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October 28, 2020

Delivered by Email

Ms. Christine Long, Registrar and Board Secretary
Ontario Energy Board
P.O.Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: PUC Distribution Inc. ("PUC" or "Applicant')
OEB File No. EB-2020-0249
Amendment to the ICM Application – The Sault Smart Grid project

We are counsel to the Applicant in the abovementioned matter.

The Applicant had previously filed an application for 2019 ICM/IRM Rates under OEB File No. EB-2018-0219. On June 28, 2019, the Applicant informed the Ontario Energy Board (the "**Board**") that it will file an amended application for ICM relief for the proposed Sault Smart Grid project ("**Amended Application**"). The Board subsequently assigned a new File No. EB-2020-0249 for the Amended Application.

Please find enclosed the Applicant's Amended Application along with supporting appendices. Amongst the appendices is Appendix AA3, which consists of the following documents:

- Appendix AA3-1 SSG Scope Overview Summary
- Appendix AA3-2 SSG Physical Scoping Diagram
- Appendix AA3-3 SSG Logical Scoping Diagram
- Appendix AA3-4 Responsibility Matrix
- Appendix AA3-5 Project Schedule
- Appendix AA3-6 EPC Pricing Summary
- Appendix AA3-7 EPC Contract
- Appendix AA3-7 – EPC Appendix A – SSG Scope of Work
- Appendix AA3-7 – EPC Appendix B – Compensation
- Appendix AA3-7 – EPC Appendix C – Owner's Policies
- Appendix AA3-7 – EPC Appendix D – Warranty Items Procedure
- Appendix AA3-7 – EPC Appendix E – Form of Parent Guaranty
- Appendix AA3-7 – EPC Appendix F – Forms
- Appendix AA3-7 – EPC Appendix G – Dispute Resolution Procedure

- Appendix AA3-7 – EPC Appendix H – Key Personnel

(collectively, "**Documents**")

The Documents pertain to the EPC contract between Black & Veatch's subsidiary ("**Black & Veatch**") and the Applicant for the Sault Smart Grid project (either being the EPC contract, the EPC contract's appendices or excerpts of the EPC contract). As part of the Amended Application, the Applicant is filing the Documents in confidence.

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

Appendix "A" to the Practice Direction sets out the Board's considerations in determining requests for confidentiality. Among those considerations are the following:

(a)(i) prejudice to any person's competitive position;

(a)(iv) whether the disclosure would be likely to produce a significant loss or gain to any person; and

(g) any other matters relating to FIPPA (the *Freedom of Information and Protection of Privacy Act*) and FIPPA exemptions.

With respect to item (g) above, the Board has provided a summary of pertinent *FIPPA* provisions at Appendix C of the Practice Direction. That summary provides, in part, as follows:

"Under section 17(1), the Board must not, without the consent of the person to whom the information relates, disclose a record where:

(a) the record reveals a trade secret or scientific, technical, commercial, financial or labour relations information;
(b) the record was supplied in confidence implicitly or explicitly; and
(c) disclosure of the record could reasonably be expected to have any of the following effects:

i. prejudice significantly the competitive position or interfere significantly with the contractual or other negotiations of a person, group of persons or organization;

iii. result in undue loss or gain to any person, group, committee or financial institution or agency;

..."

The Applicant submits that the disclosure of the Documents could reasonably be expected to prejudice the EPC contractor's (i.e. Black & Veatch) competitive position. Black & Veatch, went through a competitive procurement process to become selected by the Applicant as the EPC contractor for the Sault Smart Grid project. Black & Veatch engages in competitive business activities, specifically in providing engineering, procurement and construction services. By placing

the Documents on public record, the information contained in the Documents could be used by Black & Veatch's competitors to similar construction or services projects as well as future potential smart grid projects by LDCs or others, allowing competitors to have a competitive advantage in such future potential projects. In addition, the details of pricing would give competitors an unfair advantage in their negotiation in providing EPC services for future potential projects as they would have knowledge of Black & Veatch's pricing scheme for this type of work and can adjust their pricing accordingly to their advantage.

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 confidential versions of the Documents by e-mailing them to Board Secretary only. The unredacted versions of the Documents will be marked "Confidential". PUC requests that the unredacted documents be kept confidential.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Per:

Flora Ho

Cc: Intervenors of Record in EB-2018-0219

Amended and Restated

Incremental Capital Module (ICM) Application

Sault Smart Grid (SSG)

PUC Distribution Inc.

EB-2020-0249

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Incremental Capital Module (ICM) – Sault Smart Grid (SSG)

1. Introduction

PUC Distribution Inc. (the "**Applicant**" or "**PUC Distribution**") submits this amended and restated ICM application (the "**Amended Application**") to secure incremental capital for 2021 to support the proposed Sault Smart Grid (SSG) project (the "**SSG Project**").

A. The Original ICM Application

On January 31, 2019, the Applicant filed an incentive rate-setting mechanism ("**IRM**") application with the Ontario Energy Board ("**OEB**" or the "**Board**") under section 78 of the *Ontario Energy Board Act*, 1998[1] seeking approval for changes to its electricity distribution rates effective May 1, 2019. As part of its 2019 IRM application, the Applicant also applied for an ICM to recover costs associated with the implementation of the Sault Smart Grid ("**SSG**") project ("**Original Application**").

The key features of the Original Application included the following:

- The scope of the SSG project involved the coordinated implementation of a combination of well understood and proven smart grid technologies across the Applicant's distribution system. The specific smart grid technologies include distribution automation systems, voltage / VAR management systems, line regulators and associated communication systems, all of which will be integrated into the Applicant's advanced metering infrastructure ("**AMI**") system.

- The SSG project was being developed using a P3 project finance structure using a special purpose vehicle known as Sault Smart Grid Inc. ("**SSG Inc.**"). The SSG project was initially going to be funded through the North American Grid Modernization Fund,

[1] Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B)

which is currently managed by Stonepeak Infrastructure Partners and Infrastructure Energy LLC ("**IE**"). The SSG Project funds were to flow through SSG Inc.

- The total capital cost of the SSG project using the SSG Inc. structure was estimated to be $34,389,046.

- The SSG project was projected to achieve an annual net benefit to PUC Distribution customers of over $200,000 excluding forecasted reliability benefits of over $2.5 million.

- The total capital cost of the SSG project was split into two components, 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**"). The Original Application only sought approval for Phase 1 expenditures.

In December 2018, PUC Distribution entered into a Contribution Agreement with Natural Resources Canada ("**NRCan**") to qualify the SSG Project for funding under the NRCan Smart Grid Program. Under the Contribution Agreement, NRCan agreed to fund the lesser of 25% of total project costs incurred or $11,807,000. A copy of this Contribution Agreement is attached to this application at Appendix AA-1.

Interrogatory responses were filed in respect of the Original Application on May 31, 2019 and a Technical Conference was convened on June 19 and 20, 2019.

Following the Technical Conference, on June 28, 2019 the Applicant filed a letter indicating its intent to amend the ICM Application and file all outstanding Technical Conference undertakings as part of its amendment (see Appendix AA5).

On July 16, 2019, the OEB issued Procedural Order No. 5, which held the Original Application in abeyance until PUC Distribution filed an amended Application with the OEB, which includes answers to undertakings given at the Technical Conference. The OEB also expressed several concerns with the Original Application, and provided the following guidance:

> "The OEB expects the amended application to show that the approval of the amended application by the OEB is independent of any OEB decision in a future application. The OEB also expects PUC Distribution to demonstrate that the scope of the project, for which approval is being sought, has tangible benefits to ratepayers commensurate with the proposed cost. Furthermore, the OEB expects PUC Distribution to update information related to project cost certainty, percentage of completed design work, structure and status of contracts, and associated risk allocation."[2]

On October 20, 2020, the OEB assigned a new EB number, EB-2020-0249, to this Amended Application.

B. Amended ICM Application

This Amended Application amends and restates the Original Application.

The key differences to the Original Application are as follows:

- The scope of the SSG project remains the same. The specific smart grid technologies include distribution automation systems, voltage / VAR management systems, line regulators and associated communication systems, all of which will be integrated into the Applicant's AMI system.

- The SSG project will no longer be developed by SSG Inc. or IE through a P3 project finance structure. During the Technical Conference, numerous parties expressed concerns with the P3 structure.

- Based on this feedback, PUC Distribution determined that it would bring the SSG project back in-house. Going forward, the SSG project will be developed, owned and

[2] EB-2018-0219 – Decision and Procedural Order No. 5 dated July 16, 2019 at page 2.

operated by PUC Distribution (rather than a special purpose vehicle), making the project more analogous to more traditional utility investments.

- PUC Distribution issued a Request for Proposals ("**RFP**") on October 4, 2019 seeking competitive proposals for engineering, procurement and construction ("**EPC**") services for the implementation of the SSG Project to provide community-scale smart grid technology applications and an integrated and intelligent distribution management platform for the PUC Distribution electrical distribution service area. The RFP also provided allowance for innovative project financing structure, innovative financing arrangements, or other novel structures or proposals, however those proposals were evaluated on a value basis against a more traditional EPC approach. A copy of the RFP issued on October 4, 2019 with an Addendum #1 issued on October 17, 2019 and Addendum #2 issued on October 31, 2019 updating the RFP Schedule dates are attached as Appendix AA2-1, AA2-2, and AA2-3.

- Proposals were received in response to the RFP in late 2019.[3] The RFP proposals were evaluated based on the five (5) criteria in Appendix AA2-4 for a qualification score. PUC Distribution elected to award the project to Black & Veatch**,** which was the most qualified proponent and had the lowest price proposal. A copy of the EPC contract scope of work and pricing is attached as Appendix AA3-1 and AA3-6.

- The EPC contract was executed by Overland Contracting Canada Inc., a wholly owned subsidiary of Black & Veatch, and PUC Distribution on October 7, 2020 (**"EPC Contract"**). The EPC Contract and its Appendices are attached as Appendix AA3-7.

- The SSG project now has a revised total capital cost of $33,007,038 and is projected to achieve an annual net benefit to PUC Distribution customers of over $616,897, excluding forecasted reliability benefits.

[3] IE, the developer behind the SSG Inc. P3 proposal, was invited by PUC Distribution to bid on the RFP. However, IE notified PUC Distribution that they did not intend to submit a proposal.

- This Amended Application is seeking approval of the full ICM amount effective May 1, 2022 as the project will be completed prior to December 31, 2022**.**

- With the decision to depart from the P3 project structure and incurred project delays, PUC Distribution also updated the contribution agreement with NRCan. A revised project Statement of Work description without reference to the P3 parties and updated estimate was developed with reduced capital contribution to ~$10.6M as placeholder subject to RFP pricing and estimate revisions expected to be required. A copy of the summary Statement of Work with NRCan is included with this Amended Application at Appendix AA4-1. The revised NRCan contribution agreement with revised Statement of Work, project structure and estimate was executed in December 2019. A copy is filed with this Amended Application at Appendix AA4-2.

- Subsequently, on September 17, 2020, NRCan informed the Smart Grid Deployment Program recipients (including PUC Distribution) that, inter alia, the eligible expense end date has been extended 1 year and is now March 31, 2023. A copy of this correspondence is filed with this Amended Application at Appendix AA4-4. PUC Distribution is working with NRCan on a further amending agreement to update the details of the contribution agreement as a result of this extension. A copy of this amending agreement will be filed with the OEB once it is available.

- The SSG Project will still benefit from the 25% NRCan contribution. With the estimated cost of the SSG Project now reduced further with EPC pricing, pursuant to the NRCan agreement the lesser of 25% of total project costs is applied so the total monetary value of the NRCan contribution will decrease accordingly (now estimated at $8,126,759, which is 25% of current eligible cost project estimate of $32,507,038 ($33,007,038 less ~$500,000 as estimated ineligible to NRCan program as costs incurred before contribution eligibility period and estimated legal costs)). Once the OEB rate process is complete, a further NRCan agreement amendment will be arranged with NRCan with updated project estimates and timelines.

- The NRCan program uses a quarterly claim process using the federal fiscal quarters. A copy of the claim form template is provided in Appendix AA4-3 for information. The process includes a 25% holdback on each claim until the final completion of the project per the program requirements.

This Amended Application sets out the Applicant's ICM funding request.

As part of this Amended Application, PUC Distribution is filing all outstanding Technical Conference undertakings from EB-2018-0129 as Appendix AA5.

In its Decision and Procedural Order No. 5[4], the Board expressed concern for the two-phased approach in the Original Application as it involves two separate ICM proceedings and two potentially different OEB panels. As such, the Amended Application has eliminated the two-phase approach and is now one ICM application with no phases. The approval of this Amended Application by the OEB is independent of any OEB decision in a future application.

2. Background

On November 23, 2010, the Minister of Energy issued an Order in Council directing the OEB to provide guidance to licensed distributors and other regulated entities regarding the OEB's expectations in relation to activities in support of the establishment and implementation of a smart grid (the "**Minister's Directive**"). The Minister's Directive is attached as Appendix AA6**.**

The OEB subsequently released its *Renewed Regulatory Framework for Electricity Distributors*[5], which provided a performance-based framework for the cost-effective planning and operation of the electricity distribution network, including smart grid investments. The OEB later released the

[4] EB-2018-0219 Procedural Order No. 5 dated July 16, 2019 at page 1 and 2.

[5] *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* released on October 18, 2012 (the "**RRFE Report**"): https://www.oeb.ca/oeb/_Documents/Documents/Report_Renewed_Regulatory_Framework_RRFE_20121018.pdf.

Supplemental Report on Smart Grid[6] which provided specific guidance on smart grid investments as part of implementing the performance-based framework set out in the RRFE Report.

PUC Distribution began developing its smart grid strategy in the second quarter of 2013, shortly following the release of the Smart Grid Supplement. Developer P3 type financing was explored in an effort to reduce PUC Distribution's development cost exposure as well as transfer risk and credit risk to the developer while striving to achieve a positive customer value project. 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.

In the first quarter of 2014, the City of Sault Ste. Marie City Council passed a resolution supporting the concept of developing a smart grid in PUC Distribution's service area.

In 2014, Leidos Engineering LLC ("**Leidos**") was retained and instructed to prepare preliminary design reports for the various smart grid components (the "**Preliminary Design Reports**") and to quantify the benefits of a smart grid. This was completed in the fourth quarter of 2014. The Preliminary Design Reports are attached at Appendix AA7**.**

During first three quarters of 2015, Navigant Consulting Ltd. ("**Navigant**") undertook the following two reviews with respect to the smart grid project (the "**Navigant Reviews**"):

1. *Review of Business Case for Smart Grid Project for PUC Distribution*, the report for which was delivered in April 2015 ("**Navigant Report #1"**), is attached at Appendix AA8; and

2. *Review of Project Costs for Smart Grid Project*, the report for which was delivered in June 2015 ("**Navigant Report #2**"), is attached at Appendix AA9.

[6] *Report of the Board: Supplemental Report on Smart Grid* (EB-2011-0004) released on February 11, 2013 (the "**Smart Grid Supplement**"): https://www.oeb.ca/oeb/_Documents/EB-2011-0004/Supplemental_Report_on_Smart_Grid_20130211.pdf.

Subsequently in 2016, the Sault Ste. Marie Innovation Centre in collaboration with PUC Distribution, the Sault Ste. Marie Economic Development Corporation and the City of Sault Ste. Marie retained Navigant to review the smart grid project. Navigant prepared a report entitled *Community Microgrid Business Case Review*, the report for which was delivered in May 2016 ("**Navigant Report #3"**). A copy of this document is attached at Appendix AA10.

In preparing Navigant Report #3, Navigant referred to a document titled "0201.12 – 2016 Projection for Distribution Capital Engineering 2016-03-15.xlsx" when discussing PUC Distribution's Long Range Distribution System Plan. This was also the subject of undertaking JTC2.13 from the Technical Conference. A copy of this document has been included with this application as Appendix AA11.

Following the Navigant Reviews, PUC Distribution concluded it needed to de-scope the smart grid project to lower costs. Accordingly, PUC Distribution set out to modify the project scope, for instance, by eliminating station upgrades and to seek funding through various grants.

With the revised scope, and assuming grant funding applications were successful, PUC Distribution was confident the SSG Project could achieve the "no net bill increase" criteria.

Since the SSG Project's ability to achieve the "no net bill increase" criteria was contingent on the success of certain grant applications, the SSG Project was delayed to await the launch of the federal Smart Grid Program which launched in January 2018.

As described above, PUC Distribution submitted its application for the NRCan Funding in March 2018 and the Contribution Agreement was executed in December 2018. An amended Contribution Agreement due to the project delay was developed and executed in December 2019. The new amended Contribution Agreement is filed at Appendix AA4-2 of this application. As mentioned above, PUC Distribution is working with NRCan on a further amending agreement to update the details of the contribution agreement as a result of the program extension by NRCan. A copy of this amending agreement will be filed with the OEB once it is available.

The SSG Project was not included in PUC Distribution's latest Distribution System Plan (OEB File No. EB-2017-0071) (the "**DSP**"), which was filed on March 29, 2018, because the status of the NRCan Funding was unknown at that time and the program requirements included maintaining complete confidentiality. Rather, the SSG Project is entirely incremental to the other projects identified in the current DSP although operating and capital program efficiencies are projected to be realizable in subsequent DSP development and in the longer term will be incorporated in the next cost of service application.

This was explained in PUC Distribution's approved 2018 Cost of Service (CoS) rate application (EB-2017-0071) at Exhibit 2, Appendix 2 at page 98[7]:

> ***"Sault Smart Grid Project***
>
> PUC Distribution 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. The project conceptually has included a "no net bill increase" (to be achieved through lower consumption as a result of voltage regulation) hurdle for customers as a primary evaluation criteria recognizing the high concern for customers on current costs for electricity. To meet this hurdle a significant level of financial support is being sought and will be needed for internal project approval. It is anticipated that PUC Distribution would be utilizing the Incremental Capital Module process for this project should the analysis and financial feasibility criteria, including the "no net bill increase" be achieved. Should the project funding applications be approved and OEB approval attained, and subject to final PUC Distribution Board of Directors approval this 2 to 3 year project

[7] PUC Distribution Inc., 2018 Cost of Service Rate Application (EB-2017-0071), Exhibit 2: Rate Base filed March 29, 2018: http://www.rds.oeb.ca/HPECMWebDrawer/Record/604151/File/document.

> would represent a substantial advancement in smart grid technologies being implemented by PUC Distribution."

It was further explained in PUC Distribution's response to interrogatory number 1-Staff-6 (EB-2017-0071) at page 8[8]:

> "This Sault Smart Grid project is still at the preliminary planning stages. No amounts associated with the Sault Smart Grid project have been included in this Application or in the DSP. The answers to the questions asked by Staff are not yet known.
>
> Whether PUC proceeds with this project or not will depend on whether it meets PUC's evaluation criteria (including the "no net bill increase" criteria). All of this remains to be determined.
>
> Should PUC elect to proceed with this project, PUC will bring an application to the OEB for approval under the Incremental Capital Module process. PUC will provide full and complete responses to each of these questions as part of that separate ICM application at that time."

In the above interrogatory response, PUC Distribution had committed to answering OEB Staff's questions in its ICM Application. Answers to the questions asked by OEB Staff in interrogatory number 1-Staff-6 (EB-2017-0071) are attached at Appendix AA1.

As described above, the Original Application was filed on January 31, 2019 and the proceedings reached the Technical Conference phase. Subsequent to the Technical Conference, which provided PUC Distribution with valuable stakeholder input, PUC Distribution decided to improve and restructure the project delivery plan and file this Amended Application.

[8] PUC Distribution Inc., 2018 Cost of Service Rate Application (EB-2017-0071), Responses to Interrogatories filed August 9, 2018: http://www.rds.oeb.ca/HPECMWebDrawer/Record/616145/File/document.

In restructuring the project delivery plan, PUC Distribution elected to depart from the P3 like project structure in the Original Application and utilize an RFP approach to seek competitive proposals from qualified proponents for the project. Various EPC contractors were invited by PUC Distribution to submit proposals for the SSG Project's EPC services. Amongst the invitees was the project development partner, IE (also known as Energizing, LLC), that was involved in the Original Application. However, IE did not submit any proposal to PUC Distribution Inc. All the RFP submissions received were evaluated and rated internally to select the preferred EPC proponent to move to the next stage of the contract negotiation process. A copy of the RFP and description of the evaluation have been included with this application in Appendix AA2-1. Black & Veatch was selected as the successful EPC proponent. The EPC contract is styled as a "maximum price limit" project to ensure cost certainty for this main element of the project costs. EPC pricing has been fixed as firm at $5,086,378 for Step 1 - Upfront Engineering Fixed Price and Step 2 - Balance of Work Fixed Price set at $22,658,667 for a total EPC maximum price of $27,745,044. The Maximum Price represents the maximum amount PUC Distribution will pay for the performance of Step 2 - Balance of Work. A copy of the EPC scope and pricing is included with this application in Appendix AA3-1 and AA3-6. It is understood by the parties of the EPC Contract that execution of the EPC Contract includes a critical condition precedent requiring successful conclusion of this ICM Application for PUC Distribution rates and revenue recovery. Further details on the EPC Contract can be found in Section 4C below.

PUC Distribution acquired the rights to the studies and preliminary engineering works from IE that were previously filed with the OEB. Including this preliminary engineering work ensured a solid base for a fast start to the next phase for detailed engineering moving forward with the EPC project structure. Costs for IE's preliminary engineering are identified in the Project Cost Estimate Memo at Appendix AA12-2.

A. OEB's Expectations for Amended Application

In its Decision and Procedural Order No. 5,[9] the OEB had set out its expectations in several areas with regards to the Amended Application and PUC Distribution addresses each of those expectations as follows:

(i) The OEB also expects PUC Distribution to demonstrate that the scope of the project, for which approval is being sought, has tangible benefits to ratepayers commensurate with the proposed cost.

The scope of the project has tangible benefits to ratepayers commensurate with the proposed costs. The SSG project is projected to achieve an annual net benefit to PUC Distribution customers of over $616,897. With regards to annual savings, the SSG Project will achieve over $2,332,953 in system loss and customer energy savings. In addition, customers will benefit from reliability improvements as further detailed in Section 3 below. Appendix AA13 to this Amended Application is a Project Benefits Estimate memo that explains the calculation of energy savings.

(ii) *Furthermore, the OEB expects PUC Distribution to update information related to project cost certainty, percentage of completed design work, structure and status of contract, and associated risk allocation.*

a. project cost certainty

To ensure project cost certainty, the EPC pricing for the SSG Project has been fixed at $5,086,378 for Step 1 - Upfront Engineering. Step 2 - Balance of Work, which is the remainder of the project, has a price set at $22,658,667. The total EPC maximum price is $27,745,045. Any price changes by the EPC contractor would be monitored by PUC Distribution using an open-to-closed book process in accordance with the fixed price as detailed in the EPC Contract. The scope of work will be reduced by PUC Distribution if required to maintain the project capital cost limit set for the project. A detailed breakdown of the EPC contract pricing can be found at Appendix AA3-6 as well as the EPC Contract at Appendix AA3-7.

[9] EB-2018-0219 – Decision and Procedural Order No. 5 dated July 16, 2019 at page 2.

b. percentage of completed design work

There has been the original 30% engineering design work completed by Leidos as the base level for the project. This has provided a level of detail sufficient to quantify the scope of work required to support fixed cost pricing for the level of detailed engineering needed for Step 1 of the EPC Contract. The design work also supported the equipment types, ratings, quantities and scope of work estimate to support the fixed price limit for Step 2 of the EPC Contract. No additional design work will be done unless the OEB approves this Amended Application.

c. structure and status of contracts

The EPC Contract with Black & Veatch is structured by a two-step process. Step 1- Upfront Engineering is the engineering stage with a fixed price for project costs. Step 2-Balance of Work is the detailed engineering, procurement and construction stage with the project costs for this stage having a fixed price limit. The EPC structure includes provision for scope of work adjustments so that the fixed price for Step 1 and Step 2 inclusive will not exceed the maximum fixed price limit set for the EPC Contract. The EPC Contract was finalized and executed by Black & Veatch's subsidiary and PUC Distribution on October 7, 2020.

d. *associated risk allocation*

The two-step process described was utilized so that undue risk premiums are not included in the EPC Contract pricing which would result given the quantity of engineering required to arrive at the best fit scope and specifications for the project. With the structure of the EPC Contract set, the EPC contractor remains responsible for the risk of project completion and performance until PUC Distribution certifies the project is complete as set out in the EPC Contract at Appendix AA3-7.

3. Overview of the SSG Project

PUC Distribution has one of the largest percentages of renewable energy generation penetration connected to its distribution utility network as ratio of system load of any LDC in Ontario, encompassing over 60 MW of embedded solar generation. PUC Distribution 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.

In part and to that end, PUC Distribution is proposing to develop the SSG Project—a community-scale smart grid in Sault Ste. Marie, Ontario—which will cover PUC Distribution's entire licensed service territory.

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.

The scope of the SSG Project involves the coordinated rapid implementation of a combination of well understood and proven smart grid technologies across the Applicant's entire distribution system, all at once. The specific smart grid technologies are well known, including distribution automation systems, voltage / VAR management systems, line regulators and associated communication systems, all of which will be integrated into the Applicant's AMI system.

The innovation in the project plan will see the implementation of these distribution system improvements in a coordinated manner across the entire distribution system, all at once with an EPC lead contractor and a project estimate consisting of a combination of the two-step EPC Contract described earlier. With this controlled cost approach and technology deployed, the SSG Project will increase the efficiency of the entire distribution grid, reducing electrical energy delivery requirements from the provincial transmission grid as well as greenhouse gas emissions and reducing total costs to consumers.

What this means is that through a combination of rate funding and a requested contribution from NRCan, the SSG Project can be implemented **without** adversely impacting costs to consumers.

The Applicant's core commitment with regards to the SSG Project is that:

The SSG Project will achieve an annual savings to PUC Distribution customers of over $2,332,953 in system loss and customer energy savings. An overall summary calculation of the benefits and

costs of the SSG Project is shown in the Table 1 below. Customer net benefits achieved through efficiencies in terms of reduced energy consumption and system losses will off-set additional revenue requirement requested. Customer reliability improvements were estimated at over two million annually as shown in the Table 1 below based on calculation of a net-present value ("**NPV**") of ~$33 million over 20 years or ~$52 million over 40 years by Navigant, which are additional non-bill benefit to customers (Navigant Report #3, page 10 and 15 – attached at Appendix AA10).

The calculation of energy savings ($2,332,953) as mentioned in Table 1 below, is further explained in the revised Project Benefits Estimate memo included in Appendix AA13 and calculation spreadsheet in Appendix AA14. PUC Distributions total system energy needs and associated purchase costs are calculated in the Cost of Power Forecast spreadsheet included in Appendix AA15. This data provides input to the VVM Energy Savings Estimate Spreadsheet included in Appendix AA14 to calculate the energy savings estimate.

Table 1: Customer Annual Net Benefit Summary

Cost of Power - updated to current estimate	$ 82,512,685	*App [AA15] -Cost of Power Spreadsheet*
Projected % energy savings with SSG implementation	2.70%	*App [AA14] -Energy Savings Spreadsheet*
Projected customer energy savings through SSG	$ 2,227,842	*App [AA14] -Energy Savings Spreadsheet*
Projected system loss energy savings through SSG	$ 105,111	*App [AA14] -Energy Savings Spreadsheet*
Total purchased power savings	$ 2,332,953	
ICM additional revenue from increased SSG asset base	$ 1,754,862	*ICM Model output*
Benefit of reduced capital expenditures witth SSG	($304,390)	*APP [AA17] CAPEX Deferral Spreadsheet*
Additional O & M expenses due to SSG implementation	$ 296,400	*App [AA13] -Project Benefit Estimate Memo*
Operating efficiency benefits due to SSG implementation	($30,816)	*App [AA13] -Project Benefit Estimate Memo*
	$ 1,716,056	
Annual net benefit to customers	$ 616,897	
Annual projected reliability benefit to customers	$ 2,017,000	*App [AA10] -Navigant Report #3 (NPV $33M)*
Total Annual projected benefit to customers w/reliability	$ 2,633,897	

The principle drivers for the changes in net benefits from the Original Application are as follows:

- Purchased Power estimates are higher than prior application due to increased purchased power cost prices from the IESO. Cost of Power used was based on annual internal estimates using the average supply cost summary from OEB 2019 report. Refer to Appendix AA15 for cost of power spreadsheet calculation and references.

- Using the 2.7% estimated energy savings the current total savings is over $2.3 million annually (increased from previous 2018 estimate of $2.1 million). More details can be found in Appendix AA13 – Project Benefits Estimate Memo.

- Note projected system energy and loss energy savings are still based on the 2018 Cost of Service normalized load forecast and can be referenced in Appendix AA14 spreadsheet.

- ICM additional revenue has decreased as a result of RFP process with the new EPC contract price and reduced total capital project cost. More details can be found in Section 2 and Section 4C.

- Benefit of reduced future capital expenditures although difficult to quantify, was forecast over a long term plan to reduce capital expenditures on station renewal and power transformer upgrades.

- Incremental OM&A projections reflect a net change on additional direct O&M work on new assets offset with improved smart grid work efficiency savings from smart device information, improved Supervisory Control and Data Acquisition ("**SCADA**") monitoring and control, and improved efficiencies in customer communications with new outage management system ("**OMS**") system.

Long term CAPEX savings benefits have been identified in industry smart grid projects through distribution automation[10] but have not been incorporated in to PUC Distribution long term Distribution System Plans at this time. The range of potential CAPEX savings could be greater

[10] Value of Distribution Automation Applications, Pier Final Project Report prepared for California Energy Commission – Public Interest Energy Research Program, April 2007.
Available online at: https://listserver.energy.ca.gov/2007publications/CEC-500-2007-028/CEC-500-2007-028.PDF

than shown but currently reflect achieving 50% of projected savings from deferral or elimination of substation and other capital expenditures in long term programs. With improved distribution system operation monitoring and control and associated additional data available for system planning and asset management long term efficiencies are expected to be attainable.

As noted above, there is a substantial overall benefit to the customers in PUC Distribution's service territory from the SSG project. However, with any change to rates, the effect on specific customers will vary. Table 2 below includes examples of bill impacts at various consumption levels once the SSG Project is included in rates. This bill impacts table is calculated using a full year revenue requirement of $1,754,862 as indicated in Table 1 above. The bill impacts below incorporated the 2.7% energy reduction savings offsetting the revenue requirement but do not reflect the additional $38,806 net savings estimated from the CAPEX benefit, the operating efficiency benefit and the additional O&M expenses or any value for projected reliability benefits.

Table 2: Customer Bill Impacts

Class	Consumption (kWh)	Consumption (kW)	Total Bill Increase/Decrease	Total Bill Impact %
Residential	750	0	-$0.04	-0.03%
Residential	825	0	-$0.27	-0.22%
Residential	738	0	$0.00	0.00%
Residential	2,000	0	-$3.98	-1.53%
GS<50	2,000	0	-$2.25	-0.77%
GS<50	815	0	$0.00	0.00%
GS<50	3,000	0	-$4.15	-0.96%
GS>50	19,740	55	-$38.17	-1.13%
GS>50	57,220	145	-$138.89	-1.48%
GS>50	142,465	452	-$327.65	-1.36%
GS>50	169,620	468	-$420.01	-1.51%

Customers will also gain the following additional benefits arising directly from the SSG Project, at no additional cost:

A. The SSG Project includes adaptive infrastructure which improves reliability and resiliency with self-healing networks and integrated data management systems for

normal outage planning and situational weather events with enhanced outage management capability. This will increase the overall reliability of the Applicant's distribution system. The estimated 20 year NPV of the customer reliability benefit is over $33M as previously referenced from Navigant work.

B. The SSG Project also provides an enabling platform for power system operating and control flexibility to support renewable energy and technology integration, and customer opportunities in energy services and solutions. This will better enable the Applicant to meet the Province of Ontario's different public policy objectives as they arise.

C. PUC Distribution will be able to utilize the new advanced distribution management system ("**ADMS**") platform to operate with increased system performance data and grid intelligence. Such operational intelligence will be critical in meeting new demands on system operators such as the continued growth in distributed energy resources ("**DER**") and emerging electric vehicle requirements. The system will support the core requirement to operate a safe, reliable and efficient distribution delivery network.

D. 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.

Moreover, the SSG Project will improve the economic attractiveness of the community as a place to live and establish new businesses. The Applicant expects the grid benefits to be very attractive to industries requiring higher reliability and high quality power, such as electronics manufacturing, e-commerce, telecommunication services, data centres, multi-modal shipping, and distribution hubs.

The SSG Project will be completed over a projected two (2) year project implementation period. The SSG Project is scheduled to go in-service by December 31, 2022.

PUC Distribution understands that the ICM is not available for incremental funding if a distributor's regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates. PUC Distribution confirms that this does not apply to PUC Distribution, which achieved a historical return on equity of 4.46% in 2015, 0.98% in 2016, 1.78% in 2017 and 4.25% in 2018.[11] Latest audit results show improved ROE for 2019 is 8.87% due to rebasing.

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. PUC Distribution customers would not receive the immediate and significant benefits identified in the SSG Project that could have been realized. A re-evaluation would be undertaken to determine a new course to follow in order to address the smart grid directives issued and to provide benefits to customers.

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

4. SSG Project Description and Business Case

A. SSG Project Overview

The PUC Distribution system is comprised of 12.5kV and 4kV feeders, with line distances and feeder attributes comparable with LDC's in Ontario. Currently, automation on PUC Distribution's system is minimal. For example, PUC Distribution current SCADA system does not extend past its substations.

The SSG Project deploys a strong foundation of state-of-the-art smart grid technologies and systems to support the goals of improving resiliency, reliability and outage management through automation and by leveraging existing AMI systems. Additionally, the SSG Project aims to reduce energy consumption behind the meter as well as distribution system losses. The key components of the SSG Project are a new ADMS and OMS, which will include the following functionality:

[11] Scorecard - PUC Distribution Inc. dated September 16, 2019: https://ssmpuc.com/documents/assets/uploads/files/en/2018_scorecard_-_puc_distribution_inc_.pdf

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

Each of these components is further detailed below.

(a) VVO

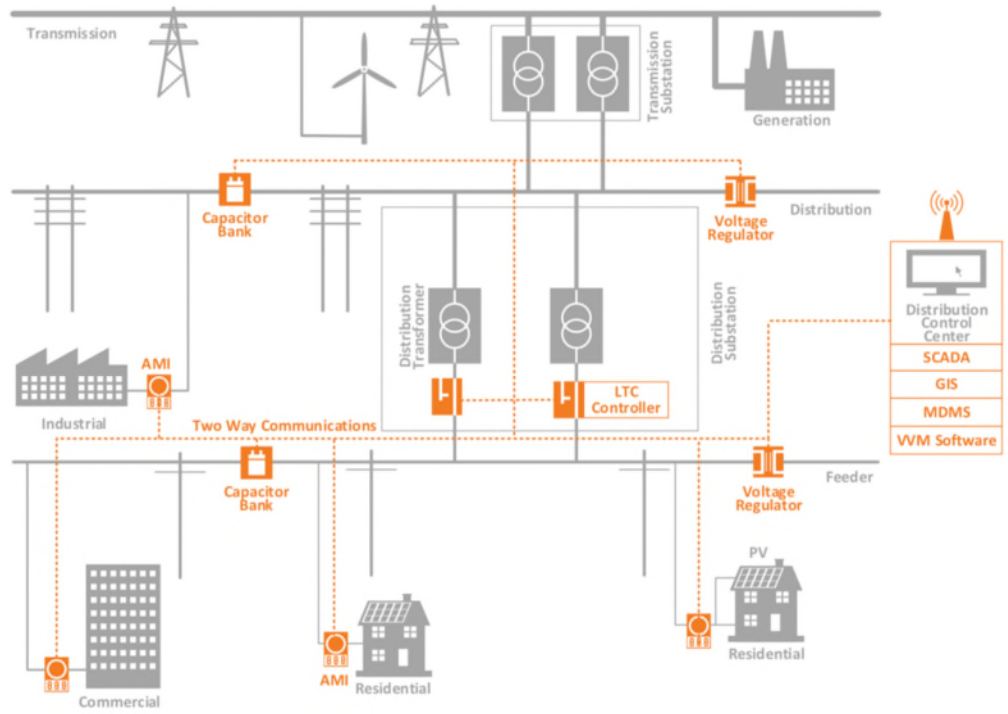
The SSG Project consists of the deployment of VVO to all 12.5 kV circuits. Existing 4 kV feeders that are part of a long-term voltage conversion program are not included but future design will be recognized where practical. The objective of VVO is to optimize the voltage profiles along feeder lines and to minimize the reactive power in lines to reduce electricity consumption, demand, and losses. This in turn can help avoid future investments in traditional transmission and distribution infrastructure upgrades and reduce the need for manual switching operations.

Currently, PUC Distribution does not have the capability to dynamically regulate voltage levels at any of its 34.5k/12.5 kV transformers.

The VVO scheme will be controlled centrally, will leverage PUC Distribution's existing AMI, geographical information system ("**GIS**") and SCADA systems, and will employ station feeder regulators and local circuit voltage regulators and capacitor banks. Load tap changer ("**LTC**") controllers, at PUC Distribution's stations will be considered in detail design work. The proposed VVO system will allow PUC Distribution to operate at the lower end of the acceptable voltage range and reduce reactive power in the feeders resulting in lower customer energy consumption, lower system losses and an overall system energy and demand reduction to the PUC Distribution system. In addition to PUC Distribution customer savings, provincial benefits will be achieved through reduced transmission grid and generation costs as less energy will be delivered to the PUC Distribution system. These provincial benefits are currently not included in PUC Distribution's "no net bill increase" assumptions.

Figure 1 below provides a schematic of the proposed VVO under the SSG Project. The VVO, further detailed in Leidos' Preliminary Design Report titled *Utility Distribution Microgrid: Volt/VAR Management (VVM)* dated October 17, 2014, is attached as Appendix AA7, although the current project scope has been adjusted since the 2014 work. Even though this preliminary work is almost 6 years ago it is still supportive of the technology proposed for the project. PUC Distribution considered a number of additional studies of US-based pilot projects on VVM technology over the past number of years and results from these continue to support the project benefits. A listing of a number of these studies is included for reference at page 7 of Project Benefits Estimate memo in Appendix AA13.

Figure 1: Schematic of the proposed VVO system



Source: Navigant

(b) DA

The SSG Project includes the deployment of DA to all 12.5 kV circuits. Existing 4 kV feeders that are part of a long-term voltage conversion program are not included, but future design will be recognized, where practical. The DA system is meant to provide PUC Distribution with better real-

time visibility and monitoring of the distribution network, which will allow it to automatically locate and isolate faults, reconfigure feeder circuits and restore power more rapidly. The key functionality of the DA system includes:

1. Monitoring and Control: This functionality enables real-time data acquisition and control of electric grid devices that are outside of the substation fence. These devices could be switches, reclosers, capacitors, regulators, sensors, meters, and fault current indicators ("**FCI**").

2. Fault Location, Isolation, Restoration (FLIR): The major function of FLIR is to provide 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. For this purpose, each feeder is divided into zones, as shown in Figure 2, and tie points between feeders are automated. When a fault occurs, the un-faulted downstream feeder zones are restored after analyzing all possible predetermined restoration scenarios, based on available capacity of the adjacent circuits. The FLIR system continuously monitors all related circuit flows to ensure proper load transfers throughout the restoration process. This process avoids overloading adjacent feeders as a result of transferring load from the un-faulted feeder zones.

3. Real-Time Power Flow: This 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. This feature enables calculation of system parameters such as voltage and current at each system node in real-time. Since real-time data is used, the results are more reliable than off-line simulation tools.

4. Auto-Transfer: Auto-transfer is 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.

The proposed systems will deploy reclosers and switches throughout the PUC Distribution network. In addition, the underground system in downtown Sault Ste Marie will benefit from the deployment of intelligent FCIs to decrease fault localization time.

Figure 2 below provides a schematic of conceptual DA system which includes creating zones for protection and FLIR. The DA system designed, further detailed in Leidos' Preliminary Design Report titled *Utility Distribution Microgrid: Distribution Automation* dated November 20, 2014, is attached at Appendix AA7**,** although the current project scope has been adjusted since the 2014 work. Although this work is six years old application to the current distribution system configuration will still be much the same in that system feeder configuration does not change a lot over time.

Figure 2: Schematic of conceptual DA system

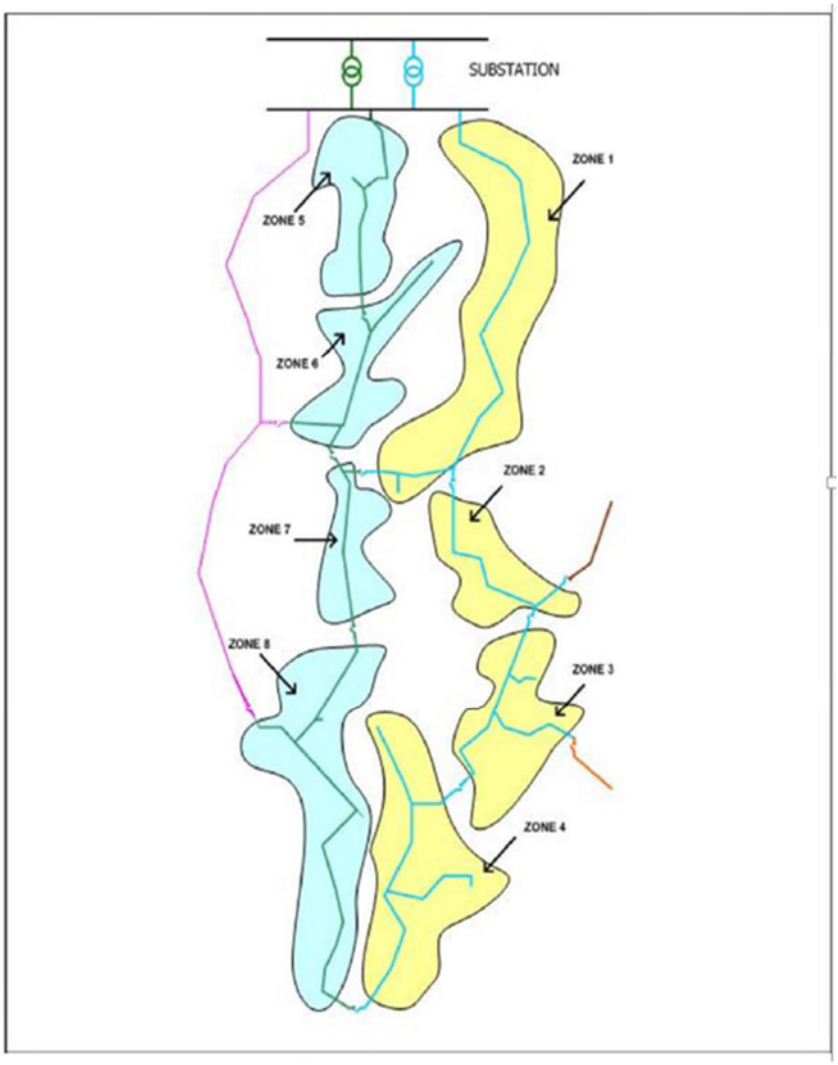
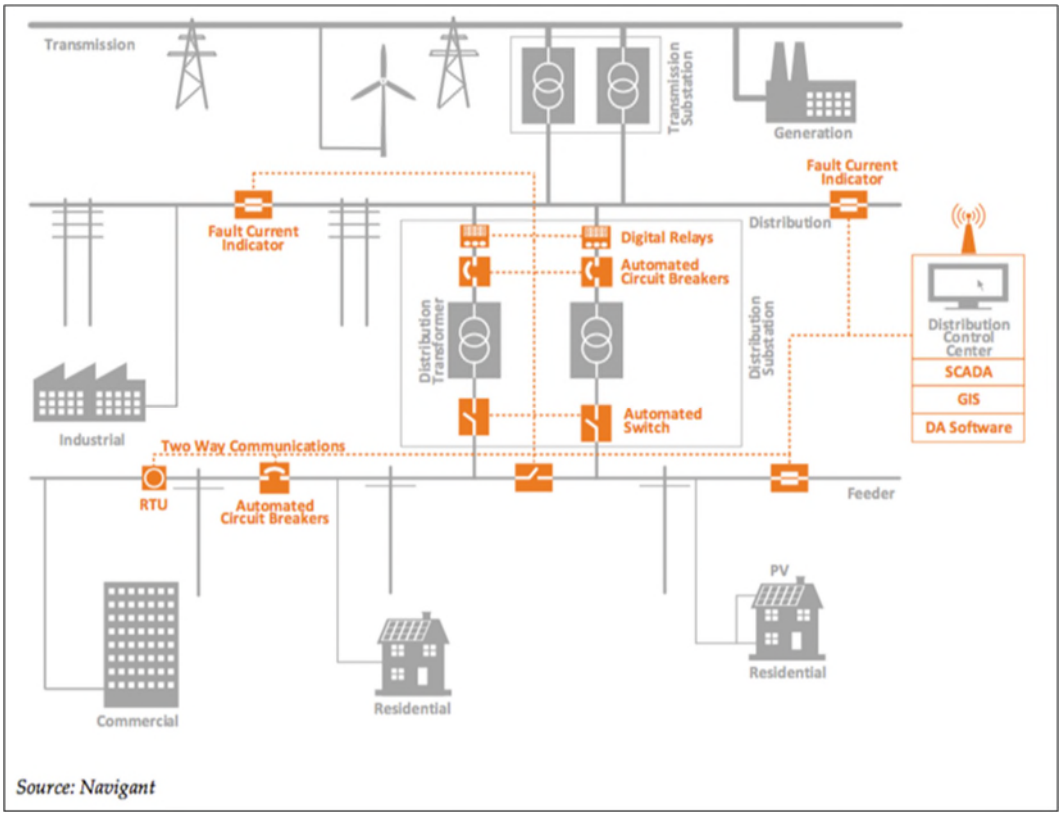


Figure 3 below provides a schematic of the proposed DA system under the SSG Project. The DA system, further detailed in Leidos' Preliminary Design Report titled *Utility Distribution Microgrid: Distribution Automation* dated November 20, 2014, is attached at Appendix AA7**.**

Figure 3: Schematic of the proposed DA system



(c) AMI Integration

The SSG Project will deploy a number of applications intended to leverage PUC Distribution's existing AMI system.

These include:

1. A robust OMS, which will integrate existing SCADA, AMI, and customer information system ("**CIS**") data and incorporate an interactive voice response ("**IVR**") system. The objective of the OMS is to complement the deployment of DA. The OMS will

automate reporting of outage information, reliability data, restoration verification, and improve customer communications during outages through the IVR system.

2. An enhanced customer service response ("**CSR**")/customer toolset ("**Enhanced CSR/Customer Toolset**") in order to manage AMI data in a more efficient manner. The SSG Project will incorporate upgrades and additional functionalities to maximize the value of the existing CIS, and to align its capability to track metrics and data inherent to the DA and VVO systems.

3. Improvement of AMI voltage reads in order to integrate data into VVO system. PUC Distribution's existing AMI platform will need to be modified in order to achieve the granularity and data requirements needed to maximize the VVO system.

4. An analytics platform to integrate and track SCADA, AMI, CIS, OMS and GIS data for better reporting and use.

The AMI integration, further detailed in Leidos' Preliminary Design Report titled *Utility Distribution Microgrid: AMI Integration* dated November 20, 2014, is attached at Appendix AA7.

B. Change to Distribution Infrastructure

The implementation of the SSG Project will alter PUC Distribution's distribution infrastructure and operational practices almost immediately but will also need to evolve with changing customer needs and system requirements. As PUC Distribution adjusts and moves through operational changes required in the beginning and over time for growing customer and system needs, changes to personnel, roles and responsibilities will need to be managed. Initial plans include dedicated operational support to meet needs of ADMS operation and new assets and equipment. Incremental hires (Net 2.5 full-time employees ("**FTE**")) are reflected in additional O&M estimates in future costs shown in Table 1 with some offset efficiencies to be realized over time with utilization of improved systems with better use of technology available. Direct project support will also have a resource impact that will require supplemental resources to maintain work programs through

temporary positions to cover staff allocated to the project. Reallocation of personnel will also be supplemented by additional hires to support the project implementation.

C. EPC Contract

The EPC Contract has been finalized and executed by PUC Distribution and Black & Veatch's subsidiary on October 7, 2020. A copy of the EPC Contract and its Appendices is attached as Appendix AA3-7. To meet PUC Distribution's important goals for delivering the SSG Project for a firm fixed price without compromising safety, quality and schedule, an RFP process was implemented in 2019 and subsequently PUC Distribution entered into an EPC contract with Black & Veatch. Fixed price amounts and an agreed maximum price limit for the project is further described in the EPC Pricing in Appendix AA3-6 and the EPC Contract at Appendix AA3-7. The two-step process described is used to arrive at the maximum EPC Contract price and is utilized so that undue risk premiums are not included in the EPC Contract pricing. This process recognizes the higher level of uncertainties and potential resulting costs that can be mitigated more fully and defined during the detailed design reviews required. A collaborative contract scope development approach will be executed by implementing the following two steps:

Step 1- Upfront Engineering: Perform the upfront engineering services at a fixed price based upon mutually agreed hours, rates and expenses as per Appendix A of the EPC Contract (see Appendix AA3-7 EPC Appendix A). An engineering package will be developed to a level of detail (~30%) to provide enough information to estimate the Balance of the Work (Engineering, Purchase equipment, Construction) for a firm price. A project execution plan would also be finalized during the Step 1- Upfront Engineering to confirm the scope and deliverables for the Step-2 Balance of the Work for the fixed maximum price that meets the safety, quality and schedule requirements. This pricing is now firm and complete.

Once the upfront engineering services is complete, it will lead to the commencement of Step 2 – Balance of Work.

Step 2- Balance of Work: Using the engineering package from Step 1 consisting of full design drawings & specifications, equipment pricing, develop a firm scope of work and a fixed price for

the Balance of Work using an open-to-close book process to negotiate any adjustment in accordance with the EPC Contract maximum price. PUC Distribution has full participation and visibility in a collaborative manner in developing the maximum price, which includes review and participation in the following:

- Engineering & Construction: Black & Veatch hours (at agreed rates) to complete the remaining engineering and manage and execute the construction.

- Procurement & Equipment Purchase: Selection of equipment and costs from PUC Distribution approved suppliers would be obtained on a competitive bid basis by Black & Veatch.

- Construction & Subcontractors: Selection of applicable subcontractor services from PUC Distribution approved suppliers would be obtained on a competitive bid basis by Black & Veatch.

- Miscellaneous Costs: Other related project costs, such as insurance, taxes per contract requirements, testing equipment, permit applications, travel and other general costs. These costs would be a direct pass through from Black and Veatch to PUC Distribution and would not include a mark-up or management fee.

Once the firm scope and price is agreed upon between PUC Distribution and Black & Veatch, the books would be closed and Black & Veatch would deliver the project for a firm fixed price. This way, PUC Distribution has created greater certainty on project costs and Black & Veatch remains responsible for the risk of project completion and performance.

If scope changes occur during project execution, PUC Distribution would have the advantage of using Black & Veatch's open book process to determine these price changes.

D. SSG Project Scope of Work and Specifications

The SSG Project is being executed as an EPC project, delivered by Black & Veatch, which will include design, procurement, installation, testing, and commissioning on technologies and applications described in section 4 (A) above**.**

The SSG Project scope of work and project tasks are further detailed in the EPC reference documents, which are attached hereto as Appendix AA3. These include:

- Scope Overview Summary (Appendix AA3-1)
- Physical Scoping Diagram (Appendix AA3-2)
- Logical Scoping Diagram (Appendix AA3-3)
- Responsibilities Matrix (Appendix AA3-4),
- Project Schedule (Appendix AA3-5), and
- Project Pricing (Appendix AA3-6).

Design and Construction Specifications documents have been revised from the previous application, but overall project elements remain the same. General specifications follow the same outline as original submission with greater changes in EPC provider project management scope, commissioning and metrics with more direct PUC Distribution role in the plan.

The 30% engineering design completed by Leidos (the "**30% Design**") and their scope of work developed provided the starting base which will be supplemented by additional engineering work by the EPC provider to cover the full distribution system and creation of a new 30% design stage of the project.

The outline of the design and construction specifications are summarized below:

(1) VVO scope includes designing, procuring, installing and commissioning a Volt/VAR control scheme on PUC Distribution's 12.5 kV distribution system.

A centralized model-based VVO software from Survalent will be installed at the PUC Distribution system control room. The interfaces with AMI and system models will be built so that VVO system can exchange data with these systems.

Each field device will be installed with a controller to enable data exchange. A cellular based communication system will be implemented by the EPC contractor to provide communication between field devices and the central software system. Field integration of all equipment will be accomplished**.** LTC controller and regulator settings will be determined and applied to the associated equipment. SCADA points list will be developed, and data acquisition system of these points will be established.

A more detailed project overview and scope is included in Appendix AA3-1.

(2) DA scope includes designing, procuring, installing and commissioning a distribution automation system that will improve reliability on PUC Distribution's 12.5 and 34.5 kV distribution and sub-transmission systems.

In the scope of work, centralized control software and FLIR will be installed at the PUC Distribution control room. The interfaces with AMI and GIS will be built so that DA system can acquire data from these systems.

The scope of work identified during the previous Leidos 30% design stage had, 38 reclosers, 40 load-break switches, 4 4-way pad-mount switches, 4 2- way pad-mount switches 32 3-phase overhead fault current indicator sets and 37 3-phase underground fault current indicator sets to be deployed to the system. With the current project scope these quantities and locations will be reviewed, and any changes needed in feeder devices for quantity and locations will be addressed in the detailed design phase.

Each field device will be installed with a controller to enable data exchange. A cellular based communication system will be implemented by the EPC contractor

to provide communication between field devices and the central software system. Field integration of all equipment will be accomplished. Controllers and protective relays settings will be determined and applied to the associated equipment. SCADA points list will be developed, and data acquisition system of these points will be established.

A more detailed project overview and scope is included in Appendix AA3-1.

(3) AMI integrations will leverage AMI data from existing systems into operational, engineering, and customer service domains in order to track outages, monitor and manage voltage, improve customer and internal key-performance indicators, and allow for more accurate problem identification, isolation and response.

The AMI aspect of the SSG Project is made up of the following:

- OMS
- Enhanced CSR/Customer Toolset
- Improved Voltage Measurement Granularity

(4) Data Analytics and Performance Reporting

(i) **Outage Management System ("OMS")**

The OMS will include:

- A robust off-the-shelf platform including advanced Interactive Voice Response ("**IVR**") technology for enhanced communications of outages to customers;
- The integration of the platform to SCADA, AMI, and CIS in order to measure, track and relay outage information to customers in real-time as well as track outage metrics historically; and

- The implementation of a platform at PUC Distribution, with SCADA, AMI, and CIS, in order to measure and track outage information in real-time and historically.

(ii) **Enhanced Customer Service Response (CSR)/Customer Toolset**

Enhancing CSR will optimize the organization and presentation of AMI data in a CSR as well as more customer friendly UI such that better answers can be given on a wider set of questions with defensible data (Specifically reliability and cost/usage trends, but also quality and creation, revision, update and delete record management.

(iii) **Improved Voltage Measurement Granularity**

The project will modify the Sensus AMI system to more frequently call-in supervisory messages with Voltage min/avg./max and integrate data to the new platform.

(iv) **Data Analytics Performance Reporting**

This was included in the Original Application but PUC Distribution no longer anticipates this to be part of the contract and will look to develop this over the long run with internal development.

To implement the SSG Project, numerous system components need to be installed or upgraded. Examples of the types of equipment to be installed are detailed in Tables 3 below.

Table 3: Summary of Equipment to be Installed/Modified

34.5 kV Sub-transmission	FCIs and auto-transfer scheme	Nine (9) 34.5 kV feeders from two (2) 115 kV TS's supply 14 DS's (12 @34.5/12.5kV and 2 @ 34.5/4.16kv)
12.5 kV Feeders	Pole and padmount equipment: switches, reclosers, voltage regulators & capacitors	4x12 (48) 12.5 kV feeders from 12 DS's 3 older 4.16 kV feeders will be designed for upcoming 12.5 kV voltage conversion program

Conceptual Major Electrical Equipment and Field Devices Bill of Material

EQUIPMENT TYPE FROM TABLE [12]	FDIR OR VVO	VENDOR	DESCRIPTION	QUANTITY
Pole top Switches	FDIR	S&C	SCADA-Mate 15kV, with controller (IED)	TBD (26)
Pole top Reclosers	FDIR	S&C	Intellirupter 15kV, with SpeedNet™ Radio and controller	TBD (25)
2-way Pad mount Switches	FDIR	S&C	PMH-3 underground 15kV switchgear, with 6801 automatic switch controller	TBD (3)
4-way Pad mount Switches	FDIR	S&C	Vista 4-Way underground 15kV switchgear, with controller	TBD (3)
O/H FCI	FDIR	Eaton	O/H FCI- Eaton GridAdvisor Series II, 3phase set	TBD (30)
U/G FCI	FDIR	Eaton	U/G FCI- Eaton GridAdvisor Series II, 3phase set	TBD (19)
Sta. Reg 333 KVA	VVO	Eaton	Substation Regulators, 333 kVA, 438A, 14.4kV, 150 kV BIL (set of 3), with CL-7 control (IED)	TBD (32)
Fdr. Reg 167 KVA	VVO	Eaton	Line Regulator, 167kVA, 200A, 7.62 kV, 95kV BIL (set of 3), with CL-7 control (IED)	TBD (2)
Capacitor 600 KVAR	VVO	Eaton	3x200kVAr, 12.5kV	TBD (2)
	Auto Transfer	Eaton	O/H FCI- Eaton GridAdvisor Series II, 3phase set	TBD (16)[12]

E. Revenue Requirement

PUC Distribution has completed the 2021 Capital Module Applicable to ACM and ICM - Version 5.01 and has provided both a hard copy (see Appendix AA16) and a live Excel file of the model. PUC Distribution used the 2021 model as it is the most recent version available. On Tab 3. Growth Factor, the information requested is 2020 Actual Distribution Demand. The numbers presented are 2019 actuals since 2020 actuals are not yet available.

The total capital cost of the SSG Project is estimated to be $33,007,038. The SSG Project is scheduled to be in service by December 31, 2022**.** The SSG Project estimate is presented in more detail in the Project Cost Estimate memo and attached hereto as Appendix AA12-2.

Ongoing operation and maintenance costs in terms of operating and maintaining the SSG Project, as well as any impacts on operating and maintaining other utility assets, are estimated at ~$29,250 per month. These costs will form part of the overall OM&A evaluation in PUC Distribution's next cost of service rate application, in 2023. Preliminary forecasts for operation management of the smart grid systems are included in the range of 2.5 to 4.5 FTE with skill areas in operations, engineering and information technology along with field crews on new line and station assets. Increased costs will be offset, at least in part, through anticipated operational efficiencies and savings with improved asset performance awareness, operating response and intelligent devices utilizing self-diagnostic systems. The project net benefit analysis used a 3 FTE forecast which will be evaluated in more detail prior to PUC Distribution's next cost of service application in 2023.

The SSG Project will still benefit from the 25% NRCan contribution. With the estimated cost of the SSG Project now reduced, pursuant to the NRCan agreement the lesser of 25% of total project costs is applied so the total monetary value of the NRCan contribution will decrease accordingly (now estimated at $8,126,759, which is 25% of current eligible cost project estimate of $32,507,038 ($33,007,038 less ~$500,000 as estimated ineligible to NRCan program as costs incurred before contribution eligibility period and estimated legal costs). With the incurred project delays the NRCan Agreement was updated with the revised project structure and Scope of Work statement and executed in December 2019. A copy is filed with this Application at Appendix AA4-2. As mentioned above, NRCan has extended the eligible expense end date to

March 31, 2023 and PUC Distribution and NRCan are now in the process of entering into an updated NRCan Agreement. Once the OEB rate process is complete a further amendment will be arranged with NRCan with updated project estimates and timelines. Hence, after the capital contribution from the NRCan Funding is applied, the net cost of the SSG Project will be $24,880,278.

This NRCan Funding amount has been factored into the calculation of capital expenditure and rate riders for the purposes of this ICM.

PUC Distribution will be responsible for investing the balance of the SSG Project cost. As such, the Applicant is requesting as part of its ICM for the SSG Project approval of a net capital expenditure exceeding the materiality threshold of $5,568,011 in 2022.

(1) Application of the Half-Year Rule (3.3.2.4 at p. 27)

Pursuant to the OEB's Accounting Direction[12], the OEB's approach has been to apply the half-year rule in cases in which the ICM request coincides with the final year of a distributor's IRM plan term. PUC Distribution's last Cost of Service was in 2018 and its IRM plan term is from 2018 to 2022. Its next Cost of Service will be in 2023. As such, PUC Distribution has applied the half-year rule in this request for incremental revenue because this ICM request coincides with the final year of PUC Distribution's IRM plan term. PUC Distribution will collect these rate riders until April 30, 2023 at which time PUC's new rates will take effect from the 2023 Cost of Service Application.

This amount of eligible incremental capital results in an incremental revenue requirement of $875,610 including the effects of the half-year rule as calculated in Table 4 below.

[12] *Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance*, July 25, 2019

Table 4: Eligible Incremental Capital for ACM/ICM Recovery

Incremental Capital Adjustment **Rate Year:** 2022

Current Revenue Requirement

Current Revenue Requirement - Total	$	19,273,165	**A**

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim	Eligible for ACM/ICM (Half Year* Prorated Amount) (from Sheet 10b)	
Amount of Capital Projects Claimed	$ 24,828,660	$ 12,414,330	**B**
Depreciation Expense	$ 695,799	$ 347,900	**C**
CCA	$ 2,722,959	$ 1,361,480	**V**

**The half year rule is applied as the distributor is scheduled to rebase in the next rate year.*

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$	12,414,330	**B**
Depreciation Expense (prorated to Eligible Incremental Capital)			$	347,900	**C**
Incremental Capital to be included in Rate Base (average NBV in year)			$	12,240,380	**D = B - C/2**
	% of capital structure				
Deemed Short-Term Debt	4.0%	**E**	$	489,615	**G = D * E**
Deemed Long-Term Debt	56.0%	**F**	$	6,854,613	**H = D * F**
	Rate (%)				
Short-Term Interest	2.29%	**I**	$	11,212	**K = G * I**
Long-Term Interest	4.12%	**J**	$	282,410	**L = H * J**
Return on Rate Base - Interest			$	293,622	**M = K + L**
	% of capital structure				
Deemed Equity %	40.00%	**N**	$	4,896,152	**P = D * N**
	Rate (%)				
Return on Rate Base -Equity	9.00%	**O**	$	440,654	**Q = P * O**
Return on Rate Base - Total			$	734,276	**R = M + Q**

Amortization Expense

Amortization Expense - Incremental	**C**	$	347,900	**S**

Grossed up Taxes/PILs

Regulatory Taxable Income	**O**	$	440,654	**T**
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)	**S**	$	347,900	**U**
Deduct CCA (Prorated to Eligible Incremental Capital)		$	1,361,480	**V**
Incremental Taxable Income		-$	572,926	**W = T + U - V**
Current Tax Rate 26.5%	**X**			
Taxes/PILs Before Gross Up		-$	151,825	**Y = W * X**
Grossed-Up Taxes/PILs		-$	206,565	**Z = Y / (1 - X)**

Incremental Revenue Requirement

Return on Rate Base - Total	**Q**	$	734,276	**AA**
Amortization Expense - Total	**S**	$	347,900	**AB**
Grossed-Up Taxes/PILs	**Z**	-$	206,565	**AC**
Incremental Revenue Requirement		$	875,610	**AD = AA + AB + AC**

F. Capital Cost Allowance (CCA)

Bill C-97 includes an Accelerated Investment Incentive which affects PUC Distribution's CCA calculations in this ICM application. 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 accelerated CCA was introduced subsequent to PUC Distribution's last Cost of Service rate application.

The calculation of CCA is shown in the following table. Table 5 illustrates the calculation of the CCA deductions for the SSG project for the year 2022. The CCA for the additions in 2022 is based on total assets put in service in 2022 (half-year rule) at a CCA rate prior to the accelerated rates introduced in Bill C-97.

Table 5: Depreciation and CCA Calculations for Net Capital Expenditure

	Cost of Addition	Contributed Capital	Net Addition	# Years	Deprec Rate	Deprec Exp	Eligible for ACM/ICM (Half Year*Prorated Amount)	CCA Class	CCA Rate	2022 CCA 8%	Eligible for ACM/ICM (Half Year*Prorated Amount)
1820 DS Equipment	$473,156	$116,497	$356,659	40	2.50%	$8,916	$4,458	47	8%	$28,533	$14,266
1830 Poles & Fixtures	$4,745,488	$1,168,400	$3,577,087	45	2.20%	$78,696	$39,348	47	8%	$286,167	$143,083
1835 OH Conductors & Devices	$15,943,059	$3,925,387	$12,017,672	60	1.67%	$200,695	$100,348	47	8%	$961,414	$480,707
1840 UG Conduit/Civil	$399,913	$98,464	$301,449	50	2.00%	$6,029	$3,014	47	8%	$24,116	$12,058
1845 UG conductors & Devices	$799,827	$196,928	$602,899	40	2.50%	$15,072	$7,536	47	8%	$48,232	$24,116
1850 Line Transformers	$7,097,338	$1,747,456	$5,349,882	40	2.50%	$133,747	$66,874	47	8%	$427,991	$213,995
1920 Computer S/W	$1,064,477	$262,088	$802,389	5	20.00%	$160,478	$80,239	12	100%	$802,389	$401,194
1980 System Supervisory Equipment	$2,483,780	$611,539	$1,872,241	20	5.00%	$93,612	$46,806	47	8%	$149,779	$74,890
In Service Dec. 31, 2022	$33,007,037	$8,126,759	$24,880,278			$697,246	$348,623			$2,728,620	$1,364,310

Any variances in revenue requirement as a result of Bill C-97 will be captured in the Account 1592 sub-account for CCA changes. This method is consistent with the Board's decision in EB-2019-0170, PUC Distribution Inc. Application for 2020 Electricity Distribution rates, page 12.

As described above, the NRCan Funding will greatly reduce the cost of the SSG Project and a reduction to the costs of PUC Distribution's ratepayers. The decision to develop the SSG Project at this time, once in receipt of the NRCan Funding, is the most prudent action for PUC Distribution to make and represents the most cost-effective option to date.

5. Materiality (3.3.2.1-3.3.2.3 at pp. 25-27)

The SSG Project is a major capital expenditure which is entirely incremental to PUC Distribution's grid sustaining capital program as outlined in the DSP. When the SSG Project is considered together with PUC Distribution's grid sustaining capital program for 2022 it exceeds the materiality threshold as calculated in the attached ICM model and as more clearly described below.

A. ICM Materiality Threshold

PUC Distribution's materiality threshold for 2022 is $5,568,011, as calculated in Table 7 below.

Table 7: PUC Distribution 2022 Materiality Threshold Calculation

Final Materiality Threshold Calculation

$$\textbf{ld Value}\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times \left((1+g) \times (1+PCI)\right)^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2018**
Price Cap IR Year in which Application is made		**4**
Price Cap Index		**1.70%**
Growth Factor Calculation		
Revenues Based on 2020 Actual Distribution Demand		$19,619,926
Revenues Based on 2018 Board-Approved Distribution Demand		$19,752,630
Growth Factor		**-0.34%**
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	**$**	**99,658,055**
Depreciation	**$**	**3,780,329**

Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)	
Price Cap IR Year 2019	**146%**
Price Cap IR Year 2020	**146%**
Price Cap IR Year 2021	**147%**
Price Cap IR Year 2022	**147%**
Price Cap IR Year 2023	**148%**
Price Cap IR Year 2024	**148%**
Price Cap IR Year 2025	**149%**
Price Cap IR Year 2026	**149%**
Price Cap IR Year 2027	**150%**
Price Cap IR Year 2028	**150%**

Threshold CAPEX	
Price Cap IR Year 2019	**$ 5,512,092**
Price Cap IR Year 2020	**$ 5,530,481**
Price Cap IR Year 2021	**$ 5,549,119**
Price Cap IR Year 2022	**$ 5,568,011**
Price Cap IR Year 2023	**$ 5,587,159**
Price Cap IR Year 2024	**$ 5,606,568**
Price Cap IR Year 2025	**$ 5,626,240**
Price Cap IR Year 2026	**$ 5,646,179**
Price Cap IR Year 2027	**$ 5,666,389**
Price Cap IR Year 2028	**$ 5,686,874**

B. Assessment of Materiality (3.3.2.3 at p. 26)

The SSG Project's capital expenditure being proposed for recovery is a significant expenditure within the context of PUC Distribution's overall capital budget.

Table 8 below is the reconciliation from the proposed capital expenditures as filed in the DSP to the proposed capital expenditures in this ICM.

Table 8: Reconciliation of Proposed Capital Expenditures as Filed in the DSP to Proposed Capital Expenditures in this ICM

The variance from the 2018 DSP plan is explained below:

Proposed CAPEX 2018 to 2022 including SSG	$59,764,014
Capex 2018 to 2022 per DSP from approved 2018 CoS rate application	$34,283,736
Variance from DSP	$25,480,278
SSGincluded in Proposed Capex	$24,880,278
Variance from DSP excluding SSG	$ 600,000

The variance from the DSP of $600,000 is the result of the inclusion of on-load tap changers in the Sub 16 rebuild as approved in ICM application EB-2019-0170.

The calculations in Table 9 below indicate that with a requested SSG Project cost of $24,880,278 and a threshold of $5,568,011, as calculated above, an incremental capital amount of $27,927,207is eligible for inclusion in the ICM.

Table 9: Materiality Calculations

	Cost of Service	*Price Cap IR*	*Price Cap IR*	*Price Cap IR*	*Price Cap IR*
	Test Year	Year 1	Year 2	Year 3	Year 4
	2018	2019	2020	2021	2022
CAPEX[1]	$ 5,388,176	$ 5,275,803	$ 9,100,376	$ 6,096,546	$ 33,495,218
Materiality Threshold		$ 5,512,092	$ 5,530,481	$ 5,549,119	$ 5,568,011
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)		$ -	$ 3,569,895	$ 547,427	$ 27,927,207

		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												$ 24,880,278	$ 697,246	$ 3,691,736
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,880,278	$ 697,246	$ 3,691,736
Maximum Allowed Incremental Capital			$ -			$ -			$ -			$ 24,880,278		

6. Need (3.3.2.1 at p. 25)

The policy and regulatory direction to the local distribution utility sector has been clearly towards development and utilization of smart grid technologies. There are continuing expectations from customers for cost control, sustained or improved reliability and direct communication and participation with their utility, as well as better service options and choices in how they can interact with their utility. Increasing development of distribution connected DER technologies and electric vehicle use is expected to continue the growing operational performance and delivery requirements falling on the management systems of distribution system operators. These developments are further examples of the challenges facing distribution utility operations both now and in the near future. These factors are creating the recognition and need for better operational system monitoring, control and access to real-time data as one of the primary challenges facing distribution utilities and PUC Distribution. Integration of smart grid technologies in to day to day operations is becoming necessary for a safe, reliable system.

The SSG Project provides PUC Distribution with efficient and cost-effective tools and data to meet and solve these challenges. The sooner the SSG Project is developed, the sooner PUC Distribution can begin to identify, anticipate and solve them.

Throughout the development period of the SSG Project, PUC Distribution was also developing its most recent cost of service application. Customer engagement during this period consistently and clearly indicated that the customer's primary concern is their bill (cost of electricity), continuing or improved reliability, and improved communication from and with their utility. Although PUC Distribution could see need for development of smart grid operation emerging, there was a clear awareness of the balance needed between new system investments and managing the impact on the customer's bill. The mandate developed internally was to strive for "no net bill increase" for PUC Distribution customers. With the significant opportunity presented to PUC Distribution and its customers with the new NRCan Smart Grid Program, the need was within reach with the right balance being achieved. Efforts were applied to build a strong application and we were ultimately successful with an executed Contribution Agreement and currently an estimated $8,126,759 funding contribution towards the SSG Project.

PUC Distribution believes the SSG Project will contribute to the four main performance outcomes of the utility Regulatory Scorecard (Customer Focus; Operational Effectiveness; Public Policy Responsiveness and Financial Performance).

Customer Focus elements are reflected in the customer engagement directions from customers to focus on cost control, especially in total bill impacts. The VVO systems' ability to lower energy use and system losses for customers will be a key deliverables of the SSG Project. Improved CSR/customer interaction and communication will be the outcome from new toolsets developed in the CIS and OMS systems.

Operational Effectiveness is clearly an outcome to be delivered through improved operational systems and control along with reliability improvements achieved through the self-healing network DA systems. Operational and capital program efficiencies over the long term will be supporting asset management and cost control solutions.

From the perspective of Public Policy Responsiveness, the SSG Project had its genesis in some of the regulatory smart grid drivers along with industry forecasts to meet integration and penetration of increasing DER and other new emerging technologies.

From the perspective of Financial Performance outcomes, the SSG Project is expected to maintain successful financial performance requirements for PUC Distribution and is especially timely in application of significant government funding support to develop and implement new technologies that benefit both existing customers and new entrants to the distribution system.

The NRCan Funding significantly decreases the costs of the SSG Project that local ratepayers would otherwise have to bear. The NRCan Funding also makes it possible to implement the SSG Project with "no net bill increase" to PUC Distribution customers.

Based on the preliminary design and cost-benefit projections which are based on the 30% Design, the SSG Project will provide the following benefits to customers, the community, and the environment:

1. Electricity customers will see direct savings in their bills due to improved energy efficiency through voltage regulation. Moreover, asset utilization and efficiency will be improved through energy use reduction and reduction of maintenance, repair, and replacement of equipment.

2. The increased reliability and resilience of the new system architecture, which is achieved through reduced interruption frequency and duration, and more rapid recovery in the face of severe weather events and other causes of power outage, further allows the utility and the province to defer or eliminate certain capital expenditures across the distribution, transmission and generating sectors.

3. The region will benefit from reduced load on the transmission grid through both peak shaving and reduced overall load.

4. The community benefits from increased reliability and enhanced power quality.

5. PUC Distribution will be able to better monitor and control impacts from DER, EV and other market driven enhanced energy services from its customers, utilizing existing system intelligence at the meter and new technologies supporting the advanced distribution management system. The SSG Project will enable consumers to either directly, or through other providers such as energy services utilities, adopt systems behind the meter, to communicate and coordinate with PUC Distribution's smart grid.

6. Increased system flexibility and renewable energy penetration—the SSG Project enables additional penetration of renewable generation, such as photovoltaics, energy storage (batteries), cogeneration, and electric vehicles, and support smart cities and other community economic development activities.

7. The system will generate new economic opportunities for a Northern community evolving towards a diversified smart energy and information, communications and technology (ICT) economy.

8. Reduced greenhouse gas ("**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.

9. 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 reinforced as they are built out and integrated.

The SSG Project was not included in PUC Distribution's most recent cost of service, and was therefore outside of the base upon which current rates were derived. The incremental capital requested in this ICM is directly related to the cost for developing and deploying the SSG Project.

The incremental revenue requested is net of government funding and there are no new customers or load growth as a direct result of the SSG Project. The incremental revenue requested will not be recovered through other means.

7. Prudence (3.3.2.1 at p. 25)

PUC Distribution has three options with regards to its pursuit of the SSG Project:

1. **Option "A"** is for PUC Distribution to pursue and develop the SSG Project over two (2) years following OEB approval, as contemplated in this ICM.

2. **Option "B"** is for PUC Distribution to pursue and develop the SSG Project over ten (10) or more years in order to spread out the costs of the SSG Project on PUC Distribution's ratepayers.

3. **Option "C"** is to not pursue or develop the SSG Project at all.

As demonstrated throughout this ICM, Option "A" is the most prudent, cost-effective and most efficient option of the three. An assessment of each option is provided below.

A. Option "A"

Option "A" is for PUC Distribution to develop the SSG Project over 2021 and 2022 following OEB approval, as contemplated in this ICM. This is the recommended option for two main reasons:

1. It allows PUC Distribution's ratepayers to realize, by December 31, 2022, the benefits associated with direct savings in their bills due to improved energy efficiency through voltage regulation, increased reliability and resilience of the grid due to DA, and the other benefits detailed in Section 6 above; and

2. It allows PUC Distribution and ratepayers to take advantage of the savings resulting from the NRCan Funding, which will reduce the capital cost of the SSG Project by $8,126,759, as provided in Table 10 below. As further detailed in Section 7(B) below, the NRCan Funding requires projects to be completed by March 31, 2023. Under Option "A", the SSG Project will be in-service by December 31, 2022; hence, this option satisfies the revised NRCan Funding timeframe.

The main drawback of Option "A" is that it requires ratepayers to cover the costs to implement the SSG Project in the amount of $24,880,278 in a one year rate change, rather than over 10 years as contemplated by Option "B". However, as discussed above and in Section 7(B) below, Option "A" allows ratepayers to realize the benefits associated with the SSG Project nine (9) years earlier (starting in 2022 versus 2031 under Option "B"), and to enjoy overall cost savings by taking advantage of the NRCan Funding, which is unavailable under Option "B".

Table 10: Capital Costs of SSG Project for Option "A"

Estimated Capital Cost of SSG Project	$33,007,038
NRCan Funding Amount	$8,126,759
Net SSG Project Cost After Deducting NRCan Funding	**$24,880,278**

B. Option "B"

Option "B" contemplates the development of the SSG Project over ten (10) years in order to spread out the costs of the SSG Project on PUC Distribution's ratepayers. Although Option "B" results in lower annual costs for ratepayers in the year 2022, it is not recommended for the following reasons:

1. Completing the project over a ten (10) year timeframe would cause PUC Distribution to forfeit the NRCan Funding, since a 2031 in-service date for the SSG Project exceeds the required completion date of March 31, 2023 under the NRCan Funding. Absent the NRCan Funding, the ratepayer will be liable to cover the full cost of $33,007,038 (or higher if additional mobilization costs are incurred with the multiple year approach) to implement the SSG Project.

   Table 11 below provides two cash flow profiles for the SSG Project over a ten (10) year timeframe: (i) a straight-line model which assumes no cost escalation; and (ii) an escalated model which assumes a Consumer Price Index ("**CPI**") rate of 2%.

   Table 12 provides the NPV of the project cash flow over 10 years adjusted for CPI of 2%. Two different discount rates of 3% and 5% were used to arrive at the present value of future cash flows. This yielded a present value of $31,535,796 and $29,010,367 at 3% and 5% respectively. Completing this project in 2022 represents a savings of $4,130,089 ($29,010,367 - $24,880,278) at the higher discount rate.

2. The direct savings due to improved energy efficiency through voltage regulation cannot be fully realized until the entire SSG Project is in-service. Option "B" phases the in-service date to an annual progress from 2022 to 2031, thereby deferring direct savings for some ratepayers by up to nine (9) years.

3. All other benefits for some ratepayers associated with the SSG Project will, similarly to above, be delayed by up to nine (9) years, including: increased system flexibility, reliability, forecasting and responsiveness; increased renewable energy and electric vehicle integration; reductions in line losses, delivery requirements from the

transmission grid, GHG emissions, better customer service responsiveness and ratepayer opportunities in energy services and solutions; and all of the other system benefits described herein.

4. SSG Project deferral could result in higher development costs, as EPC contractor mobilization and demobilization costs would bring higher costs to the work and the higher investment in the SSG Project costs would need to be borne by ratepayers over that period of time.

Table 11: Capital Cost Cash Flows of SSG Project for Option "B"

Cash Flow Profile	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
(i) Straight Line (No Price Escalation)	$3,293,821	$3,293,821	$3,293,821	$3,293,821	$3,293,821	$3,293,821	$3,293,821	$3,293,821	$3,293,821	$3,293,821	**$32,938,213**
(ii) Escalated (assuming CPI Annual Cost Impact	$3,293,821	$3,359,698	$3,426,892	$3,495,430	$3,565,338	$3,636,645	$3,709,378	$3,783,565	$3,859,237	$3,936,421	**$36,066,424**

Table 12: Net Present Values of SSG Project for Option "B"

Cash Flow Profil	Total Cost	NPV (3% Discount Rate)	NPV (5% Discount Rate)
(ii) Escalated (assuming CPI Annual Cost Impact of 2%)	$36,066,424	$31,535,796	$29,010,367

C. Option "C"

Option "C", the "do nothing" option, is not recommended because it prevents PUC Distribution from modernizing its grid and keeping up with the technological advances facing all utilities. This is contrary to good utility practice. Additionally, if PUC Distribution pursues Option "C", the NRCan Funding would be forfeited as the timeframe for funding is five years, starting April 1, 2018 to March 31, 2023. Although ratepayers will incur no incremental costs under this option, ratepayers would not receive any of the benefits associated with the SSG Project, as detailed in Section 6 above.

Moreover, in keeping with good utility practice, the SSG would likely still need to occur at some point in the near future in order to ensure that PUC Distribution's grid operation is able to meet

the needs of the increasing challenges for distribution system operators as well as the mandate the OEB has set for distributors. As new DER technologies become more cost competitive, numerous and interconnected to distribution systems it will require enhanced monitoring and control systems including such systems as voltage control and remote switching, being necessary to operate a safe and reliable distribution system to meet industry utility practice standards. As such investment becomes necessary, our ratepayers will lose the cost reductions afforded by the NRCan Funding, which is only available to us prior to March 31, 2023.

D. Additional Considerations

In the Navigant Report #2, attached at Appendix AA9, Navigant concludes the SSG Project is technically sound, designed and configured consistent with current utility practices.

As indicated earlier, the SSG Project has been evolving through a number of iterations and changes in project scope and scale over the past five (5) years since the initial 30% Design work. PUC Distribution's engineering and operations staff had opportunity for input and cost review throughout this process including access to work of line contractors brought in by the prior developer to provide estimates for some of the field construction works. Fundamentally the core scope of work for voltage optimization and distribution automation has remained consistently directed towards achieving improved and enhanced distribution system performance to the benefit of current and future customers.

The scope of work has been confirmed with the EPC Contractor and reviewed extensively internally by PUC Distribution to deliver a successful project delivering the expected outcomes at the expected costs. Total project cost estimates have been developed to fully consider the fixed EPC costs, developing final portion of EPC costs from a controlled upset limit and internal estimates with contingencies to arrive at the current final project cost estimate for the SSG Project. The amended application cost estimate reflects a reasonable breakdown in engineering and construction costs including ~7.5% for PUC Distribution project management, legal and regulatory costs including oversight as further detailed in Appendix AA12 – Project Cost, which included Appendix AA12-1 Project Cost Summary, Appendix AA12-2 Project Cost Estimate Memo and Appendix AA12-3 SSG Revised Scope and Project Estimate Summary Live Excel Model.

PUC Distribution had an internal objective from early in the concept of the smart grid project which was to aim for an average "no net bill increase". This objective was specifically directed to the residential and under 50kW customer groups. As the analysis for the project cost/benefit was being developed, the challenge of expressing, in some cases, long term NPV values along with current and near term bill impact savings was recognized as much for internal communication as external understanding and need. Full access to the Leidos-detailed base work, which looked at a full feeder by feeder analysis with customer GIS locational and connection data, allowed for thorough understanding of benefit calculations on the complete supply chain from the customer to the provincial system and energy supply.

After internal discussion the decision to not overly rely on non-bill savings such as reliability improvements but focus on the customers' main perspective "the bottom line on their bill", a strong theme from customer engagement was reaffirmed and the "no net bill increase" became the primary metric for success using energy savings criteria for customers directly plus system losses savings.

The estimated annual customer and system energy savings projected to be achieved by the SSG project is $2,332,953. Calculations supporting this estimate are included in Appendix AA14. Review of project scope and preliminary engineering work by Black & Veatch confirmed PUC Distribution estimate of an average 2.7% energy savings "*has a high probability*" of being achieved in their view and potential exists for even greater savings than the estimate. The following opinion statement from Black & Veatch was provided in this regard.

> *"Working with other utilities on voltage control projects, it is common for normal operating bus voltage regulation to be in the low 120 volt range and achieve over 2% energy savings with VVO. Reviewing PUC substation bus voltage being reported as approximately 126 volts, our experience indicates this has a high probability of achieving volt / var savings in the 2.7% range. The 12kv backbone features a conductor size that also helps achieve energy savings through VVO. With these conditions, along with the fact that the loads at PUC have remained relatively flat throughout the service history, it is our opinion that PUC would be able to achieve average energy savings in the 3-5% range."*

Other benefits which will be realized with full consideration of the technology being implemented are also recognized to have significant long-term value and are provided in more general context throughout the application. As an example, industry reports referenced on valuing improved customer reliability showed large 20 year NPV benefits of around $33M to customers from improved distribution reliability. Benefits from reliability although of importance to residential customers are generally recognized as providing more significant value to commercial, institutional and industrial customers. In the end PUC Distribution looked for a method of representing the most clearly recognized benefits to be achieved and the SSG Project achieves this. These benefits are reflected earlier in Table 1 with a net annual benefit of $616,897.

(a) Potential DA Reduction

Customer engagement has indicated that reliability of electrical service is very important to PUC Distribution customers and is most often ranked right after the cost of electricity on their bill in terms of priority needs. The value of improved reliability to customers with the SSG Project as described earlier in the application has been estimated as over $30 million dollars (NPV over 20 years – see Appendix AA13 Smart Grid Benefits Estimate Memo). Reliability improvements are recognized and presented as a real benefit from the SSG Project, but they do not add to the net bill savings calculation for customers.

If the full estimated value of these reliability benefits was cost valued as part of the overall project business case, then the positive net benefits to customers of over $2,600,000 annually becomes even more favourable to the project. The scope of the Distribution Automation (DA) in the SSG Project has been recognized by PUC Distribution as the area of project implementation that would be prioritized and reduced if needed to ensure an overall “no net bill increase” project benefit target so it has been considered in this context. If the Board has concern about the project investments in reliability improvements through DA and the rate impacts arising, an alternative for the Board’s consideration is proposed as follows.

The intent of the 100% feeder coverage scope of work proposed by PUC Distribution is for all customers to both contribute to the costs of the improvements but also receive the benefits of those improvements. An alternative approach that could be applied is to consider a reduced scope in

feeder DA coverage to focus on the worst performing feeders so that more customers receive closer to an average level of reliability. Each alternative has been used in decision criteria by utilities and is difficult to reach consensus from a customer perspective depending on what they experience in their location in the distribution system. Reducing the scope of DA coverage is a potential approach to overall project cost reduction. An example reduction of ~50% DA coverage to focus only on those feeders with greatest reliability benefit first would reduce project costs by approximately $3 million to $4 million and add approximately $150,000 to $200,000 to the net benefit summary currently calculated as $616,897.

8. Calculation of Rate Rider (3.3.2.1 at p. 25)

PUC Distribution has followed the instructions in the OEB Capital Module to determine rate riders. As per the OEB's letter issued July 16, 2015[13], the residential class rate rider is a fixed charge only. The remainder of the classes are a combination of a fixed and a variable charge. The total to be recovered from each class is based on the number of customers/connections and kwh/kw as per the 2018 approved cost of service load forecast. The proposed rate riders are shown in Table 13 below.

Table 13: PUC Distribution's Proposed Rate Riders

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
	From Sheet 7	*From Sheet 7*	*From Sheet 7*	Col C * Col I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*
RESIDENTIAL R1	58.75%	0.00%	0.00%	514,438	0	0	514,438
GENERAL SERVICE LESS THAN 50 kW	4.41%	11.92%	0.00%	38,593	104,378	0	142,971
GENERAL SERVICE 50 TO 4,999 KW	2.60%	0.00%	20.93%	22,770	0	183,236	206,005
UNMETERED SCATTERED LOAD	0.02%	0.17%	0.00%	160	1,520	0	1,680
SENTINEL LIGHTING	0.08%	0.00%	0.10%	686	0	919	1,605
STREET LIGHTING	0.69%	0.00%	0.33%	6,026	0	2,885	8,911
Total	**66.54%**	**12.09%**	**21.36%**	**582,673**	**105,898**	**187,040**	**875,610**
							875,610

[13] *Implementing a New Rate Design for Electricity Distributors OEB File No. EB-2012-0410*: http://www.rds.oeb.ca/HPECMWebDrawer/Record/487038/File/document.

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 4	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
29,897	296,035,266		1.43	0.0000	0.0000
3,388	91,718,380		0.95	0.0011	0.0000
362	240,708,316	594,560	5.24	0.0000	0.3082
23	866,480		0.58	0.0018	0.0000
351	206,826	605	0.16	0.0000	1.5182
8,037	2,410,546	7,056	0.06	0.0000	0.4089
42,058	**631,945,814**	**602,221**			

These Rate Riders would be in effective from May 1, 2022 to April 30, 2023 at which time PUC would be rebasing under its 2023 Cost of Service Application. The impact to customers as a result of these rate riders is shown in Table 14 below. A comparison was shown to determine the net increase to customers if they were receiving the full benefit from consumptions savings compared to no consumption savings.

Table 14: Total Bill Impacts

			With Consumption Savings		Without Consumption Savings	
Class	Consumption (kWh)	Consumption (kW)	Total Bill Increase/Decrease	Total Bill Impact %	Total Bill Increase/Decrease	Total Bill Impact %
Residential	750	0	-$1.21	-1.05%	$1.16	1.01%
Residential	825	0	-$1.44	-1.17%	$1.16	0.94%
Residential	367	0	$0.00	0.00%	$1.16	1.66%
Residential	2,000	0	-$5.15	-1.97%	$1.16	0.44%
GS<50	2,000	0	-$4.92	-1.68%	$2.56	0.87%
GS<50	272	0	$0.00	0.00%	$1.01	1.83%
GS<50	3,000	0	-$7.76	-1.80%	$3.45	0.80%
GS>50	19,740	55	-$62.85	-1.86%	$25.08	0.74%
GS>50	57,220	145	-$194.19	-2.07%	$56.42	0.60%
GS>50	142,465	452	-$487.42	-2.02%	$163.34	0.68%
GS>50	169,620	468	-$585.22	-2.10%	$168.91	0.61%

9. ICM Accounting Treatment (3.3.2.5 at p. 28)

PUC Distribution will record actual amounts in the following Sub-Accounts of Account 1508 – Other Regulatory Assets:

- Account 1508 – Other Regulatory Assets, Sub-Account Incremental Capital Expenditures
- Account 1508 – Other Regulatory Assets, Sub-Account Depreciation Expense
- Account 1508 – Other Regulatory Assets, Sub-Account Accumulated Depreciation
- Account 1508 – Other Regulatory Assets, Sub-Account Incremental Capital Expenditures Rate Rider Revenues

PUC Distribution will also record monthly carrying charges using OEB prescribed interest rates in the following SubAccounts:

- Account 1508 – Other Regulatory Assets, Sub-Account Incremental Capital Expenditures, Carrying charges
- Account 1508 – Other Regulatory Assets, Sub-Account Incremental Capital Expenditures Rate Rider Revenues, Carrying Charges

10. ICM Rate Generator and Supplementary Filing Module (3.3.2.6 at p. 29)

Attached hereto as Appendix AA16 is PUC Distribution's 2021 Capital Module, which is applicable to the ICM (Version 5.01) as provided by the OEB.

Appendix AA1
Response to Interrogatories 1-Staff-6

Appendix G
Responses to Interrogatory 1-Staff-6

In the EB-2017-0071 Application process, OEB Staff asked several questions about the SSG Project in interrogatory 1-Staff-6.

In response, during that Application process, PUC stated:

> "This Sault Smart Grid project is still at the preliminary planning stages. No amounts associated with the Sault Smart Grid project have been included in this Application or in the DSP. The answers to the questions asked by Staff are not yet known.
>
> Whether PUC proceeds with this project or not will depend on whether it meets PUC's evaluation criteria (including the "no net bill increase" criteria). All of this remains to be determined.
>
> Should PUC elect to proceed with this project, PUC will bring an application to the OEB for approval under the Incremental Capital Module process. PUC will provide full and complete responses to each of these questions as part of that separate ICM application at that time."

PUC committed that it would provide full and complete responses to each of OEB Staff's questions as part of this ICM application. Those responses are set out below.

1-Staff-6

Ref: Exhibit 2, Appendix 2, PUC Distribution Inc. Distribution System Plan, p. 98
http://www.saultstar.com/2018/07/06/sault-puc-touts-smart-grid-project
http://www.saultstar.com/2018/07/09/council-unanimously-approves-smart-grid

In the first reference, PUC Distribution states that it is exploring a large scale 2 – 3 year smart grid project. It also states that "It is anticipated that PUC Distribution would be utilizing the Incremental Capital Module process for this project should the analysis and financial feasibility criteria, including the "no net bill increase" be achieved".

The first article referenced states that:

> The project will cost a total of $32,751,469. 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, meaning that they will only require $18,501,469. PUC will present the project to city council Monday to gain their approval so it can begin installation.

The second article referenced states:

> Coun. Susan Myers, who asked about Smart Grid's cost to citizens, was told that neither taxpayers nor electricity users would face any charges or experience any increase in fees from the development and construction of Smart Grid. All they would notice would be a small, 11 cent reduction in their monthly bills and a more reliable system that would drastically reduce CO2 emissions within the city, to the tune of 2,804 tonnes annually.

a) Please confirm or correct the amounts quoted.

The total cost of the project (over two years) is $34,389,046. Anticipated funding is $11,807,000 from NRCan. The resulting net cost is $22,582,046.

b) Please confirm that both references refer to the same project, or clarify what each project entails

The references are for the same project – the SSG Project.

c) Please clarify which entity or entities will be responsible for investing the remaining $18,501,469, and the amounts to be invested by each if the cost is to be shared.

PUC Distribution is proposing to make the investment in the SSG Project by investing the remaining $22,582,046.

In this ICM Application, PUC is seeking ICM approval for $4,552,714 in incremental capital in 2019 – which is the amount by which the SSG Project assets that go into service in 2019 exceed PUC's materiality threshold.

d) In the event that the project costs more or less than forecasted, which entity or entities will be responsible for the variance? If applicable, how will this be apportioned?

While PUC Distribution is responsible for the SSG Project, the project has been structured such that PUC Distribution will be paying a fixed amount pursuant to a turn-key EPC agreement. By doing this, the risk of overages will be the responsibility of the EPC and Developer.

e) Has PUC Distribution prepared any forecasts of the ongoing implications for Operation and Maintenance in terms of operating and maintaining the smart grid investment as well as any impacts on operating and maintaining other utility assets. If so, please provide, if not, why not?

Ongoing maintenance costs directly associated with the SSG Project are currently estimated at ~$29,250 per month. Opportunity for O&M cost savings and efficiencies will also be fully explored and integrated in PUC Distribution's next cost of service rate application.

f) If the $18,501,469 is to be funded by PUC Distribution rate payers, please confirm that PUC Distribution will be applying to the OEB for approval of this project through a separate application to the OEB prior to any amounts being spent.

Confirmed. PUC Distribution is requesting approval of this ICM for the SSG Project prior to proceeding with the project.

g) Has this project been ranked against other projects in the forecast period?

No. The SSG Project is separate from and incremental to the balance of PUC's other capital projects. This project will not affect PUC Distribution's other capital renewal projects but is being undertaken to improve reliability, reduce consumption, and address provincial smart grid goals.

h) Please explain how PUC Distribution anticipates achieving a no net bill increase when applying of an ICM.

As described throughout the application, the SSG Project will result in increased system efficiency leading to reduced consumption that offset rate increases.

i) Has PUC Distribution considered any opportunities for the smart grid to defer or replace investment in other capital assets?

Yes. PUC Distribution has considered such opportunities as a result of the SSG Project. PUC Distribution can confirm that any capital asset replacement deferrals are projected to occur more than five years into the future (i.e. outside the current DSP timeframe).

j) Has PUC Distribution carried out any customer engagement with respect to this project?

PUC Distribution undertook extensive customer engagement during its 2018 Cost of Service rate application. No other customer engagement has been undertaken as it is important not to overburden our customers with customer engagement surveys.

Appendix AA2-1
Copy of the SSG RFP

REQUEST FOR PROPOSALS

RFP No. **SSG2019**

for

Engineering, Procurement & Construction Services

Issued by: PUC Services Inc.

("**PUC**")

Date of RFP Issuance: October 4, 2019

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REQUEST FOR PROPOSALS

1. INTRODUCTION

1.1 Introduction

PUC is requesting Proposals for engineering, procurement and construction ("**EPC**") services for the implementation of the Sault Smart Grid Project ("**Project**") to provide community-scale smart grid technology applications and an integrated and intelligent distribution management platform for the PUC electrical distribution service area. Background information, scope of work and Proposal expectations are presented in the balance of this RFP.

This RFP is being issued and administered by PUC in order to obtain Proposals from one or more Respondents that would result, if selected by PUC and otherwise agreeable to the Respondent, in the successful Respondent(s) entering into negotiations to execute a Contract with PUC for the supply of the deliverables as further described herein.

As further described in this RFP, a secured project website will be used by PUC to provide to the Respondents certain related documents and materials to this RFP. The indication of an intention to bid in the Expression of Interest is non-binding.

As used herein, "deliverables" includes all goods and services being requested pursuant to this RFP as more specifically described in SCHEDULE B.

1.2 Sections

This RFP is divided into five (5) sections and schedules, as follows:

1. Introduction
2. RFP Rules and Procedures
3. Proposal Requirements
4. Deliverables Required
5. Contract Negotiations

Schedule A: RFP Procedures

Schedule B: Proposal and RFP Requirements

- Appendix A: Project Tasks
- Appendix B: Project Estimate Matrix
- Appendix C: Communication Systems
- Appendix D: Station Energy

Schedule C: Proposal Cover Sheet

Schedule D: Respondent's Certificate

Schedule E: Defined Terms

Schedule F: PUC Statistics

1.3 Defined Terms

(a) All capitalized terms in this RFP are as defined in SCHEDULE E, unless otherwise defined herein.

(b) Words and abbreviations that have well known technical or trade meanings are used in this RFP in accordance with such recognized meanings.

1.4 RFP Not a Tender Call

TO BE CLEAR, AND NOTWITHSTANDING ANY OTHER TERM OF THIS RFP THAT MAY BE INTERPRETED OTHERWISE, IT IS NOT THE INTENT OF PUC, NOR THE EFFECT OF THIS RFP, TO INITIATE CONTRACTUAL RELATIONS BY THE PROVISION OF A PROPOSAL BY ANY RESPONDENT IN RESPONSE TO THIS RFP.

NOTWITHSTANDING ANY OTHER TERM OF THIS RFP, THIS RFP IS MERELY A CALL FOR PROPOSALS AND NOT A TENDER CALL INTENDING TO PLACE LEGALLY BINDING OBLIGATIONS ON PUC OR ON ANY RESPONDENT TO ENTER INTO A CONTRACT OR TO BE BOUND BY ANY OF THE TERMS OF ITS PROPOSAL. IT IS NOT THE INTENTION OF PUC TO ENTER INTO A CONTRACT FOR THE DELIVERABLES DESCRIBED IN THIS RFP OR ENTER INTO ANY OTHER LEGALLY BINDING OBLIGATIONS UNLESS AND UNTIL PUC HAS COMPLETED THE NEGOTIATION AND FINALIZATION OF A CONTRACT SATISFACTORY TO BOTH PUC AND THE RESPONDENT, IF ANY, THAT PUC DETERMINES TO NEGOTIATE WITH. PUC SHALL NOT BE BOUND BY ANY AGREEMENT ENTERED INTO BY PUC AND A RESPONDENT UNLESS AND UNTIL PUC ALSO EXECUTES AN AGREEMENT OR ACKNOWEDGEMENT WITH THE RESPONDENT AGREEING TO BE BOUND BY THE APPLICABLE TERMS OF THAT CONTRACT.

IT IS CONCEIVABLE THAT THESE EVENTS WILL NOT OCCUR DUE TO THE DISCRETION OF PUC AND/OR ANY RESPONDENT TO NOT PROCEED, AS THERE IS NO LEGALLY BINDING OBLIGATION ON PUC OR THE RESPONDENT TO PROCEED.

2. RFP RULES AND PROCEDURES

2.1 Rules and Procedures

The submission of a Proposal by the Respondent shall be deemed to signify that the Respondent has read, understood and agrees to comply with all of the terms and conditions of this RFP including without limitation all RFP Rules and Procedures as detailed in this Section 2.

2.2 Respondents

PUC reserves the right to contact additional parties regarding this RFP, or issue a separate or supplementary RFP, for this or any related matter, in its discretion and at any time.

PUC reserves the right to consider such criteria as described in this RFP in selecting or rejecting any Proposal.

2.3 Communications

(a) Unless otherwise notified by the Buyer in writing and as further detailed in Sections 2.5 and 2.6 of this RFP, all questions or other communications regarding this RFP, including any notices required hereunder are to be addressed solely to PUC, in writing, to the attention of the Buyer identified in SCHEDULE A.

(b) **Respondents shall communicate with PUC in accordance with this RFP and shall not communicate with any other department or Representative of PUC regarding this RFP.**

2.4 RFP Schedule

Subject to any modifications in PUC's discretion and subject to all other terms of this RFP, the schedule and timelines set out in SCHEDULE A will apply to this RFP.

2.5 Questions and Clarifications regarding this RFP

(a) Upon review of this RFP, Respondents shall immediately notify the Buyer identified in SCHEDULE A, in writing, of any omissions, discrepancies, ambiguities or details contained in this RFP requiring further clarification. PUC will not be responsible for any misunderstanding on the part of the Respondent concerning this RFP or its process.

(b) Respondents should not make verbal inquiries associated with this RFP. All questions regarding the RFP shall be made in writing to the Buyer **by no later than the Deadline for Submission of Questions in SCHEDULE A.** Questions received prior to the Deadline for Submission of Questions and PUC's responses to such questions will be recorded by PUC, and will be made available to all Respondents via PUC's secured project website. PUC will respond to those questions that, in PUC's discretion, provide clarification to this RFP. Respondents are advised that the Deadline for Submission of Questions is the final opportunity for Respondents to seek clarification with respect to this RFP.

(c) In answering a Respondent's questions, PUC will set out the question(s), but without identifying the Respondent that submitted the question(s) and may, in its sole discretion: (i) edit the question(s) for clarity and to remove any information that may identify Respondents; (ii) exclude questions that are either unclear or inappropriate; and (iii) answer similar questions from various Respondents only once. In submitting questions, Respondents are encouraged to not include any references that may identify themselves, their services, product and partners as such material may inadvertently become part of the answer.

2.6 Addenda to RFP and Supplementary Documents

(a) PUC reserves the right to issue addenda in order to supplement and make amendments to this RFP at any time, in its discretion. Addenda to this RFP will be issued up to the Deadline for Addenda Issuance found in SCHEDULE A and will be made available to the Respondents via PUC's secured project website. If any addendum is issued after the Deadline for Addenda Issuance, PUC may at its discretion extend the Submission Deadline for a reasonable amount of time. All addenda to this RFP shall be deemed to form an integral part of this RFP as if specifically restated herein. The Respondent is solely responsible to ensure that it has received all addenda if any, issued by PUC. PUC will not be responsible for any issues or problems related to the delivery or receipt of any addenda by the Respondent.

(b) PUC will also provide to the Respondents, through PUC's secured project website, access to: (i) a MS Excel spreadsheet template of the Project Estimate Matrix (as further detailed in PART B of SCHEDULE B) and (ii) information references (such as for instance: wall map sub-transmission schematic; TS 1 schematics; TS line schematics; wall map distribution feeders and feeder book drawings) that may be helpful to the Respondents in the preparation of the Proposals. The Respondent is solely responsible to ensure that it has received all such information issued by PUC. PUC will not be responsible for any issues or problems related to the delivery or receipt of any such information by the Respondent.

(c) Respondents should contact the Buyer identified in SCHEDULE A, by email, to receive instructions on how to access PUC's secured project website. PUC will provide instructions to the Respondent on how to access PUC's secured project website once it becomes available.

2.7 Submitting the Proposal

(a) **RESPONDENTS SHOULD SUBMIT ITS PROPOSAL TO PUC IN ACCORDANCE WITH THIS SECTION 2.7 AND SCHEDULE A.**

(b) Proposals shall be delivered to PUC by personal delivery, or by courier in accordance with the terms in SCHEDULE A. No facsimile transmission of Proposals will be accepted. Proposals shall be deemed received by PUC on the date, and at the time, recorded in writing by PUC representative at the Customer Care main desk. Respondents shall be entirely responsible to ensure that Proposals are received by the PUC representative at the Customer Care main desk by the Submission Deadline as described in SCHEDULE A. PUC will not be responsible for any issues or problems related to the delivery or receipt of any Proposal by the Submission Deadline. Without limitation, Respondents are solely responsible for ensuring that Proposals are delivered to the PUC representative at the Customer Care main desk as indicated in SCHEDULE A so as to allow the representative sufficient time to receive and time stamp the Proposal to indicate receipt before the time described in SCHEDULE A.

2.8 Modifications or Withdrawal of Proposals before Submission Deadline

(a) Proposals submitted prior to the Submission Deadline may be modified at any time prior to the Submission Deadline or withdrawn by the Respondent at any time prior to or after the Submission Deadline in accordance to this Section 2.8.

(b) Respondents may not make modifications to their Proposal after the Submission Deadline.

(c) To modify a Proposal prior to the Submission Deadline, the Respondent must withdraw the original Proposal and submit another Proposal to PUC, prepared in accordance with the terms of this RFP, bearing the same signature of the authorized representative of the Respondent who executed the original Proposal (or such other authorized representative if the original representative is no longer available, provided a written explanation regarding same is included), clearly marked to show that it supersedes and invalidates the Proposal(s) previously delivered. No other method of Proposal modification shall be considered.

(d) To withdraw a Proposal prior to or after the Submission Deadline, the Respondent shall submit to PUC as described in SCHEDULE A, a letter to this effect, bearing the same signature of the authorized representative of the Respondent who executed the original Proposal (or such other authorized representative if the original representative is no longer available, provided a written explanation regarding same is included), duly signed by an authorized Representative of the Respondent. No other method of Proposal withdrawal shall be considered.

(e) Proposals not submitted by the Submission Deadline will not be considered by PUC.

2.9 Ownership of Proposals

Upon the Respondent's submission of the Proposal, all Proposals and other support documentation received by PUC from Respondents shall become the property of PUC and will not be returned to Respondents. PUC may, as deemed necessary or appropriate by PUC, disclose the Respondent's Proposal to PUC Representative (including for clarity, PUC's advisors)for the purposes of administering this RFP and any resulting Contract, as required by PUC in conjunction with any rate applications or as required by Applicable Law, court order or other legal compulsion including, without limitation, requests under the *Municipal Freedom of Information and Protection of Privacy Act* (Ontario) and requests made by any Governmental Authority.

2.10 Clarifications or Supplements to Proposals

In submitting a Proposal, the Respondent acknowledges and agrees that PUC and its Representatives reserve the right but is not obligated to, in their discretion, to independently verify any or all of the information provided in a Proposal or to seek further information or clarification from any Respondent after the Submission Deadline, including but not limited, contacting any person identified in the Proposal and persons or entities other than those identified in the Proposal. PUC is entitled to utilize the information or clarifications received in evaluating any Proposal, and may require one or more or all of the Respondents to answer questions or submit supplementary documentation clarifying any matters contained in their Proposals. In submitting a Proposal, a Respondent is deemed to consent to PUC's verification or clarification rights. The response received by PUC pursuant to this Section will, if accepted by PUC, form an integral part of that Respondent's Proposal. Respondents are cautioned that any verifications or clarifications sought will not be an opportunity either to correct errors or change their Proposals in any substantive manner. A Proposal may be rejected should the results of the verification not substantially match the information submitted by the Respondent at the sole discretion of PUC.

2.11 Evaluation of Proposals

Proposals will be opened in private by PUC and a PUC Representative (in PUC's discretion). PUC is under no obligation to disclose to any Respondent(s) the contents of the Proposals received or to reveal the Proposal prices.

The successful Respondent(s), if any, will be selected by PUC, in its sole discretion, based on PUC's assessment of which Proposal is considered to be the most beneficial to PUC based on any number of criteria which PUC, in its discretion, considers relevant, including, without limitation, the rated requirements as further set out in PART B of SCHEDULE B.

PUC reserves the right, in its discretion, to negotiate with the Respondent, which, in the opinion of PUC, has submitted the most beneficial Proposal, or with any other Respondent or Respondents concurrently. PUC and its Representatives shall incur no liability to any other Respondents as a result of such negotiations.

2.12 Selection of Proposals

(a) This RFP does not constitute a call for tenders or a contract to purchase deliverables, and PUC is under no obligation or commitment whatsoever to select any Proposal and expressly reserves the right, in its discretion, to reject any or all Proposals without notice or reasons including, without limitation, the lowest priced Proposal. Alternatively, PUC reserves the right to select the Proposal that, in its discretion, it deems most advantageous, notwithstanding any custom, usage or agreement in the industry or trade, or any other policy or practice to the contrary.

(b) PUC reserves the right, in its discretion to waive non-compliance where, in PUC's sole and absolute discretion, such non-compliance is minor and not of a material nature, or to accept or reject in whole or in part any or all Proposal, with or without giving notice. Such minor non-compliance will be deemed substantial compliance and capable of acceptance. PUC will be the sole judge of whether a Proposal is accepted or rejected.

(c) Without limiting the generality of the foregoing, PUC may, in its discretion and at any time without notice or reasons, and without liability, take any steps it deems appropriate in connection with this RFP process including, without limitation:

(i) modify the terms of this RFP, including the RFP Schedule located in SCHEDULE A;

(ii) adjust a Respondent's score or reject a Respondent's Proposal on the basis of:

1) a financial analysis determining the actual cost of the Proposal when considering factors including quality, service, price, and transition costs arising from the replacement of existing goods, services, practices, methodologies, and infrastructure (howsoever originally established);

2) information provided by references;

3) the Respondent's past performance on previous contracts awarded by PUC;

4) the information provided by a Respondent pursuant to PUC exercising its clarification rights under this RFP process; and/or

5) other relevant information that arises during the RFP process;

(iii) terminate this RFP at any stage;

(iv) terminate this RFP at any stage and issue a new RFP for the same or similar services;

(v) decline to permit any Respondent to participate in this RFP process;

(vi) disqualify any Respondent whose Proposal contains misrepresentations or any other inaccurate or misleading information;

(vii) disqualify any Respondent or Proposal of any Respondent who has engaged in conduct prohibited by this RFP;

(viii) accept or reject any, or part of any, or all Proposals in its absolute discretion;

(ix) select any Respondent other than the Respondent whose Proposal reflects the lowest cost to PUC or the highest overall score;

(x) terminate discussions or negotiations with any or all Respondents;

(xi) negotiate in respect of any term or condition proposed by the Respondent in its Proposal, whether a business or legal term or condition or otherwise;

(xii) select one or more Respondent's services as identified by the parties;

(xiii) negotiate with any third party regarding matters covered by or related to this RFP, whether such party has been invited to submit a Proposal or not; or

(xiv) make public the names of any and all Respondents.

These reserved rights are in addition to any other expressed rights or any other rights which may be implied in the circumstances and PUC shall not be liable for any expenses, costs, losses or any direct or indirect or punitive or other damages incurred or suffered by any Respondent or any third party resulting from PUC exercising any of its expressed or implied rights under this RFP or otherwise, whether in contract, tort (including gross negligence) or under any equitable or other principle available at law or otherwise.

(d) If PUC does not receive any satisfactory Proposals, which only PUC, in its discretion, may determine, or if an insufficient number of Proposals are submitted, or where unforeseen circumstances arise before the Date for Selection of the Successful Respondent(s), PUC may, in its discretion, either:

(i) revise the scope of work identified in this RFP by issuing post-RFP addenda;

(ii) negotiate modifications of any term of this RFP with any Respondent, or Respondents, concurrently;

(iii) include one or more of the Respondents in post-Submission Deadline negotiations;

(iv) reject all Proposals and re-issue the RFP; or

(v) cancel this RFP.

Neither PUC nor any of its Representatives shall incur any obligation or liability to any Respondent in the exercise of any of the rights noted above.

2.13 Confidentiality

(a) This RFP, and all information and data disclosed by PUC in relation thereto, including without limitation all information related to PUC's business operations, processes or technology, whether marked as confidential or not, constitutes "**Confidential Information**" which is, and will remain, the property of PUC, and is not to be copied or distributed without the prior written approval of PUC, except as reasonably required to respond to this RFP.

(b) Notwithstanding the foregoing, Confidential Information does not include any information or data which:

(i) is or becomes publicly known through no breach of the terms or conditions of this RFP; or

(ii) is independently developed by a third party without reference to Confidential Information and without breach of the terms or conditions of this RFP.

(c) The Respondent agrees to maintain the confidentiality of the Confidential Information, and further agrees not to use or duplicate such Confidential Information for any purpose other than responding to this RFP, negotiating the Contract or providing the deliverables and will not, without the prior written consent of PUC, disclose or make any Confidential Information available to any third party, except sub-contractors involved in the Proposal, as reasonably required to develop the Proposal, negotiate the Contract or provide the deliverables.

(d) Notwithstanding any obligations of confidentiality herein, the Respondent may disclose Confidential Information where required to do so by court order or other legal compulsion, provided the Respondent gives PUC prior notice, as permitted by law, of the compulsory disclosure.

(e) Upon request, the Respondent shall forthwith return to PUC all Confidential Information, including any copies thereof; and, where such Confidential Information is in electronic form, destroy such Confidential Information and provide PUC with a certificate from a senior officer of the Respondent attesting to such destruction.

(f) The terms of this Section 2.13 shall survive any termination or expiry of this RFP for the longer of five (5) years after (i) the Submission Deadline; and (ii) the termination or expiry of this RFP.

(g) A Respondent should not at any time directly or indirectly communicate with the media in relation to this RFP or any contract awarded pursuant to this RFP without first obtaining the written permission of PUC.

2.14 No Representations or Warranties

(a) Nothing in this RFP is intended to relieve Respondents of their responsibility to form their own opinions and conclusions in respect of the matters addressed in this RFP and to satisfy themselves independently regarding the accuracy and completeness of the information provided and the

assumptions made in this RFP. PUC and its Representatives make no representations or warranties, either express or implied, in fact or in law, with respect to the accuracy or completeness of the information provided in this RFP.

(b) Without limiting the generality of the foregoing, PUC and its Representatives shall not be liable for any claim, action, cost, loss, damage or liability whatsoever arising from or related to any information or advice or any errors or omissions that may be contained in this RFP or any data, materials, or documents disclosed or provided to the Respondent pursuant to this RFP or otherwise, whether in contract, tort or otherwise. The only representations and warranties made by PUC or its Representatives, if any, will be those contained in the Contract.

2.15 No Damages

(a) All costs, expenses, losses, damages and liabilities which may be incurred by the Respondents as a result of or arising out of the submission, acceptance, selection or rejection of their Proposals, including the cost of preparing and submitting a Proposal, shall be borne entirely by the Respondents. PUC and its Representatives shall not be liable for any costs and expenses incurred by the Respondents or to reimburse the Respondents in any manner whatsoever or under any circumstances, including, without limitation, in the event of rejection of all Proposals, rejection of the Respondent's Proposal, selection of another Respondent's Proposal, waiver or non-waiver of a non-compliance by any Respondent, including the matters described in SCHEDULE A and SCHEDULE B, issuance of a post-RFP addenda, a decision not to include any Respondent in post-Submission Deadline negotiations, or cancellation of this RFP.

(b) Without limiting the generality of the foregoing, PUC and its Representatives shall not be liable, in contract, tort, restitution or any other legal theory, to a Respondent for any claim, action, costs, losses, damages or liability whatsoever arising from any act or omission by PUC or its Representatives, including the rejection of any or all of the Proposals, the consideration or evaluation of any or all of the Proposals, negotiations in respect to the Proposals, the selection of a Respondent, the decision to issue post-RFP addenda, the decision not to include a Respondent in post-Submission Deadline negotiations, the decision to waive or not to waive a non-compliance by a Respondent, including in respect of the matters described in SCHEDULE A and SCHEDULE B, or for any information or advice or any errors or omissions that may be contained in this RFP or any data, materials, or documents disclosed or provided to a Respondent pursuant to this RFP or otherwise.

2.16 No Collusion

Each Respondent's Proposal shall be prepared without any connection, knowledge, comparison of information, or arrangement with any other Respondent (or any Representative thereof) and each Respondent shall be responsible to ensure that its participation in this RFP process is conducted fairly and without collusion or fraud.

2.17 Conflicts of Interest

The Respondent is required to disclose in its Proposal and on an ongoing basis thereafter any conflict of interest, real or perceived, that exists now or may exist in the future, with respect to this RFP, any resulting Contract, or in relation to PUC or its Representatives. PUC may disqualify a Respondent for any conduct,

situation or circumstance that constitutes a real or perceived conflict of interest as determined by PUC. PUC may also disqualify a Respondent for: (a) a failure to disclose an actual or potential conflict of interest; (b) a failure to comply with any requirements prescribed by PUC to resolve a conflict of interest; or (c) a situation or circumstance where the Respondent's conflict of interest cannot be resolved.

2.18 Assignment

The Respondent may not assign the right to issue a Proposal in response to this RFP to any third party, including any of the Respondent's Affiliates, without PUC's prior written consent.

2.19 Governing Law

This RFP, all Proposals submitted in response thereto, and any resulting Contract, shall be governed by the laws in force in the Province of Ontario and the laws of Canada applicable therein. Any dispute shall be brought before the Courts of Ontario located in Toronto, Ontario.

3. PROPOSAL REQUIREMENTS

3.1 Proposal Requirements

All Proposals should contain the information set out in PART A of SCHEDULE B.

4. DELIVERABLES REQUIRED

PUC is seeking Proposals from Respondents for the deliverables described in PART B of SCHEDULE B, including any Appendices thereto. Respondents shall indicate in their Proposals whether they can meet the requirements and specifications listed in PART B of SCHEDULE B, including any Appendices thereto.

5. CONTRACT NEGOTIATIONS

5.1 Contract Terms and Conditions

It is expected that PUC and the successful Respondent, if any, will negotiate and execute a Contract setting out the commercial terms and conditions that are typical in a fixed price engineering, procurement and construction contract with contractually defined milestones and which shall include, without limitation, reference to the specifications and requirements in PART B of SCHEDULE B.

To facilitate negotiations, the Contract could be based on an amended form of the successful Respondent's standard legal documentation, as amended to reflect the negotiations of the parties.

PUC has the discretion to conduct contract negotiations in such manner as it will determine. That said, it is anticipated that PUC may select two (2) short-listed Respondents with whom PUC will consider contract negotiations. PUC may elect to negotiate with both short-listed Respondents concurrently or to select one Respondent with whom to commence negotiations with while the second Respondent is held in abeyance pending the results of the negotiations with the first Respondent.

Each Respondent is requested to attach, in unlocked Word format, an agreement or agreements that they wish to have PUC consider for negotiation purposes. PUC will consider whether the form of those agreements is appropriate for the basis of negotiating the Contract. The attachment of any such forms of agreements in a Proposal shall not be considered to be acceptance by PUC, either as to form or substance, in whole or in part, of such agreement or agreements.

To be clear, in the course of such negotiations, Respondents involved in the Contract negotiation process may be requested to consider improving upon the terms set out in their Proposals.

PUC anticipates finalizing and signing the Contract by no later than the estimated Date for Execution of the Contract specified in SCHEDULE A. However, the selection of the Successful Respondent(s) and PUC's execution of any agreement, including the Contract, is conditional upon PUC's election to proceed subsequent to its rate application approval at the OEB estimated to occur during Q1/Q2 of 2020.

5.2 No Liability

No Respondent shall have any rights against PUC or its Representatives arising from the selection or non-selection of any Respondent(s), including the selection of a Respondent with a Proposal that is non-compliant with the terms of this RFP. Any and all commitments, representations, warranties or obligations of PUC or its Representatives shall be limited to those specifically stated in an executed Contract between PUC and a successful Respondent(s), if any.

SCHEDULE A

RFP PROCEDURES

(a) QUESTIONS/COMMUNICATIONS WITH PUC

All questions or communications regarding this RFP are to be addressed in accordance with Sections 2.3 and 2.5 of the RFP and solely to (the "**Buyer**"):

Attention: Kevin Bell P.Eng.
Project Manager
E-mail: kevin.bell@ssmpuc.com

Proposals **shall** be delivered to the Customer Care main desk at 500 Second Line East, Sault Ste. Marie, Ontario, P6A 6P2, PUC P.O. Box 9000.

(b) RFP SCHEDULE

The RFP Schedule is tentative only and may be changed by PUC in its discretion.

Expression of Interest Posting	**October 1, 2019**
Date of RFP Issuance	**October 4, 2019**
Deadline for Submission of Questions	**October 17, 2019 4:00:00 PM EST**
Deadline for Addenda Issuance	**October 25, 2019**
Submission Deadline	**November 11, 2019 3:00:00 PM EST**
Date for Selection of Successful Respondent(s) (estimated)*****	**November 20, 2019**
Date for Execution of the Contract (estimated)*****	**December 24, 2019**

***** The selection of the Successful Respondent(s) and PUC's execution of a Contract, if any, is conditional upon PUC's election to proceed subsequent to its rate application approval at the OEB during Q1/Q2 of 2020.

(c) SUBMISSION OF PROPOSALS

Proposals **shall** be submitted in English. A Respondent **shall** submit **one (1) original hard copy** of its Proposal, signed by an authorized signing officer of the Respondent and should include as well **2 additional hard copies** of its Proposal **and 1 electronic copy** of the Proposal on a memory key, to the Buyer as indicated in paragraph (a) above **by no later than the Submission Deadline.** In the event of any inconsistency or conflict, the original, signed hard copy shall be paramount.

The one (1) original hard copy, 2 additional hard copies and 1 electronic copy of the Proposal should be submitted in sealed envelopes bearing the Respondent's name and address and the project title and be prepared as follows:

1. First sealed package labeled: "EPC Proposal" to include the one (1) original hard copy, 2 additional hard copies and 1 electronic copy of the Proposal **with the exception of the** pricing proposal.

2. Second sealed package labeled: "EPC Pricing Proposal" to include the one (1) original hard copy, 2 additional hard copies and 1 electronic copy of the pricing proposal.

The entire content of the Respondent's Proposal should be submitted in a fixed form. The content of websites or other external documents incorporated by reference into the Respondent's Proposal will not be considered to form part of its Proposal.

SCHEDULE B

PROPOSAL AND RFP REQUIREMENTS

For the purposes of the requirements stated in this RFP: (i) "must" and "shall" indicate that a requirement is mandatory and that must be met in substantially unaltered form in order for the Proposal to receive consideration; and (ii) "should", "could" and "may" indicate that the requirement is discretionary. For clarity, the mere use of the term "requirement" is not, in and of itself, determinative of whether a particular requirement is either mandatory or discretionary.

PART A – PROPOSAL REQUIREMENTS

All Proposals **shall** contain the following information, and be presented in the following order:

(a) **Title page**

The cover page of all Proposals should be in the form of SCHEDULE C.

(b) **Table of Contents**

All Proposals in excess of five (5) pages should contain a table of contents showing all required sections and all submitted appendices, if any.

(c) **Respondent's Certificate**

Respondents **shall** complete, sign, and attach a copy of the Respondent's Certificate in SCHEDULE D to their Proposal. The Respondent's Certificate **must** be signed by an individual authorized to bind the Respondent pursuant to the terms and conditions of this RFP.

(d) **Letter of Introduction and Summary of Proposal**

The next section of each Proposal should consist of a letter, no more than two (2) pages in length that introduces the Respondent and highlights the key features of the Respondent's Proposal.

(e) **General Information Regarding Respondent**

The next section of the Proposal should provide details regarding the Respondent, including without limitation, and as may be applicable:

(i) a description of the Respondent's corporate structure, including an organizational chart identifying the Respondent's parent, subsidiaries or other Affiliated corporations, partnerships or organizations;

(ii) if the Proposal is submitted by a partnership, the correct name, firm and style of such partnership **must** be given, together with the names of all partners;

(iii) a copy of all regulatory licences, approvals and authorizations held by Respondent in Ontario that may be relevant to the Contract; and

(iv) a current copy of the Respondent's current credit report and name of rating agency.

(f) **Proposal Response**

This section of the Proposal should provide details regarding the Respondent's Proposal with specific reference to the specifications and requirements listed in PART B of SCHEDULE B.

(g) **Pricing Proposal**

This section of the Proposal contains the Respondent's detailed itemized pricing information for all deliverables as further described in PART B of SCHEDULE B. All pricing **shall** be expressed in Canadian currency.

PART B – RATED REQUIREMENTS

(a) Program Objective and Background

The Sault Smart Grid Project provides for community-scale smart grid technology applications and an integrated and intelligent distribution management platform for the PUC Distribution electrical distribution service area. The Project will deliver customer benefits from its broad impact and integration of complementary smart grid technologies.

As part of the Project, Appendix A and Section (c) (Scope of Work) of this PART B of SCHEDULE B describe the deliverables that PUC anticipates the successful Respondent to provide.

The Project will increase the efficiency of the distribution grid, reducing electrical energy losses and electricity customers will see direct savings in their bills due to improved voltage control. The Project will also improve 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. A "bill neutral" objective for customers will utilize quantified benefits and particularly customer energy savings to support Project investment.

As a prime contractor, the Respondent will be responsible for all phases of design, purchasing, and construction as well as achieving and validating their designed system energy savings results. The Project and Contract award are subject to successful rate submission approval by the Ontario Energy Board (OEB) as the provincial regulator for approval of rate adjustments to the PUC customers. The input from this RFP process will be included in support of an amending application submission to PUC's current rate application and Incremental Capital Module (ICM) for the Project before the OEB (see EB-2018-0219 on the OEB website).

(b) Rated Requirements

PUC is seeking Proposal(s) that demonstrate the following rated requirements in material respects. The Respondent **shall** provide a detailed response to each of the rated requirements and if unable to comply, the reasons for non-compliance.

1) Respondent's firm qualifications and experience;

2) Respondent's key personnel, qualifications and experience;

3) Respondent's project methodology, technical understanding and delivery plan;

4) Respondent's quality of Proposal and completeness;

5) Respondent's innovation in its Proposal; and

6) Respondent's proposed pricing.

Each of the rated requirements above are further discussed below:

(i) *Respondent's firm qualifications and experience*

The Respondent should demonstrate its qualifications and technical excellence of the Respondent's firm for this Project by providing examples of its prior experience in performing project tasks similar to those set out in this RFP. PUC considers prior experience that are "similar" to those set out in this RFP to be those containing the following elements: projects involving voltage/VAR optimization, distribution automation, SCADA and OMS; distribution projects that cover a large number of stations; and circuits in scope and time demonstrating an understanding of the operational and planning challenges of construction work in an operating environment where scheduling and planning over potentially 2 years is a key element.

Specifically, in demonstrating experience in the areas above, the Proposal should include 3 to 5 examples of similar and related projects carried out by the Respondent's firm in the past five (5) years, including references (with contact information).

(ii) *Respondent's key personnel, qualifications and experience*

The Respondent should demonstrate qualifications and technical excellence of its key personnel for this Project by providing examples of its prior experience in performing project tasks similar to those set out in this RFP. PUC considers prior experience that are "similar" to those set out in this RFP to be those containing the following elements: projects involving voltage/VAR optimization, distribution automation, SCADA and OMS; distribution projects that cover a large number of stations; and circuits in scope and time demonstrating an understanding of the operational and planning challenges of construction work in an operating environment where scheduling and planning over potentially 2 years is a key element.

Specifically, in demonstrating experience in the areas above, the Proposal should include 3 to 5 examples of similar and related projects carried out by the Respondent's key personnel in the past five (5) years, including references (with contact information) and key personnel involved in each project. If the Respondent proposes to use sub-consultants or contractors for any aspect of the project, similar information as described above for each should be included showing the area of responsibility.

A competent project manager and project team should be assigned to the Project. The project manager will serve as the primary project contact with the PUC project manager and will provide written project progress updates a minimum of bi-weekly. The project manager will also be responsible for giving the guidance required to keep the Project on schedule and to advise the PUC project manager when it is anticipated the schedule might fall behind. The Respondent should identify the key personnel and in particular the project manager who will be assigned to the Project. Information about the key personnel should include: resumes, their role in the project and how their experience qualifies them for this role, their anticipated percent participation, the location of the office(s) where key personnel are located and where they will perform the work.

(iii) *Respondent's project methodology, technical understanding and delivery plan*

The Respondent should demonstrate a clear understanding of the Project requirements and sets out clear and detailed description of the services being offered.

The Respondent should include a clear and detailed description of the services being offered based on PUC's scope of work description described in Section (c) of PART B of SCHEDULE B below.

The Project award is conditional on the OEB's anticipated approval in Q1/Q2 of 2020 and reliant on the government grant funding program ending on March 31, 2022 so schedule will be a critical

requirement. **As such, the Project must be completed by March 31, 2022.** The Respondent **must** include a proposed schedule for the Project within its Proposal and indicate that the Project completion is March 31, 2022 or earlier. The Respondent **must** include within its proposed schedule, the approximate dates for completion of all major tasks.

The Respondent is encouraged to identify that all work will be done in accordance with Applicable Laws, including but not limited to the requirements of the Electrical Safety Authority (ESA), PUC Distribution, the OEB Distribution System Code, the Independent Electricity System Operator (IESO), Hydro One Networks Inc. (HONI), the Ministry of Environment (MOE), The Ontario Building Code (OBC) latest edition, City of Sault Ste. Marie Bylaws, and other local regulatory agencies.

The Respondent should identify and describe the standards on quality management, assurance and control process proposed to be used for the Project, including whether the Respondent meets the ISO9000 standard for instance.

The Respondent should describe their health and safety policies including attaching a copy of the Respondent's health and safety policy as part of the Proposal.

(iv) *Respondent's quality of Proposal and completeness*

The Respondent is encouraged to provide clear responses to all components of this RFP and to present the materials in the Proposal in a clear and organized manner.

(v) *Respondent's innovation in its Proposal*

The Respondent is encouraged to identify any innovative aspects of their proposed approach in their Proposal that may differ from a traditional fixed price engineering, procurement and construction Contract. This may include innovative project financing structures, innovative financing arrangements, or other novel structures or proposals. Any Proposal that includes an innovative element should include pricing (a) if the innovative element of the Proposal is adopted by PUC; and (b) if the innovative element of the Proposal is not adopted by PUC and instead a more traditional fixed price Engineering, Procurement and Construction Contract approach is used.

(vi) *Respondent's proposed pricing*

As part of its pricing proposal for the Project, each Respondent **must** submit a pricing proposal using a MS Excel spreadsheet template to detail the Project estimate that PUC will provide. A reference to the details found in this MS Excel template is also found in Appendix B which can be used by the Respondents for information purposes only. PUC will provide the MS Excel spreadsheet template via PUC's secured project website for the Respondent's completion and inclusion as part of the Respondent's pricing proposal. In the event of any discrepancy between the information listed in Appendix B and in the MS Excel template, the information listed in the MS Excel template shall take precedence.

PUC is seeking Proposal(s) that describe the estimated capital costs with unit cost-based tasks or elements summed to a **total project cost**. The Respondent **must** provide a detailed project estimate in MS Excel for the complete Project, by (i) providing an upset limit and unit based **all-inclusive cost and total price for the completion of each scope of work stipulated in Appendix B** and (ii) providing unit and/or hourly rates for all ancillary tasks not stipulated in Appendix B. The unit costs for the project are to be all-inclusive for engineering, procurement, construction (including

the commissioning) phases of the Project. The MS Excel spreadsheet to detail the project estimate includes 4 worksheets for the Respondents to provide total project costs of the four (4) feeder DA coverage scope options as described in the scope of work section below.

The foregoing approach will facilitate any PUC required adjustment to scale the project while meeting cost and rate impact objectives. The capital input to the OEB ICM process and resulting incremental revenue requirement calculation for the utility will be balanced by PUC for the Project as part of the application submitted to achieve the benefits and customer bill savings expected.

To meet this objective, PUC is seeking Proposal(s) with an innovative approach for scope of work adjustment of identified phases or elements of the Project with costs and benefits delivered in the proposed solution. PUC's priorities for the Project is to deliver the best value for our customers and therefore energy savings brought to bill savings will be a key priority. In addition to the base pricing proposal structure provided by PUC, alternative innovative proposals with sufficient clarity in the Respondent's Proposal may be considered.

PUC will also consider the Respondent's options for a solution that encompasses project financing although it would need to be provided without a PUC general security agreement requirement.

The pricing information should also include or address the following:

(i) a description of any conditions or qualifications relevant to the Respondent's ability to contract with PUC at the quoted prices or generally;

(ii) all prices **shall** indicate the extent to which the prices quoted include or exclude any applicable taxes (including Harmonized Sales Tax), duties or charges (any such taxes, duties or charges to be indicated separately);

(iii) any alternative pricing offer(s), as may be available in the Respondent's discretion; and

(iv) any further details or description of the Respondent's proposed pricing which the Respondent deems relevant or important to disclose, including details regarding how volume adjustments would be managed, and what impact such adjustments would have on the price, if any, should PUC wish to reduce or increase volumes during the Contract term.

Any alternative price offers may be considered by PUC, in its sole discretion.

(c) Scope of Work

The Project includes the following major scope of work areas and as further described in Appendix A. It is anticipated by PUC that the Respondent will provide the deliverables listed in Appendix A under the column titled "RFP" and as further described in this section. It is anticipated that PUC will be responsible for a portion of the deliverables pursuant to its labour agreements, as further described in Section 7 below (PUC Services Inc. Staff Engineering and Construction Work). These deliverables to be performed by PUC are listed in Appendix A under the column titled "PUC".

1) Volt/ VAR Management system (VVM):

i. The successful Respondent **must** be responsible for the design, purchase, installation and commissioning of the VVM system.

ii. The design, purchase, installation and commissioning of the VVM system **must** include or incorporate the following components**:**

(1) a VVM optimization design for PUC's feeders in DS#'s 1, 2, 10, 11, 12, 13, 15, 16, 18, 19, 20, 21 and which is focused on the customer and system energy savings over capacity. Currently, there are few capacity constraints present in PUC system. PUC's 12.5 kV distribution system includes 12 x 34.5 kV/ 12.47 kV substations. DS#'s 1, 2, 10, 11, 12, 13, 15, 16, 18, 19, 20, 21 contain ~4 feeders per station (please refer to station drawings). DS#16 is in current design phase for reconstruction with target in-service date of Nov/Dec 2020. This station will include 2 new 10 MVA transformers with LTC's. Other station transformers have no LTC capability. Bus and/or feeder voltage regulation is anticipated with value added engineering assessment consideration for alternative solutions;

(2) a centralized model-based control and management software scheme at PUC System Operations centre which fully integrates with the Survalent SCADA software. PUC currently utilizes the Survalent SCADA software and envisions upgrade to their higher-level Distribution Management System platform with Volt/VAR Optimization (VVO) module as required; and

(3) the integration of the field device controllers for data and communication system solution with the central VVM software. PUC currently uses SpeedNet 900 MHz radios as well as SCADA network backhaul via internal fibre network from some DS's however, the Respondent may propose alternative solutions.

iii. As part of the VVM system, the successful Respondent's Proposal **should** contain or address the following:

(1) anticipate and provide mitigation strategy around certain system constraints, such as feeder improvements, as engineering design review phase is completed;

(2) include the provision of major equipment such as Station LTC's, Bus/Line Voltage Regulators and Capacitors or its equivalent as proposed by the Respondent;

(3) propose the delivery optimized kWh energy savings and bill savings for customers by leveraging the Advanced Metering Infrastructure (AMI) Sensus metering data (bell weather meters) and CYME or GIS based model;

(4) provide all data records and requirements for engineering and operations asset management systems such as: settings, SCADA points, field devices, operations and maintenance standards, etc. consistent with section (d) of this PART B of SCHEDULE B (Deliverables); and

(5) include the estimated energy savings to be attained and the process used by the Respondent to "confirm" such performance measure after the detailed engineering phase. The Proposal should include details relating to the as-built engineering assessment, methodology and execution to confirm and validate energy savings results after the commissioning phase.

2) Sub-transmission Distribution Automation (DA) system:

i. The successful Respondent **must** be responsible for the design, purchase, installation and commissioning of a DA system that will provide self-healing sub-transmission service supply.

ii. The design, purchase, installation and commissioning of a DA system **must** include or incorporate the following components:

(1) the design of the sub-transmission DA system **must** be focused on customer and system reliability and resiliency with auto-transfer solution for the 34.5 kV sub-transmission network supplying DS's and large customer locations. Currently, ten (10) 34.5 kV circuits are supplied from PUC's two 115 kV transmission stations that supply two 4.16 kV DS's and twelve 12.47 kV DS's plus some large direct customers. The 4.16 kV stations are being phased out through voltage conversion program and are not presently included in VVM and Feeder DA design plans;

(2) a centralized model-based control and management software scheme at PUC System Operations. PUC currently utilizes the Survalent SCADA software and envisions upgrade to their higher-level Distribution Management System platform with Fault Location Isolation and Service Restoration (FLISR) module as required;

(3) the integration of the field device controllers for data and communication system solution with the central DA software. PUC currently uses SpeedNet 900 MHz radios as well as SCADA network backhaul via internal fibre network from some DS's is in use by PUC at this time however, the Respondent may propose alternative solutions.

iii. As part of the sub-transmission DA system, the successful Respondent's Proposal **should** contain or address the following:

(1) provision of all data records and requirements for engineering and operations asset management systems such as: recloser settings, SCADA points, field devices, operations and maintenance standards, etc. consistent with section (d) of this PART B of SCHEDULE B (Deliverables);

(2) details on the estimated outage minutes savings to be attained and the process used by the Respondent to "confirm" such performance measure after the detailed engineering phase; and

(3) include details on the reliability and resiliency benefits that will be provided to all customers with DA applied to the sub-transmission network.

3) Feeder Distribution Automation (DA) system:

i. As part of the Proposal, Respondents **must** provide system level design for the feeder DA system with 4 levels of feeder coverage as described below, which **must** include the following components:

(1) the design, purchase, install and commission of the feeder DA system that will provide self-healing feeders;

(2) the estimated work stages, phases of feeder or area design coverage so that overall capital cost of the Project can be managed by PUC to meet cost/ benefit objectives. It is anticipated that PUC will select feeders based on the value-added design phase while assessing the basis of performance improvement and capital investment;

(3) existing and new tie points for recloser installations and coordination with station breakers will need to be selected for PUC's 12.5 kV distribution system which includes 12 x 34.5 kV/ 12.47 kV substations (DS#'s 1, 2, 10, 11, 12, 13, 15, 16, 18, 19, 20, 21) with ~4 feeders per station for a total of 48 feeders (please refer to station drawings). Priority selection of feeders to include scenario for 12, 24, 36 and 48 feeders should be addressed in the Proposal;

(4) the integration of the field device controllers for data and communication system solution with the central DA software. PUC currently uses SpeedNet 900 MHz radios as well as SCADA network backhaul via internal fibre network from some DS's is in use by PUC at this time however, the Respondent may propose alternative solutions;

(5) provision of all data records and requirements for engineering and operations asset management systems such as recloser settings, SCADA points, field devices, operations and maintenance standards, etc. consistent with section (d) (Deliverables) of this PART B of SCHEDULE B; and

(6) details on the estimated outage minutes savings to be attained and the process used by the Respondent to "confirm" such performance measure after the detailed engineering phase.

4) Field Communications Systems:

i. The system proposed by the successful Respondent **should** be designed for an integrated communication solution to cover required network area using new and existing wireless and network communications to devices supporting FLISR, VVM, and auto-transfer. PUC has access to internal fibre communication backhaul at a number of distribution stations which may be included in the solution. It is expected by PUC that the successful Respondent will need to coordinate the communications system with PUC's IT Department.

5) Integration of Advanced Distribution/ SCADA/ AMI Metering Infrastructure:

i. The system proposed by the successful Respondent **should** be an integrated solution. The system should be able to integrate the AMI and SCADA systems with any new software provided for VVM, sub-transmission DA, feeder DA, OMS and an engineering analysis tool like CYME. The successful Respondent **must** provide an estimate for their proposed solutions for resources and costs with expected scope of work and for on-going operations support for related data systems brought together to the operational performance and analytics data platform.

ii. *Advanced Distribution/SCADA Upgrades* - The Respondent **should** propose System Operations processes for the upgrade to the existing Survalent SCADA system with integrated modules for new smart grid systems. The Respondent may also propose operations processes for the system CYME based model, including a fully integrated real-time "non-controlling" testing and training model for daily operational planning purposes and long-term system planning. Project costs to include all related software licensing as required and hardware cost estimates with PUC intent to integrate in PUC IT virtual server structure.

iii. *Outage Management System (OMS)* – The Respondent **should** propose an outage management solution, preferably a non-custom, off-the-shelf solution, with integration to available data platforms for real-time measurement, reporting and supporting historical outage metrics. As part of the OMS, the Respondent should consider the provision of additional functionalities such as, web portal dealing with customer outages, a dedicated dashboard for internal stakeholders and a crew management system, etc.

iv. *Customer Care Tools* **–** The Respondent **should** propose enhancements to PUC's current CIS platform such as those relating to access to outage information, and customer specific service measures and performance. PUC currently uses the Harris NorthStar CIS platform. As such, the Respondent's proposed enhancements, if any, **should** be directly for the Harris NorthStar CIS platform which **should** also integrate with the OMS for internal operations and customer care.

6) Operations, Maintenance and Life Cycle

i. The successful Respondent **must** be responsible for the providing operations, maintenance and life cycle plans and procedures of all new equipment, systems and processes as part of the Project including:
   (1) the System Operating procedures of all new equipment, systems and processes related to the Project including any transition-change management planning along with the orientation and training of PUC staff;
   (2) the maintenance and inspection procedures of new equipment;
   (3) the asset management asset life cycle plans of new equipment; and
   (4) set out the optional price list for any specialty testing tools and equipment proposed by the Respondent for the related equipment.

ii. As an optional project element for operations, maintenance and life cycle services, the successful Respondent's Proposal **should** contain or address the following:
   (1) Propose a 10 year warranty service with operations, maintenance and life cycle plan for the proposed system and equipment including execution of required equipment operations and maintenance services proposed in section (6)(i) above along with the relevant lump sum pricing for that warranty service.

7) PUC Services Inc. Staff Engineering and Construction Work

i. The successful Respondent **must** be responsible for design selected site specific pole replacement and installation services ("**Installation Services**"), subject to the resource allocation restrictions under PUC's Labour Agreement. Pursuant to the Labour Agreement, PUC is required to utilise its own employees for a certain percentage of the Installation Services undertaken by or on behalf of PUC. As such, the successful Respondent **must** utilize PUC's employees as its subcontractors to complete a portion of the Installation Services.

ii. Installation Services may include services relating to: the design and installation for what is generally overhead line construction work; pole replacements; new pole installation; framing; equipment installation in proximity zone to live circuits; and overhead terminations, including the design, approval and application of new EPC developed framing standards if required.

iii. For the purposes of the evaluation of Proposals, PUC has included an estimated quantity of pole replacement and installation work that may be required by PUC in the Notes/ Comments column of Appendix A.

(d) Deliverables required

As part of the deliverables provided for the Project, successful Respondents **should** provide all Project document deliverables in the following formats: one paper copy, one electronic copy in native file format, and one PDF copy unless specified otherwise specified by PUC. These documents will become the sole property of the PUC to use as they wish to support the business upon completion of this Project. All drawings will be in PUC provided borders with PUC provided numbering. All drawings are to be completed in AutoCAD. All design documents are to be stamped and signed by a Professional Engineer (P. Eng) licensed in the Province of Ontario.

(e) Evaluation Criteria

The following components will be used in guiding PUC's evaluation of each Respondent's Proposal and selection of the successful Respondent(s).

Stage 1 – Compliance with Mandatory Requirements

Stage 1 of the evaluation process will consist of a review of each Proposal to determine which Proposal complies with all of the mandatory requirements (of an administrative nature) in the RFP, including without limitation, the mandatory requirements set out in SCHEDULE A (RFP Procedures) and PART A of SCHEDULE B (Proposal Requirements). Respondents must meet all mandatory requirements under Stage 1 to proceed to Stage 2.

Stage 2 – Scoring of Rated Requirements

Stage 2 of the evaluation process will consist of evaluating Proposals based on the rated requirements set out in Section (b) of PART B of SCHEDULE B and the following score methodology (for items 1 to 5 below):

Item	Rated Requirements	Maximum allocated points	Minimum score required to proceed to Stage 3
1	Respondent's firm qualifications and experience	15	7.5
2	Respondent's key personnel, qualifications and experience	15	7.5
3	Respondent's project methodology, technical understanding and delivery plan	50	25
4	Respondent's quality of Proposal and completeness	10	5
5	Respondent's innovation in its Proposal	10	5
6	Total Score	100	-

Each Respondent is required to achieve for each Item 1 to 5, the minimum scores described above, which is 50% of the points allocated for each of Items 1 to 5 individually, in order to proceed to Stage 3.

Stage 3 – Pricing

The score received by each Respondent in Stage 3 will be determined by the formula below:

Price per Point Score = [Total price of Proposal] / Total Qualification Score

The Respondent with the lowest Price per Point Score will be deemed the highest scoring Respondent and is the successful Respondent. In the unlikely event of a tie between two or more highest scoring Respondent, the Respondent achieving the highest score in Stage 3 will be scored first overall. In the event that a tie still remains, PUC shall flip a coin to determine a winner.

Appendix A – Project Tasks (1 of 3)

The following tables reflect the individual elements of the overall Project. It is anticipated that PUC will be responsible for a portion of the work pursuant to its labour agreements, as further described in Section 7 below (PUC Services Inc. Staff Engineering and Construction Work). These services are listed below under the column titled "PUC".

The 100%, 75%, 50%, 25% line items reflect the 48, 36, 24, 12 feeder scenarios where the scope of Feeder DA work that may be adjusted to meet overall Project cost/benefit objectives. To be clear, the Respondents must provide the system design for feeder DA system with 4 levels of feeder coverage. However, it is up to PUC to decide if it wants the coverage for all 4 feeders.

Engineering

	Task/ Area Responsibility	RFP	PUC	Notes				
Overall System Design				[1] [2] [3]				
5.1.1	Volt/ VAR Management	x						
5.2.1	Sub-transmission Distribution Automation (DA)	x						
5.3.1	Feeder Distribution Automation (DA)	x		[7]	**100%**	**75%**	**50%**	**25%**
5.4.1	Field Communication System	x						
5.5.1	ADMS/SCADA/AMI/OMS	x						
5.6.1	Operations, Maintenance & Life Cycle	x						
Field Design - Stations				[1] [2] [3]				
5.1.2	Volt/ VAR Management	x						
5.2.2	Sub-transmission Distribution Automation (DA)	x						
5.3.2	Feeder Distribution Automation (DA)	x		[7]	**100%**	**75%**	**50%**	**25%**
5.4.2	Field Communication System	x						
5.5.2	ADMS/SCADA/AMI/OMS	x						
5.6.2	Operations, Maintenance & Life Cycle	x						
Field Design - Lines								
5.1.3	Volt/ VAR Management	x	x	[4] [5] [6]				
5.2.3	Sub-transmission Distribution Automation (DA)	x	x	[4] [6]				
5.3.3	Feeder Distribution Automation (DA)	x	x	[4] [6] [7]	**100%**	**75%**	**50%**	**25%**
5.4.3	Field Communication System	x	x	[4] [6]				
5.5.3	ADMS/SCADA/AMI/OMS	x						
5.6.3	Operations, Maintenance & Life Cycle	x						

Notes:	[1] RFP Respondent will have overall system design responsibility.
	[2] Engineering estimate will be complete for full system but may include sub-components based on Respondents methodology.
	[3] Engineering table of hourly rates for value added- engineering and scope changes to be provided.
	[4] Field design at specific pole locations subject to PUC Labour Agreement for "Make Ready" works.
	[5] PUC assumption - if 100 pole locations required then PUC will complete 50 and RFP will complete 50.
	[6] Final quantity and ratio of PUC/RFP subject to final design and contract decisions.
	[7] Engineering estimate will have some scaling for selected DA feeder coverage.

Appendix A – Project Tasks (2 of 3)

Procurement

	Task/ Area Responsibility	RFP	PUC	Notes				
Procurement				[1] [2]				
5.1.4	Volt/ VAR Management	x						
5.2.4	Sub-transmission Distribution Automation (DA)	x						
5.3.4	Feeder Distribution Automation (DA)	x		[3]	**100%**	**75%**	**50%**	**25%**
5.4.4	Field Communication System	x		[3]				
5.5.4	ADMS/SCADA/AMI	x						
5.6.4	Operations, Maintenance & Life Cycle	x		[3]				
Notes:	[1] RFP will provide all materials and equipment in estimate							
	[2] Materials and equipment estimate based on defined cost plus proposal							
	[3] DA feeder coverage will result in 4 scenarios with estimate required.							

Appendix A – Project Tasks (3 of 3)

Construction

	Task/ Area Responsibility	RFP	PUC	Notes				
Construction/ Commissioning - System				[1] [2] [3]				
5.1.5	Volt/ VAR Management	x						
5.2.5	Sub-transmission Distribution Automation (DA)	x						
5.3.5	Feeder Distribution Automation (DA)	x						
5.4.5	Field Communication System	x						
5.5.5	ADMS/SCADA/AMI	x						
5.6.5	Operations, Maintenance & Life Cycle	x						
Construction/ Commissioning - Stations								
5.1.6	Volt/ VAR Management	x						
5.2.6	Sub-transmission Distribution Automation (DA)	x						
5.3.6	Feeder Distribution Automation (DA)	x						
5.4.6	Field Communication System	x						
5.5.6	ADMS/SCADA/AMI	x						
5.6.6	Operations, Maintenance & Life Cycle	x						
Construction/ Commissioning - Lines								
5.1.7	Volt/ VAR Management	x	x	[4] [5] [6]				
5.2.7	Sub-transmission Distribution Automation (DA)	x	x	[4] [5] [6]				
5.3.7	Feeder Distribution Automation (DA)	x	x	[4] [5] [6] [7]	**100%**	**75%**	**50%**	**25%**
5.4.7	Field Communication System	x	x	[4] [5] [6] [7]				
5.5.7	ADMS/SCADA/AMI	x						
5.6.7	Operations, Maintenance & Life Cycle	x		[7]				
Notes:	[1] RFP Respondent will have overall system construction responsibility.							
	[2] Construction estimate will be complete for full system but may include sub-components based on Respondents methodology.							
	[3] Construction subcontractor estimate if utilized, may be based on defined cost plus proposal .							
	[4] Field construction at specific pole locations subject to PUC Labour Agreement for "Make Ready" works.							
	[5] PUC assumption - if 100 pole locations required then PUC will complete 50 and RFP will complete 50.							
	[6] Final quantity and ratio of PUC/RFP subject to final design and contract decisions.							
	[7] Construction estimate will have some scaling for selected DA feeder coverage.							

Appendix B – Project Estimate Matrix

The spreadsheet image below is for information purposes only. An MS Excel Spreadsheet will be posted to PUC's secured project website to be accessed and **must** be completed by the Respondents in preparing their Proposal. The spreadsheet layout will have no embedded formulas. Respondents may revise and develop with formula as live spreadsheet but are to maintain layout to facilitate RFP evaluation.

Project Name	Sault Smart Grid								Refer to RFP description for full description of requirements.
					Cost Before Markup	Markup (Material & Sub Cont.)	Total Project Estimate	10 Year O&M and Warranty Estimate	Notes & Comments:
Volt/VAR Optimization /Management	**Supply & Install**								optimization for customer/ system energy savings
14 DS/ 48 feeders	***Qty***		***$Unit/Ea***						
Engineering									Includes, VVM system design, Station works and feeder delivery points.
System VVM Engineering Design		Hrs							
Site/ Field Design		Hrs							Location/ siting part of "system design". "Make Ready" part of PUC shared scope.
Subtotals									
Procurement									
LTC's (at Sub 16)	2		PUC	2 x 10MVA	--	--	--	--	
Interface Sub 16 LTC's with VVM solution	2	ea							Equipment selection and quantities used for RFP comparison. Final project contract subject to adjustment based on proponent detailed engineering and solution.
Station Feeder Regulators	44	ea		300A					
Station Feeder Regulators	10	ea		200A					
Add'l Feeder VReg	6	ea		100A					
Cap Bank	6	ea		600kVAR					
Poles & framing	12	ea							Assume any poles required included in DA section below.
Survalent Modules/ Upgrades for VVM									Modules as required from Respondent design for VVM, AMI interface, Operator "live" simulator, Load Flow, etc.
Subtotals									
Construction - V/VAR									
Labour & Equipment - Installation									
Interface Sub 16 LTC's with VVM solution	2	ea							Equipment selection and quantities used for RFP comparison. Final project contract subject to adjustment based on proponent detailed engineering and solution.
Station Feeder Regulators	44	ea		300A					
Station Feeder Regulators	10	ea		200A					
Add'l Feeder VReg	6	ea		100A					
Cap Bank	6	ea		600kVAR					
Pole installations & "Make Ready"									Assume a poles required included in DA section below.
Subtotals									
Totals				**VVM TOTAL**					
					VVM 10 Yr O&M and Warranty Total				**VVM 10 Yr O&M and Warranty Total**
Distribution Automation (*48)	**Supply & Install**					**Material &**	**Project**	**10 Year O&M and**	
34.5kV sub transmission auto transfer	***Qty***		***$Unit/Ea***			**Sub Markup**	**Estimate**	**Warranty**	
plus distribution feeder deployment								**Estimate**	*** NOTE: Worksheets for 12/24/36/48 feeders required**
Engineering									Includes, 34.5 kV TT, DA system design, station works and feeder DA points.
System DA Engineering Design		Hrs							
Site/ Field Design		Hrs							Location/ siting part of "system design". "Make ready" part of PUC shared scope.
Subtotals									
Procurement									
S&C Intellirupter, control,communications	40	ea							Equipment selection and quantities subject to adjustment based on proponent detailed engineering and solution. Qty estimated on full DA coverage so reduced as ratio if required.
S&C Scada-mate, control, communications	40	ea							
S&C Vista 4-way UG, control, communications	8	ea							
S&C Vista 2-way UG, control, communications	4	ea							
S&C PMH-3, control, communciations	8	ea							
FCI's overhead, 3ph, communications	20	ea							
FCI's underground, 3 ph, communications	20	ea							
Pole installations & "Make Ready"	50		PUC						see PUC "Make Ready" assumption [50 + 50]
	50	ea							
Survalent Modules/ Upgrades for DA									Modules as required for DA, AMI interface, Operator "live" simulator, Load Flow, FLIR (12/24/36/48), other?
Subtotals									
Construction - DA									
Labour & Equipment - Installation									
S&C Intellirupter, control,communications	40	ea							Equipment selection and quantities used for RFP comparison. Final project contract subject to adjustment based on proponent detailed engineering and solution.
S&C Scada-mate, control, communications	40	ea							
S&C Vista 4-way UG, control, communications	8	ea							
S&C PMH-3, control, communciations	8	ea							
FCI's overhead, 3ph, communications	20	ea							
FCI's underground, 3 ph, communications	20	ea							
Pole installations & "Make Ready"	50		PUC						see PUC "Make Ready" assumption [50 + 50]
	50	ea							
Subtotals									
PUC "Make Ready" Assumption									PUC Make Ready Work: Some % of the field engineering and line construction for equipment installation will be executed by PUC Services Inc. as sub to EPC contractor. [Work such as field engineering work order, pole replacement, new pole installs, framing.] Assume PUC executes 50 total locations out of total required.
				DA TOTAL					
Project Total			**EPC TOTAL**						
					DA 10 Yr O&M and Warranty Total				**DA 10 Yr O&M and Warranty Total**
					10 Yr O&M and Warranty Total				**10 Yr O&M and Warranty Total**
Common Systems/ Other							Estimate		
Outage Management System	1	ea							PUC looking for upset limit estimates. May exclude from EPC contract and develop scope and estimates directly with selected proponent.
Data Analytics and KPI platform and reporting	1	ea							
Customer Service integration - CSR's and customers	1	ea							
		ea		TOTAL					

SCHEDULE C

PROPOSAL COVER SHEET

PROPOSAL

of

_____

in response to

PUC Services Inc.'s

RFP No. **SSG2019**

Date: _____

Respondent Contact Information:

Company Name: _____

Primary Contact Name: _____

Primary Contact Title: _____

Address: _____

Email: _____

Telephone: _____

Fax: _____

SCHEDULE D

RESPONDENT'S CERTIFICATE

I, the undersigned, in submitting the accompanying Proposal to PUC in response to RFP No. SSG2019 (the "**RFP**") on behalf of _____ (the "**Respondent**") do hereby certify, on behalf of the Respondent and not in my personal capacity that:

1. I have read, understand and agree to comply with the terms of this RFP.

2. I have read, understand and agree to comply with the statements made in this Certificate.

3. Information that is submitted is complete, accurate and up-to-date. I understand that the accompanying Proposal may be disqualified if this Certificate is found not to be true and complete in every respect.

4. I am authorized by the Respondent to sign this Certificate, and to submit the accompanying Proposal, on behalf of the Respondent.

5. Each person whose signature appears on the accompanying Proposal has been authorized by the Respondent to determine the terms of, and to sign, the Proposal, on behalf of the Respondent.

6. The Respondent consents to the disclosure of its information, including any information identified as confidential by it, by PUC to any of PUC's consultants or advisors who may be retained for the purposes of evaluating the information, as well as PUC's employees and officers, who need to know in relation to the RFP and the procurement of the applicable deliverables.

7. For the purposes of this Certificate and the accompanying Proposal, I understand that the word "Competitor" shall include any individual or organization, other than the Respondent, whether or not affiliated with the Respondent, who:

   (a) has been requested to submit a Proposal in response to the above-noted RFP; or

   (b) could potentially submit a Proposal in response to the above-noted RFP, based on their qualifications, abilities or experience.

8. The Respondent has arrived at the accompanying Proposal independently from, and without consultation, communication, agreement or arrangement with, any Competitor.

9. The terms of the accompanying Proposal have not, and will not be disclosed by the Respondent, directly or indirectly, to any Competitor.

10. Any and all potential conflicts of interest between the Respondent and PUC (or any Representative thereof) are expressly identified and fully disclosed by the Respondent in the attached Proposal, including the disclosure of any personal or business relationships between the Respondent and PUC (or any Representative thereof) and the Respondent (or any Representative thereof).

11. The RFP and this Proposal do not create any legal obligation on the part of PUC or restrict PUC's rights regarding the procurement of any deliverable.

12. The Respondent acknowledges and agrees that PUC shall have no liability to the Respondent or its sub-contractors in respect of the conduct of the procurement process relating to this RFP by PUC, whether in contract or tort or otherwise, and including, without limitation, for costs that the Respondent or its sub-contractors incur with respect to the procurement process or for any loss of profit the Respondent or its sub-contractors incur as a result of not being awarded a contract under this procurement process.

13. The Respondent acknowledges and agrees that: (i) as of the date hereof there are no existing, current or contemplated claim, demand, suit, action, or cause of action, whether arising in contract, tort or otherwise, from or involving the Respondent or its affiliates against PUC or its affiliates ("**Claim**") and (ii) the Respondent hereby irrevocably waives the right to make any such Claim against PUC and it's affiliates.

14. Any capitalized terms used in this Certificate but not defined herein shall have the meaning as defined in the RFP.

_____
Respondent's Full Corporate Name

_____
Authorized Representative's Signature

_____
Name

_____
Title

_____
Date

SCHEDULE E

DEFINED TERMS

In this RFP, the following definitions shall apply:

"Affiliates"	has the meaning prescribed to it in the *Business Corporations Act* of Ontario;
"Applicable Laws"	means all federal, provincial and municipal statutes, regulations, codes, by-laws, orders in council, directives, rules, guidelines and ordinances applicable to this RFP and any resulting Contract, including without limitation all applicable OEB codes, rules or guidelines;
"Business Day"	means a day on which banks are open for business in the City of Toronto, Ontario, but does not include a Saturday, Sunday, or a statutory holiday in the Province of Ontario;
"Buyer"	means the Representative of PUC identified in Section (a) of SCHEDULE A;
"Confidential Information"	has the meaning prescribed to it in Section 2.13;
"Contract"	means the definitive written Engineering, Procurement and Construction agreement(s), if any, which may be entered into between the successful Respondent and PUC, as a result of this RFP process;
"Date for Execution of the Contract (estimated)"	has the meaning prescribed to it in SCHEDULE A;
"Date for Selection of Successful Respondent(s)"	has the meaning prescribed to it in SCHEDULE A;
"Date of RFP Issuance"	has the meaning prescribed to it in SCHEDULE A;
"Deadline for Addenda Issuance"	has the meaning prescribed to it in SCHEDULE A;
"Deadline for Submission of Questions"	has the meaning prescribed to it in SCHEDULE A;
"EST"	means Eastern Standard Time;
"Governmental Authority"	means any government, legislature, municipality, regulatory authority, agency, commission, department, board or court or other law, regulation or rule-making public entity of similar authority, including, without limitation the OEB;

“OEB”	means Ontario Energy Board;
“Proposal”	means the document(s) submitted by a Respondent to PUC in response to this RFP;
“PUC”	has the meaning identified on the cover page of this RFP;
“Representative”	in respect of a party, means such party's directors, officers, employees, agents, contractors and advisors, the party's Affiliates, and all such Affiliates' respective directors, officers, employees, agents, contractors and advisors;
“Respondent”	means each party that submits a Proposal to PUC in response to this RFP;
“RFP”	means this Request for Proposals, including any and all addenda, schedules, attachments, amendments, supplements or revisions thereto;
“RFP Schedule”	has the meaning prescribed to it in SCHEDULE A; and
“Submission Deadline”	has the meaning prescribed to it in SCHEDULE A.

Appendix AA2-2
Copy of the SSG RFP Addendum #1

PUC SERVICES	Request for Proposals Engineering, Procurement & Construction Services	RFP No. SSG2019 Addendum #1
	RFP SCHEDULE EXTENSION	October 17, 2019

Reference:

Schedule A

RFP Procedures

(b) RFP SCHEDULE

Extension of Timelines:

Expression of Interest Posting	**October 1, 2019**
Date of RFP Issuance	**October 4, 2019**
Deadline for Submission of Questions	**October 24, 2019 4:00:00 PM EST**
Deadline for Addenda Issuance	**November 1, 2019**
Submission Deadline	**November 18, 2019 3:00:00 PM EST**
Date for Selection of Successful Respondent(s) (estimated)*	**November 27, 2019**
Date for Execution of the Contract (estimated)*	**December 24, 2019**

Appendix AA2-3
Copy of the SSG RFP Addendum #2

PUC SERVICES	Request for Proposals Engineering, Procurement & Construction Services	RFP No. SSG2019 Addendum #2
	RFP SCHEDULE EXTENSION	October 31, 2019

Reference:

Schedule A

RFP Procedures

(b) RFP SCHEDULE

Extension of Timelines:

Expression of Interest Posting	**October 1, 2019**
Date of RFP Issuance	**October 4, 2019**
Deadline for Submission of Questions	**October 24, 2019 4:00:00 PM EST**
Deadline for Addenda Issuance	**November 11, 2019**
Submission Deadline	**November 27, 2019 3:00:00 PM EST**
Date for Selection of Successful Respondent(s) (estimated)*	**December 3, 2019**
Date for Execution of the Contract (estimated)*	**December 24, 2019**

Appendix AA2-4
SSG RFP Evaluation

SSG RFP was issued October 4, 2019 and submissions received from two (2) proponents by the deadline of December 3, 2019. Each proposal was evaluated on the basis of the five (5) criteria in the table shown and outlined in the RFP documents for a qualification score. The price proposal was divided by the qualification score for a price per point score rating.

Respondent's firm qualifications and experience
Respondent's key personnel, qualifications and experience
Respondent's project methodology, technical understanding and delivery plan
Respondent's quality of Proposal and completeness
Respondent's innovation in its Proposal

PUC Distribution selected the proponent representing the best value for the next phase of review and negotiation of final terms and conditions and detailed project specifications towards the final project contract. The EPC Step 1 Firm Price (engineering stage) has been set and the Step 2 Upset Limit (detailed engineering, procurement and construction) has been set. Final contract documents are in progress for execution at time of drafting the application.

A pdf copy of the RFP document has been provided with the Amended Application, including the Addenda on noted date changes in process.

Appendix AA3
EPC Contract Scope & Pricing
(Filed in Confidence)

Appendix AA3 -1
SSG Scope Overview Summary
(Filed in Confidence)

Appendix AA3-2
Physical Scoping Diagram
(Filed in Confidence)

Appendix AA3-3
Logical Scoping Diagram
(Filed in Confidence)

Appendix AA3-4
Responsibilities Matrix
(Filed in Confidence)

Appendix AA3-5
Project Schedule
(Filed in Confidence)

Appendix AA3-6
EPC Pricing
(Filed in Confidence)

Appendix AA3-7
EPC Contract and Appendices
(Filed in Confidence)

Appendix AA4
Updated Statement of Work, Updated NRCan Contribution Agreement and Claim Form

Appendix AA4-1
Statement of Work (changes made for amended Contribution Agreement)

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. 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.
BENEFITS:	**Benefits to Canada/Canadians** 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 (e.g. electronics manufacturing, e-commerce, telecommunication services and data centres). **Benefits to Stakeholders:** 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.

Appendix AA4-2
Contribution Agreement (amended) [JTC 1.16] (pdf file)

PROTECTED A

DEPARTMENT OF NATURAL RESOURCES

RENEWABLE ENERGY AND SMART GRID DEPLOYMENT PROGRAMS

SMART GRID DEPLOYMENT PROGRAM

AMENDMENT NO. 1 TO THE REPAYABLE CONTRIBUTION AGREEMENT

THIS AMENDING 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 and the Proponent entered into a Contribution Agreement signed by Canada on December 19, 2018, and by the Proponent on December 11, 2018 (the Agreement);

WHEREAS the Proponent is requesting an amendment to incorporate changes to the Project timelines, and to reallocate the Contribution amounts in whole or in part from one Fiscal Year to another;

AND WHEREAS Canada and the Proponent wish to amend the Agreement;

NOW, THEREFORE, Canada and the Proponent agree as follows:

1. **"Agreement"** as defined in the Interpretation Section of the Agreement (Article 1) is revoked and replaced by the following:

   "Agreement" means this Agreement and the attached Schedules A, B, C and D;

2. **"Eligible Expenditure Period"** as defined in the Interpretation Section of the Agreement (Article 1) is revoked and replaced by the following:

   "Eligible Expenditure Period" means the period of September 5, 2018 to March 31, 2022;

3. Paragraph 1.2 of the Agreement is revoked and replaced by the following:

   1.2 Schedules

   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); and
   d) Schedule D (Certification of Eligible Expenditures Incurred and Paid).

4. Paragraph 3.3 of the Agreement is revoked and replaced by the following:

   3.3 Ontario Energy Board Approval

   The Proponent undertakes to receive approval from the Ontario Energy Board for the Required Rate Adjustment by March 31, 2020.

5. Paragraph 3.5 of the Agreement is revoked and replaced by the following:

   3.5 Survival

   The following clauses shall survive the termination of this Agreement for an additional three (3)

years:

a) ***Accounts and Audits Article;***
b) ***Intellectual Property Article;***
c) ***Indemnity Article;***
d) ***Default Article;***
e) ***Reports Article;***
f) ***Confidentiality Article;*** **and**
g) ***Dispute Resolution Article.***

6. Paragraph 4.2 of the Agreement is revoked and replaced by the following:

4.2 Project Schedule

Subject to Paragraph 3.3, the Proponent shall complete the Project by March 31, 2022, unless terminated earlier pursuant to the provisions of this Agreement

7. Article 5 of the Agreement is revoked and replaced by the following:

5. ENVIRONMENT

5.1 The Proponent represents and warrants that the Project is not a designated project under the *Impact Assessment Act* 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 *Impact Assessment Act* 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 *Impact Assessment Act* 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 *Impact Assessment Act*, 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 *Impact Assessment Act* including any such conditions requiring the implementation of mitigation measures and any follow up program.

8. Paragraph 6.1 of the Agreement is revoked and replaced by the following:

6.1 Contribution

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) Ten Million Six Hundred Twenty Six Thousand Five Hundred Dollars ($10,626,500)

9. Paragraph 6.2 of the Agreement is revoked and replaced by the following:

6.2 Fiscal Year Allocations

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	One Million Dollars ($1,000,000)
2020-2021	Two Hundred Fifty Thousand Dollars ($250,000)
2021-2022	Two Million Seven Hundred Twenty Three Thousand Five Hundred Dollars ($2,723,500)
Total:	Ten Million Six Hundred Twenty Six Thousand Five Hundred Dollars ($10,626,500)

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.

10. Paragraph 6.3 of the Agreement is revoked and replaced by the following:

6.3 Final Claim of the Contribution

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, 2022.

11. Paragraph 6.6 of the Agreement is revoked and replaced by the following:

6.6 Total Government Funding

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):	Ten Million Six Hundred Twenty Six Thousand Five Hundred Dollars ($10,626,500)
Other Federal:	Zero Dollars ($0)
Provincial:	Zero Dollars ($0)
Territorial:	Zero Dollars ($0)
Municipal:	Zero Dollars ($0)
Total Government Funding:	Ten Million Six Hundred Twenty Six Thousand Five Hundred Dollars ($10,626,500)

The Proponent shall advise the Minister promptly of any change in the Total Government Funding listed above during the term of this Agreement.

12. Paragraph 7.5 of the Agreement is revoked and replaced by the following:

7.5 Claims for Payment

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 sixty (60) days after the end of each quarter, except the claim for the final payment.

13. Paragraph 9.1 of the Agreement is revoked and replaced by the following:

9.1 Books and Records

Prior to the Completion Date and for three (3) 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).

14. Schedule A (Statement of Work) is revoked and replaced by the attached Schedule A (Statement

of Work).

15. Schedule B (Budget and Eligible Expenditures) is revoked and replaced by the attached Schedule B (Budget and Eligible Expenditures).

16. Schedule C (Reports) is revoked and replaced by the attached Schedule C (Reports).

17. Schedule D (Certification of Eligible Expenditures Incurred and Paid) is revoked and replaced by the attached Schedule D (Certification of Eligible Expenditures Incurred and Paid).

18. Schedule E (Proposal) is revoked.

19. All other terms and conditions of the Agreement remain in full force and in effect.

20. This Amending Agreement comes into force when signed by the Parties.

IN WITNESS WHEREOF this Amending Agreement has been 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

DEC 1 8 2019
Date

Mollie Johnson
Assistant Deputy Minister
Low Carbon Energy Sector

PUC DISTRIBUTION INC.

Dec 18/19
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. 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.
BENEFITS:	**Benefits to Canada/Canadians** 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 (e.g. electronics manufacturing, e-commerce, telecommunication services and data centres). **Benefits to Stakeholders:** 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. 2020)**	- 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. 2021)**	- 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 2022)**	- 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 2022)**	- Project management and oversight provided by PUC Services, including general project management, change orders and relationships between EPC and vendors - PUC to ensure project coordination between PUC distribution system operations and EPC contractor.	- 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 ($)	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**TOTAL ($)**
The Program (NRCan Contribution)	$6,653,000.00	$1,000,000.00	$250,000.00	$2,723,500.00	$10,626,500.00
ELIGIBLE EXPENDITURES					
Salaries and Benefits	$0.00	$0.00	$0.00	$0.00	**$0.00**
Overhead	$0.00	$0.00	$0.00	$0.00	**$0.00**
Professional, Scientific &	$13,306,000.00	$1,000,000.00	$17,400,000.00	$10,800,000.00	**$42,506,000.00**
Travel, including Meals and Accomodations	$0.00	$0.00	$0.00	$0.00	**$0.00**
Equipment and Products	$0.00	$0.00	$0.00	$0.00	**$0.00**
Other Expenses	$0.00	$0.00	$0.00	$0.00	**$0.00**
Total by Fiscal Year:	**$13,306,000.00**	**$1,000,000.00**	**$17,400,000.00**	**$10,800,000.00**	
			Total Eligible Expenditures		**$42,506,000.00**

INELIGIBLE COSTS					
INELIGIBLE EXPENDITURES	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**TOTAL ($)**
Incurred before Eligible Expenditure period (between June 13, 2018 and August 28, 2018)	$300,000.00	$0.00	$0.00	$0.00	$300,000.00
Ineligible Overhead Expenditures	$0.00	$0.00	$0.00	$0.00	$0.00
			Total Ineligible Expenditures		**$300,000.00**
IN-KIND COSTS					
					$0.00
			Total In-Kind Costs		**$0.00**
			Total Ineligible Costs		**$300,000.00**
			TOTAL PROJECT COSTS		**$42,806,000.00**

Source of Contributions:	**Percentage (%)**	**Cash ($)**	**In-Kind ($)**	**Total ($)**
The Program (NRCan Contribution)	**25%**	10,626,500	N/A	**10,626,500**
The Proponent	**75%**	32,179,500	0	**32,179,500**
TOTAL	**100%**	**$42,806,000**	**$0**	**$42,806,000**

NOTE: the following limitations apply to the approved budget above:

a) 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.

b) Overhead expenditures, directly related to the conduct of the Project, are limited to fifteen percent (15%) of total Eligible Expenditures, up to a maximum of $1,000,000.

c) Ineligible costs, such as the reimbursable portion of Federal and Provincial Taxes, and expenditures incurred before or after the Eligible Expenditure Period, are considered towards Total Project Costs; however, they are not eligible for reimbursement.

d) 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. 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 **sixty (60) 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 report summarizing Project activities during the Fiscal Year together with key performance outputs to indicate how the Project has been contributing to the overall Program objectives. The report must be provided with the fourth quarter claim for payment, no later than **sixty (60) days after the end of the fourth quarter**. The Program will provide the Proponent with a template for this report.

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;

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; and

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. **Revenue reporting**

For five (5) years following the completion of the Project, the Proponent must submit annually a report indicating the revenues received as a result of the Project. Where no revenue has been received, a nil report is still required. The Program will provide the Proponent with a template for the revenue report. The Proponent shall provide this report no later than **ninety (90) days following the anniversary of the Project Completion date.**

5. 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.

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, 2022, 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: _____

Appendix AA4-3
Contribution Agreement Claim Form

Smart Grid Deployment Program

Within thirty (30) days after the end of each quarter, recipients of Smart Grid Deployment Program funding must provide a claim, an updated budget forecast and project task updates, as per Schedule C of the Contribution Agreement.

Project Name:	Sault Smart Grid
Project ID:	GISC - 3030
Proponent Company Name:	PUC Distribution Inc.
Claim number:	No. 1
Expenses for Quarter Ending on:	

	Costs Incurred	Costs Expected Next Quarter
ELIGIBLE EXPENDITURES		
Salaries and Benefits		
Overhead		
Professional, Scientific and Contracting Services*		
Travel, including Meals and Accomodations		
Equipment and Products**		
Other expenses***		
Total Eligible Expenditures	$ -	$ -

INELIGIBLE EXPENDITURES		
Salaries and Benefits		
Overhead		
Professional, Scientific and Contracting Services*		
Travel, including Meals and Accomodations		
Equipment and Products**		
Other expenses***		
Total Ineligible Expenditures	$ -	$ -

TOTAL PROJECT COSTS	$ -	$ -
Smart Grid Contribution (this quarter)		
Less 25% holdback (in contribution agreement)	$ -	
CLAIM PAYMENT AMOUNT	$ -	

** Complete "Professional, Scientific and Contracting Services" worksheet*

*** Complete "Equipment and Products" worksheet*

**** Complete "Other Expenses" worksheet*

NOTE 1: *For Eligible Expenditures under the "Equipment and Products" category, or contracting services related to the purchase of equipment, materials, or products, any claim greater than $100,000 must be supported by a copy of the invoice.*

NOTE 2: *For Eligible Expenditures under all other categories, any claim greater than $50,000 must be supported by a copy of the invoice.*

NOTE 3: *For the Eligible Expenditures above, the Proponent can include the Goods and Services Tax (GST), Harmonized Sales Tax (HST) and Provincial Sales Tax (PST) costs paid on their project invoices, provided it's net of any tax rebate to which the Proponent is entitled. Program reimbursement for these taxes is also dependent on completion of the* ***Certification for the Treatment of GST, PST and HST*** *form provided by the Program.*

Professional, Scientific and Contracting Services

Note: Expenses above $50,000 must be supported by a copy of the invoice.

ELIGIBLE EXPENDITURES		
Name of the contractor	**Description of the work**	**Costs Incurred**
Total Eligible *Professional, Scientific and Contracting Services* Costs		**$ -**

INELIGIBLE EXPENDITURES		
Name of the contractor	**Description of the work**	**Costs Incurred**
Total Ineligible *Professional, Scientific and Contracting Services* Costs		**$ -**

Equipment and Products

Note: *Expenses above $100,000 for equipment, materials, or products (or contracting services related to these purchases) must be supported by a copy of the invoice.*

ELIGIBLE EXPENDITURES		
Name of Equipment or Product	**Purpose of Item**	**Costs Incurred**
Total Eligible *Equipment and Products* Costs		**$ -**

INELIGIBLE EXPENDITURES		
Name of Equipment or Product	**Purpose of Item**	**Costs Incurred**
Total Ineligible *Equipment and Products* Costs		**$ -**

Other Expenses

Note: *Expenses above $50,000 must be supported by a copy of the invoice*

ELIGIBLE EXPENDITURES		
Type of Other Expense*	**Description of Item**	**Costs Incurred**
Total Eligible *Other Expenses*		**$ -**

INELIGIBLE EXPENDITURES		
Type of Other Expense*	**Description of Item**	**Costs Incurred**
Total Ineligible *Other Expenses*		**$ -**

** "Other Expenses" can include: 1) Field supplies and materials; 2) Printing services and translation; 3) Data collection services, including processing, analysis and management; 4) Facility expenses for seminars, conference room rentals, etc. (excluding hospitality); 5) License fees and permits; and 6) Field testing services.*

Certification and Project Update

Project Update - Provide updates on key project tasks performed during last quarter
Attach in a separate document the key project tasks completed and expected in the next quarter and describe how they align with the tasks identified in Schedule A of the contribution agreement. Also, please provide information about any project related issues and how they are being addressed. Bullet form is acceptable.

I, a duly authorized officer of *PUC Distribution Inc.* *certify that the amounts claimed are correct.*
(Sign and date below)

Date: _____

Name: Robert Brewer

Title: President & CEO

Submit quarterly claim package to: nrcan.sg-ri.rncan@canada.ca

Appendix AA4-4
Correspondence from NRCan

Beaulac, Zoe (NRCan/RNCan) <zoe.beaulac@canada.ca> | Mertikas, Bill (NRCAN/RNCAN); Hanna, Catherine (NRCan/RNCan); + 1 | 17/09/2020

Notice: Changes to Smart Grid Deployment Program Terms and Conditions

Dear Smart Grid Deployment Program Recipients:

We are pleased to inform you that effective September 15, 2020, the Minister has approved the following changes to the terms and conditions of the Smart Grid Deployment Program:

- The eligible expense end date has been extended 1 year and is now **March 31, 2023**; and
- The mandatory holdback of 25% on all payments has been waived and can be reduced. Holdback amounts can now be based on project risk.

If any Recipient wishes to amend their agreement to reflect the program extension, we ask that you contact the program through the Smart Grid mailbox with a revised schedule A (statement of work) and Schedule B (budget). If only seeking to reduce the holdback percentage, please simply notify us by email.

The program hopes to bundle all required amendments for this fiscal year for approval of the ADM in December. As such, we are requesting that you provide your information required for amendments by early October.

We wish you continued success on your projects and feel free to contact us if you have any questions.

Sincerely,
Smart Grid Deployment Program Team (Bill, Lara, Catherine, and Zoe)

Zoe Beaulac
Program Commerce Manager
REED/DERE
Zoe.beaulac@canada.ca
Office mobile NEW* 613-302-7506

<< CAUTION: This email originated from outside your organization. Exercise caution when opening attachments or clicking links, especially from unknown senders. >>

Appendix AA5
Technical Conference Undertakings from EB-2018-0219

EB-2020-0249
Incremental Capital Module (ICM) Application
Sault Smart Grid (SSG)
PUC Distribution Inc.

APPENDIX AA5

Response to EB-2018-0219 Technical Conference Undertakings

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UNDERTAKING JTC1.1

Reference:
EB-2018-0219 – PUC IRM ICM Application – Appendix 11 – Incremental Capital Module – Table 1: Customer Benefit Summary

Undertaking:
To provide the foundation for the $324,708 benefit.

Response:

PUC Distribution has provided the spreadsheet utilized for the calculated benefit from capital deferral as part of the Table 1: Customer Annual Net Benefit Summary in the Amended Application. Note that Amended Application includes a reduction in the value from the prior $324,708 figure to $304,390.

In the Original Application project assumptions developed by IE as the project developer, an estimate and calculation for future deferred capital expenditure savings to be realized from the Smart Grid Project was presented. Expectations for capital savings was mainly derived from forecasts in stations work although other asset systems may be expected to benefit. The forecast included high probability of achieving a reduction in number of stations needing to be replaced as aged assets came due for replacement through improved system insight and operational awareness with the new smart grid system and controls. Additionally, savings were anticipated from deferred future power transformer replacements. For the period 2019 through 2039 a forecast was developed that deferred 2 DS's and other station upgrade expenditures across that period. A present value calculation was then converted to an equivalent monthly value to represent the impact to the monthly P3 payment.
In this amended application PUC has updated the forecast amending the P3 developer spreadsheet with more recent information and then to be conservative, applied a discount factor to this of 50% or ~$25k/month ($304,390 per year) as the estimated value to be realized from future deferred capital investments. See Appendix 1.

			'000s	'000s/MM		'000s				
PV Direct Avoided Capex			$ 6,469	$ 51		$ 25.37	**Assume 50% of estimate savings achieved**			
				$ 608.780		$ 304.390	**Annual**			
				$386k if DS in for 2025 & not deferred						

Used IE spreadsheet framework but revised forecast dates of deferred capital to align with Engineering LT Station forecast. Deferred CAPEX from delayed or complete deferred station rebuild and power transformers. Then added 50% factor for conservative assumption for equivalent annual value of ~$300k.

UNDERTAKING JTC1.2

Reference:
EB-2018-0219 – PUC IRM ICM Application – Appendix 11 – Incremental Capital Module – Appendix J

Undertaking:
To advise SENSUS assumptions for frequency of voltage readings.

Response:
Consultation with Sensus and Black & Veatch on this topic did not specifically address the frequency of voltage feedback but did confirm the capability of existing AMI infrastructure to support the VVM systems. The following information was provided to PUC by Black & Veatch.

Consideration for use of AMI Meter Data in dynamic Volt Var Optimization of the Sault Smart Grid

A Volt Var Optimization (VVO) system needs voltage feedback from the grid to be truly effective. This voltage information can be achieved from any device on a feeder that can provide the appropriate data, but the ideal is to use a small subset of the AMI (Automated Metering Infrastructure) meters. This "bellwether set" of meters typically represents only 0.5% to 1.8% of the overall meter population, between 3 to 12[1] meters per feeder, allowing the system to be designed to prevent conflicts with the critical metering processes.

With a total residential meter population of 30,000 customers spread across 48 feeders Black & Veatch plans on using roughly 400 meters or approximately 1.3% of the meter population to monitor line voltages for VVO. While there is typically no issue accommodating the VVO voltage data requirements across an AMI system PUC is in the very fortunate position of having a Sensus metering infrastructure that is currently well below capacity. As a result, we anticipate the added VVO data traffic across the AMI network will not interrupt critical meter reading data and will have little overall effect on the existing system[2].

From Sensus, they confirm their Sensus AMI system is designed to support VVO with voltage information measured in two ways. First, all of the meters on the feeder can be programmed to

[1] Survalent has indicated to Black & Veatch that "Bellwether meters are one of the possible inputs that could be used for VVO. If they are used, on average, 3 – 12 bellwether meters per feeder would be required. Survalent would recommend having them distributed throughout the feeder in addition to all the endpoints."
[2] In a VVO project that Black & Veatch implemented that also utilized a bellwether set of Sensus AMI meters, 12 meters per feeder were used, representing 2.4% (485 meters) of the meter population. There was no degradation in quality of AMI meter reading.

send voltage data into Sensus' head-end software (as part of their normal billing read). Second, Sensus meters have the added capability of calculating a one-minute average of voltage and frequently reporting those detailed values. The combined approach provides additional voltage resolution for improved accuracy and confirming the additional overhead of voltage data required for VVO is not significant.

There are other options that could be utilized to obtain voltage measurements. This could include the Grid 2020 product (should it be deployed), capacitor bank monitors or stand-alone voltage measuring devices. These are all options that are available and could be considered with the Sault Smart Grid Project.

UNDERTAKING JTC1.3

Reference:
EB-2018-0219 - PUC's Interrogatory Responses dated May 31, 2019 - Appendix 13

Undertaking:
To produce the schedules to the draft Project Agreement filed with Appendix 13 of the Interrogatory Responses at whatever current state they're at.

Response:
Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC1.4

Reference:
EB-2018-0219 - PUC's Interrogatory Responses dated May 31, 2019 - Appendix 13 – Draft Project Agreement

Undertaking:
To produce the financial model at Schedule 15 and, if available, in excel format.

Response:
Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC1.5

Reference:
EB-2018-0219 - PUC's Interrogatory Responses dated May 31, 2019 - Appendix 13 – Draft Project Agreement

Undertaking:
To advise whether ARC would still apply to the services provided by PUC Services even though they're being provided through Project Co.

Response:

Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC1.6

Reference:
EB-2018-0219 – Technical Conference Day 1 on June 19, 2019 - Exhibit No. KTC1.1: Corrections to IR Responses.

Undertaking:
To provide an updated version of the slide entitled "Monthly Costs" attached to Exhibit KTC1.1.

Response:

Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC1.7

Reference:
None.

Undertaking:
To enquire of IE whether there is any debt financing that it is incurring to invest in the project and, if so, to provide details about that, including the name of the lender, terms of the loan, the rate of interest, and an other relevant details.

Response:
Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC1.8

Reference:
None.

Undertaking:
To make best efforts to obtain information from IE with respect to the equity investment by Diode Ventures LLC.

Response:
Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC1.9

Reference:
None.

Undertaking:
To make best efforts to obtain information from IE with respect to the equity investment by Alma Global Infrastructure.

Response:

Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC1.10

Reference:
None.

Undertaking:
To provide details and documents, in particular amounts that are supposedly invested in Project Co. and the terms of the investment.

Response:
Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC1.11

Reference:
None.

Undertaking:
To make best efforts to provide IE's financial statements.

Response:
Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC1.12

Reference:
None.

Undertaking:
To provide information about what types of funding would be coming into Project Co. at which phases of the project.

Response:
Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC1.13

Reference:
EB-2018-0219- PUC IRM ICM Application filed May 31, 2019 – Appendix K to Appendix 11 – Incremental Capital Module

Undertaking:
To provide the sources of the costs in Appendix K.

Response:

No longer applies to Amended Application.
Prior Appendix K cost estimates were a combination of IE developer provided estimates derived from Navigant Reports and internal PUC Distribution staff assumptions. Given complete revision of project structure to an RFP and EPC approach the prior cost estimates have been replaced by new information from the RFP/EPC process and assumptions further described in the Amended Application filed.

UNDERTAKING JTC1.14

Reference:
EB-2018-0219 - PUC's Interrogatory Responses dated May 31, 2019 - Appendix 13 – Draft Project Agreement

Undertaking:
To provide the early works contract referred to in the Project Agreement at Appendix 13, Section 2.1, Sub (c).

Response:

A copy of the early works contract referred to in the Project Agreement at Appendix 13, Section 2.1, Sub (c) of the original ICM Application filed on January 31, 2019 is attached as Appendix 2.

UNDERTAKING JTC1.15

Undertaking:
To provide the reference to the disclosure to NRCan regarding payment to an affiliate.

Response:

Although the Smart Grid project is no longer proceeding under the P3 type of model, in the interests of clarity, the supporting material in regards to disclosure to NRCan regarding payments to an affiliate have been included below.

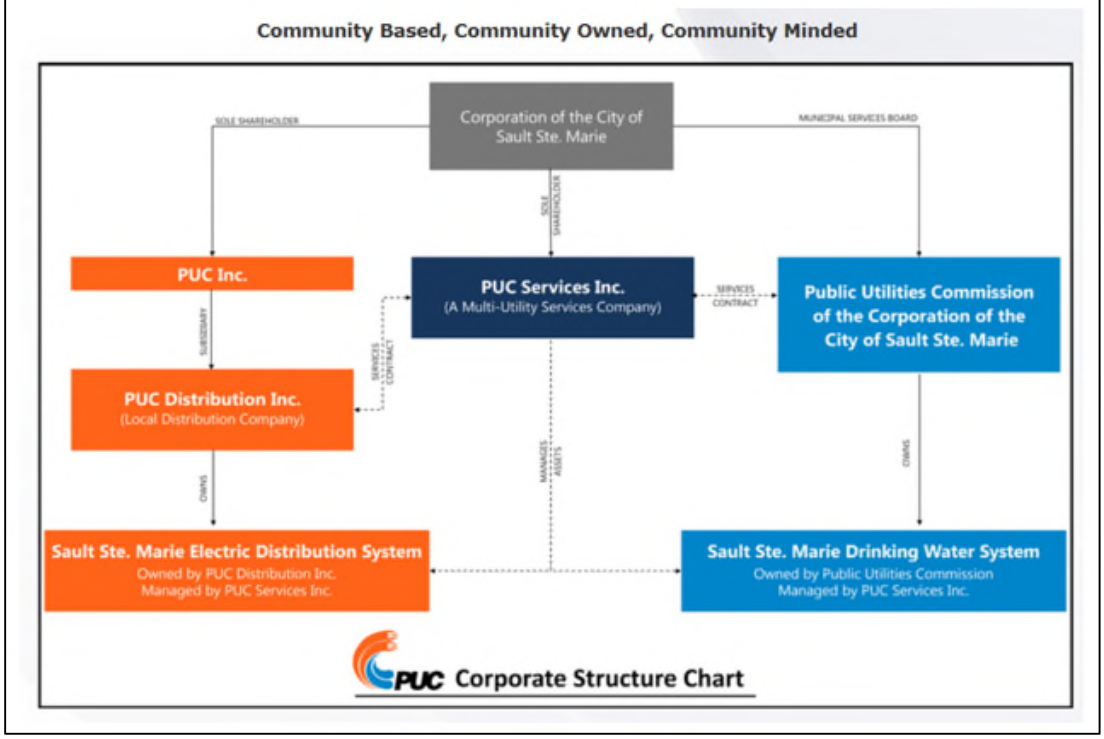
In preparing the application for the NRCan Smart Grid Program and throughout the due diligence process PUC Services has made every effort to fully describe the PUC Group of companies shared services model and structure. The relationships of the companies were described and thoroughly discussed with respect to the project structure for both the application and how the project would be executed. This included sharing and discussing the affiliate organizational structure chart at Figure 1 below and the specific question item following with NRCan staff.

Figure 1: Affiliate Organization Structure Chart

PUC Corporate Organization Structure

The diagram below which was copied from our website illustrates the corporate structure for the PUC group of companies and helps to describe our shared services model. All staff are employed by PUC Services Inc. Each of the asset companies (electric and water) are operated under long term contract by PUC Services. All companies are ultimately held by one shareholder which is the City of Sault Ste. Marie.

[http://www.ssmpuc.com/index.cfm?fuseaction=content&menuid=3&pageid=1002]



The following question was extracted from the NRCan Due Diligence process and further confirms the intent at that time of the need for some of the work by PUC Services being performed during construction under the SSG Contract and ongoing through the life of the contract. PUC has also updated NRCan on the change to the more traditional EPC project structure.

What partners are/or will be involved in your project? Please provide the name of the organizations and their project role (e.g. systems design, systems integration, supplier, operations, etc.)

The project has identified the following parties as key partners and participants:

- PUC Distribution Inc. – Local Distribution Company (LDC) for Sault. Ste. Marie.
- PUC Inc. - Sole Shareholder and holding company for PUC Distribution
- The Corporation of the City of Sault Ste. Marie – Sole shareholder of PUC Inc. and PUC Services Inc.
- PUC Services Inc. – line work contractor for installation, and ongoing services to SSG.
- North American Grid Modernization Fund – Finance source for development of project. The fund will finance an SPV for project development. The fund consists of contributions from:
    - Stonepeak Infrastructure Partners (SPIP) – financial source
    - Infrastructure Energy (IE) – project developer
- Sault Smart Grid Inc. – a special purpose vehicle acting as contractual counter-part to purchase agreement (PA), engineering, procurement and construction (EPC), and services contracts
- Black & Veatch – The primary EPC contractor for the project, also responsible for managing key subcontracts including:
    - Energrid – Engineering consulting services
    - Milsoft – Supplier for interactive voice response (IVR) systems
    - Survalent – Supplier for:
        - Advanced Distribution Management System (ADMS)
        - Outage Management System (OMS)
- Navigant Consulting – Management consulting services

UNDERTAKING JTC1.16

Reference:
None.

Undertaking:
To provide the estimates provided to NRCan.

Response:

The revised estimate provided to NRCan is in Schedule B to the Amendment No. 1 to the Repayable Contribution Agreement between Her Majesty the Queen in Right of Canada and PUC Distribution Inc. dated December 18, 2019 attached herewith as Appendix 3.

The NRCan capital contribution is based on the lesser of 25% of total project costs incurred or $11,807,000. As such, PUC Distribution will be updating the estimates provided to NRCan as per the Amended Application and the SSG Project when PUC Distribution receives OEB approvals.

UNDERTAKING JTC1.17

Reference:
None.

Undertaking:
To provide details of the process undertaken by IE to select the EPC partner.

Response:

Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC1.18

Reference:
PUC's Interrogatory Responses dated May 31, 2019 - Appendix 11 – Amendment to Letter of Intent at page 1.

Undertaking:
To provide any reports of the Study Review Team and any reports of the CAO, whether to council or committees.

Response:

Report to Council by CAO located at City of Sault Ste. Marie Council website attached in Appendix 4 City website and Council Agenda of November 20, 2017 Item #6.7 and can also be found online here: https://saultstemarie.ca/Cityweb/media/City-Clerk/Council-Agendas/2017/2017_11_20_MERGED_AGENDA.pdf?ext=.pdf

The primary Navigant Report "Community Microgrid Business Case Review" has been filed in previous application materials in EB-2018-0219 Interrogatories- Appendix 7 - Staff-31(e) "Copy of PUC SSM UDM Business Case Analysis_FINAL 20160504.pdf". A copy is also included for this undertaking in Appendix 4.

Slide deck titled "PUC SSM Weekly Update" for presentation of above report is also included in Appendix 4.

UNDERTAKING JTC2.1

Reference:
EB-2018-0219 – PUC IRM ICM Application – Appendix 11 – Incremental Capital Module – Table 2: Customer Bill Impacts

Undertaking:
To file a comparison of costs and benefits by rate class.

Response:
The following table is a comparison of costs and benefits by customer rate class which is also included in the Amended Application at Appendix AA13.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Rev$ Requirement	VVM Savings	Allocate Losses	Energy Savings by Class (2)+(3)	From Energy Savings (4)-(1)	Allocate Estimated OM&A	Allocate Estimated CAPEX	Net Savings (5)-(6)+(7)
Residential	$1,031,015	$1,096,853	$ 51,750	$1,148,603	$117,588	$156,036	$178,835	$140,387
GS<50kW	$ 286,537	$ 349,275	$ 16,479	$ 365,755	$ 79,218	$ 43,365	$ 49,701	$ 85,554
GS>50kW	$ 412,868	$ 768,430	$ 36,255	$ 804,685	$391,817	$ 62,484	$ 71,614	$400,947
USL	$ 3,367	$ 3,566	$ 168	$ 3,734	$ 367	$ 510	$ 584	$ 442
Sentinel lights	$ 3,216	$ 786	$ 37	$ 823	-$ 2,393	$ 487	$ 558	-$ 2,322
Street lights	$ 17,859	$ 8,932	$ 421	$ 9,354	-$ 8,505	$ 2,703	$ 3,098	-$ 8,110
	$1,754,862	$2,227,842	$105,111	$2,332,954	$578,092	$265,584	$304,390	**$616,898**

UNDERTAKING JTC2.2

Reference:
EB-2018-0219 – Technical Conference Day 2 on June 20, 2019 - Exhibit No. KTC1.1: Corrections to IR Responses.

Undertaking:
To calculate the difference in amount recoverable by ratepayers compared to monthly payments under payment agreement.

Response:

Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC2.3

Reference:
EB-2018-0219 – Technical Conference Day 2 on June 20, 2019 - Exhibit No. KTC1.1: Corrections to IR Responses.

Undertaking:
To calculate forecast of maintenance in city council presentation.

Response:
Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC2.4

Reference:
EB-2018-0219 – Technical Conference Day 2 on June 20, 2019 - Exhibit No. KTC1.1: Corrections to IR Responses.

Undertaking:
To report the depreciation tax benefit following OM&A reduction and clarify the timing difference between the CCA that you are able to take and the depreciation for accounting purposes. Show the calculation and where it fits in.

Response:

Not applicable. PUC Distribution is no longer using depreciation tax benefit structure as proposed in the P3 analysis as supporting the net zero bill impact for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC2.5

Reference:
None.

Undertaking:
To provide the PowerPoint presentation (presented to PUC Inc. to obtain their approval for large capital expenditure)

Response:

The relevant part of the presentation to PUC Inc. for the Board of Director for their approval of the capital expenditure attached in Appendix 5.

UNDERTAKING JTC2.6

Reference:
EB-2018-0219 - PUC's Interrogatory Responses dated May 31, 2019 - Appendix 13 – Draft Project Agreement

Undertaking:
Timing of collections from customers to timing of payment schedules.

Response:
Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC2.7

Reference:
EB-2018-0219 - PUC's Interrogatory Responses dated May 31, 2019 - Appendix 13 – Draft Project Agreement

Undertaking:
To provide obligations that PUC will take on in collateral material project contractor agreement.

Response:

Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC2.8

Reference:
None.

Undertaking:
To file the additional studies that were considered by PUC Distribution of US-based pilot projects on VVM technology.

Response:

Given that there are a number of studies and the reports are voluminous, PUC Distribution is providing a list of the studies considered by PUC Distribution of US-based pilot projects on VVM technology and their relevant web address links below:

1. The Value of Distribution Automation: Navigant Report for California Energy Commission – good summary list of https://listserver.energy.ca.gov/2007publications/CEC-500-2007-028/CEC-500-2007-028.PDF
2. Ontario Smart Grid Assessment and Roadmap for Ontario Ministry of Energy by Navigant Consulting – January 2015 https://www.ontarioenergyreport.ca/pdfs/Navigant-Smart-Grid-Assessment-and-Roadmap-Final-Report-.pdf
3. Considerations for Deploying In-Front-of-the-Meter Conservation Technologies in Ontario for Ontario Ministry of Energy (average CVR=0.91 (2.7% savings) by Navigant Consulting – July 2017 https://www.ontarioenergyreport.ca/pdfs/2017-07-18_MoE%20IFMC%20FINAL%20Report.pdf
4. Evaluation of Conservation Voltage Reduction (CVR) on a National Level: Pacific Northwest National Laboratory for US Department of Energy (projected energy savings 3.04%) https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf
5. Using AMI-based Volt/VAR Optimization (VVO/CVR) to Drive Energy Efficiency and System Reliability (presentation at SmartGrid Canada Conference 2015 - EPRI research study table of feeders avg 2.13%; Glendale Case Study 2.95%;) (copy of presentation slide deck included in OEB ICM application at Appendix N)
6. Utilidata paper on Voltage Optimization (2015) - American Electric Power VVO project in Ohio (reported energy savings of 4.27%) https://utilidata.com/wp-content/uploads/2015/08/AEP_CaseStudyVer88-14.pdf

7. Distribution Automation – Results from the Smart Grid Investment Grant Program – Sept 2016 by US Department of Energy – (includes examples of VVO and DA projects and positive benefits results including Glendale above – interesting to note that Glendale is advancing past pilot with plan for system coverage by 2026) https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf
8. Smart Grid Regional Business Case for the Pacific Northwest – Navigant report prepared for Bonneville Power Administration (Sept 2015) (general smart grid background "positive benefits over time"; LDC incentives noted of up to $0.18 /kwh) https://www.bpa.gov/Projects/Initiatives/SmartGrid/DocumentsSmartGrid/Navigant-BPA-PNW-Smart-Grid-Regional-Business-Case-2013-White-Paper.pdf
9. Smart Grid Roadmap & Business Case – Hawaiian Electric – March 2014 (general background information and approaches) http://www.solari.net/portfolio/Solari-Smart-Grid-Roadmap-&-Business-Case.pdf

UNDERTAKING JTC2.9

Reference:
None.

Undertaking:
To provide the details of what you have to provide to NRCan and when you will get money from them at various stages along the way.

Response:

The NRCan Smart Grid Deployment Program Claim Form is attached herewith at Appendix 6 ("Claim Form"). As shown on the Claim Form, the funding is provided quarterly. The Claim Form lists out what information PUC Distribution needs to provide to NRCan in order to obtain the funding.

UNDERTAKING JTC2.10

Reference:
PUC's Interrogatory Responses dated May 31, 2019 - Appendix 12 - Schedule 1 – Project Agreement at Page 20

Undertaking:
To advise what the Note to Draft means.

Response:

Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC2.11

Reference:
PUC's Interrogatory Responses dated May 31, 2019 - Appendix 12 - Schedule 1 – Project Agreement at Page 25

Undertaking:
To provide the definition of Discriminatory Change in Tax Law.

Response:

Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC2.12

Reference:
PUC's Interrogatory Responses dated May 31, 2019 - Appendix 13 – Draft Project Agreement – Schedule 15

Undertaking:
When you provide the financial model, can you also give an explanation -- if it's not already in the model -- as to why payments are escalating, each component of the payments, why they're escalating, if it is not obvious in the model.

Response:

Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.

UNDERTAKING JTC2.13

Reference:
PUC Interrogatory Responses dated May 31, 2019 - Appendix 7 Navigant Community Microgrid Business Case Review Report at page 8.

Undertaking:
To look for and if possible, to file the document referred to as "2016 Projection for Distribution Capital Engineering", dated March 15th, 2016.

Response:

Attached herewith at Appendix 7 is a copy of the document titled "*0201.12 – 2016 Projection for Distribution Capital Engineering 2016-03-15.xlsx*".

UNDERTAKING JTC2.14

Reference:
PUC Interrogatory Responses dated May 31, 2019 – SEC-29

Undertaking:
To provide an excel version of the table attached to the response to SEC 29.

Response:

This spreadsheet is from the original project estimate and is no longer applicable to the new Amended Application as PUC Distribution is no longer using P3 type project structure for the SSG Project.

UNDERTAKING JTC2.15

Reference:
None.

Undertaking:
To provide the Project Schedule going forward.

Response:

Please see Appendix AA3-5 of the Amended Application.

UNDERTAKING JTC2.16

Reference:
PUC Interrogatory Responses dated May 31, 2019 - Appendix 7 Navigant Community Microgrid Business Case Review Report at page 6 item 8 – Eco-Cost Allocation & Evaluating Value of Risk-Transfer for UDM Project.

Undertaking:
To find and file the document ECO supplied to Navigant.

Response:

Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application

UNDERTAKING JTC2.17

Reference:
PUC Interrogatory Responses dated May 31, 2019 - Appendix 7 Navigant Community Microgrid Business Case Review Report at page 6 item 10 - ECo – PUC Board Brief

Undertaking:
To file the PUC Board Brief on ECO, No. 10

Response:

Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application

UNDERTAKING JTC2.18

Reference:
PUC Interrogatory Responses dated May 31, 2019 - Appendix 7 Navigant Community Microgrid Business Case Review Report at page 6 item 11 – ECo-UDM Project Financial Analysis

Undertaking:
To make best efforts to find and file Document 11, ECo UDM Project Financial Analysis.

Response:

Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application

Appendix AA5 - Appendix 1 JTC1_1 CAPEX Deferral Value Calculation – Revised from Early UDM estimates

The Sault Microgrid/Le Micro-reseau de Sault Sainte Marie

Simplified Financial Model (CAD MM)

Avoided CAPEX Calculation

			Assumptions													
PUC pricing per DS	3.500		Reduction of Distribution Substation network from 18 to 16													
20% contingency	0.700		Reduction of individual transformer replacements across network by 5													
Cost per DS	4.200		Avoided substation rebuilds in years 2025 and 2030 (option of only 2030 also calculated0													
2 substations out of 15 (elliminated)	8.400		Elimination plan in progress order (Load forecast and Load Flow models needed, along with full ADMS network monitoring & control to use switching and feeder balancing to achive full potential) 17, 14, 2/4/5/15?,other?													
			TS optiimization is also part of long term planning consideration : site, feeder qty, etc.													
Transformers @$.75M plus 20% contingency	0.900		note DS17 & DS14 already eliminated - right about time we started the earliest studies on smart grid (??2012/14?)													
5 individual transformers (eliminated)	4.500															
Savings TOTAL	12.900															
										2020-01-31	2022-01-31	2025-01-31	2026-03-31	2029-01-31	2031-03-31	2036-03-31
		2017-09-30	2017-10-31	2017-11-30	2017-12-31	2018-01-31	2018-02-28	2018-03-31	2018-04-30	2020-01-31	2022-01-31	2025-01-31	2026-03-31	2029-01-31	2031-03-31	2036-03-31
Avoided substation/transformer spending		0	0	0	0	0	0	0	0	0	0	4.2	0	4.2	0	0
PV of avoided spending before LTC Regulators	**8.14%**	**$ 4.092**														
LTC Regulators (2020-22-24-26)		0	0	0	0	0	0	0	0	0.9	0.9	0	0.9	0	0.9	0.9
PV of avoided spending LTC Regulators TOTAL	**8.14%**	**$ 2.377**														
PV of avoided spending TOTAL	**8.14%**	**$ 6.469**														

						Deemed	***Annual***	***Monthly***								
						Portion	***Effective Rate***	***Effective Rate***								
				LT Debt		60%	4.54%									
				Return On Equity		40%	9.19%									
				Regulated Rate of Return			***6.400%***									
				Average CPI over 3 years			**1.79%**									
						OEB WACC	**8.19%**	**0.68%**								
						MOE DF	5.00%	0.42%								
				25 Yr		NPER	300	MONTHS								
						'000s	'000s/MM		'000s							
Avoided CAPEX Estimate		PV Direct Avoided Capex				$ 6,469	$ 51		$ 25.37	**Assume 50% of estimate savings achieved**						
							$ 608.780		$ 304.390	**Annual**						
							$386k if DS in for 2025 & not deferred									

Used IE spreadsheet framework but revised forecast dates of deferred capital to align with Engineering LT Station forecast. Defferred CAPEX from delayed or complete deferred station rebuild and power transformers. Then used 50% factor for conservative assumption for equivalent annual value of ~$300k.

Appendix AA5 - Appendix 2 JTC1_14 SA19 01 003 - Service Agreement - Eng Firm - Smart Grid

THIS AGREEMENT dated as of the 14th day of January, 2019, between **PUC Inc**. a corporation incorporated under the laws of Ontario, (the **Client**) and **Infrastructure Energy, LLC (Infrastructure Energy),** a limited liability company organized under the laws of Delaware, (the **Engineer**).

1 TERMS

1.1 Brief Description of Service

Infrastructure Energy will provide Pre-Engineering Services as outlined in the attached Scope of Work for the **Smart Grid Project (the Project)** in advance of financial close of the **Project**. **PUC Inc.** agrees to pay **Infrastructure Energy** $400,000 for engineering work against the Scope of Work both (i) already completed on the **Project**, and (ii) additional engineering work completed during the **Duration**.

In the event the Smart Grid Project reaches financial close, $400,000 will be refunded and/or credited against the purchase price of the **Project**. In the event the Smart Grid **Project** does not reach financial close, PUC will own all rights to the engineering work delivered under the Terms of this agreement.

1.2 Location

500 Second Line E., Sault Ste. Marie, ON *or* as mutually agreed pending type of work activity.

1.3 Duration

The additional Pre-Engineering Services work will commence upon execution of this agreement. Invoicing will be provided by Engineer for review and approval by PUC Inc. It is understood that some work may already be completed and will be invoiced for shortly after the agreement is executed. In all cases, Pre-Engineering Services work will conclude upon financial close of the Smart Grid Project (the **Duration**).

1.4 Provided with Service

Any extraordinary materials and equipment that becomes necessary during performance of service must be agreed upon with **PUC Inc.** Representative prior to execution of inclusion.

1.5 Insurance

The Service Provider shall furnish evidence of General Liability Insurance and any other permits, approvals, WSIB certificates, if so requested at any time.

1.6 Covenant of Good Faith

Each Party agrees that, in respective dealings with the other Party under or in connection with this Agreement, it shall act in good faith.

1.7 Sub-Consultant

The Service Provider herein discloses any sub-consultants they may engage, or have already engaged to complete the services in this agreement.

Name of Firm

Black & Veatch New York LLP

EnerGrid Group, LLC

Deloitte Development LLC

Leidos Engineering, LLC

1.8 Termination

PUC Inc. reserves the right to terminate this Agreement, or any part thereof, for its sole convenience, and without requirement of cause, by giving 10 days' notice of termination to **Infrastructure Energy**.

1.9 Site Safety Orientation

A Site Specific Orientation meeting may be required and if so, must be attended by all of the service provider's personnel who will be on site during execution of any work.

2 SCOPE OF WORK

Smart Grid Project Pre-Engineering Work

2.1 General Overview

In broad terms, **Infrastructure Energy** will provide Pre-Engineering and Preliminary Design Engineering Services to summarize all the details necessary to allow for the future detailed design, construction and implementation of an automated self-healing control system that would sit astride the PUC 34.5kV distribution sub-transmission system and that would lay the groundwork for future detailed engineering of DA and VVM. The deliverables are to generally be all pre-engineering and preliminary design engineering activities but would exclude detailed design engineering such as point-to-point wiring diagrams and programming code. More specifically the following tasks would be completed:

1 – A System Protection Coordination Study for 34.5kV and 12kV systems

2 – A System Load Flow Analysis that accounts for the proposed 34.5kV automated self-healing control system

3 – A 34.5kV automated self-healing control system conceptual and preliminary design

2.2 System Protection Coordination Study

Engineer is to complete the following activities:

- Build a detailed model of the PUC 115kV, 34.5kV and 12kV distribution system using a version of CYMEDist software consistent with that which PUC Distribution owns at the date of signing this contract
- Coordinate directly with the Transmitter (HONI) to establish an acceptable source impedance model for the supply point
- The model is to include connectivity of all nodes and branches to reflect the current state of the PUC distribution system and all switching points to allow the model to reconfigured in the scenarios that the system is normally/currently operated
- Collect all input information through verification of existing PUC resources as necessary (i.e.: from GIS data, SCADA, Engineering maps, records, drawings, current P&C settings/configurations files, field assessments, industry standards where actual data is missing)
- Establish an acceptable system of nomenclature and presentation (i.e.: symbols, colours line-types, fonts)

- Build the model and from it, prepare an 'as-found' protective device coordination study for all protective elements in the 115kV, 34.5kV and key elements in the 12kV distribution system
- Make recommendations on any protection coordination settings changes that are recommended or are required to get the distribution system protection to a 'pre-project state', suitable for the deployment of the future overall smart grid project and prepare an according coordination study
- Deliverables will include an electronic copy of the CymeDist Model as well as an Ontario licensed, P.Eng stamped paper and Adobe pdf copies of the co-ordination studies. The printed and pdf documents will contain all details including an executive summary, overview of findings/recommendations, single line/connectivity drawings showing all branches and nodes visually, tables/listings of all input parameters pre fault voltages, SLG, 2LG, 3PHG fault levels in kA and MVA. The document will be assembled in an organized fashion with all information grouped by Transformer Station, Distribution Station and circuit.

2.3 System Load Flow Analysis

The connected system model developed in CymeDIST in Section 2.2 shall be used as the basis of a System Load Flow Analysis. The purpose of analysis will be to gain an understanding of the impact of the current and future 'status quo' loading scenarios expected on the distribution system, and further, to understand the impacts to be expected with the implementation of the proposed 34.5kV Self-Healing Control System, 12kV DA strategies, and VVO.

Engineer is to complete the following activities:

- Add to the detailed model of the PUC 115kV, 34.5kV and 12kV distribution system built in Section 2.2 circuit loading profiles representative of three circumstances:
    - Actual current (last 5-year) load data obtained from PUC metering data and SCADA data
    - Projected future loading in 10 years
    - Theoretical intended design load limits of existing circuits
- Collect all input information through verification of existing PUC resources as necessary (i.e.: from Meter data, GIS data, SCADA reads, Engineering maps, records, drawings, current P&C settings/configurations files, field assessments, industry standards where actual data is missing). Include manufacturers' steady state or thermal loading limits for all elements (i.e.: switches, breakers, fuses, conductors, transformers, etc.)

- Establish an acceptable system of nomenclature and presentation (i.e.: symbols, colours line-types, fonts)
- Run the model and from it, prepare an 'as-found' load flow study for existing loading conditions in the 115kV, 34.5kV and key elements in the 12kV distribution system
- Make recommendations on any load rebalancing or steady state re-circuiting changes that are recommended for the system running in its current state and further, that are required to get the distribution system to a 'pre-project state', suitable for the deployment of the future overall smart grid project
- Run additional model scenarios to explore two additional 'base-case' scenarios (projected loading in 10 years and theoretical design load limit scenario)
- Run all additional scenarios required to determine the impact of all system state permutations and combinations as the system is automatically switched into each possible operating scenarios to be implemented in proposed self-healing control system
- Deliverables will include an electronic copy of the CymeDist study files as well as an Ontario licensed, P.Eng stamped paper and Adobe pdf copies of the compiled load flow studies completed. The printed and pdf documents will contain all details including an executive summary, overview of findings/recommendations, single line/connectivity drawings showing all branches and nodes visually, tables/listings of all input loading parameters and details of where data was sourced. The study will also include tables/listings of all max/min load conditions (expressed in kW, % of element rating) and associate min/max load voltage levels (expressed in kV, % and % deviation from allowable CSA limits. The document will be assembled in an organized fashion with all information grouped by Transformer Station, Distribution Station and circuit.

2.4 34.5kV Automated Self-Healing Control System Conceptual and Preliminary Design

Conceptual and Preliminary Engineering for a 34.5kV Automated Self-Healing Control System shall be prepared with the understanding that detailed design and implementation would occur at a later stage as part of overall smart grid project.

Engineer is to complete the following activities:

- Use the models developed in 2.2 and 2.3 to determine all possible scenarios for Self-Healing rings within the 34.5kV distribution (ie: review of impact on system fault levels, system loading, available automated switching points, critical customer connection implications)
- Develop Preliminary Engineering single line diagrams for all such scenarios

- Develop Preliminary Engineering scope of work, bill of materials and class C cost estimates for implementation stages (ie: any additional wo HV work or switch point additions, associated automation, any DS or control system wiring, programming or configuring, communications upgrades, any modifications at two SCADA control room locations)
- Develop a functional specification, diagrams and process narrative documents that describe at a Conceptual Design level:
    - Hardware and software will be employed to achieve the automation
    - How the control system will be overlaid and interact with the existing level 0, 1 & 2 systems (ie: protection, control, SCADA and communications infrastructure)
    - A description of each of the proposed operational modes

Conceptual and Preliminary Engineering for a 34.5kV Automated Self-Healing Control System shall be prepared with the understanding that detailed design and implementation would occur at a later stage as part of overall smart grid project. To this end, **Engineer** is to complete the following activities:

- Use the models developed in 2.2 and 2.3 to determine all possible scenarios for Self-Healing rings within the 34.5kV distribution (ie: review of impact on system fault levels, system loading, available automated switching points, critical customer connection implications)
- Develop Preliminary Engineering single line diagrams for all such scenarios
- Develop Preliminary Engineering scope of work, bill of materials and class C cost estimates for implementation stages (ie: any additional wo HV work or switch point additions, associated automation, any DS or control system wiring, programming or configuring, communications upgrades, any modifications at two SCADA control room locations)
- Develop a functional specification, diagrams and process narrative documents that describe at a Conceptual Design level:
    - Hardware and software will be employed to achieve the automation
    - How the control system will be overlaid and interact with the existing level 0, 1 & 2 systems (ie: protection, control, SCADA and communications infrastructure)
    - A description of each of the proposed operational modes

- Develop a 'fail-safe' review. Provide narrative and illustrations of how the integrity of worker and public protection will be maintained in normal operating, maintenance, automated and failed state modes of the system.
- An operational descriptive narrative that explains how, operationally, the system will be taken on and off line, activated and deactivated, how modes are changed, and how messages and alarms are addressed
- Develop mockup HMI screens and descriptions of associated controls

3 HEADINGS AND CONVENIENCE

The division of this Agreement into Articles and sections, the insertion of headings, and the provision of any table of contents are for convenience of reference only and shall not affect the construction or interpretation of this Agreement.

4 GENERAL CONDITIONS

Drawings and Documents
Drawings and documents or copies thereof required for the Project shall be exchanged between the parties on a reciprocal basis. Documents prepared by the **Engineer** for **PUC** may be used by **PUC**, for the Project herein described, including "record" drawings. PUC has ownership of the drawings and **PUC** indemnifies the **Engineer** for unauthorized use of the documents and deliverables**.**

Staff and Methods
The **Engineer** shall perform the services under this agreement with the degree of care, skill and diligence normally provided in the performance of such services as contemplated by the agreement at the time such services are rendered and as required by the Professional Engineers Act (RSO 1990, Chapter P.28) and the regulations therein. The **Engineer** shall employ only competent staff who will be under the supervision of a senior member of the **Engineer's** staff.

Inspection (Review by the Client)
The Client, or persons authorized by the Client, shall have the right, at all reasonable times, to inspect or otherwise review the Services performed, or being performed, under the Project and the premises where they are being performed.

Publication
The **Engineer** agrees to obtain the consent in writing of the Client before publishing or issuing any information regarding the Project.

Confidential Data
The **Engineer** shall not divulge any specific information identified as confidential, communicated to or acquired by him, or disclosed by the client in the course of carrying out the Services provided for herein. These obligations of confidentiality shall not apply to information which is in the public domain, which is provided to the **Engineer** by a third party without obligation of confidentially, which is independently developed by the **Engineer** without access to **PUC Inc.'s** information, or which is required to be disclosed by law or court order. No such information shall be used by the **Engineer** on any other project without the approval in writing of **PUC Inc.**

Approval by Other Authorities
Unless otherwise provided in this Agreement, where the work of the **Engineer** is subject to the approval or review of an authority, department of government, or agency other than **PUC Inc.**, such applications for approval or review shall be the responsibility of the **Engineer**, but shall be

submitted through the offices of the Client and unless authorized by the Client in writing, such applications for approval or review shall not be obtained by direct contact by the **Engineer** with such other authority, department of government or agency. Costs for all application fees shall be borne by the Client unless otherwise provided for by the **Engineer**. The foregoing in no way limits the **Engineer's** responsibility to identify, understand and coordinate any and all approvals and permits required for the Project unless otherwise agreed to by the Client.

Indemnification

Each party shall indemnify the other against any and all claims, demands, losses, costs, obligations and liabilities that the Party may incur or suffer as a result of the other Party's breach of any agreement, covenant or warranty in this Contract.

Assignment

Neither party to the contract shall assign the whole or any portion of this contract, without the consent in writing of the other, provided that any such consent may be withheld for any reason whatsoever.

Monthly Reporting of Progress

When requested, the **Engineer** shall provide a written report showing the portion of the Services completed in the preceding month to the Client.

IN WITNESS WHEREOF, the parties have authorized their undersigned representatives to sign this Agreement and to bind them to its terms and conditions.

PUC INC.

_____ _____

Print name: *Date*

Title:

I have the authority to bind the corporation

INFRASTRUCTURE ENERGY, LLC

_____ January 14, 2019

Print name: GLEN MARTIN *Date*

Title: CEO

I have the authority to bind the corporation

Appendix AA5 - Appendix 3 JTC1_16 GISG 3030 Signed Amending Agreement No. 1

PROTECTED A

DEPARTMENT OF NATURAL RESOURCES

RENEWABLE ENERGY AND SMART GRID DEPLOYMENT PROGRAMS

SMART GRID DEPLOYMENT PROGRAM

AMENDMENT NO. 1 TO THE REPAYABLE CONTRIBUTION AGREEMENT

THIS AMENDING 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 and the Proponent entered into a Contribution Agreement signed by Canada on December 19, 2018, and by the Proponent on December 11, 2018 (the Agreement);

WHEREAS the Proponent is requesting an amendment to incorporate changes to the Project timelines, and to reallocate the Contribution amounts in whole or in part from one Fiscal Year to another;

AND WHEREAS Canada and the Proponent wish to amend the Agreement;

NOW, THEREFORE, Canada and the Proponent agree as follows:

1. **"Agreement"** as defined in the Interpretation Section of the Agreement (Article 1) is revoked and replaced by the following:

   "Agreement" means this Agreement and the attached Schedules A, B, C and D;

2. **"Eligible Expenditure Period"** as defined in the Interpretation Section of the Agreement (Article 1) is revoked and replaced by the following:

   "Eligible Expenditure Period" means the period of September 5, 2018 to March 31, 2022;

3. Paragraph 1.2 of the Agreement is revoked and replaced by the following:

   1.2 Schedules

   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); and
   d) Schedule D (Certification of Eligible Expenditures Incurred and Paid).

4. Paragraph 3.3 of the Agreement is revoked and replaced by the following:

   3.3 Ontario Energy Board Approval

   The Proponent undertakes to receive approval from the Ontario Energy Board for the Required Rate Adjustment by March 31, 2020.

5. Paragraph 3.5 of the Agreement is revoked and replaced by the following:

   3.5 Survival

   The following clauses shall survive the termination of this Agreement for an additional three (3)

years:

a) ***Accounts and Audits Article;***
b) ***Intellectual Property Article;***
c) ***Indemnity Article;***
d) ***Default Article;***
e) ***Reports Article;***
f) ***Confidentiality Article;*** **and**
g) ***Dispute Resolution Article.***

6. Paragraph 4.2 of the Agreement is revoked and replaced by the following:

4.2 Project Schedule

Subject to Paragraph 3.3, the Proponent shall complete the Project by March 31, 2022, unless terminated earlier pursuant to the provisions of this Agreement

7. Article 5 of the Agreement is revoked and replaced by the following:

5. ENVIRONMENT

5.1 The Proponent represents and warrants that the Project is not a designated project under the *Impact Assessment Act* 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 *Impact Assessment Act* 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 *Impact Assessment Act* 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 *Impact Assessment Act*, 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 *Impact Assessment Act* including any such conditions requiring the implementation of mitigation measures and any follow up program.

8. Paragraph 6.1 of the Agreement is revoked and replaced by the following:

6.1 Contribution

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) Ten Million Six Hundred Twenty Six Thousand Five Hundred Dollars ($10,626,500)

9. Paragraph 6.2 of the Agreement is revoked and replaced by the following:

6.2 Fiscal Year Allocations

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	One Million Dollars ($1,000,000)
2020-2021	Two Hundred Fifty Thousand Dollars ($250,000)
2021-2022	Two Million Seven Hundred Twenty Three Thousand Five Hundred Dollars ($2,723,500)
Total:	Ten Million Six Hundred Twenty Six Thousand Five Hundred Dollars ($10,626,500)

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.

10. Paragraph 6.3 of the Agreement is revoked and replaced by the following:

6.3 Final Claim of the Contribution

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, 2022.

11. Paragraph 6.6 of the Agreement is revoked and replaced by the following:

6.6 Total Government Funding

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):	Ten Million Six Hundred Twenty Six Thousand Five Hundred Dollars ($10,626,500)
Other Federal:	Zero Dollars ($0)
Provincial:	Zero Dollars ($0)
Territorial:	Zero Dollars ($0)
Municipal:	Zero Dollars ($0)
Total Government Funding:	Ten Million Six Hundred Twenty Six Thousand Five Hundred Dollars ($10,626,500)

The Proponent shall advise the Minister promptly of any change in the Total Government Funding listed above during the term of this Agreement.

12. Paragraph 7.5 of the Agreement is revoked and replaced by the following:

7.5 Claims for Payment

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 sixty (60) days after the end of each quarter, except the claim for the final payment.

13. Paragraph 9.1 of the Agreement is revoked and replaced by the following:

9.1 Books and Records

Prior to the Completion Date and for three (3) 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).

14. Schedule A (Statement of Work) is revoked and replaced by the attached Schedule A (Statement

of Work).

15. Schedule B (Budget and Eligible Expenditures) is revoked and replaced by the attached Schedule B (Budget and Eligible Expenditures).

16. Schedule C (Reports) is revoked and replaced by the attached Schedule C (Reports).

17. Schedule D (Certification of Eligible Expenditures Incurred and Paid) is revoked and replaced by the attached Schedule D (Certification of Eligible Expenditures Incurred and Paid).

18. Schedule E (Proposal) is revoked.

19. All other terms and conditions of the Agreement remain in full force and in effect.

20. This Amending Agreement comes into force when signed by the Parties.

IN WITNESS WHEREOF this Amending Agreement has been 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

DEC 1 8 2019
Date

Mollie Johnson
Assistant Deputy Minister
Low Carbon Energy Sector

PUC DISTRIBUTION INC.

Dec 18/19
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. 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.
BENEFITS:	**Benefits to Canada/Canadians** 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 (e.g. electronics manufacturing, e-commerce, telecommunication services and data centres). **Benefits to Stakeholders:** 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. 2020)**	- 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. 2021)**	- 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 2022)**	- 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 2022)**	- Project management and oversight provided by PUC Services, including general project management, change orders and relationships between EPC and vendors - PUC to ensure project coordination between PUC distribution system operations and EPC contractor.	- 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 ($)	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**TOTAL ($)**
The Program (NRCan Contribution)	$6,653,000.00	$1,000,000.00	$250,000.00	$2,723,500.00	$10,626,500.00
ELIGIBLE EXPENDITURES					
Salaries and Benefits	$0.00	$0.00	$0.00	$0.00	**$0.00**
Overhead	$0.00	$0.00	$0.00	$0.00	**$0.00**
Professional, Scientific &	$13,306,000.00	$1,000,000.00	$17,400,000.00	$10,800,000.00	**$42,506,000.00**
Travel, including Meals and Accomodations	$0.00	$0.00	$0.00	$0.00	**$0.00**
Equipment and Products	$0.00	$0.00	$0.00	$0.00	**$0.00**
Other Expenses	$0.00	$0.00	$0.00	$0.00	**$0.00**
Total by Fiscal Year:	**$13,306,000.00**	**$1,000,000.00**	**$17,400,000.00**	**$10,800,000.00**	
			Total Eligible Expenditures		**$42,506,000.00**

INELIGIBLE COSTS					
INELIGIBLE EXPENDITURES	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**TOTAL ($)**
Incurred before Eligible Expenditure period (between June 13, 2018 and August 28, 2018)	$300,000.00	$0.00	$0.00	$0.00	$300,000.00
Ineligible Overhead Expenditures	$0.00	$0.00	$0.00	$0.00	$0.00
			Total Ineligible Expenditures		**$300,000.00**
IN-KIND COSTS					
					$0.00
			Total In-Kind Costs		**$0.00**
			Total Ineligible Costs		**$300,000.00**
			TOTAL PROJECT COSTS		**$42,806,000.00**

Source of Contributions:	**Percentage (%)**	**Cash ($)**	**In-Kind ($)**	**Total ($)**
The Program (NRCan Contribution)	**25%**	10,626,500	N/A	**10,626,500**
The Proponent	**75%**	32,179,500	0	**32,179,500**
TOTAL	**100%**	**$42,806,000**	**$0**	**$42,806,000**

NOTE: the following limitations apply to the approved budget above:

a) 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.

b) Overhead expenditures, directly related to the conduct of the Project, are limited to fifteen percent (15%) of total Eligible Expenditures, up to a maximum of $1,000,000.

c) Ineligible costs, such as the reimbursable portion of Federal and Provincial Taxes, and expenditures incurred before or after the Eligible Expenditure Period, are considered towards Total Project Costs; however, they are not eligible for reimbursement.

d) 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. 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 **sixty (60) 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 report summarizing Project activities during the Fiscal Year together with key performance outputs to indicate how the Project has been contributing to the overall Program objectives. The report must be provided with the fourth quarter claim for payment, no later than **sixty (60) days after the end of the fourth quarter**. The Program will provide the Proponent with a template for this report.

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;

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; and

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. **Revenue reporting**

For five (5) years following the completion of the Project, the Proponent must submit annually a report indicating the revenues received as a result of the Project. Where no revenue has been received, a nil report is still required. The Program will provide the Proponent with a template for the revenue report. The Proponent shall provide this report no later than **ninety (90) days following the anniversary of the Project Completion date.**

5. 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.

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, 2022, 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: _____

Appendix AA5 - Appendix 4 JTC1_18 CAO Utility Distribution Microgrid Update Report

The Corporation of the
City of Sault Ste. Marie

C O U N C I L R E P O R T

November 20, 2017

TO: **Mayor Christian Provenzano and Members of City Council**

AUTHOR: **Al Horsman, Chief Administrative Officer**

DEPARTMENT: **CAO Office**

RE: **Utility Distribution Microgrid**

PURPOSE

The purpose of this report is to provide information on the socio-economic and development benefits of the Utility Distribution Microgrid (UDM) project to be called 'The Sault Microgrid' (TSM), and currently being reviewed by the Sault Ste. Marie Public Utilities Commission (PUC).

BACKGROUND

On September 25, 2017, City Council passed the following resolution:

> Whereas PUC has been working on a Utility Distribution Microgrid (UDM) project for three years and the project will require the approval and support of City Council to proceed if approved by the PUC Board of Directors;
>
> Whereas the UDM project is a large project and City Council should have thorough information at its disposal to assess whether or not it will ultimately support the UDM project;
>
> Whereas the PUC executive will present the technical aspects and costs of the UDM project to City Council including the risks and benefits from the PUC perspective;
>
> Whereas the UDM project may have broader social, economic or developmental benefits and City Council should have an assessment of those prior to making its decision;
>
> Now therefore, City Council directs the CAO to ensure that City Council receives a report from the City, with input from the SSMEDC and the SSMIC outlining whether or not there are any broader socio-economic or development benefits (or risks) of the UDM project.

As noted in the Council resolution, this report examines the potential socio-economic impacts of the UDM project only. It does not investigate the technical or financial components of this project. This latter work is being undertaken by PUC staff and the project is still to be presented to the PUC Board for review and final decision.

Smart Grid and Microgrid Background

According to the International Energy Agency (IEA), a smart grid is defined as an electricity network system that uses digital technology to monitor and manage the transport of electricity from all generation sources to meet the varying electricity demands of end users. Such grids are able to coordinate the needs and capabilities of all generators, grid operators, end-users and electricity market stakeholders in such a way that they can optimize asset utilization and operation and, in the process, minimize both costs and environmental impacts while maintaining system reliability, resilience and stability.

A microgrid is a small energy system consisting of a group of connected power sources and loads within a defined boundary. Microgrids are fully interconnected with a local utility grid, but can also provide service on their own if there is an outage or disturbance on the larger grid to which they are connected. They can be of various sizes, from nano-grids that serve a single building, to community-scale microgrids.

Microgrids are made possible by the emergence of distributed generation, in which new energy sources such as wind and solar can be built much closer to the consumers. This in turn reduces the need for costly long-distance transmission of power from large generation plants to distant users via the grid. Longer term, it is possible that the grid could evolve into a series of adjoining microgrids. The spread of distributed generation and the rise of microgrids will be shaped by two factors: the expansion of the Internet of Things (IoT) and the growing influence of big data. These factors drive growth in enabling technologies such as sensors, control systems, software and analytics.

The International Energy Agency (IEA) broadly recognizes a number of benefits of smart grids, namely they:

- Enable informed choices about consumption by customers; (Economic)
- Accommodate all generation and storage options; (Economic)
- Stimulate new products, services and markets; (Economic)
- Optimize asset utilization and operating efficiency; (Economic)
- Provide the power quality required for a range of identified needs; (Social and Economic)
- Provide resiliency to disturbances, attacks and natural disasters; (Social), and

- Catalyze sustainable energy infrastructures for cities, regions and countries (Social and Economic).

Global Market

Countries, regions and utilities the world over are embracing smart grid technologies. According to one recent report (Smart Grid Market by Solution – Global Forecast to 2021) the smart grid market is estimated to grow from US $19.8 billion in 2016 to US $65.4 billion by 2021, at a compound annual growth rate of 27%.The rising technology adoption will be driven by mandatory regulations and policies to reduce carbon emissions and the need to ensure grid reliability on a global scale at the same time. Additionally, today's utility grid needs to be upgraded because in most cases infrastructure is aging, inadequate, and is outdated in many respects. Investment is needed to improve its material condition, ensure adequate capacity exists, and enable it to address future power supply challenges.

Canadian Context

One of the major development drivers of the electricity system in Canada has been the need for more efficient networks and better resource use as systems become more flexible and adaptable to the energy supply. Policy drivers for smart grid development in Canada vary regionally. In Ontario, they have focused on the integration of renewable energy, grid reliability and resiliency, system efficiency, managing aging infrastructure and enabling customer participation.

Of the C$350 billion required in electricity infrastructure investment over the next two decades as estimated by the Conference Board of Canada, the Canadian Electricity Association expects that 20% of that would be in distribution infrastructure, and about 13% in transmission infrastructure. Most smart grid technology would fall into the distribution infrastructure category, with some considered as transmission infrastructure. This makes the investment opportunity to apply smart grid technologies in the order of C$70 billion. Spread over two decades this could represent approximately C$3.5 billion annually.

Canada provides an excellent Research and Development (R & D) and test bed environment for smart grid technologies. Ontario presents many competitive advantages supporting this business area: very strong ICT and energy sectors; Ontario is a leading player in software development, Internet of Things (IoT) and Artificial Intelligence; the existence of well-developed advanced metering infrastructure with over four million meters already installed and a highly skilled workforce in several subdomains.

The Sault Microgrid

Infrastructure Energy (IE) is a California-based development and finance platform company creating community-scale microgrid projects comprised of integrated

renewable energy, smart grid and communications networks that span entire communities. IE's focus is on the establishment of regional smart grid and renewable energy clusters in Ontario, and other leading energy markets in North America.

The Sault Microgrid project will be a ‘first-in-North-America’, community-scale Microgrid. The project would establish Sault Ste. Marie as a 'proof-of-concept' smart city that could be used as a model for other communities in Ontario, and the rest of North America. The project would expand Sault Ste. Marie's already strong regional role as an economic and service hub for renewable energy investment, education and services.

The International Institute for Sustainable Development (IISD) released a white paper titled “Cities and Smart Grids Canada” in September 2017 and highlighted the smart grid opportunity in Canada. Below is a quote taken from page 20 of that paper:

> *"The business case for smart grid technologies is already present and is steadily improving as technologies mature. Fundamentally, smart grids can reduce the cost of electricity production, consumption and distribution by identifying and reducing wasteful consumption; matching demand and supply to reduce the costs of dealing with short term peaks; operating electricity networks to minimize transmission and distribution losses; and pooling demand to match availability of resources and operate generators closer to their maximum efficiencies. In addition, they can provide information back to consumers, which can result in behavioural changes that reduce energy costs."*
>
> *"Finally, Canadian leadership on smart grids can unlock demand for smart grid technologies and provide export opportunities for Canadian technology innovators. It can create domestic opportunities through asset investments that translate into skilled labour jobs. It can also help to reduce energy costs over the longer term and/ or provide a new source of income, which increases free capital that can be invested in other sectors of the economy."*

<u>Key Activities for Sault Ste. Marie</u>
The key activities to be undertaken as part of The Sault Microgrid project as proposed by IE would include the following components:

1. The Sault Microgrid Inc.: Consists of a dedicated company for financing and construction of a series of smart energy systems, establishing a smart cities platform in the community. The systems include an integrated communications network that leverage legacy networks, advanced metering infrastructure (AMI), distribution automation (DA), and

voltage/VAR optimization and management (VVO/VVM). These investments will be made under the auspices of a long-term project agreement (PA), a first in Ontario, with primary project funds provided by a joint venture infrastructure investment platform between IE and Stonepeak Infrastructure Partners (SPIP).

2. Centre of Energy Excellence for Northern Environments (CENEX_North): Should the project proceed, IE has indicated they will establish a corporate presence in Northern Ontario, to be headquartered Sault. Ste. Marie. Through a separate real estate development project, IE and partner companies will be anchor tenants in a ~23,000 sq ft local facility.

3. Energy Services Company - There is an opportunity to establish an energy services company that would be able to provide services that are enabled/supported by the Sault Microgrid. While such a company could be started independent of the Sault Microgrid, it is felt the project would provide additional capability and services for such a company to develop.

Current Status of Project

- Infrastructure Energy has been working with the PUC for the past three years on this opportunity;
- Application to NOHFC under the New Investment Project for $2.5M has passed through Phase I, and is now in Phase II awaiting final NOHFC Board Approval;
- Project Concept Questionnaire (PCQ) has been submitted to NRCan with regards to the Smart Grid Deployment and Demonstration Fund. The RFP submittal window is anticipated to open in early November 2017 with a submission deadline 30 days later, near the end of November 2017; the request to NRCan will be for contribution of $9.2M.
- IE is proposing to invest $38.6M into The Sault Microgrid.

ANALYSIS

Project Outcome and Benefits for Sault Ste. Marie and Area

From a high level, the smart grid project is expected to provide benefits to Sault Ste. Marie in the following areas:

- Reduced duration and frequency of power outages
- Improved power quality and reduced line losses
- Improved operating efficiencies for the PUC reducing their operations, maintenance and capital costs -- keeping downward pressure on electricity prices for all consumers
- Enhanced cyber-security, customer safety, and

- Expanded and diversified economic growth.

The Sault Microgrid will also allow clean and distributed forms of power generation, energy and thermal storage systems, and electric vehicles to be integrated into the newly upgraded distribution grid by residential, commercial and industrial customers -- thus creating a grid that is ready for the future along with meeting new and growing demand for reliable and high-quality 'premium' power.

The Sault Ste. Marie economy will also be substantially more resilient in the face of severe weather events, providing for critical services even during prolonged outages of the macrogrid in other parts of Ontario and Michigan.

From socio-economic perspective, benefits that have been identified for Sault Ste. Marie include:

- Direct Project Benefits
    - The Sault Microgrid - The technology purchased for TSM project will be sourced from established firms. The technology installation will be handled by a global firm with UDM experience however it is anticipated that portions of the project installation will be sourced with local firms. This is estimated to be approximately $9M. Jobs generated from this project will include professional engineers, licensed electricians, procurement, construction and installation, finance, and operations and maintenance employees.
    - CENEX_North – The construction of a 20-30,000 sq. ft. facility will create up to 45 direct jobs with an investment of approximately $5.0MM to $10.00MM. For every $110,000 in cost is one full- time equivalent during the construction phase. IE envisions that this facility will act as a hub for development of smart grid/renewable energy/smart cities projects, with an eye toward expansion of operations across the region. It is proposed that this facility serve as a Northern hub for energy research, innovation and investment in commercial deployment. Jobs generated from this entity will include construction, real estate operation, business development and finance and network administration.
    - Improved reliability and power quality – The installation of TSM in Sault Ste. Marie will result in improvement in power reliability, reduced GHG emissions, climate resilience and power quality. This impacts businesses currently operating in Sault Ste. Marie and could also influence decisions of prospective companies looking to

establish operations in Sault Ste. Marie. Estimated economic value of reduced frequency and duration of outages is $31.8MM, analyzed by Leidos and confirmed by Navigant Consulting.

- Table 1 – Direct Project Benefits Summary

Item	**Benefit**
Sault Microgrid	• $36.6M total project cost • $9M dollars estimated for local sub-contracted work
CENEX	• $5-10M construction of new building • 45 direct jobs and 74 indirect jobs* • Approximately $250,000 annual tax revenue**
Total	• 45 direct jobs; 74 indirect jobs • $41.6M-$46.6M project costs (Sault Microgrid and CENEX_North) • Approximately $250,000 annual tax assessment increase

* The factors are based on NAICS 2211: Electric power generation, transmission and distribution industry sector.
** Assuming an $8M value for a commercial building located in the downtown. Should a Community Improvement Program that decreases tax assessment be implemented in the future, this would reduce this amount.

- Capacity Building
  - Position SSM as a leading ‘Smart City’ – there is an abundance of research papers, conferences and funding programs that point to utility-led smart grid initiatives as the key driver to global leadership in this growing sector.
  - Collaboration with colleges/universities – a direct opportunity for collaboration with Sault College and Algoma University on a cutting edge project with opportunities for student learning and advancement. Further with a project of this scope that are opportunities to collaborate with energy research leaders across Canada and globally.

- IE has indicated that CENEX_North will provide K-12, college and university students with cooperative educational opportunities, and direct work experience with companies doing leading smart grid research, development and deployment.
- R&D Opportunities – with an advanced UDM installation, there are a number of opportunities for SSM to be a location for advanced research and development in a number of areas including:
  - Vehicle to grid integration – there are future possibilities to use automotive electric vehicle batteries as a storage function for over supply of electricity and for them to feed electricity into the grid
  - Advanced metering infrastructure (AMI) – application development for smart meters
  - Distributed energy resources (DERs) – demand response, energy storage
  - Customer-side systems – home energy management systems, building energy management systems, electric transportation, control-centre systems, distribution automation, substation automation, asset management
  - Machine learning – this is utilizing the power of the cloud and big data, with the ability to predict energy consumption, reduce outages and improve grid security
  - Plug and play (PnP) – PnP technologies for the smart grid can enable and incentivize consumers to give back, e.g. redistribute energy generated by the consumer via personal means (solar cells, microwind turbines etc.) through the smart grid to other consumers in need
  - The Self-Healing Grid – a system comprised of sensors, automated controls and advanced software that utilizes real-time distribution data to detect and isolate faults and to reconfigure the distribution network to minimize the customers impacted.
  - Total automation – the future goal will be to automate the grid – from power generation to service distribution and service management
  - Block chain for trans active layers on microgrids
  - Cross-cutting technologies – ICT, security and privacy

- Indirect Economic Benefits

- Energy Services Company – Preliminary analysis indicated that such a company could grow to up to 60 jobs at its expected peak with 99 indirect/induced jobs. The service offerings of such a company would include such items as premium power, energy efficiency and nested Microgrid services. The markets for this expertise could expand from Sault Ste. Marie to other regions of Northern Ontario and Upper Peninsula Michigan. Jobs generated from this firm include professional engineers, licensed electricians, procurement, construction and installation, business development and finance, operations and maintenance, and sales and customer service employees.
- Attraction of new industries – SSM would have the ability to market this as a differentiator in attracting companies requiring high levels of power reliability and quality (such as data centres)
- Alignment with government funding – there have been a number of funding programs announced by Federal and Provincial governments to support this area which is a current and future benefit.
- Alignment with government policy - There is close alignment with Growth Plan for Northern Ontario, Ontario's Five Year Climate Change Action Plan (2016-2020), the Ministry of Energy's Long-Term Energy Plan (LTEP), Sault Ste. Marie Smart Energy Strategy, as well as a number of other provincial and federal legislative and regulatory initiatives.
- Corporate goodwill – IE has demonstrated support for tourism industry of SSM through title sponsorship of Grist at the Mill and The Frozen Few and has indicated an interest to continue such events.

FINANCIAL IMPLICATIONS

The purpose of this report is to provide an overview of the socio-economic benefits of The Sault Microgrid project. Many direct/indirect benefits have been outlined above. As the project requires final approval from the PUC Board, these benefits are speculative and there are no financial implications at this point.

STRATEGIC PLAN / POLICY IMPACT

The Sault Microgrid is supportive of the City of Sault Ste. Marie's Corporate Strategic Plan on the following fronts:

- Infrastructure - Planning for new infrastructure to replace deteriorating assets and create new public spaces will support competitiveness on a

global scale. New infrastructure is essential to the City's growth, economic development, citizen safety and quality of life

- Community Development and Partnerships
  - Develop Partnerships with Key Stakeholders - Continued revitalization of public spaces creates opportunities for economic growth, diversity and social interaction. A truly dynamic community demonstrates vibrant social activity. We are committed to ongoing communication and stakeholder consultation to create an environment that encourages engagement and the exploration of mutual goals to grow our community. Collaboration with community partners and stakeholders is essential to our success.
  - Maximize Economic Development and Investment - We foster an environment where economic development dollars are maximized so that existing and new business can flourish. Citizens expect true value for their tax dollars. We are committed to maintaining financial viability by strategically embracing our future with careful consideration and calculated risk in all undertakings.

RECOMMENDATION

Resolved that the report dated 2017 11 20 concerning The Sault Microgrid project be received as information.

Respectfully submitted,

Al Horsman
Chief Administrative Officer
705.759.5347
cao.horsman@cityssm.on.ca

Appendix AA5 - Appendix 4 JTC1_18 Copy of PUC SSM UDM Business Case Analysis_FINAL 20160504

NAVIGANT

Community Microgrid Business Case Review

Final Report

Prepared for:

Sault Ste. Marie Innovation Centre

SAULT STE. MARIE INNOVATION CENTRE

Submitted by:
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May 4, 2016

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Disclaimer

This report ("report") was prepared for Sault Ste. Marie Innovation Centre, in collaboration with PUC Distribution Inc., the Sault Ste. Marie Economic Development Corporation and the City of Sault Ste. Marie, (collectively, the "Proponents") on terms specifically limiting the liability of Navigant Consulting Ltd. (Navigant), and is not to be distributed without Navigant's prior written consent. Navigant's conclusions are the results of the exercise of its reasonable professional judgment. By the reader's acceptance of this report, you hereby agree and acknowledge that (a) your use of the report will be limited solely for internal purpose, (b) you will not distribute a copy of this report to any third party without Navigant's express prior written consent, and (c) you are bound by the disclaimers and/or limitations on liability otherwise set forth in the report. Navigant does not make any representations or warranties of any kind with respect to (i) the accuracy or completeness of the information contained in the report, (ii) the presence or absence of any errors or omissions contained in the report, (iii) any work performed by Navigant in connection with or using the report, or (iv) any conclusions reached by Navigant as a result of the report. Any use of or reliance on the report, or decisions to be made based on it, are the reader's responsibility. Navigant accepts no duty of care or liability of any kind whatsoever to you, and all parties waive and release Navigant from all claims, liabilities and damages, if any, suffered as a result of decisions made, or not made, or actions taken, or not taken, based on this report.

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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

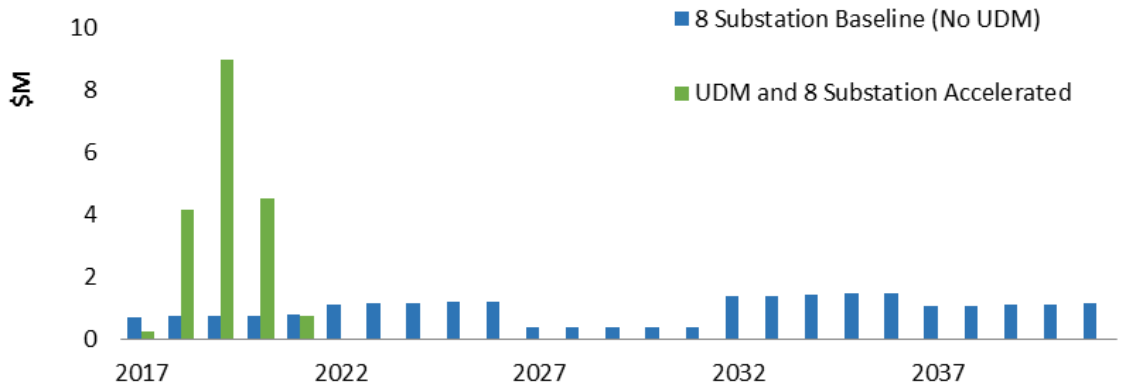
This section presents Navigant's analysis and findings with respect to the costs and benefits of each project option.

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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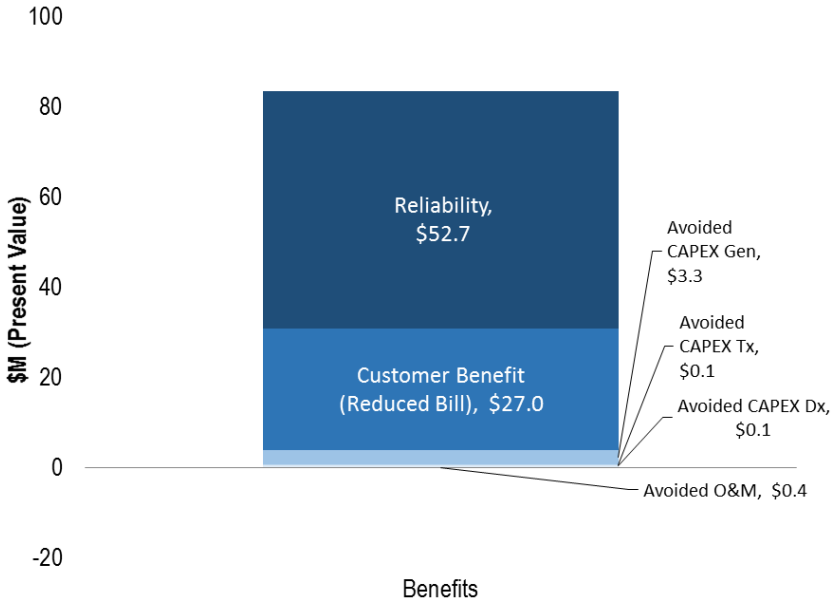
conducted below are highly dependent on the time period over which the project is analyzed. Although the ECo proposal includes 20 years of service fee payments, the benefits are expected to be realized over the lifetime of the assets. For the purposes of this analysis, Navigant assumes that hardware 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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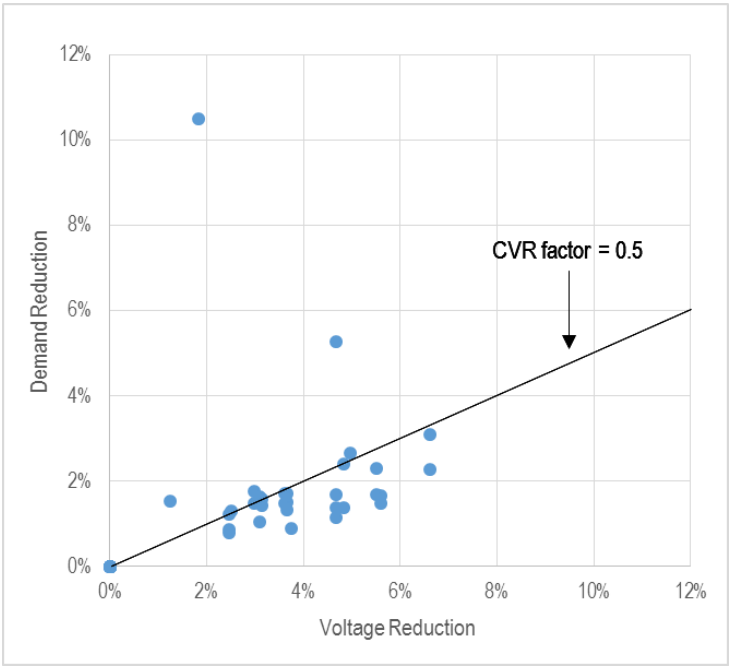
- SAIDI reduced by 46%
- Customer Average Interruption Duration Index (CAIDI[12]) reduced by 16%

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

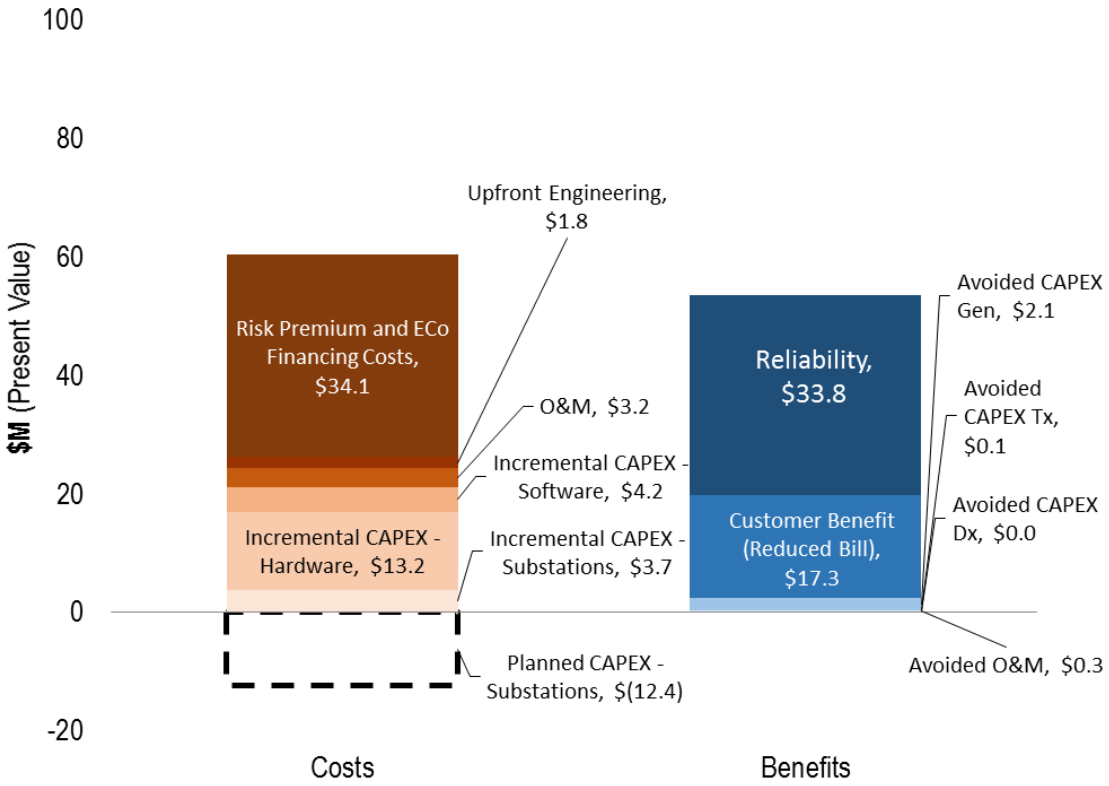

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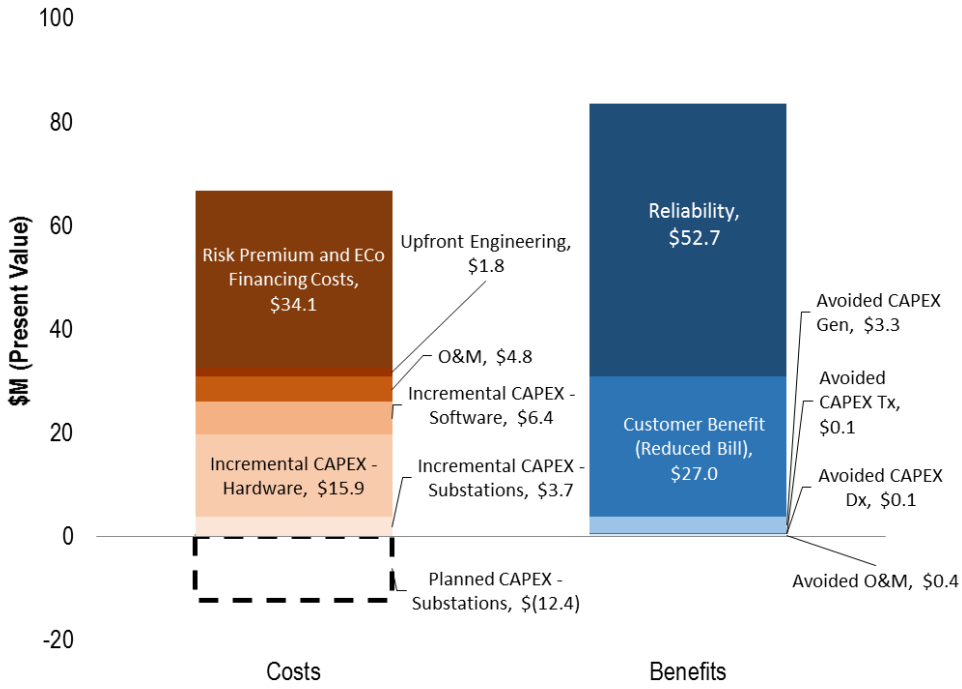
Figure 5. Net Present Value (40 years) Costs and Benefits of ECo-funded UDM



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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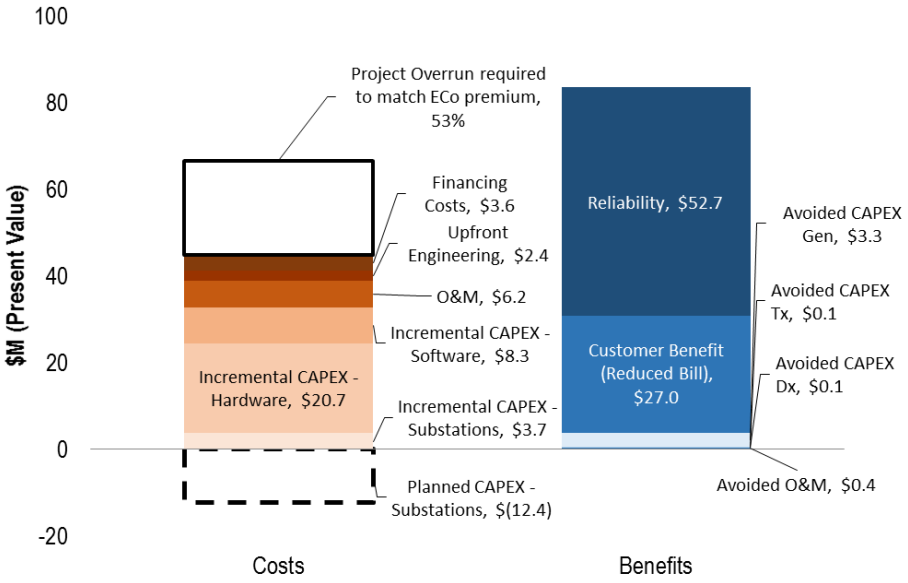
UDM assets and extend the period during which UDM benefits are realized. It is assumed that hardware assets have a 40 year useful life. Thus, in the 20 year term analysis, we assume the hardware has a residual value based on the net present value of its depreciated value at 20 year which reduces the 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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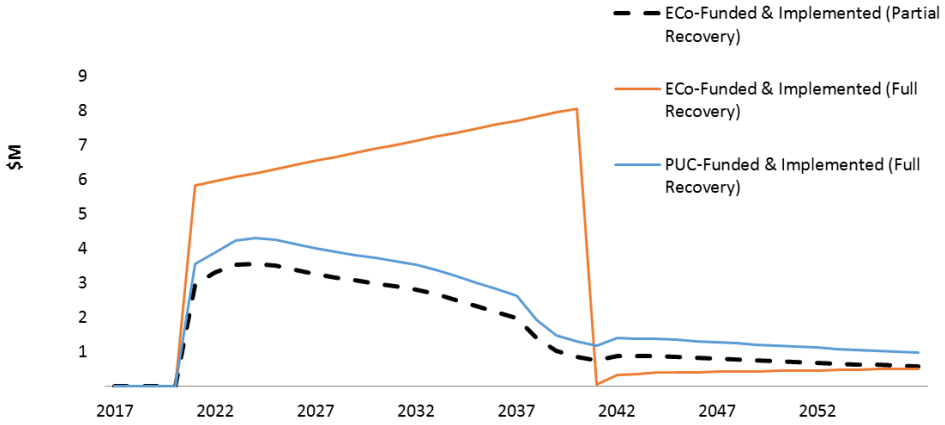
The impact on distribution revenue requirement is significantly lower for both the ECo-Funded – Partial Recovery option and the PUC-Funded – Full Recovery option due to two factors. First, the risk premium cost component has been excluded for recovery through PUC's distribution rates, and second, the 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.

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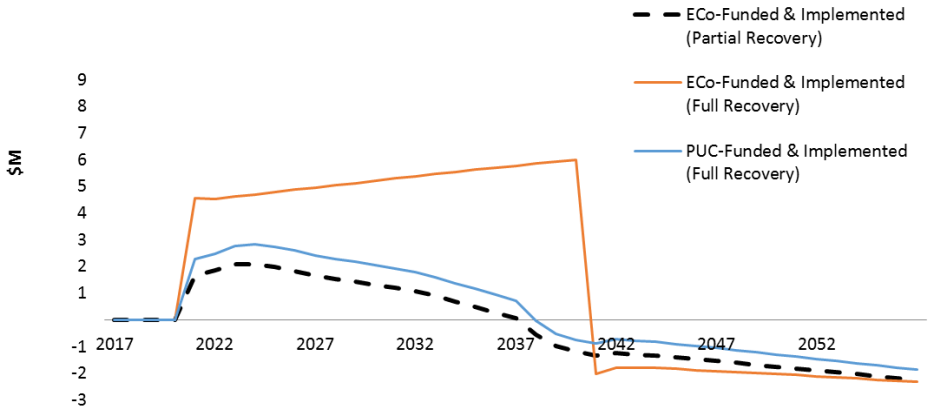
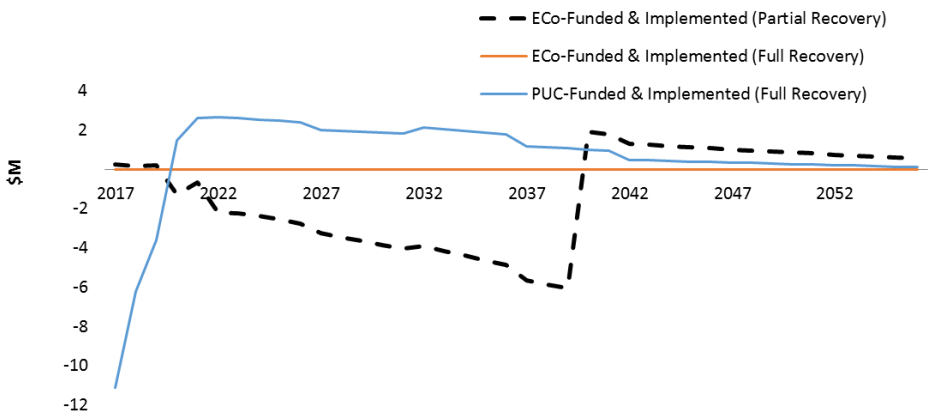
Figure 8. Net Customer Impact of Project Options[19]



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

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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

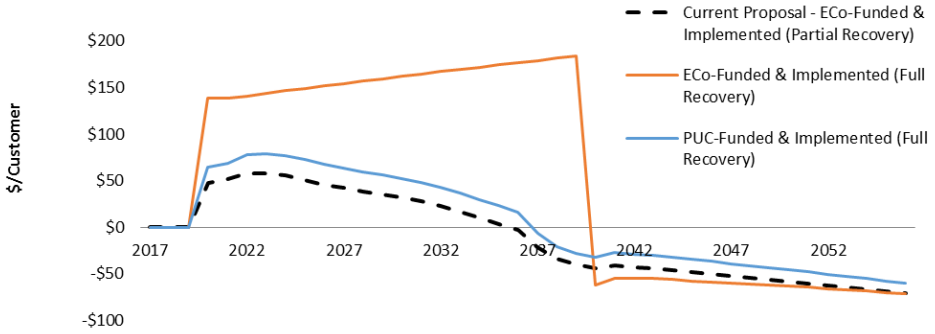
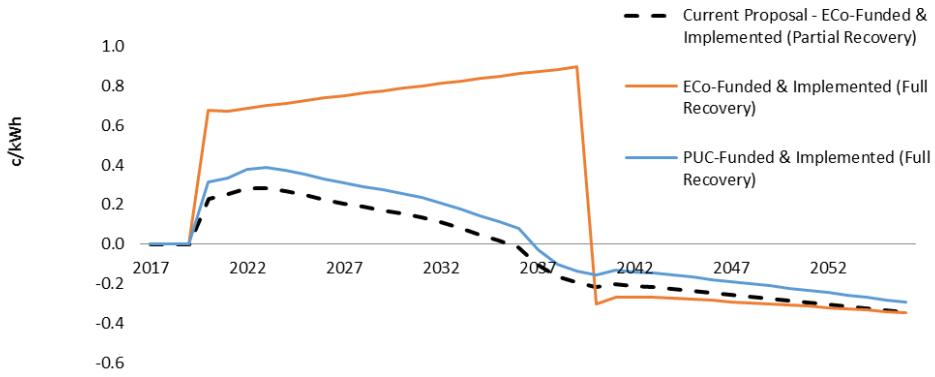


Figure 12. Average Distribution Rate Increase by Project Option



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

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. ✓

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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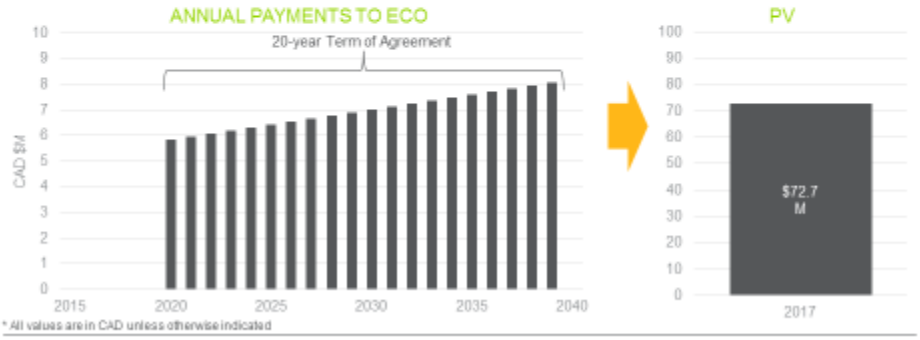
DECONSTRUCTING THE COSTS

- 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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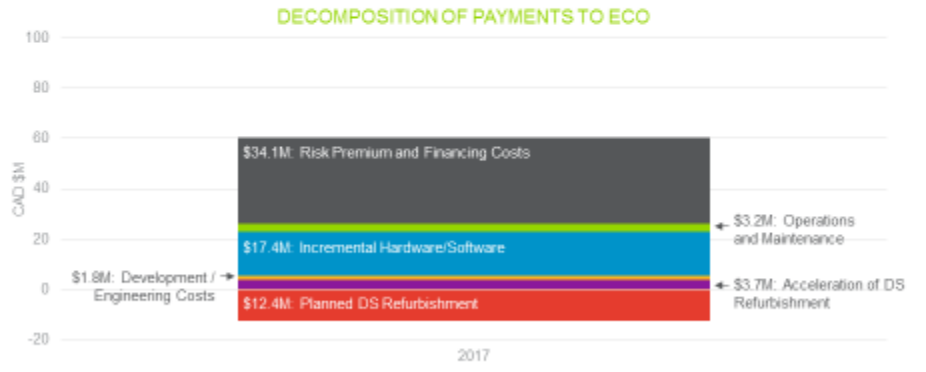
DECONSTRUCTING THE COSTS

- Breaking out other known components of the ECo payment results in an estimate of the embedded risk premium and financing cost of $34.1M



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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

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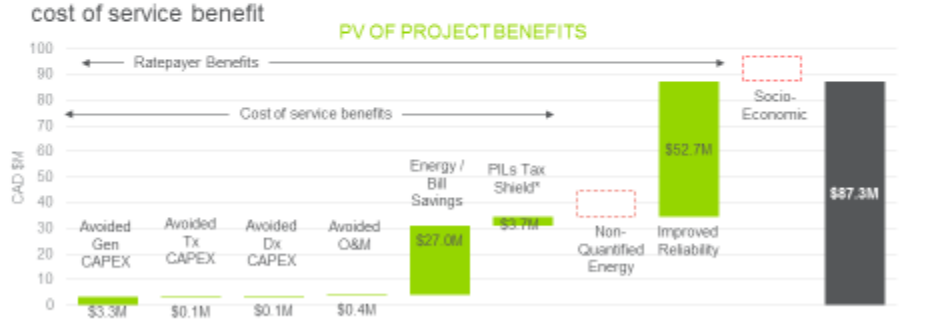
UNDERSTANDING THE BENEFITS

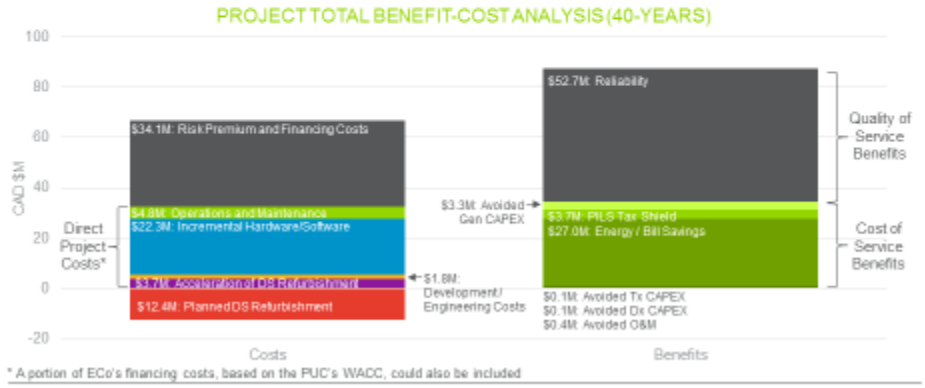
- Benefits total an estimated $87.3M over 40 years
  - Does not include some non-quantified energy and socio-economic benefits
- From a regulatory approval standpoint, six benefit categories result in a reduction in cost of service to customers
- Reliability improvements, provide a quality of service benefit, but do not provide a cost of service benefit



* Based on the incremental capital costs incurred by ECo up to and through commissioning of the project

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

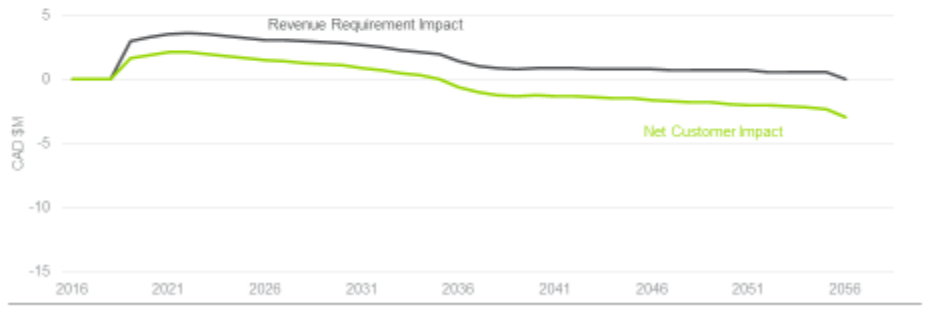


* A portion of ECo's financing costs, based on the PUC's WACC, could also be included

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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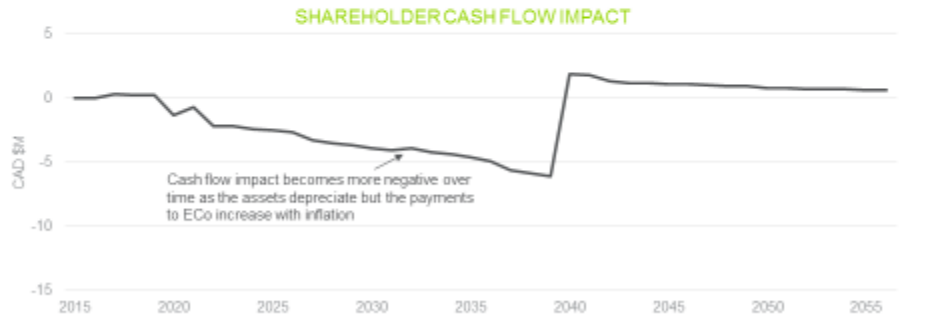
RATEPAYER AND SHAREHOLDER IMPACT

- 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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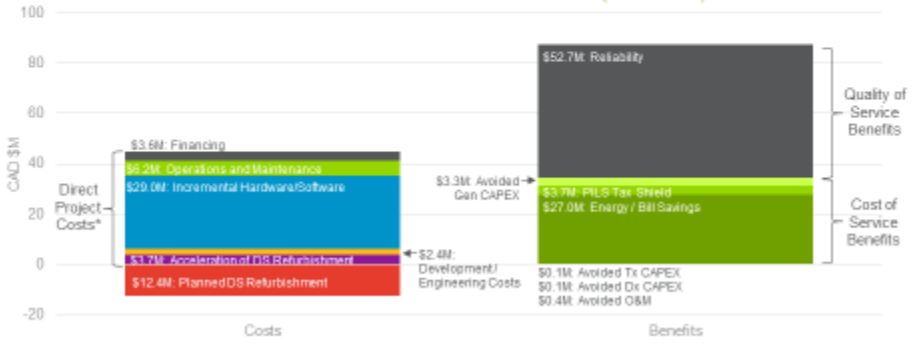
ALTERNATIVE PROJECT OPTIONS

- 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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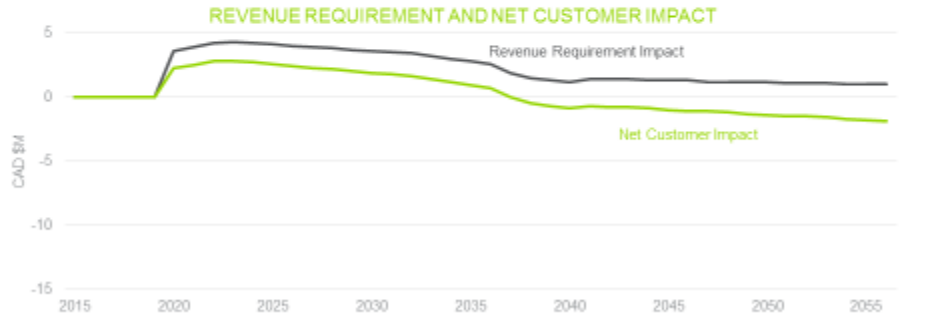
ALTERNATIVE PROJECT OPTIONS

- 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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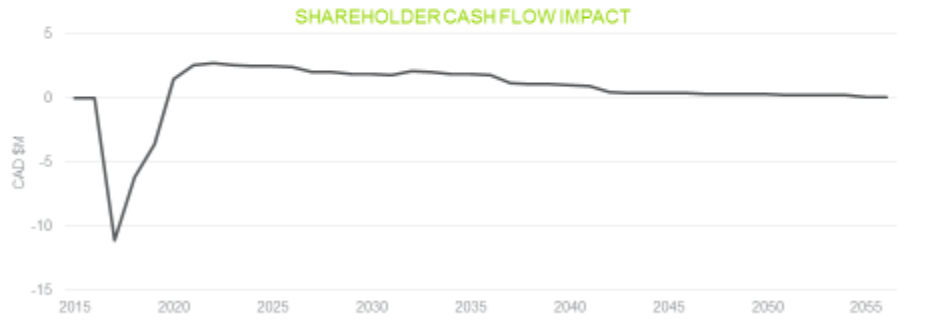
ALTERNATIVE PROJECT OPTIONS

- 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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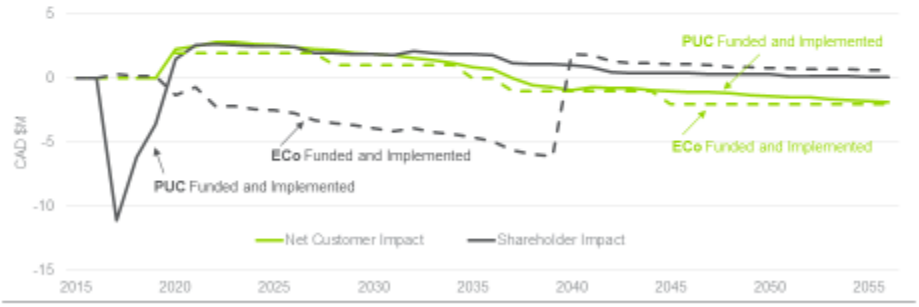
ALTERNATIVE PROJECT OPTIONS

- 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

NET CUSTOMER AND SHAREHOLDER CASH FLOW IMPACT



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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 AA5 - Appendix 4 JTC1_18 PUC SSM Weekly Update

SSM COMMUNITY MICROGRID BUSINESS CASE REVIEW

WEEKLY MEETING #6 (FINAL)

April 8, 2016

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RECAP OF PROJECT TIMELINE

- **Task 1**: Review Available Documentation and Identify Gaps
- **Task 2**: Develop Decision Support Model
- **Task 3**: Identify and Outline Possible Financing or Equity Partnership Alternatives
- **Task 4**: Develop Framework for OEB Submission

	Week of:					
	29-Feb	7-Mar	14-Mar	21-Mar	28-Mar	4-Apr
Task 1: Document						
Task 2: Model						
Task 3: Finance Opts						
Task 4: OEB Submit						
Weekly Touchpoint	x	x	x	x	x	x
Final Presentation						x

Draft Report to PUC by start-of-day on 4/11/2016

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***Note**: Items #2 – #7 align with the structure of our draft report*

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PROJECT INTRODUCTION

- 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.

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INFORMATION GAP ANALYSIS

- **Main information gaps:**
  - **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) study to value the customer costs of outages. However, it is unknown what proportion of those benefits PUC's customers would be willing to pay for, as well as the proportion of those benefits that OEB would be willing to accept.
  - **Reliability impacts from the DA system** – for the purposes of this study and the 30% preliminary design phase level of the project, Navigant considers the reliability impacts of the DA system as estimated by Leidos to be reasonable. However, given the significance of the reliability benefits relative to the other benefits streams, any changes to the estimated impacts in the next-level of engineering design could have a large effect on the benefit-cost analysis of the project. More refined estimates of the reliability benefits would provide significant clarity in the benefit-cost ratio.
  - **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.

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OVERVIEW OF PROJECT OPTIONS

*Project options are analyzed relative to the baseline scenario

		Project Scope	
		UDM + 8 Dist. Substations**	Key Characteristics
Project Options*	**ECo-funded** (fully bundled) – *current offer 20-year service fee term*	X	• Monthly service fee to ECo • Risk premium from ECo for operating & construction risk • Cost of capital
	PUC-funded & implemented	X	• PUC funded • PUC assumes all risk
	PUC-funded; ECo Performance Guarantee	X	• PUC funded • Risk premium from ECo for operating & construction risk

- **20-year horizon**: assumes residual value on the hardware.
- **40-year horizon**: assumes that PUC must re-invest in the software in year 21.

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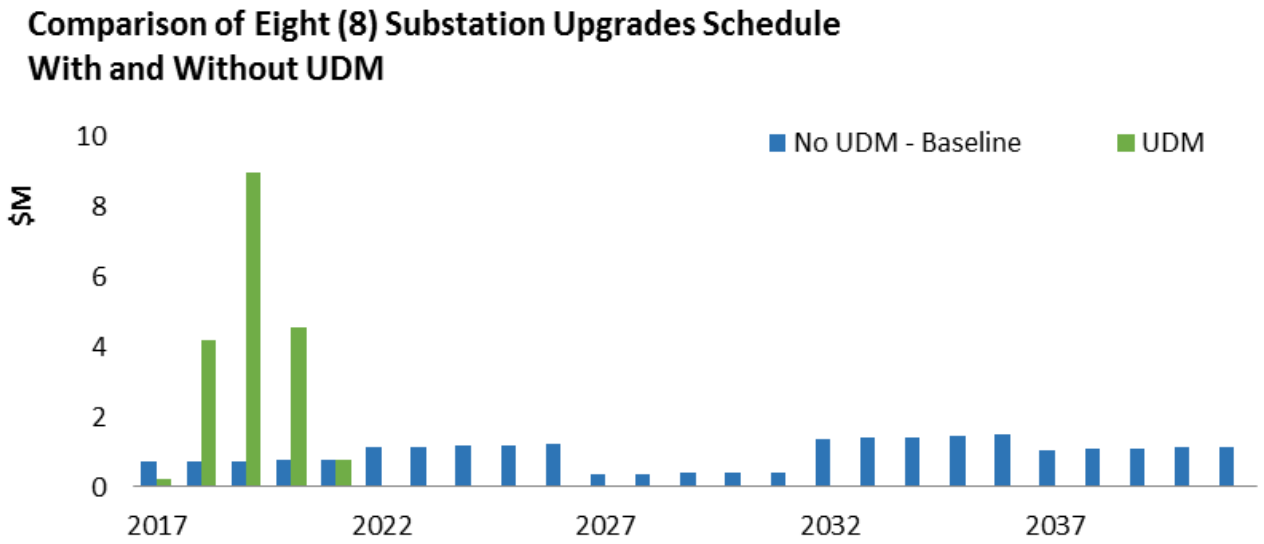
BASELINE DEFINITION

- Assumes no incremental automation in the baseline case
- Incremental cost of substation upgrades due to**:
  - Time value of money (*3 year versus 20 year*) +
  - Substation functionality (*load tap changers versus feeder regulators only*)



**Potential risk of stranded assets by accelerating asset upgrades (i.e., substation investments) before they are fully depreciated.

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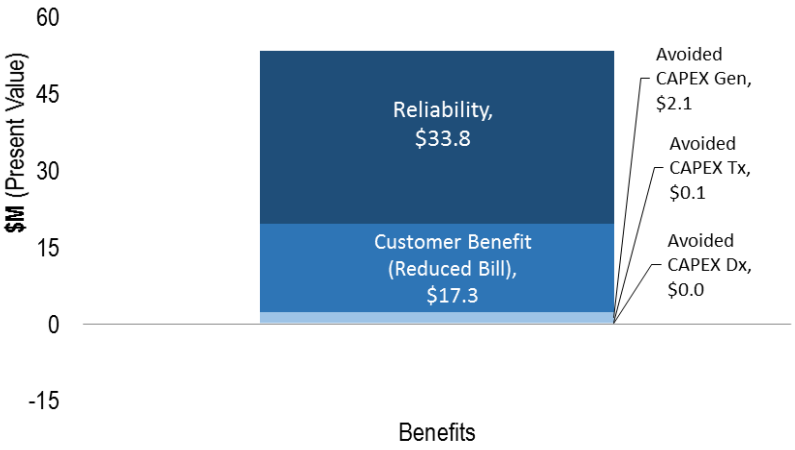
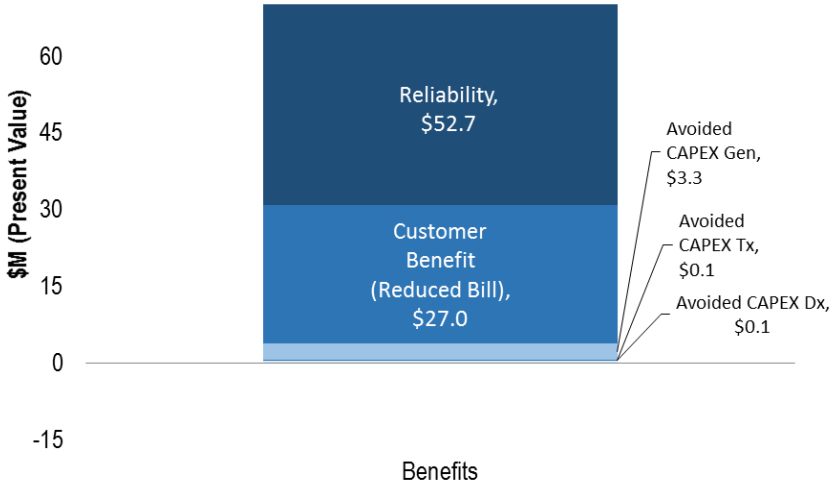
BENEFITS ANALYSIS

Present Value of Benefits of ECo UDM Implementation (20 Yrs)



Present Value of Benefits of ECo UDM Implementation (40 Yrs)



Reliability Benefits

- LBNL Study
- Alignment of customer groups with study
- High confidence that the valuation is *conservative*

VVO Benefits

- Assumes 1.5% energy (bill) reduction
- Assumes electricity supply costs increase at inflation (2%)
- Medium-to-high confidence in accuracy

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SOCIO-ECONOMIC (& ENERGY-RELATED NON-QUANTIFIED) BENEFITS

- Energy Center of Excellence possibly moved to SSM
- 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).

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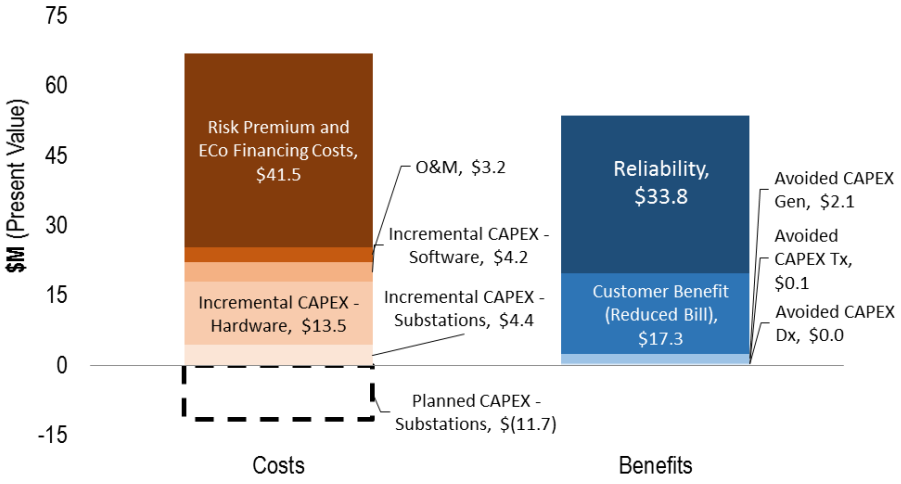
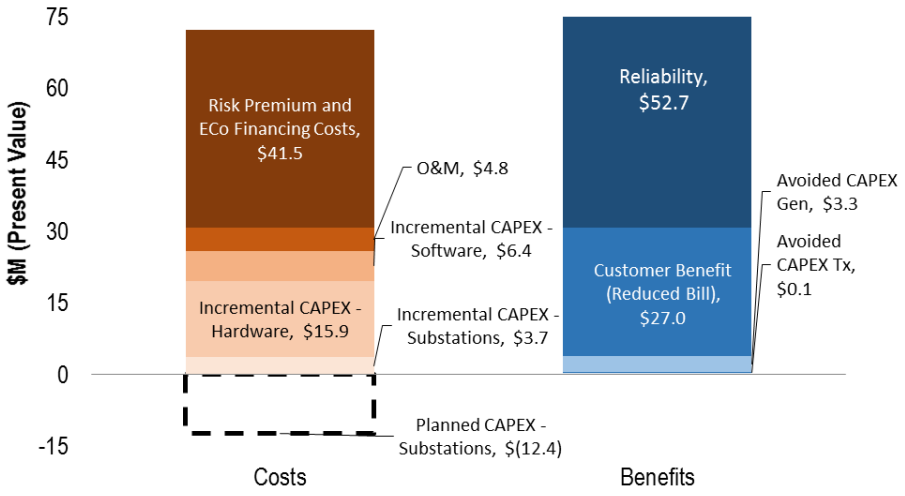
ECO-FUNDED & IMPLEMENTED OPTION: CUSTOMER VIEW

Present Value of Costs and Benefits of ECo UDM Implementation (20 Yrs)



Present Value of Costs and Benefits of ECo UDM Implementation (40 Yrs)



- Benefit/Cost analysis from customer perspective
- Risk premium is equal to the net present value of the payments streams to ECo less the project costs

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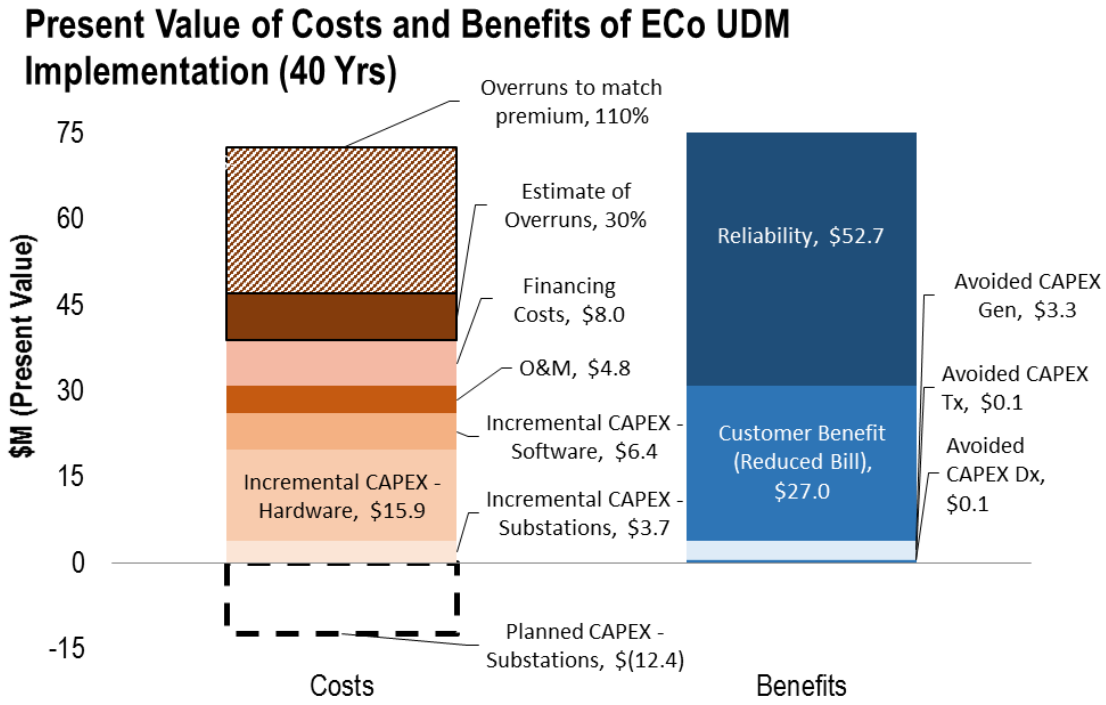
PUC-FUNDED & IMPLEMENTED OPTION: CUSTOMER VIEW



- Benefit/Cost analysis from customer perspective
- Project overruns would need to be significant to equal the ECo risk premium as calculated

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OVERVIEW OF REGULATORY TREATMENT

ECo-funded & Implemented project option:

1. ECo payments are a pass-through as O&M.
2. Actual capital expenditures are rate based, actual O&M is passed through as an expense, risk premium (i.e., difference between payments to ECo and increased revenue requirements) is not recoverable.

PUC-funded & Implemented project option:

3. Actual capital expenditures and contingency are rate based, actual O&M is passed through as an expense.

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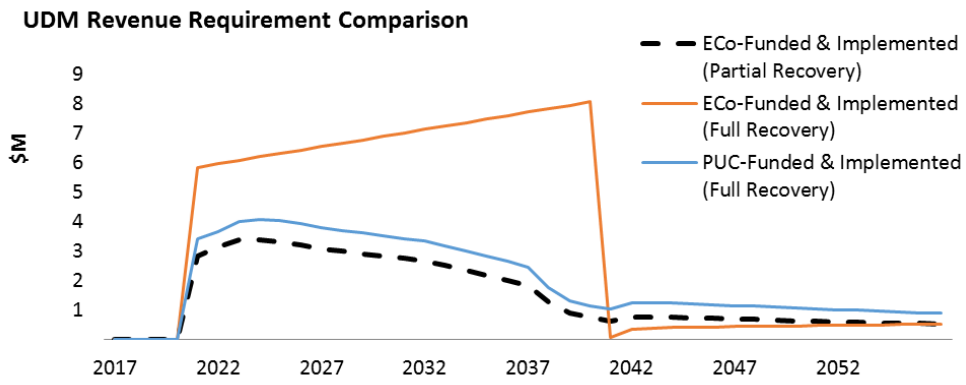
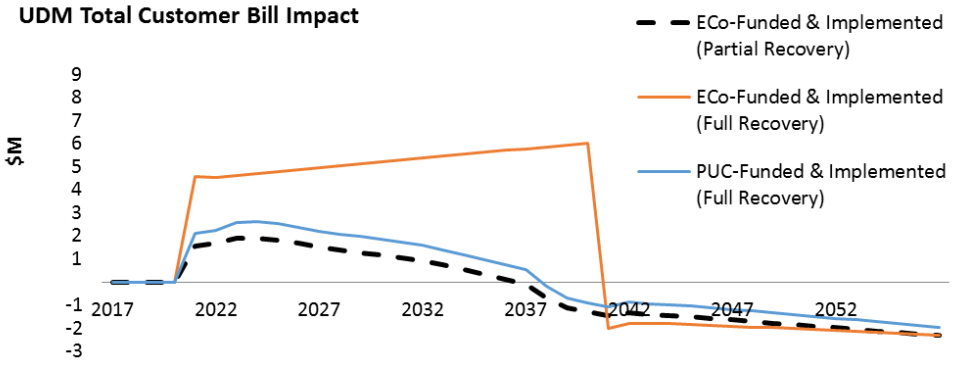
CUSTOMER IMPACTS: DX REVENUE REQUIREMENT VS CUSTOMER BILL





- Capital UDM + Incremental Substation + O&M
- Includes avoided distribution system upgrades (small)
- Bottom graph shows offset by direct customer benefits, in particular avoided energy

Average Customer Bill Impacts

	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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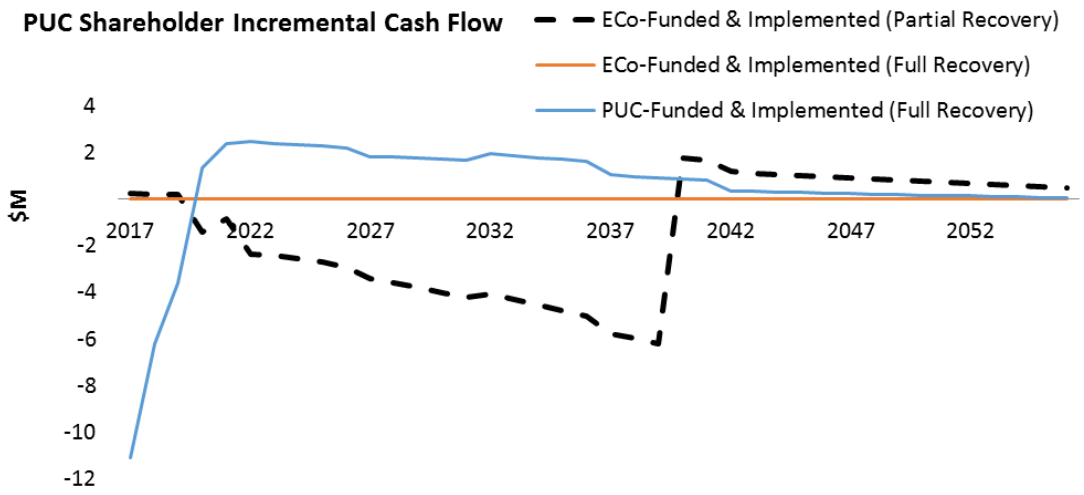
PUC SHAREHOLDER PERSPECTIVE (CASH FLOWS)



1. **ECo-Funded & Implemented (Partial Recovery)**: No upfront costs, then 20 years of service payments, then residual value of assets in rate base
   - Shareholders pay for risk premium
2. **ECo-Funded & Implemented (Full Recovery)**: ECo payments recovered through revenue requirements (low probability of OEB approval)
3. **PUC-Funded & Implemented (Full Recovery)**: Capital investment upfront, earn return over the life of the asset (traditional utility investment)

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OVERVIEW OF REGULATORY CONSIDERATIONS

Regulatory Considerations:

- Customer Rate impact – mitigation measures, rate smoothing, paced capital investment
- Customer Need - are project benefits aligned with customer needs (to be demonstrated by customer survey?)
- Shareholder – the risk premium includes construction and operating risk, and higher cost of capital for Eco (> PUC). If not fully recoverable through rates, it will be at the expense of the shareholder.
- Accelerated sub-station work – will the undepreciated value be recoverable through rates or is this a stranded asset?

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CONCLUSIONS

- UDM project itself (sans risk and ECo financing premium) **poses a strong benefit-cost ratio** (i.e., 1.8 for 40-year outlook including 30% cont. and financing costs)
- From a customer perspective, ECo's proposed financing structure is **not an efficient way to finance** the UDM project.
- **ECo's proposal results in a large step-change in customer costs** and is likely to pose **significant regulatory challenges** (bill impact and rate smoothing). If the risk premium is not recoverable through rates (OEB approval), this cost will be **at the expense of shareholders**. Shareholders are foregoing an opportunity to invest in infrastructure and earn the allowed return.
- **PUC-Funded & Implemented** option also results in a **large step-change in customer costs** and poses similar **regulatory challenges** as above, but would only proceed if the full capital investment/ O&M is recoverable through rates. **PUC would be taking the construction and operating risks** associated with the project (instead of ECo).

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RECOMMENDATIONS

- **Explore an alternative project option** with ECo, where:
  - ECo designs, builds and operates the project providing performance guarantees, in exchange for an up-front payment and smaller ongoing installments to cover operational costs.
  - PUC finances the up-front payment and recovers the cost through rate-base.
- Another option is to have ECo finance the work at PUC's cost of capital.
- Investigate a scenario where **investments are paced over a longer time period** to mitigate customer rate impacts (i.e., rate smoothing).

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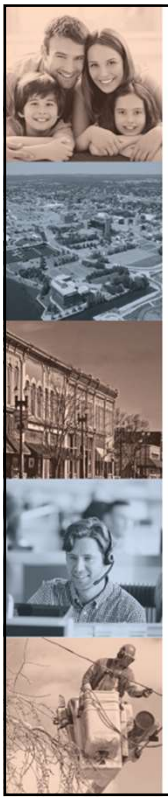
Appendix AA5 - Appendix 5 JTC2_5 Smart Grid Overview BoD June 27 2018

Sault Smart Grid

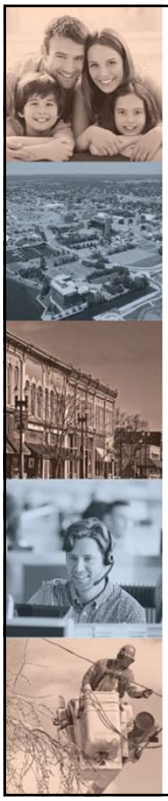
1



Smart Grid & Regulation

- 1998 Electricity Act – some regulatory definition provided
- OEB Regulatory understanding & oversight developing
- 2009 - Green Energy & Green Economy Act
- Mar 25, 2010 – OEB Filing Requirements: Distribution Plans – Filing under Deemed Conditions of Licence
- Nov 23, 2010 – Min. of Energy Order in Council to OEB - …steps in relation to the establishment, implementation and promotion of a smart grid.
  - (objectives from Electricity Act +objectives from Green Energy Act)

2



Smart Grid History SSM

- UDM Project came to the Board in Aug 2015

3

Due Diligence - Project Cost Overview

MONTHLY	ANNUAL	CPI	TERM	PUC WACC (60/40) (Discount Factor includes debt refinancing in year 10)	PROJECT PV (Calculated monthly)
$0.486K (mid-range)	$5.832MM	2.0%	20 YR	7.18%	$67.3MM
				DEBT 4.77%	
				EQUITY 9.30%	
CAPEX OFFSETS - SUBSTATIONS	-$2.500MM**				
NET ANNUAL PROJECT	$3.332MM				
TOTAL OPEX*	$10.878MM				
TOTAL CAPEX*	$9.870MM				
POWER AND DISTRIBUTION REVENUES*	$88.808MM				

** 2013 Yearbook of Electricity Distributors*
*** 0.75 substation per year build rate*

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4

Smart Grid History SSM

- UDM Project came to the Board on Aug 26, 2015.
  - Project was declined
- Study-Recommend team launched Nov 5, 2015 (City, EDC, SSMIC, PUC) to look at opportunities for broader community benefits
  - Navigant review conducted and reported to F&A on April 23, 2016.
  - F&A recommended not moving forward
    - Board passed resolution on April 27, 2016 to end further consideration
- Proponent presented revised proposal to City:
  - Scope reduced
  - Project cost cut in half
  - Introduced the Energy Services Company concept

5

Sept 2016 Proposal

PUC Distribution Pays:	Without External Funding
Project Developer (SPV) - per month	$231,485
PUC Services - per month	$32,993
Total Monthly Payments (average)	$264,478
Total Annual Payments (average)	$3,173,736
Sum of Total Payments Over 25 Years	$79,343,400
Today's Value of 25 Years of Payments (discounted at deemed OEB WACC)	$33,855,071

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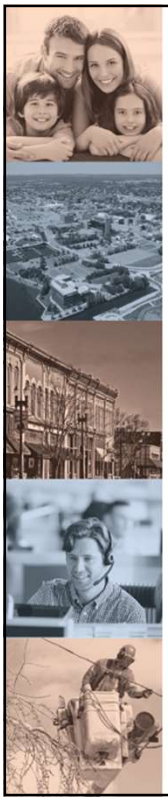

Smart Grid History SSM

- Negotiations in late 2016 and through early 2017
- Nov 22, 2017, PUC Services Board approved:
  - It is hereby recommended that the Board approve in principle construction of the Sault Smart Grid in conjunction with Infrastructure Energy Co. subject to the following conditions:
    - Zero negative bill impact to residential customers, considering all direct and indirect benefits;
    - Successful contract negotiations, including final price, performance guarantees, risk mitigation, and other terms;
    - Successful detailed business case for launch of an Energy Services Company (ESCO) business line;
    - Successful funding from other sources (such as Federal, Provincial, IE);
    - OEB rate approval (including Distribution System Plan requirements);
    - Final Approval by the Board; and
    - Shareholder approval.

7

2018 Project Proposal

Project Cost	$32,751,469	
PUC Co-Investment	$(2,540,000)	From NOHFC loan
NRCan	$(11,800,000)	
NOHFC grant	$(2,540,000)	
Net Project Cost	$18,501,469	
Other Potential funding	$2,500,000	CDM, Prov Smart Grid

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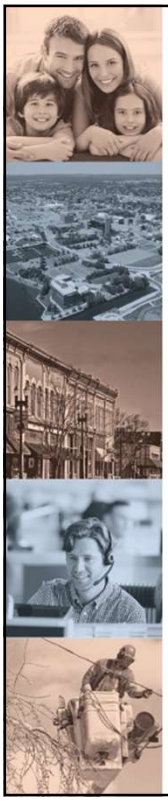

Monthly Costs

Item	Monthly Payment
I.E. Lease payment	$108,336 indexed
Co-Inv loan	$15,653 linear
LEASE PAYMENT TOTAL	$123,989 indexed
Maintenance*	$42,487 indexed
Contingency	$20,000
TOTAL	$186,476 indexed

* Does not include Stakeholder Engagement

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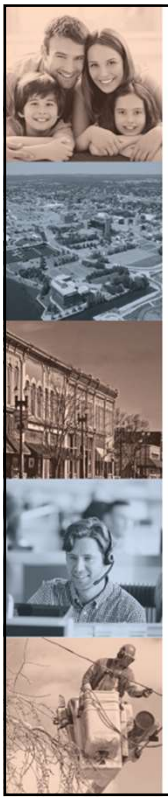

Monthly Benefits

Item	Monthly Amount
Energy Savings	$129,500
Avoided CapEx	$28,559
LDC Efficiencies	$2,568
Depreciation Tax Benefit	$28,930
TOTAL MONTHLY SAVINGS	$189,557

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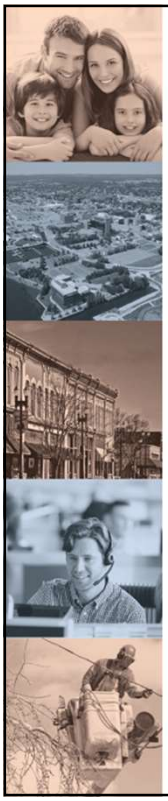


Bill Impacts

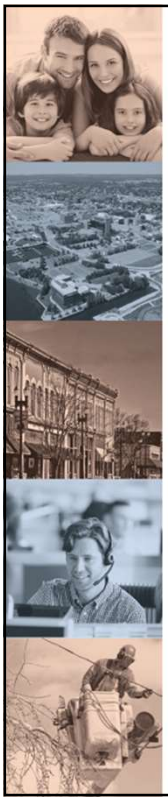
Residential	Fixed portion	Variable portion	Total
SSG cost (includes 20k/mth contingency)	$0.66	$1.01	$1.67
SSG Efficiency Gain			$(1.78)
Impact to bill (direct savings vs costs)			$(0.11)
Reliability gain (Leidos analysis)			$(3.27)
Direct and Indirect Impact			$(3.38)

11

Smart Grid History SSM

- Negotiations in late 2016 and through early 2017
- Nov 22, 2017, PUC Services Board approved:
  - It is hereby recommended that the Board approve in principle construction of the Sault Smart Grid in conjunction with Infrastructure Energy Co. subject to the following conditions:
    - Zero negative bill impact to residential customers, considering all direct and indirect benefits;
    - Successful contract negotiations, including final price, performance guarantees, risk mitigation, and other terms;
    - Successful detailed business case for launch of an Energy Services Company (ESCO) business line;
    - Successful funding from other sources (such as Federal, Provincial, IE);
    - OEB rate approval (including Distribution System Plan requirements);
    - Final Approval by the Board; and
    - Shareholder approval.

12



Project Agreement

- Agreement has been drafted
- Final agreement and cost will be subject to the funding received, timing of funding, and any OEB requirements.

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OEB

- Ideal way would have been to have included the project in the DSP and the Cost of Service (CoS) Application.
  - May have complicated the CoS application
- We've engaged OEB staff and have come up with the following course of action:
  - This fall submit the first of two ICM's (Interim Capital Module).
  - Approval would be received in spring 2019.
  - Second ICM submitted in fall of 2019 for approval in spring 2020.
- This would require us to amend the original board approval as it required a number of conditions, one of which was OEB approval of the project prior.
  - We would propose substituting this for OEB staff support, and limiting investment prior to first ICM approval.

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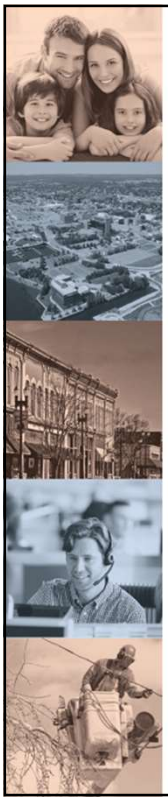

Risk Mitigation

- Prior to OEB approval, we would propose limiting our exposure to the value of the engineering work to us.
  - Estimated at $400,000

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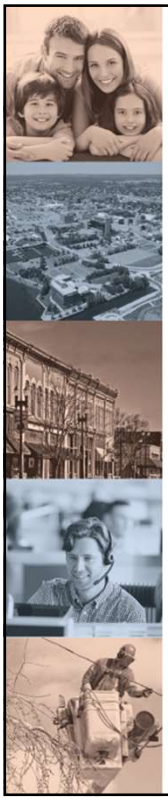
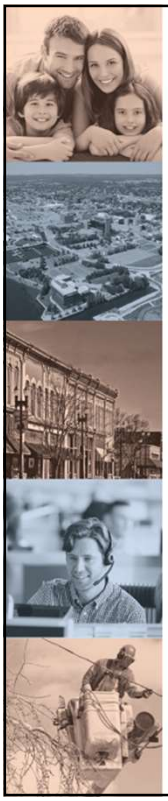


Board Approval

- Board is being asked to approve the project structure and projected costs based on the potential funding contributions of NRCan and NOHFC.
  - Deal is contingent on the NRCan funding

16



Shareholder Approval

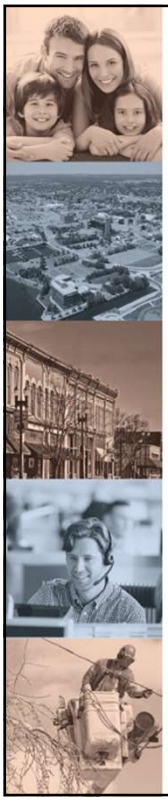
- PUC will present to Council 'In camera' on July 16th.

17

Smart Grid History SSM

- Negotiations in late 2016 and through early 2017
- Nov 22, 2017, PUC Services Board approved:
  - It is hereby recommended that the Board approve in principle construction of the Sault Smart Grid in conjunction with Infrastructure Energy Co. subject to the following conditions:
    - Zero negative bill impact to residential customers, considering all direct and indirect benefits;
    - Successful contract negotiations, including final price, performance guarantees, risk mitigation, and other terms;
    - Successful detailed business case for launch of an Energy Services Company (ESCO) business line;
    - Successful funding from other sources (such as Federal, Provincial, IE);
    - OEB rate approval (including Distribution System Plan requirements);
    - Final Approval by the Board; and
    - Shareholder approval.

18



Questions?

19

Appendix AA5 - Appendix 6 JTC2_9 Smart Grid Quarterly Claim - Blank Form

Smart Grid Deployment Program

Within thirty (30) days after the end of each quarter, recipients of Smart Grid Deployment Program funding must provide a claim, an updated budget forecast and project task updates, as per Schedule C of the Contribution Agreement.

Project Name:	Sault Smart Grid
Project ID:	GISC - 3030
Proponent Company Name:	PUC Distribution Inc.
Claim number:	No. 1
Expenses for Quarter Ending on:	

	Costs Incurred	Costs Expected Next Quarter
ELIGIBLE EXPENDITURES		
Salaries and Benefits		
Overhead		
Professional, Scientific and Contracting Services*		
Travel, including Meals and Accomodations		
Equipment and Products**		
Other expenses***		
Total Eligible Expenditures	$ -	$ -

INELIGIBLE EXPENDITURES		
Salaries and Benefits		
Overhead		
Professional, Scientific and Contracting Services*		
Travel, including Meals and Accomodations		
Equipment and Products**		
Other expenses***		
Total Ineligible Expenditures	$ -	$ -

TOTAL PROJECT COSTS	$ -	$ -
Smart Grid Contribution (this quarter)		
Less 25% holdback (in contribution agreement)	$ -	
CLAIM PAYMENT AMOUNT	$ -	

** Complete "Professional, Scientific and Contracting Services" worksheet*

*** Complete "Equipment and Products" worksheet*

**** Complete "Other Expenses" worksheet*

NOTE 1: *For Eligible Expenditures under the "Equipment and Products" category, or contracting services related to the purchase of equipment, materials, or products, any claim greater than $100,000 must be supported by a copy of the invoice.*

NOTE 2: *For Eligible Expenditures under all other categories, any claim greater than $50,000 must be supported by a copy of the invoice.*

NOTE 3: *For the Eligible Expenditures above, the Proponent can include the Goods and Services Tax (GST), Harmonized Sales Tax (HST) and Provincial Sales Tax (PST) costs paid on their project invoices, provided it's net of any tax rebate to which the Proponent is entitled. Program reimbursement for these taxes is also dependent on completion of the* ***Certification for the Treatment of GST, PST and HST*** *form provided by the Program.*

Professional, Scientific and Contracting Services

Note: Expenses above $50,000 must be supported by a copy of the invoice.

ELIGIBLE EXPENDITURES		
Name of the contractor	**Description of the work**	**Costs Incurred**
Total Eligible *Professional, Scientific and Contracting Services* Costs		**$ -**

INELIGIBLE EXPENDITURES		
Name of the contractor	**Description of the work**	**Costs Incurred**
Total Ineligible *Professional, Scientific and Contracting Services* Costs		**$ -**

Equipment and Products

Note: *Expenses above $100,000 for equipment, materials, or products (or contracting services related to these purchases) must be supported by a copy of the invoice.*

ELIGIBLE EXPENDITURES		
Name of Equipment or Product	**Purpose of Item**	**Costs Incurred**
Total Eligible *Equipment and Products* Costs		**$ -**

INELIGIBLE EXPENDITURES		
Name of Equipment or Product	**Purpose of Item**	**Costs Incurred**
Total Ineligible *Equipment and Products* Costs		**$ -**

Other Expenses

Note: *Expenses above $50,000 must be supported by a copy of the invoice*

ELIGIBLE EXPENDITURES		
Type of Other Expense*	**Description of Item**	**Costs Incurred**
Total Eligible *Other Expenses*		**$ -**

INELIGIBLE EXPENDITURES		
Type of Other Expense*	**Description of Item**	**Costs Incurred**
Total Ineligible *Other Expenses*		**$ -**

** "Other Expenses" can include: 1) Field supplies and materials; 2) Printing services and translation; 3) Data collection services, including processing, analysis and management; 4) Facility expenses for seminars, conference room rentals, etc. (excluding hospitality); 5) License fees and permits; and 6) Field testing services.*

Certification and Project Update

Project Update - Provide updates on key project tasks performed during last quarter
Attach in a separate document the key project tasks completed and expected in the next quarter and describe how they align with the tasks identified in Schedule A of the contribution agreement. Also, please provide information about any project related issues and how they are being addressed. Bullet form is acceptable.

I, a duly authorized officer of *PUC Distribution Inc.* *certify that the amounts claimed are correct.*
(Sign and date below)

Date: _____

Name: Robert Brewer

Title: President & CEO

Submit quarterly claim package to: nrcan.sg-ri.rncan@canada.ca

Appendix AA5 - Appendix 7 JTC2_13 0201.12 - 2016 Projection for Distribution Capital Engineering 2016-03-15

PUC Distribution Inc.
Long Range Capital Planning

Revision Date: 2016-03-15

Notes

1) In the two attached spreadsheets, the estimated capital cost expenditures for Distribution Station and Transmission Station rebuilds is considered for two scenarios. The first scenario considers if we were to continue with our current long term plan. The second considers if we were to accelerate a number of DS rebuilds, those shaded in blue, all to occur in the next OEB rate cycle.

2) the budget numbers in the long range plan are preliminary and order of magnitude only, based on presently available information. These will be further refined in 2016 as part of the development of an Asset Management Plan (AMP) and Distribution System Plan (DSP) for the OEB.

3) The sequence of station rebuilt projects proposed in this plan may be changed somewhat due to the outcomes of the DSP. At present the sequencing is based primarily on simple age and condition based assessments and technical factors (e.g.: risk associate with loosing a station that has no backup or where no ability exists to transfer loads in a contingency). The DSP is will see these factors more systematically documented than current planning processes and may lead to a more optimal sequence. In all cases, one underlying goal has been to flatten expenditures as evenly as possible over time and that will continue to be the case with the implementation of the DSP.

4) The attached long range plan does not consider Customer Demand or Allocated Capital. Nor does it consider 'Overhead Distribution System' , 'Underground Distribution System', 'Distribution Transformers' or 'Voltage Conversion Program' which were identified in Exhibit 5-6, p 77 of the METSCO Asset Management Plan prepared in 2012 for the period 2013-2016. It is expected that in all the aforementioned areas, levels consistent with past practice will continue to be required to keep up asset sustainment and respond to customer demand.

CAPEX for Transformer Stations and Distribution Stations				NPV rate	4.00%							
Without UDM												
Priority	Station	Age at Replacement	Comments	NPV 2016	2017-2021	2022-2026	2027-2031	2032-2036	2037-2041	2042-2046	2047-2051
1	Sub 14	▲ 54 years in 2015	Completing voltage conversion will allow retirement of substation. Target 2017 with some 4kV load supplied via Sub 4 temporarily.								
2	Sub 16	▲ 52 years in 2017	UDM #1 rebuild - Health Index Score 50 in 2012	$ 3.37	$ 3.50	$ -	$ -	$ -	$ -	$ -	$ -
	TS1	▲ 45 years in 2018	Health Index Score 52 in 2012	$ 22.88	$ 23.80	$ -	$ -	$ -	$ -	$ -	$ -
				$ 26.25	$ 27.30	$ -	$ -	$ -	$ -	$ -	$ -
3	Sub 19 LTC	▲ 45 years in 2018	Health Index Score 54 in 2012	$ 1.39	$ -	$ 1.50	$ -	$ -	$ -	$ -	$ -
	Sub 19 SwG	▲ 45 years in 2018	Health Index Score 54 in 2012	$ 1.39	$ -	$ 1.50	$ -	$ -	$ -	$ -	$ -
	Sub New		To replace Sub 4 & 5 at end of Voltage conversion	$ 3.24	$ -	$ 3.50	$ -	$ -	$ -	$ -	$ -
	Sub 20	▲ 45 years in 2018	UDM #3 Rebuild - Health Index Score 56 in 2012	$ 3.24	$ -	$ 3.50	$ -	$ -	$ -	$ -	$ -
				$ 9.25	$ -	$ 10.00	$ -	$ -	$ -	$ -	$ -
4	TS2	▲ 51 years in 2028	Health Index Score 66 in 2012	$ 21.16	$ -	$ -	$ 23.80	$ -	$ -	$ -	$ -
	Sub 18 LTC	▲ 63 years in 2031	Health Index Score 61 in 2012	$ 1.33	$ -	$ -	$ 1.50	$ -	$ -	$ -	$ -
	Sub 18	▲ 63 years in 2031	Health Index Score 61 in 2012	$ 1.33	$ -	$ -	$ 1.50	$ -	$ -	$ -	$ -
				$ 23.83	$ -	$ -	$ 26.80	$ -	$ -	$ -	$ -
5	Sub 11	▲ 57 years in 2033	UDM #2 rebuild - Health Index Score 61 in 2012	$ 2.99	$ -	$ -	$ -	$ 3.50	$ -	$ -	$ -
	Sub 2 LTC	▲ 62 years in 2036	(rebuilt) Health Index Score 71 in 2012	$ 1.28	$ -	$ -	$ -	$ 1.50	$ -	$ -	$ -
	Sub 2 SwG	▲ 62 years in 2036	Health Index Score 71 in 2012	$ 1.71	$ -	$ -	$ -	$ 2.00	$ -	$ -	$ -
				$ 5.98	$ -	$ -	$ -	$ 7.00	$ -	$ -	$ -
6	Sub 12	▲ 62 years in 2038	Health Index Score 61 in 2012	$ 2.88	$ -	$ -	$ -	$ -	$ 3.50	$ -	$ -
	Sub 1	▲ 60 years in 2041	UDM #4 Rebuild - Health Index Score 64 in 2012	$ 2.88	$ -	$ -	$ -	$ -	$ 3.50	$ -	$ -
				$ 5.75	$ -	$ -	$ -	$ -	$ 7.00	$ -	$ -
7	Sub 21	▲ 60 years in 2044	Health Index Score 58 in 2012	$ 2.77	$ -	$ -	$ -	$ -	$ -	$ 3.50	$ -
	Sub 13	▲ 54 years in 2046	Health Index Score 76 in 2012	$ 2.77	$ -	$ -	$ -	$ -	$ -	$ 3.50	$ -
				$ 5.53	$ -	$ -	$ -	$ -	$ -	$ 7.00	$ -
8	Sub 15	▲ 54 years in 2048	Health Index Score 62 in 2012	$ 2.66	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.50
				$ 2.66	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.50
Totals				$ 79.25	$ 27.30	$ 10.00	$ 26.80	$ 7.00	$ 7.00	$ 7.00	$ 3.50
			PV of Average Annual CAPEX over next 35 years	$ 2.26							
		Legend:	blue indicates CAPEX within UDM that is part of long term PUC Capital Plan								
			indicates required CAPEX not yet identified in OEB AMP of DSP								

CAPEX for Transformer Stations and Distribution Stations				NPV rate	4.00%							
With UDM												
Priority	Station	Age at Replacement	Comments	NPV 2016	2017-2021	2022-2026	2027-2031	2032-2036	2037-2041	2042-2046	2047-2051	
1	Sub 14	▲ 54 years in 2015	Completing voltage conversion will allow retirement of substation. Target 2017 with some 4kV load supplied via Sub 4 temporarily.									
2	Sub 16	▲ 52 years in 2017	UDM #1 rebuild - Health Index Score 50 in 2012	$ 3.37	$ 3.50	$ -	$ -	$ -	$ -	$ -	$ -	
	TS1	▲ 45 years in 2018	Health Index Score 52 in 2012	$ 22.88	$ 23.80	$ -	$ -	$ -	$ -	$ -	$ -	
				$ 26.25	$ 27.30	$ -	$ -	$ -	$ -	$ -	$ -	
3	Sub 19 LTC	▲ 45 years in 2018	Health Index Score 54 in 2012	$ 1.44	$ 1.50	$ -	$ -	$ -	$ -	$ -	$ -	
	Sub 19 SwG	▲ 45 years in 2018	Health Index Score 54 in 2012	$ 1.39	$ -	$ 1.50	$ -	$ -	$ -	$ -	$ -	
	Sub New		To replace Sub 4 & 5 at end of Voltage conversion	$ 3.24	$ -	$ 3.50	$ -	$ -	$ -	$ -	$ -	
	Sub 20	▲ 45 years in 2018	UDM #3 Rebuild - Health Index Score 56 in 2012	$ 3.37	$ 3.50	$ -	$ -	$ -	$ -	$ -	$ -	
				$ 9.43	$ 5.00	$ 5.00	$ -	$ -	$ -	$ -	$ -	
4	TS2	▲ 51 years in 2028	Health Index Score 66 in 2012	$ 21.16	$ -	$ -	$ 23.80	$ -	$ -	$ -	$ -	
	Sub 18 LTC	▲ 63 years in 2031	Health Index Score 61 in 2012	$ 1.44	$ 1.50	$ -	$ -	$ -	$ -	$ -	$ -	
	Sub 18	▲ 63 years in 2031	Health Index Score 61 in 2012	$ 1.33	$ -	$ -	$ 1.50	$ -	$ -	$ -	$ -	
				$ 23.93	$ 1.50	$ -	$ 25.30	$ -	$ -	$ -	$ -	
5	Sub 11	▲ 57 years in 2033	UDM #2 rebuild - Health Index Score 61 in 2012	$ 3.37	$ 3.50	$ -	$ -	$ -	$ -	$ -	$ -	
	Sub 2 LTC	▲ 62 years in 2036	(rebuilt) Health Index Score 71 in 2012	$ 1.44	$ 1.50	$ -	$ -	$ -	$ -	$ -	$ -	
	Sub 2 SwG	▲ 62 years in 2036	Health Index Score 71 in 2012	$ 1.71	$ -	$ -	$ -	$ 2.00	$ -	$ -	$ -	
				$ 6.52	$ 5.00	$ -	$ -	$ 2.00	$ -	$ -	$ -	
6	Sub 12	▲ 62 years in 2038	Health Index Score 61 in 2012	$ 2.88	$ -	$ -	$ -	$ -	$ 3.50	$ -	$ -	
	Sub 1	▲ 60 years in 2041	UDM #4 Rebuild - Health Index Score 64 in 2012	$ 3.37	$ 3.50	$ -	$ -	$ -	$ -	$ -	$ -	
				$ 6.24	$ 3.50	$ -	$ -	$ -	$ 3.50	$ -	$ -	
7	Sub 21	▲ 60 years in 2044	Health Index Score 58 in 2012	$ 2.77	$ -	$ -	$ -	$ -	$ -	$ 3.50	$ -	
	Sub 13	▲ 54 years in 2046	Health Index Score 76 in 2012	$ 2.77	$ -	$ -	$ -	$ -	$ -	$ 3.50	$ -	
				$ 5.53	$ -	$ -	$ -	$ -	$ -	$ 7.00	$ -	
8	Sub 15	▲ 54 years in 2048	Health Index Score 62 in 2012	$ 2.66	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.50	
				$ 2.66	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.50	
Totals				$ 80.57	$ 42.30	$ 5.00	$ 25.30	$ 2.00	$ 3.50	$ 7.00	$ 3.50	
			PV of Average Annual CAPEX over next 35 years	$ 2.30								
		Legend:	blue indicates CAPEX within UDM that is part of long term PUC Capital Plan									
			indicates required CAPEX not yet identified in OEB AMP of DSP									

Appendix AA6
Minister's Directive

Ontario
Executive Council
Conseil des ministres

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil des ministres, décrète ce qui suit:

WHEREAS it is desirable that the Province and the Ontario Energy Board move forward together with a plan to implement the advanced information exchange systems and equipment that together comprise the Smart Grid ("Smart Grid"), as defined in the amendments to the *Electricity Act, 1998* made by the *Green Energy and Green Economy Act, 2009*;

AND WHEREAS in furtherance of this goal, it is desirable that the Province provide guidance and direction to the Board as to the principles and objectives which must be met in order to fully achieve the Province's objectives related to the Smart Grid in a cost-efficient manner;

AND WHEREAS the Minister of Energy has the authority, with the approval of the Lieutenant Governor in Council, to issue Directives pursuant to section 28.5 of the *Ontario Energy Board Act, 1998*, as amended by the *Green Energy and Green Economy Act, 2009,* in relation to the establishment, implementation or promotion of a Smart Grid for Ontario;

NOW THEREFORE the Directive attached hereto, is approved.

Recommended: _____
Minister of Energy

Concurred: _____
Chair of Cabinet

Approved and Ordered: NOV 2 3 2010
Date

_____
Administrator of the Government

O.C./Décret 1515/2010

MINISTER'S DIRECTIVE

TO: THE ONTARIO ENERGY BOARD

I, Brad Duguid, Minister of Energy, hereby direct the Ontario Energy Board pursuant to section 28.5 of the *Ontario Energy Board Act, 1998* (the "Act"), as described below.

The Board shall take the following steps in relation to the establishment, implementation and promotion of a smart grid:

1. The Board shall provide guidance to licensed electricity distributors and transmitters, and other regulated entities whose fees and expenditures are reviewed by the Board, that propose to undertake smart grid activities, regarding the Board's expectations in relation to such activities in support of the establishment and implementation of a smart grid.

2. For licensed distributors and transmitters, the guidance referred to in paragraph 1 shall be provided in particular to: (a) guide these regulated entities in the preparation of plans for the development and implementation of the smart grid, as contemplated in subparagraph 70(2.1)2(ii) of the Act ("Smart Grid Plans"); and (b) identify the criteria that the Board will use to evaluate Smart Grid Plans.

3. In developing the guidance referred to in paragraph 1, and in evaluating the Smart Grid Plans and activities undertaken by the regulated entities referred to in that paragraph, the Board shall be guided by, and adopt where appropriate, the parameters for the three objectives of a smart grid referred to in subsection 2(1.3) of the definition for "smart grid" as provided for under the *Electricity Act, 1998*, where such elements of said objectives are set out in Appendices A through C.

4. Further, in developing the guidance referred to in paragraph 1 and in evaluating the smart grid activities of the regulated entities referred to in that paragraph, the Board shall be guided by the following policy objectives of the government:

    (i) *Efficiency***:** Improve efficiency of grid operation, taking into account the cost-effectiveness of the electricity system.

    (ii) *Customer value:* The smart grid should provide benefits to electricity customers.

    (iii) *Co-ordination*: The smart grid implementation efforts should be coordinated by, among other means, establishing regionally

coordinated Smart Grid Plans ("Regional Smart Grid Plans"), including coordinating smart grid activities amongst appropriate groupings of distributors, requiring distributors to share information and results of pilot projects, and engaging in common procurements to achieve economies of scale and scope.

(iv) *Interoperability:* Adopt recognized industry standards that support the exchange of meaningful and actionable information between and among smart grid systems and enable common protocols for operation. Where no standards exist, support the development of new recognized standards through coordinated means.

(v) *Security:* Cybersecurity and physical security should be provided to protect data, access points, and the overall electricity grid from unauthorized access and malicious attacks.

(vi) *Privacy:* Respect and protect the privacy of customers. Integrate privacy requirements into smart grid planning and design from an early stage, including the completion of privacy impact assessments.

(vii) *Safety:* Maintain, and in no way compromise, health and safety protections and improve electrical safety wherever practical.

(viii) *Economic Development:* Encourage economic growth and job creation within the province of Ontario. Actively encourage the development and adoption of smart grid products, services, and innovative solutions from Ontario-based sources.

(ix) *Environmental Benefits:* Promote the integration of clean technologies, conservation, and more efficient use of existing technologies.

(x) *Reliability***:** Maintain reliability of the electricity grid and improve it wherever practical, including reducing the impact, frequency and duration of outages.

The Board may consider such other factors as are relevant in the circumstances.

5. In furtherance of the government's policy objective as described in item (iii) of paragraph 4 above, the Board shall undertake a consultation process with licensed electricity distributors and other relevant stakeholders for the purpose of developing a regional or otherwise coordinated approach to the planning and implementation of smart grid activities by licensed electricity distributors that promotes coordination

amongst them having regard to, among other things, cost-effective outcomes.

6. Nothing in paragraph 5 shall be construed as limiting the ability of licensed electricity distributors to engage in smart grid activities or the authority or discretion of the Board in exercising its responsibilities in relation to the smart grid activities of licensed electricity distributors pending the development of the regional or coordinated approach referred to in that paragraph.

APPENDIX “A”

CUSTOMER CONTROL OBJECTIVES

For the purpose of providing the customer with increased information and tools to promote conservation of electricity, which will “expand opportunities to provide demand response, price information and load control to electricity customers”, in accordance with subsection 2(1.3)(b) of the Electricity Act, the following objectives apply:

- **ACCESS:** Enable access to data by customer authorized parties who can provide customer value and enhance a customer’s ability to manage consumption and home energy systems.

- **VISIBILITY:** Improve visibility of information, to and by customers, which can benefit the customer and the electricity system, such as electricity consumption, generation characteristics, and commodity price.

- **CONTROL:** Enable consumers to better control their consumption of electricity in order to facilitate active, simple, and consumer-friendly participation in conservation and load management.

- **PARTICIPATION IN RENEWABLE GENERATION:** Provide consumers with opportunities to provide services back to the electricity grid such as small-scale renewable generation and storage.

- **CUSTOMER CHOICE:** Enable improved channels through which customers can interact with electricity service providers, and enable more customer choice.

- **EDUCATION:** Actively educate consumers about opportunities for their involvement in generation and conservation associated with a smarter grid, and present customers with easily understood material that explains how to increase their participation in the smart grid and the benefits thereof.

APPENDIX “B”

POWER SYSTEM FLEXIBILITY OBJECTIVES

For the purpose of “enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system,” , in accordance with subsection 2(1.3)(a) of the Electricity Act, and recognizing the need for flexibility on the integrated power system, the following objectives apply:

- **DISTRIBUTED RENEWABLE GENERATION:** Enable a flexible distribution system infrastructure that promotes increased levels of distributed renewable generation.

- **VISIBILITY:** Improve network visibility of grid conditions for grid operations where a demonstrated need exists or will exist, including the siting and operating of distributed renewable generation.

- **CONTROL AND AUTOMATION:** Enable improved control and automation on the electricity grid where needed to promote distributed renewable generation. To the extent practical, move toward distribution automation such as a self-healing and self-correcting grid infrastructure to automatically anticipate and respond to system disturbances for faster restoration.

- **QUALITY:** Maintain the quality of power delivered by the grid, and improve it wherever practical.

APPENDIX "C"

ADAPTIVE INFRASTRUCTURE OBJECTIVES

For the purpose of "accommodating the use of emerging, innovative and energy-saving technologies and system control applications," in accordance with subsection 2(1.3)(c) of the Electricity Act, the following objectives apply:

- **FLEXIBILITY:** Provide flexibility within smart grid implementation to support future innovative applications, such as electric vehicles and energy storage.

- **FORWARD COMPATIBILITY:** Protect against technology lock-in to minimize stranded assets and investments and incorporate principles of modularity, scalability and extensibility into smart grid planning.

- **ENCOURAGE INNOVATION:** Nest within smart grid infrastructure planning and development the ability to adapt to and actively encourage innovation in technologies, energy services and investment / business models.

- **MAINTAIN PULSE ON INNOVATION:** Encourage information sharing, relating to innovation and the smart grid, and ensure Ontario is aware of best practices and innovations in Canada and around the world.

Appendix AA7
Leidos Preliminary Design

1. Utility Distribution Microgrid: Volt/VAR Management (VVM)

2. Utility Distribution Microgrid: Distribution Automation

3. Utility Distribution Microgrid: AMI Integration

leidos

Leidos Engineering, LLC

Utility Distribution Microgrid: Volt/VAR Management (VVM)

Preliminary Design

Energizing Co.

PUC Distribution, Sault Ste. Marie, ON

Leidos
10/17/2014

leidos

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1. Background

This document was prepared by Leidos Engineering, LLC for Energizing Co. in support of Energizing Co.'s Utility Distribution Microgrid (UDM) project in Sault Ste. Marie, Ontario, Canada. Energizing Co. has a contract with the local electric utility, PUC, to perform a detailed feasibility analysis and preliminary design for smart grid technologies, including microgrids, distribution automation systems, Volt/VAR management systems, Outage Management Systems, Demand response and AMI enhancements. Energizing Co. has retained Leidos Engineering to support the feasibility and preliminary design tasks of this project.

2. Overview

This document summarizes preliminary design results for the Volt/VAR Management (VVM) portion of the UDM project. The proposed VVM system will provide significant benefits in the areas of conservation, efficiency, and peak reduction. None of the existing 34.5/12.5 kV transformers in PUC's system have operational load-tap changing (LTC) controls; thus, PUC does not have the capability to dynamically regulate distribution system voltage.

Most of the 34.5 kV/12.5 kV substation transformers in the PUC system are approaching the end of their lifetime and will need to be replaced in the coming years. Based on a request from PUC, Leidos conducted feasibility analyses and developed VVM recommendations with additional consideration to the aged utility infrastructure. The methodology followed to select substations and calculate benefits will be described in Sections 4 and 5.

To support feasibility analysis and preliminary design efforts, Leidos developed a distribution network model in CYME using PUC GIS data provided by the Sault Ste. Marie Innovation Center (SSMIC). The model was used to run simulations and perform analysis for the technologies studied.

In summary, VVM substation recommendations include four substation rebuilds at Subs 11, 16, 20, and 1; six transformer replacements at Sub 2, 18 and 19; and two busbar regulator installations at Sub 13. In addition, there are feeder improvements that are covered in detail in the report.

3. Volt VAR Management Concept

VVM systems typically operate to regulate distribution system voltage profiles within allowable limits and minimize reactive power flows. Operating at the lower end of voltage limits provides conservation, peak reduction and efficiency benefits. In general, performing certain system improvements on feeders such as phase balancing, re-conductoring and capacitor bank additions prior to or in conjunction with VVM can flatten the voltage profile, allowing more room for voltage regulation.

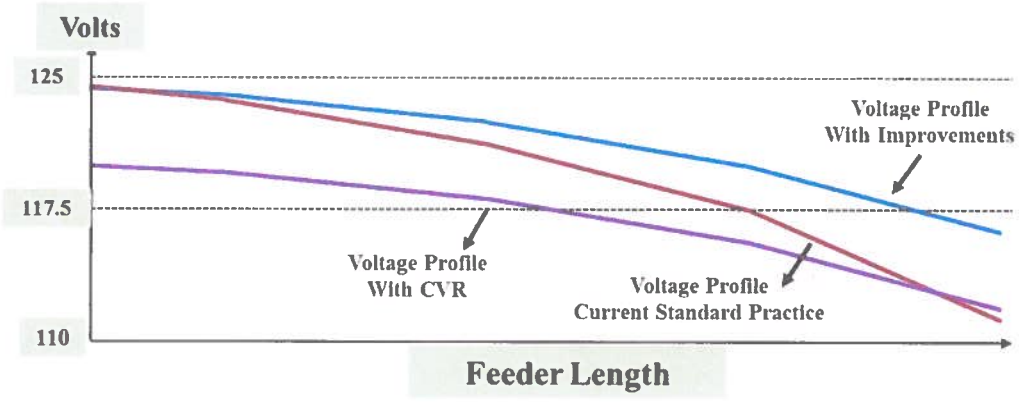

Figure 1. Distribution Voltage Profile

VVM systems can be designed in many ways. The most common six design options are listed below with their important features listed. Leidos recommends Design Option 6 for PUC.

Design Option 1. Fixed Lower Voltage Setting

- Distributed control
- No communication
- Substation/line voltage constant

Design Option 2. Line Drop Compensation

- Distributed control
- No communication
- Setting changes as load varies to avoid violations at the end of the line

Design Option 3. End-Of-Line Feedback

- Distributed control
- Requires communication system
- EOL meter communicates with LCT/regulator to change settings

Design Option 4. End-Of-Line Feedback

- Centralized control
- Requires communication system
- EOL meter communicates with centralized software to change settings

Design Option 5. AMI Feedback

- Centralized control
- Requires communication system
- Centralized software communicates with AMI system to change settings

*Design Option 6. Volt/VAR Optimization w/AMI – **RECOMMENDED OPTION FOR PUC***

- Centralized control
- Requires communication system
- AMI data used in optimization
- Model-based centralized software calculates optimal settings

4. VVM Design Methodology

a. Preliminary Design Methodology

Figure 2 illustrates the design and cost-benefit analysis methodology. The first step in the process was a review of PUC's Advanced Metering Infrastructure (AMI) and transformer data to identify potential substations and feeders for VVM deployment. Leidos also incorporated PUC's operational insight to finalize the selection of VVM substations/feeders.

The next step included load flow simulations on VVM feeders to propose the system improvements such as phase balancing, capacitor bank placements, re-conductoring, and in-line voltage regulator placements. Load flow simulations were carried out again on the improved case to determine the voltage reduction capability of each feeder, and to calculate the energy and demand reductions due to the voltage reduction. Finally, the Leidos Benefit Monetization Tool was used to monetize system benefits for the entire VVM solution.

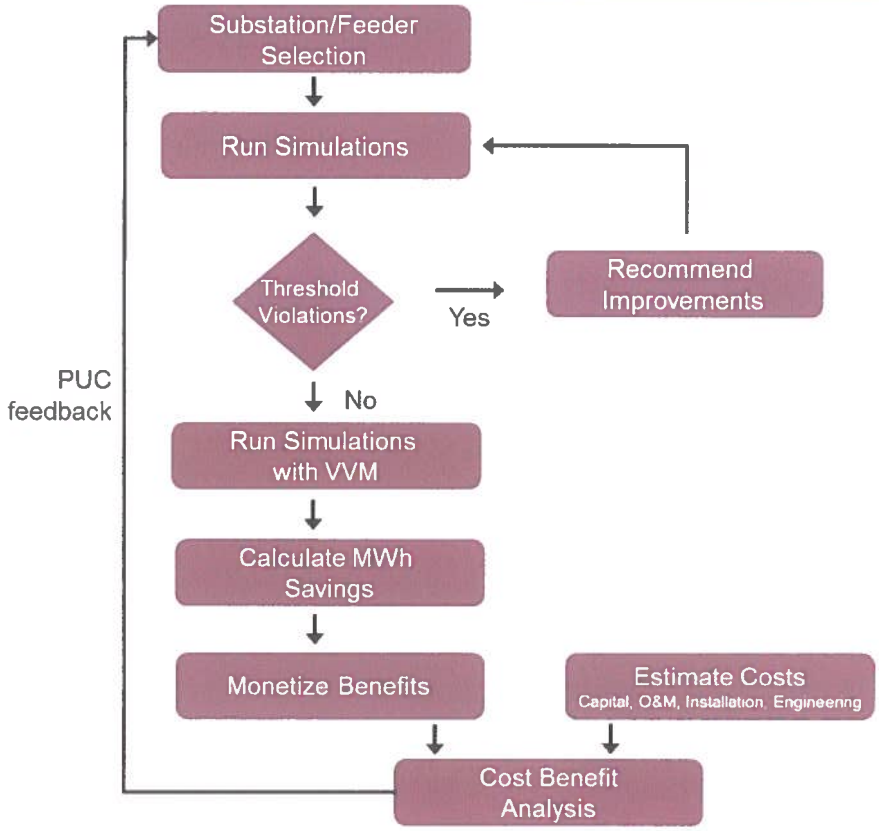

Figure 2. VVM Design Methodology

b. Substation/Feeder Selection

Substation transformer and AMI data was used to determine potential substations for VVM deployment. Transformer ages were obtained from the substation transformer database, and feeder End-of-the-Line (EOL) meter average voltages were captured from AMI data provided by PUC.

An indexing mechanism illustrated in Figure 3 was used for the selection process. An index (Index_Age) value is given to each substation transformer based on its age. The oldest transformer is given the highest index value and the newest transformer is given the lowest index value. Another index (Index_Voltage) is given to each feeder based on its EOL meter average voltage. The highest index value is given to the feeder with the highest EOL average voltage and the lowest index value is given to the feeder with the lowest EOL average voltage. The final index, Index_Total, is computed by sum-product of all the individual indexes (Index_Age, Index_Voltage) with their respective weights (W_Age, W_Voltage) for each substation transformer. Finally, all substation transformers are ranked according to the normalized value of Index_Total.

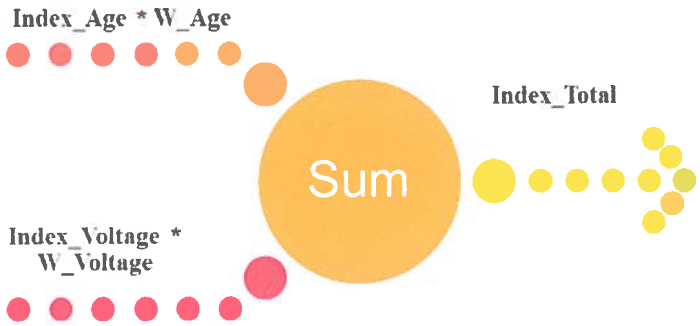

Figure 3. Indexing Mechanism to Rank Substation Transformers for VVM

Figure 4 lists the substation transformers that are ranked according to the mechanism explained above with a different set of weights (W_Age and W_Voltage). Leidos selected the following substations to include in the VVM project by using the ranking given in Figure 4 and feedback from PUC.

Substation	Base or Extended
16	Base Case
11	
2	
13	
18	Extended Case
19	
1	
20	

Substations 16, 11, 2, and 13 were considered in the initial project scope, defined as the Base Case. Substations 18, 19, 1 and 20 were later added to the project scope, and together with the Base Case stations comprise the Extended Case. The remainder of this document describes analysis and design results for the *Extended Case.*

% W_Age	100%	75%	50%	25%
% W_Voltage	0%	25%	50%	75%
#1	18-T2	18-T2	18-T2	13-T2
#2	16-T2	16-T1	16-T1	18-T2
#3	16-T1	16-T2	16-T2	1-T1
#4	18-T1	19-T1	1-T1	16-T1
#5	19-T1	18-T1	19-T1	20-T2
#6	2-T3	2-T4	2-T4	1-T2
#7	2-T4	11-T3	11-T3	13-T1
#8	11-T3	11-T4	13-T2	16-T2
#9	12-T4	12-T4	18-T1	20-T1
#10	19-T2	2-T3	20-T2	2-T4
#11	11-T4	19-T2	11-T4	11-T3
#12	4-T1	1-T1	12-T4	19-T1
#13	12-T3	20-T2	20-T1	11-T4
#14	20-T2	20-T1	1-T2	12-T4
#15	20-T1	12-T3	2-T3	18-T1
#16	1-T1	13-T2	13-T1	21-T1
#17	21-T1	4-T1	19-T2	21-T2
#18	1-T2	1-T2	12-T3	12-T3
#19	13-T1	13-T1	21-T1	2-T3
#20	13-T2	21-T1	21-T2	19-T2
#21	21-T2	21-T2	4-T1	4-T1
#22	15-T1	15-T1	15-T1	15-T1
#23	15-T2	15-T2	15-T2	15-T2

Figure 4. VVM Substation Transformer Ranking

5. VVM Design Recommendations

VVM recommendations include a centralized VVM software solution as well as substation and feeder upgrades. Substation and feeder recommendations are summarized below in Figure 5 and Figure 6. Note that four substation rebuilds are recommended to be modeled after the recently completed substation 10 rebuild. This was based on guidance from PUC management.

	Sub 16	Complete rebuild similar to Sub 10
	Sub 11	Complete rebuild similar to Sub 10
	Sub 2	LTC transformers only
	Sub 13	Add two busbar regulators
	Sub 18	LTC transformers only
	Sub 19	LTC transformers only
	Sub 20	Complete rebuild similar to Sub 10
	Sub 1	Complete rebuild similar to Sub 10

Figure 5. VVM Substation Recommendations

Feeder	Improvements	
16-01	Rephasing: Section ID: OH7038 from A to C	Rephasing: Section ID: OH66911 from A to C
16-02	None	
16-03	Place 200 kVAR/phase fixed cap bank at ID: 25293_	
16-04	Rephasing: Section ID: OH8252 from C to A	Install 200kVAR/phase fixed cap bank at OH59880
11-11	Rephasing: Section ID: OH803 from A to C	
11-12	Rephasing: Section ID: OH6032 from B to C	
11-13	None	
11-14	None	
2-13	Rephasing: Section ID: 25727_ from C to A	
2-14	None	
2-15	Rephasing: Section ID: 26568_ from A to C	Rephasing: Section ID: 26579_ from A to B
2-16	Rephasing: Section ID: 34876_ from C to A	Rephasing: Section ID: 34784_ from C to B
18-01	Place 167kVA/phase regulator at ID: 20381_ with 125V Setpoint	Rephasing: Section ID: 19437_ from C to B
18-02	Rephasing: Section ID: OH6098 from B to C	
18-03	Rephasing: Section ID: OH5641 from C to B and OH6926 from B to A	
18-04	Place 167kVA/phase regulator at ID: 23885_ with 120 V set point	
19-01	None	
19-02	None	
19-03	None	
19-04	None	
13-01	None	
13-02	None	
13-03	None	
13-04	None	
20-01	Rephasing Section ID: UG28407 from B to C	
20-02	None	
20-03	None	
20-04	None	
1-11	None	
1-12	Rephasing: Section ID 27075_ from A to C	Rephasing: Section ID 27253_ from A to C
1-13	None	
1-14	Rephasing: Section ID OH2154 from B to C	

Figure 6. VVM Feeder Improvement Recommendations

a. System Architecture

The proposed VVM system architecture is shown in Figure 7, along with the proposed Distribution Automation architecture. The centralized intelligence of the VVM system will reside in the PUC Control Room, provided by the Survalent VVO system. This system will interface with GIS, MDM, and SCADA systems to exchange information. The distributed intelligence of the VVM system will be provided by Load-Tap Changing (LTC) controllers at substations.

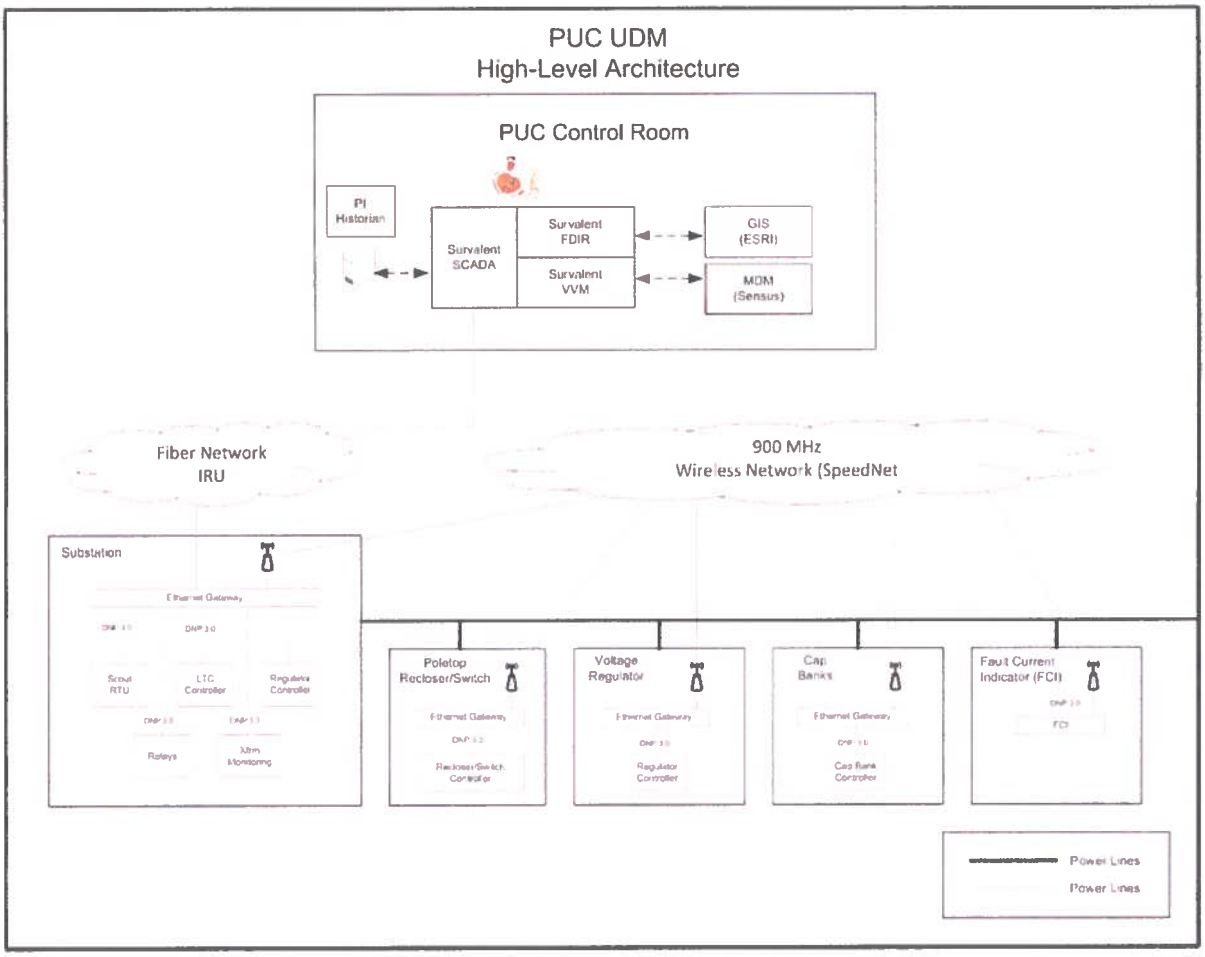

Figure 7. UDM System Architecture

b. VVM Software

The VVM software is a critical component of the proposed VVM solution. The major function of VVM Software is to calculate optimal settings for voltage and reactive power control devices, including LTC controllers, regulators and cap banks. AMI and GIS interfaces will be built to the existing software. AMI data will be used by VVM Software to ensure that optimal set-points are calculated without violating any constraints. A GIS interface will enable network model updates with the latest configuration data.

PUC currently has a Survalent SCADA system that is primarily used to monitor and control substation equipment. Due to the relative cost that would be incurred from switching to a different vendor SCADA and VVM platform, and since PUC is generally content with the capabilities and performance of the Survalent system, we recommend deploying Survalent's VVM solution, LaZer 3[1]. LaZer 3 would be installed with a load flow module, providing a network-based solution that can handle a wider variety of system conditions than a rule-based algorithm.

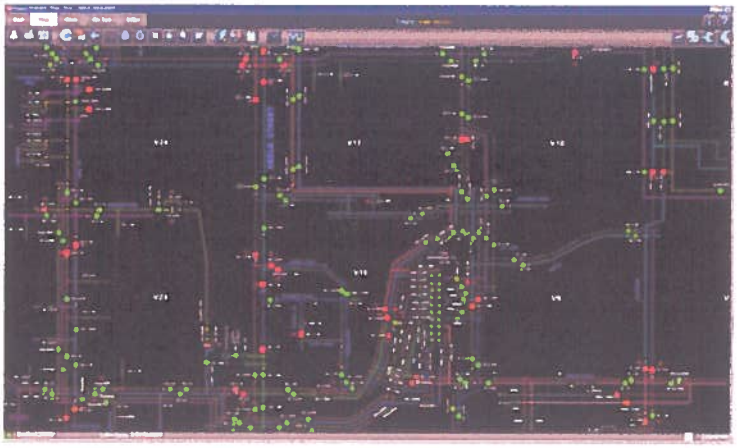

Figure 8. VVM Software

All substations that are included in the VVM program have SCADA already installed. .

Operation of the system: Real-time voltage control would be accomplished by local controllers at LTC transformers and voltage regulators. The VVM Software would process AMI data at regular intervals and determine optimal settings for LTC and regulator controllers. These settings would be automatically adjusted by the master controls software.

The VVM software allows for three operating modes: 1) Disabled, 2) Semi-automatic and 3) Full automatic.

> *Disabled Mode:* In disabled mode, VVM Software does not calculate any settings or take any actions. VVM software can be disabled for the entire system or for only select substations.
>
> *Semi-Automatic Mode*: In semi-automatic mode, the VVM Software calculates settings but does not execute any recommendations without operator approval. The operator may view VVM recommendations in the log file and initiate control actions.

[1] Survalent refers to LaZer 3 as a Volt-VAR Optimization (VVO) solution.

Full Automatic Mode: In full automatic mode, the VVM Software calculates settings and executes control actions automatically. Operators are notified of actions the system initiated and details of these actions are available for viewing in system log files.

c. LTC Controllers

LTC controllers are an important component of the VVM solution. They provide a local control capability by dynamically controlling transfer tap positions based on configured settings, keeping the secondary voltage of the transformer within the desired voltage range. The VVM solution settings will be changed by the VVM software located in PUC Control Room.

Currently, PUC does not have any operational LTC controllers. Since existing transformers in the substations are approaching the end of their lifetime, it is planned to replace existing transformers with new LTC transformers. Figure 9 lists the substations where new LTC transformers will be installed.

Sub 16	2 x LTC Transformers
Sub 11	2 x LTC Transformers
Sub 2	2 x LTC Transformers
Sub 20	2 x LTC Transformers
Sub 1	2 x LTC Transformers
Sub 18	2 x LTC Transformers
Sub 19	2 x LTC Transformers

Figure 9. Substations with LTC Transformers

d. Voltage Regulators

Voltage regulators are used to regulate distribution system voltage. Two pad-mounted voltage regulators, as shown in Figure 10 are recommended to regulate the busbar voltage at Substation 13. These busbar regulators will be connected on the low side of each substation transformer. There are two feeders connected to each busbar in Substation 13. At each busbar, three single-phase 500 kVA pad mounted regulators will be installed.

Figure 10. Busbar Regulators

e. Capacitor Banks

Capacitor banks reduce reactive power flows and improve power factor. Reduced reactive power flow results in a better voltage profile and reduced losses. As a result of our analysis, new capacitor banks are proposed (see Figure 6). These capacitor banks will be monitored and controlled by the VVM Software.

f. Communication System

PUC currently has fiber and/or radio communications to all substations that are included in the VVM design (see Figure 12 for communication infrastructure for all substations). PUC has historically used GE's MDS radio for SCADA communication. However, a fiber ring is being installed at all DA substations except Sub 16 and Sub 18. Communication in these substations is currently provided by 900 MHz MDS radios. When Substation 16 is rebuilt, the station will have fiber communication as the fiber cables are already available outside of the substation. There is no near-term plan to pull fiber cable to Sub 18; therefore, this substation will continue to communicate via MDS radios.

Location	Address	Fiber Connected	MDS Radio
Substation 2	894 Wellington St E	X	X
Substation 10	87 Blake Ave	X	
Substation 19	885 McNabb St	X	X
Substation 20	500 2nd Line E	X	X
Substation 11	8 Hare Ave	X	X
Substation 13	760 Shafer Ave	X	
Substation 1	270 Queen St E	X	X
Substation 21	3835 Queen St E	X	
Substation 12	288 Bennett Blvd	X	X
Substation 16	601 3rd Line E		X
Substation 18	855 Goulais Ave		X
Substation 5	261 Lake St		X
Substation 15	183 Spring St		X
Substation 14	143 Willoughby St		X
Substation 4	140 MacDonald Ave		

Figure 11: Existing Communication System at Substations

900 MHz SpeedNet radios are recommended for communication to new devices, including reclosers, switches, and regulators. PUC staff has experience with these devices at existing 34.5 kV switch locations, and PUC thus expressed a preference for their use. It is also noted that extra repeaters are needed to overcome line-of-sight issues for certain locations. Leidos included extra repeaters in the materials list for this purpose.

6. VVM Benefits

Leidos calculated three main benefits for the VVM project:

(1) Line Loss Reduction – Line losses are the I^2R losses on the distribution system. These losses will be reduced by the VVM system as a result of reduced demand.

(2) No-Load Loss Reduction – No-load losses are transformer core losses and are a function of actual voltage on the transformers. Since the voltage on distribution transformers will be reduced by VVM, no-load losses will also be reduced.

(3) Customer Energy/Demand Reduction – Customer Demand Reduction is realized due to the fact that total demand decreases as the voltage is reduced at the customer meter. These benefits are calculated for each feeder and will be presented in the following figures.

As described in Section 5, Leidos recommends certain feeder improvements to achieve more levelized feeder voltage profiles. These improvements are expected to further increase the benefits of the VVM system. The details of these recommendations are presented in the following benefits figures and Appendix 5.

Voltage Optimization (VO) is the application of voltage regulation on VVM feeders. PostVO Benefits is defined as the benefits that are observed after the VO is implemented. VO can be applied with or without the improvements that are recommended. The improvements enable further regulation and, therefore, result in larger benefits. The figures below show benefit calculation results for PostVo Benefits with and without improvements. The difference between these two will show how much additional benefit is obtained with the help of recommended improvements.

Substation Bus Voltage Change is the average percent voltage reduction that can be applied at a specific Voltage Control Zone. The amount of voltage reduction at the LTC transformer or at the regulator is limited with the end-of-line voltage because minimum allowed voltage at the customer meter is 110V for PUC. Substation Bus Voltage Change is determined with the help of load flow simulations for each control zone.

Another important factor in calculating the Customer Demand Reduction is the CVR Factor. CVR Factor is a scalar quantity that is defined as the percent demand reduction for every percent of voltage reduction. CVR factor heavily depends on the load mix as each type of load responds in a different way for the reduced voltage. Based on the Leidos past project experience, CVR factor can be in the range of 0.3-1. Considering the electric heating loads and the climate region of PUC's service territory, Leidos used a CVR factor of 0.5 for benefit calculations. Though it is possible and even likely that the actual CVR factor will be different than assumed, we feel this is a conservative number based on our prior experience analyzing and designing VVM solutions. After the VVM system is deployed, the CVR factor can be refined through a testing and measurement process whereby system voltage is lowered and raised and load impact measured. This verification process would help to determine how much load is reduced with a modified voltage profile. Final kW and kWh benefit estimates would have to be adjusted with the actual *measured* CVR factor.

As mentioned in Section 4.a., several load flow simulations were carried out to derive the demand/energy reduction benefits due to VVM. There were a total of three sets of load flow simulations conducted that are listed below.

- **Base Case:** In this step, load flow simulations were performed at average loading scenario on the base case feeders without any feeder improvements. This provided an understanding of the base case situation and revealed any set violations in power factor, load balancing, and feeder EOL voltages. Leidos recommends several improvements such as re-phasing, re-conductoring, placing capacitor banks, and placing in-line voltage regulators that will address the system violations mentioned above.

- **Pre-VVM Case:** In this step, the load flow simulations are performed at average loading scenario on the base case feeders with the improvements to check if the existing system violations were cleared. Once confirmed, the voltage reduction capability of each feeder was determined using the load flow simulations.

- **Post VO Case:** In this step, the load flow simulations were carried out at average loading scenario by reducing the voltage at the substation bus. These simulations were carried out for two sets of models, one with the improvements and the other without improvements.

The load flow results from all the above sets of load flow simulations were entered in an Excel-based tool to compute the VVM benefits such as energy Savings (MWh), line loss reductions (MWh), and transformer no-load loss reductions (MWh) for two different feeder scenarios, one with the suggested improvements and the other without improvements. Simulation results are used as an input in the tool and VVM benefits are calculated with additional inputs that can be directly entered into the spreadsheet. In general, the VVM benefits are more for feeders with improvements than feeders without improvements. Screenshots of the tool are presented in Appendix 5.

The following figures show the VVM benefits and recommended feeder improvements for Substations 16, 11, 2, 18, 19, 13, 20, and 1 respectively. CYME snapshots of all the feeder recommendations are furnished in Appendix 6.

	Substation Transformer	Sub16-T1	Sub16-T1	Sub16-T2	Sub16-T2
	Feeder	16-01	16-02	16-03	16-04
PostVVM Benefits Without Improvements	Total Energy Savings for Project (MWh/yr)	259.7	371.6	221.7	201.0
	Substation Bus Voltage Change (%)	3.15%	3.15%	2.98%	2.98%
	Line Loss Reduction (MWh/yr)	-0.2	-0.2	-0.3	0.0
	No_Load Loss Reduction (MWh/yr)	20.3	29.3	16.6	15.0
	VVM Energy Savings (MWh/yr)	239.7	342.5	205.4	185.9
PostVVM Benefits With Improvements	Total Energy Savings for Project (MWh/yr)	370.0	507.8	339.6	296.3
	Substation Bus Voltage Change (%)	4.30%	4.30%	4.38%	4.38%
	Line Loss Reduction (MWh/yr)	14.7	-0.3	14.4	1.8
	No_Load Loss Reduction (MWh/yr)	27.3	39.4	23.9	21.6
	VVM Energy Savings (MWh/yr)	328.0	468.7	301.4	272.8
Recommended Improvements		Rephasing: Section ID: OH7038 from A to C	None	Install 200kVAR/phase fixed cap bank at 25293_	Rephasing: Section ID: OH8252 from C to A
		Rephasing: Section ID: OH66911 from A to C			Install 200kVAR/phase fixed cap bank at OH59880

Figure 12: Substation 16 VVM Benefits and Feeder Improvements

	Substation Transformer	Sub11-T3	Sub11-T3	Sub11-T4	Sub11-T4
	Feeder	11-11	11-12	11-13	11-14
PostVVM Benefits Without Improvements	Total Energy Savings for Project (MWh/yr)	239.2	373.1	293.0	334.7
	Substation Bus Voltage Change (%)	3.65%	3.65%	5.61%	5.61%
	Line Loss Reduction (MWh/yr)	-0.1	-0.2	0.0	-0.1
	No_Load Loss Reduction (MWh/yr)	14.2	14.1	16.3	21.5
	VVM Energy Savings (MWh/yr)	225.0	359.1	276.6	313.4
PostVVM Benefits With Improvements	Total Energy Savings for Project (MWh/yr)	240.5	374.4	293.0	334.7
	Substation Bus Voltage Change (%)	3.65%	3.65%	5.61%	5.61%
	Line Loss Reduction (MWh/yr)	1.2	1.1	0.0	-0.1
	No_Load Loss Reduction (MWh/yr)	14.2	14.1	16.3	21.5
	VVM Energy Savings (MWh/yr)	225.0	359.1	276.6	313.4
Recommended Improvements		Rephasing: Section ID: OH803 from A to C	Rephasing: Section ID: OH6032 from B to C	None	None

Figure 13: Substation 11 VVM Benefits and Feeder Improvements

	Substation Transformer	Sub2-T4	Sub2-T3	Sub2-T3	Sub2-T3
	Feeder	2-13	2-14	2-15	2-16
PostVVM Benefits Without Improvements	Total Energy Savings for Project (MWh/yr)	343.1	152.8	248.5	216.3
	Substation Bus Voltage Change (%)	2.50%	2.46%	2.46%	2.46%
	Line Loss Reduction (MWh/yr)	-0.6	-0.1	-0.1	-0.1
	No_Load Loss Reduction (MWh/yr)	9.3	11.7	11.4	10.4
	VVM Energy Savings (MWh/yr)	334.4	141.2	237.2	206.0
PostVVM Benefits With Improvements	Total Energy Savings for Project (MWh/yr)	344.3	157.9	259.5	225.9
	Substation Bus Voltage Change (%)	2.50%	2.54%	2.54%	2.54%
	Line Loss Reduction (MWh/yr)	0.6	-0.1	2.5	2.3
	No_Load Loss Reduction (MWh/yr)	9.3	12.1	11.8	10.7
	VVM Energy Savings (MWh/yr)	334.4	145.9	245.2	212.9
Recommended Improvements		Rephasing: Section ID: 25727_ from C to A	None	Rephasing: Section ID: 26568_ from A to C	Rephasing: Section ID: 34876_ from C to A
				Rephasing: Section ID: 26579_ from A to B	Rephasing: Section ID: 34784_ from C to B

Figure 14: Substation 2 VVM Benefits and Feeder Improvements

	Substation Transformer	Sub18-T1	Sub18-T1	Sub18-T1	Sub18-T2	Sub18-T2	Sub18-T2
	Feeder	18-01	18-01R	18-02	18-03	18-04	18-04R
PostVVM Benefits Without Improvements	Total Energy Savings for Project (MWh/yr)	0.0	0.0	278.8	224.1	44.2	90.5
	Substation Bus Voltage Change (%)	0.0	0.0	3.66%	4.97%	1.24%	1.18%
	Line Loss Reduction (MWh/yr)	0.0	0.0	1.2	0.6	-0.5	2.7
	No_Load Loss Reduction (MWh/yr)	0.0	0.0	13.9	8.7	3.3	6.4
	VVM Energy Savings (MWh/yr)	0.0	0.0	263.8	214.7	41.4	81.3
PostVVM Benefits With Improvements	Total Energy Savings for Project (MWh/yr)	0.0	0.0	279.8	226.2	80.7	242.1
	Substation Bus Voltage Change (%)	0.0	0.0	3.66%	4.97%	2.57%	3.24%
	Line Loss Reduction (MWh/yr)	0.0	0.0	2.1	2.8	-11.6	2.9
	No_Load Loss Reduction (MWh/yr)	0.0	0.0	13.9	8.7	6.8	16.9
	VVM Energy Savings (MWh/yr)	0.0	0.0	263.8	214.7	85.5	222.3
Recommended Improvements		Place a 167kVA/phase regulator at ID: 20381_ with 125V Setpoint Rephasing: Section ID: 19437_ from C to B	None	Rephasing: Section ID: OH6098 from B to C	Rephasing: Section ID: OH5641 from C to B and OH6926 from B to A	None	Place a 167kVA single phase regulator at ID: 23885_ with 120 V set point

Figure 15: Substation 18 VVM Benefits and Feeder Improvements

	Substation Transformer	Sub19-T1	Sub19-T1	Sub19-T1	Sub19-T2	Sub19-T2
	Feeder	19-01	19-01R	19-02	19-03	19-04
PostVVM Benefits Without Improvements	Total Energy Savings for Project (MWh/yr)	51.2	119.6	215.7	452.7	377.6
	Substation Bus Voltage Change (%)	1.83%	2.50%	3.75%	3.10%	3.10%
	Line Loss Reduction (MWh/yr)	2.9	-0.1	0.1	-0.4	-0.4
	No_Load Loss Reduction (MWh/yr)	1.5	21.0	16.4	24.0	14.4
	VVM Energy Savings (MWh/yr)	46.8	98.7	199.2	429.2	363.7
PostVVM Benefits With Improvements	Total Energy Savings for Project (MWh/yr)	51.2	119.6	215.7	452.7	377.6
	Substation Bus Voltage Change (%)	1.83%	2.50%	3.75%	3.10%	3.10%
	Line Loss Reduction (MWh/yr)	2.9	-0.1	0.1	-0.4	-0.4
	No_Load Loss Reduction (MWh/yr)	1.5	21.0	16.4	24.0	14.4
	VVM Energy Savings (MWh/yr)	46.8	98.7	199.2	429.2	363.7
Recommended Improvements		None	None	None	None	None

Figure 16: Substation 19 VVM Benefits and Feeder Improvements

	Substation Transformer	Sub13-T1	Sub13-T1	Sub13-T2	Sub13-T2
	Feeder	13-01	13-02	13-03	13-04
PostVVM Benefits Without Improvements	Total Energy Savings for Project (MWh/yr)	565.9	475.7	453.5	388.6
	Substation Bus Voltage Change (%)	5.51%	5.51%	4.83%	4.83%
	Line Loss Reduction (MWh/yr)	-0.1	-0.2	-0.2	-0.3
	No_Load Loss Reduction (MWh/yr)	27.2	24.0	18.4	10.2
	VVM Energy Savings (MWh/yr)	538.8	451.9	435.2	378.7
PostVVM Benefits With Improvements	Total Energy Savings for Project (MWh/yr)	565.9	475.7	453.5	388.6
	Substation Bus Voltage Change (%)	5.51%	5.51%	4.83%	4.83%
	Line Loss Reduction (MWh/yr)	-0.1	-0.2	-0.2	-0.3
	No_Load Loss Reduction (MWh/yr)	27.2	24.0	18.4	10.2
	VVM Energy Savings (MWh/yr)	538.8	451.9	435.2	378.7
Recommended Improvements		None	None	None	None

Figure 17: Substation 13 VVM Benefits and Feeder Improvements

	Substation Transformer	Sub20-T1	Sub20-T1	Sub20-T2	Sub20-T2
	Feeder	20-01	20-02	20-03	20-04
PostVVM Benefits Without Improvements	Total Energy Savings for Project (MWh/yr)	487.0	528.8	382.6	559.5
	Substation Bus Voltage Change (%)	6.62%	6.62%	3.62%	3.62%
	Line Loss Reduction (MWh/yr)	-0.1	-0.1	-0.1	-0.9
	No_Load Loss Reduction (MWh/yr)	21.6	35.3	21.6	26.6
	VVM Energy Savings (MWh/yr)	465.5	493.6	361.0	533.7
PostVVM Benefits With Improvements	Total Energy Savings for Project (MWh/yr)	488.3	528.8	382.6	559.5
	Substation Bus Voltage Change (%)	6.62%	6.62%	3.62%	3.62%
	Line Loss Reduction (MWh/yr)	1.2	-0.1	-0.1	-0.9
	No_Load Loss Reduction (MWh/yr)	21.6	35.3	21.6	26.6
	VVM Energy Savings (MWh/yr)	465.5	493.6	361.0	533.7
Recommended Improvements		Rephasing Section ID: UG28407 from B to C	None	None	None

Figure 18: Substation-20 VVM Benefits and Feeder Improvements

	Substation Transformer	Sub1-T1	Sub1-T1	Sub1-T2	Sub1-T2
	Feeder	1-11	1-12	1-13	1-14
PostVVM Benefits Without Improvements	Total Energy Savings for Project (MWh/yr)	606.5	261.8	307.1	206.8
	Substation Bus Voltage Change (%)	4.67%	4.67%	4.67%	4.67%
	Line Loss Reduction (MWh/yr)	-0.4	-0.1	-0.1	-0.1
	No_Load Loss Reduction (MWh/yr)	29.9	18.9	29.1	8.1
	VVM Energy Savings (MWh/yr)	577.0	243.0	278.1	198.9
PostVVM Benefits With Improvements	Total Energy Savings for Project (MWh/yr)	606.5	262.0	307.1	207.5
	Substation Bus Voltage Change (%)	4.67%	4.67%	4.67%	4.67%
	Line Loss Reduction (MWh/yr)	-0.4	0.1	-0.1	0.6
	No_Load Loss Reduction (MWh/yr)	29.9	18.9	29.1	8.1
	VVM Energy Savings (MWh/yr)	577.0	243.0	278.1	198.9
Recommended Improvements		None	Rephasing: Section ID 27075_ from A to C Rephasing: Section ID 27253_ from A to C	None	Rephasing: Section ID OH2154 from B to C

Figure 19: Substation-1 VVM Benefits and Feeder Improvements

7. VVM Requirements

a. VVM Software Requirements

1. VVM software shall provide a capability to control reactive power and voltage on the distribution system in a coordinated way.
2. VVM software shall be a network-based solution that can run optimization using network parameters.
3. VVM software shall allow users to select objective functions for the VVM optimizations.
4. The operator shall be able to change the objective function from the main menu.
5. VVM objective functions shall include: Maximum Energy Conservation and Minimum Losses.
6. VVM software shall allow operators to set constraints for acceptable feeder voltage profile (upper and lower limits on line voltages), feeder load limits (upper limits on line currents), and power factor limits (at the substation and along the feeder)
7. VVM Software shall have a data interface with Sensus MDM system and utilize AMI data to determine optimal settings.
8. VVM Software shall have two operating modes: automatic mode and semi-automatic mode.
9. In automatic mode, VVM Software shall issue controls signals automatically. A notification signal shall be sent to indicate that VVM operated.
10. In semi-automatic mode, VVM Software shall develop recommendations without executing any controls. The controls shall be executed after the operator's approval.
11. Operators shall be able to enable/disable VVM system for the entire system or for voltage control zones.
12. VVM Software shall log all control actions and shall allow operators to query reports.

b. LTC Controller Requirements

To be developed as part of the substation upgrade project.

c. Regulator Requirements

To be developed as part of the substation upgrade project.

Appendix 1. Bill of Materials

Volt-VAr Management (VVM)		
	Item Description	**Qty**
1	Survalent -Volt/VAR Management Software	1
2	10/13 MVA LTC Transformers at Sub16	2
3	10/13 MVA LTC Transformers at Sub11	2
4	10/13 MVA LTC Transformers at Sub2	2
5	Busbar Regulators at Sub13	2
6	10/13 MVA LTC Transformers at Sub 1	2
7	10/13 MVA LTC Transformers at Sub 20	2
8	10/13 MVA LTC Transformers at Sub 18	2
9	10/13 MVA LTC Transformers at Sub 19	2
10	600 kVAR, Cap Bank, Fixed, 15 kV	2
11	167 kVA/Phase Feeder Regulator, 15 kV	2
12	Survalent -ESRI GIS Interface (also used for DA)	1
13	Survalent -MultiSpeak AMI Interface (also used for DA)	1
14	Survalent -Operator Training Simulator (also used for DA)	1
15	Survalent -Load Flow (also used for DA)	1
16	VVM Implementation (8 Subs, 32 feeders)	1

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Volt Var Management (VVM)		
#	Item Descrption	Qty
1	Survalent -Volt/VAR Management Software	1
2	10/13 MVA LTC Transformers at Sub16	2
3	10/13 MVA LTC Transformers at Sub11	2
4	10/13 MVA LTC Transformers at Sub2	2
5	Busbar Regulators at Sub13	2
6	10/13 MVA LTC Transformers at Sub 1	2
7	10/13 MVA LTC Transformers at Sub 20	2
8	10/13 MVA LTC Transformers at Sub 18	2
9	10/13 MVA LTC Transformers at Sub 19	2
10	600 kVAR, Cap Bank, Fixed, 15 kV	2
11	167 kVA/Phase Feeder Regulator, 15 kV	2
12	Survalent -ESRI GIS Interface (also used for DA)	1
13	Survalent -MultiSpeak AMI Interface (also used for DA)	1
14	Survalent -Operator Training Simulator (also used for DA)	1
15	Survalent -Load Flow (also used for DA)	1

Appendix 2. Scope of Services

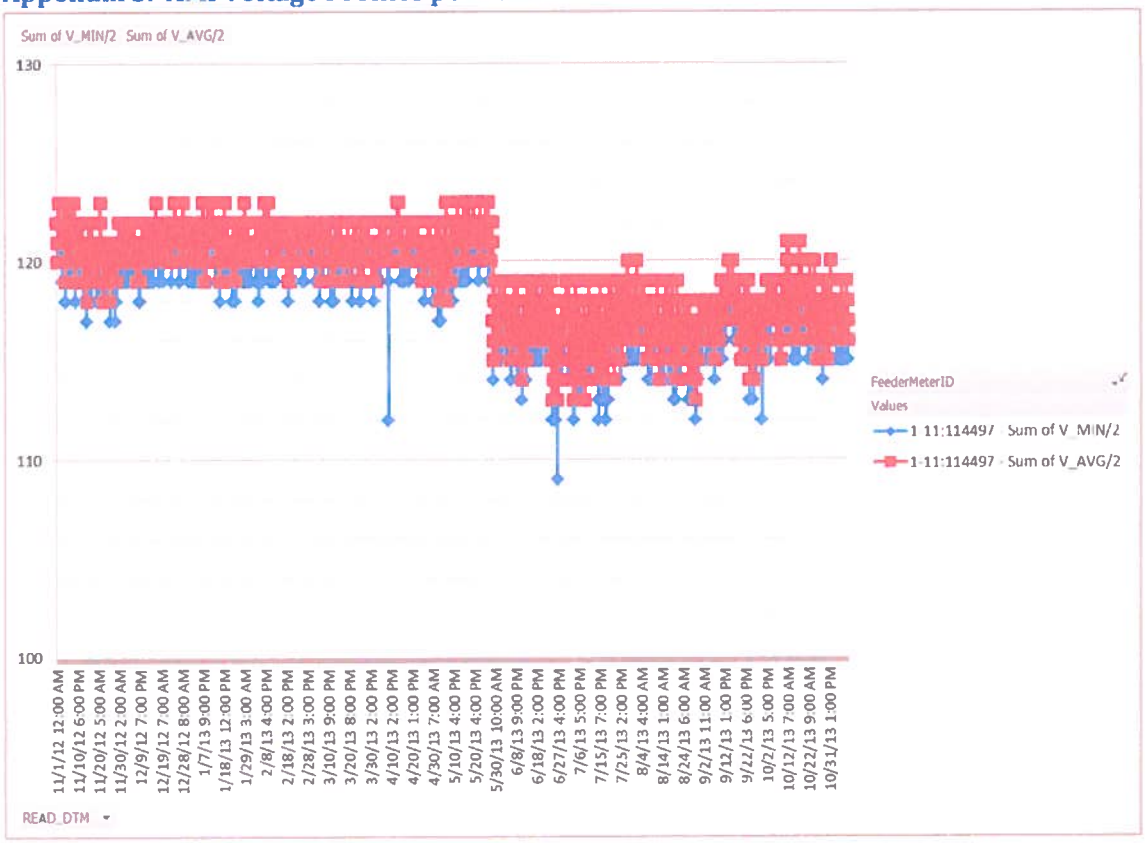
Volt/VAR Management (VVM) scope includes designing, procuring, installing and commissioning a Volt/VAR control scheme on PUC's 12.5 kV distribution system. The proposed system will be installed at 8 substations. The scope in these substations include four substation rebuilds at Subs 11, 16, 20 and 1 with 10/13 MVA LTC transformers,; six 10/13 MVA LTC transformer replacements at Sub 2, 18 and 19; and two busbar regulator installations at Sub 13.

Feeder improvement scope includes installing 200kVAR/phase fixed cap banks on feeders 16-03 and 16-04, and installing 167kVA/phase regulators on feeders 18-01 and 18-04. In addition, 17 re-phasing of feeder segments are recommended for PUC to implement.

A centralized model-based VVM software will be installed at the PUC Control Room. The interfaces with AMI and GIS will be built so that VVM system can exchange data with these systems.

Each field device will be installed with a controller to enable data exchange. SpeedNet 900 MHz communication system will be deployed to provide communication between field devices and the central software system. Field integration of all equipment will be accomplished. LTC controller and regulator settings will be determined and applied to the associated equipment. SCADA points list will be developed and data acquisition system of these points will be established.

Appendix 3. AMI Voltage Profiles per Feeder



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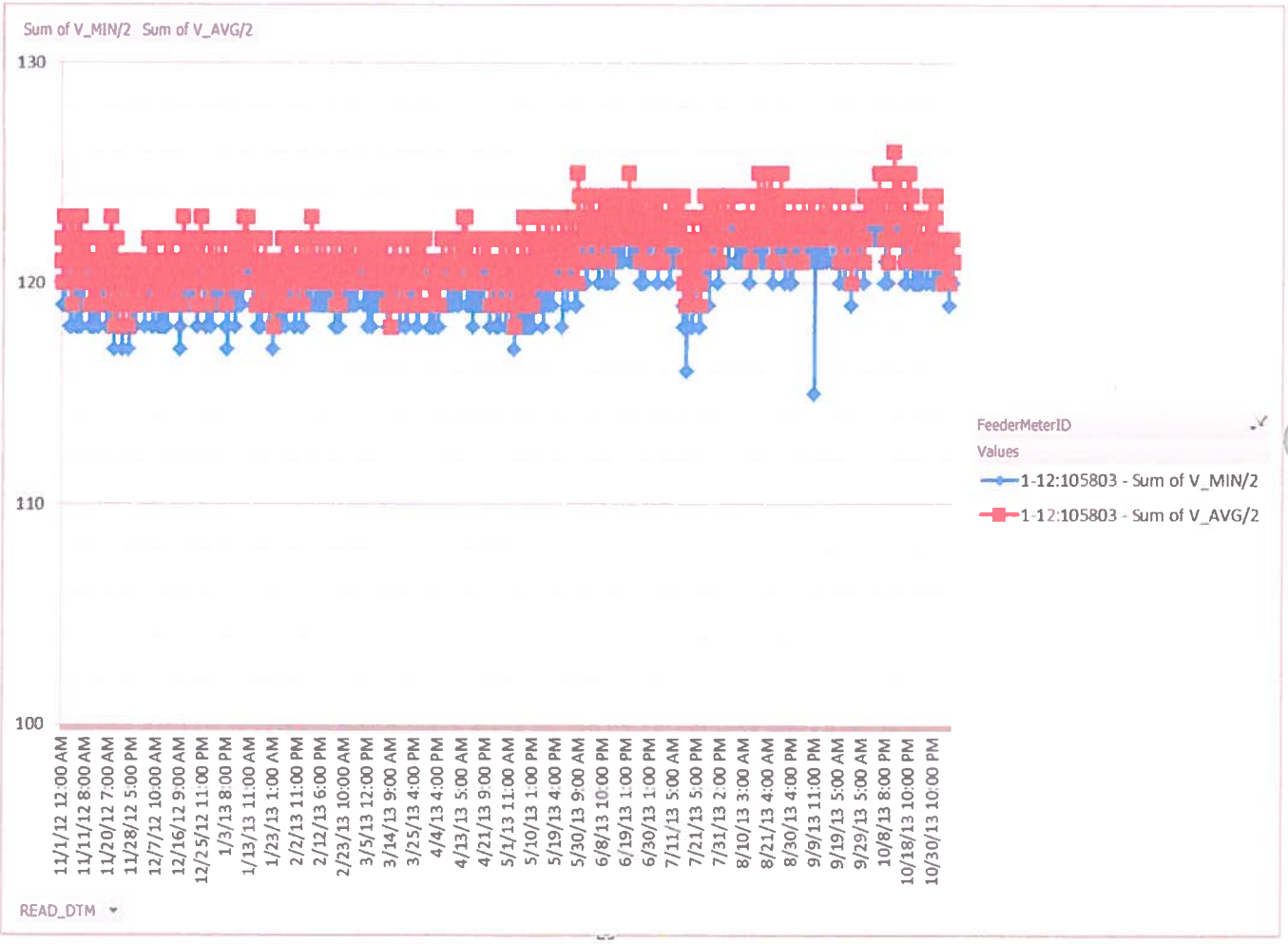
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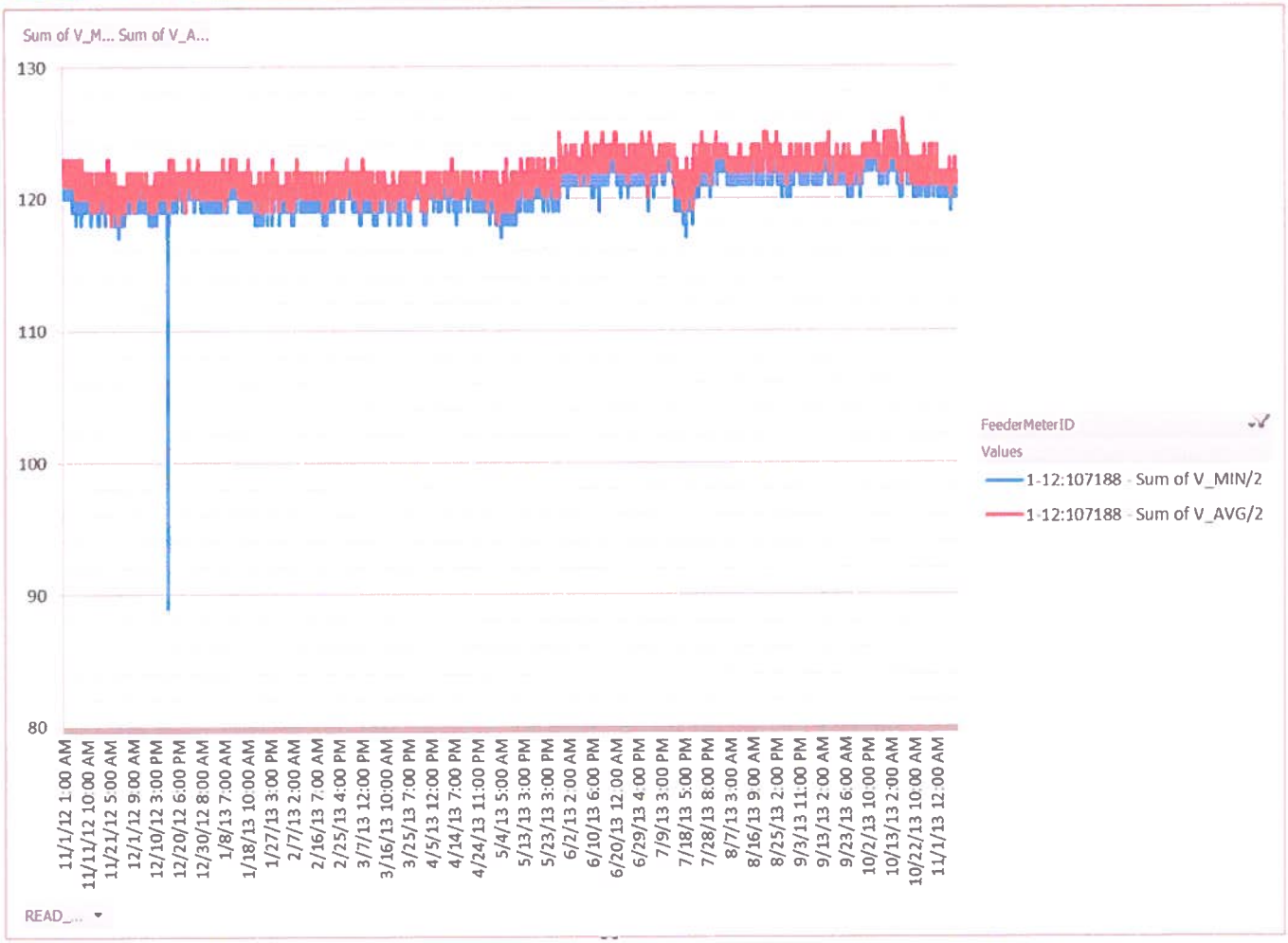
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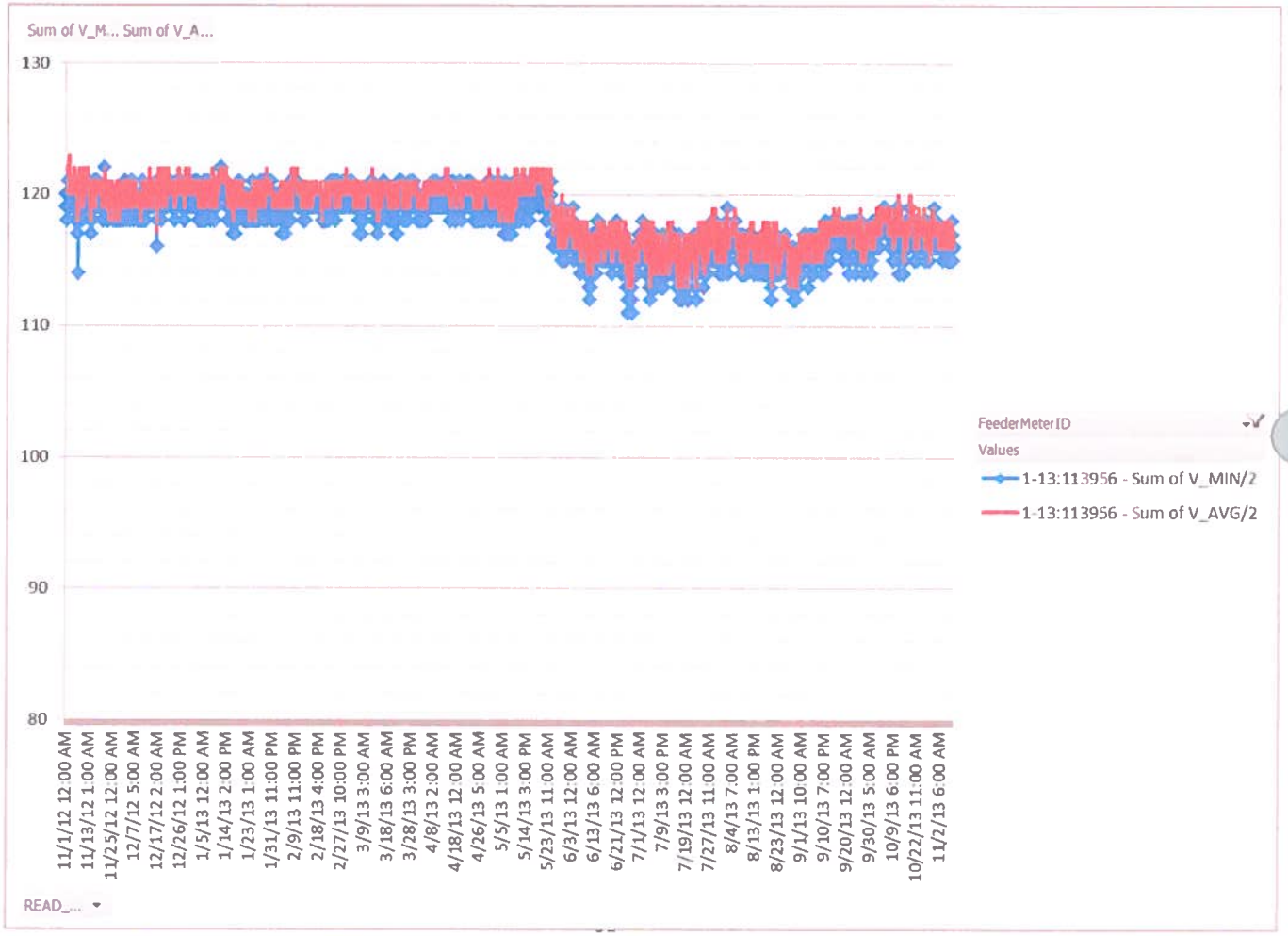
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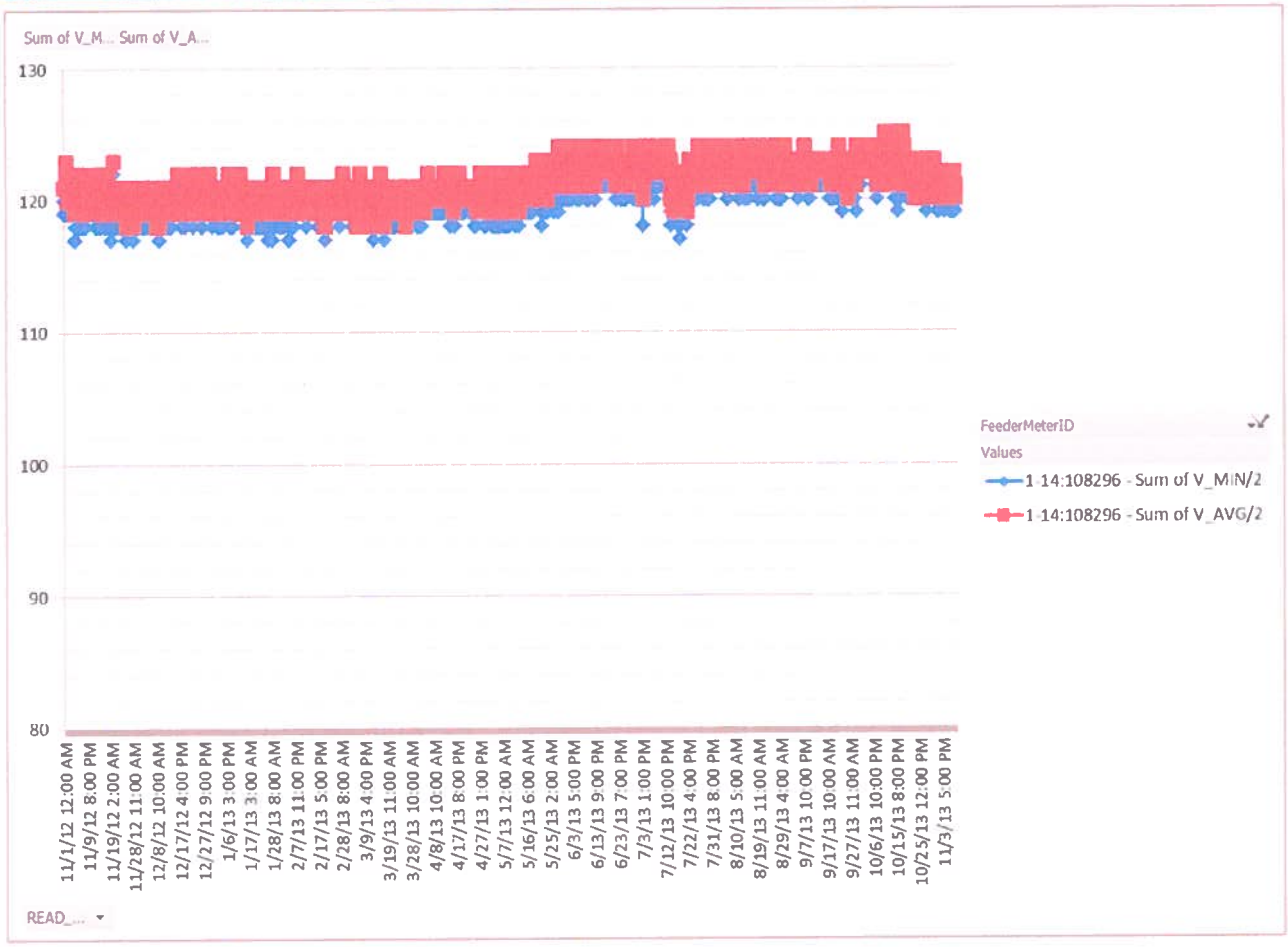
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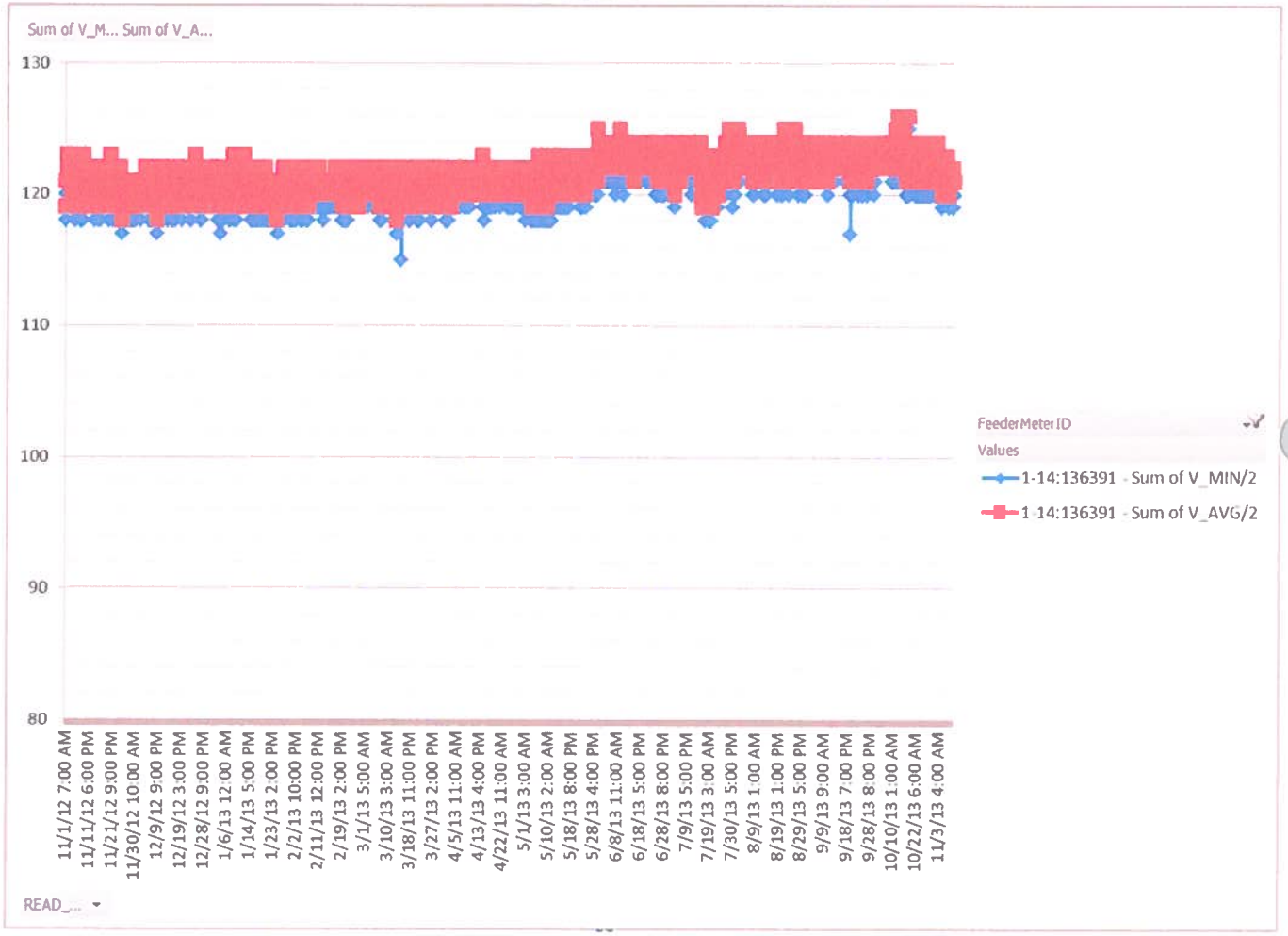
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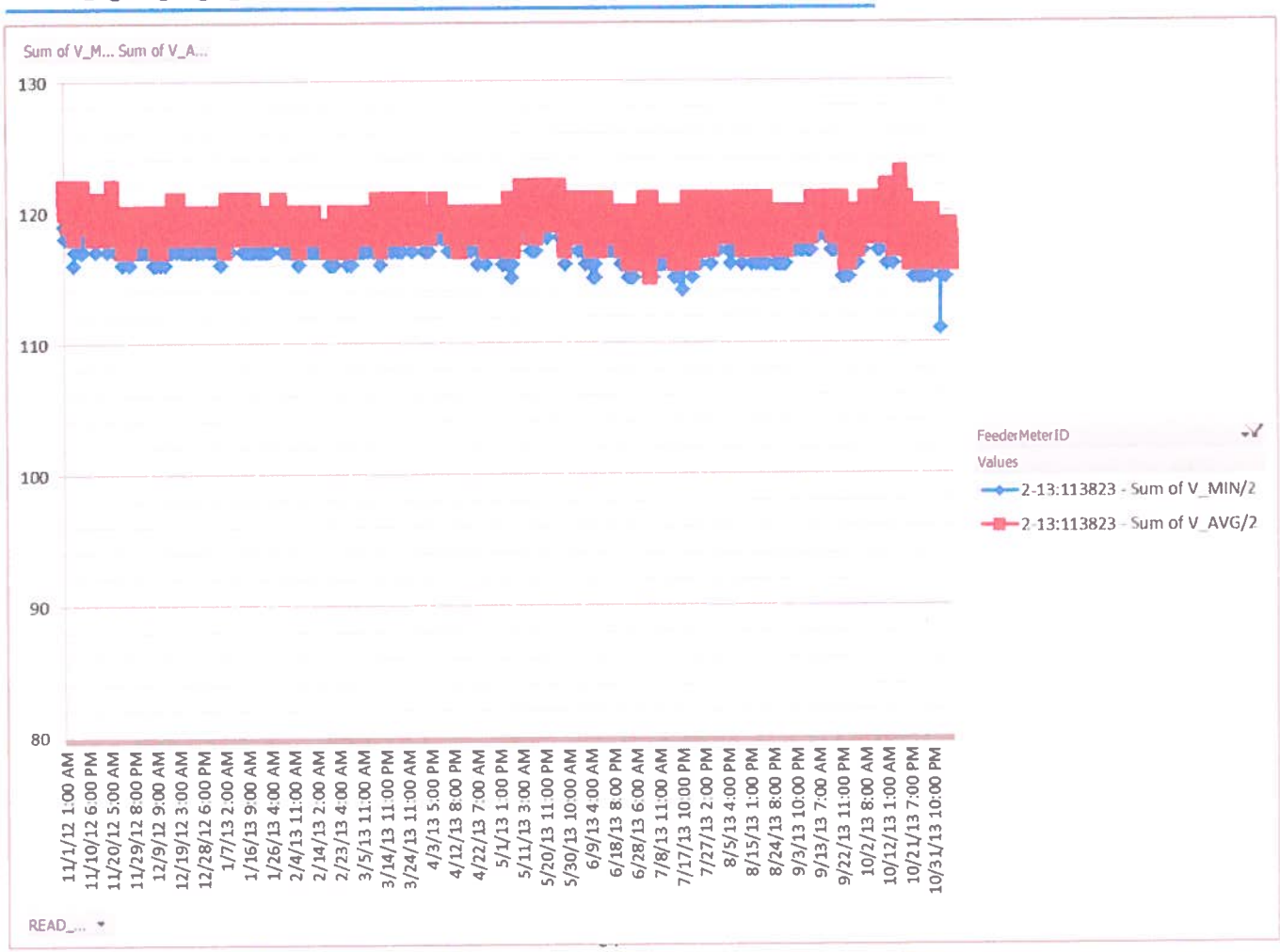
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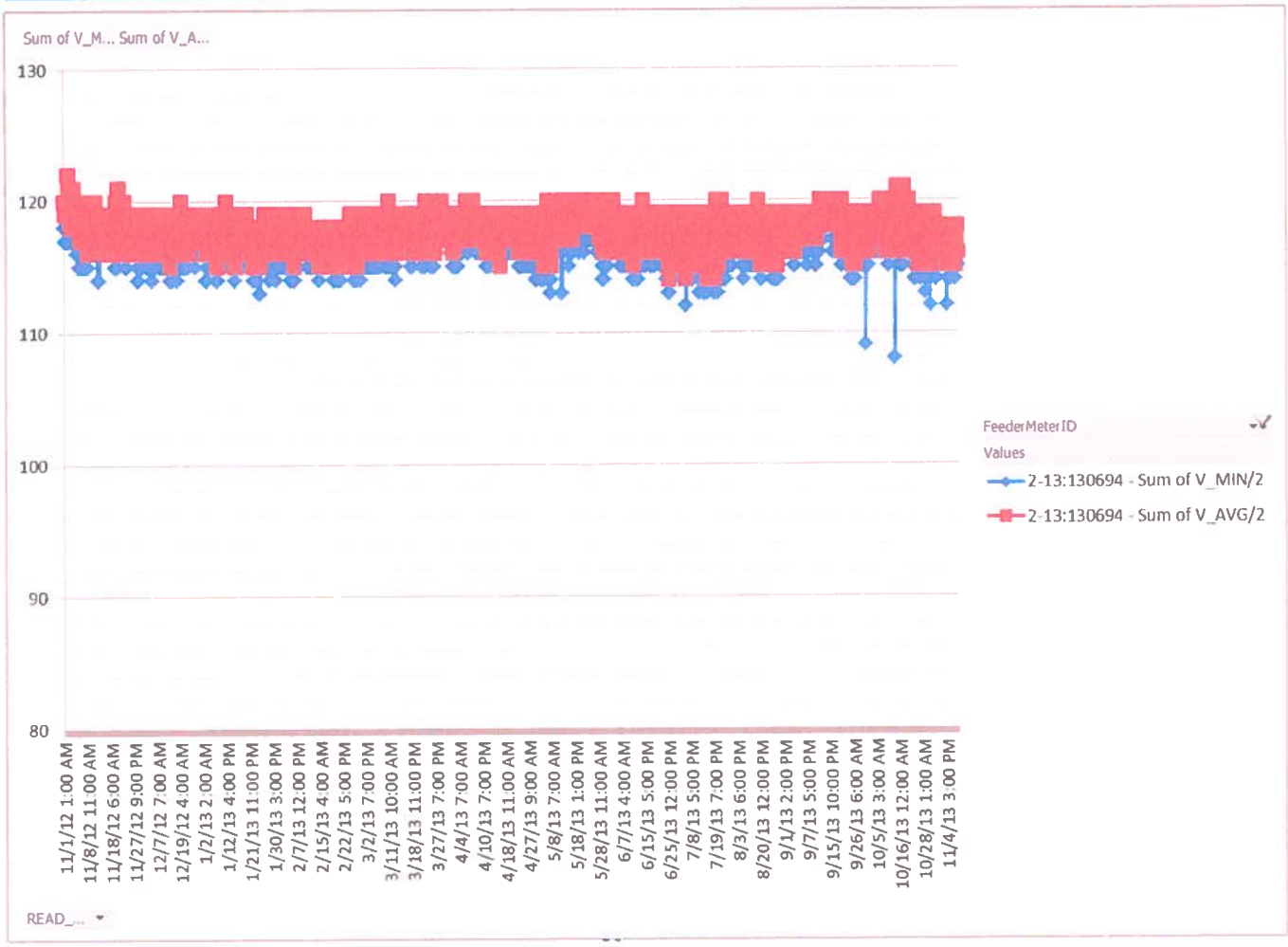
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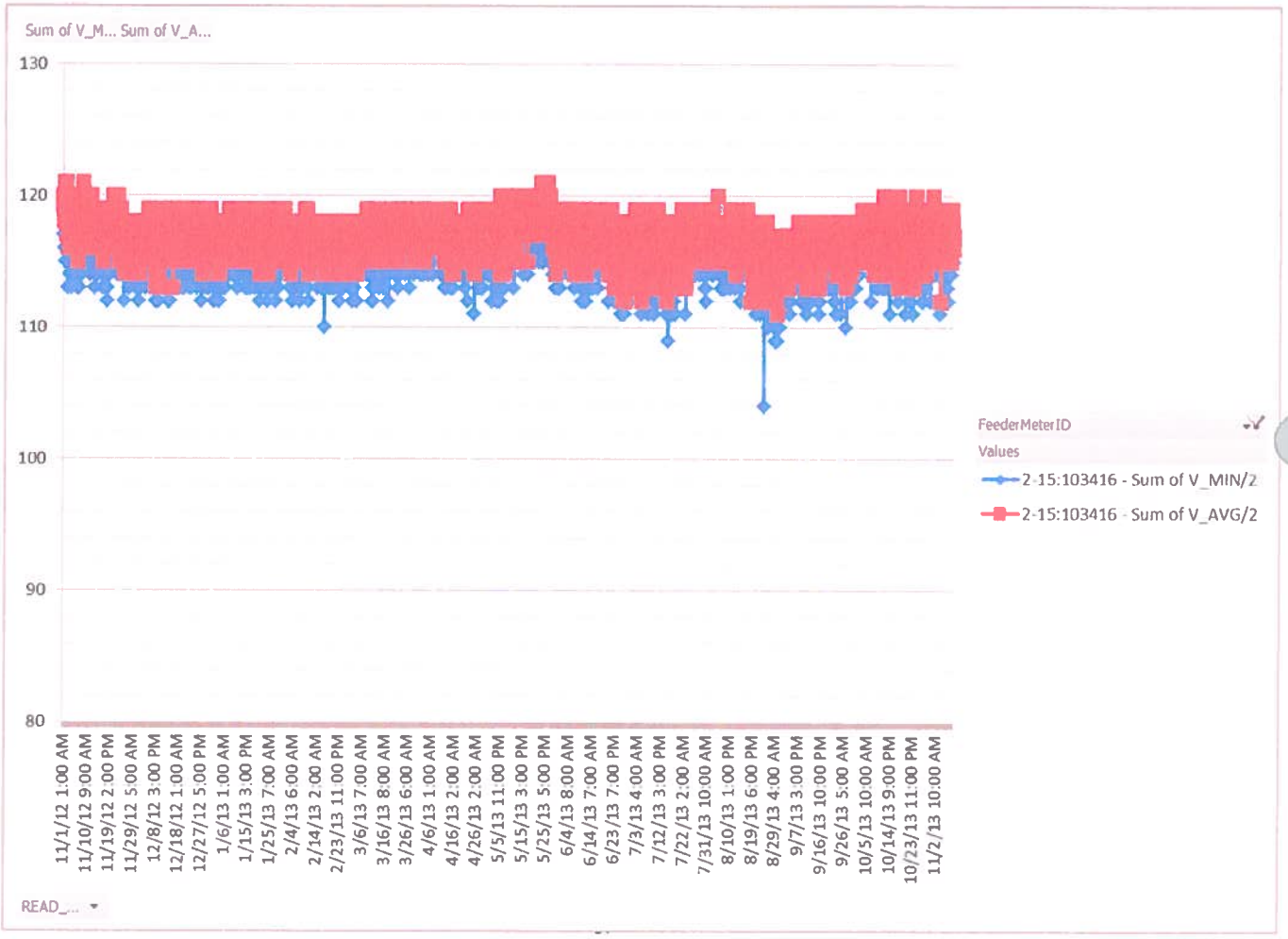
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1/31/13 12:00 AM
2/8/13 8:00 AM
2/17/13 5:00 PM
3/1/13 5:00 PM
3/10/13 8:00 AM
3/20/13 4:00 PM
3/30/13 5:00 AM
4/9/13 8:00 AM
4/18/13 5:00 AM
4/27/13 12:00 PM
5/5/13 9:00 PM
5/15/13 1:00 PM
5/25/13 9:00 PM
6/5/13 12:00 PM
6/15/13 7:00 PM
6/25/13 11:00 AM
7/5/13 5:00 AM
7/14/13 6:00 PM
7/24/13 1:00 PM
8/4/13 1:00 PM
8/16/13 2:00 PM
8/27/13 1:00 AM
9/4/13 8:00 PM
9/14/13 4:00 AM
9/23/13 5:00 PM
10/2/13 7:00 AM
10/13/13 12:00 AM
10/22/13 5:00 PM
11/1/13 7:00 AM
READ_...
FeederMeterID
Values
2-16:112647 - Sum of V_MIN/2
2-16:112647 - Sum of V_AVG/2

leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
70
60
11/1/12 2:00 AM
11/11/12 2:00 AM
11/20/12 2:00 PM
11/30/12 1:00 AM
12/9/12 12:00 PM
12/18/12 6:00 PM
12/28/12 4:00 PM
1/7/13 4:00 PM
1/17/13 4:00 AM
1/26/13 10:00 AM
2/4/13 6:00 PM
2/14/13 11:00 AM
2/24/13 4:00 PM
3/5/13 5:00 PM
3/15/13 4:00 AM
3/24/13 11:00 PM
4/4/13 9:00 PM
4/14/13 2:00 PM
4/24/13 3:00 AM
5/4/13 1:00 AM
5/13/13 8:00 PM
5/23/13 7:00 AM
6/1/13 7:00 PM
6/11/13 12:00 AM
6/20/13 9:00 AM
6/30/13 12:00 AM
7/9/13 6:00 AM
7/19/13 1:00 AM
7/28/13 11:00 AM
8/6/13 7:00 PM
8/16/13 4:00 PM
8/25/13 8:00 PM
9/4/13 2:00 PM
9/14/13 4:00 AM
9/24/13 5:00 AM
10/4/13 1:00 AM
10/13/13 3:00 PM
10/23/13 1:00 PM
11/2/13 2:00 AM
READ_...
FeederMeterID
Values
2-16:128685 - Sum of V_MIN/2
2-16:128685 - Sum of V_AVG/2

leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
70
60
11/1/12 1:00 AM
11/10/12 10:00 PM
11/20/12 3:00 PM
11/30/12 9:00 AM
12/9/12 9:00 PM
12/19/12 8:00 PM
12/29/12 6:00 PM
1/8/13 10:00 AM
1/18/13 5:00 AM
1/27/13 1:00 PM
2/6/13 3:00 AM
2/15/13 12:00 PM
2/25/13 7:00 AM
3/7/13 12:00 AM
3/16/13 6:00 PM
3/26/13 9:00 AM
4/5/13 7:00 PM
4/15/13 1:00 AM
4/24/13 4:00 PM
5/4/13 5:00 AM
5/13/13 3:00 PM
5/22/13 9:00 PM
6/1/13 6:00 AM
6/10/13 8:00 PM
6/20/13 4:00 AM
6/29/13 8:00 PM
7/9/13 4:00 PM
7/18/13 10:00 PM
7/28/13 5:00 PM
8/7/13 5:00 AM
8/16/13 1:00 PM
8/25/13 7:00 PM
9/4/13 9:00 AM
9/13/13 9:00 PM
9/23/13 2:00 PM
10/2/13 9:00 PM
10/12/13 7:00 AM
10/22/13 1:00 AM
10/31/13 7:00 AM
READ_...
FeederMeterID
Values
4-02:111818 - Sum of V_MIN/2
4-02:111818 - Sum of V_AVG/2

leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 9:00 PM
11/20/12 2:00 PM
11/30/12 4:00 AM
12/9/12 6:00 PM
12/19/12 10:00 AM
12/28/12 11:00 PM
1/7/13 10:00 AM
1/17/13 11:00 AM
1/26/13 8:00 PM
2/5/13 1:00 PM
2/15/13 8:00 AM
2/25/13 3:00 AM
3/6/13 11:00 AM
3/16/13 2:00 AM
3/25/13 12:00 PM
4/5/13 4:00 AM
4/14/13 1:00 PM
4/24/13 3:00 AM
5/3/13 4:00 PM
5/13/13 6:00 AM
5/22/13 7:00 PM
6/1/13 5:00 AM
6/10/13 11:00 PM
6/20/13 12:00 PM
6/29/13 8:00 PM
7/9/13 5:00 PM
7/18/13 10:00 PM
7/28/13 11:00 AM
8/7/13 3:00 AM
8/16/13 12:00 PM
8/25/13 3:00 PM
9/3/13 11:00 PM
9/13/13 9:00 AM
9/22/13 5:00 PM
10/2/13 6:00 AM
10/11/13 4:00 PM
10/21/13 7:00 AM
10/30/13 7:00 PM
READ_...
FeederMeterID
Values
4-02:128413 - Sum of V_MIN/2
4-02:128413 - Sum of V_AVG/2

leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 5:00 AM
11/19/12 8:00 AM
11/28/12 10:00 PM
12/8/12 1:00 PM
12/18/12 4:00 AM
12/27/12 5:00 PM
1/6/13 12:00 PM
1/15/13 4:00 PM
1/25/13 8:00 AM
2/4/13 6:00 AM
2/14/13 12:00 PM
2/24/13 1:00 PM
3/5/13 10:00 PM
3/15/13 7:00 AM
3/24/13 6:00 PM
4/4/13 6:00 AM
4/14/13 3:00 AM
4/24/13 2:00 AM
5/3/13 11:00 PM
5/13/13 5:00 AM
5/22/13 9:00 PM
6/1/13 11:00 PM
6/11/13 4:00 PM
6/21/13 5:00 AM
7/1/13 5:00 AM
7/10/13 4:00 PM
7/20/13 4:00 AM
7/29/13 9:00 PM
8/8/13 12:00 PM
8/18/13 3:00 AM
8/27/13 3:00 PM
9/5/13 9:00 PM
9/15/13 6:00 AM
9/24/13 11:00 AM
10/3/13 5:00 PM
10/13/13 3:00 AM
10/22/13 11:00 AM
11/1/13 7:00 AM
READ_...
FeederMeterID
Values
4-04:105959 - Sum of V_MIN/2
4-04:105959 - Sum of V_AVG/2

leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 9:00 AM
11/19/12 8:00 PM
11/29/12 5:00 AM
12/8/12 8:00 AM
12/17/12 11:00 AM
12/26/12 2:00 PM
1/4/13 5:00 PM
1/14/13 5:00 AM
1/23/13 8:00 AM
2/1/13 6:00 PM
2/11/13 9:00 PM
2/21/13 10:00 AM
3/3/13 3:00 AM
3/12/13 8:00 PM
3/22/13 7:00 AM
4/1/13 12:00 PM
4/10/13 10:00 PM
4/20/13 11:00 AM
4/30/13 2:00 AM
5/9/13 3:00 PM
5/19/13 1:00 AM
5/28/13 9:00 PM
6/7/13 2:00 PM
6/17/13 9:00 PM
6/27/13 8:00 AM
7/7/13 4:00 AM
7/17/13 5:00 AM
7/26/13 9:00 PM
8/5/13 3:00 PM
8/15/13 11:00 AM
8/24/13 8:00 PM
9/3/13 7:00 PM
9/13/13 9:00 AM
9/22/13 4:00 PM
10/2/13 5:00 AM
10/12/13 12:00 AM
10/21/13 8:00 AM
10/31/13 2:00 AM
READ_...
FeederMeterID
Values
4-11:102857 - Sum of V_MIN/2
4-11:102857 - Sum of V_AVG/2

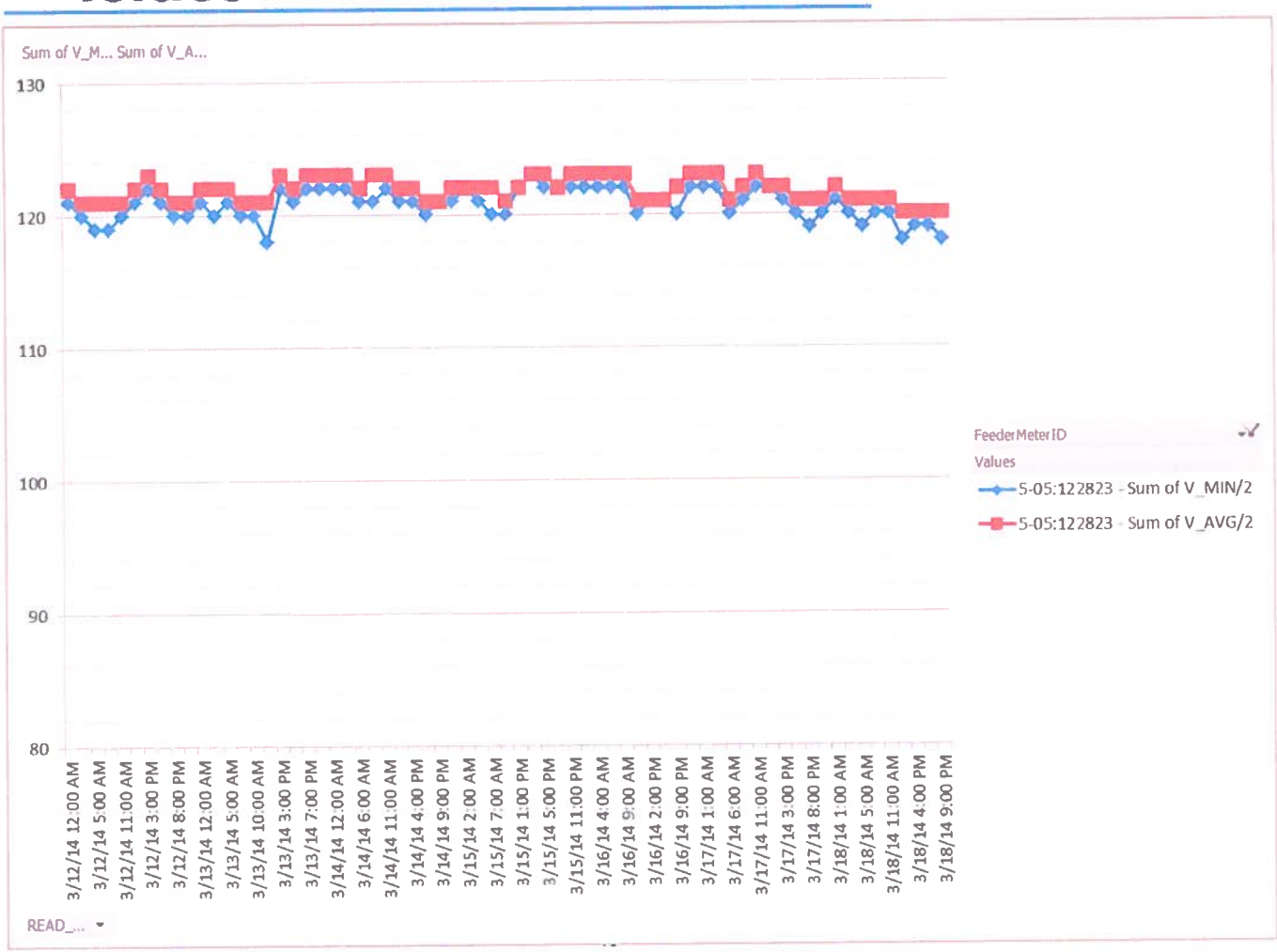
leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/10/12 5:00 PM
11/19/12 6:00 PM
11/29/12 1:00 AM
12/8/12 3:00 PM
12/18/12 10:00 AM
12/27/12 10:00 PM
1/6/13 10:00 AM
1/16/13 1:00 AM
1/25/13 12:00 PM
2/4/13 8:00 AM
2/13/13 11:00 PM
2/23/13 8:00 AM
3/4/13 11:00 PM
3/14/13 9:00 AM
3/23/13 10:00 PM
4/3/13 2:00 AM
4/12/13 12:00 PM
4/22/13 12:00 AM
5/2/13 5:00 AM
5/12/13 4:00 PM
5/22/13 11:00 AM
6/1/13 1:00 AM
6/10/13 10:00 AM
6/20/13 10:00 AM
6/30/13 3:00 AM
7/10/13 12:00 PM
7/19/13 2:00 PM
7/29/13 12:00 PM
8/8/13 7:00 AM
8/18/13 12:00 AM
8/27/13 5:00 PM
9/6/13 3:00 PM
9/16/13 8:00 AM
9/25/13 9:00 PM
10/5/13 2:00 PM
10/15/13 12:00 AM
10/24/13 1:00 PM
11/3/13 4:00 AM
READ_...
FeederMeterID
Values
4-12:109840 - Sum of V_MIN/2
4-12:109840 - Sum of V_AVG/2

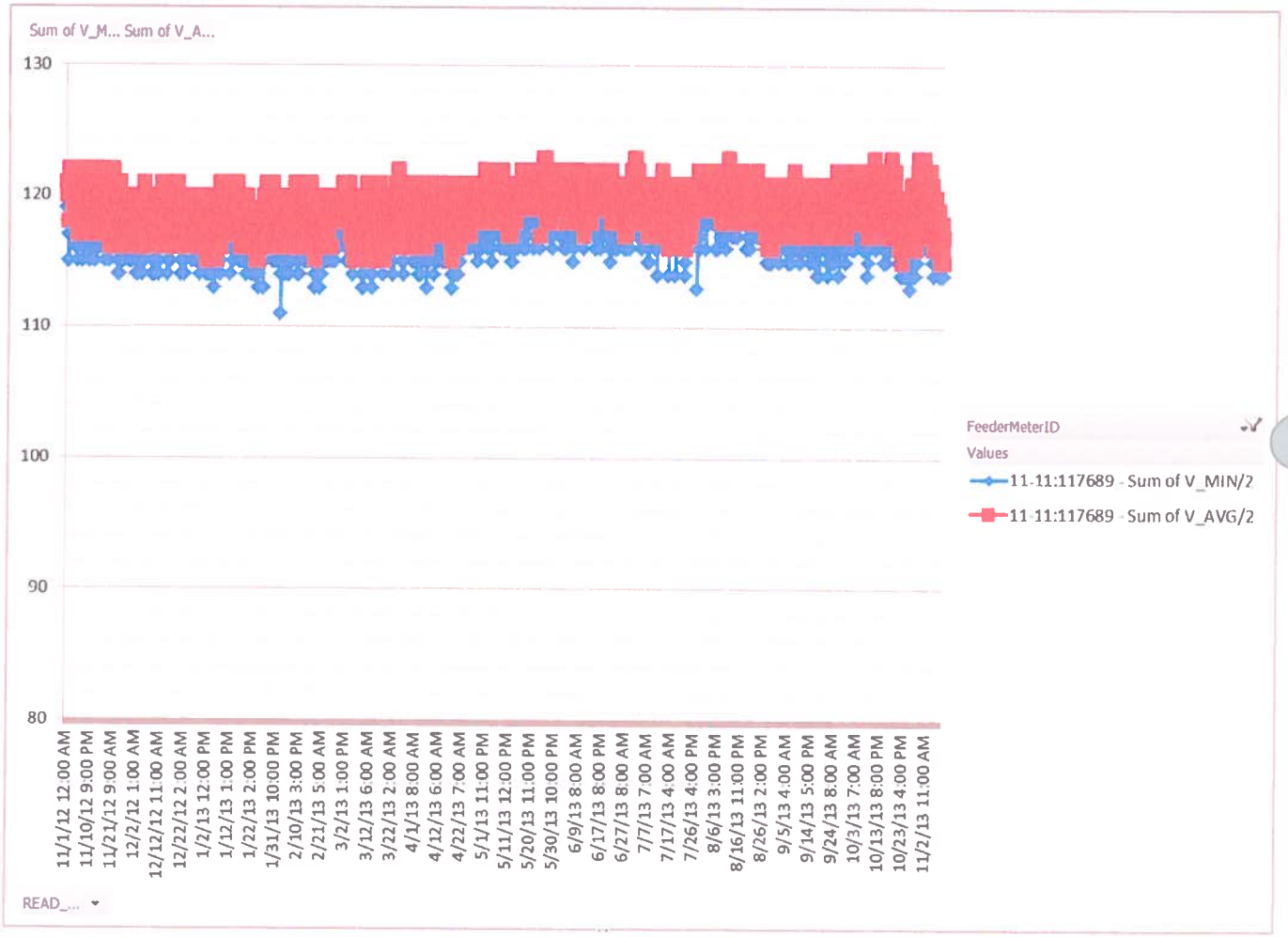
leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 6:00 AM
11/19/12 3:00 PM
11/29/12 11:00 AM
12/8/12 8:00 PM
12/18/12 5:00 AM
12/27/12 11:00 AM
1/5/13 9:00 PM
1/15/13 10:00 PM
1/25/13 10:00 AM
2/3/13 3:00 PM
2/13/13 8:00 PM
2/23/13 1:00 PM
3/4/13 8:00 PM
3/14/13 8:00 AM
3/24/13 12:00 AM
4/3/13 10:00 AM
4/12/13 8:00 PM
4/22/13 2:00 AM
5/2/13 1:00 AM
5/11/13 8:00 PM
5/21/13 2:00 PM
5/31/13 7:00 AM
6/9/13 11:00 PM
6/19/13 7:00 PM
6/29/13 5:00 AM
7/8/13 1:00 PM
7/18/13 1:00 AM
7/27/13 9:00 AM
8/6/13 8:00 AM
8/16/13 8:00 AM
8/26/13 5:00 AM
9/4/13 3:00 PM
9/14/13 3:00 AM
9/23/13 6:00 AM
10/2/13 1:00 PM
10/12/13 4:00 AM
10/21/13 9:00 PM
10/31/13 7:00 PM
READ_...
FeederMeterID
Values
5-02:127913 - Sum of V_MIN/2
5-02:127913 - Sum of V_AVG/2

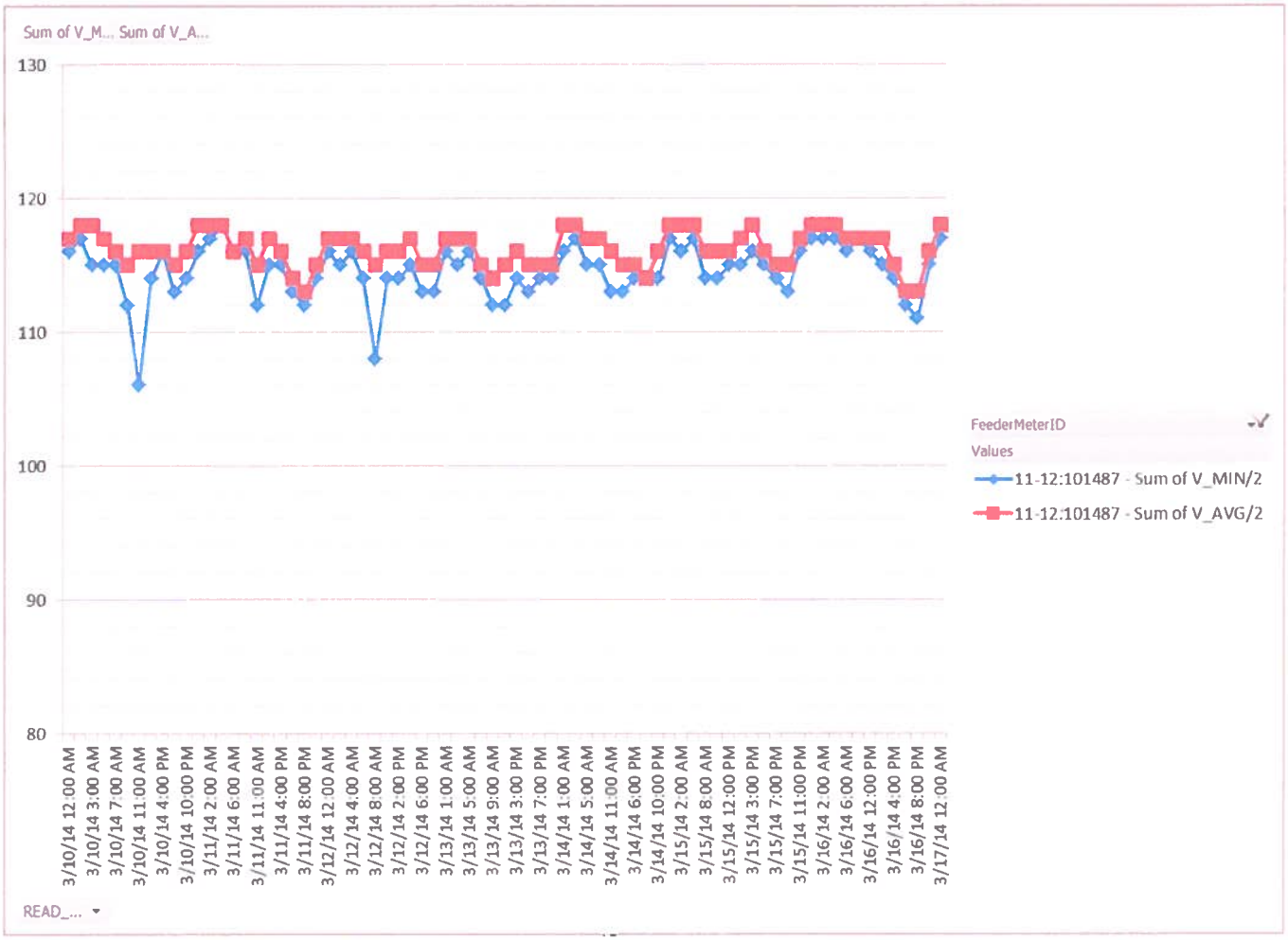
leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
3/12/14 12:00 AM
3/12/14 5:00 AM
3/12/14 11:00 AM
3/12/14 3:00 PM
3/12/14 8:00 PM
3/13/14 12:00 AM
3/13/14 5:00 AM
3/13/14 10:00 AM
3/13/14 3:00 PM
3/13/14 7:00 PM
3/14/14 12:00 AM
3/14/14 6:00 AM
3/14/14 11:00 AM
3/14/14 4:00 PM
3/14/14 9:00 PM
3/15/14 2:00 AM
3/15/14 7:00 AM
3/15/14 1:00 PM
3/15/14 5:00 PM
3/15/14 11:00 PM
3/16/14 4:00 AM
3/16/14 9:00 AM
3/16/14 2:00 PM
3/16/14 9:00 PM
3/17/14 1:00 AM
3/17/14 6:00 AM
3/17/14 11:00 AM
3/17/14 3:00 PM
3/17/14 8:00 PM
3/18/14 1:00 AM
3/18/14 5:00 AM
3/18/14 11:00 AM
3/18/14 4:00 PM
3/18/14 9:00 PM
READ_...
FeederMeterID
Values
5-05:122823 - Sum of V_MIN/2
5-05:122823 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 9:00 PM
11/21/12 9:00 AM
12/2/12 1:00 AM
12/12/12 11:00 AM
12/22/12 2:00 AM
1/2/13 12:00 PM
1/12/13 1:00 PM
1/22/13 2:00 PM
1/31/13 10:00 PM
2/10/13 3:00 PM
2/21/13 5:00 AM
3/2/13 1:00 PM
3/12/13 6:00 AM
3/22/13 2:00 AM
4/1/13 8:00 AM
4/12/13 6:00 AM
4/22/13 7:00 AM
5/1/13 11:00 PM
5/11/13 12:00 PM
5/20/13 11:00 PM
5/30/13 10:00 PM
6/9/13 8:00 AM
6/17/13 8:00 PM
6/27/13 8:00 AM
7/7/13 7:00 AM
7/17/13 4:00 AM
7/26/13 4:00 PM
8/6/13 3:00 PM
8/16/13 11:00 PM
8/26/13 2:00 PM
9/5/13 4:00 AM
9/14/13 5:00 PM
9/24/13 8:00 AM
10/3/13 7:00 AM
10/13/13 8:00 PM
10/23/13 4:00 PM
11/2/13 11:00 AM
READ_...
FeederMeterID
Values
11-11:117689 - Sum of V_MIN/2
11-11:117689 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
3/10/14 12:00 AM
3/10/14 3:00 AM
3/10/14 7:00 AM
3/10/14 11:00 AM
3/10/14 4:00 PM
3/10/14 10:00 PM
3/11/14 2:00 AM
3/11/14 6:00 AM
3/11/14 11:00 AM
3/11/14 4:00 PM
3/11/14 8:00 PM
3/12/14 12:00 AM
3/12/14 4:00 AM
3/12/14 8:00 AM
3/12/14 2:00 PM
3/12/14 6:00 PM
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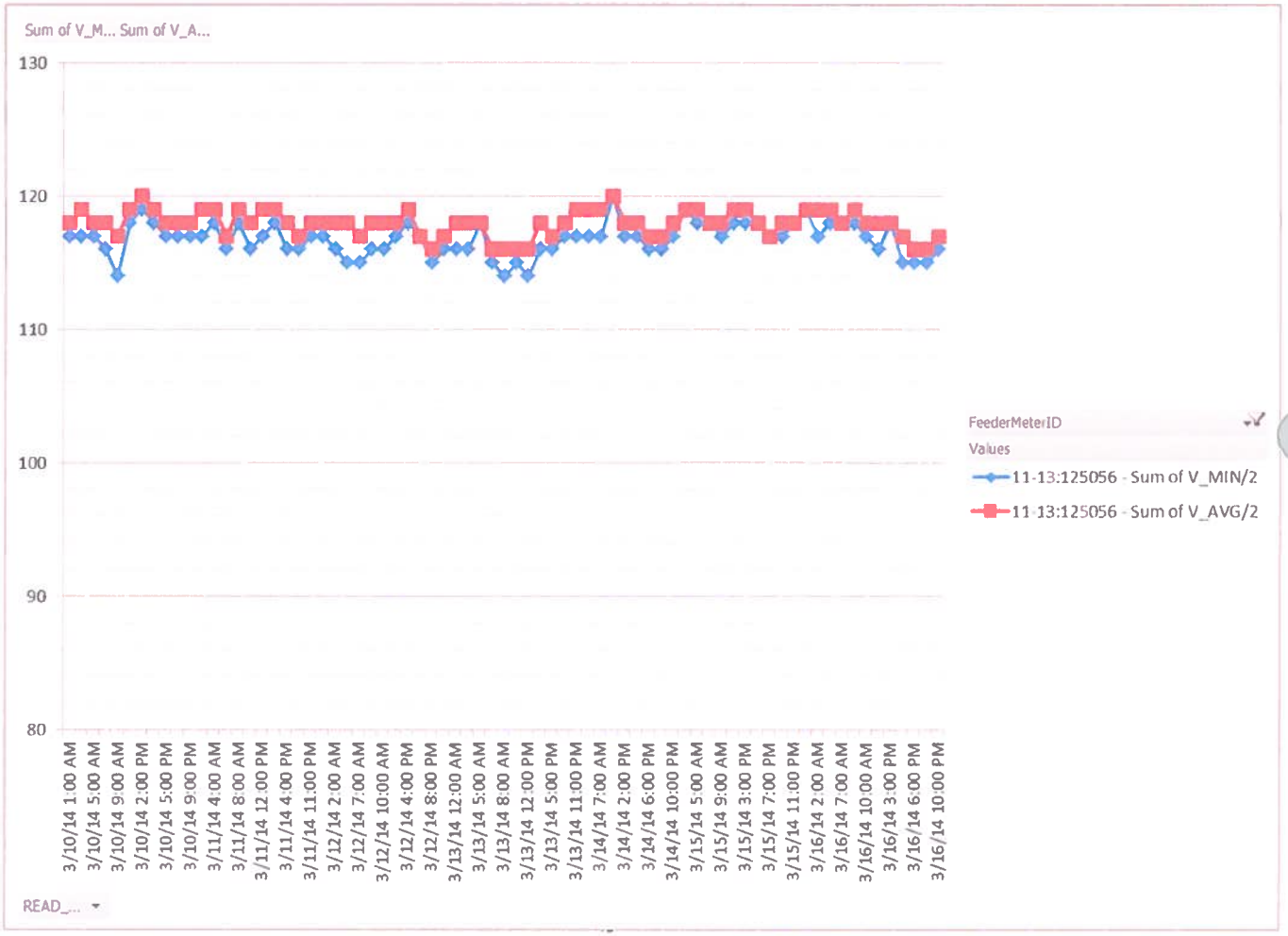
3/13/14 5:00 AM
3/13/14 9:00 AM
3/13/14 3:00 PM
3/13/14 7:00 PM
3/14/14 1:00 AM
3/14/14 5:00 AM
3/14/14 11:00 AM
3/14/14 6:00 PM
3/14/14 10:00 PM
3/15/14 2:00 AM
3/15/14 8:00 AM
3/15/14 12:00 PM
3/15/14 3:00 PM
3/15/14 7:00 PM
3/15/14 11:00 PM
3/16/14 2:00 AM
3/16/14 6:00 AM
3/16/14 12:00 PM
3/16/14 4:00 PM
3/16/14 8:00 PM
3/17/14 12:00 AM
READ_...
FeederMeterID
Values
11-12:101487 - Sum of V_MIN/2
11-12:101487 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
3/10/14 1:00 AM
3/10/14 5:00 AM
3/10/14 9:00 AM
3/10/14 2:00 PM
3/10/14 5:00 PM
3/10/14 9:00 PM
3/11/14 4:00 AM
3/11/14 8:00 AM
3/11/14 12:00 PM
3/11/14 4:00 PM
3/11/14 11:00 PM
3/12/14 2:00 AM
3/12/14 7:00 AM
3/12/14 10:00 AM
3/12/14 4:00 PM
3/12/14 8:00 PM
3/13/14 12:00 AM
3/13/14 5:00 AM
3/13/14 8:00 AM
3/13/14 12:00 PM
3/13/14 5:00 PM
3/13/14 11:00 PM
3/14/14 7:00 AM
3/14/14 2:00 PM
3/14/14 6:00 PM
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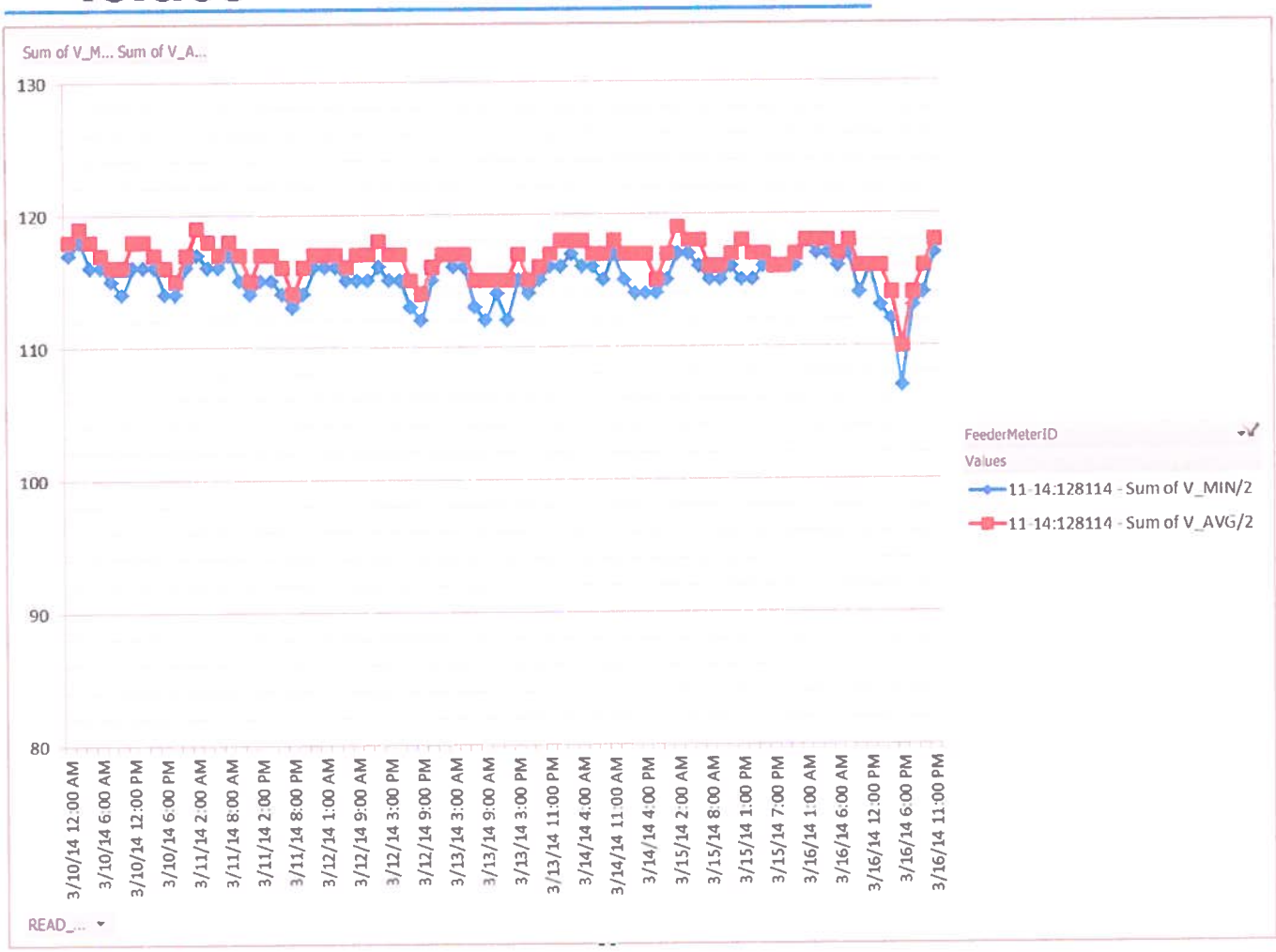
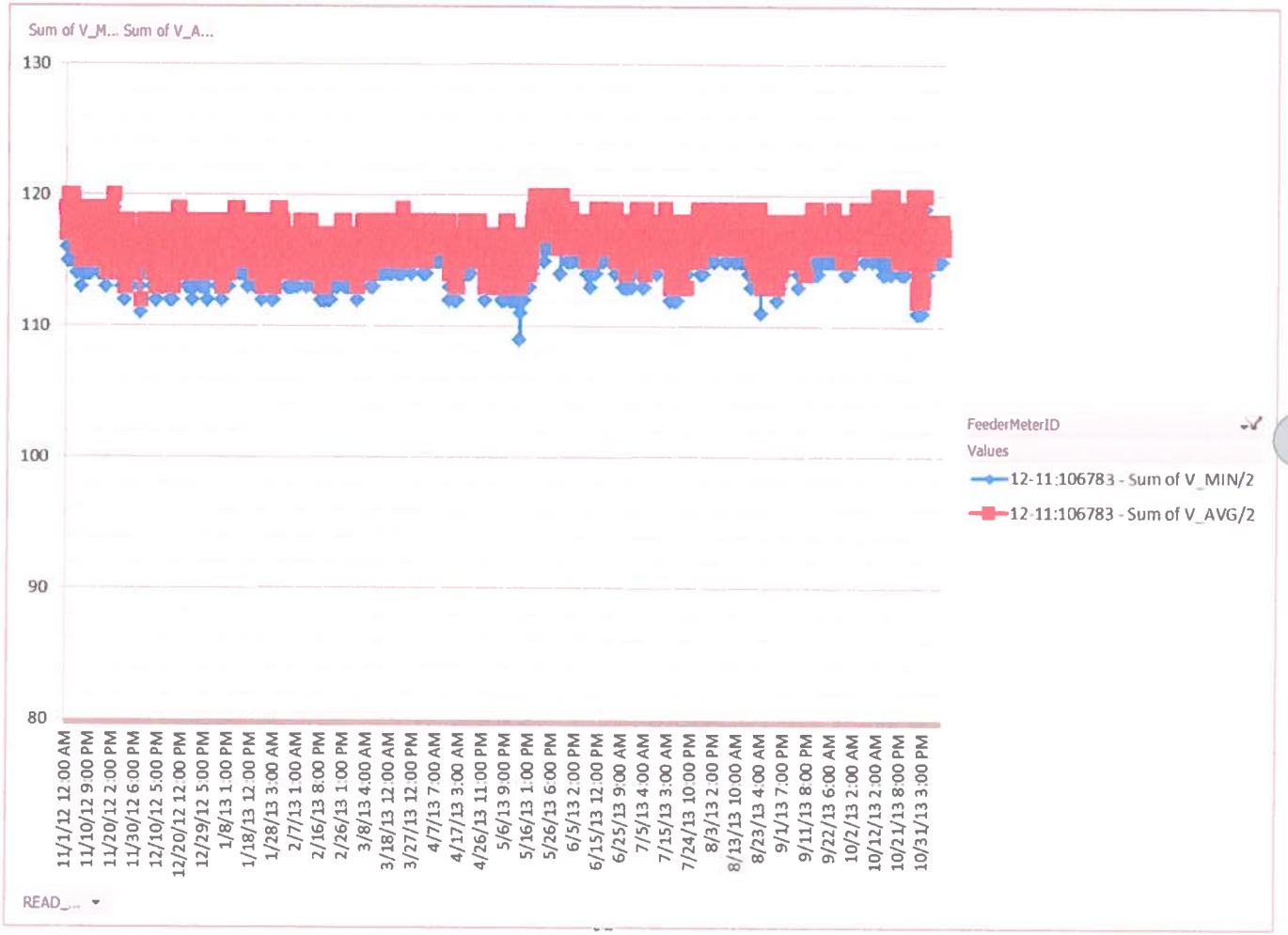
3/15/14 5:00 AM
3/15/14 9:00 AM
3/15/14 3:00 PM
3/15/14 7:00 PM
3/15/14 11:00 PM
3/16/14 2:00 AM
3/16/14 7:00 AM
3/16/14 10:00 AM
3/16/14 3:00 PM
3/16/14 6:00 PM
3/16/14 10:00 PM
READ_...
FeederMeterID
Values
11-13:125056 - Sum of V_MIN/2
11-13:125056 - Sum of V_AVG/2

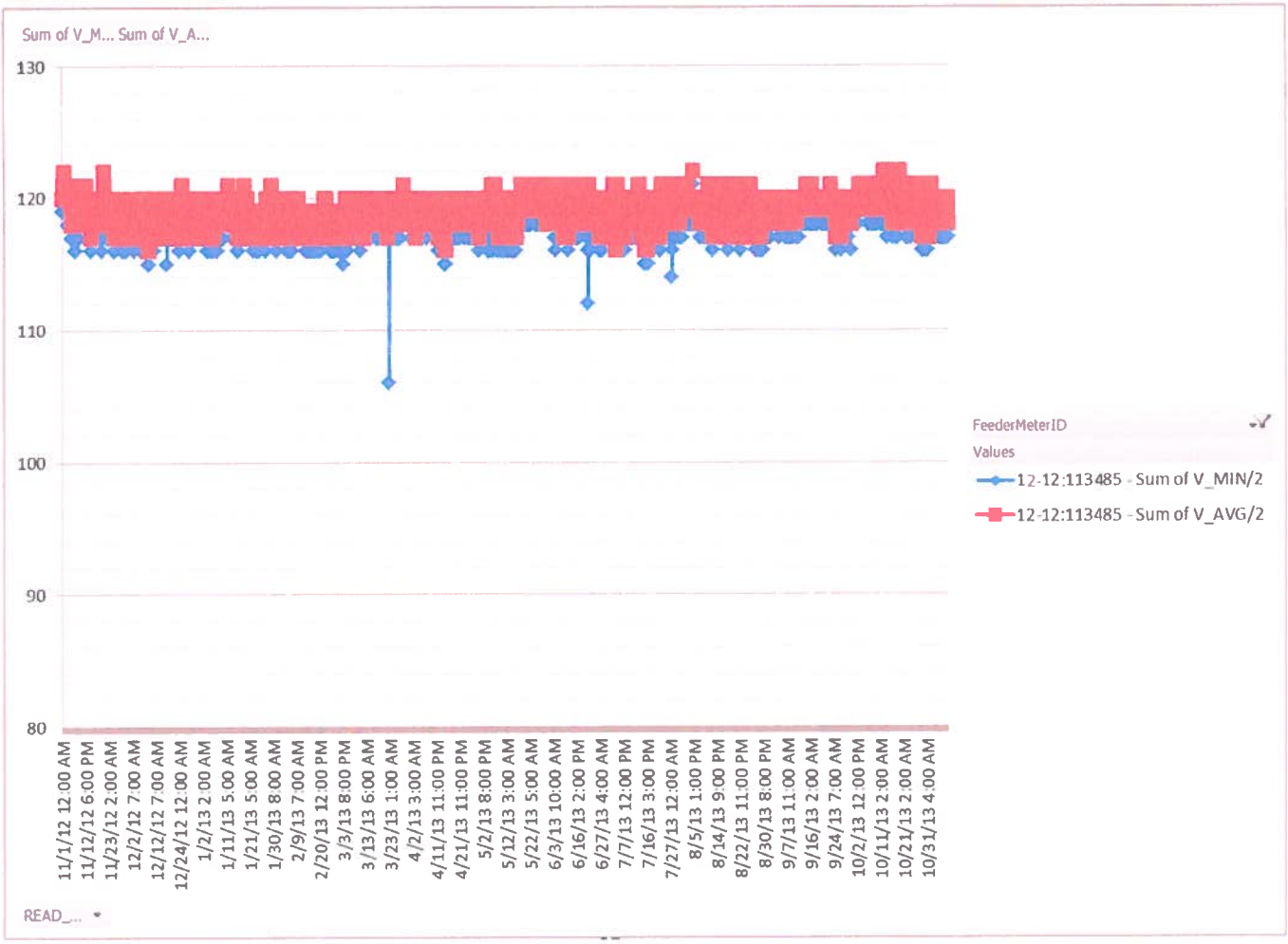
leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
3/10/14 12:00 AM
3/10/14 6:00 AM
3/10/14 12:00 PM
3/10/14 6:00 PM
3/11/14 2:00 AM
3/11/14 8:00 AM
3/11/14 2:00 PM
3/11/14 8:00 PM
3/12/14 1:00 AM
3/12/14 9:00 AM
3/12/14 3:00 PM
3/12/14 9:00 PM
3/13/14 3:00 AM
3/13/14 9:00 AM
3/13/14 3:00 PM
3/13/14 11:00 PM
3/14/14 4:00 AM
3/14/14 11:00 AM
3/14/14 4:00 PM
3/15/14 2:00 AM
3/15/14 8:00 AM
3/15/14 1:00 PM
3/15/14 7:00 PM
3/16/14 1:00 AM
3/16/14 6:00 AM
3/16/14 12:00 PM
3/16/14 6:00 PM
3/16/14 11:00 PM
READ_...
FeederMeterID
Values
11-14:128114 - Sum of V_MIN/2
11-14:128114 - Sum of V_AVG/2

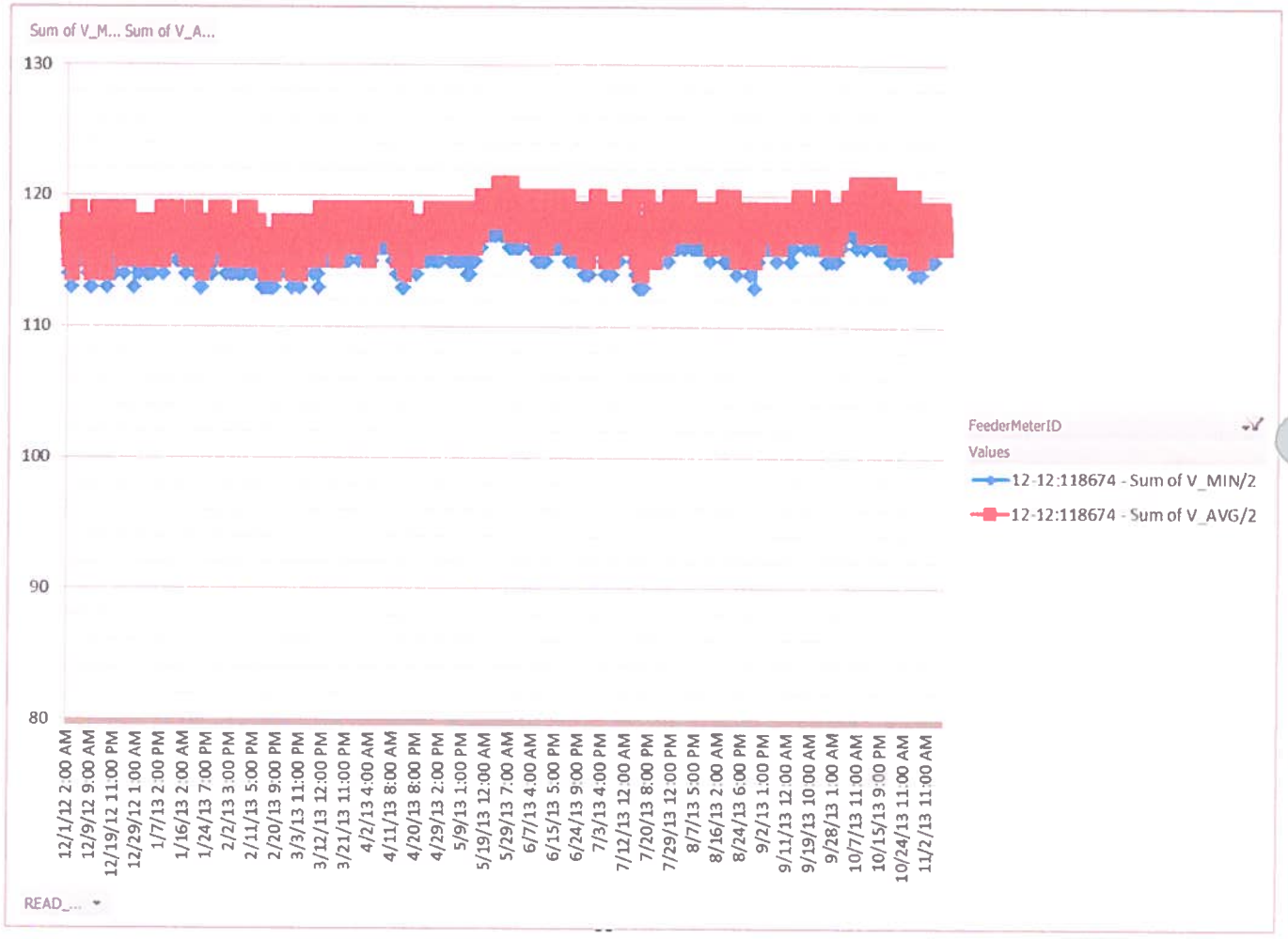
leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 9:00 PM
11/20/12 2:00 PM
11/30/12 6:00 PM
12/10/12 5:00 PM
12/20/12 12:00 PM
12/29/12 5:00 PM
1/8/13 1:00 PM
1/18/13 12:00 PM
1/28/13 3:00 AM
2/7/13 1:00 AM
2/16/13 8:00 PM
2/26/13 1:00 PM
3/8/13 4:00 AM
3/18/13 12:00 AM
3/27/13 12:00 PM
4/7/13 7:00 AM
4/17/13 3:00 AM
4/26/13 11:00 PM
5/6/13 9:00 PM
5/16/13 1:00 PM
5/26/13 6:00 PM
6/5/13 2:00 PM
6/15/13 12:00 PM
6/25/13 9:00 AM
7/5/13 4:00 AM
7/15/13 3:00 AM
7/24/13 10:00 PM
8/3/13 2:00 PM
8/13/13 10:00 AM
8/23/13 4:00 AM
9/1/13 7:00 PM
9/11/13 8:00 PM
9/22/13 6:00 AM
10/2/13 2:00 AM
10/12/13 2:00 AM
10/21/13 8:00 PM
10/31/13 3:00 PM
READ_...
FeederMeterID
Values
12-11:106783 - Sum of V_MIN/2
12-11:106783 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/12/12 6:00 PM
11/23/12 2:00 AM
12/2/12 7:00 AM
12/12/12 7:00 AM
12/24/12 12:00 AM
1/2/13 2:00 AM
1/11/13 5:00 AM
1/21/13 5:00 AM
1/30/13 8:00 AM
2/9/13 7:00 AM
2/20/13 12:00 PM
3/3/13 8:00 PM
3/13/13 6:00 AM
3/23/13 1:00 AM
4/2/13 3:00 AM
4/11/13 11:00 PM
4/21/13 11:00 PM
5/2/13 8:00 PM
5/12/13 3:00 AM
5/22/13 5:00 AM
6/3/13 10:00 AM
6/16/13 2:00 PM
6/27/13 4:00 AM
7/7/13 12:00 PM
7/16/13 3:00 PM
7/27/13 12:00 AM
8/5/13 1:00 PM
8/14/13 9:00 PM
8/22/13 11:00 PM
8/30/13 8:00 PM
9/7/13 11:00 AM
9/16/13 2:00 AM
9/24/13 7:00 AM
10/2/13 12:00 PM
10/11/13 2:00 AM
10/21/13 2:00 AM
10/31/13 4:00 AM
READ_...
FeederMeterID
Values
12-12:113485 - Sum of V_MIN/2
12-12:113485 - Sum of V_AVG/2

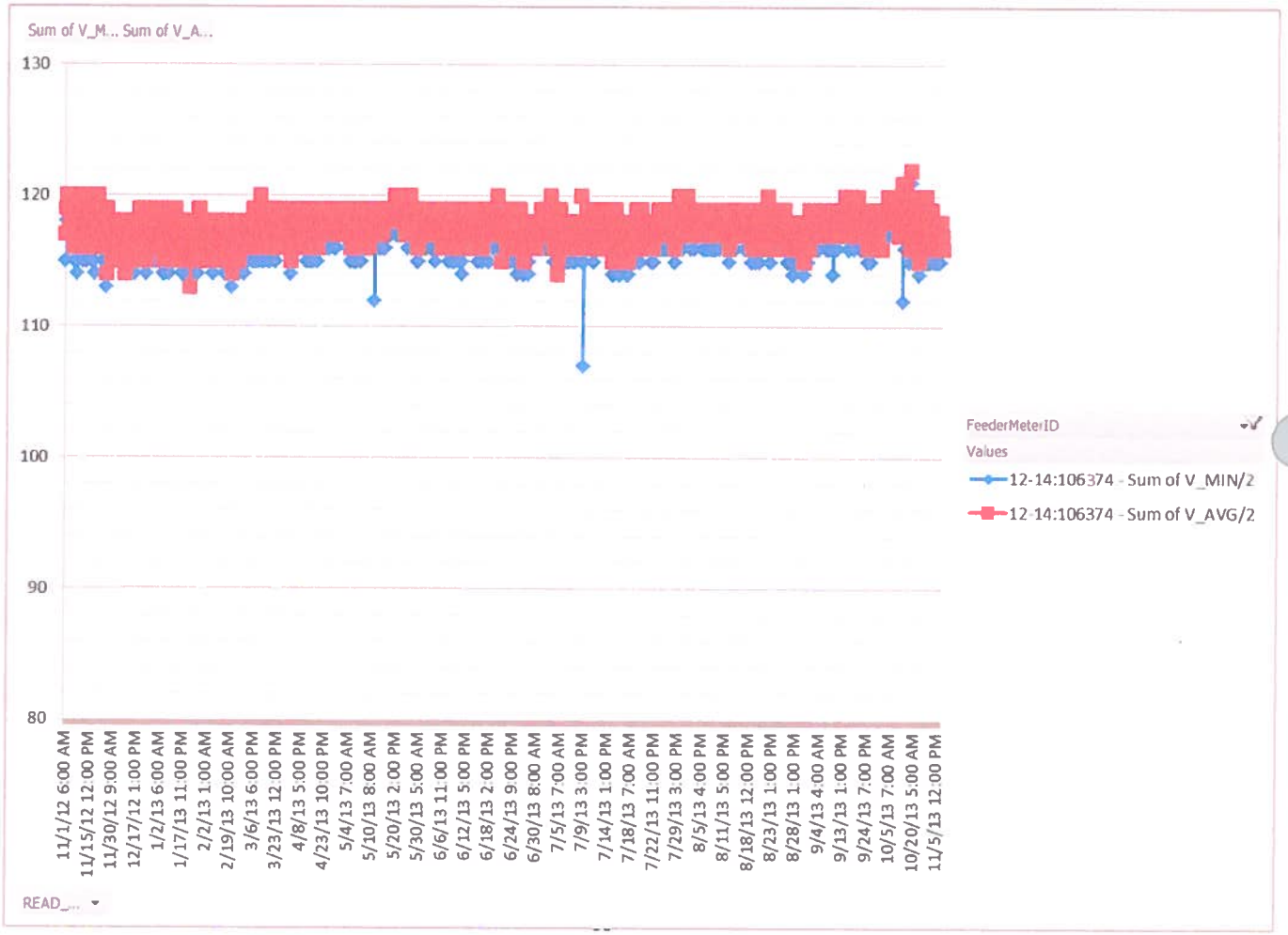
leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
12/1/12 2:00 AM
12/9/12 9:00 AM
12/19/12 11:00 PM
12/29/12 1:00 AM
1/7/13 2:00 PM
1/16/13 2:00 AM
1/24/13 7:00 PM
2/2/13 3:00 PM
2/11/13 5:00 PM
2/20/13 9:00 PM
3/3/13 11:00 PM
3/12/13 12:00 PM
3/21/13 11:00 PM
4/2/13 4:00 AM
4/11/13 8:00 AM
4/20/13 8:00 PM
4/29/13 2:00 PM
5/9/13 1:00 PM
5/19/13 12:00 AM
5/29/13 7:00 AM
6/7/13 4:00 AM
6/15/13 5:00 PM
6/24/13 9:00 PM
7/3/13 4:00 PM
7/12/13 12:00 AM
7/20/13 8:00 PM
7/29/13 12:00 PM
8/7/13 5:00 PM
8/16/13 2:00 AM
8/24/13 6:00 PM
9/2/13 1:00 PM
9/11/13 12:00 AM
9/19/13 10:00 AM
9/28/13 1:00 AM
10/7/13 11:00 AM
10/15/13 9:00 PM
10/24/13 11:00 AM
11/2/13 11:00 AM
READ_...
FeederMeterID
Values
12-12:118674 - Sum of V_MIN/2
12-12:118674 - Sum of V_AVG/2

leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 3:00 AM
11/10/12 7:00 AM
11/19/12 10:00 PM
11/29/12 9:00 PM
12/9/12 3:00 PM
12/19/12 7:00 AM
12/28/12 4:00 PM
1/6/13 7:00 PM
1/16/13 12:00 PM
1/26/13 5:00 PM
2/5/13 5:00 AM
2/14/13 4:00 PM
2/24/13 7:00 AM
3/6/13 3:00 AM
3/15/13 9:00 AM
3/24/13 4:00 PM
4/4/13 9:00 PM
4/15/13 4:00 AM
4/25/13 11:00 PM
5/7/13 2:00 AM
5/18/13 4:00 AM
5/28/13 9:00 PM
6/8/13 10:00 AM
6/17/13 7:00 PM
6/27/13 6:00 PM
7/7/13 1:00 PM
7/17/13 8:00 PM
7/27/13 7:00 PM
8/6/13 5:00 AM
8/16/13 3:00 AM
8/25/13 3:00 PM
9/4/13 3:00 AM
9/13/13 9:00 PM
9/22/13 8:00 PM
10/2/13 7:00 PM
10/12/13 11:00 AM
10/22/13 10:00 AM
10/31/13 8:00 PM
READ_...
FeederMeterID
Values
12-13:118469 - Sum of V_MIN/2
12-13:118469 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 6:00 AM
11/15/12 12:00 PM
11/30/12 9:00 AM
12/17/12 1:00 PM
1/2/13 6:00 AM
1/17/13 11:00 PM
2/2/13 1:00 AM
2/19/13 10:00 AM
3/6/13 6:00 PM
3/23/13 12:00 PM
4/8/13 5:00 PM
4/23/13 10:00 PM
5/4/13 7:00 AM
5/10/13 8:00 AM
5/20/13 2:00 PM
5/30/13 5:00 AM
6/6/13 11:00 PM
6/12/13 5:00 PM
6/18/13 2:00 PM
6/24/13 9:00 PM
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7/5/13 7:00 AM
7/9/13 3:00 PM
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7/18/13 7:00 AM
7/22/13 11:00 PM
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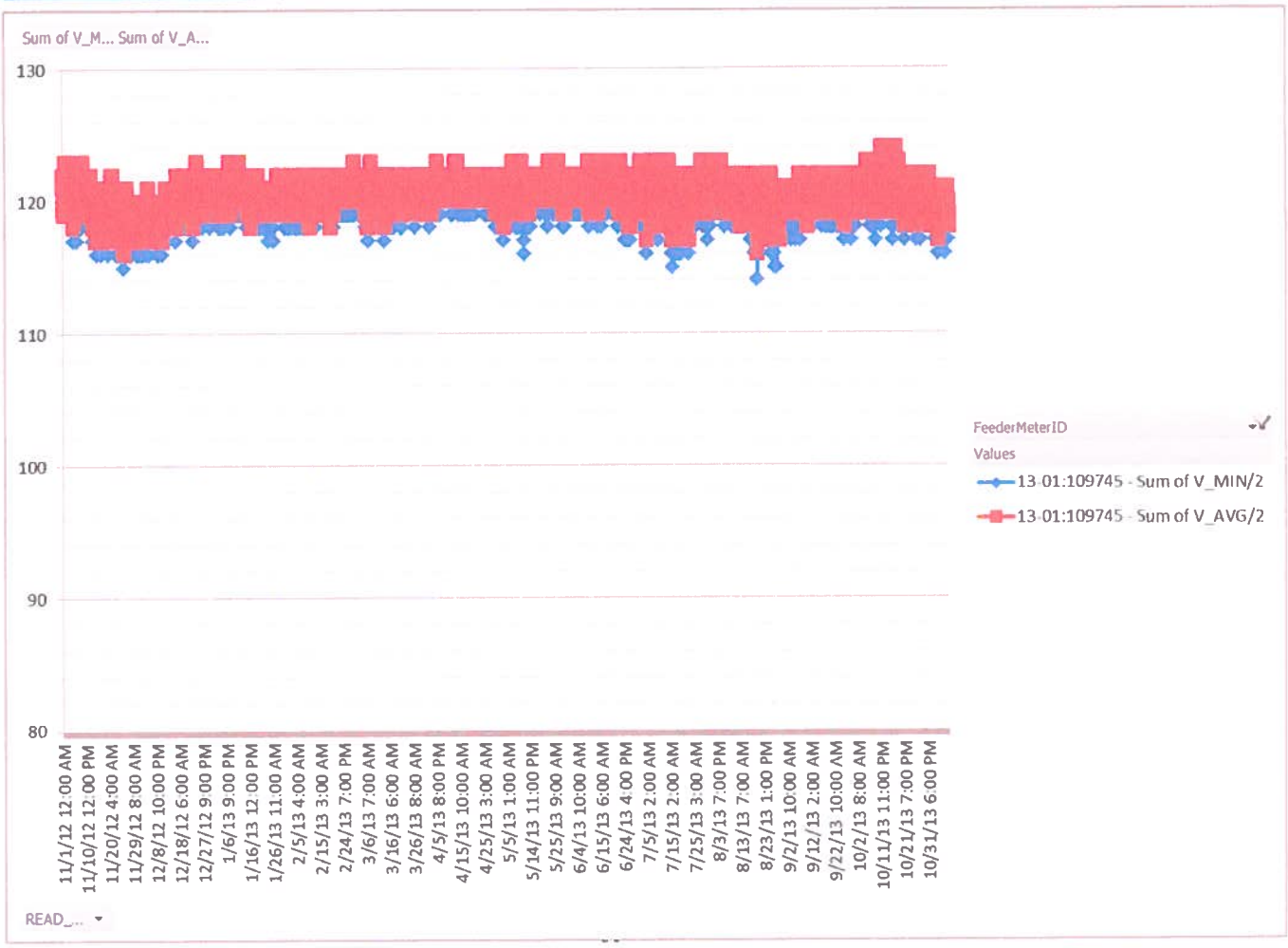
8/5/13 4:00 PM
8/11/13 5:00 PM
8/18/13 12:00 PM
8/23/13 1:00 PM
8/28/13 1:00 PM
9/4/13 4:00 AM
9/13/13 1:00 PM
9/24/13 7:00 PM
10/5/13 7:00 AM
10/20/13 5:00 AM
11/5/13 12:00 PM
READ_...
FeederMeterID
Values
12-14:106374 - Sum of V_MIN/2
12-14:106374 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 12:00 PM
11/20/12 4:00 AM
11/29/12 8:00 AM
12/8/12 10:00 PM
12/18/12 6:00 AM
12/27/12 9:00 PM
1/6/13 9:00 PM
1/16/13 12:00 PM
1/26/13 11:00 AM
2/5/13 4:00 AM
2/15/13 3:00 AM
2/24/13 7:00 PM
3/6/13 7:00 AM
3/16/13 6:00 AM
3/26/13 8:00 AM
4/5/13 8:00 PM
4/15/13 10:00 AM
4/25/13 3:00 AM
5/5/13 1:00 AM
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7/25/13 3:00 AM
8/3/13 7:00 PM
8/13/13 7:00 AM
8/23/13 1:00 PM
9/2/13 10:00 AM
9/12/13 2:00 AM
9/22/13 10:00 AM
10/2/13 8:00 AM
10/11/13 11:00 PM
10/21/13 7:00 PM
10/31/13 6:00 PM
READ_...
FeederMeterID
Values
13-01:109745 - Sum of V_MIN/2
13-01:109745 - Sum of V_AVG/2

leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/11/12 1:00 PM
11/21/12 8:00 PM
12/2/12 2:00 AM
12/11/12 9:00 PM
12/21/12 7:00 PM
12/31/12 10:00 AM
1/10/13 6:00 AM
1/19/13 1:00 PM
1/29/13 9:00 AM
2/8/13 6:00 AM
2/18/13 8:00 AM
2/28/13 8:00 AM
3/10/13 10:00 AM
3/20/13 4:00 AM
3/30/13 3:00 AM
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4/29/13 8:00 AM
5/8/13 10:00 PM
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7/16/13 2:00 PM
7/26/13 4:00 AM
8/4/13 9:00 PM
8/14/13 11:00 AM
8/24/13 4:00 AM
9/3/13 8:00 AM
9/13/13 5:00 AM
9/22/13 10:00 PM
10/3/13 12:00 AM
10/13/13 9:00 AM
10/23/13 12:00 AM
11/1/13 11:00 PM
READ_...
FeederMeterID
Values
13-01:109900 - Sum of V_MIN/2
13-01:109900 - Sum of V_AVG/2

leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/10/12 2:00 PM
11/20/12 7:00 AM
11/29/12 10:00 PM
12/9/12 2:00 PM
12/19/12 7:00 AM
12/28/12 8:00 PM
1/7/13 7:00 PM
1/17/13 7:00 PM
1/27/13 9:00 AM
2/5/13 11:00 PM
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7/25/13 12:00 AM
8/4/13 4:00 AM
8/14/13 4:00 AM
8/24/13 7:00 AM
9/3/13 3:00 AM
9/12/13 5:00 PM
9/22/13 12:00 PM
10/2/13 3:00 PM
10/12/13 10:00 AM
10/22/13 4:00 AM
10/31/13 3:00 PM
READ_...
FeederMeterID
Values
13-02:101924 - Sum of V_MIN/2
13-02:101924 - Sum of V_AVG/2

leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 12:00 PM
11/20/12 5:00 AM
11/29/12 10:00 PM
12/9/12 9:00 PM
12/19/12 7:00 PM
12/29/12 5:00 PM
1/9/13 2:00 AM
1/19/13 8:00 AM
1/29/13 4:00 AM
2/8/13 10:00 AM
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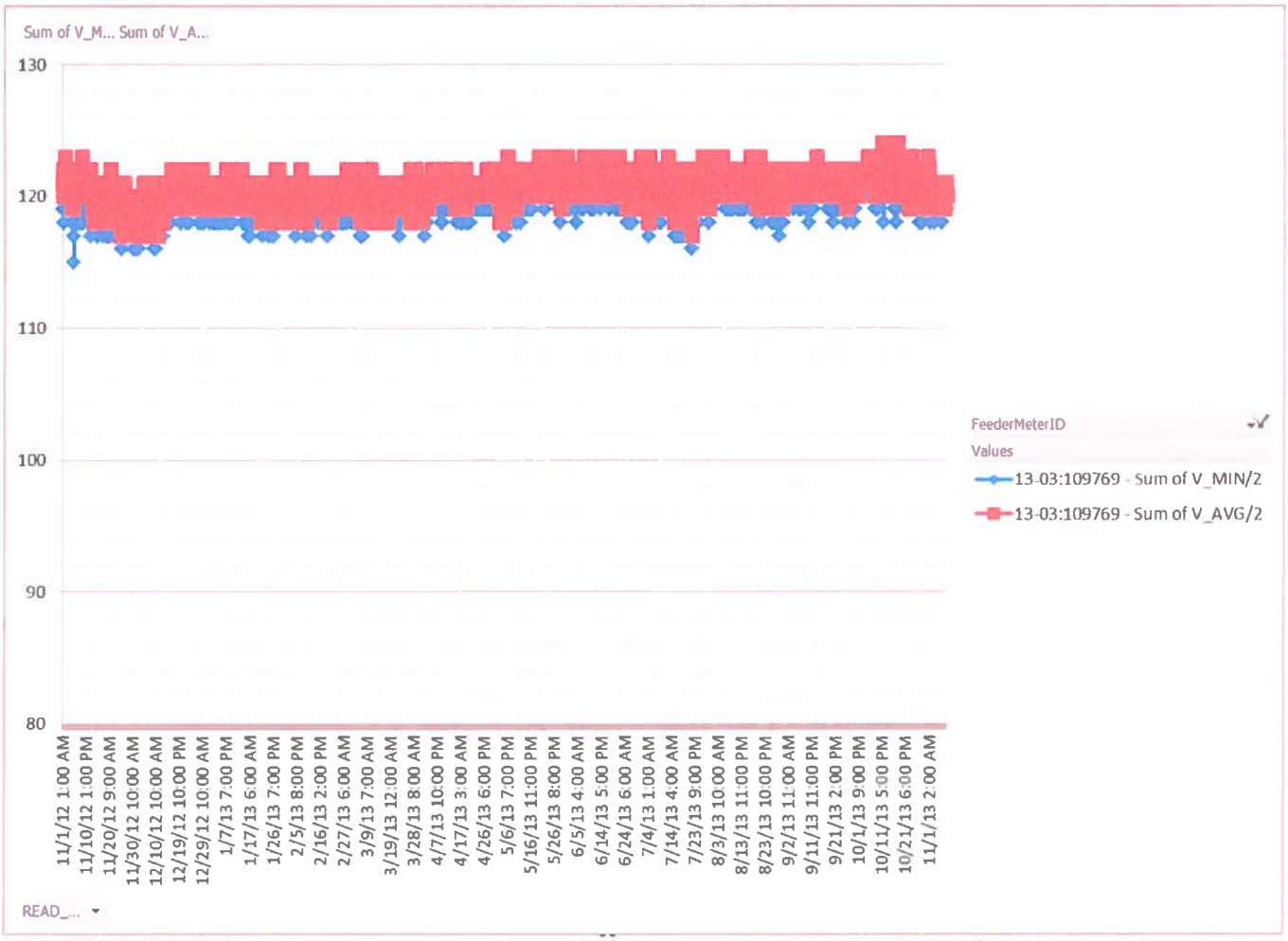
8/17/13 12:00 PM
8/27/13 4:00 AM
9/5/13 6:00 PM
9/15/13 3:00 PM
9/25/13 2:00 AM
10/4/13 10:00 AM
10/14/13 4:00 AM
10/23/13 1:00 PM
11/2/13 4:00 AM
READ_...
FeederMeterID
Values
13-02:117774 - Sum of V_MIN/2
13-02:117774 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/10/12 1:00 PM
11/20/12 9:00 AM
11/30/12 10:00 AM
12/10/12 10:00 AM
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3/28/13 8:00 AM
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8/13/13 11:00 PM
8/23/13 10:00 PM
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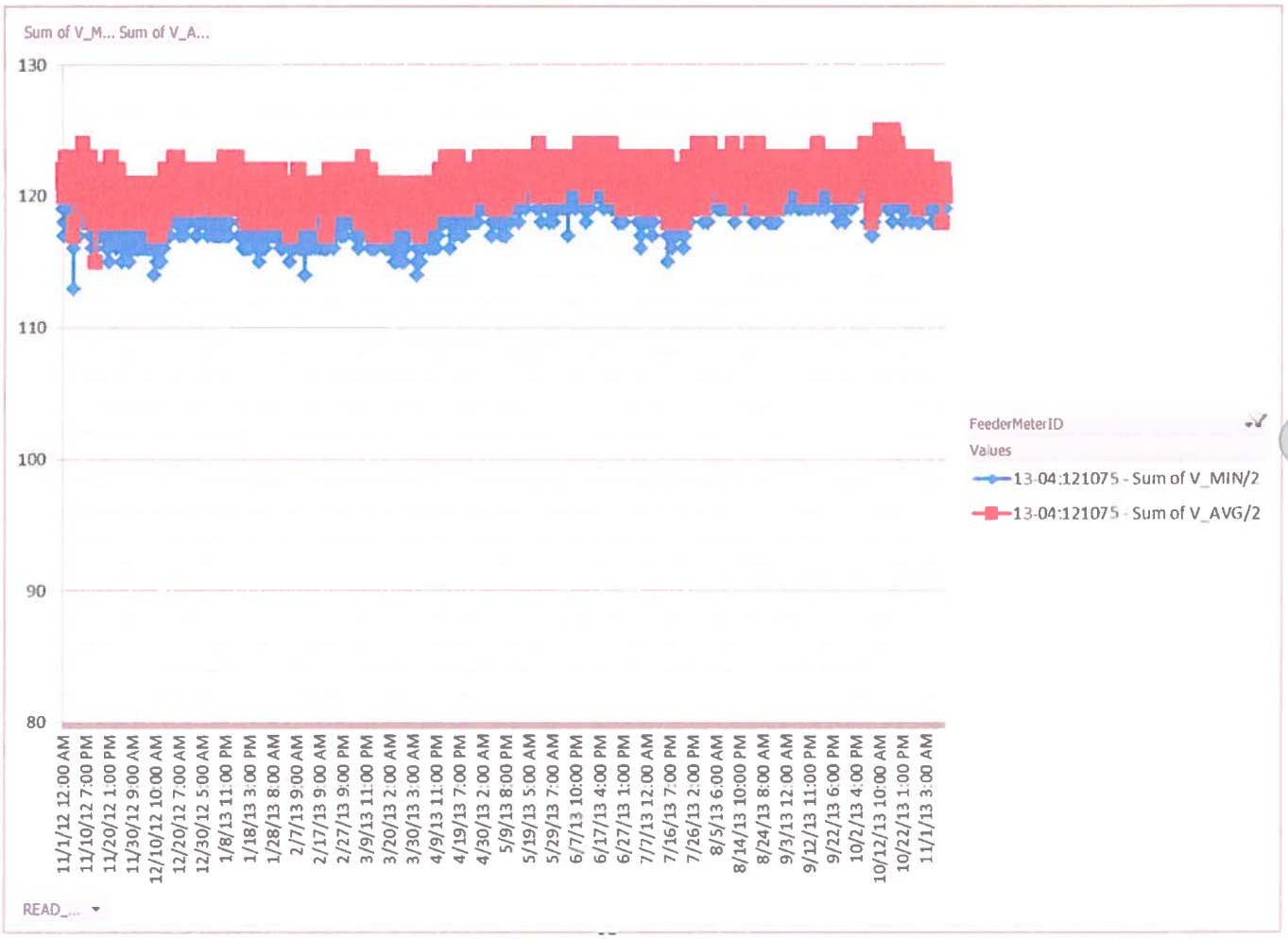
9/21/13 2:00 PM
10/1/13 9:00 PM
10/11/13 5:00 PM
10/21/13 6:00 PM
11/1/13 2:00 AM
READ_...
FeederMeterID
Values
13-03:109769 - Sum of V_MIN/2
13-03:109769 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 7:00 PM
11/20/12 1:00 PM
11/30/12 9:00 AM
12/10/12 10:00 AM
12/20/12 7:00 AM
12/30/12 5:00 AM
1/8/13 11:00 PM
1/18/13 3:00 PM
1/28/13 8:00 AM
2/7/13 9:00 AM
2/17/13 9:00 AM
2/27/13 9:00 PM
3/9/13 11:00 PM
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3/30/13 3:00 AM
4/9/13 11:00 PM
4/19/13 7:00 PM
4/30/13 2:00 AM
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5/29/13 7:00 AM
6/7/13 10:00 PM
6/17/13 4:00 PM
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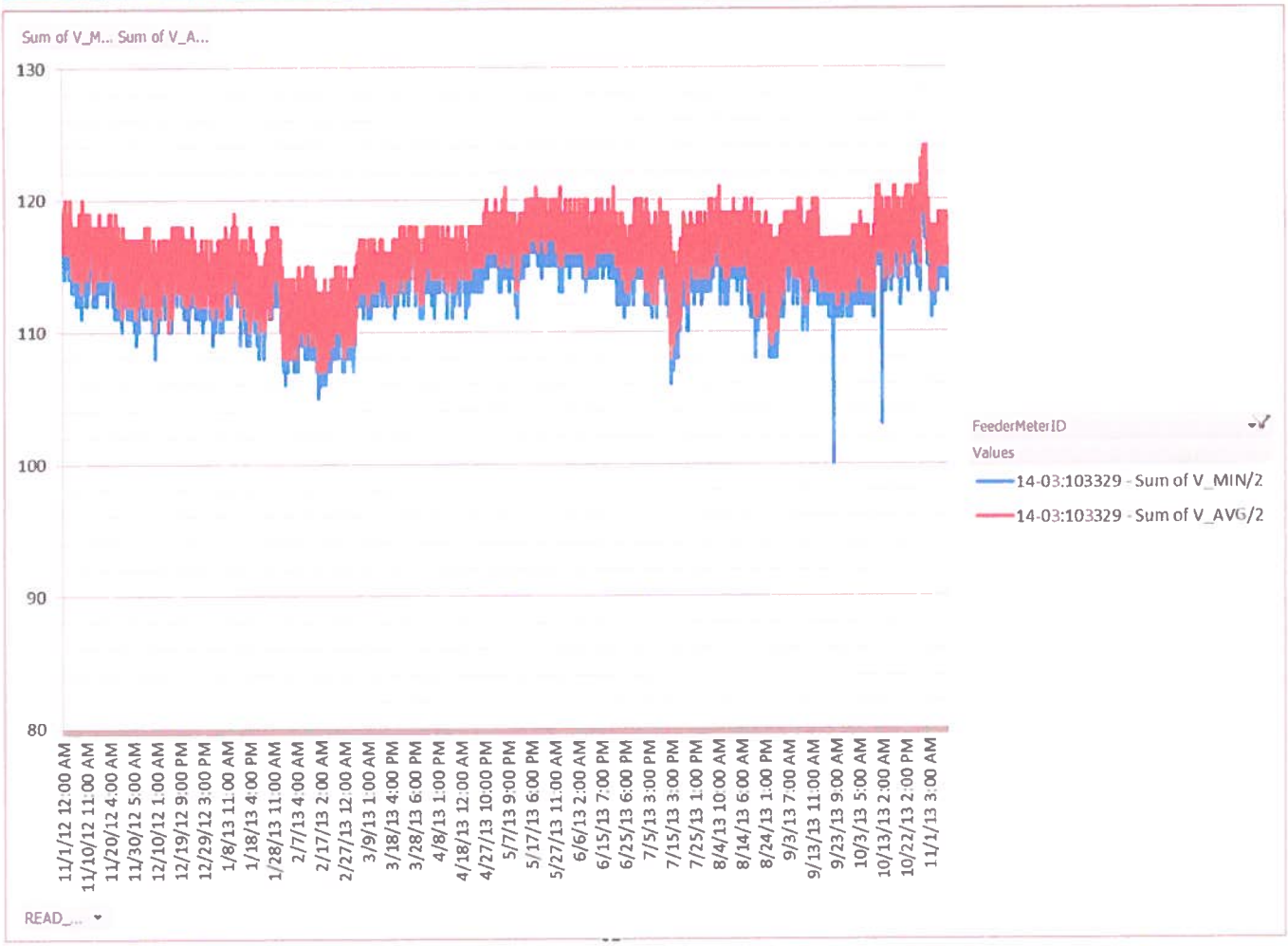
7/7/13 12:00 AM
7/16/13 7:00 PM
7/26/13 2:00 PM
8/5/13 6:00 AM
8/14/13 10:00 PM
8/24/13 8:00 AM
9/3/13 12:00 AM
9/12/13 11:00 PM
9/22/13 6:00 PM
10/2/13 4:00 PM
10/12/13 10:00 AM
10/22/13 1:00 PM
11/1/13 3:00 AM
READ_...
FeederMeterID
Values
13-04:121075 - Sum of V_MIN/2
13-04:121075 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 11:00 AM
11/20/12 4:00 AM
11/30/12 5:00 AM
12/10/12 1:00 AM
12/19/12 9:00 PM
12/29/12 3:00 PM
1/8/13 11:00 AM
1/18/13 4:00 PM
1/28/13 11:00 AM
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2/17/13 2:00 AM
2/27/13 12:00 AM
3/9/13 1:00 AM
3/18/13 4:00 PM
3/28/13 6:00 PM
4/8/13 1:00 PM
4/18/13 12:00 AM
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8/4/13 10:00 AM
8/14/13 6:00 AM
8/24/13 1:00 PM
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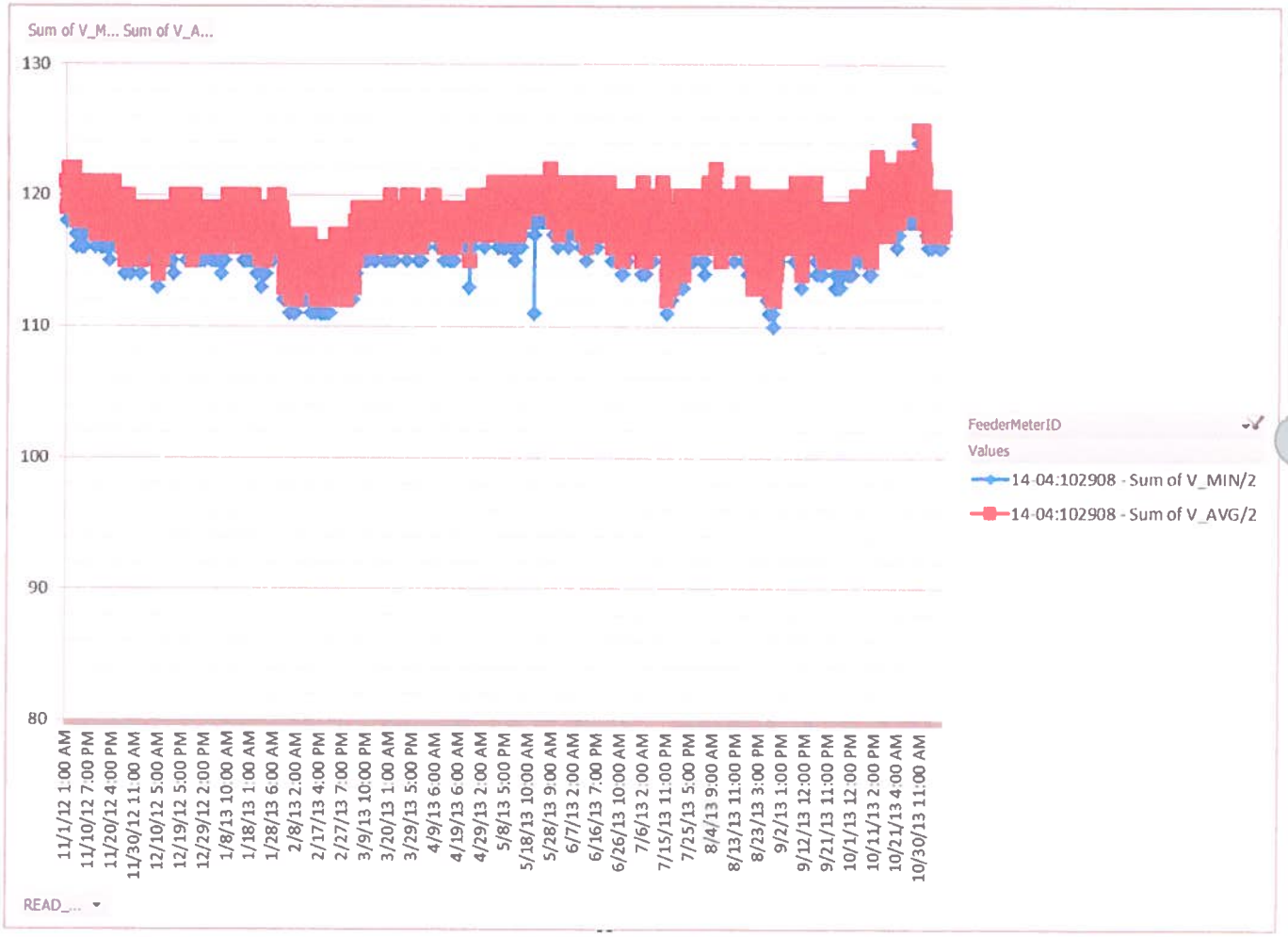
9/23/13 9:00 AM
10/3/13 5:00 AM
10/13/13 2:00 AM
10/22/13 2:00 PM
11/1/13 3:00 AM
READ_...
FeederMeterID
Values
14-03:103329 - Sum of V_MIN/2
14-03:103329 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/10/12 7:00 PM
11/20/12 4:00 PM
11/30/12 11:00 AM
12/10/12 5:00 AM
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12/29/12 2:00 PM
1/8/13 10:00 AM
1/18/13 1:00 AM
1/28/13 6:00 AM
2/8/13 2:00 AM
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8/23/13 3:00 PM
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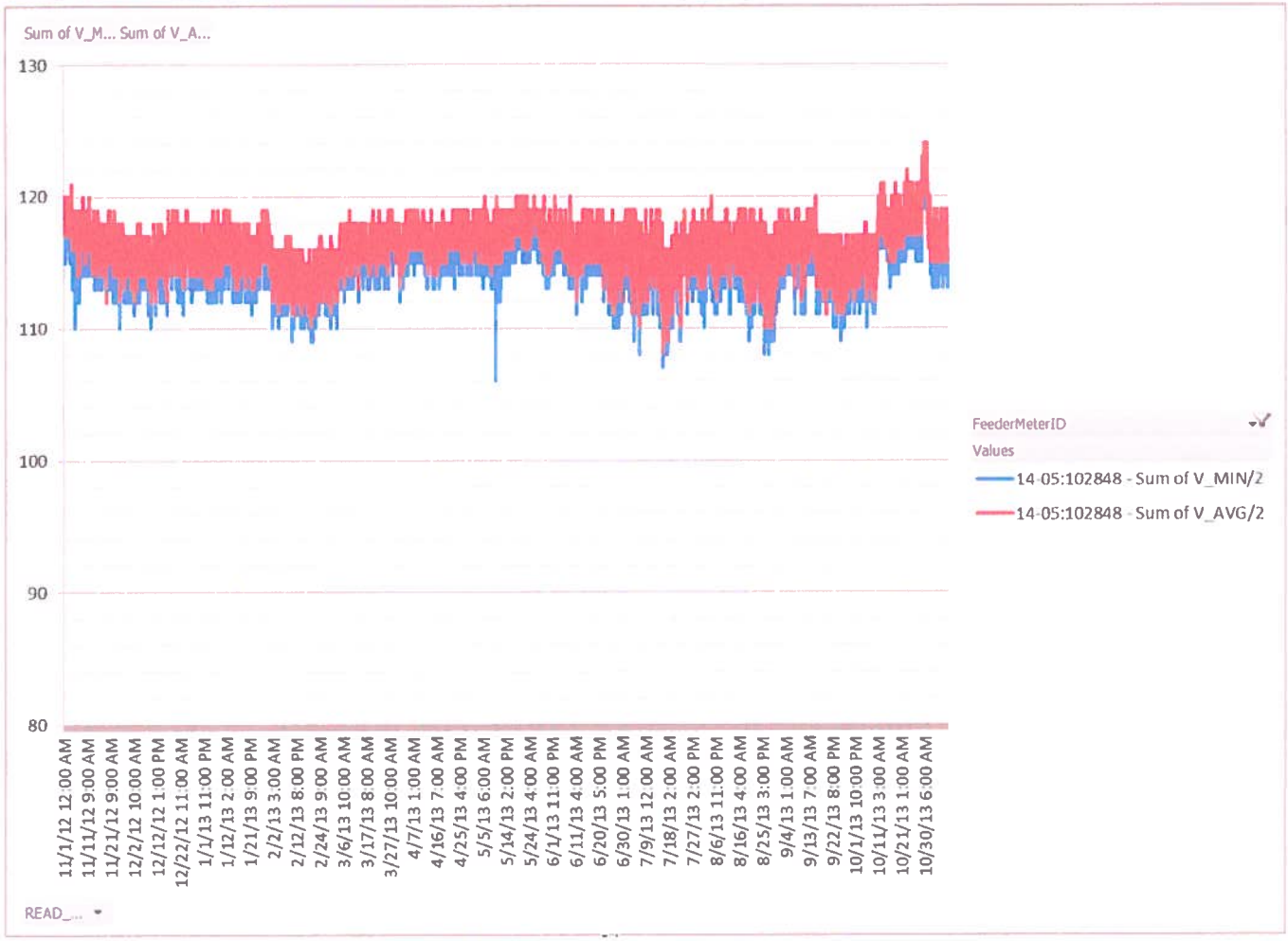
9/12/13 12:00 PM
9/21/13 11:00 PM
10/1/13 12:00 PM
10/11/13 2:00 PM
10/21/13 4:00 AM
10/30/13 11:00 AM
READ_...
FeederMeterID
Values
14-04:102908 - Sum of V_MIN/2
14-04:102908 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/11/12 9:00 AM
11/21/12 9:00 AM
12/2/12 10:00 AM
12/12/12 1:00 PM
12/22/12 11:00 AM
1/1/13 11:00 PM
1/12/13 2:00 AM
1/21/13 9:00 PM
2/2/13 3:00 AM
2/12/13 8:00 PM
2/24/13 9:00 AM
3/6/13 10:00 AM
3/17/13 8:00 AM
3/27/13 10:00 AM
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4/16/13 7:00 AM
4/25/13 4:00 PM
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6/11/13 4:00 AM
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8/6/13 11:00 PM
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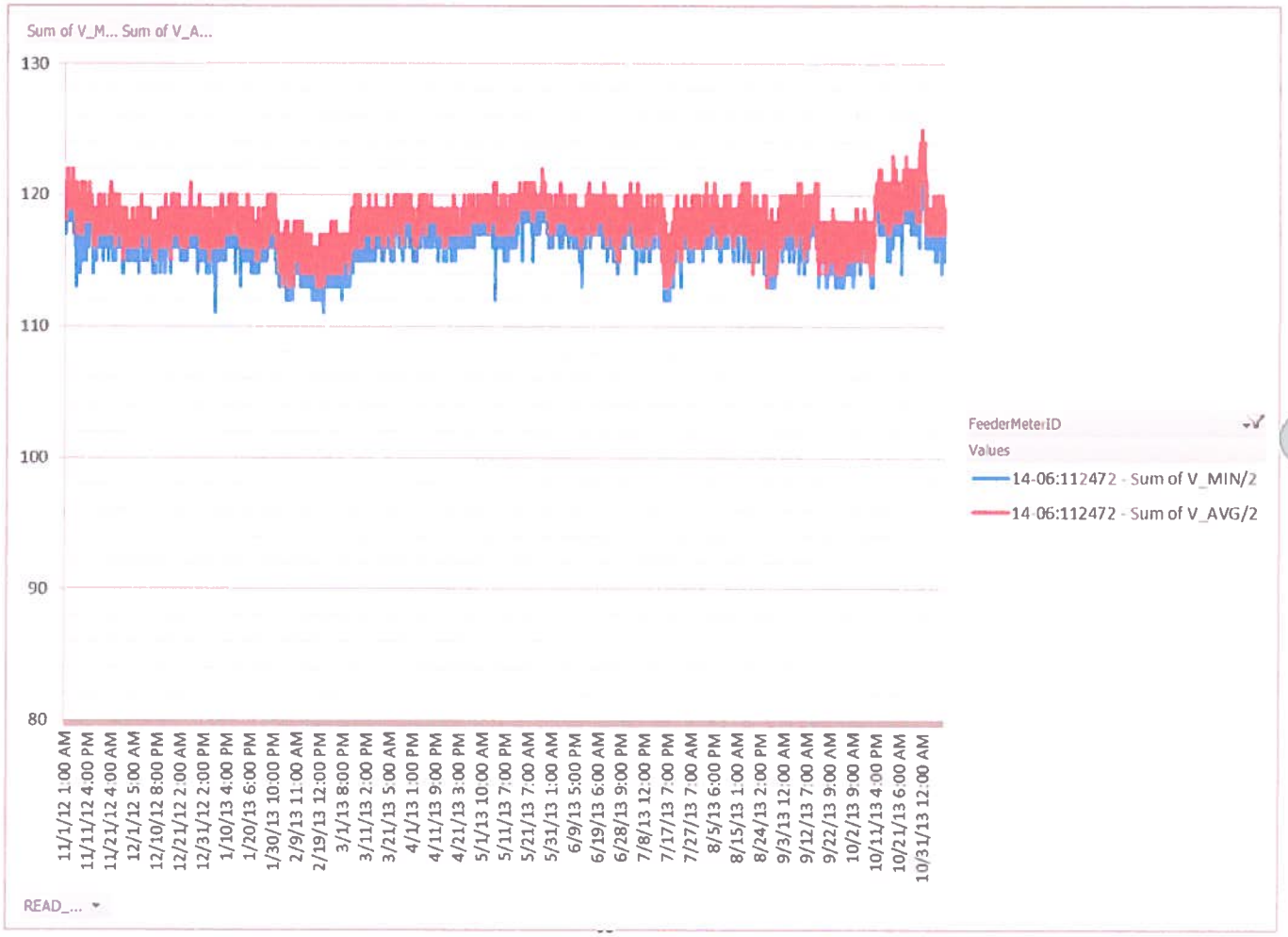
8/25/13 3:00 PM
9/4/13 1:00 AM
9/13/13 7:00 AM
9/22/13 8:00 PM
10/1/13 10:00 PM
10/11/13 3:00 AM
10/21/13 1:00 AM
10/30/13 6:00 AM
READ_...
FeederMeterID
Values
14-05:102848 - Sum of V_MIN/2
14-05:102848 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/11/12 4:00 PM
11/21/12 4:00 AM
12/1/12 5:00 AM
12/10/12 8:00 PM
12/21/12 2:00 AM
12/31/12 2:00 PM
1/10/13 4:00 PM
1/20/13 6:00 PM
1/30/13 10:00 PM
2/9/13 11:00 AM
2/19/13 12:00 PM
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8/24/13 2:00 PM
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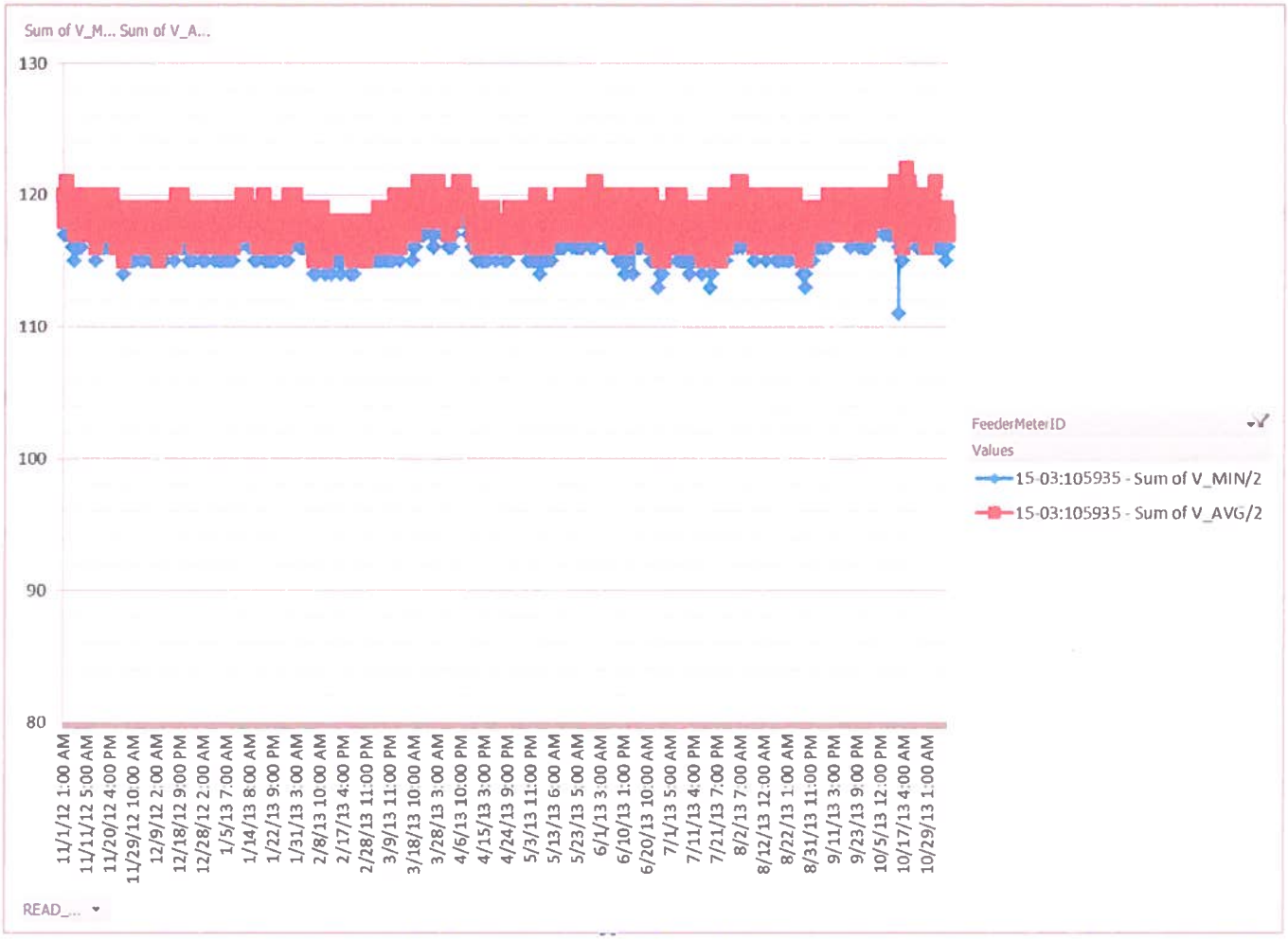
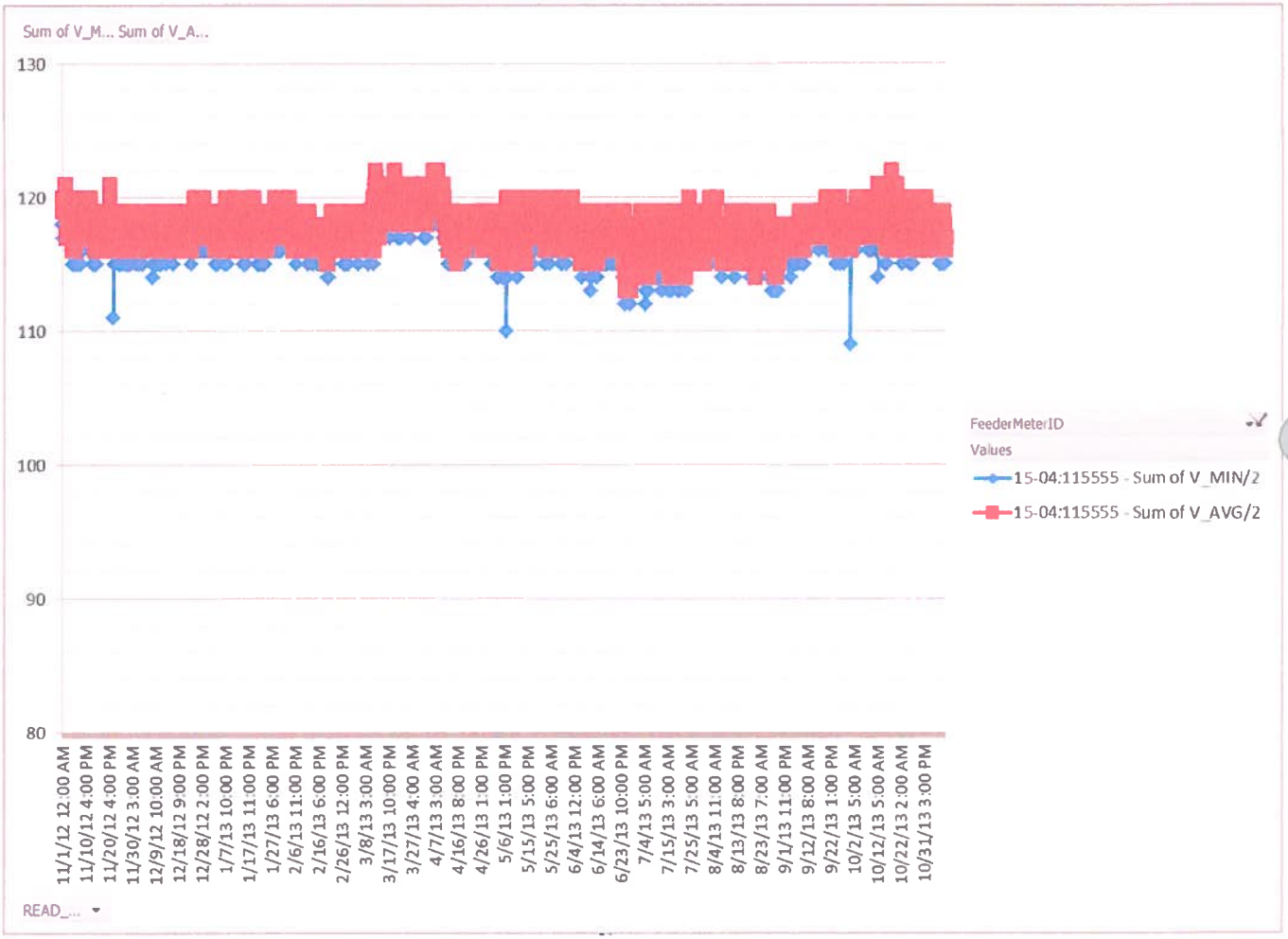
9/22/13 9:00 AM
10/2/13 9:00 AM
10/11/13 4:00 PM
10/21/13 6:00 AM
10/31/13 12:00 AM
READ_...
FeederMeterID
Values
14-06:112472 - Sum of V_MIN/2
14-06:112472 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/11/12 5:00 AM
11/20/12 4:00 PM
11/29/12 10:00 AM
12/9/12 2:00 AM
12/18/12 9:00 PM
12/28/12 2:00 AM
1/5/13 7:00 AM
1/14/13 8:00 AM
1/22/13 9:00 PM
1/31/13 3:00 AM
2/8/13 10:00 AM
2/17/13 4:00 PM
2/28/13 11:00 PM
3/9/13 11:00 PM
3/18/13 10:00 AM
3/28/13 3:00 AM
4/6/13 10:00 PM
4/15/13 3:00 PM
4/24/13 9:00 PM
5/3/13 11:00 PM
5/13/13 6:00 AM
5/23/13 5:00 AM
6/1/13 3:00 AM
6/10/13 1:00 PM
6/20/13 10:00 AM
7/1/13 5:00 AM
7/11/13 4:00 PM
7/21/13 7:00 PM
8/2/13 7:00 AM
8/12/13 12:00 AM
8/22/13 1:00 AM
8/31/13 11:00 PM
9/11/13 3:00 PM
9/23/13 9:00 PM
10/5/13 12:00 PM
10/17/13 4:00 AM
10/29/13 1:00 AM
READ_...
FeederMeterID
Values
15-03:105935 - Sum of V_MIN/2
15-03:105935 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 4:00 PM
11/20/12 4:00 PM
11/30/12 3:00 AM
12/9/12 10:00 AM
12/18/12 9:00 PM
12/28/12 2:00 PM
1/7/13 10:00 PM
1/17/13 11:00 PM
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2/6/13 11:00 PM
2/16/13 6:00 PM
2/26/13 12:00 PM
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8/4/13 11:00 AM
8/13/13 8:00 PM
8/23/13 7:00 AM
9/1/13 11:00 PM
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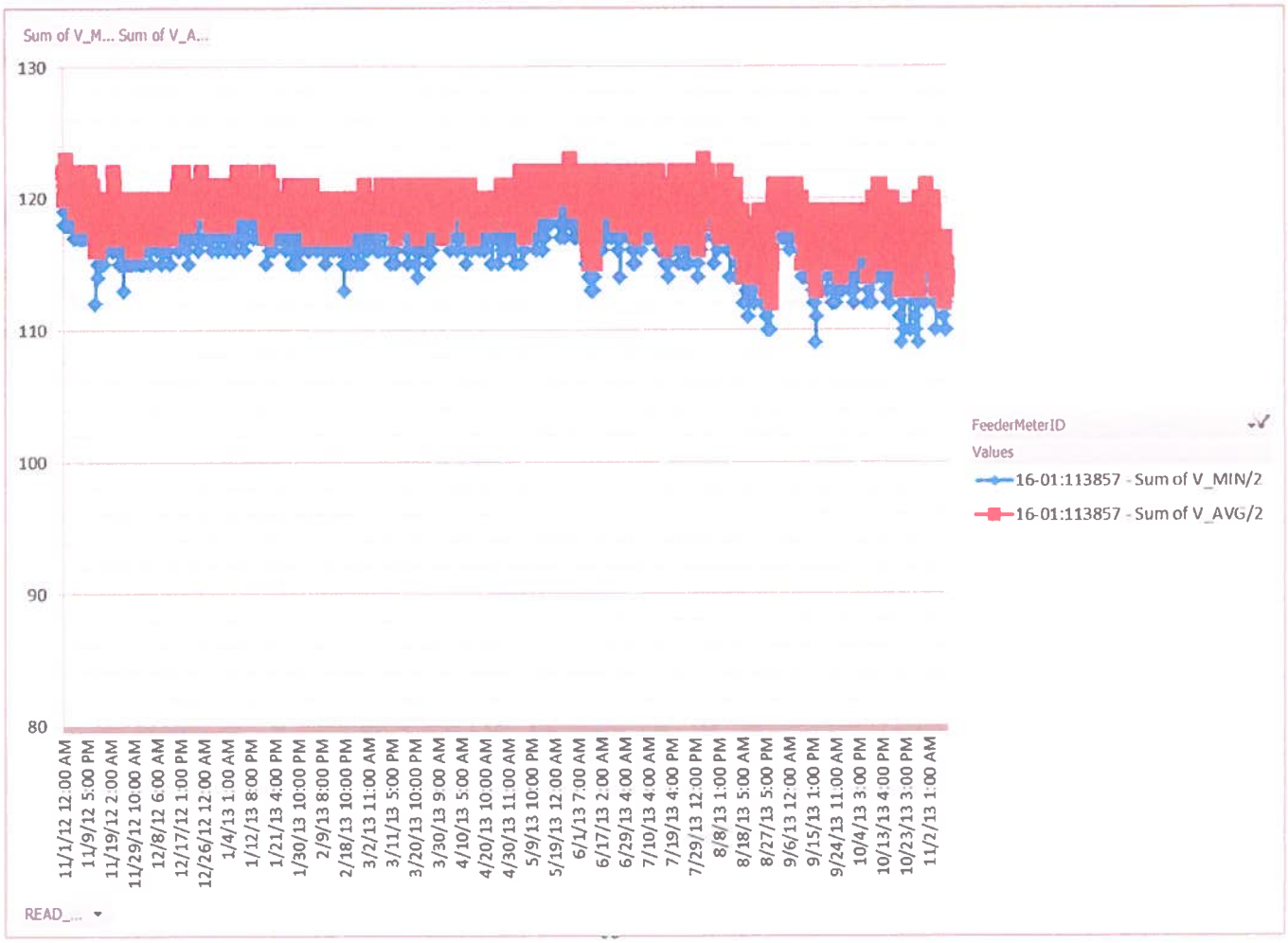
9/22/13 1:00 PM
10/2/13 5:00 AM
10/12/13 5:00 AM
10/22/13 2:00 AM
10/31/13 3:00 PM
READ_...
FeederMeterID
Values
15-04:115555 - Sum of V_MIN/2
15-04:115555 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/9/12 5:00 PM
11/19/12 2:00 AM
11/29/12 10:00 AM
12/8/12 6:00 AM
12/17/12 1:00 PM
12/26/12 12:00 AM
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9/24/13 11:00 AM
10/4/13 3:00 PM
10/13/13 4:00 PM
10/23/13 3:00 PM
11/2/13 1:00 AM
READ_...
FeederMeterID
Values
16-01:113857 - Sum of V_MIN/2
16-01:113857 - Sum of V_AVG/2

leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/9/12 11:00 PM
11/19/12 10:00 PM
11/28/12 6:00 PM
12/7/12 11:00 PM
12/16/12 2:00 PM
12/26/12 9:00 AM
1/5/13 7:00 AM
1/14/13 8:00 AM
1/23/13 8:00 PM
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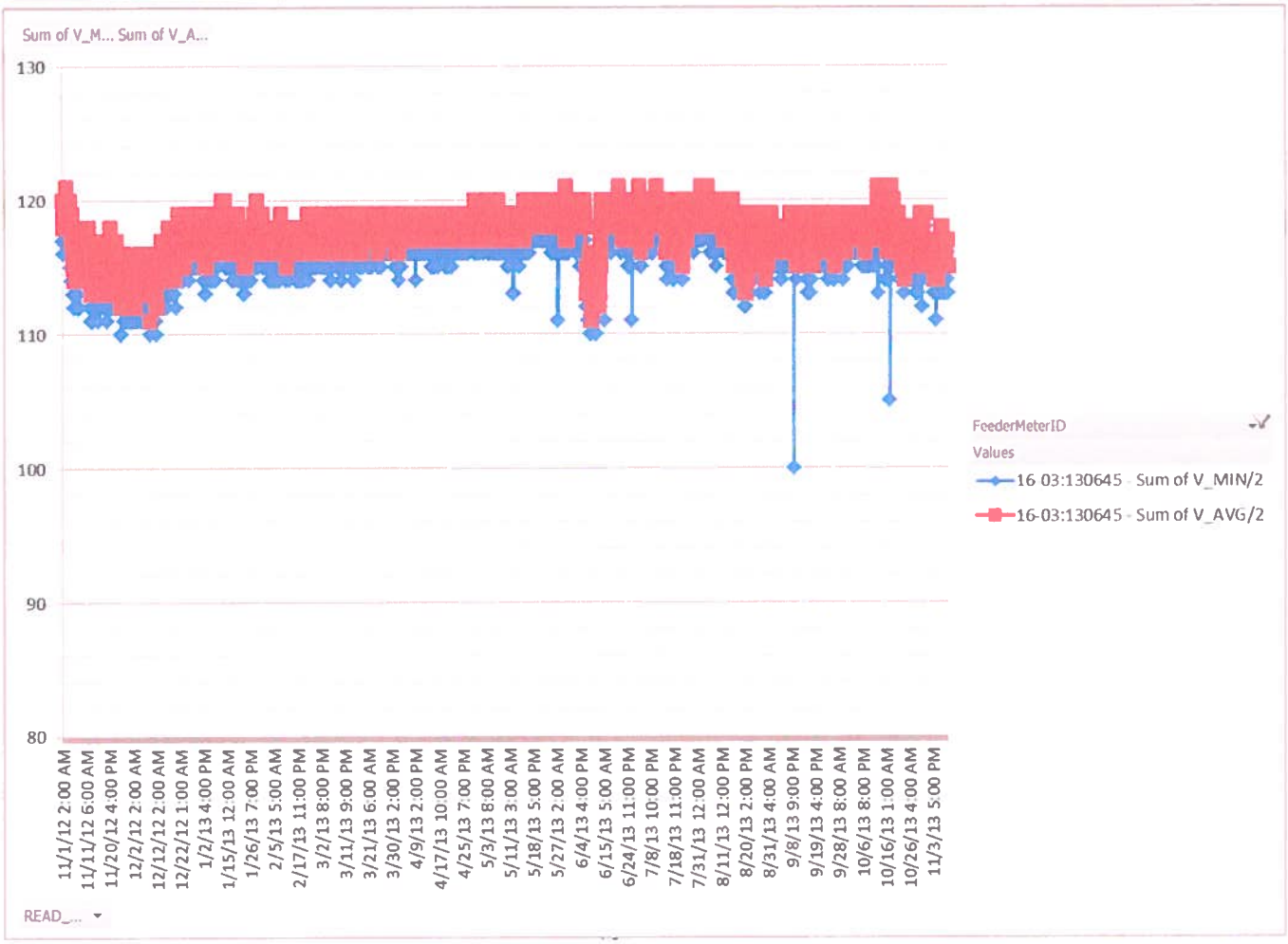
10/2/13 11:00 AM
10/13/13 4:00 AM
10/23/13 2:00 AM
11/2/13 4:00 AM
READ_...
FeederMeterID
Values
16-02:100406 - Sum of V_MIN/2
16-02:100406 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
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11/11/12 6:00 AM
11/20/12 4:00 PM
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1/2/13 4:00 PM
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3/2/13 8:00 PM
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9/28/13 8:00 AM
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10/16/13 1:00 AM
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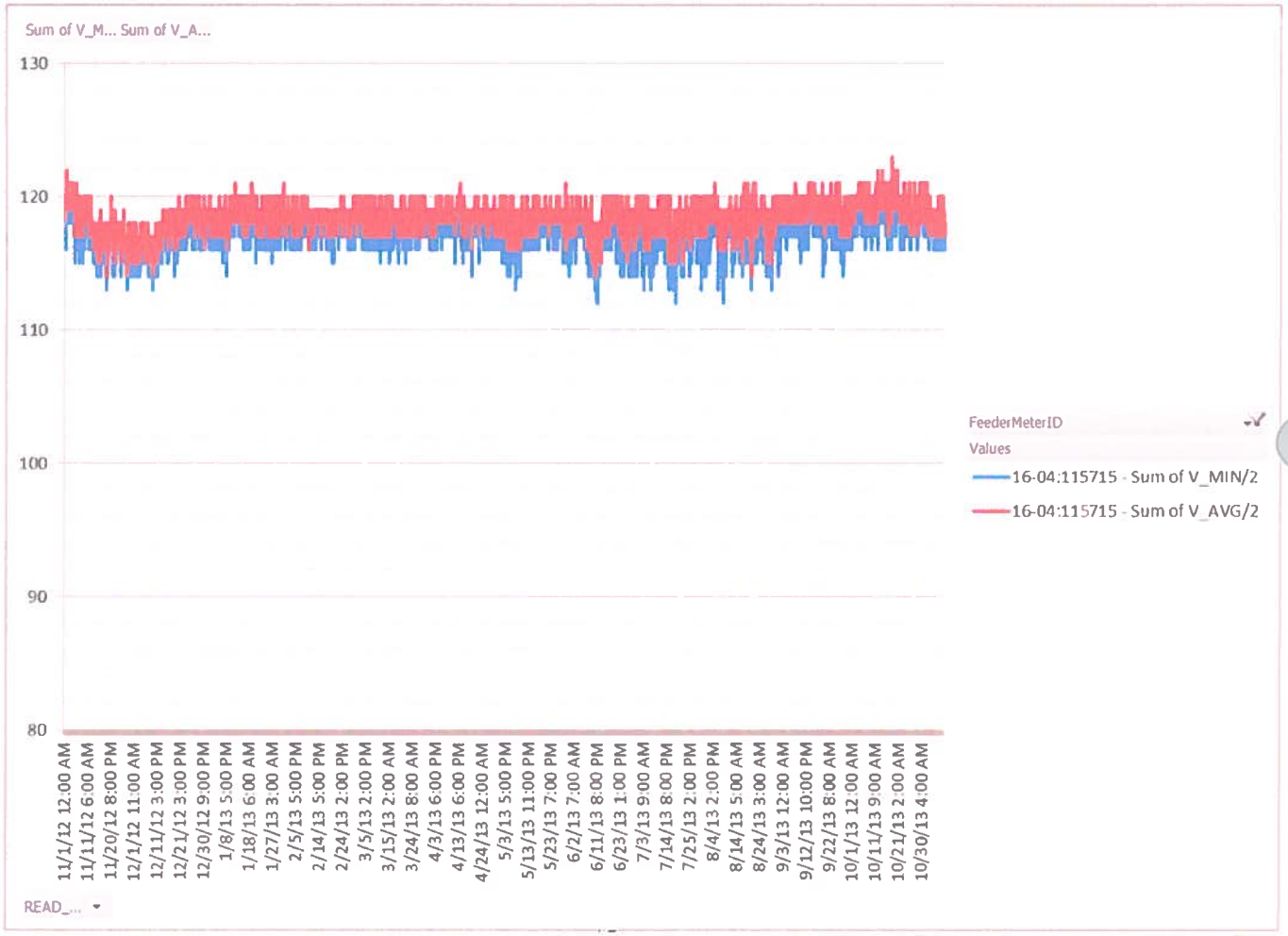
11/3/13 5:00 PM
READ_...
FeederMeterID
Values
16 03:130645 - Sum of V_MIN/2
16-03:130645 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
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120
110
100
90
80
11/1/12 12:00 AM
11/11/12 6:00 AM
11/20/12 8:00 PM
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9/22/13 8:00 AM
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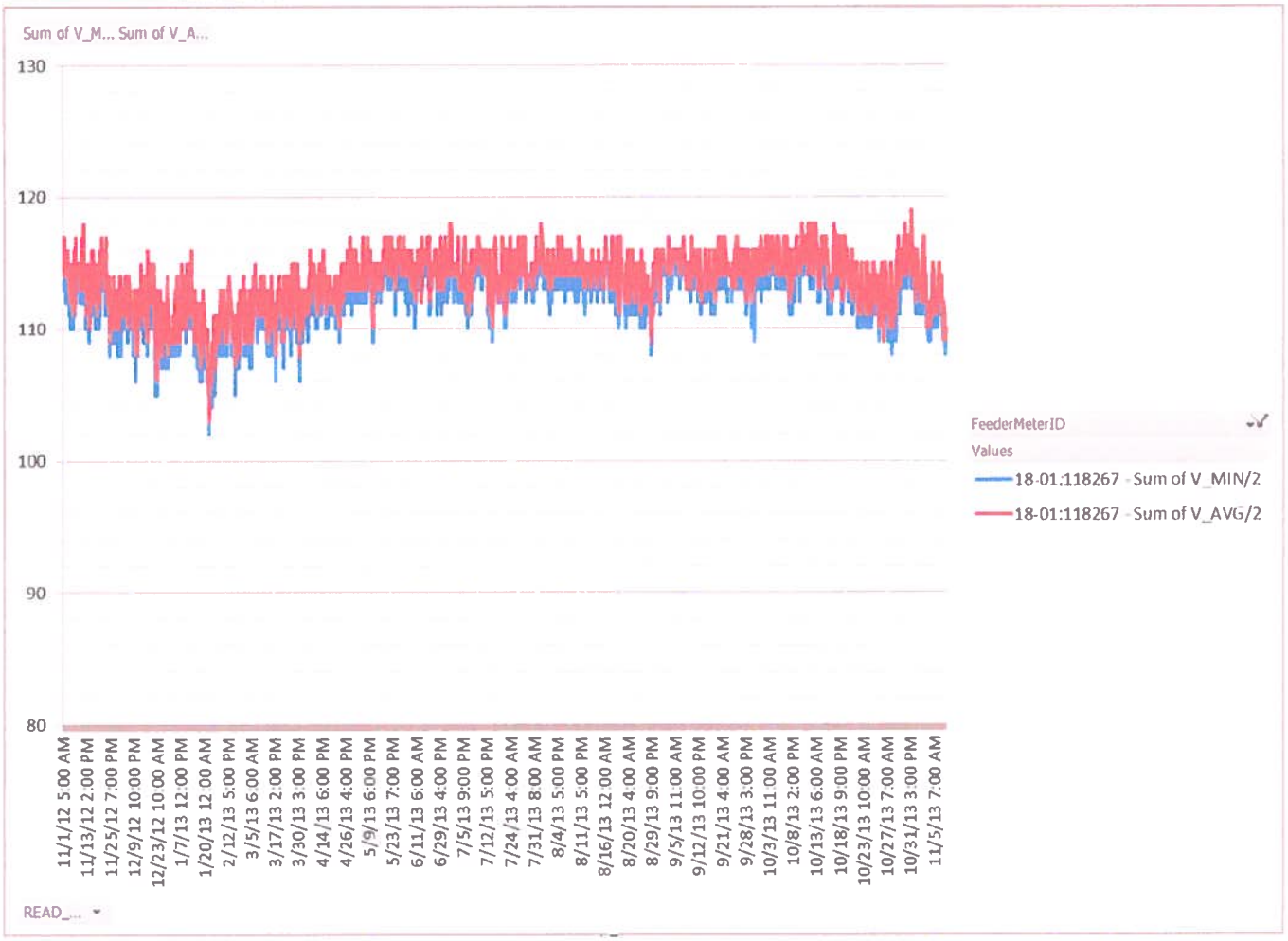
10/30/13 4:00 AM
READ_...
FeederMeterID
Values
16-04:115715 - Sum of V_MIN/2
16-04:115715 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 5:00 AM
11/13/12 2:00 PM
11/25/12 7:00 PM
12/9/12 10:00 PM
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10/8/13 2:00 PM
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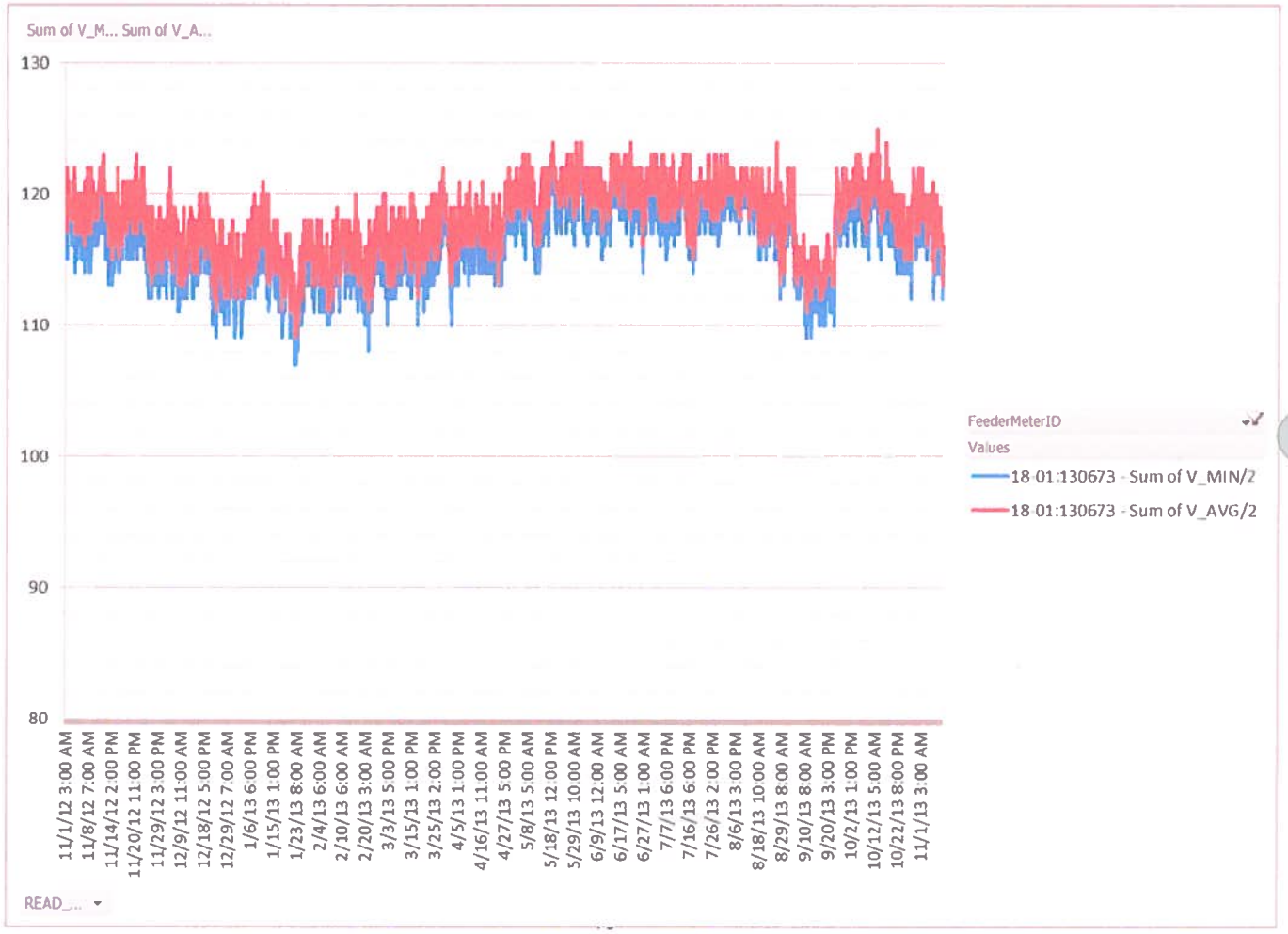
10/27/13 7:00 AM
10/31/13 3:00 PM
11/5/13 7:00 AM
READ_...
FeederMeterID
Values
18-01:118267 - Sum of V_MIN/2
18-01:118267 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 3:00 AM
11/8/12 7:00 AM
11/14/12 2:00 PM
11/20/12 11:00 PM
11/29/12 3:00 PM
12/9/12 11:00 AM
12/18/12 5:00 PM
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1/6/13 6:00 PM
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1/23/13 8:00 AM
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8/29/13 8:00 AM
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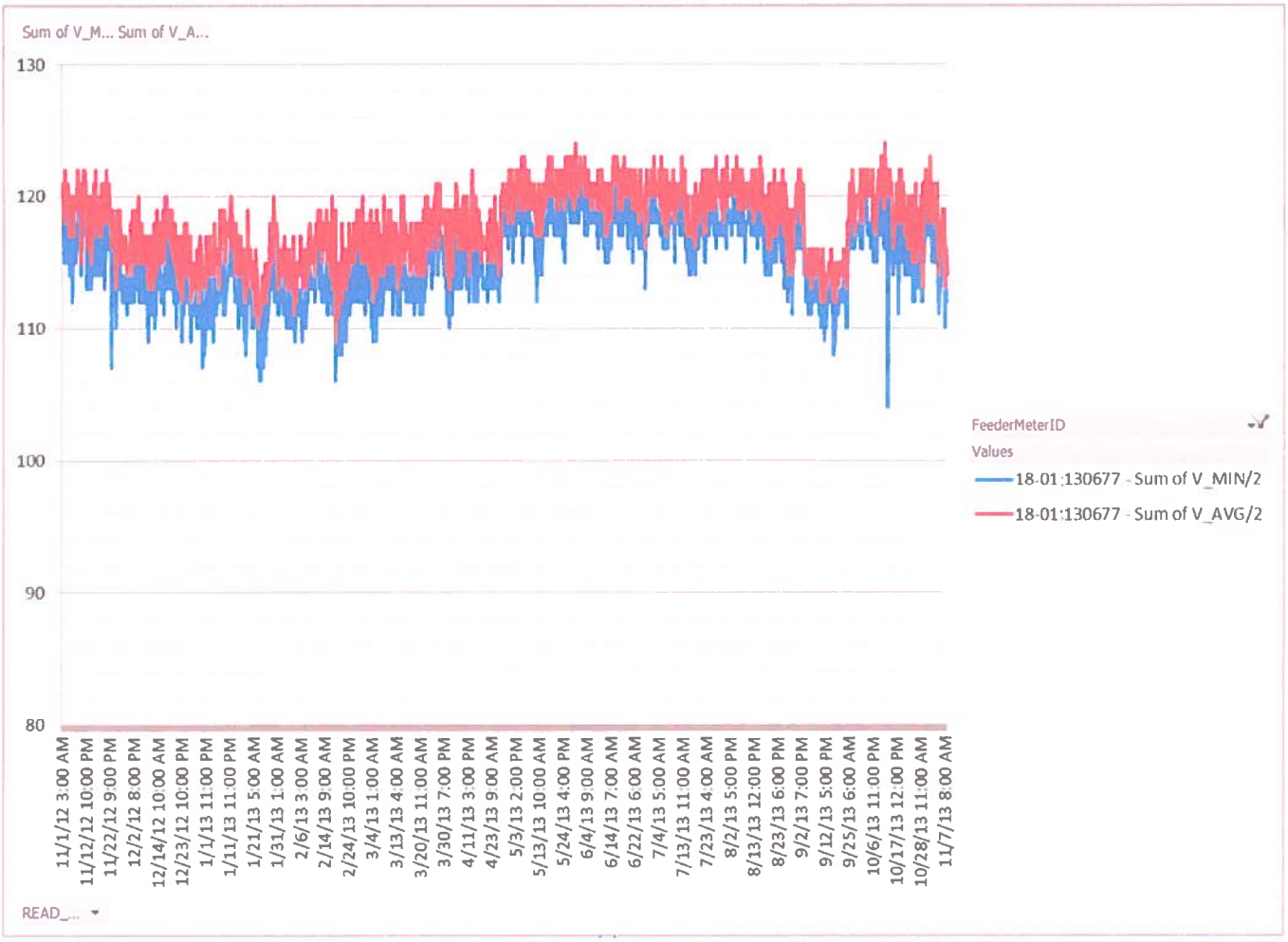
9/20/13 3:00 PM
10/2/13 1:00 PM
10/12/13 5:00 AM
10/22/13 8:00 PM
11/1/13 3:00 AM
READ_...
FeederMeterID
Values
18 01:130673 - Sum of V_MIN/2
18 01:130673 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 3:00 AM
11/12/12 10:00 PM
11/22/12 9:00 PM
12/2/12 8:00 PM
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8/23/13 6:00 PM
9/2/13 7:00 PM
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9/25/13 6:00 AM
10/6/13 11:00 PM
10/17/13 12:00 PM
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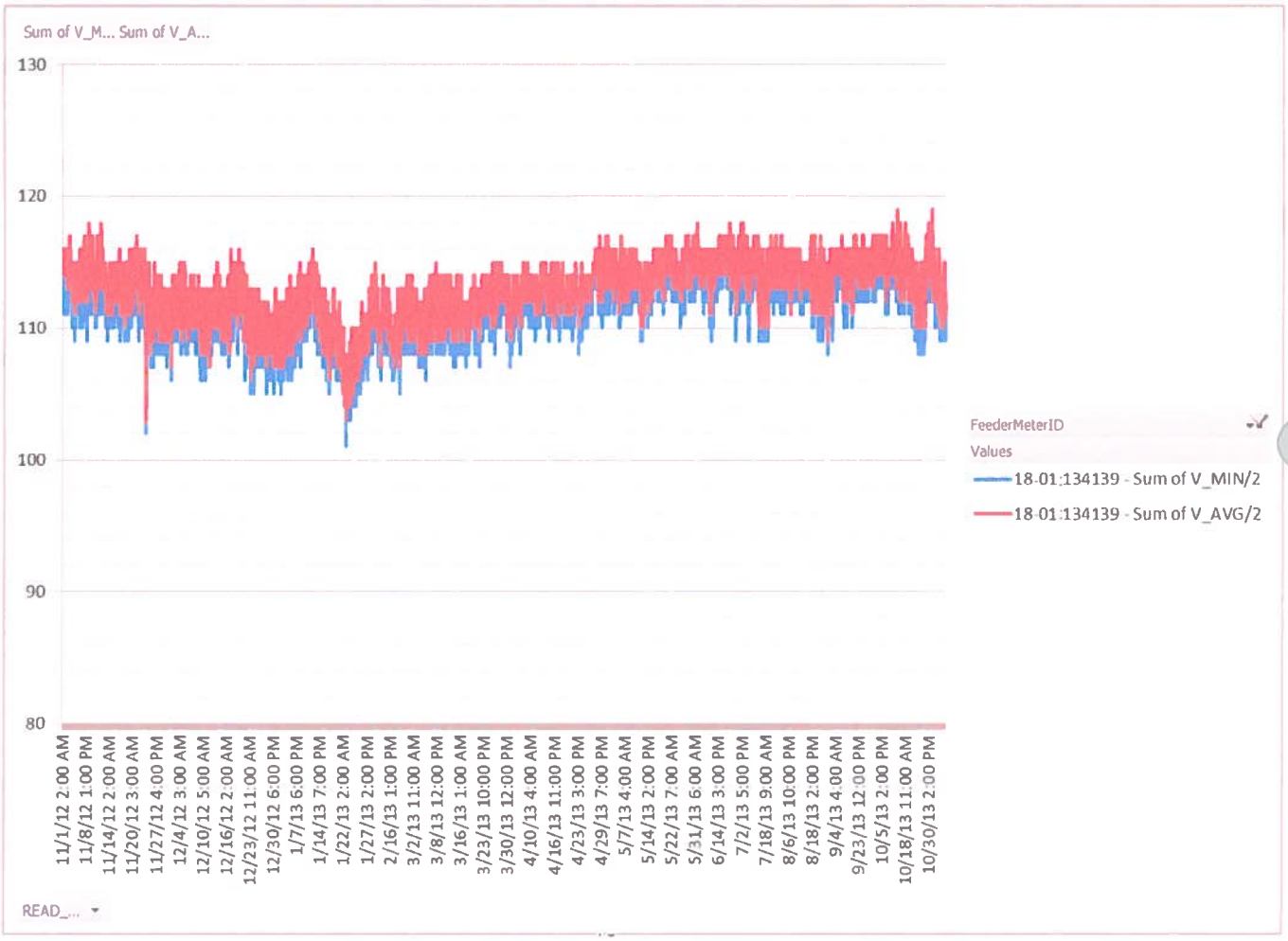
11/7/13 8:00 AM
READ_...
FeederMeterID
Values
18-01:130677 - Sum of V_MIN/2
18-01:130677 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 2:00 AM
11/8/12 1:00 PM
11/14/12 2:00 AM
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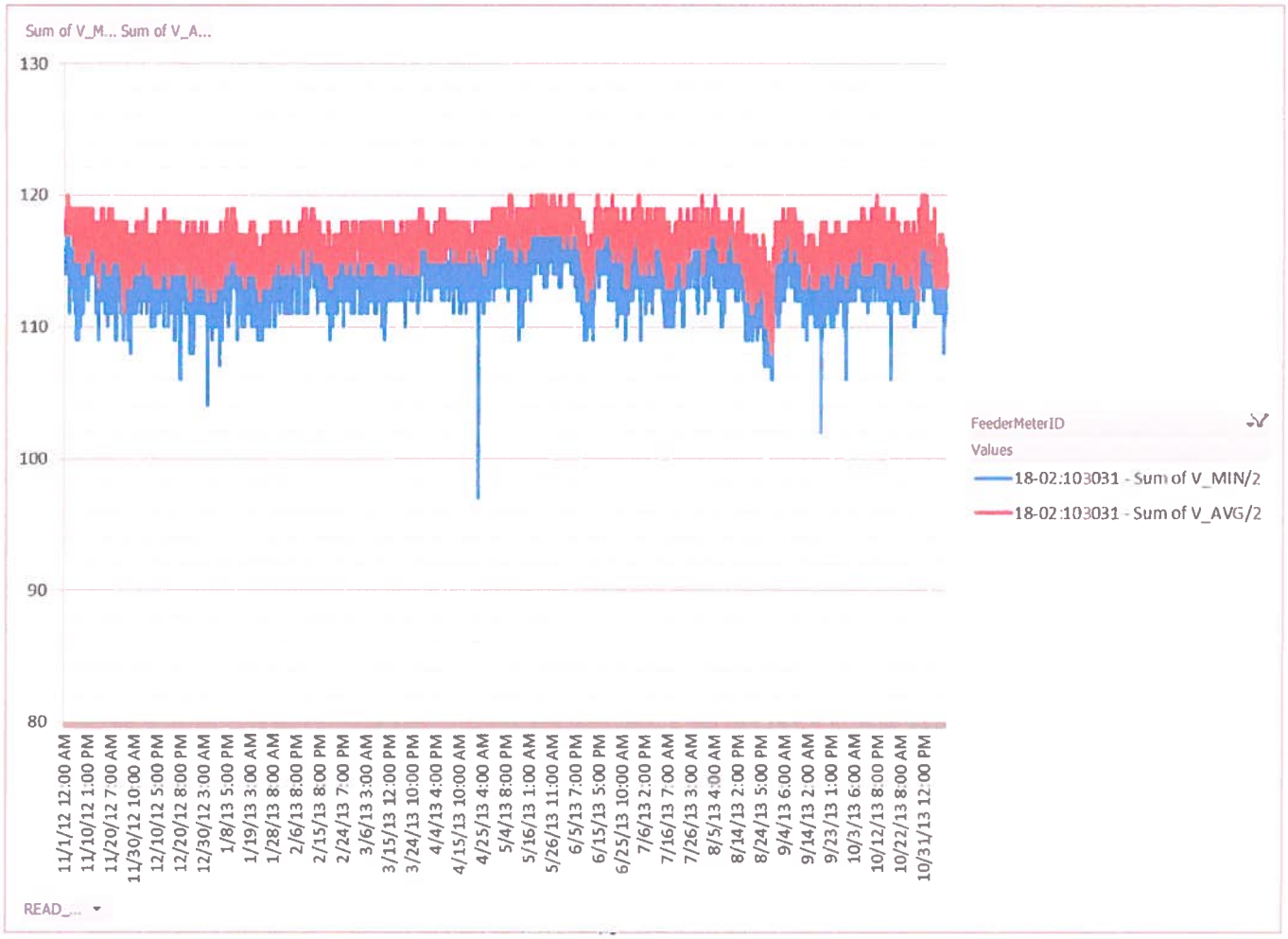
9/4/13 4:00 AM
9/23/13 12:00 PM
10/5/13 2:00 PM
10/18/13 11:00 AM
10/30/13 2:00 PM
READ_...
FeederMeterID
Values
18-01:134139 - Sum of V_MIN/2
18-01:134139 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 1:00 PM
11/20/12 7:00 AM
11/30/12 10:00 AM
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10/22/13 8:00 AM
10/31/13 12:00 PM
READ_...
FeederMeterID
Values
18-02:103031 - Sum of V_MIN/2
18-02:103031 - Sum of V_AVG/2

leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/10/12 7:00 PM
11/20/12 12:00 PM
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11/1/13 12:00 PM
READ_...
FeederMeterID
Values
18 02:109287 - Sum of V_MIN/2
18 02:109287 - Sum of V_AVG/2

leidos

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 4:00 AM
11/20/12 1:00 PM
11/30/12 1:00 PM
12/10/12 8:00 PM
12/20/12 12:00 PM
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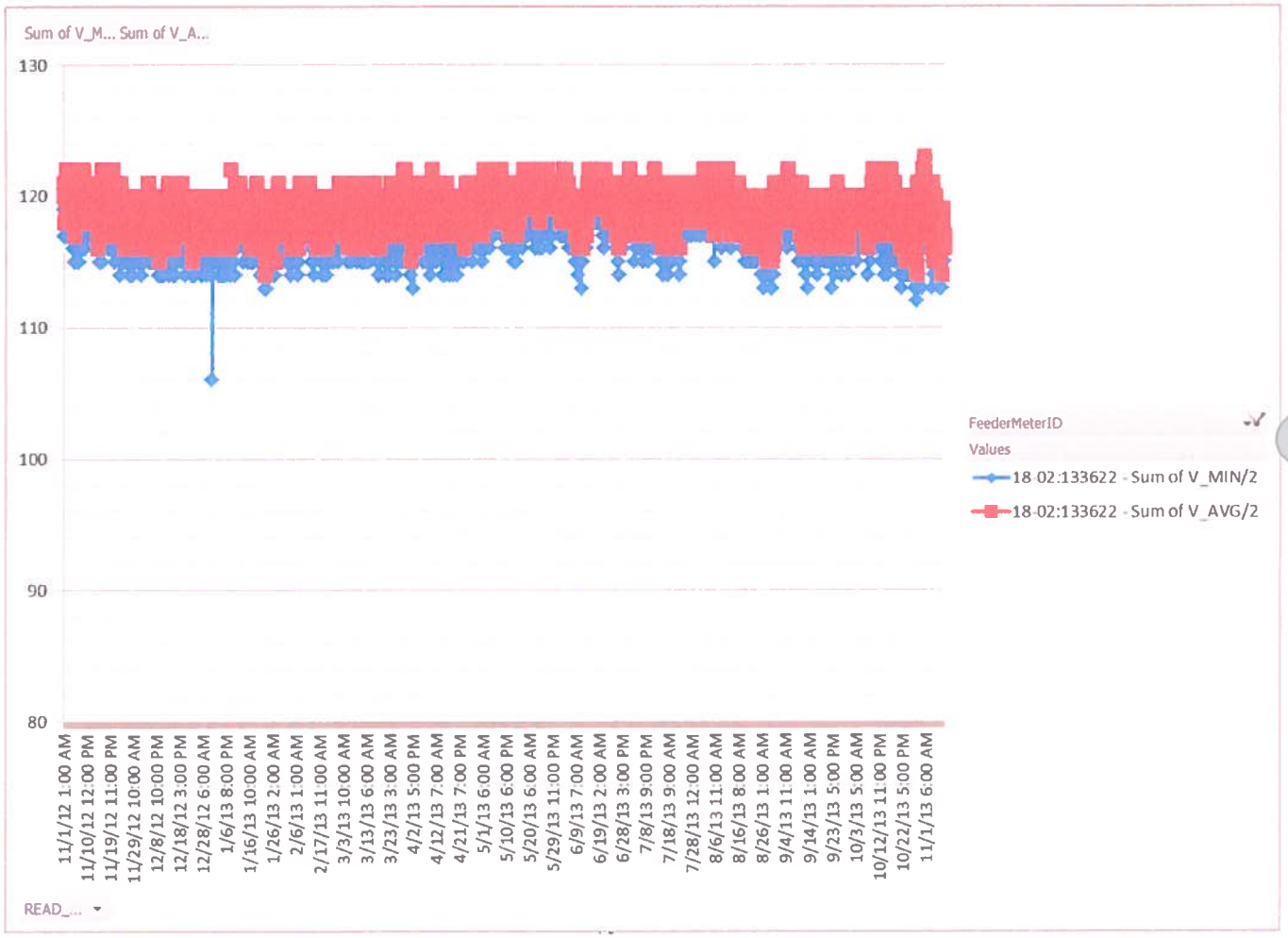
10/13/13 3:00 PM
10/23/13 5:00 PM
11/2/13 6:00 PM
READ_...
FeederMeterID
Values
18-02:109898 - Sum of V_MIN/2
18-02:109898 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
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11/19/12 11:00 PM
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7/28/13 12:00 AM
8/6/13 11:00 AM
8/16/13 8:00 AM
8/26/13 1:00 AM
9/4/13 11:00 AM
9/14/13 1:00 AM
9/23/13 5:00 PM
10/3/13 5:00 AM
10/12/13 11:00 PM
10/22/13 5:00 PM
11/1/13 6:00 AM
READ_...
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Values
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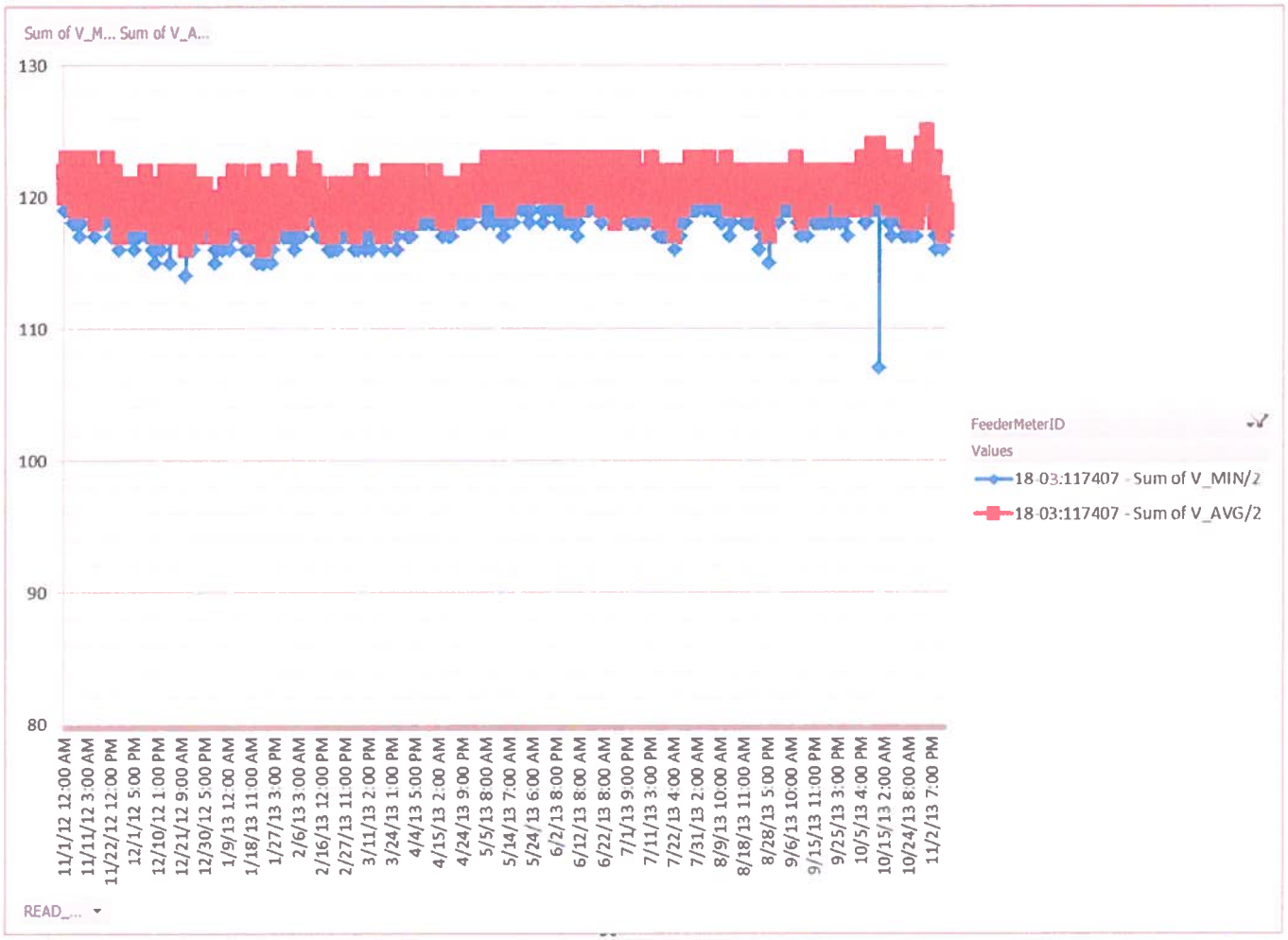
18-02:133622 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
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80
11/1/12 12:00 AM
11/11/12 3:00 AM
11/22/12 12:00 PM
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12/21/12 9:00 AM
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1/18/13 11:00 AM
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READ_...
FeederMeterID
Values
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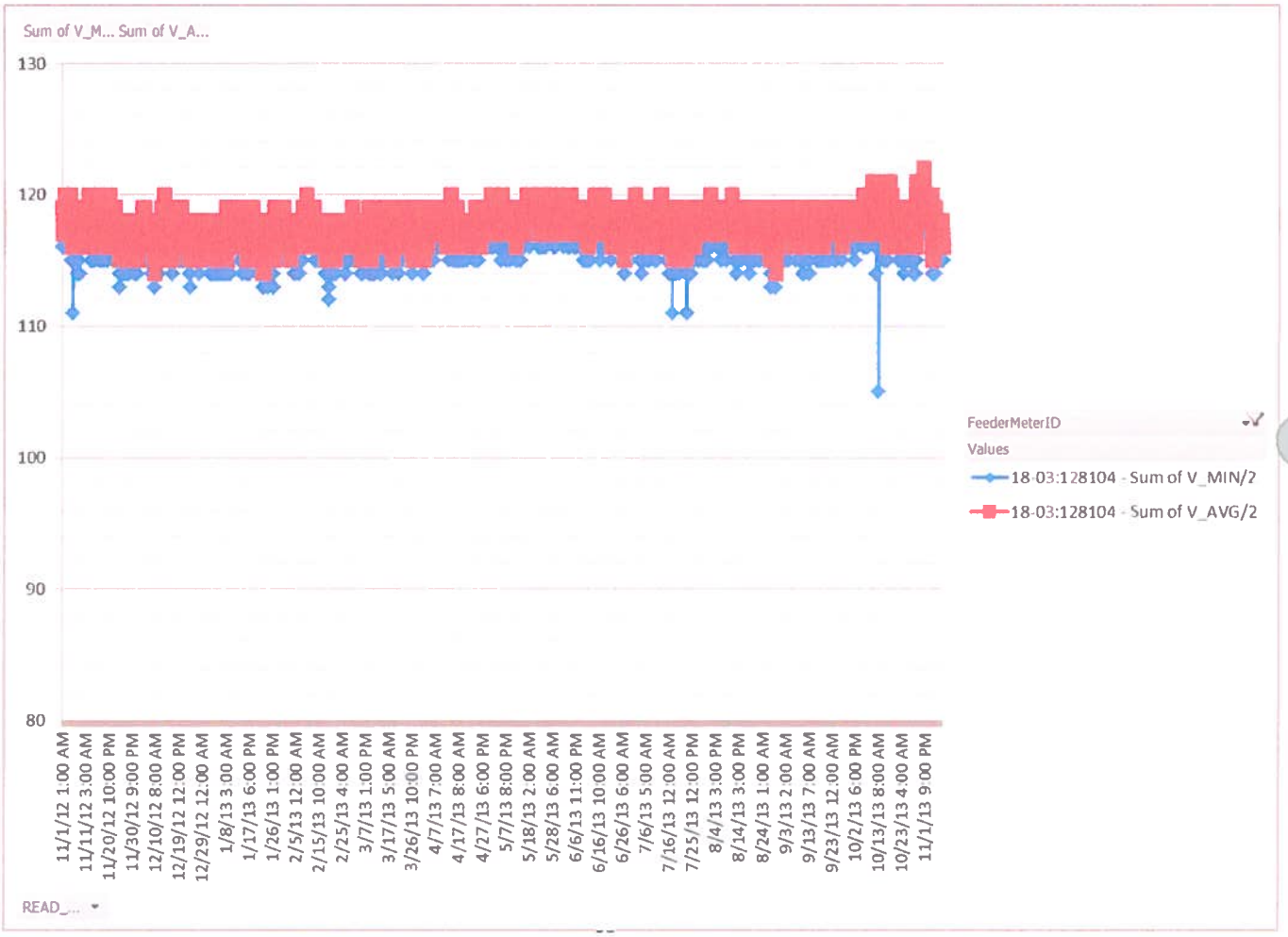
18-03:117407 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
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80
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READ_...
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Values
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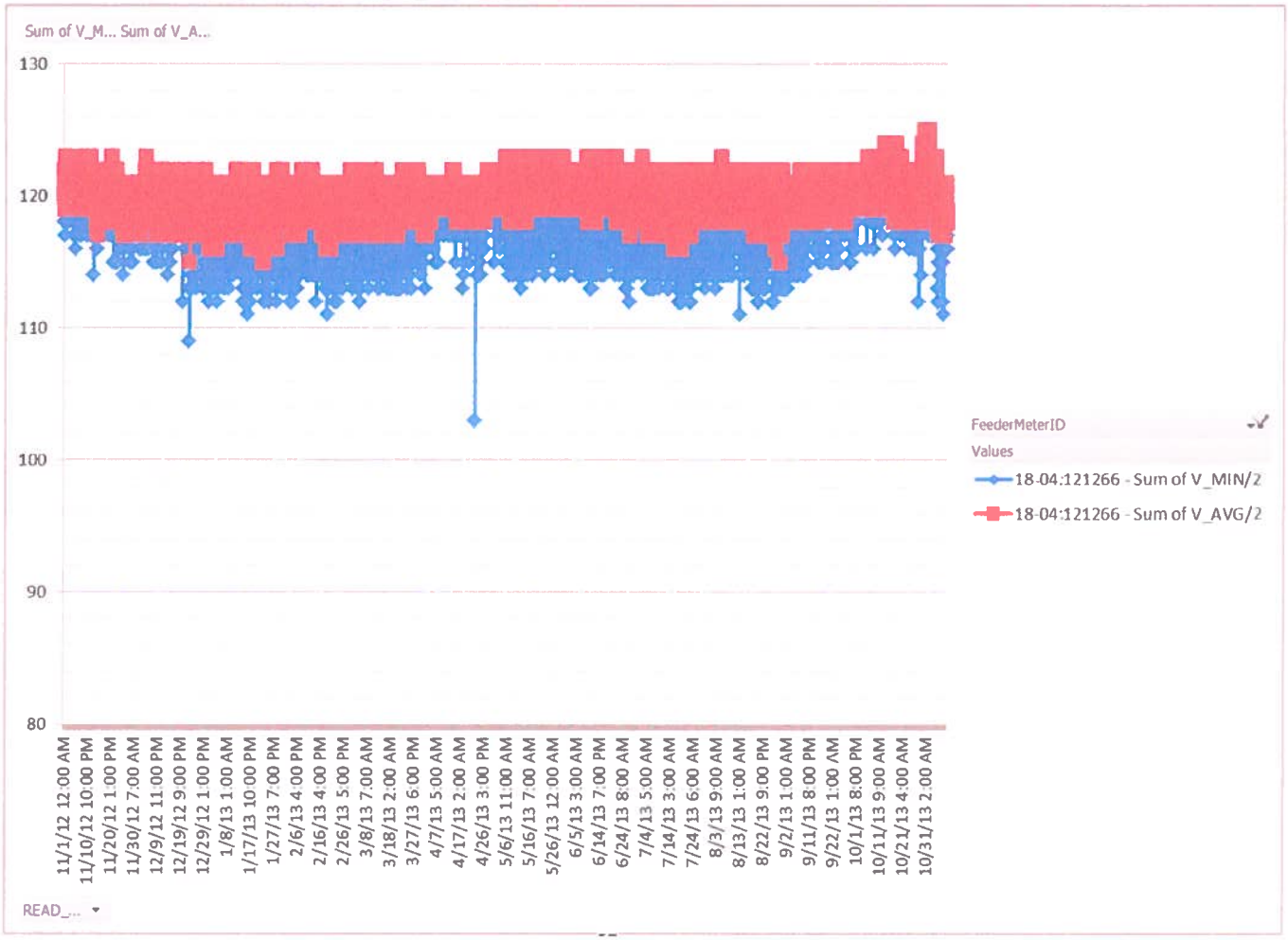
18-03:128104 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
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120
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80
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READ_...
FeederMeterID
Values
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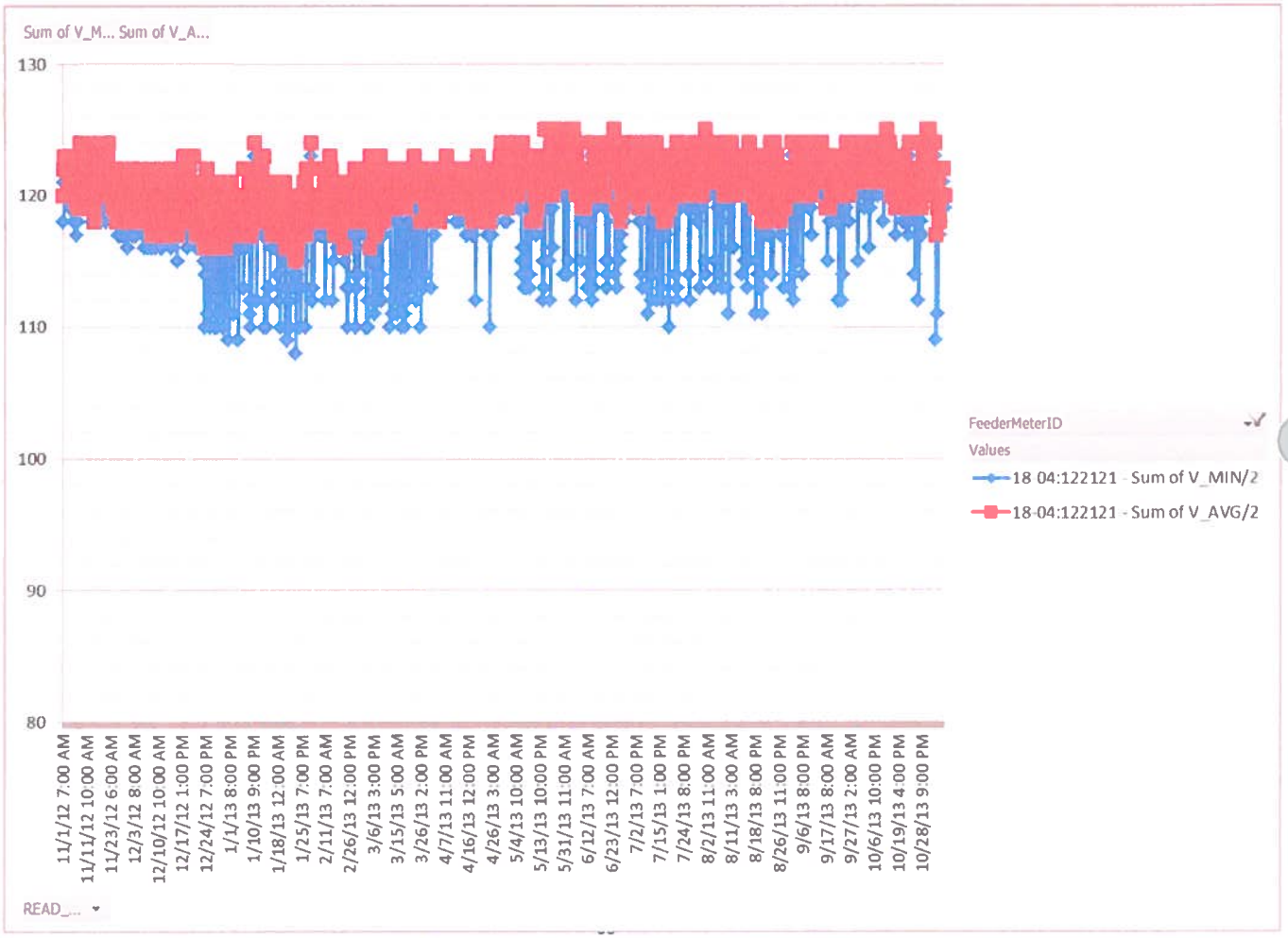
18-04:121266 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
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READ_...
FeederMeterID
Values
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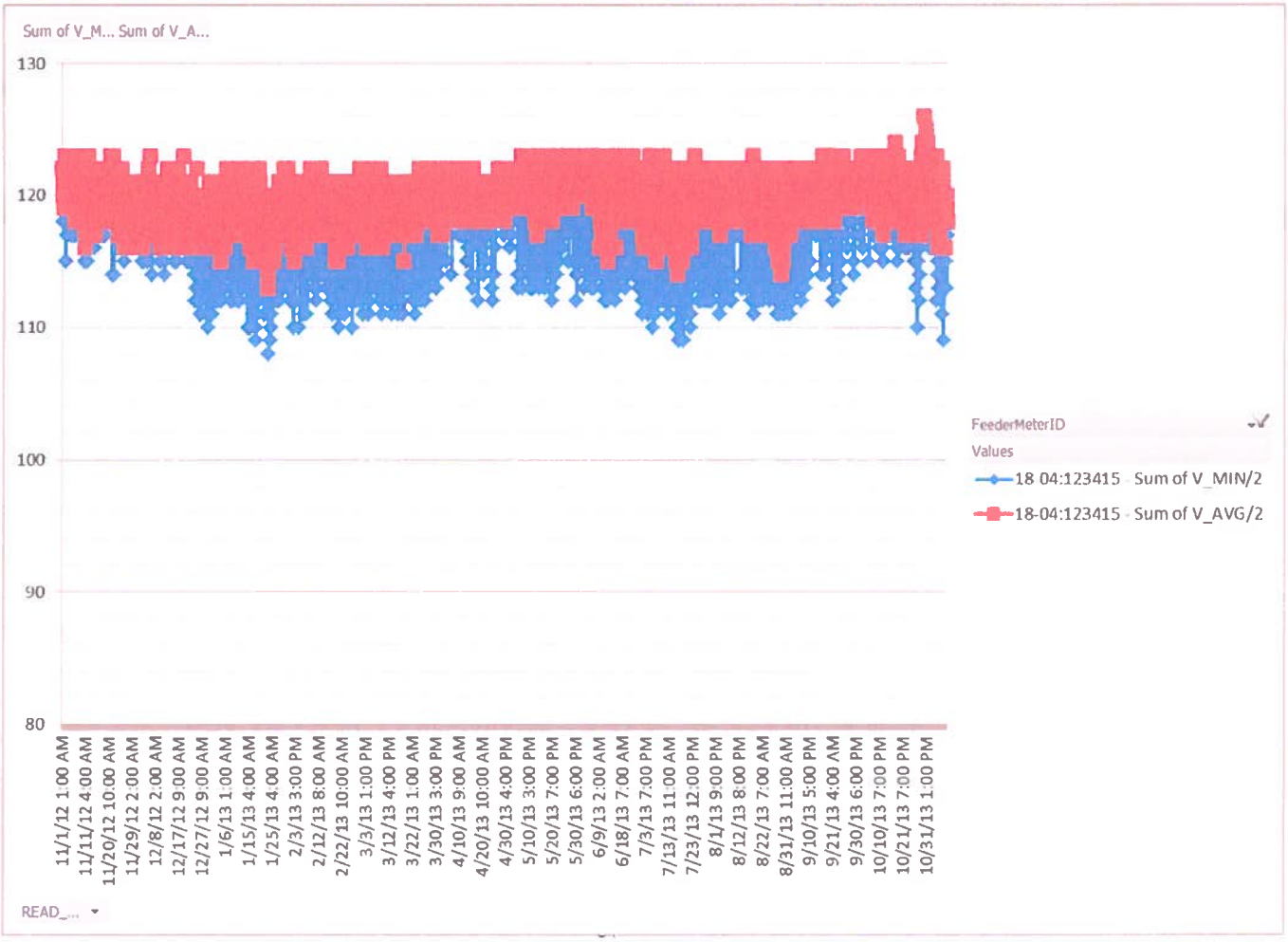
18-04:122121 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
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READ_...
FeederMeterID
Values
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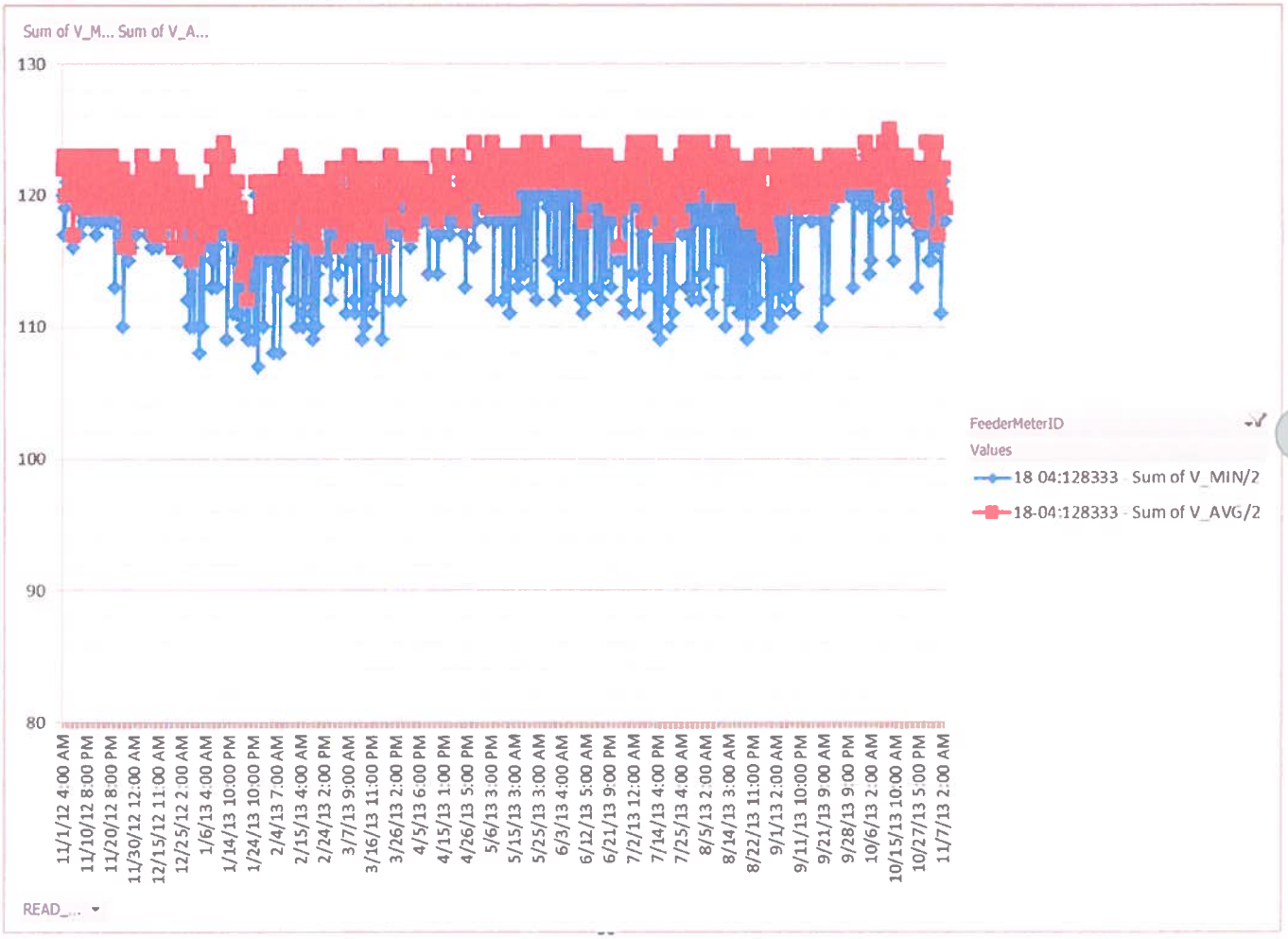
18-04:123415 Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
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10/15/13 10:00 AM
10/27/13 5:00 PM
11/7/13 2:00 AM
READ_...
FeederMeterID
Values
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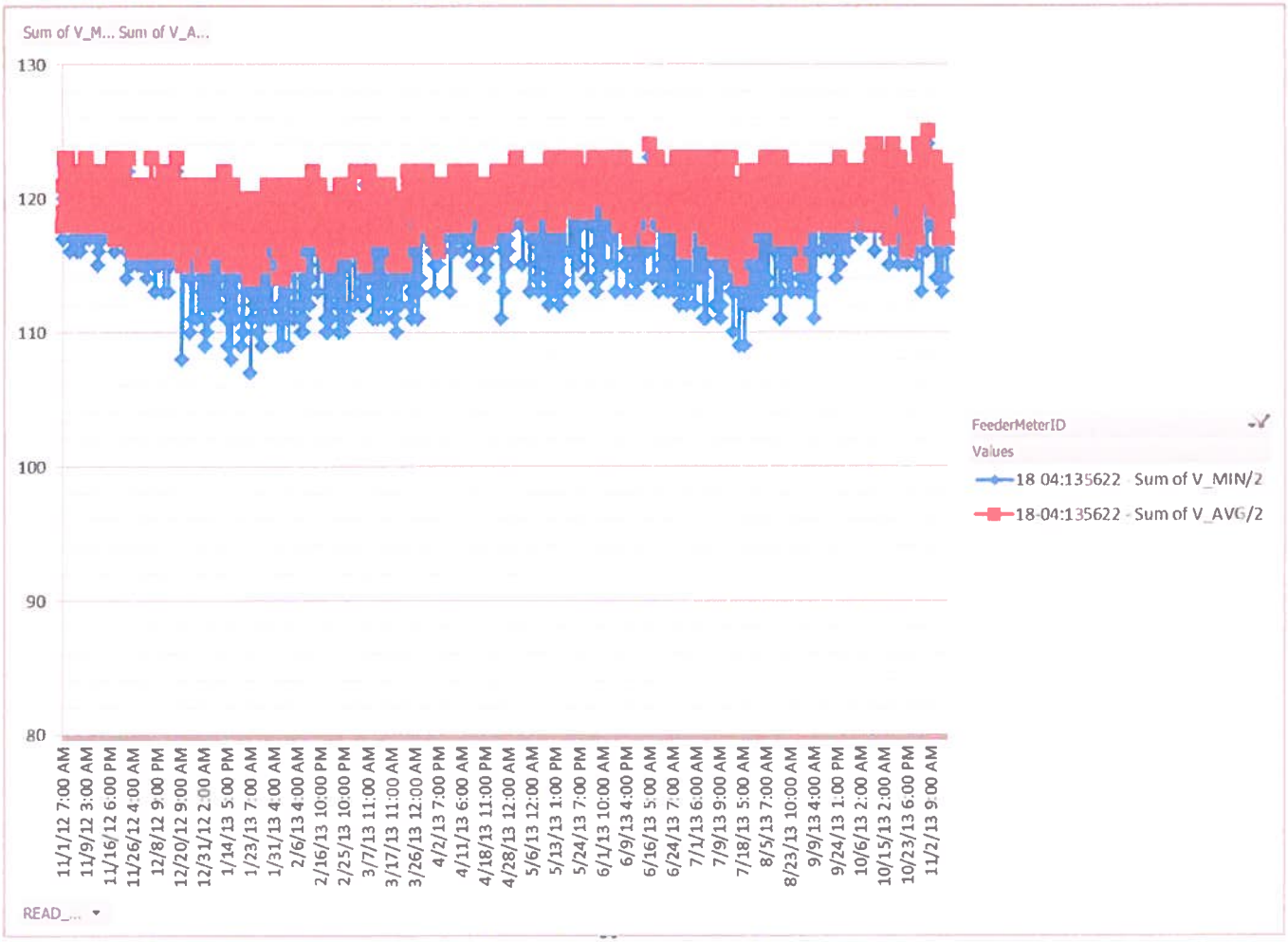
18-04:128333 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
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80
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10/23/13 6:00 PM
11/2/13 9:00 AM
READ_...
FeederMeterID
Values
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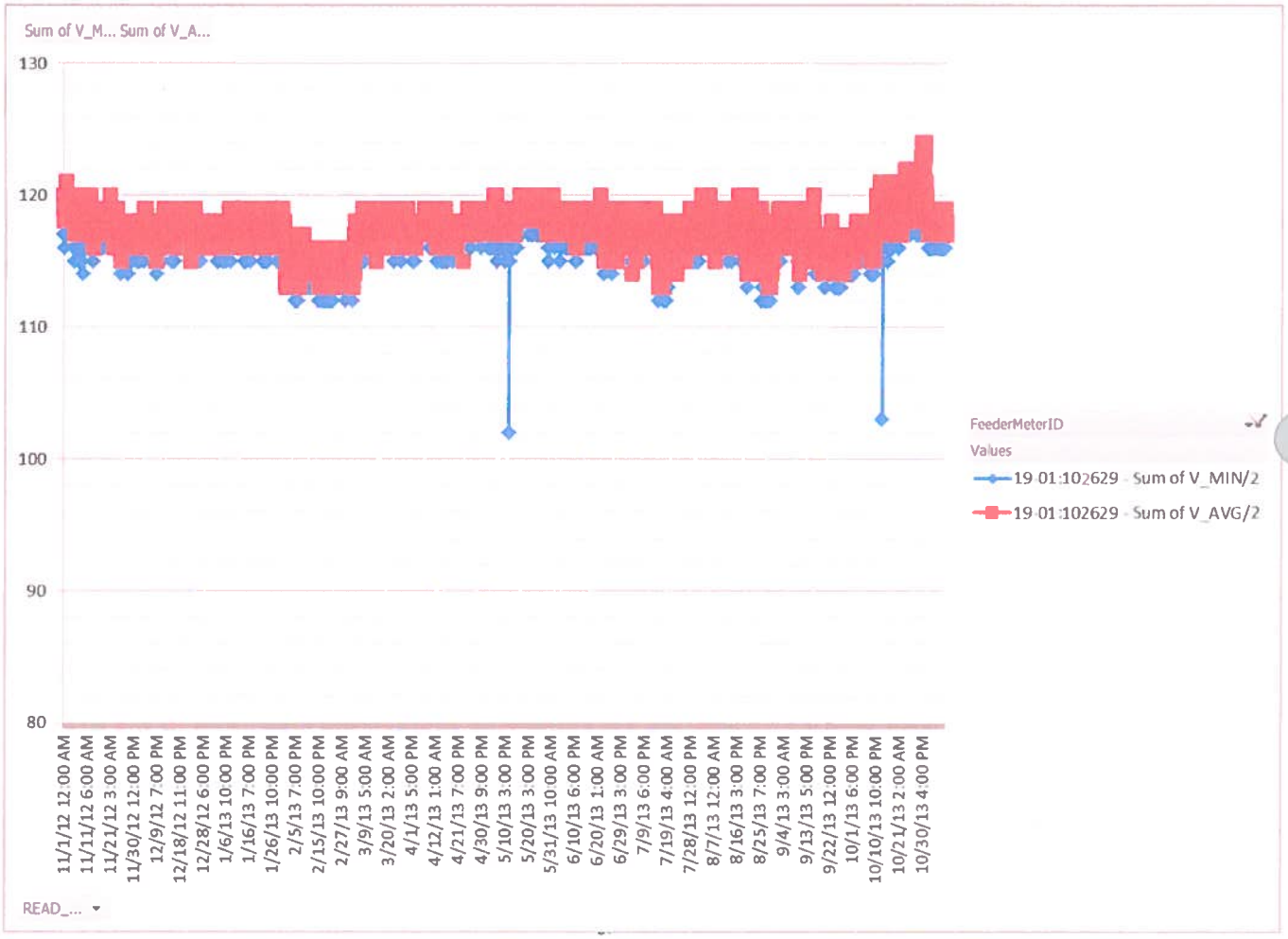
18-04:135622 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
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80
11/1/12 12:00 AM
11/11/12 6:00 AM
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READ_...
FeederMeterID
Values
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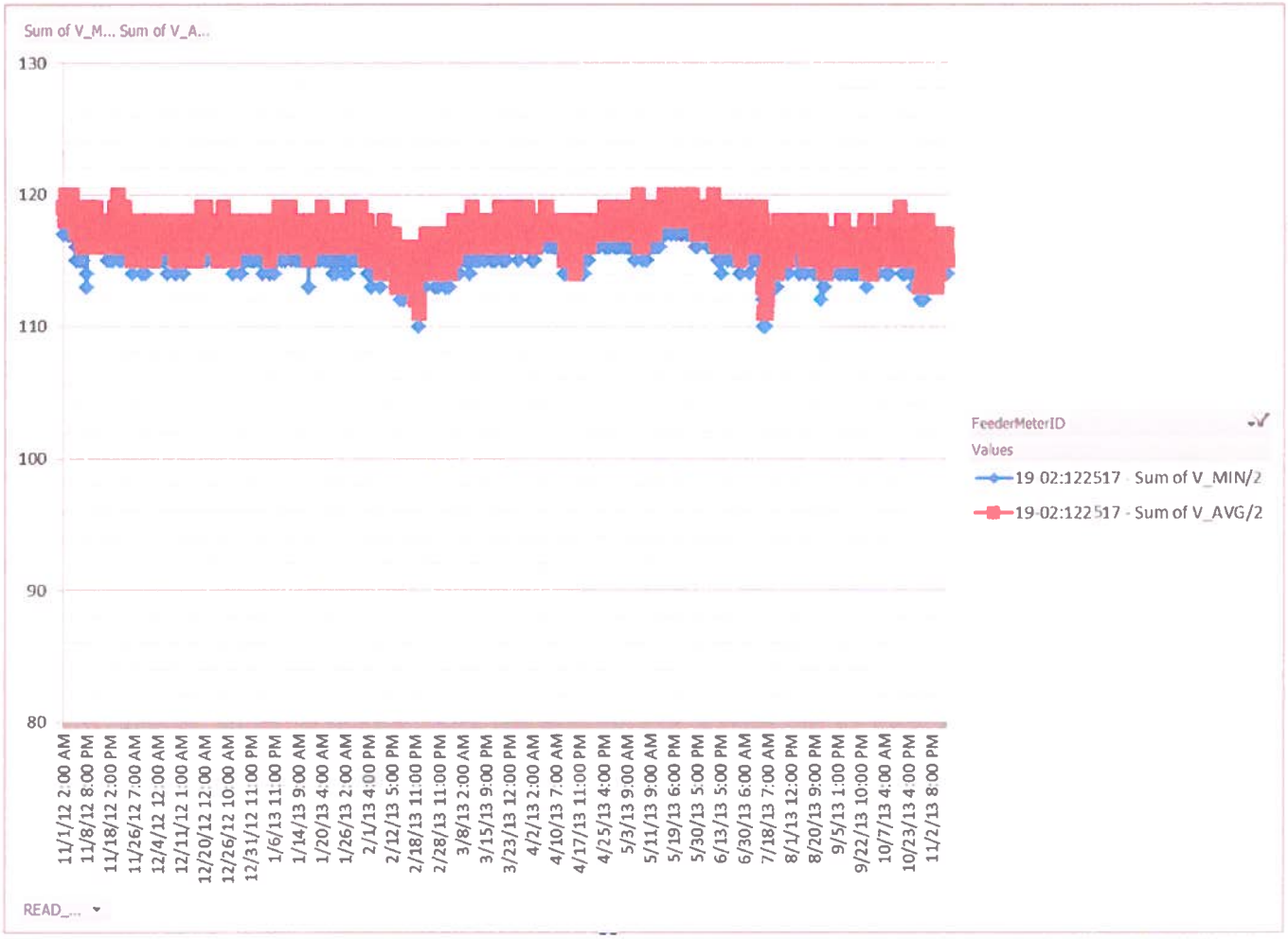
19 01 102629 Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
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11/2/13 8:00 PM
READ_...
FeederMeterID
Values
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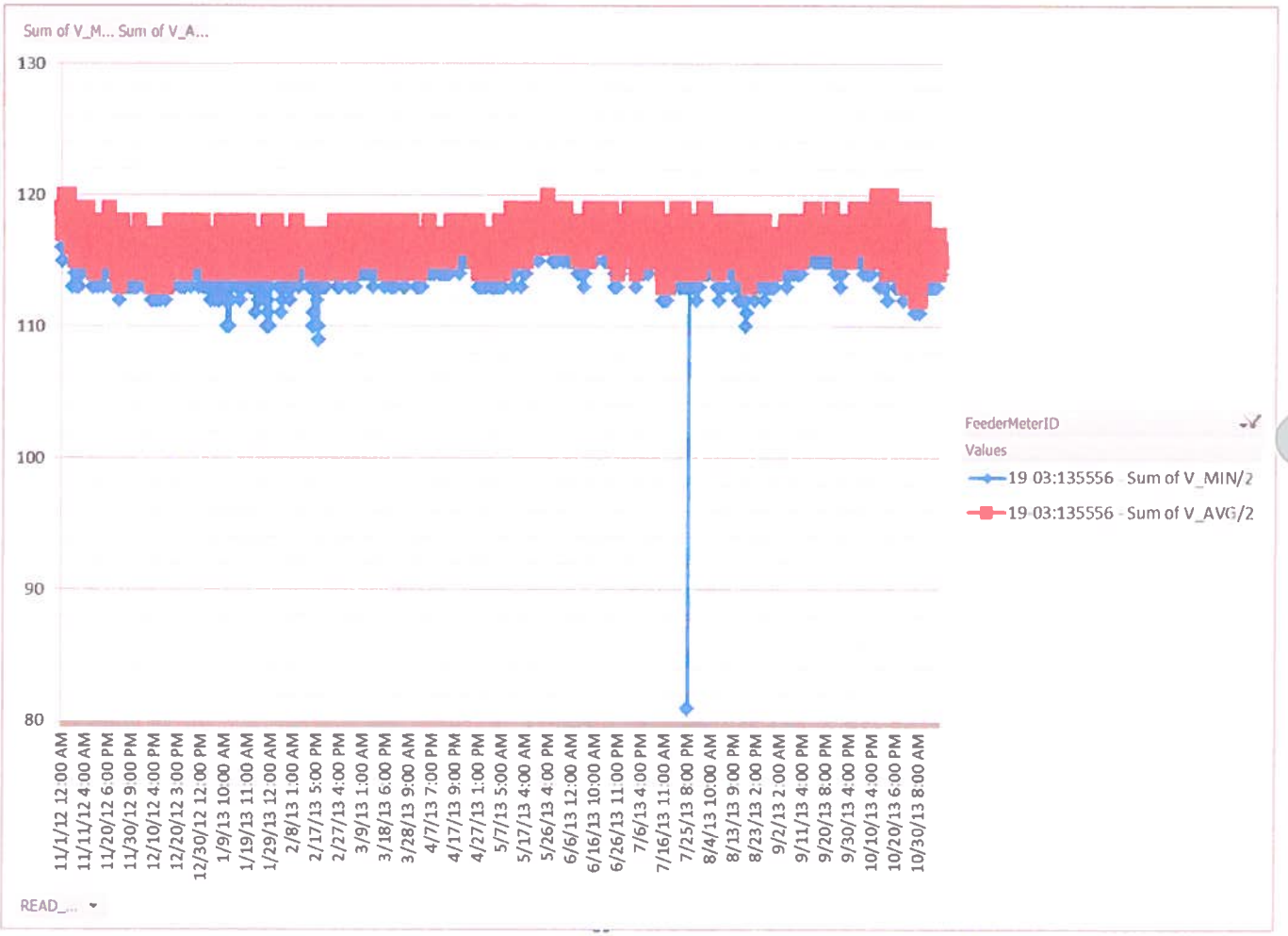
19 02:122517 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
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READ_...
FeederMeterID
Values
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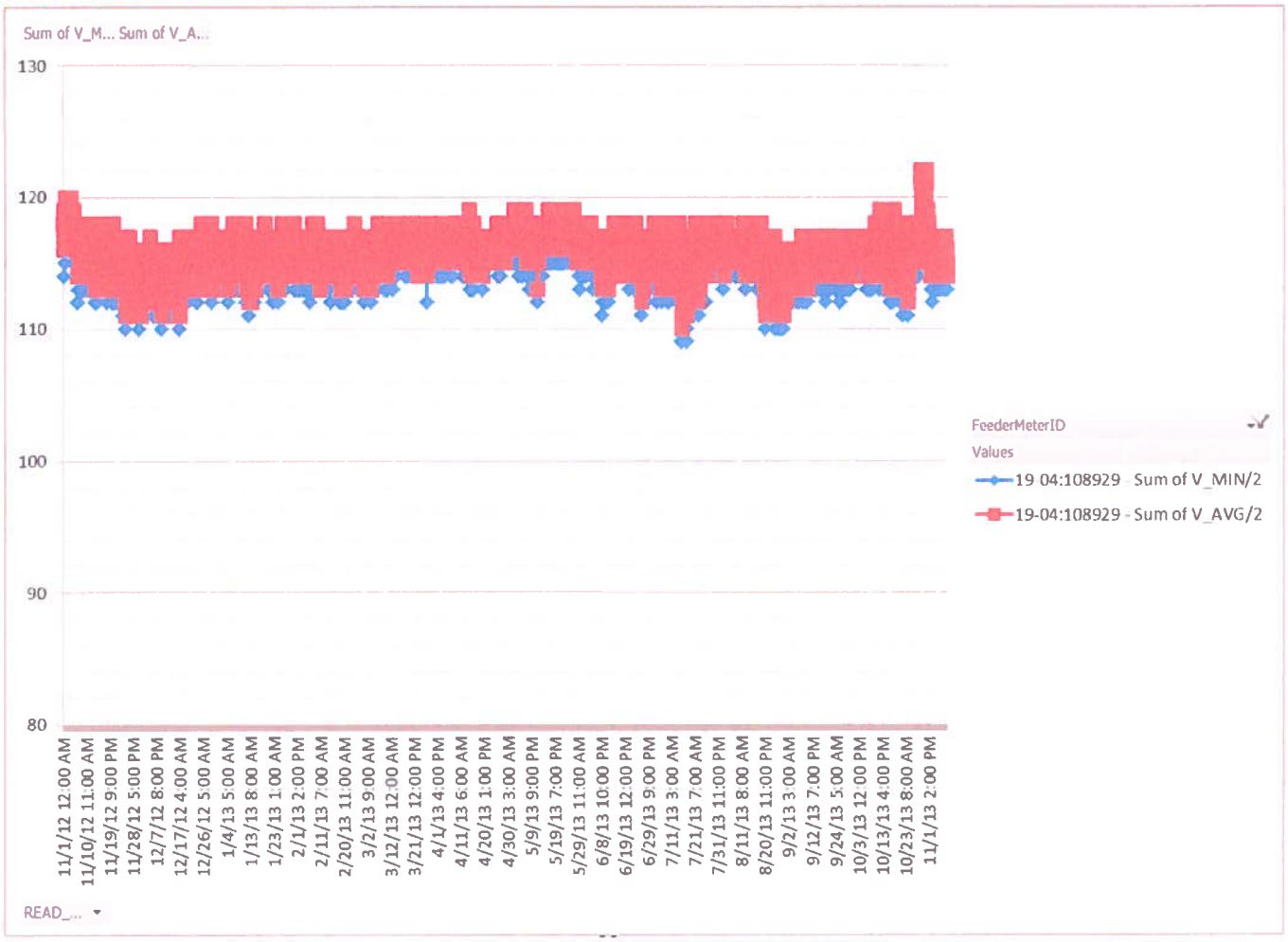
19 03:135556 Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
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11/1/12 12:00 AM
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11/19/12 9:00 PM
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READ_...
FeederMeterID
Values
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19-04:108929 - Sum of V_AVG/2

leidos

Sum of V_M... Sum of V_A...
130
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11/1/12 2:00 AM
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11/20/12 4:00 PM
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READ_...
FeederMeterID
Values
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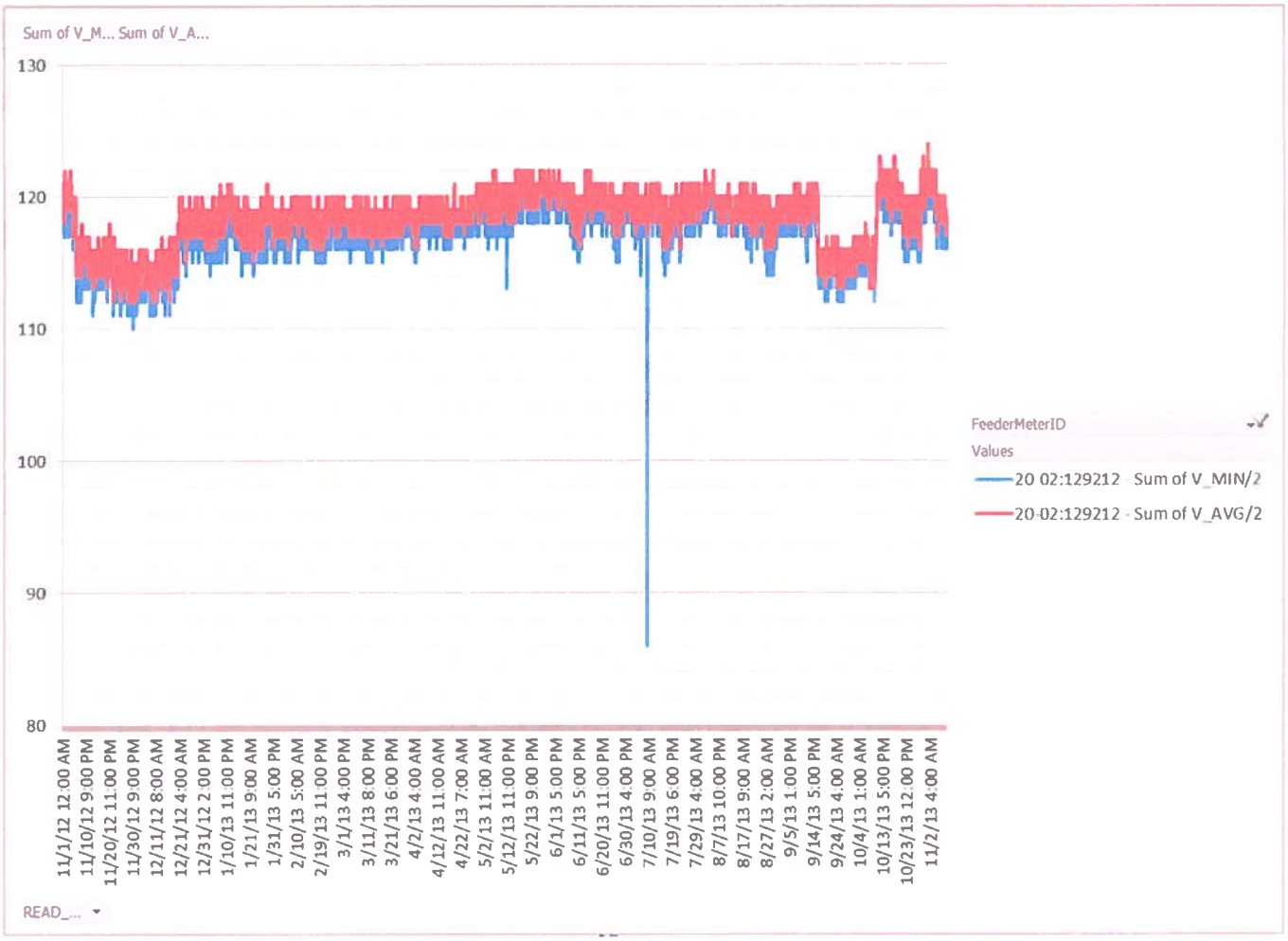
20 01:129882 Sum of V_AVG/2

leidos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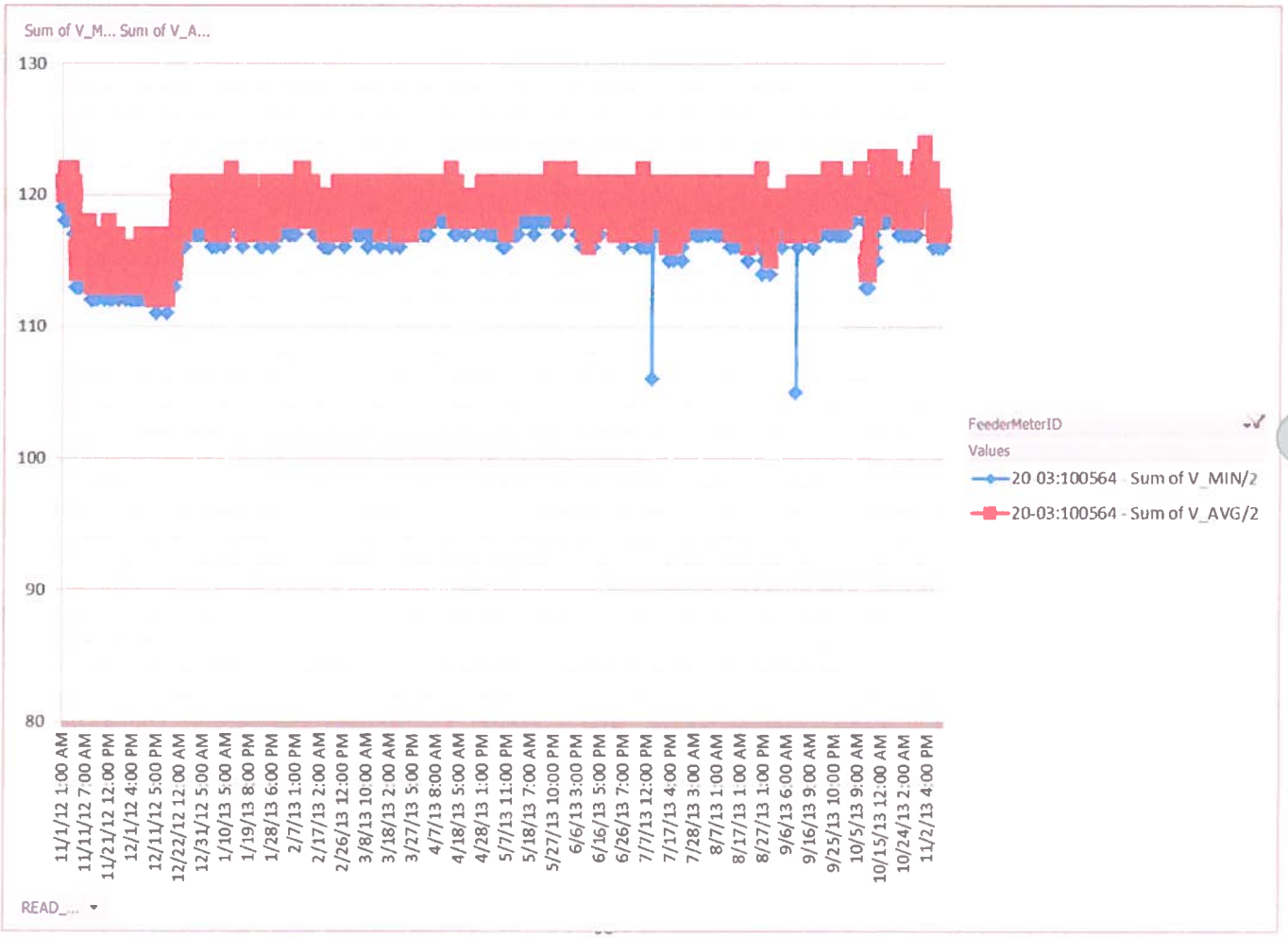
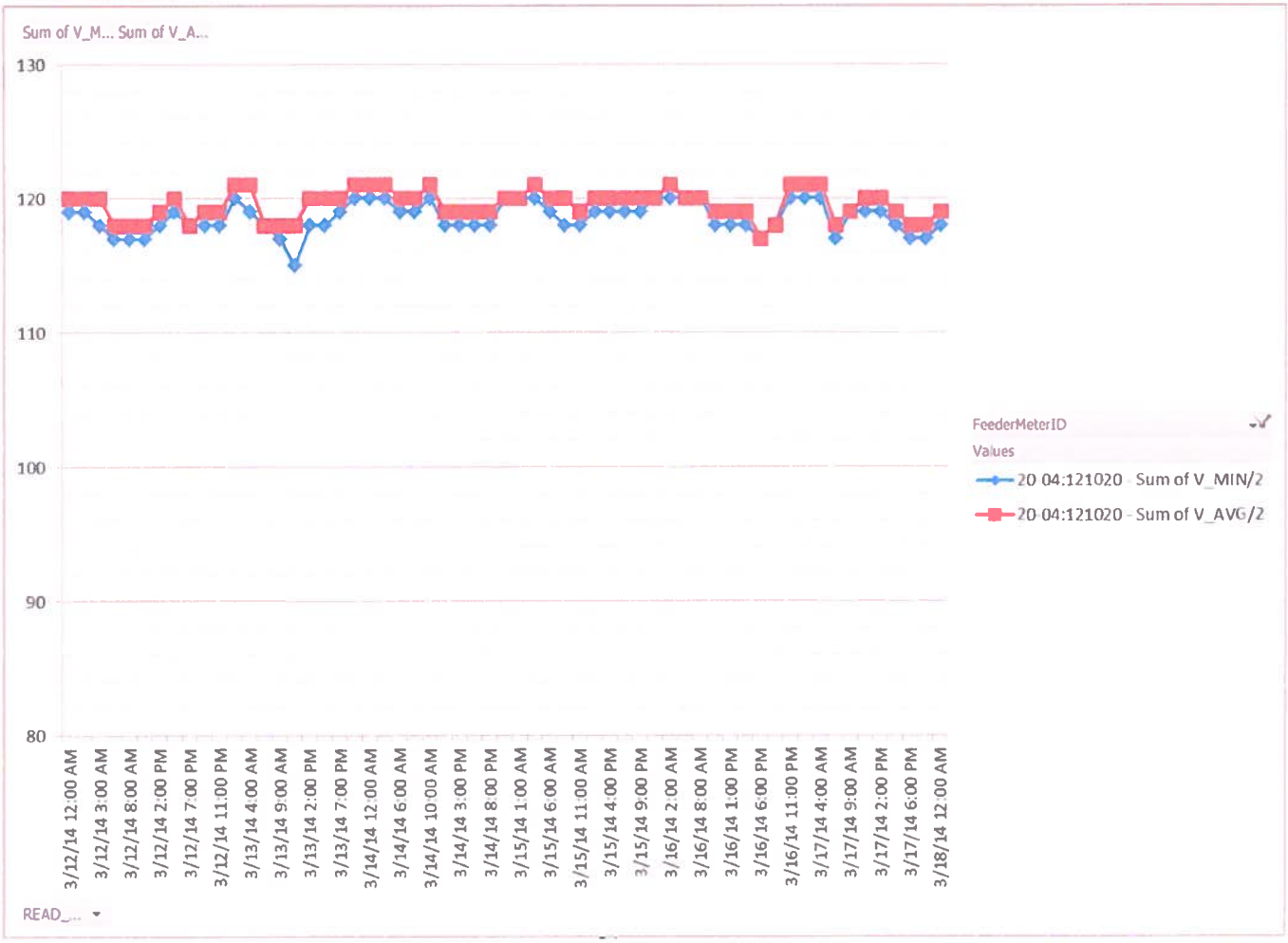
8/7/13 10:00 PM
8/17/13 9:00 AM
8/27/13 2:00 AM
9/5/13 1:00 PM
9/14/13 5:00 PM
9/24/13 4:00 AM
10/4/13 1:00 AM
10/13/13 5:00 PM
10/23/13 12:00 PM
11/2/13 4:00 AM
READ_...
FeederMeterID
Values
20 02:129212 Sum of V_MIN/2
20 02:129212 Sum of V_AVG/2

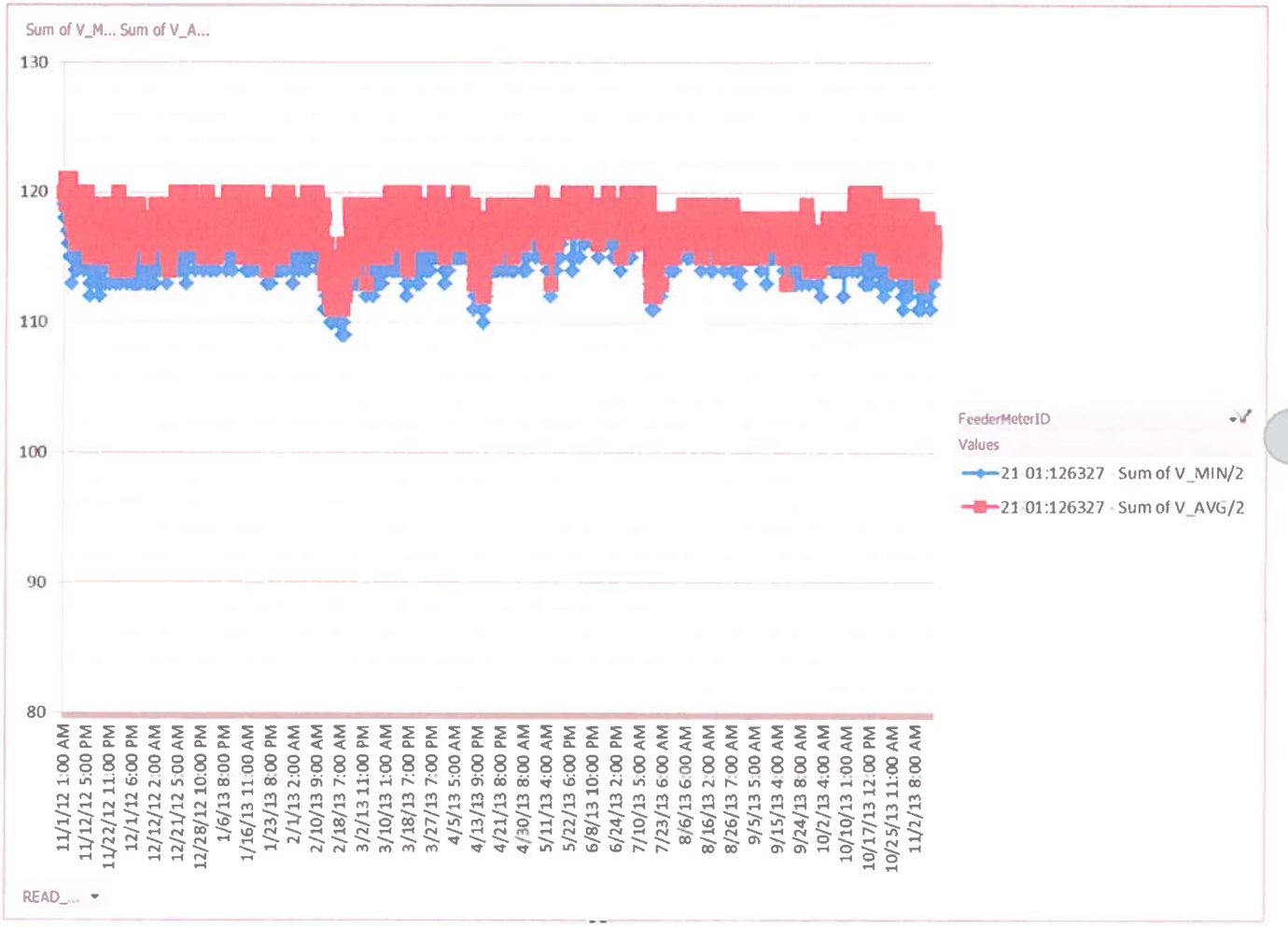
leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/11/12 7:00 AM
11/21/12 12:00 PM
12/1/12 4:00 PM
12/11/12 5:00 PM
12/22/12 12:00 AM
12/31/12 5:00 AM
1/10/13 5:00 AM
1/19/13 8:00 PM
1/28/13 6:00 PM
2/7/13 1:00 PM
2/17/13 2:00 AM
2/26/13 12:00 PM
3/8/13 10:00 AM
3/18/13 2:00 AM
3/27/13 5:00 PM
4/7/13 8:00 AM
4/18/13 5:00 AM
4/28/13 1:00 PM
5/7/13 11:00 PM
5/18/13 7:00 AM
5/27/13 10:00 PM
6/6/13 3:00 PM
6/16/13 5:00 PM
6/26/13 7:00 PM
7/7/13 12:00 PM
7/17/13 4:00 PM
7/28/13 3:00 AM
8/7/13 1:00 AM
8/17/13 1:00 AM
8/27/13 1:00 PM
9/6/13 6:00 AM
9/16/13 9:00 AM
9/25/13 10:00 PM
10/5/13 9:00 AM
10/15/13 12:00 AM
10/24/13 2:00 AM
11/2/13 4:00 PM
READ_...
FeederMeterID
Values
20 03:100564 - Sum of V_MIN/2
20-03:100564 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
3/12/14 12:00 AM
3/12/14 3:00 AM
3/12/14 8:00 AM
3/12/14 2:00 PM
3/12/14 7:00 PM
3/12/14 11:00 PM
3/13/14 4:00 AM
3/13/14 9:00 AM
3/13/14 2:00 PM
3/13/14 7:00 PM
3/14/14 12:00 AM
3/14/14 6:00 AM
3/14/14 10:00 AM
3/14/14 3:00 PM
3/14/14 8:00 PM
3/15/14 1:00 AM
3/15/14 6:00 AM
3/15/14 11:00 AM
3/15/14 4:00 PM
3/15/14 9:00 PM
3/16/14 2:00 AM
3/16/14 8:00 AM
3/16/14 1:00 PM
3/16/14 6:00 PM
3/16/14 11:00 PM
3/17/14 4:00 AM
3/17/14 9:00 AM
3/17/14 2:00 PM
3/17/14 6:00 PM
3/18/14 12:00 AM
READ_...
FeederMeterID
Values
20 04:121020 Sum of V_MIN/2
20 04:121020 Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/12/12 5:00 PM
11/22/12 11:00 PM
12/1/12 6:00 PM
12/12/12 2:00 AM
12/21/12 5:00 AM
12/28/12 10:00 PM
1/6/13 8:00 PM
1/16/13 11:00 AM
1/23/13 8:00 PM
2/1/13 2:00 AM
2/10/13 9:00 AM
2/18/13 7:00 AM
3/2/13 11:00 PM
3/10/13 1:00 AM
3/18/13 7:00 PM
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5/22/13 6:00 PM
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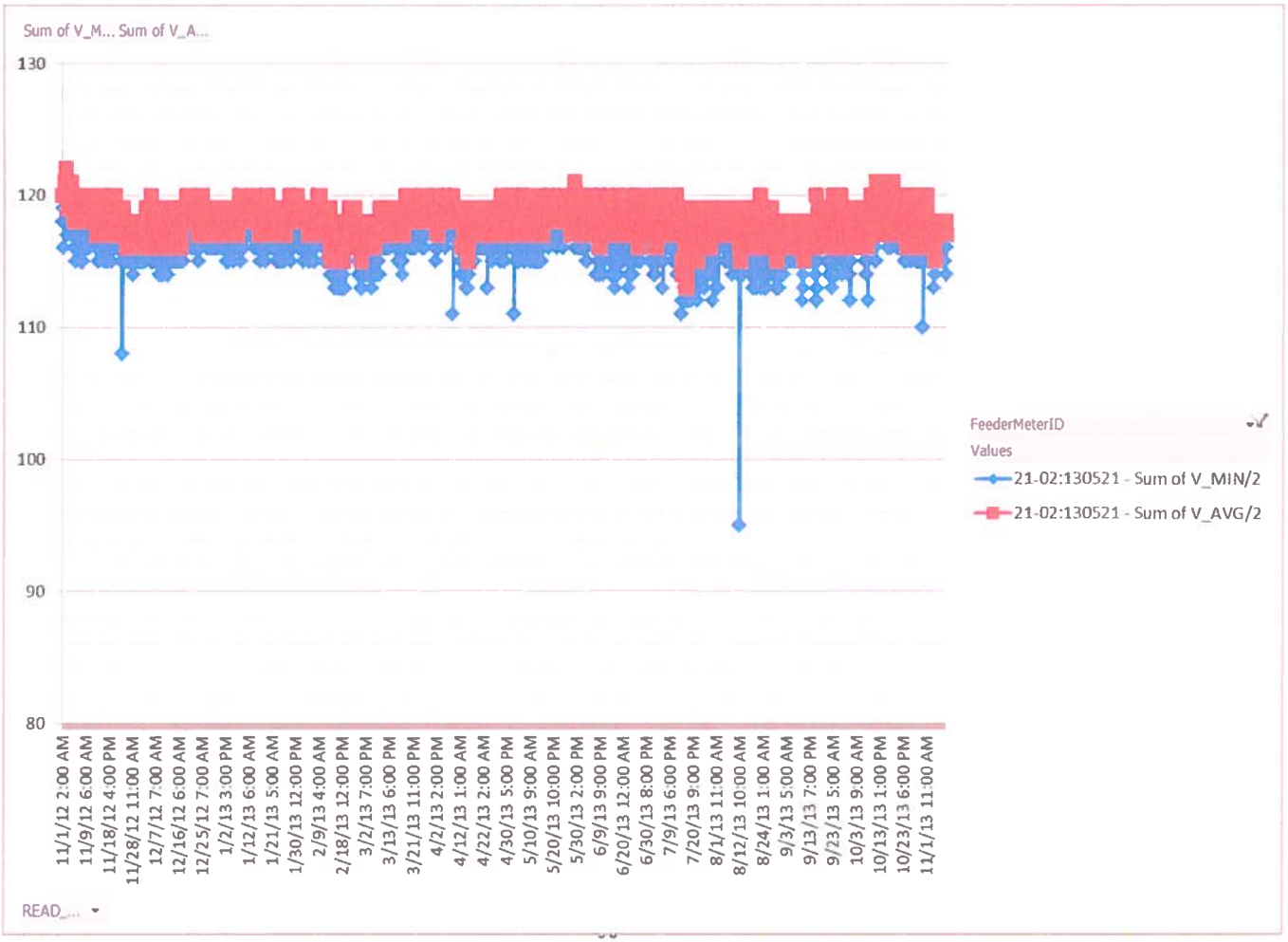
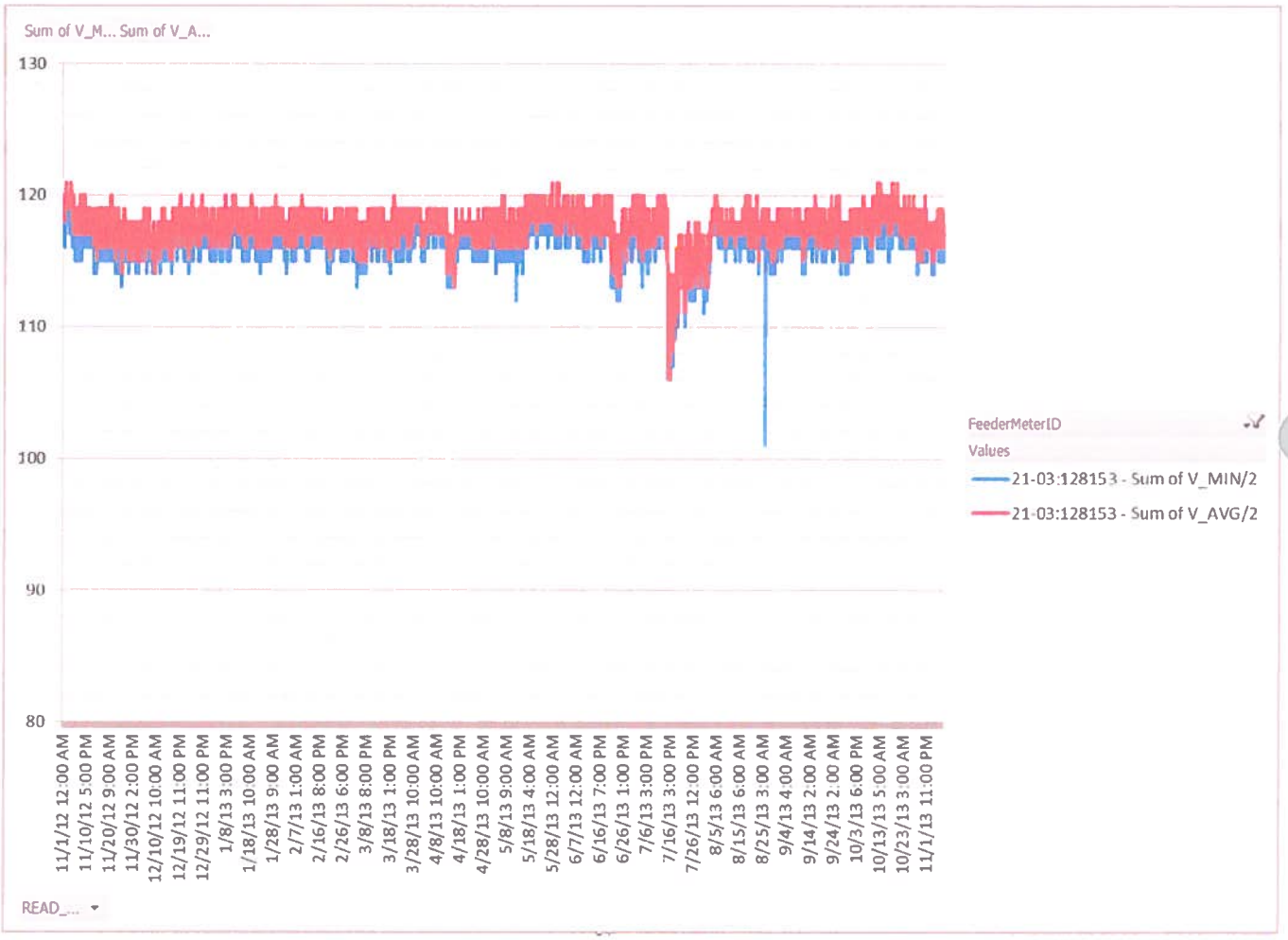
7/10/13 5:00 AM
7/23/13 6:00 AM
8/6/13 6:00 AM
8/16/13 2:00 AM
8/26/13 7:00 AM
9/5/13 5:00 AM
9/15/13 4:00 AM
9/24/13 8:00 AM
10/2/13 4:00 AM
10/10/13 1:00 AM
10/17/13 12:00 PM
10/25/13 11:00 AM
11/2/13 8:00 AM
READ_...
FeederMeterID
Values
21 01:126327 Sum of V_MIN/2
21 01:126327 Sum of V_AVG/2

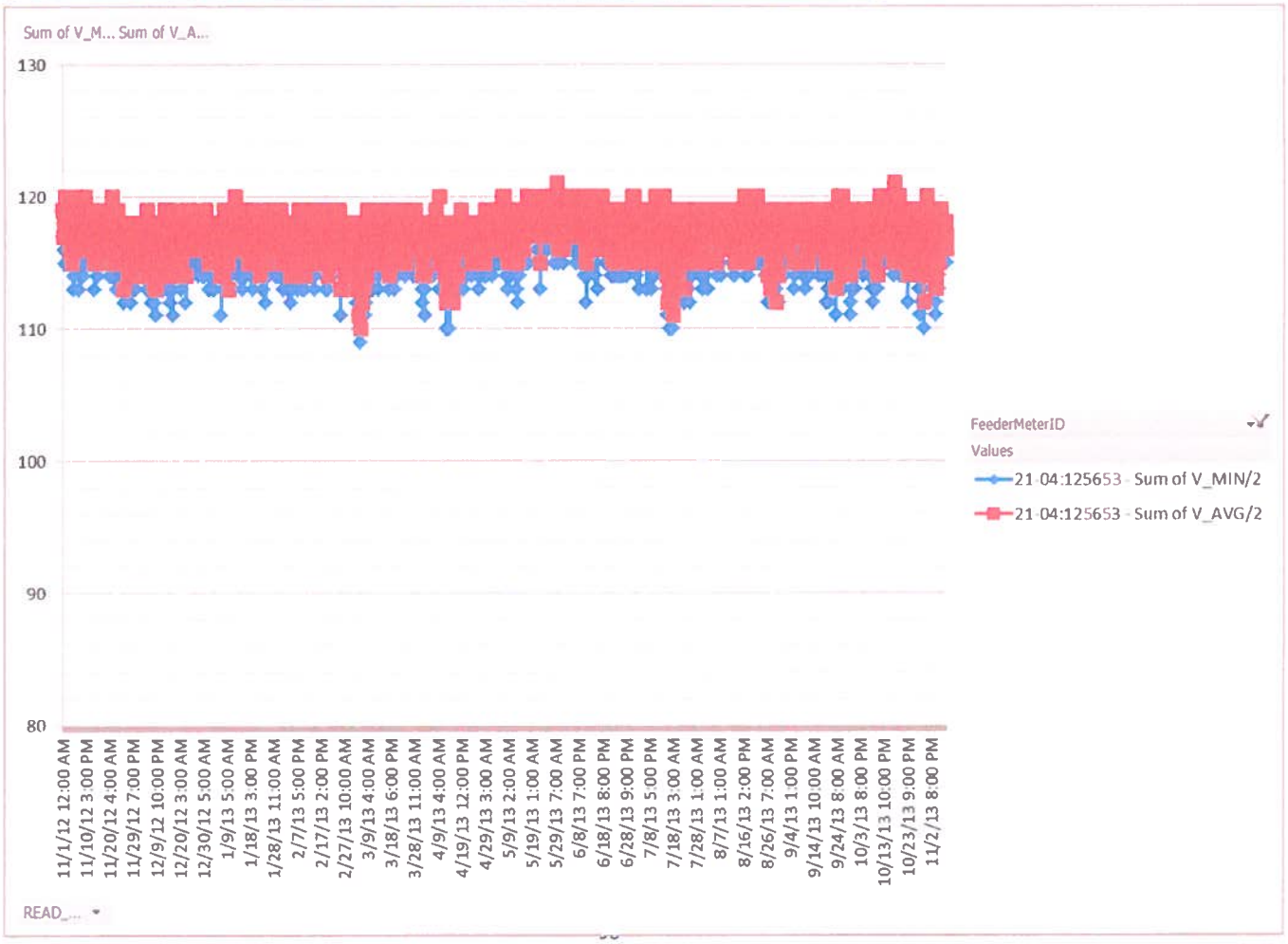
leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 2:00 AM
11/9/12 6:00 AM
11/18/12 4:00 PM
11/28/12 11:00 AM
12/7/12 7:00 AM
12/16/12 6:00 AM
12/25/12 7:00 AM
1/2/13 3:00 PM
1/12/13 6:00 AM
1/21/13 5:00 AM
1/30/13 12:00 PM
2/9/13 4:00 AM
2/18/13 12:00 PM
3/2/13 7:00 PM
3/13/13 6:00 PM
3/21/13 11:00 PM
4/2/13 2:00 PM
4/12/13 1:00 AM
4/22/13 2:00 AM
4/30/13 5:00 PM
5/10/13 9:00 AM
5/20/13 10:00 PM
5/30/13 2:00 PM
6/9/13 9:00 PM
6/20/13 12:00 AM
6/30/13 8:00 PM
7/9/13 6:00 PM
7/20/13 9:00 PM
8/1/13 11:00 AM
8/12/13 10:00 AM
8/24/13 1:00 AM
9/3/13 5:00 AM
9/13/13 7:00 PM
9/23/13 5:00 AM
10/3/13 9:00 AM
10/13/13 1:00 PM
10/23/13 6:00 PM
11/1/13 11:00 AM
READ_...
FeederMeterID
Values
21-02:130521 - Sum of V_MIN/2
21-02:130521 - Sum of V_AVG/2

leidos

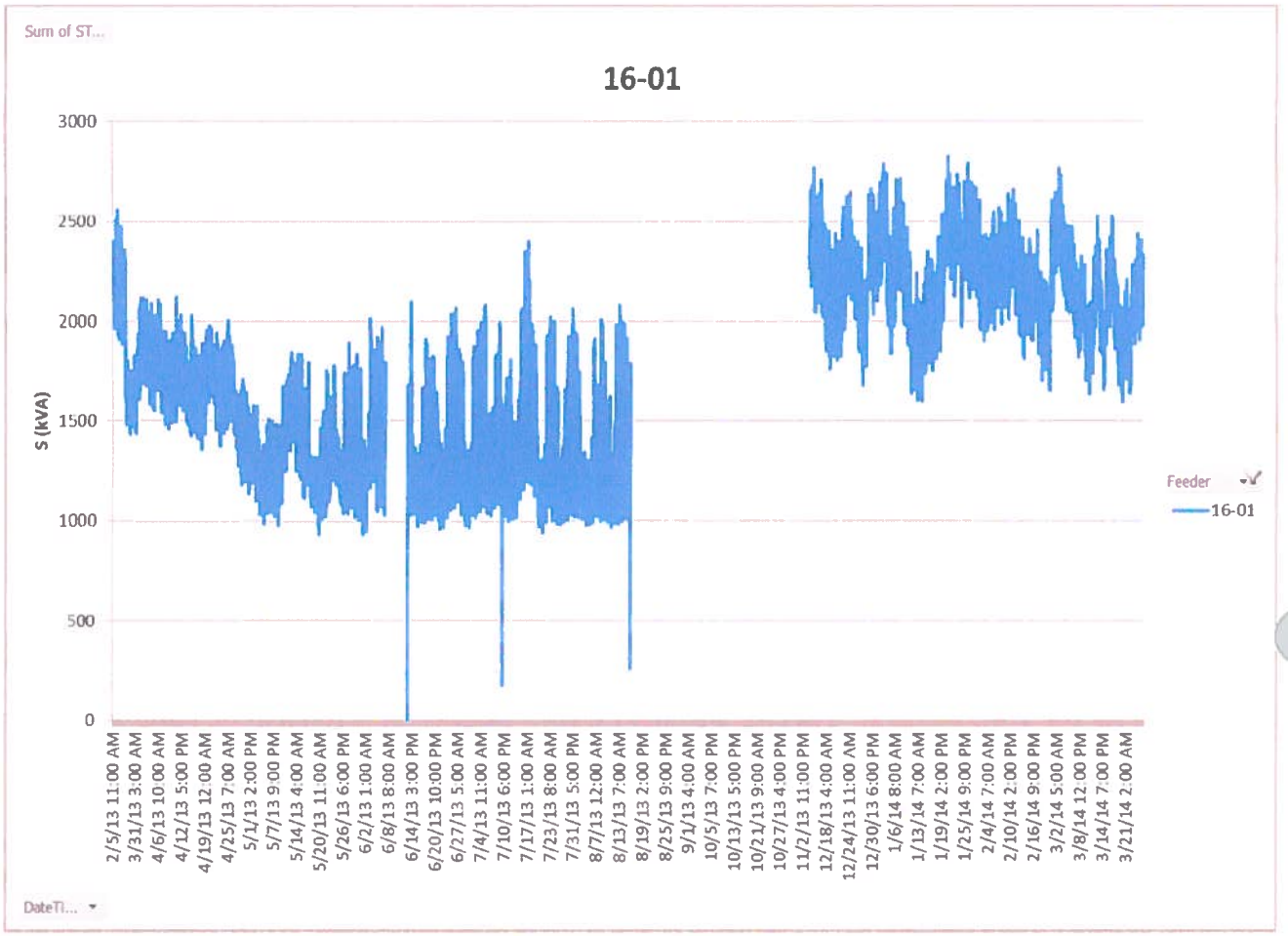

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 5:00 PM
11/20/12 9:00 AM
11/30/12 2:00 PM
12/10/12 10:00 AM
12/19/12 11:00 PM
12/29/12 11:00 PM
1/8/13 3:00 PM
1/18/13 10:00 AM
1/28/13 9:00 AM
2/7/13 1:00 AM
2/16/13 8:00 PM
2/26/13 6:00 PM
3/8/13 8:00 PM
3/18/13 1:00 PM
3/28/13 10:00 AM
4/8/13 10:00 AM
4/18/13 1:00 PM
4/28/13 10:00 AM
5/8/13 9:00 AM
5/18/13 4:00 AM
5/28/13 12:00 AM
6/7/13 12:00 AM
6/16/13 7:00 PM
6/26/13 1:00 PM
7/6/13 3:00 PM
7/16/13 3:00 PM
7/26/13 12:00 PM
8/5/13 6:00 AM
8/15/13 6:00 AM
8/25/13 3:00 AM
9/4/13 4:00 AM
9/14/13 2:00 AM
9/24/13 2:00 AM
10/3/13 6:00 PM
10/13/13 5:00 AM
10/23/13 3:00 AM
11/1/13 11:00 PM
READ_...
FeederMeterID
Values
21-03:128153 - Sum of V_MIN/2
21-03:128153 - Sum of V_AVG/2

leidos

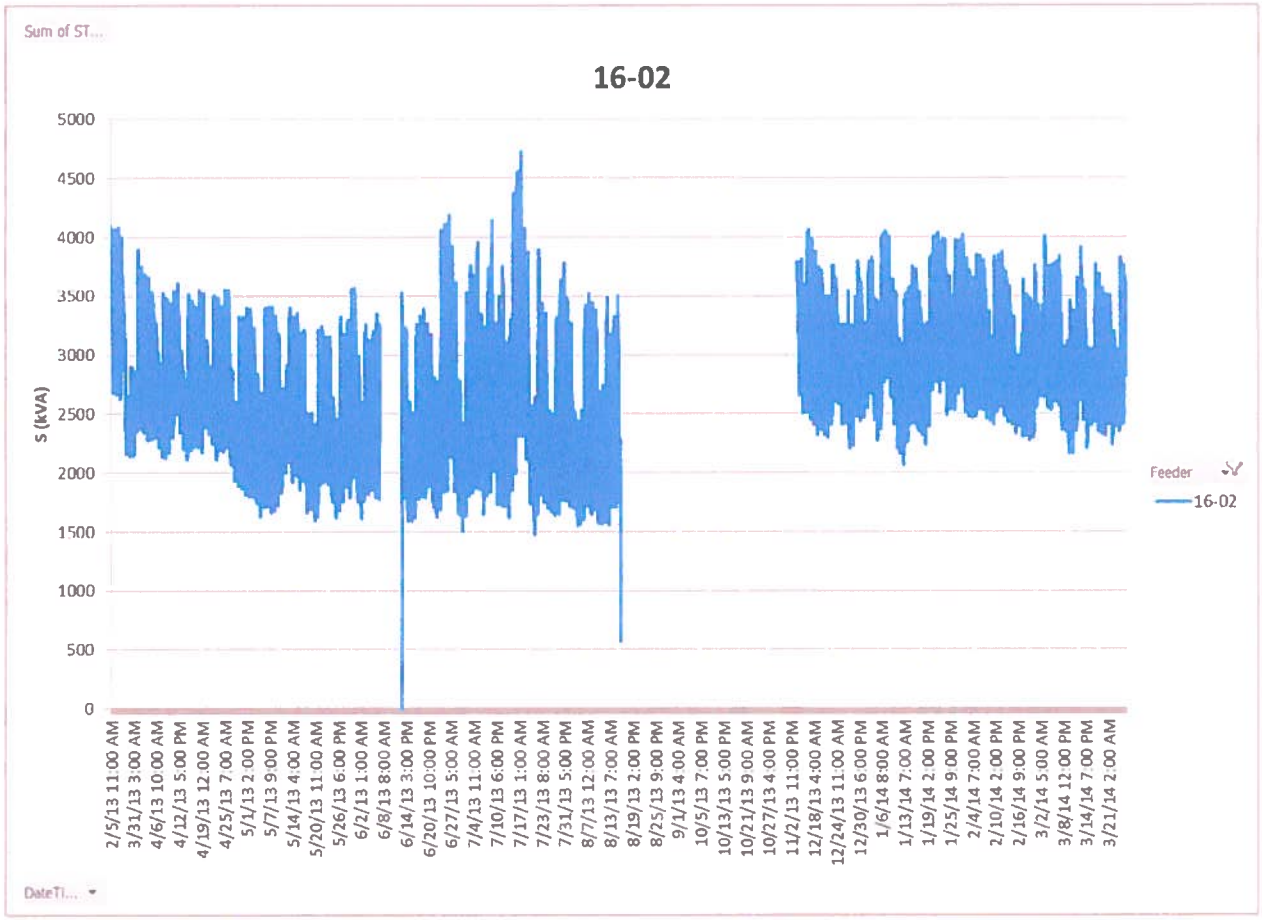

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 3:00 PM
11/20/12 4:00 AM
11/29/12 7:00 PM
12/9/12 10:00 PM
12/20/12 3:00 AM
12/30/12 5:00 AM
1/9/13 5:00 AM
1/18/13 3:00 PM
1/28/13 11:00 AM
2/7/13 5:00 PM
2/17/13 2:00 PM
2/27/13 10:00 AM
3/9/13 4:00 AM
3/18/13 6:00 PM
3/28/13 11:00 AM
4/9/13 4:00 AM
4/19/13 12:00 PM
4/29/13 3:00 AM
5/9/13 2:00 AM
5/19/13 1:00 AM
5/29/13 7:00 AM
6/8/13 7:00 PM
6/18/13 8:00 PM
6/28/13 9:00 PM
7/8/13 5:00 PM
7/18/13 3:00 AM
7/28/13 1:00 AM
8/7/13 1:00 AM
8/16/13 2:00 PM
8/26/13 7:00 AM
9/4/13 1:00 PM
9/14/13 10:00 AM
9/24/13 8:00 AM
10/3/13 8:00 PM
10/13/13 10:00 PM
10/23/13 9:00 PM
11/2/13 8:00 PM
READ_...
FeederMeterID
Values
21-04:125653 - Sum of V_MIN/2
21-04:125653 - Sum of V_AVG/2

Appendix 4. SCADA Load Profiles per Feeder

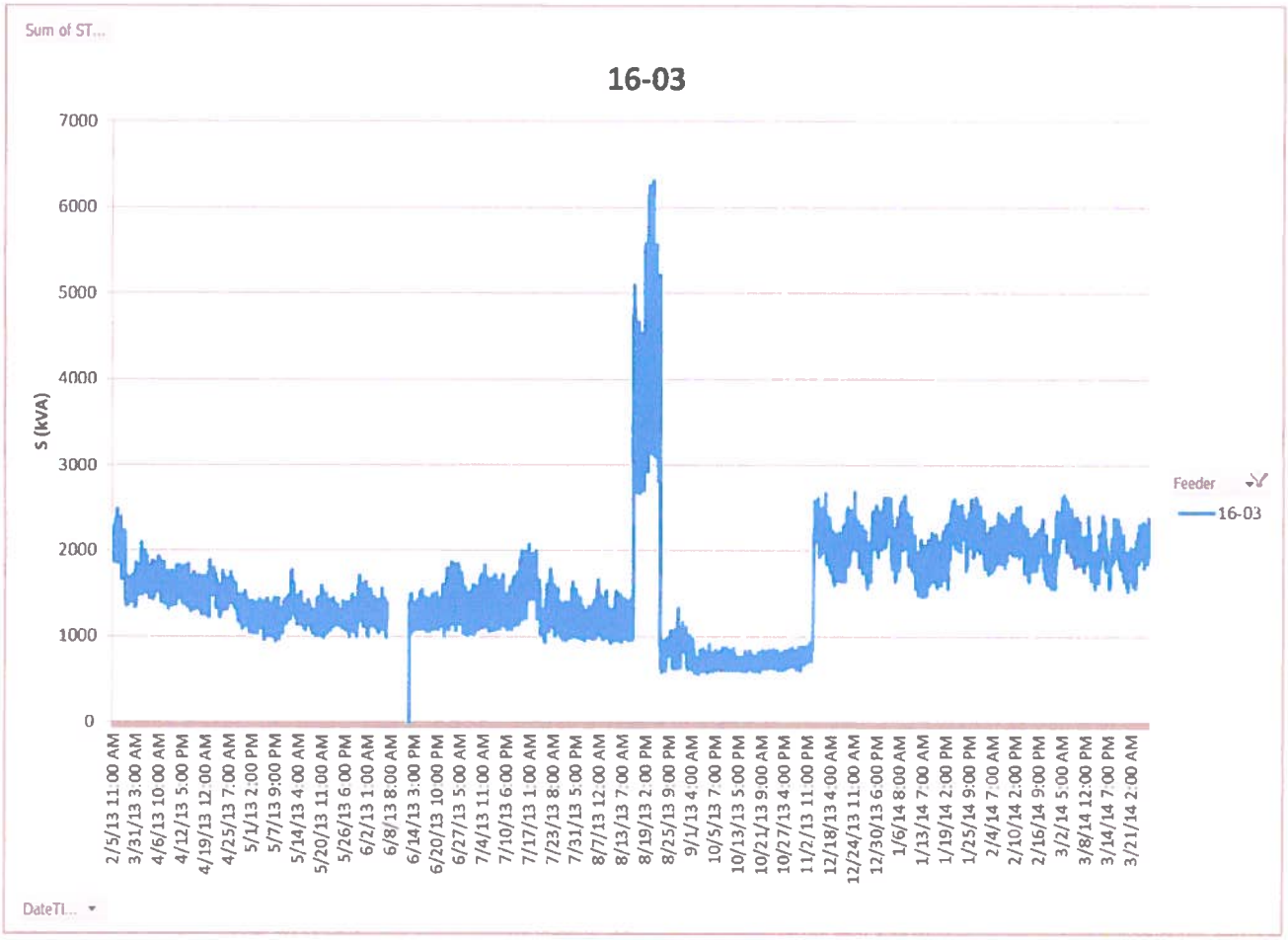
16-01:



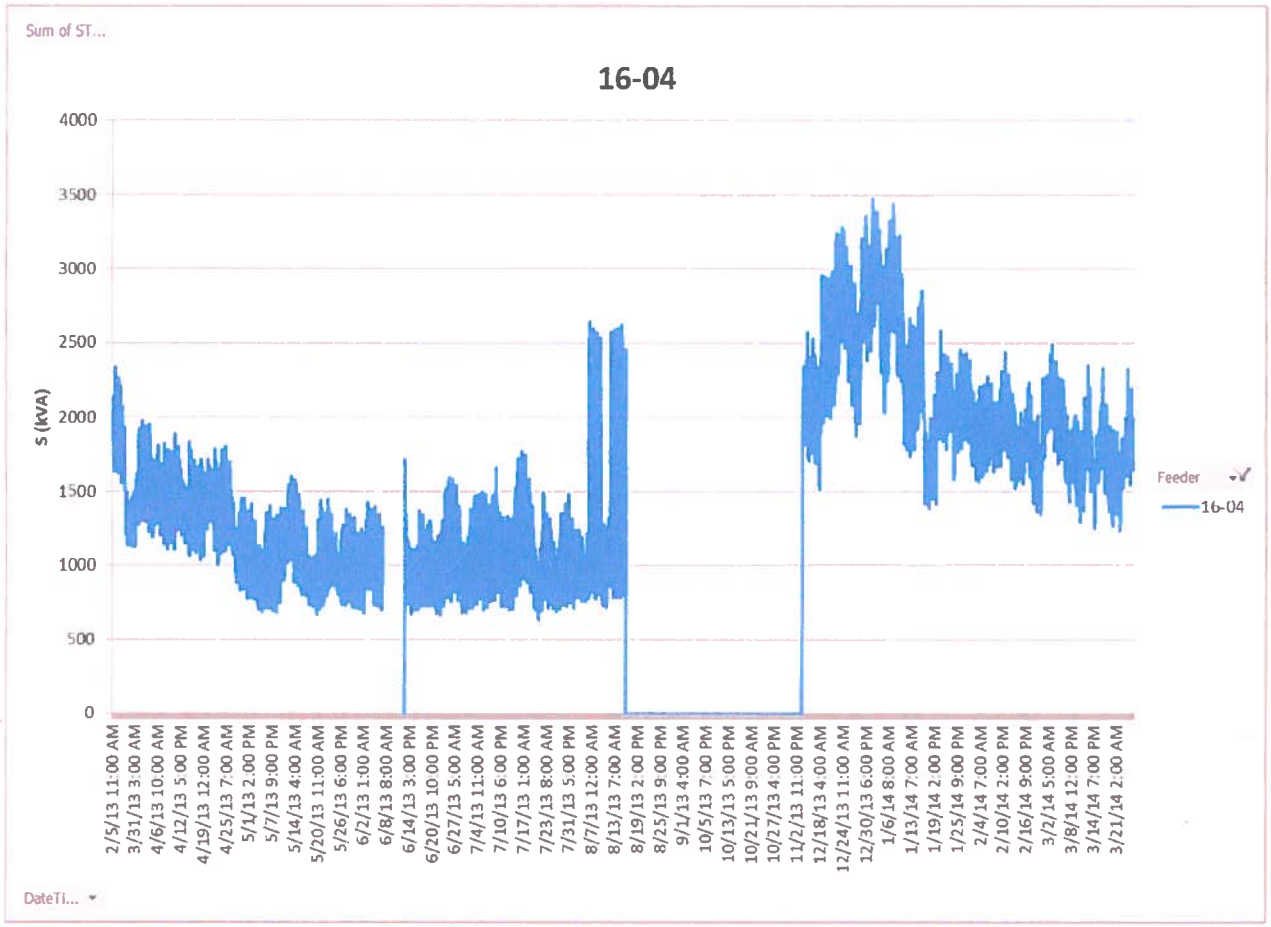
16-02:


Sum of ST...
16-02
S (kVA)
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
2/5/13 11:00 AM
3/31/13 3:00 AM
4/6/13 10:00 AM
4/12/13 5:00 PM
4/19/13 12:00 AM
4/25/13 7:00 AM
5/1/13 2:00 PM
5/7/13 9:00 PM
5/14/13 4:00 AM
5/20/13 11:00 AM
5/26/13 6:00 PM
6/2/13 1:00 AM
6/8/13 8:00 AM
6/14/13 3:00 PM
6/20/13 10:00 PM
6/27/13 5:00 AM
7/4/13 11:00 AM
7/10/13 6:00 PM
7/17/13 1:00 AM
7/23/13 8:00 AM
7/31/13 5:00 PM
8/7/13 12:00 AM
8/13/13 7:00 AM
8/19/13 2:00 PM
8/25/13 9:00 PM
9/1/13 4:00 AM
10/5/13 7:00 PM
10/13/13 5:00 PM
10/21/13 9:00 AM
10/27/13 4:00 PM
11/2/13 11:00 PM
12/18/13 4:00 AM
12/24/13 11:00 AM
12/30/13 6:00 PM
1/6/14 8:00 AM
1/13/14 7:00 AM
1/19/14 2:00 PM
1/25/14 9:00 PM
2/4/14 7:00 AM
2/10/14 2:00 PM
2/16/14 9:00 PM
3/2/14 5:00 AM
3/8/14 12:00 PM
3/14/14 7:00 PM
3/21/14 2:00 AM
DateTi...
Feeder
16-02

16-03:


Sum of ST...
16-03
7000
6000
5000
4000
3000
2000
1000
0
S (kVA)
2/5/13 11:00 AM
3/31/13 3:00 AM
4/6/13 10:00 AM
4/12/13 5:00 PM
4/19/13 12:00 AM
4/25/13 7:00 AM
5/1/13 2:00 PM
5/7/13 9:00 PM
5/14/13 4:00 AM
5/20/13 11:00 AM
5/26/13 6:00 PM
6/2/13 1:00 AM
6/8/13 8:00 AM
6/14/13 3:00 PM
6/20/13 10:00 PM
6/27/13 5:00 AM
7/4/13 11:00 AM
7/10/13 6:00 PM
7/17/13 1:00 AM
7/23/13 8:00 AM
7/31/13 5:00 PM
8/7/13 12:00 AM
8/13/13 7:00 AM
8/19/13 2:00 PM
8/25/13 9:00 PM
9/1/13 4:00 AM
10/5/13 7:00 PM
10/13/13 5:00 PM
10/21/13 9:00 AM
10/27/13 4:00 PM
11/2/13 11:00 PM
12/18/13 4:00 AM
12/24/13 11:00 AM
12/30/13 6:00 PM
1/6/14 8:00 AM
1/13/14 7:00 AM
1/19/14 2:00 PM
1/25/14 9:00 PM
2/4/14 7:00 AM
2/10/14 2:00 PM
2/16/14 9:00 PM
3/2/14 5:00 AM
3/8/14 12:00 PM
3/14/14 7:00 PM
3/21/14 2:00 AM
DateTi...
Feeder
16-03

16-04:


Sum of ST...
16-04
4000
3500
3000
2500
2000
1500
1000
500
0
S (kVA)
2/5/13 11:00 AM
3/31/13 3:00 AM
4/6/13 10:00 AM
4/12/13 5:00 PM
4/19/13 12:00 AM
4/25/13 7:00 AM
5/1/13 2:00 PM
5/7/13 9:00 PM
5/14/13 4:00 AM
5/20/13 11:00 AM
5/26/13 6:00 PM
6/2/13 1:00 AM
6/8/13 8:00 AM
6/14/13 3:00 PM
6/20/13 10:00 PM
6/27/13 5:00 AM
7/4/13 11:00 AM
7/10/13 6:00 PM
7/17/13 1:00 AM
7/23/13 8:00 AM
7/31/13 5:00 PM
8/7/13 12:00 AM
8/13/13 7:00 AM
8/19/13 2:00 PM
8/25/13 9:00 PM
9/1/13 4:00 AM
10/5/13 7:00 PM
10/13/13 5:00 PM
10/21/13 9:00 AM
10/27/13 4:00 PM
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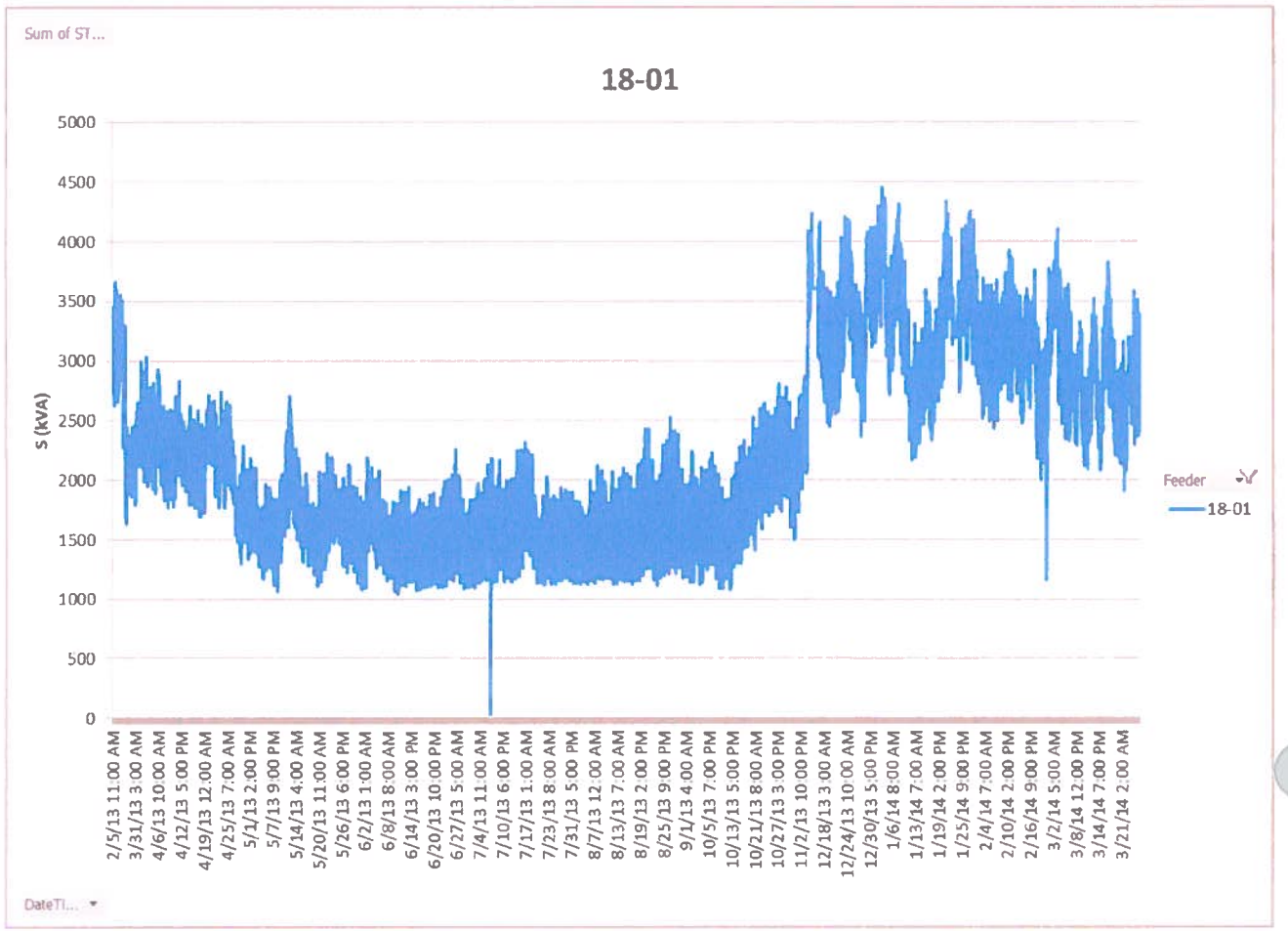
12/18/13 4:00 AM
12/24/13 11:00 AM
12/30/13 6:00 PM
1/6/14 8:00 AM
1/13/14 7:00 AM
1/19/14 2:00 PM
1/25/14 9:00 PM
2/4/14 7:00 AM
2/10/14 2:00 PM
2/16/14 9:00 PM
3/2/14 5:00 AM
3/8/14 12:00 PM
3/14/14 7:00 PM
3/21/14 2:00 AM
DateTi...
Feeder
16-04

18-01:


Sum of ST...
18-01
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
S (kVA)
2/5/13 11:00 AM
3/31/13 3:00 AM
4/6/13 10:00 AM
4/12/13 5:00 PM
4/19/13 12:00 AM
4/25/13 7:00 AM
5/1/13 2:00 PM
5/7/13 9:00 PM
5/14/13 4:00 AM
5/20/13 11:00 AM
5/26/13 6:00 PM
6/2/13 1:00 AM
6/8/13 8:00 AM
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7/4/13 11:00 AM
7/10/13 6:00 PM
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7/23/13 8:00 AM
7/31/13 5:00 PM
8/7/13 12:00 AM
8/13/13 7:00 AM
8/19/13 2:00 PM
8/25/13 9:00 PM
9/1/13 4:00 AM
10/5/13 7:00 PM
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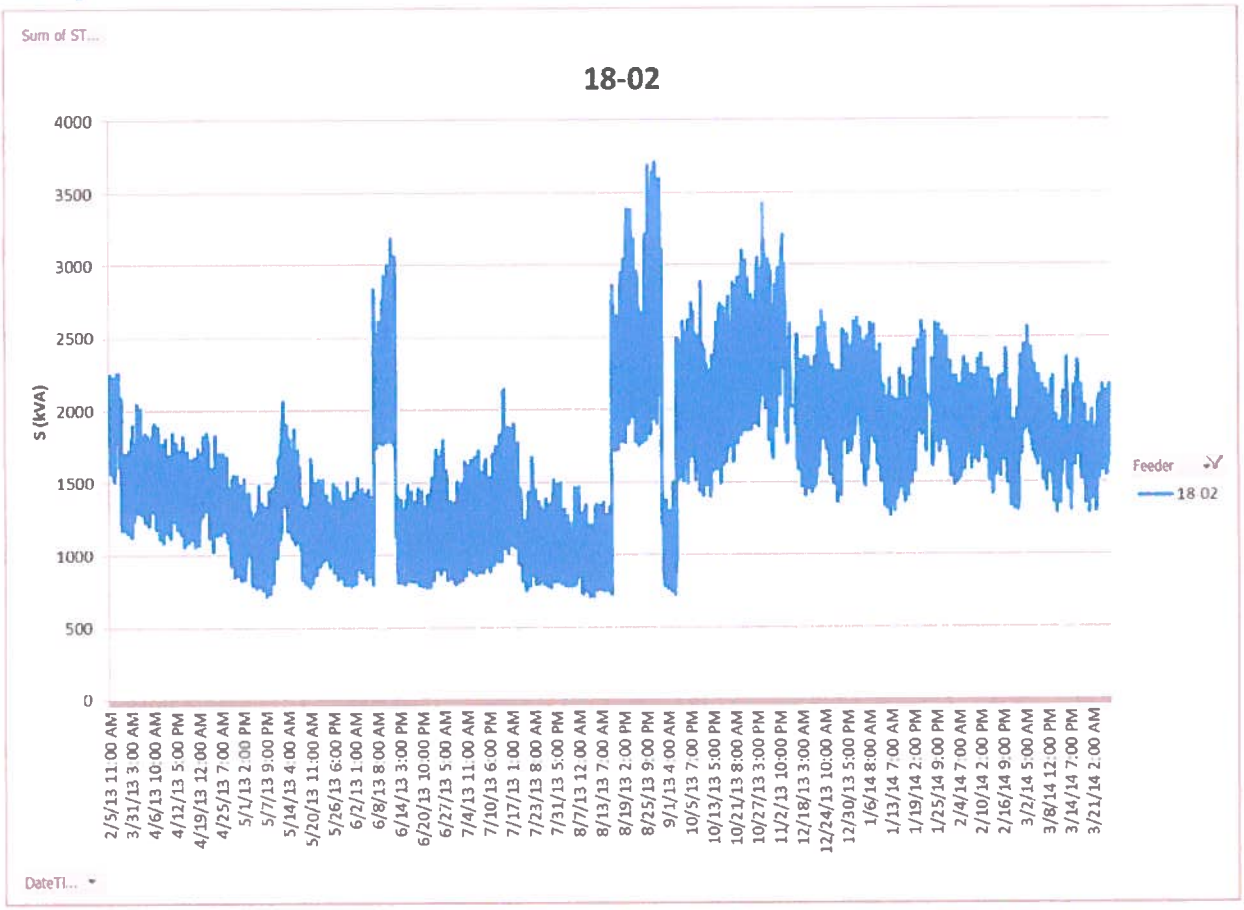
12/24/13 10:00 AM
12/30/13 5:00 PM
1/6/14 8:00 AM
1/13/14 7:00 AM
1/19/14 2:00 PM
1/25/14 9:00 PM
2/4/14 7:00 AM
2/10/14 2:00 PM
2/16/14 9:00 PM
3/2/14 5:00 AM
3/8/14 12:00 PM
3/14/14 7:00 PM
3/21/14 2:00 AM
DateTi...
Feeder
18-01

18-02:


Sum of ST...
18-02
4000
3500
3000
2500
2000
1500
1000
500
0
S (kVA)
2/5/13 11:00 AM
3/31/13 3:00 AM
4/6/13 10:00 AM
4/12/13 5:00 PM
4/19/13 12:00 AM
4/25/13 7:00 AM
5/1/13 2:00 PM
5/7/13 9:00 PM
5/14/13 4:00 AM
5/20/13 11:00 AM
5/26/13 6:00 PM
6/2/13 1:00 AM
6/8/13 8:00 AM
6/14/13 3:00 PM
6/20/13 10:00 PM
6/27/13 5:00 AM
7/4/13 11:00 AM
7/10/13 6:00 PM
7/17/13 1:00 AM
7/23/13 8:00 AM
7/31/13 5:00 PM
8/7/13 12:00 AM
8/13/13 7:00 AM
8/19/13 2:00 PM
8/25/13 9:00 PM
9/1/13 4:00 AM
10/5/13 7:00 PM
10/13/13 5:00 PM
10/21/13 8:00 AM
10/27/13 3:00 PM
11/2/13 10:00 PM
12/18/13 3:00 AM
12/24/13 10:00 AM
12/30/13 5:00 PM
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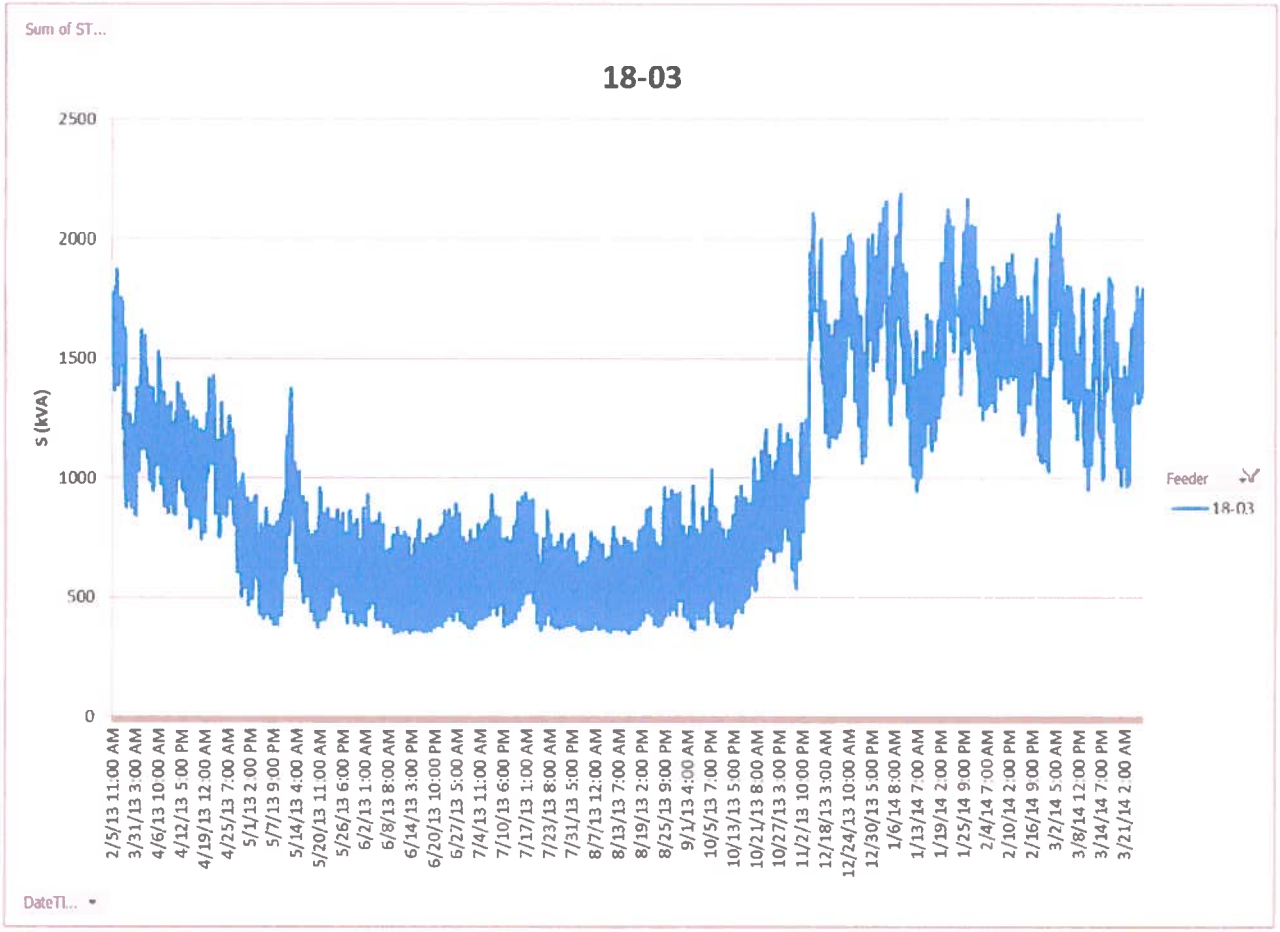
1/13/14 7:00 AM
1/19/14 2:00 PM
1/25/14 9:00 PM
2/4/14 7:00 AM
2/10/14 2:00 PM
2/16/14 9:00 PM
3/2/14 5:00 AM
3/8/14 12:00 PM
3/14/14 7:00 PM
3/21/14 2:00 AM
DateTi...
Feeder
18 02

18-03:


Sum of ST...
18-03
2500
2000
1500
1000
500
0
S (kVA)
2/5/13 11:00 AM
3/31/13 3:00 AM
4/6/13 10:00 AM
4/12/13 5:00 PM
4/19/13 12:00 AM
4/25/13 7:00 AM
5/1/13 2:00 PM
5/7/13 9:00 PM
5/14/13 4:00 AM
5/20/13 11:00 AM
5/26/13 6:00 PM
6/2/13 1:00 AM
6/8/13 8:00 AM
6/14/13 3:00 PM
6/20/13 10:00 PM
6/27/13 5:00 AM
7/4/13 11:00 AM
7/10/13 6:00 PM
7/17/13 1:00 AM
7/23/13 8:00 AM
7/31/13 5:00 PM
8/7/13 12:00 AM
8/13/13 7:00 AM
8/19/13 2:00 PM
8/25/13 9:00 PM
9/1/13 4:00 AM
10/5/13 7:00 PM
10/13/13 5:00 PM
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12/18/13 3:00 AM
12/24/13 10:00 AM
12/30/13 5:00 PM
1/6/14 8:00 AM
1/13/14 7:00 AM
1/19/14 2:00 PM
1/25/14 9:00 PM
2/4/14 7:00 AM
2/10/14 2:00 PM
2/16/14 9:00 PM
3/2/14 5:00 AM
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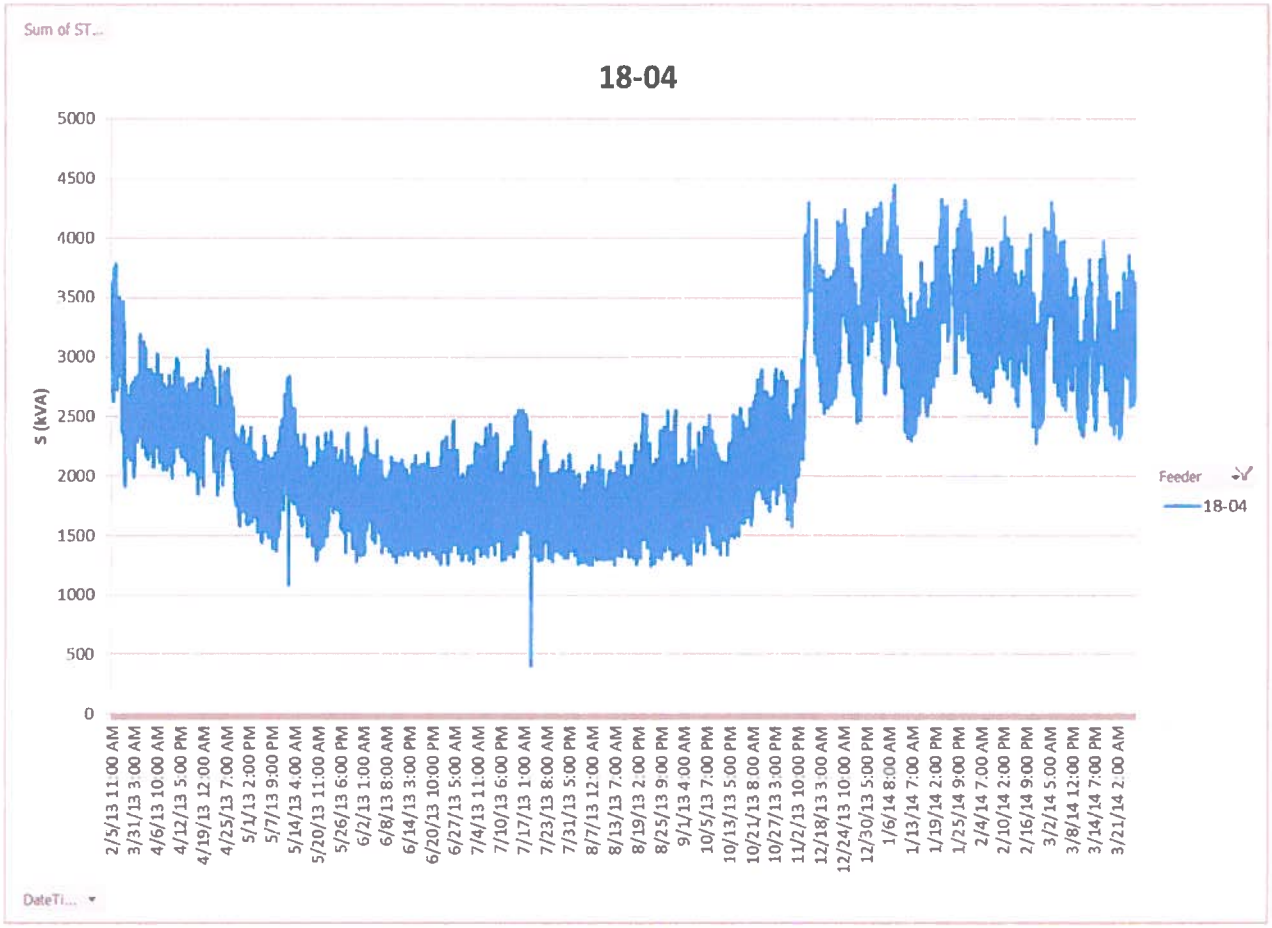
3/14/14 7:00 PM
3/21/14 2:00 AM
DateTi...
Feeder
18-03

18-04:


Sum of ST...
18-04
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4/25/13 7:00 AM
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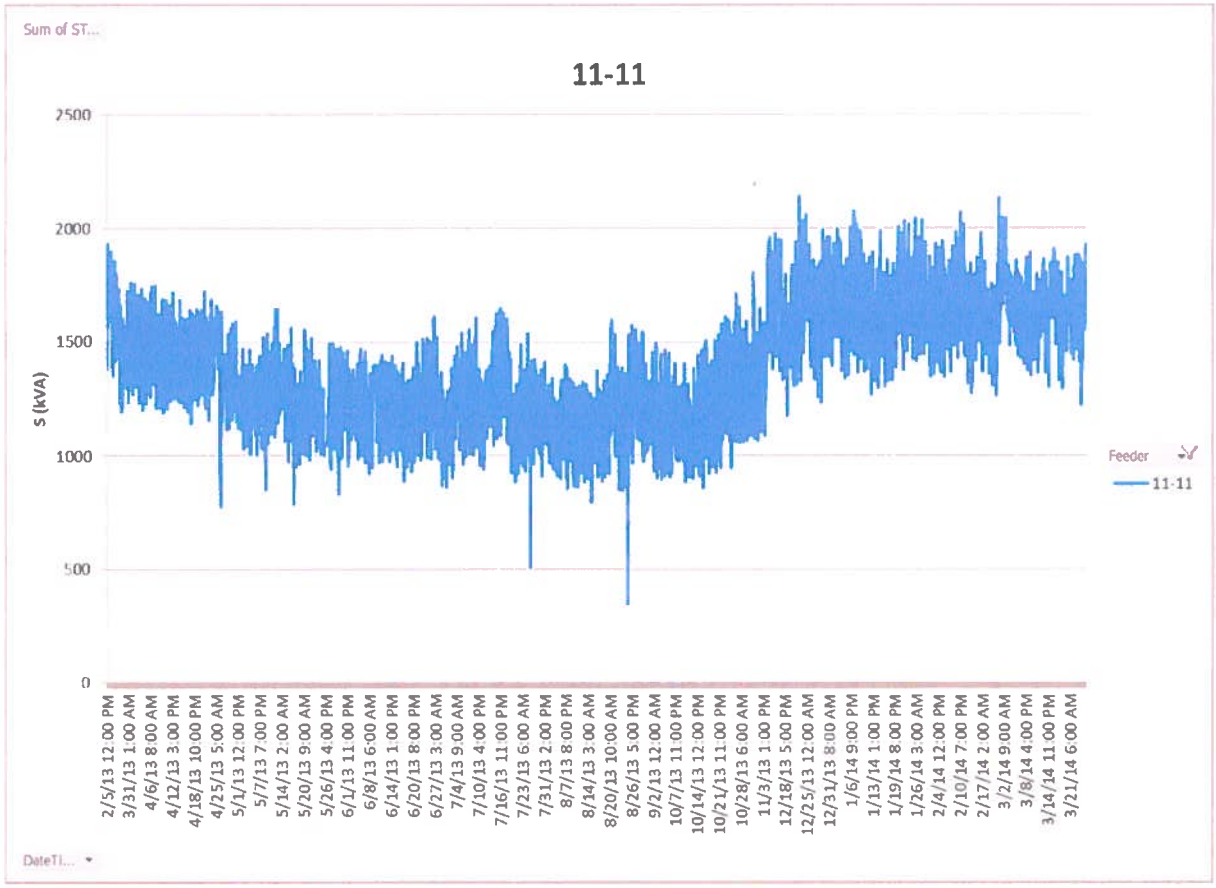
3/21/14 2:00 AM
DateTi...
Feeder
18-04

11-11: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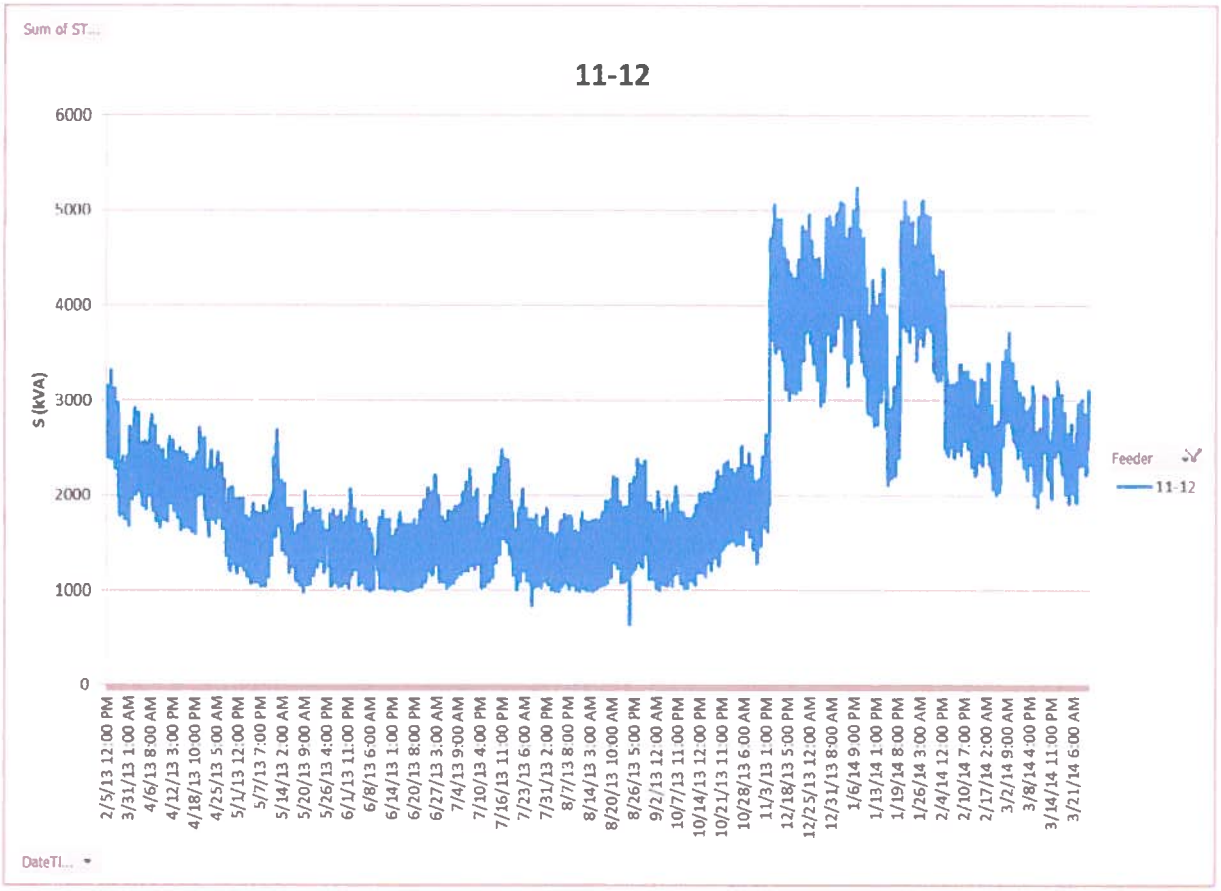
DateTi...
Feeder
11-11

11-12: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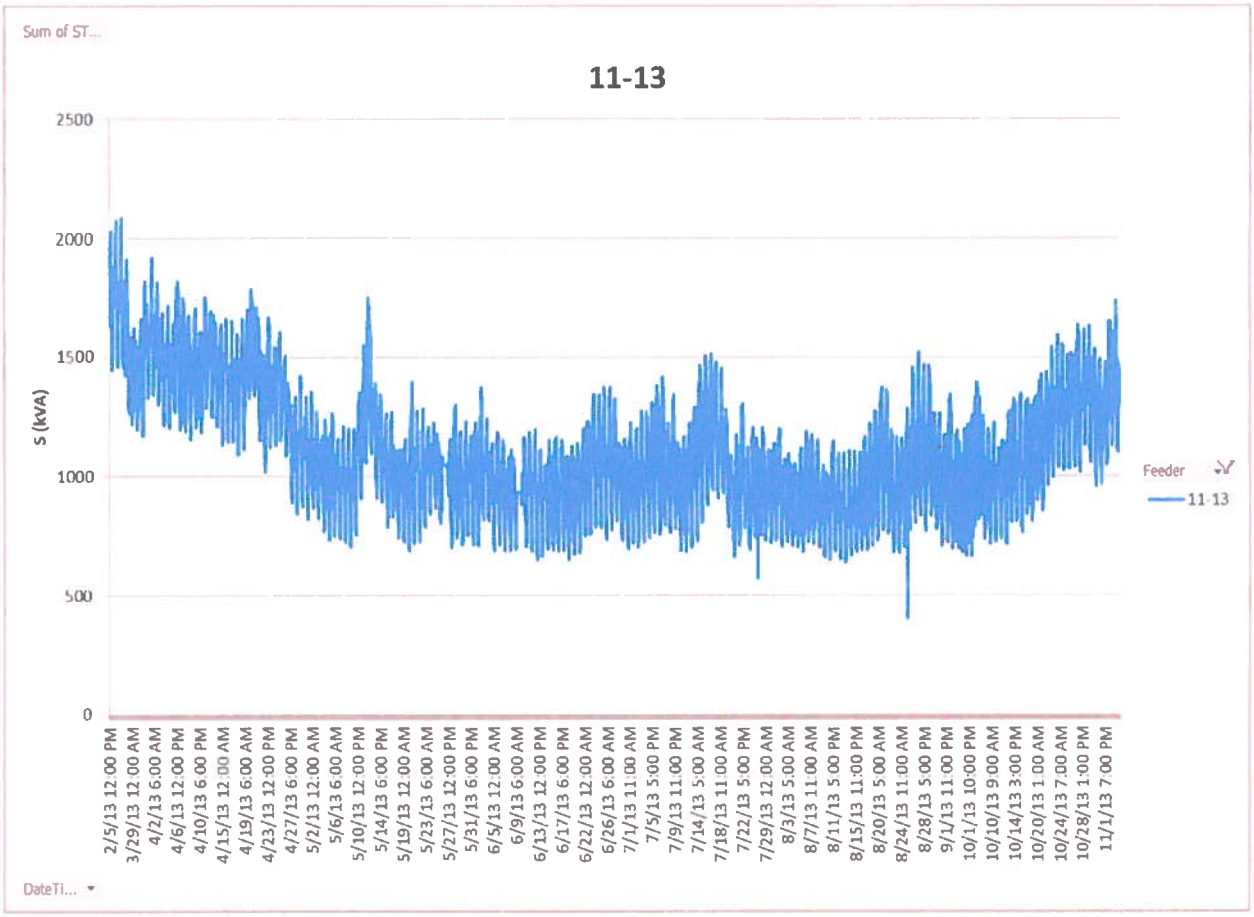
DateTI...
Feeder
11-12

11-13: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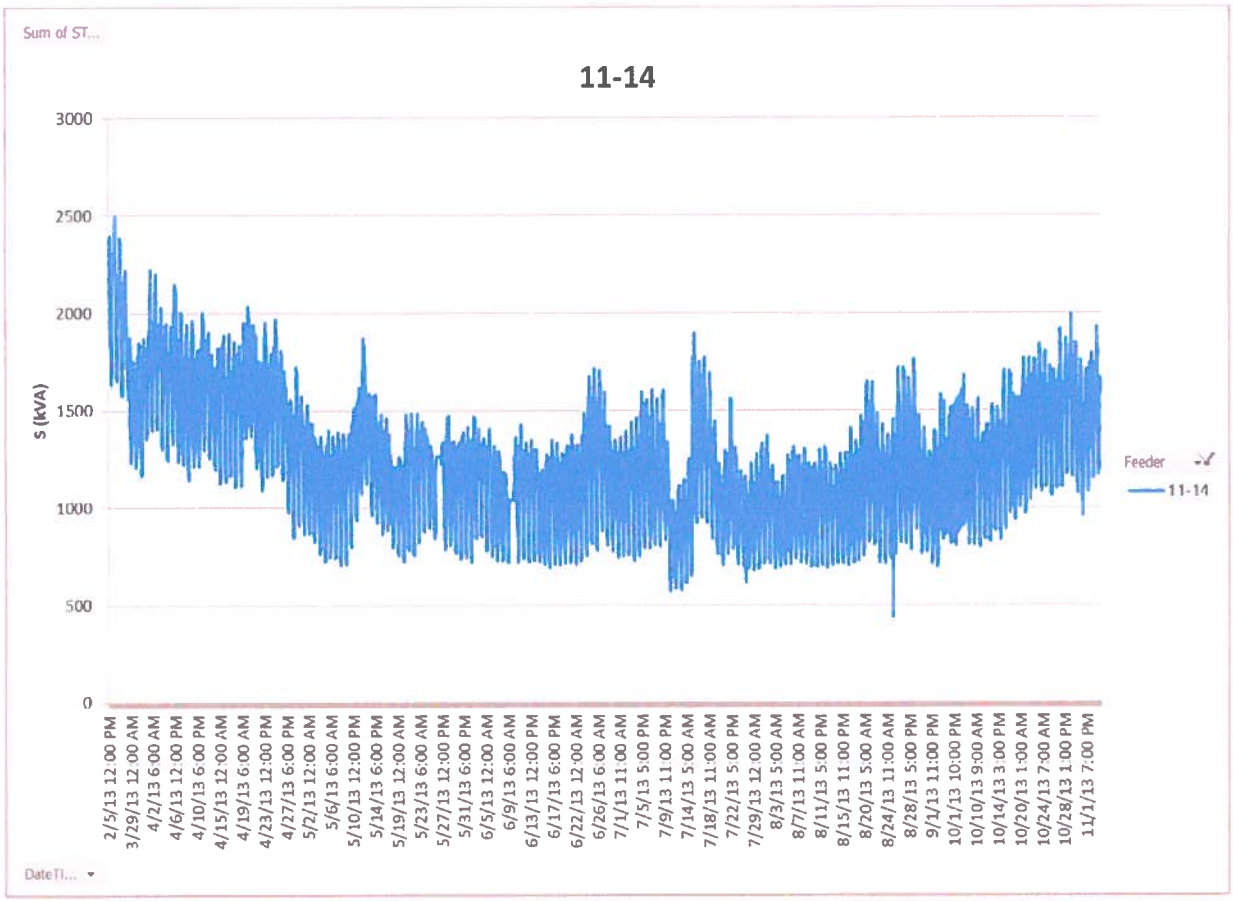
DateTi...
Feeder
11-13

11-14: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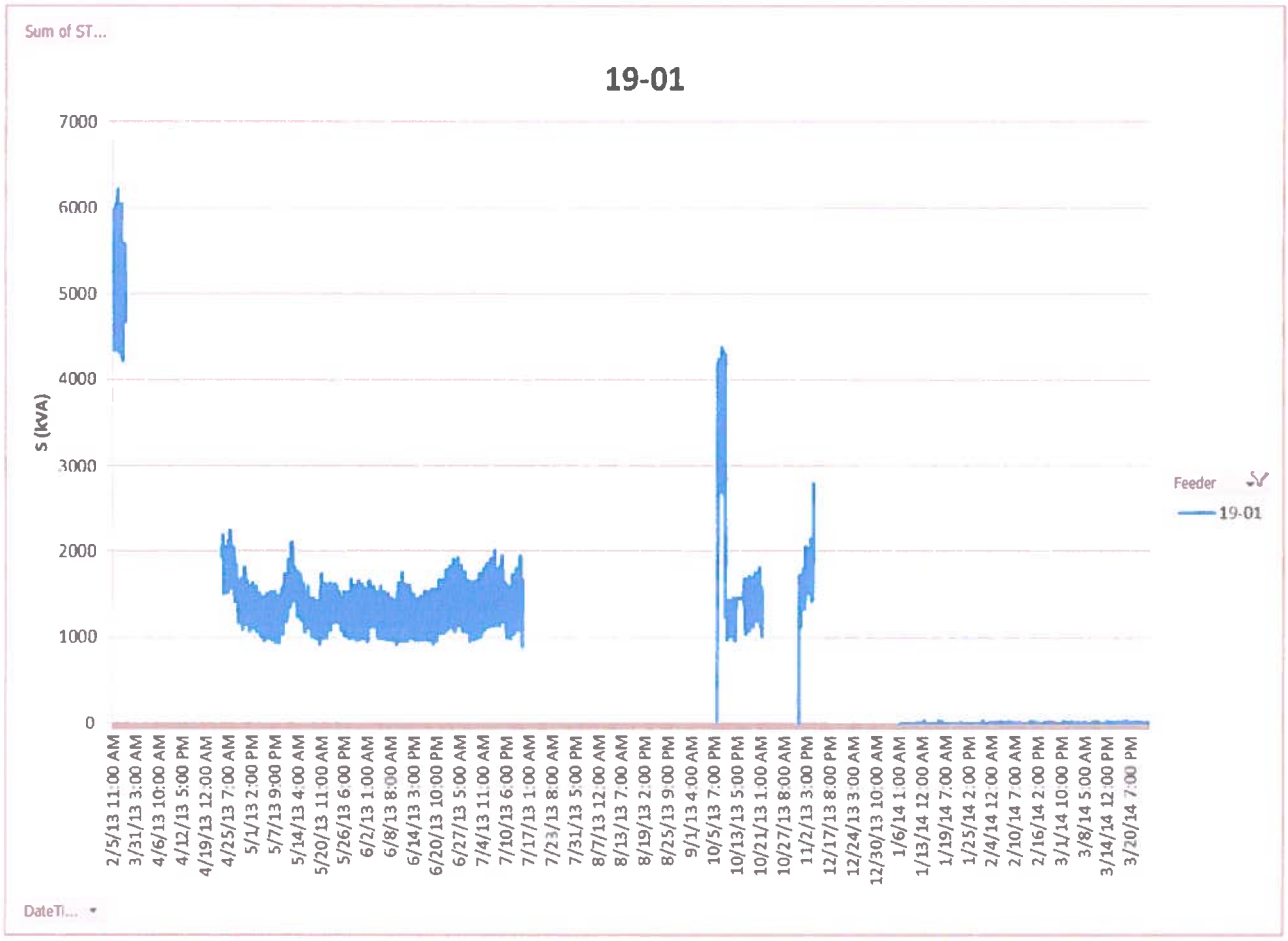
DateTi...
Feeder
11-14

19-01:


Sum of ST...
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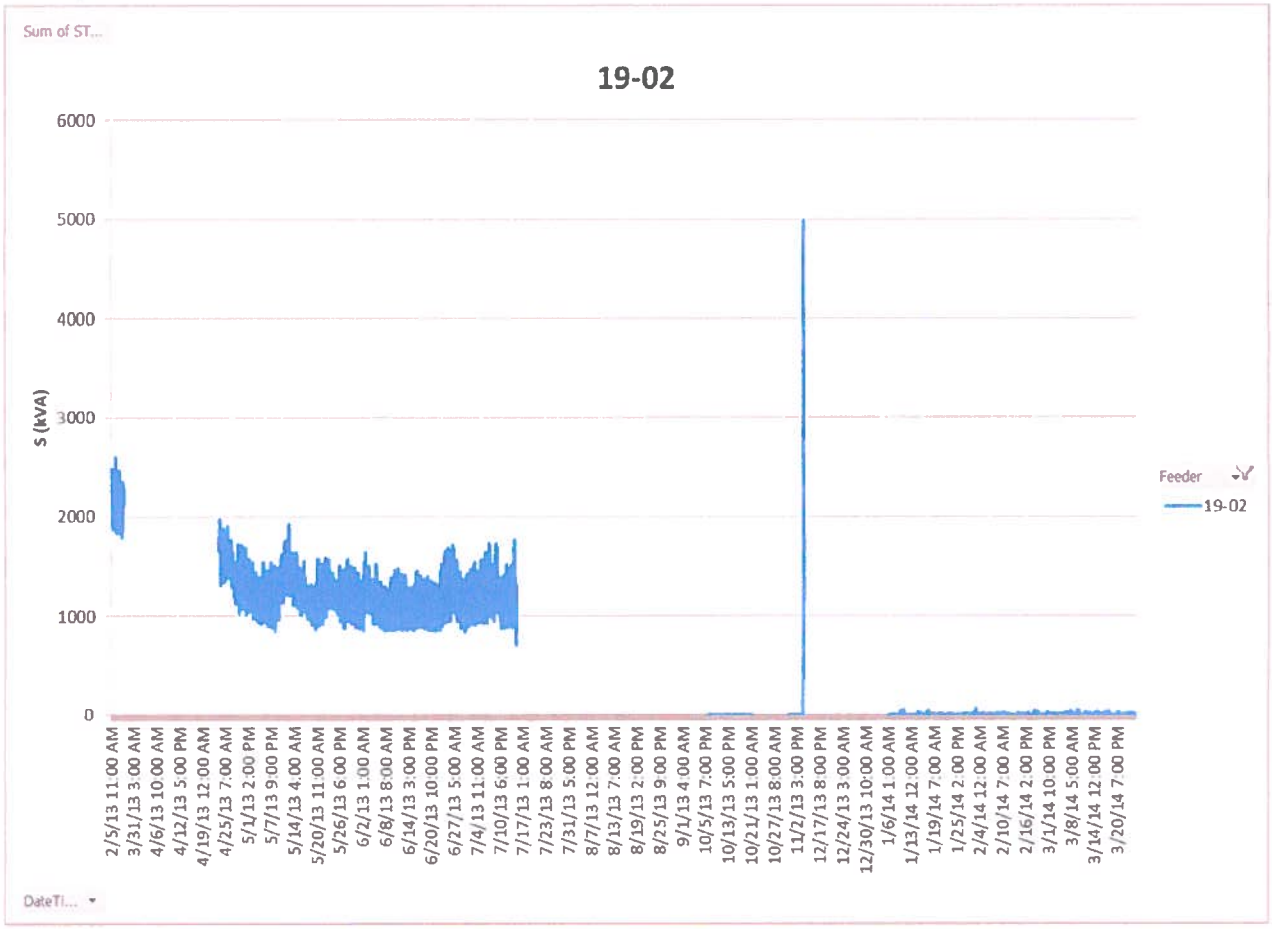
DateTi...
Feeder
19-01

19-02: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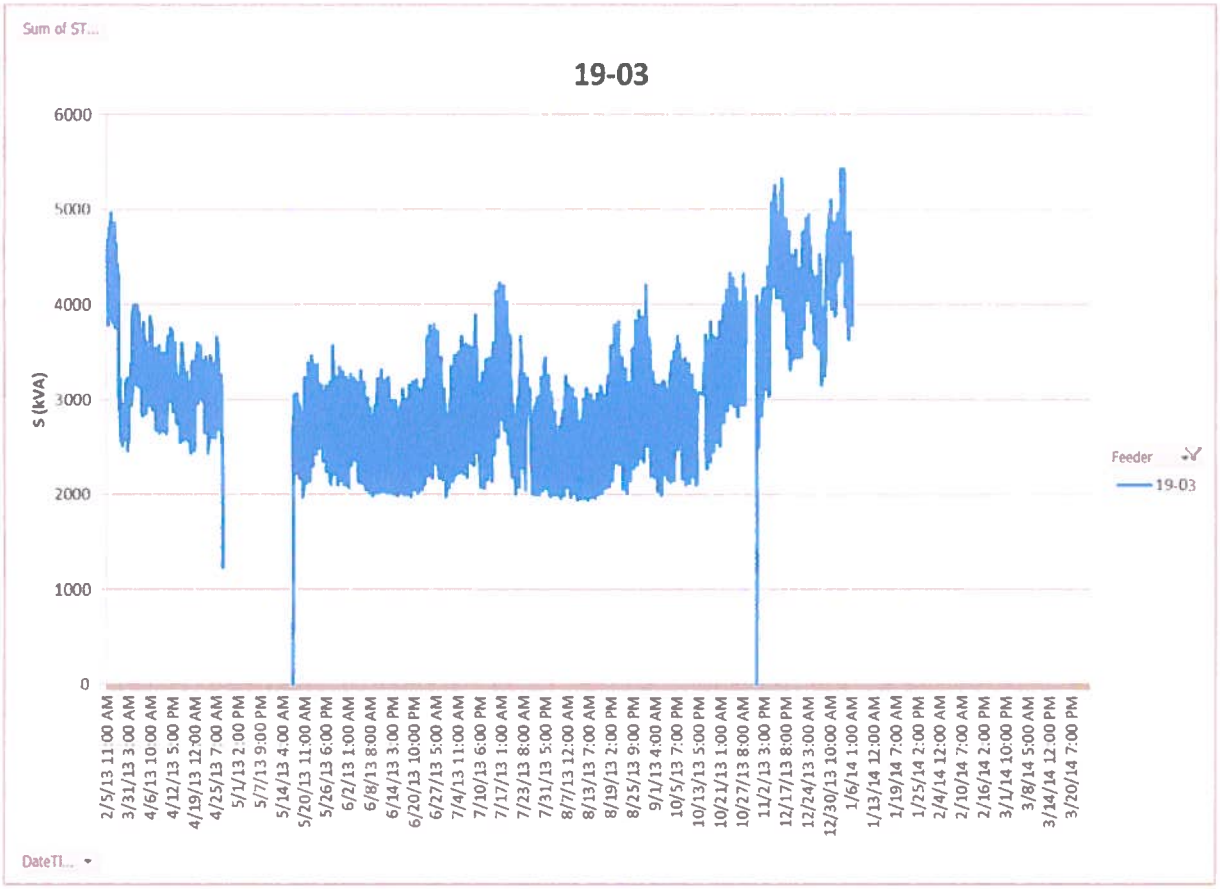
DateTi...
Feeder
19-02

19-03: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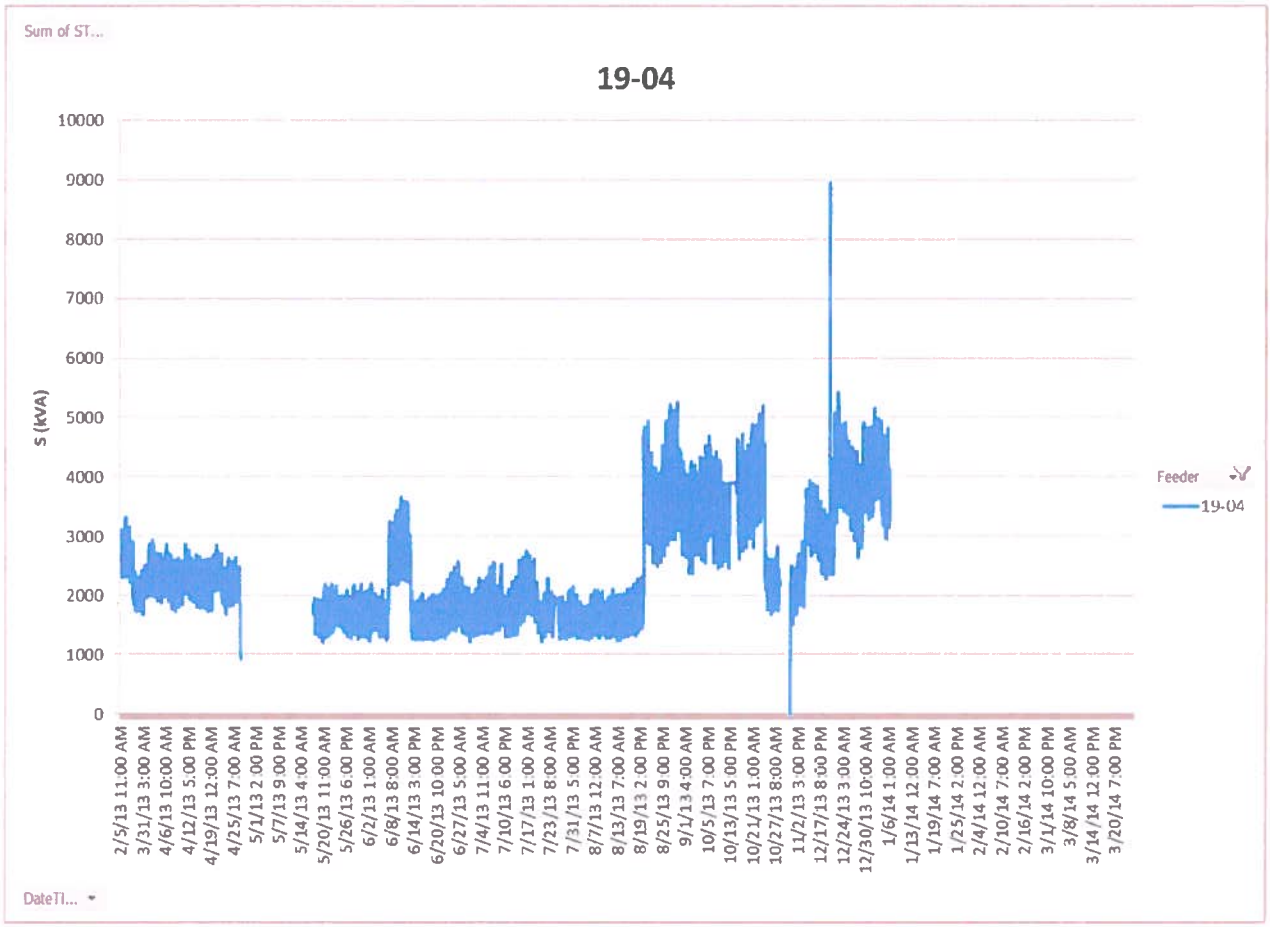
DateTi...
Feeder
19-03

19-04: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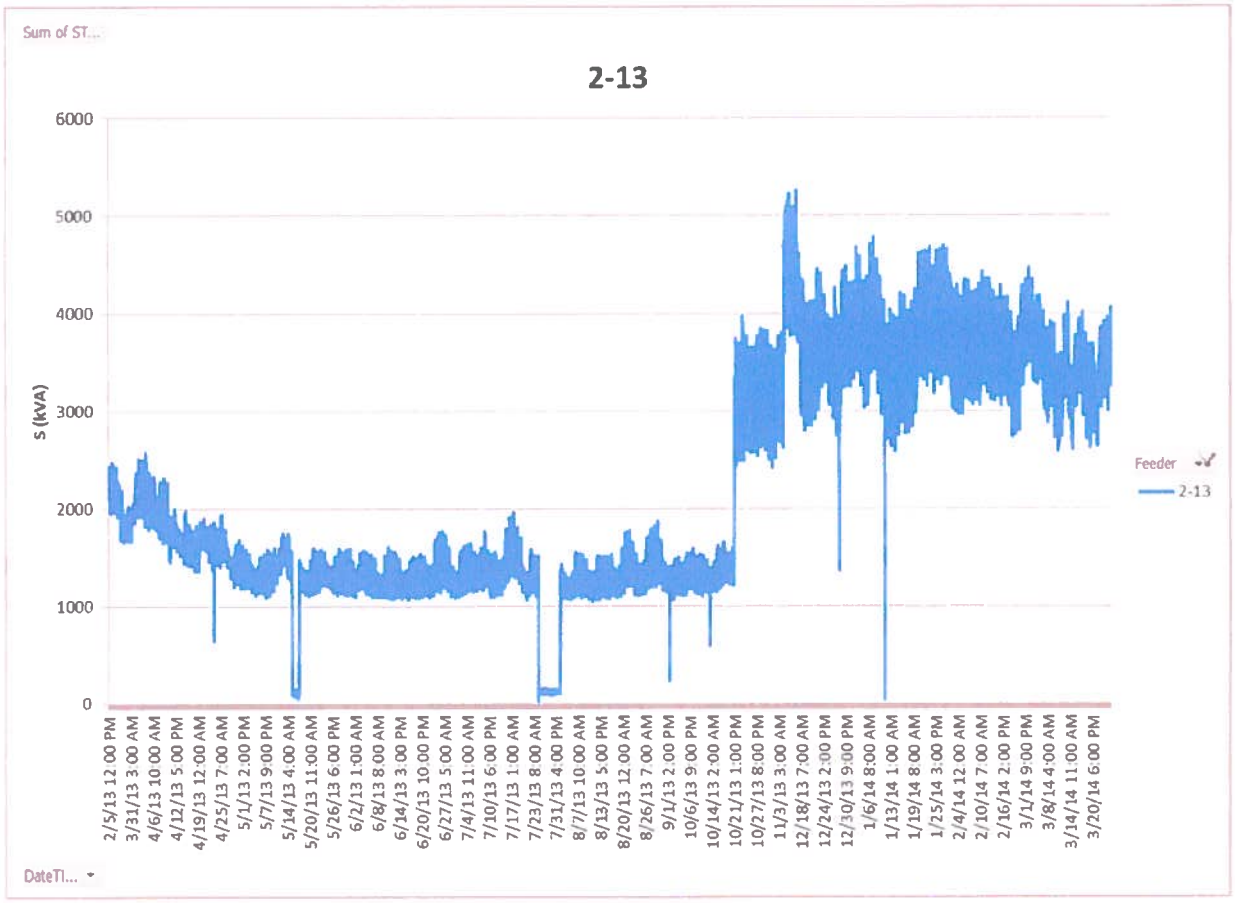
Feeder
19-04
DateTi...

2-13:


Sum of ST...
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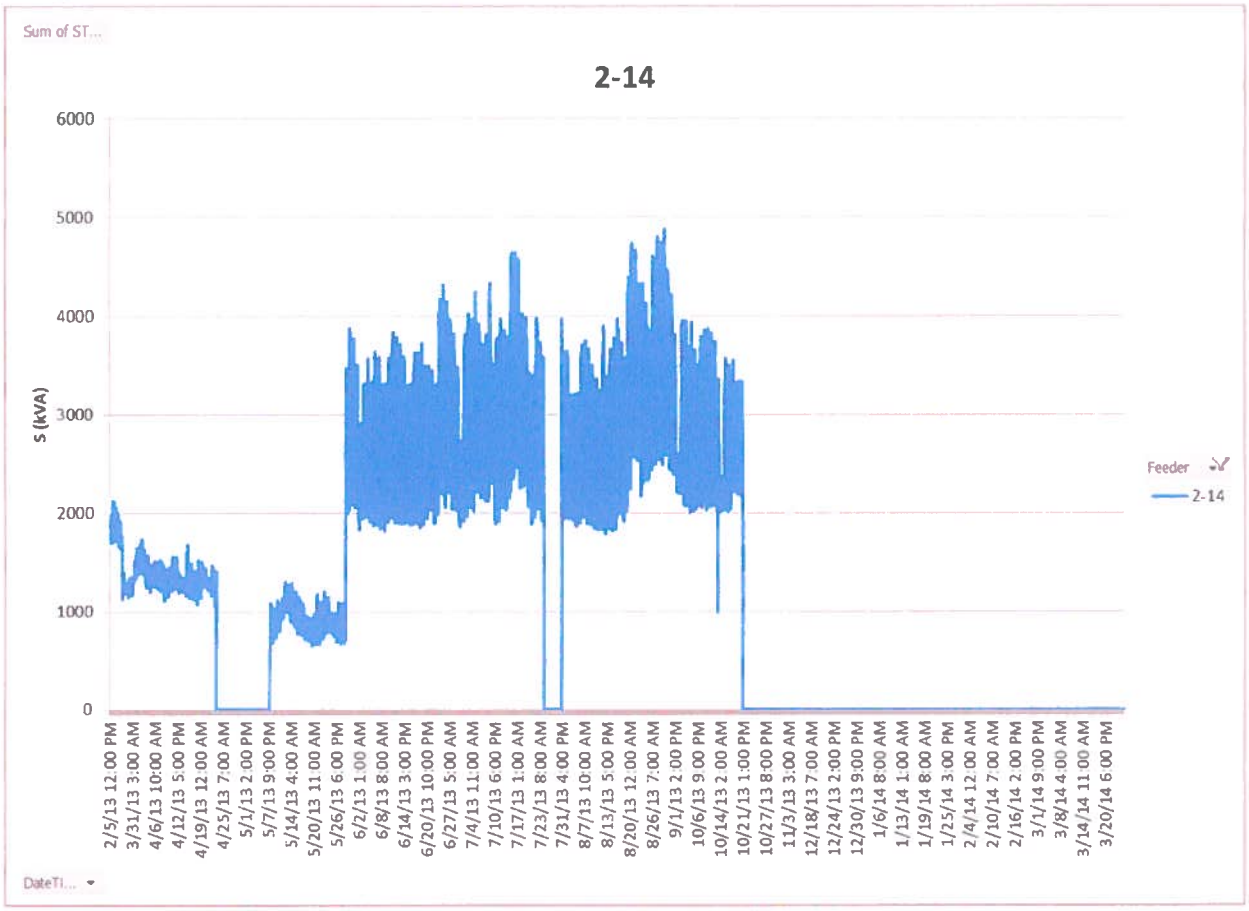
Feeder
2-13

2-14:


Sum of ST...
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DateTi...
Feeder
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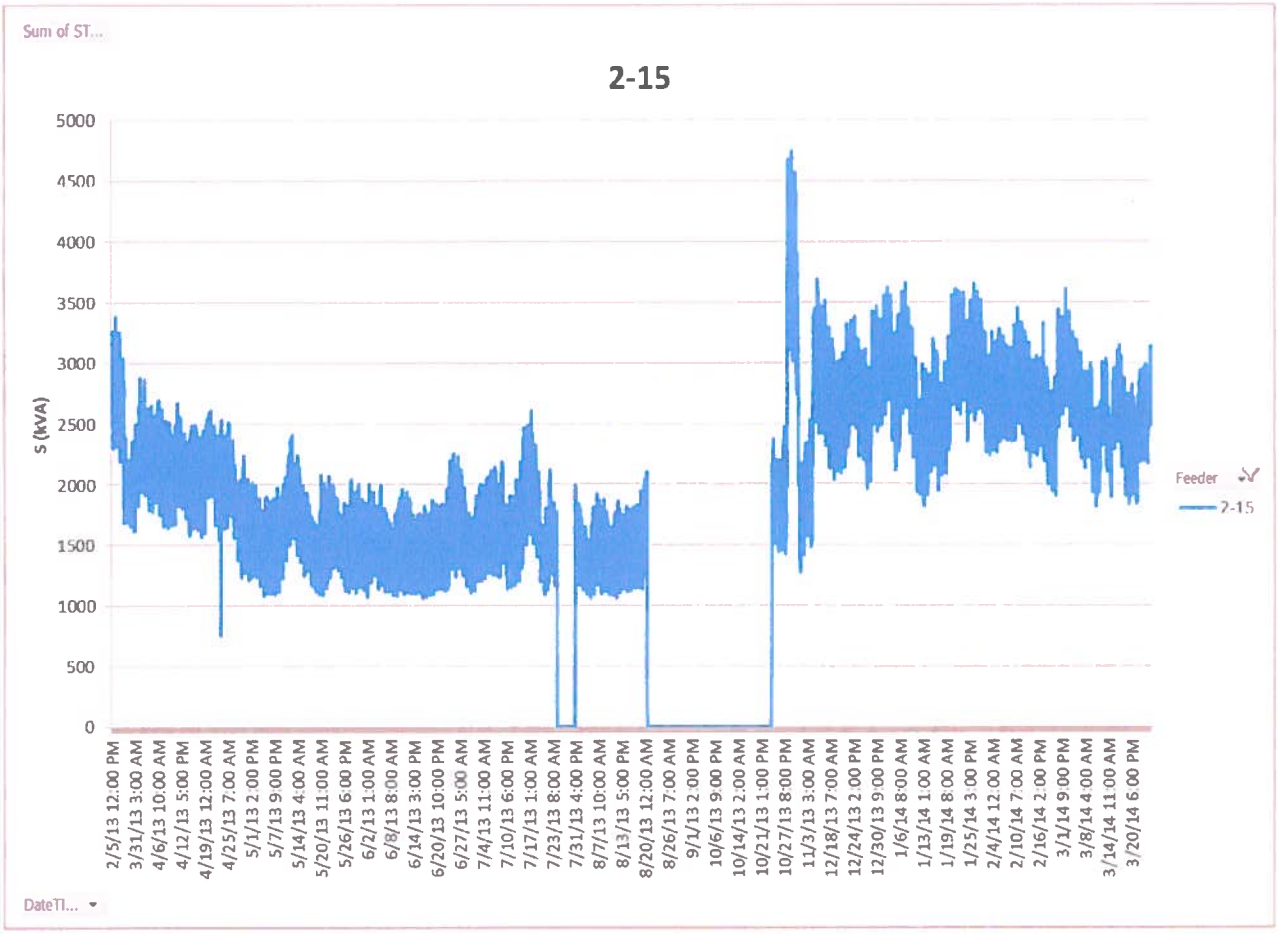
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9/1/13 2:00 PM
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2-15

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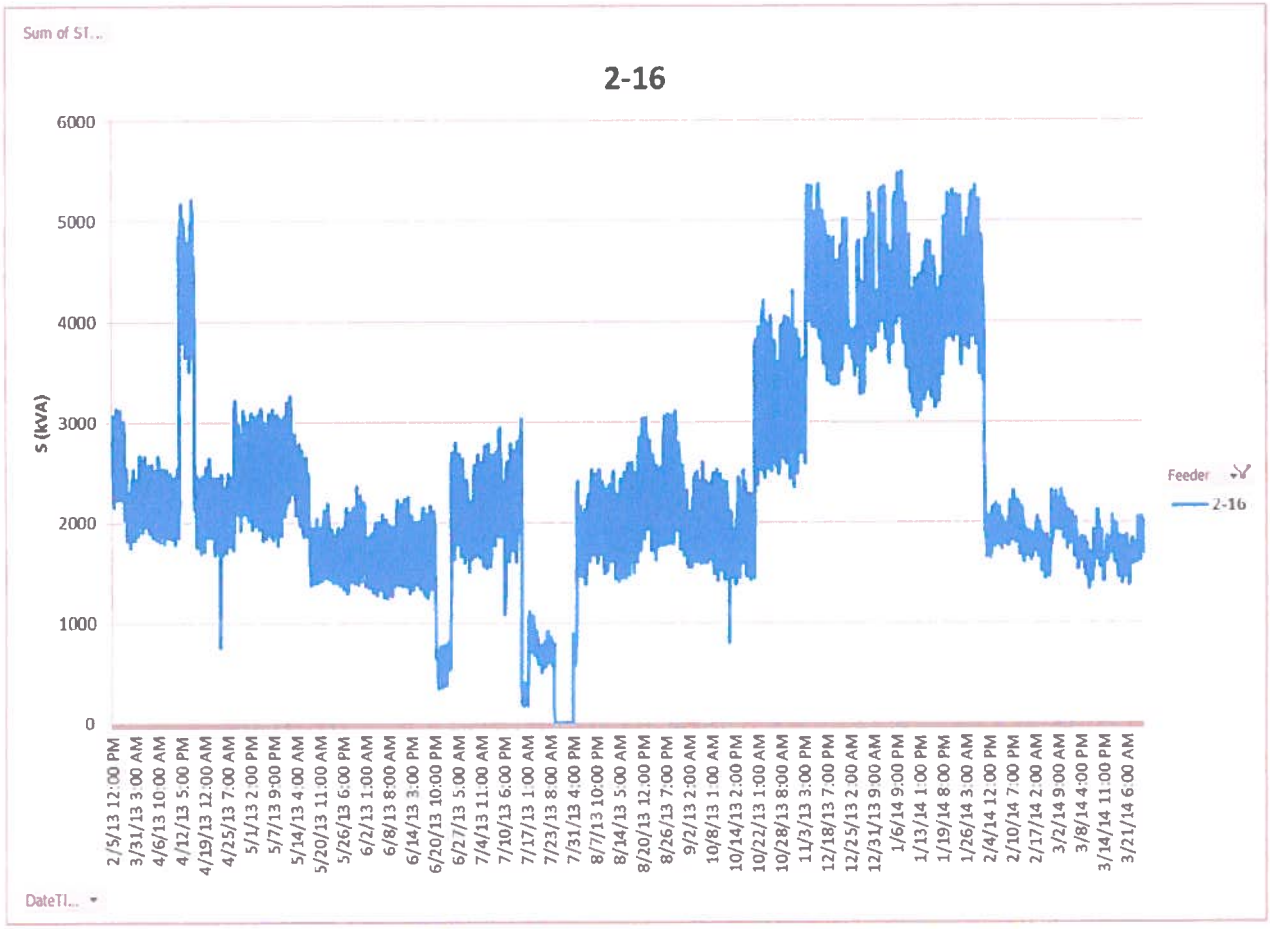
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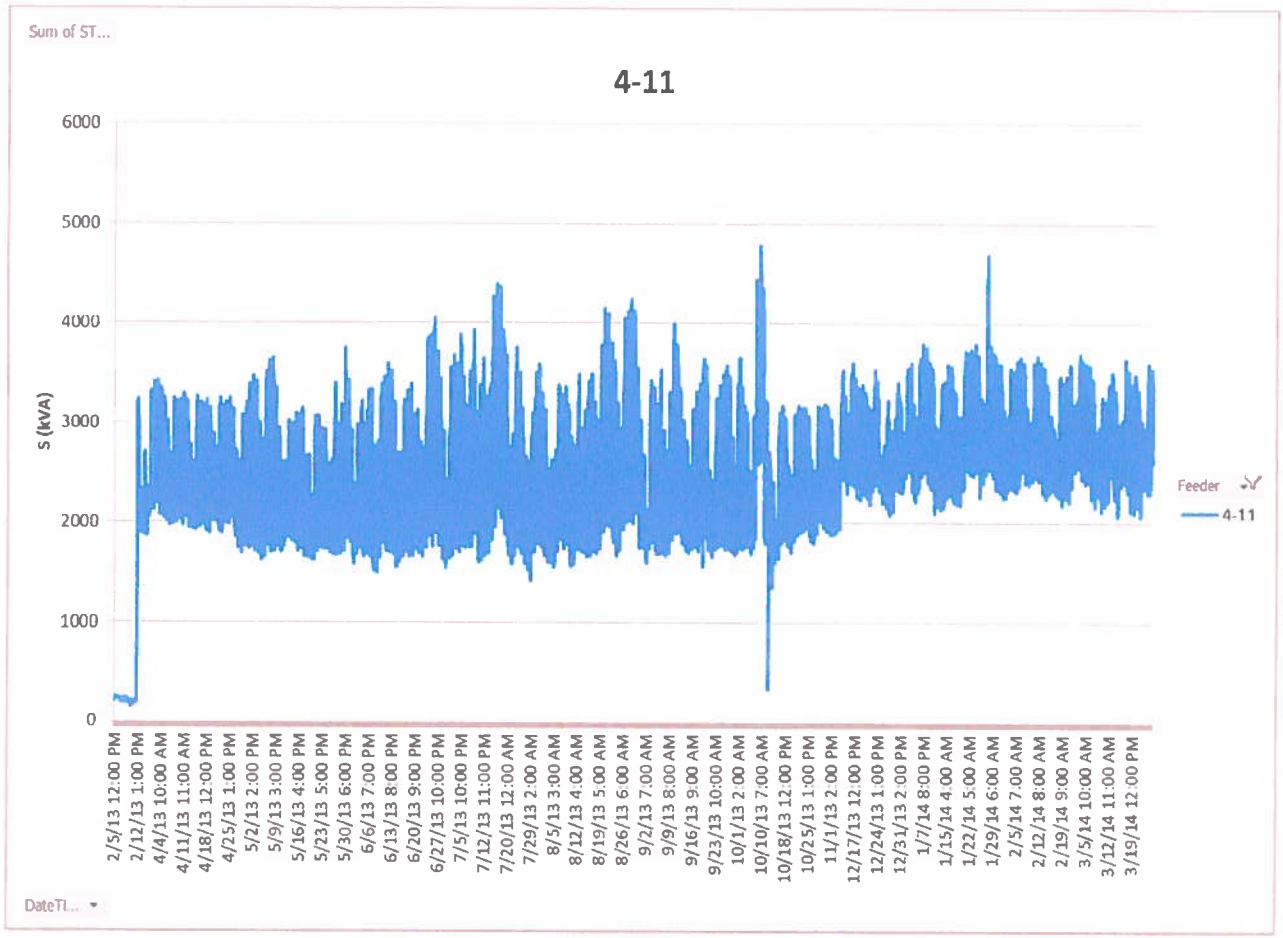
DateTI...
Feeder
2-16

4-11: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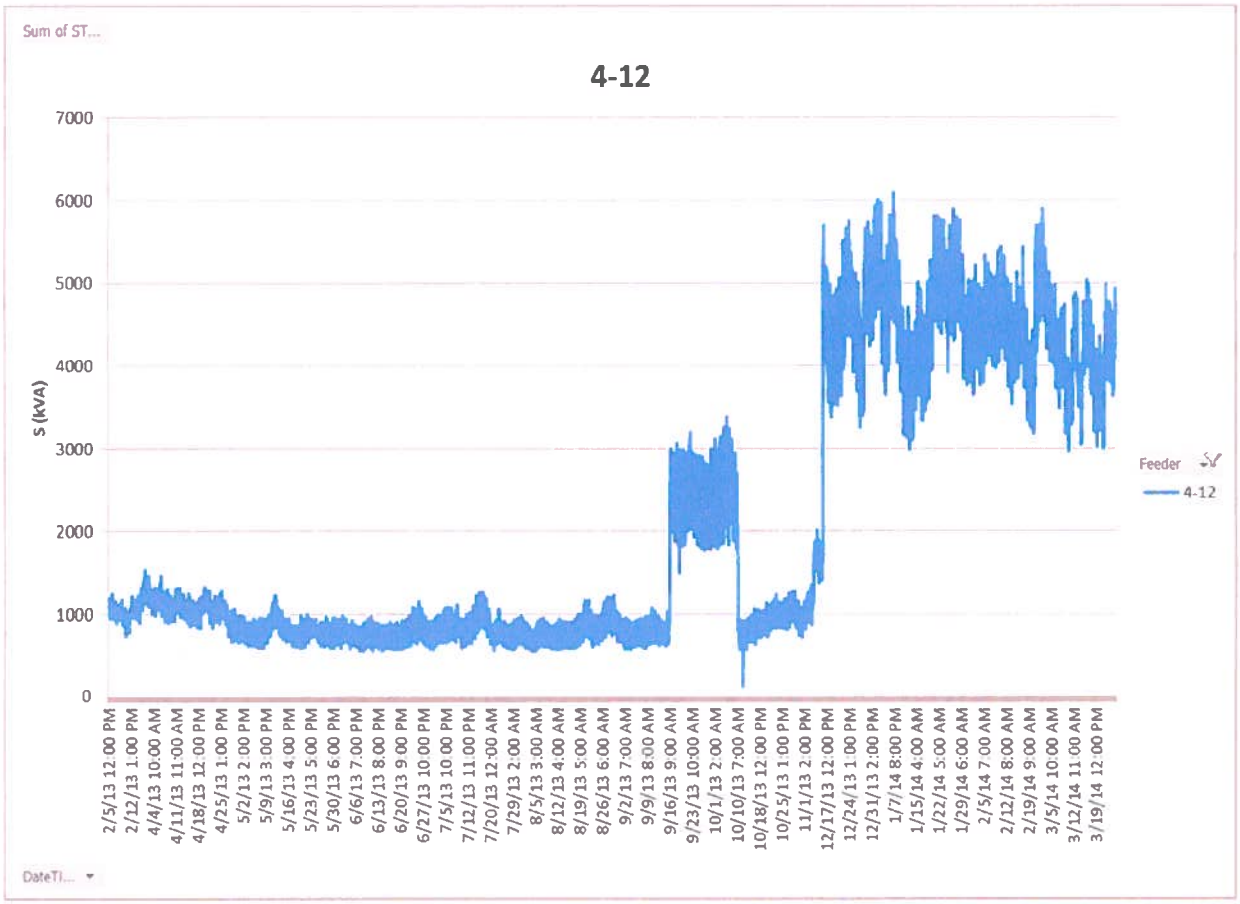
DateTi...
Feeder
4-11

4-12:


Sum of ST...
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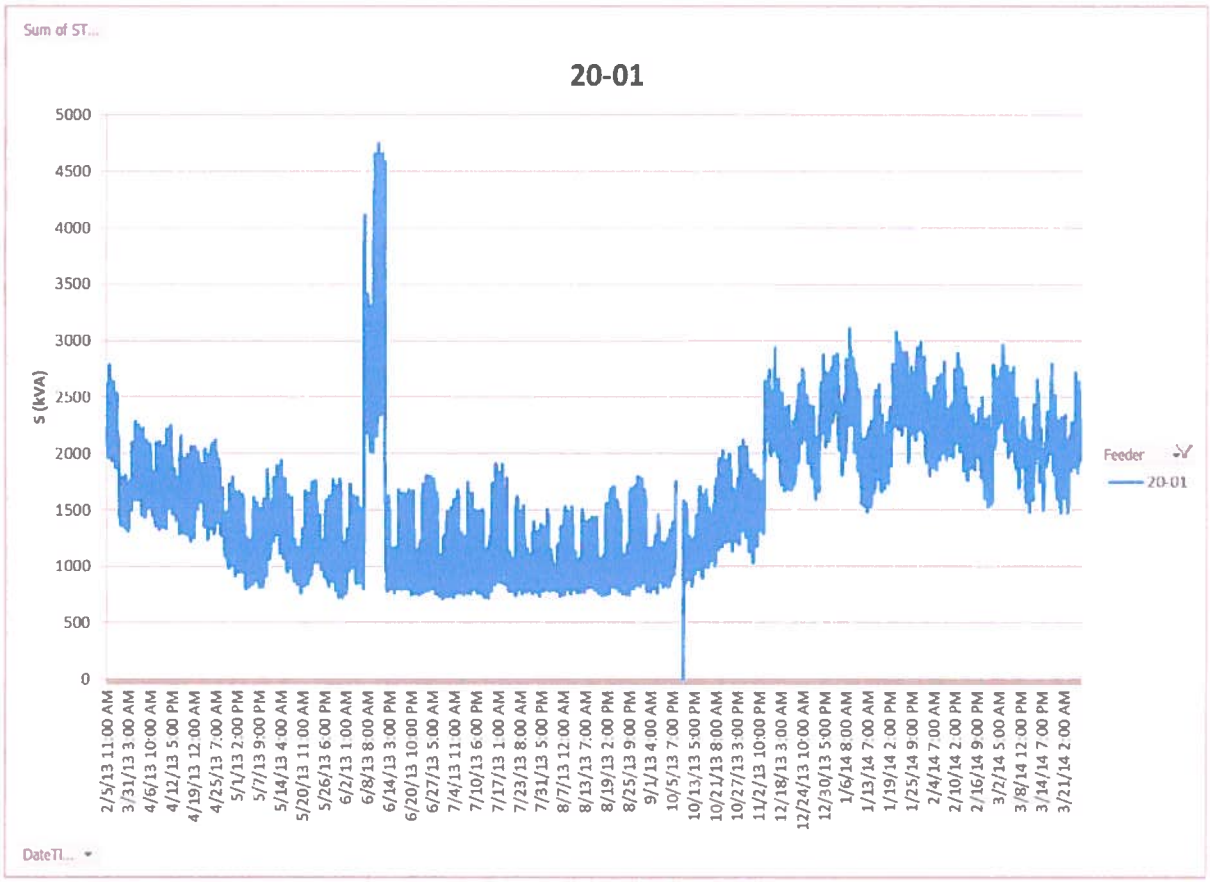
DateTi...
Feeder
4-12

20-01: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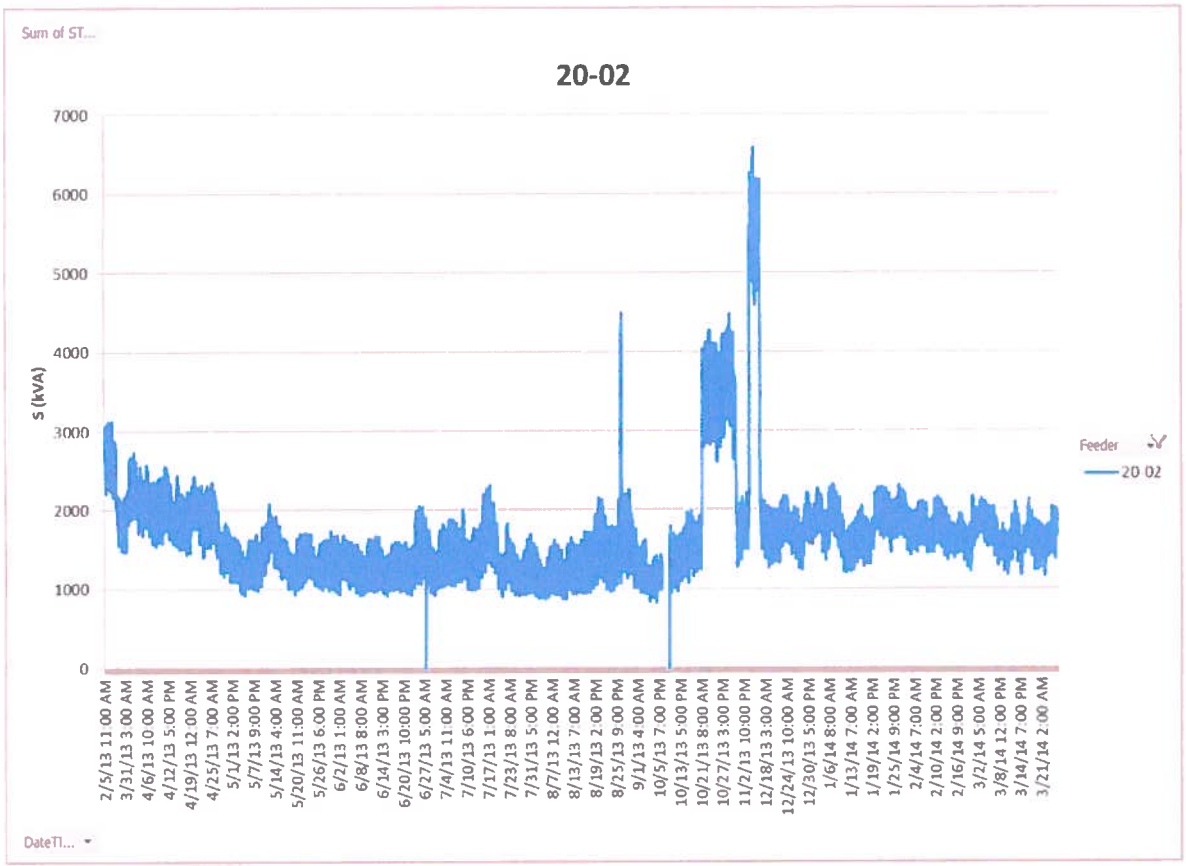
DateTi...
Feeder
20-01

20-02: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DateTi...
Feeder
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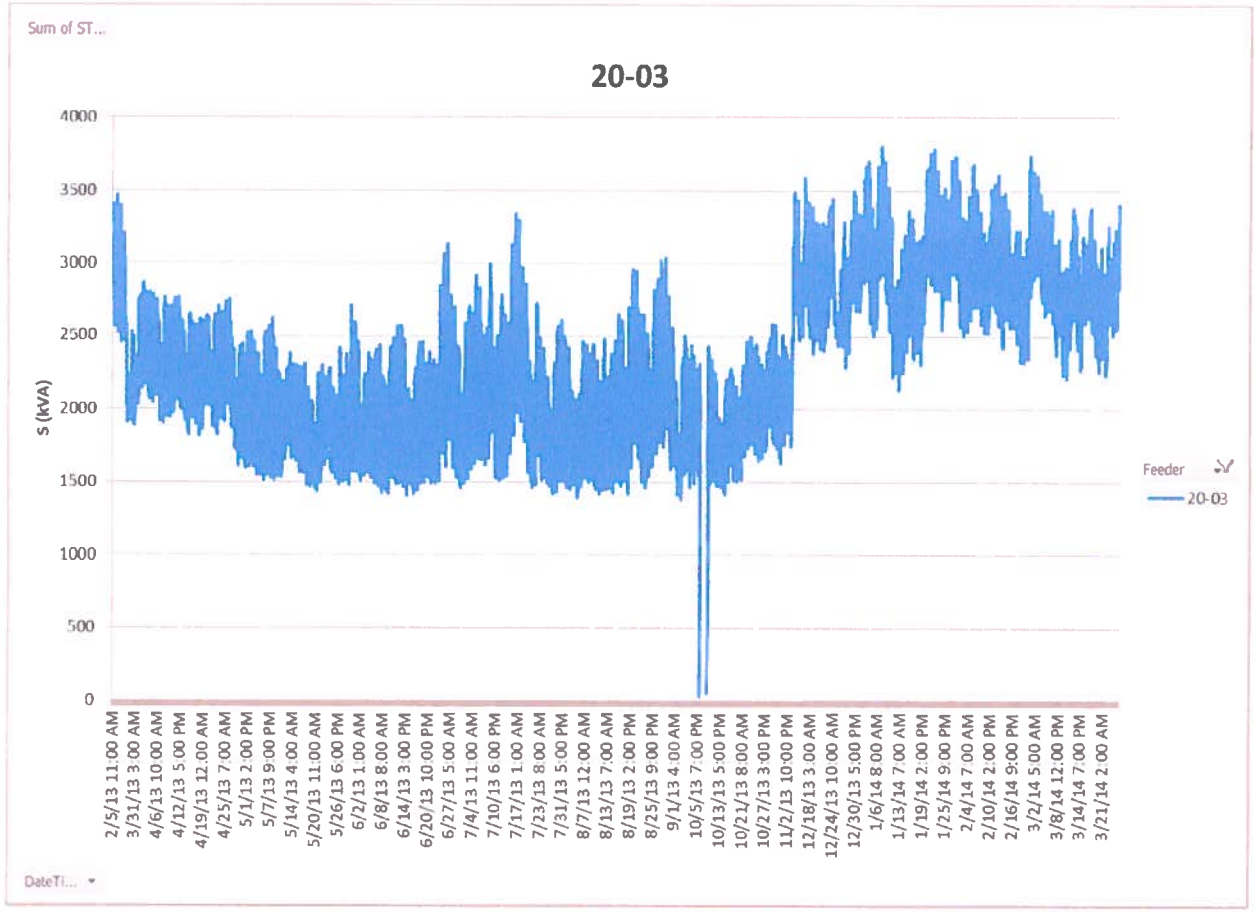
20-03: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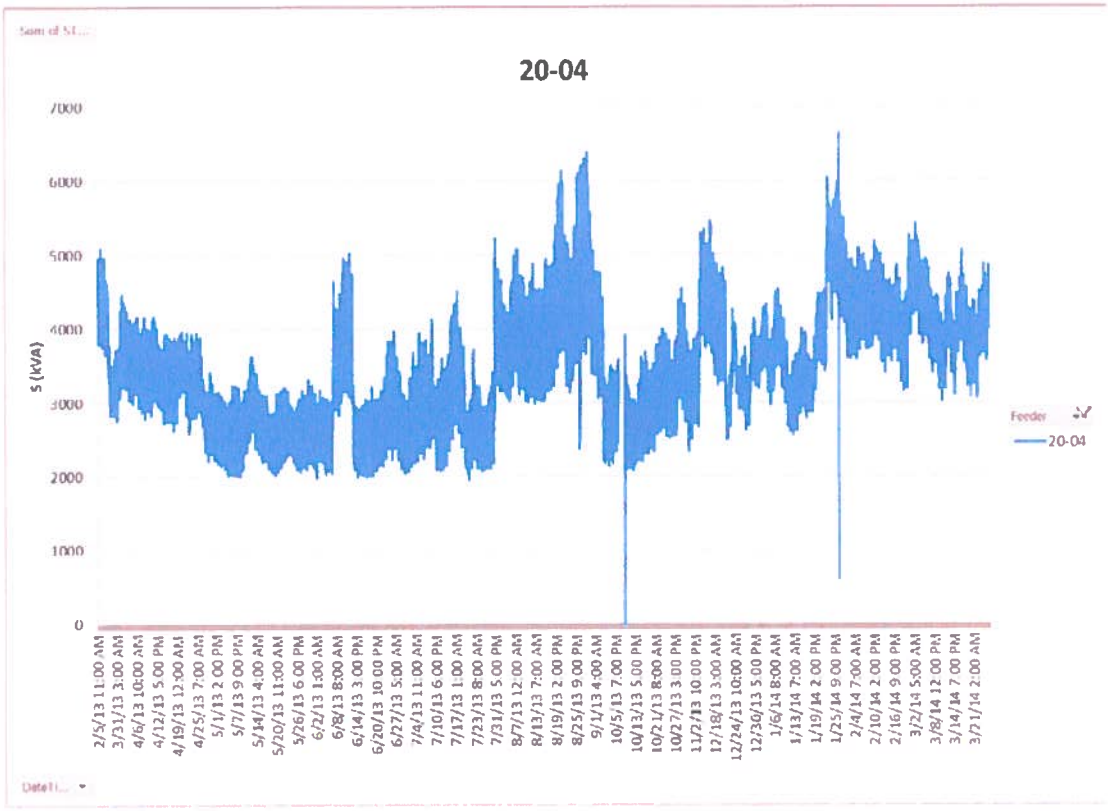
Feeder
20-03

20-04: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Feeder
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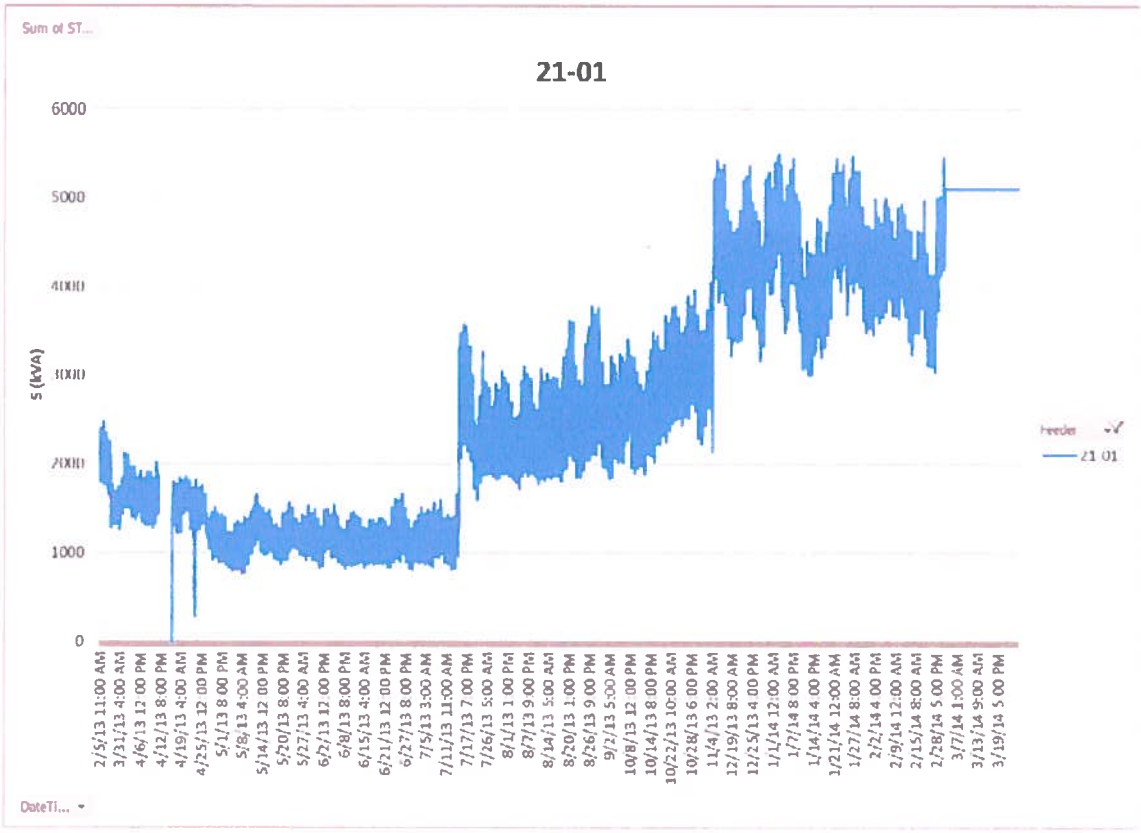
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21-01

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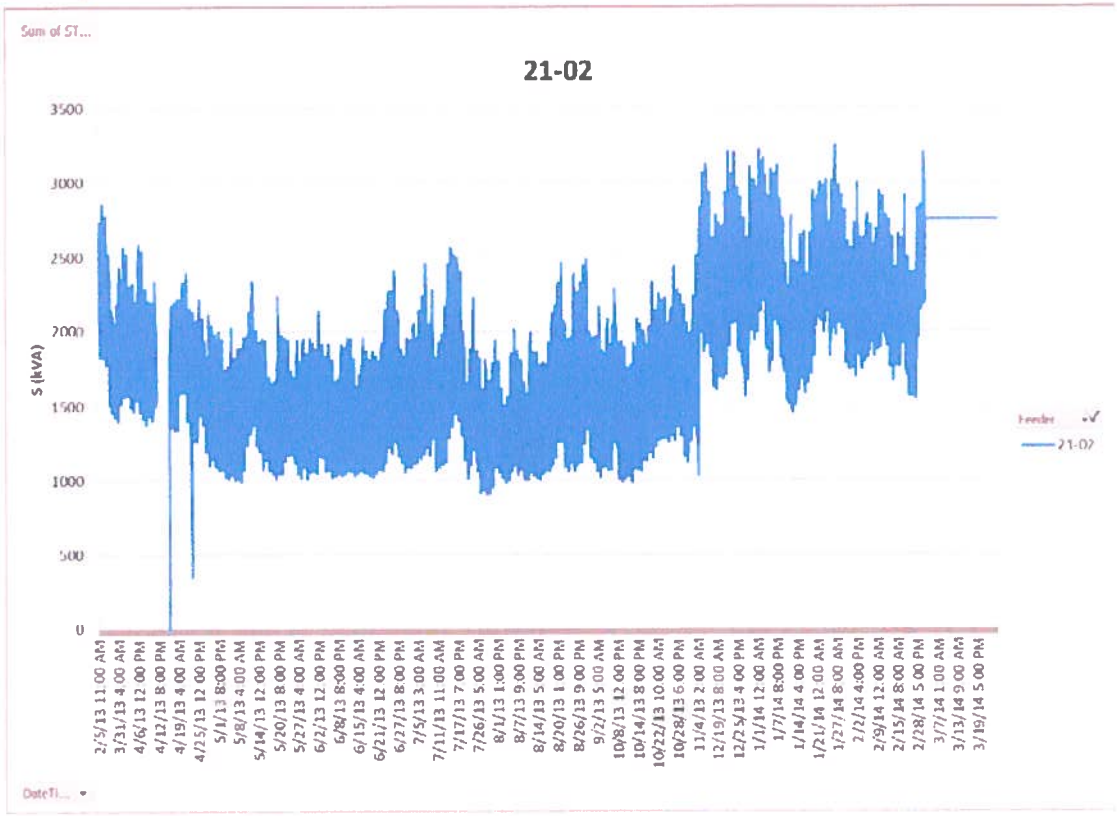
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Feeder
21-02
DateTi...

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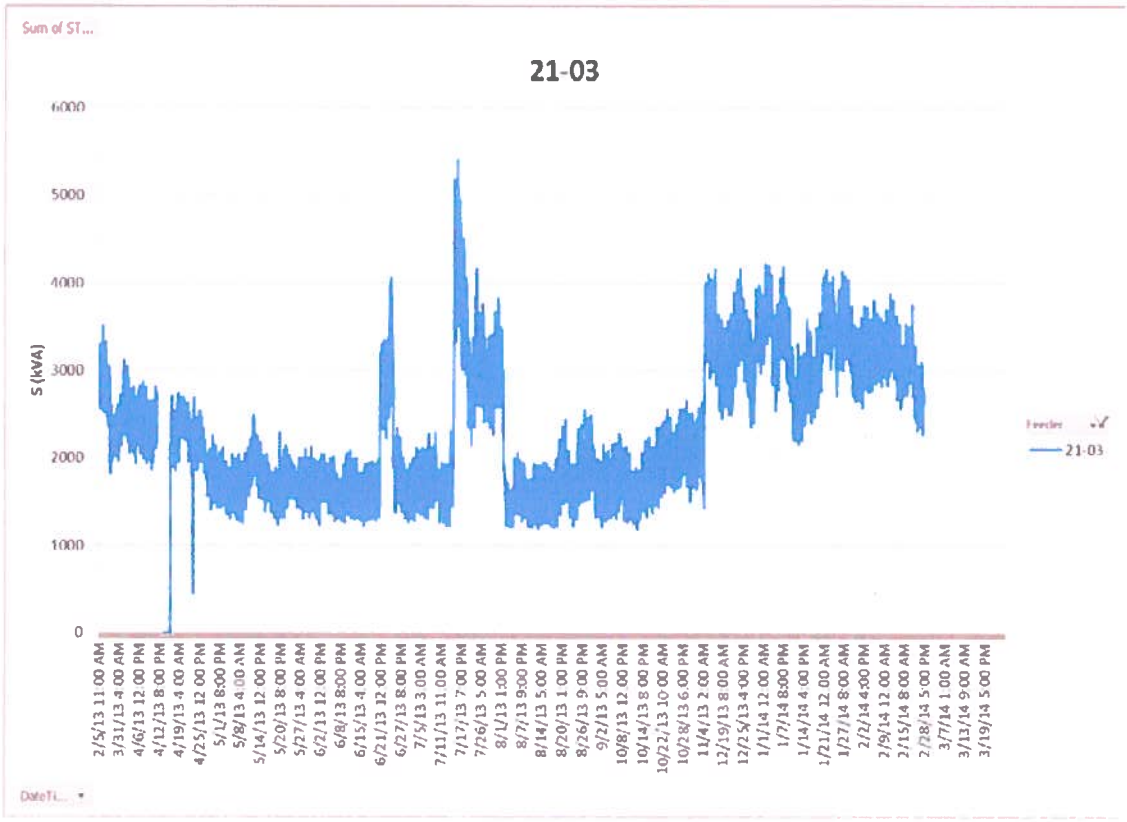
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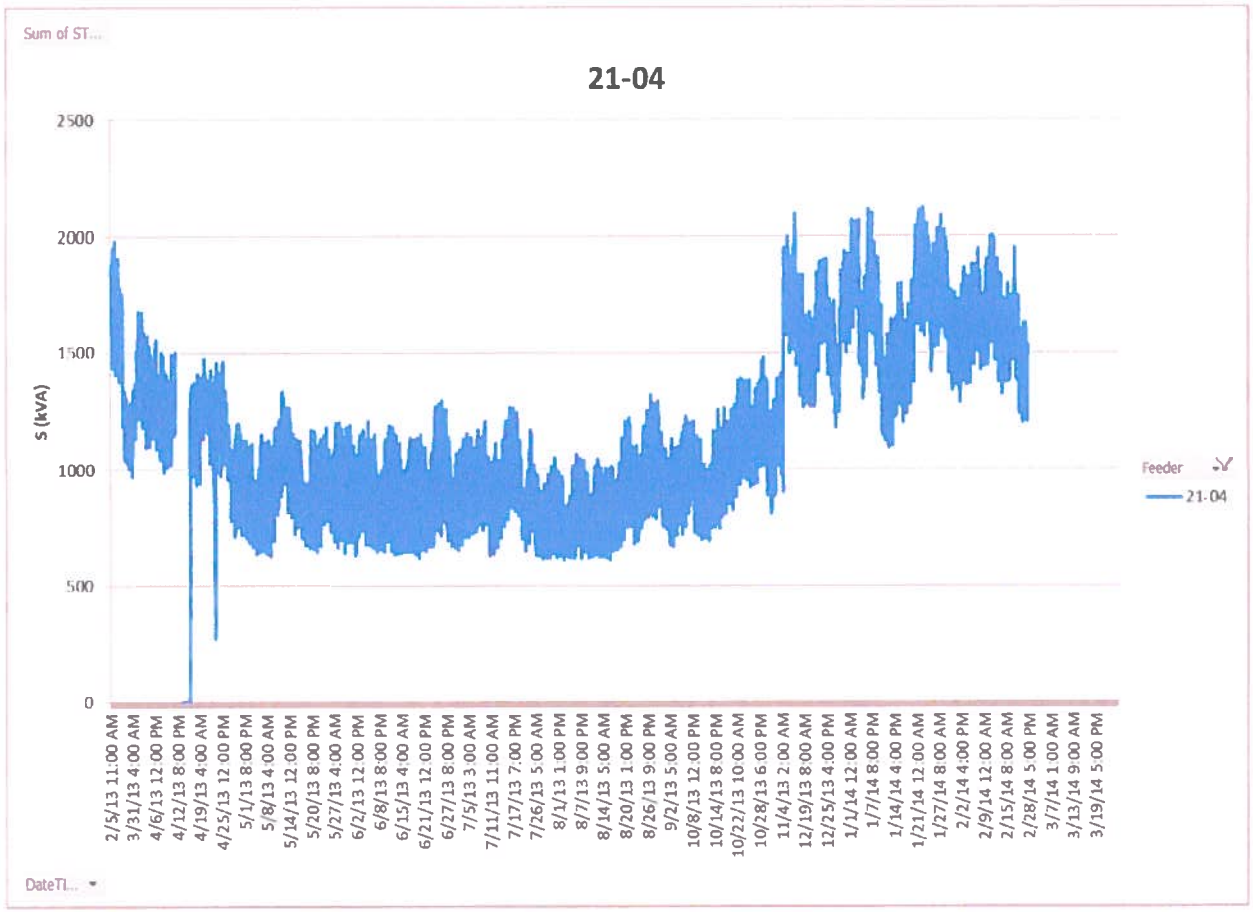
21-04:


Sum of ST...
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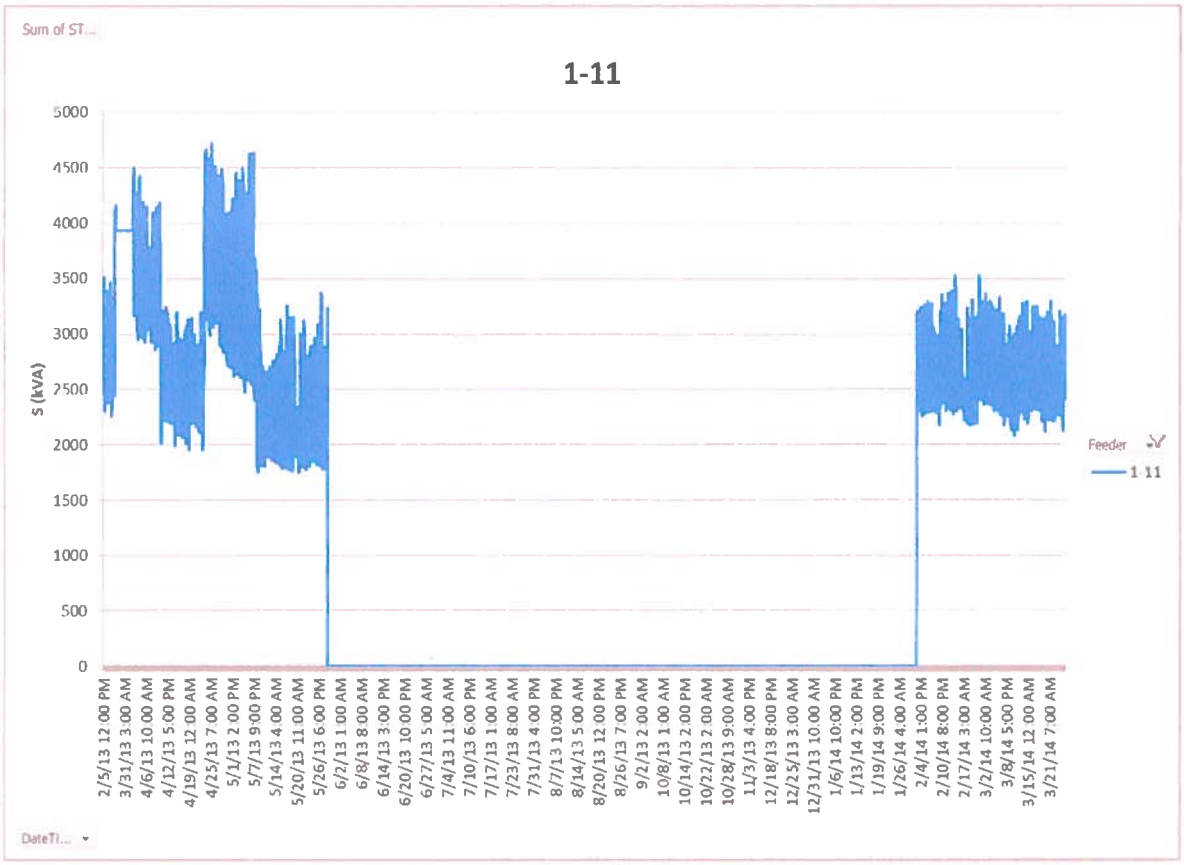
Feeder
21-04

1-11: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DateTi...
Feeder
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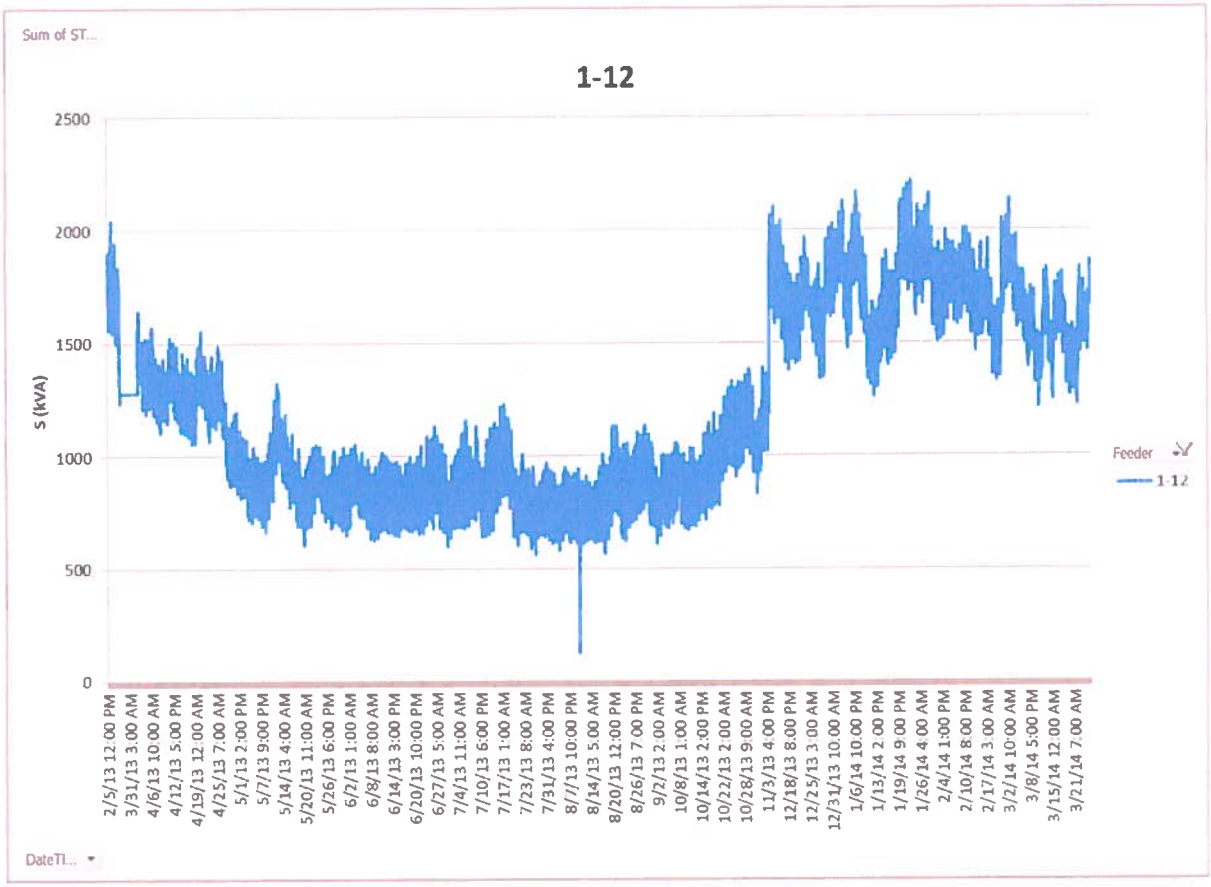
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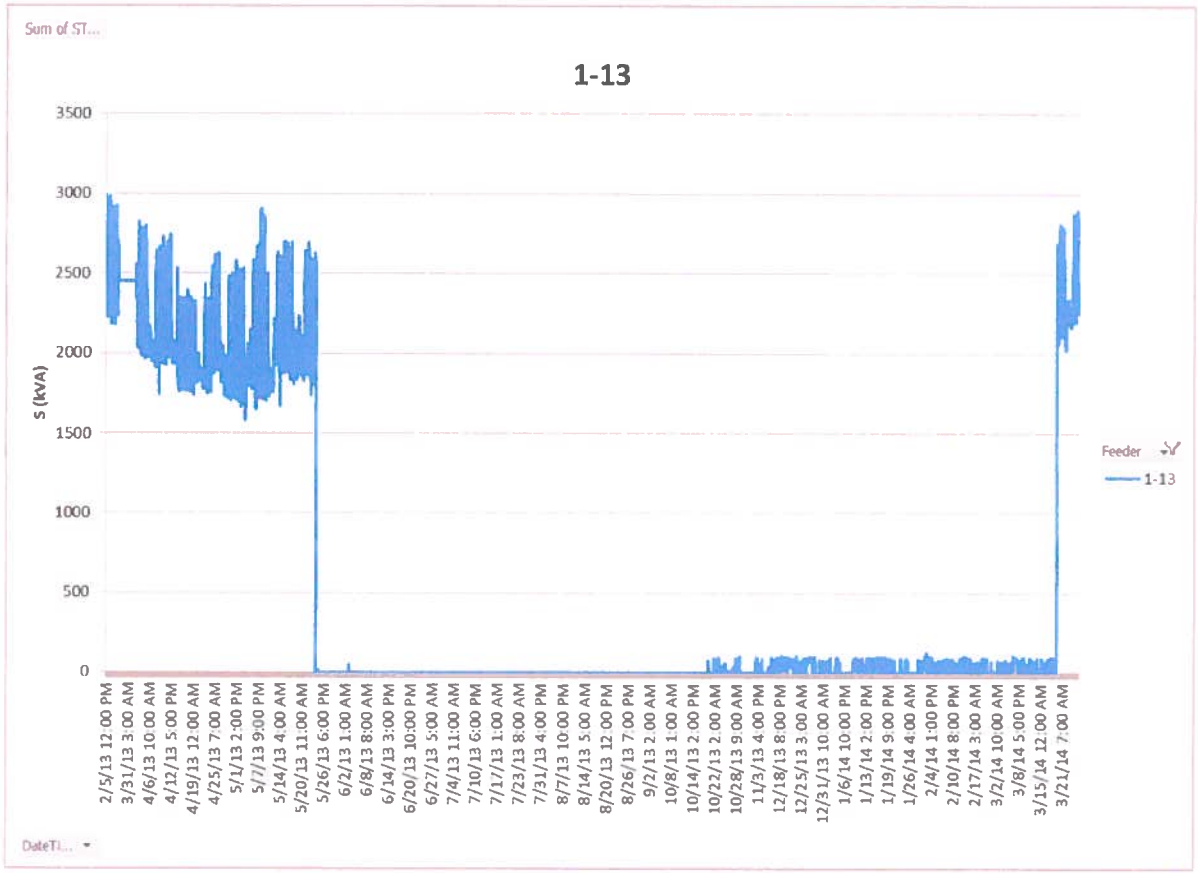
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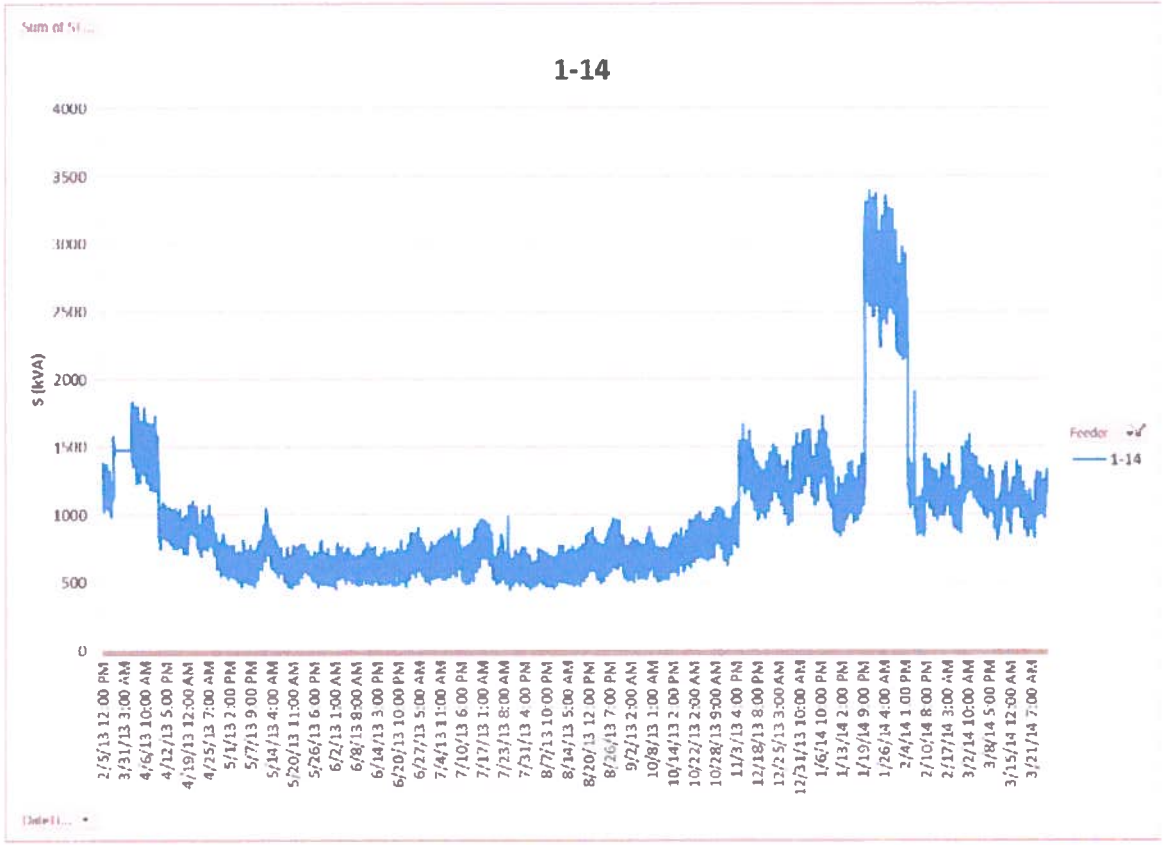
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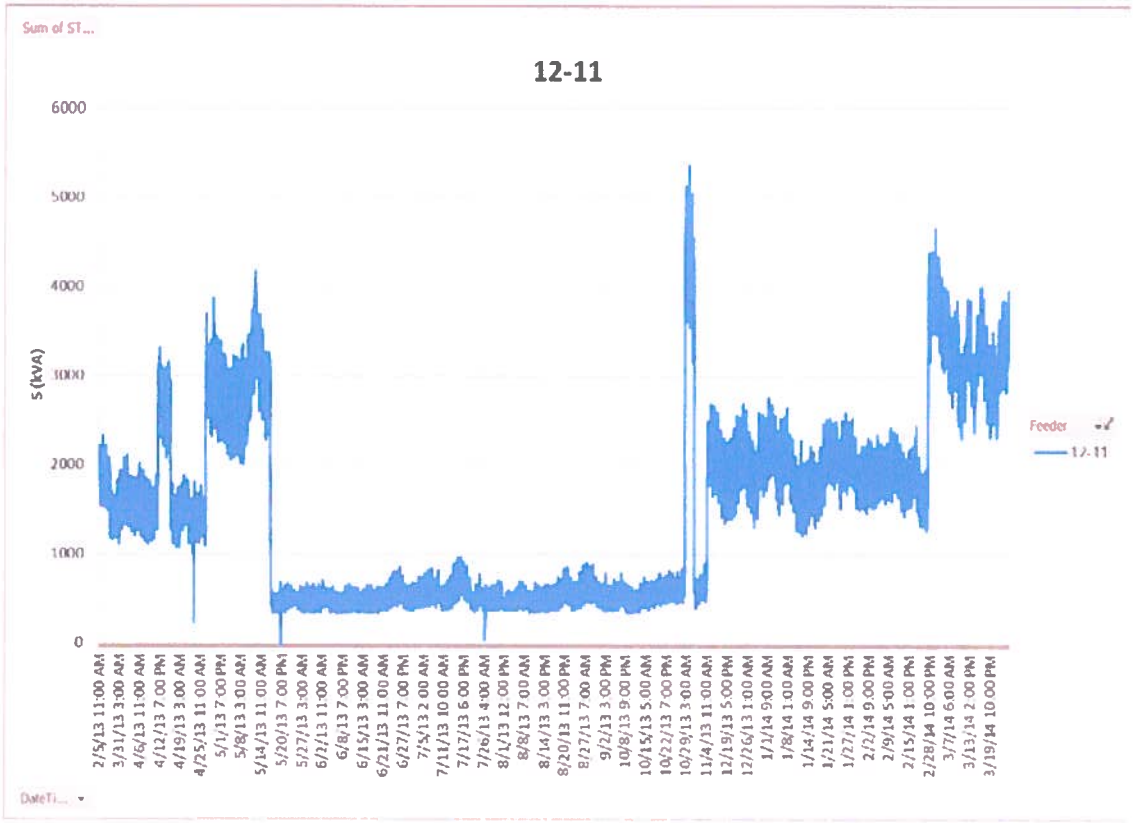
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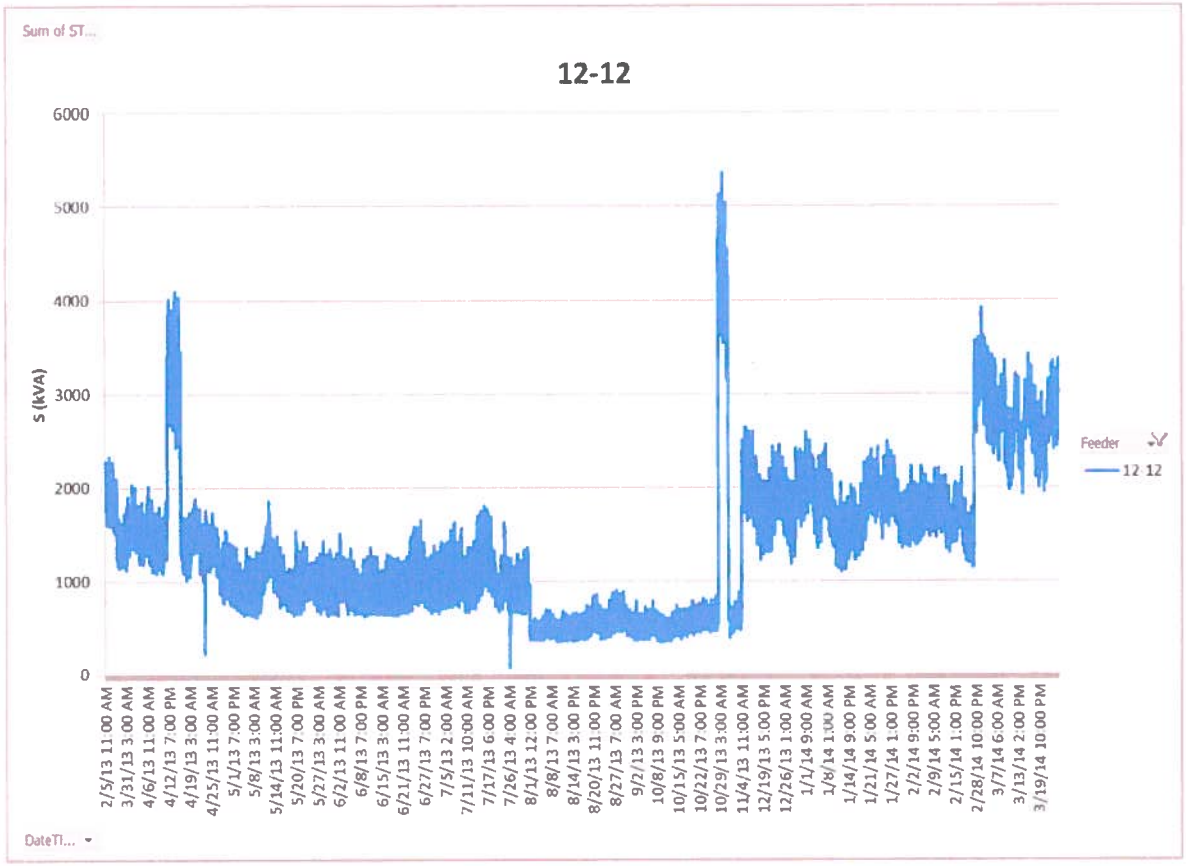
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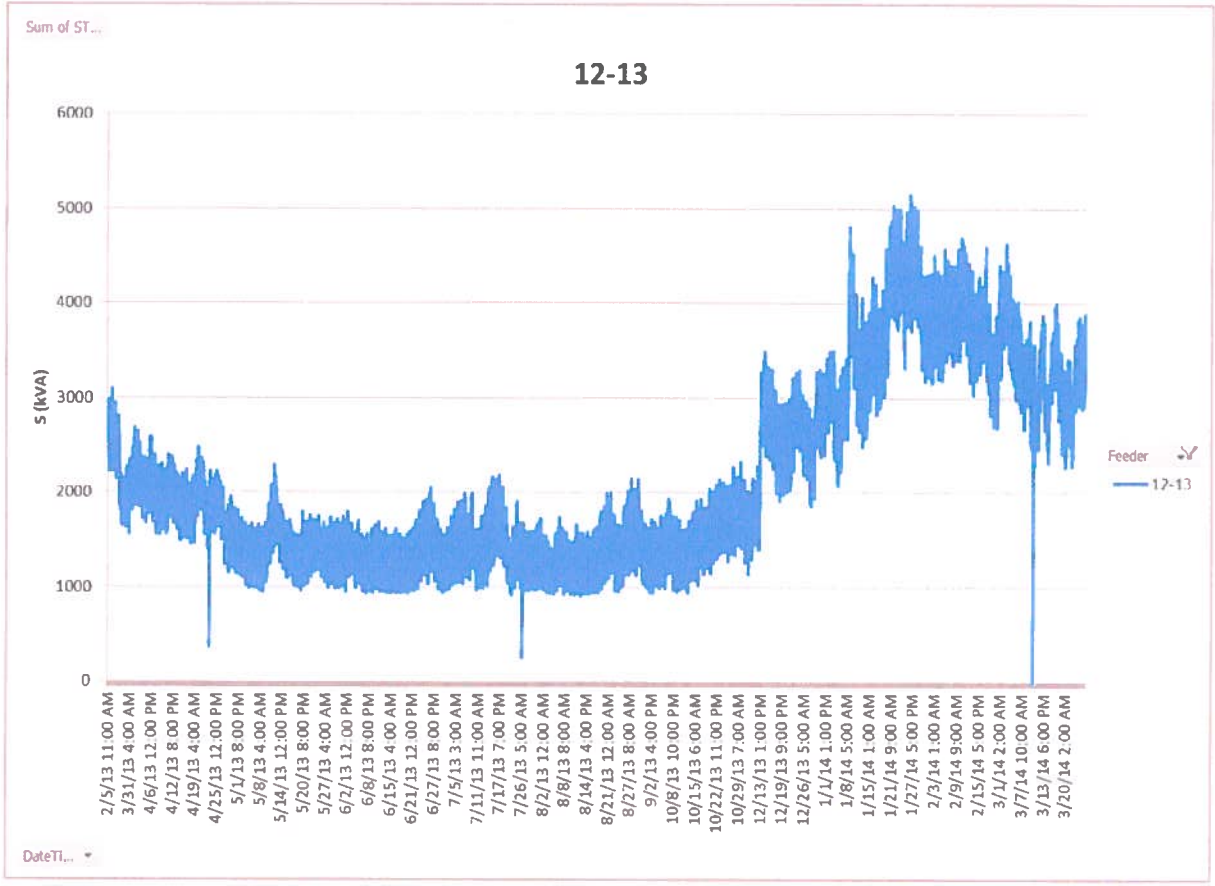
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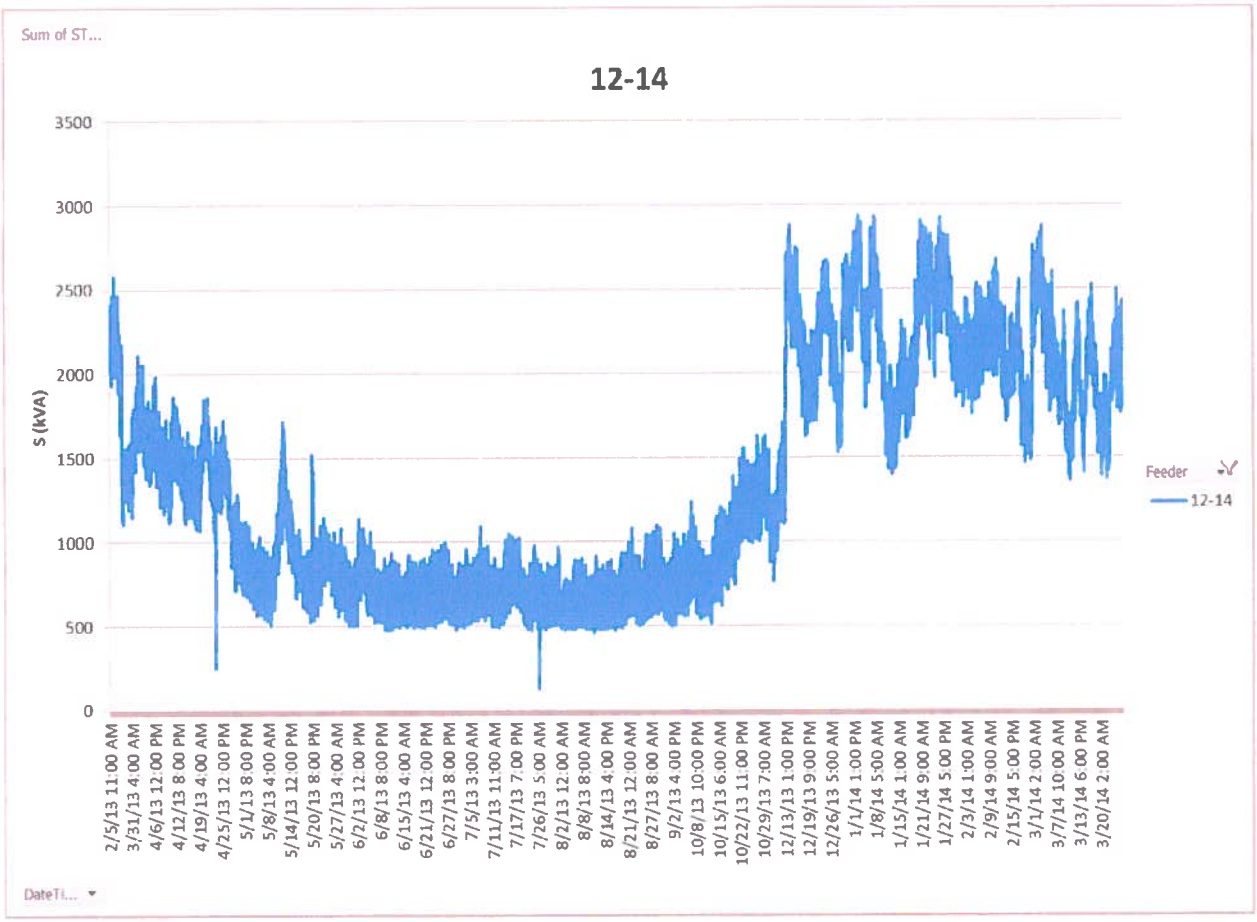
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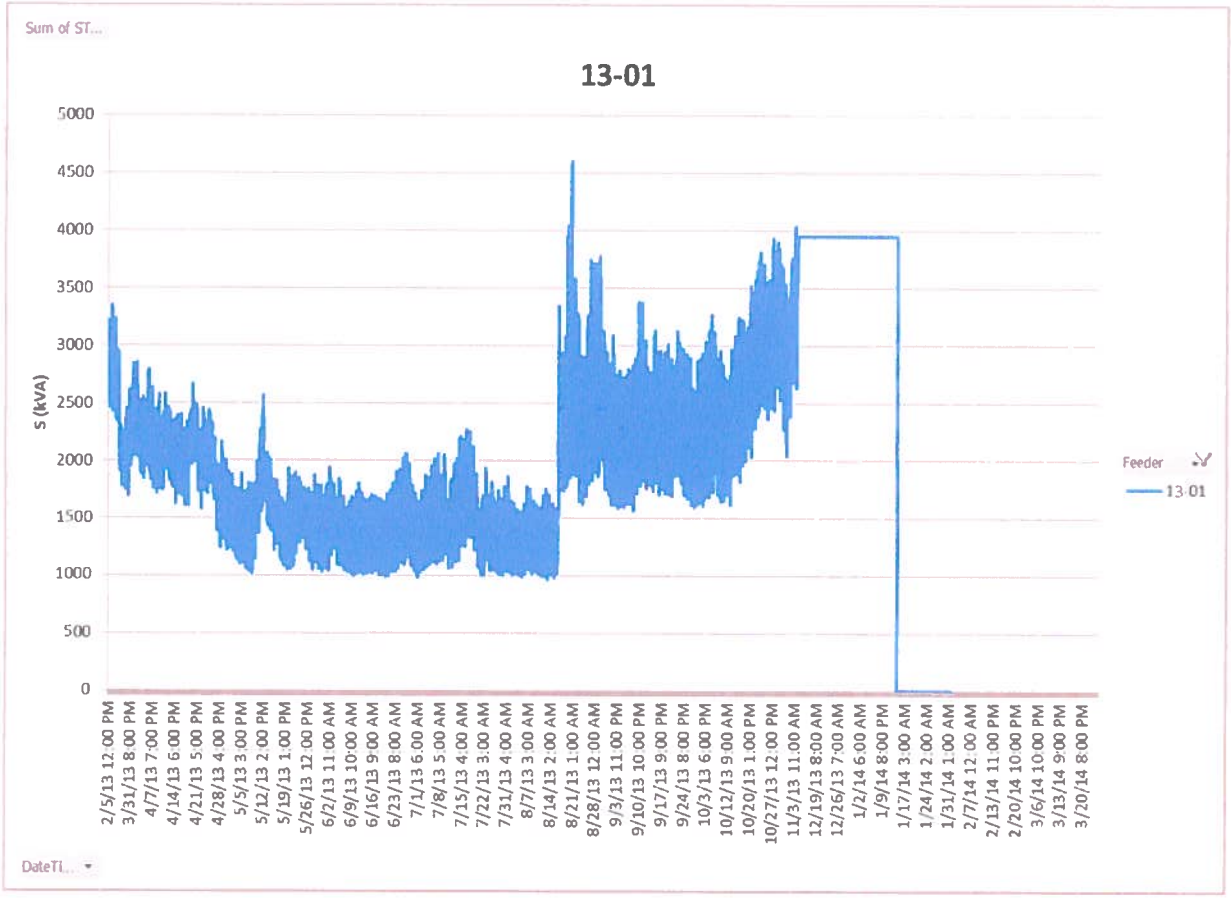
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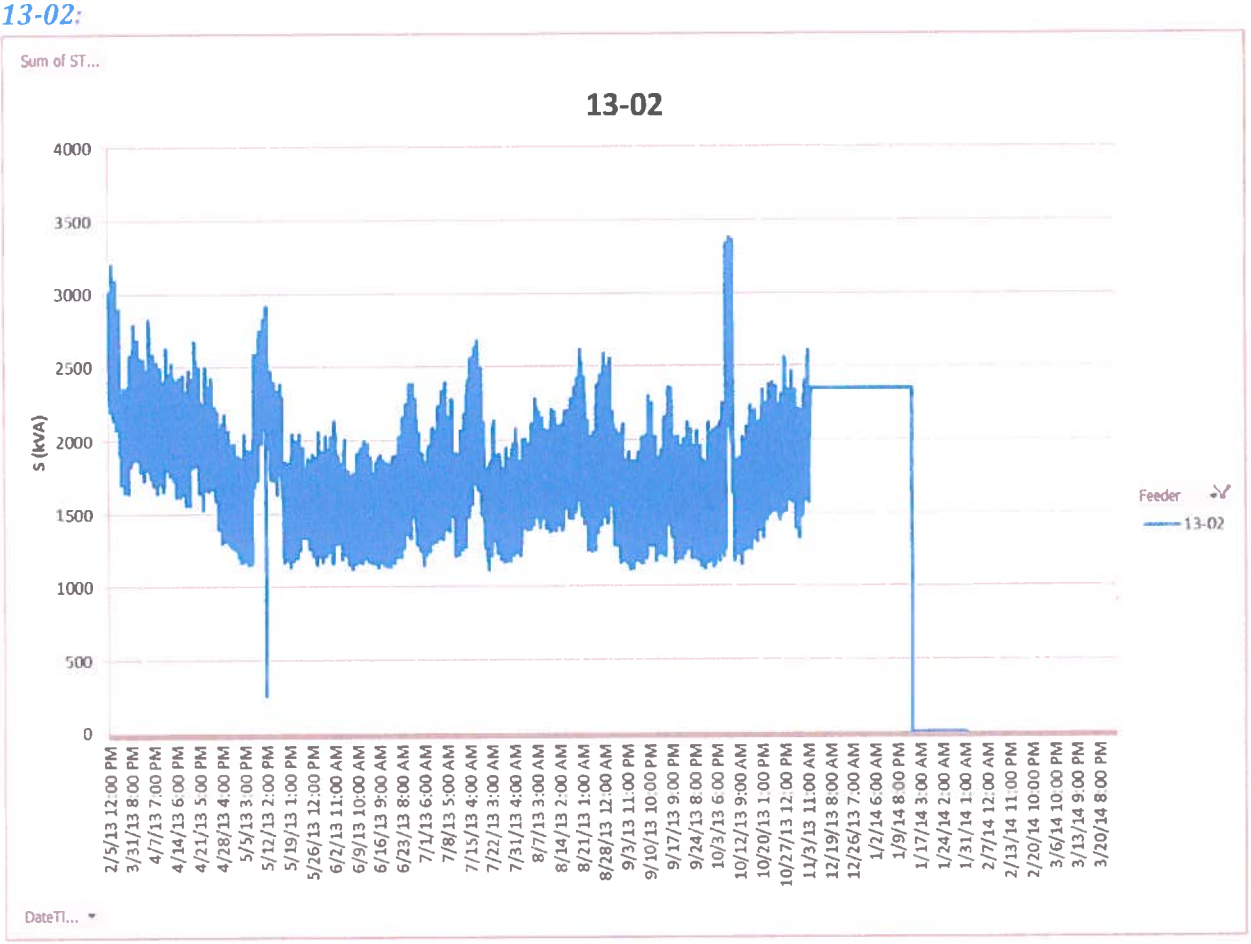
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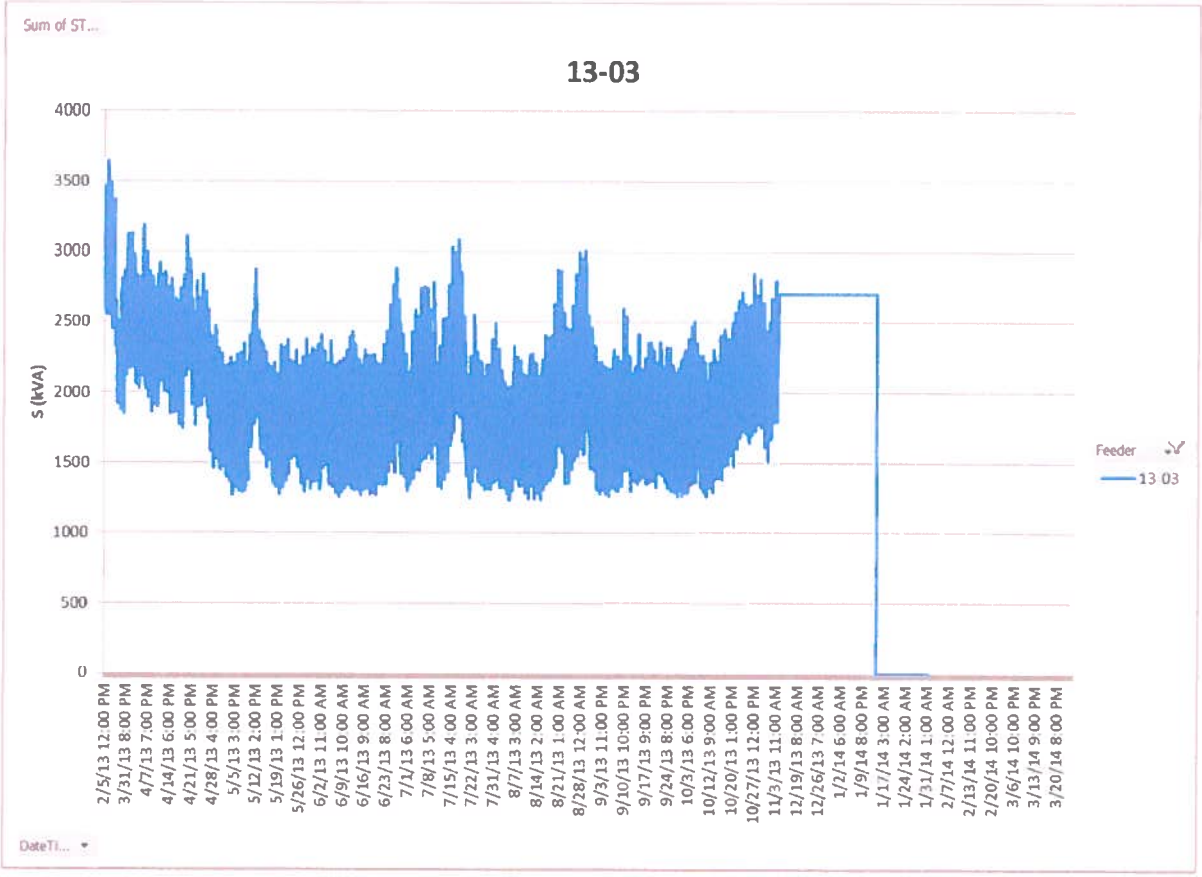
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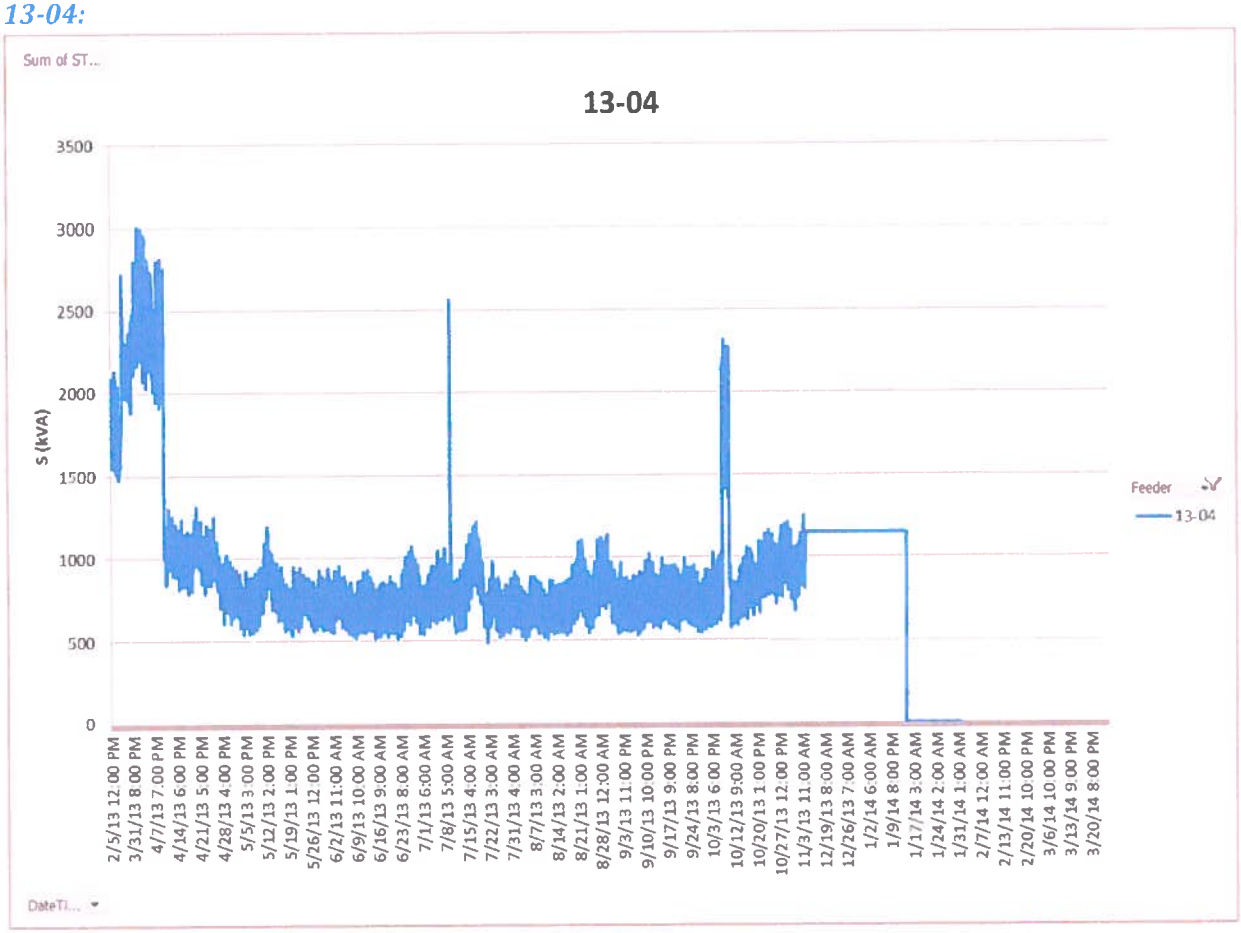
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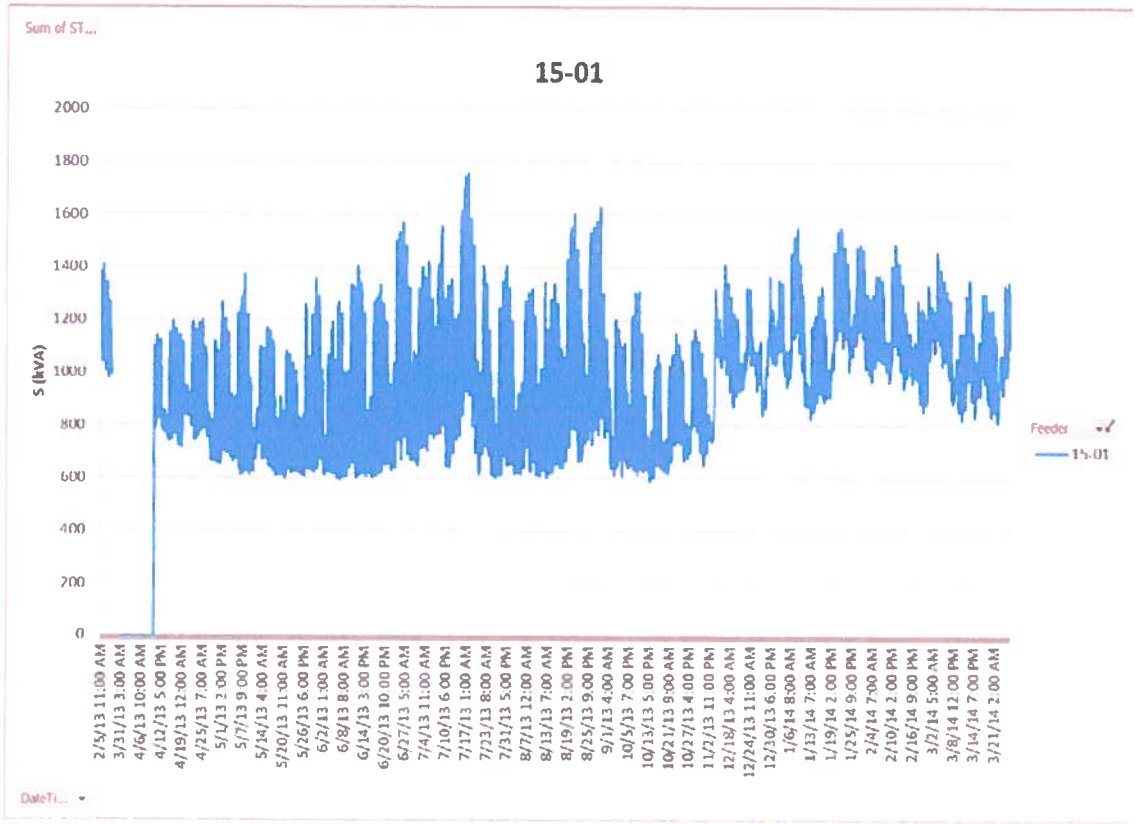
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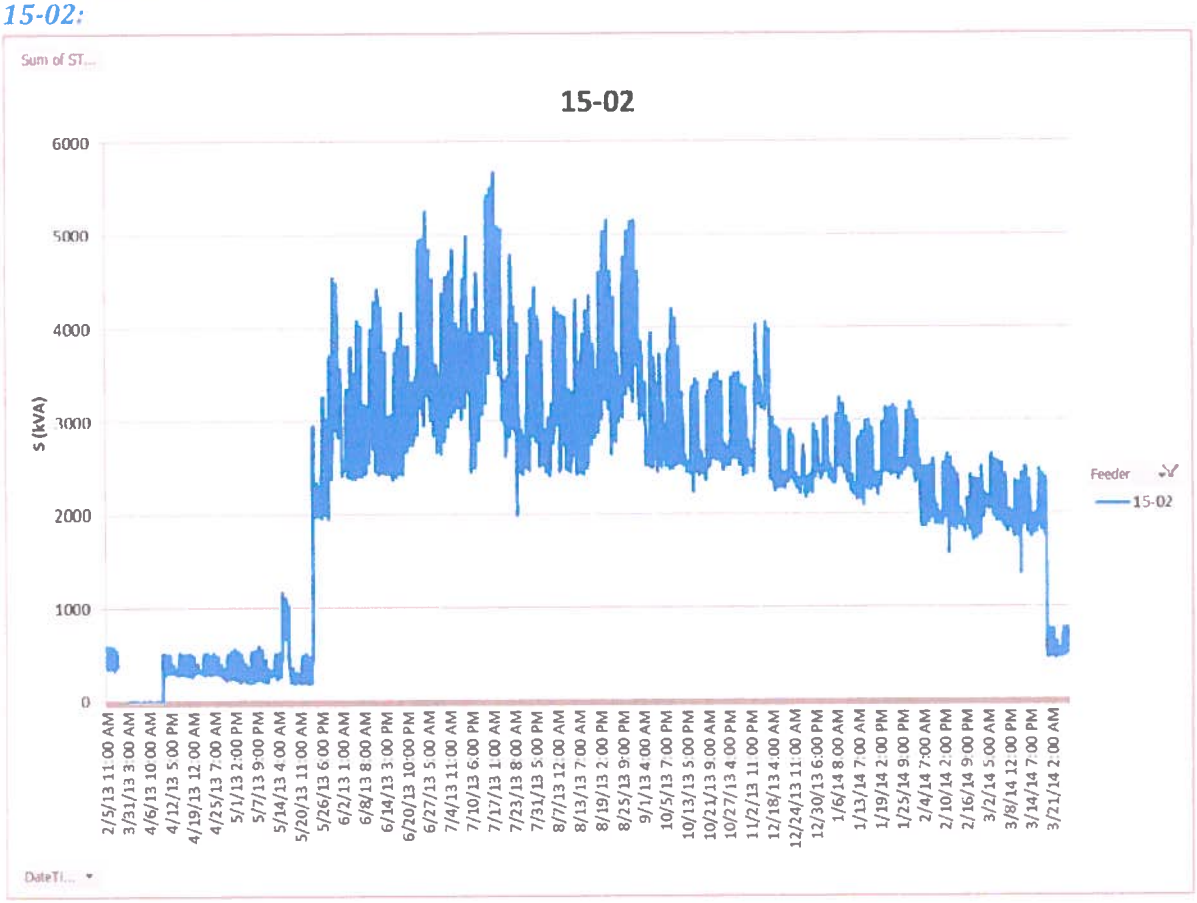
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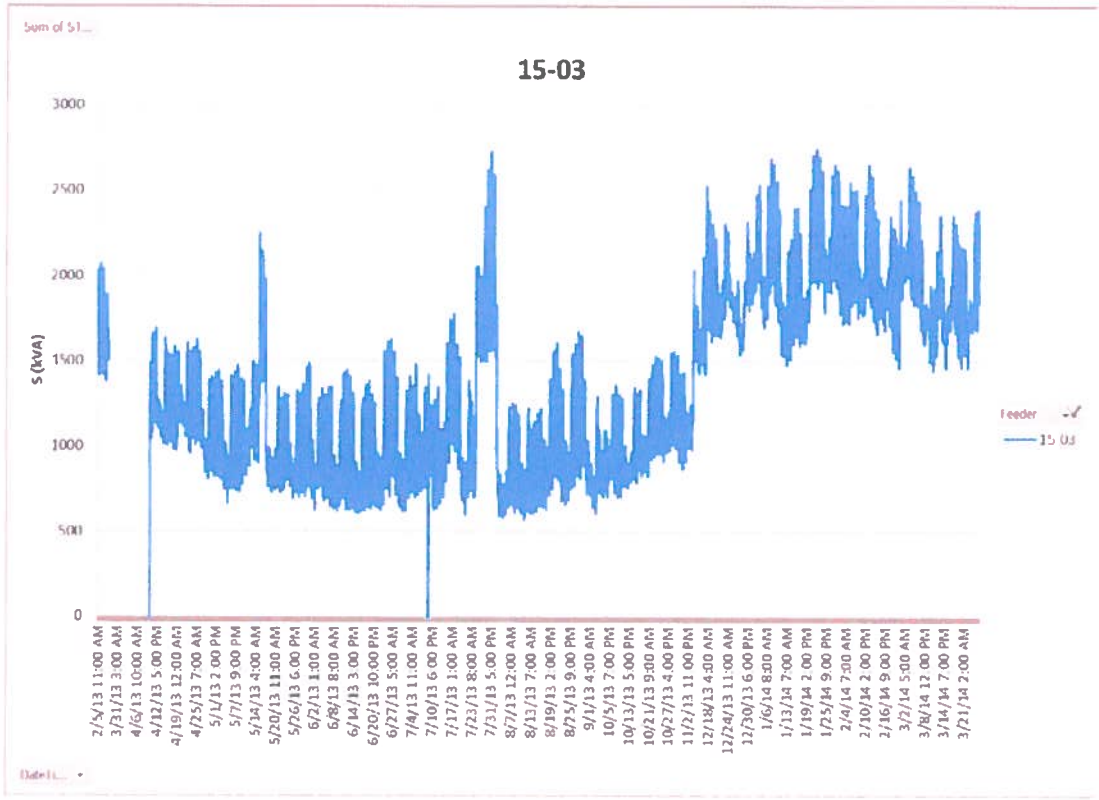
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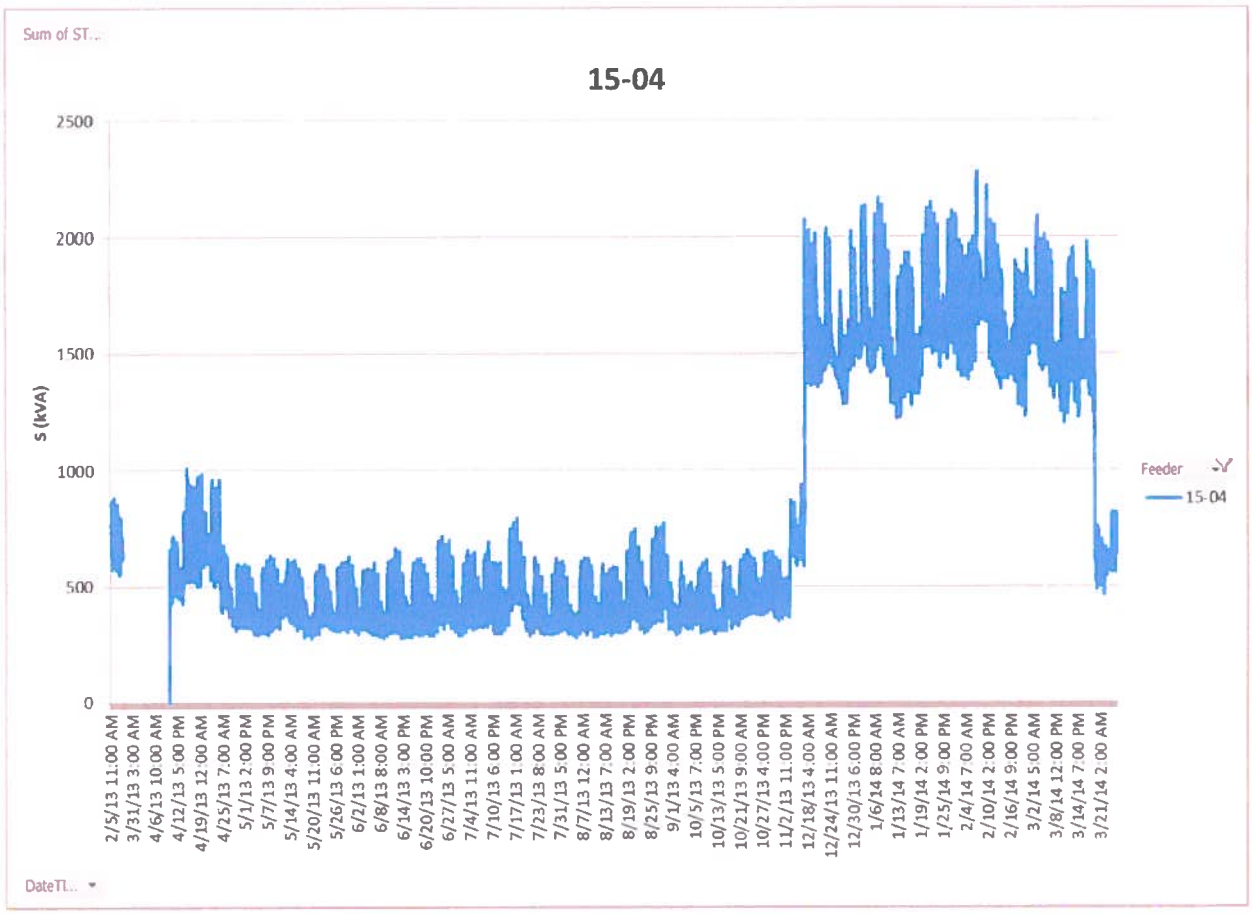
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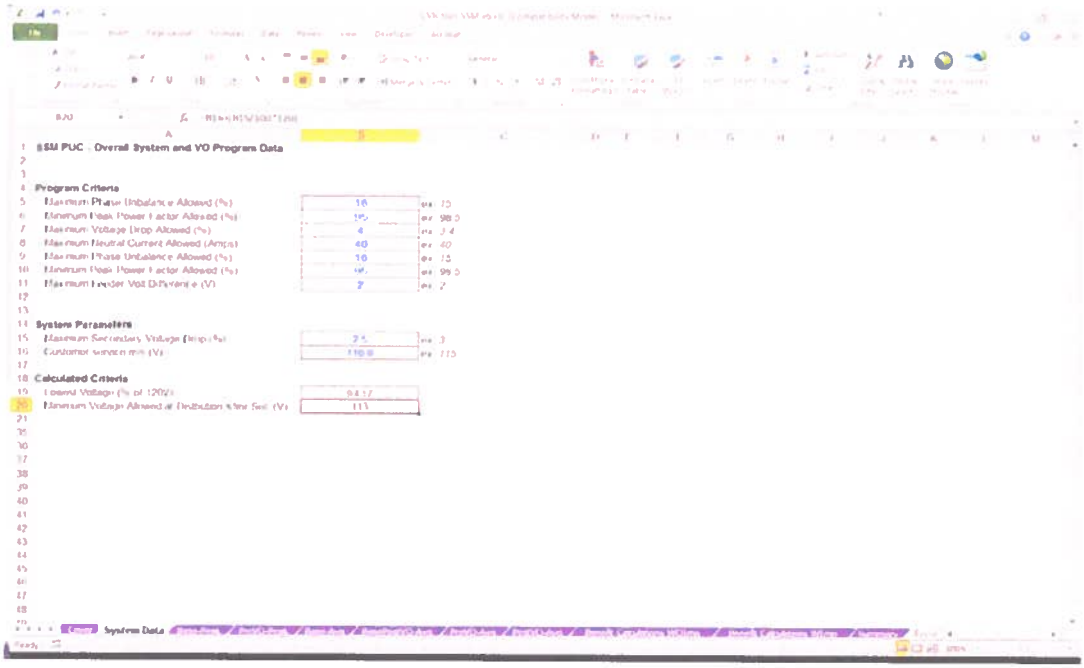
15-04

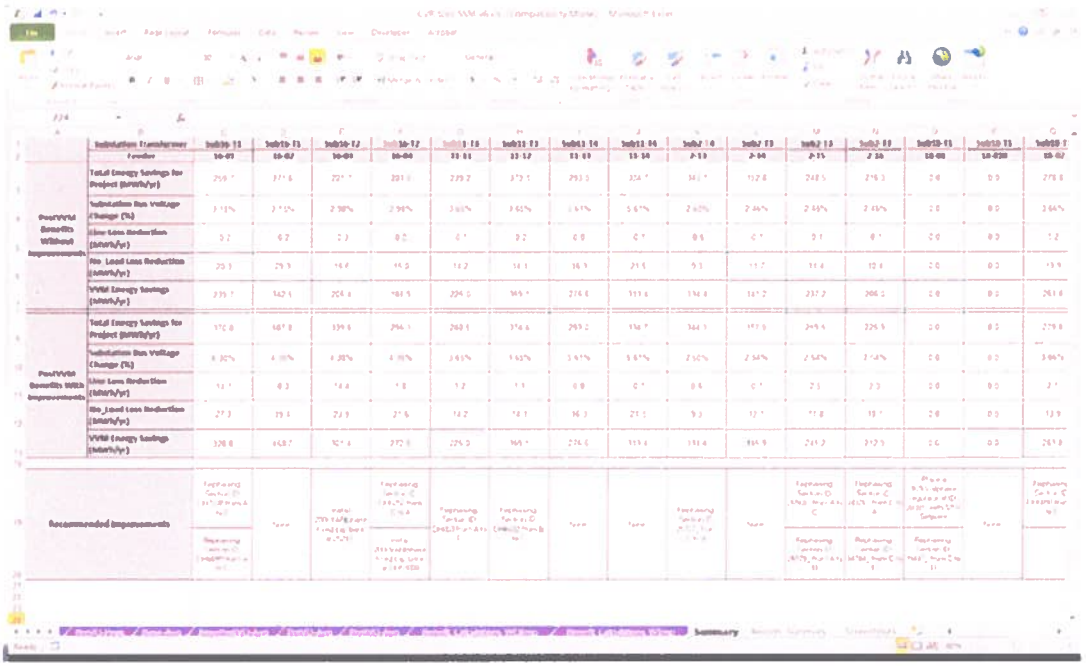
Appendix 5. Screenshots of VVM Benefit Spreadsheet



System Data Tab

Base-Avg Tab

Benefit Calculations Wimp Tab



Summary Tab

Appendix 6. Feeder Improvement Recommendations-CYME Snapshots

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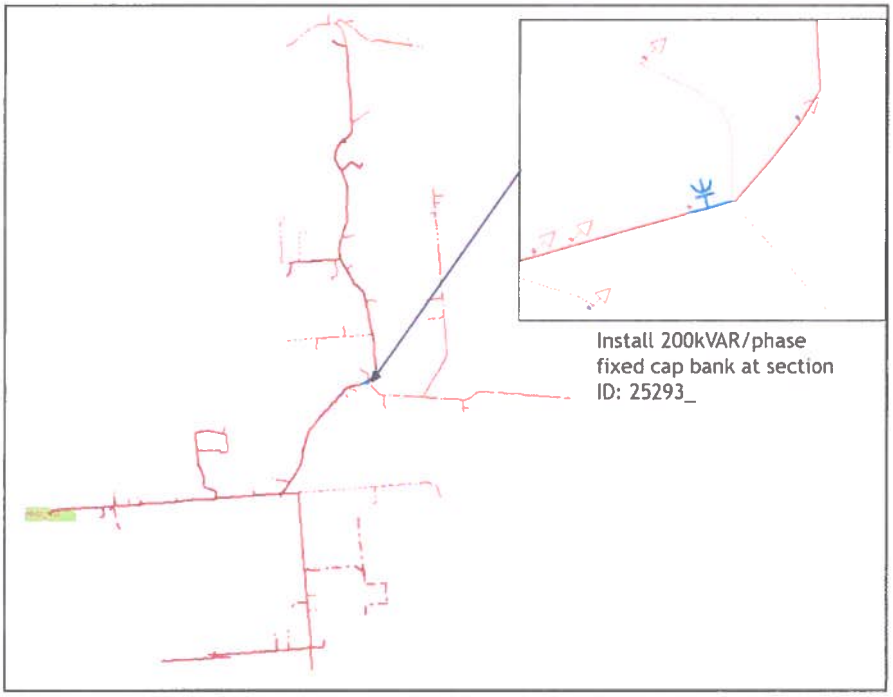
16-03:



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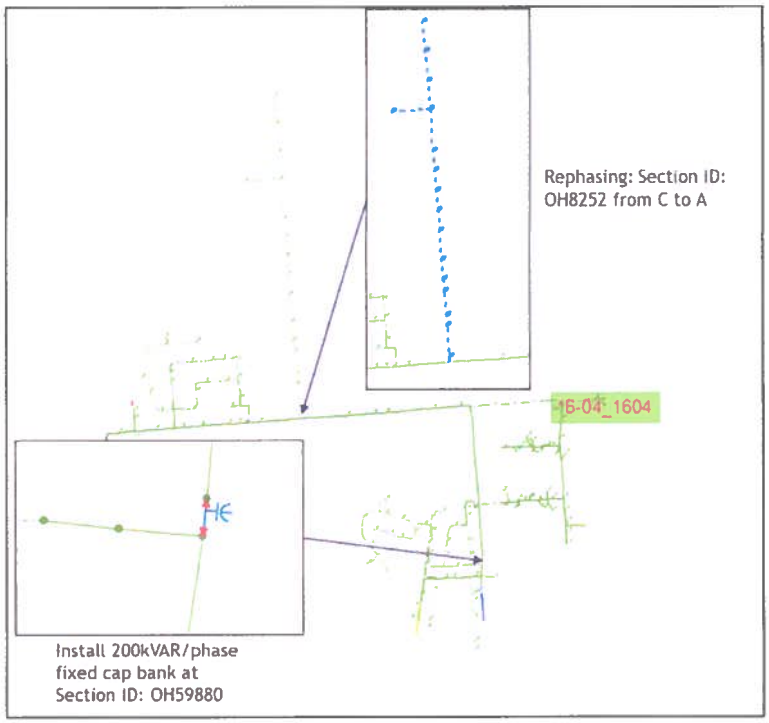
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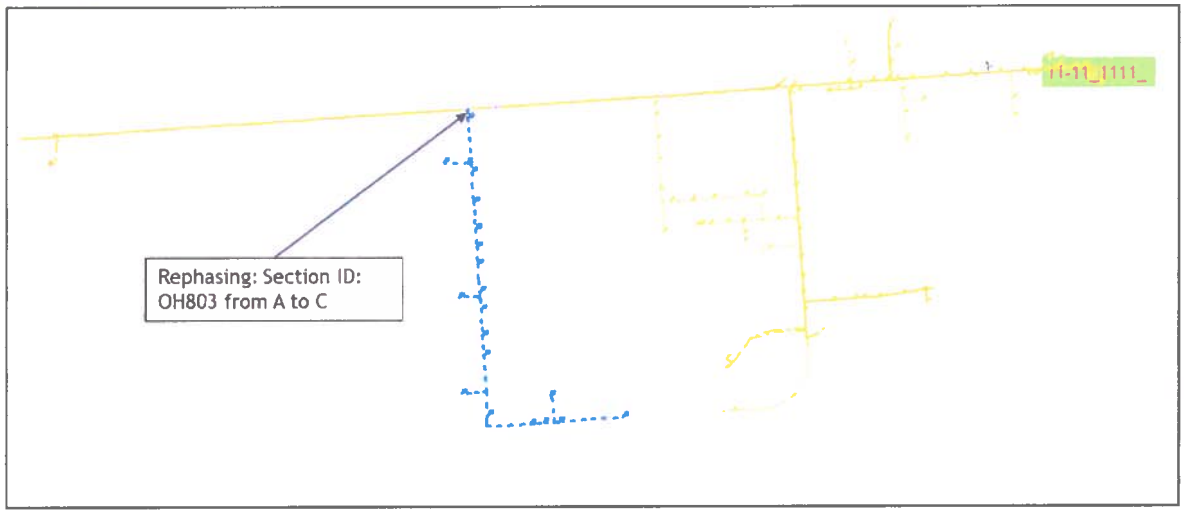
fixed cap bank at
Section ID: OH59880

11-11: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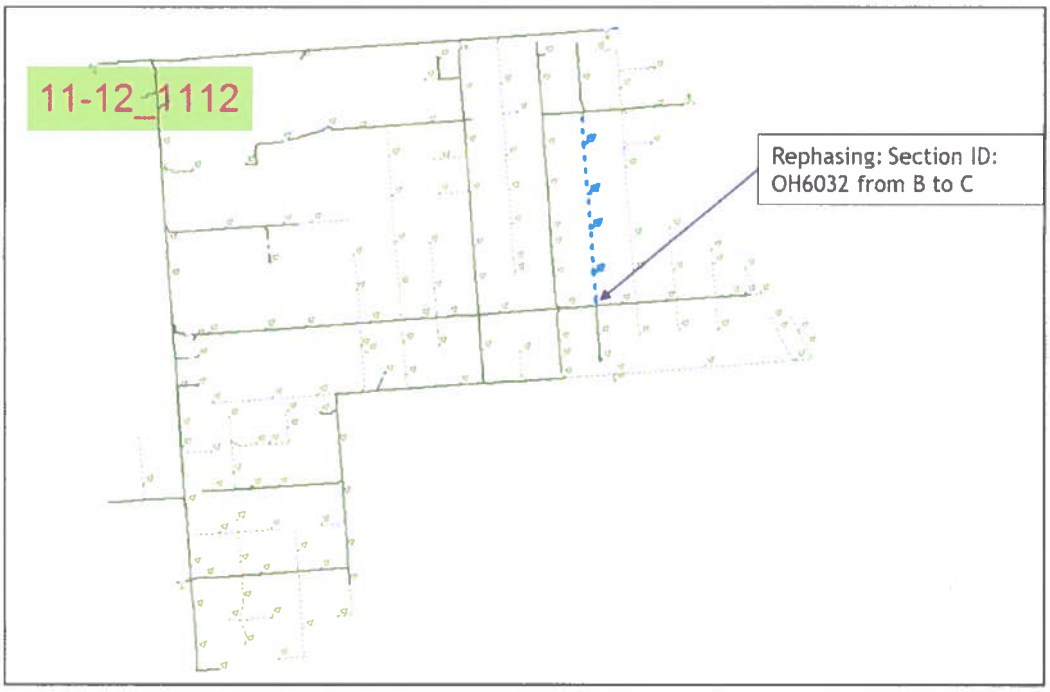
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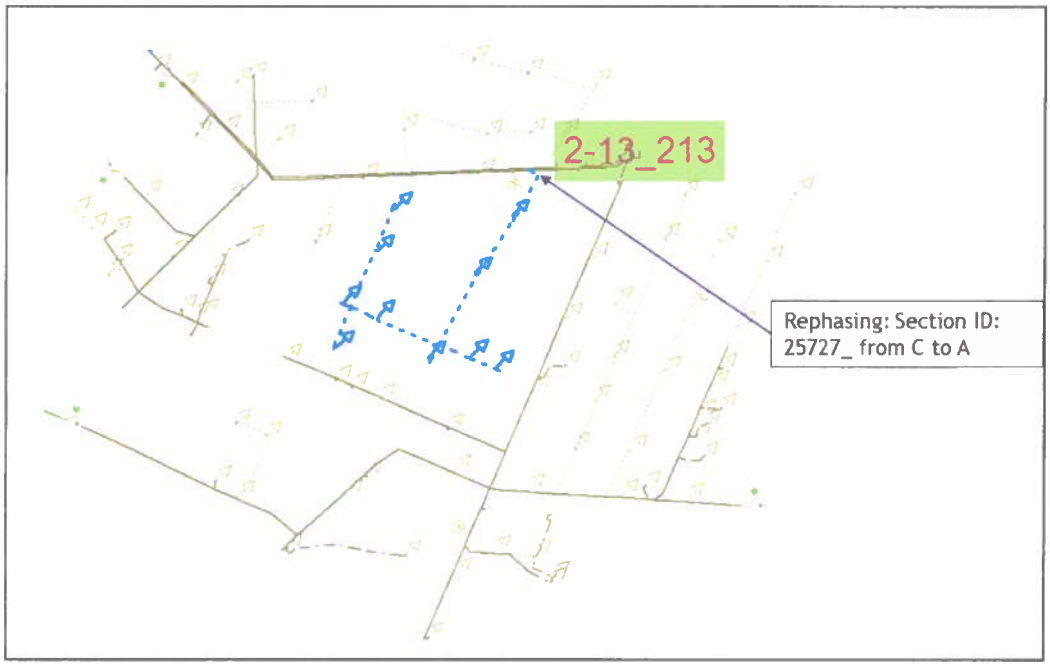
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2-15:

2-15_215
Rephasing: Section ID:
26568_ from A to C
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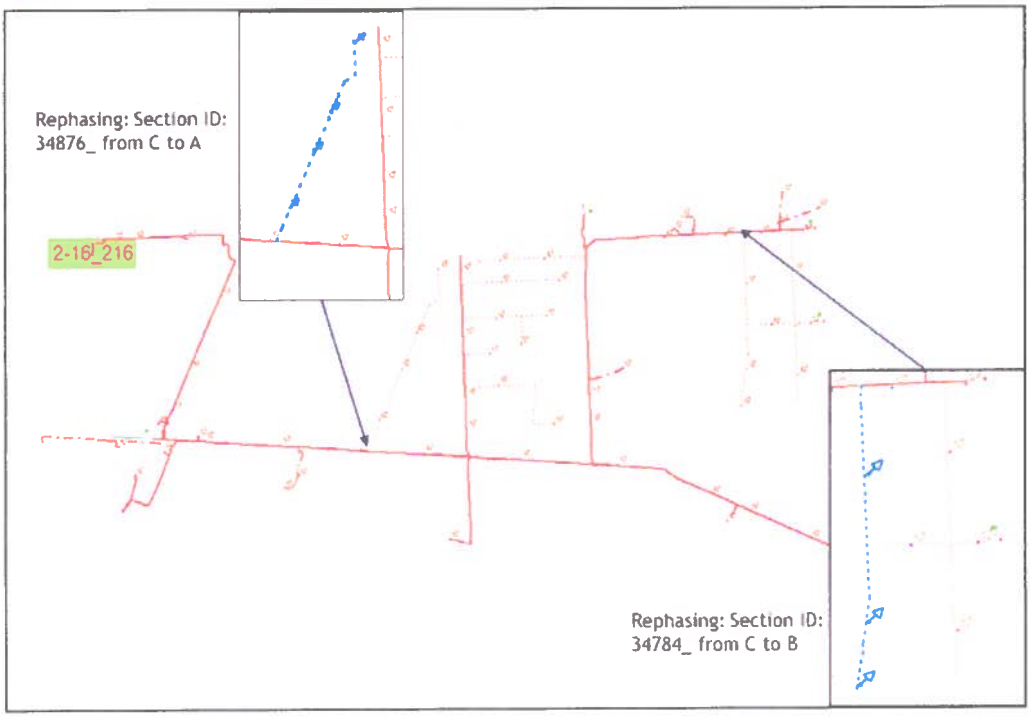
26579_ from A to B

2-16: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34784_ from C to B

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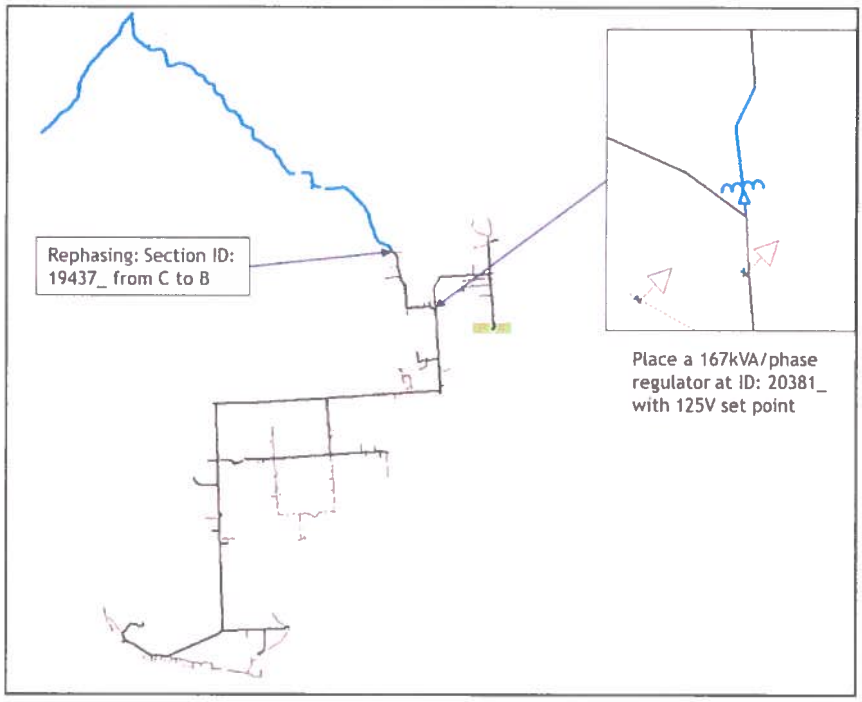
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regulator at ID: 20381_
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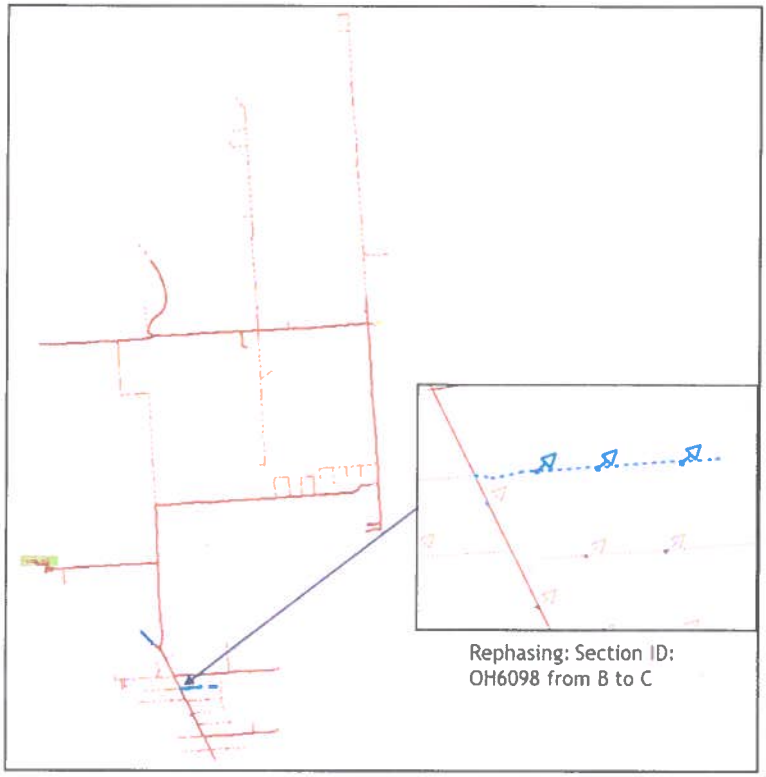
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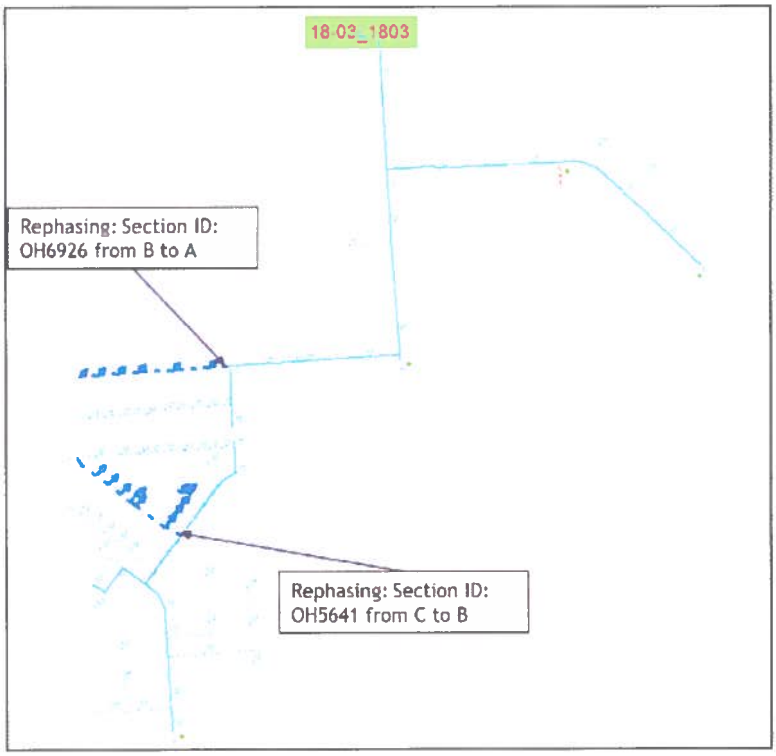
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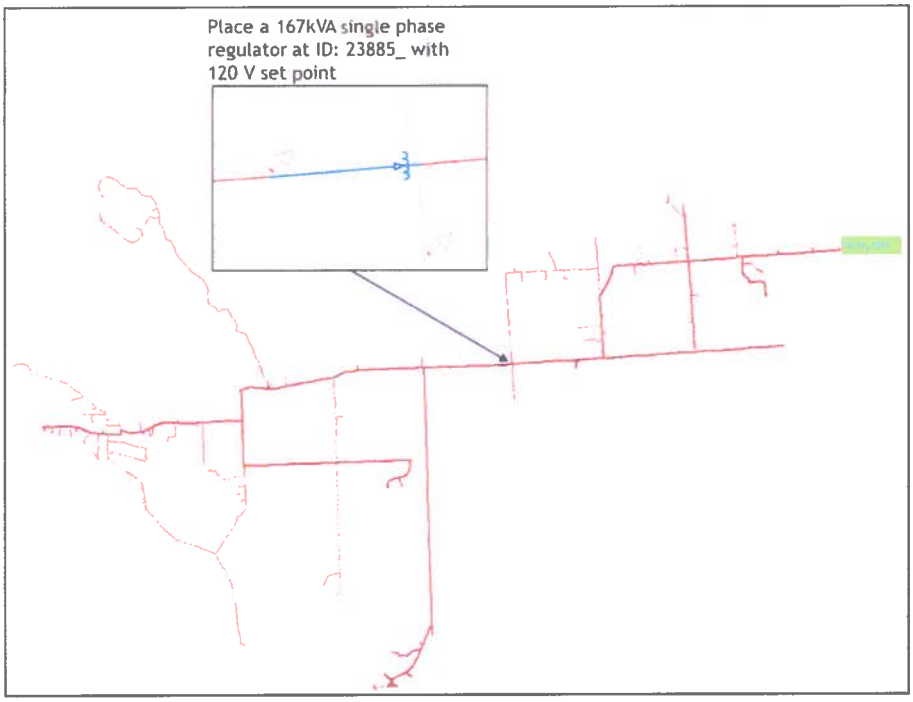
Place a 167kVA single phase regulator at ID: 23885_ with 120 V set point

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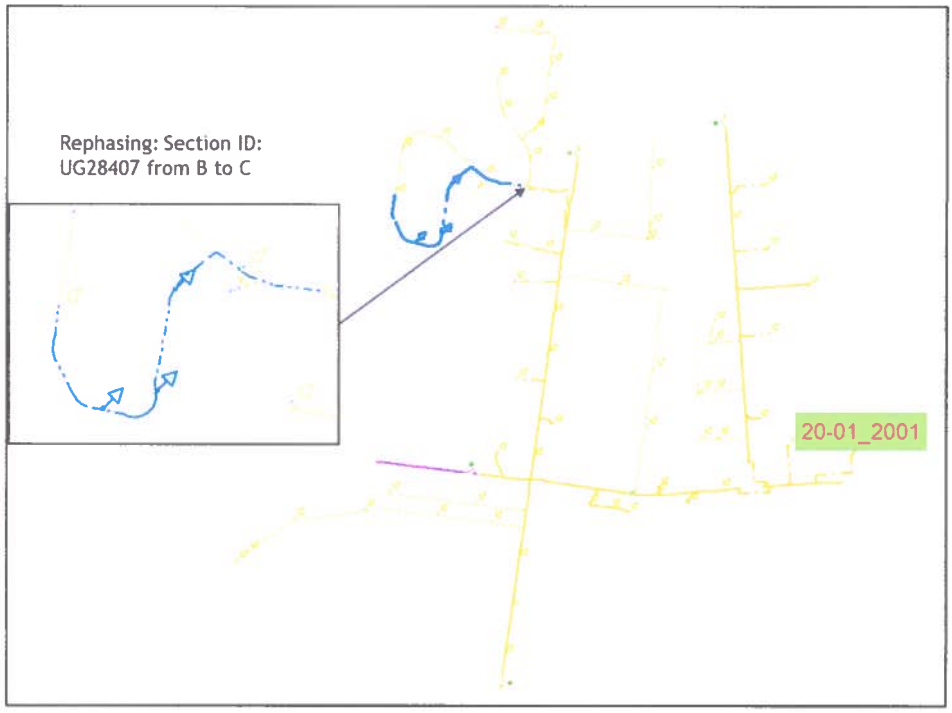
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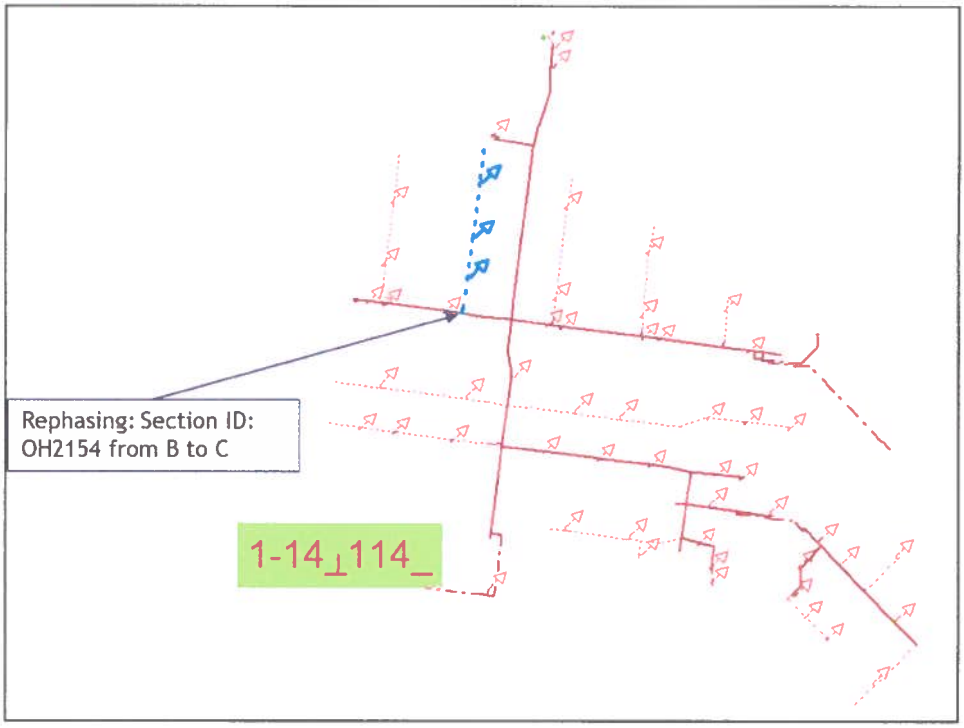
UG28407 from B to C
20-01_2001

1-12:

Rephasing: Section ID:
27075_ from A to C
1-12_112
Rephasing: Section ID:
27253_ from A to C

1-14:



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Leidos Engineering, LLC

Utility Distribution Microgrid: Distribution Automation

Preliminary Design

Energizing Co.

PUC Distribution, Sault Ste. Marie, ON

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1. Background

This document was prepared by Leidos Engineering, LLC for Energizing Co. in support of Energizing Co.'s Utility Distribution Microgrid (UDM) project in Sault Ste. Marie, Ontario, Canada. Energizing Co. has a contract with the local electric utility, PUC Distribution (PUC), to perform a detailed feasibility analysis and preliminary design for smart grid technologies, including microgrids, distribution automation (DA) systems, Volt/VAR Management (VVM) systems, Outage Management Systems (OMS), Demand Response (DR) and Advanced Metering Infrastructure (AMI) enhancements. Energizing Co. has retained Leidos Engineering to support the feasibility and preliminary design tasks of this project.

2. Overview

This document summarizes the preliminary design efforts of the DA component of the UDM project. The proposed DA system will significantly improve reliability on PUC's 12.5 kV and 34.5 kV systems. The DA system is designed to be expandable, so additional feeders and substations could be added to the DA system in the future.

To support feasibility analysis and preliminary design efforts, Leidos developed a distribution network model using PUC GIS data provided by the Sault Ste. Marie Innovation Center (SSMIC). The model was used to run simulations and perform analysis for the technologies studied.

A review of PUC's historical reliability data has shown that reliability indices were historically calculated at the system level; feeder level reliability data was not available. To better understand past outage trends and patterns, Leidos reviewed PUC's outage database file beginning in the year 2007. Based on this analysis, Leidos identified the west and north sections of PUC's distribution system as the primary focus of DA design efforts due to relatively low reliability performance. In addition, it was determined that feeders in the eastern area of Sault Ste. Marie could also achieve measureable reliability benefits from a DA system. Therefore, those feeders were also included in the automation program.

Downtown Sault Ste. Marie is served primarily by underground 12.5 kV feeders. Although underground systems are generally more reliable than overhead systems, the general complexity of the existing network topology resulted in some operational issues in this area. Since locating faults in the downtown area has generally taken longer than average, those feeders were included in DA analysis and program design, with fault current indicators (FCIs) recommended for installation at existing S&C Electric PMH switch and k-bar locations.

Finally, a script-based automation system is recommended for the 34.5 kV system, which will improve 34.5 kV reliability significantly. The proposed system will perform automatic switching actions to accomplish source-transfer when the main source is lost at a 34.5/10.5 kV substation. This script will be

developed in the DA controls software and use existing Supervisory Control and Data Acquisition (SCADA) controls.

Due to resource constraints, PUC does not currently man their control room 24/7/365. For this reason, a system is proposed that can autonomously locate and isolate faults when an operator is not present. When an operator is present, the system could be switched from fully-automated mode to semi-automated mode to allow for operator override and event control. This is described further in the requirements section.

In summary, DA system recommendations include the following:

12.5 kV System

- Centralized Fault Location Isolation and Restoration (FLIR) Software w/GIS Interface & Load Flow (i.e. Survalent FLIR)
- 38 reclosers on 39 feeders
- 40 pole-top load break switches at tie points
- 4 4-way pad-mount switches
- 2 2-way pad-mount switches
- 28 UG fault current indicators
- 20 O/H fault current indicators

34.5 kV System

- Source-transfer scheme in the centralized DA software

Details of these recommendations are provided in Section 4.

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3. Distribution Automation Concept

Distribution Automation is a smart-grid technology that can provide reliability and efficiency benefits through automation of the distribution system. The major functionalities of this system are listed below.

- Monitoring and Control
- Fault, Location, Isolation and Control
- Real-time Power Flow
- Auto-Transfer

Monitoring and Control: This functionality enables real-time data acquisition and control of electric grid devices that are outside of the substation fence. These devices could be switches, reclosers, capacitors, regulators, sensors, meters, and FCIs.

Fault Location, Isolation, Restoration (FLIR): The major function of FLIR is to provide 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. For this purpose, each feeder is divided into zones, as shown in Figure 2, and tie points between feeders are automated.

When a fault occurs, the un-faulted downstream feeder zones are restored after analyzing all possible predetermined restoration scenarios, based on available capacity of the adjacent circuits.

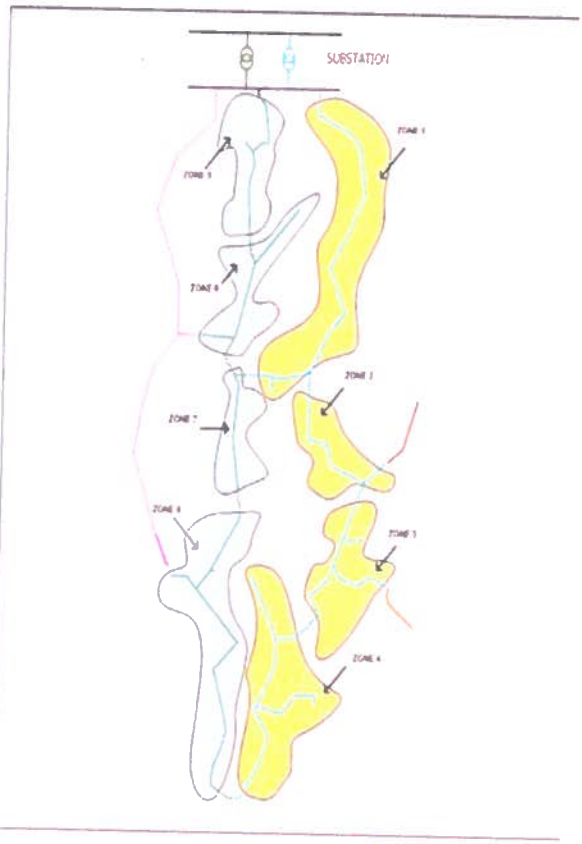

Figure 1. Sample DA Feeder

The FLIR system continuously monitors all related circuit flows to ensure proper load transfers throughout the restoration process. This process avoids overloading adjacent feeders as a result of transferring load from the un-faulted feeder zones.

Real-Time Power Flow: This 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. This feature enables calculation of system parameters such as voltage and current at each system node in real-time. Since real-time data is used, the results are more reliable than off-line simulation tools.

Auto-Transfer: Auto-Transfer is 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.

4. DA Design Methodology

a. Analysis Approach

Figure 2 illustrates the design and cost-benefit analysis methodology. The first step in the process was to utilize PUC's outage data to identify the potential substations/feeders for the DA deployment. The initial results were reviewed with PUC staff and their feedback incorporated before finalizing the feeder selection.

The next step was determining the number and location of DA components (reclosers/tie-switches/FCIs) using a CYME distribution model of the PUC system. After this step, a reconfiguration study was conducted to ensure the proposed design would not violate any thermal or voltage limits. Reliability improvements are estimated from theoretical computations and industry standard data for each DA feeder. Finally, the Leidos Benefit Monetization Tool was used to monetize system benefits for the entire DA solution.

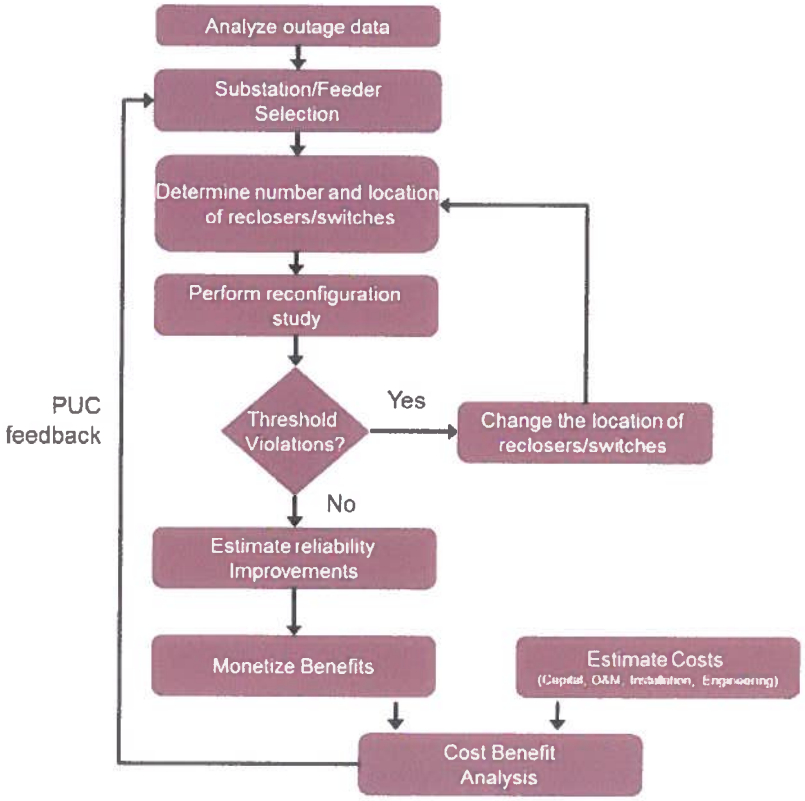

Figure 2. DA Design Methodology

b. DA Feeder Selection

Leidos ranked individual feeders based on average per-feeder Customer Minute Interruption (CMI) values for the years 2008 to 2012 (excluding 2011). 2011 outage data is excluded from the analysis per PUC guidance due to the excessive number of outages experienced during solar integration projects in Sault Ste. Marie.

The CMI value for each outage event is computed by multiplying the number of customers impacted by the event by the event duration. Events occurring at the same location are grouped together. Location of the grouped events with large CMI values (>10,000) are then mapped to individual feeders with the help of PUC. These annual CMI values are used to rank the feeders as shown in Figure 3.

As a result of this initial analysis and review/concurrence from PUC, Leidos studied the substations and connected feeders listed below for the DA design.

- Sub 18
- Sub 19
- Sub 21
- Sub 16
- Sub 11
- Sub 12
- Sub 2
- Sub 15
- Sub 1
- Sub 13

Rank #	Feeder	CMI 2008	CMI 2009	CMI 2010	CMI 2012	Average CMI
1	18-04	214421	40678	36401	66600	89525
2	18-01	164151	72364	66432	40112	85765
3	19-02		62938	93120		78029
4	13-03		126295		16559	71427
5	21-04		102030	23753		62892
6	11-13	82229	99189	32495	23659	59393
7	4-12	72806			22990	47898
8	21-03		67872	22061	51744	47226
9	18-03	76577		34827	22990	44798
10	19-04		44016			44016
11	19-01		41656			41656
12	21-01	64124	57294	21025	23868	41578
13	18-02	76577		21868	22990	40478
14	21-02		56876	23753		40315
15	20-03	26458			47245	36852
16	1-12	28749	74655	11739	21991	34283
17	20-04	45475	28780	14489	43374	33030
18	16-01	30563	48714	14877	35453	32402
19	12-11	28597	47652	6811	37878	30234
20	20-02		12530	34706	37026	28087
21	2-15		46342	4594	29237	26724
22	12-12		27824	23175		25499
23	16-03	51192	16385	15554	17679	25202
24	4-04				23923	23923
25	13-02			24826	21906	23366
26	4-02				22990	22990
27	20-01				22990	22990
28	12-14	13744	33040	4594	39228	22651
29	16-04		34980	13087	19145	22404
30	11-11	19700	19487	23808	24007	21751
31	11-12		19487		22990	21238
32	11-14	16475	19487		22990	19651

Figure 3. DA Feeder Ranking Based on Feeder CMI

5. DA Recommended Design

a. System Architecture

The proposed DA system architecture system is shown below. The system intelligence and control logic will be housed in the centralized software system (i.e., Survalent FLIR System) located in the PUC Control Room. This system will interface with GIS, MDM, and SCADA systems to exchange operational and device data. Field devices within and outside the substation will be monitored and controlled via the communication network.

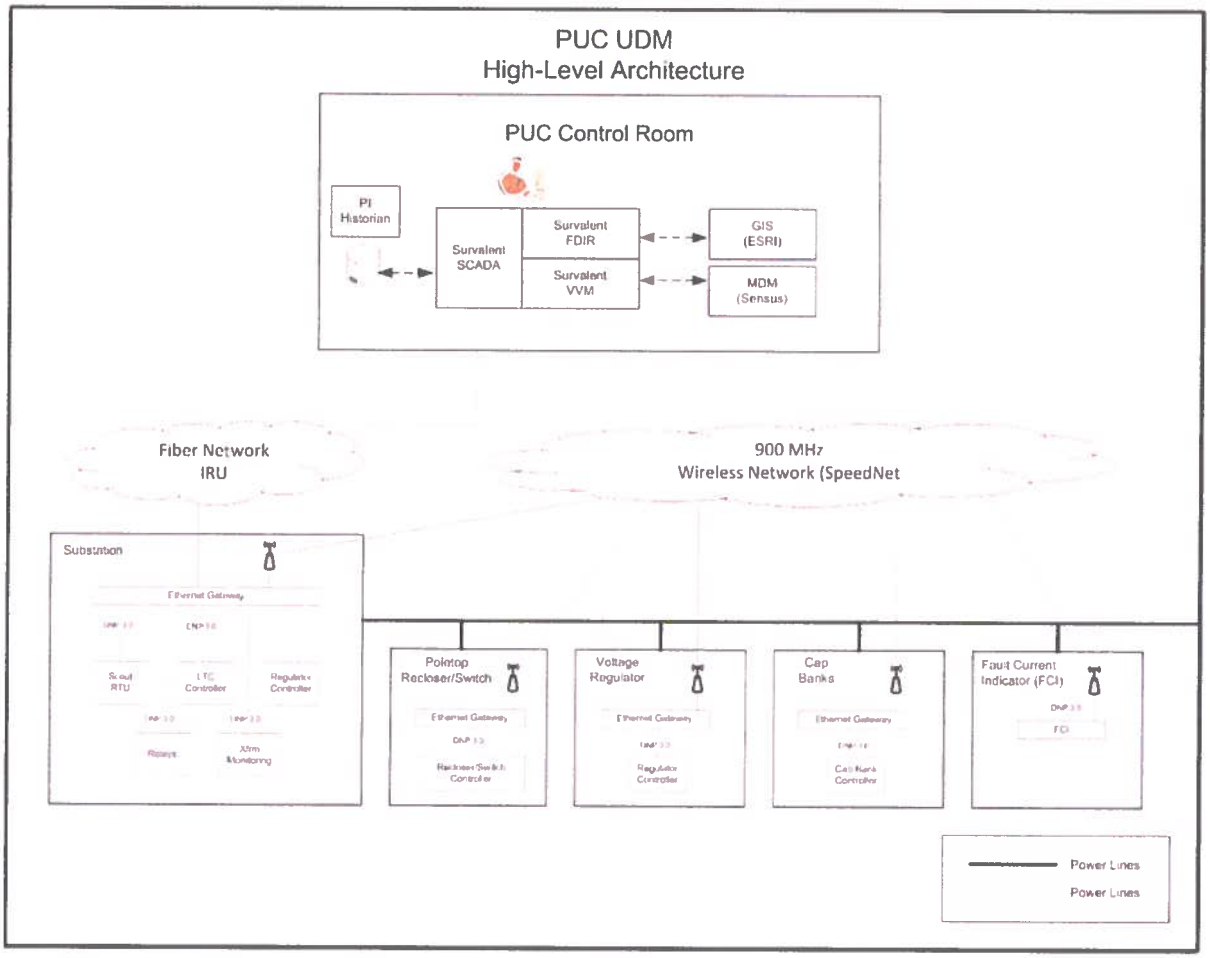

Figure 4. UDM System Architecture

b. Distribution Automation (DA) Software

The DA software is the core component of the proposed DA solution, providing the intelligence to find the fault location, isolate the fault and restore power to the entire upstream section of the feeder and as much of the downstream feeder as possible.

PUC currently has a Survalent SCADA system that is primarily used to monitor and control substation equipment. Due to the relative cost that would be incurred from switching to a different vendor SCADA and DA platform, and since PUC is generally content with the capabilities and performance of the Survalent system, we recommend deploying Survalent' s DA solution, LaZer 3 Fault Location, Isolation, and Restoration (FLIR). LaZer 3 FLIR will be installed with the load flow module, which will provide capability to run load flow simulations. All substations that are included in the DA program have SCADA already installed.

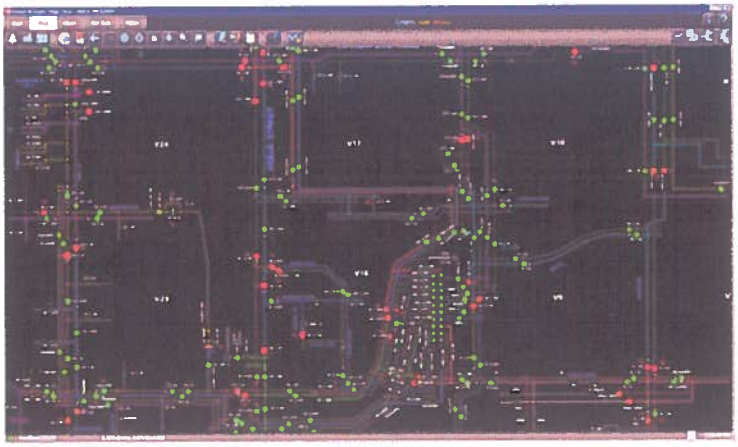

Figure 5. DA Software

In case of a fault, the un-faulted downstream feeder zones will be restored after analyzing all possible predetermined restoration scenarios based on available capacity of the adjacent circuits. The DA Software will be able to locate three-phase, phase-to-phase and phase-to-ground faults.

The fault location, isolation, and restoration processes will be accomplished in less than five minutes. This means that customers on un-faulted zones will be re-energized within five minutes so that their outage duration will not be counted towards sustained outages as defined in IEEE 1366 standard.

When there is a system fault, the substation recloser will go through its trip and close operations as configured. The DA system will start its fault location, isolation, and restoration process following a recloser lock-out signal. The system will not take any action when a recloser trips on a temporary fault and remains closed after a close operation. Nor will any action be taken if switches or breakers are manually operated.

The DA system will have three different operating modes: Disabled, Semi-Automatic, and Full Automatic.

Disabled Mode:

In disabled mode, the DA Software will not issue any control commands to switches and reclosers. However, real-time analog and digital data will continue to be monitored. When a fault occurs, switches that were exposed to fault current will send a signal to the control center. In this mode, fault location, isolation, and restoration will be done by the operator as required.

Semi-Automatic Mode:

In semi-automatic mode, the DA system will locate the fault but wait for operator approval before implementing any switching actions. Following operator approval, the switching plan will be executed.

Full Automatic Mode

In full automatic mode, the DA system will perform all fault location, isolation, and restoration functions automatically without the need for operator intervention. The operator will be notified about actions taken by the system.

After the fault location is determined, the faulted zone will be isolated from the system so that un-faulted zones can be restored. The system will open switches around the faulted zone to achieve isolation.

When a faulted zone is isolated, the system will restore the upstream zones, or zones on the source side, by automatically closing the substation recloser. To restore the downstream zones, the system will develop a restoration plan that shall not overload any circuit and shall not cause any voltage violations.

When a fault has occurred and reconfiguration has been satisfactorily accomplished, the system will be able to perform all of its pre-fault functions to support other faults that may occur. In other words, the system will update itself according to the reconfigured network topology, and in case of another fault, it will be able to find the new fault location and restore the service utilizing the new network topology.

The solution will allow operators to remotely monitor the DA equipment through the DA software.

c. Determining Zones

Leidos used a CYME distribution model to evaluate and propose the number and location of reclosers, load-break tie switches, and zones for each DA feeder. The model was helpful in understanding the network configuration and load distribution of each feeder. In general, one sectionalizing recloser is recommended for all the DA feeders except a few lengthy or poor reliability feeders for which two reclosers are recommended. Recloser placement is established so that it is possible to divide the feeder into two equal zones as per the connected kVA and the circuit length. The following list shows the factors that are taken into consideration while selecting the recloser location.

- Feeder circuit length
- Connected kVA
- Topology
- Back-feed capability
- Operational considerations

One load-break tie switch for each zone of the DA feeder is proposed, so that it can be back-fed by the adjacent feeders following an outage. When Leidos selected the switch locations, the following factors were taken into consideration:

- Adjacent feeder peak load
- Different substation/transformer source
- Adjacent feeder included in DA

Figure 6 shows the number of reclosers, load-break tie switches, and zones proposed for each DA feeder. Figure 7 presents connected kVA and electrical length details of each DA zone created within the DA feeders. CYME snapshots of each DA feeder showing the exact location of proposed reclosers, load-break tie switches, and zones are furnished in Appendix 4.

Feeder	# Poletop Switches	# Poletop Reclosers	# 2-way Padmount Switches	# 4-way Padmount Switches	# Zones
11-11	1	1	0	0	2
11-12	1	1	0	0	2
11-13	1	1	0	0	2
11-14	1	1	0	0	2
12-11	1	1	0	0	2
12-12	1	1	0	0	2
12-13	1	1	0	0	2
12-14	1	1	0	0	2
16-01	2	1	0	0	2
16-02	2	2	0	0	3
16-03	2	2	0	0	3
16-04	1	1	0	0	2
18-01	2	2	0	0	3
18-02	1	1	0	0	2
18-03	1	1	0	0	2
18-04	2	2	0	0	3
19-01	0	0	0	0	0
19-02	1	1	0	0	2
19-03	2	2	0	0	3
19-04	1	1	0	0	2
21-01	1	1	0	0	2
21-02	1	1	0	0	2
21-03	1	1	0	0	2
21-04	1	1	0	0	2
13-01	1	1	0	0	2
13-02	1	1	0	0	2
13-03	1	1	0	0	2
13-04	1	1	0	0	2
1-11	0	0	0	1	2
1-12	0	0	1	1	2
1-13	0	0	0	1	2
1-14	1	1	0	0	2
2-13	1	1	0	0	2
2-14	0	0	2	0	2
2-15	1	1	0	0	2
2-16	1	1	0	0	2
15-01	0	0	1	1	2
15-02	1	0	0	0	2
15-03	1	1	0	0	2
15-04	1	1	0	0	2
Total	40	38	4	4	83

12.5 kV U/G System	
Feeder	# of FCIs (3-phase set)
1-11	7
1-12	3
1-13	5
2-14	11
15-01	2
Total	28

12.5 kV O/H System	
Feeder	# of FCIs (3-phase set)
11-13	2
18-04	1
18-01	3
18-02	2
18-03	2
19-02	2
19-04	2
21-01	2
21-02	1
21-03	2
21-04	1
Total	20

Figure 6: Number of Switches/Reclosers/FCIs per DA Feeder.

Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Z4 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)	Z4 EL (ft)
11-11	7818	5978	1840			57139	30863	26276		
11-12	7650	3120	4530			56791	25148	31644		
11-13	6018	3713	2305			52451	31978	20472		
11-14	7903	4515	3388			34423	13852	20571		
12-11	4916	1853	3063			49908	22352	27556		
12-12	5926	2813	3113			47044	21148	25896		
12-13	6973	3110	3863			39580	21460	18120		
12-14	5413	1888	3525			22224	11467	10758		
16-01	12718	6480	6238			113133	49764	63369		
16-02	18543	6905	8085	3553		59022	12080	13409	33533	
16-03	11053	4255	2308	4490		105371	18051	29022	58297	
16-04	10017	4329	5688			55049	9698	45351		
18-01	17378	5903	3185	3965	4325	304469	74370	71027	83537	75535
18-02	7620	3490	4130			78638	38960	39678		
18-03	3534	1095	2439			23484	11345	12139		
18-04	15676	5723	2613	7340		268648	96906	26234	145509	
19-01	1625					30878				
19-02	8819	3607	5212			59843	27369	32474		
19-03	15383	5153	6780	3450		44075	14318	18251	11506	
19-04	9199	5054	4145			54662	32474	22188		
21-01	9210	5230	3980			54560	30479	24081		
21-02	8573	4328	4245			67657	42008	25650		
21-03	10963	3303	7660			64839	27215	37625		
21-04	6618	3638	2980			20896	7060	13835		
13-01	10188	3295	6893			54688	17421	37267		
13-02	9000	3720	5280			59715	24672	35043		
13-03	7793	2913	4880			43219	16942	26276		
13-04	4330	1435	2895			33527	12992	20535		
1-11	13050	7350	5700			17782	9672	8110		
1-12	8235	2535	5700			41673	19469	22205		
1-13	12703	7500	5203			19879	10623	9255		
1-14	3513	1933	1580			16030	9104	6926		
2-13	9111	4013	5098			26936	16043	10892		
2-14	7635	2900	4735			14383	6716	7667		
2-15	9135	5200	3935			47818	25781	22037		
2-16	8325	3850	4475			30066	17064	13002		
15-01	5475	1625	3850			8156	2874	5282		
15-02	3001	970	2031			8048	4354	3694		
15-03	4798	2170	2628			15135	8005	7129		
15-04	2895	250	2645			10935	6883	4052		

Figure 7. DA Zone Summary.

d. Automated Switches

PUC's preferred vendor for automated switches is S&C Electric. As such, we have recommended S&C products in this area.

Leidos visited all substations included in the DA design and observed that all DA feeders have existing reclosing relays at the substation. PUC has an ongoing relay replacement program at the substations.

Based on discussions with PUC staff, we assume that all substations except Sub 18 will have SEL 351 relays installed at the feeder ends.

There are two types of automated switches recommended for the DA system: Overhead Reclosers and Overhead Load-break Switches.

The overhead reclosers will be used to sectionalize the feeders so that the faulted area can be minimized and other parts of the feeder can be restored.

Figure 8. Overhead Recloser

S&C Electric's IntelliRupter PulseCloser is the recommended recloser product because it has a unique pulse closing technology. Following a lock-out, this recloser tests the line with a pulse signal to determine whether there is a permanent fault. This advanced feature reduces stress on system components and extends equipment lifetime.

Load-break switches are located at the tie points between feeders. These switches will be used to back-feed the un-faulted Zones.

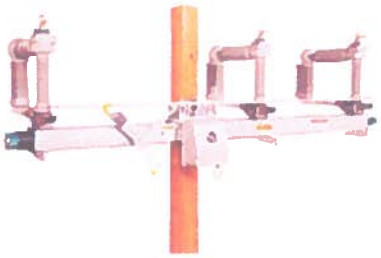

Figure 9. Overhead Loadbreak Switch

S&C Electric's Scada-Mate Switch is the recommended product for the load-break switch. Circuit making and breaking are accomplished within sealed interrupters, in a controlled SF_6 environment.

Overhead reclosers and overhead load-break switches will have voltage sensors on both sides of the switches. Also, they will be equipped with automatic switch controllers that will be communicating with the DA Software.

Figure 10. Automatic Switch Controller

S&C Electric's 6800 Series Automatic Switch Controls is recommended for the switch controllers. This controller has automatic control schemes with RTU functionality, data logging, and communication capabilities in one integrated package.

e. Fault Current Indicators

In addition to automated reclosers and load-break switches, the DA system also includes Fault Current Indicators to be installed at selected overhead and underground feeders. The 12.5 kV underground system in downtown Sault Ste. Marie has many S&C Electric 4-way PMH switches that are being operated without any protection or fault indication equipment on them. This makes it very complicated to locate faults in this part of the system. Therefore, the design includes FCIs that will be installed at PMH switches and k-bars. Overhead FCIs are also recommended on some feeders to further improve reliability. The locations of the FCIs are shown in Appendix 5.

FCIs will be connected to SCADA so that system operators will be able to see the status of each device and dispatch crews accordingly.

Figure 11. Fault Current Indicator

f. Sub-Transmission System (34.5 kV) Automation

PUC's 34.5 kV system currently serves as the sub-transmission system feeding 34.5/12.5 kV and 34.5/4.16 kV substations. 34.5/12.5 kV substations generally have two 34.5 kV connections, in most cases, from different sources. Substation 11, noted in Figure 12, is an example of this. As shown, the substation is served from one 34.5 kV feeder and the other 34.5 kV feeder is left open in the substation to be used as a backup in case of primary source failure. Currently, if the main source fails, there is no automated system in place that can switch to the alternative system.

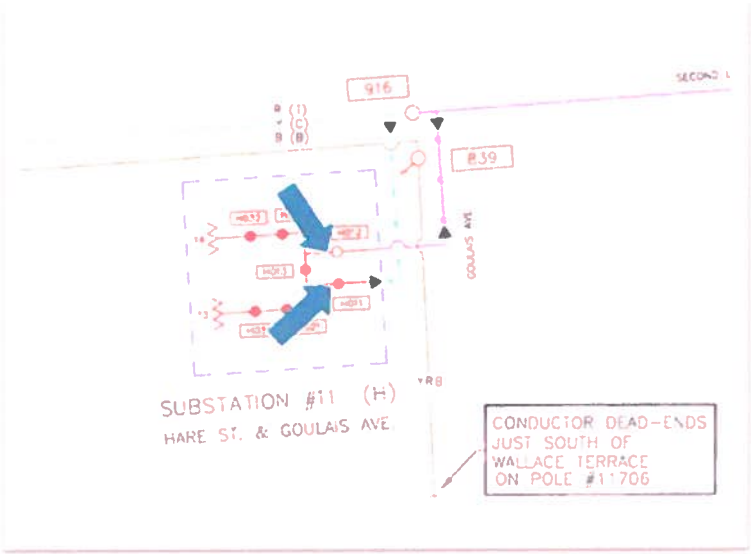

Figure 12. Fault Current Indicator

In the proposed design, DA software will be used to monitor the main and alternative source feeders. Voltage sensors will be used at each feeder which will be connected to the DA Software system. A custom script will be developed by Survalent in the SCADA system that will detect the loss of voltage at the main source. As a next step, loading conditions will be

checked to avoid any overloading on the alternative source. Finally, switching signals will be sent to the breakers (shown with arrows) to shift the substation transformer to the alternative feeder. This system will be implemented at the substations that are presented in Appendix 6.

g. Communication System

PUC currently has fiber and/or radio communications to all substations that are included in the DA design (see Figure 13). PUC has historically used GE MDS radios for SCADA communications. However, a fiber ring is being installed at all DA substations except Sub 16 and Sub 18. Communication in these substations is currently provided by 900 MHz MDS radios. When Substation 16 is rebuilt, the station will have fiber communication as the fiber cables are already available outside the substation. There is no near-term plan to pull fiber cable to Sub 18; therefore, this substation will continue to communicate via MDS radios.

Location	Address	Fiber Connected	MDS Radio
Substation 2	894 Wellington St E	X	X
Substation 10	87 Blake Ave	X	
Substation 19	885 McNabb St	X	X
Substation 20	500 2nd Line E	X	X
Substation 11	8 Hare Ave	X	X
Substation 13	760 Shafer Ave	X	
Substation 1	270 Queen St E	X	X
Substation 21	3835 Queen St E	X	
Substation 12	288 Bennett Blvd	X	X
Substation 16	601 3rd Line E		X
Substation 18	855 Goulais Ave		X
Substation 5	261 Lake St		X
Substation 15	183 Spring St		X
Substation 14	143 Willoughby St		X
Substation 4	140 MacDonald Ave		

Figure 13. Existing Communication System at Substations

Leidos evaluated communication alternatives for proposed field equipment including reclosers, switches and regulators. Because of the large geographic footprint, pulling fiber optic cables to each equipment location would not be economically viable. Therefore, wireless solutions operating in the 900 MHz and 2.4 GHz unlicensed bands were considered. The communication system is required to be scalable and shall provide adequate bandwidth and signal strength for standard monitoring and control functions of field devices.

Considering these requirements, Leidos recommends S&C Electric's 900 MHz SpeedNet radios for communication to new devices, including reclosers, switches, and regulators. PUC staff has experience with these devices at existing 34.5 kV switch locations, and PUC expressed a preference for their use. It is also noted that extra repeaters are needed to overcome line-of-sight issues for certain locations. Extra repeaters were included in the materials list for this purpose.

Figure 14. SpeedNet Radios.

h. DA Analysis - Reconfiguration Simulations

A reconfiguration study has been carried out on all DA feeders to check whether the proposed tie-switch locations and the reconfiguration plans cause any thermal or voltage violations. This task is accomplished by running load flows on all DA feeders for all circuit configurations (normal and fault-reconfigured) at peak loading scenario. Minimum down-line voltage and maximum conductor loading are recorded for each load-flow run. All load-flow results are provided in Appendix 3. Following are the threshold values used for minimum down-line voltage and maximum conductor loading in the analysis. Results violating these thresholds are flagged in RED.

- Minimum down-line voltage – 94% p.u.
- Maximum conductor loading – 100%

Figure 15 shows the load flow results for feeder 16-01. In the DA design for feeder 16-01, tie-switch location is chosen to back-feed feeder 16-01 from feeder 18-02. The first two rows of Figure 15 are the load flow results of feeders 16-01 and 18-02 in a normal configuration. The tabulated results show that there are no violations in this configuration. The last two rows of the table show the load flow results of 16-01 and 18-02 for the scenario where there is a fault in the upstream zone of feeder 16-01 and the down-stream zone of feeder 16-01 is back-fed from feeder 18-02. The results indicate that there would be no thermal or voltage violations for this fault-reconfigured configuration.

Feeder	Feeder/Adj Feeder	Load Transferred To	Load Transferred From	Min Downline Voltage (%)	Max Conductor Loading (%)
16-01	16-01	NA	NA	95.88	85.3
	18-02	NA	NA	97.39	36.8
	16-01	18-02	NA	98.39	26.8
	18-02	NA	16-01	94.35	72.6

Figure 15. Reconfiguration Study Results for Feeder 16-01.

6. DA Benefits

a. PUC Reliability Data

A review of PUC's historical reliability data has shown that reliability indices were only calculated at the system level; feeder-level reliability data was not available. In order to get more insight on historic outages, Leidos reviewed PUC's outage database file including records dating back to 2007. Based on this analysis, the west and north part of the Sault Ste. Marie distribution system is identified as the primary focus of DA design efforts due to relatively poor reliability performance. It was determined in coordination with PUC that the east Sault Ste. Marie feeders could also benefit from automation and were thus included in the program design.

Feeder-level reliability data was estimated using the outage data for each feeder (average CMI values for years 2008-2012) and PUC system-level reliability data. Average values for five-year, historic system-level reliability data from the SSM PUC 2012 annual report shown in Figure 16 and Figure 17 are used in the analysis as baseline numbers.

Year	SAIDI (Hours)	CAIDI (Hours)	SAIFI
2008	2.25	1.3	1.7
2009	2.2	0.73	3
2010	2.1	0.73	2.85
2011	2.9	0.8	3.6
2012	1.65	0.76	2.17
Average	2.22	0.864	2.664

Figure 16. PUC Five Year Historic and Average Baseline Reliability Data

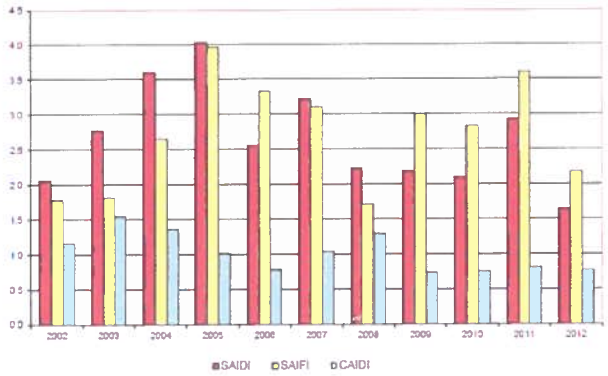

Figure 17. PUC System Level Reliability Data (PUC 2012 Annual Report)

Feeders are segregated into four major groups based on the average CMI data. Each group is assigned a weight based on average feeder CMI values in that group. These group weights are then used to normalize the system-level baseline reliability data to compute the feeder-specific baseline reliability numbers shown in Figure 18.

Feeder	SAIDI (minutes)	CAIDI (minutes)	SAIFI
11-11	113	50	2.25
11-12	113	50	2.25
11-13	233	50	4.66
11-14	113	50	2.25
12-11	113	50	2.25
12-12	113	50	2.25
12-13	113	50	2.25
12-14	113	50	2.25
16-01	113	50	2.25
16-02	113	50	2.25
16-03	113	50	2.25
16-04	113	50	2.25
18-01	402	50	8.04
18-02	233	50	4.66
18-03	233	50	4.66
18-04	402	50	8.04
19-01	233	50	4.66
19-02	233	50	4.66
19-03	235	93	2.51
19-04	233	50	4.66
21-01	233	50	4.66
21-02	233	50	4.66
21-03	233	50	4.66
21-04	233	50	4.66
13-01	56	50	1.13
13-02	113	50	2.25
13-03	233	50	4.66
13-04	56	50	1.13
1-11	56	50	1.13
1-12	113	50	2.25
1-13	56	50	1.13
1-14	56	50	1.13
2-13	56	50	1.13
2-14	56	50	1.13
2-15	113	50	2.25
2-16	56	50	1.13
15-01	56	50	1.13
15-02	56	50	1.13
15-03	56	50	1.13
15-04	56	50	1.13

Figure 18.DA Feeder Baseline Reliability Data

b. Estimating DA Reliability Improvements

Estimating DA reliability improvements would be a very straight-forward task if outage locations and frequency could be accurately predicted for a feeder. Since PUC does not have detailed outage data to help predict future outage locations and frequency, assumptions were used to guide the estimation process.

- Feeders are divided into either two or three equal zones by the placement of one or two sectionalizing switches.
- The probability of fault occurrence in all zones is similar.
- All outage events are of the same duration.
- Pre-DA deployment: If it takes 100 minutes to restore service after a fault, it is assumed that 40 minutes is required to pinpoint the fault and 60 minutes is required to repair the fault
- Post-DA deployment: For a feeder with two zones, it will take 20 minutes to pinpoint the fault in this example (50% less time). So, overall it is assumed that post-DA outage duration is 20% less than Pre-DA outage duration as the crews can locate faults more quickly with DA in place.

Using these assumptions, Leidos calculated theoretical reliability improvement percentages, which are listed in Figure 19.

n (# of switches)	1	2
CMI Improvement	-60%	-73%
SAIDI Improvement	-60%	-73%
CAIDI Improvement	-20%	-20%
SAIFI Improvement	-50%	-67%

Figure 19. Theoretical Reliability Improvements

The DA recommendation includes installing reclosers on the 12.5 kV distribution feeders and creating multiple zones on feeders. Assuming that there will be one recloser installed on a particular feeder, Figure 19 shows a 60% improvement is calculated for CMI and SAIDI. In this example, when there is a fault downstream of the mid-line recloser, the customers above the recloser will not experience any sustained outages because the mid-line recloser is expected to operate; therefore, 50% improvement is expected, assuming zones are equal. In addition, there will be more improvements due to the fact that it will take less time for PUC crews to pinpoint the fault because they do not need to drive the entire feeder. Therefore, post-DA outage duration is assumed to be 20% less. Post-DA outage duration is defined as the duration between when the outage location is isolated by the DA system and when the service is restored to the faulted zone after repair is done.

The calculations described above are only true if the assumptions are correct. Given the uncertainties about expected fault frequency and locations, Leidos utilized improvement percentages that are more conservative than the numbers listed in Figure 19. The final reliability improvements used in benefit calculations are listed in Figure 20.

Reliability Indices	Percent Changes	
# of switches	1	2
SAIFI	-40%	-50%
SAIDI	-50%	-60%
CAIDI	-15%	-20%

Figure 20. Reliability Improvements Used in Benefit Calculations

The U.S. Department of Energy (DOE) has provided funds for smart grid investment projects in the past 5 years, and there were many DA projects implemented as part of the program. DOE has collected data from each project and conducted benefit analysis. The results were published in the *"Reliability Improvements from the Application of Distribution Automation Technologies – Initial Results"* report. The summary of the reliability improvements from the report is shown in Figure 21.

Reliability Indices	Range of Percent Changes
SAIFI	-11% to -49%
SAIDI	+4% to -56%
CAIDI	+29% to -15%

Figure 21. Reliability Improvements from DA (DOE Report)

Figure 22 shows the post-DA reliability numbers calculated by using the reliability improvement estimations presented in Figure 20.

Feeder	# of Switches	PreDA SAIDI	PreDA CAIDI	PreDA SAIFI	PostDA SAIDI	PostDA CAIDI	PostDA SAIFI
11-11	1	113	50	2.25	57	43	1.35
11-12	1	113	50	2.25	57	43	1.35
11-13	1	233	50	4.66	117	43	2.80
11-14	1	113	50	2.25	57	43	1.35
12-11	1	113	50	2.25	57	43	1.35
12-12	1	113	50	2.25	57	43	1.35
12-13	1	113	50	2.25	57	43	1.35
12-14	1	113	50	2.25	57	43	1.35
16-01	1	113	50	2.25	57	43	1.35
16-02	2	113	50	2.25	45	40	1.13
16-03	2	113	50	2.25	45	40	1.13
16-04	1	113	50	2.25	57	43	1.35
18-01	2	402	50	8.04	161	40	4.02
18-02	1	233	50	4.66	117	43	2.80
18-03	1	233	50	4.66	117	43	2.80
18-04	2	402	50	8.04	161	40	4.02
19-01	NA	233	50	4.66	233	50	4.66
19-02	1	233	50	4.66	117	43	2.80
19-03	2	235	93	2.51	94	74	1.26
19-04	1	233	50	4.66	117	43	2.80
21-01	1	233	50	4.66	117	43	2.80
21-02	1	233	50	4.66	117	43	2.80
21-03	1	233	50	4.66	117	43	2.80
21-04	1	233	50	4.66	117	43	2.80
13-01	1	56	50	1.13	28	42	0.68
13-02	1	113	50	2.25	57	43	1.35
13-03	1	233	50	4.66	117	43	2.80
13-04	1	56	50	1.13	28	42	0.68
1-11	1	56	50	1.13	28	42	0.68
1-12	1	113	50	2.25	57	43	1.35
1-13	1	56	50	1.13	28	42	0.68
1-14	1	56	50	1.13	28	42	0.68
2-13	1	56	50	1.13	28	42	0.68
2-14	1	56	50	1.13	28	42	0.68
2-15	1	113	50	2.25	57	43	1.35
2-16	1	56	50	1.13	28	42	0.68
15-01	1	56	50	1.13	28	42	0.68
15-02	1	56	50	1.13	28	42	0.68
15-03	1	56	50	1.13	28	42	0.68
15-04	1	56	50	1.13	28	42	0.68

Figure 22.Pre-DA and Post-DA Reliability Numbers

Pre-DA and Post-DA reliability metrics presented in this table are used in the cost benefit analysis to monetize the DA benefits.

7. DA Requirements

a. FCI Requirements

FCI requirements describe the features, specifications, and operation of the FCIs.

1. FCIs shall be used to detect and report faults on the 12.5 kV and 34.5 kV distribution systems.
2. FCIs shall provide load profiling and internal diagnostic information for planning and maintenance purposes.
3. FCIS shall be used for both overhead and underground applications.
4. FCIs shall have and LED-based visual indication that shows the status of the device.
5. FCIs shall be self-powered and shall not need external power sources.
6. FCIs shall be hot stick installable.
7. No additional hardware or software shall be required to acquire data from the FCIs.
8. FCIs shall be DNP 3.0 Level 2 compliant.
9. FCIs data shall be directly retrieved by SCADA via DNP polls.
10. FCIs shall be configured to report by exception via DNP3 messages when line monitoring data changes outside of a configurable dead band.
11. FCIs shall operate between -40 degrees C to +85 degrees C.
12. FCIs shall be compatible with IEEE Std 495™-2007 standard.
13. FCI firmware shall be upgradable remotely.
14. The voltage sensing accuracy shall be +/-5%.
15. The current sensing accuracy shall be +/-1% up to 600 A, and 5% up to saturation at 20 kA.

b. DA Software Requirements

1. DA software shall provide a capability to find the fault location, isolate the fault, and restore power to the entire upstream section of the feeder and as much of the downstream feeder as possible.
2. DA Software shall interface with ESRI GIS system and shall have the ability to update the underlying distribution network on an as needed or automated basis.
3. DA Software shall support standard protocols such as Multispeak, DNP 3.0, and Modbus to interface with external applications.
4. DA software shall also enable remote monitoring and control of DA equipment from PUC Control Room.
5. DA software shall be a network-based solution that can run optimization using network parameters.
6. DA software shall be installed at the PUC Control Room.
7. DA Software shall be able to monitor reclosers, switches, and FCIs in the system.
8. DA Software shall be able to locate three-phase, phase-to-phase and phase-to-ground faults.
9. In case of a fault, the un-faulted downstream feeder zones shall be restored after analyzing all possible predetermined restoration scenarios, based on available capacity of the adjacent circuits.
10. The fault location, isolation, and restoration processes shall be accomplished in less than five minutes. This means that customers on unfaulted zones shall be energized within five minutes following the recloser lock-out.

11. When there is a fault in the system, the recloser shall go through its trip and close operations as configured. DA Software shall start its fault location, isolation, and restoration processes following a recloser lock-out signal.
12. DA Software shall not take any action when recloser trips on a temporary fault and remains closed after a close operation. Nor shall any action be taken if switching or breaker operations are manually operated.
13. DA Software shall have three different operating modes: Disabled, Semi-Automatic and Full Automatic.
14. Operator shall be able to change the mode of operation through display screens easily.
15. In the disabled mode, DA Software shall not issue any control commands to switches and reclosers. However, real-time analog and digital data shall continue to be monitored from the screen. In case of a fault, the switches that saw the fault current shall be sending this information back to the control center as well. In this mode, fault location, isolation, and restoration shall be done by the operator if required.
16. In the semi-automatic mode, DA Software shall find the fault location, but wait for operator approval for any switching actions.
17. In the fully-automatic mode, DA Software shall perform all fault location, isolation, and restoration functions automatically without the need of an operator intervention. The operator shall be notified about the actions taken by the DA Software.
18. DA Software shall collect fault detection data from each switch controller and FCI to be able to determine the fault location.
19. After the fault location is determined by the DA Software, the faulted zone shall be isolated from the system so that un-faulted zones can be restored.
20. DA Software shall open switches around the faulted zone to achieve isolation.
21. When a faulted zone is isolated, DA Software shall restore the upstream zones, if any, by closing the recloser at the substation.
22. In order to restore the downstream zones, DA Software has to develop a dynamic restoration plan. This restoration plan shall not overload any circuit and shall not cause any voltage violations.
23. DA Software shall be able to simulate the restoration plan by running a power flow with the latest load data to check whether the proposed restoration plan creates voltage or thermal violations.
24. In case of voltage or thermal violations, operators shall be informed before taking any further action.
25. After the fault is repaired by the field personnel, system operators shall be able to send a "Return to Normal" command from the DMS, which reconfigures the circuits to their original topology through a series of switching operations.
26. When a fault has occurred and reconfiguration has been satisfactorily accomplished, the intended system shall be able to perform all of its pre-fault functions in case of another fault. In other words, DA Software shall update itself according to the reconfigured network topology, and in case of another fault, it shall be able to find the new fault location and restore the service utilizing the new network topology.
27. The system shall reconfigure the network after a fault condition with the capacity available at that specific time. However, if the demand increases after a certain amount of time and any component in the new network configuration gets close to its thermal limits, the feeder automation system shall make another configuration plan to avoid overloading.

28. DA Software shall monitor substation transformer data (current, voltage, active power, reactive power).
29. DA Software shall monitor substation feeder breaker (recloser) and relay status (open-close-lock out).
30. DA Software shall monitor distribution feeder analog data (current, voltage, active power, reactive power).
31. DA Software shall monitor recloser/load break switch status (open-close) data.
32. DA Software shall monitor recloser/load break switch analog data (current, voltage, active power, reactive power).
33. DA Software shall monitor fault detection data from recloser/load break switches and reclosers.
34. DA Software shall have functionality to remotely control substation breakers/reclosers and loadbreak switches from the Control Center.
35. DA Software shall acquire below data from reclosers and loadbreak switches:
    a. Voltage each phase on a 120 V base (source side)
    b. Voltage each phase on a 120 V base (load side)
    c. Amps each phase
    d. Fault detection data
    e. kW – Three phase
    f. kVAR – Three phase (leading kVAR shall be negative)
    g. Direction of power flow
    h. Status of switch
    i. Time stamp
    j. Battery Status data
    k. Battery Charger Status data
36. If there is a communication failure between the DA Software and a recloser or loadbreak switch, fault isolation and restoration functionalities for that feeder shall be disabled by the DA Software. In this case, the DA Software shall not perform any fault isolation and restoration related to that feeder. However, fault isolation and location functionality shall continue be operational for other feeders if they do not have any communication issues.
37. After a communication failure is detected and the DA functionality is disabled for a feeder, if the communication is established again, the DA Software shall recognize this and enable the fault isolation and location functionality for that feeder.

c. Recloser Requirements

1. Three-Phase electronically controlled operation with vacuum interrupting automatic circuit reclosing.
2. Supplied with applicable accessories for pole mount applications on concrete poles using stainless steel bands or pre-drilled holes in the concrete poles.
3. Supplied with visible air-gap isolation of switched open circuits either through an integrated or external solution.
4. The recloser shall be capable of performing four (4) open operations before lockout for a permanent fault. The number of reclose operations shall be adjustable and shipped from the factory as specified on the order.
5. Supplied with three 600/5-ampere CTs installed on each load side bushing. CTs will be specified in detail when purchase order is issued.
6. Minimum mechanical operations of 2500.

7. The controller will use an Ethernet connection to the communication modem and use DNP 3.0 Level 2 as the communication protocol to exchange data and information to the DMS via the ESB.
8. Voltage measurements (rms) on all three phases with 1% accuracy on both sides of the recloser from internal or external PT device and able to be communicated back to SCADA. Internally powered from the distribution line with battery backup for support operations for a minimum of four hours after loss of AC line voltage on both sides of recloser.
9. Nominal line-to-line Voltage 14.4 kV
10. Maximum line-to-line Voltage 17 kV
11. Minimum Basic Insulation Level (BIL) 110 kV
12. Minimum Continuous Current Rating 600 A
13. Minimum Interrupting Current Rating 12,500 A

d. Loadbreak Switch Requirements

1. Three-Phase electronically controlled operation with vacuum interrupting functionality.
2. Supplied with applicable accessories for pole mount applications on concrete poles.
3. Supplied with three 600/5-ampere CTs installed on each load side bushing.
4. Supplied with appropriate motor operator to enable remote open and close operation.
5. Supplied with visible air-gap isolation of switched open circuits either through an integrated or external solution.
6. The controller will use an Ethernet connection to the communication modem and use DNP 3.0 Level 2 as the communication protocol to exchange data and information to the DMS via the ESB.
7. Microprocessor-based controller shall have capability to detect distribution system faults using local CT and PT measurements.
8. The controller shall be able to communicate the "fault detected" information to SCADA.
9. Fault detection logic of the microprocessor-based controller shall be configurable for voltage, current, and duration.
10. Voltage measurements (rms) on all three phases of switch with 1% accuracy from internal or external PT device and able to be communicated back to SCADA.
11. Minimum mechanical operations of 2500.
12. Nominal line-to-line Voltage 14.4 kV
13. Maximum line-to-line Voltage 17 kV
14. Minimum Basic Insulation Level (BIL) 110 kV
15. Minimum Continuous Current Rating 600 A
16. Minimum Interrupting Current Rating 600 A

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Appendix 1. Bill of Materials

Distribution Automation (DA)		
	Item Description	**Qty**
1	S&C Electric Intellirupter, Controller, Communications	38
2	S&C Electric Scada-Mate , Controller, Communications	40
3	S&C Remote Supervisory Vista 4-Way Underground Distribution Switchgear, Controller, Communications	4
4	S&C Remote Supervisory PMH-3 Pad-Mounted Gear, w/6801 Automatic Switch Controls, Communications	4
5	O/H FCI - Eaton Viper - 3-phase set	32
6	U/G FCI - Eaton Viper - 3-phase set	37
7	Communication repeaters	10
8	Voltage Sensors for Source Transfer - 3 Phase set	16
9	FCI w/out communications	30
10	Pole replacement	86
11	Survalent -FDIR	1
12	Survalent -Source Transfer Logic	1
13	Survalent -ESRI GIS Interface (also used for VVM)	1
14	Survalent -MultiSpeak AMI Interface (also used for VVM)	1
15	Survalent -Operator Training Simulator (also used for VVM)	1
16	Services - AMI, GIS integration (also used for VVM)	1
17	Survalent -Load Flow (also used for VVM)	1
18	FDIR Implementation 40 Feeders	1
19	Integration with Survalent (field integration)	1

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Appendix 2. Scope of Services

DA extended scenario scope includes designing, procuring, installing and commissioning a distribution automation system that will improve reliability on PUC's 12.5 and 34.5 kV distribution and sub-transmission systems.

In the extended scope, centralized control software, Fault Location Isolation Restoration (FLIR) will be installed at the PUC Control Room. The interfaces with AMI and GIS will be built so that DA system can acquire data from these systems. The DA system includes automating 40 feeders as listed in the table.

In this scenario, 38 reclosers, 40 load-break switches, 4 4-way pad-mount switches, 4 2-way pad-mount switches 32 3-phase overhead fault current indicator sets and 37 3-phase underground fault current indicator sets will be deployed to the system.

Each field device will be installed with a controller to enable data exchange. SpeedNet 900 MHz communication system will be deployed to provide communication between field devices and the central software system. Field integration of all equipment will be accomplished. Controllers and protective relays settings will be determined and applied to the associated equipment. SCADA points list will be developed and data acquisition system of these points will be established.

Feeder	# Poletop Switches	# Poletop Reclosers	# 2-way Padmount Switches	# 4-way Padmount Switches	# Zones
11-11	1	1	0	0	2
11-12	1	1	0	0	2
11-13	1	1	0	0	2
11-14	1	1	0	0	2
12-11	1	1	0	0	2
12-12	1	1	0	0	2
12-13	1	1	0	0	2
12-14	1	1	0	0	2
16-01	2	1	0	0	2
16-02	2	2	0	0	3
16-03	2	2	0	0	3
16-04	1	1	0	0	2
18-01	2	2	0	0	3
18-02	1	1	0	0	2
18-03	1	1	0	0	2
18-04	2	2	0	0	3
19-01	0	0	0	0	0
19-02	1	1	0	0	2
19-03	2	2	0	0	3
19-04	1	1	0	0	2
21-01	1	1	0	0	2
21-02	1	1	0	0	2
21-03	1	1	0	0	2
21-04	1	1	0	0	2
13-01	1	1	0	0	2
13-02	1	1	0	0	2
13-03	1	1	0	0	2
13-04	1	1	0	0	2
1-11	0	0	0	1	2
1-12	0	0	1	1	2
1-13	0	0	0	1	2
1-14	1	1	0	0	2
2-13	1	1	0	0	2
2-14	0	0	2	0	2
2-15	1	1	0	0	2
2-16	1	1	0	0	2
15-01	0	0	1	1	2
15-02	1	0	0	0	2
15-03	1	1	0	0	2
15-04	1	1	0	0	2
Total	40	38	4	4	83

Appendix 3. DA Reconfiguration Simulation Results

Feeder	Feeder/Adj Feeder	Load Transferred To	Load Transferred From	Min Downline Voltage (%)	Max Conductor Loading (%)
11-11	11-11	NA	NA	96.12	36.5
	18-04	NA	NA	91.84	68.1
	11-11	18-04	NA	97.42	36.3
	18-04	NA	11-11	90.64	85.8
11-12	11-12	NA	NA	96.41	54.6
	13-03	NA	NA	97.84	45.1
	11-12	13-03	NA	97.13	33.9
	13-03	NA	11-12	96.07	77.8
11-13	11-13	NA	NA	98.7	33.5
	11-12	NA	NA	96.41	54.6
	11-13	11-12	NA	98.81	22.8
	11-12	NA	11-13	95.93	65.4
11-14	11-14	NA	NA	99.04	28.2
	18-02	NA	NA	97.39	36.8
	11-14	18-02	NA	99.12	28.2
	18-02	NA	11-14	97.26	52.7

Feeder	Feeder/Adj Feeder	Load Transferred To	Load Transferred From	Min Downline Voltage (%)	Max Conductor Loading (%)
12-11	12-11	NA	NA	95.39	63.5
	12-13	NA	NA	97.44	67
	12-11	12-13	NA	98.06	18.8
	12-13	NA	12-11	96.37	100
12-12	12-12	NA	NA	98.22	42.4
	21-02	NA	NA	98.58	40.9
	12-12	21-02	NA	98.42	21.5
	21-02	NA	12-12	97.26	62.9
12-13	12-13	NA	NA	97.44	67
	19-03	NA	NA	98.02	51.1
	12-13	19-03	NA	98.56	27.6
	19-03	NA	12-13	96.51	73.7
12-14	12-14	NA	NA	98.12	43
	12-11	NA	NA	95.39	63.5
	12-14	12-11	NA	98.63	27.5
	12-11	NA	12-14	94.09	84.7

Feeder	Feeder/Adj Feeder	Load Transferred To	Load Transferred From	Min Downline Voltage (%)	Max Conductor Loading (%)
16-01	16-01	NA	NA	95.88	85.3
	18-02	NA	NA	97.39	36.8
	16-01	18-02	NA	98.39	26.8
	18-02	NA	16-01	94.35	72.6
16-02	16-02	NA	NA	97.58	81.9
	16-03	NA	NA	95.08	42.7
	16-04	NA	NA	98.2	19.1
	16-02	16-03;16-04	NA	98.91	30.4
	16-03	NA	16-02	94.6	54.7
	16-04	NA	16-02	98.16	33.9
16-03	16-03	NA	NA	95.08	42.7
	16-02	NA	NA	97.58	81.9
	19-04	NA	NA	96.85	77.2
	16-03	16-02;19-04	NA	98.54	29.3
	16-02	NA	16-03	93.13	94.9
	19-04	NA	16-03	96.72	89.8
16-04	16-04	NA	NA	98.2	19.1
	18-02	NA	NA	97.39	36.8
	16-04	18-02	NA	98.88	9.8
	18-02	NA	16-04	95.42	53

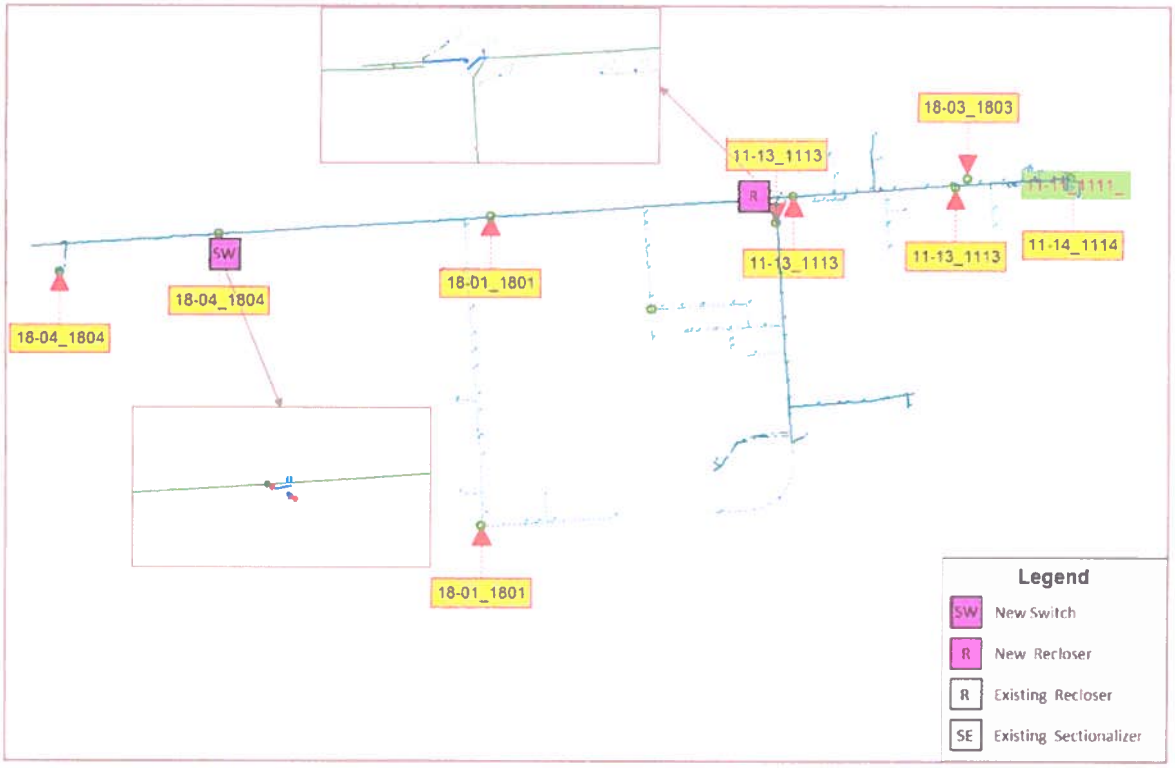
Feeder	Feeder/Adj Feeder	Load Transferred To	Load Transferred From	Min Downline Voltage (%)	Max Conductor Loading (%)
18-01	18-01	NA	NA	83.33	70.9
	18-04	NA	NA	91.84	68.1
	18-01	18-04	NA	97.8	20.5
	18-04	NA	18-01	81.09	116.8
18-02	18-02	NA	NA	97.39	36.8
	16-04	NA	NA	98.2	19.1
	18-02	16-04	NA	98.46	19.2
	16-04	NA	18-02	97.25	28.8
18-03	18-03	NA	NA	97.45	26.7
	11-11	NA	NA	96.12	36.5
	18-03	11-11	NA	98.72	14.2
	11-11	NA	18-03	96.04	43.6
18-04	18-04	NA	NA	91.84	68.1
	18-01	NA	NA	83.33	70.9
	18-04	18-01	NA	96.14	31.5
	18-01	NA	18-04	79.67	100

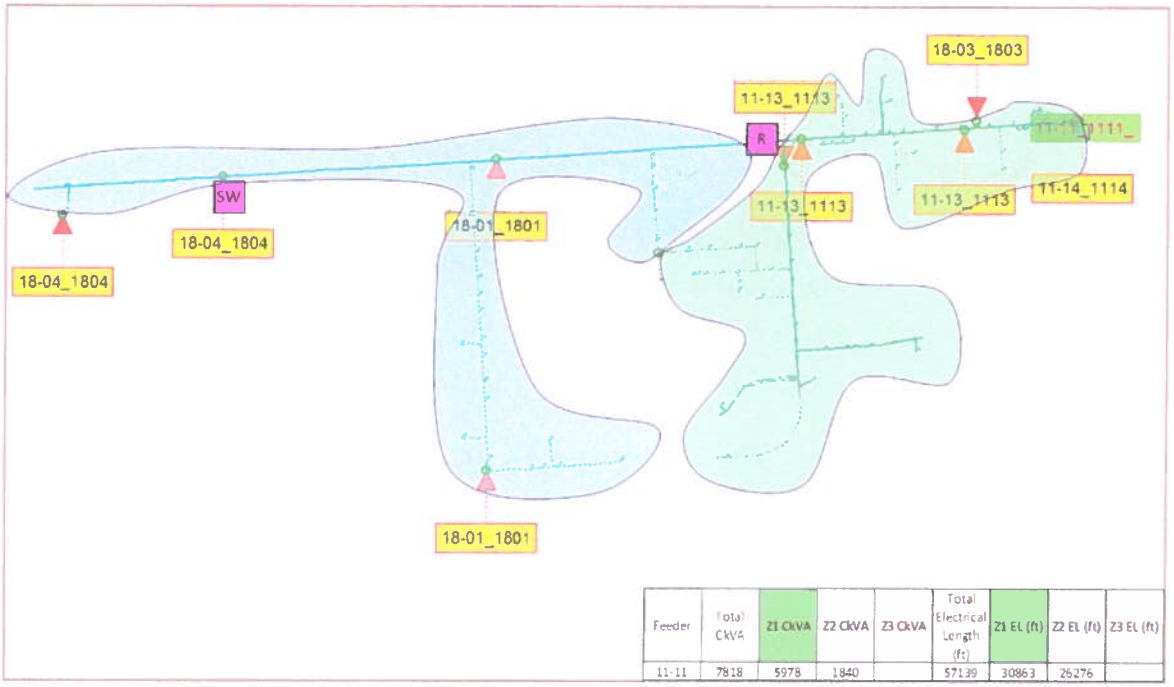
Feeder	Feeder/Adj Feeder	Load Transferred To	Load Transferred From	Min Downline Voltage (%)	Max Conductor Loading (%)
19-01	19-01	NA	NA	NA	NA
	19-01	NA	NA	NA	NA
	19-01	NA	NA	NA	NA
	19-01	NA	NA	NA	NA
19-02	19-02	NA	NA	97.34	26.2
	21-01	NA	NA	98.46	34.6
	19-02	21-01	NA	98.66	13
	21-01	NA	19-02	96.9	58.6
19-03	19-03	NA	NA	98.02	51.1
	2-15	NA	NA	98.33	50.9
	19-03	2-15	NA	99.01	19.1
	2-15	NA	19-03	96.05	93.7
19-04	19-04	NA	NA	96.85	77.2
	2-15	NA	NA	98.33	50.9
	19-04	2-15	NA	98.25	47.6
	2-15	NA	19-04	97.12	83.7

Feeder	Feeder/Adj Feeder	Load Transferred To	Load Transferred From	Min Downline Voltage (%)	Max Conductor Loading (%)
21-01	21-01	NA	NA	98.46	34.6
	21-04	NA	NA	98.38	29.4
	21-01	21-04	NA	98.46	21.5
	21-04	NA	21-01	98.25	30.6
21-02	21-02	NA	NA	98.58	40.9
	21-03	NA	NA	95.1	37.8
	21-02	21-03	NA	98.76	21.3
	21-03	NA	21-02	94.43	58.2
21-03	21-03	NA	NA	95.1	37.8
	2-16	NA	NA	98.11	28.1
	21-03	2-16	NA	98.3	10.2
	12-11	NA	21-03	95.8	55.6
21-04	21-04	NA	NA	98.38	29.4
	19-02	NA	NA	97.34	26.2
	21-04	19-02	NA	98.81	13.5
	19-02	NA	21-04	97.01	43.8

Appendix 4. DA Switch Locations

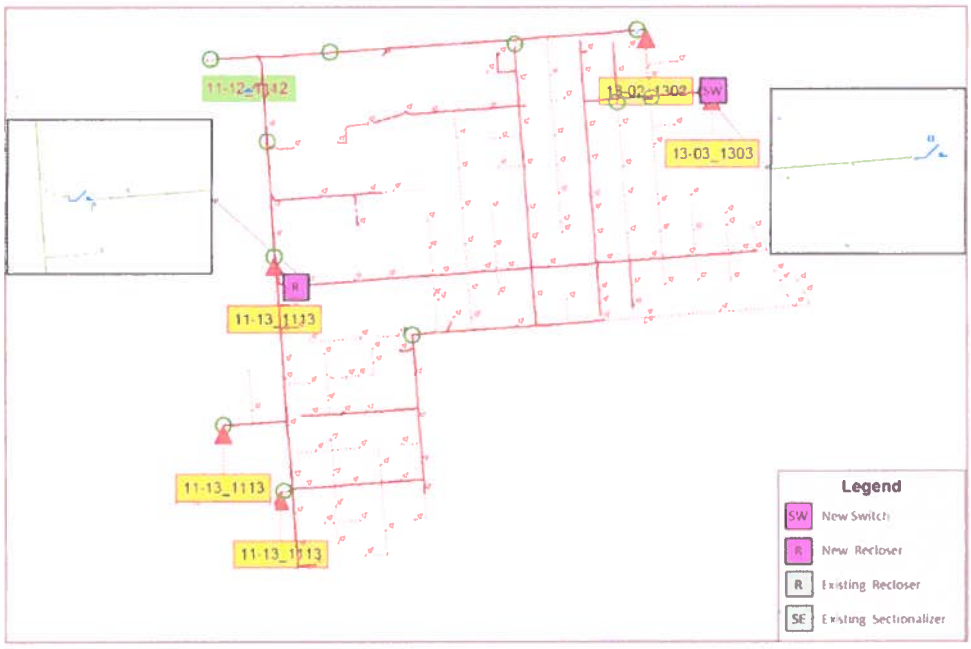
11-11:

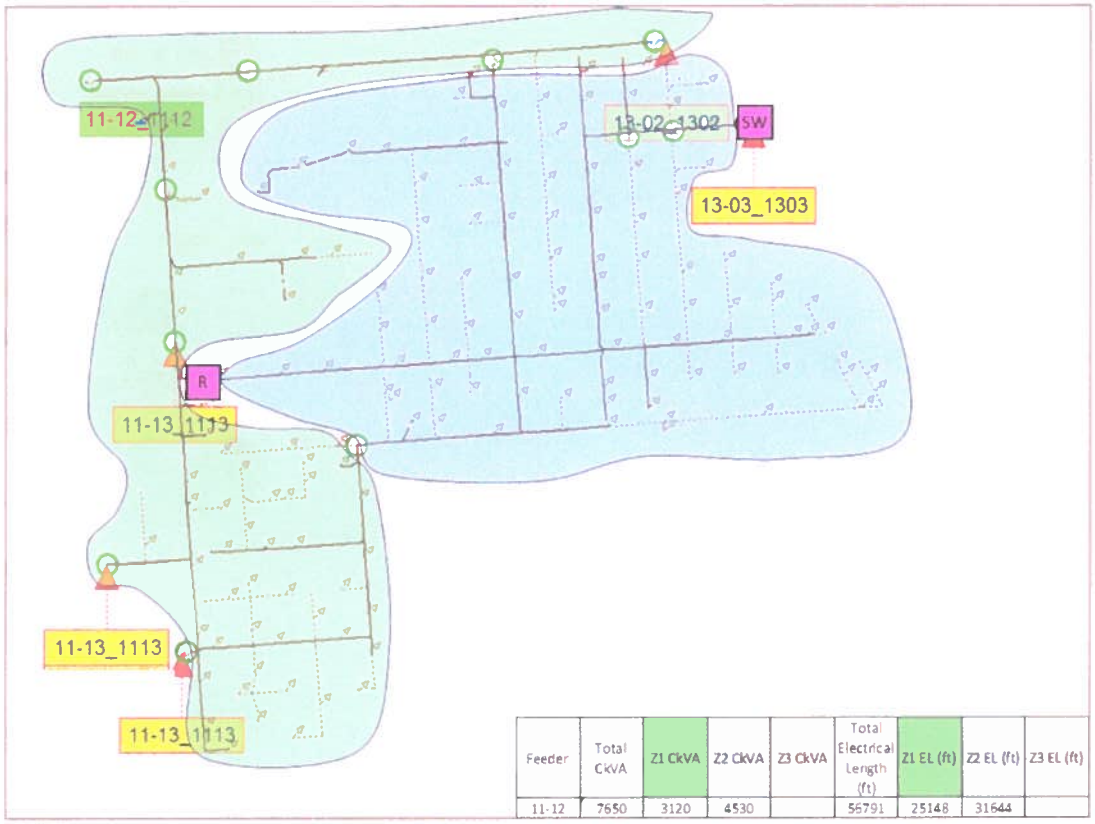




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
11-11	7818	5978	1840		57139	30863	26276	

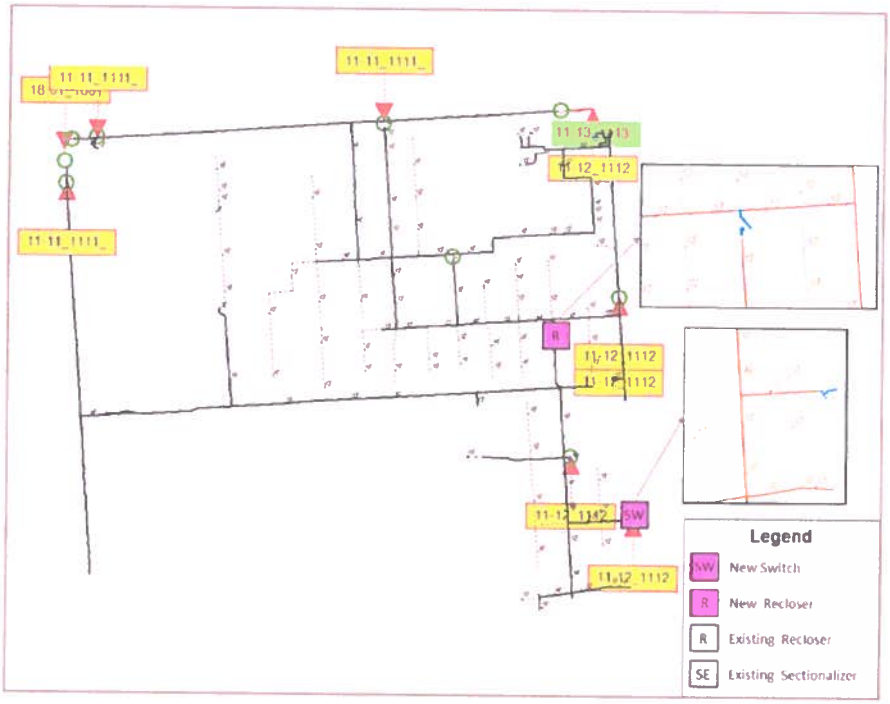
11-12:

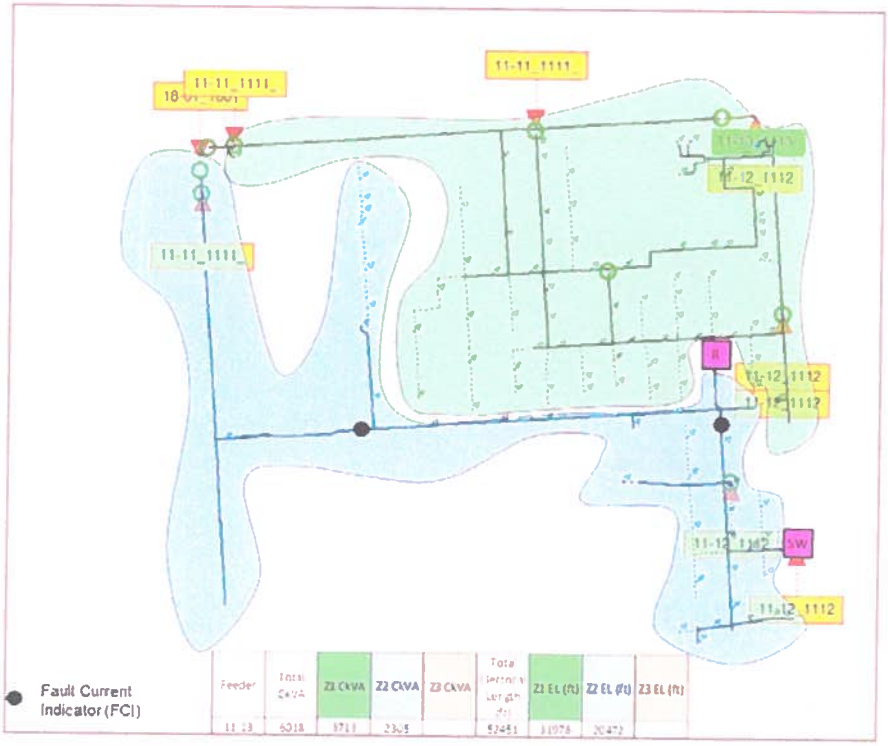




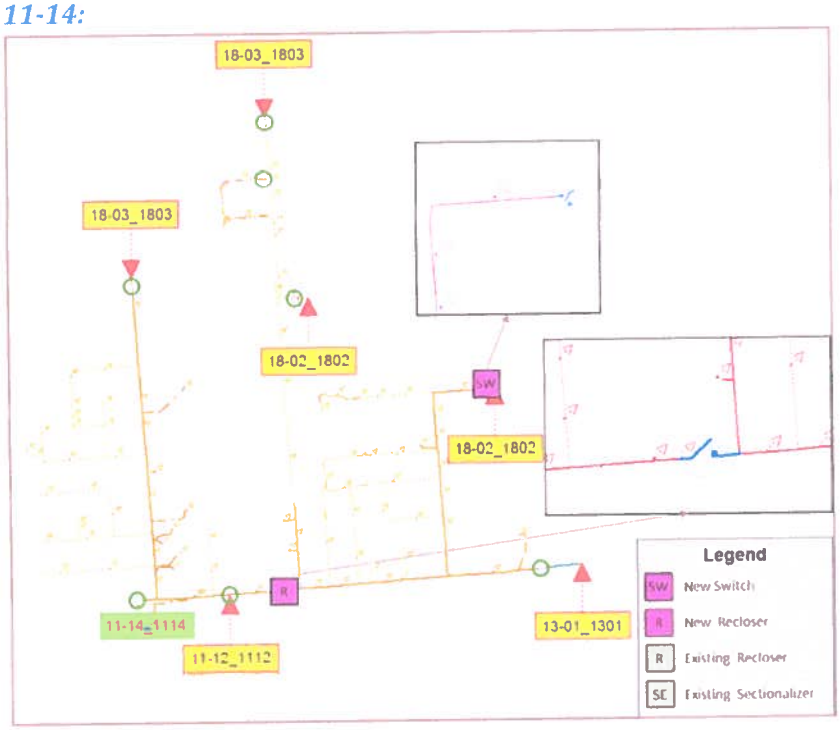
Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
11-12	7650	3120	4530		56791	25148	31644	

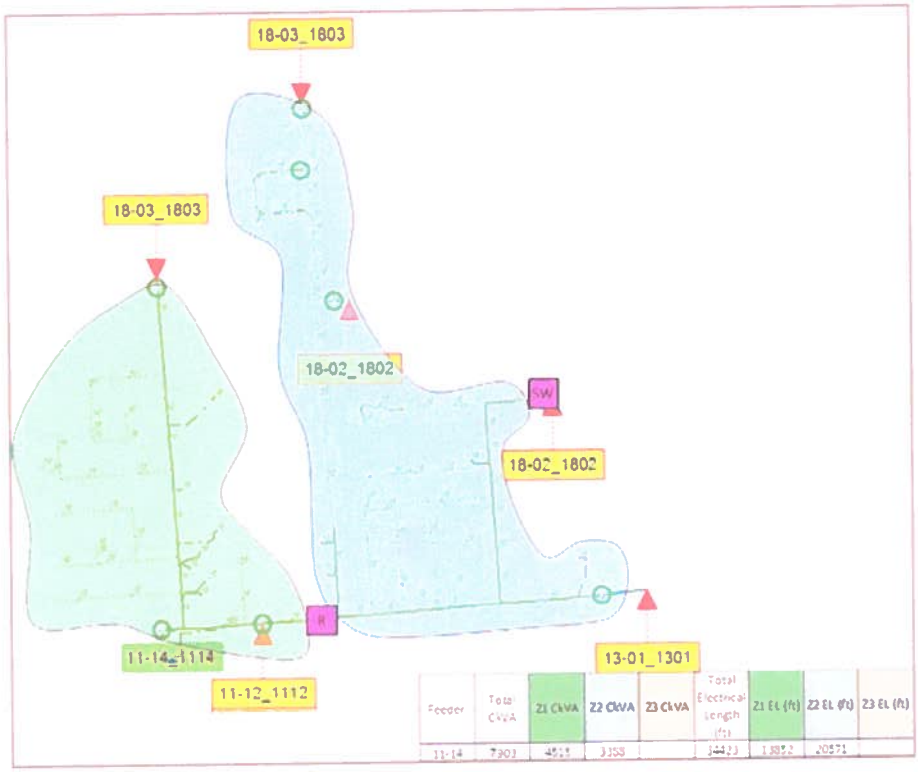
11-13:


Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer

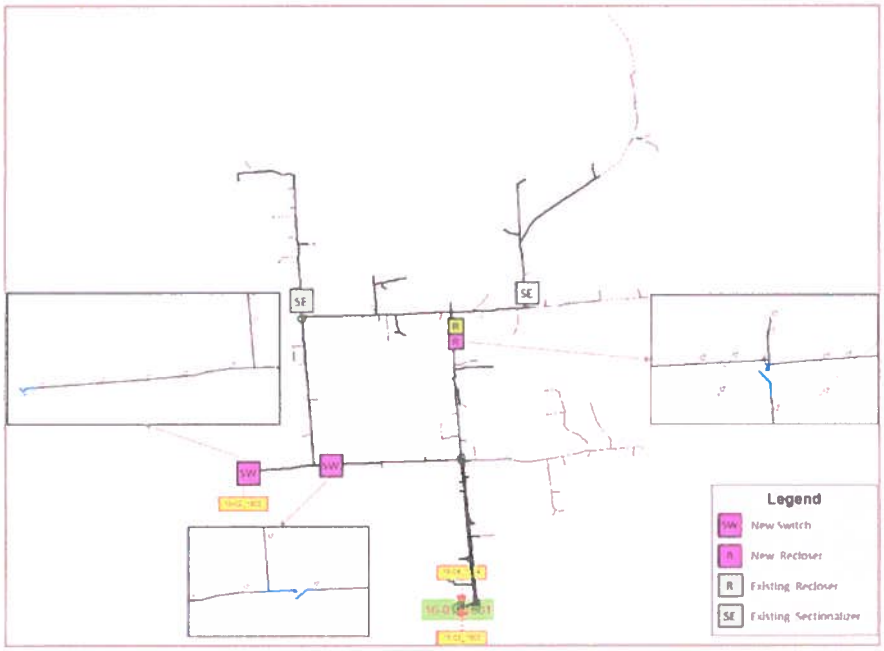

Fault Current Indicator (FCI)

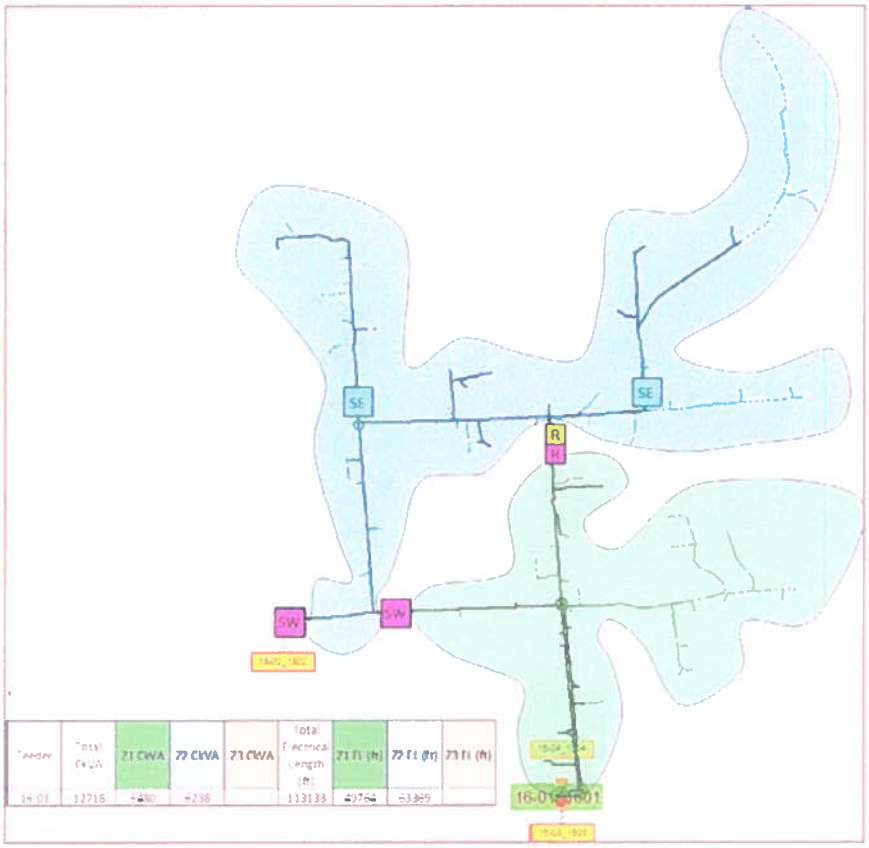
11-14:


18-03_1803
18-03_1803
18-02_1802
18-02_1802
SW
11-14_1114
11-12_1112
13-01_1301
Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer

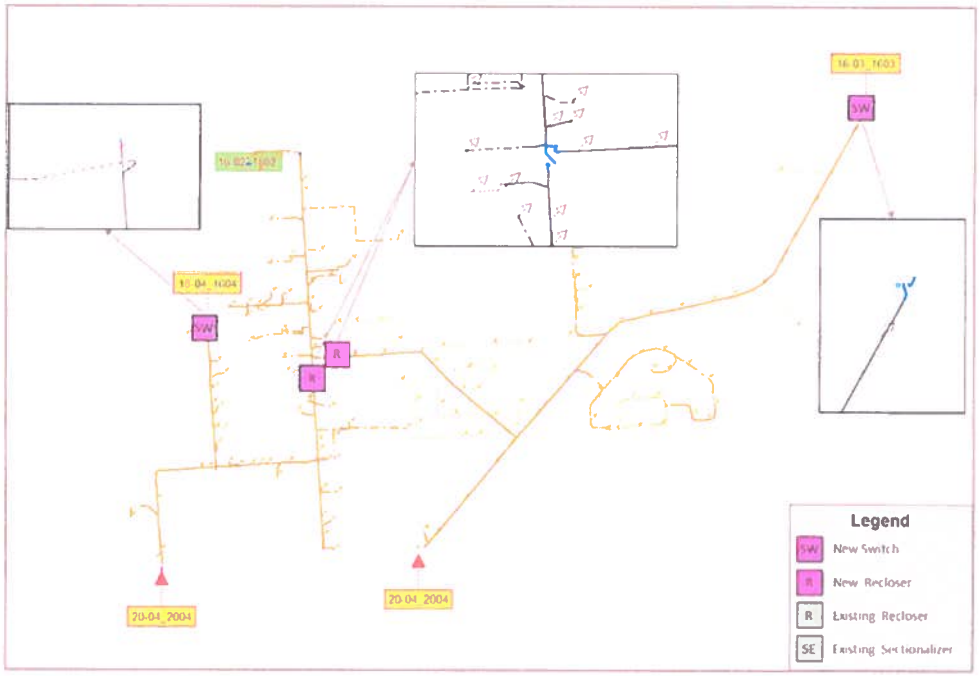

18-03_1803
18-03_1803
18-02_1802
SW
18-02_1802
11-14_1114
11-12_1112
13-01_1301
Feeder
Total CkVA
Z1 CkVA
Z2 CkVA
Z3 CkVA
Total Electrical Length (ft)
Z1 EL (ft)
Z2 EL (ft)
Z3 EL (ft)
11-14
7303
4615
3358
14423
13852
20571

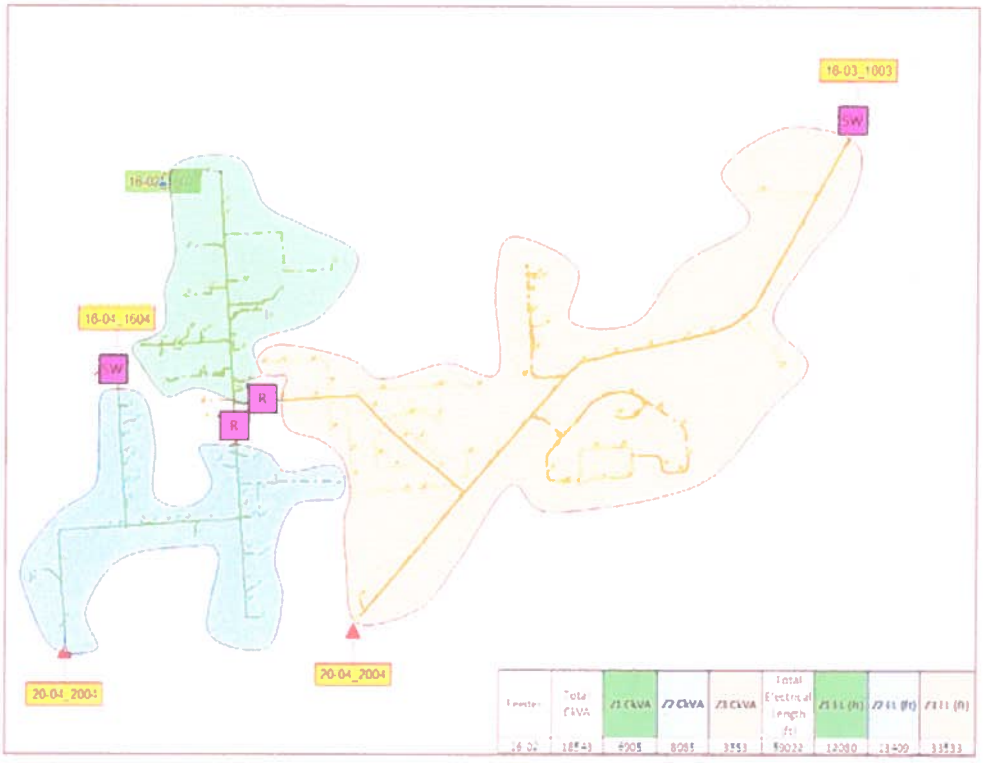
16-01:


SE
SE
R
R
SW
SW
Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer

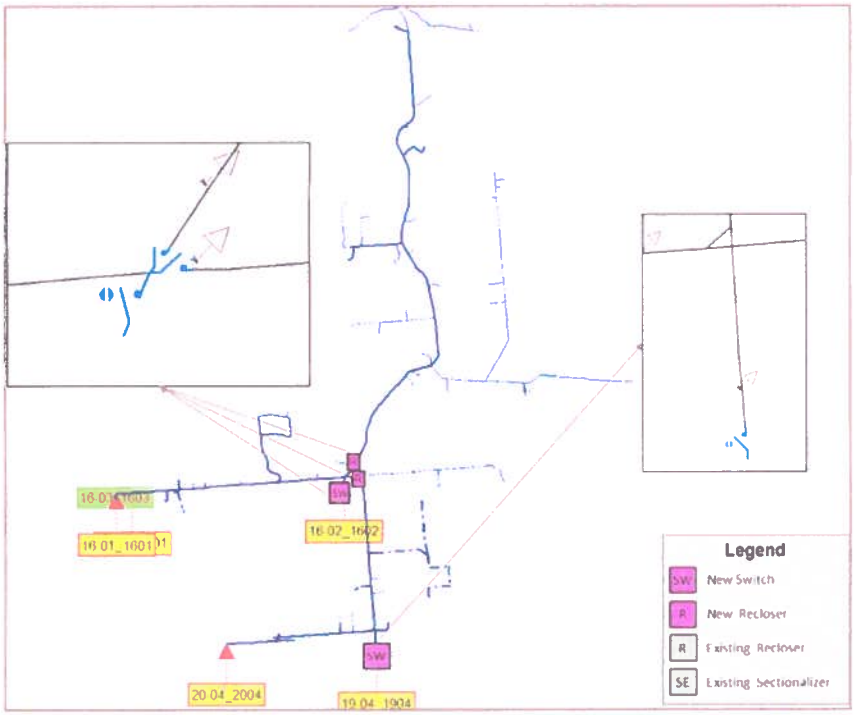

SE
SE
R
R
SW
SW
Feeder
Total CMVA
21 CMVA
22 CMVA
23 CMVA
Total Overhead Length (ft)
21 Ft (ft)
22 Ft (ft)
23 Ft (ft)
16-01
12716
113133
16-01_601

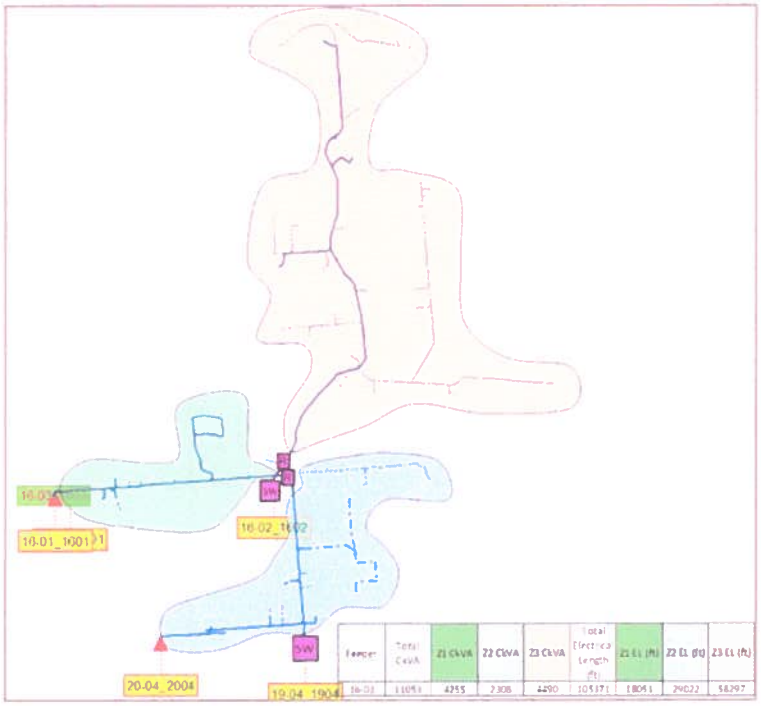
16-02:


16-03_1003
SW
16-04_1604
SW
R
R
20-04_2004
20-04_2004
Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer

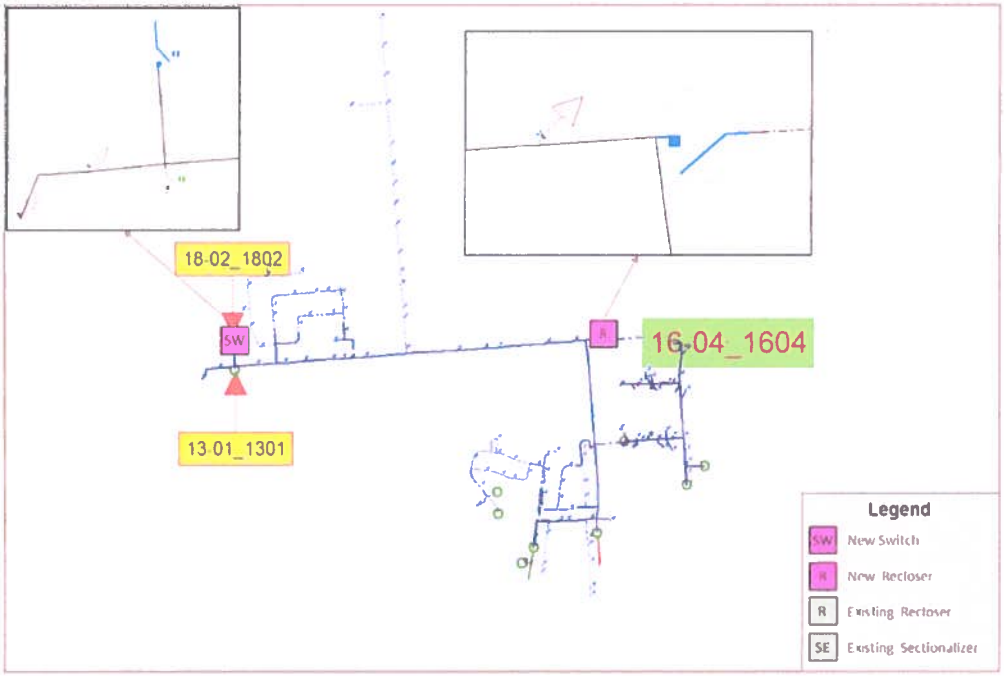

16-03_1003
SW
16-04_1604
SW
R
R
20-04_2004
20-04_2004

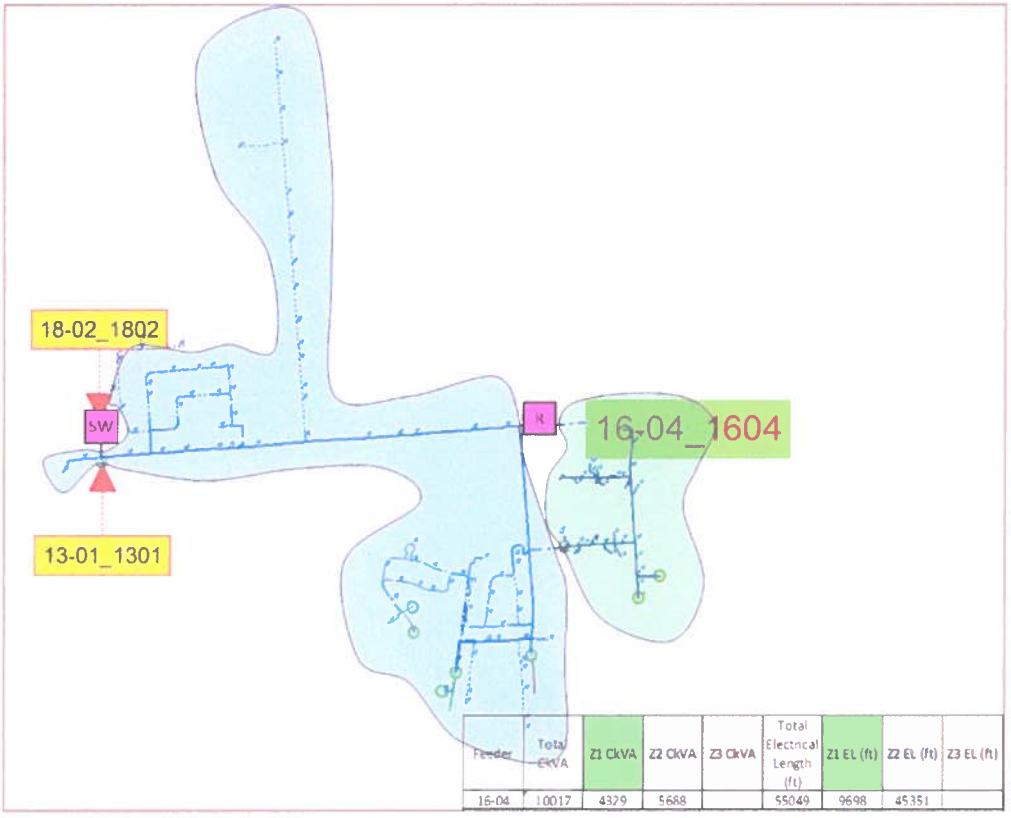
16-03:


16-01_1601
16-01_1601
16-02_1602
20-04_2004
19-04_1904
Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer


16-01_1601
16-02_1602
20-04_2004
19-04_1904

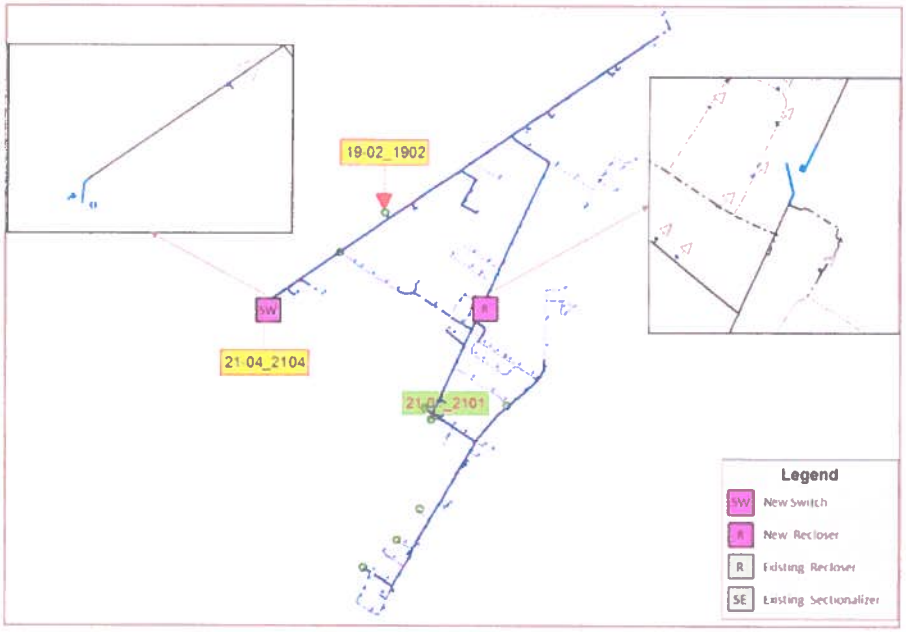
16-04:

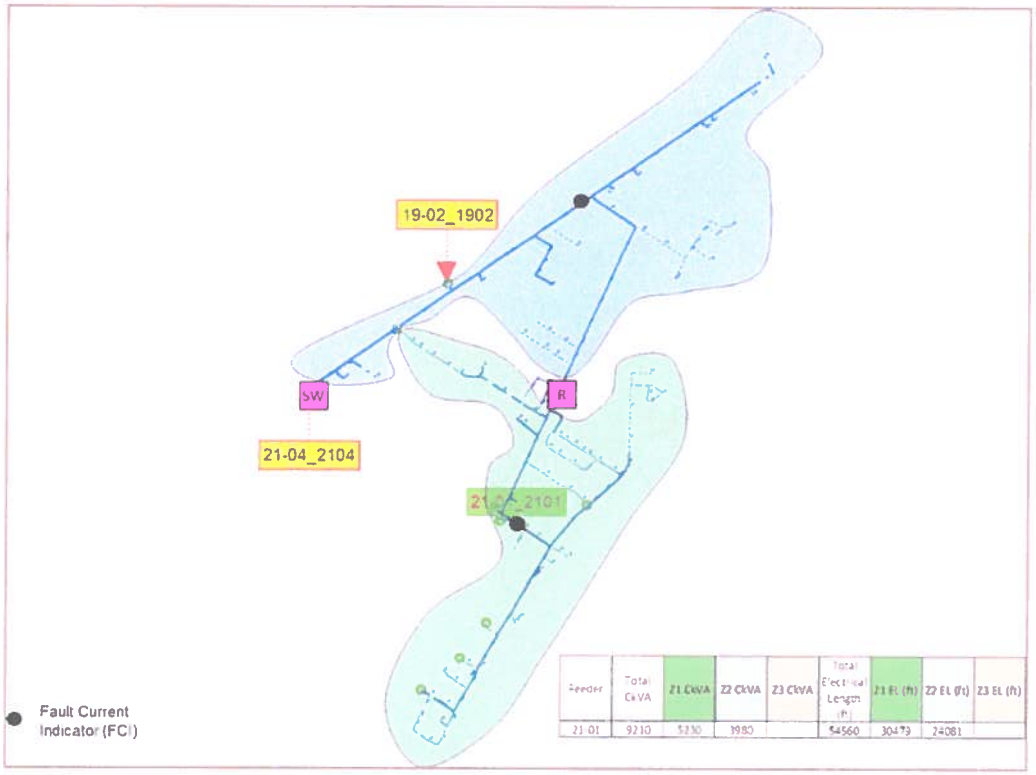




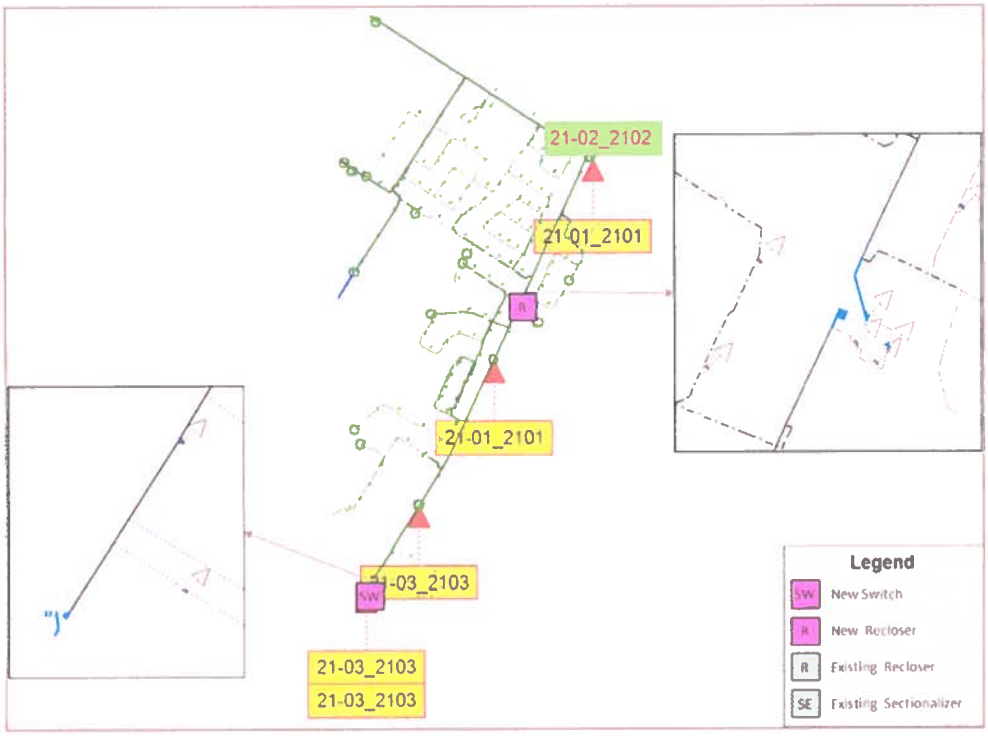
Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
16-04	10017	4329	5688		55049	9698	45351	

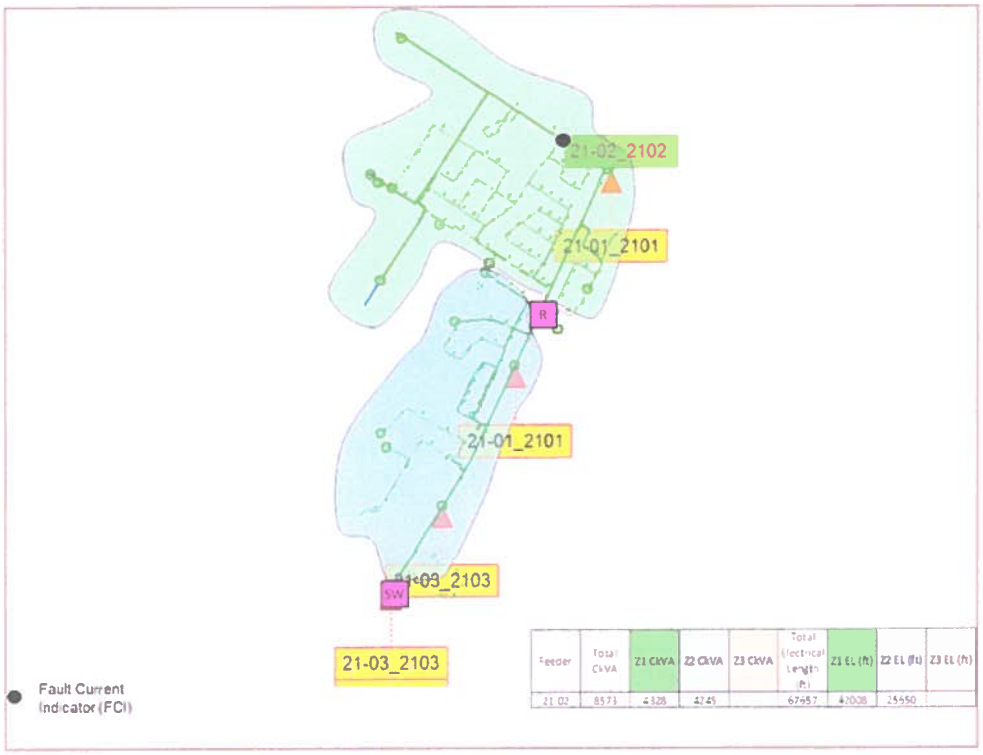
21-01:


19-02_1902
SW
R
21-04_2104
21-01_2101
Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer

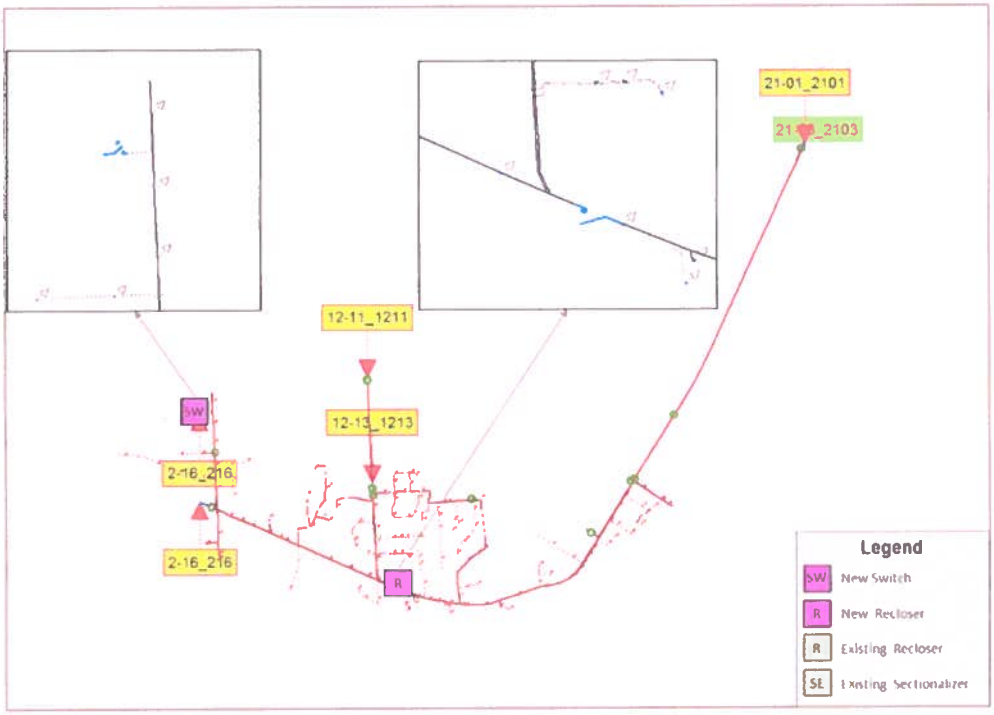

19-02_1902
SW
R
21-04_2104
21-01_2101
Fault Current Indicator (FCI)
Feeder
Total CkVA
Z1 CkVA
Z2 CkVA
Z3 CkVA
Total Electrical Length (ft)
Z1 EL (ft)
Z2 EL (ft)
Z3 EL (ft)
21-01
9210
5230
3980
54560
30479
24081

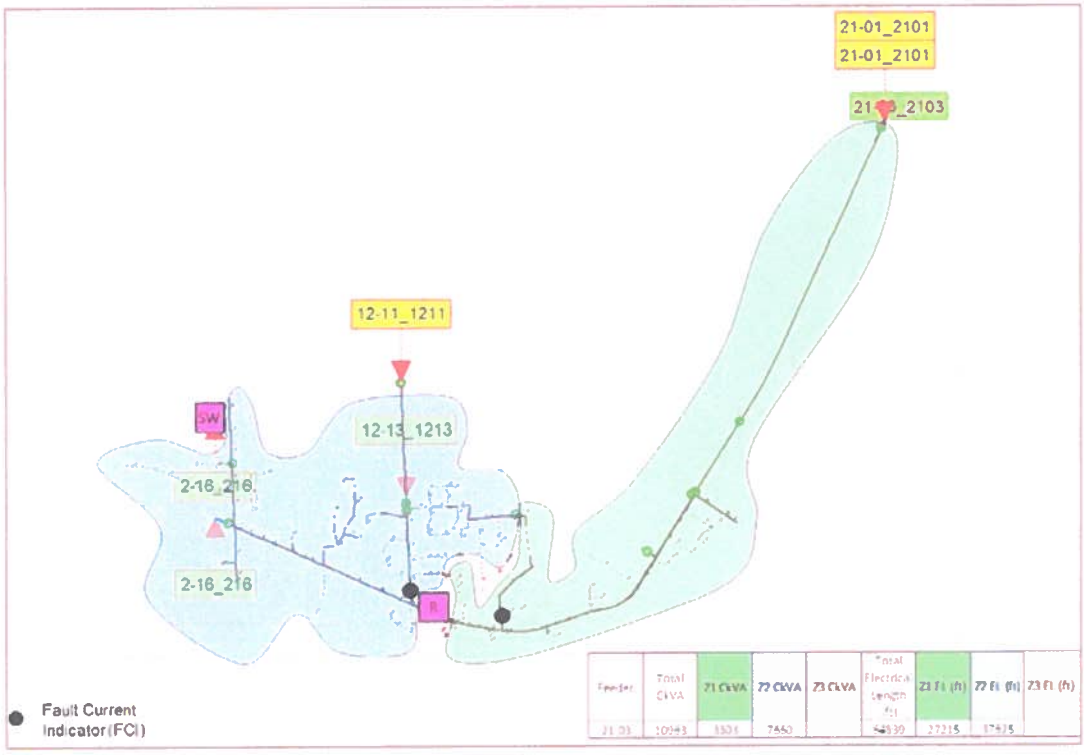
21-02:


21-02_2102
21-01_2101
21-01_2101
21-03_2103
21-03_2103
21-03_2103
Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer

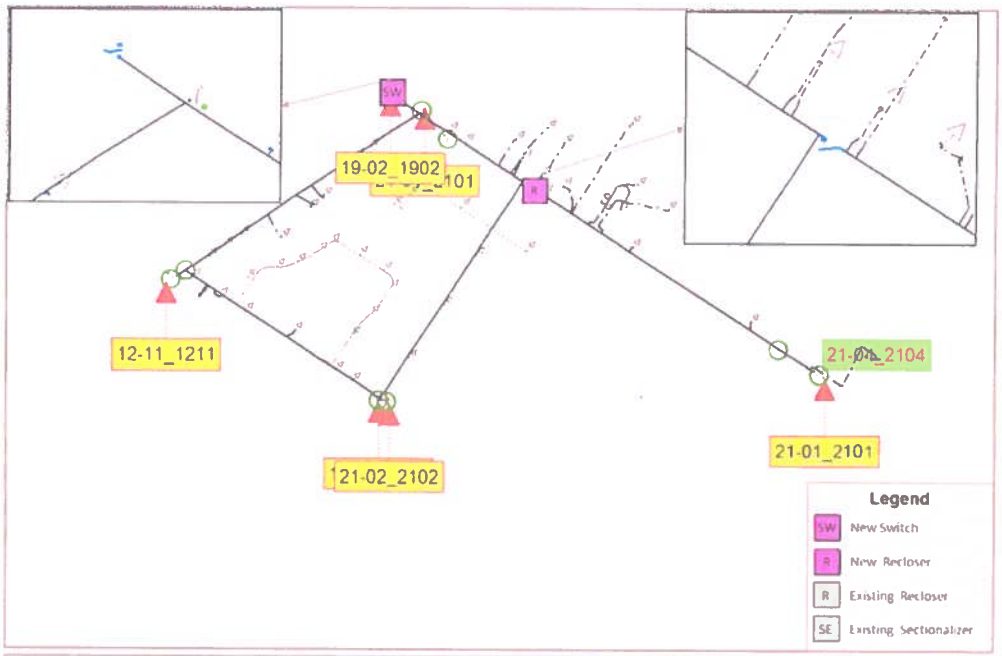

21-02_2102
21-01_2101
21-01_2101
21-03_2103
21-03_2103
Fault Current Indicator (FCI)
Feeder
Total CkVA
Z1 CkVA
Z2 CkVA
Z3 CkVA
Total Electrical Length (ft)
Z1 EL (ft)
Z2 EL (ft)
Z3 EL (ft)
21-02
8573
4328
4745
67657
42008
25550

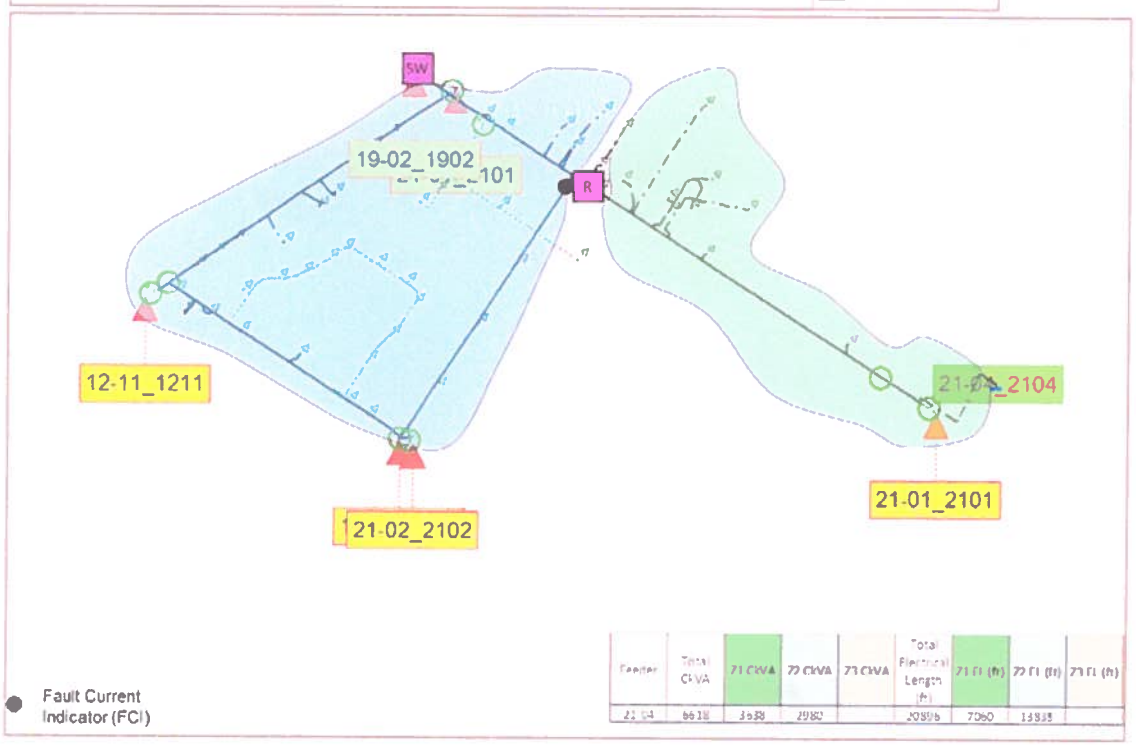
21-03:


21-01_2101
12-11_1211
12-13_1213
SW
2-16_216
2-16_216
R
Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer

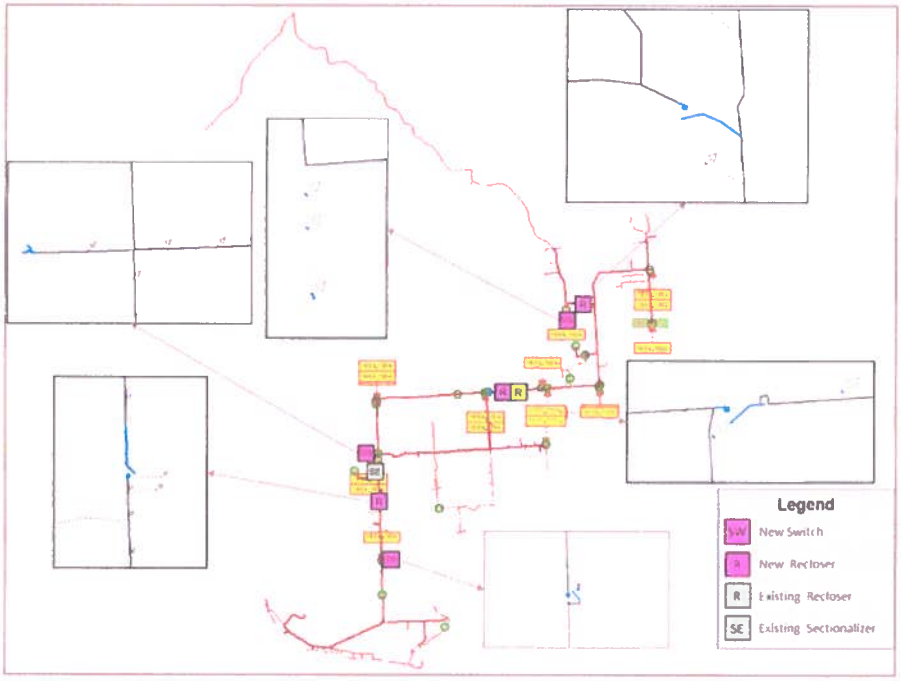

21-01_2101
21-01_2101
12-11_1211
12-13_1213
SW
2-16_216
2-16_216
R
Fault Current Indicator(FCI)

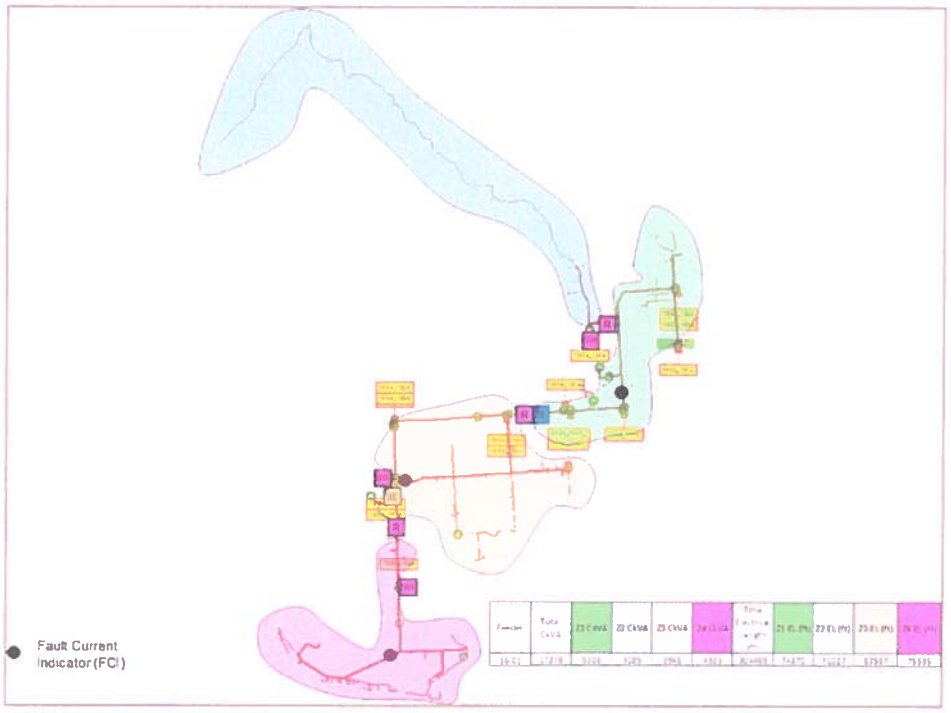
21-04:


SW
19-02_1902
R
12-11_1211
21-02_2102
21-01_2104
21-01_2101
Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer

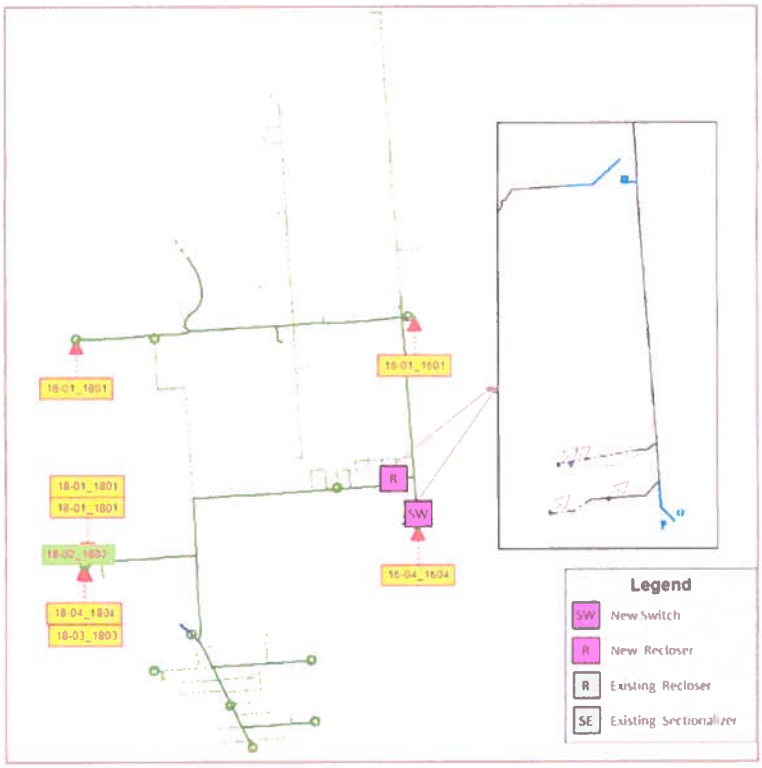

SW
19-02_1902
R
12-11_1211
21-02_2102
21-01_2104
21-01_2101
Fault Current Indicator (FCI)

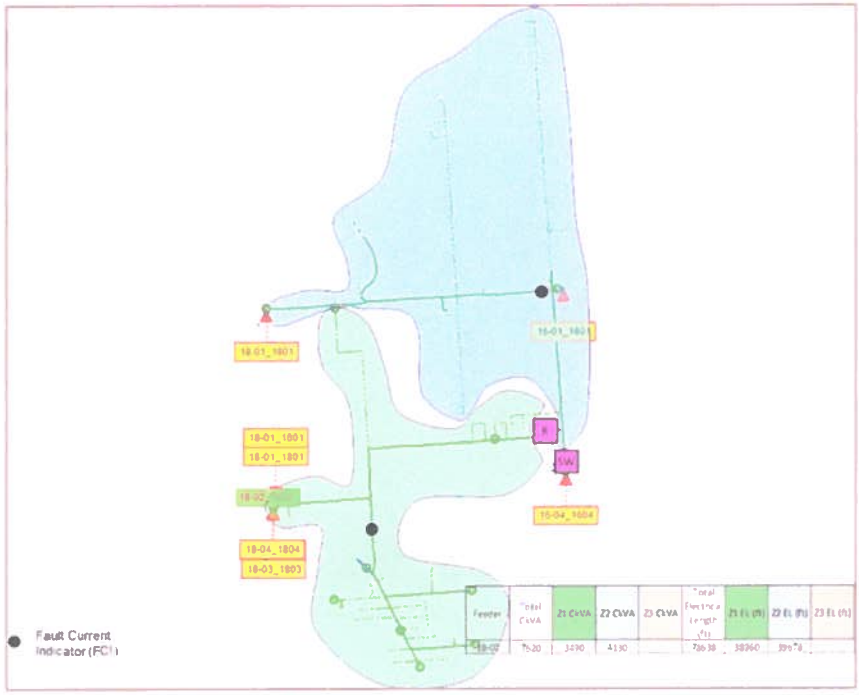
18-01:


Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer

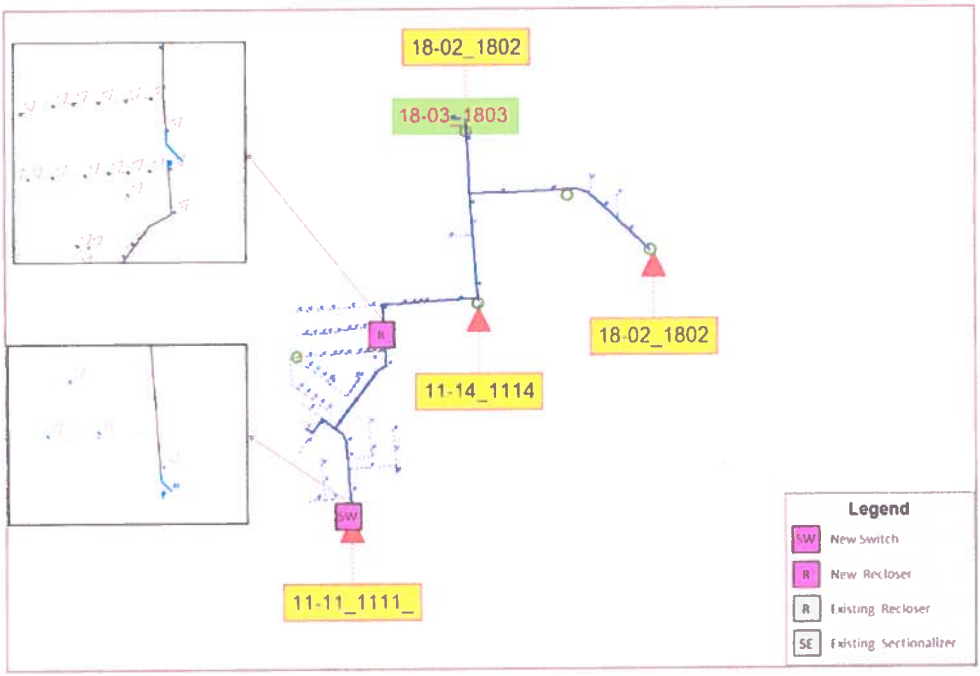

Fault Current Indicator (FCI)

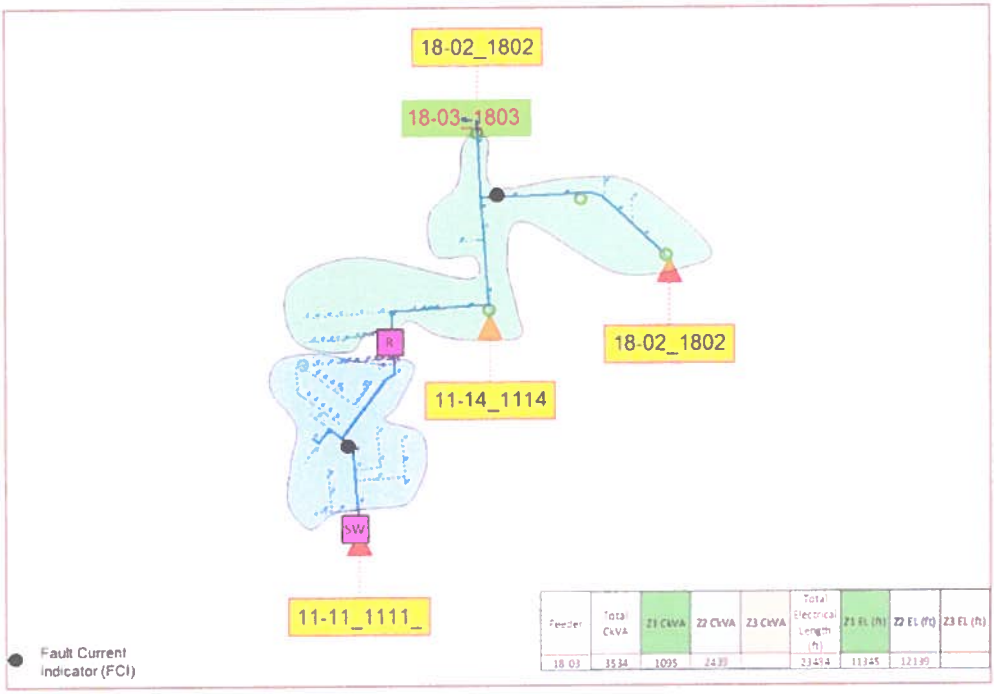
18-02:


18-01_1801
18-01_1801
18-01_1801
18-01_1801
18-02_1802
18-04_1804
18-03_1803
R
SW
18-04_1804
Legend
SW New Switch
R New Recloser
R Existing Recloser
SE Existing Sectionalizer

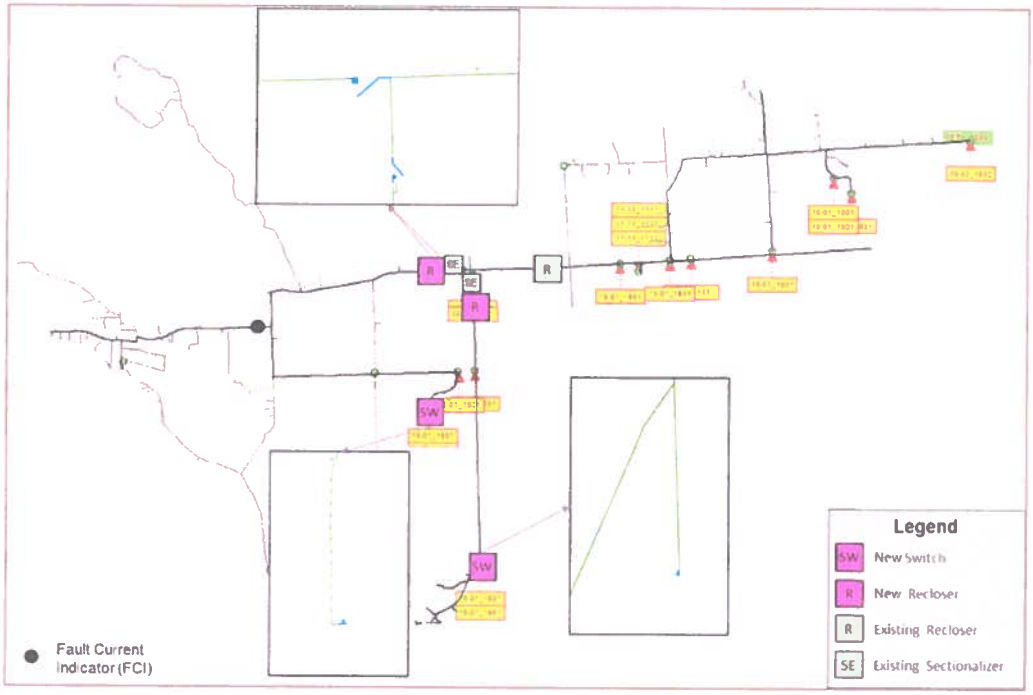

18-01_1801
18-01_1801
18-01_1801
18-02
18-04_1804
18-03_1803
R
SW
Fault Current Indicator (FCI)

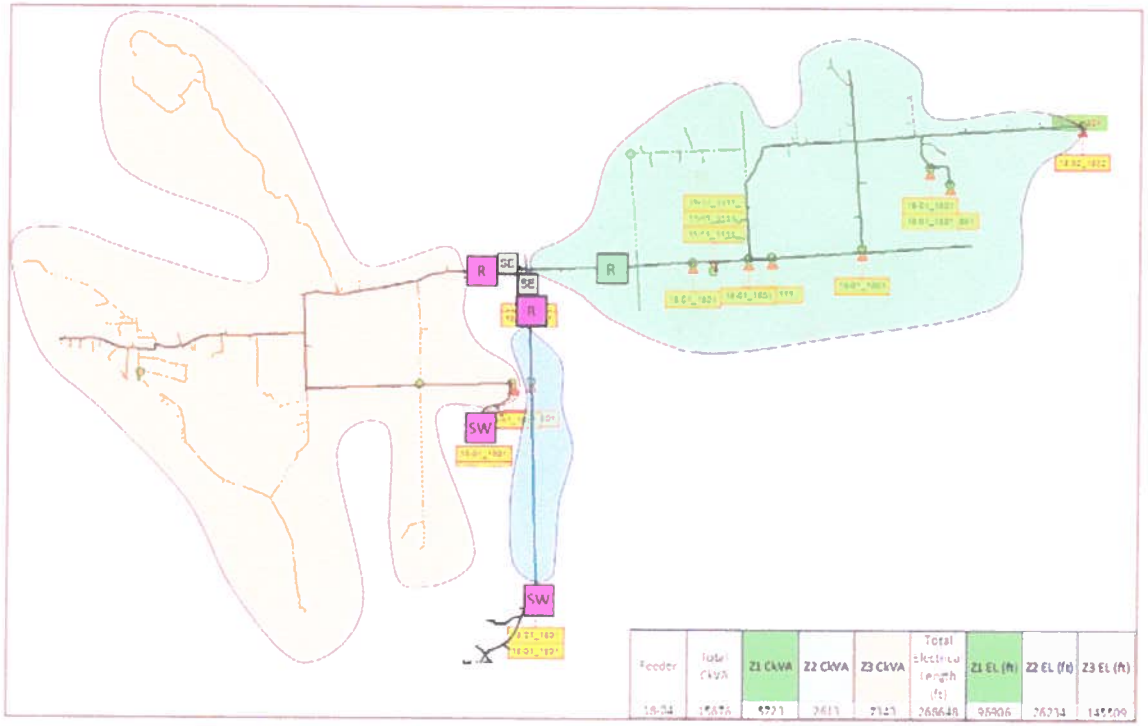
18-03:


18-02_1802
18-03_1803
18-02_1802
11-14_1114
11-11_1111_
Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer

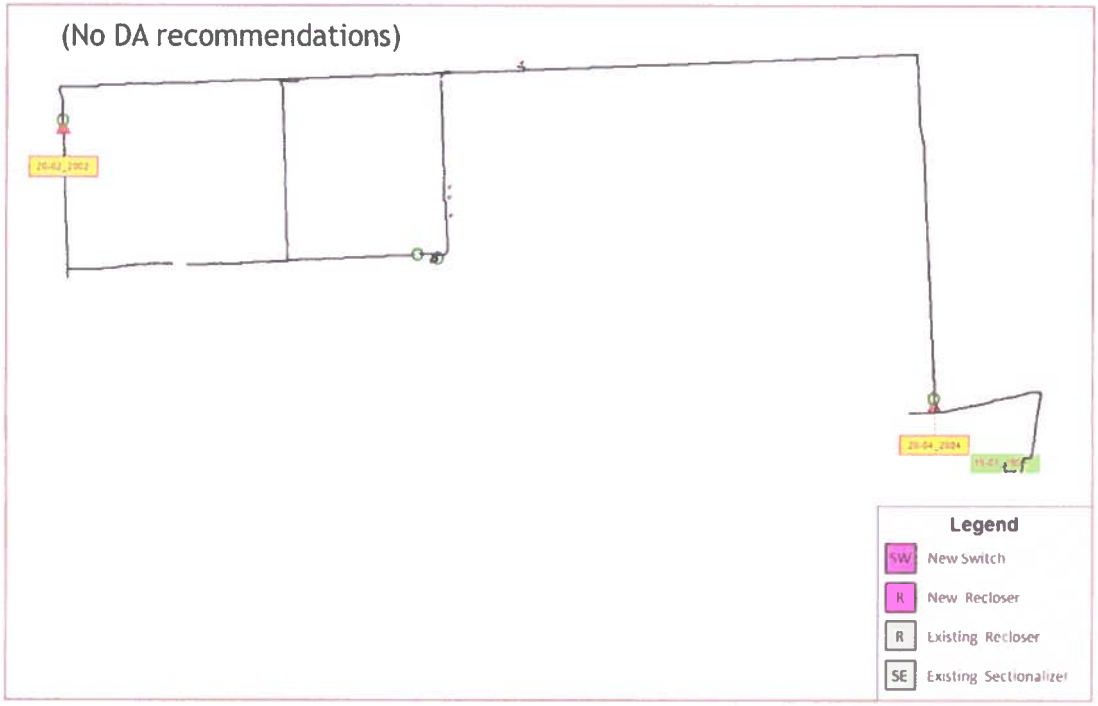

18-02_1802
18-03_1803
18-02_1802
11-14_1114
11-11_1111_
Fault Current Indicator (FCI)
Feeder
Total CkVA
Z1 CkVA
Z2 CkVA
Z3 CkVA
Total Electrical Length (ft)
Z1 EL (ft)
Z2 EL (ft)
Z3 EL (ft)
18-03
3534
1095
2439
23494
11345
12149

18-04:

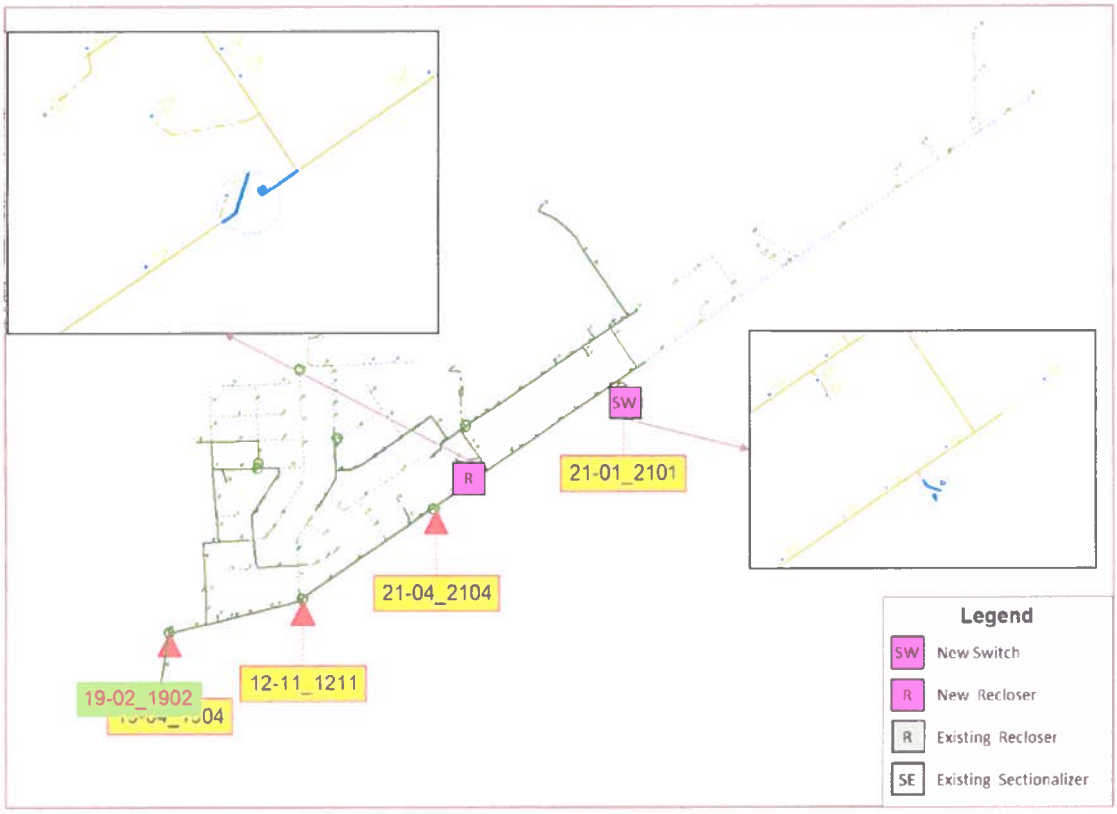

Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer
Fault Current Indicator (FCI)

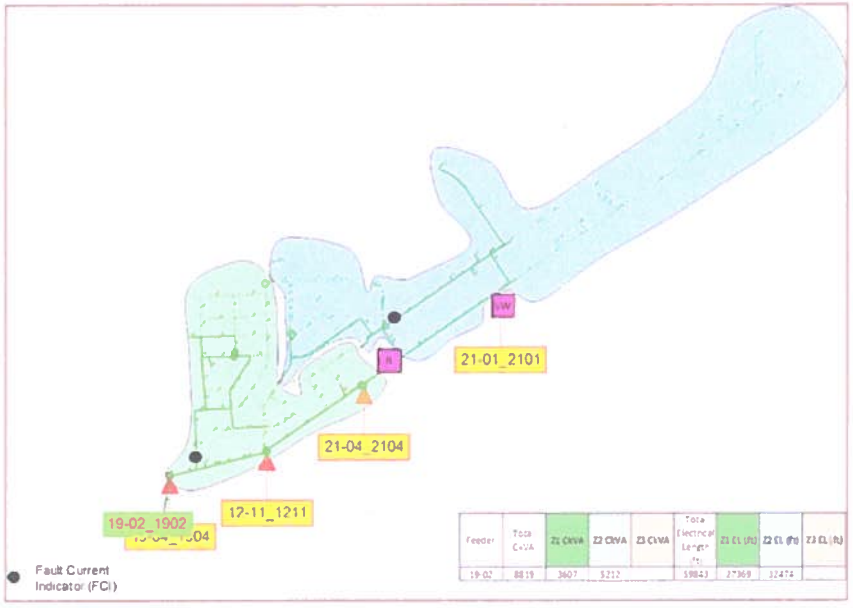

Feeder
Total CkVA
Z1 CkVA
Z2 CkVA
Z3 CkVA
Total Electrical Length (ft)
Z1 EL (ft)
Z2 EL (ft)
Z3 EL (ft)

19-01:

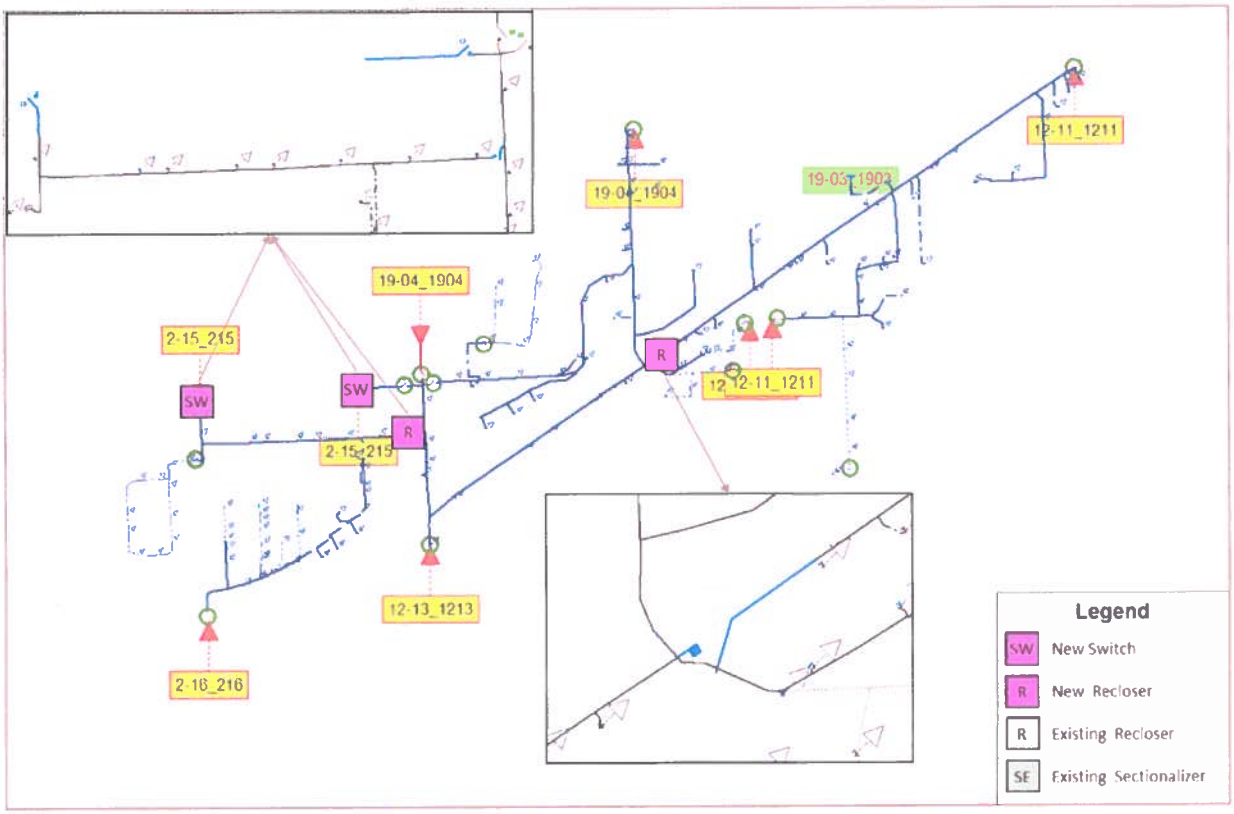

(No DA recommendations)
Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer

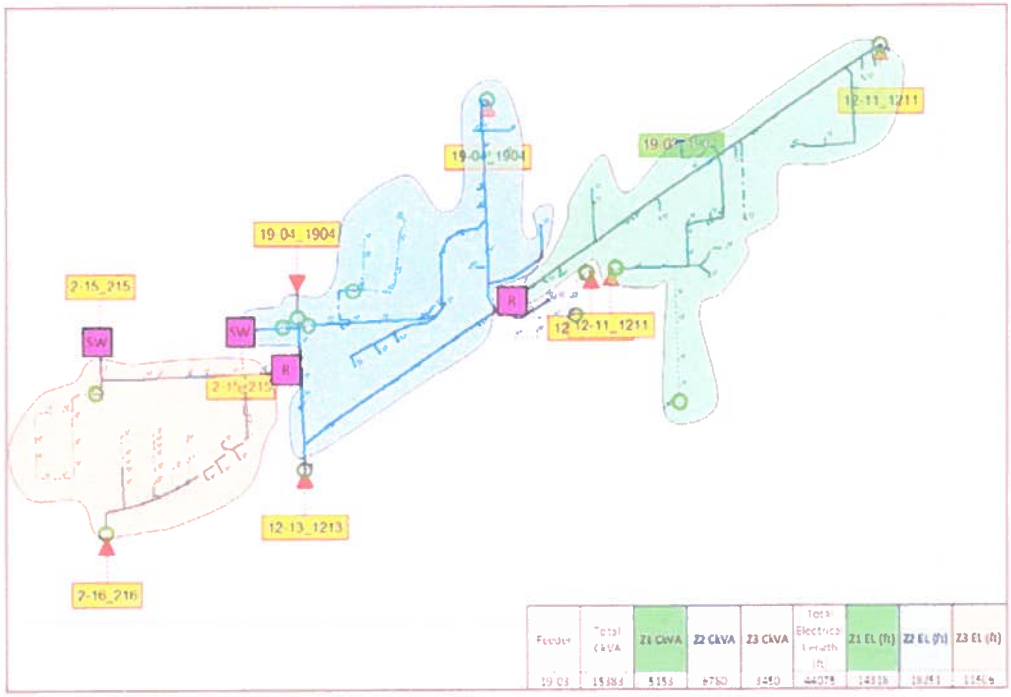
19-02:


SW
R
21-01_2101
21-04_2104
12-11_1211
19-02_1902
Legend
SW New Switch
R New Recloser
R Existing Recloser
SE Existing Sectionalizer

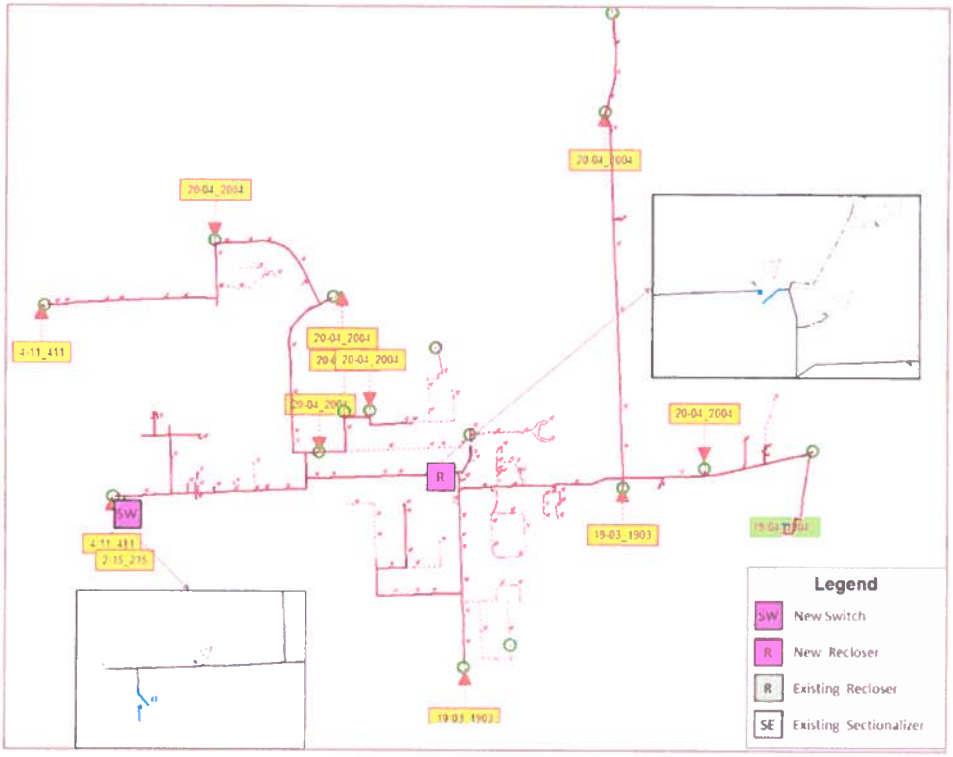

SW
R
21-01_2101
21-04_2104
12-11_1211
19-02_1902
Fault Current Indicator (FCI)

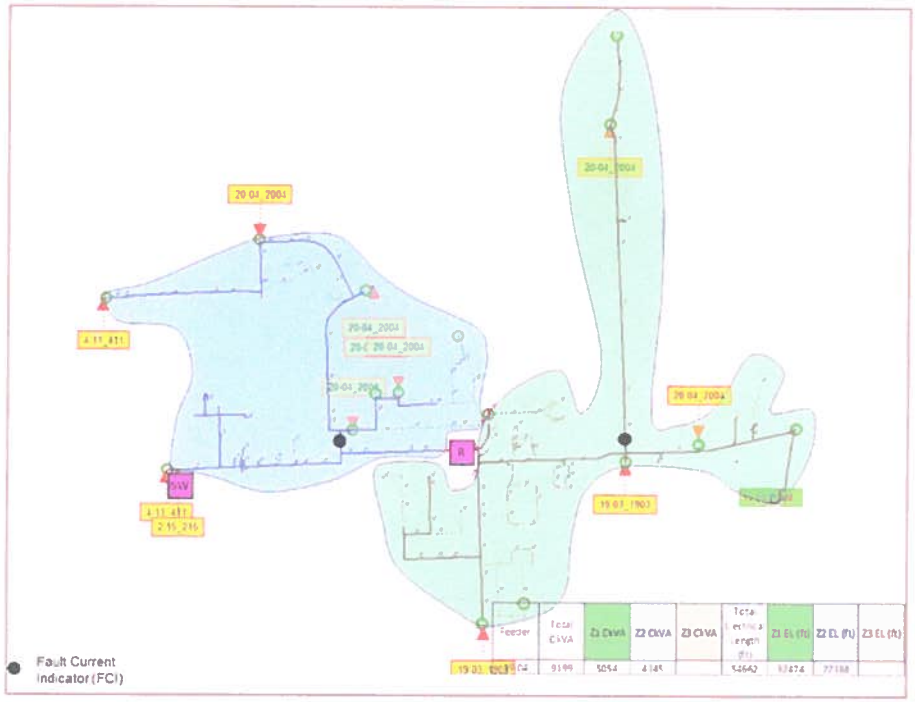
19-03:


19-04_1904
19-03_1903
12-11_1211
2-15_215
SW
SW
R
2-15_215
19-04_1904
R
12-11_1211
12-13_1213
2-16_216
Legend
SW New Switch
R New Recloser
R Existing Recloser
SE Existing Sectionalizer

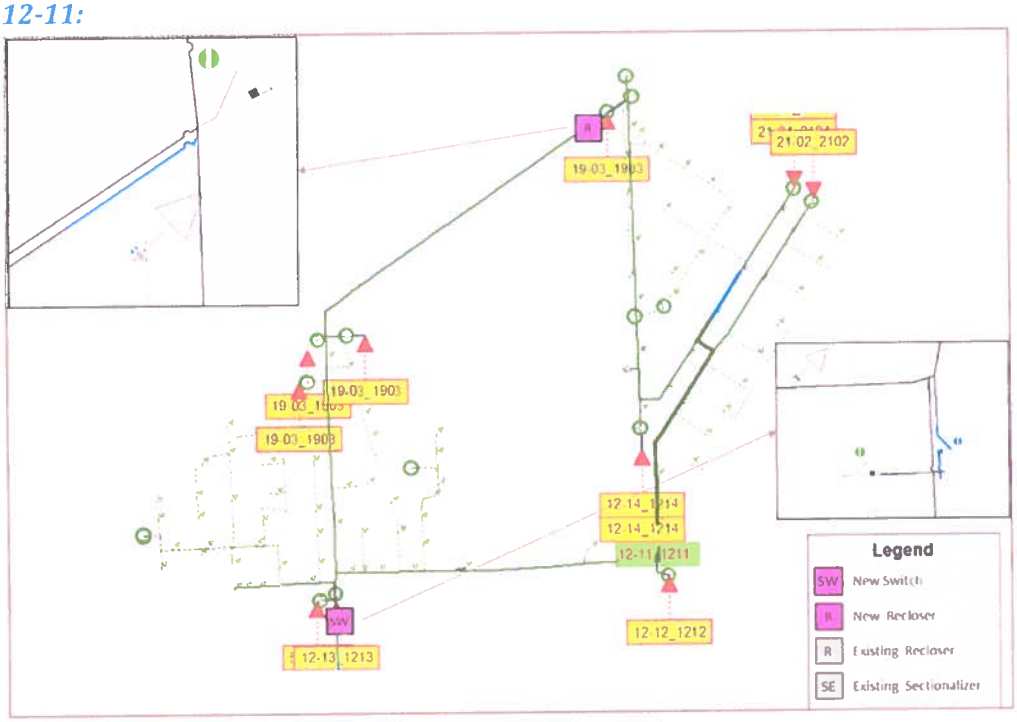

12-11_1211
19-04_1904
19-03_1903
19 04_1904
2-15_215
SW
SW
R
12-11_1211
12-13_1213
2-16_216
Feeder
Total CkVA
Z1 CkVA
Z2 CkVA
Z3 CkVA
Total Electrical Length (ft)
Z1 EL (ft)
Z2 EL (ft)
Z3 EL (ft)

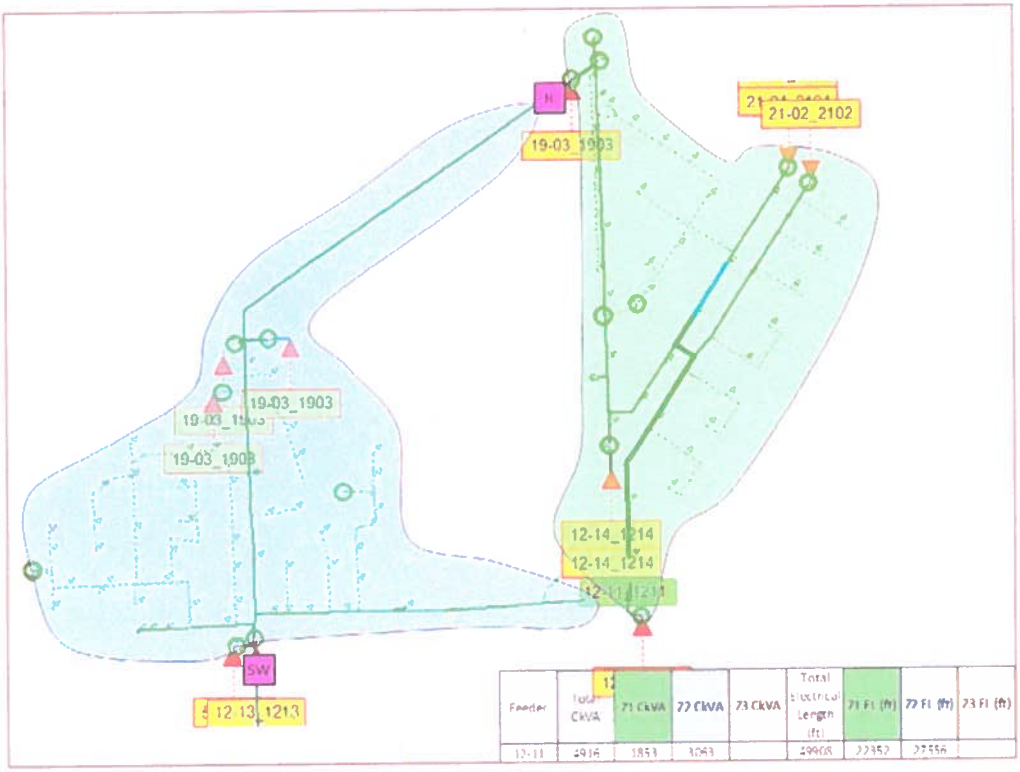
19-04:


Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer

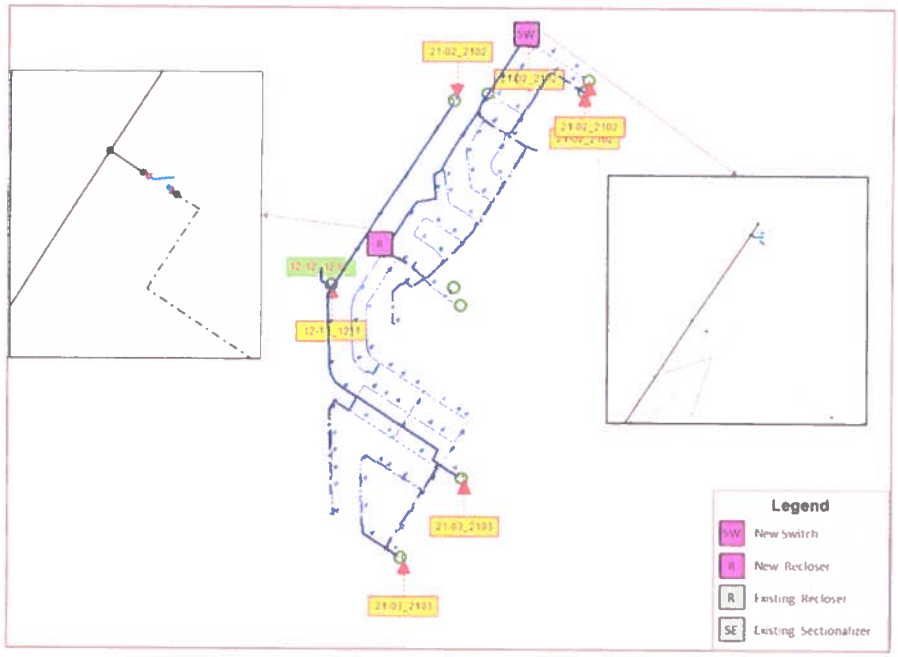

Fault Current Indicator (FCI)

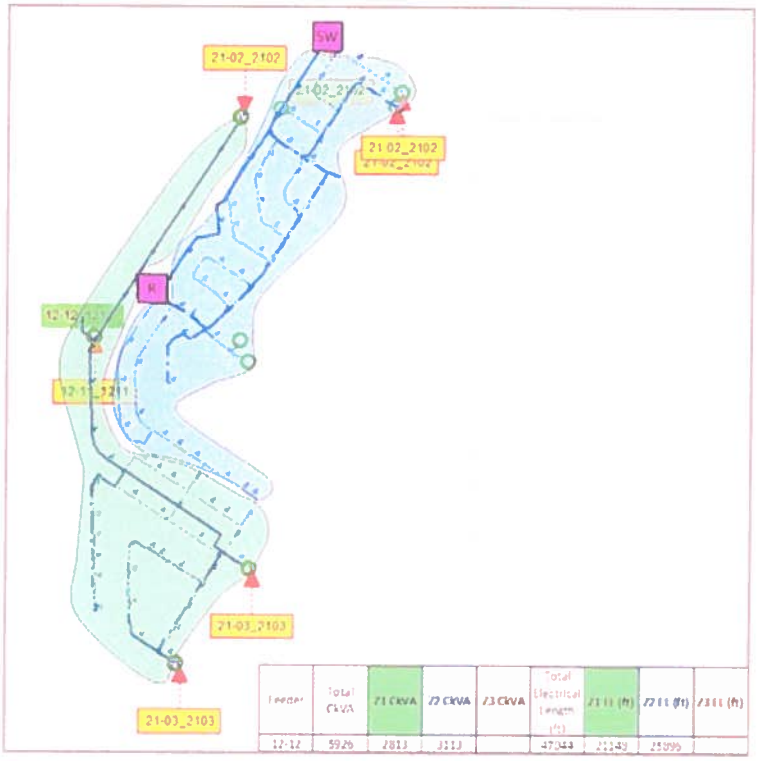
12-11:


R
19-03_1903
21-02_2102
19-03_1903
19-03_1903
19-03_1903
12-14_1214
12-14_1214
12-11_1211
12-12_1212
SW
12-13_1213
Legend
SW New Switch
R New Recloser
R Existing Recloser
SE Existing Sectionalizer

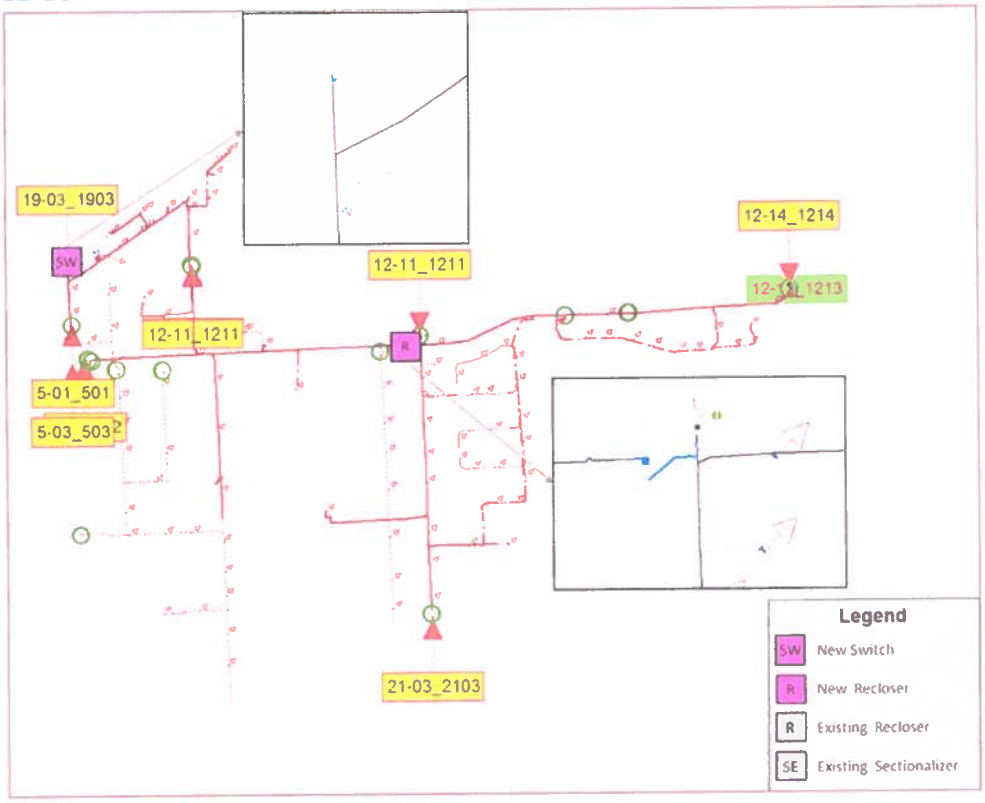

R
19-03_1903
21-02_2102
19-03_1903
19-03_1903
12-14_1214
12-14_1214
SW
12-13_1213
Feeder
71 CkVA
72 CkVA
73 CkVA
71 Fl (ft)
72 Fl (ft)
73 Fl (ft)
12-11
3853
3063
27556

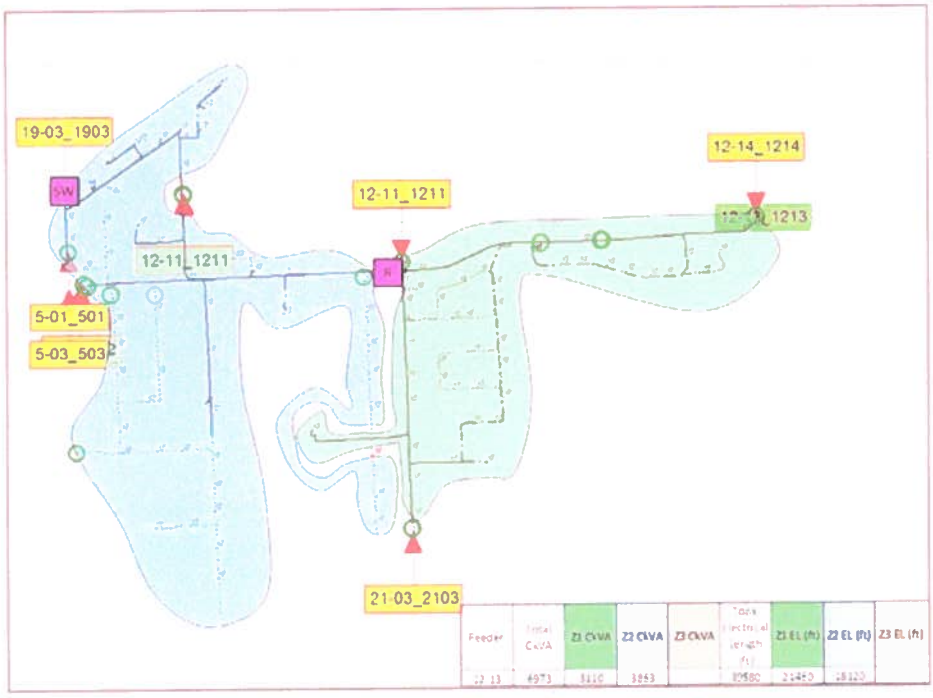
12-12:


SW
21-02_2102
21-03_2103
R
Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer

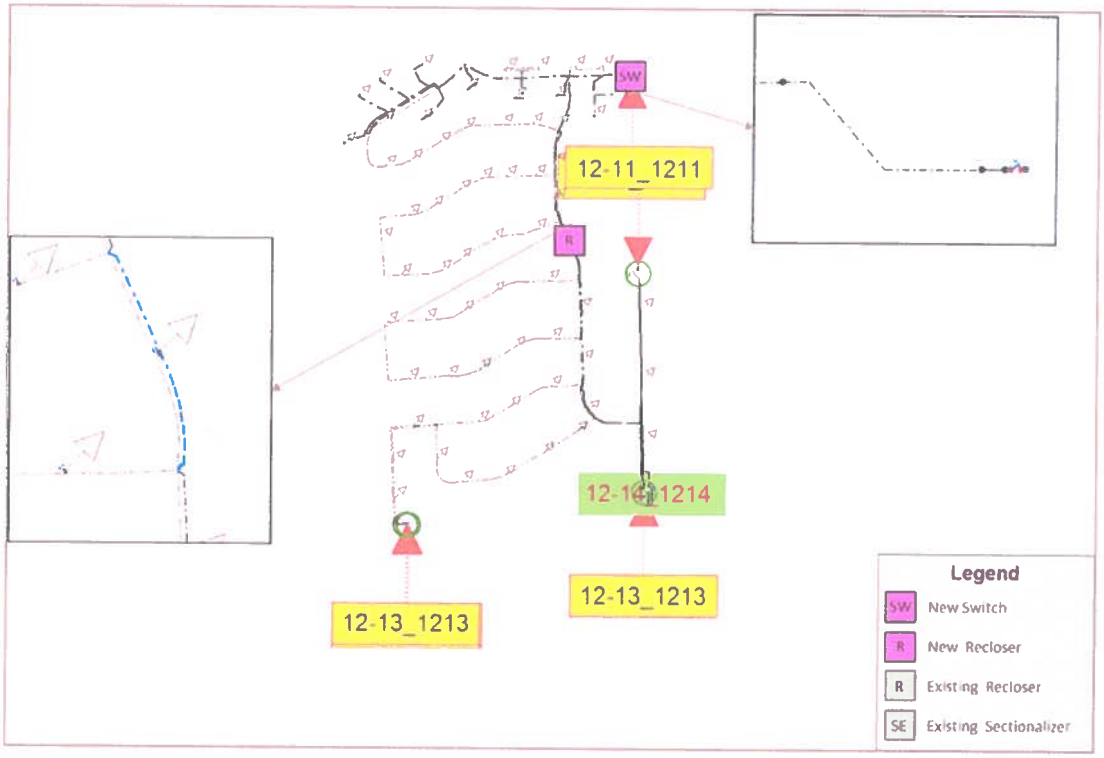

SW
21-02_2102
21-02_2102
R
21-03_2103
21-03_2103
Feeder
Total CkVA
Z1 CkVA
Z2 CkVA
Z3 CkVA
Total Electrical Length (ft)
Z1 (ft)
Z2 (ft)
Z3 (ft)
12-12
5926
2813
3113
47043
25949
25996

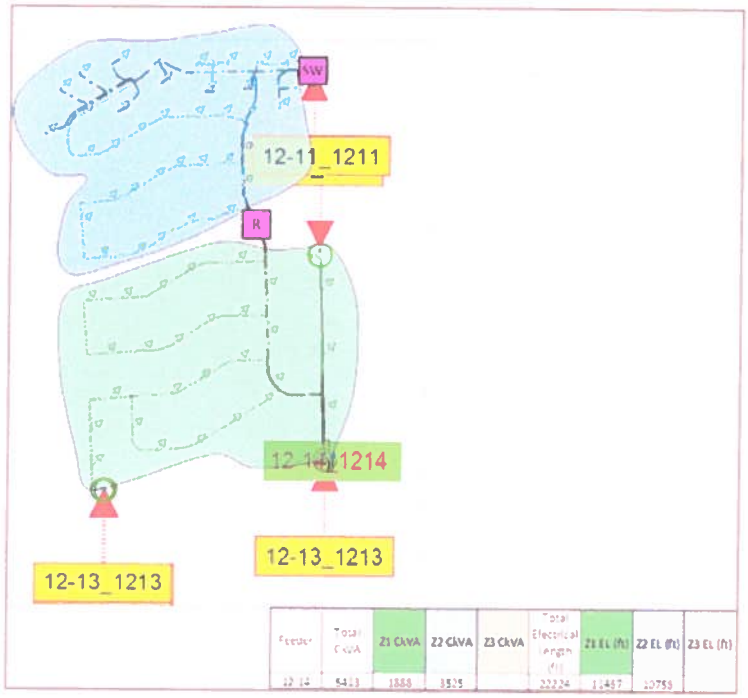
12-13:


19-03_1903
SW
12-11_1211
12-14_1214
12-13_1213
12-11_1211
R
5-01_501
5-03_503
21-03_2103
Legend
SW New Switch
R New Recloser
R Existing Recloser
SE Existing Sectionalizer

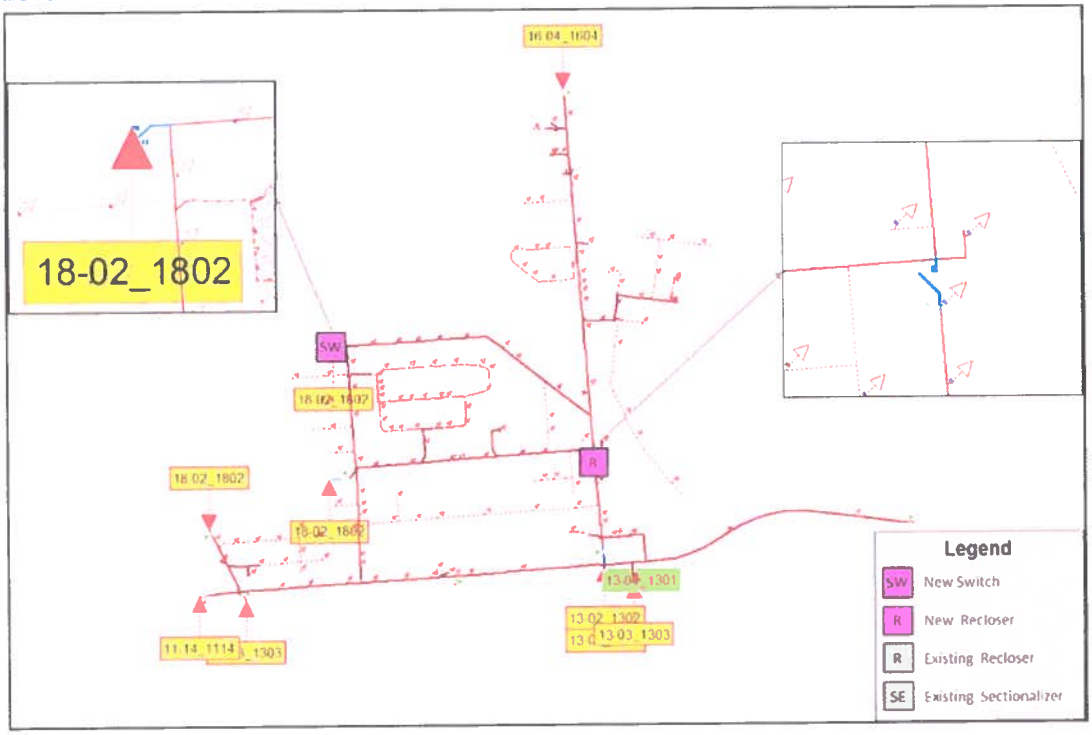

19-03_1903
SW
12-11_1211
12-14_1214
12-13_1213
12-11_1211
R
5-01_501
5-03_503
21-03_2103

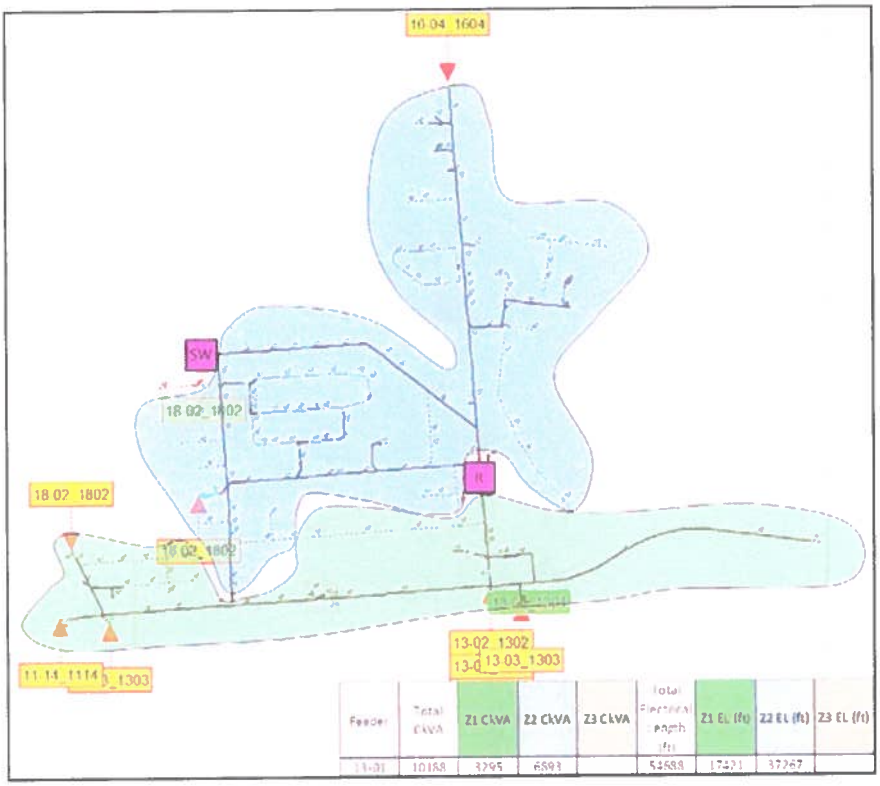
12-14:


SW
12-11_1211
R
12-14_1214
12-13_1213
12-13_1213
Legend
SW New Switch
R New Recloser
R Existing Recloser
SE Existing Sectionalizer

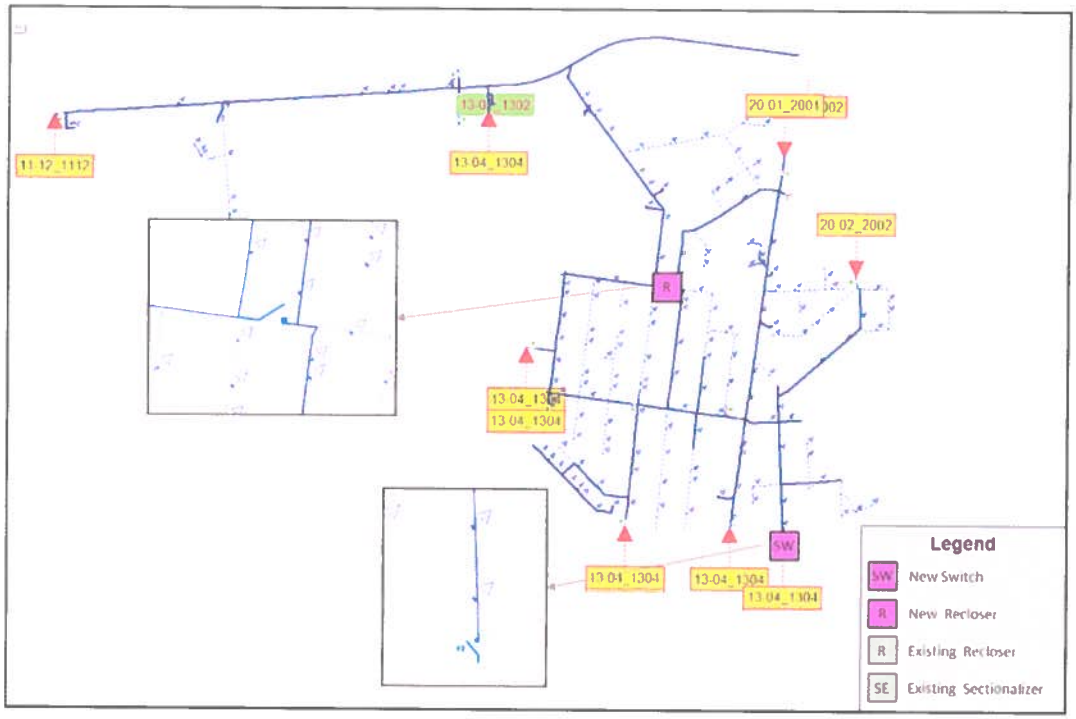

SW
12-11_1211
R
12-14_1214
12-13_1213
12-13_1213
Feeder
Total CkVA
Z1 CkVA
Z2 CkVA
Z3 CkVA
Total Electrical Length (ft)
Z1 EL (ft)
Z2 EL (ft)
Z3 EL (ft)
12-14
5413
1888
3525
22224
11467
10759

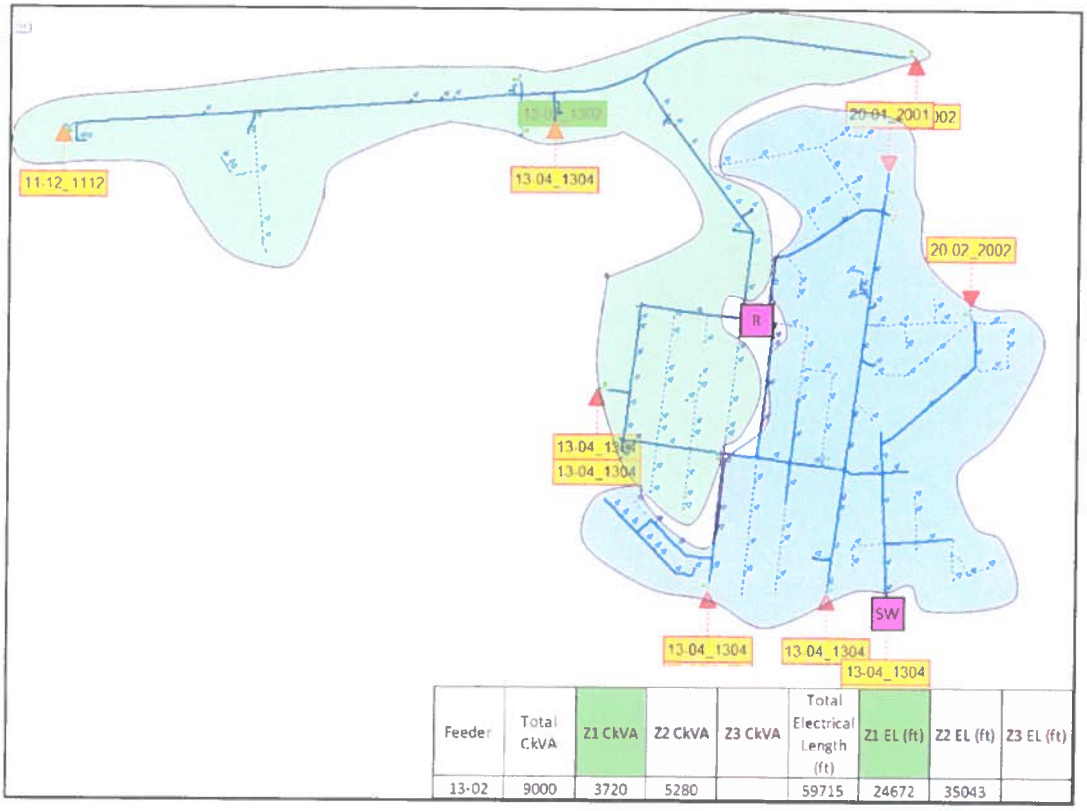
13-01:


16-04_1604
18-02_1802
SW
18-02_1802
R
18-02_1802
18-02_1802
13-03_1301
13-02_1302
13-03_1303
11-14_1114
_1303
Legend
SW New Switch
R New Recloser
R Existing Recloser
SE Existing Sectionalizer


16-04_1604
SW
18-02_1802
R
18-02_1802
18-02_1802
13-02_1302
13-03_1303
11-14_1114
_1303
Feeder
Total CkVA
Z1 CkVA
Z2 CkVA
Z3 CkVA
Total Electrical path (ft)
Z1 EL (ft)
Z2 EL (ft)
Z3 EL (ft)
13-01
10158
3295
6593
54589
17421
37267

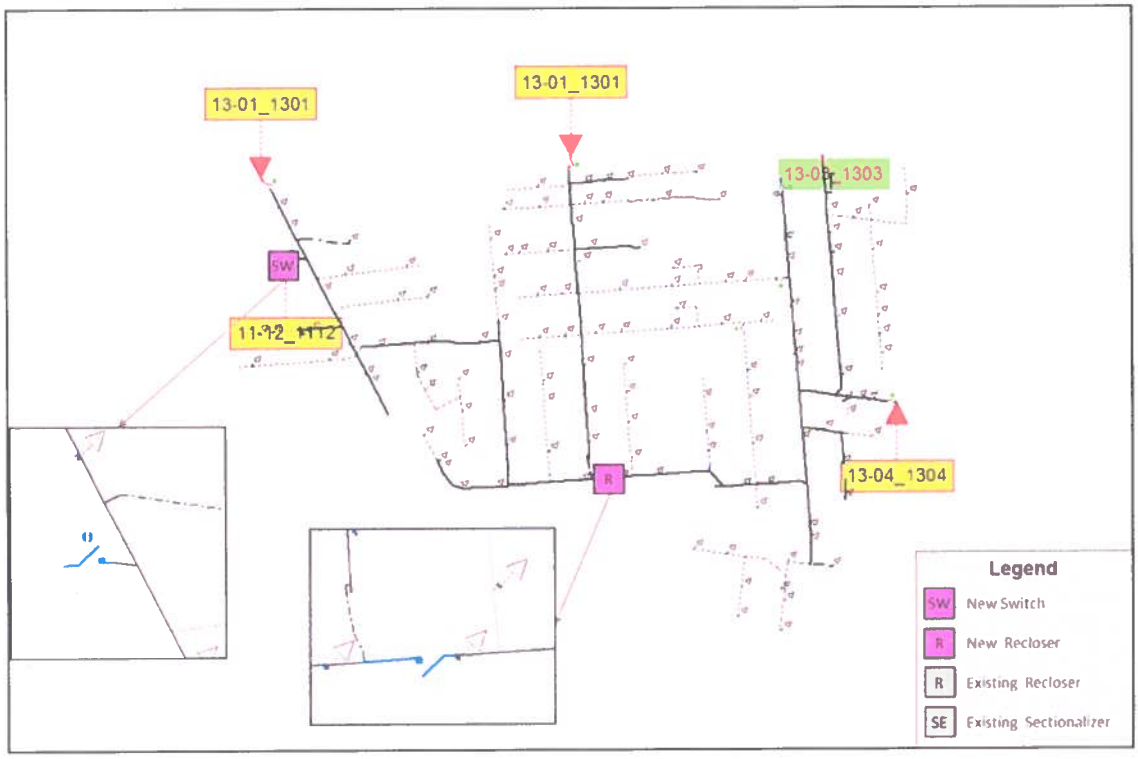
13-02:

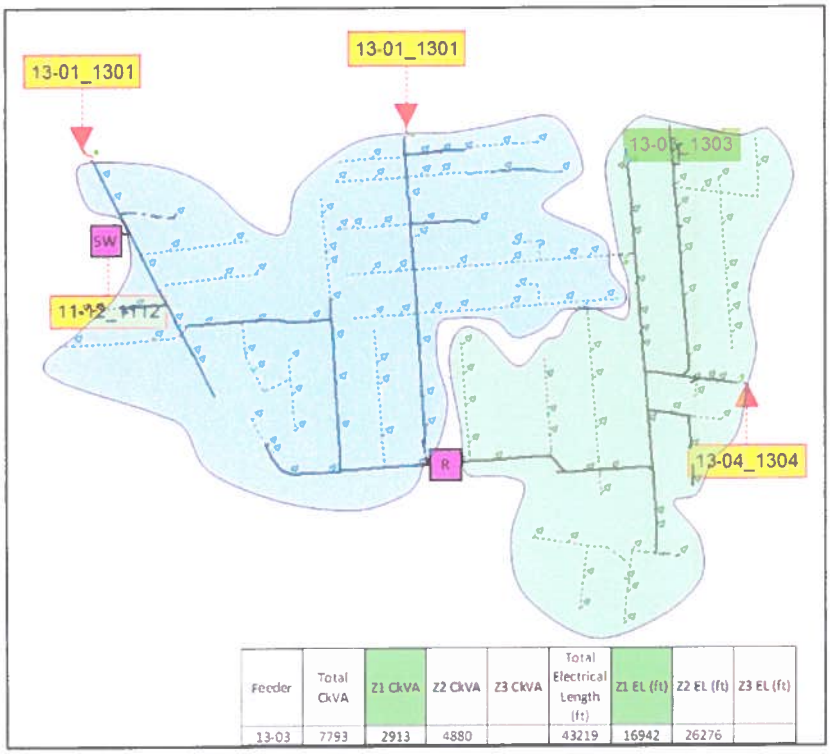




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
13-02	9000	3720	5280		59715	24672	35043	

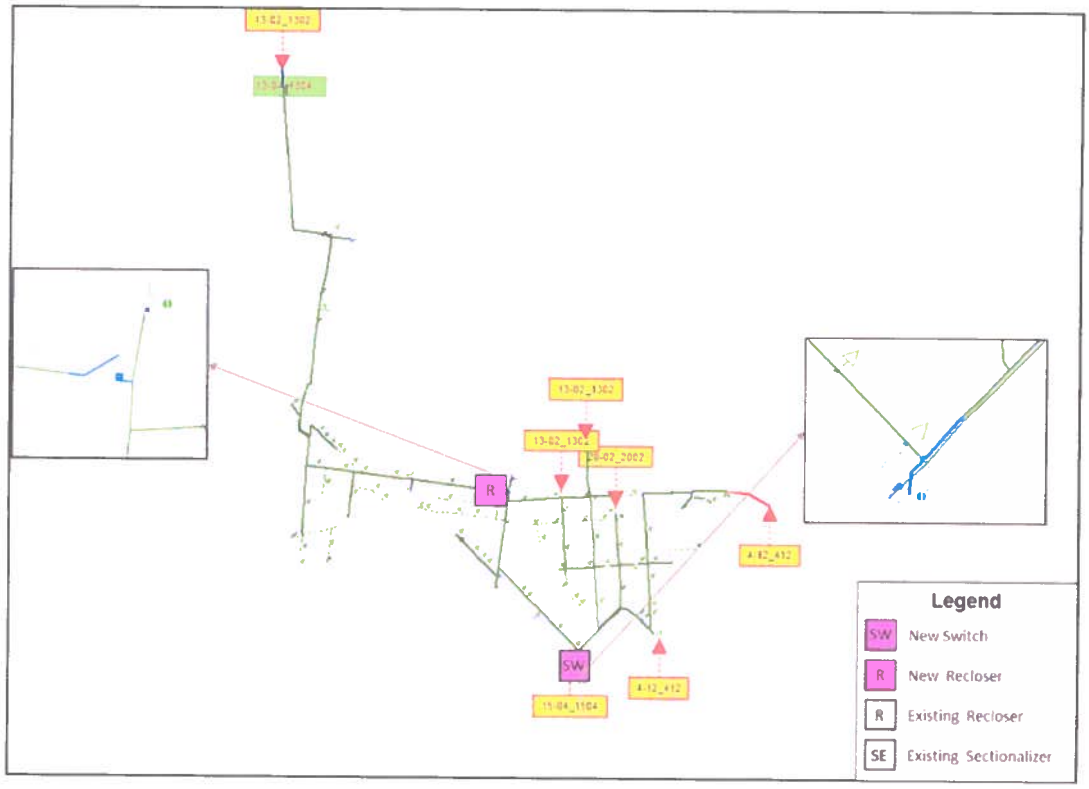
13-03:

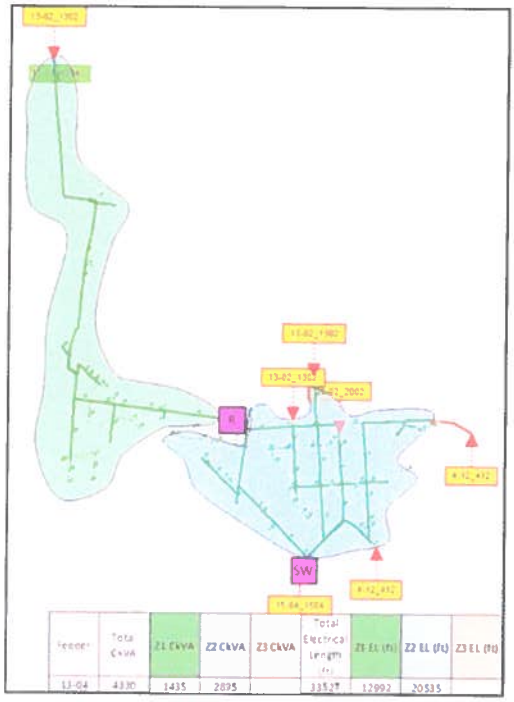




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
13-03	7793	2913	4880		43219	16942	26276	

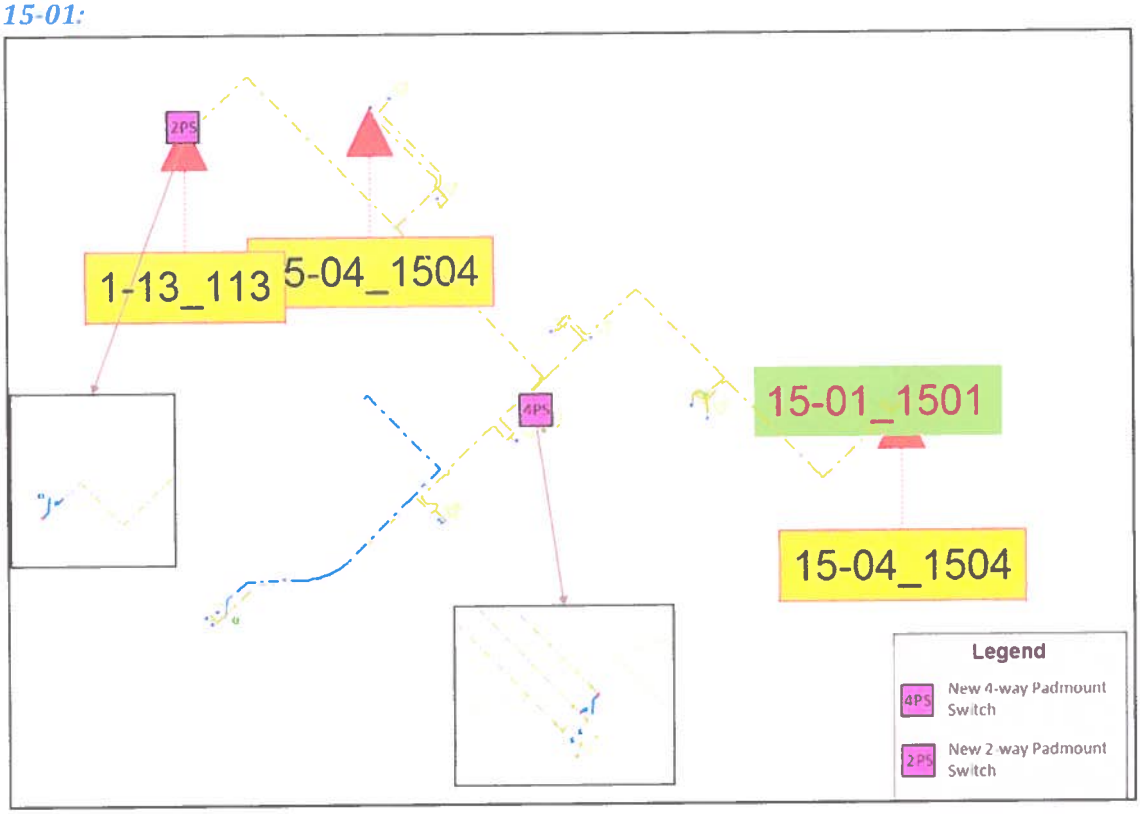
13-04:

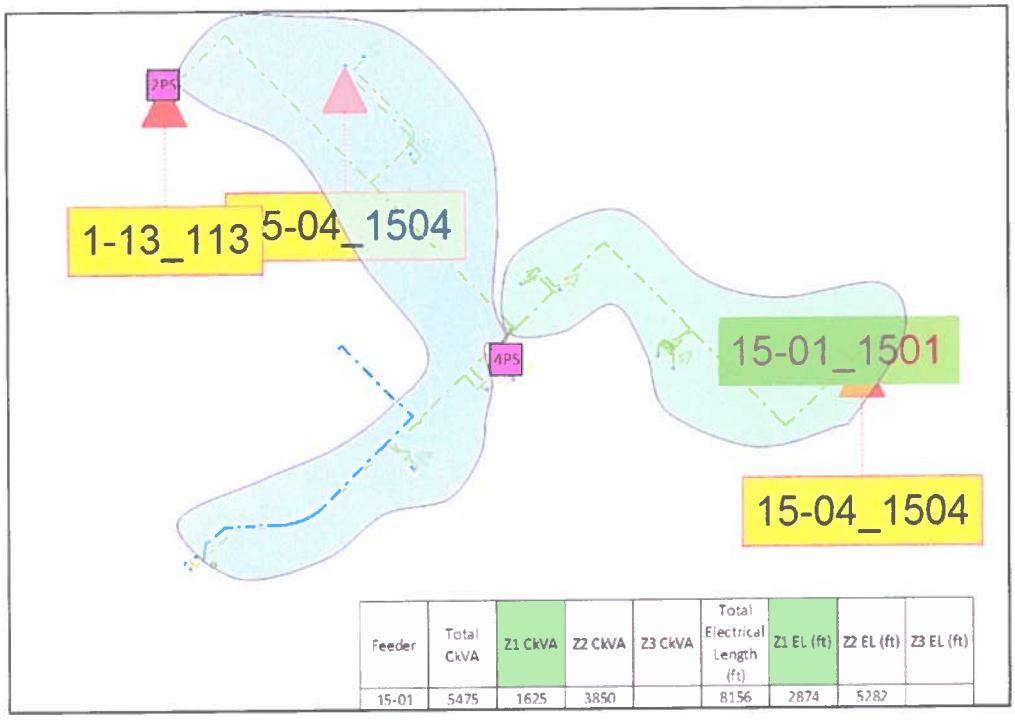




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
13-04	4330	1435	2895		33527	12992	20535	

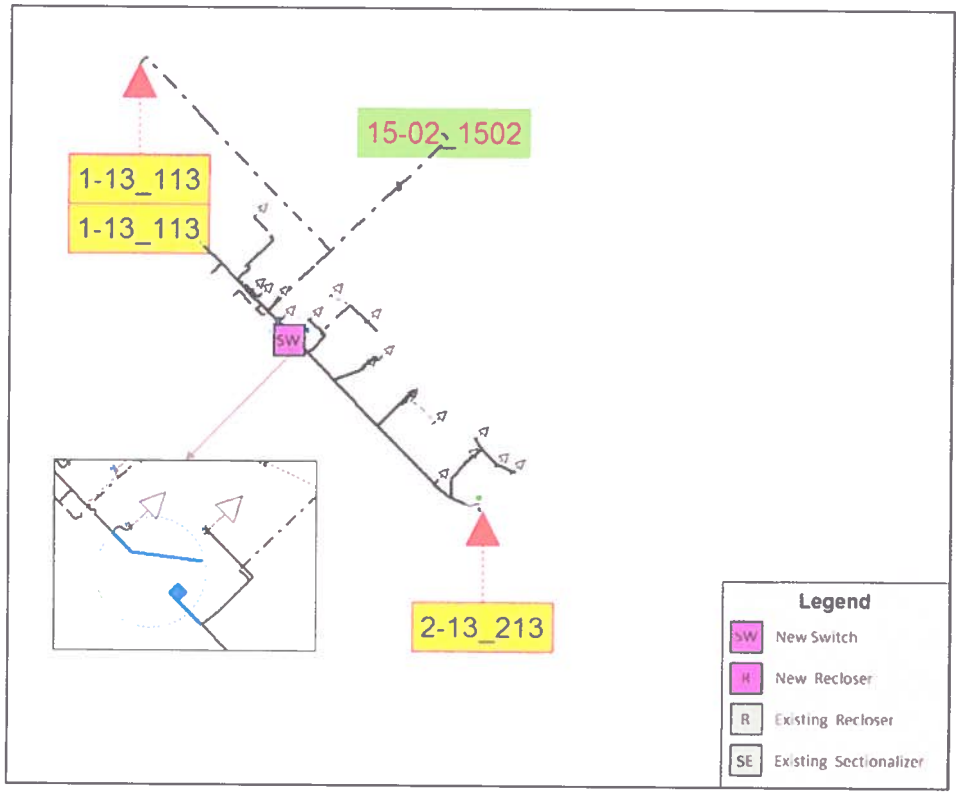
15-01:

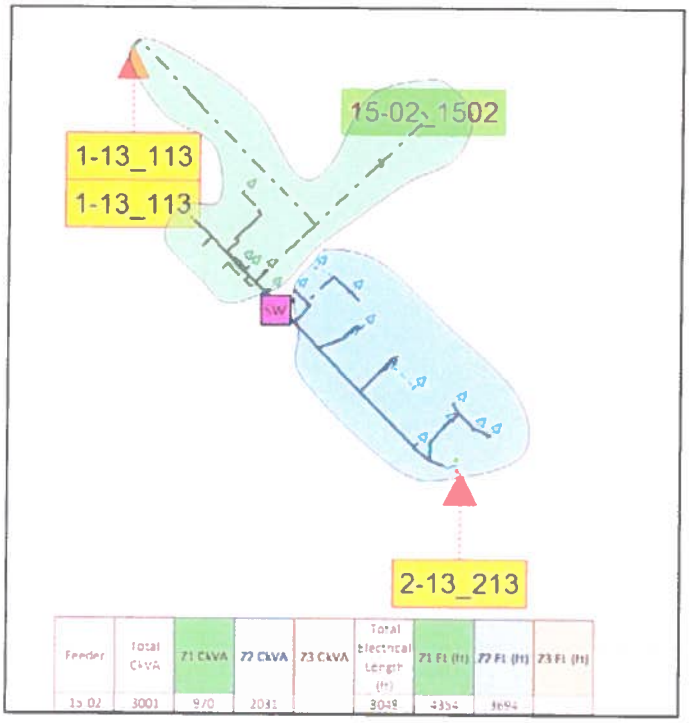




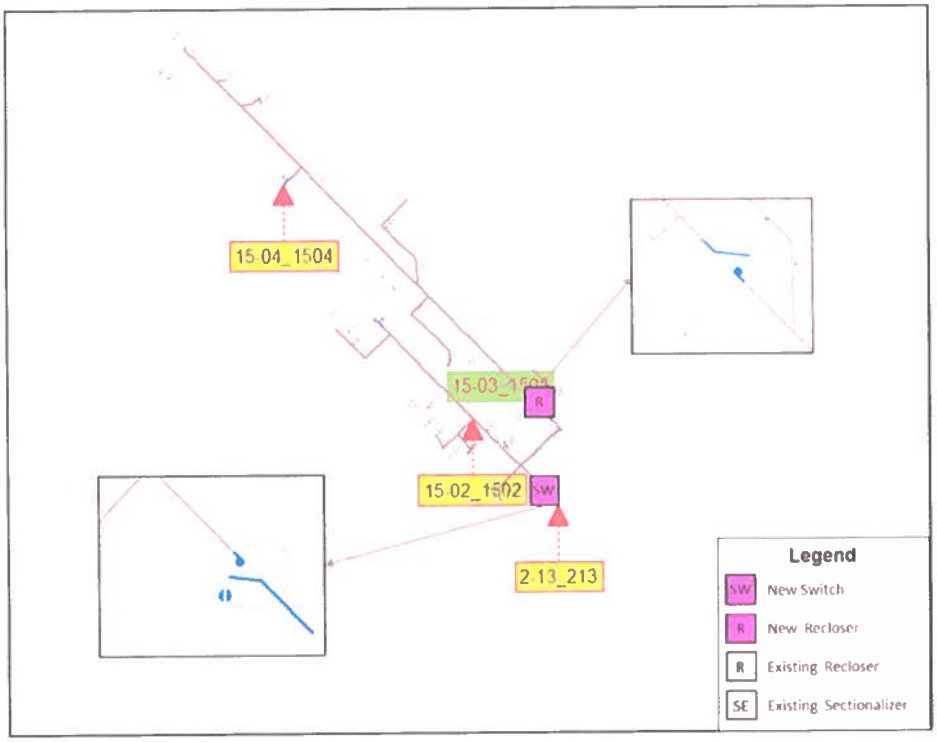
Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
15-01	5475	1625	3850		8156	2874	5282	

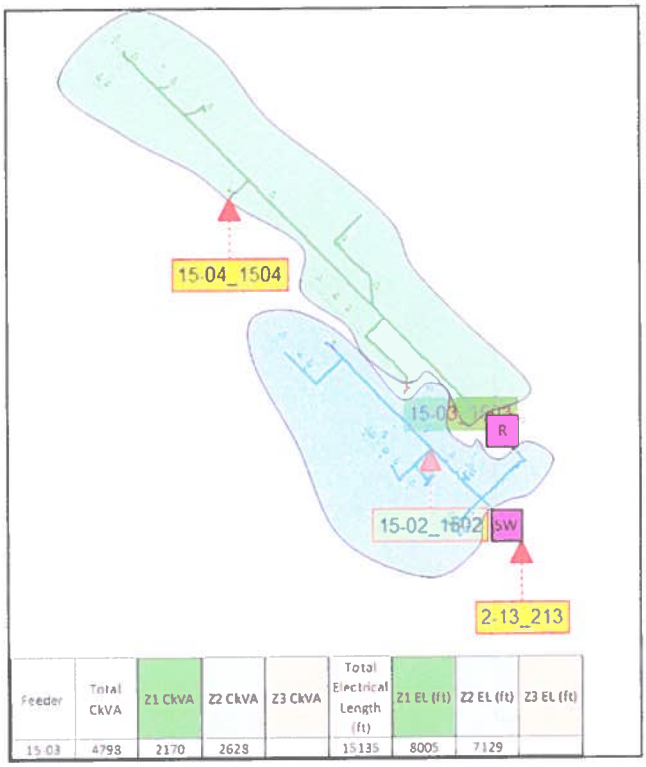
15-02:


15-02_1502
1-13_113
1-13_113
SW
2-13_213
Legend
SW New Switch
R New Recloser
R Existing Recloser
SE Existing Sectionalizer


15-02_1502
1-13_113
1-13_113
SW
2-13_213
Feeder
Total CkVA
71 CkVA
72 CkVA
73 CkVA
Total Electrical Length (ft)
71 Ft (ft)
72 Ft (ft)
73 Ft (ft)
15-02
3001
970
2031
3049
4354

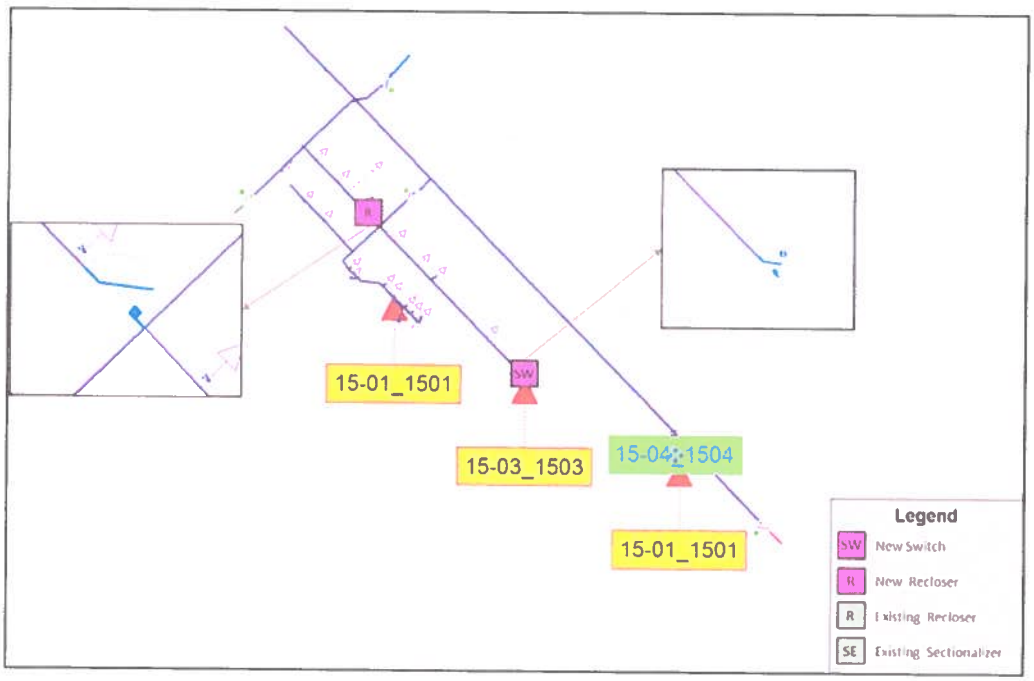
15-03:

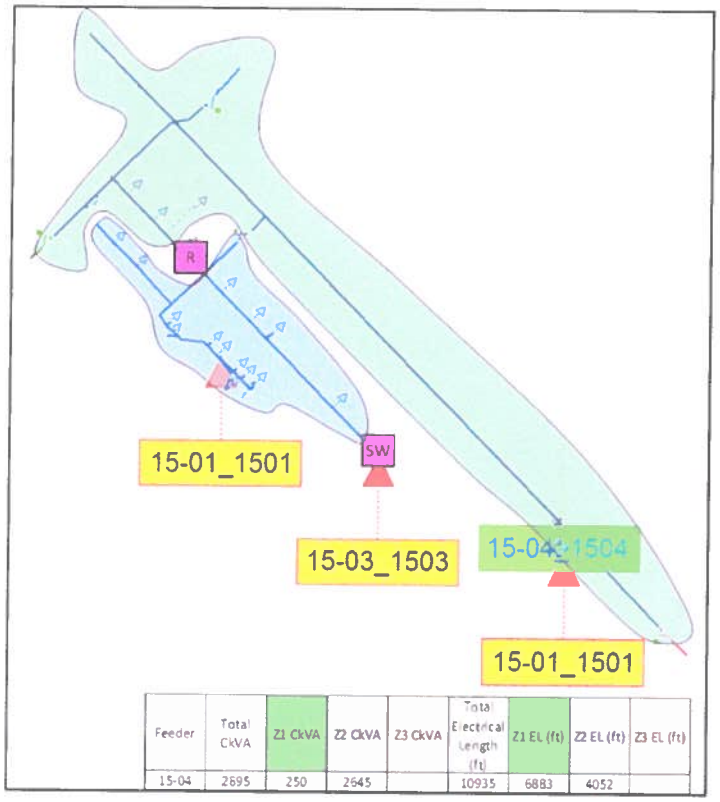




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
15-03	4793	2170	2628		15135	8005	7129	

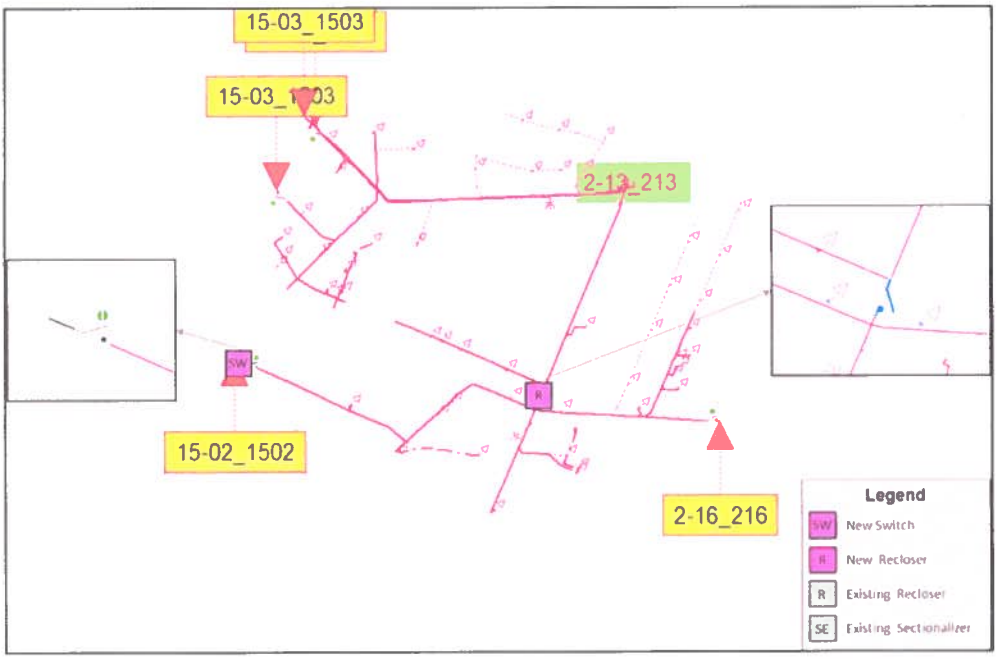
15-04:

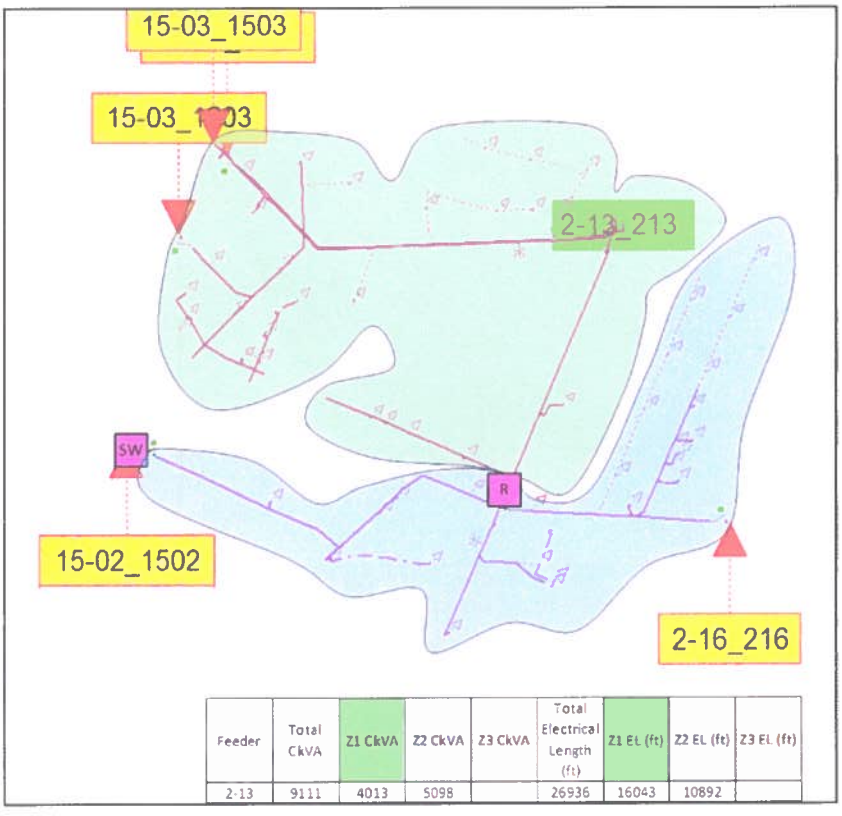




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
15-04	2695	250	2645		10935	6883	4052	

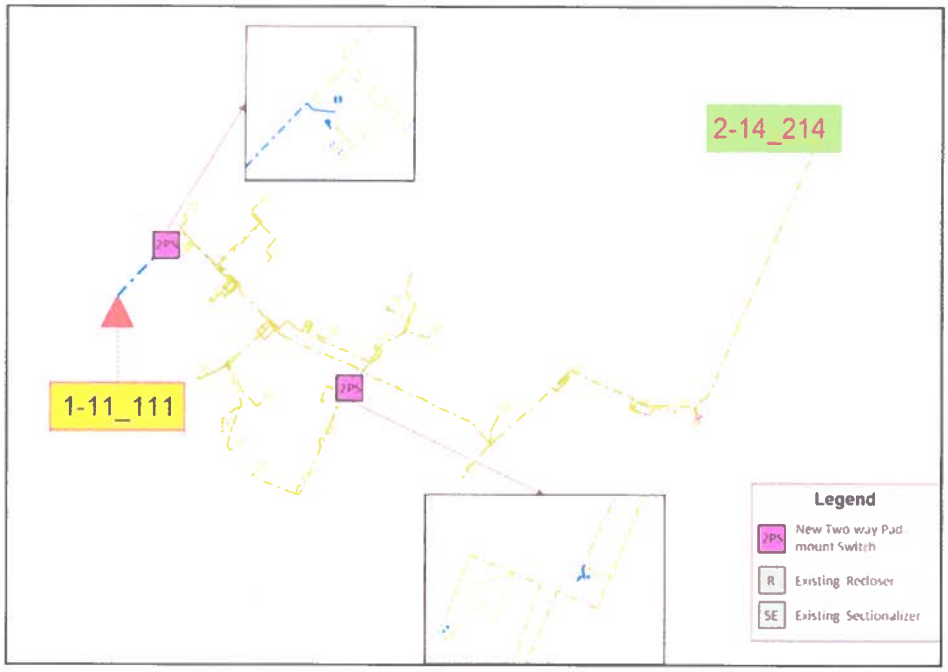
2-13:

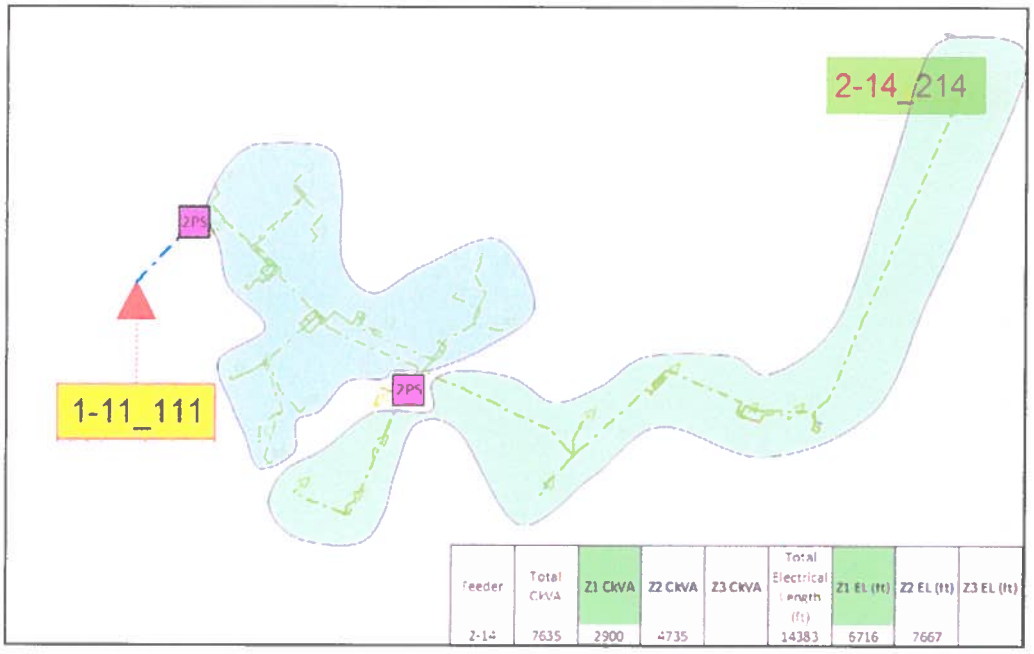




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
2-13	9111	4013	5098		26936	16043	10892	

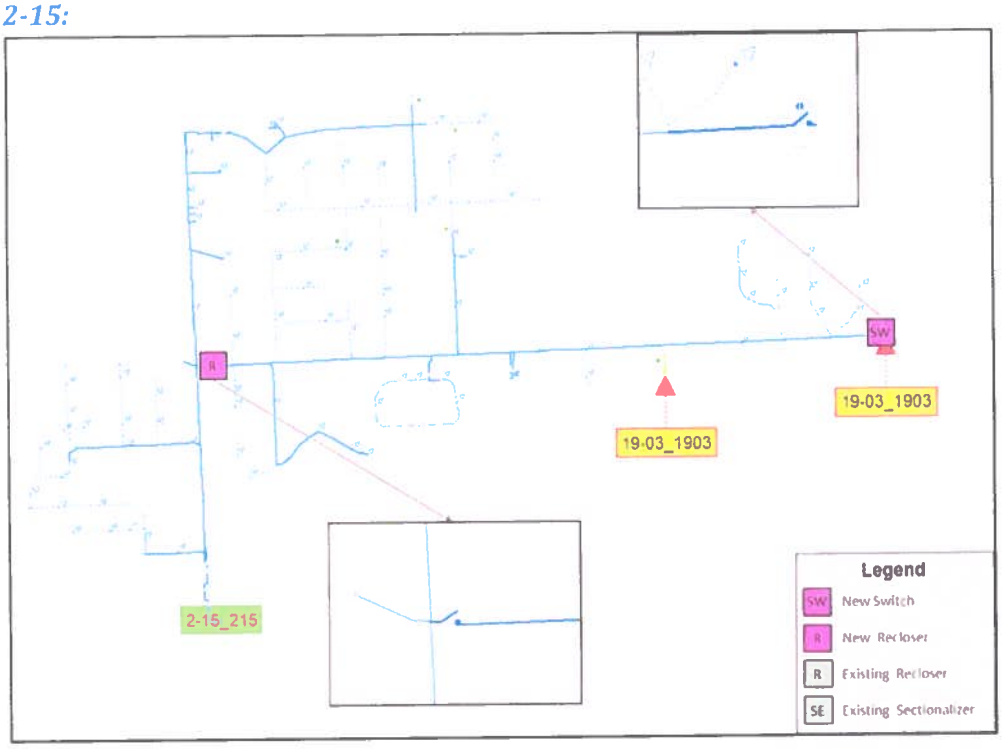
2-14:

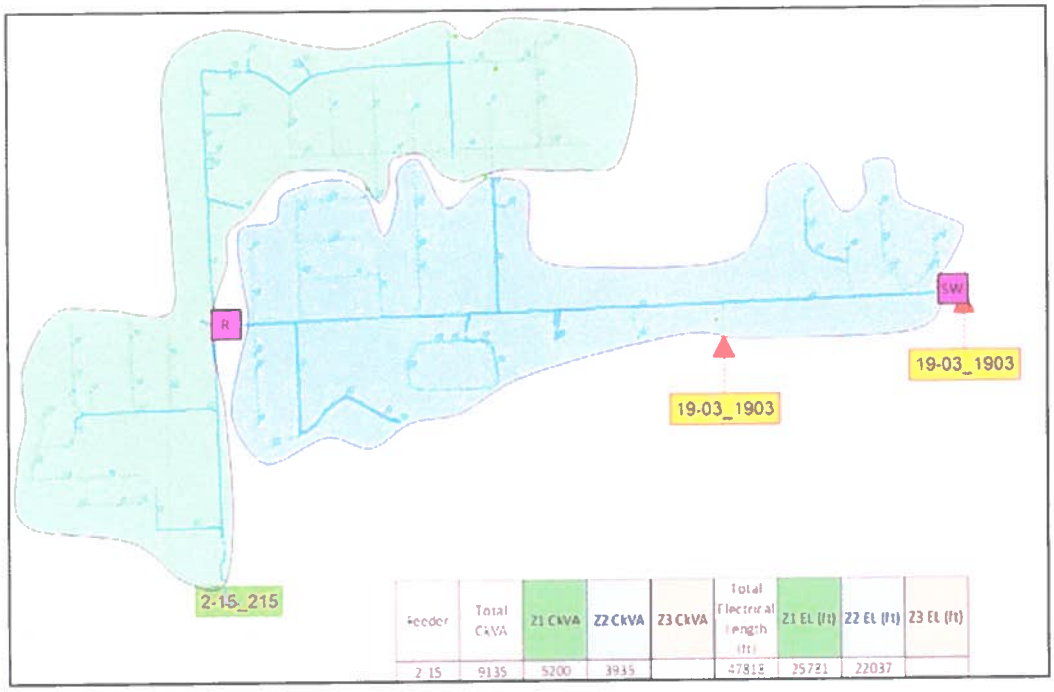




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
2-14	7635	2900	4735		14383	6716	7667	

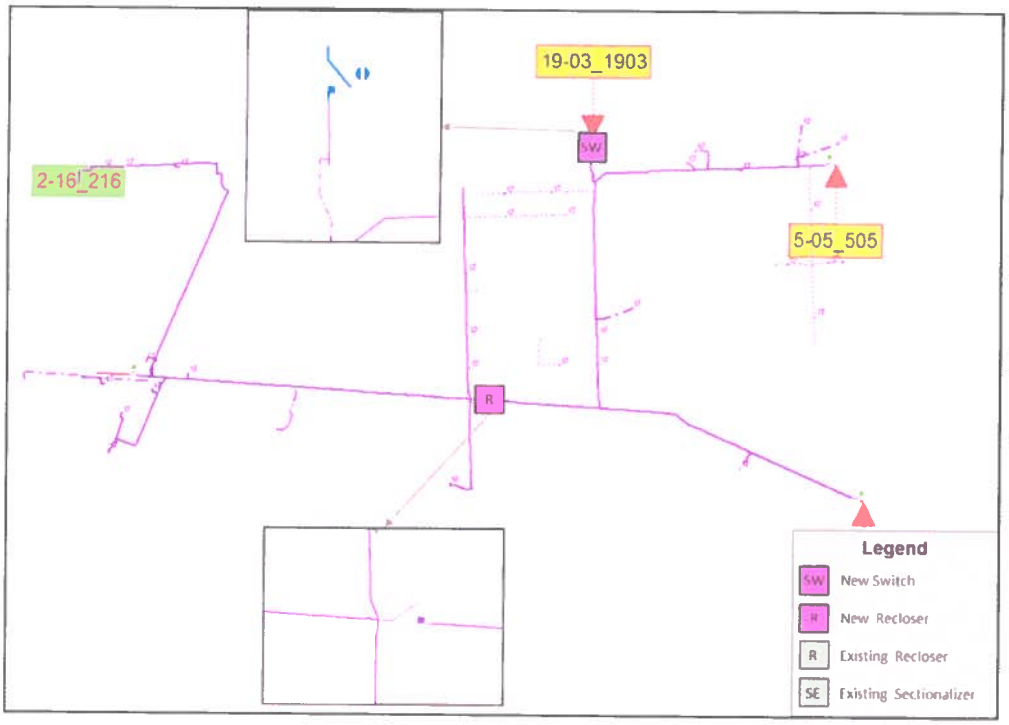
2-15:

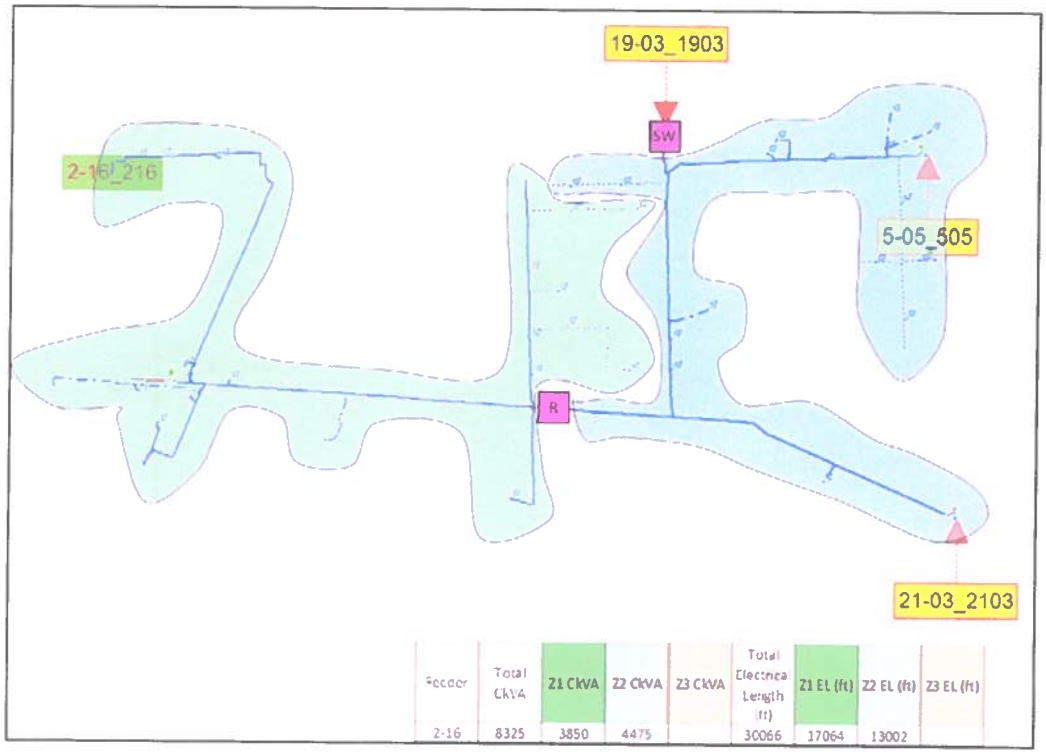




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
2_15	9135	5200	3935		47819	25721	22037	

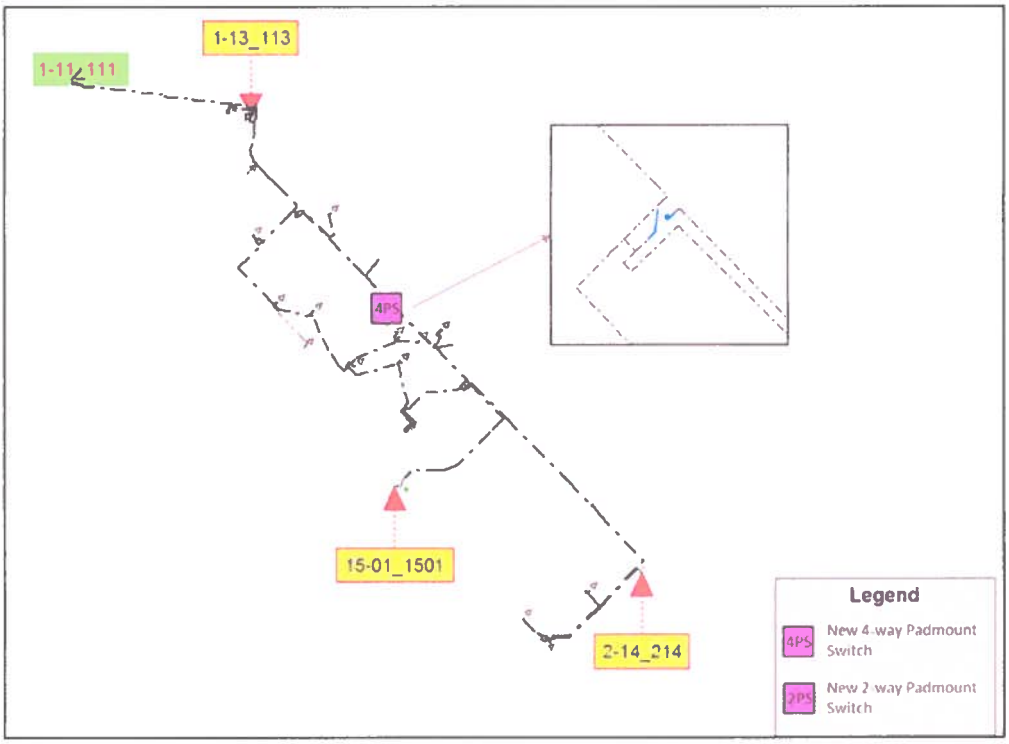
2-16:

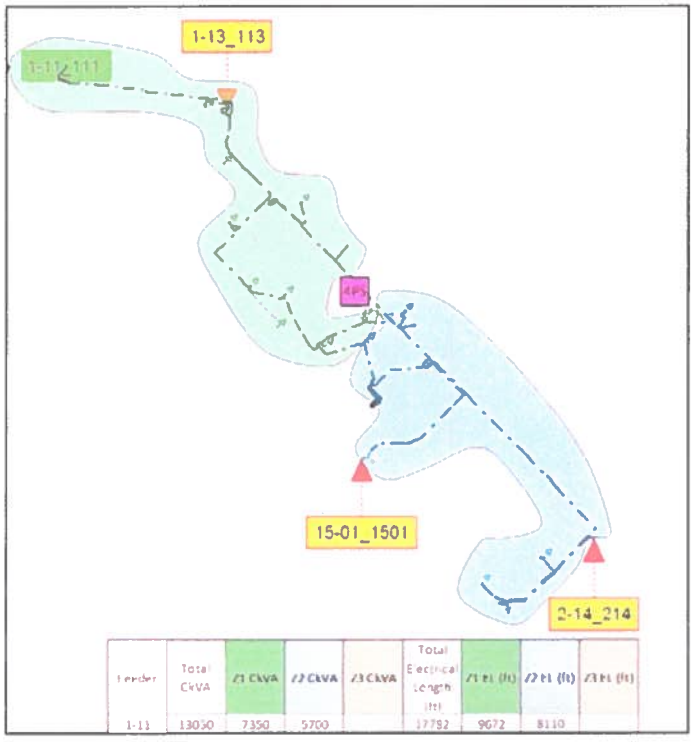




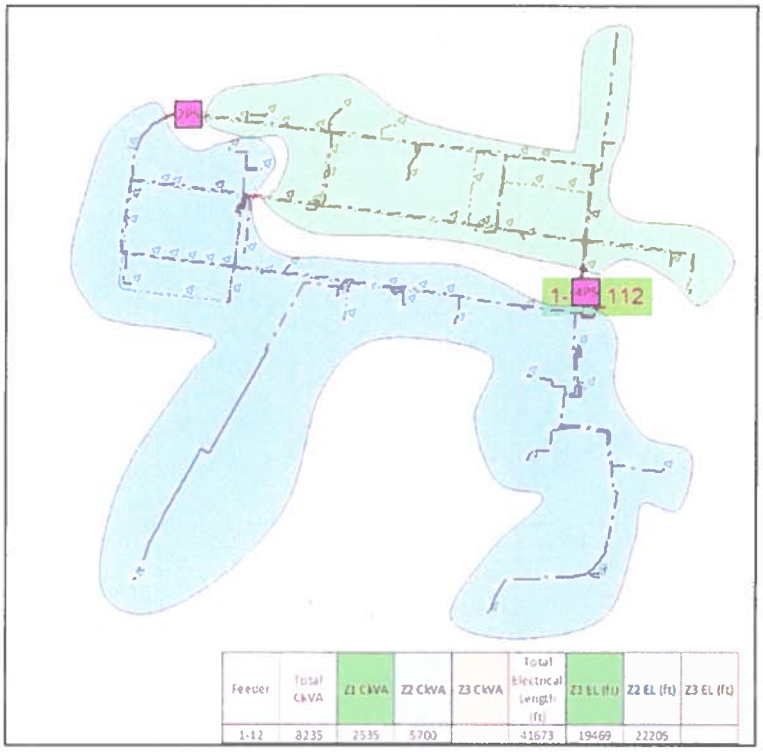
Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
2-16	8325	3850	4475		30066	17064	13002	

1-11:


1-13_113
1-11_111
4PS
15-01_1501
2-14_214
Legend
4PS
New 4-way Padmount Switch
2PS
New 2-way Padmount Switch

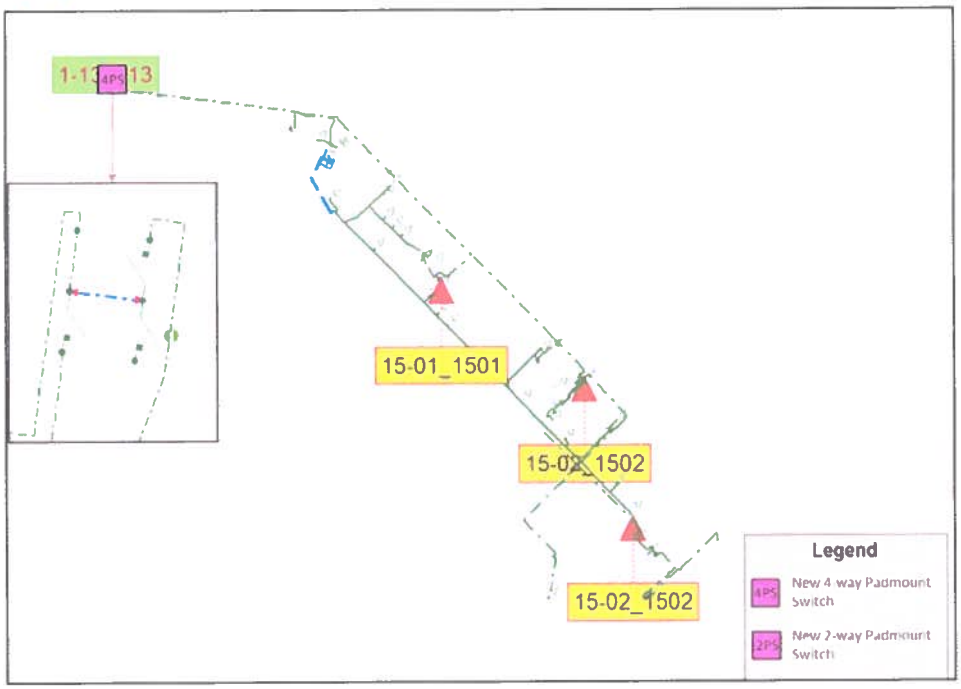

1-13_113
1-11_111
4PS
15-01_1501
2-14_214
Feeder
Total CkVA
Total Electrical Length (ft)
1-11
13050
7350
5700
17752
9672
8110

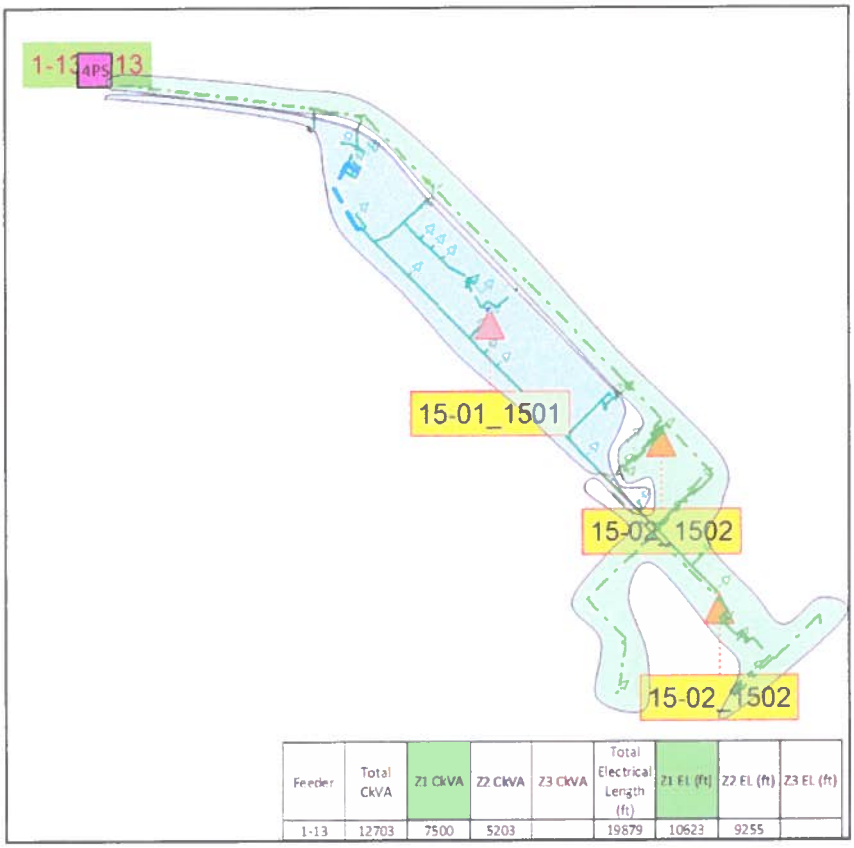
1-12:



Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
1-12	8235	2535	5700		41673	19469	22205	

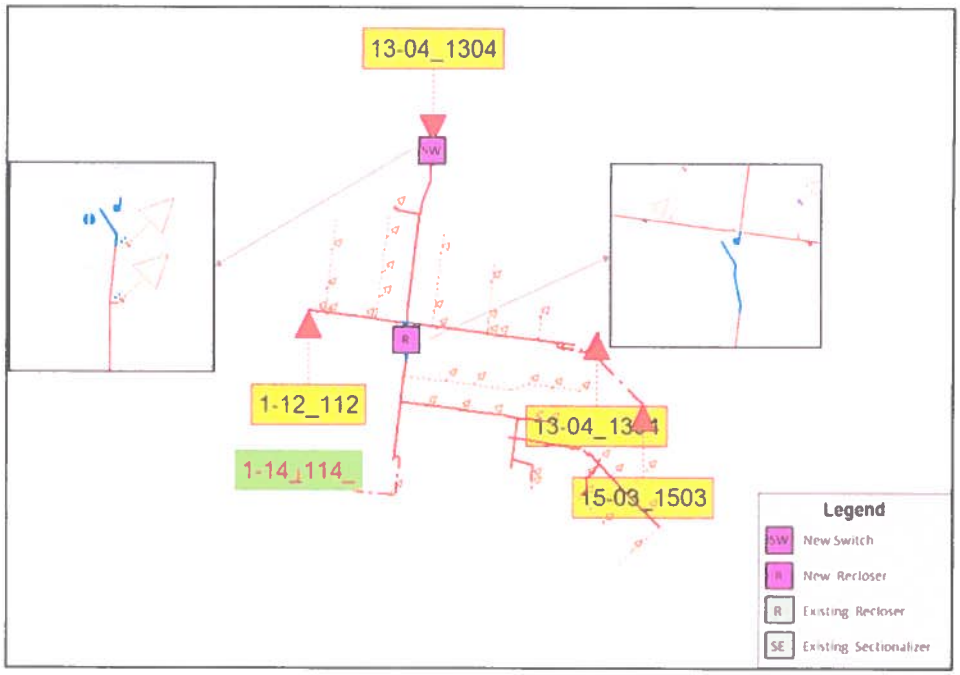
1-13:

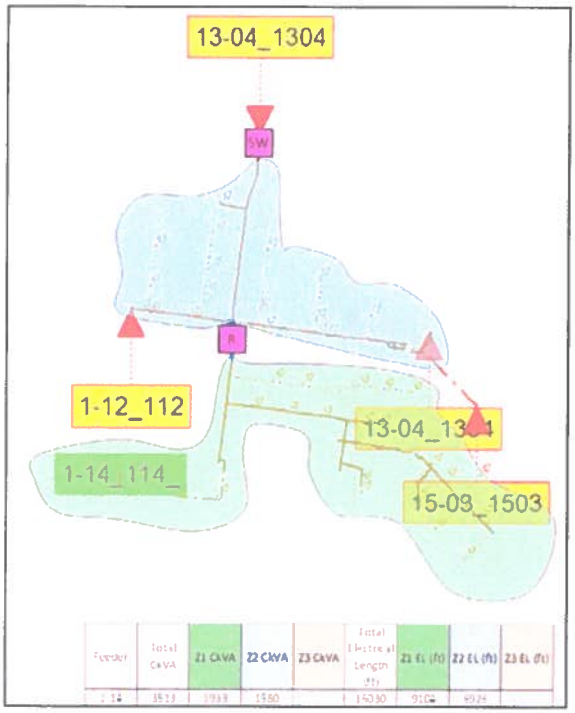




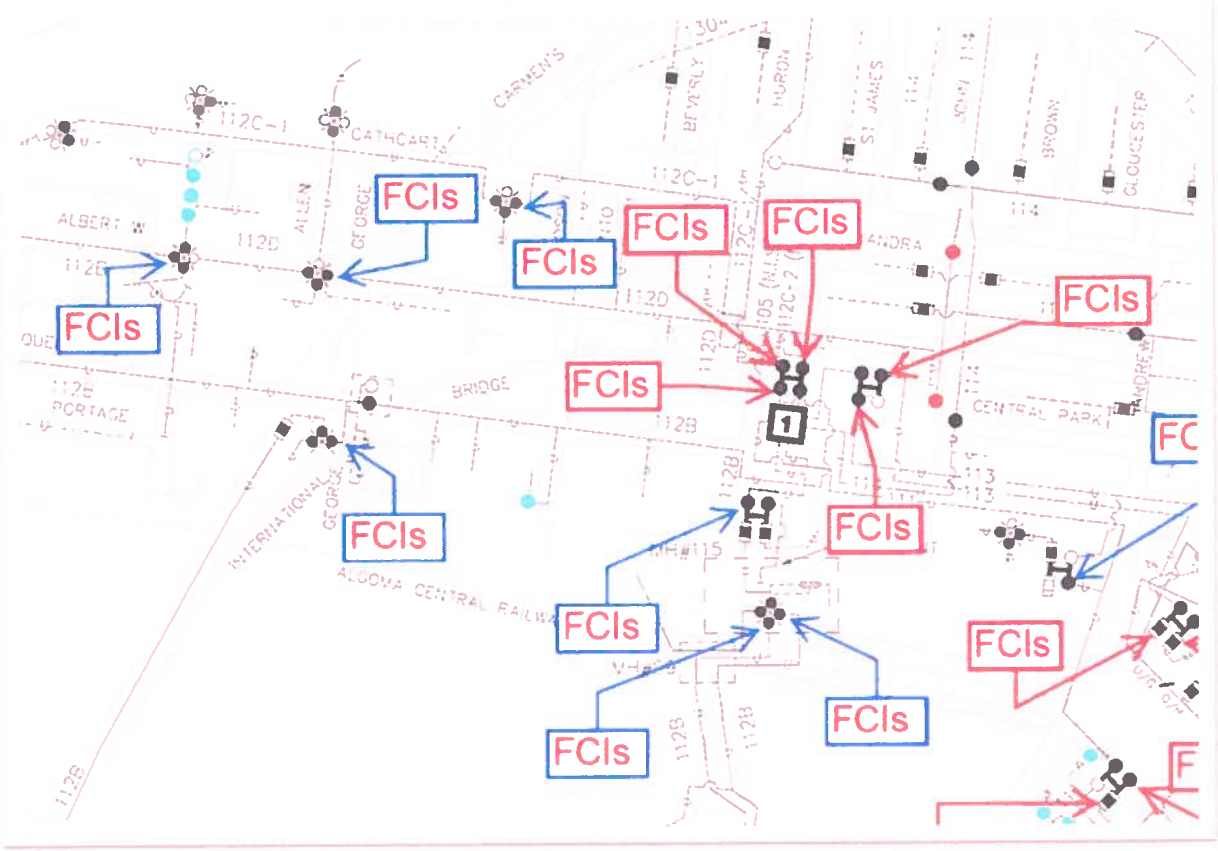
Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
1-13	12703	7500	5203		19879	10623	9255	

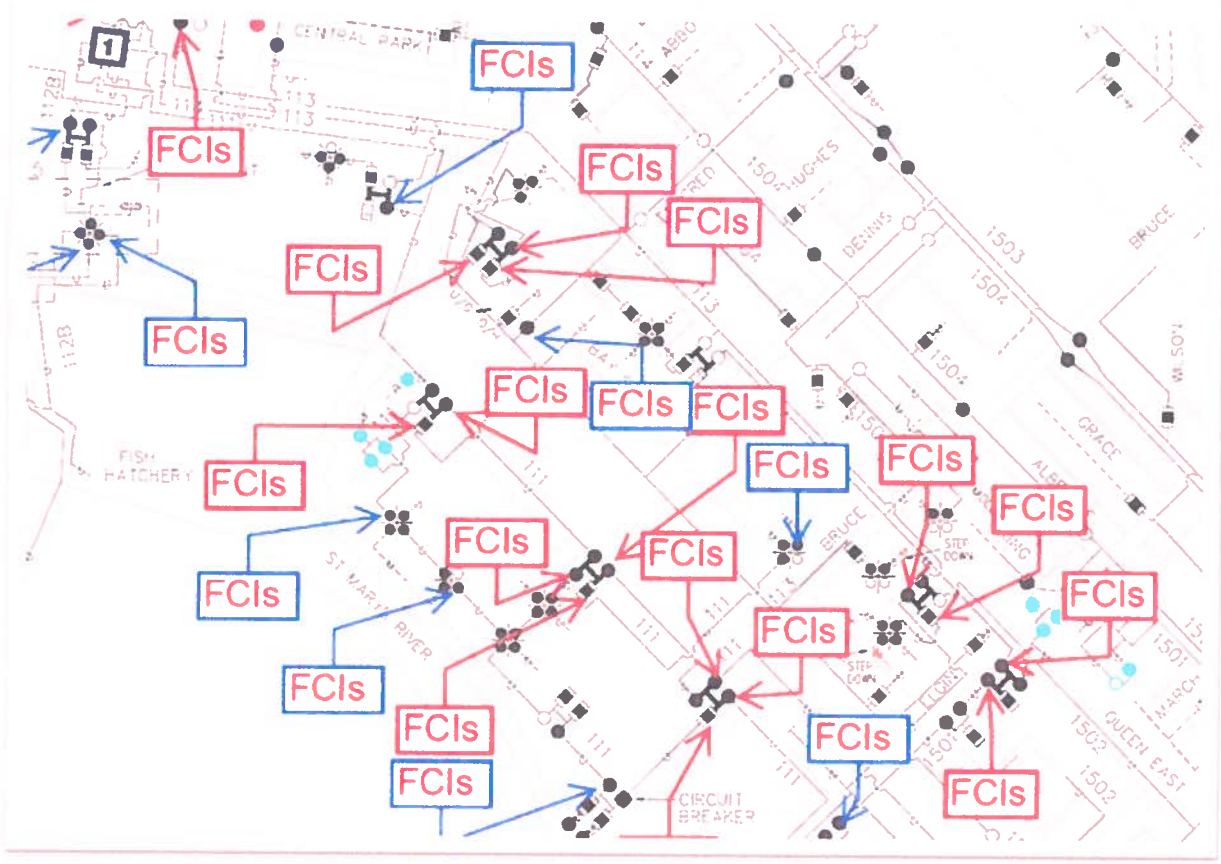
1-14:

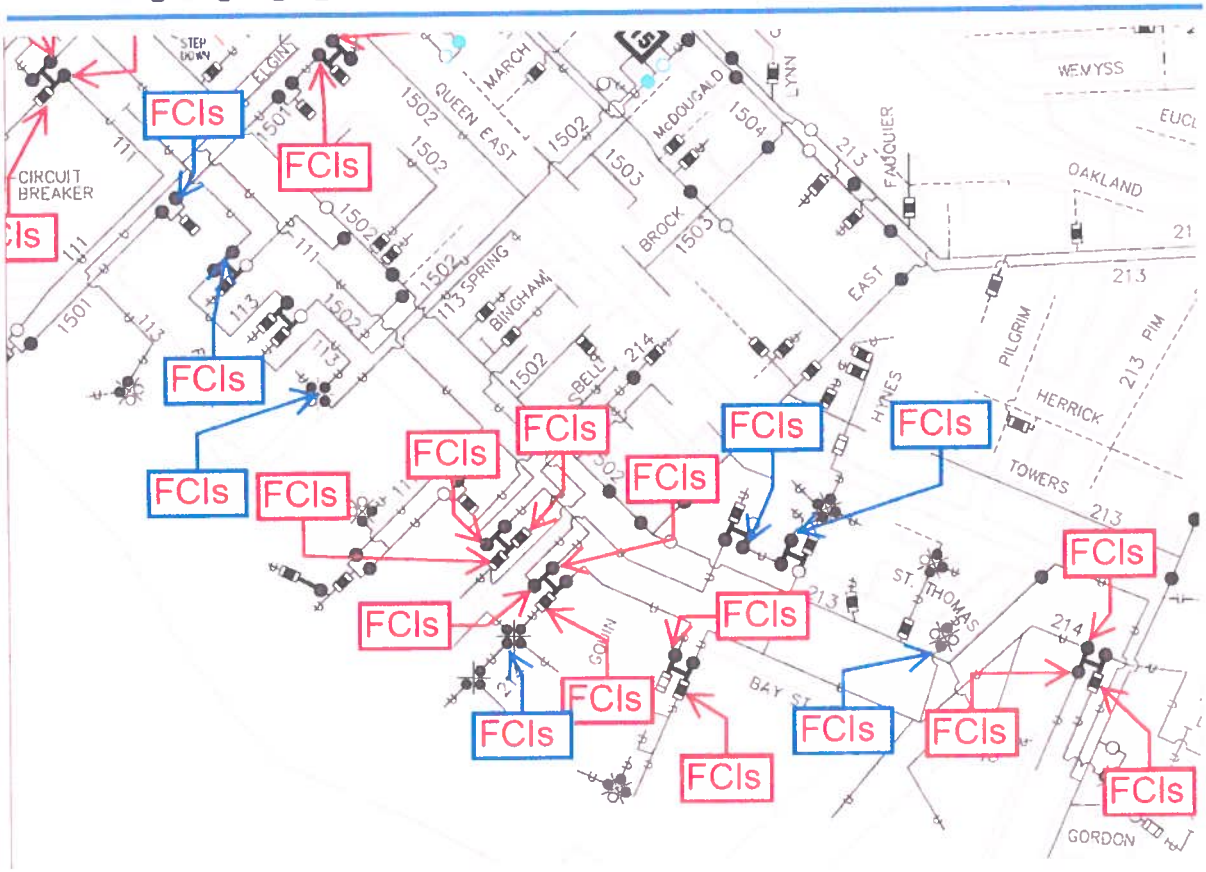

13-04_1304
SW
R
1-12_112
1-14_114_
15-03_1503
Legend
New Switch
New Recloser
Existing Recloser
Existing Sectionalizer


13-04_1304
SW
R
1-12_112
1-14_114_
15-03_1503

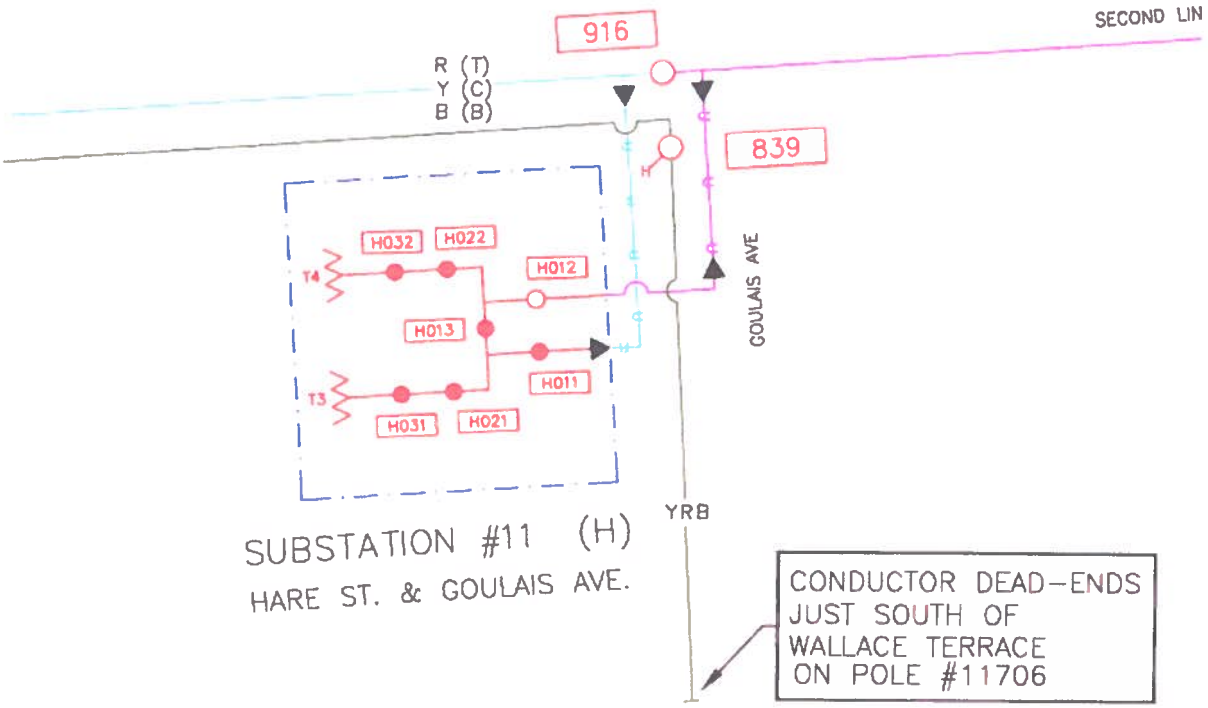
Appendix 5. FCI Locations

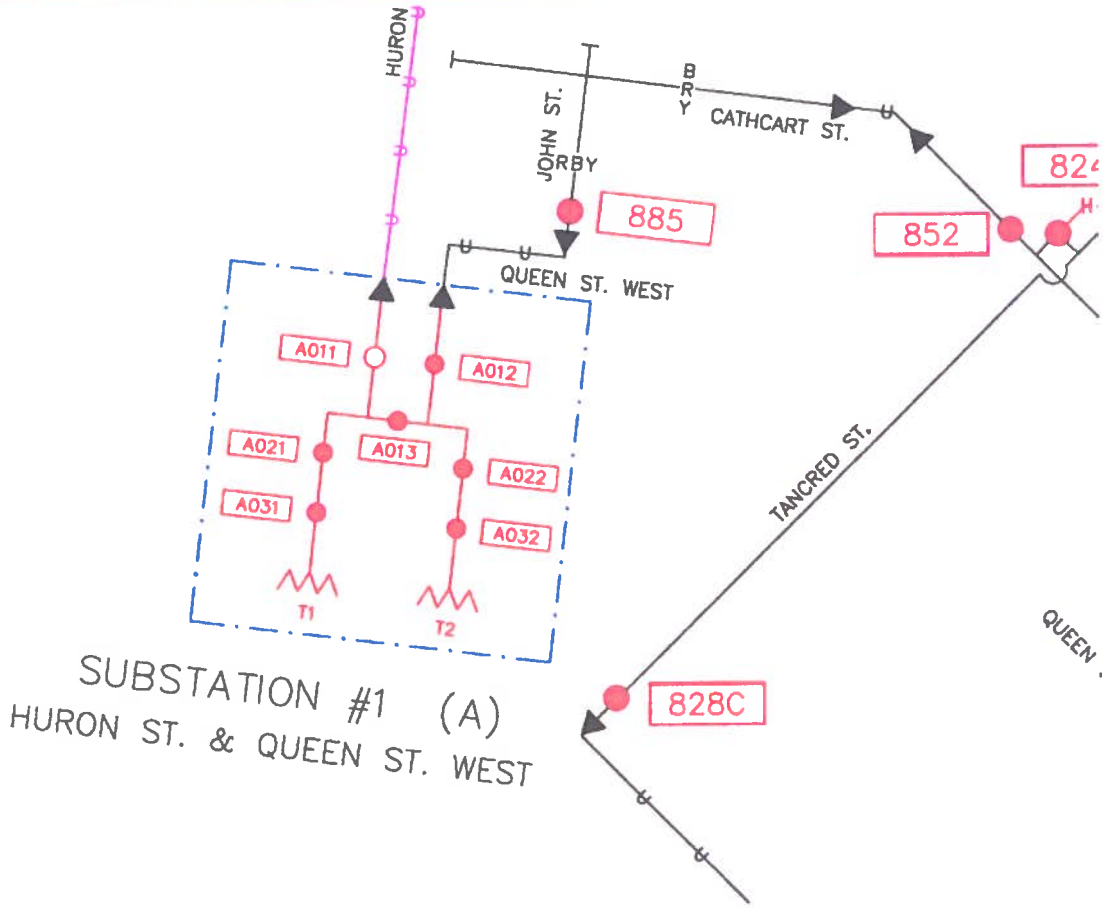

FCIs
FCIs
FCIs


FCIs
FCIs
FCIs

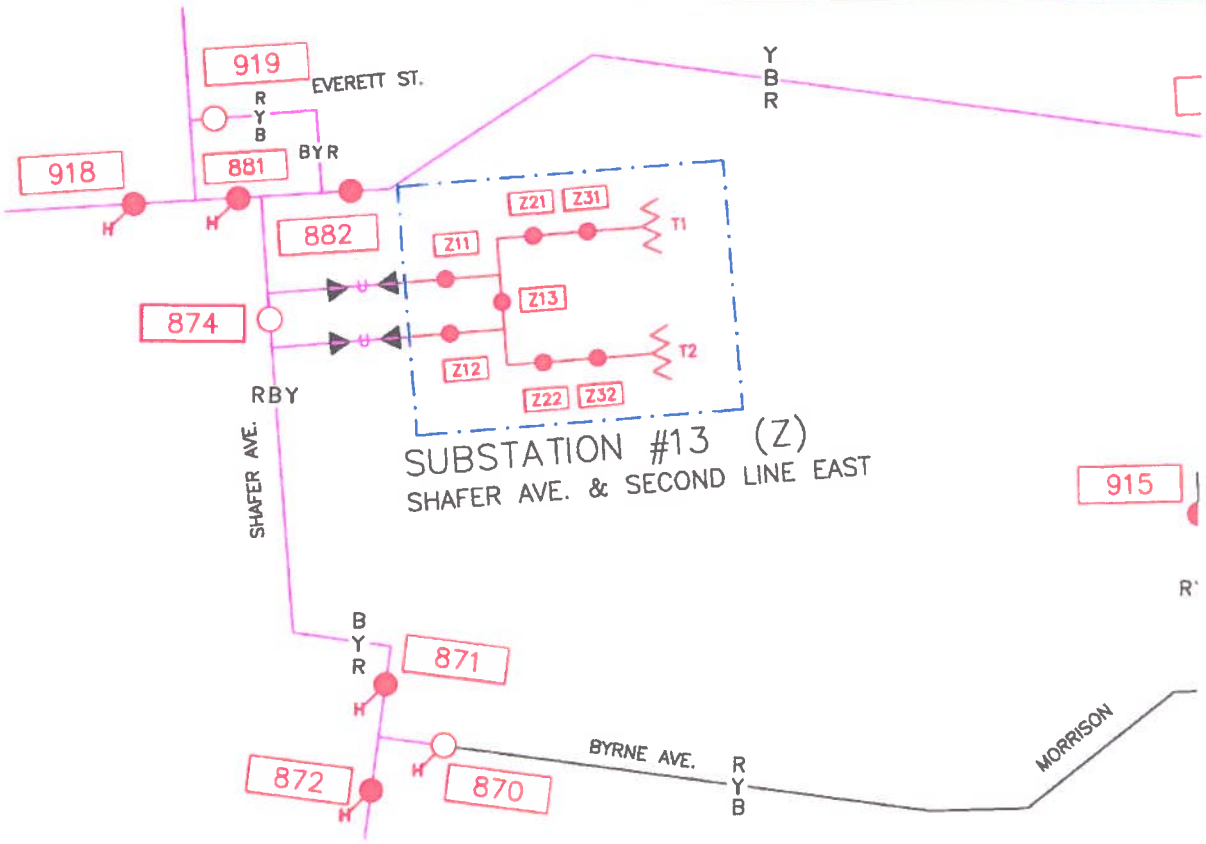

FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
CIRCUIT BREAKER
QUEEN EAST
MARCH
McDOUGALD
LYNN
WEMYSS
OAKLAND
FAIRQUIER
BROCK
EAST
SPRING
BINGHAM
BELL
HYNES
PILGRIM
HERRICK
PIM
TOWERS
ST. THOMAS
GOULD
BAY ST
GORDON
ELGIN
STEP DOWN

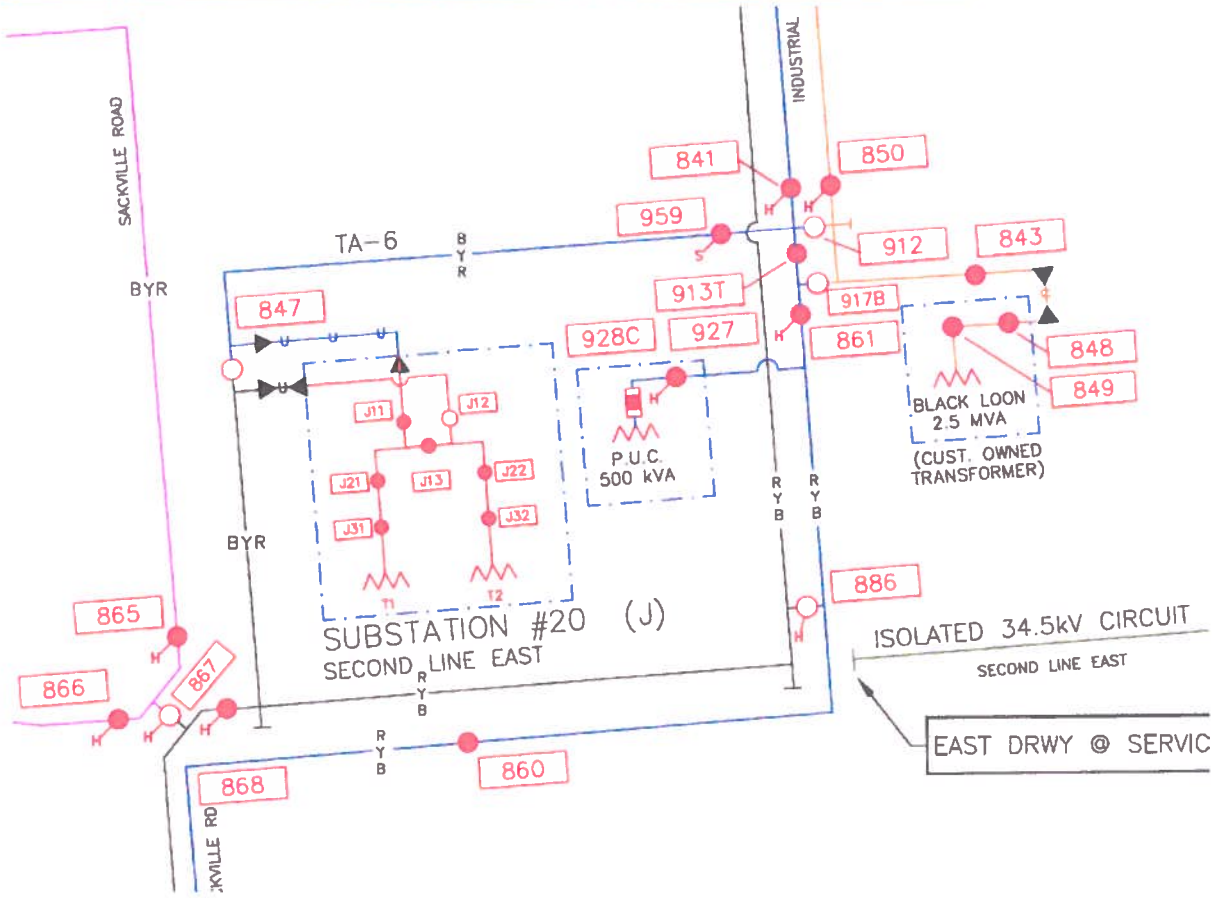
Appendix 6. Substations Included in Source-Transfer Scheme

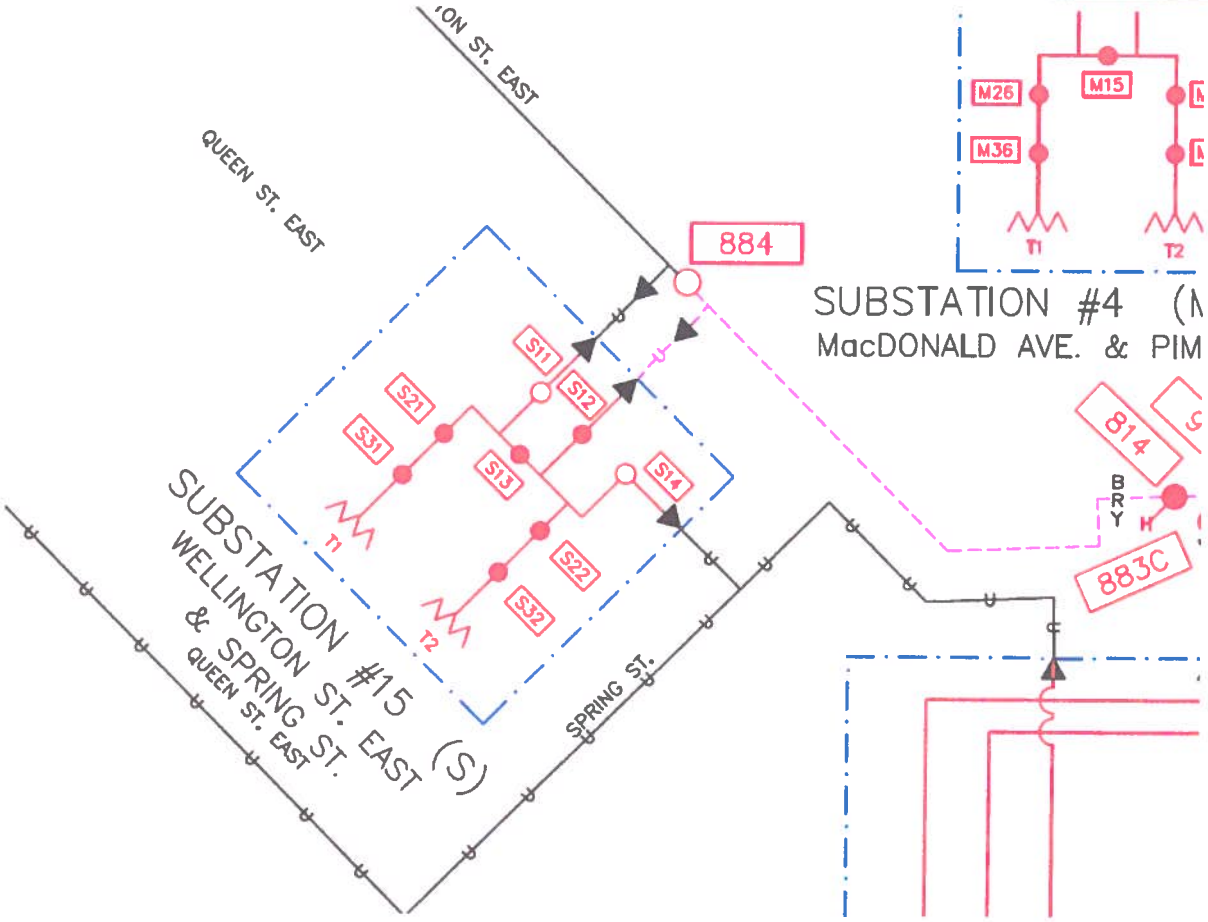


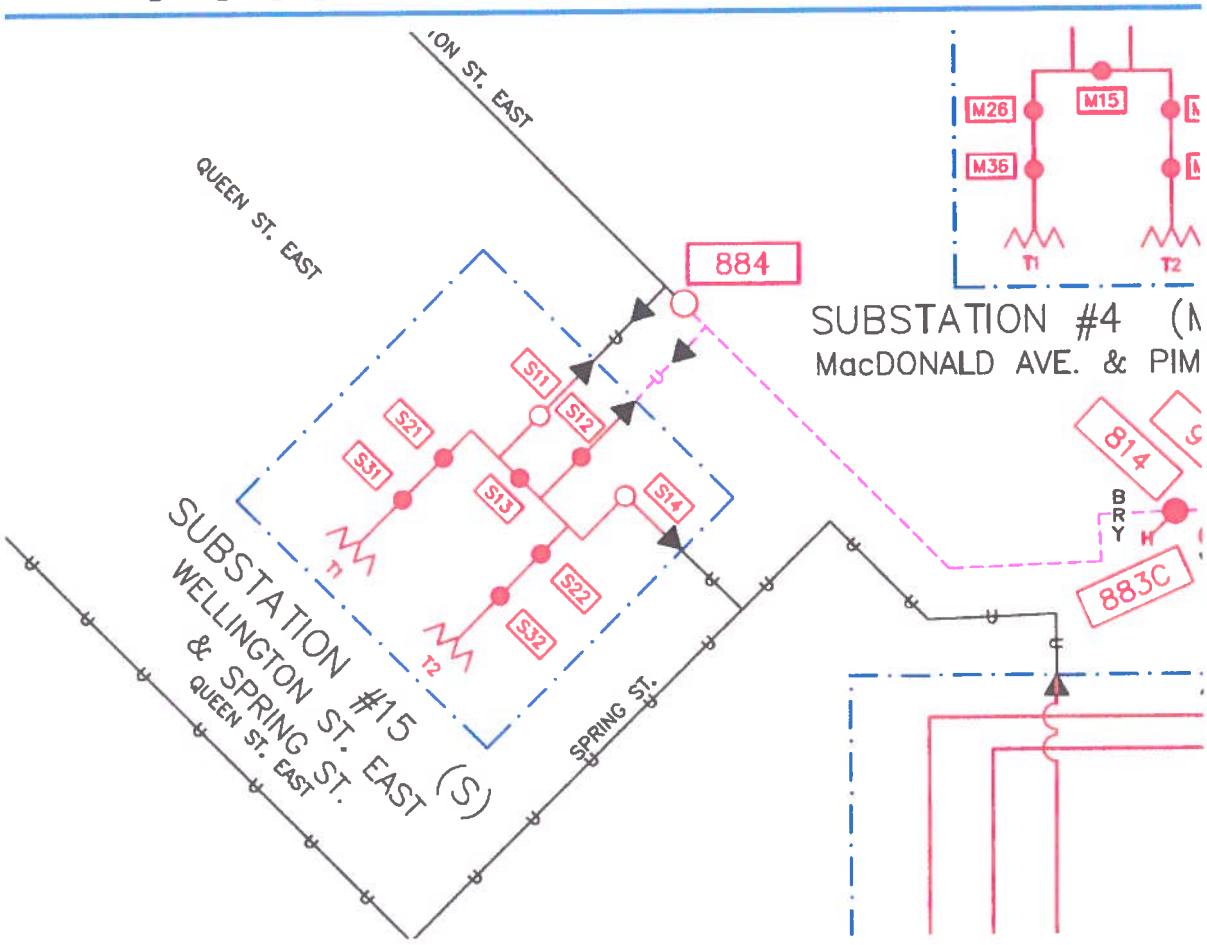


SUBSTATION #1 (A)
HURON ST. & QUEEN ST. WEST


919
EVERETT ST.
R
Y
B
881
BYR
918
882
874
RBY
SHAFER AVE.
Y
B
R
Z21
Z31
T1
Z11
Z13
T2
Z12
Z22
Z32
SUBSTATION #13 (Z)
SHAFER AVE. & SECOND LINE EAST
915
B
Y
R
871
872
870
BYRNE AVE.
R
Y
B
MORRISON


SACKVILLE ROAD
BYR
INDUSTRIAL
TA-6
B Y R
847
841
850
959
912
843
913T
917B
928C
927
861
848
849
J11
J12
J21
J13
J22
J31
J32
T1
T2
P.U.C.
500 kVA
BLACK LOON
2.5 MVA
(CUST. OWNED
TRANSFORMER)
R Y B
886
865
866
867
868
860
SUBSTATION #20 (J)
SECOND LINE EAST
ISOLATED 34.5kV CIRCUIT
SECOND LINE EAST
EAST DRWY @ SERVIC


QUEEN ST. EAST
884
S11
S12
S21
S31
S13
S14
T1
T2
S22
S32
SUBSTATION #15 (S)
WELLINGTON ST. EAST
& SPRING ST.
QUEEN ST. EAST
SPRING ST.
M26
M15
M36
T1
T2
SUBSTATION #4
MacDONALD AVE. & PIM
814
BRY H
883C


'ON ST. EAST
QUEEN ST. EAST
884
M26
M15
M36
T1
T2
SUBSTATION #4 (M
MacDONALD AVE. & PIM
814
BRY
H
883C
S11
S12
S21
S31
S13
S14
S22
S32
T1
T2
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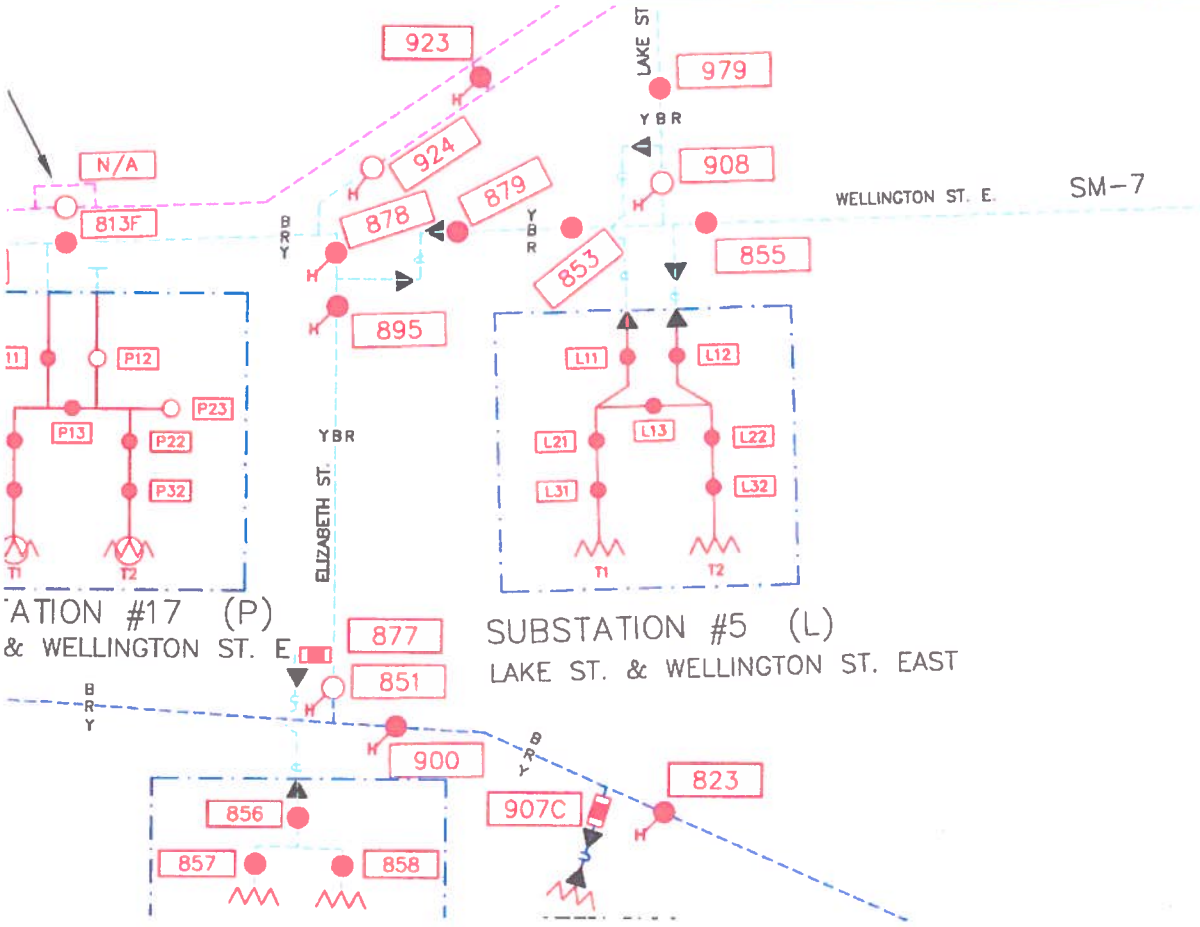
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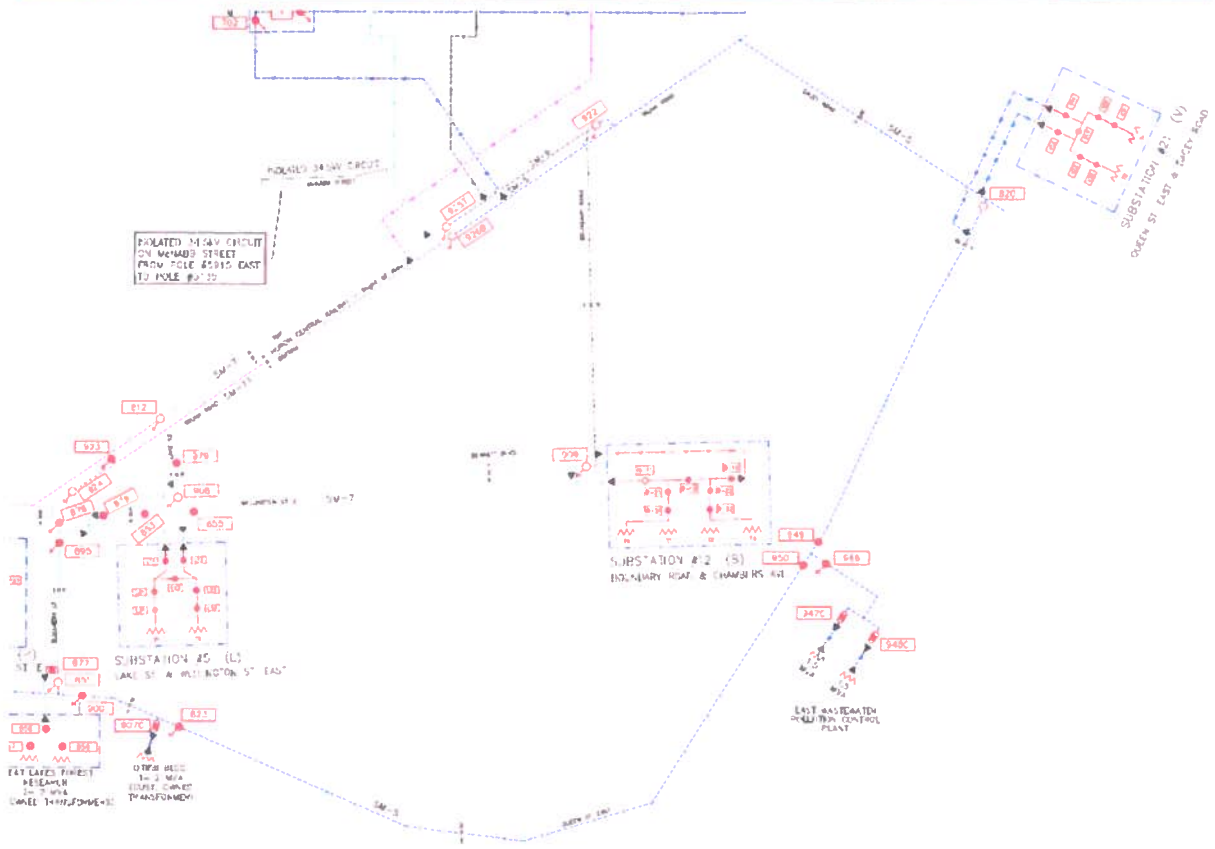
ISOLATED 34.5kV CIRCUIT
ON McNABB STREET
FROM POLE #5915 EAST
TO POLE #5735
SUBSTATION #2 (S)
SUBSTATION #5 (L)
EAST GASPEREAUX
POLLUTION CONTROL
PLANT

leidos

Leidos Engineering, LLC

Utility Distribution Microgrid: AMI Integration

Preliminary Design

Energizing Co.

PUC Distribution, Sault Ste. Marie, ON

Leidos
11/20/2014

leidos

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1 Background

This document was prepared by Leidos Engineering for Energizing Co. in support of Energizing Co.'s Utility Distribution Microgrid (UDM) project in Sault Ste. Marie, Ontario Canada. Energizing Co. has a contract with the local electric utility, PUC Distribution (PUC), to perform a detailed feasibility analysis and preliminary design for smart grid technologies including, microgrids, distribution automation (DA) systems, Volt/VAR Management (VVM) systems, Outage Management Systems (OMS), Demand Response (DR) and Advanced Metering Infrastructure (AMI) enhancements. Energizing Co. has subcontracted the feasibility and preliminary design tasks of this project to Leidos Engineering.

2 Overview

In support of Energizing Co. and the overall utility distribution microgrid study, members of the Leidos team reviewed the existing AMI infrastructure, technologies, business processes, and regulatory environment to evaluate where additional value could be achieved from integrating AMI data. Leidos held numerous discovery sessions with PUC Distribution leaders, customer service leadership, and operations leadership, as well as reviews with key partners: Sensus, Util-Assist, and SSMIC.

The result of this effort was a set of identified opportunities for advancing the functional and business capabilities of the AMI system in support of financial, regulatory, and overall UDM goals and objectives, as well as industry direction and best practices. This document summarizes the preliminary design efforts of the AMI component of the UDM project. The proposed AMI integrations will leverage AMI data from existing systems into operational, engineering, and customer service domains in order to track outages, monitor and manage voltage, improve customer and internal key-performance indicators, and allow for more accurate problem identification, isolation, and response.

3 AMI Integration Findings and Defined Projects

As a result of the initial feasibility study and investigation with PUC, The Leidos team identified ten AMI integration areas that would likely improve the quality and scope of the AMI data, as well as the application of the AMI data in support of broad business, engineering, and operational goals (both existing PUC and UDM related). The initial AMI integration areas were:

#	Finding	Description
1	Automated Outage Reporting	Load SCADA, AMI, and GIS data into a common platform so SCADA events can be auto reported for impact based on time and scale.
2	Enhance CSR Toolset with AMI data	Better organize and present AMI data in a CSR friendly UI such that they can better answer a wider set of questions with defensible data. Specifically reliability and cost/usage trends, but also quality and AMCD.
3	Enhance Customer Toolset with AMI data	Better organize and present AMI data in a consumer friendly UI such that they can better answer their own questions. Specifically reliability and cost/usage trends in a similar way to CSRs.
4	Improve Voltage Measurement Granularity	Modify Sensus system to more frequently call-in supervisory messages with Voltage min/avg/max. Include A3 if possible.
5	AMI/GIS Rollup Analytics	Load SCADA, AMI, and GIS data into a common platform so source, load, and network events can be correlated and analyzed in detail. Includes: load, voltage, energy, reliability, DG.
6	Complete AMI electric rollout to get universal data feed	Migrate MV90 LP meters to A3 Sensus meters. Complete >50kW service locations.
7	Implement water meters at scale to ease BP change	Accelerate water module implementation to accelerate business process transformation and cost savings.
8	Collect VARs in order to track PF	Upgrade meters in the field to measure additional engineering metrics including reactive power.
9	Implement disconnect switches to address collections	Swap out meters with disconnect capable meters to optimize business process, reduce truck rolls, and address collections challenges.
10	Expanded Data Export and Reporting	Join and connect a wider set of data so data reporting and bulk export becomes more timely and easier.

Table 1: Initial AMI Integration Findings

Of the 10 initial areas, six were identified as priorities for a UDM project that can return value to UDM design, build, and operations, and ultimately to PUC and its customers. The six priority finding areas were:

#	Finding	Description
1	Automated Outage Reporting	Load SCADA, AMI, and GIS data into a common platform so SCADA events can be auto reported for impact based on time and scale.
2	Enhance CSR Toolset with AMI data	Better organize and present AMI data in a CSR friendly UI such that they can better answer a wider set of questions with defensible data. Specifically reliability and cost/usage trends, but also quality and AMCD.
3	Enhance Customer Toolset with AMI data	Better organize and present AMI data in a consumer friendly UI such that they can better answer their own questions. Specifically reliability and cost/usage trends in a similar way to CSRs.
4	Improve Voltage Measurement Granularity	Modify Sensus system to more frequently call-in supervisory messages with Voltage min/avg/max. Include A3 if possible.
5	AMI/GIS Rollup Analytics	Load SCADA, AMI, and GIS data into a common platform so source, load, and network events can be correlated and analyzed in detail. Includes: load, voltage, energy, reliability, DG.
10	Expanded Data Export and Reporting	Join and connect a wider set of data so data reporting and bulk export becomes more timely and easier.

Table 2: Prioritized AMI Integration Findings

The prioritized findings were expanded to develop a set of initial project requirements, discussed with PUC, and evaluated against existing systems and vendor capabilities to find the best mix of commercial, technical, and practical options. Based on the responses from vendors and vendor discussions, the six priority findings were mapped to four integration projects as outlined below:

#	Project Name	Project Description
1	Outage Management System	Implement a robust off-the-shelf OMS platform at PUC including advanced Interactive Voice Response (IVR) technology for enhanced communications of outages to customers. Integrate OMS platform to SCADA, AMI, and CIS in order to measure, track and relay outage information to customers in real-time as well as track outage metrics historically.
1	Outage Management System	Implement a standard OMS platform at PUC and integrate the platform to SCADA, AMI, and CIS in order to measure and track outage information in real-time and historically.

2	Enhanced CSR/Customer Toolset	Better organize and present AMI data in a CSR and customer friendly UI such that they can better answer a wider set of questions with defensible data. Specifically reliability and cost/usage trends, but also quality and CRUD.
3	Improve Voltage Measurement Granularity	Modify the Sensus AMI system to more frequently call-in supervisory messages with Voltage min/avg/max and integrate data to CVR platform.
4	Data Analytics and Performance Reporting	Load SCADA, AMI, CIS, OMS, and GIS data into a common platform in order to provide system analytics and key performance indicator reporting.

Table 3: Integration Projects

4 AMI Integration Project Details

In this section we outline the requirements and delivery plan for each of the four AMI Integration projects.

4.1 Outage Management System

This project focuses on the automated outage reporting findings and seeks to provide clear and correct outage metrics and operational support at a significantly reduced level of effort to the organization.

4.1.1 Problem Statement

PUC currently utilizes a highly manual process to manage electric outages and electric system trouble calls from customers. All North American electric utilities are under ever-increasing pressure to minimize outage time and the cost of restoration work, maximize accountability to affected customers, and increase customer satisfaction, all while managing costs and rates.

4.1.2 Expected Benefits

Primarily, the business drivers to invest in OMS technology come from the improvement to power trouble management, targeted reliability improvements, safety and enhanced customer service. The primary benefits PUC should seek from an OMS are:

1. Ultimately improve the customer experience at PUC by improving and modernizing the trouble call management practices with advanced IVR and OMS. The IVR and OMS will provide visibility and understanding of customer outage calls and improve outage call management throughout PUC, creating more informed staff to serve customers.
2. Improve safety for crews by having visibility of crew locations and activities during restoration work.
3. Bolster dispatch practices and decrease restoration times through failure prediction, outage prioritization, and better crew management during unplanned outages.
4. Modernize and automate the process for planned outages. Integrate dispatch center's process through use of the IVR for customer notification of planned outages from OMS.
5. Leverage investments in Geographic Information System (GIS) and Supervisory Control and Data Acquisition (SCADA). Modernize dispatch practices with GIS-based OMS integrated to SCADA to provide crucial situational awareness in the control room about the distribution system down-line of the breaker and real-time visibility of customers affected during a breaker operation.
6. Automate and make reporting reliability indices more accurate. Using a systematic methodology through a historian OMS for tracking outages as they happen and archiving them for tracking outage metrics.
7. Enable PUC to target weaknesses or troubled equipment on the distribution system for from the ability to data mine outage history information archived over time through the OMS.

4.1.3 Solution Summary

PUC presently uses Survalent SmartSCADA and Harris NorthStar CIS. PUC has communicated that they wish to have well rounded and comprehensive capabilities for managing outages. OMS solutions are readily available from many software vendors. Best-fit OMS solutions for working PUC's electric distribution outages come from Survalent and Milsoft Utility Solutions.

The "preferred OMS solution option" below is provided as a best-fit solution of an OMS platform for PUC based on legacy software, features and integration requirements. PUC may decide upon different OMS software solution based on pricing, features or other parameters, but the solution below is provided as a best-fit solution, based on what is known about PUC, PUC existing technology and the OMS vendor community offerings.

Item	Description	User Type	Module
OMS Core Software	SmartOMS software is designed to run on the SCADA/OMS host computers, with a user interface built into the SmartSCADA WorldView operator interface. The OMS is fully redundant along with the rest of the redundant SCADA/OMS system. It supports, ☐ Automated Data Entry ☐ Call Analysis ☐ Callbacks ☐ IVR and Caller ID ☐ Outage Web Portal ☐ Worldview Management ☐ Switch Order & Guarantees ☐ SCADA/OMS Event and Operations Note: The existing System Configuration Status license will be used for SmartOMS	Dispatchers, Engineers	Survalent SmartOMS
GIS-OMS/DMS Converter (for incremental updates)	Convert ESRI geometric map features into Survalent' s electrical network model: 1. Establish connectivity model by connecting devices e.g., switch, capacitor, regulator etc. with conductors, e.g., overhead/underground conductors 2. Check the integrity and validity of the raw GIS data, and provide reports of data errors	DMS / OMS Administrator	Survalent ESRI GIS Converter
AMI-OMS/DMS (for real-time AMI power-on/off indications/verifications)	Automatic Metering Infrastructure (AMI) Interface allows you to ping meters, disconnect and reconnect meters (with or without arming), receive unsolicited outage and event reports from meters, and read voltages	DMS / OMS Administrator	Survalent MultiSpeak AMI Interface - Sensus

	and other data on demand or on schedule. Scheduled readings received from meters can be displayed on the map and used by other applications, such as command sequencing, DVR etc.		
CIS-OMS/DMS Converter (for incremental updates)	Interface to Harris NorthStar CIS for customer account information to accompany electrically connected meter to associate customer info from CIS	DMS / OMS Administrator	Survalent Harris Interface (may utilize Milsoft CIS-IVR interface instead, depending on which is most advantageous)
Outage Web Client	The module interface uses Bing, or OpenStreet maps as the background, and shows the locations and extents of outages. It allows the CSR to create call records, displaying the location of that call on the map. When the CSR is finished recording the call, the OMS database on the SCADA system is immediately updated, notifying the operators of the customer issue. If the caller is in a verified outage area, a button allows the CSR to view the current details of the outage case. Note: Hardware will be supplied by customer (Middle ware server and tablet).	CSR's and all PUC internal users requiring OMS access	Survalent Outage CSR/Web Client
Mobile OMS	This is a tablet-oriented web application for use by crews in the field. The Mobile Crew (MC) client will show a map of the service area using OpenStreet Map. It will display primary line sections and transformers and meters in the map. It will not display substations. No SCADA operations (e.g. open/close) will be supported. The dispatcher will be able to send a text message to the crew members in order to notify them of a change in work. MC will show the following panels that a crew member will be able to navigate: Case List showing details of outage cases. This panel is mostly view-only, but it will be possible for the crews to	Line Crews and field personnel	Survalent MC

	modify Cause code, ETOR, and Notes.; Work List showing the list of all the work items that are assigned to this crew. Crew members will be able to make modifications to work items (e.g. Work status, Completion time, and material use). Note: Hardware will be supplied by customer. (Middle ware server)		
Hosted IVR Solution	Offsite software IVR communications software configured to PUC's customized scripting requirements and hosted by Milsoft	CSR's and all PUC internal users requiring access to customer calls/contacts through IVR	Milsoft Hosted IVR Software and Services

4.1.4 Scope and Detailed Requirements

High-level scope is outlined as follows:

Scope	Responsible Party
Specify and acquire OMS and IVR software modules vendor assistance and necessary hardware	Leidos/PUC
Coordinate IT needs for PUC	Leidos
Provide GIS conversion and GIS-OMS/DMS Converter Software Tool	Leidos/Survalent
Implement integration platform	Leidos
Design, build, and document integrations between Sensus AMI, Survalent SmartSCADA/OMS/ADMS, Milsoft IVR, Harris NorthStar CIS, PUC GIS	Leidos/Survalent/Milsoft
Provide documentation and train PUC OMS Administrator to maintain current version of "as operated electrical distribution system" electrical network model within Survalent SmartOMS.	Leidos/Survalent
Provide documentation and train PUC dispatchers and engineers to operate, input and manage outages within Survalent SmartOMS environment for OMS functionality.	Survalent
Provide documentation and train PUC OMS/IVR Administrator to maintain customer data and scripts within Milsoft IVR for customer communications functionality.	Leidos/Milsoft
Provide documentation and train PUC CSR's to operate, input and manage customer outage call data within Milsoft Communications (IVR) for OMS functionality.	Milsoft

Requirements:

Detailed Requirement	Solution Alignment
Manage outage events and work multiple and nested outages	Aligned
Manage outage indications from AMI	Aligned
Ping AMI meters for verification of power restoration	Assumed to be part of the Sensus interface but will require validation in detailed design.
Automate the trouble call process and manage outage indications from customers via IVR through the OMS	Aligned
Automate development of customers affected lists and manage planned outages	Aligned
Provide detailed reports of standard industry outage indices/metrics and develop customized outage metric reports	Aligned
Provide crews outage information via mobile technologies	Aligned as stated in functionality of Survalent SmartOMS MC, but full-functions of OMS not available on mobile devices
Manage crews and crew callout and integrate with employee resource databases and mobile technology	Limited/TBD
Communicate outage information to customers via IVR on a map with general outage totals.	Aligned/Specific Requirements TBD
Communicate outage information to customers via Web on a map with general outage totals.	Limited/TBD
Receive outage information from customers and communicate outage information to customers via text and email	Limited/TBD – Custom development required between Survalent OMS and Milsoft IVR capabilities

4.1.5 Project Assumptions

The following assumptions were made in the development of this project:

- PUC will utilize the "preferred OMS solution option" as outlined above. If other vendors or additional modules are selected or required, a change order will be required.
- A hosted IVR solution is specified for maximum flexibility and reliability for PUC. If an on-site IVR is required, phone line requirements and existing telephony information will be required to develop a change order
- Very basic crew call out and crew management is required by PUC

- Limited or no outage texting or email capabilities are included, but may be added in later phases. A customer opt-in program and detailed requirements will need to be developed if this capability is desired by PUC

4.2 Enhanced CSR/Customer Toolset

This project focuses on the CSR and Customer findings to deliver clear and consistent customer facing metrics and details.

4.2.1 Problem Statement

The UDM will require a focused, timely, and easy-to-use mechanism to communicate benefits of the UDM to consumers. This mechanism needs to be accessible to customer service as well as consumers, and deliver clarity on metrics that are fast, easy-to-access, and consistent with the rest of the user experience.

4.2.2 Expected Benefits

The expected benefits of the enhanced CSR and Customer Toolset are to more clearly demonstrate the value of the UDM to customers through clear metrics and performance data. Clear cost, usage, reliability, and power-quality statistics can be used to show constant improvement and relate benefits other than total-cost metrics which can be beyond PUC's control.

4.2.3 Solution Summary

PUC presently uses the Harris NorthStar CIS and CustomerConnect consumer engagement module. PUC has communicated that they are happy with the platform, well invested in it, and employees prefer to work within that platform. This has been true to the extent that using "second screen" solutions have not had traction in the past. As a result, the current CIS platform and customer engagement solution are being preferred for this project in order to maximize value, user acceptance, and to accelerate progress.

Once the upgrades are completed, the UDM project will review and work with PUC to potentially enhancement the scope of work delivered by Harris NorthStar to provide additional CSR and Customer views. Specific views may include the following depending on specifically delivered Harris scope (as determined by PUC's existing project).

View	Description	User Type	Module
Interval Data over Time	View consumption data related to kWh channel data (Delivered, Received, and NET) and associated cost data to clearly understand the effect of consumption on cost.	CSR & Consumer	NorthStar and HomeConnect
Reliability Details	To the extent possible, present outage history or time aggregated details for each service location.	CSR & Consumer	NorthStar and HomeConnect
Demand Values	View demand (kW) values for C&I customers as it relates to kWh-Delivered data.	CSR & Consumer	NorthStar and HomeConnect

4.2.4 Scope and Detailed Requirements

This project is already in motion at PUC and a 2015 CIS/CC upgrade is already planned to provide many of the required features and functionality. As a result, the AMI Integration project is not pursuing alternative solutions, but will instead focus on feature requirements and feature review within NorthStar and CustomerConnect in order to assist PUC in delivering the benefits required within the platforms already in use.

High-level scope is outlined as follows:

Scope	Responsible Party
Communicate requirements and value proposition for Harris upgrade to PUC	Leidos
Review and determination of scope for Harris	PUC
Contract directly for Harris upgrades to CIS and CustomerConnect	PUC
Execute associated upgrades and configurations	Harris
Commissioning and Testing	Harris
Executed solution review and feedback	Leidos
PUC decision to augment scope or expand based on Leidos feedback	PUC

Requirements

Requirement	Harris Alignment
An enhanced set of customer and customer-service tools are required that will ideally be based/built on the existing PUC CIS and Customer Portals	Aligned
The portals should be web-based and require no thick-client software	Aligned
The portals should use HTTPS and secure protocols for access	Aligned
The portals should be integrated with the existing PUC CIS platform	Aligned
The portals should provide similar views of data to internal CSRs and external customers	Aligned
The customer portal should be self-service administration	Aligned
The portals should interface with AMI channel and register data as needed	Aligned
The portals should provide interactive load-profile (channel) data analysis that drills down from year,	Aligned

to, month, to day, to interval views	
The interactive load-profile (channel) data analysis should align usage and spend data to clarify consumption patterns and alignment to cost	An additional module is required that PUC is considering.
The portals should provide reliability views that communicate outage metrics such as CAIDI, SAIDI, SAIFI, or MAIFI.	Unable to Deliver – this will be investigated through OMS as an alternative
The reliability views should aggregate over time	Unable to Deliver – this will be investigated through OMS as an alternative
C&I customers should be provided additional data including demand, voltage or power factor data.	An additional module is required that PUC is considering.
Residential customers should have additional data including demand, voltage, or power factor data hidden.	Aligned
Portal data should be pre-calculated to provide rapid user interaction and minimize wait times.	Aligned
Portals should have customizable user interfaces to align with existing PUC online identify.	Aligned

4.2.5 Project Assumptions

The following assumptions were made in the development of this project:

- PUC will complete the CIS upgrade to NorthStar CIS 6.4 as planned
- PUC will complete the HomeConnect component of CustomerConnect upgrade as planned
- PUC will acquire the SiteConnect component of CustomerConnect upgrade as planned
- Customized interfaces to meet requirements will be performed by Harris under Prime leadership as professional services as separate scope post planed upgrade
- Specific Harris user-interface details will be derived post upgrade in cooperation with PUC
- User-interface changes will be capped to T&M budget an prioritized with PUC
- Reliability statistics will likely be shown separately

4.3 Improved Voltage Measurement Granularity

This project addresses the findings from the initial voltage granularity findings in order to provide an effective CVR solution.

4.3.1 Problem Statement

The UDM will require more frequent, timely, and very reliable voltage measurement data in order to monitor and optimize voltage controls on the distribution system. By increasing fidelity, we can increase the ability to control and optimize, and reduce the impact of occasional read failures.

4.3.2 Expected Benefits

The expected benefits for this project come from the ability of the CVR platform to dynamically identify voltage optimization opportunities from bell-weather meters. These changes should provide cost savings, system efficiency, and energy efficiency benefits. Additional benefits will come from the integration platform that will ease future data movement between users and systems.

4.3.3 Solution Summary

In order to deliver this capability, the Sensus AMI system will require certain bell-weather meters to have voltage registers read at hourly intervals and made available to the Survelant CVR platform hourly. The solution will be delivered in two parts: Sensus changes and an integration platform.

The Sensus system is likely not suited, based on current capacity, to perform 100% hourly voltage register reads via the supervisory module, but could support certain bell-weather meters at that read frequency. Sensus would have to write a new script to make the hourly reads available via an interface, possibly MultiSpeak, which the solution could call via an integration platform. The changes to the Sensus platform will be performed by Sensus, under the existing PUC contract, and under Leidos direction.

The proposed integration platform, based on the NextAxiom ESB, provides for data extract, transform, and loading and will allow for application integration between Sensus and Survelant, as well as other data integration requirements such as OMS. It is expected that numerous future integrations and data interfaces, not currently in scope to the project, will be required as the UDM matures and operational requirements evolve. The NextAxiom scope of work, performed by Leidos, will include the design, build, commissioning of the NextAxiom Production and Dev/Test environments at PUC on PUC provided hardware. Leidos will also perform the design, implementation, test, and commissioning of the integrations required to exchange the Sensus Voltage data and the Survelant CVR platform.

4.3.4 Scope and Detailed Requirements

High-level scope is outlined as follows:

Scope	Responsible Party
Define bell-weather meters based on PUC system model	Leidos/PUC

Update Sensus AMI system to collect voltage register data hourly from defined meter group	Sensus
Create Sensus Application-layer interface	Sensus
Enable Voltage interface on CVR platform	Leidos
Implement integration platform	Leidos
Design, build, and document integration between Sensus and Survelant for "GetLatestRead" for voltage data related to bell-weather meters	Leidos
Document and train PUC to leverage data as required for CVR solution.	Leidos

Requirement	Sensus Alignment
The existing AMI system should be tuned to provide more granular voltage register reads on a scheduled and persistent basis	Aligned
Increased frequency of voltage reads should be limited to the capabilities of existing tower hardware	Aligned
Increased frequency of voltage reads may leverage updated tower software (TGB) if appropriate	Aligned
Ideal configuration would be one hour fidelity of voltage reads for all AMI electric meters delivered to the RNI each hour.	Platform could provide this but would likely require more towers or TGBs and that cost is not commensurate with value provided.
An acceptable configuration would be to define and program a set of bell-weather meters to return one hour fidelity voltage reads to the RNI each hour, but not the entire meter population, if there are technical or commercial restrictions to the ideal configuration.	Aligned
Voltage reads should provide MIN, MAX, and AVG voltage values in each read for single-phase meters	Aligned
Voltage reads should provide AVG voltage values for each phase in each read for poly-phase meters	Values are instantaneous, not average. This should be okay.
All voltage data collected in this scope of work should be available via a MultiSpeak, CIM, or other application interface from the RNI each hour in order to provide other systems one hour voltage fidelity data in near-real-time.	Aligned

4.3.5 Project Assumptions

The following assumptions were made in the development of this project:

- There is no desire to deploy additional towers or bulk-replace electric meters in the field
- All changes can be instituted as software changes by the vendor
- All changes can be performed within the existing contract with AMI vendor
- Vendor will provide guidance on impact of increased voltage reads and assist in tuning scope to meet system capability
- PUC/Leidos can define a bell-weather set of meters if required.

4.4 Data Analytics and Performance Reporting

This project merges the requirements from the GIS Rollup Analytics findings and the Data Export findings as both requirements can be served from the same data sets and a single data ingest will maximize value and minimize cost and labor/effort to PUC.

4.4.1 Problem Statement

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 operate 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.

4.4.2 Expected Benefits

The expected benefits from this project are clarified metrics that drive action, ease of reporting across PUC, and ease of data access that allows "big picture" reporting without constantly digging for data.

4.4.3 Solution Summary

To meet the requirement for performance monitoring, metrics calculation, and associated analytics specific to this project, we propose leveraging the Leidos Cloud Analytics Platform (CAP). CAP provides three basic components to address the GIS rollup analytics and KPI reporting components of the requirements:

- Data Extract, Transform, and Loading (ETL)
- Smart Grid Data Warehouse and Data Reporting
- Data Visualization

The final detailed requirements will be identified and agreed with PUC in the detailed design stage. A general overview of CAP is provided below.

4.4.3.1 Data Extract, Transform, and Loading (ETL)

The Data ETL portion of the solution loads export data from PUC source systems in order to connect and prepare it for a broad set of reporting requirements for utilities. The Data ETL will load specific data

from the following PUC systems: NorthStar CIS, Cuyanta WMS, Harris CustConnect Portal, Survalent SmartOMS, Survalent DA, Survalent VVM, Harris MeterSense MDM. These systems will each be required to export data in flat-files (or in other agreed upon formats) in order to transfer them to CAP, and the Data ETL to load them into the Leidos Smart Grid Data Warehouse.

4.4.3.2 Smart Grid Data Warehouse and Data Reporting

Once data is loaded into the cloud, CAP is based on the Leidos Smart Grid Data Warehouse, which provides an optimized and connected repository for KPI reporting, service-location and group reporting, and geospatial visualizations. The smart grid data warehouse leverages the Common Information Model and MultiSpeak data models for standards-compliant data storage, interaction, and analysis. The data warehouse automatically loads, organizes, and aggregates data into standard reports including specific AMI data driven reports as outlined in Figure 1 and Figure 2.

Channel Analytics – By Group By Rate Class

	Fact / Measure	Organization					Time					
Channel	Flow	Utility	Rateclass	SLOC	Meter	Group	Interval	Hour	Day	Month	Quarter	Year
kWh	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x	x	x
kVAh	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x	x	x
kVARh	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x	x	x
kW	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x	x	x
kVA	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x	x	x
kVAR	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x	x	x
Voltage - Phase A - Avg		x	x	x	x	x	x	x	x	x	x	x
PF	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x	x	x
LF	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x	x	x

Figure 1: AMI Analytics Reports based on Meter/Group

Channel Analytics – By Distribution Network Topology

	Fact / Measure	Distribution Topology			Time					
Channel	Flow	Top/Peak Level	Features/Node Level	Base/Bottom Level	Interval	Hour	Day	Month	Quarter	Year
kWh	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x
kVAh	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x
kVARh	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x
kW	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x
kVA	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x
kVAR	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x
Voltage - Phase A - Avg		x	x	x	x	x	x	x	x	x
PF	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x
LF	Delievered, Received, and Net	x	x	x	x	x	x	x	x	x

Figure 2: AMI Analytics Reports based on GIS Topology

The SGDW includes the following reporting based on the sourced data from PUC. Actual report availability will be constrained by the data PUC can make available from the identified source systems but should broadly align to the list below.

Report Categories	Description
Channel Facts By Rate Class	A report for each channel provided in a table format with aggregate values by rate class over a period time. Provides drill through from Year to Day increments to find when a point of interest occurred. Provides drill through on maximum and maximum values to the Outlier (Top and Bottom) Reports.
Top and Bottom Reports	A tabular report that reveals the top and bottom channel values for a rate class by service location (and meter). This report provides meter, rank, by channel at each of the time levels of Day, Month, Quarter, and Year.
Channel Charts at Utility Level	These time series charts show channel for the whole utility at aggregate time levels of Interval, Hour, Day, Month, Quarter, and Year.
Channel Charts By Rate Class	These time series charts show channel by rate class at aggregate time levels of Interval, Hour, Day, Month, Quarter, and Year.
Channel by Service Location / Meter Reports	These time series charts show channel by service location (by meter) at aggregate time levels of Interval, Hour, Day, Month, Quarter, and Year.
Group Reports	Group reports show data in aggregate groups of meters. This aggregation allows a set of meters to be viewed as one collection device. Basic reports show meters that belong to a group and the groups for a meter.
Group Channel Chart Reports	These time series charts show the channel data for each group at aggregate time level of: Interval, Hour, Day, Month, Quarter and Year.
Transformer Report	This crosstab report compares the KVA ratings to the actuals and provides a normalized utilization value. Drill through provides links to time series charts by Month and by Day.
Event Reports	Event reports list the AMI events over a period of time for the selected service locations.
Register Reports	These reports show the register values captured (usually on a daily basis) over a period of time for the select service locations.
Channel Report by Distribution Network Element	This set of reports shows the channel data aggregation to the non-meter devices defined for in the network topology model. This includes the standard and derived channels data over the time levels from Interval to Year.
Reliability Reports	Reliability reports provide views at the time levels of SAIDI, SAIFI, CAIDI, and MAIFI for each non-meter element in the distribution network topology.

Figure 3: Standard AAM Reports

GROUP NAME	2014-2 GROUP RATING (Highest)	2014-2 CH KVA D MAX (Highest)	2014-2 TRANS UTILIZATION (Highest)	2014-3 GROUP RATING (Highest)	2014-3 CH KVA D MAX (Highest)	2014-3 TRANS UTILIZATION (Highest)	Totals GROUP RATING (Highest)	Totals CH KVA D MAX (Highest)	Totals TRANS UTILIZATION (Highest)
Client Private 270	10.00	30.15	1.01	10.00	50.60	5.06	10.00	50.60	5.06
270	15.00	13.81	0.92	15.00	32.00	2.13	15.00	32.00	2.13
140	15.00	9.01	0.60	15.00	32.00	2.13	15.00	32.00	2.13
180	25.00	11.45	0.46	25.00	32.00	1.28	25.00	32.00	1.28
040	15.00	4.59	0.31	15.00	16.00	1.07	15.00	16.00	1.07
020	15.00	12.87	0.86	15.00	12.65	0.84	15.00	12.87	0.86
440	15.00	9.91	0.66	15.00	12.00	0.80	15.00	12.00	0.80
340	25.00	10.01	0.40	25.00	8.00	0.32	25.00	10.04	0.40
280	25.00	4.25	0.17	25.00	4.00	0.16	25.00	4.25	0.17

Figure 4: Transformer Report Example

Additional planned and in-scope PUC-specific UDM KPI reports are likely to include the following but will be subject to detailed design work with PUC and the UDM team:

KPI/Metric Report	Description
Service Order Metrics	Tracks service order number and times in order to assess the impact of data driven engineering and internal organizational improvements.
CustConnect Usage Metrics	Tracks user metrics in CustomerConnect to identify what content proves valuable and where customers are and are not consistently being engaged online.
SCADA DA Metrics	Tracks Distribution Automation metrics and reliability improvements that result from DA actions.
SCADA VVM Metrics	Tracks Voltage Optimization metrics and reliability improvements that result from VVM actions.
2-3 Additional as per mutual agreement	Leidos expects to complete 2-3 additional KPI reports per UDM and PUC requirements as a result of the detailed design stage efforts.

4.4.3.3 Data Visualization

CAP includes a System Visualization Module (SVM) tool that provides focused, clear, and action-oriented geospatial analysis views that merge smart meter, GIS, CIS, and other data sources together. The results for PUC and the UDM are GIS "apps" that can identify and isolate issues—providing actionable intelligence, out of the box. As illustrated in Figure 3, SVM provides a view of AMI and Smart Grid data geospatially that will allow PUC to monitor thresholds and adjust the settings of the UDM to precisely deliver the operational parameters required.

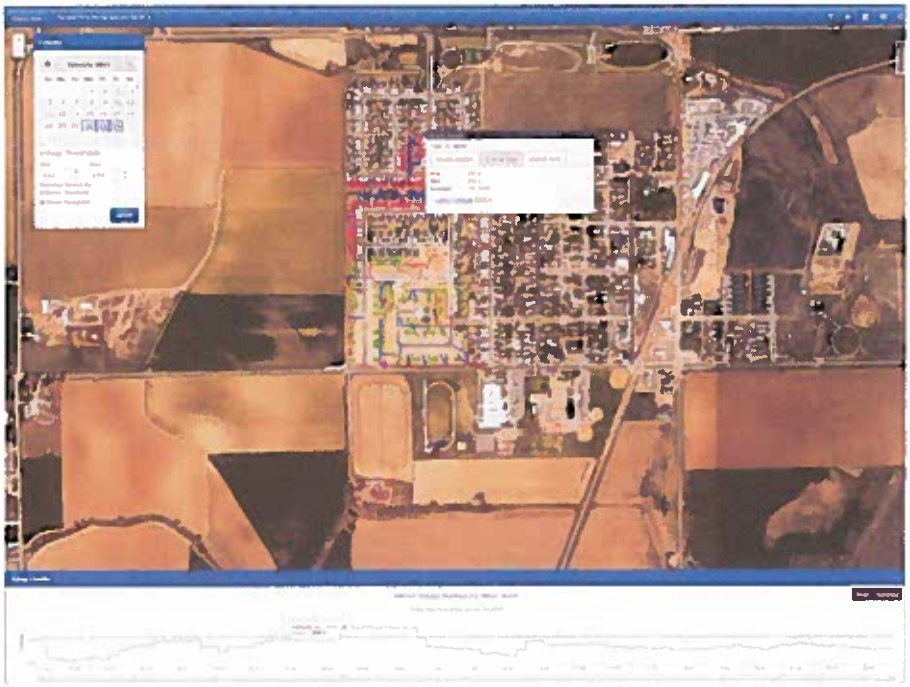

Figure 5: SVM Voltage Analysis View

SVM includes the following visualizations in the standard product (subject to suitable data being made available from PUC systems):

Visualization	Description
Voltage	The Voltage visualization maps voltage channel data and alarms across the distribution system and allows for threshold analysis to identify power quality issues and CVR opportunity areas.
Reliability	The Reliability visualization leverages key outage statistics from meters to map reliability statistics across the distribution system and allows for threshold analysis to identify best and worst performing circuits and assets.
Load	The Load visualization leverages available energy and power channel data across the distribution system and allows for threshold analysis to identify high/low/no load assets on the system.

Outage	The Outage visualization leverages real-time outage data from smart meters across the distribution system and allows for outage tracking (this view is similar to existing views at PUC, but can be accessed by any user at the utility with credentials and network access).
Orphans	The Orphans visualization allows for map correction and attribution scope to be identified in order to get the most out of roll-up analytics.

4.4.4 Scope and Detailed Requirements

Overall CAP solution roles are summarized below

Scope Item	Design	Build	Operate
ETL	Leidos	Leidos	Leidos
PUC Systems	PUC	PUC	PUC
Site-to-Site VPN	Leidos	Leidos	Leidos
Hosting and Storage	Leidos	Leidos	Leidos
Security Documentation	Leidos	Leidos	Leidos
Cloud Deployment	Leidos	Leidos	Leidos
Base AAM Reports	Leidos	Leidos	Leidos
Custom Reports	Leidos	Leidos	Leidos
Base SVM Visualizations	Leidos	Leidos	Leidos
Solution Documentation	Leidos	Leidos	Leidos

CAP systems integration and reporting scope are summarized below:

Scope	Responsible Party
• Business Analysis - Use Case and Data Analysis	Leidos and PUC
○ Review of customer use cases	
○ Review of existing solution	
○ Review of in-scope enrichments	
○ Establish metric definitions and extensions not cover by base solution	
• Source System Exporting	Leidos and PUC
○ Create change data capture process and export process from source systems	
○ Leverage ESB scripts for master data (similar to Meter Data Management Load)	
○ Requires customer to create flat files – (no human created)	
○ Change data capture will be on providing system	
• Extend Data Model	Leidos
○ Create Fact objects to support additional metrics	

• Loading and Transformation	Leidos
○ Receive and load data into the CAP	
○ Most of this can be done directly from ESB scripts	
○ Leverage existing staging approach and tables, but some custom work	
• Metric Calculation and Aggregation	Leidos
○ Extend to for new metrics	
• Reporting Extensions	Leidos
○ Service/Work Order	
○ SCADA	
○ Other as defined in the Business Analysis	
• Training	Leidos
○ Data and Usage	
○ Conduct Workshops	

Detailed Requirements:

Requirement	Leidos Alignment
A platform is required to interconnect the network model and AMI data for ad-hoc analytics.	Aligned
AMI data should include channel, register, and event data	Aligned
GIS/OMS data should include the full connectivity model and update regularly	Aligned where full model is available
The platform should connect AMI meter data to service locations within the GIS model	Aligned
The platform should summarize AMI data according to network model structures	Aligned
The platform should provide a business intelligence and reporting platform and include base reports	Aligned
The platform should support ad-hoc reporting through a user interface or support personnel	Aligned
The platform should have an interactive map-based visualization platform	Aligned
The platform should provide data reliably and in a fashion to optimize UI performance	Aligned
The platform should use HTTPS and secure protocols to access cloud applications	Aligned
The platform can identify and report on data issues within AMI or GIS data	Aligned

Solution will flexibly ingest a wide range of data sources and provide flexible structured and ad-hoc reporting based on user defined criteria	Aligned
Solution will produce raw data export, summary reports, charts, graphs, and/or crosstabs	Aligned
Solution should handle a wide range of data types including time-series data	Aligned
Solution should include an initial phase to catalog existing data from across the organization, select and prioritize, and define initial reporting requirements	Aligned
Solution should deliver a web-based reporting interface	Aligned
Solution should load data in order to deliver an operational platform which includes a defined set of reports	Aligned

4.4.5 Project Assumptions

The following assumptions were made in the development of this project:

- Based on Leidos Cloud Analytics Platform
- Other vendors had partially overlapping solutions and can also be used for specific scope where needed.
- Customer will need to export data
- Standard site-to-site VPN or FTP be used for data exchange
- FTP / file transfer site will require no new hardware or software
- PUC has a perimeter firewall that can be used for site-to-site VPN
- Local ESB platform is not required as cloud solution can ETL data
- No direct access to customer systems required. Our system will accept files for upload.
- No new licensing costs required
- Business Staff will be available to review source data
- Business Staff will be available to project staff to define use cases
- Latency of a few days is acceptable, but not a hard metric
- Historic Loading – Limit is 13 months
- CustConnect – Portal has usage metrics saved. We are not creating this functionality – only sourcing what is saved.
- SSMIC GIS export can be provided as MultiSpeak export format
- For WMS metrics, the WMS will collect or have the base data to support them.
- Data Cleansing is the responsibility of the PUC and its staff
- Data analytics will be performed from Leidos datacenters in the USA

5 AMI Integration Architecture

In this section we outline the overall AMI Integration architecture that results from the four individual projects.

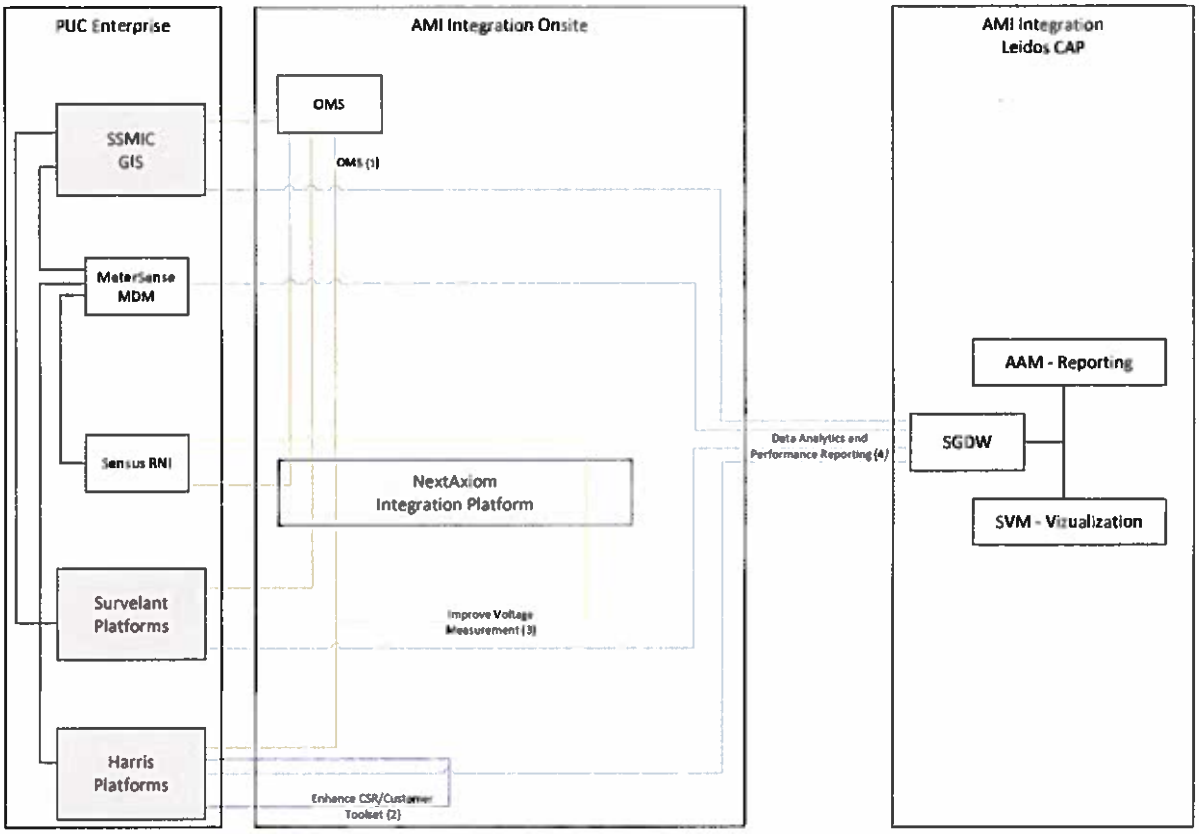

Figure 6: Summary AMI Integration Architecture

The summary architecture above results in the following AMI integrations:

Project	Integration Name	Src System	Tgt System	Standard	Int Platform
OMS	OMS-SCADA	Survelant	Survalent	MultiSpeak	Yes
OMS	OMS-AMI	Sensus	Survalent	MultiSpeak	Yes
OMS	OMS-GIS	SSMIC Esri	Survalent	MultiSpeak	Yes
OMS	OMS-CIS	NorthStar	Survalent	MultiSpeak	Yes
Enhanced Toolset	None*				
Voltage	AMI-SCADA	Sensus	Survelant	MultiSpeak	Yes
Cloud Analytics	SGDW-GIS	SSMIC Esri	SGDW	MultiSpeak	No
Cloud Analytics	SGDW-CIS	NorthStar	SGDW	TBD	No

Cloud Analytics	SGDW-SCADA	Survelant	SGDW	MultiSpeak	No
Cloud Analytics	SGDW-AMI	MeterSense	SGDW	MultiSpeak	No

Table 4: AMI Integrations List

**Note the CSR/Customer toolset does not require external non-Harris integrations, only professional services to create views and reports post NorthStar and CustomerConnect upgrades.*

Appendix AA8
Navigant Report #1 – Review of Business Case for Smart Grid Project for PUC Distribution

NAVIGANT

Review of Business Case for Smart Grid Project for PUC Distribution

Prepared for:

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April 15, 2015

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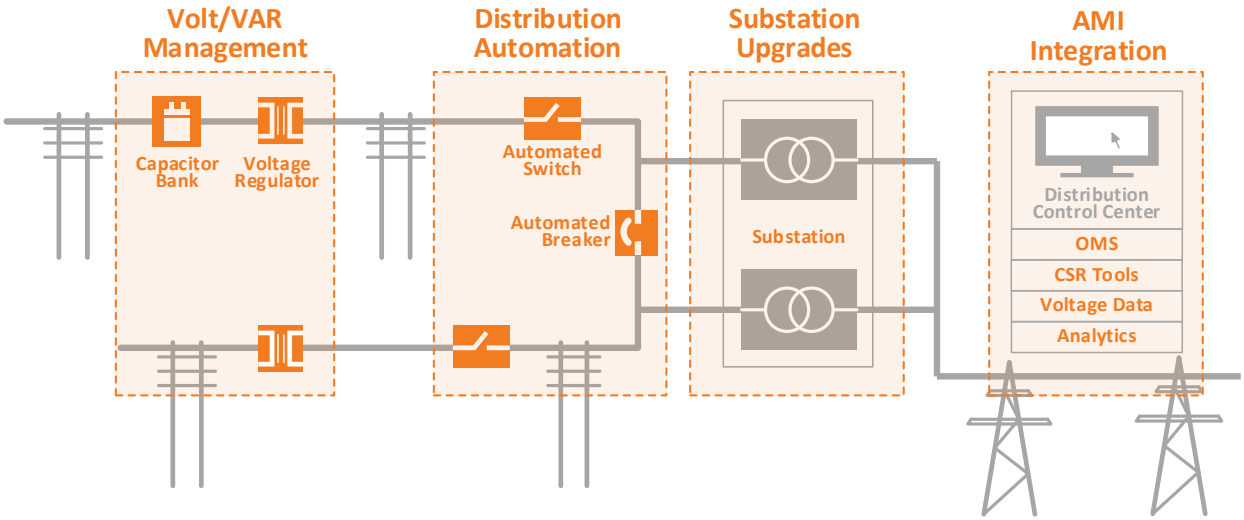
Executive Summary

Energizing Company (ECo) is proposing to assist PUC with the implementation of a Utility Distribution Micro-Grid (UDM). The proposed UDM project is characterized by distribution automation (DA) systems; Voltage/VAR management (VVM) systems; and integration and enhancement of the existing Advanced Metering Infrastructure (AMI). ECo has also proposed to accelerate PUC's planned investment in upgrading several substations, which are fundamental to support the functionality of the UDM operations.

Figure 1: Illustrative Schematic of UDM project



Source: Navigant

The UDM project also includes an extensive 3-year community engagement process for community outreach and stakeholder education. As part of the proposed project, PUC will make a fixed monthly payment to ECo, escalating with inflation, for the operating period of the contract. The final amount of these payments has not yet been determined, however, ECo provided Navigant with an expected range for these payments, which has been used in our analysis. The contractual arrangements include a *performance management strategy* intended to ensure that the performance of the UDM system meets all contract expectations and design specifications.

The UDM's 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. The proposed solution for PUC however is a very comprehensive solution. Relative to PUC's service territory the proposed feeder coverage for DA and VVM, 84% and 68%; higher than many other systems Navigant has encountered.

While the UDM project is significant given the level of coverage and equipment relative to the size of PUC's distribution system, Navigant does not view the project scope or Leidos' engineering and design capability as a technical concern. Navigant concludes the UDM project is technically sound, designed and configured consistent with current utility practices.

The UDM project consists of the deployment of VVM to 31 feeders, and DA to 39 feeders. The objective of the VVM system is to optimize voltage profiles along feeder lines and to minimize the reactive power in lines; reducing electricity consumption, demand, and line losses. The DA system will provide PUC with better real-time visibility and monitoring of the network, and enable automatic re-configuration of feeders to reduce the duration, impact, and frequency of outages. The UDM project also includes the deployment of an Outage Management System (OMS), which will integrate existing Supervisory Control and Data Acquisition (SCADA), AMI, and PUC's Customer Information System (CIS) data, as well as incorporating an Interactive Voice Response (IVR) system. The project will also include an enhanced CSR/Customer toolset, improvement to the AMI platform which will be leveraged for the VVM systems, and an analytics platform to integrate and track SCADA, AMI, CIS, OMS and GIS data for better reporting and use.

With regards to the design, construction, operations and hand-over costs, Navigant understands that the contractual arrangements will protect PUC and its customers from any risk of cost overruns. With respect to the particular project aspects, Navigant considers that the costs allocated to the business process change, should be reviewed when project costs are more fully completed as significant changes in software and business aspects for utilities are often underestimated. The cost estimates for the AMI, DA VVM and substation upgrades appear reasonable, and are not of particular concern given that the cost estimates for most of the associated equipment are based on well understood equipment and estimates from suppliers.

The evaluation of benefits is based on a load-flow and feeder-level analysis evaluating the benefits of the DA and VVM deployment on each individual feeder. This approach is consistent with industry practice, and is appropriate given the nature and detail of the project. Based on Leidos' valuation of benefits Navigant performed a benefit-cost analysis to determine the UDM's net value. This analysis estimated the net present value (NPV) based on a range of the monthly payment PUC will make to ECo for the duration of the project. As shown in Table 1, the NPV is estimated to range from approximately $6.1 million to $15.5 million, with benefit-cost ratios of 1.12 to 1.37, respectively. All dollar amounts shown in the report are in Canadian dollars.

Table 1: Summary of Results *(CAD $)*

	Low	High
Costs	41,391,630	50,815,617
Benefits	56,910,572	56,910,572
NPV	15,518,942	6,094,954
Benefit-Cost Ratio	1.37	1.12

Source: Navigant; all values in 2015 CAD $ and reflect benefits and costs through 2035

Based on the valuation of benefits, Navigant identified areas of uncertainty and risk that impact the overall value of the UDM. With regards to the DA system, a number of factors are known to influence the degree of reliability improvements. These include, feeder health; circuit topology, frequency of severe weather events; grid resiliency; and the appropriate valuation of a customer's reliability. Similarly, the VVM system is also subject to a number of influential factors. These include, different types of end-use loads, seasonal weather patterns, feeder reconditioning, electricity and demand forecasts, and the evolution of tariff structure and regulatory policy.

Taking these uncertainties into account, Navigant performed a number of sensitivity analyses. These analysis estimated the impact of different levels of benefits, using more conservative estimates of electricity and demand savings for the VVM system and lower reliability improvements for the DA system. In addition, the sensitivity analyses explored the impact on the UDM business case of extending the project term up to 30 years. The objective of this analysis is to explore the sensitivity of the benefit-cost ratio to different project uncertainties and the ability to adjust the financial structuring of the project to respond to changes as the project evolves.

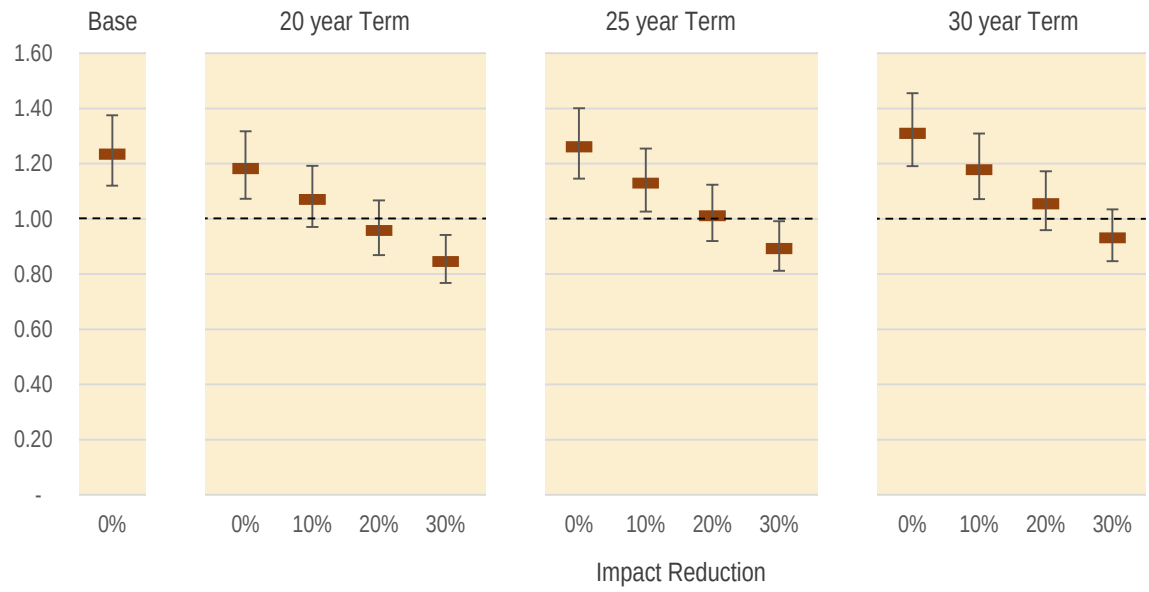
Table 1 above showed the cost-benefit ratios for the range of expected payments (high and low) using a 20 year project life. This *Base* scenario includes all of the local benefits (e.g., LDC and customer benefits), as well as the broader provincial benefits (e.g., generation and transmission benefits). For the sensitivity scenarios only the local benefits that can be attributed to the UDM have been included (i.e. the provincial benefits are not credited to the project).

These results suggest that as the project term is extended to 30 years, the UDM business case is strengthened. In contrast, as the impacts from consumption and demand, and reliability are reduced, the business case is weakened. In general, for a 20 year project term, if the provincial benefits are excluded and local benefits are reduced by more than 20% impacts reduction, the cost-benefit ratio for the UDM project falls below unity.

ECo has some flexibility in how the project is structured, including the ability to extend the project term. As shown in Figure 2 shows, if the project term is extended to 25 or 30 years, the cost-benefit ratio rises above unity for all but the high monthly payment case with a 30%

reduction in benefits. That case approaches but does not reach unity under a longer (30 year) project term.

Figure 2: Benefit-Cost Ratio Results of Sensitivity Analysis



Navigant considers that several aspects of the project framework and scope, currently not reflected in the UDM business case, add merit to the UDM value proposition and should be considered as part of the broader evaluation.

- The AMI integration scope, which includes the deployment of an OMS, CSR tools, enhanced AMI data, and an analytics platform, will enable PUC to improve a number of elements of their distribution business. While these benefits have not been included in the business case assessment given the overlap of system functionality and operation of these investments with the VVM and DA deployments, PUC and its customers will benefit from better outage management and customer communication, fault localization, asset monitoring, and improvements in system operation and maintenance.
- The project agreement, between Project Co and PUC, provides PUC with protection against the risks associated with cost increases over the term of the project. PUC. As per the project agreement, and project structure, the Designer and Construction Contractor will be responsible for the costs of the design and construction phase, such that neither PUC nor its customers are subject to financial risk. In addition, the performance strategy incentivizes all parties to ensure the performance of the UDM meets contract expectations. This risk transfer provides added value to PUC, which

while not reflected by the benefit-cost analysis, should never the less be kept in mind in the UDM evaluation

- The three-year customer engagement activities are designed to increase customer awareness, educate customers of the new capabilities and resiliency of their local electricity grid and obtain feedback from customer and stakeholder groups in the community.
- The UDM project allows PUC to meet the Ministry of Energy's Smart Grid objectives; addressing key areas of customer engagement and education, grid resiliency, intelligence and modernization, and operational effectiveness.
- Finally, as noted earlier, not taking action is not an option given the direction from the Ontario government and the OEB. PUC will be required to develop a Smart Grid Plan and make investments to introduce Smart Grid capabilities into its system. The project as developed with ECo provides comprehensive Smart Grid capability and delivers that capability to PUC and its customers more quickly than PUC might otherwise be able to access it.

1. Introduction

This section of the report introduces the purpose and scope of the 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 Review

Energizing Company (ECo) retained Navigant to provide a review of the business case for a Smart Grid (SG) project that it has proposed for PUC Distribution (PUC) in Sault-Ste. Marie, Ontario. The proposed project offers the utility an opportunity to implement a comprehensive SG project with the technical and financial assistance of ECo.

1.2 Overview of 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 Utility Distribution Micro-Grid (UDM), improvements to the utility's sub-stations as well as integration and enhancements to the existing Advanced Metering Infrastructure (AMI). The project also includes an extensive stakeholder engagement process.

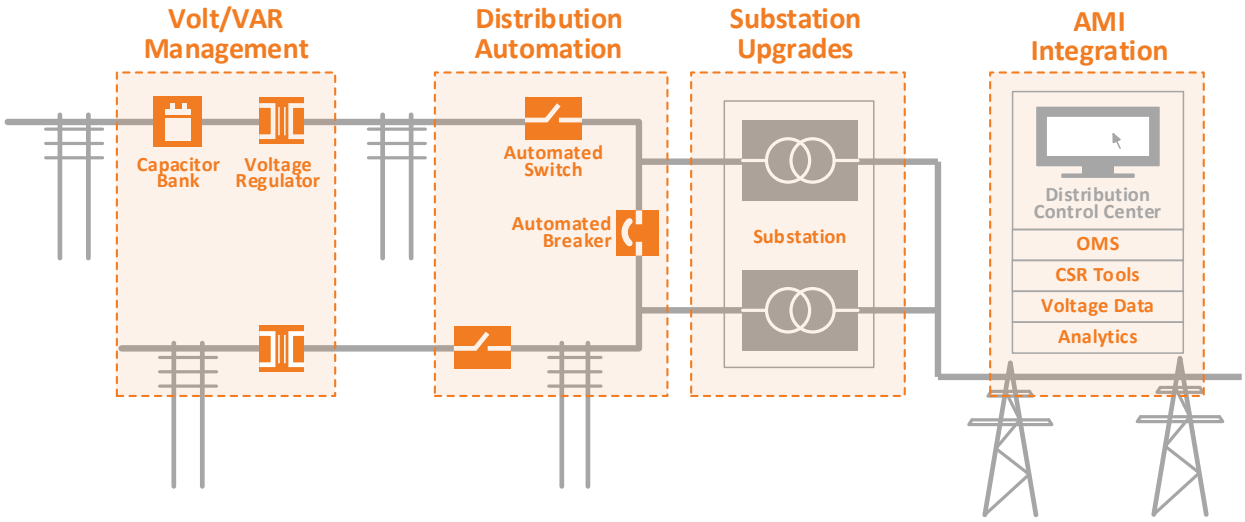
ECo proposes to fund the project in return for a fixed monthly fee; delivering engineering design, construction and on-going support of the system (described more fully below) over a contract period of 20-30 years. The proposal incorporates performance management provisions designed to assure PUC of a defined level of system performance over the life of the contract. The proposed Smart Grid system would enable PUC to meet the Minister's Directive that utilities develop and implement a Smart Grid plan; providing one of the most comprehensive SG implementations in Ontario.

ECo engaged Leidos Engineering to conduct a feasibility study and design for the proposed UDM. As shown by Figure 3, the project is characterized by four features:

1) Distribution automation (DA) systems;
2) Voltage/VAR management (VVM) systems;
3) Substation upgrades; and
4) Integration, and enhancement, of the existing advance metering infrastructure (AMI).

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. ECo has included the substation upgrades as part of the UDM scope, and has proposed to accelerate the work to upgrade the appropriate substations. These upgrades are required to support the full functionality of the UDM system.

Figure 3: Illustrative Schematic of UDM project



Source: Navigant

As part of the UDM project, ECo will be responsible for all design and construction costs, in addition to some portions of maintenance, and replacement costs. ECo has also proposed a 3 year community engagement process for community outreach and stakeholder education with respect to the UDM project.

The proposed project goes beyond a traditional design and build proposal to include project financing and contractual arrangements designed to ensure the continued operation of the project to a specified level of performance over the contract period. 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 5 minutes, the monthly payment could reflect a financial penalty for failing to meet performance standards.

The proposed project is designed to improve operating efficiency, improve system reliability and deliver savings to PUC, its customers and the provincial system. These benefits align with the objectives laid out in the Minister of Energy's Smart Grid Directive as well as the utility's own strategic objectives. The financing arrangements provided by ECo provide PUC with access to capital to achieve these benefits more quickly than may have been possible through conventional funding options.

From the standpoint of the business case review, PUC could choose an alternative approach rather than pursue the ECo proposal, however, the status quo is not really an option. Under the GEEA, the Minister's Directive and direction from the OEB, PUC is required to pursue development of SG capabilities as a condition of its license. Therefore we view the alternative choices as:

1) Partial implementation of SG capability: PUC could choose to implement only portions of the capabilities proposed by ECo or to implement the system over a longer period of time. This approach would reduce the initial level of investment required but would also reduce or delay the estimated SG benefits. While Navigant has not analysed alternative implementation plans, we anticipate that piecemeal implementation of the project would result in higher overall costs, as some synergies would be lost.

2) Implementation by PUC: PUC could engage in developing its own SG plan and implement that capability using the normal funding mechanisms available to Ontario LDC's. This would require a substantial investment in engineering and design, contractor and vendor selection and management and of course, would require obtaining the financing needed to implement the resulting design. Navigant expects that it would be difficult for a utility of the size of PUC to resource this type of effort without the assistance of a project partner such as ECo.

In either of these alternatives it should be noted that PUC would still be required to make investments that will be required to replace some substations which would otherwise be moved forward as part of the SG project. In addition to the requirement to invest in SG capability, PUC would also need to implement investments already planned and/or approved as part of its capital budget, some of which would be included in the ECo proposed project.

1.3 Scope of Analysis

The intent of this review is to review the business case for the proposed project from the perspective of ECo and PUC[1]. The costs, benefits and risks of the project will be reviewed in terms of how they may be expected to impact those two parties. While there are a number of other parties which play a role in the project or who will be contractually involved in the project, the scope of the review does not extend to addressing their respective interests.

Navigant notes that this analysis is based on a review of the design prepared by Leidos. We understand that the Leidos analysis was prepared when 30% of the engineering design had been completed. This represents a reasonably complete indication of the final design, however, final costs may vary. Navigant also notes that contract arrangements between the parties were

[1] The viewpoint of the PUC is assumed to include the interests of the utility's customers.

not fully in place at the time of the review. Navigant did not review contractual arrangements or terms as part of this review.

Finally, the review includes discussion of the possible regulatory treatment of the proposed project based on our understanding of the current policy and regulatory framework with regards to Smart Grid investments. Navigant has provided our best assessment of the regulatory processes in place with respect to approval for such investments, however we cannot prejudge how the OEB will ultimately view the investments for this specific project.

1.4 Policy Context

The ***Green Energy and Green Economy Act, 2009*** (GEEA)[2] requires that each distribution utility develop a so-called Green Energy Act (GEA) Plan to address renewable generation connections and smart grid development. In the GEEA, smart grid was defined as:

> *"advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of,*
>
> *(a) enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system;*
> *(b) expanding opportunities to provide demand response, price information and load control to electricity customers;*
> *(c) accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or*
> *(d) supporting other objectives that may be prescribed by regulation."*

The Act enabled the government to make regulations governing the implementation and regulation of smart grid; including assigning roles and responsibilities and the timeframe for development, implementation and standardization. Facilitation of smart grid was also added to the goals laid out for the OEB in subsection 1(1) of OEB Act.

The GEEA amended the deemed conditions of licences for transmitters and distributors, which all distributors must meet, to state that:

> *"1. The licensee is required to prepare plans, in the manner and at the times mandated by the Board or as prescribed by regulation and to file them with the Board for approval for,*
>
> *i. the expansion or reinforcement of the licensee's transmission system or distribution system to accommodate the connection of renewable energy generation facilities, and*

[2] The Ontario GEEA is often referred to using the shorthand term "Green Energy Act" or GEA.

ii. *the development and implementation of the smart grid in relation to the licensee's transmission system or distribution system.*

2. *The licensee is required, in accordance with a plan referred to in paragraph 2 that has been approved by the Board or in such other manner and at such other times as mandated by the Board or prescribed by regulation,*

   i. *to expand or reinforce its transmission system or distribution system to accommodate the connection of renewable energy generation facilities, and*

   ii. *to make investments for the development and implementation of the smart grid in relation to the licensee's transmission system or distribution system."*[3]

As a result, pursuing smart grid development is now a requirement for distributors in order to maintain their license in Ontario.

On November 23rd, 2010 the Minister of Energy for Ontario issued a Ministerial Directive to provide guidance to the Ontario Energy Board and Local Distribution Companies (LDCs) with respect to Smart Grid investments. The Directive, included as Appendix A, sets out policy objectives for Smart Grid investments as well as specific objectives relating to customer control power system flexibility and adaptive infrastructure.

Responding to the GEEA and Ministerial Directive, the OEB introduced new filing requirements for electricity distributors. Chapter 5 of the filing requirements describes a requirement for utilities to submit a "*Consolidated Distribution System Plan*". The Distribution System (DS) Plan must be filed when the utility applies for rebasing of their rates under the 4th Generation IR or a Custom IR application. Utilities which have already filed a 4th generation Cost of Service application and are using the "Annual IR Index" must make a Chapter 5 filing within 5 years of the date of their COS approval. The Board may also choose to require a DS plan in relation to a leave to construct, Incremental Capital Model or Z-factor application.

> "*Distributors yet to file a cost of service application containing a consolidated capital plan pursuant to Chapter 5 will continue to be able to record renewable energy generation costs, smart grid demonstration costs and funding adder revenues (for existing funding adders) in deferral accounts already established for this purpose. Likewise, such distributors may also seek new funding adders for material eligible investments if they are on the 4th generation IR plan as part of their IRM applications, until such time as the first cost of service application containing a consolidated capital plan.*" [4]

[3] Bill 150, Green Energy and Green Economy Act, 2009, available at: http://www.ontla.on.ca/web/bills/bills_detail.do?BillID=2145

[4] Ontario Energy Board Filing Requirements For Electricity Distribution Rate Applications - 2014 Edition for 2015 Rate Applications - Chapter 2: Cost of Service, July 18, 2014, page 5.

In February 2013, the OEB issued a "Supplemental Report on Smart Grid" (EB-2011-0004) which set out the Board's expectations with respect to Smart Grid as part of the Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (the RRFE report). The Supplemental Report outlines a set of evaluation criteria that the Board will use to assess a capital plan for approval and indicates that "*the evaluation of smart grid investments will be no different from any other investment made by a regulated entity*"[5]. These evaluation criteria include:

- Efficiency, Customer Value, and Reliability,
- Safety,
- Cyber-security and Privacy,
- Co-ordination and Interoperability,
- Economic Development,
- Environmental Benefits.

1.5 Utility Context

PUC Distribution is a subsidiary of PUC Inc. which in turn is wholly owned by the City of Sault St. Marie. PUC and its predecessor companies have served the City of Sault Ste. Marie since 1888[6]. As a Local Distribution Company (LDC), licensed as an electricity distribution company by the OEB, PUC distributes electricity to over 33,000 residential and business customers in Sault Ste. Marie. PUC has annual electricity sales of over 730 GWh. In 2013, its annual power and distribution revenues were just under $89 million and its net revenues just over $2.1 million with total assets of over 104 million[7].

PUC filed a Cost of Service rate application with the OEB on October 11, 2013 following the 4th Generation Incentive Rate-Setting (IRM) guidelines.

> *"PUC has prepared the 2014 4th Generation Incentive Rate-Setting (IR) Application consistent with Chapter 3 of the filing requirements for electricity distribution rate applications revised by the Ontario Energy Board (the "OEB") on July 17, 2013[8].*

This means that PUC will be required to submit a smart grid plan as part of a Distribution System Plan when it files its next COS application; expected in 2017.

The 2014 IRM application was for an annual adjustment under the 4th Generation IRM. It did not include any rate riders for tax legislation, off ramps or Z-Factor claims.

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[5] OEB, Report of the Board: Supplemental Report on Smart Grid, (EB-2011-0004), February 11, 2013, Page 17.
[6] The first electric lighting in Sault Ste. Marie was supplied by the Sault Ste. Marie Water, Gas and Light Company which was incorporated in 1888 (Sault Ste. Marie PUC website - http://www.ssmpuc.com/index.cfm?fuseaction=content&menuid=4&pageid=1003).
[7] Figures for 2013, based on Ontario Energy Board, 2013 Yearbook of Electricity Distributors, August 13, 2014.
[8] *Manager's Summary EB-2013-0167.*

The dates of recent PUC Distribution's Board filings are shown below:

Table 2: Recent PUC Filings with the OEB

Rate Year	OEB Number	Description
2013	EB-2012-0162	Cost of Service (COS) application
		Letter requesting delay in filing submitted August 27, 2012 (indicating that they intended to file by September 30, 2012).
		Decision and rate order – July 4, 2013. (Settlement Agreement).
2014	EB-2013-0167	4th Generation IR Distribution Rate Application - filed October 11, 2013
		Notice of Application published /filed with OEB
		Board decision and Rate Order – March 13, 2014
2015		2015 Price Cap IR – filed September 26, 2014. Decision and rate order issues March 19, 2015.

Source: OEB regulatory filings

In its 2013 filing (EB-2012-0162) PUC requested the continuation of a capital structure of 40% Equity, 4% Short Term Debt, and 56% Long Term Debt. The submission included $29,966,569 of capital projects in the 2012 Bridge year and $7,974,607 of projects in the 2013 Test Year. Approximately $23 million of the proposed expenditures in the Bridge Year was for a new Service Centre. PUC also moved from Canadian Generally Accepted Accounting Principles (CGAAP) to the Modified International Financial Reporting Standards (MIFRS) in the bridge year[9].

According to the 2013 submission, "*PUC used the half year rule for calculating depreciation expense for the 2008 to 2011 Actual and 2012 Bridge Year and 2013 Test Year*" and used straight line amortization to determine the depreciation expense for all distribution assets. Accumulated depreciation was reported as $52,427,983 for the 2012 Bridge year and 52,747,931 for the 2013 Test Year[10]. Annual depreciation was stated as $ 3,407,501 (using MIFRS accounting).

PUC submitted a Green Energy Act Plan as part of its 2013 Cost of Service (COS) Application EB-2012-0162. The Plan described Smart Grid investments made by PUC to that time but did not seek approval for any additional costs related to the Green Energy Act:

[9] Table 2-19 2007 to 2013 Test Year Capital Projects, Appendix 2-A, Capital Projects Table, PUC Inc. ("PUC"), EB-2012-0162, Exhibit 2, Tab 2, Schedule 7, Page 2 of 26.
[10] Table 2-19 Accumulated Depreciation Table PUC Inc. ("PUC"), EB-2012-0162, Exhibit 2, Tab 2, Schedule 8, Page 2 of 2.

"PUC is seeking approval of the Green Energy Act Plan. PUC is not seeking approval of any costs related to the Green Energy Act in this application. PUC proposes that any costs that may arise as part of the Green Energy Act be recorded in a deferral/variance account for future disposition." [11]

1.6 Organization of Report

The following report is organized into three main sections. Following the Executive Summary and this Introduction, section 2 provides an "Analysis of the Proposed Project"; describing the project and its financial structure, providing a technical assessment of the proposal and reviewing the project costs, benefits and risks. Section 3 addresses regulatory considerations of the proposed project and how the proposal aligns with provincial policy objectives.

The Smart Grid Directive from the Ontario Minister of Energy is included as Appendix A.

[11] EB-2012-0391 Exhibit 2 Tab 3 Schedule 5 Page 1 of 44.

2. Analysis of Proposed Project

2.1 UDM Project Features

The following sections describe the four key elements of the project, as well as the three-year community engagement process.

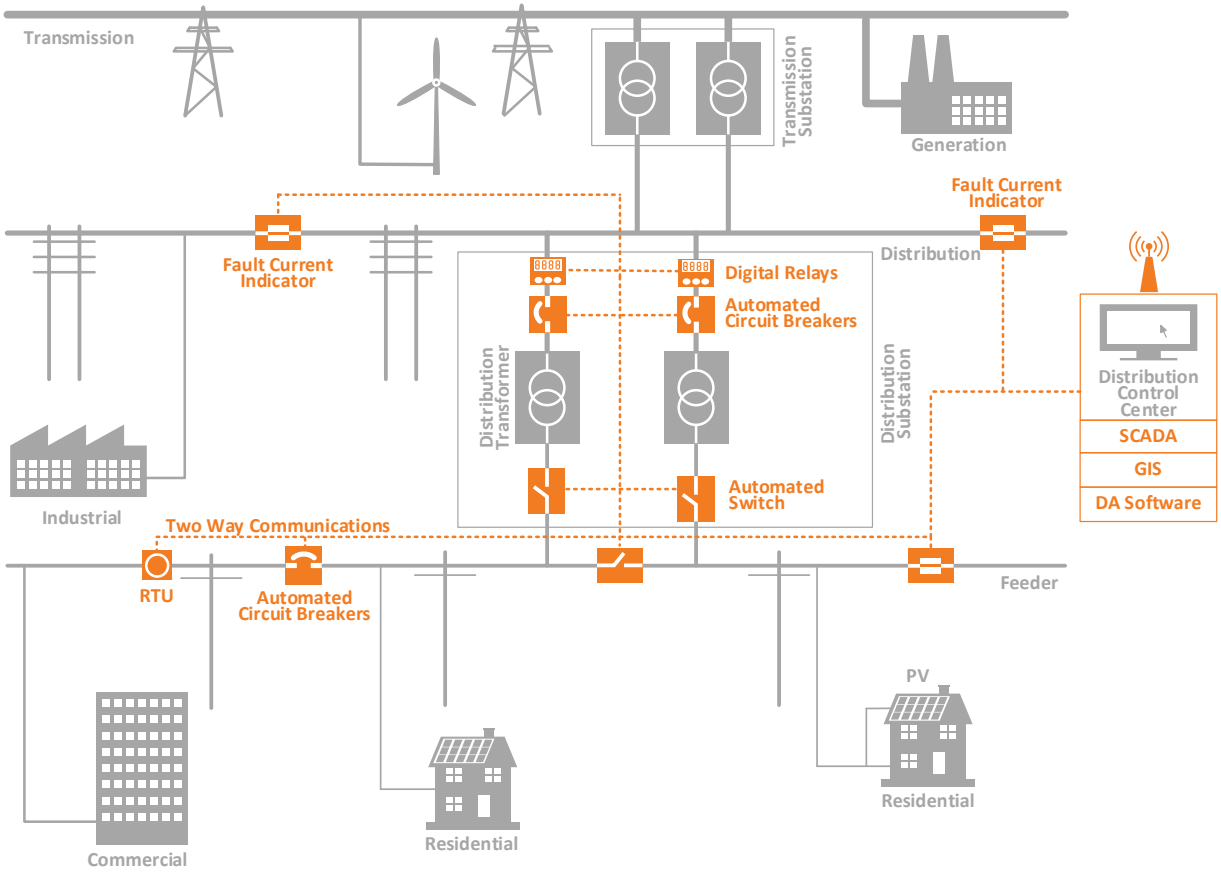
2.1.1 Distribution Automation (DA)

The UDM project also includes the deployment of DA to 39 feeders. The DA system will provide PUC with better real-time visibility and monitoring of the network, and the ability automatically locate and isolate faults, reconfigure feeder circuits and restore power more rapidly. The DA system involves real-time re-configuration of feeders to reduce the duration, impact, and frequency of outages. The proposed system will also ensure that load-transfer switching operations will not result in voltage or over-loading violations.

Currently, the only guidance for understanding system reliability is from PUC's outage database and system-level reliability data. Historic feeder-level data does not exist, nor is detailed outage data available. In addition, PUC uses a largely manual process to track the occurrence of outages and customer outage-calls. The underground system in the downtown area of Sault Sainte Marie is reported to be an area targeted for reliability improvement. Outages in the underground system serving the downtown generally take much longer to locate, and hence have more significant impact, than in the overhead system.

Leidos has recommended a robust DA system that targets the most critical reliability issues in the city. The proposed systems will deploy reclosers and switches in the majority of the PUC system. In addition, the underground system in downtown Sault Sainte Marie will benefit from the deployment of fault current indicators to decrease fault localization time. Additionally, the UDM project also includes an OMS (part of the scope of *AMI Integration*) that will improve operations and customer communications during interruptions, and automate tracking of outage metrics and system performance. Finally, the proposed design ensures interoperability with PUC legacy SCADA and communications systems.

Figure 4: Schematic of Proposed Distribution Automation System



Source: Navigant

2.1.2 Voltage/VAR Management (VVM)

The UDM project consists of the deployment of VVM to 31 feeders. The objective of the VVM system is to optimize the voltage profiles along feeder lines and to minimize the reactive power in lines to reduce electricity consumption, demand, and losses. This in turn can help avoid future investments in traditional transmission and distribution (T&D) infrastructure upgrades and reduce the need for manual switching operations.

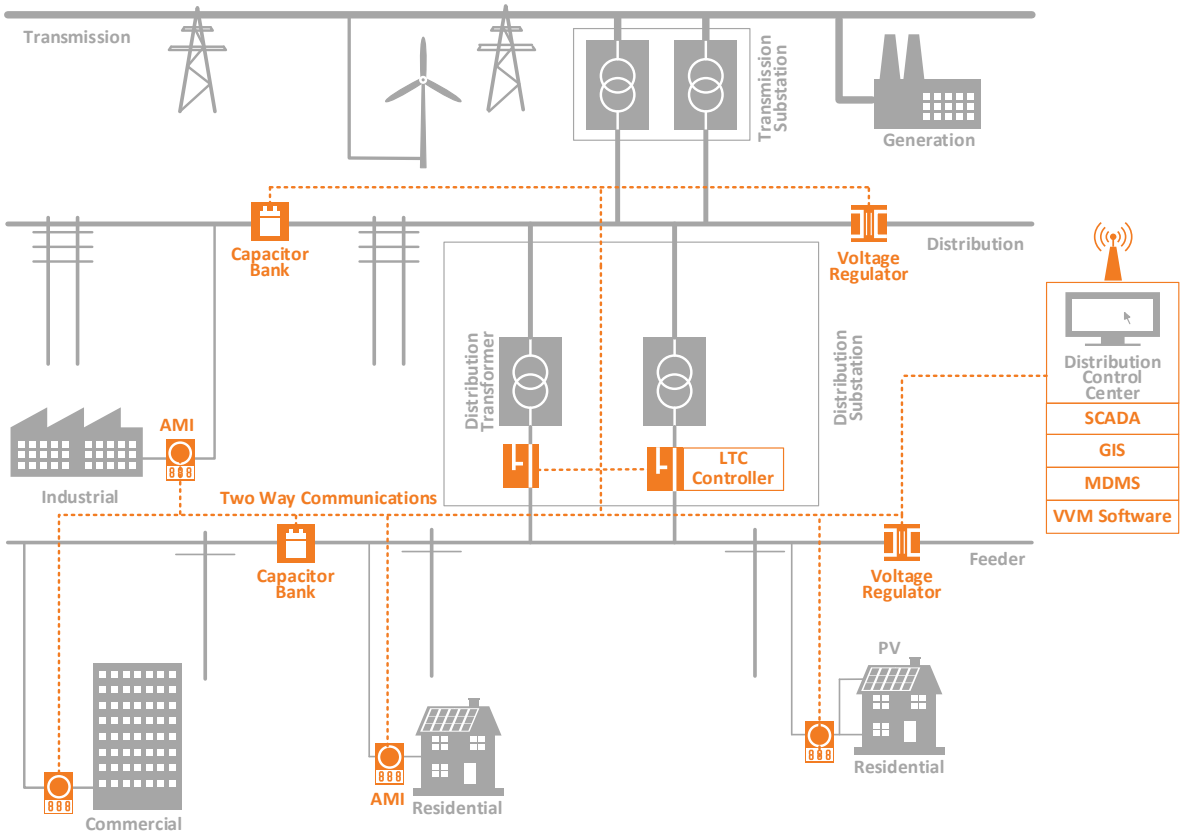
Currently, PUC does not have the capability to dynamically regulate voltage levels at any of the 34.5k/12.5 kV transformers. In addition, most of these transformers are approaching the end of their useful life and will have to be replaced in the coming years[12].

Leidos has proposed a Volt/VAR optimization scheme with a centralized control. The VVM system will leverage the existing AMI, Geographical Information System (GIS) and

[12] For more information see: Leidos. 2014. "Utility Distribution Microgrid: Volt/VAR Management (VVM) – Preliminary Design".

Supervisory Control and Data Acquisition (SCADA) systems and will employ Load Tap Changer (LTC) controllers, voltage regulators and capacitor banks. The VVM will benefit from the planned substations upgrades, as well as from feeder-reconditioning recommended for a selection of feeders. The proposed VVM system has the potential to help PUC and Sault Sainte Marie to achieve future conservation and demand management (CDM) goals.

Figure 5: Schematic of Proposed Voltage/VAR Management System



Source: Navigant

2.1.3 AMI Integration

The UDM project will deploy a number of applications intended to leverage the existing AMI system. These include:

- A robust Outage Management System (OMS), which will integrate existing Supervisory Control and Data Acquisition (SCADA), AMI, and Customer Information System (CIS) data, and incorporate an Interactive Voice Response (IVR) system. The objective of the OMS is to complement the deployment of DA. The OMS will automate reporting of outage information, reliability data, restoration verification, and to improve customer communications during outages through the IVR system
- An enhanced CSR/Customer toolset in order to manage AMI data in a more efficient manner. According to Leidos, PUC is content with its existing CIS platform. The proposed solution will leverage this affinity and will incorporate upgrades and additional functionalities to maximize the value of the CIS, and to align its capability to track metrics and data inherent to the DA and VVM systems.
- Improvement of AMI voltage reads in order to integrate data into VVM system. The existing Sensus AMI platform will need to be modified in order to achieve the granularity and data requirements needed to maximize the VVM system.
- An analytics platform to integrate and track SCADA, AMI, CIS, OMS and GIS data for better reporting and use. Leidos has proposed to deploy a Cloud Analytics Platform to integrate data from all systems and provide DA and VVM performance reports, and that facilitates the visualization and management of PUC's distribution system.

2.1.4 Substation Upgrades

The substation upgrades will support the deployment of the DA and VVM functionality. These substations require upgrading or replacement in order to enable the automated functionality for voltage control and automated switching in the 34.5kV and 12.47kV systems. The UDM project includes work at eight substations; four of which will require complete rebuilds, three require new LTC transformers, and one will require new bus-bar regulators.

Currently, most of these transformers are approaching the end of their useful life. Absent the UDM project, PUC would have to replace them in the coming years. The substation upgrades have been included as part of the UDM scope as they are a fundamental aspect of the project. Additionally, the proposed investments in VVM and DA will leverage the existing AMI infrastructure and the proposed substation upgrades to create a more robust business case for the combined deployment.

2.1.5 Community Engagement Process

An important aspect of the UDM project is the customer engagement process proposed for the first three years of the UDM projects. These activities are targeted to ensure the UDM team develops a clear understanding of the community, and to facilitate customer education and support for the project. In addition, these activities are intended to increase customer awareness and to inform customers of the new capabilities and resiliency of their local electricity grid. The community engagement process includes outreach to a wide variety of interests in the Sault Ste. Marie community, regular surveys to obtain feedback and continued communication and education over a three year period.

- *Community Research*

  The community research activities are designed to develop a thorough understanding of the Sault Sainte Marie region, the local community and neighborhoods. The intention is to develop a qualitative and quantitative baseline to characterize the region with regard to demographics, outages history, and customer awareness and response to the UDM project, as part of the community.

- *Stakeholder & Consensus Building*

  The stakeholdering activities are centered on building relationships and reaching out to all members of the community. These activities include conducting meetings with stakeholders, regional and community leaders, and local businesses and organizations. The objective of these meetings is to communicate the potential benefits of the UDM project and the positive impact they will have for the community.

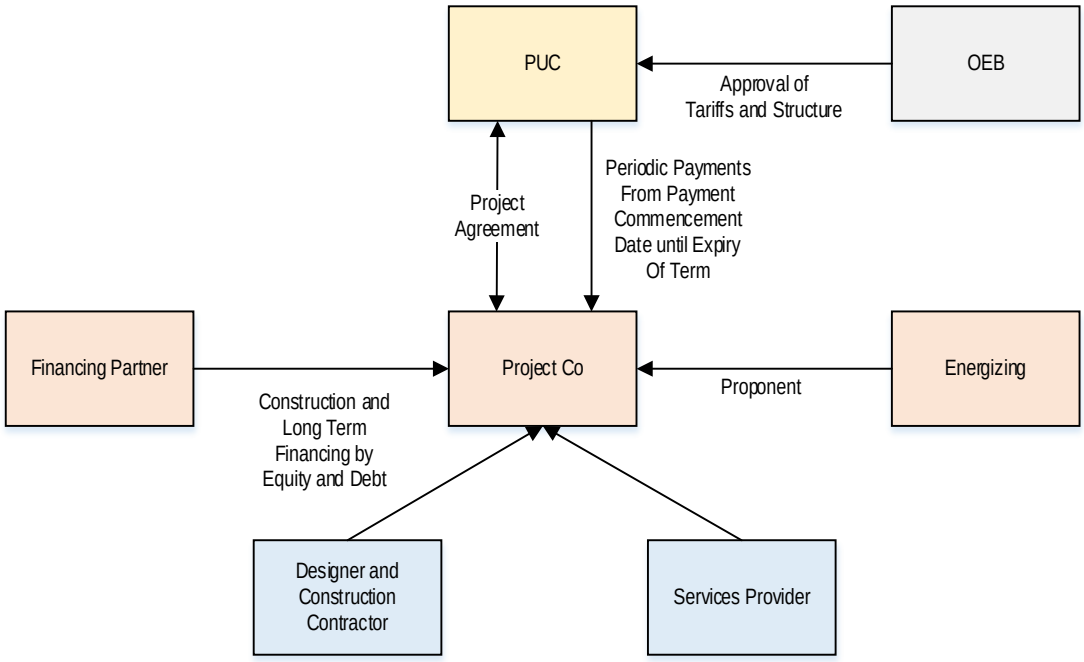
- *Community Outreach & Education*

  Public events will be arranged to introduce the UDM project team to the community and civic leaders, and engage community volunteers to act as 'champions' for the project. Educational events, presentations and science fairs will be arranged or used to engage with local elementary and high schools in order to highlight and promote innovative energy technologies part of the UDM project.

2.2 Financial and Organizational Structure

Figure 6 illustrates the organizational and contractual structure for the project. The roles of each of these organizations through the different phases of the project are described below.

Figure 6: UDM Project Structure and Relationships



Source: Energizing

Design and Construction

Project Company (or Project Co) will be responsible to PUC for the UDM project delivery. The project design will be developed in coordination with PUC to ensure compatibility with PUC's system. The Design and Construction Contractor also referred to as the Engineering, Procurement and Construction (EPC) contractor will be responsible for costs of the design and construction phase of the project. When construction is complete, the system will be tested to ensure it is performing to specifications. Once performance has been assured the parties will sign-off on an agreement of construction completion. Ownership of any component of the project vest with PUC upon installation of the respective components.

Operation and Maintenance

The Parties will agree to a maintenance plan, to be developed by the Service Provider in consultation with the PUC as well as the EPC. PUC will be responsible for carrying out all maintenance, rehabilitation and lifecycle work, in accordance with the plan, for the duration of the project. While PUC will implement all the work, Project Co and the Services Provider will be responsible for all maintenance costs of the UDM system, excluding substation work. Project Co and the Services Provider will also be responsible for the replacement of UDM assets that have a design or actual life less than the project term

The operating responsibility and operating authority for the UDM project will remain solely with PUC throughout the contract period.

Project Transfer / Hand back

At the end of the project contract term, Project Co and the Services Provider will "hand-back" the UDM system to PUC. The system will be tested to ensure that it is fully meeting all of the established design criteria before the PUC accepts the system.

2.2.1.1 Financing Approach

PUC will assume legal title for all components of the UDM System (including any sub-station upgrades and new-builds) upon installation of the respective components. That legal title will be subject to a licence by PUC to Project Co to access and use such component for the purpose of carrying out the Project.

PUC will make monthly payments to ECo for the duration of the contract. The monthly payment will be fixed in advance, and will be escalated annually for increases in the CPI. The monthly payment will:

- Amortize design and construction costs (e.g. DA, VVM, AMI);
- Pay for the three-year community engagement process;
- Pay for maintenance, development and Project Co. operating costs;
- Pay for replacement and lifecycle costs; and
- Pay a return on equity/debt, over the term of the Project Agreement.

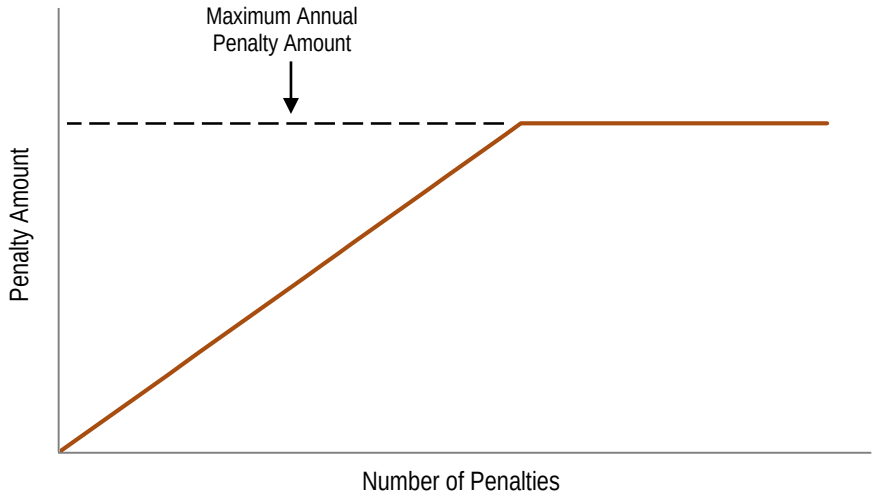
For this review it is assumed that the Service Fee will be treated as an operating cost and the UDM System assets will not be included in PUC's asset based until the end of the contract period. Under these conditions, PUC would not earn a rate of return or claim depreciation expenses for those assets. From a rates perspective this would mean that the PUC would not need to add this rate of return to customer's rates, but would instead reflect the cost of capital, replacement, life cycle costs, and other charges incorporated in the monthly Service Fee in their rates request as an operating expense.

2.3 Performance Management Strategy

Contractual arrangements will be included to incent parties to control costs and ensure systems are designed, operated and maintained to meet performance expectations. The performance management strategy forms an important element of the project design, which is intended to ensure that the performance of the UDM aspects meets all contract expectations. The monthly payment will suffer deductions (e.g. through a financial penalty) if the UDM fails to perform to pre-defined specifications. The performance penalty is paid annually to PUC as a lump sum reflective of the UDM performance in the previous calendar year.

Performance standards will be set for the VVM and DA systems. The annual penalty, for each system, is determined as the summation of all event violations multiplied by an event penalty amount, up to an annual maximum penalty amount, as shown below.

Figure 7: Illustrative Penalty Amount Calculations



Source: Navigant

An event violation is defined as:

- For the VVM system:
  - Occurrences where the end-of-line (EOL) voltage is outside the 110-115V range;
- For the DA system:
  - In *Full-Automatic* mode; number of un-faulted zones that have not been restored within 5 minutes; and,
  - In *Semi-Automatic* mode; number of instances when faults have not been located within 5 minutes.

No penalties apply in cases where the DA system is operated in disabled-mode or where the VVM system is operated in semi-automatic mode. In addition, penalties may not be valid and accounted for in situations where the DA and VVM systems, and the associated assets, infrastructure, communications systems, or operations and maintenance plans, have not been maintained or updated as specified, or where system failure occurs from external causes.

2.4 Technical Assessment

The Utility Distribution Micro-Grid[13] proposed for PUC includes DA and VVM technologies designed to achieve several MOE objectives.[14] These technologies focus on meeting three key MOE objectives, (1) efficiency, (2) customer value and (3) reliability. These three categories also produce a substantial percentage of economic benefits as described in Section 2.8. Navigant's review includes an assessment of UDM technologies designed for these three objectives, in addition to other objectives outlined in the MOE's directive, including interoperability, security, and safety. We also address the *Power System Flexibility* and *Adaptive Infrastructure* objectives set out in the MOE's Directive. Navigant's technical assessment is based on the preliminary design and cost studies and supporting documents prepared by Leidos, and several telephone conference calls conducted with Leidos design and planning staff.[15] Navigant also reviewed the UDM with PUC technical and operational staff.

2.4.1 DA and VVM Design and System Architecture

The PUC distribution system is comprised of 12.5kV and 4kV feeders, with line distances and feeder attributes comparable with LDC's in Ontario and elsewhere in Canada. There is currently a minimal amount of automation on PUC's distribution system, so integration of new DA and VVM will not interfere with nor prematurely replace other existing systems. For example, PUC currently does not have SCADA access to distribution equipment located beyond its substations.[16] The primary components of the UDM include upgraded communications, automation and controls, distribution substation and feeder equipment and upgrades. Approximately 84% and 68% percent of PUC's system will be covered by DA and VVM, respectively.

Figure 8 presents the overall system architecture for the DA/VVM system, which includes wireless communications at the feeder level and a new fiber ring between PUC system control room and each substation equipped with DA or VVM automation. The DA and VVM automation systems will be provided by Survalent Technology. Survalent is a well-known supplier of SCADA and DMS systems for numerous LDC's in Ontario, including PUC.

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[13] The project title suggests Micro-Grid (MG) technologies are included in the set of technologies proposed for the PUC distribution grid. However, the UDM does not include MG technologies at the time of this review. Navigant's review of the UDM, instead, addresses DA and Volt-VAR Optimization (VVO) systems [the term "Volt-VAR Management" appears in Leidos and PUC documents and will be used hereafter] that constitute most of the costs and benefits associated with the project. Navigant recognizes the technologies installed to support DA and VVM also can be used to support and integrate future MG

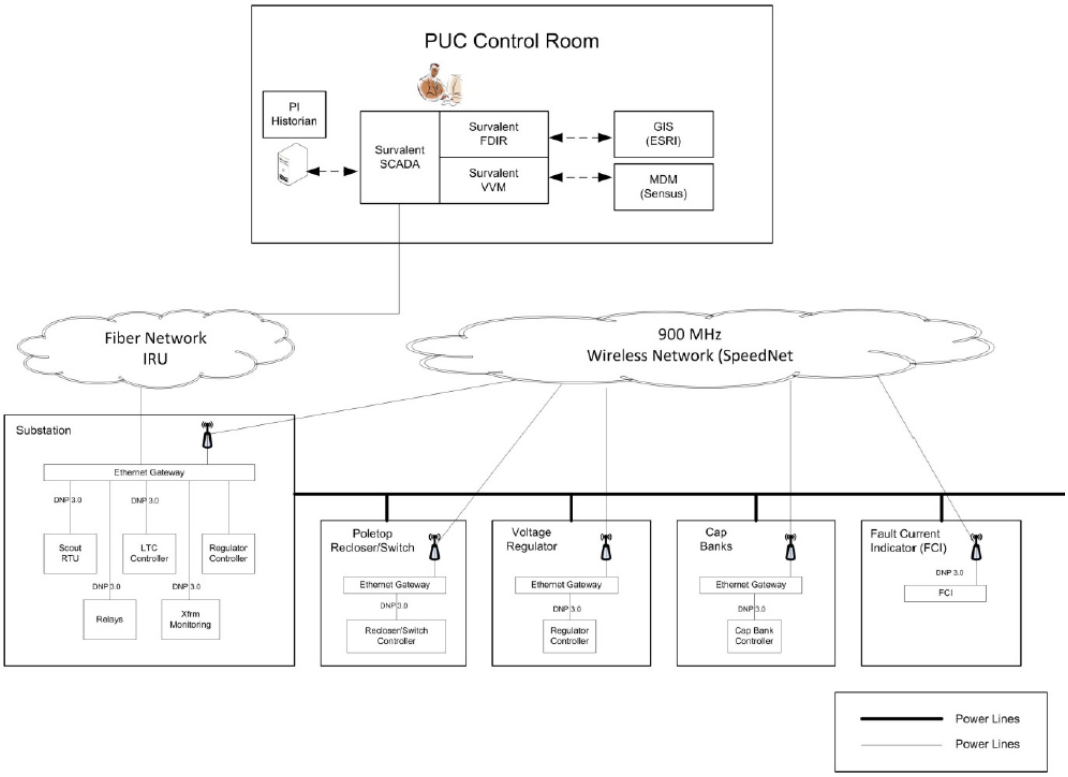
[14] See Appendix A: "Smart Grid Directive from Ontario Minister of Energy".

[15] Leidos experts sought explain the data, assumptions and methods it used to design the UDM, estimate costs and benefits, and to address questions Navigant raised on design details and documentation that Leidos prepared for the UDM. In each of these calls, Leidos was fully cooperative and responded to all questions by the Navigant team.

[16] PUC currently uses a Survalent SCADA system to monitor and control equipment in substations.

Leidos selected Survalent based on PUC's familiarity and favorable experience with its existing SCADA system, and Survalent's products and service offerings in Advanced Distribution Management Systems (ADMS), which includes VVM and FDIR (Fault Detection Isolation Restoration). Survalent-equipment Leidos has proposed for the UDM includes centralized automated control of DA and VVM for distribution substations and feeders, which can be operated on a fully automated basis or semi-automated mode with system operator over-ride or control.[17] The Survalent system will interface with PUC GIS, Meter Data Management (MDM), and SCADA to exchange operational data for DA and VVM field equipment. PUC System Operations will maintain operational responsibility of the UDM throughout the life of the project.

Figure 8. High-Level UDM Architecture



Source: Leidos

The DA segment of the control system will operate in 3 modes: (1) Disabled; (2) Semi-Automated; and (3) Full-Automatic. Control system flexibility is essential, as PUC does not now have, nor does it plan to provide, 24 hour/7 day staffing of its Operations Control Center. During day time hours, PUC operating staff can select manual mode for shut down during feeder switching or line construction or maintenance. During evening hours, the DA scheme will typically operate in full automation mode.

[17] PUC System Operations center is staffed for daytime hours only, and

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. This observation does not raise any specific technical concerns, but acknowledges that net project benefits may be lower for different segments of PUC's distribution system where opportunities for reliability improvement and VVM energy savings opportunities are more limited[18].

2.4.2 Distribution Automation (DA)

The DA system proposed for the UDM centers on installing FLIR systems on circuits that provide coverage for 84% of PUC's distribution system[19]. The FLIR proposed for PUC is based on proven control technologies that have been implemented on utility systems throughout North America, and typically produce strong business cases from an economic perspective. The DA design and feeder selection appears appropriate, as Leidos conducted a detailed analysis of PUC reliability data by feeder, and applied industry-accepted methods to identify feeder segments best suited for FLIR technology and to predict reliability benefits.[20] Leidos conducted CYME distribution simulation studies – CYME is a model used by many Canadian utilities and engineering firms - for each scheme under normal and transfer states to ensure PUC loading and voltage criteria were not violated. The preliminary design lists and describes the additional or upgraded equipment needed to successfully implement the schemes. Navigant agrees the new equipment is required to implement the FLIR schemes, which includes:

- Centralized FLIR automation software with GIS interface, including load flow simulation
- Source (34.5kV supply) transfer scheme in software
- 39 reclosers (38 feeders)
- 40 Pole top switches
- Four 2-way padmount switches (for underground lines)

[18] For example, distribution feeders that are expected to be upgraded or targeted for reliability improvements over the next few years may produce lower than expected level of benefits. Also, some feeders may currently have higher reliability than other feeders, and therefore, less cost effective. Navigant understands Leidos and PUC selected the worst performing feeders for DA, which should reduce the likelihood that some locations may have limited economic benefits.

[19] Navigant understands that PUC recently requested an amendment to the DA design to implement a fuse control strategy that would effectively increase the current 84% coverage to approximately 100% of PUC's territory.

[20] The DA system proposed for PUC include feeder transfer for loss of incoming 34.5kV transmission, a design aspect that ensures maximum reliability benefits are achieved for both a loss of main line feeder sections and substation supply.

- Two 4-way padmount switches (for underground lines)
- 20 overhead fault indicators
- 28 underground fault indicators

The equipment suppliers and technology Leidos presents in its preliminary design are appropriate, and from reputable firms, with technology that has been successfully deployed by other utilities for DA FLIR schemes. It includes fault indicators to direct crews to fault locations to reduce travel and repair time. Navigant notes the use of gang-operated switches instead of reclosers, a cost-effective choice when more expensive reclosers provide limited additional value. Leidos' design also includes radio communications to field equipment and switching devices, a less costly alternative to fiber expansion and suitable for DA applications.

Navigant recognizes the level of reliability benefits may vary from the estimate presented in Leidos' preliminary design documents, as PUC reliability data does not distinguish lateral from main line interruptions. Leidos sought to address data quality issues by reviewing in detail PUC interruption statistics, making revisions or omitting data that appeared as outliers, and then grouping the data by line segment to estimate interruption statistics by line section. Leidos reduced the level of potential reliability improvement, as measured by SAIFI and SAIDI[21], 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.[22]

2.4.3 Voltage/VAR Management (VVM)

The proposed VVM system is designed to achieve energy savings via permanent reductions in feeder voltage, achieved by reducing starting voltage at the substation and installing voltage regulating equipment, where needed, to ensure line voltage to not drop below minimum

[21] SAIFI and SAIDI and industry-accepted metrics utilities use to measure the average frequency and duration of sustained outages. Because the FLIR are designed to operate in less than 5 minutes, a threshold used by the electric utility industry to define sustained outages, SAIFI and SAIDI will significantly improve reliability.

[22] Conversations with PUC engineering and operations confirm reliability records do not distinguish main line versus lateral interruptions in its data bases. This has the potential to overstate potential benefits by DA. Leidos and PUC confirmed that most interruptions are caused by main line outage events. However, PUC noted that many lateral lines do have separate protection zones (e.g., fuses), which increases the number of main line interruptions that otherwise would not have occurred if protective devices were installed. If PUC were to enhance line protection by installing fuses or other protective devices on laterals, the reduction in customer interruptions via DA would be lower.

thresholds set forth in the Ontario Distribution Code. The Survalent VVM system will continuously monitor voltage via sensors at various locations on each distribution feeder and adjust voltages via station regulators and line capacitors or regulators. Leidos' approach identified the oldest substation transformers on the system scheduled for replacement in the near future under the assumption that new substations and replacement transformers at existing substation would be equipped with modern load tap changers suitable for VVM applications.[23] The analysis led to a determination that eight substations and 32 feeders are the best candidates for VVM. Similar to DA, Leidos conducted load flow studies; in this case to identify the level of energy savings that could achieved on the 32 feeders. For some feeders, additional upgrades such as line re-conductoring and installation of capacitors are needed to maximize energy savings potential.

The approach undertaken by Leidos to identify and evaluate substations and feeders where VVM is likely to produce the greatest benefits (as a function of cost) is consistent with methods that Navigant has observed or used to evaluate other comparable systems. Notably the use of a CVR factor of 0.50 is conservative to estimate energy savings. The use of AMI data to select feeders and for use in CVR automation also ensures maximize energy savings will be achieved. The equipment and systems needed to implement CVR at the eight PUC substations, listed, below, also are appropriate and necessary to maximize energy savings.

- Survalent Volt-Var Management system with GIS interface
- 4 new/rebuilt substations
- 2 new LTC transformers (10/13 MVa) at 7 existing substations
- 2 new distribution capacitors
- 2 new phase voltage regulators
- 2 padmount voltage regulators (Busbar)
- 17 feeders with phase rebalancing (may not require new equipment on some feeders)

[23] PUC's existing transformers do not have load tap changing capability, a requirement for effective CVR schemes.

The approach Leidos used to estimate energy savings, which includes lower energy, and line and transformer losses, is consistent with industry practices. It includes determination of the maximum allowable decrease in substation bus voltages using load flow simulation (CYME) under a range of loading conditions.

2.4.4 Summary Assessment

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]

The UDM DA and VVM program and associated objective are entirely consistent with MOE objectives outlined in the appendices to this report. The UDM introduces smart technologies where none exist today, and provides sufficient flexibility for expansion to introduce new technologies such as distribution generation or other efficiency programs. The design of the DA and VVM components of the UDM program will maximize energy and efficiency savings, including use of AMI data to enhance energy savings via CVR. Notably, the scope of the UDM is extensive, as it includes coverage of most of PUC's distribution system, well beyond pilot programs and limited implementation Navigant has encountered for some utilities.

We note that 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. We understand PUC's agreements with the Project Company protect PUC from potential cost and scheduling issues, so the PUC and it customers are protected from these risk factors.

2.5 Project Costs

Navigant's review of the full life cycle costs of the UDM are based on the design and cost studies, and supporting documents, prepared by Leidos. These costs are reflective of full life cycle costs for all project components, including installation, system integration, testing and

[24] Navigant did not obtain or review PUC historic reliability data or conduct independent analysis of PUC's distribution system.

commissioning, project management and controls, and training. These costs do not reflect costs associated with project financing, risk transfer or other services which will also be included in the monthly fee to PUC. As noted, the proposed UDM project will only accelerate the investments in substation upgrades. Absent the UDM project, PUC will have to incur the full costs of substation upgrades in the near future since most substations, and their associated assets, are approaching the end of their useful life. The distribution of project costs across the different elements of the UDM, shown below in Table 3, shows that Leidos estimates that substation upgrades will amount to approximately 40% of all project costs.

Table 3: Distribution of UDM Project Costs

Project Feature	Costs
DA	10%
VVM	24%
DA & VVM Common	1%
AMI	4%
Sub Total	39%
Substation Upgrades	38%
Post-Implementation	22%
Total	100%

Source: Leidos

The financial and asset ownership arrangement for the UDM is structured to enable Project Company to manage UDM assets over the 20-year term of the financing period without the need for a distributor license. This contractual framework reduces risk for PUC and its customers as Project Company assumes financial risk if actual cost exceed contractual commitments. Project Company is also responsible for ongoing maintenance and upgrades or replacement of UDM hardware and software components that are required during the financing term, which further reduces financial risk to PUC.[25]

The final costs of the overall project have not been finalized, however, ECo has indicated that the monthly payments are expected to fall in the range shown in Table 4, below. The range of possible monthly payments has been estimated based on a 30% preliminary design prepared by Leidos.

[25] PUC will retain operational control and responsibility for UDM assets. PUC also will be responsible for maintenance of electric power delivery assets, including substation equipment, overhead and underground switches and voltage regulating devices, communications equipment and systems, and any equipment operating at sub-transmission, primary distribution and secondary distribution voltage.

Table 4: UDM Monthly Payment *(CAD $)*

Feature	Low	High
UDM	$224,000	$275,000
Substation Upgrades	$213,000	$260,000
Total	$437,000	$535,000

Source: ECo

2.5.1 Design, Construction, Operations and Hand Over

As noted, all costs for design and construction of the UDM were prepared by Leidos, with input provided by PUC with respect to design standards, equipment specifications and procurement practices. Engineering costs are estimated at just under 10% of total UDM cost, which Navigant deems reasonable as a substation portion, roughly 7% is for conventional substation and distribution feeder upgrades, an area in which both Leidos and PUC have considerable experience estimating costs. In addition, about 5% of total UDM cost is for system integration of AMI, VVM, and DA systems, mostly Leidos support. Another 5% is for project management and control. Taken together, total design, project management and system integration cost are within industry averages. A substantial portion of total design and integration cost is directly payable to Leidos, which lessens risk since Leidos will be bound by contractual limits set by Project Company.

Navigant understands that operational costs are the responsibility of PUC. Navigant agrees that additional PUC staff will be required both during project-implementation and post-implementation. Approximately 2.3% of project costs are included for Client Staff Augmentation (for PUC), and nearly half of the post-implementation cost is allocated for supplemental staff augmentation over the 20-year contract period. Navigant considers that the amount estimated for business process change (at approximately 1.5% of project costs) appears to be on the low side, and should reviewed in conjunction with final project design. We encourage Leidos and PUC to further analyze business process change requirements as these costs are sometimes underestimated when significant changes in software and business aspects of utility operations are implemented[26].

2.5.2 AMI, Substations, DA and VVM.

The cost of major equipment hardware such as upgraded substation equipment and feeders constitute about 45% of total UDM cost. The cost of most of this equipment is reasonably well known, as PUC has recently installed similar equipment on its system or has obtained initial estimates from suppliers. For example, substation power transformers and station upgrades represent over 26% of total UDM cost; mostly conventional upgrades and systems that many

[26] Navigant notes that at the time this report was being prepared PUC was undertaking a 12 week business process improvement (BPI) project which will identify current baseline conditions and begin to introduce some of the BPI changes that may occur as a result of implementing the smart grid project.

utilities have installed as part of it ongoing capital planning and budgeting. An additional 9% is for S&C Intellerupters and switchgear. Leidos has advised Navigant that it obtained these estimates based on quotes from the vendor.

The total cost estimates for AMI, DA and VVM (and associated substation upgrades) each appear reasonable, particularly with regard to cost associated with major equipment. The cost of software and related support is based on estimates provided by Survalent, who will provide DA and VVM, software and support. While Navigant does not have any basis for assuming these estimates are low, we are aware that variances in software costs and implementation can occur due to changes in design or issues identified during the implementation phase. We note however, per the above described contractual framework approach, the risk for PUC and its customers is reduced as the Project Company assumes financial risk if actual cost exceed contractual commitments. Navigant also understands project contingencies, which have been estimated between 10% and 20% for the preliminary design, are embedded in the above cost estimates.

2.5.3 Summary Assessment

Navigant does not view the project costs as a potential concern for project delivery and success. The project agreement, between Project Co and PUC, ensures that PUC is protected from any risks regarding costs. Neither PUC, nor its customers, are put at risk as a result of potential cost overruns. As per the project agreement, and project structure, the Designer and Construction Contractor will be responsible for the costs of the design and construction phase. Once the project is completed and PUC is content with the delivery, functionality and compatibility with its distribution system, parties will sign-off in agreement. Additionally, while PUC will be responsible for implementing all maintenance work, as per an agreed-upon maintenance plan, the costs will be a sole responsibility of Project Co and the Services Provider.[27]

The agreement ensures that from project delivery PUC assumes operational responsibility and operating authority for the UDM (e.g., DA, VVM, AMI integration, and substation upgrades), and all associated assets, and upon hand-back UDM-ownership remains solely with PUC. The financial agreement outlines that PUC will make monthly payments to Project Co for the duration of the contract. The monthly payment will be fixed in advance, and will be escalated annually for increases in the CPI. This financial agreement ensures predictability with respect to capital expenditure from PUC, as well as with respect to electricity rates for PUC's customers. Smart grid investments, which are characterized by large upfront capital costs, generally yield benefits that accrue over many years into the future. The proposed agreement, enables PUC to manage the pace of the overall UDM investments to ensure that costs are smoothened and minimized over the long term, and that risks are fully mitigated. In addition, this financial structure enables PUC to accrue benefits commensurate with when costs are incurred.

[27] Any unscheduled work, and corresponding costs, will be a responsibility of PUC

2.6 Project Benefits

Leidos' model for evaluating benefits from the UDM project is appropriate for analyzing the impacts from VVM and DA deployments and is consistent with standard practice. The benefit-analysis framework evaluates the impacts of the VVM and DA acknowledging that these deployment occur in parallel, and as such, their individual impacts are interdependent, as opposed to assuming individual deployments occur in a vacuum. The evaluation of benefits is based on a feeder-level analysis for each individual feeder included in the project scope.

The UDM project is expected to yield benefits to PUC, its customers and the broader province through improvements in network reliability and resiliency, improvements in utility operation and maintenance, reduced electricity bills for customers, and avoided generation capacity, and transmission and distribution infrastructure.

2.6.1 Distribution Automation

2.6.1.1 Evaluation of Benefits

The UDM consists of the deployment of DA to 39 feeders. The objective of the DA system is to improve network reliability and resiliency. Customers will be the largest beneficiary of DA as a result of reductions in the number, duration, and impact of outages. In addition, PUC will benefit from faster power restoration, and in certain cases from avoided restoration operations.

PUC historical reliability data are based on system level data. Feeder-level reliability data was estimated by Leidos using the available outage data (measured as Customer Minutes of Interruption [CMI]) per feeder. Based on this information, Leidos identified the west and north segments of Sault Sainte Marie as the main focus of the DA system given their poor reliability record. The assumptions for improvements in reliability are shown in the following table. These values are theoretical reliability improvements based on the number of switches/reclosers installed per feeder. Feeders with two switches are assumed to be able to isolate the faulted sections of the feeder and hence results in a lesser impact than a feeder with one switch. A similar logic follows for each reliability index.

Table 5: Reliability Improvements

Number of switches	1	2
SAIFI	40%	50%
SAIDI	50%	60%
CAIDI	15%	20%

Source: Leidos

The number of switches/reclosers per feeder is then used to determine the time taken for power restoration, which ultimately determines the valuation of avoided utility O&M. The O&M evaluation parameters are shown below:

Table 6: Avoided Utility O&M

Measure	Parameter
Underground	20 min per mile
Overhead	5 min per mile
Line crew	$500 per hour

Source: Leidos

In addition, Leidos performed load-flows simulations to ensure that system reconfiguration designs would not cause any thermal or voltage violations in the event of switching operations. These reconfiguration simulations also determined savings from T&D infrastructure and generation capacity as a result of more efficient capacity utilization which resulted in lower demand and lower losses.

The valuation of reliability is generally determined from a customer's *Value of Lost Load*; which is a customer's foregone monetary value resulting as a result of an interruption. Leidos used a research study by the Power Research Group Study (1991) in order to determine the value of loss load. Leidos later benchmarked those findings with the Interruption Cost Estimator (ICE) calculator developed by the US Department of Energy. Leidos adjusted the valuation of reliability from 1991 Canadian dollars to present day dollars through the ICE values. The ICE calculator is generally considered an industry standard in the valuation of customer reliability improvements from distribution automation investments.

2.6.1.2 Assessment and Uncertainties

DA systems are triggered when faults occur, generally caused by natural events or equipment failure. A particular fault may be located using fault sensors which then communicate this information to the DA server. The DA control system may then trigger a switch to open upstream and downstream from the fault in order to isolate the fault successfully. If the circuit topology allows sectionalizing switches may transfer load from the un-faulted, de-energized sections of the faulted feeders to healthy feeders supplied from neighboring substations. The

objective is that eventually, only loads served by the faulted section of the feeder remain de-energized such that the extent of the outage is minimized.

In practice, however, DA switching operations may not be as simple as this example. A number of factors influence the degree of reliability improvements. These include: feeder health, circuit configuration (radial, looped, networked), the number and load of customers served, the number of switches, seasonal weather patterns, frequency of severe weather events and localized conditions. Radial circuits connected to a single substation may not be able to transfer un-faulted sections to another feeder. Networked feeder circuits may not necessarily be able to transfer loads to working-feeders if the power source is unable to meet load requirements. Multiple faults may prevent power restoration to un-faulted zones is switching operations cannot be completed. Equipment damage or a failed communication system may prevent switching operations to be completed.

Results from the Smart Grid Investment Grant (SGIG) projects funded by the U.S. Department of Energy (DOE) provide a sense of the variability of the improvement in reliability. The range of values shown in the table below highlight the uncertainty that can be expected from DA deployments. In addition, SGIG results might reflect what may be carefully selected feeders which are intended to provide proof-of-concept and develop operational expertise, as opposed to a reflect a business-as-usual deployment.

Table 7: Range of Reliability Improvements for SGIG Projects

Reliability Indices	Range of Percent Changes
SAIFI	-11% to -49%
SAIDI	+4% to -56%
CAIDI	+29% to -15%

Source: US DOE SGIG Projects

Communications infrastructure is also considered a fundamental element of DA deployment. Communication systems may, in fact, require greater resiliency and contingency than the distribution grid itself. Continuous communication between the DA software with reclosers, switches and fault indicators is most critical during outage events, and even more so during severe conditions.

2.6.2 Voltage/VAR Management

2.6.2.1 Evaluation of Benefits

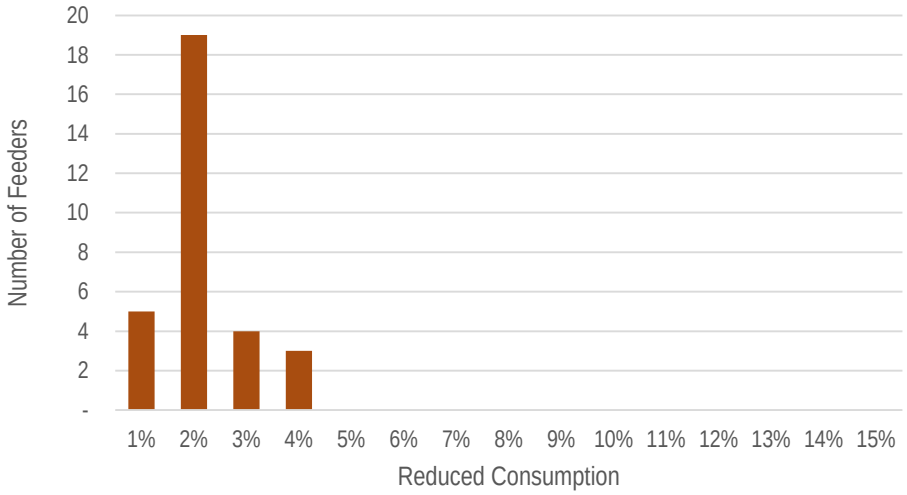
The UDM consists of the deployment of VVM to 31 feeders. Part of the scope of the VVM deployment includes substation upgrades and feeder reconditioning in order to maximize the potential benefits. The objective of the VVM system is to optimize the voltage profiles and to

reduce reactive power along feeder lines in order to reduce electricity consumption, demand, and line losses.

The voltage standard in Ontario for a single-phase residential customer allows for a range of 110 to 125 volts.[28] Leidos' preliminary design specifications shows substation voltage reductions in the range of 1% to 4%, as well as the corresponding reductions in feeder voltage, before and after VVM deployment.

Figure 9 show the reductions in annual electricity consumption per feeder. Navigant's experience with the CVR deployments is that these reductions are in line with results observed from VVM deployments across North America.[29]

Figure 9: Reduced Electricity Consumption across all Feeders



Source: Navigant analysis of Leidos' model

The impacts from the deployment of VVM are captured in Table 8. With respect to the VVM feeders only, the reductions in electricity consumption and demand are estimated as 2.1% and 1.6%, respectively. Similarly, line losses are expected to decrease by 2.6%. Table 8 also shows the reductions in consumption, demand, and losses relative to all of the PUC system.

[28] The 110 to 125 volt range is for a nominal voltage of 120V and is based on CSA Standard CAN3-C235-83

[29] For more information see: Northwest Energy Efficiency Alliance. December 2007. "Distribution Efficiency Initiative." Pacific Northwest National Laboratory. January 2010. "The Smart Grid: An Estimation of the Energy and CO2 Benefits", US Department of Energy. December 2012. "Application of Automated Controls for Voltage and Reactive Power Management – Initial Results." and Pacific Northwest National Laboratory. July 2010. "Evaluation of Conservation Voltage Reduction (CVR) on a National Level."

Table 8: Impacts of VVM Deployment

Measure	Reduction	Reduction (%) relative to VVM feeders only	Reduction (%) relative to all PUC feeders
Electricity Consumption (MWh)	10,363	2.1%	1.5%
Demand (MW)	1.2	1.6%	1.1%
Line Losses (MWh)	653	2.6%	1.8%

Source: Navigant analysis of Leidos' model

The valuation of avoided T&D infrastructure and generation capacity is determined from the IESO's (formerly OPA's) CDM Cost Effectiveness Guide, generally used by Ontario distributors to evaluate the impacts, benefits and cost effectiveness of conservation and demand management programs. Since the PUC distribution system is not currently capacity constrained, the benefits from avoided distribution infrastructure are estimated to appear in 2024.

The customer benefits are determined from reduced electricity bills as a result of reduced consumption for residential and GS<50kW customers, and reduced demand for GS>50kW customers. For customers on time-of-use rates, the evaluation uses the weighted average of on-peak, off-peak and mid-peak rates. The analysis calculates the impact on a customer's electricity bill including the electricity, distribution, transmission, loss and regulatory charges. Navigant notes that the analysis prepared by ECo and Leidos is quite conservative in that it does not assume any escalation in electricity rates over the period. In 2012, the Ontario Power Authority (OPA) projected that residential electricity prices would rise "*29% in real dollars between 2011-2031, with the highest increase occurring in the mid-term, at 43%*"[30]. While electricity rates have increased significantly since then, the OPA forecast projected slight increases in electricity rate for the near future. The larger fraction of the projected increases in rates occurred from 2011-2015, however rates are still forecasted to increase through 2017, with very small increase beyond 2017, before decreasing down to 2015-2016 levels. VVM electricity savings are accrued starting 2017, and will capture part of the rates increases over this period. Navigant's assessment of benefits and costs, and the overall business case of the UDM, in Section 2.8 incorporates the forecasted electricity rate hikes.

2.6.2.2 Assessment and Uncertainties

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 contrast, a water heater, though a resistive load, has a

[30] Ontario Power Authority, Ontario Electricity Demand: 2012 Annual Long Term Outlook, Summer 2012, Page 60. For more information see: Ontario Power Authority. December 2013. Ontario's Long Term Energy Plan.

thermal cycle. That is, it 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.

The uncertainty around the types of end-use loads served is an important determinant of the CVR factor. The CVR factor is a proportionality variable that relates reductions in electricity demand to voltage reductions. In addition to the type of end-use equipment, seasonal temperatures can also affect the predominance of certain types of loads such as heating and cooling, as well as the prevalent of a particular customer class served by a feeder. Leidos' use of a CVR factor of 0.50 is notably conservative.

Further, feeder length and health are also important characteristics for determining the cost-effectiveness of feeders for VVM deployment. The length of the feeder could limit the range of controllability, as the steady state voltage at one end may be significantly lower than the steady state voltage at the other end. Reconditioning investments on a feeder with poor health could make the investment less cost-effective. Leidos has identified a number of feeder and substation improvements which would be needed to optimize the operation of the VVM system. These improvements included phase balancing, re-conductoring, and additions of capacitor banks and voltage regulators. In certain cases feeder reconditioning costs may ultimately deem an investment in VVM unattractive. [31]

The valuation of VVM benefits is also dependent on forecasts of electricity consumption and demand over the analysis period. If the demand and consumption are forecasted to decrease annually by 1%, then the potential impact of VVM, and hence the valuation of benefits, should decrease nearly proportionally. Conversely, if demand and consumptions are expected to increase over time, so would the benefits attributed to VVM.

Leidos' analysis determines the baseline for consumption and demand based on the 2009-2013 5-year averages. It is unclear whether consumption and demand for PUC are expected to increase, decrease, or remain steady in the near-term, and in the long-term. PUC's 2013 Cost of Service Rate Application (EB-2012-0162) provided a forecast for consumption and demand for 2013 through 2016. [32] Both consumption and demand were forecasted to decrease slightly over time. These conclusions were based on the historical trends shown in the following figures:

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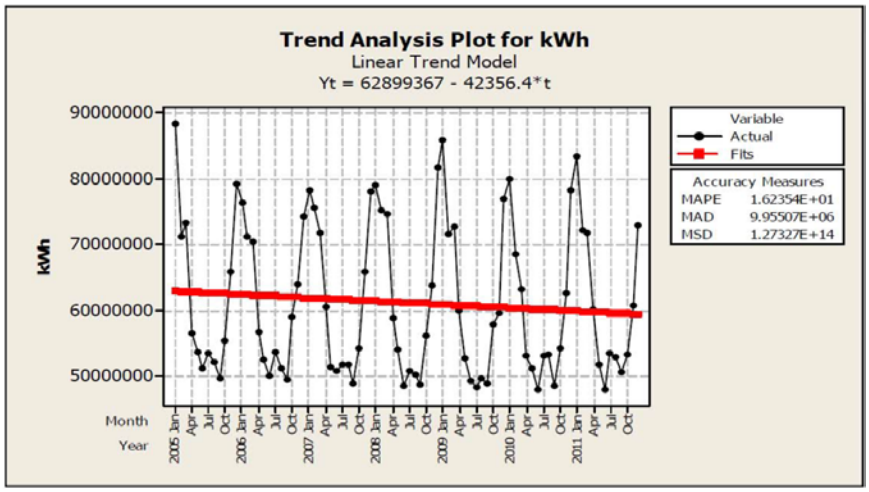
[31] Navigant. December 2013. "Smart Grid Regional Business Case for the Pacific Northwest". Available at: https://www.bpa.gov/Projects/Initiatives/SmartGrid/DocumentsSmartGrid/Navigant-BPA-PNW-Smart-Grid-Regional-Business-Case-2013-White-Paper.pdf

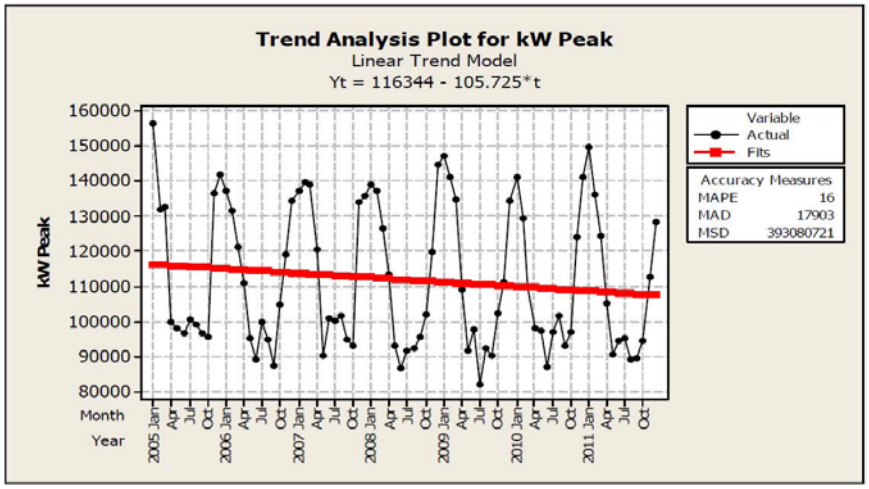
[32] EB-2012-0162, Exhibit 2, Tab 3, Schedule 1 (pg. 319). Available at: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/371636/view/PUC%20Distribution_2013_COS_Application_20121106.PDF

Figure 10: Historical Trend of Electricity Consumption



Source: METSCO Load Forecast Report for Asset Management Plan, 2013-2016

Figure 11: Historical Trend for Electricity Demand



Source: METSCO Load Forecast Report for Asset Management Plan, 2013-2016

The forecasts of load growth, both in terms of consumption and peak demand, have direct consequences on the valuation of benefits. As noted, if demand and consumption are forecasted to decrease slightly then the potential electricity bill savings from VVM would decrease commensurately.

Similarly, the benefit stream from avoided distribution upgrades is also impacted. PUC's Load Forecast Report stated that *"no capacity upgrades [were] required at the existing transformer or distribution stations on account of the load growth of PUC's customers"*. Since the PUC distribution system is not capacity constrained, Leidos does not anticipated that PUC will, in the near term, benefit from deferred distribution infrastructure. Leidos attributes benefits from avoided distribution infrastructure starting in 2024. While there is more certainty in the needs of PUC's

distribution system in the near future, there is much more uncertainty looking 20 years into the future.

The valuation of benefits is also dependent on the evolution of tariff structures and regulatory policy. Given the current structure of customer's electricity bills, VVM has a negative impact on PUC's revenue as a result of the distribution charge. The distribution charge for residential and GS<50kW customers is determined on a $/kWh basis, whereas for GS>50kW customers it is measured on a $/kW basis. Leidos valued the revenue impact at $116,731 (nominal $) per year based on the annual electricity consumption and demand. With regards to the revenue impact from VVM, PUC informed Leidos that *"the [Ontario] Ministry of Energy is in the process of revamping the revenue structure of LDCs to ensure a fixed level of distribution funding in the future".* As a result of this, the Leidos model assumes that PUC only experiences reduced revenue in 2017, and that as of 2018 the distribution charge is decoupled from electricity consumption and demand, such that VVM has no effect on PUC's revenue streams. Navigant notes that this is an area of risk for PUC in that it is not known at this time whether this revenue impact will continue or be eliminated as suggested by PUC.

2.6.3 AMI Integration

The scope of the AMI integration work includes the deployment of the OMS, CSR tools, enhanced AMI data, and an analytics platform. These enhanced capabilities will leverage the exiting AMI infrastructure, communications system and smart meters, and will be incorporated into the UDM architecture. Given the nature, and the overlap of these investments with the VVM and DA deployments, the UDM cost-benefit analysis does not explicitly monetize benefits that arise from these particular deployments. Akin to the substation upgrades, the AMI Integration deployment will support the investments in DA and VVM systems, and will be integrated into PUC's regular operations. Given the overlap of system functionality and operation, Navigant agrees with Leidos' approach of incorporating AMI investments into the DA and VVM benefits.

Outside of the UDM scope, the enhanced AMI capabilities are, in addition, expected to provide better outage management, fault localization, customer communication, and asset monitoring; enabling PUC to improve operations and maintenance. While Leidos has not monetize these enhanced uses, these capabilities will enable PUC to improve a number of elements of their business, as described below.

- **Outage management and communication**: The integration of AMI, OMS and CSR tools will enhance PUC's communication with customers during outages, reducing inbound call volume and improving customer satisfaction.
- **Service restoration and fault localization**: AMI-OMS integration will leverage smart meter pinging tools to verify when power has been restored to customers, avoiding service calls or direct notification from customers.

- **Equipment monitoring and grid oversight**: AMI, OMS, and the data analytics platform will enable PUC to monitor asset loading conditions (e.g., distribution transformers) enabling better assessments of equipment condition and to more efficiently planned future investments.

2.6.4 Broader Benefits

This analysis has not reviewed or attempted to quantify benefits that may accrue outside of the electricity system (e.g., macroeconomic or societal benefits). Navigant has not accounted for these *benefits* in the evaluation of the UDM business case; though, it does expect that investments in smart grid, akin to investments in public infrastructure, will create broader economic opportunities in the Sault region and to a lesser extent across the province.

For example the Conference Board of Canada[33] has estimated that *"for every $100 million (inflation adjusted) invested in electricity generation, transmission, and distribution infrastructure, real GDP will be boosted by $85.6 million, and roughly 1,200 person-years of employment will be created".*

These benefits will arise from economic activity for smart grid technology and solutions companies, growth of secondary industries such as electric vehicles, energy storage, distributed generation and renewable energy, as well as supply chain impacts in labor and equipment. The project may also serve as an example to other utilities pursuing development of Smart Grid capabilities. Additionally, the UDM project, through improved reliability, reduced costs and the customer engagement strategy should lead to increased customer satisfaction and awareness.

2.7 Risks

There are a number of potential areas of risk associated with implementing any project of this nature. ECo has proposed a number of contractual arrangements as part of the project which are designed to manage risk exposure and transfer these risks to the appropriate parties. Table 9 summarizes the distribution of the different types of risk associated with the project;

- Regulatory risk – The risk associated with obtaining approval to recover the expenditures (monthly fees) from its ratepayers rests primarily with PUC. Navigant expects that PUC will want to assure itself that the project will be viewed as prudent and that it will reasonably expect to be able to obtain regulatory approval for these project costs before it will enter into an agreement to proceed with the project. Navigant offers comments on the prudence of the project in section 3 below. On the other hand, partnering with ECo may help smooth out large capital investments required over the period, thereby reducing the need for larger periodic rate changes.

[33] The Conference Board of Canada, *Shedding Light on the Economic Impact of Investing in Electricity Infrastructure,* Len Coad, Todd Crawford, and Alicia Macdonald, 2012, page 11.

- Cost overruns and completion delays will be the responsibility of the EPC contractor.
- Performance risks during the construction and design phases will lie with EPC contractor. Once the system has been tested and assumed by PUC, operational risks related to the performance of substations and AMI systems will be assumed by PUC. The Service Provider will risk a reduction in revenues from lower payments if the system does not perform to agreed specification.
- The risk of higher than expected maintenance costs for scheduled maintenance will be borne by the Service Provider. Unscheduled maintenance costs will be the responsibility of PUC.
- Financial risks, such as higher than expected financing costs associated with system maintenance and equipment replacement over time will be borne by Project Co.

Table 9: Risk Matrix for UDM Project

Type of Risk	EPC^	Project Co	Service Provider	PUC
Rate Approval				√
Construction Cost Overrun	√			
Construction Completion Delays	√			
Design/Performance Risk	√			
Performance on Completion	√			
Operating Performance			*DA/VVM*	√
Scheduled Maintenance Costs			√	
Unscheduled Maintenance Costs				√
Lifecycle costs*			√	
Hand back/Performance			√	
Financing risk		√		

^ EPC - Engineering, Procurement and Construction contractor
** Addressed in items above*

Notes:
DA/VVM - Distribution Automation/Volt/Var Management – Operating performance risk for DA/VVM assumed by Service Provider. Operating performance risk for other project elements will rest with PUC.

Source: Navigant

Navigant considers that several aspects of the contractual arrangements add significant value that should be considered in the evaluation of the UDM proposition. In particular, as shown above, the transfer of risk protects PUC from potential cost overruns. For example, under the proposed project agreement and project structure the Design and Construction Contractor is responsible for the costs of the design and construction phase, such that neither PUC nor its customers bear the risk associated with cost overruns. While the transfer of risk is not explicitly

accounted for in the benefit-cost and sensitivity analyses presented in Section 2.8, it is an important aspect that provides predictability of costs for PUC. Many of these risks would of course lie with PUC if it chose to implement its own smart grid and other capital investments.

2.8 Findings & Recommendations

Navigant's assessment of the project seeks to determine if the project development and financing costs as well as ongoing O&M for UDM assets are reasonable with respect to project benefits. To assess the business case for the project, we have used information provided by Leidos and ECo to identify the costs and savings for the project, reviewed the reasonableness of those estimates based on other SG experience and identified potential areas of risk or uncertainty.

With regards to the design, construction, operations and hand-over costs, Navigant understands that PUC and it customers are protected from any risk of cost overruns. In addition, Navigant suggests that the costs allocated to the business process change should be reviewed once the design is complete as significant changes in software and business aspects for utilities are often underestimated. The cost estimates for the AMI, DA VVM and substation upgrades appear reasonable, and are not of particular concern given that the cost of most of the associated equipment is well known given estimates from suppliers.

Navigant conducted a benefit-cost analysis to determine the net value of the UDM investment to PUC; estimating the net present value of the UDM based on the range of monthly payments that PUC will make to ECo for the duration of the contract, as show in the table below. The monthly payment will be set in advance, and will be escalated annually for increases in the CPI.

Table 10: Estimated Monthly Payments from PUC to ECo *(CAD $)*

Feature	Low	High
UDM	$224,000	$275,000
Substation Upgrades	$213,000	$260,000
Total	$437,000	$535,000

Source: ECo

Navigant has excluded the *Substation Upgrade* payments from the benefit-cost analysis since it is expected that PUC will make the substation investments regardless of the implementation of the UDM. The net present value of the UDM has been estimated using the following

assumptions; CPI of 2.0%, discount factor of 5%[34] and project term of 20 years[35]. In addition, the results incorporate the projected electricity rate increases over the duration of the project term[36].

Overall, as shown in Table 11, benefits from the UDM project are valued at just under $57 million, and with costs expected to range from $41 million to $51 million, the investments delivers a benefit-cost ratio in the range of 1.12 to 1.37. The net present value is expected to range from $6 million to $15.5 million.

Table 11: Summary of Results *(Present Value in CAD $)*

	Range of Costs	
	Low	High
Costs	41,391,630	50,815,617
Benefits	56,910,572	56,910,572
NPV	15,518,942	6,094,954
Benefit-Cost Ratio	1.37	1.12

Source: Navigant; all values in 2015 $ and reflect benefits and costs through 2035

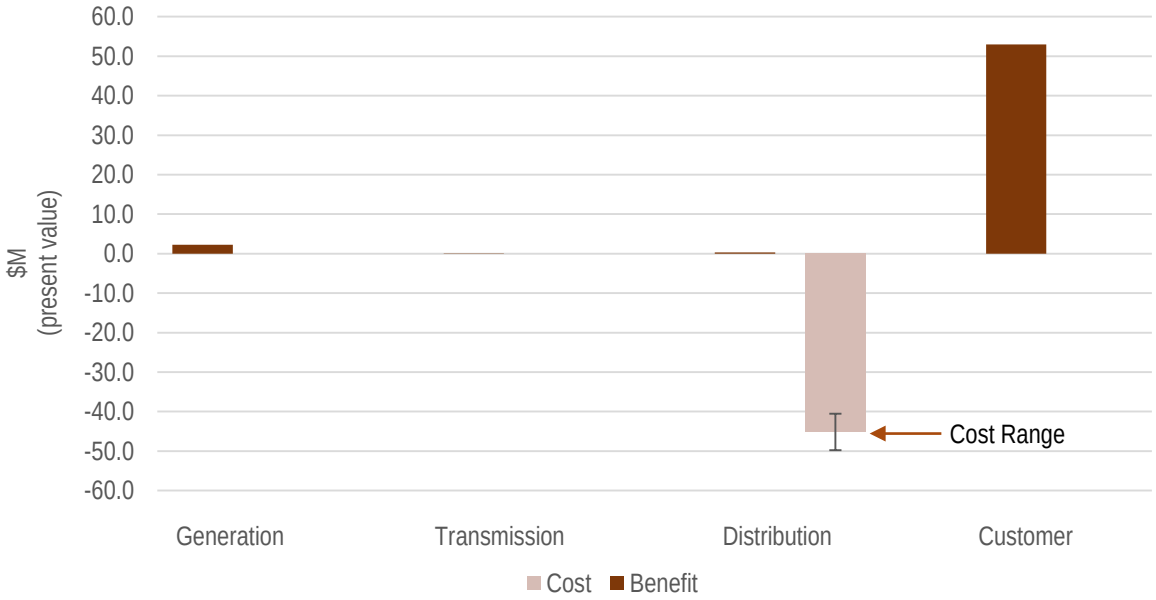
Navigant also examined the allocation of costs and benefits across industry segments. Smart grid investments generally deliver a wide range of benefits (e.g., reliability improvements, reduction in losses, reduced consumption, deferred traditional network reinforcement, etc.) which accrue across different segments of the industry, whereas costs are borne primarily by one segment; in this case the distribution segment. This alignment of the benefits and costs by industry segment means that a party that carries a disproportionate fraction of the costs, relative to the benefits, and may be less inclined to proceed with these investments unless they are allowed to recover the some of the benefits enjoyed by other segments. If distributors such as PUC are not allowed recovery of costs based on benefits to other segments Navigant expects that this would limit future investments in smart grid projects.

Figure 12 shows the distribution of UDM costs and benefits by industry segment. The "whiskers" on the cost bar indicate the range of costs. The graph represents the present value of costs and benefits over the project term. Note that the graph excludes the costs associated with substation upgrades since it is expected that PUC will have to incur those regardless of the deployment of the UDM project.

[34] A discount rate of 5% was selected to be consistent with modeling of other smart grid pilot programs modelled for the Ministry of Energy.
[35] Statistics Canada data for the annual CPI in Ontario since 2001 ranges from 0.3% to 2.9%, with an average of 2.0%
[36] The projected increases in electricity rates over the project term are expected to increase the valuation of the customer benefits, as a result of reduced electricity bills, by approximately $950K.

The uneven distribution of costs and benefits for the distribution sector (e.g., PUC) acts as a significant financial barrier to wider adoption of smart grid technologies. The UDM financial agreement mitigates this barrier by enabling PUC to smooth out the UDM investment over the long term. The proposed agreement also enables predictability for PUC with respect to capital expenditure.

Figure 12: Distribution of Costs and Benefits across Industry Segments
(*Present Value in CAD $)*



Source: Navigant; all values in 2015 $ and reflect benefits and costs through 2035

Table 12, below, shows the breakdown of the benefits for each segment of the industry. As shown, the largest benefits arise from reduced electricity bills and the value of improved reliability. The impact of VVM on customer's electricity bills is valued at approximately $18 million. In contrast, improvements in reliability result in slight increases in customer's bills. The impact of DA on customer's reliability is valued at approximately $36 million. This valuation is largely driven by the value of reliability for commercial and industrial customers.

Table 12: Distribution of Benefits across Industry Segments *(Present Value in CAD $)*

Benefit Category		Generation	Transmission	Distribution	Customers
Avoided Generation Capacity	DA	59,499			
	VVM	2,271,009			
Avoided Transmission Capacity	DA		1,520		
	VVM		58,012		
Avoided Distribution Capacity	DA			869	
	VVM			35,464	
Avoided O&M	DA			331,297	
	VVM			-	
Revenue Impact	DA			90,288	
	VVM			(113,395)	
Reduced Bill	DA				(130,068)
	VVM				18,238,410
Reliability	DA				36,067,668
	VVM				-
Benefit		2,330,508	59,532	344,522	54,176,010

Source: Navigant; all values in 2015 $ and reflect benefits and costs through 2035

2.8.1 Sensitivity Analysis

As noted earlier, Navigant identified certain areas of uncertainty and risks that may undermine the evaluation of benefits. With regards to the DA system, a number of factors are known to influence the degree of reliability improvements. These include, feeder health; circuit topology, frequency of severe weather events; grid resiliency; and the appropriate valuation of a customer's reliability. Similarly, the VVM system is also subject to a number of influential factors. These include, end-use loads, seasonal weather patterns, feeder reconditioning, electricity and demand forecasts, and the evolution of tariff structure and regulatory policy.

Navigant performed a sensitivity analysis to assess impact on the business case if benefits from the DA and VVM systems are lower than projected. This sensitivity analysis takes a more conservative approach to the electricity and demand savings estimated for the VVM system and the reliability improvements estimated for the DA system. In addition, the analysis also considered the impact of extending the project term up to 30 years.

In calculating the total benefits for Scenario 2, the net present value and the benefit-cost ratio, Navigant has excluded the provincial benefits (e.g. benefits attributed to the generation and transmission segments). As show in Table 12 (above), these benefits account for approximately 4% of the total value of benefits, or approximately $2.4 million.

The underlying assumptions of the sensitivity analysis, relative to the evaluation of benefits performed by Leidos ("Base"), are shown in Table 13 below. In addition, Navigant has incorporated the forecasts for electricity rates which show slight increases in charges through 2035. Table 14 shows the low to high range of monthly payments for extended project terms of 25 and 30 years.

Table 13: Scenario Analysis Assumptions

Measure	Base		Sensitivity Analysis
Analysis Period			
Project Term	20 years		20 - 30 years
UDM Monthly Payment	CAD 224,000 – 275,000		See Table 14
Substation Upgrade Monthly Payment	CAD 213,000 – 260,000		See Table 14
Voltage/VAR Management			
Reduced Electricity Consumption	1.5%		0 - 30% impact reduction
Reduced Demand	1.1%		0 - 30% impact reduction
Reduced Line Losses	1.8%		0 - 30% impact reduction
Distribution Automation			
	1 switch	2 switches	
SAIFI Reduction	40%	50%	0 - 30% impact reduction
SAIDI Reduction	50%	60%	0 - 30% impact reduction
CAIDI Reduction	15%	20%	0 - 30% impact reduction

Source: Navigant

Table 14: Payment Range for Increased Project Term *(CAD $)*

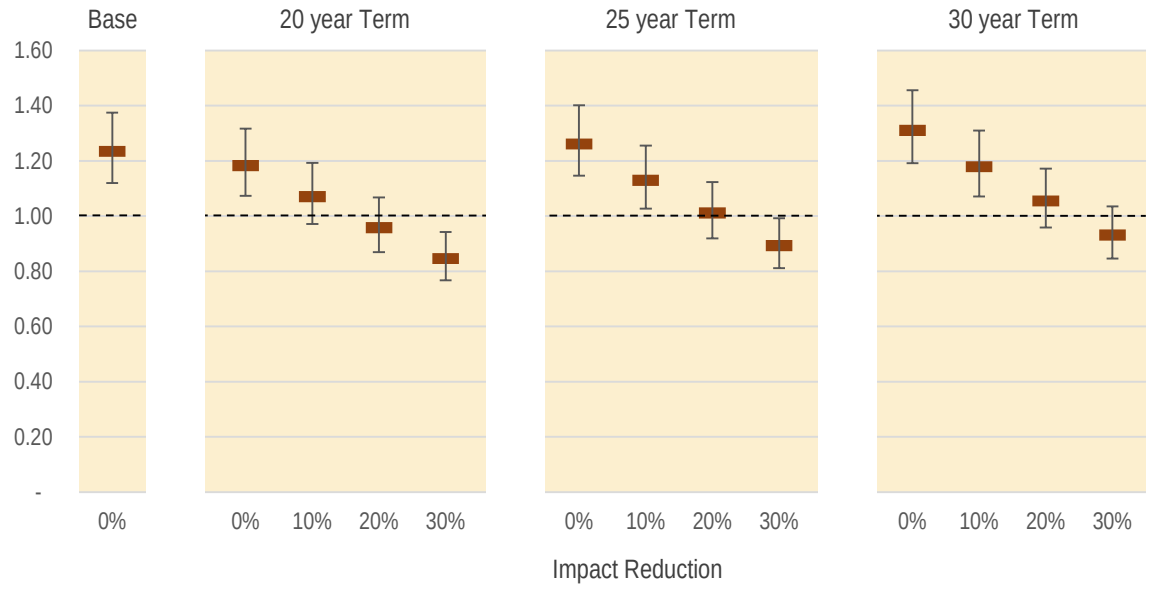
Feature	20 Years		25 Years		30 Years	
	Low	High	Low	High	Low	High
UDM	$224,000	$275,000	$211,139	$258,000	$203,578	$248,818
Substation Upgrades	$213,000	$260,000	$200,417	$245,000	$193,240	$236,182
Total	$437,000	$535,000	$411,557	$503,014	$396,818	$485,000

Source: ECo

The sensitivity analysis highlights a more conservative approach with regards to the reduction of electricity consumption and demand observed by Leidos, as well in terms of the expected improvements in reliability. The results of the analysis are shown in Figure 13 and Table 15. This figure summarizes the sensitivity results over discrete intervals for both the duration of the project term and impact reductions. The whiskers indicate the range of benefit-cost ratios as a result of the high and low monthly payments. The *Base* case, the leftmost scenario in the

graph, reflects the scenario presented above; which includes both local (e.g., LDC and customer benefits) and provincial benefits (e.g., transmission and distribution benefits). All of the other cases (0%, 10%, 20% and 30% benefit reductions for 20, 25 and 30 year terms) are conservative in excluding all provincial benefits.

Figure 13: Benefit-Cost Ratio Results of Sensitivity Analysis



Source: Navigant

Table 15: Benefit-Cost Ratio Results of Sensitivity Analysis

Scenario	Base	20 year term				25 year term				30 year term			
Impact Reduction	0%	0%	10%	20%	30%	0%	10%	20%	30%	0%	10%	20%	30%
High	1.37	1.32	1.19	1.07	0.94	1.40	1.26	1.12	0.99	1.46	1.31	1.17	1.03
Average	1.23	1.18	1.07	0.96	0.85	1.26	1.13	1.01	0.89	1.31	1.18	1.05	0.93
Low	1.12	1.07	0.97	0.87	0.77	1.15	1.03	0.92	0.81	1.19	1.07	0.96	0.85

Source: Navigant

These results show that as the project term is extended to 25 and 30 years, the business case for UDM deployment is stronger. In contrast, as the impacts from consumption and demand, and reliability become less effective, the business case is weakened. The worst case scenario is observed for a project term of 20 years with a 30% reduction in the impacts, whereas the best case arises from a 30 year project term and no reduction in benefits.

The breakeven points for the high, mid and low sensitivities are show in Table 16. For example, in the 20 year term analysis, the breakeven point for the high monthly payment occurs if the UDM impacts are reduced by 7%. Given these constraints, the cost-benefit ratio for the UDM is

positive if benefits are not reduced more than 7%. Similarly, for the low monthly payment, the benefit-cost ratio is positive for benefit reductions lower than 25%, and at the average monthly payment the benefit-cost ratio is positive for benefit reductions of less than 16%.

The UDM business case is always positive for the range of monthly payments modelled if the level of UDM benefits estimated by Leidos (e.g., 0% impact reduction) are achieved (*green circles indicate a cost-benefit ratio greater than 1.0*). At the other end of the spectrum, if a 30% reduction of benefits is assumed, the cost-benefit ratio is greater than 1.0 for the low monthly payment for a project term greater than 26 years, but always less than 1.0 for the cases with the average and high monthly payments (*as denoted by the red circle*).

Table 16: UDM Positive Business Case Sensitivity Analysis[37]

	Project Term			Impact			
	20 years	25 years	30 years	0%	10%	20%	30%
Low monthly payment	< 25%	< 29%	🟢	🟢	🟢	🟢	> 26 years
Average monthly payment	< 16%	< 21%	< 24%	🟢	🟢	> 24 years	🔴
High monthly payment	< 7%	< 13%	< 19%	🟢	> 23 years	🔴	🔴

Source: Navigant analysis

It is important to consider, and understand, the results presented above with regards to the sensitivity of the overall UDM business case as a result of lower than expected impacts, and an extended project term. In particular, if the performance of the UDM does not achieve the baseline benefits attributed to the DA and VVM systems, for example, in the 30% impact reduction scenarios, the reduced valuation of benefits may deem the UDM project not worth pursuing. The evaluation of the UDM project should, in addition, consider several aspects of the project framework and scope, which although are not explicitly reflected in the business case, add significant merit to the UDM value proposition. These include:

- The AMI integration scope; encompassing the deployment of an OMS, CSR tools, enhanced AMI data, and an analytics platform. As a result of these, PUC and its customers will benefits from better outage management and customer communication, fault localization, asset monitoring, and improved operations and maintenance.
- The transfer of risks as a result of the contractual obligations of each party. The project agreement defines the Designer and Construction Contractor as responsible for all design and construction phase costs. As a result, PUC and its customers are protected from any cost overrun risks.

[37] This table shows the breakeven points determined for the sensitivity analysis. In certain scenarios, the business case may, either, always be positive or negative, such that a breakeven point does not apply. For those scenarios; a green circle denotes a positive business case and a red circle denotes a negative business case.

- The performance management strategy, which incentivizes all parties to ensure the performance of the UDM meets contract expectations.
- The three-year customer engagement activities, which are targeted to facilitate customer education and support for the project, increase customer awareness and to inform customers of the new capabilities and resiliency of their local electricity grid
- Meeting the Ministry of Energy's Smart Grid objectives; addressing key areas of customer engagement and education, grid resiliency, intelligence and modernization, and operational effectiveness.

3. Regulatory Considerations

The Smart Grid project proposed by ECo represents a significant cost for PUC. As discussed in section 1.5, PUC's capital budget for the 2013 Test year was just under $8 million. It's reported OM&A expenditures for 2013 were about $18 million, including $3.5 million for depreciation and operating expenses of just under $3.7 million[38]. While some of the costs included in the ECo proposal represent expenditures that would otherwise be included in PUC's capital or operating budgets, a fee in the order of $250,000 per month for the Smart Grid project is expected to be material and would be expected to require some change in rates to recover.

PUC is partway through the anticipated 5 year cycle of rate changes under the 4th Generation IRM process. PUC submitted a Cost of Service (COS) application in 2012 for the 2013 rate year. It has since filed rate applications for 2014 and 2015. Under the normal IRM process, PUC would not be expected to file its next COS application until 2017 for 2018 rates. Given the lead time for preparing a COS application Navigant anticipates that PUC would likely begin work on the application as early as 2016.

In the interim, there are a limited number of mechanism available for adjusting rates within 4th Generation IRM. Each would be filed as part of an IRM filing. They include:

- Rate Adder
- Rate Rider
- Incremental Capital Module

The choice of which approach is most appropriate depends on the nature and size of the expenditures.

Rate Adders and Rate Riders

"The Board recognizes that distributors may need additional funding for expenditures proposed in a GEA Plan between cost of service applications, and will consider applications for suitable funding mechanisms. The nature of the mechanism used will depend on whether the Board is able to properly assess prudence of the proposed expenditures based on the evidence filed in the application.

A rate rider is a tool to allow recovery of expenditures that have been examined as part of an application, found to be prudent, and approved for recovery by the Board. An account to track variances from budget may be established in conjunction with a rate rider."[39]

[38] Budget figures per Ontario Energy Board, 2013 Yearbook of Electricity Distributors, August 13, 2014.
[39] Page 24, EB-2009-0397, Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence, Revised May 17, 2012 (Originally issued March 25, 2010).

In discussing the obligation of utilities under the GEEA, the ***Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence*** indicates that:

> *"Distributors may make expenditures relating to renewable generation connection, or to the smart grid, in accordance with applicable legal and regulatory requirements. The prudence of those expenditures and recovery of their costs will be subject to Board review in the normal course."*[40]

The **OEB Filing Requirements for Transmission and Distribution Applications** (July 9, 2010) describes two types of rate riders that may be used to recover certain types of investments.

- ***Rate Adder*** - A rate adder is an interim measure that utilities may use to provide advance funding and smooth out the anticipated impact of certain investments. As such it does not constitute an approval of, or the ability to recover the investments. *(page 6, Chapter 3)*
- ***Rate Rider*** - A rate rider is designed to recover or refund Board-approved amounts following a prudence review. Approval of a rate rider provides regulatory certainty that the amount of the rider can be recovered until the sunset or termination date of the rider.

Rate adders or rate riders must pass a materiality test in order to be added to the utility's rate schedule. On a volumetric basis the rate change must be greater than zero when rounded to the 4th decimal place for kWh charges or when rounded to the 2nd decimal place for kW charges. PUCs residential rates in 2014 are $0.144/kWh.

The "Smart Grid Funding Adder" was initially proposed by the OEB as the main tool for recovering Smart Grid investments[41].

> *"The Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence (EB-2009-0397) issued on March 25, 2010 recognized that distributors may need additional funding for expenditures proposed in a GEA Plan between cost-of-service applications. For 2011 IRM applications, distributors may request the following:*
>
> - *Renewable Generation Connection Funding Adder; and*
> - *Smart Grid Funding Adder.*

Given the scope of the UDM project, Navigant does not expect that use of a rate rider would be appropriate, however, the decision as to which approach is most appropriate will be made by PUC and will depend to some degree on the extent to which work proposed under the project replaces work already anticipate in their capital plan.

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[40] Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence, page 8, section 2.7

[41] As will be discussed below Navigant does not believe that a rate rider would be appropriate for this project given the comprehensive nature of the proposal.

Chapter 5 of the filing requirements describes a requirement for utilities to submit a "*Consolidated Distribution System Plan*". The Distribution System (DS) Plan must be filed when the utility applies for rebasing of their rates under the 4th Generation IR or a Custom IR application. Utilities which have already filed a 4th Generation Cost of Service application and are using the "*Annual IR Index*", such as PUC, must make a Chapter 5 filing within 5 years of the date of their COS approval. The Board may also require a DS plan in relation to a leave to construct, an Incremental Capital Model or Z-factor application.

> "*Distributors yet to file a cost of service application containing a consolidated capital plan pursuant to Chapter 5 will continue to be able to record renewable energy generation costs, smart grid demonstration costs and funding adder revenues (for existing funding adders) in deferral accounts already established for this purpose. Likewise, such distributors may also seek new funding adders for material eligible investments if they are on the 4th generation IR plan as part of their IRM applications, until such time as the first cost of service application containing a consolidated capital plan.*" [42]

Incremental Capital Module (ICM)

The Board has set out a number of criteria that must be met in order for a distributor to request relief for incremental capital spending during the term of its IRM3 plan. The criteria make it clear that the ICM should be for non-discretionary spending and the distributor must demonstrate that non-discretionary spending exceeds the materiality threshold. The distributor must also demonstrate that the expenditures are unusual and unanticipated.

The requirements for an ICM application are described in Chapter 3 of the Filing Guidelines:

> "*The Board requires that a distributor requesting relief for incremental capital during the IRM plan term must include comprehensive evidence to support the claimed need, which should include the following:*
>
> - *An analysis demonstrating that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor;*
> - *Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (but not necessarily the least initial cost) for ratepayers;*
> - *Justification that amounts being sought are directly related to the cause, which must be clearly non-discretionary and clearly outside of the base upon which current rates were derived.*
> - *Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers and other load growth);*

[42] Chapter 5, page 4.

- *Details by project for the proposed capital spending plan for the test year, segregated between discretionary and non-discretionary;*
- *A description of the proposed non-discretionary capital projects and expected in-service dates;*
- *Calculation of the revenue requirement (i.e. the cost of capital, depreciation, and PILs) associated with each proposed incremental non-discretionary capital project;*
- *Calculation of revenue requirement offsets associated with each incremental non-discretionary projects due to revenue to be generated through other means (e.g. customer contributions in aid of construction);*
- *A description of the actions the distributor would take in the event that the Board does not approve the application.*
- *Calculation of a rate rider to recover the incremental revenue from each applicable customer class and the rationale for the proposed approach."* [43]

If the Board approves the ICM, the distributor is required to report annually on the actual amounts spent. At the time of the next rebasing the distributor must file a calculation of the amounts to be incorporated in the rate base. The Board will make a determination at that time on the treatment of any differences between the forecast and actual capital spending during the IRM Plan term.

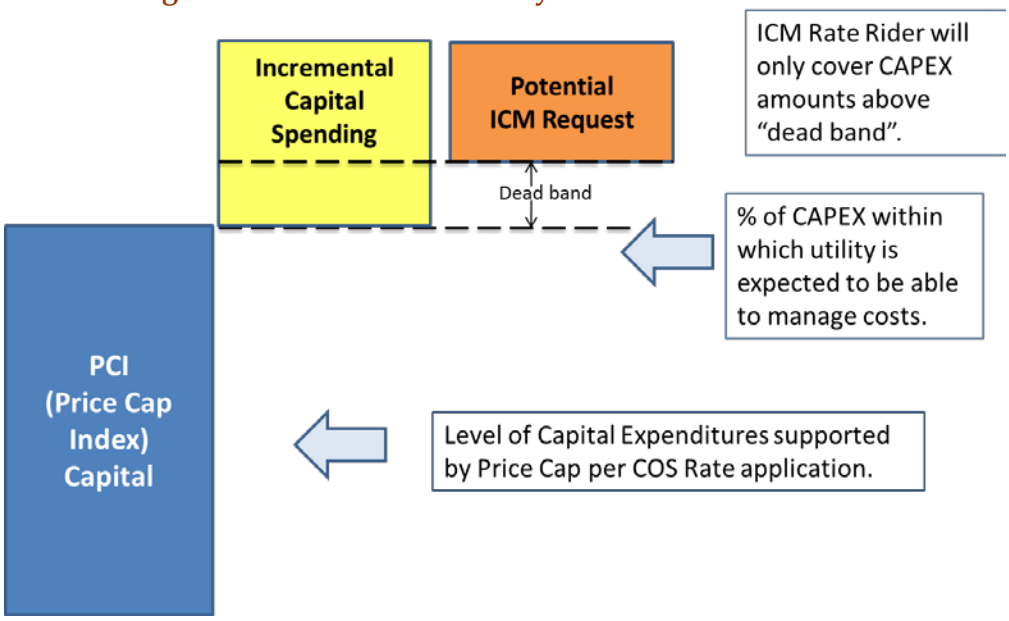
After the distributor has filed and approved its ICM, it must track and record eligible amounts, subject to the assets being "used and useful" following processes specified by the Board; as well as any carrying charges. Carrying charge amounts are calculated using simple interest applied to the monthly opening balance in the account and recorded in a separate account. Revenues received under the ICM rate rider must also be recorded in a specified account.

Incremental Costs Eligible under ICM

In its decision with respect to THESL's submission (EB-2012-0064), the Board made clear that any rate rider approved as a result of an ICM application would be structured so that it only allowed the recovery of capital expenditures above the level of capital expenditures covered by rates under the IRM plus the materiality threshold (see figure below). In other words, only eligible capital expenditures which exceed the sum of the utility's '*Price Cap Index (PCI) capital*' and a 20% dead band adjustment would be eligible for the ICM. The Board also indicated that in considering existing utility assets, only in-service assets would be considered (i.e. capital work in progress would not be considered). Any expenditure for assets not yet in-service would be dealt with when the utility completes its next rebasing application.

[43] OEB, Chapter 3 of the "*Filing Requirements for Electricity Distribution Rate Applications*", July 17, 2013, Section 3.3.1.5, "*ICM Filing Guidelines*", page 17.

Figure 14: Effect of Materiality Threshold Dead Band



The threshold test referenced in the ICM guidelines refers to a materiality threshold, calculated based on the utility's rate base using the formula below.

Figure 15: Formula for Materiality Threshold

$$\textit{Threshold Value} = 1 + \left(\frac{RB}{d}\right) * (g + PCI * (1 + g)) + 20\%$$

Where:

RB = rate base included in base rates ($);
d = depreciation expense included in base rates ($);
g = distribution revenue change from load growth (%); and
PCI = price cap index (% inflation less productivity factor less stretch factor).

The values for "RB" and "d" are the Board-approved amounts in the distributor's base year rate decision.

PUC calculated the materiality threshold in its 2013 COS Application EB-2012-0162 and indicated a materiality threshold of $100,000 for that application. The threshold formula is also used in calculating the "dead band" referred to in Figure 14.

In its 2013 filing (EB-2012-0162) PUC provided the following information that can be used to estimate the materiality calculation.

- PUCs rate base was stated as $91,994,402 (MIFRS).
- Depreciation was stated as $ 3,407,501 (MIFRS).
- The change in consumption in Bridge and Test Years to be 0.26%.

Using the formula in Figure 15 and information from PUC's COS application (EB-2012-0162), we estimate the "dead band" as 132%. Applying this to the $3,407,501 depreciation for the 2013 Test Year implies that the OEB would only entertain a request under the ICM to recover costs for projected capital expenditures above $4.5 million (i.e. $3.4 million x 132%). PUC would be expected to manage any increase in expenditures up to that amount. If the capital expenditures in excess of this amount were approved under the ICM, the PUC would receive incremental revenue to provide capital recovery for the incremental capital expenditures during the remainder of the IRM period and, if the capital investments were ultimately deemed prudent by the Board, then they could be included in rates when the utility goes through re-basing.

Treatment of Benefits:

As discussed in section 2.6, three benefit streams are projected to flow from the UDM project proposed by ECo:

- Provincial benefits (upstream from the PUC system).
- Benefits to the PUC system.
- Downstream benefits to customers

The benefits which accrue to PUC can be used to offset expenditures on the UDM project. Savings upstream or downstream of the system may be used to justify the project but will not contribute savings directly to PUC. Downstream savings to customers may be presented as the basis for permitting recovery of the associated costs from customers if the investment is deemed to be prudent. As mentioned earlier, if distributors such as PUC are not allowed recovery of costs based on benefits to other segments Navigant expects that this would limit future distributor investments in smart grid projects.

Navigant's understanding is that the OEB may not consider or provide credit for benefits from the project which occur upstream to the provincial system. While the estimation of these savings may be reasonable, we have therefore excluded the value of "provincial benefits" in conducting sensitivity analyses of the business case for the project.

As discussed, under the proposed project PUC will pay ECo a monthly fee over the period covered by the contract term. While PUC could consider treating the project as a capital lease, this is not felt to be an appropriate option. Using a capital leasing arrangement could create a

requirement for Project Co, as an owner of distribution assets, to become a licensed distributor, creating a number of operational and legal issues.

Navigant expects that PUC would be expected to treat the costs as an on-going O&M expense. O&M expenses are treated as a recoverable cost, subject as with all costs, to a review for prudence. Navigant believes that the monthly Service Fee could be treated as an O&M expense under the Accounting Procedures for Electricity Distributors and filing requirements for rate applications. Under this approach, the value of the assets involved in the project would not be assumed by PUC which would therefore not be able to earn a rate of return on these assets.

In our experience, capital expenditures typically receive greater attention as part of rate reviews, however we expect that the burden, level of information detail, etc. will reflect the materiality of the expenditure. In the case of the UDM expenditures, we expect that these costs will be material regardless of whether they are treated as part of the capital or operating budgets.

In summary, we expect that these expenditures are likely to attract a similar level of scrutiny regardless of whether they are treated as a capital or operating expenditure. We note that it is also possible that these expenditure may receive closer scrutiny to the extent that they represent a new approach which has not be followed by other LDCs in their COS applications. Regardless of whether the project is treated as a capital or operating expense, the key issue will be the prudence of the investment, reflecting the business case for the investment.

In assessing the prudence of the project, Navigant expects that the OEB will of course pay close attention to the cost-effectiveness of the project, as represented by the net present value of present costs and project benefits. As indicated in the "Supplemental Report" on Smart Grid, discussed in section 1.4, the Board has indicate that the criteria it will use to evaluate smart grid investments will be "no different from any other investment made by a regulated entity" and will include:

- Efficiency, Customer Value, and Reliability,
- Safety,
- Cyber-security and Privacy,
- Co-ordination and Interoperability,
- Economic Development,
- Environmental Benefits.

The following section discusses how the proposed project aligns with these evaluation criteria and with the policy objectives set out in the Minister's Directive.

3.1 Alignment with Provincial Policy Objectives

As discussed in section 1.4, distributors such as PUC are required under the GEEA to develop a plan for "*the development and implementation of the smart grid in relation to the licensee's transmission system or distribution system*". Acting in response to a directive from the Minister of Energy (see Appendix A), the Ontario Energy Board has directed that distributors must address this requirement as part of a Distribution System Plan to be submitted to the Board as part of their next COS filing. As a result, pursuing smart grid development of is now a deemed condition of PUC's license as a distributor.

The project proposed for PUC is one of the most comprehensive Smart Grid initiatives Navigant has reviewed. As discussed, approximately 84 percent and 68 percent of PUC's system will be covered by DA and VVO systems respectively. Navigant has reviewed the capabilities of the proposed system relative to the objectives set out in the Minister's Smart Grid Directive (Figure 16) and concluded that the proposed system will meet or facilitate most of those objectives.

Figure 16: Addressing Policy Objectives

1. CUSTOMER CONTROL OBJECTIVES
ACCESS: The proposed system will facilitate improved access to customer data by customers or authorized parties. This access will enhance a customer's ability to manage their energy consumption and demand.
VISIBILITY: The AMI system enhancements will provide greater transparency and visibility of consumption information. The project is designed to enhance both the Customer Service Representative (CSR) toolset so that CSR's can provide improved service to customers and enhance the customer toolset to provide a customer friendly user interface (UI) so that customers can better answer their own questions. The customer engagement process proposed as part of the project will also help educate customers on the capabilities of the system to support their energy management efforts.
CONTROL: Improved access to customer information will provide assist customers in controlling energy costs and in more effectively managing their consumption.
PARTICIPATION IN RENEWABLE GENERATION: See Distributed Renewable Generation below.
CUSTOMER CHOICE: While not directly addressed by the project, improved access to customer consumption information may help to facilitate customer choice.
EDUCATION: The proposed project includes an extensive 3 year outreach and education component that will reach out to customers and stakeholders across the community. These outreach and education activities will provide consumers with information about opportunities for their involvement in generation and conservation associated with a smarter grid and collect feedback from the community. The intent is to present customers with easily understood material that explains the benefits of the program and how to increase their participation in those benefits.
2. POWER SYSTEM FLEXIBILITY OBJECTIVES
DISTRIBUTED RENEWABLE GENERATION: While the proposed project does not include distributed generation, the capabilities included in the proposed project will enable PUC to more effectively manage and accommodate renewable or other distributed generation installed within their system.
VISIBILITY: The proposed UDM system will provide PUC with improved ability to see and monitor conditions within its network and to integrate that information into its other systems, allowing improved control, faster response to outage conditions, integration of outage management and customer information systems, and improved ability to manage the integration of distributed renewable generation.

CONTROL AND AUTOMATION: PUC will have the ability to operate its distribution system in fully automated or semi-automated mode. The system will enable improved control and automation of the PUC grid and improved response and information sharing with customers where outages do occur.
QUALITY: Improved reliability and faster response to outages is a key benefit of the proposed system as discussed in earlier sections.
3. ADAPTIVE INFRASTRUCTURE OBJECTIVES
FLEXIBILITY: The design of the proposed system offers flexibility to support future innovative applications, such as electric vehicles and energy storage as well as "islanding" of e.g. hospital, university, and police-stations.
FORWARD COMPATIBILITY: The proposed system enables PUC to achieve SG capabilities more rapidly than would be possible absent the project. The equipment and design being installed provides sufficient flexibility for expansion to introduce new technologies such as distribution generation or other efficiency programs. The design of the DA and VVM components of the UDM program will maximize energy and efficiency savings, including use of AMI data to enhance energy savings via CVR. Notably, the scope of the UDM is extensive, as it includes coverage of most of PUC's distribution system, well beyond pilot programs and limited implementation Navigant has encountered for some utilities
ENCOURAGE INNOVATION: This project represents an innovative implementation of SG capability as well as an innovative financing and risk management arrangement, which could encourage similar innovations / smart grid implementations by other Ontario LDCs. As one of the most comprehensive Smart Grid implementations in Ontario it could serve as an example to other LDC's considering their own smart grid plans.
MAINTAIN PULSE ON INNOVATION: We anticipate that PUC and ECo will wish to share their experience if the project is proposed as implemented. It will represent one of the most comprehensive SG installations in the province.

Appendix A: Smart Grid Directive from Ontario Minister of Energy

MINISTER'S DIRECTIVE

TO: THE ONTARIO ENERGY BOARD (issued November 23, 2010)

I, Brad Duguid, Minister of Energy, hereby direct the Ontario Energy Board pursuant to section 28.5 of the Ontario Energy Board Act, 1998 (the "Act"), as described below.

The Board shall take the following steps in relation to the establishment, implementation and promotion of a smart grid:

1. The Board shall provide guidance to licensed electricity distributors and transmitters, and other regulated entities whose fees and expenditures are reviewed by the Board, that propose to undertake smart grid activities, regarding the Board's expectations in relation to such activities in support of the establishment and implementation of a smart grid.

2. For licensed distributors and transmitters, the guidance referred to in paragraph 1 shall be provided in particular to: (a) guide these regulated entities in the preparation of plans for the development and implementation of the smart grid, as contemplated in subparagraph 70(2.1)2(ii) of the Act ("Smart Grid Plans"); and (b) identify the criteria that the Board will use to evaluate Smart Grid Plans.

3. In developing the guidance referred to in paragraph 1, and in evaluating the Smart Grid plans and activities undertaken by the regulated entities referred to in that paragraph, the Board shall be guided by, and adopt where appropriate, the parameters for the three objectives of a smart grid referred to in subsection 2(1.3) of the definition for "smart grid" as provided for under the Electricity Act, 1998, where such elements of said objectives are set out in Appendices A through C.

4. Further, in developing the guidance referred to in paragraph 1 and in evaluating the smart grid activities of the regulated entities referred to in that paragraph, the Board shall be guided by the following policy objectives of the government:

   (i) Efficiency: Improve efficiency of grid operation, taking into account the cost-effectiveness of the electricity system.

   (ii) Customer value: The smart grid should provide benefits to electricity customers.

   (iii) Co-ordination: The smart grid implementation efforts should be coordinated by, among other means, establishing regionally coordinated Smart Grid Plans ("Regional Smart Grid Plans"), including coordinating smart grid activities amongst appropriate groupings of distributors, requiring distributors to share information

and results of pilot projects, and engaging in common procurements to achieve economies of scale and scope.

(iv) Interoperability: Adopt recognized industry standards that support the exchange of meaningful and actionable information between and among smart grid systems and enable common protocols for operation. Where no standards exist, support the development of new recognized standards through coordinated means.

(v) Security: Cybersecurity and physical security should be provided to protect data, access points, and the overall electricity grid from unauthorized access and malicious attacks.

(vi) Privacy: Respect and protect the privacy of customers. Integrate privacy requirements into smart grid planning and design from an early stage, including the completion of privacy impact assessments.

(vii) Safety: Maintain, and in no way compromise, health and safety protections and improve electrical safety wherever practical.

(viii) Economic Development: Encourage economic growth and job creation within the province of Ontario. Actively encourage the development and adoption of smart grid products, services, and innovative solutions from Ontario-based sources.

(ix) Environmental Benefits: Promote the integration of clean technologies, conservation, and more efficient use of existing technologies.

(x) Reliability: Maintain reliability of the electricity grid and improve it wherever practical, including reducing the impact, frequency and duration of outages. The Board may consider such other factors as are relevant in the circumstances.

5. In furtherance of the government's policy objective as described in item (iii) of paragraph 4 above, the Board shall undertake a consultation process with licensed electricity distributors and other relevant stakeholders for the purpose of developing a regional or otherwise coordinated approach to the planning and implementation of smart grid activities by licensed electricity distributors that promotes coordination amongst them having regard to, among other things, cost-effective outcomes.

6. Nothing in paragraph 5 shall be construed as limiting the ability of licensed electricity distributors to engage in smart grid activities or the authority or discretion of the Board in exercising its responsibilities in relation to the smart grid activities of licensed electricity distributors pending the development of the regional or coordinated approach referred to in that paragraph.

APPENDIX "A"

CUSTOMER CONTROL OBJECTIVES

For the purpose of providing the customer with increased information and tools to promote conservation of electricity, which will "expand opportunities to provide demand response, price information and load control to electricity customers", in accordance with subsection 2(1.3)(b) of the Electricity Act, the following objectives apply:

- ACCESS: Enable access to data by customer authorized parties who can provide customer value and enhance a customer's ability to manage consumption and home energy systems.
- VISIBILITY: Improve visibility of information, to and by customers, which can benefit the customer and the electricity system, such as electricity consumption, generation characteristics, and commodity price.
- CONTROL: Enable consumers to better control their consumption of electricity in order to facilitate active, simple, and consumer-friendly participation in conservation and load management.
- PARTICIPATION IN RENEWABLE GENERATION: Provide consumers with opportunities to provide services back to the electricity grid such as small-scale renewable generation and storage.
- CUSTOMER CHOICE: Enable improved channels through which customers can interact with electricity service providers, and enable more customer choice.
- EDUCATION: Actively educate consumers about opportunities for their involvement in generation and conservation associated with a smarter grid, and present customers with easily understood material that explains how to increase their participation in the smart grid and the benefits thereof.

APPENDIX "B"

POWER SYSTEM FLEXIBILITY OBJECTIVES

For the purpose of "enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system," , in accordance with subsection 2(1.3)(a) of the Electricity Act, and recognizing the need for flexibility on the integrated power system, the following objectives apply:

- DISTRIBUTED RENEWABLE GENERATION: Enable a flexible distribution system infrastructure that promotes increased levels of distributed renewable generation.

- VISIBILITY: Improve network visibility of grid conditions for grid operations where a demonstrated need exists or will exist, including the siting and operating of distributed renewable generation.

- CONTROL AND AUTOMATION: Enable improved control and automation on the electricity grid where needed to promote distributed renewable generation. To the extent practical, move toward distribution automation such as a self-healing and self-correcting grid infrastructure to automatically anticipate and respond to system disturbances for faster restoration.

- QUALITY: Maintain the quality of power delivered by the grid, and improve it wherever practical.

APPENDIX "C"

ADAPTIVE INFRASTRUCTURE OBJECTIVES

For the purpose of "accommodating the use of emerging, innovative and energy-saving technologies and system control applications," in accordance with subsection 2(1.3)(c) of the Electricity Act, the following objectives apply:

- FLEXIBILITY: Provide flexibility within smart grid implementation to support future innovative applications, such as electric vehicles and energy storage.

- FORWARD COMPATIBILITY: Protect against technology lock-in to minimize stranded assets and investments and incorporate principles of modularity, scalability and extensibility into smart grid planning.

- ENCOURAGE INNOVATION: Nest within smart grid infrastructure planning and development the ability to adapt to and actively encourage innovation in technologies, energy services and investment / business models.

- MAINTAIN PULSE ON INNOVATION: Encourage information sharing, relating to innovation and the smart grid, and ensure Ontario is aware of best practices and innovations in Canada and around the world.

Glossary & Terms

ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
CAD	Canadian Dollars
CAIDI	Customer Average Interruption Duration Index
CDM	Conservation and Demand Management
CGAAP	Canadian Generally Accepted Accounting Principles
CIS	Customer Information System
CMI	Customer Minutes of Interruption
COS	Cost of Service
CPI	Consumer Price Index
CSR	Customer Service Representative
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DMS	Distribution Management System
DOE	United States Department Of Energy
EOL	End of Line
EPC	Engineering, Procurement, Construction
FDIR	Fault Detection, Isolation and Restoration
FLIR	Fault Location, Isolation and Restoration
GEA	Green Energy Act
GEEA	Green Energy and Economy Act
GIS	Geographical Information System
ICE	Interruption Cost Estimator
ICM	Incremental Capital Module
IR	Incentive Rate-Setting
IRM	Incentive Regulation Mechanism
IVR	Interactive Voice Response
LDC	Local Distribution Company
LTC	Load Tap Changer
MDM	Meter Data Management
MIFRS	Modified International Financial Reporting Standards
MOE	Ontario Ministry of Energy
MW	Megawatt
NPV	Net Present Value
OEB	Ontario Energy Board
OMS	Outage Management System
OPA	Ontario Power Authority
PCI	Price Cap Index
PUC	Public Utilities Commission – Sault Sainte Marie
RRFE	Renewed Regulatory Framework for Electricity Distributors

SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SG	Smart Grid
SGIG	Smart Grid Investment Grant
UDM	Utility Distribution Microgrid
UI	User Interface
VAR	Volt-Ampere Reactive
VVM	Voltage/VAR Management
VVO	Voltage/VAR Optimization

Appendix AA9
Navigant Report #2 – Review of Project Costs for Smart Grid Project

NAVIGANT

Review of Project Costs for Smart Grid Project for PUC Distribution

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NAVIGANT

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NAVIGANT

1. Introduction

This section of the report introduces the purpose and scope of the 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 Review

Energizing Company (ECo) retained Navigant to provide a review of the business case for a Smart Grid (SG) project that it has proposed for PUC Distribution (PUC) in Sault-Ste. Marie, Ontario. The proposed project offers the utility an opportunity to implement a comprehensive SG project with the technical and financial assistance of ECo.

1.2 Overview of 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 Utility Distribution Micro-Grid (UDM), improvements to the utility's sub-stations 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;
2) Voltage/VAR management (VVM) systems;
3) Substation upgrades; and
4) Integration, and enhancement, of the existing advance metering infrastructure (AMI).

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. ECo has included the substation upgrades as part of the UDM scope, and has proposed to accelerate the work to upgrade the appropriate substations. These upgrades are required to support the full functionality of the UDM system.

As part of the UDM project, ECo will be responsible for all design and construction costs, in addition to some portions of maintenance, and replacement costs. ECo has also proposed a 3 year community engagement process for community outreach and stakeholder education with respect to the UDM project.

The proposed project goes beyond a traditional design and build proposal to include project financing and contractual arrangements designed to ensure the continued operation of the project to a specified level of performance over the contract period. As part of the proposed

project, PUC will make 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. 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 5 minutes, the monthly payment could reflect a financial penalty for failing to meet performance standards.

The proposed project is designed to improve operating efficiency, improve system reliability and deliver savings to PUC, its customers and the provincial system. These benefits align with the objectives laid out in the Minister of Energy's Smart Grid Directive as well as the utility's own strategic objectives. The financing arrangements provided by ECo provide PUC with access to capital to achieve these benefits more quickly than may have been possible through conventional funding options.

2. Project Design and Features

2.1 UDM Project Overview

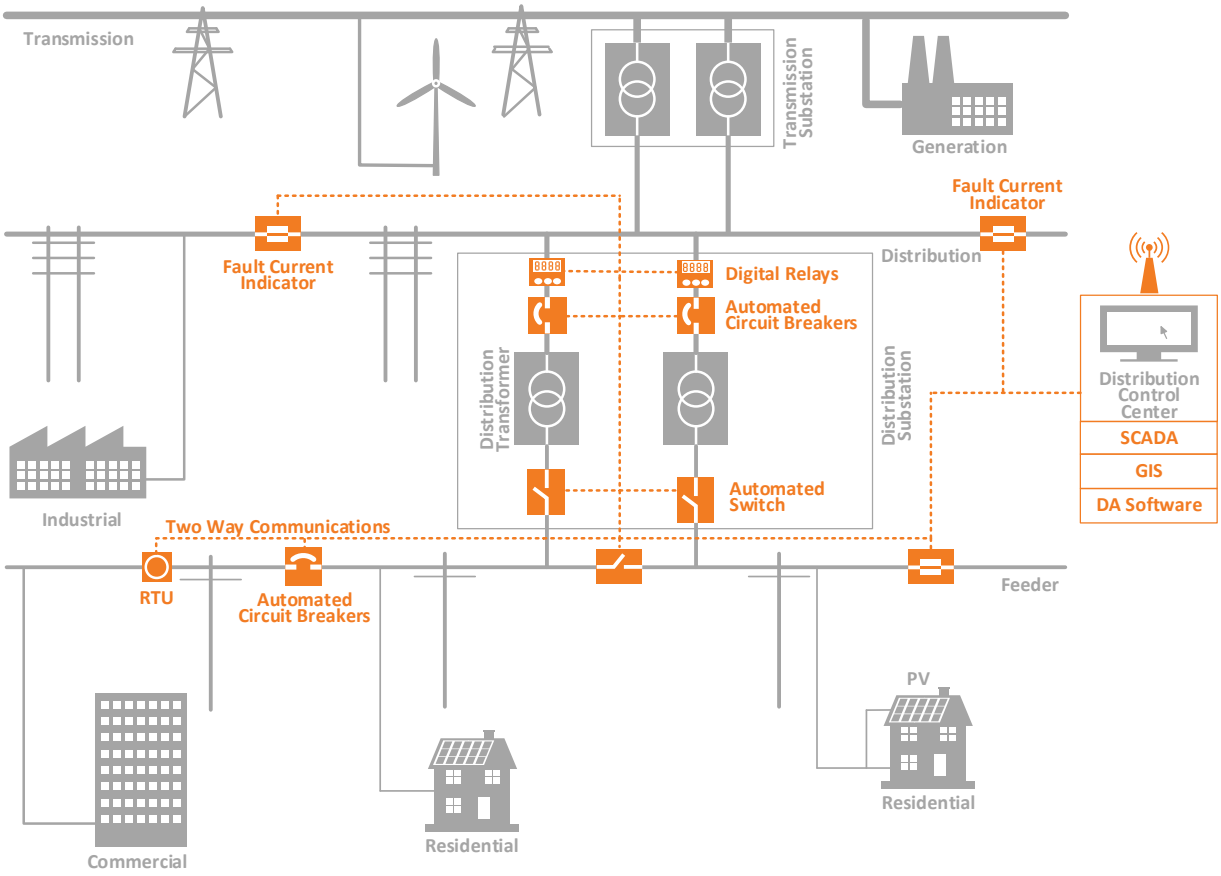
The following sections describe the four key elements of the project, as well as the three-year community engagement process.

2.1.1 Distribution Automation (DA)

The UDM project also includes the deployment of DA to 40 feeders. The DA system will provide PUC with better real-time visibility and monitoring of the network, and the ability automatically locate and isolate faults, reconfigure feeder circuits and restore power more rapidly. The DA system involves real-time re-configuration of feeders to reduce the duration, impact, and frequency of outages. The proposed system will also ensure that load-transfer switching operations will not result in voltage or over-loading violations.

Leidos has recommended a robust DA system that targets the most critical reliability issues in the city. The proposed systems will deploy reclosers and switches in the majority of the PUC system. In addition, the underground system in downtown Sault Saint Marie will benefit from the deployment of fault current indicators to decrease fault localization time. Additionally, the UDM project also includes an OMS (part of the scope of *AMI Integration*) that will improve operations and customer communications during interruptions, and automate tracking of outage metrics and system performance. Finally, the proposed design ensures interoperability with PUC legacy SCADA and communications systems.

Figure 1: Schematic of Proposed Distribution Automation System



Source: Navigant

2.1.2 Voltage/VAR Management (VVM)

The UDM project consists of the deployment of VVM to 32 feeders at 8 substations. The objective of the VVM system is to optimize the voltage profiles along feeder lines and to minimize the reactive power in lines to reduce electricity consumption, demand, and losses. This in turn can help avoid future investments in traditional transmission and distribution (T&D) infrastructure upgrades and reduce the need for manual switching operations.

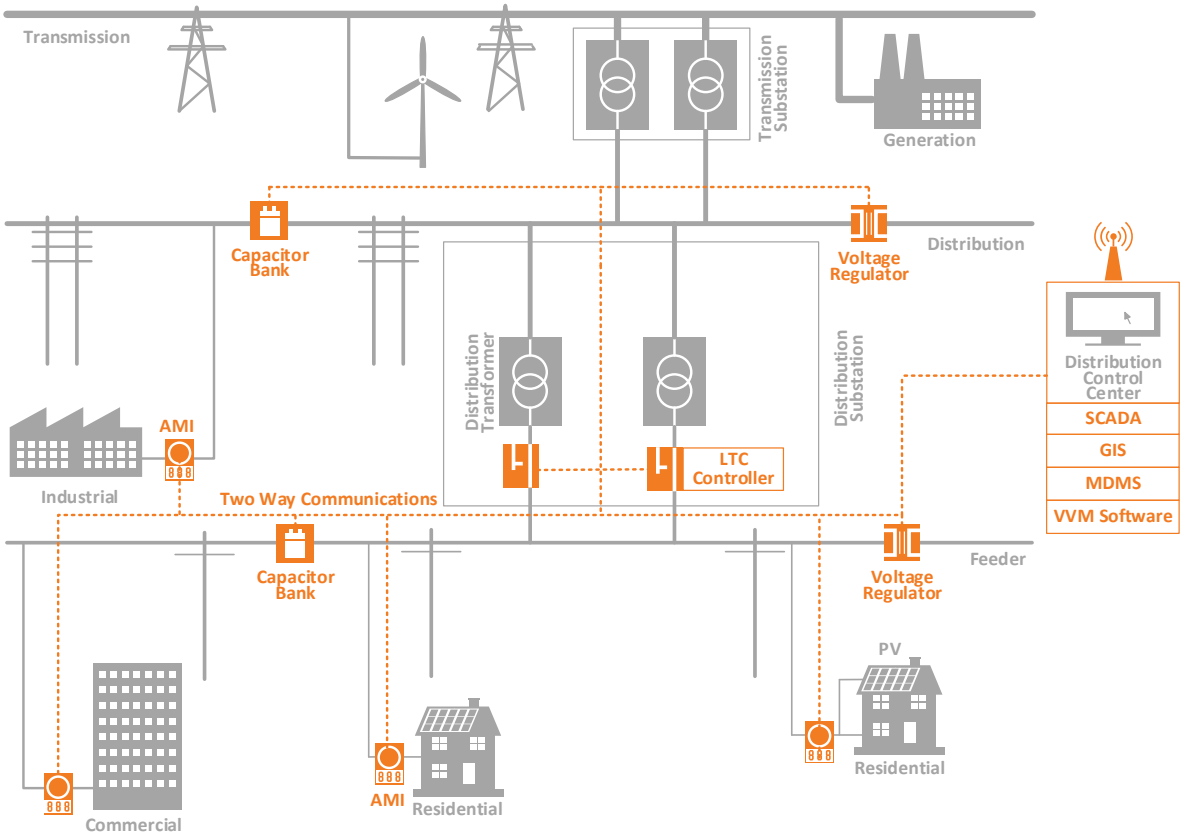
Currently, PUC does not have the capability to dynamically regulate voltage levels at any of the 34.5k/12.5 kV transformers. In addition, most of these transformers are approaching the end of their useful life and will have to be replaced in the coming years[1].

Leidos has proposed a Volt/VAR optimization scheme with centralized control. The VVM system will leverage the existing AMI, Geographical Information System (GIS) and

[1] For more information see: Leidos. 2014. "Utility Distribution Microgrid: Volt/VAR Management (VVM) – Preliminary Design".

Supervisory Control and Data Acquisition (SCADA) systems and will employ Load Tap Changer (LTC) controllers, voltage regulators and capacitor banks. The VVM will benefit from the planned substations upgrades, as well as from feeder-reconditioning recommended for a selection of feeders. The proposed VVM system has the potential to help PUC and Sault Saint Marie to achieve future conservation and demand management (CDM) goals.

Figure 2: Schematic of Proposed Voltage/VAR Management System



Source: Navigant

2.1.3 AMI Integration

The UDM project will deploy a number of applications intended to leverage the existing AMI system. These include:

- A robust Outage Management System (OMS), which will integrate existing Supervisory Control and Data Acquisition (SCADA), AMI, and Customer Information System (CIS) data, and incorporate an Interactive Voice Response (IVR) system. The objective of the OMS is to complement the deployment of DA. The OMS will automate reporting of outage information, reliability data, restoration verification, and to improve customer communications during outages through the IVR system
- An enhanced CSR/Customer toolset in order to manage AMI data in a more efficient manner. According to Leidos, PUC is content with its existing CIS platform. The proposed solution will leverage this affinity and will incorporate upgrades and additional functionalities to maximize the value of the CIS, and to align its capability to track metrics and data inherent to the DA and VVM systems.
- Improvement of AMI voltage reads in order to integrate data into VVM system. The existing Sensus AMI platform will need to be modified in order to achieve the granularity and data requirements needed to maximize the VVM system.
- An analytics platform to integrate and track SCADA, AMI, CIS, OMS and GIS data for better reporting and use. Leidos has proposed to deploy a Cloud Analytics Platform to integrate data from all systems and provide DA and VVM performance reports, and facilitates the visualization and management of PUC's distribution system.

2.1.4 Substation Upgrades

The substation upgrades will support the deployment of the DA and VVM functionality. These substations require upgrading or replacement in order to enable the automated functionality for voltage control and automated switching in the 34.5kV and 12.47kV systems. The UDM project includes work at eight substations; four of which will require complete rebuilds, three require new LTC transformers, and one will require new bus-bar regulators.

Currently, most of these transformers are approaching the end of their useful life. Absent the UDM project, PUC would have to replace them in the coming years. The substation upgrades have been included as part of the UDM scope as they are a fundamental aspect of the project. Additionally, the proposed investments in VVM and DA will leverage the existing AMI infrastructure and the proposed substation upgrades to create a more robust business case for the combined deployment.

2.1.5 Design and Construction

Project Company (or Project Co) will be responsible to PUC for the UDM project delivery. The project design will be developed in coordination with PUC to ensure compatibility with PUC's system. The Design and Construction Contractor also referred to as the Engineering, Procurement and Construction (EPC) contractor will be responsible for costs of the design and construction phase of the project. When construction is complete, the system will be tested to ensure it is performing to specifications. Once performance has been assured the parties will sign-off on an agreement of construction completion. Ownership of any component of the project vest with PUC upon installation of the respective components.

2.2 Project Components

The Utility Distribution Micro-Grid[2] proposed for PUC includes DA and VVM technologies designed to achieve several MOE objectives.[3] Navigant's review is based on the preliminary design and cost studies and supporting documents prepared by Leidos Engineering, and several telephone conference calls conducted with Leidos Engineering design and planning staff.[4] Navigant also reviewed the UDM with PUC technical and operational staff.

The PUC distribution system is comprised of 12.5kV and 4kV feeders, with line distances and feeder attributes comparable with LDC's in Ontario and elsewhere in Canada. There is currently a minimal amount of automation on PUC's distribution system, so integration of new DA and VVM will not interfere with nor prematurely replace other existing systems. For example, PUC currently does not have SCADA access to distribution equipment located beyond its substations.[5] The primary components of the UDM include upgraded communications, automation and controls, distribution substation and feeder equipment and upgrades. Approximately 84 percent and 68 percent of PUC's system will be covered by DA and VVM, respectively.

Figure 3 presents the overall system architecture for the DA/VVM system, which includes wireless communications at the feeder level and a new fiber ring between PUC system control

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[2] The project title suggests Micro-Grid (MG) technologies are included in the set of technologies proposed for the PUC distribution grid. However, the UDM does not include MG technologies at the time of this review. Navigant's review of the UDM, instead, addresses DA and Volt-VAR Optimization (VVO) systems [the term "Volt-VAR Management" appears in Leidos and PUC documents and will be used hereafter] that constitute most of the costs and benefits associated with the project. Navigant recognizes the technologies installed to support DA and VVM also can be used to support and integrate future MG

[3] See Appendix A: "Smart Grid Directive from Ontario Minister of Energy".

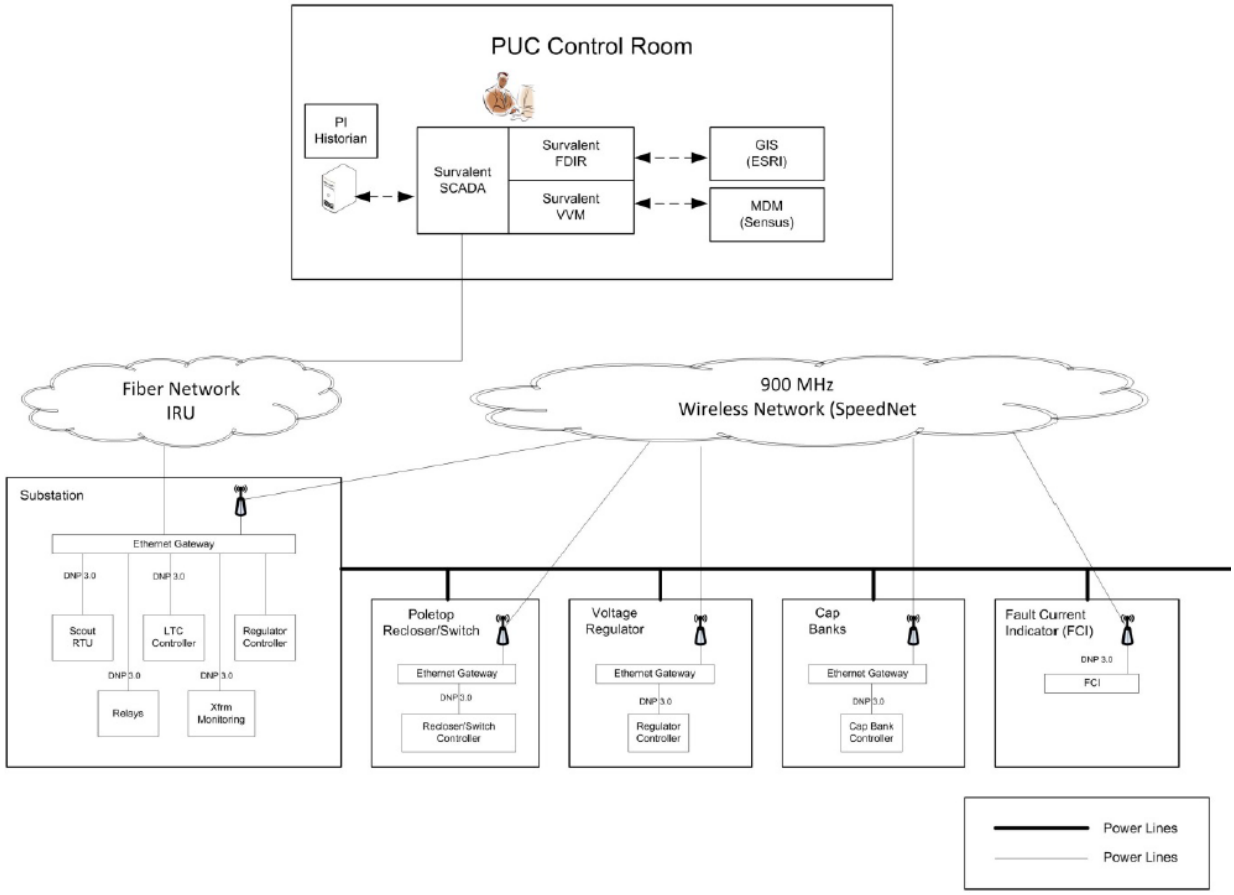
[4] Leidos experts sought explain the data, assumptions and methods it used to design the UDM, estimate costs and benefits, and to address questions Navigant raised on design details and documentation that Leidos prepared for the UDM. In each of these calls, Leidos was fully cooperative and responded to all questions by the Navigant team.

[5] PUC currently uses a Survalent SCADA system to monitor and control equipment in substations.

room and each substation equipped with DA or VVM automation. The DA and VVM automation systems will be provided by Survalent Technology. Survalent is a well-known supplier of SCADA and DMS systems for numerous LDC's in Ontario, including PUC.

Leidos selected Survalent based on PUC's familiarity and favorable experience with its existing SCADA system, and Survalent's products and service offerings in Advanced Distribution Management Systems (ADMS), which includes VVM and FDIR (Fault Detection Isolation Restoration). Survalent equipment Leidos has proposed for the UDM includes centralized automated control of DA and VVM for distribution substations and feeders, which can be operated on a fully automated basis or semi-automated mode with system operator over-ride or control.[6] The Survalent system will interface with PUC GIS, Meter Data Management (MDM), and SCADA to exchange operational data for DA and VVM field equipment. PUC System Operations will maintain operational responsibility of the UDM throughout the life of the project.

Figure 3. High-Level UDM Architecture



Source: Leidos

[6] PUC System Operations center is staffed for daytime hours only, and

The DA segment of the control system will operate in 3 modes: (1) Disabled; (2) Semi-Automated; and (3) Full-Automatic. Control system flexibility is essential, as PUC does not now have, nor does it plan to provide, 24 hour/7 day staffing of its Operations Control Center. During day time hours, PUC operating staff can select manual mode for shut down during feeder switching or line construction or maintenance. During evening hours, the DA scheme will typically operate in full automation mode.

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.

3. Analysis of Project Costs

Navigant's review of the full life cycle costs of the UDM are based on the design and cost studies, and supporting documents, prepared by Leidos. These costs are reflective of full life cycle costs for all project components, including installation, system integration, testing and commissioning, project management and controls, and training. These costs do not reflect costs associated with project financing, risk transfer or other services which will also be included in the monthly fee to PUC. As noted, the proposed UDM project will only accelerate the investments in substation upgrades. Absent the UDM project, PUC will have to incur the full costs of substation upgrades in the near future since most substations, and their associated assets, are approaching the end of their useful life. The distribution of project costs across the different elements of the UDM, shown in Table 1 below indicates substation upgrades represent a substantial portion of total project costs.

Table 1: Distribution of UDM Project Costs

Project Feature	Costs
DA	10%
VVM	24%
DA & VVM Common	1%
AMI	4%
Sub Total	39%
Substation Upgrades	38%
Post-Implementation	22%
Total	100%

Source: Leidos

Navigant's review and assessment of project costs, by program and for each major system or equipment category is presented below. Our review and findings are based on our background and knowledge of similar AMI, DA and VVM schemes implemented by other North American utilities; and our background in electric utility planning, design and operations.

3.1 Distribution Automation (DA)

The DA system proposed for the UDM centers on installing FLIR systems on circuits that provide coverage for 84% of PUC's distribution system[7]. The FLIR proposed for PUC is based on proven control technologies that have been implemented on utility systems throughout North America, and typically produce strong business cases from an economic perspective.

[7] Navigant understands that PUC recently requested an amendment to the DA design to implement a fuse control strategy that would effectively increase the current 84% coverage to approximately 100% of PUC's territory.

The DA design and feeder selection appears appropriate, as Leidos conducted a detailed analysis of PUC reliability data by feeder, and applied industry-accepted methods to identify feeder segments best suited for FLIR technology and to predict reliability benefits.[8] Leidos conducted CYME distribution simulation studies – CYME is a model used by many Canadian utilities and engineering firms - for each scheme under normal and transfer states to ensure PUC loading and voltage criteria were not violated. The preliminary design lists and describes the additional or upgraded equipment needed to successfully implement the schemes. Navigant recognizes that the above systems and equipment is required to implement the FLIR schemes. The equipment and systems needed to implement DA on 40 overhead and underground distribution feeders is listed below. Navigant's opinion on the accuracy are potential variability of these costs are presented for major equipment categories.

3.1.1 Centralized FLIR Automation Software (with GIS interface and load Flow Simulation)

The FLIR Automation in the "heart" of the DA scheme, as it is the intelligence that enables the DA scheme to successfully isolate faults and transfer unfaulted line segments to adjacent lines. Leidos and PUC propose a FLIR offered by Survalent, a company that has provided DA and VVM schemes to other LDCs. The $400,000 cost appears to be based on recent quotations or costs from similar installations, which should reduce the variability in final installed costs. Nonetheless, Navigant's experience suggests final installed costs can vary (increase) due to a variety of factors, many related to unanticipated software modifications and adjustments that often accompany new software systems. Further, complete specifications and system requirements must be prepared by Leidos and approved by the PUC to enable Survalent to prepare a firm bid based on a design for each of the 40 feeders where DA is proposed. Absent written confirmation of preliminary costs provided by Leidos, Navigant views the potential for cost increases to be high for DA automated software.

3.1.2 Source (34.5kV supply) Transfer Scheme (Software)

There are 10 PUC substations where transfer schemes will be installed to enable transfer of 34.5kV supply lines within the substation for supply-side faults. This is a desirable scheme as many customers are served at the substation level, so enhanced transfer schemes, particularly where this capability does not exist today, can provide significant reliability benefits. The average cost of each scheme, approximately $30,000 is a reasonable cost to provide this capability. This estimate appears reasonable, but could be low if other unanticipated substation upgrades are needed. These cost and design details will be determined with greater certainty upon completion of final engineering.

[8] The DA system proposed for PUC include feeder transfer for loss of incoming 34.5kV transmission, a design aspect that ensures maximum reliability benefits are achieved for both a loss of main line feeder sections and substation supply.

3.1.3 Reclosers (38 feeders)

Reclosers and pole top switches are the primary sectionalizing equipment hardware used in DA schemes. Each feeder must be equipped with these devices to enable automated sectionalizing for each feeder in the DA scheme. The cost of 38 15kV class reclosers, equipped with communications capability, is approximately $80,000 per device. Similar to other UDM components, this amount includes engineering, installation and testing, project management, and business processes. Leidos recommends the purchase of S&C equipment, a well-known and reputable supplier of DA equipment. The cost of each recloser is about $40,000. Excluding total business process change of $350,000, the average installed cost per device is about $70,000. The cost of the reclosers and total installation cost is consistent with DA schemes Navigant has encountered with other utilities. The cost of business process change at $350,000, while high, is reasonable as the adoption of automated systems represents a major change in how PUC will operate and manage its distribution system. These schemes will require documentation along with training of PUC engineering, operations and maintenance staff on equipment hardware and controls, and the automated systems associated with each DA scheme.

3.1.4 40 Pole top switches

The 40 pole top switches work in concert with feeder reclosers for automated DA transfer schemes. These devices are less complex with lower costs than reclosers, and the $60,000 average installed costs is expected and consistent with costs Navigant has seen at other utilities. The total cost of sectionalizing equipment, about $130,000, for both reclosers and tie switches is also comparable to DA schemes implemented by other utilities. The use of S&C SCADA-Mate devices is common among utilities and is appropriate for the proposed DA scheme for PUC. The cost of business process changes in included in the costs of reclosers.

3.1.5 Four 2-way padmount switches (for underground lines)

The four 2-way padmounted switches are required for underground lines (in lieu of use of reclosers and pole-top switches for overhead lines). Similar to overhead reclosers and pole-top switches, these devices are an essential component of DA schemes. The cost of padmounted switches is well above overhead equipment providing comparable functionality. At $110,000 total installed cost per device, Leidos' preliminary estimate is reasonable and consistent with those of other utilities. However, due to normal cost fluctuations and adjustment from suppliers, the formal quotes for these devices could be higher, but likely within the contingency adder assigned for the UDM.

3.1.6 4-Way Padmount Switches (for underground lines)

The 4-way padmount switches are similar to 2-way devices, but with added sectionalizing capability. They also are an essential component of DA schemes for underground lines. The average installed cost of approximately $120,000 per devices is reasonable and consistent with those of other utilities. The potential for cost variability is the same as described above for 2-way switches.

3.1.7 Overhead Fault Indicators

The 20 fault indicators for overhead lines are an enhancement to the DA schemes that will improve fault location detection. The average installed cost of each device, approximately $7,000 each, appears slightly high, but generally is reasonable and consistent with other utilities. We note that the quantity in Leidos' Bill of Materials (32) is greater than the 20 cited in the main body of the preliminary Design report, which may account for the apparent higher cost. We also note a similar potential discrepancy for fault indicators without communications, where 30 is listed in the Bill of Materials with an associate average cost of $2,500 each.

3.1.8 Underground Fault Indicators

The 28 fault indicators for underground lines are an enhancement to the DA schemes that will improve fault location detection. The average installed cost of each device, approximately $6,000 appears slightly high, but generally each is reasonable and consistent with other utilities. We note that the quantity in Leidos' Bill of Materials (37) is greater than the 28 cited in the main body of the preliminary Design report, which may account for the apparent higher cost.

3.1.9 Pole Additions and Replacements

Leidos proposes 86 new poles to accommodate new reclosers and switches, and other ancillary upgrades. This is a common practices among utilities, as the height and strength of existing poles typically are inadequate (and not designed) for the additional physical loading and clearances for the new equipment. The average cost of each pole, approximately $11,000, appears somewhat higher than costs Navigant has encountered with other utilities. We note that Leidos' spreadsheet has just two entries, $900,000 for all poles and $90,000 for project management, suggesting high-level PUC estimates have been applied. Navigant does not view pole costs as a major concern, as they are required and the total cost of just under $1 million likely will be identified and required in the detailed design phase of the project.

3.1.10 Summary Assessment - DA

The equipment suppliers and technology Leidos presents in its preliminary design are appropriate, and from reputable firms, with technology that has been successfully deployed by other utilities for DA FLIR schemes. It includes automated switches from reputable suppliers, commonly used by utilities that have implemented similar DA schemes, and fault indicators to direct crews to fault locations to reduce travel and repair time. Navigant notes the use of gang-operated switches instead of reclosers, a cost-effective choice when more expensive reclosers provide limited additional value. Leidos' design also includes radio communications to field equipment and switching devices, a less costly alternative to fiber expansion and suitable for DA applications.

The equipment and systems specified by Leidos are necessary DA components, and the cost of each is mostly consistent with DA schemes implemented by other utilities. Actual installed cost for most equipment should be within the project contingency for the preliminary design.

However, preliminary design cost estimates exclude future adjustments, enhancement and replacements that may be associated with load growth, feeder reconfiguration, operating and design criterion, or other changes normally encountered over time for most electric utilities. Navigant recognizes that the project agreement is expected to contractually specify the future costs which will be borne by ProjectCo and transfer the risk of any potential cost overruns to the Services Provider.

3.2 Voltage/VAR Management (VVM)

The proposed VVM system is designed to achieve energy savings via permanent reductions in feeder voltage, achieved by reducing starting voltage at the substation and installing voltage regulating equipment, where needed, to ensure line voltage to not drop below minimum thresholds set forth in the Ontario Distribution Code. The Survalent VVM system will continuously monitor voltage via sensors at various locations on each distribution feeder and adjust voltages via station regulators and line capacitors or regulators. Leidos' approach identified the oldest substation transformers on the system scheduled for replacement in the near future under the assumption that new substations and replacement transformers at existing substation would be equipped with modern load tap changers suitable for VVM applications.[9] The analysis led to a determination that eight substations and 32 feeders are the best candidates for VVM. Similar to DA, Leidos conducted load flow studies; in this case to identify the level of energy savings that could achieved on the 32 feeders. For some feeders, additional upgrades such as rebalancing of loads and installation of capacitors are needed to maximize energy savings potential.

The equipment and systems needed to implement CVR at the eight PUC substations, listed, below. Navigant's opinion on the accuracy are potential variability of these costs are presented for major equipment categories.

3.2.1 Survalent Volt-Var Management System with GIS interface

Similar to DA, VVM software is the heart of the system, providing centralized active voltage control via transformer load tap changers to maximize savings while meeting feeder voltage limits. The cost of the VVM can be highly variable if the system, as designed, is to be capable of actively managing feeder voltages. The values prepared by Leidos for Survalent VVM software and hardware appear to be based on recent quotations or actual costs, which should reduce the variability in final installed costs. Navigant's experience suggests final installed costs can vary (increase) due to a variety of factors, many related to unanticipated software modifications and adjustments that often accompany new software systems. Further, complete specifications and system requirements must be prepared by Leidos and approved by the PUC to enable Survalent to prepare firm bids on each of the 32 feeders where VVM is proposed. Absent written confirmation of preliminary costs provided by Leidos Navigant views the potential for cost increases to be high for the VVM.

[9] PUC's existing transformers do not have load tap changing capability, a requirement for effective CVR schemes.

3.2.2 New/rebuilt substations

At approximately $3 million each, the cost of the four new and rebuilt substations associate with the project is, by far, among the most costly components of the UDM. This cost is consistent with similar substations that Navigant has seen at other utilities. However, the costs of substations can vary based on several site-related and electrical considerations. This variability is tempered by experience: the type and cost of substation equipment associated with new and rebuilt substations is well-known by utilities and engineering firms such as Leidos. The equipment listed in the preliminary design is very high level and does not include a detailed listing of equipment and construction by major category. For example, substations include site work, major electrical equipment, structures, control buildings, breakers, instrument transformers, protection and controls, communications, security and other ancillary equipment. Navigant expected to see 30% preliminary design cost estimates for each of these categories. Further, engineering at $1.5 million for four substations appears slightly on the high side, but this may be due to site-related and other ancillary improvements needed at each substation.

Given the above, Navigant recommends that Leidos prepare estimates based on the final engineering design to confirm with greater certainty costs for equipment, construction and engineering. Notably, the large majority of the equipment is not required for VVM functionality; only the load-tap changer of the station transformers, which represents about 10 percent of total substation cost, is included in the benefit cost analysis. The average cost of the load-tap changing component, approximately $250,000 each, has less variability than other substation components.

3.2.3 New LTC transformers (10/13 MVa): 6 Units at 3 Existing Substations

Although the total installed cost of each unit is high compared to other VVM components, approximately $0.6 million, the level of variability in costs for new transformers is lower than other VVM components. The average cost of each transformer, $400,000, is reasonable and comparable to other transformer purchases that Navigant has seen elsewhere. Because the cost of these devices is a function of material cost such as copper, an internal component, they can vary with increases or decreases in cost of commodities. Installation costs at $750,000 for six transformers appear to be somewhat high, but this may be due to other ancillary improvements needed at each substation to accommodate these devices, such as expansion of oil retention facilities and bus structures.

3.2.4 New distribution capacitors

The total installed cost of the two proposed distribution capacitors, $8,000 each, is consistent with values Navigant has seen at other utilities. However, given the large number of feeders (32) that will be controlled for VVM, Navigant's experience suggests that additional capacitors may be needed at the time of the initial installation or over time. No additional capacitors are included in post-implementation costs. However, changes in feeder configuration, load

growth or desire to improve voltage regulation may require additional capacitors. However, because the cost of these devices is low compared to other VVM components, total cost exposure is low.

3.2.5 New phase voltage regulators

The total installed cost of the two proposed feeder regulators, about $90,000 each, is consistent with values Navigant has seen at other utilities. There should be minor cost variability compared to other VVM components.

3.2.6 Padmount voltage regulators (Substation)

Navigant has limited experience with padmount substation voltage regulators. We expect the cost of the padmount devices is well above the cost of comparable devices for overhead lines. The amount Leidos has estimated for these devices, $200,000 each, appears reasonable, as it approximately double the cost of the feeder regulators.

3.2.7 Phase rebalancing (may not require new equipment on some feeders) - 17

Phase rebalancing is necessary to enable VVM, and the cost Leidos has included for this work is reasonable based on Navigant's background and experience. However, despite best efforts, there is a fairly high level of variability with load balancing, as adjustments to other feeders may be needed following the initial installation of VVM. Due to the relatively low cost of rebalancing, total cost exposure is low.

3.2.8 Summary Assessment - VVM

The equipment suppliers and technology Leidos presents in its preliminary design for VVO are appropriate, and from reputable firms, with technology that has been successfully deployed by other utilities for VVO schemes. It includes new voltage regulators and capacitors consistent with those used by utilities that have implemented similar VVO schemes. Further, Leidos includes rebalancing of feeders, which should improve VVO capability and efficiency. Navigant notes only the load-tap changing component of the transformer replacements are required for VVO and the cost of the load-tap changer is a relatively small percentage of the total cost of the transformer or substation upgrades.

Notwithstanding the above distinction for the load-tap changer and distribution substations, the equipment and systems described above are necessary VVO components, and the cost of each is mostly consistent with VVO schemes implemented by other utilities. Actual installed cost for most equipment should be within the project contingency for the preliminary design. Similar to DA, preliminary design cost estimates exclude future adjustments, enhancement and replacements that may be associated with load growth, feeder reconfiguration, operating and design criterion, or other changes normally encountered over time for most electric utilities. Navigant recognizes that the project agreement is expected to contractually specify the future

costs which will be borne by ProjectCo and transfer the risk of any potential cost overruns to the Services Provider.

3.3 AMI Integration

The scope of the AMI integration work includes the deployment of the OMS, CSR tools, enhanced AMI data, and an analytics platform. These enhanced capabilities will leverage the existing AMI infrastructure, communications system and smart meters, and will be incorporated into the UDM architecture. Given the nature, and the overlap of these investments with the VVM and DA deployments, the UDM cost-benefit analysis does not explicitly monetize benefits that arise from these particular deployments. Similar to substation upgrades, the AMI Integration deployment will support the investments in DA and VVM systems, and will be integrated into PUC's regular operations. Given the overlap of system functionality and operation, Navigant understands and agrees with Leidos' approach of incorporating AMI investments into the DA and VVM benefits.

Outside of the UDM scope, the enhanced AMI capabilities are, in addition, expected to provide better outage management, fault localization, customer communication, and asset monitoring; enabling PUC to improve operations and maintenance. While Leidos has not monetized these enhanced uses, these capabilities will enable PUC to improve a number of elements of their business, as described below.

- **Outage management and communication**: The integration of AMI, OMS and CSR tools will enhance PUC's communication with customers during outages, reducing inbound call volume and improving customer satisfaction.
- **Service restoration and fault localization**: AMI-OMS integration will leverage smart meter pinging tools to verify when power has been restored to customers, avoiding service calls or direct notification from customers.
- **Equipment monitoring and grid oversight**: AMI, OMS, and the data analytics platform will enable PUC to monitor asset loading conditions (e.g., distribution transformers) enabling better assessments of equipment condition and to more efficiently planned future investments.

Similar to DA and VVM, software and hardware costs for AMI system upgrades tend to have the great potential variability in costs. Further, virtually all costs related to AMI are for software and hardware systems; unlike DA and VMM, it excludes major distribution substation or feeder equipment, thereby increasing variability in costs. The Leidos and PUC propose AMI enhancements offered by Survalent, a company that has provided AMI software and systems integration schemes to other LDCs. The $1.1 million included for software, hardware and implementation appears to be based on recent quotations or costs for similar programs, which should reduce the variability in final installed costs. Navigant's experience suggests final installed costs can vary (increase) due to a variety of factors, many related to

unanticipated software modifications and adjustments that often accompany new software systems. Further, complete specifications and system requirements must be prepared by Leidos and approved by the PUC to enable Survalent to prepare a firm bid based on a design for the integrated AMI/OMS/CSR system. Absent written confirmation of preliminary costs provided by Leidos, Navigant views the potential for cost increases to be high the associated software required for complete and successful integration.

3.4 Summary Assessment

Based its technical review, Navigant concludes the UDM project is technically sound, designed and configured consistent with current utility practices. All costs for design and construction of the UDM were prepared by Leidos, with input provided by PUC with respect to design standards, equipment specifications and procurement practices. Engineering costs are just under 10% of total UDM cost, which Navigant deems reasonable. Roughly 7% is for conventional substation and distribution feeder upgrades, an area in which both Leidos and PUC have considerable experience engineering and estimating costs. In addition, about 5% of total UDM cost is for system integration of AMI, VVM, and DA systems, mostly Leidos support. Another 5% is for project management and control. Taken together, total design, project management and system integration cost are within industry averages.

The cost of major equipment hardware such as upgraded substation equipment and feeders constitute about 60 percent of total UDM cost. The cost of most of this equipment is reasonably well known, as PUC has recently installed similar equipment on its system or has obtained initial estimates from suppliers. For example, substation power transformers and station upgrades represent over 30% of total UDM cost; mostly conventional upgrades and systems that many utilities have installed as part of it ongoing capital planning and budgeting. An additional 12% is for S&C Intellerupters and switchgear. Leidos has advised Navigant that it obtained these estimates are based on quotes from the vendor.

The total cost estimates for AMI, DA and VVM (and associated substation upgrades) each appear reasonable, particularly with regard to cost associated with major equipment components. However, there is potential for upgrades and additions that may not be identified during the preliminary design such as site related costs for substations and additional equipment needed to fully implement DA and VVM. Further, equipment costs may increase upon receipt of final quotes from equipment suppliers, both due to detailed specifications provided in formal requests for quotes, in addition to increases in supplier costs that may not be included in initial quotes or in prior cost estimates.

Navigant's experience indicates the cost of software and related support are typically areas where potential variances are highest, particularly at the preliminary engineering design phase. We understand the estimates either were provided by Survalent or based on data from comparable installations. Survalent also will provide AMI, DA and VVM, software and support. While Navigant does not have any basis for assuming these estimates are low, we are

aware that variances in software and hardware costs can occur due to changes in design or issues identified during the implementation phase. Often, cost increases for software and associated hardware occur due to extended timeframes caused by delays or revisions in DA and VVM schemes as the project is in progress.

Navigant also notes that post-implementation costs from Leidos' cost worksheet do not appear to include equipment and system upgrades that often occur during the life of the project. Post-implementation project costs currently include software and hardware maintenance and support, and staff support; but does not specifically list equipment upgrades or capital replacements for distribution lines and substations that are part of the UDM. Over 20 years, it is quite conceivable that issues may arise, leading to additional costs needed to maintain desired functionality and to avoided penalty clause provisions. If Navigant's premise is correct, then post-implementation may be insufficient or there would need to be a provision for exclusion of future capital upgrades in the project agreements. As noted in section in section 3.1.10, Navigant understands that the intent is to transfer the risk for these costs to the Services Provider through the project agreement.

Examples of the types of issues which may arise include:

- Overhead and underground distribution feeder upgrades needed for load growth, changes in feeder load density, operational reasons or to address feeder performance issues, among other potential factors.
- Changes in design and performance standards, either at PUC or at the provincial level via the Distribution system Code.
- Replacement of equipment or systems due to failures, obsolescence, lack of vendor support (e.g. suppliers goes out of business), or loss of functionality
- Capitalized corrective maintenance that are deemed to be part of UDM project cost and the responsibility of the Project Company
- Regulatory mandates that may require changes in AMI and other equipment due to provincial electricity initiatives; thereby making existing equipment obsolete or inadequate

Operational costs are the responsibility of PUC while ongoing maintenance is the responsibility of the service provider. It is unclear from Leidos' project estimate spreadsheet if funds are allocated for post-implementation capital maintenance. Further, Navigant considers that the amount estimated for business process change (at approximately 1.5% of project costs) appears to be on the low side, and should reviewed in conjunction with final project design. We encourage Leidos and PUC to further analyze business process change requirements as these

costs are sometimes underestimated when significant changes in software and business aspects of utility operations are implemented[10].

Navigant understands project contingencies, which have been estimated between 10% and 20% for the preliminary design, are embedded in Leidos' UDM cost estimates. Navigant believes a project contingency for the UDM between 20 to 30 percent may be appropriate due to the scope and complexity of each of the programs and potential uncertainty on hardware and software costs. This level of contingency would like cover many of the potential cost increases cited in our review of program component costs. It also is consistent with the sensitivity analysis Navigant performed for the cost benefit analysis, where project costs are increased by 30 percent. Navigant's opinion based on its review of project costs herein is that actual project costs are likely to be closer to the 30 percent above the preliminary design estimate; this would be 10% to 20% beyond the 10% and 20% contingencies embedded in the Leidos estimates.

We note that Leidos was not able to cite other LDC's where it has designed and implemented systems of comparable scope (i.e. level of coverage). 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 acknowledge 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.

[10] Navigant notes that at the time this report was being prepared PUC was undertaking a 12 week business process improvement (BPI) project which will identify current baseline conditions and begin to introduce some of the BPI changes that may occur as a result of implementing the smart grid project.

Appendix AA10
Navigant Report #3 – Community Microgrid Business Case Review Report

NAVIGANT

Community Microgrid Business Case Review

Final Report

Prepared for:

Sault Ste. Marie Innovation Centre

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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

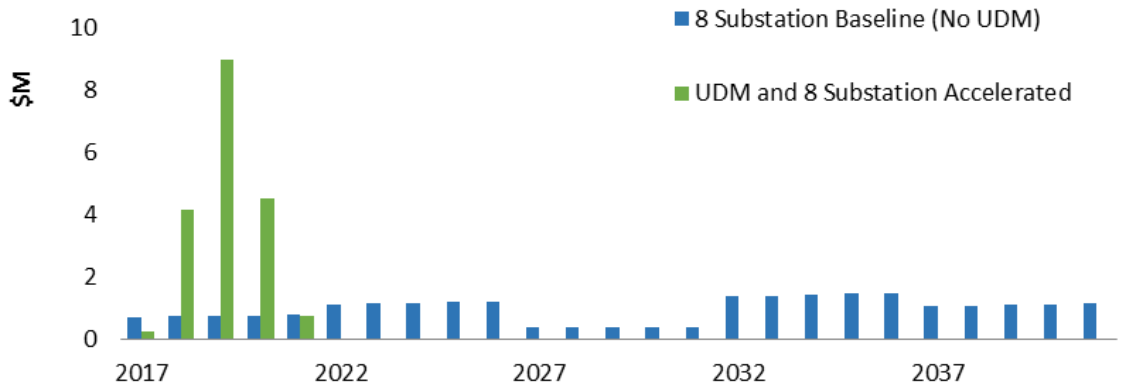
This section presents Navigant's analysis and findings with respect to the costs and benefits of each project option.

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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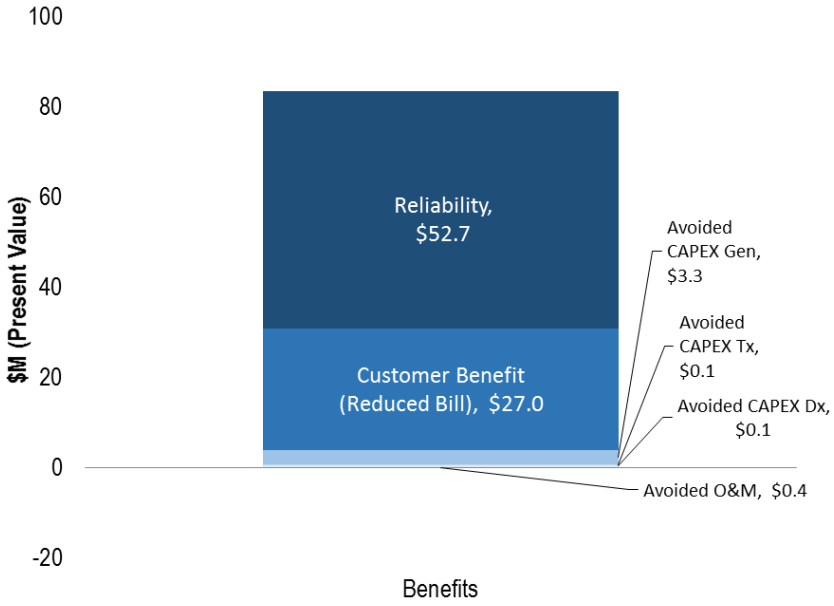
conducted below are highly dependent on the time period over which the project is analyzed. Although the ECo proposal includes 20 years of service fee payments, the benefits are expected to be realized over the lifetime of the assets. For the purposes of this analysis, Navigant assumes that hardware 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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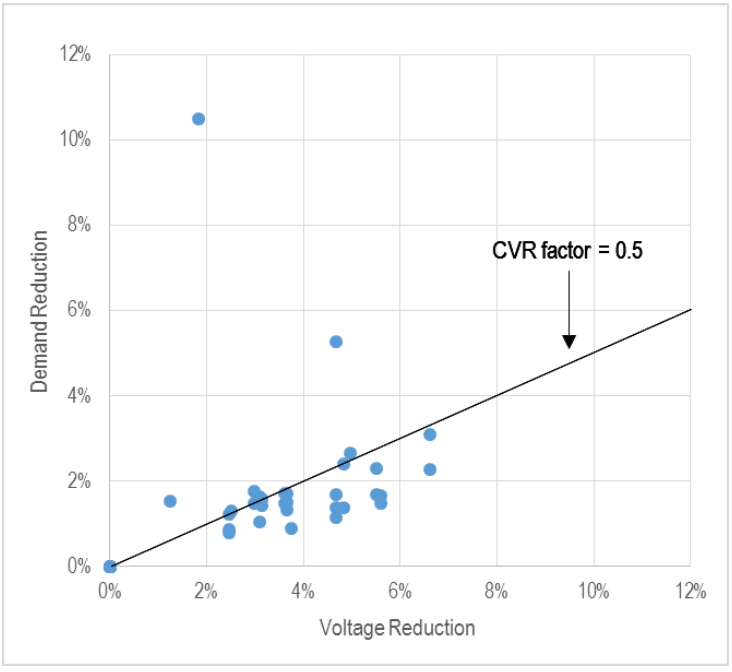
- SAIDI reduced by 46%
- Customer Average Interruption Duration Index (CAIDI[12]) reduced by 16%

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

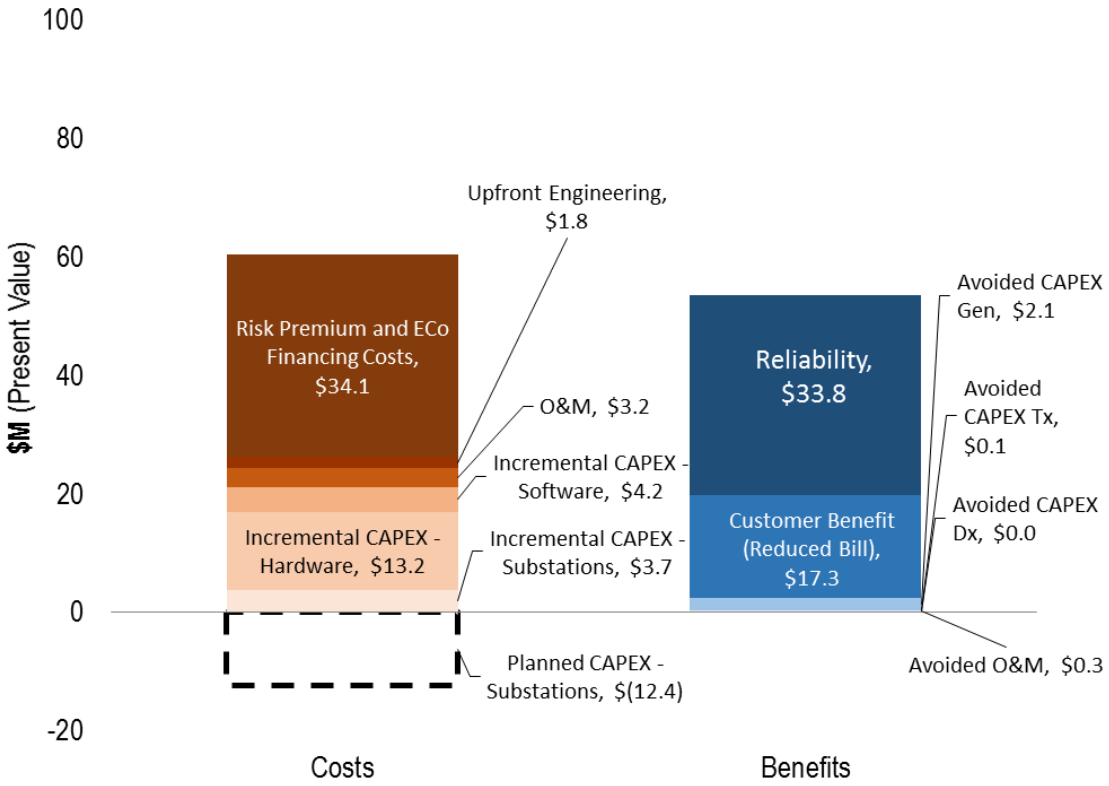

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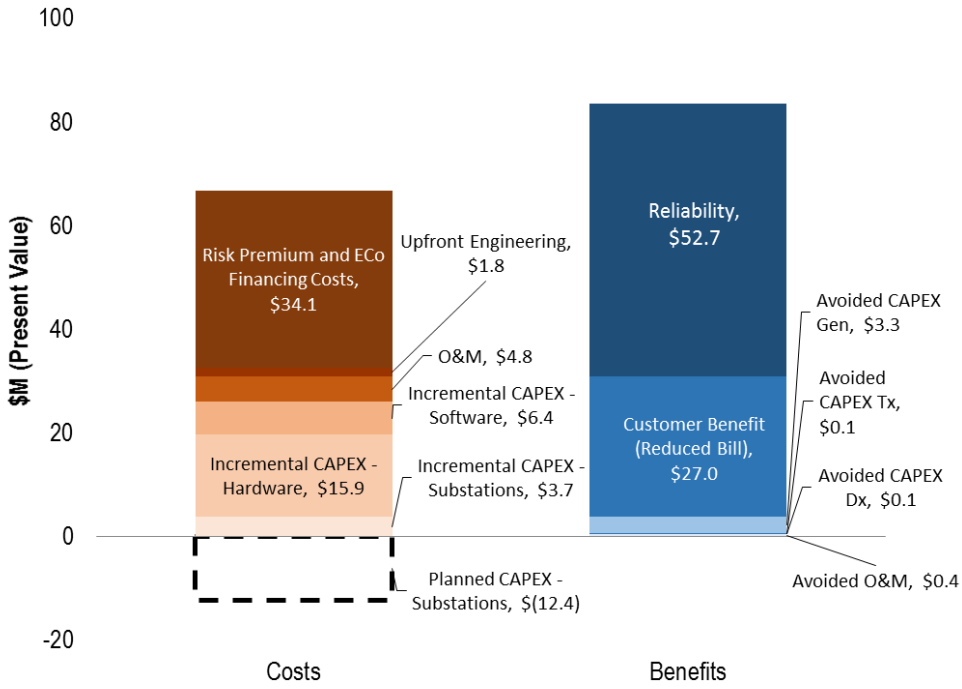
Figure 5. Net Present Value (40 years) Costs and Benefits of ECo-funded UDM



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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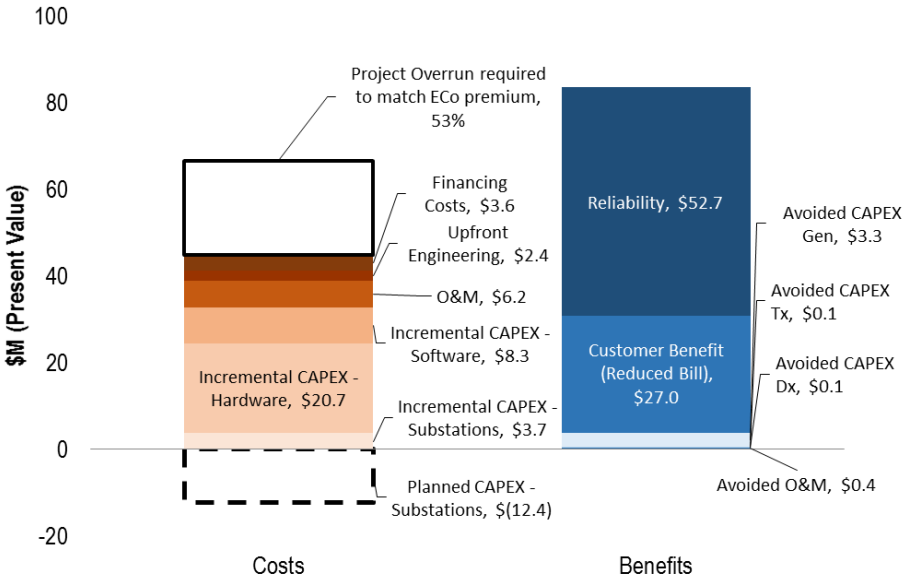
UDM assets and extend the period during which UDM benefits are realized. It is assumed that hardware assets have a 40 year useful life. Thus, in the 20 year term analysis, we assume the hardware has a residual value based on the net present value of its depreciated value at 20 year which reduces the 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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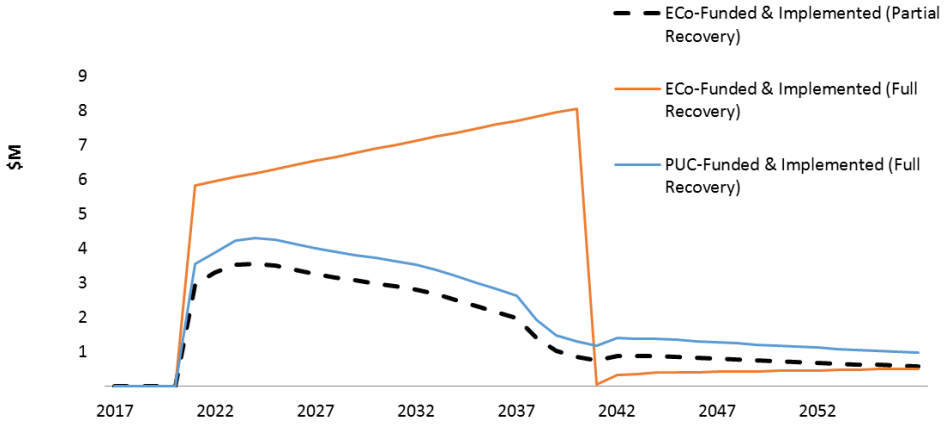
The impact on distribution revenue requirement is significantly lower for both the ECo-Funded – Partial Recovery option and the PUC-Funded – Full Recovery option due to two factors. First, the risk premium cost component has been excluded for recovery through PUC's distribution rates, and second, the 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.

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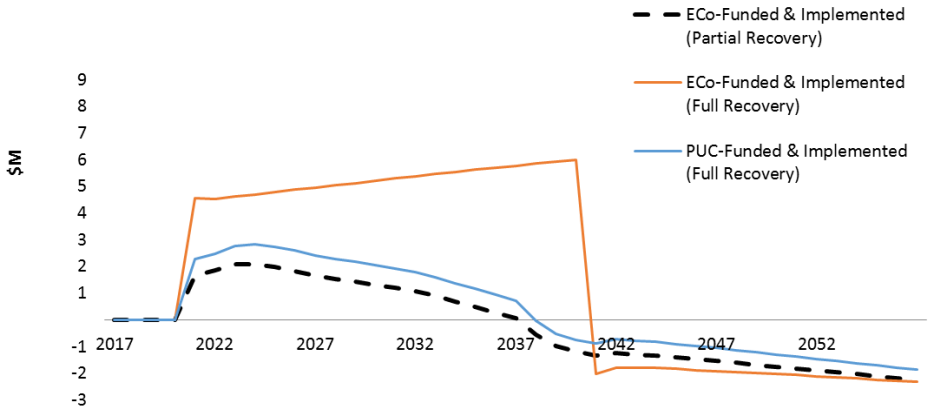
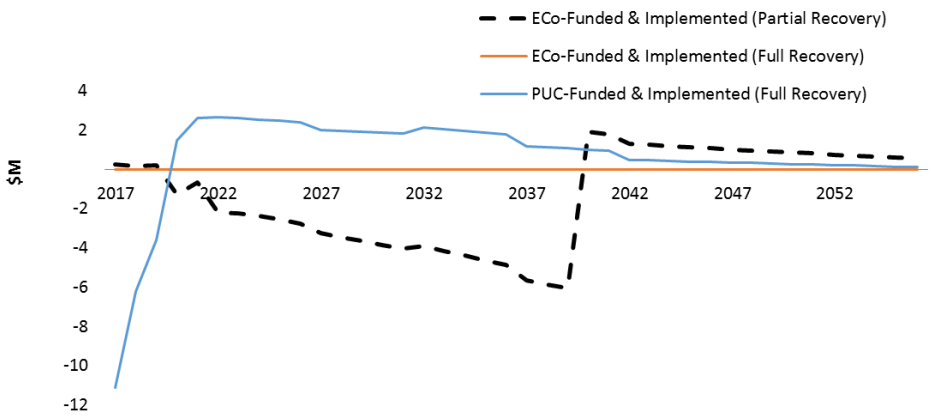
Figure 8. Net Customer Impact of Project Options[19]



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

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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

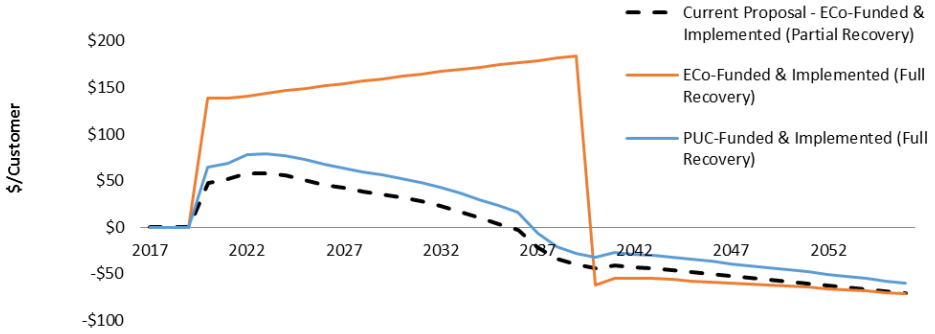
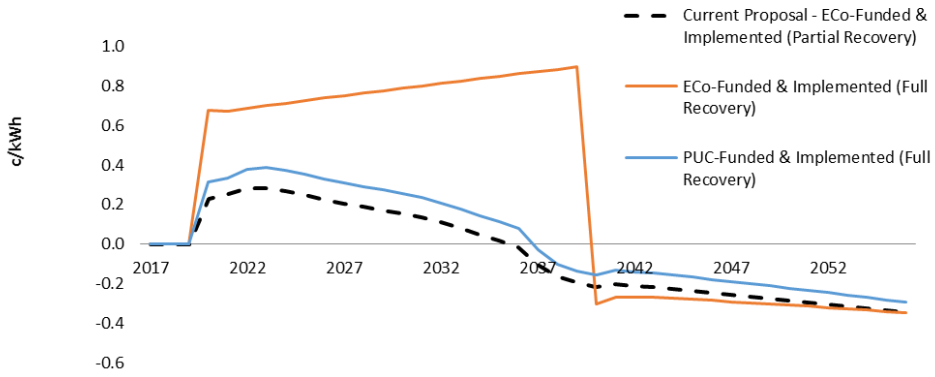


Figure 12. Average Distribution Rate Increase by Project Option



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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SECTION 7:	Alternative Project Option
SECTION 8:	Recommendations and Next Steps

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PROJECT OVERVIEW

- Distribution Automation (DA)
- Voltage/VAR Management (VVM)
- Incremental Substation Upgrades
- AMI Integration and Enhancements

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. ✓

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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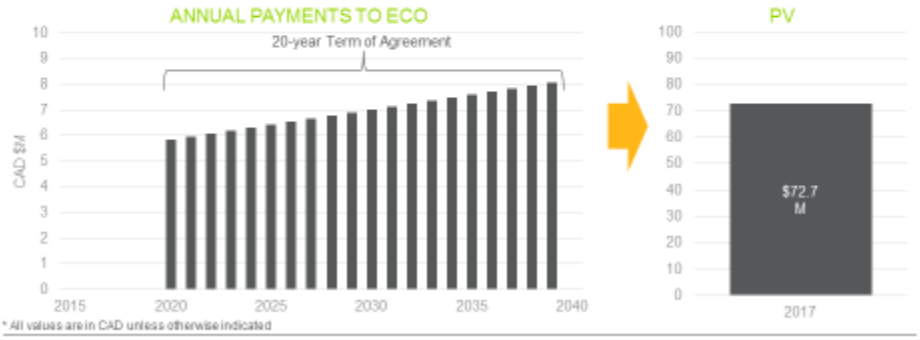
DECONSTRUCTING THE COSTS

- 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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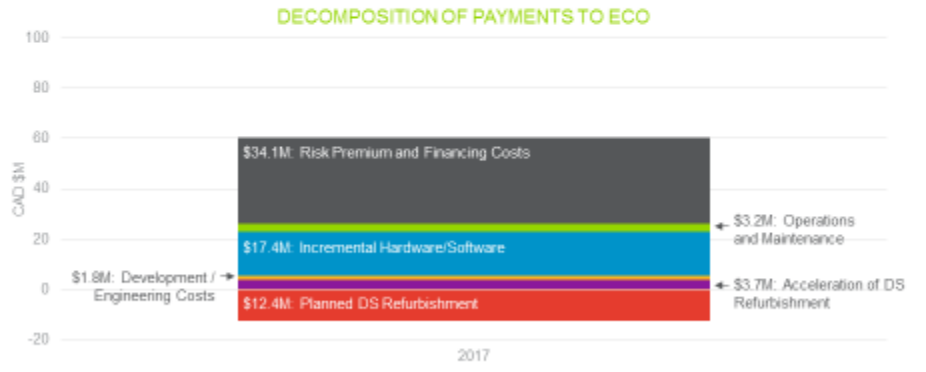
DECONSTRUCTING THE COSTS

- Breaking out other known components of the ECo payment results in an estimate of the embedded risk premium and financing cost of $34.1M



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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

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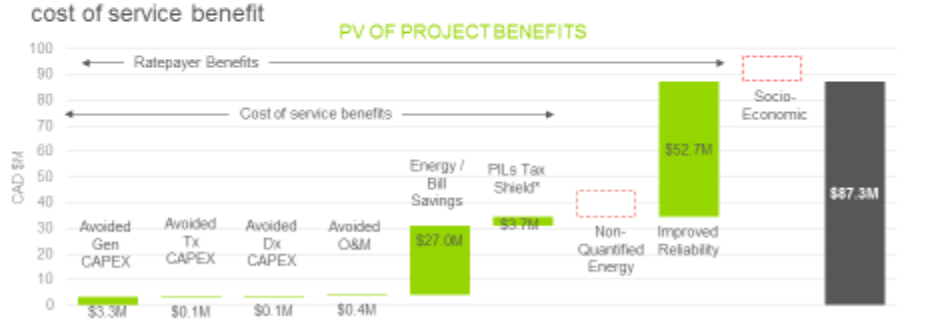
UNDERSTANDING THE BENEFITS

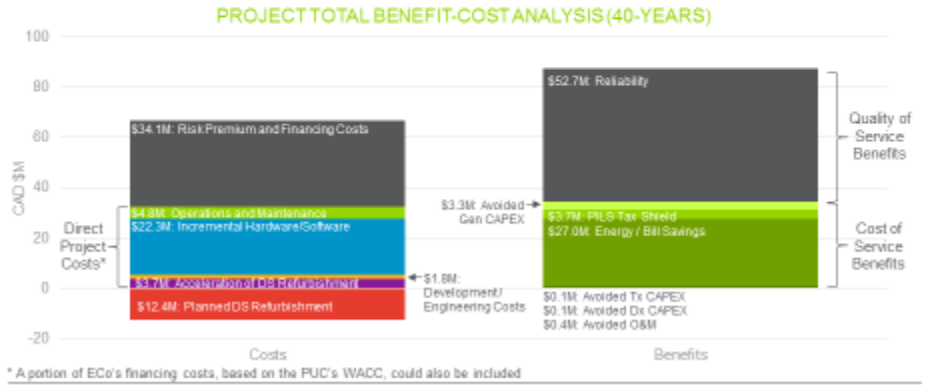
- Benefits total an estimated $87.3M over 40 years
  - Does not include some non-quantified energy and socio-economic benefits
- From a regulatory approval standpoint, six benefit categories result in a reduction in cost of service to customers
- Reliability improvements, provide a quality of service benefit, but do not provide a cost of service benefit



* Based on the incremental capital costs incurred by ECo up to and through commissioning of the project

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

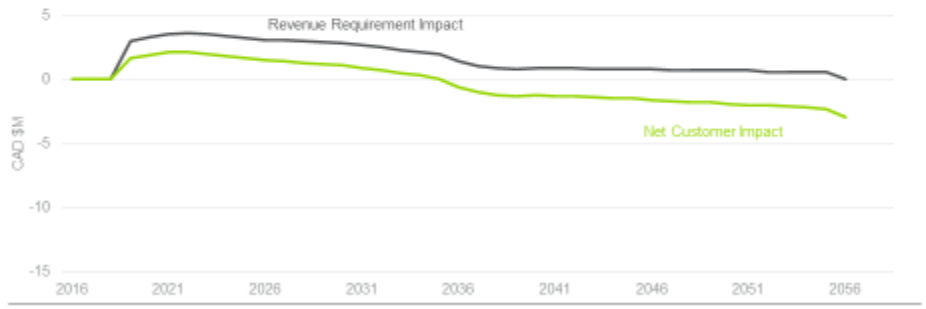


* A portion of ECo's financing costs, based on the PUC's WACC, could also be included

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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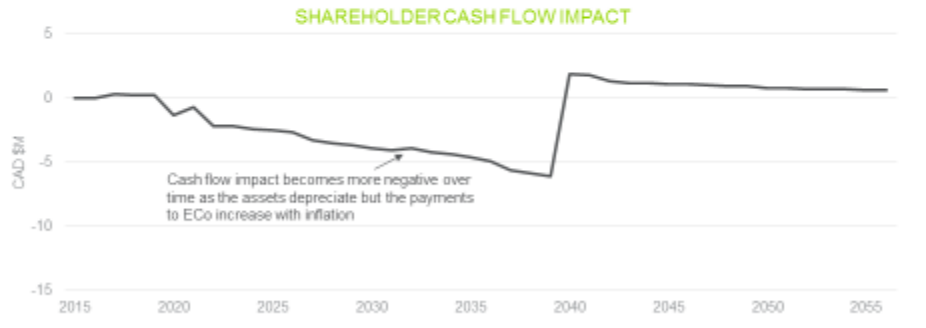
RATEPAYER AND SHAREHOLDER IMPACT

- 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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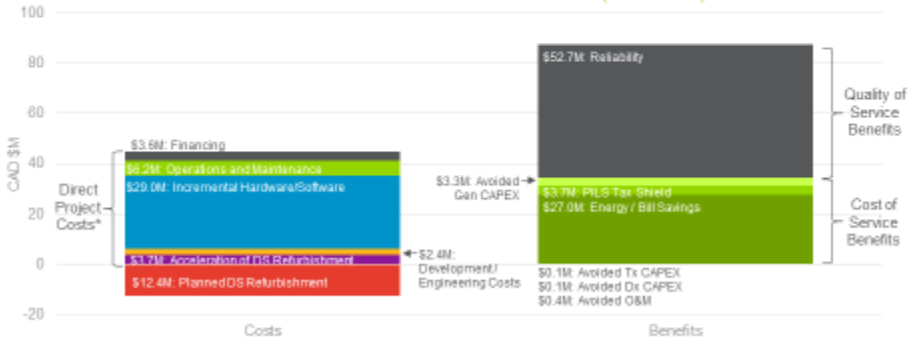
ALTERNATIVE PROJECT OPTIONS

- 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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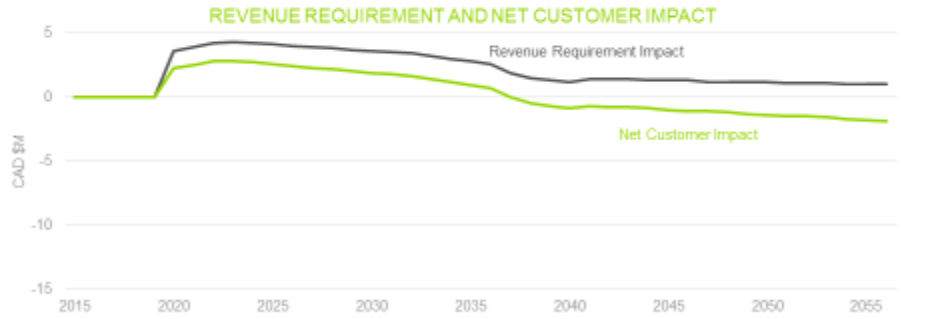
ALTERNATIVE PROJECT OPTIONS

- 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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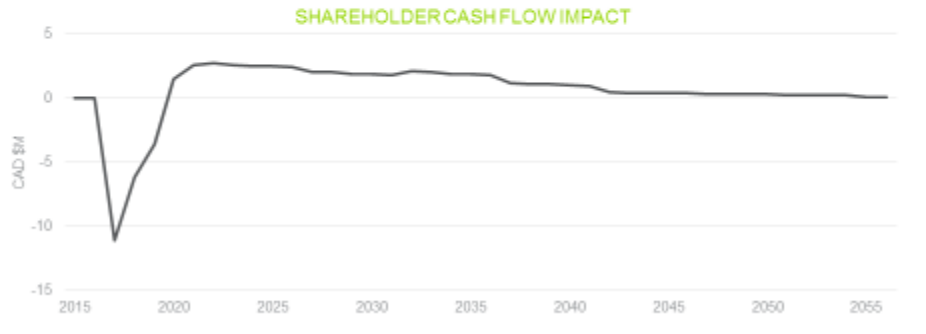
ALTERNATIVE PROJECT OPTIONS

- 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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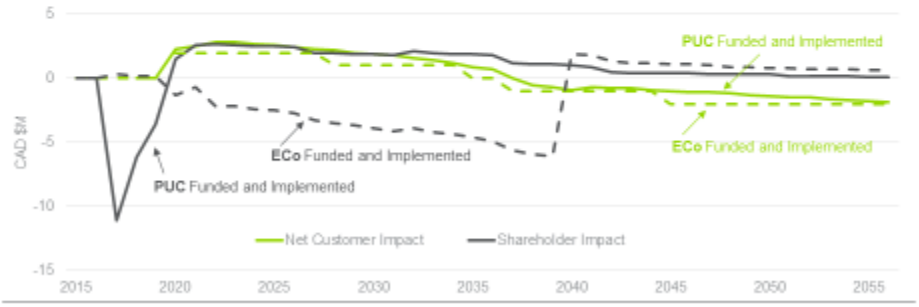
ALTERNATIVE PROJECT OPTIONS

- 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

NET CUSTOMER AND SHAREHOLDER CASH FLOW IMPACT



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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 AA11
2016 Projection for Distribution Capital [JTC 1.13]

PUC Distribution Inc.
Long Range Capital Planning

Revision Date: 2016-03-15

Notes

1) In the two attached spreadsheets, the estimated capital cost expenditures for Distribution Station and Transmission Station rebuilds is considered for two scenarios. The first scenario considers if we were to continue with our current long term plan. The second considers if we were to accelerate a number of DS rebuilds, those shaded in blue, all to occur in the next OEB rate cycle.

2) the budget numbers in the long range plan are preliminary and order of magnitude only, based on presently available information. These will be further refined in 2016 as part of the development of an Asset Management Plan (AMP) and Distribution System Plan (DSP) for the OEB.

3) The sequence of station rebuilt projects proposed in this plan may be changed somewhat due to the outcomes of the DSP. At present the sequencing is based primarily on simple age and condition based assessments and technical factors (e.g.: risk associate with loosing a station that has no backup or where no ability exists to transfer loads in a contingency). The DSP is will see these factors more systematically documented than current planning processes and may lead to a more optimal sequence. In all cases, one underlying goal has been to flatten expenditures as evenly as possible over time and that will continue to be the case with the implementation of the DSP.

4) The attached long range plan does not consider Customer Demand or Allocated Capital. Nor does it consider 'Overhead Distribution System' , 'Underground Distribution System', 'Distribution Transformers' or 'Voltage Conversion Program' which were identified in Exhibit 5-6, p 77 of the METSCO Asset Management Plan prepared in 2012 for the period 2013-2016. It is expected that in all the aforementioned areas, levels consistent with past practice will continue to be required to keep up asset sustainment and respond to customer demand.

CAPEX for Transformer Stations and Distribution Stations | NPV rate 4.00%

Without UDM

Priority	Station	Age at Replacement	Comments	NPV 2016	2017-2021	2022-2026	2027-2031	2032-2036	2037-2041	2042-2046	2047-2051
1	Sub 14	▲ 54 years in 2015	Completing voltage conversion will allow retirement of substation. Target 2017 with some 4kV load supplied via Sub 4 temporarily.								
2	Sub 16	▲ 52 years in 2017	UDM #1 rebuild - Health Index Score 50 in 2012	$ 3.37	$ 3.50	$ -	$ -	$ -	$ -	$ -	$ -
	TS1	▲ 45 years in 2018	Health Index Score 52 in 2012	$ 22.88	$ 23.80	$ -	$ -	$ -	$ -	$ -	$ -
				$ 26.25	$ 27.30	$ -	$ -	$ -	$ -	$ -	$ -
3	Sub 19 LTC	▲ 45 years in 2018	Health Index Score 54 in 2012	$ 1.39	$ -	$ 1.50	$ -	$ -	$ -	$ -	$ -
	Sub 19 SwG	▲ 45 years in 2018	Health Index Score 54 in 2012	$ 1.39	$ -	$ 1.50	$ -	$ -	$ -	$ -	$ -
	Sub New		To replace Sub 4 & 5 at end of Voltage conversion	$ 3.24	$ -	$ 3.50	$ -	$ -	$ -	$ -	$ -
	Sub 20	▲ 45 years in 2018	UDM #3 Rebuild - Health Index Score 56 in 2012	$ 3.24	$ -	$ 3.50	$ -	$ -	$ -	$ -	$ -
				$ 9.25	$ -	$ 10.00	$ -	$ -	$ -	$ -	$ -
4	TS2	▲ 51 years in 2028	Health Index Score 66 in 2012	$ 21.16	$ -	$ -	$ 23.80	$ -	$ -	$ -	$ -
	Sub 18 LTC	▲ 63 years in 2031	Health Index Score 61 in 2012	$ 1.33	$ -	$ -	$ 1.50	$ -	$ -	$ -	$ -
	Sub 18	▲ 63 years in 2031	Health Index Score 61 in 2012	$ 1.33	$ -	$ -	$ 1.50	$ -	$ -	$ -	$ -
				$ 23.83	$ -	$ -	$ 26.80	$ -	$ -	$ -	$ -
5	Sub 11	▲ 57 years in 2033	UDM #2 rebuild - Health Index Score 61 in 2012	$ 2.99	$ -	$ -	$ -	$ 3.50	$ -	$ -	$ -
	Sub 2 LTC	▲ 62 years in 2036	(rebuilt) Health Index Score 71 in 2012	$ 1.28	$ -	$ -	$ -	$ 1.50	$ -	$ -	$ -
	Sub 2 SwG	▲ 62 years in 2036	Health Index Score 71 in 2012	$ 1.71	$ -	$ -	$ -	$ 2.00	$ -	$ -	$ -
				$ 5.98	$ -	$ -	$ -	$ 7.00	$ -	$ -	$ -
6	Sub 12	▲ 62 years in 2038	Health Index Score 61 in 2012	$ 2.88	$ -	$ -	$ -	$ -	$ 3.50	$ -	$ -
	Sub 1	▲ 60 years in 2041	UDM #4 Rebuild - Health Index Score 64 in 2012	$ 2.88	$ -	$ -	$ -	$ -	$ 3.50	$ -	$ -
				$ 5.75	$ -	$ -	$ -	$ -	$ 7.00	$ -	$ -
7	Sub 21	▲ 60 years in 2044	Health Index Score 58 in 2012	$ 2.77	$ -	$ -	$ -	$ -	$ -	$ 3.50	$ -
	Sub 13	▲ 54 years in 2046	Health Index Score 76 in 2012	$ 2.77	$ -	$ -	$ -	$ -	$ -	$ 3.50	$ -
				$ 5.53	$ -	$ -	$ -	$ -	$ -	$ 7.00	$ -
8	Sub 15	▲ 54 years in 2048	Health Index Score 62 in 2012	$ 2.66	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.50
				$ 2.66	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.50
Totals				$ 79.25	$ 27.30	$ 10.00	$ 26.80	$ 7.00	$ 7.00	$ 7.00	$ 3.50
			PV of Average Annual CAPEX over next 35 years	$ 2.26							

Legend:

blue indicates CAPEX within UDM that is part of long term PUC Capital Plan

indicates required CAPEX not yet identified in OEB AMP of DSP

CAPEX for Transformer Stations and Distribution Stations | NPV rate | 4.00%

With UDM

Priority	Station	Age at Replacement	Comments	NPV 2016	2017-2021	2022-2026	2027-2031	2032-2036	2037-2041	2042-2046	2047-2051
1	Sub 14	▲ 54 years in 2015	Completing voltage conversion will allow retirement of substation. Target 2017 with some 4kV load supplied via Sub 4 temporarily.								
2	Sub 16	▲ 52 years in 2017	UDM #1 rebuild - Health Index Score 50 in 2012	$ 3.37	$ 3.50	$ -	$ -	$ -	$ -	$ -	$ -
	TS1	▲ 45 years in 2018	Health Index Score 52 in 2012	$ 22.88	$ 23.80	$ -	$ -	$ -	$ -	$ -	$ -
				$ 26.25	$ 27.30	$ -	$ -	$ -	$ -	$ -	$ -
3	Sub 19 LTC	▲ 45 years in 2018	Health Index Score 54 in 2012	$ 1.44	$ 1.50	$ -	$ -	$ -	$ -	$ -	$ -
	Sub 19 SwG	▲ 45 years in 2018	Health Index Score 54 in 2012	$ 1.39	$ -	$ 1.50	$ -	$ -	$ -	$ -	$ -
	Sub New		To replace Sub 4 & 5 at end of Voltage conversion	$ 3.24	$ -	$ 3.50	$ -	$ -	$ -	$ -	$ -
	Sub 20	▲ 45 years in 2018	UDM #3 Rebuild - Health Index Score 56 in 2012	$ 3.37	$ 3.50	$ -	$ -	$ -	$ -	$ -	$ -
				$ 9.43	$ 5.00	$ 5.00	$ -	$ -	$ -	$ -	$ -
4	TS2	▲ 51 years in 2028	Health Index Score 66 in 2012	$ 21.16	$ -	$ -	$ 23.80	$ -	$ -	$ -	$ -
	Sub 18 LTC	▲ 63 years in 2031	Health Index Score 61 in 2012	$ 1.44	$ 1.50	$ -	$ -	$ -	$ -	$ -	$ -
	Sub 18	▲ 63 years in 2031	Health Index Score 61 in 2012	$ 1.33	$ -	$ -	$ 1.50	$ -	$ -	$ -	$ -
				$ 23.93	$ 1.50	$ -	$ 25.30	$ -	$ -	$ -	$ -
5	Sub 11	▲ 57 years in 2033	UDM #2 rebuild - Health Index Score 61 in 2012	$ 3.37	$ 3.50	$ -	$ -	$ -	$ -	$ -	$ -
	Sub 2 LTC	▲ 62 years in 2036	(rebuilt) Health Index Score 71 in 2012	$ 1.44	$ 1.50	$ -	$ -	$ -	$ -	$ -	$ -
	Sub 2 SwG	▲ 62 years in 2036	Health Index Score 71 in 2012	$ 1.71	$ -	$ -	$ -	$ 2.00	$ -	$ -	$ -
				$ 6.52	$ 5.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
6	Sub 12	▲ 62 years in 2038	Health Index Score 61 in 2012	$ 2.88	$ -	$ -	$ -	$ -	$ 3.50	$ -	$ -
	Sub 1	▲ 60 years in 2041	UDM #4 Rebuild - Health Index Score 64 in 2012	$ 3.37	$ 3.50	$ -	$ -	$ -	$ -	$ -	$ -
				$ 6.24	$ 3.50	$ -	$ -	$ -	$ 3.50	$ -	$ -
7	Sub 21	▲ 60 years in 2044	Health Index Score 58 in 2012	$ 2.77	$ -	$ -	$ -	$ -	$ -	$ 3.50	$ -
	Sub 13	▲ 54 years in 2046	Health Index Score 76 in 2012	$ 2.77	$ -	$ -	$ -	$ -	$ -	$ 3.50	$ -
				$ 5.53	$ -	$ -	$ -	$ -	$ -	$ 7.00	$ -
8	Sub 15	▲ 54 years in 2048	Health Index Score 62 in 2012	$ 2.66	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.50
				$ 2.66	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.50
Totals				$ 80.57	$ 42.30	$ 5.00	$ 25.30	$ 2.00	$ 3.50	$ 7.00	$ 3.50
			PV of Average Annual CAPEX over next 35 years	$ 2.30							

Legend:

blue indicates CAPEX within UDM that is part of long term PUC Capital Plan

indicates required CAPEX not yet identified in OEB AMP of DSP

Appendix AA12-1
Project Cost Summary

2020/2021 Smart Grid Project			
Project Costing w/ EPC & PUC Cost Estimate			
VVM (excludes AMI, SCADA, Comm, etc.)	***Qty***	**Unit Costs**	**Total**
DS with new LTC's (incremental)			-
48 feeders (note Sub 16 LTC)			
> Bus/Padmount /Feeder/ VReg's(per set of 3)	44	120,834	5,316,678
> feeder balancing Vregs	6	55,487	332,922
> feeder balancing Caps	6	42,634	255,802
			5,905,402
Engineering (check sum)	1	2,362,042	2,362,042
Add'l Scope & Contingency	1	943,608	462,846
			8,730,290
Project Mgmt/ Ext'l Commissioning Review	1	379,800	379,800
Contract/Regulatory/ Legal	1	359,116	353,703
VVM			**9,463,794**
			9,463,794
DA (excludes AMI, SCADA, Comm, etc.)			
Reclosers	40	99,573	3,982,933
SW's(pole)	40	93,279	3,731,157
2 way padmount SW's	12	62,231	746,775
4 way padmount SW's	8	304,825	2,438,597
OH FCI's	40	1,549	61,972
UG FCI's	40	1,931	77,220
Poles (added qty for adjacent lift/siting issues)	120	11,837	1,420,456
			12,459,110
Engineering (check sum)	1	5,205,849	5,205,849
Add'l Scope & Contingency	1	1,840,995	844,036
			18,508,995
Project Mgmt/ Ext'l Commissioning Review	1	759,600	759,600
Contract/Regulatory/ Legal	1	738,164	726,371
DA			**19,994,966**
			19,994,966
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.			
VVO/FLSIR/OMS/CIS/AMI	1	2,013,446	2,013,446
			2,013,446
Engineering (check sum)	1	1,284,009	1,284,009
Add'l Scope & Contingency	1	185,277	-
			3,297,455
Project Mgmt/ Ext'l Commissioning Review	1	126,600	126,600
Contract/Regulatory/ Legal	1	126,349	124,223
AMI			**3,548,278**
			3,548,278
Project Estimate Total System			**33,007,038**

Construction	Engineering	Ctct Legal/Reg	Project Mgmt	
21,684,840	8,851,900	1,204,297	1,266,000	33,007,038
65.7%	26.8%	3.6%	3.8%	
33,007,038				
	Note: Engineering includes EPC+PUCD			
	6,060,205	*2,791,695*	*8,851,900*	

Appendix AA12-2
Project Cost Estimate memo

SUBJECT: Sault Smart Grid Project
Revised Cost Estimate Memo
DATE: June 2020

Project Scope and Cost Estimates

This memo serves to summarize the Sault Smart Grid (SSG) Project cost estimate and methodology applied with the associated supporting spreadsheet calculations. This estimate assumes the full project scale implementation to all PUC Distribution12.5 kV distribution feeders. Note that PUC Distribution will maintain the "net zero" bill impact objective throughout the project delivery and if required scope reduction will be included to stay within an upset limit balanced to the benefits estimate delivered by the project for customers. Source references are noted throughout this memo as well as a list at the end of the report including website link addresses.

PUC Distribution developed the SSG Project cost estimate using the following: (1) the results of a competitive RFP process that PUC Distribution conducted in 2019 (representing approximately 85% of the project); and (2) an estimate of PUC Distribution's internal engineering, operations and project management costs directly attributable to the SSG Project (representing approximately 15% of the project). Based on these inputs, PUC Distribution has estimated the total SSG Project cost of $33,007,038.

Analysis

The preliminary engineering design work of Leidos and others still forms the foundation for the project. This engineering effort included scope of work descriptions and main bill of material equipment selection and quantities to the ~30% level of design in 2014/15. Work included development of a feeder level distribution system model for selected feeders for the analysis work required including supporting benefits estimated for the project. Work also included some segment reinforcement recommendations, some of which have been executed by PUC Distribution since that point in time in selected voltage regulator installations on more rural feeders to meet voltage limit standards. With the current proposed scope to include all 12.5 kV feeders the remaining feeders above the original ~80% of feeders will need to undergo an initial design review as well as a high level review of prior engineering works to establish a new 30% base level design to determine the final scope of work required for the project.

PUC Distribution is developing the project using two main sections. The first is developed from the new EPC Step 1 firm + upset limit Step 2 price developed in the competitive RFP process conducted. This portion will represent the main EPC construction contract and comprise about 85% of the project costs. The last section of the total project costs are for PUC Distribution's engineering, operations and regulatory support directly attributable to the project and represents about 15% of the total project costs. This also includes preliminary engineering works purchased from the previous project developer Infrastructure Energy (IE).

PUC Distribution in developing the overall project scope, specifications and evaluating the project total cost estimate has utilized a number of input sources including early preliminary engineering works, the current EPC estimates, information from the Navigant reports as well as input from PUC Distribution project, engineering and operations staff. The commentary on the project costs and scope risks in the Navigant Review of Business Case report (April 2015) as well as considerations from PUC Distribution staff were used to help consider contingency risk factor adjustment in non-fixed project cost estimates. Navigant comments on risk to cost certainty, especially in areas of software implementation and integration were also noted and considered. None of the proposed work is expected to have immediate impact on the current Distribution System Plan and asset management program although integration will be needed with the current Substation reconstruction project currently in progress and expected to be in service by the end of 2021 due to deferral this year due to COVID-19 impacts. (referenced reports are listed below)

The Volt/ VAR Management (VVM) scope will encompass 100% of the 12.5 kV system coverage (excludes 4kV circuits) and Distribution Automation (DA) scope of work includes 100% coverage adding another 8 feeders to the Leidos preliminary engineering work. EPC pricing estimates have also been obtained for reducing the number of feeders as scope adjustment if required to maintain the cost/ benefit objectives. This VVM part of the project is estimated from a fixed asset perspective to cost ~$9.5M. The DA scope of work for all 48 12.5 kV feeders will have an estimated cost of ~$20M in fixed asset capital additions. AMI integration which generally includes the major software and integration challenge for the project includes all SCADA and communications hardware/software, AMI and GIS integration, the outage management system and customer service interfaces has an estimated cost of $~3.5M for the total project cost estimate of ~$33M.

Note: The allocation of the project costs to each asset and system were developed internally by PUC from the overall scope and EPC provider estimates to support the fixed asset categories and rate application development. Actual proportions will be confirmed as project design and construction is completed and trued up in fixed asset records. The project costing will be managed by PUC Distribution very closely to meet our cost/ benefit objective and minimize potential for project cost overrun. Detail engineering estimates were also developed by PUC Distribution internally from project scope and EPC proposals in efforts to identify skill/ expertise areas for internal resource planning support and liaison with EPC contractor once efforts are underway.

A key aspect of the project that sees this comprehensive set of smart grid applications being applied as one concurrent project beyond the contract administrative and mobilization aspects, is to take advantage of the synergies of common design and installation elements, particularly in the Advanced Distribution System Management (ADMS) platform and system wide communication coverage. Having the ADMS in place with the system visibility and data awareness allowed will be an enabling platform for the future smart grid application growth. Ongoing incremental replacements and additions of aging equipment and new expansions utilizing smart grid technology and communication capability will enable continuous improvement opportunities for the distribution system. DA using real system event data that will be collected on events will not only add operational and engineering insight to how the system operates and performs today but potentially in new areas just being considered. An example would be

growth of future applications with artificial intelligence (AI) learning will allow for fine tuning improvements in system operational performance and emergency event response.

Referenced Reports:

1	Utility Distribution Microgrid: Volt/VAR Management – Preliminary Design - Leidos Engineering, October 17, 2014	*Original Application App C1*
2	Utility Distribution Microgrid: Distribution Automation – Preliminary Design - Leidos Engineering, November 20, 2014	*Original Application App C2*
3	Utility Distribution Microgrid: AMI Integration – Preliminary Design - Leidos Engineering, November 20, 2014	*Original Application App C3*
4	Review of Business Case for Smart Grid Project for PUC Distribution - Navigant Consulting, April 15, 2015	*Original Application App D*
5	Review of Project Costs for Smart Grid Project for PUC Distribution - Navigant Consulting, June 23, 2015	*Original Application App E*
6	Community Microgrid Business Case Review for SSMIC (shared with PUC) - Navigant Consulting, May 4, 2016	*IRR Filing at Appendix 7*

This memo also includes a number of different breakouts of the project cost estimate. Table 1 below shows the full project cost breakdown of the total cost estimate of $33M.

Table 1: Full Cost Estimate for SSG Project

2020/2021 Smart Grid Project			
Project Costing w/ EPC & PUC Cost Estimate			
VVM (excludes AMI, SCADA, Comm, etc.)	***Qty***	**Unit Costs**	**Total**
DS with new LTC's (incremental)			-
48 feeders (note Sub 16 LTC)			
> Bus/Padmount /Feeder/ VReg's(per set of 3)	44	120,834	5,316,678
> feeder balancing Vregs	6	55,487	332,922
> feeder balancing Caps	6	42,634	255,802
			5,905,402
Engineering (check sum)	1	2,362,042	2,362,042
Add'l Scope & Contingency	1	462,846	462,846
			8,730,290
Project Mgmt/ Ext'l Commissioning Review	1	379,800	379,800
Contract/Regulatory/ Legal	1	353,703	353,703
VVM			**9,463,794**
			9,463,794
DA (excludes AMI, SCADA, Comm, etc.)			
Reclosers	40	99,573	3,982,933
SW's(pole)	40	93,279	3,731,157
2 way padmount SW's	12	62,231	746,775
4 way padmount SW's	8	304,825	2,438,597
OH FCI's	40	1,549	61,972
UG FCI's	40	1,931	77,220
Poles (added qty for adjacent lift/siting issues)	120	11,837	1,420,456
			12,459,110
Engineering (check sum)	1	5,205,849	5,205,849
Add'l Scope & Contingency	1	844,036	844,036
			18,508,995
Project Mgmt/ Ext'l Commissioning Review	1	759,600	759,600
Contract/Regulatory/ Legal	1	726,371	726,371
DA			**19,994,966**
			19,994,966
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.			
VVO/FLSIR/OMS/CIS/AMI	1	2,013,446	2,013,446
			2,013,446
Engineering (check sum)	1	1,284,009	1,284,009
Add'l Scope & Contingency	1	-	-
			3,297,455
Project Mgmt/ Ext'l Commissioning Review	1	126,600	126,600
Contract/Regulatory/ Legal	1	124,223	124,223
AMI			**3,548,278**
			3,548,278
Project Estimate Total System			**33,007,038**

Table 2 below is a summary of how the total project cost estimate of $33,007,038 is being broken down by different categories of work for the SSG Project and the percentage of costs that will be spent on each category. 65.7% of the total costs will be apportioned to Construction (i.e. $21,684,840), 26.8% of the total costs will be apportioned to Engineering (i.e. $8,851,900), 3.6% of the total costs will be apportioned to Contract, Legal & Regulatory support (i.e. $1,204,297), and 3.8% will be apportioned to Project Management (i.e. $1,266,000). These percentages are all within generally expected industry ranges for this type of project.

Table 2: Breakdown of Total Project Cost Estimate by Category of Work

Construction	Engineering	Ctct Legal/Reg	Project Mgmt
21,684,840	8,851,900	1,204,297	1,266,000
65.7%	26.8%	3.6%	3.8%
33,007,038			
	Note: Engineering includes EPC+PUCD		
	6,060,205	*2,791,695*	*8,851,900*

Tables 3 and 4 below show further detail on the Project Engineering scope by the EPC Contract and PUC Distribution. Table 5 below shows detail on how the scope of engineering work is broken down by the EPC Contractor, preliminary engineering work by IE and PUC Distribution. The costs are further broken down by each component of the SSG Project (DA, VVM, and AMI) and by the different engineers/specialist. Table 6 shows a detailed breakdown of the Project Management and Regulatory, Financial, and Legal scope and estimate of $2,470,297.

Table 3: EPC Contract – Engineering Scope

EPC Contract - Engineering Scope
• Distribution Automation System
• Volt/ VAR Management System
• AMI Integration
• Engineeering work includes all EPC estimates including from subcontractors as required.

Table 4: PUC Engineering Scope

• Engineering & Technical Oversights & Approvals
• Regulatory material & equipment approval
• Perform design reviews for EPC Gates
• Regulatory Construction Verification Program (CVP)
• Asset and GIS records management
• Perf measurement system oversight/installation

Table 5: SSG Engineering Estimate – EPC, Preliminary Works & PUC

EPC Engineering Estimate								
		DA	DA $	VVM	VVM$	AMI	AMI$	
			3,696,725		1,757,459		606,021	6,060,205

Note EPC breakout to assets is PUC estimate.

Developer (IE) - Preliminary Engineering Works								
		DA	DA $	VVM	VVM$	AMI	AMI$	
			595,791		311,203		116,701	1,023,695

PUC Engineering & Technical Oversight/ Approvals								
Sr Engineer	6,000	24	144,000	24	144,000	20	120,000	
Elec Eng	5,000	24	120,000	24	120,000	20	100,000	
P&C Eng	5,000	24	120,000	24	120,000	20	100,000	
IT Network Eng	5,000	24	120,000	24	120,000	20	100,000	
Ops Specialist	5,000	24	120,000	24	120,000	20	100,000	
		120	624,000	120	624,000	100	520,000	1,768,000

Table 6: Project Management/ Regulatory/Legal/ etc.

PUCS - Owner Project Mgmt					
Owner Proj Mgmt/ Oversight					
		DA $	VVM$	AMI$	
Proj Mgmt	$/wk	$	$	$	
Proj Manager	6,000	288,000	288,000	72,000	
Proj Engineer	5,000	60,000	60,000	30,000	
Ops Specialist	5,000	120,000	120,000	60,000	
Admin	2,800	67,200	67,200	33,600	
		535,200	535,200	195,600	1,266,000
PUCS - Owner Regulatory/ Financial/ Legal					
PUC Project Development Team/ CWIP		629,297			
Legal/Financial/Contracts		250,000			
Regulatory/ OEB ICM/Consulting		200,000			
Ops & Eng'g		125,000			
		1,204,297			
		DA $	VVM$	AMI$	
		493,762	566,020	144,516	1,204,297

Tables 7 to 9 below shows the revised cost estimate by each major element of the SSG Project: VVM, DA and AMI. These estimates were revised from the Original Application.

Table 7: Revised Project Estimate – Volt/VAR Management

2020/2021 Smart Grid Project			
Project Costing w/ EPC & PUC Cost Estimate			
VVM (excludes AMI, SCADA, Comm, etc.)	***Qty***	**Unit Costs**	**Total**
DS with new LTC's (incremental)			-
48 feeders (note Sub 16 LTC)			
> Bus/Padmount /Feeder/ VReg's(per set of 3)	44	120,834	5,316,678
> feeder balancing Vregs	6	55,487	332,922
> feeder balancing Caps	6	42,634	255,802
			5,905,402
Engineering (check sum)	1	2,362,042	2,362,042
Add'l Scope & Contingency	1	462,846	462,846
			8,730,290
Project Mgmt/ Ext'l Commissioning Review	1	379,800	379,800
Contract/Regulatory/ Legal	1	353,703	353,703
VVM			**9,463,794**

Table 8: Revised Project Estimate – Distribution Automation

2020/2021 Smart Grid Project			
Project Costing w/ EPC & PUC Cost Estimate			
DA (excludes AMI, SCADA, Comm, etc.)			
Reclosers	40	99,573	3,982,933
SW's(pole)	40	93,279	3,731,157
2 way padmount SW's	12	62,231	746,775
4 way padmount SW's	8	304,825	2,438,597
OH FCI's	40	1,549	61,972
UG FCI's	40	1,931	77,220
Poles (added qty for adjacent lift/siting issues)	120	11,837	1,420,456
			12,459,110
Engineering (check sum)	1	5,205,849	5,205,849
Add'l Scope & Contingency	1	844,036	844,036
			18,508,995
Project Mgmt/ Ext'l Commissioning Review	1	759,600	759,600
Contract/Regulatory/ Legal	1	726,371	726,371
DA			**19,994,966**

Table 9: Revised Project Estimate – AMI Integration & Project Totals

2020/2021 Smart Grid Project			
Project Costing w/ EPC & PUC Cost Estimate			
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.			
VVO/FLSIR/OMS/CIS/AMI	1	2,013,446	2,013,446
			2,013,446
Engineering (check sum)	1	1,284,009	1,284,009
Add'l Scope & Contingency	1	-	-
			3,297,455
Project Mgmt/ Ext'l Commissioning Review	1	126,600	126,600
Contract/Regulatory/ Legal	1	124,223	124,223
AMI			**3,548,278**
			3,548,278
Project Estimate Total System			**33,007,038**

Table 10 below shows the current net capital investment after applying the NRCan capital contribution of 25% of the total estimated project costs to the SSG Project.

Table 10: Net Capital Investment

33,007,038	
500,000	ineligible for NRCan (estim)
32,507,038	
8,126,759	NRCan 25%
24,880,278	Net Capital

Appendix AA12-3
Live Excel Model for SSG Revised Scope and Project Estimate Summary

	2020/2021 Smart Grid Project			
	Project Costing w/ EPC & PUC Cost Estimate			
	VVM (excludes AMI, SCADA, Comm, etc.)	***Qty***	**Unit Costs**	**Total**
	DS with new LTC's (incremental)			-
	48 feeders (note Sub 16 LTC)			
	> Bus/Padmount /Feeder/ VReg's(per set of 3)	44	120,834	5,316,678
	> feeder balancing Vregs	6	55,487	332,922
	> feeder balancing Caps	6	42,634	255,802
				5,905,402
	Engineering (check sum)	1	2,362,042	2,362,042
	Add'l Scope & Contingency	1	462,846	462,846
				8,730,290
	Project Mgmt/ Ext'l Commissioning Review	1	379,800	379,800
	Contract/Regulatory/ Legal	1	353,703	353,703
	VVM			**9,463,794**
				9,463,794
	DA (excludes AMI, SCADA, Comm, etc.)			
	Reclosers	40	99,573	3,982,933
	SW's(pole)	40	93,279	3,731,157
	2 way padmount SW's	12	62,231	746,775
	4 way padmount SW's	8	304,825	2,438,597
	OH FCI's	40	1,549	61,972
	UG FCI's	40	1,931	77,220
	Poles (added qty for adjacent lift/siting issues)	120	11,837	1,420,456
				12,459,110
	Engineering (check sum)	1	5,205,849	5,205,849
	Add'l Scope & Contingency	1	844,036	844,036
				18,508,995
	Project Mgmt/ Ext'l Commissioning Review	1	759,600	759,600
	Contract/Regulatory/ Legal	1	726,371	726,371
	DA			**19,994,966**
				19,994,966
	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.			
	VVO/FLSIR/OMS/CIS/AMI	1	2,013,446	2,013,446
				2,013,446
	Engineering (check sum)	1	1,284,009	1,284,009
	Add'l Scope & Contingency	1	-	-
				3,297,455
	Project Mgmt/ Ext'l Commissioning Review	1	126,600	126,600
	Contract/Regulatory/ Legal	1	124,223	124,223
	AMI			**3,548,278**
				3,548,278
	Project Estimate Total System			**33,007,038**

Construction	Engineering	Ctct Legal/Reg	Project Mgmt
21,684,840	8,851,900	1,204,297	1,266,000
65.7%	26.8%	3.6%	3.8%
33,007,038			

33,007,038

Note: Engineering includes EPC+PUCD

	6,060,205	*2,791,695*	*8,851,900*

Appendix AA13
Project Benefits Estimate Memo

SUBJECT: Sault Smart Grid Project
Revised Benefits Estimate
DATE: June 2020

Project Benefit Estimates – Internal Net Benefit Analysis

This memo serves to summarize the Sault Smart Grid (SSG) Project benefit estimates and methodology applied with the associated supporting spreadsheet calculations. This estimate assumes the full project scale implementation to all PUC 12.5 kV distribution feeders. Source references are noted throughout as well as a list at the end of the report including website link addresses.

PUC forecasts the annual net benefit to customers associated with the Sault Smart Grid (SSG) Project as shown in Table 1 below. This net benefit calculation adopts a 0.9 CVR factor, which is consistent with the *Ontario Ministry of Energy Final Report: Considerations for Deploying In-Front-of-the-Meter Conservation Technologies in Ontario* (July 18, 2017) by Navigant that identified an average of all the various projects in their study of CVR =0.91. [*Other Industry References list #2 pg. 159 below*].

Table 1: Quantified annual net benefit to customers associated with the SSG Project.

Cost of Power - updated to current estimate	$ 82,512,685	*App [AA15] -Cost of Power Spreadsheet*
Projected % energy savings with SSG implementation	2.70%	*App [AA14] -Energy Savings Spreadsheet*
Projected customer energy savings through SSG	$ 2,227,842	*App [AA14] -Energy Savings Spreadsheet*
Projected system loss energy savings through SSG	$ 105,111	*App [AA14] -Energy Savings Spreadsheet*
Total purchased power savings	$ 2,332,953	
ICM additional revenue from increased SSG asset base	$ 1,754,862	*Full Year Revenue Requirement*
Benefit of reduced capital expenditures witth SSG	($304,390)	*APP [AA17] CAPEX Deferral Spreadsheet*
Additional O & M expenses due to SSG implementation	$ 296,400	*App [AA13] -Project Benefit Estimate Memo*
Operating efficiency benefits due to SSG implementation	($30,816)	*App [AA13] -Project Benefit Estimate Memo*
	$ 1,716,056	
Annual net benefit to customers	$ 616,897	
Annual projected reliability benefit to customers	$ 2,017,000	*App [AA10] -Navigant Report #3 (NPV)*
Total Annual projected benefit to customers w/reliability	$ 2,633,897	

With improved distribution system operation monitoring and control and associated data availability for system planning and asset operations to support asset management and renewal, further efficiencies are expected to be attainable. Long term CAPEX savings benefits have been identifed in smart grid project as an equivalent savings from PV projections for PUC but have not been incorporated in to the Distribution System Plan at this time.

PUC has allocated both the incremental costs and benefits of the SSG Project to each customer class as shown in Table 2 below. (excludes reliability savings)

Table 2: Allocated costs and benefits of the SSG Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Rev$ Requirement	VVM Savings	Allocate Losses	Energy Savings by Class (2)+(3)	From Energy Savings (4)-(1)	Allocate Estimated OM&A	Allocate Estimated CAPEX	Net Savings (5)-(6)+(7)
Residential	$1,031,015	$1,096,853	$ 51,750	$1,148,603	$117,588	$156,036	$178,835	$140,387
GS<50kW	$ 286,537	$ 349,275	$ 16,479	$ 365,755	$ 79,218	$ 43,365	$ 49,701	$ 85,554
GS>50kW	$ 412,868	$ 768,430	$ 36,255	$ 804,685	$391,817	$ 62,484	$ 71,614	$400,947
USL	$ 3,367	$ 3,566	$ 168	$ 3,734	$ 367	$ 510	$ 584	$ 442
Sentinel lights	$ 3,216	$ 786	$ 37	$ 823	-$ 2,393	$ 487	$ 558	-$ 2,322
Street lights	$ 17,859	$ 8,932	$ 421	$ 9,354	-$ 8,505	$ 2,703	$ 3,098	-$ 8,110
	$1,754,862	$2,227,842	$105,111	$2,332,954	$578,092	$265,584	$304,390	**$616,898**

Background

The average system customer energy savings of 2.7% to be realized from the VVM system implementation used in this estimate is reasonable in our view. Review of project scope and preliminary engineering work by Black & Veatch confirmed PUC Distribution estimate of an average 2.7% energy savings "*has a high probability*" of being achieved in their view and potential exists for even greater savings than the estimate. An overall better than breakeven net benefit will be realized with the project and this excludes consideration of any assigned monetary value for non-bill benefits such as reliability improvements that will be achieved. (energy savings of 2.6% on distribution system losses are included in the estimate)

The early preliminary engineering design work of Leidos utilized historical energy consumption from 2012/13 consumption built up from individual smart meter and GIS feeder data to build a bottom up data set of customers and system data that had higher energy consumption levels than current load forecasts and recent actuals. All energy consumption estimates have been updated to use most recent 2018 Cost of Service (COS) load forecast information as a normalized base level which being lower than some of the historical use, results in a conservative approach to energy savings as compared to early assumptions.

One of the main adjustments applied to the project energy savings assumptions from the Leidos Engineering work is an adjustment to the total system energy used as a base starting value (2013 consumption figures) to the current lower 2018 COS load forecast. In addition, the CVR factor estimated by Leidos in preliminary screening work was also considered extensively and although preliminary work looked at a CVR and savings factors of 0.5 (1.5%) and 0.7 (2.1%), current industry reports and Navigant

Business Case Review report (April 2015) suggested these may be overly conservative for the type of AMI integrated voltage control system being deployed. There is also an estimated 2.6% savings in distribution system losses in the Leidos work that has been included in the savings.

A number of industry studies utilizing the "smart grid" approach to voltage control have suggested potential for greater overall energy savings of as much as 4% in some cases. PUC has a mix of some high density feeders along with some with lesser density and the overall range is typical to distribution systems and so in the end PUC Distribution selected a CVR = 0.9 (2.7% savings) as a reasonable assumption to apply as a system or project average. PUC Distribution also considered and reviewed many other project reports and industry studies that had applied a smart grid approach to support the 2.7% estimate and these are included in other references listed at end of this report with some VVM projects notably achieving over 4% energy savings. (see *Other Industry References list below*)

As the VVM scope includes 100% of the 12.5 kV system coverage (excludes 4kV circuits) the revised total estimated energy savings is now 17,456,712 kWh. Using 2020 COS Purchased Power estimates the current total savings is over $2.3M annually. The recommended VVM design utilizes an integrated smart grid approach of voltage control equipment utilizing AMI feedback for a volt/VAR optimization and energy savings.

The SSG project for Distribution Automation (DA) scope of work now includes all 48 12.5 kV distribution feeders as well as the 34.5 kV subtransmission auto-transfer application. The detailed design phase and value-added reviews in the EPC contract negotiation phase will consider scope adjustments in this aspect to meet project upset spending limits as required. Reliability benefits estimated in Leidos preliminary engineering work looking at a complete year of feeder outage data on the original scope had reliability improvements of over 35% on average system outage duration and 16% on customer average outage durations. These are comparable to those from smart grid studies reviewed for the California Energy Commission. *[Other Industry Reference list #1]*

The "energy" component to the project "bill neutral" objective only considered the VVM energy savings benefits and system losses savings. Additional benefits for deferred capital and operations costs net of efficiency savings from implementation of the project provide additional benefits towards this objective. The reliability value benefits calculated for customers for avoided outages is also provided to support the project benefit to customers but was not directly included in the "bill neutral" target. The estimated net-present value ("**NPV**") of the customer reliability benefit is a significant value in DA projects but is still contentious to some. Preliminary business case review where only 40 feeders were included looked at NPV at 20 year ($33.8M) and 40 year ($52.7M) forecast periods. *(PUC Referenced Reports table #6 below - Community Microgrid Business Case Review for SSMIC by Navigant)*

Additional efficiencies and benefits arising from the project in the area of future O&M cost savings and in longer term benefits to asset management and utilization are expected to be realizable in future five year Distribution System Plans, likely in 2025 or beyond. From an O&M perspective the smart grid system will improve the efficiency of outage response and will reduce overtime callouts and quantity and

duration of truck rolls. Specific avoided O&M was valued at about $30k annually from faster outage response and reduced truck rolls. A report for the California Energy Commission provides a good summary of benefits achievable from distribution automation. The list of these potential benefits is extracted and included below for information under heading "**General List of 12 Smart Grid/ Distribution Automation Benefit Areas".** The full report is noted in the Other Industry references listed below.

A key aspect of the project that sees the selected set of smart grid applications being applied as one concurrent project beyond the contract administrative and mobilization aspects, is to take advantage of the synergies of common design and installation elements, particularly in the Advanced Distribution System Management (ADMS) platform and system wide communication coverage for DA and VVM systems. With this new platform there will also be an integrated Outage Management System (OMS), enhanced engineering tools for GIS based network modeling and enhanced customer service tools and information which will be brought to Customer Care Staff for improved customer information access and awareness. Having the ADMS and related systems in place will be an enabling platform for the future smart grid application growth and support access for distributed energy resources and network optimization efforts.

Referenced PUC Reports:

1	Utility Distribution Microgrid: Volt/VAR Management – Preliminary Design - Leidos Engineering, October 17, 2014	*Original Application App C1*
2	Utility Distribution Microgrid: Distribution Automation – Preliminary Design - Leidos Engineering, November 20, 2014	*Original Application App C2*
3	Utility Distribution Microgrid: AMI Integration – Preliminary Design - Leidos Engineering, November 20, 2014	*Original Application App C3*
4	Review of Business Case for Smart Grid Project for PUC Distribution - Navigant Consulting, April 15, 2015	*Original Application App D*
5	Review of Project Costs for Smart Grid Project for PUC Distribution - Navigant Consulting, June 23, 2015	*Original Application App E*
6	Community Microgrid Business Case Review for SSMIC (shared with PUC) - Navigant Consulting, May 4, 2016	*IRR Filing at Appendix 7*

Future Direction in Smart Grid Investments in the US

Many of the studies, pilot projects and successful implementation of smart grid technology and investments we have monitored over the past few years are confirming positive results and plans are announced for larger and continuing scaled up investments. Some examples are listed in Table 3 below which is an extract from the report published by the US Department of Energy on Distribution Automation – Results from the Smart Grid Investment Grant Program – September 2016 [*Other Industry Reference List #7*]. Table 3 includes a number of the prior referenced projects applicable to PUC Distribution smart grid project elements such as Volt/VAR control and distribution automation.

Table 3: Examples of smart grid technology relevant project plans

- Glendale Water and Power plans a system-wide upgrade to be completed by 2026.
- PPL Electric Utilities Corporation plans to upgrade all feeders by continuing DA investments through 2018.
- Florida Power and Light is rapidly expanding its deployment of additional automated feeder switches based on project success.
- Duke Energy's SGIG project was part of a 10-year plan for grid modernization and FLISR deployment.
- Pepco plans to deploy its FLISR technologies to 15 percent of its systems.
- Central Lincoln Public Utility District plans to implement CVR territory-wide.

[https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf]

General List of 12 Smart Grid/ Distribution Automation Benefit Areas
(extracted from California Energy Commission Report by Navigant (Other Industry Reference List #1.)

1. Increase Distribution Energy Efficiency

As DA is implemented, sensors throughout the distribution system will support better situational awareness, analytical tools will support enhanced decision-making, and control devices can take action. All of this will enable utilities to optimize the performance of the distribution system to maximize the utilization of the system and reduce energy losses. Requires resources throughout a distribution area, including capacitors, transformer load-tap changers, and voltage regulators, to have the ability to communicate and coordinate.

2. Support Solar PV Installations

The majority of PV systems will be interconnected to the distribution system. DA could provide a cost effective platform for monitoring high penetrations of PV at the distribution level.

***3. Leverage & Support Decentralized* Generation**

Support distributed generation (DG), which includes both PV and CHP. DG systems produce power where it is being consumed, avoiding transmission and distribution (T&D) losses. DG can provide important benefits for utilities and their customers. While PV systems will likely be accommodated passively due to the intermittent nature of the resource, other DG resources such as CHP can be actively dispatched and controlled. In addition to enabling higher penetration of PV, DA could play an important role in supporting control of these resources.

4. Increase Distribution Reliability

Reliability improvement is one of the most common reasons cited by utilities for implementing DA. Automatic or remote controlled switches installed on distribution circuits enable utilities to isolate faults more quickly, and reduce the amount of time many customers are without power.

This application, becoming known in the industry as "Fault Location, Isolation, and Restoration" (FLIR), can yield significant reductions in outage minutes experienced by customers. By combining FLIR capabilities with advanced sensors and controls that enable automatic condition-based equipment maintenance, DA could yield even greater reliability improvements.

5. Increase Distribution Power Quality

Power quality can be affected by a number of factors throughout the T&D systems, but also from within the electrical systems of end users. DA can contribute to higher power quality by better controlling voltage throughout the distribution system. Sensor networks and information from DA systems will also help utilities identify and mitigate situations where power quality is below targets.

6. Help Manage an Aging Infrastructure

Despite massive T&D capitalization efforts underway throughout the country, much of the existing infrastructure is reaching or exceeding its estimated useful life. Infrastructure failures are costly in terms of reliability impact and repair, so any ability to prevent failures or mitigate their impacts will provide significant benefits to all stakeholders. DA can add value by:

- isolating failures to limit interruption to fewer customers;
- avoiding the stress placed on aging infrastructure by "through-fault" current from conventional reclosing; and
- monitoring equipment condition to diagnose potential failures before they occur.

7. Leverage Plug-In Hybrid Electric Vehicles

PHEVs may offer benefits that are similar to those provided by DG. For example, utilities may "dispatch" groups of PHEV for purposes such as meeting peak demand, known as vehicle-to grid or V2G.

8. Support a Utility-Scale Microgrid

With developments in distribution system technologies and DER, it is expected that the distribution system will evolve to include increasing levels of DG (PV and CHP), energy storage (for example, PHEV), and DR. DA will enable the implementation of microgrids which will coordinate these technologies to improve the reliability, stability, and security of the electric grid.

9. Enable High Penetration of Demand Response

Higher penetrations of DR will be an important resource in California as peak loads continue to increase. DR can be used by system operators as a resource to mitigate increasing loads to address peak loads on the entire system, in a planning area, at a substation, and on a feeder.

10. Support a Resilient Distribution System

Emergency response and system restoration after major events are critical to utilities and the customers they serve. Heat storms, high winds, and seismic events all pose a threat to distribution systems in California. DA will enable utilities to optimally reconfigure the distribution following major outage events, and restore service more quickly.

11. Optimize Distribution Capital Investments

DA will enable utilities to optimize the distribution system and get better system performance from investments in capital. Greater visibility into system conditions and utilization will improve asset optimization and capital prioritization efforts. In some cases, it will be possible to defer capital investment by reconfiguring parts of the system to manage peak load conditions. It may also be possible to optimize parts of the system to improve capacity factor and resource efficiency. All of this could lead to greater capital efficiency and cost reductions related to capital.

12. Improve Distribution Operations and Maintenance

Distribution operations and maintenance is a labor intensive business requiring highly skilled crews and expensive equipment. By applying automation and detection technologies to the distribution system, utilities can reduce the amount of time crews spend on routine activities such as switching, fault location and equipment inspection and maintenance.

Other Industry References:

1. The Value of Distribution Automation: Navigant Report for California Energy Commission – good summary list of *[https://listserver.energy.ca.gov/2007publications/CEC-500-2007-028/CEC-500-2007-028.PDF]*
2. Ontario Smart Grid Assessment and Roadmap for Ontario Ministry of Energy by Navigant Consulting – January 2015 [*https://www.ontarioenergyreport.ca/pdfs/Navigant-Smart-Grid-Assessment-and-Roadmap-Final-Report-.pdf]*
3. Considerations for Deploying In-Front-of-the-Meter Conservation Technologies in Ontario for Ontario Ministry of Energy (average CVR=0.91 (2.7% savings) by Navigant Consulting – July 2017 *[https://www.ontarioenergyreport.ca/pdfs/2017-07-18_MoE%20IFMC%20FINAL%20Report.pdf]*
4. Evaluation of Conservation Voltage Reduction (CVR) on a National Level: Pacific Northwest National Laboratory for US Department of Energy (projected energy savings 3.04%) *[https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf]*
5. Using AMI-based Volt/VAR Optimization (VVO/CVR) to Drive Energy Efficiency and System Reliability (presentation at SmartGrid Canada Conference 2015 - EPRI research study table of feeders avg 2.13%; Glendale Case Study 2.95%;) *[copy of presentation slide deck included in OEB ICM application at Appendix N]*
6. Utilidata paper on Voltage Optimization (2015) - American Electric Power VVO project in Ohio (reported energy savings of 4.27%) *[https://utilidata.com/wp-content/uploads/2015/08/AEP_CaseStudyVer88-14.pdf]*
7. Distribution Automation – Results from the Smart Grid Investment Grant Program – Sept 2016 by US Department of Energy – (includes examples of VVO and DA projects and positive benefits results including Glendale above – interesting to note that Glendale is advancing past pilot with plan for system coverage by 2026) *[https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf]*
8. Smart Grid Regional Business Case for the Pacific Northwest – Navigant report prepared for Bonneville Power Administration (Sept 2015) (general smart grid background "positive benefits over time"; LDC incentives noted of up to $0.18 /kwh)

[https://www.bpa.gov/Projects/Initiatives/SmartGrid/DocumentsSmartGrid/Navigant-BPA-PNW-Smart-Grid-Regional-Business-Case-2013-White-Paper.pdf]

9. Smart Grid Roadmap & Business Case – Hawaiian Electric – March 2014 (general background information and approaches) *[http://www.solari.net/portfolio/Solari-Smart-Grid-Roadmap-&-Business-Case.pdf]*

Walk Through of the VVM Energy Savings Spreadsheet Calculations:

Tables 4 through 7 in this section illustrate steps and assumptions for the estimated total energy project savings. The starting basis was developed from the detailed normalized load forecast developed for the 2018 COS application and incorporated the purchased power forecast model for energy costing. In addition adjustment of the total load forecast energy to exclude 35 kV connected customers (~16.3% of total energy purchases in the >50kW customer class) that will not be included in the VVM system was used although they will be included in DA reliability system benefit improvements along with other estimated project benefits from operational performance improvements. The applied CVR factor of 0.9 (2.7%) energy savings and 2.6% system losses savings result in a calculated annual energy benefit savings of over $2.3M and 17.4 GWh with the SSG project.

Table 1 above summarizes the cost and benefit calculation of monetary items that demonstrate PUC delivery on the "no net bill increase" objective with an annual positive net benefit of about $617k.

Savings Estimate from Purchased Power Cost and VVM Energy Savings Spreadsheets

The first step in calculating the total estimated savings is to look at the PUC total cost of power forecast. For the year 2020, the total cost of power forecast is $88,047,744. This number is calculated based on the 2019 rates published by the OEB in their Regulated Price Plan Supply Cost Report using the loads from the PUC Weather Normalized Load Forecast from the 2018 COS. *(Reference to Revised Application - Appendix [AA10] 2020 Cost of Power Forecast spreadsheet)*

Next, for the energy savings made possible by VVM a second spreadsheet is used, starting again with the Weather Normalized Load Forecast that includes detail for each customer class. *(reference to Amended Application - Appendix [AA7] VVM Energy Savings Estimate spreadsheet)*

As the VVM Energy Savings estimate is only applicable to customers on the 12.5kV distribution network with intended design and application a reduction of the energy consumption for GS>50kW customers connected to the 34.5kV sub-transmission network is needed. This reduction is shown below in Table 4 and Table 5.

Table 4: 2018 CoS Application with Normalized Load Forecast

1. Table below is from 2018 CoS application with normalized load forecast.								
2018 CoS Rate Application Data						Loss Factor	1.0481	
	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 %
Res	$ 11,226,807	58.50%	29,816	288,323,799	45.85%		302,192,174	45.85%
GS<50kW	$ 3,149,458	16.41%	3431	92,411,463	14.69%		96,856,454	14.69%
GS>50kW	$ 4,544,464	23.68%	357	244,620,598	38.90%	614,743	256,386,849	38.90%
Sentinel lights	$ 34,742	0.18%	354	209,800	0.03%	593	219,891	0.03%
Street lights	$ 195,345	1.02%	8070	2,398,221	0.38%	7,030	2,513,575	0.38%
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%

The annual energy consumption for 7 customer accounts, which are part of the GS>50kW class but connected to the 34.5 kV subtransmission system, was totaled across two years to an average use of 41,744,343.60 kWh. These customers will not have VVM savings so the kWh total was reduced from load forecast. However, they will still see DA benefits. Table 5 below shows this reduced kWh usage showing historical 34.5kV customers (the 7 accounts) with a consumption of ~16.3% for GS>50kW (i.e. 41,744,344 kWh).

Table 5: Reduce kWh use from load forecast by large customer loads

[Historical 34.5kV connected customers (7 accounts) - consumption ~16.3% of GS>50kW]

2018 CoS Rate Application Data - adjusting 34.5kV load				Loss Factor	1.0481		
	Total Base Revenue Requirement	Number of Customers	2018 Test Year Weather Normal kWh (Load Forecast)	kW	2018 Test Year Weather Normal (kWh w/LF)	Reduce GS>50kW 34.5kV (no VVM)	LV Feeder Energy Consumption Base for VVM
Res	$ 11,226,807	29,816	288,323,799		302,192,174		302,192,174
GS<50kW	$ 3,149,458	3431	92,411,463		96,856,454		96,856,454
GS>50kW	$ 4,544,464	357	244,620,598	614,743	256,386,849	41,744,344	214,642,505
Sentinel lights	$ 34,742	354	209,800	593	219,891		219,891
Street lights	$ 195,345	8070	2,398,221	7,030	2,513,575		2,513,575
USL	$ 39,551	22	944,731		990,173		990,173
	$ 19,190,367		628,908,612		659,159,116	16.3%	617,414,773

After determining the reduction in kWh by large customer loads (GS>50kW), that percentage (i.e. 16.3%) is taken and applied as a reduction to the cost of power for that customer class. Table 6 below shows the calculation of purchase power reduced by the large customer loads reduction determined in Table 5.

Table 6: Total system purchase power with large customer loads reduction

[apply % reduction to purchased power in GS> 50kW class]

2020 CoS Cost of Power (uses 2019 IESO rates)							
	Total	GS <50	GS>50-Regular	GS >50-Intermediate	Street Light	Sentinel	Unmetered Scattered Load
Cost of Power (COP*)	$88,047,743	$12,936,129	$33,995,412	$0	$330,827	$29,119	$132,080
(*) gross w/loss factor	$ 0.1336						
REDUCE GS>50kW by 16.3%			$ 5,535,058				
Revised COP	$82,512,685	$12,936,129	$28,460,354	$0	$330,827	$29,119	$132,080
Estimate for VVM customers							

The revised cost of power derived is multiplied by the energy savings percentage to calculate the VVM energy and savings. Table 7 below shows the VVM energy (kWh) savings and monetary savings estimated to be achieved by the VVM system. The estimated energy savings used for the VVM system is 2.7%. In addition, the energy savings on system losses of 2.6% (applied only to the difference between load forecast and total including loss factor). The total energy savings is estimated as 17,456,712 kWh and cost savings of $2,332,954 is shown in Table 7 below.

Table 7: Estimated customer VVM energy and monetary savings on system

ENTER VALUES	***CVR factor***	0.9	
	Voltage Savings	3.0	volts
	Energy Savings	2.7	%

System Energy Loss Savings Estimate kWh	2.60%	786,513
Using avg $/kWh from COP	$ 0.1336	$ 105,111

Difference (659,159,116-628,908,612) x % savings or avg rate

Total $'s saved with VVM	$2,227,842
Total VVM w/Syst losses included	***$2,332,954***
Total kWh saved with VVM	16,670,199
Total kWh saved with losses incl.	***17,456,712***

2.7% on $82,512,685
Adding $105,111 (losses saved)
2.7% on 617,414,773 kWh
Adding 786,513 kWh (losses saved)

The next Table is for the other OM&A cost/benefit calculations included in the benefit summary in Table 1 above. The first section calculates an estimate of the forecast of 2.5 FTE positions net, related to future OM&A post project completion. An estimated range for incremental FTE's of between 2.5 – 4.5 for operation and maintenance needs for the new SSG system and assets was developed with the work of Leidos and then recognition of expected net gains from efficiencies to be realized in operational processes considered with an estimated operating cost increase of ~$265k. The second part of the table is the calculation of estimated OM&A cost savings from reduced truck rolls and better response to both planned and unplanned system operating events including after-hours outage response. Estimated savings amounted to ~$30k using 67 crew callout hour savings estimated by Leidos annually which were updated to current 2020 labour rates.

Table 8: Additional OM&A Estimate offsetting Benefits Calculations:

OM&A Costs/ Savings							
Estimated Additional FTE Costs	Hourly Rate	Benefits	Total Hourly	Annual Hours	Annual Cost	Qty	**Cost**
Supervisor	$51	25%	$63.75	2,080	$ 132,600	1	$ 132,600
Hourly Staff (system operator, substation electrician)	$42	25%	$52.50	2,080	$ 109,200	1.5	$ 163,800
							$ 296,400
Estimated OM&A Savings							
reduced truck rolls, less patrol to find outages, less manual switching							
estimated 67 call out hours savings annual							**Savings**
2-man crew and truck with OH's	$459.94			67			**$30,816**
				Savings Net OM&A			-$265,584

The last table shows estimated PV of capital savings from deferred capital expenditures estimated to be achievable over a long term program for the capital program. It was developed from a 25 year present value analysis of proposed station and transformer deferred capital works from the Long Term Station Asset reviews. The spreadsheet calculated equivalent annual value was then discounted 50% as a further conservative assumption for the benefit assessment summary.

Table 9: CAPEX Savings Estimate

		25 Yr	NPER	300	MONTHS					
			'000s	'000s/MM		'000s				
PV Direct Avoided Capex			$ 6,469	$ 51		$ 25.37	**Assume 50% of estimate savings achieved**			
						$ 304.390	**Annual**			

Appendix AA14
VVM Energy Savings Estimate Spreadsheet
(Live Excel model filed with Amended Application)

Energy Savings Estimated from VVM System

1. Table below is from 2018 CoS application with normalized load forecast.

2018 CoS Rate Application Data						Loss Factor	1.0481	
	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 %
Res	$ 11,226,807	58.50%	29,816	288,323,799	45.85%		302,192,174	45.85%
GS<50kW	$ 3,149,458	16.41%	3431	92,411,463	14.69%		96,856,454	14.69%
GS>50kW	$ 4,544,464	23.68%	357	244,620,598	38.90%	614,743	256,386,849	38.90%
Sentinel lights	$ 34,742	0.18%	354	209,800	0.03%	593	219,891	0.03%
Street lights	$ 195,345	1.02%	8070	2,398,221	0.38%	7,030	2,513,575	0.38%
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%

2. VVM Energy Savings estimate is only applicable to customers on the 12.5 kV distribution network with intended design & application.

3. A reduction of the energy consumption above in the GS>50kW customers connected to the 34.5kV subtransmission network is thus needed .

4. The 7 customers for above annual energy consumption was totaled across two years and an average of 41,744,343.60 kWh used.

5. Note: as actual consumption in period was above Normalized this creates a more conservative estimate on total energy saved by VVM.

6. The Table below shows where the reduction applied results in 617,414,773 kWh energy for VVM targeted customers on the LV customers.

2018 CoS Rate Application Data - adjusting 34.5kV load						Loss Factor	1.0481			
	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 34.5kV (no VVM)	LV Feeder Energy Consumption Base for VVM
Res	$ 11,226,807	58.50%	29,816	288,323,799	45.85%		302,192,174	45.85%		302,192,174
GS<50kW	$ 3,149,458	16.41%	3431	92,411,463	14.69%		96,856,454	14.69%		96,856,454
GS>50kW	$ 4,544,464	23.68%	357	244,620,598	38.90%	614,743	256,386,849	38.90%	41,744,344	214,642,505
Sentinel lights	$ 34,742	0.18%	354	209,800	0.03%	593	219,891	0.03%		219,891
Street lights	$ 195,345	1.02%	8070	2,398,221	0.38%	7,030	2,513,575	0.38%		2,513,575
USL	$ 39,551	0.21%	22	944,731	0.15%		990,173	0.15%		990,173
	$ 19,190,367	100.00%		628,908,612	100%		659,159,116	100%	16.3%	617,414,773

7. The Cost of Power forecast from the 2018 CoS rate Applcation was used in original application for estimating energy $ savings.

2018 CoS Cost of Power (CoS Application)

	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											
REDUCE GS>50kW by 16.3%				$ 4,865,121							
Revised COP	**$72,860,305**	$35,945,091	$11,467,389	$25,015,646	$0		$0	$0	$288,889	$25,865	$117,425
Estimate for VVM customers											

8. Table below uses the current Cost of Power forecast with updated IESO rates as provided below and the 16.3% reduction in energy from the GS>50kW class kWh used to get balance for VVM customers.

2020 CoS Cost of Power (uses 2019 IESO rates)

	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*)	**$88,047,743**	$40,624,176	$12,936,129	$33,995,412	$0		$0	$0	$330,827	$29,119	$132,080
(*) gross w/loss factor	*$ 0.1336*	*Avg rate*									
REDUCE GS>50kW by 16.3%				$ 5,535,058							
Revised COP	**$82,512,685**	$40,624,176	$12,936,129	$28,460,354	$0	$0	$0	$0	$330,827	$29,119	$132,080
Estimate for VVM customers											

9. Next table describes the VVM energy and $ savings estimated to be achieved by the VVM system.

ENTER VALUES	***CVR factor***	0.9			System Energy Loss Savings Estimate kWh		2.60%	786,513		
	Voltage Savings	3.0	volts		Using avg $/kWh from COP		$ 0.1336	$ 105,111		
	Energy Savings	2.7	%							
Total $'s saved with VVM	**$2,227,842**	$1,096,853	$349,275	$768,430	$0	$0	$0	$0	$8,932	$786	$3,566
Total VVM w/Syst losses included	*$2,332,954*										
Total kWh saved with VVM	**16,670,199**	8,159,189	2,615,124	5,795,348	-	-	-	-	67,867	5,937	26,735
Total kWh saved with losses incl.	*17,456,712*										

Appendix AA15
Cost of Power Forecast Spreadsheet
(Live Excel model filed with Amended Application)

This spreadsheet was adapted from The 2018 CoS models.. The 2019 Cost of Power forecast $88,047,744 for internal budget was used as the updated input to the SSG energy savings calculation speadsheet. Customer savings will actually be even greater when SSG goes in to service in 2022 as there will likely be some inflation cost increase to market prices. If this was a 1.5% annual the CoP would be ~$91.87M.

Cost of Power 2019			
2018 Load Forecast	**kWh**	**kW**	**2018 %RPP**
Residential	288,323,799		96.64%
General Service < 50 kW	92,411,463		92.68%
General Service 50 to 4,999 kW	244,620,598	614,743	35.64%
Sentinel Lights	209,800	593	100.00%
Street Lights	2,398,221	7,030	2.88%
Unmetered Loads	944,731		100.00%
TOTAL	**628,908,614**	**622,366**	

Note:
OEB Website -> Quick Links -> RPP -> Oct 16-14 RPP Price Report -> Table ES-1 page 3 -> give How to calculate RPP - divide by 1000
Note (update): - 2019- now called the RPP Supply Cost Report.

Electricity - Commodity RPP										1.50%
Class per Load Forecast RPP	**2018 Forecasted Metered kWhs**	**2018 Loss Factor**	**2019 Rates**			**2018 Rates**	**2019 Rates**	**2020**	**2021**	**2022**
Residential	278,636,120	1.0481	292,038,517	$0.12389	$36,180,652	$0.10909	$0.12389	$0.12575	$0.12763	$0.12955
General Service < 50 kW	85,646,944	1.0481	89,766,562	$0.12389	$11,121,179					
General Service 50 to 4,999 kW	87,182,781	1.0481	91,376,273	$0.12389	$11,320,606					
Sentinel Lights	209,800	1.0481	219,892	$0.12389	$27,242					
Street Lights	69,069	1.0481	72,391	$0.12389	$8,969					
Unmetered Loads	944,731	1.0481	990,173	$0.12389	$122,673					
TOTAL	**452,689,446**		**474,463,808**		**$58,781,321**					

Note:
Non-RPP is Forecast Wholesale Electricity Price + Impact on Global Adj then divide by 1000
Note (update):
Both come from the RPP Supply Cost Report

Electricity - Commodity Non-RPP								1.50%	1.50%	1.50%
Class per Load Forecast	**2018 Forecasted Metered kWhs**	**2017 Loss Factor**	**2019**			**2018 Rates**	**2019 Rates**	**2020**	**2021**	**2022**
Residential	9,687,680	1.0481	10,153,657	$0.12290	$1,247,884	$0.10616	$0.12290	$0.12474	$0.12661	$0.12851
General Service < 50 kW	6,764,519	1.0481	7,089,892	$0.12290	$871,348					
General Service 50 to 4,999 kW	157,437,817	1.0481	165,010,576	$0.12290	$20,279,800					
Sentinel Lights	0	1.0481	0	$0.12290	$0					
Street Lights	2,329,153	1.0481	2,441,185	$0.12290	$300,022					
Unmetered Loads	0	1.0481	0	$0.12290	$0					
TOTAL	**176,219,168**		**184,695,310**		**$22,699,054**					

Transmission - Network		**Volume Metric**						0.00%	0.00%	0.00%
Class per Load Forecast				**2019**		**2018 Rates**	**2019 Rates**	**2020**	**2021**	**2022**
Residential		kWh	302,192,174	$0.0060	$1,813,153	$0.0060	$0.0060			
General Service < 50 kW		kWh	96,856,455	$0.0056	$542,396	$0.0056	$0.0056			
General Service 50 to 4,999 kW		kW	614,743	$2.2694	$1,395,098	$2.2694	$2.2694			
Sentinel Lights		kW	593	$1.7202	$1,019	$1.7202	$1.7202			
Street Lights		kW	7,030	$1.7116	$12,033	$1.7116	$1.7116			
Unmetered Loads		kWh	990,173	$0.0056	$5,545	$0.0056	$0.0056			
TOTAL					**$3,769,244**					

Note:
Get rates from the approved/proposed Tariff of rates

Transmission - Connection		**Volume Metric**			
Class per Load Forecast				**2019**	
Residential		kWh	302,192,174	$0.0000	$0
General Service < 50 kW		kWh	96,856,455	$0.0000	$0
General Service 50 to 4,999 kW		kW	614,743	$0.0000	$0
Sentinel Lights		kW	593	$0.0000	$0
Street Lights		kW	7,030	$0.0000	$0
Unmetered Loads		kWh	990,173	$0.0000	$0
TOTAL					**$0**

Wholesale Market Service								0.00%	0.00%	0.00%
Class per Load Forecast				**2019**		**2018 Rates**	**2019 Rates**	**2020**	**2021**	**2022**
Residential		kWh	302,192,174	$0.0034	$1,027,453	$0.0036	$0.0034			
General Service < 50 kW		kWh	96,856,455	$0.0034	$329,312	$0.0036	$0.0034			
General Service 50 to 4,999 kW		kWh	256,386,849	$0.0034	$871,715	$0.0036	$0.0034			
Sentinel Lights		kWh	219,892	$0.0034	$748	$0.0036	$0.0034			
Street Lights		kWh	2,513,576	$0.0034	$8,546	$0.0036	$0.0034			
Unmetered Loads		kWh	990,173	$0.0034	$3,367	$0.0036	$0.0034			
TOTAL			**659,159,118**		**$2,241,141**					

Note:
Get rates from the approved/proposed Tariff of rates

Rural Rate Assistance								0.00%	0.00%	0.00%
Class per Load Forecast				**2019**		**2018 Rates**	**2019 Rates**	**2020**	**2021**	**2022**
Residential		kWh	302,192,174	$0.0005	$151,096	$0.0003	$0.0005			
General Service < 50 kW		kWh	96,856,455	$0.0005	$48,428	$0.0003	$0.0005			
General Service 50 to 4,999 kW		kWh	256,386,849	$0.0005	$128,193	$0.0003	$0.0005			
Sentinel Lights		kWh	219,892	$0.0005	$110	$0.0003	$0.0005			
Street Lights		kWh	2,513,576	$0.0005	$1,257	$0.0003	$0.0005			
Unmetered Loads		kWh	990,173	$0.0005	$495	$0.0003	$0.0005			
TOTAL			**659,159,118**		**$329,580**					

Note:
Get rates from the approved/proposed Tariff of rates

Smart Meter Entity Charge							0.00%	0.00%	0.00%
Class per Load Forecast	**Customers**	**2019**			**2018 Rates**	**2019 Rates**	**2020**	**2021**	**2022**
Residential	29,816	$0.5700	$203,938	$203,938	$0.5700	$0.5700			
General Service < 50 kW	3,431	$0.5700	$23,466	$23,466	$0.5700	$0.5700			
General Service 50 to 4,999 kW			$0						
Sentinel Lights			$0						
Street Lights			$0						
Unmetered Loads			$0						
TOTAL	**33,246**		**$227,404**						

	2019	**2020**	**2021**	**2022**	
4705-Power Purchased	$81,480,375	$82,702,580	$83,943,119	$85,202,266	1.5% annual
4708-Charges-WMS	$2,241,141	$2,274,758	$2,308,879	$2,343,513	1.5% annual
4714-Charges-NW	$3,769,244	$3,769,244	$3,769,244	$3,769,244	
4716-Charges-CN	$0	$0	$0	$0	
4730-Rural Rate Assistance	$329,580	$329,580	$329,580	$329,580	
4750-Low Voltage					
4751 - Smart Metering Entity charge	$227,404	$227,404	$227,404	$227,404	
TOTAL	**88,047,744**	$89,303,566	$90,578,226	**$91,872,006**	

This IESO report used for estimating energy prices for purchased power.

https://www.oeb.ca/sites/default/files/RPP-Supply-Cost-Report-20190501-20200430.pdf

Regulated Price Plan

Supply Cost Report

May 1, 2019 to April 30, 2020

Ontario Energy Board

April 17, 2019

Table ES-1: Average RPP Supply Cost Summary

RPP Supply Cost Summary for the period from May 1, 2019 through April 30, 2020		$/MWh
Forecast Wholesale Electricity Price - Simple Average		$18.73
Load-Weighted Costs for RPP Consumers		
Wholesale Electricity Cost - RPP-Weighted		$20.68
Global Adjustment	+	$102.22
Adjustment to Address Bias Towards Unfavourable Variance	+	$1.00
Adjustment to Clear Existing Variance[4]	+	$0.00
Average Supply Cost for RPP Consumers	=	123.89

Source: Power Advisory

Appendix AA16
2021 Capital Module Applicable to an ICM

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.

Version 5.01

Utility Name	PUC Distribution Inc.
Assigned EB Number	EB-2019-0170
Name of Contact and Title	Tyler Kasubeck, Regulatory Financial Analyst
Phone Number	705-759-3009
Email Address	regulatory@ssmpuc.com
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	**Price-Cap IR**
Rate Year	**2022**
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which PUC Distribution Inc. is applying:	**4**
Next OEB Scheduled Rebasing Year	**2023**
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	**2020**
Current IPI	**2.00%**
Strech Factor Assigned to Middle Cohort*	**III**
Stretch Factor Value	**0.30%**
Price Cap Index	**1.70%**

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

Revenues Based on 2020 Actual Distribution Demand

Revenues Based on 2018 Board-Approved Distribution Demand

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your ICM application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

**As per ACM/ICM policy, the middle cohort stretch factor is applied to all ACM/ICM applications.*

OEB policies regarding rate-setting and rebasing following distributor consolidations could allow a distributor to not rebase rates for up to ten years. A distributor could also apply for and receive OEB approval to defer rebasing. If a distributor is under Price Cap IR for more than four years after rebasing and applies for an ICM, this spreadsheet will need to be adapted to accommodate those circumstances. The distributor should contact OEB staff to discuss the circumstances so that a customized model can be provided.

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 R1
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 4,999 KW
4	UNMETERED SCATTERED LOAD
5	SENTINEL LIGHTING
6	STREET LIGHTING

Ontario Energy Board

Capital Module
Applicable to ACM and

PUC Distribution Inc.

Input the billing determinants associated with PUC Distribution Inc.'s Revenues Based distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth facto

Rate Class	Units
RESIDENTIAL R1	$/kWh
GENERAL SERVICE LESS THAN 50 kW	$/kWh
GENERAL SERVICE 50 TO 4,999 KW	$/kW
UNMETERED SCATTERED LOAD	$/kWh
SENTINEL LIGHTING	$/kW
STREET LIGHTING	$/kW

l on 2020 Actual Distribution Demand. Input the current approved
r calculation.

2020 Actual Distribution Demand

Billed Customers or Connections	Billed kWh	Billed kW (if applicable)
29,897	296,035,266	
3,388	91,718,380	
362	240,708,316	594,560
23	866,480	
351	206,826	605
8,037	2,410,546	7,056

Current Approved Distribution Rates

Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW
32.13		
21.27	0.0255	
117.45		6.9056
13.02	0.0393	
3.65		34.0175
1.40		9.1619

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

PUC Distribution Inc.

Calculation of pro forma 2018 Revenues. No input required.

	2020 Actual Distribution Demand			Current Approved Distribution Rates										
Rate Class	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
	A	B	C	D	E	F	G	H	I	J	K = G / J	L = H / J	M = I / J	N
RESIDENTIAL R1	29,897	296,035,266		32.13	0.0000	0.0000	11,527,087	0	0	11,527,087	100.0%	0.0%	0.0%	58.8%
GENERAL SERVICE LESS THAN 50 kW	3,388	91,718,380		21.27	0.0255	0.0000	864,753	2,338,819	0	3,203,572	27.0%	73.0%	0.0%	16.3%
GENERAL SERVICE 50 TO 4,999 KW	362	240,708,316	594,560	117.45	0.0000	6.9056	510,203	0	4,105,791	4,615,994	11.1%	0.0%	88.9%	23.5%
UNMETERED SCATTERED LOAD	23	866,480		13.02	0.0393	0.0000	3,594	34,053	0	37,646	9.5%	90.5%	0.0%	0.2%
SENTINEL LIGHTING	351	206,826	605	3.65	0.0000	34.0175	15,374	0	20,586	35,960	42.8%	0.0%	57.2%	0.2%
STREET LIGHTING	8,037	2,410,546	7,056	1.40	0.0000	9.1619	135,022	0	64,645	199,667	67.6%	0.0%	32.4%	1.0%
Total	**42,058**	**631,945,814**	**602,221**				**13,056,032**	**2,372,871**	**4,191,022**	**19,619,926**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

PUC Distribution Inc.

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 4)	$	19,619,926	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 2018 Board-Approved Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

	2018 Board-Approved 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
	A	B	C	D	E	F	G	H	I	J	K = G / J_{total}	L = H / J_{total}	M = I / J_{total}	N
RESIDENTIAL R1	29,816	288,323,799		32.13	0.0000	0.0000	11,495,857	0	0	11,495,857	58.2%	0.0%	0.0%	58.2%
GENERAL SERVICE LESS THAN 50 kW	3,431	92,411,463		21.27	0.0255	0.0000	875,728	2,356,492	0	3,232,221	4.4%	11.9%	0.0%	16.4%
GENERAL SERVICE 50 TO 4,999 KW	357	244,620,598	614,743	117.45	0.0000	6.9056	503,156	0	4,245,169	4,748,325	2.5%	0.0%	21.5%	24.0%
UNMETERED SCATTERED LOAD	22	944,731		13.02	0.0393	0.0000	3,437	37,128	0	40,565	0.0%	0.2%	0.0%	0.2%
SENTINEL LIGHTING	354	209,800	593	3.65	0.0000	34.0175	15,505	0	20,172	35,678	0.1%	0.0%	0.1%	0.2%
STREET LIGHTING	8,070	2,398,221	7,030	1.40	0.0000	9.1619	135,576	0	64,408	199,984	0.7%	0.0%	0.3%	1.0%
Total	**42,050**	**628,908,612**	**622,366**				**13,029,260**	**2,393,620**	**4,329,750**	**19,752,630**				**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.

	Current OEB-Approved Base Rates			2020 Actual Distribution Demand										
Rate Class	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
	A	B	C	D	E	F	G	H	I	J	L = G / J_{total}	M = H / J_{total}	N = I / J_{total}	O
RESIDENTIAL R1	32.13	0	0	29,897	296,035,266	0	11,527,087	0	0	11,527,087	58.75%	0.00%	0.00%	58.8%
GENERAL SERVICE LESS THAN 50 kW	21.27	0.0255	0	3,388	91,718,380	0	864,753	2,338,819	0	3,203,572	4.41%	11.92%	0.00%	16.3%
GENERAL SERVICE 50 TO 4,999 KW	117.45	0	6.9056	362	240,708,316	594,560	510,203	0	4,105,791	4,615,994	2.60%	0.00%	20.93%	23.5%
UNMETERED SCATTERED LOAD	13.02	0.0393	0	23	866,480	0	3,594	34,053	0	37,646	0.02%	0.17%	0.00%	0.2%
SENTINEL LIGHTING	3.65	0	34.0175	351	206,826	605	15,374	0	20,586	35,960	0.08%	0.00%	0.10%	0.2%
STREET LIGHTING	1.40	0	9.1619	8,037	2,410,546	7,056	135,022	0	64,645	199,667	0.69%	0.00%	0.33%	1.0%
Total							**13,056,032**	**2,372,871**	**4,191,022**	**19,619,926**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

PUC Distribution Inc.

No Input Required.

Final Materiality Threshold Calculation

$$\textbf{\textit{Threshold Value}}\,(\%) = \mathbf{1} + \left[\left(\frac{\boldsymbol{RB}}{\boldsymbol{d}}\right) \times (\boldsymbol{g} + \boldsymbol{PCI} \times (\mathbf{1} + \boldsymbol{g}))\right] \times \left((\mathbf{1} + \boldsymbol{g}) \times (\mathbf{1} + \boldsymbol{PCI})\right)^{n-1} + \mathbf{10}\%$$

Cost of Service Rebasing Year		**2018**	
Price Cap IR Year in which Application is made		**4**	n
Price Cap Index		**1.70%**	PCI
Growth Factor Calculation			
Revenues Based on 2020 Actual Distribution Demand		**$19,619,926**	
Revenues Based on 2018 Board-Approved Distribution Demand		**$19,752,630**	
Growth Factor		**-0.34%**	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	**146%**
Price Cap IR Year 2020	**146%**
Price Cap IR Year 2021	**147%**
Price Cap IR Year 2022	**147%**
Price Cap IR Year 2023	**148%**
Price Cap IR Year 2024	**148%**
Price Cap IR Year 2025	**149%**
Price Cap IR Year 2026	**149%**
Price Cap IR Year 2027	**150%**
Price Cap IR Year 2028	**150%**

Threshold CAPEX $Threshold\ Value \times d$

Price Cap IR Year 2019	**$ 5,512,092**
Price Cap IR Year 2020	**$ 5,530,481**
Price Cap IR Year 2021	**$ 5,549,119**
Price Cap IR Year 2022	**$ 5,568,011**
Price Cap IR Year 2023	**$ 5,587,159**
Price Cap IR Year 2024	**$ 5,606,568**
Price Cap IR Year 2025	**$ 5,626,240**
Price Cap IR Year 2026	**$ 5,646,179**
Price Cap IR Year 2027	**$ 5,666,389**
Price Cap IR Year 2028	**$ 5,686,874**

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 and ICM projects and related CAPEX costs in the relevant years

	Cost of Service	*Price Cap IR*	*Price Cap IR*	*Price Cap IR*	*Price Cap IR*
	Test Year 2018	Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022
CAPEX[1]	$ 5,388,176	$ 5,275,803	$ 9,100,376	$ 6,096,546	$ 33,495,218
Materiality Threshold		$ 5,512,092	$ 5,530,481	$ 5,549,119	$ 5,568,011
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)		$ -	$ 3,569,895	$ 547,427	$ 27,927,207

		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**
												$ 24,828,660	$ 695,799	$ 2,722,959
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,828,660	$ 695,799	$ 2,722,959
Maximum Allowed Incremental Capital			$ -			$ -			$ -			$ 24,828,660		

1. For the Cost of Service Test Year, CAPEX refers to the CAPEX approved in the DSP. For subsequent Price CAP IR years, the CAPEX to be entered is the actual CAPEX. For the current Price Cap IR year, the CAPEX to be entered is the proposed CAPEX including any ICM/updated ACM project CAPEX for the year.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

PUC Distribution Inc.

Incremental Capital Adjustment **Rate Year:** 2022

Current Revenue Requirement

Current Revenue Requirement - Total	$ 19,273,165	A

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim	Eligible for ACM/ICM (Half Year* Prorated Amount) (from Sheet 10b)	
Amount of Capital Projects Claimed	$ 24,828,660	$ 12,414,330	B
Depreciation Expense	$ 695,799	$ 347,900	C
CCA	$ 2,722,959	$ 1,361,480	V

**The half year rule is applied as the distributor is scheduled to rebase in the next rate year.*

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$ 12,414,330	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$ 347,900	C
Incremental Capital to be included in Rate Base (average NBV in year)			$ 12,240,380	D = B - C/2
	% of capital structure			
Deemed Short-Term Debt	4.0%	E	$ 489,615	G = D * E
Deemed Long-Term Debt	56.0%	F	$ 6,854,613	H = D * F
	Rate (%)			
Short-Term Interest	2.29%	I	$ 11,212	K = G * I
Long-Term Interest	4.12%	J	$ 282,410	L = H * J
Return on Rate Base - Interest			$ 293,622	M = K + L
	% of capital structure			
Deemed Equity %	40.00%	N	$ 4,896,152	P = D * N
	Rate (%)			
Return on Rate Base -Equity	9.00%	O	$ 440,654	Q = P * O
Return on Rate Base - Total			$ 734,276	R = M + Q

Amortization Expense

Amortization Expense - Incremental	C	$ 347,900	S

Grossed up Taxes/PILs

Regulatory Taxable Income		O	$ 440,654	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$ 347,900	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$ 1,361,480	V
Incremental Taxable Income			-$ 572,926	W = T + U - V
Current Tax Rate	26.5%	X		
Taxes/PILs Before Gross Up			-$ 151,825	Y = W * X
Grossed-Up Taxes/PILs			-$ 206,565	Z = Y / (1 - X)

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$ 734,276	AA
Amortization Expense - Total	S	$ 347,900	AB
Grossed-Up Taxes/PILs	Z	-$ 206,565	AC
Incremental Revenue Requirement		$ 875,610	AD = AA + AB + AC

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

PUC Distribution Inc.

Calculation of incremental rate rider. Choose one of the 3 options: Fixed and Variable Rate Riders

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 7	*From Sheet 7*	*From Sheet 7*	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
RESIDENTIAL R1	58.75%	0.00%	0.00%	514,438	0	0	514,438	29,897	296,035,266		1.43	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	4.41%	11.92%	0.00%	38,593	104,378	0	142,971	3,388	91,718,380		0.95	0.0011	0.0000
GENERAL SERVICE 50 TO 4,999 KW	2.60%	0.00%	20.93%	22,770	0	183,236	206,005	362	240,708,316	594,560	5.24	0.0000	0.3082
UNMETERED SCATTERED LOAD	0.02%	0.17%	0.00%	160	1,520	0	1,680	23	866,480		0.58	0.0018	0.0000
SENTINEL LIGHTING	0.08%	0.00%	0.10%	686	0	919	1,605	351	206,826	605	0.16	0.0000	1.5182
STREET LIGHTING	0.69%	0.00%	0.33%	6,026	0	2,885	8,911	8,037	2,410,546	7,056	0.06	0.0000	0.4089
Total	**66.54%**	**12.09%**	**21.36%**	**582,673**	**105,898**	**187,040**	**875,610**	**42,058**	**631,945,814**	**602,221**			
							875,610						
							From Sheet 11, E93						

Note: As per the OEB's letter issued July 16, 2015 (EB-2012-0410), Resid

'ential Rates will be applied on a fixed basis only.