APPENDIX 11

Incremental Capital Module

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

PUC Distribution Inc.

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

1. Introduction

PUC Distribution Inc. (the "**Applicant**" or "**PUC Distribution**") submits this ICM to secure incremental capital for 2019 to support the first phase of the proposed Sault Smart Grid (SSG) project (the "**SSG Project**").

In this 2019 ICM, the Applicant is requesting approval of a net capital expenditure exceeding PUC Distribution's 2019 materiality threshold of $4,552,714. This results in an incremental revenue requirement of $510,553.

PUC Distribution's management had a number of criteria that the SSG Project needed to meet before PUC Distribution was willing to submit this request for ICM funding.

One key criterion was that the SSG Project would result in "no net bill increase" for PUC Distribution customers.

This recognizes that while the SSG Project will result in an increase in the distribution component of a customer's bill, the SSG Project will also drive efficiencies in terms of reduced energy consumption, system losses and other forecast benefits that will off-set any such increases.

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

On March 3, 2018, PUC Distribution submitted an application to the Natural Resources Canada ("**NRCan**") Smart Grid Program (the "**NRCan Funding**") for a total of $11,807,000 in funding. Information on this Smart Grid Program is included at Appendix A. PUC Distribution successfully completed due diligence with NRCan on the SSG Project and executed a contribution agreement with the Federal Government of Canada in December 2018 (the "**Contribution Agreement**") which includes a requirement for PUC Distribution to undertake and receive approval from the Ontario Energy Board (the "**OEB**") for the required rate adjustment in support of the SSG Project. The NRCan Funding is expected to provide $2,628,256 in 2019 and $9,178,744 in 2020 in funding for the SSG Project.

The NRCan Funding is required for the SSG Project to meet the "no net bill increase" criteria.

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 hereto as Appendix B.

The OEB subsequently released its *Renewed Regulatory Framework for Electricity Distributors*[1], 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 *Supplemental Report on Smart Grid*[2] 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.

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[1] *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.

[2] *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.

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 hereto as Appendix C.

During the 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**) (attached hereto as Appendix D); and

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

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. A full timeline of events is included at Appendix F.

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[3]:

> ***"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 Board of Directors approval this 2 to 3 year project would represent a substantial advancement in smart grid technologies being implemented by PUC Distribution."

[3] 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.

It was further explained in PUC Distribution's response to interrogatory number 1-Staff-6 (EB-2017-0071) at page 8[4]:

> "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 committed to answering OEB Staff's questions in this Application. Answers to the questions asked by OEB Staff in interrogatory number 1-Staff-6 are provided in Appendix G.

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.

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[4] 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 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 advanced metering infrastructure ("**AMI**") system.

The innovation is the implementation of these distribution system improvements in a coordinated manner across the entire distribution system, all at once with project design and operating performance risk transfer to the developer through fixed developer/Engineering, Procurement and Construction ("**EPC**") pricing. With this approach, the SSG Project will increase the efficiency of the entire distribution grid, reducing electrical energy delivery requirements from the transmission grid, greenhouse gas emissions, and reducing total costs to consumers.

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:

1. The SSG Project will achieve an annual net benefit to PUC Distribution customers of over $200,000. Overall the project returns a positive benefit to cost ratio of 1.1:1 for customers from a billing perspective and with assuming only a 25% value for reliability, a 1.4:1 ratio results for the project. An overall 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, system losses and other forecast benefits shown here will off-set additional revenue requirement requested. Customer reliability improvements are also calculated and projected as $2.55M annually to provide additional non-bill benefit to customers.

The calculation of energy savings ($2,061,069) as mentioned Table 1 below, is further explained in Appendix H.

Table 1: Customer Benefit Summary

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

As noted above, there is an overall benefit to the customers in PUC Distribution's service territory. However, with any change to rates, the effect on specific customers will vary. Table 2 below includes examples of bill impacts at various consumption levels once the full SSG Project is included in rates. The bills impacts below do not include the effect of the system loss reduction, the capex benefit, the operating efficiency benefit and the additional O & M expenses which net to an annual overall benefit to customers of $115,902. The annual reliability benefit, which is significant ($2,550,000) is also not included in the bill impacts.

Table 2: Customer Bill Impacts

Class	Consumption (kWh)	Consumption (kW)	Total Bill Increase/Decrease	Total Bill Impact %
Residential	750	0	$1.08	1.00%
Residential	1,130	0	$0.00	0.00%
Residential	2,000	0	-$2.47	-1.03%
GS<50	2,000	0	$0.23	0.08%
GS<50	2,250	0	$0.00	0.00%
GS<50	3,000	0	-$0.71	-0.18%
GS>50	19,740	55	-$34.57	-1.03%
GS>50	57,220	145	-$130.60	-1.40%
GS>50	142,465	452	-$303.39	-1.27%
GS>50	169,620	468	-$394.91	-1.42%

2. 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 25 year net-present value ("**NPV**") of the customer reliability benefit is over $40M.

(b) The SSG Project also provides an enabling platform for power system 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.

3. 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 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 two (2) year project implementation period. Phase 1 of the SSG Project is scheduled to go in-service by December 31, 2019. Phase 2 of the SSG Project is anticipated to go in-service by December 31, 2020.

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 and 1.78% in 2017.[5] Based on preliminary unaudited results, the estimated ROE for 2018 is 5.63%. As a result of the 2018 CoS rate change, the ROE for 2019 is projected to increase to 8.49%.

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.

[5] Scorecard - PUC Distribution Inc. dated September 24, 2018:
https://www.oeb.ca/documents/scorecard/2017/Scorecard%20-%20PUC%20Distribution%20Inc..pdf

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. Project Partners and Organizational Structure

The SSG Project is being developed through a special purpose vehicle known as Sault Smart Grid Inc. ("**SSG Inc.**"). The SSG Project will initially be funded through the North American Grid Modernization Fund (the "**Fund**"), which is currently managed by Stonepeak Infrastructure Partners and Infrastructure Energy LLC ("**IE**"). The SSG Project funds will flow through SSG Inc.

Black & Veatch ("**BV**") has been selected to act as the EPC contractor on the SSG Project. BV will be responsible for performing all phases of design, build, and validation. BV assumes the risk of project completion and performance to design, with PUC Distribution accepting transfer of asset title at completion and commissioning of the SSG Project—PUC Distribution will not be leasing the assets.

An organizational chart illustrating the relationship between the PUC Distribution and its project partners is attached hereto as Appendix I.

B. 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 Supervisory Control and Data Acquisition ("**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 outage management system ("**OMS**"), which will include the following functionality:

i. Voltage / VAR Optimization ("**VVO**")

ii. Distribution Automation ("**DA**")

iii. AMI Integration

Each of these components is further detailed below.

i. 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.

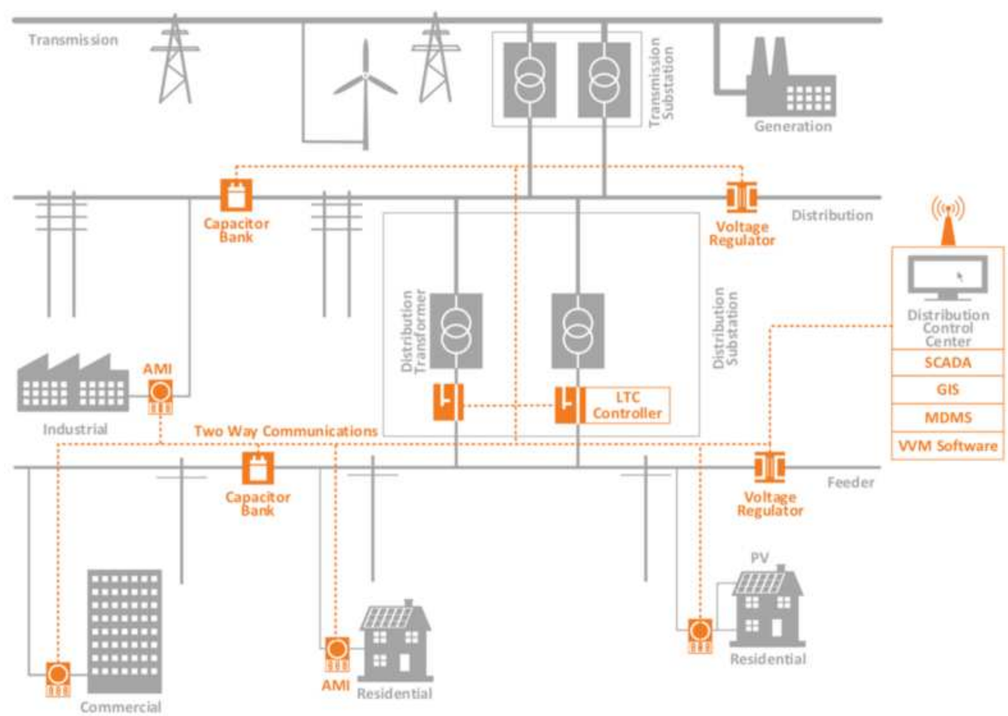
Currently, PUC Distribution does not have the capability to dynamically regulate voltage levels at any of its 34.5k/12.5 kV transformers.

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 customer savings, provincial conservation and demand management

("**CDM**") goals are also benefitting through reduced transmission grid and generation costs. However, these provincial benefits are currently not eligible for PUC Distribution's CDM targets.

Figure 1 below provides a schematic of the proposed VVO under the SSG Project. The VVO is further detailed in Leidos' Preliminary Design Report titled *Utility Distribution Microgrid: Volt/VAR Management (VVM)* dated October 17, 2014, attached hereto in Appendix C although the current project scope has been adjusted since the 2014 work.

Figure 1: Schematic of the proposed VVO system



Source: Navigant

ii. 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 Saint 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 is further detailed in Leidos' Preliminary Design Report titled *Utility Distribution Microgrid: Distribution Automation* dated November 20, 2014, attached hereto in Appendix C although the current project scope has been adjusted since the 2014 work.

Figure 2: Schematic of conceptual DA system

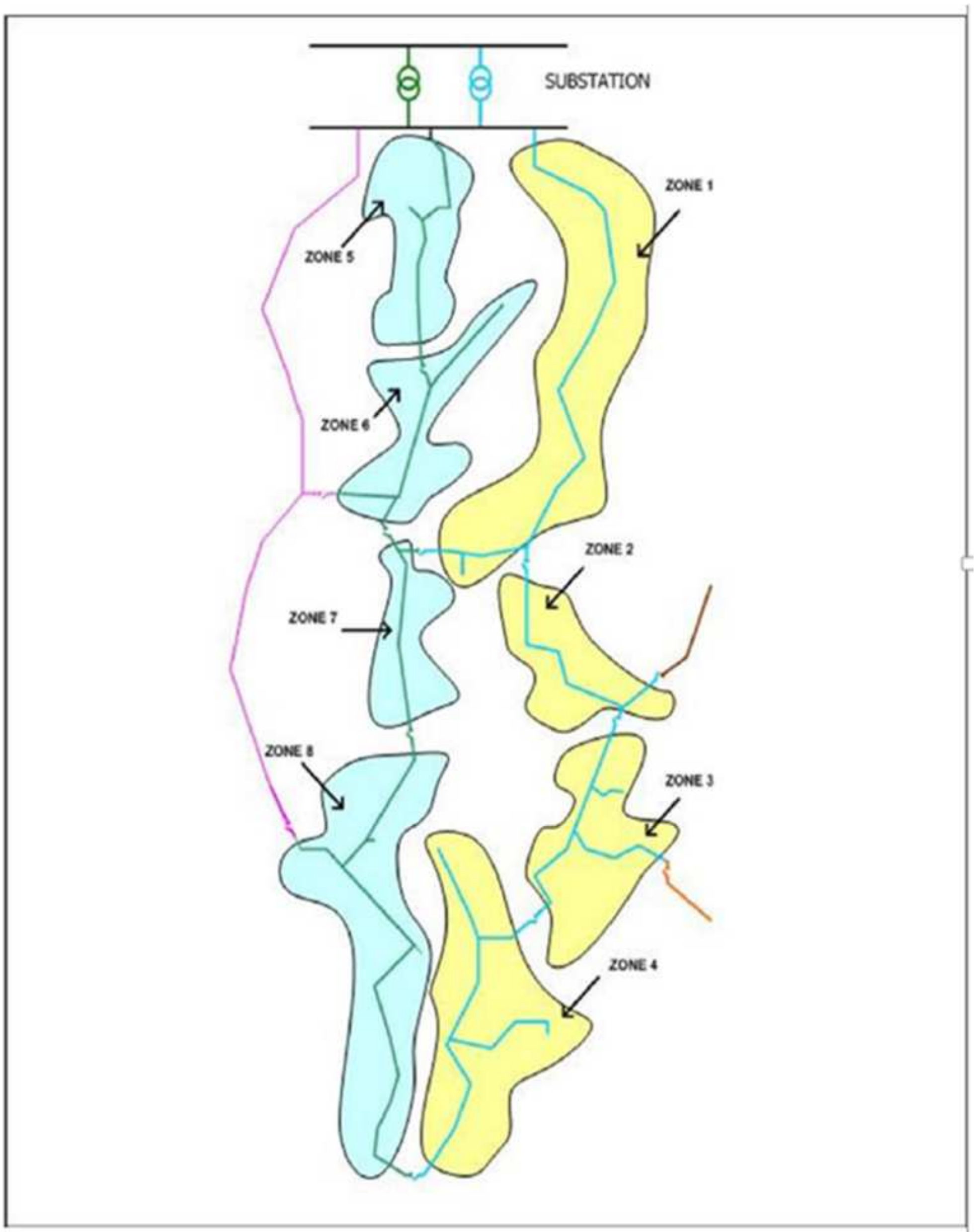
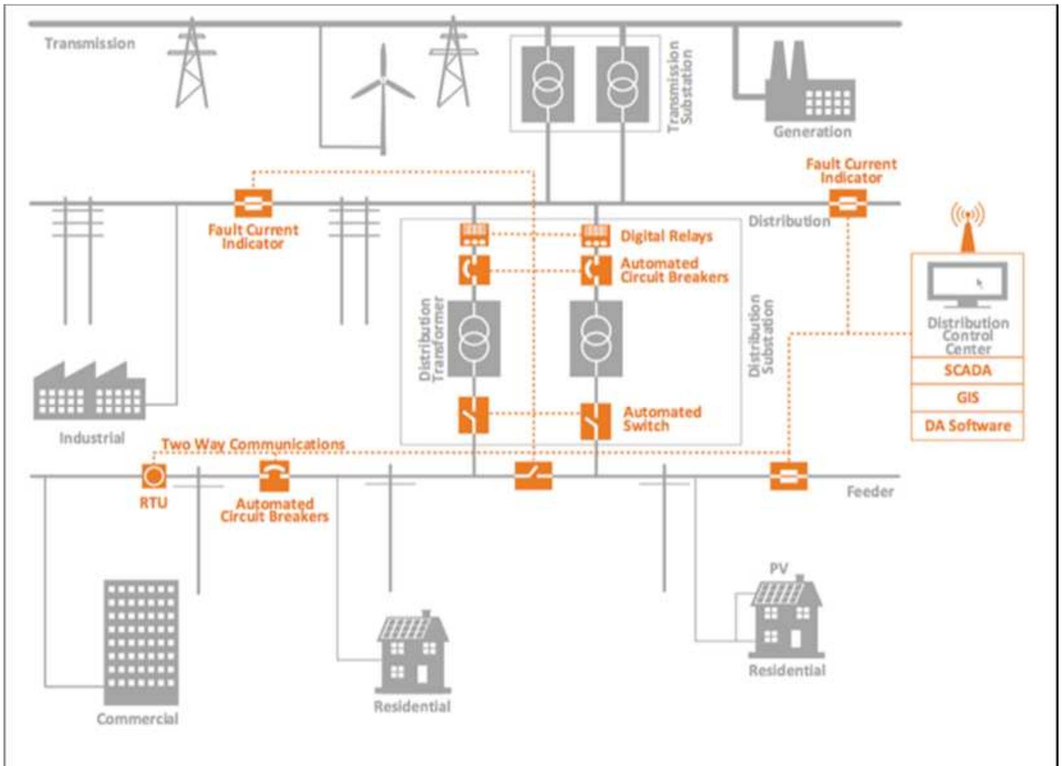


Figure 3 below provides a schematic of the proposed DA system under the SSG Project. The DA system is further detailed in Leidos' Preliminary Design Report titled *Utility Distribution Microgrid: Distribution Automation* dated November 20, 2014, attached hereto in Appendix C although the current project scope has been adjusted since the 2014 work.

Figure 3: Schematic of the proposed DA system



Source: Navigant

iii. 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 to 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 is further detailed in Leidos' Preliminary Design Report titled *Utility Distribution Microgrid: AMI Integration* dated November 20, 2014, attached hereto in Appendix C.

C. SSG Project Scope of Work and Specifications

The SSG Project is being executed as a design-build project, delivered by BV, which will include design, procurement, installation, testing, and commissioning on technologies and applications described in section 4(B) above**.**

The SSG Project scope of work and project tasks are further detailed in the following draft documents, which are attached hereto as Appendix J:

1. Design and Construction Specifications document, which specifies the equipment description (hardware and software) in a bill of material with quantities; all required system integrations; defines the feeders included in the project; and assumptions. The document is further illustrated by items 2, 3, and 4 below.

2. Physical Scoping Diagram

3. Logical Scoping Diagram

4. Responsibilities Matrix

The 30% engineering design completed by Leidos (the "**30% Design**") and scope of work developed to date will be subject to further change in the detailed design phase of the project with the EPC provider.

The design and construction specifications identified to date are detailed below:

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

Specific feeder improvement scope identified during the 30% Design stage 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 were included to implement. Balance of feeders added to increased project scope will all be addressed in the detailed design phase.

A centralized model-based VVO software will be installed at the PUC Distribution control room. The interfaces with AMI and GIS 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 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.

(b) DA scope (as described below) 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 30% Design 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 additional 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 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.

(c) 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

(d) Data Analytics and Performance Reporting

(i) OMS

The OMS will include:

- A robust off-the-shelf platform including advanced 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 the PUC Distribution control room, with SCADA, AMI, and CIS, in order to measure and track outage information in real-time and historically.

(ii) Enhanced CSR/Customer Toolset

Enhancing CSR will optimize the organization and presentation of AMI data in a CSR as well as more customer friendly user interface 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 PUC Distribution's 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 and Performance Reporting

SCADA, AMI, CIS, OMS, and GIS data will be loaded into a common platform in order to provide system analytics and key performance indicator reporting.

To implement the SSG Project, numerous system components need to be installed or upgraded, as detailed in Tables 3 and 4 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

Table 4: Equipment Quantities

Project 30% Design level on ~60% of feeders estimated up to 100% coverage.

Quantities are approx.

Table 7 – Major Electrical Equipment and Field Devices Bill of Material

EQUIPMENT TYPE FROM TABLE 6	DA APPLICATION	VENDOR[21]	DESCRIPTION	QUANTITY
EQUIPMENT TYPE FROM TABLE 6	DA APPLICATION	VENDOR[21]	DESCRIPTION	
Pole top Switches	FDIR	S&C	SCADA-Mate 15kV, with controller (IED)	35-40
Pole top Reclosers	FDIR	S&C	Intellirupter 15kV, with SpeedNet™ Radio and controller	35-40
2-way Pad mount Switches	FDIR	S&C	PMH-3 underground 15kV switchgear, with 6801 automatic switch controller	4-8
4-way Pad mount Switches	FDIR	S&C	Vista 4-Way underground 15kV switchgear, with controller	4-8
O/H FCI	FDIR	Eaton	O/H FCI- Eaton GridAdvisor Series II, 3phase set	~30
U/G FCI	FDIR	Eaton	U/G FCI- Eaton GridAdvisor Series II, 3phase set	~20
Sta. Reg 333 KVA	VVO	Eaton	Substation Regulators, 333 kVA, 438A, 14.4kV, 150 kV BIL (set of 3), with CL-7 control (IED)	~48
Fdr. Reg 167 KVA	VVO	Eaton	Line Regulator, 167kVA, 200A, 7.62 kV, 95kV BIL (set of 3), with CL-7 control (IED)	3-5
Capacitor 600 KVAR	VVO	Eaton	3x200kVAr, 12.5kV	2-4
	Auto Transfer	Eaton	O/H FCI- Eaton GridAdvisor Series II, 3phase set	~15
	FAN	S&C	SpeedNet™ 900 MHz radios- all required equipment - antenna, cables, and connectors.	~45
	FAN	S&C	SpeedNet™ repeater- all required equipment - antenna, cables, and connectors.	~12
	FAN	S&C	SpeedNet™ 900 Mhz as gateway radio that has a control house mounted antenna	~10

D. Revenue Requirement

The total capital cost of the SSG Project is estimated to be $34,389,046, with 22% of the SSG Project ($7,655,053) to be in service by December 31, 2019 in Phase 1 with the remaining 78% ($26,733,992) to be in service by December 31, 2020 in Phase 2. The SSG Project estimate is attached hereto as Appendix K.

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 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 full-time employees ("**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. Our 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 NRCan Funding is expected to provide $2,628,256 in 2019 and $9,178,744 in 2020, for a total of $11,807,000. The NRCan Contribution Agreement was executed in December 2018. Hence, after the amount of $11,807,000, which the Applicant will receive from NRCan Funding, is applied, the net cost of the SSG Project will be $22,582,046.

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 $5,026,797 in 2019 ($7,655,053 less $2,628,256). This amount of eligible incremental capital results in an incremental revenue requirement of $510,553 as calculated in Table 5 below.

Table 5: Eligible Incremental Capital for ACM/ICM Recovery

Eligible Incremental Capital for ACM/ICM Recovery	Total Claim	Eligible for ACM/ICM (Prorated Amount) (from Sheet 10b)	
Amount of Capital Projects Claimed	$ 5,026,797	$ 4,552,714	**B**
Depreciation Expense	$ 293,436	$ 265,762	**C**
CCA	$ 531,424	$ 481,305	**V**

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

Return on Rate Base				
Incremental Capital			$ 4,552,714	**B**
Depreciation Expense (prorated to Eligible Incremental Capital)			$ 265,762	**C**
Incremental Capital to be included in Rate Base (average NBV in year)			$ 4,419,833	**D = B - C/2**
	% of capital structure			
Deemed Short-Term Debt	4.0%	**E**	$ 176,793	**G = D * E**
Deemed Long-Term Debt	56.0%	**F**	$ 2,475,106	**H = D * F**
	Rate (%)			
Short-Term Interest	2.29%	**I**	$ 4,049	**K = G * I**
Long-Term Interest	4.12%	**J**	$ 101,974	**L = H * J**
Return on Rate Base - Interest			$ 106,023	**M = K + L**
	% of capital structure			
Deemed Equity %	40.00%	**N**	$ 1,767,933	**P = D * N**
	Rate (%)			
Return on Rate Base -Equity	9.00%	**O**	$ 159,114	**Q = P * O**
Return on Rate Base - Total			$ 265,137	**R = M + Q**

Amortization Expense			
Amortization Expense - Incremental	**C**	$ 265,762	**S**

Grossed up Taxes/PILs				
Regulatory Taxable Income		**O**	$ 159,114	**T**
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		**S**	$ 265,762	**U**
Deduct CCA (Prorated to Eligible Incremental Capital)			$ 481,305	**V**
Incremental Taxable Income			-$ 56,429	**W = T + U - V**
Current Tax Rate	26.5%	**X**		
Taxes/PILs Before Gross Up			-$ 14,954	**Y = W * X**
Grossed-Up Taxes/PILs			-$ 20,345	**Z = Y / (1 - X)**

Incremental Revenue Requirement			
Return on Rate Base - Total	**Q**	$ 265,137	**AA**
Amortization Expense - Total	**S**	$ 265,762	**AB**
Grossed-Up Taxes/PILs	**Z**	-$ 20,345	**AC**
Incremental Revenue Requirement		$ 510,553	**AD = AA + AB + AC**

Table 6 below provides the calculation for depreciation and CCA for the net capital expenditure of $5,026,797. The CCA for the computer software is 100% in year (1) one; however to avoid double counting that benefit, PUC Distribution has spread the benefit over the four (4) remaining years until the next cost of service rebasing.

Table 6: Depreciation and CCA Calculations for Net Capital Expenditure

	Cost of Addition	Contributed Capital	Net Addition	# Years	Deprec Rate	Deprec Exp	CCA Class	CCA Rate	CCA	CCA For 2019 IRM
1820 DS Equipment	$0	$0	$0	40	2.50%	$0	47	8%	$0	
1830 Poles & Fixtures	$1,929,153	$662,348	$1,266,805	45	2.20%	$27,870	47	8%	$101,344	$101,344
1835 OH Conductors & Devices	$1,523,016	$522,906	$1,000,109	60	1.67%	$16,702	47	8%	$80,009	$80,009
1840 UG Conduit/Civil	$162,455	$55,777	$106,678	50	2.00%	$2,134	47	8%	$8,534	$8,534
1845 UG conductors & Devices	$0	$0	$0	40	2.50%	$0	47	8%	$0	$0
1850 Line Transformers	$0	$0	$0	40	2.50%	$0	47	8%	$0	$0
1920 Computer S/W	$1,158,085	$397,612	$760,473	5	20.00%	$152,095	12	100%	$760,473	$190,118
1980 System Supervisory Equipment	$2,882,345	$989,613	$1,892,732	20	5.00%	$94,637	47	8%	$151,419	$151,419
In Service Dec. 31, 2019	$7,655,053	$2,628,256	$5,026,797			$293,436			$1,101,779	$531,424

The SSG Project is being structured such that PUC Distribution will be paying a fixed amount for the delivery of the SSG Project; hence, the risk of cost overruns will be the borne by the developer and their EPC contractor. The developer assumes the risk of project completion and performance, with PUC Distribution accepting transfer of asset title at commissioning.

The SSG Project is completed on PUC Distribution's side of the meter with no requirement for direct involvement from the customers, improving the performance of PUC Distribution's system. Payment for the SSG Project will financed over a twenty five (25) year term through long term financing.

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 2019, 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 2019 is $5,749,886, as calculated in Table 7 below.

1 **Table 7: PUC Distribution 2019 Materiality Threshold Calculation**

Final Materiality Threshold Calculation

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

Cost of Service Rebasing Year		**2018**
Price Cap IR Year in which Application is made		**1**
Price Cap Index		**0.90%**
Growth Factor Calculation		
Revenues Based on 2018 Board-Approved Distribution Demand		$19,255,556
Revenues Based on 2017 Actual Distribution Demand		$19,123,457
Growth Factor		**0.69%**
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	**152%**
Price Cap IR Year 2020	**153%**
Price Cap IR Year 2021	**153%**
Price Cap IR Year 2022	**154%**
Price Cap IR Year 2023	**155%**
Price Cap IR Year 2024	**156%**
Price Cap IR Year 2025	**156%**
Price Cap IR Year 2026	**157%**
Price Cap IR Year 2027	**158%**
Price Cap IR Year 2028	**159%**

Threshold CAPEX		
Price Cap IR Year 2019	**$**	**5,749,886**
Price Cap IR Year 2020	**$**	**5,775,303**
Price Cap IR Year 2021	**$**	**5,801,125**
Price Cap IR Year 2022	**$**	**5,827,360**
Price Cap IR Year 2023	**$**	**5,854,014**
Price Cap IR Year 2024	**$**	**5,881,093**
Price Cap IR Year 2025	**$**	**5,908,605**
Price Cap IR Year 2026	**$**	**5,936,556**
Price Cap IR Year 2027	**$**	**5,964,953**
Price Cap IR Year 2028	**$**	**5,993,804**

2

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

	2019	2020	2021	2022
System Access as proposed in 2018 DSP	$ 1,615,276	$ 2,086,480	$ 1,603,804	$ 1,560,434
System Renewal as proposed in 2018 DSP	$ 6,905,898	$ 3,296,444	$ 4,532,889	$ 7,092,642
System Services as proposed in 2018 DSP	$ -	$ -	$ -	$ -
General Plant as proposed in 2018 DSP	$ 54,629	$ 61,932	$ 59,853	$ 55,100
Total as proposed in 2018 DSP	$ 8,575,803	$ 5,444,856	$ 6,196,546	$ 8,708,176
Rescheduling of Sub 16 rebuild (System Renewal)	$ (3,300,000)	$ 3,600,000		
SSG implementation	$ 5,026,797	$ 17,555,248		
	$ 10,302,600	$ 26,600,104	$ 6,196,546	$ 8,708,176

The calculations in Table 9 below indicate that with a requested SSG Project cost of $5,026,797 and a threshold of $5,749,886 as calculated above, an incremental capital amount of $4,552,714 is eligible for inclusion in the ICM as per below.

Table 9: Materiality Calculations

		Test Year 2018	Year 1 2019	Year 2 2020
Distribution System Plan CAPEX		$ 5,358,355	$ 10,302,600	$ 26,600,104
Materiality Threshold			$ 5,749,886	$ 5,775,303
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)		$ -	$ 4,552,714	$ 20,824,801

Project Descriptions:	**Type**	**Test Year 2018**	**Year 1 2019**	**Year 2 2020**
Sault Smart Grid	**New ICM**		$ 5,026,797.00	$ 17,555,248.00
Substation 16	**New ICM**			$ 3,600,000
Total Cost of ACM/ICM Projects		$ -	$ 5,026,797	$ 21,155,248
Maximum Allowed Incremental Capital			$ 4,552,714	$ 20,824,801

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 DER and electric vehicle use is expected to increase. 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 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 an expected $11,807,000 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 bare. 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, which was funded by IE, 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 offer premium and enhanced energy services to its customers, adding system intelligence on both sides of the meter. 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 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 two (2) years 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, 2020, 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 $11,807,000, 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, 2022. Under Option "A", the SSG Project will be in-service by December 31, 2020; hence, this option satisfies the 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 $22,582,046 over two years, rather than 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 eight (8) years earlier (in 2020 versus 2028 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	$34,389,046
NRCan Funding Amount	$11,807,000
Net SSG Project Cost After Deducting NRCan Funding	**$22,582,046**

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 years 2019 and 2020, 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 2028 in-service date for the SSG Project exceeds the required completion date of March 31, 2022 under the NRCan Funding. Absent the NRCan Funding, the ratepayer will be liable to cover the full cost of $34,389,046 (or higher) 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 for each cash flow profile, calculated for different discount rates (3%, 5%, and 8%). In each scenario in Table 12, the NPV exceeds $22,582,046, which is the net SSG Project cost after deducting NRCan Funding. For instance, the straight line cash flow profile and 8% discounting rate yield a NPV of $23,075,330, which represents the best-case NPV in Table 12. However, even this NPV exceeds the net SSG Project Cost after deducting NRCan Funding by $493,284.

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 from2020 to 2028, thereby deferring direct savings for some ratepayers by up to eight (8) years.

3. All other benefits for some ratepayers associated with the SSG Project will, similarly to above, be delayed by up to eight (8) 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 the developer/EPC contractor requires a return on its time and investment in the SSG Project and these costs would need to be borne by ratepayers for a longer period of time.

5. PUC Distribution’s cost of capital would be higher with a longer development term.

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

Cash Flow Profile	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
(i) Straight Line (No Price Escalation)	$3,438,905	$3,438,905	$3,438,905	$3,438,905	$3,438,905	$3,438,905	$3,438,905	$3,438,905	$3,438,905	$3,438,905	**$34,389,046**
(ii) Escalated (assuming CPI Annual Cost Impact of 2%)	$3,438,905	$3,507,683	$3,577,836	$3,649,393	$3,722,381	$3,796,829	$3,872,765	$3,950,220	$4,029,225	$4,109,809	**$37,655,046**

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

Cash Flow Profile	Total Cost	NPV (3% Discount Rate)	NPV (5% Discount Rate)	NPV (8% Discount Rate)
(i) Straight Line (No Price Escalation)	$34,389,046	$29,334,554	$26,554,310	$23,075,330
(ii) Escalated (assuming CPI Annual Cost Impact of 2%)	$37,655,046	$31,965,880	$28,845,895	$24,953,249

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 four years, starting April 1, 2018 to March 31, 2022. 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 future in order to upgrade PUC Distribution's grid to the industry standard, but the ratepayers will lose the cost reductions afforded by the NRCan Funding.

D. Additional Considerations

The 30% Design was fully funded by IE. Hence, ratepayers are not at risk of incurring any costs prior to receiving OEB approval.

In the Navigant Report #2, Navigant concludes the SSG Project is technically sound, designed and configured consistent with current utility practices. Unit costs for the different project elements were considered reasonable. Much of the cost elements were in areas in which both Leidos and PUC Distribution have considerable experience engineering and estimating costs. Taken together, total design, project management and system integration cost are within industry averages.

As indicated earlier, the SSG Project has been evolving through a number of iterations and changes in project scope and scale over the past four (4) 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 developer to provide estimates for some of the field construction works. Leidos totalized construction cost estimates and then the compiled project estimate was also reviewed in detail by Navigant who indicated that the costs proposed were reasonable for the work proposed. This project cost data and this cost report has been filed with the application in the Navigant Report #2, attached hereto as Appendix E.

With the confirmation of the EPC contractor, the more detailed scope of work was developed and reviewed extensively with PUC Distribution's engineering and operations staff. Project cost estimates have been reviewed and checked for reasonable escalation (CPI) based on the Navigant-validated earlier work and cost estimates as well as the basis of any adjustments for changes in scope to the current final project as proposed in our SSG Project. Navigant comments on areas of scope/cost risk were considered by PUC Distribution in review of total project costs being developed for this application. The final project application estimate reflects the fixed price amount for the developer/EPC project and ~5% for PUC Distribution project management including oversight and design review as referenced in Appendix K – Project Cost Estimate.

PUC Distribution had an internal objective from early in the concept of the smart grid project which was to aim for a "no net bill increase". As the analysis for the project cost/benefit was being developed, the challenge of expressing, in some cases, long term NPV value along with current and near term bill impact savings was recognized as much for internal communication as any 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. With working support of the developer and internal financial staff, a method of representing the savings was arrived at and is reflected above in Table 1.

Additional evaluation work in development of the ICM application provided another check on assumptions and impacts estimated for the two (2) year project implementation period. For instance, an analysis using the ICM model as if the SSG Project was developed over a one (1) year installation term was created and assessed. As indicated previously, the primary real cost benefits are realized in energy and system losses savings which are estimated as $2.061M in current year dollars which would be realized in the first year of full SSG operation (expected to be 2021). Benefits from reliability are also quantified as $2.55M and although of importance to residential customers are generally recognized as providing more significant value to commercial, institutional and industrial customers.

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[6], 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

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

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
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	Col C * Col I_{total}	Col D* Col I_{total}
RESIDENTIAL	45.36%	12.88%	0.00%	231,571	65,745
GENERAL SERVICE LESS THAN 50 kW	4.43%	11.90%	0.00%	22,630	60,766
GENERAL SERVICE 50 TO 4,999 KW	2.55%	0.00%	21.48%	13,001	0
SENTINEL LIGHTING	0.08%	0.00%	0.10%	400	0
STREET LIGHTING	0.69%	0.00%	0.33%	3,518	0
UNMETERED SCATTERED LOAD	0.02%	0.19%	0.00%	89	959
Total	**53.12%**	**24.97%**	**21.91%**	**271,209**	**127,471**

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
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
0	297,316	29,816	288,323,799		0.83	0.0000	0.0000
0	83,396	3,431	92,411,463		0.55	0.0007	0.0000
109,689	122,690	357	244,620,598	614,743	3.03	0.0000	0.1784
521	921	354	209,800	593	0.09	0.0000	0.8790
1,664	5,182	8,070	2,398,221	7,030	0.04	0.0000	0.2367
0	1,048	22	944,731		0.34	0.0010	0.0000
111,874	**510,553**	**42,050**	**628,908,612**	**622,366**			
	510,553						

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

PUC Distribution has not applied the half-year rule as this request for incremental revenue does not coincide with the final year of PUC Distribution's IRM plan term.

10. 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

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

Attached hereto as Appendix L is PUC Distribution's 2019 Capital Module, which is applicable to the ICM (Version 4.0) as provided by the OEB. The proposed rate riders have been added to Tab – 18 Additional Rates of the rate generator model.

Appendix A
NRCan Program Details

Website: https://www.nrcan.gc.ca/energy/science/programs-funding/19793

Smart Grid Program

The Call for Proposals under the Smart Grid Component of the Green Infrastructure Phase II Program is now closed following the submission deadline of 23:59 EST, March 4, 2018.

Proposal selection was completed by an Expert Panel in April 2018.

Notifications were sent in May / June 2018 to those applicants who will now move onto the due diligence phase.

Projects announced under the Smart Grid program can be found on our Current Investments page.

Program Background

Up to $100 million will be invested for utility-led projects to reduce GHG emissions, better utilize existing electricity assets and foster innovation and clean jobs for:

- demonstration of smart grid technologies
- deployment of smart grid integrated systems

Do you qualify?

The request for proposals was open to:

- legal entities formed in Canada, including: electricity and gas utilities, electricity system operators, transmission system owners and operators (including provincial Crown corporations, agencies, co-operatives, Indigenous and municipally owned) and local distribution companies as direct or ultimate recipients; and
- provincial, territorial, regional and municipal governments and their departments and agencies where applicable as initial recipients.

Frequently Asked Questions

A list of commonly asked questions and their answers will be maintained on this site. It will be updated as often as required. Please **click here** to go to the FAQs.

Why is Canada investing in Smart Grids?

Smart grids help ensure safer and more secure delivery of electricity, provide foundations for new market structures and a higher quality of service for customers. They are a key enabler for GHG mitigation as they increase the hosting capacity of renewable generation, improve asset utilization and increase resiliency. Benefits of smart grids include:

- better utilizing the existing capacity of electricity assets
- increasing the penetration of renewable generation
- increasing the reliability, resiliency and flexibility of the power system
- maintaining cyber security
- reducing greenhouse gas emissions
- creating jobs

NRCan reserves the right to alter the currently envisaged process, funding amounts and deadlines, or to cancel the entire application process at its sole discretion. Any changes will be communicated to registered applicants via email.

Date Modified: 2018-12-05

Smart Grid Program - Project Unique ID (to be filled in by Program):

1.2 Project Description Summary

Please note: this information could be used on NRCan's public facing website. Keep the information brief, non-technical, and non-confidential.

Problem Statement (150 words maximum)

What issue or problem is this project trying to address? In what context is this project being introduced?

Canadian communities and the electrical utilities that serve them are faced with rapidly evolving challenges in providing clean, reliable and resilient power service. The needs for utilities to reduce greenhouse gas emissions, improve asset efficiency, enhance reliability, enable renewable generation and electric vehicle integration, all while ensuring their systems are cyber-secure and promote economic development and diversification of their local economies is a substantial challenge. These challenges present an opportunity during replacement of aging electricity distribution infrastructure to incorporate emerging technologies and systems using new and innovative financing models that will support meeting or exceeding aggressive carbon reduction goals at Federal and Provincial levels. Our utility is proposing the creation of a community-scale smart grid that covers the entire service territory of PUC Distribution, benefiting our customers with an integrated and intelligent distribution management platform that will allow us to integrate smart energy technologies now and into the future.

Project Summary (150 words maximum)

Provide a brief, high-level summary of this project.

PUC intends to establish a community-scale smart grid in Sault Ste. Marie, Ontario, the Sault Smart Grid (SSG). The innovative SSG is characterized by substantially improved efficiency, reliability, and resilience of the local distribution grid. The project will benefit from its broad impact and integration of complementary smart grid technologies, including; distribution automation (DA), Voltage/VAR management (VVM), and the enhancement of the existing advanced metering infrastructure (AMI). PUC will also engage directly with the community promoting understanding of the benefits of the new low-carbon electricity distribution system. The SSG will be financed under an innovative public-private partnership (P3) strategy that minimizes risk and lowers costs. The project advances reliability and efficiency benefits for customers, provides an enabling platform for renewable energy and smart grid technology applications, and expands customer opportunities to take advantage of enhanced energy services and solutions.

Benefit to Canadians and Stakeholders (150 words maximum)

Describe how this project benefits Canadians and project stakeholders.

The SSG project provides a number of benefits for Canadians and Stakeholders. Electricity customers will see direct savings in their bills due to improved efficiency. The increased reliability and resilience of the new system architecture allows the utility and the province to defer or eliminate certain capital expenditures across the distribution, transmission and generating sectors. The region will benefit from reduced load on the transmission grid through both peak shaving and reduced overall load. The community benefits from increased reliability and enhanced power quality. The utility will be able to offer premium and enhanced energy services to its customers, adding system intelligence on both sides of the meter. Finally, the system will generate new economic opportunities for a Northern community evolving towards a diversified smart energy and information, communications and technology (ICT) economy.

Proposed indicators have been extracted from all six metric areas in the Federal NRCan Smart Grid Program which are included in the summary table below.

SSG Project Volt-Var Management (VVM) and Distribution Automation (DA)

Metrics	Project Title:
GHG Emission Reductions and other Environmental Benefits	**Process indicators-VVM:** Reduced energy losses from GHG emitting supply (kWh); reduced customer energy consumption (kWh) **Impact indicators-VVM:** Tons CO_2e avoided from reduced energy losses and reduced customer consumption **Process indicators-DA:** # of truck rolls avoided; reduced energy losses from GHG emitting supply (kWh), resulting from re-conductoring and phase-balancing **Impact indicators-DA:** Tons CO_2e avoided from reduced vehicle emissions and reduced energy losses
Improved Asset Utilization and Increased Efficiency	**Process indicators-VVM:** Reduced peak demand on utility assets (kW); Reduced need for grid reserve capacity (kW); Increased load factor on certain assets; Reduced energy losses (kWh) **Impact indicators-VVM:** $ savings from deferred system upgrades; $ reduced utility demand charges; $ energy savings to customers **Process indicators-DA:** # of truck rolls avoided (vehicle miles); reduced overtime (OT hours); # of customer minutes with outages avoided (minutes) **Impact indicators-DA:** O&M savings due to reduced truck rolls and overtime;
Increased Reliability and Resiliency	**Process indicators-VVM:** None **Impact indicators-VVM:** None **Process indicators-DA:** # of events Fault Location, Isolation and Restoration responded to; # customer calls/complaints avoided due to fewer outages **Impact indicators-DA:** $ revenue loss avoided from outages avoided; customer average interruption duration index (CAIDI) for customers served by the project; customer minute interruptions avoided
Increased System Flexibility and Renewable Energy Penetration	**Process indicators-VVM:** # of feeders with VVM installed and operational **Impact indicators-VVM:** # of voltage actions taken annually to improve grid efficiency and mitigate renewable intermittency

	Process indicators-DA: # of feeders integrated into Fault Location, Isolation and Restoration (FLIR) system **Impact indicators-DA:** % of feeders with automation
Cyber Security	**Process indicators-VVM:** Best practices developed or applied on system communications with AMI (qualitative indicator) **Impact indicators-VVM:** Real-time issue identification and reaction to cyber security threats **Process indicators-DA:** best practices developed or adhered to **Impact indicators-DA:** real-time issue identification and reaction to cyber security threats
Economic and Social Benefits	**Process indicators-VVM:** # jobs to implement system and highly qualified personnel trained, business case established/documented for VVM (Project) **Impact indicators-VVM:** Reduced customer charges due to improved (flatter, lower) voltage profile across the feeder (project); reduced customer charges or off-set increases to customer charges due to the lower demand charges and energy saved at the system level **Process indicators-DA:** # jobs to implement system and created to monitor the system; # customer jobs created due to higher reliability/resiliency **Impact indicators-DA:** $ customer value (e.g. avoided revenue loss) from avoided outages

Appendix B
Minister's Directive Regarding Smart Grid

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 C
Leidos Preliminary Design Reports

1. Utility Distribution Microgrid: Volt/VAR Management (VVM)

2. Utility Distribution Microgrid: Distribution Automation

3. Utility Distribution Microgrid: AMI Integration

Leidos Engineering, LLC

Utility Distribution Microgrid: Volt/VAR Management (VVM)

Preliminary Design

Energizing Co.

PUC Distribution, Sault Ste. Marie, ON

Leidos
10/17/2014

Contents

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.

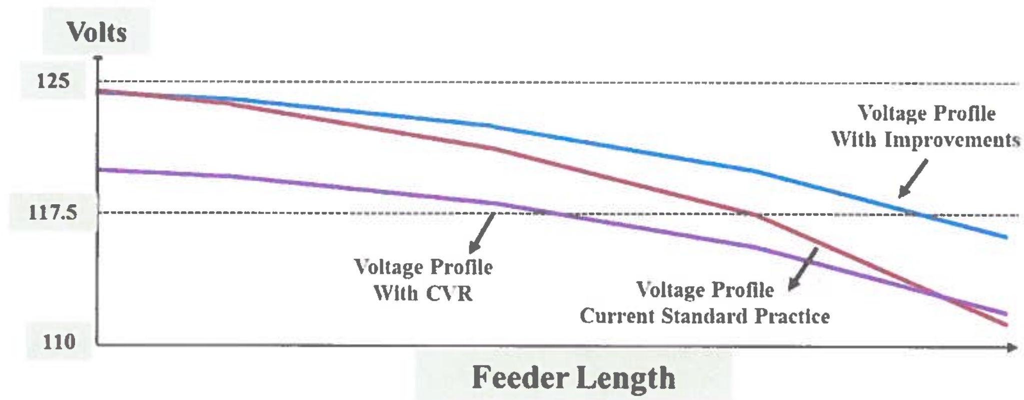


Figure 1. Distribution Voltage Profile

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.

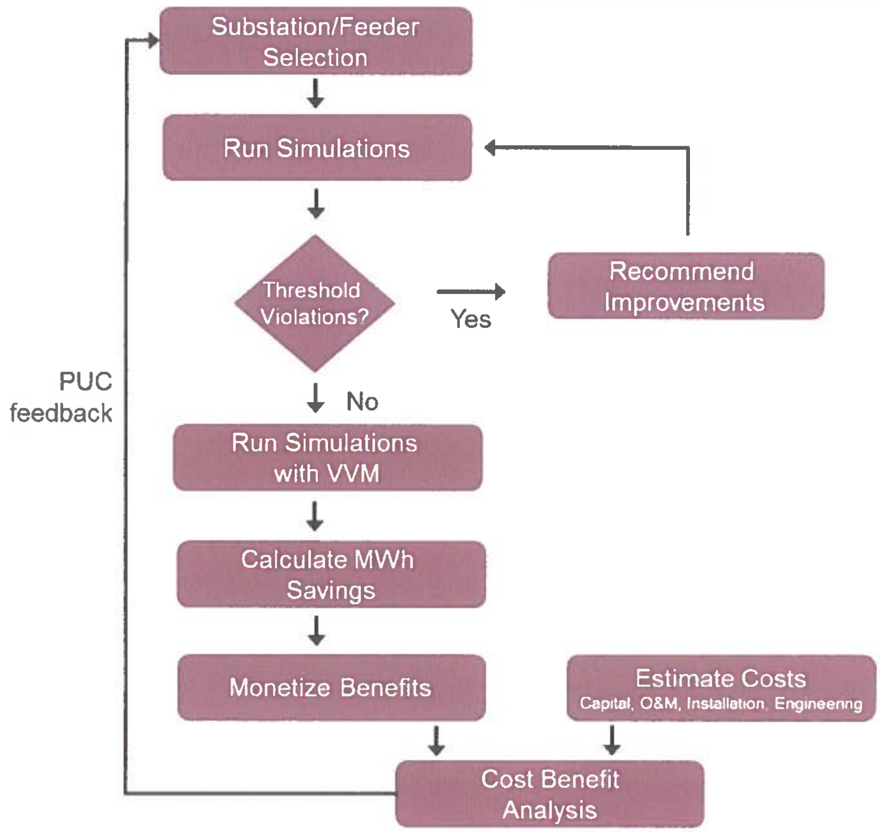


Figure 2. VVM Design Methodology

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.

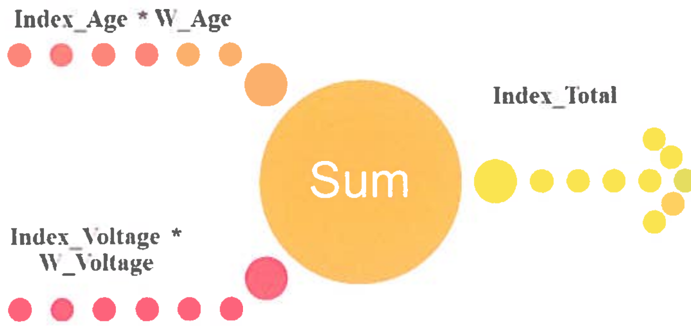


Figure 3. Indexing Mechanism to Rank Substation Transformers for VVM

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*.

leidos

% 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.

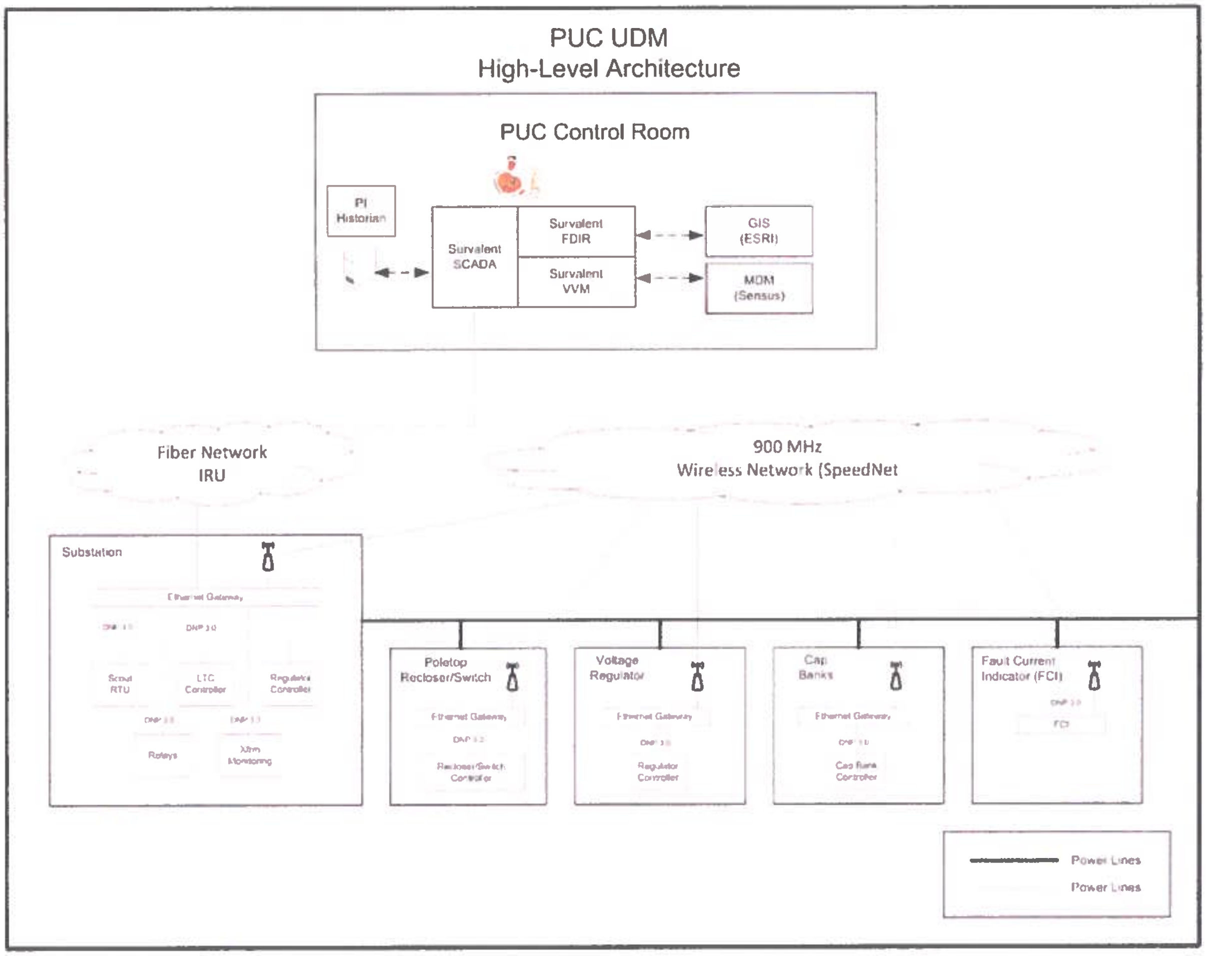


Figure 7. UDM System Architecture

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.

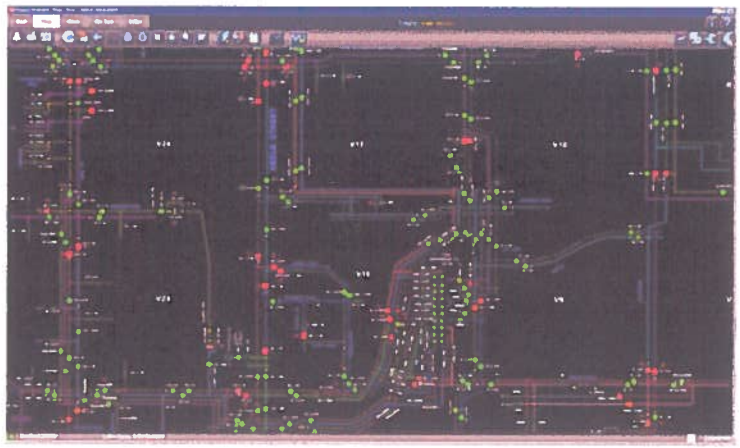


Figure 8. VVM Software

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.

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 Rephasing: Section ID: OH66911 from A to C	None	Install 200kVAR/phase fixed cap bank at 25293_	Rephasing: Section ID: OH8252 from C to A 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 Feeder	Sub2-T4 2-13	Sub2-T3 2-14	Sub2-T3 2-15	Sub2-T3 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: 26579_ from A to B	Rephasing: Section ID: 34876_ from C to A Rephasing: Section ID: 34784_ from C to B

Figure 14: Substation 2 VVM Benefits and Feeder Improvements

	Substation Transformer / Feeder	Sub18-T1 18-01	Sub18-T1 18-01R	Sub18-T1 18-02	Sub18-T2 18-03	Sub18-T2 18-04	Sub18-T2 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 Feeder	Sub20-T1 20-01	Sub20-T1 20-02	Sub20-T2 20-03	Sub20-T2 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

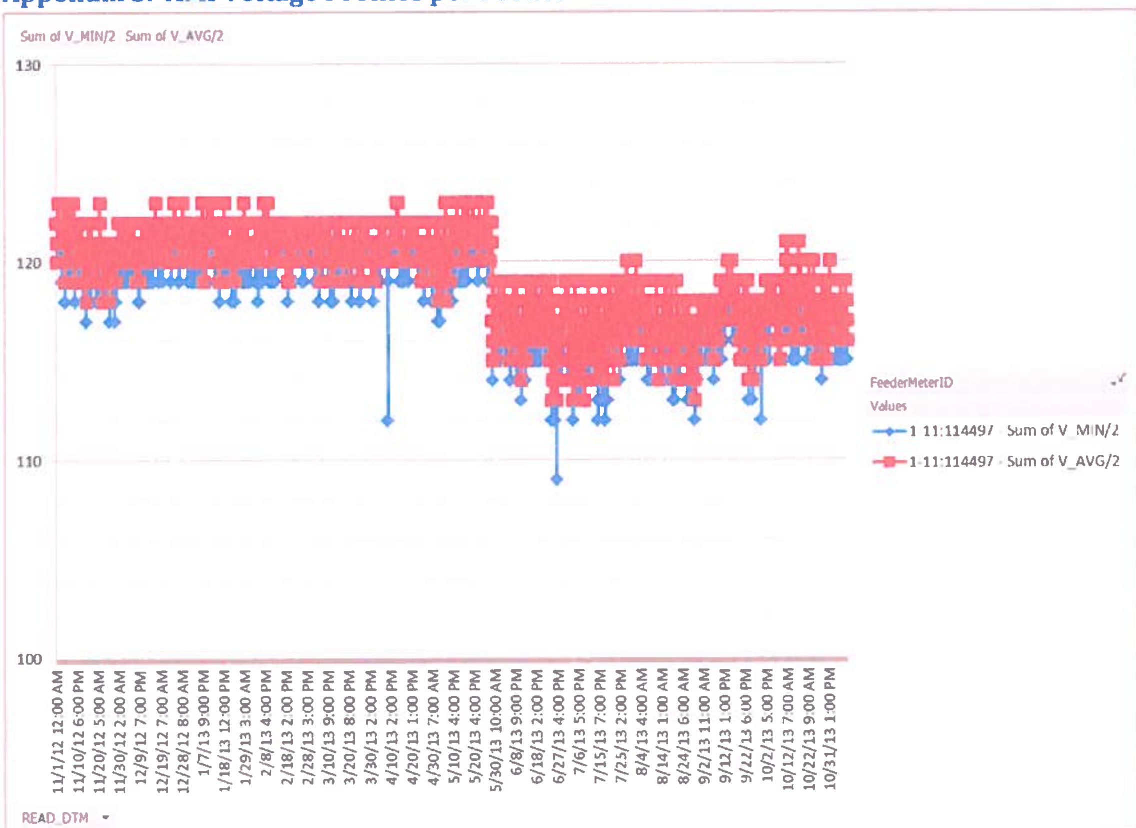
Volt/VAR Management (VVM) scope includes designing, procuring, installing and commissioning a Volt/VAR control scheme on PUC's 12.5 kV distribution system. The proposed system will be installed at 8 substations. The scope in these substations include four substation rebuilds at Subs 11, 16, 20 and 1 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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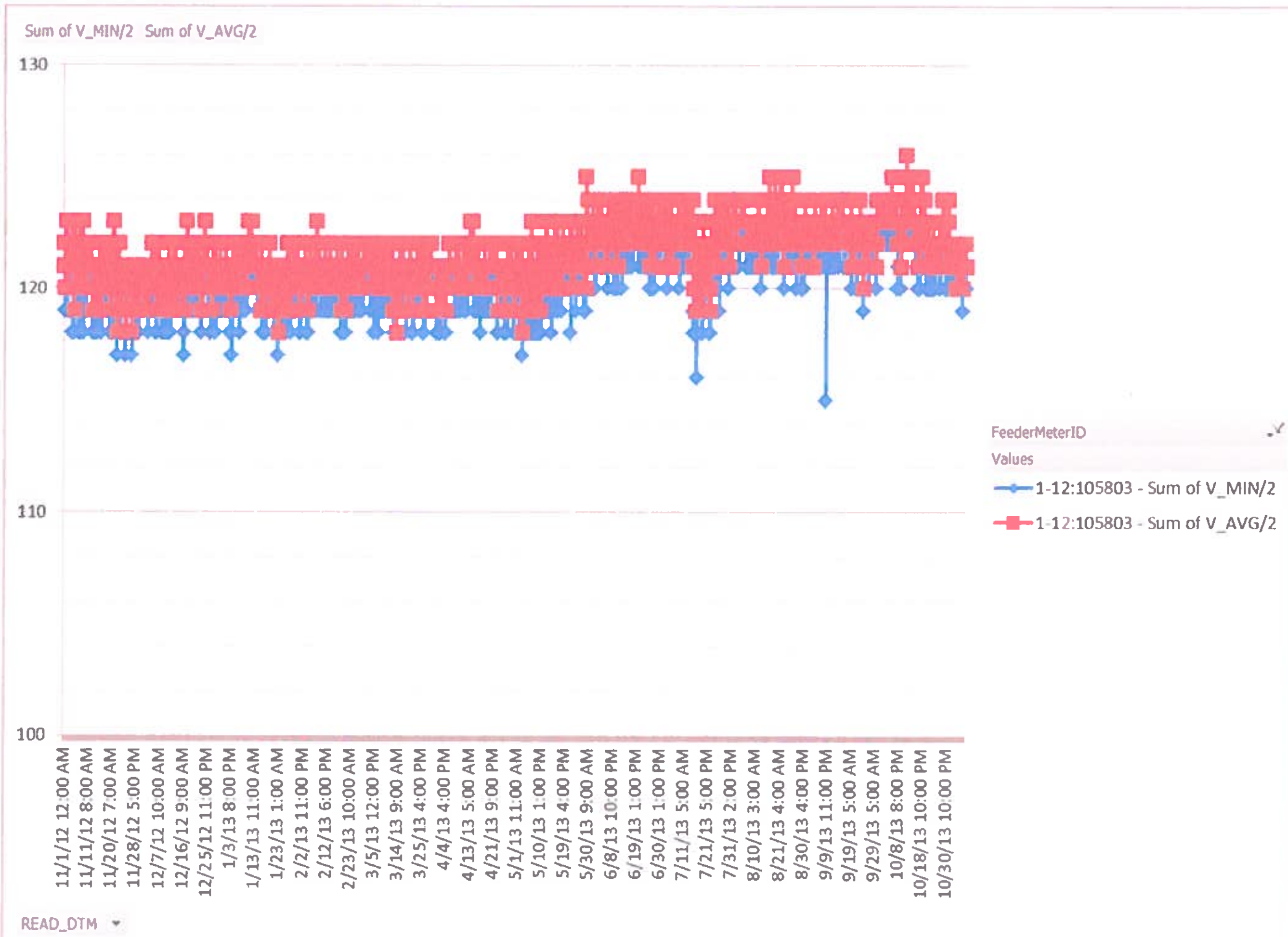
Sum of V_MIN/2
Sum of V_AVG/2
130
120
110
100
11/1/12 12:00 AM
11/11/12 8:00 AM
11/20/12 7:00 AM
11/28/12 5:00 PM
12/7/12 10:00 AM
12/16/12 9:00 AM
12/25/12 11:00 PM
1/3/13 8:00 PM
1/13/13 11:00 AM
1/23/13 1:00 AM
2/2/13 11:00 PM
2/12/13 6:00 PM
2/23/13 10:00 AM
3/5/13 12:00 PM
3/14/13 9:00 AM
3/25/13 4:00 PM
4/4/13 4:00 PM
4/13/13 5:00 AM
4/21/13 9:00 PM
5/1/13 11:00 AM
5/10/13 1:00 PM
5/19/13 4:00 PM
5/30/13 9:00 AM
6/8/13 10:00 PM
6/19/13 1:00 PM
6/30/13 1:00 PM
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7/21/13 5:00 PM
7/31/13 2:00 PM
8/10/13 3:00 AM
8/21/13 4:00 AM
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9/29/13 5:00 AM
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10/18/13 10:00 PM
10/30/13 10:00 PM
READ_DTM
FeederMeterID
Values
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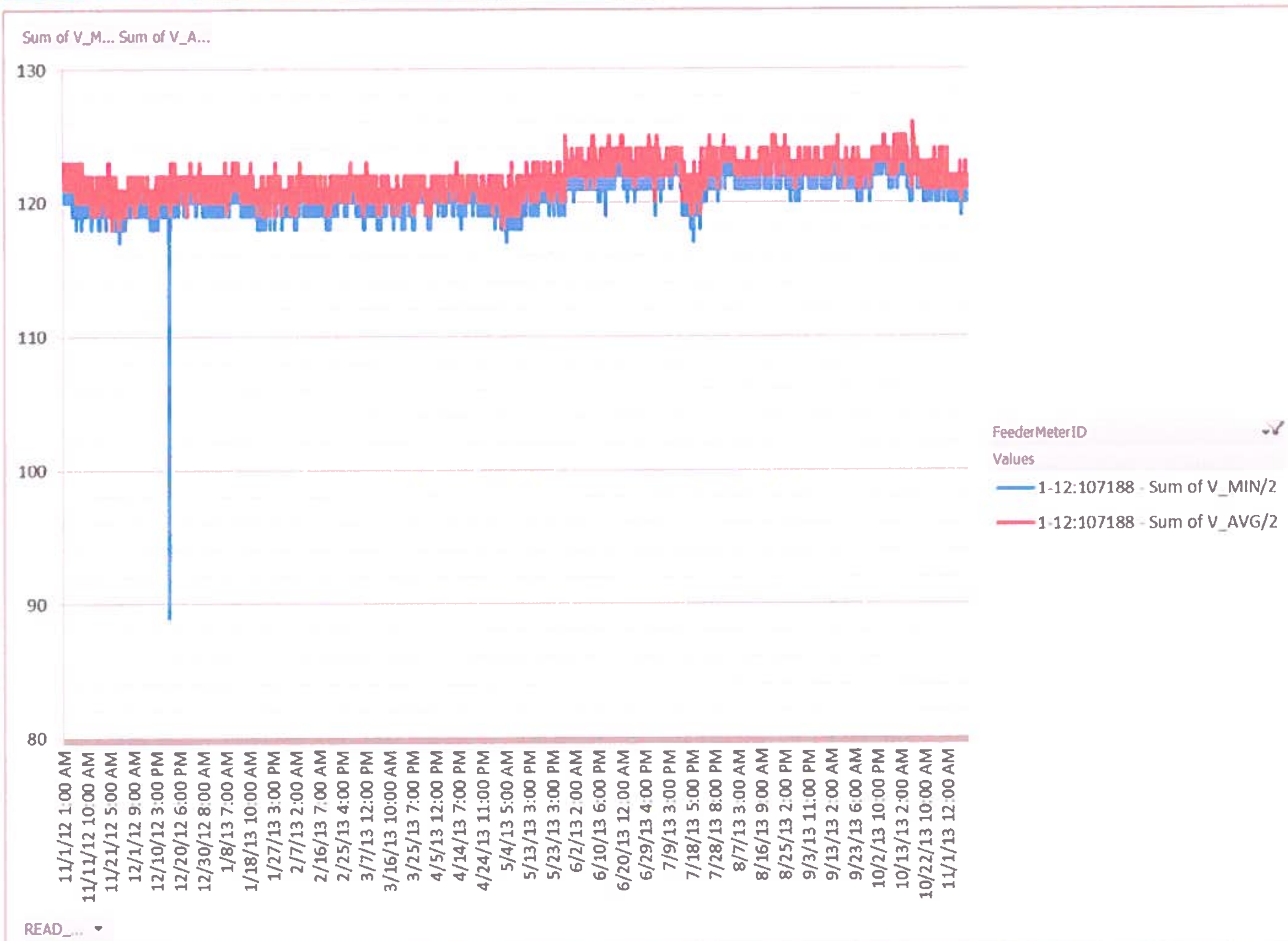
1-12:105803 - Sum of V_AVG/2



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/11/12 10:00 AM
11/21/12 5:00 AM
12/1/12 9:00 AM
12/10/12 3:00 PM
12/20/12 6:00 PM
12/30/12 8:00 AM
1/8/13 7:00 AM
1/18/13 10:00 AM
1/27/13 3:00 PM
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2/16/13 7:00 AM
2/25/13 4:00 PM
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8/16/13 9:00 AM
8/25/13 2:00 PM
9/3/13 11:00 PM
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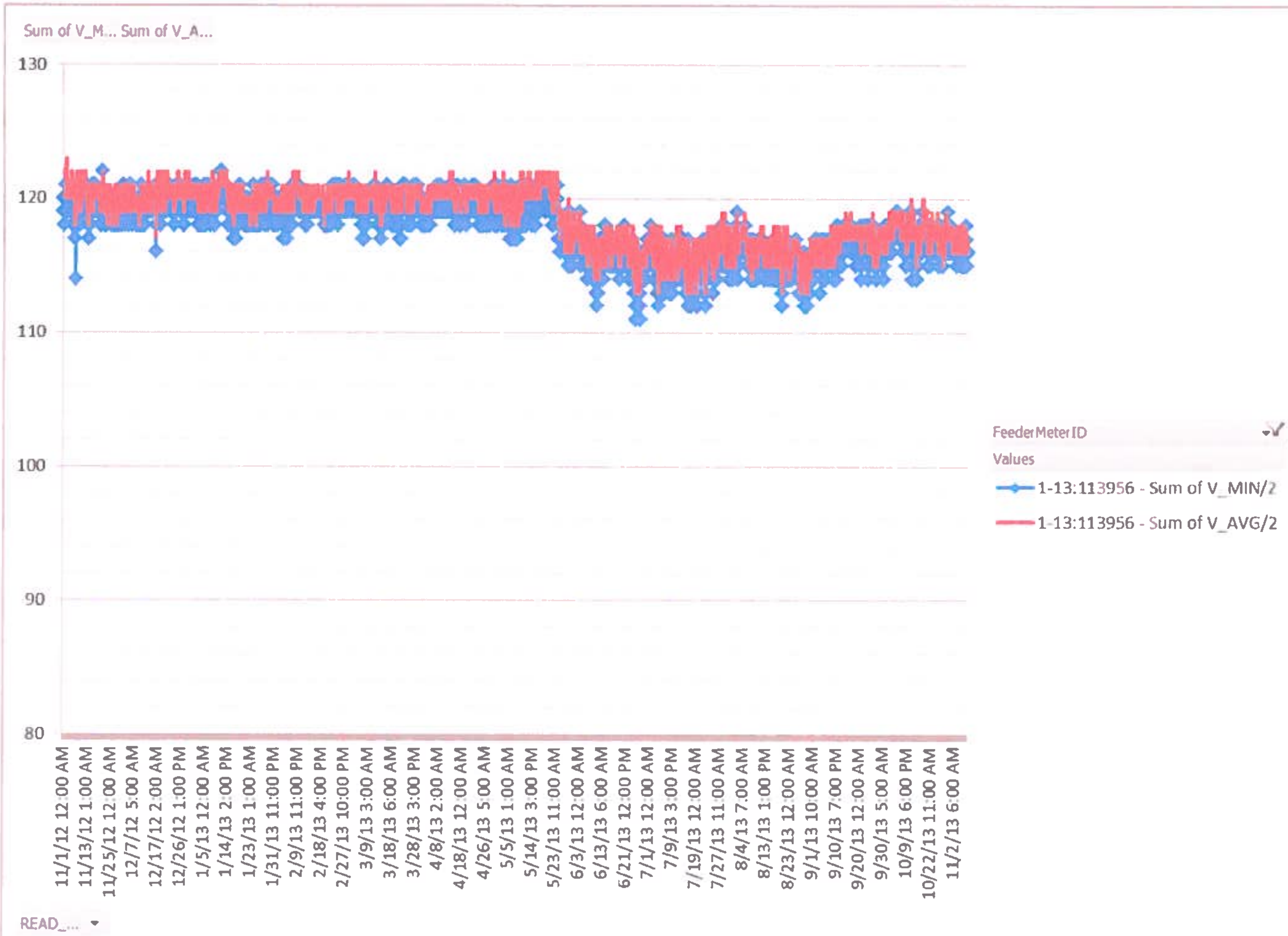
9/23/13 6:00 AM
10/2/13 10:00 PM
10/13/13 2:00 AM
10/22/13 10:00 AM
11/1/13 12:00 AM
READ_...
FeederMeterID
Values
1-12:107188 - Sum of V_MIN/2
1-12:107188 - Sum of V_AVG/2

leidos



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/13/12 1:00 AM
11/25/12 12:00 AM
12/7/12 5:00 AM
12/17/12 2:00 AM
12/26/12 1:00 PM
1/5/13 12:00 AM
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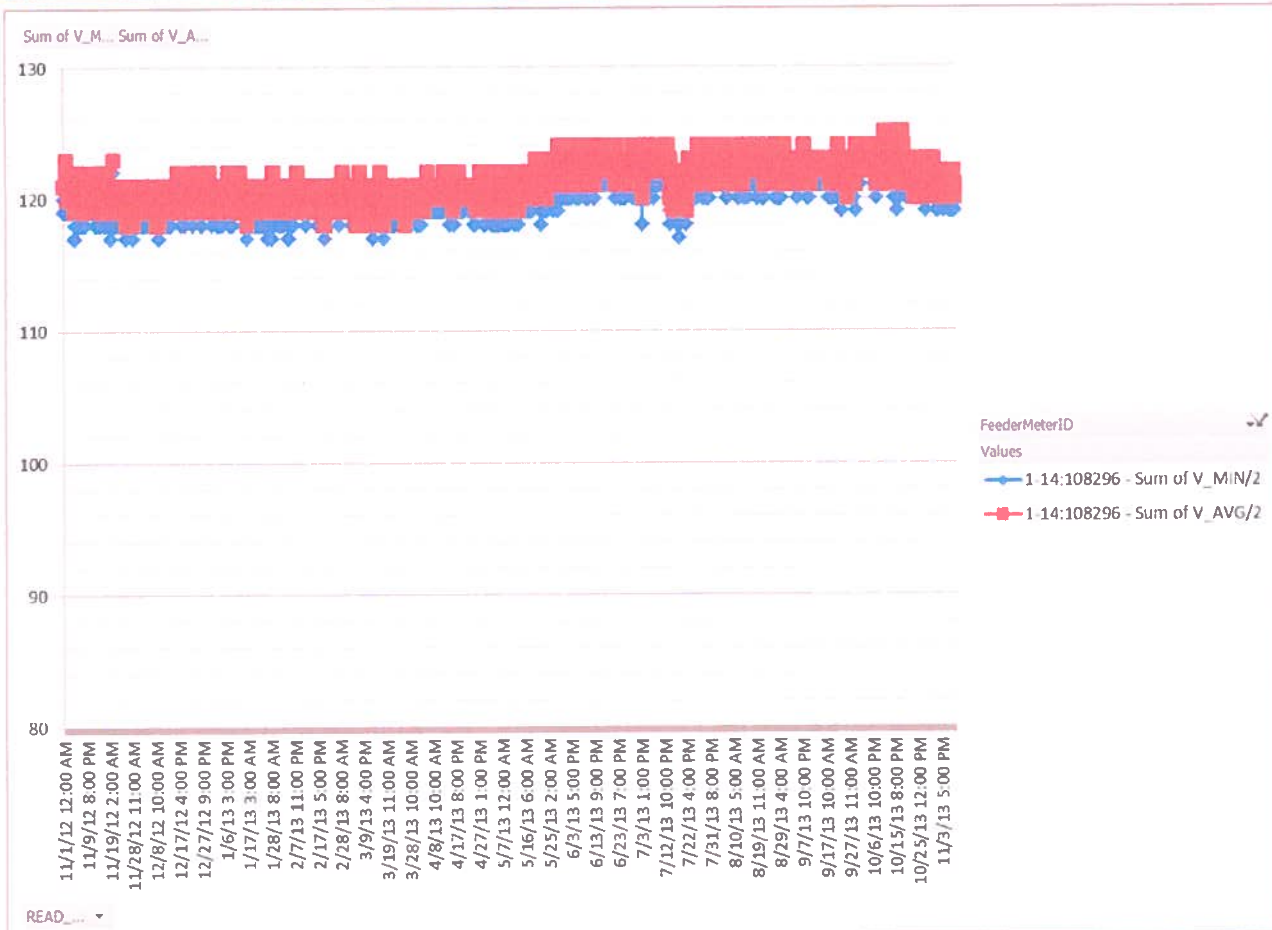
8/13/13 1:00 PM
8/23/13 12:00 AM
9/1/13 10:00 AM
9/10/13 7:00 PM
9/20/13 12:00 AM
9/30/13 5:00 AM
10/9/13 6:00 PM
10/22/13 11:00 AM
11/2/13 6:00 AM
READ_...
FeederMeterID
Values
1-13:113956 - Sum of V_MIN/2
1-13:113956 - Sum of V_AVG/2


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/9/12 8:00 PM
11/19/12 2:00 AM
11/28/12 11:00 AM
12/8/12 10:00 AM
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9/27/13 11:00 AM
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10/15/13 8:00 PM
10/25/13 12:00 PM
11/3/13 5:00 PM
READ_...
FeederMeterID
Values
1-14:108296 - Sum of V_MIN/2
1-14:108296 - Sum of V_AVG/2

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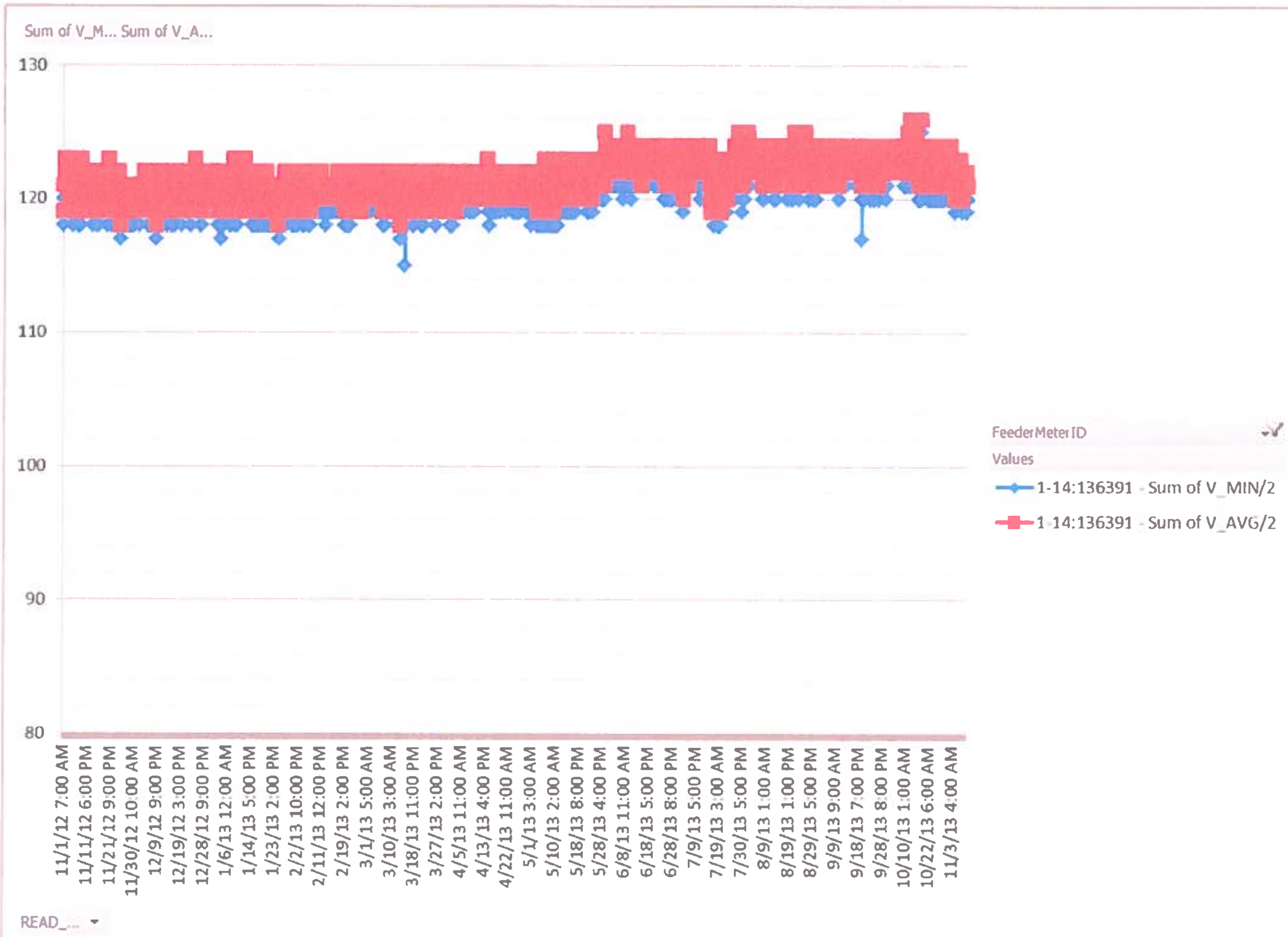

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 7:00 AM
11/11/12 6:00 PM
11/21/12 9:00 PM
11/30/12 10:00 AM
12/9/12 9:00 PM
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10/10/13 1:00 AM
10/22/13 6:00 AM
11/3/13 4:00 AM
READ_...
FeederMeterID
Values
1-14:136391 - Sum of V_MIN/2
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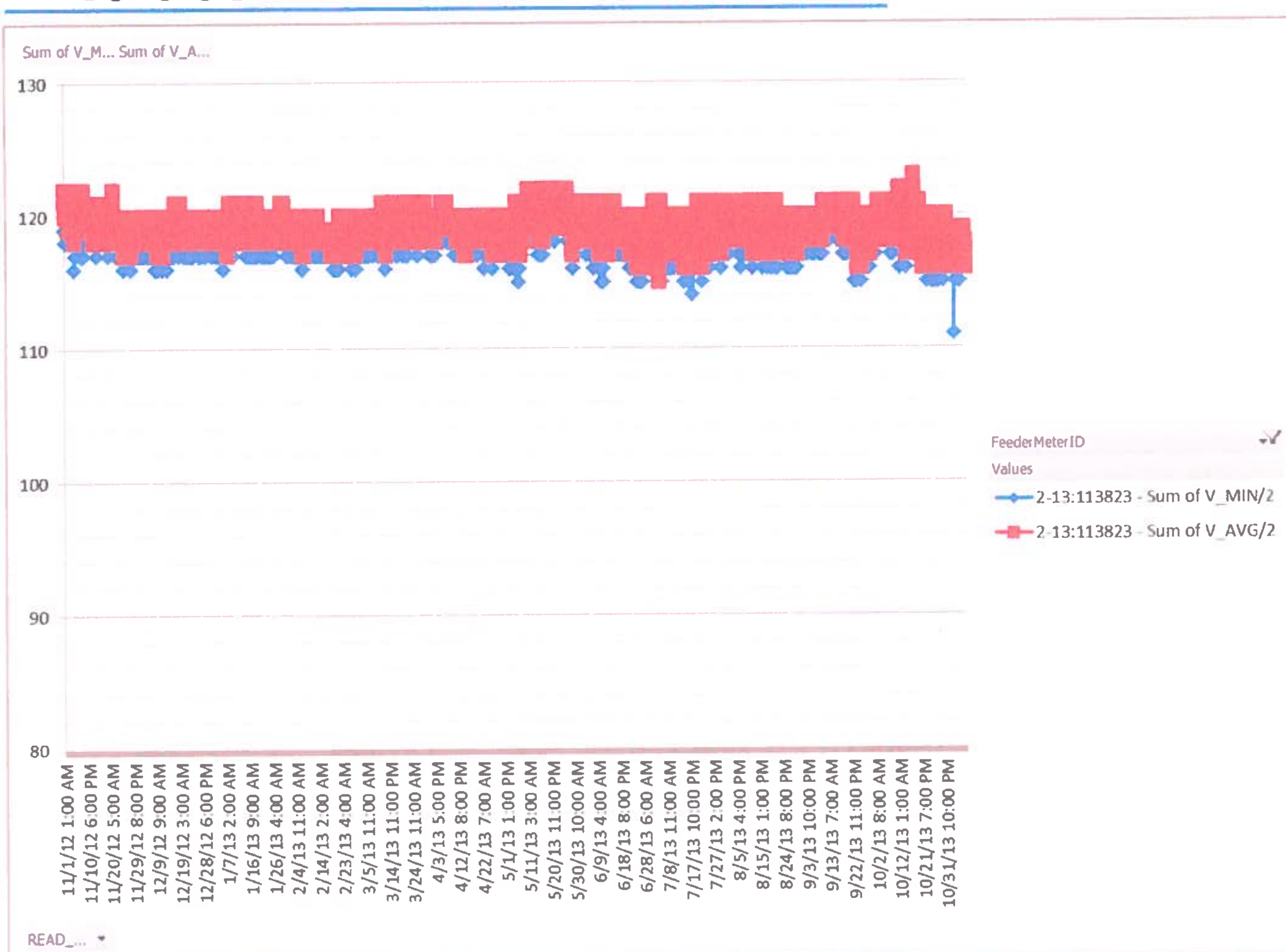

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
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11/20/12 5:00 AM
11/29/12 8:00 PM
12/9/12 9:00 AM
12/19/12 3:00 AM
12/28/12 6:00 PM
1/7/13 2:00 AM
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9/22/13 11:00 PM
10/2/13 8:00 AM
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10/21/13 7:00 PM
10/31/13 10:00 PM
FeederMeterID
Values
2-13:113823 - Sum of V_MIN/2
2-13:113823 - Sum of V_AVG/2
READ_...

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/10/12 11:00 AM
11/20/12 12:00 AM
11/29/12 7:00 AM
12/8/12 1:00 PM
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10/13/13 7:00 AM
10/22/13 6:00 PM
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FeederMeterID
Values
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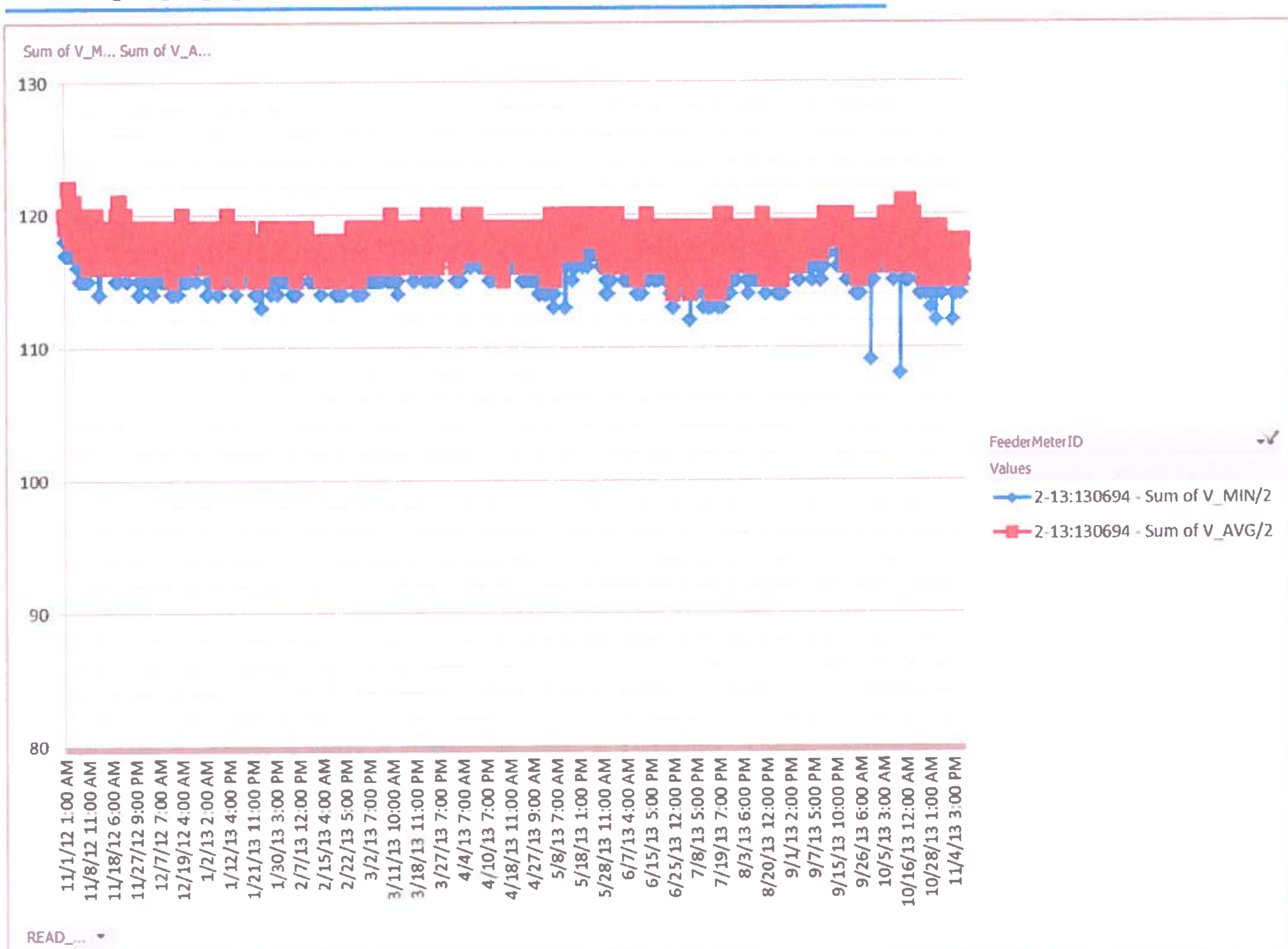
2-13:128933 - Sum of V_AVG/2
READ_...



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/8/12 11:00 AM
11/18/12 6:00 AM
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9/7/13 5:00 PM
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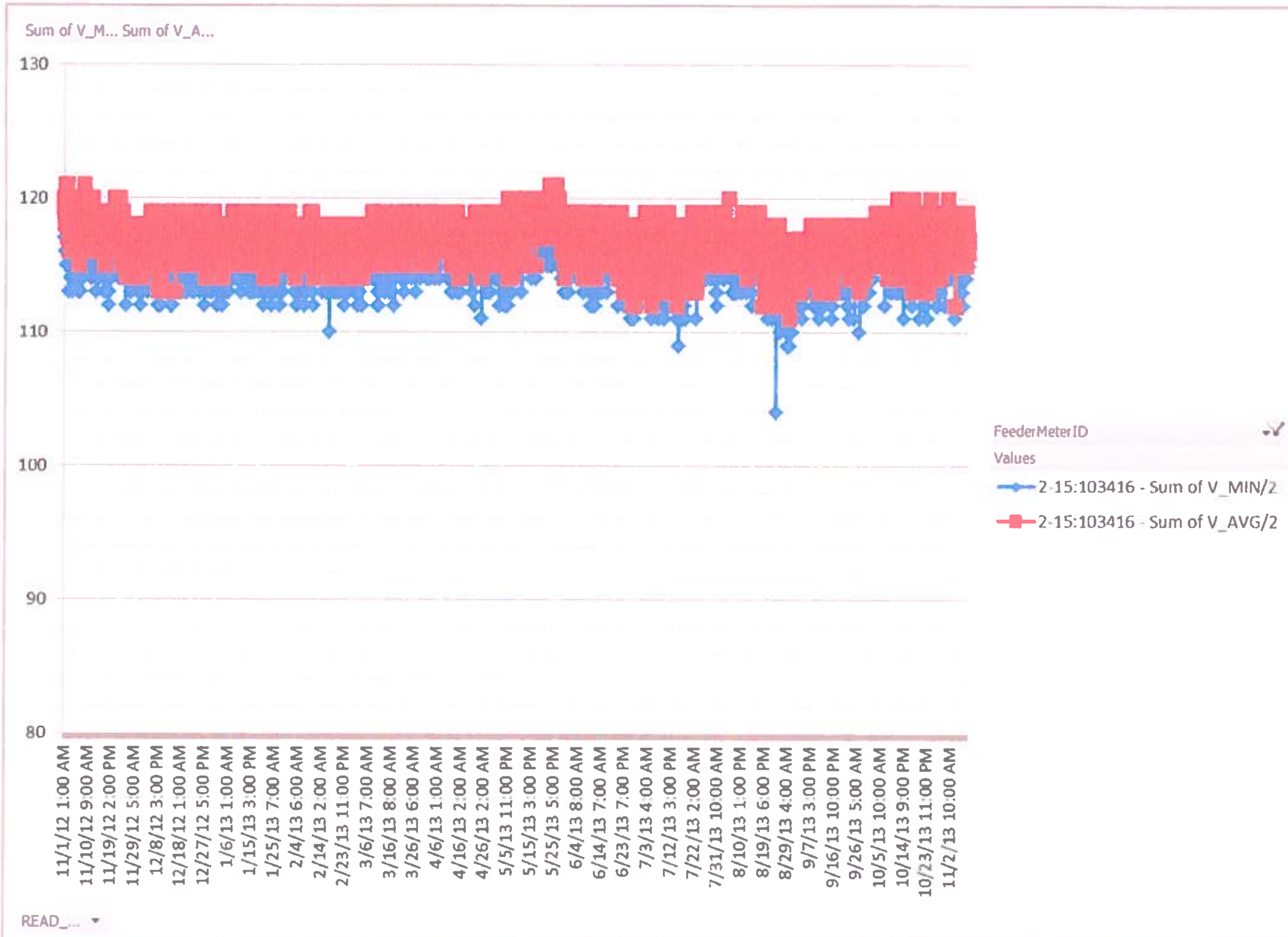
10/5/13 3:00 AM
10/16/13 12:00 AM
10/28/13 1:00 AM
11/4/13 3:00 PM
READ_...
FeederMeterID
Values
2-13:130694 - Sum of V_MIN/2
2-13:130694 - Sum of V_AVG/2


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/10/12 9:00 AM
11/19/12 2:00 PM
11/29/12 5:00 AM
12/8/12 3:00 PM
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9/26/13 5:00 AM
10/5/13 10:00 AM
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10/23/13 11:00 PM
11/2/13 10:00 AM
READ_...
FeederMeterID
Values
2-15:103416 - Sum of V_MIN/2
2-15:103416 - Sum of V_AVG/2

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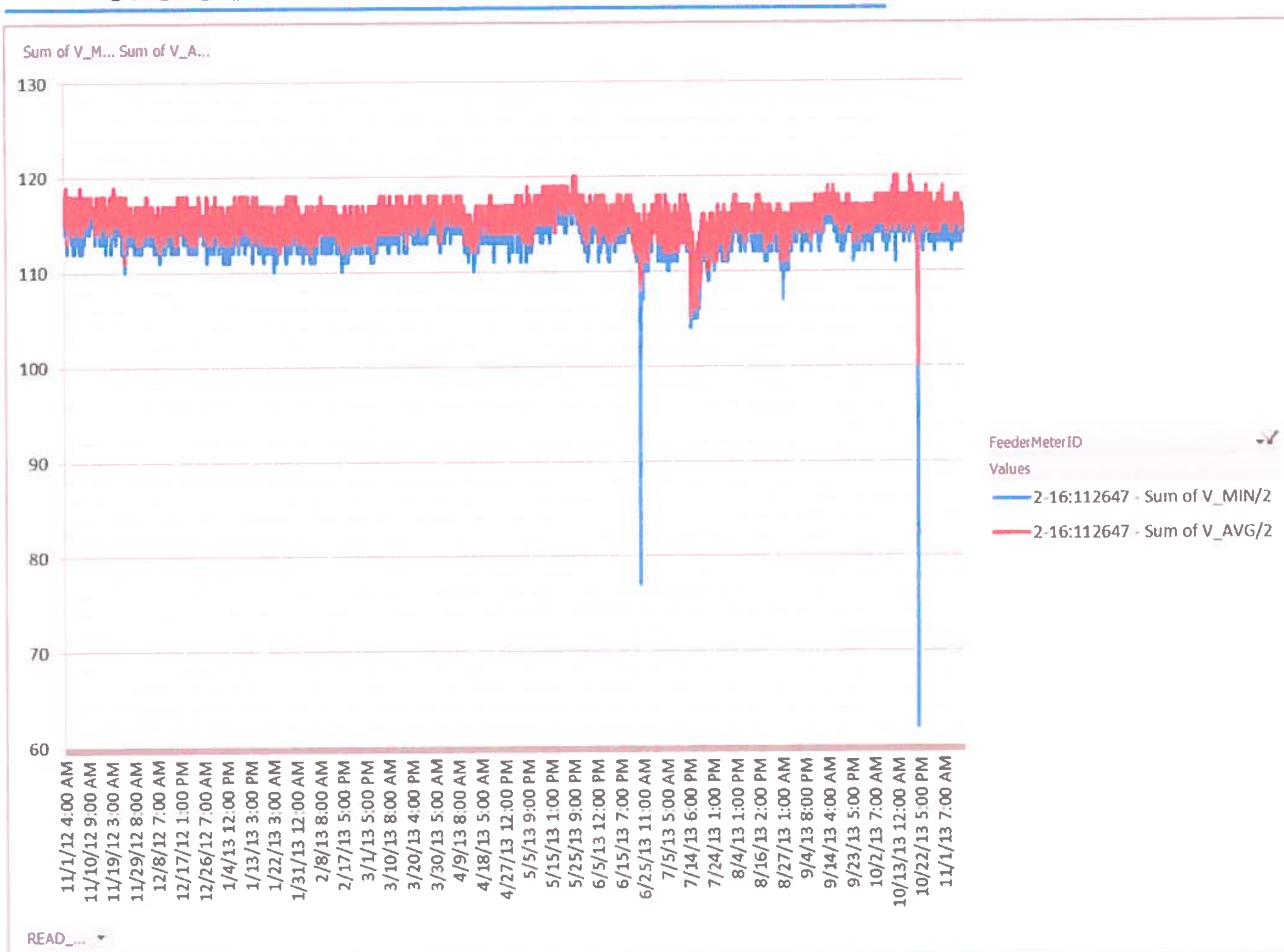

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
70
60
11/1/12 4:00 AM
11/10/12 9:00 AM
11/19/12 3:00 AM
11/29/12 8:00 AM
12/8/12 7:00 AM
12/17/12 1:00 PM
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10/2/13 7:00 AM
10/13/13 12:00 AM
10/22/13 5:00 PM
11/1/13 7:00 AM
READ_...
FeederMeterID
Values
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2-16:112647 - Sum of V_AVG/2

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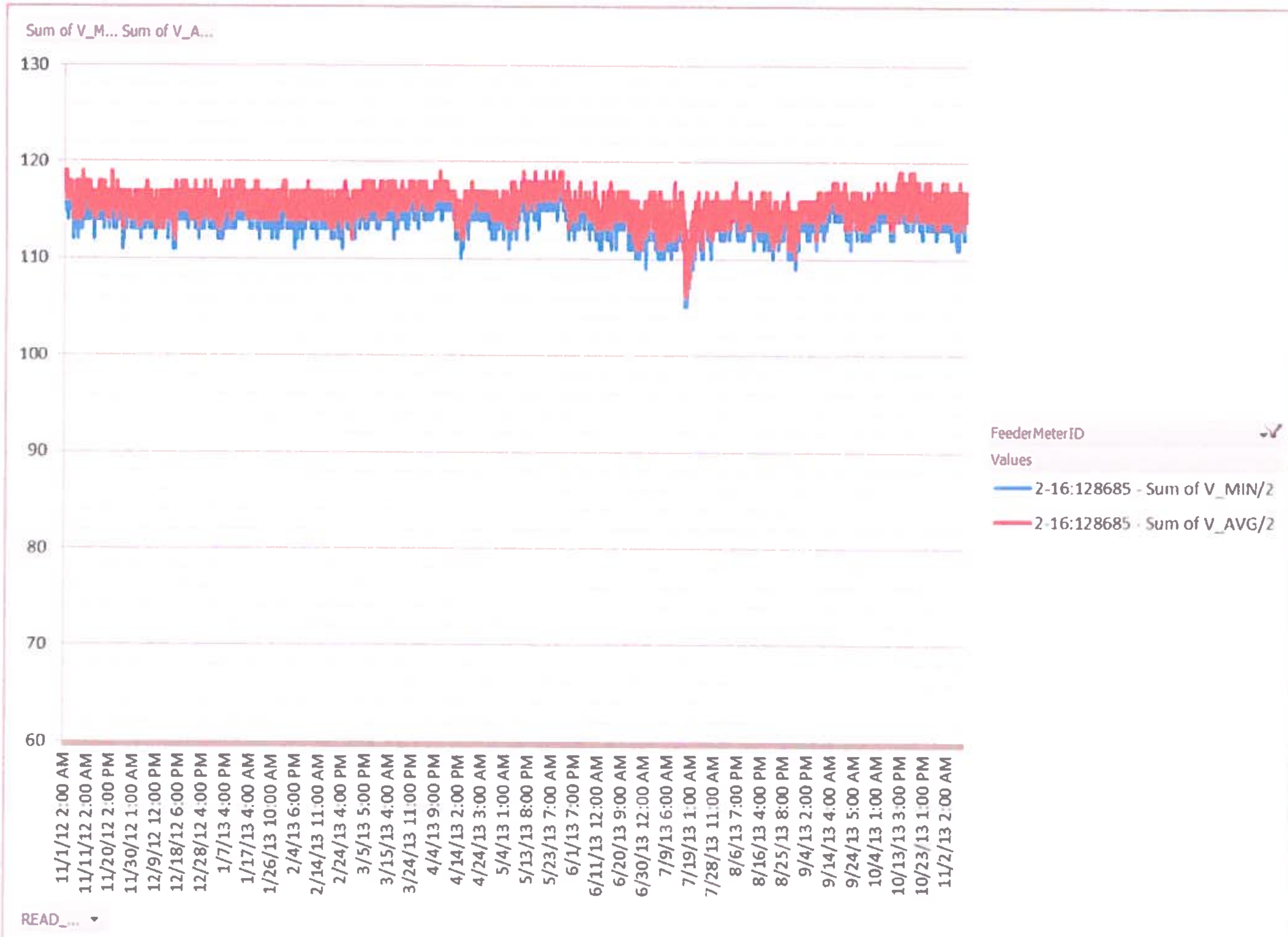

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
70
60
11/1/12 2:00 AM
11/11/12 2:00 AM
11/20/12 2:00 PM
11/30/12 1:00 AM
12/9/12 12:00 PM
12/18/12 6:00 PM
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10/4/13 1:00 AM
10/13/13 3:00 PM
10/23/13 1:00 PM
11/2/13 2:00 AM
READ_...
FeederMeterID
Values
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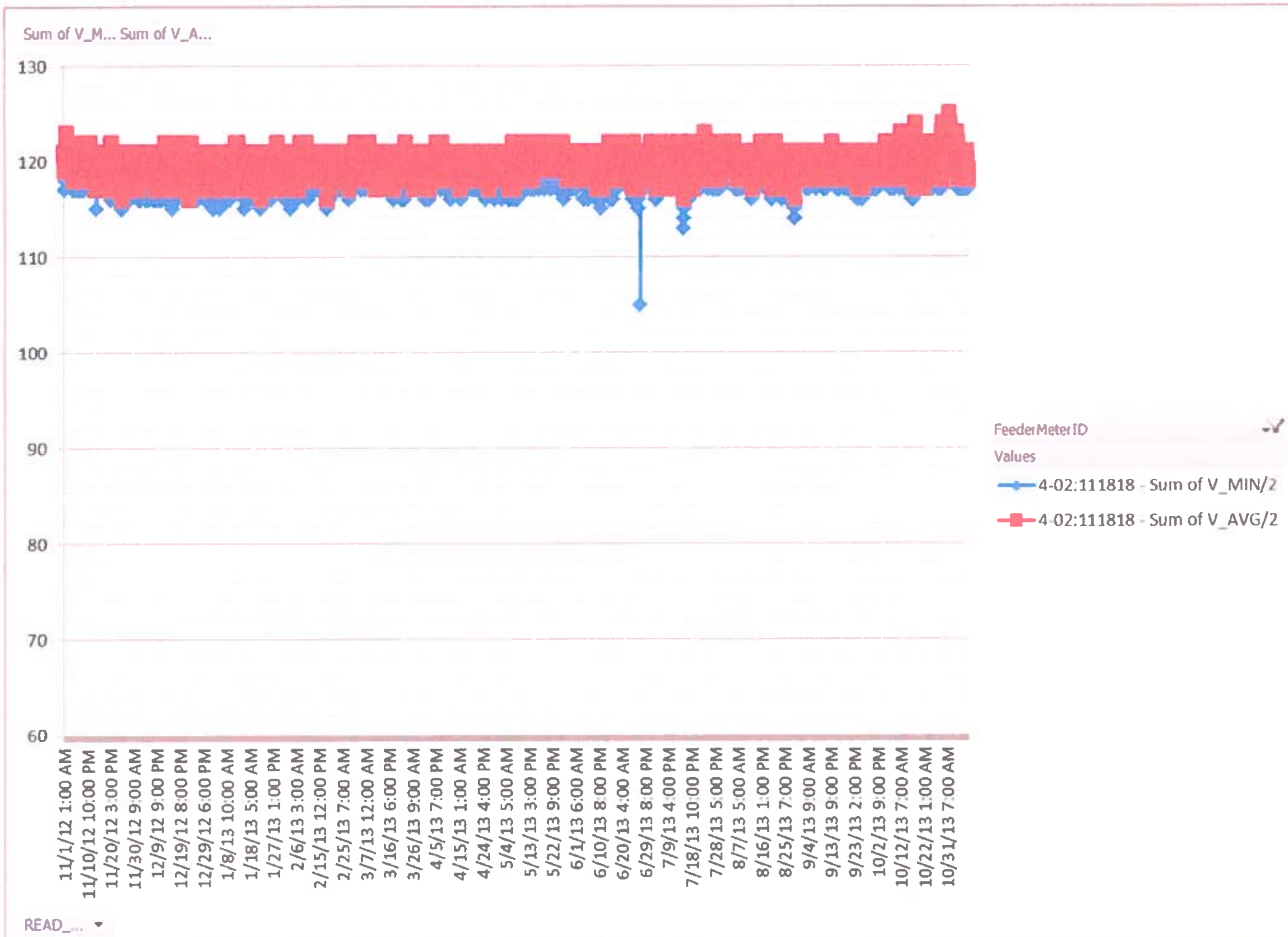
2-16:128685 - Sum of V_AVG/2


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
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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


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
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FeederMeterID
Values
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4-02:128413 - Sum of V_AVG/2
READ_...

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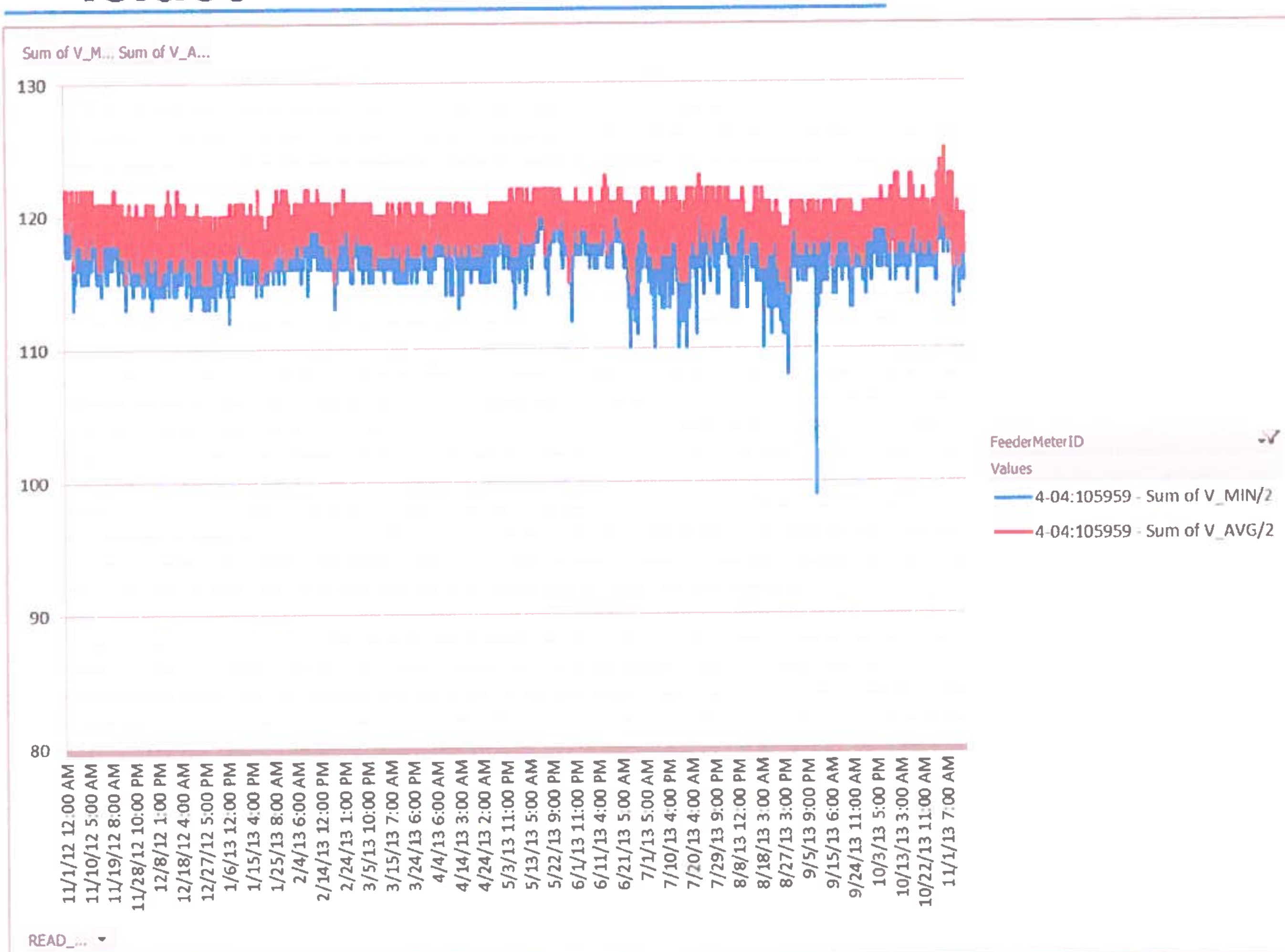

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 5:00 AM
11/19/12 8:00 AM
11/28/12 10:00 PM
12/8/12 1:00 PM
12/18/12 4:00 AM
12/27/12 5:00 PM
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8/27/13 3:00 PM
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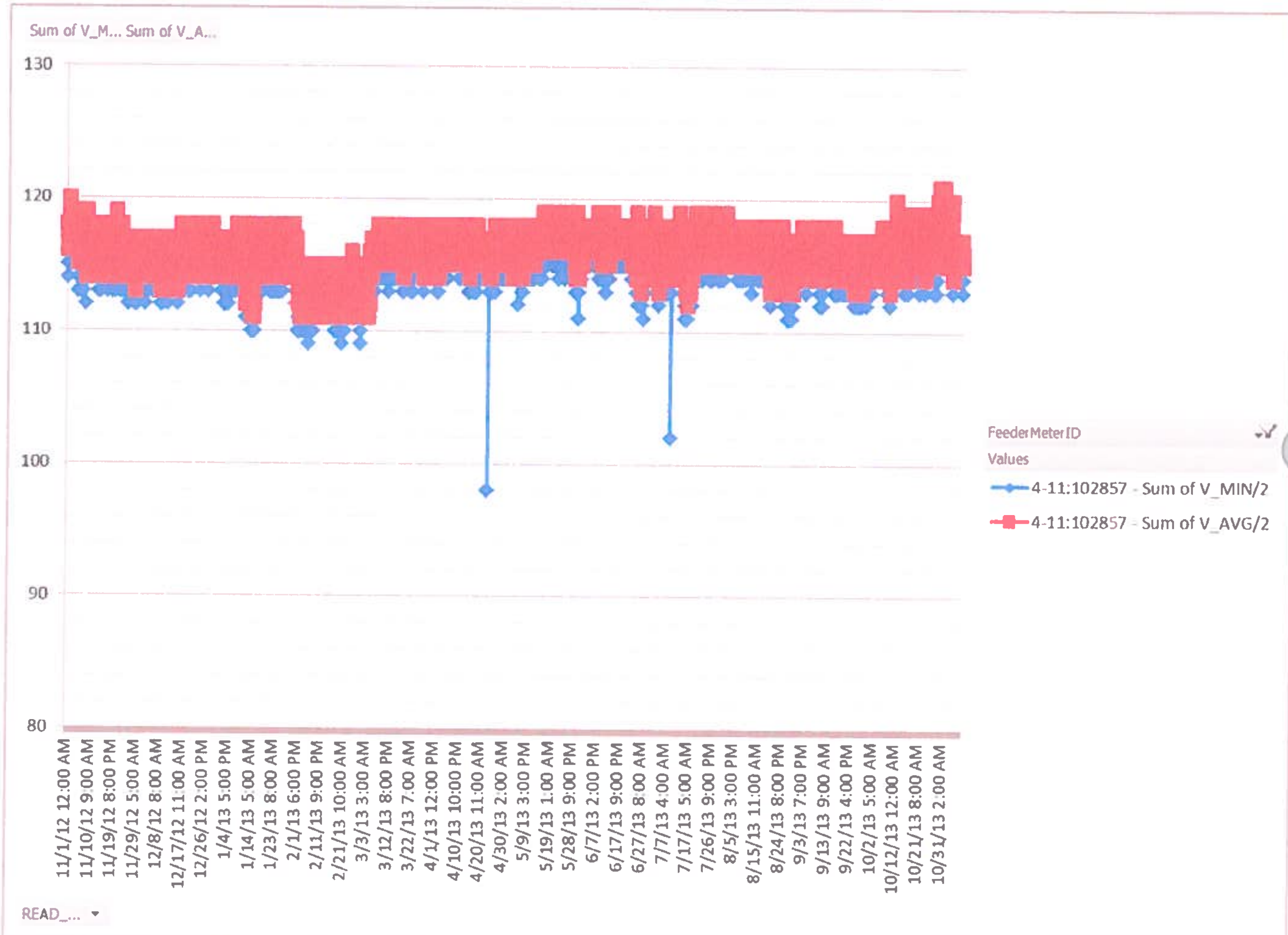
10/3/13 5:00 PM
10/13/13 3:00 AM
10/22/13 11:00 AM
11/1/13 7:00 AM
READ_...
FeederMeterID
Values
4-04:105959 - Sum of V_MIN/2
4-04:105959 - Sum of V_AVG/2

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
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5/28/13 9:00 PM
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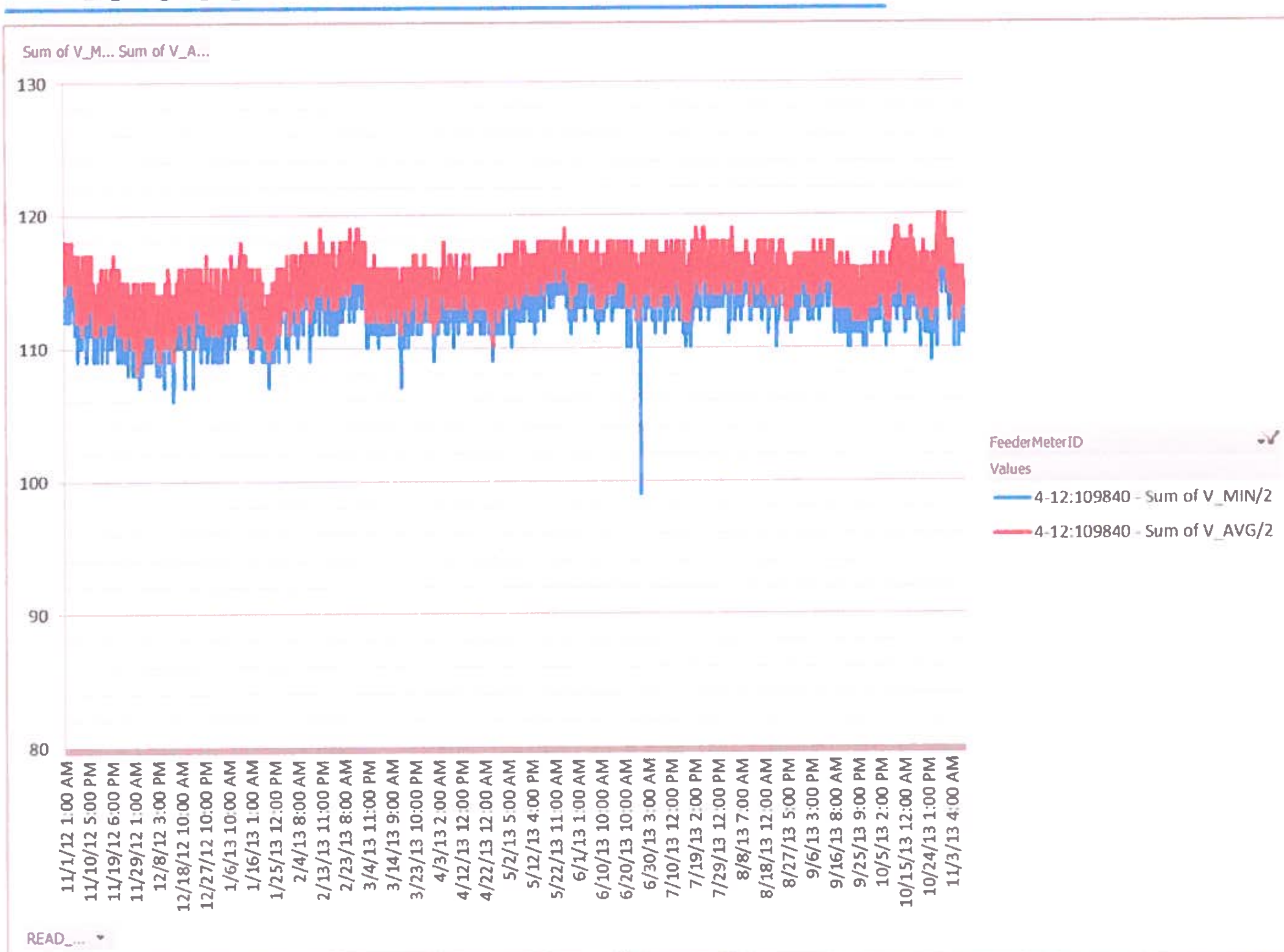
7/17/13 5:00 AM
7/26/13 9:00 PM
8/5/13 3:00 PM
8/15/13 11:00 AM
8/24/13 8:00 PM
9/3/13 7:00 PM
9/13/13 9:00 AM
9/22/13 4:00 PM
10/2/13 5:00 AM
10/12/13 12:00 AM
10/21/13 8:00 AM
10/31/13 2:00 AM
FeederMeterID
Values
4-11:102857 - Sum of V_MIN/2
4-11:102857 - Sum of V_AVG/2
READ_...



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
FeederMeterID
Values
4-12:109840 - Sum of V_MIN/2
4-12:109840 - Sum of V_AVG/2
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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
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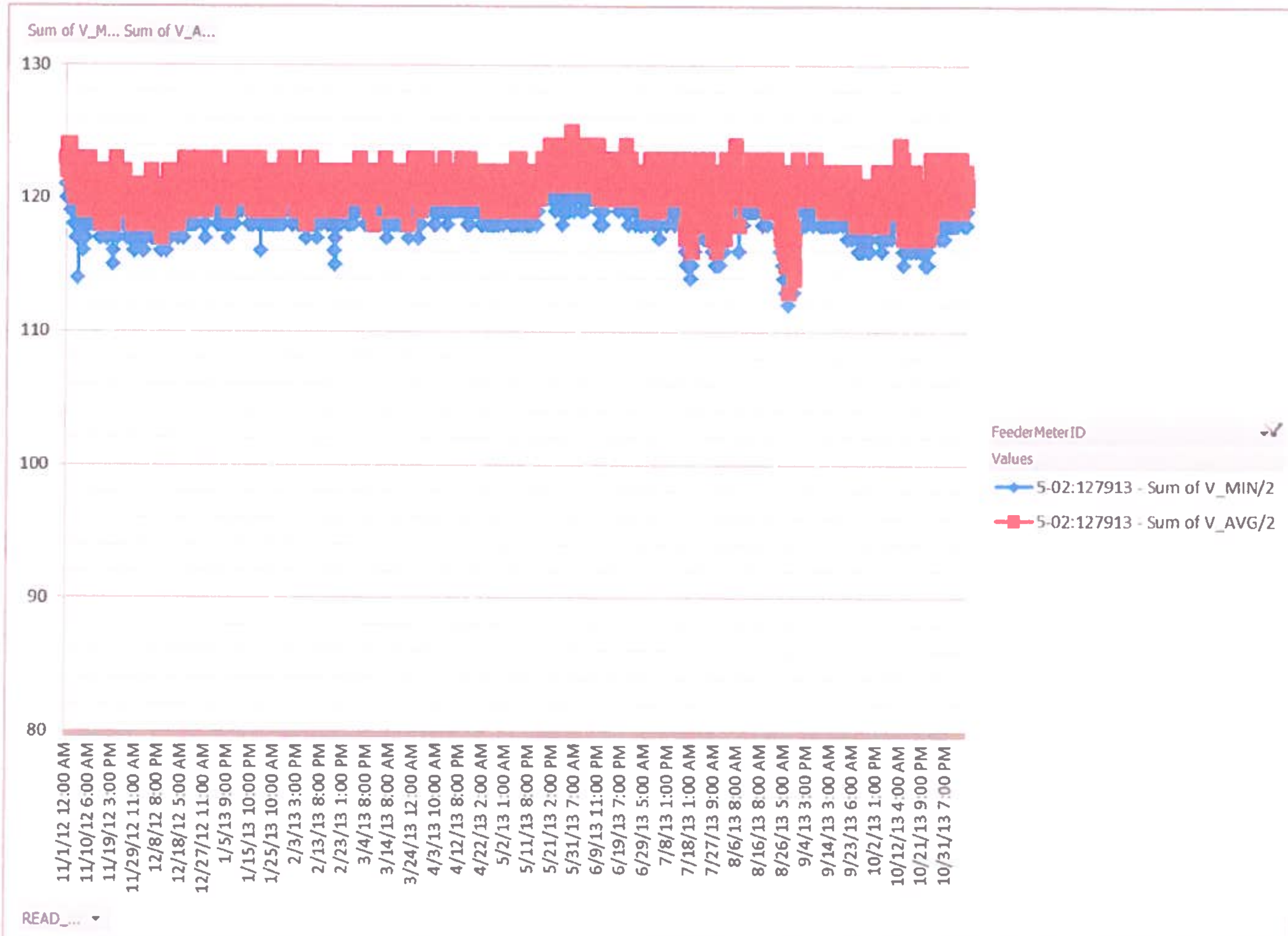
11/3/13 4:00 AM
READ_...


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
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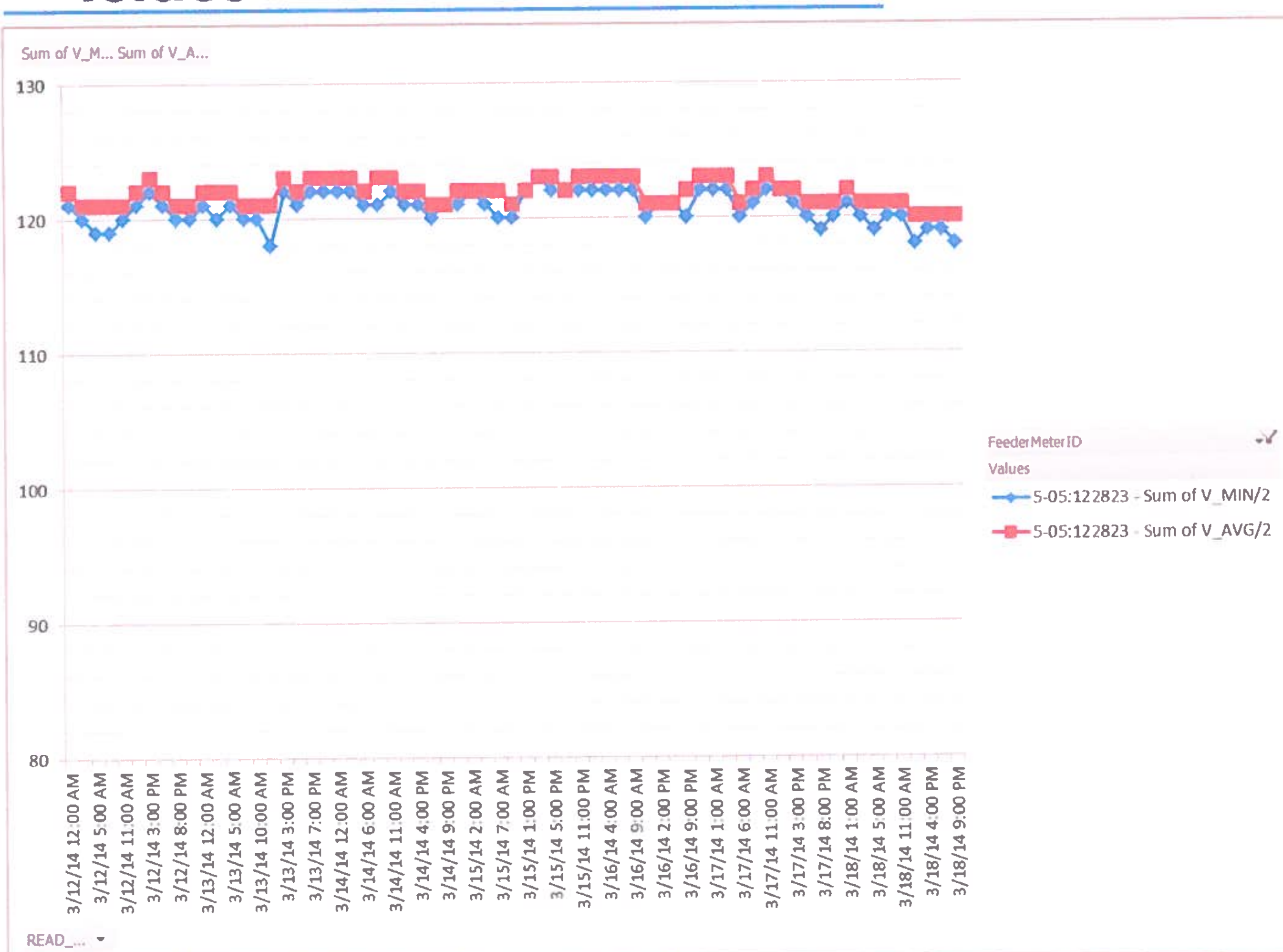
8/16/13 8:00 AM
8/26/13 5:00 AM
9/4/13 3:00 PM
9/14/13 3:00 AM
9/23/13 6:00 AM
10/2/13 1:00 PM
10/12/13 4:00 AM
10/21/13 9:00 PM
10/31/13 7:00 PM
READ_...
FeederMeterID
Values
5-02:127913 - Sum of V_MIN/2
5-02:127913 - Sum of V_AVG/2

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
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3/13/14 5:00 AM
3/13/14 10:00 AM
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3/14/14 4:00 PM
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3/17/14 1:00 AM
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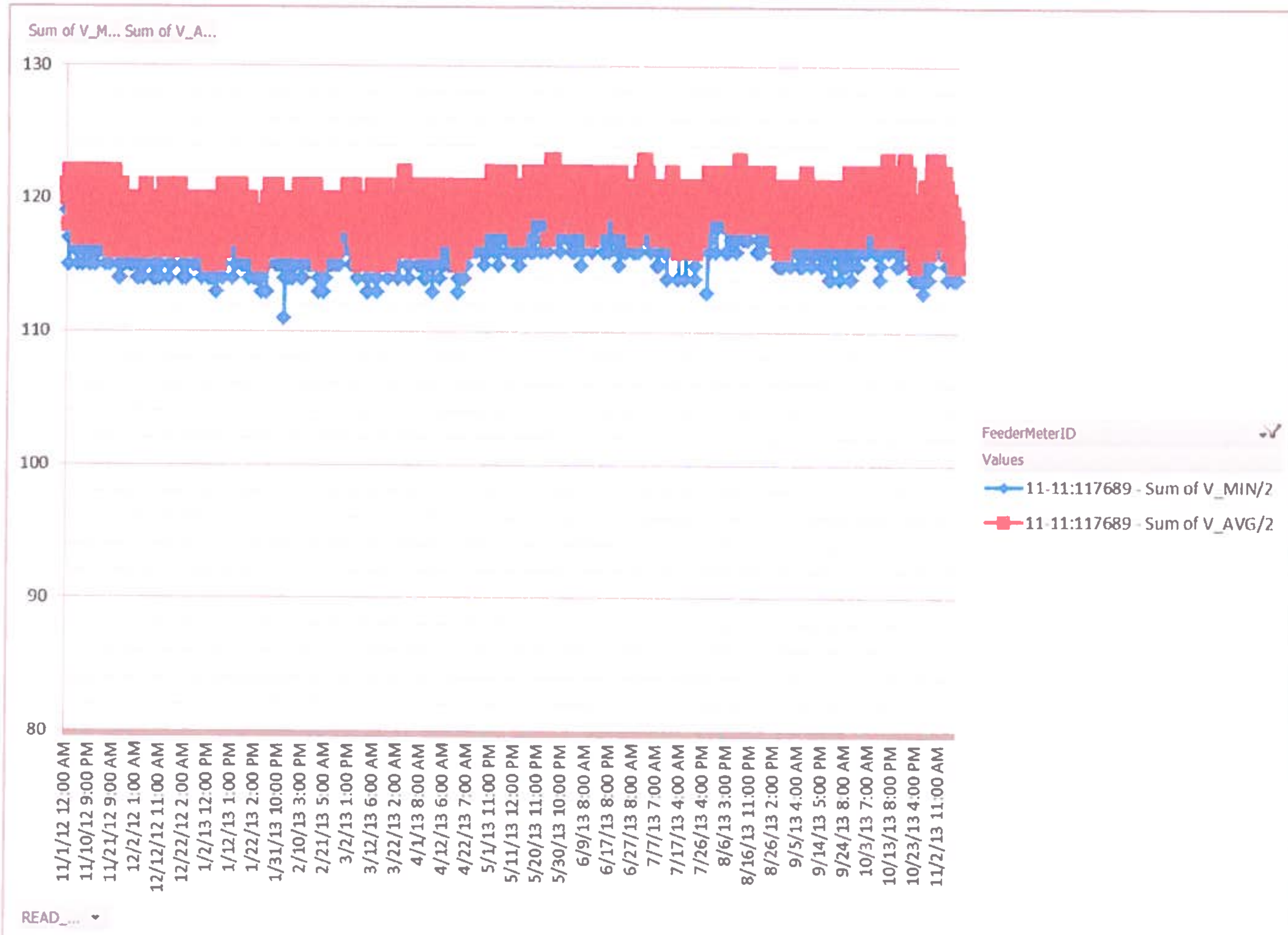
3/18/14 1:00 AM
3/18/14 5:00 AM
3/18/14 11:00 AM
3/18/14 4:00 PM
3/18/14 9:00 PM
READ_...
FeederMeterID
Values
5-05:122823 - Sum of V_MIN/2
5-05:122823 - Sum of V_AVG/2

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
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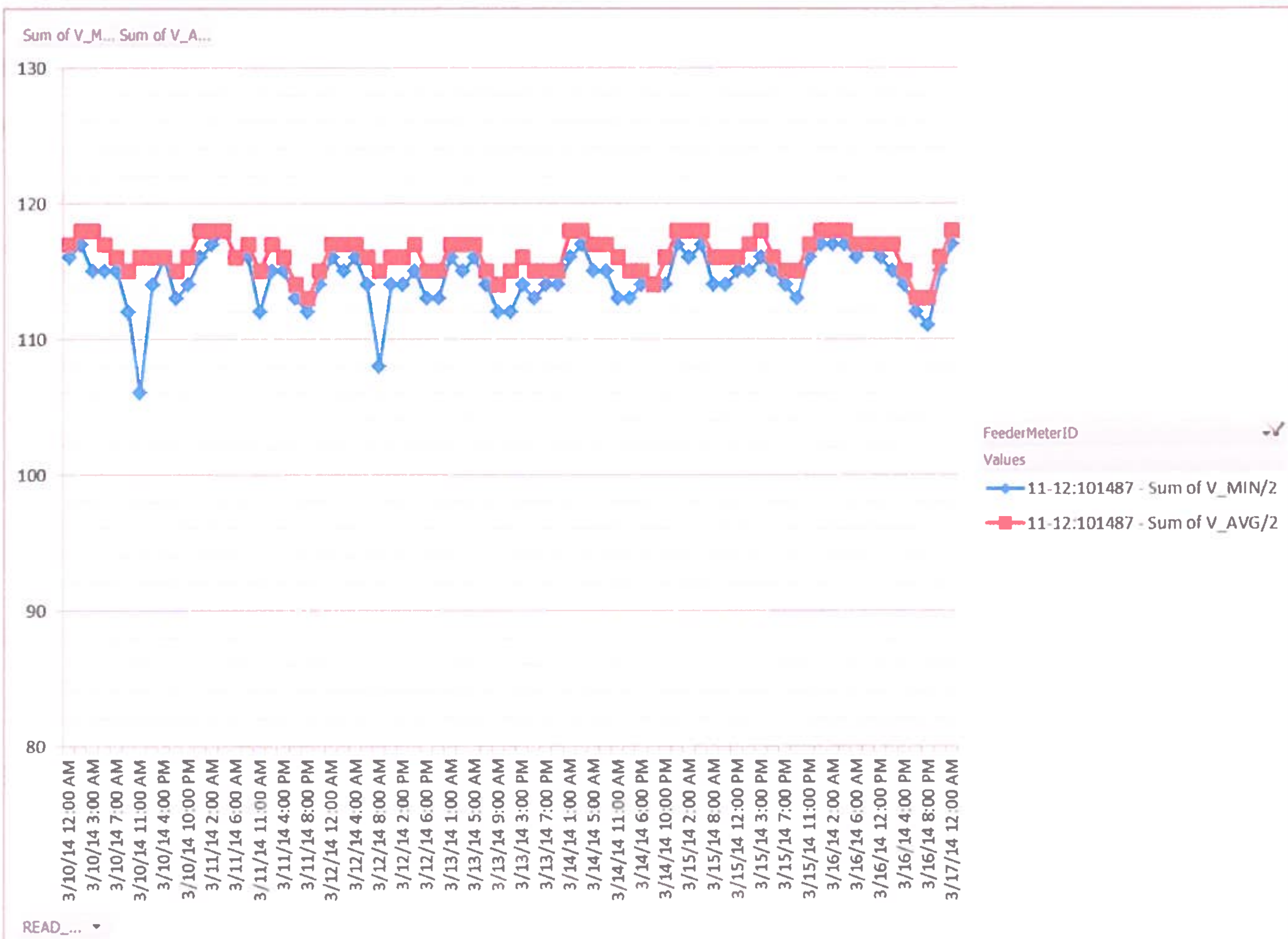
8/16/13 11:00 PM
8/26/13 2:00 PM
9/5/13 4:00 AM
9/14/13 5:00 PM
9/24/13 8:00 AM
10/3/13 7:00 AM
10/13/13 8:00 PM
10/23/13 4:00 PM
11/2/13 11:00 AM
READ_...
FeederMeterID
Values
11-11:117689 - Sum of V_MIN/2
11-11:117689 - Sum of V_AVG/2

leidos



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
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3/10/14 3:00 AM
3/10/14 7:00 AM
3/10/14 11:00 AM
3/10/14 4:00 PM
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3/11/14 2:00 AM
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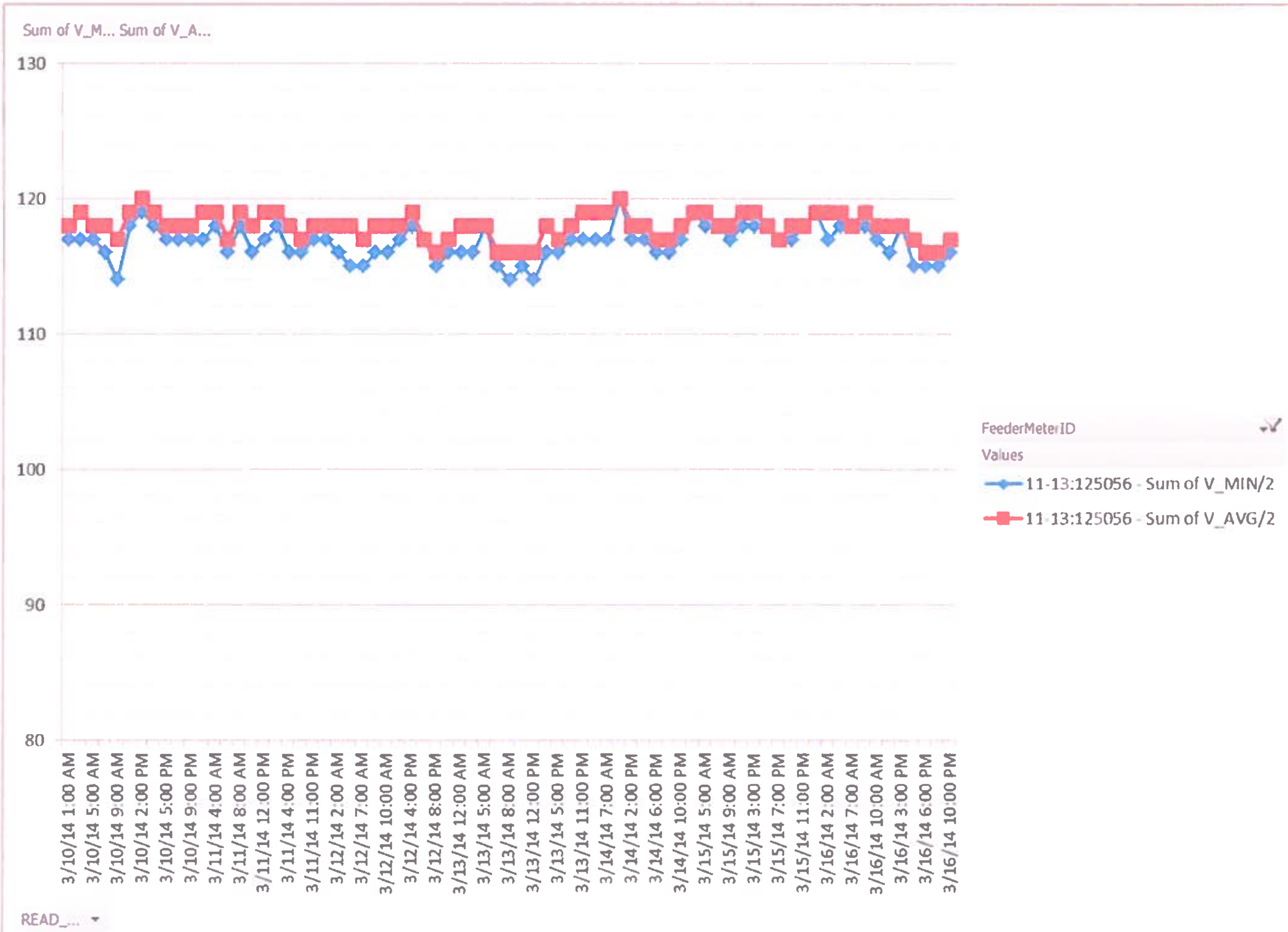
3/16/14 12:00 PM
3/16/14 4:00 PM
3/16/14 8:00 PM
3/17/14 12:00 AM
READ_...
FeederMeterID
Values
11-12:101487 - Sum of V_MIN/2
11-12:101487 - Sum of V_AVG/2


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
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3/10/14 9:00 AM
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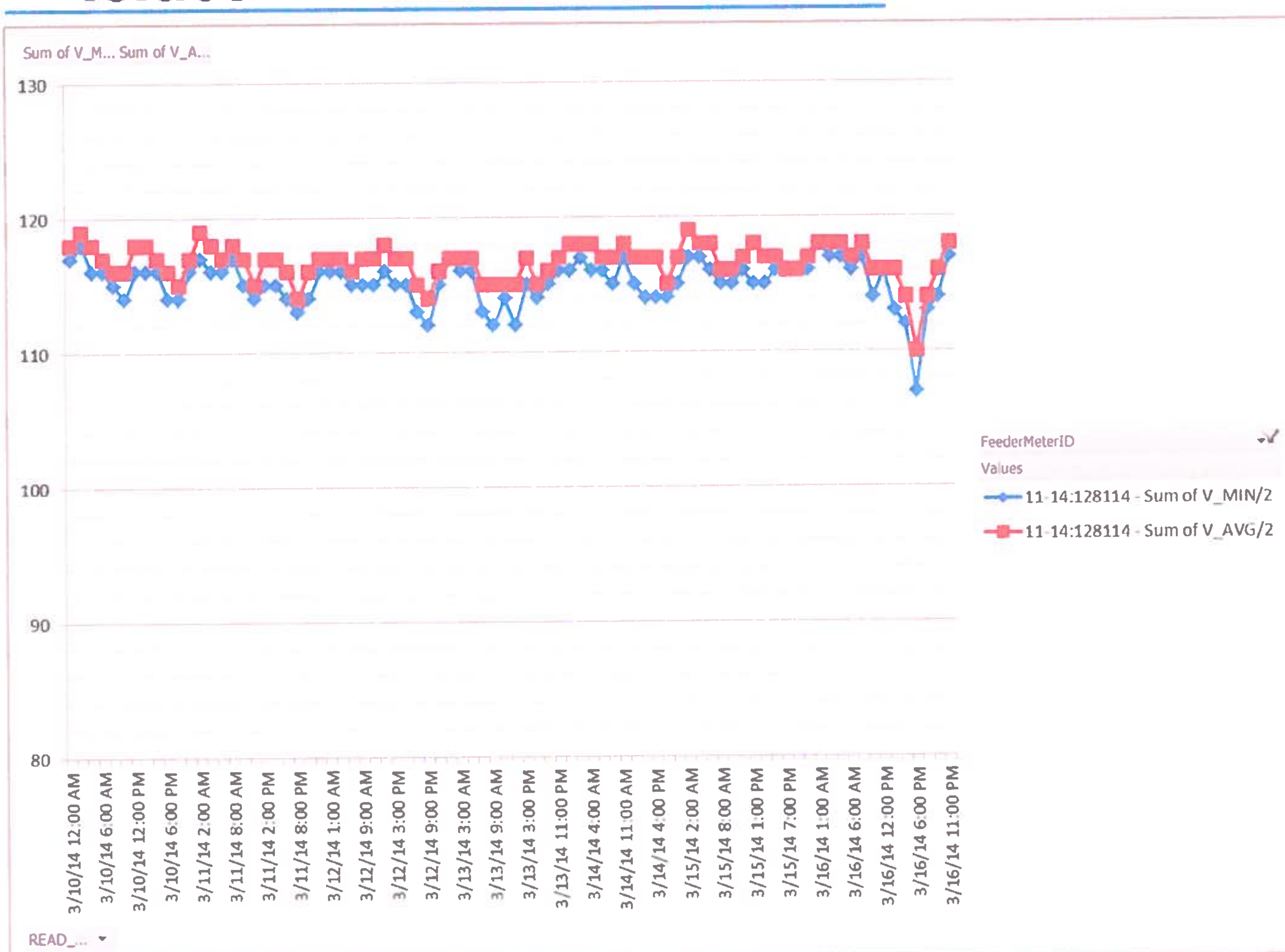
3/16/14 10:00 AM
3/16/14 3:00 PM
3/16/14 6:00 PM
3/16/14 10:00 PM
READ_...
FeederMeterID
Values
11-13:125056 - Sum of V_MIN/2
11-13:125056 - Sum of V_AVG/2

leidos



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
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3/10/14 6:00 AM
3/10/14 12:00 PM
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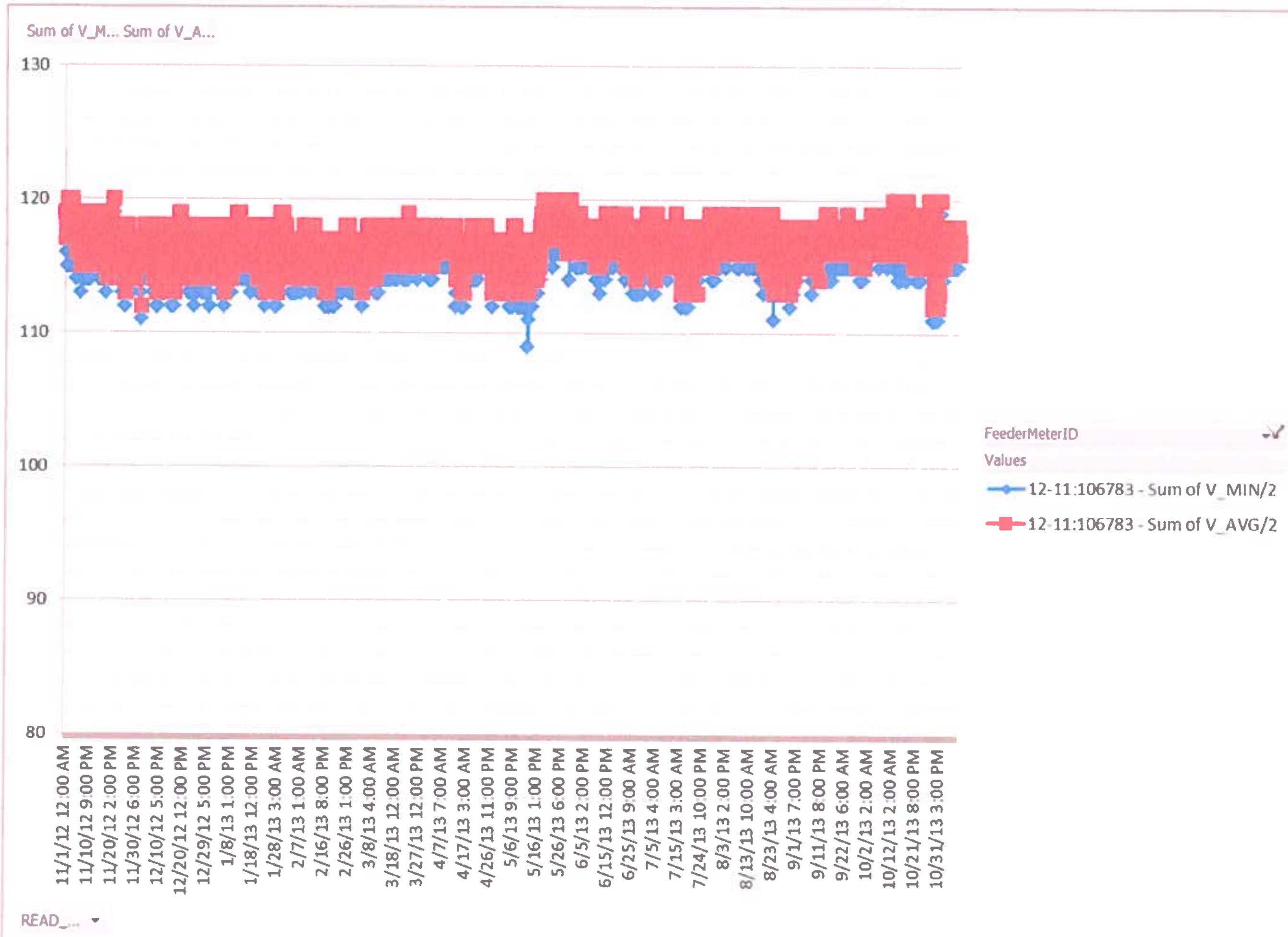
3/16/14 6:00 AM
3/16/14 12:00 PM
3/16/14 6:00 PM
3/16/14 11:00 PM
READ_...
FeederMeterID
Values
11-14:128114 - Sum of V_MIN/2
11-14:128114 - Sum of V_AVG/2


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
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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
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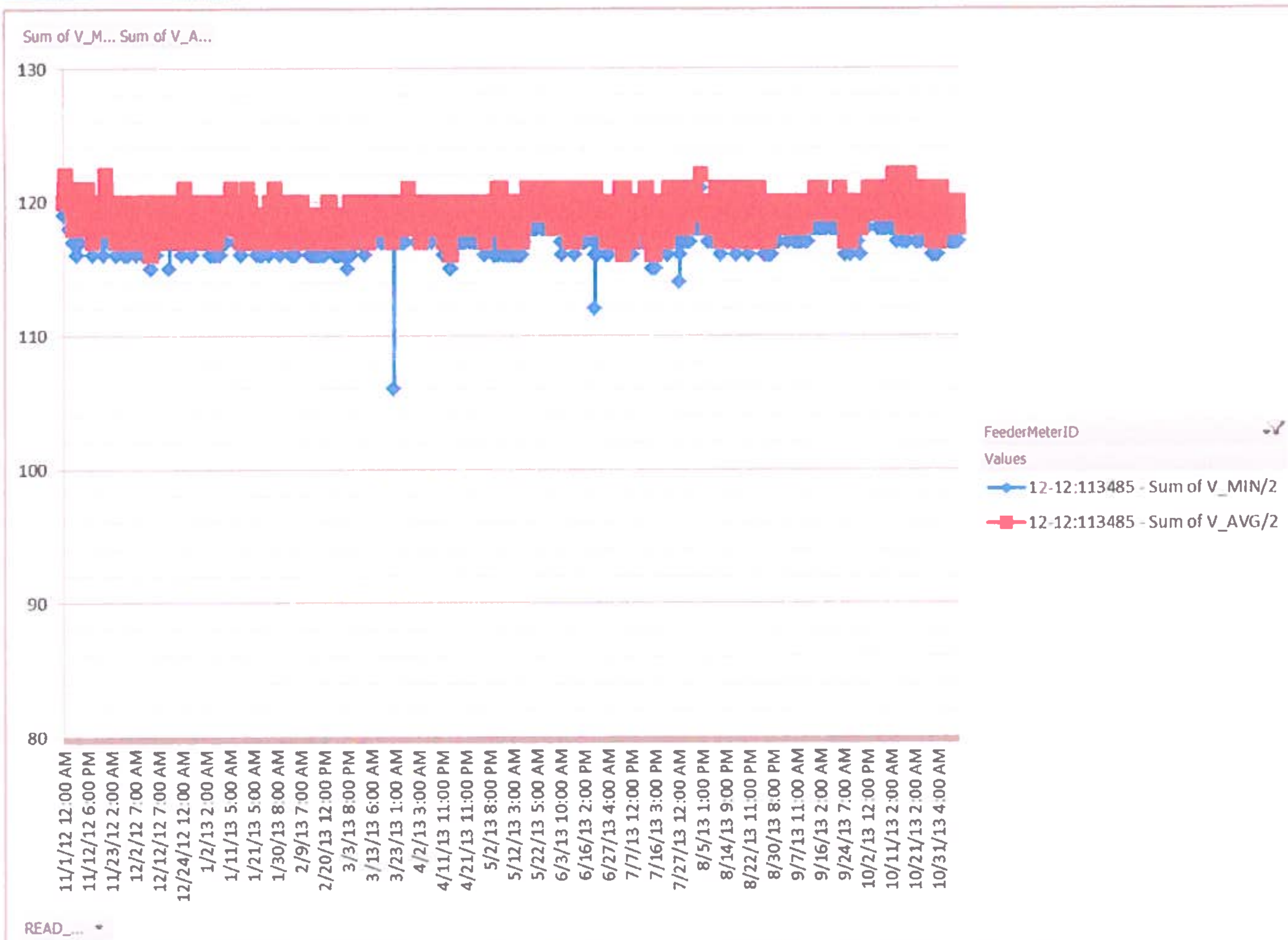
9/22/13 6:00 AM
10/2/13 2:00 AM
10/12/13 2:00 AM
10/21/13 8:00 PM
10/31/13 3:00 PM
FeederMeterID
Values
12-11:106783 - Sum of V_MIN/2
12-11:106783 - Sum of V_AVG/2
READ_...

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
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9/24/13 7:00 AM
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10/11/13 2:00 AM
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10/31/13 4:00 AM
FeederMeterID
Values
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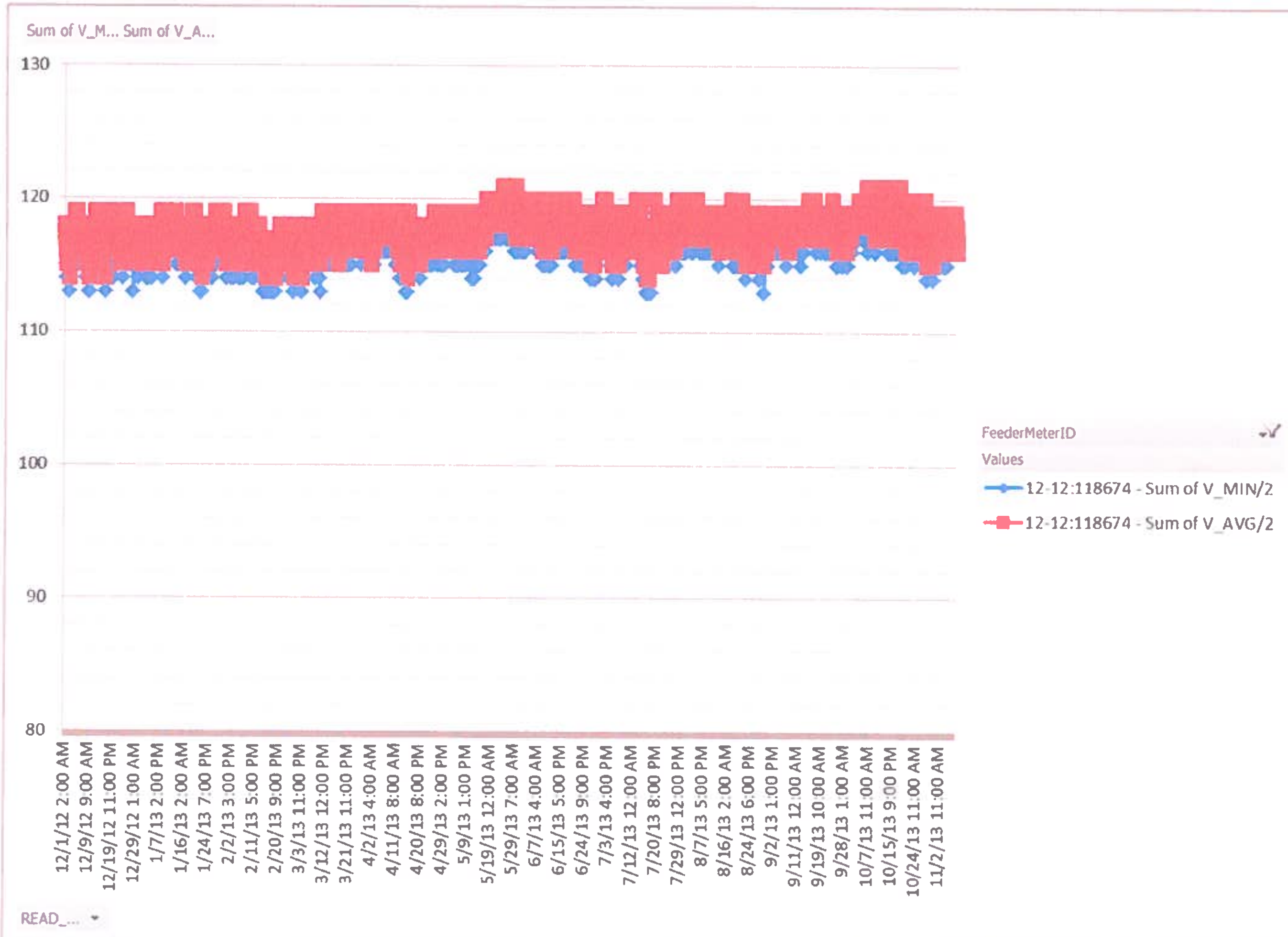
12-12:113485 - Sum of V_AVG/2
READ_...

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
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1/7/13 2:00 PM
1/16/13 2:00 AM
1/24/13 7:00 PM
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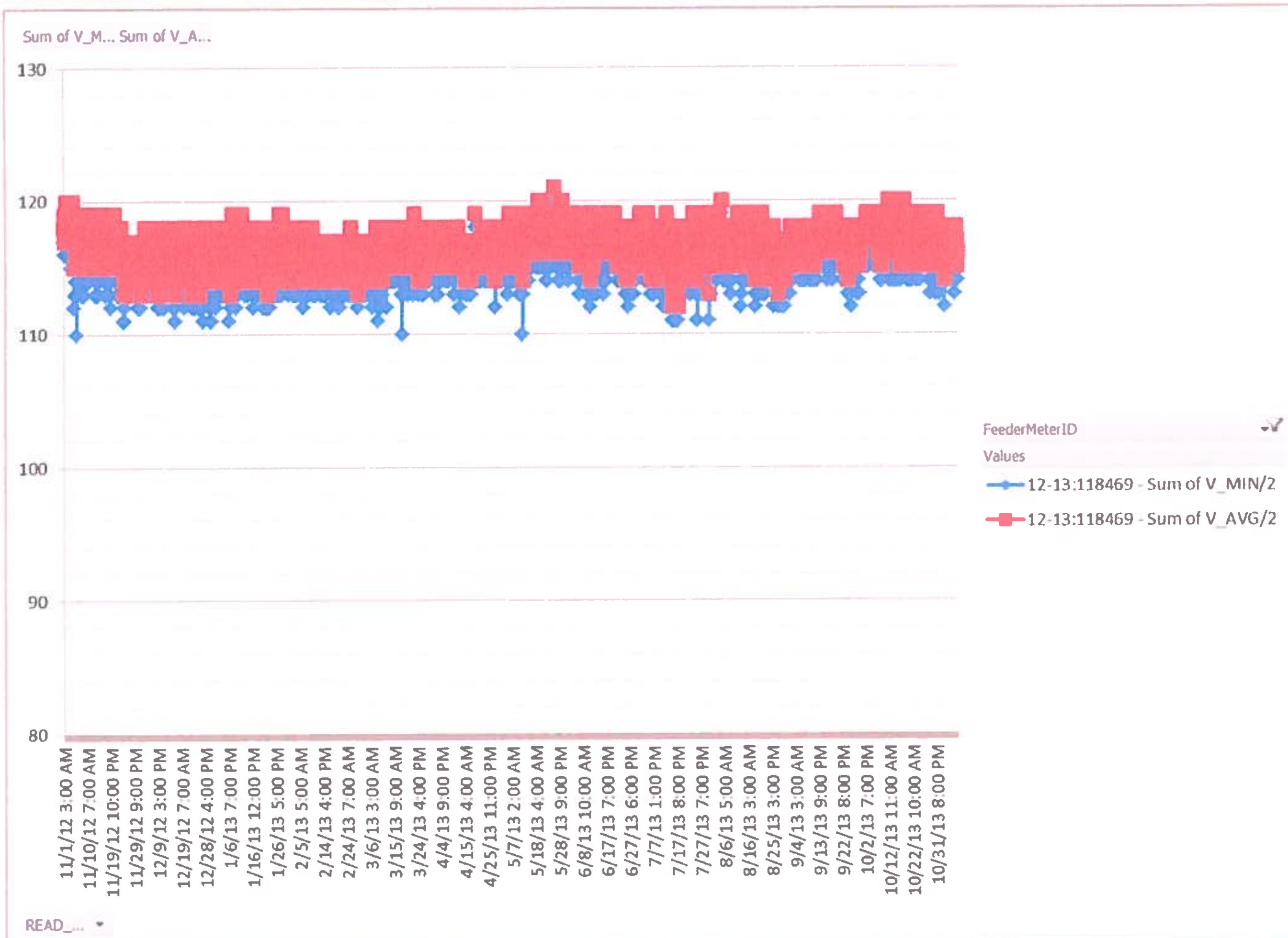
10/7/13 11:00 AM
10/15/13 9:00 PM
10/24/13 11:00 AM
11/2/13 11:00 AM
FeederMeterID
Values
12-12:118674 - Sum of V_MIN/2
12-12:118674 - Sum of V_AVG/2
READ_...



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
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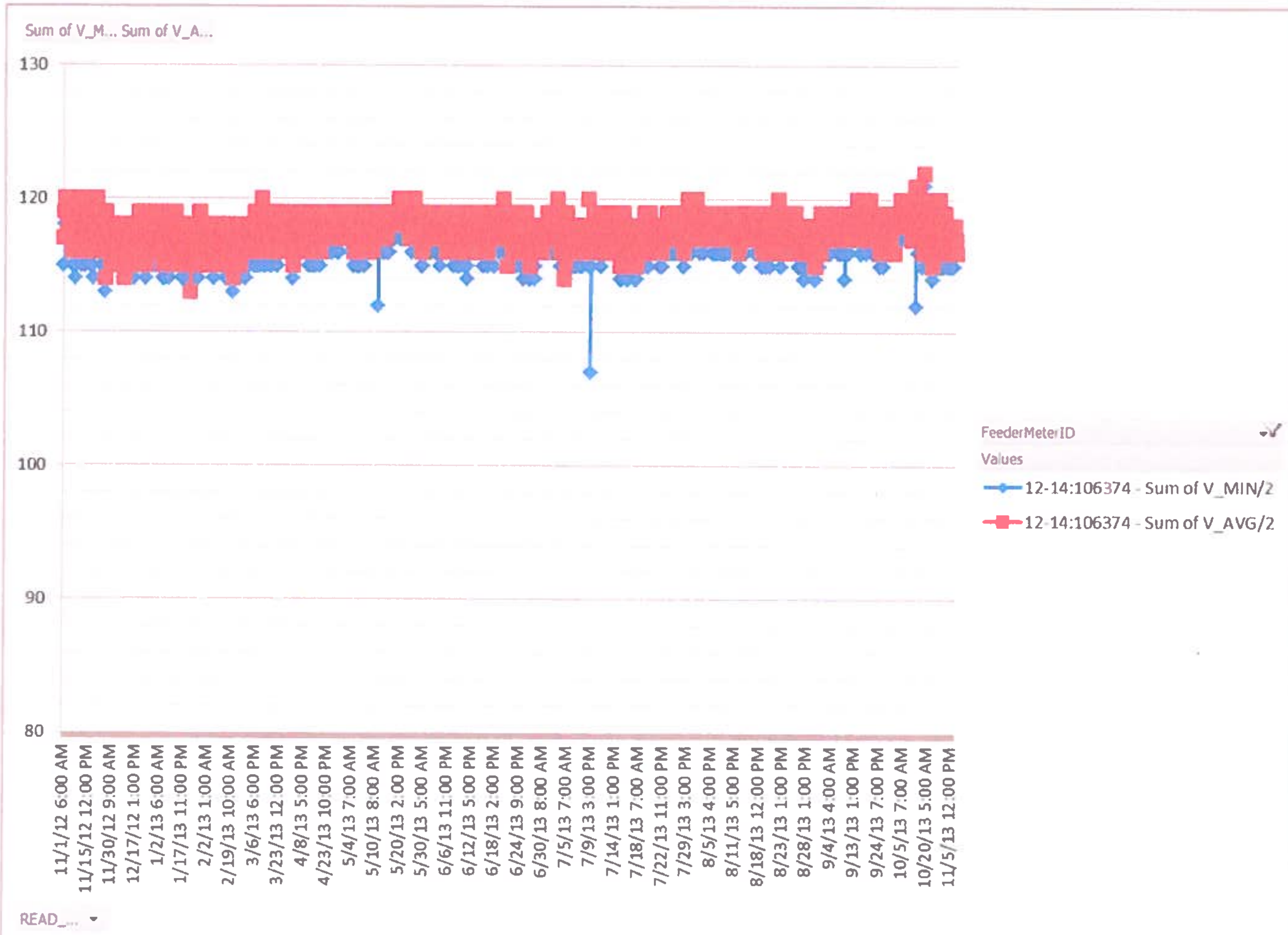
9/22/13 8:00 PM
10/2/13 7:00 PM
10/12/13 11:00 AM
10/22/13 10:00 AM
10/31/13 8:00 PM
READ_...
FeederMeterID
Values
12-13:118469 - Sum of V_MIN/2
12-13:118469 - Sum of V_AVG/2



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
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8/18/13 12:00 PM
8/23/13 1:00 PM
8/28/13 1:00 PM
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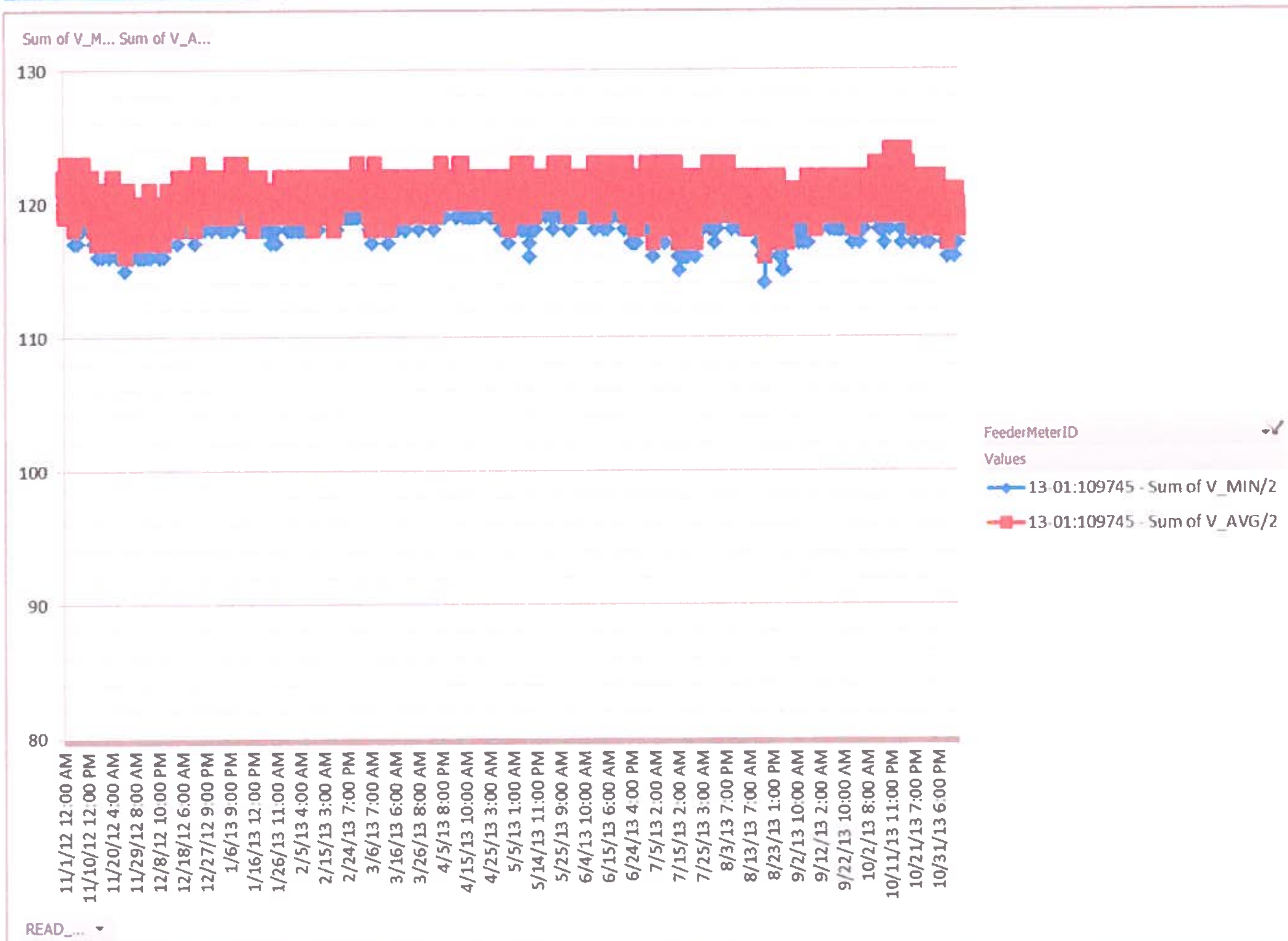
9/24/13 7:00 PM
10/5/13 7:00 AM
10/20/13 5:00 AM
11/5/13 12:00 PM
FeederMeterID
Values
12-14:106374 - Sum of V_MIN/2
12-14:106374 - Sum of V_AVG/2
READ_...


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
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11/20/12 4:00 AM
11/29/12 8:00 AM
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12/18/12 6:00 AM
12/27/12 9:00 PM
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4/5/13 8:00 PM
4/15/13 10:00 AM
4/25/13 3:00 AM
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6/15/13 6:00 AM
6/24/13 4:00 PM
7/5/13 2:00 AM
7/15/13 2:00 AM
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
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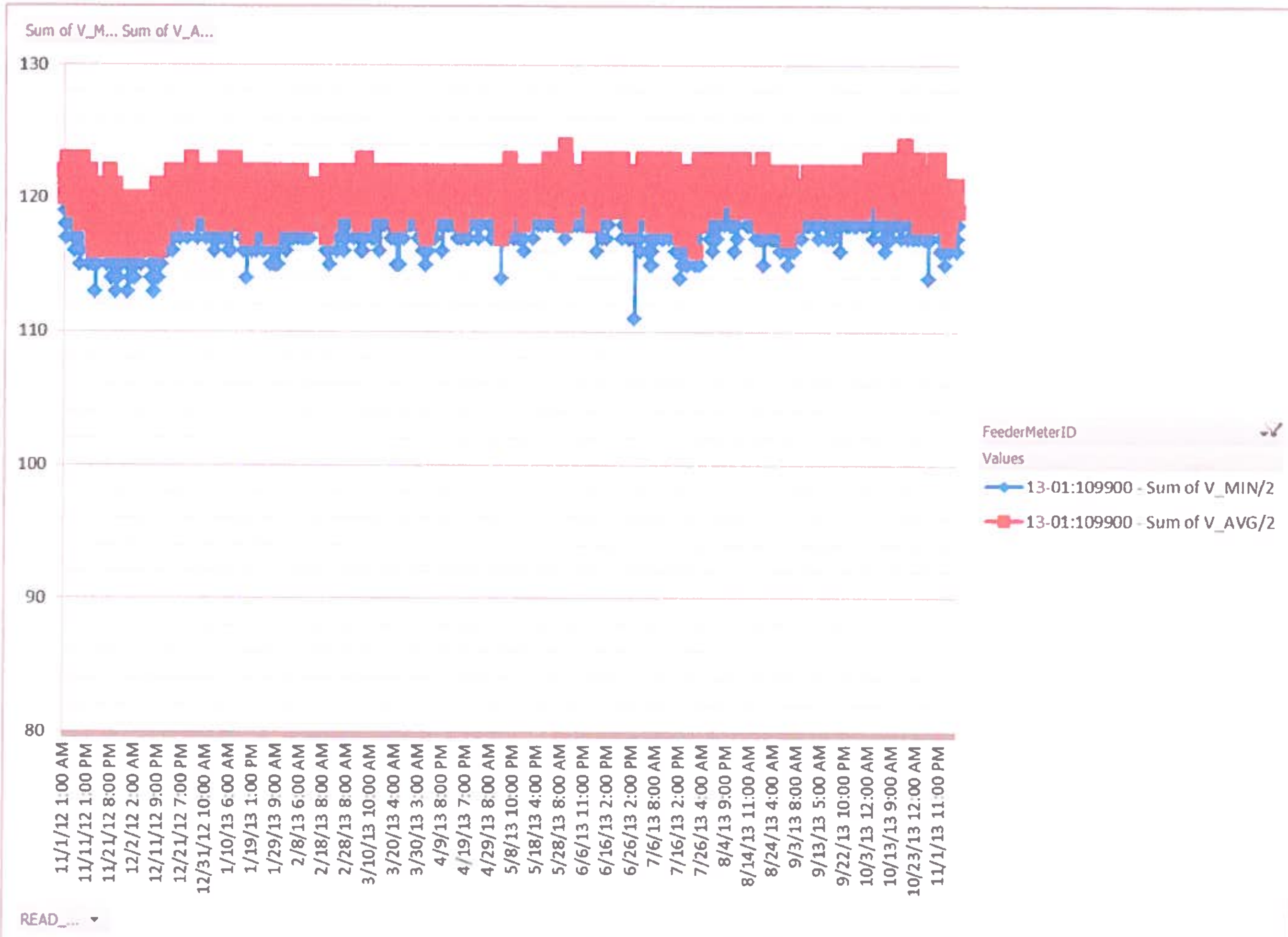
13-01:109745 - Sum of V_AVG/2



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
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1/19/13 1:00 PM
1/29/13 9:00 AM
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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
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FeederMeterID
Values
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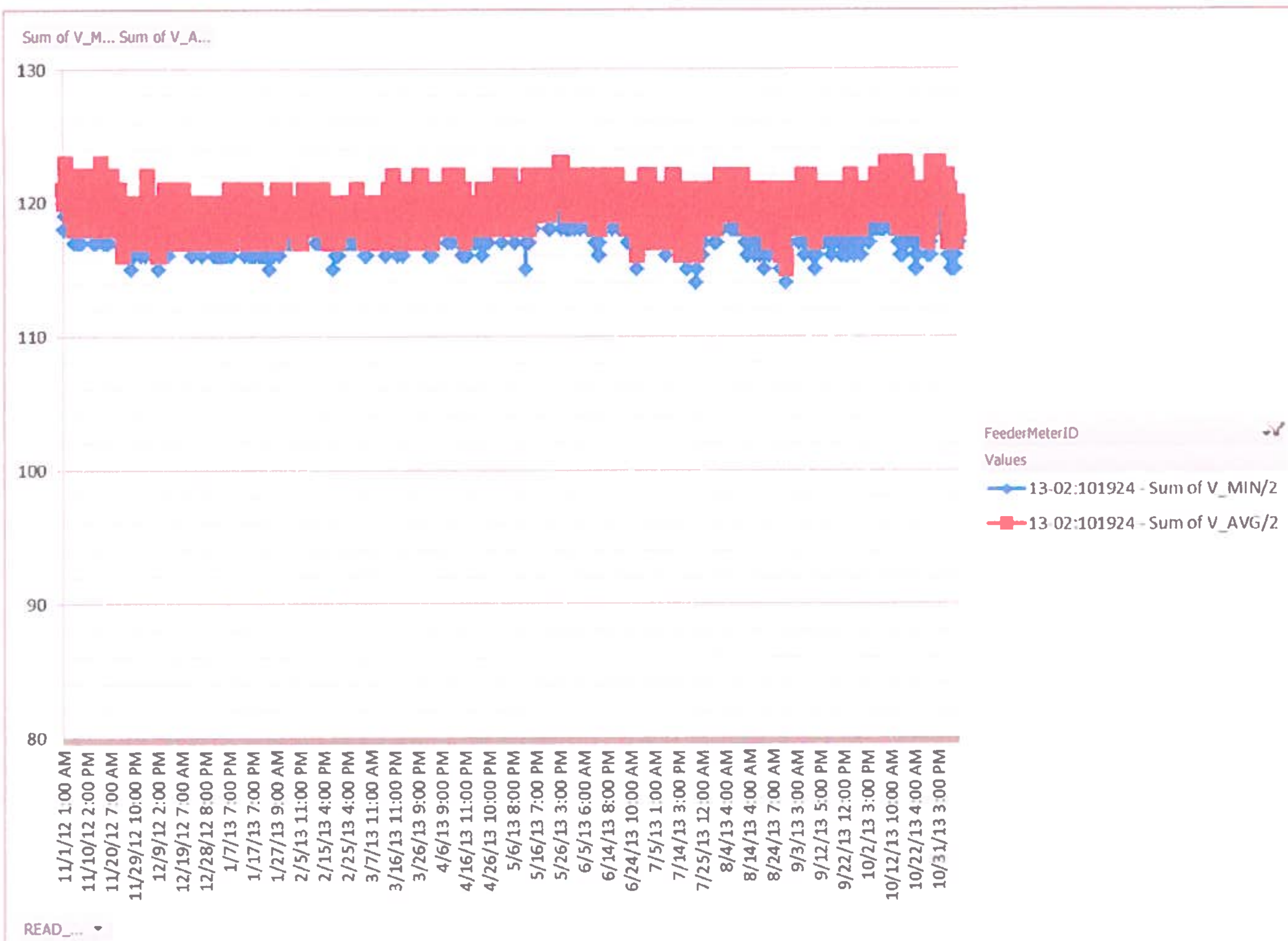
13-01:109900 - Sum of V_AVG/2
READ_...


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
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12/28/12 8:00 PM
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10/2/13 3:00 PM
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10/22/13 4:00 AM
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FeederMeterID
Values
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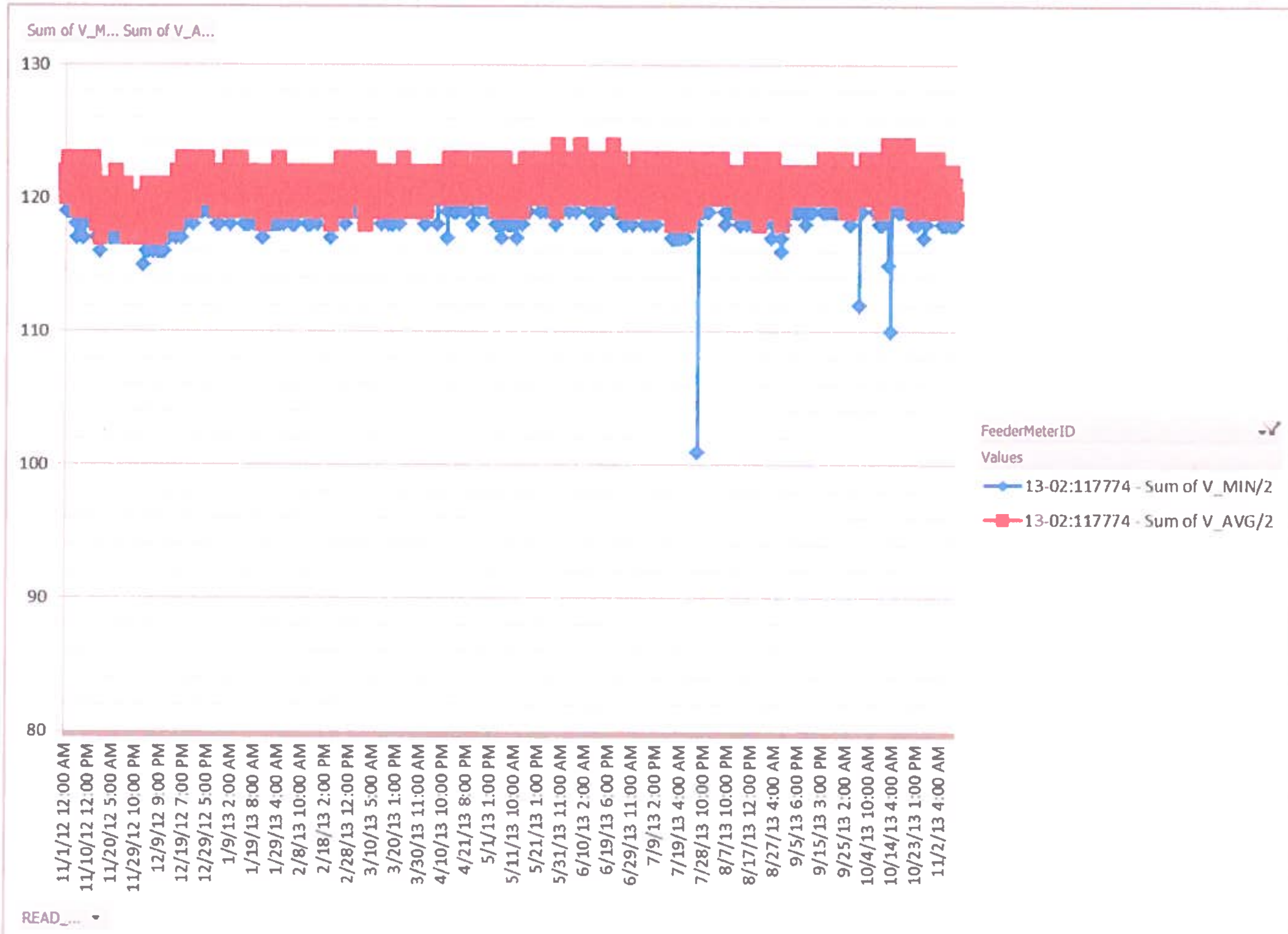
READ_...



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
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1/19/13 8:00 AM
1/29/13 4:00 AM
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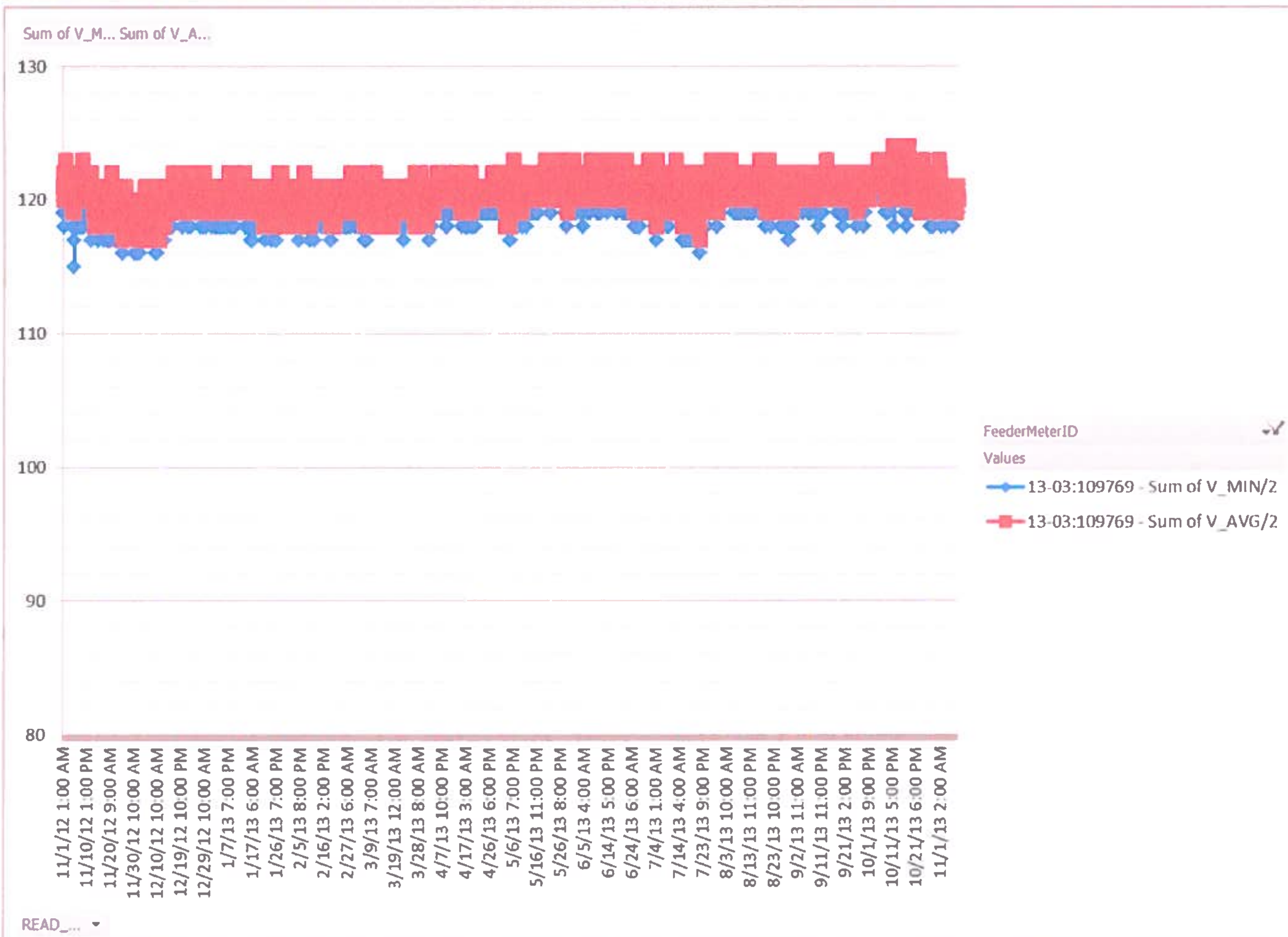
10/4/13 10:00 AM
10/14/13 4:00 AM
10/23/13 1:00 PM
11/2/13 4:00 AM
FeederMeterID
Values
13-02:117774 - Sum of V_MIN/2
13-02:117774 - Sum of V_AVG/2
READ_...



Sum of V_M... Sum of V_A...
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120
110
100
90
80
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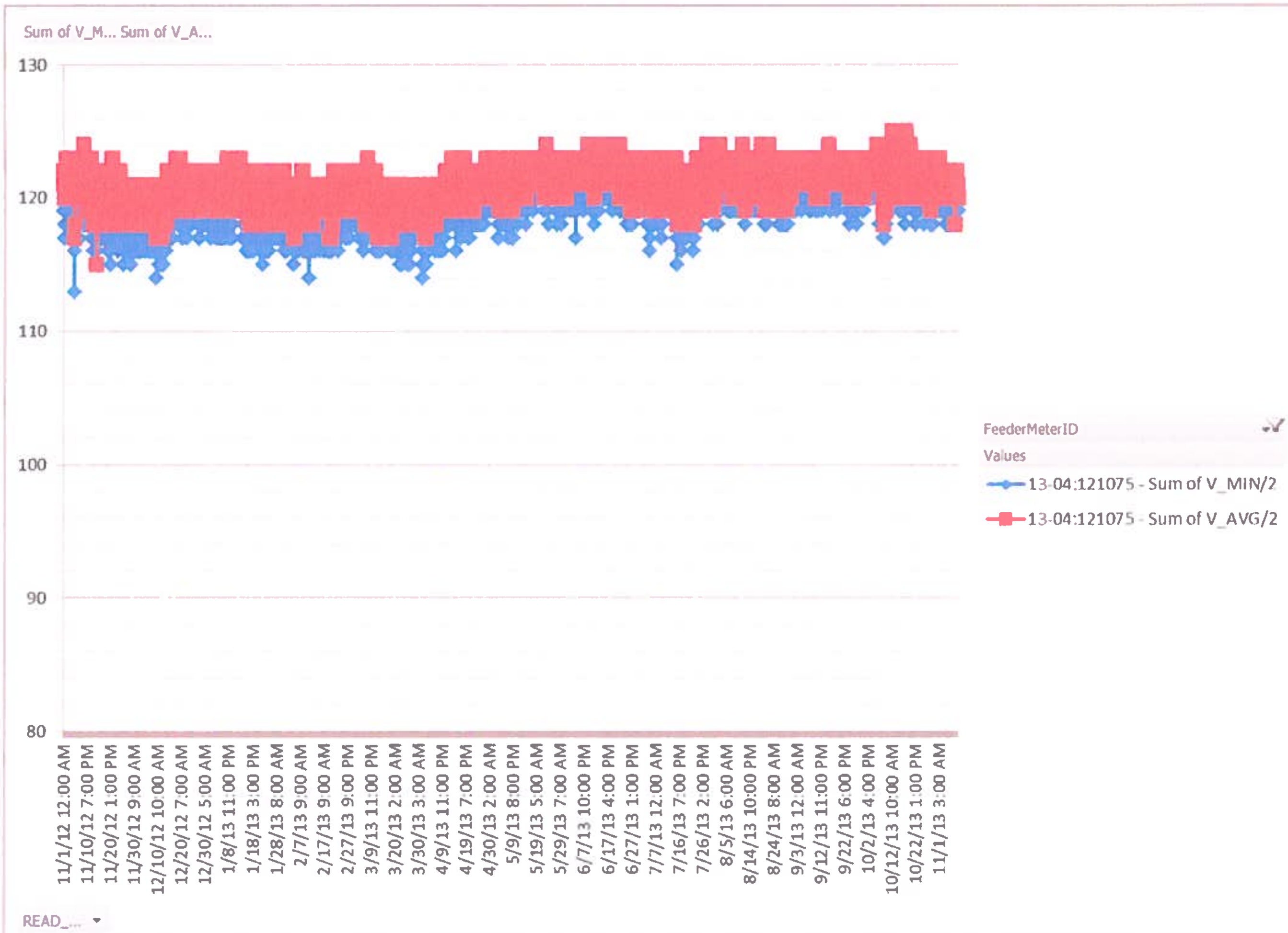
11/1/13 2:00 AM
FeederMeterID
Values
13-03:109769 - Sum of V_MIN/2
13-03:109769 - Sum of V_AVG/2
READ_...

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
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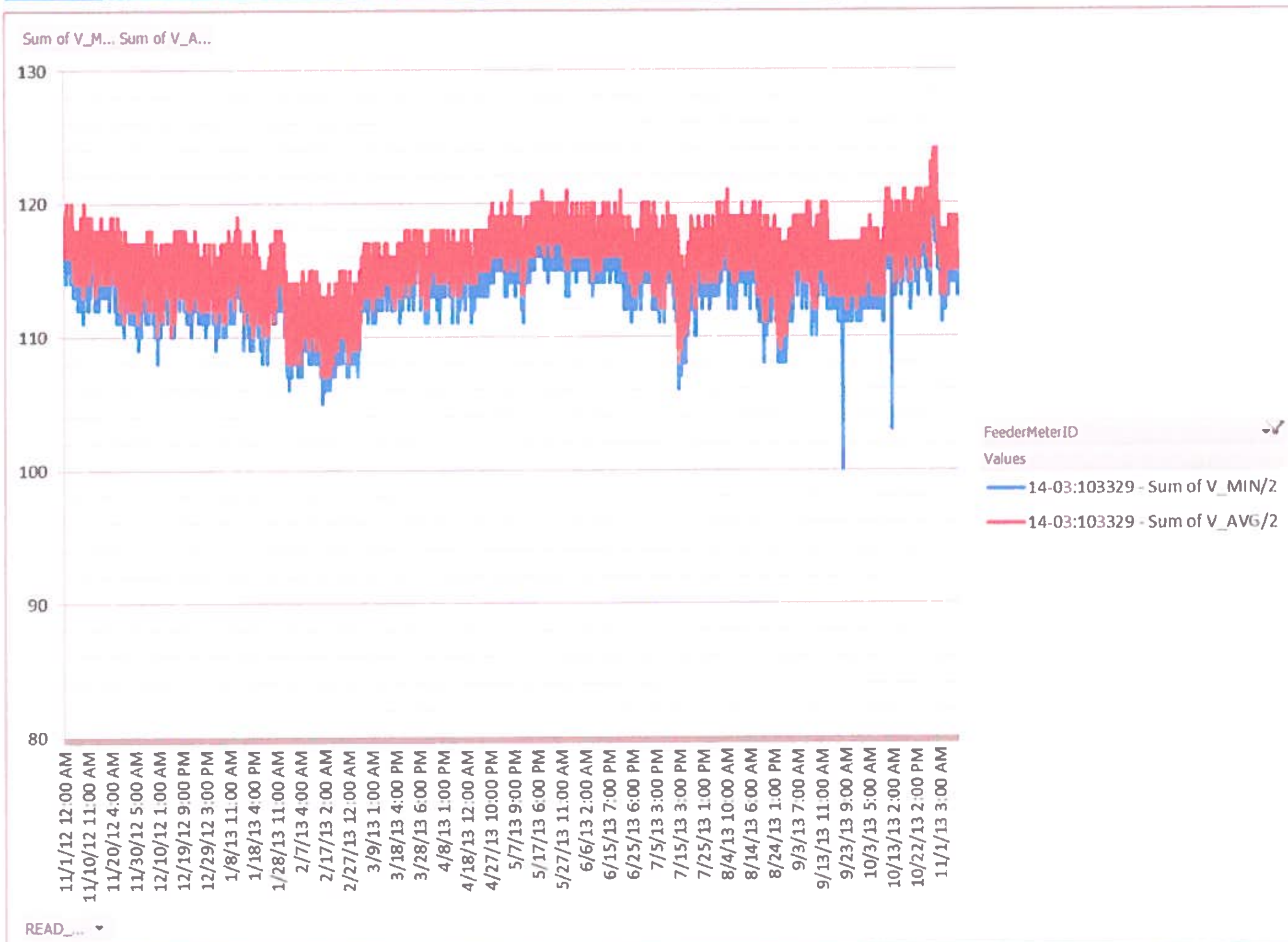
11/1/13 3:00 AM
FeederMeterID
Values
13-04:121075 - Sum of V_MIN/2
13-04:121075 - Sum of V_AVG/2
READ_...

leidos



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
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11/20/12 4:00 AM
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12/19/12 9:00 PM
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8/24/13 1:00 PM
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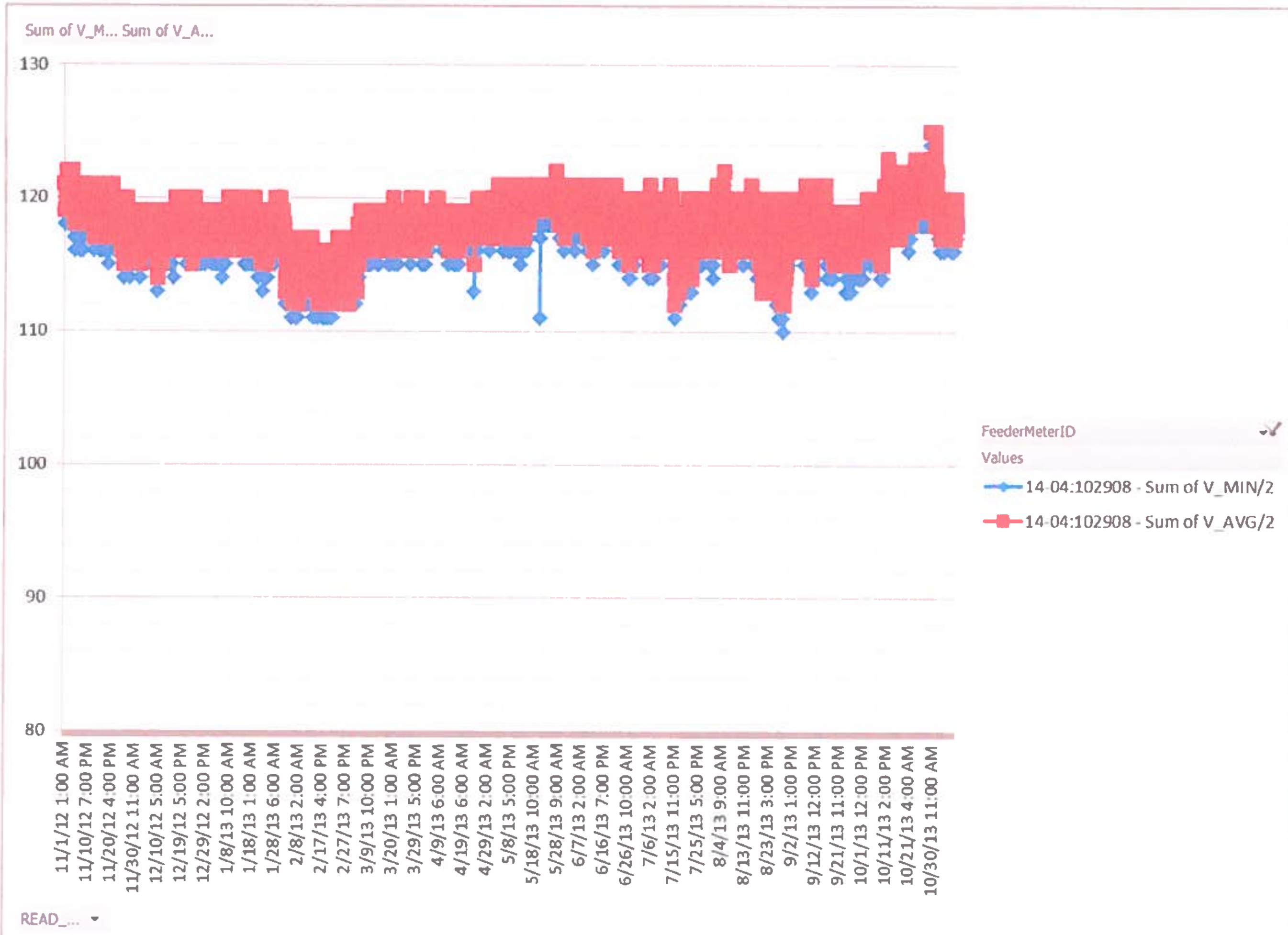
9/23/13 9:00 AM
10/3/13 5:00 AM
10/13/13 2:00 AM
10/22/13 2:00 PM
11/1/13 3:00 AM
FeederMeterID
Values
14-03:103329 - Sum of V_MIN/2
14-03:103329 - Sum of V_AVG/2
READ_...

leidos



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
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11/20/12 4:00 PM
11/30/12 11:00 AM
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9/21/13 11:00 PM
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10/11/13 2:00 PM
10/21/13 4:00 AM
10/30/13 11:00 AM
READ_...
FeederMeterID
Values
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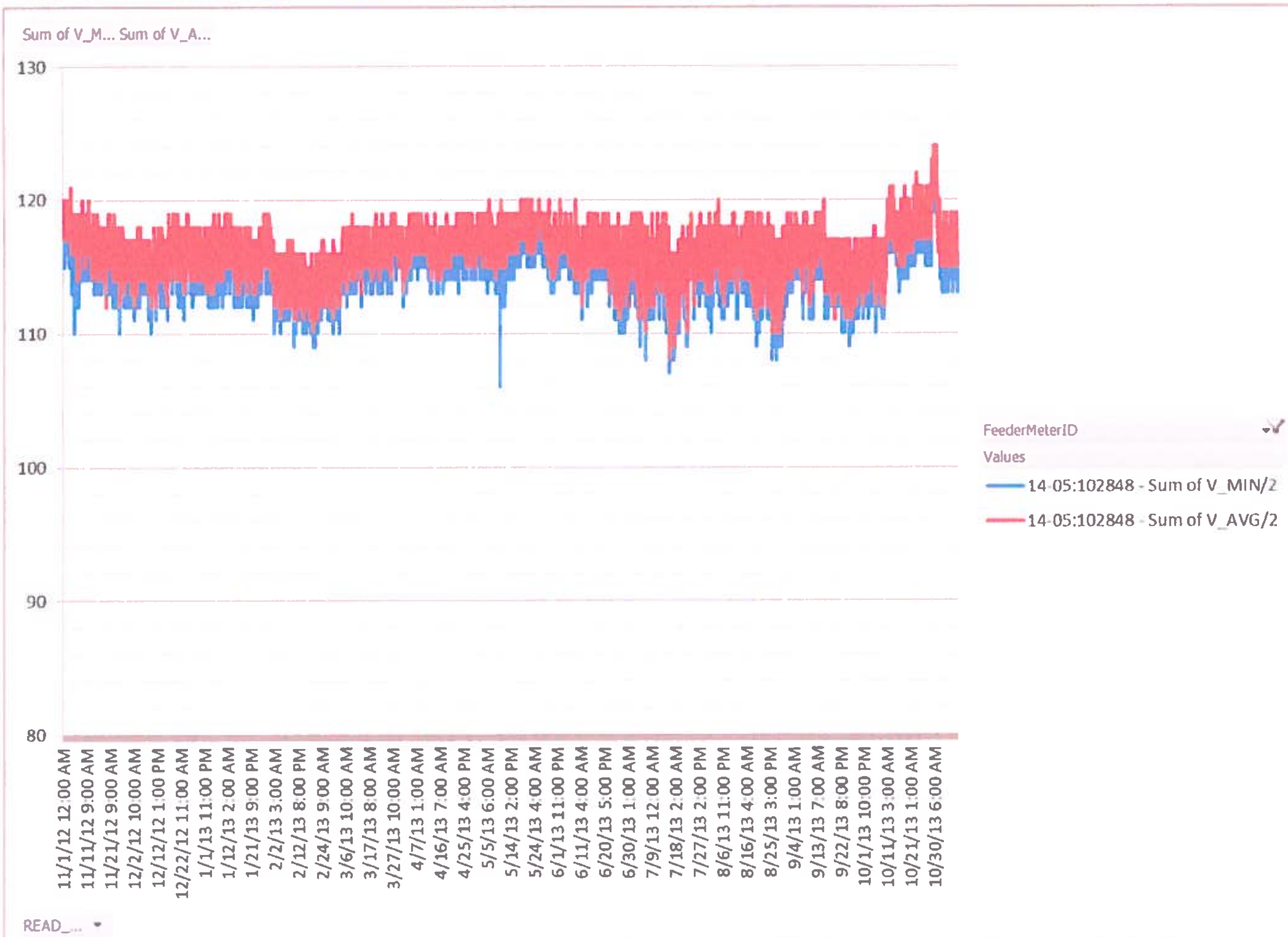
14-04:102908 - Sum of V_AVG/2


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
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9/22/13 8:00 PM
10/1/13 10:00 PM
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10/21/13 1:00 AM
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FeederMeterID
Values
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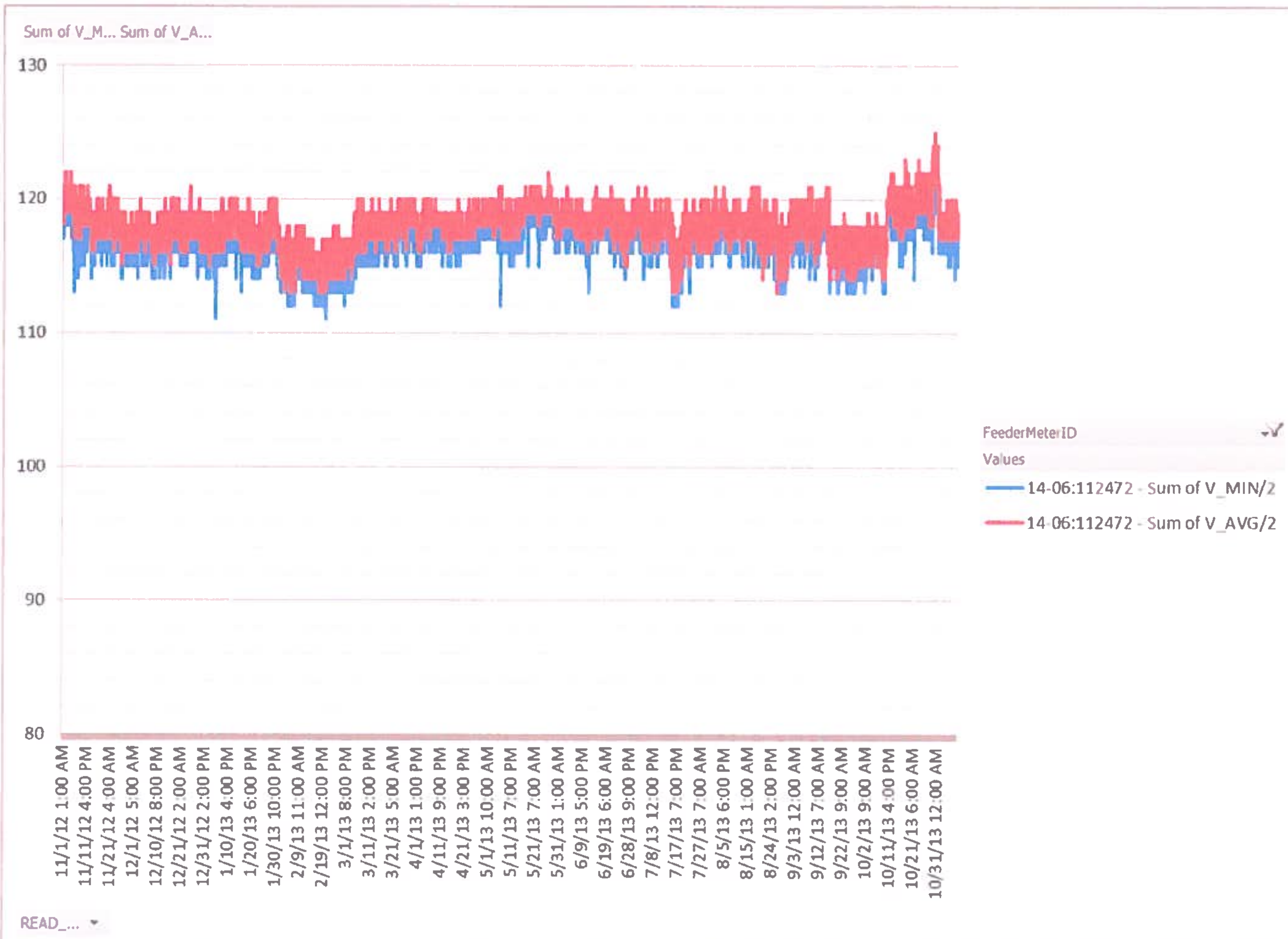
14-05:102848 - Sum of V_AVG/2
READ_...


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
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9/22/13 9:00 AM
10/2/13 9:00 AM
10/11/13 4:00 PM
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10/31/13 12:00 AM
READ_...
FeederMeterID
Values
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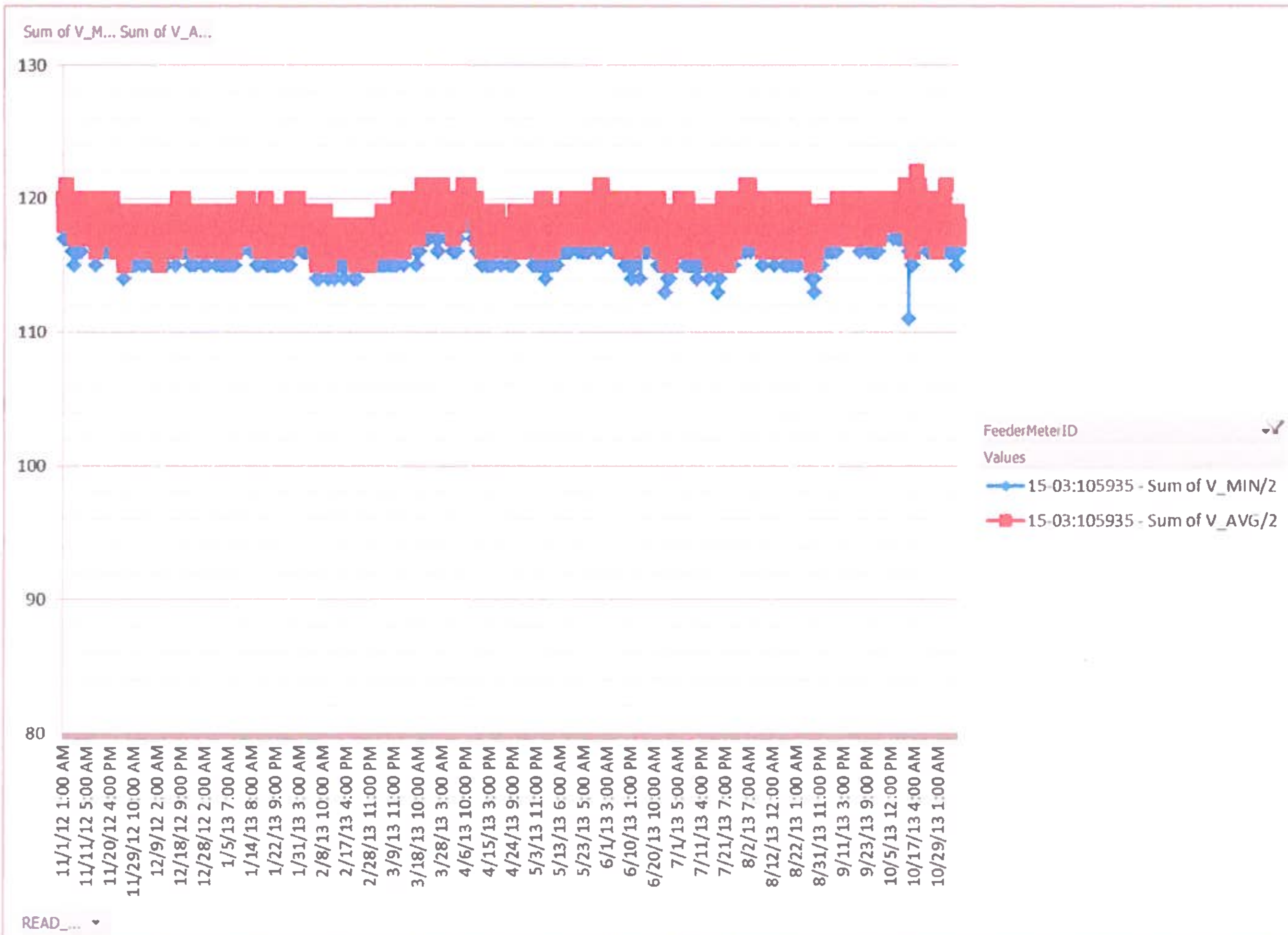
14-06:112472 - Sum of V_AVG/2



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
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12/9/12 2:00 AM
12/18/12 9:00 PM
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1/14/13 8:00 AM
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10/29/13 1:00 AM
READ_...
FeederMeterID
Values
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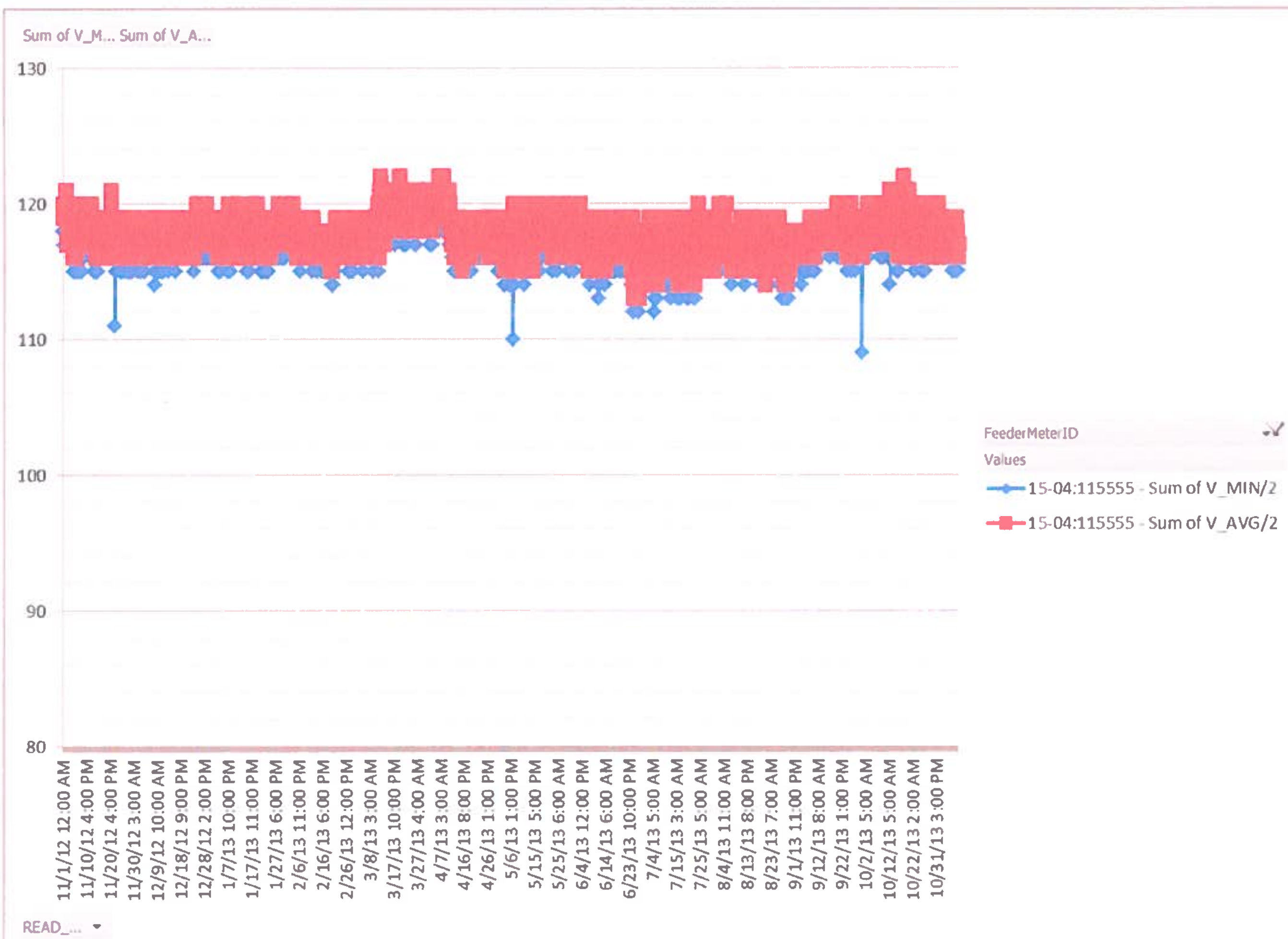
15-03:105935 - Sum of V_AVG/2


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
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READ_...
FeederMeterID
Values
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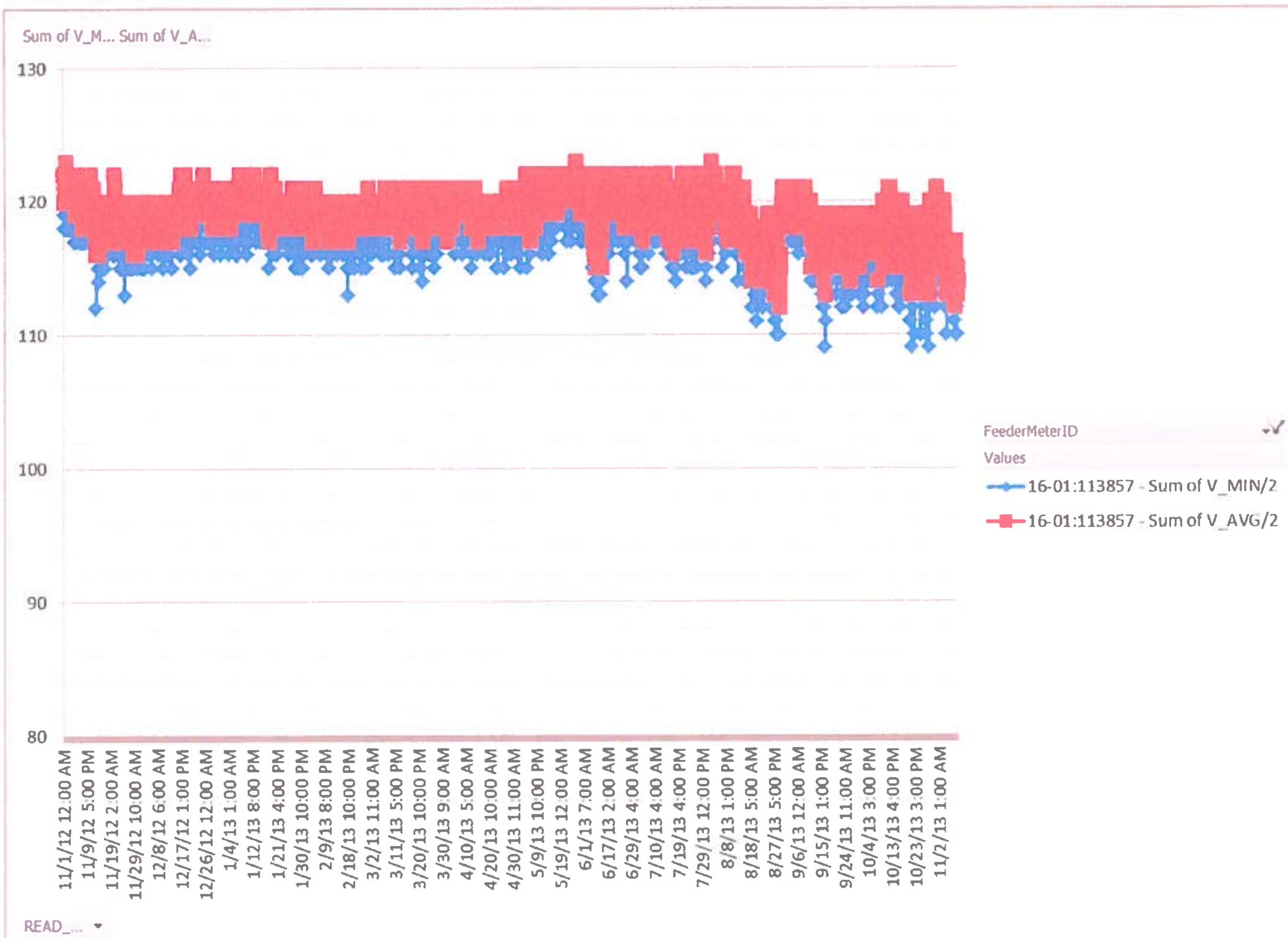
15-04:115555 - Sum of V_AVG/2



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
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11/2/13 1:00 AM
FeederMeterID
Values
16-01:113857 - Sum of V_MIN/2
16-01:113857 - Sum of V_AVG/2
READ_...

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
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11/19/12 10:00 PM
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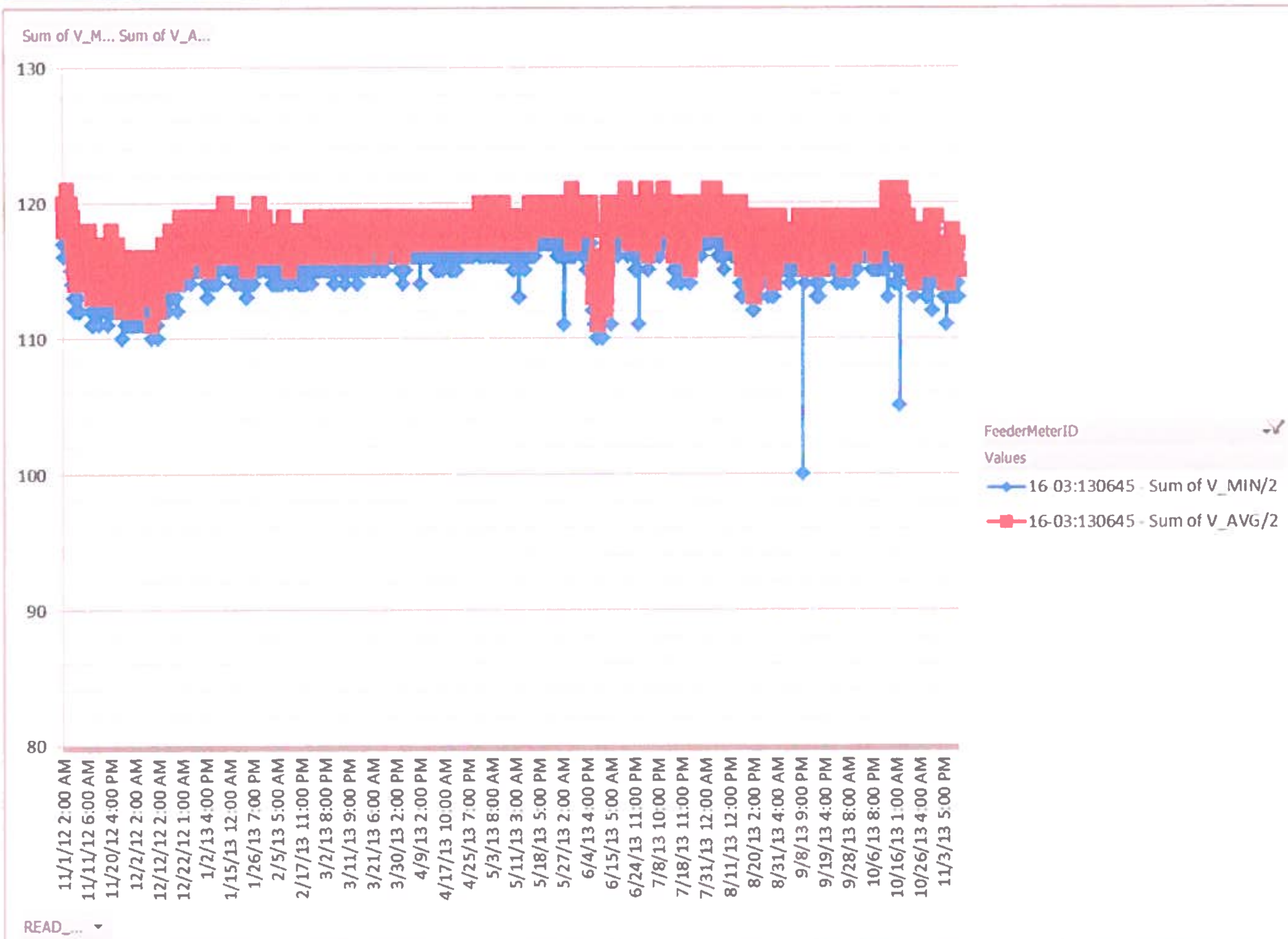
11/2/13 4:00 AM
READ_...
FeederMeterID
Values
16-02:100406 - Sum of V_MIN/2
16-02:100406 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
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90
80
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12/22/12 1:00 AM
1/2/13 4:00 PM
1/15/13 12:00 AM
1/26/13 7:00 PM
2/5/13 5:00 AM
2/17/13 11:00 PM
3/2/13 8:00 PM
3/11/13 9:00 PM
3/21/13 6:00 AM
3/30/13 2:00 PM
4/9/13 2:00 PM
4/17/13 10:00 AM
4/25/13 7:00 PM
5/3/13 8:00 AM
5/11/13 3:00 AM
5/18/13 5:00 PM
5/27/13 2:00 AM
6/4/13 4:00 PM
6/15/13 5:00 AM
6/24/13 11:00 PM
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7/18/13 11:00 PM
7/31/13 12:00 AM
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8/20/13 2:00 PM
8/31/13 4:00 AM
9/8/13 9:00 PM
9/16/13 4:00 PM
9/28/13 8:00 AM
10/6/13 8:00 PM
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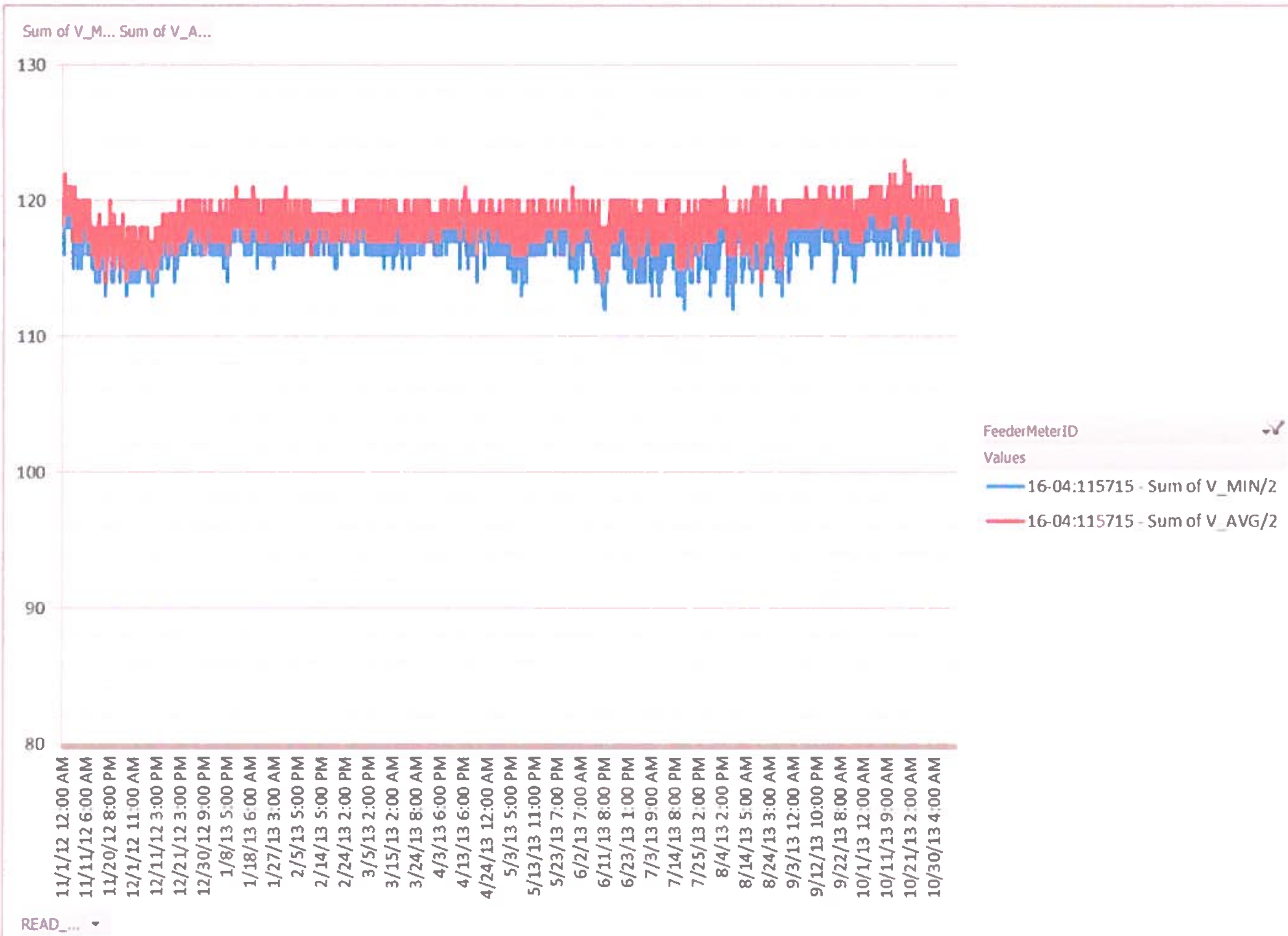
10/26/13 4:00 AM
11/3/13 5:00 PM
FeederMeterID
Values
16-03:130645 - Sum of V_MIN/2
16-03:130645 - Sum of V_AVG/2
READ_...

leidos


Sum of V_M... Sum of V_A...
130
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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12/11/12 3:00 PM
12/21/12 3:00 PM
12/30/12 9:00 PM
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9/22/13 8:00 AM
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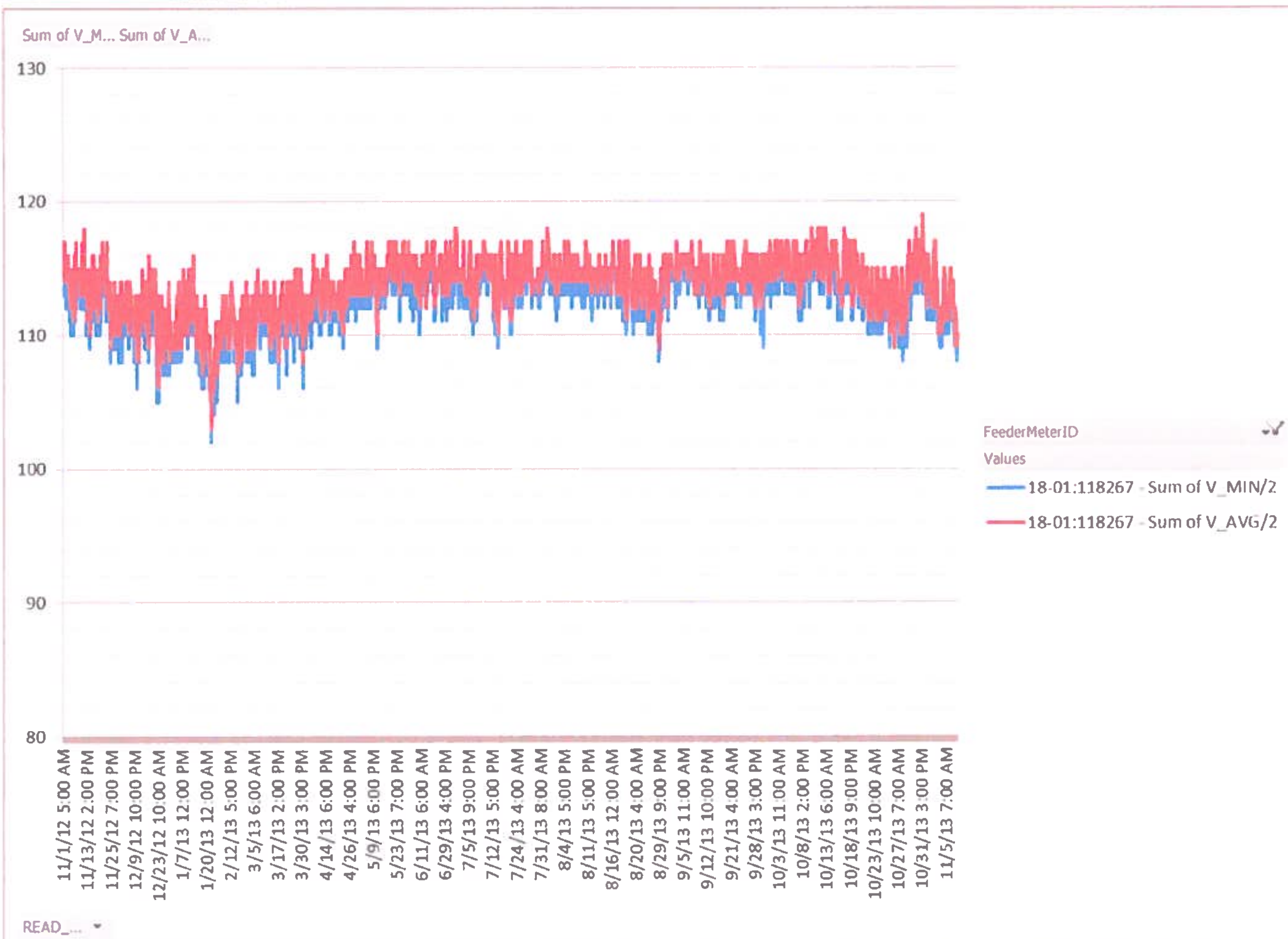
10/11/13 9:00 AM
10/21/13 2:00 AM
10/30/13 4:00 AM
READ_...
FeederMeterID
Values
16-04:115715 - Sum of V_MIN/2
16-04:115715 - Sum of V_AVG/2



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
12/23/12 10:00 AM
1/7/13 12:00 PM
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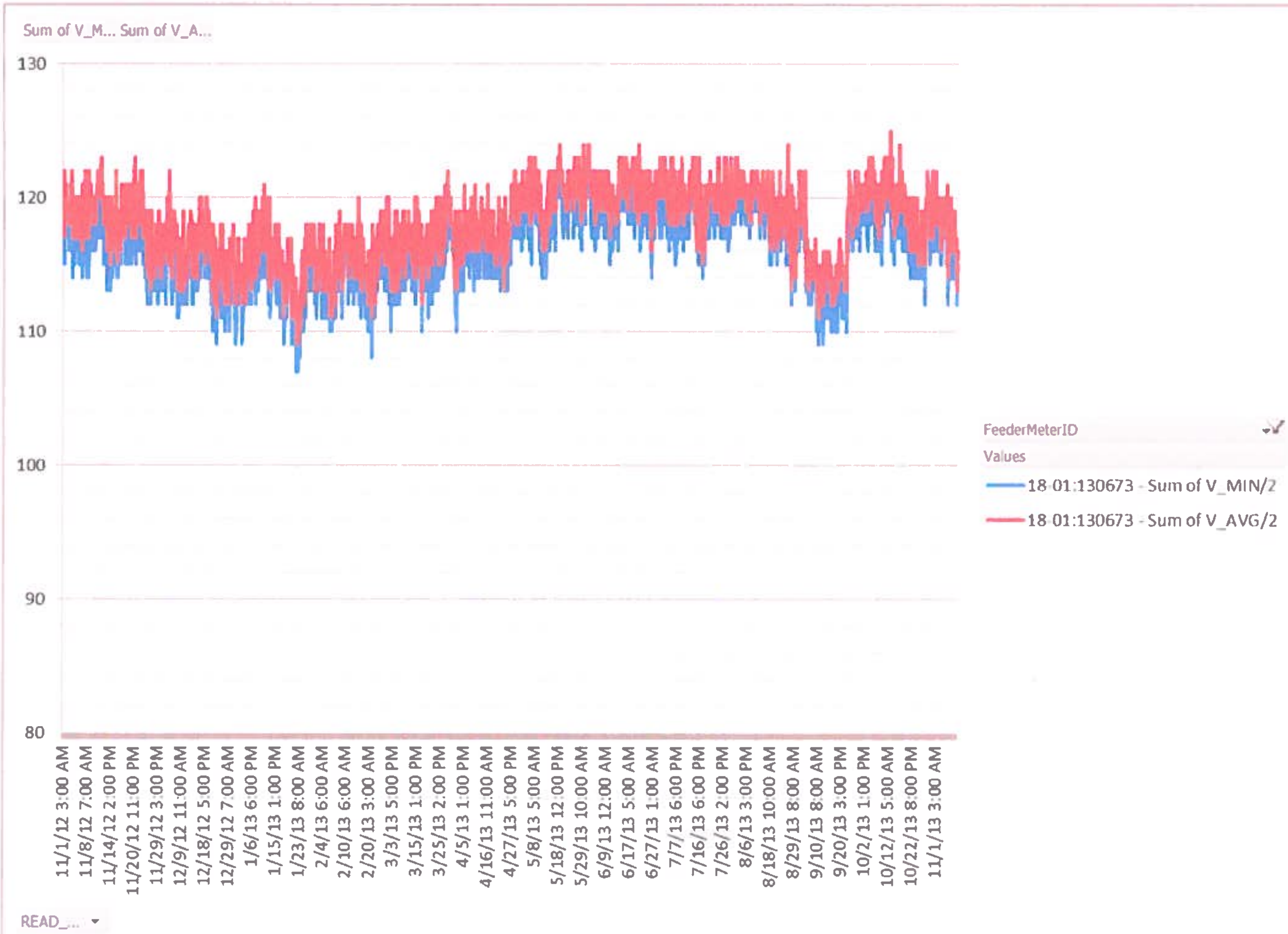
10/27/13 7:00 AM
10/31/13 3:00 PM
11/5/13 7:00 AM
READ_...
FeederMeterID
Values
18-01:118267 - Sum of V_MIN/2
18-01:118267 - Sum of V_AVG/2

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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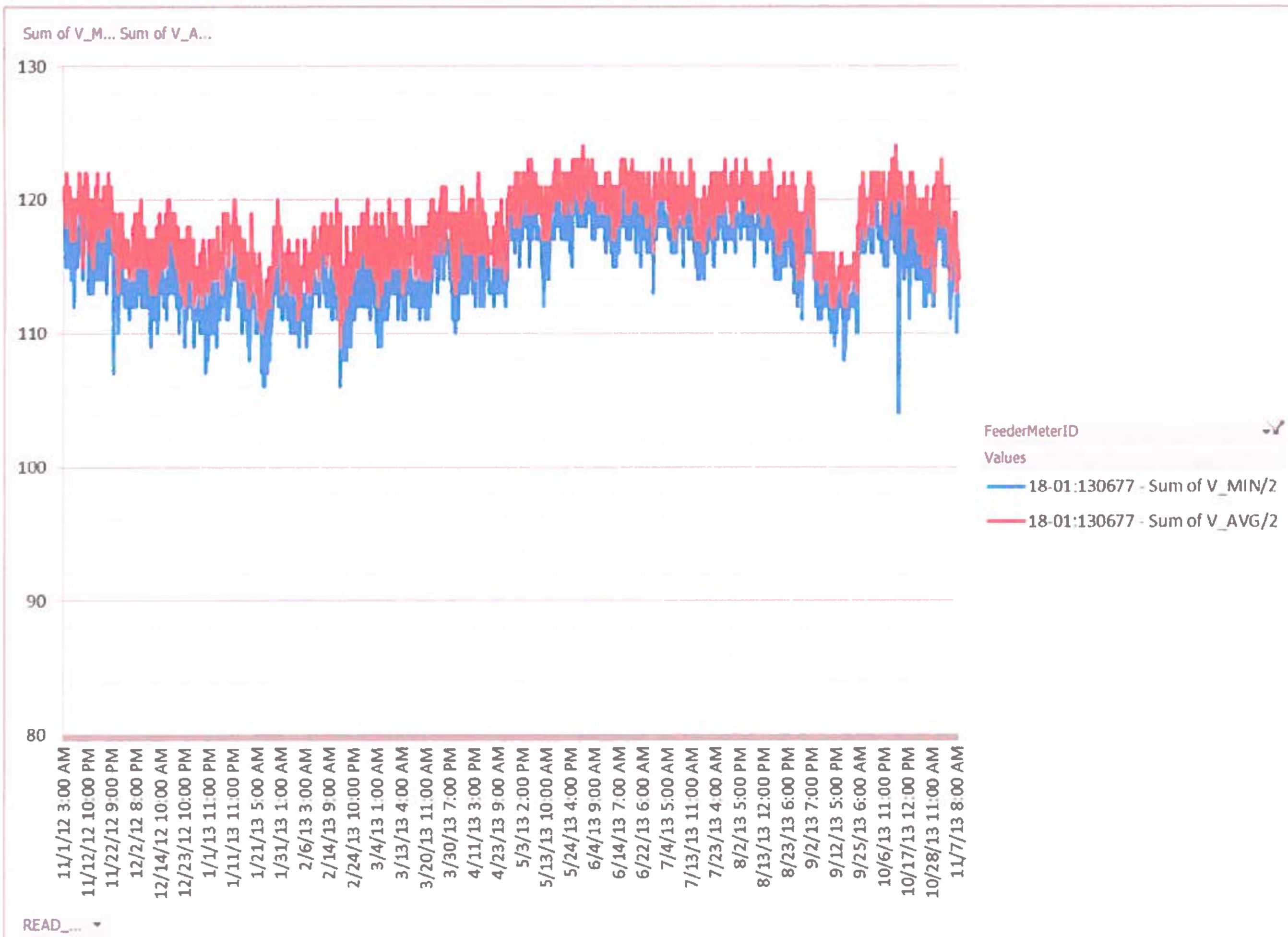
10/2/13 1:00 PM
10/12/13 5:00 AM
10/22/13 8:00 PM
11/1/13 3:00 AM
FeederMeterID
Values
18-01:130673 - Sum of V_MIN/2
18-01:130673 - Sum of V_AVG/2
READ_...


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
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11/22/12 9:00 PM
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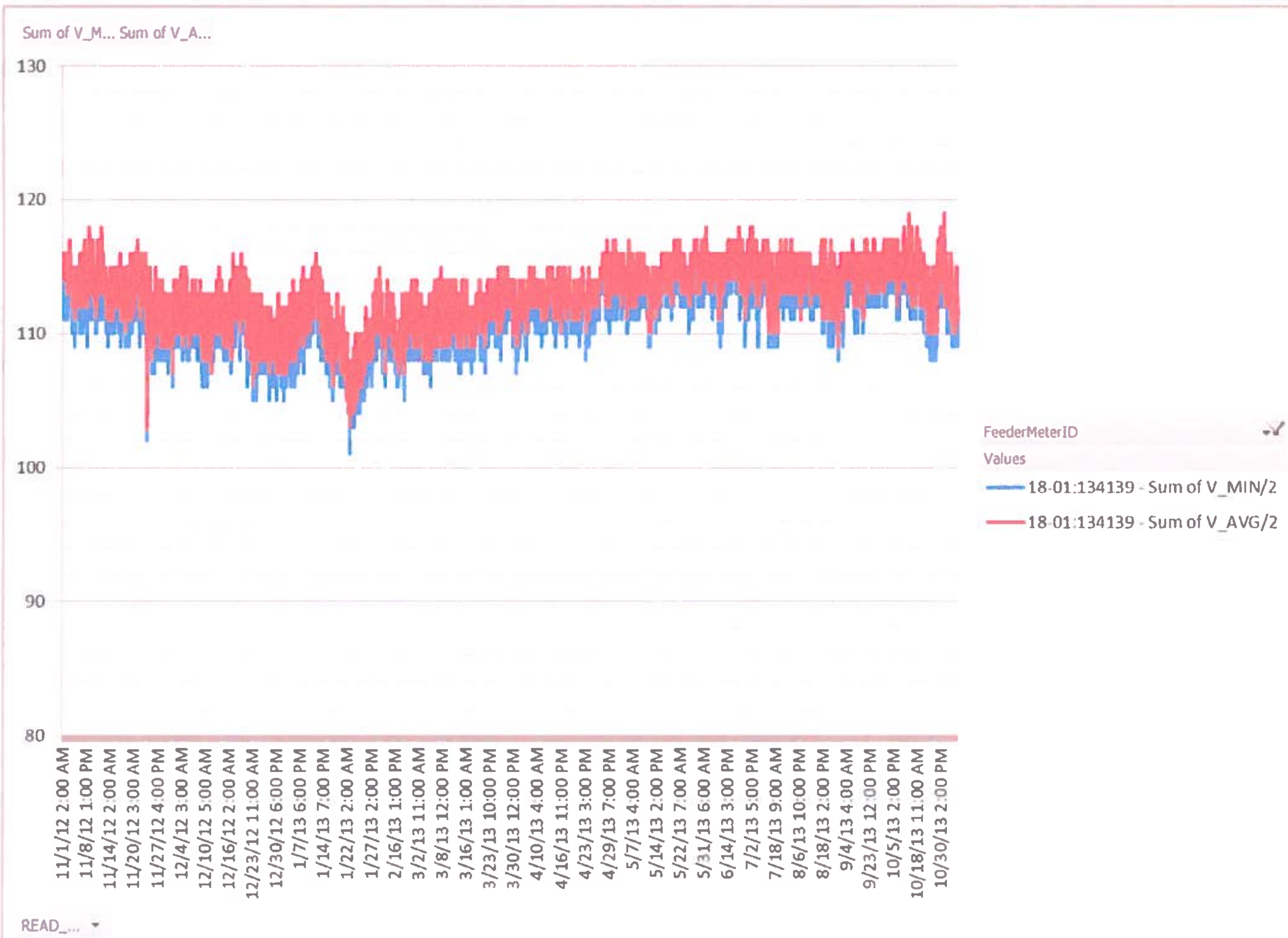
11/7/13 8:00 AM
READ_...
FeederMeterID
Values
18-01:130677 - Sum of V_MIN/2
18-01:130677 - Sum of V_AVG/2

leidos



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 2:00 AM
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11/14/12 2:00 AM
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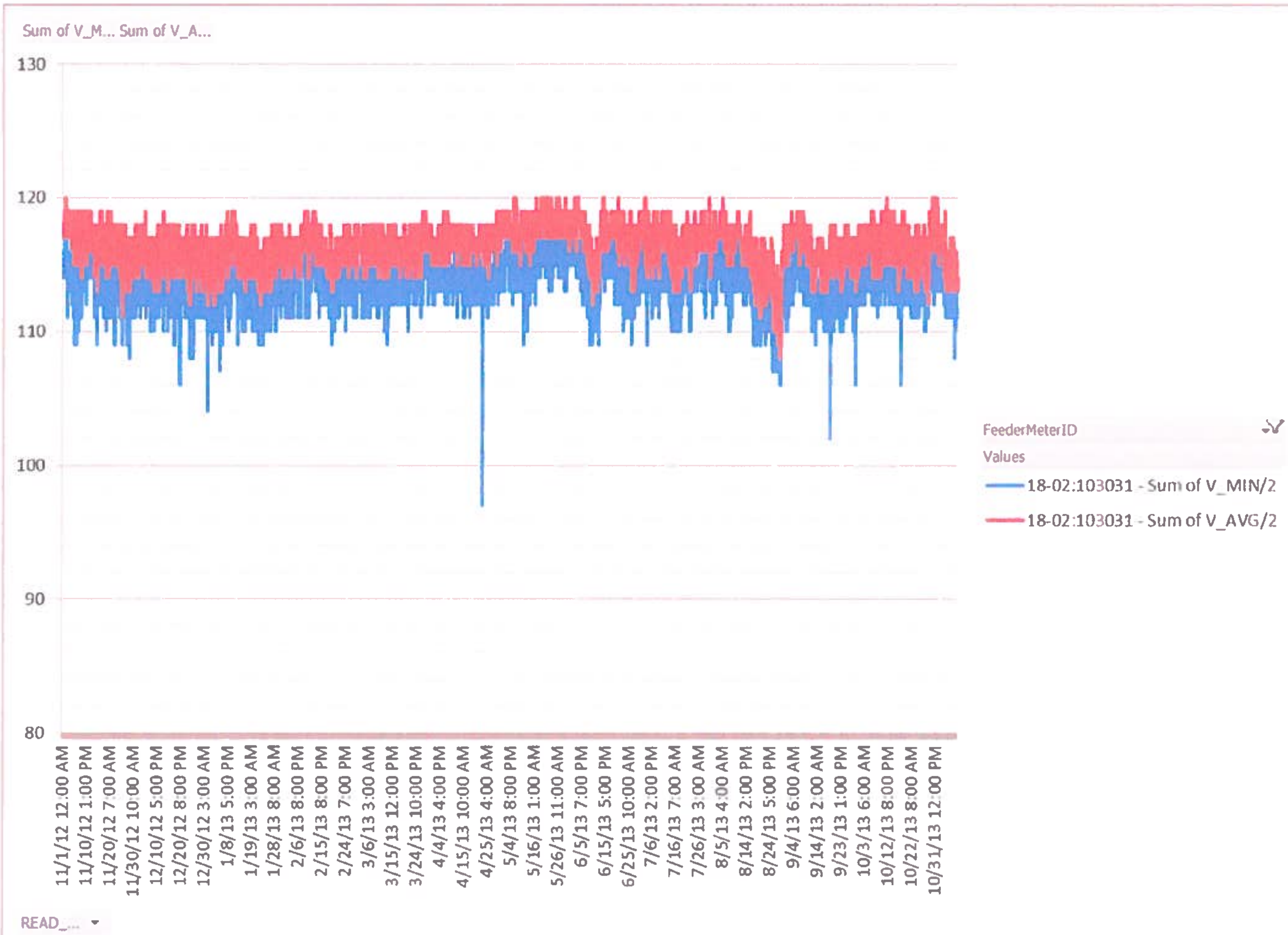
10/18/13 11:00 AM
10/30/13 2:00 PM
FeederMeterID
Values
18-01:134139 - Sum of V_MIN/2
18-01:134139 - Sum of V_AVG/2
READ_...

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
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11/20/12 7:00 AM
11/30/12 10:00 AM
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9/23/13 1:00 PM
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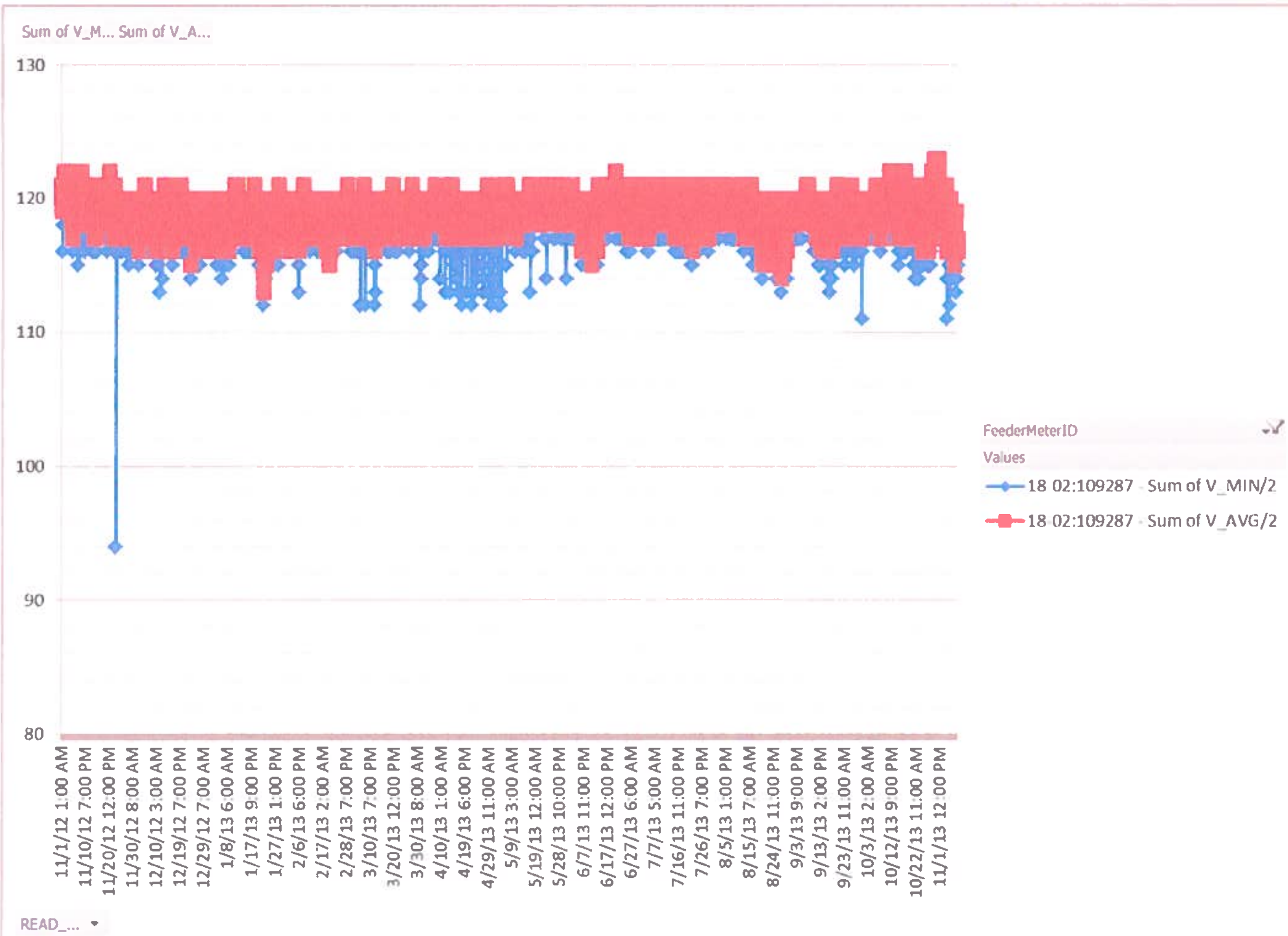
10/12/13 8:00 PM
10/22/13 8:00 AM
10/31/13 12:00 PM
READ_...
FeederMeterID
Values
18-02:103031 - Sum of V_MIN/2
18-02:103031 - Sum of V_AVG/2

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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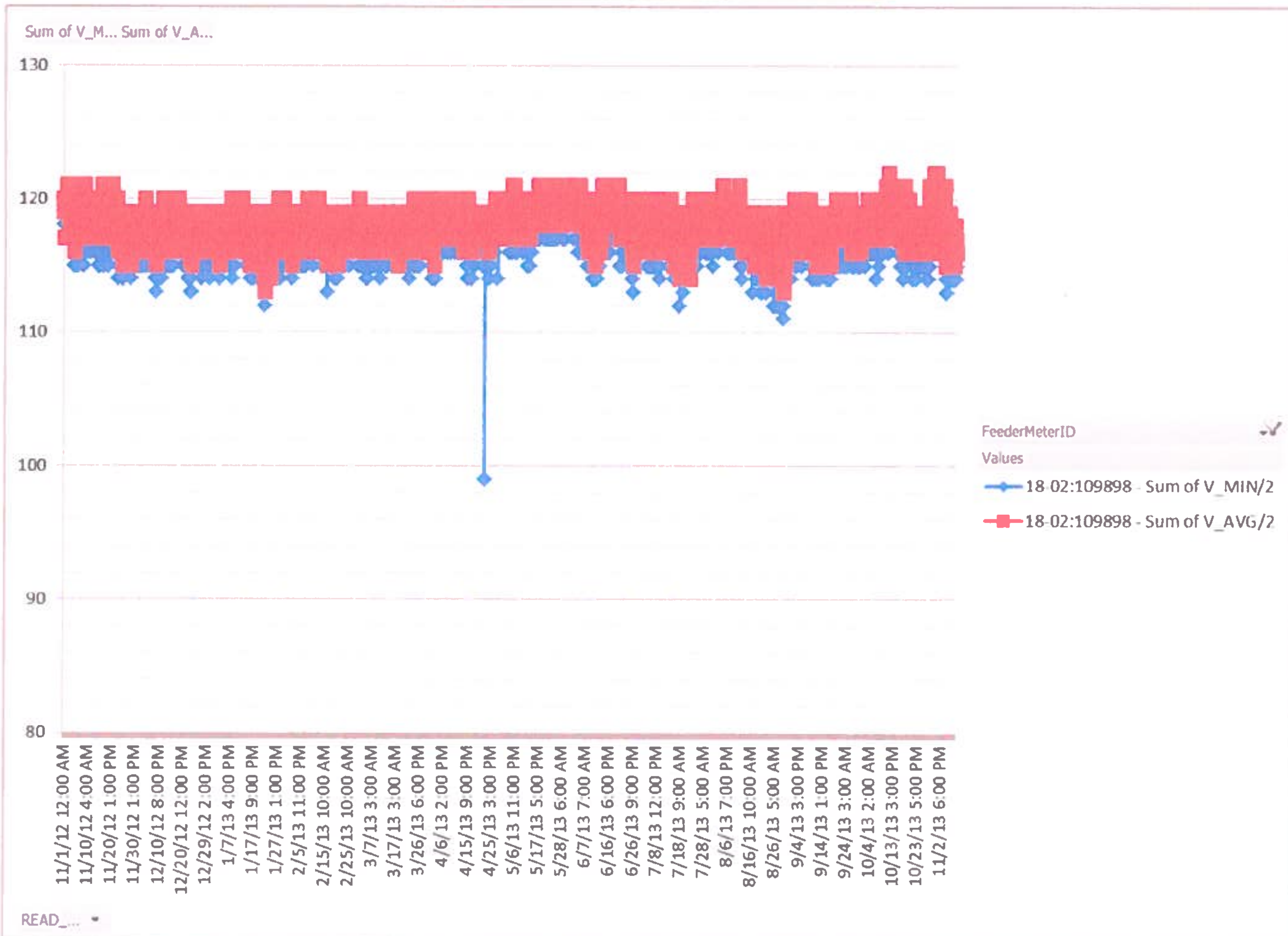
9/23/13 11:00 AM
10/3/13 2:00 AM
10/12/13 9:00 PM
10/22/13 11:00 AM
11/1/13 12:00 PM
READ_...
FeederMeterID
Values
18 02:109287 - Sum of V_MIN/2
18 02:109287 - Sum of V_AVG/2

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
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10/4/13 2:00 AM
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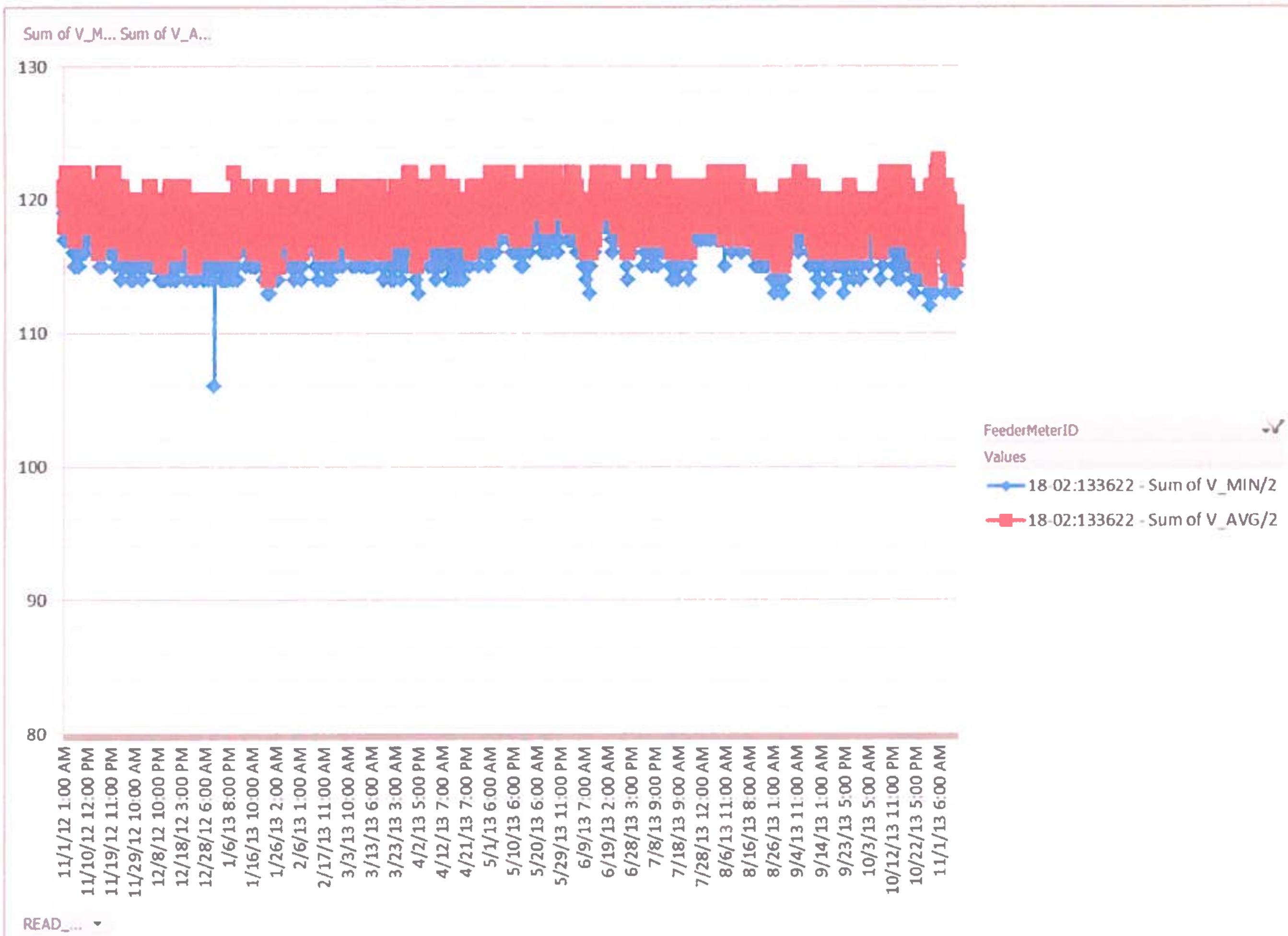
10/23/13 5:00 PM
11/2/13 6:00 PM
FeederMeterID
Values
18-02:109898 - Sum of V_MIN/2
18-02:109898 - Sum of V_AVG/2
READ_...


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/10/12 12:00 PM
11/19/12 11:00 PM
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10/22/13 5:00 PM
11/1/13 6:00 AM
READ_...
FeederMeterID
Values
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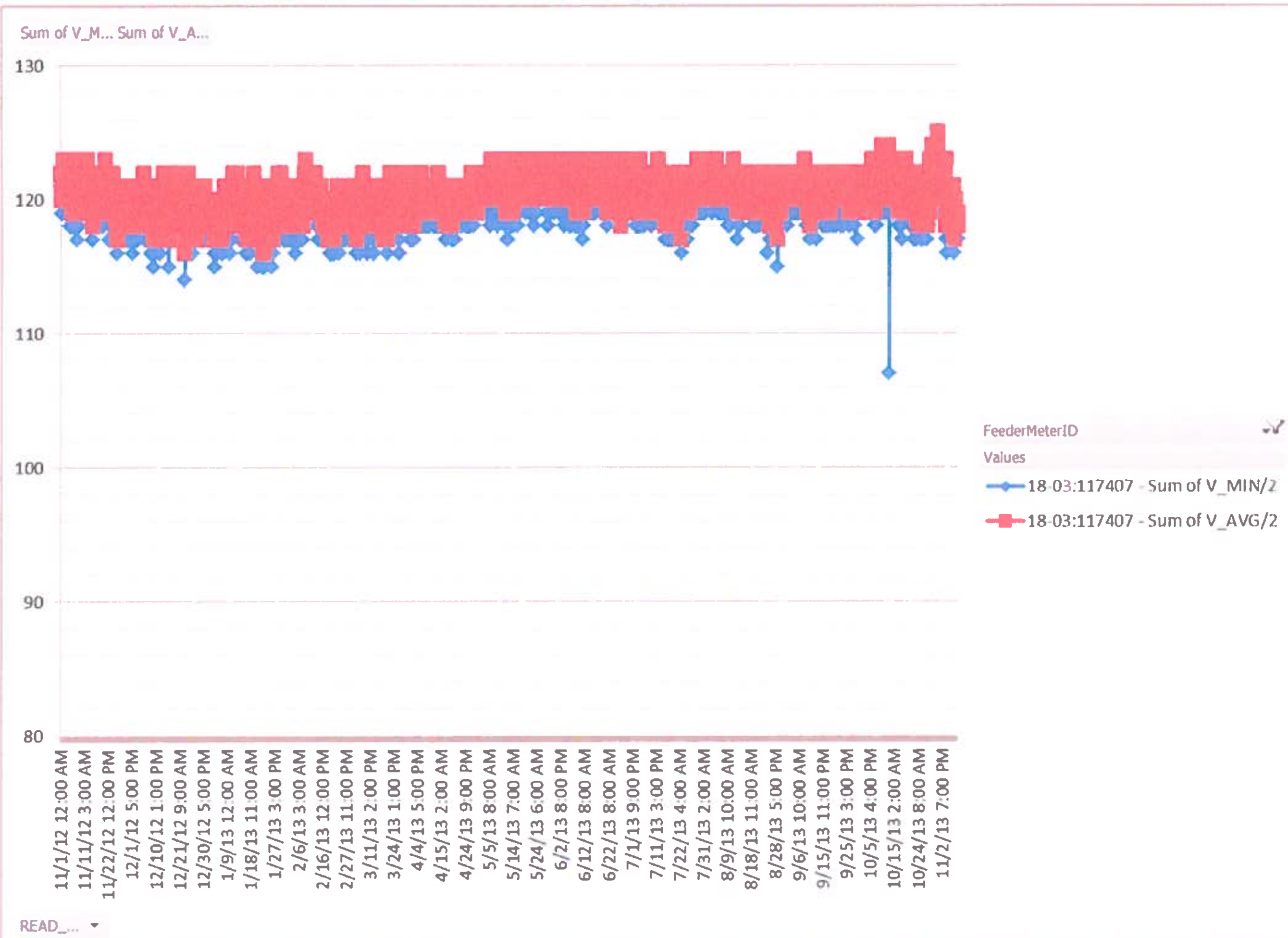
18-02:133622 - Sum of V_AVG/2

leidos



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
FeederMeterID
Values
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18-03:117407 - Sum of V_AVG/2
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11/22/12 12:00 PM
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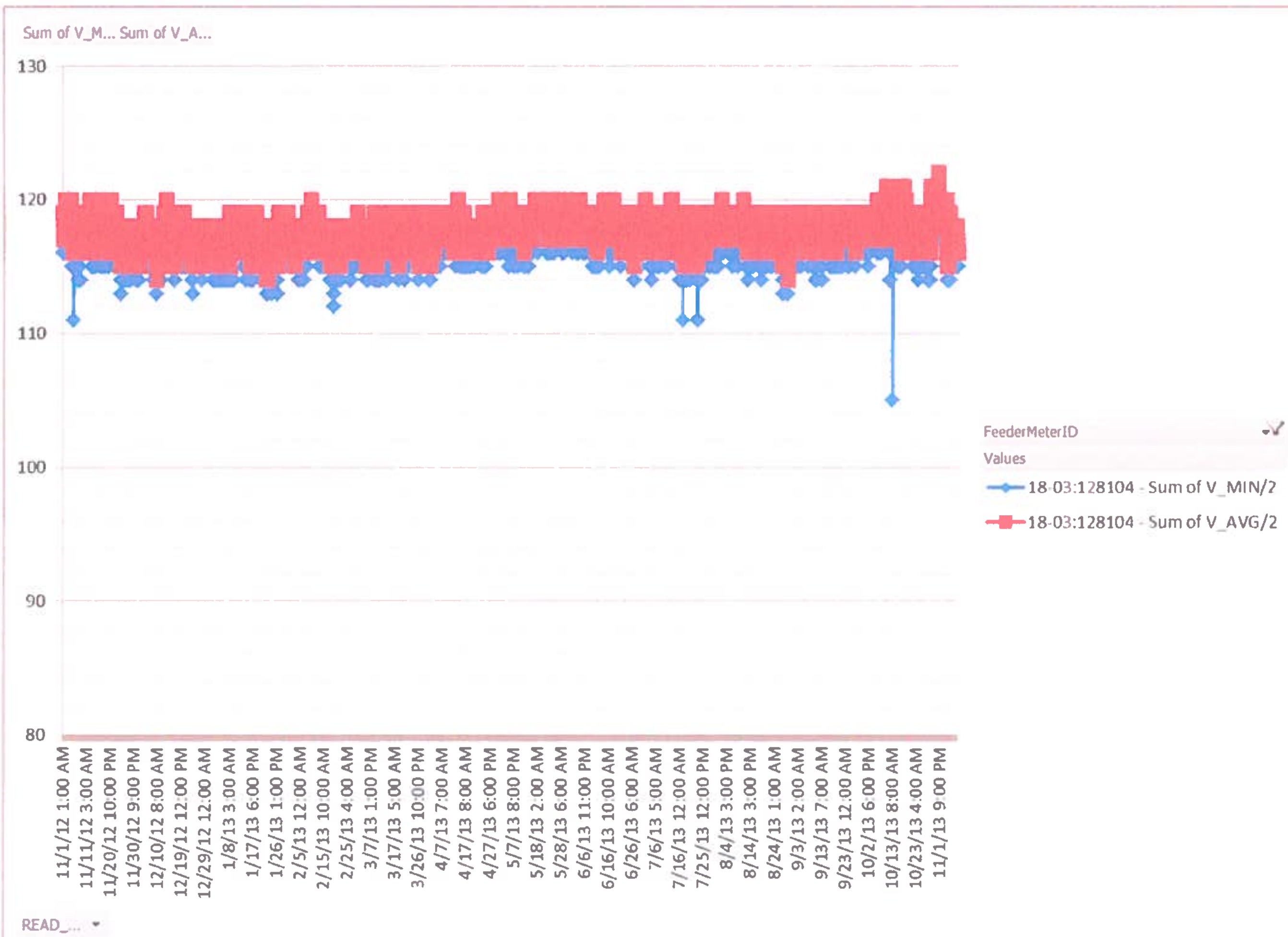
READ_...



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 1:00 AM
11/11/12 3:00 AM
11/20/12 10:00 PM
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1/17/13 6:00 PM
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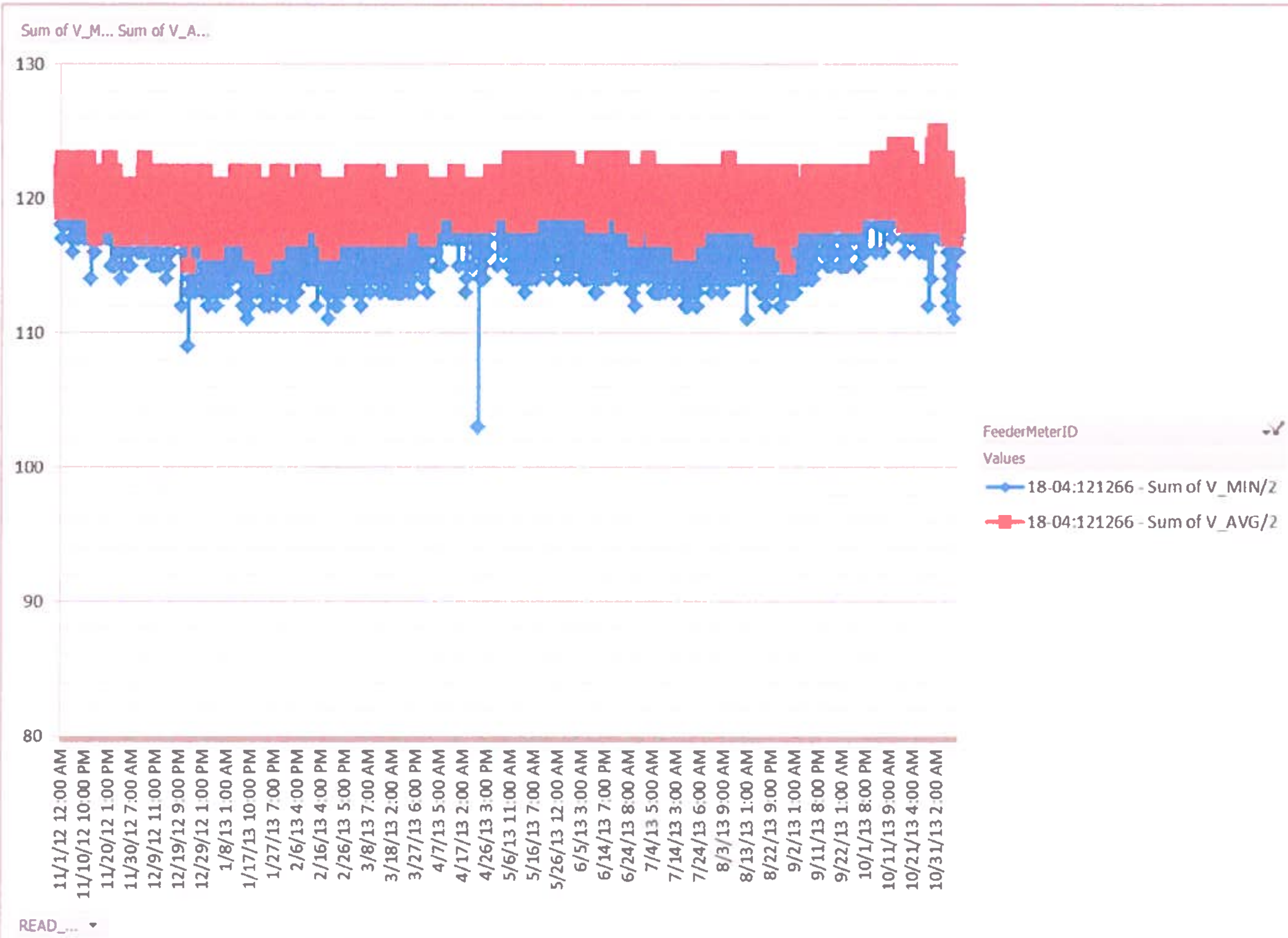
10/23/13 4:00 AM
11/1/13 9:00 PM
FeederMeterID
Values
18-03:128104 - Sum of V_MIN/2
18-03:128104 - Sum of V_AVG/2
READ_...

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
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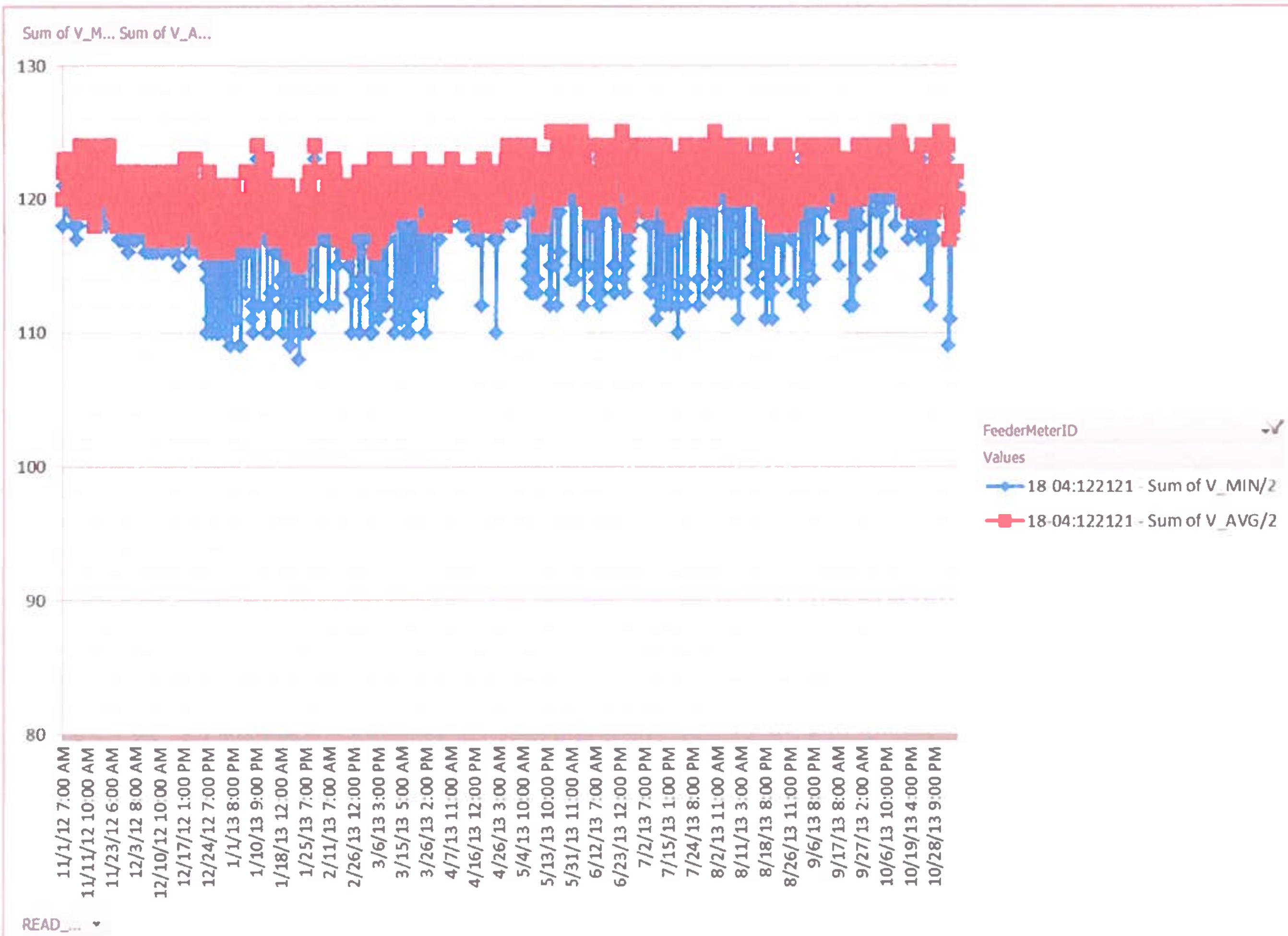
10/21/13 4:00 AM
10/31/13 2:00 AM
FeederMeterID
Values
18-04:121266 - Sum of V_MIN/2
18-04:121266 - Sum of V_AVG/2
READ_...

leidos



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 7:00 AM
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11/23/12 6:00 AM
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12/24/12 7:00 PM
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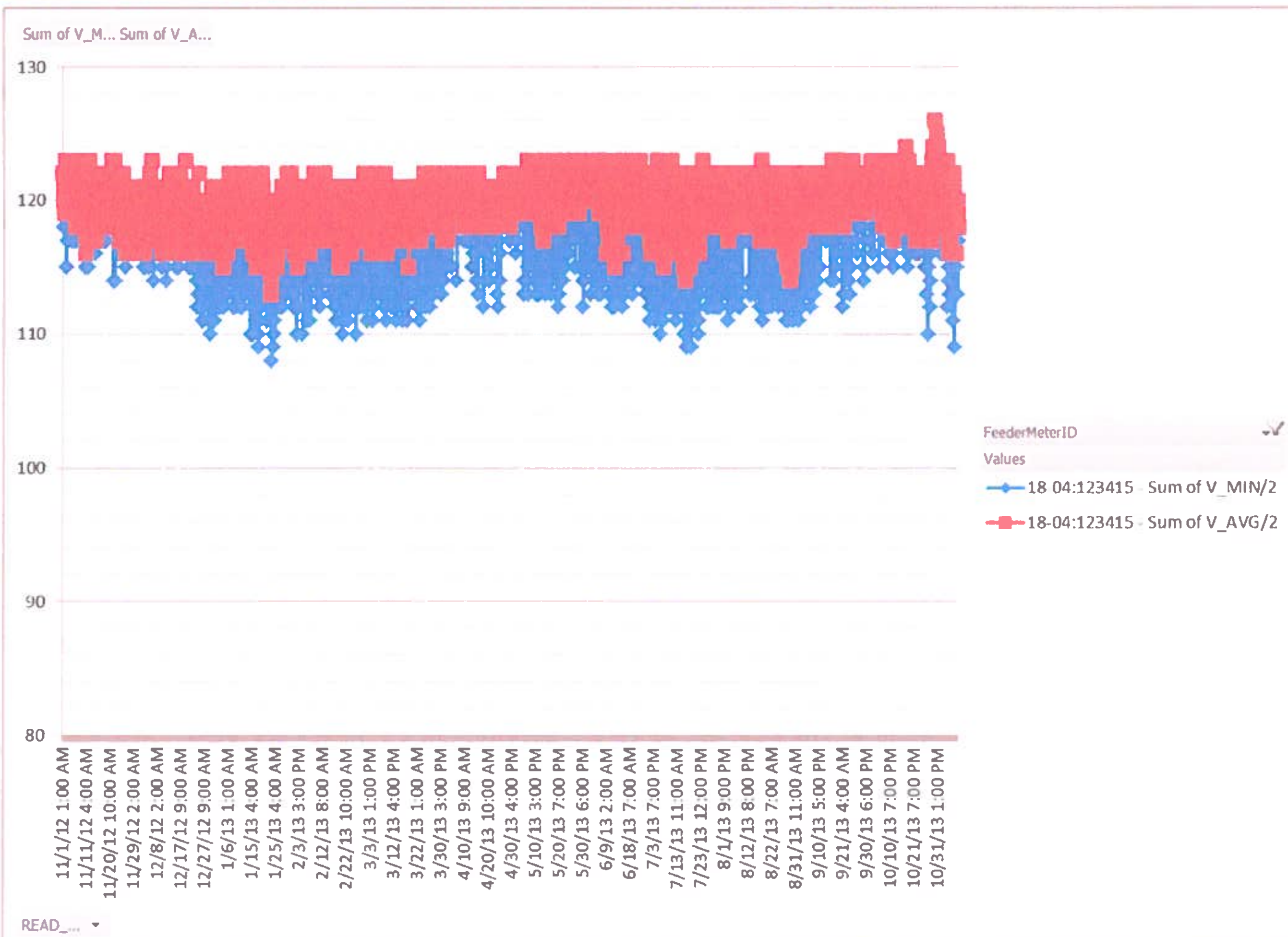
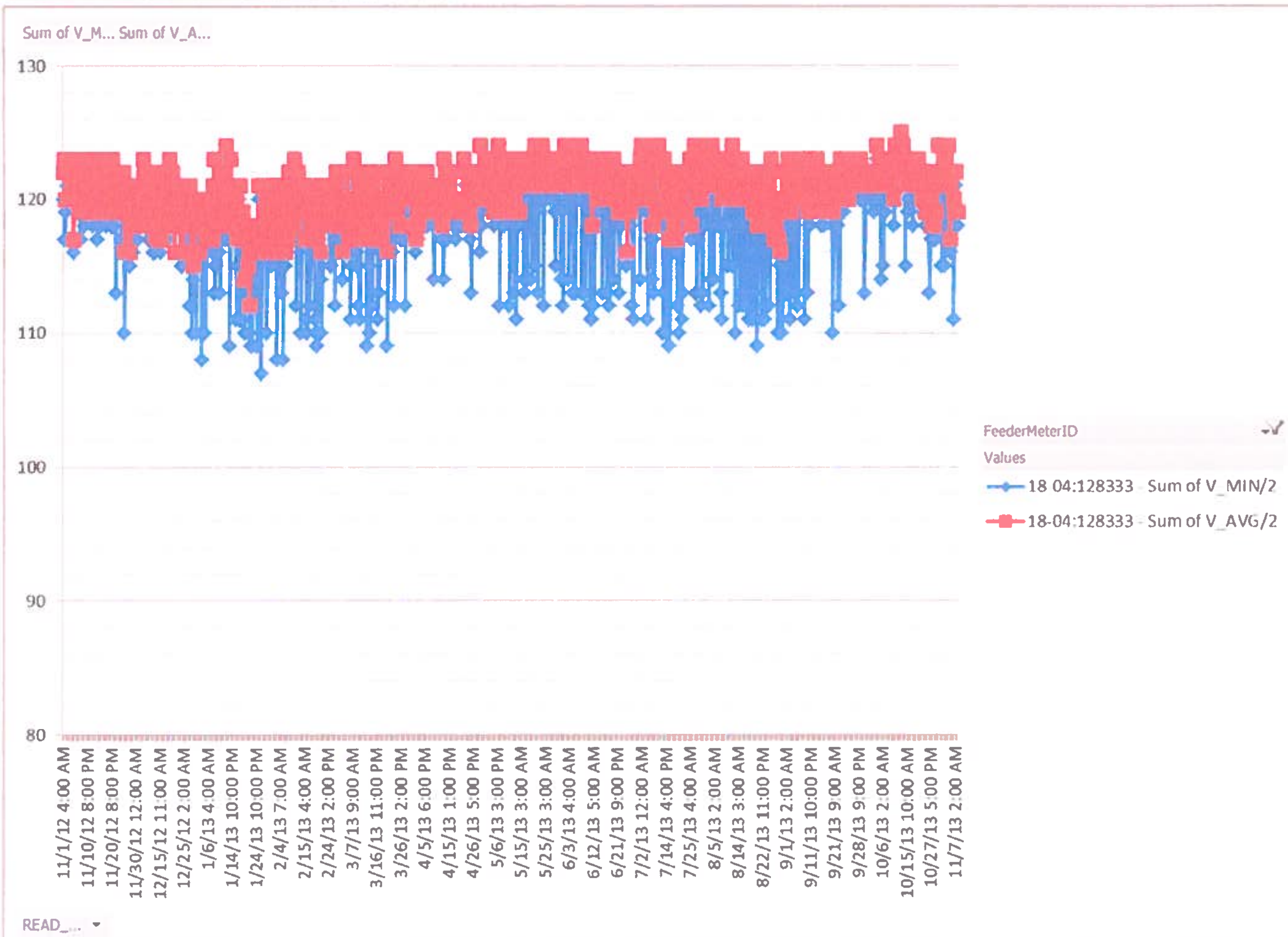
9/17/13 8:00 AM
9/27/13 2:00 AM
10/6/13 10:00 PM
10/19/13 4:00 PM
10/28/13 9:00 PM
READ_...
FeederMeterID
Values
18-04:122121 - Sum of V_MIN/2
18-04:122121 - Sum of V_AVG/2

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 AM
11/20/12 10:00 AM
11/29/12 2:00 AM
12/8/12 2:00 AM
12/17/12 9:00 AM
12/27/12 9:00 AM
1/6/13 1:00 AM
1/15/13 4:00 AM
1/25/13 4:00 AM
2/3/13 3:00 PM
2/12/13 8:00 AM
2/22/13 10:00 AM
3/3/13 1:00 PM
3/12/13 4:00 PM
3/22/13 1:00 AM
3/30/13 3:00 PM
4/10/13 9:00 AM
4/20/13 10:00 AM
4/30/13 4:00 PM
5/10/13 3:00 PM
5/20/13 7:00 PM
5/30/13 6:00 PM
6/9/13 2:00 AM
6/18/13 7:00 AM
7/3/13 7:00 PM
7/13/13 11:00 AM
7/23/13 12:00 PM
8/1/13 9:00 PM
8/12/13 8:00 PM
8/22/13 7:00 AM
8/31/13 11:00 AM
9/10/13 5:00 PM
9/21/13 4:00 AM
9/30/13 6:00 PM
10/10/13 7:00 PM
10/21/13 7:00 PM
10/31/13 1:00 PM
READ_...
FeederMeterID
Values
18-04:123415 - Sum of V_MIN/2
18-04:123415 - Sum of V_AVG/2

leidos


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 4:00 AM
11/10/12 8:00 PM
11/20/12 8:00 PM
11/30/12 12:00 AM
12/15/12 11:00 AM
12/25/12 2:00 AM
1/6/13 4:00 AM
1/14/13 10:00 PM
1/24/13 10:00 PM
2/4/13 7:00 AM
2/15/13 4:00 AM
2/24/13 2:00 PM
3/7/13 9:00 AM
3/16/13 11:00 PM
3/26/13 2:00 PM
4/5/13 6:00 PM
4/15/13 1:00 PM
4/26/13 5:00 PM
5/6/13 3:00 PM
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5/25/13 3:00 AM
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6/21/13 9:00 PM
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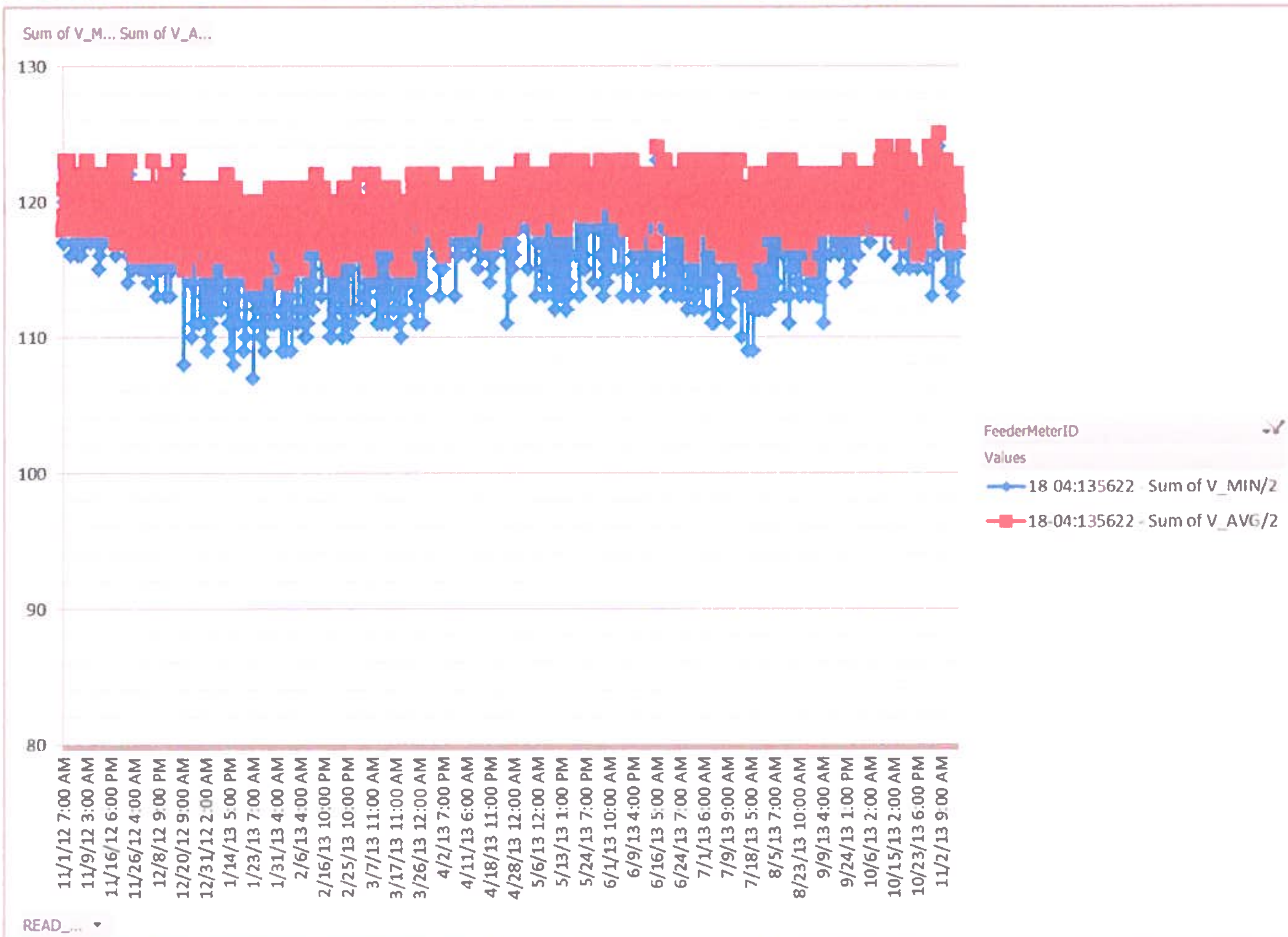
7/14/13 4:00 PM
7/25/13 4:00 AM
8/5/13 2:00 AM
8/14/13 3:00 AM
8/22/13 11:00 PM
9/1/13 2:00 AM
9/11/13 10:00 PM
9/21/13 9:00 AM
9/28/13 9:00 PM
10/6/13 2:00 AM
10/15/13 10:00 AM
10/27/13 5:00 PM
11/7/13 2:00 AM
READ_...
FeederMeterID
Values
18-04:128333 - Sum of V_MIN/2
18-04:128333 - Sum of V_AVG/2

leidos



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 7:00 AM
11/9/12 3:00 AM
11/16/12 6:00 PM
11/26/12 4:00 AM
12/8/12 9:00 PM
12/20/12 9:00 AM
12/31/12 2:00 AM
1/14/13 5:00 PM
1/23/13 7:00 AM
1/31/13 4:00 AM
2/6/13 4:00 AM
2/16/13 10:00 PM
2/25/13 10:00 PM
3/7/13 11:00 AM
3/17/13 11:00 AM
3/26/13 12:00 AM
4/2/13 7:00 PM
4/11/13 6:00 AM
4/18/13 11:00 PM
4/28/13 12:00 AM
5/6/13 12:00 AM
5/13/13 1:00 PM
5/24/13 7:00 PM
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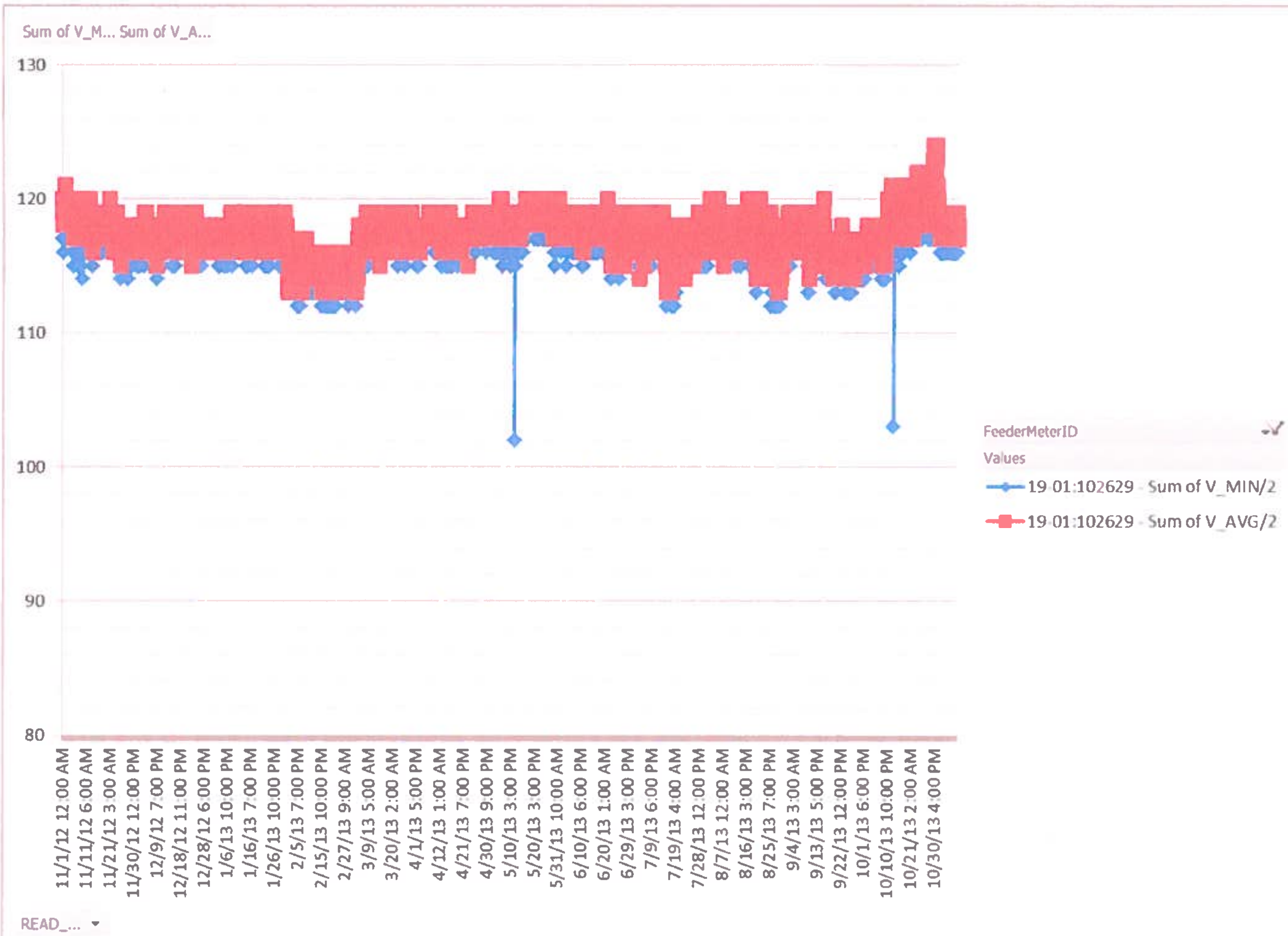
6/9/13 4:00 PM
6/16/13 5:00 AM
6/24/13 7:00 AM
7/1/13 6:00 AM
7/9/13 9:00 AM
7/18/13 5:00 AM
8/5/13 7:00 AM
8/23/13 10:00 AM
9/9/13 4:00 AM
9/24/13 1:00 PM
10/6/13 2:00 AM
10/15/13 2:00 AM
10/23/13 6:00 PM
11/2/13 9:00 AM
READ_...
FeederMeterID
Values
18-04:135622 - Sum of V_MIN/2
18-04:135622 - Sum 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 6:00 AM
11/21/12 3:00 AM
11/30/12 12:00 PM
12/9/12 7:00 PM
12/18/12 11:00 PM
12/28/12 6:00 PM
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4/21/13 7:00 PM
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8/16/13 3:00 PM
8/25/13 7:00 PM
9/4/13 3:00 AM
9/13/13 5:00 PM
9/22/13 12:00 PM
10/1/13 6:00 PM
10/10/13 10:00 PM
10/21/13 2:00 AM
10/30/13 4:00 PM
FeederMeterID
Values
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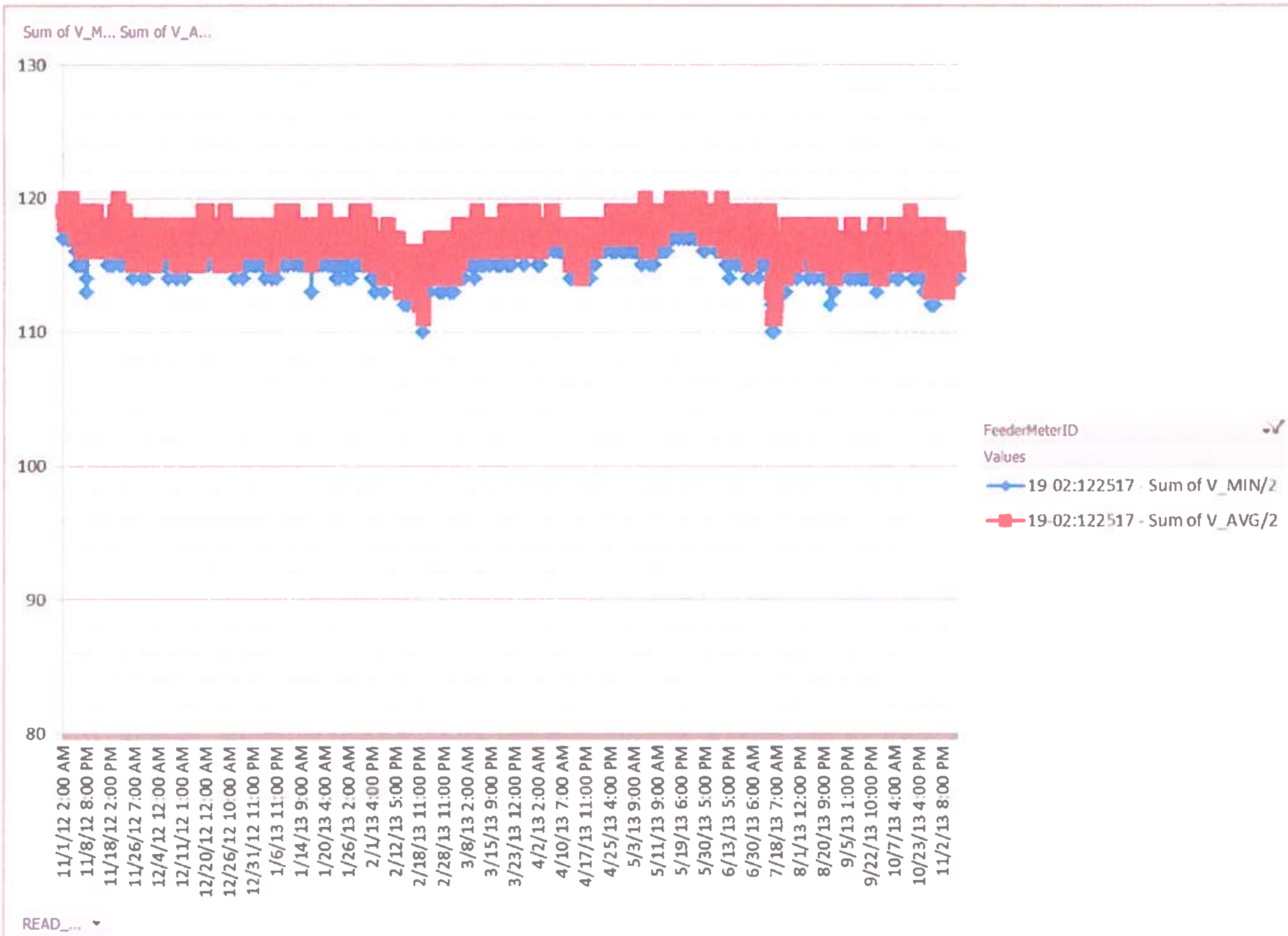
19-01:102629 - Sum of V_AVG/2
READ_...



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 2:00 AM
11/8/12 8:00 PM
11/18/12 2:00 PM
11/26/12 7:00 AM
12/4/12 12:00 AM
12/11/12 1:00 AM
12/20/12 12:00 AM
12/26/12 10:00 AM
12/31/12 11:00 PM
1/6/13 11:00 PM
1/14/13 9:00 AM
1/20/13 4:00 AM
1/26/13 2:00 AM
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2/28/13 11:00 PM
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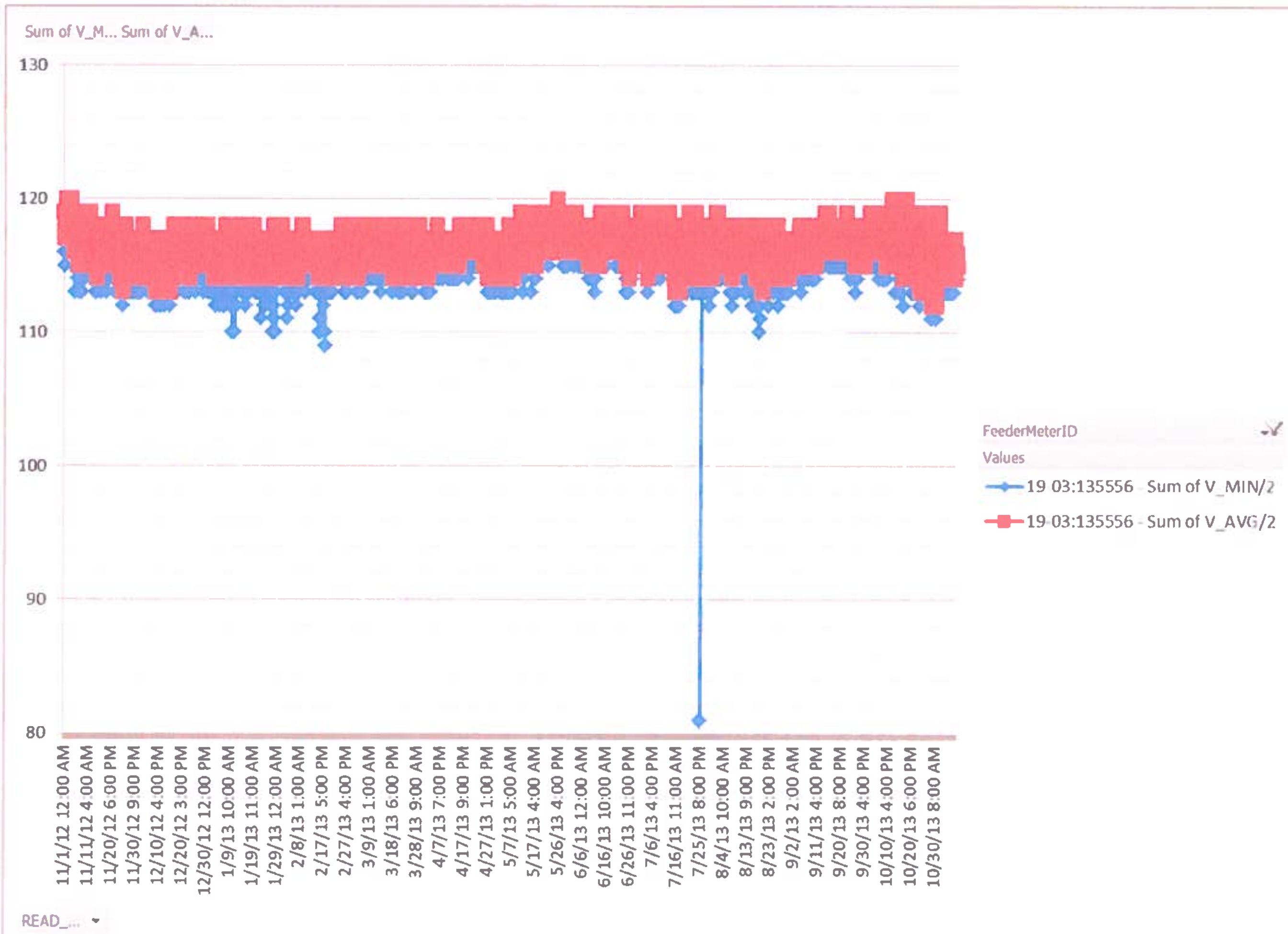
6/13/13 5:00 PM
6/30/13 6:00 AM
7/18/13 7:00 AM
8/1/13 12:00 PM
8/20/13 9:00 PM
9/5/13 1:00 PM
9/22/13 10:00 PM
10/7/13 4:00 AM
10/23/13 4:00 PM
11/2/13 8:00 PM
FeederMeterID
Values
19-02:122517 - Sum of V_MIN/2
19-02:122517 - Sum of V_AVG/2
READ_...



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/11/12 4:00 AM
11/20/12 6:00 PM
11/30/12 9:00 PM
12/10/12 4:00 PM
12/20/12 3:00 PM
12/30/12 12:00 AM
1/9/13 10:00 AM
1/19/13 11:00 AM
1/29/13 12:00 AM
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2/17/13 5:00 PM
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5/26/13 4:00 PM
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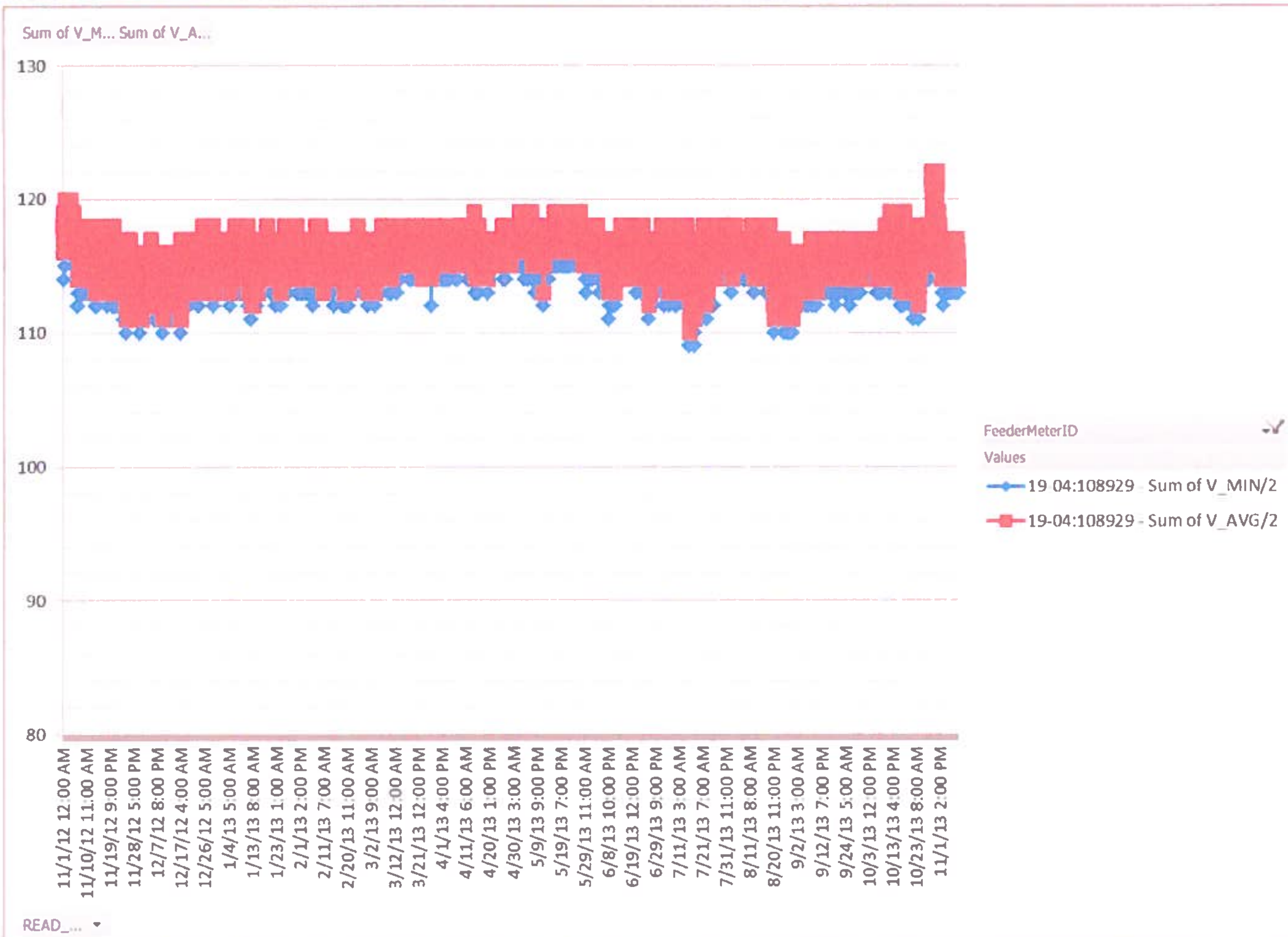
8/23/13 2:00 PM
9/2/13 2:00 AM
9/11/13 4:00 PM
9/20/13 8:00 PM
9/30/13 4:00 PM
10/10/13 4:00 PM
10/20/13 6:00 PM
10/30/13 8:00 AM
FeederMeterID
Values
19-03:135556 - Sum of V_MIN/2
19-03:135556 - Sum of V_AVG/2
READ_...



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
11/19/12 9:00 PM
11/28/12 5:00 PM
12/7/12 8:00 PM
12/17/12 4:00 AM
12/26/12 5:00 AM
1/4/13 5:00 AM
1/13/13 8:00 AM
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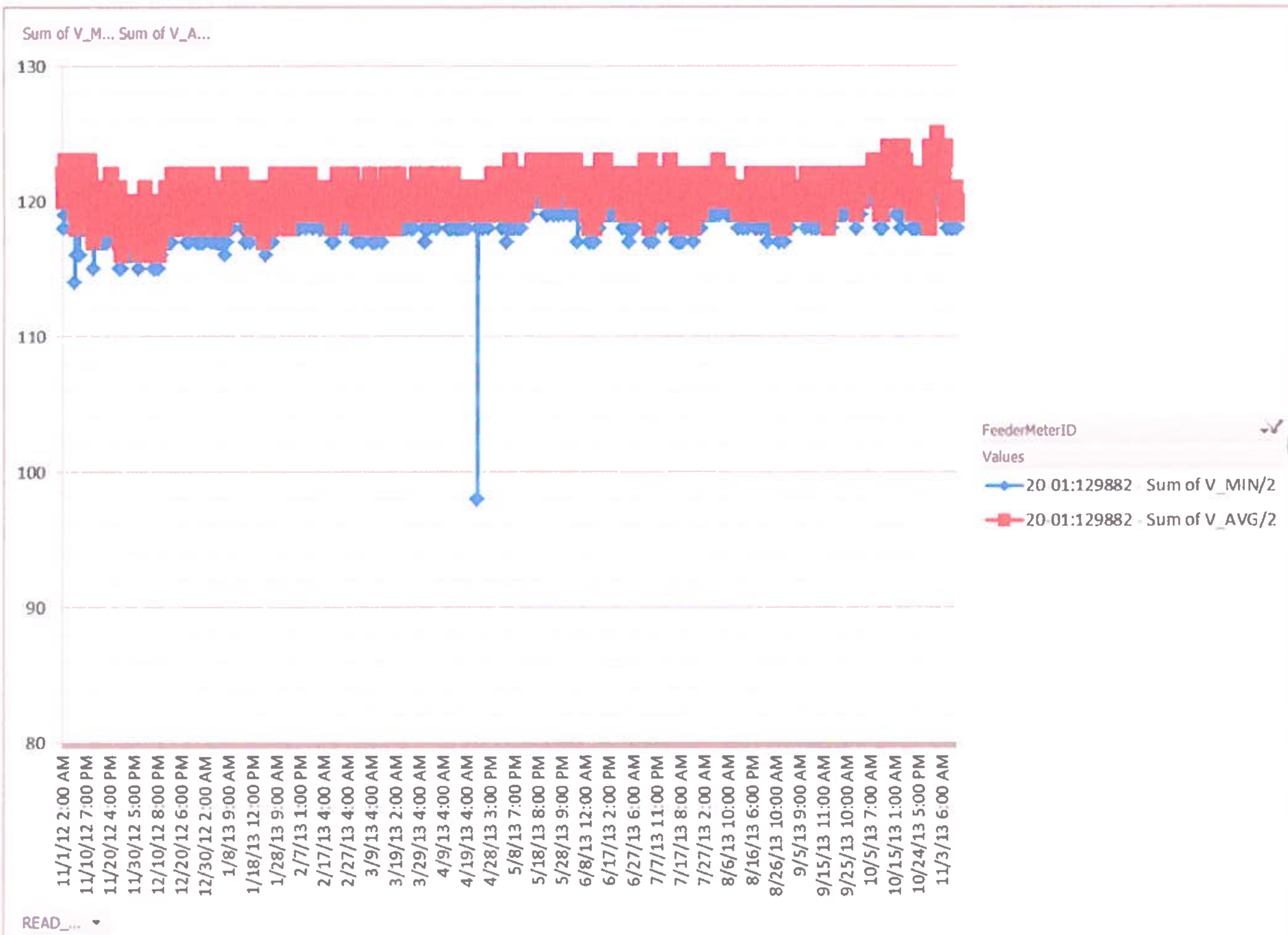
9/24/13 5:00 AM
10/3/13 12:00 PM
10/13/13 4:00 PM
10/23/13 8:00 AM
11/1/13 2:00 PM
READ_...
FeederMeterID
Values
19-04:108929 - Sum of V_MIN/2
19-04:108929 - Sum of V_AVG/2



Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 2:00 AM
11/10/12 7:00 PM
11/20/12 4:00 PM
11/30/12 5:00 PM
12/10/12 8:00 PM
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9/15/13 11:00 AM
9/25/13 10:00 AM
10/5/13 7:00 AM
10/15/13 1:00 AM
10/24/13 5:00 PM
11/3/13 6:00 AM
FeederMeterID
Values
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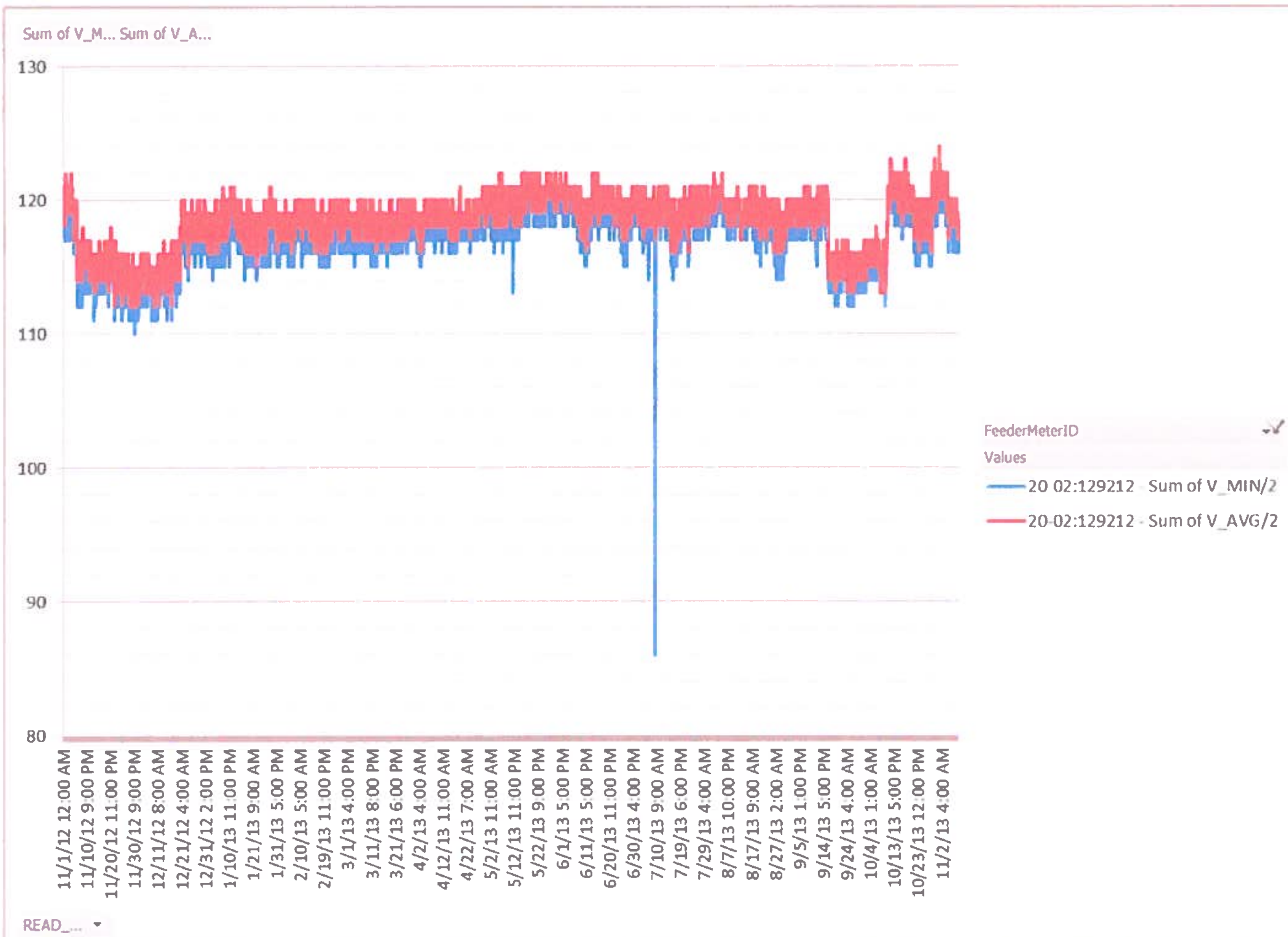
20 01:129882 Sum of V_AVG/2
READ_...



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 11:00 PM
11/30/12 9:00 PM
12/11/12 8:00 AM
12/21/12 4:00 AM
12/31/12 2:00 PM
1/10/13 11:00 PM
1/21/13 9:00 AM
1/31/13 5:00 PM
2/10/13 5:00 AM
2/19/13 11:00 PM
3/1/13 4:00 PM
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6/30/13 4:00 PM
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8/17/13 9:00 AM
8/27/13 2:00 AM
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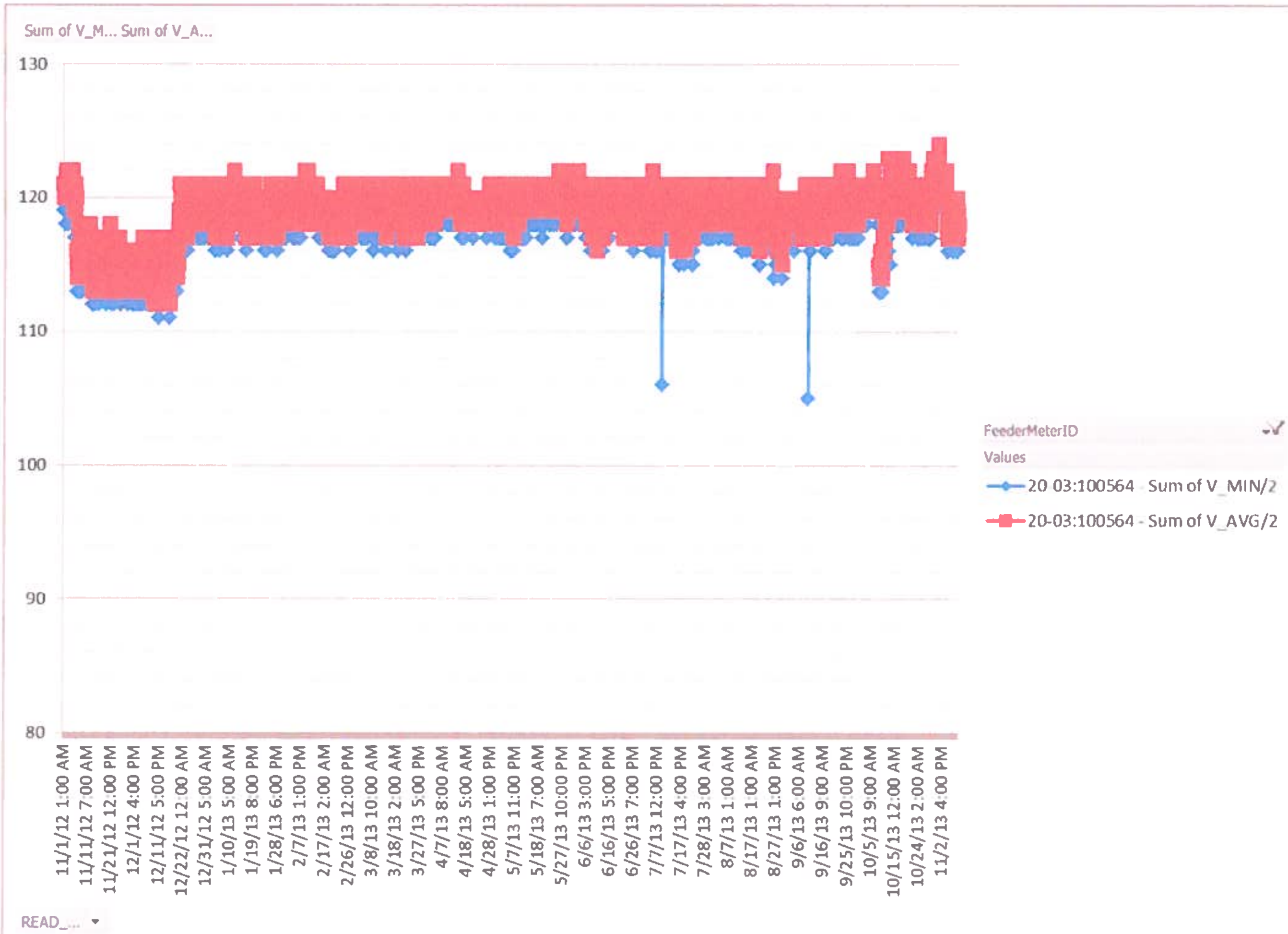
9/14/13 5:00 PM
9/24/13 4:00 AM
10/4/13 1:00 AM
10/13/13 5:00 PM
10/23/13 12:00 PM
11/2/13 4:00 AM
READ_...
FeederMeterID
Values
20 02:129212 Sum of V_MIN/2
20-02:129212 Sum of V_AVG/2


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
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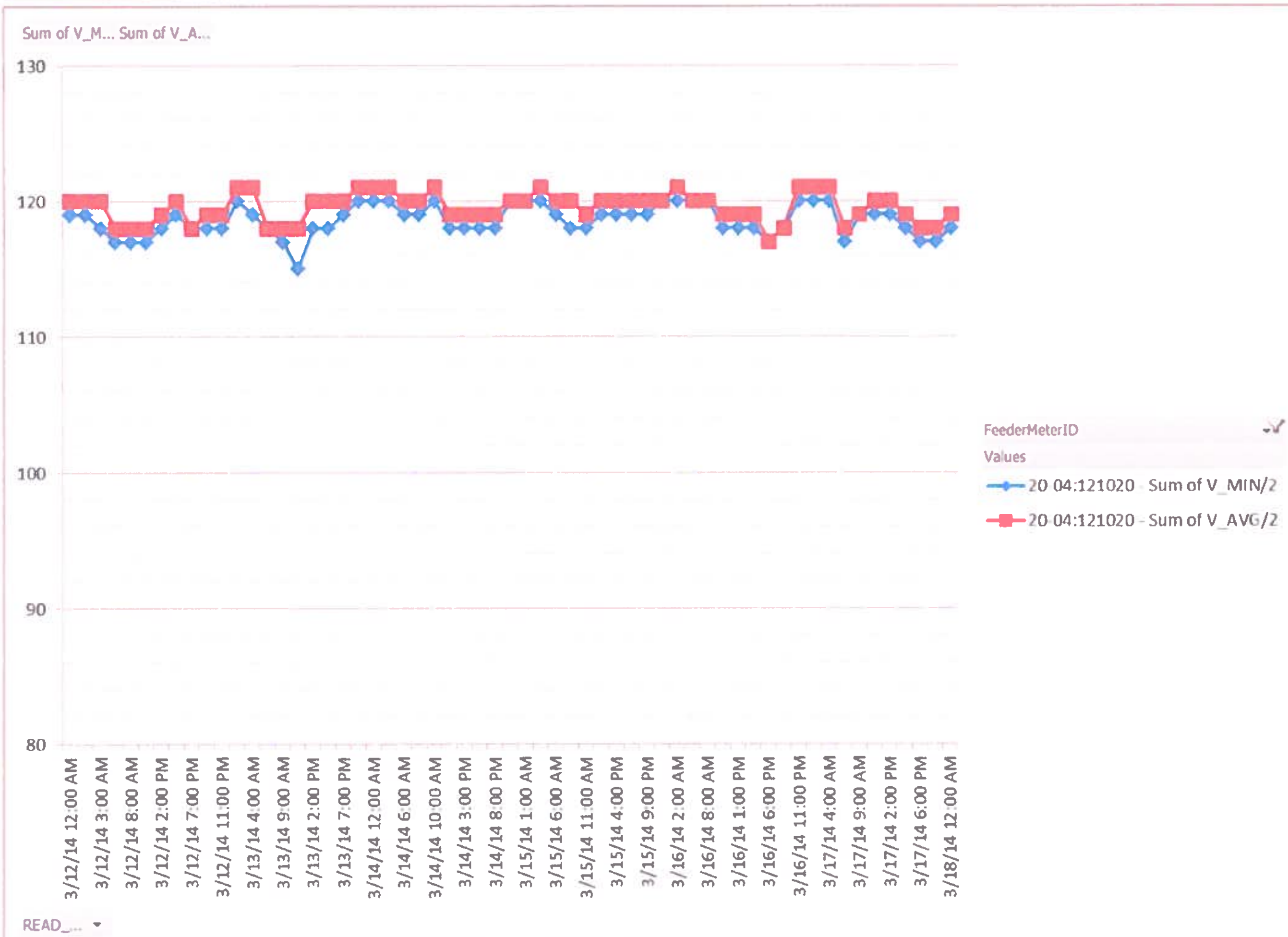
8/27/13 1:00 PM
9/6/13 6:00 AM
9/16/13 9:00 AM
9/25/13 10:00 PM
10/5/13 9:00 AM
10/15/13 12:00 AM
10/24/13 2:00 AM
11/2/13 4:00 PM
FeederMeterID
Values
20-03:100564 - Sum of V_MIN/2
20-03:100564 - Sum of V_AVG/2
READ_...

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
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3/13/14 7:00 PM
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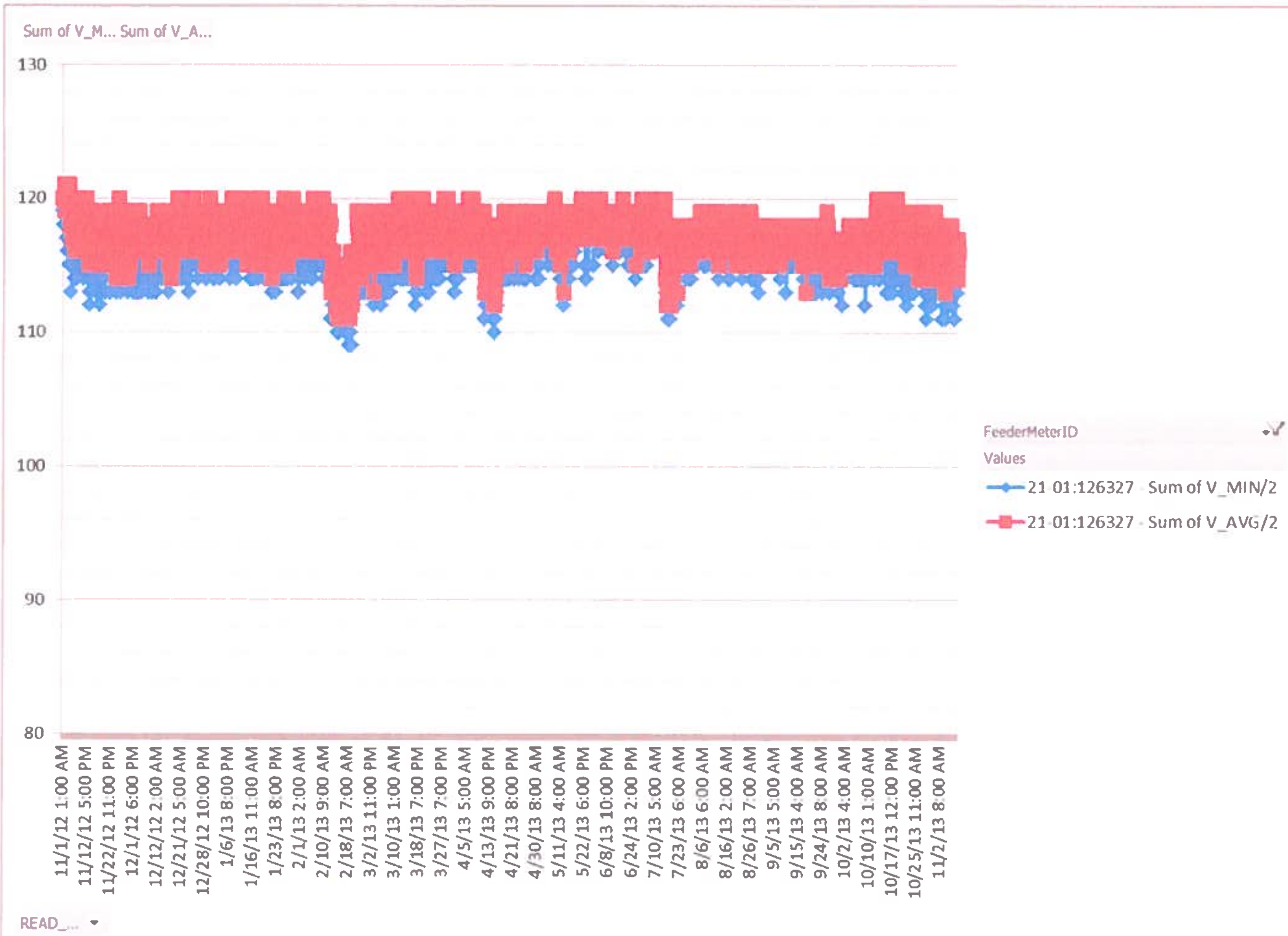
3/17/14 4:00 AM
3/17/14 9:00 AM
3/17/14 2:00 PM
3/17/14 6:00 PM
3/18/14 12:00 AM
READ_...
FeederMeterID
Values
20-04:121020 - Sum of V_MIN/2
20-04:121020 - Sum of V_AVG/2

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
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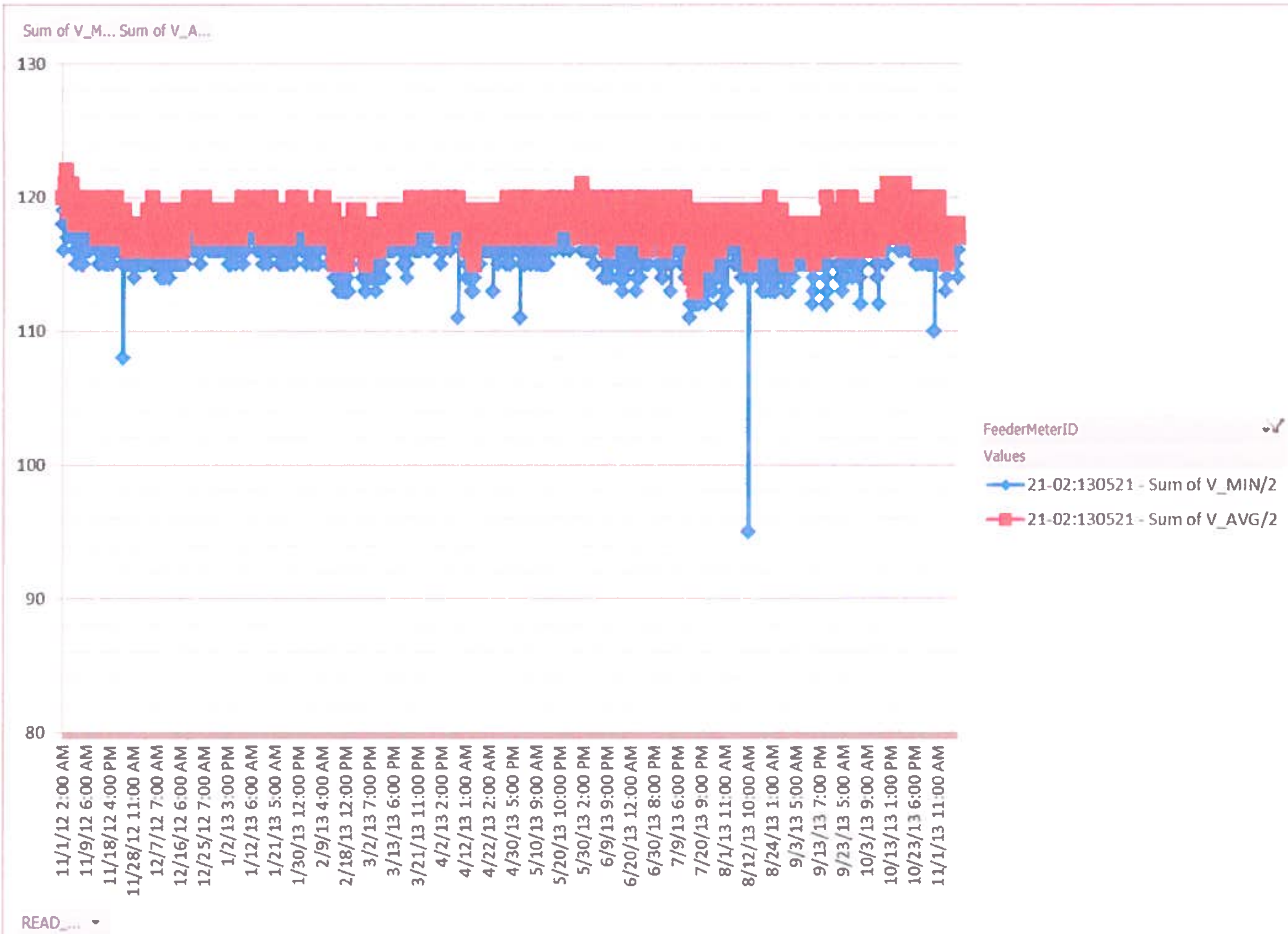
8/26/13 7:00 AM
9/5/13 5:00 AM
9/15/13 4:00 AM
9/24/13 8:00 AM
10/2/13 4:00 AM
10/10/13 1:00 AM
10/17/13 12:00 PM
10/25/13 11:00 AM
11/2/13 8:00 AM
READ_...
FeederMeterID
Values
21 01:126327 - Sum of V_MIN/2
21 01:126327 - Sum of V_AVG/2

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
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4/22/13 2:00 AM
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8/24/13 1:00 AM
9/3/13 5:00 AM
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9/23/13 5:00 AM
10/3/13 9:00 AM
10/13/13 1:00 PM
10/23/13 6:00 PM
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FeederMeterID
Values
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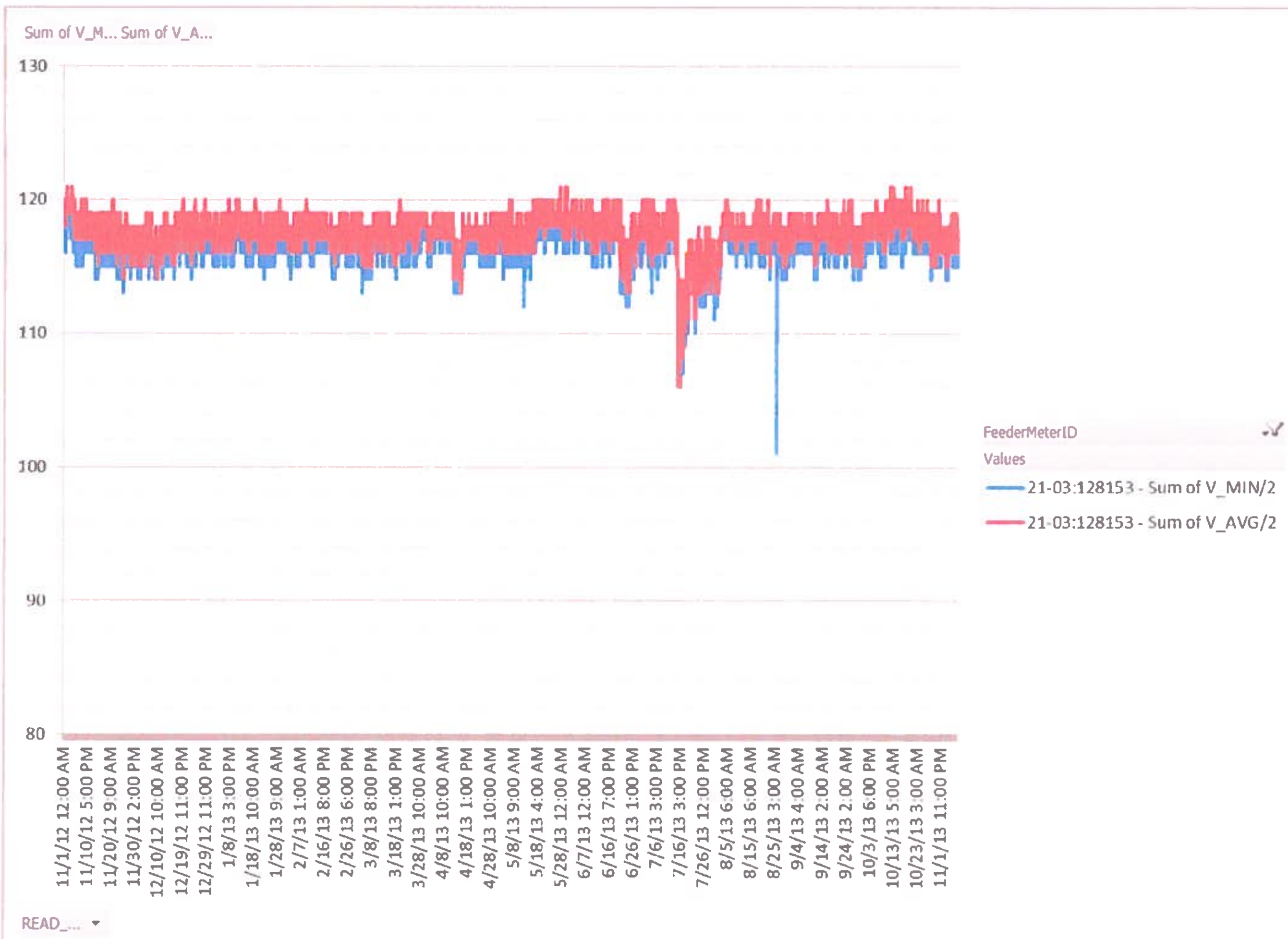
21-02:130521 - Sum of V_AVG/2
READ_...


Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
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11/20/12 9:00 AM
11/30/12 2:00 PM
12/10/12 10:00 AM
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12/29/12 11:00 PM
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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
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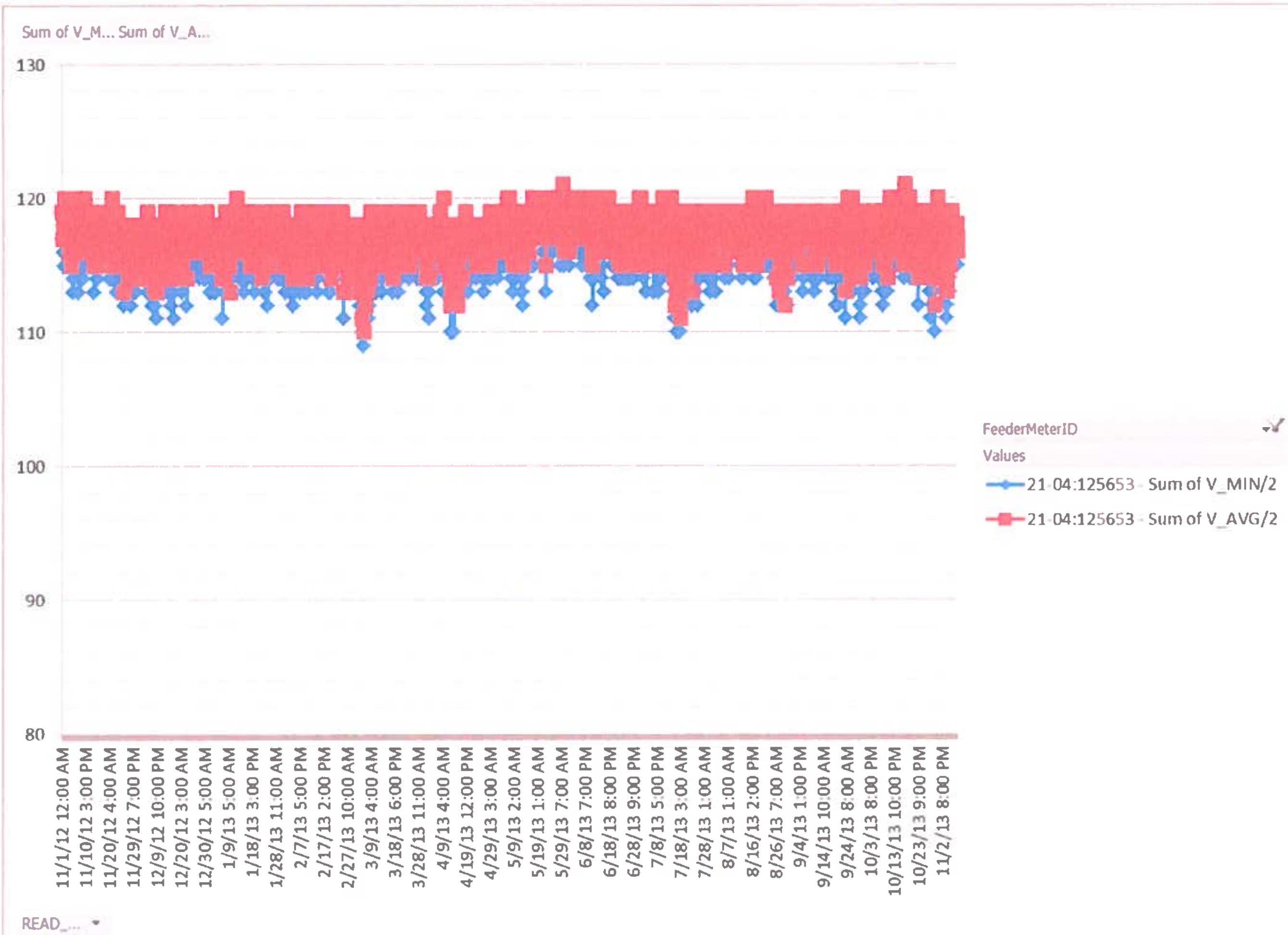
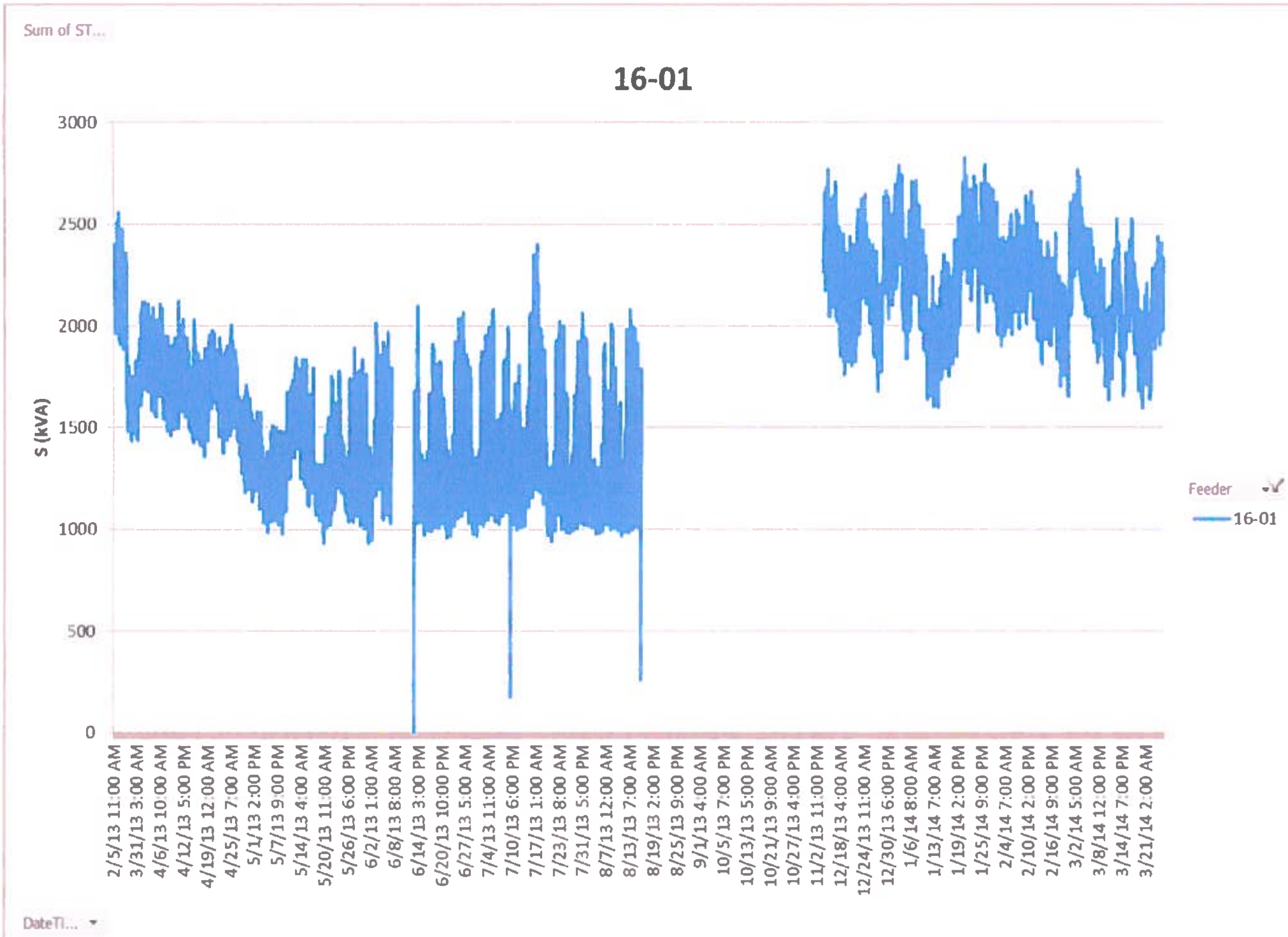
3/18/13 1:00 PM
3/28/13 10:00 AM
4/8/13 10:00 AM
4/18/13 1:00 PM
4/28/13 10:00 AM
5/8/13 9:00 AM
5/18/13 4:00 AM
5/28/13 12:00 AM
6/7/13 12:00 AM
6/16/13 7:00 PM
6/26/13 1:00 PM
7/6/13 3:00 PM
7/16/13 3:00 PM
7/26/13 12:00 PM
8/5/13 6:00 AM
8/15/13 6:00 AM
8/25/13 3:00 AM
9/4/13 4:00 AM
9/14/13 2:00 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

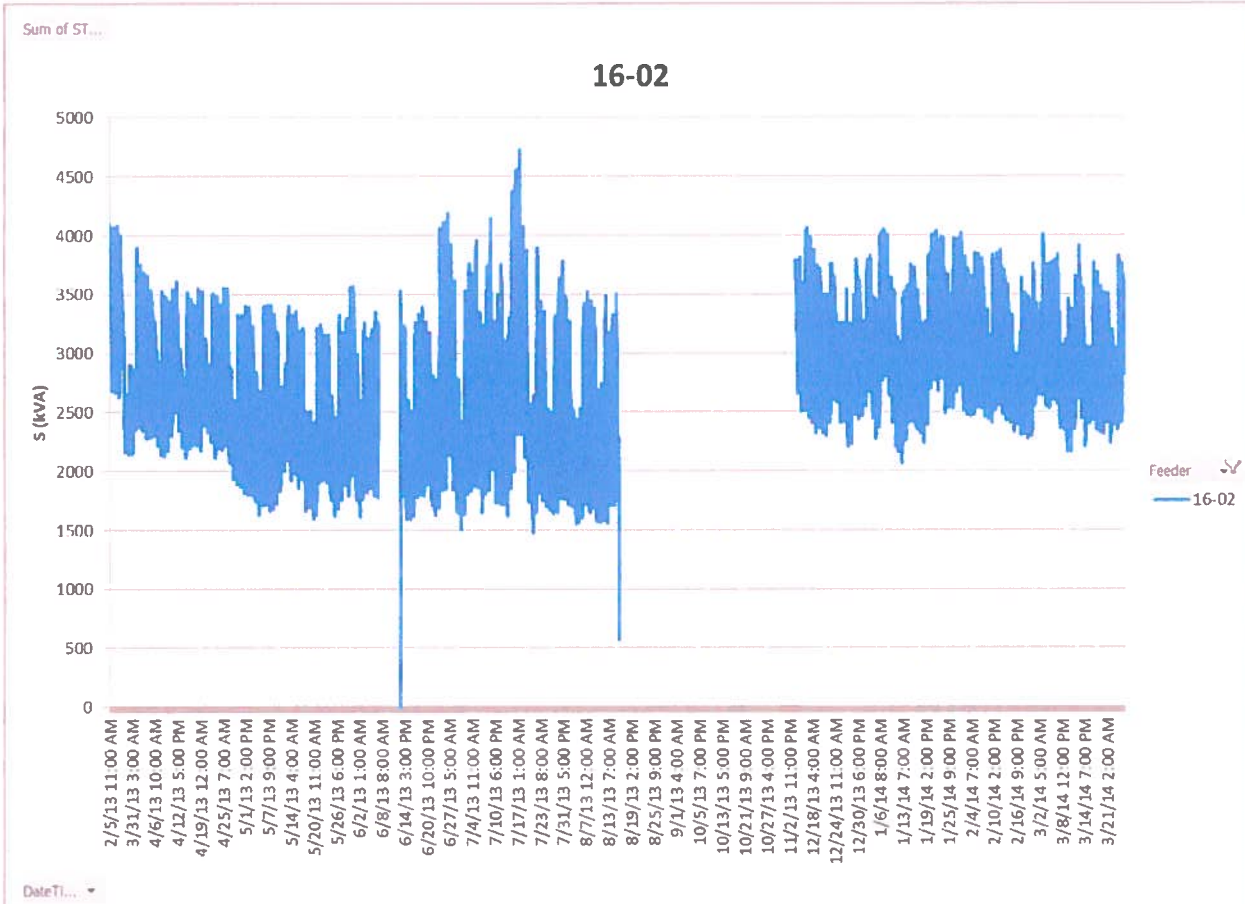

Sum of V_M... Sum of V_A...
130
120
110
100
90
80
11/1/12 12:00 AM
11/10/12 3:00 PM
11/20/12 4:00 AM
11/29/12 7:00 PM
12/9/12 10:00 PM
12/20/12 3:00 AM
12/30/12 5:00 AM
1/9/13 5:00 AM
1/18/13 3:00 PM
1/28/13 11:00 AM
2/7/13 5:00 PM
2/17/13 2:00 PM
2/27/13 10:00 AM
3/9/13 4:00 AM
3/18/13 6:00 PM
3/28/13 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
FeederMeterID
Values
21-04:125653 - Sum of V_MIN/2
21-04:125653 - Sum of V_AVG/2
READ_...

Appendix 4. SCADA Load Profiles per Feeder

16-01:

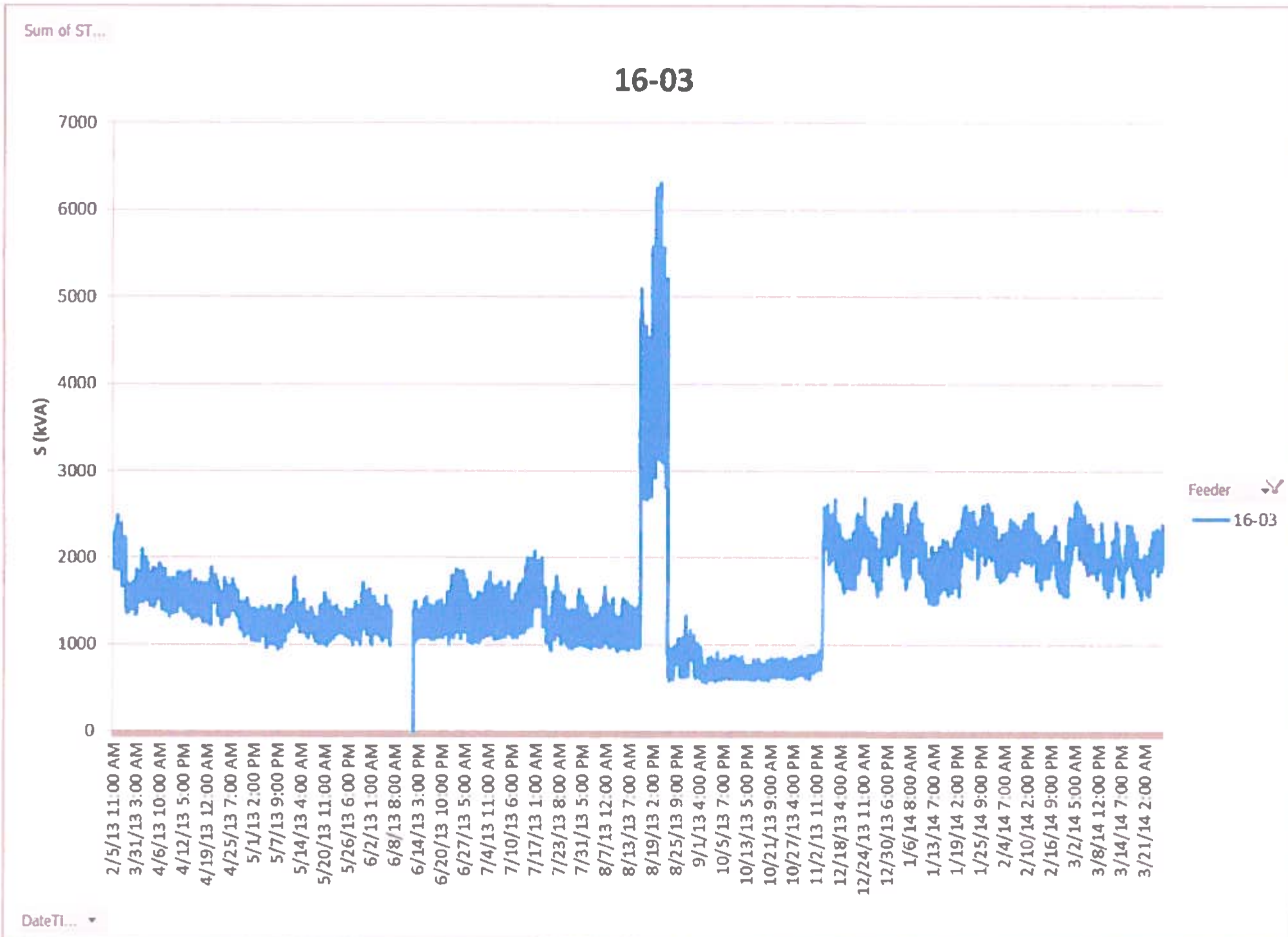


16-02:



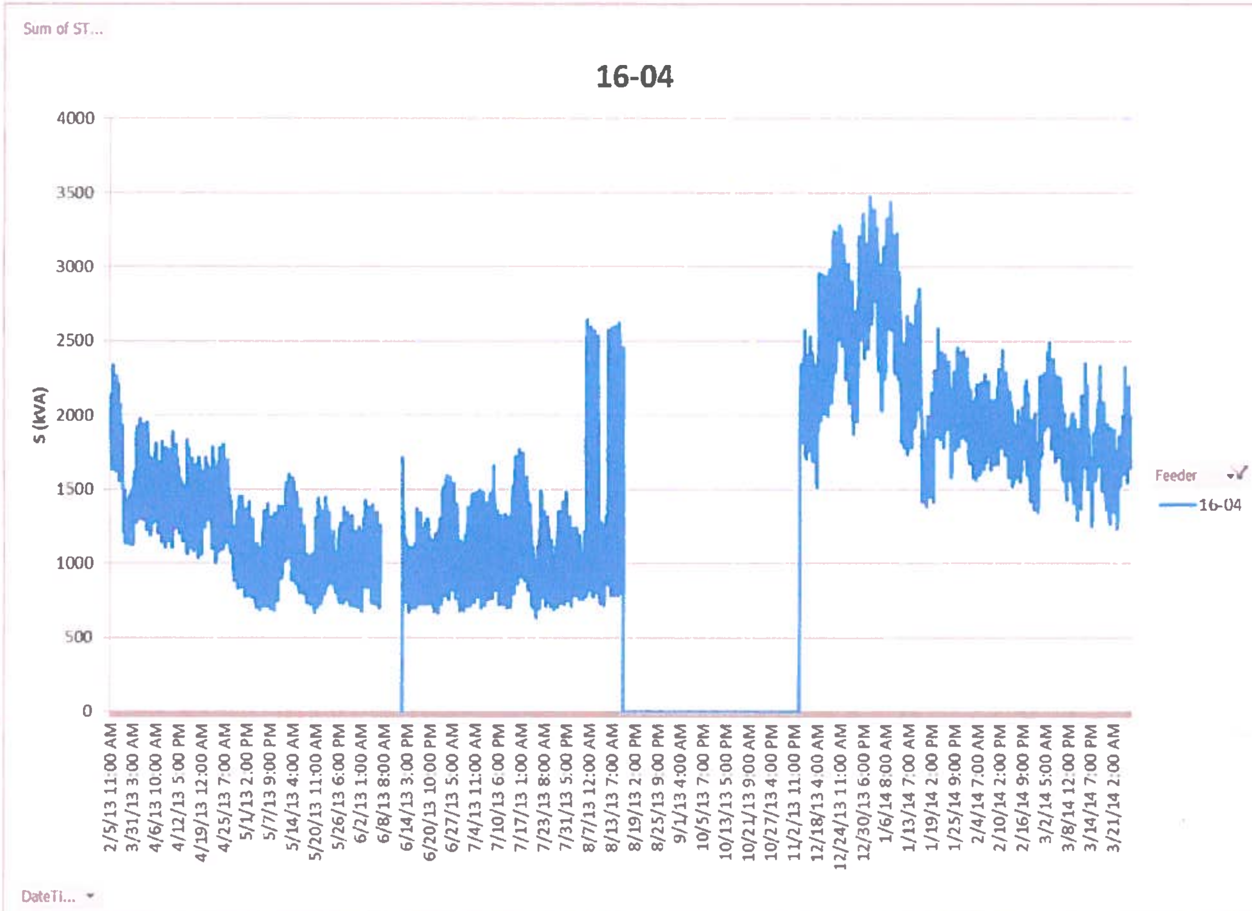
Sum of ST...
16-02
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
S (kVA)
Feeder
16-02
2/5/13 11:00 AM
3/31/13 3:00 AM
4/6/13 10:00 AM
4/12/13 5:00 PM
4/19/13 12:00 AM
4/25/13 7:00 AM
5/1/13 2:00 PM
5/7/13 9:00 PM
5/14/13 4:00 AM
5/20/13 11:00 AM
5/26/13 6:00 PM
6/2/13 1:00 AM
6/8/13 8:00 AM
6/14/13 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 AM
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...

16-03:



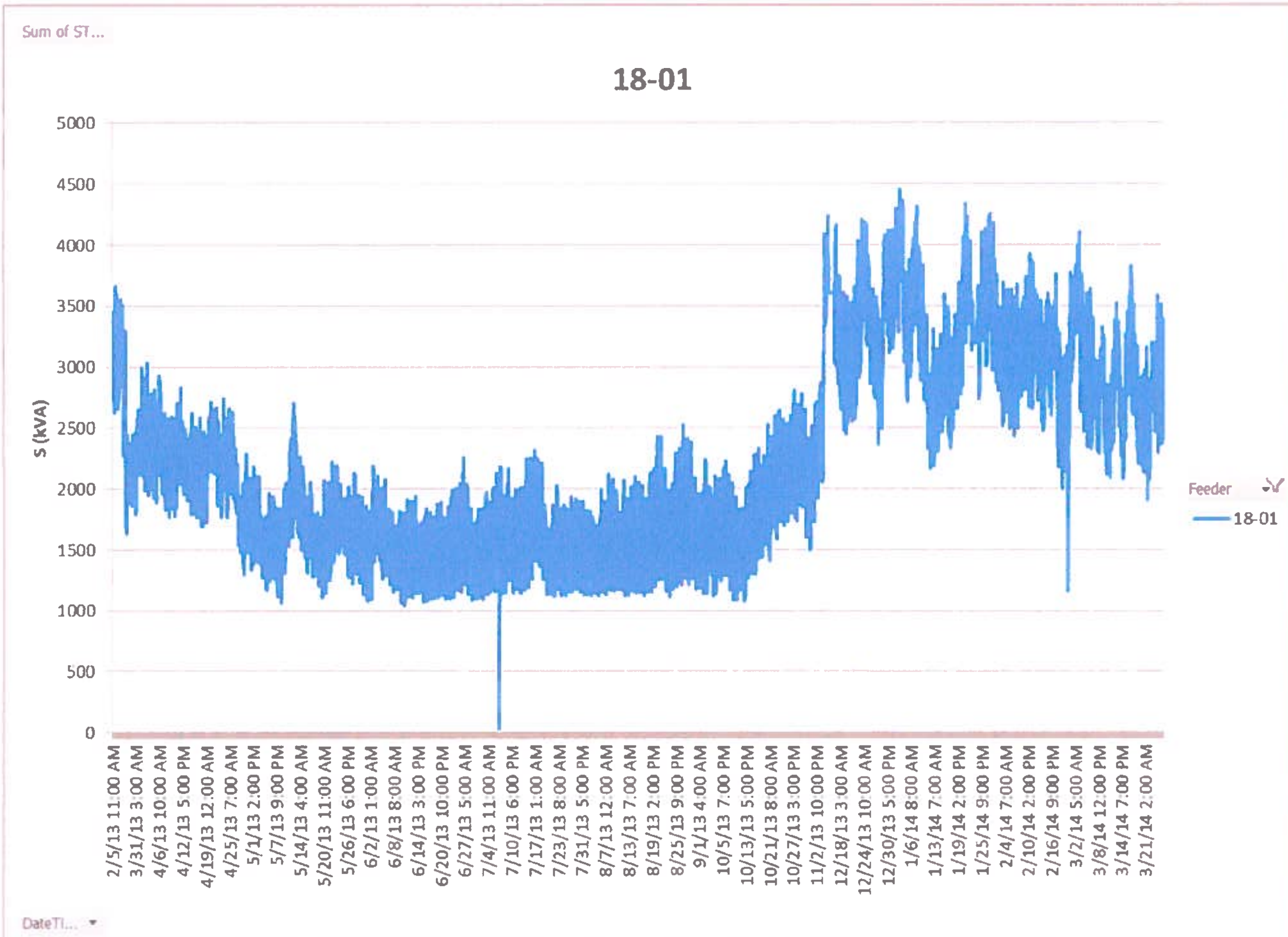
Sum of ST...
16-03
7000
6000
5000
4000
3000
2000
1000
0
S (kVA)
Feeder
16-03
DateTi...

16-04:

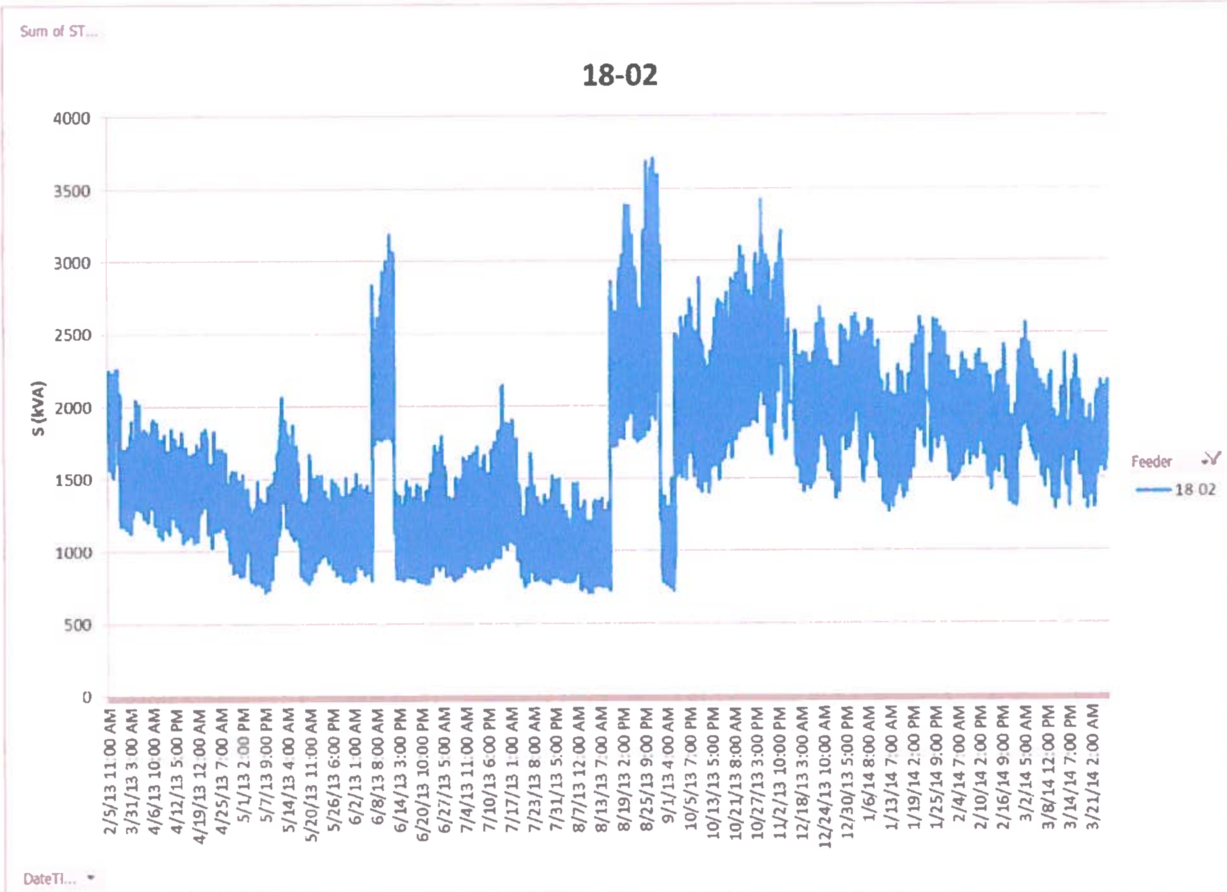


Sum of ST...
16-04
4000
3500
3000
2500
2000
1500
1000
500
0
S (kVA)
Feeder
16-04
DateTi...

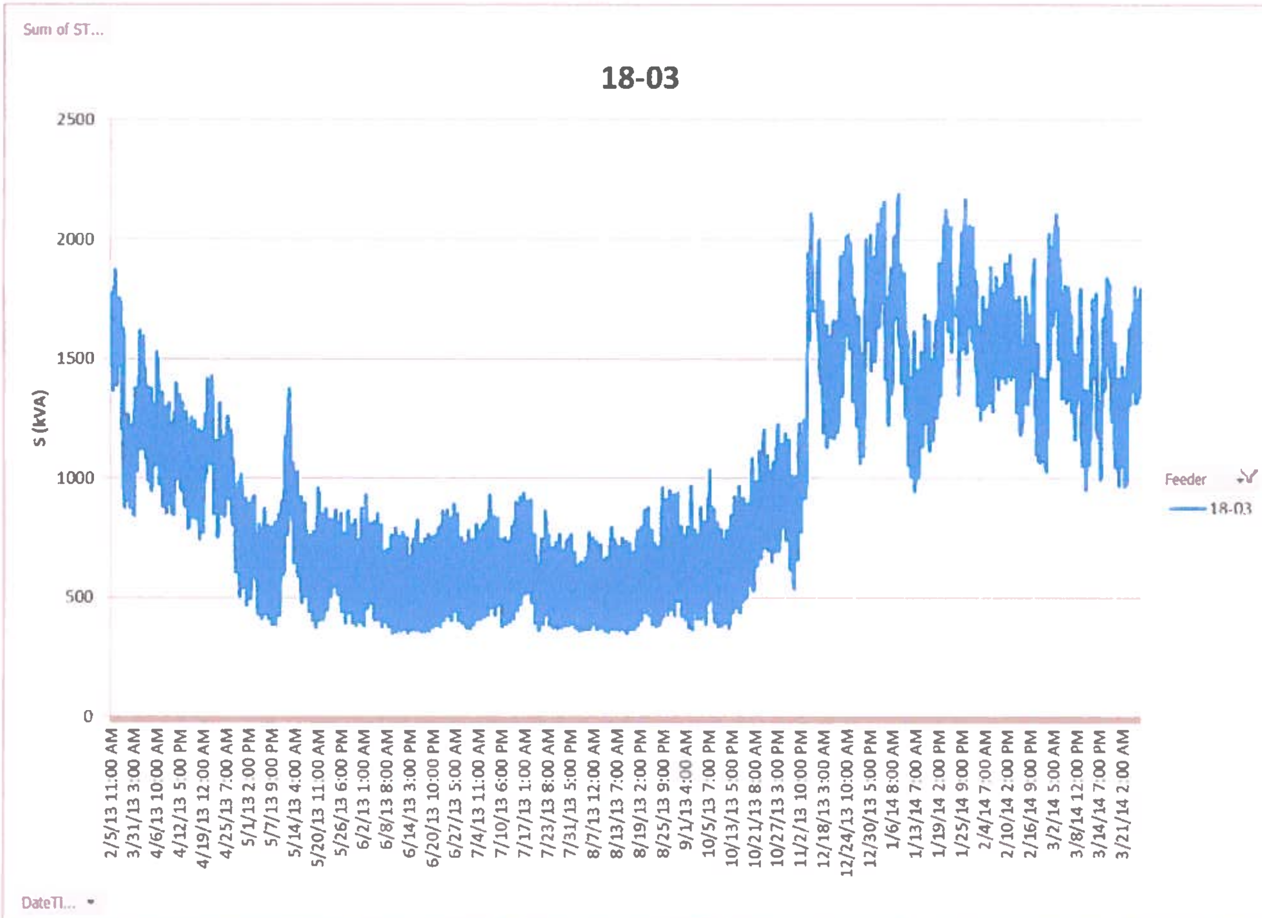
18-01:


Sum of ST...
18-01
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 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
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

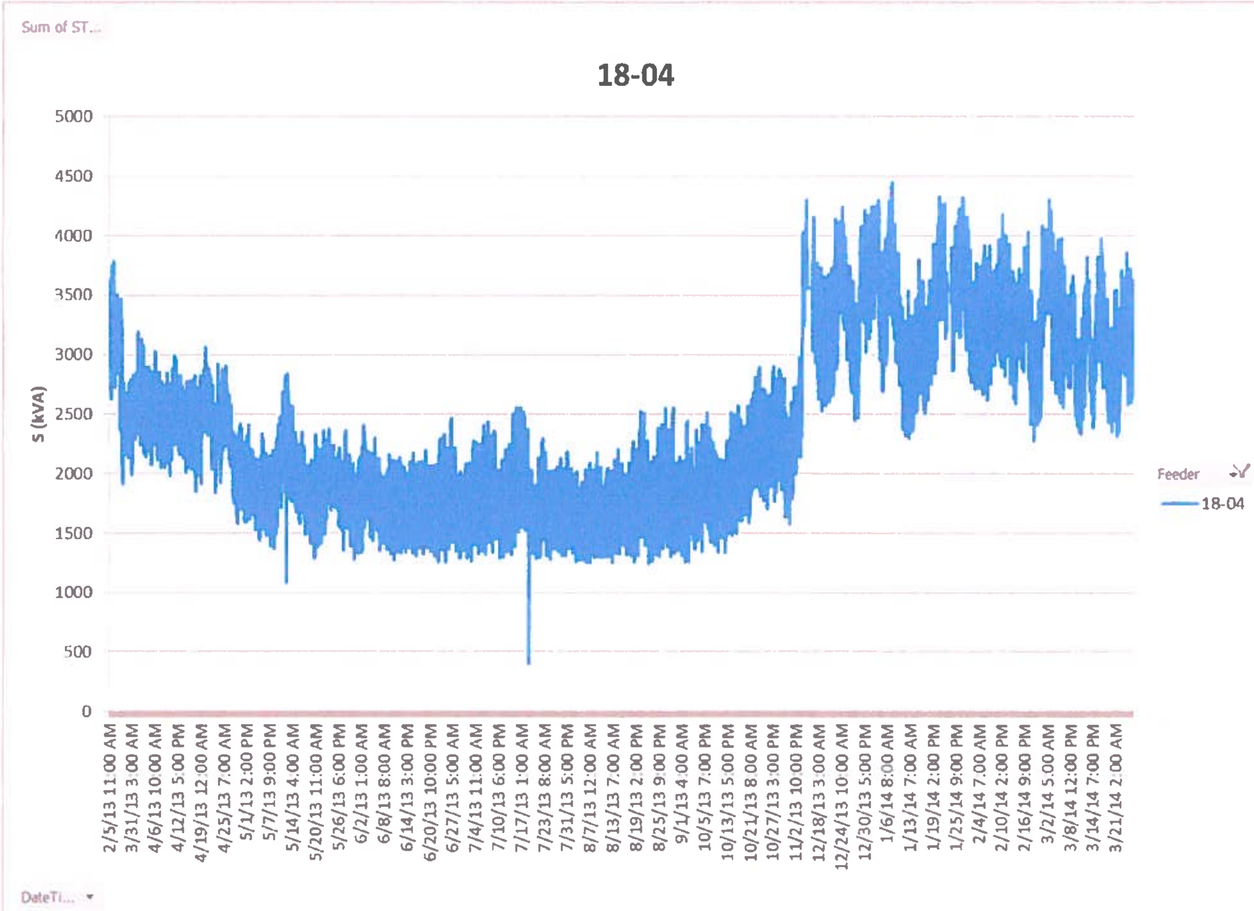
18-02:


Sum of ST...
18-02
4000
3500
3000
2500
2000
1500
1000
500
0
S (kVA)
Feeder
18 02
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
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...

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
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
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
Feeder
18-03
DateTi...

18-04:



Sum of ST...
18-04
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
S (kVA)
Feeder
18-04
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
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8/13/13 7:00 AM
8/19/13 2:00 PM
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10/13/13 5:00 PM
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10/27/13 3:00 PM
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12/24/13 10:00 AM
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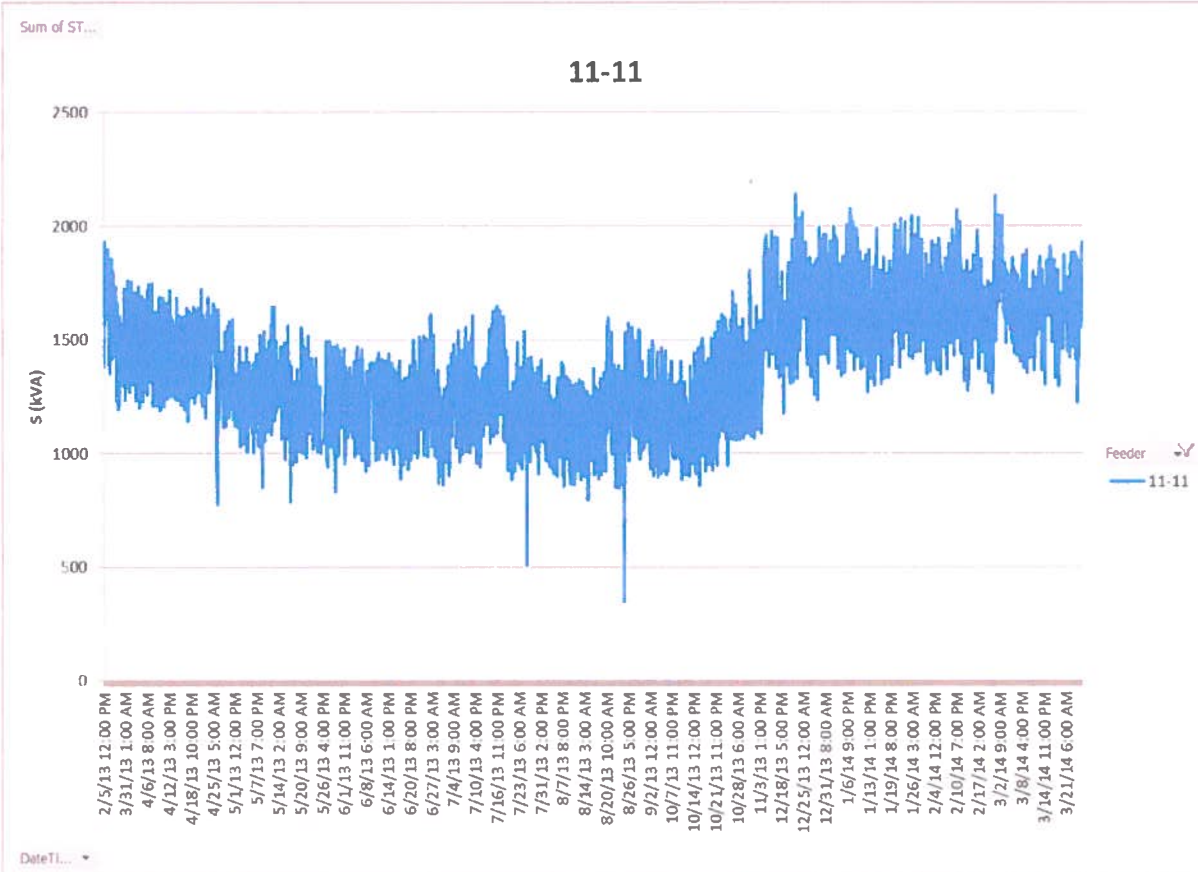
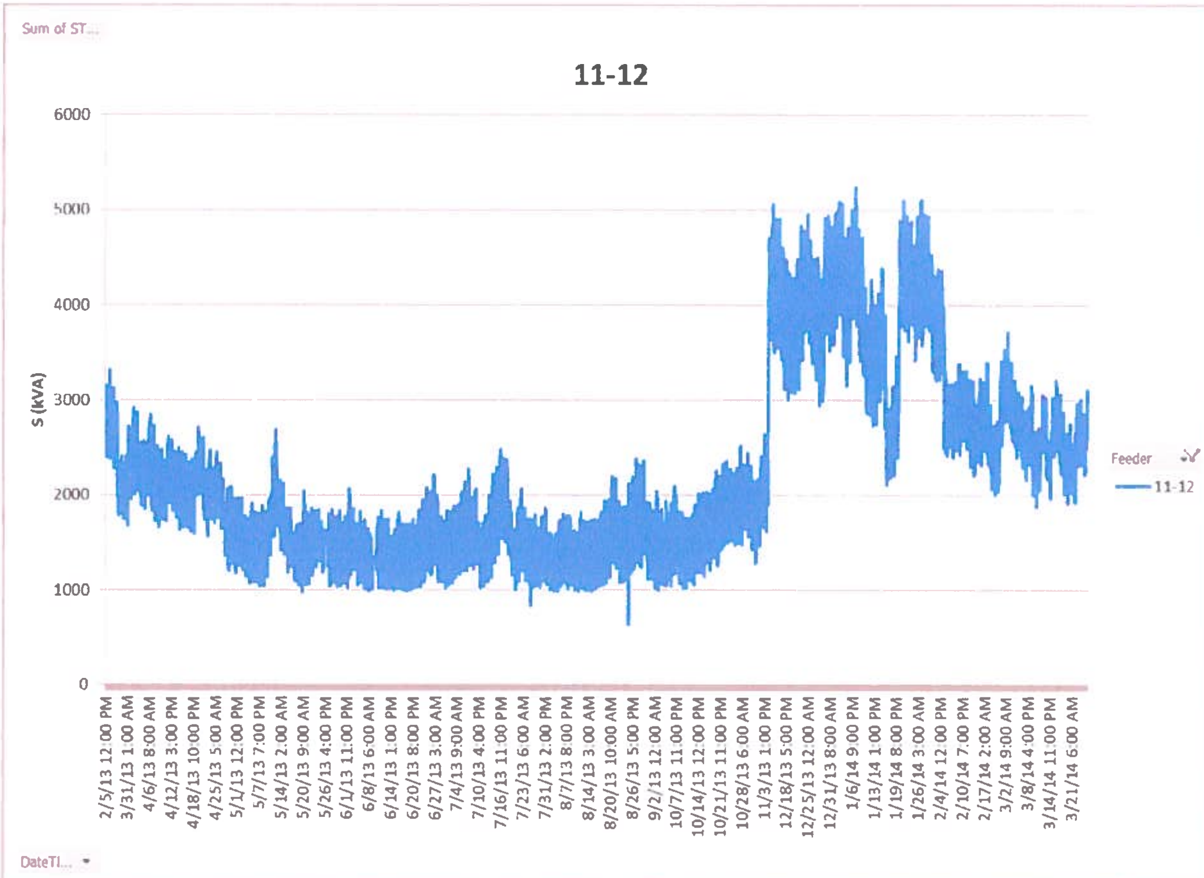
1/6/14 8:00 AM
1/13/14 7:00 AM
1/19/14 2:00 PM
1/25/14 9:00 PM
2/4/14 7:00 AM
2/10/14 2:00 PM
2/16/14 9:00 PM
3/2/14 5:00 AM
3/8/14 12:00 PM
3/14/14 7:00 PM
3/21/14 2:00 AM
DateTi...

11-11:


Sum of ST...
11-11
2500
2000
1500
1000
500
0
S (kVA)
Feeder
11-11
DateTi...

11-12:



Sum of ST...
11-12
6000
5000
4000
3000
2000
1000
0
S (kVA)
Feeder
11-12
2/5/13 12:00 PM
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4/6/13 8:00 AM
4/12/13 3:00 PM
4/18/13 10:00 PM
4/25/13 5:00 AM
5/1/13 12:00 PM
5/7/13 7:00 PM
5/14/13 2:00 AM
5/20/13 9:00 AM
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6/27/13 3:00 AM
7/4/13 9:00 AM
7/10/13 4:00 PM
7/16/13 11:00 PM
7/23/13 6:00 AM
7/31/13 2:00 PM
8/7/13 8:00 PM
8/14/13 3:00 AM
8/20/13 10:00 AM
8/26/13 5:00 PM
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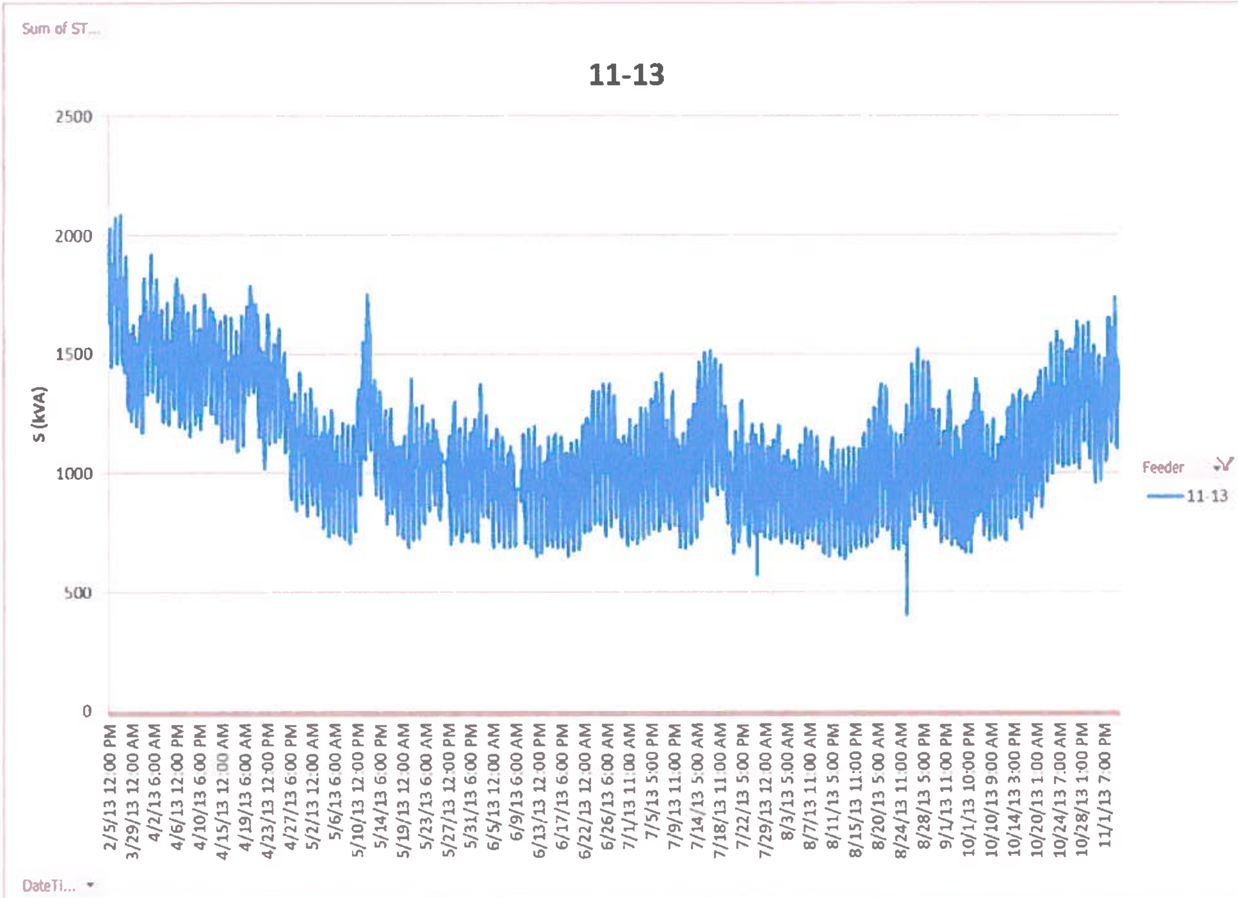
12/25/13 12:00 AM
12/31/13 8:00 AM
1/6/14 9:00 PM
1/13/14 1:00 PM
1/19/14 8:00 PM
1/26/14 3:00 AM
2/4/14 12:00 PM
2/10/14 7:00 PM
2/17/14 2:00 AM
3/2/14 9:00 AM
3/8/14 4:00 PM
3/14/14 11:00 PM
3/21/14 6:00 AM
DateTi...

11-13:



Sum of ST...
11-13
2500
2000
1500
1000
500
0
S (kVA)
Feeder
11-13
2/5/13 12:00 PM
3/29/13 12:00 AM
4/2/13 6:00 AM
4/6/13 12:00 PM
4/10/13 6:00 PM
4/15/13 12:00 AM
4/19/13 6:00 AM
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5/6/13 6:00 AM
5/10/13 12:00 PM
5/14/13 6:00 PM
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9/1/13 11:00 PM
10/1/13 10:00 PM
10/10/13 9:00 AM
10/14/13 3:00 PM
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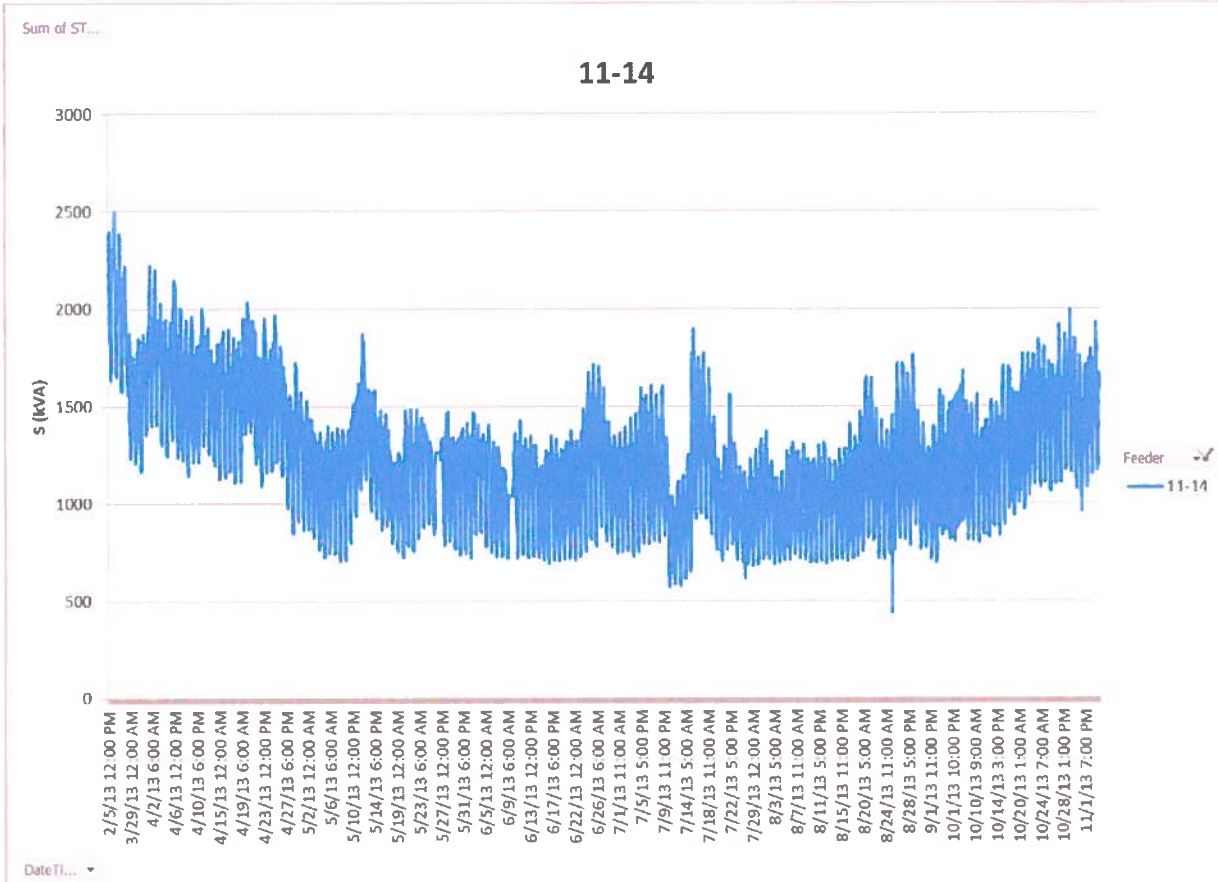
10/24/13 7:00 AM
10/28/13 1:00 PM
11/1/13 7:00 PM
DateTi...

11-14:


Sum of ST...
11-14
3000
2500
2000
1500
1000
500
0
S (kVA)
Feeder
11-14
2/5/13 12:00 PM
3/29/13 12:00 AM
4/2/13 6:00 AM
4/6/13 12:00 PM
4/10/13 6:00 PM
4/15/13 12:00 AM
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5/23/13 6:00 AM
5/27/13 12:00 PM
5/31/13 6:00 PM
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6/9/13 6:00 AM
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8/15/13 11:00 PM
8/20/13 5:00 AM
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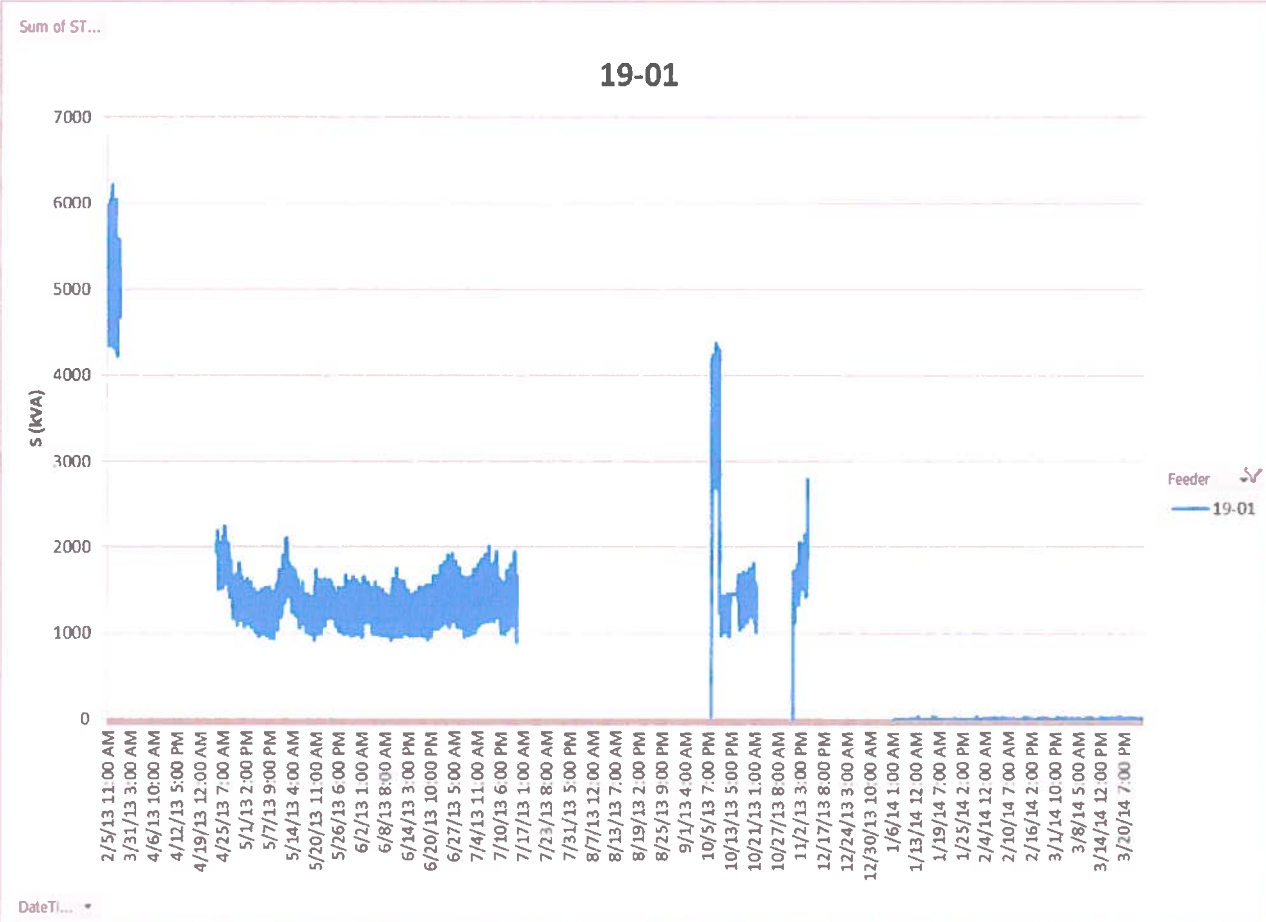
9/1/13 11:00 PM
10/1/13 10:00 PM
10/10/13 9:00 AM
10/14/13 3:00 PM
10/20/13 1:00 AM
10/24/13 7:00 AM
10/28/13 1:00 PM
11/1/13 7:00 PM
DateTi...

19-01:



Sum of ST...
19-01
7000
6000
5000
4000
3000
2000
1000
0
S (kVA)
Feeder
19-01
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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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
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12/24/13 3:00 AM
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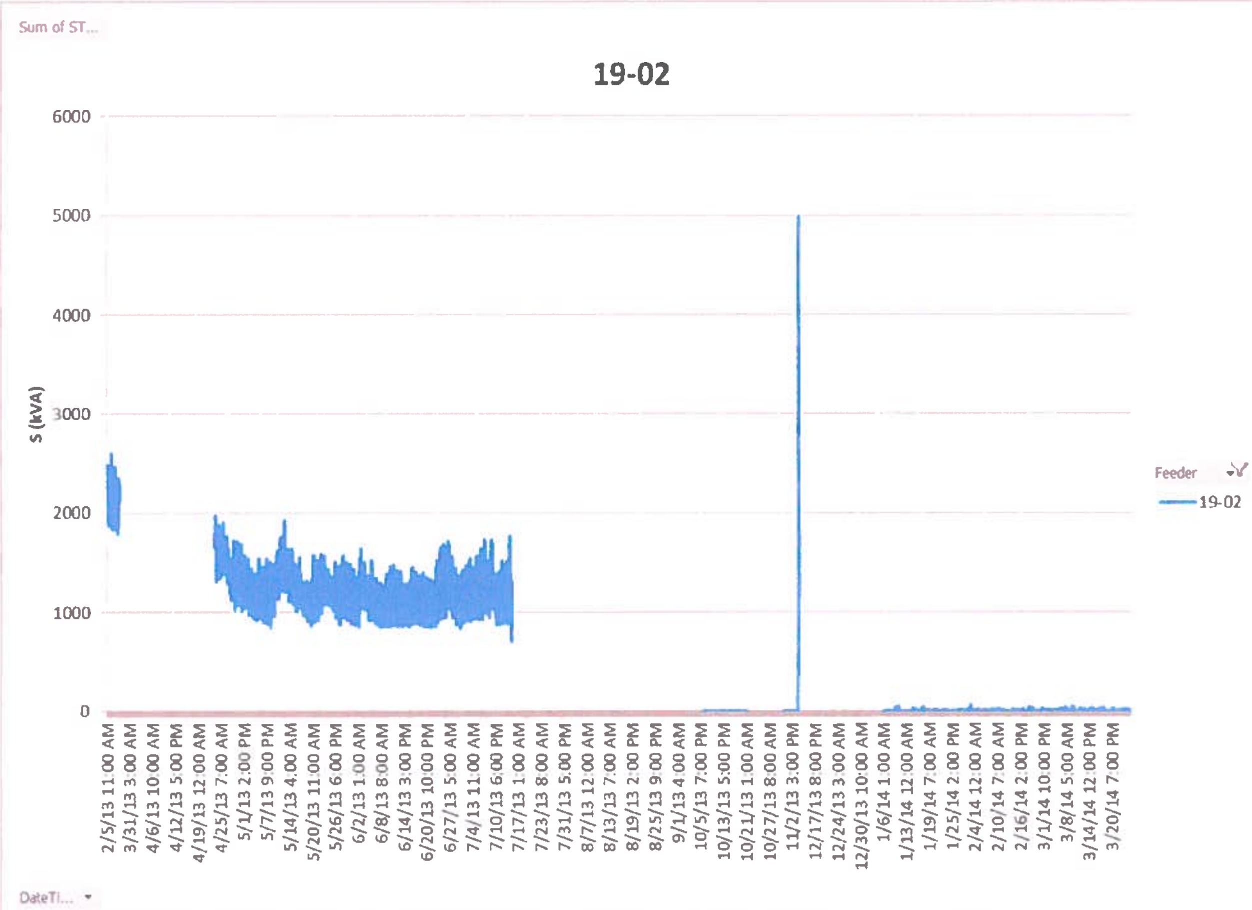
1/6/14 1:00 AM
1/13/14 12:00 AM
1/19/14 7:00 AM
1/25/14 2:00 PM
2/4/14 12:00 AM
2/10/14 7:00 AM
2/16/14 2:00 PM
3/1/14 10:00 PM
3/8/14 5:00 AM
3/14/14 12:00 PM
3/20/14 7:00 PM
DateTi...

19-02:


Sum of ST...
19-02
6000
5000
4000
3000
2000
1000
0
S (kVA)
Feeder
19-02
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
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7/23/13 8:00 AM
7/31/13 5:00 PM
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8/13/13 7:00 AM
8/19/13 2:00 PM
8/25/13 9:00 PM
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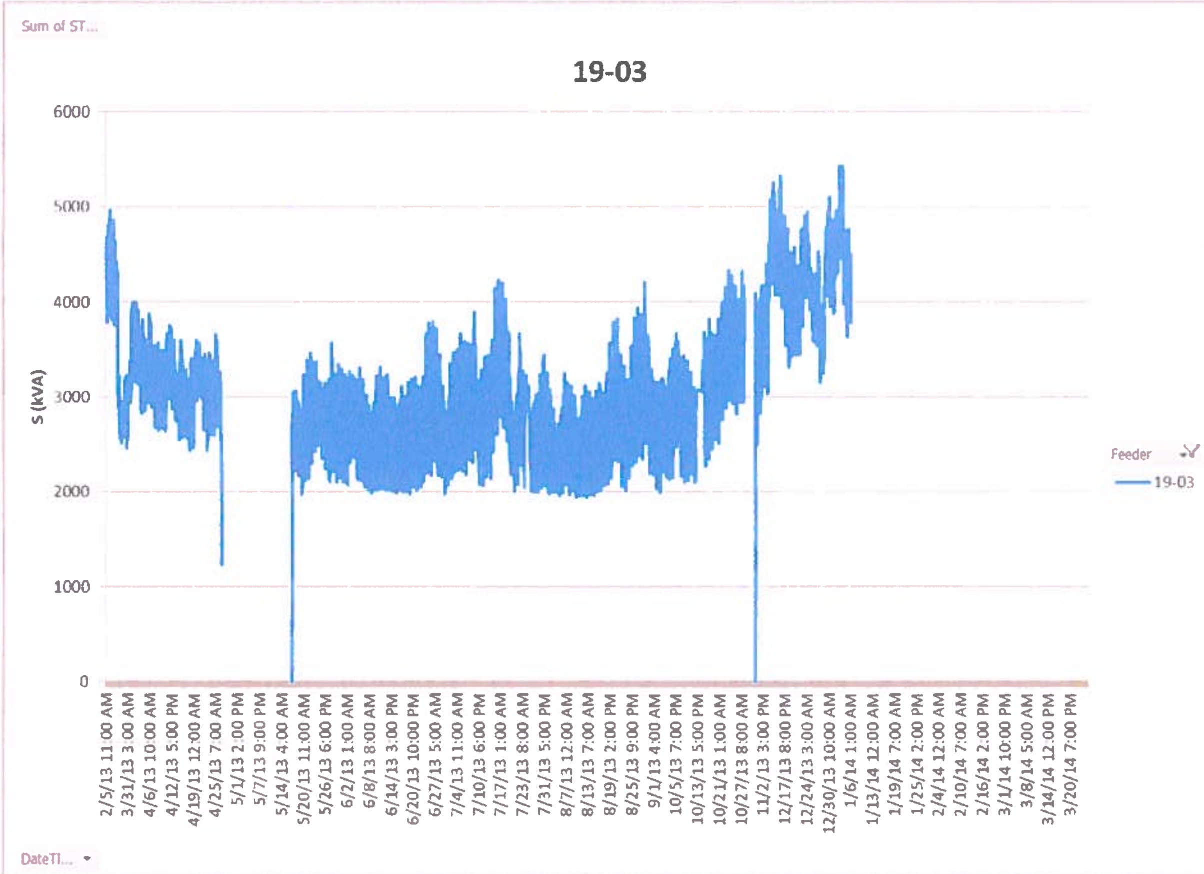
1/6/14 1:00 AM
1/13/14 12:00 AM
1/19/14 7:00 AM
1/25/14 2:00 PM
2/4/14 12:00 AM
2/10/14 7:00 AM
2/16/14 2:00 PM
3/1/14 10:00 PM
3/8/14 5:00 AM
3/14/14 12:00 PM
3/20/14 7:00 PM
DateTi...

19-03: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Feeder
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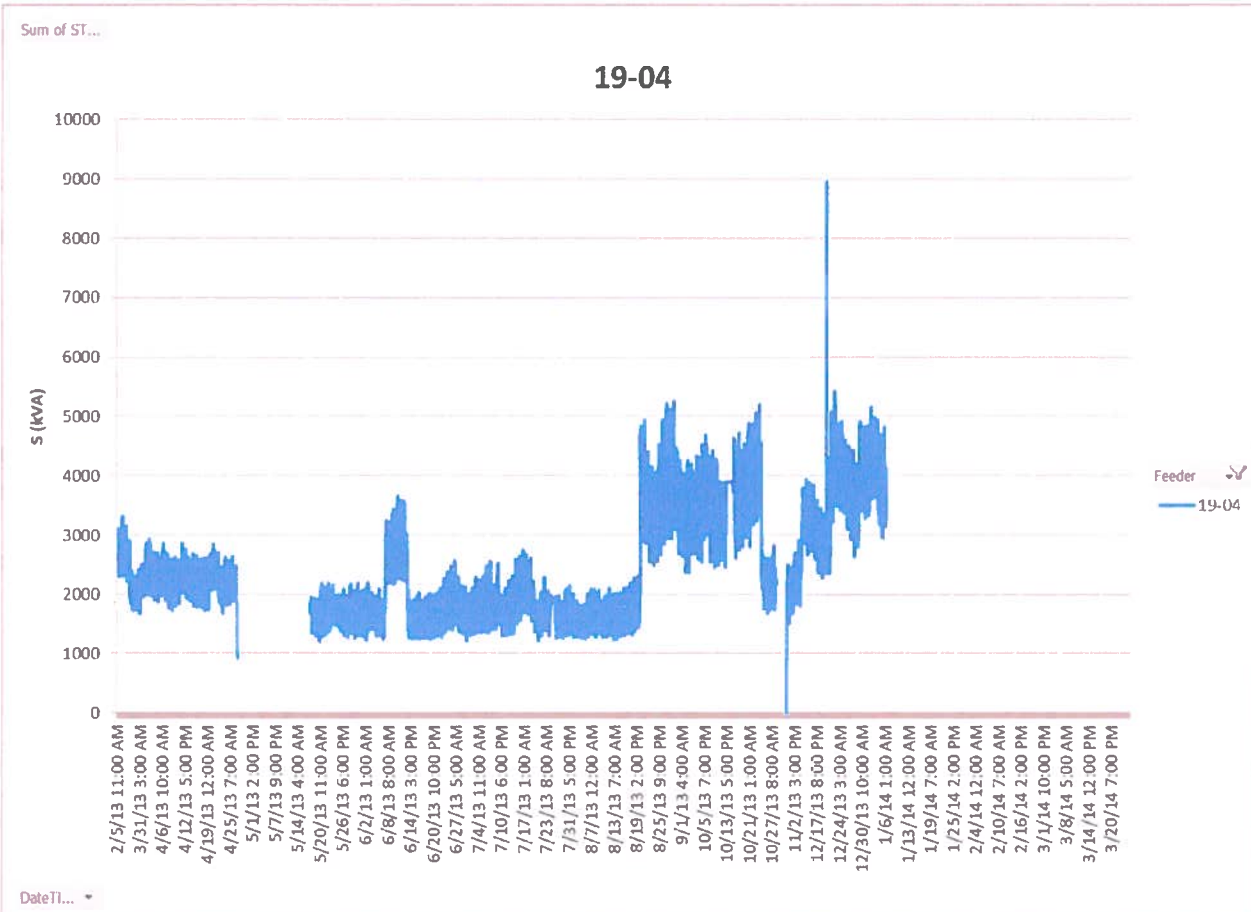
DateTI...

19-04: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S (kVA)
Feeder
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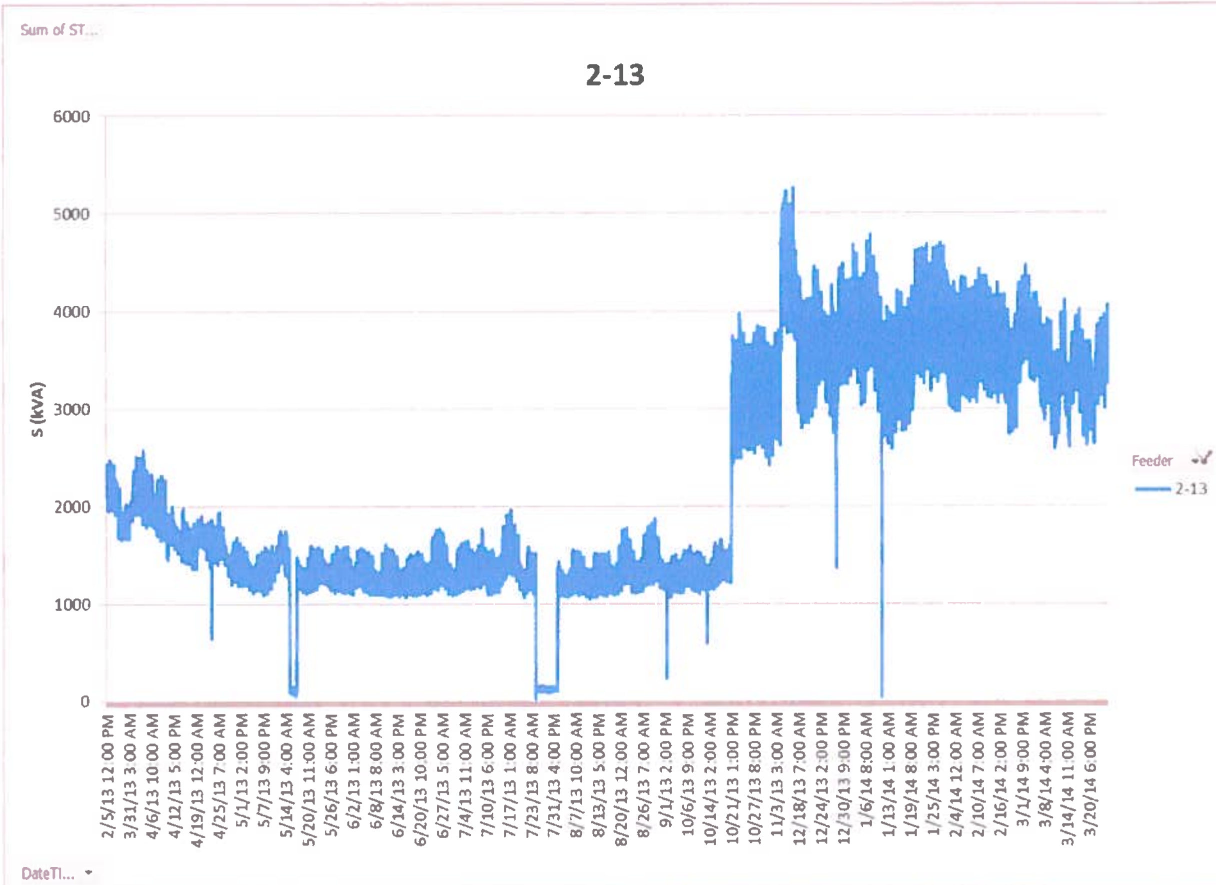

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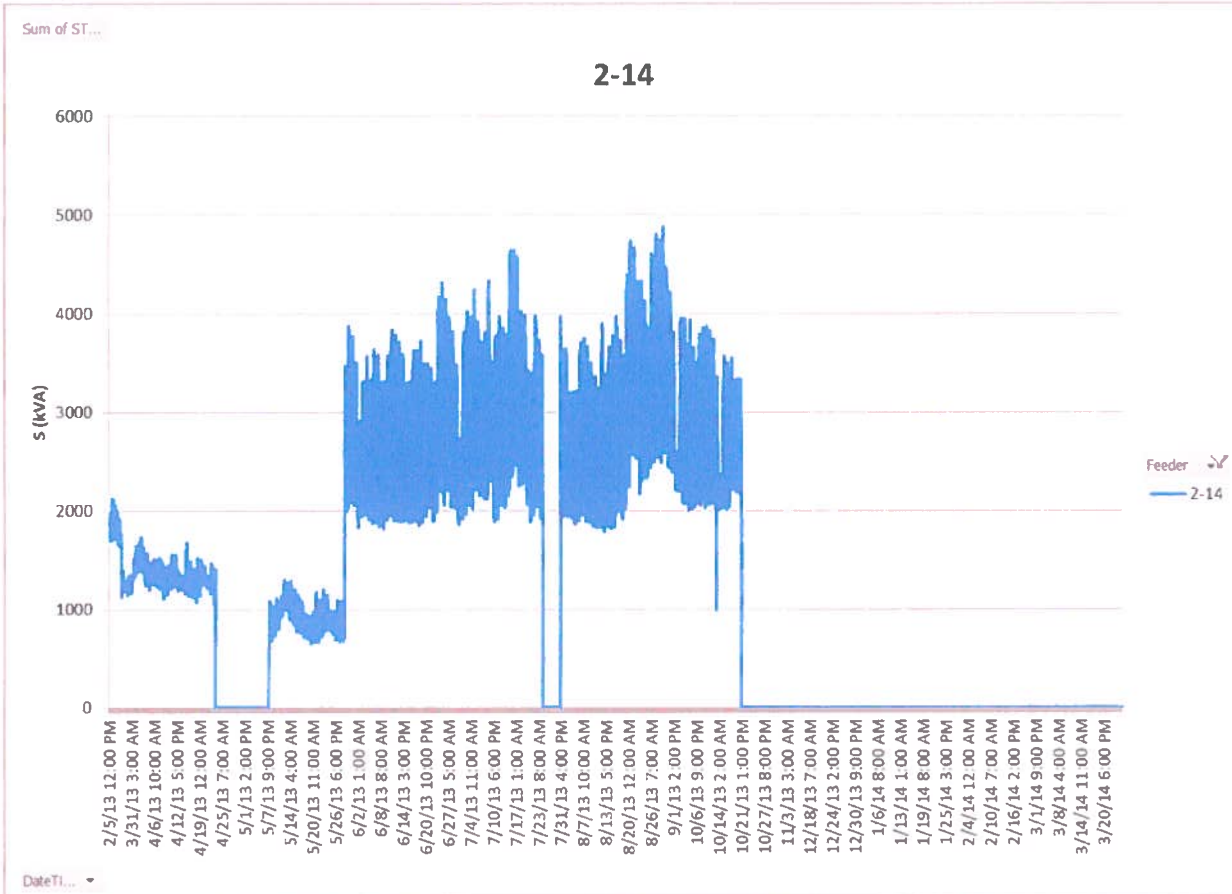
2-14:



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DateTi...

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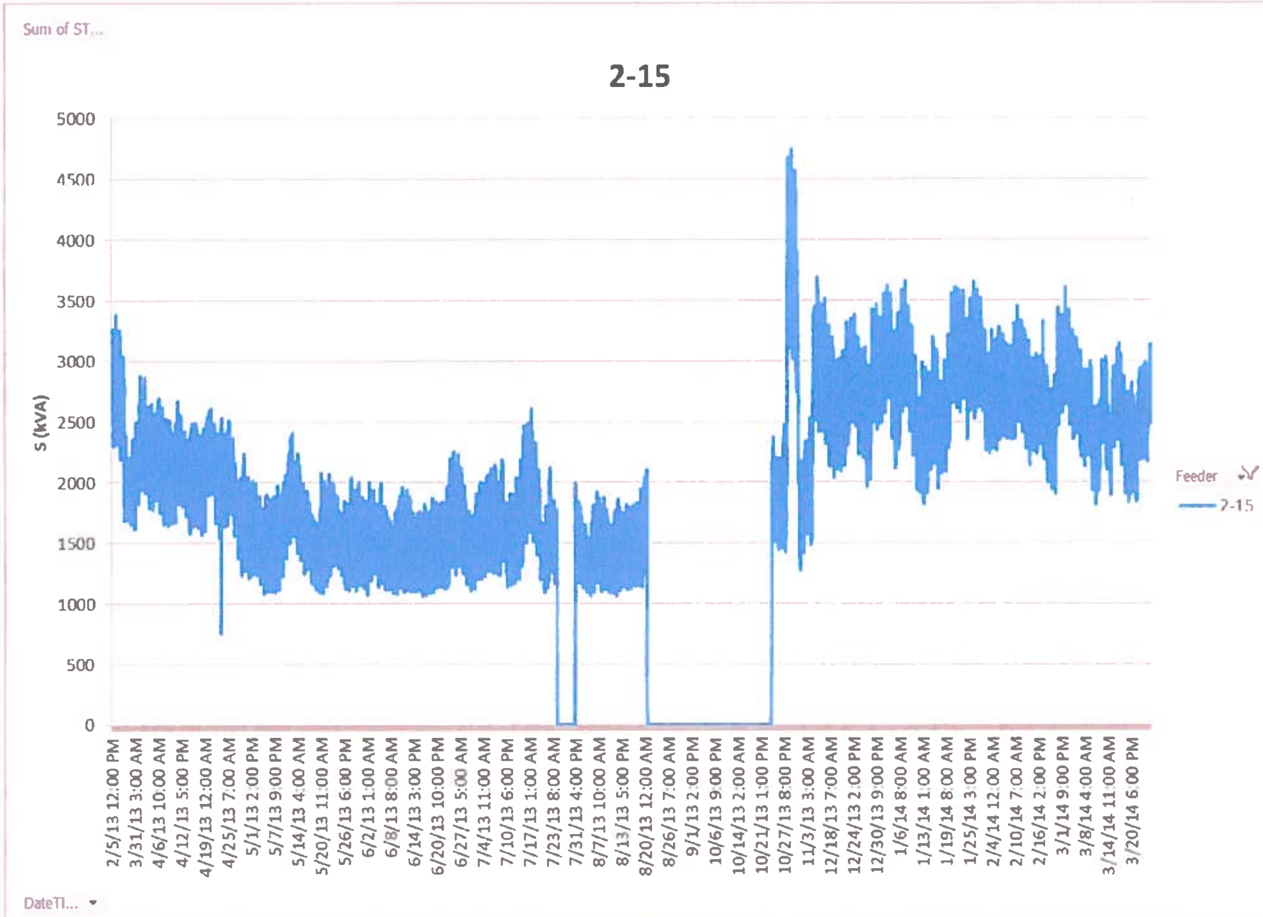

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1000
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S (kVA)
Feeder
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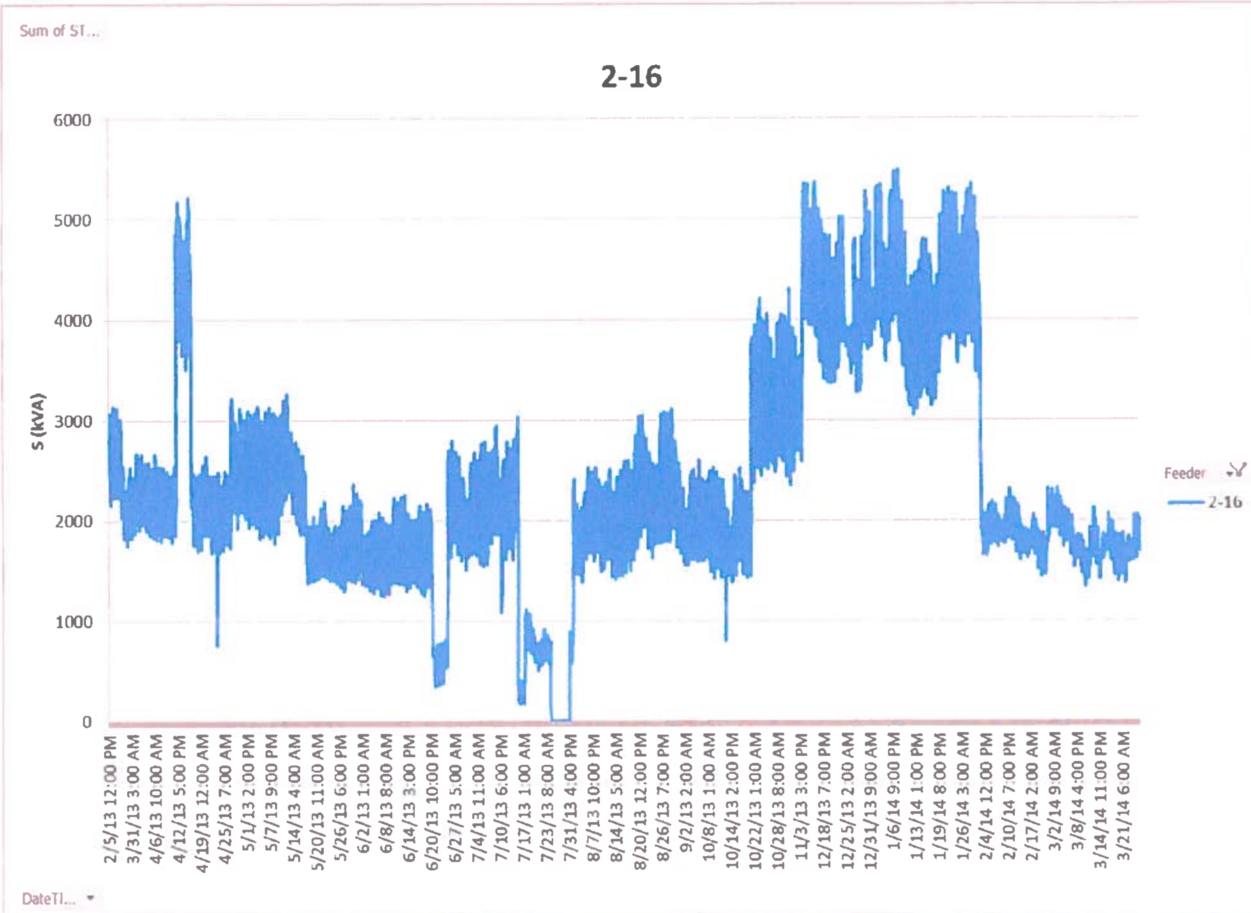

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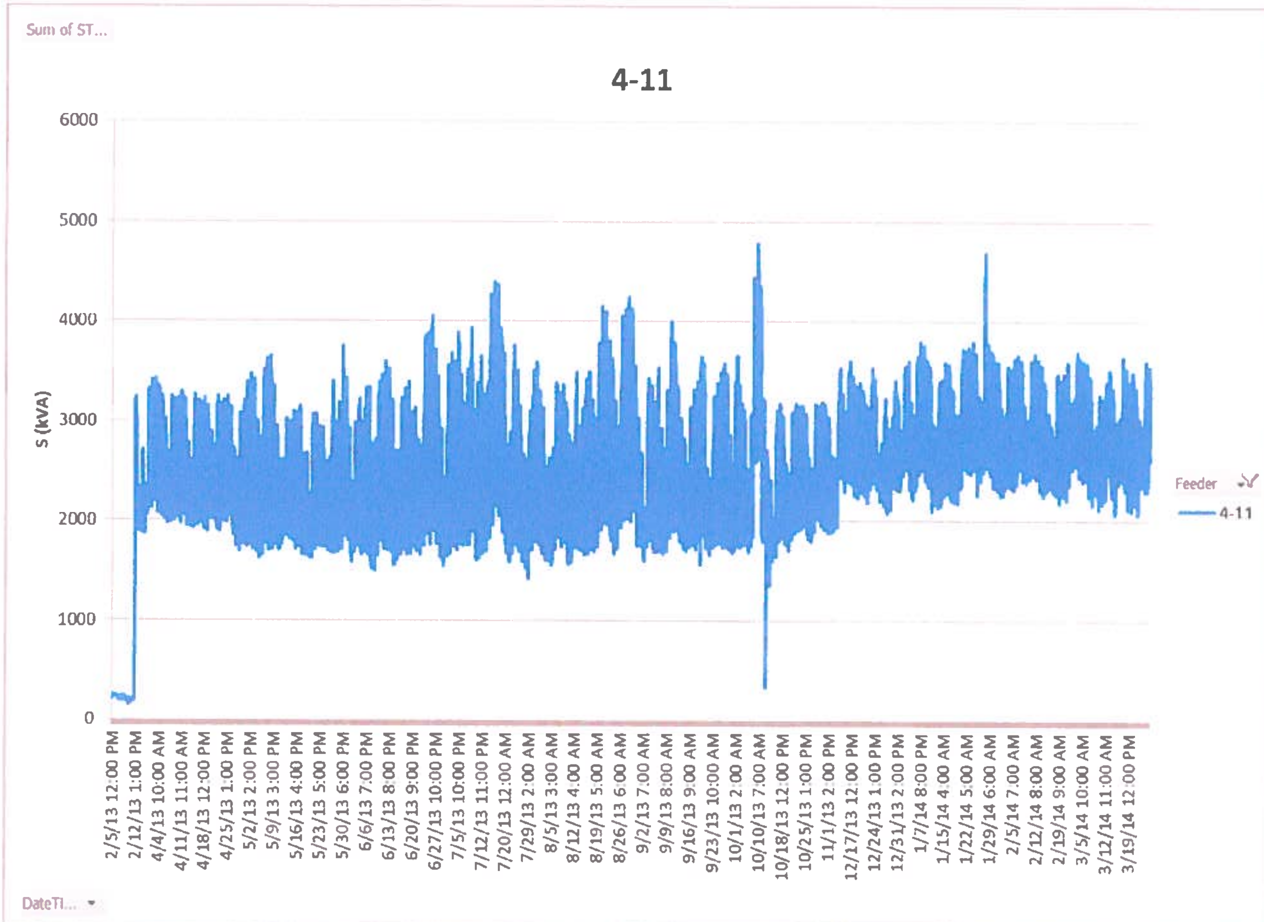
DateTi...

4-11: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DateTi...

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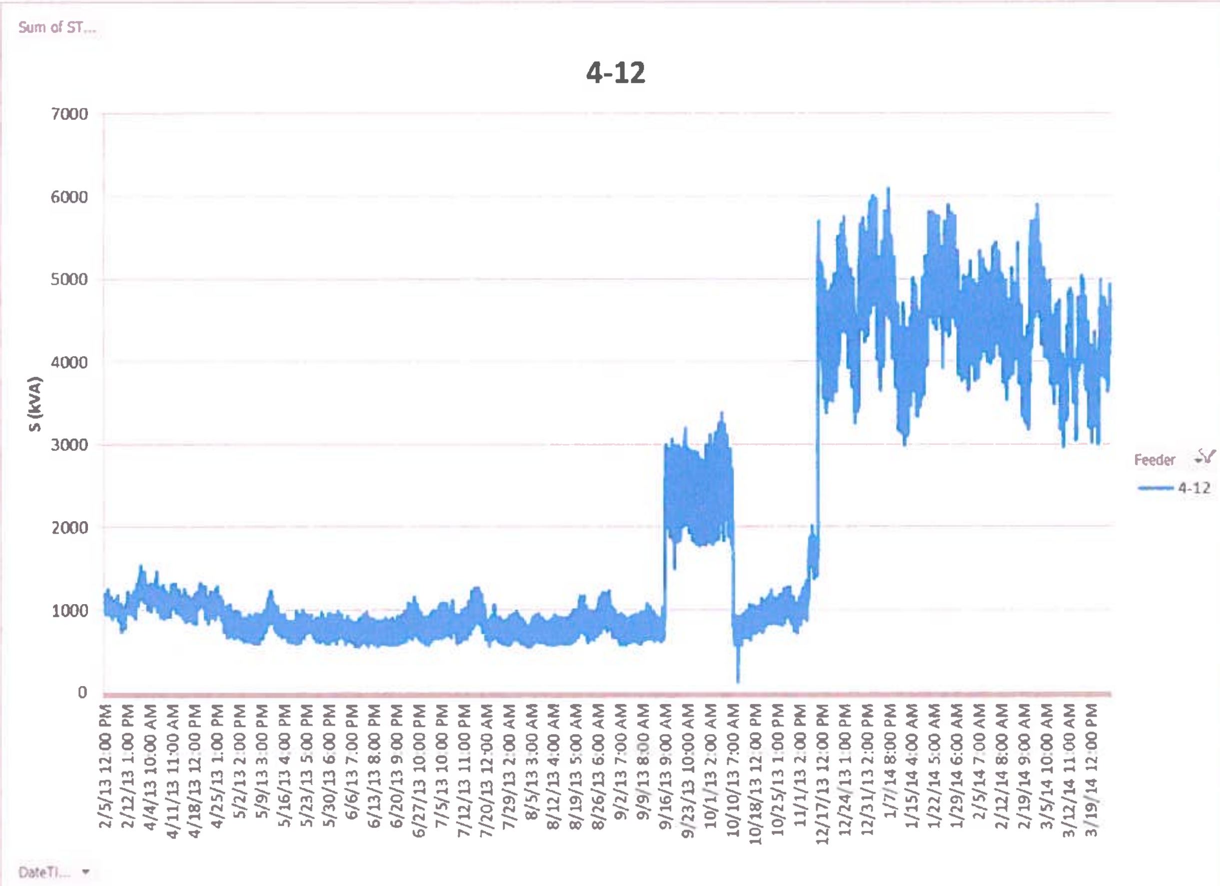
4-12:



Sum of ST...
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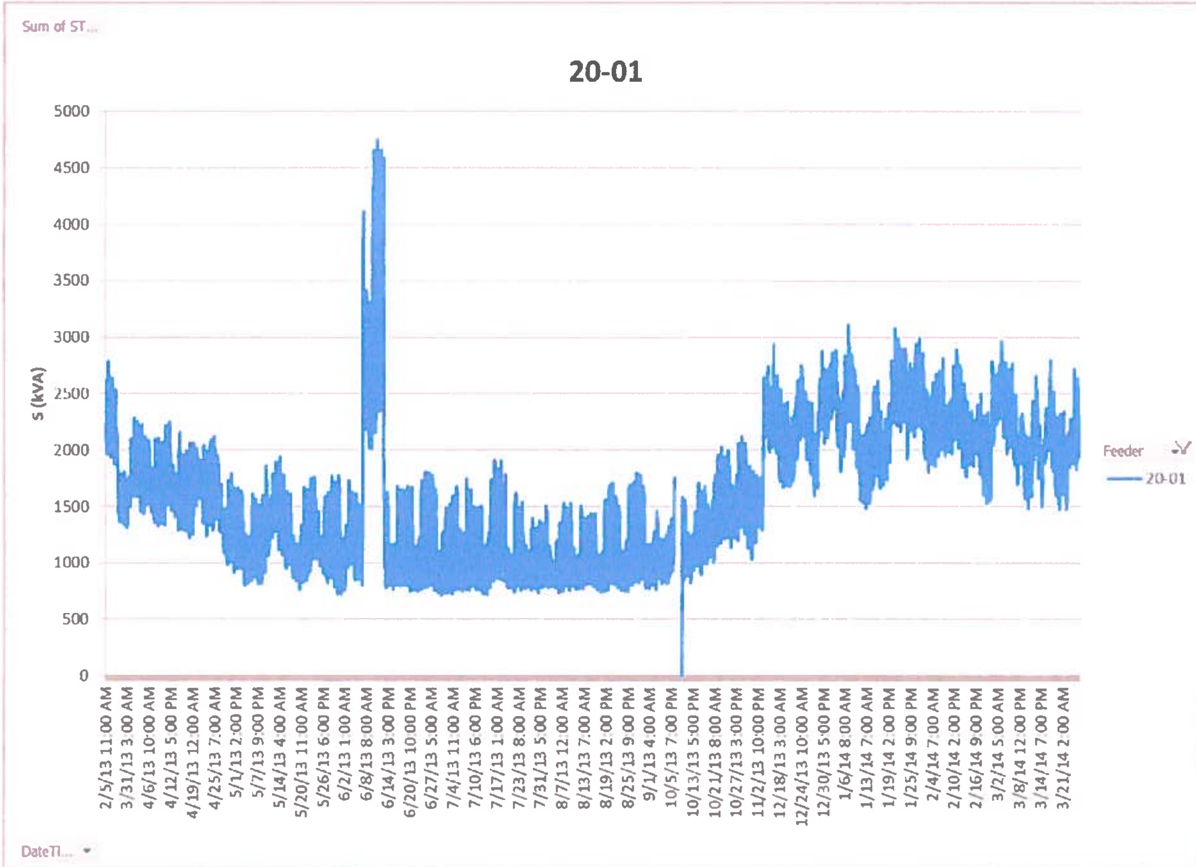
20-01: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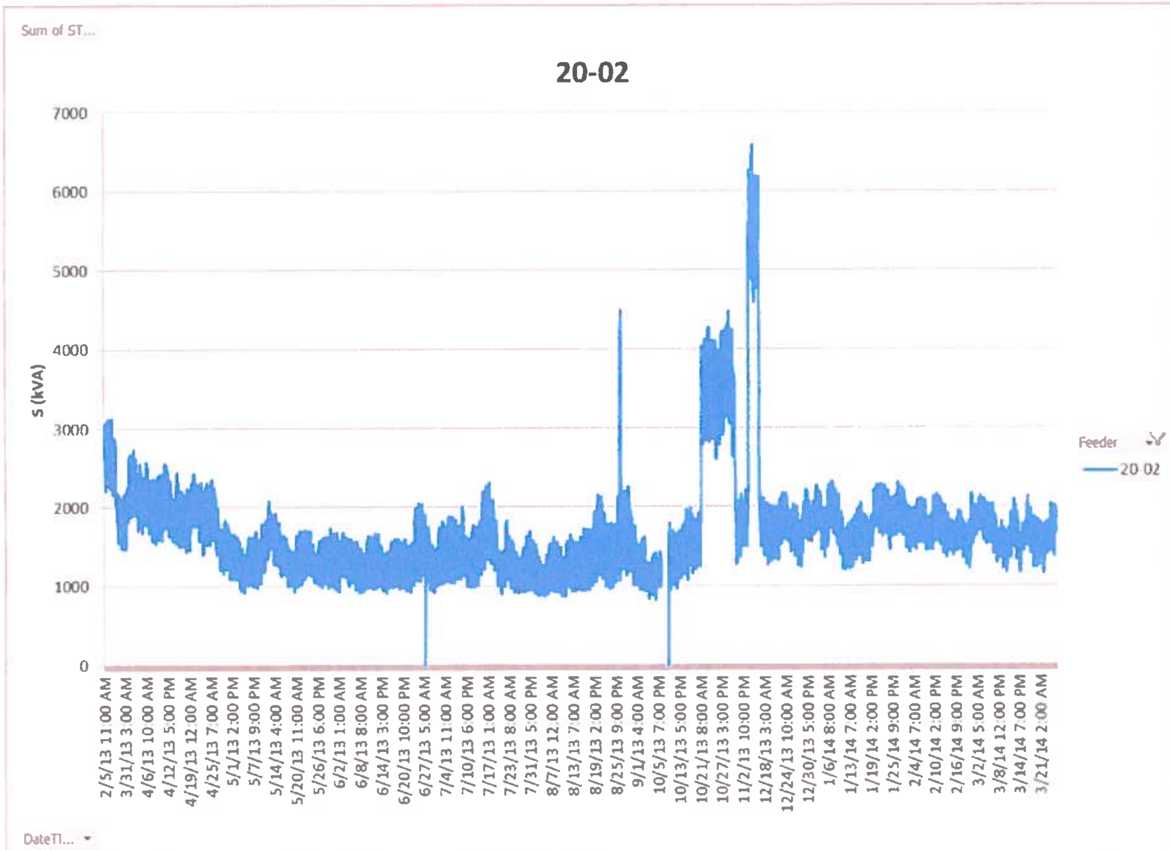
20-02: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DateTi...

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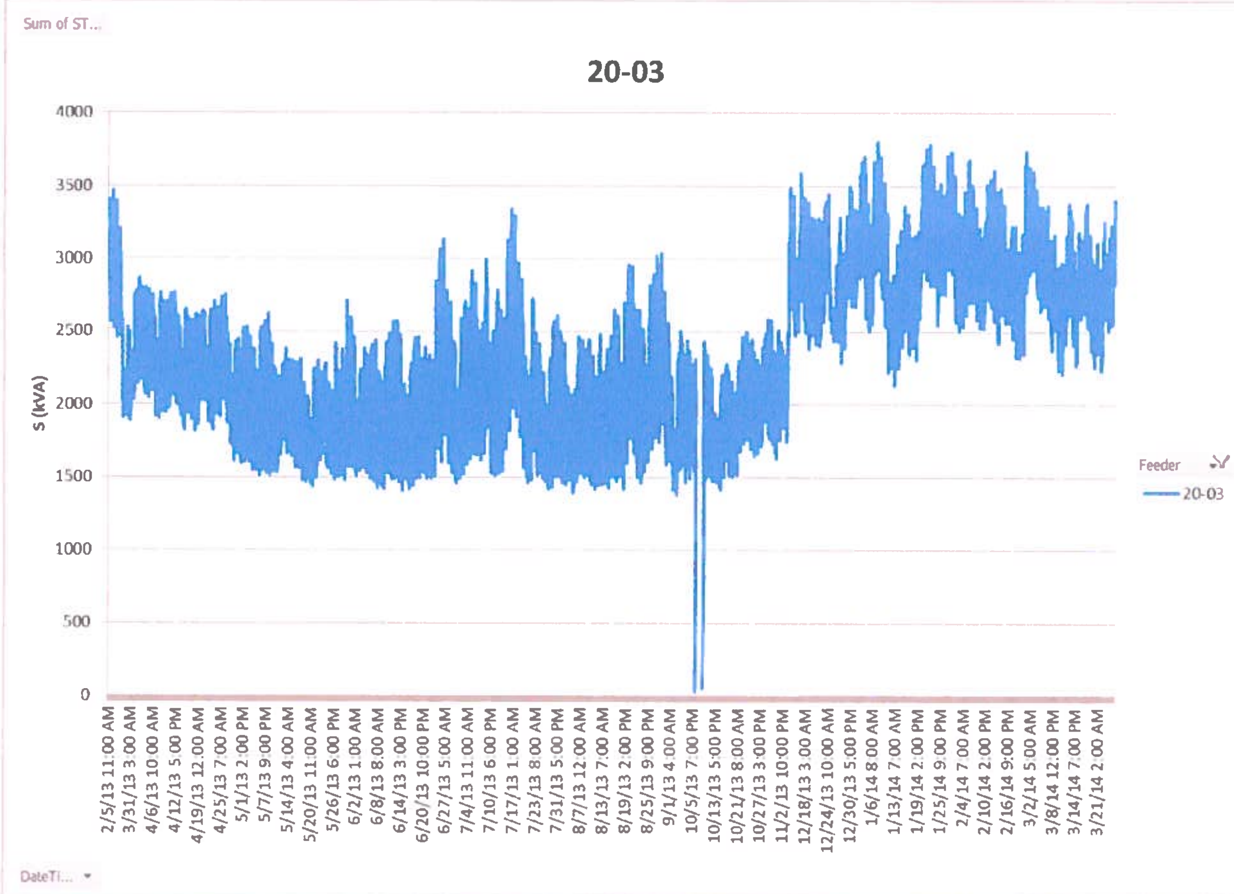
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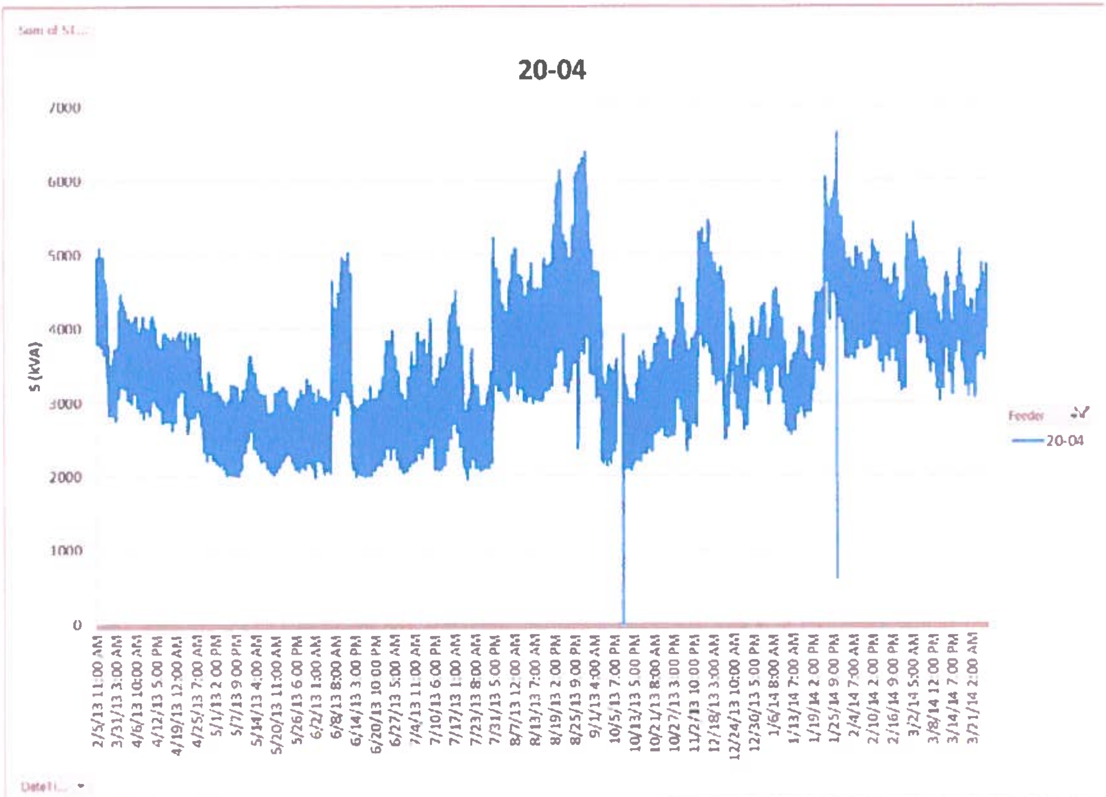
DateTi...

20-04:



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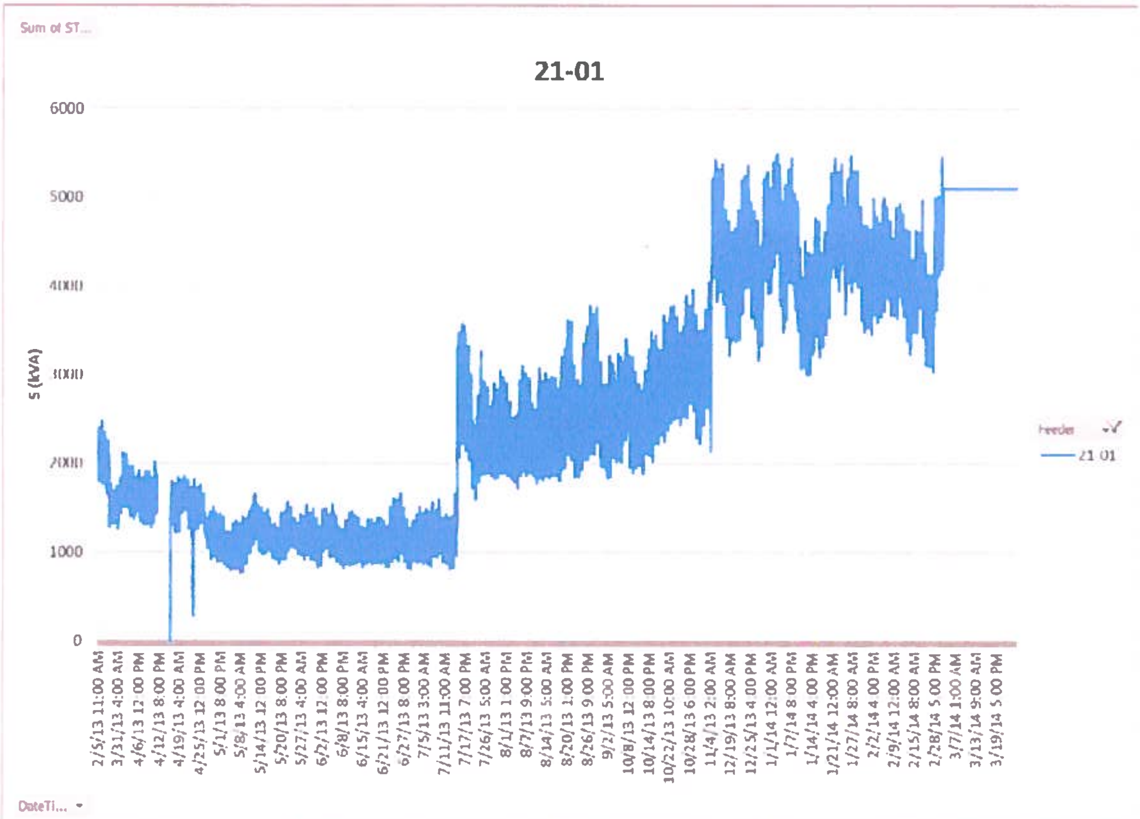
Feeder
20-04

21-01: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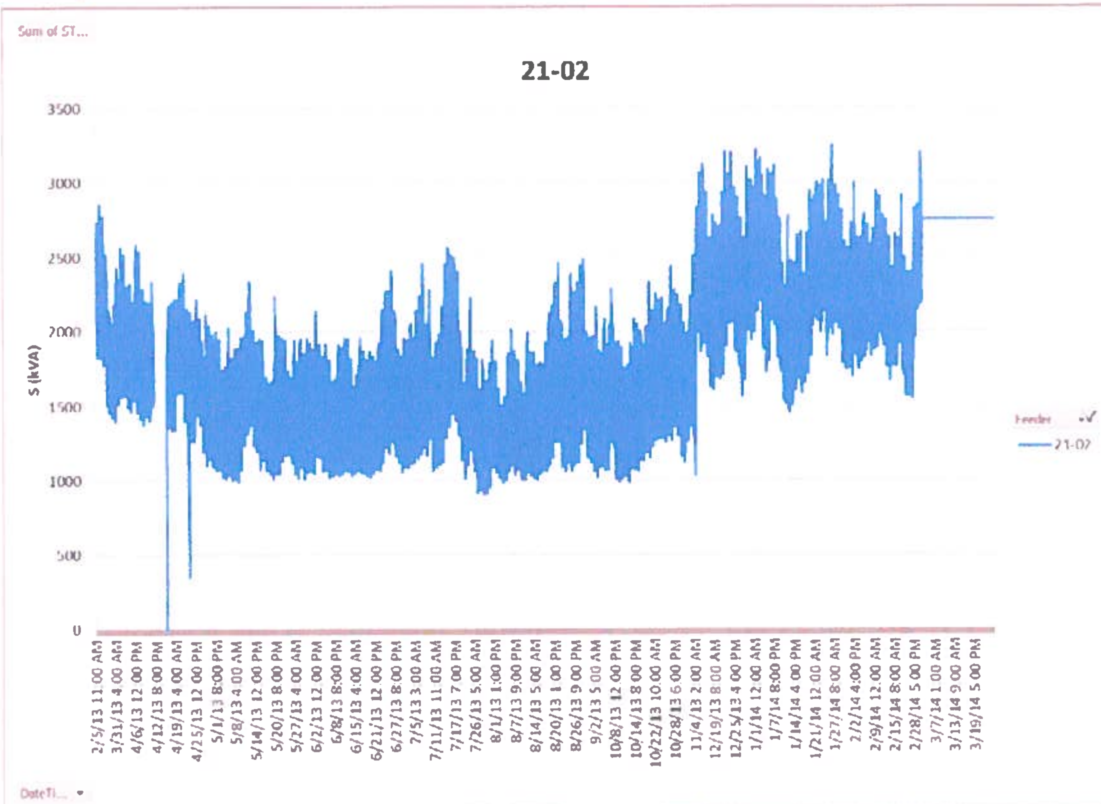
Feeder
21-01

21-02:



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DateTi...

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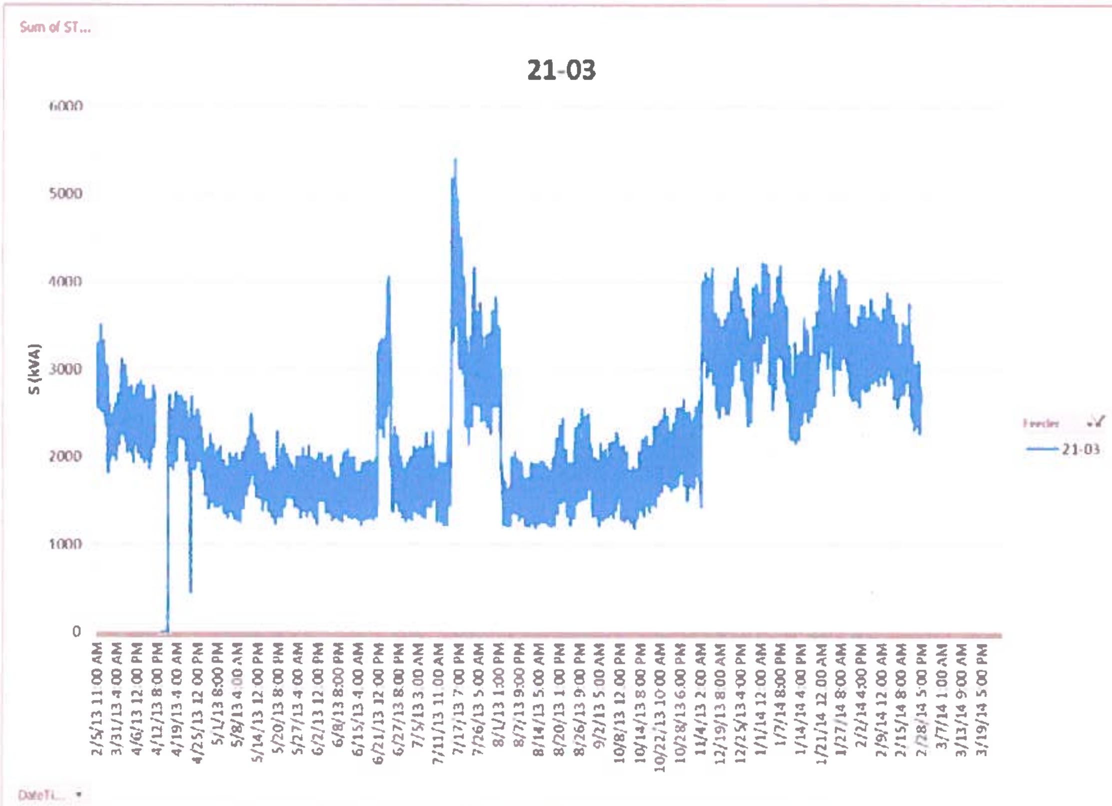

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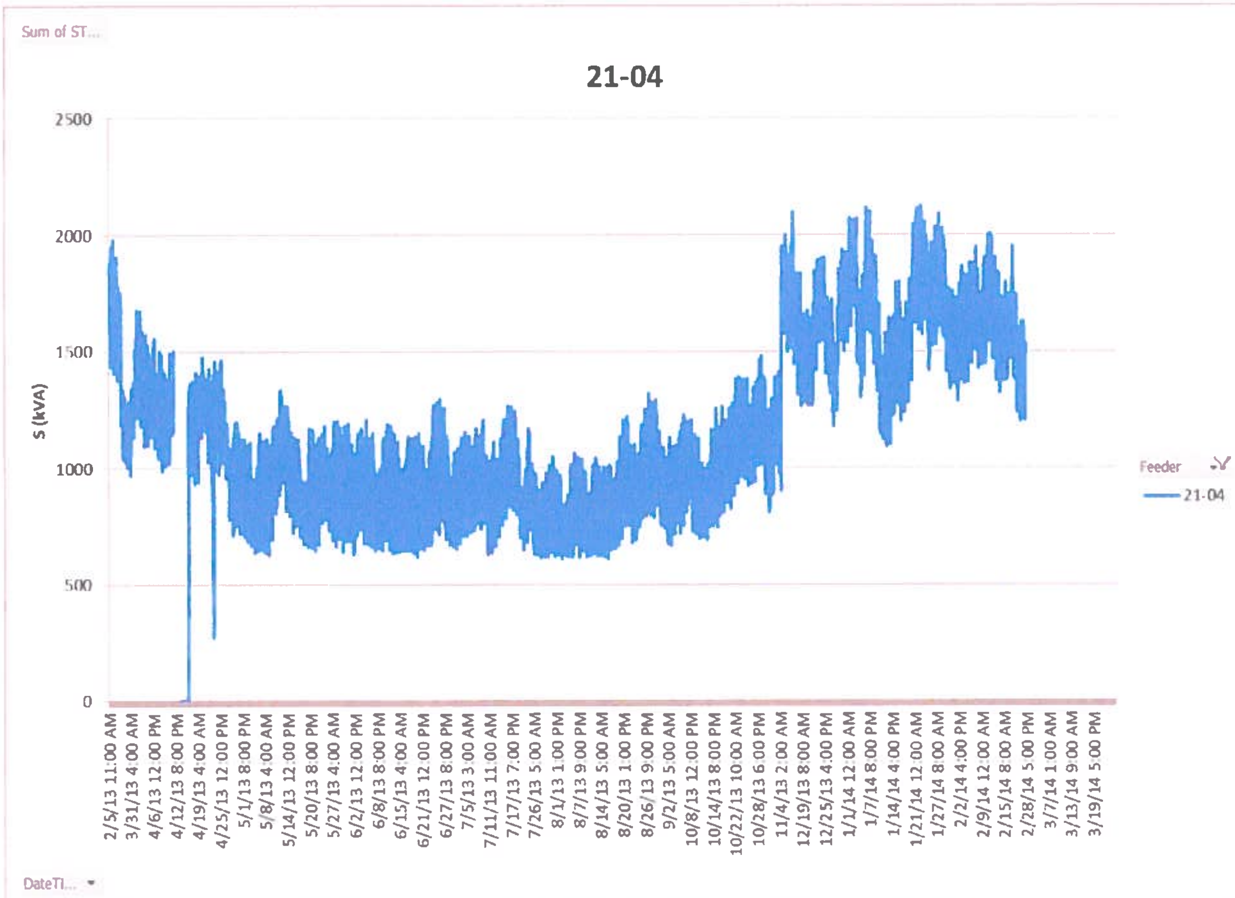
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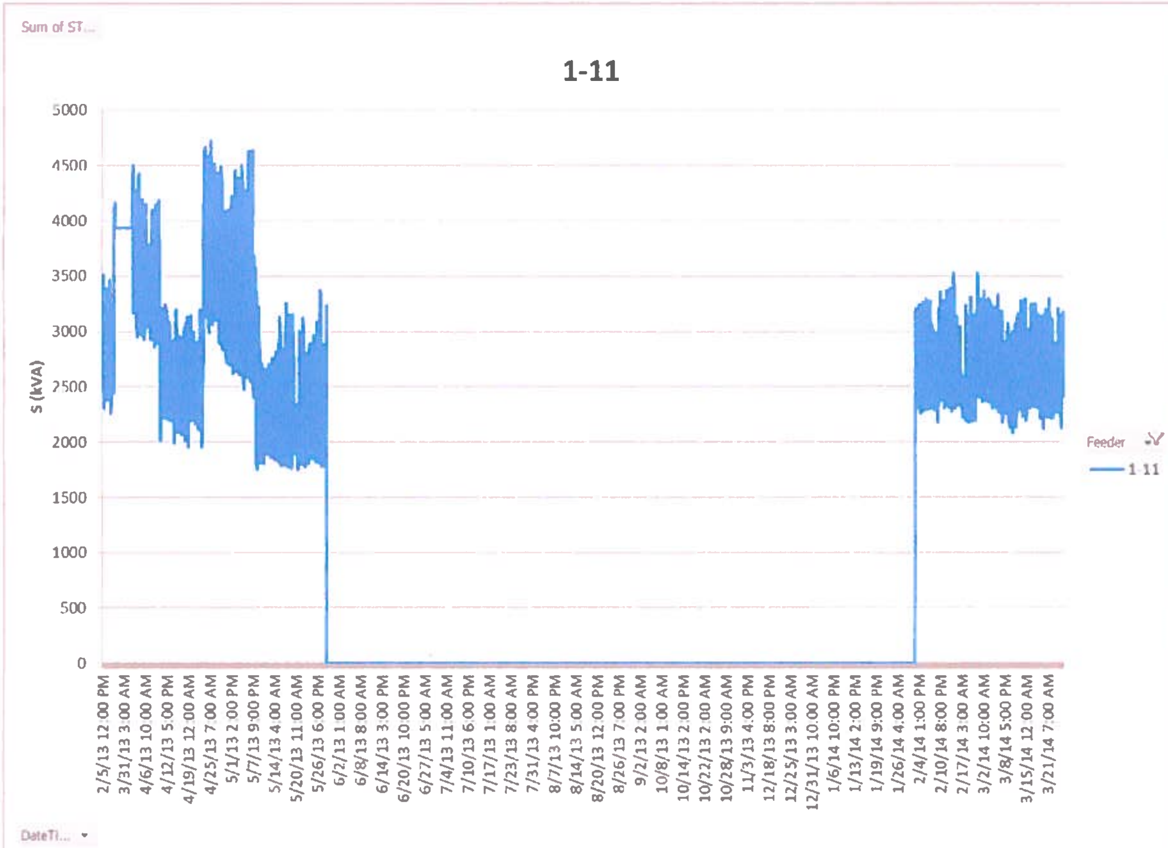

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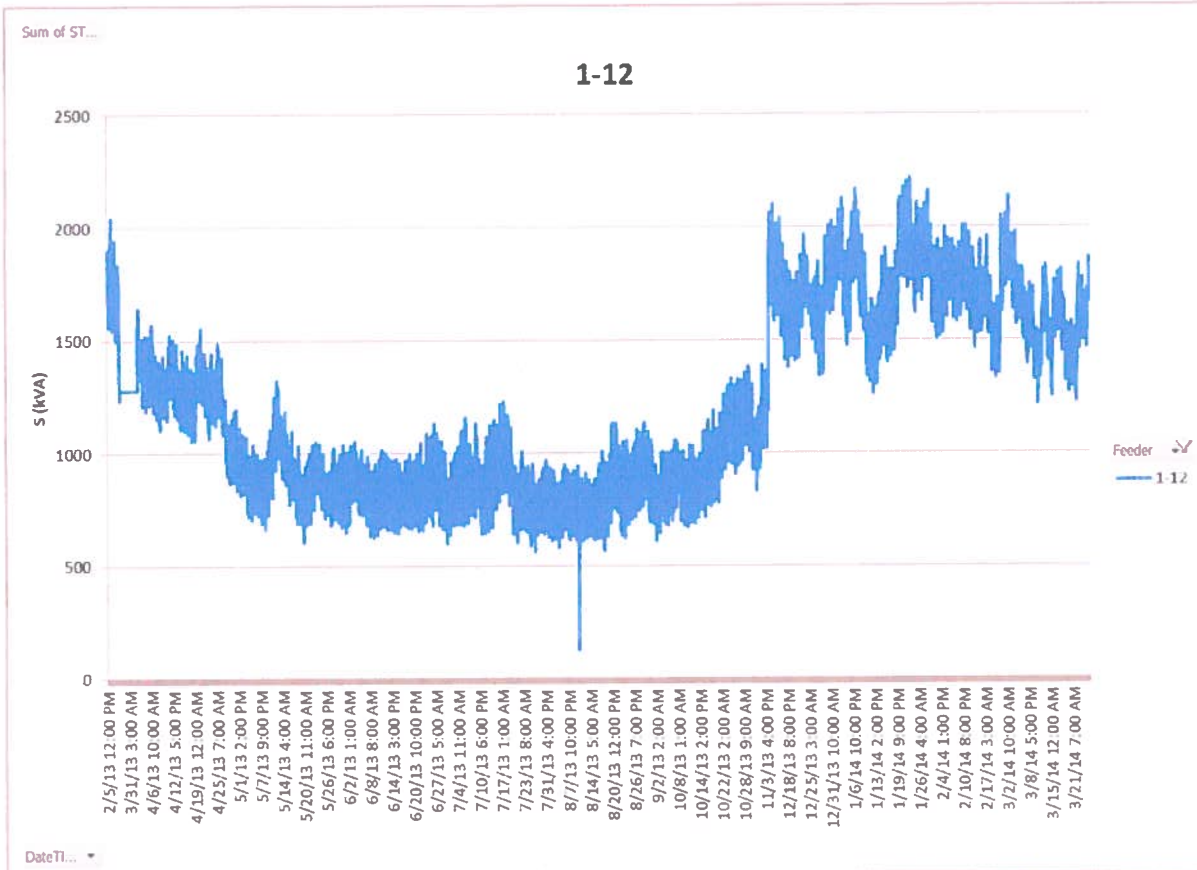
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DateTi...

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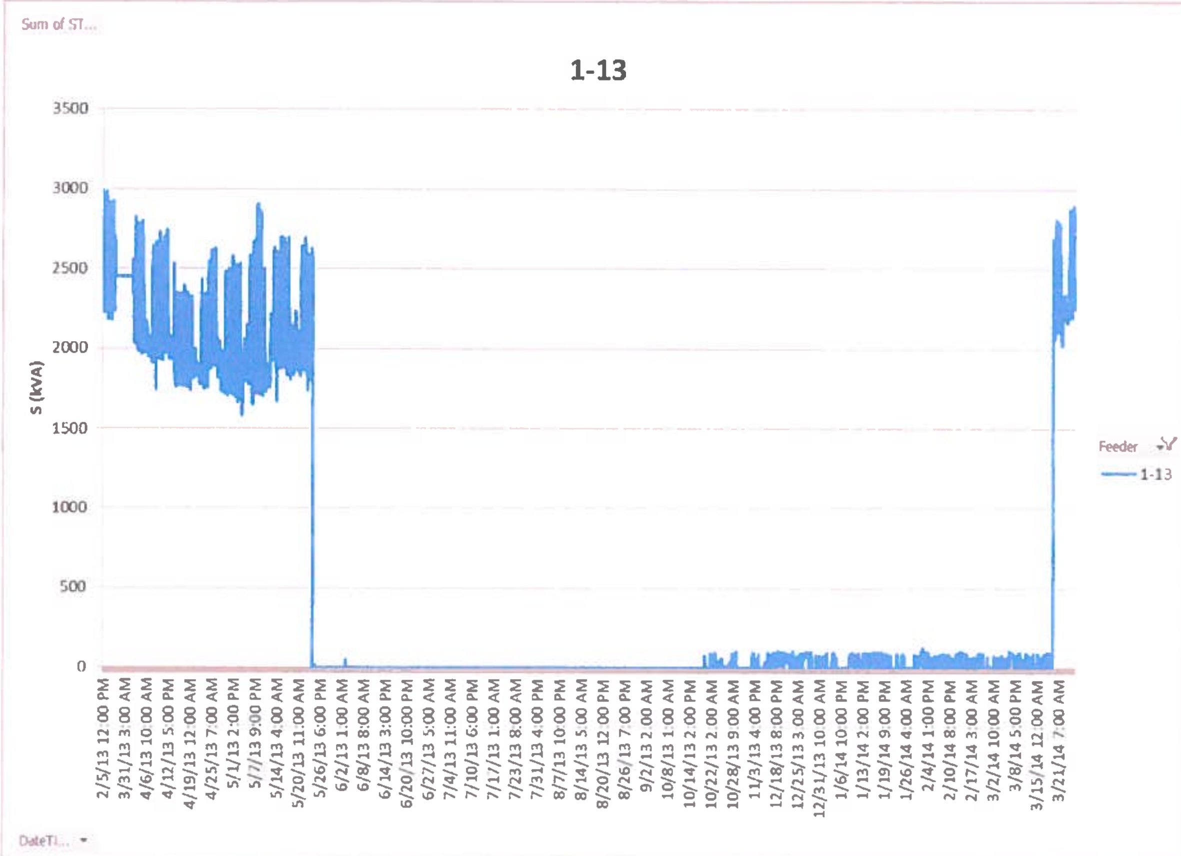
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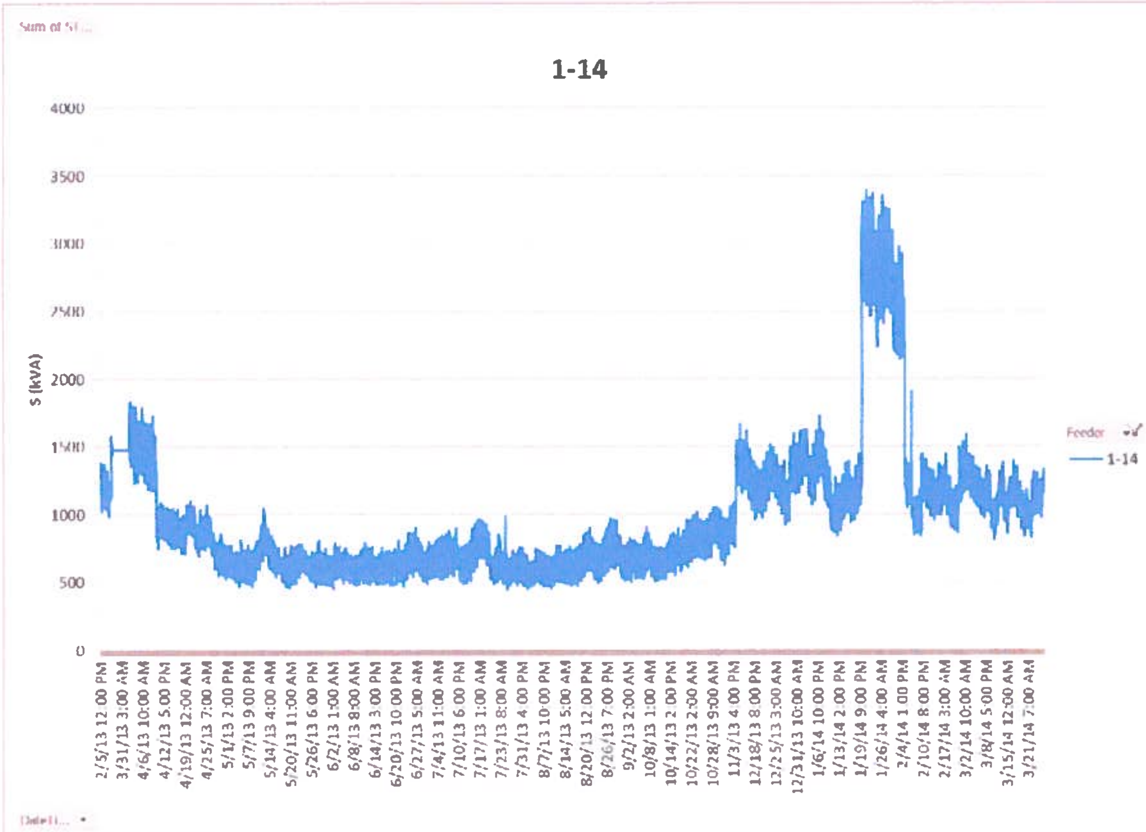

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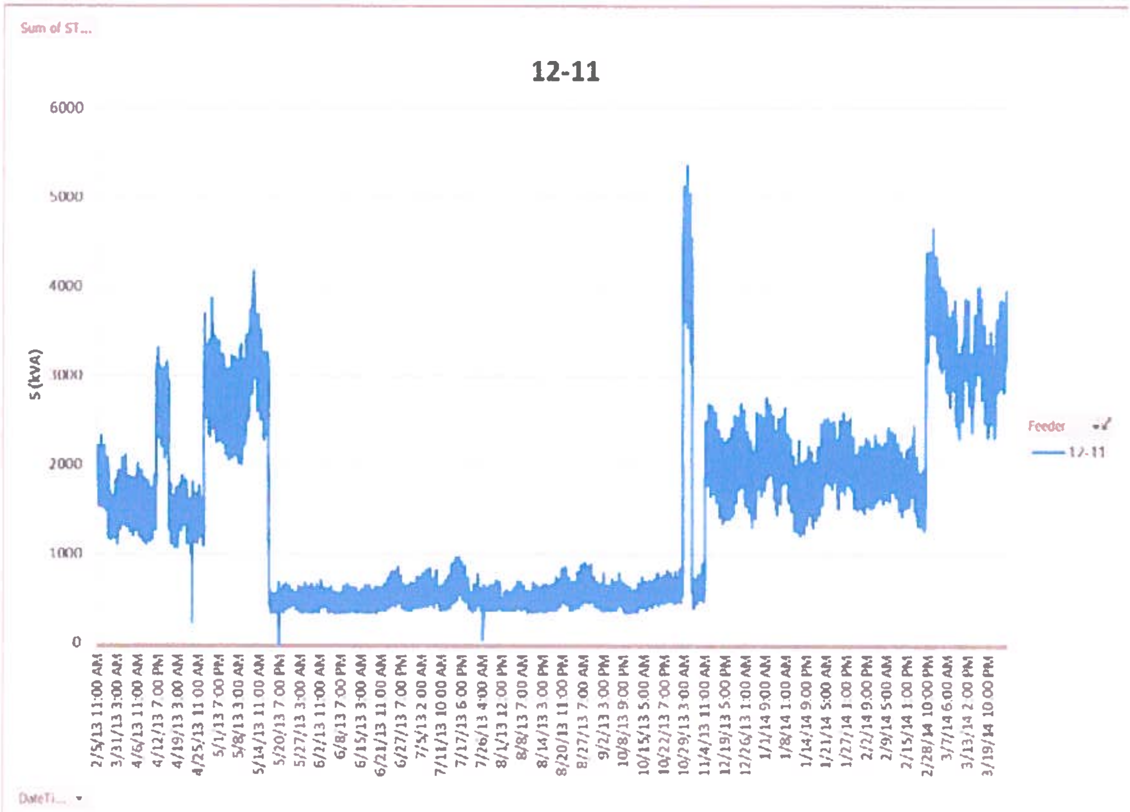
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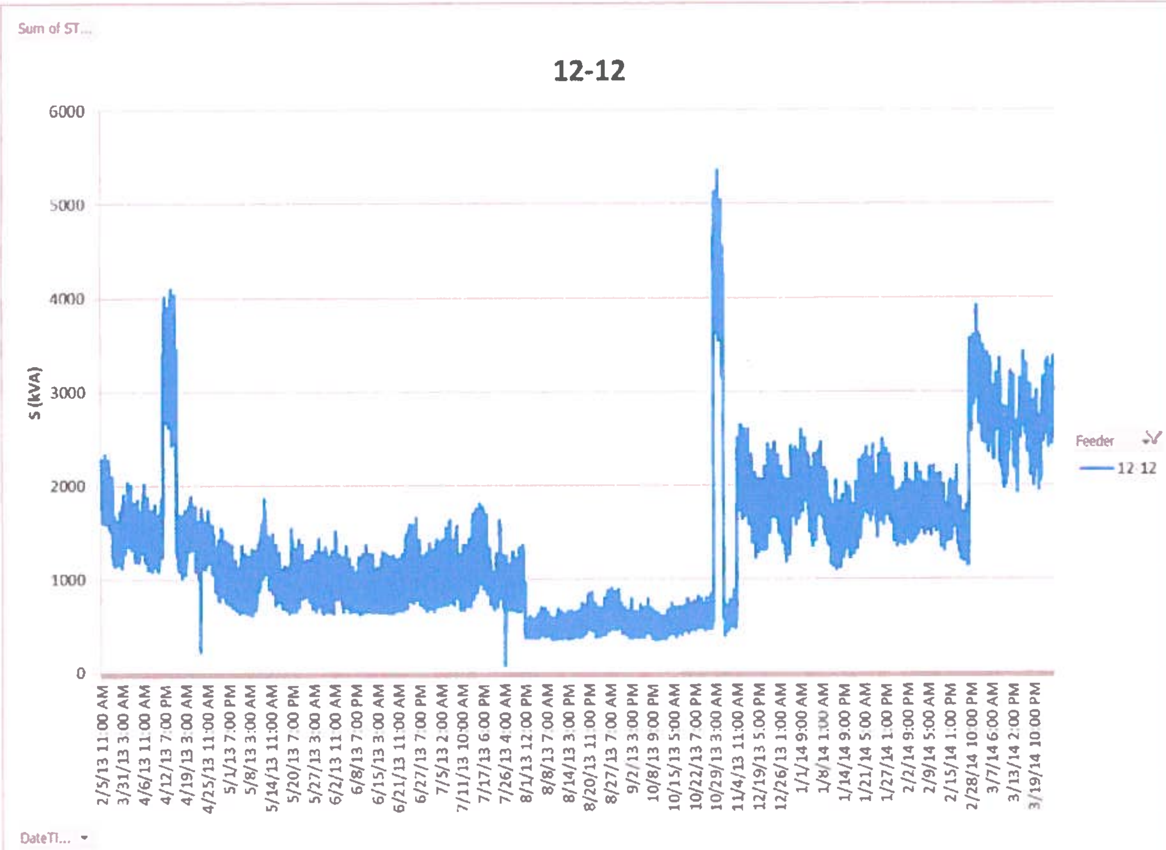

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12-12
DateTi...

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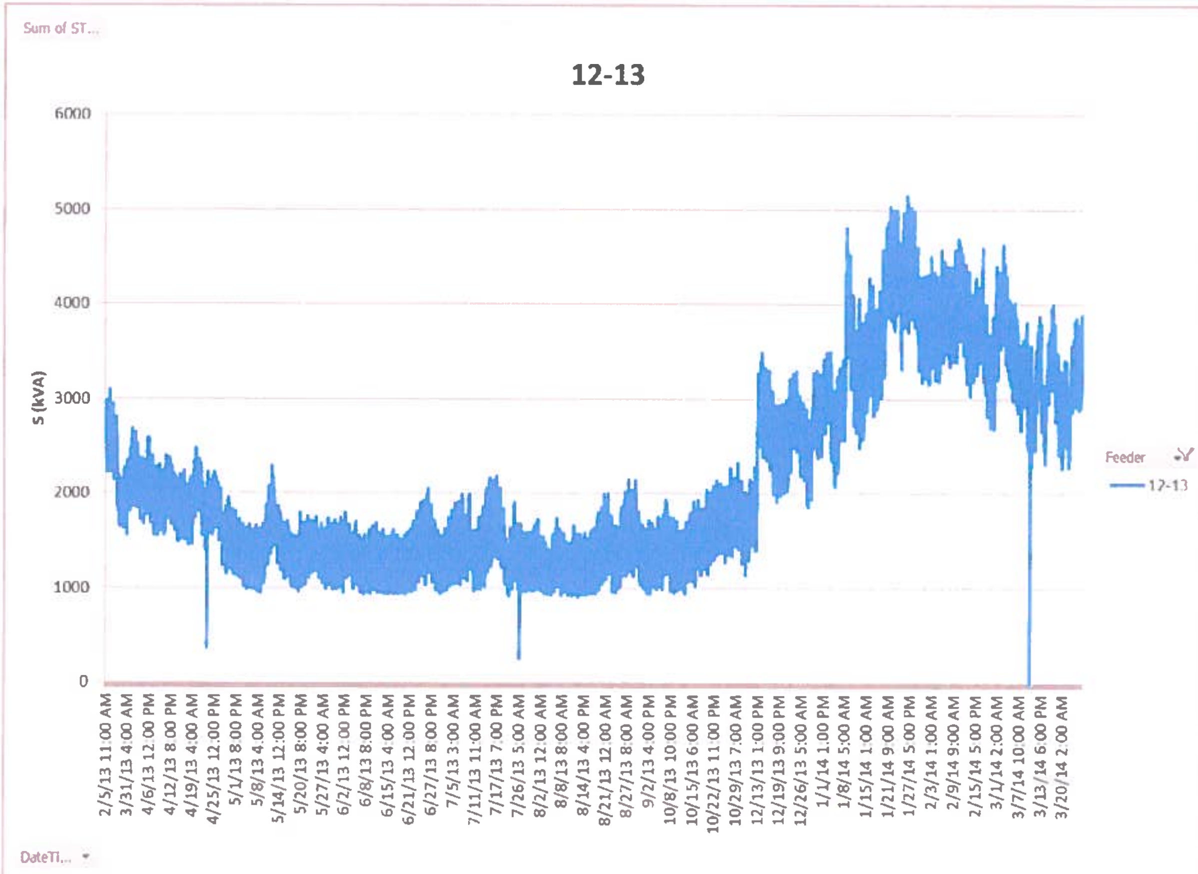

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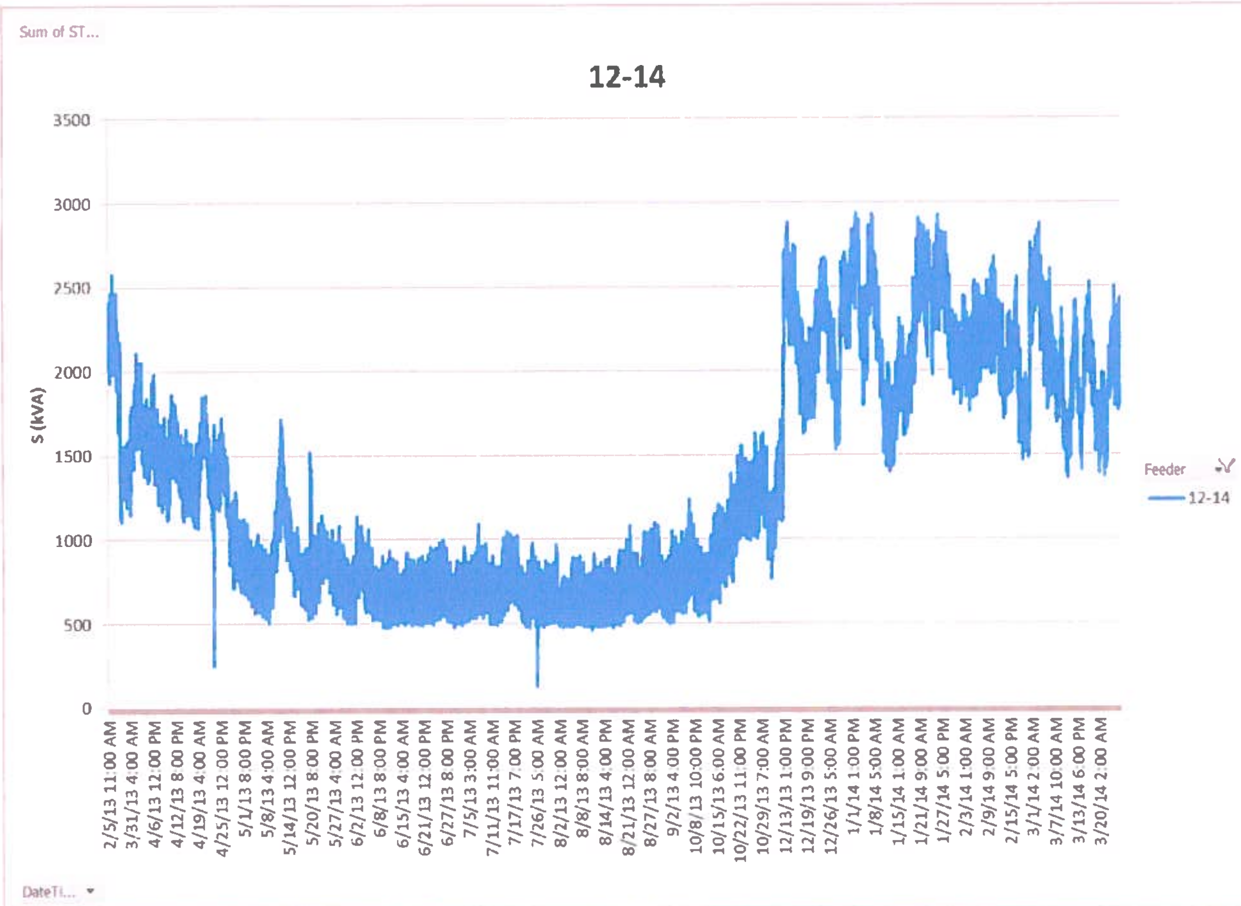
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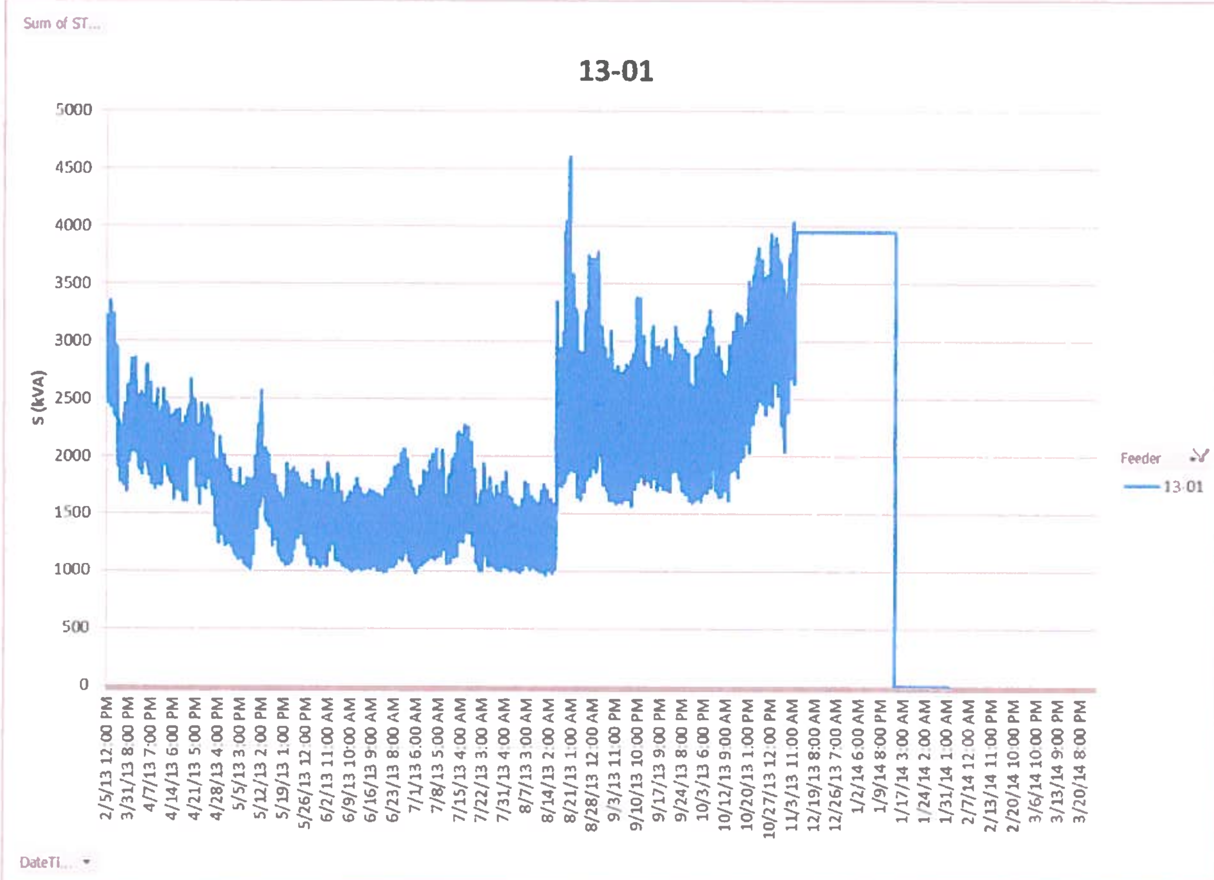
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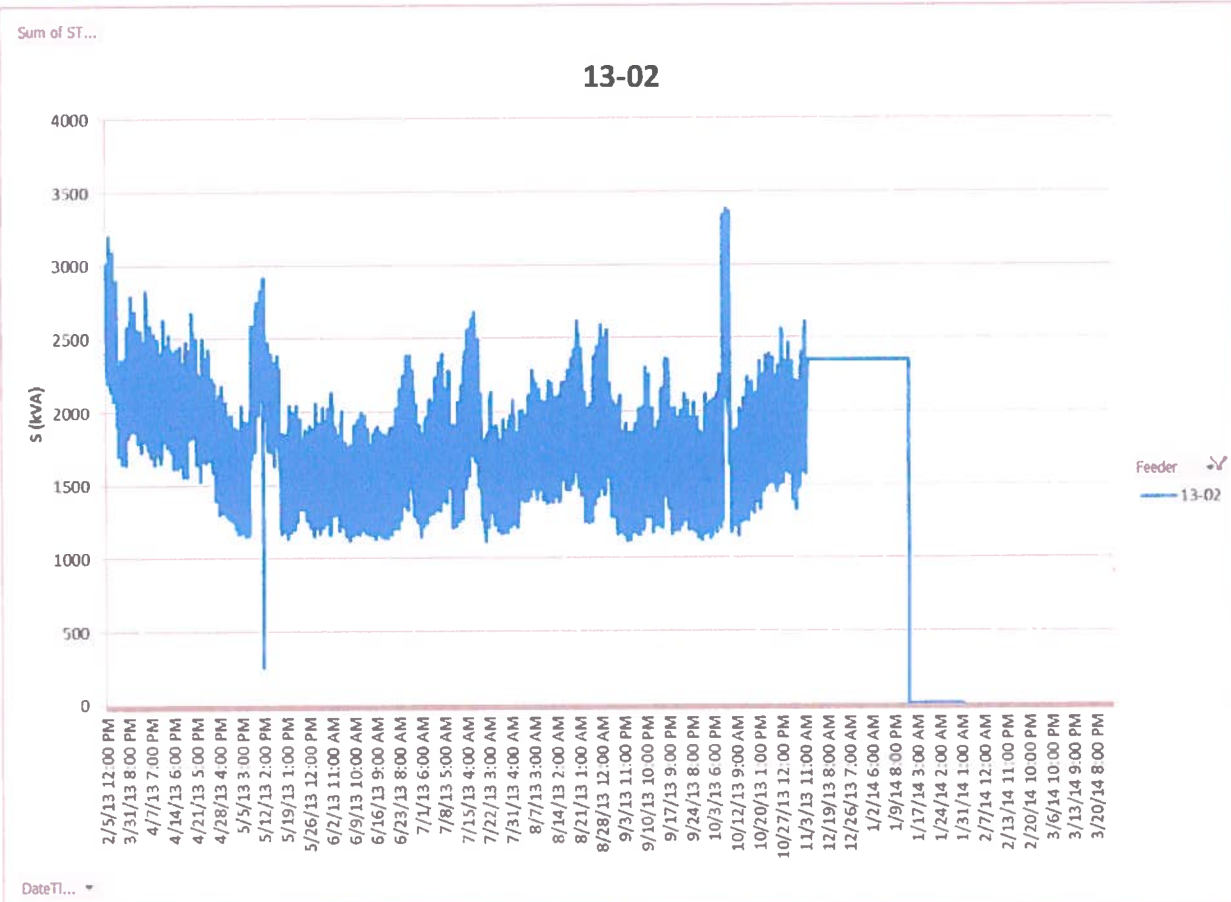
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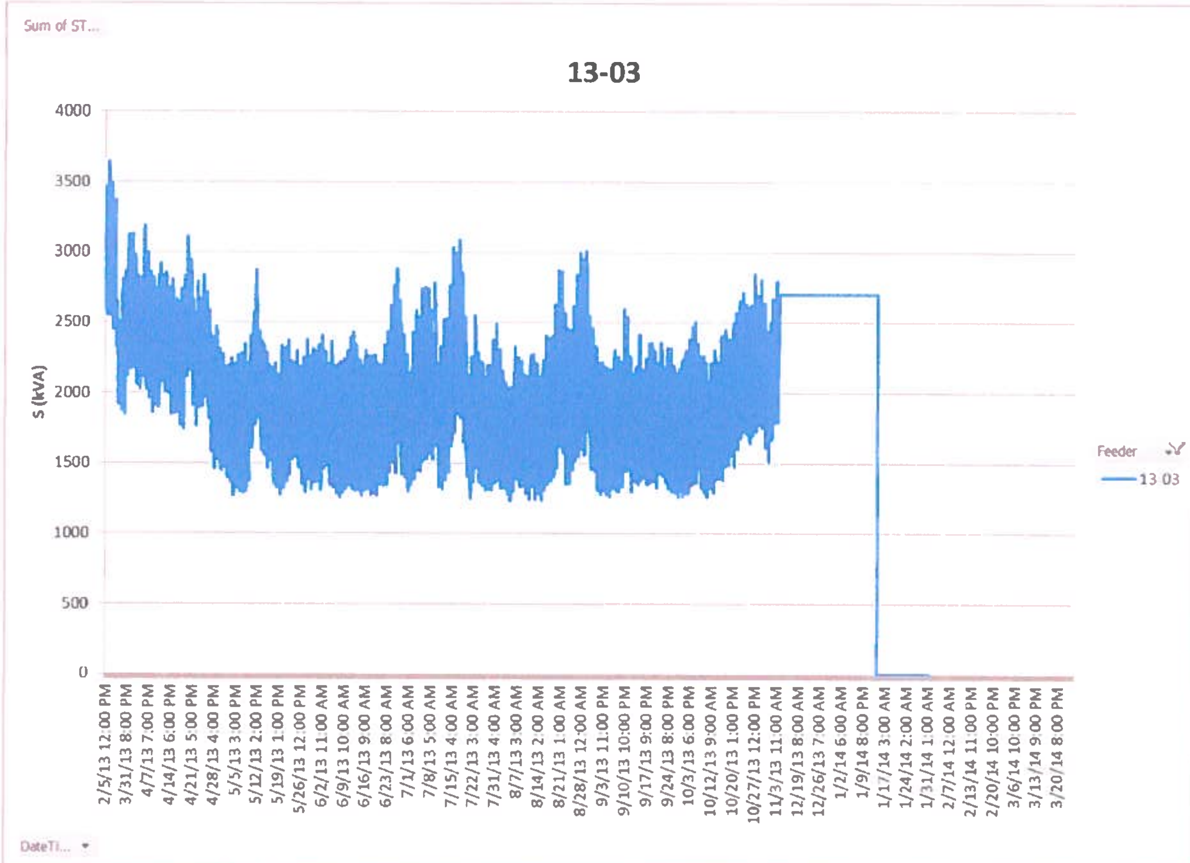
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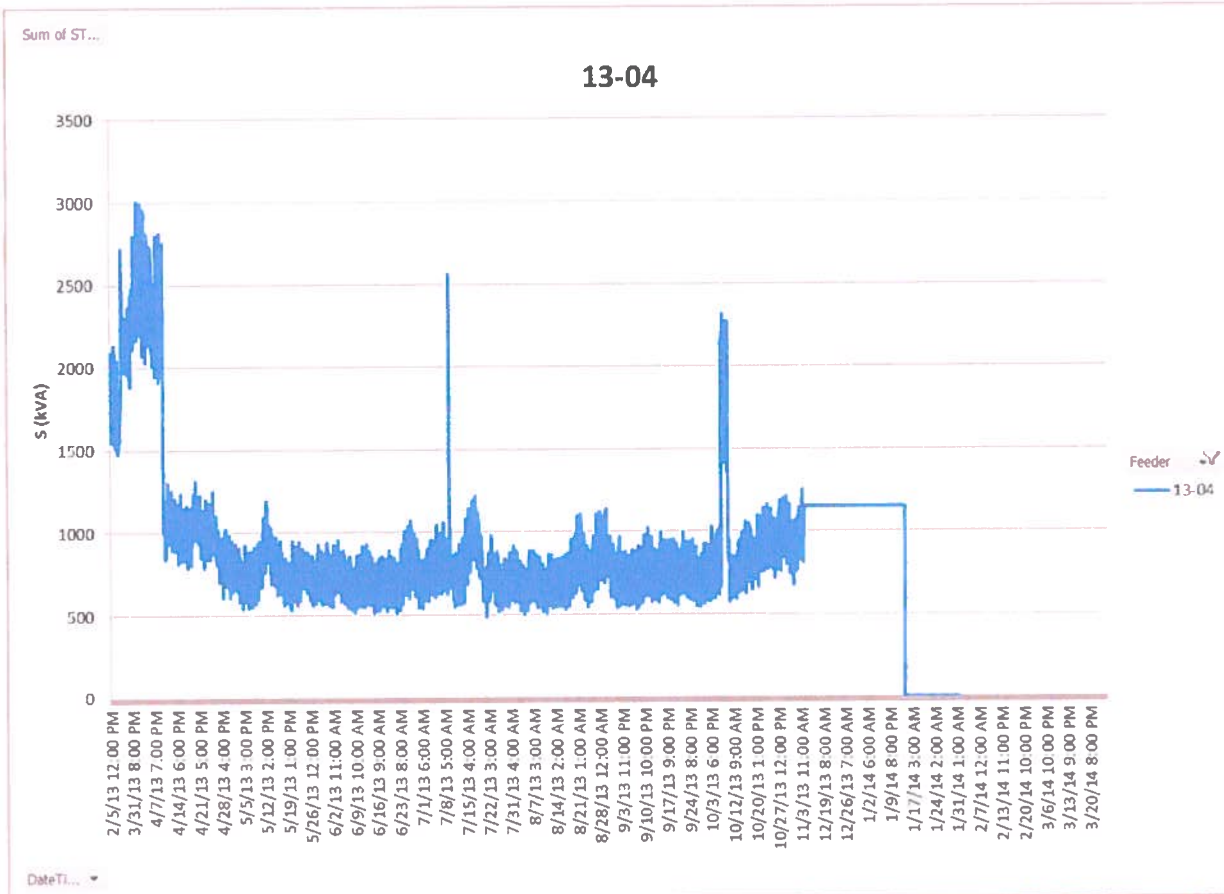

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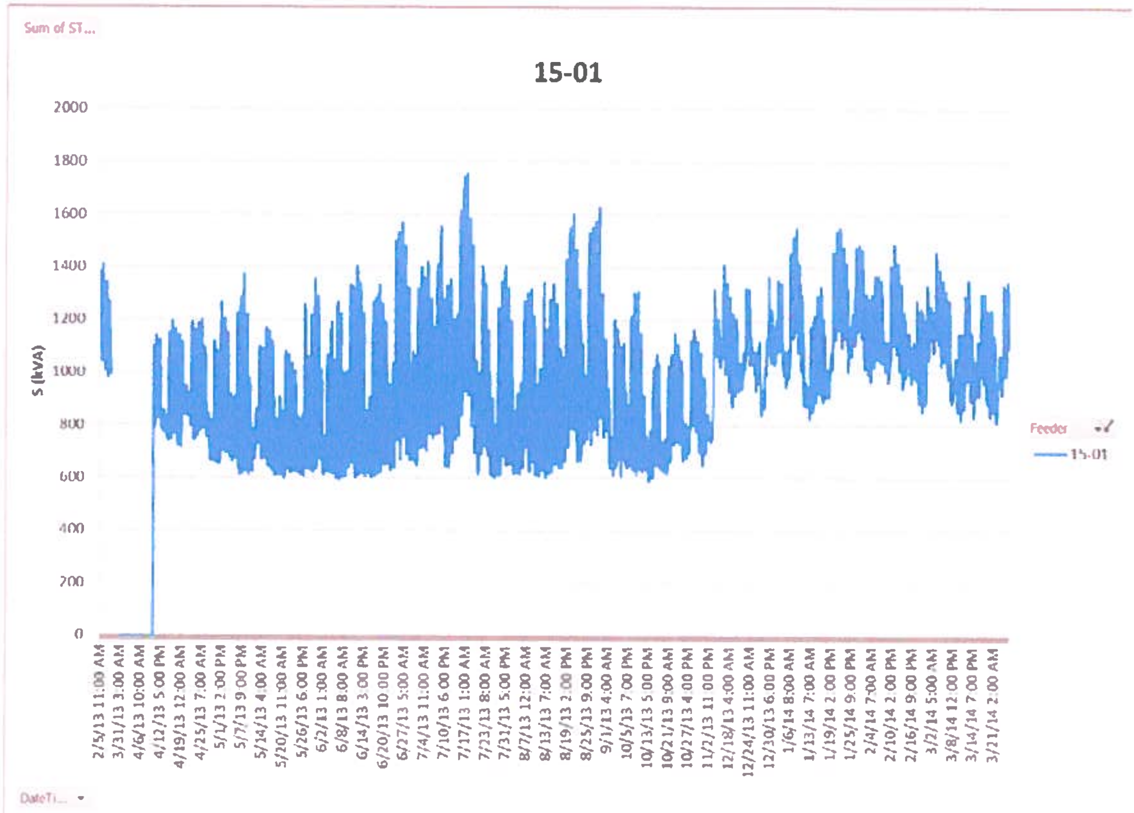

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5/7/13 9:00 PM
5/14/13 4:00 AM
5/20/13 11:00 AM
5/26/13 6:00 PM
6/2/13 1:00 AM
6/8/13 8:00 AM
6/14/13 3:00 PM
6/20/13 10:00 PM
6/27/13 5:00 AM
7/4/13 11:00 AM
7/10/13 6:00 PM
7/17/13 1:00 AM
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1/6/14 8:00 AM
1/13/14 7:00 AM
1/19/14 2:00 PM
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2/10/14 2:00 PM
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3/21/14 2:00 AM
DateTi...

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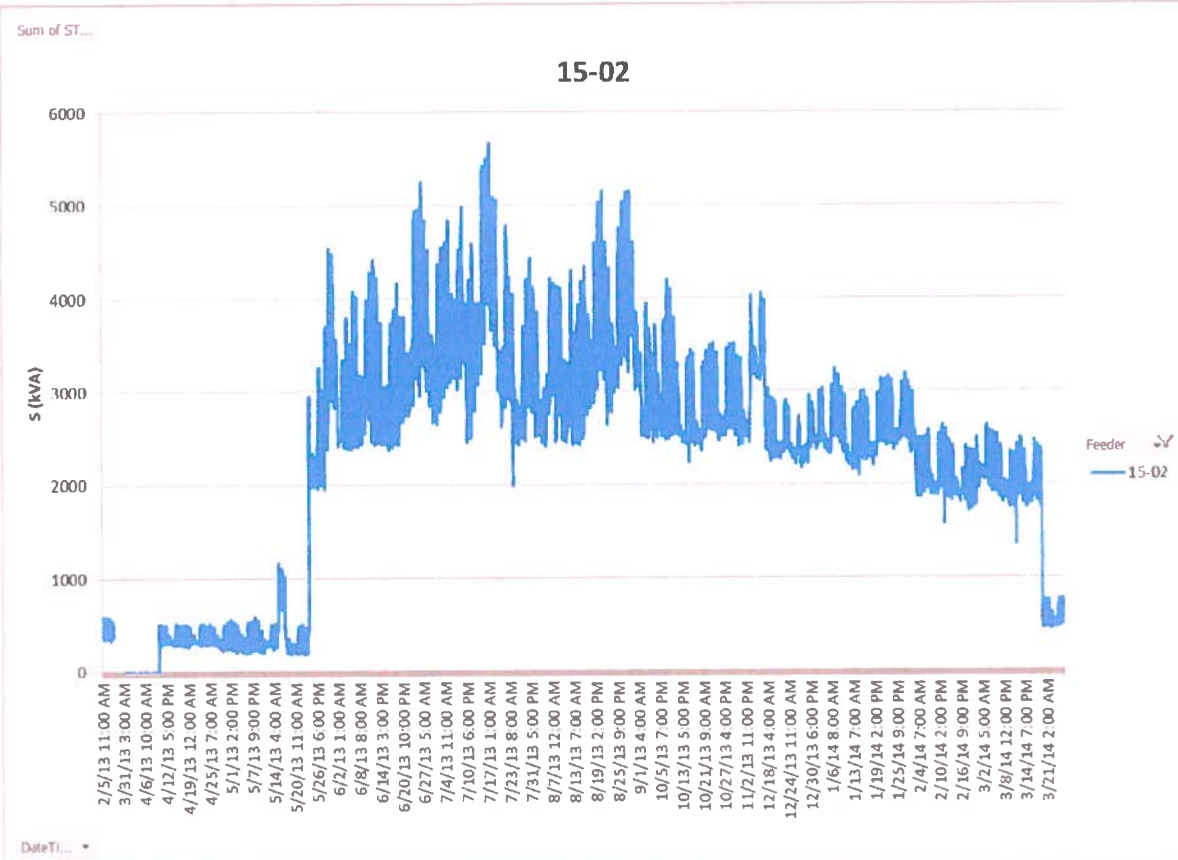

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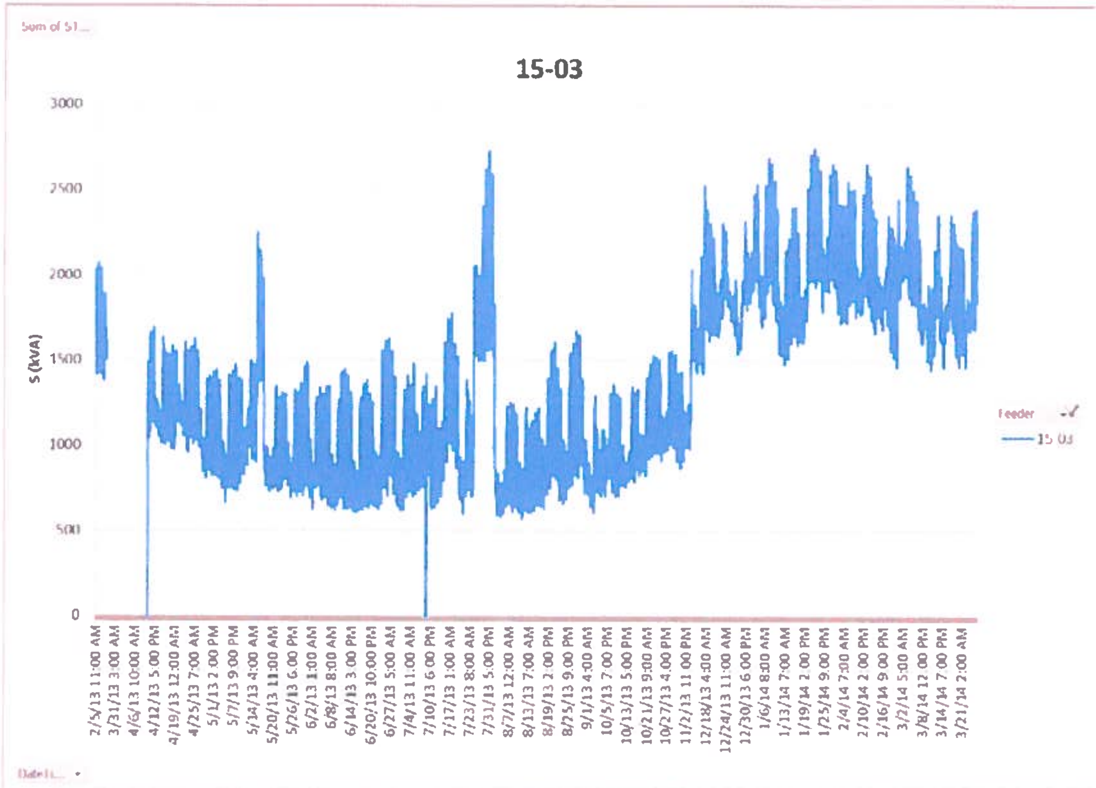
5000
4000
3000
2000
1000
0
Feeder
15-02
DateTi...

15-03: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Feeder
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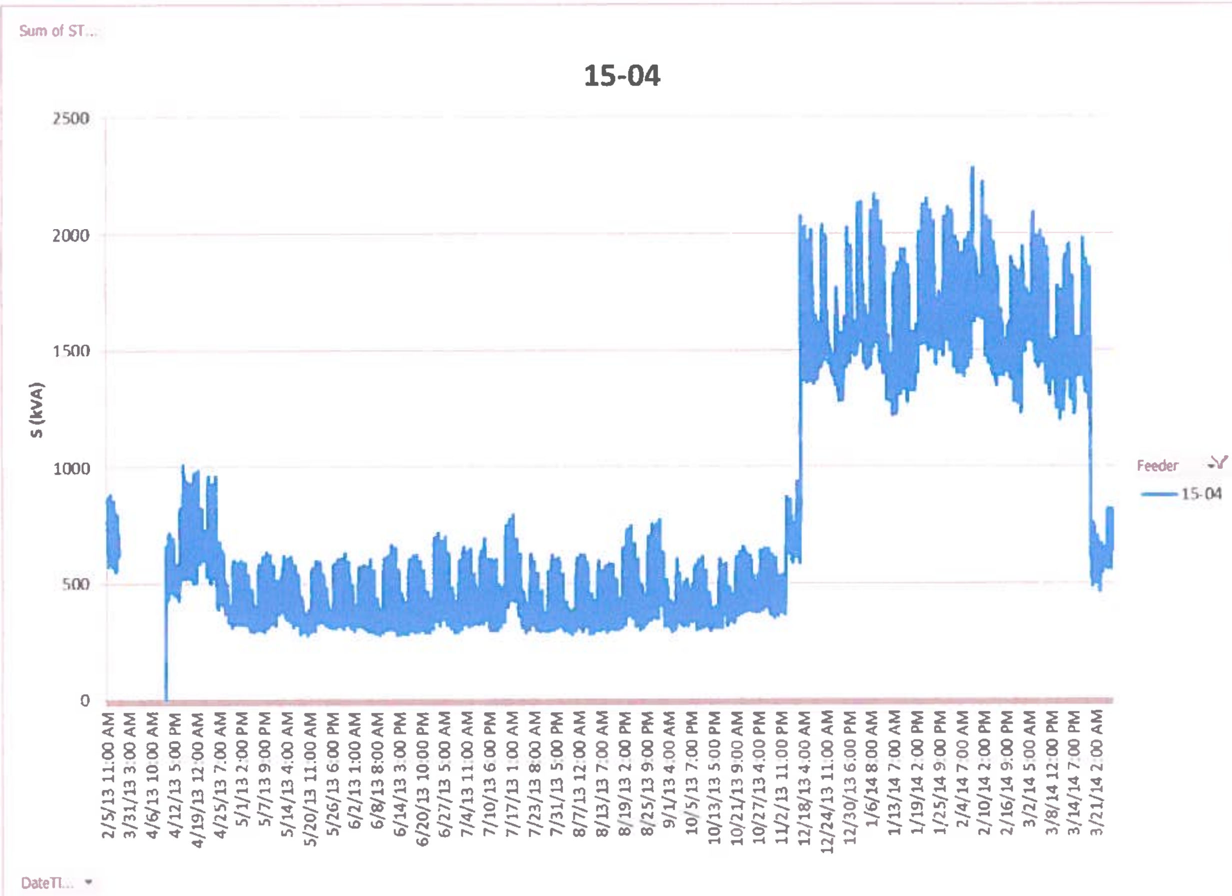
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2000
1500
1000
500
0
S (kVA)
Feeder
15-04
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4/6/13 10:00 AM
4/12/13 5:00 PM
4/19/13 12:00 AM
4/25/13 7:00 AM
5/1/13 2:00 PM
5/7/13 9:00 PM
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1/13/14 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
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DateTI...

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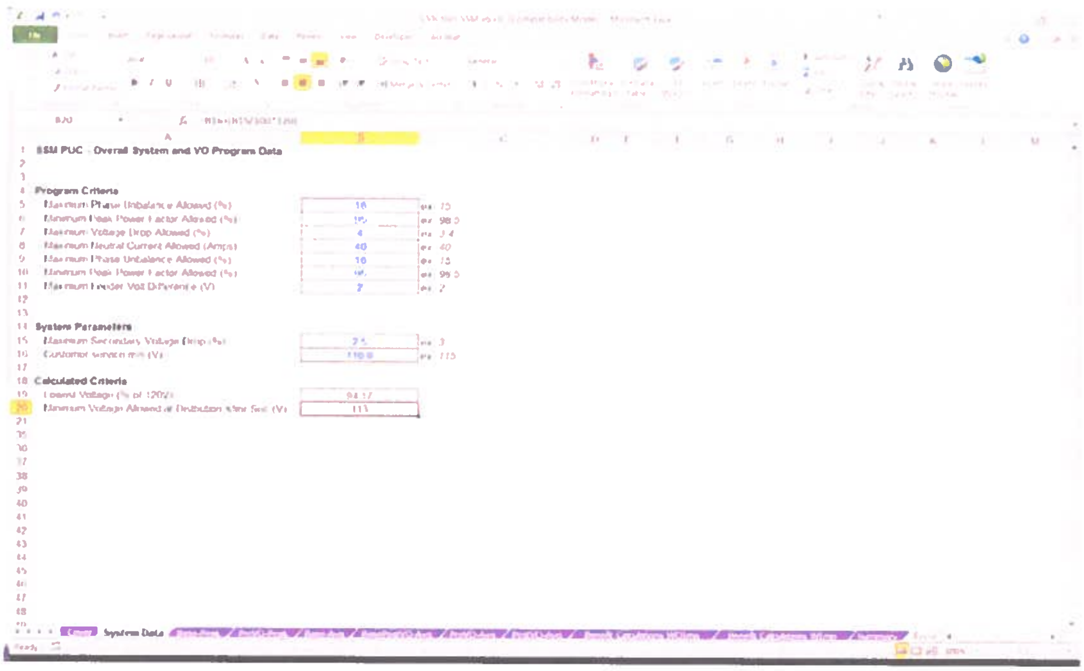
Appendix 5. Screenshots of VVM Benefit Spreadsheet



System Data Tab

Base-Avg Tab

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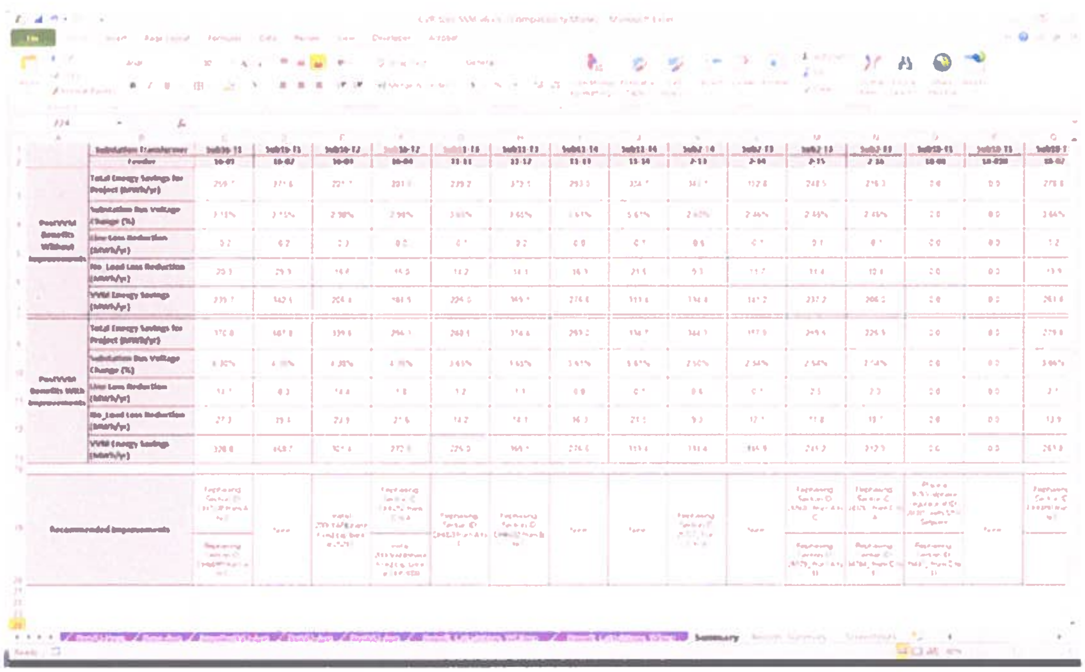
Benefit Calculations Wimp Tab



Summary Tab

Appendix 6. Feeder Improvement Recommendations-CYME Snapshots

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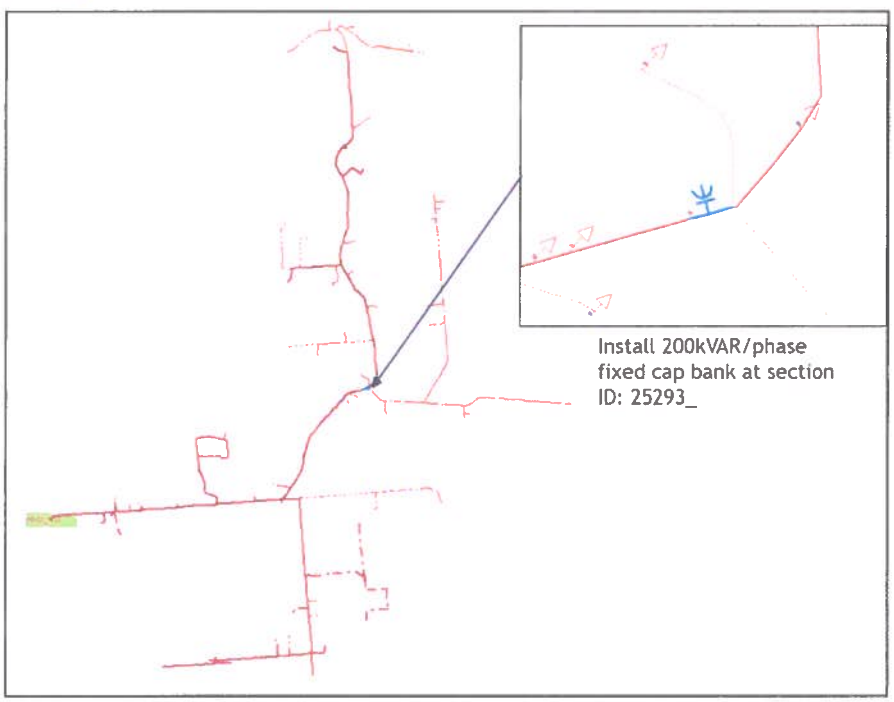
16-03:



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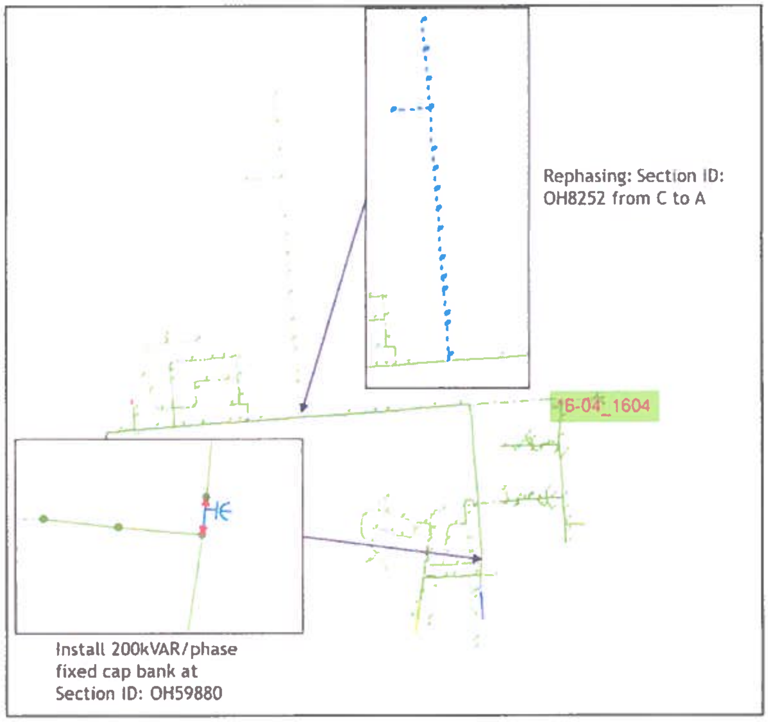
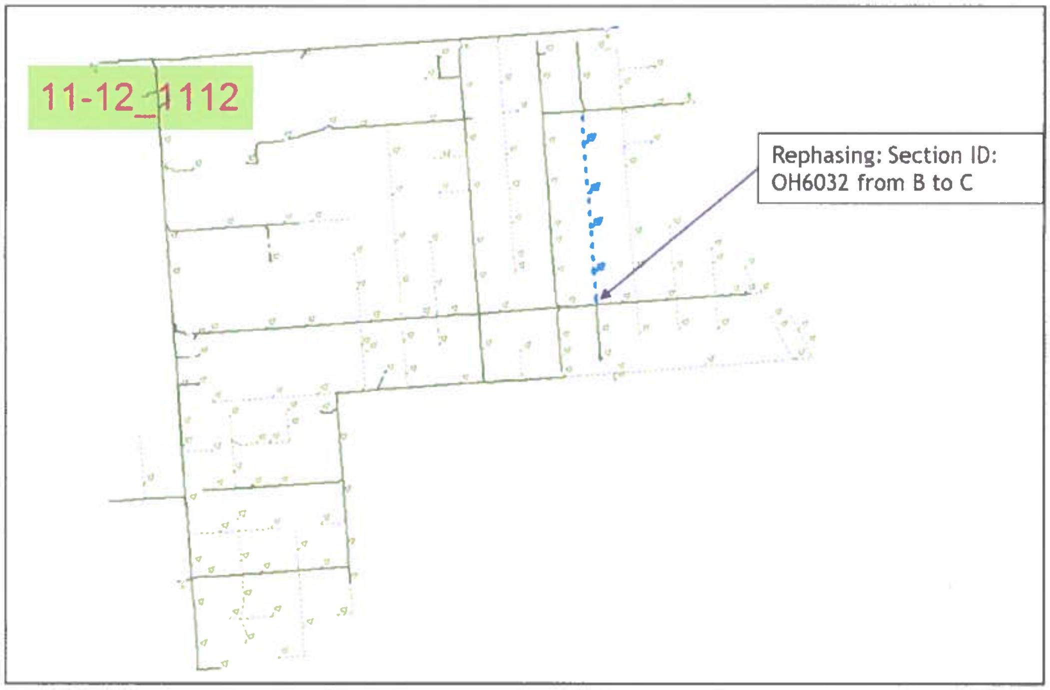

Rephasing: Section ID:
OH8252 from C to A
16-04_1604
Install 200kVAR/phase
fixed cap bank at
Section ID: OH59880

11-11:


11-11_1111_
Rephasing: Section ID:
OH803 from A to C

11-12: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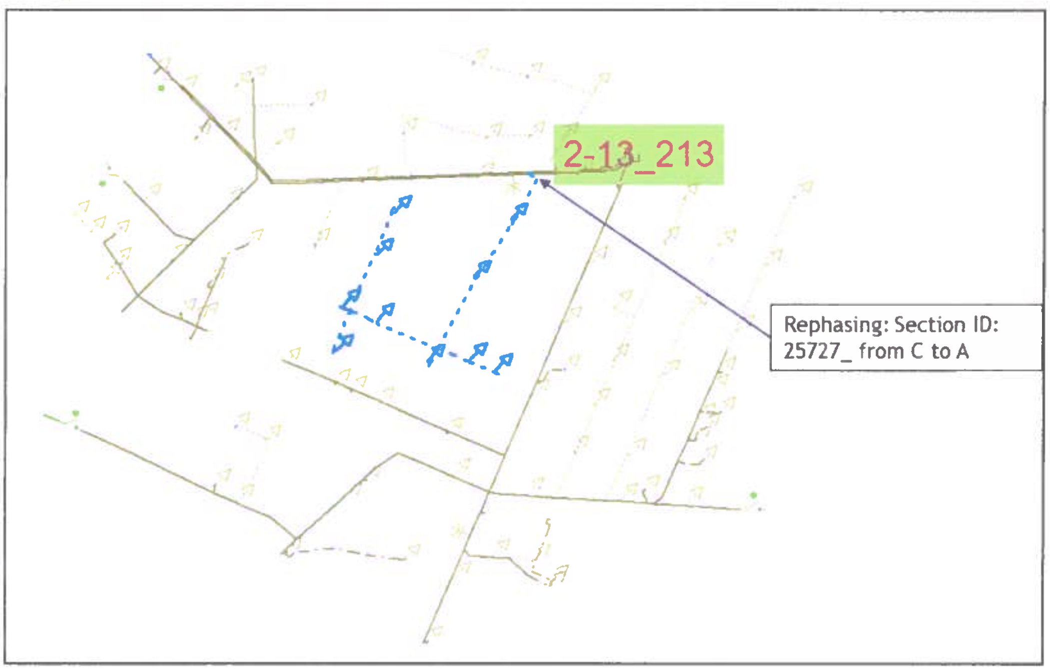
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25727_ from C to A

2-15:


2-15_215
Rephasing: Section ID:
26568_ from A to C
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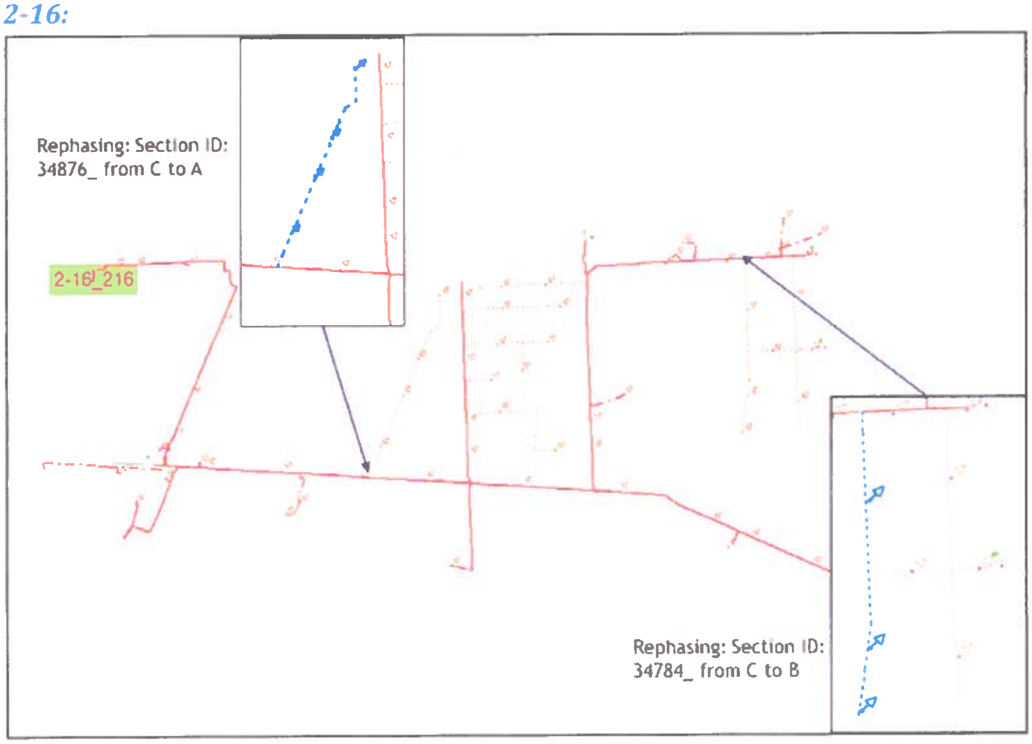
26579_ from A to B

2-16: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2-16_216
Rephasing: Section ID:
34784_ from C to B

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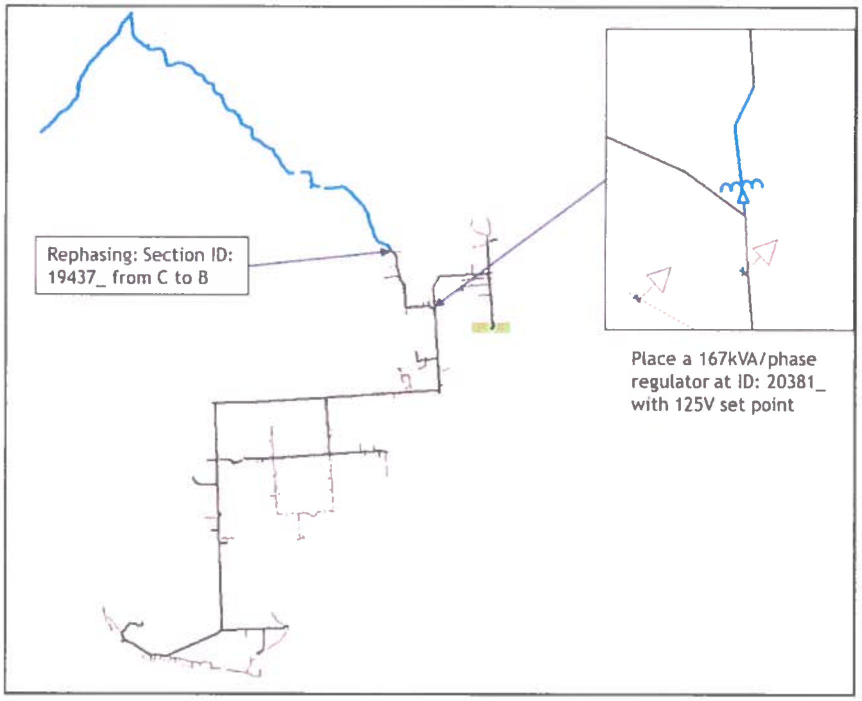
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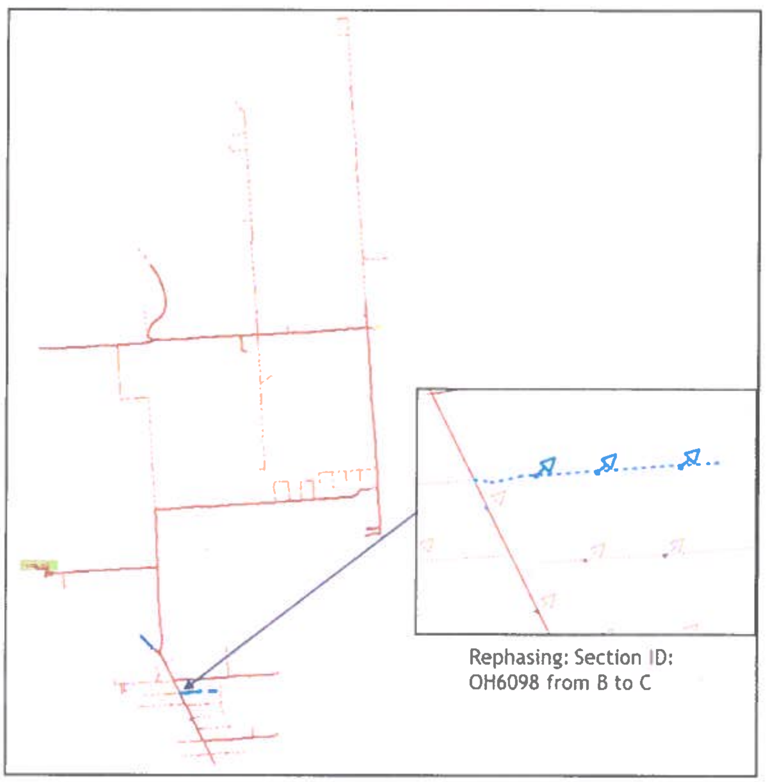
18-02: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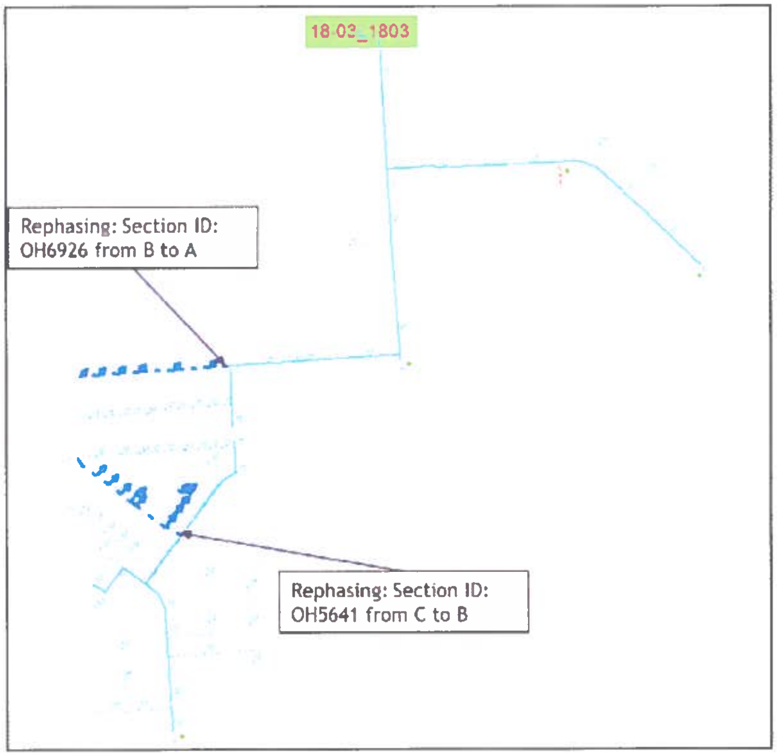
18-03_1803
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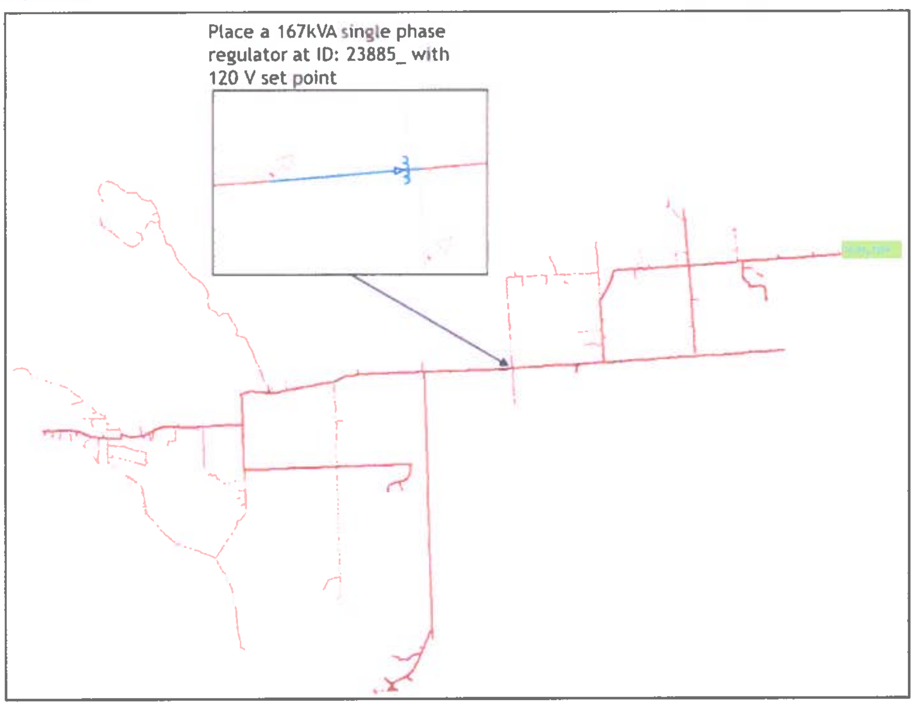
Rephasing: Section ID: OH5641 from C to B

18-04: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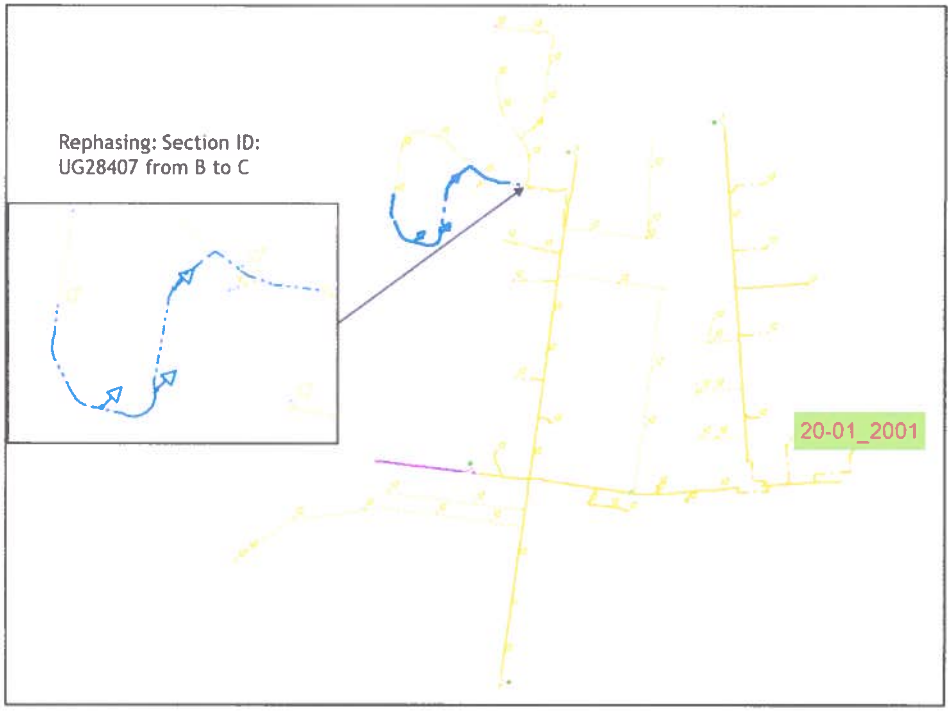
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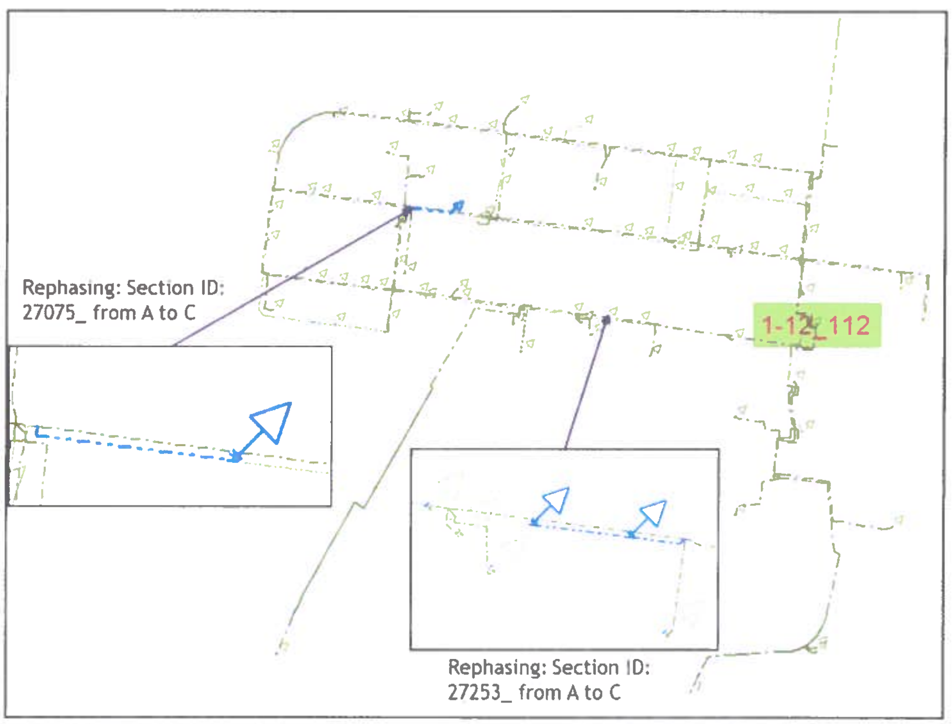
1-12: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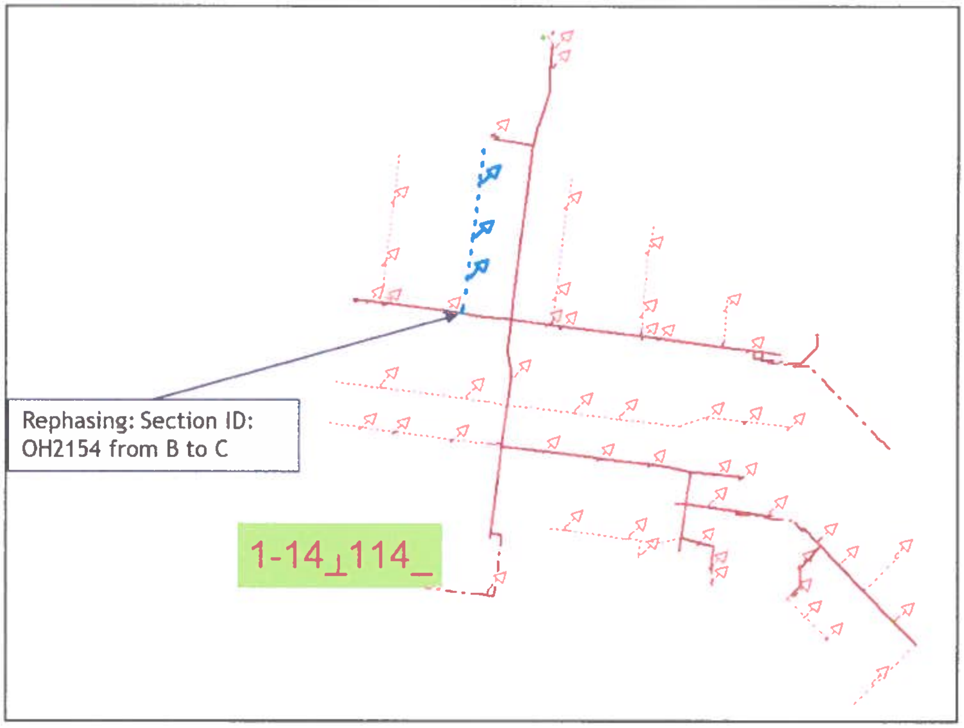
1-12_112
Rephasing: Section ID:
27253_ from A to C

1-14:



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Leidos Engineering, LLC

Utility Distribution Microgrid: Distribution Automation

Preliminary Design

Energizing Co.

PUC Distribution, Sault Ste. Marie, ON

Leidos
11/20/2014

Contents

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.

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.

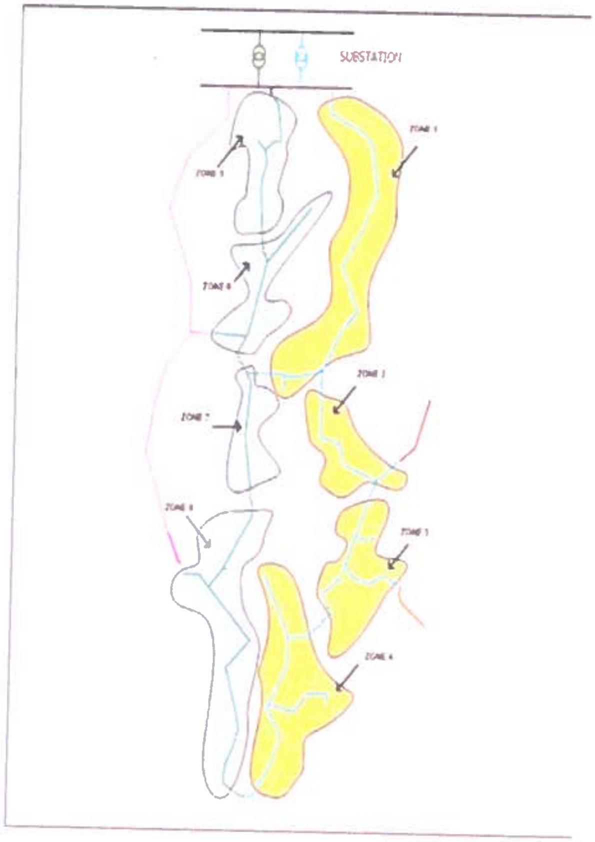

Figure 1. Sample DA Feeder

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.

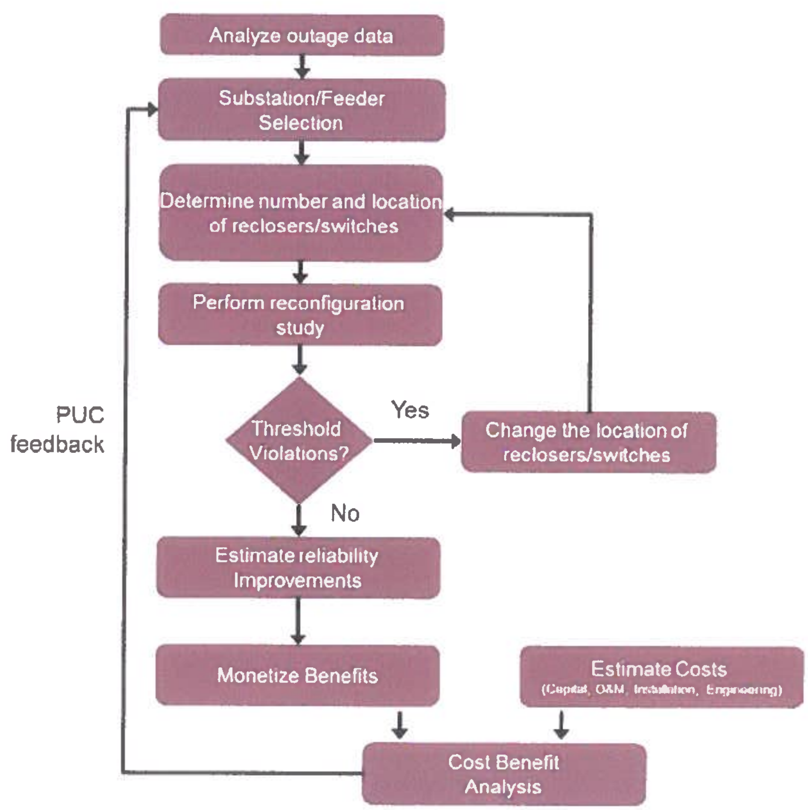

Figure 2. DA Design Methodology

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.

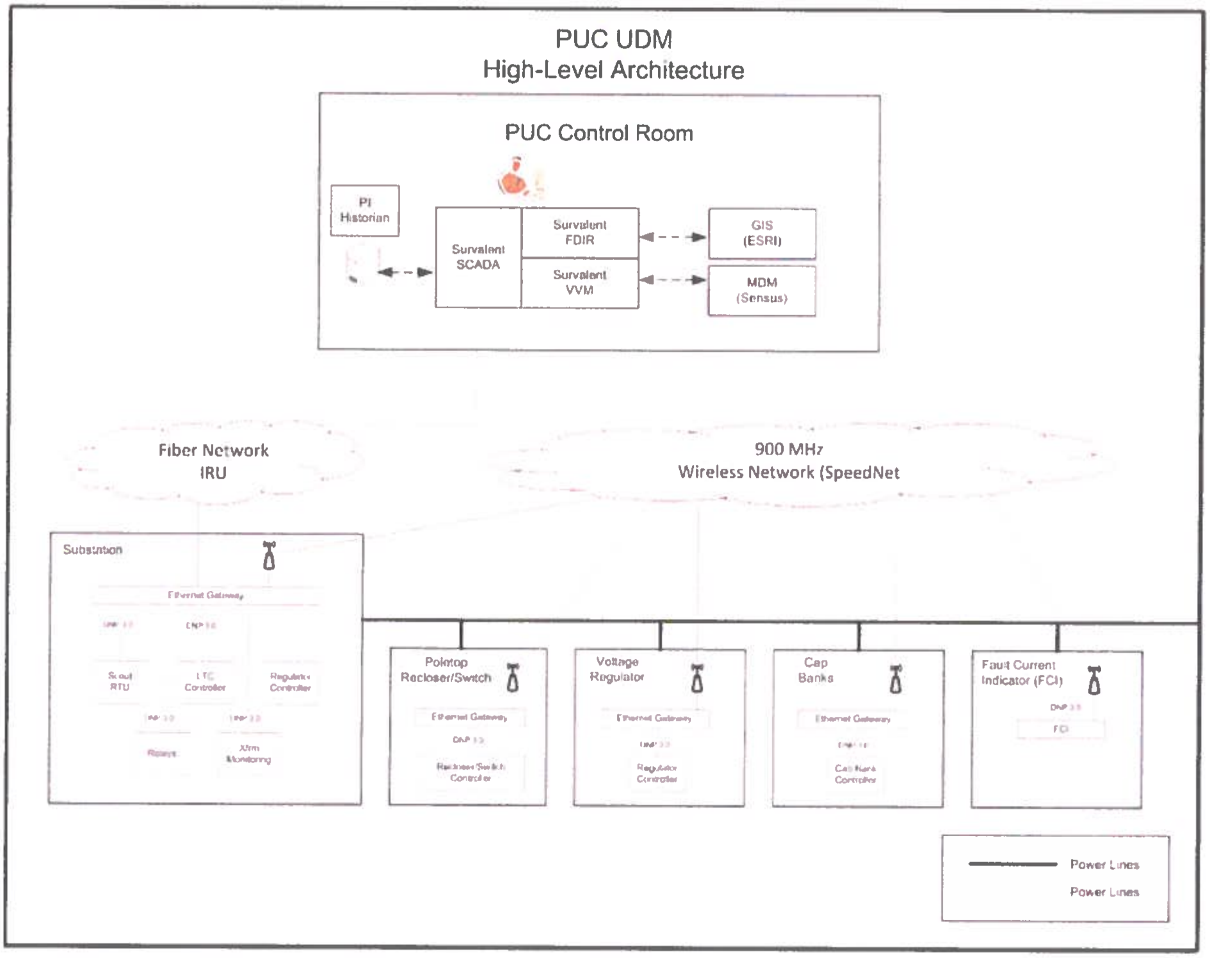

Figure 4. UDM System Architecture

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.

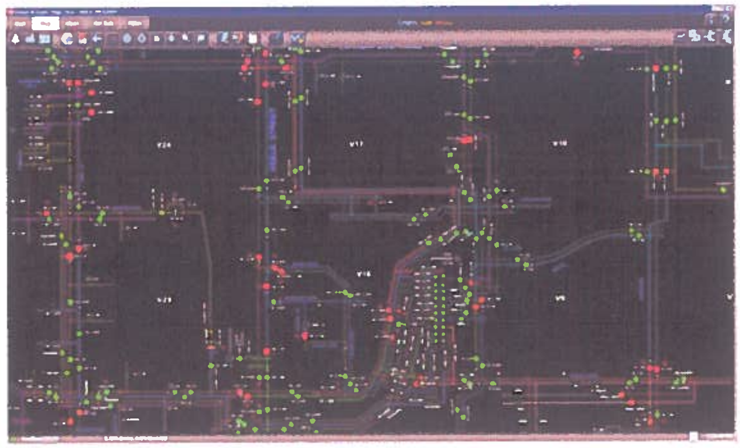

Figure 5. DA Software

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.

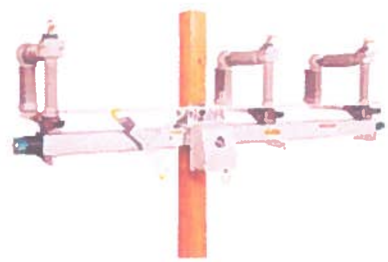

Figure 9. Overhead Loadbreak Switch

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.

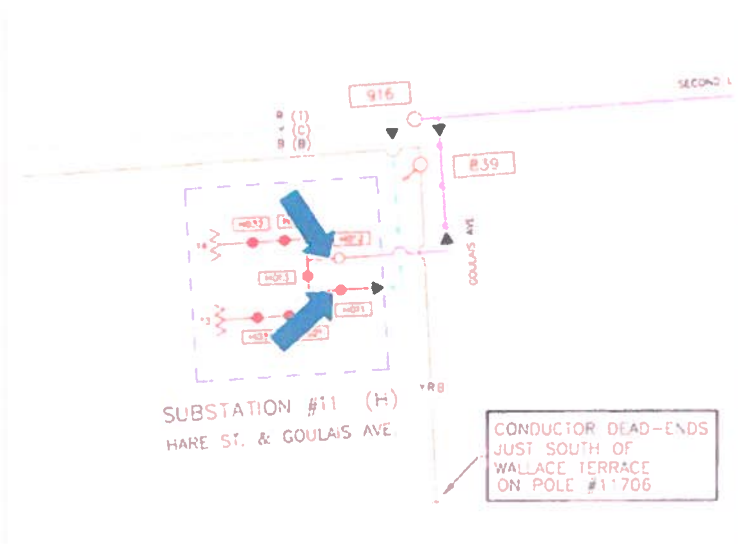

Figure 12. Fault Current Indicator

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

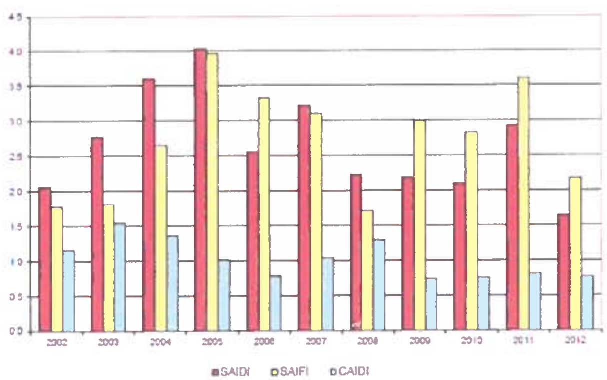

Figure 17. PUC System Level Reliability Data (PUC 2012 Annual Report)

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

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

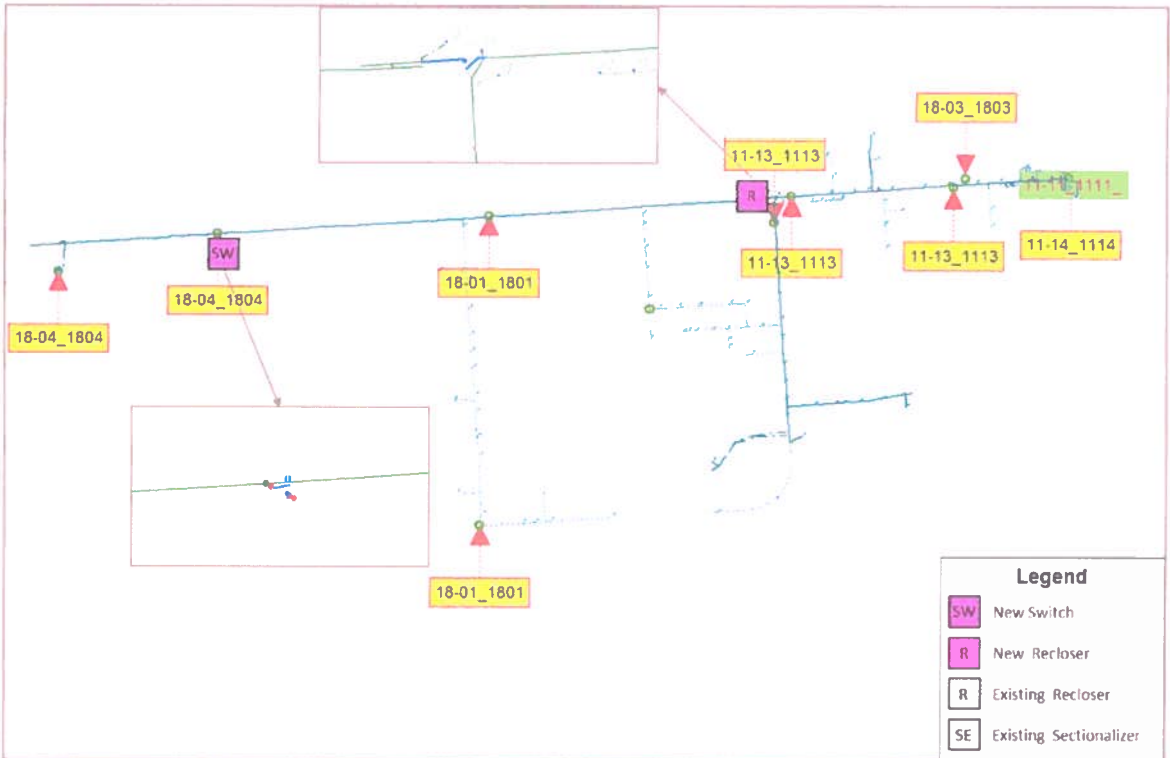
Feeder	Feeder/Adj Feeder	Load Transferred To	Load Transferred From	Min Downline Voltage (%)	Max Conductor Loading (%)
18-01	18-01	NA	NA	83.33	70.9
	18-04	NA	NA	91.84	68.1
	18-01	18-04	NA	97.8	20.5
	18-04	NA	18-01	81.09	116.8
18-02	18-02	NA	NA	97.39	36.8
	16-04	NA	NA	98.2	19.1
	18-02	16-04	NA	98.46	19.2
	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

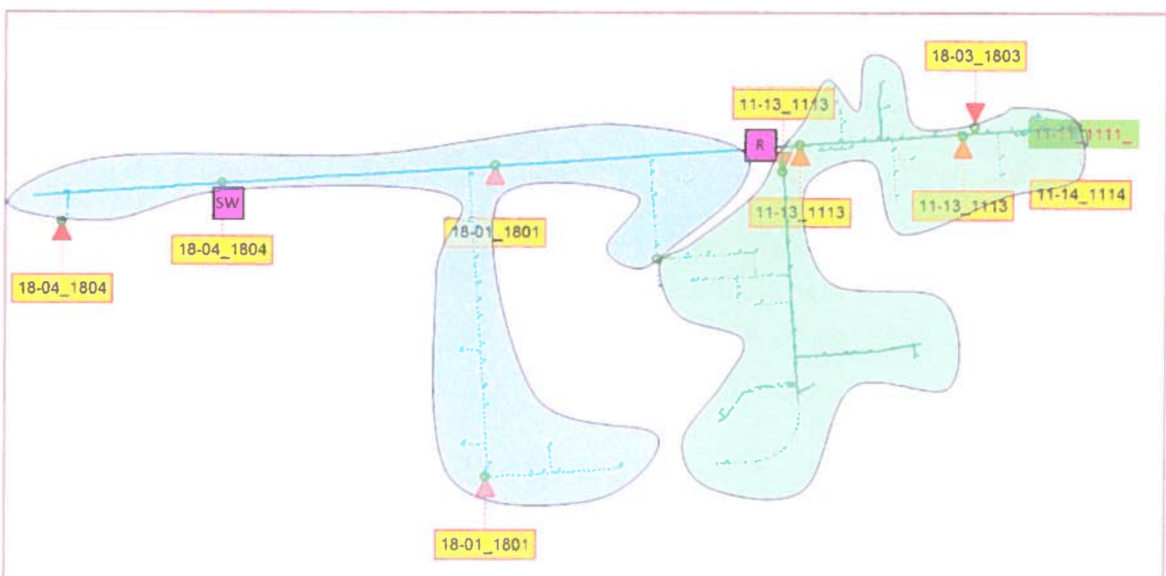
Feeder	Feeder/Adj Feeder	Load Transferred To	Load Transferred From	Min Downline Voltage (%)	Max Conductor Loading (%)
19-01	19-01	NA	NA	NA	NA
	19-01	NA	NA	NA	NA
	19-01	NA	NA	NA	NA
	19-01	NA	NA	NA	NA
19-02	19-02	NA	NA	97.34	26.2
	21-01	NA	NA	98.46	34.6
	19-02	21-01	NA	98.66	13
	21-01	NA	19-02	96.9	58.6
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	

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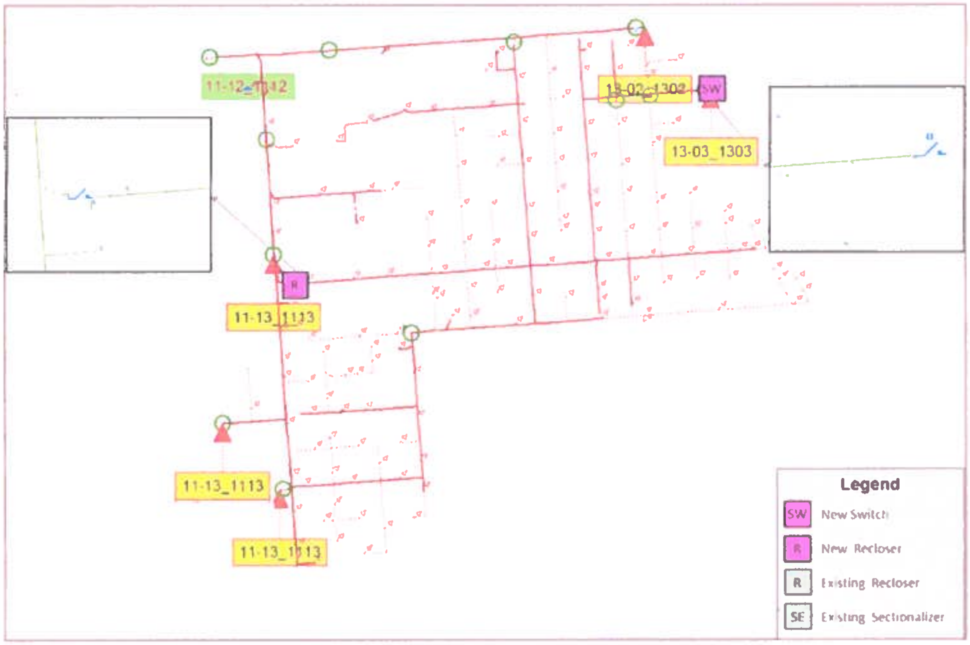
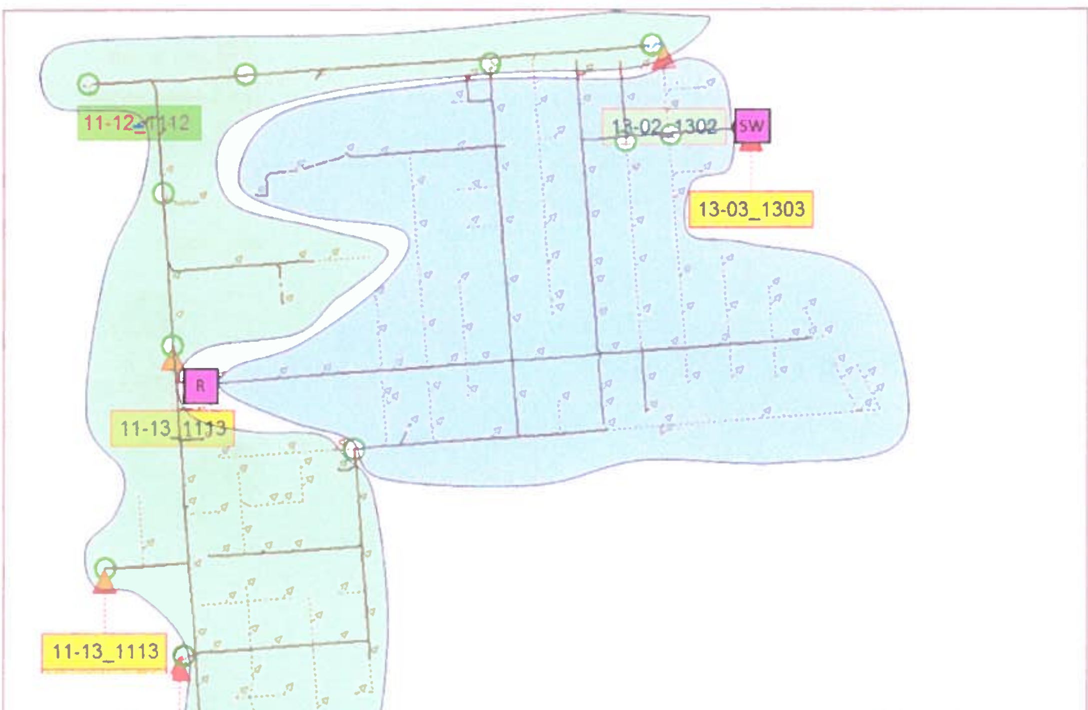
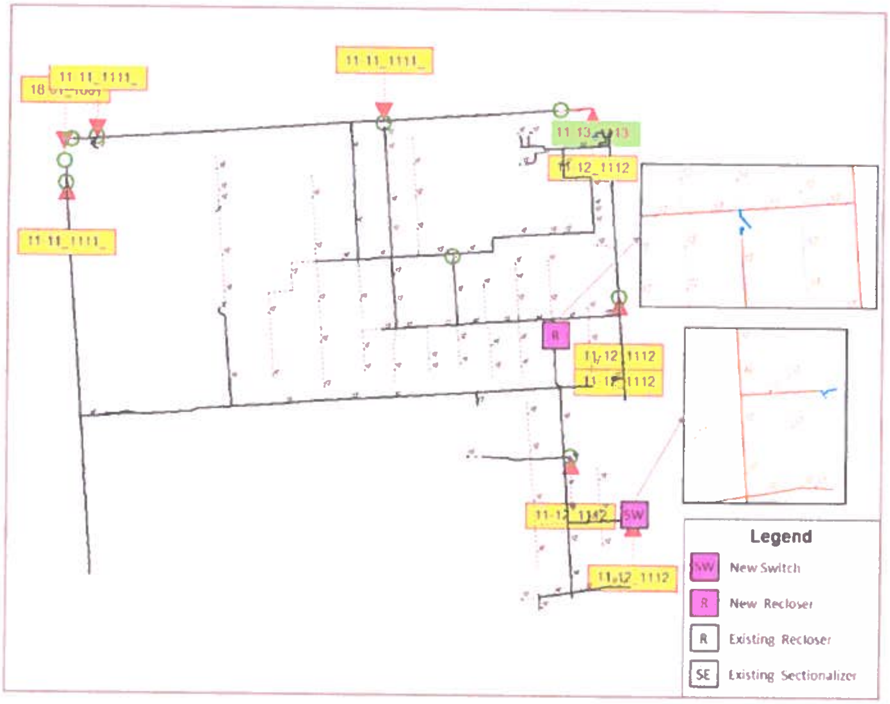
11-12:

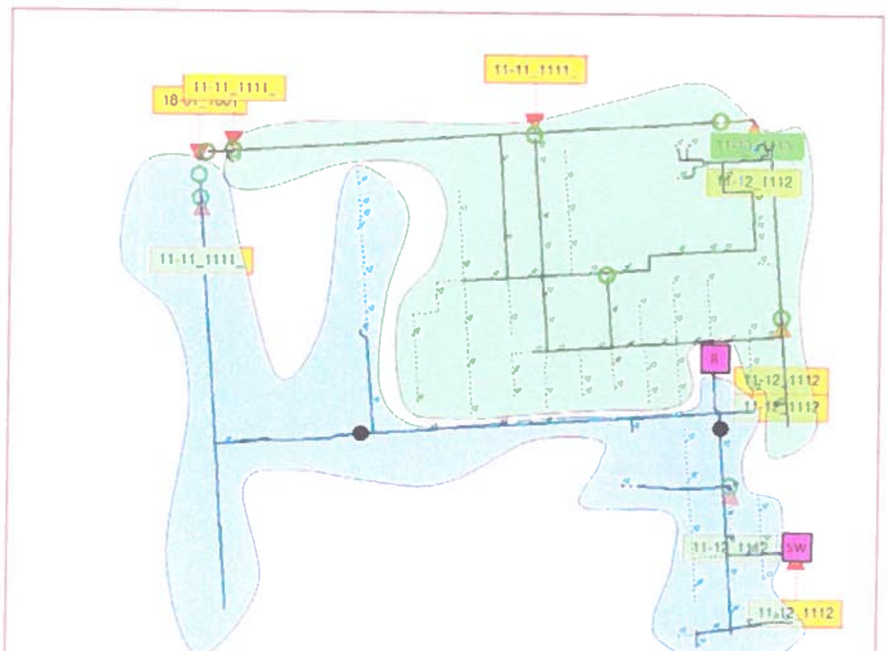




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
11-12	7650	3120	4530		56791	25148	31644	

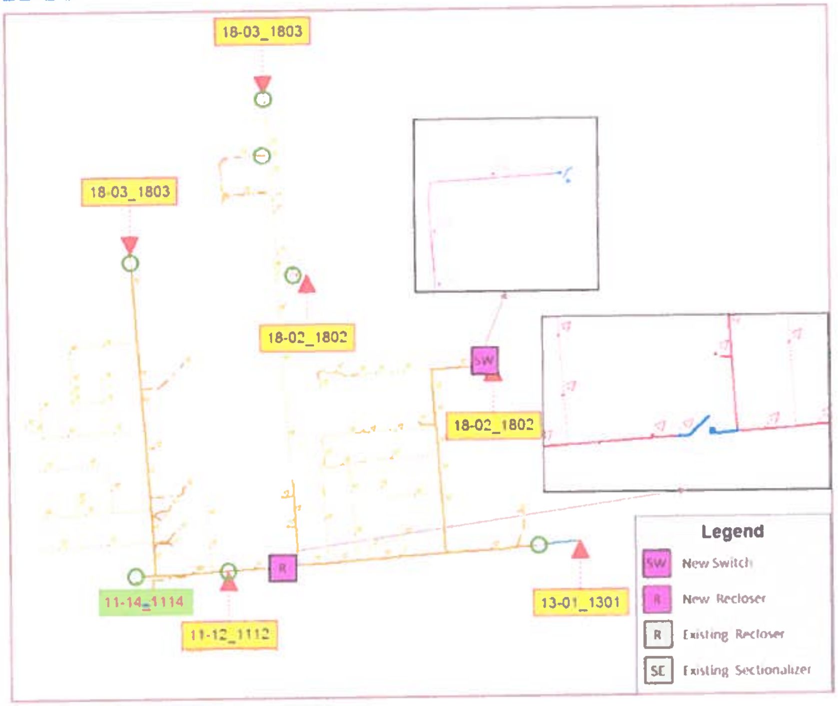
11-13:

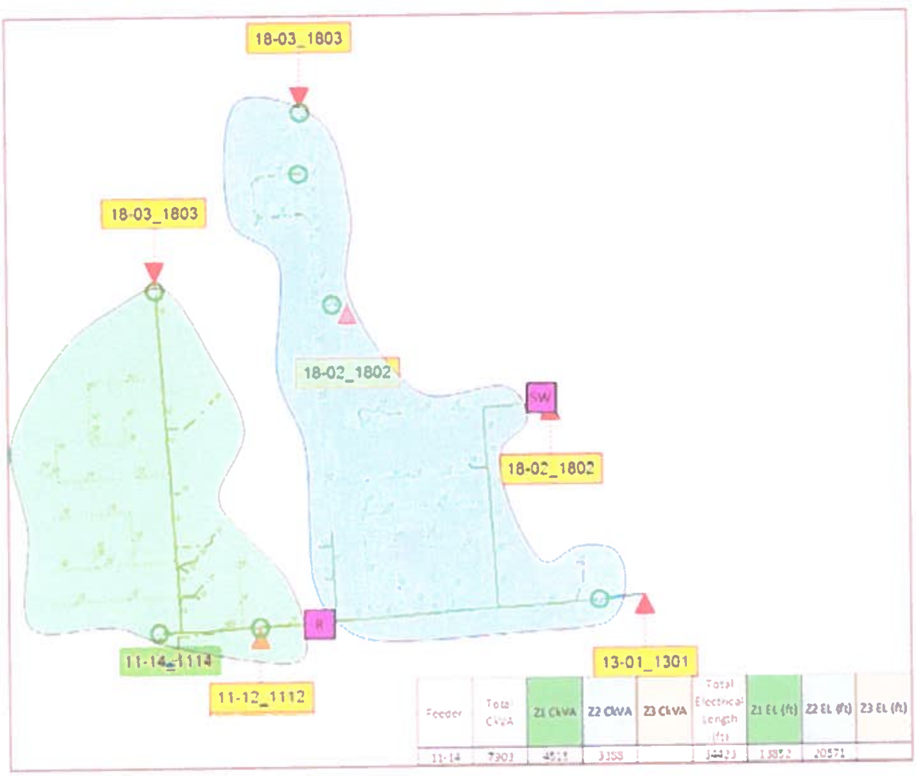




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Section Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
11-13	6018	3711	2305		52451	31978	20472	

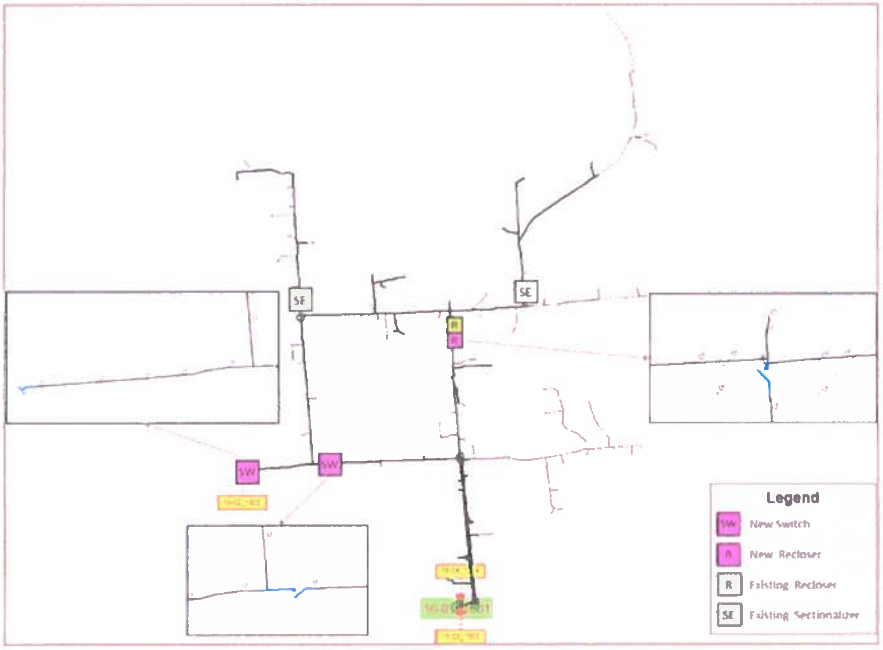
11-14:

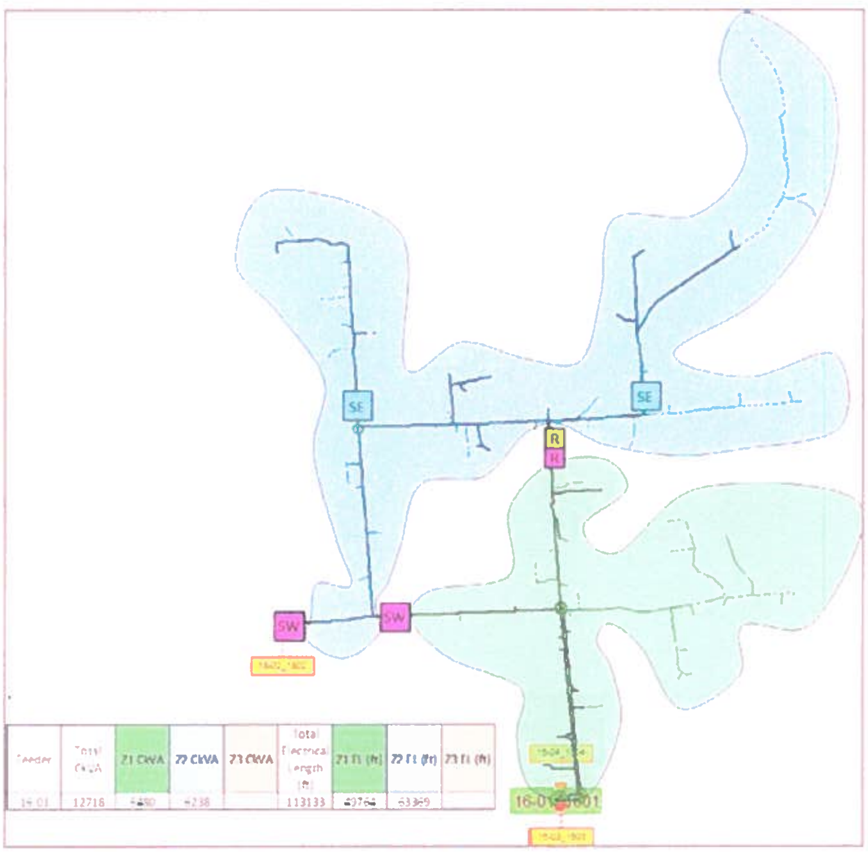




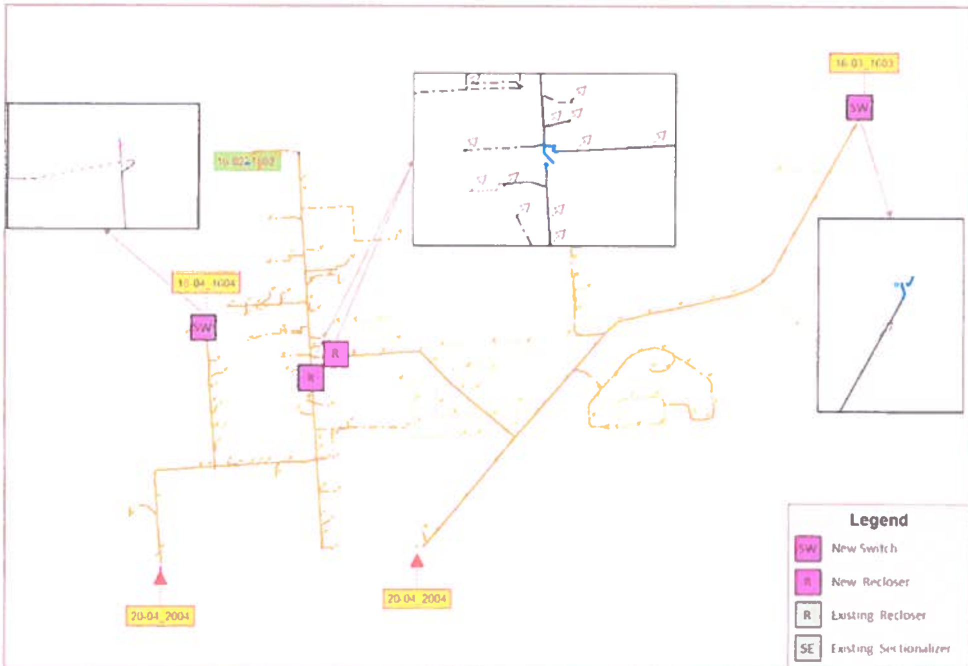
Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
11-14	7303	4515	3355		34423	13852	20571	

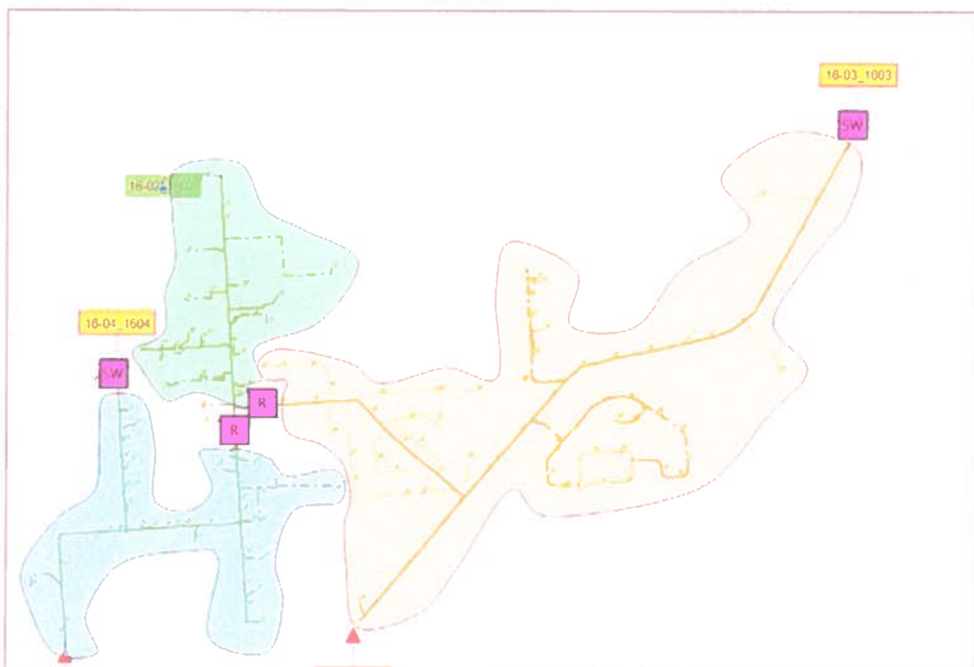
16-01:


SE
SE
R
SW
SW
16-01
Legend
SW New Switch
New Recloser
R Existing Recloser
SE Existing Sectionalizer


SE
SE
R
SW
SW
16-01-0601
Feeder
Total CkVA
Z1 CkVA
Z2 CkVA
Z3 CkVA
Total Electrical Length (ft)
Z1 EL (ft)
Z2 EL (ft)
Z3 EL (ft)
16-01
12716
113133

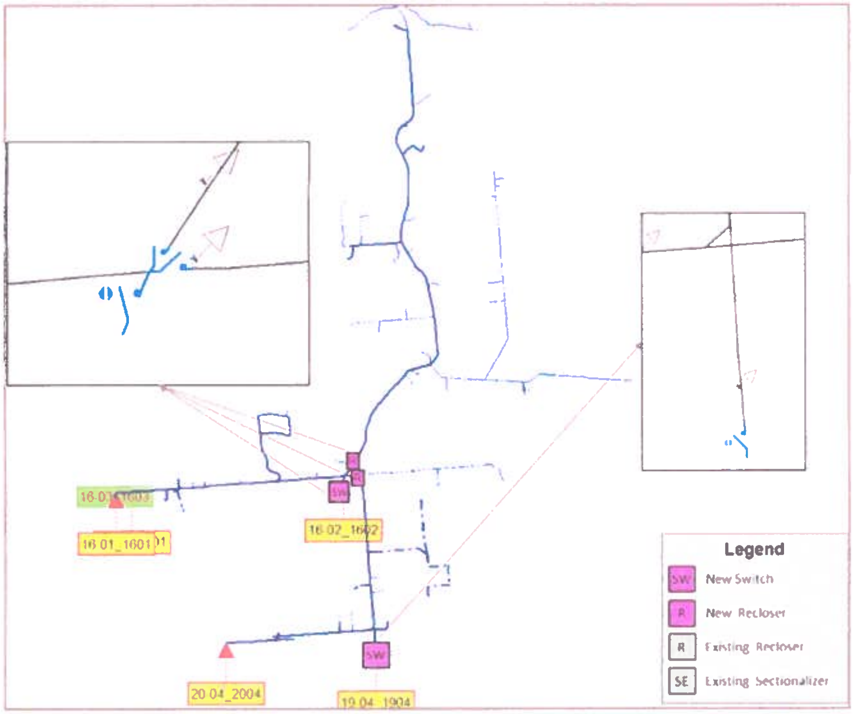
16-02:

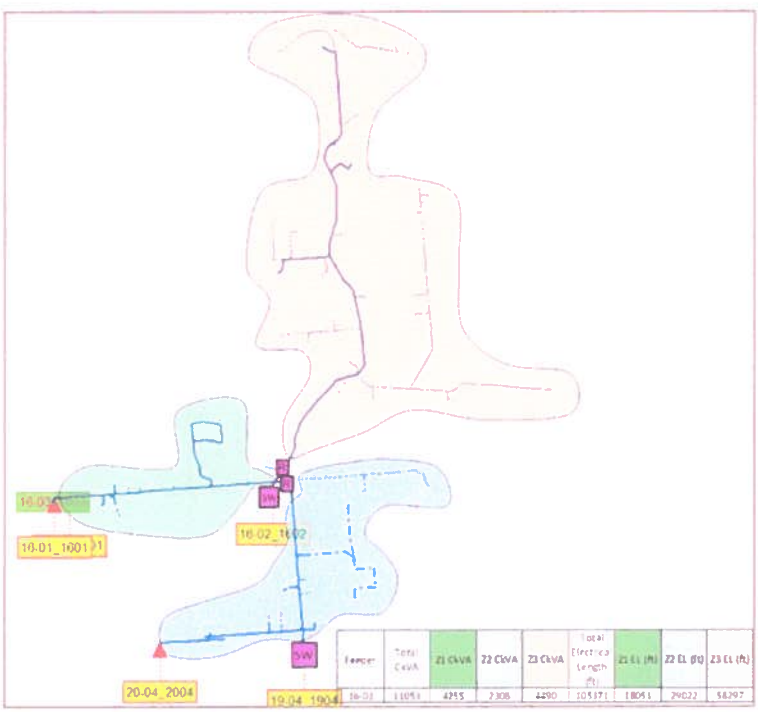




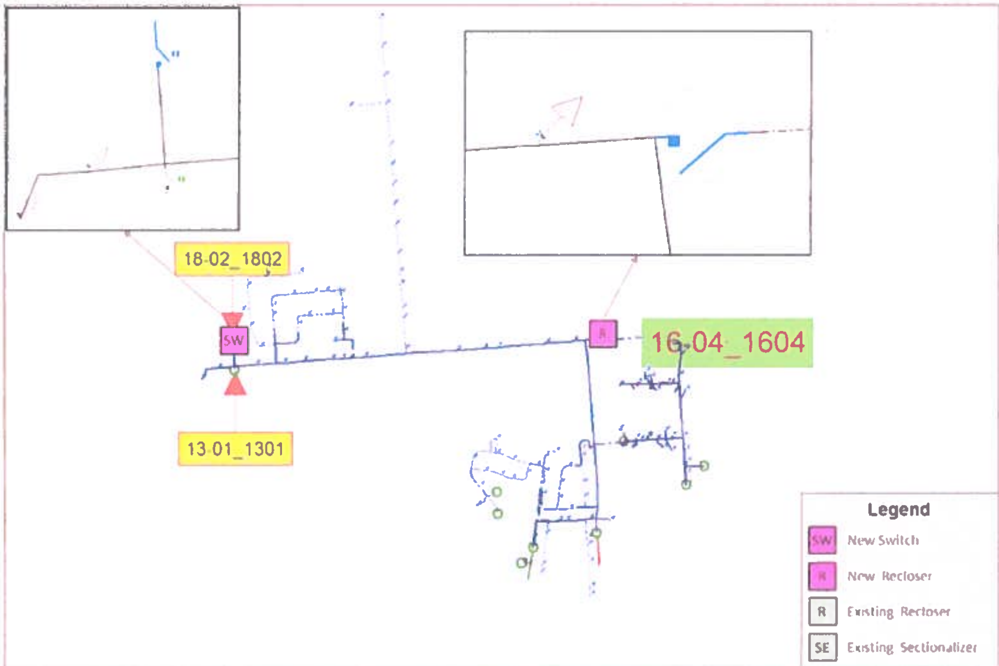
Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 LL (ft)	Z2 LL (ft)	Z3 LL (ft)
16-02	16543	4905	8085	3553	59022	12080	13409	33533

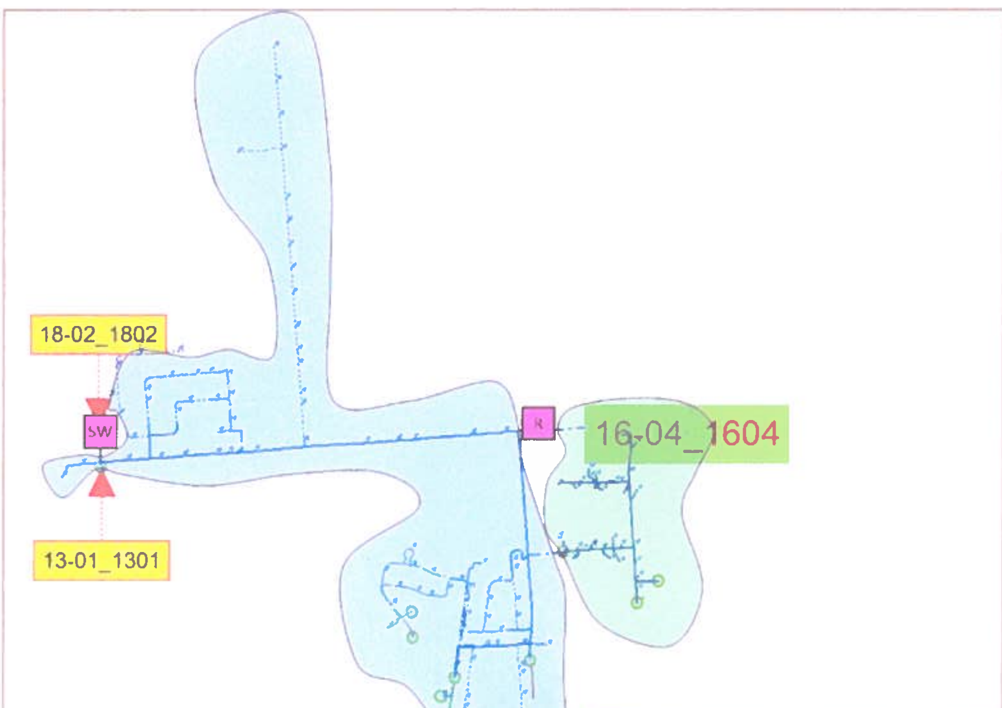
16-03:


16-03_1603
16-01_1601
16-02_1602
20-04_2004
19-04_1904
SW
R
Legend
SW New Switch
R New Recloser
R Existing Recloser
SE Existing Sectionalizer


16-01_1601
16-02_1602
20-04_2004
19-04_1904
SW
Feeder
Total CkVA
Z1 CkVA
Z2 CkVA
Z3 CkVA
Total Electrical Length (ft)
Z1 EL (ft)
Z2 EL (ft)
Z3 EL (ft)
16-03
11053
4255
2308
4490
105371
18051
29022
58297

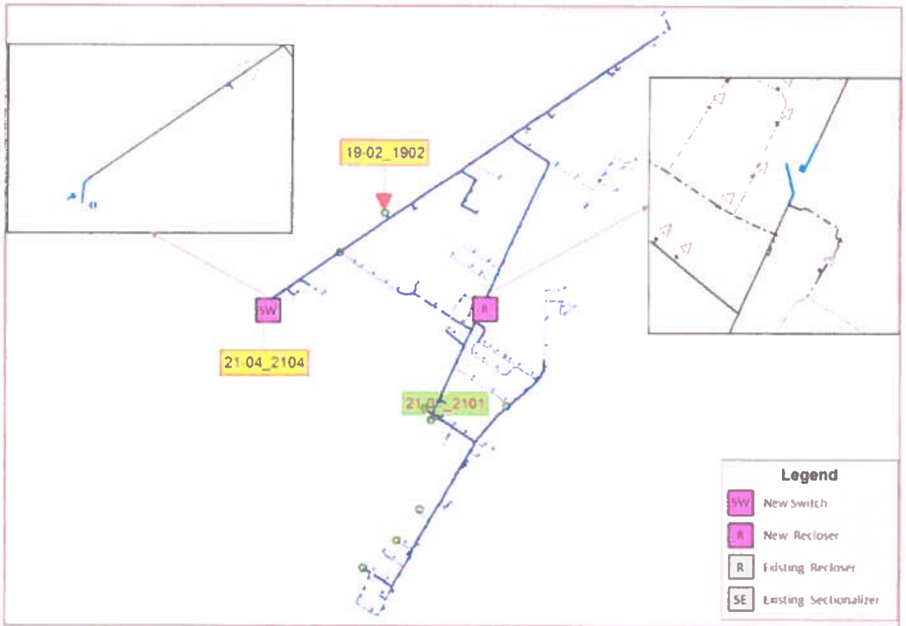
16-04:

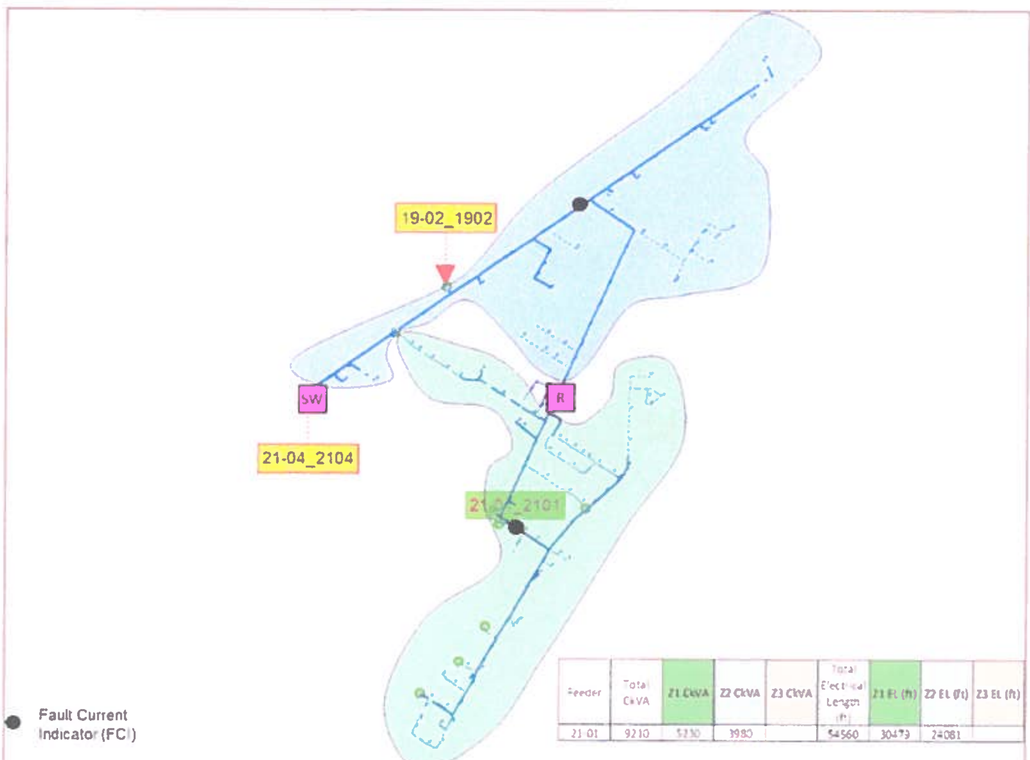




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
16-04	10017	4329	5688		55049	9698	45351	

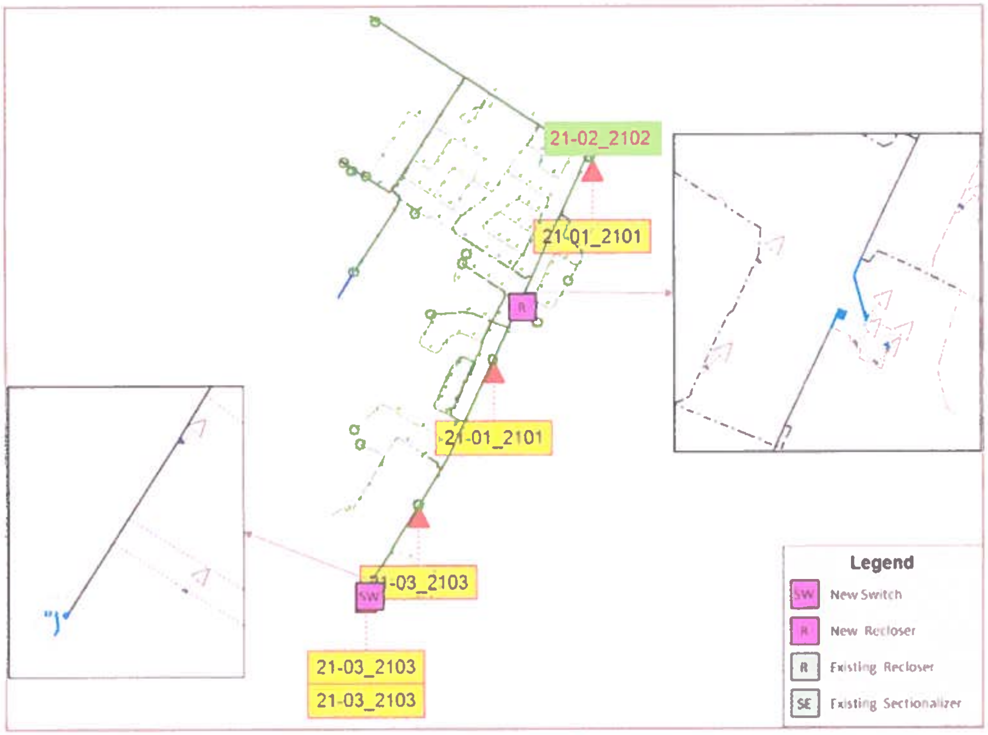
21-01:

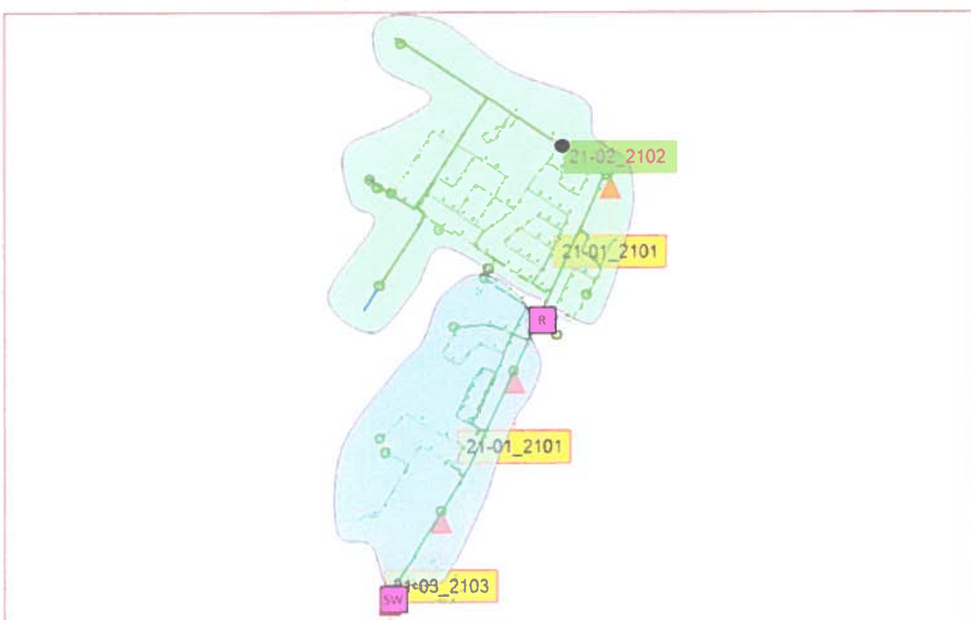




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
21-01	9210	5230	3980		54560	30479	24081	

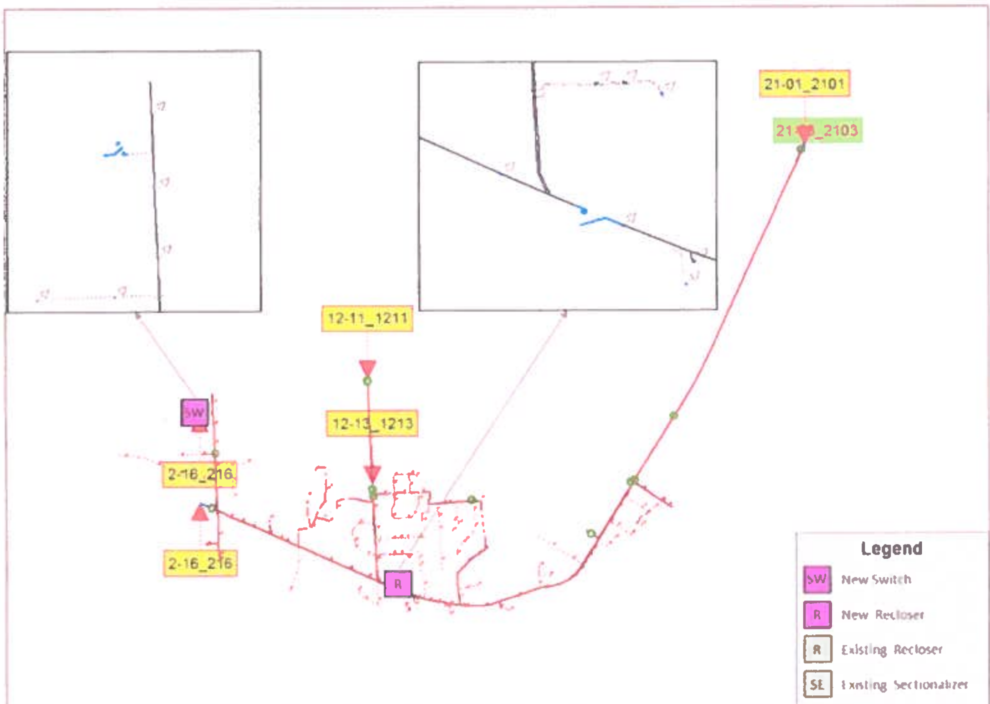
21-02:

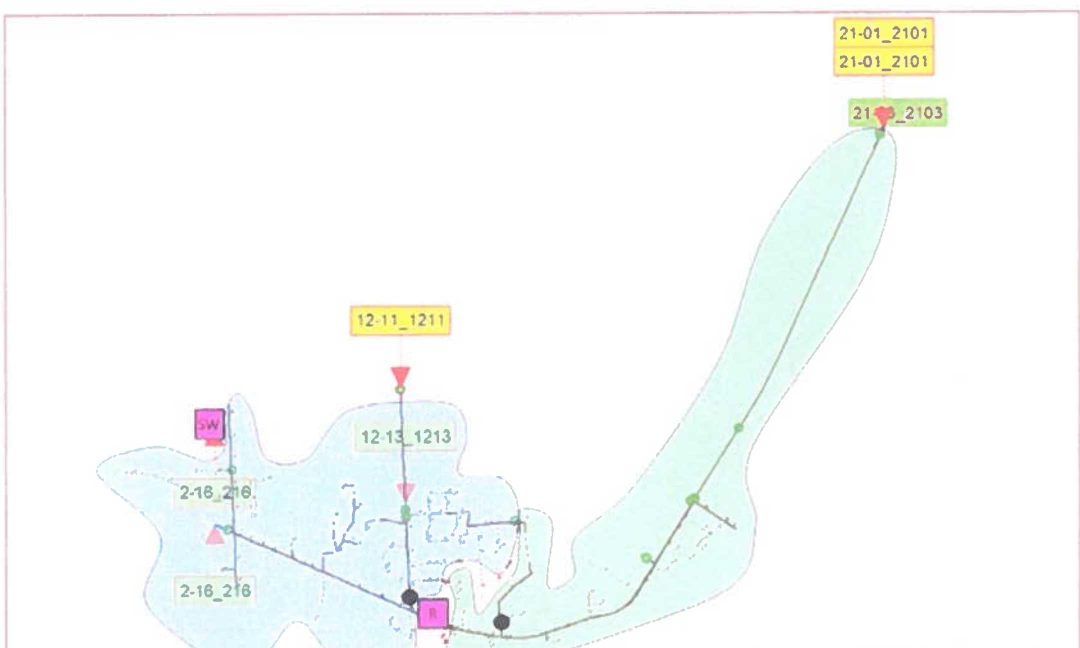




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
21-02	8573	4328	4245		67657	42008	25550	

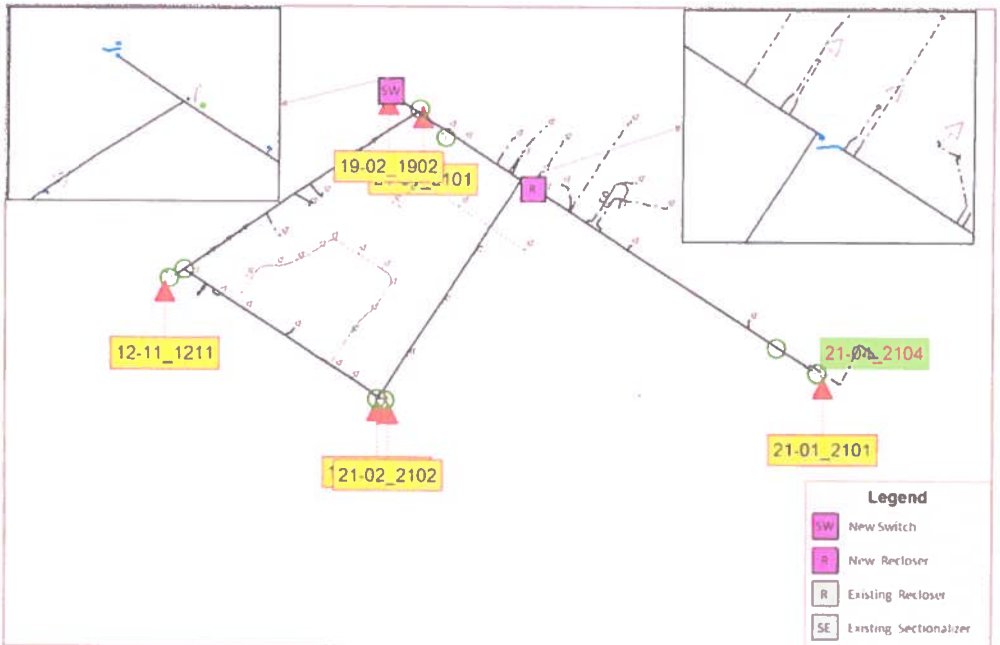
21-03:

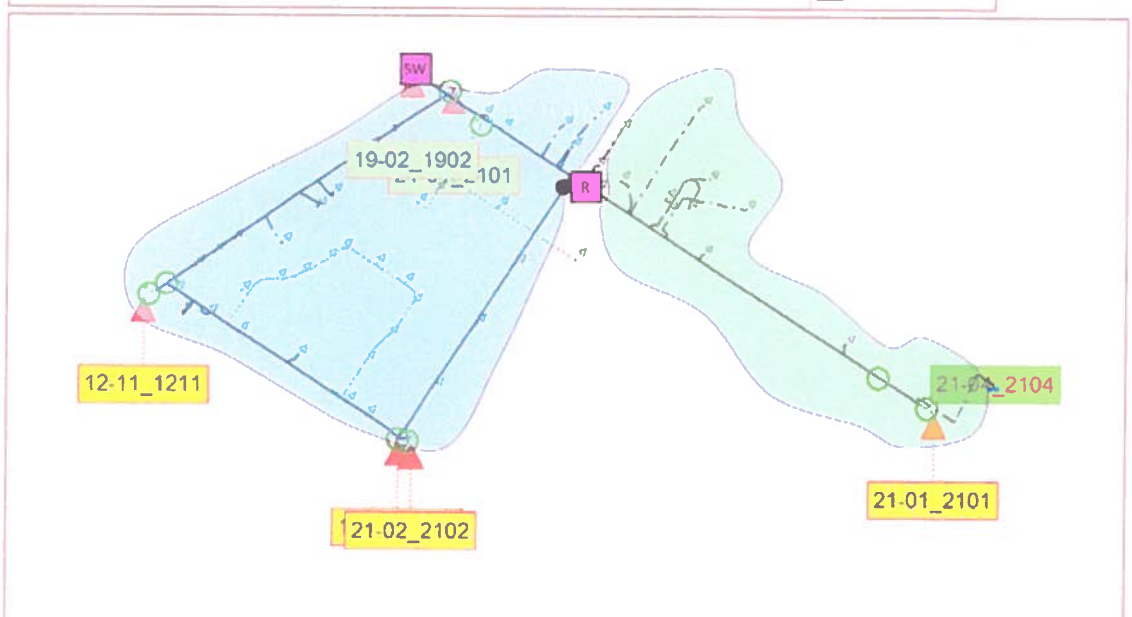




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 FL (ft)	Z2 FL (ft)	Z3 FL (ft)
21-03	10943	3501	7450		54530	27215	17575	

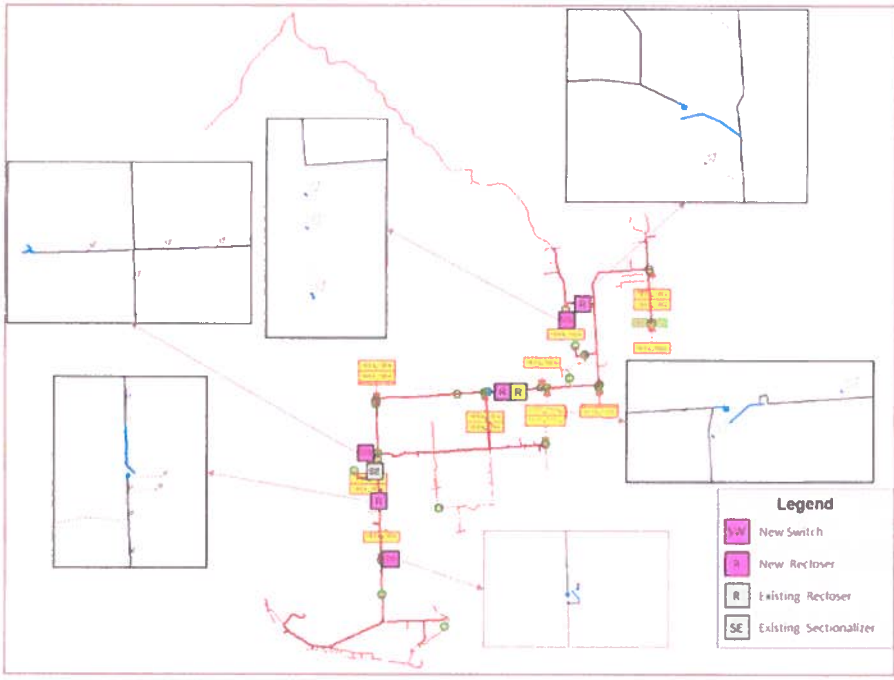
21-04:

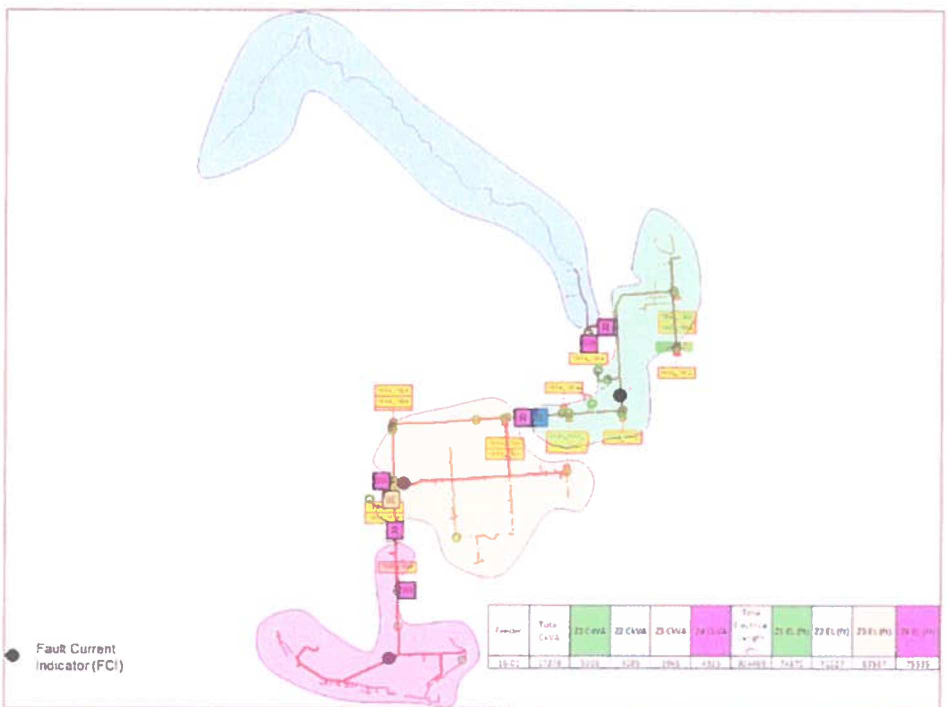




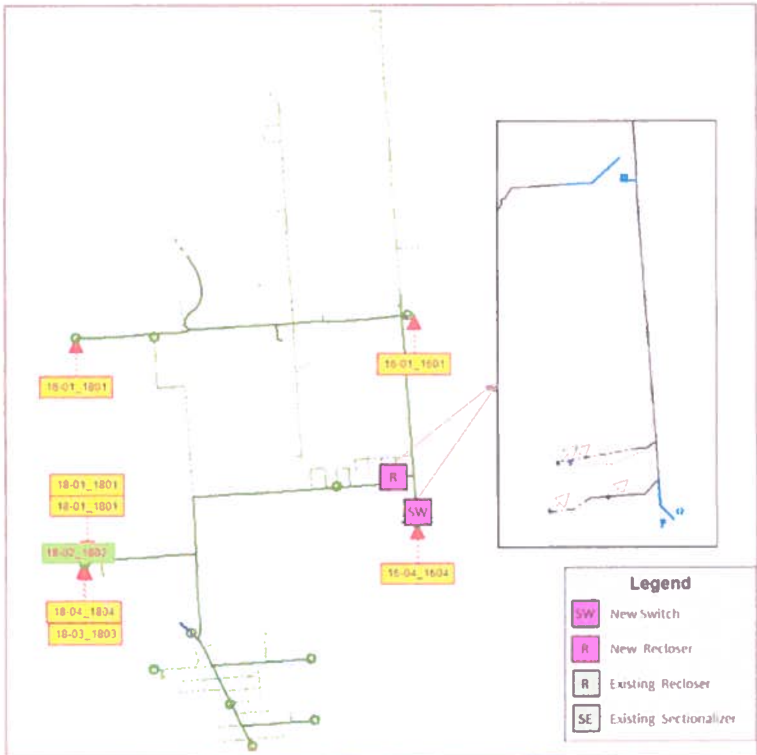
Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
21-04	6618	3638	2980		20895	7060	13835	

18-01:


Legend
SW New Switch
R New Recloser
R Existing Recloser
SE Existing Sectionalizer

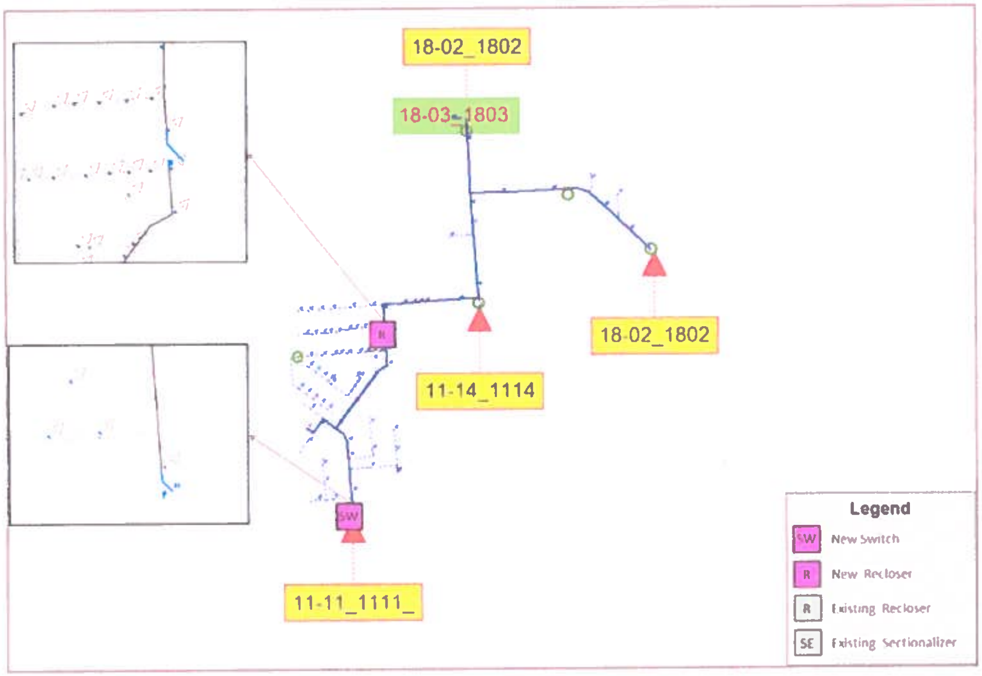

Fault Current Indicator (FCI)

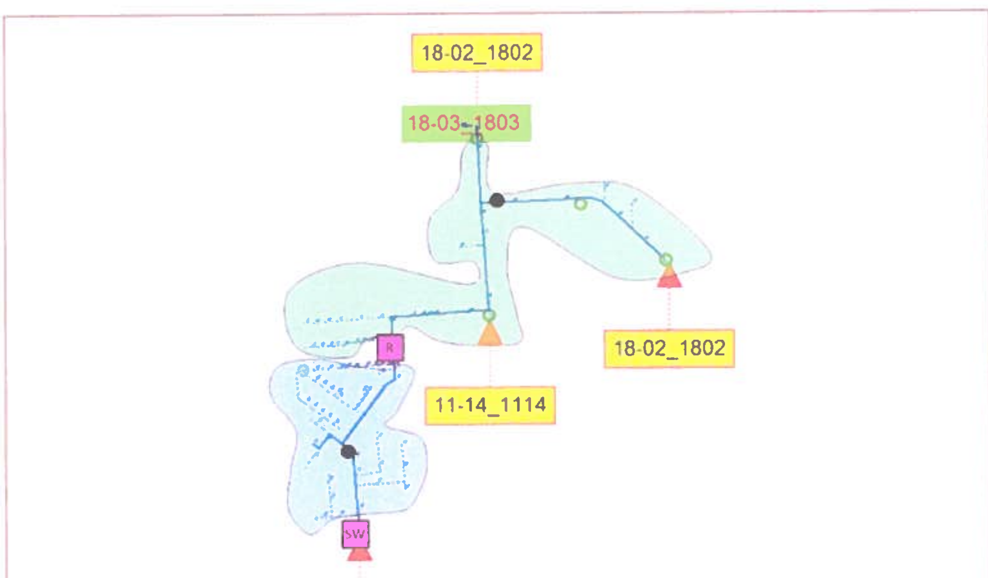
18-02:


Legend
SW
New Switch
R
New Recloser
R
Existing Recloser
SE
Existing Sectionalizer


Fault Current Indicator (FCI)
Feeder

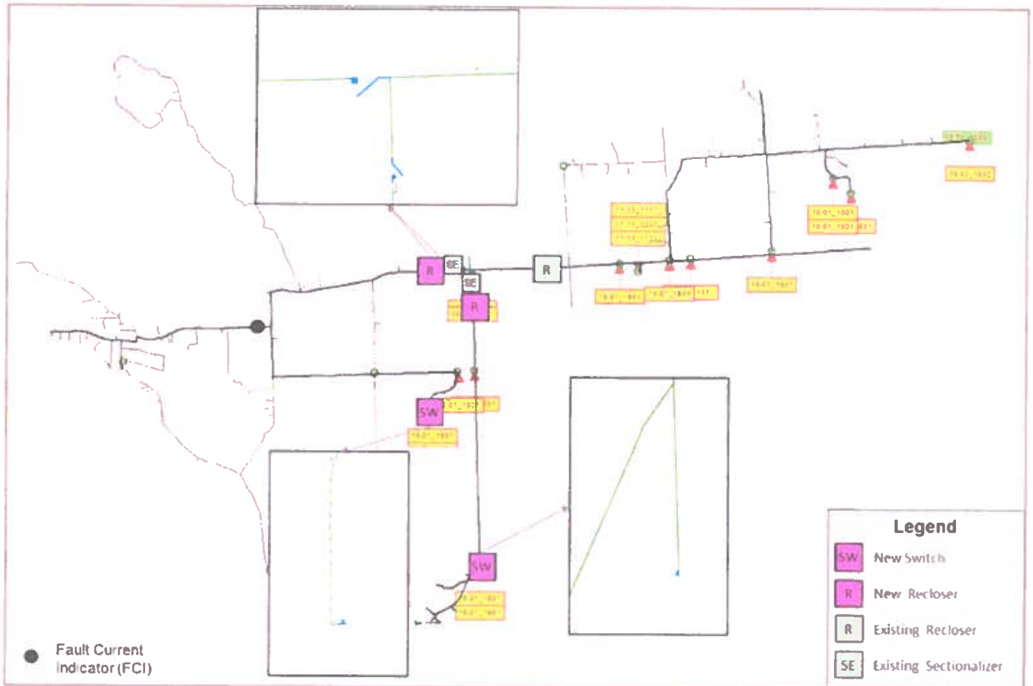
18-03:

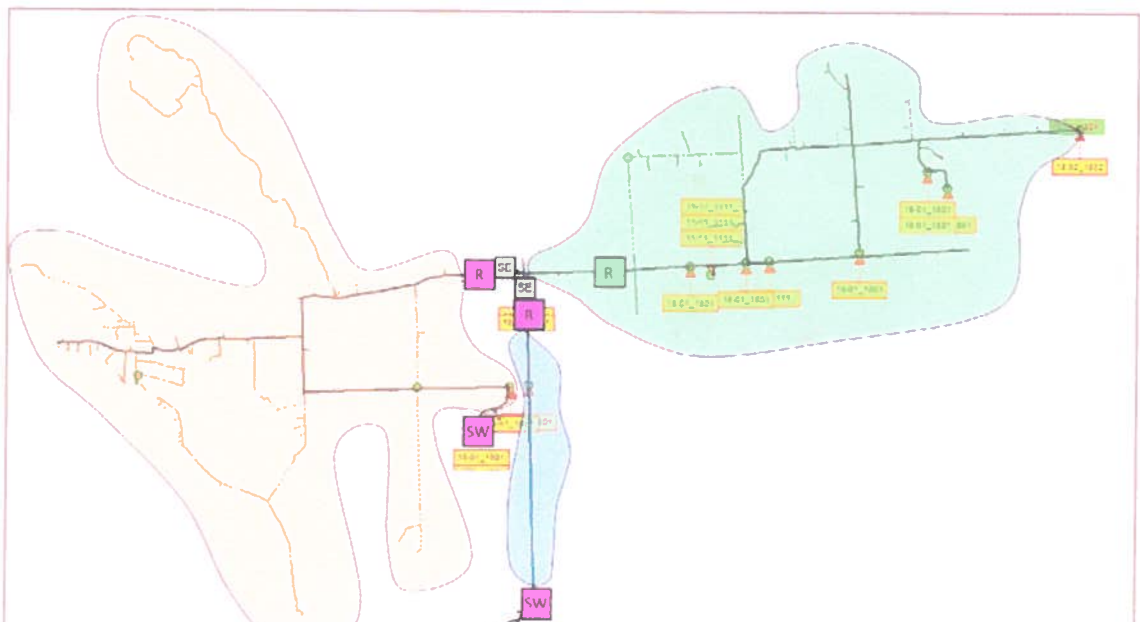




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
18 03	3534	1095	2439		23484	11345	12139	

18-04:

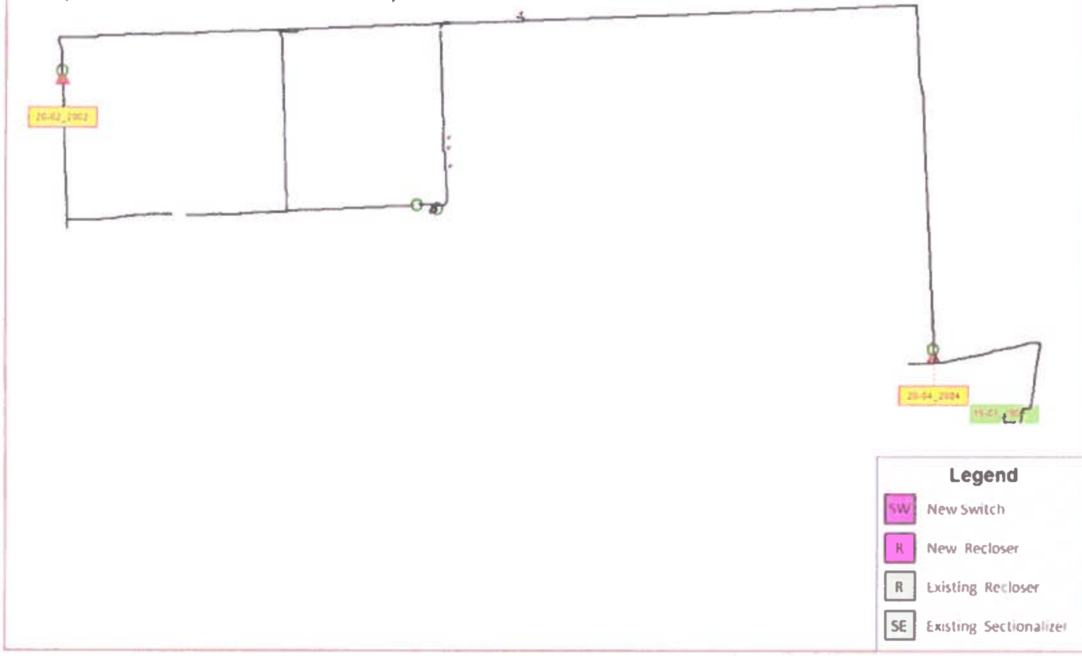




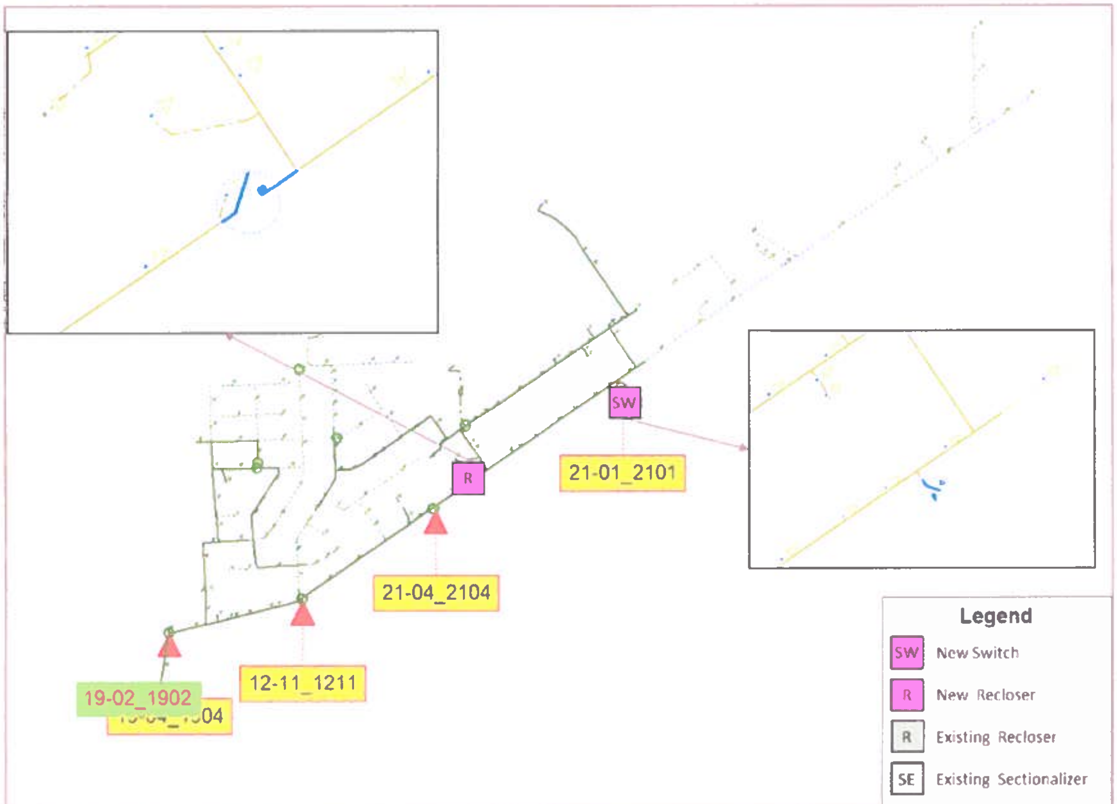
Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
18-04	15676	5721	2613	7143	268648	95906	26234	145509

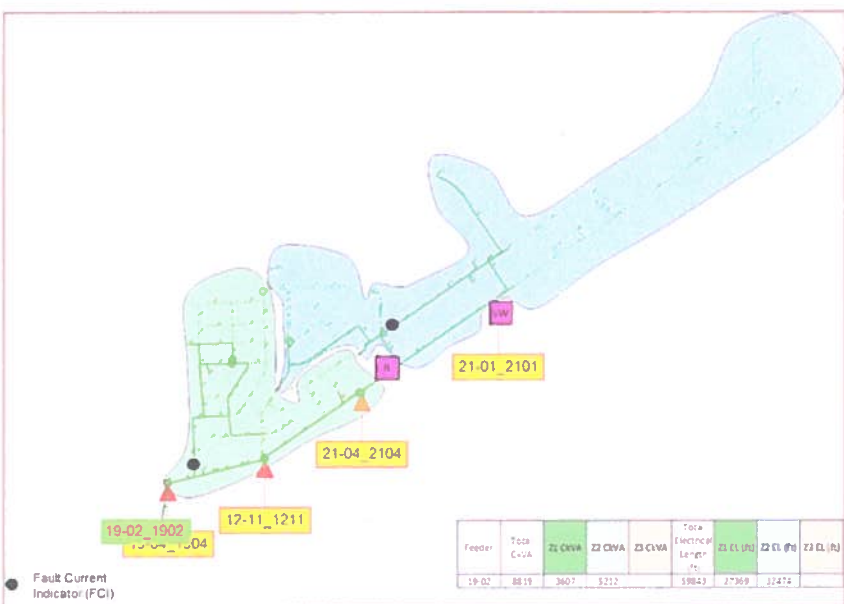
19-01:

(No DA recommendations)



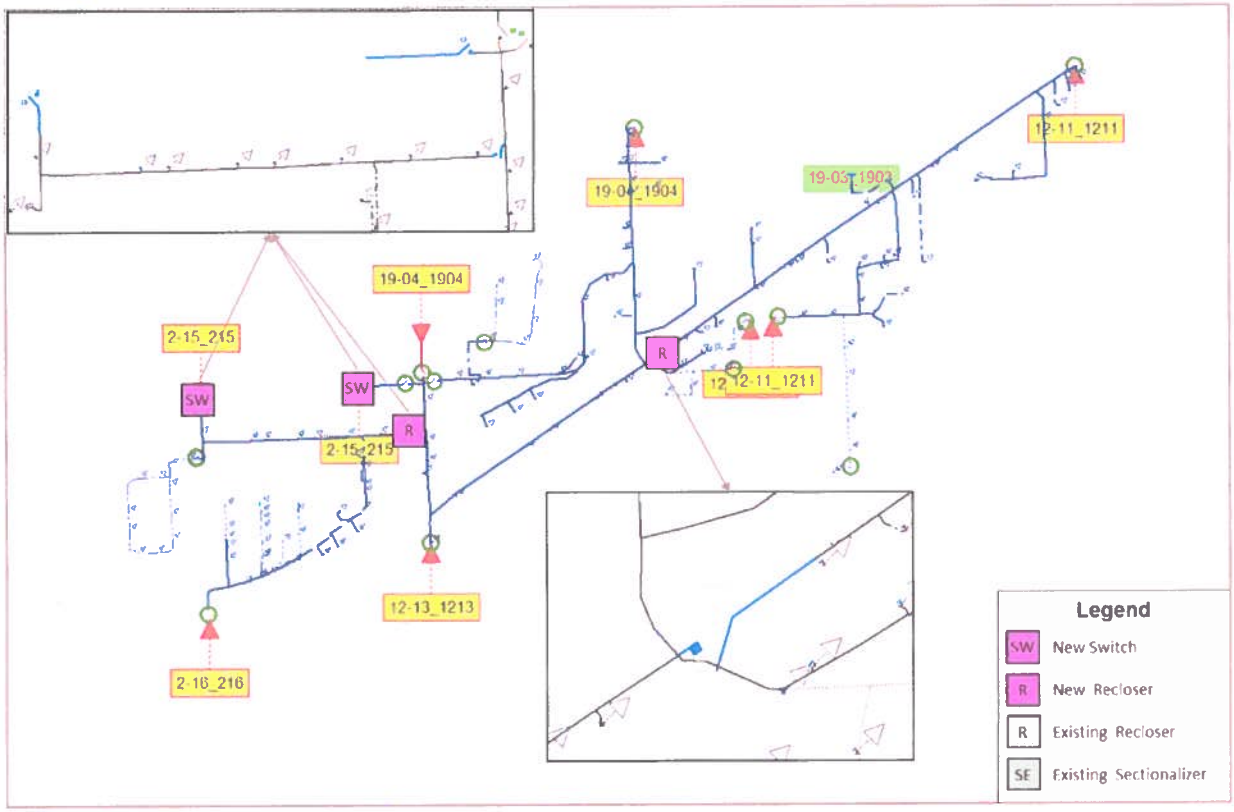
19-02:

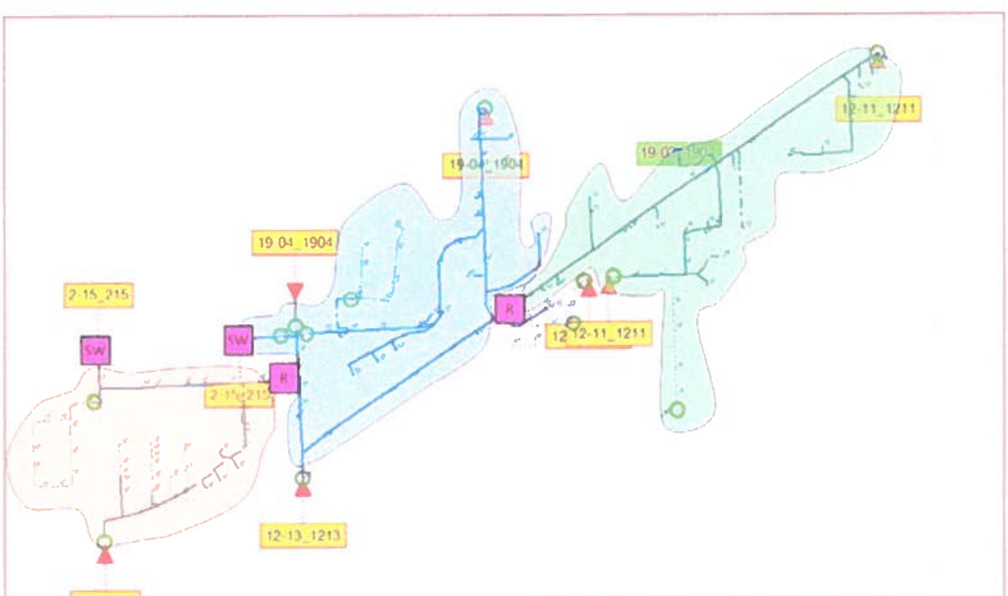




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 CL (ft)	Z2 CL (ft)	Z3 CL (ft)
19-02	8819	3607	5212		59843	27369	32474	

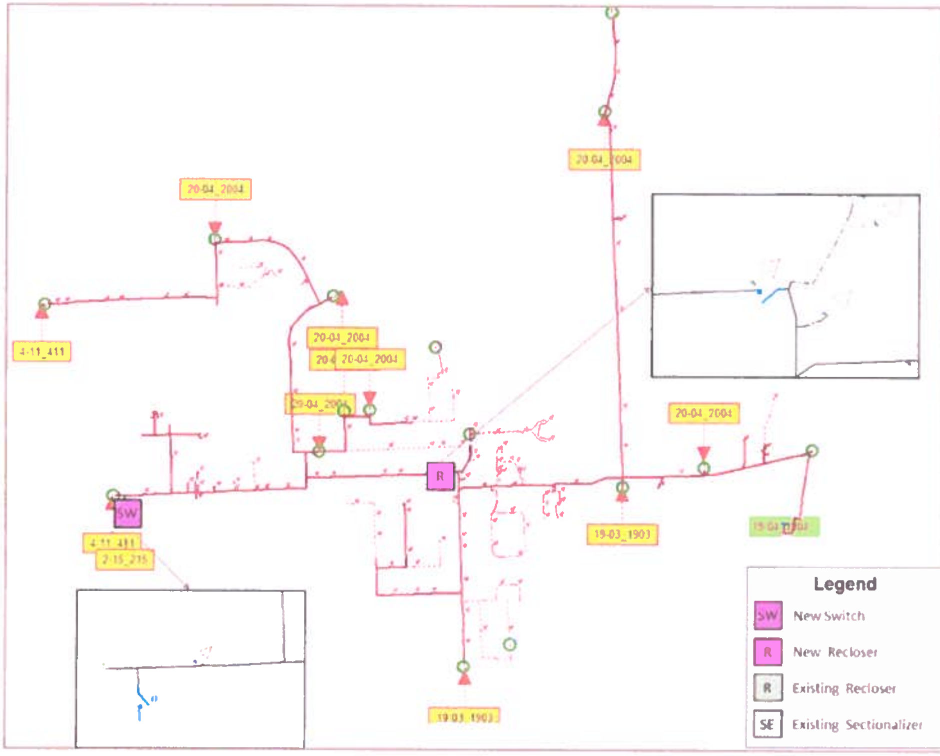
19-03:

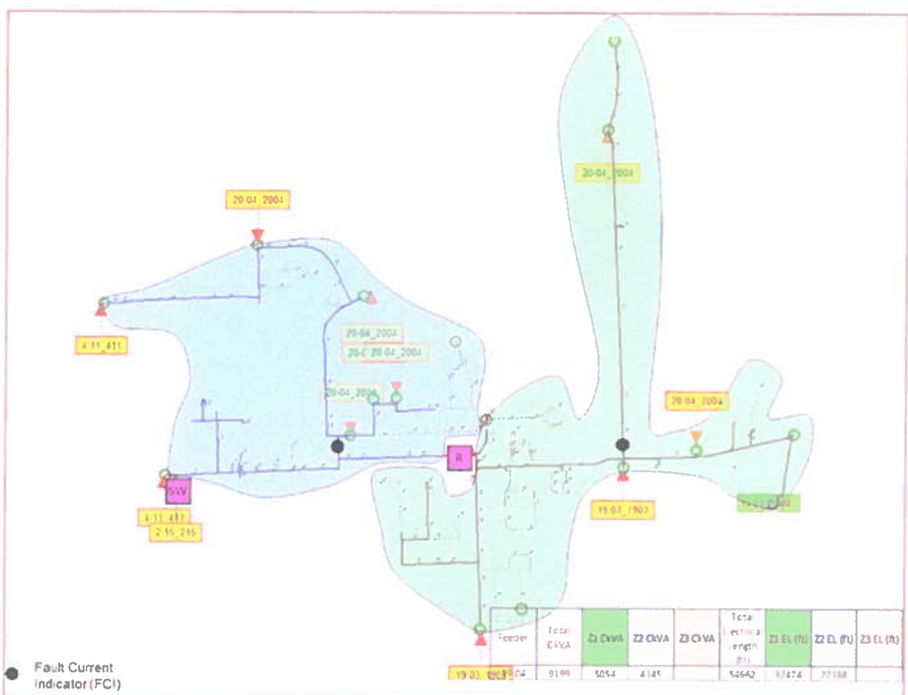




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
19-03	15383	5153	6780	3450	44078	[illegible]	[illegible]	[illegible]

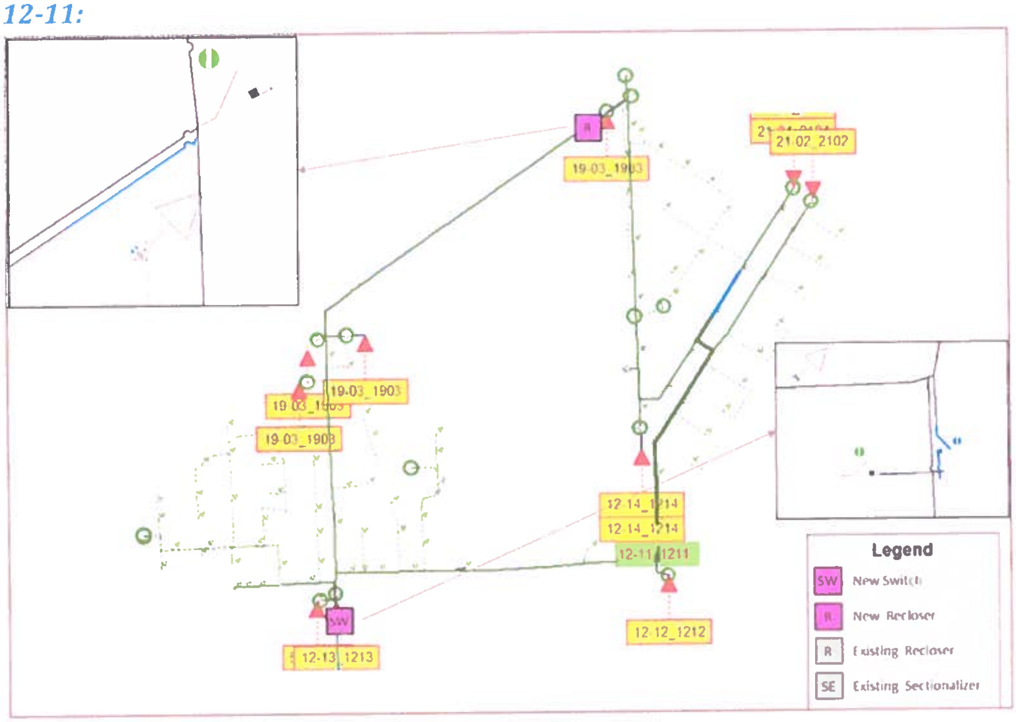
19-04:

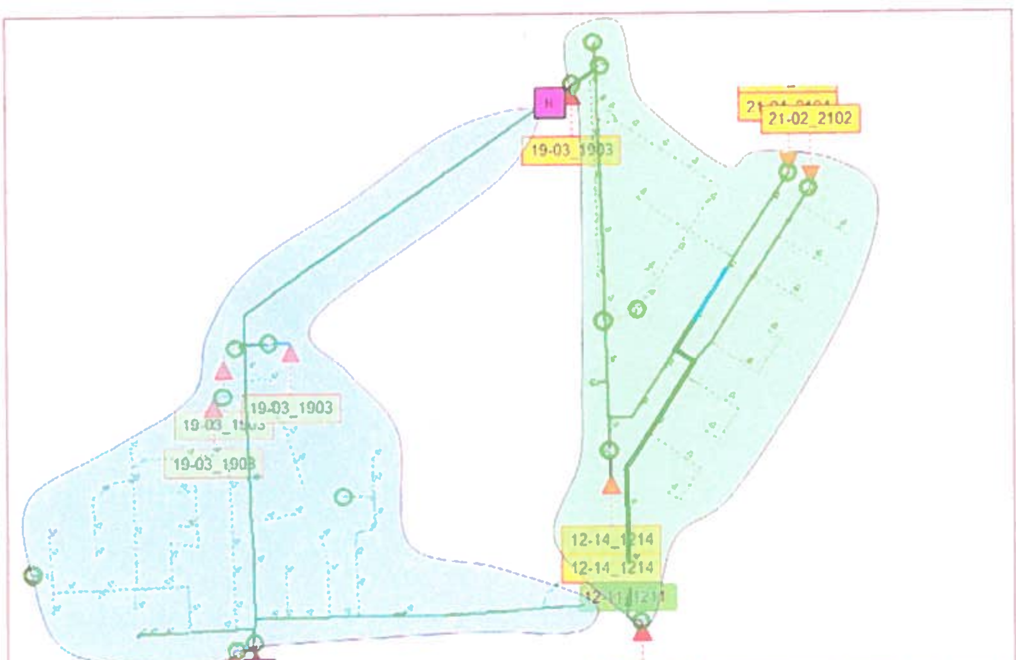




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
[illegible]04	9199	5054	4145		54642	32474	22168	

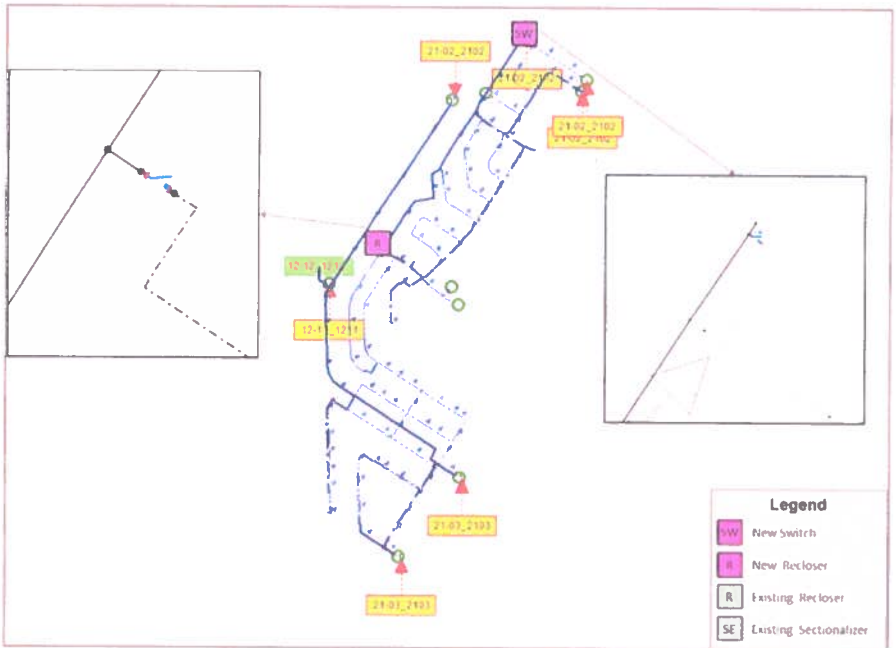
12-11:





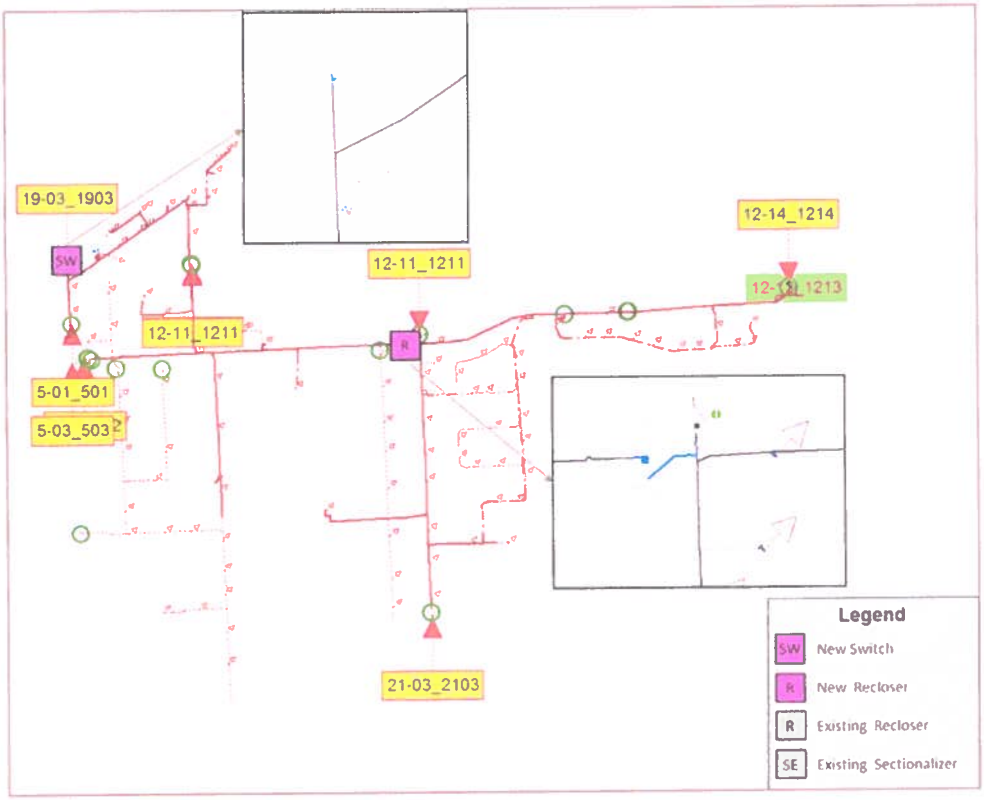
Feeder	Total CkVA	71 CkVA	72 CkVA	73 CkVA	Total Electrical Length (ft)	71 FI (ft)	72 FI (ft)	73 FI (ft)
12-11	4916	1853	3063		49908	22352	27556	

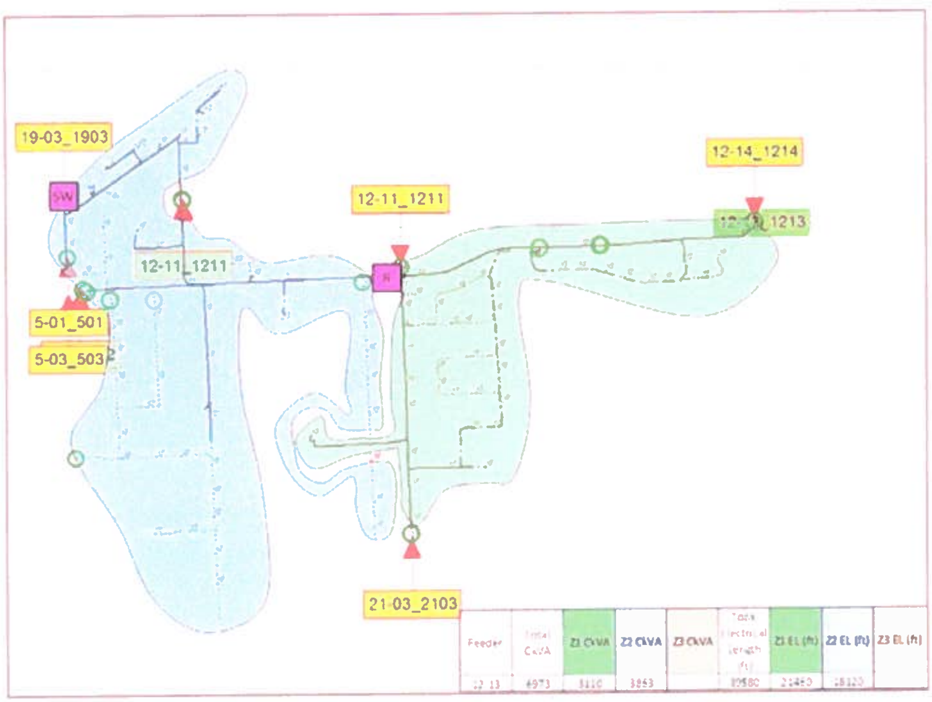
12-12:



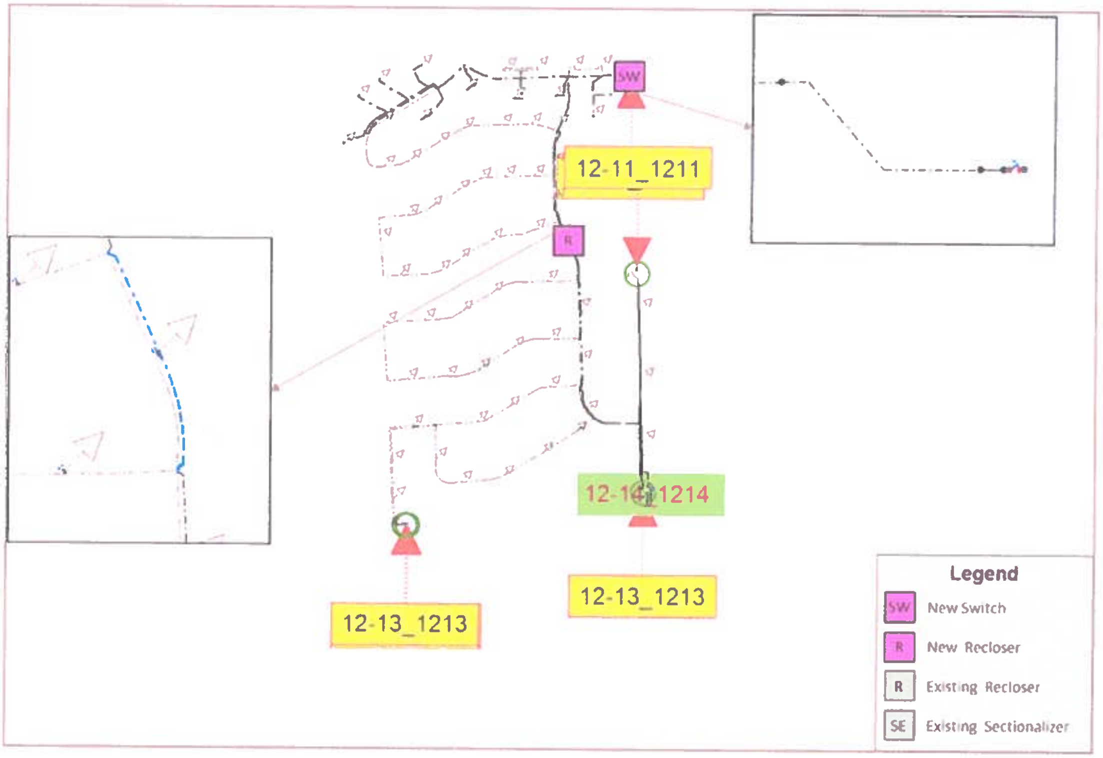
Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 LL (ft)	Z2 LL (ft)	Z3 LL (ft)
12-12	5926	2813	3113		47044	21149	25895	

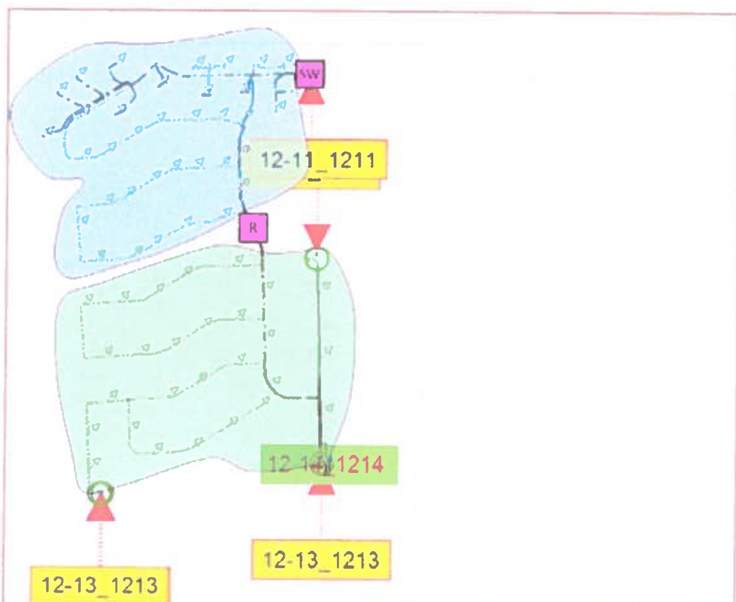
12-13:


19-03_1903
SW
12-11_1211
12-14_1214
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
1213
12-11_1211
R
5-01_501
5-03_503
21-03_2103
Feeder
Z1 CkVA
Z2 CkVA
Z3 CkVA
Z1 EL (ft)
Z2 EL (ft)
Z3 EL (ft)

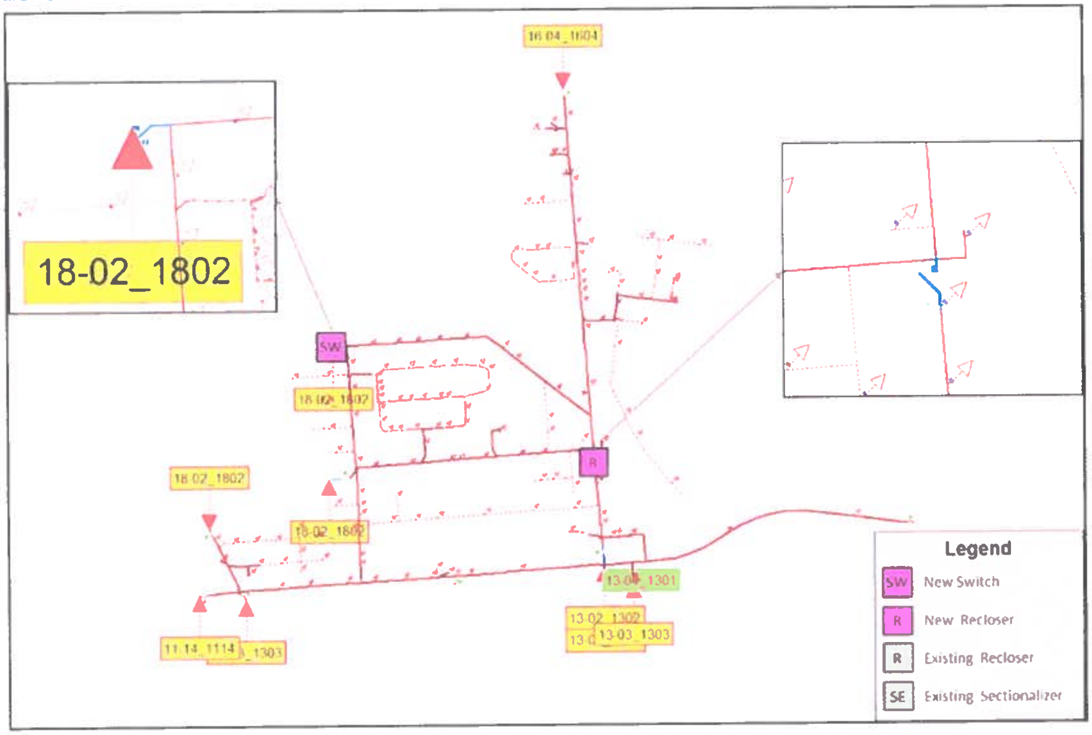
12-14:

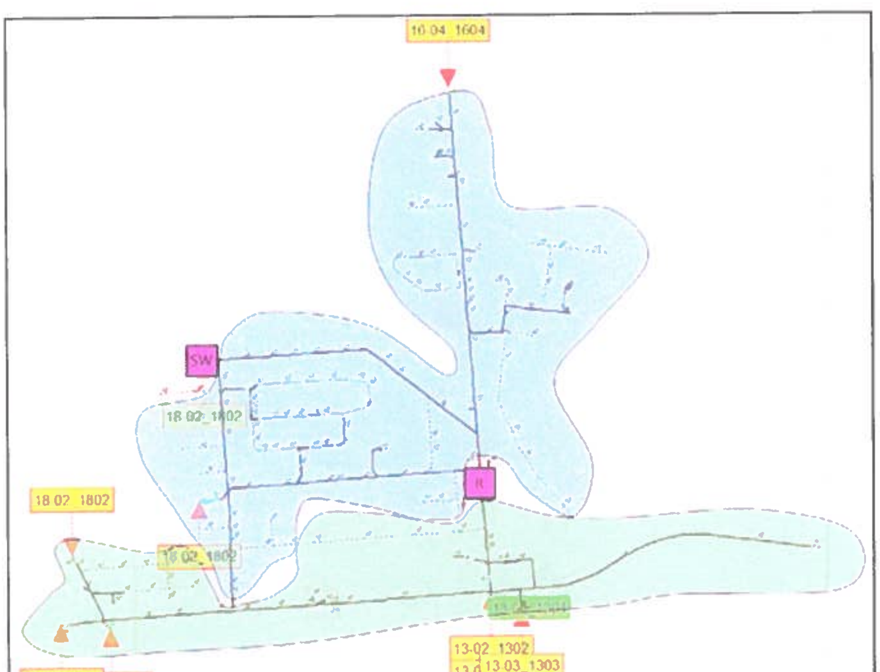




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
12-14	5413	1888	3525		22224	11467	10755	

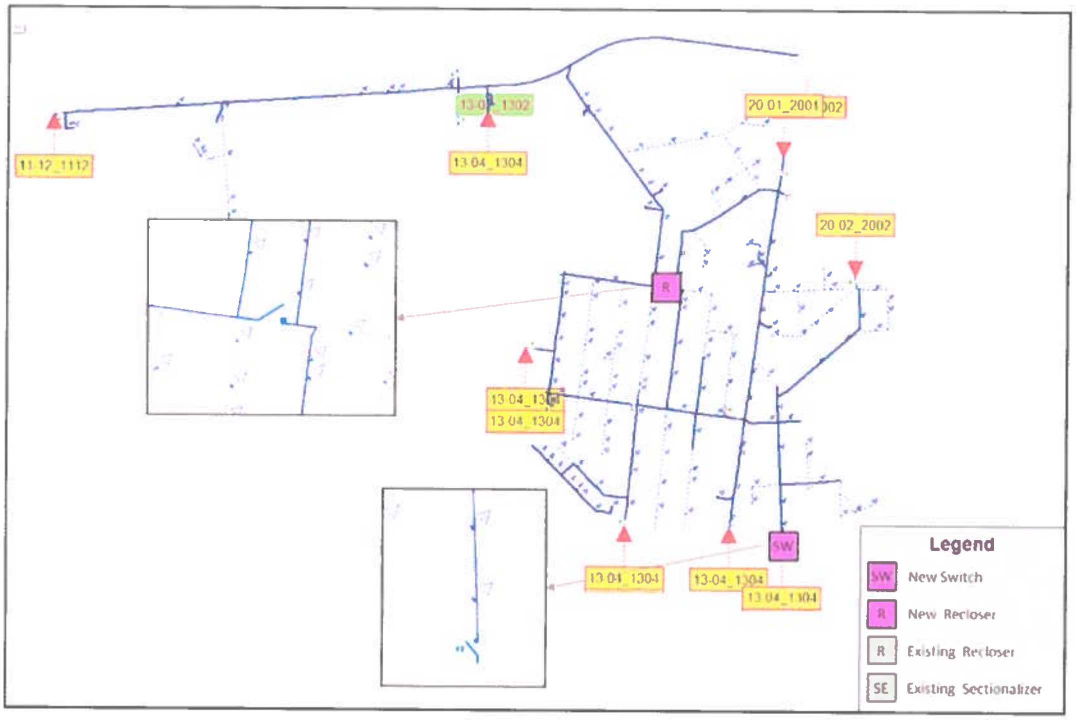
13-01:

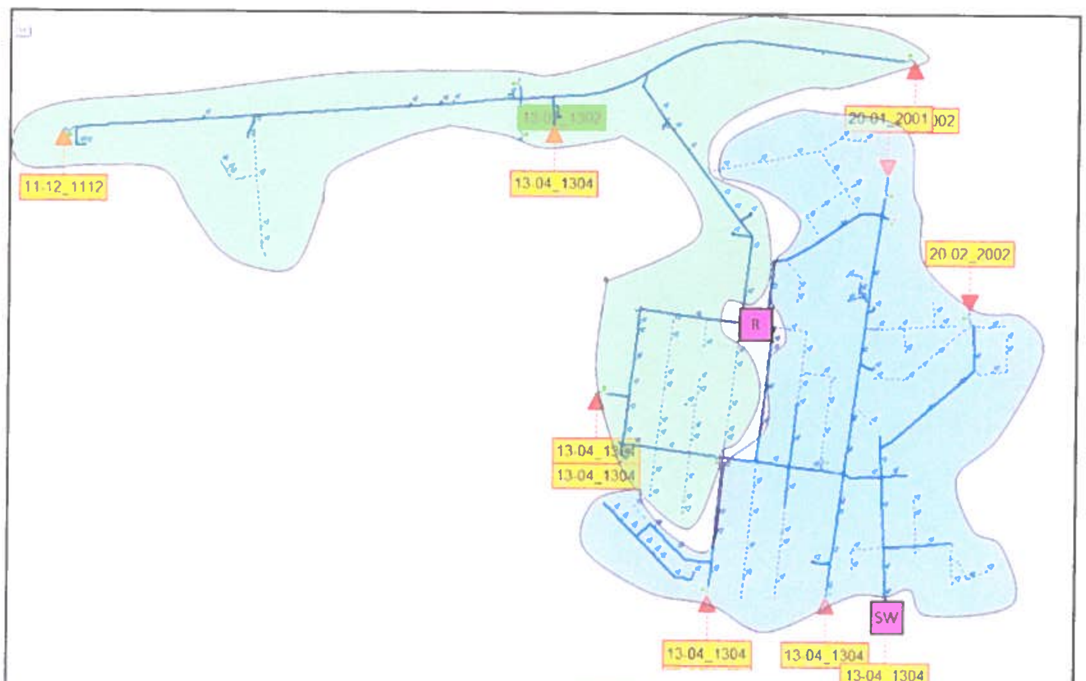




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
13-01	10188	3295	6893		54588	17421	37267	

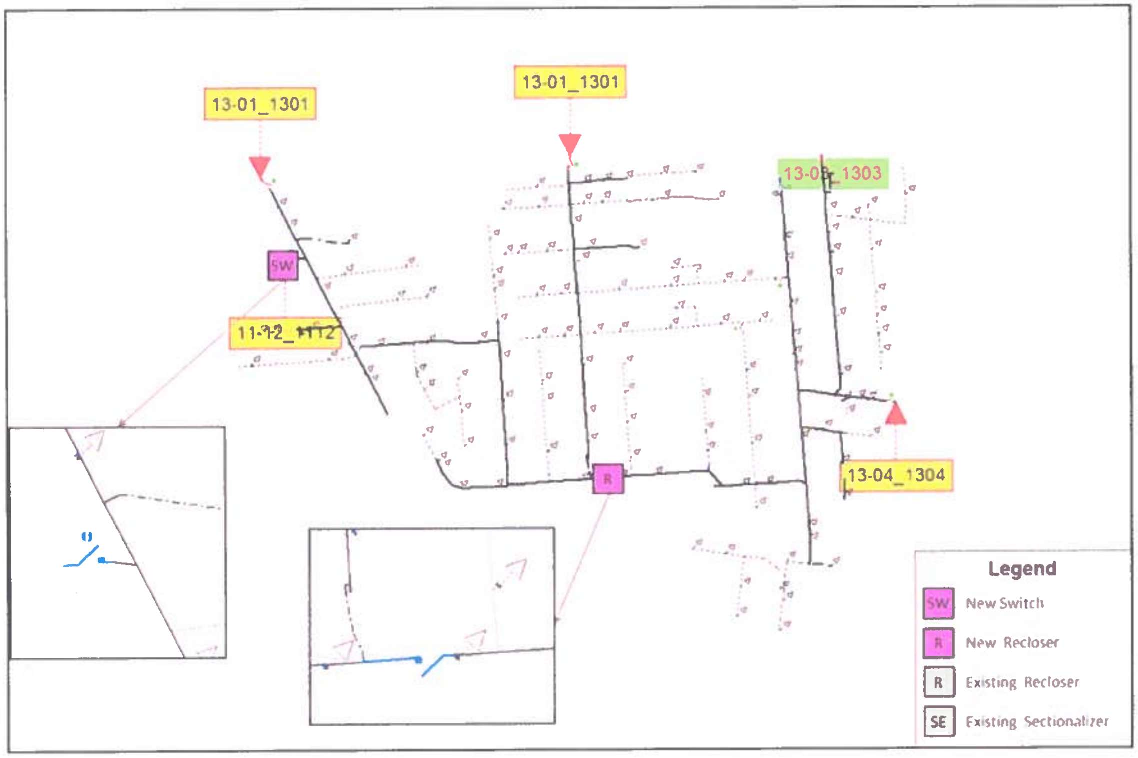
13-02:

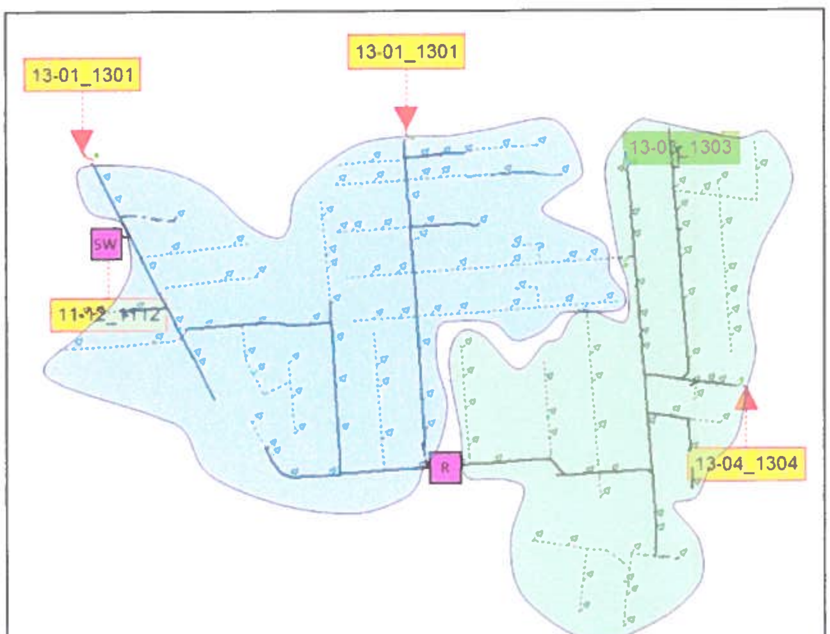




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
13-02	9000	3720	5280		59715	24672	35043	

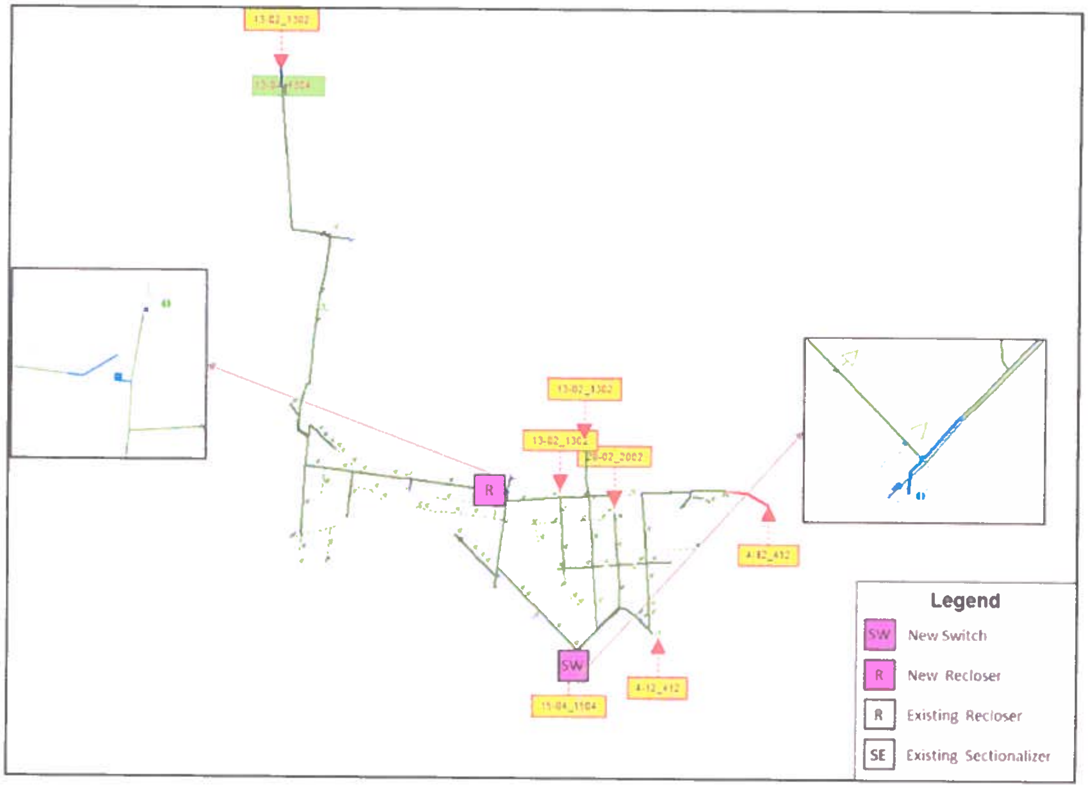
13-03:

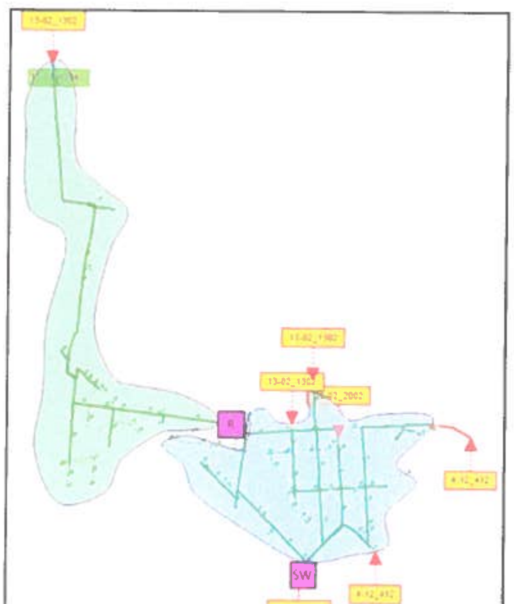




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
13-03	7793	2913	4880		43219	16942	26276	

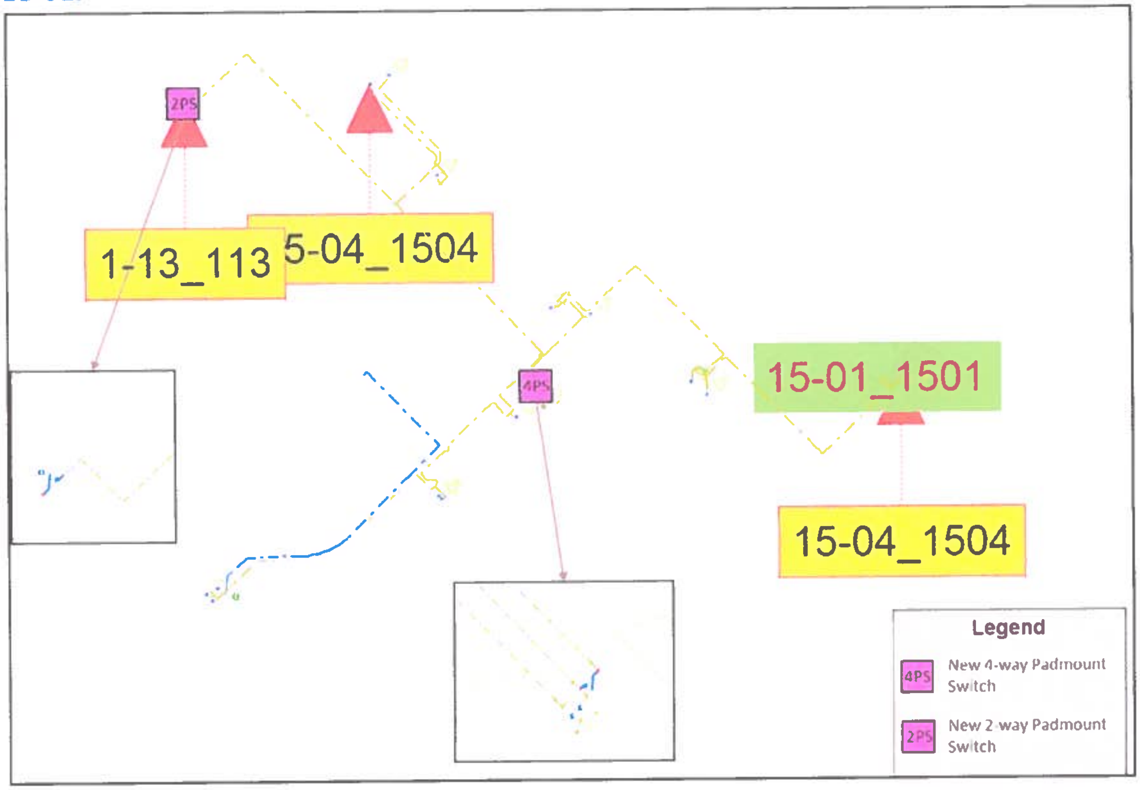
13-04:

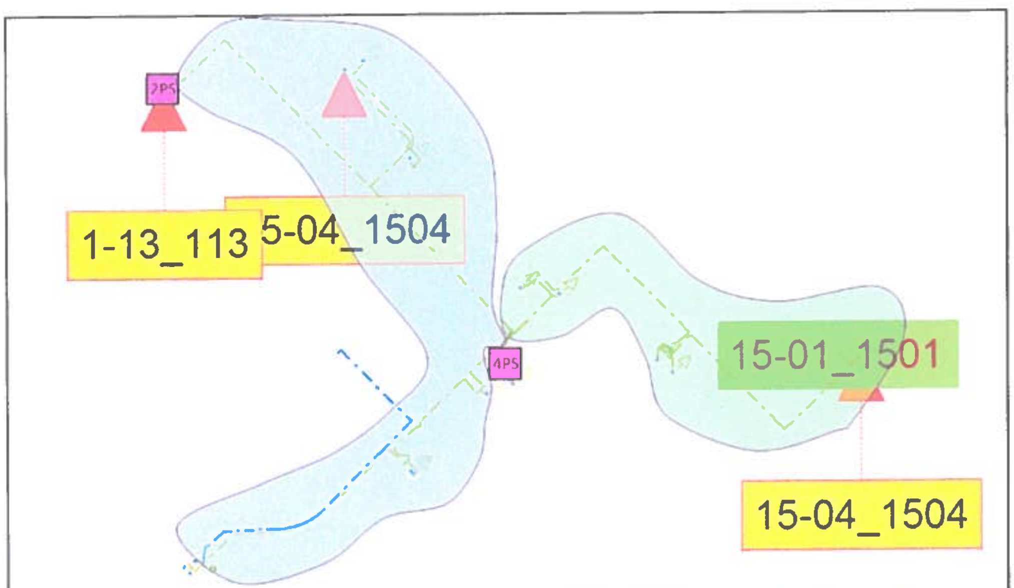




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
13-04	4330	1435	2895		33527	12992	20535	

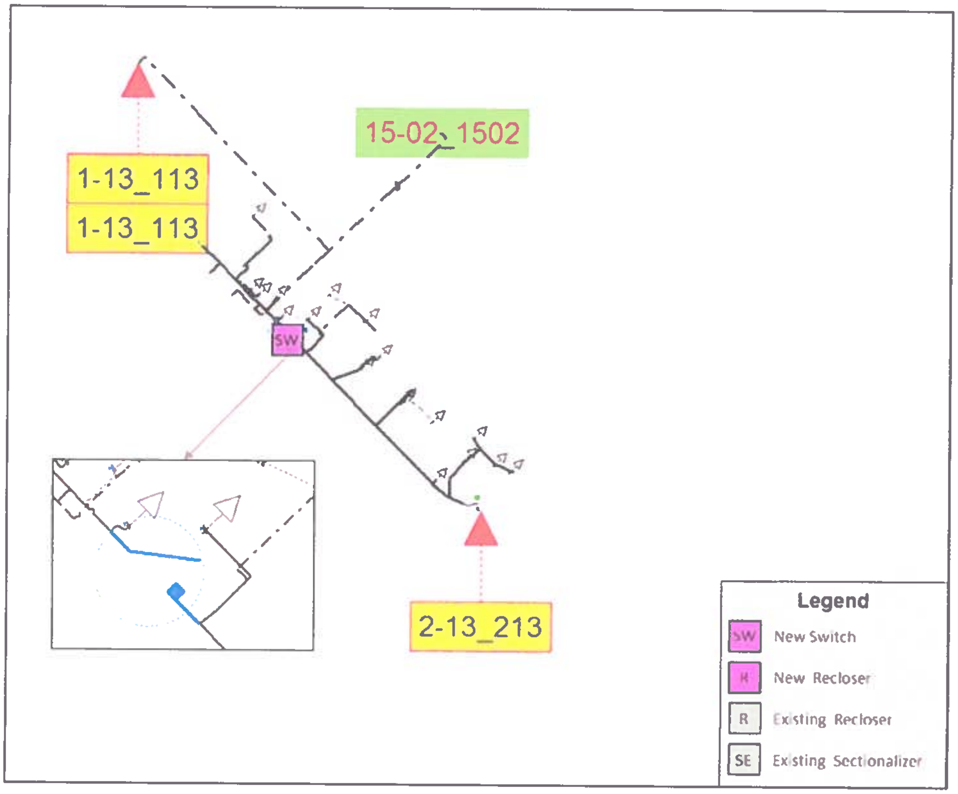
15-01:

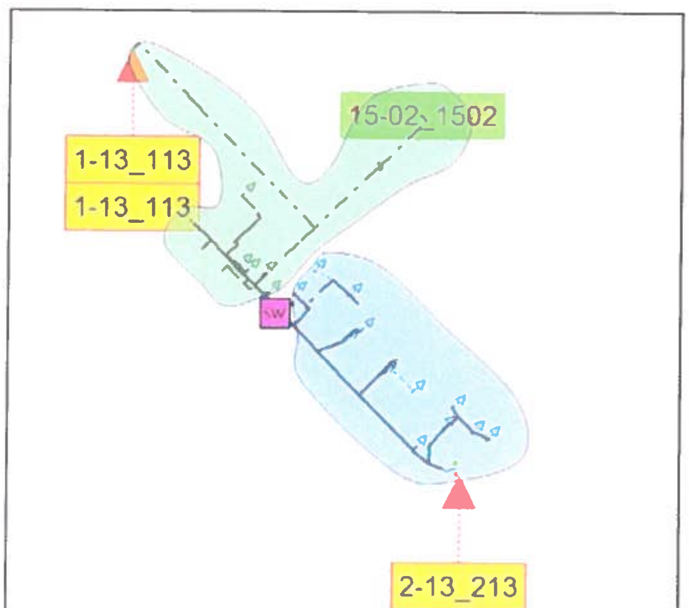




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
15-01	5475	1625	3850		8156	2874	5282	

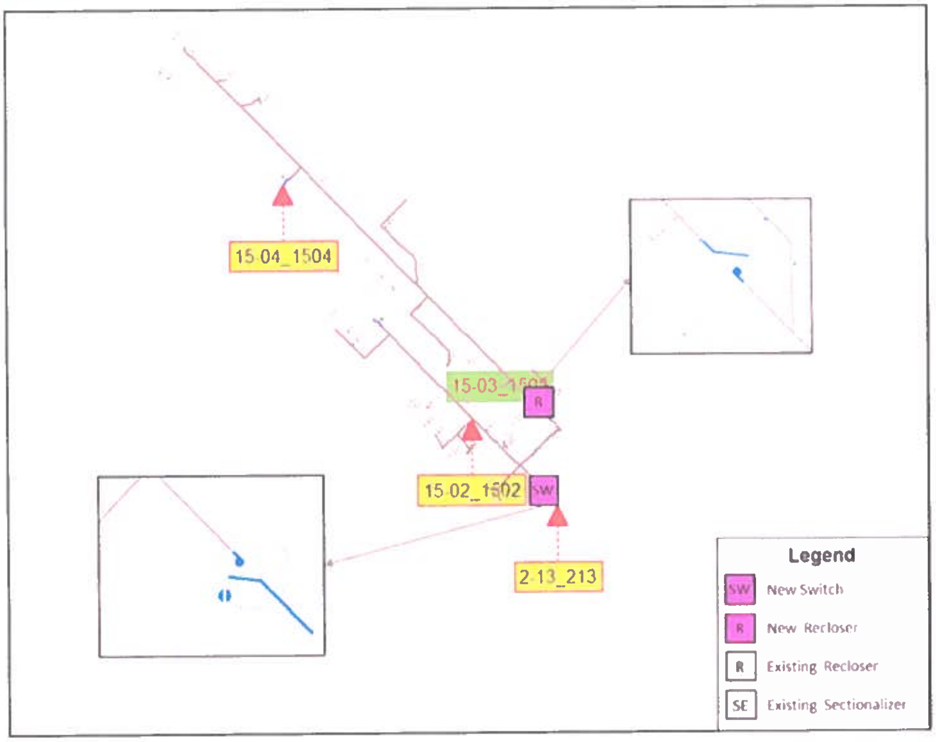
15-02:

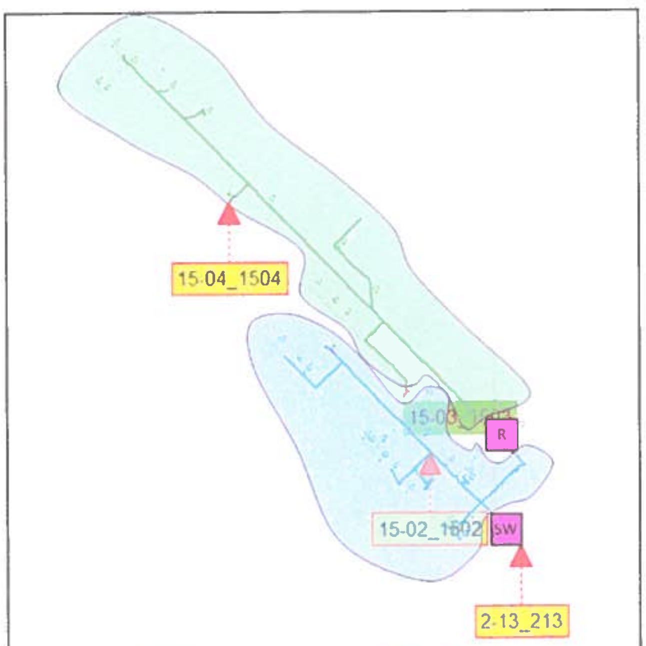




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 FL (ft)	Z2 FL (ft)	Z3 FL (ft)
15-02	3001	970	2031		3048	4354	3694	

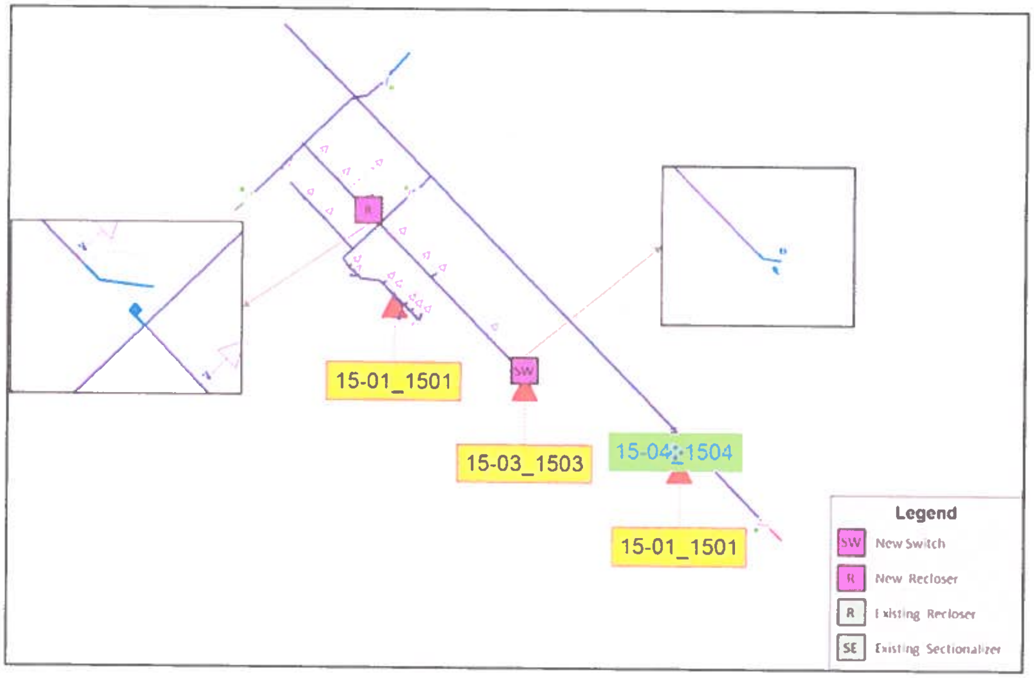
15-03:

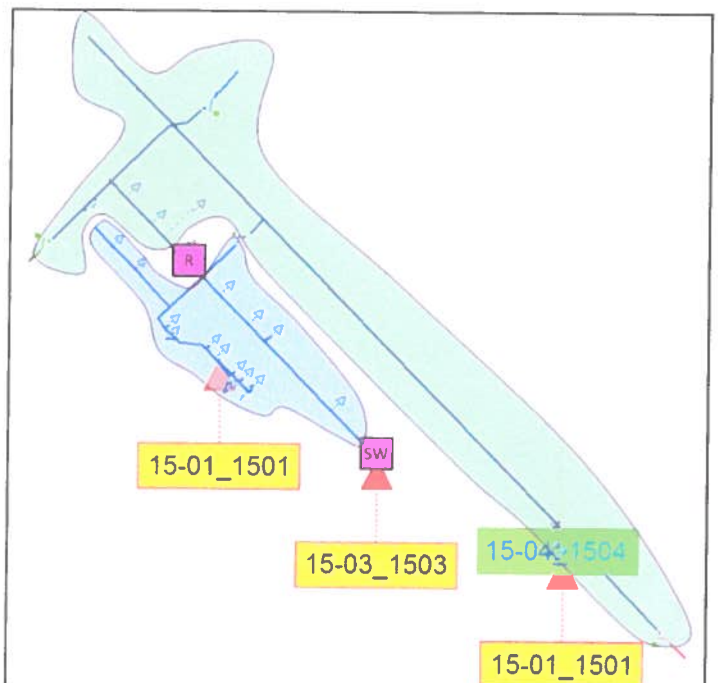




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
15-03	4798	2170	2628		15135	8005	7129	

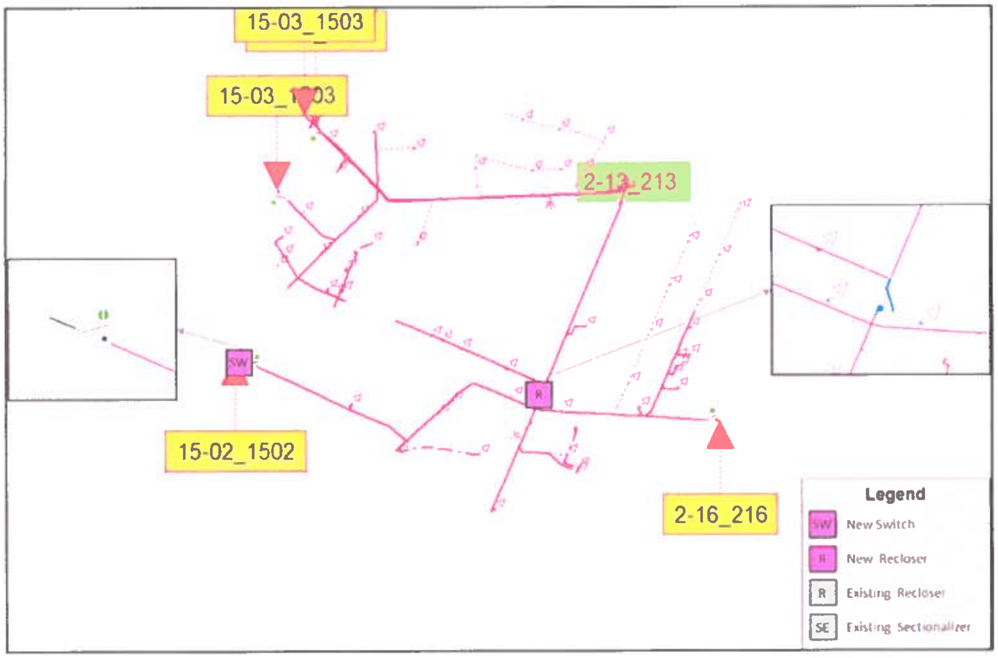
15-04:

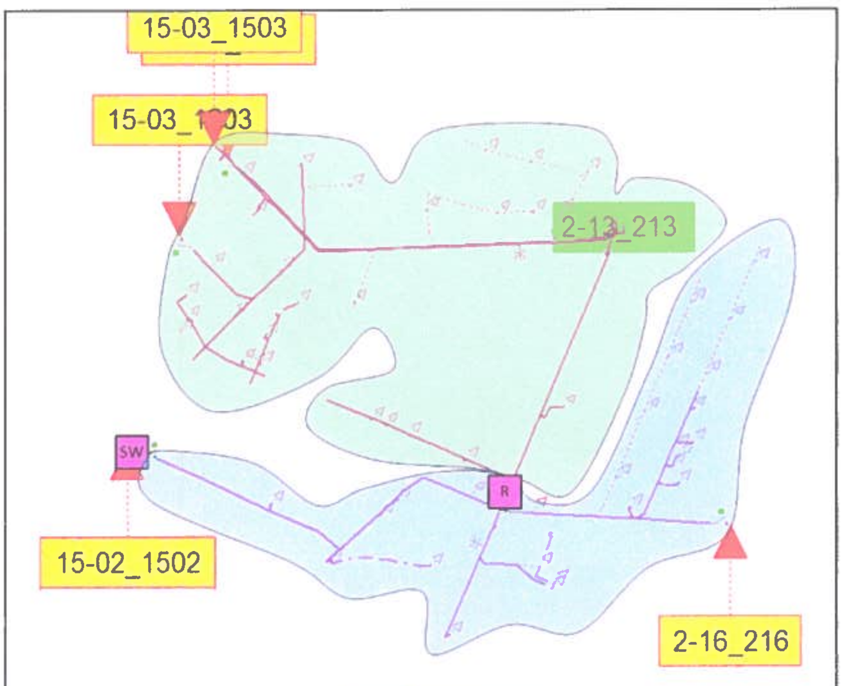




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
15-04	2695	250	2645		10935	6883	4052	

2-13:

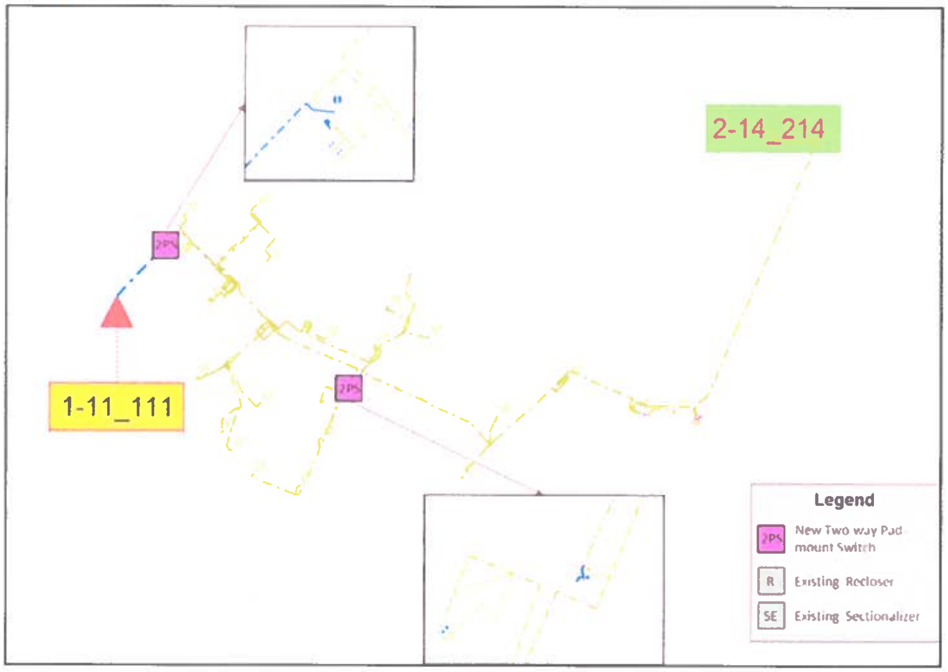




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
2-13	9111	4013	5098		26936	16043	10892	

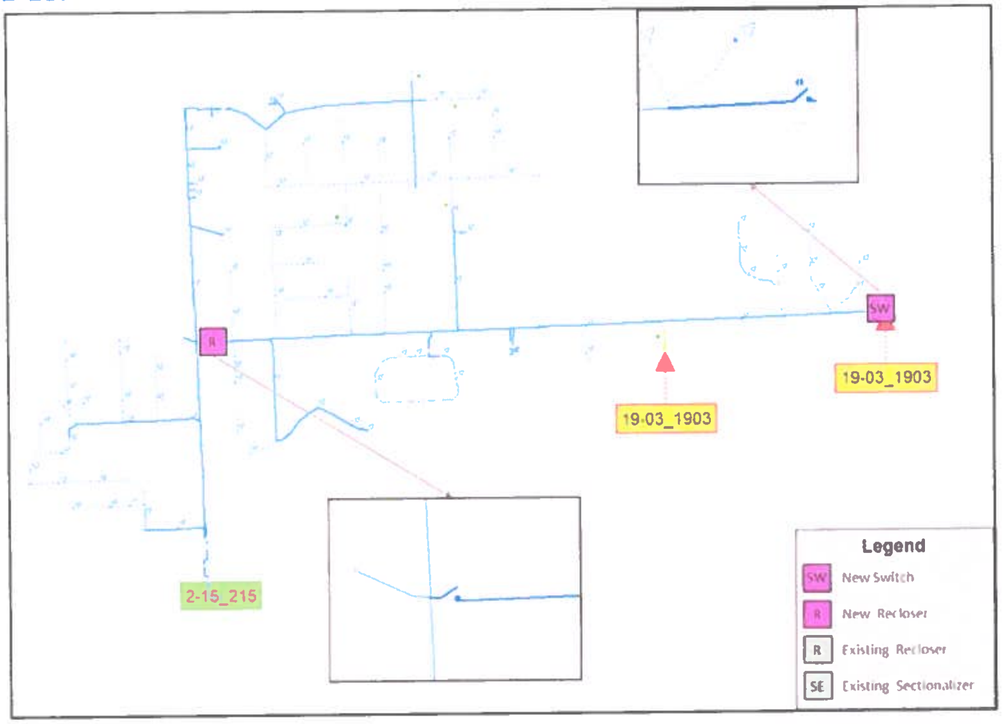
leidos

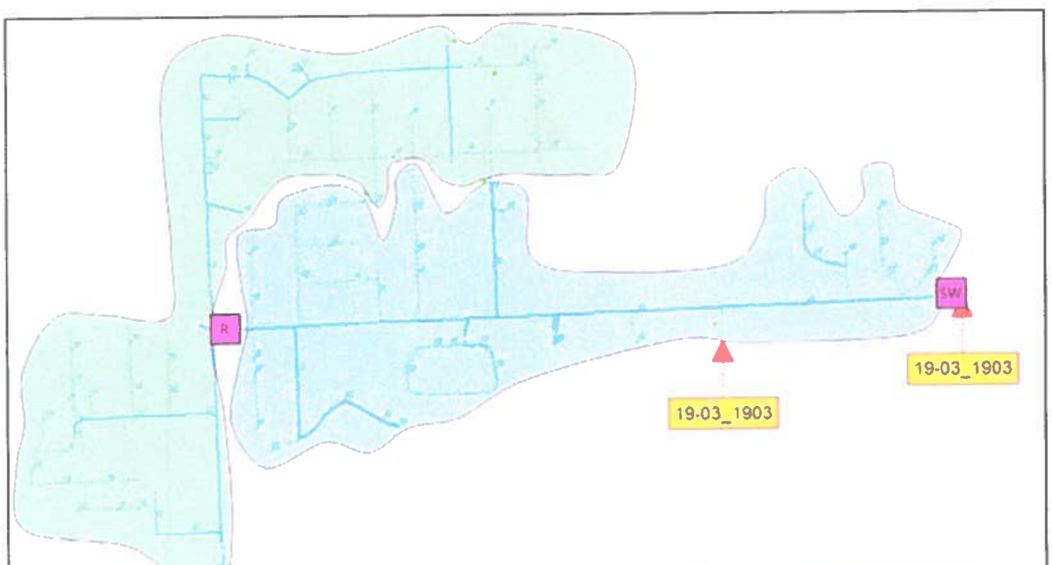
2-14:



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	

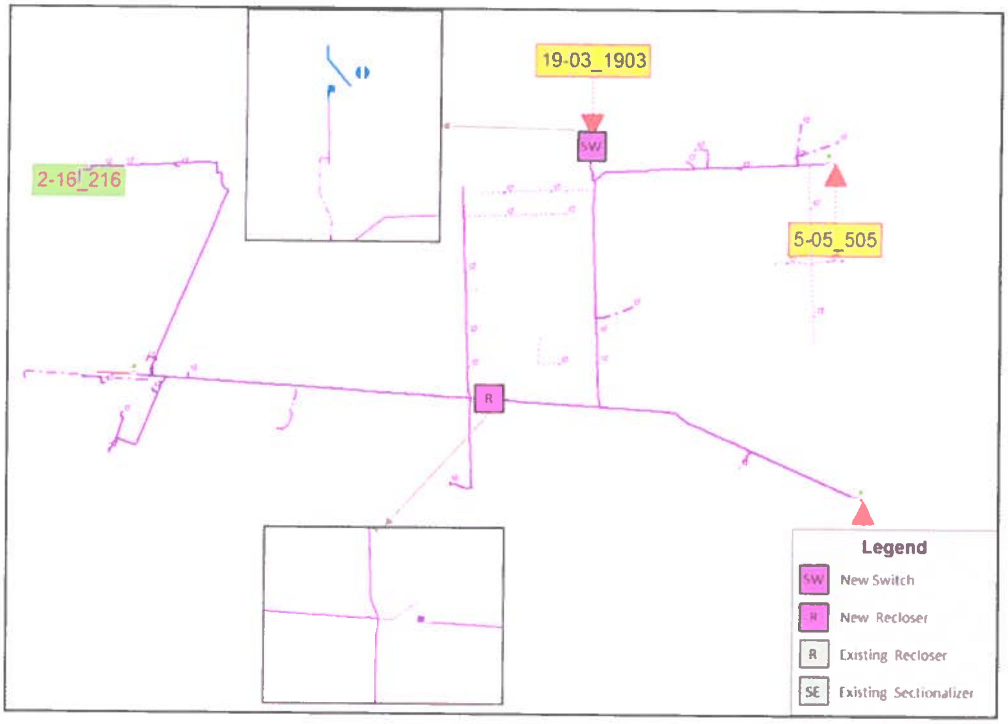
2-15:

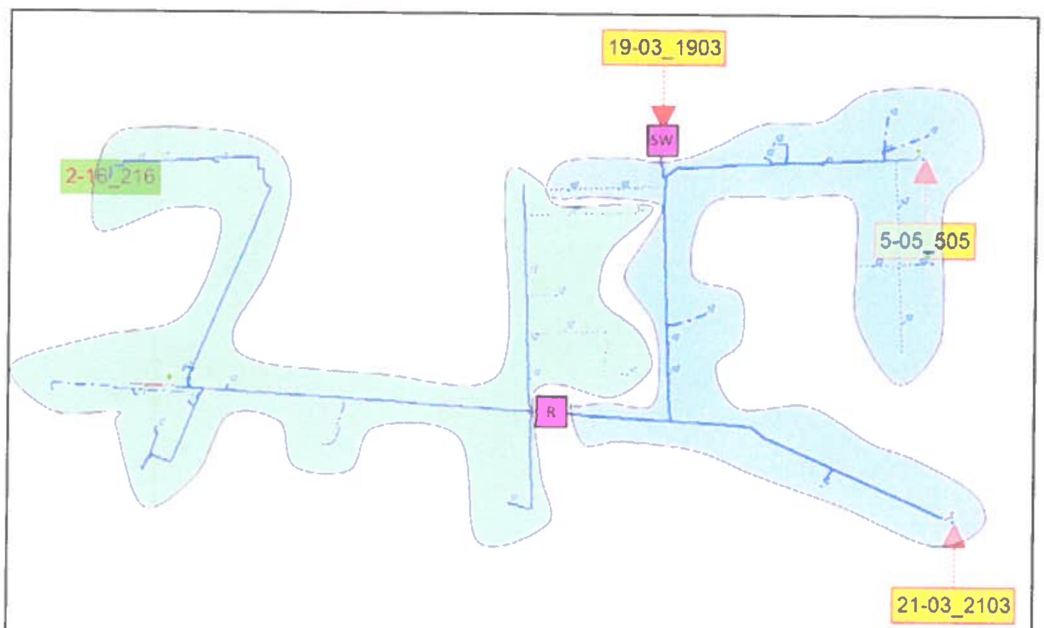




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
2 15	9135	5200	3935		47818	25721	22037	

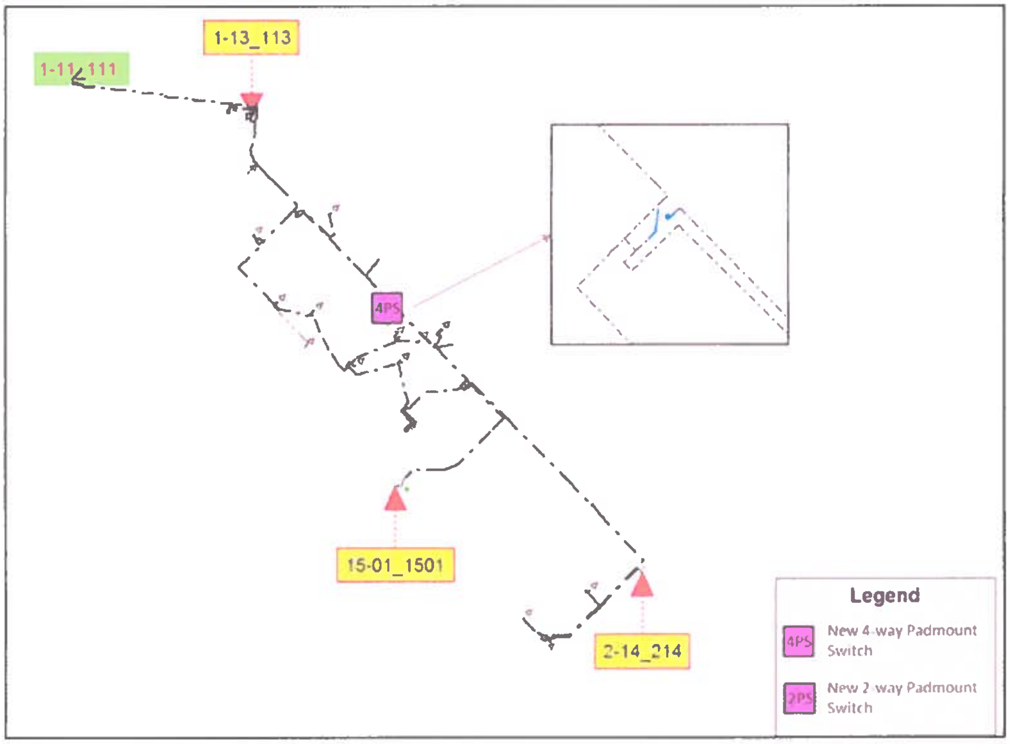
2-16:

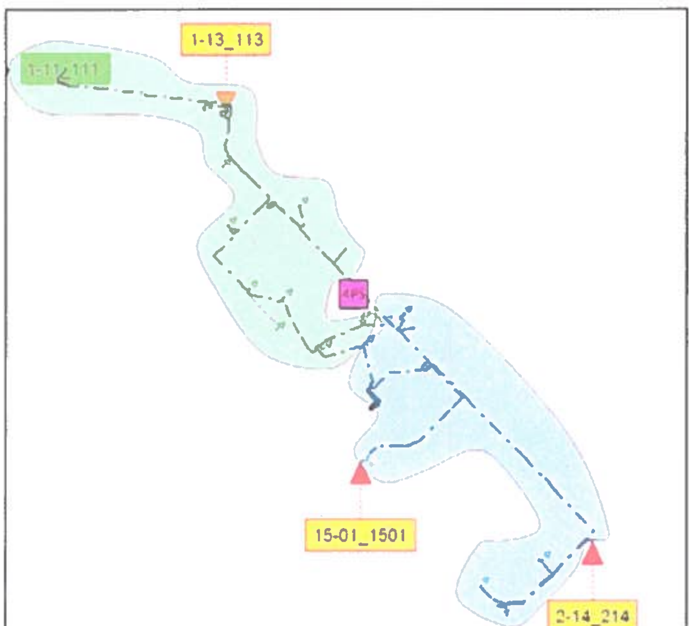




Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
2-16	8325	3850	4475		30066	17064	13002	

1-11:



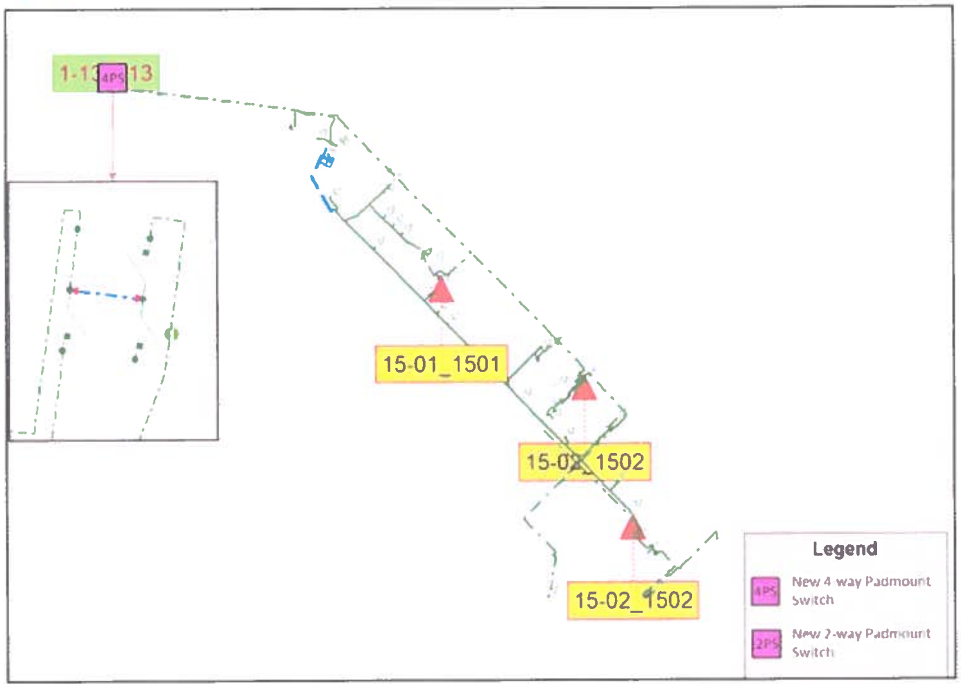


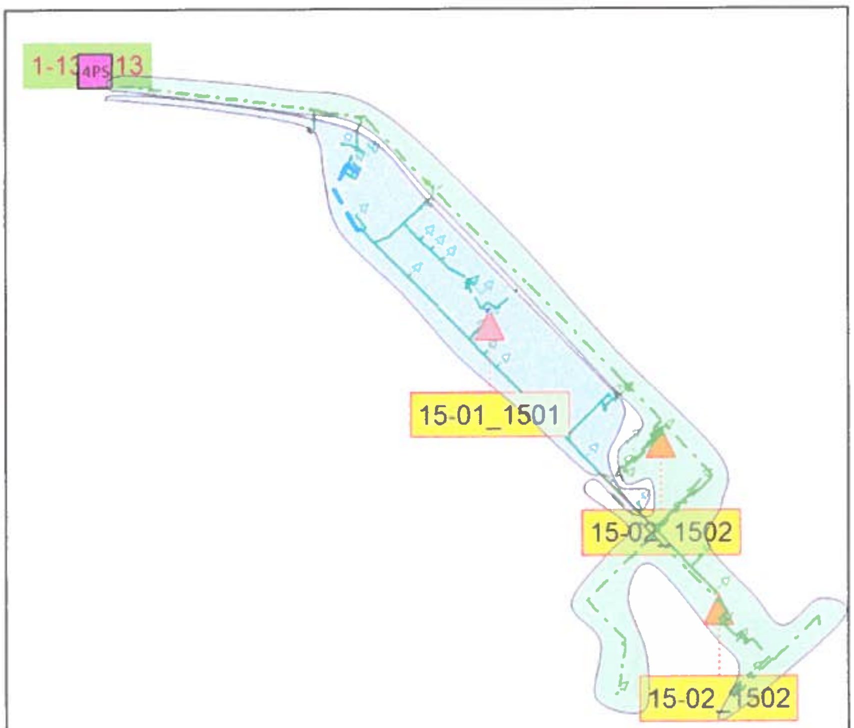
Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
1-11	13050	7350	5700		17792	9672	8110	

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	

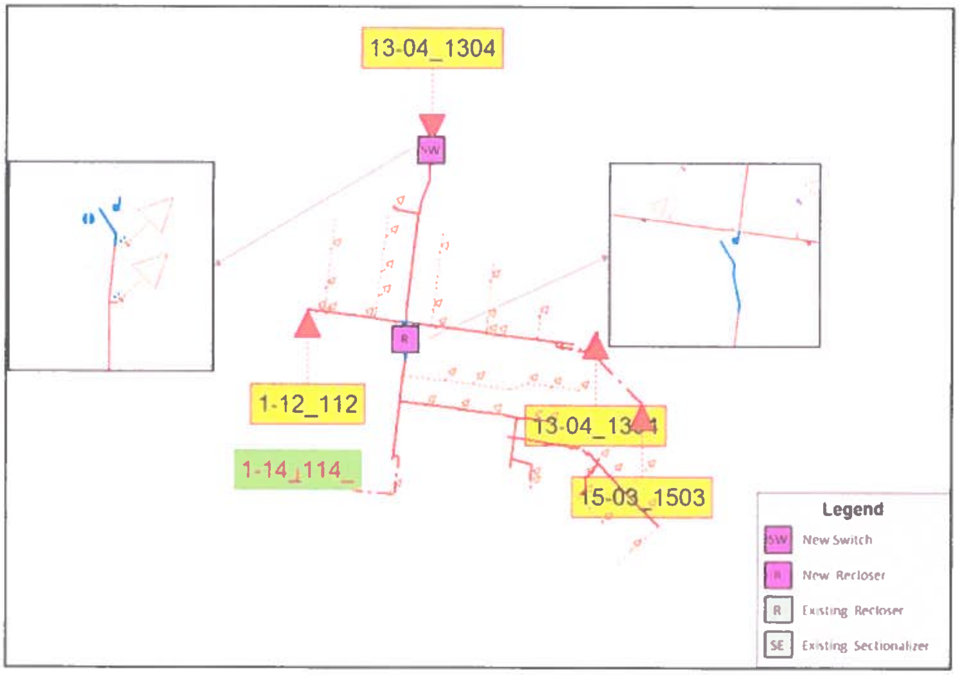
1-13:

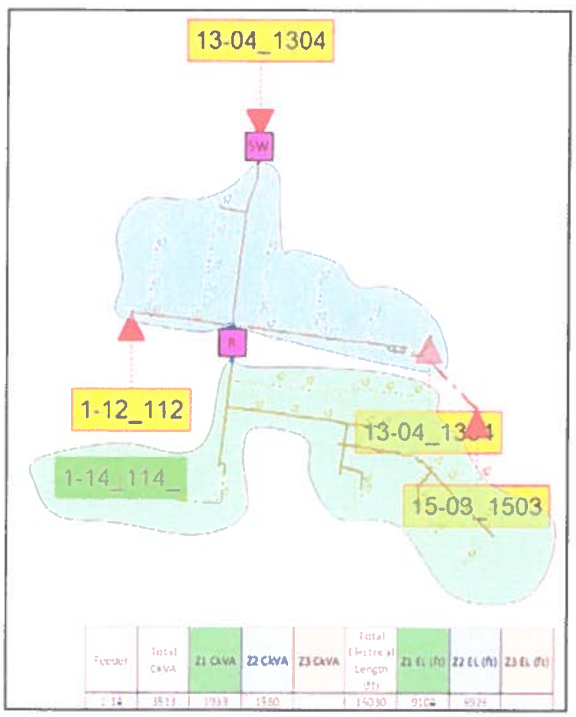




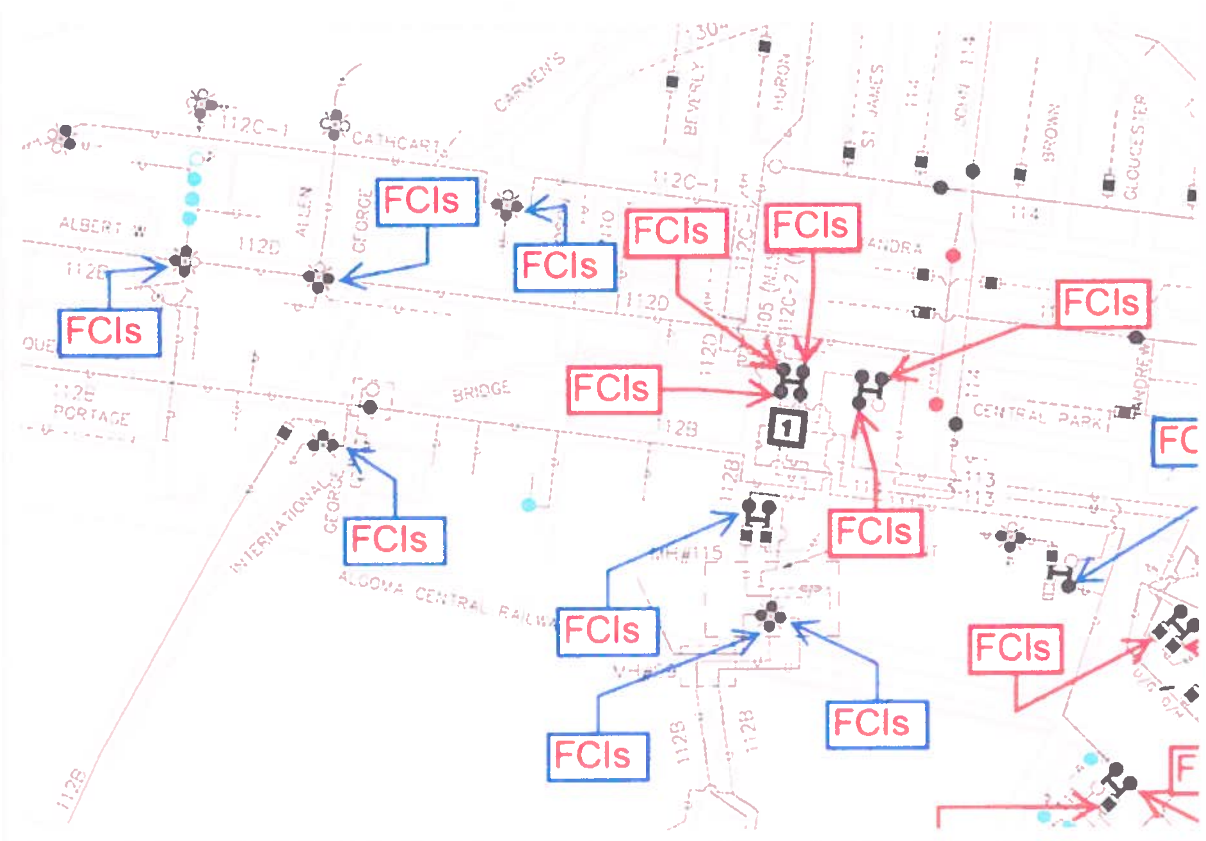
Feeder	Total CkVA	Z1 CkVA	Z2 CkVA	Z3 CkVA	Total Electrical Length (ft)	Z1 EL (ft)	Z2 EL (ft)	Z3 EL (ft)
1-13	12703	7500	5203		19879	10623	9255	

1-14:


13-04_1304
SW
R
1-12_112
1-14_114_
13-04_13
15-03_1503
Legend
SW New Switch
R New Recloser
R Existing Recloser
SE Existing Sectionalizer


13-04_1304
SW
R
1-12_112
1-14_114_
13-04_13
15-03_1503
Feeder
Total CkVA
Z1 CkVA
Z2 CkVA
Z3 CkVA
Total Electrical Length (ft)
Z1 EL (ft)
Z2 EL (ft)
Z3 EL (ft)

Appendix 5. FCI Locations



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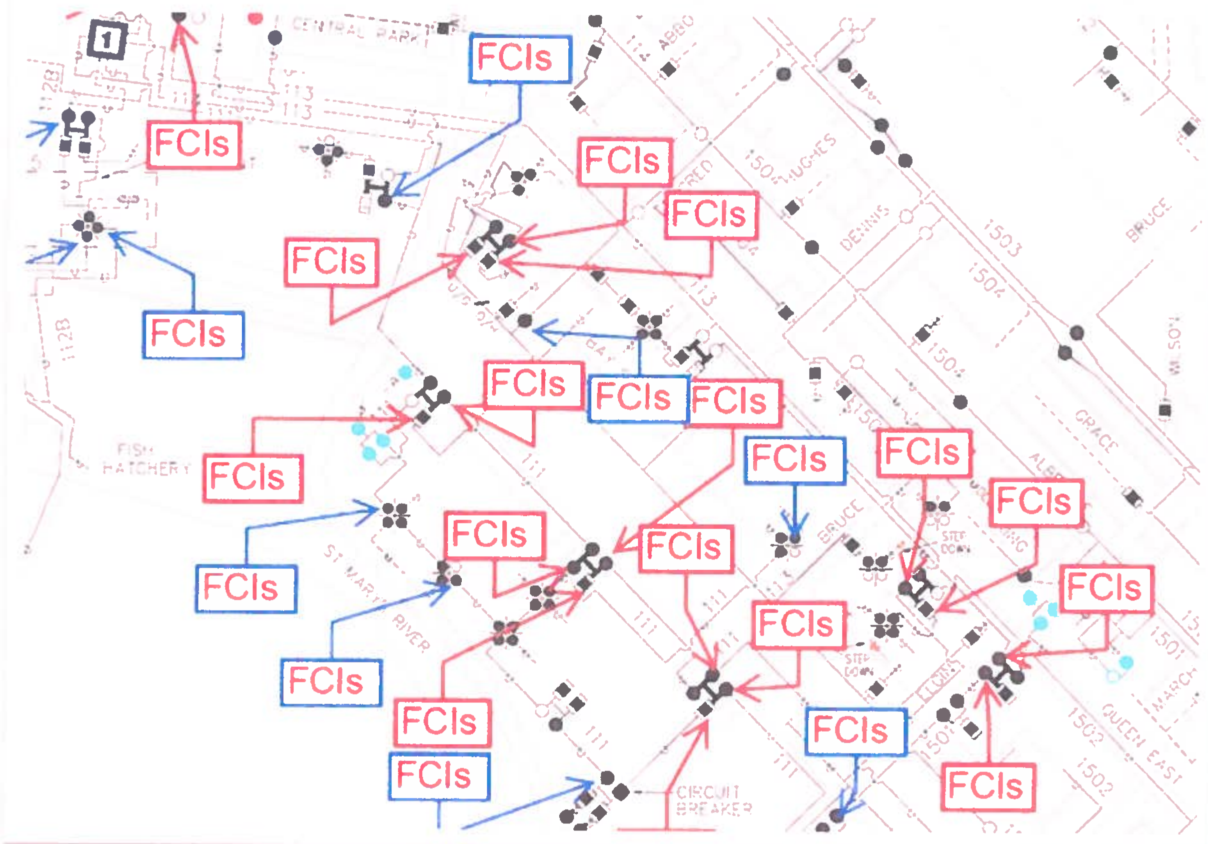
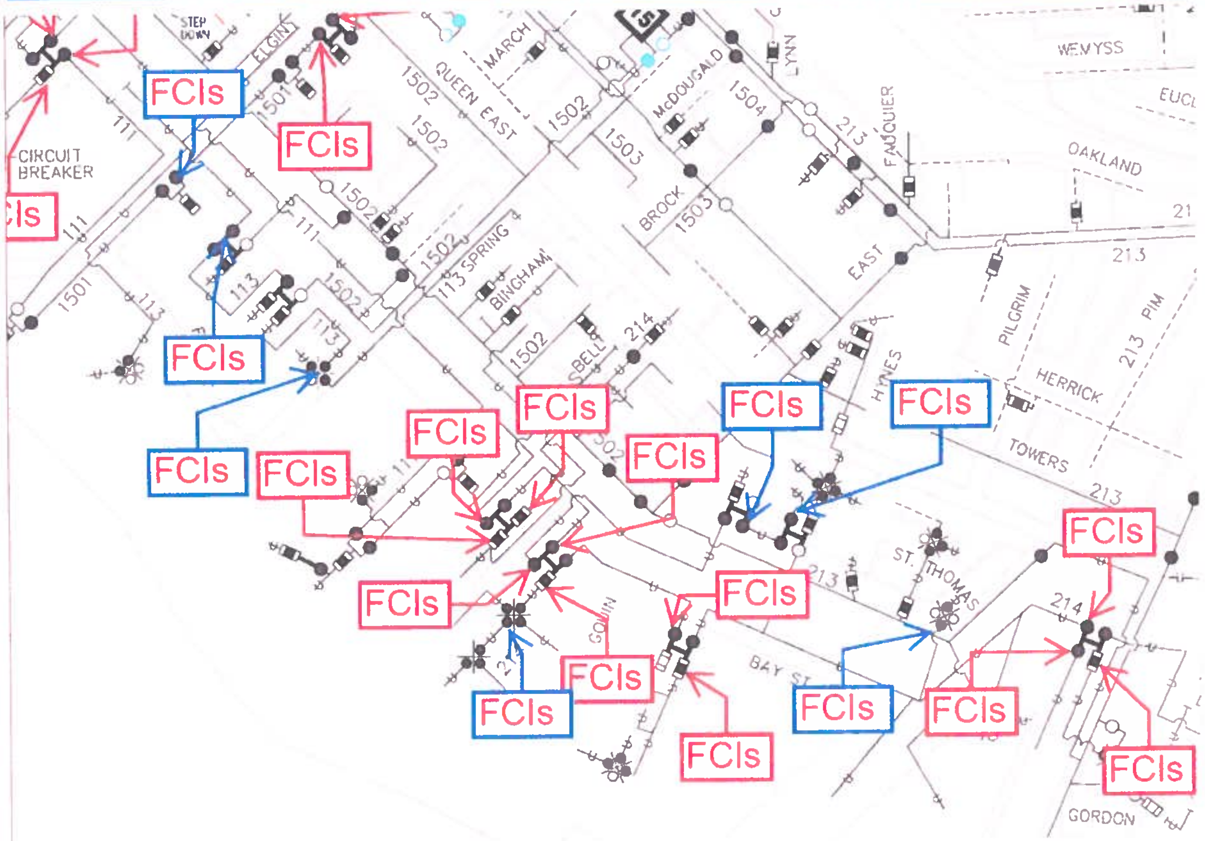
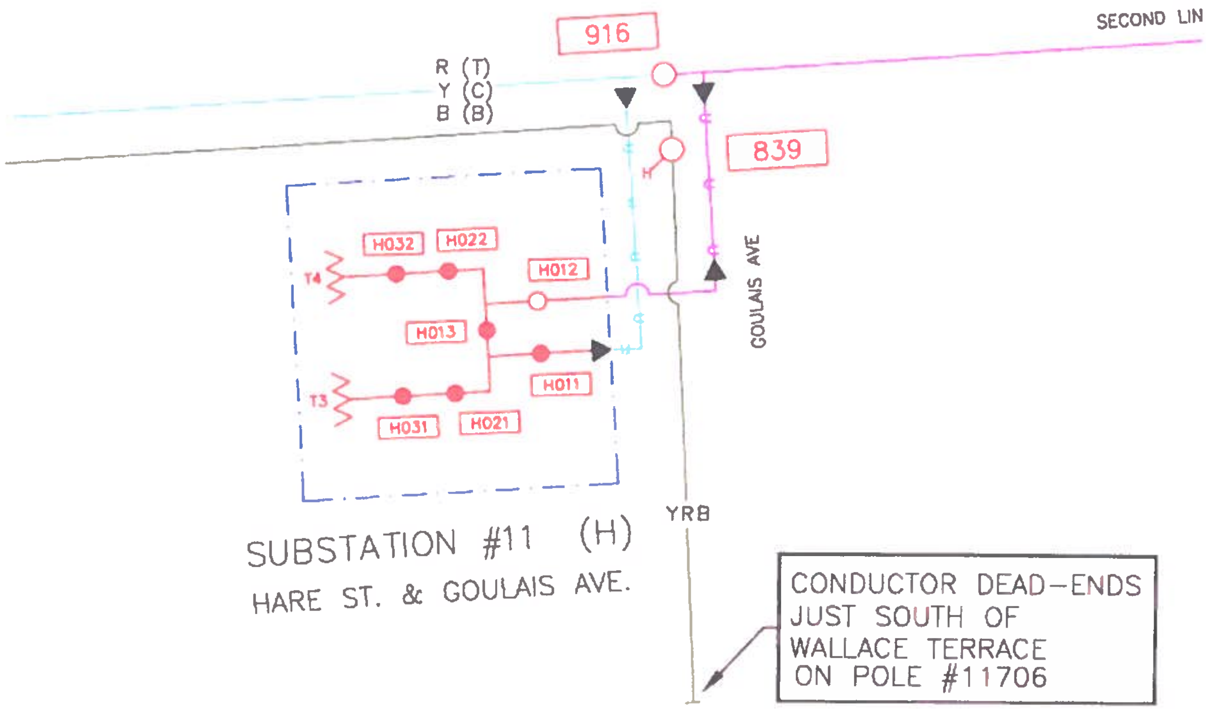


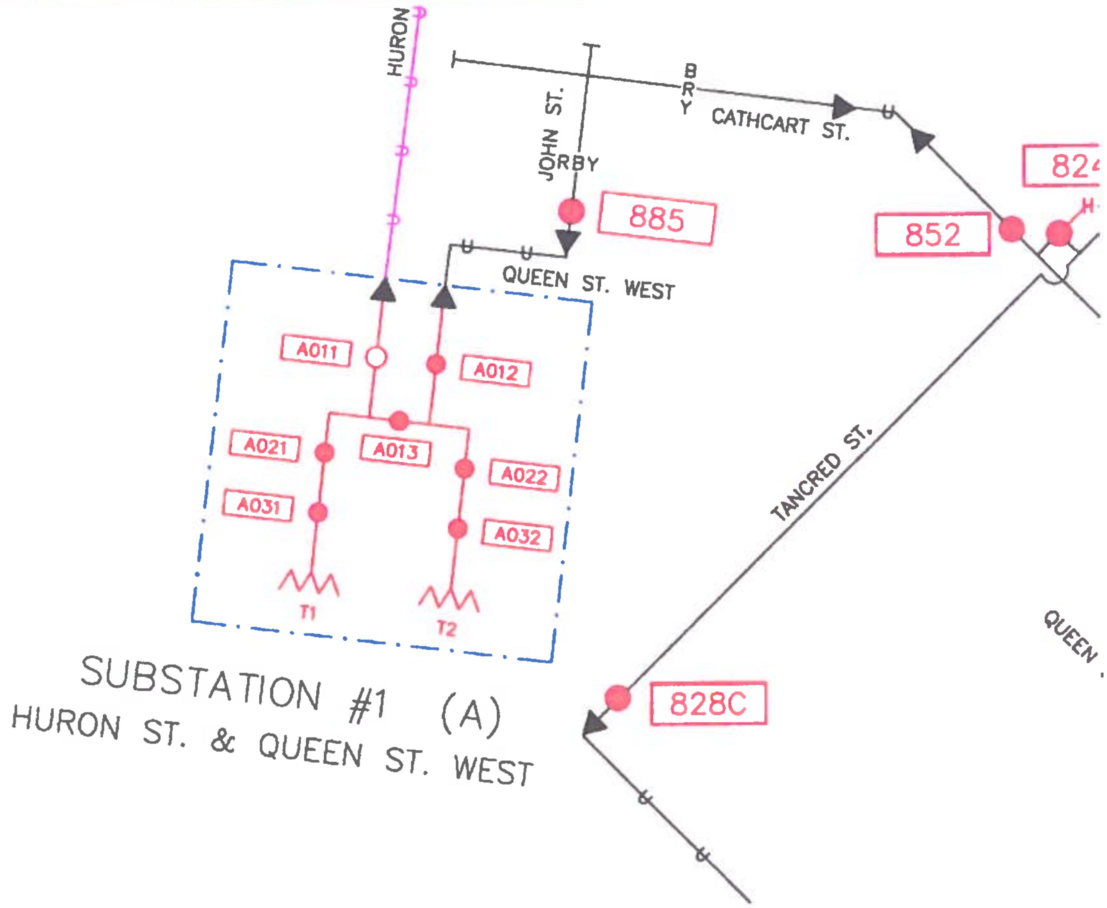
1
CENTRAL PARK
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FCIs
FISH HATCHERY
ST MARYS RIVER
CIRCUIT BREAKER
STEP DOWN
STEP DOWN
HUGHES
DENNIS
BRUCE
GRACE
WILSON
QUEEN EAST
1503
1504
1504
1501
1502
1502

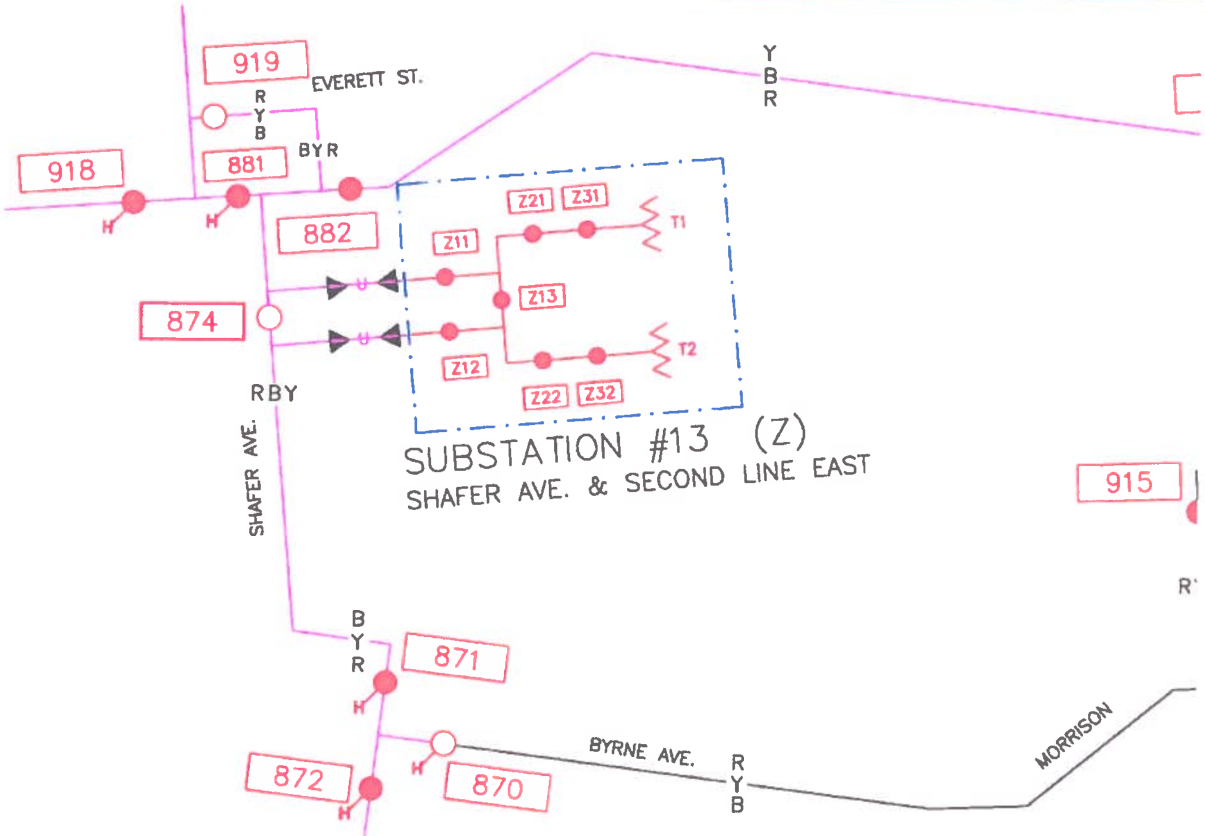


FCIs
CIRCUIT BREAKER
STEP DOWN
ELGIN
MARCH
QUEEN EAST
McDOUGALD
LYNN
FAUQUIER
WEMYSS
OAKLAND
BROCK
EAST
SPRING
BINGHAM
BELL
PILGRIM
PIM
HERRICK
HYNES
TOWERS
ST. THOMAS
GODIN
BAY ST
GORDON
1501
1502
1503
1504
111
113
213
214

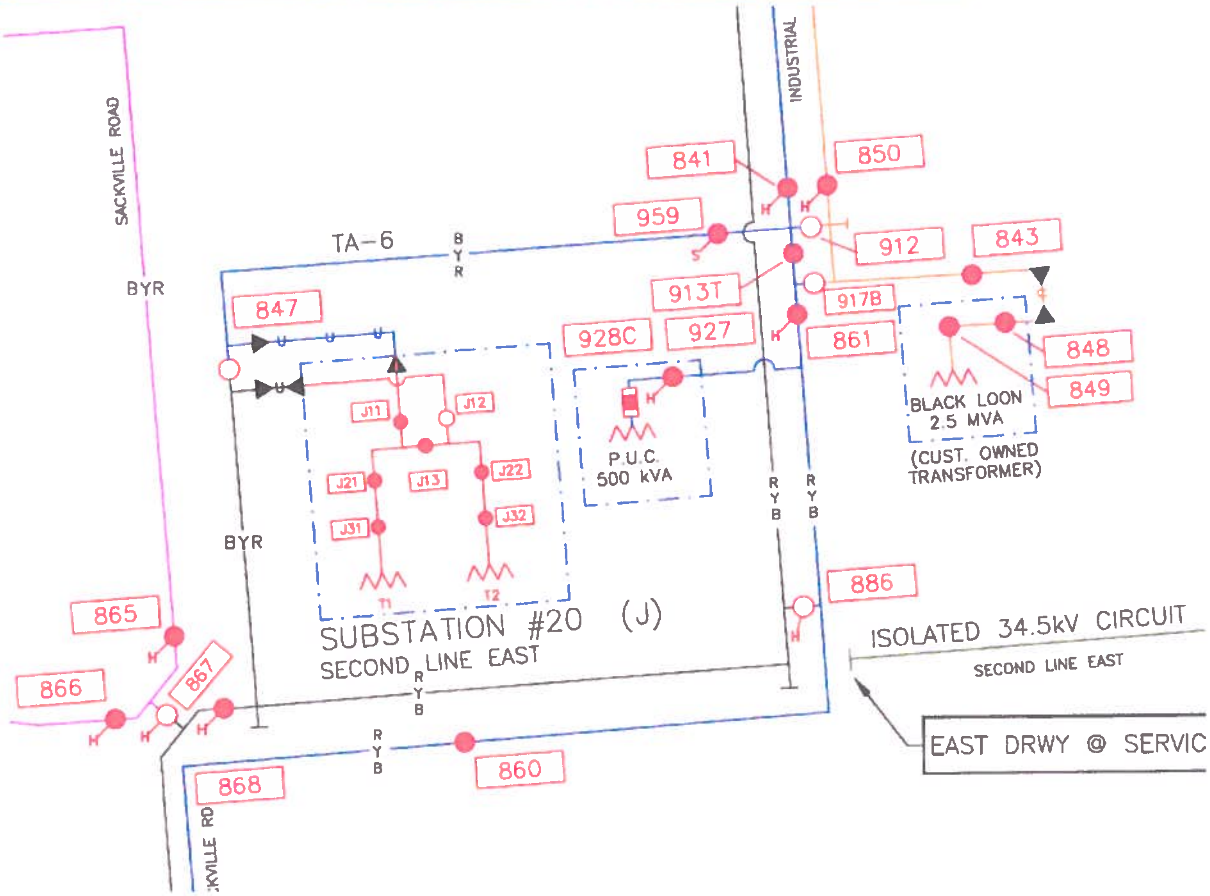
Appendix 6. Substations Included in Source-Transfer Scheme



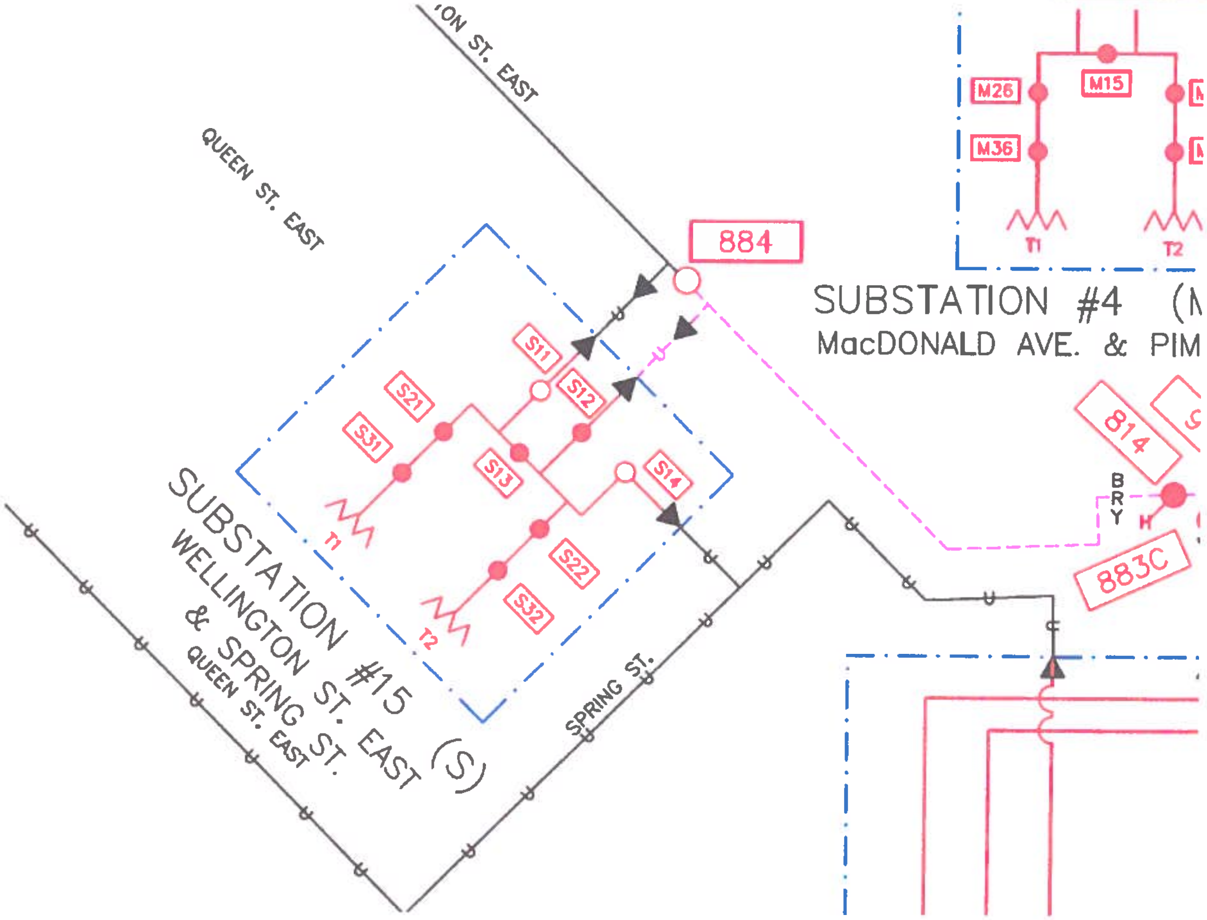

HURON
JOHN ST.
B R Y
CATHCART ST.
ORBY
885
824
852
QUEEN ST. WEST
A011
A012
A021
A013
A022
A031
A032
T1
T2
TANCRED ST.
QUEEN
828C
SUBSTATION #1 (A)
HURON ST. & QUEEN ST. WEST



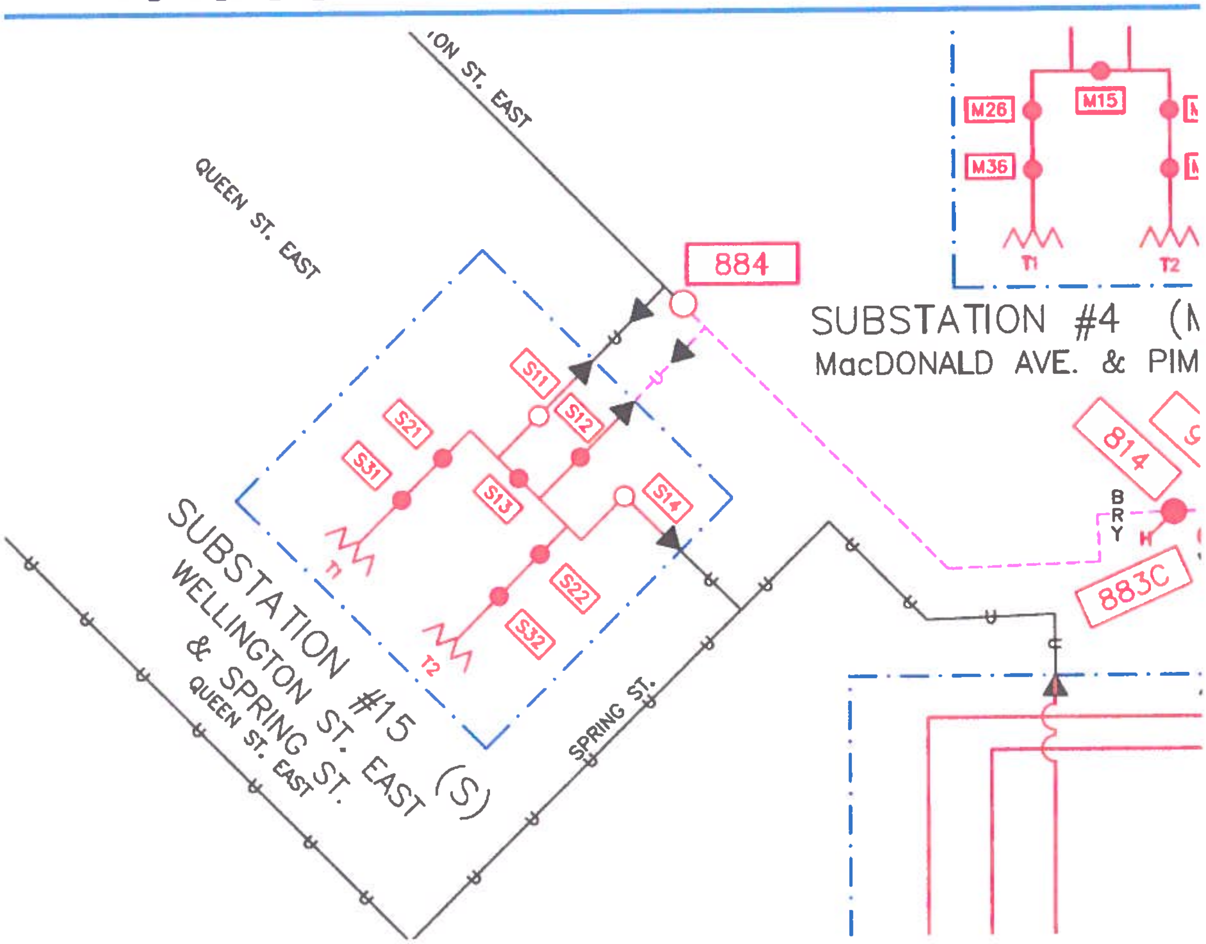
919
EVERETT ST.
R Y B
918
881
BYR
882
Z11
Z21
Z31
T1
Z13
874
Z12
Z22
Z32
T2
RBY
SHAFER AVE.
SUBSTATION #13 (Z)
SHAFER AVE. & SECOND LINE EAST
Y B R
915
B Y R
871
872
870
BYRNE AVE.
R Y B
MORRISON



SACKVILLE ROAD
INDUSTRIAL
TA-6
BYR
841
850
959
912
843
913T
917B
847
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)
886
865
SUBSTATION #20 (J)
SECOND LINE EAST
ISOLATED 34.5kV CIRCUIT
866
867
868
860
EAST DRWY @ SERVIC



QUEEN ST. EAST
ON ST. EAST
884
SUBSTATION #4 (M
MacDONALD AVE. & PIM
M26
M15
M36
T1
T2
S11
S12
S13
S14
S21
S22
S31
S32
T1
T2
SUBSTATION #15 (S)
WELLINGTON ST. EAST
& SPRING ST.
QUEEN ST. EAST
SPRING ST.
814
B
R
Y
H
883C


ON ST. EAST
QUEEN ST. EAST
884
M26
M15
M36
T1
T2
SUBSTATION #4
MacDONALD AVE. & PIM
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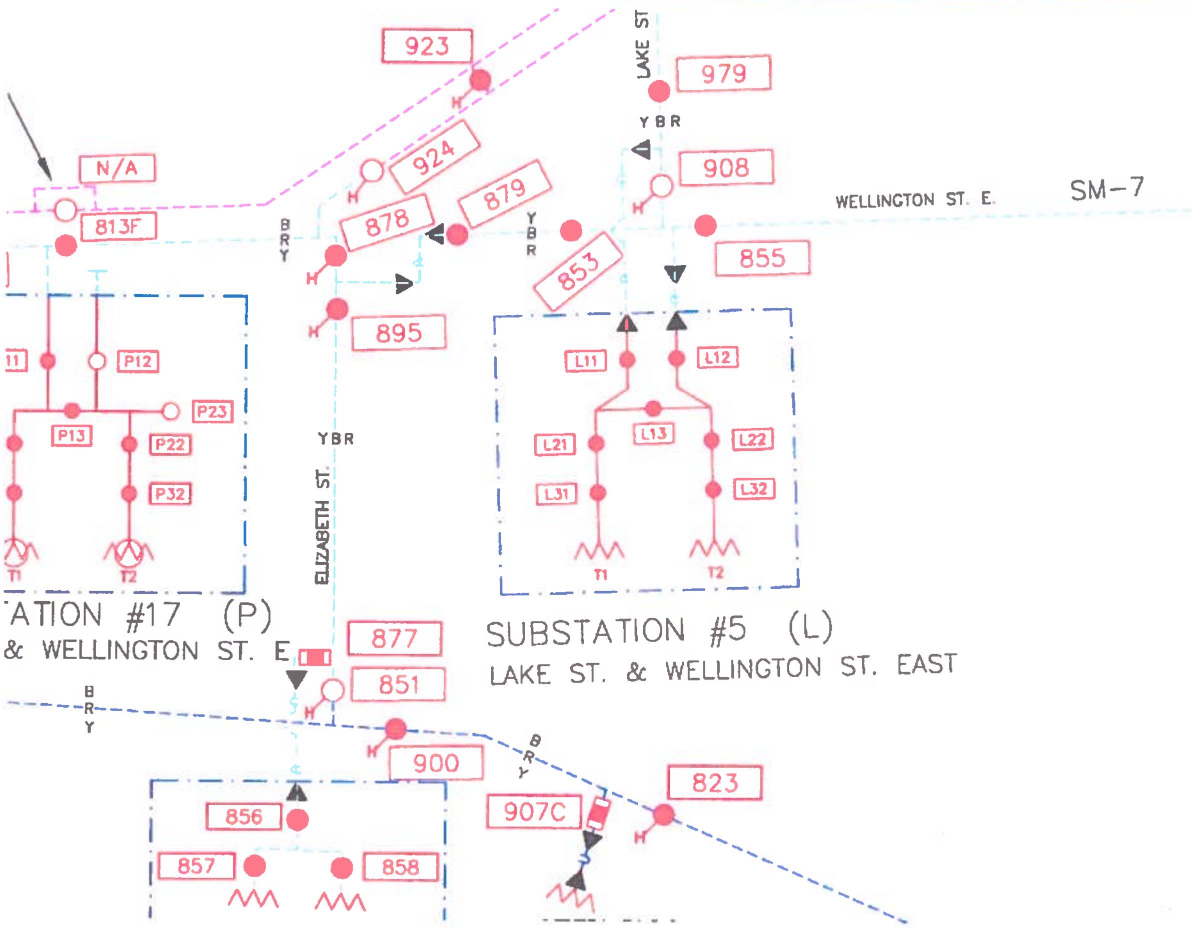
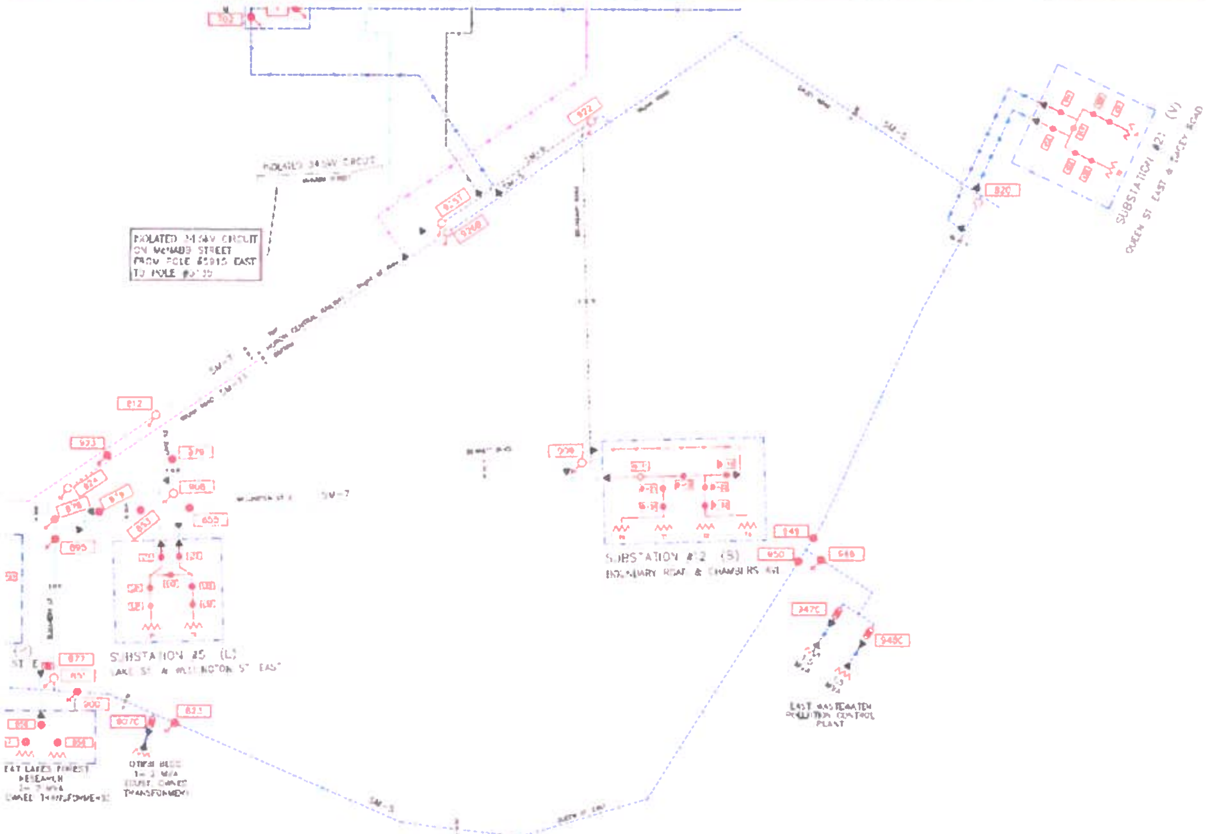
S12
S21
S31
S13
S14
S22
S32
T1
T2
814
B
R
Y
883C
SUBSTATION #15
WELLINGTON ST. EAST (S)
& SPRING ST.
QUEEN ST. EAST
SPRING ST.


923
LAKE ST
979
YBR
908
924
N/A
879
878
813F
BRY
YBR
WELLINGTON ST. E.
SM-7
853
855
895
P12
P23
P13
P22
P32
T1
T2
L11
L12
L13
L21
L22
L31
L32
T1
T2
YBR
ELIZABETH ST.
ATION #17 (P)
& WELLINGTON ST. E
877
851
SUBSTATION #5 (L)
LAKE ST. & WELLINGTON ST. EAST
BRY
900
BRY
823
907C
856
857
858


SUBSTATION #5 (L)
SUBSTATION #12 (S)
812
923
655
877
949
950
347C
948C
EAST WASTEWATER POLLUTION CONTROL PLANT

Leidos Engineering, LLC

Utility Distribution Microgrid: AMI Integration

Preliminary Design

Energizing Co.

PUC Distribution, Sault Ste. Marie, ON

Leidos
11/20/2014

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Contents

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.

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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 Toplogy			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			2014-3			Totals		
		GROUP RATING (Highest)	CH KVA D MAX (Highest)	TRANS UTILIZATION (Highest)	GROUP RATING (Highest)	CH KVA D MAX (Highest)	TRANS UTILIZATION (Highest)	GROUP RATING (Highest)	CH KVA D MAX (Highest)	TRANS UTILIZATION (Highest)
Client Private	220	10.00	10.15	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
	150	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	0.85	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	10.04	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.

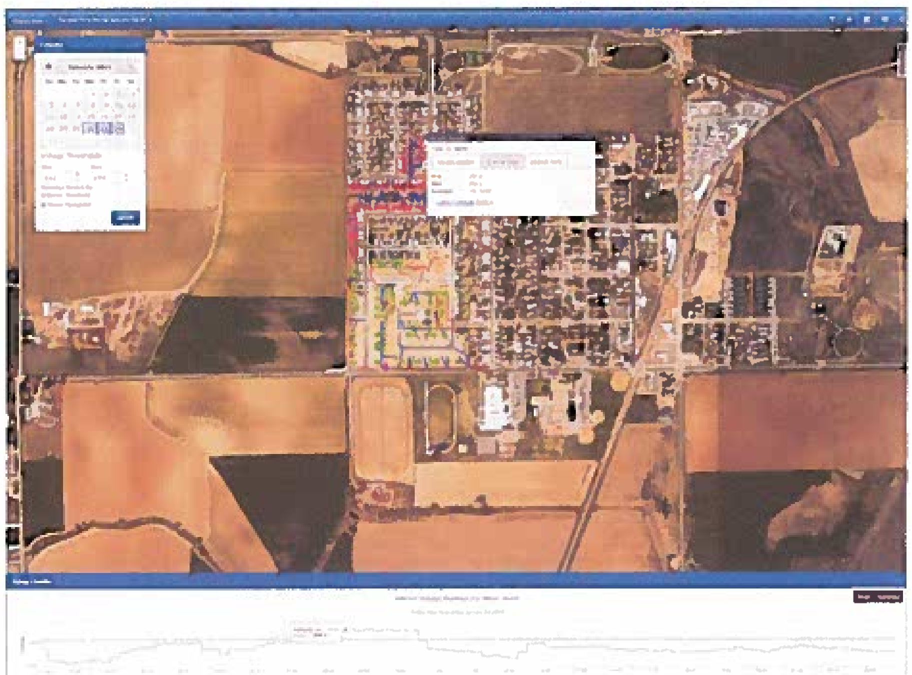

Figure 5: SVM Voltage Analysis View

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
o Review of customer use cases	
o Review of existing solution	
o Review of in-scope enrichments	
o Establish metric definitions and extensions not cover by base solution	
• Source System Exporting	Leidos and PUC
o Create change data capture process and export process from source systems	
o Leverage ESB scripts for master data (similar to Meter Data Management Load)	
o Requires customer to create flat files – (no human created)	
o Change data capture will be on providing system	
• Extend Data Model	Leidos
o Create Fact objects to support additional metrics	

• Loading and Transformation	Leidos
o Receive and load data into the CAP	
o Most of this can be done directly from ESB scripts	
o Leverage existing staging approach and tables, but some custom work	
• Metric Calculation and Aggregation	Leidos
o Extend to for new metrics	
• Reporting Extensions	Leidos
o Service/Work Order	
o SCADA	
o Other as defined in the Business Analysis	
• Training	Leidos
o Data and Usage	
o 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.

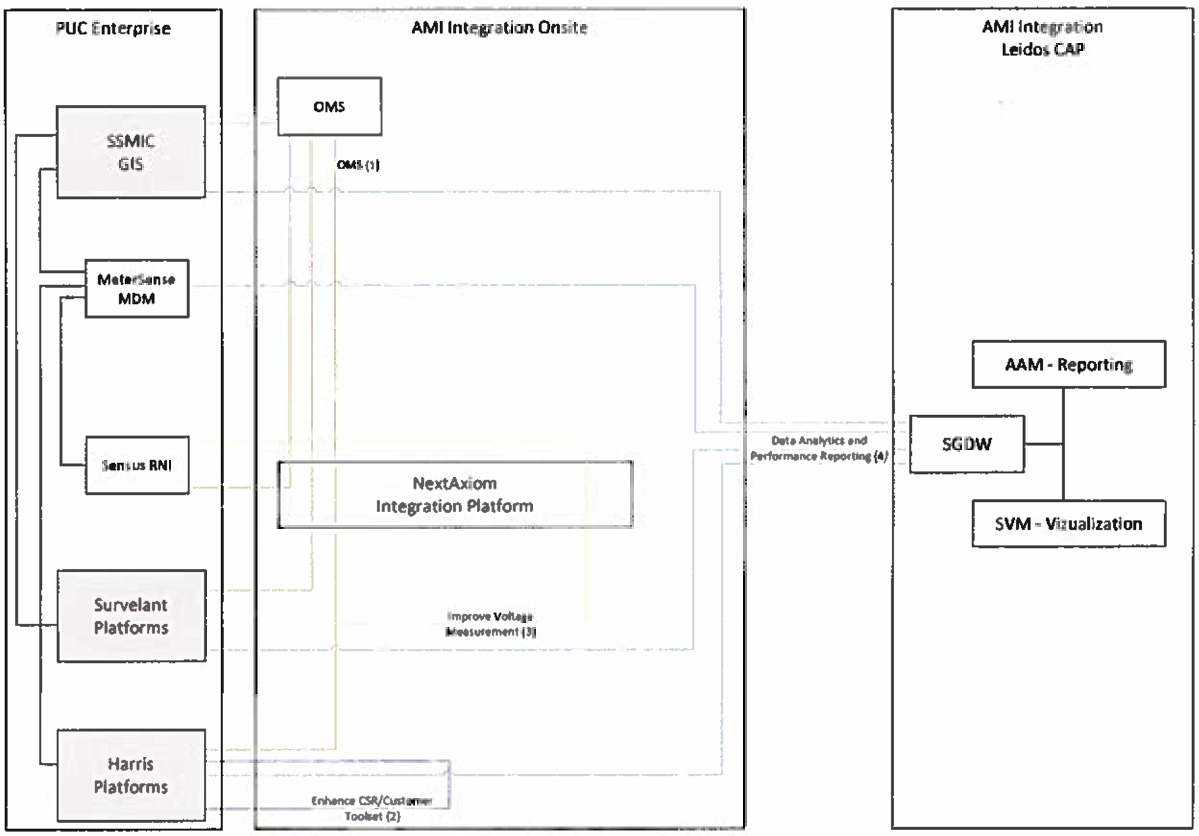

Figure 6: Summary AMI Integration Architecture

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 D

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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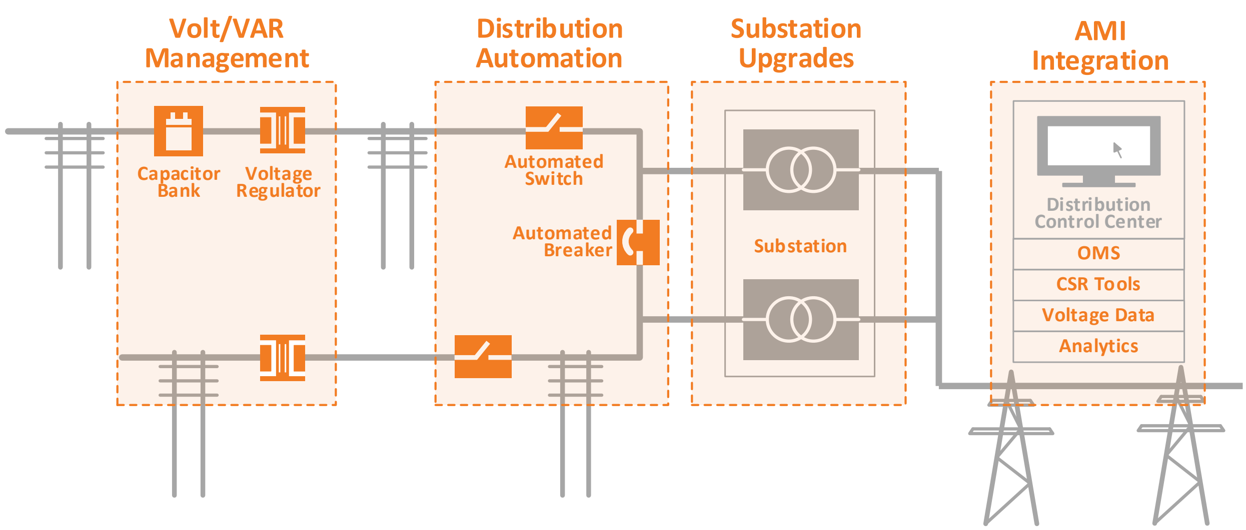
Executive Summary

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.

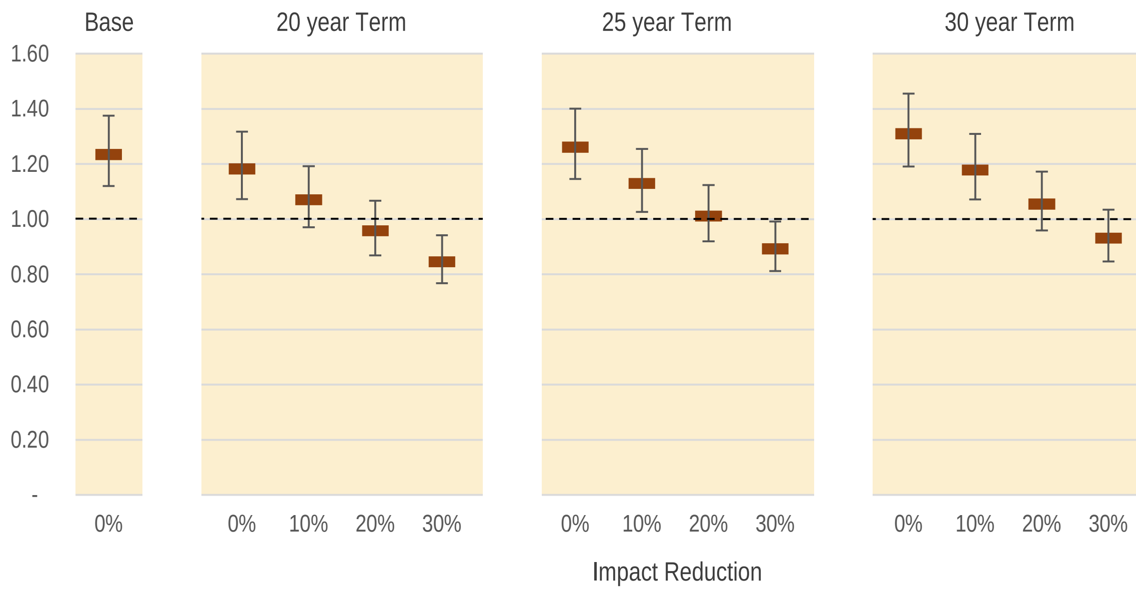
Table 1 above showed the cost-benefit ratios for the range of expected payments (high and low) using a 20 year project life. This *Base* scenario includes all of the local benefits (e.g., LDC and customer benefits), as well as the broader provincial benefits (e.g., generation and transmission benefits). 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.

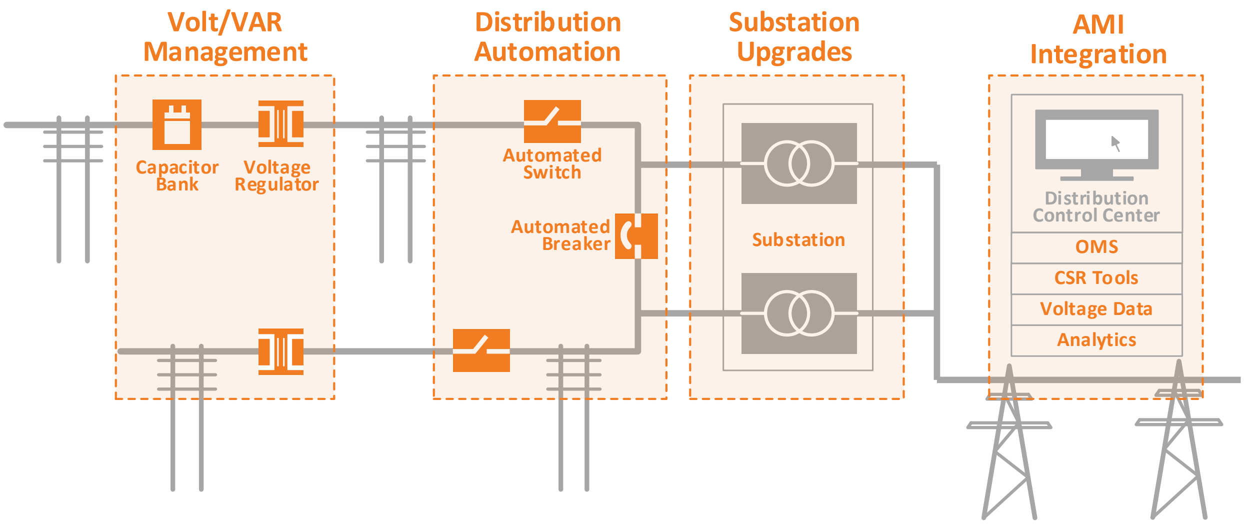
ECo proposes to fund the project in return for a fixed monthly fee; delivering engineering design, construction and on-going support of the system (described more fully below) over a contract period of 20-30 years. The proposal incorporates performance management provisions designed to assure PUC of 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]

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[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.

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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.

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[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.

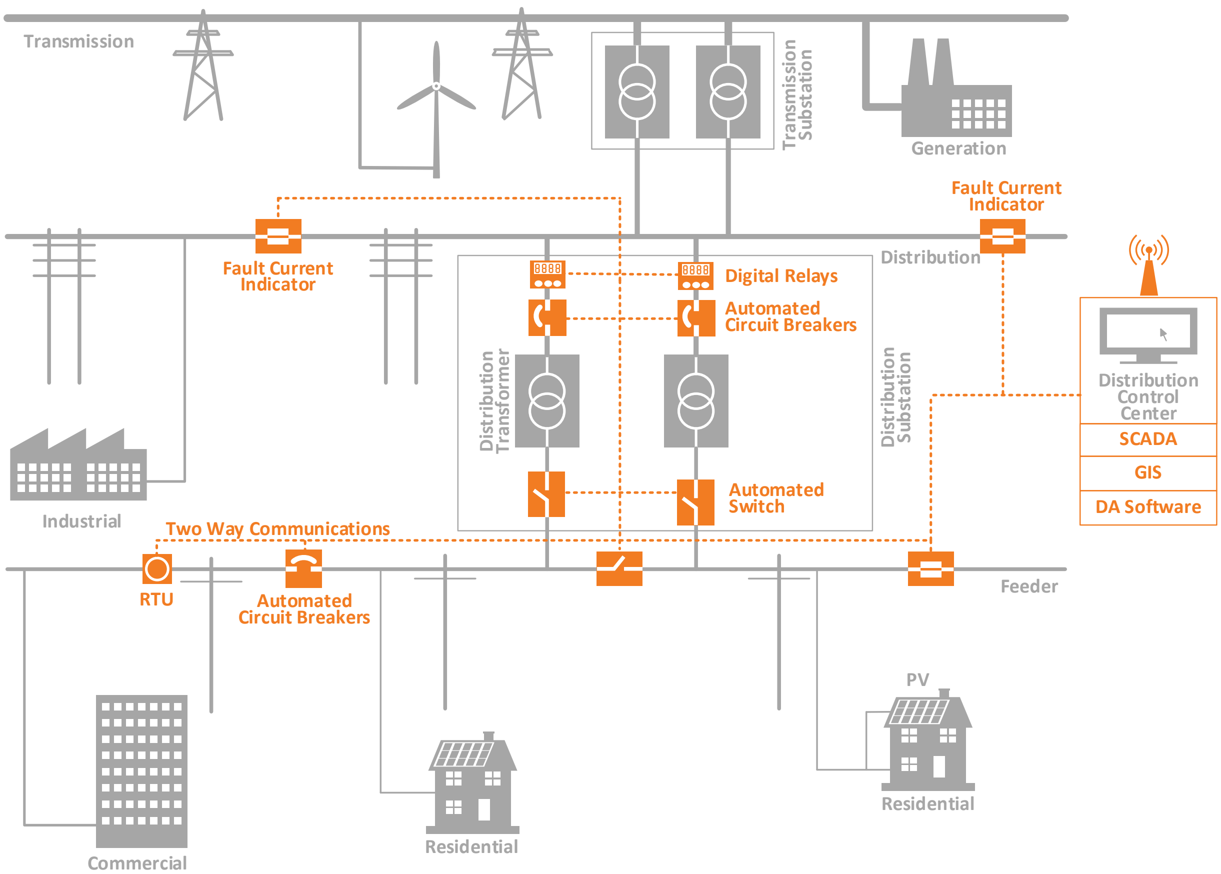
2.1.1 Distribution Automation (DA)

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.

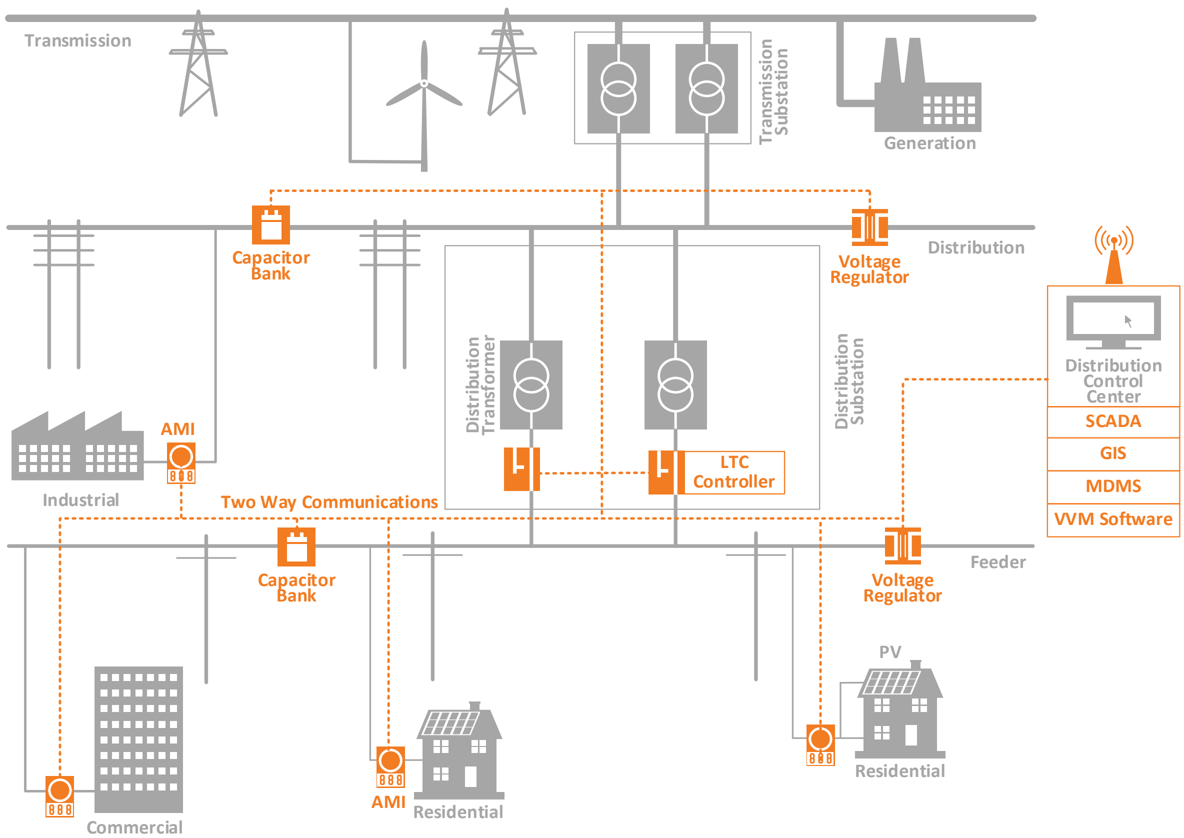
Currently, PUC does not have the capability to dynamically regulate voltage levels at any of the 34.5k/12.5 kV transformers. In addition, most of these transformers are approaching the end of their useful life and will have to be replaced in the coming years[12].

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.

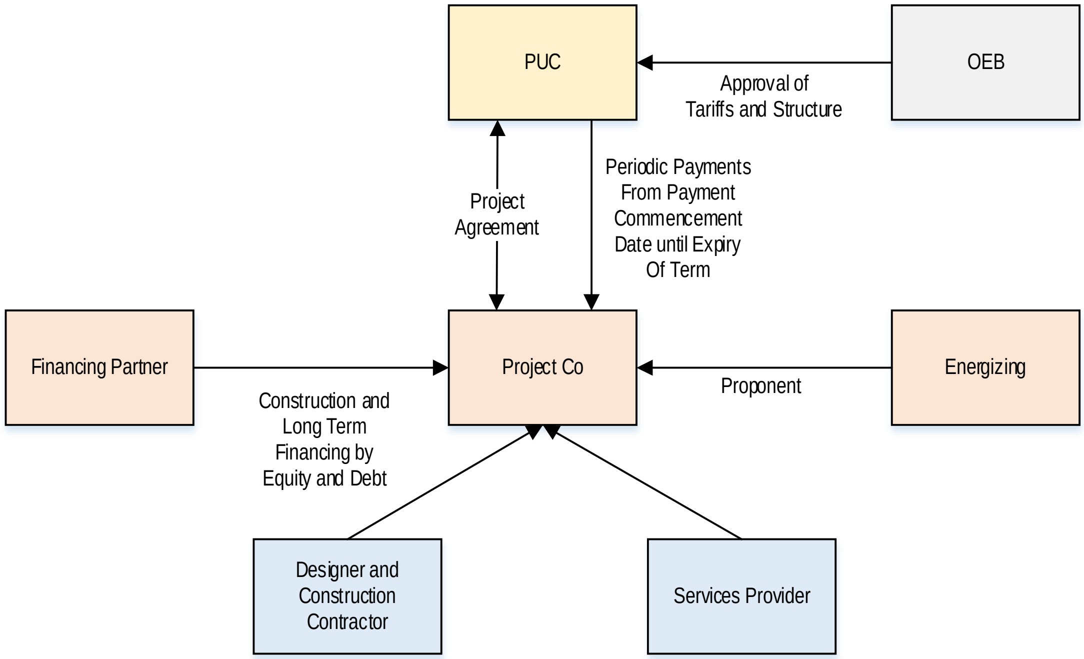
- *Community Outreach & Education*

  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.

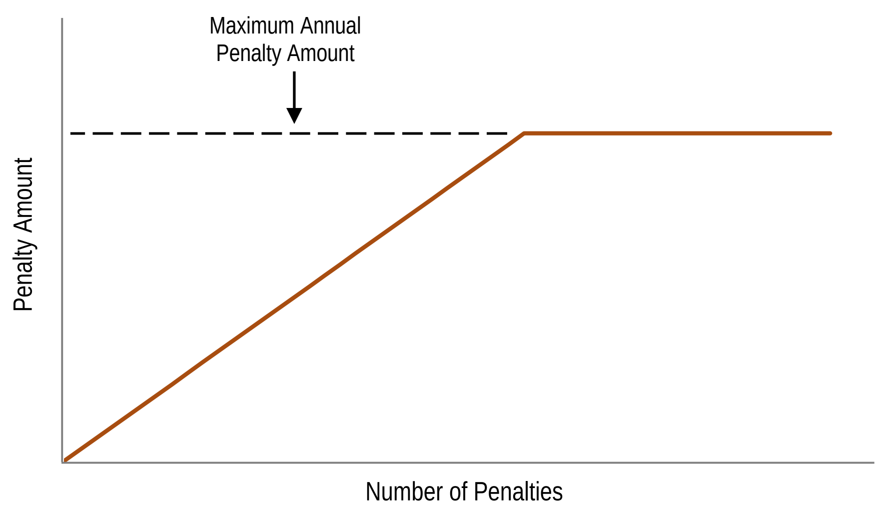
For this review it is assumed that the Service Fee will be treated as an operating cost and the UDM System assets will not be included in PUC's asset based until the end of the contract period. Under these conditions, PUC would not earn a rate of return or claim depreciation expenses for those assets. 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

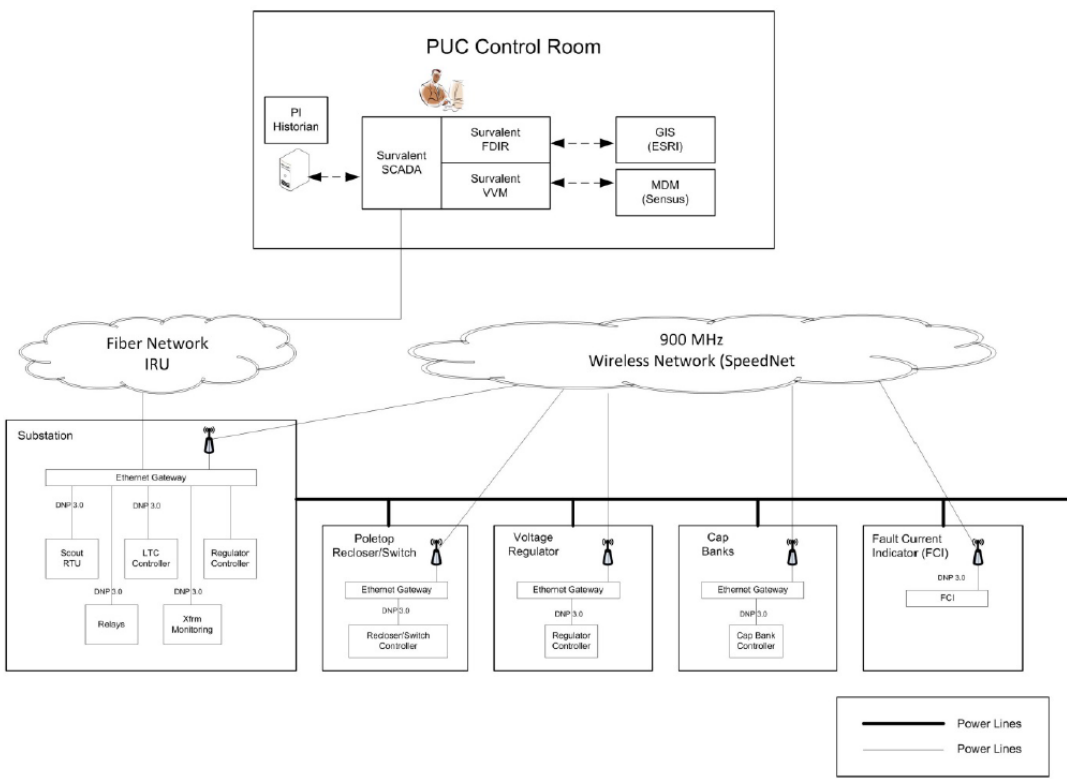
[14] See Appendix A: "Smart Grid Directive from Ontario Minister of Energy".

[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

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[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.

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[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

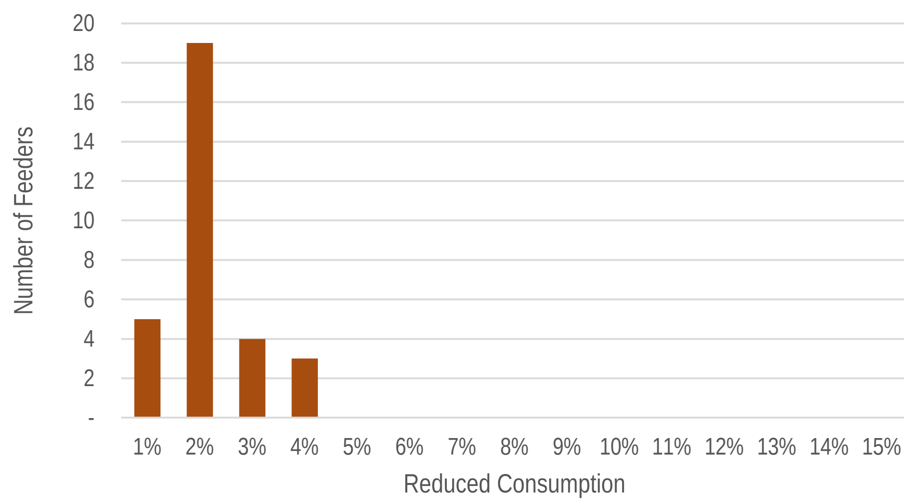
2.6.2.1 Evaluation of Benefits

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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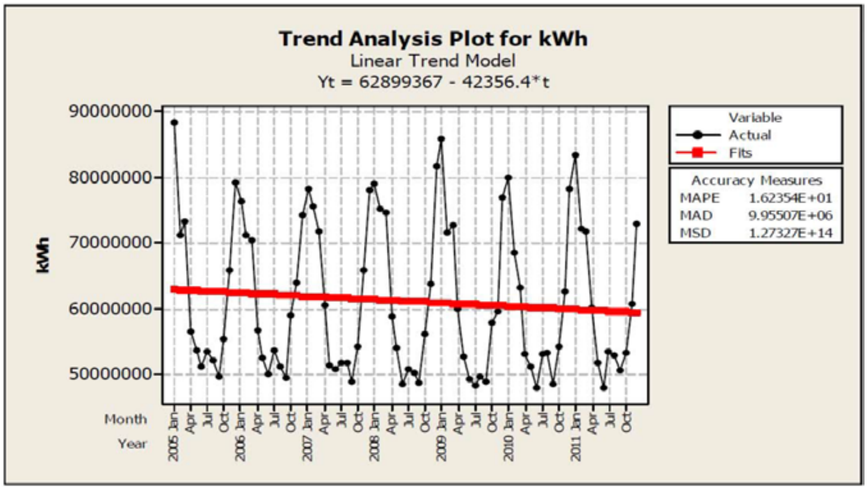
31 Navigant. December 2013. "Smart Grid Regional Business Case for the Pacific Northwest". Available at: https://www.bpa.gov/Projects/Initiatives/SmartGrid/DocumentsSmartGrid/Navigant-BPA-PNW-Smart-Grid-Regional-Business-Case-2013-White-Paper.pdf

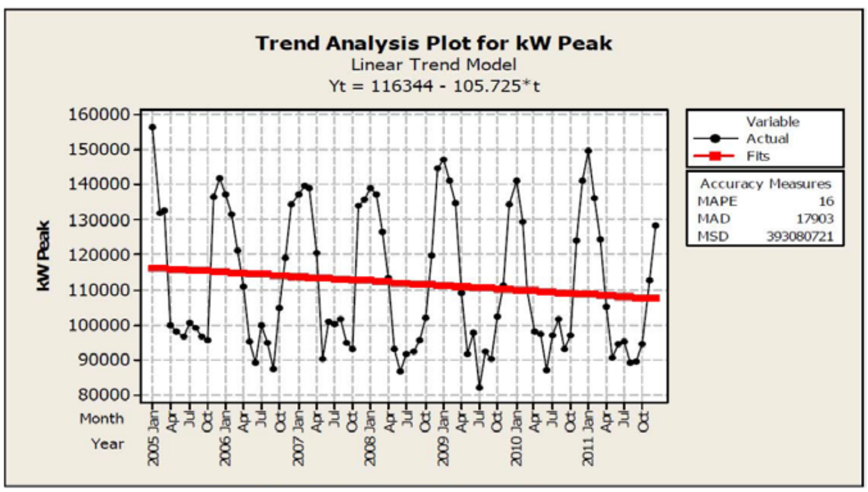
32 EB-2012-0162, Exhibit 2, Tab 3, Schedule 1 (pg. 319). Available at: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/371636/view/PUC%20Distribution_2013_COS_Application_20121106.PDF

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.

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[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.

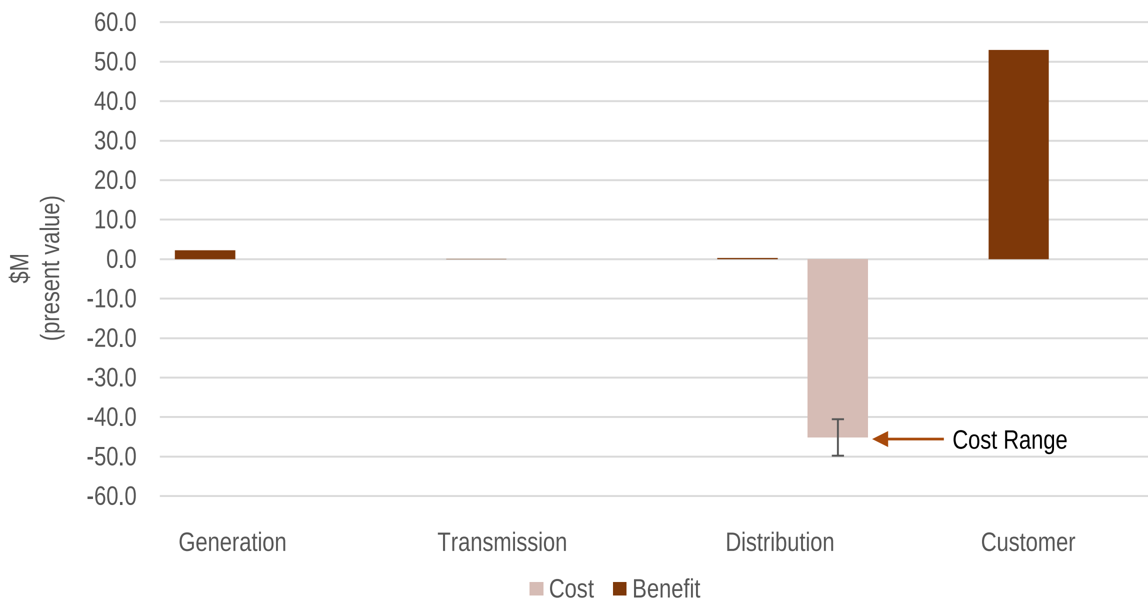
[34] A discount rate of 5% was selected to be consistent with modeling of other smart grid pilot programs modelled for the Ministry of Energy.

[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

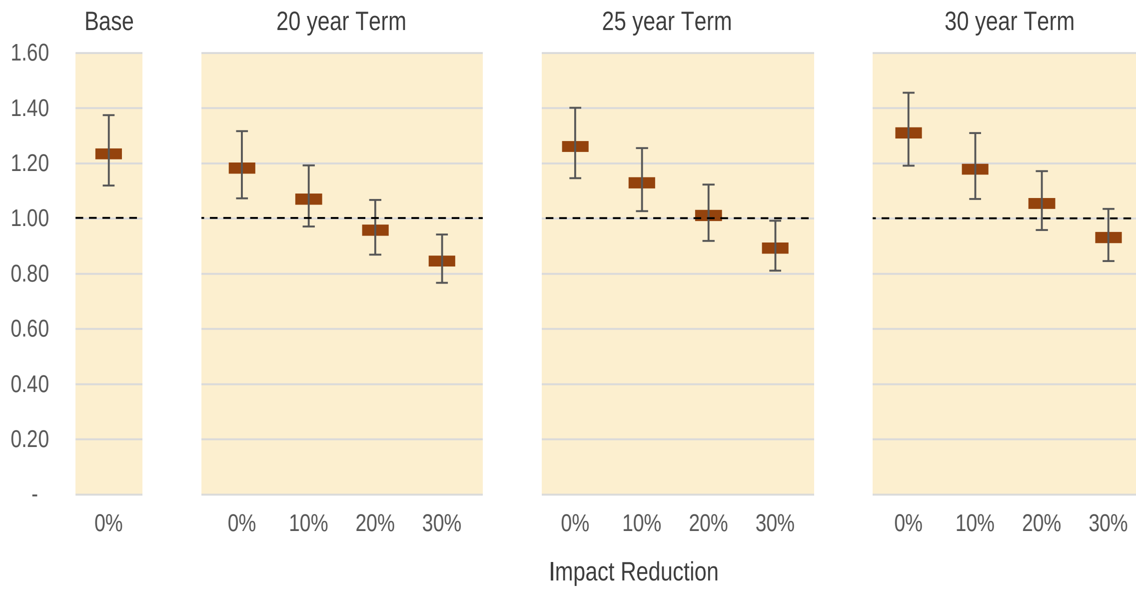
Table 14: Payment Range for Increased Project Term *(CAD $)*

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.

<u>Rate Adders and Rate Riders</u>

"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.

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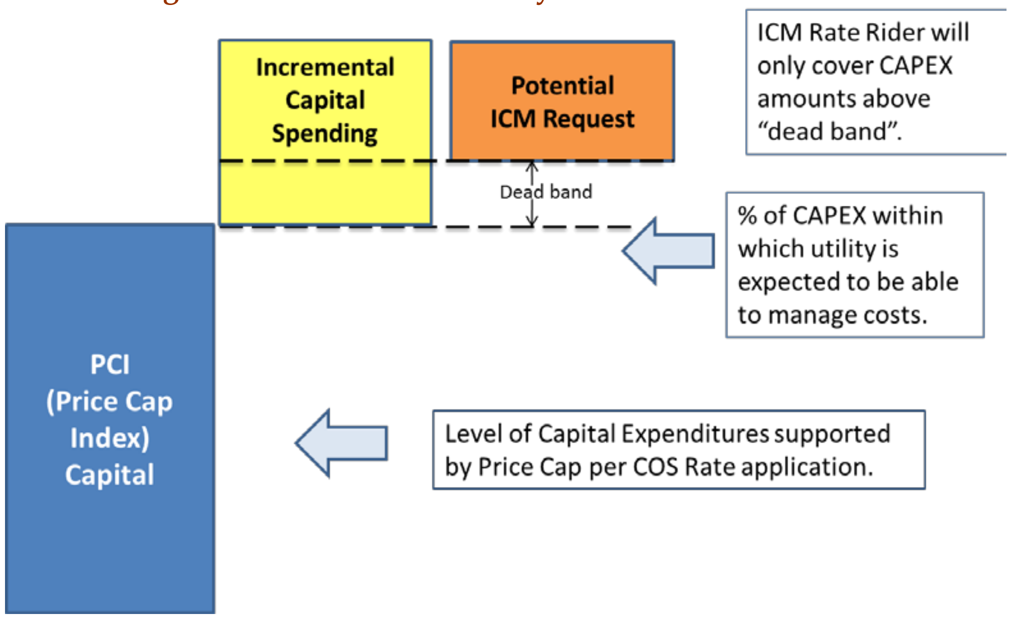
[43] OEB, Chapter 3 of the "*Filing Requirements for Electricity Distribution Rate Applications*", July 17, 2013, Section 3.3.1.5, "*ICM Filing Guidelines*", page 17.

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 E
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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June 23, 2015

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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

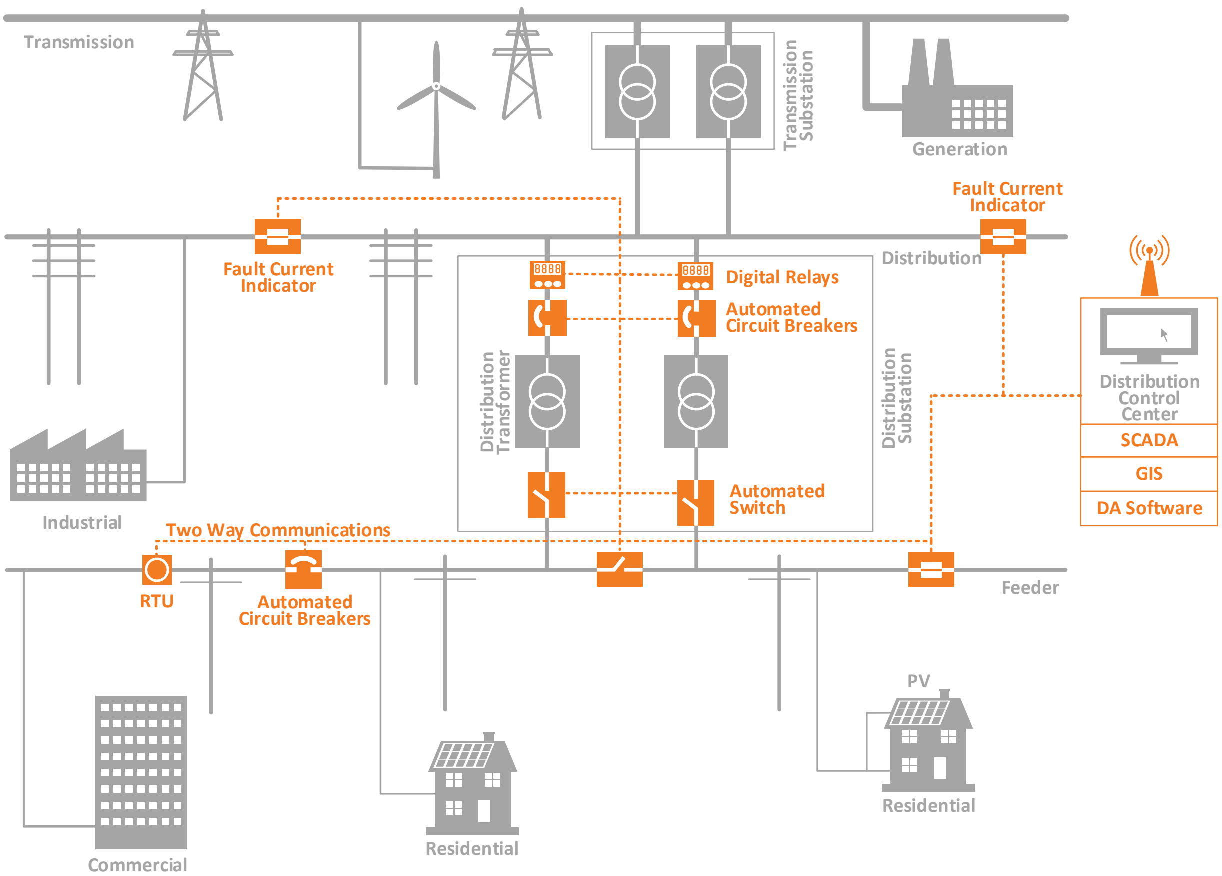
The following sections describe the four key elements of the project, as well as the three-year community engagement process.

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.

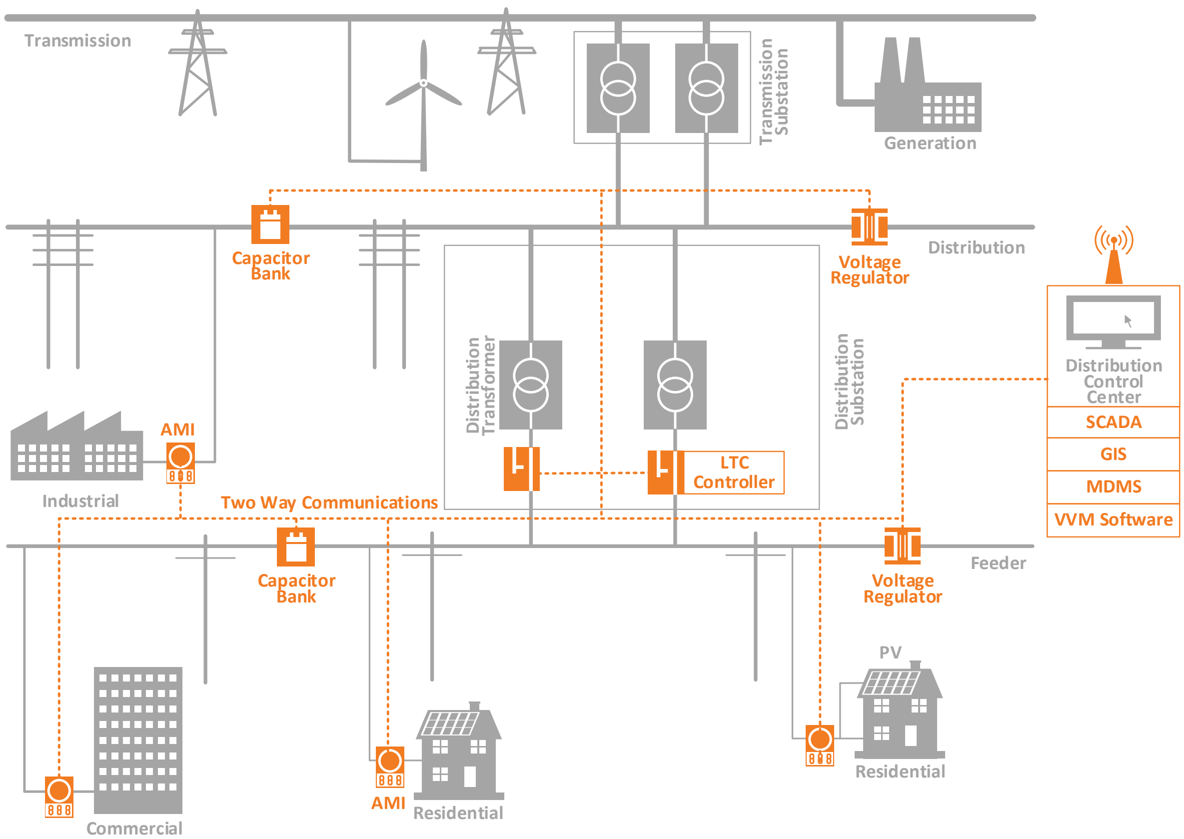
Currently, PUC does not have the capability to dynamically regulate voltage levels at any of the 34.5k/12.5 kV transformers. In addition, most of these transformers are approaching the end of their useful life and will have to be replaced in the coming years[1].

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".

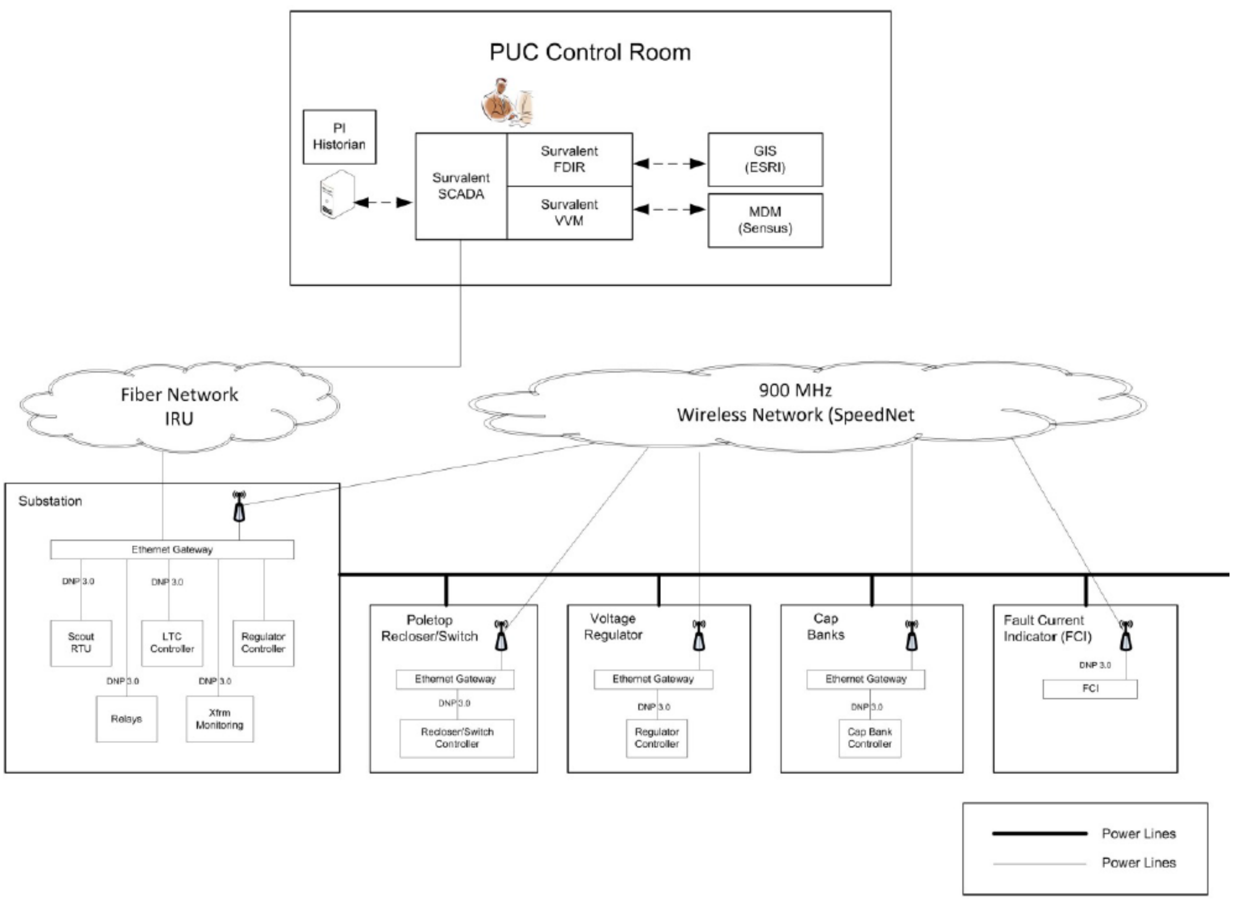
[4] Leidos experts sought explain the data, assumptions and methods it used to design the UDM, estimate costs and benefits, and to address questions Navigant raised on design details and documentation that Leidos prepared for the UDM. In each of these calls, Leidos was fully cooperative and responded 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.

NAVIGANT

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.

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[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 F
Smart Grid Initiatives, History & Timeline

2010/ Nov	- Minsters Directive (Smart Grid)
2010/ onward	- OEB Renewed Regulatory Framework for Electricity Distributors
2011/Mar to 2012/Nov	- OEB Smart Grid Working Group
2013/ Feb	- OEB Supplemental Report on Smart Grid

2013/Q2	- PUC Distribution smart grid strategy
2013/Q3 to 2014/Q1	- PUC Distribution/ Project Partners - *data collection/analysis*
2014/Q1	- Shareholder/ City Council - *resolution supporting concept*
2014/Q4	- Leidos Engineering Work - *Preliminary Design Reports (AMI Integration, VVM, DA, DS Upgrades)* - *Benefit Calculations*
2015/Q1 to Q3	- Business case review/ scope changes/ alternatives - *April 2015 Report - Business Case Review – Navigant* - *June 2015 Report - Review of Project Costs for Smart Grid Project - Navigant* - *PUC conclusion - need to lower costs scale/scope* o *remove DS Upgrades (moved to normal DSP)* o *examine & reduce scope of DA coverage* o *re-visit project costs* - *PUC Distribution trying to find a cost/ benefit solution yet that met corporate objectives of zero net bill*
2015/Q3 to 2016/Q2	- PUC Board of Directors approach City for "Community Interest" - *Study Team in collaboration with Sault Ste. Marie Innovation Centre, Sault Ste. Marie Economic Development Corporation, City of Sault Ste. Marie and PUC Distribution*

	- *April 2016 Report* **-** *Community Microgrid Business Case Review Report w/ Sault Ste. Marie Innovation Centre – Navigant*
2016/Q3	- Public Purpose Microgrid Concept exploration - *PUC Exploring recommendations from SSMIC Report*
2016/Q3-2017/Q1	**- With revised scope of project and assuming positive funding applications a net bill zero project looks feasible.**
2017/Q2	- Federal NRCan Smart Grid Program proposed
	- *Oct ’17 Questionnaire phase* - *Jan ’18 Program launch & Application phase* - *Mar ’18 Application submitted* - *June ’18 Due Diligence phase* - *Sept ’18 Contribution Agreement negotiations phase* - *Dec ’18 Contribution Agreement Executed*
2018/Q4	**-** NRCan Contribution Agreement Signed
2019/Q1	- PUC Distribution ICM Application
Dec. 31, 2019	**- SSG Project – Phase 1 In-service**
Dec. 31, 2020	**- SSG Project – Phase 2 In-service**

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 CO_2 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 H
Project Benefit Estimate

SUBJECT: Sault Smart Grid Project – Business Case
Revised Scope & Benefits Estimate

DATE: Initial Draft - November 2018

Project Scope and Benefit Estimates – Internal Net Benefit Analysis

Project scope and benefit estimate adjustments have been developed from the preliminary engineering work of Leidos Engineering and reflect input from the Navigant Review of Project Costs report (June 2015) as well as input from PUC project, engineering and operations staff. The starting project preliminary engineering design work utilized historical energy consumption from customer classes and system that with successful CDM and conservation programs over the past few years are now much lower in total system energy use. All energy consumption estimates have been updated to use most recent 2018 Cost of Service (COS) load forecast information. (reference to most recent PUC Distribution Cost of Service application if required.)

The main adjustment applied to the project energy savings estimates 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 2018 COS load forecast. The CVR factor was also reviewed and although preliminary work looked at a CVR and savings factors of 0.5 (1.5%) and 0.7 (2.1%), industry reports and Navigant Business Case Review report (April 2015) suggested these may be overly conservative. There is also an estimated 2.6% savings in distribution system losses in the Leidos work that has been included in the savings. Some studies have suggested potential for greater overall energy savings of as much as 4% in some cases. Although PUC does have some high density feeders where PUC customers could realize higher savings, there are also some with lesser density so in the end PUC selected a CVR = 0.9 (2.7% savings) as a reasonable assumption to apply as a system or project average. Reference can also be found in 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 (pg 159).

The VVM scope has been adjusted from ~two thirds to 100% of the12.5 kV system coverage (excludes 4kV circuits) and revised total estimated energy savings is now 16,573,627 kWh. Using 2018 COS Purchased Power estimates the current total savings is over $2.M annually. The recommended VVM design utilizes an AMI feedback for a volt/VAR optimization and energy savings.

The Distribution Automation (DA) scope of work started with the extended business case scope then was scaled to 100% coverage adding another 8 feeders to the Leidos preliminary engineering work. The detailed design phase will now encompass all distribution stations and all 48 12.5 kV feeders. Reliability benefits estimated in Leidos work looking at a complete year of feeder outage data, are identified here.

* SAIFI reduced by 37%
* SAIDI reduced by 46%

* CAIDI reduced by 16%

Reliability savings estimates very pretty widely in industry studies but in the Navigant Community Microgrid Business Case Review report (May 2016) the Leidos values were considered reasonable based on industry data. The community study in addition to PUC Distribution needs looked at broader community benefits and included socio-economic considerations of interest to the City and was not funded by PUC Distribution.

The “energy” component to the project “bill neutral” objective only considered the VVM energy savings benefits and system losses savings. Additional benefits were quantified for deferred capital and operations from implementation of the project that 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 reliability improvements initially developed were reviewed and adjusted to the current project scope. The estimated 25 year net-present value (“**NPV**”) of the customer reliability benefit is over $40M. 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 Distribution applied approximation adjustments due to subsequent project scope changes to add additional station feeders to the Distribution Automation scope with a now all 48 12.5 kV feeders included and applied a 10% value increase to a ~$2.55M annual savings estimate. The current project cost/benefit is being looked at over the 25 year financing period and an estimated 25 year NPV of the customer reliability benefit is over $40M.

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 5 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 an NPV of $0.8M over 25 years or about $30k annually. As the capital deferment value was much longer term in forecast and also had more uncertainty initial NPV values of as high as $10+M, PUC elected to discount this value and utilized a $3.7M 25 year NPV or ~$340k annual in current project cost/benefit considerations.

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 for DA and VVM systems. With this new platform 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 access for distributed energy resources and network optimization efforts. In negotiations on project scope and costs with the developer and EPC contractor these benefits were more fully realized.

Referenced Reports:

- Utility Distribution Microgrid: Volt/VAR Management – Preliminary Design
  - Leidos Engineering – October 17, 2014
- Utility Distribution Microgrid: Distribution Automation – Preliminary Design
  - Leidos Engineering – November 20, 2014
- Utility Distribution Microgrid: AMI Integration – Preliminary Design
  - Leidos Engineering – November 20, 2014
- Review of Business Case for Smart Grid Project for PUC Distribution
  - Navigant Consulting – April 15, 2015
- Review of Project Costs for Smart Grid Project for PUC Distribution
  - Navigant Consulting – June 23, 2015
- Ontario Smart Grid Assessment and Roadmap for Ontario Ministry of Energy
  - Navigant Consulting – January 2015
- Considerations for Deploying In-Front-of-the-Meter Conservation Technologies in Ontario for Ontario Ministry of Energy
  - Navigant Consulting – July 2017

Notes on Scope Changes:

- Sub 16 scheduled for rebuild in 2019/2020 (in DSP)
- LTC may be considered if economic based on specific locations but generally assumed bus/feeder voltage regulators
- All 12.5kV Feeders to be part of VVM system (excludes 4kV except in design for post voltage conversion program)
- VVM estimate scaled to 12 DS's (from 8) and all feeders (48 from 32)
- Sub1 is an all underground area so pad mounted VReg equipment assumed
- Sub 2,10,11,12,13,15,18,19,20,21 evaluated for OH/UG all options in detailed design for best site fit
- DA system applications expanded to all 12.5 kV feeders

Tables later in this memo illustrate steps and assumptions for the estimated total energy project savings. This included adjustment of the total load forecast energy to exclude 35 kV connected customers (~16% of total energy purchases in the >50kW customer class) that will not be included in the VVM system although they will be included in DA reliability system improvements along with other estimated project benefits and the applied CVR factor of 0.9 (2.7%) energy savings.

After all project benefits and costs are collected including estimated future non-energy benefits as well as forecast operating cost increases the overall project achieves our “ no net bill increase” objective with an annual positive net benefit of about $205k.

Cost of Power	$72,877,427
Saving	2.70%
Projected customer savings	$1,967,691
System Loss Reduction	$93,378
	$2,061,069
Additional Revenue request	$1,877,976
Capex benefit	($342,708)
Operating Efficiency benefit	($30,816)
Add'l O&M	$351,000
	$1,855,452
Net benefit (increase) to customers	$205,617
Annual reliability benefit	$2,550,000
	$2,755,617

Table 1: Reduce total system purchase power by large customer loads connected to 34.5kV sub-transmission network that will not have VVM energy savings (will still see DA benefits)

[Historical 34.5kV connected customers (8 accounts) - consumption ~16.2% of GS>50kW]

Bill Impact Analysis							
					Loss Factor		
2018 CoS Rate Application					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 for 34.5kV (no VVM kwh)	LV Feeder Energy Consumption Base for VVM
Res	$ 11,226,807	29,816	288,323,799		302,192,174		302,192,174
GS<50	$ 3,149,458	3431	92,411,463		96,856,454		96,856,454
GS>50	$ 4,544,464	357	244,620,598	614,743	256,386,849	(41,597,434)	214,789,415
Sent lights	$ 34,742	354	209,800	593	219,891		
Street lights	$ 195,345	8070	2,398,221	7,030	2,513,575		
USL	$ 39,551	22	944,731		990,173		
	$ 19,190,367		628,908,612		659,159,116		613,838,043
						-16.2%	

[apply % reduction to purchased power]

	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Cost of Power (COP*)	$77,725,426	$35,945,091	$11,467,389	$29,880,767	$288,889	$25,865	$117,425
(*) gross w/loss factor		46.25%	14.75%	38.44%	0.37%	0.03%	0.15%
Reduce GS>50kW for 34.5kV (no VVM)				($4,847,999.19)			

Table 2: Estimated customer VVM energy savings on system with a CVR factor of 0.9.

[2.7% of 613,838,043 kWh]

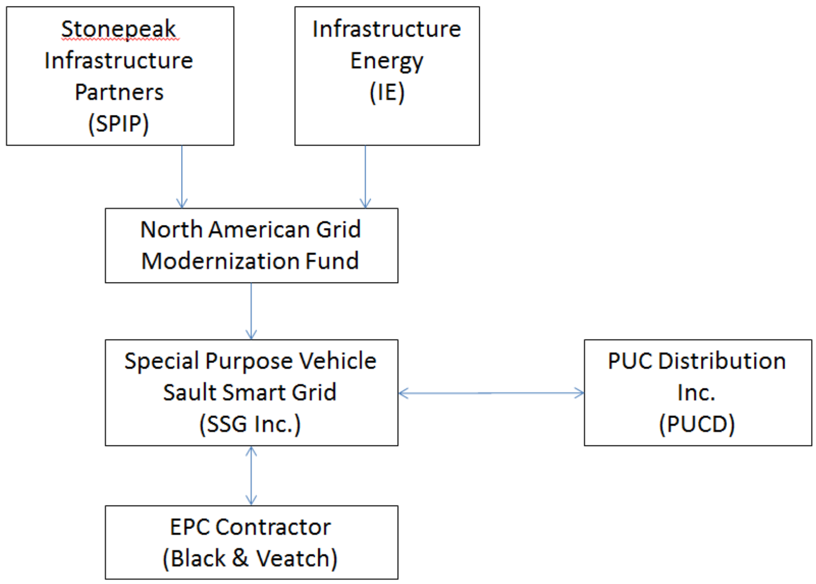
CVR factor	0.9	
Voltage Savings	3.0	volts
Energy Savings	2.7	%
	Estim Energy Savings (kWh)	Estim Energy Savings per Month (kWh)
	16,573,627	1,381,136

Table 3: Energy Savings $'s Estimate (VVM and system losses)

[2.7% of $72,877,427]

Cost of Power Analysis		**Total**
Cost of Power (COP*)		$77,725,426
Reduce GS>50kW for 34.5kV (no VVM)		($4,847,999)
COP to VVM cust's		$72,877,427
Estim VVM Energy Savings /Yr		**$1,967,691**
per month		$163,974
per kWh	$	0.1187
2.6% Reduced System Losses		$93,378
Losses per month		$7,782
TOTAL Savings per Mth		$171,756
Total Annual Savings	**$**	**2,061,069**

Appendix I
SSG Project Organizational Chart



Appendix J
Project Specification and Scope Documents

1. Design and Construction Specifications document

2. Physical Scoping Diagram

3. Logical Scoping Diagram

4. Responsibilities Matrix

DESIGN AND CONSTRUCTION SPECIFICATIONS *

❖ *Scope will be finalized by Black & Veatch during the formal engineering phase to reflect a not-to-exceed agreement price.*

SAULT STE. MARIE PUC DESIGN-BUILD (DB) PROJECT

Project Overview

The Design-Build (DB) Project for Sault Ste. Marie PUC (the PUC) is a project to modernize its distribution energy infrastructure based upon the Leidos statement of work[1]. The project deploys a strong foundation of state of the art technology to support the goals of enhancing reliability, improving outage management, and reducing energy consumption. The foundation is a new Advanced Distribution Management System (ADMS) and advanced Outage Management System (OMS), which will enhance reliability by implementing two Distribution Automation (DA) applications to improve outage management and reliability: Fault Detection Isolation Restoration (FDIR) and an auto-transfer scheme. A third DA application will be implemented to optimize the distribution grid and reduce energy consumption: Volt/VAr Optimization (VVO)[2].

The DB Project will design, procure, install, test, commission, and providing training on the following set of technologies and applications collectively called the Utility Distribution Microgrid (UDM):

- ADMS software that includes integrated FDIR, VVO, and auto-transfer applications.
- OMS software that is tightly-integrated with the new ADMS to provide outage management functions.
- SCADA-enabled line distribution equipment such as reclosers, switches, and faulted circuit indicators (FCIs) to support FDIR.
- SCADA-enabled voltage regulators and capacitors to support VVO.
- FCIs that will support an auto-transfer scheme on the 34.5 kV system.
- Field area networks to collect the data and provide control in support of the three DA applications, which will be integrated into existing PUC communication networks.
- Integration with the PUC's existing Customer Information System (CIS), Advanced Metering Infrastructure (AMI), and CYME distribution model[3].

The UDM provides state of the art technology that is standards-based and open, which positions the PUC to deploy and/or accommodate new distributed energy resources (DERs) such as photovoltaics, energy storage (batteries), cogeneration, and electric vehicles (EVs) and support smart city and other community growth initiatives.

This Design and Construction Specifications document specifies the equipment description (hardware and software) in a bill of material (BOM) with quantities; all required system integrations; defines the feeders included in the project; and assumptions. This document includes the following to further define the project and project tasks:

- Physical Scoping Diagram (refer to Appendix H-2)
- Logical Scoping Diagram (refer to Appendix H-3)
- Responsibilities Matrix (refer to Appendix H-4)

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[1] The "Leidos statement of work" is used to describe a previous baseline of work established in the "Statement of Work for Phase III – Implementation of a Utility Distribution Microgrid in Sault Ste. Marie, ON" in file "PUC UDM Statement of Work FINAL to E Co. 12142015 r1.pdf".

[2] In earlier versions the application was called Volt/VAr Management or VVM.

[3] Integration with the PUC's existing Geographic Information System (GIS) was originally planned, but based upon discussions with PUC staff and Survalent, the approach was changed so that GIS integration is no longer required.

❖ *Scope will be finalized by Black & Veatch during the formal engineering phase to reflect a not-to-exceed agreement price.*

Project Domains

Black & Veatch will manage the design and construction via the following phases established in this document:

- Project Management
- Engineering
- Procurement

1. There are no specific assumptions for this task. Refer to General Assumptions.

- Construction/Implementation

Each phase contains tasks, deliverables, and task-specific assumptions to address the design, procurement, installation, testing, commissioning, and training related.

Testing Plans

The DB Project will develop testing plans in the engineering domain that will be implemented across other domains as part of the overall Commissioning Plan for the DB Project. Figure 1 visualizes the Commissioning Plan concept. The DB Project will be broken down into “manageable pieces” in task CN1.2 Create Turnover Packages with different testing plans for each that will build upon each other as described in this section. This approach limits the level of troubleshooting required should errors occur during testing phases. Testing plans will be developed for each type of field device (refer to Table 7) and field communications equipment (refer to Table 8). Testing plans will also be developed for all integrations and software.

Each testing plan includes the following:

1. A revision block to track the revisions to the plan, submissions, and approvals.
2. Introduction. This contains the summary of the testing plan and includes the following:
    a. Objectives (goals) of the testing plan.
    b. Test items, a list of what will be tested.
    c. Test descriptions, a high-level description of the tests being performed and justifications for anything that will not be tested.
    d. Resource requirements (people and tools) for the tests being performed
    e. Expected test duration (based upon budget constraints)
    f. Any constraints and limitations of the testing plan.
3. Approach. This contains details of how testing will be performed, including information such as the sources of test data, inputs and outputs, testing techniques and priorities. The approach defines the guidelines for requirements analysis, develop scenarios, derive acceptance criteria, construct and execute test cases.
4. Tests to be performed. This contains all of the test cases with details on how testing will be performed, with a tie to a specific design requirement from this document, the expected results, and the actual results. If a master testing plan, this will include only references to other testing plans and their order of completion and tracking of their completion.
5. Action items (punch list). This section identifies items encountered during testing that require resolution. This section is used to track the action items until all are successfully completed.

Each testing plan will be submitted to the PUC for review per the review cycles shown in Table 1 and be approved prior to first use on the DB Project.

Lab testing plan
The lab testing plan defines what testing plans will be executed at the lab facility. The objective of the lab testing is to confirm the complete functionality of the delivered UDM systems (ADMS and OMS) and their applications (FDIR, VVO, and auto-transfer) being supported by RF communications integrated into existing communications and the installation of new devices (refer to Table 7 and Table 8). The lab testing plan is created in task EA7.2 Create Lab Testing Plan and executed in task ST3.3 Lab Testing.

Field testing plan
The field testing plan defines the two tests to be performed by the commissioning team at the unit level[4] after turnover from the construction team (i.e., construction is complete on the unit) either in the field (commissioning) or in the lab (lab testing)[5]:

1. Functional checkout, whose objective is to verify proper construction and the as-installed working order of the unit such that the unit can support the logical checkout.
2. Logical checkout, whose objective is to verify that the local operation of the unit properly supports the unit's intended purpose in the DB Project.

The functional checkout tests include those recommended by the vendor, such as

1. Comparison of as installed condition with the design drawings and specifications, such as:
    a. Mechanical checks: such as mounting, orientation, location, access, installed condition, alignment, etc.
    b. Electrical and control checks: such as wire / cable size, heater / overload settings, cable routings, and cable terminations; electrical equipment and instrument mounting, orientation, location, access, installed condition, etc.
    c. Electrical equipment, and power / control circuit testing verifications: such as Meggering, HyPot, wire ring out (termination verification), motor rotation check, etc.
    d. Instrumentation / status / control circuit functionality checks: such as calibrations and other generally functional checks for its purpose.
    e. Development of construction completion punch list with follow-through to ensure critical items (such as manufacturer defects) are resolved in time to support the project schedule.
2. Minor system specific cleaning operations (such as relatively small tasks of flushing, blowing, or mechanical cleaning on a component or within a system) and any necessary lubrication of components of the unit.
3. Operability review: Reviewing the as designed/as installed system and ensuring it will function properly for its intended purpose, implementing any process related changes required to correct deficiencies, and/or making provisional preparations for the next phase of tests. This review includes simple power on tests to verify proper operation through simple observation of status indications (e.g., LEDs, lights, status messages on LCD screens).

Next, logic checkout or other similar local functional checks (e.g., relay trip checks) are performed to confirm proper local operation of the unit including logical functions, local alarms, local user interface or display, proper power on test, reboot test, etc. This check includes simple communication test to confirm proper communications (e.g., the controller for the DA equipment is on the communication network or

[4] For the DA equipment, refer to Table 7 for a listing of units (i.e., recloser, switch, etc.); for RF equipment refer to Table 8 for a listing of units (i.e., radio, repeater, etc.).

[5] For lab testing, the unit will not include the whole assembly, but just the controller connected to equipment to simulate the whole assembly.

that the RF equipment is properly communicating with other RF equipment at a basic level prior to a more comprehensive test in the RF end-to-end testing plan).

Note that field testing plans will be successfully completed first on RF equipment because basic communication tests for any controllers will not be successful if the RF equipment is not first functioning properly.

RF end-to-end testing plan

The RF end-to-end testing plan objective is to confirm the proper functionality of the RF communications without testing the supported IP-based communications.

The RF end-to-end test will start after completion of the field test for the RF equipment and be successfully completed before the communications end-to-end test is started.

This testing will not test the supported TCP/IP communications, which is part of the communications end-to-end testing.

Communications end-to-end testing plan

The communications end-to-end testing plan objective is to confirm whether the communications TCP/IP network is functional and that traffic is as designed and the network is performing as expected (e.g., bandwidth utilization).

This testing plan will address how to test the actual network monitoring bandwidth against expected network monitoring bandwidth calculated for the location as initially estimated in task EF2.2 Field Area Network Conceptual Design.

This testing will not start until the successful completion of the RF end-to-end test. This testing will be successfully completed before the SCADA end-to-end testing is started for the DA equipment location.

SCADA end-to-end testing plan

The SCADA end-to-end testing plan objective is to verify that the SCADA master communicates with the controller for the DA equipment (refer to Table 7) performs as designed. The tests will perform a typical SCADA point check to perform control and monitoring of the DA equipment. This test will include trip/close simulation to the test switches (as applicable and available) and simulation of monitored points (as applicable and available).

This testing plan will address how to test the actual SCADA bandwidth against expected SCADA bandwidth calculated for the location as initially estimated in task EF2.2 Field Area Network Conceptual Design.

Application testing plan

The application testing plan objective is to confirm proper operation of the following applications: FDIR, VVO and auto-transfer.

Application testing will only occur in the lab by staging a minimum set of DA equipment and RF equipment from available stock as follows:

1. FDIR: three typical feeder configurations (e.g., feeder tie to same substation with two zones, feeder tie to different substation with two zones, feeder ties to different substation with multiple zones).

2. VVO: typical feeder with voltage regulator. One of the three typical FDIR feeder configurations is expected to also include a voltage regulator.
3. Auto-transfer: a minimum of one FCI for the scheme with the remainder FCI simulated (as required).

Application testing will start as follows:

1. FDIR: after the successful completion of the SCADA end-to-end testing for each of the typical feeder configurations and ADMS software testing.
2. VVO: after the successful completion of the SCADA end-to-end testing for a single feeder with voltage regulator and successful completion of the software testing for the CYME and AMI integrations and ADMS software testing.
3. Auto-transfer: after the successful completion of the SCADA end-to-end testing for at least a single 34.5 kV FCI and all simulated FCI and ADMS software testing.

Software testing plan

The software testing plan objective is to confirm proper operation of the following:

1. The design of the following integrations: IVR, CIS, AMI, and CYME. These will be tested to confirm the data transfer between applications occurs as designed.
2. ADMS functionality outside of that which was confirmed during SCADA end-to-end testing.
3. OMS functionality is as designed outside of the integrations.

The CYME integration test will be used to perform the final import of CYME data into the test system. No additional updates to the CYME data are expected with this final import.

Software testing will be first performed in the lab and then repeated on the development system prior to cut-over to production.

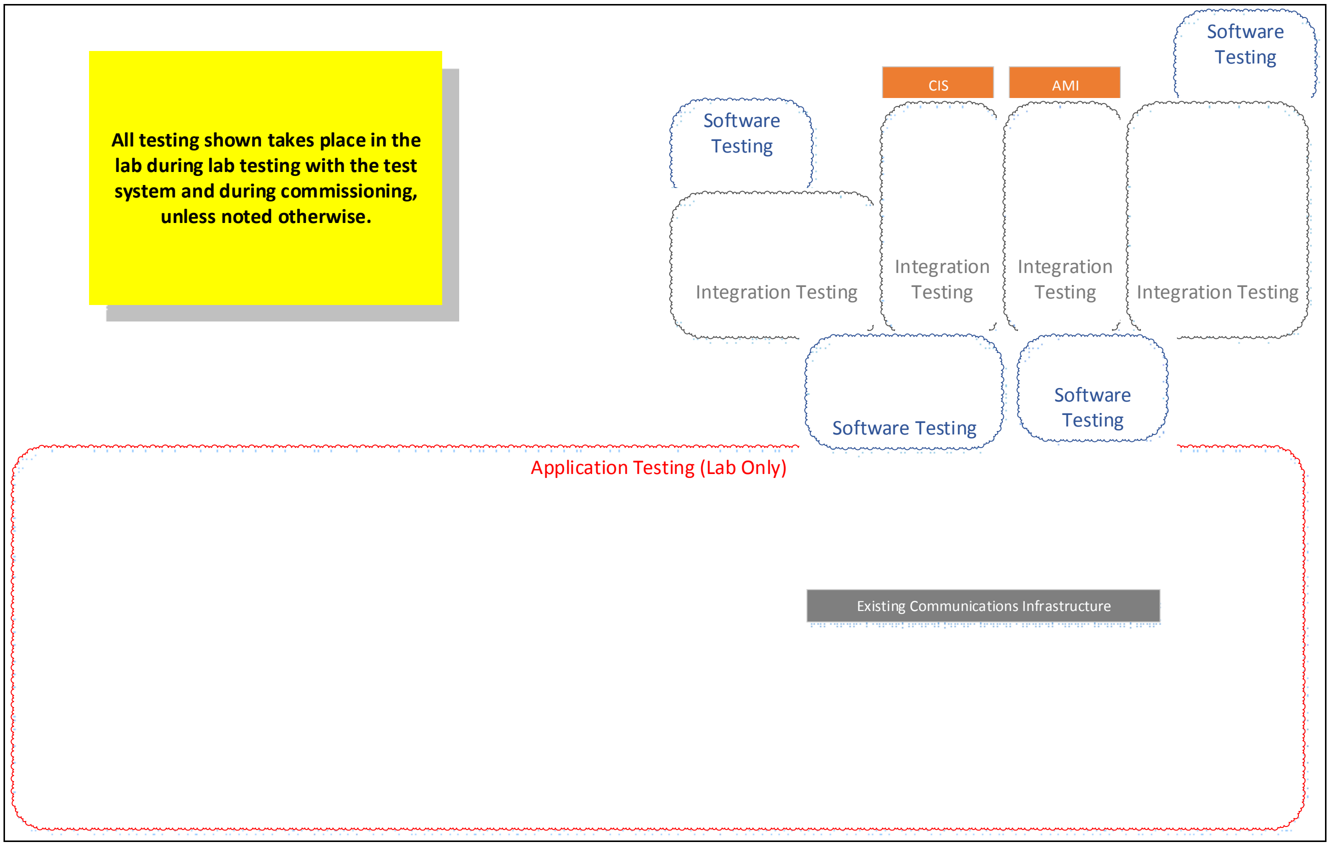

Figure 1 – High Level Testing Concept for Lab Testing and Commissioning

A more detailed relationship between the testing plans is shown in Figure 2. Note that in Figure 2 the following:

1. There are blocks of time that can be inferred, but these do not represent any defined period and are not meant to imply any level of effort.
2. Tasks are not linked for simplification purposes, but order is represented from left to right (any predecessor tasks are shown to the left of any given task). This is meant to provide some sense of order, but it is entirely possible that some tasks could occur in parallel if resources permit (for example, the field tests for reclosers and switches).
3. The testing is organized for the feeders and substations involved (refer to the total row in Table 6 for the number of feeders involved and substations involved). After the application tests are completed, the additional testing up to the SCADA end-to-end testing will be carried out on a first set of feeders that are assumed to completely support VVO and FDIR applications; the second set support only VVO; and the final set is for testing the FCI that support the auto-transfer scheme.
4. Not all feeders will have all field equipment and the actual testing plans will be adjusted.

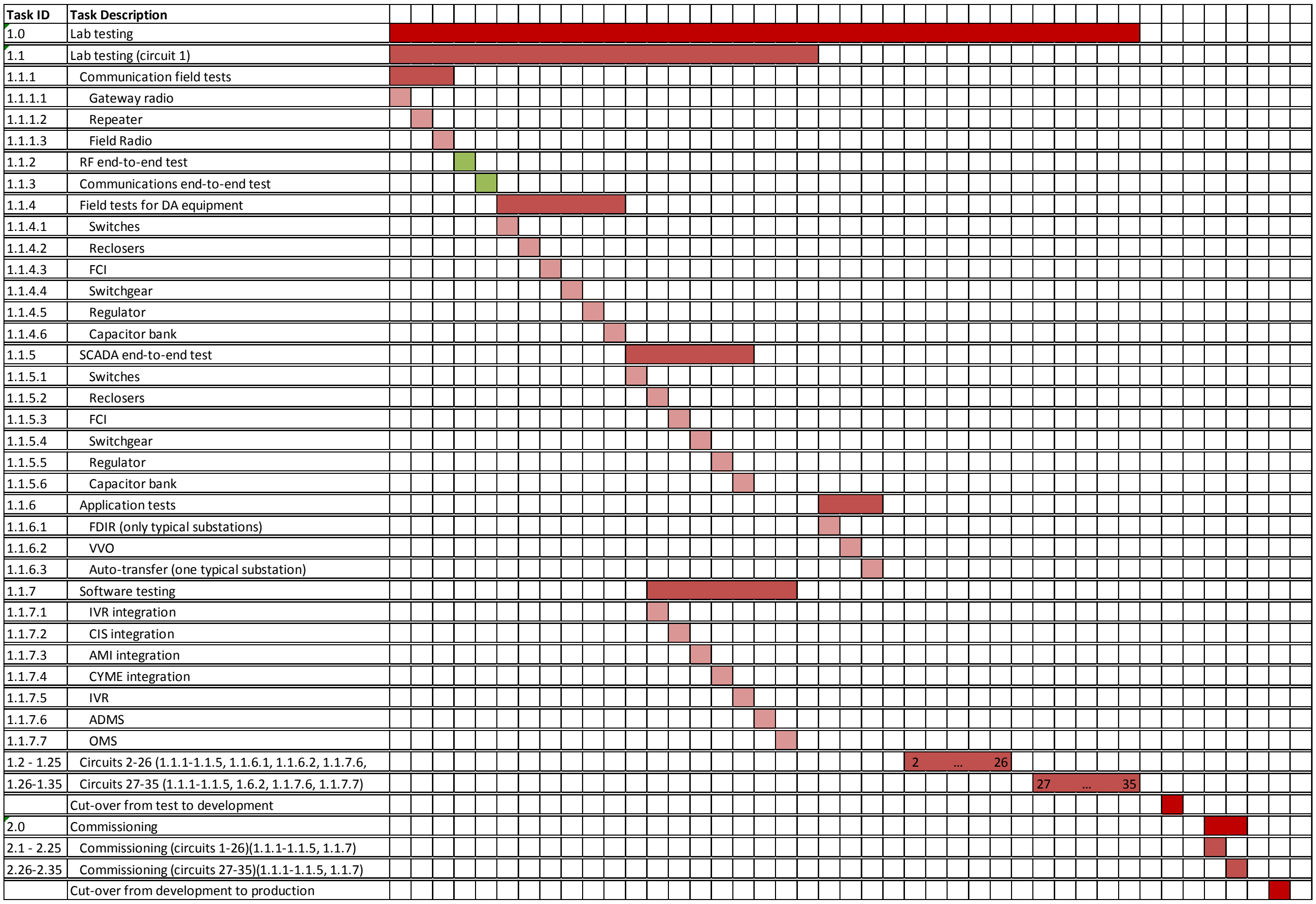

Figure 2: Example Commissioning Plan

Reviews

All project tasks include a list or table of deliverables that categorizes the deliverable as requiring a 30%, 60%, and 90% review, where the review cycles are shown in Table 1.

In general, during the review process the comments from a previous submittal will be incorporated into the next submittal. For example:

- 30% design review comments will be incorporated into 60% deliverables; 60% design review comments will be incorporated into 90% deliverables; and 90% design review comments incorporated into the IFC.
- Some deliverable material may only have one design review and could be provided in additional design review packages for reference.
- Where the PUC is responsible for the deliverable as indicated in the responsibility matrix, the deliverable will be provided to Black & Veatch and follow the same deliverable schedule as shown in Table 1.

The following are examples of as-builts (as appropriate to the deliverable description):

❖ *Scope will be finalized by Black & Veatch during the formal engineering phase to reflect a not-to-exceed agreement price.*

- Completed testing plans with all punch list items completed
- Final files (such as configurations)
- System backups
- Marked up field prints
- Training logs

General Assumptions

5. The following general assumptions apply to all tasks in the Project Management, Engineering, Procurement, and There are no specific assumptions for this task. Refer to General Assumptions.

Construction/Implementation domains:

1. Four week notice will be provided of any change in the scheduled dates for any project team members to be on site.
2. Upon contract award, the PUC will lock down, to the current versions for the duration of the DB Project, all IT systems as described in this Design and Construction Specifications. System lockdown will end when the PUC has completed operational transition and is operating and maintaining its systems (refer to turnover in task CN1.4 Construction Activities and Management). Specifically, these systems include the CIS system, AMI system, SCADA, and CYME. Any changes to existing systems that occur after contract award are not included. Annual maintenance of all hardware and software after the end of system lockdown will be performed in a timely manner and is the PUC's responsibility.
3. Any impact of Black & Veatch's standard terms and conditions on the scope, schedule, and price of our subcontractors is not included.
4. This Design and Construction Specifications document includes the PUC's required 35% reduction in cost. The corresponding reduction in benefits has not been calculated and is not included. Any changes occurring during the project that impact project scope, schedule, and budget will be evaluated as part of the change management process (refer to task PM4 Change Management).
5. The PUC requires limited business process and organizational change management support as described in this Design and Construction Specifications document.
6. All reports will be provided using Microsoft Word 2010.
7. All testing plans will be provided using Microsoft Excel 2010.
8. All data flow diagrams will be provided using Microsoft Visio 2010.
9. All engineering design drawings and work order drawings will be provided using AutoCAD.
10. The PUC's required design reviews will be:
    a. 30% design review.
    b. 60% design review.
    c. 90% design review.
11. Deliverables will be posted with version control on a project portal accessible by all project team members.
12. The Design and Construction Specifications document includes four, one week long, on-site meetings with the project manager and discipline leads from OMS, protection and control, field communications, and DA/ADMS, and VVO for:
    a. Project kickoff meeting.
    b. 30% design review meeting.
    c. 60% design review meeting.
    d. 90% design review meeting.
13. The PUC will provide reasonable access to the PUC's managerial, business, field, operations, IT resources, stakeholder, administrative, and technical resources to support the project and its reliance

and connectivity on the PUC's existing systems as described in this Design and Construction Specifications document (e.g., IT/networks, SCADA, operations, construction, communications, etc.). The PUC staff will support in a timely manner at least the following: all requests for information, data, and files; phone discussions; meetings; deliverable reviews; and conference calls so that the project schedule and budget may be maintained.

14. This Design and Construction Specifications document does not include any services beyond the project's completion.
15. The PUC will provide appropriate training and badging to members of the team when they are working on-site for an extended time for the purpose of easy access to PUC facilities without the need for daily temporary badging and/or escorts.
16. The PUC will provide the following while team members are on site executing tasks associated with this Design and Construction Specifications document, including: adequate working space, including conference rooms, internet access, resources (including data, software, utility tools and software, and associated maintenance, if specified and approved by PUC), parking facilities, telephone equipment and services, facsimile machines, utilities and office-related equipment, and supplies reasonably required.
17. Substations and control centers have existing and adequate cybersecurity[6] as well as routing and switching hardware that can be easily adapted by the PUC to support the application of the PUC's cybersecurity requirements to this project.
18. The cybersecurity features implemented by the IEDs and software procured by the project meet the PUC's requirements.
19. The PUC has adequate communication network monitoring capabilities that will be configured by the PUC to monitor the new communications equipment using SNMPv3.
20. Black & Veatch will estimate the bandwidth requirements to support the UDM at the substations listed in Table 6. The PUC will determine whether the backhaul is adequate to support the additional traffic.
21. The PUC will configure and test the PUC's communication connectivity connecting to the field area network prior as identified in the project schedule.
22. The PUC will provide copies of policies and procedures related to the Design and Construction Specifications document and notice of any modifications and amendments in a timely manner so as not to adversely impact project scope, schedule, or budget.
23. Not used.
24. Black & Veatch's baseline scope is described by this Design and Construction Specifications document and associated scoping diagrams, which does not include an Enterprise Integration Platform (EIP) that is supported by an Enterprise Service Bus (ESB). Task EA1.1 Data Integration Evaluation includes a review of the baseline integrations to evaluate integrated bus options such as Enterprise Service Bus (ESB) using an EIP.
25. Not used.
26. Workshops will be conducted on-site and will be attended by appropriate project team subject matter experts, including Survalent and Sensus AMI experts as identified.
27. Not used.
28. Final acceptance will be initiated by Black & Veatch after confirming receipt of PUC approval for all indicated deliverables and all testing results (including resolution of all punch list items) as well as completion of all training activities.

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[6] The term "cybersecurity" used in this document refers to both "cyber security" (the security of the communications equipment, regardless of IP-based or serial-based) and "physical security" (the physical protection of the facilities protecting electrical and communication assets).

29. As-builts for markups of issued for construction (IFC) drawings for construction work completed in the field will be updated in the GIS by the PUC.
30. All proposed Survalent software will run on virtualized servers provided and configured by the PUC to meet Survalent's minimum hardware requirements of a 1 terabyte (TB) hard drive, 16 gigabyte (GB) of random access memory (RAM) and operating system requirement of Microsoft Windows Server 2012R2 Standard Edition. Because the servers are now virtual, Black & Veatch will not provide any physical drawings.
31. Table 1 shows the review and comment timeline in business days for many deliverables and will be met by Black & Veatch and the PUC in order to maintain project schedule.
32. Not used.
33. PUC data may be hosted on USA-based servers will not include Personally Identifiable Information (PII). There are no restrictions on importing this non-PII utility data to the USA. Non-PII data must not be capable, on its own or in combination with other data, of identifying the individual whose information has been removed. There are no known regulations that limit utility-specific, non-PII data and/or information in terms of transfer or storage outside of Canada.
34. Equipment to be installed on up to 100 wooden poles within the public ROW under the jurisdiction of the City of Sault Ste. Marie.
35. Up to 25% of existing poles may require replacement.
36. Black & Veatch does not warrant or guarantee the existing equipment or subsystems, but will add to these systems to create the UDM.
37. Black & Veatch will design, install, test, and commission the integration to existing systems but does not warrant or guarantee the performance of existing systems.

Table 1 - Review and Comment Timeline in Business Days

DELIVERABLE	PUC REVIEW	BLACK & VEATCH UPDATES	FINAL ACCEPTANCE
1. Conceptual (30%) and detailed design (60% and 90%) documents 2. Testing plan templates 3. Training plans and logs 4. Maintenance plans 5. Reports 6. Cut-over plan	10	5	5
7. Completed testing plans (i.e., testing as outlined in the plan is completed and all action items resolved) 8. Materials for neighborhood or community meetings	5	3	3
9. As-builts 10. Turnover package 11. Completed cut-over plan	10	5	5
12. Meeting Minutes (refer to Table 3) 13. Monthly schedules (refer to Table 3) 14. Project plan (refer to Table 3)	3	2	1

❖ *Scope will be finalized by Black & Veatch during the formal engineering phase to reflect a not-to-exceed agreement price.*

DELIVERABLE	PUC REVIEW	BLACK & VEATCH UPDATES	FINAL ACCEPTANCE
15. Commissioning Plan	Per the Project Agreement		

Project Management

This project management domain will provide project management, oversight, and reporting to monitor and manage the project collaboratively with the PUC. This task will track status, scope, and schedule in accordance with the agreed-to objectives for quality, scope, budget, and schedule.

PM1 Project Kickoff Meeting

This task will plan and conduct a project kickoff meeting on-site with the PUC's internal program leadership including other stakeholders as appropriate. All design leads will attend the project kickoff meeting and subsequent workshops related to the project's scope (refer to task PM1.6 Scope and Change Management). Black & Veatch will develop an agenda for the project kickoff meetings and provide follow-up meeting notes including issues, decisions, and action items.

PM1.1 Organizational Structure

This task will introduce the project manager assigned to the project and the project's high-level organizational structure, focusing on senior leadership and establishing the Project Steering Committee members (refer to task PM3 Project Steering Committee Meetings).

PM1.2 Staffing and Resources

This task will review the staffing model covering all aspects of the defined project. This task will also review the PUC's staffing and resources to match them with the tasks outlined in the responsibility matrix and this Design and Construction Specifications document.

PM1.3 Stakeholders

This task will identify all PUC stakeholders and their relationships to the project. The protocol of communication to each from the project team members is addressed in task PM1.7 Communications Plan.

PM1.4 Reporting Methodology

This task will discuss the planned project reporting associated with project controls tasks PM5 Overall Schedule, Phases, and Milestones and PM7 Budget Planning & Forecasting. This task will also cover risk and opportunity matrix (refer to task PM6 Risk Management).

PM1.5 Schedule

This task will review the planned project schedule. Note that continuing schedule management is addressed in task PM5 Overall Schedule, Phases, and Milestones.

PM1.6 Scope and Change Management

This task will review the planned project scope as contained within this Design and Construction Specifications document. This task will also review the planned overall change management process that will be formalized in task PM4 Change Management.

❖ *Scope will be finalized by Black & Veatch during the formal engineering phase to reflect a not-to-exceed agreement price.*

After the scope and change management review is completed, this task will confirm the schedule and attendees for the following workshops held immediately after the project kickoff meeting concludes:

- Data integration approach (refer to task EA1.1.1 Data Integration Workshop)
- Feeder selection (refer to task EA3.1.1 Feeder Evaluation Workshop)
- FCI wireless communication evaluation (refer to task EA3.2.1 FCI Wireless Workshop)
- DA monitoring and awareness (refer to task EP1.1 DA Monitoring and Awareness Workshop)

PM1.7 Communications Plan

This task will review the planned format for communications between project team members and establish the basis of the communications plan deliverable for this task (refer to Table 3).

The communication plan will address items such as:

- Transmittal of large electronic files between project parties
- Standard templates for typical types of communications between project parties
- Email subject line standardization
- Documentation of phone conversations and other exchanges between team members if it has an official or significant status
- Conference and meeting memorandums

The communications plan will also review the planned document management process deliverable for this task (refer to Table 3). The document control process defines how to handle items such as:

- Incoming project hard copy document received by project personnel
- Incoming project electronic copy document or email communication received directly by project personnel
- Outgoing documents created by project personnel requiring review (typically deliverables)

In addition, the document control process defines items such as:

- Document (record) retention
- Classification of records (such as confidential, sensitive, or classified)
- Storage method(s)
- Retention times

PM2 Management Status Meetings

This task will plan and conduct a bi-weekly meeting with the PUC's internal project leadership including other stakeholders and design leads as appropriate. Management status meetings will start after the project kickoff and end before project completion. Black & Veatch will develop an agenda for the meetings and provide follow-up meeting minutes including issue management (refer to Table 3), decisions, action items, and review of the risk register developed from task PM6 Risk Management.

PM3 Project Steering Committee Meetings

This task will plan and conduct a project steering committee on a monthly basis (refer to task PM1.1 Organizational Structure for determining who will attend these meetings). Black & Veatch will utilize documentation from project reporting to support the PUC and collaborate with project leadership as needed to prepare and present project status. Black & Veatch will develop an agenda for the meetings and provide follow-up meeting minutes.

Project design leads along with their corresponding resources and stakeholders at the PUC are not expected to attend this meeting.

Executive status meetings will start after the project kickoff and end before project completion.

PM4 Change Management

Change management focuses on scope and quantity changes identified by any project team member that impact project budget and/or schedule. This task will monitor, report, and manage these changes. At any time during the project, team members will monitor potential deviations to scope (tasks and/or deliverables contained within this Design and Construction Specifications document) for possible impacts to project schedule and budget and report them to the project management team for tracking under this task.

Once a potential change is identified by the project management team, this process will identify and track these changes using an internal change notification form. In the case where the change is initiated by the PUC, the request must be in writing. Upon review of the project manager, a formal change notification will be issued to the PUC and approved by the PUC before the appropriate change in project scope, schedule, and budget are updated in this Design and Construction Specifications document before being executed by the project team.

PM5 Overall Schedule, Phases, and Milestones

This task will create and manage the overall project schedule (not resource loaded), showing progress on project milestones. Developing and maintaining the project schedule is a vital component of executing a successful project. Effectively incorporating the schedule commitments of the internal and external stakeholders across the program is a primary challenge of any utility project.

PM5.1 Overall Project Schedule
This task will create and maintain the overall project schedule at a high level, highlighting key milestones and deliverables in a three-week look ahead.

PM5.2 Engineering Schedule
This task will create and maintain the engineering schedule as defined in this Design and Construction Specifications document.

PM5.3 Procurement Schedule
This task will create and maintain the procurement schedule as defined in this Design and Construction Specifications document. Also refer to task PR1 Purchase Major Materials and Equipment.

PM5.4 Construction Schedule
This task will create and maintain the construction schedule as defined in this Design and Construction Specifications document.
PM5.5 Schedule Consolidation

Based on the engineering and construction schedules, this task will create and maintain a consolidated schedule.

PM5.6 Execution Logistics: Scheduling access, safety escorts, Training
Coordination of logistics with the PUC to provide escorts where required will be key to maintaining schedule efficiency. All required escorts, training, etc. are anticipated to be provided by the PUC. This task will coordinate and manage these requirements on the program with the PUC's stakeholders and the project team.

PM6 Risk Management

Contract terms, weather, accidents, suppliers, subcontractors, socioeconomic issues, technology, scope definition, and estimates all introduce elements of risk. Project risk cannot be eliminated but it can be controlled and mitigated. Through the process of identifying and documenting, risk exposure is controlled on projects. This task will assist the PUC in identifying and addressing strategies to optimally manage and mitigate risks and manage opportunities on the project.

This task will create the risk management process as well as manage the risk and opportunity register, a project deliverable (refer to Table 3) that documents specific risks and opportunities of the project and associated strategies to mitigate risk or to leverage the opportunity.

This task will only address project risks due to external influences. Risks due to internal project factors will be internally addressed by the project manager.

The risk and opportunity register will include several items, such as:

- Identifier (ID), which will uniquely identify the risk or opportunity
- Title, which will be a shortened version of the description
- Description, which will contain a complete description of the risk or opportunity
- Impact, which will indicate the impact to the project in terms of budget, time, quality, etc.
- Probability, which will indicate the probability of occurrence
- Severity, which will indicate whether the risk is critical, high, medium or low
- Rating, which will be a simple product of the probability and severity
- Type, which will indicate the type of risk, such as technical (design), construction, safety, organizational, and procurement
- Plan, which for risks will describe the mitigation plan and for opportunities will describe how the opportunity will be implemented
- Contingency, which will describe whether there is any alternate approach or compensating measure that could be used if the risk is not mitigated or the opportunity not pursued
- Status, which will indicate whether the risk or opportunity is open or closed
- Owner, which will indicate who is responsible for the risk or opportunity

PM7 Budget Planning & Forecasting

This task for project controls will monitor the project budget, updating the project schedule.

PM8 Quality Assurance

This task performs quality assurance (QA) work throughout all project execution activities as applicable to Telecom's Quality Management System (QMS) and supporting QMS documents (Black & Veatch Telecommunications has ISO-9001:2015 certification). This Design and Construction Specifications document has several deliverable tables showing what deliverables are provided to the PUC for review and at what stage (30-60-90).

As part of this task, the Black & Veatch Project Manager designates the lead discipline engineers responsible for documenting that the applicable codes, procedures, guides, and design requirements have been read and applied by project staff under their direction when executing their portion of the project work.

Our internal quality management plan will not be provided in whole to the PUC; however, what our QMS calls a "Project Quality Plan" will be provided as the deliverable from this task shown in Table 3.

PM9 Project Execution Plan (PEP) and Project Plan

This task will create and maintain the PEP, a standard, internal document required by our QMS that will not be directly provided to the PUC. The PEP defines the scope and requirements for the project from start to finish. Portions of the PEP will be provided to the PUC as shown in Table 3 as part of a project plan[7]. This task will also create and maintain the project plan and coordinate it with the PEP.

Table 2 – PEP and Project Plan Cross Reference[8]

STANDARD PEP SECTION	PROJECT PLAN[9]
1. Project Initiation	Project Plan: Governance Model
2. Scope Management	Project Plan: Issue Management and Problem Escalation Process
3. Resource Management	Project Plan: Staffing Plan
4. Quality Management	Project Plan: Quality Management Plan
5. Environmental, Safety, Health & Security (ESH&S) Management	
6. Commercial Management	
7. Project Controls Management	Project Plan: Change Control and Scope Management Process Project Plan: Master Schedule
8. Project Health Evaluation	
9. Engineering Management	Design and Construction Specifications
10. Procurement Management	Design and Construction Specifications

[7] A project plan was originally proposed by Leidos in Table 2 in the Leidos statement of work.

[8] This cross reference shows a simple mapping of major PEP sections where project plan deliverables will be located in the PEP. It is not intended to indicate that the project plan will include the complete section of the PEP.

[9] Also refer to Table 3 for a mapping of project plan deliverables to project tasks.

STANDARD PEP SECTION	PROJECT PLAN[9]
11. Construction Management	Design and Construction Specifications
12. Commissioning Management	Design and Construction Specifications
13. Risk And Opportunity Management	Project Plan: Risk Register and Tracking Process
14. Communication Management	Project Plan: Communications Plan Project Plan: Document Management Process
15. Closeout Management	Design and Construction Specifications
Attachment 16.1 - Prime Contract	
Attachment 16.2 - Project Setup	
Attachment 16.3 - Project Site List	Design and Construction Specifications
Attachment 16.4 - Project Deliverables	Design and Construction Specifications
Attachment 16.5 - Project Level 1 Schedule	Project Plan: Master Schedule
Attachment 16.6 - Bill of Quantities/Basis of Estimate	Design and Construction Specifications
Attachment 16.7 - File Structure	
Attachment 16.8 - Processes	
Attachment 16.9 - Design Tool Use Plan	

Any changes required to the PEP and/or project plan will be implemented via the change management process (refer to task PM4 Change Management).

PM Deliverables

Deliverables provided by task Project Management are listed in 3.

Table 3 – PM Deliverable List

DELIVERABLE DESCRIPTION	TASK	DRAFT / FINAL	SCHEDULED UPDATES	UPDATES AS NEEDED
1. Project Plan: Governance model	PM1.1 Organizational Structure	■		■
2. Project Plan: Master schedule	PM5 Overall Schedule, Phases, and Milestones		■	
3. Project Plan: Quality management plan	PM8 Quality Assurance	■		■
4. Project Plan: Communications plan	PM1.7 Communications Plan	■		■
5. Project Plan: Staffing plan	PM1.2 Staffing and Resources	■		■
6. Project Plan: Issue management and problem escalation process	PM2 Management Status Meetings	■		■
7. Project Plan: Risk register and tracking process	PM6 Risk Management	■		■
8. Project Plan: Document management process	PM1.7 Communications Plan	■		■
9. Project Plan: Change control and scope management process	PM4 Change Management	■		■
10. Design and Construction Specifications document[10]	PM4 Change Management			■
11. Meeting minutes	PM1 Project Kickoff Meeting PM2 Management Status Meetings PM3 Project Steering Committee Meetings	■		

[10] The Leidos statement of work does not indicate whether it includes any updates to the statement of work. By including the Design and Construction Specifications in this table, Black & Veatch simply recognizes that its finalization prior to project kickoff, the Design and Construction Specifications will be occasionally updated as required by change management just like the other deliverables in this table.

PM Reviews

The review schedule for project management deliverables as shown in Table 3 is different than all other provided design-related deliverables (refer to Table 1), without a formal 30-60-90 percent design review process with the following clarifications:

- Submittals with a draft are submitted and finalized per the assumptions stated in PM Assumptions or other notes in this table.
- Submittals with regularly scheduled updates are reviewed and finalized per the assumptions stated in PM Assumptions.
- Deliverables are updated as needed when changes are identified through the change management process. The same review cycles for revisions will be followed as for the original draft.

Refer to the PM Assumptions regarding review cycles.

PM Assumptions

1. The deliverables shown with a draft in Table 3 are submitted for review within 90 calendar days of the completion of the project kickoff meeting. Reviews are then completed on these deliverables as shown in Table 1.
2. Schedule updates will be submitted for review on a monthly basis. Reviews are then completed on these deliverables as shown in Table 1.
3. Updates to deliverables shown in 3 are expected no more frequent than on a quarterly basis.
4. Task PM7 Budget Planning & Forecasting is an internal project control task. There will be no PUC review or acceptance of internal Black & Veatch processes for internal project controls, internal reporting and internal escalation of forecasted variances, such as included in our internal project dashboard.

Engineering

PUC Operational Domain

The PUC operational domain has the following major tasks:

1. System integration in task EA1 System Integration.
2. The implementation of the Survalent OMS in task EA2 OMS.
3. The implementation of the Survalent ADMS in task EA3 ADMS.
4. The upgrade of the Survalent SCADA in task
5. EA4 SCADA **Master**.
6. The implementation of the IVR solution in task EA5 IVR.
7. The development of the cut-over plans in task EA6 Cut-Over Plans.

EA1 System Integration
This task performs the following tasks:

- EA1.1 Data Integration Evaluation
- EA1.2 IVR Integration
- EA1.3 CIS Integration
- EA1.4 CYME Integration
- EA1.5 AMI Integration

This task will be coordinated with the following design activities:

- EA2 OMS
- EA3 ADMS
-
- EA4 SCADA **Master**
- EA5 IVR
- EA6 Cut-Over Plans

EA1.1 Data Integration Evaluation

This task will conduct a data integration workshop and create a report that will provide a recommendation on the data integration approach for the project (whether to maintain the baseline scope or proceed with an EIP and ESB).

EA1.1.1 Data Integration Workshop

This task will plan and conduct a data integration workshop after the project kickoff meeting (refer to task PM1 Project Kickoff Meeting). The data integration workshop will review the proposed architecture (as baseline scope) against an EIP and ESB approach for the production and test systems. The workshop will review how changes to an EIP and ESB will impact the project:

1. Conceptual integration, including conceptual use cases, hardware requirements, software requirements, third party, training, testing, and maintenance requirements.
2. Procurement of hardware and software and engagement of third party (as required)
3. Integration design[11] to address the following:
    a. Initial infrastructure setup – virtual server provisioning and operating system installation
    b. Installation and configuration of the ESB[12]
    c. Design of firewall, network, and external security gateway[13]
    d. Data cleansing and maintenance of existing systems/applications to ensure the data accessed within PUC systems is complete and correct before testing
    e. Monitoring, troubleshooting, and maintaining the production/development/test environments on PUC provided hardware during project implementation
    f. Documenting the ESB
4. Training of PUC staff on operations and maintenance of the ESB platform and integrations so the PUC has the resource(s) to assume operational responsibility for ESB platform
5. Integration testing
    a. Perform User Acceptance Testing on integrations
    b. ESB User Acceptance Sign off
6. ESB operational transition to PUC personnel.

EA1.1.2 Data Integration Report

This task will prepare a report that will document the results of the workshop plus any additional investigations. The report will document the ADMS and OMS system integration design for the production and test systems with the following systems:

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[11] The PUC team may need to assist with vendor engagement during integration design if required by third parties.

[12] It is anticipated that Black & Veatch would need access (both remote and local) to the PUC test, development, and production systems to perform the related installation, configuration, development, testing, and deployment activities.

[13] The PUC may be required to perform the necessary network or security modifications to allow connectivity between integration points.

- CIS (refer to task EA1.3 CIS for the detailed design)
- IVR (refer to task EA1.2 IVR for the detailed design)
- CYME (refer to task EA1.4 CYME Integration)
- AMI (refer to task EA1.5 AMI)

Any changes to project scope, schedule, or budget that result from the approval of any part of this report will be input into the task PM4 Change Management.

The data integration report will include a detailed responsibility matrix to document all resources (e.g., Black & Veatch, Survalent, and the PUC) that will support the integration of systems described in the task EA1.1 Data Integration Evaluation.

EA1.2 IVR Integration

The IVR integration will allow the OMS to receive outage call records from the IVR. The OMS will analyze these call records to predict the locations of the outages. When a predicted outage location is verified, the case information, including estimated time of restoration, is transmitted back to the IVR, which can use this data when handling subsequent customer calls. When the outage is restored, the dispatcher can, via this interface, forward callback requests to the IVR.

EA1.2.1 IVR Integration Design

Once the data integration requirements are formalized in task EA1.1 Data Integration Evaluation, the IVR integration design will begin with a workshop, continue with the creation of a design report, and finish with the detailed design.

EA1.2.1.1 IVR Integration Workshop

This task will plan and conduct an IVR design workshop to:

1. Develop the use cases for the MultiSpeak integration, such as:
    a. The IVR communicates with the OMS to determine a location's current service status.
    b. The IVR sends trouble reports to the OMS so that the OMS can create trouble reports.
    c. The OMS will send callback requests to the IVR to perform outgoing restoration confirmation call backs for callers that requested a callback.
    d. The OMS will send close call requests to the IVR for restored trouble reports for callers that did not request a callback.
    e. The IVR will send StillOff callback results to OMS for callers indicating they are still experiencing service interruptions.
    f. The IVR will send ResolvedCaller requests to update outage call records that have been changed to be associated with a different service location.
2. Develop the MultiSpeak requirements for the IVR system so that the interface provides the required data.
3. Work with Milsoft to establish tasks and milestones that will be added to the schedule for monitoring as part of normal project management activities (refer to task PM5 Overall Schedule, Phases, and Milestones).
4. Establish the documentation, testing, commissioning, maintenance, and training requirements.
5. Identifies any potential organizational and/or process changes for input into task EO1 Business Process and Organizational Change Management.

EA1.2.1.2 IVR Integration Report

Upon completion of task EA1.2.1.1 IVR Integration Workshop, this task will prepare a report that:

1. Documents the IVR-OMS MultiSpeak requirements by answering questions such as:
    a. What are the use cases for the interface?
    b. How do the existing workflows impact interface triggers?
    c. What information is required by the OMS and in what format using what methods?
    d. Are any data transformations required?
    e. What data is missing from the IVR system that the OMS requires?
    f. How should the OMS respond/behave?
    g. What priority is the data transfer?
    h. How are errors handled and reported?
2. Evaluates the Milsoft scope and estimate of work.
3. Provides conceptual testing plans.
4. Provides conceptual training plans.
5. Provides conceptual maintenance plans.
6. Identifies any conceptual organizational and/or process changes for input into task EO1 Business Process and Organizational Change Management.
7. Discusses schedule updates.

Any changes to project scope, schedule, or budget that result from the approval of any part of this report will be input into the task PM4 Change Management.

EA1.2.1.3 IVR Interface Design

This task will perform the detailed design of the ADMS-IVR interface by Survalent and Milsoft based upon the interface report. Delivery of design documentation will be from Survalent and Milsoft.

EA1.2.2 IVR Integration Software Testing Plan

This task will develop the software testing plan (refer to
Software testing plan) for the IVR integration, which will be addressed in Milsoft's factory acceptance testing plan (refer to task EA5.4 IVR Software Testing Plan).

EA1.2.3 IVR Integration Training Plan

This task will develop the MultiSpeak IVR interface training materials from Survalent and Milsoft. Training will be performed in task TR1 Training.

EA1.2.4 IVR Integration Maintenance Plan

This task will develop the IVR interface maintenance plan from Survalent and Milsoft.

EA1.3 CIS Integration

The CIS integration will allow the operator to view customer service information from the OMS production and test systems and will provide the transformer to which each meter is associated. This interface will allow dispatchers to view customer account information (service location, contact info, etc.) through the OMS interface as soon as customers call in, allow the OMS to identify outage areas, and allow the load flow application to calculate circuit loads.

After the completion of the construction portion of the DB Project in task CN1.4 Construction Activities and Management, the PUC will schedule automated CIS imports to ensure customer information data in the OMS is up to date.

EA1.3.1 CIS Integration Design

Once the data integration requirements are formalized in task EA1.1 Data Integration Evaluation, the CIS integration design will begin with a workshop, continue with the creation of a design report, and finish with the detailed design.

EA1.3.1.1 CIS Integration Workshop

This task will plan and conduct a CIS integration workshop to:

1. Develop the use cases for the interface.
2. Develop the CIS flat file requirements for the CIS system so that the file provides the required data.
3. Work with Harris NorthStar to establish tasks and milestones that will be added to the schedule for monitoring as part of normal project management activities (refer to task PM5 Overall Schedule, Phases, and Milestones).
4. Establish the documentation, testing, commissioning, maintenance, and training requirements.
5. Identifies any potential organizational and/or process changes for input into task EO1 Business Process and Organizational Change Management.

EA1.3.1.2 CIS Report

Upon completion of task EA1.3.1.1 CIS Integration Workshop, this task will prepare a CIS integration report that:

1. Documents the CIS-OMS flat file requirements by answering questions such as:
    a. What are the use cases for the interface?
    b. How do the existing workflows impact interface triggers?
    c. What information is required in the flat file and in what format?
    d. Are any data transformations required?
    e. What data is missing from the CIS system that the OMS requires?
    f. How should the OMS respond/behave?
    g. What priority is the file transfer?
    h. How are errors handled and reported?
2. Evaluates the Harris NorthStar scope and estimate of work.
3. Provides conceptual testing plans.
4. Provides conceptual training plans.
5. Provides conceptual maintenance plans.
6. Identifies any conceptual organizational and/or process changes for input into task EO1 Business Process and Organizational Change Management.
7. Discusses schedule updates.

Any changes to project scope, schedule, or budget that result from the approval of any part of this report will be input into the task PM4 Change Management.

EA1.3.1.3 CIS Interface Design

This task will perform the detailed design of the ADMS-CIS interface by Survalent and Harris NorthStar based upon the interface report. Delivery of design documentation will be from Survalent and Harris NorthStar.

EA1.3.3 CIS Integration Software Testing Plan

This task will develop the software testing plan for the CIS integration (refer to
Software testing plan), which relies on the delivery of testing plans from Survalent and Harris NorthStar.

EA1.3.4 CIS Integration Training Plan

This task will develop the MultiSpeak CIS interface training materials from Survalent and Harris NorthStar. Training will be performed in task TR1 Training.

EA1.3.5 CIS Integration Maintenance Plan

This task will develop the CIS interface maintenance plan from Survalent and Harris NorthStar.

EA1.4 CYME Integration

This task will use the CYME model to establish a primary connectivity model in the ADMS and OMS production and test systems. This task also leverages the customer to transformer information from the CIS integration and utilizes an import of the existing SCADA database to associate existing SCADA points to the new connectivity model.

After the substantial completion of the DB Project, the PUC will perform an ongoing process to import CYME model changes into Survalent's electrical network model.

EA1.4.1 CYME Integration Design

Once the data integration requirements are formalized in task EA1.1 Data Integration Evaluation, the CYME integration design will begin with a workshop, continue with the creation of a design report, and finish with the detailed design.

EA1.4.1.1 CYME Integration Workshop

This task will plan and conduct a CYME integration workshop to:

1. Discuss the critical dependency of the proposed FDIR and VVO applications on accurate GIS data and timely CYME updates.
2. Develop the interface requirements between the Survalent system and CYME to support the conversion of geometric map features from the PUC's provided CYME data files into Survalent's electrical network model.
3. Identify any expected impacts on the CYME that also impact scope, schedule, and budget. Any required scope changes will be input into the task PM4 Change Management.
4. Establish the methodology and constraints for the import process.
5. Identifies any potential organizational and/or process changes for input into task EO1 Business Process and Organizational Change Management.
6. Establish the general documentation, testing, commissioning, maintenance, and training requirements.

EA1.4.1.2 CYME Integration Report

Upon completion of task EA1.4.1.1 CYME Integration Workshop, this task will prepare a report that:

- Documents the interface requirements.
- Provides the CYME conversion methodology and constraints.
- Addresses any CYME impacts.
- Identifies conceptual organizational and/or process changes for input into task EO1 Business Process and Organizational Change Management.
- Provides conceptual testing plans.
- Provides conceptual training plans.
- Provides conceptual maintenance plans.

Any changes to project scope, schedule, or budget that result from the approval of any part of this report will be input into the task PM4 Change Management.

EA1.4.1.3 CYME Interface Design

This task will perform the detailed design of the CYME interface by Survalent. Delivery of design documentation will be from Survalent.

This task will also:

1. Import the PUC's provided CYME data files and then:
    a. Analyze the CYME files
    b. Report any issues or errors found with the CYME data
    c. Import the connectivity model into Survalent database and Graphical User Interface (GUI) (also refer to)
    d. Import the service territory map (DWG or DXF format)
    e. Overlay the connectivity model with the service territory map
2. Optimize the maps by:
    a. Geographically correcting placement of substations and associated single line diagrams (SLDs).
    b. Implementing System Configuration Status (SCS) in the substation SLDs so that substations are included in the connectivity model.
    c. Connecting substations to the connectivity model (feeder) outside of the substation.
    d. Validating connectivity.
    e. Optimizing the overall view and associated substation views.

EA1.4.3 CYME Integration Software Testing Plan

This task will develop the software testing plan for the CYME integration (refer to

Software testing plan), which relies on the delivery of the testing plans from Survalent.

EA1.4.4 CYME Integration Training Plan

This task will develop the CYME integration training materials from Survalent. Training will be performed in task TR1 Training.

EA1.4.5 CYME Integration Maintenance Plan

This task will develop the CYME integration maintenance plan materials from Survalent.

EA1.5 AMI Integration

This task will design the MultiSpeak interface between the Survalent ADMS and the Sensus AMI so that the AMI system provides the data required by the ADMS in support of the provided applications (VVO) for both the production and test systems.

EA1.5.1 AMI Integration Design

Once the data integration requirements are formalized in task EA1.1 Data Integration Evaluation, the AMI integration design will begin with a workshop, continue with the creation of a design report, and finish with the detailed design.

EA1.5.1.1 AMI Integration Workshop

This task will plan and conduct an AMI integration workshop to:

1. Develop the interface requirements between the Survalent system and Sensus AMI system to support the following functions:
    a. Ping, disconnect and reconnect meters (with or without arming).
    b. Receive unsolicited outage and event reports from meters.
    c. Read voltages and other data on demand or on schedule (e.g., hourly), from bellwether meters and other meters, where scheduled readings will be displayed on the map and used by other applications, such as command sequencing, VVO, etc.
2. Identify any other use cases for the interface.
3. Identify any expected impacts on the AMI communication network. Any impacts on scope, schedule, and budget will be reviewed and any required scope changes will be input into the task PM4 Change Management
4. Establish the methodology and constraints for bellwether meters.
5. Work with Sensus to establish tasks and milestones that will be added to the schedule for monitoring as part of normal project management activities (refer to task PM5 Overall Schedule, Phases, and Milestones).
6. Establish the documentation, testing, commissioning, maintenance, and training requirements.
7. Identify potential impacts on business processes and organizational structure.

EA1.5.1.2 AMI Integration Report

Upon completion of task EA1.5.1.1 AMI Integration Workshop, this task will prepare a report that:

1. Documents the AMI-ADMS interface requirements by answering questions such as:
    a. What are the use cases for the interface?
    b. How do the existing workflows impact interface triggers?
    c. What information is sent and requested, in what format and exactly where is it sent?
        i. Outage events (from AMI)
        ii. Restore events (from AMI)
        iii. Power status (bi-directional)
        iv. Outage history (from AMI)
    d. Are any data transformations required?
    e. What data is missing from the AMI system that the OMS requires?
    f. How should the receiving system respond/behave?
    g. What priority are these information transfers?
    h. How are errors handled and reported?
2. Provides conceptual bellwether meter selection and constraints.
3. Addresses any AMI communication network impacts.
4. Evaluates the Sensus scope and estimate of work.
5. Identifies any conceptual organizational and/or process changes for input into task EO1 Business Process and Organizational Change Management.
6. Provides conceptual testing plans.
7. Provides conceptual training plans.
8. Provides conceptual maintenance plans.
9. Discusses schedule updates.

Any changes to project scope, schedule, or budget that result from the approval of any part of this report will be input into the task PM4 Change Management.

EA1.5.1.3 Bellwether Meter Report

Upon completion of EA1.5.1.2 AMI Integration Report, this task will create a bellwether meter report that documents the set of bellwether meters based upon the PUC’s validated CYME model (refer to task EA3.1

Feeder Evaluation) and existing customer-transformer-feeder relationships (refer to task EA1.3 CIS Integration).

EA1.5.1.4 AMI Interface Design

This task will perform the detailed design of the ADMS-AMI interface by Survalent and Sensus based upon the interface requirements document. Delivery of design documentation will be from Survalent and Sensus.

EA1.5.4 AMI Integration Software Testing Plan

This task will develop the software testing plan for the AMI integration (refer to

Software testing plan), which relies on the delivery of testing plans from Survalent and Sensus.

EA1.5.5 AMI Integration Training Plan

This task will develop the MultiSpeak AMI interface training materials from Survalent and Sensus. Training will be performed in task TR1 Training.

EA1.5.6 AMI Integration Maintenance Plan

This task will develop the MultiSpeak AMI interface maintenance plan from Survalent and Sensus.

EA1.5.7 Enhanced CSR/Customer Toolset

As part of the AMI integration, this task will review the results of the CIS upgrade project to determine whether there is opportunity to improve the organization and presentation of AMI data in a CSR and customer-friendly user interface such that they can better answer a wider set of customer questions with defensible data. This could specifically include reliability and cost/usage trends, but also quality and create, read, update, and delete (CRUD[14]) functions.

EA1.5.7.1 Review the CIS Upgrade Program

This task will plan and conduct a site visit to meet with the PUC's stakeholders responsible for the CIS upgrade project and those working with the CIS. This site visit will collect information about the CIS upgrade project to determine whether the following or related views were achieved with the CIS upgrade program:

- Interval data over time. The CSR/customer is able to 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.
- Reliability details. The CSR/customer is able, to the extent possible, review outage history or time aggregated details for each service location.
- Demand values. For commercial/industrial (C/I or C&I) customers, the CSR/customer is able to view demand (kW) values as it relates to kWh-delivered data.

EA1.5.7.2 CIS Toolset Assessment Report

After the completion of the site visit, this task will create a report that will assess the capabilities achieved and their applicability to the DB Project with respect to the functions identified while on site.

As necessary, the report will identify alternatives and recommend a path forward for additional work to achieve additional functionality, whether through Harris or another software platform:

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[14] CRUD is an acronym that is not defined in the Leidos statement of work.

- If the PUC has already achieved the solution scope recommended herein, no further work will be required for this task after the report completion.
- If not, the PUC will evaluate the report's recommendations and determine whether additional work is warranted to benefit the UDM. Any changes in scope, schedule, and budget will be implemented via the change management process (refer to task PM4 Change Management).

EA1 Deliverables

Deliverables provided by task EA1 System Integration are listed in Table 4.

Table 4 – EA1 Deliverable List

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB[15]
1. Integration design report.	EA1.1.2 Data Integration Report			■	■	
2. IVR integration report.	EA1.2.1.2 IVR Integration Report	■	■	■	■	
3. IVR integration design deliverables.	EA1.2.1.3 IVR Interface Design		■	■	■	■
4. IVR integration software testing plan.	EA1.2.2 IVR Integration Software Testing Plan			■	■	
5. IVR integration training plan.	EA1.2.3 IVR Integration Training Plan			■	■	
6. IVR integration maintenance plan.	EA1.2.4 IVR Integration Maintenance Plan			■	■	
7. CIS integration report.	EA1.3.1.2 CIS Report	■	■	■	■	
8. CIS integration design deliverables.	EA1.3.1.3 CIS Interface Design		■	■	■	■
9. CIS integration software testing plan.	EA1.3.3 CIS Integration Software Testing Plan			■	■	
10. CIS integration training plan.	EA1.3.4 CIS Integration Training Plan			■	■	
11. CIS integration maintenance plan.	EA1.3.5 CIS Integration Maintenance Plan			■	■	
12. CYME integration report.	EA1.4.1.2 CYME Integration Report	■	■	■	■	
13. CYME integration design deliverables.	EA1.4.1.3 CYME Interface Design		■	■	■	■
14. CYME integration software testing plan.	EA1.4.3 CYME Integration Software Testing Plan			■	■	
15. CYME integration training plan.	EA1.4.4 CYME Integration Training Plan			■	■	
16. CYME integration maintenance plan.	EA1.4.5 CYME Integration Maintenance Plan			■	■	
17. AMI integration report.	EA1.5.1 AMI Integration Design	■	■		■	
18. Bellwether meter report.	EA1.5.1.3 Bellwether Meter Report		■	■	■	■

[15] AB is an acronym for as-built, final as-left files, or equivalent

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB[15]
19. AMI integration design deliverables.	EA1.5.1.4		■	■	■	■
20. AMI integration software testing plan.	EA1.5.4 AMI Integration Software Testing Plan			■	■	■
21. AMI integration training plan.	EA1.5.5 AMI Integration Training Plan			■	■	■
22. AMI integration maintenance plan.	EA1.5.6 AMI Integration Maintenance Plan			■	■	
23. CIS toolset assessment report.	EA1.5.7.2 CIS Toolset Assessment Report			■	■	
24. Design review packages.	EA1 Reviews	■	■	■		

EA1 Reviews
Refer to Reviews.

EA1 Assumptions
1. Not used.
2. Not used.
3. The CIS flat file interface is Survalent's standard interface only.
4. The IVR interface is Survalent's standard MultiSpeak interface only.
5. The flat file format will be provided from CIS system.
6. The IVR system is a MultiSpeak compliant system.
7. Moved to EA2 OMS.
8. Moved to EA2 OMS.
9. All workshops will be held over contiguous days.
10. Moved to EA2 OMS.
11. Not used.
12. Not used.
13. Not used.
14. The PUC has existing data flow diagrams that will be updated to support task EA1.1 Data Integration Evaluation.
15. Not used.
16. All changes in software required by the integration between the Survalent system and Sensus AMI system can be accomplished under existing software releases and maintenance agreements. The PUC can modify the existing contract with Sensus to include new work scope via task order.
17. The AMI communications networks are sufficient in capacity to support the application data requirements for the AMI system to support the implemented applications (i.e., VVO and OMS). Sensus will provide guidance on the impact of increased reads (such as voltage) and any work required on the AMI communications network to attain sufficient application performance.
18. A meter to transformer to feeder relationship already exists and readily available in the CIS data table.
19. Moved to EA2 OMS.
20. Moved to EA2 OMS.
21. No longer applies. Approach changed to use CYME.
22. No longer applies. Approach changed to use CYME.
23. The PUC completed a contract with Harris Norhtstar to upgrade to CIS 6.4 with the HomeConnect and SiteConnect components of CustomerConnect.
24. The PUC has authorized Black & Veatch to work with Harris NorthStar for this scope of work.
25. Harris NorthStar will be contracting directly with the PUC and Black & Veatch will not be responsible for the contractual performance of Harris NorthStar.
26. Task EA1.1 Data Integration Evaluation will occur during the initial project kickoff meeting on site.

EA2 OMS
In coordination with the task EA1 System Integration, this task will design the OMS system to support:

- OMS functionality (refer to task EA2.1 OMS Design)
- Customer Outage Web Portal (refer to task EA2.2 Customer Outage Web Portal)
- Internal stakeholder dashboard (refer to task EA2.3 Internal Stakeholder Dashboard)

- Crew management (refer to task EA2.4 Mobile Crew)

This task will also create the following plans:

- Software testing (refer to task EA2.5 OMS Software Testing Plan)
- Training (refer to task EA2.6 OMS Training Plan)
- Maintenance (refer to task EA2.7 OMS Maintenance Plan)

The OMS will:

- Reduce outage durations due to faster restoration based upon outage location predictions.
- Reduce outage duration averages due to prioritizing
- Improve media relations by providing accurate outage & restoration information.
- Reduce complaints to regulators due to ability to prioritize restoration of emergency facilities and other critical customers.
- Reduce outage frequency due to use of outage statistics for making targeted reliability improvements.
- Fast track of problem location by meter ping analysis with AMI interface

EA2.1 OMS Design

This task will design the OMS to support the following capabilities:

- Automated data entry
- Call analysis
- Callbacks
- SmartVU management
- Switch order and clearances
- SCADA event and operations

Note that the following tasks will coordinate the OMS integration with the OMS design:

- EA1.2 IVR Integration
- EA1.3 CIS Integration
- EA1.4 CYME Integration
- EA1.5 AMI Integration

The deliverable will be documentation indicating the designed functionality.

EA2.2 Customer Outage Web Portal

This task will review and document the standard outage web portal provided by Survalent, including configuration of default options and user access control for both the production and test systems.

The customer outage web portal will allow the PUC's customers to:

- View outage locations and the extent of existing outage cases
- View outage ticket information such as cause, estimated time of restoration and outage messages
- Submit outage reports
- View a list of all planned outages

EA2.3 Internal Stakeholder Dashboard

This task will review and document the internal stakeholder dashboard provided by Survalent, such as any additional interface requirements, the configuration of default options, and user access control for both the production and test systems.

DA data summarization and analysis will be supported by the OMS through the OMS reporting functionality, the provided internal stakeholder dashboard, and the Key Performance Indicator (KPI) editor (refer to task EP1 DA Monitoring and Awareness Assessment that will align the approach with requirements). OMS reporting provides four types of standard reports to support DA data summarization and analysis:

1. Outage Case Report. A multi-line report that shows all of the details of the cases selected based upon filtered criteria (serial number, case description, case status, start time, cause, number of calls, priority, customer minutes, type, lost kVA, count of customers affected, phase, restoration time, duration, work status, etc.). This report type can be used to review the complete details of a set of outages based upon the specified selection criteria. Outage cases are displayed in ascending order of case number.
2. Outage Summary Report. This report shows the summary information for the cases selected based upon filtered criteria.
3. Reliability Index Report. This report shows monthly reliability index information based upon filtered criteria, such as a certain reliability index being within a range of values.
4. Quality of Service Report

The OMS reports can be:

- Customized by user/workstation
- Saved to a folder location for future retrieval

The internal stakeholder dashboard will allow approved PUC's internal stakeholders to:

- View locations and the extent of existing outage cases
- View outage ticket information such as cause, estimated time of restoration, and outage messages
- View a list of all planned outages

In addition, the internal stakeholder dashboard:

1. Integrates real-time outage information including location, and customer information for each outage case
2. Presents a customizable layout for KPIs, customers impacted, outage location, reliability indices
3. Provides configurable map layers: connectivity model, meters/transformers, outages, jobs, vehicles
4. Allows for outage cases to be updated remotely, including the estimated time of restoration and 'Message to Public', for display in the Customer Outage Portal.

The KPI editor provides two functions: displaying the KPI values as calculated by the OMS and allowing the KPIs to be mapped to analog values. The KPIs are organized into the following categories:

1. Customers
    a. Total customers
    b. Customers out, unplanned
    c. Customers out, planned
    d. Customers out, total

    e. Customers restored, total
    f. Hi-priority customers out
    g. Total smart meters
    h. Total power-on smart meters
    i. Total power-off smart meters
2. Outages
    a. Feeders with outages
    b. Transformers out
    c. Total lost KVA
    d. Active outages
    e. Today's sustained outages
    f. Yesterday's sustained outages
    g. This month's sustained outages
    h. Last month's sustained outages
    i. Today's momentary outages
    j. Yesterday's momentary outages
    k. This month's momentary outages
    l. Last month's momentary outages
3. Calls
    a. Outage calls this hour
    b. Outage calls last hour
    c. Outage calls today
    d. Outage calls yesterday
    e. Unhandled emergency calls
    f. Dispatched emergency calls
    g. Outage portal accesses this hour
    h. Outage portal accesses last hour
    i. Outage portal accesses today
    j. Outage portal accesses yesterday
    k. On-duty customer service representatives (CSRs)
    l. Number of manual outage calls in the last 60 minutes
    m. Number of IVR outage calls in the last 60 minutes
    n. Number of TCS outage calls in the last 60 minutes
    o. Number of WEB outage calls in the last 60 minutes
    p. Number of CSR outage calls in the last 60 minutes
4. Response
    a. Assigned crews
    b. % Acceptable outage response current month
    c. % Acceptable emergency response current month
    d. % Acceptable outage response previous month
    e. % Acceptable emergency response previous month
5. Reliability
    a. Yesterday's SAIDI
    b. Yesterday's CAIDI
    c. This month's SAIDI
    d. This month's CAIDI
    e. Last month's SAIDI
    f. Last month's CAIDI
    g. Yesterday's SAIFI
    h. Yesterday's CAIFI

i. This month's SAIFI
j. This month's CAIFI
k. Last month's SAIFI
l. Last month's CAIFI

EA2.4 Mobile Crew

This task will perform the design of the Mobile Crew (MC) client. MC client is a tablet-oriented web application is used by field crews. When provided, the 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 to notify them of a change in work.

MC will show two panels that a crew member will be able to navigate. The first is a case list that shows details of outage cases and is mostly view-only; however, it will be possible for the crews to modify the cause code, estimated time of restoration, and notes. The second panel is the work list that displays all of the work items that are assigned to a crew, which crew members will be able to make modifications to work items (e.g., work status, completion time, and material use).

EA2.5 OMS Software Testing Plan

This task will develop the software testing plan for the OMS (refer to

Software testing plan), which relies on the delivery of the testing plan from Survalent.

EA2.6 OMS Training Plan

This task will develop the training plan for the following:

1. IVR interface, including how to maintain customer data and scripts within the IVR for customer communications functionality and how to operate, input and manage customer outage call data within the IVR for OMS functionality.
2. CIS interface.
3. Outage web portal.
4. Internal Stakeholder Dashboard.

Training will be performed in task TR1 Training.

EA2.7 OMS Maintenance Plan

This task will perform the design of the OMS maintenance plan for the following.

1. IVR interface.
2. CIS interface.
3. Outage web portal.
4. Internal Stakeholder Dashboard.

EA2 Deliverables

Deliverables provided by task EA2 OMS are listed in Table 5.

Table 5 – EA2 Deliverable List

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
1. OMS design document.	EA2.1 OMS Design			■	■	
2. Outage web portal design document.	EA2.2 Customer Outage Web Portal			■	■	
3. Internal stakeholder dashboard design document.	EA2.3 Internal Stakeholder Dashboard			■	■	
4. Mobile crew design document.	EA2.4 Mobile Crew			■	■	
5. OMS testing plans.	EA2.5 OMS Software Testing Plan			■	■	
6. OMS training plans.	EA2.6 OMS Training Plan			■	■	
7. OMS maintenance plans.	EA2.7 OMS Maintenance Plan			■	■	
8. Design review packages.	EA2 Reviews			■		

EA2 Reviews
Refer to Reviews.

EA2 Assumptions
1. Not used.
2. Not used.
3. Not used.
4. Not used.
5. Not used.
6. Not used.
7. The PUC has an existing license for MS SQL server that can be used for SCADA Replicator and Archiver.
8. The Outage Web Portal is Survalent's standard offering and the PUC will provide a virtualized server for the Outage Web Portal (middleware server and web portal server).
9. Not used.
10. Mobile Crew Client License was excluded from the proposed solution since there was no understanding of quantity of field deployments or the infrastructure required.
11. Not used.
12. Not used.
13. Not used.
14. Not used.
15. Not used.
16. Not used.
17. Not used.
18. Not used.
19. The bellwether meters will be a subset of the total number of AMI meters that can be supported by the AMI communications network.
20. Bellwether meter selection will be constrained such that there will be no requirements for adding towers to the AMI communications network will PUC and will require no bulk-replace electric meters in the field.
21. Not used.
22. Not used.
23. Not used.
24. Not used.
25. Not used.

EA3 ADMS
In coordination with the task EA1 System Integration, this task will design the Survalent ADMS along with the following DA applications:

- FDIR for the number of locations shown in Table 6.
- VVO for the number of feeders shown in Table 6.
- Auto-transfer scheme.

This task includes the following tasks:

- EA3.1 Feeder Evaluation
- EA3.2 FCI Wireless Evaluation
- EA3.3 Identify Virtual Server Requirements

- EA3.4 Define SCADA design templates
- EA3.5 Substation SCADA Point Assessment
- EA3.6 Provide Mapping Requirements
- EA3.7 Develop Auto-Transfer Scheme
- EA3.8 Develop Standardized DA Designs

The ADMS applications will require field data supplied by the Survalent SCADA master from each of the intelligent electronic devices (IEDs) (such as FCI, regulator controller, and switch controller) supporting the field equipment listed in the headers in Table 6 and further detailed in Table 7 ("field devices") to support the ADMS applications. DNP3 (IEEE 1815) will be used for communications to all field devices, using as necessary the field communications equipment (refer to Table 8). The VVO and FDIR applications require a feeder connectivity model that is maintained and up-to-date (refer to task EA1.4 CYME Integration).

The FDIR algorithm provided by Survalent will analyze the pattern of fault targets received from the field by the SCADA system. When a breaker lockout is detected:

1. FDIR analyzes the pattern of fault targets received by the SCADA master to determine the fault location.
2. FDIR opens a new blank switch order record.
3. If the fault is between the breaker and the first level of closed switches, FDIR adds commands to the switch order to open the first level of closed switches. The breaker is left open to isolate the faulted section.
4. If the fault is downstream of the first level of closed switches, FDIR isolates the fault by adding commands to open all closed switches around the faulted area. FDIR then adds a command to close the breaker. This restores service above the fault.
5. FDIR then analyzes the area beyond each opened switch to see if the area downstream can be transferred to another feeder.

The centralized VVO algorithm provided by Survalent will coordinate control of reactive power (via capacitor banks) and voltage (via regulators). VVO will require load flow and will optimize the following user-selectable objective functions subject to user-configurable constraints:

- Loss Minimization: This objective minimizes total losses (transformer losses at the substation and line losses along the feeders).
- Energy Conservation: This objective reduces load by minimizing voltage throughout the network without violating constraints.
- Revenue Maximization: This objective maximizes the difference between energy sales (price of energy delivered to customers) and cost (cost of production or purchase). Voltage is raised until increased losses start to outweigh increased sales. Where this point falls depends on the actual mix of load types (constant current, constant impedance and constant power).

The load flow application will periodically run a three-phase unbalanced load flow:

- Automatically at on a user-defined periodic interval
- Whenever there is a significant change in the substation data (voltage, load) in the SCADA system database, where the definition of "significant" is user-defined
- After a feeder reconfiguration has occurred (by switching action) or after the dispatcher has made some changes in the line sections database via the Line Section Editor

The load flow application will:

- Redistribute the feeder load data so that the total matches the substation data in the SCADA system
- Update the feeder voltage/loss profiles
- Update the feeder min/max margin and min/max volts data
- Provides the calculation results in reports; however, for many of the calculated data items, the Line Section Editor allows the user to specify database points to receive them, for easy viewing directly on the map. Some of the calculated data items that can be mapped to SCADA database points are:
  - Three-phase voltages and currents at a line section
  - The magnitude of the minimum current margin between the line section and the substation
  - The magnitudes of the minimum and maximum voltages between the line section and the end of the feeder

The VVO application will provide VVO performance metrics when the VVO application generates a log, at each hour's operation, of its calculations and decision-making process. The log:

- Is viewable as a softcopy or printed report.
- Includes the value of the objective function at each substation, both before and after optimization, providing an estimate of the calculated benefit of each VVO operation.
- Contains a list of the controls that were executed (if in automatic mode) or controls that VVO recommended to be executed (if in semi-automatic mode).

EA3.1 Feeder Evaluation

This task will evaluate scope elements associated with the feeder selection through a workshop and provide a feeder evaluation report.

EA3.1.1 Feeder Evaluation Workshop

This task will plan and conduct a feeder evaluation workshop after the project kickoff meeting (refer to task PM1 Project Kickoff Meeting). The feeder evaluation workshop will:

- Validate the PUC's existing CYME model to ensure it includes all required information to support ADMS and OMS.
- Investigate the extent of changes to the 12.5 kV distribution system since the model was last updated.[16]
- Identify the C&I feeders and the differences between those feeders and the feeders listed in Table 6.
- Evaluate the need of performing power flow, protection, and reliability analysis on the 12.5 kV and 34.5 kV system (since those feeders are not in the CYME model).[17]

EA3.1.2 Feeder Evaluation Report

Upon completion of task EA3.1.1 Feeder Evaluation Workshop, this task will prepare a report that:

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[16] The Leidos statement of work references a model dated around 2014-09-29, the model obtained by Black & Veatch has this date in the filename.

[17] During the meetings held with the PUC and IECo on April 10, 2017, the PUC indicated additional power flow, protection, and reliability modeling is desired on the 12.5 kV and 34.5 kV systems. In addition, it was indicated by the PUC that no updates to the model have been accomplished since the PUC did not have a copy of the model.

1. Documents the impacts of the changes required in CYME to support the project and recommends methods to minimize any identified impacts
2. Documents a new list of feeders based upon the C&I identification
3. Provides an estimate of performing a complete distribution circuit analysis and protection study on the 12.5 kV system compared to the original scope of work.
4. Provides an estimate for the recommended additional work (e.g., adding all 34.5 kV circuits to the CYME model and performing a circuit analysis and protection study).

Any changes to project scope, schedule, or budget that result from the approval of any part of this report will be input into the task PM4 Change Management.

EA3.2 FCI Wireless Evaluation

This task will evaluate other FCI communication technologies and the impact on the selected Grid Advisor Series II FCI.

EA3.2.1 FCI Wireless Workshop

This task will plan and conduct an FCI wireless workshop after the project kickoff meeting (refer to task PM1 Project Kickoff Meeting). The FCI wireless workshop will evaluate other communication technologies available for FCI in addition to SpeedNet radios. The workshop will investigate any issues with SpeedNet radios based upon experience and develop the criteria to be used for evaluating the different technologies.

EA3.2.2 FCI Wireless Report

Upon completion of task EA3.2.1 FCI Wireless Workshop, this task will prepare a report that compares the different wireless technologies available for FCI and their impact on the baseline scope of work (SpeedNet radios and Grid Advisor Series II FCI). The deliverable from this task is a report that includes an assessment with recommendations and impacts to project scope, schedule, and budget (i.e., moving from SpeedNet radios to FlexNet, MDS radios, or other wireless technologies, and the impact on the selected Grid Advisor Series II FCI). This selection will be coordinated with task EF2 Design DA Field Area Network.

Any changes to project scope, schedule, or budget that result from the approval of any part of this report will be input into the task PM4 Change Management.

EA3.3 Identify Virtual Server Requirements

This task will define and finalize the virtual server requirements for the production and test systems (refer to General Assumptions). For the hardware, Survalent's greatest concern is the hard drive size; minimum hard drive size is driven by the number of data points being logged, sample rate (or frequency of logging), and duration of historical data being maintained in the database. An example of typical virtual server hardware specified by Survalent is as follows:

- Dell PowerEdge™ R320 Server
- 3.5" Chassis Configuration with up to 4 hot plug hard drives
- Intel® Xenon® E5-2430 v2
- 16GB memory
- RAID 1 configuration with a PowerEdge™ RAID Controller (PERC) integrated RAID controller, model H310
- Two 2TB hard drives

Windows Server® 2012 R2 Standard Edition with 5-pack of client access licenses is Survalent's required operating system (subject to change).

EA3.4 Define SCADA design templates

This task will establish the standard templates for DNP3 settings and polling schemes required to support VVO, FDIR, and auto-transfer and leverage the templates for networking settings created from task EA4.1 SCADA Master Logical. This task will also be coordinated with task EA3.8.2 Device Template Point Lists.

EA3.5 Substation SCADA Point Assessment

This task will confirm the adequacy of the existing substation SCADA implementations (for the applicable substations listed in Table 6) in that the available data meets or exceeds the data requirements for the FDIR, VVO, and auto-transfer applications. If any deficiencies in SCADA points exist, the report will recommend the correction of any deficiencies with an estimate of any additional integration work, new substation equipment, programming, or other required work for its impacts on scope, schedule, and budget. Any approved scope changes will be input into the task PM4 Change Management.

This task will be coordinated with task EA3.8.2 Device Template Point Lists that will develop the field device points required by the FDIR, VVO, and auto-transfer applications.

This task will be completed prior to starting with tasks EF1.2 DA Field Survey (and its related task EF2.1 Wireless Communications Field Survey).

EA3.6 Provide Mapping Requirements

This task will review the mapping capabilities of the ADMS related to symbols and graphics and align them with the PUC's requirements for the major electrical equipment being installed in the field as listed in Table 6 and detailed in Table 7. These graphics and symbol standards will be used as required to support the tasks described in EA1.4 CYME Integration and EA4.3 SCADA Master Displays and Database.

EA3.7 Develop Auto-Transfer Scheme

This task will develop the 34.5 kV auto-transfer scheme in the Survalent ADMS[18] that will be implemented at substations 1, 2, 11, 12, 13, 16, 18, and 19 and the associated testing, maintenance, and training plans. This design work will be coordinated with development of standardized designs related to the scheme in task EA3.8 Develop Standardized DA Designs.

EA3.7.1 Auto-Transfer Detailed Logic

The 34.5 kV auto-transfer scheme concept is to determine when substations can be safely transferred from their normal to alternate feeds on the 34.5 kV loop system. Safely transferred is defined as at least the following (with associated alarms as necessary):

- When the normal source has been lost (voltage is less than some configurable value, such as 10% of nominal value for a configurable duration related to polling rates) due to faults occurring on higher-voltage systems (i.e., faults not internal to the 34.5 kV system)
- There is adequate capacity available on the source transformers and line equipment to avoid an overload condition

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[18] During the meetings held with the PUC and IECo on April 10, 2017, the PUC indicated that the 34.5 kV system is a basic loop fed from two sources and there was concern that an auto-transfer could result in the overload of the other source.

- Data quality for the received data is good quality (e.g., no communication errors, stale data, invalid data, etc.)

The scheme will use data collected (such as line-to-ground voltage and fault current detection) (refer to task EA3.8.2 Device Template Point Lists) from FCI (refer to Table 7) mounted on the 34.5 kV lines as they enter each substation. Other existing data from the ADMS will be used as available and/or required (e.g., 34.5 kV switch/breaker status, substation line voltage, fault current and targets; distributed generation data as applicable) to support the analysis (refer to task EA3.5 Substation SCADA Point Assessment).

The scheme can run in several modes: automatic (fully automatic), semi-automatic (requires operator intervention to review recommended switching), and off. All switching shall be identified by the logic such that the switching can be completed within a period that reduces the applicable reliability indices. The application shall maintain a log of all completed auto-transfers in a similar manner as other logs produced by the ADMS.

There are manual switches in the 34.5 kV system, which have no status information available and will not be converted to automatic switches. The scheme will account for these manual switch locations.

EA3.7.2 Auto-Transfer Application Testing Plan

This task will develop the application testing plan for the 34.5 kV auto-transfer scheme (refer to Application testing plan), which relies on the delivery of the testing plan from Survalent. Note that the application testing plans for DA and VVO will be developed in task EA3.8.4.1 Template DA Field Testing Plans.

EA3.7.3 Auto-Transfer Training Plan

This task will develop the auto-transfer scheme training materials from Survalent for training of the PUC's technical and operations personnel. The task will develop and review the training program, assign PUC groups that need to attend each training session, and develop the training deliverable (e.g., the method used to document training attendance). The task will develop separate training plans and materials for the 34.5 kV auto-transfer scheme.

Operator/dispatcher training will include a system overview of how the scheme operates from the head end to the field (provided by Black & Veatch), along with how the operators will use the scheme, such as:

- How to use the ADMS to manage the scheme (auto, semi-auto, and off modes)
- Troubleshooting techniques in the ADMS

Engineer training will include how to implement and test new scheme scenarios with new devices, what adjustments are required to meet operational expectations, and troubleshooting techniques.

- How the scheme was created, how it runs, how to test it, and how to modify it
- Troubleshooting techniques in the ADMS and supporting systems

Training will be performed in task TR1 Training.

EA3.7.4 Auto-Transfer Maintenance Plan

This task will develop the auto-transfer scheme maintenance plan from Survalent.

EA3.8 Develop Standardized DA Designs

This task will create the DA design standards or templates that will be leveraged for the detailed design of each confirmed field location of equipment related to FDIR, VVO, and auto-transfer; such as overhead regulator, overhead recloser, overhead switch, pad mounted switchgear, cap bank, radio, repeater, gateway radio, and FCI (refer to Table 7 and Table 8). Work in this task related to the auto-transfer scheme will be coordinated as necessary with the task EA3.7 Develop Auto-Transfer Scheme, EA3.1 Feeder Evaluation, and EA3.2 FCI Wireless Evaluation.

Site-specific design occurs in tasks EF1.3 DA Detailed Design and EF2.3 Field Area Network Detailed Design.

EA3.8.1 DA Template Design Drawings

This task will create design template drawings (or construction standards) for all DA major electrical field equipment and substation equipment.

EA3.8.1.1 DA Template Design Drawings

This task will create design template drawings (or construction standards) for major electrical equipment installation drawing templates for the major electrical equipment installed in the field (refer to Table 7). This task will create a standard bill of materials to support the procurement of major materials (refer to task PR1 Purchase Major Materials and Equipment) and minor materials (refer to task PR2 Purchase All Other Materials and Equipment).

EA3.8.1.2 RF Template Design Drawings

This task will create design template drawings (or construction standards) for major electrical equipment installation drawing templates for the major communications equipment shown in Table 8 installed in the field (field radio and repeater) and in substations (gateway radio). This task will create a standard bill of materials that identifies major materials (refer to task PR1 Purchase Major Materials and Equipment) and minor materials (refer to task PR2 Purchase All Other Materials and Equipment) for the equipment being installed

Table 6 – List of Feeders Supporting FDIR[19] and VVO

12.5 KV FEEDER	# POLE TOP SWITCHES	# POLE TOP RECLOSERS[20]	# 2-WAY PADMOUNT SWITCHES	# 4-WAY PADMOUNT SWITCHES	O/H FCI	U/G FCI	STA. REG 333 KVA	FDR. REG 167 KVA	CAPACITOR 600 KVAR	FEEDER REPHASING
11-11	1	1					1			
11-12	1	1					1			2
11-13	1	1			2		1			
11-14	1	1					1			1
12-11	1	1								
12-12	1	1								
12-13	1	1								
12-14	1	0	1							
16-01	2	1					1			2
16-02	2	2					1			
16-03	1	2					1		1	
16-04	0	1					1		1	1
18-01	3	3			3		1	1		1
18-02	1	1			2		1			1
18-03	1	1			2		1			1
18-04	1	2			1		1	1		
19-01	0	0					1			
19-02	1	1			2		1			

[19] The number of feeders and equipment has been reduced 35% in accordance with PUC direction.
[20] Reclosers are ordered with SpeedNet™ radios included.

12.5 KV FEEDER	# POLE TOP SWITCHES	# POLE TOP RECLOSERS[20]	# 2-WAY PADMOUNT SWITCHES	# 4-WAY PADMOUNT SWITCHES	O/H FCI	U/G FCI	STA. REG 333 KVA	FDR. REG 167 KVA	CAPACITOR 600 KVAR	FEEDER REPHASING
19-03	2	2					1			
19-04	1	1			2		1			
1-11				1		8	1			
1-12			1	1			1			2
1-13				1		5	1			
1-14	1	1				3	1			1
2-13	1	1					1			
2-14			1			3	1			
2-15							1			
2-16							1			
13-1							1			
13-2							1			
13-3							1			
13-4							1			
20-01							1			
20-02							1			
20-03							1			
20-04							1			
TOTAL	25	26	3	3	14	19	32	2	2	12

Table 7 – Major Electrical Equipment and Field Devices Bill of Material

EQUIPMENT TYPE FROM TABLE 6	DA APPLICATION	VENDOR	DESCRIPTION	QUANTITY	SCOPING LEGEND[21]
Pole top Switches	FDIR	S&C	SCADA-Mate 15kV, with controller (IED)	26	E
Pole top Reclosers	FDIR	S&C	Intellirupter 15kV, with SpeedNet™ Radio and controller	25	D
2-way Pad mount Switches	FDIR	S&C	PMH-3 underground 15kV switchgear, with 6801 automatic switch controller	3	G
4-way Pad mount Switches	FDIR	S&C	Vista 4-Way underground 15kV switchgear, with controller	3	F
O/H FCI	FDIR	Eaton	O/H FCI- Eaton GridAdvisor Series II, 3phase set	30	J
U/G FCI	FDIR	Eaton	U/G FCI- Eaton GridAdvisor Series II, 3phase set	19	K
Sta. Reg 333 KVA	VVO	Eaton	Substation Regulators, 333 kVA, 438A, 14.4kV, 150 kV BIL (set of 3), with CL-7 control (IED)	32	C
Fdr. Reg 167 KVA	VVO	Eaton	Line Regulator, 167kVA, 200A, 7.62 kV, 95kV BIL (set of 3), with CL-7 control (IED)	2	B
Capacitor 600 KVAR	VVO	Eaton	3x200kVAr, 12.5kV	2	A
	Auto Transfer	Eaton	O/H FCI- Eaton GridAdvisor Series II, 3phase set	16[22]	L

[21] The scoping legend refers to the drawing titled "PUC UDM Project – EPC Scoping Diagram", where the alpha character can be matched up with alpha characters in circles showing where on the diagram the equipment in these tables is installed in the proposed system architecture.

[22] Used for the Auto-Transfer scheme on the 34.5 kV system as follows: 2 per substation, for 8 substations involved in auto-transfer.

Table 8 – Major Field Area Network (FAN) Equipment Bill of Material

EQUIPMENT TYPE FROM TABLE 6	SYSTEM	VENDOR	DESCRIPTION	QUANTITY	SCOPING LEGEND
Not shown, installed with all equipment except regulators, FCI, and pole top reclosers (refer to footnote 20)	FAN	S&C	SpeedNet™ 900 MHz radios- all required equipment - antenna, cables, and connectors.	35	H
	FAN	S&C	SpeedNet™ repeater- all required equipment - antenna, cables, and connectors.	10	I
	FAN	S&C	SpeedNet™ 900 Mhz as gateway radio that has a control house mounted antenna	8	M

EA3.8.2 Device Template Point Lists

This task will define for the field devices (refer to Table 7) a template DNP3 point lists that includes all points required to support FDIR, VVO, and auto-transfer (refer to task EA3.7 Develop Auto-Transfer Scheme) and assess whether they are available from the field devices. This task is coordinated with the development of the related substation points in task EA3.5 Substation SCADA Point Assessment and also coordinated with the DNP3 settings defined in task EA3.4 Define SCADA design templates.

EA3.8.3 DA Template Configurations

This task will create design template configurations (or construction standards) required for the DA devices.

EA3.8.3.1 DA Template Configurations

This task will develop the template configuration files required for the field devices (refer to Table 7)[23]. These templates will be used to develop the site specific configurations in task EF1 Site-Specific DA Design.

This task depends upon the approval of the point list templates from task EA3.8.2 Device Template Point Lists.

EA3.8.3.2 RF Template Configurations

This task will develop the template configuration files required for the field radio, repeater, and gateway radio (refer to Table 8). These templates will be used to develop the site specific configurations in task EF2.3 Field Area Network Detailed Design and task ES1 Substation Communication Design.

EA3.8.4 DA and RF Template Testing Plans

This task will develop the template testing plans for DA devices and their associated RF equipment.

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[23] For example, FCI use ProView NXG software will be used to create the configuration, which is typically downloaded to the FCI using a Bluetooth connection and prior to the FCI being installed.

EA3.8.4.1 Template DA Field Testing Plans

This task will develop template field testing plans (refer to Field testing plan) for the DA equipment listed in Table 7 (i.e., recloser, switch, etc.).

EA3.8.4.2 Template Field Portion of SCADA End-to-End Testing Plans

This task will also support the development of the SCADA end-to-end testing plan for the DA equipment listed in Table 7 (i.e., recloser, switch, etc.). Note that the SCADA master portion will be addressed in task EA4.4 SCADA Master End-to-End Testing Plan..

EA3.8.4.3 Template DA Application Testing Plans

This task will develop template application testing plans (refer to Application testing plan) for:

1. FDIR.
2. VVO.

Note that the auto-transfer testing plan will be developed in task EA3.7.2 Auto-Transfer Application Testing Plan.

EA3.8.4.4 Template RF Field Testing Plans

This task will develop template RF field testing plans for the field radio, repeater, and gateway radio (refer to Table 8).

EA3.8.4.5 Template RF End-to-End Testing Plans

This task will develop template RF end-to-end testing plan associated with the field devices and substations (refer to RF end-to-end testing plan) for the field radio, repeater, and gateway radio (refer to Table 8).

EA3.8.4.6 Template Communications End-to-End Testing Plans

This task will develop template communications end-to-end testing plan associated with the field devices and substations (refer to RF end-to-end testing plan) for the field radio, repeater, and gateway radio (refer to Table 8).

EA3.8.5 DA Training Plans

This task will develop the DA training plan for training of the PUC's technical and operations personnel.

EA3.8.5.1 DA Training Plans

The task will develop and review the training program, assign PUC groups that need to attend each training session, and develop the training deliverable (e.g., the method used to document training attendance). The task will develop separate training plans and materials for each of the following:

1. All of the field device (refer to Table 7). Note that some of the training plans may be only the provision of the vendor's standard training.
2. Base ADMS training, including the following applications (the auto-transfer application training plan will be developed in task EA3.7.3 Auto-Transfer Training Plan):
    a. VVO.
    b. FDIR.
3. Test system, which will include plans for the implementation of the complete test system staging for the complete project, including OMS, SCADA, ADMS, DA, and field devices.

Operator/dispatcher training will include a system overview of how the FDIR, VVO and OMS systems operate from the head end to the field (provided by Black & Veatch), along with how the operators will use each device/system (standard vendor training services), such as:

- How to use the software to operate, input and manage outages within Survalent SmartOMS environment for OMS functionality
- How to enable and disable controls
- Troubleshooting techniques

Engineer training will include how to implement and test new FDIR and VVO scenarios with new devices, what adjustments are required to meet operational expectations, and troubleshooting techniques.

- How to use the software to operate, input and manage outages within Survalent SmartOMS environment for OMS functionality
- How to use configuration software to create and maintain the current version of "as operated electrical distribution system" electrical network model within the OMS
- How to enable and disable controls
- Troubleshooting techniques

Training will be performed in task TR1 Training.

EA3.8.5.2 RF Training Plans

The task will develop and review the training program, assign PUC groups that need to attend each training session, and develop the training deliverable (e.g., the method used to document training attendance). The task will develop separate training plans and materials for each of the following:

1. All of the field communications equipment (refer to Table 8). Note that some of the training plans may be only the provision of the vendor's standard training.
2. Base RF training for the gateway and field radios.
3. Test system, which will include plans for the implementation of the complete test system staging for the complete project, including OMS, SCADA, ADMS, DA, and field devices.

Operator/dispatcher training will include a system overview of how the radios support DA, VVO (ADMS) and OMS systems (provided by Black & Veatch), along with how the operators will use each device/system (standard vendor training services), such as:

- How to use the software to operate and manage outages with the radios
- How to monitor radios
- Troubleshooting techniques

Engineer training will include how to implement and test the radios, what adjustments are required to meet operational expectations, and troubleshooting techniques.

- How to use the software to operate and manage outages with the radios
- How to use configuration software to create and maintain the radios
- How to monitor radios
- Troubleshooting techniques

Training will be performed in task TR1 Training.

EA3.8.6 DA Template Maintenance Plans

This task will develop the template maintenance plans for DA devices.

EA3.8.6.1 DA Maintenance Plans

This task will develop the FDIR and VVO maintenance plans that address the following:

1. All of the field devices (refer to Table 7). Note that some of the maintenance plans may be only the provision of the vendor's operation and maintenance manual.
2. Maintenance of the following (the auto-transfer application maintenance plan will be developed in task EA3.7.4 Auto-Transfer Maintenance Plan)
    a. VVO.
    b. FDIR.
3. VVO and FDIR in the test system.

EA3.8.6.2 RF Maintenance Plans

This task will develop the RF maintenance plans that address the following:

1. All of the field communications equipment (refer to Table 8). Note that some of the maintenance plans may be only the provision of the vendor's operation and maintenance manual.
2. Maintenance of the field radios and repeaters.
3. Field radios and repeaters in the test system.

EA3 Deliverables

Deliverables provided by task EA3 ADMS are listed in Table 9.

Table 9 – EA3 Deliverable List

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
1. Feeder evaluation report.	EA3.1.2 Feeder Evaluation Report			■	■	
2. FCI wireless report.	EA3.2.2 FCI Wireless Report			■	■	
3. Virtual server requirements.	EA3.3 Identify Virtual Server Requirements			■	■	
4. Standard DNP3 setting and polling scheme setting templates.	EA3.4 Define SCADA design templates			■	■	
5. Standard graphics and symbols.	EA3.6 Provide Mapping Requirements			■	■	
6. Auto-transfer logic.	EA3.7.1 Auto-Transfer Detailed Logic	■[24]	■[25]	■[26]	■	
7. Auto-transfer testing plan.	EA3.7.2 Auto-Transfer Application Testing Plan			■	■	
8. Auto-transfer training plan.	EA3.7.3 Auto-Transfer Training Plan			■	■	
9. Auto-transfer maintenance plan.	EA3.7.4 Auto-Transfer Maintenance Plan			■	■	
10. A final list of the FDIR and VVO bill of material (refer to Table 7 and Table 8).	EA3.8.1.1 DA Template Design Drawings			■	■	
11. A final list of the FAN bill of material (refer to Table 7 and Table 8).	EA3.8.1.2 RF Template Design Drawings			■	■	
12. Template FDIR and VVO design drawings (refer to Table 7).	EA3.8.1.1 DA Template Design Drawings	■[27]	■[28]	■[29]	■	

[24] The auto-transfer scheme 30% design is conceptual logic, such as written description of logic.

[25] The auto-transfer scheme 60% is the incorporation of comments from the 30% design plus the initial logic diagrams or code, plus required points from the field devices.

[26] The auto-transfer scheme 90% is a final review of the incorporation of comments from the 60% design.

[27] The 30% design includes schematics.

[28] The 60% design incorporates comments from the 30% design and includes wiring diagrams.

[29] The 90% design incorporates comments from the 60% design and issues a final design.

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
13. Template FAN design drawings (refer to Table 8).	EA3.8.1.2 RF Template Design Drawings	■[27]	■[28]	■[29]	■	
14. Standard point list templates for FDIR and VVO devices (refer to Table 7).	EA3.8.2 Device Template Point Lists			■	■	
15. Report for the number of substations listed in Table 6 evaluating the existing SCADA implementation against the data requirements.	EA3.5 Substation SCADA Point Assessment			■	■	
16. Template configuration files for the field devices (refer to Table 7).	EA3.8.3.1 DA Template Configurations			■	■	
17. Template configuration files for the FAN equipment (refer to Table 8).	EA3.8.3.2 RF Template Configurations			■	■	
18. Template field testing plans for the field devices (refer to Table 7).	EA3.8.4.1 Template DA Field Testing Plans			■	■	
19. Template field end of SCADA end-to-end testing (refer to Table 7).	EA3.8.4.2 Template Field Portion of SCADA End-to-End Testing Plans			■	■	
20. Template application testing plans for the FDIR and VVO applications.	EA3.8.4.3 Template DA Application Testing Plans			■	■	
21. Template field testing plan for the FAN equipment (refer to Table 8).	EA3.8.4.4 Template RF Field Testing Plans			■	■	
22. Template RF end-to-end testing plan for the FAN equipment (refer to Table 8).	EA3.8.4.5 Template RF End-to-End Testing Plans			■	■	
23. Template communications end-to-end testing plan associated with the FAN equipment (refer to Table 8).	EA3.8.4.6 Template Communications End-to-End Testing Plans			■	■	
24. Template training plans for the field devices (refer to Table 7).	EA3.8.5.1 DA Training Plans			■	■	
25. Template training plans for the FDIR and VVO applications).	EA3.8.5.1 DA Training Plans			■	■	

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
26. Template training plans for the FAN equipment (refer to Table 8).	EA3.8.5.2 RF Training Plans			■	■	
27. Template the maintenance plans for the field equipment and FDIR and VVO applications (refer to Table 7).	EA3.8.6.1 DA Maintenance Plans			■	■	
28. Template maintenance plans for the FAN equipment (refer to Table 8).	EA3.8.6.2 RF Maintenance Plans			■	■	
29. Design review packages.	EA3 Reviews	■	■	■		

EA3 Reviews
Refer to Reviews.

EA3 Assumptions
1. Not used.
2. All required ADMS points from the field devices (refer to Table 7 and Table 8) are available as standard points.
3. DNP3 Level 2 communications will sufficiently support the ADMS application requirements.
4. Standard graphics and symbols from the Survalent ADMS will be implemented in the graphics built in the ADMS.
5. Not used.
6. The PUC has an acceptable standard point list format (as determined by Black & Veatch) or Black & Veatch can use its standard point list template (as determined by the PUC) to support the field devices and task EA3.8.2 Device Template Point Lists.
7. The quantity of overhead voltage sensors that will be installed to support the 34.5 kV auto-transfer scheme are shown in Table 7.
8. The PUC will assist in developing the 34.5 kV auto-transfer logic.
9. The PUC will implement the necessary cellular service contracts for the GridAdvisor field device communications (refer to Table 7) so the devices can provide the required SCADA data.[30] The PUC will be responsible for the data plans, service level agreement, and contractual agreements, including all supporting head-end network infrastructure and configuration to enable TCP/IP ping-able path from the Survalent ADMS to the GridAdvisor devices.
10. Equipment cabinets installed in the field will:
    a. Be capable of being locked using the PUC's standard padlock, with the locks provided by the PUC.
    b. Have a door contact wired to an IED status point as available from an IED vendor's standard offering with mapping of the point back to SCADA for monitoring the physical security of the field equipment.
11. Template configuration files will include the configuration of any cyber security capabilities, when available from vendors as a standard product offering. The PUC will indicate what security settings must be defaulted before field installation and then be changed in the field for the final configuration.
12. The number of pole replacements required is indicated in Table 10. All replacement poles will be a 50 foot, class 2, Red Pine pole.
13. The PUC will have one review of the testing plan, maintenance plan, and training plan.
14. The training provided includes each vendor's standard offering for on-site training for the equipment listed in Table 7 and Table 8 (with input from Black & Veatch), along with overall integration training that is custom developed by Black & Veatch.
15. DNP3 Level 2 communications will sufficiently support the ADMS application requirements.
16. Not used.
17. The test system will be located in lab facility, which will be temporarily located in Sault Ste. Marie for lab testing and moved to a final location specified by the PUC (refer to task CN1.1 Pre-Mobilization/Mobilization Activities). If the PUC wants the final test lab to include field equipment, that field equipment will be purchased separately by the PUC.
18. The PUC will supply each substation's existing RTU point list.

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[30] Eaton will provide a list of Mobile Equipment Identification (MEID) numbers for the devices purchased with cellular communications. The PUC will provide these numbers to their cellular service provider to establish cellular service contracts using a private VPN service involving machine-to-machine communications. A VPN service is required so that the DA devices are not directly accessible from the public internet. The PUC should also understand the cellular plan rates are impacted by data update rates and any other access attempts.

19. The PUC will supply the substation RTU configuration file if requested to support this work.
20. The existing SCADA data is adequate (such as points for circuit breaker lockout, fault targets, breaker status, and feeder/breaker currents and other required data to support the DA applications).
21. The substation IEDs will require no updates.
22. Substation protection relays are primarily GE 760.

Table 10 – Pole Replacements

DEVICE	DEVICE COUNT	NEW	REQUIRED
FDIR			
Reclosers	25	70%	18
Switches	26	70%	18
VVO			
Capacitors / Line Regulators	4	70%	2
Station Regulators	32	100%	64
Total New Poles			**102**

EA4 SCADA Master
In coordination with the task EA1 System Integration, this task will design the upgrade to the Survalent SCADA with ADMS applications.

EA4.1 SCADA Master Logical
This task will define and document the TCP/IP network addressing and related settings to establish the basic TCP/IP network connectivity for the added devices and hardware. These settings will be provided by the PUC and will support the task EA3.4 Define SCADA design templates.

EA4.2 SCADA Master Sub-System Integration
This task will develop the detailed integration configuration based upon the template for protocol communication developed in EA3.4 Define SCADA design templates and point list templates developed in EA3.8.2 Device Template Point Lists.

The deliverables will also be used for the test system.

EA4.3 SCADA Master Displays and Database
This task will create the ADMS displays for FDIR and VVO based upon the standards developed in task EA3.6 Provide Mapping Requirements. The deliverable will be screen shots of the created displays for PUC review.

This task will develop the ADMS database for adding support for FDIR and VVO based upon the template point lists. The deliverable will be an export of the database.

EA4.4 SCADA Master End-to-End Testing Plan

This task will further develop the SCADA end-to-end testing plan (refer to SCADA end-to-end testing plan) started with the templates for field devices in task EA3.8.4.1 Template DA Field Testing Plans.

EA4.5 SCADA and ADMS Software Testing Plan

This task will perform the design of SCADA and ADMS testing plans (including the balance of ADMS functionality not already covered in the application testing).

EA4.6 SCADA and ADMS Master Training Plan

This task will perform the design of SCADA master training materials (including the balance of ADMS functionality not already covered in the application training). Training will be performed in task TR1 Training.

EA4.7 SCADA and ADMS Master Maintenance Plan

This task will perform the design of SCADA master maintenance plan (including the balance of ADMS functionality not already covered in the application training).

EA4 Deliverables
Deliverables provided by task

EA4 SCADA **Master** are listed in Table 11.

Table 11 – EA4 Deliverable List

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
1. Logical design.	EA4.1 SCADA Master Logical			■	■	■
2. Integration settings.	EA4.2 SCADA Master Sub-System Integration			■	■	■
3. Screenshots of displays.	EA4.3 SCADA Master Displays and Database	■	■	■	■	■
4. Database exports.	EA4.3 SCADA Master Displays and Database	■	■	■	■	■
5. SCADA master end-to-end testing plan.	EA4.4 SCADA Master End-to-End Testing Plan			■	■	
6. SCADA master and ADMS testing plans.				■	■	
7. SCADA master and ADMS training plan.	EA4.6 SCADA and ADMS Master Training Plan			■	■	
8. SCADA master and ADMS maintenance plan.	EA4.7 SCADA and ADMS Master Maintenance Plan			■	■	
9. Design review packages.	EA4 Reviews	■	■	■		

EA4 Reviews
Refer to Reviews.

EA4 Assumptions

1. All required ADMS points are available as standard points from the field devices (refer to Table 7 and Table 8).
2. Standard graphics and symbols from the Survalent ADMS will be implemented in the graphics built in the ADMS.
3. Substations are FDIR-ready, requiring no modifications to provide data to the SCADA System to support the provided ADMS applications. This includes points for circuit breaker lockout, fault targets, breaker status, and feeder/breaker currents and other FDIR and VVO required data.
4. The PUC has the following existing drawings available to support task:
    a. System/communication block diagram
    b. Data flow diagram

EA5 IVR
In coordination with the task EA1 System Integration, this task will design the IVR system.

EA5.1 IVR Logical

This task will define and document the TCP/IP network addressing and related settings to establish the basic TCP/IP network connectivity to the hosted IVR solution. These settings will be implemented by the PUC.

EA5.2 IVR Integration

This task will develop the detailed integration configuration for the test and production systems based upon the standard MultiSpeak protocol communication.

EA5.3 IVR Configuration

This task will create the IVR configuration.

EA5.4 IVR Software Testing Plan

This task will develop the IVR software testing plan (refer to

Software testing plan), which relies on the delivery of factory acceptance testing (FAT) plan from Milsoft that will also include IVR integration testing (refer to EA1.2.2 IVR Integration Software Testing Plan). Note that since Milsoft is a hosted solution, the lab testing plan (refer to task EA7.2 Create Lab Testing Plan) includes the IVR FAT instead of performing testing in the lab.

EA5.5 IVR Training Plan

This task will develop the IVR training materials. Training will be performed in task TR1 Training.

EA5.6 IVR Maintenance Plan

This task will develop the IVR maintenance plan.

EA5 Deliverables
Deliverables provided by task EA5 IVR are listed in Table 12.

Table 12 – EA5 Deliverable List

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
1. Logical design.	EA5.1 IVR Logical			■	■	■
2. Integration settings.	EA5.2 IVR Integration			■	■	■
3. IVR configuration.	EA5.3 IVR Configuration	■	■	■	■	■
4. IVR software testing plan.	EA5.4 IVR Software Testing Plan			■	■	
5. IVR training plan.	EA5.5 IVR Training Plan			■	■	
6. IVR maintenance plan.	EA5.6 IVR Maintenance Plan			■	■	
7. Design review packages.	EA5 Reviews	■	■	■		

EA5 Reviews
Refer to Reviews.

EA5 Assumptions
1. There are no specific assumptions for this task. Refer to General Assumptions.

EA6 Cut-Over Plans
This task will develop the cut-over plans that describe the process of cut-over from one system to another:

1. Cut-over plan from the test system to development system that will be performed in task CO2 Cut-Over from Test System to Development System.
2. Cut-over plan from the development system to the production system that will be performed in task CO4 Cut-Over from Development System to Production System.

The cut-over plan contents will have the same structure as the testing plans (a revision block, introduction, approach, tests, and action items; refer to Testing Plans), with the addition of steps that specify the following:

1. The cut-over sequence, which specify the steps required to perform the cut-over
2. Fallback procedures in case issues are encountered during the cut-over sequence
3. How the areas of responsibilities are restored to operations

The development of the cut-over plan will be coordinated with the development of the commissioning plan in task CN1.3 Create Commissioning Plan.

EA6 Deliverables
Deliverables provided by task EA6 Cut-Over Plans are listed in Table 13.

Table 13 – EA6 Deliverable List

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
1. Cut-over plan for test system cut-over to development system.	EA6 Cut-Over Plans	■	■	■	■	■
2. Cut-over plan for development system cut-over to the production system	EA6 Cut-Over Plans			■	■	■
3. Design review packages.	EA6 Reviews	■	■	■		

EA6 Reviews
Refer to Reviews with the following clarifications:

- The 30% design of the cut-over plan is the concept, or outline of the plan plus the plan objective/description and deliverable description.
- The 60% design of the cut-over plan incorporates comments from the 30% review and develops the detailed contents of the cut-over plan.
- The 90% design of the cut-over plan incorporates comments from the 60% design review.
- The IFC of the cut-over plan incorporates comments from the 90% design review.
- The AB of the cut-over plan is a completed plan.
- The design reviews for each cut-over plan will not be submitted together. The production system cut-over will be based upon the IFC-issue of the development system cut-over, thus reducing the number of reviews for the production system cut-over.

EA6 Assumptions
1. Each cut-over involves exporting the configurations and database from one system to create the other system; for example, the cut-over from the test to production system requires an export of the configuration and database from the test system for import into the production system.
2. The production system supports development system functionality by using limited areas of responsibility to isolate from operations all testing activities and its associated data, alarms, etc.

EA7 Lab Facility
This task will develop the design for the lab facility and create the lab testing plan. These tasks are coordinated with task ST1 Inventory and Warehouse.

EA7.1 Design Lab Facility and Test System
This task will design the lab facility located at a warehouse for testing the new database points, graphics, protocols, and provided applications in the UDM. The test system design will be coordinated with and leverage the template deliverables from task EA3.8 Develop Standardized DA Designs to create a set of installation drawings for the lab facility. The design will utilize a test server license (refer to task EA3.3 Identify Virtual Server Requirements) that will be installed on new virtual server(s) as part of the overall installation in task ST3.2 Install the Lab Test System.

This task will review and comment on the application of the PUC's existing procedures to the migration of the existing Survalent SCADA server from the existing, dedicated hardware platform to the virtual server environment (refer to task EA3.3 Identify Virtual Server Requirements). The PUC will approve and update the procedures. Any changes in scope, schedule, and budget will be implemented via the change management process (refer to task PM4 Change Management). Migration will only occur after the PUC has approved the report.

EA7.2 Create Lab Testing Plan
This task will create the lab testing plan (refer to Lab testing plan) as early in the project as possible and in coordination with the creation of the Commissioning Plan (refer to task CN1.3 Create Commissioning Plan and Figure 2). The lab testing plan will have tasks that execute the various testing plans shown in Table 14. Lab testing will utilize the test system and the field equipment and radios installed in a lab facility setting.

The lab testing plan will first test the applications and then test the remaining feeders as they are made ready for construction. Lab testing is completed on the new equipment to test those configurations before the equipment is shipped to the field for construction. One result is that any equipment that requires a configuration file will be shipped to the field with its configuration loaded and tested, so there is no need to load the configuration during construction and/or commissioning.

Table 14 – Lab Testing Tasks

TASK DESCRIPTION	TESTING PLAN CREATION	PREREQUISITE LAB TESTING TASKS
1. RF field tests for the gateway radio, repeater, and field radio.	EA3.8.4.4 Template RF Field Testing Plans	N/A, lab construction
2. RF end-to-end test.	EA3.8.4.5 Template RF End-to-End Testing Plans	1
3. Communications end-to-end test.	EA3.8.4.6 Template Communications End-to-End Testing Plans	2
4. Field tests for DA equipment.	EA3.8.4.1 Template DA Field Testing Plans	3
5. SCADA master end-to-end test.	EA4.4 SCADA Master End-to-End Testing Plan	4
6. Software tests for the required CYME integration.	EA1.4.3 CYME Integration Software Testing Plan	N/A
7. FDIR application test.	EA3.8.4.3 Template DA Application Testing Plans	5, 6
8. Software tests for the required CIS integration.	EA1.3.3 CIS Integration Software Testing Plan	N/A
9. Software tests for the required AMI integration.	EA1.5.4 AMI Integration Software Testing Plan	N/A
10. VVO application test.	EA3.8.4.3 Template DA Application Testing Plans	5, 6, 8, 9
11. Software tests for SCADA and ADMS covering the balance of functionality not already tested.	EA4.5 SCADA and ADMS Software Testing Plan	5
12. Auto-transfer application test.	EA3.7.2 Auto-Transfer Application Testing Plan	11

TASK DESCRIPTION	TESTING PLAN CREATION	PREREQUISITE LAB TESTING TASKS
13. Software tests for OMS covering the balance of functionality not already tested.	EA2.5 OMS Software Testing Plan	12
14. IVR FAT with IVR integration testing.	EA1.2.2 IVR Integration Software Testing Plan	Coordinated with 13

EA7 Deliverables

Deliverables provided by task EA7 Lab Facility are listed in Table 15.

Table 15 – EA7 Deliverable List

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
1. Report that reviews the PUC's applicable procedures to server migration.	EA7.1 Design Lab Facility and Test System			■	■	
2. Report that reviews the PUC's applicable procedures to creating the test system.	EA7.1 Design Lab Facility and Test System			■	■	
3. Modified or new drawings.	EA7.1 Design Lab Facility and Test System					
a. System/communication block diagram		■	■	■	■	■
b. Equipment layout drawing showing all of the equipment locations for the lab.			■	■	■	■
c. Equipment layout detail drawings showing power connection, communication connections, etc.				■	■	■
4. Completed lab testing plan.	EA7.2 Create Lab Testing Plan			■	■	
5. Design review packages.		■	■	■		

EA7 Reviews
Refer to Reviews.

EA7 Assumptions
1. No building permits are required for the installation of the lab facilities.

Black & Veatch Digital Domain

This domain includes design tasks associated with identifying gaps in UDM performance management compared to what is included as described within this document.

EP1 DA Monitoring and Awareness Assessment
This task will hold a workshop to review the provided performance monitoring objectives and the provided capabilities by collecting stakeholder input and data around KPIs associated with FDIR and VVO.

EP1.1 DA Monitoring and Awareness Workshop

This task will plan and conduct a workshop after the project kickoff meeting (refer to task PM1 Project Kickoff Meeting). The DA monitoring and awareness workshop will evaluate the DA monitoring and awareness plan, review the performance monitoring objectives and requirements along with the provided capabilities, and collect stakeholder input and data around KPIs associated with FDIR and VVO:

1. DA performance monitoring
    a. DA performance metric and penalty calculation. Survalent is confirming whether the ADMS can report a list of outages where fault restoration (to un-faulted segments) was not achieved within 1 minute[31] of fault inception, whether in automatic mode or semi-automatic mode.
    b. Data summarization and analysis that gathers and analyzes outage event data and archives summarized data in a meaningful format to enable trending of outage data statistics and is accessible by approved stakeholders. This may already be supported in the OMS reporting and OMS Internal Stakeholder Dashboard (refer to EA2 OMS).
2. Data summarization and analysis that gathers and analyzes outage event data and archive the data in a meaningful summary format. This may already be supported in the OMS reporting and OMS Internal Stakeholder Dashboard (refer to EA2.3 Internal Stakeholder Dashboard).
3. Data verification and validation[32]
4. VVO performance metrics that compute an average of daily end-of-line meter average voltage data (i.e., an average of averages). The report will flag violations if the daily average voltage readings are outside of a pre-determined voltage band (e.g, 110-115V).

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[31] "Electricity Reporting & Record Keeping Requirements", section 2.1.4.2, dated May 3, 2016, from the Ontario Electric Board, states:

> *An "Interruption" means the loss of electrical power, being a complete loss of voltage, of a duration of one minute or more, to one or more customers, including planned interruptions scheduled by the distributor but excluding part power situations, outages scheduled by a customer, interruptions by order of emergency services, disconnections for non-payment or power quality issues such as sags, swells, impulses or harmonics.*

[32] The Leidos statement of work does not provide definition around the term "data verification and validation". Given the "SCADA data" requested in Appendix II of the Leidos statement of work, this could be the verification and validation of received values against average values for per-phase amps and volts; and 3-phase apparent power, real power, and reactive power.

EP1.2 DA Monitoring and Awareness Report

Upon completion of task EP1.1 DA Monitoring and Awareness Workshop, this task will review stakeholder input and project data sources, address any action items from the workshop, perform an analysis against industry standards and best practices, and review related Survalent products and/or enhancements. The deliverable from this task is a report that includes an assessment with recommendations and impacts to project scope, schedule, and budget.

If needed, the report will include a conceptual design of the required changes to the system architecture to provide the ability to support the identified performance monitoring enhancements. The report will also discuss as necessary the training, testing, deployment, and maintenance requirements (such as a new business process around monthly analysis to prepare reports, compute metrics, perform root cause analysis, and create recommendations).

The PUC will review and approve the recommendations, any changes to project scope, schedule, or budget that result from the approval of any part of this report will be input into the task PM4 Change Management.

EP1 Deliverables

Deliverables provided by task EP1 DA Monitoring and Awareness Assessment are listed in Table 16.

Table 16 – EP1 Deliverable List

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
1. DA monitoring and awareness report.	EP1.2 DA Monitoring and Awareness Report			■	■	
2. Design review packages.				■		

EP1 Reviews
Refer to Reviews.

EP1 Assumptions
1. There are no specific assumptions for this task. Refer to General Assumptions.

PUC Substation Domain

The PUC substation domain major task will initiate:

1. The implementation of the substation communications in task ES1 Substation Communication Design

The implementation will provide complete and coordinated design packages for each implementation on a site-specific basis.

Note that field surveys of the substations are included in task EF1.2 DA Field Survey.

ES1 Substation Communication Design
This task will design the substation portion of the SpeedNet™ radio communications system to connect the SCADA Master ADMS to each of the field devices being installed. The SpeedNet™ radio will then be connected to the existing PUC fiber backbone. Work will be coordinated with any requirements developed out of task EF2 Design DA Field Area Network (such as required antenna height and location) and the final selection of the FCI wireless technology performed in task EA3.2.2 FCI Wireless Report.

ES1.1 Gateway Radio Design
Gateway radios and antennas will be installed at the number of PUC substations shown in Table 6. The gateway radios will be mounted within the substation, DC powered, and the communications circuit connected to the SCADA Master via the PUC's IP fiber network.

ES1.1.1 Electrical Design (Power, Grounding, Cabling, etc.)
The electrical design will design the addition of the DC-powered gateway radio to an existing "Telecom Rack" or other rack inside the existing control house. This task will develop detailed engineering design drawings as listed in ES1 Deliverables that will address racking requirements, power supply, and network connection that connects the gateway radio into the PUC's backhaul system.

This task will develop:

1. The site-specific gateway radio configuration file based upon the template configuration developed in task EA3.8.3.2 RF Template Configurations.
2. The site-specific interconnection design that connects the gateway radio into the PUC's backhaul system.
3. The site-specific gateway radio field testing plan based upon the template developed in task EA3.8.4.4 Template RF Field Testing Plans.
4. The site-specific RF end-to-end testing plan based upon the template developed in task EA3.8.4.5 Template RF End-to-End Testing Plans.
5. The site-specific communications end-to-end testing plan based upon the template developed in task EA3.8.4.6 Template Communications End-to-End Testing Plans.

ES1.1.2 Civil (Below Grade, Trenching, Concrete Pads, Pull Boxes, etc.)
Civil work will only be required if the radio antennas cannot be mounted on a suitable substation structure.

ES1 Deliverables

Deliverables provided by task ES1 Substation Communication Design are listed in Table 17.

Table 17 – ES1 Deliverable List

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
1. Modified or new substation drawings.	ES1.1.1 Electrical Design (Power, Grounding, Cabling, etc.)					
a. System/communication block diagram (existing)		■	■	■	■	■
b. Rack layout drawing with bill of material for each rack on the drawing (existing)		■	■	■	■	■
c. DC schematic (existing)			■	■	■	■
d. Rack wiring drawing (existing)				■	■	■
e. Communication cable list (existing)				■	■	■
f. Control house elevation (existing)			■	■	■	■
2. Gateway radio configuration file.	ES1.1.1 Electrical Design (Power, Grounding, Cabling, etc.)			■	■	■
3. Site specific network interconnection design.	ES1.1.1 Electrical Design (Power, Grounding, Cabling, etc.)			■	■	■
4. Site specific testing plans.	ES1.1.1 Electrical Design (Power, Grounding, Cabling, etc.)			■	■	■
5. Civil design.	ES1.1.2 Civil (Below Grade, Trenching, Concrete Pads, Pull Boxes, etc.)	■	■	■	■	■
6. Design review packages.	ES1 Reviews	■	■	■		

ES1 Reviews

Refer to Reviews.

ES1 Assumptions

1. The PUC will assist in substation site reviews.
2. Each substation has available space in a "Telecom Rack" or other rack where the gateway radio can be installed.
3. Sufficient DC power supply and cable routes are available within the PUC substation without modification.
4. The PUC will make any necessary modifications to the PUC's backhaul system to support the communication connection to the gateway radio.
5. All locations will have a suitable antenna mounting location that does not require deviation from the standard design developed from task EA3.8.1 DA Template Design Drawings.
6. Any radio antennas that cannot be mounted on the substation structure will be identified and additional electrical and civil work estimated on a per-site basis for its impacts on scope, schedule, and budget. Any required scope changes will be input into the task PM4 Change Management
7. The PUC will update all configurations of existing communications equipment being connected to the gateway radio and coordinate that configuration with the design work in this task such that those configurations are coordinated by the PUC with each IFC package.
8. The communications security provided by the SpeedNet radios is acceptable to the PUC (128-bit AES data encryption with user-defined keysets created using the supplied Keygen tool).

PUC Field Domain

EF1 Site-Specific DA Design

This task will develop a complete work order package to design, install and test the equipment being installed to support FDIR, VVO, and auto-transfer as shown in Table 6 and Table 7 (voltage regulators and capacitors).

EF1.1 Load Flow and Protection Analysis of Feeders

Upon approval of the report in task EA3.1 Feeder Evaluation, this task will perform distribution circuit analysis (load flow, reliability, and protection) in CYME based upon the feeders shown in Table 6.

The study will determine the general installation regions for the equipment specified in Table 6 and perform feeder balancing (re-phasing). This analysis will be focused on feeders using various criteria, such as whether the placement meets PUC criteria by considering circuit placement, customer voltage, reactive loads, has sufficient wireless coverage (refer to approval of the field communication survey report from task EF2.2 Field Area Network Conceptual Design), or other site-specific considerations. This task will create a report documenting the results of the circuit analysis and providing the final model.

The output of this task is required for task EA1.5.1.3 Bellwether Meter Report.

EF1.2 DA Field Survey

Once the feeder analysis in EF1.1 Load Flow and Protection Analysis of Feeders is complete and potential locations are identified, a field survey will be coordinated with task EF2.1 Wireless Communications Field Survey and task EA3.5 Substation SCADA Point Assessment.

In particular for the FCI, at least the following will be confirmed:

1. RF coverage (refer to task EF2.2 Field Area Network Conceptual Design)

2. Line current [33]
3. Phase identification
4. General location

For VVO, the site visits will confirm the location of the voltage regulators.[34]

This task will create a VVO, FDIR, and auto-transfer conceptual design report that details the results of the analysis performed. Impacts on scope, schedule, and budget will be identified. Any required scope changes will be input into the task PM4 Change Management.

EF1.3 DA Detailed Design

After the report from task EF1.2 DA Field Survey is approved, this task will perform a site-specific survey to address local conditions and finalize location selection. This task will use the standards developed in task EA3.8.1 DA Template Design Drawings to create a complete Work Order for each location.

A complete work order package may include (as appropriate for the field location, e.g., FCI, radio, repeater):

1. A GIS-based sketch of the work location and other drawings as necessary, such as:
    a. Communication block diagram
    b. Rack/cabinet/pole layout drawing example or standard
    c. Rack/cabinet/pole wiring drawing example or standard
    d. AC and/or DC schematic
    e. Data flow diagram
2. Equipment installation and removal, plus any re-use (e.g., new or reuse existing pole).
3. Notes pertinent to construction, permits, and testing.
4. Required permits.
5. Tree trimming. Requirements for tree trimming will be identified on the work order and evaluated in the change management process (refer to task PM4 Change Management).
6. Antenna and radio coordinated with task EF2.3 Field Area Network Detailed Design.
7. AC power.
8. A BOM that is adapted from the BOM developed in task EA3.8.1 DA Template Design Drawings so that the BOM becomes site-specific and describes all materials required at each specific work location. This is coordinated with the BOM developed out of task EF2.3 Field Area Network Detailed Design.
9. Not used.
10. Configuration files for all IEDs and radios installed at each location included in the work order, based upon the templates developed in task EA3.8.3 DA Template Configurations.
11. Field testing plans (refer to Field testing plan) based upon the templates developed in task EA3.8.4.1 Template DA Field Testing Plans.

The design will be finalized for permitting at the 90% stage and coordinated as required with task EF3 Siting.

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[33] The GridAdvisor II has a nominal current range of 3 – 600 A with a ±1% accuracy, with capability up to 20 kA of fault current. A minimum of 3 A of current is required for energy harvesting.

[34] During the meetings held with the PUC and IECo on April 10, 2017, all substation locations were reviewed using Google Earth. It was observed that many substations had no room for pole-mounted regulators nor pad-mounted regulators. Replacement of the existing transformers to transformers with an LTC appeared to be the only option at some substations. The site visits will be used to confirm the best approach.

This task performs protection coordination analysis for each recloser and switch site to develop appropriate protection settings with protective relay coordination curves. Control settings (SCADA and communications) will be based upon the template settings developed by task EA3.8.3 DA Template Configurations.

All configurations (reclosers and switches) will be ready for download to the controller.

This task will perform an engineering analysis for each pole location involved in equipment installation in order to meet the Ontario Regulation 22/04.

EF1 Deliverables

Deliverables provided by task EF1 Site-Specific DA Design are listed in Table 18.

Table 18 – EF1 Deliverable List

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
1. Distribution feeder analysis report.	EF1.1 Load Flow and Protection Analysis of Feeders		■		■	
2. Field survey report confirming all equipment locations with pictures and mapping information; associated analysis; and identifying any deviations from the planned scope of work.	EF1.2 DA Field Survey			■	■	
3. Complete work order package.	EF1.3 DA Detailed Design		■	■	■	■
4. Design review packages.		■	■	■		

EF1 Reviews

Refer to Reviews.

EF1 Assumptions

1. Refer to General Assumptions, item 25.
2. Not used.
3. Not used.
4. Not used.
5. The field survey work will not consider distribution line improvements or pole improvements not directly associated with this project's scope of work. For example, the re-phasing work will not upgrade the tap to the most recent distribution design standards, replace fuses, or install fuses; but be a simple transfer.
6. Not used.
7. The PUC will provide examples of standard work order packages, which align with the content described in task EF1.3 DA Detailed Design.
8. The number of field survey trips included is at most one per feeder for task and coordinated with the task EF2.1 Wireless Communications Field Survey.
9. The PUC will provide all construction standards related to the equipment being installed as detailed in Table 6, Table 7, and Table 8 without delaying the project schedule. Detailed design activities will not begin until approved design standards are available for the designs.
10. The PUC will review and approve each field survey report submitted from task EF1.2 DA Field Survey at the 30% design review. Each report will identify any additional work and provide an estimate of impacts on scope, schedule, and budget. Any required scope changes will be input into the task PM4 Change Management. No work orders will be prepared in task EF1.3 DA Detailed Design on locations that have not been approved by the PUC.
11. Secondary voltage is available within one span of new equipment to provide power for new IEDs.
12. Recloser settings will be coordinated with the feeder breaker. Lack of protection coordination with existing line devices (fuses) is only identified but remediation is not included in the proposed scope of work.
13. Substation regulators will be mounted on an "H-frame" structure at each of the feeder exits outside the substation fence and are rated at 438 A (333 kVA).
14. All permitting is complete prior to the work order being released IFC.
15. The PUC will provide all required substation protective relay setting files.
16. Distribution system protection analysis will limit its coordination to one mainline device up and one mainline device downstream of recloser devices.
17. Feeder ties (switches) have sufficient capacity to handle load back-feed conditions.
18. Underground switches and reclosers will be replaced one for one. No additional underground cabling or foundation work will be required to install these devices.
19. Black & Veatch will coordinate with the PUC and Eaton for the setup and site commissioning of FCI and voltage sensors.

EF2 Design DA Field Area Network

This task will design the field area network using wireless communications to devices supporting FDIR, VVO, and auto-transfer. The field area network will utilize unlicensed IP-based radios to gateway radios located in the substation (SpeedNet™ radios). Repeaters will be provided to support field communications.

EF2.1 Wireless Communications Field Survey

Upon final selection of the FCI wireless technology performed in task EA3.2.2 FCI Wireless Report, this task will perform a coordinated field survey for the wireless field area network. The field survey will review each proposed field device location identified in task EF1.2 DA Field Survey along with each substation. The field survey report will include a constructability assessment, documentation of field conditions, pictures of each site, and a system communication block diagram showing what will be implemented for the field area network.

EF2.2 Field Area Network Conceptual Design

This task will create a conceptual field area network report with two conceptual design components:

1. The radio frequency (RF) path design for the field area network emanating from the substations and connecting field devices utilizing SpeedNet™ radios[35].
2. A cellular coverage for the FCI devices.

Both will include an RF interference study.

This task will also estimate the required bandwidth for connection from the DA field equipment to the PUC's backhaul and control center.

A wireless conceptual engineering design package will include a communication block diagram and coverage map and will provide recommendations to resolve any issues or concerns.

Any impacts to the project scope, schedule, or budget will be evaluated by the project team with approved changes submitted through the change management process task PM4 Change Management.

EF2.3 Field Area Network Detailed Design

This task will develop the detailed design of the field area network for each radio location and repeater location based upon the standard design and BOM created in task EA3.8.1.2 RF Template Design Drawings. This design work will be coordinated with the work orders developed in the task EF1.3 DA Detailed Design.

This task will also develop the site-specific testing plans based upon the templates developed in task EA3.8.4.4 Template RF Field Testing Plans.

Note the substation gateway radio detailed design is performed and associated test plans created in task ES1.1.1 Electrical Design (Power, Grounding, Cabling, etc.).

EF2 Deliverables

Deliverables provided by task EF2 Design DA Field Area Network are listed in Table 19.

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[35] The SpeedNet™ radios use the unlicensed 902-928 MHz band, so RF licensing is not required.

Table 19 – EF2 Deliverable List

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
1. Field survey report for each field device and substation.	EF2.1 Wireless Communications Field Survey	■				
2. Field area network conceptual design report.	EF2.2 Field Area Network Conceptual Design		■			
3. Field area network final engineering design package	EF2.3 Field Area Network Detailed Design			■[36]	■	■
4. Design review packages.		■	■	■		

[36]The physical design packages will be coordinated with task EF1.3 DA Detailed Design.

EF2 Reviews
Refer to Reviews.

EF2 Assumptions
1. This task does not address cellular enabled equipment (FCI and voltage sensors) that will use existing public carrier cellular networks and PUC-contracted data plans and agreements.
2. A path is defined as a field device to the gateway radio, located at the substation of the feeder origin that the device is normally serving. Each path requires no more than two hops from the substation to field device, including repeaters.
3. RF interference, line-of-sight (LOS), non-LOS (NLOS), and clutter issues will be identified and recommendations will be provided as part of the task EF2.2 Field Area Network Conceptual Design. Wireless network performance will be engineered to support design functionality of FDIR and VVO devices. Issues not resolved by additional repeaters, or exceeding the maximum number of repeaters shown in Table 8, will be an additional scope of work.
4. Network performance will be measured from field device to substation gateway radio and will be consistent with industry standard unlicensed wireless metrics.
5. SpeedNet™ radios will meet the performance and cyber security requirements for all applications being supported by the radios.
6. Underground DA switches will have appropriate above ground structure to mount an antenna mast and antenna without additional civil or structural engineering or construction.

EF3 Siting
This task will review all permitting and environmental requirements for all field work and initiate a protocol for each type of permit required.

EF3.1 Local Permits
This task will confirm permitting requirements, processes and timelines with the City of Sault Ste Marie, Ontario for installation of proposed equipment onto existing infrastructure within the public Right of Way (ROW) including replacement of some wooden poles (refer to Table 10).

This task will complete and submit applicable permits. This task will also coordinate, compile and manage documents and information necessary for submittal and completion of the permitting process.

EF3.2 Public Relations
This task will support public relations by attending neighborhood or community meetings and/or creating materials to support the meetings (e.g, presentation slides).

EF3 Deliverables
1. Local municipal permits, as required from the City of Sault Ste Marie, for installation of proposed equipment onto existing infrastructure within the public ROW including replacement of wooden poles.
2. Materials for neighborhood or community meetings, such as presentation slides.

EF3 Reviews
One review is planned for the deliverables created to support public relations meetings (refer to Table 1).

EF3 Assumptions
1. Required permits for this project will be issued by the City of Sault Ste. Marie, Ontario.
2. Timeline for permitting is six months.

3. Public Relations support limited to attendance at two neighborhood or community meetings to support positive messaging to the community regarding the project.
4. The following are excluded:
    a. Provincial, Federal or Tribal regulatory/environmental assessments or approvals, including related third party studies.
    b. Zoning or variances, or special permits/approvals other than a Building/Electrical and/or ROW permit and Traffic permits or approvals from the City of Sault Ste Marie.
    c. Zoning or permitting for replacement infrastructure beyond or in addition to standard permitting scope, if necessary.
    d. Leasing, easements and pole attachment agreements, including negotiations, amendments and execution.
    e. Floodplain, wetlands or storm water approvals and requirements.
    f. Third party services, including outside counsel, experts, third party reviews, inspections or studies.
    g. Municipal meetings and hearings (other than two public relations related meetings).
    h. Zoning, permitting, application, notice, filing, expediting and review fees.
5. Permits under this scope include building/electrical, ROW, and traffic permits.

PUC Organizational Domain

This domain includes design tasks associated with identifying the impacts of the UDM on the PUC's organization and processes. Accurate business processes are a fundamental element in effective implementation of complex and transformative technology. All effective business implementation steps flow from sound and detailed business process design; including:

- Business and functionality requirements to institute transformative ways of working; technical requirements flow from these business and functional requirements
- Use Case test requirements to help ensure that required functional and performance capabilities will support the new business processes
- Role changes, skill requirements, training needs and organizational changes
- Communications requirements to impart change to those impacted by the new/changed processes
- Process transition, phasing, and migration plans to effectively migrate from existing processes to new processes while mitigating the risks of change
- Business readiness assessment and Go Live criteria

Thus, business process design is a critical element of the program implementation that assures that the proposed solutions are implemented in a manner that mitigates the risks of change while providing a transition to the future business processes that unlock the value resulting from the implementation of the new AMI solutions.

Business process design starts with a complete understanding of current and future business processes. Successful implementation of complex systems also requires clear knowledge of the transitional business and operational processes required to get from the As-Is to the To-Be state. The understanding and careful planning for interim "transitional states" is vital to the sustaining operational states that are inevitable on the path to the fully integrated solution.

Business process transformation also drives the operational and business metrics that are needed to effectively manage the business. Development of these metrics and Service Level Agreements (SLAs), and the trending of these over time, is crucial to measurement of the solutions success and effectiveness in achieving expected benefits. While some SLAs may already be defined within the Vendor contracts, the development and measurement of end-to-end business metrics and SLAs helps assure the PUC that it has achieved its complete business goals with these investments.

EO1 Business Process and Organizational Change Management

EO1.1 Business Process Workshops

This task will identify existing business processes affected by (such the processes around CYME updates, refer to task EA1.4 CYME Integration) and new business processes required by the UDM project implementation. Workshops will be held with PUC employees involved in the organization whose processes may be impacted by the UDM. Examples of the required information and functional groups are shown in Table 20.

Table 20 – Examples of Required Information for Business Process and Organizational Change Management

FUNCTIONAL GROUP	TYPES OF INFORMATION
Operations Engineering System Planning Maintenance and Construction Communications IT OT Security Asset Management	Long range (3-5 years) technology and/or organizational roadmaps Current IT plans Business processes Job family descriptions Organization charts Enterprise vision, goals and objectives Strategic business plans and summaries of strategic initiatives Prior analysis and business process models, if applicable Organizational chart and overview of departmental responsibilities Cost information work processes Enterprise application architecture designs/diagrams Planned capital projects Data management process and requirements Maintenance, disaster recovery and IT security plans Business process definitions and flows Recently completed internal technology assessments Cyber and physical security documents IT/information system standards, infrastructure, plans and costs (including implementation, and maintenance)

EO1.2 Develop Recommended Business Process Changes

This task will review the information gathered in the previous task to create a report that documents the as-is state of business processes and the recommended to-be state. The report will also include recommended train-the-trainer training and its general outline.

EO1.3 Organizational Change Workshops

This task will identify existing organization structures affected by and new organizational structures required by the UDM. Workshops will be held with PUC employees whose organization may be impacted by the UDM. Examples of the required information and functional groups are shown in Table 20.

EO1.4 Develop Recommended Organizational Changes

This task will review the information gathered in the previous task to create a report that documents the as-is state of the organization and the recommended to-be state. The report will also include recommended train-the-trainer training and its general outline.

EO1.5 Training for Business Process and Organizational Changes

Once the final report deliverables are approved, this task will create the training materials, coordinate training activities, and provide the train-the-trainer training to PUC employees.

EO1 Deliverables

Deliverables provided by task EO1 Business Process and Organizational Change Management are listed in Table 21.

Table 21 – EO1 Deliverable List

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
1. Business process change report.		■	■	■	■	
2. Organizational change report.		■	■	■	■	
3. Business process train-the-trainer materials.				■	■	■
4. Organizational train-the-trainer materials.				■	■	■
5. Design review packages.		■	■	■		

EO1 Reviews
Refer to Reviews.

EO1 Assumptions
1. This task will evaluate the requirements generated from business process workshops and analysis against project scope, schedule, and budget and provide recommendations. The PUC will review and approve the recommendations. Any changes in scope, schedule, and budget will be implemented via the change management process (refer to task PM4 Change Management).
2. This task will conduct/lead up to four Business Process Workshops with PUC employees over the course of one site trip lasting one week.
3. The baseline scope includes one business processes (expected to be the process that results in the update of the SCADA map) and one organizational change.
4. This task will conduct/lead up to four organizational change workshops with PUC employees over the course of one site trip lasting one week.
5. Training included for business process change management is for the assumed number of changes and includes daily training sessions over one contiguous week.
6. Training included for organizational change management is for the assumed number of changes and includes daily training sessions over one contiguous week.
7. Not used.
8. Not used.
9. After training is complete, the PUC will perform the leadership role for the adoption and maintenance of the associated business process and organizational change management within the utility.

Procurement

Purchasing

PR1 Purchase Major Materials and Equipment
This task will perform the procurement process that follows the project's procurement plan to purchase materials, equipment, and training (refer to task TR1 Training) as described in the following tasks:

1. PR1.1 Survalent Software
2. PR1.2 VVO Equipment
3. PR1.3 RF Equipment
4. PR1.4 DA Equipment
5. PR1.5 IVR Software
6. PR1.6 Server Hardware

Any specialized storage and handling to meet vendor warranty requirements will be identified during procurement (refer to task ST3 Stage Major Systems and Test). An internal project procurement plan will be developed that defines all procurement activities for these items, such as:

- Purchasing and subcontracting
- Inspecting and testing
- Remittance
- Material management. Material management is comprised of all purchasing, expediting, supplier quality surveillance, traffic and logistics, and field purchasing and warehousing activities required for project execution.

This task will be coordinated with the task EA3.8.1 DA Template Design Drawings that develops standard bill of materials (refer to Table 9). Purchase Orders will be created in Oracle and automatically loaded into the material management system to allow tracking of material receipts and issues (refer to tasks ST1 Inventory and Warehouse and ST2 Inspect and Verify OEM Specs).

Materials required for the test lab facility will be diverted from the ordered quantities and/or obtained on loan from vendors, used in the lab facility, and then shipped to the field for installation or returned to the vendor.

Any procurement activities that result in an impact to the project scope, schedule, or budget will be evaluated by the project team with approved changes submitted through the change management process task PM4 Change Management.

PR1.1 Survalent Software

This task will track and manage the purchase of all software procured from Survalent. For related hardware, refer to task EA3.3 Identify Virtual Server Requirements. This task also provides the vendor's standard set of documentation, such as user's guide, installation guide, editing guide, operator guide, etc.

PR1.2 VVO Equipment

This task will track and manage the purchase of voltage regulators, capacitor banks, controllers and other line equipment shown in Table 6 and Table 7. This task also provides the deliverable of the vendor's standard set of documentation, such as user's guide, installation guide, operator guide, etc.

PR1.3 RF Equipment

This task will track and manage the purchase of radios, repeaters and other associated equipment including cable entrance equipment as required for the installation of the major RF equipment supporting the field area network as shown in Table 8**.** This task also provides the vendor's standard set of documentation, such as user's guide, installation guide, operator guide, etc.

PR1.4 DA Equipment

This task will track and manage the purchase of equipment as required for the installation of the major equipment shown in Table 6 and Table 7. This task also provides the vendor's standard set of documentation, such as user's guide, installation guide, operator guide, etc.

PR1.5 IVR Software

This task will track and manage the purchase of the IVR software. This task also provides the vendor's standard set of documentation, such as user's guide, installation guide, operator guide, etc.

PR1.6 Server Hardware

This task will track and manage the purchase of the server hardware identified in task EA3.3 Identify Virtual Server Requirements.

PR1 Deliverables

1. Copies of all purchase orders when orders placed.
2. Copies of all delivery receipts of received materials.
3. Standard set of Survalent software documentation.
4. Standard set of server hardware documentation.
5. Standard set of VVO equipment documentation.
6. Standard set of RF equipment documentation.
7. Standard set of DA equipment documentation.

PR1 Reviews

1. There deliverables for task PR1 Purchase Major Materials and Equipment will be issued without any planned reviews.

PR1 Assumptions

1. The PUC purchases the required cellular licenses that establish cellular connectivity with the field devices supporting cellular communications.

PR2 Purchase All Other Materials and Equipment

This task will perform the procurement process that follows the project's procurement plan to purchase all other materials and equipment not accounted for in task PR1 Purchase Major Materials and Equipment (i.e., minor materials such as fuse blocks, connectors, wire, etc.).

PR2 Deliverables

1. Copies of all purchase orders when orders placed.
2. Copies of all delivery receipts of received materials.

PR2 Reviews

1. The deliverables for task PR2 Purchase All Other Materials and Equipment will be issued without any planned reviews.

PR2 Assumptions

1. There are no specific assumptions for this task. Refer to General Assumptions.

Staging and Testing

ST1 Inventory and Warehouse

This task will establish and manage the warehouse to (as required):

- Allow access to authorized persons only.
- Require documentation prior to withdrawal of materials and equipment from the warehouse.
- Provide service counters for presenting, processing documents.
- Provide loading/unloading docks.
- Equip with fire extinguishers and storage racks.
- Designate spaces for subcontractor use.

This task will coordinate with task PR1 Purchase Major Materials and Equipment to warehouse the equipment until it is required for tasks ST3 Stage Major Systems and Test and ST4 Kit and Prepare for Field. Design of the lab facilities will also be coordinated (refer to task EA7.1 Design Lab Facility and Test System).

This task will also close the warehouse facility once all material has been received and distributed to the field for installation.

ST1 Deliverables

1. There are no deliverables to the PUC for task ST1 Inventory and Warehouse except for updates to the project schedule related to receipt and disbursement of received materials.

ST1 Reviews

1. There are no deliverables planned for task ST1 Inventory and Warehouse.

ST1 Assumptions

1. The warehouse will be located in Sault Ste. Marie.

ST2 Inspect and Verify OEM Specs

Once task ST1 Inventory and Warehouse receives shipments, this task will inspect and verify all equipment received and tag each component as required. The inspection and verification process will (as applicable):

- Check all deliveries against the packing list and/or a copy of the purchase order prior to being off-loaded whenever possible. If this is not possible, the delivery shall be checked against the purchase order as soon as possible after off-loading.
- Photograph the received material prior to off-loading whenever possible. Photographs should be uploaded to the material management system and attached to the receiving document.
- Perform a visual inspection of the shipment and all containers, boxes, pallets, crates, etc., to determine whether any damage has occurred.
- Check load binders, cribbing, and tie-downs for evidence of load shifting during transit.
- Review the manufacturer's shipping and receiving requirements to determine whether the carrier has complied with all shipping and handling instructions during transit.
- If impact recorders are used, remove the records/results and check against the recorder instructions. Date, file, and distribute results appropriately.

ST2 Deliverables

1. There are no deliverables to the PUC for task ST2 Inspect and Verify OEM Specs except for updates to the project schedule related to receipt and disbursement of received materials.

ST2 Reviews

1. There are no deliverables planned for task ST2 Inspect and Verify OEM Specs.

ST2 Assumptions

1. All deliveries will be properly checked and inspected immediately upon delivery (or within 48 hours of time of receipt), including photographs.

ST3 Stage Major Systems and Test

This task will coordinate and use the lab facilities to execute the lab testing plans (refer to Lab testing plan).

ST3.1 SCADA to ADMS Server Migration

This task will migrate the existing Survalent SCADA server from the existing, dedicated hardware platform to the virtual server environment (refer to task EA3.3 Identify Virtual Server Requirements).

This task will then follow the identified procedure to migrate the existing Survalent SCADA server from the existing, dedicated hardware platform to the virtual server environment (refer to task EA3.3 Identify Virtual Server Requirements).

ST3.2 Install the Lab Test System

This task will install the lab test system at the warehouse facility using the design created in task EA7.1 Design Lab Facility and Test System.

After the successful migration of the Survalent system to a virtual environment in task ST3.1 SCADA to ADMS Server Migration, the PUC will follow the identified process to replicate the existing Survalent production system from the new virtual server to another virtual server.

ST3.3 Lab Testing

This task will execute the lab testing plan (refer to Lab testing plan) created in task EA7.2 Create Lab Testing Plan.

ST3.4 Delivery of Lab to the PUC

1. Once all lab testing is successfully completed in task ST3.3 Lab Testing and the cut-over to the development system in task There are no specific assumptions for this task. Refer to General Assumptions.

CO2 Cut-Over from Test System to Development System is complete, this task will relocate the test system to its final location at the PUC.

ST3.5 Installation of Lab at the PUC

This task will receive the lab equipment and permanently install it in the PUC's facility.

ST3 Deliverables

Deliverables provided by task ST3 Stage Major Systems and Test are listed in Table 22.

Table 22 – ST4 Deliverable List

DELIVERABLE DESCRIPTION	TASK	30%	60%	90%	IFC	AB
1. Completed server migration procedure documentation.	ST3.1 SCADA to ADMS Server Migration			■	■	
2. Completed lab testing plan.	ST3.3 Lab Testing			■	■	
3. Delivery confirmation of lab equipment to PUC facility.	ST3.4 Delivery of Lab to the PUC				■	

ST3 Reviews

Refer to Reviews.

ST3 Assumptions

1. Once the testing is complete, the test system will be removed from the lab and moved to a location specified by the PUC with a minimum of 1,000 square feet of available space with adequate power and communications capabilities to support the test lab on a permanent basis. Costs for moving the test system from the lab testing facility to a PUC-specified location in Sault Ste. Marie will be evaluated as part of the change management process (refer to task PM4 Change Management).
2. No Survalent software upgrade is required during the hardware migration in task ST3.1 SCADA to ADMS Server Migration.
3. Not used.
4. Two weeks of onsite services are included for OMS commissioning that also includes system training (refer to task TR1 Training.).
5. Two weeks of onsite services are provided for FDIR and auto-transfer points checkup, validation of database points including field devices and substation devices.
6. Four weeks of onsite services are provided for VVO commissioning, validation of database and displays for regulators and capacitor bank controllers.
7. Two weeks onsite commissioning for AMI system integrations.

ST4 Kit and Prepare for Field

This task will create kits for all equipment required to be delivered to the field for the construction crews. Kits will be ready for field deployment.

ST4 Deliverables

1. There are no deliverables to the PUC for task ST4 Kit and Prepare for Field except for updates to the project schedule to indicate site-specific kits are ready for installation.

ST4 Reviews

1. There are deliverables planned for task ST4 Kit and Prepare for Field.

ST4 Assumptions

1. There are no specific assumptions for this task. Refer to General Assumptions.

Training

Because training depends upon procurement[37], the actual training activity has been collected under procurement tasks as a single task. This does not imply all training activities will occur at the same time, but training will be coordinated with engineering and procurement activities, ideally taking place before construction activities.

TR1 Training

This task performs the training activities associated with the procured equipment and software (refer to task PR1 Purchase Major Materials and Equipment). This task will perform the training activities as identified in the developed training plans:

- EA1.2.3 IVR Integration Training Plan

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[37] Vendors of major materials and equipment will be quoting materials and standard training options (refer to task PR1 Purchase Major Materials and Equipment).

- EA1.3.4 CIS Integration Training Plan
- EA1.4.4 CYME Integration Training Plan
- EA1.5.5 AMI Integration Training Plan
- EA2.6 OMS Training Plan
- EA3.7.3 Auto-Transfer Training Plan
- EA3.8.5 DA Training Plans
- EA4.6 SCADA and ADMS Master Training Plan
- EA5.5 IVR Training Plan

Other training not directly associated with major materials and equipment occurs during task EO1.5 Training for Business Process and Organizational Changes.

TR1 Deliverables

1. Training logs.

TR1 Reviews

1. The review and approval of the training logs will be in accordance with Table 1 and Appendix H-4.

TR1 Assumptions

2. There are no specific assumptions for this task. Refer to General Assumptions.

Construction/Implementation

The construction domain includes the construction and implementation across all three domains, plus a commissioning phase that spans all three domains.

Commissioning Phase

The commissioning phase occurs during construction, spans all three domains, and relies on the UDM project being broken down into more "manageable pieces" for commissioning purposes. The definition of these "manageable pieces" will be a deliverable provided in task CN1.2 Create Turnover Packages. Once the "manageable pieces" are established, the Commissioning Execution Plan is created (refer to task CN1.3 Create Commissioning Plan). The Commissioning Execution Plan is used to manage the commissioning sequence for each defined "manageable piece".

The actual commissioning phase work starts when the construction team completes its work on items within a defined "manageable piece", provides the commissioning team with the turnover package, and the turnover package is accepted by the commissioning team. Each transfer is accomplished by using a turnover package, which will be a deliverable provided in task CN1.2 Create Turnover Packages.

Turnover is the transfer of the care, custody and control of the unit from one team to another team (e.g., construction to commissioning, Black & Veatch to the PUC after the completion of an activity). Turnover involves the transfer of substantial quantities of documentation and physical assets. All turnovers will be documented with detailed, itemized, signed manifests and receipts (refer to task CN1.2 Create Turnover Packages).

CN1 Construction Activities and Management

This task will provide construction management services and perform construction activities:

1. CN1.1 Pre-Mobilization/Mobilization Activities
2. CN1.2 Create Turnover Packages
3. CN1.3 Create Commissioning Plan
4. CN1.4 Construction Activities and Management
5. CN1.5 Commissioning
6. CN1.6 Closeout

This task will provide the functional direction and support of all construction operations. Construction departments, including Construction Operations, Technology, Quality Control, and Safety report to the Construction Operations Manager and are responsible for the execution of their assigned construction activities.

CN1.1 Pre-Mobilization/Mobilization Activities
This task will:

1. Provide input to project-specific project instructions.
2. Conduct internal construction meetings.
3. Create an internal Construction Execution Plan (CEP) and other internal construction execution manuals, which contain the requirements for execution of all construction activities on the project as required by the PEP.

Prepare and maintain the project's construction schedule (refer to task
4. PM5.4 Construction Schedule).
5. Setup the project's site construction operation and facilities, which include lab testing facilities to execute testing plans (refer to task ST3.3 Lab Testing).

CN1.2 Create Turnover Packages
This task will develop the turnover packages by breaking down the project into small "manageable pieces" (refer to Figure 1). The grouping should promote the most efficient execution of construction completion, commissioning activities, staffing and task assignments, documentation organization, and ultimately turnover to the PUC.

Development of turnover packages is a two stage process:

1. Define the turnover packages using Figure 1 as a guideline, whose output will be a list of turnover packages. This list shows the breakdown of all components into groupings of common equipment that are logically grouped together to sequence the testing leading up to larger turnover packages until a final turnover package is generated for the UDM. The following types of turnover packages are expected:
    a. Construction work to commissioning work for each equipment and/or location.
    b. System turnover package for each group of equipment and/or location.
    c. Final turnover package to the PUC.
2. Develop the listed turnover packages. These will be used during the commissioning phase (refer to Commissioning Phase) to formally document the turnover of the work.

These two stages will be started as early as possible in the project, allowing personnel to concentrate on construction completion and commissioning activities instead of the development of turnover packages while construction and commissioning activities are ongoing. Field/lab turnover packages should all be completed prior to the commencement of any field/lab commissioning activities on the project.

System and construction turnover packages typically contain the following information:

1. Package Scope Definition. This section defines the scope of the package and how it fits into either lab testing or the commissioning phase.
2. Package Status Section. This section is used to track the turnover package, from its completion by the construction team, acceptance by the commissioning team, and final acceptance by the PUC.
3. Sections for each discipline involved, as necessary:
    a. Mechanical, such as rotating equipment and piping, plus related accessories.
    b. Electrical, such as power and control circuits.
    c. Instrumentation, such as equipment providing a signal to a controller.
    d. SCADA, such as proper reporting of information from instrumentation and control functions.
4. Supplier/Miscellaneous Section. This includes miscellaneous information as required to complete the record of the specific activities (e.g., supplier site visit reports, maintenance records, etc.).
5. Package Drawings. This includes a list of as-built drawings within the package scope boundaries defined as described above.
6. Welding Quality Control Records. If required, these would be turned over separately by the construction team to the PUC per the Project Agreement.
7. Demonstration/Acceptance Testing Reports. This may be turned over to support Provisional Acceptance, if supported by the Project Agreement. A preliminary report format may be utilized for the performance test in order to expedite Provisional acceptance.
8. Supplier Documentation (Manuals, shop drawings, etc.). This may be turned over to support Provisional Acceptance, if supported by the Project Agreement.
9. Conformed to Construction Records, or as-builts. These will be maintained locally and turned over to the PUC per the Project Agreement (e.g., one markup copy could be kept on site and available for reference until such time as the final conformed drawings are available).

The final turnover package will contain, in addition to the items above, include an inventory of all turnover packages and their assembly into a final, completed turnover package.

Other items relating to final turnover package will be handled as follows:

1. Contract spares will be turned over as required by the Project Agreement.
2. Special tools will be turned over as required by the Project Agreement.

CN1.3 Create Commissioning Plan

This task will develop the Commissioning Plan (CP) that formally documents and coordinates the commissioning process. The CP will be created as early in the project as possible and in coordination with the task EA7.2 Create Lab Testing Plan. The CP defines the execution order for the testing plans developed in the following tasks as defined in Testing Plans and laid out in Figure 1 and Figure 2:

- EA1.2.2 IVR Integration Software Testing Plan
- EA1.3.3 CIS Integration Software Testing Plan
- EA1.4.3 CYME Integration Software Testing Plan
- EA1.5.4 AMI Integration Software Testing Plan
- EA2.5 OMS Software Testing Plan
- EA3.8.4 DA and RF Template Testing Plans
- EA4.4 SCADA Master End-to-End Testing Plan
- EA4.5 SCADA and ADMS Software Testing Plan
- EA5.4 IVR Software Testing Plan

- EA6 Cut-Over Plans

The CP is coordinated with the schedule development.

As the CP is completed with actual and planned dates, it is provided to the project team and related updates to the project schedule occur.

CN1.4 Construction Activities and Management
This task manages the following construction tasks in accordance with the CEP:

1. Safety management.
2. Field supervision and monitoring of construction activities.
3. Permitting assistance (refer to task CF3 Siting).
4. Construction of the work order packages for each site or location or unit, e.g., recloser location, FCI location, switch location, radio location, gateway radio location, etc.
5. Construction inspection, which ensures that each site is ready for commissioning activities. The turnover process consists of a review of package documentation and walk-down of the system to ensure that construction is complete and generates a punch list of items that must be completed before turnover. Upon turnover, ownership transfers to the commissioning staff.

CN1.5 Commissioning
This task manages the execution of the CP.

CN1.6 Closeout
This task will perform the closeout activities, starting after the completion of task CN1.5 Commissioning. During these activities site staff and operations are demobilized. Actual project closeout activities will be coordinated with the Project Agreement.

CN1 Deliverables
1. Startup Completion Certificate from task CN1.5 Commissioning.
2. Turnover package list from task CN1.2 Create Turnover Packages.
3. Turnover package from task CN1.2 Create Turnover Packages.
4. System turnover acceptance certificate.
5. System turnover package.

CN1 Reviews
1. The review and approval of the system turnover package will be in accordance with Table 1 and Appendix H-4.

CN1 Assumptions
1. Construction management activities do not include staff augmentation or owner's/resident engineer during construction.

PUC Operational Domain

CO1 Construction of Test System
This task constructs the test system per the design developed in task EA7.1 Design Lab Facility and Test System.

CO1 Deliverables
1. No deliverables are expected for the task CO1 Construction of Test System.

CO1 Reviews
1. No reviews are expected for the task CO1 Construction of Test System.

CO1 Assumptions

2. There are no specific assumptions for this task. Refer to General Assumptions.

CO2 Cut-Over from Test System to Development System

This task performs the cut-over from the test system utilized in task ST3 Stage Major Systems and Test to the development system using the plan developed in task EA6 Cut-Over Plans.

CO2 Deliverables

1. Completed cut-over plan.

CO2 Reviews

1. The review and approval of the completed cut-over plan will be in accordance with Table 1 and Appendix H-4.

CO2 Assumptions

1. The SCADA master control room will be ready for the cut-over from the test system and be able to function as a development system (refer to EA6 Assumptions).

CO3 Survalent SCADA End-to-End Testing

This task will use the development system (refer to EA6 Assumptions) to perform the end-to-end testing plan created in task EA4.4 SCADA Master End-to-End Testing Plan as part of the overall CP (refer to Testing Plans), which also addresses the prerequisites for testing.

The SCADA end-to-end testing plan for a particular field location will require the following testing plans be complete for that field location and its associated communication path before end-to-end testing begins (prerequisites):

1. Communication field tests for the gateway radio (refer to task CS1.2 Field Test Communications to Substations)
2. Communication field tests for the repeater (refer to task CF2.2 Field Test RF Field Equipment)
3. Communication field tests for the field radio (refer to task CF2.2 Field Test RF Field Equipment)
4. RF end-to-end test for each feeder
5. Communications end-to-end test for each feeder
6. Field tests for DA equipment for each feeder (refer to task CF1.2 Field Test DA Equipment)

CO3 Deliverables

1. Completed testing plans.

CO3 Reviews

1. The review and approval of the completed testing plan will be in accordance with Table 1 and Appendix H-4.

CO3 Assumptions

1. Because the SCADA point check has already been tested in the lab facility in task ST3 Stage Major Systems and Test, the end-to-end testing performed in task is expected to experience only minor issues and no significant delays.
2. Two weeks of contiguous onsite services are required for end-to-end testing for FDIR devices, which is the validation of SCADA database points for all FDIR associated field devices and substation devices.

CO4 Cut-Over from Development System to Production System

This task performs the cut-over from the development system utilized in task CO3 Survalent SCADA End-to-End Testing to the production system using the plan developed in task EA6 Cut-Over Plans.

CO4 Deliverables

1. Completed cut-over plan.

CO4 Reviews

1. The review and approval the completed cut-over plan will be in accordance with Table 1 and Appendix H-4.

CO4 Assumptions

1. The cut-over is completed during a single contiguous site trip for two days.

CO5 IVR Go-Live

This task performs the go-live for the IVR system.

CO5 Deliverables

1. Completed go-live plan.

CO5 Reviews

1. The review and approval of the completed go-live plan will be in accordance with Table 1 and Appendix H-4.

CO5 Assumptions

1. The go-live is completed during a single contiguous site trip for one day.

PUC Substation Domain

CS1 Install Communications to and at Substations

This task will install the radio communications equipment at the substations and connect it to the existing communication network.

CS1.1 Construct Communications to the Substation

This task will review and install the communications equipment inside substations using the work orders developed in task ES1 Substation Communication Design.

CS1.2 Field Test Communications to Substations

This task will perform the field testing plan for the gateway radio located at the substation using the site-specific field testing procedure provided with the work order.

CS1 Deliverables

1. Completed work order as-built from task CS1.1 Construct Communications to the Substation that installed equipment.
2. Completed testing plans from task CS1.2 Field Test Communications to Substations.

CS1 Reviews

1. The review and approval of the work order as-builts and completed testing plans will be in accordance with Table 1 and Appendix H-4.

CS1 Assumptions

1. The PUC will coordinate task CS1 Install Communications to and at Substations with the field construction of any changes required to the PUC's communication network.

CS2 Update Substation IEDs (placeholder)

This task is a placeholder task because under the baseline scope it is not required because of assumption number 20 under EA3 Assumptions. This task remains here as a placeholder in case it is discovered that substation IEDs require one or more modifications to support the data requirements to support FDIR and/or VVO (refer to task EA3.5 Substation SCADA Point Assessment).

PUC Field Domain

CF1 Install Field DA Equipment

This task will install and test the DA devices (refer to Table 7) in the field (outside the substations) supporting the DA applications VVO, FDIR, and auto-transfer.

CF1.1 Construct DA Equipment

This task will review and install the field equipment supporting FDIR, VVO, and auto-transfer applications per the work orders developed in task EF1.3 DA Detailed Design.

CF1.2 Field Test DA Equipment

This task will perform the field testing plan for the field equipment supporting FDIR, VVO, and auto-transfer applications using the site-specific field testing provided with the work orders.

CF1 Deliverables

1. Work order as-built from task CF1.1 Construct DA Equipment.
2. Completed field testing plan from task CF1.2 Field Test DA Equipment.

CF1 Reviews

1. The review and approval of the work order as-builts and completed testing plans will be in accordance with Table 1 and Appendix H-4.

CF1 Assumptions

1. The DA applications are working and tested prior to field testing.
2. No hot line work will be performed on distribution circuits requiring pole and/or equipment installation on those circuits. Circuits not being worked on that are adjacent or underbuilt are assumed to be left in an energized state unless outages are required based upon the PUC's requirements.
3. All new pole installations will be dug by vacuum truck.
4. Imported granular material for backfilling of pole holes will be used.
5. No new guying or anchoring will be needed.
6. Isolation and restoration activities on the power system will be performed by the PUC.

CF2 Install Field Communications Equipment

This task will install and test the field communications equipment (repeater and field radios, refer to Table 8).

CF2.1 Construct Communications Equipment

This task will review and install the RF equipment per the coordinated work orders developed in task EF2.3 Field Area Network Detailed Design.

CF2.2 Field Test RF Field Equipment

This task will perform the field testing plan for the RF equipment installed outside substations using the site-specific field testing plans provided with the work orders.

CF2 Deliverables

1. Work order as-built from task CF2.1 Construct Communications Equipment.
2. Completed field testing plan from task CF2.2 Field Test RF Field Equipment.

CF2 Reviews

1. The review and approval of the work order as-builts and completed testing plans will be in accordance with Table 1 and Appendix H-4.

CF2 Assumptions

1. FCIs and 900 MHz communication repeaters will be installed by PUC personnel.
2. The PUC will install all communication equipment at a rate such that the project schedule is not delayed. This includes the PUC's configuration of radios, network, and security devices.

CF3 Siting

CF3.1 Required Permits

This task will support permitting activities during construction.

CF3 Deliverables

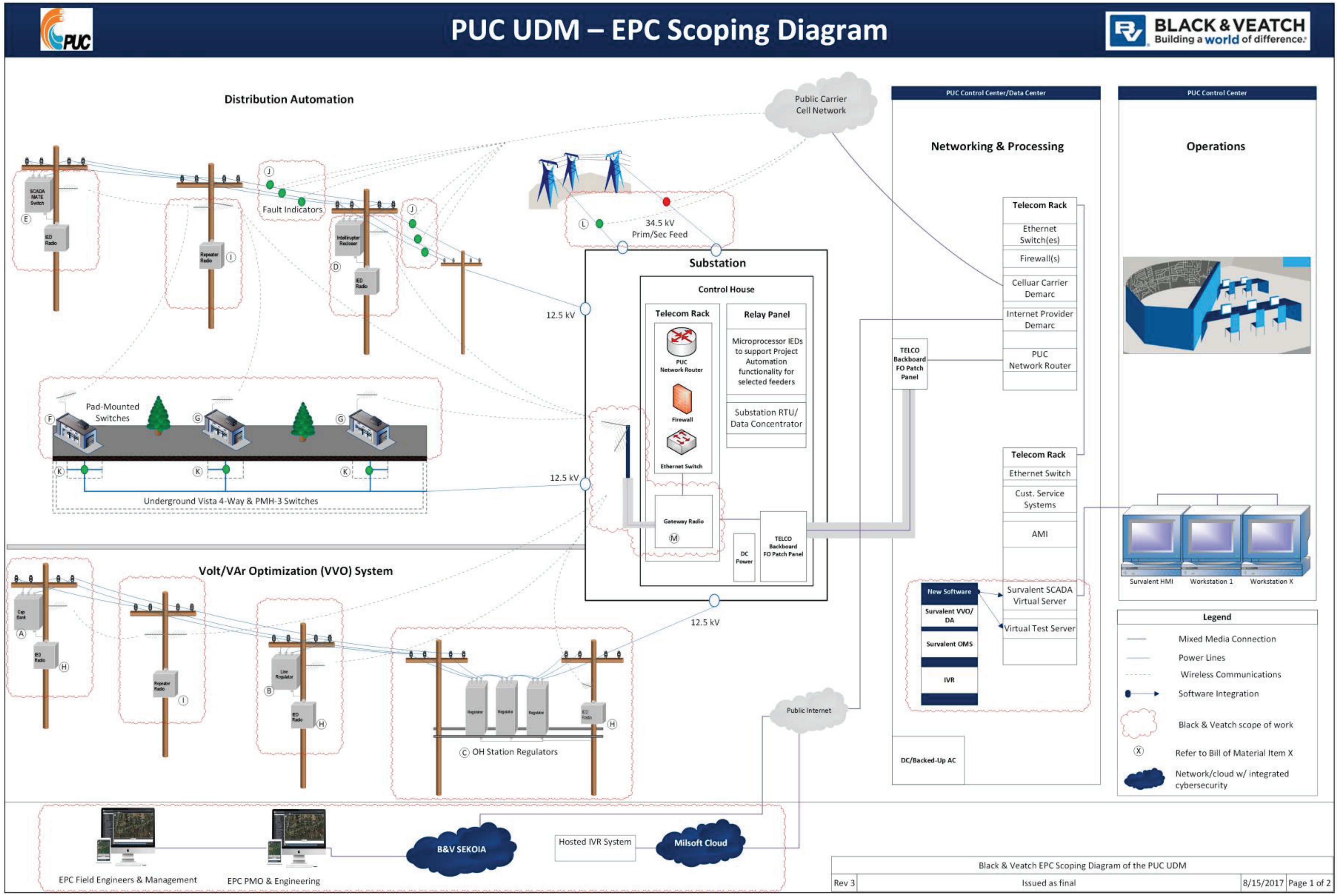
1. There are no deliverables to the PUC for task CF3 Siting except for updates to the project schedule related to this task.

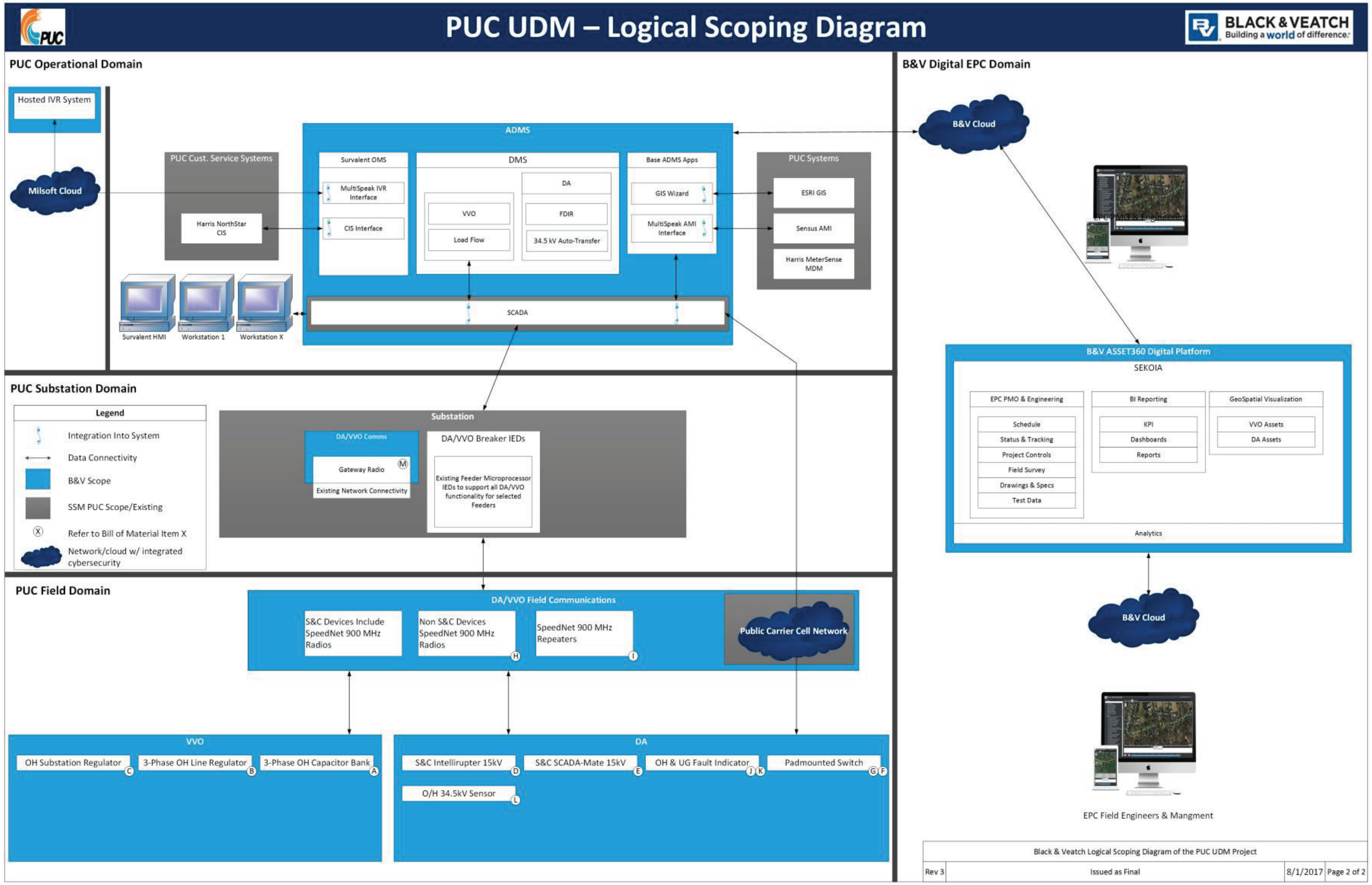
CF3 Reviews

1. There are no reviews planned for task CF3 Siting.

CF3 Assumptions

1. Permits will not be obtained nor managed by the PUC.


PUC UDM – EPC Scoping Diagram
BLACK & VEATCH
Building a world of difference.
Distribution Automation
Public Carrier Cell Network
PUC Control Center/Data Center
PUC Control Center
Networking & Processing
Operations
Fault Indicators
34.5 kV Prim/Sec Feed
Substation
Control House
Telecom Rack
Relay Panel
PUC Network Router
Firewall
Ethernet Switch
Microprocessor IEDs to support Project Automation functionality for selected feeders
Substation RTU/ Data Concentrator
Gateway Radio
DC Power
TELCO Backboard FO Patch Panel
12.5 kV
Pad-Mounted Switches
Underground Vista 4-Way & PMH-3 Switches
Telecom Rack
Ethernet Switch(es)
Firewall(s)
Celluar Carrier Demarc
Internet Provider Demarc
PUC Network Router
TELCO Backboard FO Patch Panel
Telecom Rack
Ethernet Switch
Cust. Service Systems
AMI
Survalent SCADA Virtual Server
Virtual Test Server
New Software
Survalent VVO/ DA
Survalent OMS
IVR
DC/Backed-Up AC
Survalent HMI
Workstation 1
Workstation X
Volt/VAr Optimization (VVO) System
OH Station Regulators
Public Internet
Legend
Mixed Media Connection
Power Lines
Wireless Communications
Software Integration
Black & Veatch scope of work
Refer to Bill of Material Item X
Network/cloud w/ integrated cybersecurity
EPC Field Engineers & Management
EPC PMO & Engineering
B&V SEKOIA
Hosted IVR System
Milsoft Cloud
Black & Veatch EPC Scoping Diagram of the PUC UDM
Rev 3
Issued as final
8/15/2017
Page 1 of 2



PUC UDM – Logical Scoping Diagram
BLACK & VEATCH
Building a world of difference.
PUC Operational Domain
Hosted IVR System
Milsoft Cloud
PUC Cust. Service Systems
Harris NorthStar CIS
ADMS
Survalent OMS
MultiSpeak IVR Interface
CIS Interface
DMS
VVO
Load Flow
DA
FDIR
34.5 kV Auto-Transfer
Base ADMS Apps
GIS Wizard
MultiSpeak AMI Interface
PUC Systems
ESRI GIS
Sensus AMI
Harris MeterSense MDM
SCADA
Survalent HMI
Workstation 1
Workstation X
PUC Substation Domain
Legend
Integration Into System
Data Connectivity
B&V Scope
SSM PUC Scope/Existing
Refer to Bill of Material Item X
Network/cloud w/ integrated cybersecurity
Substation
DA/VVO Comms
Gateway Radio
Existing Network Connectivity
DA/VVO Breaker IEDs
Existing Feeder Microprocessor IEDs to support all DA/VVO functionality for selected Feeders
PUC Field Domain
DA/VVO Field Communications
S&C Devices Include SpeedNet 900 MHz Radios
Non S&C Devices SpeedNet 900 MHz Radios
SpeedNet 900 MHz Repeaters
Public Carrier Cell Network
VVO
OH Substation Regulator
3-Phase OH Line Regulator
3-Phase OH Capacitor Bank
DA
S&C Intellirupter 15kV
S&C SCADA-Mate 15kV
OH & UG Fault Indicator
Padmounted Switch
O/H 34.5kV Sensor
B&V Digital EPC Domain
B&V Cloud
B&V ASSET360 Digital Platform
SEKOIA
EPC PMO & Engineering
Schedule
Status & Tracking
Project Controls
Field Survey
Drawings & Specs
Test Data
BI Reporting
KPI
Dashboards
Reports
GeoSpatial Visualization
VVO Assets
DA Assets
Analytics
B&V Cloud
EPC Field Engineers & Mangment
Black & Veatch Logical Scoping Diagram of the PUC UDM Project
Rev 3
Issued as Final
8/1/2017
Page 2 of 2

SSM Design-Build Project

Responsibility Matrix

Major Task: Engineering	PUC Distribution	PUC Services	IECO/Black & Veatch	Other	Notes
Engineering					
PUC Operational Domain (Refer to Scoping Diagram)					
EA1 OMS					
EA1.1 Specify Data Integration with PUC Systems		O, A	R		
EA1.2 Define Responsibilities of Data Integration		O, A	R		
EA1.3 IVR Integration		O	R		
EA1.4 CIS Integration		O	R		
EA1.5 Customer Outage Web Portal		O, A	R		
EA1.6 Internal Stakeholder Dashboard		O, A	R		
EA1.7 OMS Testing Plans		O, A	R		
EA1.8 OMS Training Plan		O, A	R		
EA1.9 OMS Maintenance Plan		O, A	R		
EA2 ADMS					
EA2.1 Identify Identify Virtual Server Requirements		O, A	R		
EA2.2 Define SCADA integration		O	R		
EA2.3 Provide Mapping Requirements		O, A	R		
EA2.4 Develop Standardized Designs DA/VVO/Auto-Transfer					
EA2.4.1 Standard Bill of Materials for Field Locations		O, A	R		
EA2.4.2 DA/VVO/Auto-Transfer Template Drawings		O, A	R		
EA2.4.3 DA/VVO/Auto-Transfer Template Points Lists		O, A	R		
EA2.4.4 DA/VVO/Auto-Transfer Template Configuration Files		O, A	R		
EA2.4.5 DA/VVO/Auto-Transfer Template Auto-Transfer Logic		O, A	R		
EA2.4.6 DA/VVO/Auto-Transfer Template Testing Plans		O, A	R		
EA2.4.7 DA/VVO/Auto-Transfer Maintenance Plans		O, A	R		
EA2.4.8 DA/VVO/Auto-Transfer Training Plans		O, A	R		
EA3 Base ADMS Applications					
EA3.1 GIS Integration					
EA3.1.1 GIS Working Session		O, A	R		
EA3.1.2 GIS Detailed Design		O, A	R		
EA3.1.3 GIS Testing Plans		O, A	R		
EA3.1.4 GIS Training Plan		O, A	R		
EA3.1.5 GIS Maintenance Plan		O, A	R		
EA3.1.6 Clear GIS Backlog		R	A		
EA3.2 AMI Integration					
EA3.2.1 AMI Working Session		O, A	R		
EA3.2.2 Bellwether Meter Report		O	R		
EA3.2.3 AMI Integration		O, A	R		
EA3.2.4 AMI Testing Plans		O, A	R		
EA3.2.5 AMI Training Plan		O, A	R		
EA3.2.6 AMI Maintenance Plan		O, A	R		
EA4 SCADA Master					
EA4.1 SCADA Master Physical		O, A	R		
EA4.2 SCADA Master Logical		O, A	R		
EA4.3 SCADA Master Sub-System Integration		O	R		
EA4.4 SCADA Master Displays and Database		O	R		
EA4.5 DA Data Concentrator Configuration		O	R		
EA4.6 SCADA Master Testing Plans		O, A	R		
EA4.7 SCADA Master Training Plan		O, A	R		
EA4.8 SCADA Master Maintenance Plan		O, A	R		
EA5 IVR					
EA5.1 IVR Physical		O, A	R		
EA5.2 IVR Logical		O, A	R		
EA5.3 IVR Integration		O	R		
EA5.4 IVR Configuration		O	R		
EA5.5 IVR Testing Plans		O	R		
EA5.6 IVR Training Plan		O, A	R		
EA5.7 IVR Maintenance Plan		O, A	R		
EA6 Cut-Over Plan					
EA6.1 Develop Cut-over Plans		O	R		
B&V Digital EPC Domain (Refer to Scoping Diagram)					
EP1-DA Monitoring and Awareness		O, A	R		

SSM Design-Build Project

Responsibility Matrix

Major Task: Engineering	PUC Distribution	PUC Services	IECO/Black & Veatch	Other	Notes
EP1.1 Working Session		O, A	R		
EP1.2 Review and Assess Data		O, A	R		

SSM Design-Build Project

Responsibility Matrix

Major Task: Engineering	PUC Distribution	PUC Services	IECO/Black & Veatch	Other	Notes
PUC Substation Domain (Refer to Scoping Diagram)					
ES1-DA/VVO Communications					
ES1.1-Gateway Radios		O	R		
ES1.1.1 Electrical (Power, Grounding, Cabling, etc.)		O	R		
ES1.1.2 Civil (Below Grade, Trenching, Concrete Pads, Pull Boxes, etc.)		O	R		
ES1.2-Existing Network		R	A		
ES2-DA/VVO Breaker IEDs					
ES2.1 Review SCADA Points		O	R		
ES2.2 Update Breaker Protection Relay Settings		O	R		
ES3-Auto-Transfer Scheme					
ES3.1 Transfer logic		O	R		
PUC Field Domain (Refer to Scoping Diagram)					
EF1 VVO, DA and Auto-Transfer					
EF1.1 Circuit Analysis		O, A	R		
EF1.1.1 Model Validation		R	A		
EF1.1.2 Circuit Report		O	R		
EF1.1.3 Load Flow and Protection Analysis		O	R		
EF1.2 Field Survey		O, A	R		
EF1.3 Detailed Design		O, A	R		
EF2 Field Communications					
EF2.1 Wireless Communications Field Survey		O, A	R		
EF2.2 Conceptual Wireless Design to DA/VVO Devices		O	R		
EF2.3 RF Detailed Design		O, A	R		
EF3- Siting					
EF3.1 Local Permits		R			
EF3.2 Public Relations		R	A		
PUC Organizational Domain					
EO1-Business Process and Organizational Change Management					
EO1.1 Business Process Working Sessions		O	R		
EO1.2 Develop Recommended Business Process Changes		O	R		
EO1.3 Organizational Change Working Sessions		O	R		
EO1.4 Develop Recommended Organizational Changes		O	R		
EO1.5 Training for Business Process and Organizational Changes		O	R		

Major Task: Procurement	PUC Distribution	PUC Services	IECO/Black & Veatch	Other	Notes
Purchasing					
PR1 Purchase Major Materials and Equipment		O	R		
PR1.1 Survalent Software and Hardware		O	R		
PR1.2 VVO Equipment		O	R		
PR1.3 RF Equipment		O	R		
PR1.4 DA Equipment		O, A	R		
PR1.5 IVR Software		O	R		
PR2 Purchase All Other Materials and Equipment		R			
Staging and Testing					
ST1 Inventory and Warehouse		O	R		
ST2 Inspect and Verify OEM Specs		O	R		
ST3 Stage Major Systems and Test		O	R		
ST3.1 Server Migration		R, O	A		
ST3.2 Survalent Test System		R, O	A		
ST3.3 Lab Test					
ST3.3.1 IVR Interface Lab Test		O, A	R		Moved from CO1.1
ST3.3.2 CIS Interface Lab Test		O, A	R		Moved from CO1.2
ST3.3.3 OMS Lab Test		O, A	R		Moved from CO1.3
ST3.3.4 DA/VVO/Auto-Transfer Lab Test		O, A	R		Moved from CO2.1
ST3.3.5 GIS Wizard Lab Test		O, A	R		Moved from CO3.1
ST3.3.6 MultiSpeak AMI Interface Lab Test		O, A	R		Moved from CO3.2
ST3.4 Delivery of Lab to the PUC		O	R		
ST3.5 Installation of Lab at the PUC		R			
ST4 Kit and Prepare for Field		O	R		
Training					
TR1 Training		O	R		

SSM Design-Build Project

Responsibility Matrix

Major Task: Engineering	PUC Distribution	PUC Services	IECO/Black & Veatch	Other	Notes
Major Task: Construction/Implementation	PUC Distribution	PUC Services	IECO/Black & Veatch	Other	Notes
Construction Domain					
CN1-Construction Activities and Management					
CN1.1 Pre-Mobilization/Mobilization Activities		O	R		
CN1.2 Commissioning Plan		O	R		
CN1.3 Construction Activities and Management		O	R		
CN1.4 Closeout		O	R		
PUC Operational Domain (Refer to Scoping Diagram)					
CO1 Test System Cut-over to Development System		O, A	R		
CO2 Survalent ADMS End-to-End Testing		O, A	R		
CO3 System Cut-over		O, A	R		
PUC Substation Domain (Refer to Scoping Diagram)					
CS1 DA/VVO Communications					
CS1.1 Communications to the Substation		R	A		
CS1.2 Field Test Communications to Substations		R	A		
CS2 DA/VVO Breaker IEDs					
CS2.1 Upload new configurations		R	A		
CS2.2 Test new configurations		R	A		
CS3 Auto-Transfer Scheme					
CS3.1 Auto-Transfer Voltage Sensors		R	A		
CS3.2 Field Test Communications to Voltage Sensors		R	A		
PUC Field Domain (Refer to Scoping Diagram)					
CF1 VVO					
CF1.1 Voltage Regulators		R	A		
CF1.2 Field Test Voltage Regulator Devices		R	A		
CF2 DA					
CF2.1 Install DA Equipment		R	A		
CF2.2 Field Test DA Devices		R	A		
CF3 Field Communications					
CF3.1 Install Communications Equipment		R	A		
CF3.2 Field Test Communication between Communications Equipment		R	A		
CF4 Permitting/Environmental					
CF4.1 Required Permits		R	A		

R = Responsible; A = Assist; O=Oversight (includes Review/Approve)

Appendix K
Project Cost Estimate

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

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

SUBJECT: Sault Smart Grid Project – Business Case
Revised Scope & Cost Estimate

DATE: Initial Draft - November 2018

Project Scope and Cost Estimates

Project scope and estimate adjustments have been developed from the preliminary engineering work of Leidos Engineering and reflect input from the Navigant Review of Project Costs report (June 2015) as well as input from PUC project, engineering and operations staff. Previously project preliminary engineering design work was considering a much larger Distribution Substation rehabilitation scope that has been cut back and left within the longer term Distribution System Plan and asset management program. (referenced reports are listed below as well, also refer to PUC Distribution latest Cost of Service application DSP.)

Two main cost adjustments have been considered to the detailed components for the project cost estimate from the prior work of Leidos and the Navigant Review of Project Costs report (June 2015). A review of inflation impact from 2014 to the 2019/2020 project and scope/risk adjustment factors were considered. A CPI adjustment from 2014 to 2018 plus an estimated 1.5% CPI to 2019/20 (=9.73%) was calculated to consider in the unit cost figures developed in the Navigant review as well as a scope/ risk factor applied to unit prices. 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 staff were used to help consider this risk factor adjustment.

The VVM scope has been adjusted from two thirds to 100% of the 12.5 kV system coverage (excludes 4kV circuits) and revised total estimate is ~$16.0M. The Distribution Automation (DA) scope of work started with the extended business case scope then was scaled to 100% coverage adding another 8 feeders to the Leidos preliminary engineering work. The detailed design phase will now encompass all 48 12.5 kV feeders and this portion of the project will have an estimated $14.6M in fixed asset capital additions. AMI integration which generally includes all SCADA and communications hardware/software, AMI and GIS integration, the outage management system and customer service interfaces along with business process development is a total of ~$3.8M for a project total cost estimate of ~$34.4M.

Note: The portions of the project costs to each system were developed internally by PUC from the overall scope and EPC provider estimates to support the asset categories and rate application development. Actual proportions will be determined as project design and construction is completed and trued up in fixed asset records. As the project developer and EPC are committed to the overall fixed price contract the level of fixed asset detail was an internal estimate but overall there is not a risk of project cost overrun to PUC. Detail engineering estimates were also developed by PUC internally from gross project estimates in efforts to identify skill/ expertise areas for internal resource planning support and liaison with EPC contractor once efforts get 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:

- Utility Distribution Microgrid: Volt/VAR Management – Preliminary Design
    - Leidos Engineering – October 17, 2014
- Utility Distribution Microgrid: Distribution Automation – Preliminary Design
    - Leidos Engineering – November 20, 2014
- Utility Distribution Microgrid: AMI Integration – Preliminary Design
    - Leidos Engineering – November 20, 2014
- Review of Business Case for Smart Grid Project for PUC Distribution
    - o Navigant Consulting – April 15, 2015
- Review of Project Costs for Smart Grid Project for PUC Distribution
    - Navigant Consulting – June 23, 2015

Notes on Scope Changes:

- Sub 16 scheduled for rebuild in 2019/2020 (in DSP)
- LTC may be considered if economic based on specific locations but generally assumed bus/feeder voltage regulators
- All 12.5kV Feeders to be part of VVM system (excludes 4kV except in design for post voltage conversion program)
- VVM estimate scaled to 12 DS's (from 8) and all feeders (48 from 32)
- Sub1 is an all underground area so pad mounted VReg equipment assumed
- Sub 2,10,11,12,13,15,18,19,20,21 evaluated for OH/UG all options in detailed design for best site fit
- DA system applications expanded to all 12.5 kV feeders

Revised unit costs are shown in table below which were then applied to current project scope for the project estimate also shown in following tables.

PUC SERVICES

Smart Grid CPI Adjustment

2014-2018	1.0651
2019	1.015
2020	1.015
	1.097293

BANK OF CANADA
BANQUE DU CANADA

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Inflation Calculator

About the Calculator

The Inflation Calculator uses monthly **consumer price index** (CPI) data from 1914 to the present to show changes in the cost of a fixed "basket" of consumer purchases. These include food, shelter, furniture, clothing, transportation, and recreation. An increase in this cost is called **inflation**.

The calculator's results are based on the most recent month for which the CPI data are available. This will normally be about two months prior to the current month.

How to Use the Calculator

Enter any dollar amount, and the years you wish to compare, then click the **Calculate** button.

YEARS MUST BE IN THE RANGE 1914 - 2018. COMMAS AND SPACES CAN BE USED IN THE DOLLAR AMOUNT.

A "basket" of goods and services

...that cost:	$	1.00	in	2014
...would cost:	$	1.07	in	2018

Clear Calculate

Per cent change: 6.51

Review of Project Costs Report (Navigant) -June 23, 2015					
(required to develop Fixed Asset Estimates for ICM)					
*(1) 2014 unit pricing adjusted CPI to 2019/20 [1.0591 to 2018 + 2*1.5%]*					
(2) Adjustment Factor - ref. Navigant Report & PUC (price/scope creep risk)					
(3) Fixed price Contract - needed "reasonable" value to allocate					(_3_)
			(_1_)	(_2_)	**2019/20**
			1.09111		**Budget**
	Qty	**$Unit/Ea**	**Adj$Unit/Ea**	**Risk**	**Adj$Unit/Ea**
LTC's	6	525,000	572,833		538,000
Bus VReg	2	200,000	218,222		210,000
Cap Bank	4	8,000	8,729		8,250
Feeder VReg	4	90,000	98,200		94,300
34.5 kV TT HW	6	50,000	54,556		53,000
Reclosers	38	80,000	87,289	10%	84,000
SW's(pole)	40	60,000	65,467		64,000
SW(2way Pad)	4	110,000	120,022	5%	114,000
SW(4way pad)	4	120,000	130,933	5%	124,000
OH FCI's	32	7,000	7,638		7,200
UG FCI's	37	6,000	6,547		6,200
Poles	90	11,000	12,002		11,500
34.5 kV TT SW	12	30,000	32,733	30%	35,000
FLIR	1	400,000	436,445	30%	450,000
AMI/OMS/CIS (*1)	1	1,100,000	1,200,222	30%	1,275,000

Revised Project Estimate – Volt/VAR Management

2019/20 Smart Grid Project			
			Project Installation
VVM (excludes AMI, SCADA, Comm, etc.)	***Qty***	**$Unit/Ea**	
DS with new LTC's (incremental)	2	60,000	120,000
40 feeders			
> Bus/Padmount /Feeder/ VReg's/	44	210,000	9,240,000
> feeder balancing Caps	6	8,250	49,500
> feeder balancing VRegs	6	94,300	565,800
			9,975,300
Engineering		See Estim	3,205,800
			13,181,100
Project Mgmt/ Ext'l Commissioning Review		See Estim	1,645,550
Regulatory/ Financial/ Legal		See Estim	1,132,830
VVM			**15,959,480**

Revised Project Estimate – Distribution Automation

2019/20 Smart Grid Project			
			Project Installation
DA (excludes AMI, SCADA, Comm, etc.)			
Generally staying with the ~80% system coverage			
Will likely be value added engineering changes			
in the detailed design phase of project.			
34.5 kV TT (10DS and TS?)	6	53,000	318,000
Reclosers	38	84,000	3,192,000
SW's(pole)	40	64,000	2,560,000
2 way padmount SW's	3	114,000	342,000
4 way padmount SW's	4	124,000	496,000
OH FCI's	32	7,200	230,400
UG FCI's	37	6,200	229,400
Poles (added qty for adjacent lift/siting issues)	90	11,500	1,035,000
			8,402,800
Engineering		See Estim	3,456,800
			11,859,600
Project Mgmt/ Ext'l Commissioning Review		See Estim	1,501,250
Regulatory/ Financial/ Legal		See Estim	1,298,610
DA			**14,659,460**

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Revised Project Estimate – AMI Integration & Project Totals

2019/20 Smart Grid Project			
			Project
			Installation
AMI Integration, SCADA, OMS, CIS, Comm, etc.)			
All IT H/W, S/W, SCADA, OMS, GIS, communication			
type work combined in to central sub-project.			
34.5 kV TT SW	14	35,000	490,000
FLIR SW	1	450,000	450,000
AMI/OMS/CIS	1	1,275,000	637,500
			1,577,500
Engineering		See Estim	1,337,400
			2,914,900
Project Mgmt/ Ext'l Commissioning Review		See Estim	523,800
Regulatory/ Financial/ Legal		See Estim	331,560
AMI			**3,770,260**
Project Estimate Total System			**34,389,200**

SSG Engineering and Project Management Estimate – SPV/EPC

SPV (Project Co.) - EPC Contract - Engineering Scope

- Distribution Automation System
- Volt/ VAR Management System
- AMI Integration
- Engineeering work includes all EPC estimates including from subcontractors as required.

EPC Engineering Estimate								
Planning & Engineering		**DA**	**DA $**	**VVM**	**VVM$**	**AMI**	**AMI$**	
	$/wk	**wks**	**$**	**wks**	**$**	**wks**	**$**	
Sr Eng	6,000	39	234,000	39	234,000	39	234,000	
Elec Eng	5,000	78	390,000	39	195,000	36	180,000	
P&C Eng	5,000	78	390,000	78	390,000	26	130,000	
IT Network Eng	5,000	26	130,000	26	130,000	26	130,000	
Tech	4,000	312	1,248,000	286	1,144,000	65	260,000	
GIS Tech	3,600	26	93,600	26	93,600	26	93,600	
Admin	2,800	39	109,200	39	109,200	36	100,800	
Mtce/Ops Eng	5,000	78	390,000	78	390,000	21	105,000	
Sys Oper	4,000	39	156,000	52	208,000	26	104,000	
Ops Planner	4,000	79	316,000	78	312,000	-	-	
		794	3,456,800	741	3,205,800	301	1,337,400	**8,000,000**

SPV (IE) Project Management & Legal

- Manage project, select vendors, ensure cash flows
- Manage all change orders and adjustments
- Communicate to PUC, Owners and other stakeholders
- Report to PUC and City stakeholders

- Deal closing costs (regulatory and accounting)
- financing fees

SPV/ Developer (IE) - Regulatory/ Financial/ Legal								
Project Management			2,405,000					
Regulatory/Financial Close/Financing			2,388,000					
		Total	4,793,000					
		Allocation by project $'s.						
		DA	**DA $**	**VVM**	**VVM$**	**AMI**	**AMI$**	
			986,050		1,130,350		288,600	
			979,080		1,122,360		286,560	
			1,965,130		2,252,710		575,160	**4,793,000**

SSG Engineering and Project Management Estimate – PUCS Work for PUCD

PUCS - Owner Project Mgmt								
Owner Proj Mgmt/ Oversight								
		DA	**DA $**	**VVM**	**VVM$**	**AMI**	**AMI$**	
Proj Mgmt	**$/wk**	**wks**	**$**	**wks**	**$**	**wks**	**$**	
Proj Manager	6,000	32	192,000	32	192,000	9	54,000	
Proj Engineer	5,000	9	45,000	9	45,000	4	20,000	
Ops Specialist	5,000	9	45,000	9	45,000	4	20,000	
Admin	2,800	9	25,200	9	25,200	4	11,200	
		59	307,200	59	307,200	21	105,200	**719,600**
(includes Fin. Reporting, safety oversight, isolations, acccess, switching)								
Engineering & Technical Oversight/ Approvals								
Sr Engineer	6,000	8	48,000	8	48,000	5	30,000	
Elec Eng	5,000	8	40,000	8	40,000	5	25,000	
P&C Eng	5,000	8	40,000	8	40,000	5	25,000	
IT Network Eng	5,000	8	40,000	8	40,000	5	25,000	
Ops Specialist	5,000	8	40,000	8	40,000	5	25,000	
		40	208,000	24	208,000	15	130,000	**546,000**
			515,200		515,200		235,200	**1,265,600**
PUCS - Owner Regulatory/ Financial/ Legal								
PUC Project Development Team/ WIP			100,000					
Legal/Financial/Contracts			100,000					
Regulatory/ OEB ICM/Consulting			100,000					
Ops & Eng'g			75,000					
		Total	375,000					
		Allocation by project $'s.						
		DA	**DA $**	**VVM**	**VVM$**	**AMI**	**AMI$**	
			153,750		176,250		45,000	**375,000**
								1,640,600

PUCS - Owner Project Management

- Oversee all aspects of project
- Manage relation to financing, project developer, EPC, EPC subcontractors, and vendors
- Manage all change orders and adjustments
- Operations liason, system access, safety oversight
- Communicate to PUC, Owners and other stakeholders
- Report to PUC and City stakeholders

- Engineerng & Technical Oversights & Approvals
- Regulatory material & equipment approval
- Perform design reviews for EPC Gates
- Regulatory Construction Verification Program (CVP)
- Asset and GIS records management

- Legal, financial and contract development
- Prepare and submit Provincial (OEB) submissions
- Ops & Eng'g support to OEB regulatory process

Appendix L
2019 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.

Utility Name	PUC Distribution Inc.		
Assigned EB Number	EB-2018-0219		
Name of Contact and Title	Andrew Belsito, Rates and Regulatory Affairs Officer		
Phone Number	705-759-3009		
Email Address	andrew.belsito@ssmpuc.com		
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	**Price-Cap IR**	**Rate Year**	**2019**
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which PUC Distribution Inc. is applying:	**1**		
PUC Distribution Inc. is applying for:	**ICM Approval**		
Last Rebasing Year:	**2018**		
The most recent complete year for which actual billing and load data exists	**2017**		
Current IPI	**1.20%**		
Strech Factor Assigned to Middle Cohort	**III**		
Stretch Factor Value	**0.30%**		
Price Cap Index	**0.90%**		

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

PUC Distribution Inc.

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **6**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 4,999 KW
4	SENTINEL LIGHTING
5	STREET LIGHTING
6	UNMETERED SCATTERED LOAD

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
PUC Distribution Inc.

Input the billing determinants associated with PUC Distribution Inc.'s Revenues Based on 2018 Board-Approved Distribution Demand. Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

Rate Class	Units	2018 Board-Approved Distribution Demand			Current Approved Distribution Rates		
		Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW
RESIDENTIAL	$/kWh	29,816	288,323,799		24.41	0.0086	0.0000
GENERAL SERVICE LESS THAN 50 kW	$/kWh	3,431	92,411,463		20.73	0.0248	0.0000
GENERAL SERVICE 50 TO 4,999 KW	$/kW	357	244,620,598	614,743	114.46	0.0000	6.7295
SENTINEL LIGHTING	$/kW	354	209,800	593	3.55	0.0000	33.1502
STREET LIGHTING	$/kW	8,070	2,398,221	7,030	1.37	0.0000	8.9284
UNMETERED SCATTERED LOAD	$/kWh	22	944,731		12.69	0.0383	0.0000

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

PUC Distribution Inc.

Calculation of pro forma 2018 Revenues. No input required.

Rate Class	2018 Board-Approved Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
Total	0	0	0	D	E	F	0	0	0	0	K = G / J	L = H / J	M = I / J	0.0%
RESIDENTIAL	29,816	288,323,799		24.41	0.0086	0.0000	8,733,703	2,479,585	0	11,213,287	77.9%	22.1%	0.0%	58.2%
GENERAL SERVICE LESS THAN 50 kW	3,431	92,411,463		20.73	0.0248	0.0000	853,496	2,291,804	0	3,145,300	27.1%	72.9%	0.0%	16.3%
GENERAL SERVICE 50 TO 4,999 KW	357	244,620,598	614,743	114.46	0.0000	6.7295	490,347	0	4,136,913	4,627,260	10.6%	0.0%	89.4%	24.0%
SENTINEL LIGHTING	354	209,800	593	3.55	0.0000	33.1502	15,080	0	19,658	34,738	43.4%	0.0%	56.6%	0.2%
STREET LIGHTING	8,070	2,398,221	7,030	1.37	0.0000	8.9284	132,671	0	62,767	195,437	67.9%	0.0%	32.1%	1.0%
UNMETERED SCATTERED LOAD	22	944,731		12.69	0.0383	0.0000	3,350	36,183	0	39,533	8.5%	91.5%	0.0%	0.2%
Total	**42,050**	**628,908,612**	**622,366**				**10,228,646**	**4,807,572**	**4,219,338**	**19,255,556**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Applicants Rate Base

Last COS Rebasing: 2018

Average Net Fixed Assets

Gross Fixed Assets - Re-based Opening	$	106,264,141	A			
Add: CWIP Re-based Opening	$	-	B			
Re-based Capital Additions	$	5,358,355	C			
Re-based Capital Disposals	$	-	D			
Re-based Capital Retirements	$	-	E			
Deduct: CWIP Re-based Closing	-$	420,179	F			
Gross Fixed Assets - Re-based Closing	$	111,202,317	G			
Average Gross Fixed Assets				$	108,733,229	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	13,880,189	I			
Re-based Depreciation Expense	$	3,780,329	J			
Re-based Disposals			K			
Re-based Retirements			L			
Accumulated Depreciation - Re-based Closing	$	17,660,518	M			
Average Accumulated Depreciation				$	15,770,354	N = (I + M) / 2
Average Net Fixed Assets				**$**	**92,962,876**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	89,269,060	P			
Working Capital Allowance Rate		7.5%	Q			
Working Capital Allowance				**$**	**6,695,180**	R = P * Q
Rate Base				**$**	**99,658,055**	S = O + R

Return on Rate Base

Deemed ShortTerm Debt %	4.00%	T	$	3,986,322	W = S * T
Deemed Long Term Debt %	56.00%	U	$	55,808,511	X = S * U
Deemed Equity %	40.00%	V	$	39,863,222	Y = S * V
Short Term Interest	2.29%	Z	$	91,287	AC = W * Z
Long Term Interest	4.12%	AA	$	2,299,311	AD = X * AA
Return on Equity	9.00%	AB	$	3,587,690	AE = Y * AB
Return on Rate Base			**$**	**5,978,287**	AF = AC + AD + AE

Distribution Expenses

OM&A Expenses	$	11,543,633	AG			
Amortization	$	3,780,329	AH			
Ontario Capital Tax	$	-	AI			
Grossed Up Taxes/PILs	$	586,716	AJ			
Low Voltage	$	-	AK			
Transformer Allowance	$	82,800	AL			
	$	-	AM			
	$	-	AN			
	$	-	AO			
				$	**15,993,478**	AP = SUM (AG : AO)

Revenue Offsets

Specific Service Charges	-$	2,698,600	AQ			
Late Payment Charges			AR			
Other Distribution Income			AS			
Other Income and Deductions			AT	**-$**	**2,698,600**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**19,273,165**	AV = AF + AP + AU

Rate Classes Revenue

Rate Classes Revenue - Total (Sheet 5)	$	19,255,556	AW

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
PUC Distribution Inc.

Input the billing determinants associated with PUC Distribution Inc.'s Revenues Based on 2017 Actual Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

Rate Class	2017 Actual Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
Total	0	0	0	D	E	F	0	0	0	0	$K = G / J_{total}$	$L = H / J_{total}$	$M = I / J_{total}$	0.0%
RESIDENTIAL	29,729	282,820,547		24.41	0.0086	0.0000	8,708,219	2,432,257	0	11,140,475	45.5%	12.7%	0.0%	58.3%
GENERAL SERVICE LESS THAN 50 kW	3,417	91,035,995		20.73	0.0248	0.0000	850,013	2,257,693	0	3,107,706	4.4%	11.8%	0.0%	16.3%
GENERAL SERVICE 50 TO 4,999 KW	361	245,166,376	610,764	114.46	0.0000	6.7295	495,841	0	4,110,136	4,605,977	2.6%	0.0%	21.5%	24.1%
SENTINEL LIGHTING	361	213,661	619	3.55	0.0000	33.1502	15,379	0	20,520	35,899	0.1%	0.0%	0.1%	0.2%
STREET LIGHTING	8,070	2,398,221	7,030	1.37	0.0000	8.9284	132,671	0	62,767	195,437	0.7%	0.0%	0.3%	1.0%
UNMETERED SCATTERED LOAD	21	907,713		12.69	0.0383	0.0000	3,198	34,765	0	37,963	0.0%	0.2%	0.0%	0.2%
Total	**41,959**	**622,542,513**	**618,413**				**10,205,320**	**4,724,715**	**4,193,423**	**19,123,457**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

PUC Distribution Inc.

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

	Current OEB-Approved Base Rates			2018 Board-Approved 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
Total	A	B	C	D	E	F	0	0	0	0	$L = G / J_{total}$	$M = H / J_{total}$	$N = I / J_{total}$	0.0%
RESIDENTIAL	24.41	0.0086	0.0000	29,816	288,323,799		8,733,703	2,479,585	0	11,213,287	45.36%	12.88%	0.00%	58.2%
GENERAL SERVICE LESS THAN 50 kW	20.73	0.0248	0.0000	3,431	92,411,463		853,496	2,291,804	0	3,145,300	4.43%	11.90%	0.00%	16.3%
GENERAL SERVICE 50 TO 4,999 KW	114.46	0.0000	6.7295	357	244,620,598	614,743	490,347	0	4,136,913	4,627,260	2.55%	0.00%	21.48%	24.0%
SENTINEL LIGHTING	3.55	0.0000	33.1502	354	209,800	593	15,080	0	19,658	34,738	0.08%	0.00%	0.10%	0.2%
STREET LIGHTING	1.37	0.0000	8.9284	8,070	2,398,221	7,030	132,671	0	62,767	195,437	0.69%	0.00%	0.33%	1.0%
UNMETERED SCATTERED LOAD	12.69	0.0383	0.0000	22	944,731		3,350	36,183	0	39,533	0.02%	0.19%	0.00%	0.2%
Total							**10,228,646**	**4,807,572**	**4,219,338**	**19,255,556**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
PUC Distribution Inc.

No Input Required.

Final Materiality Threshold Calculation

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

Cost of Service Rebasing Year		**2018**	
Price Cap IR Year in which Application is made		**1**	n
Price Cap Index		**0.90%**	PCI
Growth Factor Calculation			
Revenues Based on 2018 Board-Approved Distribution Demand		**$19,255,556**	
Revenues Based on 2017 Actual Distribution Demand		**$19,123,457**	
Growth Factor		**0.69%**	$g\ (Note\ 1)$
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	106,264,141	
Add: CWIP Opening	$	-	
Capital Additions	$	5,358,355	
Capital Disposals	$	-	
Capital Retirements	$	-	
Deduct: CWIP Closing	-$	420,179	
Gross Fixed Assets - Closing	$	111,202,317	
Average Gross Fixed Assets	$	108,733,229	
Accumulated Depreciation - Opening	$	13,880,189	
Depreciation Expense	$	3,780,329	
Disposals	$	-	
Retirements	$	-	
Accumulated Depreciation - Closing	$	17,660,518	
Average Accumulated Depreciation	$	15,770,354	
Average Net Fixed Assets	$	92,962,876	
Working Capital Allowance			
Working Capital Allowance Base	$	89,269,060	
Working Capital Allowance Rate		8%	
Working Capital Allowance	$	6,695,180	
Rate Base	**$**	**99,658,055**	RB
Depreciation	**$**	**3,780,329**	d
Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)			
Price Cap IR Year 2019		**152%**	
Price Cap IR Year 2020		**153%**	
Price Cap IR Year 2021		**153%**	
Price Cap IR Year 2022		**154%**	
Price Cap IR Year 2023		**155%**	
Price Cap IR Year 2024		**156%**	
Price Cap IR Year 2025		**156%**	
Price Cap IR Year 2026		**157%**	
Price Cap IR Year 2027		**158%**	
Price Cap IR Year 2028		**159%**	
Threshold CAPEX			$\textit{Threshold Value} \times d$
Price Cap IR Year 2019	**$**	**5,749,886**	
Price Cap IR Year 2020	**$**	**5,775,303**	
Price Cap IR Year 2021	**$**	**5,801,125**	
Price Cap IR Year 2022	**$**	**5,827,360**	
Price Cap IR Year 2023	**$**	**5,854,014**	
Price Cap IR Year 2024	**$**	**5,881,093**	
Price Cap IR Year 2025	**$**	**5,908,605**	
Price Cap IR Year 2026	**$**	**5,936,556**	
Price Cap IR Year 2027	**$**	**5,964,953**	
Price Cap IR Year 2028	**$**	**5,993,804**	

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
PUC Distribution Inc.

Identify ALL Proposed ACM projects and related CAPEX costs in the relevant years

	Cost of Service	Price Cap IR				Price Cap IR (Deferred Rebasing)					
	Test Year 2018	Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Year 6 2024	Year 7 2025	Year 8 2026	Year 9 2027	Year 10 2028
Distribution System Plan CAPEX	$ 5,358,355	$ 10,302,600	$ 26,600,104	$ 6,196,546	$ 8,708,176						
Materiality Threshold		$ 5,749,886	$ 5,775,303	$ 5,801,125	$ 5,827,360	$ 5,854,014	$ 5,881,093	$ 5,908,605	$ 5,936,556	$ 5,936,556	$ 5,936,556
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ 4,552,714	$ 20,824,801	$ 395,421	$ 2,880,816	$ -	$ -	$ -	$ -	$ -	$ -

Project Descriptions:	**Type**	**Test Year 2018**	**Year 1 2019**	**Year 2 2020**	**Year 3 2021**	**Year 4 2022**	**Year 5 2023**	**Year 6 2024**	**Year 7 2025**	**Year 8 2026**	**Year 9 2027**	**Year 10 2028**	**Total**
Sault Smart Grid	**New ICM**		$ 5,026,797.00	$ 17,555,248.00									**$ 22,582,045**
Substation 16	**New ICM**			$ 3,600,000		$ 3,300,000							**$ 6,900,000**
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													$ -
Total Cost of ACM/ICM Projects		$ -	$ 5,026,797	$ 21,155,248	$ -	$ 3,300,000	$ -	$ -	$ -	$ -	$ -	$ -	**$ 29,482,045**
Maximum Allowed Incremental Capital			$ 4,552,714	$ 20,824,801	$ -	$ 2,880,816	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,258,331

	Test Year 2018	Price Cap IR Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022
Distribution System Plan CAPEX	$ 5,358,355	$ 10,302,600	$ 26,600,104	$ 6,196,546	$ 8,708,176
Materiality Threshold		$ 5,749,886	$ 5,775,303	$ 5,801,125	$ 5,827,360
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ 4,552,714	$ 20,824,801	$ 395,421	$ 2,880,816

		Test Year	Year 1			Year 2			Year 3			Year 4		
		2018	2019			2020			2021			2022		
Project Descriptions:	**Type**		**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**
Sault Smart Grid	**New ICM**		**$ 5,026,797**	$ 293,436	$ 531,424	**$ 17,555,248**	$ 461,735	$ 1,468,638	$ -			$ -		
Substation 16	**New ICM**		$ -	$ -	$ -	**$ 3,600,000**	$ 72,000	$ 288,000	$ -			**$ 3,300,000**		
			$ -			$ -			$ -			$ -		
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Total Cost of ACM/ICM Projects			$ 5,026,797	$ 293,436	$ 531,424	$ 21,155,248	$ 533,735	$ 1,756,638	$ -	$ -	$ -	$ 3,300,000	$ -	$ -

Price Cap IR (Deferred Rebasing) (if necessary)

Price Cap IR			
Year 5 2023	Year 6 2024	Year 7 2025	Year 8 2026

		Year 5 2023	Year 6 2024	Year 7 2025	Year 8 2026
Distribution System Plan CAPEX		$ -	$ -	$ -	$ -
Materiality Threshold		$ 5,854,014	$ 5,881,093	$ 5,908,605	$ 5,936,556
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -	$ -	$ -

		Year 5			Year 6			Year 7			Year 8		
		2023			2024			2025			2026		
Project Descriptions:	Type	Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA
Sault Smart Grid	New ICM	$ -			$ -	$ -		$ -			$ -		
Substation 16	New ICM	$ -			$ -	$ -		$ -			$ -		
		$ -			$ -			$ -			$ -		
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		$ -			$ -			$ -			$ -		
Total Cost of ACM/ICM Projects		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Price Cap IR (Deferred Rebasing) (if necessary)

Price Cap IR

		Year 9 2027	Year 10 2028
Distribution System Plan CAPEX		$ -	$ -
Materiality Threshold		$ 5,936,556	$ 5,936,556
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -

		Year 9			Year 10		
		2027			2028		
Project Descriptions:	Type	Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA
Sault Smart Grid	New ICM	$ -			$ -		
Substation 16	New ICM	$ -			$ -		
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		$ -			$ -		
Total Cost ofACM/ICM Projects		$ -	$ -	$ -	$ -	$ -	$ -

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
PUC Distribution Inc.

Incremental Capital Adjustment **Rate Year:** 2019

Current Revenue Requirement

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

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim	Eligible for ACM/ICM (Prorated Amount) *(from Sheet 10b)*	
Amount of Capital Projects Claimed	$ 5,026,797	$ 4,552,714	B
Depreciation Expense	$ 293,436	$ 265,762	C
CCA	$ 531,424	$ 481,305	V

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

Return on Rate Base

Incremental Capital			$ 4,552,714	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$ 265,762	C
Incremental Capital to be included in Rate Base (average NBV in year)			$ 4,419,833	D = B - C/2
	% of capital structure			
Deemed Short-Term Debt	4.0%	E	$ 176,793	G = D * E
Deemed Long-Term Debt	56.0%	F	$ 2,475,106	H = D * F
	Rate (%)			
Short-Term Interest	2.29%	I	$ 4,049	K = G * I
Long-Term Interest	4.12%	J	$ 101,974	L = H * J
Return on Rate Base - Interest			$ 106,023	M = K + L
	% of capital structure			
Deemed Equity %	40.00%	N	$ 1,767,933	P = D * N
	Rate (%)			
Return on Rate Base -Equity	9.00%	O	$ 159,114	Q = P * O
Return on Rate Base - Total			$ 265,137	R = M + Q

Amortization Expense

Amortization Expense - Incremental		C	$ 265,762	S

Grossed up Taxes/PILs

Regulatory Taxable Income		O	$ 159,114	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$ 265,762	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$ 481,305	V
Incremental Taxable Income			-$ 56,429	W = T + U - V
Current Tax Rate	26.5%	X		
Taxes/PILs Before Gross Up			-$ 14,954	Y = W * X
Grossed-Up Taxes/PILs			-$ 20,345	Z = Y / (1 - X)

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$ 265,137	AA
Amortization Expense - Total	S	$ 265,762	AB
Grossed-Up Taxes/PILs	Z	-$ 20,345	AC
Incremental Revenue Requirement		$ 510,553	AD = AA + AB + AC

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	Col C * Col I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	45.36%	12.88%	0.00%	231,571	65,745	0	297,316	29,816	288,323,799		0.83	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	4.43%	11.90%	0.00%	22,630	60,766	0	83,396	3,431	92,411,463		0.55	0.0007	0.0000
GENERAL SERVICE 50 TO 4,999 KW	2.55%	0.00%	21.48%	13,001	0	109,689	122,690	357	244,620,598	614,743	3.03	0.0000	0.1784
SENTINEL LIGHTING	0.08%	0.00%	0.10%	400	0	521	921	354	209,800	593	0.09	0.0000	0.8790
STREET LIGHTING	0.69%	0.00%	0.33%	3,518	0	1,664	5,182	8,070	2,398,221	7,030	0.04	0.0000	0.2367
UNMETERED SCATTERED LOAD	0.02%	0.19%	0.00%	89	959	0	1,048	22	944,731		0.34	0.0010	0.0000
Total	**53.12%**	**24.97%**	**21.91%**	**271,209**	**127,471**	**111,874**	**510,553**	**42,050**	**628,908,612**	**622,366**			