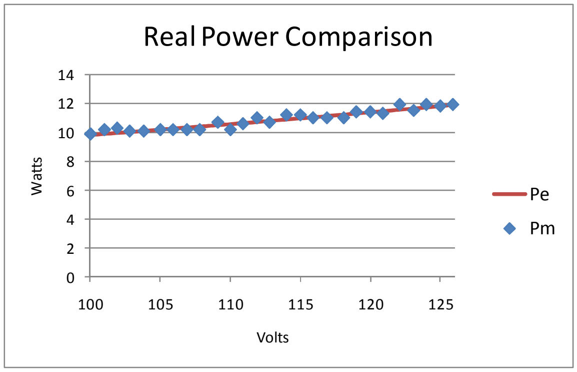


Figure 2.8: Voltage Dependent Energy Consumption of a Clarity LCD

	ZIP Values					
	Z-%	I-%	P-%	Z-pf	I- pf	P-pf
LCD - Clarity	-3.83%	3.96%	99.87%	0.61	-0.54	-1.00

2.3.1.7. Compact Fluorescent Light (CFL) 13W



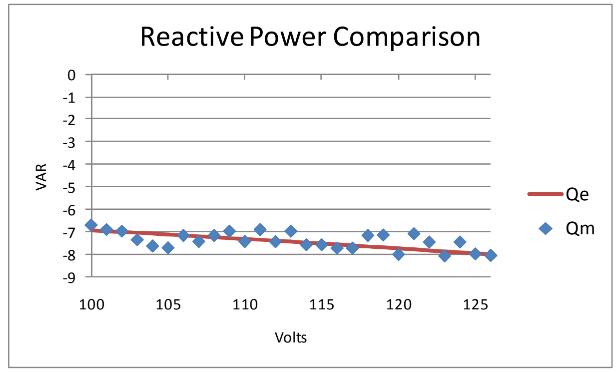
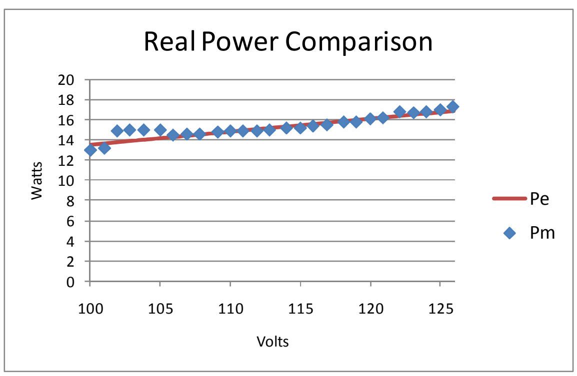


Figure 2.9: Voltage Dependent Energy Consumption of a 13W CFL

	ZIP Values					
	Z-%	I-%	P-%	Z-pf	I- pf	P-pf
CFL-13W	40.85%	0.67%	58.49%	-0.88	0.42	-0.78

2.3.1.8. Compact Fluorescent Light (CFL) 20W



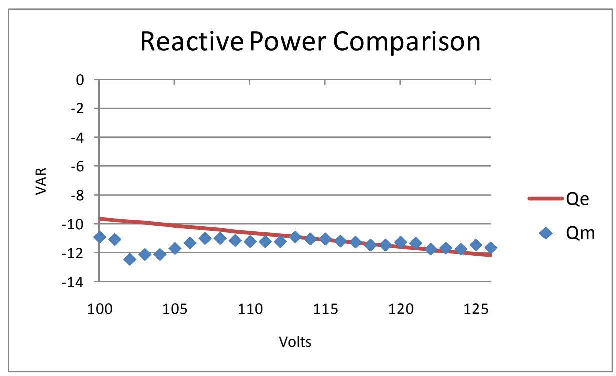


Figure 2.10: Voltage Dependent Energy Consumption of a 20W CFL

	ZIP Values					
	Z-%	I-%	P-%	Z-pf	I- pf	P-pf
CFL-20W	-1.05%	100.00%	1.05%	0.00	-0.81	0.90

2.3.1.9. Compact Fluorescent Light (CFL) 42W

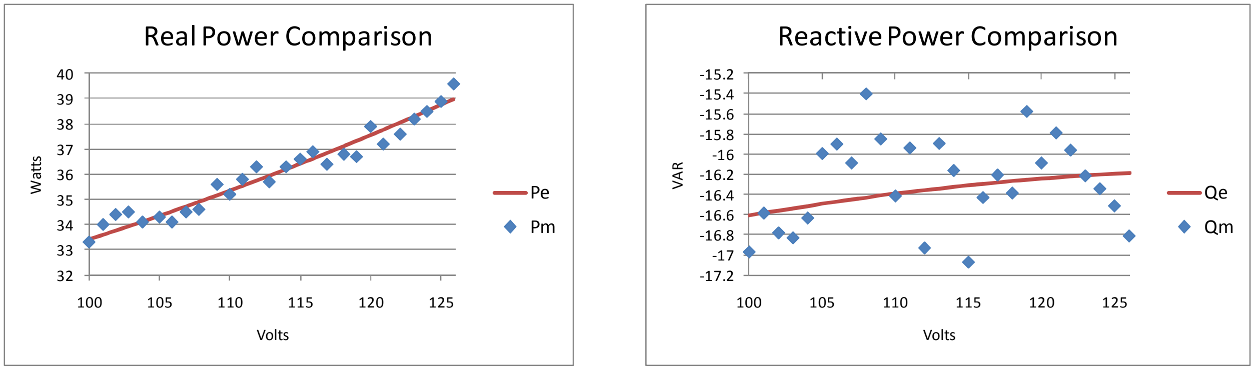


Figure 2.11: Voltage Dependent Energy Consumption of a 42W CFL

	ZIP Values					
	Z-%	I-%	P-%	Z-pf	I- pf	P-pf
CFL-42W	48.67%	-37.52%	88.84%	-0.97	-0.70	-0.79

2.3.2. Observations of ZIP Values

As can be seen in the plots, and ZIP values obtained through the least squares fit from Sections 2.3.1.1 through 2.3.1.9, the accurate ZIP representations for end use loads are not always intuitive. For example, an oscillating fan is not 100% constant power and an incandescent light bulb is not 100% constant impendence. A further issue to note is that the six constants are not always positive; a condition that generally occurs in loads with active components such as switching power supplies. This does not indicate that the load generates power, just that some elements within the ZIP model generate power which is then consumed by another element. The net result is that power is consumed, but a more complicated load behavior emerges.

The ZIP values shown in Sections 2.3.1.1 through 2.3.1.9 have been used to generate composite ZIP models for time invariant loads within each residential, commercial, and industrial points of interconnection. This ensures that changes in the supply voltage due to the CVR system generate the proper change in system load. In addition to the ZIP load, loads with thermal cycles are included in Residential and Commercial loads.

2.3.3. Loads with Thermal Cycles

Whether a load has a thermal cycle or not, it must have the voltage dependent energy consumption of a ZIP load. If the load does have a thermal cycle, there is the added complexity of an additional control loop, which determines when the load is energized, and for how long. One of the largest load types that have a thermal cycle are Heating, Ventilation, and Air Conditioning (HVAC) systems. An equivalent thermal parameter (ETP) model is used to approximate the response of the electrical demand of the HVAC system as a function of solar input, temperature, humidity, voltage, and thermostatic set points [3-5]. The thermal parameters of the building are the mass of the building, which defines how much stored thermal energy is in the building, and the envelope, which defines how quickly the energy moves from inside to outside the building and can loosely be described as the insulation quality. These parameters are determined by the actual physical properties of the building, and include such things as floor area, ceiling height, aspect ratio, window types, air exchange rate, etc. Additionally, HVAC properties such as heating and cooling set points, heat type (gas, electric, or heat pump), fan power, motor losses, etc. can be defined. Figure 2.13 is a diagram of the ETP model for a residential HVAC system.

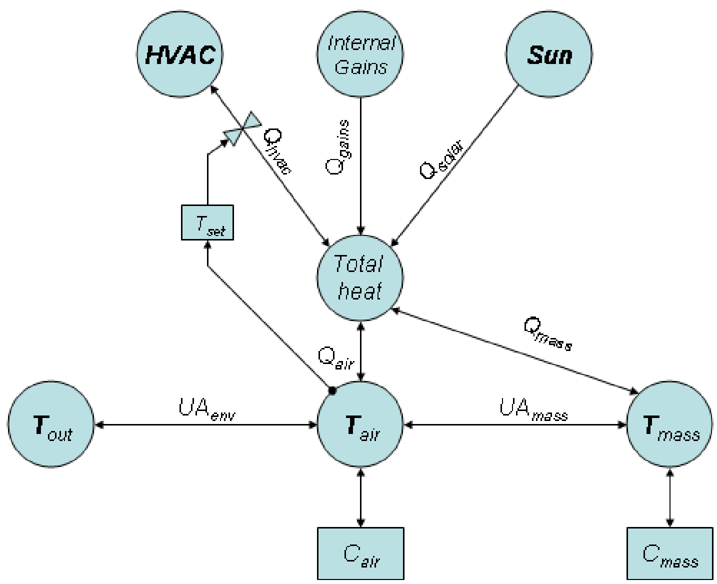


Figure 2.12: The ETP model of a residential HVAC system

where,

C_{air} : air heat capacity
C_{mass} : mass heat capacity
UA_{env} : the gain/heat loss coefficient between air and outside
UA_{mass} : the gain/heat loss coefficient between air and mass
T_{out} : air temperature outside the house
T_{air} : air temperature inside the house
T_{mass} : mass temperature inside the house
T_{set} : temperature set points of HVAC system
Q_{air} : heat rate to house air
Q_{gains} : heat rate from appliance waste heat
Q_{hvac} : heat rate from HVAC
Q_{mass} : heat rate to house mass
Q_{solar} : heat rate from solar gains

Equations (2.4) and (2.5) are the two ordinary differential equations (ODEs) which describe the heat flows shown in Figure 2.12. These equations are used to determine the thermal behavior of the house in response to the three heat sources and the user defined thermostatic set points. The solution to (2.4) and (2.5) represents the thermal behavior of the house and forms the basis for determining the electrical power consumption of the HVAC system.

$$\frac{dT_{air}}{dt} = \frac{1}{C_{air}}\left[T_{mass}UA_{mass} - T_{air}(UA_{env} + UA_{mass}) + Q_{air} + T_{out}UA_{env}\right] \qquad (2.4)$$

$$\frac{dT_{mass}}{dt} = \frac{1}{C_{mass}}\left[UA_{mass}(T_{air} + T_{mass}) + Q_{mass}\right] \qquad (2.5)$$

Equations (2.4) and (2.5) can also be represented by a single second order differential equation as shown in (2.6).

$$a\frac{d^2T_{air}}{dt^2} + b\frac{dT_{air}}{dt} + cT_{air} = d \qquad (2.6)$$

where:

$$a = \frac{C_{mass}C_{air}}{UA_{mass}}$$

$$b = \frac{C_{mass}(UA_{env} + UA_{mass})}{UA_{mass}} + C_{air}$$

$$c = UA_{env}$$

$$d = Q_{mass} + Q_{air} + UA_{env}T_{out}$$

2.3.4. Load Composition for Prototypical Feeders

Using the two load modeling methods described in Section 2.3.1 and 2.3.3 composite load models were developed for each building in the prototypical feeders. For Residential and Commercial buildings both ZIP models and Physical Models (those with thermostatic control loops and physical parameters) were used, Industrial Loads only used ZIP models. Only ZIP models were used for Industrial Loads because of the complexity required to model specific industrial processes.

For Commercial and Residential buildings, Physical Models were used for HVAC and hot water heating, and the remainder of the load was represented by a composite ZIP model using the information from Section 2.3.1. For the Physical Models there were a number of parameters which were sensitive with respect to climate region. For example, Regions 4 and 5 had very high levels of air conditioning, while Region 1 was relatively low. Table 2.3 shows the composition of HVAC by region for the United States as determined by EIA data, rounded to the nearest 5% [6]. This information was used to determine what percentage of residential houses on each feeder was supplied by the various types of HVAC. As noted in Table 2.3, some residences contain natural gas as well as a heat pump. This is due to the poor efficiency of heat pumps at low temperatures where the natural gas is used for heating.

Table 2.3: HVAC Percentages by Region

	R1	R2	R3	R4	R5
% Natural Gas	60.00%	65.00%	50.00%	30.00%	40.00%
% Heat Pump	30.00%	25.00%	45.00%	60.00%	50.00%
% Electric Heat	10.00%	10.00%	5.00%	10.00%	10.00%
% AC	51.20%	85.22%	86.57%	95.52%	95.72%
*Differences due to the use of heats pumps for heating >20 degrees and gas < 20 degrees					

Water heaters used a similar model to the ETP model used for the thermal properties of the building. Water demand of an average home and the insulation level become the inputs for each device, and is translated into an electrical power demand as a function of time of day. The heater coil of a water heater is a resistor and reduces power demand when voltage is reduced; however, the same amount of heat energy must be put into the water to heat the water. So, while the peak demand of a single water heater is reduced by a reduction in voltage, the amount of time it stays on is increased and energy consumed is held nearly constant. For the purpose of this study, water heaters were assumed to be natural gas if the house had a natural gas connection, and therefore consumed minimal electrical energy.

2.4. Population of Loads

To analyze the effects of CVR, time-series simulations were performed. Because the original taxonomy feeders contained only static load models, which were representative of peak load, time varying load models were added. The static loads were replaced with time-varying thermostatic models and time-varying ZIP models. The goal was to populate the feeder with individual representative building and load models, which provided, in aggregate, a nearly identical time-varying demand at the substation level as that found in SCADA (Supervisory Control and Data Acquisition) data. This provided not only an aggregate model of the characteristics of the particular feeder, but also gave a representative model of the behavior of individual loads. While a single load populated into the model would not actually represent a particular home, the distribution of populated buildings and loads will approach the actual behavior of all the loads within the real system. This provides an understanding of how the loads and feeder would respond, in aggregate, to a reduction in voltage.

2.5. Transformers

To appropriately model the effects of voltage reduction, full-load and no-load losses, and all states in between, must be properly handled. Classical transformer models are used in GridLAB-D to capture these effects, and include series and shunt losses. This is necessary because as voltage is reduced, series losses may decrease or increase depending on the type of load, but shunt losses will always decrease. Shunt losses are always present, regardless of the demand level, so by reducing those losses, the benefits are accumulated over time.

To populate the feeder models with appropriate transformer models, standard transformer data sheets from COOPER Power Systems were used to convert no-load and full-load losses to series and shunt impedance values as a function of power rating [7]. The size of the load (load sizing will be discussed further in Load Magnitude) determined the power rating of the transformer, where the specified load from the original model was rounded up to the next smallest available standard power rating. Split-phase center-tap models were used to connect residential 1-6 and commercial 2 to 240V circuits, while 1-, 2-, and 3-phase wye-wye models were used to connect commercial 1 and industrial loads to 480V circuits.

2.6. Load Magnitude and Shape

To develop an accurate annual load profile for the feeders, each of the individual end use loads were calibrated. Relative loading across a feeder is approximately equal to that specified for the original taxonomy feeders, but with added time-dependent outdoor temperature, solar insolation, voltage, etc. However, to create a model that accurately matches provided SCADA data over the provided time interval, a number of adjustments were needed.

First, daily, weekly, and seasonal schedules were created to control thermostat set points within the homes. These were created to loosely represent a variety of customers, including those who leave their settings the same throughout a season, those who adjust the set points only on weekends, and those who adjust them on a daily or hourly basis (away versus awake versus asleep). These schedules were created from a combination of survey data and randomly distributed throughout the population of residential buildings. Adjustments were made to represent differences between seasons, between daytime and nighttime, and between weekends and weekdays, and each building contained its own unique schedule. Commercial buildings were assumed to keep more constant thermostat settings, with adjustments only made between their daytime and nighttime settings, and used similar settings for both weekdays and weekends. While the commercial settings were more constant, there were still variations between weekday and weekend to represent the behavior of commercial office buildings.

Second, hot water demand schedules were created to represent the amount of demand by hot water heaters. These were created from a combination of survey data and Department of Energy (DOE) water heater loading approximations. Events related to showers, dishwashers, hand washing, and clothes washers were simulated to represent the demand on the hot water heater. Once again, each building with an electric hot water heater (buildings supplied by gas lines were assumed to have gas water heaters) contained its own unique water demand schedule.

These two loads were selected as physical models (as opposed to generic ZIP models) due to their large impact on the demand of a residential home. Capturing the actual state driven behavior, as opposed to average behavior, was essential in understanding the effects of voltage reduction, since the average behavior has not been fully quantified during voltage reduction operations. To capture the effects of smaller appliances, time-varying ZIP models were created. The time dependent effect was created using a library of yearly load shapes, containing seasonal, weekly, daily, and hourly variations at 15-minute intervals, most created from raw SCADA data. Large commercial and industrial loads were created using a similar method. Power factor and ZIP fractions were assigned from available anecdotal information, including measured laboratory data and previous CVR studies.

At each spot load location from the original feeder model, the load was replaced with a combination of building and ZIP load models. By varying the relative number of building models to the number of ZIP models, then varying their relative magnitudes, a reasonable approximation could be found that matched SCADA data for the entirety of a year. By fitting data on approximately 6-12 days per year per feeder, it was found that overall difference between simulated and actual demand could be limited to approximately 5% of the total demand at all times throughout the year, except during times of topological changes (for example, if a large amount of load was shifted from one circuit to another).

2.7. Method of Conservation Voltage Reduction

CVR is not a new technology. There have been numerous proposed methods [8-14], numerous studies of deployed systems [13-20], and many vendors offer CVR based systems [23-26]. For the purposes of this analysis, a CVR scheme that has been published in the IEEE Transactions on Power Systems and is openly available has been selected [11].

In the selected system, there are two major functions: reactive power control and voltage optimization. The reactive power control operates the shunt capacitors on the distribution feeder in order to improve the power factor at the substation. The voltage optimization operates the sub-station voltage regulator in order to control the system voltage as measured at the End Of Line (EOL) measurements. For the selected CVR system, control of additional downstream voltage regulators is not supported. Control of multiple voltage regulators on a distribution feeder is provided in modern, commercially available CVR products, and will further increase the performance.

3. Individual Prototypical Feeder Results

To estimate the national benefit of CVR, the Taxonomy of Prototypical distribution feeders developed at PNNL for the Modern Grid Initiative (MGI), now the Modern Grid Strategy (MGS), was used. Each of the 24 prototypical distribution feeders was populated with ZIP models and full Equivalent Thermal Parameter (ETP) models for residential and commercial HVAC, which included their associated secondary distribution systems. The populated feeders were then simulated in a “traditional” voltage control scheme for an entire year at a 1 minute time step. The total energy consumed was then calculated for: the total feeder, the residential loads, the commercial and industrial loads, and the various system losses. Additionally, a set of End of Line (EOL) voltages was recorded for each phase. The EOL point was determined based on the low voltage primary node at maximum system load. This voltage was then assumed to be lowest voltage point on the system at any given time. The simulation was then rerun with the exact same feeders and load conditions, but with the CVR system operating. The difference in energy consumption was then examined.

The two key benefits of CVR are peak load reduction and reduction in annual energy consumption. When the peak load is reduced, fewer generating units are required, especially costlier peaking units, while annual energy reduction requires less primary fuel to be consumed. The following sections examine the peak load reduction and reduction in annual energy consumption for each of the individual prototypical feeders.

3.1. Peak Load Reduction

Figure 3.1 shows the peak demand change in kW, while Figure 3.2 shows the peak demand change as a percent of total feeder loading, for each of the prototypical feeders. By observation, it can be seen that all but two of the prototypical feeders sees a reduction in the peak demand when CVR is in operation. The one feeder experiencing a noticeable increase in the peak demand, R1-25.00-1, is a long feeder that already has a low end of line voltage. As a result, when CVR begins to regulate, it actually raises the voltage during the peak load, resulting in a higher peak demand. This is not an unexpected occurrence because many feeders in the United States are long, rural feeders, where significant capital investment in infrastructure is not cost effective. R1-25.00-1 is a higher voltage 25 kV class feeder, but with a peak load of only 2,300 kW, from Figure 3.3. The low voltage is due to the small cross section of conductor that is used on this feeder, representative of a cost savings effort for a lightly loaded rural feeder. With reconductoring or a mid-line regulator, peak reductions would be observed, but this may not be a cost effective measure.

With the exception of R1-25.00-1, and to a much less extent, R4-25.00-1, each of the taxonomy feeders experiences a noticeable reduction in peak load, between 0.5% and 4.0%. One point to notice is that while the percent reduction in peak load is similar among many feeders, the kW reductions vary significantly; this is primarily due to the loading of the different feeders. The reduction in energy consumed is a function of two factors: the first is how many volts the average voltage can be reduced, and the second is the amount of load being supplied by the feeder. The ideal feeder for CVR would be a heavily loaded feeder that is able to support a significant reduction in voltage.

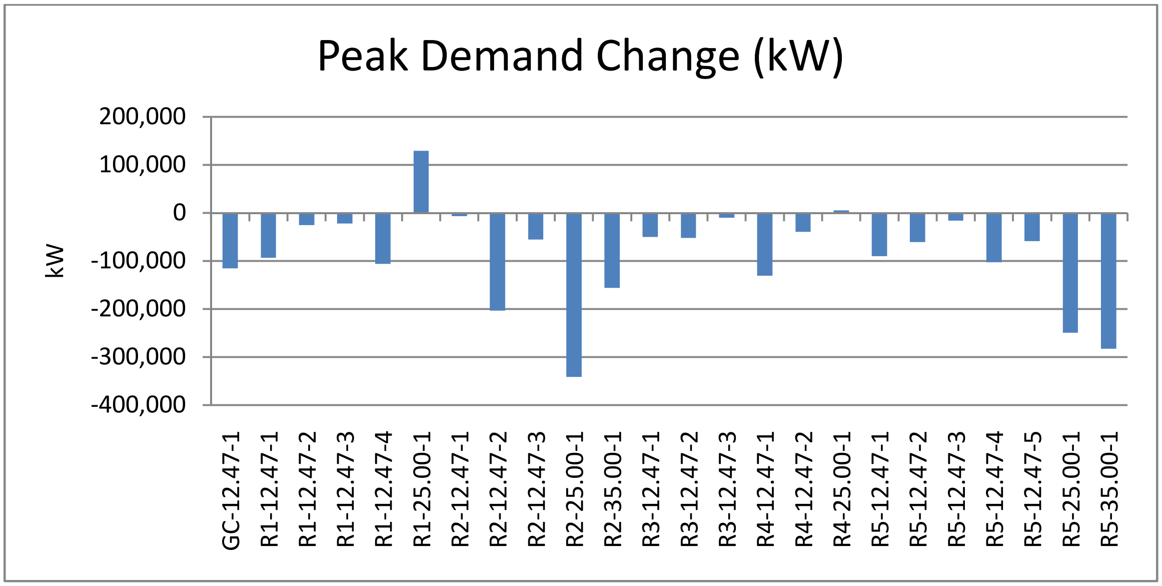


Figure 3.1: Peak Demand Change (kWh) by Taxonomy Feeder

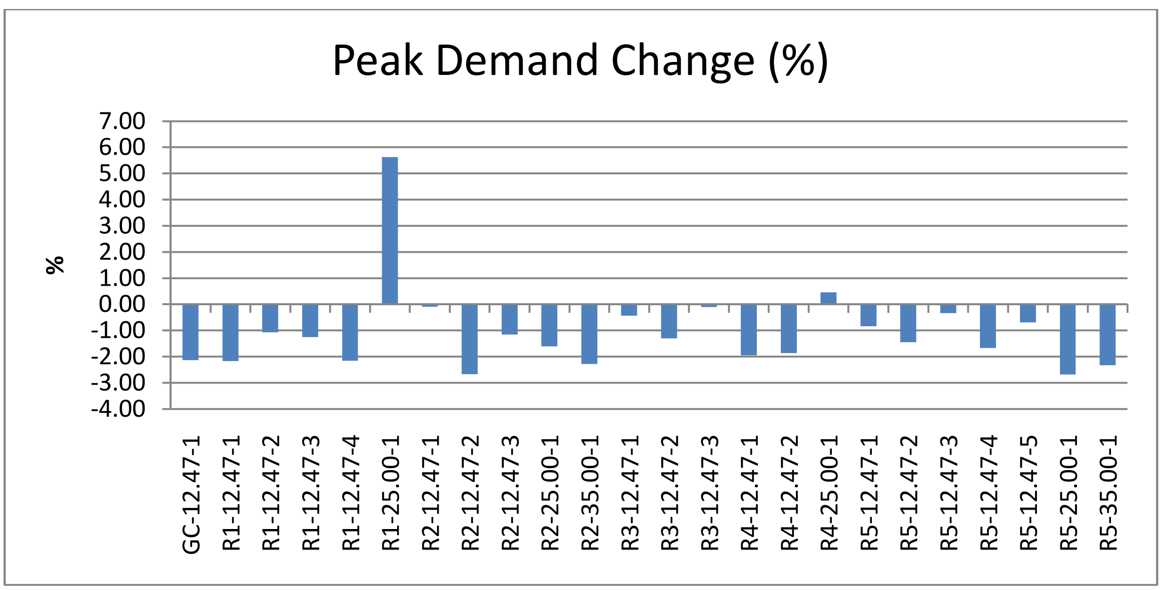


Figure 3.2: Peak Demand Change (%) by Taxonomy Feeder

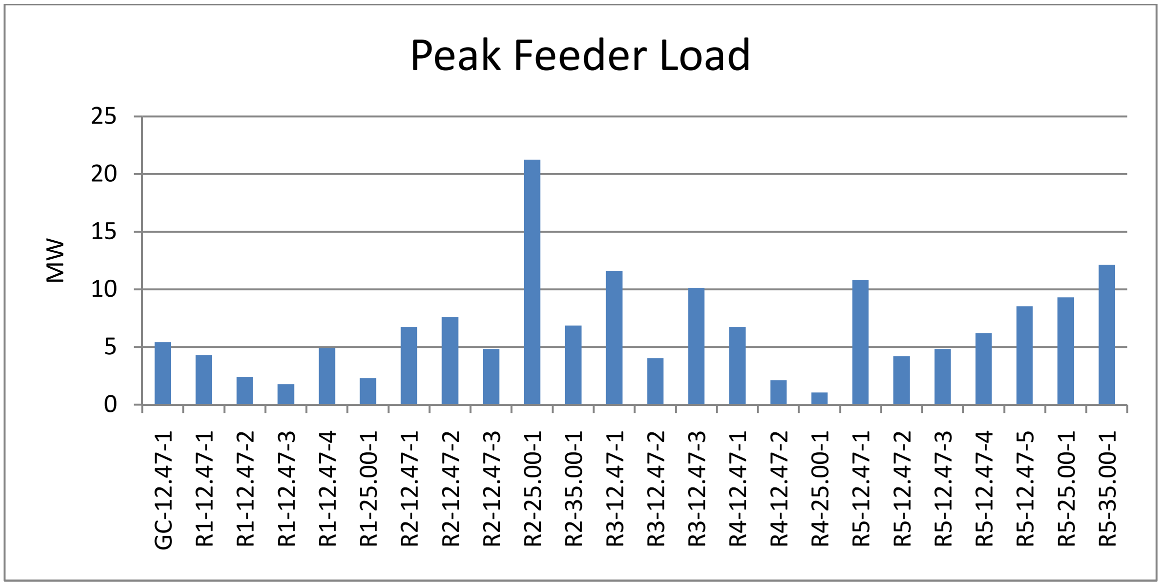


Figure 3.3: Peak loading (MW) by Taxonomy Feeder

For CVR to be effective it must be possible to reduce the average voltage along the feeder; an inability to do this is why R1-25.00-1 underwent an increase in peak demand. Figures 3.4 and 3.5 show the annual minimum voltage at the end of line measurements when operating without CVR, and with CVR. Figures 3.6 and 3.7 show the average annual voltage as measured at the end of line points when operating without CVR, and with CVR respectively. The CVR system of Section 2.7 operates to ensure that the EOL measurements are never below 118V +/- 1V, effectively ensuring that the end of line measurements are greater than 117V. From Figure 3.5, it is clear that the voltage does drop below 117 volts on almost every feeder. This is a transient condition and the voltage is quickly raised. Figure 3.7 shows the average voltage and it is clear that the CVR system is regulating to an 118V average. By comparing the without and with CVR average voltages, it can be seen that the average voltage at the end of line points is reduced. While this is a reasonable indicator of the effectiveness of CVR on a particular feeder, it does not take into consideration system load, or the fact that this is the voltage as measured at one point in the system. A limitation with the majority of current CVR schemes is that they rely on remote measurements from a handful of locations, and assume that they are representative of the entire system.

In general, it is clear that CVR has the potential to reduce peak demand on distribution feeders. The ability to reduce the peak demand of a feeder could be further increased through upgrades such as feeder reconductoring and installation of downstream voltage regulators.

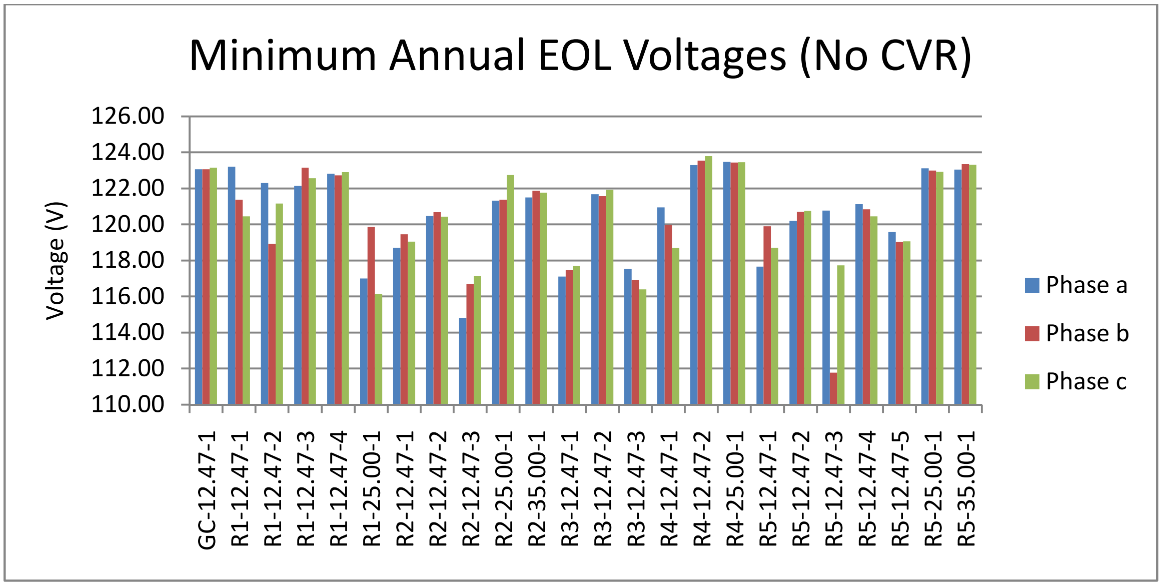


Figure 3.4: Minimum Annual EOL Voltages for Prototypical Feeders with CVR Off

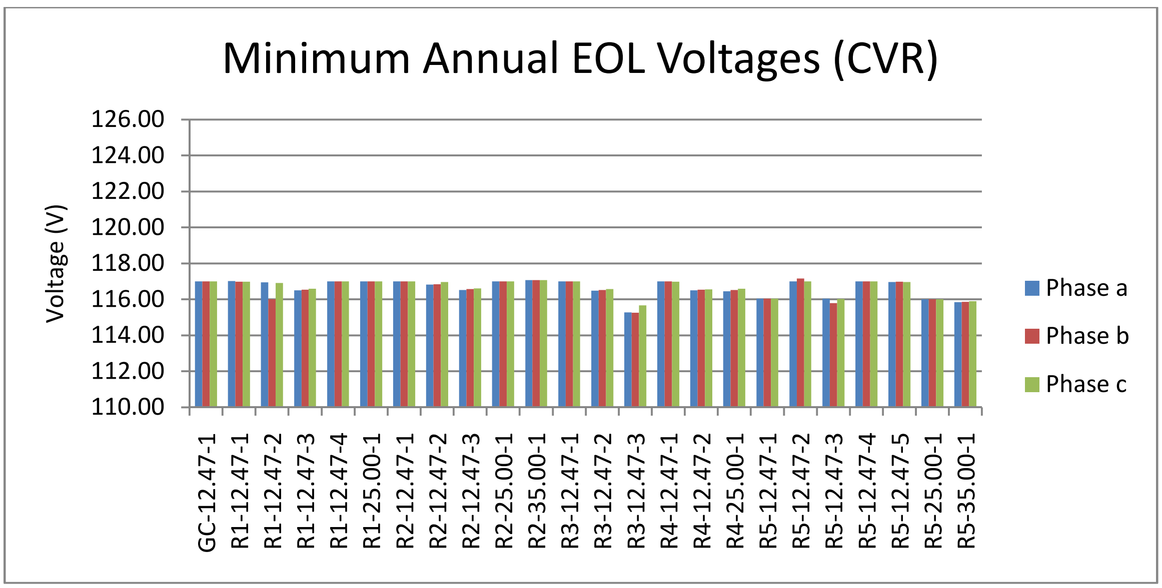


Figure 3.5: Minimum Annual EOL Voltages for Prototypical Feeders with CVR On

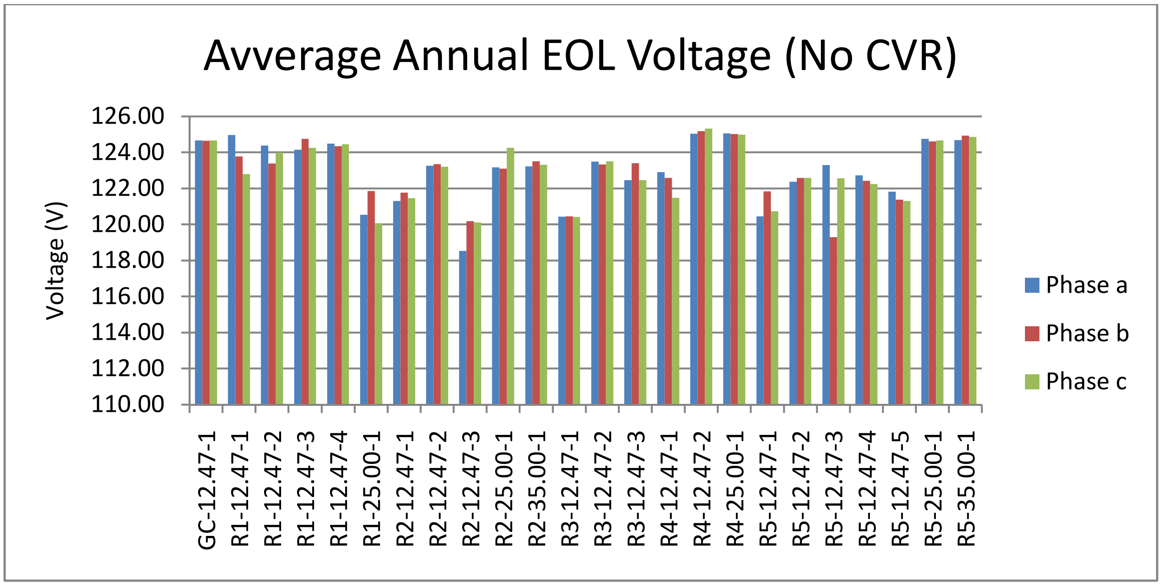


Figure 3.6: Average Annual EOL Voltages for Prototypical Feeders with CVR Off

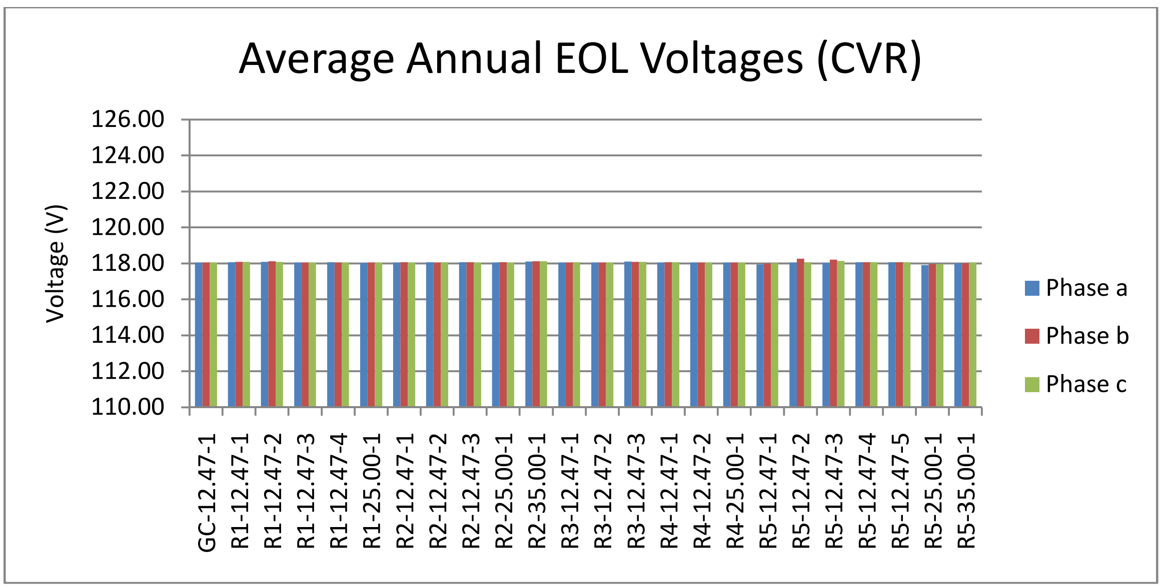


Figure 3.7: Average Annual EOL Voltages for Prototypical Feeders with CVR On

3.2. Reduced Annual Energy Consumption

While the last section focused on the ability of CVR to provide a power reduction during the peak day of the year, this section will focus on the ability of CVR to provide continued energy reduction over the course of an entire year. Figures 3.8 and 3.9 are similar to Figures 3.1 and 3.2 except that they show that annual reduction in energy as opposed to the peak demand reduction. As with peak demand, the ability of CVR to reduce the annual energy consumption is evident, as shown in Figures 3.8 and 3.9. Once again R1-25.00-1 is the notable exception in that the annual energy consumption increases when CVR is in operation. As with peak demand, the inability of CVR to reduce annual energy consumption is due to the particular design of the feeder. If capital improvements were made, superior performance would be expected.

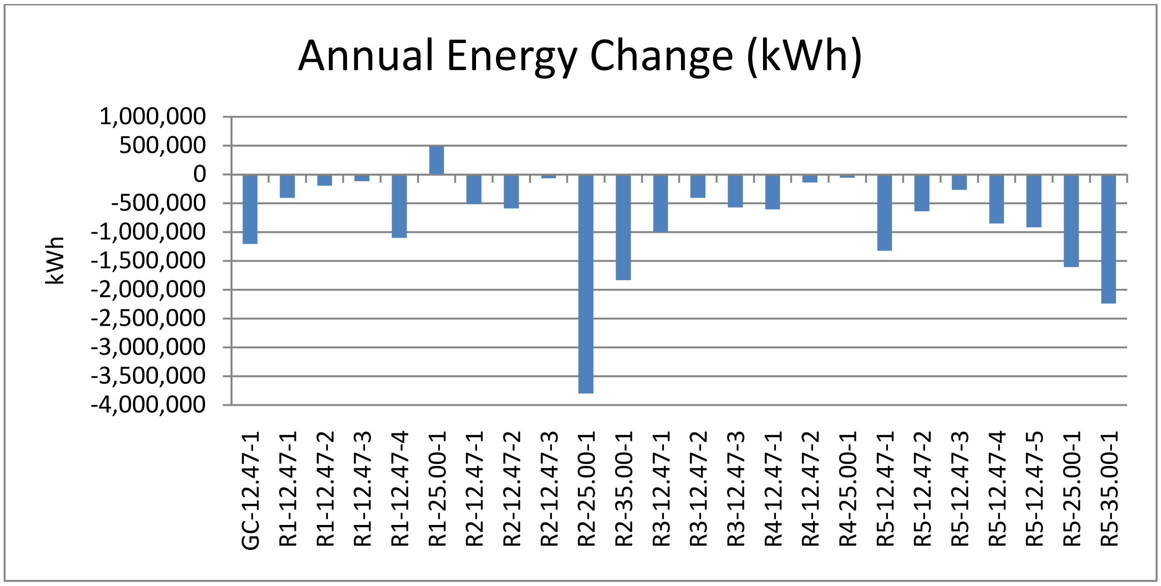


Figure 3.8: Annual Energy Change (kWh) by Taxonomy Feeder

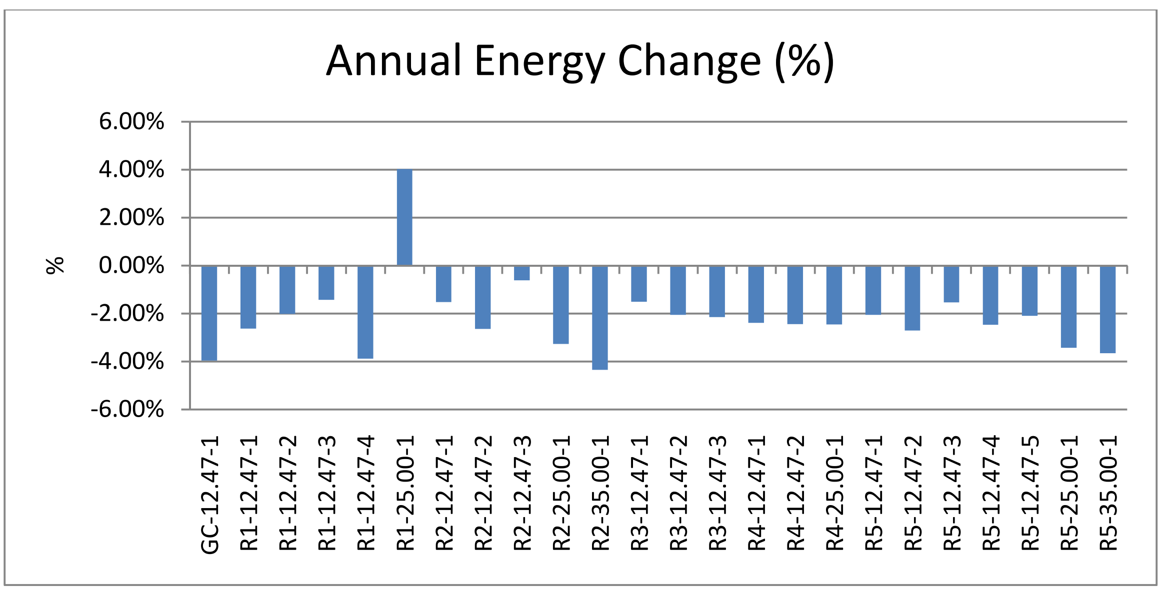


Figure 3.9: Annual Energy Change (%) by Taxonomy Feeder

Figures 3.1 through 3.9 have given high level information about the performance of CVR on the various prototypical feeders. Since GridLAB-D was use to perform the analysis, there is a substantial amount of additional information that can be examined. For each of the prototypical distribution feeders this report will examine the following six (6) plots:

1) Total Energy Change (kWh)
2) Total Energy Change (%)
3) Total Load Change (kWh)
4) Total Load Change (%)
5) Total Loss Change (kWh)
6) Total Loss Change (%)

Total Energy Change, plots 1 and 2, represents the change in energy as measured at the output of the feeder regulator. Total Load Change, plots 3 and 4, represents the change in energy of the end use loads, as measured at the customer point of interconnections. Total Loss Change, plots 5 and 6, represents the change in energy of the system losses, which include: overhead lines losses, underground line losses, transformer loses, and triplex line losses. Total Energy Change, plot 1, is the sum of Total Load Change, plot 3, and Total Loss Change, plot 5. Figures 3.10 through 3.15 show the six plots for feeder GC-12.47-1. Additionally, Figure 3.16 is a comparison of the change in total load and change in total losses.

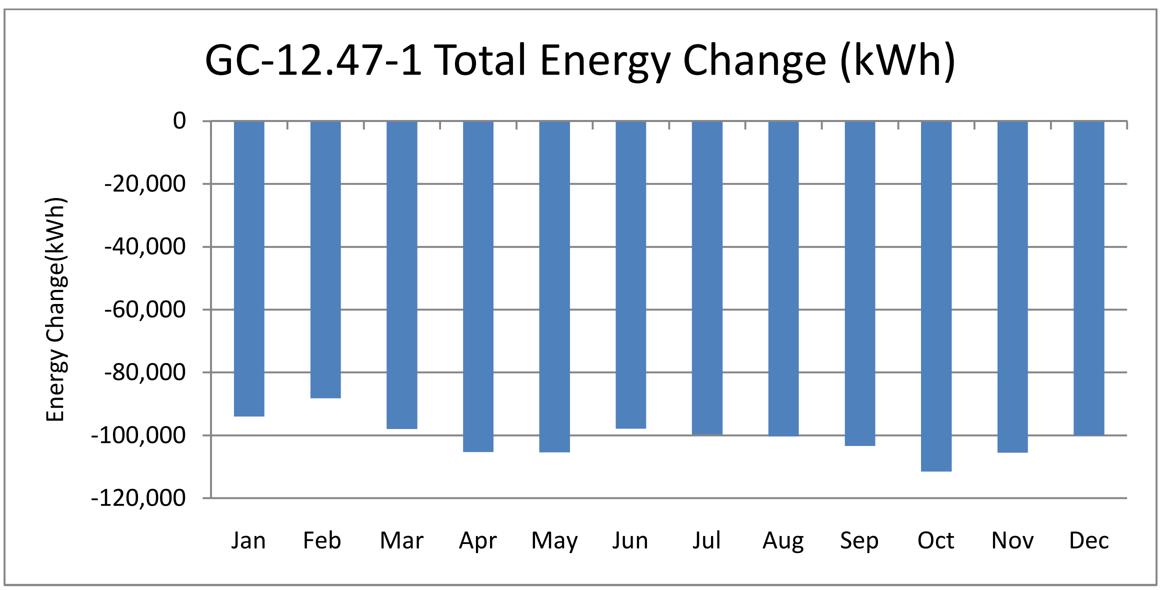


Figure 3.10: GC-12.47-1 Total Energy Change (kWh)

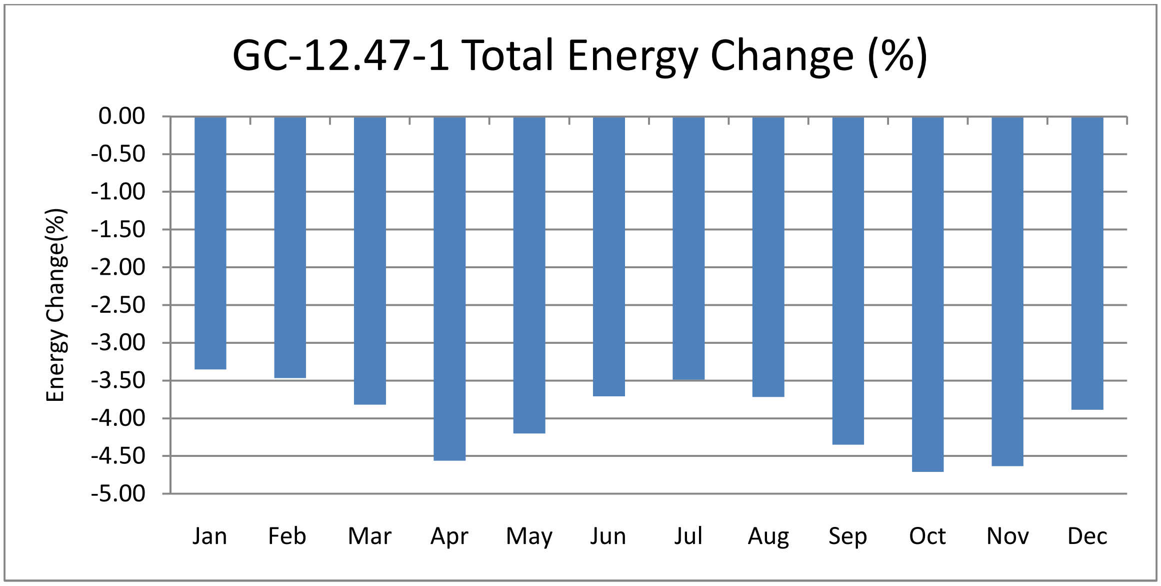


Figure 3.11: GC-12.47-1 Total Energy Change (%)

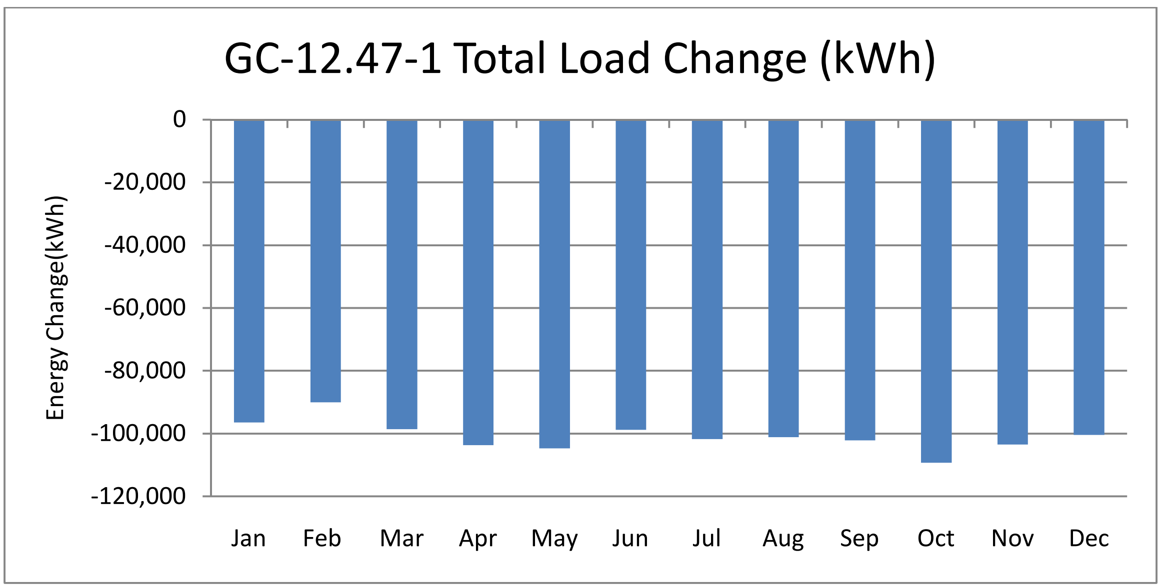


Figure 3.12: GC-12.47-1 Total Load Change (kWh)

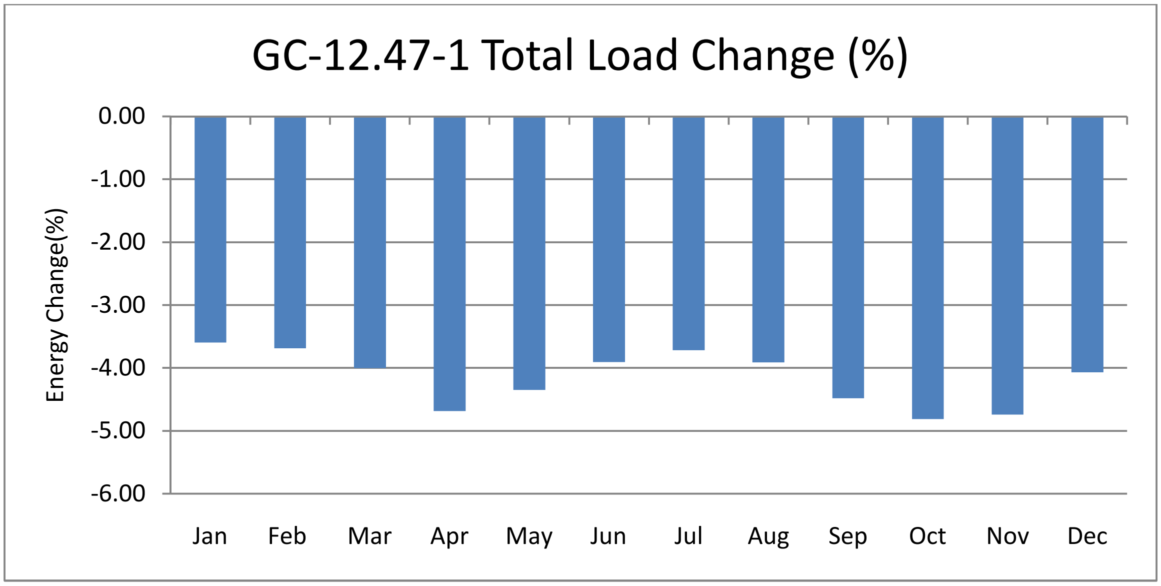


Figure 3.13: GC-12.47-1 Total Load Change (%)

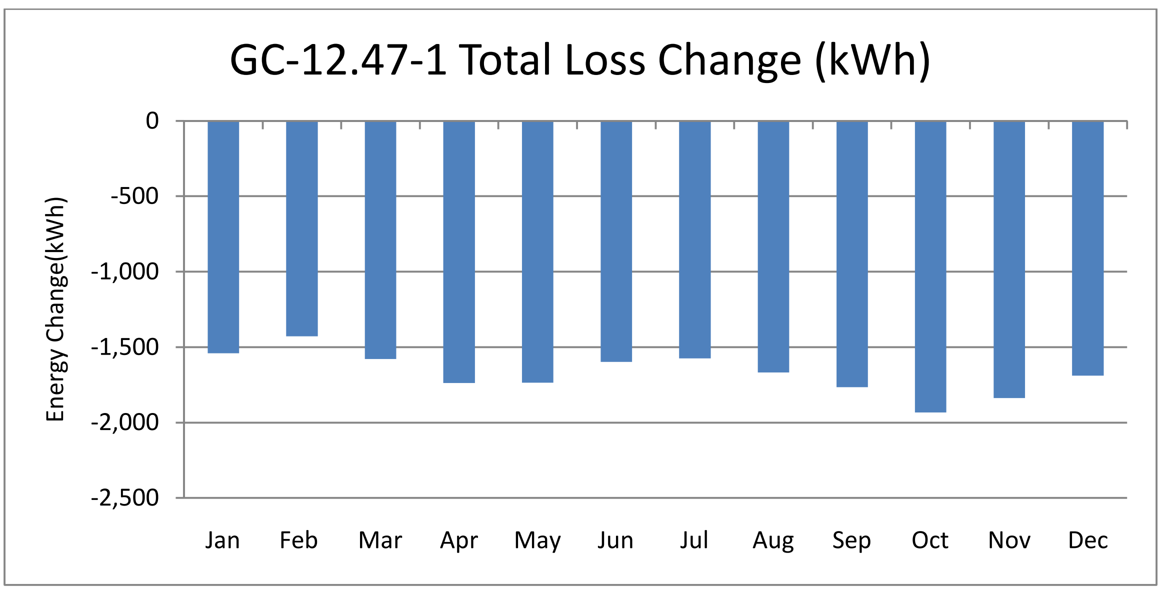


Figure 3.14: GC-12.47-1 Total Loss Change (kWh)

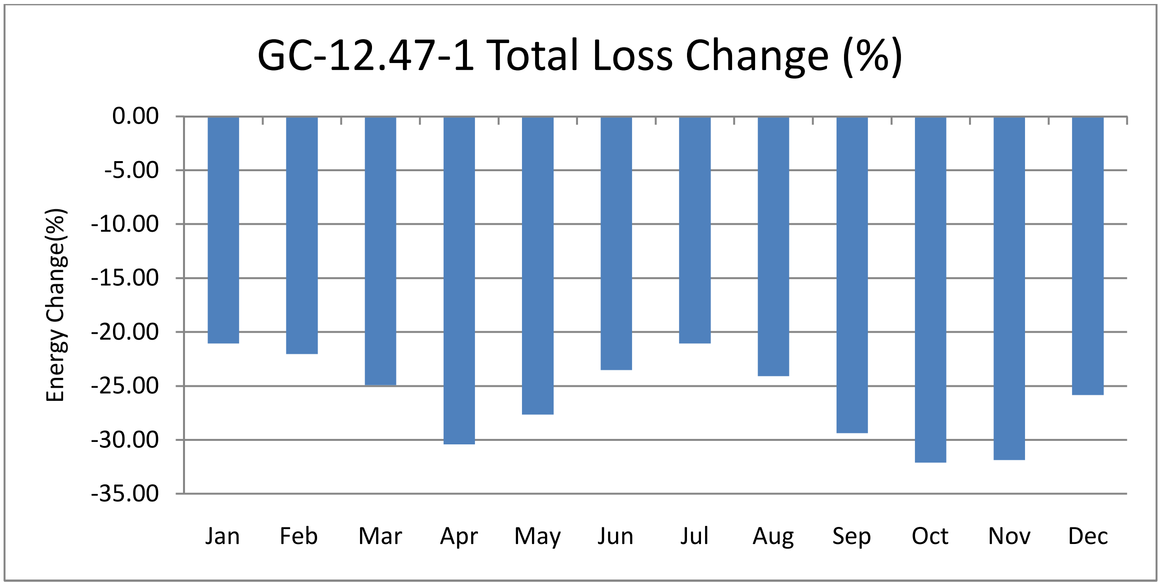


Figure 3.15: GC-12.47-1 Total loss Change (%)

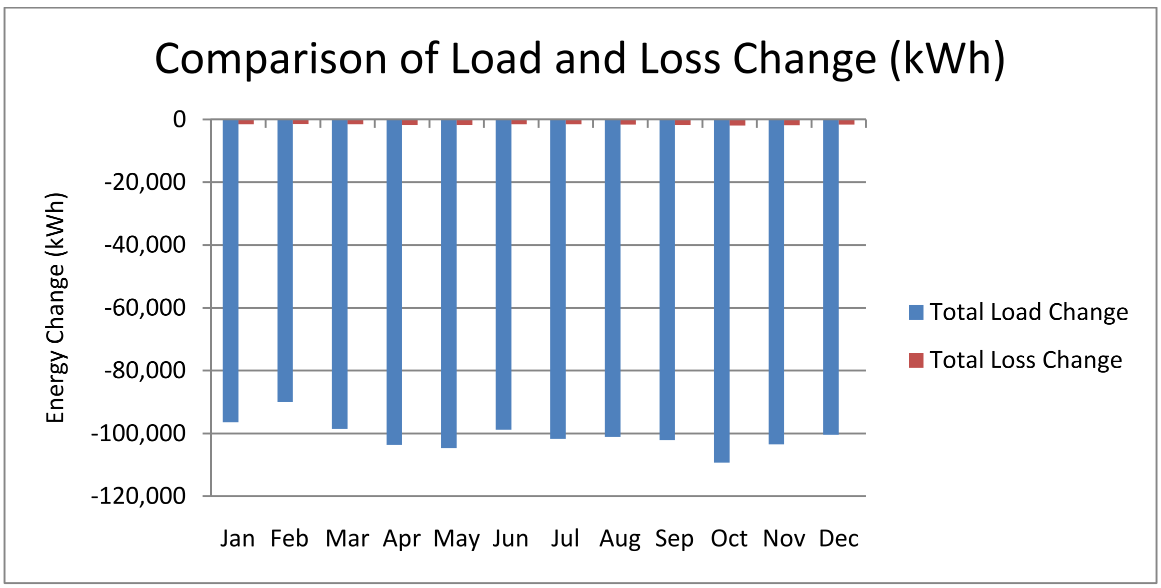


Figure 3.16: Comparison of Load and Loss Change (kWh)

One key observation from Figure 3.16, which can be seen on every feeder, is the difference in scale between the total load change, plot 3, and the total loss change, plot 5. Without exception, the reduction in load accounts for the vast majority of the change in energy consumption. In general, when CVR is in operation 98%-99% of the change in energy consumption occurs in the end use loads, while only 1%-2% of the reduction in energy consumed can be attributed to losses. Reduction in systems losses is not a significant benefit of CVR.

Because of the large number of prototypical distribution feeders it is not practical to place six plots for each feeder in the main body of the report. Section 6 of this report is Appendix I and it provides detailed plots for each feeder on a month by month basis, similar to Figures 3.10 through 3.15.

4. Extrapolation to a National Level

While section three examined the detailed effects of CVR on the prototypical distribution feeders, it is the extrapolation of these results to a national level that is of the most interest. The taxonomy of prototypical feeders was chosen for this work because of its ability to readily extrapolate results to a national level [1]; each of the 24 prototypical feeders is representative of a number of feeders within the climate regions shown in Figure 2.1.

Table 4.1 is a reprint of Table 9 from [1], which gives an estimate of the number of feeders in each climate region that are represented by the various prototypical feeders. For example, R2-12.47-3 is representative of 3,000 feeders within region 2. Therefore, the results of CVR analysis on R2-12.47-3 can be assumed to represent similar behavior on 3,000 distribution feeders. This method can be used to extrapolate the results of analysis of the 24 prototypical feeders to the national level.

Table 4.1: Prototypical Feeder Weighting Factors

Region	Feeder	kV	# of feeders	% within a region
Region 1	R1-12.47-1	12.5	2,200	20.56%
	R1-12.47-2	12.47	2,500	23.36%
	R1-12.47-3	12.47	2,000	18.69%
	R1-12.47-4	12.47	1,800	16.82%
	R1-25.00-1	24.9	1,200	11.21%
	GC-12.47-1	12.47	1,000	9.35%
Region 2	R2-12.47-1	12.47	3,500	18.72%
	R2-12.47-2	12.47	3,200	17.11%
	R2-12.47-3	12.47	3,000	16.04%
	R2-25.00-1	24.9	3,500	18.72%
	R2-35.00-1	34.5	4,000	21.39%
	GC-12.47-1	12.47	1,500	8.02%
Region 3	R3-12.47-1	12.47	1,500	30.00%
	R3-12.47-2	12.47	1,500	30.00%
	R3-12.47-3	12.47	1,000	20.00%
	GC-12.47-1	12.47	1,000	20.00%
Region 4	R4-12.47-1	13.8	14,000	33.14%
	R4-12.47-2	12.5	15,000	35.50%
	R4-25.00-1	24.9	12,500	29.59%
	GC-12.47-1	12.47	750	1.78%
Region 5	R5-12.47-1	13.8	400	8.79%
	R5-12.47-2	12.47	600	13.19%
	R5-12.47-3	13.8	650	14.29%
	R5-12.47-4	12.47	500	10.99%
	R5-12.47-5	12.47	450	9.89%
	R5-25.00-1	22.9	450	9.89%

	R5-35.00-1	34.5	500	10.99%
	GC-12.47-1	12.47	1,000	21.98%

Table 4.2 shows the results of the individual prototypical feeders multiplied by the number of feeders from Table 4.1 in order to determine the regional level impact of CVR on total energy change. For example, Feeder R1-12.47-1 showed an annual reduction of 407 kWh, which applied to 2,200 feeders, yields a reduction of 897 MWh in Region 1.

Table 4.2: Prototypical Feeder Regional Results

		Individual Level kWh Change	#	Regional Level MWh Change
Region 1	R1-12.47-1	-407,868	2,200	-897,310
	R1-12.47-2	-195,907	2,500	-489,768
	R1-12.47-3	-117,830	2,000	-235,661
	R1-12.47-4	-1,102,200	1,800	-1,983,960
	R1-25.00-1	485,613	1,200	582,735
	GC-12.47-1	-1,209,248	1,000	-1,209,248
Region 2	R2-12.47-1	-510,276	3,500	-1,785,966
	R2-12.47-2	-588,283	3,200	-1,882,506
	R2-12.47-3	-67,624	3,000	-202,872
	R2-25.00-1	-3,800,280	3,500	-13,300,981
	R2-35.00-1	-1,835,717	4,000	-7,342,868
	GC-12.47-2	-1,209,248	1,500	-1,813,872
Region 3	R3-12.47-1	-996,426	1,500	-1,494,639
	R3-12.47-2	-408,226	1,500	-612,339
	R3-12.47-3	-573,844	1,000	-573,844
	GC-12.47-3	-1,209,248	1,000	-1,209,248
Region 4	R4-12.47-1	-609,469	750	-457,102
	R4-12.47-2	-138,193	14,000	-1,934,695
	R4-25.00-1	-56,084	15,000	-841,262
	GC-12.47-4	-1,209,248	12,500	-15,115,599
Region 5	R5-12.47-1	-1,324,791	1,000	-1,324,791
	R5-12.47-2	-639,862	400	-255,945
	R5-12.47-3	-270,192	600	-162,115
	R5-12.47-4	-851,251	650	-553,313
	R5-12.47-5	-919,006	500	-459,503
	R5-25.00-1	-1,609,031	450	-724,064
	R5-35.00-1	-2,238,386	450	-1,007,274
	GC-12.47-5	-1,209,248	500	-604,624

If the analyzed CVR scheme were applied to all of the non-networked distribution feeders in the United States, with the exception of feeders represented by R1-25.00-1, the reduction in energy consumption would be approximately 6,500 MWyr; which is nearly the output of Grand Coulee Dam if operated at nameplate capacity for the entire year.

As with most technologies it is necessary to use discretion when deploying CVR. From Section 3 it is clear that while some feeders do show improvement, it is minimal and would not warrant the capital expenditure of a CVR system. Figure 4.1 is a plot showing the percent total benefit as a function of percent of total number of feeders. For example, it can be seen that if CVR is deployed on 40% of the total feeders in the United States, over 80% of the potential benefit can be achieved. In fact, the individual feeder results from Section 3 as well as Figure 4.1 show that CVR deployment on only the heavily loaded, higher voltage feeders yields 37% of the total benefit and only requires 10% of the total feeders to deploy CVR.

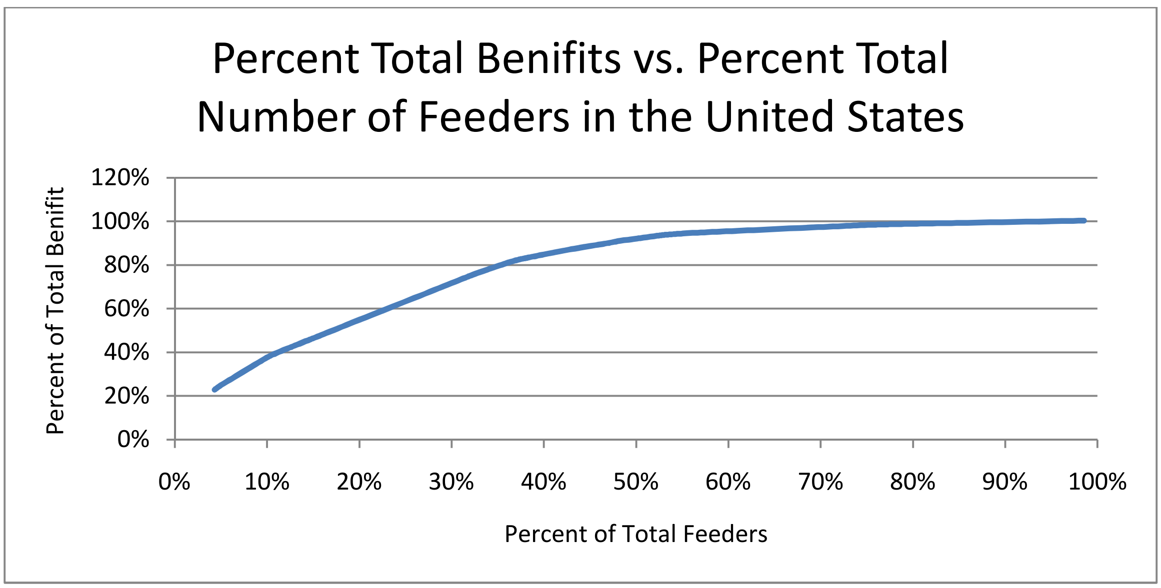


Figure 4.1: Percent Total Benefit vs. Percent Total Number of Feeders in the United States

5. Concluding Remarks

This report has examined the benefits of deploying CVR and extrapolated those benefits to a national level. The CVR scheme implemented is 20 years old and is in the public domain, but newer proprietary methods are expected to provide improved results. The principle results obtained from this analysis are as follow:

1) The analysis of CVR, as well as other smart grid technologies, requires the use of time-series simulations.
2) The behavior of end use loads is more complicated than generally acknowledged. Voltage dependent multi-state models must be used.
3) CVR provides peak load reduction and annual energy reduction of approximately 0.5%-3% depending on the specific feeder.
4) When extrapolated to a national level it can be seen that a complete deployment of CVR, 100% of distribution feeders, provides a 3.04% reduction in annual energy consumption.
5) If deployed only on high value distribution feeders, 40% of distribution feeders, the annual energy consumption is still reduced by 2.4%.
6) In a practical deployment of CVR heavily loaded higher voltage feeders should be targeted.
7) Loss reduction is not a significant benefit of CVR.

6. Appendix I: Regional CVR Plots

Because of the large number of plots which are generated by the analysis of the 24 prototypical feeders, they have been collected into a single appendix.

6.1. Region 1: CVR Plots

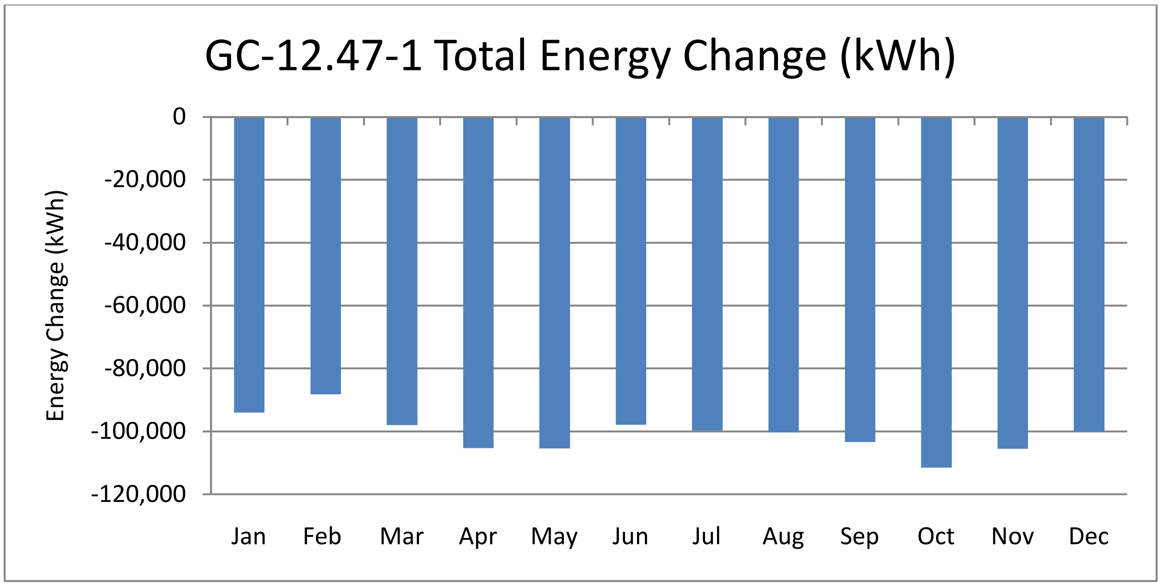


Figure 6.1: GC-12.47-1 Total Energy Change (kWh)

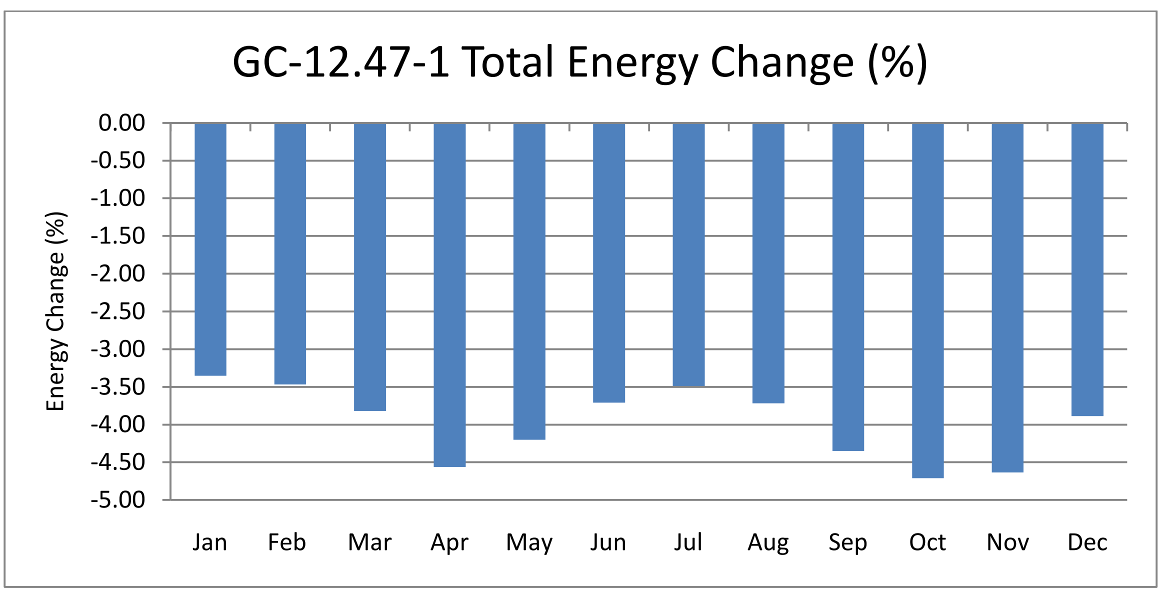


Figure 6.2: GC-12.47-1 Total Energy Change (%)

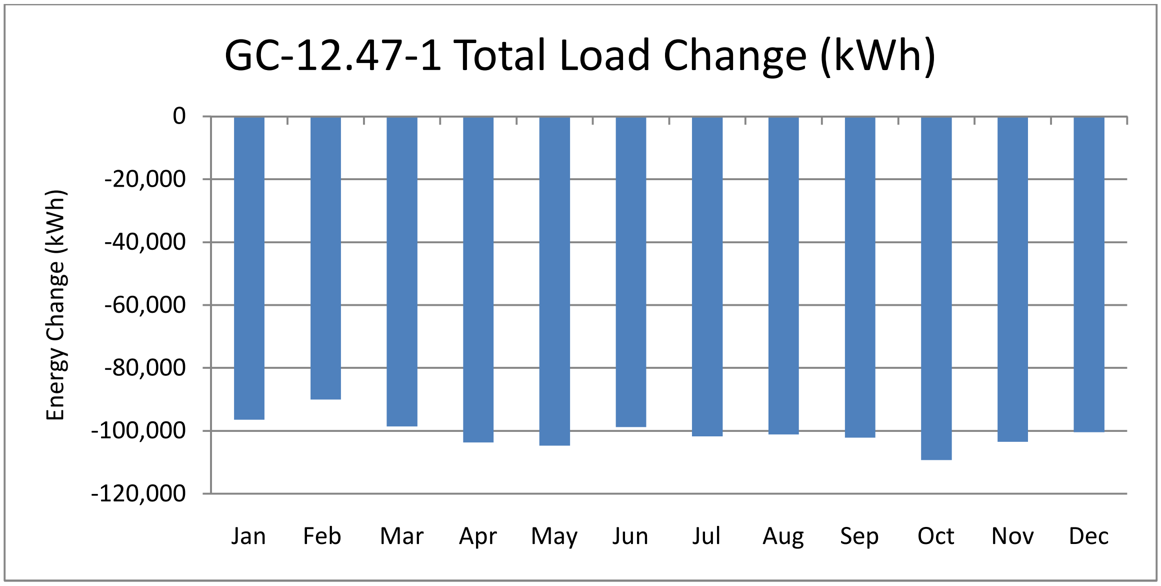


Figure 6.3: GC-12.47-1 Total Load Change (kWh)

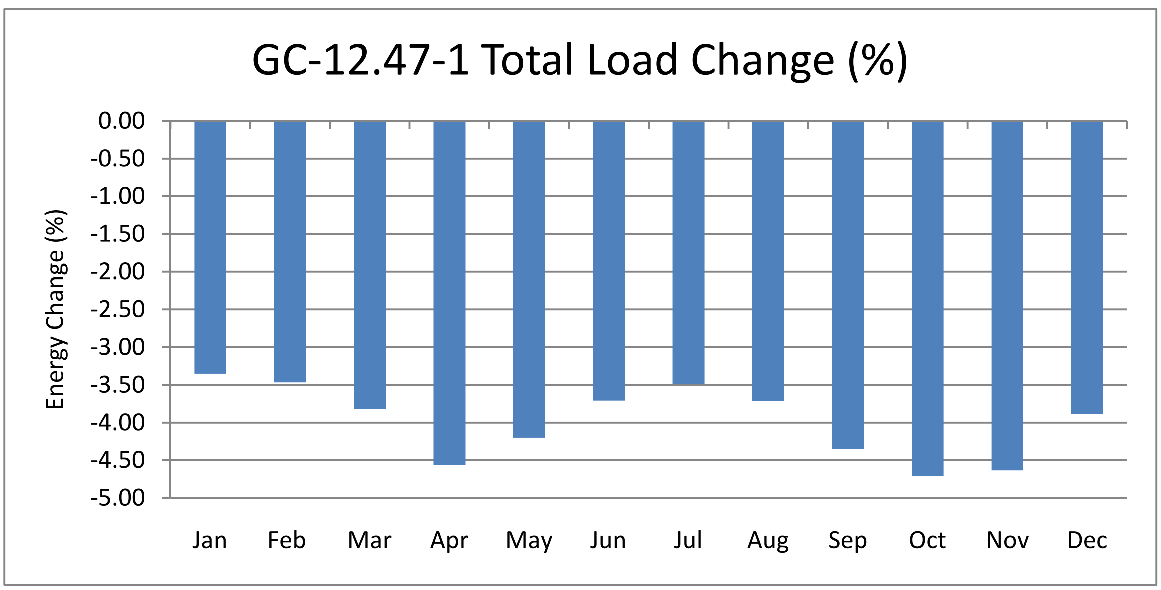


Figure 6.4: GC-12.47-1 Total Load Change (%)

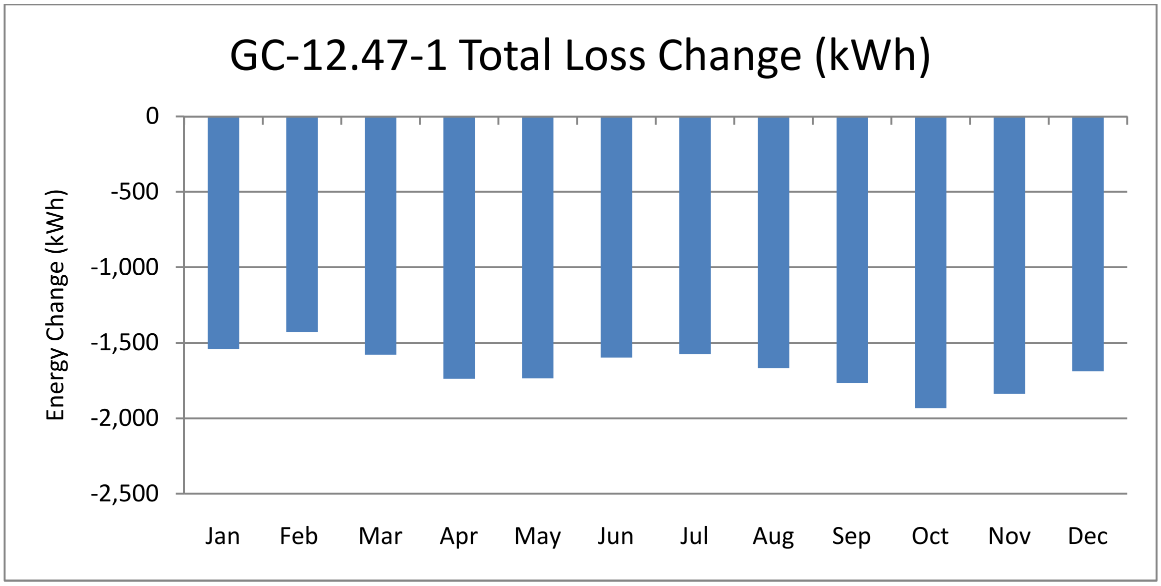


Figure 6.5: GC-12.47-1 Total Loss Change (kWh)

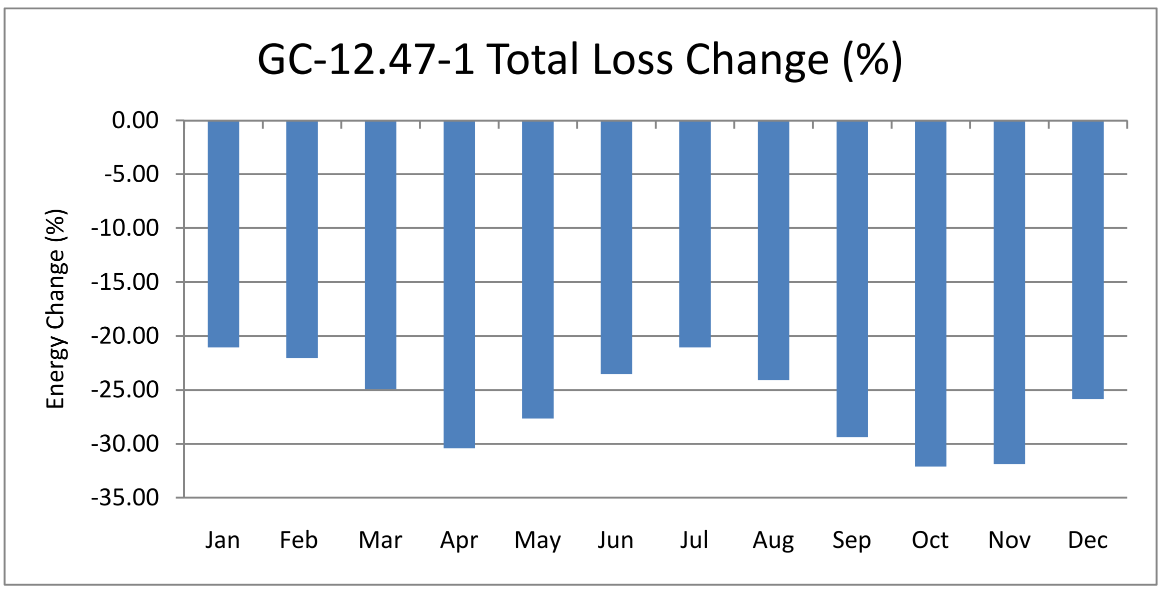


Figure 6.6: GC-12.47-1 Total loss Change (%)

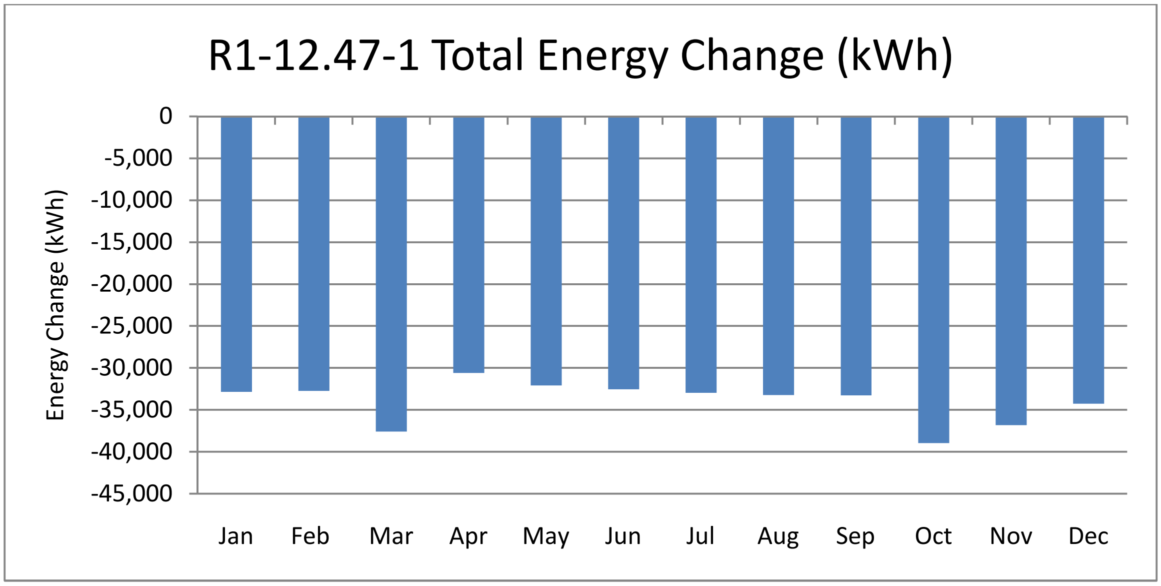


Figure 6.7: R1-12.47-1 Total Energy Change (kWh)

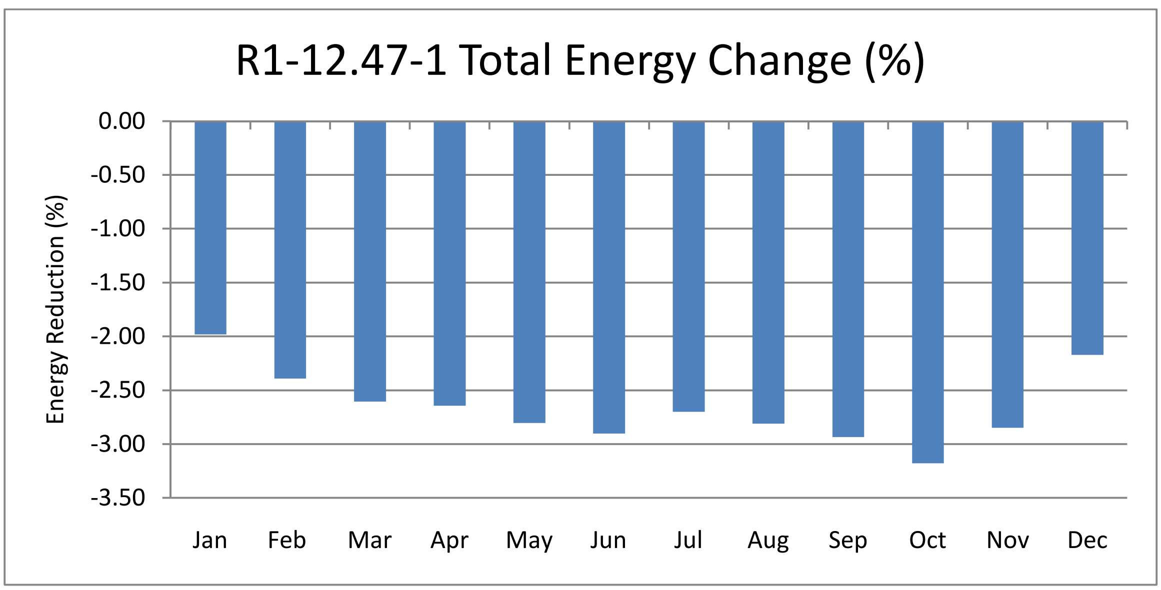


Figure 6.8: R1-12.47-1 Total Energy Change (%)

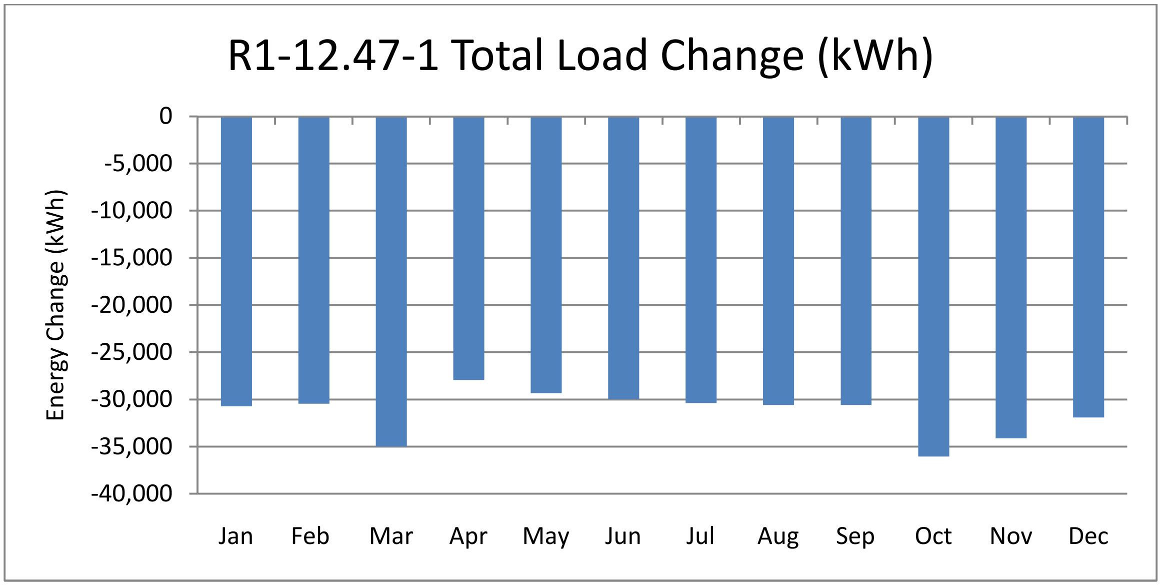


Figure 6.9: R1-12.47-1 Total Load Change (kWh)

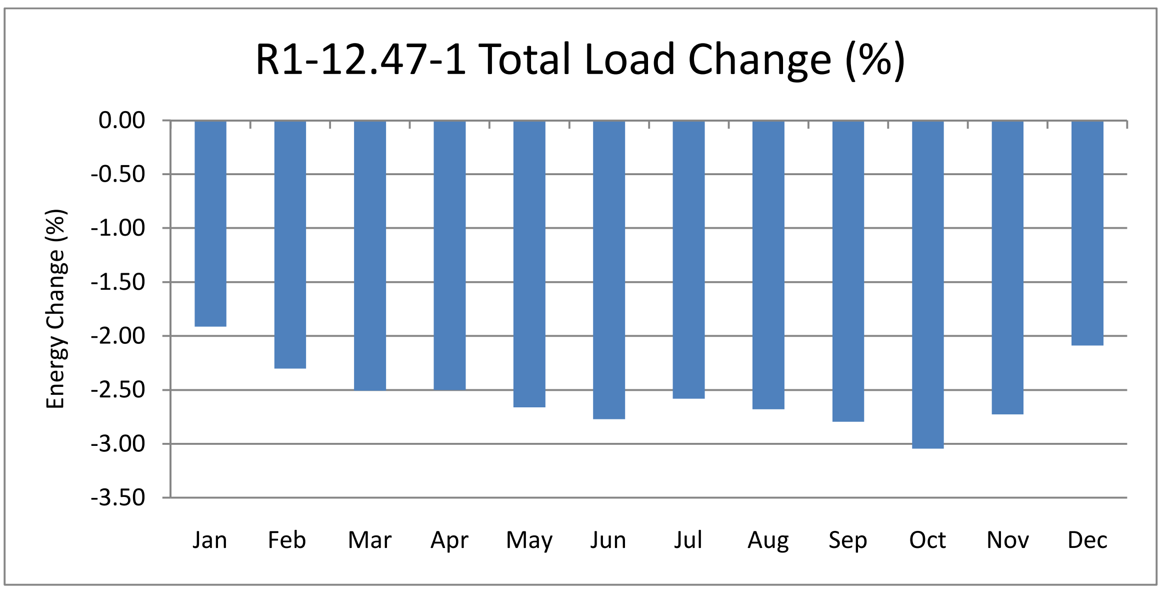


Figure 6.10: R1-12.47-1 Total Load Change (%)

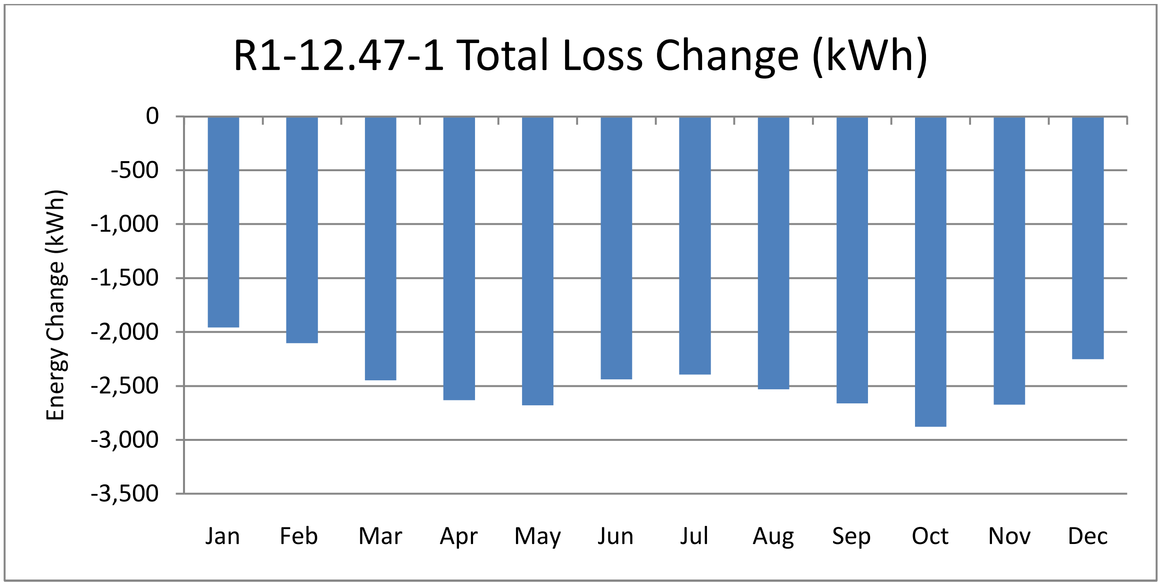


Figure 6.11: R1-12.47-1 Total Loss Change (kWh)

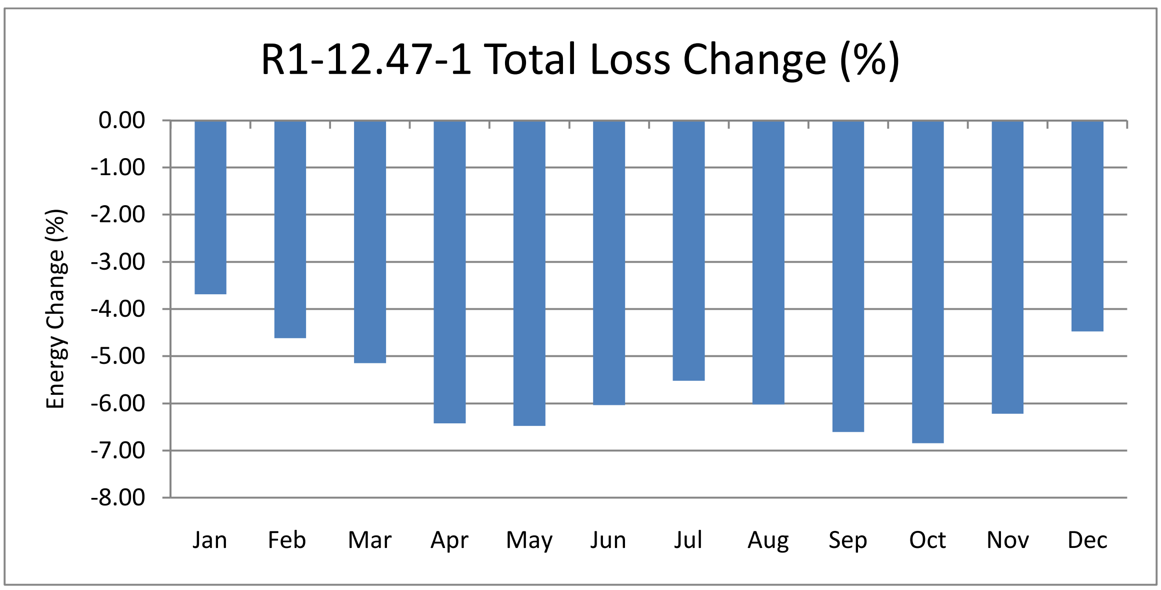


Figure 6.12: R1-12.47-1 Total Loss Change (%)

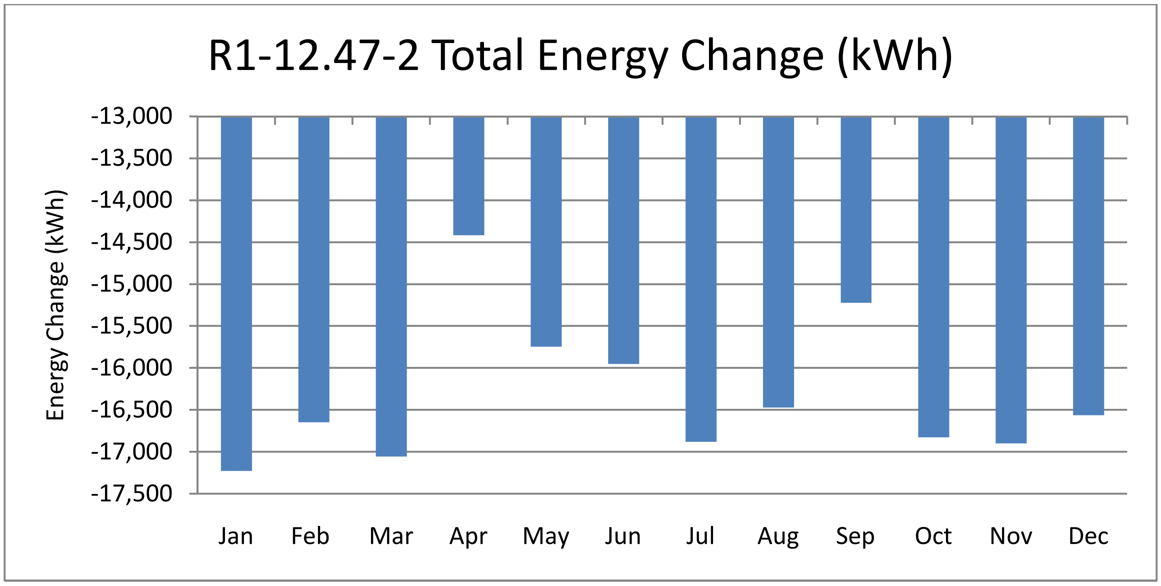


Figure 6.13: R1-12.47-2 Total Energy Change (kWh)

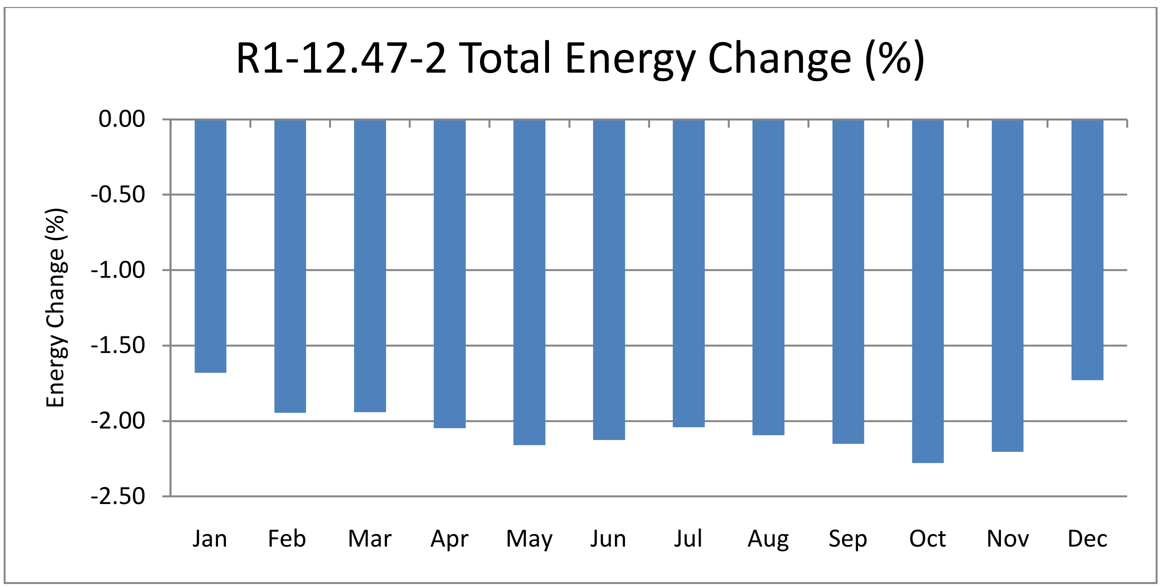


Figure 6.14: R1-12.47-2 Total Energy Change (%)

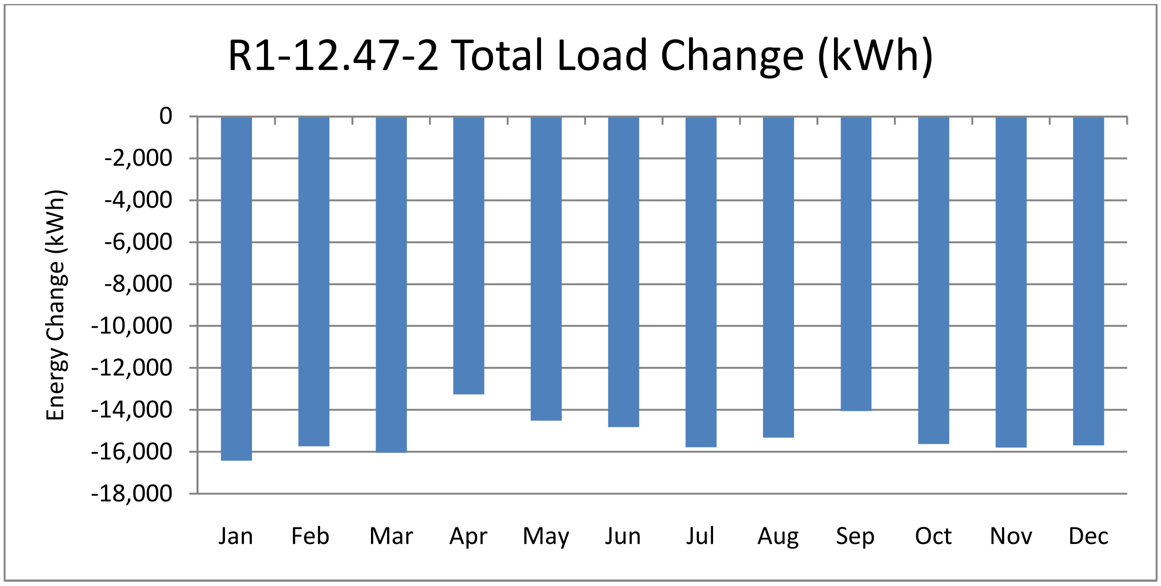


Figure 6.15: R1-12.47-2 Total Load Change (kWh)

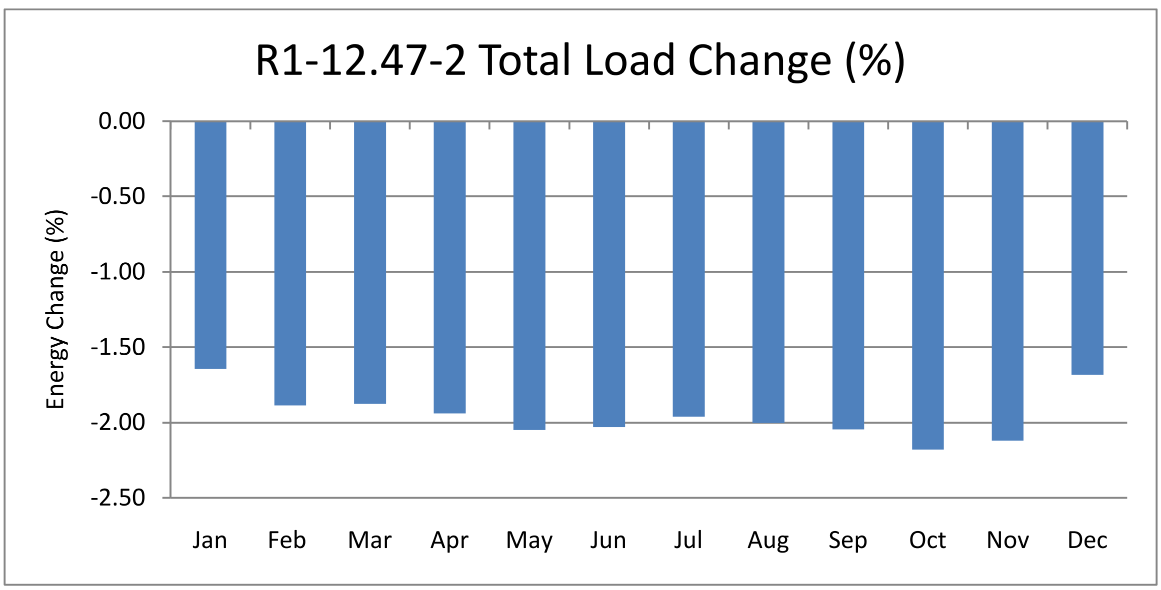


Figure 6.16: R1-12.47-2 Total Load Change (%)

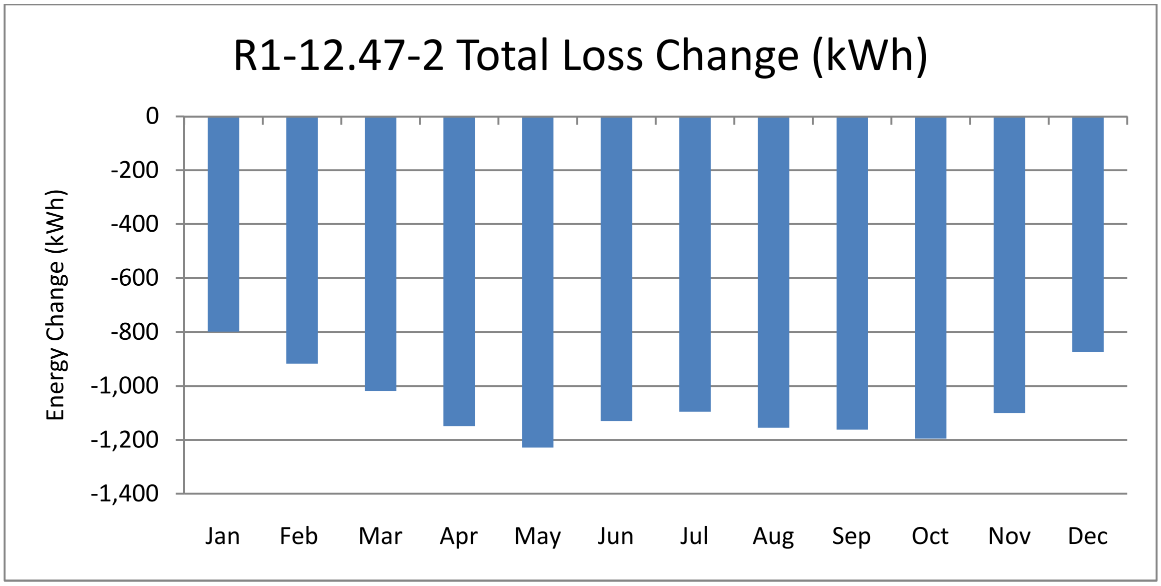


Figure 6.17: R1-12.47-2 Total Loss Change (kWh)

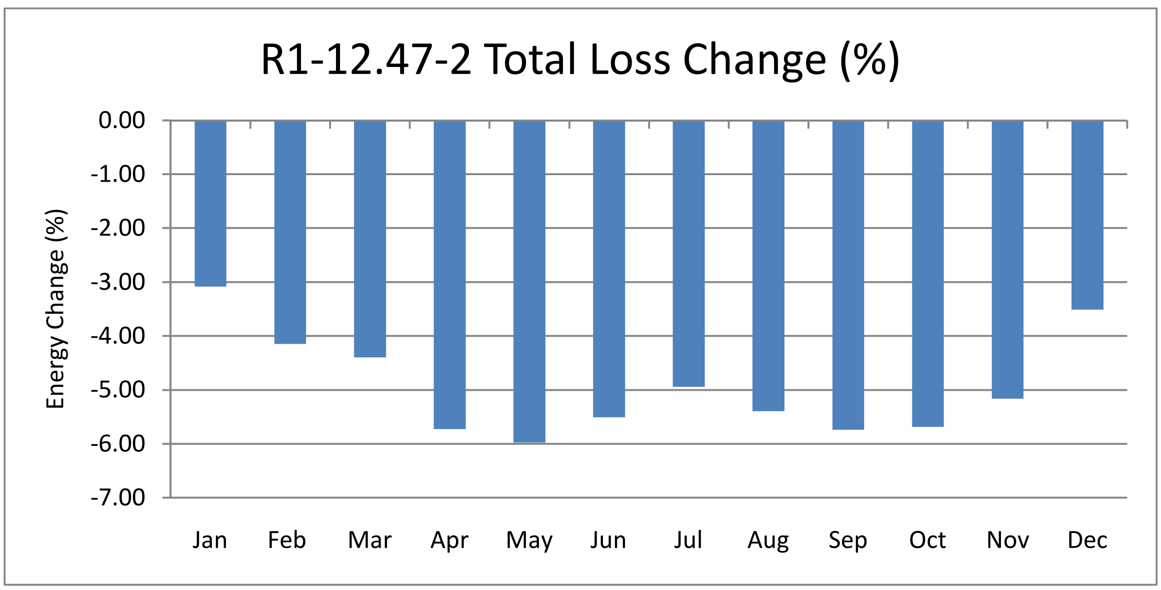


Figure 6.18: R1-12.47-2 Total Loss Change (%)

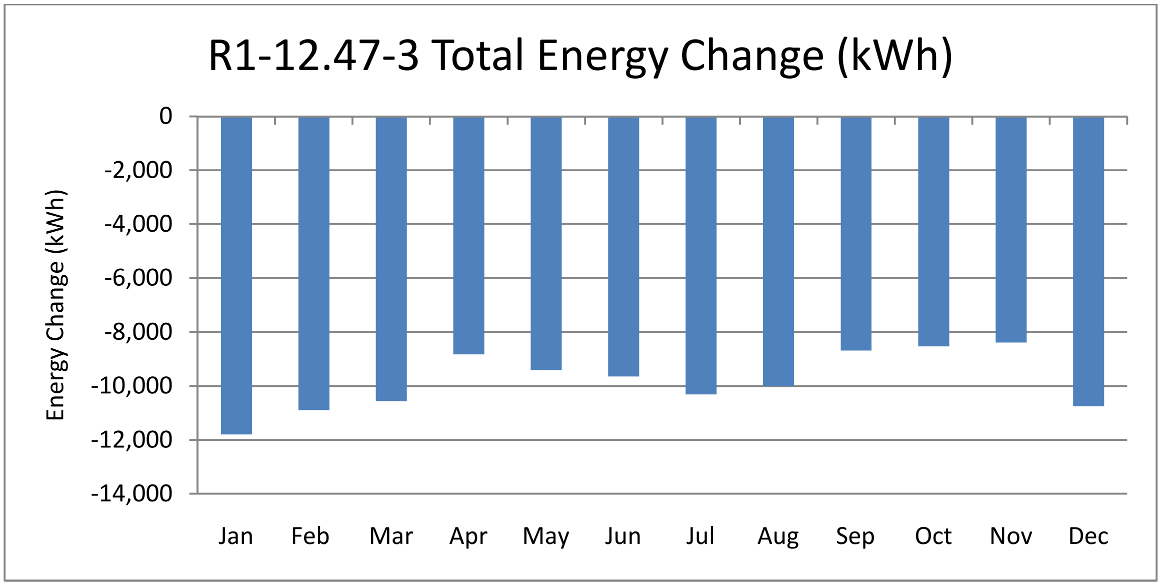


Figure 6.19: R1-12.47-3 Total Energy Change (kWh)

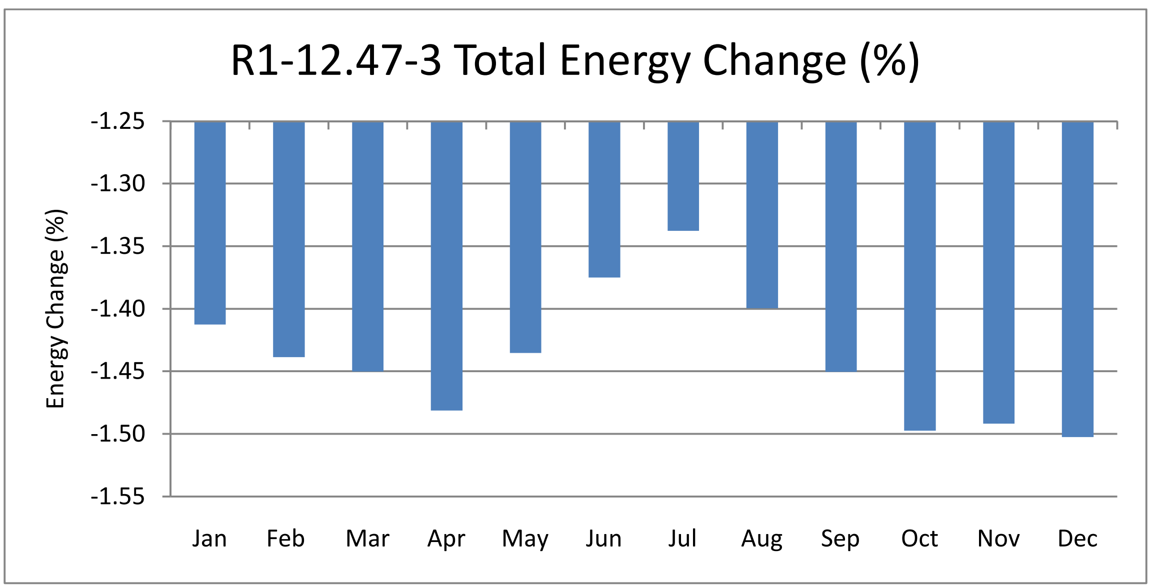


Figure 6.20: R1-12.47-3 Total Energy Change (%)

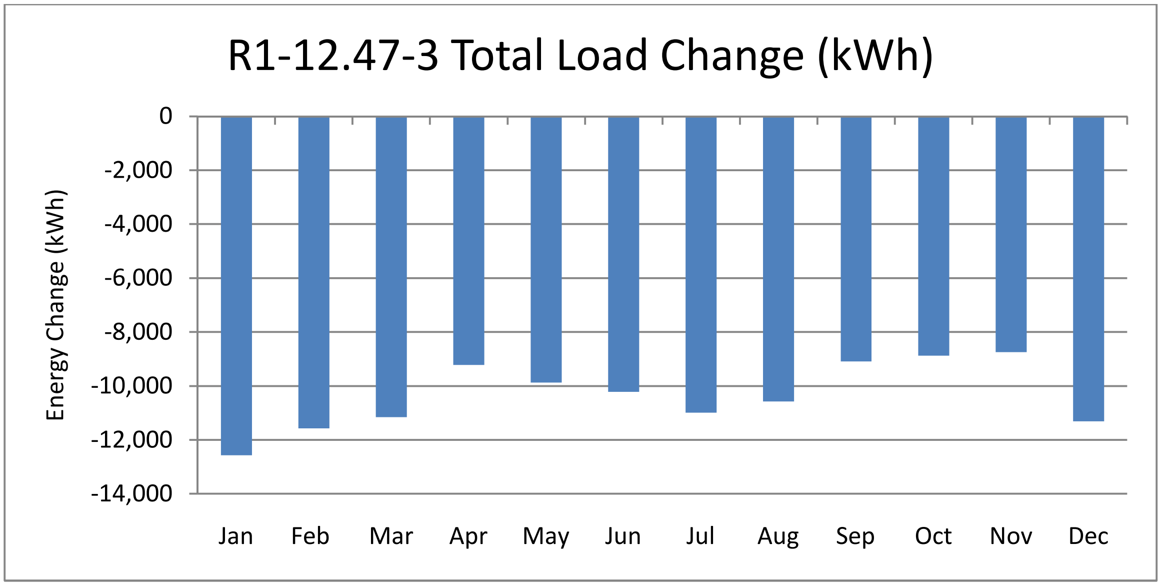


Figure 6.21: R1-12.47-3 Total Load Change (kWh)

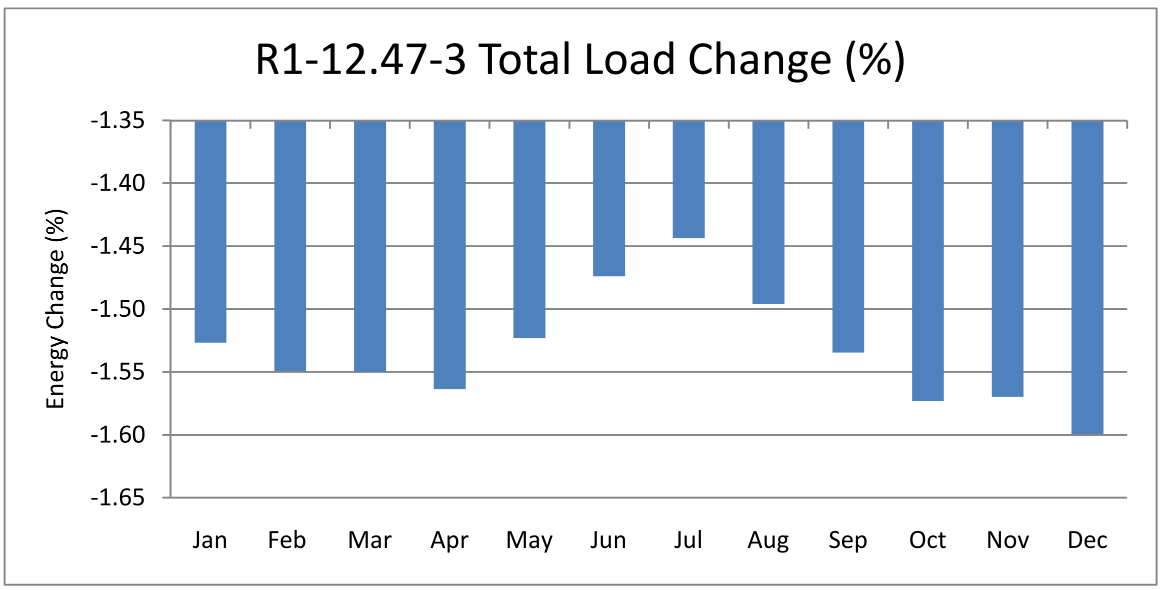


Figure 6.22: R1-12.47-3 Total Load Change (%)

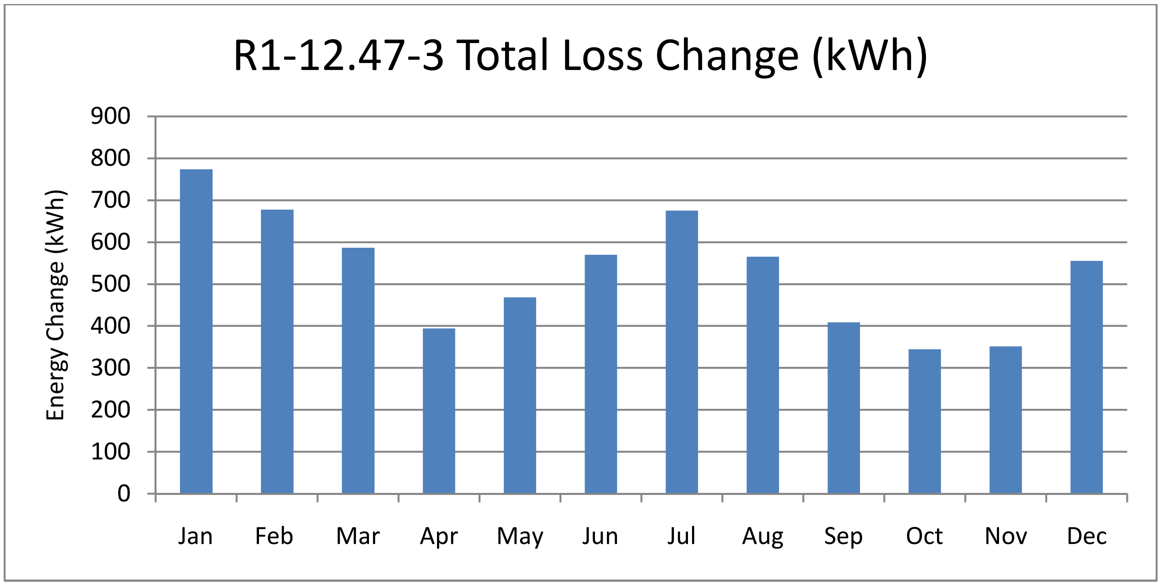


Figure 6.23: R1-12.47-3 Total Loss Change (kWh)

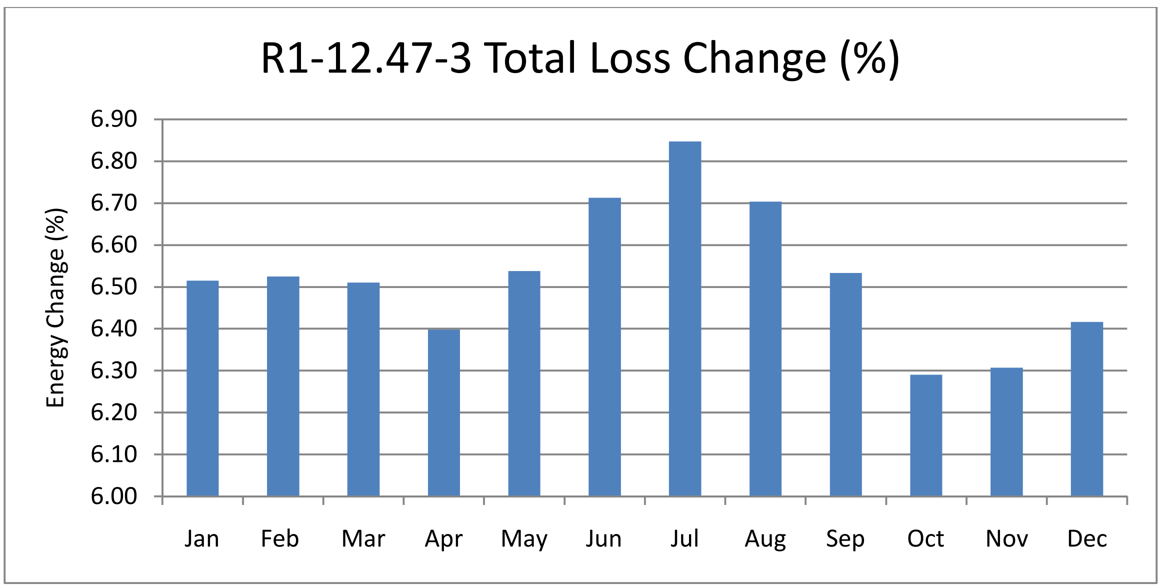


Figure 6.24: R1-12.47-3 Total Loss Change (%)

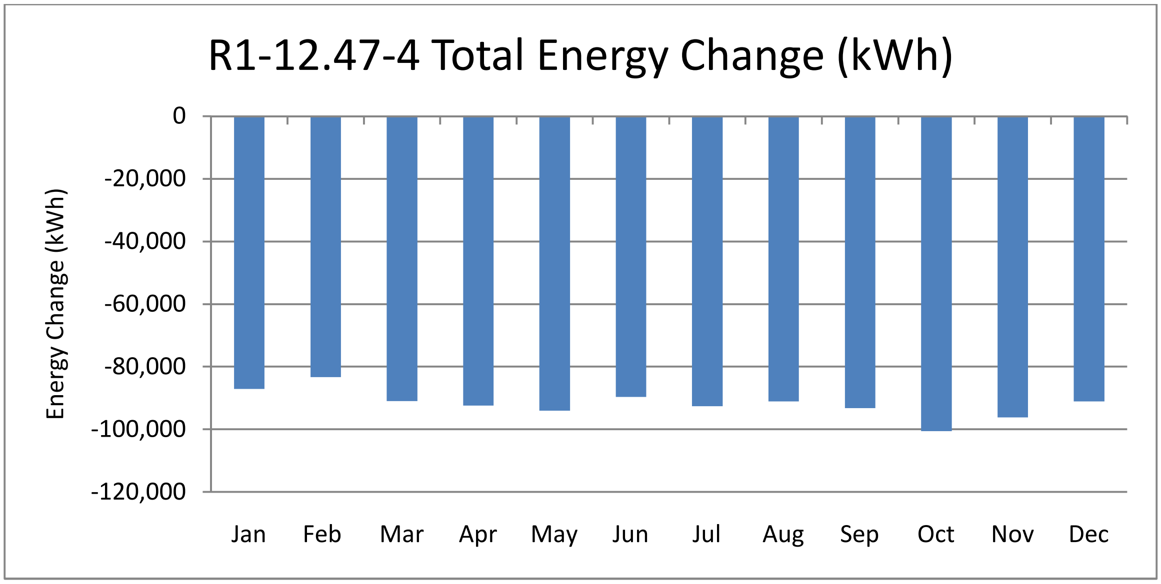


Figure 6.25: R1-12.47-4 Total Energy Change (kWh)

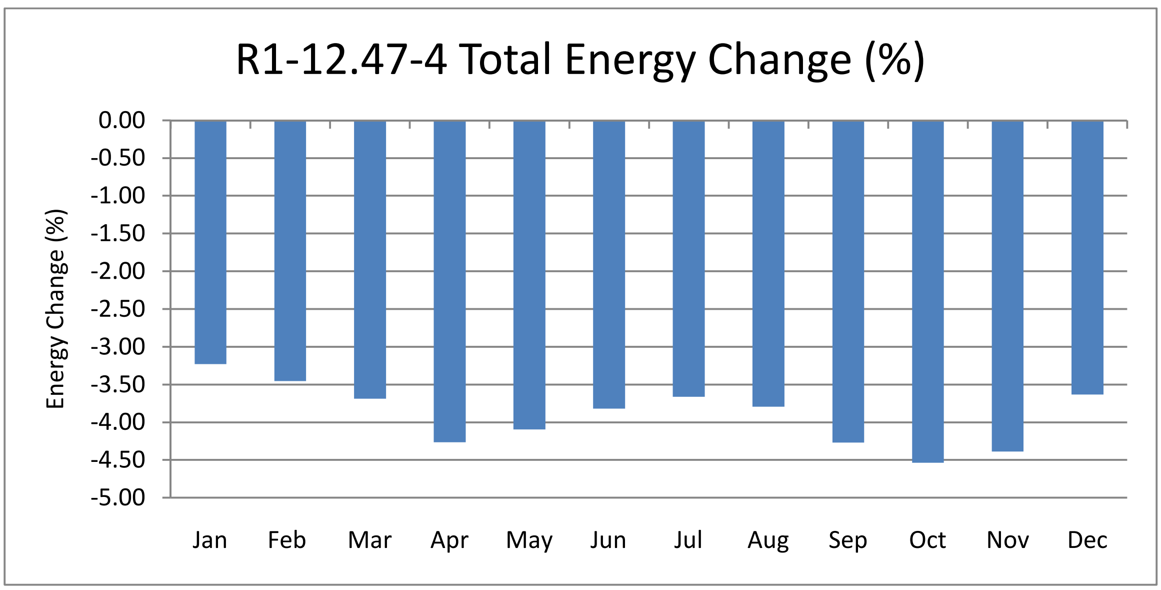


Figure 6.26: R1-12.47-4 Total Energy Change (%)

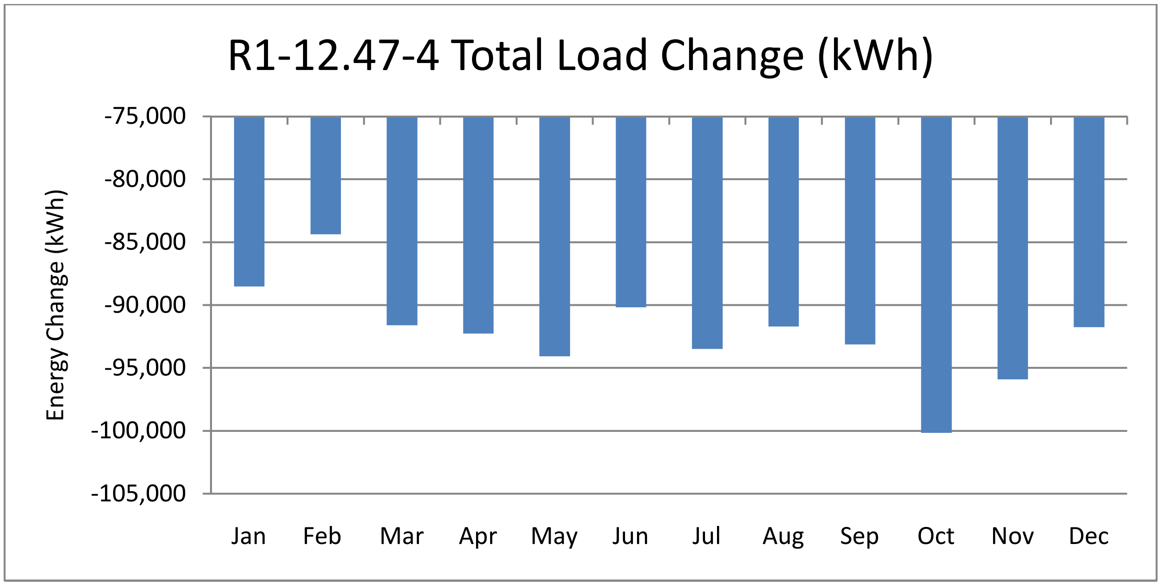


Figure 6.27: R1-12.47-4 Total Load Change (kWh)

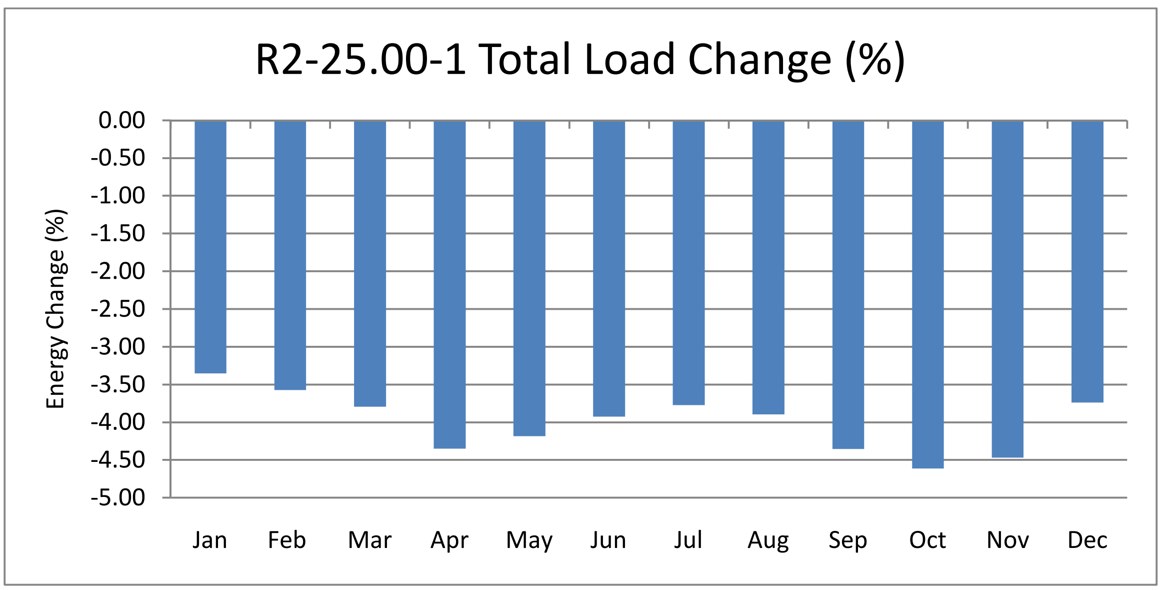


Figure 6.28: R1-12.47-4 Total Load Change (%)

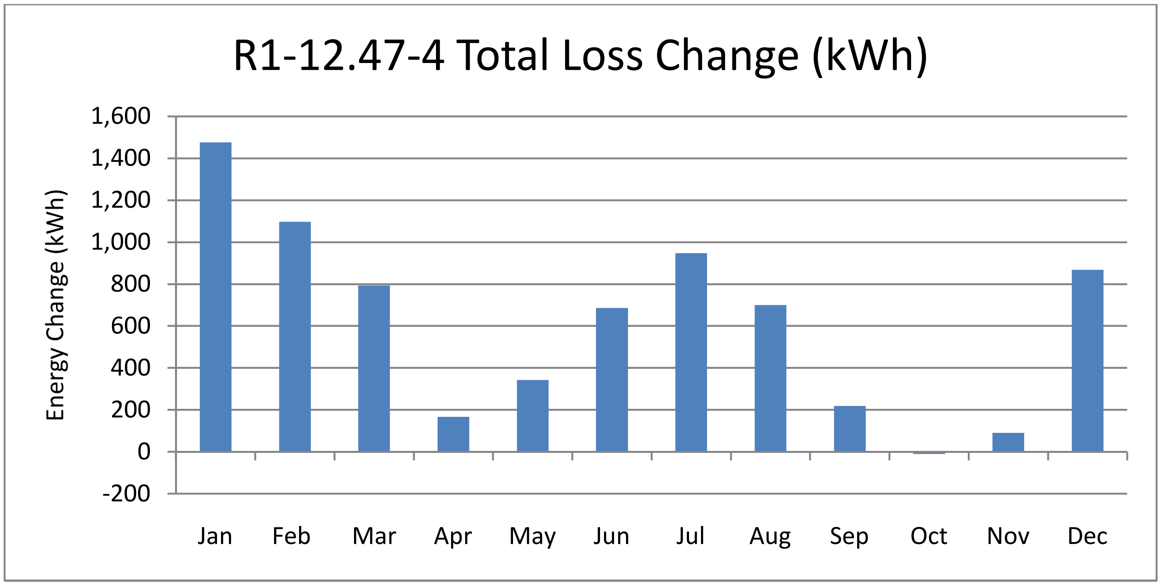


Figure 6.29: R1-12.47-4 Total Loss Change (kWh)

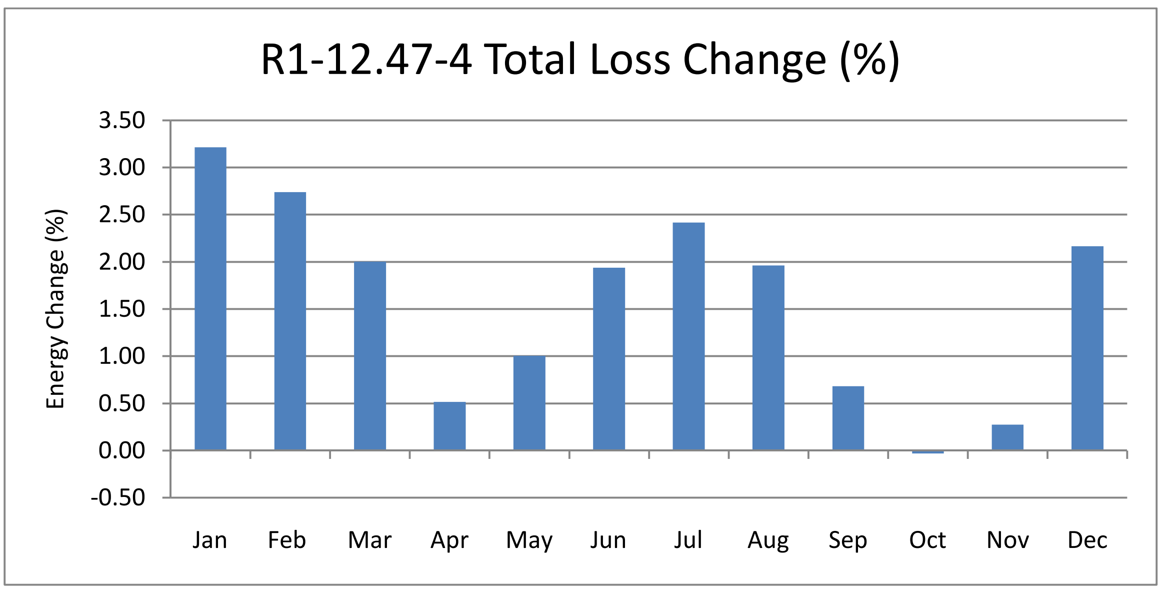


Figure 6.30: R1-12.47-4 Total Loss Change (%)

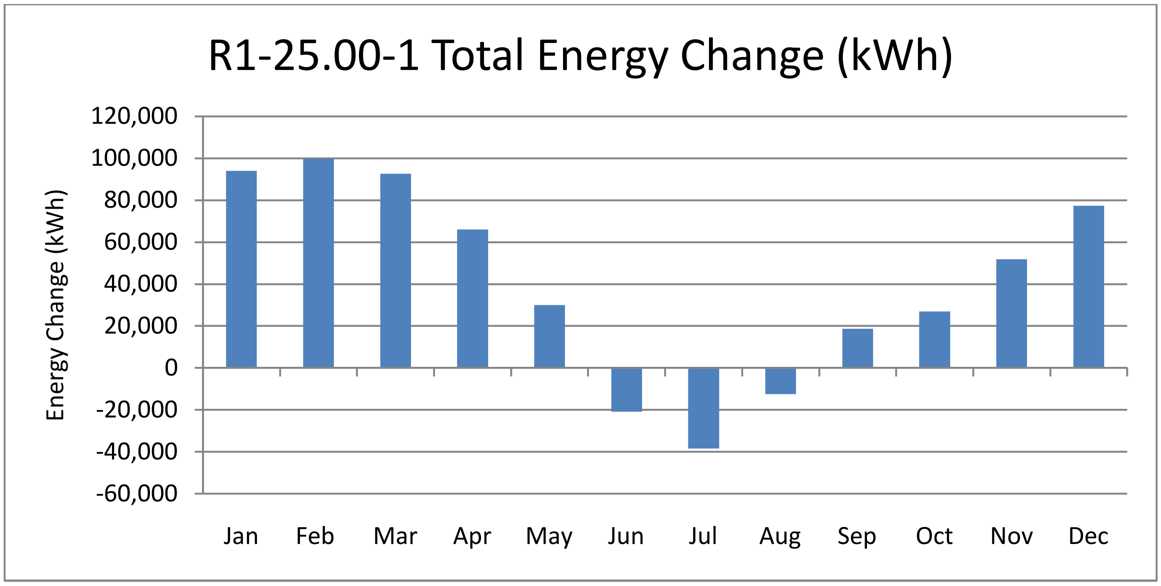


Figure 6.31: R1-25.00-1 Total Energy Change (kWh)

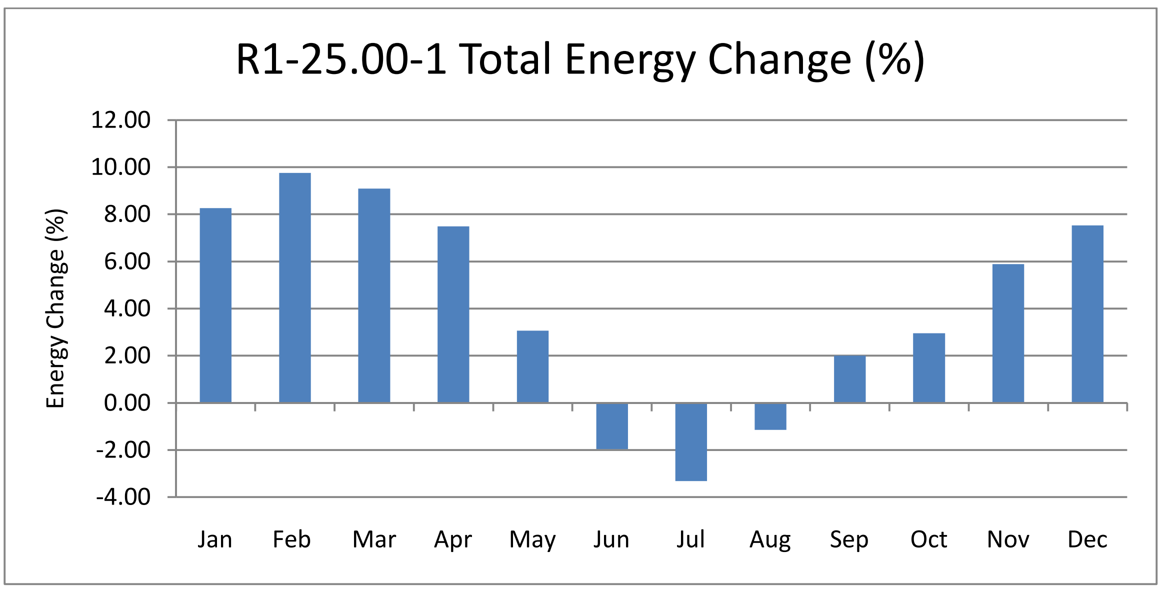


Figure 6.32: R1-25.00-1 Total Energy Change (%)

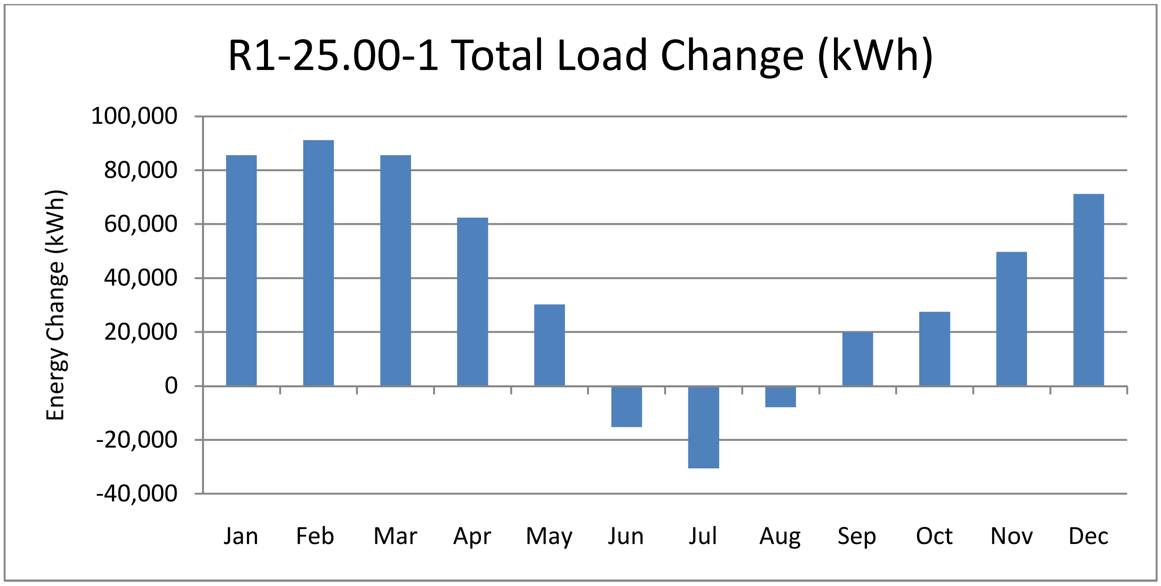


Figure 6.33: R1-25.00-1 Total Load Change (kWh)

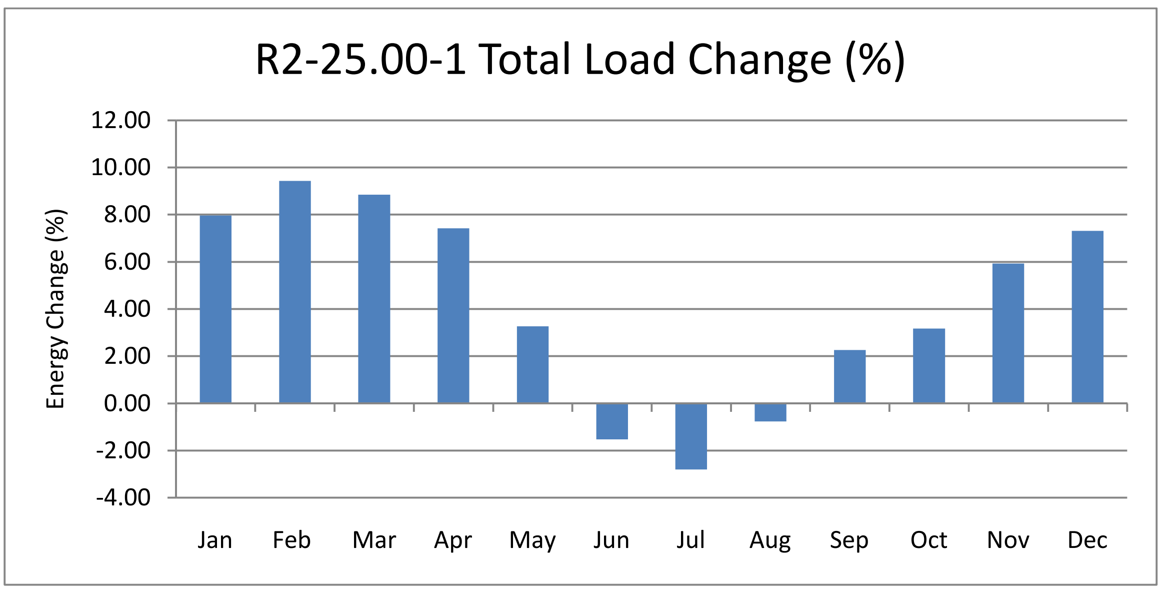


Figure 6.34: R1-25.00-1 Total Load Change (%)

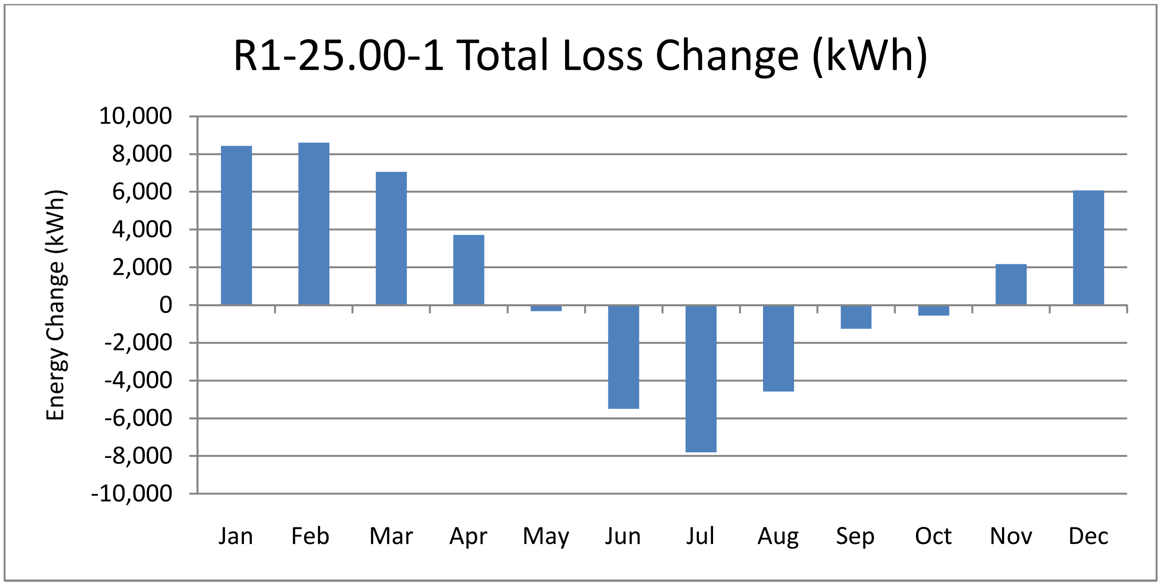


Figure 6.35: R1-25.00-1 Total Loss Change (kWh)

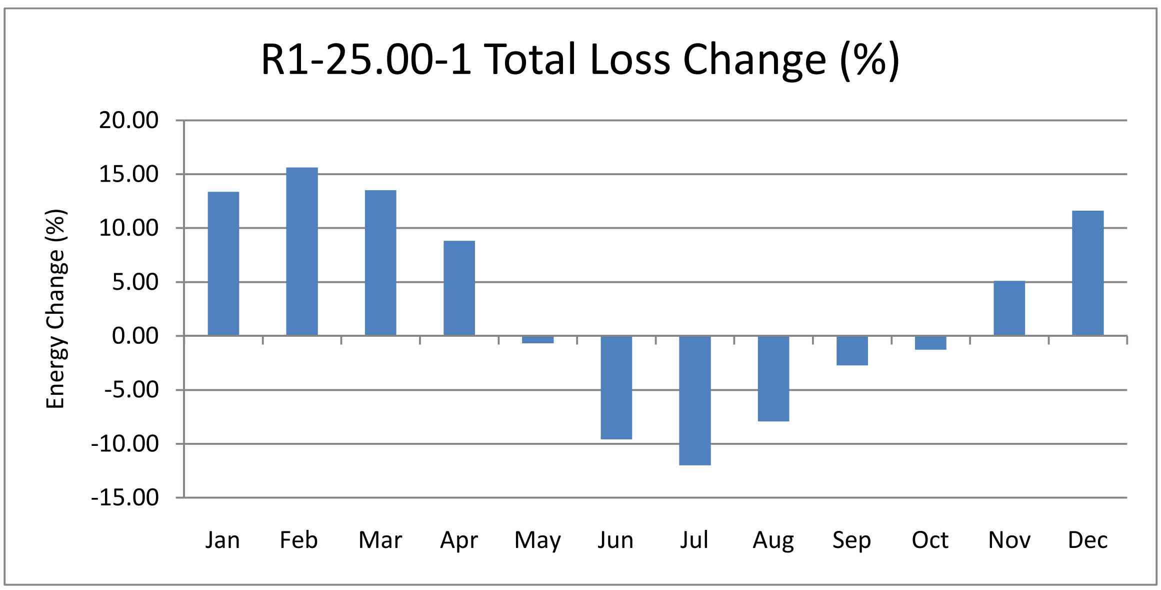


Figure 6.36: R1-25.00-1 Total Loss Change (%)

6.2. Region 2: CVR Plots

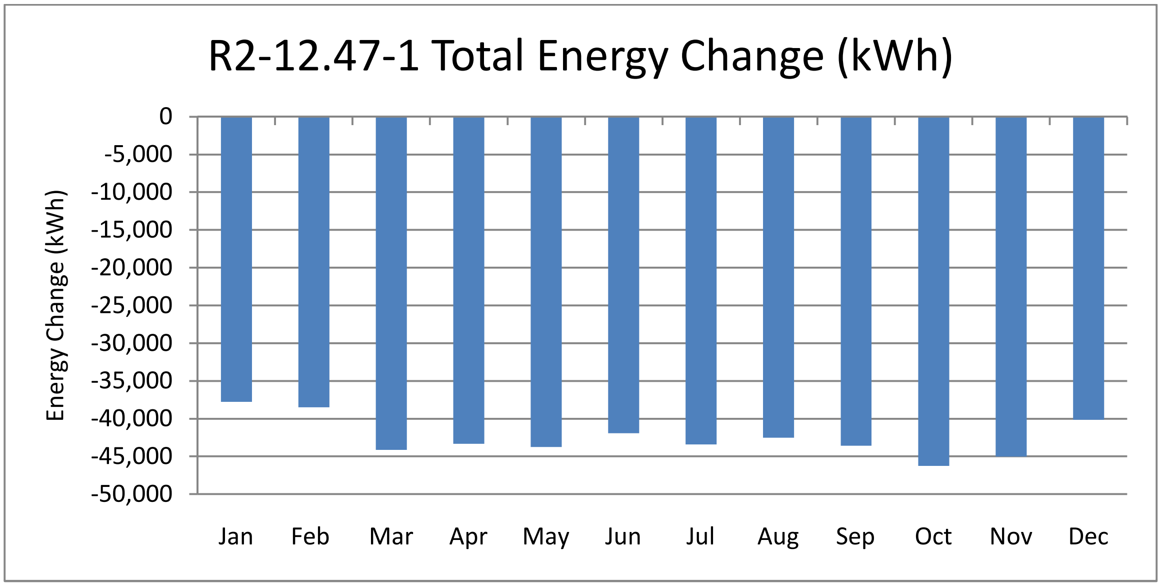


Figure 6.37: R2-12.47-1 Total Energy Change (kWh)

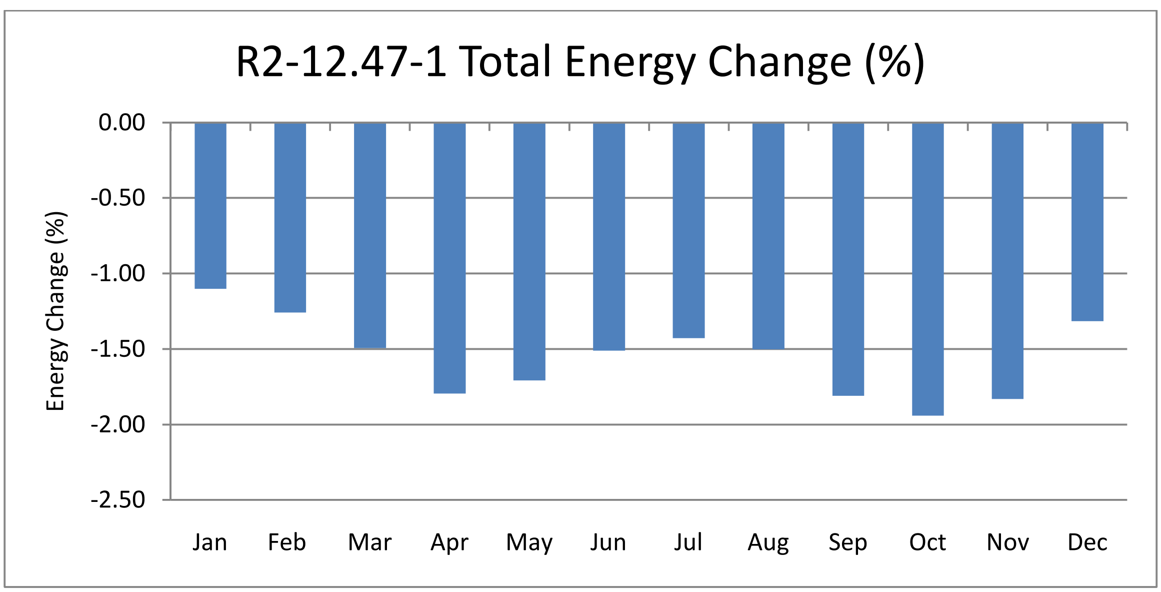


Figure 6.38: R2-12.47-1 Total Energy Change kWh

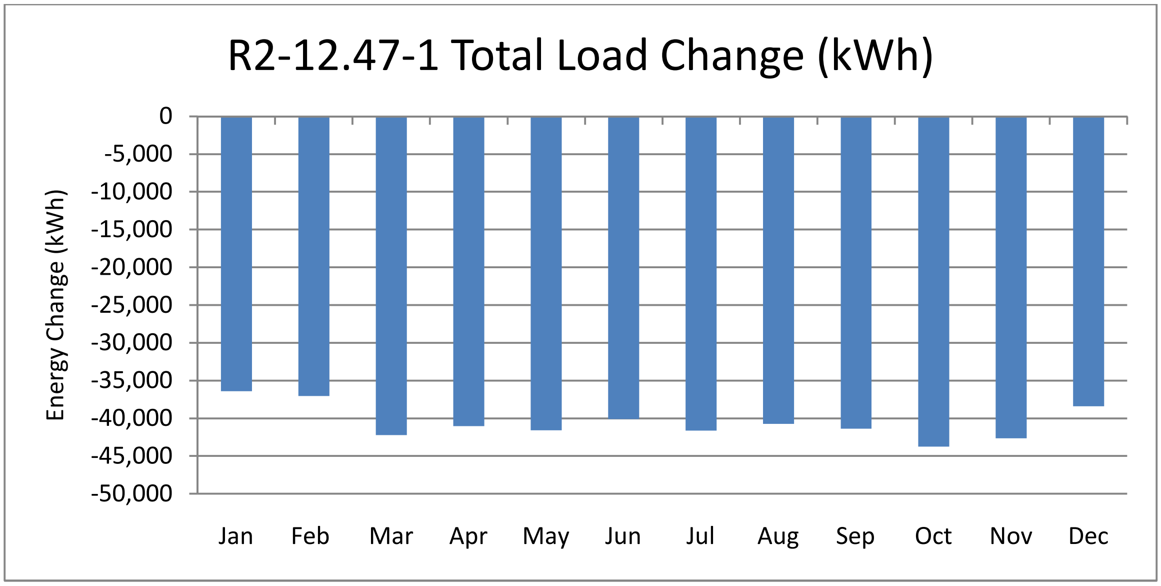


Figure 6.39: R2-12.47-1 Total Load Change (kWh)

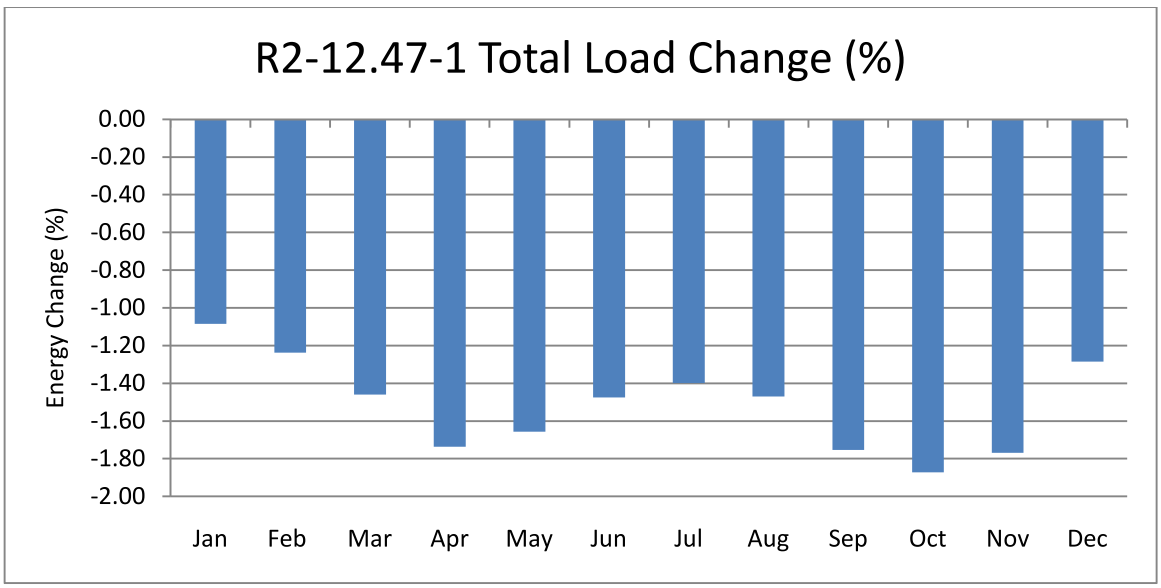


Figure 6.40: R2-12.47-1 Total Load Change (%)

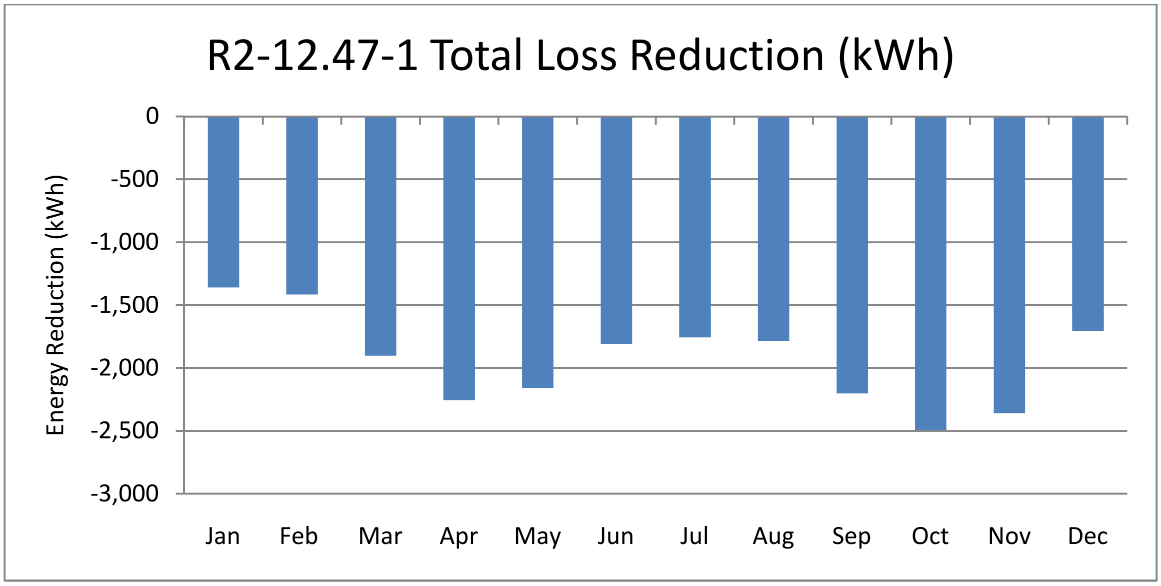


Figure 6.41: R2-12.47-1 Total Loss Change (kWh)

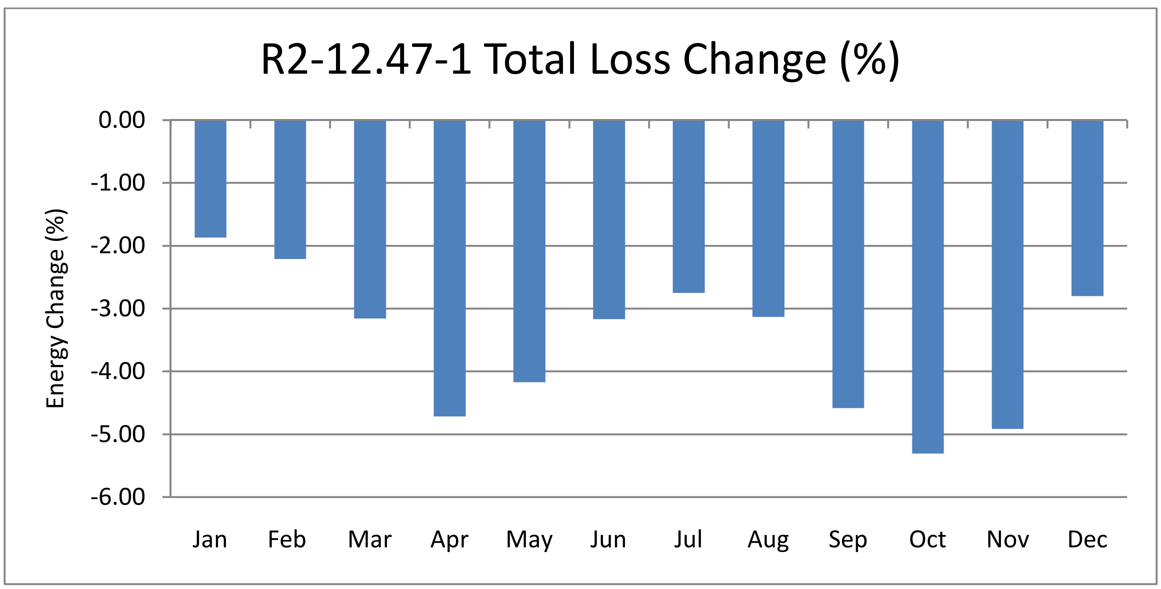


Figure 6.42: R2-12.47-1 Total Loss Change (%)

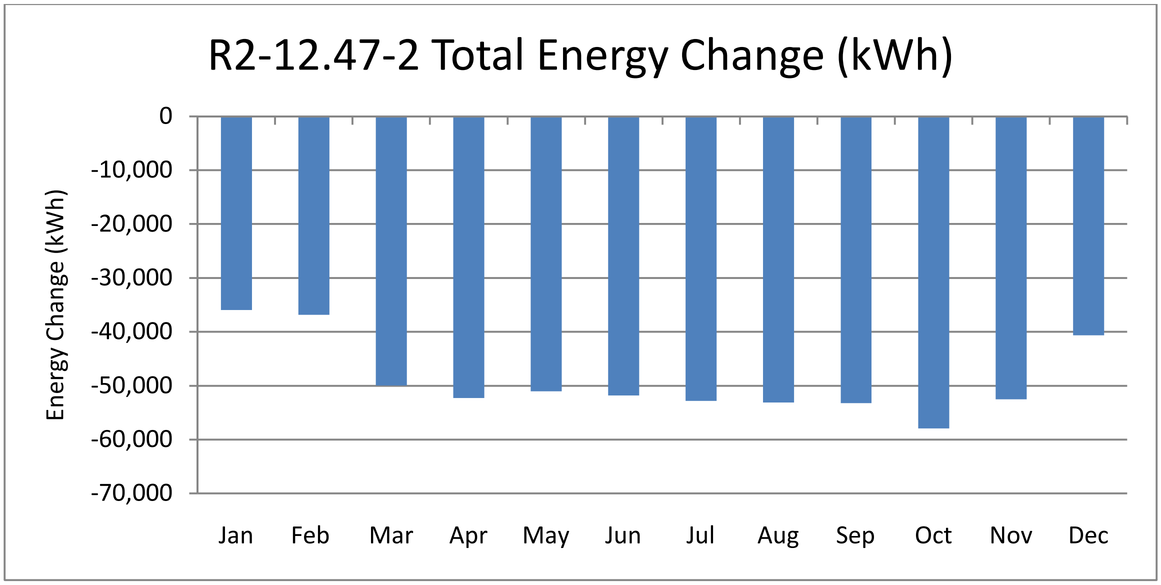


Figure 6.43: R2-12.47-2 Total Energy Change (kWh)

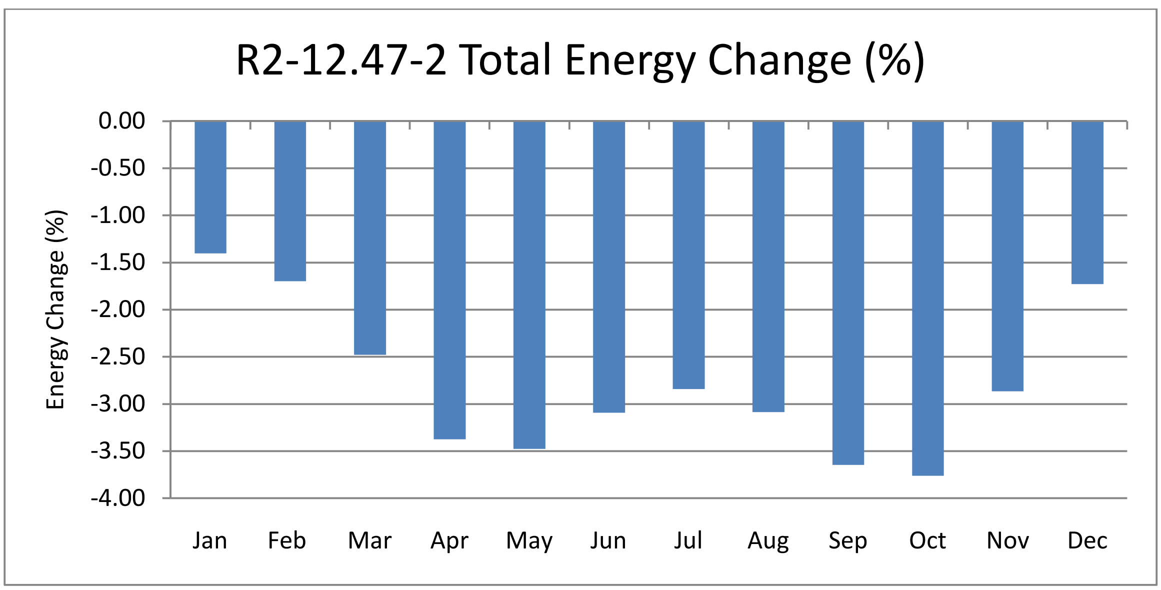


Figure 6.44: R2-12.47-2 Total Energy Change (%)

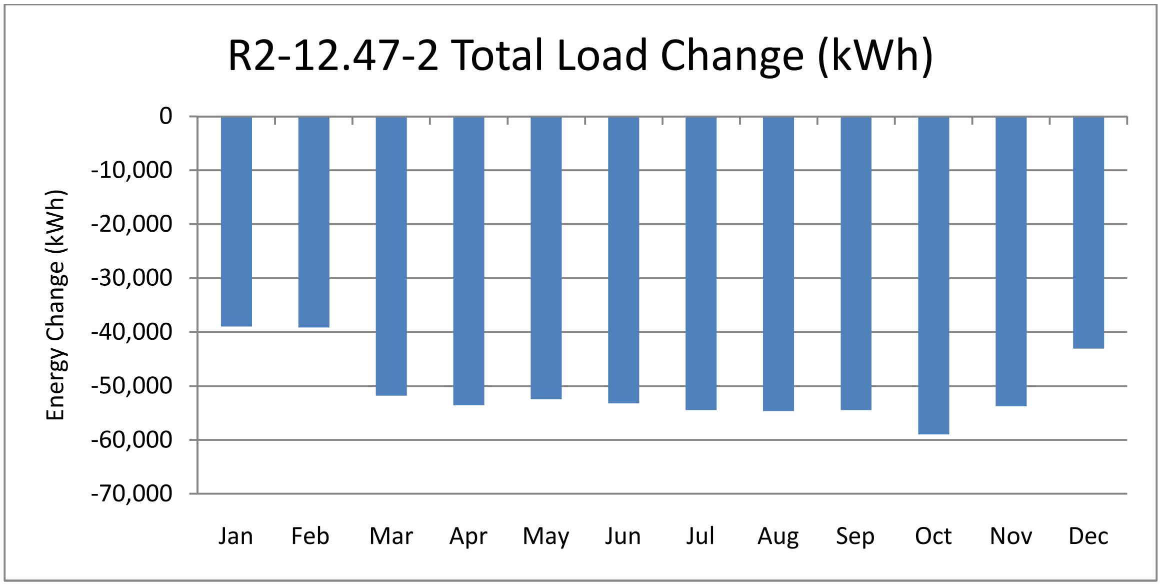


Figure 6.45: R2-12.47-2 Total Load Change (kWh)

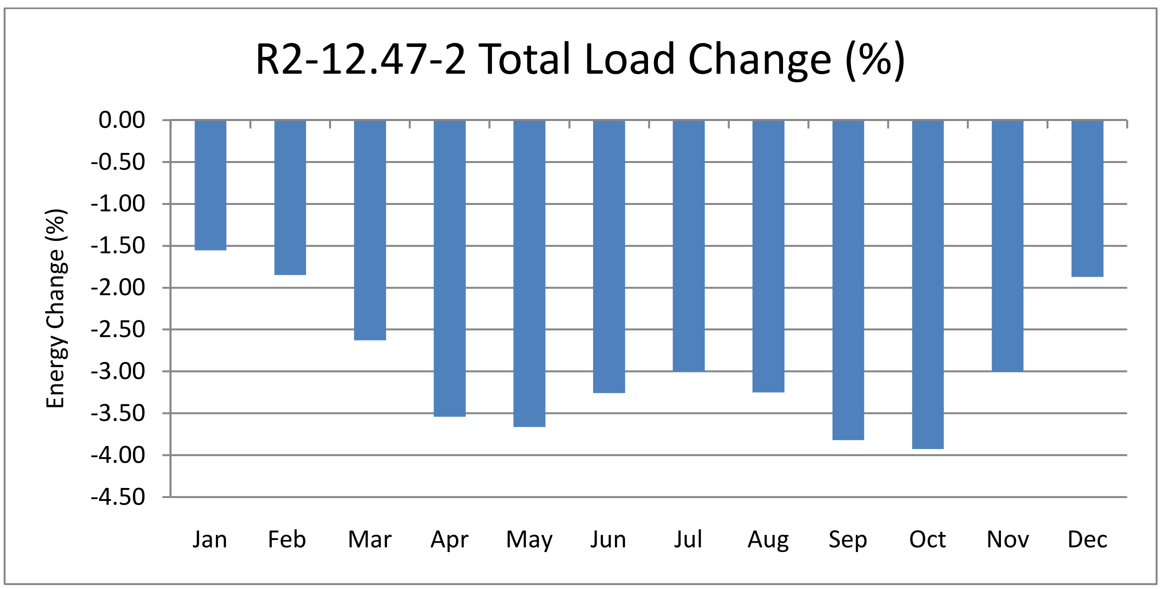


Figure 6.46: R2-12.47-2 Total Load Change (%)

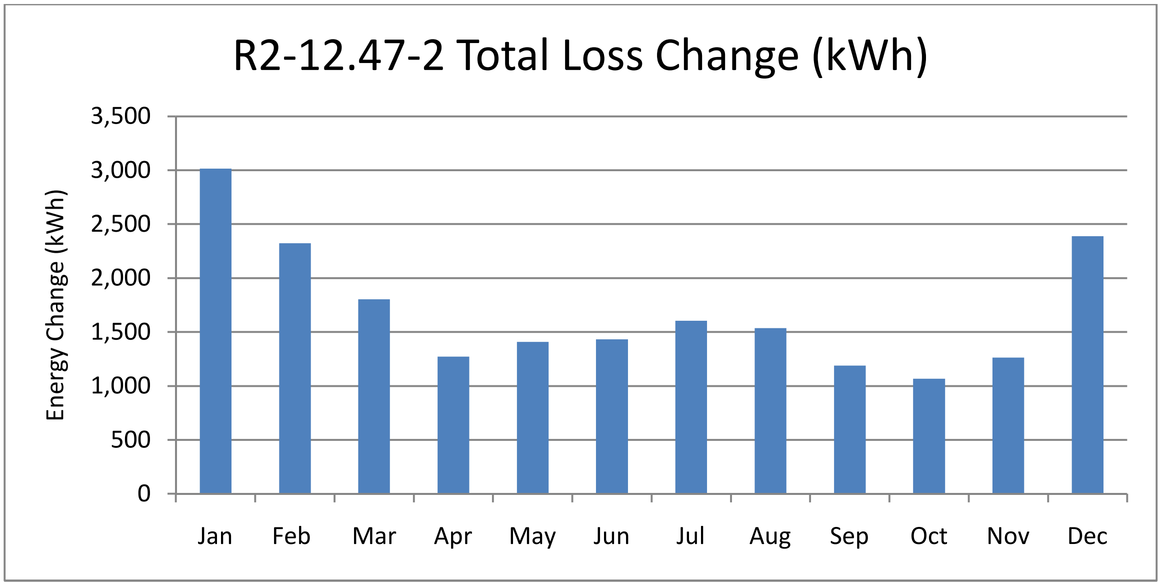


Figure 6.47: R2-12.47-2 Total Loss Change (kWh)

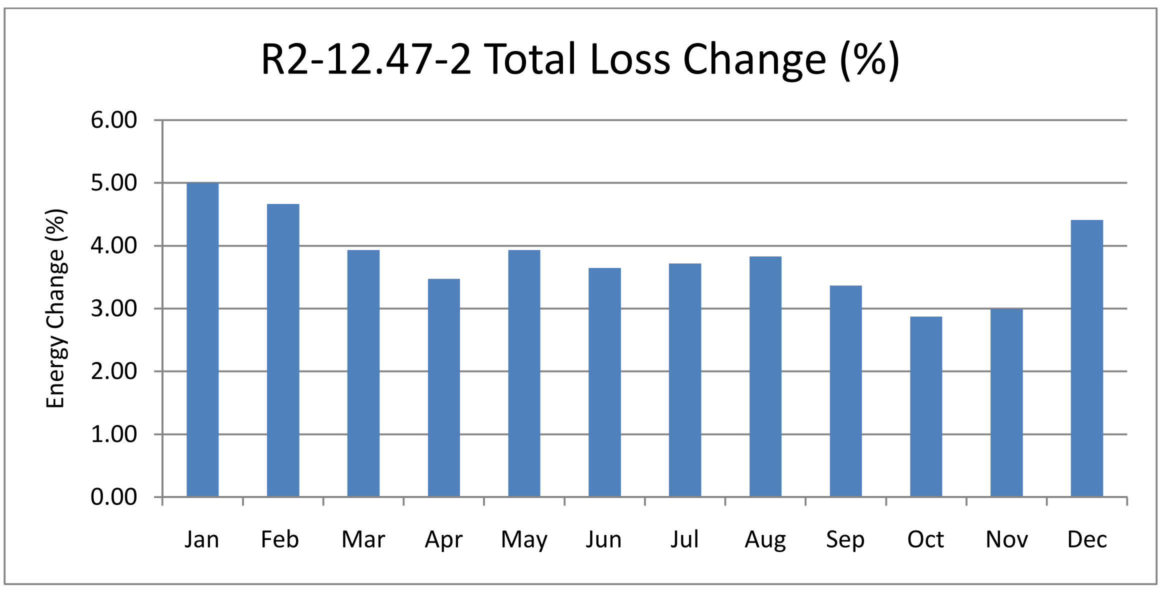


Figure 6.48: R2-12.47-2 Total Loss Change (%)

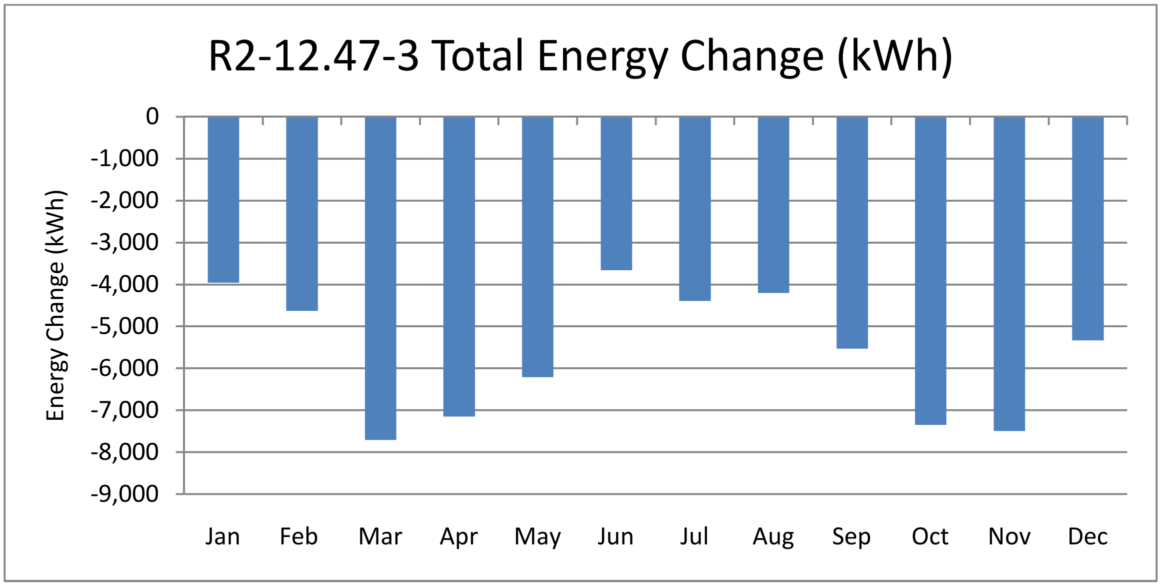


Figure 6.49: R2-12.47-3 Total Energy Change (kWh)

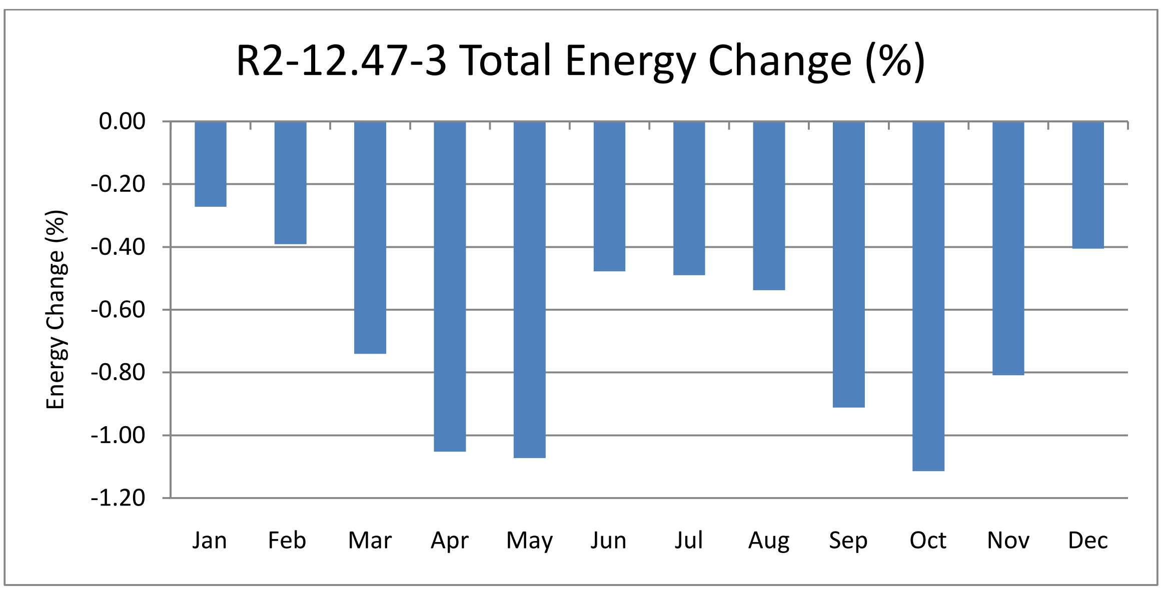


Figure 6.50: R2-12.47-3 Total Energy Change (%)

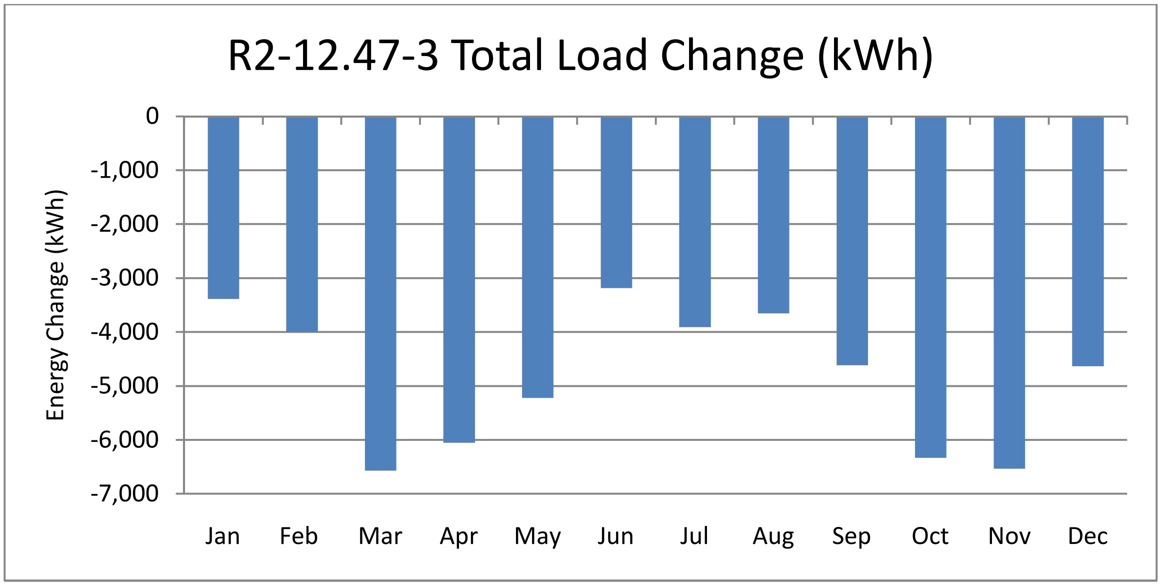


Figure 6.51: R2-12.47-3 Total Load Change (kWh)

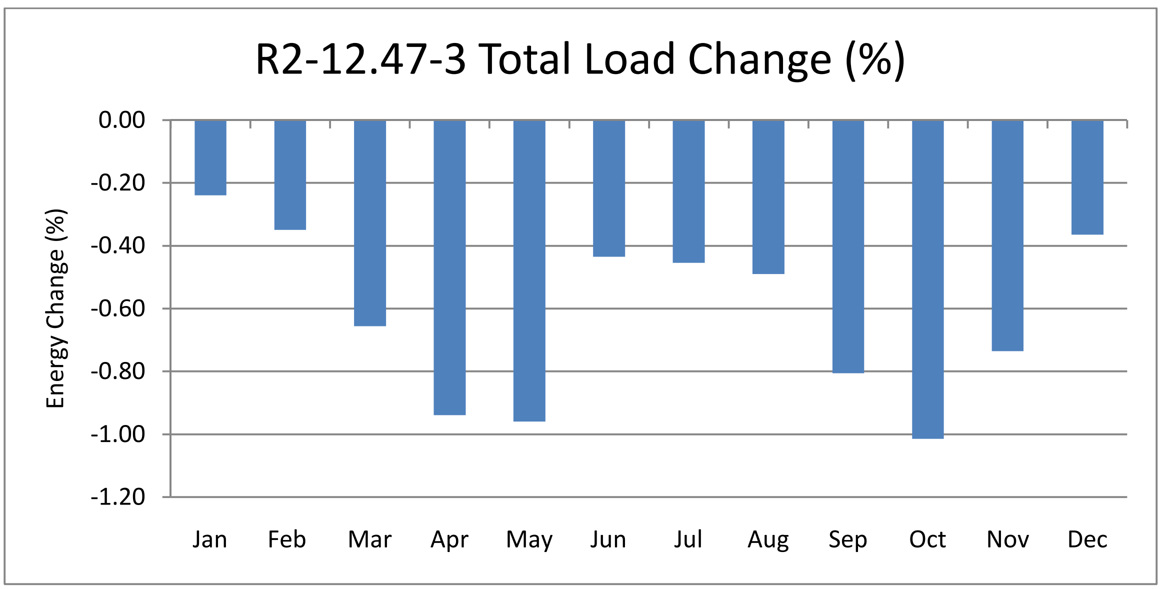


Figure 6.52: R2-12.47-3 Total Load Change (%)

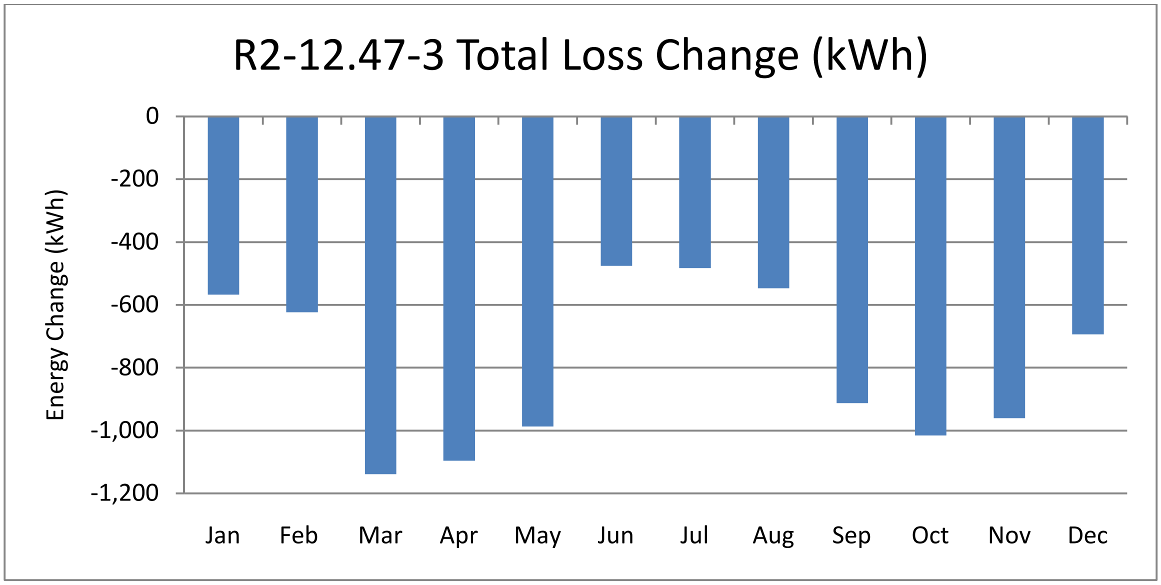


Figure 6.53: R2-12.47-3 Total Loss Change (kWh)

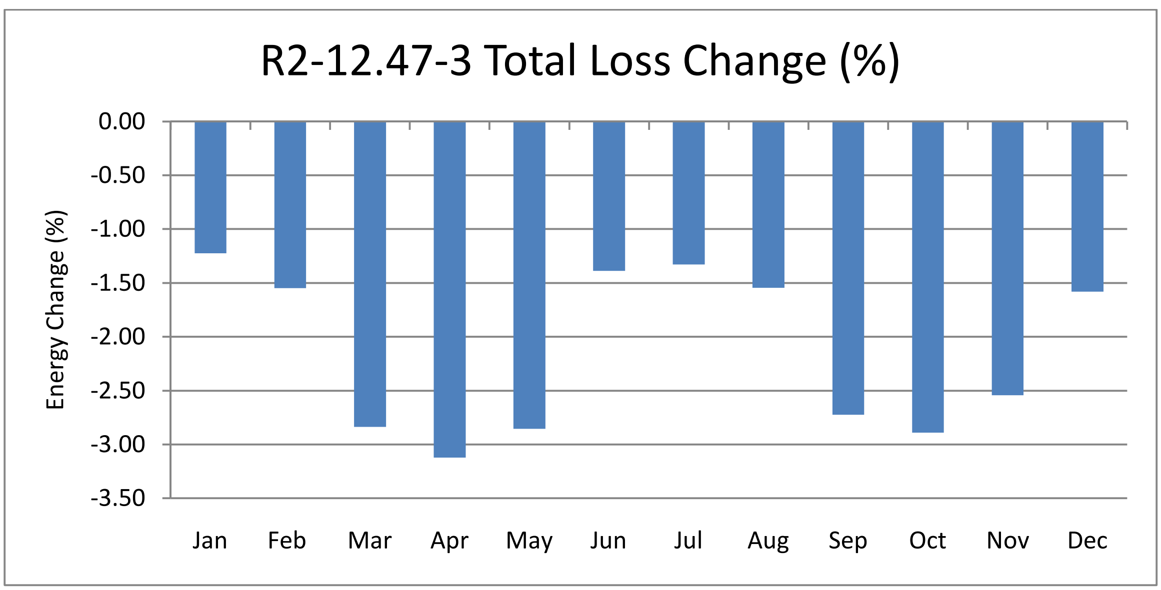


Figure 6.54: R2-12.47-3 Total Loss Change (%)

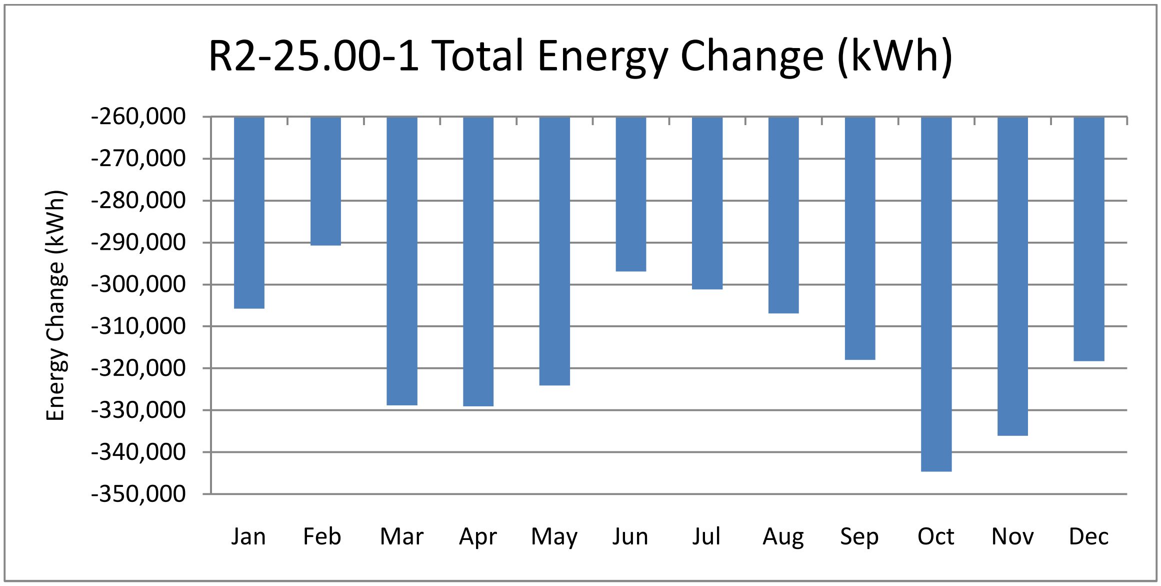


Figure 6.55: R2-25.00-1 Total Energy Change (kWh)

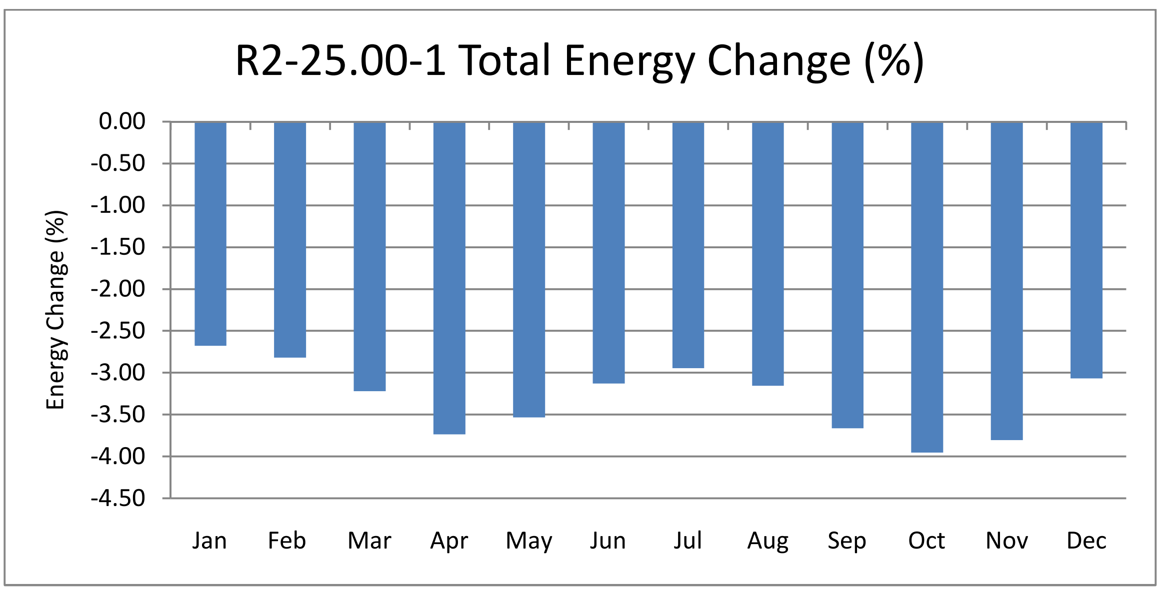


Figure 6.56: R2-25.00-1 Total Energy Change (%)

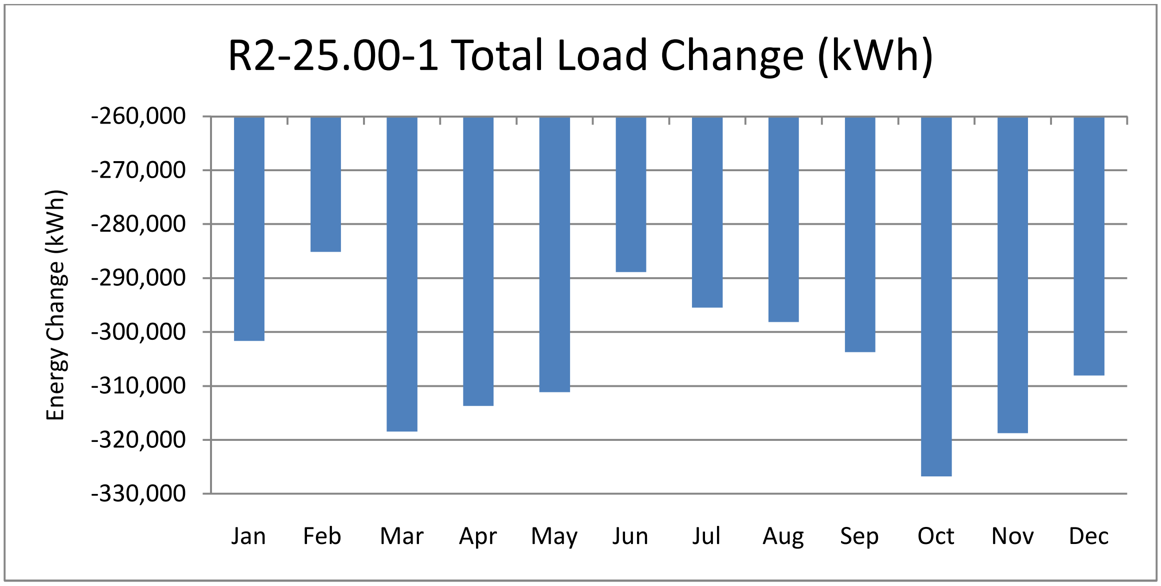


Figure 6.57: R2-25.00-1 Total Load Change (kWh)

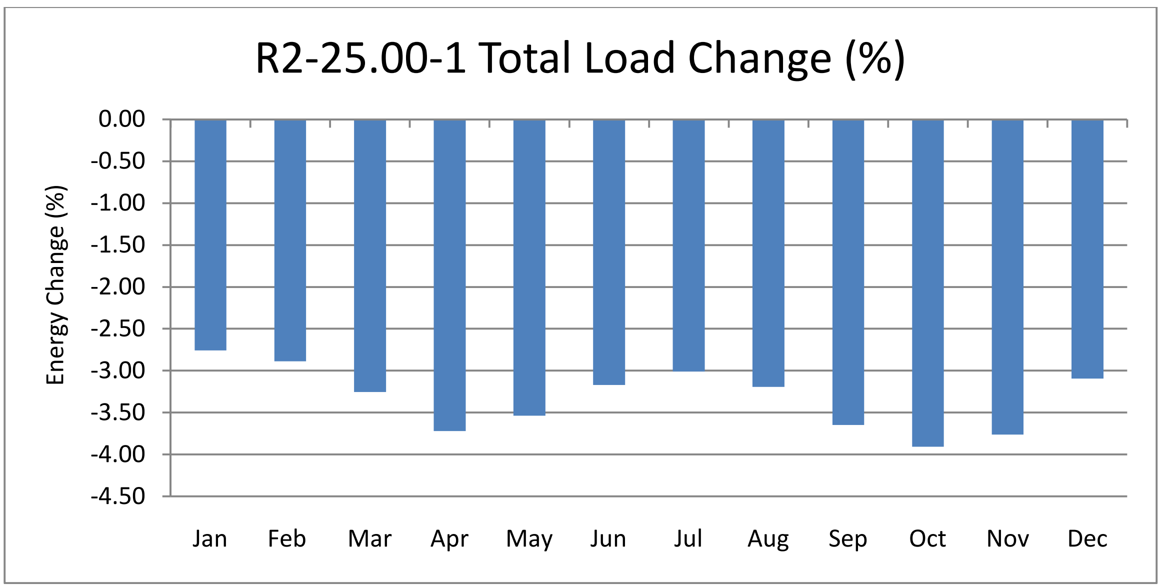


Figure 6.58: R2-25.00-1 Total Load Change (%)

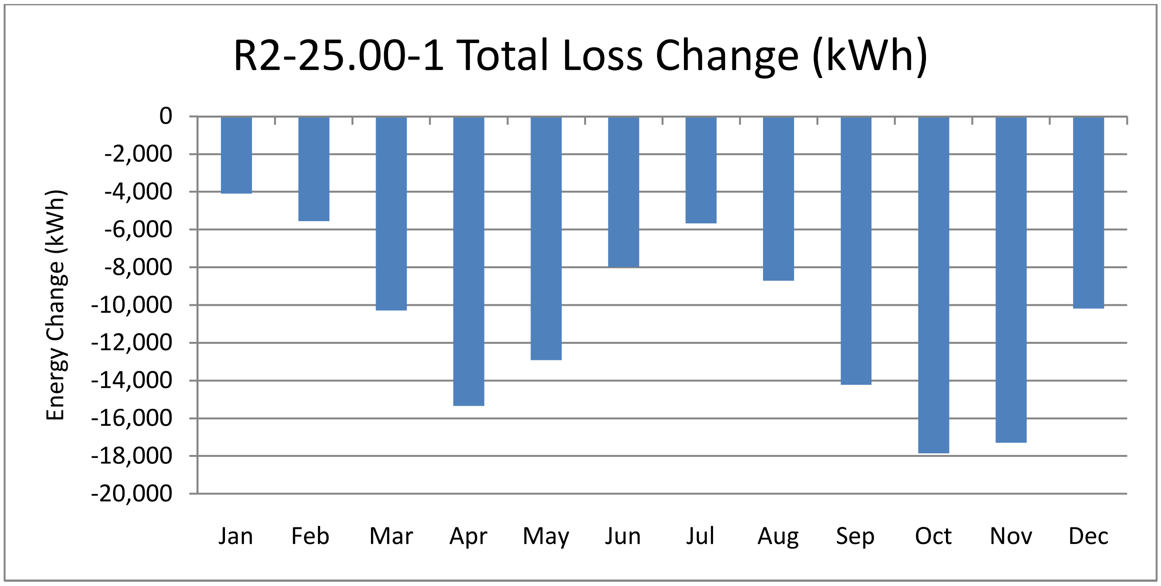


Figure 6.59: R2-25.00-1 Total Loss Change (kWh)

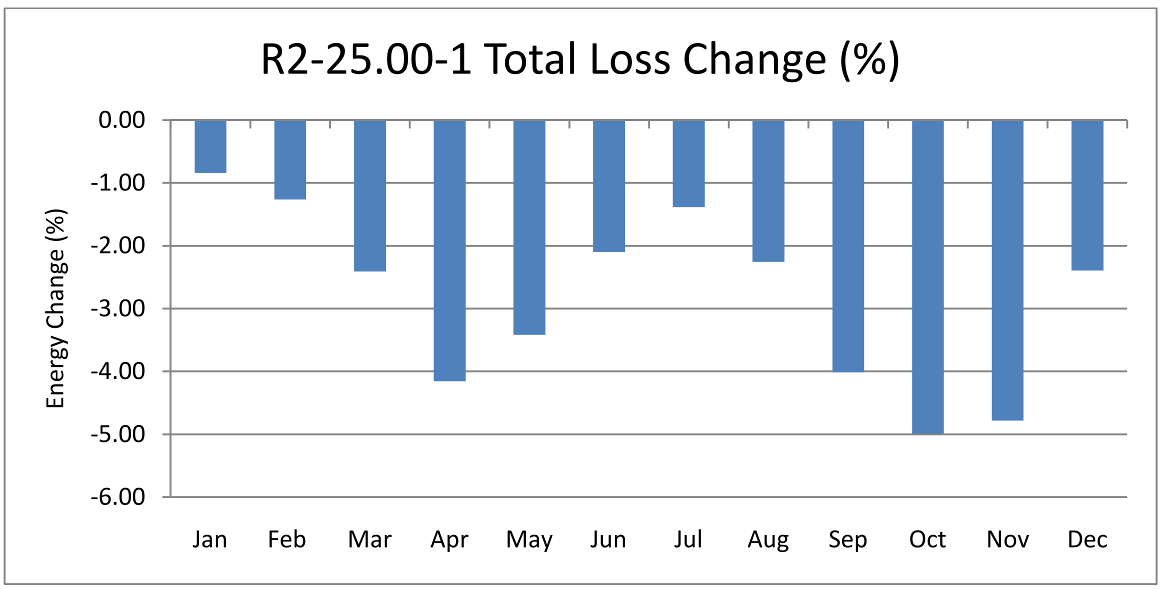


Figure 6.60: R2-25.00-1 Total Loss Change (%)

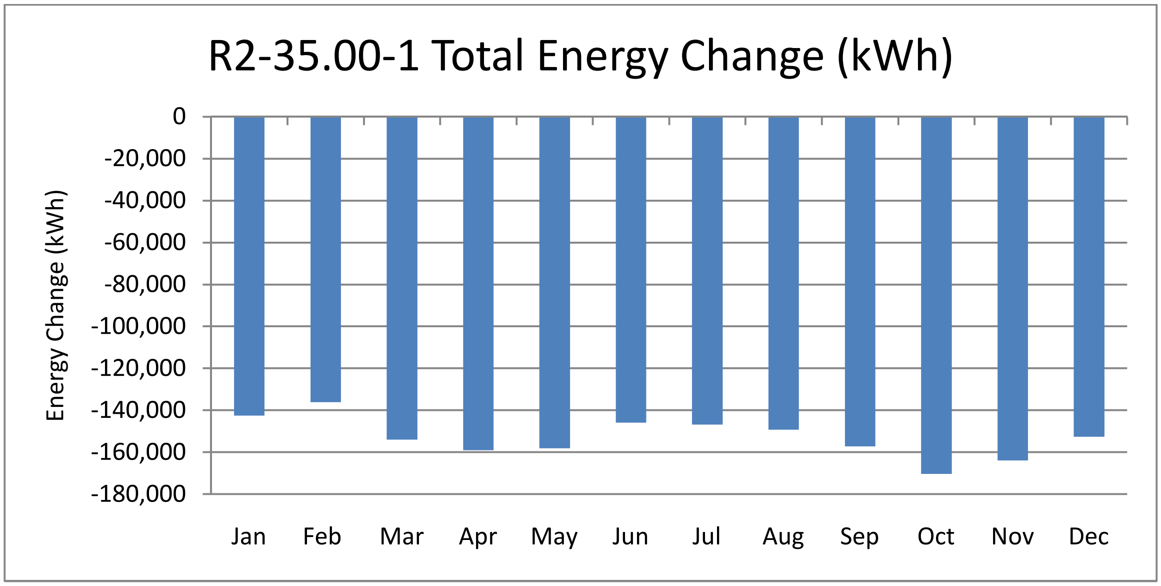


Figure 6.61: R2-35.00-1 Total Energy Change (kWh)

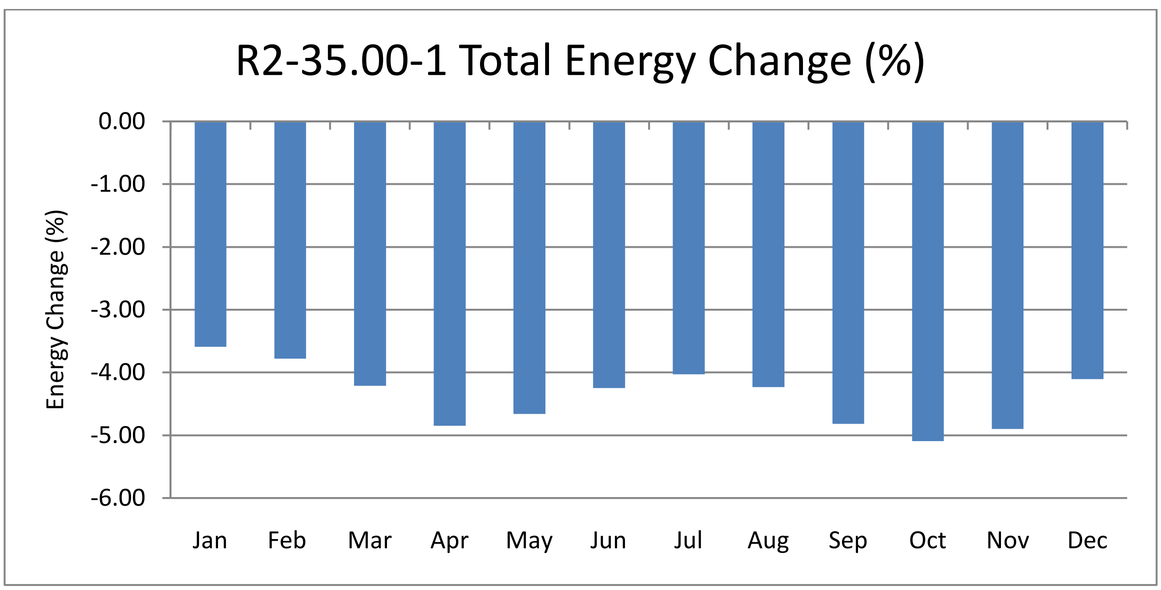


Figure 6.62: R2-35.00-1 Total Energy Change (%)

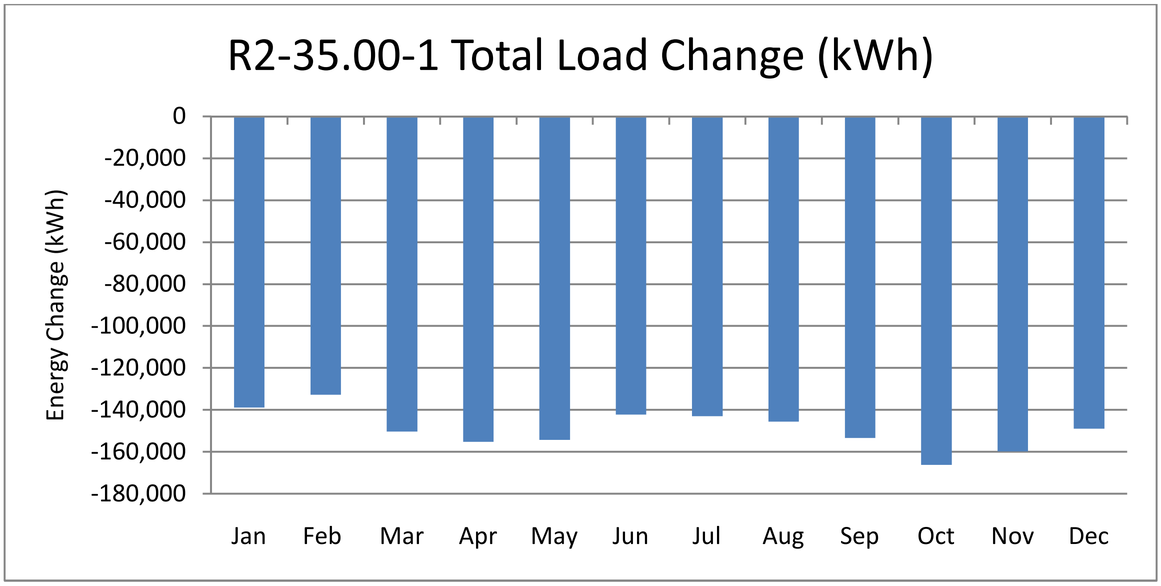


Figure 6.63: R2-35.00-1 Total Load Change (kWh)

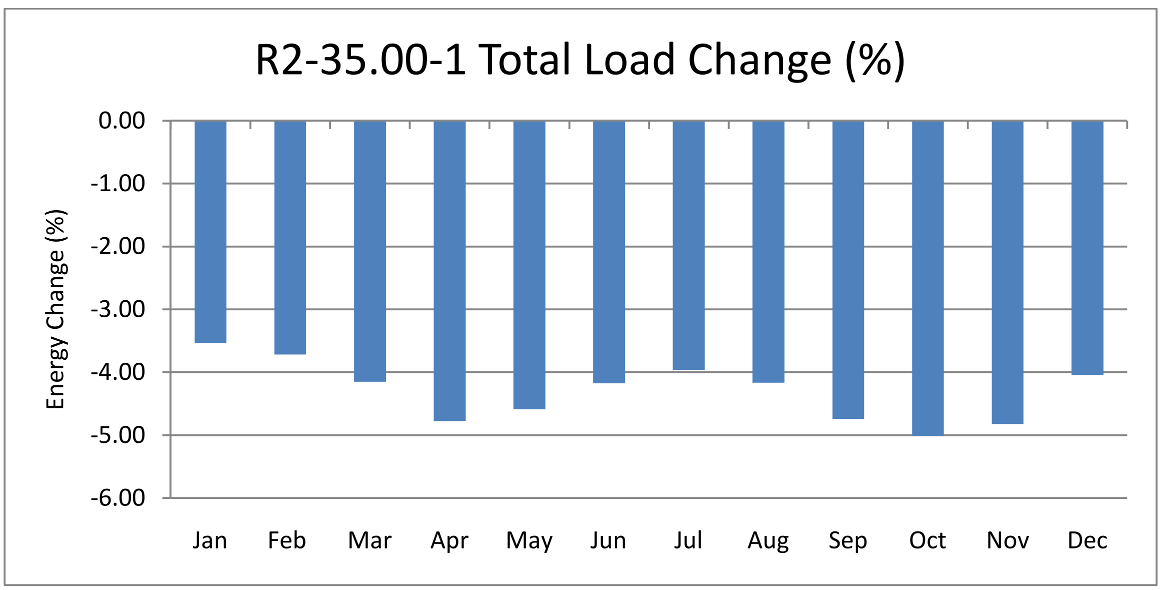


Figure 6.64: R2-35.00-1 Total Load Change (%)

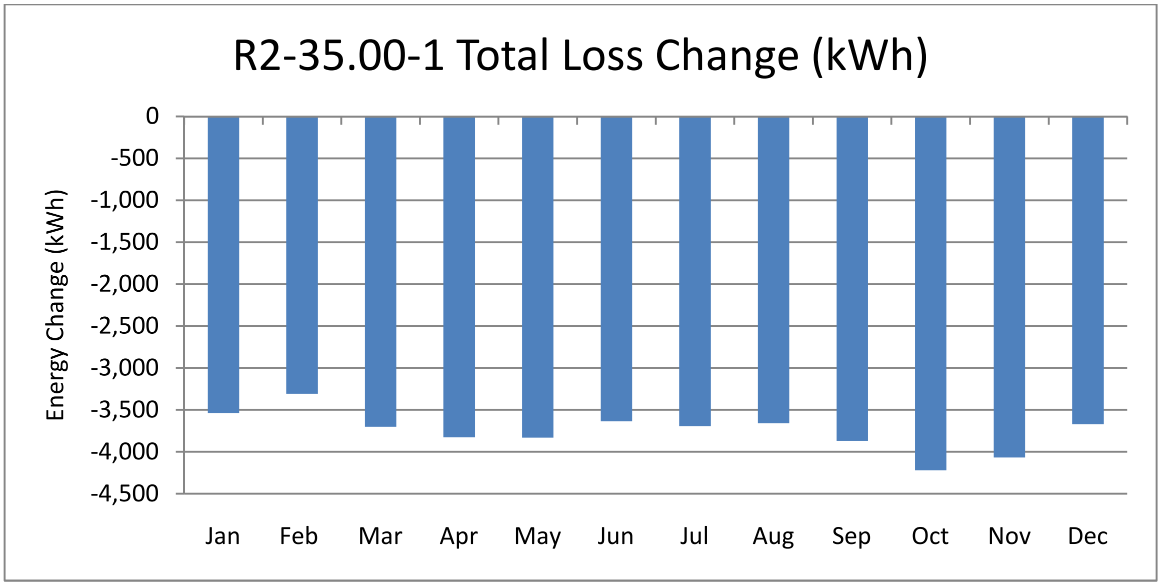


Figure 6.65: R2-35.00-1 Total Loss Change (kWh)

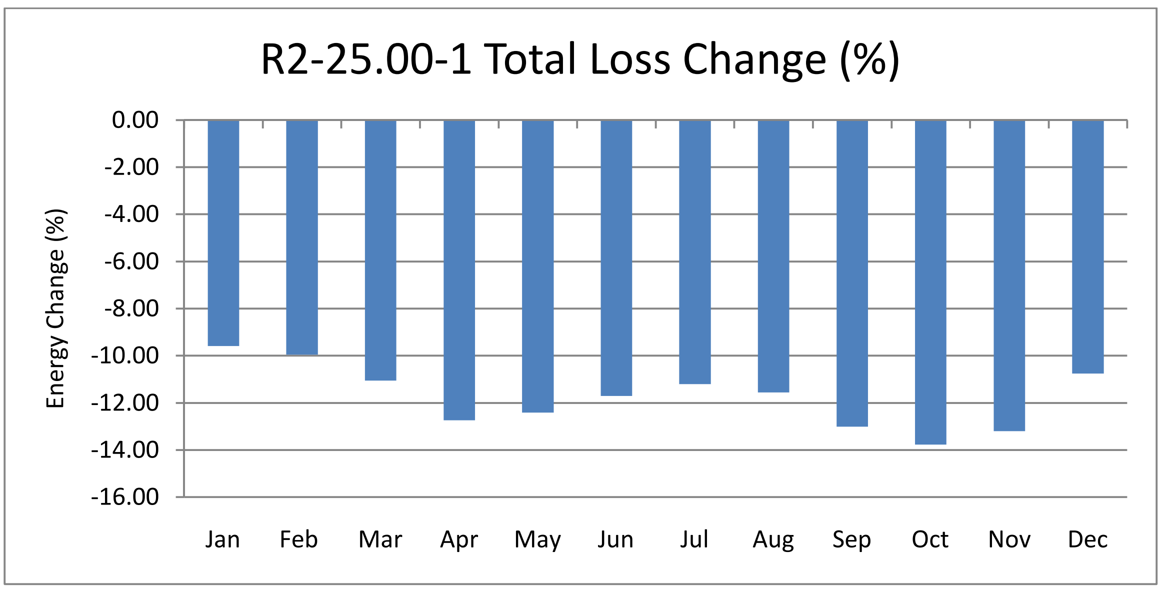


Figure 6.66: R2-35.00-1 Total Loss Change (%)

6.3. Region 3: CVR Plots

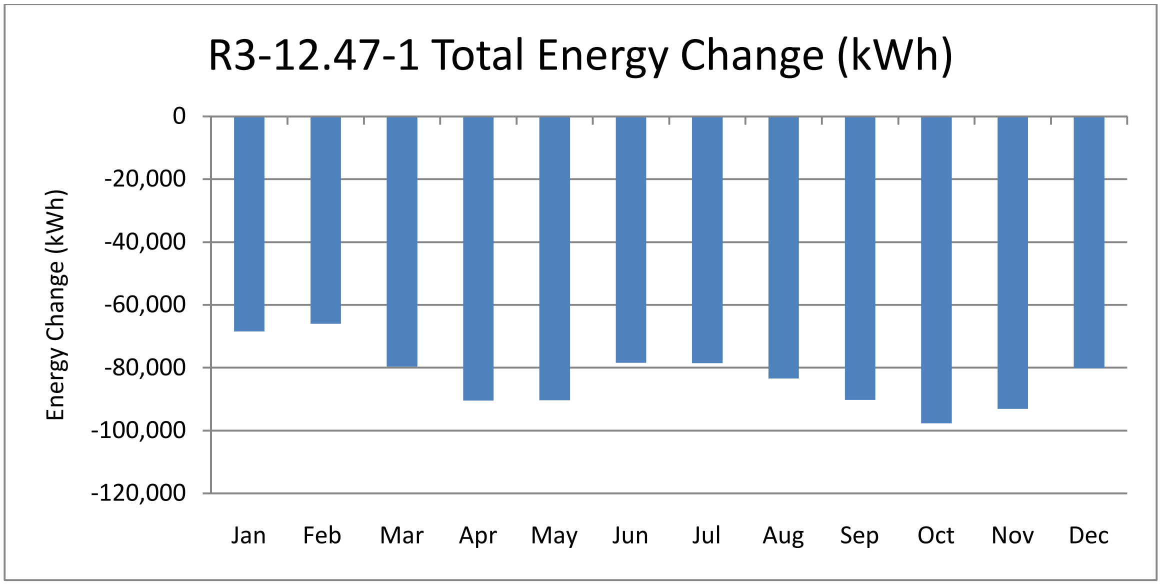


Figure 6.67: R3-12.47-1 Total Energy Change (kWh)

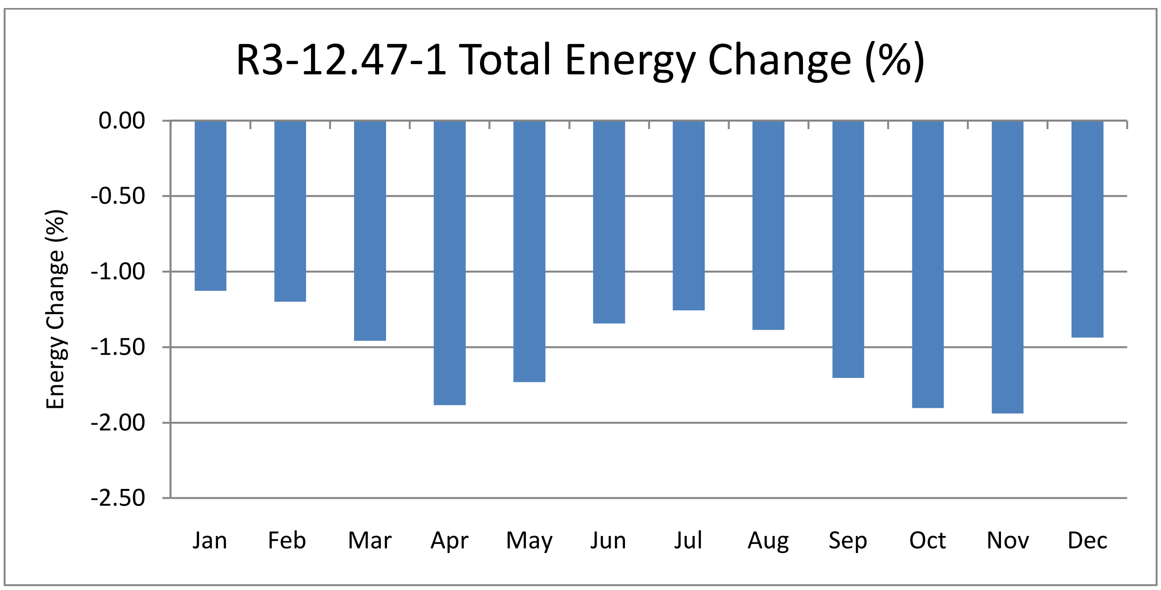


Figure 6.68: R3-12.47-1 Total Energy Change (%)

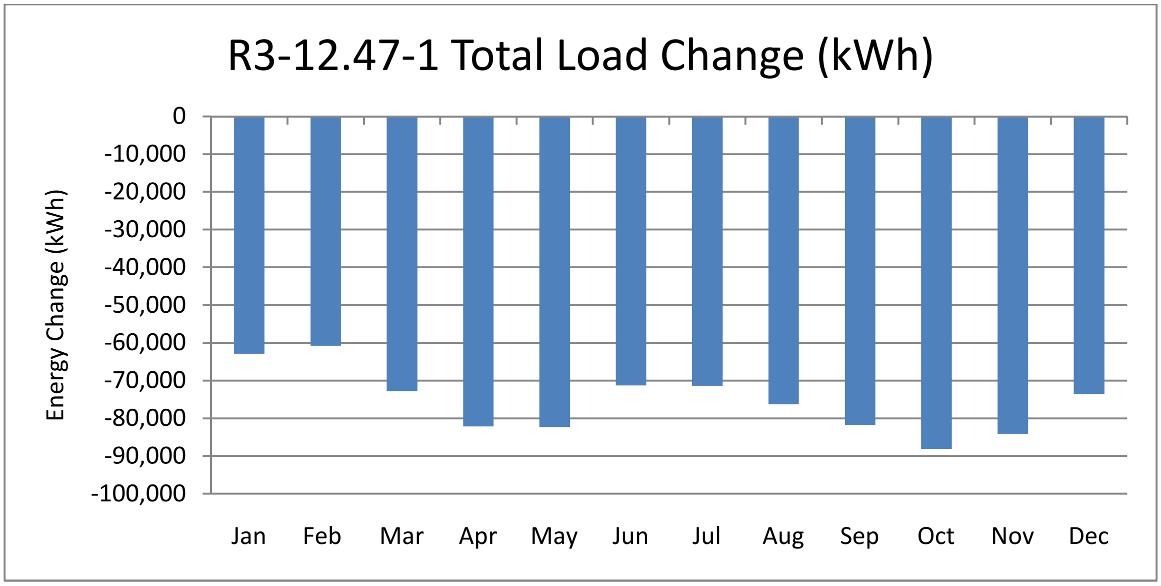


Figure 6.69: R3-12.47-1 Total Loss Change (kWh)

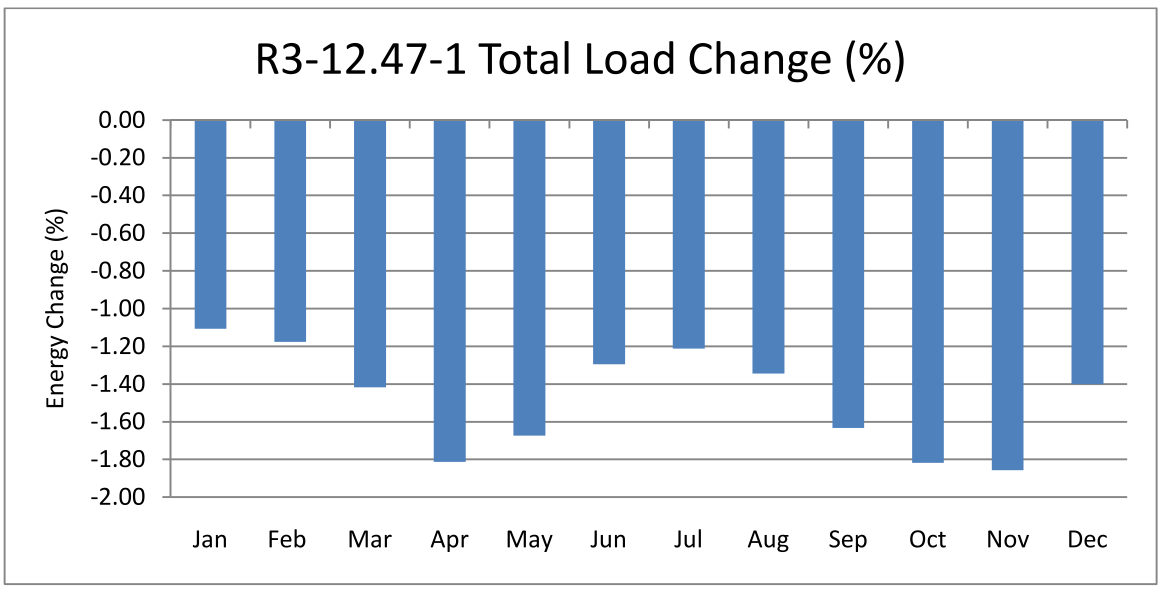


Figure 6.70: R3-12.47-1 Total Loss Change (%)

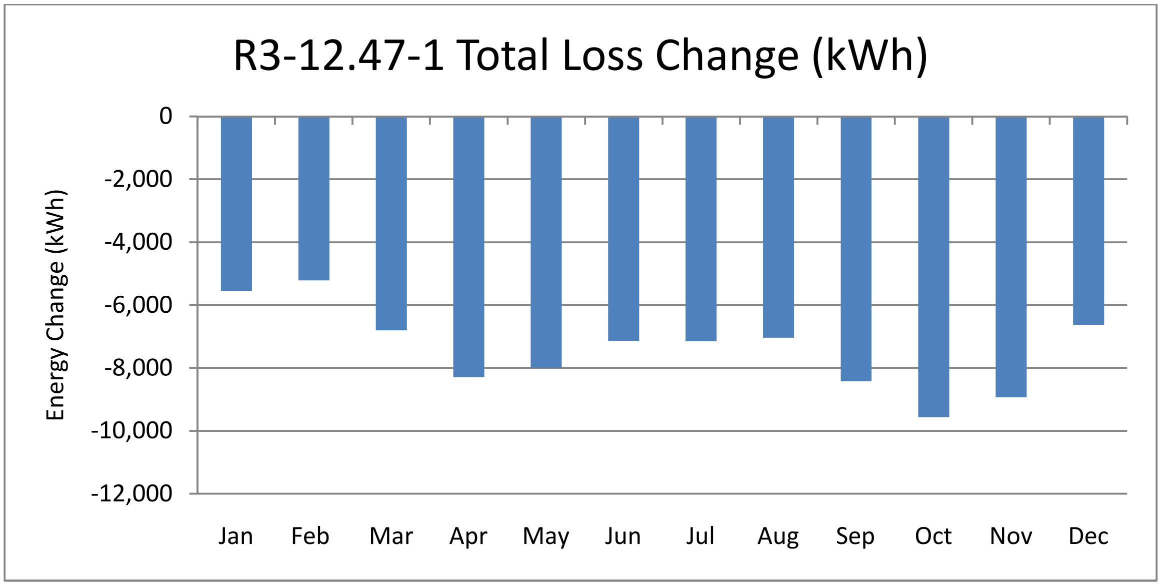


Figure 6.71: R3-12.47-1 Total Loss Change (kWh)

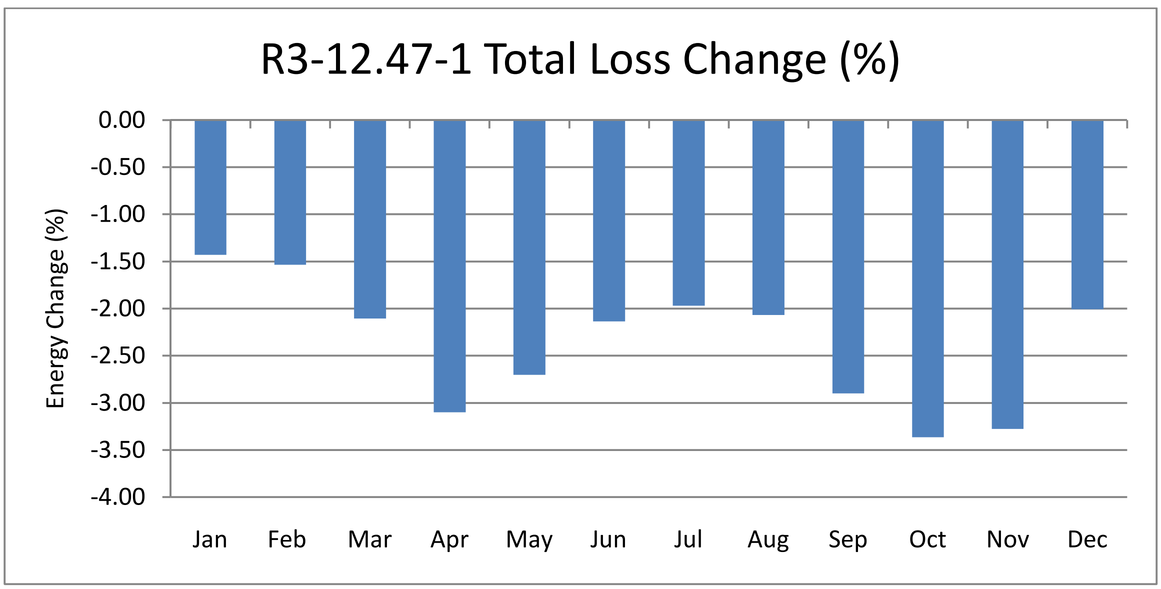


Figure 6.72: R3-12.47-1 Total Loss Change (%)

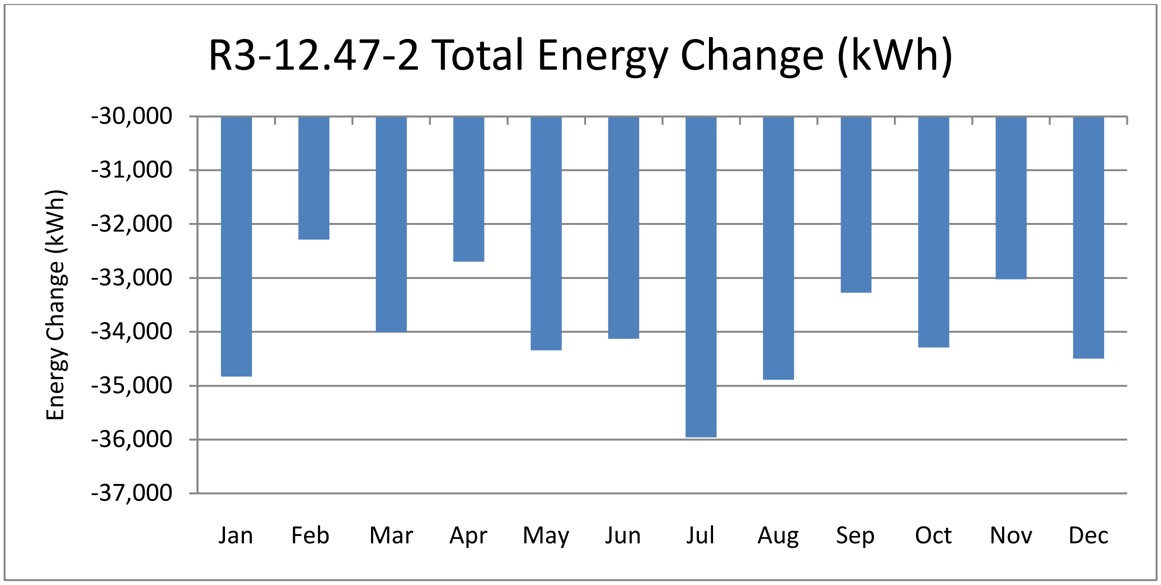


Figure 6.73: R3-12.47-2 Total Energy Change (kWh)

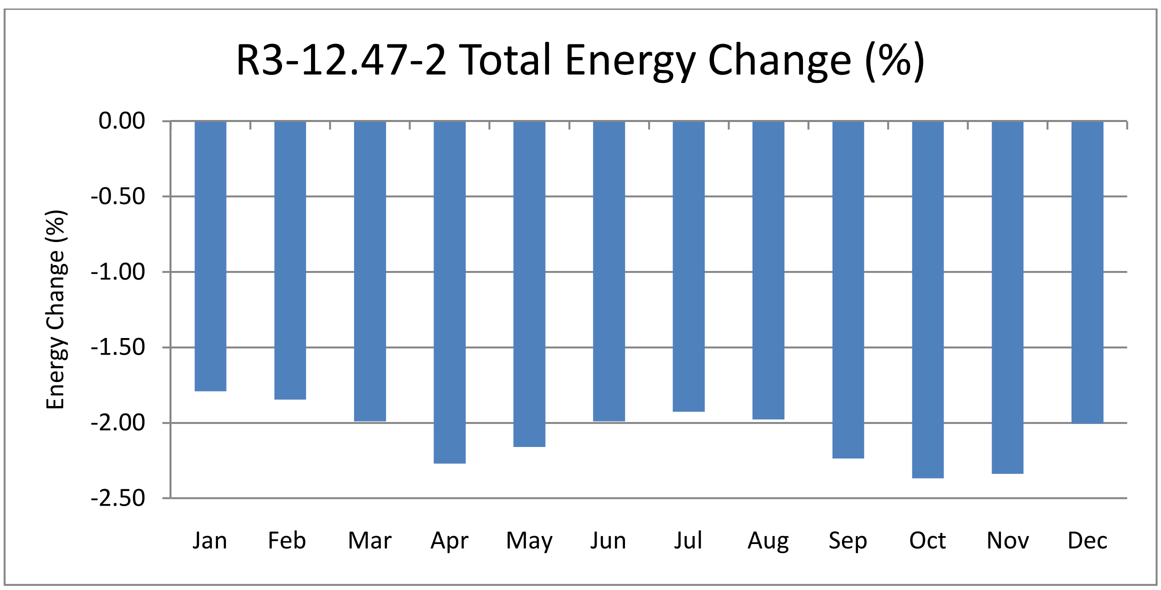


Figure 6.74: R3-12.47-2 Total Energy Change (%)

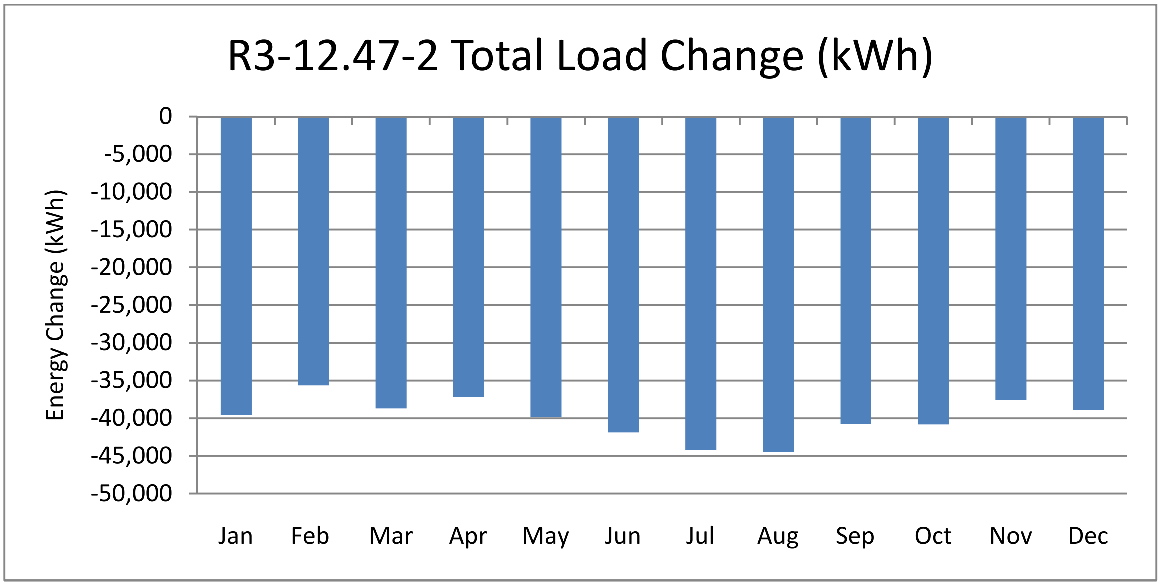


Figure 6.75: R3-12.47-2 Total Load Change (kWh)

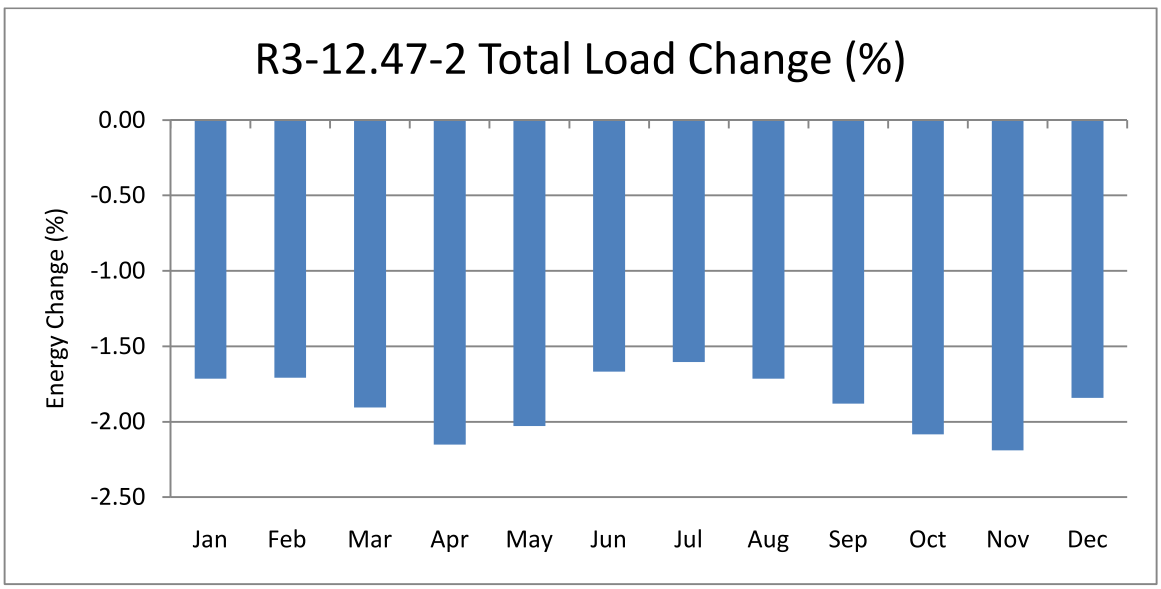


Figure 6.76: R3-12.47-2 Total Load Change (%)

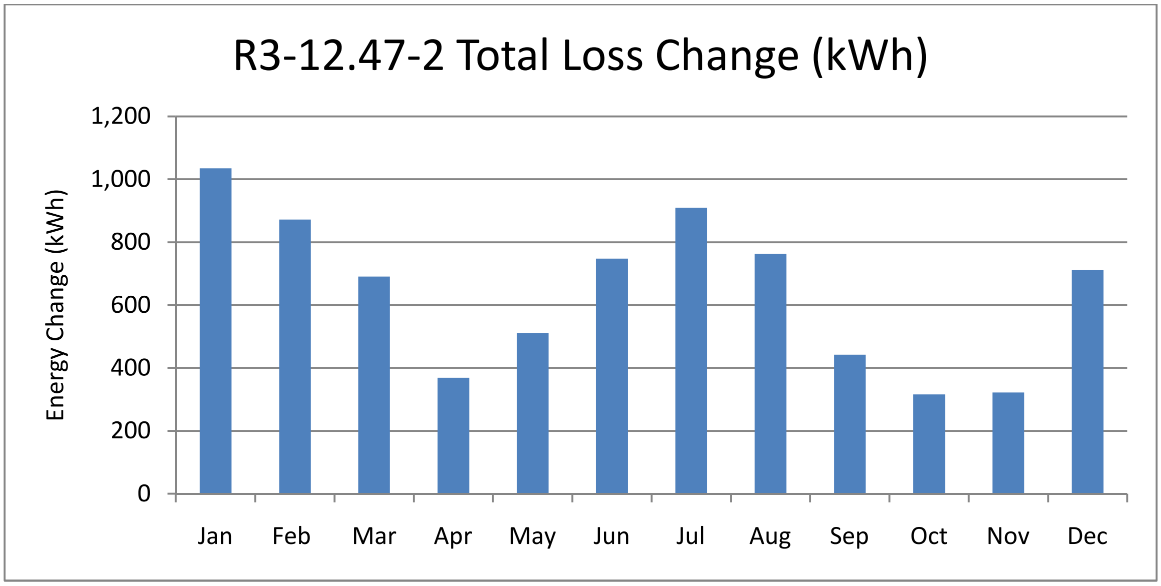


Figure 6.77: R3-12.47-2 Total Loss Change (kWh)

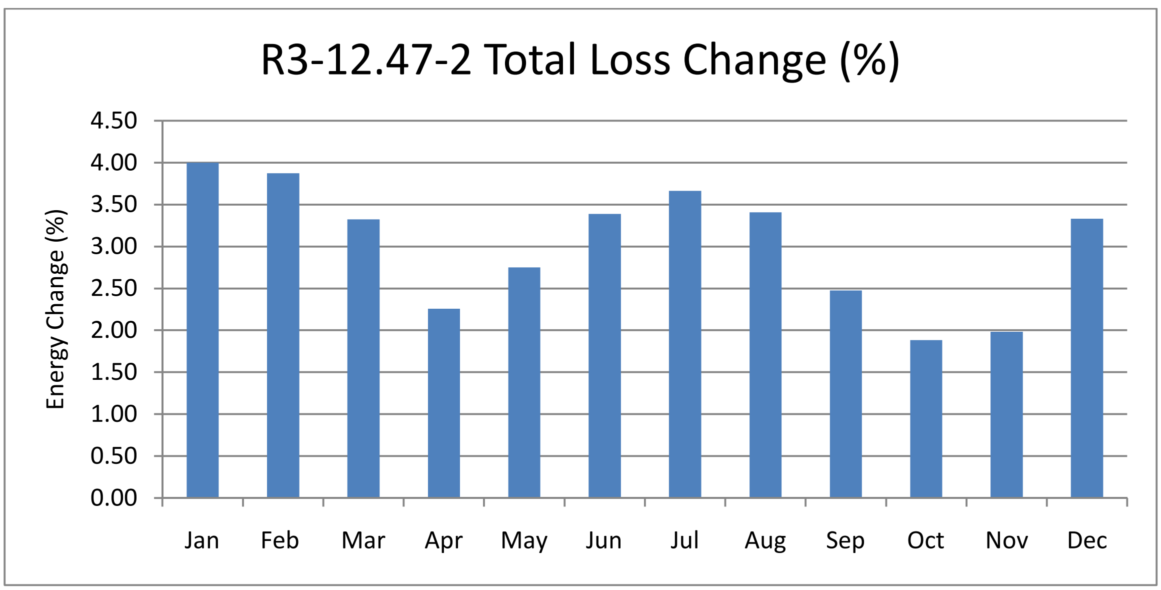


Figure 6.78: R3-12.47-2 Total Loss Change (%)

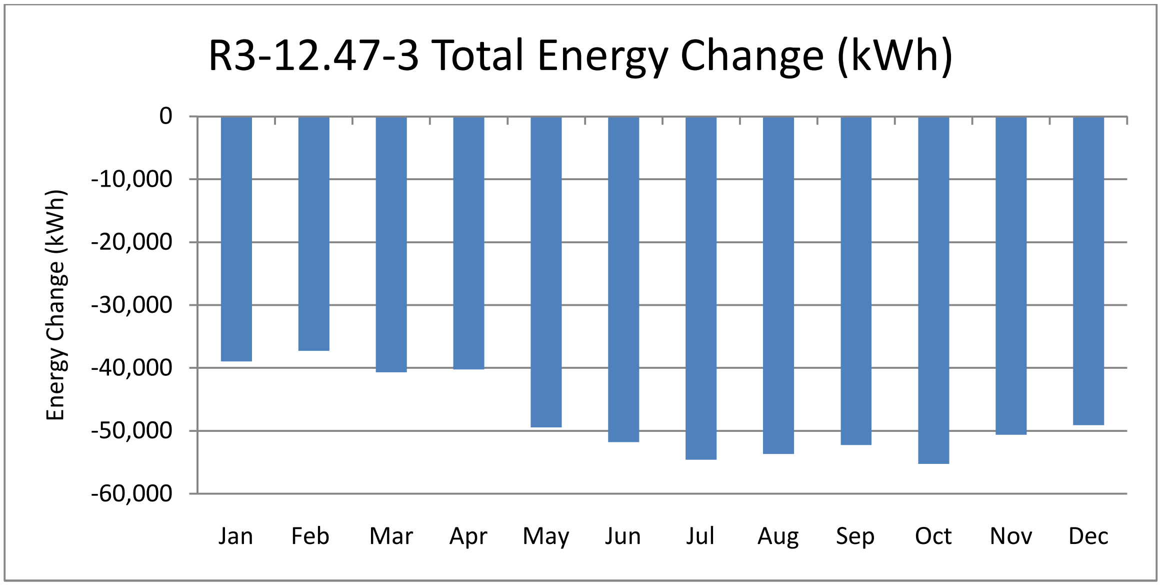


Figure 6.79: R3-12.47-3 Total Energy Change (kWh)

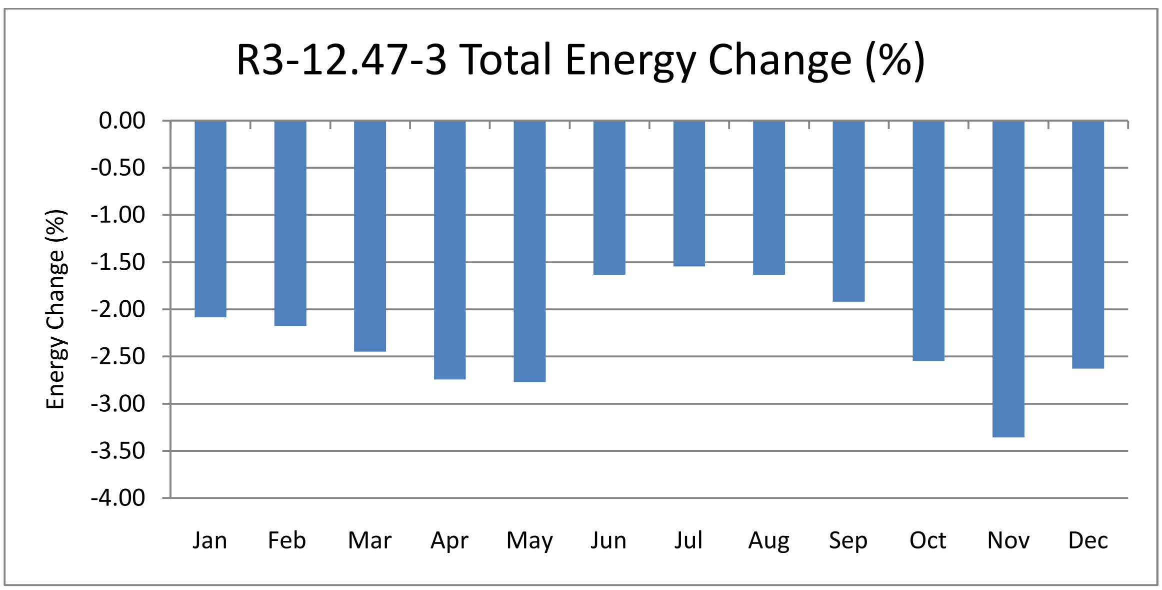


Figure 6.80: R3-12.47-3 Total Energy Change (%)

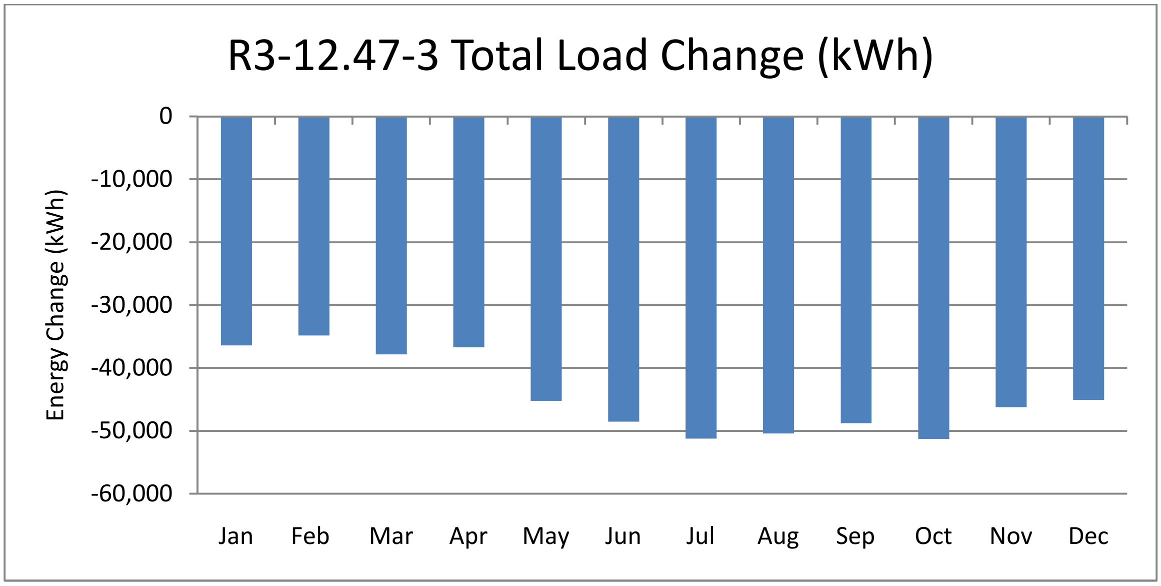


Figure 6.81: R3-12.47-3 Total Load Change (kWh)

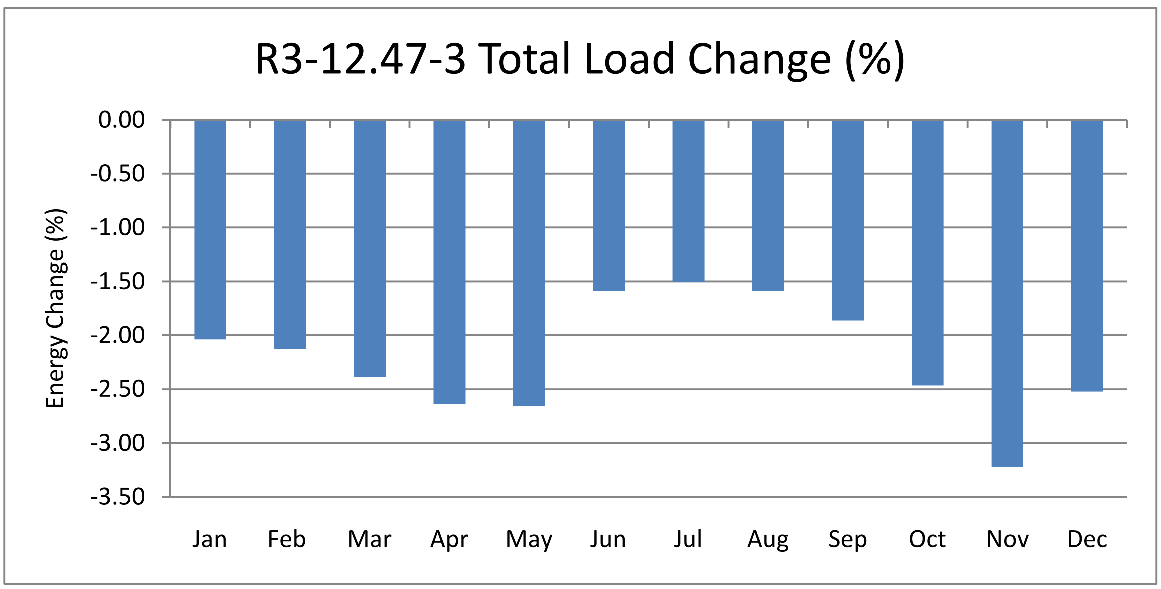


Figure 6.82: R3-12.47-3 Total Load Change (%)

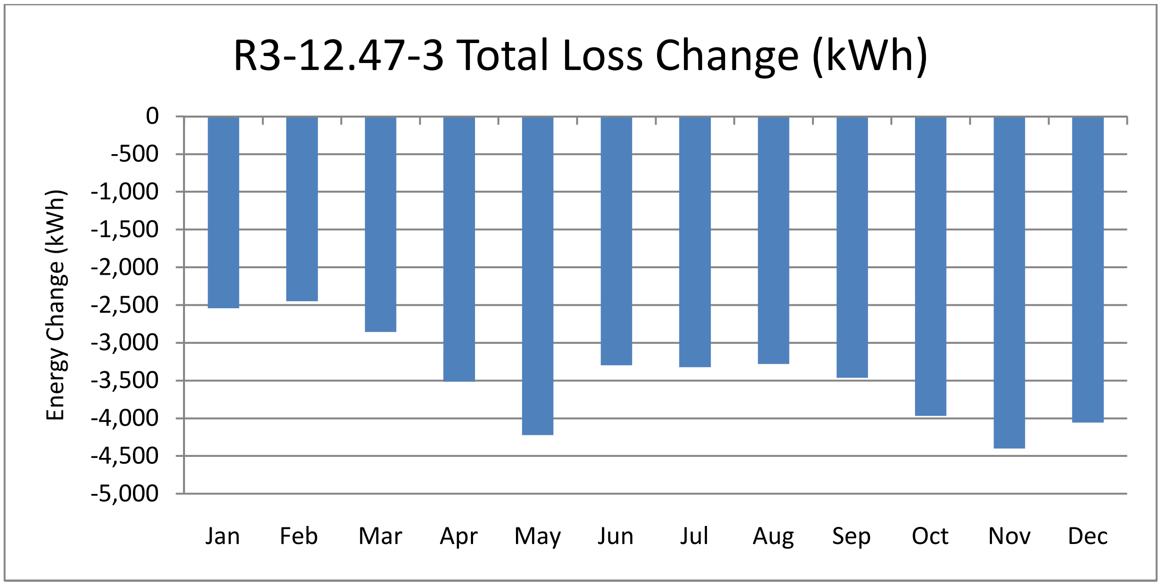


Figure 6.83: R3-12.47-3 Total Loss Change (kWh)

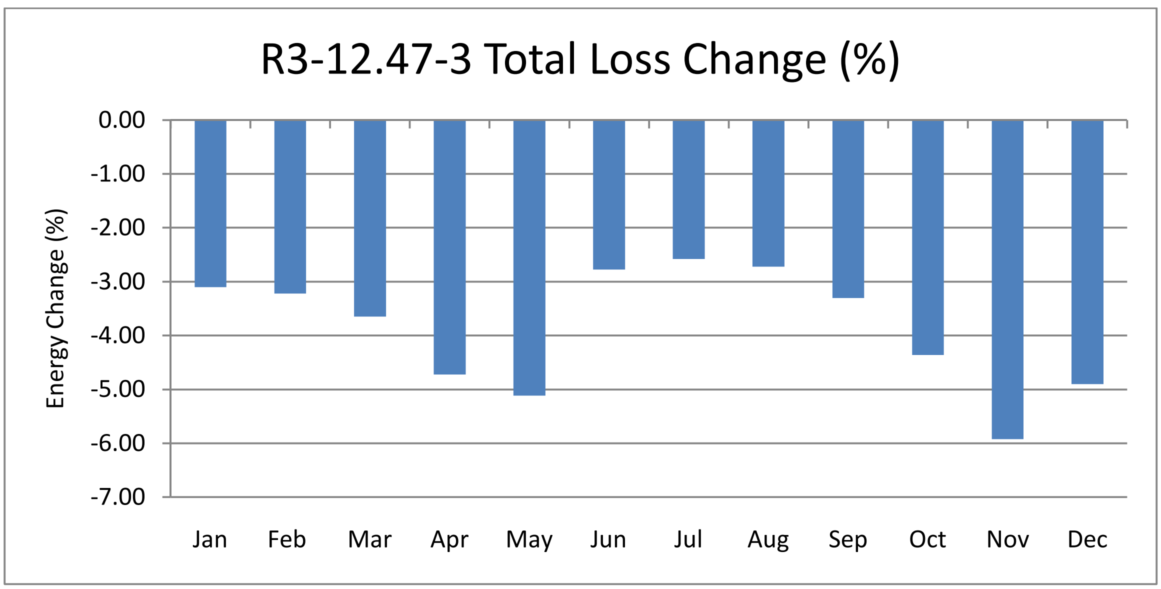


Figure 6.84: R3-12.47-3 Total Loss Change (%)

6.4. Region 4: CVR Plots

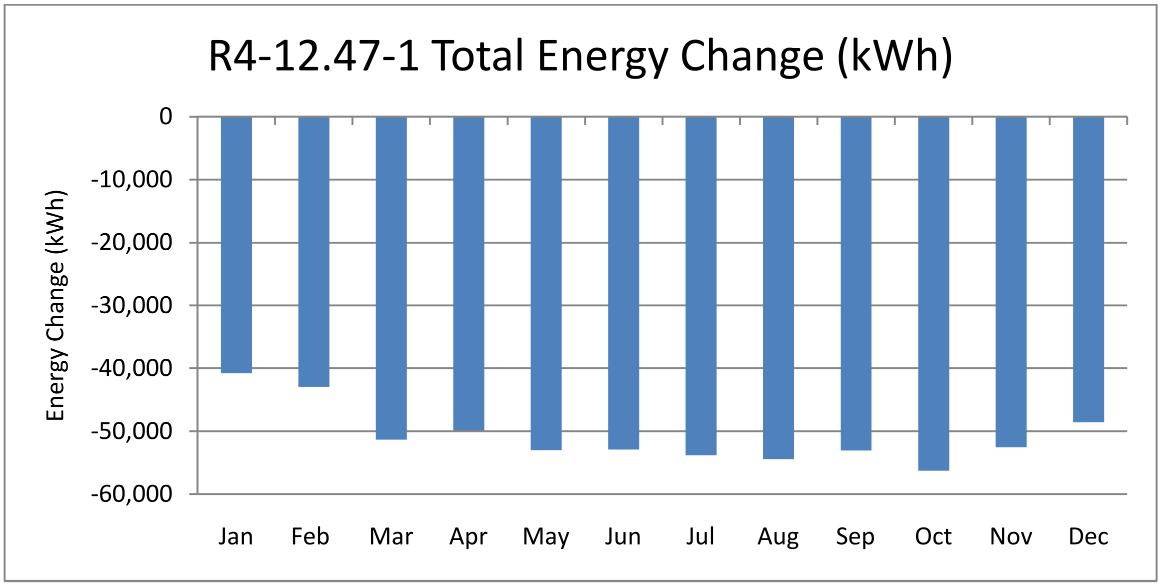


Figure 6.85: R4-12.47-1 Total Energy Change (kWh)

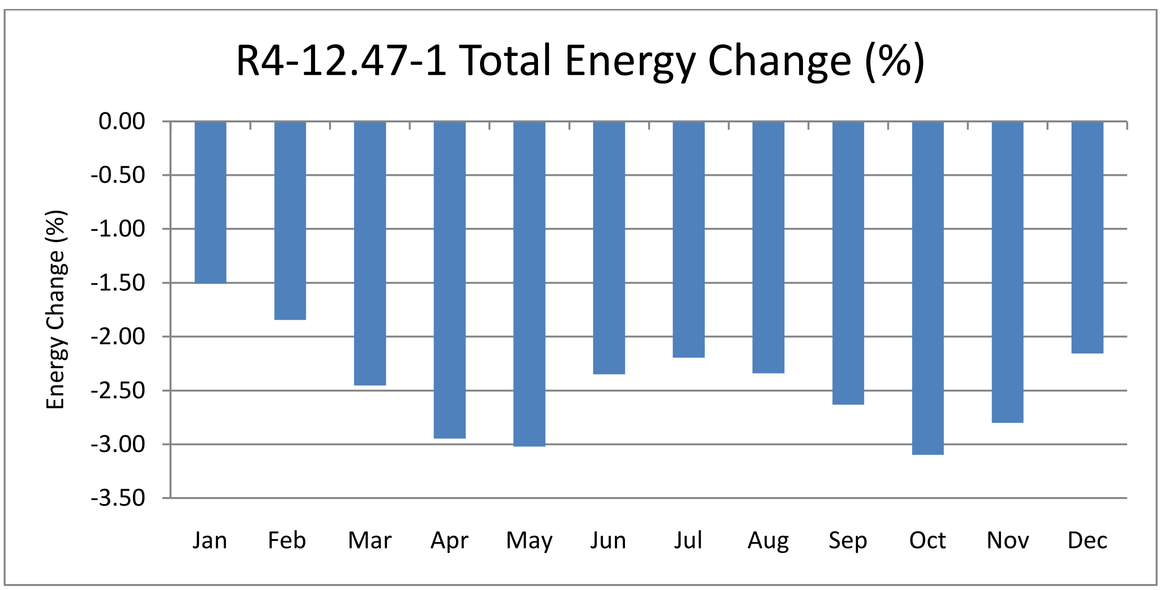


Figure 6.86: R4-12.47-1 Total Energy Change (%)

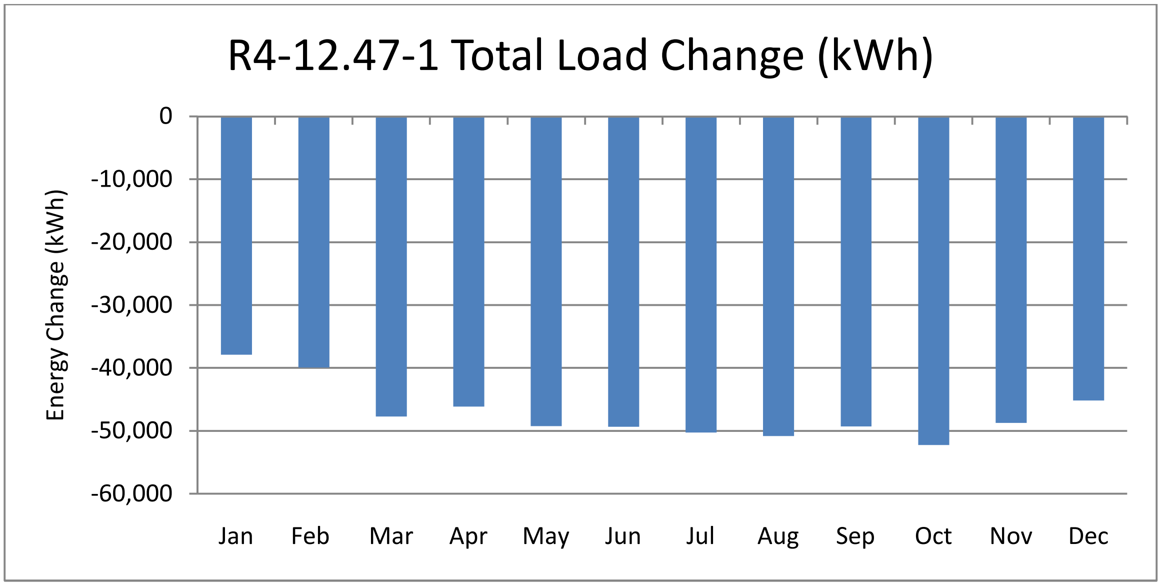


Figure 6.87: R4-12.47-1 Total Load Change (kWh)

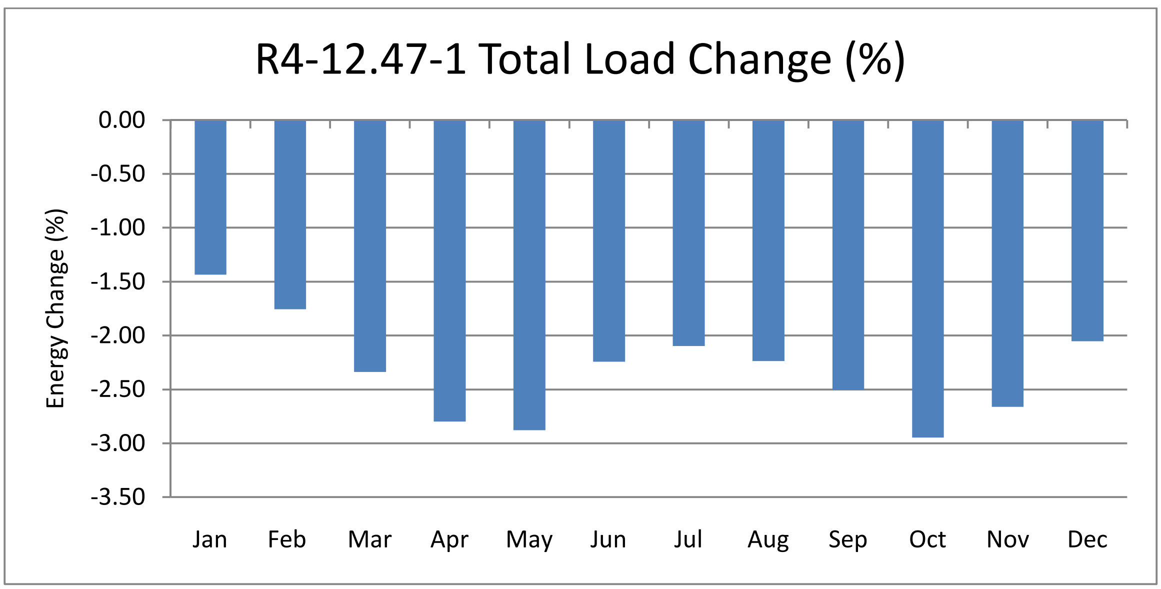


Figure 6.88: R4-12.47-1 Total Load Change (%)

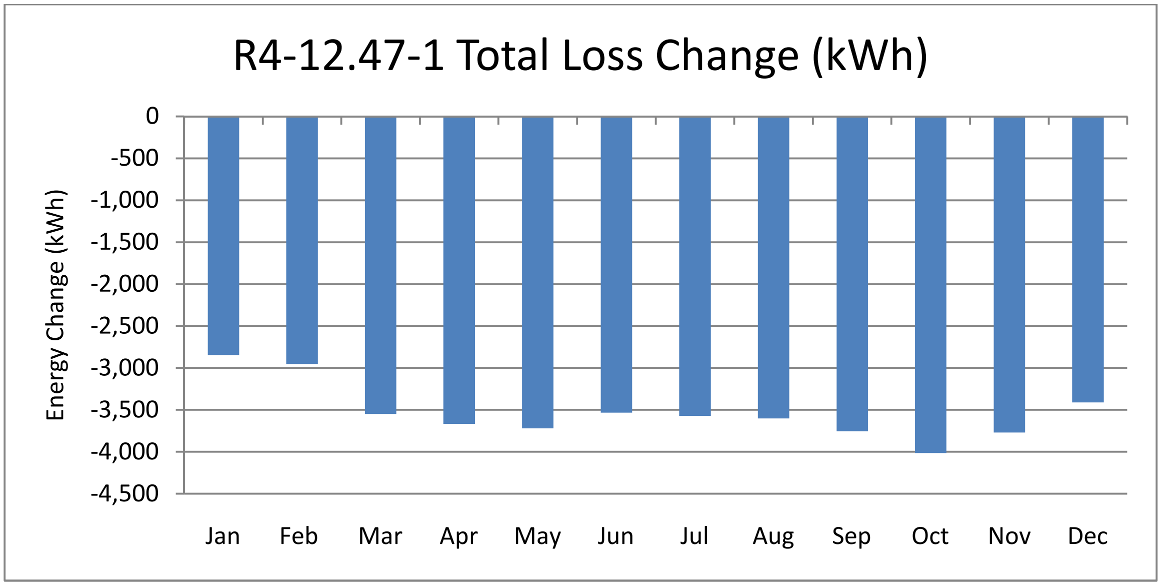


Figure 6.89: R4-12.47-1 Total Loss Change (kWh)

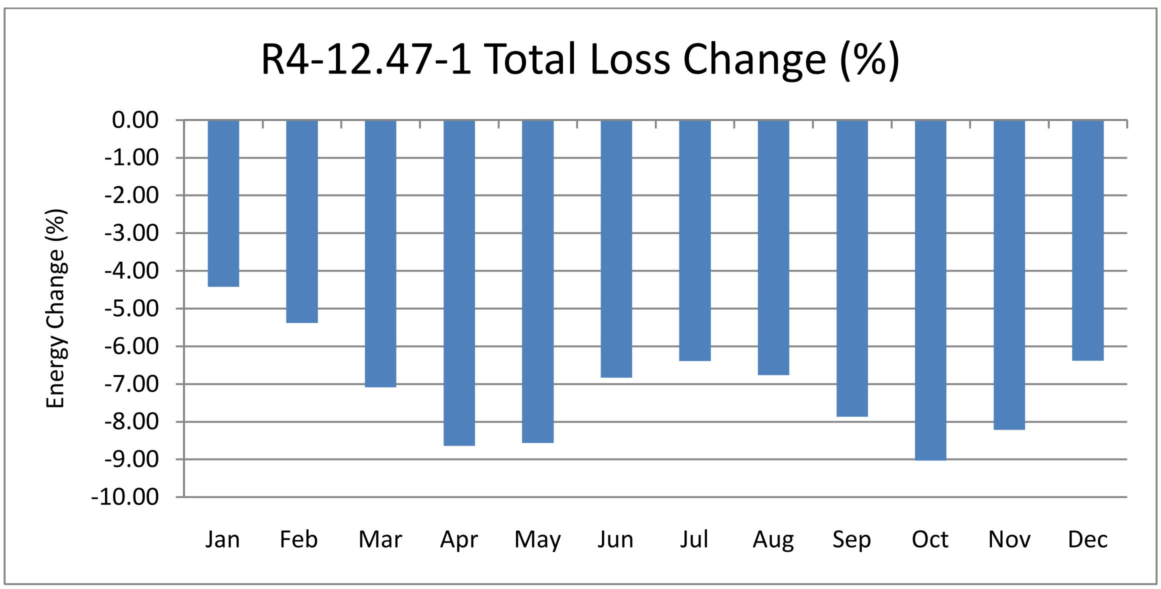


Figure 6.90: R4-12.47-1 Total Loss Change (%)

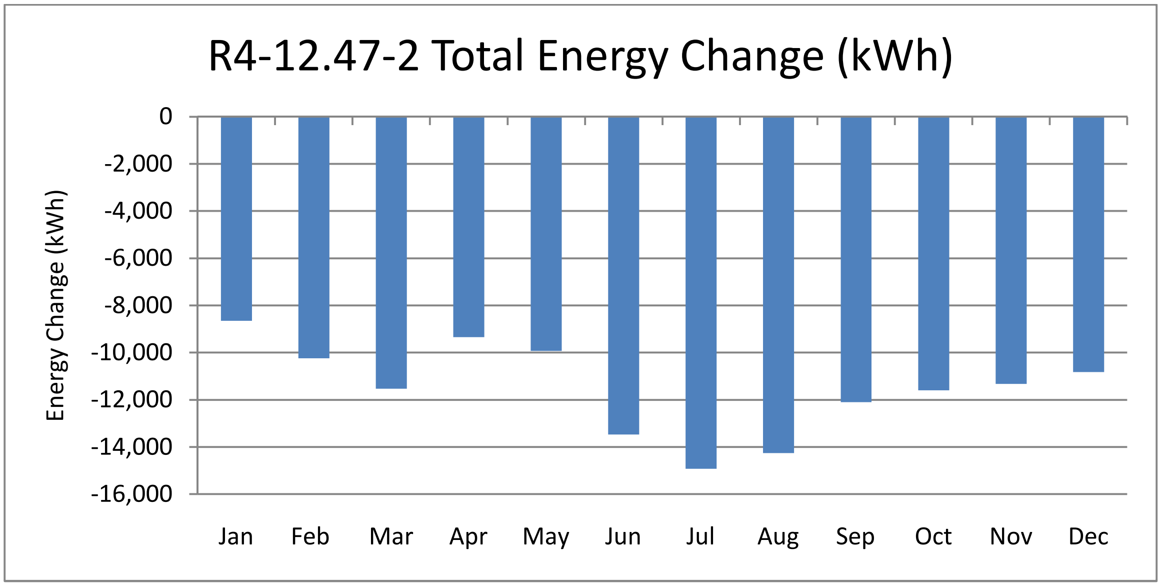


Figure 6.91: R4-12.47-2 Total Energy Change (kWh)

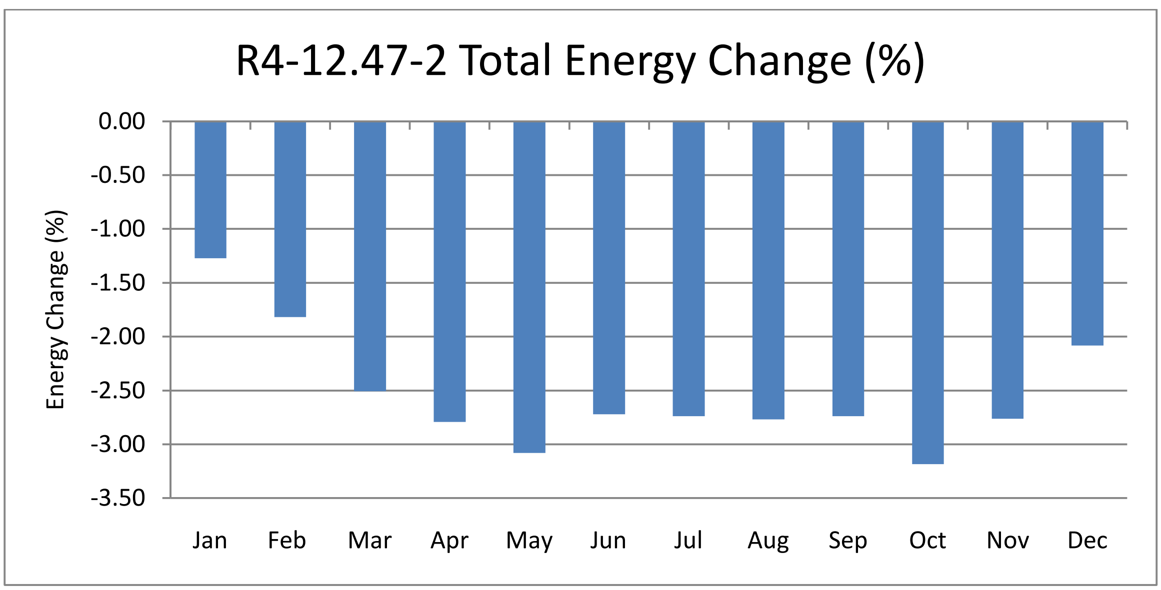


Figure 6.92: R4-12.47-2 Total Energy Change (%)

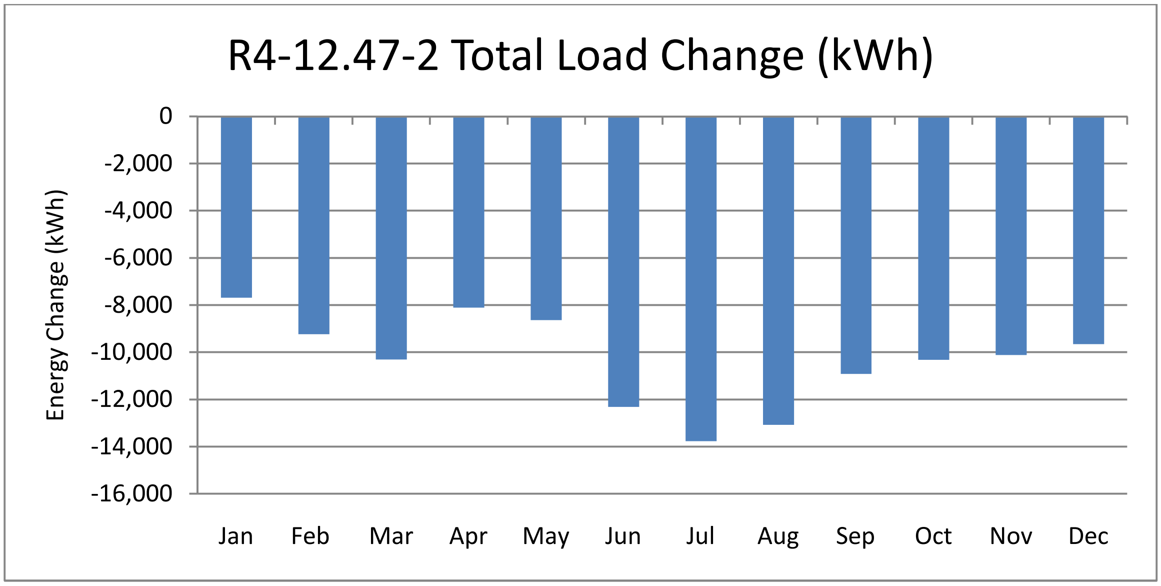


Figure 6.93: R4-12.47-2 Total Load Change (kWh)

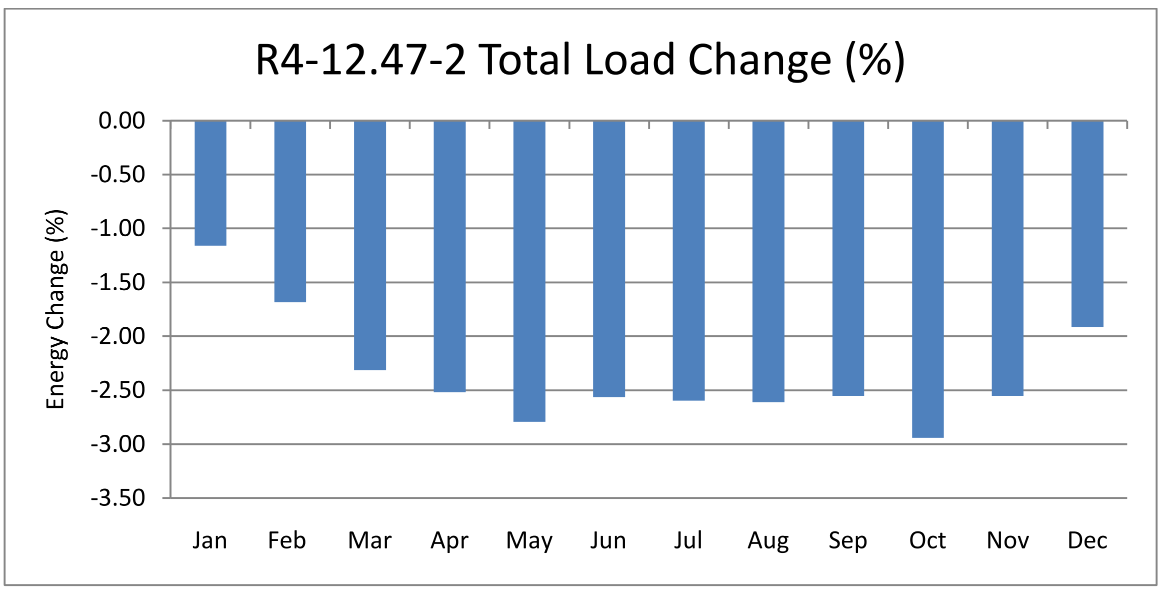


Figure 6.94: R4-12.47-2 Total Load Change (kWh)

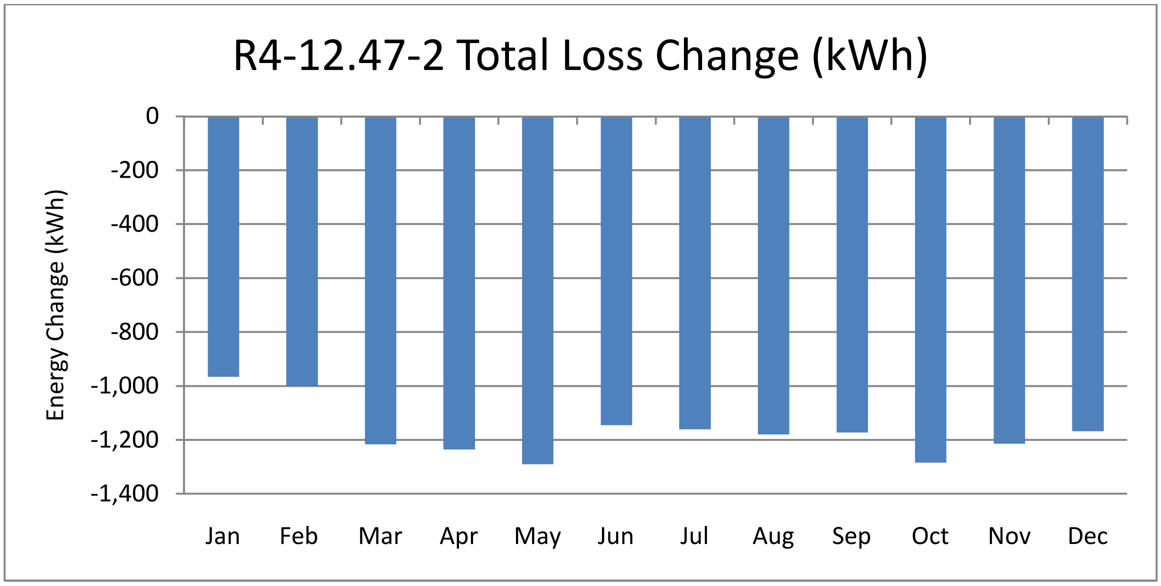


Figure 6.95: R4-12.47-2 Total Loss Change (kWh)

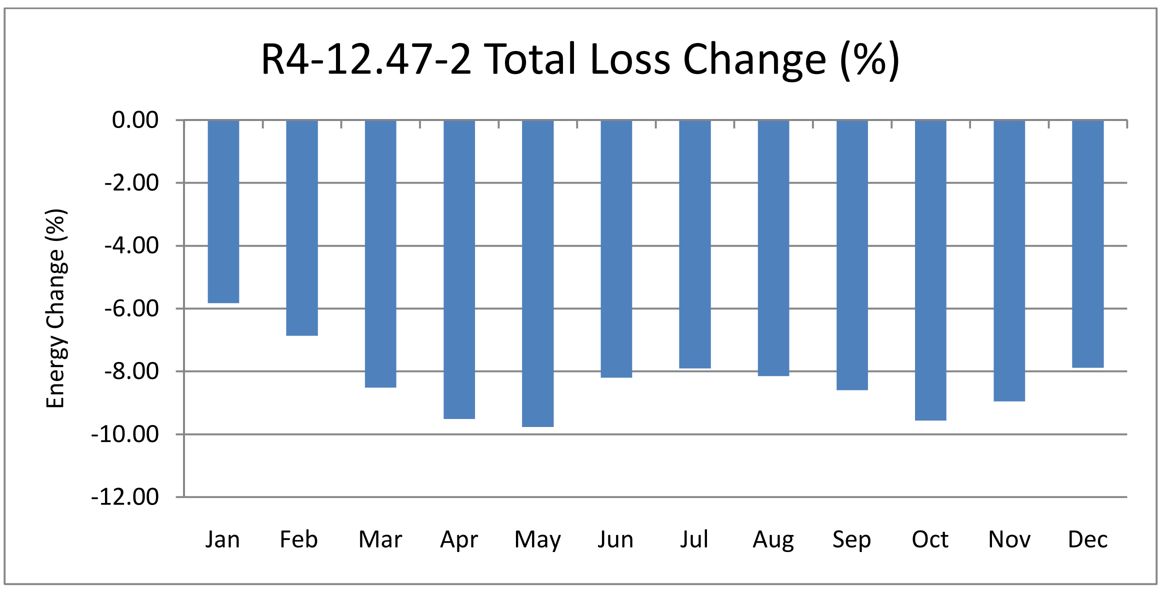


Figure 6.96: R4-12.47-2 Total Loss Change (%)

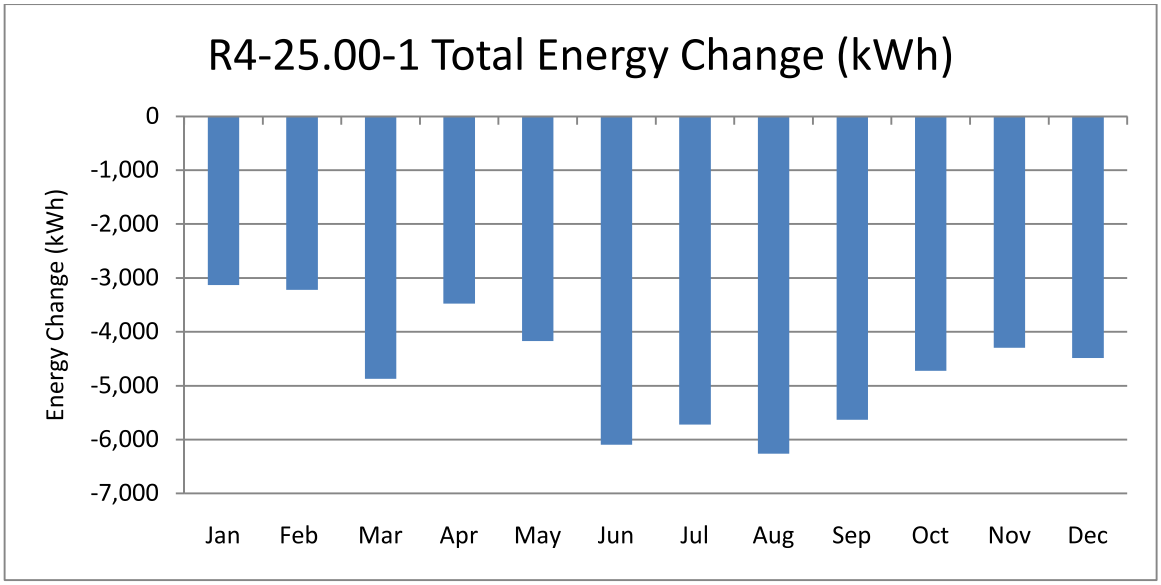


Figure 6.97: R4-25.00-1 Total Energy Change (kWh)

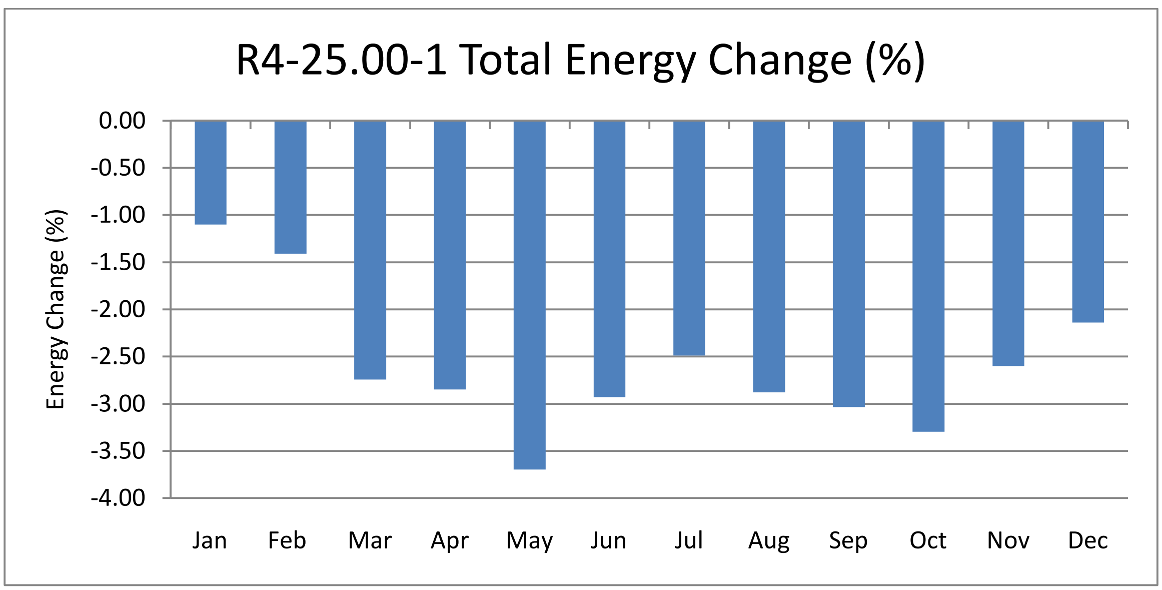


Figure 6.98: R4-25.00-1 Total Energy Change (%)

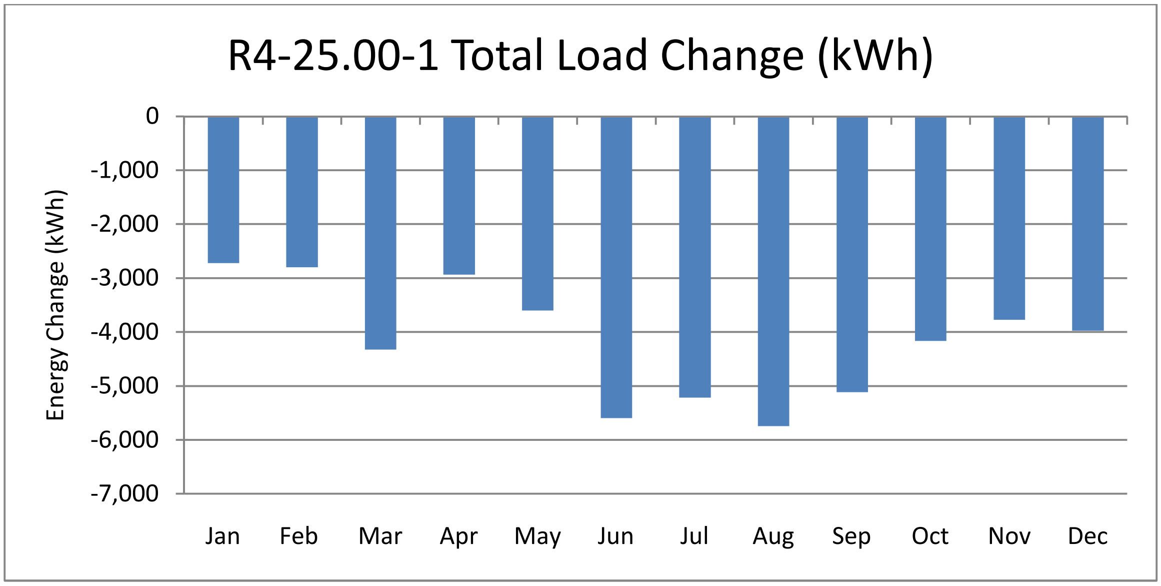


Figure 6.99: R4-25.00-1 Total Load Change (kWh)

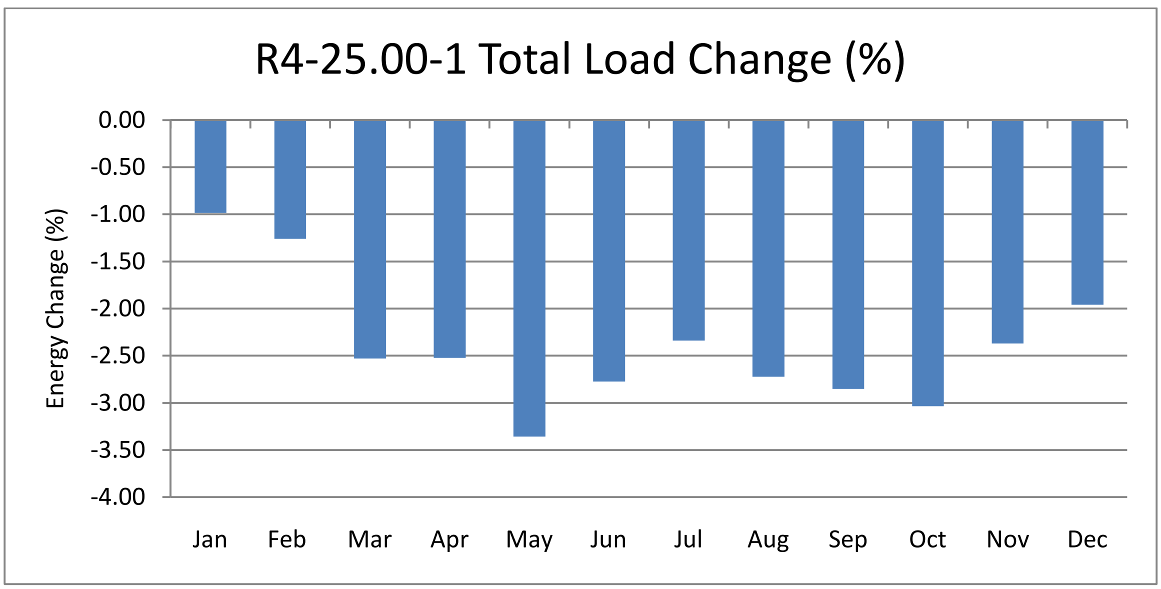


Figure 6.100: R4-25.00-1 Total Load Change (%)

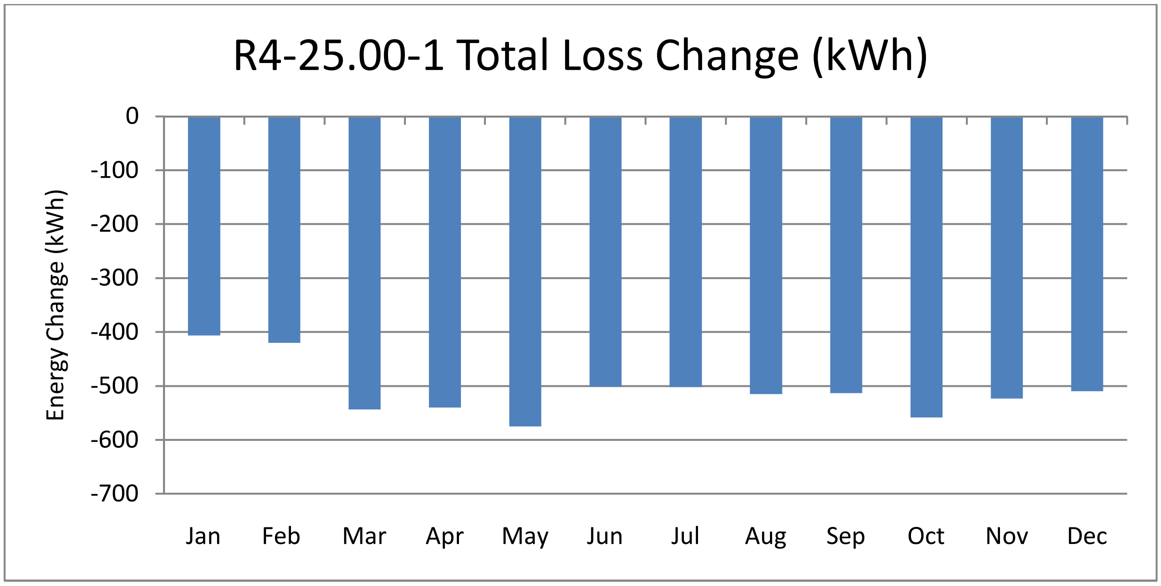


Figure 6.101: R4-25.00-1 Total Loss Change (kWh)

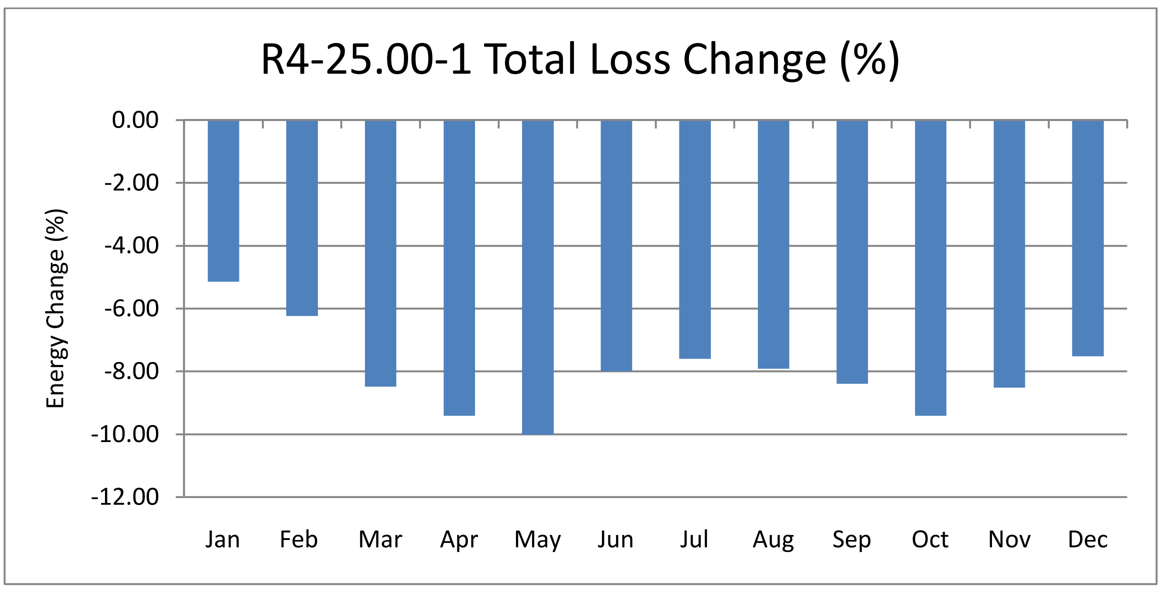


Figure 6.102: R4-25.00-1 Total Loss Change (%)

6.5. Region 5: CVR Plots

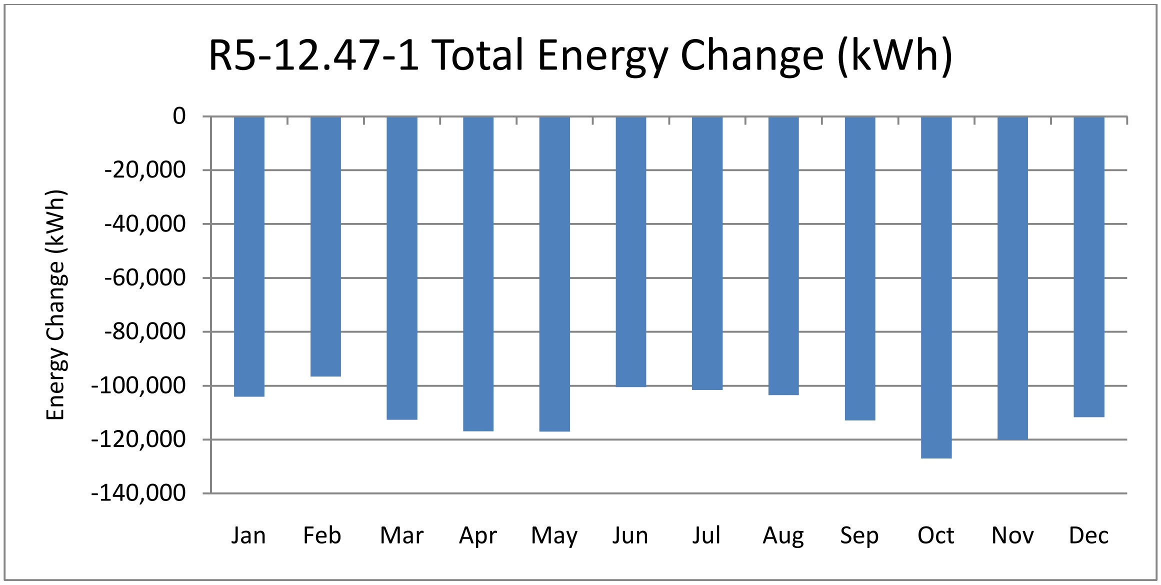


Figure 6.103: R5-12.47-1 Total Energy Change (kWh)

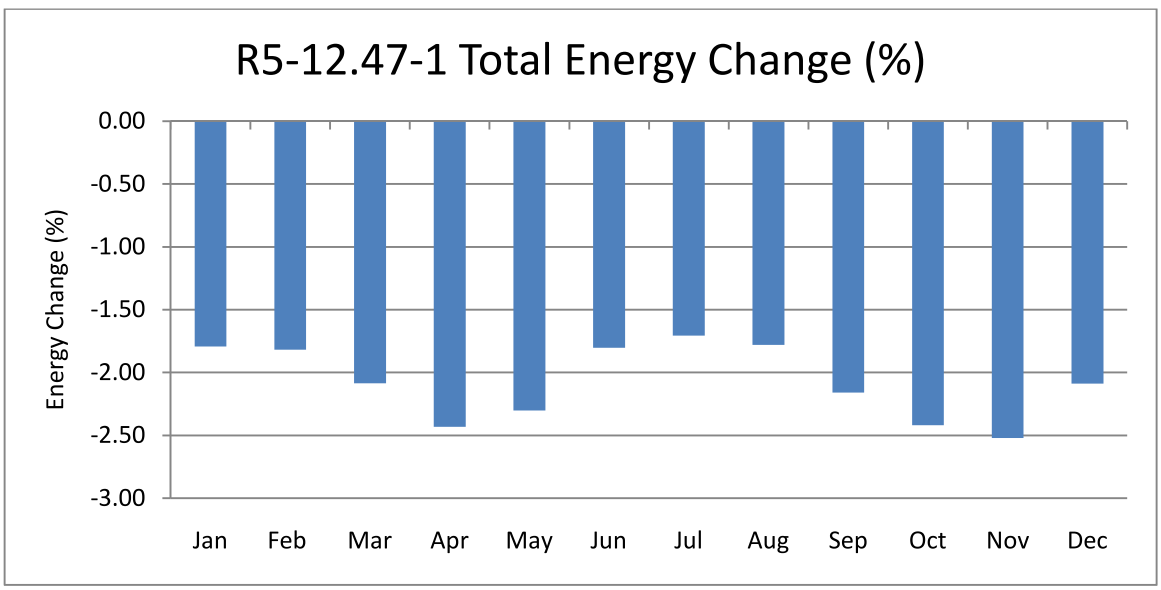


Figure 6.104: R5-12.47-1 Total Energy Change (%)

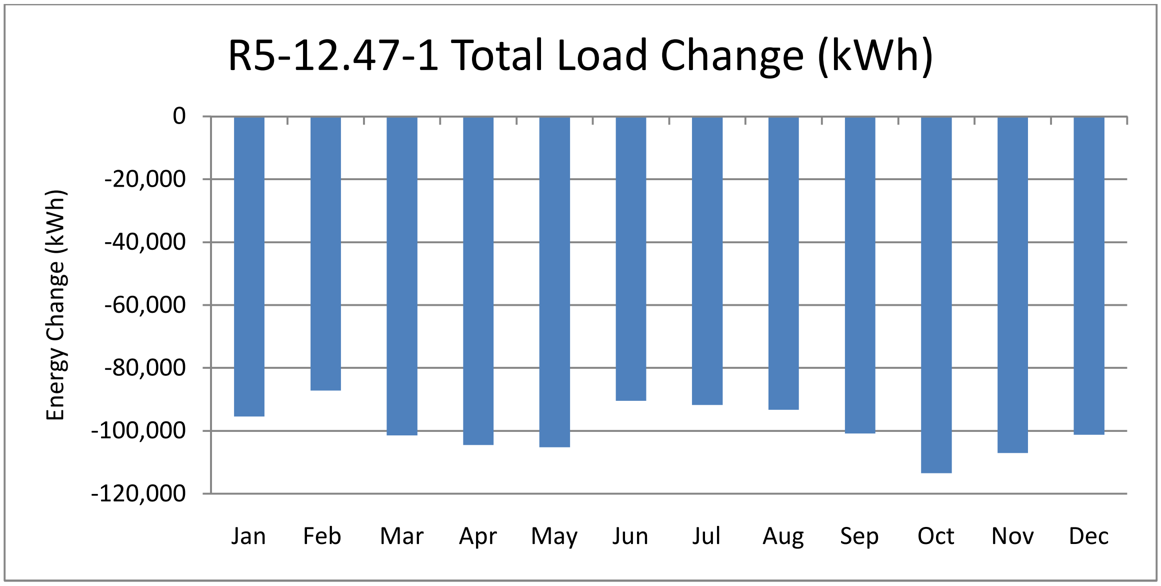


Figure 6.105: R5-12.47-1 Total Load Change (kWh)

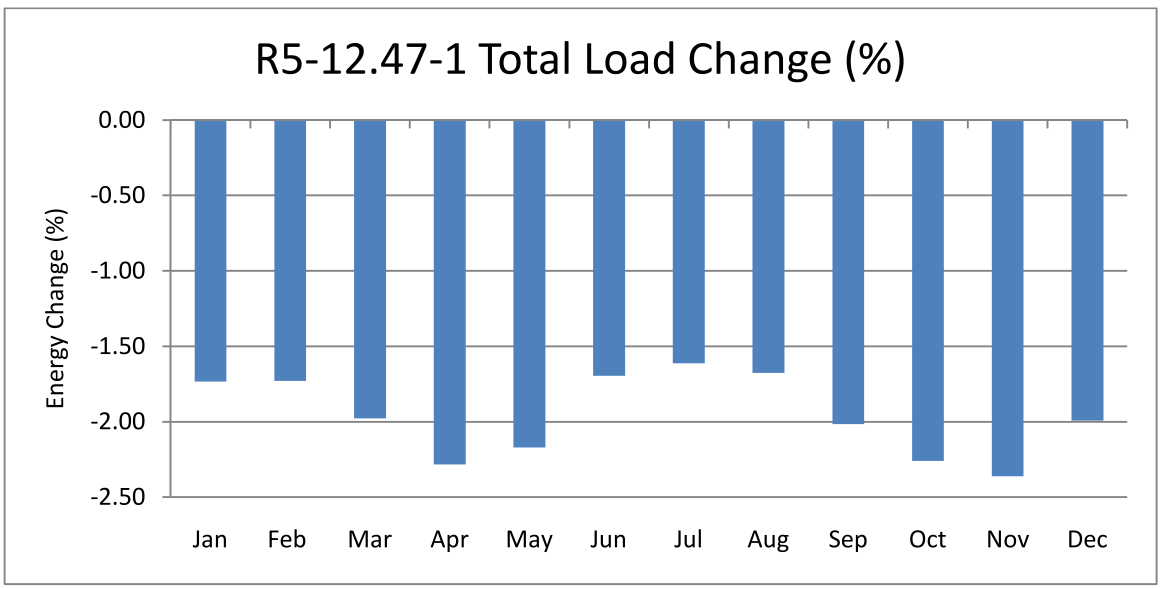


Figure 6.106: R5-12.47-1 Total Load Change (%)

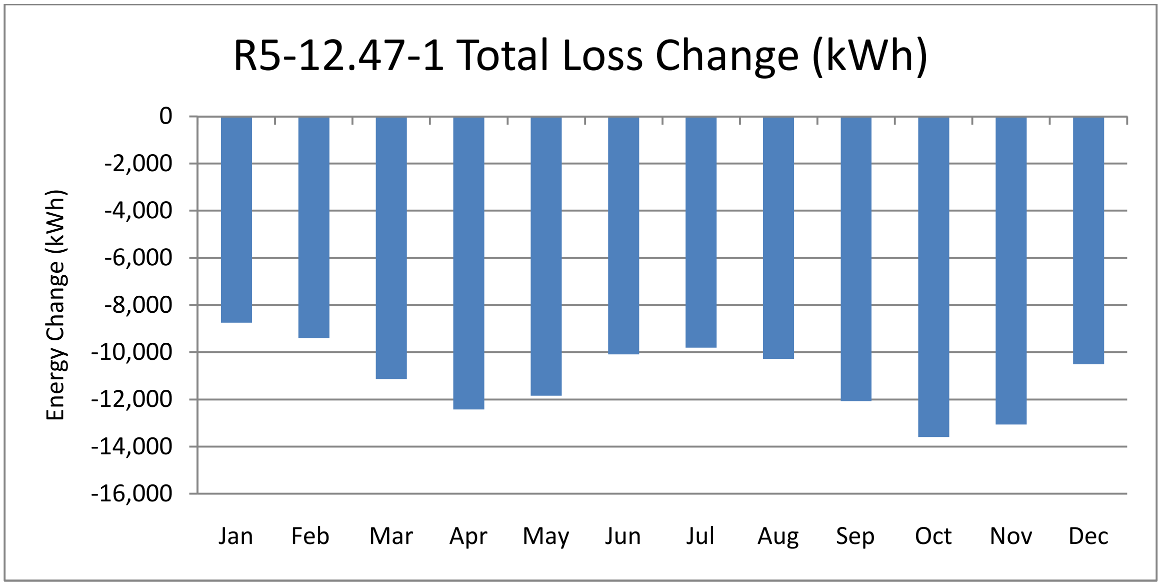


Figure 6.107: R5-12.47-1 Total loss Change (kWh)

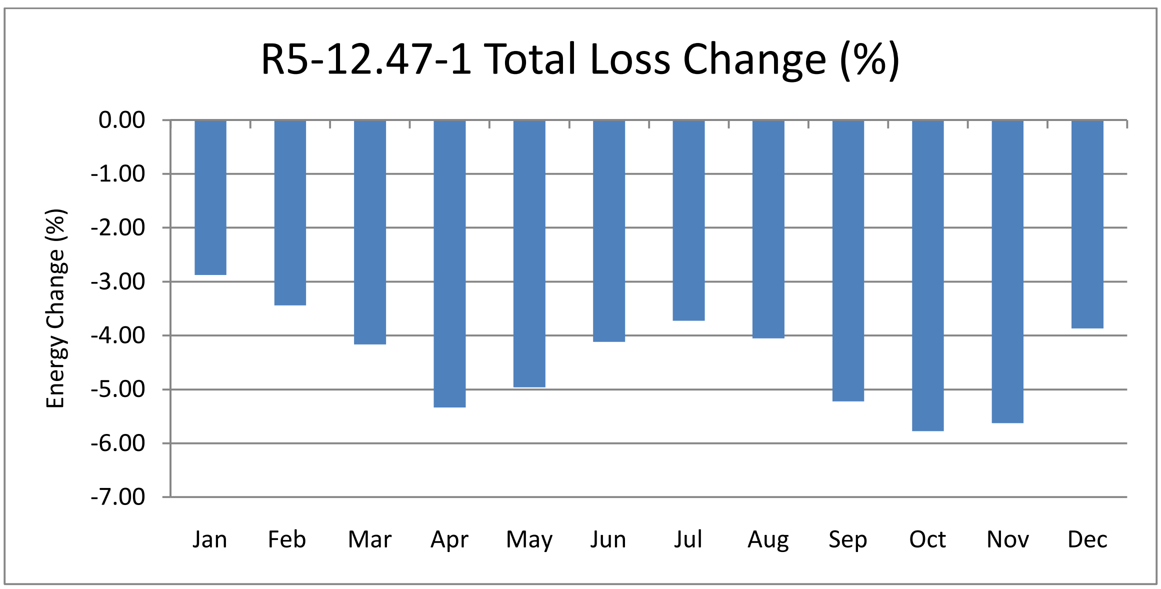


Figure 6.108: R5-12.47-1 Total Loss Change (%)

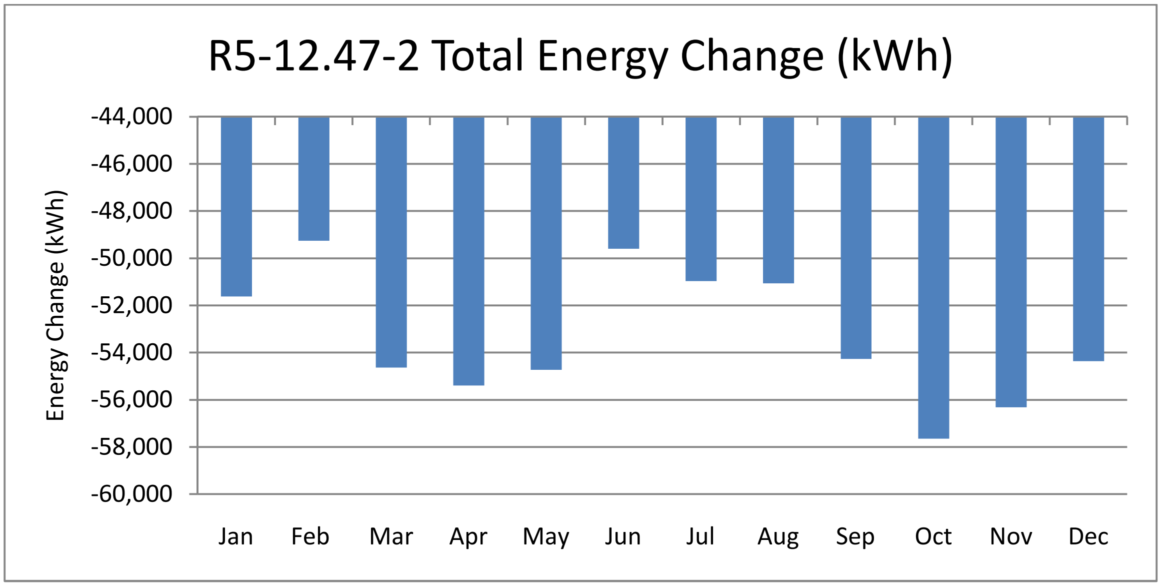


Figure 6.109: R5-12.47-2 Total Energy Change (kWh)

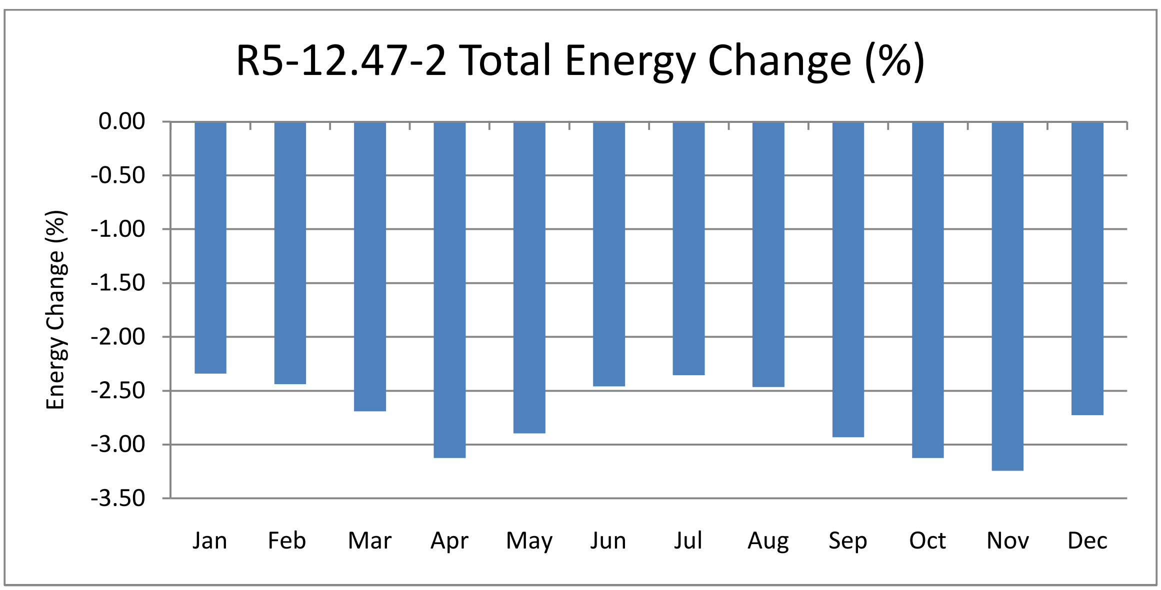


Figure 6.110: R5-12.47-2 Total Energy Change (%)

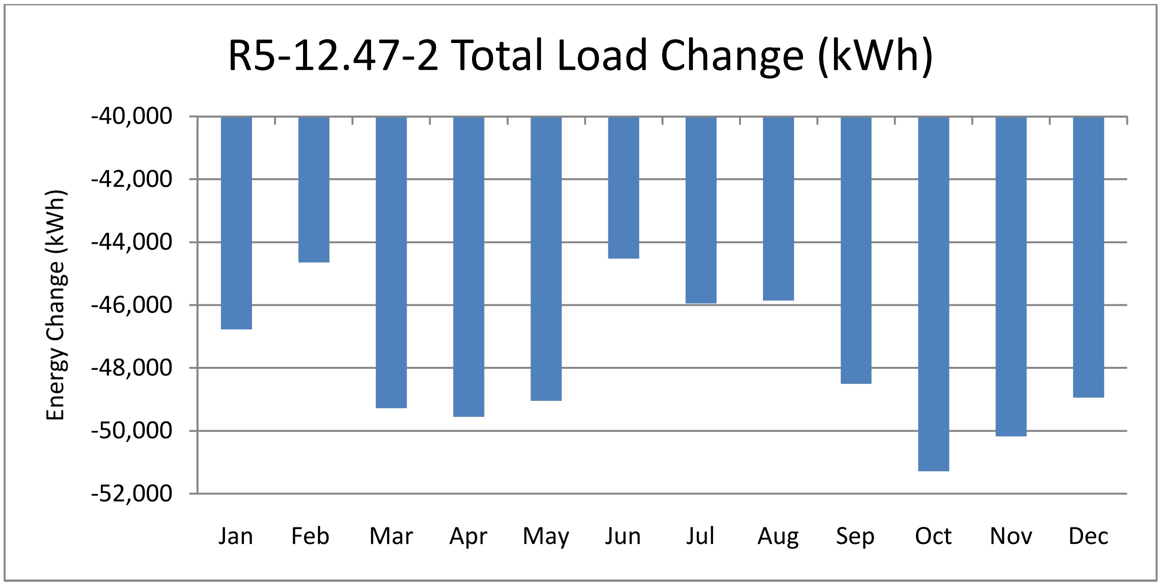


Figure 6.111: R5-12.47-2 Total Load Change (kWh)

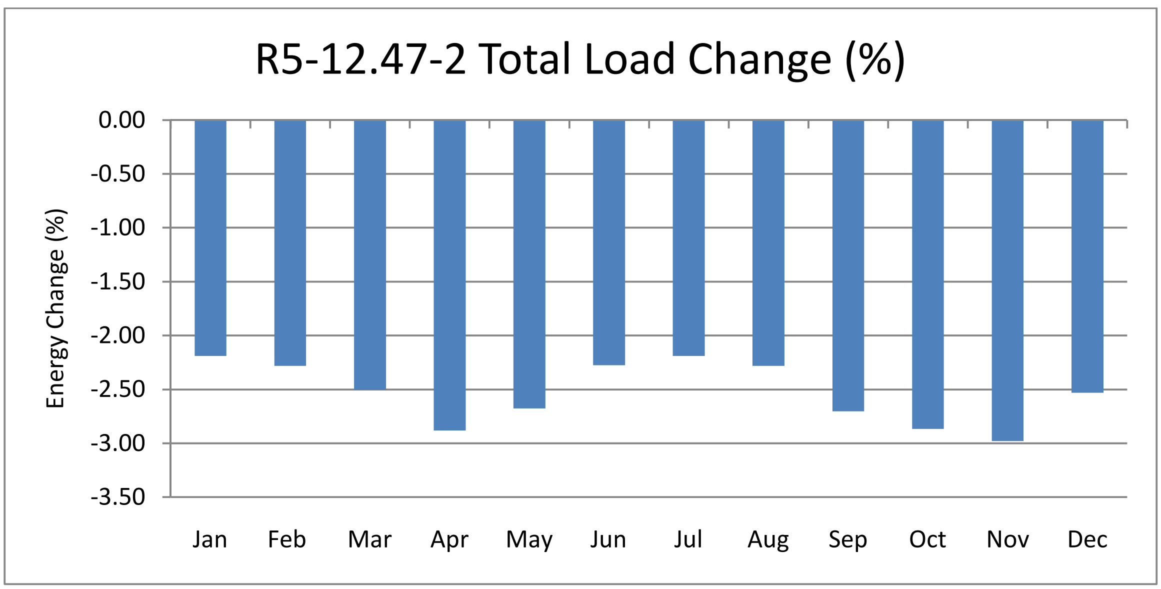


Figure 6.112: R5-12.47-2 Total Load Change (%)

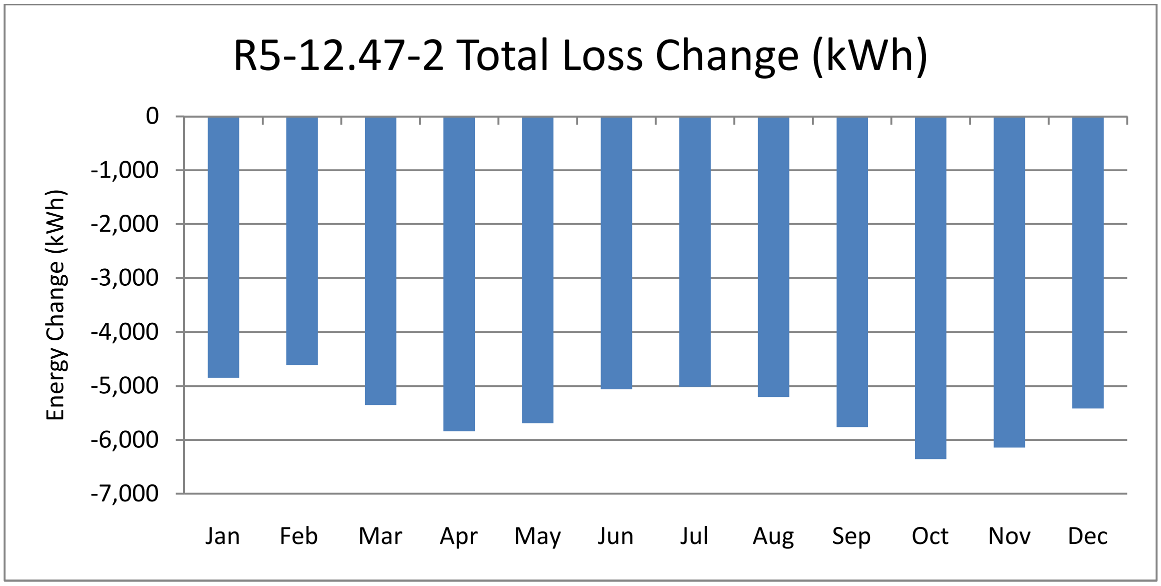


Figure 6.113: R5-12.47-2 Total Loss Change (kWh)

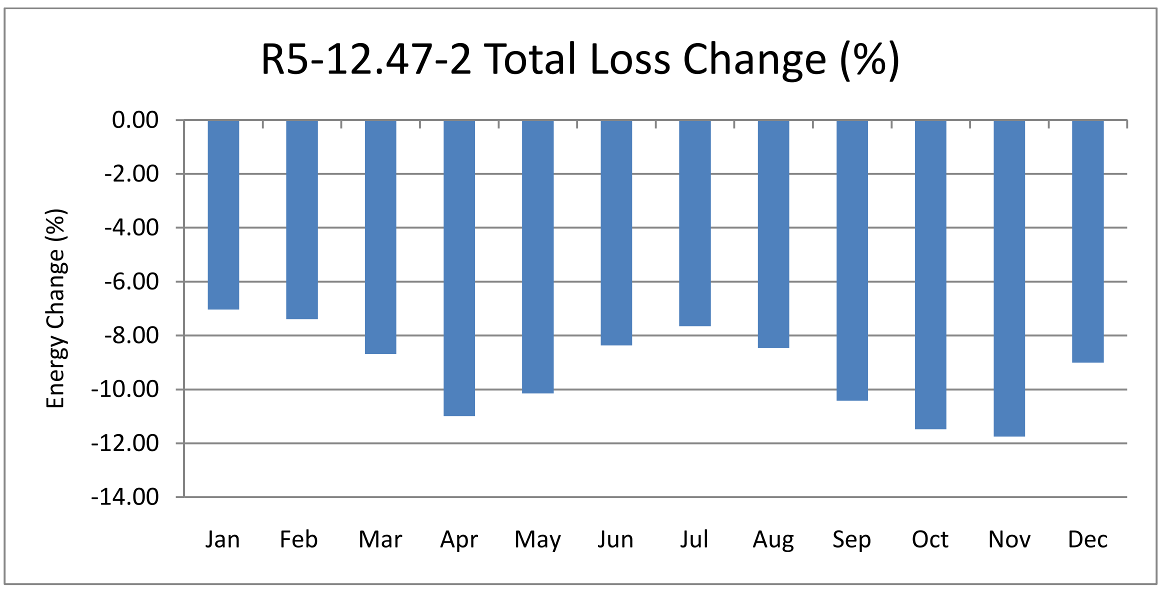


Figure 6.114: R5-12.47-2 Total Loss Change (%)

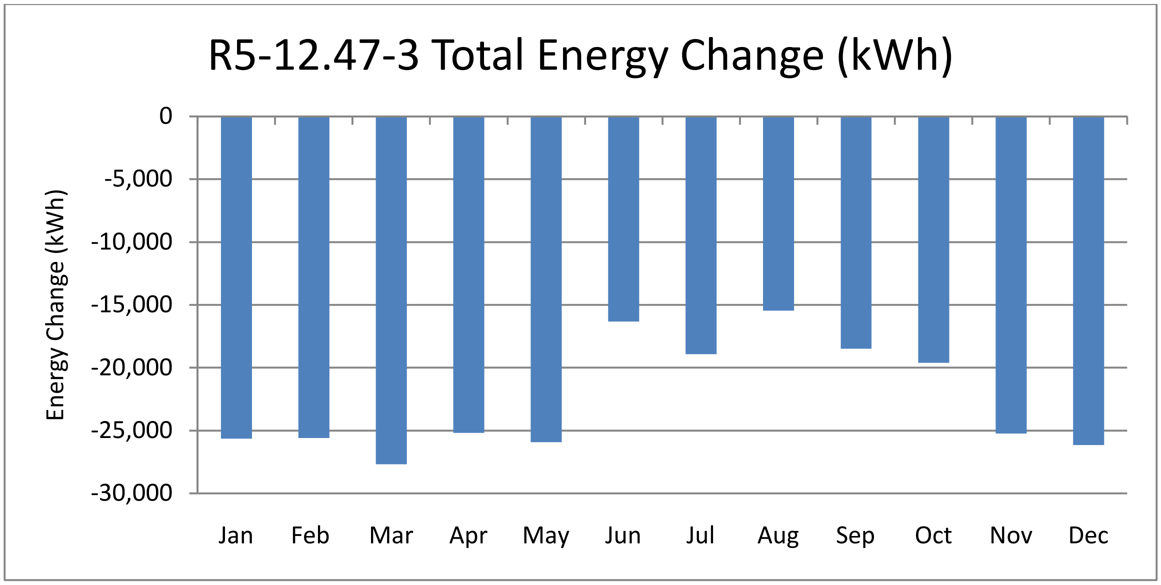


Figure 6.115: R5-12.47-3 Total Energy Change (kWh)

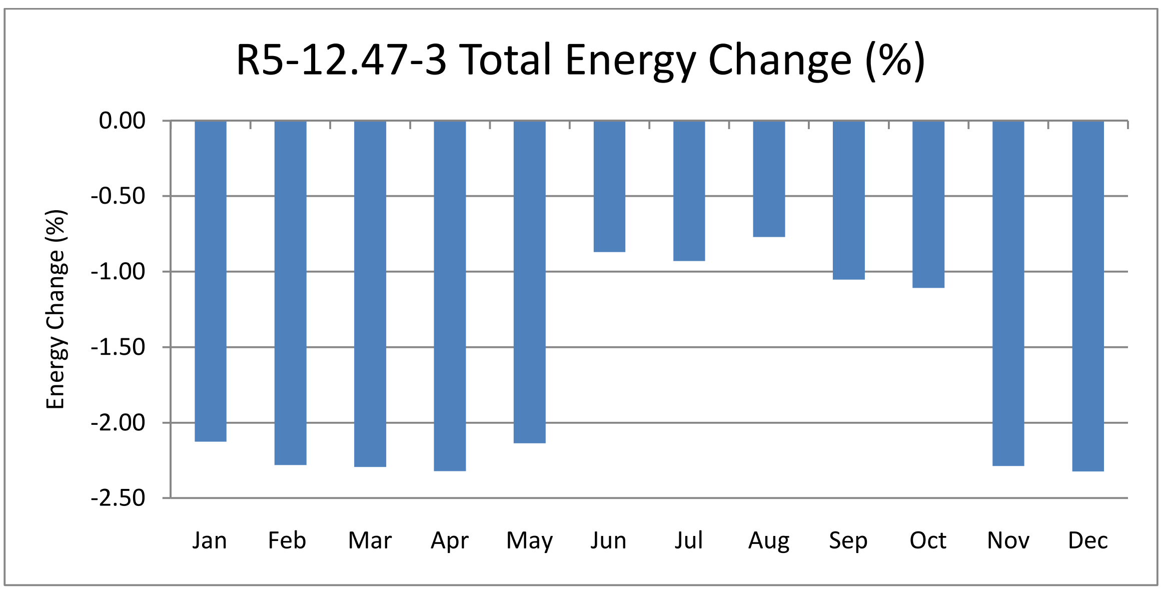


Figure 6.116: R5-12.47-3 Total Energy Change (%)

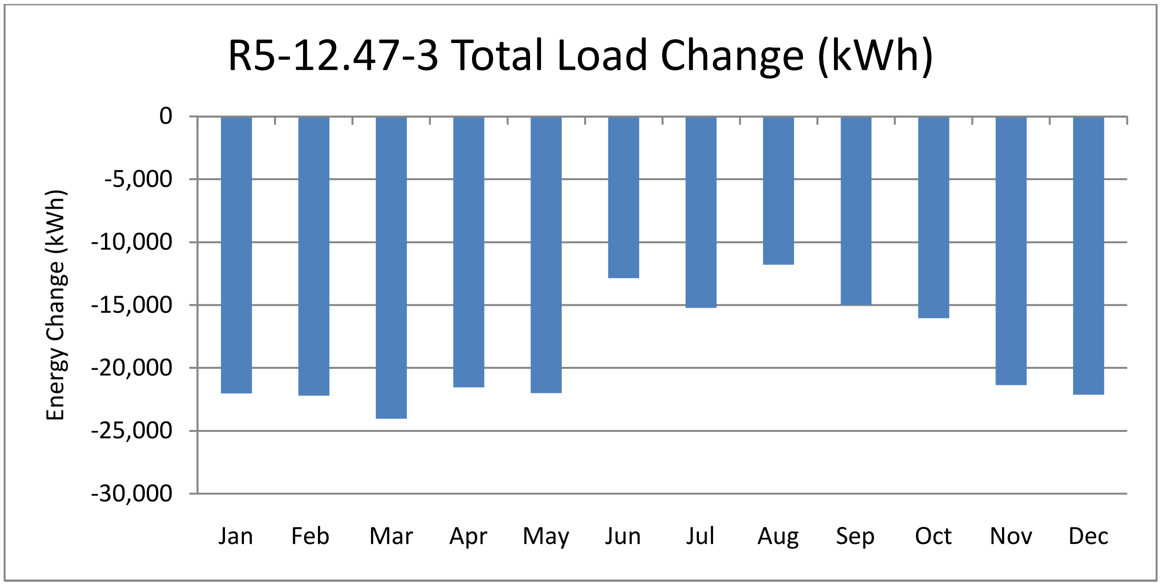


Figure 6.117: R5-12.47-3 Total Load Change (kWh)

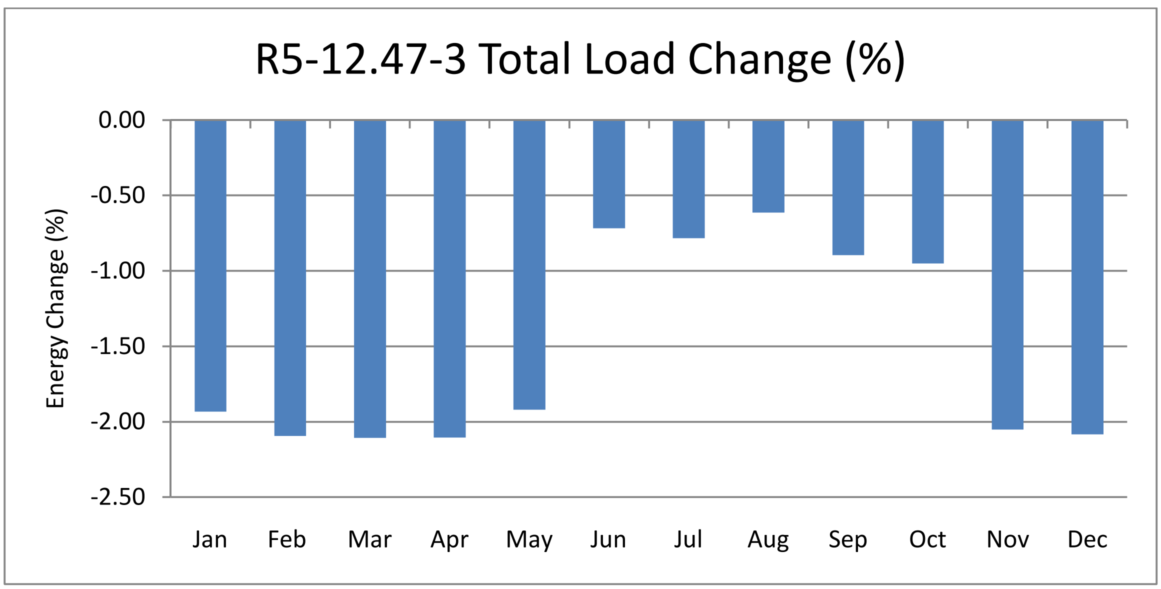


Figure 6.118: R5-12.47-3 Total Load Change (%)

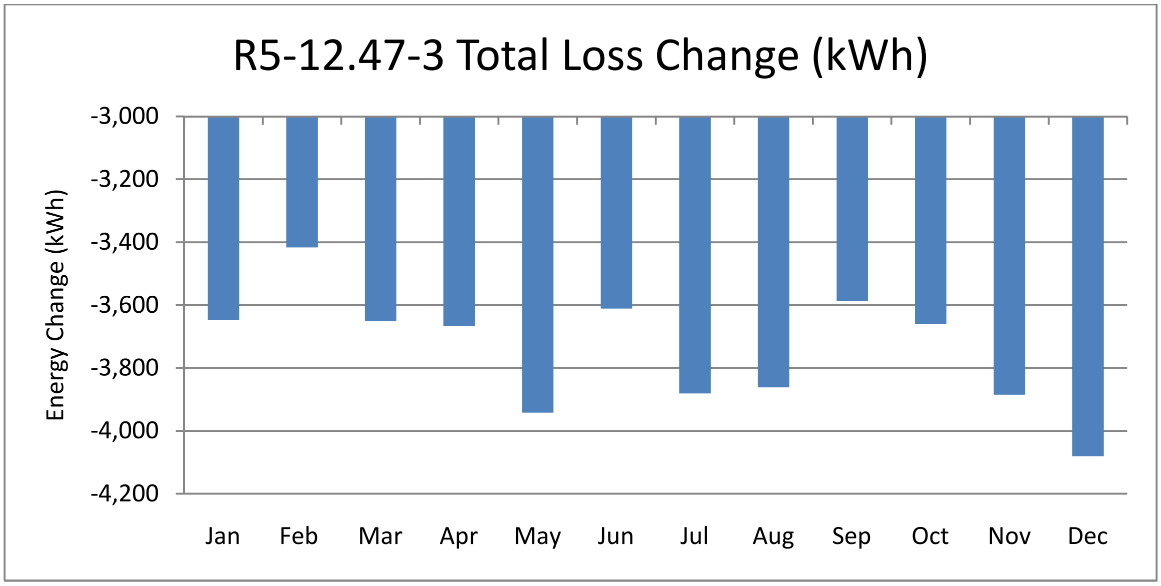


Figure 6.119: R5-12.47-3 Total Loss Change (kWh)

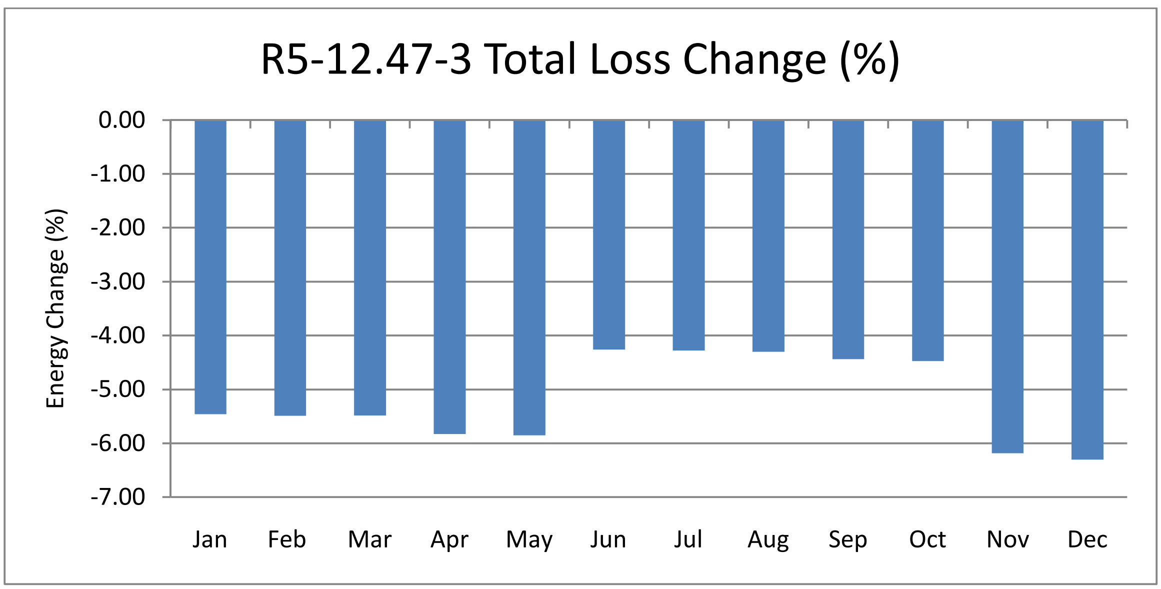


Figure 6.120: R5-12.47-3 Total Loss Change (%)

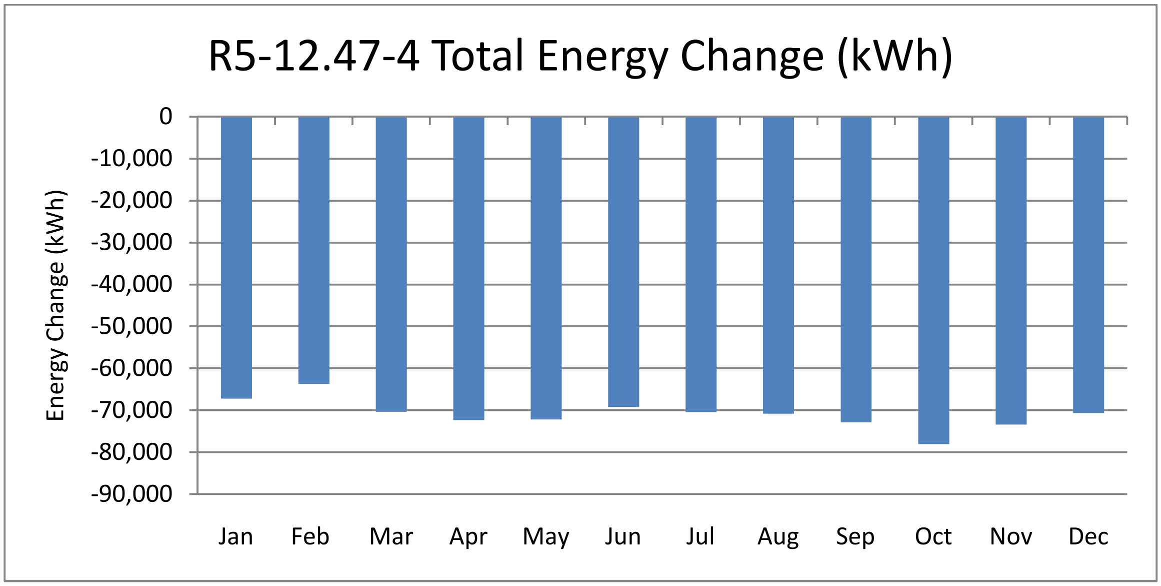


Figure 6.121: R5-12.47-4 Total Energy Change (kWh)

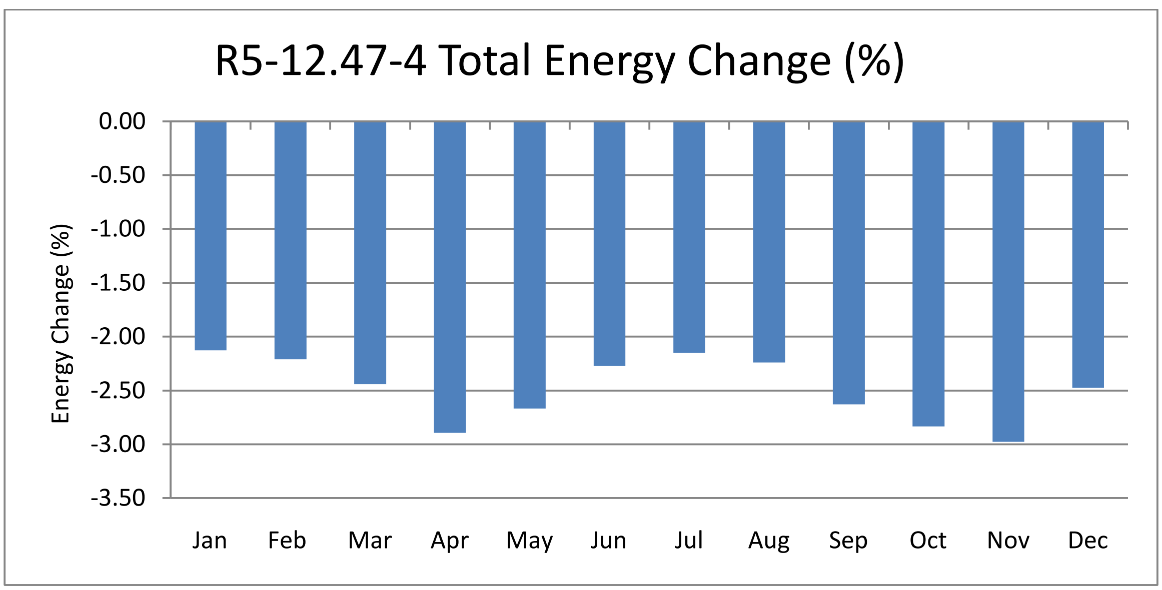


Figure 6.122: R5-12.47-4 Total Energy Change (%)

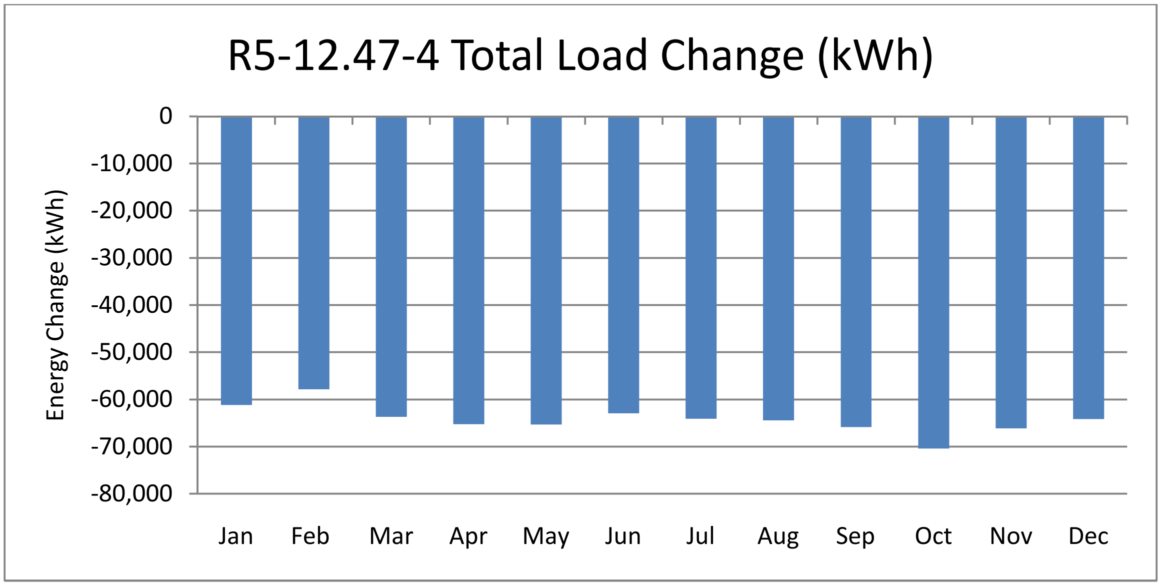


Figure 6.123: R5-12.47-4 Total Load Change (kWh)

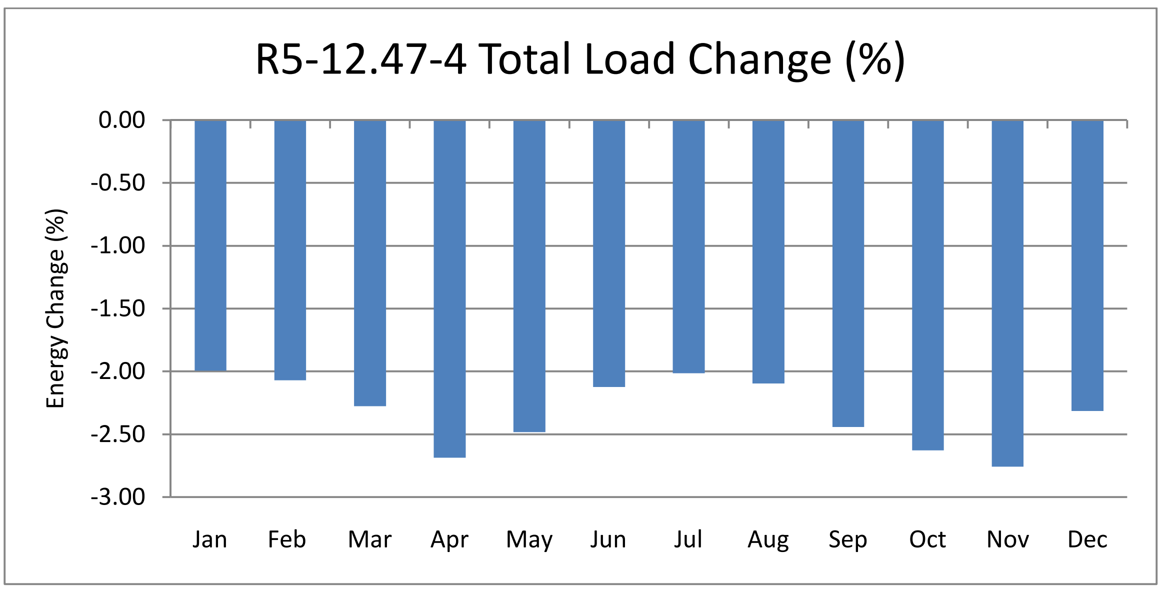


Figure 6.124: R5-12.47-4 Total Load Change (%)

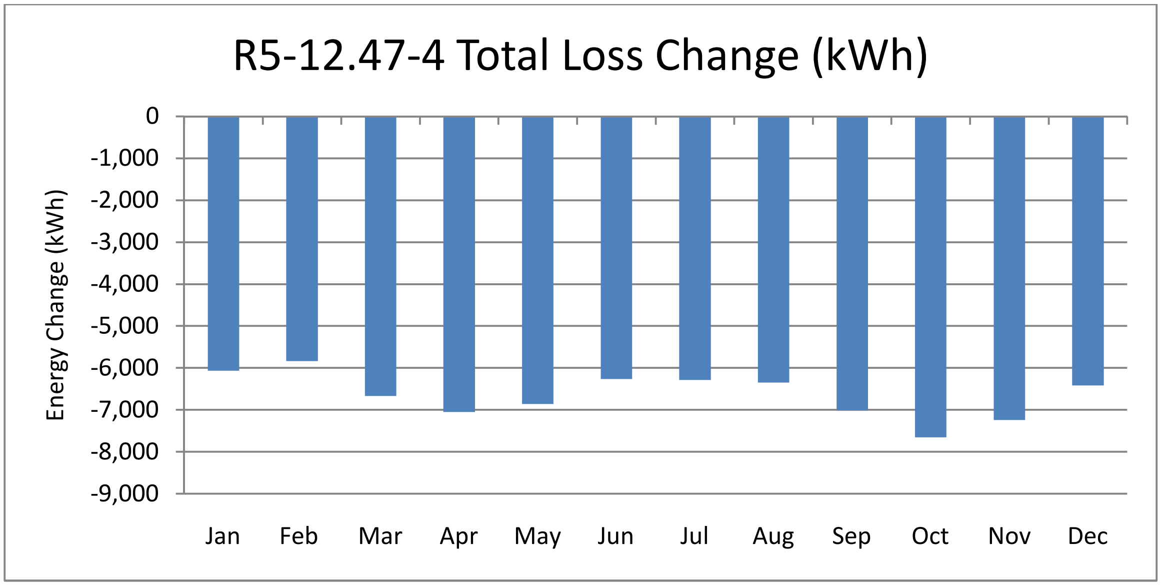


Figure 6.125: R5-12.47-4 Total Loss Change (kWh)

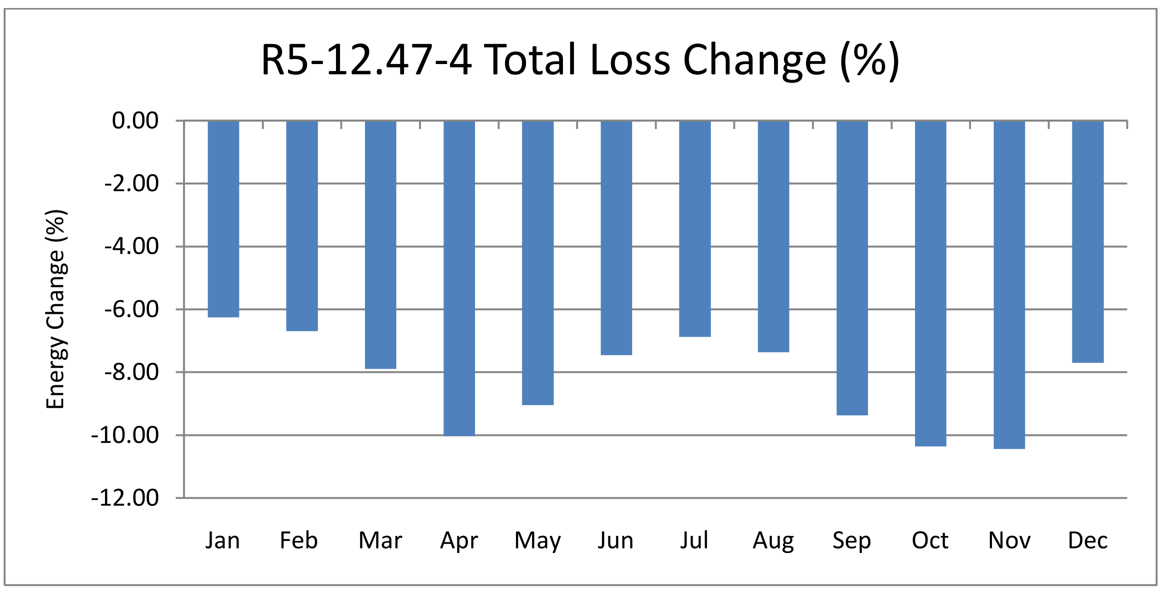


Figure 6.126: R5-12.47-4 Total Loss Change (%)

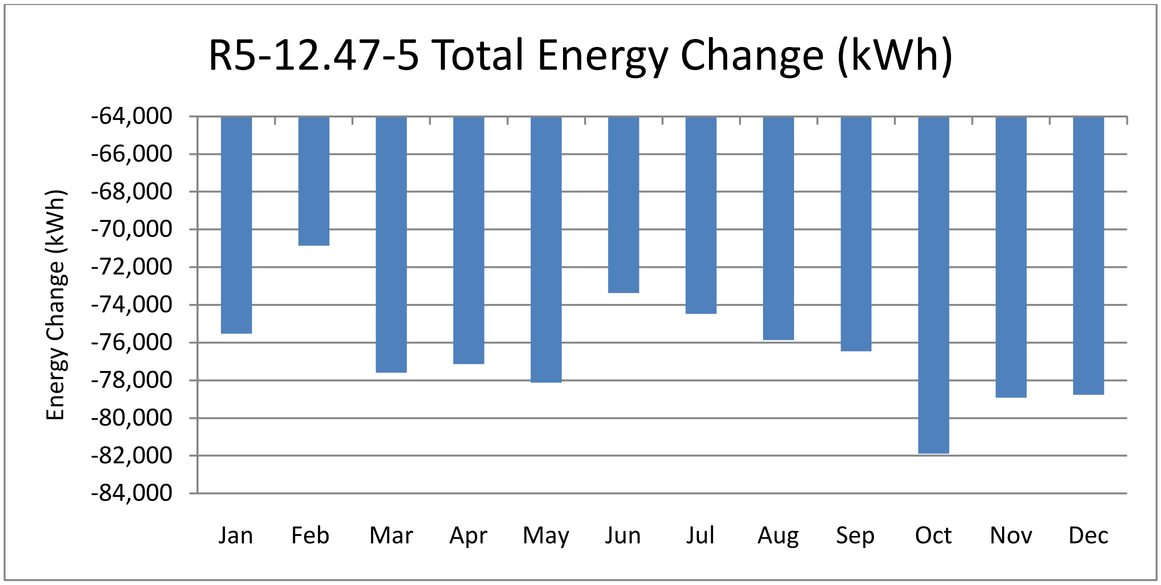


Figure 6.127: R5-12.47-5 Total Energy Change (kWh)

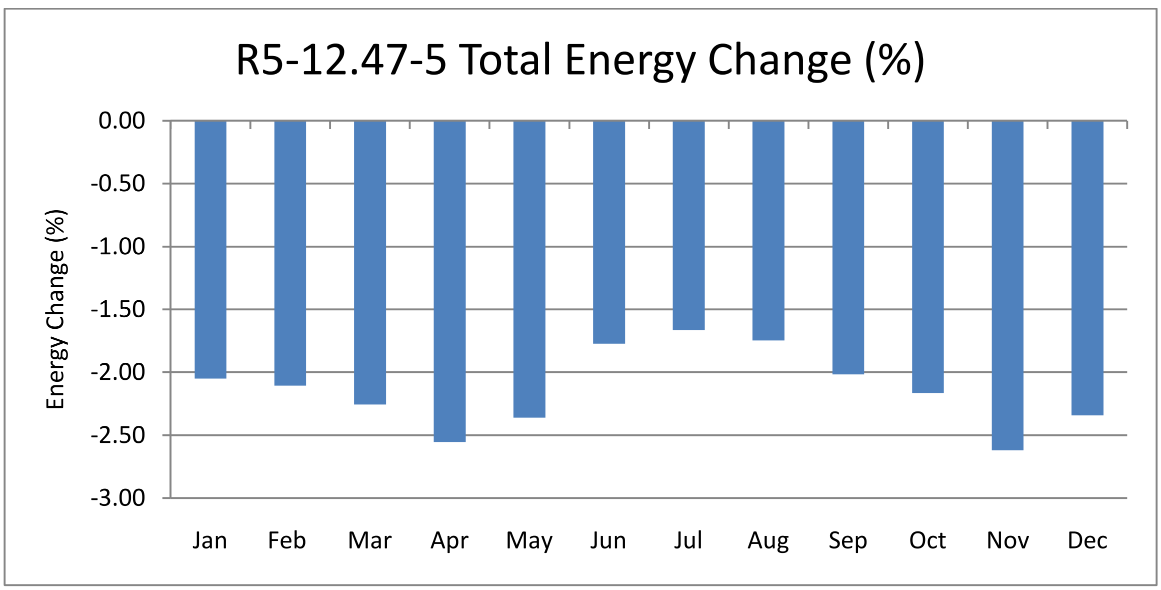


Figure 6.128: R5-12.47-5 Total Energy Change (%)

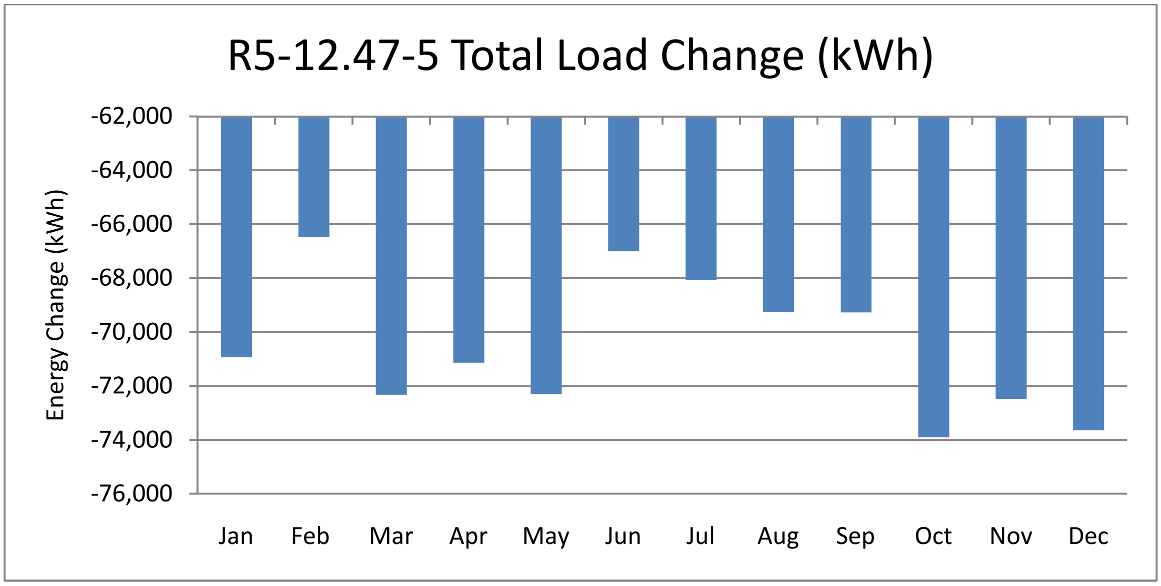


Figure 6.129: R5-12.47-5 Total Load Change (kWh)

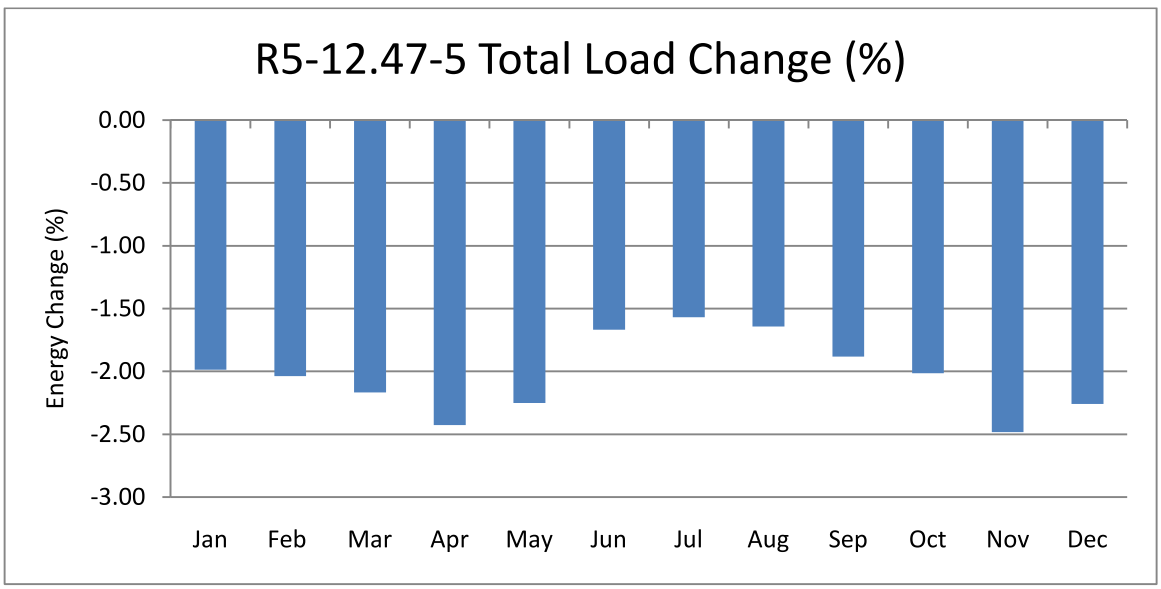


Figure 6.130: R5-12.47-5 Total Load Change (%)

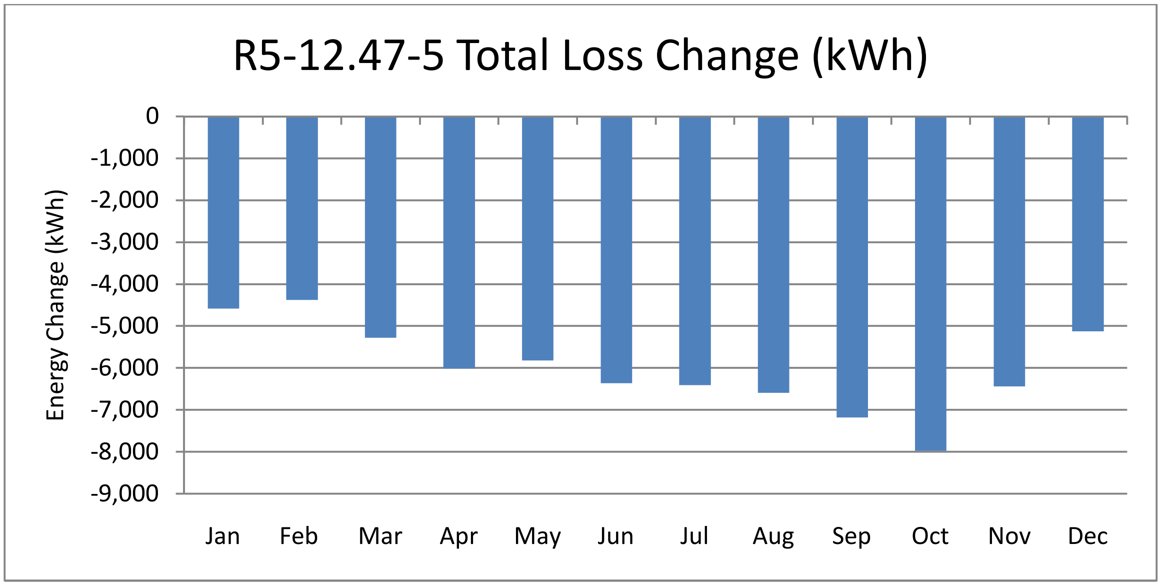


Figure 6.131: R5-12.47-5 Total Loss Change (kWh)

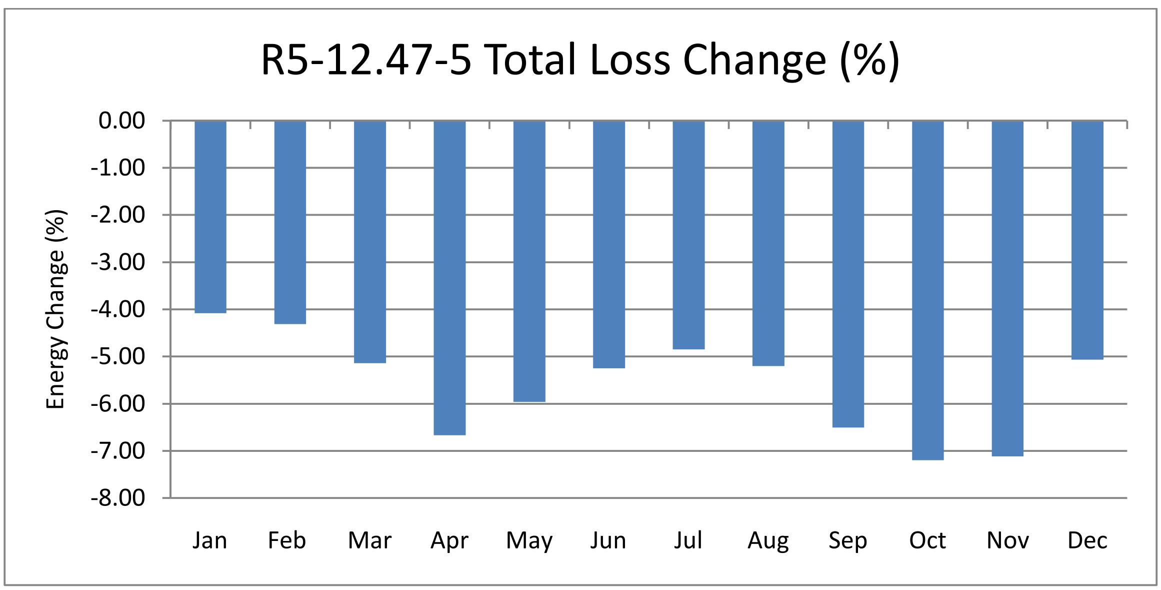


Figure 6.132: R5-12.47-5 Total Loss Change (%)

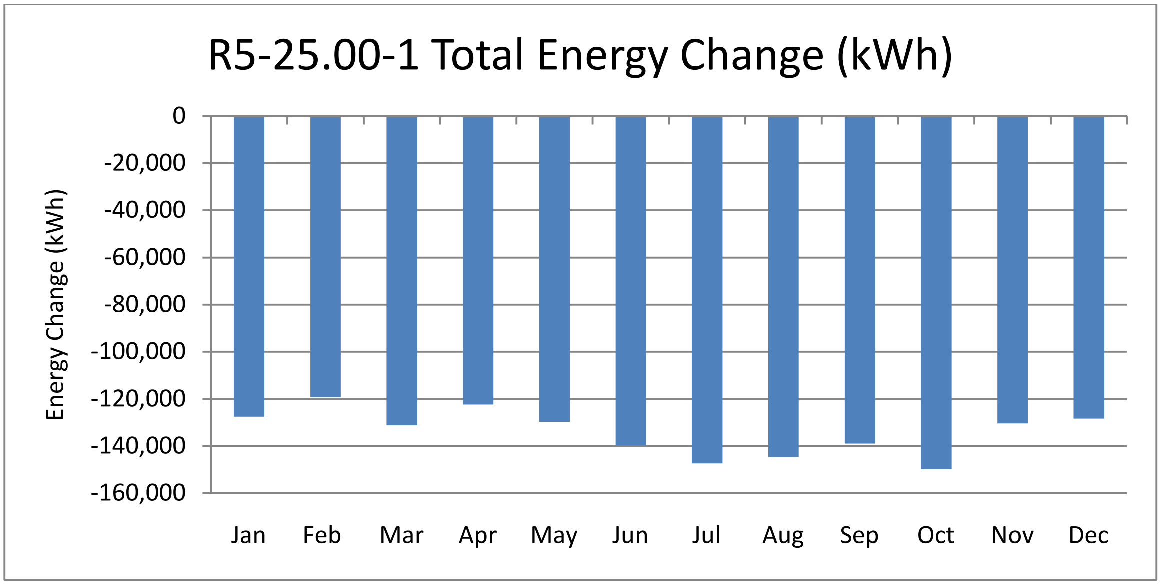


Figure 6.133: R5-25.00-1 Total Energy Change (kWh)

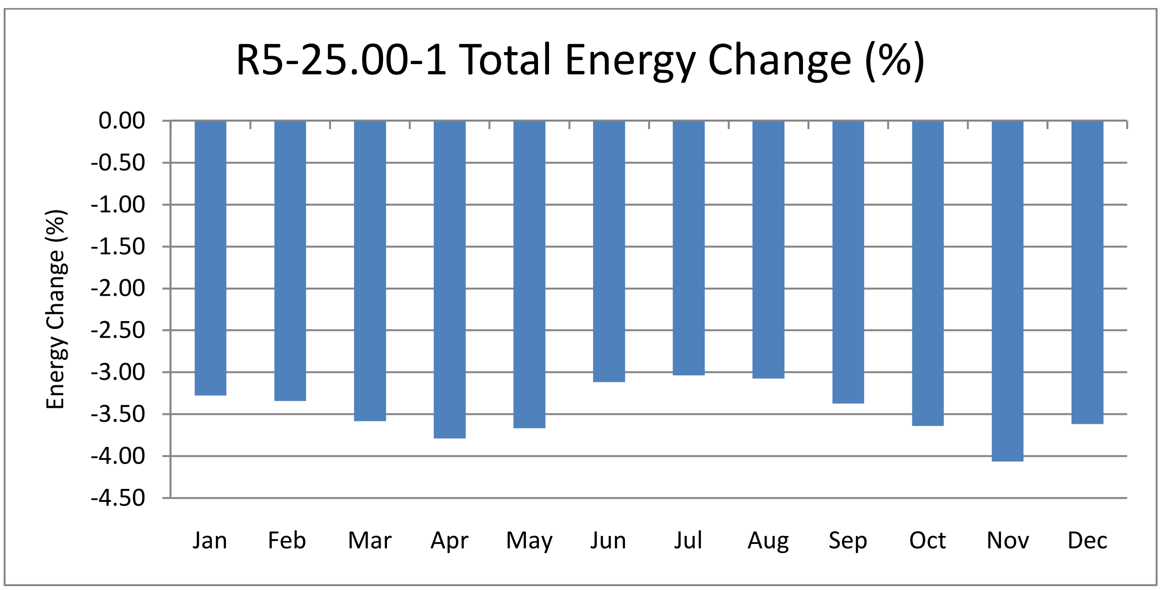


Figure 6.134: R5-25.00-1 Total Energy Change (%)

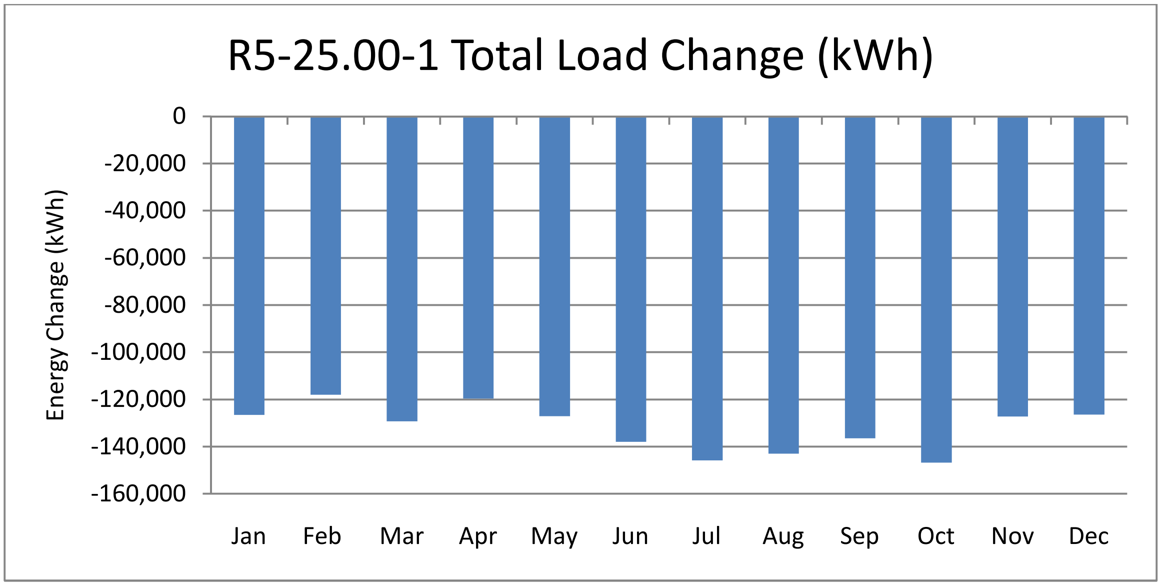


Figure 6.135: R5-25.00-1 Total load Change (kWh)

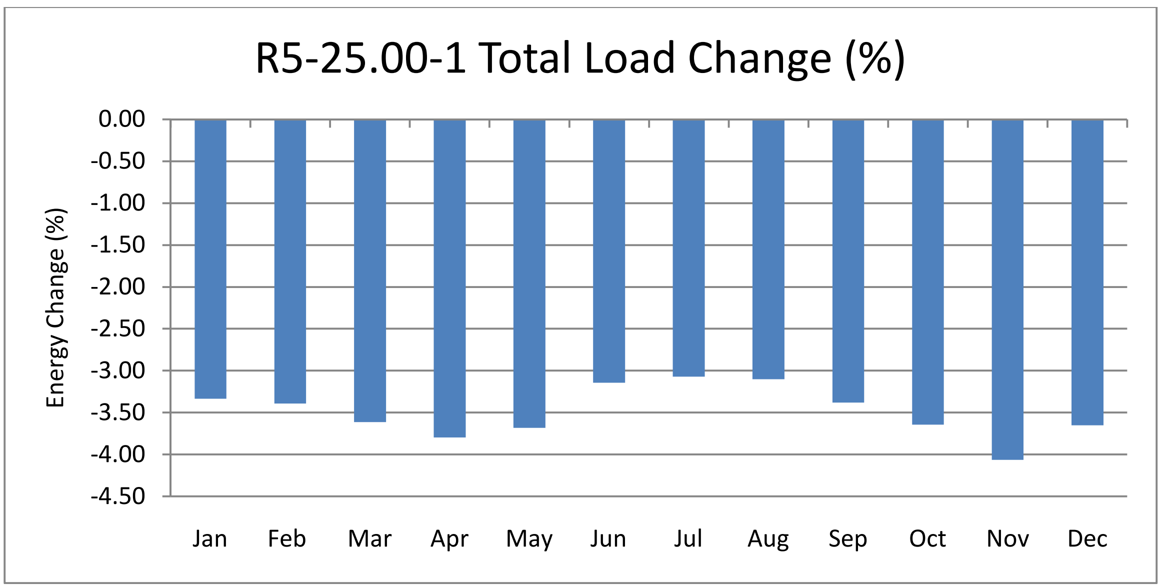


Figure 6.136: R5-25.00-1 Total load Change (%)

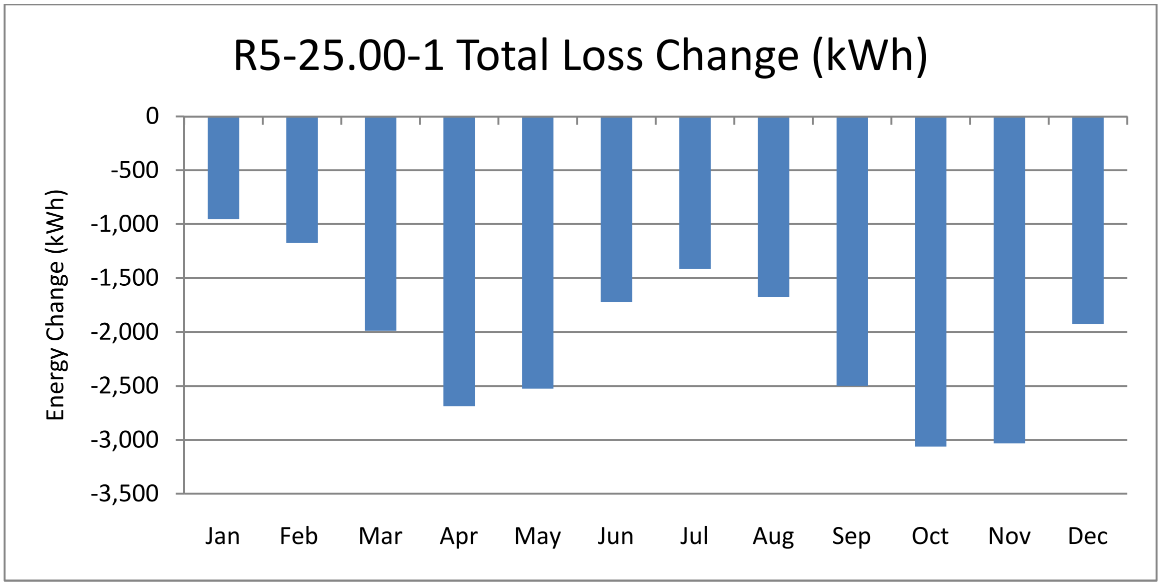


Figure 6.137: R5-25.00-1 Total Loss Change (kWh)

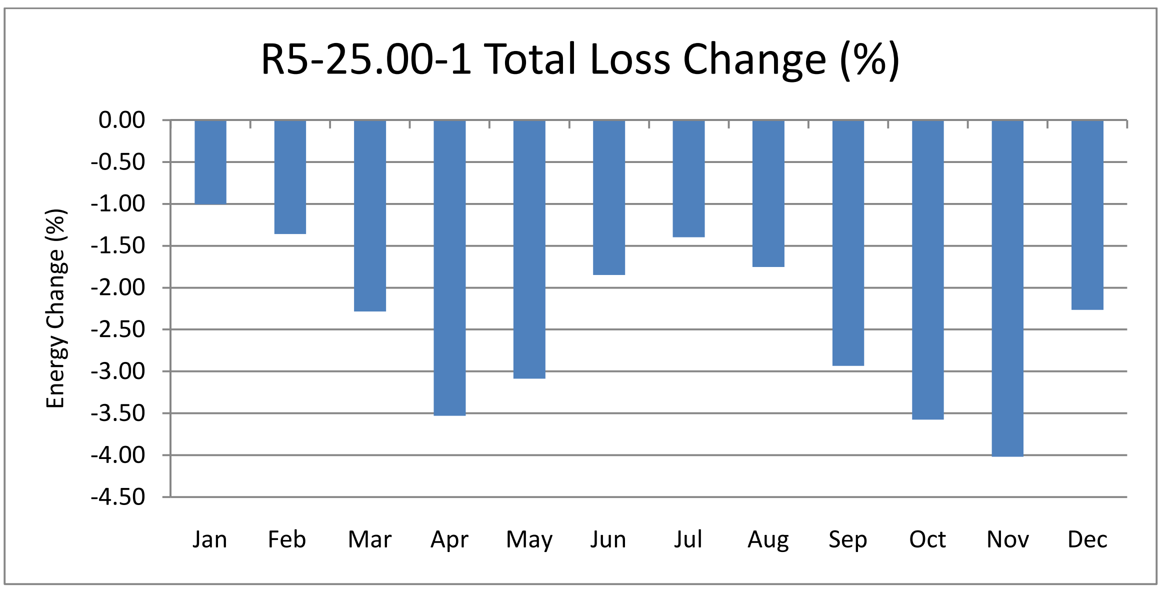


Figure 6.138: R5-25.00-1 Total Loss Change (kWh)

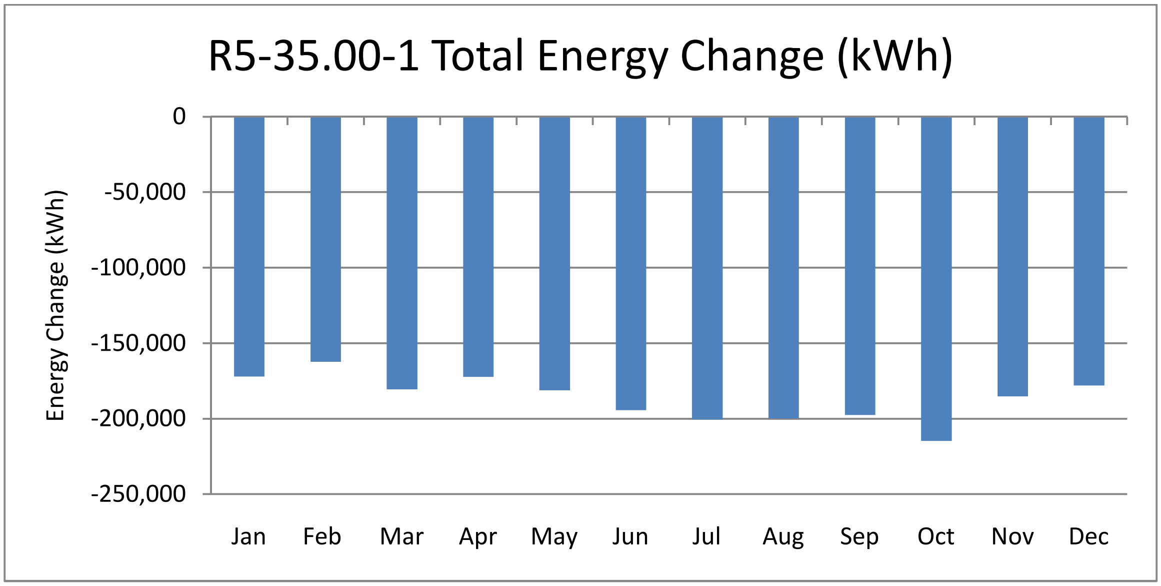


Figure 6.139: R5-35.00-1 Total Energy Change (kWh)

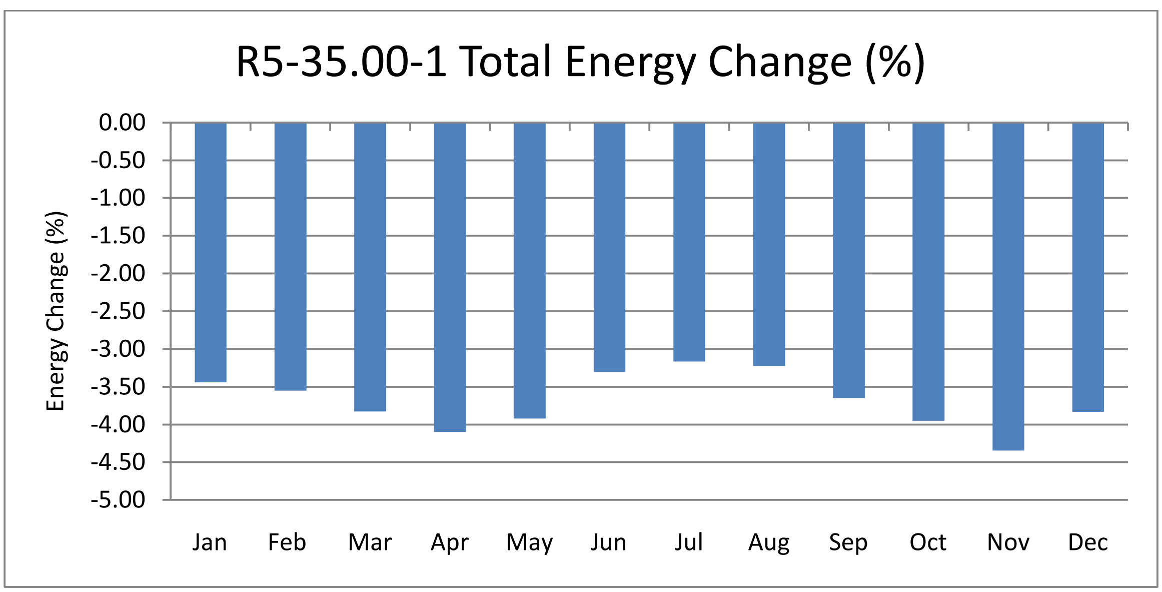


Figure 6.140: R5-35.00-1 Total Energy Change (%)

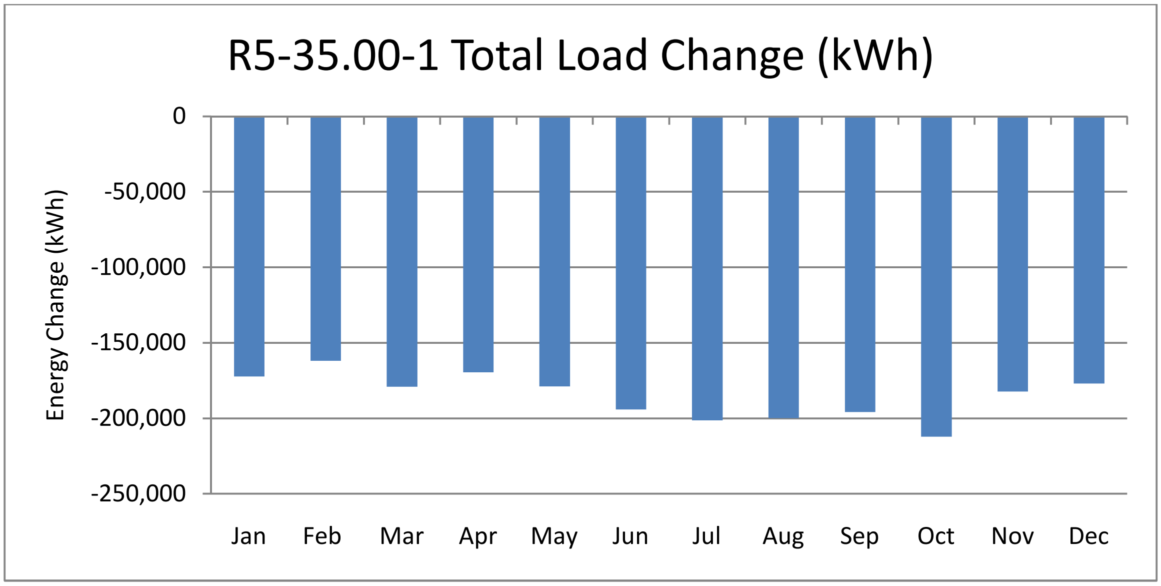


Figure 6.141: R5-35.00-1 Total Load Change (kWh)

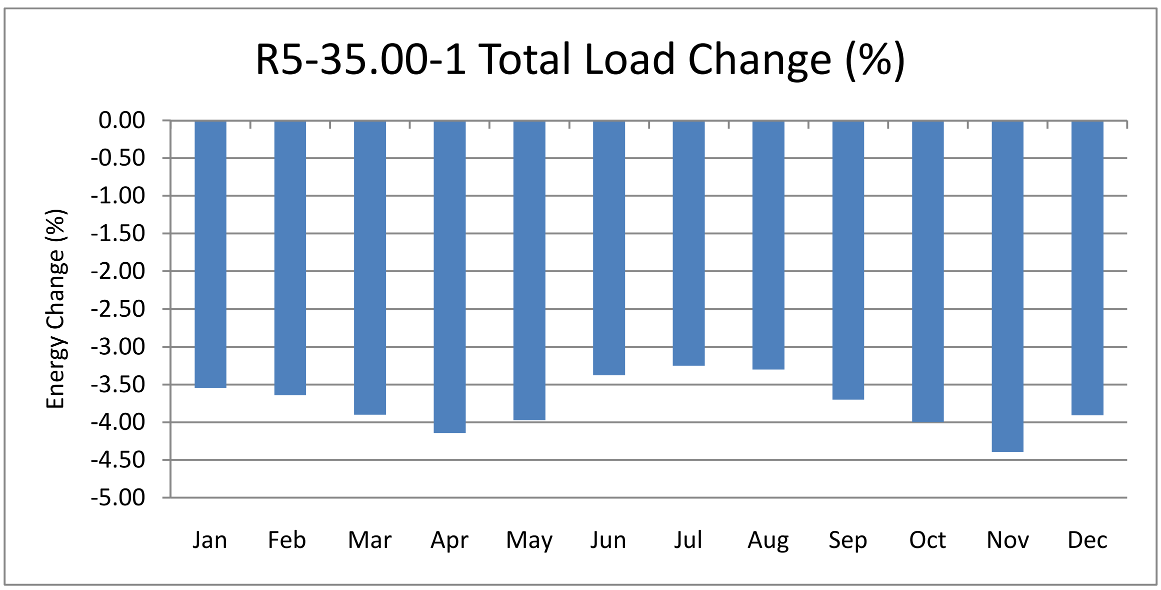


Figure 6.142: R5-35.00-1 Total Load Change (%)

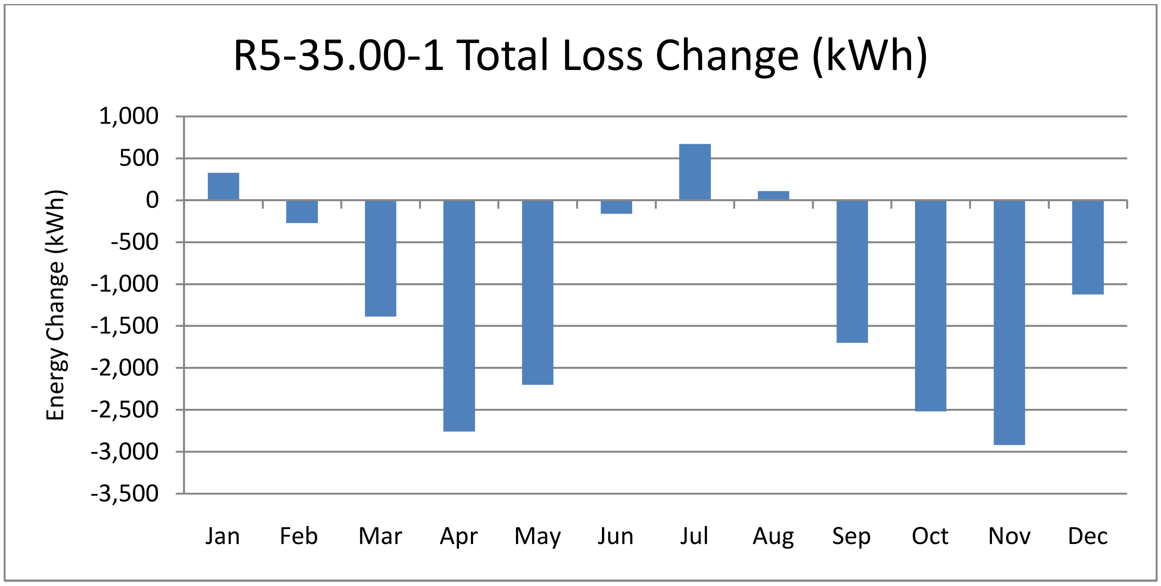


Figure 6.143: R5-35.00-1 Total Loss Change (kWh)

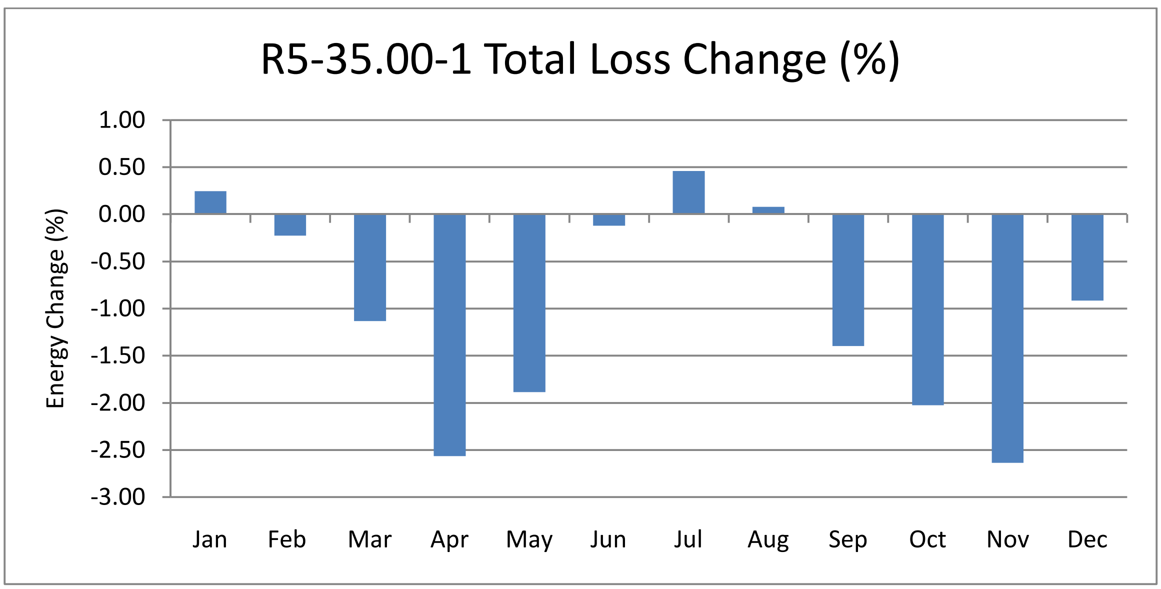


Figure 6.144: R5-35.00-1 Total Loss Change (%)

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APPENDIX 7
NAVIGANT COMMUNITY MICROGRID BUSINESS CASE REVIEW REPORT

Community Microgrid Business Case Review

Final Report

Prepared for:

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Submitted by:
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May 4, 2016

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EXECUTIVE SUMMARY

Navigant conducted a business case analysis of a utility distribution microgrid (UDM) project proposed by Energizing Company (ECo) for Sault Ste. Marie. As part of this analysis, Navigant reviewed available documentation on the existing business case and benefit-cost analyses performed by ECo, assessed the major elements of the project in regards for value for money, develop a recommended accounting framework for submission in an OEB rate application to meet regulatory requirements, identified and outlined possible financing or equity partnership alternatives or opportunities to carry out the project, and developed a final recommendation.

With respect to ECo's proposal, Navigant anticipates that the portion of ECo's proposed payment representing capital expenditures associated with the project would be rate-based, and the portion representing operating and maintenance (O&M) expenditures would be expensed. Collectively, these two cost components would be recoverable through the PUC's revenue requirements, but would result in a material increase in customer rates. The remainder of ECo's proposed payment representing ECo's risk premium and financing costs would NOT be recoverable through the PUC's revenue requirements but would have to be covered by the shareholder. This would result in a negative incremental cash flow to the shareholder for the duration of the ECo agreement.

Considered over the 40-year life of the primary assets, the core UDM project – comprising the capital costs for construction and ongoing costs for operation – provides a strong benefit-cost ratio from a customer perspective. Even with a 30% contingency on capital and operating costs, and including PUC financing costs, the benefit / cost ratio for the project is forecast to be 1.3 based on what Navigant believes are conservative estimates of the benefits. It is important to note, however, that reliability benefits comprise more than two-thirds of the project's expected benefits. It is also unclear the degree to which customers are willing to pay more than they would otherwise pay for these reliability benefits. Given this uncertainty, Navigant believes that the cost-benefit analysis underlying any regulatory submission by the PUC related to the UDM project should only incorporate a small portion of the reliability benefits (with the remainder not needed to achieve a benefit / cost ratio of 1 essentially being "free" to the customers).

The project financing and implementation approach is not expected to impact the project benefits, but it will impact costs. Specifically, based on the information available, Navigant does not believe that ECo's proposed financing structure is an efficient way to finance the UDM project. As currently proposed, ECo's proposal would result in a large step-change in customer bills and is likely to pose significant regulatory challenges for the PUC due to the magnitude of the bill impacts. Assuming the full payment for the UDM project as currently proposed by ECo cannot be recovered through rates, then some portion of the ECo payments would have to be borne by the shareholder. Although there are several socio-economic benefits and other energy-related benefits that are expected to flow from the UDM project, how much the shareholder is willing to pay for the UDM project is unknown.

As an alternative to ECo's proposal, it may be possible for the PUC to fund and implement the UDM project. This approach would require some form of investment by the shareholder – either through reduced dividends or an equity injection – that would provide a return to the shareholder. This approach would also result in a significant step-change in customer costs creating similar regulatory challenges as above, but the all-in costs may be lower for this option than the other two options. With this lower cost also comes more risk, since the PUC would be taking the construction and operating risks associated with the project instead of ECo.

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Unless the shareholder is willing to pay the portion of the ECo payments that are not recoverable through rates in return for the benefits realized, Navigant does not believe ECo's current proposal is sufficiently attractive – from a regulatory and customer perspective – to pursue. However, the core UDM project has a strong benefit-cost ratio and both the PUC and ECo have invested a significant amount of time and effort to shape and design the UDM project.

Rather than dismiss ECo's proposal, Navigant recommends that the Proponents explore alternative project options with ECo that might better fit within the PUC's current regulatory framework and the shareholder's willingness to pay. Ideally, these discussions would be undertaken on an "open book" basis with ECo with a view to better understanding the various components underlying ECo's proposed fees, particularly the financing costs and risk premium/performance guarantee.

One possible option that could preserve the key benefits of the project, but with a lower impact on PUC's customers and shareholders, would involve:

- ECo designing, building and operating the project and providing performance guarantees, in exchange for an up-front payment and smaller ongoing payments to cover operational costs, and
- The PUC financing the up-front payment and recovering the cost through rate-base. Alternatively, it may be possible for ECo to finance the project at PUC's cost of capital.

Further options and variations to explore with ECo would include:

- Shaping ECo's payments over time to reduce the present value of the cost to customers, and
- Slowing the pace of investments such that they are undertaken over a longer time period.

Additionally, the Proponents could explore smart grid grants from the federal and provincial governments to cover some of the cost of the UDM project.

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1. PROJECT INTRODUCTION

This section of the report introduces the purpose and scope of Navigant's review, provides an overview of the proposed project, and discusses the policy and utility context in which the proposed project will operate.

1.1 Purpose of the Review

Sault Ste. Marie Innovation Centre in collaboration with PUC Distribution Inc. (PUC), the Sault Ste. Marie Economic Development Corporation and the City of Sault Ste. Marie (collectively the "Proponents") retained Navigant Consulting Ltd. (Navigant) to conduct an independent business case review of a proposed comprehensive community-scale utility distribution microgrid (UDM) project in Sault Ste. Marie, Ontario. The UDM development firm, Energizing Company ("ECo"), is proposing to develop this project by providing financial and technical assistance to PUC in exchange for a fixed monthly service fee.

The purposes of Navigant's review are to:

1. Review available documentation and identify gaps in information required to make an informed final decision.
2. Review the existing business case and benefit-cost analyses performed and assess the major elements of the project in regards for value for money.
3. Develop a recommended accounting framework for submission in an OEB rate application to meet regulatory requirements and long term needs (i.e., rate sensitivity and reliability) of electricity consumers in Sault Ste. Marie.
4. Identify and outline possible financing or equity partnership alternatives or opportunities to carry out the project.
5. Develop a final recommendation and present final report.

1.2 Overview of the Proposed Project

ECo is proposing to assist PUC with the implementation of a comprehensive Smart Grid investment. The project will entail the installation of a UDM, improvements to the utility's substations as well as integration and enhancements to the existing advanced metering infrastructure (AMI). The project also includes an extensive stakeholder engagement process.

ECo engaged Leidos Engineering to conduct a feasibility study and design for the proposed UDM. The project is characterized by four features:

1. Distribution automation (DA) systems[1];
    a. Monitoring & Control - enables real-time data acquisition and control of electric grid devices that are outside of the substation fence. These devices includes pole-top

[1] Language from "PUC UDM Statement of Work FINAL to E Co. 12142015 r1.pdf" developed by Leidos Engineering, LLC

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reclosers, pole-top load break switches, pad mounted switches and fault current indicators.

   b. Fault, Location, Isolation & Restoration – provides a capability to locate and isolate a fault, and restore power to the entire upstream section of the feeder and as much of the downstream feeder as possible.

   c. Real-Time Power Flow – provides capabilities to run power-flow studies utilizing telemetered real-time data. A network model of the system will be developed and system connectivity updated based on telemetered switch status data. In addition, load data will be used in power simulations to better allocate loads to each customer.

   d. Auto-Transfer – the functionality to transfer a substation to an alternative source when the main power source is lost. This function requires real-time monitoring and control of the system to make safe switching decisions that will be provided by the DA system.

2. Voltage/VAR management (VVM) systems;

   a. VVM system to be installed on PUC's 12.5 kV distribution grid.

   b. VVM solution is comprised of: Volt/VAR management software, load tap changing transformers, busbar regulators, pole-top voltage regulators and capacitor banks, phase balancing on recommended feeders, reconductoring on recommended feeders, 900 MHz wireless communication system (for pole-top regulators)

3. Eight (8) substation upgrades;

   a. Rebuilds at Substations 11, 16, 20 and 1 to include 10/13 MVA Load-Tap-Changing (LTC) transformers;

   b. Six (6) 10/13 MVA LTC transformer replacements at Substations 2, 18 and 19

   c. Two (2) busbar regulator installations at Substation 13.

4. Integration, and enhancement, of the existing AMI.

   a. Provide a robust Outage Management System (OMS),

   b. Enable enhanced CSR/Customer toolset that more efficiently manages AMI data.

   c. Provide improved operational analytics that integrate SCADA, AMI, CIS, OMS and GIS data for improved reporting and usage.

The substation upgrades will support the deployment of DA, VVM and AMI enhancements. Absent the UDM project, PUC would have to incur the costs of substation upgrades in the future per their asset management plan. As part of the UDM scope, ECo proposed to accelerate the work to upgrade the appropriate substations. It is assumed that these upgrades are required to support the full functionality of the UDM system.

As included in the ECo proposal, ECo will be responsible for all design and construction costs, in addition to some portions of maintenance, and replacement costs. In addition, ECo has proposed to provide project financing and contractual arrangements designed to ensure the continued operation of the project to a specified level of performance over the contract period. PUC would agree to pay a fixed monthly payment to ECo for the operating period of the contract. This contractual arrangement includes a performance management strategy intended to ensure that the performance of the UDM system meets all contract expectations and design specifications.

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The proposed UDM project is designed to improve system reliability, reduce customer bills, improve operating efficiency, and deliver generation and transmission capacity benefits to the provincial system. These benefits align with the objectives laid out in the Minister of Energy's Smart Grid Directive as well as PUC's strategic objectives.

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2. INFORMATION GAP ANALYSIS

This section provides details on the identification of gaps in information required for the Proponents to make an informed final decision on “go” versus “no go” for the UDM project.

2.1 Sources Reviewed

Navigant reviewed the following documents during the business case review:

1. Leidos BCA model
2. Reliability Statistics - METSCO
3. Distribution Load Forecast – METSCO
4. Ontario Energy Board Guidelines for Distribution System Planning
5. Infrastructure Ontario – Alternative Financing and Procurement
6. Infrastructure Ontario – Assessing Value for Money
7. ECo – UDM Project Bill Impact and CAPEX Offset Analysis
8. ECo – Cost Allocation & Evaluating Value of Risk-Transfer for UDM Project
9. Illume Advising - Customer Outreach Plan
10. ECo – PUC Board Brief
11. ECo – UDM Project Financial Analysis
12. Leidos – Technical Substantiation and Design Documents
13. Overview of Regulatory Framework and Rate-making process
14. Review of Project Costs for Smart Grid Project for PUC Distribution
15. UDM Project Review (Review of Leidos Technical Design documents)
16. Term sheet for the Provision of UDM Technology and Services to PUC Distribution Inc.
17. PUC Asset Management Plan via METSCO Energy Solutions
18. Parker Venture Management Inc. – Smart Energy Strategy

2.2 Information Gaps Identified

Navigant conducted extensive follow-up discussions with ECo, Leidos, and PUC to ensure that all available data was leveraged within this analysis. Navigant identified a number of information gaps that would be helpful in strengthening the confidence of the analysis. However, Navigant does not expect any of the gaps presented below to fundamentally change the final recommendations. These gaps include:

- **Customers’ willingness to pay for increased reliability** – the most significant benefit stream from this project is from reliability. Navigant used a Lawrence Berkeley National Laboratory (LBNL)[2] study to value the customer costs of outages. However, it is unknown what portion of those benefits PUC’s customers would be willing to pay for, as well as the portion of those benefits that OEB would allow to be recovered in rates.
- **Costs of capital for ECo** – ECo’s cost of capital is unknown. Thus, it is not possible to accurately break out the risk premium from the financing cost (see Section 4.3 for more details). What is

[2] Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States.* Updated January 2015.

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known however is that Eco's cost of capital would be higher than PUC's, and that this higher cost financing would be incorporated in the service fee payments to Eco over the term of the contract. PUC's cost of capital, or allowed return on capital invested is prescribed by the Ontario Energy Board.

- **Eco's willingness to explore alternative project arrangements** – ECo presented two project proposals. It is not clear to what extent ECo is willing to consider alternative project configurations and pricing structures. From preliminary discussions with ECo, it seems possible that ECo would be open to alternative arrangements that optimize the project from the Proponents perspective.

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3. PROJECT OPTIONS

Navigant analyzed the benefits, costs, and regulatory submission framework of two project options with different financing schemes compared to the baseline (i.e., business-as-usual) case:

1. ECo-funded & implemented
2. PUC-funded & implemented

In the ECo-funded option, ECo bears all of the risk associated with the project and thus charges a risk premium that is embedded within the monthly service fee. The risk premium includes 1) the contingency on the capital investment, 2) the performance guarantee, and 3) the cost of financing the project over the term of the contract.

In the PUC-funded option, PUC would arrange financing and would be exposed to all of the risks associated with the project. In the event of construction overruns or performance shortfalls, these costs would be borne by either PUC's ratepayers or shareholders.

For each project option, Navigant analyzed:

- Expected benefits by stream [*See Section 4.2*]
- Expected costs for each project option [*See Sections 4.3 and 4.4*]
- Customer-perspective impacts [*See Section 5.1*]
- Shareholder-perspective based on PUC cash flow analysis [*See Section 5.1*]
- Alternative regulatory treatments [*See Section 5.1*]

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4. BENEFIT-COST ANALYSIS

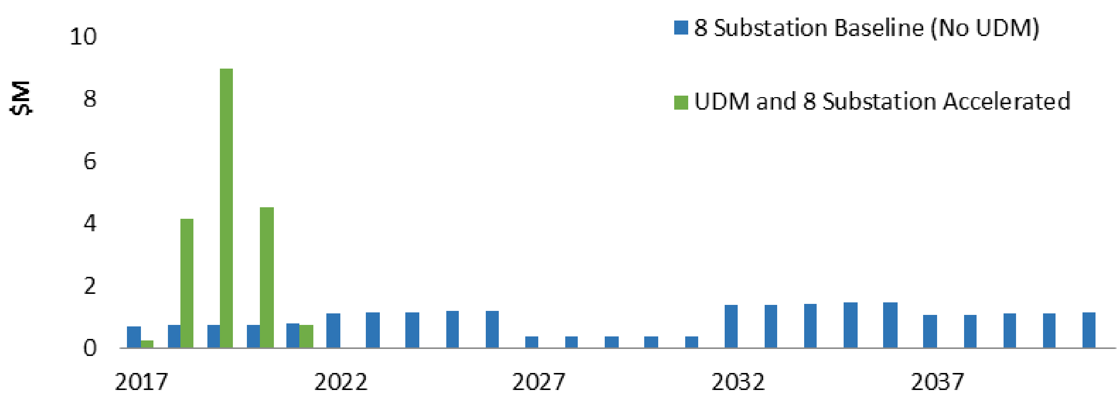
This section presents Navigant's analysis and findings with respect to the costs and benefits of each project option.

4.1 Baseline Analysis

This business case considers the implementation of the UDM relative to the baseline (i.e., business-as-usual case). Based on PUC's Long Range DS Plan[3], PUC would have upgraded eight (8) distribution substations and two (2) transmission substations from 2017 to 2041 absent of the UDM project.

It is assumed that in order to implement the UDM project, the distribution substations upgrades would need to occur upfront concurrent with the UDM construction period. This concept is illustrated in Figure 1, where the blue bars represent substation costs in the baseline case, and the green bars represent the front-loaded substation costs required for UDM implementation.

Figure 1. Substation Upgrades With and Without UDM



The baseline also assumes that no incremental automation is implemented by PUC relative to what exists today. Thus, PUC would go forward with their asset replacement plan while maintaining the current capabilities of their system.

4.2 Benefits Analysis

Navigant conducted an analysis of the benefits associated with the UDM project relative to the baseline case. It is assumed that each project option (i.e., ECo-Funded & Implemented, PUC-Funded & Implemented) deploys a UDM project with identical specifications. Also in both cases, the benefits are discounted at the societal discount rate of 5%[4]. It is important to note that the benefit-cost analyses

[3] 0201.12 – 2016 Projection for Distribution Capital Engineering 2016-03-15.xlsx

[4] Based on 2010 analysis conducted here: http://www.peterspiro.com/Social_Discount_Rate.pdf

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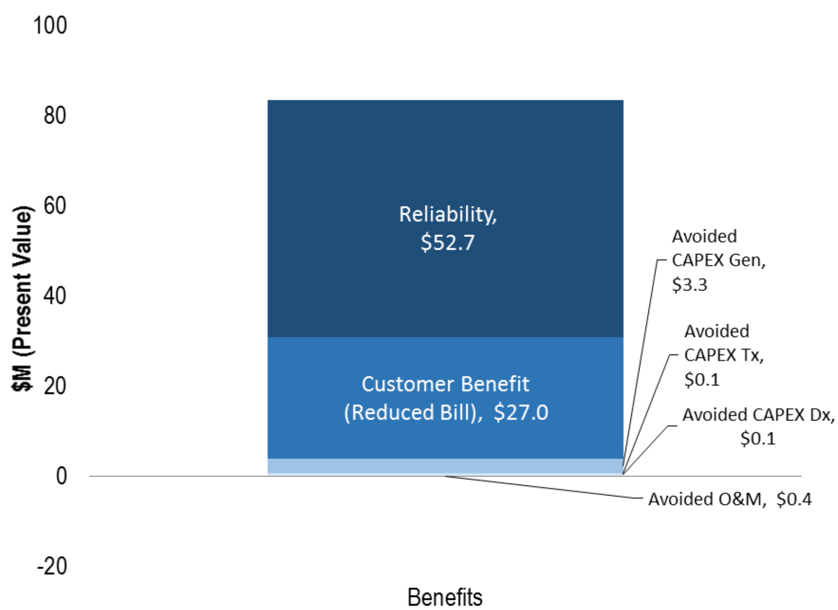
conducted below are highly dependent on the time period over which the project is analyzed. Although the ECo proposal includes 20 years of service fee payments, the benefits are expected to be realized over the lifetime of the assets. For the purposes of this analysis, Navigant assumes that hardware assets have a lifetime of 40 years, while software assets have a useful life of 20 years, requiring re-investment by PUC in year 21. The benefits in each project option are expected to be identical based on the assumption that the same project is implemented in each option.

Figure 2 presents the expected benefits from each category over a 40 year time period. As seen in the figure, the two largest benefit streams are reliability and reduced bill. Navigant focused our review on these two benefit streams due to their significance relative to the other benefits. We also conducted a review of the other benefit streams, summarized below.

Figure 2. Present Value of UDM Project Benefits (40 Years)



Reliability

As seen in Figure 2 above, the majority of benefits are due to increased reliability from Fault Location, Isolation, and Service Restoration (FLIR) functionality enabled by DA. Over 40 years, customers in Sault Ste. Marie are expected to accrue approximately $52.7M in present value of reliability benefits. These benefits are due to two factors: (1) reduced number of outages (i.e., SAIFI) and (2) reduced length of outages (i.e., CAIDI).

Previous estimates of reliability benefits used a Canada-based study from 1991[5]. Navigant updated the benefits calculation using a recent US-based LBNL study[6] which was published in 2015. Navigant

[5] G. Tollefson, R. Billinton (Fellow), G. Wacker (Member), E. Chan, and J. Aweya. *A Canadian Customer Survey to Assess Power System Reliability Worth*. February 1991.

[6] Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States.* Updated January 2015.

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believes that the LBNL study provides a more accurate picture of the value of reliability because it is more recent and contains a larger sample size. As a result of using the more recent LBNL study rather than the older Canada-based study, the estimates of reliability benefits did not significantly change, but Navigant has higher confidence in the accuracy of the estimate.

Table 1 summarizes the cost per 60 minute outage of the average customer by class per the LBNL study.

Table 1. LBNL Study Customer Outage Costs

LBNL Customer Class[7]	Cost per Customer per 60 Minute Outage ($CAD[8])
Medium & Large C&I (> 50,000 Annual kWh)	$22,737
Small C&I (< 50,000 Annual kWh)	$826
Residential	$6.50

It is important to note that the "Small C&I" customer group characterized in the LBNL Study had an average annual consumption of 19,000 kWh, and the "Medium & Large C&I" customer group had an average annual consumption of 7,100,000 kWh. When comparing to PUC's customers, the average "GS < 50kW" customer consumes 30,000 kWh, and the average "GS >50kW" customer consumes 800,000 kWh. To avoid overvaluing reliability for the larger commercial customers, Navigant assigned all "GS >50kW" customers, with the exception of five[9], to the "Small C&I" customer class to apply the LBNL valuation. Residential customers are characterized closely between PUC and the LBMP Study, where the average residential customer consumes 11,300 kWh and 13,300 kWh per year, respectively. As a result of the re-mapping of customers as described above, the reliability benefit identified in this business case is a conservative estimate.

Previous estimates of reliability also understated the baseline reliability metrics. This is because PUC considers 2011 as an outlier year with an abnormally high number of outages. With the baseline reliability metrics mischaracterized in this manner, the benefits due to increased reliability were slightly overstated. Navigant adjusted the reliability baseline by removing 2011 from the analysis, causing the baseline average System Average Interruption Frequency Index (SAIFI[10]) and System Average Interruption Duration Index (SAIDI[11]) to be reduced by approximately 4% and 1%, respectively. This in turn caused about a 4% reduction in the calculated benefits.

Navigant reviewed the reliability impacts that were previously estimated by Leidos due to the implementation of the DA system. On average it is assumed that the FLIR functionality enabled by DA results in the following impacts to reliability metrics:

- SAIFI reduced by 37%

[7] LBNL's study splits customer classes into residential (13,351 kWh of average annual consumption), small C&I (under 50,000 annual kWh, with 19,214 kWh of average annual consumption), and medium and large C&I (over 50,000 annual kWh, with 7,140,501 kWh of average annual consumption)

[8] CAD / USD conversion rate of 1.277 was used based on the BMO Canadian Economic Outlook located here: http://www.bmonesbittburns.com/economics/forecast/ca/cdamodel.pdf

[9] Per PUC's reply to a Navigant industrial survey indicating 5 customers with demand over 1 MW.

[10] SAIFI is the number of average times that a system customer experience an outage in a given time period (e.g., year).

[11] SAIDI measures the total duration of interruption for the average customer during a given time period (e.g., year).

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- SAIDI reduced by 46%
- Customer Average Interruption Duration Index (CAIDI[12]) reduced by 16%

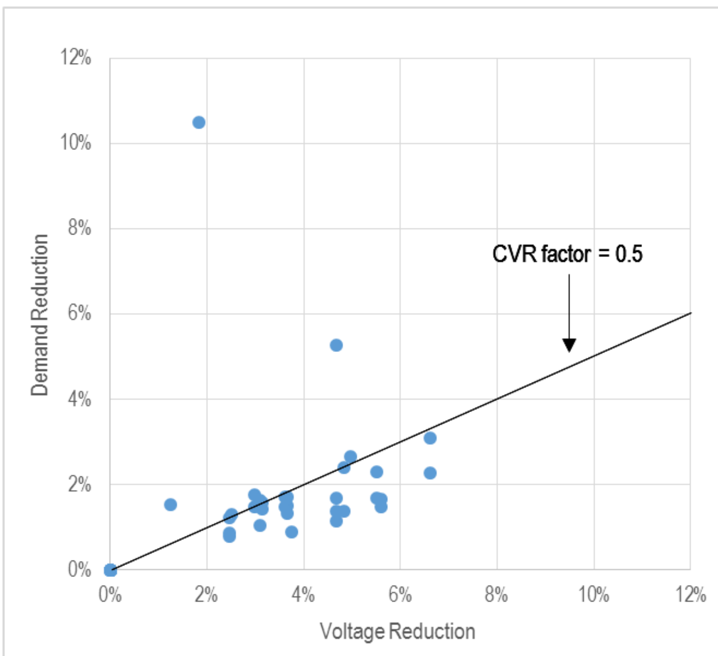
Navigant considers these impacts to be reasonable based on the industry data available on FLIR[13].

These impacts result in an average annual reduction of 34,000 customer-interruptions per year and an average reduction in customer minutes of interruption (CMI) of 2.1 million minutes.

Customer Benefit (Reduced Bill)

The second largest benefit stream from the UDM implementation is reduced customer bills due to reduced voltage delivered to customers from the VVM system, estimated at $27.0M of present value benefits over a 40 year analysis horizon. The analysis conducted by Leidos assumed an average demand reduction of approximately 1.5% from the VVO implementation due to an average of 3% reduction in voltage, resulting in a CVR factor[14] of 0.5, as seen in Figure 3 below. Each blue dot represents the savings estimate due to VVO implementation on a distribution circuit.

Figure 3. Feeder-Level VVO Savings Estimates



Source: Leidos Analysis

This 1.5% average demand reduction results in a 1.5% average reduction in customer bills. Navigant identified an outlier located at the top left of the graph at ~2% voltage reduction and ~10% demand

[12] CAIDI represents the average time to restore service to a customer; CAIDI = SAIDI / SAIFI.

[13] See http://www.energy.ca.gov/2007publications/CEC-500-2007-103/CEC-500-2007-103.PDF for more details on FLIR impacts.

[14] CVR Factor = Demand Reduction / Voltage Reduction

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reduction, but determine that this data point had a minute effect on the analysis. Navigant considers this estimate reasonable as a preliminary estimate, given the industry data available[15].

Avoided CAPEX Generator

The avoided generation CAPEX benefit was estimated to be $3.3M present value over a 40 year span. This is a provincial benefit resulting from reduced system load at the generator due to the implementation of VVO, allowing the avoidance or deference of investments to add new generation capacity. This benefit is calculated by estimating the coincident peak load impact (in kW) and multiplying by the avoided cost of generation (in $/kW-yr). For this calculation, it is assumed that the avoided cost of generation capacity is $133.10/kW-yr.

Avoided CAPEX Transmission

The avoided transmission CAPEX benefit was estimated to be $0.1M present value over a 40 year span. This is provincial benefit resulting from reduced system load on the transmission system due to the implementation of VVO, allowing the transmission utility to avoid or defer investments in upgrading or reinforcing elements of the transmission system. This benefit is calculated by estimating the coincident peak load impact on the transmission system (in kW) and multiplying by the avoided cost of transmission (in $/kW-yr). For this calculation, the assumed avoided cost of transmission capacity is $3.40/kW-yr.

Avoided CAPEX Distribution

The avoided distribution CAPEX benefit was estimated to be $0.1M present value over a 40 year span. This is a benefit accrued to PUC resulting from reduced system load on the distribution system due to the implementation of VVO, allowing the PUC to avoid or defer investments in upgrading or reinforcing elements of the distribution system. This benefit is calculated by estimating the coincident peak load impact on the distribution system (in kW) and multiplying by the avoided cost of distribution (in $/kW-yr). For this calculation, it is assumed that the avoided cost of distribution capacity is $4.30/kW-yr.

Avoided O&M

The Avoided O&M benefit was estimated to be $0.4M present value over a 40 year span. The majority of this benefit stream comes from avoided overtime spent by restoration crews in order to restore faults, due to the avoided outages from the DA system. It is assumed that 50% of the restoration time occurs during crew overtime hours, and during that time restoration crew cost $500/hour.

Revenue Impact

The revenue impact benefit was minimal over 40 years. This benefit was determined by comparing the sum of the electric charges, distribution charges, and loss charges for each customer class (i.e., residential, GS < 50kW, GS > 50 kW) before and after the implementation of the VVM system. The energy charge differential was calculated using an average time-of-use (TOU) rate for each customer class. Each tariff was forecasted to be constant (with inflation) going into the future.

Socio-Economic Benefits

Navigant identified the following socio-economic benefits due to the UDM project. Also included in this list are energy-related benefits that were not quantified in this analysis, but are expected to produce value.

- Energy Center of Excellence possibly moved to SSM

[15] See https://www.smartgrid.gov/files/VVO_Report_-_Final.pdf for a summary of United States Smart Grid Investment Grant (US SGIG) VVO project results.

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- Increased number of jobs
- Future opportunities to incorporate more renewables without sacrificing reliability
- Increased ability to control customer loads, such as hot water heaters, to reduce customer energy consumption at peak demand times.
- Future ability to integrate electric vehicle (EV) charging stations into the distribution system
- Future ability to develop and connect Combined Heat & Power (CHP) projects and other forms of thermal or electrical storage systems at the residential, neighborhood or community level.
- Applications may be developed to take better advantage of existing smart meter data so as to provide Conservation and Demand Management (CDM) opportunities for customers and to integrate the AMI with an existing Geographic Information System (GIS), potentially to develop an Outage Management System (OMS).

Payments in Lieu (PILs) of Corporate Income Tax
There may be some reduction to PILs that are associated with the transfer of UDM assets to PUCs books that have not been quantified in this analysis.

4.3 Cost Analysis for ECo-Funded & Implemented UDM Option

Navigant developed a benefit-cost analysis framework to assess the economic viability of the incremental work associated with the ECo-Funded & Implemented UDM project and eight substation rebuild. The figures below compare the cost and benefit streams of the project over a 20 year and 40 year period. Furthermore, Navigant has assessed the capital and operations costs to ECo’s build out in the Leidos proprietary model, and developed an estimate for the "risk premium" associated with ECo's performance guarantee. This risk premium includes capital and O&M risks as well as financing costs associated with the capital investment of the project.

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Figure 4. Net Present Value (20 years) Costs and Benefits of ECo-funded UDM

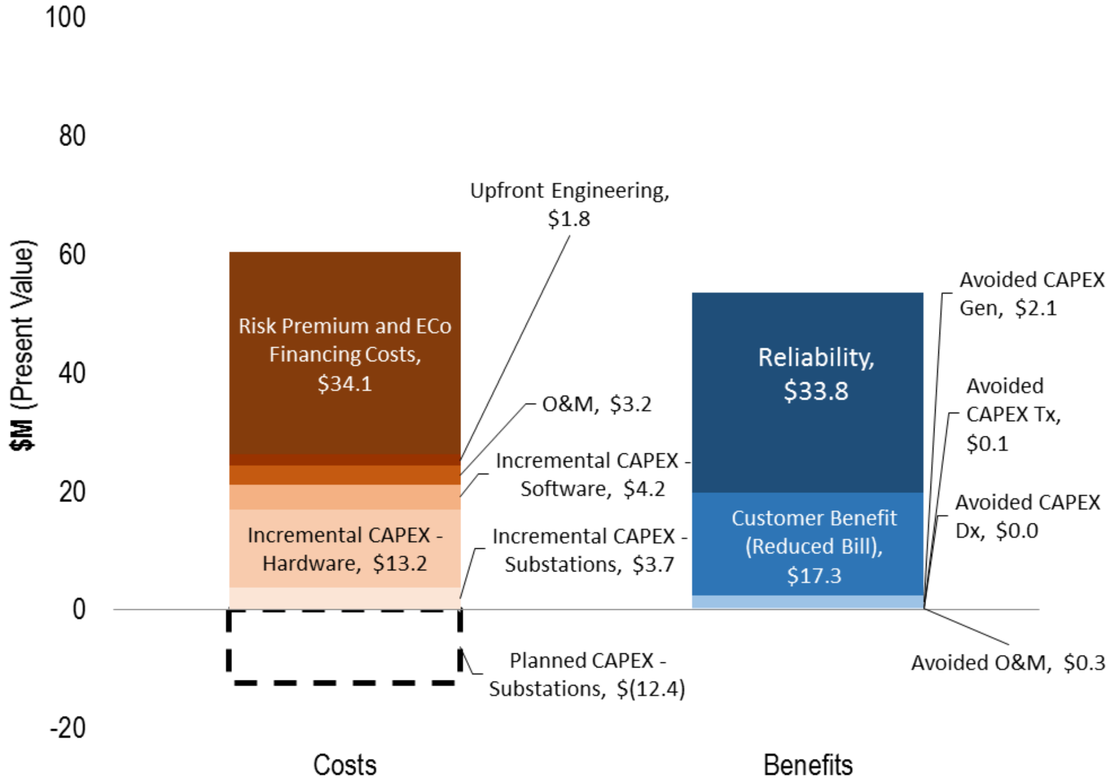

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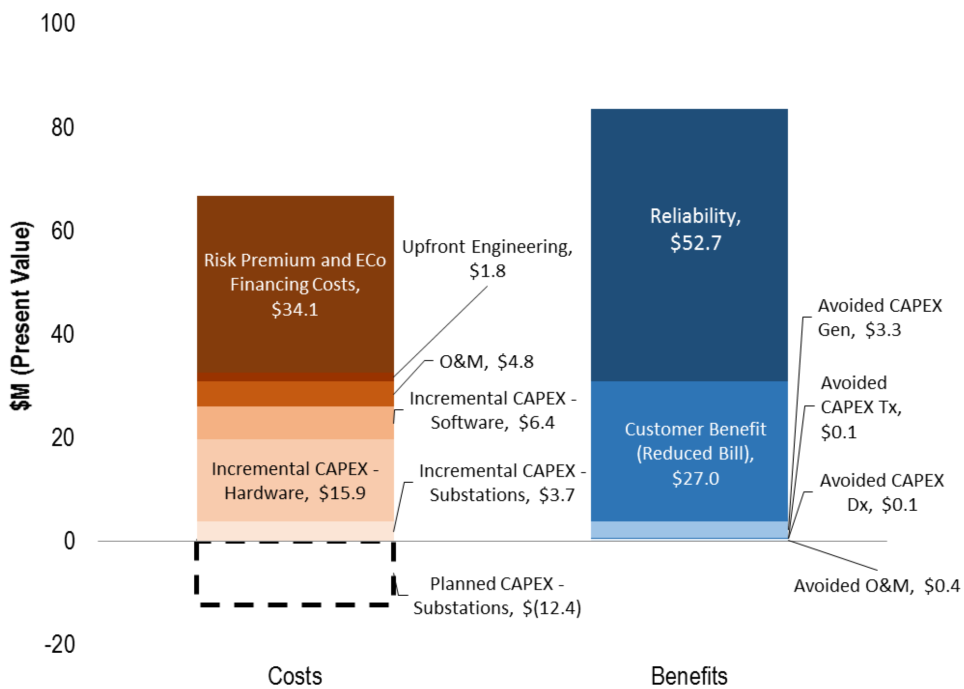
Figure 5. Net Present Value (40 years) Costs and Benefits of ECo-funded UDM



The incremental CAPEX components built out in the above are referenced from the Leidos Proprietary Model and from ECo sources. Incremental CAPEX components are assumed to include all UDM related capital costs in the referenced model, as well as the substation costs which are incremental relative to the baseline assumption (see Section 4.1). The Upfront Engineering cost is an estimate of the capital cost incurred by ECo in order to accomplish the 30% project design work that has occurred to this point in time. The planned substation CAPEX components is referenced from PUC's Long Range DS Plan[16]. The incremental substation costs are due to the time value of money related to the accelerated schedule (3 years vs. 40 years) per PUC's Distribution System Plan, as well as additional functionality of the substations by installing load tap changer regulators (versus planned busbank regulating devices in the baseline case).

The Risk Premium and ECo Financing Costs category is calculated by the difference between the present value of the payment stream to ECo ($5.832M annually beginning at project commissioning for 20 years, escalating at 2% annually)[17] and the present value of the incremental CAPEX. Both the payment stream and the cost streams were discounted at the aforementioned 5% societal discount rate.

Costs are assessed in a 20 year term in
Figure 4 and a 40 year term in Figure **5.** Incremental capital expenditure on software increases from Figure 4 to Figure 5 due to an assumed reinvestment to mitigate for end of useful life of assets. Furthermore, O&M activities are extended until the end of year 40 to maintain proper operation of the

[16] 0201.12 – 2016 Projection for Distribution Capital Engineering 2016-03-15.xlsx

[17] PUC Boards Briefing – UDM Project. July 21, 2015. ECo.

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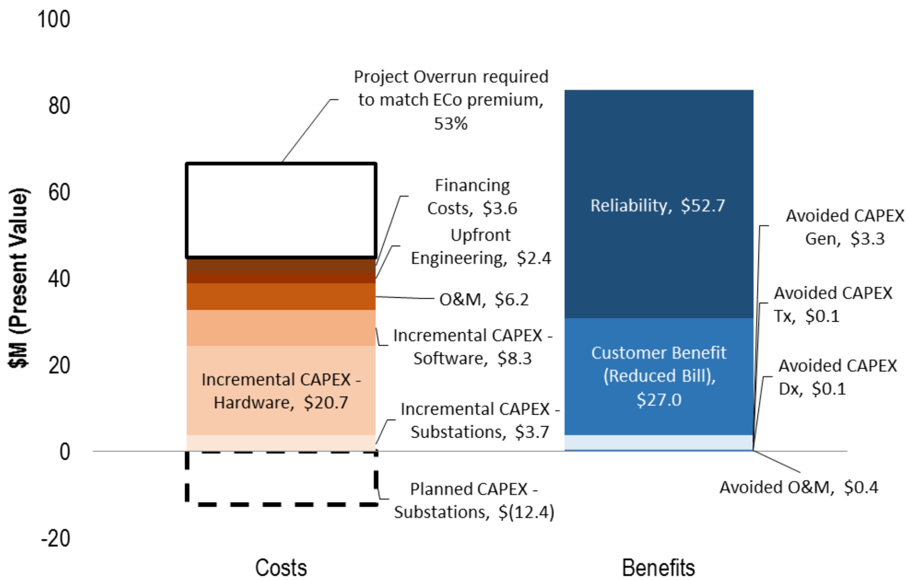
UDM assets and extend the period during which UDM benefits are realized. It is assumed that hardware assets have a 40 year useful life. Thus, in the 20 year term analysis, we assume the hardware has a residual value based on the net present value of its depreciated value at 20 year which reduces the effective cost.

4.4 Cost Analysis for PUC-Funded & Implemented UDM Option

Navigant has also estimated the benefits and costs of the UDM work under a scenario where the PUC undertakes the financing and implementing of the project. This option was developed with a 40 year outlook, assuming a reinvestment in software in year 21 (similar to the 40 year assessment of the option presented in Section 4.3). Navigant has estimated the risk that may exist for the PUC due to unfamiliarity with smart grid design and operation as 30% of all project capital and operations costs (inclusive of development risk which is estimated at 3-5% of the 30% contingency). Furthermore, financing costs were estimated by subtracting the project costs from the incremental revenue requirements due to the implementation of the UDM.

Figure 6. Net-Present Value (40 years) Costs and Benefits of PUC Build



The total construction, operations, and development risk, as well as upfront engineering, legal and stakeholder engagement costs required to match the total costs of the ECo proposal are shown in Figure **6**. Navigant has calculated that the total cost of these streams would need to equal 53% of ECo estimated capital and operations costs. All UDM technical project-related assumptions in the ECo-funded and implemented case apply to Figure 6. All costs and benefits presented in Figure 6 are present values, calculated using the same 5% societal discount rate used in previous sections.

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4.5 Benefit-Cost Analysis Conclusions

From the analysis presented above, the key conclusion is that the benefit-cost ratio of the proposed project including the risk premium and financing costs is strong (i.e., 1.31, 87.3M of benefits vs. 66.8M of costs) when considered over a 40 year time horizon. Based on analysis of ECo's proposed offer, about half of the cost is due to the risk premium and financing costs. It is also important to note that a significant portion of the expected benefits are due to increased reliability, and it is assumed that there is a 1:1 attribution of reliability benefits to cost savings for the PUC customer (i.e., customers' willingness to pay for reliability). Recommendations to improve the project's cost-effectiveness are provided in Section 6.

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5. PROJECT DELIVERY AND FINANCING OPTIONS

5.1 Project Options Analyzed

Navigant analyzed two ECo-Funded & Implemented project options, and a third option for the PUC-funded & Implemented project, as described below.

ECo-funded & Implemented option:

1. This is ECo's current proposal. Actual capital expenditures are rate based, actual O&M is passed through as an expense, and the risk premium is assumed to not be recoverable through rates and would be borne by the shareholder. **(ECo Funded – Partial Recovery)**
2. The full amount of the ECo payments are assumed to be recoverable through distribution rates and are treated as a pass-through as O&M[18] expense. **(ECo Funded – Full Recovery)**

PUC-funded & Implemented option:

3. The capital and operating costs are assumed to be 30% higher than in options 1 and 2. Actual capital expenditures including contingency are rate based, actual O&M is passed through as an expense. **(PUC Funded – Full Recovery)**

Navigant has evaluated the project options from three perspectives:

- ***PUC Revenue Requirement*** – evaluates the incremental change in revenue requirement for the distribution component of electricity rates.
- ***PUC Net Customer Impact*** – evaluates the incremental change in the overall costs billed by PUC to its customers. This includes the distribution component of rates as described above, and any electricity benefits that the UDM project would provide, but does not include reliability or any other benefits not captured on the customer electricity bill.
- ***PUC Shareholder Cash Flows*** – evaluates the incremental change in shareholder cash flows.

The evaluations are completed on an incremental basis relative to a base case scenario which assumes no UDM project and a status quo substation replacement program as described in Section 4.1. The evaluation assumes useful life of 40 years for hardware and substation assets, and 20 years for software assets, with a reinvestment in software systems in year 21.

Figure 7 below presents the incremental change in distribution revenue requirement for the three project structures. The largest increase in revenue requirement and subsequent increase in the distribution component of rates occurs for the ECo-Funded – Full Recovery option where the entire service fee is passed through to customer as a cost of service expense over the 20 year term of the contract. While it is unlikely the OEB would approve the full recovery of the Eco payment through rates, this option presents the most extreme outcome and largest rate impact.

[18] It is of Navigant's opinion that this approach is unlikely to gain OEB approval.

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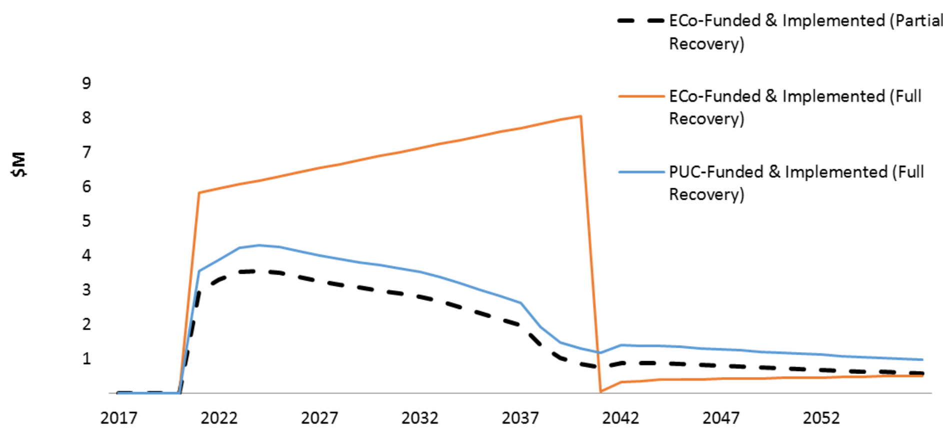
The impact on distribution revenue requirement is significantly lower for both the ECo-Funded – Partial Recovery option and the PUC-Funded – Full Recovery option due to two factors. First, the risk premium cost component has been excluded for recovery through PUC's distribution rates, and second, the capital portion of the UDM project costs have been recovered over the entire 40 year life of the assets, instead of a compressed time period of only 20 years as is the case for the ECo-Funded – Full Recovery option.

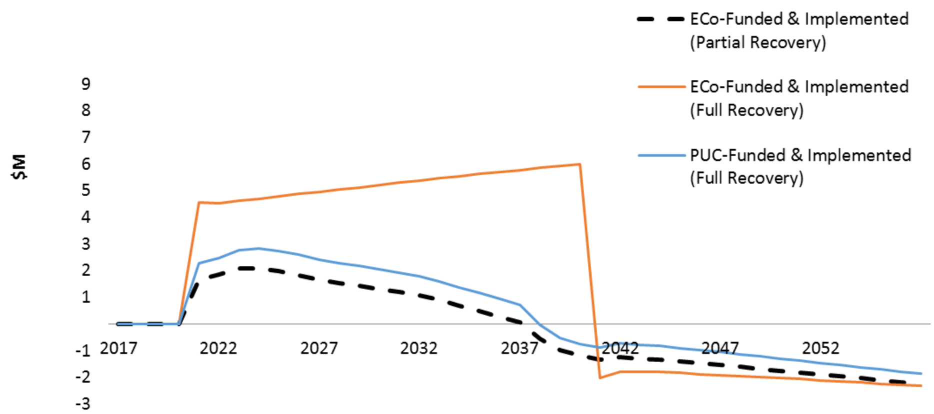
The revenue requirement associated with the PUC-Funded – Full Recovery option is higher than the ECo-Funded – Partial Recovery option because the UDM capital costs are conservatively assumed to be 30% higher if implemented by the PUC instead of by ECo. This is partially offset by a lower cost of capital for the PUC compared to ECo. As noted above, the ECo-Funded – Partial Recovery option assumes the risk premium is not recoverable through the PUC's distribution rates and is borne by the shareholder, and the costs of the UDM assets are recovered through rates over their entire 40 year life.

Figure 7. Revenue Requirement Impact of Project Options



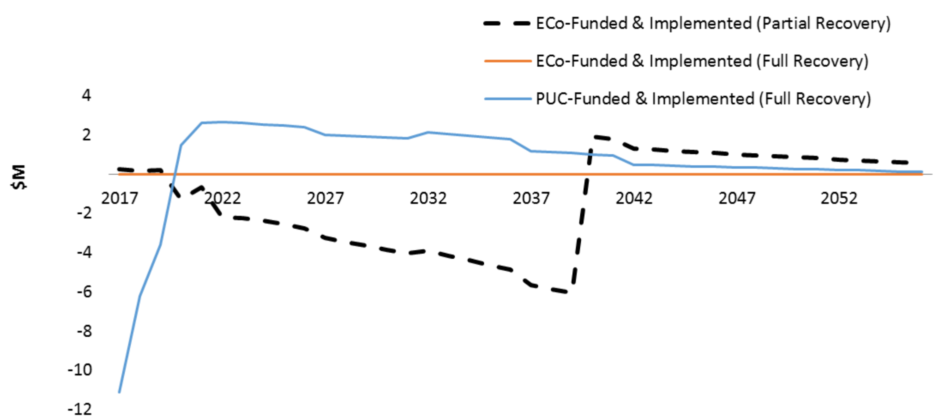
Net customer impact – shown in Figure 8 – is calculated as the sum of the calculated revenue requirement and the benefits of the UDM project that directly impact the PUC customer bill. These benefits include 1) reduced electricity consumption (from a reduction in volume of energy delivered due to VVM technology), and 2) distribution, transmission and generation capacity deferrals, which represent a reduction in system costs that will flow through to customer. Reliability benefits have no impact on customer bills, and have not been included in Figure 8. Given that the distribution system cost increases are greater than the direct customer benefits, the result is a net increase in PUC customer costs.

Figure 8. Net Customer Impact of Project Options[19]



The PUC shareholder cash flow impacts for the three project structures are provided in Figure 9.

Figure 9. PUC Shareholder Cash Flow Impact of Project Options[20]



The ECo-Funded – Partial Recovery option shows no change in shareholder cash flows during construction through 2020, followed by negative cash flows to 2040. The negative cash flows are due to the combined effect of 1) an increase in net income attributable to the capital cost of the UDM project being included in the PUC's rate-base, and 2) the annually increasing payments to ECo. Since the payments to ECo are greater than the increase in net income, the cash flows to the PUC shareholder are negative during the first 20 years of the project life. Shareholder cash flows become positive after the ECo service fees are terminated and the remaining undepreciated value of the UDM assets in rate base continue to earn the allowed rate of return.

There is no impact to shareholder cash flows when the Eco service fees are treated as an O&M expense in the ECo-Funded – Full Recovery option, since the risk premium is assumed to be recovered through customer rates as a cost of service. While this option has been included to present a worst case customer rate impact, it is Navigant's view that this option is unlikely to be approved by the OEB. In the

[19] This figure shows the revenue requirement impact less the direct customer benefits, in particular avoided energy.

[20] The NPV of the ECo-Funded – Partial Recovery option is $-28.5M. The NPV of the PUC-Funded – Full Recovery option is $3.9M

event that any costs are disallowed for recovery through customer rates they would be at the expense of the PUC shareholder.

The shareholder cash flows for the PUC-Funded – Full Recovery option represent those for a typical utility investment. Shareholder cash flows are negative during the construction period, followed by positive cash flows once the project is operational and the assets earn the allowed rate of return. The cash flows decrease over time as the assets are depreciated.

5.2 Customer Bill Impacts

For each of the regulatory treatments outlined above, Navigant examined the rudimentary impacts to the individual PUC customer due to the implementation of the UDM project. The net present values of the annual total bill impacts presented in Figure 8 were divided by the number of PUC customers to arrive at an average annual customer bill impact, and also by post-project customer kWh consumption to arrive at an average annual distribution rate impact. Based on information from PUC, the customer base and consumption in PUC's service territory is not expected to increase significantly over the analysis period. The results are tabulated in
Figure 10 and shown graphically in Figures 11 and 12.

Figure 10. Average Incremental Customer Bill Impacts due to UDM

	20-yr Outlook		40-yr Outlook	
Treatment Option	**Annual ΔBill ($)**	**Avg ΔRate (¢/kWh)**	**Annual ΔBill ($)**	**Avg ΔRate (¢/kWh)**
ECo-Funded & Implemented (Partial Recovery)	+$16.51	+0.08¢	+$2.76	+0.01¢
ECo-Funded & Implemented (Full Recovery)	+$80.22	+0.39¢	+$34.11	+0.17¢
PUC-Funded & Implemented (Full Recovery)	+$26.47	+0.13¢	+$8.94	+0.04¢

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Figure 11. Average Bill Increase by Project Option

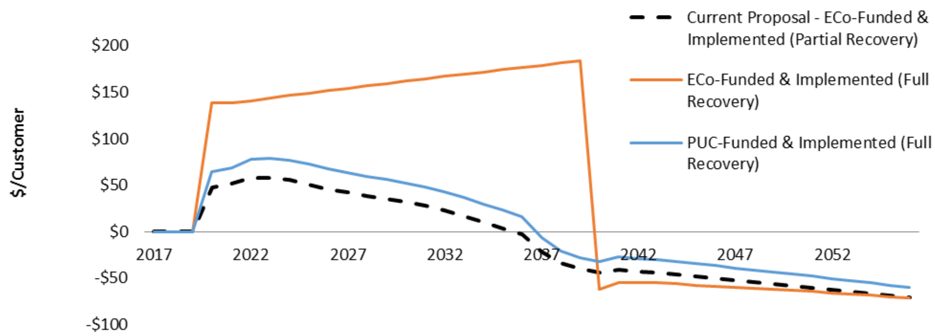
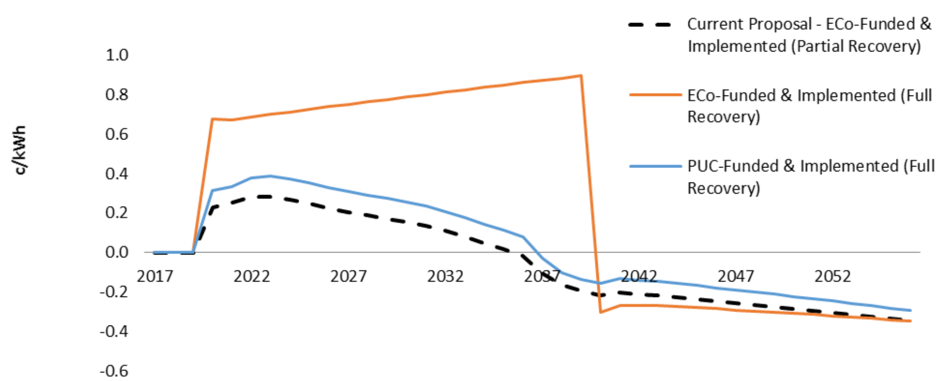


Figure 12. Average Distribution Rate Increase by Project Option



The above is consistent with the total customer bill impact analysis conclusions. The most impactful implementation of the UDM project with regards to customer bills and rates is the ECo-Funded & Implemented structure, where all ECo payments are fully recovered through rates.

It is also notable that the 20 year outlook for customers is significantly more costly than the 40 year outlook. Due to the current nature of the implementation schedule, the majority of the capital costs related to construction and implementation of the UDM are recovered in this time frame, which results in the noted step change in rates. The average outlook over 40 years is more favorable, as more of the benefits of the UDM are realized versus the revenue required from the customer to recover ongoing operation and maintenance costs.

5.3 Regulatory Considerations

The ability to recover the costs of the UDM project though distribution rates is a key factor in the evaluation of the project and ultimately the decision of whether or not to proceed. To the extent that any costs are disallowed for recovery through rates, the difference will be borne by PUC shareholders who would then earn less than the allowed rate of return, and potentially compromise PUC's ability to raise funds in the future. This section summarizes some of the regulatory aspects of the project to be considered when seeking approval from the OEB for the recovery of costs through rates.

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5.3.1 Customer Rate Impact

The OEB's primary objective is to protect the interest of ratepayers and will seek to both minimize rates and avoid "rate shock". To the extent possible the OEB look for a paced investment strategy that will smooth out rate increases over a number of years instead of a large rate increase in one year. The distributor may be required to submit a rate mitigation plan if a rate increase exceeds a threshold (~10%).

5.3.2 Customer Need

As part of the justification for a capital investment or project that results in a customer rate increase, the OEB may require evidence that the benefits of the project are aligned with the customer needs and there is a willingness of the customers to pay the increased rates. This is applicable for the UDM project where a significant portion of the projects justification is related to reliability benefits which are not quantified as part of the PUC customer bill.

5.3.3 Cost of Capital

The rate of return that distributors are allowed to earn on capital investments is based on the deemed cost of capital as prescribed by the OEB from time to time. Any returns exceeding the allowed rate of return would be disallowed by the OEB for recovery through distribution rates. It is Navigant's view that the Eco proposal, and more specifically the risk premium, has an embedded cost of capital that exceeds the OEB allowed rate of return and would not be eligible for recovery through distribution rates.

5.3.4 Asset Recovery Period

A cost of service rate making principle is to recover the costs of an asset when it becomes used and useful. An extension of this principle is that the costs should be recovered over a time period that matches the life of the asset in order to ensure that the customers paying the costs are also receiving the benefits associated with the asset. With this in mind, there is a disconnect with the Eco proposal which has a service fee term of 20 years for assets with a 40 year useful life. From a regulatory perspective there is an argument that customers in the first 20 year who pay the Eco service fee will be subsidizing customers who do not pay the service fee after year 20, but still benefits from these assets.

5.3.5 Recovery of Undepreciated Sub-station Assets

The Eco proposal accelerates the replacement and or refurbishment for a number of PUS's existing sub-stations. Consideration should be given to minimizing any undepreciated value of these assets and recovering the costs through rates in order to minimize any negative impact to shareholder returns. This includes ensuring that the assets are fully depreciated or requesting approval though a rate rider or alternative regulatory mechanism.

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6. CONCLUSIONS & RECOMMENDATIONS

6.1 Conclusions

Considered over the 40 year life of the primary assets, the core UDM project – comprising the capital costs for construction and ongoing costs for operation – provides a strong benefit-cost ratio from a customer perspective. Even with a 30% contingency on capital and operating costs, and including PUC financing costs, the benefit / cost ratio for the project is forecast to be 1.3 / 1 based on what Navigant believes are conservative estimates of the benefits. Furthermore, there are several socio-economic benefits and other energy-related benefits expected to be realized as a direct result of the UDM project that are not currently included in Navigant's estimate of the project benefits.

It is important to note, however, that reliability benefits comprise more than two-thirds of the project's expected benefits. It is also unclear the degree to which customers are willing to pay more than they would otherwise pay for these reliability benefits. Put another way, it is unclear if customers are willing to pay $1 more in rates to get $1 in reliability benefits. Given this uncertainty, Navigant believes that any regulatory submission by the PUC related to the UDM program would need to reflect a significant discount to the reliability benefits.

The project financing and implementation approach is not expected to impact the benefits, but it will impact costs. Specifically, based on the information available, Navigant does not believe that ECo's proposed financing structure is an efficient way to finance the UDM project. As currently proposed, the ECo-Funded – Full Recovery option would result in a large step-change in customer bills and is likely to pose significant regulatory challenges for the PUC due to the magnitude of the bill impacts. Assuming the full payment for the UDM project as currently proposed by ECo cannot be recovered through rates, then the financing approach devolves to the ECo-Funded – Partial Recovery option with some portion of the ECo payments being borne by the shareholder. As stated, there are several socio-economic benefits and other energy-related benefits that are expected to flow from the UDM project, but how much the shareholder is willing to pay for the UDM project is unknown. Shareholders would also be foregoing an opportunity to invest in infrastructure and earn the allowed return under ECo's proposed financing structure.

The remaining project financing and implementation approach, the PUC-Funded – Full Recovery option, would require some form of investment by the shareholder – either through reduced dividends or an equity injection – that would provide a return to the shareholder. This approach would also result in a significant step-change in customer costs creating similar regulatory challenges as above, but the all-in costs are likely to be lower for this option than the other two options. With this lower cost also comes more risk, since PUC would be taking the construction and operating risks associated with the project instead of ECo.

6.2 Recommendations & Next Steps

Unless the shareholder is willing to pay the portion of the ECo payments that are not recoverable through rates in return for the benefits realized, Navigant does not believe ECo's current proposal is sufficiently attractive – from a regulatory and customer perspective – to pursue. However, the core UDM project has

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a strong benefit-cost ratio and both the PUC and ECo have invested a significant amount of time and effort to shape and design the UDM project.

Rather than dismiss ECo's proposal, Navigant recommends that the Proponents explore alternative project options with ECo that might better fit within the PUC's current regulatory framework and the shareholder's willingness to pay. Ideally, these discussions would be undertaken on an "open book" basis with ECo with a view to better understanding of the various components underlying ECo's proposed fees, particularly the financing costs and risk premium/performance guarantee.

One possible option that could preserve the key benefits of the project, but with a lower impact on PUC's customers and shareholders, would involve:

- ECo designing, building and operating the project and providing performance guarantees, in exchange for an up-front payment and smaller ongoing payments to cover operational costs, and
- The PUC financing the up-front payment and recovering the cost through rate-base. Alternatively, it may be possible for ECo to finance the project at PUC's cost of capital.

Further options and variations to explore with ECo would include:

- Shaping ECo's payments over time to reduce the present value of the cost to customers, and
- Slowing the pace of investments such that they are undertaken over a longer time period.

Additionally, the Proponents could explore smart grid grants from the federal and provincial governments to cover some of the cost of the UDM project.

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7. APPENDIX

A.1 Glossary

Abbreviation	Description
AMI	Advanced Metering Infrastructure
C&I	Commercial & Industrial
CAIDI	Customer Average Interruption Duration Index
CAPEX	Capital Expenditures
DA	Distribution Automation
FLIR	Fault Location, Isolation, and Restoration
LBNL	Lawrence Berkeley National Laboratory
O&M	Operations & Maintenance
OEB	Ontario Energy Board
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TOU	Time-of-use rate
UDM	Utility Distribution Microgrid
VVM	Volt-Var Management
VVO	Volt-Var Optimization

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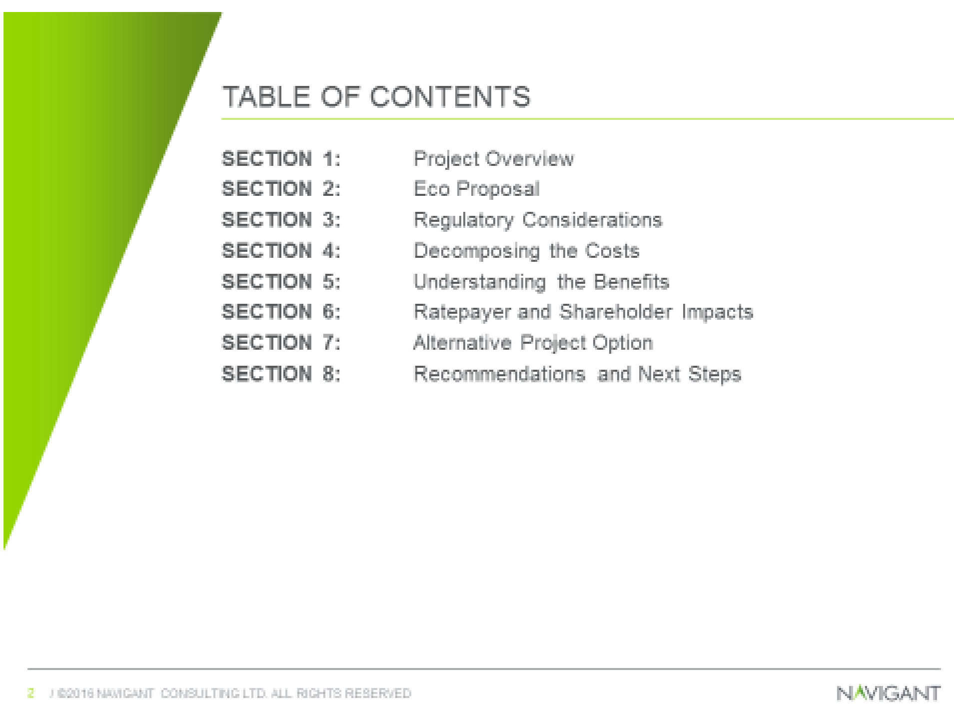
A.2 Board Presentation 5/23/2016



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PROJECT OVERVIEW

- Distribution Automation (DA)
- Voltage/VAR Management (VVM)
- Incremental Substation Upgrades
- AMI Integration and Enhancements

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PROJECT OVERVIEW

- Navigant's was retained to:
  - Review available documentation and identify gaps in information required to make an informed final decision. ✓
  - Review the existing business case and benefit-cost analyses performed and assess the major elements of the project in regards for value for money. ✓
  - Develop a recommended accounting framework for submission in an OEB rate application to meet regulatory requirements and long term needs (i.e., rate sensitivity and reliability) of electricity consumers in Sault Ste. Marie. ✓
  - Identify and outline possible financing or equity partnership alternatives or opportunities to carry out the project. ✓
  - Develop a final recommendation and present final report. ✓

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ECO PROPOSAL

- ECo designs, builds, finances, and operates the UDM, providing cost and performance guarantees
- Ownership of the UDM assets transfers to PUC at commissioning in exchange for monthly payments over a 20-year term

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REGULATORY CONSIDERATIONS

- Not all of the monthly/annual payment amount to ECo is likely to be recoverable through rates
  - The value of the assets transferred to PUC at commissioning likely to be treated as an increase in rate base and hence will result in an increase in revenue
  - The cost of operating and maintaining the UDM assets likely to be treated as a cost of service and hence will result in an increase in revenue
  - The difference between the payments to ECo and the increase in revenue to PUC through the increase in rate base and recoverable O&M expenses (i.e. the risk premium and excess financing costs) likely to be an additional non-recoverable expense
- In addition, the OEB is likely to be focused on:
  - Customer Rate Impact – *"rate shock"*
  - Customer Need – *willingness to pay for reliability improvements*
  - Asset Recovery Period – *payment structure vs. asset lifetime*
  - Stranded Assets – *recovery of undepreciated value of substation assets*

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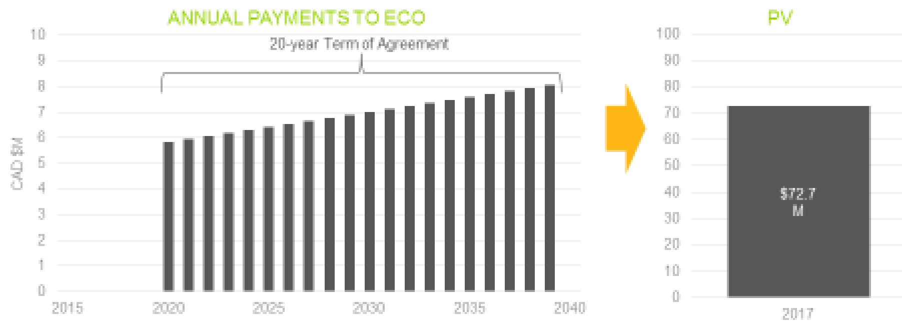
DECONSTRUCTING THE COSTS

- From a ratepayer / taxpayer perspective, the annual payments to ECo are equivalent to a present value (PV) of CAD $72.7M*
  - For all of the ratepayer / taxpayers perspective calculations, annual payments are discounted using a 5% societal discount rate to 2017



* All values are in CAD unless otherwise indicated

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DECONSTRUCTING THE COSTS

- Included in the ECo payments are costs that the PUC would otherwise have incurred to refurbish seven substations between 2017 and 2039
- From a ratepayer perspective, the PV of the PUC's cost to refurbish these substations on its originally proposed timeline is an estimated $12.4M
- As a result, the incremental cost of the ECo proposal over 20 years is $60.3M

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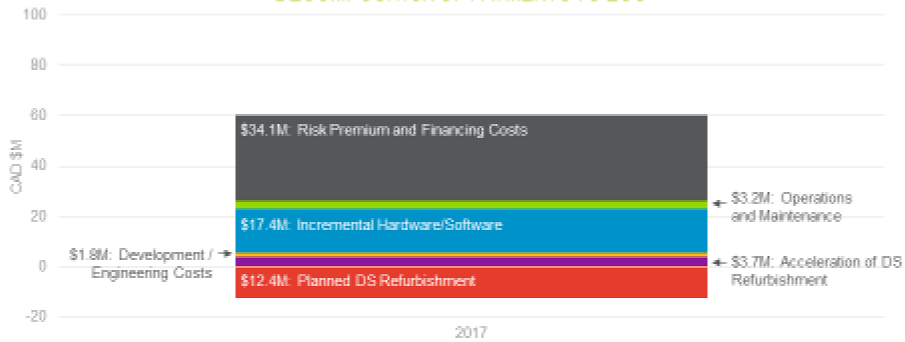
DECONSTRUCTING THE COSTS

- Breaking out other known components of the ECo payment results in an estimate of the embedded risk premium and financing cost of $34.1M

DECOMPOSITION OF PAYMENTS TO ECO



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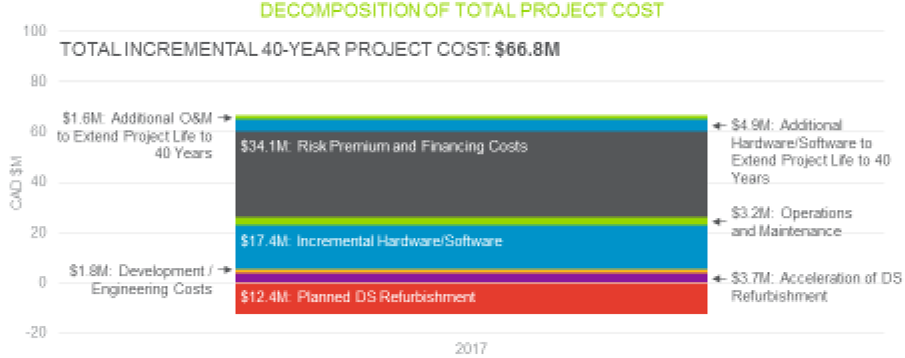
DECONSTRUCTING THE COSTS

- The proposed term of the ECo agreement is 20-years, however, a number of the assets expected to have a 40-year useful life
- To establish a common 40-year project life, additional operating and maintenance and capital costs are likely to be required in years 21 to 40

DECOMPOSITION OF TOTAL PROJECT COST



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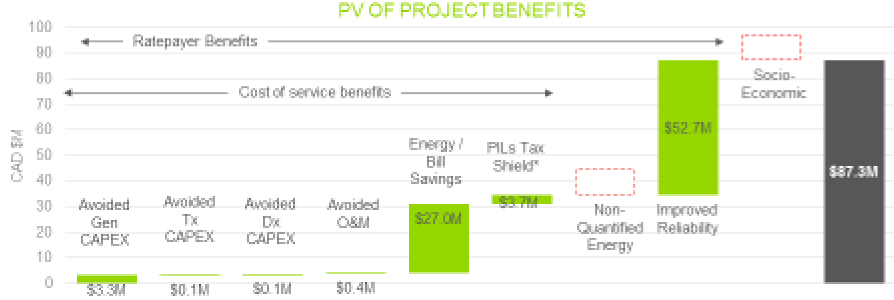
UNDERSTANDING THE BENEFITS

- Benefits total an estimated $87.3M over 40 years
  - Does not include some non-quantified energy and socio-economic benefits
- From a regulatory approval standpoint, six benefit categories result in a reduction in cost of service to customers
- Reliability improvements, provide a quality of service benefit, but do not provide a cost of service benefit

PV OF PROJECT BENEFITS



* Based on the incremental capital costs incurred by ECo up to and through commissioning of the project

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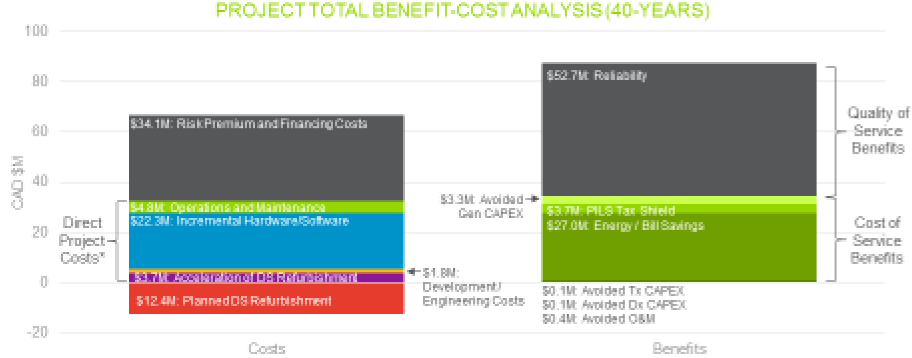
RATEPAYER AND SHAREHOLDER IMPACTS

- The overall benefit-cost ratio for the project is ~1.3, that is the benefits are ~30% greater than the costs
- However, if only the cost of service benefits are included the benefit-cost ratio drops to ~0.50, that is the benefits are ~50% lower than the costs

PROJECT TOTAL BENEFIT-COST ANALYSIS (40-YEARS)



* A portion of ECo's financing costs, based on the PUC's WACC, could also be included

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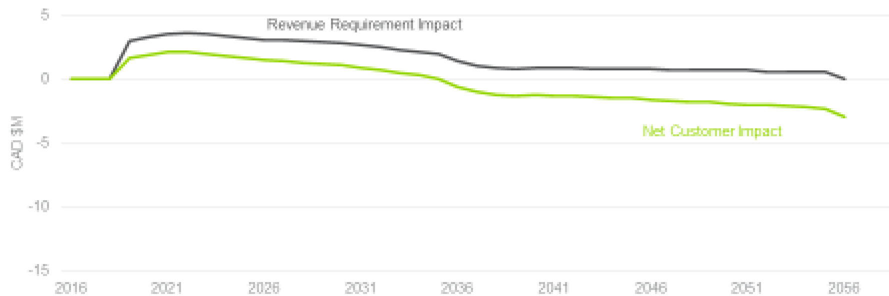
RATEPAYER AND SHAREHOLDER IMPACTS

- The value of the assets transferred to PUC likely to be treated as an increase in rate base, the cost of operating and maintaining the UDM assets likely to be treated as a cost of service; will result in an increase in the revenue requirement
  - Risk premium and financing costs are likely not recoverable and are borne by shareholder
- From a customer perspective, the increase in the revenue requirement is partially offset by the cost of service benefits

REVENUE REQUIREMENT AND NET CUSTOMER IMPACT



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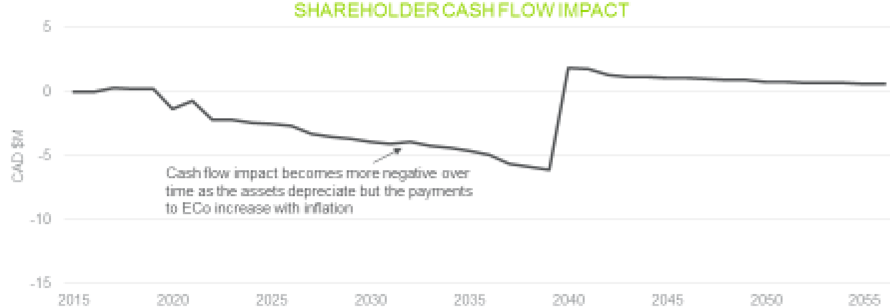
RATEPAYER AND SHAREHOLDER IMPACT

- During the term of the agreement, the difference between the payments to ECo and the increased revenue to the PUC will result in a reduction in net income and ultimately the cash flow available for distribution to the shareholder
- After 20-years, the residual asset value results in an increase in revenue and net income

SHAREHOLDER CASH FLOW IMPACT



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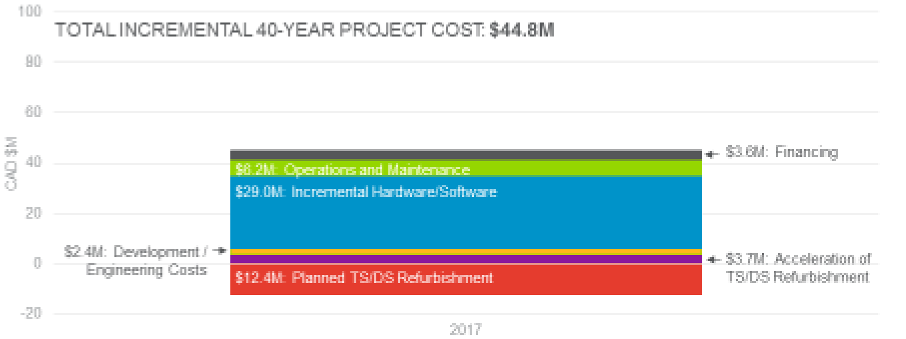
ALTERNATIVE PROJECT OPTIONS

- Navigant also evaluated a PUC design, build, finance and operate option
- Navigant assumed that the PUC's costs to design, build, and operate the UDM project, with the exception of the substation work, are 30% higher than ECo's
  - The PUC's costs would have to be 100% higher for the cost of the two options to reconcile

PUC FUNDED AND IMPLEMENTED PROJECT COSTS



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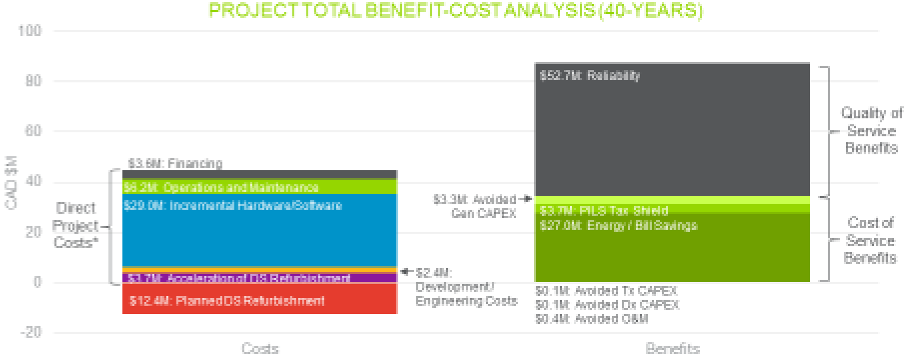
ALTERNATIVE PROJECT OPTIONS

- The overall benefit-cost ratio for this alternative is ~2.0, that is the benefits are ~100% greater than the costs (ECo proposal is ~1.3)
- If only the cost of service benefits are included the benefit-cost ratio drops to ~0.75, that is the benefits are ~25% lower than the costs (ECo Proposal is ~0.50)

PROJECT TOTAL BENEFIT-COST ANALYSIS (40-YEARS)



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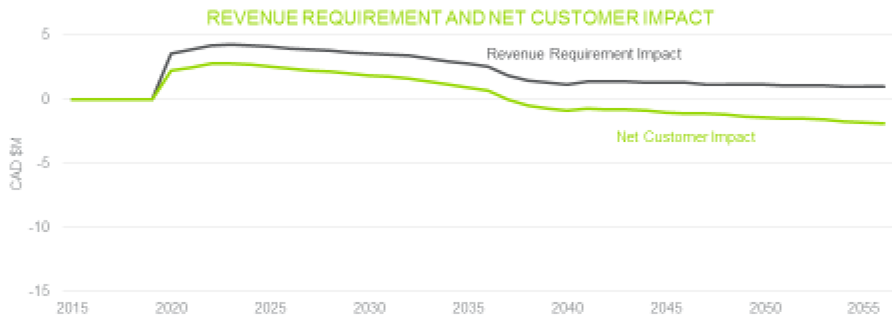
ALTERNATIVE PROJECT OPTIONS

- The capital cost of the project results in increase in rate base, the cost of operating and maintaining the UDM assets treated as a cost of service; will result in an increase in the revenue requirement
- From a customer perspective, the increase in the revenue requirement is partially offset by the cost of service benefits



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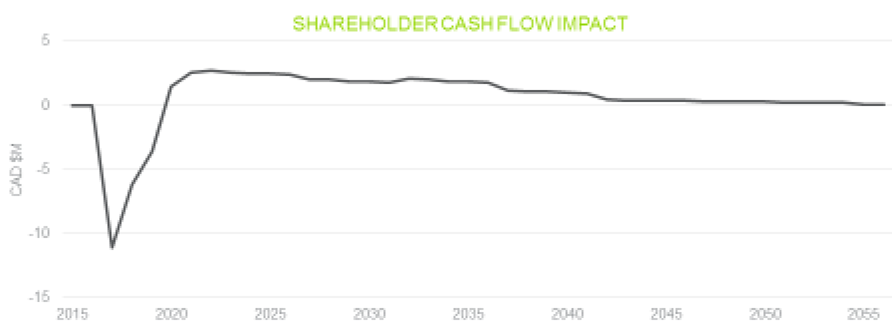
ALTERNATIVE PROJECT OPTIONS

- Under this option, the shareholder is required to make an upfront capital investment which is recovered over the life of the asset through an increase in net income and the cash available for distribution to the shareholders
  - Typical utility investment where the shareholder earns a return on investment, whereas under the ECo proposal the shareholder foregoes this investment opportunity



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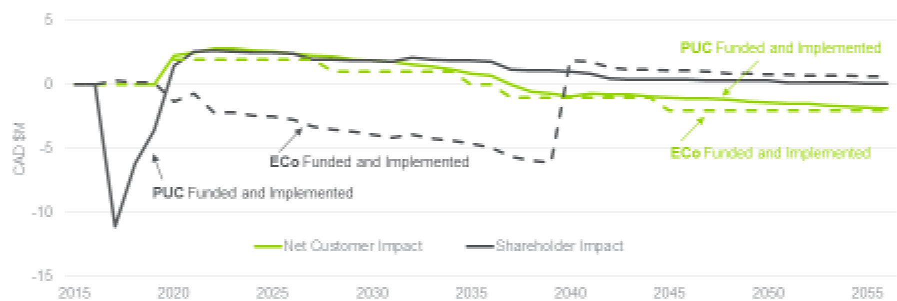
ALTERNATIVE PROJECT OPTIONS

- Comparing the two options, the PUC funded and implemented project option results in better value for the PUC's shareholder but a higher cost to ratepayers

NPV @ 5%	Shareholder Cash Flow	Net Customer Impact
ECo Funded and Implemented	($28.6)M	$5.6M
PUC Funded and Implemented	$3.9M	$14.3M



RECOMMENDATIONS AND NEXT STEPS

- Explore alternative project options with ECo on an "open book" basis that might better fit with current regulatory framework and the shareholder's willingness to pay
- One possible option that could preserve key benefits, but with a lower impact on PUC's customers and shareholders, would involve:
  - ECo designing, building and operating the project and providing performance guarantees, in exchange for an up-front payment and lower ongoing payments to cover operational costs, and
  - The PUC financing the up-front payment and recovering the cost through rate-base. Alternatively, it may be possible for ECo to finance the project at PUC's cost of capital
- Further options and variations to explore with ECo would include:
  - Shaping ECo's payments over time to reduce the present value of the cost to customers;
  - Slowing the pace of investments such that they are undertaken over a longer time period
- Explore smart grid grants from the federal and provincial governments

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APPENDIX 8
COPY OF FINAL SHAREHOLDER APPROVAL RESOLUTION

RESOLUTION OF THE SHAREHOLDER OF
PUC SERVICES INC. and PUC INC.

WHEREAS the PUC Inc. and PUC Services Board has approved the Smart Grid Proposal as presented on June 26, 2018 subject to the following conditions precedent:

- **Federal/Provincial funding approved (>$9 million)**
- **Shareholder approves the project**
- **OEB approval for the first of two consecutive ICMs in place**

AND WHEREAS the PUC Inc. and PUC Services Inc. Board is required to seek Shareholder approval for a single capital expenditure in excess of $5 million or any capital expenditure in aggregate in excess of $10 million. An approval decision is now being requested for the Smart Grid Proposal by the Shareholder.

BE IT RESOLVED THAT the Shareholder approves the Sault Smart Grid proposal as presented subject to the following remaining Conditions Precedent:

- Federal/Provincial funding approved (>$9 million)
- OEB approval for the first of two consecutive ICMs in place

The undersigned being the sole Shareholder of the Corporation hereby signs the foregoing resolution pursuant to the provisions of the Ontario Business Corporations Act.

Dated this 25 day of June, 2018

The Corporation of the City of Sault Ste. Marie

Per: ______________________
Christian Provenzano, Mayor

Per: ______________________
Malcolm White, City Clerk

APPENDIX 9
COPY OF LETTER OF INTENT
(FILED IN CONFIDENCE)

APPENDIX 10
UDM PROJECT ATP LETTER

500 Second Line East, P.O. Box 9000
Sault Ste. Marie, Ontario, P6A 6P2
tel. (705) 759-6500 fax. (705) 759-6510

January 22, 2014

Mr. Glen Martin, Chief Executive Officer
Energizing, LLC
120 North Topanga Canyon Boulevard, Suite 219
Topanga, California
90290 USA

Dear Glen:

Re: UDM Project Authority to Proceed/Amendment to Letter of Intent

PUC Distribution Inc. ("**PUC**") is pleased to grant Energizing, LLC ("**ECo**") this Authority to Proceed (this "**ATP**") with the next phase of development of the proposed utility distribution microgrid ("**UDM**") project in Sault Ste. Marie, Ontario, Canada, which project (the "**UDM Project**") is contemplated by that certain Letter of Intent between ECo and PUC dated July 26, 2013 (the "**Letter of Intent**").

Specifically, this ATP authorizes ECo to proceed with the Preliminary Design Phase of the UDM Project (the "**Preliminary Design Phase**"). In the Preliminary Design Phase, ECo will develop, with cooperation and input from PUC at ECo's request, (a) detailed UDM systems requirements (site integration, operation sequences, reliability, monitoring and maintenance); (b) preliminary technical architecture(s) (equipment type and sizing; drawings); (c) detailed financial estimates; and (d) a risk review. In addition, ECo will initiate the negotiation of a definitive, multi-party Design, Build, Own, Operate and Maintain with Transfer Option ("**DBOOM-T**") contract, previously referred to as the DBFMOT Contract in the Term Sheet of the Letter of Intent, and the related, "drop-down" engineering, procurement and construction ("**EPC**") and operations and maintenance ("**O&M**") contracts, in each case in accordance with the terms and conditions set forth in the Letter of Intent.

PUC recognizes that ECo has already incurred substantial expense in pursuing the UDM Project, including without limitation by retaining Leidos Holdings Inc. to prepare a Project Feasibility Analysis that includes conceptual technical architecture(s) and a detailed project cost-benefit analysis, which was presented to PUC for review and comment on January 16, 2014.

PUC further recognizes that proceeding with the Preliminary Design Phase will require ECo to incur additional expenses, including without limitation additional engineering, financial modeling, travel, and legal expenses. We agree to amend the Letter of Intent so as to extend the term of the Exclusivity Period (as defined therein) to December 31, 2014, and hereby affirm the

Letter of Intent as so amended. If you are in agreement with this, please so indicate by countersigning this letter below.

We congratulate you on reaching this milestone and look forward to continuing to work with you.

Yours truly,
PUC Distribution Inc.

Dominic Parrella, P. Eng.
President & C.E.O.

Tel. (705) 759-6552 Fax. (705) 759-6596 Email: dominic.parrella@ssmpuc.com

AGREED AND ACKNOWLEDGED AS TO THE
AMENDMENT OF THE LETTER OF INTENT
AS SET FORTH ABOVE:
Energizing, LLC

By: __________________________
Glen D. Martin
Its: Chief Executive Officer

APPENDIX 11
COPY OF AMENDMENT TO LETTER OF INTENT
(FILED IN CONFIDENCE)

APPENDIX 12
COPY OF SCHEDULE 1 – PROJECT AGREEMENT
(FILED IN CONFIDENCE)

APPENDIX 13
COPY OF UDM PROJECT AGREEMENT
(FILED IN CONFIDENCE)

APPENDIX 14
COPY OF AMENDMENTS TO NON-DISCLOSURE AGREEMENT AND LETTER OF INTENT

ENERGIZING, LLC
120 NORTH TOPANGA CANYON BOULEVARD, SUITE 219
TOPANGA, CALIFORNIA, 90290 USA

January 16, 2015

Dominic Parrella
President & CEO
PUC Distribution Inc.
550 Second Line East, P.O. Box 9000
Sault Ste. Marie, ON
P6A 6P2

Re: Amendments to Non-Disclosure Agreement and Letter of Intent

Dear Dominic:

Energizing, LLC ("**ECo**") is nearing completion of the Preliminary Design Phase of the proposed utility distribution microgrid ("**UDM**") project in Sault Ste. Marie, Ontario, Canada, which project (the "**UDM Project**") is the subject of a Letter of Intent dated July 26, 2013 (the "**Letter of Intent**") between ECo and PUC Distribution Inc. ("**PUC**").

We note that ECo has already incurred substantial expense in pursuing the UDM Project, including without limitation engineering, financial modeling, travel, and legal expenses ("**ECo Pursuit Costs**"), without any commitment or obligation on the part of PUC to pursue the UDM Project or reimburse ECo for any ECo Pursuit Costs if PUC elects not to proceed. It is further noted that, in order to move to the next phase of development, ECo needs to share certain information concerning the UDM Project with potential providers of products, technologies, services, and financing ("**Providers**"). We therefore request that the Non-Disclosure Agreement dated July 29, 2013 between PUC and ECo is hereby amended to permit ECo to share such information concerning the UDM Project and the PUC as ECo may deem necessary or advisable to pursue the UDM Project with a Provider, so long as such Provider first executes a confidentiality agreement with ECo.

We note further that, in order for PUC to determine whether to proceed, ECo needs to share or cause to be shared with PUC or its representatives detailed information concerning the UDM Project (any such information, as supplemented from time to time the "**Project Information**").

Finally, in consideration of the foregoing, and for other good and valuable consideration, the receipt and adequacy of which are hereby acknowledged, PUC agrees to amend the Letter of Intent to extend the term of the Exclusivity Period to June 30, 2015.

If you are in agreement with this, please so indicate by countersigning this letter below.

We look forward to continuing to work with you.

Sincerely,

Glen Martin, Chief Executive Officer

AGREED AND ACKNOWLEDGED AS TO THE
AMENDMENT OF THE LETTER OF INTENT
AS SET FORTH ABOVE:

PUC Distribution Inc.

By: ______________________

Dominic Parrella

Its: President & CEO

APPENDIX 15
OPERATING MAPS

RED ROCK
NORTH
WEST
NOTE: PLEASE ADVISE ENGINEERING OF ANY ERRORS AND/OR REVISIONS.
NOTE: WHITE PHASE CLOSED R & B BURNT OFF
NOTE: REFER TO FEEDER BOOK FOR DETAILS ON UNDERGROUND SINGLE PHASE FEEDS TO DISTRIBUTION TRANSFORMERS IN THE EAST END OF CITY.
PUC
PRIMARY ELECTRICAL DISTRIBUTION SYSTEM
LEGEND
FUSED SWITCH (NORMALLY CLOSED)
FUSED SWITCH (NORMALLY OPEN)
SOLID BLADE SWITCH (NORMALLY CLOSED)
SOLID BLADE SWITCH (NORMALLY OPENED)
FUSED SWITCH (NORMALLY CLOSED – DO NOT OPEN)
FUSED SWITCH (NORMALLY OPEN – DO NOT CLOSE)
SOLID BLADE SWITCH (NORMALLY CLOSED – DO NOT OPEN)
SOLID BLADE SWITCH (NORMALLY OPENED – DO NOT CLOSE)
NORMALLY CLOSED SWITCH (BLUE) NOT CONFIRMED AS SOLID BLADE OR FUSED
NORMALLY OPEN SWITCH (BLUE) NOT CONFIRMED AS SOLID BLADE OR FUSED
THREE POSITION KABAR
FOUR POSITION KABAR
SECTIONALIZER
RECLOSER
GENERATOR
VOLTAGE REGULATOR
ELECTRICAL SUBSTATION RED OUTLINE – 4.16 kV BLACK OUTLINE – 12.47 kV GREEN OUTLINE – N.I.S.
THREE PHASE OVERHEAD LINE
TWO PHASE OVERHEAD LINE
SINGLE PHASE OVERHEAD LINE
THREE PHASE UNDERGROUND LINE
TWO PHASE UNDERGROUND LINE
SINGLE PHASE UNDERGROUND LINE
1214 CIRCUIT NUMBER
SECONDARY/SERVICE OVERHEAD LINE
SECONDARY/SERVICE UNDERGROUND LINE
NOTE: ALL PHM SWITCHES IN LEGEND SYMBOLOGY ARE SHOWN AS SOLID BLADE SWITCHES AND OPEN. ACTUAL SWITCH TYPE AND STATUS WILL BE SHOWN ON MAP AND WILL FOLLOW SWITCH SYMBOLOGY CONVENTIONS.
PMH – (2) THREE PHASE SWITCHES
PMH – (3) THREE PHASE SWITCHES
PMH – (4) THREE PHASE SWITCHES
NOTE: ALL ELECTRICAL EQUIPMENT ON THIS MAP IS COLOUR CODED TO SHOW OPERATING VOLTAGE AS FOLLOWS: RED – 4.16/2.4 kV BLACK – 12.47/7.2 kV UNLESS OTHERWISE SHOWN.
DRAWN BY: J. ROBINSON
DATE: AUGUST 17, 1987
REVISED BY: J. TEVC
SCALE: NTS
REVISION DATE: FEB. 28, 2019
DRAWING NO. EPD–1
REV. NO. 21

SWITCH NUMBERS AND LOCATION
HOSSM–THIRD LINE T.S.
115 kV
TS–2 (TA) TARENTORUS
INDUSTRIAL PARK CRES. & THIRD LINE EAST
TS–1 (SM) ST. MARY'S
SUBSTATION #19 (Q)
915 McNABB STREET
SUBSTATION #18 (G)
GOULAIS AVE. & THIRD LINE WEST
SUBSTATION #16 (T)
SUBSTATION #11 (H)
HARE ST. & GOULAIS AVE.
SUBSTATION #13 (Z)
SHAFER AVE. & SECOND LINE EAST
SUBSTATION #20 (J)
SUBSTATION #10 (W)
BLAKE AVE. & MANANOSH AVE.
SUBSTATION #1 (A)
HURON ST. & QUEEN ST. WEST
SUBSTATION #4 (M)
MacDONALD AVE. & PIM ST.
SUBSTATION #2 (C)
CHURCH ST. & WELLINGTON ST. EAST
SUBSTATION #5 (L)
LAKE ST. & WELLINGTON ST. EAST
SUBSTATION #12 (B)
BOUNDARY ROAD & CHAMBERS AVE.
SAULT AREA HOSPITAL
CONVERGENT ENERGY
EAST WASTEWATER POLLUTION CONTROL PLANT
PHASING AT DISCONNECTS ONLY– IS R, B, Y FROM TOP TO BOTTOM
CONDUCTOR DEAD–ENDS JUST SOUTH OF WALLACE TERRACE ON POLE #11706
ISOLATED 34.5kV CIRCUIT
NOTE: PLEASE ADVISE ENGINEERING OF ANY ERRORS AND/OR REVISIONS.
34.5 kV
SUB-TRANSMISSION
SYSTEM
LEGEND
DO NOT OPERATE
TRANSFORMER
REGULATING TRANSFORMER
LIGHTNING ARRESTOR
CAPACITOR
SWITCH NUMBER
SWITCH NUMBER (MOTORIZED SWITCH)
ENERGY STORAGE FACILITY
SOLID BLADE SWITCH OPEN
SOLID BLADE SWITCH CLOSED
FUSED SWITCH OPEN
FUSED SWITCH CLOSED
GROUP OPERATED SWITCH HANDLE OPERATED
GROUP OPERATED SWITCH HOOK STICK OPERATED
SF6 VACUUM BREAKER
GENERATOR
115 kV
TS OR SUBSTATION
ISOLATED CONDUCTOR
CIRCUIT SM–5 (TS–1)
CIRCUIT SM–7 (TS–1)
CIRCUIT SM–9 (TS–1)
CIRCUIT SM–11 (TS–1)
UNDERGROUND CABLE (TYPICAL FOR ANY CIRCUIT)
CIRCUIT TA–6 (TS–2)
CIRCUIT TA–7 (TS–2)
CIRCUIT TA–9 (TS–2)
CIRCUIT TA–10 (TS–2)
CIRCUIT TA–11 (TS–2)
DRAWN BY: DD
DATE: Mar 6/03
REVISED BY: JT
SCALE: NTS
REVISION DATE:
OCT. 17/2017
DRAWING No.
EST–1
REVISION No.
10

APPENDIX 16
BLACK & VEATCH- OVERVIEW & GRID MODERNISATION

Black & Veatch

Black & Veatch Corporation is an employee-owned global engineering, consulting and construction company with the mission of *Building a World of Difference*®. Since 1915, we have provided our clients with solutions to their most complex challenges, thereby helping improve and sustain the quality of life around the world.

With more than 100 offices worldwide, we have completed projects in more than 100 countries on six continents. Our revenues in 2018 were US $3.5 billion. Follow us on www.bv.com and in social media

Black & Veatch specializes in innovative infrastructure development in Energy, Water, Telecommunications and Government Services. We provide solutions from the broad line of service expertise available in-house, including:

- Consulting and management consulting
- Conceptual and preliminary engineering services
- Engineering design, procurement, construction
- Program management / construction management
- Financial management / asset management
- Facilities and infrastructure planning
- Security design
- Information technology

FOCUSED ON QUALITY & INNOVATION

Black & Veatch has a reputation for innovative technical solutions and the ability to make the complex manageable. Clients know us for delivering quality, sustainable solutions of lasting value and operating with the highest level of integrity.

Industry Leadership

Black & Veatch's expertise and ability to deliver highly reliable solutions result in annual recognition, including industry awards.

Black & Veatch Telecommunications is ranked # 1 in the world by Engineering News Record in 2019 and has received this recognition in 9 of the last 10 years.

Our professionals earn this kind of recognition because they have the expertise necessary to solve complex client challenges, understand regulatory and market issues, and provide reliable solutions and projects. By listening to our clients and focusing on their needs and objectives, we create and sustain trusted relationships that our clients and business partners want to come back for again and again.

11,000+ Professionals
110+ offices
Six continents
7,000 active projects worldwide.

$3.5 Billion
in revenue in 2018.

Safety Performance
0.35
Recordable Incident Rate
0.08
Lost Time Incident Rate

Grid Modernization

DESIGN-BUILD SYSTEM INTEGRATION FOR A DIGITAL GRID

BUILDING A WORLD OF DIFFERENCE®

BLACK & VEATCH

The Digital Age is here; presenting new perspectives and solutions to how we operate and serve. It's making things faster, more efficient and simply better.

With its promises of reliable service, efficient performance and increased security and resilience, a Digital Grid is essential to the dynamic power and information flow needed for a flexible, scalable utility. To achieve full digitization, utilities need to first modernize their infrastructure. Black & Veatch's Grid Modernization design-build approach and system-wide technology expertise is a single, seamless solution for building the Digital Grid.

Black & Veatch provides the People, Processes and Tools to help utilities ready their networks, substations, and distribution assets for a future of efficiency, reliability and resiliency. Together, this system-wide vantage point allows us to see the interrelationships and connections between operations, technology and the network, ensuring we address all operational and stakeholder requirements.

PEOPLE

From the operations to the control center to the digital grid devices installed in the field, Black & Veatch provides end-to-end planning, implementation and integration for all technology and network applications. Our utility automation professionals work side-by-side with our network engineers, ensuring each technology solution is aptly supported by an advanced communications network.

Communications	Automation	IT
• LTE • WiMAX • Microwave • Land Mobile Radio • Fiber / OSP Networks • Wide Area Networks • Field Area Networks	• Substation Integration Automation • Distribution Automation • SCADA Systems • Feeder Automation/FLISR • Integrated Volt/VAR Control and Optimization • Distribution System Sensor Integration • Renewable Integration • Demand Response Control	• IP/MPLS/SONET • DWDM/CWDM • Network Management • Network Operation Centers • Data Centers • Cybersecurity

PROCESS

With a single partner to manage, deploy and integrate your grid modernization projects, utilities are assured a seamless and efficient system implementation. By taking an Engineering, Procurement and Construction (EPC) approach, Black & Veatch is able to provide a collaborative and flexible solution resulting in accelerated schedules and cost savings.

Program Management

Black & Veatch applies proven program management and ISO-certified quality management processes gained from our traditional energy projects, and uses best practices from our many distributed, multi-site communication deployments to provide insightful oversight of grid modernization programs.

- Scope, schedule and budget oversight and management
- Design and management of execution plan
- Safety and quality assurance

Consulting Engineering Services

Modern innovation gives way to numerous scenarios and solutions for optimizing the grid. Our consulting engineers help utilities select the best path towards the greatest regulatory, operational and consumer benefits. This includes the hardware, software and services, processes and people required to achieve operational excellence.

- Vision, conceptual design and architecture
- Technology assessment and solution selection
- Power system studies, planning and design

Engineering Services

Black & Veatch designs automation schemes and communication network solutions to integrate grid technology. This dramatically improves monitoring and control capabilities at the control center and increases reliability and efficiency of the distribution system.

- Detailed network design and architecture
- Installation design
- Make-ready engineering
- Field engineering

Procurement and Construction Services

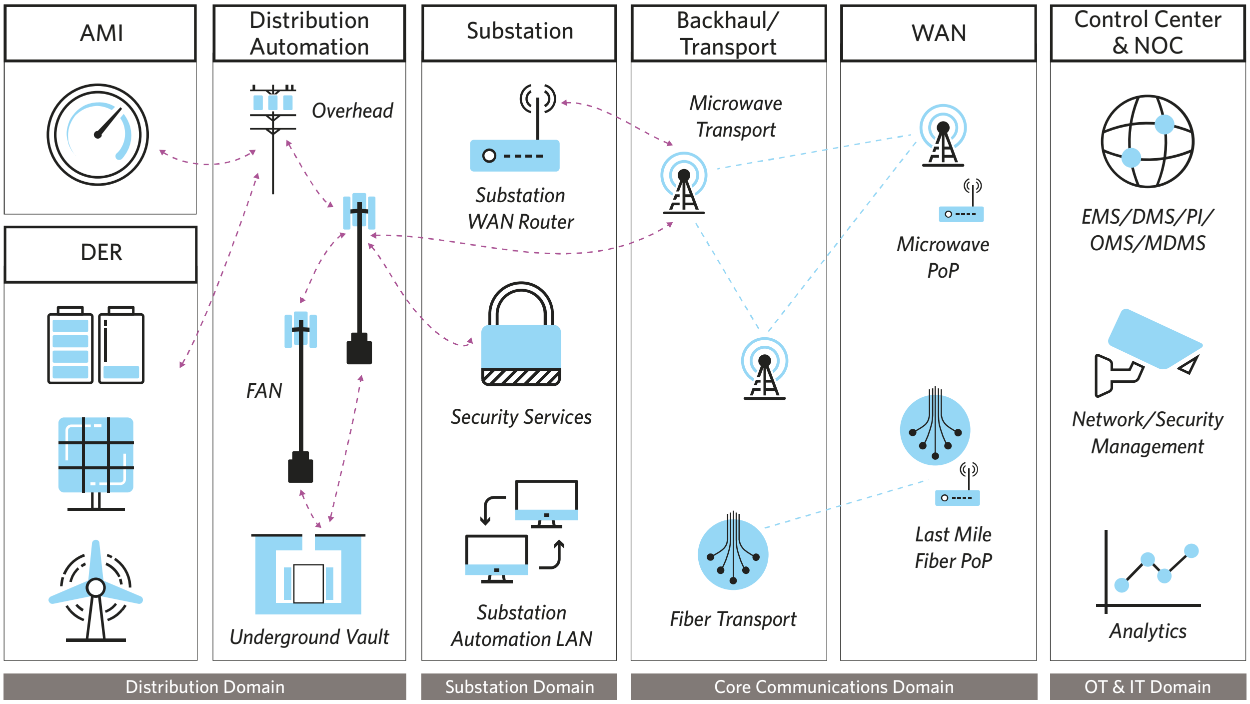
Black & Veatch is a leader in power delivery system construction and management. Through hands-on experience on thousands of projects, we've refined our materials management and have become proficient in installation and testing of technology.

- Vendor selection and management
- Equipment and material logistics and tracking
- Construction management
- Installation testing and commissioning

TOOLS

By harnessing the power of geospatial technology and the data integration of Black & Veatch's ASSET360® platform, Program Navigator is a powerful program management and execution tool that provides a single, centralized location to view a project's design and performance at any time — past, present and even future. It improves planning and forecasting through enhanced dimensional design and mapping, and drives schedule efficiency, intelligent decisions, and quicker issue resolution through data integration and analytics. The tool captures, integrates and analyzes data and defined key performance indicators, such as field data, drawings, schedule, budget, resources and quality metrics, and combines them with massive-scale project management and controls. This creates a holistic view of a project's performance to guide day-today tasks, decision-making and real-time scenario planning. We've integrated GIS spatial engineering with enhanced knowledge base and data analytics to create a truly unique tool. We find it makes project teams faster, more efficient and, ultimately, smarter.

SMART DISTRIBUTION SYSTEM: ACTIVE NETWORK



Black & Veatch's solutions begin with a system wide-view of a Smart Distribution System. By delivering a wide breadth of services among a deep list of technologies, Black & Veatch provides a highly-efficient project execution. Our expertise covers communications, smart applications, technology and data analytics across the grid.

Black & Veatch
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