NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

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HAND DELIVERED

April 4, 2014

Board of Commissioners of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NL A1A 5B2

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies & Gentlemen:

Re: Application for approval of a capital expenditure supplemental to Newfoundland Power Inc.'s (the "Company") 2014 Capital Budget

Please find enclosed the original and eight copies of an application for approval of a capital expenditure supplemental to the Company's approved 2014 capital budget (the "Application").

The Application

The Application seeks the Board's approval of a capital expenditure supplemental to the Company's approved 2014 capital budget (the "Application"). The need for this supplementary expenditure arises from the unforeseen requirement to improve electrical system performance following the events of January 2nd, 2014 to January 8th, 2014.

Supplementary Capital Expenditures

The Application is filed in accordance with the revised Capital Budget Application Guidelines issued in October 2007 (the "Guidelines"), in particular, part *B.1. Application for Approval of Supplemental Capital Expenditures*. The Guidelines provide for approval of a supplemental capital expenditure where a utility determines that a capital expenditure which was not anticipated and included in the annual capital budget is necessary in the year and should not be delayed until the following year. These capital expenditures were not anticipated at the time of preparation of the Company's 2014 Capital Budget Application. However, to ensure the Company is prepared to better respond to certain conditions on the electrical system, it is necessary to proceed with the project prior to the 2014/2015 winter season.

In these circumstances, Newfoundland Power believes it is appropriate to seek approval at this time of a supplementary capital expenditure to complete the necessary work to prepare the Company's electrical system for the upcoming 2014/2015 winter season.

In making application for approval of supplemental capital budget expenditures, the Guidelines require that, in addition to such evidence as would normally be required to support an application for the approval of capital expenditures, the utility must show why the project was not anticipated and included in the annual capital budget application for the year; and why the project cannot wait until next year and be included in the annual capital budget application.

As noted in the report titled *Electrical System Improvements, April 4, 2014*, the events of January 2nd, 2014 to January 8th, 2014 have identified opportunities to improve electrical operations in advance of the upcoming winter season. The estimated cost of completing the additional infrastructure and technology is approximately $2.9 million in 2014.

Concluding
A draft of the Order requested is enclosed for the Board's convenience. If there are any questions in relation to this matter, please contact the undersigned at the direct number noted below.

Yours very truly,

Gerard M. Hayes
Senior Counsel

Enclosure

c. Geoffrey Young
Newfoundland & Labrador Hydro

Telephone: (709) 737-5609 *Email: ghayes@newfoundlandpower.com* *Fax: (709) 737-2974*

IN THE MATTER OF the *Public Utilities Act*, (the "Act"); and

IN THE MATTER OF an Application by Newfoundland Power Inc. (the "Applicant") for approval to proceed with the construction and purchase of certain improvements and additions to its property pursuant to Section 41(3) of the Act.

TO: The Board of Commissioners of Public Utilities (the "Board")

THE APPLICATION OF Newfoundland Power Inc. (the "Applicant") **SAYS THAT:**

1. The Applicant is a corporation duly organized and existing under the laws of the Province of Newfoundland and Labrador, is a public utility within the meaning of the Act, and is subject to the provisions of the *Electrical Power Control Act, 1994.*

2. Newfoundland Power operates transmission lines, distribution lines and substations to deliver electricity to customers throughout its service territory on the island portion of the Province of Newfoundland and Labrador.

3. From January 2-8, 2014, Newfoundland Power's electrical system operated in extraordinary conditions. These conditions included rotating power outages and successive equipment failures on the Island Interconnected System which resulted in widespread interruptions of electrical service to large numbers of customers.

4. Following the electrical system events of January 2-8, 2014, Newfoundland Power identified changes to its electrical system which will improve electrical system operations generally, including during conditions like those experienced in January 2014.

5. Schedule A to this Application is a report titled *Electrical System Improvements, April 4, 2014* which details work identified to improve electrical system operations during conditions like those experienced in January 2014 and provides estimates of the expenditures necessary to execute that work.

6. The projects for which the Board's approval is sought by this Application are described in Schedule B to this Application and have a total estimated 2014 capital expenditure of $2,892,000.

7. The Applicant submits that the proposed expenditures for 2014 as described in paragraphs 5 and 6 hereof, are necessary to provide service and facilities which are reasonably safe and adequate and just and reasonable, all as required pursuant to Section 37 of the Act.

8. Communications with respect to this Application should be sent to Gerard Hayes, Counsel for the Applicant.

9. **THE APPLICANT REQUESTS** that the Board approve, pursuant to Section 41 (3) of the Act, the capital expenditures associated with the purchase and construction of the improvements and additions to the Applicant's property as set out in this Application.

DATED at St. John's, Newfoundland and Labrador, this 4th day of April, 2014

NEWFOUNDLAND POWER INC.

Gerard M. Hayes
Counsel for the Applicant
Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, Newfoundland A1B 3P6

Telephone: (709) 737-5609
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IN THE MATTER OF the *Public Utilities Act,* (the "Act"); and

IN THE MATTER OF an Application by Newfoundland Power Inc. (the "Applicant") for approval to proceed with the construction and purchase of certain improvements and additions to its property pursuant to Section 41(3) of the Act.

AFFIDAVIT

I, Peter Alteen, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. That I am Vice-President, Regulation & Planning of Newfoundland Power Inc.
2. To the best of my knowledge, information and belief, all matters, facts and things set out in this Application are true.

SWORN to before me at St. John's in the Province of Newfoundland and Labrador this 4th day of April, 2014:

Barrister

Peter Alteen

NEWFOUNDLAND AND LABRADOR

AN ORDER OF THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

NO. P.U. ___ (2014)

IN THE MATTER OF THE PUBLIC
UTILITIES ACT, R.S.N. 1990,
CHAPTER P-47 (THE "ACT")

AND

IN THE MATTER OF AN APPLICATION BY
NEWFOUNDLAND POWER INC. (THE "APPLICANT")
FOR APPROVAL TO PROCEED WITH THE
CONSTRUCTION AND PURCHASE OF CERTAIN
IMPROVEMENTS AND ADDITIONS TO ITS PROPERTY
PURSUANT TO SECTION 41(3) OF THE ACT.

WHEREAS the Applicant is a corporation duly organized and existing under the laws of the Province of Newfoundland and Labrador, is a public utility within the meaning of the Act, and is also subject to the provisions of the *Electrical Power Control Act*, *1994*, and

WHEREAS the Applicant operates transmission lines, distribution lines and substations to deliver electricity to customers throughout its service territory on the island portion of the Province of Newfoundland and Labrador, and

WHEREAS on January 2nd through 8th, 2014, as a result of peak load conditions, a shortfall in available supply and a winter storm, the electricity system throughout the island of Newfoundland was stressed, and

WHEREAS rotating outages, and equipment failures on the Island interconnected system, resulted in an interruption of electrical service to a large number of customers, and

WHEREAS at its peak approximately 190,000 customers throughout the entirety of the island of Newfoundland were without electricity service, and

WHEREAS throughout the January 2nd through 8th, 2014 period Newfoundland Power operated its generation, transmission, distribution and substation systems to deliver the available supply to the maximum number of customers possible., and

WHEREAS the Applicant has identified improvements and additions to the Applicant's property necessary to improve electricity system operations during conditions like those experienced in January 2014, and

WHEREAS the estimated capital expenditure to construct the improvements and additions to the Applicant's property as proposed in the Application is $2,892,000, and

WHEREAS the proposed expenditure is necessary for the Applicant to provide service and facilities which are reasonably safe and adequate and just and reasonable pursuant to Section 37 of the Act.

IT IS THEREFORE ORDERED THAT: Pursuant to Section 41 (3) of the Act, the Board approves the capital expenditure of $2,892,000 associated with the improvements and additions to the Applicant's property as proposed in the Application.

DATED at St. John's, Newfoundland and Labrador, this ______ day of   , 2014.

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G. Cheryl Blundon
Board Secretary

Electrical System Improvements

April 4, 2014

Prepared by:

Robert Cahill, P. Tech.

Jack Casey, P. Eng.

REGISTERED PROFESSIONAL ENGINEER
J. W. CASEY
SIGNATURE
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

In this 2014 Capital Budget Supplemental Application, Newfoundland Power Inc. ("Newfoundland Power" or the "Company") proposes to address some electrical system capacity and control limitations which became apparent during the system events of January 2-8, 2014.[1]

Newfoundland Power has identified a number of improvements which may be completed in advance of the 2014/2015 winter season to address these capacity and control limitations and to improve electrical system performance.[2] These projects will improve the system's resilience and flexibility to respond to both major disruptions and local system events. This includes improved capability to deal with cold load pickup and improved efficiency of restoration operations following outages.[3]

The system improvements proposed in this 2014 Capital Budget Supplemental Application include the following:

- (i) 14 downline automated distribution feeder sectionalizing reclosers,
- (ii) upgrading of 4.3 km of distribution feeder conductor,
- (iii) 7 automated substation feeder reclosers, and
- (iv) 2 automated transmission line breakers.

The total estimated cost of the work is $2,892,000.[4]

2.0 Background

Newfoundland Power serves approximately 256,000 customers through 306 distribution feeders. A distribution feeder is an electrical circuit which originates in a substation, and along its route connects customer premises to the electrical system. Distribution feeders vary in length, voltage and number of customers served.[5] At the beginning of all distribution feeders is a recloser or

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1 These system events are fully described in Newfoundland Power's *Interim Report,* March 24, 2014 in A*n Investigation and Hearing Into Supply Issues and Power Outages on the Island Interconnected System by the Board of Commissioners of Public Utilities of Newfoundland and Labrador.*

2 The improvements identified in this 2014 Capital Budget Supplemental Application can be completed in addition to the Company's current 2014 Capital Budget.

3 *Cold load pickup* is simply the additional electrical demand which presents itself when a disconnected feeder is reconnected. The electrical demand which can be expected upon reconnection will be higher than that which existed at disconnection. This is the result of a lack of diversity of demand at the time of reconnection. Prior to disconnection, a distribution feeder normally has a degree of diversity (randomness of electrical devices on at any given time). When that distribution feeder is disconnected and later reconnected, or "picked up", this diversity is lost (all electrical devices are on at the moment of reconnection). This serves to increase the demand on the feeder at the moment of reconnection from what it was at the moment of disconnection.

4 The work has been packaged into 2 specific capital projects; *2014 Distribution Feeder Improvements* (which includes downline sectionalizing reclosers and conductor upgrade) and *Substations Refurbishment and Modernization* (which includes automated substation feeder reclosers and transmission line breakers). This presentation conforms to projects typically presented as part of Newfoundland Power's annual capital budget applications.

5 Some distribution feeders are only a few hundred metres in length while others are over 100 kms in length. Feeder voltages vary from 4,160 volts to 25,000 volts. Some feeders serve only a handful of customers while others serve thousands.

breaker, located in the substation, that can be operated to disconnect and reconnect the feeder from the electrical system ("substation feeder breakers and reclosers").[6]

Approximately 60% of Newfoundland Power's substation feeder breakers and reclosers are currently automated, meaning they are connected to the Company's Supervisory Control And Data Acquisition ("SCADA") system and can be operated remotely from the Company's System Control Center ("SCC") located in Mount Pearl. The remaining 40% are not automated, and field staff are required to travel to substations to manually operate the devices.

Newfoundland Power's distribution feeders typically have one substation recloser or breaker and multiple downline reclosers and sectionalizing switches. These downline devices provide the capability to subdivide distribution circuits.[7] Currently, 88% of downline reclosers and 100% of sectionalizing switches on the Company's distribution feeders are operated manually by field staff.[8]

Reconnecting a distribution feeder that has been disconnected from the electrical system requires due regard for an engineering phenomenon known as *cold load pickup*. For Newfoundland Power, demand at reconnection can be twice as high at disconnection.[9] For example, a distribution feeder disconnected with 6 MW of customer load in winter conditions would typically be reconnected with as much as 12 MW of customer load.[10] Cold load pickup is also a consideration in determining the loading limit of aerial conductor.[11]

The additional automated (i) substation feeder reclosers and (ii) downline reclosers proposed in this 2014 Capital Budget Supplemental Application will permit the Company more flexibility in the operation of its electrical system. This includes improved service restoration capability for

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[6] Feeder reclosers and breakers protect equipment from electrical faults by quickly disconnecting the feeder from the electrical system when a downline fault is detected. These devices are also operated to protect the feeder conductors from being overloaded. Further, they serve to protect employees and the general public.

[7] Typical reasons to subdivide a distribution circuit would include enabling the performance of maintenance on de-energized circuits or to isolate a fault. In both cases this serves to limit the number of customers affected.

[8] See the response to Request for Information PUB-NP-078 in *An Investigation and Hearing Into Supply Issues and Power Outages on the Island Interconnected System by the Board of Commissioners of Public Utilities of Newfoundland and Labrador*.

[9] A feeder with a cold load pickup factor of 2.0 is predicted to have twice as much load when it is reconnected after an extended outage than at the time it was originally disconnected. The cold load pickup factor is defined as the cold load pickup divided by the normal winter peak load. Cold load pickup factors can range from 1.5 to 2.0 during extended outages under winter peak conditions. Generally, feeders with a high penetration of electric heating have the highest cold load pickup factors. Newfoundland Power's database of cold load pickup measurements is continually updated and more accurate predictions become available as this database expands.

[10] The impact of cold load pickup on particularly large feeders with higher loads made it difficult to rotate those feeders in the rotating power outages undertaken by Newfoundland Power in January 2-8, 2014 period. See Newfoundland Power's *Interim Report,* March 24, 2014 in *An Investigation and Hearing Into Supply Issues and Power Outages on the Island Interconnected System by the Board of Commissioners of Public Utilities of Newfoundland and Labrador,* page 20, lines 6-11.

[11] The *loading limit* of aerial conductor is the maximum amount of current that the Company will load a conductor under normal operating conditions. If load growth results in this limit being exceeded, the Company will consider alternatives such as transferring load to an adjacent feeder or installing larger conductor with a higher loading limit.

customers. The proposed upgrade to distribution feeder conductor is necessary to effectively address a transformer overload condition identified in the January 2-8, 2014 period.

Newfoundland Power's transmission line 39L supplies electricity to customers in the Conception Bay North area. In addition, 39L provides an alternate transmission route from Newfoundland and Labrador Hydro's ("Hydro") Western Avalon ("WAV") Terminal Station to Hydro's Holyrood Terminal Station. There are 3 Newfoundland Power substations between the Company's Bay Roberts ("BRB") substation and Hydro's Holyrood Terminal Station. None of these 3 substations have modern protection and control technology.

The risk of extended outages, such as those experienced by Newfoundland Power's customers during the January 2-8, 2014 period, will be reduced by the proposed installation of 2 automated transmission line breakers on 39L.[12]

3.0 Distribution Projects

Automated Feeder Sectionalizing Reclosers

Increased capability to automatically sectionalize certain distribution feeders will permit (i) better isolation of faults in all operating conditions, (ii) more flexible response to cold load pickup, (iii) more timely restoration of feeders following extended outages and (iv) more efficient use of line crews that could otherwise be used to respond to other customer outages or emergencies.

Newfoundland Power proposes to install automated downline distribution feeder reclosers in the Northeast Avalon portion of the Company's service territory.[13] Three-phase downline reclosers are proposed for 3 distribution feeders originating in Chamberlains ("CHA") substation; 4 distribution feeders originating in Kenmount ("KEN") substation; 1 distribution feeder originating in Hardwoods ("HWD") substation; and 1 distribution feeder originating in Virginia Waters ("VIR") substation. Each of these distribution feeders have peak loads which are above the average Company distribution feeder peak load. Except for VIR-06, all of these distribution feeders operate at 25 kV.[14] Automated single-phase downline reclosers are also proposed for the most heavily loaded unfused distribution feeder taps in the Northeast Avalon.

Installing automatic reclosers to sectionalize heavily loaded distribution feeders and taps provides customers with a greater degree of reliability in all operating conditions. For example, the ability to automatically sectionalize a tap which is subject to a fault provides enhanced reliability to those customers served by that feeder but not on the faulted tap.[15]

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[12] Newfoundland Power's electrical system has 103 transmission lines, 94 of which already have some remote monitoring and control.

[13] The Northeast Avalon portion of the Company's service territory has the greatest concentration of customer load. It includes the cities of St. John's and Mount Pearl and the towns of Paradise and Conception Bay South.

[14] The CHA, KEN and HWD substations are the only Newfoundland Power substations in the Northeast Avalon area which have distribution feeders which operate at 25 kV. VIR-06 is the most heavily loaded 12.5 kV distribution feeder on Newfoundland Power's system.

[15] For distribution feeders which do not have sectionalizing devices or fused taps, a fault on a tap has the ability to cause an outage to all customers served by the distribution feeder.

When a feeder has been disconnected for an extended period during cold temperatures, cold load pickup is experienced when the feeder is reconnected. Downline remote controlled reclosers can be used on 3-phase distribution feeders to sectionalize the feeder into smaller sections. This enables service to be restored to customers in stages while staying within the capacity limits of the feeder conductors and substation equipment.[16] Without automation, field staff must be deployed to manually operate downline devices such as disconnects or switches. Travel time, equipment setup, and switching required by field staff in these circumstances extends the length of the customer outage and limits the Company's ability to deploy resources where they could be better utilized.

Based on a review of the events of January 2-8, 2014, (i) 9 three-phase distribution feeders and (ii) 5 single-phase taps have been identified for the installation of remotely controlled reclosers to improve flexibility in the operation of Newfoundland Power's distribution feeders.

Upgrading of Distribution Feeder Conductor

As load increases on the electrical system, individual components can become overloaded. The focus of Newfoundland Power's system planning is to avoid or minimize component overloading through cost effective upgrades to the system. In the case of substation power transformers, engineering studies typically identify and evaluate technical alternatives in advance of the overload occurring. These technical alternatives may include substation upgrades to increase transformer capacity or distribution system upgrades to transfer load to adjacent substations. For this reason, consideration of alternatives to address load growth commonly includes multiple substations.

In its 2011 Capital Budget Application, Newfoundland Power presented a planning study for the Northeast St. John's area.[17] The least cost solution to addressing transformer capacity issues in the Northeast St. John's area included a new 25 MVA power transformer at PUL substation in 2011 and a new distribution feeder in 2011 to transfer load from BCV substation to PUL substation. The solution also indicated that transfers would be required in future years as load growth continued in the area.[18]

During the January 2-8, 2014 period, the power transformer at BCV substation was loaded above its nameplate rating.[19] Additional load transfers from BCV substation to PUL substation are necessary to alleviate the overload condition on the power transformer. This will require a section of conductor to be upgraded.

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16 See Appendix C for an example of conductor loading and sectionalizing during cold load pickup.

17 The Northeast St. John's area includes customers served from Pulpit Rock ("PUL"), Broad Cove ("BCV") and HWD substations.

18 The alternative selected in the 2011 planning study for the Northeast St. John's area forecasted additional load to be transferred from BCV substation to PUL substation in 2016.

19 BCV-T1 is rated at 25 MVA. On January 2, 2014, relay settings were adjusted to allow for temporary peak loading of the power transformer above the nameplate rating while maintaining compliance with ANSI/IEEE Standard C57.91 – Guide for Loading Mineral-Oil-Immersed Power Transformers. The load on this transformer peaked at 28.5 MVA on January 2, 2014.

4.0 Substation Projects

Automated Substation Feeder Breakers and Reclosers

Approximately 60% of Newfoundland Power's distribution feeders are currently automated at the substation breaker or recloser. On the Avalon Peninsula the penetration of automated distribution feeder breakers and reclosers is 72%.

The automation of distribution feeders allows the SCC operators to remotely monitor and control the status (open/closed) of the breaker or recloser. Modern digital breaker and recloser controls provide information regarding operations related to the protection systems. The monitoring of telemetry (voltage, current, load, etc.) records the present and historical condition of the distribution feeder. Under normal operations, the unplanned opening of the breaker or recloser alerts the SCC operators to the loss of electrical supply to customers on the distribution feeder. In addition, the information is essential when undertaking activities such as feeder rotations and restoration. This information enables timely system operations and improves overall reliability in a variety of operating conditions.[20]

In the approved 2014 Capital Budget, 12 distribution feeders will be automated through previously identified projects. This application proposes automation of an additional 7 distribution feeders.[21]

Automated Transmission Line Breakers

Typically, in urban areas of Newfoundland the transmission network is *looped*, providing multiple transmission lines between substations. Looped transmission networks by their redundant nature are more reliable as there are alternate paths to power the substation during maintenance and after a single transmission line trip.[22]

Transmission line 39L supplies electricity to customers in the Conception Bay North area. 39L operates as part of a 138 kV looped transmission system that extends from Hydro's Holyrood Terminal Station to Newfoundland Power's BRB substation, passing through Newfoundland Power's Holyrood ("HOL"), Colliers ("COL") and Springfield ("SPF") substations along its route. In addition, 39L in conjunction with Newfoundland Power's transmission lines 48L, and 64L, provides an alternate transmission route from Hydro's WAV Terminal Station to its

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[20] The benefits of automation to the distribution feeder network was described in the study *Distribution Feeder Remote Control and Relay/Recloser Replacement Review* filed with the response to Request for Information PUB 9.3 of Newfoundland Power's 2002 Capital Budget Application. These benefits included improvements in safety, improvements in reliability, reduced environmental risk and lower operating cost.

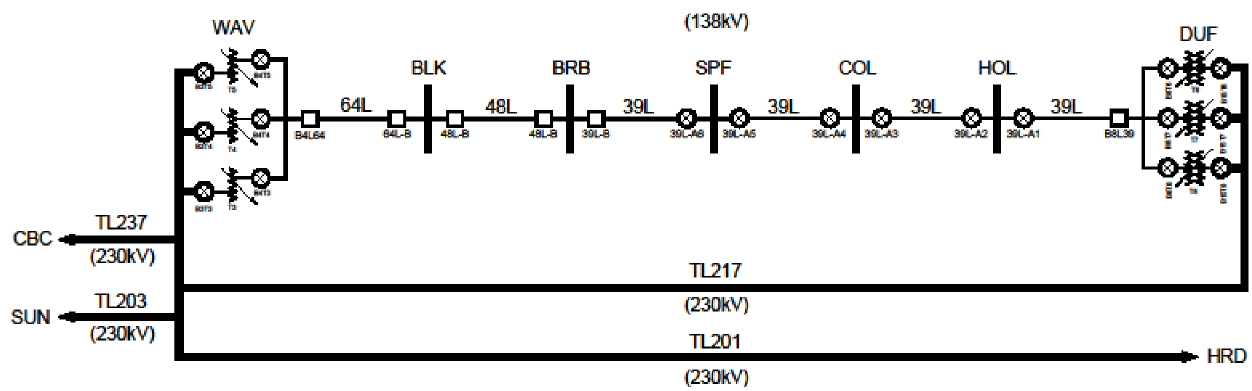
[21] For distribution feeders that use breakers, automation involves the replacement of electromechanical relays with modern microprocessor relays. For distribution feeders that use reclosers, automation involves the replacement of hydraulic reclosers with modern microprocessor controlled reclosers. In both applications, the relays and reclosers require a communication network to allow them to be connected to the Company's SCADA system.

[22] In some rural areas of Newfoundland, the transmission network is *radial* providing a single transmission line between substations. Radial transmission systems have no contingency for supplying the downline substation and require alternative approaches for maintaining reliability. For example, Newfoundland Power deploys its mobile generation to ensure customers on radial systems are served during scheduled maintenance or major transmission line damage.

Holyrood Terminal Station.[23] Hydro's Energy Management System ("EMS") and Newfoundland Power's SCADA system remotely monitor and control breakers at both ends of 39L at Hydro's Holyrood Terminal Station and Newfoundland Power's BRB substation, respectively.[24]

Figure 1 shows the 3 Newfoundland Power substations along 39L (SPF, COL, HOL).

Figure 1
Single Line Diagram of 138kV Loop



39L is terminated at each of these substations using manually operated switches with the power transformers at each substation protected by high speed ground switches.[25] When a fault occurs on any of the four sections of 39L or in any of the 3 substations along its route, the entire line is de-energized and approximately 6,700 customers experience an outage. As none of the 3 substations have transmission line breakers or any automation, technicians are dispatched to troubleshoot the fault location, isolate the fault and restore service to customers not affected by the faulted piece of equipment.[26]

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23 Transmission line 48L is a 138kV line that extends from Newfoundland Power's BRB substation to its Blaketown ("BLK") substation. Transmission line 64L is a 138kV line that extends from BLK substation to Hydro's WAV Terminal Station (see Figure 1). The 138kV line from Hydro's WAV Terminal Station to its Holyrood Terminal Station, located at Hydro's Holyrood Thermal Generating Station ("Holyrood"), is an alternate transmission route to Holyrood during forced outages or summer maintenance outages to Hydro's 230kV in-feed lines.

24 At Newfoundland Power's BRB substation end of 39L, the breaker is monitored and controlled by the Company's SCADA system. At the Holyrood end of 39L, the breaker is monitored and controlled by Hydro's EMS.

25 The high speed ground switch protects the power transformer by placing a solid ground on the transmission line's conductor which is detected by the transmission line protection back at the source and trips the breaker supplying the transmission line, in this case, at Hydro's Holyrood Terminal Station and Newfoundland Power's BRB substation.

26 By comparison, Newfoundland Power's 66 kV transmission system from Hydro's Holyrood Terminal Station to Hydro's Hardwoods Terminal Station includes 5 transmission lines with 10 transmission line breakers remotely monitored and controlled from the SCC.

Replacement of the manually operated switches at Newfoundland Power's SPF, COL and HOL substations with automated transmission line breakers would decrease the impact of outages to customers supplied from these substations. These transmission line breaker additions will allow for faster determination of transmission line fault locations along 39L, automatically isolate a transmission line fault between substations without any impact to customers and limit customer outages to the affected substation in the event of a fault within the substation. The breaker additions would also provide more reliable transformer protection at each substation.[27] This will also improve the reliability of 39L to provide 170 MVA transfer capability as an alternative to Hydro's 230kV in-feed lines.

5.0 Project Description

This Application includes improvements to the electrical system in preparation for the 2014/2015 winter season. This work responds to the events of January 2-8, 2014 and improves the reliable delivery of electricity to customers during system wide events and local outage events. The project is organized into both distribution and substation cost categories as follows.

5.1 Distribution Feeders

Automated Feeder Sectionalizing – Chamberlains Distribution Feeders ($243,000)

CHA substation is located on Fowlers Road in the town of Conception Bay South. There are 2 transformers located in the substation, CHA-T1 and CHA-T2. Both transformers are rated 25 MVA and are used to convert 66 kV transmission voltage to 25 kV distribution voltage and supply customers through CHA distribution feeders.

There are 3 25 kV distribution feeders originating from CHA substation. CHA-01 feeder supplies approximately 2,450 primarily residential customers in the Chamberlains and Manuels areas of Conception Bay South. CHA-02 feeder supplies approximately 2,700 primarily residential customers in the Topsail area of Conception Bay South as well as in the town of Paradise. CHA-03 feeder extends south along Fowlers Road and then along the Conception Bay South Bypass Road supplying approximately 2,350 primarily residential customers in the Chamberlains, Manuels and Foxtrap areas of Conception Bay South.

The 3 distribution feeders require automated sectionalizing to enable the effective restoration of the feeders during cold load pickup conditions.

The addition of automated feeder sectionalizing reclosers at the locations identified in Appendix B, Figures B1 to B3, will provide increased flexibility in Newfoundland Power's operations

[27] The improved protection results from the ability of the transmission line breakers to operate and isolate the substation which is the site of the fault. This is superior protection to the existing high speed ground switch which operates and causes the transmission line breakers at Newfoundland Power's BRB substation and Hydro's Holyrood Terminal Station to operate.

which will enhance reliability generally and ensure more timely restoration of customers following extended outages.[28]

Automated Feeder Sectionalizing – Hardwoods Distribution Feeder HWD-07 ($81,000)

HWD substation is located in Paradise. There are 3 transformers located in the substation. HWD-T1 and HWD-T2 are both 20 MVA rated transformers used to convert 66 kV transmission voltage to 12.5 kV distribution voltage and supply customers on 5 distribution feeders through HWD substation.

HWD-T3 is a 25 MVA transformer used to convert 66 kV transmission voltage to 25 kV distribution voltage and supply customers through two 25 kV feeders.[29] HWD-07 extends along Karwood Drive onto Topsail Road and along Paradise Road to St. Thomas Line supplying approximately 2,600 primarily residential customers. HWD-08 feeder extends along Karwood Drive onto Topsail Road and supplies approximately 2,550 primarily residential customers in the Paradise area.

Distribution feeder HWD-07 requires automated sectionalizing to enable the effective restoration of the feeder during cold load pickup conditions.

The addition of an automated feeder sectionalizing recloser at the location identified in Appendix B, Figure B4, will provide increased flexibility in Newfoundland Power's operations which will enhance reliability generally and ensure more timely restoration of customers following extended outages.[30] [31]

Automated Feeder Sectionalizing – Kenmount Distribution Feeders ($324,000)

KEN substation is located on Kenmount Road in the city of St. John's. There are 2 transformers located in the substation: KEN-T1 and KEN-T2. Both transformers are rated for 25 MVA and are configured to operate in parallel. These transformers are used to convert a transmission level voltage of 66 kV to a distribution level voltage of 25 kV to supply power to customers through 4 distribution feeders.

There are 4 25 kV feeders originating from KEN substation. KEN-01 feeder extends west along Kenmount Road onto Wyatt Boulevard and Mount Carson Avenue, supplying to approximately

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28 Appendix A, Figures A1 to A3, includes load curves that show actual cold load pickup for the 3 CHA feeders during the period from January 2-8, 2014. The curves show the cold load pickup experienced was approximately 2 times normal loading.

29 Newfoundland Power's approved 2014 Capital Budget includes an additional 25 MVA of 25kV power transformer capacity for HWD substation to accommodate load growth.

30 Appendix A, Figure A4 includes a load curve that shows actual cold load pickup for the HWD-07 feeder during the period from January 2-8, 2014. The curve shows the cold load pickup experienced was approximately 2 times normal loading.

31 Newfoundland Power's approved 2014 Capital Budget includes a project to install a new distribution feeder, HWD-09, in 2014. The construction of this additional feeder prior to December 2014 will include a permanent load transfer to offload a portion of HWD-08 feeder. This will allow for more timely restoration following extended outages.

1,800 primarily residential customers. KEN-02 feeder extends east along Kenmount Road onto Pippy Place and O'Leary Avenue, supplying approximately 700 primarily commercial customers. KEN-03 feeder extends south from the substation over Kenmount Hill, supplying approximately 2,400 primarily residential customers along Blackmarsh Road, Frecker Drive, and Canada Drive. KEN-04 feeder extends along Ladysmith Drive and Great Eastern Avenue, supplying approximately 2,500 primarily residential customers in the Kenmount Terrace area, as well as a portion of Elizabeth Park in Paradise.

The distribution feeders require automated sectionalizing to enable the effective restoration of smaller sections of the feeder during cold load pickup conditions.

The addition of automated feeder sectionalizing reclosers at the locations identified in Appendix B, Figures B5 to B8, will provide increased flexibility in Newfoundland Power's operations which will enhance reliability generally and ensure more timely restoration of customers following extended outages.[32]

Automated Feeder Sectionalizing – Virginia Waters Distribution Feeder VIR-06 ($81,000)

VIR substation is located at the intersection of Stavanger Drive and Snow's Lane. There are 3 transformers located in the substation: VIR-T1, VIR-T2, and VIR-T3. All 3 of the transformers are 25 MVA, 66/12.5 kV distribution power transformers that are used to convert transmission level voltage of 66 kV to a distribution level voltage of 12.5 kV to supply customers through 8 distribution feeders.

VIR-06 feeder extends west along the Outer Ring Road and then north along Torbay Road, supplying approximately 1,150 residential and commercial customers in the Stavanger Drive and Torbay Road areas.

Distribution feeder VIR-06 requires automated sectionalizing to enable the effective restoration of smaller sections of the feeder during cold load pickup conditions.

The addition of an automated feeder sectionalizing recloser on VIR-06 feeder at the location identified in Appendix B, Figure B9, will allow for more timely restoration of customers following rotating power outages and system disruptions.[33]

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[32] Appendix A, Figures A5 to A8 includes load curves that show actual cold load pickup for the 4 KEN feeders during the period from January 2-8, 2014. The curves show the cold load pickup experienced was approximately 2 times normal loading for KEN-01, 02 and 04 feeders. KEN-03 loading graph shows approximately 3 times normal loading since the feeder had been previously sectionalized and not all customers were connected to the feeder prior to the outage.

[33] Appendix A, Figure A9, includes a load curve that shows actual cold load pickup for the VIR-06 feeder during the period from January 2-8, 2014. The curve shows the cold load pickup experienced was approximately 2.5 times normal loading since the feeder had been previously sectionalized and not all customers were connected to the feeder prior to the outage.

Single-Phase Recloser – Chamberlains Distribution Feeder CHA-02 ($43,000)

CHA-02 feeder supplies approximately 2,700 primarily residential customers in the Topsail area of Conception Bay South as well as Paradise. This includes customers in the Lanark Drive areas in Paradise. This area is supplied from a single-phase tap serving approximately 200 customers. Due to loading on this tap, it is no longer connected with a fuse. As a result, a fault on this tap will cause a trip of the substation feeder breaker which will result in an outage to all 2,708 customers on CHA-02 feeder.

The addition of an automated single-phase recloser on the tap at the location identified in Appendix B, Figure B10, will enable the effective restoration of customers following system disruptions under cold load pickup conditions and will prevent feeder level outages for faults on the tap.

Single-Phase Recloser – Goulds Distribution Feeder GOU-01 ($43,000)

GOU-01 feeder extends along Bay Bulls Road and supplies approximately 1,700 primarily residential customers in the Kilbride area of St. John’s. This includes customers in the Lannon Street area of Kilbride. This area is supplied from a single-phase tap serving approximately 100 customers. Due to loading on this tap, it is no longer connected with a fuse. As a result, a fault on this tap will cause a trip of the substation feeder breaker which will result in an outage to all 1,700 customers on GOU-01 feeder.

The addition of an automated single-phase recloser on this tap at the location identified in Appendix B, Figure B11, will enable the effective restoration of customers following system disruptions under cold load pickup conditions and will prevent feeder level outages for faults on the tap.

Single-Phase Recloser – Goulds Distribution Feeder GOU-03 ($43,000)

GOU-03 feeder extends along the Main Road in the Goulds area of St. John’s and supplies approximately 1,900 primarily residential customers. This includes customers on Doyle’s Road which is supplied from a single-phase tap serving approximately 100 customers. Due to loading on this tap, it is no longer connected with a fuse. As a result, a fault on this tap will cause a trip of the substation feeder breaker which will result in an outage to all 1,900 customers on GOU-03 feeder.

The addition of an automated single-phase recloser on this tap at the location identified in Appendix B, Figure B12, will enable the effective restoration of customers following system disruptions under cold load pickup conditions and will prevent feeder level outages for faults on the tap.

Single-Phase Reclosers – Hardwoods Distribution Feeder HWD-08 ($86,000)

HWD-08 feeder extends along Karwood Drive onto Topsail Road and supplies approximately 2,550 primarily residential customers. This includes customers in the Octagon Heights and Glenderek Drive areas of Paradise. These areas are supplied through 2 separate single-phase taps with approximately 200 customers on each tap. Due to loading on these taps they are no longer connected with fuses. As a result a fault on either of these taps will cause a trip of the substation feeder breaker which will result in an outage to all 2,550 customers on HWD-08 feeder.

The addition of an automated single-phase recloser on each of these taps at the locations identified in Appendix B, Figure B13, will enable the effective restoration of customers following system disruptions under cold load pickup conditions and will prevent feeder level outages for faults on the tap.

PUL-04 - Overloaded Distribution Feeder Conductor ($643,000)

PUL substation is located in the town of Torbay. There are 2 transformers located in the substation, PUL-T1 and PUL-T2.[34] Both transformers are rated at 25 MVA and used to convert 66 kV transmission voltage to 12.5 kV distribution voltage and supply customers through 4 distribution feeders.

There are 4 12.5 kV feeders originating from PUL substation. PUL-01 feeder supplies approximately 1,700 customers in Torbay. PUL-02 feeder extends north from the substation and supplies approximately 1,700 customers in the towns of Flatrock and Pouch Cove. PUL-03 feeder also extends north from the substation along the Bauline Line and supplies approximately 950 customers in Torbay and Bauline. PUL-04 extends south from the substation along the Torbay Bypass Road to Indian Meal Line and supplies approximately 550 customers along Indian Meal Line.

PUL-04 feeder was constructed in 2011. The purpose of the new feeder was to transfer load from BCV substation to PUL substation where additional transformer capacity was available. PUL-04 feeder currently consists of a combination of new line construction and pre-existing sections of feeder.[35] The amount of load available for transfer from BCV substation to PUL substation is now being restricted by the conductor size of the pre-existing sections. To maximize the amount of load transferred, a 4.3 km section of PUL-04 must now be reconductored to 477 ASC conductor. Once complete, approximately 4.5 MVA of load will be transferred from BCV substation to PUL substation via PUL-04 feeder.[36]

[34] PUL-T2 was installed in 2011 as approved in Newfoundland Power's 2011 Capital Budget Application

[35] Sections of new line on PUL-04 feeder along the Torbay Bypass Road and Indian Meal Line were constructed using 477 ASC conductor which has a planning rating of 590 amps (12.7 MVA). Pre-existing sections of line consist of a combination of 1/0 ASC conductor, with a planning rating of 228 amps (4.9 MVA), and #4 Copper conductor, with a planning rating of 153 amps (3.3MVA).

[36] This includes approximately 1 MVA from BCV-04 feeder to PUL-04 feeder, and 3.5 MVA from BCV-01 feeder to PUL-04 feeder.

5.2 Substation Systems

Install Automated Recloser – Cape Broyle Substation ($75,000)

The existing hydraulic recloser at Cape Broyle ("CAB") substation will be replaced with a modern digital recloser on distribution feeder CAB-01.[37] The digital recloser will be connected to the communications equipment in the Cape Broyle hydro plant and integrated with the Company's SCADA system.

Install Automated Recloser – Fermuse Substation ($73,000)

The existing hydraulic recloser at Fermuse ("FER") substation will be replaced with a modern digital recloser on distribution feeder FER-01.[38] The digital recloser will be connected to the communications equipment in the FER substation building and integrated with the Company's SCADA system.

Install Automated Reclosers – Colliers Substation ($122,000)

The 2 existing hydraulic reclosers at COL substation will be replaced with modern digital reclosers on distribution feeders COL-01 and COL-02.[39] Establish a new communications channel to connect the digital reclosers to the Company's SCADA system.

Install Automated Reclosers – Springfield Substation ($160,000)

The 3 existing hydraulic reclosers at SPF substation will be replaced with modern digital reclosers on distribution feeders SPF-01, SPF-02 and SPF-03.[40] Establish a new communications channel to connect the digital reclosers to the Company's SCADA system.

39L Breakers Holyrood Substation ($875,000)

Transmission line 39L between Hydro's Holyrood facility and Newfoundland Power's BRB substation has 3 substations along its route. Newfoundland Power's HOL substation is 1 of these 3 substations. It serves approximately 2,200 customers.

The approved 2014 Capital Budget includes a project to refurbish and modernize the Company's HOL substation. This 2014 Capital Budget Supplemental Application includes the installation of 2 breakers on transmission line 39L at HOL substation during the summer of 2014. This will permit synergies with the approved project.[41]

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37 There are approximately 1,300 customers on distribution feeder CAB-01.

38 There are approximately 650 customers on distribution feeder FER-01.

39 There are approximately 1,400 customers on distribution feeders COL-01 and COL-02.

40 There are approximately 3,100 customers on distribution feeders SPF-01, SPF-02 and SPF-03.

41 These synergies include completing all of the work when the Company's portable substation is installed during the summer of 2014. Doing the breaker installations in a future year would involve another installation of a portable substation and the associated cost. Also, there will be engineering and project management work that would have to be duplicated when installing these breakers in a future year.

Addition of further breakers along transmission line 39L at Colliers and Springfield will be addressed in the Company's 2015 Capital Plan.

6.0 Project Cost

Distribution Cost

The estimated cost to complete all work associated with improving the automation of the distribution system is $1,587,000. Table 1 provides a detailed breakdown of the costs to be incurred.

Table 1
Distribution Cost Estimate

Cost Category	2014
Material	$706,000
Labour Internal	306,000
Labour Contract	360,000
Engineering	133,000
Other	82,000
Total	**$1,587,000**

Substation Cost

The estimated cost to complete all work associated with improving the automation of substations is $1,305,000. Table 2 provides a detailed breakdown of the costs to be incurred.

Table 2
Substation Cost Estimate

Cost Category	2014
Material	$1,050,000
Labour Internal	78,000
Labour Contract	-
Engineering	151,000
Other	26,000
Total	**$1,305,000**

Total Cost

The estimated cost to complete all work associated with the 2014 Capital Budget Supplemental Application is $2,892,000. Table 3 provides a detailed breakdown of the costs to be incurred.

Table 3
Total Cost Estimate

Cost Category	**2014**
Material	$1,756,000
Labour Internal	384,000
Labour Contract	360,000
Engineering	284,000
Other	108,000
Total	**$2,892,000**

7.0 Project Schedule

The projects included in this 2014 Capital Budget Supplemental Application are being proposed to improve electrical system performance in advance of the 2014/2015 winter season. In most cases, the improvements involve automation of the electrical system. The automation equipment will take between 12 and 26 weeks for manufacture and delivery.[42] To ensure all equipment is delivered and installed before the 2014/2015 winter season, timely approval of the Board is required.

8.0 Concluding

The electrical system improvements identified to be included in this 2014 Capital Budget Supplemental Application include:

(i) 14 downline automated distribution feeder sectionalizing reclosers,
(ii) upgrading of 4.3 km of distribution feeder conductor,
(iii) 7 automated substation feeder reclosers, and
(iv) 2 automated transmission breakers.

The estimated cost to complete this work in 2014 is $2,892,000.

[42] Distribution class reclosers have a 12 to 14 week delivery. High voltage switches for distribution and transmission voltages classes have a 14 to 16 week delivery. Transmission line breakers have an estimated delivery of 26 weeks.

Appendix A
Cold Load Pickup Curves

Figure A1 CHA-01 Peak Loading - Jan. 04, 07:00 to 19:00

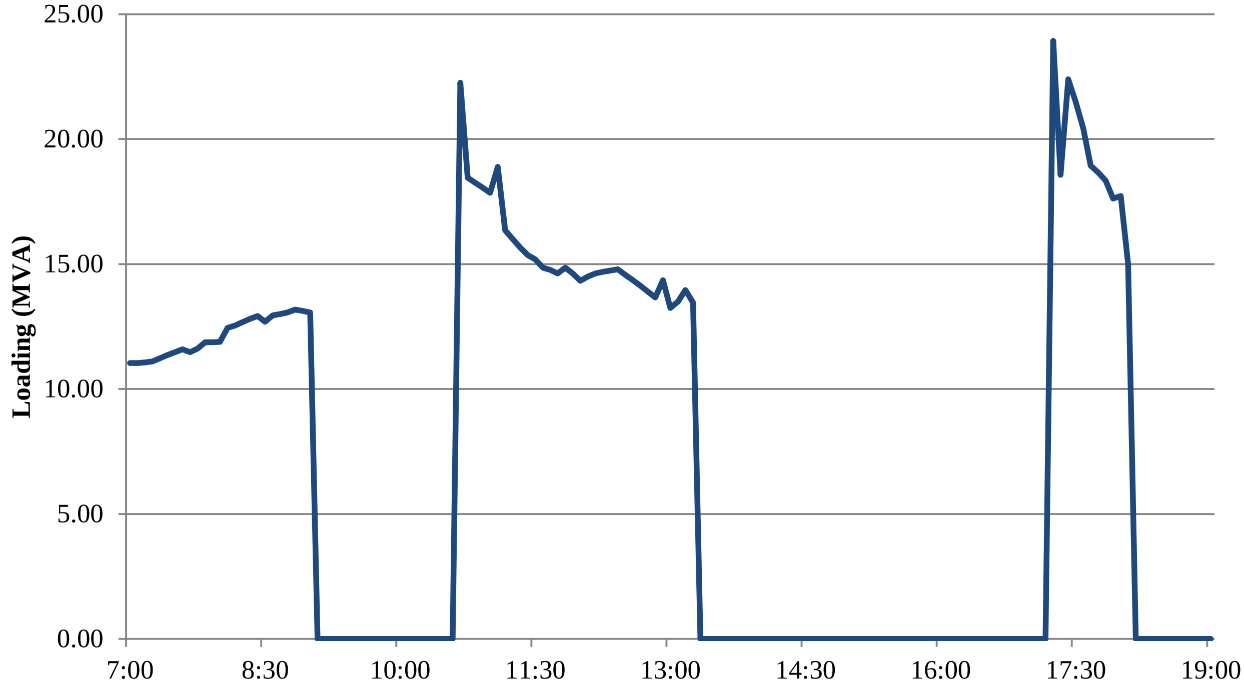


Figure A2 CHA-02 Peak Loading - Jan. 04, 05:30 to 15:00

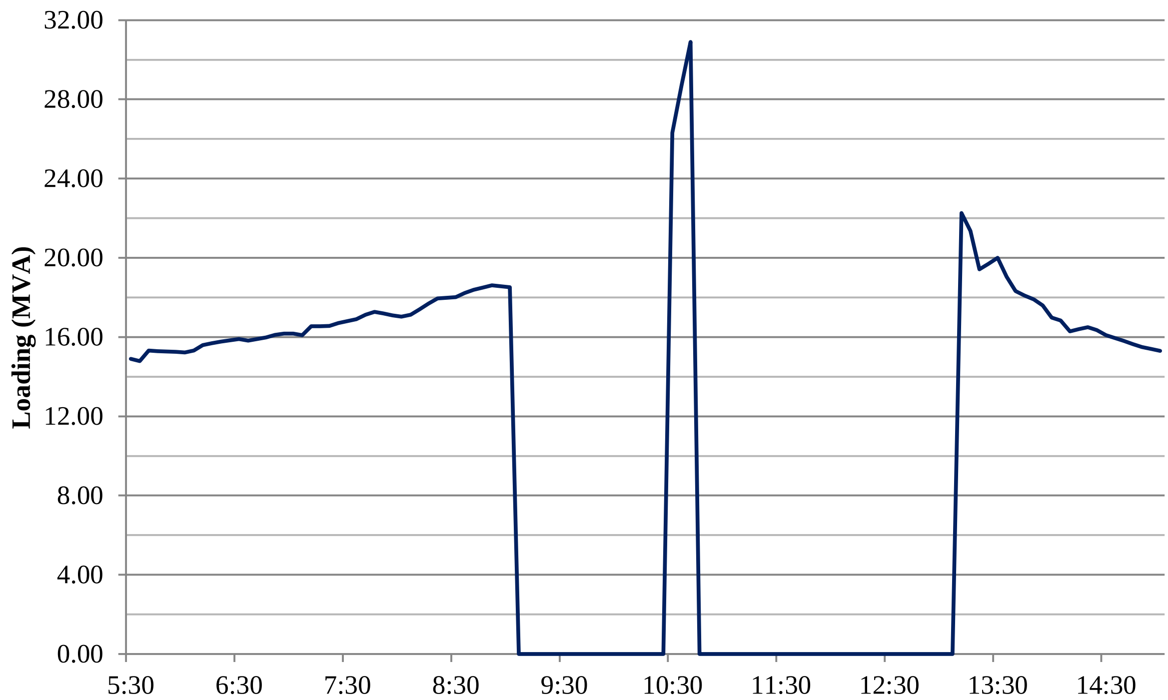


Figure A3 CHA-03 Peak Loading - Jan. 04, 07:00 to Jan. 05, 01:00

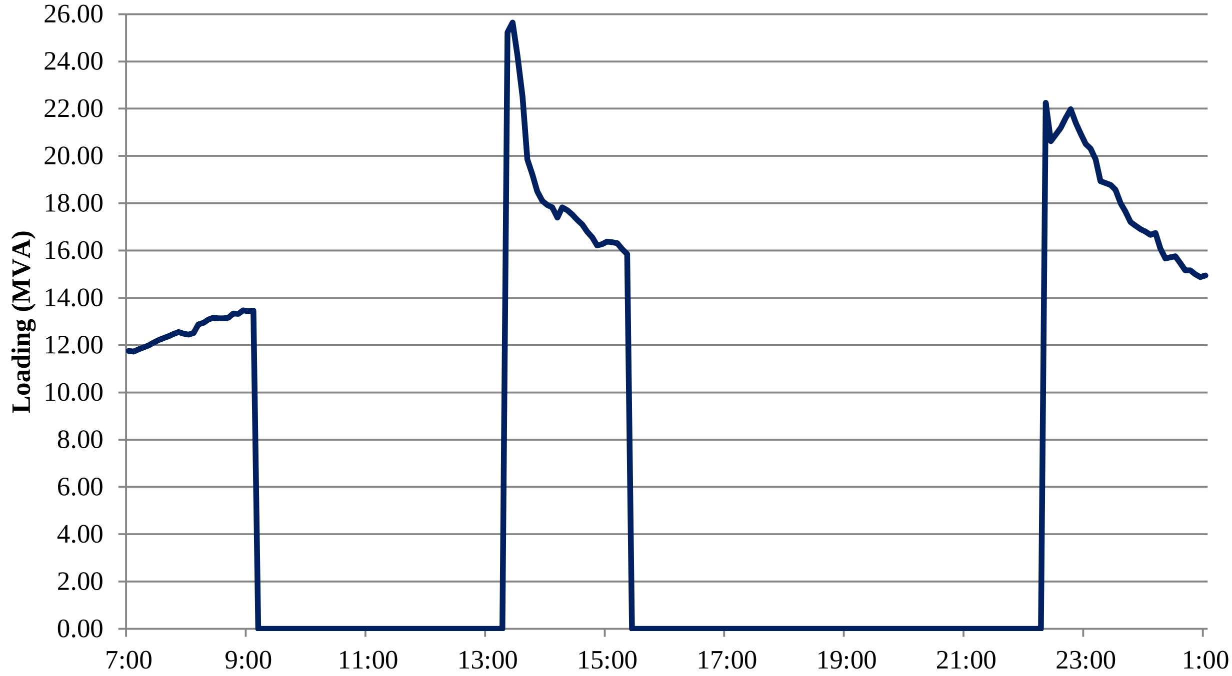


Figure A4 HWD-07 Peak Loading - Jan. 04, 07:00 to 14:00

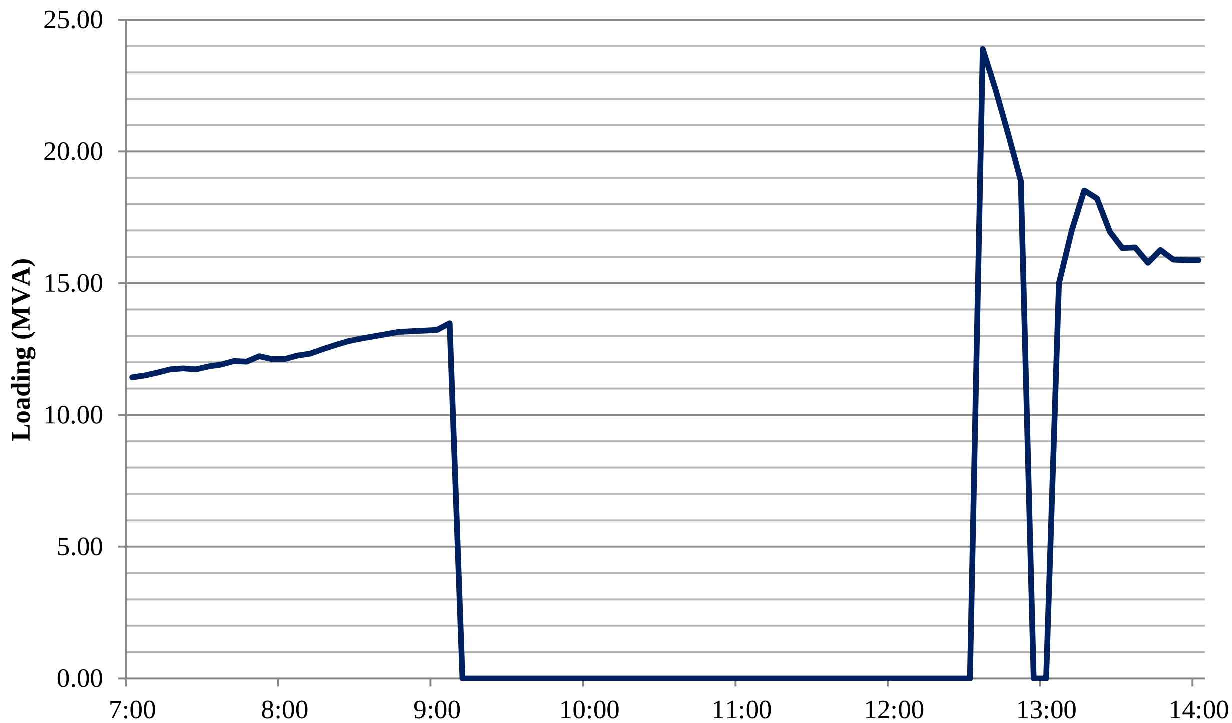


Figure A5 KEN-01 Peak Loading - Jan. 04, 07:00 to 14:00

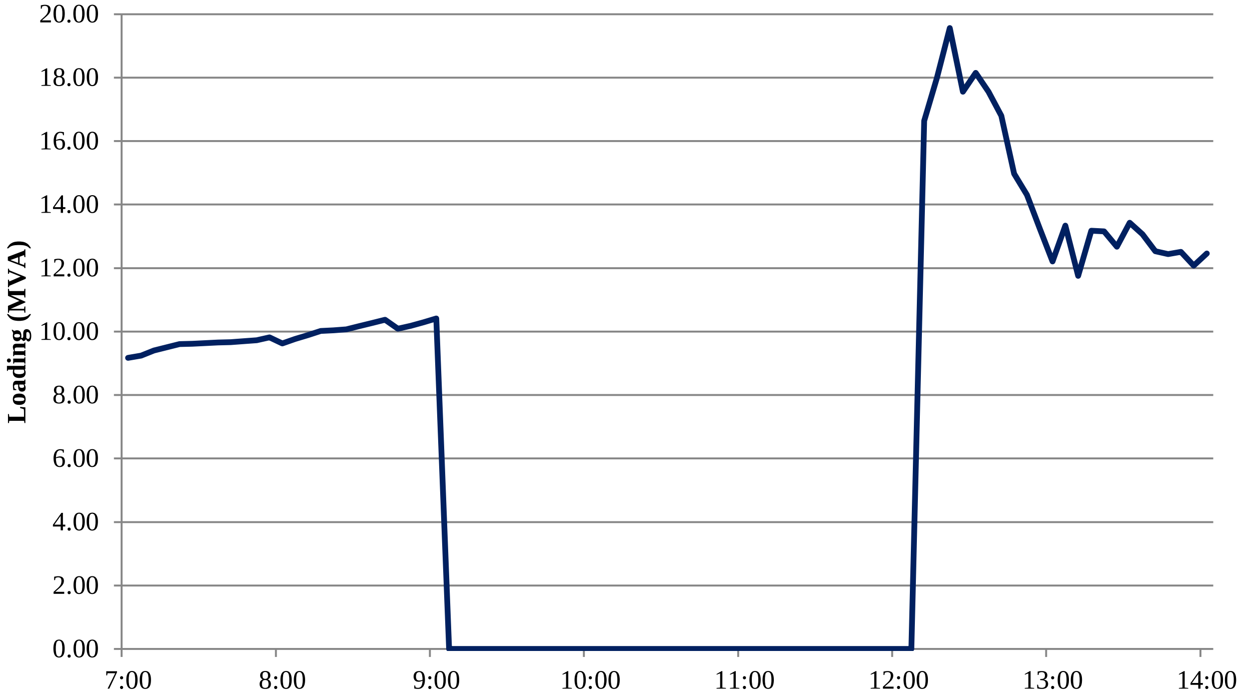


Figure A6 KEN-02 Peak Loading - Jan. 04, 07:00 to 15:00

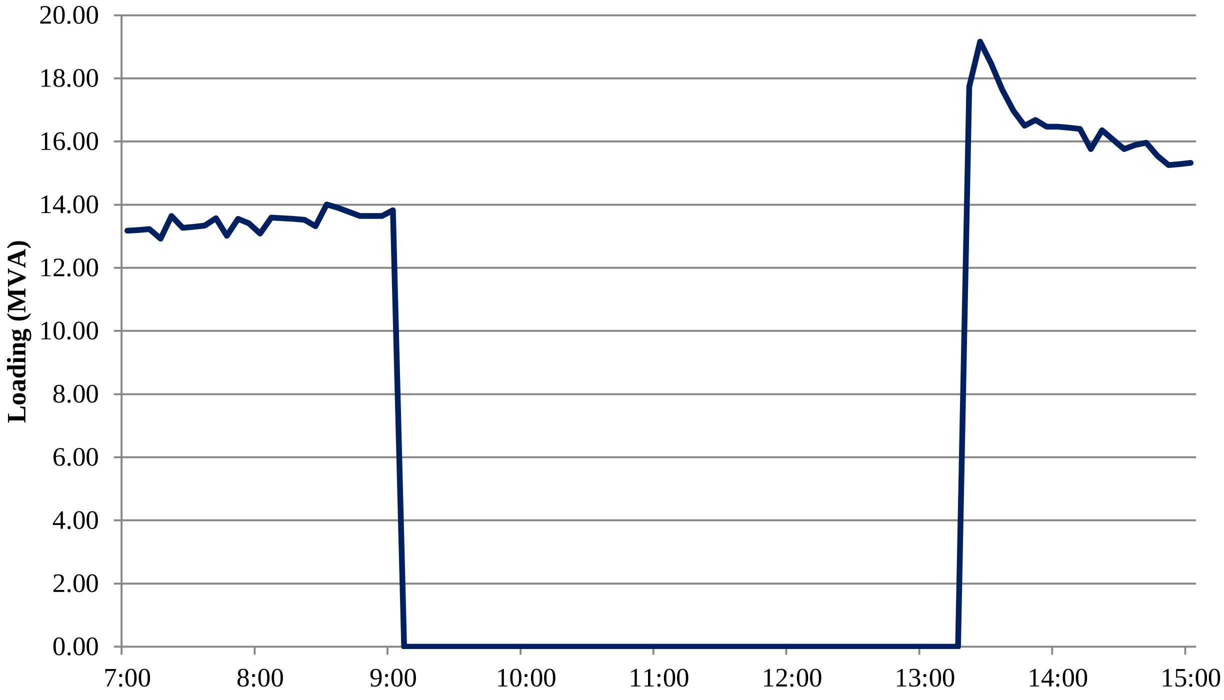


Figure A7 KEN-03 Peak Loading - Jan. 04, 23:00 to Jan. 05, 04:00

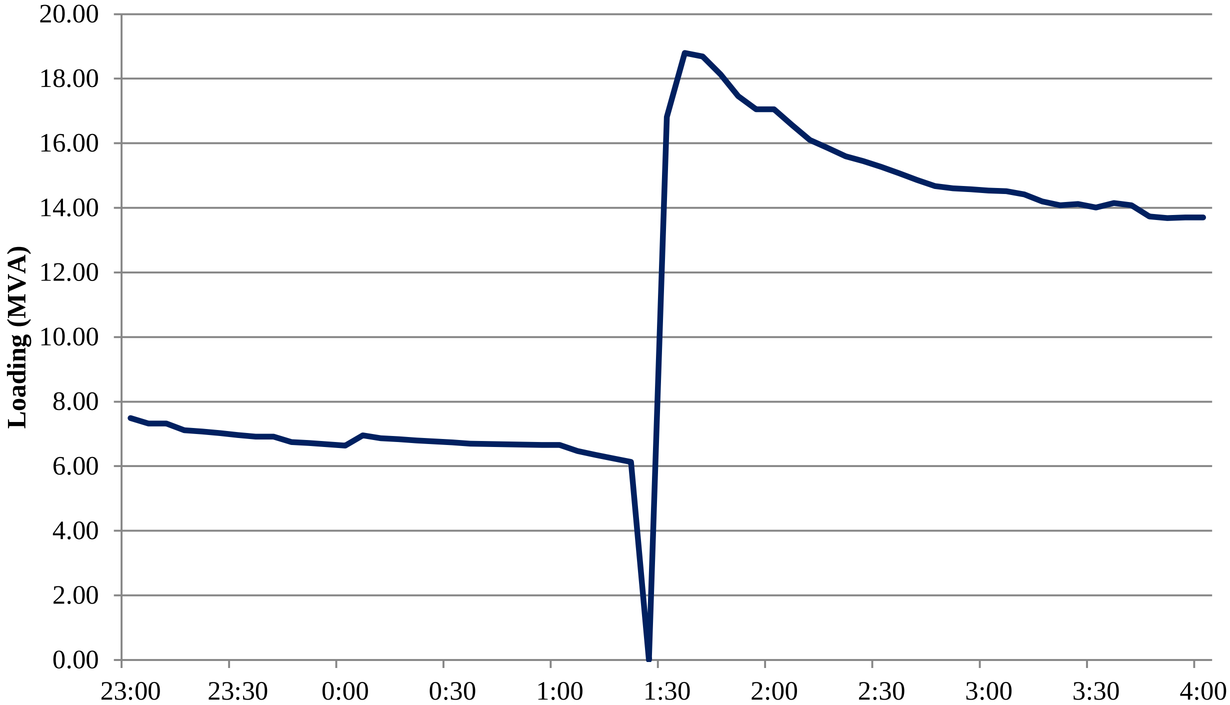


Figure A8 KEN-04 Peak Loading - Jan. 05, 03:00 to 07:00

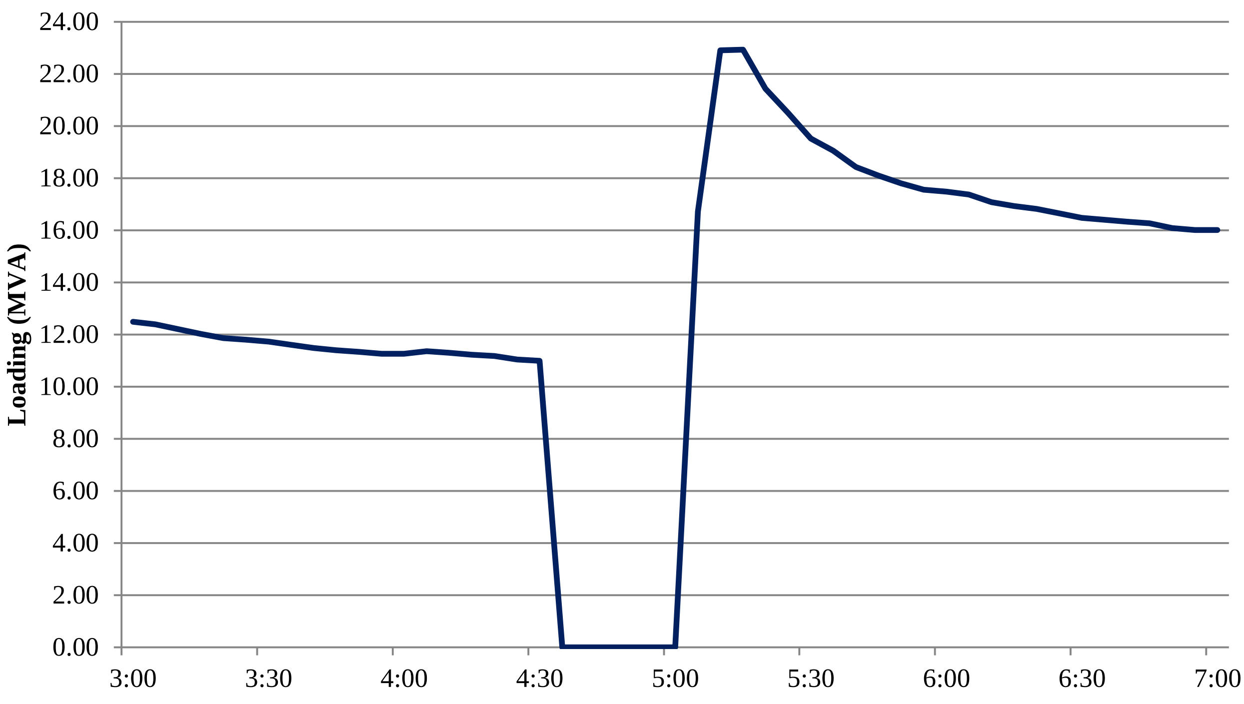
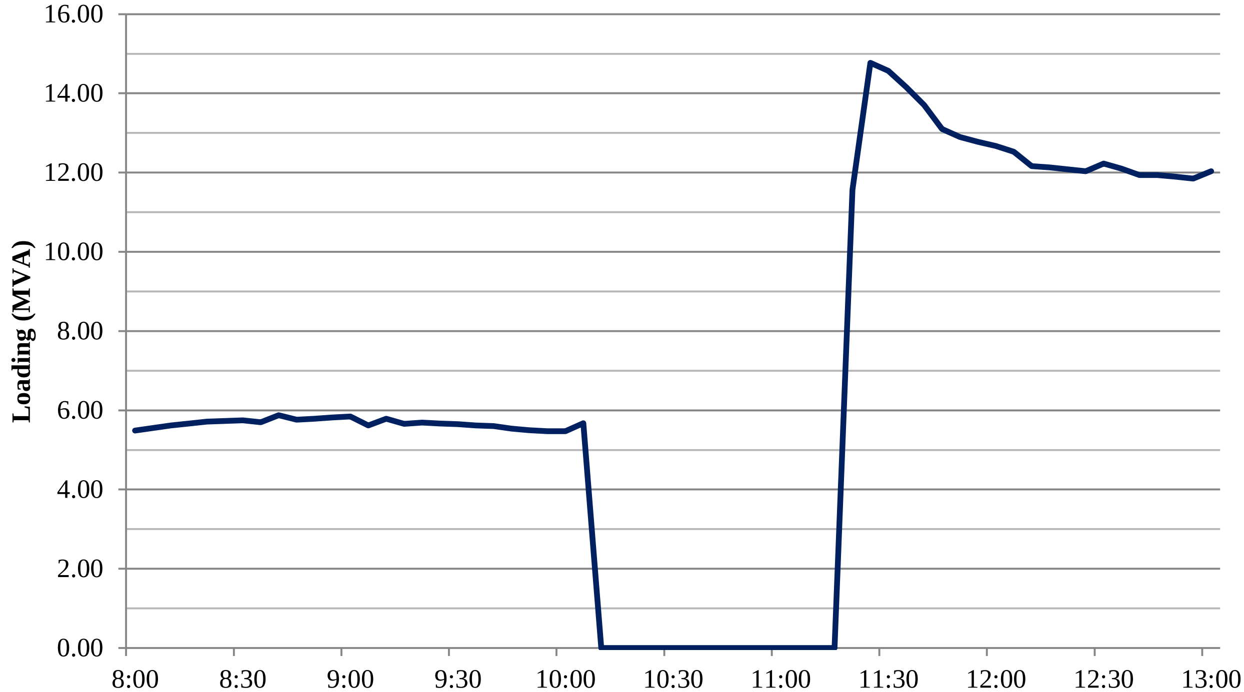


Figure A9 VIR-06 Peak Loading - Jan. 05, 08:00 to 13:00



Appendix B
Distribution Feeder Maps

Figure B1 – Location of CHA-01 Three Phase Sectionalizing Recloser

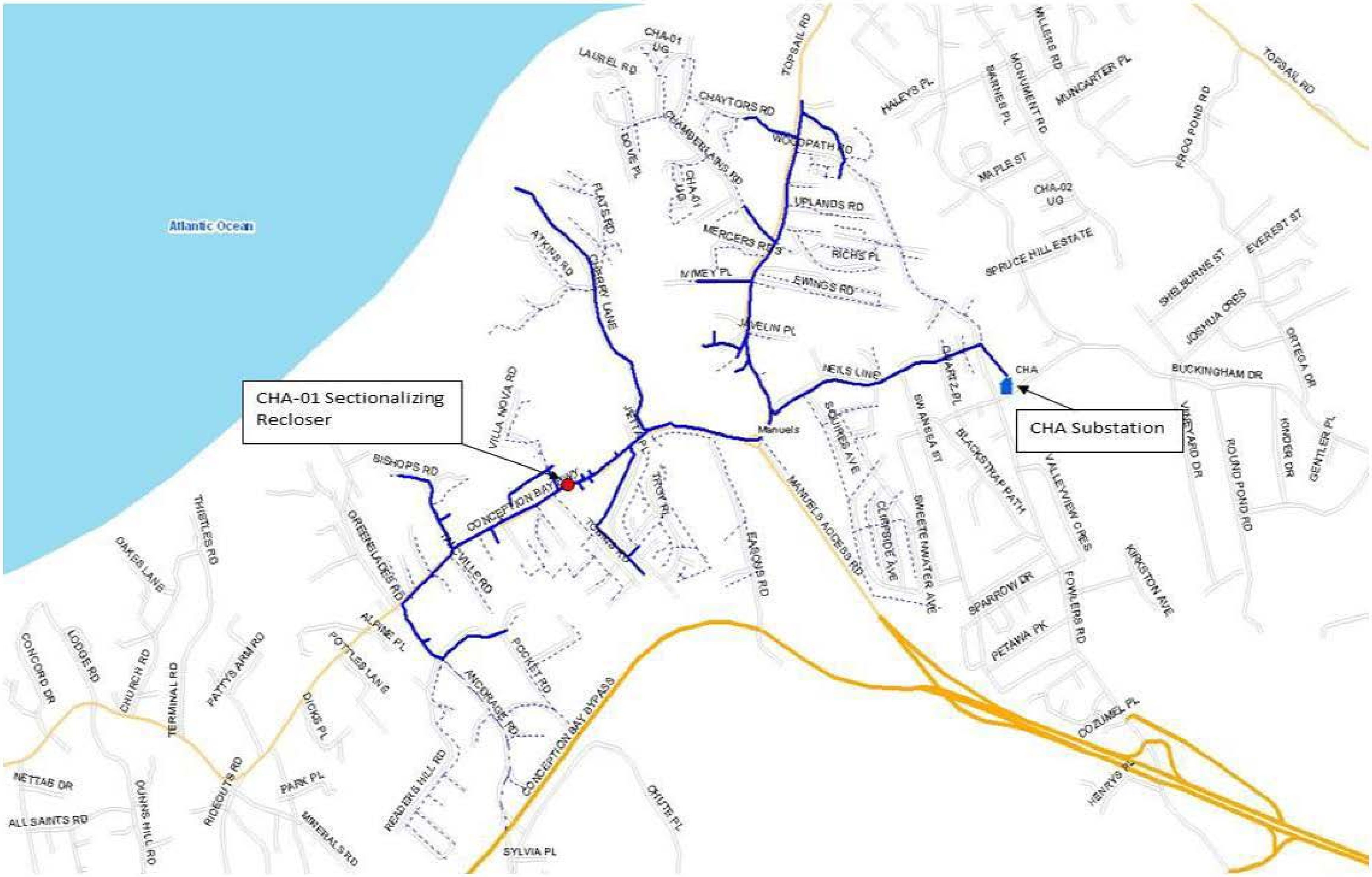


Figure B2 – Location of CHA-02 Three Phase Sectionalizing Recloser

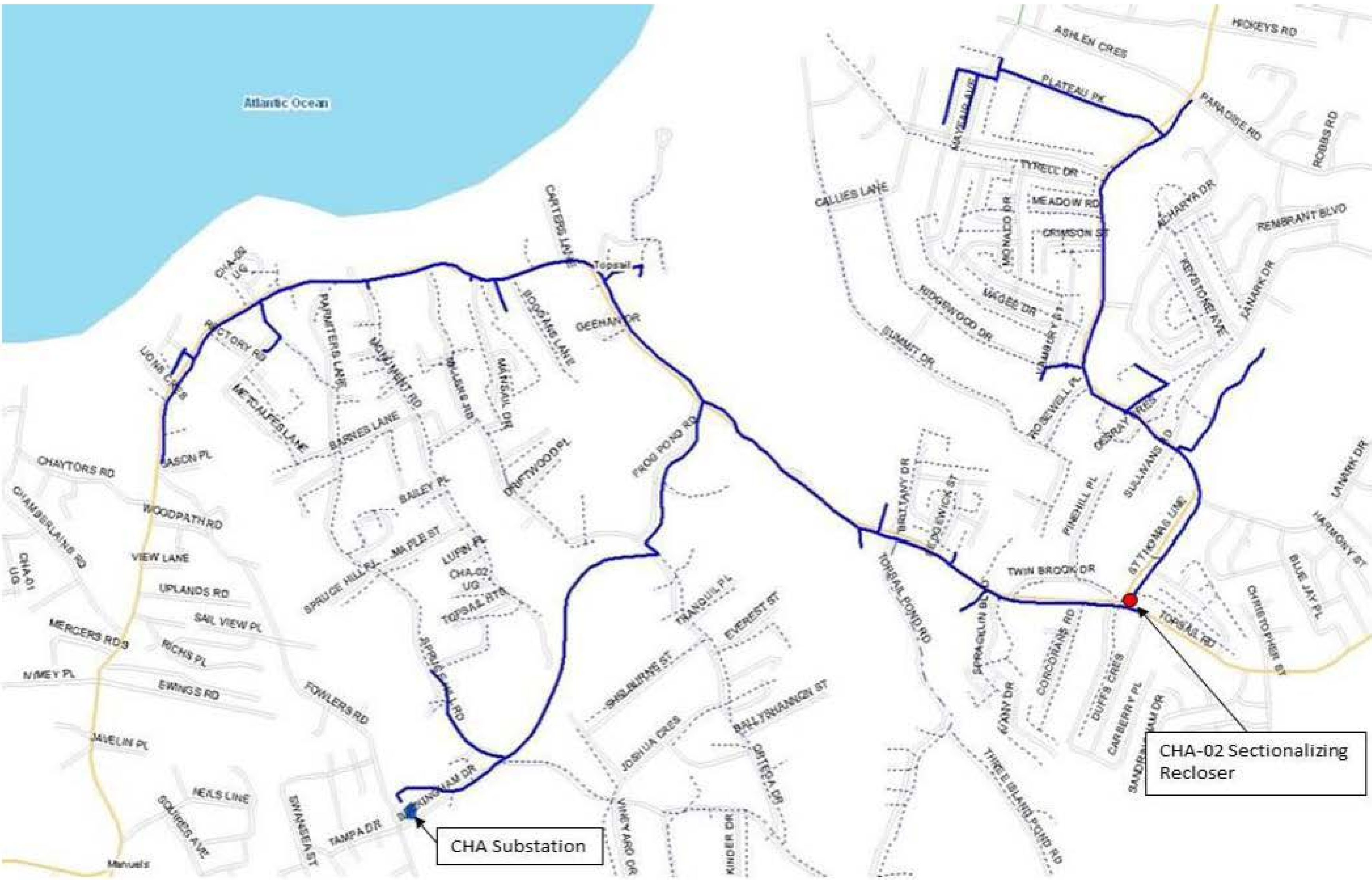


Figure B3 – Location of CHA-03 Three Phase Sectionalizing Recloser

Figure B4 – Location of HWD-07 Three Phase Sectionalizing Recloser

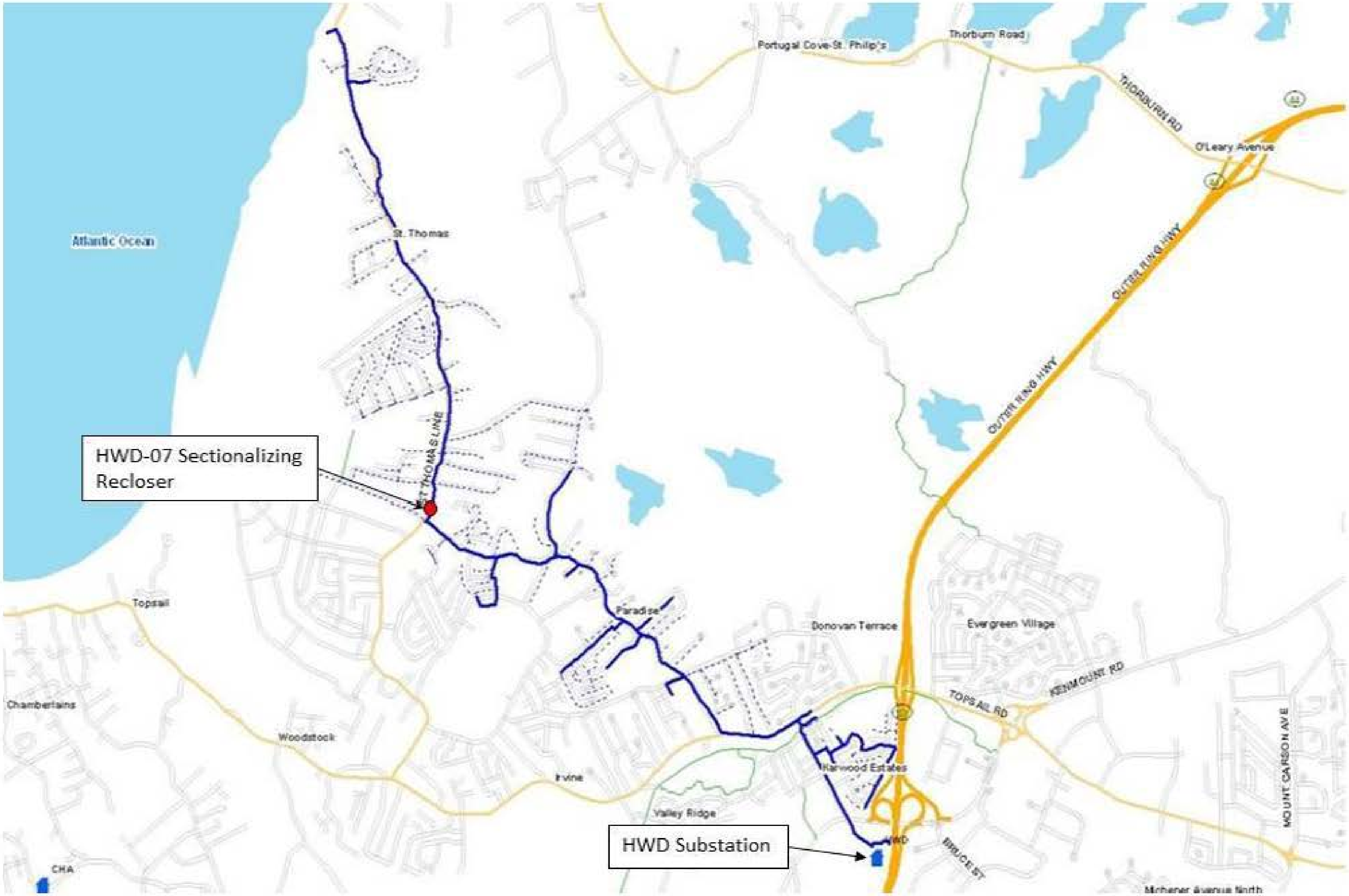


Figure B5 – Location of KEN-01 Three Phase Sectionalizing Recloser

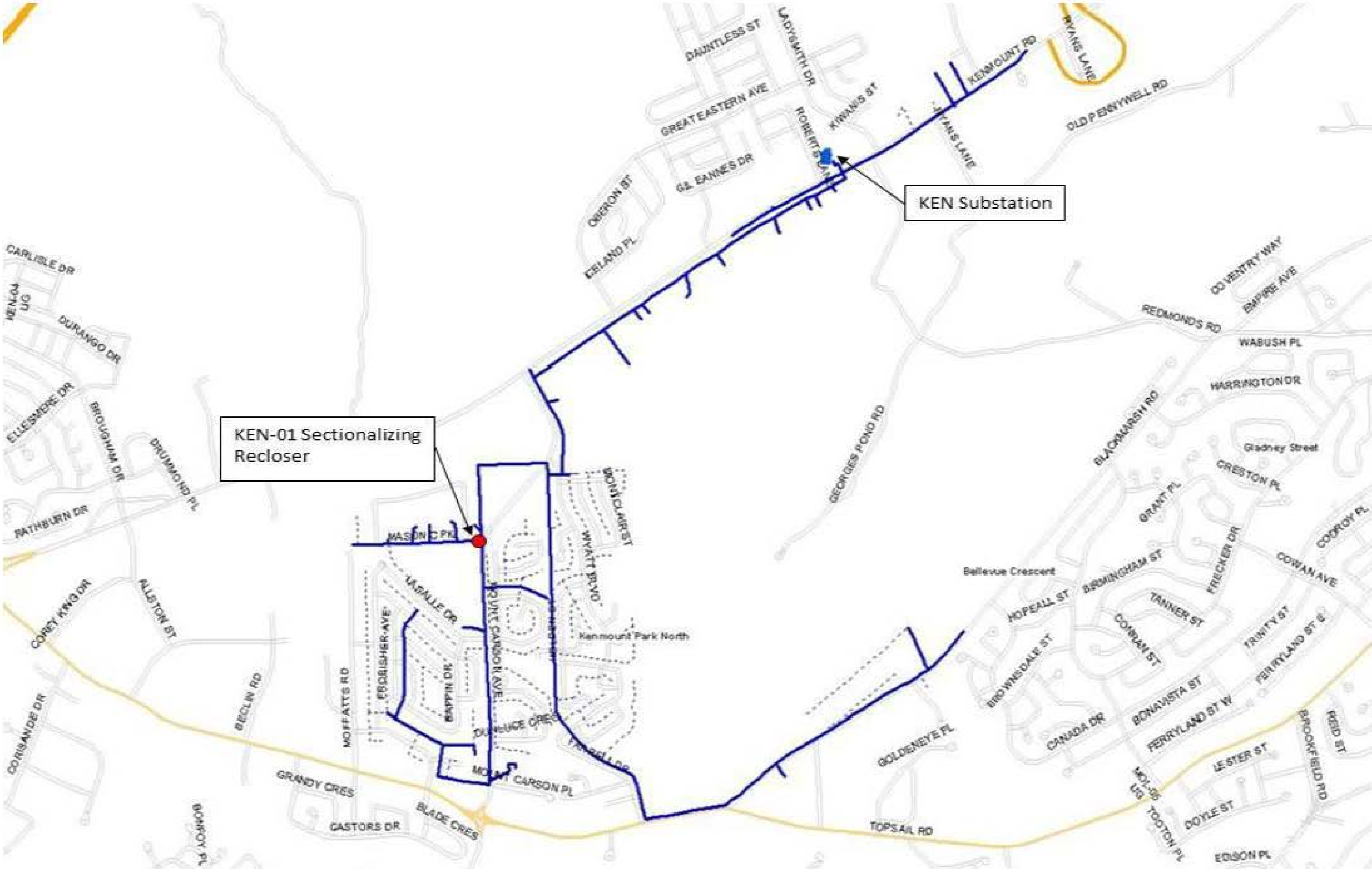


Figure B6 – Location of KEN-02 Three Phase Sectionalizing Recloser

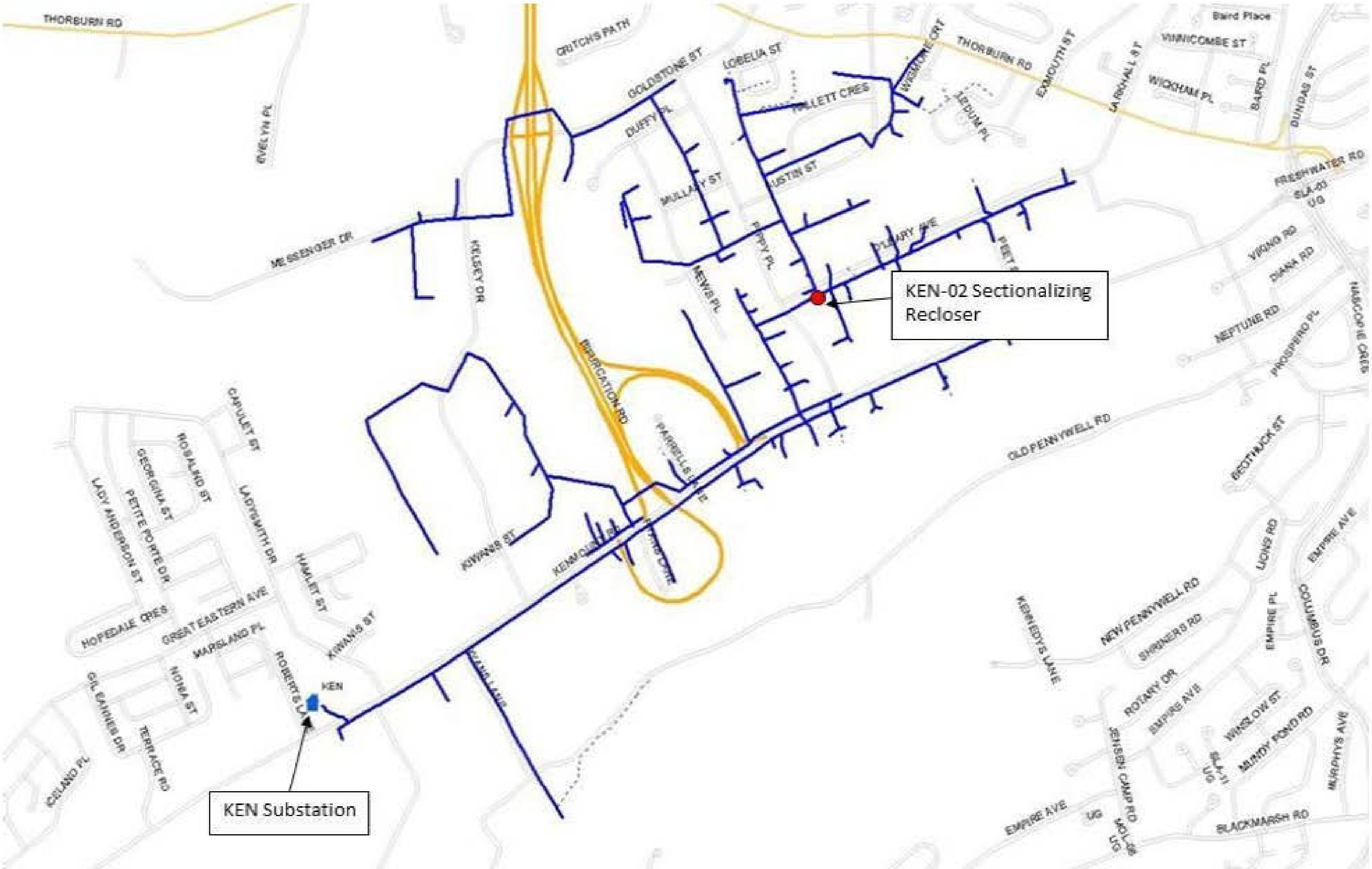


Figure B7 – Location of KEN-03 Three Phase Sectionalizing Recloser

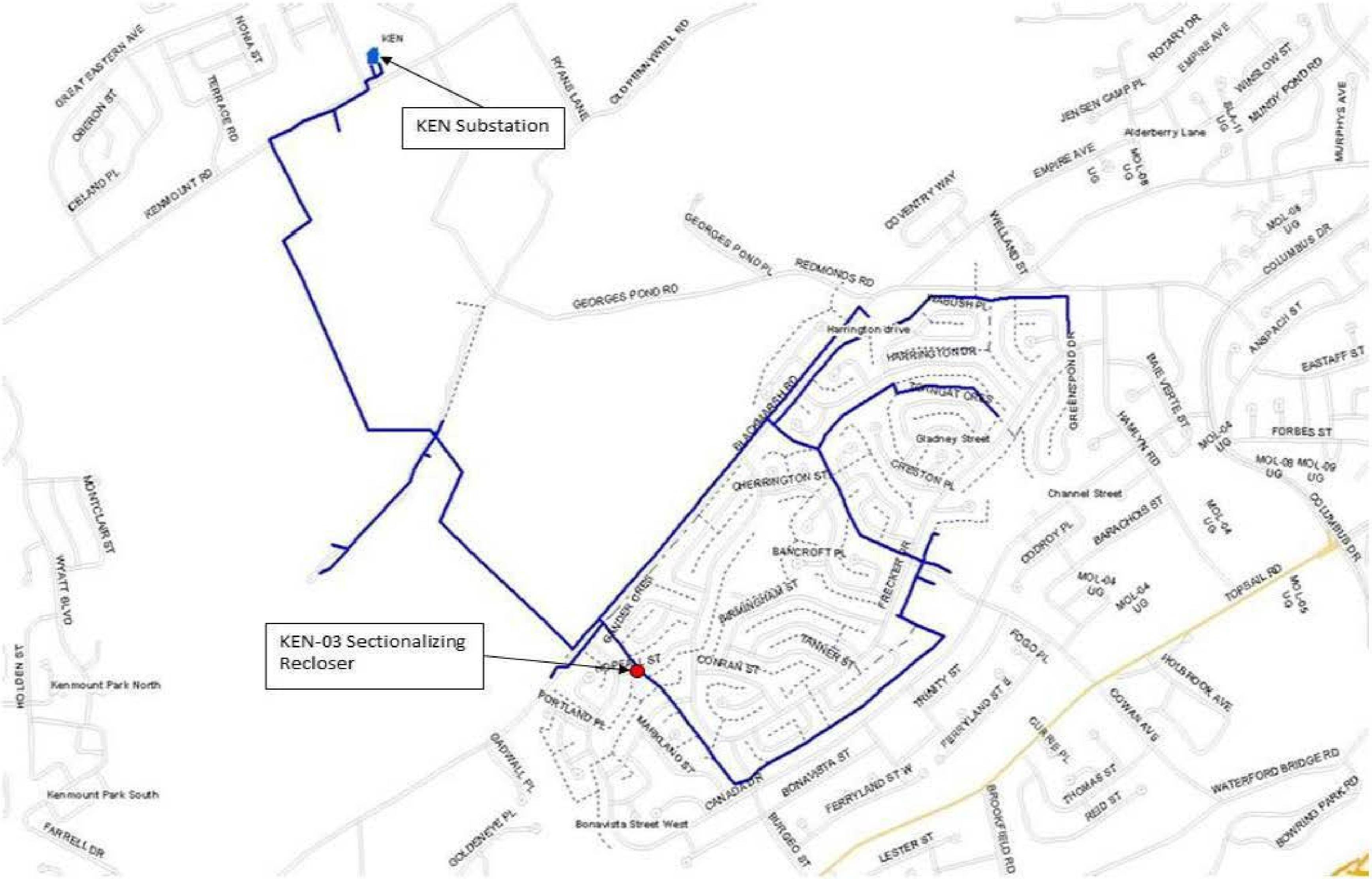


Figure B8 – Location of KEN-04 Three Phase Sectionalizing Recloser

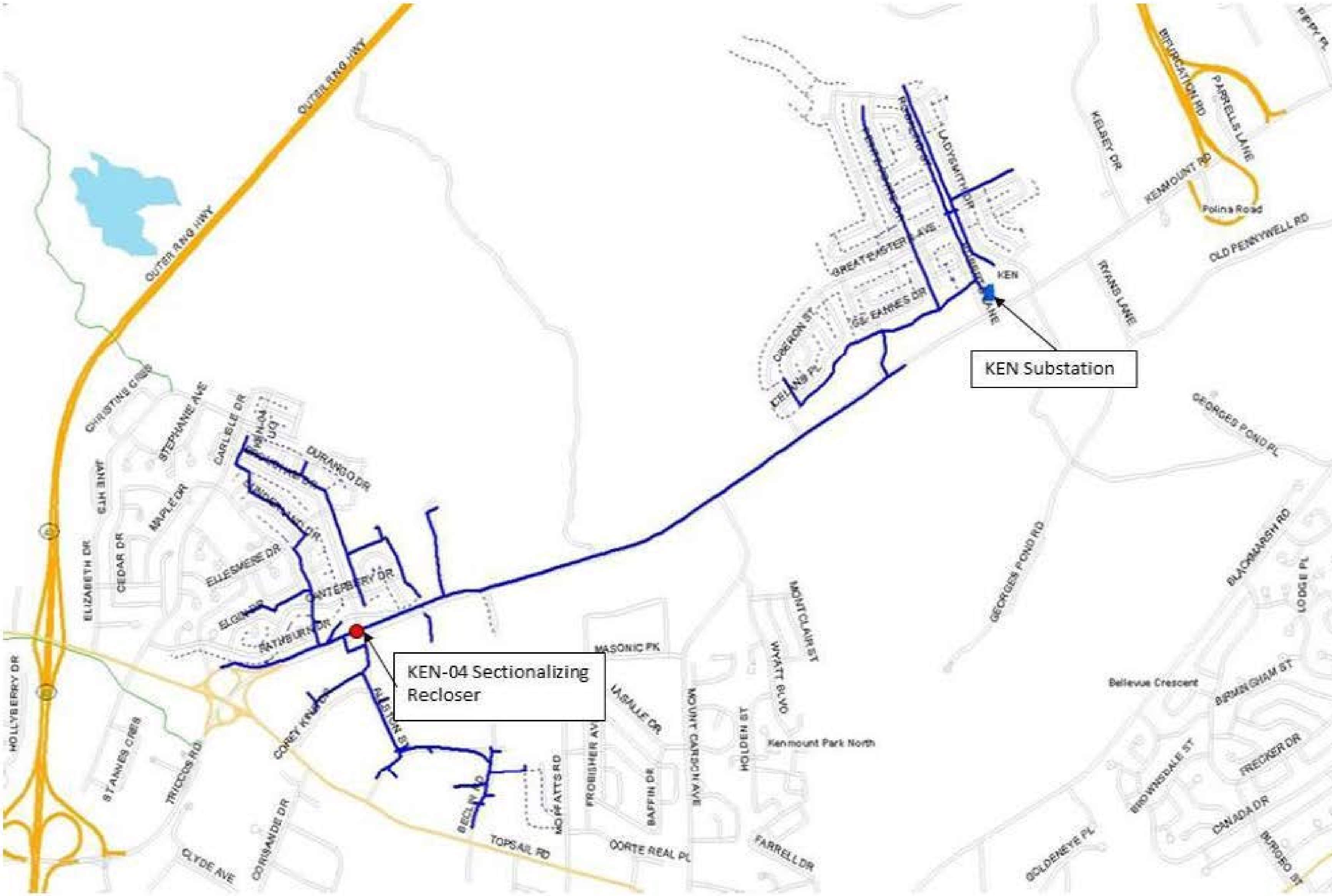


Figure B9 – Location of VIR-06 Three Phase Sectionalizing Recloser

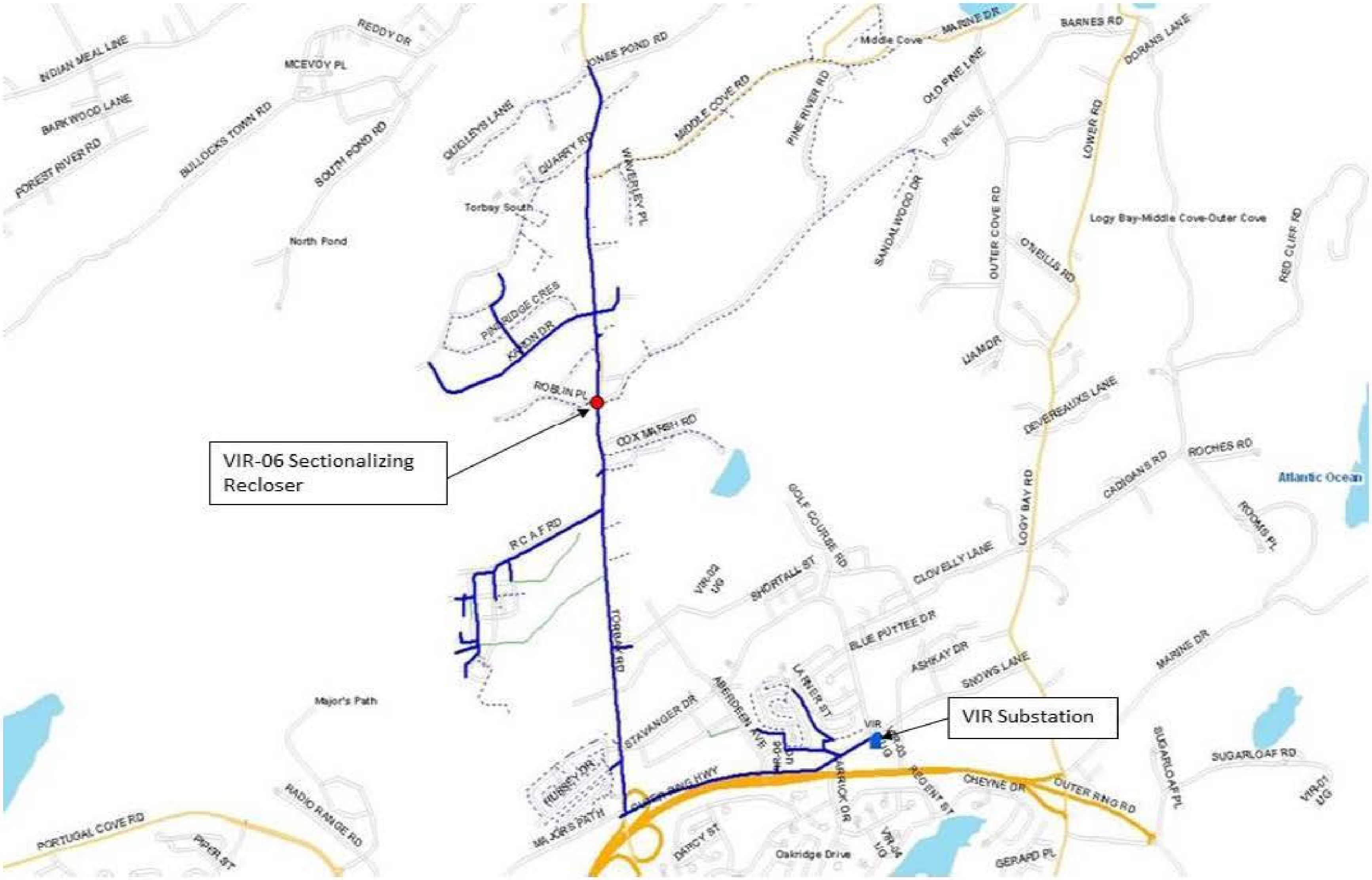


Figure B10 – Location of CHA-02 Single Phase Recloser

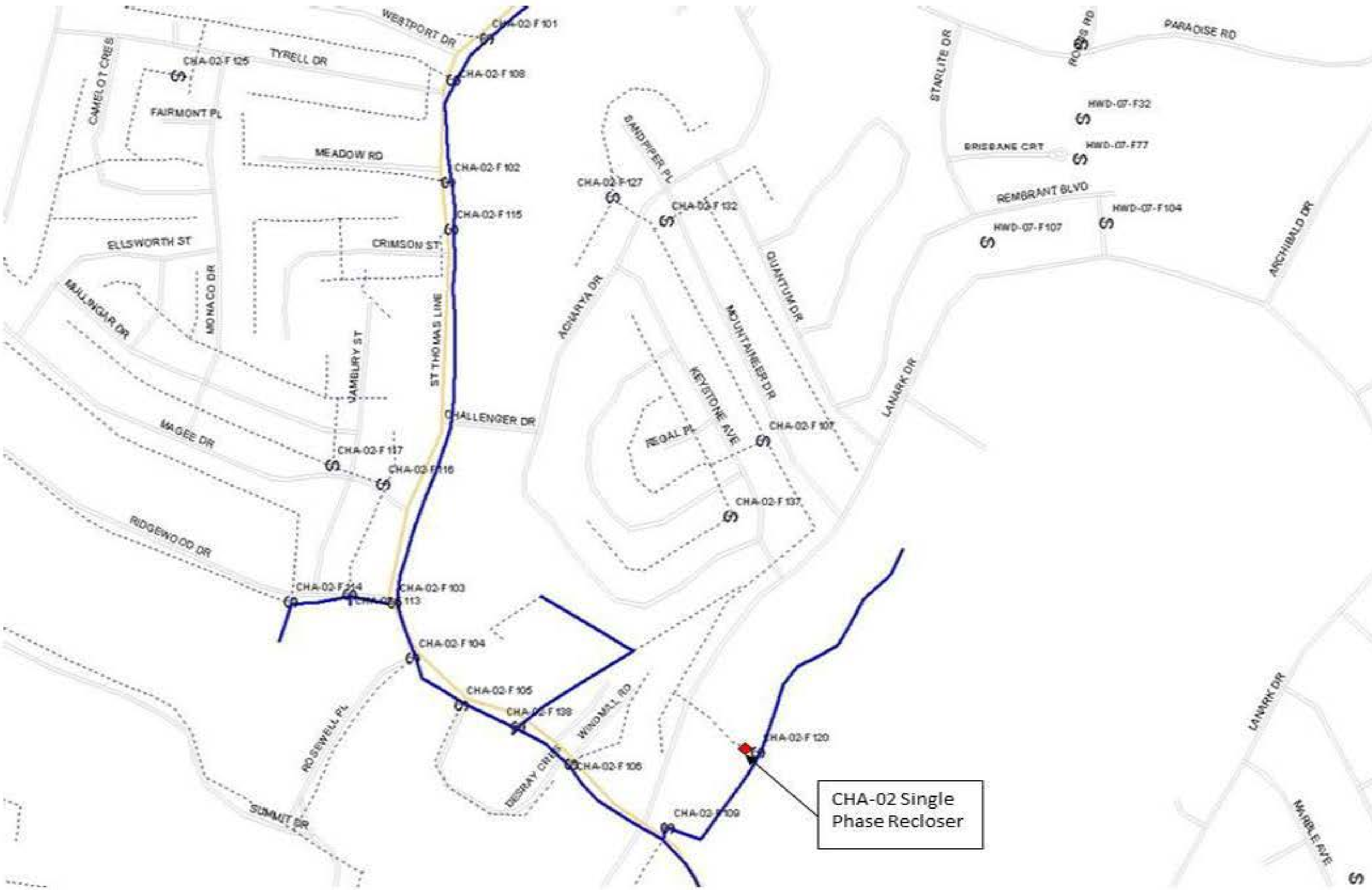


Figure B11 – Location of GOU-01 Single Phase Recloser

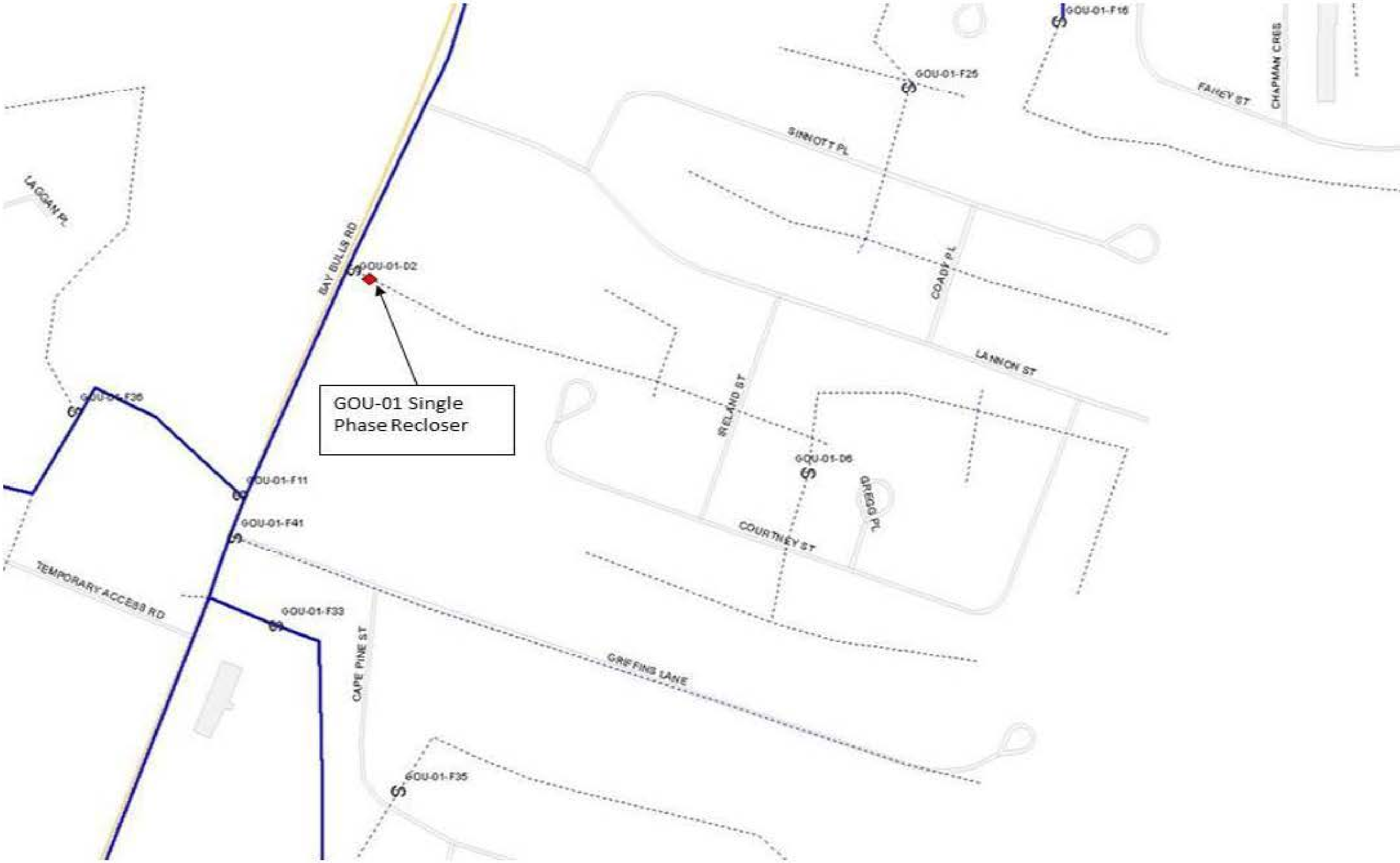


Figure B12 – Location of GOU-03 Single Phase Recloser

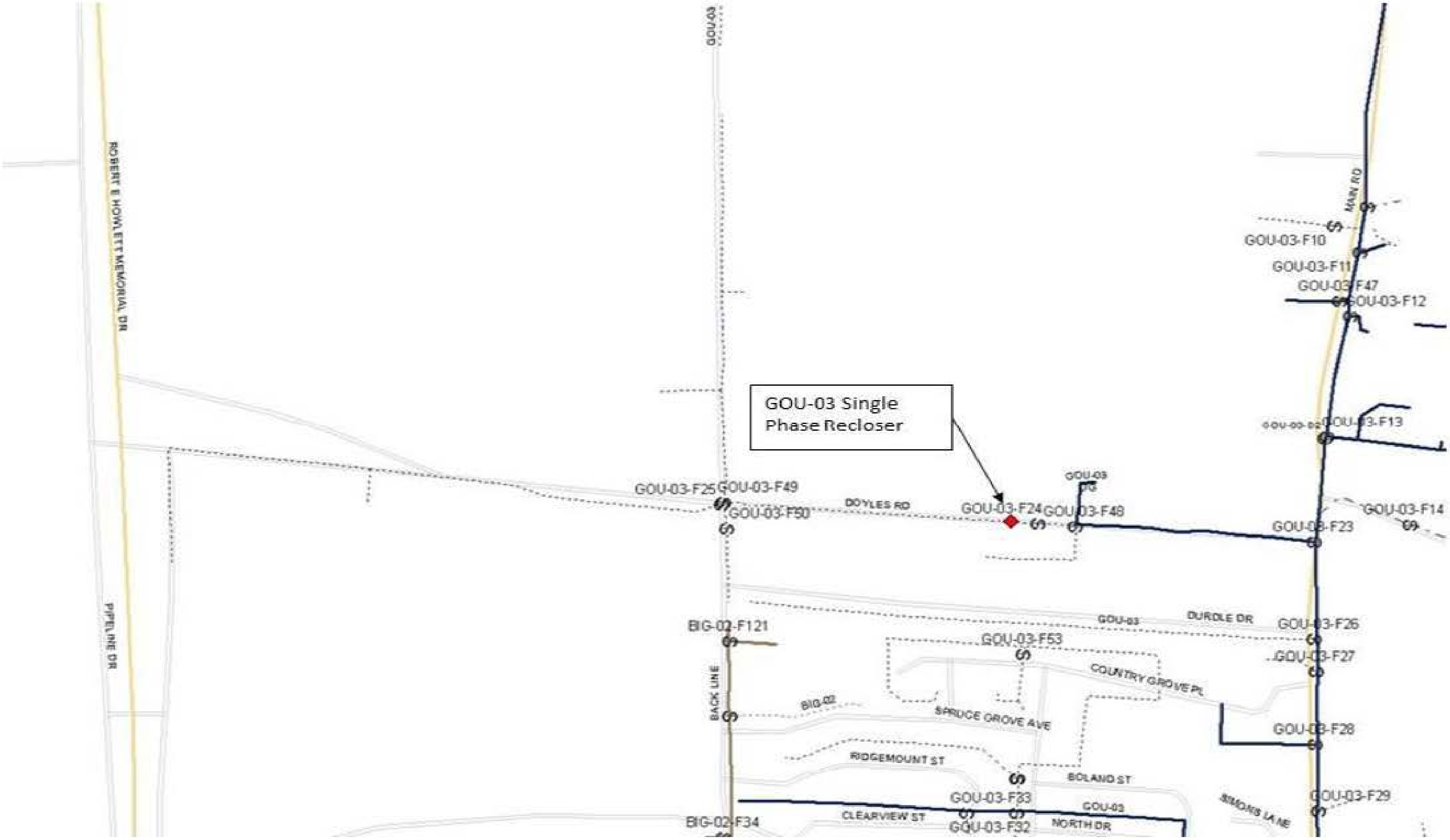
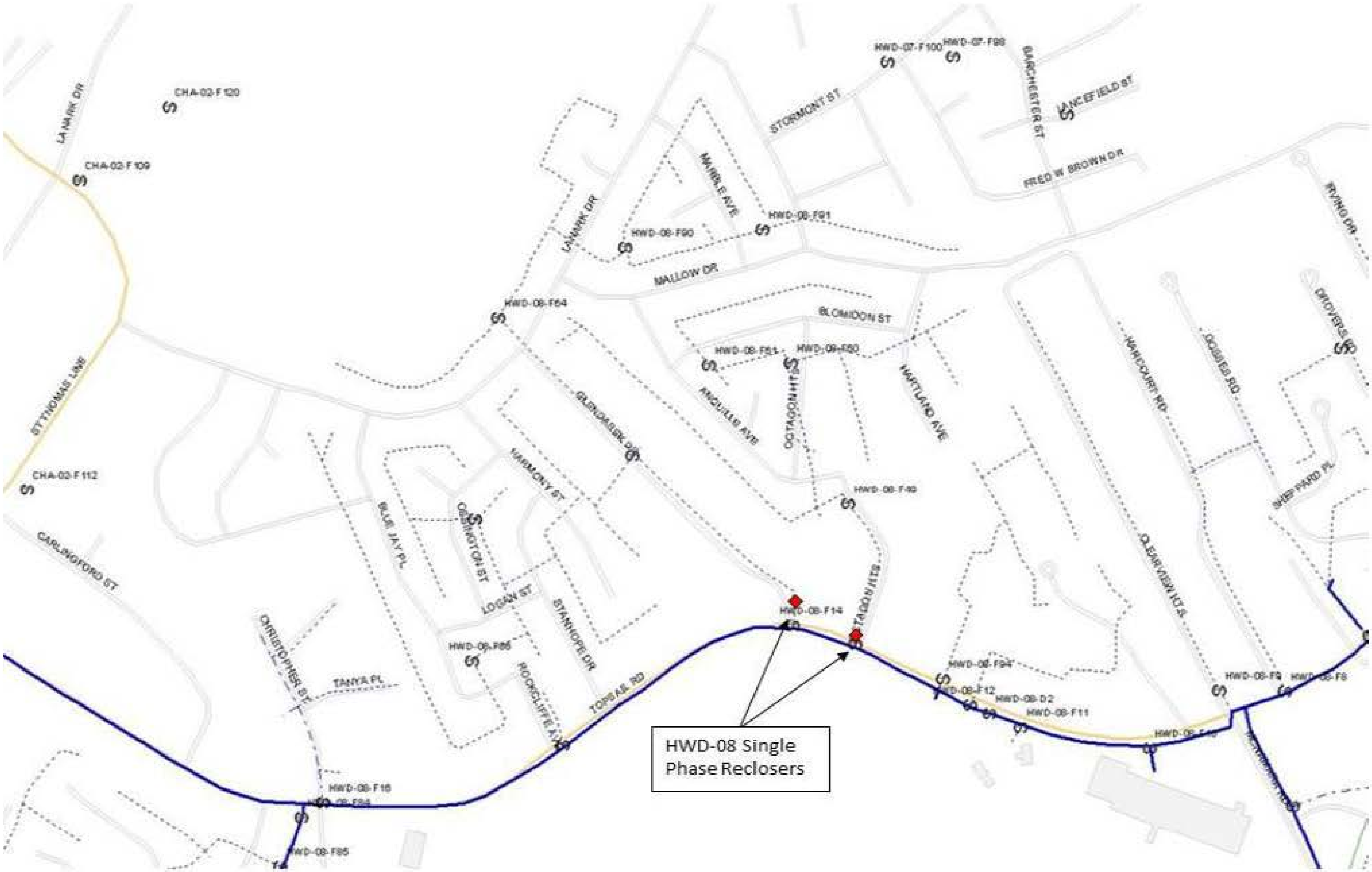


Figure B13 – Location of HWD-08 Single Phase Reclosers



Appendix C
Optimal Sectionalizing Example

Example of Feeder Sectionalizing for Cold Load Pickup

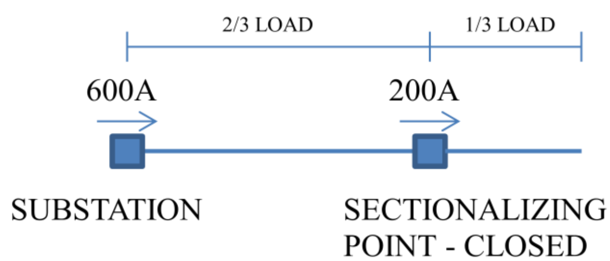
Consider an aerial feeder with no sectionalizing using 477 ASC conductor. The winter conductor ampacity is approximately 800 amps. Using a typical cold load pickup factor ("CLPU") of 2.0, the "feeder ampacity without sectionalizing" is 400 amps (i.e. 50% of the conductor winter ampacity).

If a sectionalizing switch were installed in the feeder at the optimal location (i.e. 2/3 of the load in the first section of the feeder), the feeder ampacity is 600 amps (i.e. 75% of the winter conductor ampacity).[43]

Under this scenario, when the first section of the feeder is energized (up to the downline sectionalizer) after an extended outage, the CLPU will be 800 amps (400 x 2.0). At no time does the CLPU exceed the winter ampacity of 800 amps.

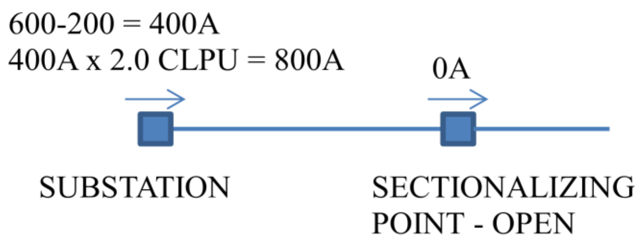
The following illustrations demonstrate the sequence of restoring a feeder under cold load pickup conditions:

Originally the feeder is loaded to 600 amps, with 200 amps or 1/3 of the load beyond the sectionalizing point.

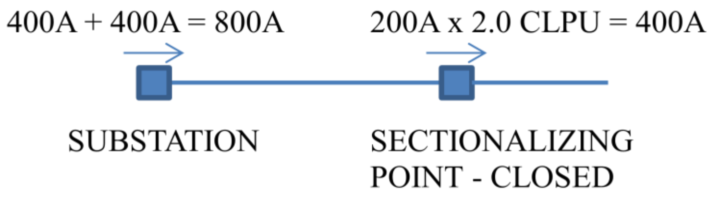


After the outage occurs, the sectionalizing point is opened and the substation breaker or recloser is closed. At this point, power is restored to the first 2/3 of customers and the load at the substation is 800 amps (i.e. 400 x 2). After a period of 0.5 to 1.0 hours, the CLPU will have subsided and the normal winter peak load of 400 amps will be present.

[43] The 75% of the winter conductor ampacity was chosen to provide a theoretical basis for the associated calculations. In practice the actual percentage will be something less due to (i) the age and physical condition of the conductor, (ii) the number of customers on the feeder, (iii) the ability to transfer load to adjacent feeders and (iv) operational considerations including the geographic layout and the distribution of customers on the feeder.



The second section of the feeder may then be energized and the total load will again be 800 amps (i.e. 400 + 200 x 2).



After a period of 0.5 to 1.0 hours, the CLPU will have subsided and the normal winter peak load of 600 amps will again be present.

Project Title: **2014 Distribution Feeder Improvements**

Project Cost: **$1,587,000**

Project Description

This distribution project consists of expenditures to address some electrical system capacity and control limitations which became apparent during the system events of January 2-8, 2014. This includes improved capability to deal with cold load pickup and improved efficiency of restoration operations following outages. The 2014 supplemental capital expenditures are required in the Northeast Avalon. The following projects have been identified to improve electrical system performance going into the 2014/2015 winter season and into the future:

1. The installation of fourteen (14) downline automated distribution feeder sectionalizing reclosers on heavily loaded distribution feeders in the Northeast Avalon. Nine (9) distribution feeders and five (5) single-phase taps have been identified for the installation of remotely controlled reclosers to improve flexibility in the operation of Newfoundland Power's distribution feeders. ($944,000), and

2. The upgrading of 4.3 km of distribution feeder conductor on Pulpit Rock Substation feeders PUL-03 and PUL-04 in order to enable transfer of load from Broad Cove Substation to Pulpit Rock Substation. ($643,000)

Details on the proposed expenditures are included in *Schedule A Electrical System Improvements – April 4, 2014*.

Justification

The project is justified based on the obligation to provide safe, least cost reliable service.

Installing automatic reclosers to sectionalize heavily loaded distribution feeders and taps provides customers with a greater degree of reliability in all operating conditions.

Projected Expenditures

Table 1 provides a breakdown of the proposed supplemental expenditures for 2014 and a projection of expenditures through 2018.

Table 1
Project Cost
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$706	-	-	$706
Labour – Internal	306	-	-	306
Labour – Contract	360	-	-	360
Engineering	133	-	-	133
Other	82	-	-	82
Total	**$1,587**	**$0**	**$0**	**$1,587**

Costing Methodology

The budget estimate is based on detailed engineering estimates of individual feeder requirements.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Substations Refurbishment and Modernization (Pooled)**

Project Cost: **$1,305,000**

Project Description

As a result of the events of January 2nd, 2014 to January 8th, 2014, Newfoundland Power has identified opportunities to improve electrical system performance through the increased automation of transmission lines and distribution feeders. The following projects have been identified to improve electrical system performance going into the 2014/2015 winter season and into the future:

1. The upgrading of seven (7) existing hydraulic reclosers at 4 of the Company's substations to fully automated digital reclosers. ($430,000), and

2. The installation of two (2) 138 kV breakers on transmission line 39L at Holyrood substation. ($875,000)

The individual requirements for the replacement of substation infrastructure are not inter-dependent. However, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Details on the proposed expenditures are included in *Schedule A Electrical System Improvements – April 4, 2014*.

Justification

This project is justified based on the need to maintain safe, reliable electrical service and ensure workplace safety by replacing deteriorated or substandard substation infrastructure.

Projected Expenditures

Table 1 provides a breakdown of the proposed supplemental expenditures for 2014 and a projection of expenditures through 2018.

Table 1
Project Cost
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$1,050	-	-	$1,050
Labour – Internal	78	-	-	78
Labour – Contract	-	-	-	-
Engineering	151	-	-	151
Other	26	-	-	26
Total	**$1,305**	**$0**	**$0**	**$1,305**

Costing Methodology

The budget for this project is based on engineering estimates for the cost of individual budget items.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.