DELIVERED BY HAND

July 9, 2020

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: Newfoundland Power's 2021 Capital Budget Application

A. 2021 Capital Budget Application

Enclosed are the original and 9 copies of Newfoundland Power Inc.'s (the "Company") *2021 Capital Budget Application* and supporting materials (the "Filing").

The Filing outlines a proposed 2021 Capital Budget totaling $111,298,000. Included in that total are 2021 capital expenditures of $700,000 previously approved in Order No. P.U. 35 (2018) (the "2019 Capital Order") and $8,914,000 previously approved in Order No. P.U. 5 (2020) (the "2020 Capital Order"). These previously approved expenditures relate to multi-year projects proposed in the *2019 Capital Budget Application* and the *2020 Capital Budget Application*. The Filing also outlines multi-year projects commencing in 2021 that include proposed 2022 capital expenditures totaling $16,071,000 and proposed 2023 capital expenditures totaling $6,162,000.

In addition, the Filing seeks approval of a 2019 rate base in the amount of $1,153,556,000.

B. Compliance Matters

B.1 Board Orders

In the 2020 Capital Order, the Board required a progress report on 2020 capital expenditures be provided with the Filing. In Order No. P.U. 35 (2003) (the "2004 Capital Order"), the Board required a 5-year capital plan be provided with the Filing. In Order No. P.U. 19 (2003) (the "2003 Rate Order"), the Board required that evidence relating to deferred charges and a reconciliation of average rate base to invested capital be filed with capital budget applications.

Newfoundland Power Inc.
55 Kenmount Road • P.O. Box 8910 • St. John's, NL A1B 3P6
PHONE (709) 737-5364 • FAX (709) 737-2974 • **khopkins@newfoundlandpower.com**

These requirements are specifically addressed in the Filing in the:

(i) *2020 Capital Expenditure Status Report*, which meets the requirements of the 2020 Capital Order;

(ii) *2021 Capital Plan*, which meets the requirements of the 2004 Capital Order; and

(iii) *Report 7.1 Rate Base: Additions, Deductions & Allowances*, which meets the requirements of the 2003 Rate Order.

B.2 The Guidelines

In the October 2007 Capital Budget Application Guidelines (the "Guidelines"), the Board provided certain directions on how to categorize capital expenditures. Although compliance with the Guidelines necessarily requires the exercise of a degree of judgment, the Filing, in the Company's view, complies with the Guidelines while remaining reasonably consistent and comparable with past filings.

Attachment A of the *2021 Capital Plan* provides a breakdown of the overall 2021 Capital Budget by definition, classification, and materiality segmentation as described in the Guidelines. Pages i through ix of Schedule B to the formal application provide details of these categorizations by project.

The Guidelines also direct that, if a capital expenditure is related to the abandonment of plant requiring approval of the Board under Section 38 of the *Public Utilities Act*, the application for abandonment of plant and the application for approval of capital expenditures should be made together.

The Filing proposes capital expenditures to conclude implementation of the recommendations arising from the *Central Newfoundland System Planning Study*. Proposed expenditures for 2021 include the construction of 2 new 138 kV transmission line extensions from Rattling Brook Substation and the related dismantling of transmission lines 101L and 102L. Newfoundland Power has notified the affected municipalities of this proposal and intends to file the required abandonment of plant application in the coming days.

B.3 Changes to the 2021 Filing

In correspondence dated March 9, 2020, the Board outlined changes to the process for 2021 capital budget applications. Specifically, the Board directed that the Filing should contain: (i) additional information related to the process for assessing deferral opportunities and why specific projects cannot be deferred; and (ii) information related to the revenue requirement impacts of the capital projects proposed.

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These requirements are specifically addressed in Section 2.0 of the *2021 Capital Plan* and Schedule B to the formal application.

C. Filing Details and Circulation

The enclosed materials have been provided in binders with appropriate tabbing. For convenience, additional materials such as responses to Requests for Information will be provided on three-hole punched paper.

A copy of the Filing has been forwarded directly to Ms. Shirley Walsh, Senior Legal Counsel of Newfoundland and Labrador Hydro, and Mr. Dennis Browne, the Consumer Advocate.

A PDF of the Filing is available to the Board and interested parties via Newfoundland Power's stranded website at https://ftp.nfpower.nf.ca/. Access information for the stranded website for all interested parties has been emailed directly to them.

The Filing will also be posted on the Company's website (newfoundlandpower.com) this week. Interested parties may contact Newfoundland Power directly for assistance if they have any issues accessing the website.

D. Concluding

We trust the foregoing and enclosed are found to be in order.

If you have any questions on the Filing, please contact us at your convenience.

Yours truly,

Kelly Hopkins
Corporate Counsel

Enclosures

c. Shirley Walsh
Newfoundland and Labrador Hydro

Dennis Browne, Q.C.
Browne Fitzgerald Morgan & Avis

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Newfoundland Power Inc.
2021 Capital Budget Application
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VOLUME 1: APPLICATION

VOLUME 2: SUPPORING MATERIALS

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:

(a) approving a 2021 Capital Budget of $111,298,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2021; and
(c) fixing and determining a 2019 rate base of $1,153,556,000.

2021 Capital Budget Application

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:

(a) approving a 2021 Capital Budget of $111,298,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2021; and
(c) fixing and determining a 2019 rate base of $1,153,556,000.

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

THE APPLICATION OF Newfoundland Power Inc. (“Newfoundland Power”) **SAYS THAT:**

1. Newfoundland Power 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. Schedule A to this Application is a summary of Newfoundland Power’s 2021 Capital Budget in the amount of $111,298,000 which includes forecast 2021 capital expenditures previously approved in Order No. P.U. 35 (2018), Order No. P.U. 5 (2020), and also includes an estimated amount of $2,500,000 in contributions in aid of construction that the Applicant intends to demand from its customers in 2021. All contributions to be recovered from customers shall be calculated in a manner approved by the Board.

3. Schedule B to this Application provides detailed descriptions of the projects for which the proposed capital expenditures included in Newfoundland Power’s 2021 Capital Budget are required.

4. Schedule C to this Application is a listing of multi-year projects including:

    (a) ongoing projects for which capital expenditures were approved in Order No. P.U. 35 (2018);

    (b) ongoing projects for which capital expenditures were approved in Order No. P.U. 5 (2020); and

    (c) projects which will commence as part of the 2021 Capital Budget but will not be completed in 2021.

5. The proposed expenditures as set out in Schedules A, B and C to this Application are necessary for Newfoundland Power to continue to provide service and facilities which are reasonably safe and adequate and are just and reasonable as required pursuant to Section 37 of the Act.

6. Schedule D to this Application shows Newfoundland Power's actual average rate base for 2019 of $1,153,556,000.

7. Communication with respect to this Application should be forwarded to the attention of Liam P. O'Brien and Kelly C. Hopkins, Counsel to Newfoundland Power.

8. Newfoundland Power requests that the Board make an Order:

   (a) pursuant to Section 41 of the Act, approving Newfoundland Power's 2021 Capital Budget in the amount of $111,298,000 as set out in Schedules A and B to the Application;

   (b) pursuant to Section 41 of the Act, approving Newfoundland Power's purchase and construction in 2022 and 2023 of improvements and additions to its property in the amount of $22,305,000 as set out in Schedule C to the Application; and

   (c) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2019 in the amount of $1,153,556,000 as set out in Schedule D to the Application.

DATED at St. John's, Newfoundland and Labrador, this 9th day of July, 2020.

NEWFOUNDLAND POWER INC.

Liam P. O'Brien and Kelly C. Hopkins
Counsel to Newfoundland Power Inc.
P.O. Box 891055 Kenmount Road
St. John's, NL A1B 3P6

Telephone: (709) 737-5364
Telecopier: (709) 737-2974

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 38 and 78 of the Act:

(a) approving a 2021 Capital Budget of $111,298,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2021; and
(c) fixing and determining a 2019 rate base of $1,153,556,000.

AFFIDAVIT

I, Byron Chubbs of Paradise in the Province of Newfoundland and Labrador, make oath and say as follows:

1. That I am Vice President, Energy Supply and 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 9th day of July, 2020:

Barrister

Byron Chubbs

2021 CAPITAL BUDGET SUMMARY

Asset Class	Budget (000s)
1. Generation - Hydro	$ 11,180
2. Generation - Thermal	330
3. Substations	14,280
4. Transmission	9,751
5. Distribution	45,875
6. General Property	2,776
7. Transportation	4,032
8. Telecommunications	462
9. Information Systems	15,362
10. Unforeseen Allowance	750
11. General Expenses Capitalized	6,500
Total	**$ 111,298**

2021 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
1. Generation – Hydro		
Hydro Facility Rehabilitation	$ 1,806	2
Topsail Hydro Plant Refurbishment[2]	9,374	5
Total Generation – Hydro	**$ 11,180**	
2. Generation – Thermal		
Thermal Plant Facility Rehabilitation	$ 330	8
Total Generation – Thermal	**$ 330**	
3. Substations		
Substation Refurbishment and Modernization	$ 5,153	11
Replacements Due to In-Service Failures	3,413	13
Additions Due to Load Growth	4,997	16
PCB Bushing Phase-out	717	18
Total Substations	**$ 14,280**	
4. Transmission		
Transmission Line Rebuild	$ 6,170	21
Transmission Line Maintenance and 3rd Party Relocations	2,238	24
Transmission Line Extension – 35L	1,343	26
Total Transmission	**$ 9,751**	

1 Project descriptions can be found in Schedule B at the page indicated.
2 This includes a multi-year project approved in Order No. P.U. 5 (2020).

2021 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[3]
5. Distribution		
Extensions	$ 10,891	29
Meters	680	31
Services	3,110	34
Street Lighting	1,979	37
Street Lighting – LED Replacement Program	5,402	39
Transformers	5,945	41
Reconstruction	5,567	43
Rebuild Distribution Lines	3,965	45
Relocate/Replace Distribution Lines for Third Parties	3,155	48
Trunk Feeders	800	51
Feeder Additions for Load Growth	2,655	53
Distribution Reliability Initiative[4]	700	55
Distribution Feeder Automation	821	57
Allowance for Funds Used During Construction	205	59
Total Distribution	**$ 45,875**	
6. General Property		
Tools and Equipment	$ 486	62
Additions to Real Property	598	64
Company Building Renovations	1,392	66
Physical Security Upgrades	300	68
Total General Property	**$ 2,776**	
7. Transportation		
Purchase Vehicles and Aerial Devices	$ 4,032	71
Total Transportation	**$ 4,032**	

[3] Project descriptions can be found in Schedule B at the page indicated.
[4] This includes the 3rd year of a multi-year project approved in Order No. P.U. 35 (2018) to rebuild distribution feeder DUN-01 as identified in Schedule C of this Application.

2021 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[5]
8. Telecommunications		
Replace/Upgrade Communications Equipment	$ 112	75
Fibre Optic Cable Builds	350	77
Total Telecommunications	**$ 462**	
9. Information Systems		
Application Enhancements	$ 978	80
System Upgrades[6]	2,410	82
Personal Computer Infrastructure	495	84
Shared Server Infrastructure	538	87
Network Infrastructure	363	89
Cybersecurity Upgrades	675	91
Customer Service System Replacement[7]	9,903	93
Total Information Systems	**$ 15,362**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	$ 750	96
Total Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	$ 6,500	98
Total General Expenses Capitalized	**$ 6,500**	

5 Project descriptions can be found in Schedule B at the page indicated.
6 *System Upgrades* includes a multi-year project for the Microsoft Enterprise Agreement identified in Schedule C of this Application.
7 The *Customer Service System Replacement* is a multi-year project commencing in 2021 as identified in Schedule C of this Application.

2021 CAPITAL PROJECTS SUMMARY

2021 Capital Project Summary

On October 29, 2007, the Board issued Capital Budget Application Guidelines (the "Guidelines") to provide direction for utility capital budget applications filed pursuant to section 41 of the *Public Utilities Act.*

The Guidelines provide that utilities present their annual capital budget with sufficient detail for the Board and interested parties to understand the nature, scope and justification for individual expenditures and the capital budget overall.

Specifically, the Guidelines require each expenditure to be defined, classified, and segmented in the following manner:

1. *Definition of the Capital Expenditure*

   Capital expenditures are to be defined as clustered, pooled or other.

   Clustered expenditures are those which would logically be undertaken together. Pooled expenditures are a series of expenditures which are neither inter-dependant nor related, but which nonetheless are logically grouped together. Other expenditures are those which do not fit the definition of clustered or pooled.

2. *Classification of the Capital Expenditure*

   Capital expenditures are to be classified as mandatory, normal capital or justifiable.

   Mandatory capital expenditures are those a utility is obliged to carry out as the result of legislation, Board Order, safety issues or risk to the environment. Normal capital expenditures are those that are required based on identified need or on an historical pattern of repair and replacement. Justifiable capital expenditures are those which are justified based on the positive impact the project will have on the utility's operations.

3. *Segmentation of the Capital Expenditure by Materiality*

   Capital expenditures are to be segmented by their materiality as follows:
   - (i) Expenditures under $200,000;
   - (ii) Expenditures between $200,000 and $500,000; and
   - (iii) Expenditures over $500,000

This 2021 Capital Project Summary provides a summary of the planned capital expenditures contained in Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") *2021 Capital Budget Application* by definition (pages iii to iv), classification (pages vi to vii), and segmentation by materiality (pages viii to ix). In addition, each project description in *Schedule B* indicates the definitions, classifications and forecast costs, as provided for in the Guidelines.

Summary of
2021 Capital Projects by Definition
(000s)

Clustered	**$22,474**	**Page**
Distribution	**2,655**	
Feeder Additions for Load Growth	2,655	53
Generation - Hydro	**1,806**	
Hydro Facility Rehabilitation	1,806	2
Substations	**10,150**	
Substation Refurbishment and Modernization	5,153	11
Additions Due to Load Growth	4,997	16
Telecommunications	**350**	
Fibre Optic Cable Builds	350	77
Transmission	**7,513**	
Transmission Line Extension – 35L	1,343	26
Transmission Line Rebuild	6,170	21

Pooled	**$70,871**	**Page**
Distribution	**42,420**	
AFUDC	205	59
Distribution Reliability Initiative	700	55
Distribution Feeder Automation	821	57
Extensions	10,891	29
Meters	680	31
Rebuild Distribution Lines	3,965	45
Reconstruction	5,567	43
Relocate/Replace Distribution Lines for Third Parties	3,155	48
Services	3,110	34
Street Lighting	1,979	37
Street Lighting - LED Replacement Program	5,402	39
Transformers	5,945	41
General Property	**2,776**	
Additions to Real Property	598	64
Tools and Equipment	486	62
Company Building Renovations	1,392	66
Physical Security Upgrades	300	68
Generation - Hydro	**9,374**	
Topsail Hydro Plant Refurbishment	9,374	5
Generation – Thermal	**330**	
Thermal Plant Facility Rehabilitation	330	8

Pooled (continued)		**Page**
Information Systems	**5,459**	
Application Enhancements	978	80
Network Infrastructure	363	89
Personal Computer Infrastructure	495	84
Shared Server Infrastructure	538	87
System Upgrades	2,410	82
Cybersecurity Upgrades	675	91
Substations	**4,130**	
Replacements Due to In-Service Failures	3,413	13
PCB Bushing Phase-out	717	18
Telecommunications	**112**	
Replace/Upgrade Communications Equipment	112	75
Transmission	**2,238**	
Transmission Line Maintenance and 3rd Party Relocations	2,238	24
Transportation	**4,032**	
Purchase Vehicles and Aerial Devices	4,032	71

Other	**$17,953**	**Page**
Distribution	**800**	
Trunk Feeders	800	51
General Expenses Capitalized	**6,500**	
General Expenses Capitalized	6,500	98
Information Systems	**9,903**	
Customer Service System Replacement	9,903	93
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	96

Project Clustering

Clustered expenditures are those that would logically be undertaken together. Clustered expenditures are either interdependent or related. Interdependent items are necessarily linked together, as one item triggers the other. Related items are not necessarily linked to each other, but are nonetheless logically undertaken together.

In 2021, the following projects have expenditures that are clustered:

1. In 2021, the *St. John's North-Portugal Cove System Planning Study* has recommended a new substation be constructed in the vicinity of the St. John's International Airport. The construction of the new substation has Distribution, Substation, Transmission and Telecommunications projects that are clustered. These projects include the *Feeder Additions for Growth* Distribution project, the *Additions Due to Load Growth* Substations project, the *Transmission Line Extension - 35L* Transmission project and the *Fibre Optic Cable Builds* Telecommunications project. These items are interdependent and are therefore clustered.

2. The *Central Newfoundland System Planning Study* included in the *2019 Capital Budget Application* recommended the reconfiguration of the existing 138 kV transmission system and the subsequent dismantling of the 66 kV transmission system in Central Newfoundland as the least-cost alternative to address the deteriorated 66 kV transmission lines. In 2021, the Company will build 2 transmission line extensions from 136L to Rattling Brook Substation, relocate the Rattling Brook maintenance garage and expand the substation to accept the 138 kV transmission lines. The *Transmission Lines Rebuild* Transmission project, the *Hydro Facility Rehabilitation* Generation Hydro project and the *Substation Refurbishment and Modernization* Substations project are all clustered to complete the Rattling Brook Substation expansion. These items are interdependent and are therefore clustered.

3. In 2021, the transformer capacity at Dunville Substation will be increased to address forecast overload conditions with an *Additions Due to Load Growth* Substations project. A *Substation Refurbishment and Modernization* project at Dunville Substation is also being completed in 2021. Coordinating the refurbishment and modernization work with the load growth transformer replacement minimizes customer outages and maximizes efficiencies associated with project management and engineering by completing both projects at the same time. The *Additions Due to Load Growth* and the *Substation Refurbishment and Modernization* Substations projects are clustered. These items are interdependent and are therefore clustered.

Summary of
2021 Capital Projects by Classification
(000s)

Normal Capital	$104,201	Page
Distribution	**40,473**	
AFUDC	205	59
Distribution Reliability Initiative	700	55
Distribution Feeder Automation	821	57
Extensions	10,891	29
Meters	680	31
Rebuild Distribution Lines	3,965	45
Reconstruction	5,567	43
Relocate/Replace Distribution Lines for Third Parties	3,155	48
Feeder Additions for Load Growth	2,655	53
Services	3,110	34
Street Lighting	1,979	37
Transformers	5,945	41
Trunk Feeders	800	51
General Expenses Capitalized	**6,500**	
General Expenses Capitalized	6,500	98
General Property	**2,776**	
Additions to Real Property	598	64
Tools and Equipment	486	62
Company Building Renovations	1,392	66
Physical Security Upgrades	300	68
Generation - Hydro	**11,180**	
Hydro Facility Rehabilitation	1,806	2
Topsail Hydro Plant Refurbishment	9,374	5
Generation – Thermal	**330**	
Thermal Plant Facility Rehabilitation	330	8
Information Systems	**14,384**	
Network Infrastructure	363	89
Personal Computer Infrastructure	495	84
Shared Server Infrastructure	538	87
System Upgrades	2,410	82
Cybersecurity Upgrades	675	91
Customer Service System Replacement	9,903	93
Substations	**13,563**	
Substation Refurbishment and Modernization	5,153	11
Replacements Due to In-Service Failures	3,413	13
Additions Due to Load Growth	4,997	16

Normal Capital (continued)		**Page**
Telecommunications	**462**	
Replace/Upgrade Communications Equipment	112	75
Fibre Optic Cable Builds	350	77
Transmission	**9,751**	
Transmission Line Extension – 35L	1,343	26
Transmission Line Rebuild	6,170	21
Transmission Line Maintenance and 3rd Party Relocations	2,238	24
Transportation	**4,032**	
Purchase Vehicles and Aerial Devices	4,032	71
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	96

Justifiable	**$6,380**	**Page**
Distribution	**5,402**	
Street Lighting - LED Replacement Program	5,402	39
Information Systems	**978**	
Application Enhancements	978	80

Mandatory	**$717**	**Page**
Substations	**717**	
PCB Bushing Phase-out	717	18

Summary of
2021 Capital Projects by Materiality
(000s)

Large – Greater than $500	$108,657	Page
Distribution	**45,670**	
Distribution Reliability Initiative	700	55
Distribution Feeder Automation	821	57
Extensions	10,891	29
Meters	680	31
Rebuild Distribution Lines	3,965	45
Reconstruction	5,567	43
Relocate/Replace Distribution Lines for Third Parties	3,155	48
Feeder Additions for Load Growth	2,655	53
Services	3,110	34
Street Lighting	1,979	37
Street Lighting - LED Replacement Program	5,402	39
Transformers	5,945	41
Trunk Feeders	800	51
General Expenses Capitalized	**6,500**	
General Expenses Capitalized	6,500	98
General Property	**1,990**	
Additions to Real Property	598	64
Company Building Renovations	1,392	66
Generation - Hydro	**11,180**	
Hydro Facility Rehabilitation	1,806	2
Topsail Hydro Plant Refurbishment	9,374	5
Information Systems	**14,504**	
Application Enhancements	978	80
Shared Server Infrastructure	538	87
System Upgrades	2,410	82
Cybersecurity Upgrades	675	91
Customer Service System Replacement	9,903	93
Substations	**14,280**	
Replacements Due to In-Service Failures	3,413	13
Substation Refurbishment and Modernization	5,153	11
Additions Due to Load Growth	4,997	16
PCB Bushing Phase-out	717	18

Large – Greater than $500 (continued)		**Page**
Transmission	**9,751**	
Transmission Line Extension – 35L	1,343	26
Transmission Line Rebuild	6,170	21
Transmission Line Maintenance and 3rd Party Relocations	2,238	24
Transportation	**4,032**	
Purchase Vehicles and Aerial Devices	4,032	71
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	96

Medium – Between $200 and $500	**$2,529**	**Page**
Distribution	**205**	
AFUDC	205	59
General Property	**786**	
Tools and Equipment	486	62
Physical Security Upgrades	300	68
Generation – Thermal	**330**	
Thermal Plant Facility Rehabilitation	330	8
Information Systems	**858**	
Network Infrastructure	363	89
Personal Computer Infrastructure	495	84
Telecommunications	**350**	
Fibre Optic Cable Builds	350	77

Small – Under $200	**$112**	**Page**
Telecommunications	**112**	
Replace/Upgrade Communications Equipment	112	75

GENERATION - HYDRO

Project Title: **Hydro Facility Rehabilitation (Clustered)**

Project Cost: **$1,806,000**

Project Description

This Generation Hydro project is necessary to improve the operation of various hydro plants or to replace plant components due to in-service failures. The project involves the replacement or refurbishment of deteriorated plant components that have been identified through routine inspections, operating experience and engineering studies.

The 2021 project includes the following items:

1. Generation Control Systems Upgrades ($350,000);
2. Replacement of Horse Chops Bypass Piping ($150,000);
3. Refurbishment of Rattling Brook Surge Tank ($300,000);
4. Replacement of Rattling Brook Garage ($225,000);
5. Refurbishment of Rose Blanche Penstock Vacuum Valve Chamber ($175,000); and
6. Equipment replacements due to in-service failures ($606,000).

The replacement or refurbishment of deteriorated components at individual plants is not interdependent or related. However, all budget items included in this project are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

The *Hydro Facility Rehabilitation* Generation Hydro project to relocate the Rattling Brook garage, the *Transmission Line Rebuild* Transmission project to extend Transmission Line 136L and the *Substation Refurbishment and Modernization* Substations project for Rattling Brook Substation are each required to connect Rattling Brook Substation to the 138 kV transmission system. These items are interdependent and are therefore clustered.

Details on 2021 proposed expenditures are included in report *1.1 2021 Facility Rehabilitation*.

Justification

Newfoundland Power operates 23 hydro plants that range in age from 21 to 120 years old. These facilities provide relatively inexpensive energy to customers served by the Island Interconnected System.

Maintaining the Company's hydroelectric production reduces the need for additional, more expensive generation to supply customers. The value of this production consists primarily of:

(i) reduced marginal energy costs; and (ii) avoidance of the need to add generation capacity.[1] Based on Newfoundland and Labrador Hydro's 2020 marginal cost update, the energy-related value of the production from the Company's hydro facilities is estimated at $18,380,000 annually, while the capacity-related value is estimated at $18,272,000 annually.[2]

Newfoundland Power maintains reliable operation of its hydro facilities through a combination of annual inspection and maintenance activities and replacement and refurbishment projects. Replacement and refurbishment projects are identified annually based on plant condition and facility requirements. These projects are necessary to ensure the continued operation of hydro facilities in a safe, reliable and environmentally compliant manner. The alternative to maintaining the Company's generation facilities would be to retire them.

For 2021, maintaining the reliable operation of Newfoundland Power's hydro facilities requires upgrading generation control systems, responding to in-service equipment failures, and replacing and refurbishing deteriorated or substandard components at the Horse Chops, Rattling Brook and Rose Blanche hydro plants.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$1,327	-	-	-
Labour – Internal	246	-	-	-
Labour – Contract	-	-	-	-
Engineering	102	-	-	-
Other	131	-	-	-
Total	**$1,806**	**$1,765**	**$5,989**	**$9,560**

[1] The Island Interconnected System's need for new capacity additions is being reviewed by the Board. Newfoundland and Labrador Hydro's most recent assessment shows that the system has limited capacity to meet future load growth.

[2] These estimates are calculated to reflect post Muskrat Falls marginal costs using the 2021 marginal cost values for energy and capacity.

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	**2016**	**2017**	**2018**	**2019**	**2020F**	**2021B**
Total	$1,689	$1,564	$2,348	$1,584	$1,519	$1,806

The budget estimate for this project is based on engineering estimates for the individual budget items and an assessment of historical expenditures for the equipment replacements due to in-service failures.

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: **Topsail Hydro Plant Refurbishment (Pooled, Multi-Year)**

Project Cost: **$9,374,000**

Project Description

This Generation Hydro project is located at the Company's Topsail hydroelectric development within the towns of Paradise and Conception Bay South on the Avalon Peninsula. The Topsail plant was placed in service in 1932 and contains one generating unit. The plant underwent a major refurbishment in the early 1980s when the turbine generator was replaced. The normal annual production of the plant is approximately 13.3 GWh of energy, or about 3% of Newfoundland Power's total hydroelectric generation.

The 2021 project includes:

1. The 2nd year of a multi-year project to refurbish the penstock; and
2. The refurbishment of the intake gate and the turbine runner.

The engineering design and procurement of the penstock and site preparation work is ongoing in 2020. The installation of the replacement penstock will take place in 2021. Details on the project to replace the Topsail penstock can be found in the *2020 Capital Budget Application* report *1.4 Topsail Hydro Plant Penstock Replacement.*

Details on 2021 proposed expenditures for the intake gate and the turbine runner are included in report *1.2 Topsail Hydro Plant Refurbishment* filed as part of this application.

Justification

The Topsail plant provides approximately 13.3 GWh of energy annually to customers served by the Island Interconnected System.

Engineering assessments have identified that the plant's intake gate is deteriorated and requires replacement and the turbine runner blades are severely corroded and require refurbishment. Completing this replacement and refurbishment project is necessary to ensure the reliable operation of the Topsail plant. Coordinating the intake gate replacement and turbine runner blade refurbishment with replacement of the penstock in 2021 will minimize the requirement for plant outages.

An economic analysis has been completed for the continued operation of the Topsail plant, assuming the 2021 project is undertaken. The results of the analysis show the levelized cost of production is 6.69 ¢/kWh. This indicates that continued operation of the plant is economical over the long term.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Multi-Year Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$7,829	-	-	
Labour – Internal	62	-	-	
Labour – Contract	-	-	-	
Engineering	225	-	-	
Other	1,258	-	-	
Total	**$9,374**	**$0**	**$0**	**$9,374**

Costing Methodology

The budget estimate for this project is based on engineering cost estimates.

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

The penstock replacement is a multi-year project which will be undertaken in 2020 and 2021. The intake gate replacement and turbine runner refurbishment to be completed in 2021 is not a multi-year project.

GENERATION - THERMAL

Project Title: **Thermal Plant Facility Rehabilitation (Pooled)**

Project Cost: **$330,000**

Project Description

This Generation Thermal project is necessary for the replacement or refurbishment of deteriorated thermal plant components that are identified through routine inspections, operating experience and engineering studies.

The 2021 project consists of the refurbishment or replacement of thermal plant structures and equipment due to damage, deterioration, corrosion and in-service failure. This equipment is critical to the safe and reliable operation of thermal generating facilities and must be replaced in a timely manner. Based on historical information, $330,000 is estimated to be the cost of refurbishing or replacing thermal plant structures in 2021.

The replacement or rehabilitation of deteriorated components at individual plants is not interdependent or related. However, all budget items included in this project are similar in nature and justification. They are therefore pooled for consideration as a single capital project.

Justification

Newfoundland Power maintains 44.5 MW of thermal generation consisting of gas turbine and diesel units. These units are used to provide emergency generation, both locally and for the Island Interconnected System, and to minimize customer outages during scheduled maintenance on transmission, distribution or substation assets.

Replacement and refurbishment requirements are identified during annual inspections and maintenance activities. Deficiencies are addressed as they occur to ensure the continued operation of thermal generation facilities in a safe, reliable and environmentally compliant manner.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$221	-	-	-
Labour – Internal	54	-	-	-
Labour – Contract	-	-	-	-
Engineering	34	-	-	-
Other	21	-	-	-
Total	**$330**	**$334**	**$1,030**	**$1,694**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$424	$242	$408	$165	$349	$330

The budget requirement for rehabilitation of thermal generating facilities is based on an historical average and is adjusted for anticipated expenditure requirements for extraordinary 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.

SUBSTATIONS

Project Title: **Substation Refurbishment and Modernization (Clustered)**

Project Cost: **$5,153,000**

Project Description

This Substations project is a continuation of work started in 2007 as a result of the *Substation Strategic Plan*. The work included in this project is consistent with that plan. An update to the *Substation Strategic Plan* is included in report *2.1 2021 Substation Refurbishment and Modernization*.

This project is necessary for the planned replacement and modernization of deteriorated and substandard substation infrastructure, such as bus structures, breakers, potential transformers, protective relaying, support structures, equipment foundations, grounding, switches and fencing. Infrastructure to be replaced is identified as a result of inspections, engineering assessments and operating experience.

In 2021, this project will refurbish and modernize the Dunville and Rattling Brook substations. The 2021 project also includes upgrading communications gateways that connect digital devices in substations to the Supervisory Control and Data Acquisition ("SCADA") system.

The *Substation Refurbishment and Modernization* and the *Additions Due to Load Growth* projects at Dunville substation are interdependent and are therefore clustered.

The *Substation Refurbishment and Modernization* for Rattling Brook Substation, the *Transmission Line Rebuild* project to extend Transmission Line 136L and the *Hydro Facility Rehabilitation* Generation Hydro project to relocate the Rattling Brook garage are each required to connect Rattling Brook Substation to the 138 kV transmission system. These items are interdependent and are therefore clustered.

Justification

Newfoundland Power operates 131 substations. These substations range in age from 18 years to greater than 100 years. Failure of critical substation equipment can result in outages to thousands of customers at once.

The annual *Substation Refurbishment and Modernization* project provides a structured, long-term approach to maintaining over 4,000 pieces of critical substation equipment. Addressing deteriorated and substandard equipment reduces in-service failures and ensures compliance with current industry standards.

Refurbishment and modernization of Dunville and Rattling Brook substations in 2021 is necessary to ensure continued reliable operation of its substation assets.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025. Appendix A of report *2.1 2021 Substation Refurbishment and Modernization* details the work planned for each of the next 5 years.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$4,197	-	-	-
Labour – Internal	163	-	-	-
Labour – Contract	-	-	-	-
Engineering	684	-	-	-
Other	109	-	-	-
Total	**$5,153**	**$8,974**	**$30,428**	**$44,555**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$7,044	$10,777	$7,917	$7,384	$10,856	$5,153

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.

Project Title: **Replacements Due to In-Service Failures (Pooled)**

Project Cost: **$3,413,000**

Project Description

This Substations project is necessary to replace substation equipment that has been removed from service due to storm damage, lightning strikes, vandalism, electrical or mechanical failure, corrosion damage, technical obsolescence or failure during maintenance testing. Substation equipment that fails in-service requires immediate attention as it is essential to the integrity and reliability of the electrical supply to customers.

The individual requirements for substation equipment are not interdependent. However, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

Newfoundland Power operates 131 substations containing approximately 4,000 pieces of critical electrical equipment. Failure of critical substation equipment can result in outages to thousands of customers at once. Addressing in-service failures of substation equipment in a timely manner is necessary to maintain the condition of the Company's substations and provide reliable service to customers.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$2,371	-	-	-
Labour – Internal	689	-	-	-
Labour – Contract	-	-	-	-
Engineering	267	-	-	-
Other	86	-	-	-
Total	**$3,413**	**$3,458**	**$10,676**	**$17,547**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as projected expenditures for 2021.

Table 2
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$2,561	$2,230	$3,861	$4,532	$3,269	$3,413

The major equipment items comprising a substation include substation transformers, circuit breakers, reclosers, voltage regulators, potential transformers and battery banks. In total, Newfoundland Power has approximately 180 substation transformers, 400 circuit breakers, 200 reclosers, 360 voltage regulators, 220 potential transformers, 115 battery banks and 2,500 high-voltage switches in service.

The need to replace equipment is determined on the basis of tests, inspections, in-service and imminent failures, and operational history of the equipment. An adequate pool of spare equipment is necessary to enable the Company to respond quickly to in-service failures. The size of the pool is based on past experience and engineering judgment, as well as a consideration of the impact that the loss of a particular apparatus would have on the electrical system.

The budget for this project is based on an assessment of historical expenditures and inventory 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: **Additions Due To Load Growth (Clustered)**

Project Cost: **$4,997,000**

Project Description

As load increases on an electrical system, individual components can become overloaded. To address these overload conditions, technical alternatives are fully examined, cost estimates are prepared, and an economic analysis is performed to identify the least-cost alternative.

This 2021 Substations project involves:

1. Replacing the existing 66/25 kV 8.3 MVA substation transformer DUN-T1 at Dunville Substation ("DUN") with a spare 66/25 kV 25 MVA substation transformer.[3] This project is necessary to address customer load growth in the Dunville and Southeast Placentia areas. ($701,000)

2. Constructing a new 25 MVA, 66/12.5 kV substation near the St. John's International Airport. Substation transformers at the Broad Cove, Ridge Road and Virginia Waters substations are overloaded. Load growth on these transformers is primarily the result of ongoing residential subdivision development in the area and expansion of the St. John's International Airport. ($4,296,000)[4]

The *Additions Due To Load Growth* Substations project is clustered with the refurbishment and modernization of Dunville substation, which is included in the *Substation Refurbishment and Modernization* project. The *Additions Due to Load Growth* Substations project, the *Feeder Additions for Growth* Distribution project, the *Transmission Line Extension - 35L* Transmission project and the *Fibre Optic Cable Builds* Telecommunications project are each required to construct a new substation near the St. John's International Airport. These items are interdependent and are therefore clustered.

Details of proposed expenditures are provided in report *2.2 2021 Additions Due to Load Growth*.

Justification

Providing an adequate supply of power requires the proper sizing of equipment to meet customers' electrical loads. Improperly sized equipment can become overloaded and result in customer outages and unsafe operation of the electrical system.

[3] The spare transformer is the former Lewisporte Substation 25 MVA substation transformer, LEW-T1, that was removed as part of the 138 kV conversion of Lewisporte Substation in 2019.

[4] The *St. John's North - Portugal Cove System Planning Study* provides details on the need to construct a substation in the vicinity of St. John's International Airport.

A 20-year load forecast has projected increased electrical demand in the Dunville, Southeast Placentia and St. John's North – Portugal Cove areas. The load forecast indicated that DUN Substation transformer DUN-T1 will be overloaded in 2021. The load forecast also indicated that the St. John's North – Portugal Cove area has 3 power transformers that will be overloaded in 2021.

The development and analysis of alternatives has identified the least-cost alternative to meet all technical criteria in each case. In the Dunville area, the least-cost alternative requires installing a spare 25 MVA substation transformer. In the St. John's North – Portugal Cove area, the least-cost alternative requires constructing a new substation near the St. John's International Airport.

This project is justified on the obligation to provide customers with equitable access to an adequate supply of power and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$3,797	-	-	-
Labour – Internal	128	-	-	-
Labour – Contract	-	-	-	-
Engineering	720	-	-	-
Other	352	-	-	-
Total	**$4,997**	**$2,500**	**$6,600**	**$14,097**

Costing Methodology

The budget estimate for this project is based on engineering estimates of 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.

Project Title: **PCB Bushing Phase-out (Pooled)**

Project Cost: **$717,000**

Project Description

This Substations project is necessary to facilitate the phase-out of polychlorinated biphenyls ("PCB") from breaker and substation transformer bushings with concentrations of greater than 50 parts-per-million ("ppm").[5]

Inspections completed before the end of 2014 identified 24 substation transformers with bushings having PCB concentrations greater than 50 ppm and less than 500 ppm. Similarly, inspections completed before the end of 2014 identified 42 bulk oil circuit breakers with PCB concentrations greater than 50 ppm and less than 500 ppm. These transformer bushings and circuit breakers will be replaced by 2025 to ensure compliance with government regulations regarding the phase out of PCBs in substation equipment.[6]

In 2021, the Company will replace bushings on 2 substation transformers and replace 4 bulk oil circuit breakers.

Justification

Substation equipment with PCB concentrations greater than 50 ppm must be addressed by 2025 as per the *PCB Regulations*. The *PCB Bushing Phase-out* project is necessary to meet the requirements outlined in these regulations.

This is a mandatory project justified on the requirement to meet the Government of Canada's *PCB Regulations* and cannot be deferred.

[5] Government of Canada PCB Regulation (SOR/2008-273) requires that substation transformer bushings, breakers and instrument transformers with PCB concentrations of greater than 50 ppm be removed from service by the end of 2025.

[6] Commencing in 2017, Newfoundland Power initiated an 8 year program to remove from service substation equipment with PCB concentrations between 50 ppm and 500 ppm.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1 Projected Expenditures (000s)				
Cost Category	**2021**	**2022**	**2023 – 2025**	**Total**
Material	$530	-	-	-
Labour – Internal	35	-	-	-
Labour – Contract	-	-	-	-
Engineering	132	-	-	-
Other	20	-	-	-
Total	**$717**	**$594**	**$2,039**	**$3,350**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2 Expenditure History (000s)						
Year	**2016**	**2017**	**2018**	**2019**	**2020F**	**2021B**
Total	-	$849	$884	$934	$789	$717

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.

TRANSMISSION

Project Title: **Transmission Line Rebuild (Clustered)**

Project Cost: **$6,170,000**

Project Description

This Transmission project is necessary to replace deteriorated and deficient transmission line infrastructure. The rebuilding of the Company's oldest, most deteriorated transmission lines is in accordance with the program outlined in report *3.1 Transmission Line Rebuild Strategy* filed with the *2006 Capital Budget Application*.

The 2021 project involves:

1. Rebuilding a 30-kilometre section of Transmission Line 124L. Transmission line 124L operates between Clarenville Substation and Gambo Substation. ($5,603,000)

2. Extending Transmission Line 136L into Rattling Brook Substation. The extension of the 138 kV transmission network is necessary to facilitate the dismantling of the existing 66 kV transmission lines 101L and 102L. ($567,000)[7]

The *Transmission Line Rebuild* project to extend Transmission Line 136L, the *Substation Refurbishment and Modernization* Substations project, and the *Hydro Facility Rehabilitation* Generation Hydro project are each required to connect Rattling Brook Substation to the 138 kV transmission system. These items are interdependent and are therefore clustered.

Details on the proposed 2021 rebuild project are included report *3.1 2021 Transmission Line Rebuild*.

Justification

Newfoundland Power operates 107 transmission lines interconnecting substation, distribution and generation assets throughout its service territory. These transmission lines are the backbone of the Company's electrical system. A single transmission line outage can cause outages to thousands of customers.

On a total kilometre basis, approximately 50% of Newfoundland Power's transmission lines are in excess of 40 years of age. Many of these lines are experiencing pole, crossarm, conductor, insulator and hardware deterioration.

Each transmission line is inspected annually to identify deterioration and deficiencies. Engineering assessments determine whether routine maintenance or the replacement of any

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[7] As part of its *2019 Capital Budget Application*, Newfoundland Power filed the *Central Newfoundland System Planning Study* to address the least-cost replacement of 66 kV transmission lines 101L and 102L.

section of line is required to maintain the strength and integrity of the line. Maintaining the strength and integrity of transmission lines is necessary to provide reliable service to customers.

Rebuilding transmission line 124L in 2021 is necessary to replace deteriorated and deficient infrastructure identified through an inspection in 2020.

Extending Transmission Line 136L into Rattling Brook Substation in 2021 is necessary to connect the substation to the 138 kV transmission network. This will permit the dismantling of the existing, deteriorated transmission lines 101L and 102L and conclude implementation of the *Central Newfoundland System Planning Study* recommendations.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025. Appendix A of report *3.1 2021 Transmission Line Rebuild* details the transmission line rebuilds planned for each year.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$2,165	-	-	-
Labour – Internal	124	-	-	-
Labour – Contract	2,832	-	-	-
Engineering	91	-	-	-
Other	958	-	-	-
Total	**$6,170**	**$9,786**	**$36,892**	**$52,848**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as projected expenditures for 2021. Annual expenditures are a function of the number of lines rebuilt, the distance covered and the construction standard used in the design.

Table 2
Expenditure History
(000s)

Year	**2016**	**2017**	**2018**	**2019**	**2020F**	**2021B**
Total	$3,336	$4,229	$5,588	$9,342	$7,378	$6,170

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.

Project Title: **Transmission Line Maintenance and 3rd Party Relocations (Pooled)**

Project Cost: **$2,238,000**

Project Description

This Transmission project is necessary to replace deteriorated transmission line infrastructure and to accommodate 3rd party requests to relocate or replace transmission lines.

The 2021 project involves:

1. Replacing transmission line poles, crossarms, conductors, insulators and hardware. Equipment replacements can result from deficiencies identified during inspections and engineering reviews, or in-service and imminent failures.

2. Accommodating 3rd party requests to relocate or replace transmission structures. The relocation or replacement of transmission lines results from: (i) work initiated by municipal, provincial and federal governments; (ii) work initiated by other users, such as Bell Aliant, Eastlink and Rogers Communications; and (iii) requests from customers.

While the individual requirements are not interdependent, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

Newfoundland Power operates over 2,000 kilometres of transmission lines. The Company's transmission line maintenance includes annual inspections and engineering reviews to assess plant condition and the requirement to replace deteriorated structures and equipment. The replacement of deteriorated structures and equipment is required annually to maintain overall plant condition. Project costs for 2021 are based on recent requirements for addressing transmission line deterioration.

Responding to 3rd party requests to relocate or replace transmission structures is necessary to maintain safe and adequate facilities. The relocation or replacement of transmission lines is governed by the provisions of agreements in place with the requesting parties. Requests by customers are governed by the Company's policy respecting Contributions in Aid of Construction.

The maintenance component of this project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

The 3rd party requests component of this project is justified on the obligation to maintain safe and adequate facilities and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$968	-	-	-
Labour – Internal	102	-	-	-
Labour – Contract	832	-	-	-
Engineering	79	-	-	-
Other	257	-	-	-
Total	**$2,238**	**$2,267**	**$7,019**	**$11,524**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.[8]

Table 2
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$1,439	$2,134	$2,747	$2,214	$2,245	$2,238

Annual expenditures are a function of the number of deficiencies identified and the number of 3rd party requests received. Budget estimates are based on an assessment of historical expenditures.

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.

[8] These expenditures were included as part of the *Transmission Line Rebuild* project in previous capital budget applications.

Project Title: **Transmission Line Extension – 35L (Clustered)**

Project Cost: **$1,343,000**

Project Description

This Transmission project is necessary to extend Transmission Line 35L to a new substation proposed for construction near the St. John's International Airport.

The *St. John's North - Portugal Cove System Planning Study* identified the least-cost alternative to address overload conditions in the area. The least-cost alternative involves constructing a new substation near the airport and extending Transmission Line 35L to the new substation.

The *Transmission Line Extension - 35L* Transmission project, the *Feeder Additions for Growth* Distribution project, the *Additions Due to Load Growth* Substations project, and the *Fibre Optic Cable Builds* Telecommunications project are each required to construct a new substation near the St. John's International Airport. These items are interdependent and are therefore clustered.

Details on the proposed 2021 extension of Transmission Line 35L are included in the *St. John's North - Portugal Cove System Planning Study, Attachment A.*

Justification

Providing an adequate supply of power requires the proper sizing of equipment to meet customers' electrical loads. Improperly sized equipment can become overloaded and result in customer outages and unsafe operation of the electrical system.

The *St. John's North - Portugal Cove System Planning Study* has identified the least-cost alternative to address load growth in the St. John's North - Portugal Cove area in 2021. The extension of Transmission Line 35L is an integral part of implementing this alternative.

This project is justified on the obligation to provide customers with equitable access to an adequate supply of power and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$407	-	-	-
Labour – Internal	333	-	-	-
Labour – Contract	287	-	-	-
Engineering	162	-	-	-
Other	154	-	-	-
Total	**$1,343**	**$0**	**$0**	**$1,343**

Costing Methodology

The budget estimates for transmission line extension projects are based on engineering cost estimates.

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.

DISTRIBUTION

Project Title: **Extensions (Pooled)**

Project Cost: **$10,891,000**

Project Description

This Distribution project involves the construction of both primary and secondary distribution lines to connect new customers to the electrical system. The project also includes upgrades to the capacity of existing lines to accommodate customers' increased electrical loads. The project includes labour, materials, and other costs to install poles, wires and related hardware.

Distribution line extensions and upgrades for new customers and for increased loads are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

Providing equitable access to an adequate supply of power requires connecting new customers to the electrical system and addressing increases in customers' electrical loads. This project is necessary to ensure these requirements are met in 2021.

This project is justified on the obligation to provide customers with equitable access to an adequate supply of power and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$3,370	-	-	-
Labour – Internal	3,206	-	-	-
Labour – Contract	2,561	-	-	-
Engineering	1,400	-	-	-
Other	354	-	-	-
Total	**$10,891**	**$11,105**	**$33,682**	**$55,678**

Costing Methodology

Table 2 shows the annual expenditures and unit costs for this project for the most recent 5-year period, as well as a projected unit cost for 2021.

Table 2
Expenditure History and Unit Cost Projection

Year	2016	2017	2018	2019	2020F	2021B
Total (000s)	$ 13,009	$ 13,371	$ 11,274	$ 13,379	$ 10,199	$ 10,891
Adjusted Costs (000s)[1]	$ 13,939	$ 14,058	$11,616	$ 13,576	-	-
New Customers	3,528	3,271	2,781	2,379	2,378	2,389
Unit Costs ($/customer)[1]	$ 3,951	$ 4,298	$ 4,177	$ 5,707	$ 4,289	$ 4,559

[1] 2020 dollars.

The project cost for connecting new customers is calculated on the basis of historical data. Historical annual expenditures over the most recent 5-year period, including the current year, are expressed in current-year dollars ("Adjusted Costs"). The Adjusted Costs are divided by the number of new customers in each year to derive the annual extension cost per customer in current-year dollars ("Unit Costs"). The average of these Unit Costs, with unusually high and low data excluded, is inflated by the GDP Deflator for Canada before being multiplied by the forecast number of new customers for the budget year to determine the budget estimate. The forecast number of new customers is derived from economic projections provided by independent agencies.

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: **Meters (Pooled)**

Project Cost: **$680,000**

Project Description

This Distribution project includes the purchase and installation of meters for new customers and replacement meters for existing customers.

Table 1 lists the meter requirement for 2021.

Table 1
2021 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	4,640
Other Energy Only and Demand Meters	1,698

The expenditures for individual meters are not interdependent, but are similar in nature and justification. They have therefore been pooled for consideration as a single capital project.

The *2016 Capital Budget Application* included an updated metering strategy in report *4.4 2016 Metering Strategy*. In 2021, the Company will continue with the objectives outlined in the *2016 Metering Strategy* with respect to accuracy and timeliness, cost management, worker safety and ratemaking.

The Company achieved 100% penetration of AMR meters at the end of 2017. The 2021 metering budget is approximately $3 million less than expenditures prior to 2018.[9]

Justification

Providing equitable access to an adequate supply of power requires connecting new customers to the electrical system. The installation of meters to serve new customers is necessary to ensure this requirement is met in 2021.

Revenue metering of electrical service is regulated under the *Electricity and Gas Inspection Act (Canada)*. The replacement component of this project ensures compliance with this legislation and that deteriorated or failed meters are removed from service.

The new component of this project is justified on the obligation to provide customers with equitable access to an adequate supply of power and cannot be deferred.

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[9] Once the newer AMR meters reach an age where they are subject to the government sampling regulations, metering requirements, and expenditures, are expected to increase.

The replacement component of this project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 2
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$555	-	-	-
Labour – Internal	111	-	-	-
Labour – Contract	14	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$680**	**$689**	**$2,125**	**$3,494**

Costing Methodology

Table 3 shows the annual expenditures for the most recent 5-year period, as well as a projection for 2021.

Table 3
Expenditure History and Unit Cost Projection

Year	2016	2017	2018	2019	2020F	2021B
Meter Requirements						
New Connections	3,528	3,271	2,781	2,379	2,378	2,389
GROs/CSOs	3,670	4,042	563	839	1,449	1,449
Replacements	41,020	36,681	2,021	1,204	2,500	2,500
Total	48,218	43,994	5,365	4,422	6,327	6,338
Meter Costs						
Actual (000s)	$4,496	$3,625	$644	$481	$696	$680
Adjusted[1] (000s)	$4,734	$3,768	$660	$487	-	-
Unit Costs[1]	$ 98	$ 87	$ 124	$ 112	$ 110	$ 107

[1] 2020 dollars.

The project cost for meters is calculated on the basis of historical data. Historical annual expenditures over the most recent 5-year period, including the current year, are expressed in current year dollars ("Adjusted Meter Costs"). The Adjusted Meter Costs are divided by the total meter requirements in each year to derive the annual meter cost in current-year dollars ("Unit Costs"). The average of the Unit Costs, with unusually high and low data excluded, is

inflated by the GDP Deflator for Canada before being multiplied by forecast meter installations. The expected number of meter installations is based on projected new customer connections, projected requirements to meet Industry Canada regulations and other requirements based on historical trends.

The quantity of meters for new customers is based on the Company's forecast growth in the number of customers the Company serves. The quantity for *replacement* purposes is based on historic data. Sampling and replacement requirements are governed by Compliance Sampling Orders ("CSOs") and Government Retest Orders ("GROs") issued in accordance with regulations under the *Electricity and Gas Inspection Act (Canada).*

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: **Services (Pooled)**

Project Cost: **$3,110,000**

Project Description

This Distribution project involves the installation of service wires to connect new customers to the electrical distribution system. Service wires are low-voltage wires that connect a customer's electrical service equipment to the Company's transformers. Also included in this project is the replacement of existing service wires due to deterioration, failure or damage, as well as the installation of larger service wires to accommodate customers' additional loads.

The proposed expenditures for new and replacement services are similar in nature. The expenditures are therefore pooled for consideration as a single capital project.

Justification

Providing equitable access to an adequate supply of power requires connecting new customers to the electrical system and addressing increases in customers' electrical loads. The installation of service wires for new customers or customers with increased electrical loads is necessary to ensure these requirements are met in 2021.

Providing reliable service requires replacing deteriorated, damaged or failed service wires serving existing customers. This project is necessary to ensure this requirements is met in 2021.

The new component of this project is justified on the obligation to provide customers with equitable access to an adequate supply of power and cannot be deferred.

The replacement component of this project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$946	-	-	-
Labour – Internal	1,681	-	-	-
Labour – Contract	162	-	-	-
Engineering	278	-	-	-
Other	43	-	-	-
Total	**$3,110**	**$3,171**	**$9,672**	**$15,953**

Costing Methodology

Table 2 shows the annual expenditures and unit costs for *new* services for the most recent 5-year period, as well as a projected unit cost for 2021.

Table 2
Expenditure History and Unit Cost Projection
New Services

Year	2016	2017	2018	2019	2020F	2021B
Total (000s)	$3,196	$2,748	$3,233	$2,769	$2,283	$2,537
Adjusted Costs (000s)[1]	$3,432	$2,892	$3,332	$2,811	-	-
New Customers	3,528	3,271	2,781	2,379	2,378	2,389
Unit Costs ($/customer)[1]	$ 973	$ 884	$1,198	$1,182	$ 960	$1,062

[1] 2020 dollars.

The project cost for the connection of new customers is calculated on the basis of historical data. For new services, historical annual expenditures over the most recent 5-year period, including the current year, are converted to current-year dollars ("Adjusted Costs"). The Adjusted Costs are divided by the number of new customers in each year to derive the annual services cost per customer in current-year dollars ("Unit Costs"). The average of the Unit Costs, with unusually high and low data excluded, is inflated by the GDP Deflator for Canada before being multiplied by the forecast number of new customers for the budget year to determine the budget estimate. The forecast number of new customers is derived from economic projections provided by independent agencies.

Table 3 shows the annual expenditures for replacement services for the most recent 5-year period, as well as a projected cost for 2021.

Table 3
Expenditure History and Average Cost Projection
Replacement Services
(000s)

Year	**2016**	**2017**	**2018**	**2019**	**2020F**	**2021B**
Total	$543	$607	$577	$321	$675	$573
Adjusted Costs[1]	$583	$639	$595	$326	-	-

[1] 2020 dollars.

The process of estimating the budget requirement for replacement services is similar to that for new services, except the budget estimate is based on the historical average of the total cost of replacement services, as opposed to a unit cost.

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: **Street Lighting (Pooled)**

Project Cost: **$1,979,000**

Project Description

This Distribution project involves the installation of new street lighting fixtures and the replacement of overhead and underground wiring, where necessary. A street light fixture includes the light head and photocell as well as the pole mounting bracket and other hardware. The project is driven by customer requests for street lighting. Commencing in 2021, the replacement of existing high pressure sodium ("HPS") street light fixtures is being budgeted in the *Street Lighting – LED Replacement Program* project.

In 2019, the Company adopted LED technology as its new service standard for all new and replacement street lighting installations. The adoption of this standard followed the approval of LED street lighting rates for customers in Order No. P.U. 2 (2019).

The proposed expenditures for new street lights are similar in nature. The expenditures are therefore pooled for consideration as a single capital project.

Justification

Street lighting is an established service offering of the Company. Providing equitable access to this service requires responding to customers' requests for street light installations. This project is necessary to ensure this requirement is met in 2021.

This project is justified on the obligation to provide equitable access to an adequate supply of power and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$1,081	-	-	-
Labour – Internal	697	-	-	-
Labour – Contract	152	-	-	-
Engineering	29	-	-	-
Other	20	-	-	-
Total	**$1,979**	**$2,011**	**$6,232**	**$10,222**

Street lighting capital expenditures for the period 2021 to 2025 include the installation of new street lighting fixtures and the replacement of overhead and underground wiring. The capital expenditures associated with replacement street lighting is now included in the *Street Lighting - LED Replacement Program* capital project.

Costing Methodology

Table 2 shows the annual expenditures and unit costs for new street lights for the most recent 5-year period, as well as a projected unit cost for 2021.

Table 2
Expenditure History and Unit Cost Projection
New Street Lights

Year	2016	2017	2018	2019	2020F	2021B
Total (000s)	$1,274	$1,319	$2,535	$2,678	$1,784	$1,762[3]
Adjusted Costs (000s)[1]	$1,359	$1,377	$2,603	$2,714	-	-
New Customers	3,528	3,271	2,781	2,379	2,378	2,389
Unit Costs ($/customer)[1]	$ 385	$ 421	$ 936	$1,141[2]	$ 750	$738

1 2020 dollars.
2 In 2019, the Company installed 23% more streetlights than the 5-year average.
3 Excludes $217,000 associated with the replacement of overhead and underground wiring.

The project cost for new street lights is calculated on the basis of historical data. Historical annual expenditures over the most recent 5-year period, including the current year, are expressed in current-year dollars ("Adjusted Costs"). The Adjusted Costs are divided by the number of new customers in each year to derive the annual street light cost per customer in current-year dollars ("Unit Costs"). The average of the Unit Costs, with unusually high and low data excluded, is inflated by the GDP Deflator for Canada before being multiplied by the forecast number of new customers for the budget year to determine the budget estimate. The forecast number of new customers is derived from economic projections provided by independent agencies.

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: **Street Lighting – LED Replacement Program (Pooled)**

Project Cost: **$5,402,000**

Project Description

This Distribution project is the 1st year of a 6-year program to replace all HPS street light fixtures with LED fixtures.

All expenditures required to replace existing HPS fixtures are included in this project. The expenditures are pooled for consideration as a single capital project.

Details on the proposed expenditures are included in the *LED Street Lighting Replacement Plan.*

Justification

Newfoundland Power adopted LED street lighting as its new service standard following the approval of customer rates in Order No. P.U. 2 (2019).

Current customer rates for LED street lights are between 9% and 39% less for customers than equivalent HPS rates. Lower customer rates are the result of lower energy and maintenance costs for LED street lights. LED street lights also provide more reliable and better quality lighting for customers.

The Company currently installs LED fixtures for new street lighting installations and when an HPS fixture fails and cannot be repaired. Based on this approach, customers would continue to pay the higher rates of HPS street lights for over 30 years.

Newfoundland Power developed a plan to accelerate the installation of LED street lights for customers. The plan will commence in 2021 and ensure all customers are provided with the lower rates of LED street lights within 6 years.

The total cost of executing the plan is estimated at approximately $32.8 million. An economic analysis determined the plan will reduce energy and maintenance costs to customers by approximately $52 million over 20 years. This results in lower overall costs for customers over the long term.

The plan is consistent with current Canadian utility practice and has received the support of the largest municipal organization in the province, Municipalities Newfoundland and Labrador.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$4,115	-	-	-
Labour – Internal	1,287	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$5,402**	**$5,428**	**$16,434**	**$27,264**

Costing Methodology

The budget estimate is based on detailed engineering estimates.

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. Future expenditures will be presented in the appropriate annual capital budget application.

Project Title: **Transformers (Pooled)**

Project Cost: **$5,945,000**

Project Description

This Distribution project includes the cost of purchasing transformers to serve customer growth and the replacement or refurbishment of units that have deteriorated or failed.

Transformer requirements are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

Providing equitable access to an adequate supply of power requires connecting new customers to the electrical system. This project is necessary to ensure this requirement is met in 2021.

Providing reliable service requires replacing deteriorated or failed transformers serving existing customers. This project is necessary to ensure this requirement is met in 2021.

The new component of this project is justified on the obligation to provide customers with equitable access to an adequate supply of power and cannot be deferred.

The replacement component of this project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$5,945	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$5,945**	**$6,006**	**$18,407**	**$30,358**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	**2016**	**2017**	**2018**	**2019**	**2020F**	**2021B**
Total	$4,956	$5,835	$5,782	$5,696	$6,581	$5,945
Adjusted Costs[1]	$5,167	$6,019	$5,902	$5,754	-	-

[1] 2020 dollars.

The process of estimating the budget requirement for transformers is based on an historical average. Historical annual expenditures related to distribution transformers over the most recent 5-year period, including the current year, are expressed in current-year dollars ("Adjusted Costs"). The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada.

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: **Reconstruction (Pooled)**

Project Cost: **$5,567,000**

Project Description

This Distribution project involves the replacement of deteriorated or damaged distribution structures and electrical equipment. This project comprises high-priority deficiencies that are identified during the budget year or recognized during follow-up on operational problems, including power interruptions and customer trouble calls.

This project differs from the *Rebuild Distribution Lines* project, which involves the planned rebuilding of sections of lines or the selective replacement of various line components based on preventive maintenance inspections or engineering reviews.

Distribution *Reconstruction* requirements are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

Newfoundland Power operates over 10,000 kilometres of distribution lines to serve customers throughout its service territory. Addressing deteriorated distribution structures and equipment is required to maintain plant condition. High-priority deficiencies must be addressed in a timely manner to maintain the safe and reliable operation of the electrical system. Project costs for 2021 are based on recent requirements for addressing high-priority deficiencies.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$1,317	-	-	-
Labour – Internal	2,241	-	-	-
Labour – Contract	1,256	-	-	-
Engineering	563	-	-	-
Other	190	-	-	-
Total	**$5,567**	**$5,677**	**$17,718**	**$28,962**

Costing Methodology

Table 2 shows the annual expenditures and costs in current dollars for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	**2016**	**2017**	**2018**	**2019**	**2020F**	**2021B**
Total	$4,876	$4,575	$5,903	$5,579	$5,513	$5,567
Adjusted Costs[1]	$5,253	$4,829	$6,091	$5,666	-	-

[1] 2020 dollars.

The process of estimating the budget requirement for *Reconstruction* is based on an historical average. Historical annual expenditures related to unplanned repairs to distribution feeders over the most recent 5-year period, including the current year, are expressed in current-year dollars ("Adjusted Costs"). The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada.

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: **Rebuild Distribution Lines (Pooled)**

Project Cost: **$3,965,000**

Project Description

This Distribution project involves the replacement of deteriorated distribution structures and electrical equipment that have been previously identified through the ongoing preventative maintenance program or engineering reviews.

Distribution rebuild projects are preventative capital maintenance projects that consist of either the complete rebuilding of deteriorated distribution line sections or the selective replacement of various line components based on preventative maintenance reviews of the power line or engineering reviews. These typically include the replacement of poles, crossarms, conductor, cutouts, surge/lightning arrestors, insulators and transformers.

Based on a 7-year inspection cycle for distribution feeders, the work for 2021 will be performed on the following 42 of the Company's 305 feeders:

BHD-01	COB-02	GOU-01	LGL-02	NWB-02	SPO-03
BIG-01	COL-01	GOU-02	LLK-03	PAS-01	STG-02
BOT-01	DUN-01	HCT-01	LOK-01	PEP-03	SUN-03
BOT-03	DUN-02	HGR-03	MKS-01	PEP-04	TWG-01
BVS-01	FRN-02	HWD-08	MOB-01	PUL-04	WAV-01
BVS-03	GAM-02	KBR-12	MOB-02	RRD-09	WAV-02
CAR-01	GDL-08	KBR-13	MSY-01	RVH-01	WAV-03

While the various components of the project are not interdependent, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

Newfoundland Power operates over 10,000 kilometres of distribution lines to serve customers throughout its service territory. The Company implements an annual inspection program to identify deteriorated structures and equipment throughout its distribution system. Deterioration is addressed under this project through either the planned rebuilding of sections of line or the selective replacement of line components. Project costs for 2021 are based on recent requirements for addressing deterioration on the distribution system.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$1,639	-	-	-
Labour – Internal	1,845	-	-	-
Labour – Contract	241	-	-	-
Engineering	40	-	-	-
Other	200	-	-	-
Total	**$3,965**	**$4,040**	**$12,586**	**$20,591**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$2,846	$3,269	$4,429	$4,371	$3,985	$3,965
Adjusted Costs[1]	$3,064	$3,442	$4,567	$4,438	-	-

[1] 2020 dollars

Distribution feeders are inspected in accordance with Newfoundland Power's distribution inspection standards to identify the following:

a) Deficiencies that are a risk to public or employee safety, or that are likely to result in imminent failure of a structure or hardware. This includes primary components, such as poles, crossarms and conductor; and

b) Specific line components targeted for replacement based on engineering reviews, including lightning arrestors, CP8080 and 2-piece insulators, current limiting fuses, automatic sleeves, porcelain cutouts and transformers.

Report *4.4 Rebuild Distribution Lines Update* included with the *2013 Capital Budget Application* described the Company's current preventative maintenance program, distribution inspection standards and targeted replacement programs. Proposed expenditures under this Distribution project are consistent with that report.

Inspections for the lines on which work is to take place in 2021 are ongoing throughout 2020. Complete inspection data will not be available until late 2020. Therefore, the 2021 budget estimate is based on average historical expenditures over the previous 5 years.

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: **Relocate/Replace Distribution Lines for Third Parties (Pooled)**

Project Cost: **$3,155,000**

Project Description

This Distribution project is necessary to accommodate 3rd party requests to relocate or replace distribution lines. The relocation or replacement of distribution lines results from: (i) work initiated by municipal, provincial and federal governments; (ii) work initiated by other users, such as Bell Aliant, Eastlink and Rogers Communications; or (iii) requests from customers.[10]

The Company's response to requests for relocation and replacement of distribution facilities by governments and other service providers is governed by the provisions of agreements in place with the requesting parties. The relocation or replacement of facilities for customers is governed by the Company's policy respecting Contributions in Aid of Construction.

While the individual requirements are not interdependent, they are similar in nature and justification and are therefore pooled for consideration as a single capital project.

Justification

Maintaining safe and adequate facilities requires responding to 3rd party requests to relocate or replace distribution lines.

This project is justified on the obligation to maintain safe and adequate facilities and cannot be deferred.

[10] Also included is distribution work associated with the installation and relocation of communications cables used by the Company's various protection and control systems.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$1,116	-	-	-
Labour – Internal	1,018	-	-	-
Labour – Contract	638	-	-	-
Engineering	326	-	-	-
Other	57	-	-	-
Total	**$3,155**	**$3,209**	**$9,962**	**$16,326**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$2,454	$2,445	$3,177	$5,192[3]	$2,553	$3,155[3]
Adjusted Costs[1]	$2,594	$2,543	$2,574[2]	$5,272	-	-

1 2020 dollars
2 Excludes $681,000 associated with Rogers Communications fibre build in St. John's area.
3 Increased expenditures are related to joint use partners expanding broadband service to rural communities.

The 2021 budget estimate is based on historical expenditures. Generally, these expenditures are associated with a number of small projects that cannot be specifically identified at the time the budget is prepared. Historical annual expenditures related to distribution line relocations and replacements over the most recent 5-year period, including the current year, are expressed in current-year dollars ("Adjusted Costs"). The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada.

Estimated contributions from customers and requesting parties associated with this project are included in the estimated contributions in aid of construction referred to in the Application.

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: **Trunk Feeders (Other)**

Project Cost: **$800,000**

Project Description

This Distribution project involves refurbishing or replacing distribution infrastructure primarily due to deterioration or other factors, such as public or employee safety and the environment. This project consists of individual high-priority projects that arise from preventive maintenance inspections or engineering reviews that are beyond the scope of other Distribution projects.

This Distribution project includes the replacement of deteriorated distribution infrastructure on distribution feeder LGL-02. Distribution feeder LGL-02 is 1 of 2 feeders originating from Long Lake Substation. The section of distribution feeder to be rebuilt connects the Rose Blanche hydro plant to the Island Interconnected System. Details on the proposed expenditures are included in report *4.3 LGL-02 Distribution Feeder Refurbishment*.

Justification

The Rose Blanche hydro plant is connected to the electrical system via a section of distribution feeder LGL-02. The normal annual plant production of the Rose Blanche hydro plant is approximately 23.5 GWh of energy, or about 5.4% of Newfoundland Power's total hydroelectric production. The plant provides relatively inexpensive energy to the Island Interconnected System. It also provides a reliability benefit to customers on the southwest coast of Newfoundland when outages occur to Newfoundland and Labrador Hydro's radial transmission lines in the area.

Inspections in 2020 identified this section of LGL-02 has deteriorated poles and cross arms, poor conductor condition, sub-standard pole spacing, and other hardware deficiencies. Many of these components are in advanced stages of deterioration and require replacement. Replacing deteriorated infrastructure on this section of LGL-02 is necessary to maintain the condition of the line and ensure the continued availability of supply from the Rose Blanche hydro plant.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$372	-	-	-
Labour – Internal	147	-	-	-
Labour – Contract	192	-	-	-
Engineering	44	-	-	-
Other	45	-	-	-
Total	**$800**	**$2,000**	**$6,110**	**$8,910**

Costing Methodology

The budget estimate is based on detailed engineering estimates.

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: **Feeder Additions for Load Growth (Clustered)**

Project Cost: **$2,655,000**

Project Description

This Distribution project consists of expenditures to address overload conditions and provide additional capacity to address growth in the number of customers and volume of energy deliveries.

For 2021, the *Feeder Additions for Load Growth* project will include the upgrading of the following distribution feeders:

1. A section of Ridge Road feeder RRD-10 ($654,000) will be upgraded and new aerial feeder exits will be constructed from the new airport substation ($151,000) as a result of distribution system reconfiguration resulting from the *St. John's North – Portugal Cove System Planning Study*.

2. A section of Springfield feeder SPF-02 will be upgraded to address an unbalanced condition that has developed as a result of load growth in the Makinsons and Hodgewater Line areas. ($600,000)

3. A section of Port Blandford feeder PBD-01 will be upgraded from single-phase to 3-phase in order to address an unbalanced condition that has developed as a result of load growth in the community of Port Blandford and the Thorburn Lake Cabin area. ($600,000)

4. A section of Pulpit Rock feeder PUL-05 will be upgraded from single-phase to 3-phase in order to address an unbalanced condition that has developed as a result of customer load growth on Middle Cove Road and surrounding area. ($360,000)

5. A section of Chamberlains feeder CHA-04 will be upgraded from single-phase to 3-phase in order to address an unbalanced condition that has developed as a result of load growth on Three Island Pond Road in the Town of Paradise. ($290,000)

Details on proposed expenditures are included in report *4.2 Feeder Additions for Load Growth*.

The RRD-10 aerial feeder exits portion of the *Feeder Additions for Load Growth* Distribution project, the *Additions Due to Load Growth* Substations project, the *Transmission Line Extension - 35L* Transmission project, and the *Fibre Optic Cable Builds* Telecommunications project are each required to construct the new substation near St. John's International Airport. These items are interdependent and are therefore clustered.

Justification

Providing equitable access to an adequate supply of power requires connecting new customers to the electrical system and addressing increases in customers' electrical loads. This project is necessary to ensure these requirements are met in 2021.

This project is justified on the obligation to provide customers with equitable access to an adequate supply of power and cannot be deferred.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$443	-	-	-
Labour – Internal	592	-	-	-
Labour – Contract	685	-	-	-
Engineering	414	-	-	-
Other	521	-	-	-
Total	**$2,655**	**$3,607**	**$11,971**	**$18,233**

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: **Distribution Reliability Initiative (Pooled, Multi-Year)**

Project Cost: **$700,000**

Project Description

This Distribution project involves the replacement of deteriorated poles, conductor and hardware to reduce both the frequency and duration of power interruptions to the customers served by specific distribution lines.[11] The upgrading work is typically determined through assessments of past service problems, knowledge of local environmental conditions (such as salt contamination, wind and ice loading), and location-specific design and construction standards.

The 2021 project involves work on the final year of a multi-year project to rebuild distribution feeder DUN-01.[12]

Table 1 shows the number of customers affected and the average unscheduled interruption statistics for DUN-01 over the 5-year period ending December 31, 2019.

Table 1
Distribution Interruption Statistics
5-Year Average to December 31, 2019

Feeder	Customers	SAIFI	SAIDI	CHIKM	CIKM
DUN-01	1,048	4.93	8.30	54	32
Company Average	**827**	**1.39**	**1.80**	**52**	**45**

These statistics exclude interruptions due to any causes other than distribution system failure. An analysis of the feeder's performance is contained in report *4.1 Distribution Reliability Initiative* of the Company's *2019 Capital Budget Application*.

Justification

Under the Distribution Reliability Initiative, individual feeder projects are identified and prioritized based on their historic interruption statistics. Customers supplied by the worst-performing feeders experience power interruptions more often or of longer duration than the Company average. Engineering assessments are completed to determine whether targeted capital investments would improve the reliability experienced by customers served by these feeders.

[11] These feeders are sometimes referred to in the industry as *worst performing feeders*.
[12] The *Distribution Reliability Initiative* work for DUN-01 was approved as a multi-year project over 3 years in Order No. P.U. 035 (2018).

The Distribution Reliability Initiative improves reliability in areas where customers experience the worst service quality. Targeting capital expenditures in these areas is consistent with maintaining an overall acceptable level of service reliability for all customers.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 2 provides the breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 2
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$167	-	-	-
Labour – Internal	206	-	-	-
Labour – Contract	51	-	-	-
Engineering	76	-	-	-
Other	200	-	-	-
Total	**$700**	**$1,000**	**$4,000**	**$5,700**

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

The Distribution Reliability Initiative work for DUN-01 was approved in Order No. P.U. 35 (2018) as a multi-year project. This is the final year of this project.

Project Title: **Distribution Feeder Automation (Pooled)**

Project Cost: **$821,000**

Project Description

This Distribution project is necessary to increase automation in the Company's distribution system. Increased automation in the distribution system improves customer service through reduced restoration times following both local and system-wide outages.[13]

Increasing automation of distribution feeders will involve the addition of new equipment to the distribution system or the replacement of some older equipment in service with modern, communications-capable equipment. The increase in automation will include the addition of technologies, such as automated downline reclosers and fault indicators. These devices reduce outage response and restoration time, as sections of feeders no longer need to be patrolled to identify the cause of outages.

Details on the various customer and operational benefits associated with the continued deployment of automated equipment throughout the Company's distribution system can be found in the *2020 Capital Budget Application* report *4.5 Distribution Feeder Automation*.

Table 1 lists the downline automated reclosers proposed to be installed in 2021.

Table 1
2021 Downline Automated Recloser Installations

Feeders	Number of Devices	Deployment Scenario[14]
GOU-01	2	Scenario 2
MOL-05	2	Scenario 2
MOL-06	2	Scenario 2
GOU-01/MOL-05 Tie	1	Scenario 3
GOU-01/MOL-06 Tie	1	Scenario 3
OPL-02	1	Scenario 1
MSY-02	1	Scenario 1
BLA-01	1	Scenario 1
WAL-04	1	Scenario 1
SUM-01	1	Scenario 2
GBS-01	1	Scenario 1
GBS-02	1	Scenario 1

[13] Increasing the level of automation in the distribution system is consistent with Recommendation 2.4 of The Liberty Consulting Group's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power*, December 17, 2014.

[14] Deployment scenarios as defined in the *2020 Capital Budget Application* report *4.5 Distribution Feeder Automation*.

Justification

The deployment of automated distribution equipment will enhance the Company's response to customer outages in all operating conditions, including local and system-wide outages. Distribution feeder automation is recognized in the electric utility industry as providing both reliability and efficiency benefits for customers.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 2 provides the breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 2
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$493	-	-	-
Labour – Internal	74	-	-	-
Labour – Contract	71	-	-	-
Engineering	81	-	-	-
Other	102	-	-	-
Total	**$821**	**$888**	**$2,933**	**$4,642**

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: **Allowance for Funds Used During Construction (Pooled)**

Project Cost: **$205,000**

Project Description

This Distribution project is an allowance for funds used during construction ("AFUDC") which will be charged on distribution work orders with an estimated expenditure of less than $50,000 and a construction period in excess of 3 months.

Effective January 1, 2008, the Company calculates AFUDC in a manner consistent with Order No. P.U. 32 (2007). This method of calculating AFUDC is the mainstream practice for regulated Canadian utilities.

Justification

AFUDC is required to implement the Company's capital program and is justified on the same basis as the distribution capital projects to which it relates.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	$205	-	-	-
Total	**$205**	**$208**	**$640**	**$1,053**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	**2016**	**2017**	**2018**	**2019**	**2020F**	**2021B**
Total	$197	$179	$177	$215	$197	205

The budget estimate for AFUDC is based on an estimated $1.0 million monthly average of distribution work in progress and capital materials upon which the interest rate will be applied. The AFUDC rate is applied each month in accordance with Order No. P.U. 32 (2007).

Future Commitments

This is not a multi-year project.

GENERAL PROPERTY

Project Title: **Tools and Equipment (Pooled)**

Project Cost: **$486,000**

Project Description

This General Property project is necessary to add or replace tools and equipment used in providing safe and reliable electrical service. Tools and equipment are used by power line technicians ("PLT"), engineering technologists, engineers and tradespersons. The majority of these tools are used in normal day-to-day operations. Additionally, specialized tools and equipment are required to maintain, repair, diagnose or commission Company assets required to deliver service to customers.

Most items within this project involve expenditures of less than $50,000. These items are consolidated into the following categories:

1. *Operations Tools and Equipment ($292,000)*: This item includes the replacement of tools and equipment used by PLTs and field technical staff in the day-to-day operations of the Company. These tools are maintained on a regular basis. However, over time they degrade and wear out, especially hot line equipment, which must meet rigorous safety requirements. Where appropriate, such tools will be replaced with battery and hydraulic alternatives to improve working conditions.

2. *Engineering Tools and Equipment ($73,000)*: This item includes engineering test equipment and tools used by electrical and mechanical maintenance personnel and engineering technologists. Engineering test equipment is required to perform system calibration, commissioning and testing of power system facilities and testing and analysis of associated data communications facilities.

3. *Office Furniture ($121,000)*: This item includes the replacement of office furniture that has deteriorated. The office furniture utilized by the Company's employees deteriorates through normal use and must be replaced.

Individual requirements for the addition or replacement of tools and equipment are not interdependent, but are similar in nature and justification. They are therefore pooled for consideration as a single capital project.

Justification

Maintaining suitable tools and equipment is required to respond to customer outages and to operate and maintain the electrical system. This project is necessary to ensure this requirement is met in 2021.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$486	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$486**	**$491**	**$1,504**	**$2,480**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$443[1]	$499	$485	$451	$476	$486

[1] Excludes cost of a load cell and tools for a new line truck. ($113,000)

The project cost is based on an assessment of historical expenditures for the replacement of tools and equipment that become broken or worn out, and is adjusted for anticipated expenditure requirements for extraordinary items.

The budget for this project is calculated on the basis of historical data respecting operations tools and equipment, engineering tools and equipment, and office furniture. To ensure consistency from year to year, expenditures related to large unplanned additions are excluded from the historical average calculation.

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

Future Commitments

This is not a multi-year project.

Project Title: **Additions to Real Property (Pooled)**

Project Cost: **$598,000**

Project Description

This General Property project is necessary to ensure the continued safe operation of Company facilities and workplaces. The Company has in excess of 20 office and other buildings. There is an ongoing requirement to upgrade or replace equipment and facilities at these buildings due to failure or normal deterioration. Past expenditures have included such items as emergency water line replacement, sewer interceptor installation and correcting major drainage problems.

The 2021 project consists of the upgrading, refurbishment or replacement of equipment and facilities due to organizational changes, damage, deterioration, corrosion and in-service failure. Based on historical expenditures for the previous 5-year period, $373,000 is required for 2021.

In addition to the historical expenditure component, this project also consists of the refurbishment of identified deteriorated transformer storage racks at Company service centres at an estimated cost of $150,000 and replacement of the uninterruptible power supply battery bank at the Duffy Place operations centre at an estimated cost of $75,000.

The individual budget items are not interdependent. However, they are similar in nature and are therefore pooled for consideration as a single capital project.

Justification

Newfoundland Power maintains office buildings and other facilities throughout its service territory to ensure a reasonable response to customer outages and customer-driven work requests. These facilities deteriorate and components fail over time. Upgrading, refurbishing and replacing building components is necessary annually to maintain these facilities in safe and adequate condition. Project costs for 2021 are estimated based on recent and identified requirements for addressing deteriorated building components.

This project is justified on the obligation to maintain safe and adequate facilities and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 – 2025	Total
Material	$518	-	-	-
Labour – Internal	18	-	-	-
Labour – Contract	-	-	-	-
Engineering	40	-	-	-
Other	22	-	-	-
Total	**$598**	**$527**	**$1,689**	**$2,814**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$391	$467	$412[1]	$353[2]	$369[2]	$372[3]

[1] Excludes Duffy Place backflow prevention ($224,000) and 2 UPS battery bank replacements ($123,000).
[2] Excludes refurbishment of deteriorated transformer storage racks ($150,000).
[3] Excludes refurbishment of deteriorated transformer storage racks ($150,000) and Duffy Place battery bank ($75,000).

The budget for this project is calculated on the basis of historical data as well as engineering estimates for planned budget items, as required. To ensure consistency from year to year, expenditures related to large unplanned additions are excluded from the historical average calculation.

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: **Company Building Renovations (Pooled)**

Project Cost: **$1,392,000**

Project Description

This General Property project involves undertaking renovations of Company facilities throughout its service territory.

The Company has in excess of 20 office and other buildings. There is an ongoing requirement to upgrade or replace equipment and building systems at these facilities due to failure or normal deterioration. Once a facility has been in service for an extended period of time more significant renovation is required to extend the service life of the facility.

In 2021, the Company will replace, refurbish and upgrade building systems and property at the following facilities:

1. *Kenmount Road Office Building Elevator Upgrade ($200,000)*
   The Kenmount Road office building was constructed in 1969 as a single-story building with a basement level. In 1982, an additional 2 stories were added and a single traction-type elevator was installed to access all 4 floors. Due to the vintage of the elevator equipment, replacement parts to ensure continued operation are no longer available. An upgrade is therefore required.

2. *Carbonear Office Building HVAC Upgrade ($312,000)*
   The Carbonear Regional Office is the Company's main facility for the Avalon operating area. In 1989, the office building was consolidated with the warehouse which included the installation of the existing HVAC system. Due to the age, deteriorated condition and operational issues associated with poor environmental controls, the HVAC system has reached the end of its service life. An upgrade is therefore required.

3. *Electrical Maintenance Centre Storage Facility Replacement ($462,000)*
   The Electrical Maintenance Center ("EMC") is located on Topsail Road in Mount Pearl. The EMC is the primary maintenance facility for the assessment, maintenance and refurbishment of the Company's high-voltage electrical equipment. The 3 existing storage sheds are deteriorated and require replacement. This project involves constructing a single, larger shed to meet the facility's storage requirements.

4. *SCC/EMC Parking Lots and Entrance Refurbishment ($418,000)*
   The System Control Centre ("SCC") and EMC are located on Topsail Road in Mount Pearl. The asphalt and curbs at both parking lots are deteriorated and require replacement. This project involves removing the existing asphalt and paving the roadway and parking lot area at these facilities.

While the individual requirements are not interdependent, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project. Details on the proposed expenditures are included in report *5.1 Company Building Renovations*.

Justification

Newfoundland Power maintains office buildings and other facilities throughout its service territory to ensure a reasonable response to customer outages and customer-driven work requests. These facilities deteriorate and components fail over time. Upgrading, refurbishing and replacing building components is necessary to maintain these facilities in safe and adequate condition.

This project is justified on the obligation to maintain safe and adequate facilities and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 – 2025	Total
Material	$1,158	-	-	-
Labour – Internal	12	-	-	-
Labour – Contract	-	-	-	-
Engineering	103	-	-	-
Other	119	-	-	-
Total	**$1,392**	**$1,982**	**$5,260**	**$8,634**

Costing Methodology

The budget estimate for this project is based on detailed engineering estimates for the work identified.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all construction materials and services for this project will be purchased using competitive bids of prospective contractors.

Future Commitments

This is not a multi-year project.

Project Title: **Physical Security Upgrades (Pooled)**

Project Cost: **$300,000**

Project Description

This General Property project consists of capital expenditures necessary for the refurbishment and upgrading of security infrastructure at Company locations.[15]

Since 2016, there have been 24 substation break-ins. This results in significant safety risk to Newfoundland Power staff and the general public in addition to property damage. Most substation break-ins result in the theft of bare copper wire due to the scrap value of copper.

Security upgrades will be performed in 14 substations to deter the entry of unauthorized persons and reduce the likelihood of copper theft occurring. Substation security upgrades will include the installation of surveillance and alarm systems to deter theft and vandalism.

Company offices contain equipment and information that needs to be effectively secured from intrusion and theft. In addition, Newfoundland Power has a number of sites where electrical equipment and hazardous materials are stored. These sites are vulnerable to theft, vandalism and trespassing. These sites are secured by perimeter fencing and controlled access gates. As this infrastructure ages, it requires refurbishment to ensure safe and secure operation of the sites.

Security upgrades will be performed at 3 Company facilities and will include upgrades to the security infrastructure, including improvements in public entrances, access control, surveillance and lighting upgrades, and the addition of security fencing, access control gates and security surveillance systems.

Based on engineering estimates, $300,000 is required for physical security upgrades in 2021.

Justification

Newfoundland Power maintains office buildings, substations and other facilities throughout its service territory to support the delivery of service to customers. Maintaining the security of these facilities is necessary to ensure the safety of employees and the general public. It is also necessary to prevent the theft or damage of materials required to provide service to customers.

This project is justified on the obligation to maintain safe and adequate facilities and cannot be deferred.

[15] Prior to 2019, corporate security upgrades for office buildings and storage sites were included in the *Additions to Real Property* General Property project. Substation security was included in the *Substation Refurbishment and Modernization* Substations project. Combining all physical security upgrades in a single project is intended to focus Company security efforts.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$250	-	-	-
Labour – Internal	25	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	25	-	-	-
Total	**$300**	**$300**	**$900**	**$1,500**

Costing Methodology

The budget estimate for this project is based on engineering estimates.

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.

TRANSPORTATION

Project Title: **Purchase Vehicles and Aerial Devices (Pooled)**

Project Cost: **$4,032,000**

Project Description

This Transportation project involves the addition and necessary replacement of heavy fleet, passenger and off-road vehicles. Detailed evaluation of the units to be replaced indicates they have reached the end of their useful service lives.

Table 1 summarizes the units to be replaced in 2021.

Table 1
2021 Proposed Vehicle Replacements

Category	No. of Units
Heavy Fleet Vehicles	6
Passenger Vehicles[1]	32
Off-road Vehicles[2]	8
Total	**46**

[1] The Passenger Vehicles category includes the purchase of cars and light duty trucks.
[2] The Off-road Vehicles category includes snowmobiles, ATVs, trailers and specialized mobile equipment.

In 2021, there are 6 heavy fleet vehicles that meet the age, mileage and condition parameters that indicate replacement is necessary. The Company has also identified 32 passenger and 8 off-road vehicles for replacement in 2021.

The Company's replacement criteria for vehicles were described in the *2016 Capital Budget Application* report *5.1 Vehicle Replacement Criteria*. This report also compared the criteria to those used by other Canadian electrical utilities. It shows the current approach of the Company is consistent with current Canadian utility practice and the least-cost delivery of service to customers.

The expenditures for individual vehicle replacements are not interdependent. However, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

Providing reliable service to customers across the Company's 70,000 km² service territory requires maintaining an adequate fleet of vehicles to respond to customer outages and maintain

the electrical system. Project costs for 2021 are estimated based on the number of vehicles expected to require replacement that year.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 2
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$4,032	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$4,032**	**$4,108**	**$12,788**	**$20,928**

Costing Methodology

Table 3 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 3
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$3,377	$3,776	$3,594	$4,223	$3,869	$4,032

Newfoundland Power individually evaluates all vehicles considered for replacement according to a number of criteria to ensure replacement is the least-cost alternative.

Evaluation for replacement is initiated when individual vehicles reach a threshold age or level of usage. Heavy fleet vehicles are considered for replacement at 10 years of age or usage of 250,000 kilometres. For passenger vehicles, the guideline is 5 years of age or 150,000 kilometres. Vehicles reaching these thresholds are evaluated on a number of criteria, such as overall condition, maintenance history and immediate repair requirements. This determines whether they have reached the end of their useful service lives.

Based on these evaluations, each unit proposed for replacement is forecast to reach the end of its useful service life and require replacement in 2021.

New vehicles are acquired through competitive tendering to ensure the lowest possible cost consistent with safe, reliable service.

Future Commitments

This is not a multi-year project.

TELECOMMUNICATIONS

Project Title: **Replace/Upgrade Communications Equipment (Pooled)**

Project Cost: **$112,000**

Project Description

This Telecommunications project is necessary to ensure the continued integrity of the Company's operational voice systems and the remote monitoring and control of field devices. These voice, monitoring and control systems allow the Company to provide acceptable levels of customer service and achieve operational efficiencies.

The Company has mobile radio, portable radio, base station radio and radio console equipment in service providing operational voice communications for field staff. The radio equipment is used for communications between: (i) field staff working in multiple crews; (ii) field staff and operations centres; and (iii) field staff and the System Control Centre.

Data communications equipment is used to link the monitoring and control technologies on distribution lines, in substations and hydro plants to the SCADA system at the System Control Centre. A variety of different technologies is used to provide these data communication links depending on local conditions and available service offerings from telecommunications providers. The technologies used include land line communications, fibre optic communications and wireless communications.

Over time, this voice and data communications equipment fails in service, becomes obsolete or no longer supports the most cost-effective service offering from telecommunications providers. As a result the equipment must be upgraded or replaced.

The 2021 project involves the replacement and/or upgrade of communications equipment, including radio communications equipment associated with electrical system operations, and data communications equipment providing remote monitoring and control capabilities associated with the Company's SCADA system.

Justification

Providing reliable service to customers requires the effective deployment of field crews, along with the safe and effective operation of the electrical system. Maintaining adequate communications equipment is necessary to ensure these requirements are met in 2021.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$69	-	-	-
Labour – Internal	11	-	-	-
Labour – Contract	-	-	-	-
Engineering	22	-	-	-
Other	10	-	-	-
Total	**$112**	**$114**	**$352**	**$578**

Costing Methodology

Table 2 shows the annual expenditures and costs in current dollars for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$109	$111	$98	$112	$108	$112
Adjusted Cost[1]	$116	$116	$100	$113	-	-

[1] 2020 dollars.

The process of estimating the budget requirement for communications equipment is based on an historical average. Historical annual expenditures related to upgrading and replacing communications equipment over the most recent 5-year period, including the current year, are expressed in current-year dollars ("Adjusted Costs"). The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada to determine the budget estimate. To ensure consistency from year to year, expenditures related to planned projects are excluded from the calculation of the historical average.

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: **Fibre Optic Cable Builds (Clustered)**

Project Cost: **$350,000**

Project Description

The Company currently operates 68 fibre optic cables. These cables are used for corporate data, substation, voice and SCADA communications, protective relay communications, forebay communications, as well as data communications between Newfoundland Power's and Newfoundland and Labrador Hydro's control centres.[16]

In St. John's, fibre optic cables are used to provide communications between digital protective relays in substations. The fibre optic cables also provide SCADA communications between the substations and the System Control Centre, allowing for the remote monitoring and control of all critical substation equipment. The communications transmitted by the fibre optic cables, for both protection and remote control functionality, are essential for the provision of safe and reliable service to customers.

In 2021, the Company will build 2 fibre optic cable links to facilitate the construction of a new substation in the vicinity of St. John's International Airport.[17] The fibre optic cable links include:

1. *Virginia Waters Substation to the new airport substation ($185,000)*
2. *Oxen Pond Substation to the new airport substation ($165,000)*

The *Fibre Optic Cable Builds* Telecommunications project to construct these 2 fibre optic cable links, the *Additions Due to Load Growth* Substations project, the *Feeder Additions for Growth* Distribution project and the *Transmission Line Extension - 35L* Transmission project are each required to construct a new substation near the St. John's International Airport. These projects are interdependent and therefore clustered.

Details on the proposed expenditures are included in the report *St. John's – Portugal Cove System Planning Study: Attachment A.*

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[16] The Company's fibre optic network in St. John's includes a cable to Newfoundland and Labrador Hydro's Energy Management Centre. This fibre cable carries the Inter Control Centre Protocol ("ICCP") link, which is used to exchange real-time power system data between the 2 SCADA systems.

[17] Details on the need for the new substation can be found in the *St. John's North – Portugal Cove System Planning Study*.

Justification

In 2021, 2 new fibre optic cables are required to facilitate the construction of a new substation near the St. John's International Airport. The construction of a new substation is the least-cost alternative to address overload conditions in the area. The new fibre optic cables are necessary to ensure adequate protection and remote control functionality for the new substation.

This project is justified on the obligation to provide customers with equitable access to an adequate supply of power and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1

Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$225	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	70	-	-	-
Other	55	-	-	-
Total	**$350**	**$300**	**$1,124**	**$1,774**

Costing Methodology

The budget for this project is based on an engineering cost estimate.

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

Future Commitments

This is not a multi-year project.

INFORMATION SYSTEMS

Project Title: **Application Enhancements (Pooled)**

Project Cost: **$978,000**

Project Description

This Information Systems project is necessary to enhance the functionality of software applications. The Company's software applications are used to support all aspects of business operations, including the provision of service to customers, the effective operation of the electrical system, and compliance with regulatory and financial reporting requirements.

The application enhancements proposed for 2021 include enhancement of: (i) the Substation Mobile System; (ii) the Human Resource Management System; (iii) digital forms for daily and weekly truck inspections and records of duty; and (iv) the customer energy conservation website.

The application enhancements proposed for 2021 are not interdependent, but are similar in nature and justification. They are therefore pooled for consideration as a single capital project.

Details on proposed expenditures are included in report *6.1 2021 Application Enhancements*.

Justification

The proposed enhancements included in this project are justified on the basis of improving customer service and operational efficiencies. Cost benefit analyses, where appropriate, are provided in report *6.1 2021 Application Enhancements*.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$170	-	-	-
Labour – Internal	603	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	205	-	-	-
Total	**$978**	**$750**	**$3,650**	**$5,378**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	**2016**	**2017**	**2018**	**2019**	**2020F**	**2021B**
Total	$1,143	$820	$891	$879	$1,428	$978

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

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist to provide competitive bids, all materials and services will be negotiated with the sole-source supplier to ensure they are least cost.

Future Commitments

This is not a multi-year project.

Project Title: **System Upgrades (Pooled, Multi-Year)**

Project Cost: **$2,410,000**

Project Description

This Information Systems project involves upgrades to third-party software products that comprise the Company's information systems.

For 2021, the project includes upgrades to the Company's SCADA System, customer website, Geographic Information System, Workforce Management System, Outage Management System, and Automated Meter Reading Collection System.

This project also includes the renewal of the Microsoft Enterprise Agreement for an additional 3-year term. The agreement covers the purchase of Microsoft software products and provides access to the latest versions of each product purchased under the agreement. Details on the multi-year expenditures associated with the Microsoft Enterprise Agreement are included in *Schedule C* to this Application.

Details on proposed expenditures are included in report *6.2 2021 System Upgrades*.

Justification

Newfoundland Power maintains a network of computers, servers, information systems and other hardware and software. This technology infrastructure is used to operate the Company's electrical system, manage field operations and provide customer service delivery in an effective and efficient manner.

System upgrades in 2021 are primarily driven by the expiration of support arrangements with 3rd party software vendors. Completing system upgrades ensures continuity in vendor support, which reduces risks of system failure. Upgrades are also required in 2021 to improve system performance.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$740	-	-	-
Labour – Internal	1,160	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	510	-	-	-
Total	**$2,410**	**$1,839**	**$8,070**	**$12,319**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$1,664	$1,676	$1,133	$933	$2,592	$2,410

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

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist to provide competitive bids, all materials and services will be negotiated with the sole-source supplier to ensure they are least cost.

Future Commitments

This project includes renewal of the Microsoft Enterprise Agreement in 2021 as a multi-year project for a 3-year term. This is not otherwise a multi-year project.

Project Title: **Personal Computer Infrastructure (Pooled)**

Project Cost: **$495,000**

Project Description

This Information Systems project is necessary for the replacement or upgrade of personal computers ("PCs"), workgroup printers and associated assets that have reached the end of their useful lives.

In 2021, a total of 145 mobile computers will be purchased.[18] This project also includes the purchase of peripheral equipment, such as monitors, mobile devices, and workgroup printers, to replace existing units that have reached the end of their useful lives.

Individual PCs and peripheral equipment are not interdependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Specifications for replacement PCs and peripheral equipment are reviewed annually to ensure the personal computing infrastructure remains effective. Industry best practices, technology trends, and the Company's experience are considered when establishing specifications.

Newfoundland Power is currently able to achieve an approximate 5-year lifecycle for its PCs before they require replacement.

Table 1 outlines the PC additions and retirements for 2019 and 2020, as well as the proposed additions and retirements for 2021.

Table 1
PC Additions and Retirements
2019 – 2021B

	2019			2020F			2021B		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	56	43	418	45	90	373	0	60	313
Mobile	85	98	322	106	61	367	145	85	427
Total	**141**	**141**	**740**	**151**	**151**	**740**	**145**	**145**	**740**

[18] In 2021, the Company plans to increase its number of mobile PCs by replacing 60 retired desktop units with mobile units. This will enable greater flexibility of the work force to work remotely.

Justification

Newfoundland Power maintains a network of computers, servers, information systems and other hardware and software. This technology infrastructure is used to operate the Company's electrical system, manage field operations and provide customer service delivery in an effective and efficient manner. The replacement of personal computers and associated equipment is necessary when it reaches the end of its useful service life.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 2
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$345	-	-	-
Labour – Internal	105	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	45	-	-	-
Total	**$495**	**$520**	**$1,635**	**$2,650**

Costing Methodology

Table 3 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 3
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$470	$493	$480	$500	$493	$495

The cost for this project is calculated on the basis of historical expenditures and on cost estimates for the individual budget items. Historical annual expenditures over the most recent 3-year period are considered and an approximate unit cost is determined based on historical average

prices and a consideration of pricing trends. These unit costs are then multiplied by the quantity of units (i.e. desktop, mobile, workgroup printer, etc.) to be purchased. Quantities are forecast by identifying the number of unit replacements resulting from lifecycle retirements and the number of new units required to accommodate new software applications or work methods. Once the unit price estimates and quantities have been determined, the work associated with the procurement and installation of the units is estimated based on experience and historical pricing.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all materials and services for this project will be purchased after examining the competitive bids of prospective suppliers.

Future Commitments

This is not a multi-year project.

Project Title: **Shared Server Infrastructure (Pooled)**

Project Cost: **$538,000**

Project Description

This Information Systems project includes the addition, upgrade and replacement of computer hardware components and related technology associated with shared server infrastructure and peripheral equipment. The Company's shared servers are used for the routine operation, testing, and disaster recovery of the Company's corporate applications. Management of these shared servers and their components are critical to ensuring these applications operate effectively at all times.

In 2021, the Company will upgrade existing server infrastructure to accommodate growth in information storage needs, to extend the service life of existing shared servers and improve performance of Company applications. It also includes upgrading the associated shared server operating systems to the current, vendor-supported versions. Additional server infrastructure is also required to support Newfoundland Power's customer website, Geographic Information System and Outage Management System. This is critical infrastructure that allows the Company to serve customers.

The project is necessary to ensure the secure operation of the Company's shared sever infrastructure and to complete lifecycle replacement of equipment that is at the end of its expected service life.

The shared server infrastructure requirements for 2021 are not interdependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

Newfoundland Power maintains a network of computers, servers, information systems and other hardware and software. This technology infrastructure is used to operate the Company's electrical system, manage field operations and provide customer service delivery in an effective and efficient manner. The addition, upgrade and replacement of shared server infrastructure is necessary to ensure the effective operation of the Company's systems and technologies.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$150	-	-	-
Labour – Internal	263	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	125	-	-	-
Total	**$538**	**$559**	**$2,236**	**$3,333**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$847	$707	$635	$879	$1,276	$538

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

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist to provide competitive bids, all materials and services will be negotiated with the sole-source supplier to ensure they are least cost.

Future Commitments

This is not a multi-year project.

Project Title: **Network Infrastructure (Pooled)**

Project Cost: **$363,000**

Project Description

This Information Systems project involves the addition of network components that provide employees with access to applications and data in order to provide service to customers and to operate efficiently.

Network components, such as routers and switches, interconnect shared servers and personal computers throughout the Company, enabling the transport of SCADA, corporate and customer service data. In addition to traditional wired network technologies, the Company has increased its use of wireless communications technologies in recent years.

For 2021, this project includes the purchase and implementation of network equipment that has reached the end of its useful life and to increase overall network availability and disaster recovery capabilities.

The individual network infrastructure requirements for 2021 are not interdependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

The reliability and availability of the network infrastructure is critical to enabling the Company to continue to provide least-cost, reliable service to customers. This project will replace components of the network equipment that facilitate communication between all of the Company's shared servers and related applications. These components have reached the end of their useful lives.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$160	-	-	-
Labour – Internal	158	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	45	-	-	-
Total	**$363**	**$375**	**$1,261**	**$1,999**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2021.

Table 2
Expenditure History
(000s)

Year	2016	2017	2018	2019	2020F	2021B
Total	$312	$407	$439	$338	$473	$363

The budget for this project is based on cost estimates for the individual budget items based on past experiences and pricing.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist to provide competitive bids, all materials and services will be negotiated with the sole-source supplier to ensure they are least cost.

Future Commitments

This is not a multi-year project.

Project Title: **Cybersecurity Upgrades (Pooled)**

Project Cost: **$675,000**

Project Description

This Information Systems project involves upgrades to Newfoundland Power's cybersecurity infrastructure.

Electrical system assets are operated using a combination of physical and technology infrastructure. Physical infrastructure includes components such as protection and control systems. Technology infrastructure includes components such as networks, software and data. Protecting this infrastructure from threats, including cybersecurity threats, is critically important to the day-to-day provision of safe and reliable service to customers.

The risk of cybersecurity threats have increased materially for utilities. Increased risks result from the widespread use of operations technology within utilities and the continual evolution and sophistication of cybersecurity threats. Ensuring cybersecurity infrastructure is adequately designed to address potential vulnerabilities and respond to threats is increasingly important to the safe and reliable operation of the electrical system.

Newfoundland Power completes annual assessments to identify measures to improve the Company's cybersecurity infrastructure. Proposed 2021 capital expenditures include the following:

1. *Identity and Access Management ($117,000)*
   Identity and Access Management improvements for 2021 involve expanding the use of Newfoundland Power's privileged access management system to reduce risk on network attached devices in the Company's substations to prevent hackers from accessing the electrical grid and causing outages to customers.

2. *Network Security ($106,000)*
   Network Security improvements for 2021 focus on reducing risk across information and operations technology networks. This includes better controls for accessing the network, reporting of failed logins to critical systems, improved management of vulnerabilities for all technology assets and continued implementation of secure communications, and improved software patching for critical assets. These improvements will ensure company and customer data remains secure.

3. *Firewall Upgrades ($246,000)*
   Upgrading of the Company's firewall technology is required to meet cybersecurity standards and performance requirements. This will strengthen the Company's infrastructure and support prevention and timely response to current and future cybersecurity threats.

4. *Miscellaneous Upgrades ($206,000)*
   Miscellaneous upgrades for 2021 will focus on upgrading technology to mitigate identified evolving risks and deficiencies to ensure the data security and the reliable operation of the electrical system.

The individual requirements for 2021 are not interdependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

The security and availability of critical infrastructure enables Newfoundland Power to provide safe and reliable service to customers at least cost. This project is consistent with the Company's Cybersecurity Risk Management Program and will enable Newfoundland Power to improve its cybersecurity infrastructure to prevent and respond to rapidly evolving cybersecurity threats.

This project is justified on the obligation to maintain safe and adequate facilities and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1
Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$370	-	-	-
Labour – Internal	210	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	95	-	-	-
Total	**$675**	**$600**	**$2,200**	**$3,475**

Costing Methodology

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

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist to provide competitive bids, all materials and services will be negotiated with the sole-source supplier to ensure they are least cost.

Future Commitments

This is not a multi-year project.

Project Title: **Customer Service System Replacement (Other, Multi-year)**

Project Cost: **$9,903,000**

Project Description

This Information Systems project is a multi-year project to replace the Company's existing Customer Service System ("CSS").

Newfoundland Power proposes to replace the existing system with a modern, commercially available solution. Details on this project are included in the *Customer Service Continuity Plan.*

Justification

Least-cost customer service delivery is a principal objective of Newfoundland Power. The Company serves more customers and responds to nearly triple the number of customer enquiries today in comparison to 20 years ago. Customer service costs are 43% lower today than 20 years ago on an inflation-adjusted basis.

All essential customer service functions are supported by Newfoundland Power's CSS. This system was implemented in 1993 with an expected service life of 20 years. The Company plans to replace the system by 2023 following 30 years of operation.

Replacement of the system is necessary to ensure continuity in customer service delivery. A risk assessment completed by Ernst & Young LLP ("EY") in 2018 found that Newfoundland Power is the last mid-to-large Canadian utility operating a legacy system with no upgrade path provided by the original vendor. The assessment concluded, in effect, that the Company's system is at risk of obsolescence and recommended Newfoundland Power explore modernization options.

An independent assessment of alternatives determined that implementing a modern Customer Information System ("CIS") is the only viable alternative to ensure continuity in Newfoundland Power's customer service delivery. A modern CIS would support the Company's existing business processes, provide opportunities to improve the customer experience, and align the Company with current industry practice.[19]

Newfoundland Power's plan for implementing a modern CIS is consistent with the recommendations of EY and industry best practices. Implementing the plan will enable the Company to continue providing responsive and efficient service to customers over the long term.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

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[19] Newfoundland Power provided an assessment and planning framework to ensure continuity in customer service delivery as part of its *2019/2020 General Rate Application*. The Company executed the framework from 2018 to 2020 with the assistance of Ernst and Young LLP ("EY"), a leading industry expert.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2021 and a projection of expenditures through 2025.

Table 1

Projected Expenditures
(000s)

Cost Category	2021	2022	2023 - 2025	Total
Material	$7,186	-	-	-
Labour – Internal	1,934	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	783	-	-	-
Total	**$9,903**	**$15,826**	**$5,917**	**$31,646**

Costing Methodology

The project cost estimates are consistent with the planning recommendations of EY, as detailed in Attachment A of the *Customer Service Continuity Plan.*

As part of implementing a modern CIS, Newfoundland Power will contract a 3rd party procurement advisor. The procurement advisor will assist in undertaking a competitive Request for Proposals process by: (i) developing hundreds of functional and technical specifications for the replacement system; (ii) providing best practices in evaluating vendors' proposals; and (iii) providing industry expertise during contract negotiations. The use of a procurement advisor will reduce execution risks for this once-in-a-generation project.

The Company will complete procurement in 2 phases. The first phase will focus on procuring a commercial solution from an established software vendor. The second phase will focus on contracting a 3rd party system integrator to provide the technical expertise required to implement the solution. A two-phase procurement approach is consistent with industry best practice

Future Commitments

This is a multi-year project to be completed in 2021, 2022 and 2023.

UNFORESEEN ALLOWANCE

Project Title: **Allowance for Unforeseen Items (Other)**

Project Cost: **$750,000**

Project Description

This Allowance for Unforeseen Items project is necessary to permit unforeseen capital expenditures that have not been budgeted elsewhere. The purpose of the account is to permit the Company to act expeditiously to respond to events affecting the electrical system in advance of seeking specific approval of the Board. Examples of such expenditures are the replacement of facilities and equipment due to major storm damages or equipment failure.

While the contingencies for which this budget allowance is intended may be unrelated, it is appropriate that the entire allowance be considered as a single capital budget item.

Justification

This project provides funds for timely service restoration in accordance with Section B Supplementary Capital Budget Expenditures of the *Capital Budget Application Guidelines*.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Costing Methodology

An allowance of $750,000 for unforeseen capital expenditures has been included in all of Newfoundland Power's capital budgets in recent years. If the balance in the Allowance for Unforeseen Items is depleted in the year, the Company may be required to file an application for approval of an additional amount in accordance with the *Capital Budget Application Guidelines.*

Future Commitment

This is not a multi-year project.

GENERAL EXPENSES CAPITALIZED

Project Title: **General Expenses Capitalized (Other)**

Project Cost: **$6,500,000**

Project Description

General Expenses Capitalized ("GEC") are general expenses of Newfoundland Power that are capitalized due to the fact that they are related, directly or indirectly, to the Company's capital projects. GEC includes amounts from two sources: direct charges to GEC and amounts allocated from specific operating accounts.

Justification

Certain of Newfoundland Power's general expenses are related, either directly or indirectly, to the Company's capital program. Expenses are charged to GEC in accordance with guidelines approved by the Board in Order No. P.U. 3 (1995-96).

GEC is required to implement the Company's capital program and is justified on the same basis as the capital projects to which it relates.

Costing Methodology

In Order No. P.U. 3 (1995-96), the Board approved guidelines to determine the expenses of the Company to be included in GEC. In Order No. P.U. 2 (2019), the Board approved a revised capitalization methodology for pension costs as part of GEC. The budget estimate of GEC is determined in accordance with pre-determined percentage allocations to GEC based on the guidelines approved by the Board.

Future Commitment

This is not a multi-year project.

Newfoundland Power Inc.
2021 Capital Budget
Multi-Year Projects Approved in Previous Years

Class	Project Description	CBA/ Board Order		Expenditure (000s) 2019	2020	2021	Total
Distribution	Distribution Reliability Initiative (DUN-01)[1]	2019 CBA P.U. 35 (2018)	Approved	$700	$700	$700	$2,100
			Actual/Forecast	$700	$700	$700	$2,100
Generation Hydro	Topsail Plant Penstock Replacement[2]	2020 CBA P.U. 5 (2020)	Approved		$485	$8,914	$9,399
			Actual/Forecast		$485	$8,914	$9,399
			Total Approved	**$700**	**$1,185**	**$9,614**	**$11,499**
			Total Actual/Forecast	**$700**	**$1,185**	**$9,614**	**$11,499**

[1] A detailed project description can be found in the *2019 Capital Budget Application*, Schedule B pages 47 to 49, and report *4.1 Distribution Reliability Initiative.*
[2] A detailed project description can be found in the *2020 Capital Budget Application*, Schedule B pages 9 to 10, and report *1.4 Topsail Hydro Plant Penstock Replacement.*

Newfoundland Power Inc.
2021 Capital Budget
Multi-Year Projects Commencing in 2021

Class	Project Description	CBA		Expenditure (000s) 2021	2022	2023	Total
Information Systems	Customer Service System Replacement[3]	2021 CBA	Budget	$9,903	$15,826	$5,917	$31,646
Information Systems	Microsoft Enterprise Agreement[4]	2021 CBA	Budget	$245	$245	$245	$735
			Total	**$10,148**	**$16,071**	**$6,162**	**$32,381**

[3] A detailed project description can be found in the *2021 Capital Budget Application*, Volume 1, Schedule B pages 93 to 94, and Volume 1, *Customer Service Continuity Plan*.
[4] A detailed project description can be found in the *2021 Capital Budget Application*, Volume 1, Schedule B pages 82 to 83, and Volume 2, report *6.2 2021 System Upgrades.*

Newfoundland Power Inc.
Computation of Average Rate Base
For The Years Ended December 31
($000s)

	2019	2018
Net Plant Investment		
Plant Investment	1,954,715	1,864,271
Accumulated Depreciation	(790,243)	(752,932)
Contributions in Aid of Construction	(44,616)	(38,575)
	1,119,856	1,072,764
Additions to Rate Base		
Deferred Pension Costs	91,824	89,678
Deferred Credit Facility Issue Costs	61	120
Cost Recovery Deferral – Hearing Costs	494	-
Cost Recovery Deferral – Conservation	17,371	15,889
Weather Normalization Reserve	5,654	1,517
Customer Finance Programs	2,494	2,460
Demand Management Incentive Account	1,881	-
	119,779	109,664
Deductions from Rate Base		
Other Post-Employment Benefits	61,791	57,112
Customer Security Deposits	1,420	1,071
Accrued Pension Obligation	5,104	5,016
Accumulated Deferred Income Taxes	10,088	4,887
2019 Cost Recovery Deferral	1,226	-
	79,629	68,086
Year End Rate Base	1,160,006	1,114,342
Average Rate Base Before Allowances	1,137,174	1,102,941
Rate Base Allowances		
Materials and Supplies Allowance	6,475	6,184
Cash Working Capital Allowance	9,907	8,216
Average Rate Base at Year End	1,153,556	1,117,341

2020 Capital Expenditure Status Report

June 2020

NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.
2020 Capital Expenditure Status Report

Compliance Matters

This report is presented in compliance with the directive of the Board of Commissioners of Public Utilities (the "Board") contained in paragraph 6 of Order No. P.U. 5 (2020):

> *Unless otherwise directed by the Board, Newfoundland Power shall provide, in conjunction with the 2021 capital budget application, a status report on the 2020 capital budget expenditures showing for each project:*
>
> *(i) the approved budget for 2020;*
>
> *(ii) the expenditures prior to 2020;*
>
> *(iii) the 2020 expenditures to the date of the application;*
>
> *(iv) the remaining projected expenditures for 2020;*
>
> *(v) the variance between the projected total expenditures and the approved budget; and*
>
> *(vi) an explanation of the variance.*

Overview

Page 1 of the 2020 Capital Expenditure Status Report outlines the forecast variances from budget of the capital expenditures approved by the Board. The detailed tables on pages 2 to 13 provide additional detail on capital expenditures in 2020, which were approved in Order No. P.U. 5 (2020). The detailed tables also include information on those capital projects approved for 2019 (and approved in Order No. P.U. 35 (2018)) that were not completed prior to 2020.

Variances of more than 10% of approved expenditure and $100,000 or greater are explained in the notes contained in Appendix A, which immediately follows at the conclusion of the 2020 Capital Expenditure Status Report. These variance criteria are as outlined in the *Capital Budget Application Guidelines*.

The variences contained in Appendix A relate to forecast reductions in gross new customer connections by approximately 10% from 2,639 to 2,378.

As a result of the particular challenges that have arisen this year, Newfoundland Power Inc. ("Newfoundland Power" or the "Company") anticipates that a number of capital projects scheduled for completion in 2020 may carry over into 2021.

The disruption caused by the major snow event in January and the declaration of states of emergency in a number of major centres impacted the Company's ability to execute work over a number of weeks. It also affected the project schedules of customers, whose service requests have been postponed as a result.

The declaration of a public health emergency in the province in response to a global pandemic has required Newfoundland Power to modify work procedures in order to ensure public and employee safety. The impact of these modified procedures on the time to complete planned capital work is still being assessed. In addition, significant uncertainty remains regarding the duration of the current restrictions.

Newfoundland Power will provide updated information to the Board in its regular reporting and upon request of the Board.

Newfoundland Power Inc. 2020 Capital Budget Variances ($000s)			
	Approved by Order No. P.U. 5 (2020) Budget	Forecast	Variance
Generation – Hydro	$6,849	$6,849	-
Generation - Thermal	349	349	-
Substations	15,204	15,204	-
Transmission	9,623	9,623	-
Distribution	44,623	42,949	(1,674)[1]
General Property	2,467	2,467	-
Transportation	3,869	3,869	-
Telecommunications	108	108	-
Information Systems	6,772	6,772	-
Unforeseen Items	750	750	-
General Expenses Capitalized	6,000	6000	-
Total	$96,614	$94,940	($1,674)
Projects carried forward from prior years		$2,879[2]	

[1] The decrease is due to a reduction in the forecast number of customer connections. Details can be found in the notes provided in Appendix A.

[2] Forecast 2020 expenditures associated with projects carried forward from prior years.

2020 Capital Expenditure Status Report
($000s)

	Capital Budget			Actual Expenditure			Forecast			
	2019 A	2020 B	Total C	2019 D	YTD 2020 E	Total To Date F	Remainder 2020 G	Total 2020 H	Overall Total I	Variance J
2020 Projects	$ -	$ 96,614	$ 96,614	$ -	$ 27,674	$ 27,674	$ 67,266	$ 94,940	$ 94,940	$ (1,674)
2019 Projects	16,215	-	16,215	13,314	719	14,033	2,160	2,879	16,193	(22)
Grand Total	**$ 16,215**	**$ 96,614**	**$ 112,829**	**$ 13,314**	**$ 28,393**	**$ 41,707**	**$ 69,426**	**$ 97,819**	**$ 111,133**	**$ (1,696)**

Column A	Approved Capital Budget for 2019
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Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2019 YTD
Column E	Actual Capital Expenditures for 2020 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2020
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2020 Capital Expenditure Status Report
($000s)

Category: Generation - Hydro

Project	Capital Budget		Actual Expenditures		Forecast				
	2020 A	Total B	YTD 2020 C	Total To Date D	Remainder 2020 E	Total 2020 F	Overall Total G	Variance H	Notes*
2020 Projects									
Facility Rehabilitation	$ 1,519	$ 1,519	$ 153	$ 153	$ 1,366	$ 1,519	$ 1,519	$ -	
Petty Harbour Plant	3,662	3,662	45	45	3,617	3,662	3,662	-	
Topsail Hydro Plant Penstock	485	485	80	80	405	485	485	-	
Rattling Brook Plant Refurbishment	1,183	1,183	102	102	1,081	1,183	1,183	-	
Total - 2020 Generation Hydro	**$ 6,849**	**$ 6,849**	**$ 380**	**$ 380**	**$ 6,469**	**$ 6,849**	**$ 6,849**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2020
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2020 YTD
Column D	Total of Column C
Column E	Forecast for Remainder of 2020
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2020 Capital Expenditure Status Report
($000s)

Category: Generation - Thermal

Project	Capital Budget			Actual Expenditure			Forecast				
	2019 A	2020 B	Total C	2019 D	YTD 2020 E	Total To Date F	Remainder 2020 G	Total 2020 H	Overall Total I	Variance J	Notes*
2020 Projects											
Facility Rehabilitation Thermal	$ -	$ 349	$ 349	$ -	$ 112	$ 112	$ 237	$ 349	$ 349	$ -	
Total - 2020 Generation Thermal	**$ -**	**$ 349**	**$ 349**	**$ -**	**$ 112**	**$ 112**	**$ 237**	**$ 349**	**$ 349**	**$ -**	
2019 Projects											
Purchase Mobile Generation	$ 7,915	$ -	$ 7,915	$ 7,131	$ 79	$ 7,210	$ 71	$ 150	$ 7,281	$ (634)	
Total - Generation Thermal	**$ 7,915**	**$ 349**	**$ 8,264**	**$ 7,131**	**$ 191**	**$ 7,322**	**$ 308**	**$ 499**	**$ 7,630**	**$ (634)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2019
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Column I	Total of Columns F and G
Column J	Column I less Column C

2020 Capital Expenditure Status Report
($000s)

Category: Substations

Project	Capital Budget		Actual Expenditures		Forecast				
2020 Projects	2020 A	Total B	YTD 2020 C	Total To Date D	Remainder 2020 E	Total 2020 F	Overall Total G	Variance H	Notes*
Substation Refurbishment and Modernization	$ 10,856	$ 10,856	$ 1,574	$ 1,574	$ 9,282	$ 10,856	$ 10,856	$ -	
Replacements Due to In-Service Failures	3,269	3,269	1,449	1,449	1,820	$ 3,269	3,269	-	
PCB Bushing Phase-out	789	789	66	66	723	$ 789	789	-	
Substation FeederTermination	290	290	13	13	277	$ 290	290		
Total - Substations	**$ 15,204**	**$ 15,204**	**$ 3,102**	**$ 3,102**	**$ 12,102**	**$ 15,204**	**$ 15,204**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2020
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2020 YTD
Column D	Total of Column C
Column E	Forecast for Remainder of 2020
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2020 Capital Expenditure Status Report
($000s)

Category: Transmission

Project	Capital Budget			Actual Expenditure			Forecast				
	2019 A	2020 B	Total C	2019 D	YTD 2020 E	Total To Date F	Remainder 2020 G	Total 2020 H	Overall Total I	Variance J	Notes*
2020 Projects											
Rebuild Transmission Lines	$ -	$ 9,623	$ 9,623	$ -	$ 1,169	$ 1,169	$ 8,454	$ 9,623	$ 9,623	$ -	
Total - 2020 Transmission	$ -	$ 9,623	$ 9,623	$ -	$ 1,169	$ 1,169	$ 8,454	$ 9,623	$ 9,623	$ -	
2019 Projects											
Relocate 114L	$ 310	$ -	$ 310	$ -	$ 16	$ 16	$ 294	$ 310	$ 310	$ -	
Total - Transportation	**$ 310**	**$ 9,623**	**$ 9,933**	**$ -**	**$ 1,185**	**$ 1,185**	**$ 8,748**	**$ 9,933**	**$ 9,933**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2019
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Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2020 Capital Expenditure Status Report
($000s)

Category: Distribution

Project	Capital Budget		Actual Expenditures		Forecast				
	2020 A	Total B	YTD 2020 C	Total To Date D	Remainder 2020 E	Total 2020 F	Overall Total G	Variance H	Notes*
2020 Projects									
Extensions	$ 11,318	$ 11,318	$ 4,053	$ 4,053	$ 6,146	$ 10,199	$ 10,199	$ (1,119)	1
Meters	741	741	632	632	64	696	696	(45)	
Services	3,272	3,272	882	882	2,076	2,958	2,958	(314)	2
Street Lighting	2,635	2,635	1,453	1,453	986	2,439	2,439	(196)	
Transformers	6,581	6,581	2,771	2,771	3,810	6,581	6,581	-	
Reconstruction	5,513	5,513	2,785	2,785	2,728	5,513	5,513	-	
Rebuild Distribution Lines	3,985	3,985	1,704	1,704	2,281	3,985	3,985	-	
Relocate/Rebuild Distribution Lines for Third Parties	2,553	2,553	1,212	1,212	1,341	2,553	2,553	-	
Trunk Feeders	2,820	2,820	102	102	2,718	2,820	2,820	-	
Feeder Additions for Growth	2,302	2,302	481	481	1,821	2,302	2,302	-	
Distribution Reliability Initiative	1,950	1,950	365	365	1,585	1,950	1,950	-	
Distribution Feeder Automation	756	756	45	45	711	756	756	-	
Allowance for Funds Used During Construction	197	197	93	93	104	197	197	-	
Total - Distribution	$ 44,623	$ 44,623	$ 16,578	$ 16,578	$ 26,371	$ 42,949	$ 42,949	$ (1,674)	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2020
Column B	Total of Column A
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Column E	Forecast for Remainder of 2020
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2020 Capital Expenditure Status Report
($000s)

Category: General Property

Project	Capital Budget 2019 A	Capital Budget 2020 B	Capital Budget Total C	Actual Expenditure 2019 D	Actual Expenditure YTD 2020 E	Actual Expenditure Total To Date F	Forecast Remainder 2020 G	Forecast Total 2020 H	Forecast Overall Total I	Variance J	Notes*
2020 Projects											
Tools and Equipment	$ -	$ 476	$ 476	$ -	$ 162	$ 162	$ 314	$ 476	$ 476	$ -	
Additions to Real Property	-	519	519	-	139	139	380	519	519	-	
Company Buildings Renovations	-	1,172	1,172	-	31	31	1,141	1,172	1,172	-	
Physical Security Upgrades	-	300	300	-	59	59	241	300	300	-	
									-		
Total - 2020 General Property	**$ -**	**$ 2,467**	**$ 2,467**	**$ -**	**$ 391**	**$ 391**	**$ 2,076**	**$ 2,467**	**$ 2,467**	**$ -**	
2019 Projects											
Company Buildings Renovations	$ 1,374	$ -	$ 1,374	$ 1,182	$ 402	$ 1,584	$ 128	$ 530	$ 1,712	$ 338	
Total - General Property	**$ 1,374**	**$ 2,467**	**$ 3,841**	**$ 1,182**	**$ 793**	**$ 1,975**	**$ 2,204**	**$ 2,997**	**$ 4,179**	**$ 338**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2019
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Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2020 Capital Expenditure Status Report
($000s)

Category: Transportation

Project	Capital Budget 2019 A	Capital Budget 2020 B	Capital Budget Total C	Actual Expenditure 2019 D	Actual Expenditure YTD 2020 E	Actual Expenditure Total To Date F	Forecast Remainder 2020 G	Forecast Total 2020 H	Forecast Overall Total I	Variance J	Notes*
2020 Projects											
Purchase Vehicles and Aerial Devices	$ -	$ 3,869	$ 3,869	$ -	$ 663	$ 663	$ 3,206	$ 3,869	$ 3,869	$ -	
Total - 2020 Transportation	**$ -**	**$ 3,869**	**$ 3,869**	**$ -**	**$ 663**	**$ 663**	**$ 3,206**	**$ 3,869**	**$ 3,869**	**$ -**	
2019 Projects											
Purchase Vehicles and Aerial Devices (2019)	$ 3,990	$ -	$ 3,990	$ 2,648	$ -	$ 2,648	$ 1,575	$ 1,575	$ 4,223	$ 233	
Total - Transportation	**$ 3,990**	**$ 3,869**	**$ 7,859**	**$ 2,648**	**$ 663**	**$ 3,311**	**$ 4,781**	**$ 5,444**	**$ 8,092**	**$ 233**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2019
Column B	Approved Capital Budget for 2020
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Column E	Actual Capital Expenditures for 2020 YTD
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Column I	Total of Columns F and G
Column J	Column I less Column C

2020 Capital Expenditure Status Report
($000s)

Category: Telecommunications

Project	Capital Budget		Actual Expenditures		Forecast				
	2020 A	Total B	YTD 2020 C	Total To Date D	Remainder 2020 E	Total 2020 F	Overall Total G	Variance H	Notes*
2020 Projects									
Replace/Upgrade Communications Equipment	$ 108	$ 108	$ 31	$ 31	$ 77	$ 108	$ 108	$ -	
Total - Telecommunications	**$ 108**	**$ 108**	**$ 31**	**$ 31**	**$ 77**	**$ 108**	**$ 108**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2020
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Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2020 Capital Expenditure Status Report
($000s)

Category: Information Systems

Project	Capital Budget 2019 A	Capital Budget 2020 B	Capital Budget Total C	Actual Expenditure 2019 D	Actual Expenditure YTD 2020 E	Actual Expenditure Total To Date F	Forecast Remainder 2020 G	Forecast Total 2020 H	Forecast Overall Total I	Variance J	Notes*
2020 Projects											
Application Enhancements	$ -	$ 1,428	$ 1,428	$ -	$ 530	$ 530	$ 898	$ 1,428	$ 1,428	$ -	
System Upgrades	-	2,592	2,592	-	571	571	2,021	2,592	2,592	-	
Personal Computer Infrastructure	-	493	493	-	333	333	160	493	493	-	
Shared Server Infrastructure	-	1,276	1,276	-	868	868	408	1,276	1,276	-	
Network Infrastructure	-	473	473	-	83	83	390	473	473	-	
Cybersecurity Upgrades	-	510	510	-	36	36	474	510	510	-	
Total - 2020 Information Systems	**$ -**	**$ 6,772**	**$ 6,772**	**$ -**	**$ 2,421**	**$ 2,421**	**$ 4,351**	**$ 6,772**	**$ 6,772**	**$ -**	
2019 Projects											
Cybersecurity Upgrades	$ 398	$ -	$ 398	$ 271	$ 57	$ 328	$ 89	$ 146	$ 417	$ 19	
Human Resources Management System	$ 1,215	$ -	$ 1,215	$ 1,244	$ 50	$ 1,294	$ 23	$ 73	$ 1,317	$ 102	
System Upgrades	$ 1,013	$ -	$ 1,013	$ 838	$ 115	$ 953	$ (20)	$ 95	$ 933	$ (80)	
Total - Information Systems	**$ 2,626**	**$ 6,772**	**$ 9,398**	**$ 2,353**	**$ 2,643**	**$ 4,996**	**$ 4,443**	**$ 7,086**	**$ 9,439**	**$ 41**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2019
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2020 Capital Expenditure Status Report ($000s)									
Category: Unforeseen Allowance									
	Capital Budget		Actual Expenditures		Forecast				
Project	2020 A	Total B	YTD 2020 C	Total To Date D	Remainder 2020 E	Total 2020 F	Overall Total G	Variance H	Notes*
2020 Projects									
Allowance for Unforeseen Items	$ 750	$ 750	$ -	$ -	$ 750	$ 750	$ 750	$ -	
Total - Unforeseen Items	$ 750	$ 750	$ -	$ -	$ 750	$ 750	$ 750	$ -	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2020
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Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2020 Capital Expenditure Status Report
($000s)

Category: General Expenses Capitalized

Project	Capital Budget		Actual Expenditures		Forecast			Variance	Notes*
	2020 A	Total B	YTD 2020 C	Total To Date D	Remainder 2020 E	Total 2020 F	Overall Total G	H	
2020 Projects									
General Expenses Capitalized	$ 6,000	$ 6,000	$ 2,827	$ 2,827	$ 3,173	$ 6,000	$ 6,000	$ -	
Total - General Expenses Capitalized	**$ 6,000**	**$ 6,000**	**$ 2,827**	**$ 2,827**	**$ 3,173**	**$ 6,000**	**$ 6,000**	**$ -**	

* See Appendix A for notes containing variance explanations.

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Column A	Approved Capital Budget for 2020
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Column H	Column G less Column B

APPENDIX A - NOTES

Distribution

1. Extensions:

Budget: $11,318,000 Forecast: $10,199,000 Variance: ($1,119,000)

The forecast expenditure for *Extensions* is expected to be approximately 10% below the budgeted amount. The reduction reflects a 10% decrease in anticipated new customer connections. In 2020, the number of new customer connections is expected to drop by approximately 10% from 2,639 to 2,378.

Distribution

2. Services:

Budget: $3,272,000 Forecast: $2,958,000 Variance: ($314,000)

The forecast expenditure for *Services* is expected to be approximately 10% below the budgeted amount. The reduction reflects a 10% decrease in anticipated new customer connections. In 2020, the number of new customer connections is expected to drop by approximately 10% from 2,639 to 2,378.

2021 Capital Plan

June 2020

NEWFOUNDLAND POWER
A FORTIS COMPANY

TABLE OF CONTENTS

1.0 Executive Summary

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") annual capital planning enables the provision of safe, reliable and least-cost service to customers.

The value of the Company's investments to customers can be observed over the long term and short term. Over the last 2 decades, Newfoundland Power's investment in the electricity system has improved the reliability experienced by customers, while reducing the Company's contribution to customer rates on an inflation-adjusted basis. Since 2016, customer rates have not increased due to changes in Newfoundland Power's costs.

In comparison to other Atlantic Canadian utilities, Newfoundland Power has had the lowest rate of growth in transmission and distribution investment over the decade ending 2018. At the same time, the Company's customers experienced the best service reliability in Atlantic Canada.

Newfoundland Power's capital investments are also consistent with good utility practice. This was confirmed in the last independent review of the Company's engineered operations completed in 2014.

Newfoundland Power's *2021 Capital Budget Application* proposes investments totalling approximately $111 million.

The capital budget proposed for 2021 is consistent with the level of expenditure over the last 5-year period. Approximately ¾ of proposed 2021 expenditures are driven by the need to replace deteriorated and failed plant, and the obligation to serve new customers and customers' increased electricity usage.

Newfoundland Power's 5-year capital plan forecasts average expenditures of approximately $120 million annually through 2025.

This includes 3 new plans to guide certain capital projects starting in 2021. These are: (i) the *LED Street Lighting Replacement Plan,* which will provide net cost savings for customers over the next 20 years; (ii) the *Customer Service Continuity Plan*, which will replace the Company's nearly 30-year-old Customer Service System; and (iii) the *St. John's North – Portugal Cove System Planning Study*, which outlines the least-cost alternative to address customers' increased electricity usage in that area over the next 20 years.

Each of these plans is consistent with sound public utility practice. These plans, and other capital investments proposed for 2021, will enable the Company to continue providing safe and reliable service to customers at least cost.

2.0 Capital Planning at Newfoundland Power

2.1 Planning and Deferring Capital Investments

2.1.1 Public Policy Context

Newfoundland Power is the primary distributor of electricity in the province of Newfoundland and Labrador. The Company serves approximately 87% of all customers in the province.

Newfoundland Power's operations, including its capital investments, are regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") pursuant to the *Public Utilities Act* and the *Electrical Power Control Act, 1994.*[1]

The *Public Utilities Act* requires a public utility to provide services and facilities that are reasonably safe and adequate and just and reasonable.[2]

[1] Section 41 of the *Public Utilities Act* requires, among other provisions, that a public utility submit an annual capital budget of proposed improvements or additions to its property to the Board for its approval.

[2] See Section 37(1) of the *Public Utilities Act.*

The *Electrical Power Control Act, 1994* contains the provincial power policy. Among other provisions, the provincial power policy requires that power be delivered to customers at the lowest possible cost consistent with reliable service.[3]

The Board has provided specific directions regarding the preparation of annual capital budget applications. These include: (i) the Capital Budget Application Guidelines (the "Guidelines");[4] (ii) the requirement to file a 5-year capital plan;[5] and (iii) the requirement to provide certain additional information in 2021 regarding the deferral and revenue requirement impact of proposed capital projects.[6]

Newfoundland Power's *2021 Capital Budget Application* is consistent with the *Public Utilities Act*, the *Electrical Power Control Act, 1994*, and all applicable policies and directives of the Board.

2.1.2 Capital Planning Process

Newfoundland Power's 5-year capital plan provides the basis of its annual capital budgeting. The 5-year plan includes: (i) a proposed capital budget for the upcoming year for approval by the Board; and (ii) a forecast of capital expenditures over the subsequent 4-year period.

The 5-year capital plan is reviewed and updated annually. The updated plan is filed with the Board as part of the Company's annual capital budget applications.

The annual review and updating of the 5-year capital plan is a comprehensive planning process based on sound engineering and objective data.

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[3] See Sections 3(b)(i), 3(b)(ii) and 3(b)(iii) of the *Electrical Power Control Act, 1994*.

[4] The Guidelines were established by the Board as Policy No. 1900.6 issued in October 2007. Appendix A to this plan provides a summary of Newfoundland Power's compliance with the Guidelines as it relates to its *2021 Capital Budget Application.*

[5] In Order No. P.U. 35 (2003), the Board required that future capital budget applications include an updated 5-year plan for maintaining the predictability and stability of the capital budget and the capital works program (see page 31). Appendix B to this plan provides Newfoundland Power's 5-year capital plan.

[6] See correspondence from the Board dated February 27, 2020, regarding changes for 2021 capital budget applications.

Each year, approximately ½ of annual capital expenditures are driven by the simple need to replace deteriorated or deficient plant, or plant that fails in service.[7] The replacement of deteriorated, deficient or failed plant is necessary to provide safe and reliable service to customers. The 5-year capital plan is updated annually to reflect the most recent information available on plant condition. This includes information obtained through the Company's annual inspection and maintenance programs,[8] engineering reviews conducted as part of long-term asset management strategies,[9] and recent operating experience.

Approximately ¼ of annual capital expenditures are driven by the need to serve new customers and customers' increased electricity usage.[10] The 5-year capital plan is updated annually to reflect the most recent customer, energy and demand forecasts.[11] This ensures the electrical system is adequately designed to meet customers' service requirements.

The remaining ¼ of annual capital expenditures include information systems, system additions, third-party requirements, General Expenses Capitalized and financing costs. The 5-year capital plan is updated annually to reflect the most recent information available for these projects, such as risk assessments for Company information systems.

This comprehensive planning process determines the necessity, scope and *timing* of each proposed capital project. As projects move from the forecast period to the budget year, they are assessed in detail to determine the least-cost alternative to meet a particular requirement.

Overall, Newfoundland Power's capital planning process ensures all proposed projects are consistent with its obligation to provide safe and reliable service to customers at least cost.

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7 The replacement of plant accounts for approximately 50% of proposed capital expenditures for 2021.

8 Substations are inspected 8 times each year, transmission lines are inspected annually, and distribution lines are inspected on a 7-year cycle.

9 Examples of long-term asset management strategies include the Company's: (i) Substation Strategic Plan; (ii) Transmission Line Rebuild Strategy; and (iii) Distribution Reliability Initiative.

10 The obligation to serve customers accounts for approximately 23% of capital expenditures proposed for 2021.

11 Forecast inflation and new customer connections are developed with economic inputs from the Conference Board of Canada.

2.1.3 Deferral in the Planning Process

The Board's Guidelines require an assessment of all available alternatives for capital projects, including whether a project can be deferred. [12] Newfoundland Power assesses the deferral of capital projects at multiple points throughout its capital planning process.

Before any expenditure is included in Newfoundland Power's 5-year capital plan, the Company assesses whether the expenditure is necessary to: (i) meet federal or provincial laws; (ii) provide customers with equitable access to an adequate supply of power; (iii) provide reliable service to customers at least cost; or (iv) maintain safe and adequate facilities in serving customers.[13]

Whether capital expenditures are necessary to meet these requirements is determined based on objective data, including inspection data, condition assessments and forecast customer requirements. Capital expenditures that are not necessary to meet these requirements are not included in the 5-year capital plan. These expenditures are, in effect, deferred.

Expenditures that *are* included as projects in the 5-year capital plan are routinely updated based on new data or information. This may result in a project being advanced to an earlier year, deferred to a later year, or removed entirely from the 5-year capital plan. Examples of new data or information that can result in the deferral of capital projects include:

(i) Updated customer, energy and demand forecasts. A reduced forecast will tend to result in the deferral of a planned substation or distribution upgrade.

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[12] The Guidelines require that all reasonable alternatives, including deferral, be considered for all Normal and Justifiable expenditures. See page 6 of the Guidelines.

[13] These requirements are established in the provincial power policy. See Section 3 of the *Electrical Power Control Act, 1994.*

(ii) Updated condition assessments of equipment. A piece of equipment that is inspected and found to be in adequate condition will tend to result in the deferral of a refurbishment or replacement project.

(iii) Updated assessments of potential customer benefits. Changes in system costs or technologies may result in a project no longer being economic for customers and therefore being deferred.

The Company considers this information in evaluating all available alternatives for meeting a particular requirement. This can include alternatives that do not require capital investments, such as transferring customer load to an adjacent substation when overload conditions arise. It can also include investing in the life extension of an electrical system asset to delay the need for a larger, one-off capital investment. Each of these alternatives can, in effect, result in the deferral of a capital project.

2.1.4 Deferred Capital Projects

Table 1 provides examples of capital projects proposed for 2021 that were previously deferred through Newfoundland Power's capital planning process.

Table 1: 2021 Capital Projects Deferred from Previous Years	
Project	**Description**
Airport Substation	Since 2013, Newfoundland Power's capital plans have included projects to address forecast overload conditions at the Virginia Waters, Broad Cove, and Ridge Road substations. These projects were deferred as a result of low-cost upgrades and additions to the distribution system which, in effect, enabled the Company to use the transformer capacity of existing facilities. All existing capacity has now been utilized and system expansion is required. Construction of a new substation near the St. John's International Airport (the "Airport Substation") is proposed for 2021.[14]
Transmission Line 124L Rebuild	The rebuilding of Transmission Line 124L was originally scheduled to begin in 2011. This project was deferred as a result of annual inspection and maintenance work. Inspections in 2020 identified that continued maintenance of this line is no longer feasible. The rebuilding of a section of this transmission line is proposed for 2021.[15]
Customer Service System Replacement	Newfoundland Power's Customer Service System is expected to exceed its useful service life by 10 years, or 50%. Extension of the system's service life was achieved through routine risk assessments and system upgrades. This has effectively deferred the replacement of this system. An assessment in 2018 determined the system is at risk of obsolescence. An evaluation of alternatives in 2020 determined that implementation of a modern Customer Information System is the only viable alternative to ensure continuity in customer service delivery. Replacement of the existing system is proposed to commence in 2021.[16]
LED Streetlight Replacement	The accelerated replacement of existing street lights with LED fixtures was originally considered in 2020. The project was deferred to enable a comprehensive analysis of potential customer benefits. The analysis determined that accelerating the installation of LED street lights is clearly least-cost for customers. The replacement of existing street lights with LED fixtures is proposed to commence in 2021.[17]

[14] For more information, see the *2021 Capital Budget Application, Volume 2, St. John's North – Portugal Cove System Planning Study.*

[15] For more information, see the *2021 Capital Budget Application, Volume 2, Report 3.1 Transmission Line Rebuild.*

[16] For more information, see the *2021 Capital Budget Application, Volume 1, Customer Service Continuity Plan.*

[17] For more information, see the *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan.*

Table 2 provides examples of capital projects originally planned for 2021 that have been deferred to subsequent years.

Table 2: Capital Projects Deferred from 2021 to Subsequent Years	
Project	**Description**
St. John's Teleprotection System Replacement	Newfoundland Power's existing teleprotection system used to monitor and protect the St. John's 66 kV transmission line network is 20 years old and at the end of its useful life. The replacement of this system was originally planned for 2021. This project has been deferred to 2022 to allow further study of system protection requirements following the commissioning of the Muskrat Falls project.
Transmission Line 95L Rebuild	The rebuilding of Transmission Line 95L was scheduled for 2021. This transmission line traverses the southern Avalon Peninsula from Riverhead to Trepassey. An engineering review completed in 2020 determined the estimated capital cost to rebuild this line was significantly higher than previous estimates. The high cost is due to environmental restrictions associated with construction activities in the Avalon Wilderness Reserve. This project has been deferred to 2022 to permit a further assessment of alternatives for rebuilding this transmission line.
Transmission Line 105L Rebuild	The rebuilding of Transmission Line 105L was scheduled for 2021. This line was inspected in 2020 and, based on its condition, does not require rebuilding in 2021. This project has been deferred to 2026 and is no longer in the Company's current 5-year capital plan.

2.1.5 Observations

Newfoundland Power's capital planning process is based on sound engineering and is consistent with the Company's obligation to provide safe and reliable service to customers at least cost.

The deferral of capital projects is thoroughly considered at multiple points throughout the capital planning process. This is consistent with the Board's Guidelines and routinely results in the deferral of specific capital projects.

2.2 Capital Investment and Customer Service

2.2.1 Capital Investment in Context

Newfoundland Power's service territory is approximately 70,000 km^2. The Company owns and operates over 10,000 kilometres of distribution line, 2,000 kilometres of transmission line, 131 substations and 28 generating plants to serve customers throughout its service territory. On average, these assets have been in service for approximately 30 years.

The reliability experienced by customers reflects both: (i) the general condition of the electrical system; and (ii) the Company's operational response when customer outages occur.

Newfoundland Power's electrical system is constructed and maintained to meet national standards and local climatic conditions.[18] The Company deploys a skilled workforce throughout its service territory to respond to equipment failures and customer outages, including Powerline Technicians, Technologists and Professional Engineers. Annual capital investments are necessary to maintain both electrical system condition and the Company's operational response capabilities.

The most recent independent review of Newfoundland Power's engineered operations was conducted by The Liberty Consulting Group ("Liberty") in 2014. Liberty found that:

> *"Newfoundland Power's planning and design of its system, its asset management practices, its system operations, its outage management and emergency practices and its customer communications processes all conform to good utility practices."*[19]

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[18] The primary engineering standard for distribution and transmission systems is Canadian Standards Association ("CSA") standard *C22.3 No.1-15 Overhead Systems*.

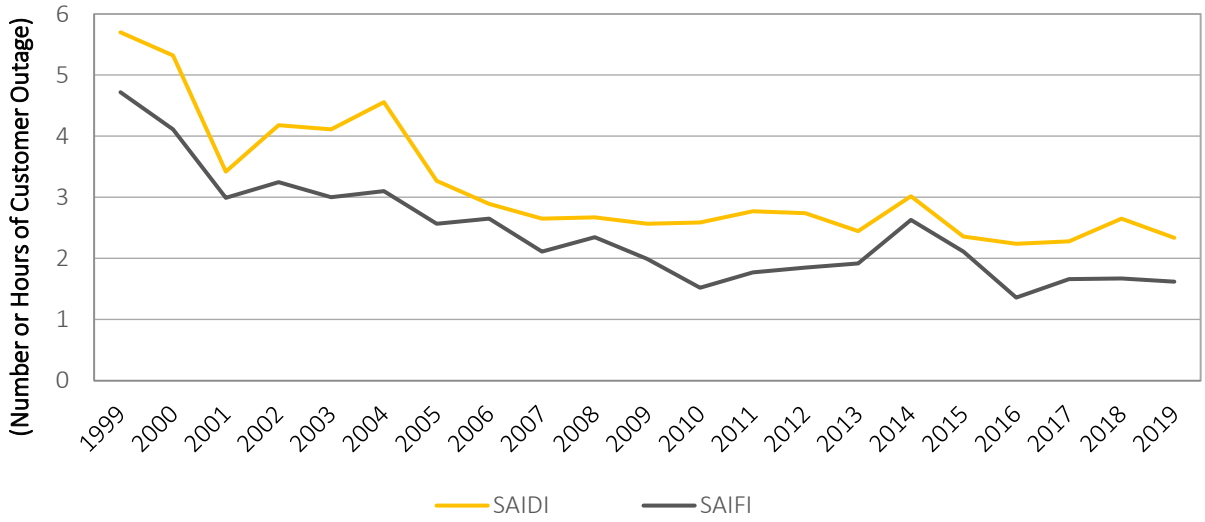
[19] Liberty, *Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power Inc.*, December 17, 2014, page ES-1.

"Its transmission and distribution systems operate effectively in ensuring adequate service reliability. Effective maintenance and capital programs, that appropriately recognize the age of its assets, have contributed materially to improved reliability." [20]

2.2.2 Customer Service Outcomes

Figure 1 shows the duration ("SAIDI") and frequency ("SAIFI") of outages to Newfoundland Power's customers over the period 1999 to 2019 under normal operating conditions.[21]

Figure 1
Duration and Frequency of Customer Outages
(1999 to 2019)



Over the 10-year period 1999 to 2009, the duration of customer outages was reduced by approximately 55%.[22] The frequency of customer outages was reduced by approximately 58% over the same period.[23]

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[20] Ibid., page ES-2.

[21] Newfoundland Power calculates its SAIDI ("System Average Interruption Duration Index") and SAIFI ("System Average Interruption Frequency Index") in accordance with Canadian Electricity Association ("CEA") Guidelines. SAIDI is calculated by dividing the total number of customer outage minutes by the total number of customers served. SAIFI is calculated by dividing the total number of customer interruptions by the total number of customers served. The data shown in Figure 1 does not include customer outages due to significant events or loss of supply from Newfoundland and Labrador Hydro.

[22] Newfoundland Power's SAIDI was 5.70 in 1999 and 2.57 in 2009 ((5.70 – 2.57) / 5.70 = 0.55, or 55%).

[23] Newfoundland Power's SAIFI was 4.72 in 1999 and 1.99 in 2009 ((4.72 – 1.99) / 4.72 = 0.58, or 58%).

The duration and frequency of customer outages has remained reasonably consistent since 2009. The duration of customer outages has ranged from approximately 2.2 to 3.0 hours per year under normal operating conditions. The frequency of customer outages has ranged from approximately 1.4 to 2.6 outages per year.

Current levels of service reliability have been viewed as acceptable by Newfoundland Power for about a decade.[24]

2.2.3 Observations

Newfoundland Power's engineered operations are consistent with good utility practice.

The Company's capital investments and operational response have improved the service reliability experienced by customers. The Company has focused on maintaining current levels of service reliability for customers over the last decade.

2.3 Capital Investment and Customer Costs

2.3.1 General

In February 2020, the Board directed that the *2021 Capital Budget Application* should include information on the revenue requirement impact of proposed capital projects.

Revenue requirement is the aggregate amount of forecast revenue required by a utility in a year to cover its cost of serving customers, including operating costs, taxes and allowed return on rate base.[25] The forecast revenue requirement is the primary determinant of customer rates.

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[24] In Newfoundland Power's *2010 General Rate Application*, the Company stated it considered then current levels of service reliability to be satisfactory (see Volume 1 (1st Revision), Section 2: Customer Operations, Page 2-8, Line 6). Similarly, the Company has characterized its electrical system performance as reliable in its *2013/2014 General Rate Application* (see Volume 1, Section 1: Introduction, Page 1-3, Line 10), its *2016/2017 General Rate Application* (see Volume 1 (1st Revision), Section 1: Introduction, Page 1-3, Line 11), and its *2019/2020 General Rate Application* (see Volume 1, Section 1: Introduction, Page 1-3, Line 21).

[25] See Order No. P.U. 7 (2002-2003), page 31.

Customers' rates also reflect the Company's customer, energy and demand forecasts and Board-approved rate structures.[26]

Newfoundland Power's revenue requirements and customer rates are interrogated by the Board on a triennial basis in the context of general rate applications ("GRA").

The Board has previously recognized the complex relationship between capital investments, revenue requirements and customer rates. In Order No. P.U. 40 (2005), the Board stated:

> *"NP undertakes a capital program and incurs capital expenditures each year and these expenditures impact the revenue requirement in other ways, in addition to depreciation. The portion of capital expenditures incurred for example as a result of customer growth will be offset somewhat by higher revenues from increased energy sales. Other capital expenditures may impact maintenance expenses…these expenses are properly dealt with in the context of a general rate application."* [27]

The Board has also stated that:

> *"From a regulatory perspective, efficient operations, fully justified capital expenditures and a low cost capital structure all combine to minimize revenue requirement, and hence provide least cost electricity to ratepayers."* [28]

Newfoundland Power shares the Board's view that fully justified capital expenditures are part and parcel of delivering least-cost service to customers.

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[26] See Order No. P.U. 40 (2005), page 13.
[27] Customer rates are stated in unit costs. For example, energy charges are priced on a ¢/kWh basis.
[28] See Order No. P.U. 7 (2002-2003), page 31.

2.3.2 Revenue Requirement Perspective

On a *pro forma* basis, the Company's 2021 revenue requirement is estimated to increase by approximately $3 million as a result of the capital projects proposed for 2021. This *pro forma* estimate includes increases in depreciation, return on rate base and income tax, as well as reduced operating costs as a result of the *LED Street Lighting Replacement Plan*.[29]

The *pro forma* estimate is, however, practically limited. It does not include potentially higher revenues from customer growth projects, or the long-term effect that fully justified capital expenditures have on minimizing aggregate costs and thus revenue requirements.[30]

To illustrate these practical limitations, Newfoundland Power assessed its revenue requirements and capital investments since its 2013/2014 GRA.

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[29] The proposed *LED Street Lighting Replacement Plan* is forecast to reduce operating costs in 2021 by approximately $2 million on a *pro forma* basis. See the *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan,* Attachment B, page B-5.

[30] For example, the systematic replacement of deteriorated plant (i.e. during regular work hours) tends to reduce the cost of making emergency repairs due to equipment failures (i.e. during overtime hours). Other capital expenditures enable efficiencies through technology. These effects will also tend to decrease future revenue requirements.

Table 3 shows Newfoundland Power's actual and inflation-adjusted contribution to revenue requirement in 2014 and 2020.[31]

Table 3: Newfoundland Power Contribution to Revenue Requirement ($millions)			
	2014	2020	Change
Actual	212.9[32]	226.5[33]	6%
Inflation-Adjusted[34]	226.9	226.5	0%

Since 2014, Newfoundland Power's contribution to revenue requirement has increased by approximately 6%. On an inflation-adjusted basis, the Company's contribution to revenue requirement has effectively remained flat.

While Newfoundland Power's contribution to revenue requirement has effectively remained flat, the Company's annual capital investments have averaged approximately $100 million/year over this period.

2.3.3 Customer Rates Perspective

To more broadly assess the long-term impact of Newfoundland Power's operations on customer costs, the Company analyzed its contribution to customer rates over the last 2 decades.

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[31] Based on the Company's test year revenue requirements, excluding purchased power costs. Purchased power costs from Newfoundland and Labrador Hydro account for approximately 70% of the Company's overall revenue requirement.

[32] Newfoundland Power's 2014 revenue requirement was $612.1 million. Excluding purchased power costs of $399.2 million, it was $212.9 million. See the Company's application filed in compliance with Order No. P.U. 13 (2013), Schedule 1, Appendix E, page 2.

[33] Newfoundland Power's 2020 revenue requirement was $673.8 million. Excluding purchased power costs of $447.3 million, it was $226.5 million. See the Company's 2019/2020 GRA, Exhibit 7 (Revised), page 2.

[34] Inflation adjusted based on the GDP Deflator for Canada.

Table 4 compares Newfoundland Power's total contribution to average customer rates in ¢/kWh in 2000 and 2020.

Table 4: Newfoundland Power Contribution to Customer Rates (¢/kWh)			
	2000	2020	Change
Actual	3.53	4.14	17%
Inflation-Adjusted[35]	5.18	4.14	-20%

Newfoundland Power's contribution to average customer rates has increased by approximately 17% over the last 2 decades. On an inflation-adjusted basis, the Company's contribution to average customer rates decreased by 20%.

2.3.4 Observations

The relationship between Newfoundland Power's capital expenditures and its revenue requirements or customer rates is not a direct one.

The Company's revenue requirements have remained relatively stable over the past 6 years. Customer rates have not changed as a result of a Newfoundland Power GRA since July 1, 2016.[36] Over the longer term, the Company's contribution to average customer rates decreased by 20% on an inflation-adjusted basis.

Newfoundland Power's approach to capital planning tends to minimize overall costs to customers over the longer term. This is consistent with the least-cost delivery of reliable service to customers.

[35] Inflation adjusted based on the GDP Deflator for Canada.

[36] On July 1, 2016, customer rates increased by 1.2% as a result of Newfoundland Power's 2016/2017 GRA. Customer rates did not change as a result of its 2019/2020 GRA.

2.4 Atlantic Canada Comparison: Capital Investment and Service Outcomes

2.4.1 Comparison

The 4 primary distributors of electricity in Atlantic Canada are: (i) Newfoundland Power; (ii) Nova Scotia Power; (iii) NB Power; and (iv) Maritime Electric. Each of these utilities serves customers in mix of urban and rural areas.[37]

Newfoundland Power compared its capital investment and service outcomes to the other 3 Atlantic Canadian utilities over the 10-year period 2009 to 2018.

Table 5 shows: (i) the capital investment of Newfoundland Power in transmission and distribution ("T&D") assets; (ii) the average investment of the other 3 Atlantic Canadian utilities over the period 2009 to 2018; and (iii) the cumulative rate of growth in T&D capital investment.[38]

Table 5:
Capital Investment
Property Plant and Equipment – T&D
(millions)

Utility	2009	2018	Growth
Newfoundland Power	$953	$1,365	43%
Average of Other Atlantic Canadian Utilities[39]	$1,092	$1,665	53%

Newfoundland Power's investment in T&D assets has increased at a rate 10% less than the average of other Atlantic Canadian utilities over the 10-year period ending 2018. The Company's

[37] NB Power, Nova Scotia Power, Maritime Electric, and Newfoundland Power are all members of the CEA and are considered Region 2 utilities. Region 2 utilities are those that serve a mix of urban and rural areas.

[38] Table 1 reflects the average Property, Plant and Equipment in T&D assets of NB Power, Nova Scotia Power and Maritime Electric over the period 2009 to 2018. Property, Plant and Equipment is the gross cost of utility assets determined in accordance with generally accepted accounting principles. This information is based on the audited and publicly available financial statements of each utility.

[39] The aggregate investment of NB Power, Nova Scotia Power and Maritime Electric was $3,275 million in 2009 ($3,275 million / 3 = $1,092 million) and $4,996 million in 2018 ($4,996 million / 3 = $1,665 million).

capital investment in T&D assets has, in fact, increased at the lowest rate of any Atlantic Canadian utility.[40] At the same time, Newfoundland Power experienced the highest rate of growth in customers served of these utilities.[41]

Table 6 compares the duration of outages experienced by Newfoundland Power's customers to the average of other Atlantic Canadian utilities over the period 2009 to 2018.[42]

Table 6:
Atlantic Canadian Utilities
Annual Duration of Customer Outage
(2009-2018)

Utility	Average SAIDI
Newfoundland Power	2.49
Other Atlantic Canadian Utilities	4.76

Over the 10-year period ending 2018, Newfoundland Power's customers have experienced approximately ½ the duration of customer outages in comparison to customers of other Atlantic Canadian utilities.[43]

2.4.2 Observations

The Company's capital investments have increased at the lowest rate of any Atlantic Canadian utility over the 2009 to 2018 period. At the same time, Newfoundland Power's customers have experienced better-than-average reliability compared to the remainder of Atlantic Canada.

Newfoundland Power's capital investments appear reasonable in comparison to other Atlantic Canadian utilities.

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[40] Over the period 2009 to 2018, increases in Property, Plant and Equipment (T&D) range from 51% to 57% for the other Atlantic Canadian utilities.

[41] Over the period 2009 to 2018, the total number of residential and commercial customers served by Newfoundland Power increased by approximately 12%. This compares to customer growth of between 2% and 6% for other Atlantic Canadian utilities, as shown in annual CEA filings.

[42] Table 2 does not include customer outages due to significant events or loss of supply.

[43] 2.49 / 4.76 = 0.52, or 52%. The average SAIDI for the other Atlantic Canadian utilities ranged from 4.1 to 5.3 over this period which, in all cases, is higher than that of Newfoundland Power.

3.0 2021 Capital Budget

3.1 2021 Planning Updates

3.1.1 Overview

Newfoundland Power's *2021 Capital Budget Application* includes 3 new plans to guide certain capital projects: (i) the *LED Street Lighting Replacement Plan*; (ii) the *Customer Service Continuity Plan*; and (iii) the *St. John's North – Portugal Cove System Planning Study*. Each of these plans is consistent with good utility practice.

3.1.2 LED Street Lighting Replacement Plan

Newfoundland Power received approval to introduce LED street lighting as a new service option for customers in Order No. P.U. 2 (2019).[44] In comparison to existing High Pressure Sodium street lights, LED street lights provide lower rates and a more reliable lighting service for customers.

The *LED Street Lighting Replacement Plan* will facilitate the replacement of all existing High Pressure Sodium fixtures with LED fixtures within 6 years. In the absence of this plan, customers would continue to pay the higher rates of High Pressure Sodium street lights for over 30 years.

The total cost of the plan is approximately $32.8 million over 6 years. This includes approximately $5.5 million in 2021.

An economic analysis determined the *LED Street Lighting Replacement Plan* will reduce overall costs to customers over the next 20 years. The plan is consistent with industry best practices and has received the support of the largest municipal organization in the province, Municipalities Newfoundland and Labrador.

[44] Order No. P.U. 2 (2019) was issued following Newfoundland Power's *2019/2020 General Rate Application*.

3.1.3 Customer Service Continuity Plan

The *Customer Service Continuity Plan* is the result of multiple years of assessing and planning for replacement of Newfoundland Power's Customer Service System.

Newfoundland Power's Customer Service System was implemented in 1993 with an expected service life of 20 years. The Company intends to replace the system by 2023 following 30 years of operation.

The need to replace the system was identified through a third-party risk assessment and an evaluation of all potential alternatives. The evaluation determined that implementation of a modern Customer Information System is the only viable alternative to provide continuity in Newfoundland Power's customer service delivery.

The *Customer Service Continuity Plan* outlines a 3-year project to implement a modern Customer Information System. The plan is based on detailed assessments of Newfoundland Power's operations and industry best practices.

The total project cost is approximately $31.6 million, including $9.9 million in 2021.

3.1.4 St. John's North - Portugal Cove System Planning Study

The St. John's North - Portugal Cove area has experienced load growth due to the recent expansion of St. John's International Airport and ongoing residential and commercial development.

This load growth has resulted in overload conditions on power transformers serving customers at the Broad Cove, Ridge Road and Virginia Waters substations. Growth in the area is expected to continue and create additional overload conditions. Overload conditions can result in unsafe operation of the electrical system and outages to customers.

The *St. John's North – Portugal Cove System Planning Study* identifies the least-cost alternative to meet the electrical system demands of customers in the area. The least-cost alternative involves constructing a new substation near the St. John's International Airport. The project includes the construction of 2 new transmission line extensions, fibre optic upgrades, distribution feeder upgrades, and the construction of feeder exits from the new substation.

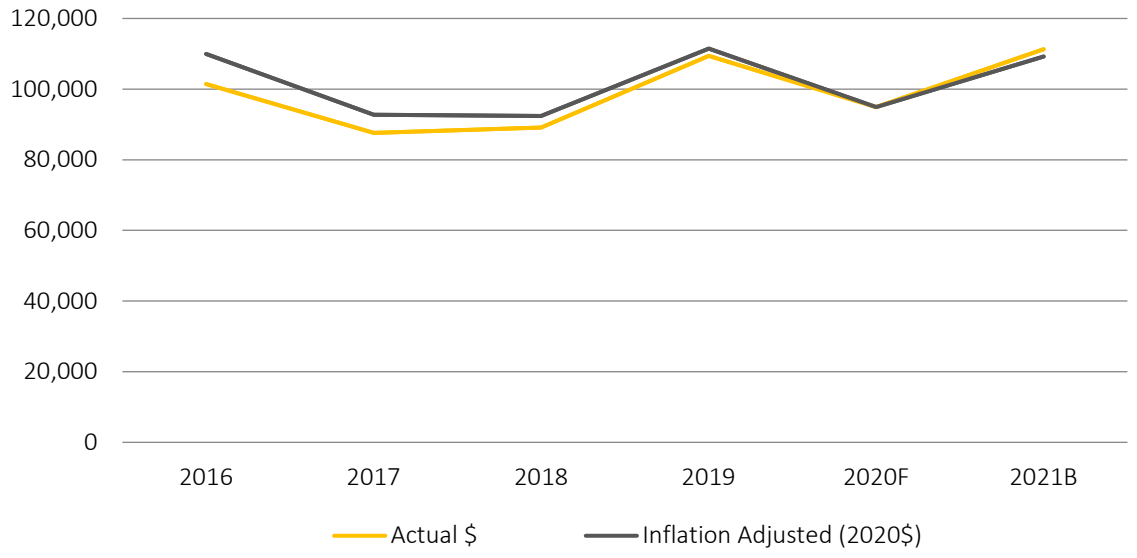
The total cost of the project is approximately $6.8 million in 2021.

3.2 2021 Budget Overall

Newfoundland Power's *2021 Capital Budget Application* proposes 40 projects totaling approximately $111 million.

Figure 2 compares Newfoundland Power's proposed 2021 Capital Budget to capital expenditures over the most recent 5-year period, including the 2020 forecast.

Figure 2:
Capital Expenditures 2016 to 2021
($000s)



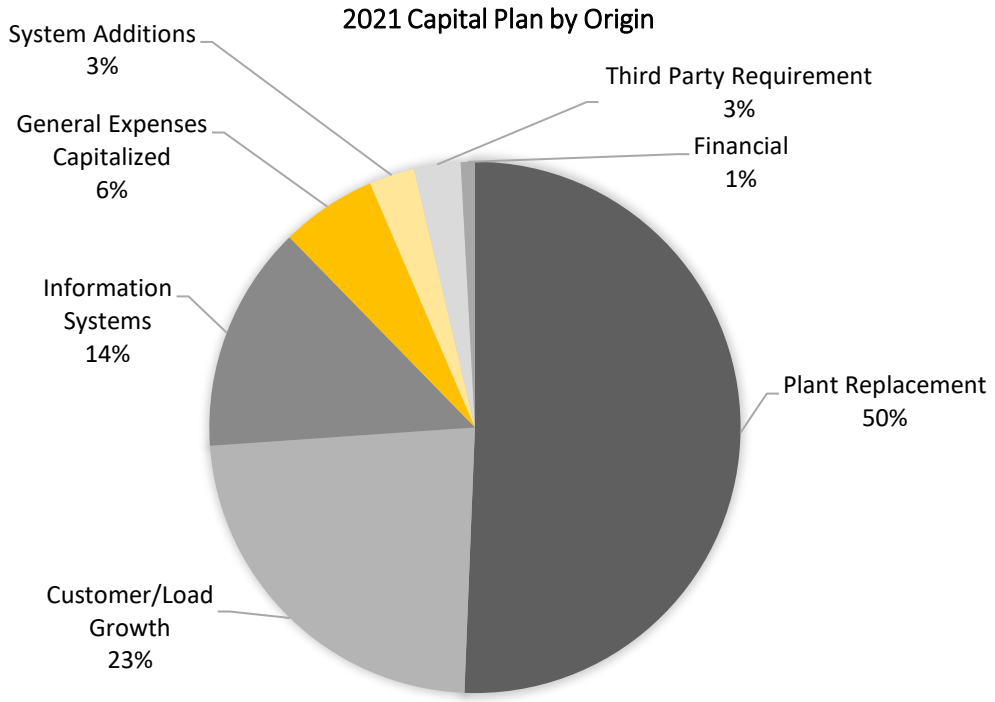
Newfoundland Power's proposed 2021 Capital Budget of $111 million is reasonably consistent with expenditures over the last 5 years on an inflation-adjusted basis. Capital expenditures totaled approximately $110 million in 2016 when adjusted for inflation.[45]

3.3 2021 Budget by Origin

Newfoundland Power's capital expenditures are primarily driven by the replacement of aging infrastructure and its obligation to serve new customers and respond to system load growth.

Figure 3 shows the Company's 2021 Capital Budget by origin, or root cause.

Figure 3:
2021 Capital Plan by Origin



[45] Historical capital expenditures are inflation-adjusted using the GDP Deflator for Canada for non-labour expenditures and its bargaining unit contracts for labour expenditures. In Order No. P.U. 36 (1998-99), the Board ordered the adoption of the GDP Deflator for Canada as an appropriate inflation index for forecasting Newfoundland Power's non-labour expenses.

Approximately 50% of proposed 2021 expenditures are driven by the replacement of existing plant. These expenditures are required to maintain the condition of the electrical system and provide reliable service to customers.

Approximately 23% of proposed 2021 expenditures are driven by connecting new customers and responding to system load growth. These expenditures are required to provide customers with equitable access to an adequate supply of power.

The remaining expenditures proposed for 2021 relate to Information Systems, System Additions, General Expenses Capitalized ("GEC"), Third Party Requirements, and Financial costs associated with the proposed investments.[46]

[46] Financial costs include the Allowance for Funds Used During Construction ("AFUDC") and the Unforeseen Allowance.

3.4 2021 Budget by Asset Class

3.4.1 Overview

Table 7 provides the 2021 Capital Budget by asset class.

Table 7: 2021 Capital Budget by Asset Class ($000s)		
Asset Class	**Budget**	**Percentage**
Distribution	$45,875	41%
Substations	14,280	13%
Information Systems	15,362	14%
Generation	11,510	10%
Transmission	9,751	9%
Transportation	4,032	4%
General Property	2,776	2%
Telecommunications	462	0%
Allowance for Unforeseen	750	1%
General Expenses Capitalized	6,500	6%
Total	**$111,298**	**100%**

3.4.2 Distribution

Distribution expenditures account for the greatest percentage of the 2021 Capital Budget, at approximately $45.9 million or 41% of the total budget.

The Company operates approximately 10,000 kilometres of distribution line serving approximately 269,000 customers. Distribution capital expenditures are primarily driven by: (i) preventative and corrective maintenance on aged and deteriorated distribution structures; and (ii) the need to serve new customers and address system load growth.

Distribution expenditures in 2021 include the 1st year of the *LED Street Lighting Replacement Plan*.

3.4.3 Substations

Substations expenditures total approximately $14.3 million in 2021, or 13% of the budget.

The Company operates 131 substations containing approximately 4,000 pieces of critical electrical equipment. Substations expenditures are primarily driven by: (i) the maintenance and refurbishment of substation assets; and (ii) system load growth.

Substations expenditures in 2021 include the construction of the new Airport Substation, refurbishment of the Dunville and Rattling Brook substations, and the mandatory phase-out of substation equipment with PCBs.[47]

3.4.4 Information Systems

Information Systems expenditures total approximately $15.4 million in 2021, or 14% of the budget.

Information Systems expenditures are driven by: (i) the replacement of shared server and network infrastructure, personal computers and peripheral equipment; (ii) upgrades to existing applications, which are primarily driven by third-party vendors; and (iii) enhancements to existing applications to provide improved performance or functionality.

Information Systems expenditures in 2021 include the 1st year of a multi-year project to replace the Company's Customer Service System.

[47] The construction of the new Airport Substation includes 4 items that are clustered: (i) the *Feeder Additions for Growth* Distribution project; (ii) the *Additions Due to Load Growth* Substations project; (iii) the *Transmission Line Extensions-35L* Transmission project; and (iv) the *Fibre Optic Cable Builds* Telecommunications project. The refurbishment of Dunville Substation is clustered with a project to install a new power transformer to address customer and load growth. The refurbishment of Rattling Brook Substation to include a 138 kV extension is clustered with the transmission project to extend transmission line 136L. The phase-out of substation equipment with polychlorinated biphenyls ("PCBs") is required by Government of Canada regulations.

3.4.5 Generation

Generation expenditures total approximately $11.5 million in 2021, or 10% of the budget.

Newfoundland Power operates 23 hydroelectric plants, 4 gas turbines and 2 diesel plants. These assets operate to provide a reliable supply of electricity to customers at least cost. Generation expenditures are primarily driven by: (i) preventative and corrective maintenance on aged and deteriorated assets; and (ii) specific capital projects, such as plant refurbishments.

Approximately $9.3 million of Generation expenditures in 2021 are driven by the Topsail Hydro Plant Refurbishment.[48]

3.4.6 Transmission

Transmission expenditures total approximately $9.8 million in 2021, or 9% of the budget.

The Company operates approximately 2,000 kilometres of transmission lines. Transmission lines are the backbone of the electrical system serving customers. Transmission expenditures are primarily driven by: (i) rebuilding aging and deteriorated transmission lines; and (ii) preventive capital maintenance of transmission line structures.

[48] The Topsail Hydro Plant Refurbishment was approved in Order No. P.U. 5 (2020) to replace the penstock at the Company's Topsail hydroelectric development on the Avalon Peninsula. Approximately $8.9 million is included in 2021 to install the new penstock. The Company is also proposing to replace the intake gate ($220,000) and refurbish the turbine runner ($240,000) in 2021. See the *2021 Capital Budget Application, Volume 2, Report 1.2 Topsail Hydro Plant Refurbishment.*

In 2021, the Company will rebuild 1 transmission line, 124L in Central Newfoundland,[49] and extend 2 existing transmission lines. The transmission lines to be extended are 136L into Rattling Brook Substation[50] and 35L to the new substation near St. John's International Airport. The remaining 13% of proposed 2021 capital expenditures relate to Transportation,[51] General Property,[52] Telecommunications,[53] the Allowance for Unforeseen and GEC.

4.0 Five-Year Capital Plan: 2021-2025

4.1 Planned Expenditures Overall

Newfoundland Power's capital planning process is a deliberate effort to balance customer requirements, reliability, productivity, safety and environmental concerns with prudent capital investments. Prudent capital investments are necessary to meet the Company's obligation to provide safe and reliable service to customers at least cost.

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[49] Transmission Line 124L is a 138 kV H-Frame line running between Gambo Substation and Clarenville Substation. The line was originally constructed in 1964 and is approximately 86 kilometres in length. In 2021, the Company plans to rebuild 30 kilometres of the line to address deteriorated poles and ball link eye bolts. See the *2021 Capital Budget Application, Volume 2, Report 3.1 2021 Transmission Line Rebuild.*

[50] The *Central Newfoundland System Planning Study* was filed with the Company's *2019 Capital Budget Application*. The study determined the least-cost alternative to address the deteriorating condition of transmission lines 101L and 102L involves extending the 138 kV transmission system into Lewisporte Substation and Rattling Brook Substation. In 2021, Transmission Line 136L will be extended to connect Rattling Brook Substation to the 138 kV transmission system.

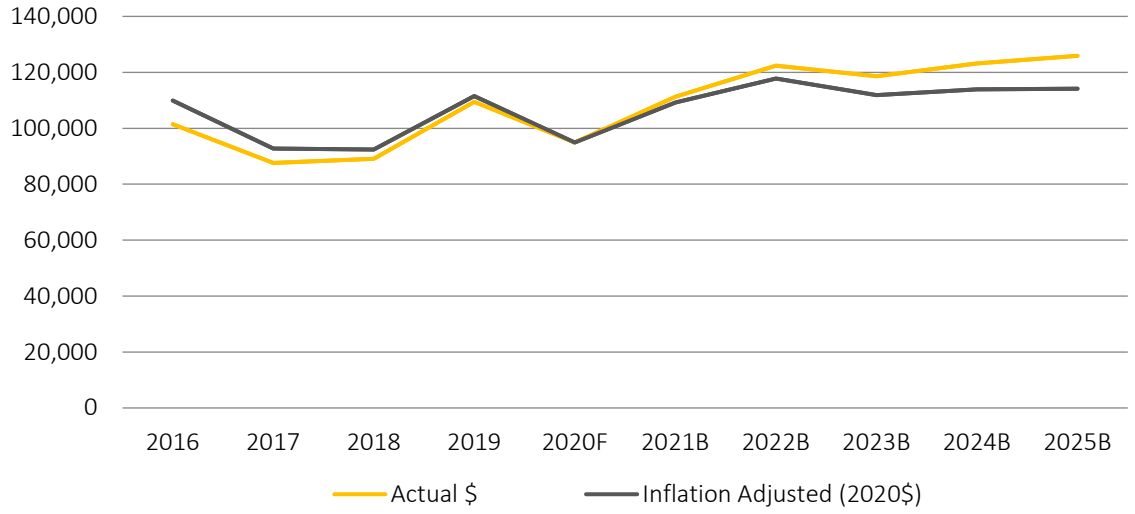
[51] The Transportation asset class includes heavy fleet, passenger and off-road vehicles. The replacement of these vehicles can be influenced by a number of factors, including kilometres traveled, vehicle condition, and operating experience and maintenance expenditures. The Company's replacement criteria for vehicles are described in *Report 5.1 Vehicle Replacement Criteria* filed as part of its *2016 Capital Budget Application*.

[52] The General Property asset class includes capital expenditures for: (i) the addition or replacement of tools and equipment utilized by line and engineering staff; (ii) the replacement or addition of office furniture and equipment; (iii) additions to real property necessary to maintain buildings and facilities; and (iv) the refurbishment of Company buildings and related security infrastructure.

[53] The Telecommunications asset class includes the replacement or upgrading of various telecommunications systems. These systems contribute to customer service, safety, and power system reliability by supporting communications between the Company's fleet of vehicles, substations, plants and offices.

Figure 4 shows Newfoundland Power's capital expenditures over the period 2016 to 2025 on an actual and inflation-adjusted basis.

Figure 4:
Capital Expenditures 2016 to 2025B
($000s)



Capital expenditures are forecast to average approximately $120.3 million annually over the period 2021 to 2025. This compares to approximately $96.5 million annually over the previous 5-year period, or $100.3 million annually on an inflation adjusted basis.

The forecast increase in annual expenditures is primarily attributable to implementation of the *LED Street Lighting Replacement Plan* and the *Customer Service Continuity Plan.* The *LED Street Lighting Replacement Plan* accounts for approximately $5.5 million in capital expenditures annually throughout the 5-year period. The *Customer Service Continuity Plan* accounts for approximately $10.5 million annually over the first 3 years of the 5-year period.

4.2 Planned Expenditures by Origin

The replacement of existing plant and the requirement to serve new customers and address system load growth will continue to be the largest drivers of Newfoundland Power's capital expenditures over the next 5 years.

Table 8 compares forecast capital expenditures over the next 5 years to the most recent 5-year period.

Table 8:
Capital Plan Comparison

	2016 - 2020	2021 - 2025	Change
Plant Replacement	55%	58%	3%
Customer/Load Growth	25%	21%	-4%
Information Systems	7%	11%	4%
System Additions	4%	1%	-3%
General Expenses Capitalized	5%	5%	0%
Third Party Requirement	3%	3%	0%
Financial	1%	1%	0%
Total	**100%**	**100%**	**-**

The drivers of capital expenditures under the *Five-Year Capital Plan: 2021-2025* are consistent with recent experience. Over ½ of forecast capital expenditures over next 5 years are driven by the replacement of existing plant. This is consistent with the most recent 5-year period.

Other changes in forecast expenditures relate to: (i) Information Systems expenditures, which are driven by the *Customer Service Continuity Plan*; (ii) a forecast reduction in expenditures required to connect new customer and address system load growth; and (iii) a forecast reduction in system additions attributed to the purchase of a new mobile gas turbine in 2018 and 2019.

4.3 Planned Expenditures by Asset Class

4.3.1 Overview

Table 9 provides the *Five-Year Capital Plan: 2021-2025* annually by asset class.

Table 9:
5-Year Capital Plan by Asset Class
($000s)

Asset Class	2021	2022	2023	2024	2025
Distribution	$45,875	$49,039	$51,049	$50,248	$51,175
Substations	14,280	15,526	15,830	15,868	18,881
Transmission	9,751	12,053	14,255	14,743	14,913
Generation	11,510	9,075	8,692	17,124	19,110
Information Systems	15,362	20,469	11,294	9,945	7,480
Transportation	4,032	4,108	4,185	4,262	4,341
General Property	2,776	3,300	3,898	3,257	2,198
Telecommunications	462	1,614	2,194	482	550
Allowance for Unforeseen	750	750	750	750	750
GEC	6,500	6,500	6,500	6,500	6,500
Total	**$111,298**	**$122,434**	**$118,647**	**$123,179**	**$125,898**

Capital expenditures are forecast to remain reasonably stable in the majority of asset classes over the next 5 years. The highest degree of variability is observed in the Information Systems, Generation and Telecommunication asset classes. In each case, this variability is attributable to large-scale, one-time capital projects, as described below under each of these asset classes.

Table 10 provides total planned capital expenditures by asset class for the period 2021 to 2025.

Table 10: 5-Year Capital Plan Percentage of Expenditures by Asset Class ($000s)		
Asset Class	**2021-2025**	**Percentage of Total**
Distribution	$247,386	41%
Substations	80,385	13%
Transmission	65,715	11%
Generation	65,511	11%
Information Systems	64,550	11%
Transportation	20,928	3%
General Property	15,429	3%
Telecommunications	5,302	1%
Allowance for Unforeseen	3,750	1%
GEC	32,500	5%
Total	**$601,456**	**100%**

The Distribution asset class is expected to continue as the largest driver of capital expenditures over the next 5 years. Approximately 41% of planned capital expenditures over the next 5 years relate to Distribution assets.

Tables 5 through 13 provide actual, forecast and budget expenditures by asset class over the period 2020 to 2025.

4.3.2 Distribution

Table 11 provides Distribution capital expenditures over the period 2016 to 2025.

Table 11: Distribution Capital Expenditures ($000s)					
Actual/Forecast					Average
2016	2017	2018	2019	2020F	2016-2020
45,072	45,879	42,333	46,801	42,949	44,607
Budget					Average
2021B	2022B	2023B	2024B	2025B	2021-2025
45,875	49,039	51,049	50,248	51,175	49,477

Distribution capital expenditures are forecast to average approximately $49.5 million annually over the period 2021 to 2025. This compares to an average of approximately $44.6 million annually over the previous 5-year period.

Increased Distribution expenditures are primarily attributable to the *LED Street Lighting Replacement Plan*, with expenditures averaging approximately $5.5 million annually over the period.

Other expenditures are forecast to remain reasonably stable.

Expenditures related to Newfoundland Power's capital maintenance programs for its distribution assets are forecast to remain reasonably stable. Both the Rebuild Distribution Lines[54] and

[54] The Company's inspection and maintenance practices are principally designed to extend the lives of the existing assets. The Company plans to perform preventive capital maintenance on approximately 43 distribution feeders per year over the planning period.

Reconstruction[55] capital projects are planned to continue at a combined average cost of approximately $5.8 million annually. Expenditures related to the *Distribution Reliability Initiative* are also expected to remain stable, averaging approximately $1.1 million annually.[56]

Table 12 provides the forecast number of new customer connections and the total capital expenditures associated with those connections over the next 5 years.[57]

Table 12:
Forecast New Customer Connections
(2021-2025)

	2021	2022	2023	2024	2025
New Customer Connections	2,389	2,392	2,376	2,358	2,261
Average Cost/Connection	$7,635	$7,755	$7,892	$8,046	$8,269
Capital Expenditure (000s)	$18,240	$18,550	$18,752	$18,972	$18,697

Over the period 2021 to 2025, capital expenditures for new customer connections are forecast to be within the range of $18.2 million to $19.0 million annually.

While customer connections are forecast to decline, additional expenditures are forecast to address load growth in certain areas. Examples include load growth in Corner Brook associated with the new hospital, load growth in Stephenville associated with a salmon hatchery and the electrification of heating systems in provincial buildings. Forecast Distribution expenditures over

55 The Distribution Reconstruction project involves the replacement of deteriorated or damaged distribution structures and electrical equipment. The project is comprised of small unplanned projects and is estimated using the historical average of the most recent 5-year period.

56 Each year, Newfoundland Power assesses and ranks the reliability performance of over 300 distribution feeders and completes targeted capital investments, when appropriate, as part of the Distribution Reliability Initiative. See the *2021 Capital Budget Application, Volume 2, Report 4.1 Distribution Reliability Initiative.*

57 Costs to connect new customers to the electricity system are included in the Extensions, Transformers, Services, Meters and Street Lighting distribution projects.

the next 5 years include approximately $3.7 million to respond to load growth driven by provincial electrification efforts.[58]

4.3.3 Substations

Table 13 provides Substations expenditures over the period 2016 to 2025.

Table 13: Substation Capital Expenditures ($000s)					
Actual/Forecast					Average
2016	2017	2018	2019	2020F	2016-2020
15,152	15,477	12,662	17,133	15,204	15,126
Budget					Average
2021B	2022B	2023B	2024B	2025B	2021-2025
14,280	15,526	15,830	15,868	18,881	16,077

Substations expenditures are forecast to average approximately $16.1 million annually over the period 2021 to 2025. This compares to an average of approximately $15.1 million annually over the previous 5-year period.

Substations expenditures over the planning period continue to be driven by the *Substation Strategic Plan,* as filed with the Company's *2007 Capital Budget Application*. Forecast expenditures over the next 5 years include the refurbishment and modernization of 16 substations, including Gander Bay Substation in 2024 and Goulds Substation in 2025.[59] Further engineering assessments of these substations will be completed prior to the proposal of specific capital projects.

[58] For more information on electrification program planning, see Section 4.4 of the plan.

[59] The *Five-Year Capital Plan: 2021-2025* currently includes refurbishment and modernization of the Dunville, Rattling Brook, Broad Cove, Glovertown, Humber, Laurentian, Memorial University, Mobile, Tors Cove, Walbournes, Gander Bay, Grand Falls, Harmon, Goulds, Molloys Lane, and Morris Plant Substations.

Two new substations are forecast to be constructed over the 2021 to 2025 period: (i) the new Airport Substation in 2021 will address system overload conditions in the St. John's North - Portugal Cove area; and (ii) a second new substation in 2025 is planned to serve customer and system load growth in the Galway development.

In total, 4 new substation transformers are forecast to be required over the 2021 to 2025 period.[60] Two transformers are forecast to be required for the new Airport and Galway substations. Two additional substation transformers are forecast to be required for Dunville to accommodate load growth and Corner Brook to accommodate a voltage conversion.[61]

4.3.4 Generation

Table 14 provides Generation capital expenditures for the period 2016 to 2025.

Table 14:
Generation Capital Expenditures
($000s)

Actual/Forecast					Average
2016	2017	2018	2019	2020F	2016-2020
18,512	6,402	8,934	11,904	7,198	10,590
Budget					**Average**
2021B	2022B	2023B	2024B	2025B	2021-2025
11,510	9,075	8,692	17,124	19,110	13,102

[60] By comparison, in the period 2016 through 2020, Newfoundland Power has purchased 4 new power transformers and relocated 2 power transformers to serve increased customer load. The purchase of new transformers and the relocation of other transformers to serve customer load growth are in addition to the requirement to replace aged or deteriorated equipment.

[61] The Company's annual capital budget applications will include engineering studies detailing the requirements for additional power transformers in the years in which they are required.

Generation capital expenditures are forecast to average approximately $13.1 million annually over the period 2021 to 2025. This compares to an average of approximately $10.6 million annually over the previous 5-year period.

The *Five-Year Capital Plan: 2021-2025* includes penstock replacements at the Topsail hydro plant in 2021 and the Sandy Brook hydro plant in 2022. It also includes the planned purchase of a 2nd mobile gas turbine to replace the existing Greenhill and Wesleyville gas turbines in 2024 and 2025.[62] All Generation projects involving plant refurbishment or upgrades are justified using marginal cost-based analysis.

4.3.5 Transmission

Table 15 provides Transmission capital expenditures for the period 2016 to 2025.

Table 15: Transmission Capital Expenditures ($000s)					
Actual/Forecast					Average
2016	2017	2018	2019	2020F	2016-2020
4,661	6,224	7,806	11,865	9,623	8,036
Budget					Average
2021B	2022B	2023B	2024B	2025B	2021-2025
9,751	12,053	14,255	14,743	14,913	13,143

Transmission capital expenditures are forecast to average approximately $13.1 million annually over the period 2021 to 2025. This compares to an average of approximately $8.0 million annually over the previous 5-year period.

[62] See *Section 4.4 Risks to Planned Expenditures* for more information on the planned purchase of a 2nd mobile gas turbine.

Increased Transmission expenditures are driven by an increase in the kilometres of transmission line forecast to be rebuilt annually as part of the *Transmission Line Rebuild Strategy.*[63] As of 2020, execution of this strategy is approximately 76% complete.

Forecast Transmission expenditures also include implementation of the recommendations from the *St. John's North - Portugal Cove System Planning Study* and capital maintenance of transmission line structures.

4.3.6 Information Systems

Table 16 provides Information Systems capital expenditures for the period 2016 to 2025.

Table 16:
Information Systems Capital Expenditures
($000s)

Actual/Forecast					Average
2016	2017	2018	2019	2020F	2016-2020
7,856	4,314	6,620	7,456	6,772	6,604
Budget					**Average**
2021B	2022B	2023B	2024B	2025B	2021-2025
15,362	20,469	11,294	9,945	7,480	12,910

Information Systems capital expenditures are forecast to average approximately $12.9 million annually over the period 2021 to 2025. This compares to an average of approximately $6.6 million annually over the previous 5-year period.

[63] The lines remaining to be completed in the 2021 to 2025 period include 3 long 138 kV H-frame construction transmission lines. The extended line length for these rebuilds, and the 138 kV H-frame construction, are the primary drivers for the increase in transmission expenditures.

Increased Information Systems expenditures are primarily driven by the *Customer Service Continuity Plan* at a cost of approximately $31.6 million over 3 years starting in 2021. Expenditures also include upgrades to the Company's Geographic Information System and Outage Management System in 2024 and 2025.

4.3.7 General Property

Table 17 provides General Property capital expenditures for the period 2016 to 2025.

Table 17: General Property Capital Expenditures ($000s)					
Actual/Forecast					Average
2016	2017	2018	2019	2020F	2016-2020
2,491	1,456	2,722	3,548	2,467	2,537
Budget					Average
2021B	2022B	2023B	2024B	2025B	2021-2025
2,776	3,300	3,898	3,257	2,198	3,086

General Property capital expenditures are forecast to average approximately $3.1 million annually over the period 2021 to 2025. This compares to an average of approximately $2.5 million annually over the previous 5-year period.

General Property capital expenditures are driven by the need to address deterioration in Company-owned buildings throughout its service territory. Many of Newfoundland Power's area offices are over 25 years old and certain components require replacement. The increase in expenditures over the 2021 to 2025 period is attributable to refurbishments required in the Company's head office in St. John's and area offices in Clarenville and Gander.

4.3.8 Transportation

Table 18 provides Transportation capital expenditures for the period 2016 to 2025.

Table 18: Transportation Capital Expenditures ($000s)					
Actual/Forecast					Average
2016	2017	2018	2019	2020F	2016-2020
3,377	3,776	3,594	4,223	3,869	3,768
Budget					Average
2021B	2022B	2023B	2024B	2025B	2021-2025
4,032	4,108	4,185	4,262	4,341	4,186

Transportation capital expenditures are forecast to average approximately $4.2 million annually over the period 2021 to 2025. This compares to an average of approximately $3.8 million annually over the previous 5-year period.

The increase in Transportation capital expenditures from 2021 through 2025 is principally a reflection of inflation and the number of heavy fleet and passenger vehicles forecast to be replaced over the period.[64]

[64] The Company operates 71 heavy fleet vehicles, which have an anticipated service life of 10 years. On average, it would be expected that approximately 7 heavy fleet vehicles and 40 passenger and off-road vehicles would be replaced annually.

4.3.9 Telecommunications

Table 19 provides Telecommunications capital expenditures for the period 2016 to 2025.

Table 19: Telecommunications Capital Expenditures ($000s)					
Actual/Forecast					Average
2016	2017	2018	2019	2020F	2016-2020
331	112	325	312	108	238
Budget					Average
2021B	2022B	2023B	2024B	2025B	2021-2025
462	1,614	2,194	482	550	1,060

Telecommunications capital expenditures are forecast to average approximately $1.1 million annually over the period 2021 to 2025. This compares to an average of approximately $238,000 annually over the previous 5-year period.

The increase in Telecommunications capital expenditures over the planning period is primarily driven by: (i) the replacement of the St. John's teleprotection system in 2022 at a cost of approximately $1.2 million;[65] and (ii) the replacement of the Company's current VHF radio mobile system in 2023 at a cost of approximately $1,750,000.[66]

[65] Newfoundland Power's existing teleprotection system used to monitor and protect the St. John's 66 kV transmission line network is 20 years old and at the end of its useful life. A reliable teleprotection system ensures that transmission line faults are detected and addressed within the critical clearing times established for system stability.

[66] Newfoundland Power's VHF mobile radio communications uses a system provided by Bell Mobility. Other users of this system include Newfoundland and Labrador Hydro and some departments of the Provincial Government. The Provincial Government has started a process to transition away from the current VHF radio system to a new province-wide public safety radio system. Newfoundland Power is investigating options to provide its field staff with mobile radio communications in the event the current Bell Mobility VHF technology is retired.

4.3.10 Unforeseen Allowance

The Unforeseen Allowance covers any unforeseen capital expenditures that have not been budgeted elsewhere. The purpose of the account is to permit the Company to act expeditiously to deal with exigent circumstances in advance of seeking approval of the Board.

The Unforeseen Allowance constitutes $750,000 in annual capital expenditures over the period 2021 to 2025.

4.3.11 General Expenses Capitalized

GEC is the allocation of a portion of administrative costs to capital. In accordance with Order No. P.U. 3 (1995-96), the Company uses the incremental cost method of accounting for the purpose of capitalizing general expenses.

GEC is expected to average $6.5 annually over the period 2021 to 2025. This compares to an average of $4.8 annually over the previous 5-year period. This increase is attributable to a change in the accounting of pension expense, as approved in Order No. P.U. 2 (2019).

4.4 Risks to Planned Expenditures

While Newfoundland Power targets stability in its annual capital expenditures, the nature of the utility's obligation to provide safe and reliable service at least cost will not, in all circumstances, facilitate such stability. The Company has identified some risks to the stability of its capital expenditures through 2025.

The potential impacts of the ongoing COVID-19 public health crisis on Newfoundland Power's future operations and capital program are currently unclear. The capital plan has not been adjusted to reflect any potential impacts of COVID-19.

Newfoundland Power has an obligation to serve customers in its service territory. The capital expenditures required to provide such service are dependent upon customer and load growth.

New home construction has decreased considerably and is expected to deteriorate further over the forecast period. Should customer and load growth vary from forecast, so too will the capital expenditures that are sensitive to growth.

The Board's *Reference on Rate Mitigation Options and Impacts* recommended the utilities develop a comprehensive electrification plan.[67] The plan is under development and will be filed with the Board by 2021. The current 5-year capital outlook includes forecast expenditures to respond to electrification-driven load growth, including fuel switching in provincially owned buildings. These expenditures will vary depending on the specific electrification programs developed and customers' response to those programs.

The age of certain electrical system assets presents another risk to the Company's capital planning. This includes the age of existing power transformers. In-service failures of power transformers, such as those that occurred with the Riverhead, Kenmount, Horse Chops, Pierre's Brook and Salt Pond power transformers, may necessitate unplanned capital expenditures.[68]

Additionally, Newfoundland Power's Greenhill and Wesleyville gas turbines are aged 45 years and 51 years, respectively. Recent inspections have identified required refurbishment work on both gas turbines. The Company is completing a system planning study to inform the long-term plan for these gas turbines.

The plan for these assets will be informed by the Board's ongoing review of the Island Interconnected System's need for new capacity additions. Newfoundland and Labrador Hydro's

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[67] In its Final Report on *Rate Mitigation Options and Impacts: Muskrat Falls Project*, the Board recommended: "Co-ordination of the development of a comprehensive electrification potential plan including electrification and conservation demand management programs to be finalized by the utilities and submitted to the Board in 2021" (see page 109).

[68] Replacement of the Riverhead power transformer was approved in Board Order No. P.U. 6 (2017). Replacement of the Horse Chops power transformer was approved as part of the 2009 Capital Budget Application in Board Order No. P.U. 27 (2008). Replacement of the Pierre's Brook power transformer was approved in Board Order No. P.U. 3 (2008). Replacement of the Salt Pond power transformer was approved in Board Order No. P.U. 15 (2002-2003). Kenmount power transformer failed in-service in March 2009 and its refurbishment was approved in Board Order No. P.U. 29 (2009).

most recent assessment shows that the system has limited capacity to meet future load growth.[69] Due to uncertainty surrounding future capacity requirements, the Company has not included expenditures to refurbish these gas turbines in the 5-year outlook. Rather, the Company is forecasting to purchase a 2nd mobile gas turbine. The mobile gas turbine would replace some of the capacity lost if either of the Greenhill or Wesleyville gas turbines were decommissioned.

The Board is currently conducting an investigation into the adequacy of reliability of electricity supply on the Island Interconnected System. It is currently uncertain what, if any, impact the results of this proceeding may have on Newfoundland Power's capital expenditures. Accordingly, the 5-year outlook does not currently include capital expenditures that may be required as a result of the matters currently under investigation by the Board

Capital expenditures can also be impacted by major storms or weather events. In March 2010, an ice storm in Eastern Newfoundland caused widespread power outages on the Bonavista and Avalon peninsulas. In September 2010, Hurricane Igor caused extensive damage to the Company's generation and distribution assets. In 2012, Tropical Storm Leslie caused damage to the distribution system. The occurrence and costs of severe storms are not predictable.

[69] See Newfoundland and Labrador Hydro's *Marginal Cost Study Update – 2018 Summary Report*, dated November 15, 2018, pages 3-4.

Attachment A Guidelines Compliance Summary

June 2020

Attachment A: Guidelines Compliance Summary

1.0 General

Newfoundland Power organizes its annual capital budget applications in a manner consistent with the Guidelines. The Guidelines require capital projects to be organized by:

(i) **Definition** as either *Clustered* expenditures that are logically undertaken together, *Pooled* expenditures that are neither inter-dependent nor related, but are logically grouped together, or *Other* expenditures;

(ii) **Classification** as either *Mandatory* expenditures required by legislation, Board Order, safety issues, or risk to the environment, *Normal* expenditures required based on identified need or historical pattern of repair or replacement, or *Justified* expenditures based on the positive impact on the utility's operations; and

(iii) **Materiality**, which requires segmentation of expenditures under $200,000, between $200,000 and $500,000, and over $500,000.

Newfoundland Power's *2021 Capital Budget Application* proposes 40 capital projects. Tables A-1 through A-4 summarize the organization of 2021 projects, as detailed in Schedule B.

2.0 Definition

Table A-1 summarizes proposed 2021 capital projects by Definition.

Table A-1:
2021 Capital Projects
By Definition

Definition	Number of Projects	Budget ($000s)
Pooled	29	$70,871
Clustered	7	22,474
Other	4	17,953
Total	**40**	**$111,298**

A total of 29 projects are Pooled, accounting for 64% of total expenditures.

There are 7 Clustered projects, accounting for 20% of total expenditures: (i) *Substations Refurbishment and Modernization* is clustered with *Transmission Line Rebuilds* and *Hydro Facilities Rehabilitation* to connect Rattling Brook Substation to the 138 kV transmission system; (ii) *Substations Refurbishment and Modernization* is clustered with *Additions Due to Load Growth* to refurbish and increase the capacity of Dunville Substation; and (iii) *Additions Due to Load Growth, Feeder Additions for Growth*, *Transmission Line Extensions-35L* and *Fibre Optic Cable Builds* are clustered to construct a new substation in the vicinity of St. John's International Airport.

3.0 Classification

Table A-2 summarizes Newfoundland Power's proposed 2021 capital projects by Classification.

Table A-2:
2021 Capital Projects
By Classification

Definition	Number of Projects	Budget ($000s)
Normal	37	$104,201
Mandatory	1	717
Justifiable	2	6,380
Total	**40**	**$111,298**

A total of 37 projects are classified as Normal, accounting for 94% of total expenditures. The *PCB Bushing Phase-out* Substations project is required by Government of Canada Regulations and is the only Mandatory project in 2021. Two projects are classified as Justifiable: (i) the *Applications Enhancement* Information Systems project; and (ii) the *LED Streetlight Replacement* project. Both projects are justified with net present value analyses.

Table A-3 summarizes proposed 2021 capital projects by Costing Method.

Table A-3: 2021 Capital Projects By Costing Method		
Definition	Number of Projects	Budget ($000s)
Identified Need	23	$61,374
Historical Pattern	17	49,924
Total	**40**	**$111,298**

Approximately 55% of total expenditures are based on Identified Need, while approximately 45% of total expenditures are based on historical patterns.

4.0 Materiality

Table A-4 segments 2021 capital projects by Materiality.

Table A-4: 2021 Capital Projects By Materiality		
Definition	Number of Projects	Budget ($000s)
Under $200,000	1	$112
$200,000 - $500,000	7	2,529
Over $500,000	32	108,657
Total	**40**	**$111,298**

A total of 34 projects are budgeted at over $500,000, accounting for 98% of total expenditures. Twenty-two projects are budgeted at over $1,000,000, accounting for 90% of total expenditures.

Attachment B Five-Year Capital Plan:

2021-2025

Five-Year Capital Plan: 2021-2025 By Asset Class ($000s)					
Asset Class	**2021**	**2022**	**2023**	**2024**	**2025**
Distribution	$45,875	$49,039	$51,049	$50,248	$51,175
Substations	14,280	15,526	15,830	15,868	18,881
Transmission	9,751	12,053	14,255	14,743	14,913
Generation	11,510	9,075	8,692	17,124	19,110
Information Systems	15,362	20,469	11,294	9,945	7,480
General Property	2,776	3,300	3,898	3,257	2,198
Transportation	4,032	4,108	4,185	4,262	4,341
Telecommunications	462	1,614	2,194	482	550
Allowance for Unforeseen	750	750	750	750	750
GEC	6,500	6,500	6,500	6,500	6,500
Total	**$111,298**	**$122,434**	**$118,647**	**$123,179**	**$125,898**

Distribution *Five-Year Capital Plan: 2021-2025* ($000s)					
Project	**2021**	**2022**	**2023**	**2024**	**2025**
Extensions	$10,891	$11,105	$11,234	$11,356	$11,092
Meters	680	689	699	708	718
Services	3,110	3,171	3,213	3,254	3,205
Street Lighting	7,381	7,439	7,496	7,555	7,615
Transformers	5,945	6,006	6,070	6,135	6,202
Reconstruction	5,567	5,677	5,790	5,905	6,023
Rebuild Distribution Lines	3,965	4,040	4,116	4,195	4,275
Relocations For Third Parties	3,155	3,209	3,264	3,320	3,378
Distribution Reliability Initiative	700	1,000	1,200	1,300	1,500
Distribution Feeder Automation	821	888	955	983	995
Feeder Additions for Load Growth	2,655	3,607	5,261	2,854	3,856
Trunk Feeders	800	2,000	1,540	2,470	2,100
AFUDC	205	208	211	213	216
Total	**$45,875**	**$49,039**	**$51,049**	**$50,248**	**$51,175**

Substations *Five-Year Capital Plan: 2021-2025* ($000s)					
Project	**2021**	**2022**	**2023**	**2024**	**2025**
Substation Refurbishment and Modernization	$5,153	$8,974	$7,671	$11,876	$10,881
Replacements Due to In-Service Failure	3,413	3,458	3,508	3,558	3,610
Additions Due to Load Growth	4,997	2,500	2,500	-	4,100
Substation Feeder Terminations	-	-	546	-	290
PCB Bushing Phase Out	717	594	1,605	434	-
Total	**$14,280**	**$15,526**	**$15,830**	**$15,868**	**$18,881**

Transmission *Five-Year Capital Plan: 2021-2025* ($000s)					
Project	**2021**	**2022**	**2023**	**2024**	**2025**
Transmission Line Rebuild	$2,238	$2,267	$2,304	$2,339	$2,376
Transmission Line Extension/Additions	1,343	-	-	-	-
Transmission Line Maintenance & 3rd Party	6,170	9,786	11,951	12,404	12,537
Total	**$9,751**	**$12,053**	**$14,255**	**$14,743**	**$14,913**

Generation *Five-Year Capital Plan: 2021-2025* ($000s)					
Project	**2021**	**2022**	**2023**	**2024**	**2025**
Facilities Rehabilitation Hydro	$1,806	$1,765	$1,824	$1,822	$2,343
Facilities Rehabilitation Thermal	330	334	339	343	348
Cape Broyle Upgrades	-	-	-	1,100	-
Horsechops Plant Upgrade	-	-	-	-	2,168
Lockston Plant Upgrade	-	-	-	595	-
Lookout Brook Plant Upgrade	-	-	1,043	727	1,283
Mobile Plant Upgrades	-	955	5,486	865	-
Morris Plant Upgrades	-	-	-	-	1,869
Petty Harbour Plant Upgrade	-	-	-	-	1,209
Sandy Brook Upgrades	-	6,021	-	-	-
Seal Cove Plant Upgrade	-	-	-	1,337	-
Topsail Plant Upgrades	9,374	-	-	-	-
Tors Cove Plant Upgrade	-	-	-	2,865	-
Gas Turbine Replacement	-	-	-	7,470	9,890
Total	**$11,510**	**$9,075**	**$8,692**	**$17,124**	**$19,110**

Information Systems *Five-Year Capital Plan: 2021-2025* ($000s)					
Project	**2021**	**2022**	**2023**	**2024**	**2025**
Application Enhancements	$978	$750	$600	$1,750	$1,300
System Upgrades	2,410	1,839	2,570	2,750	2,750
Personal Computer Infrastructure	495	520	535	545	555
Shared Server Infrastructure	538	559	586	1,000	650
Network Infrastructure	363	375	386	400	475
Cybersecurity Upgrades	675	600	700	750	750
Operations Technology	-	-	-	2,750	1,000
Customer Service System	9,903	15,826	5,917	-	-
Total	**$15,362**	**$20,469**	**$11,294**	**$9,945**	**$7,480**

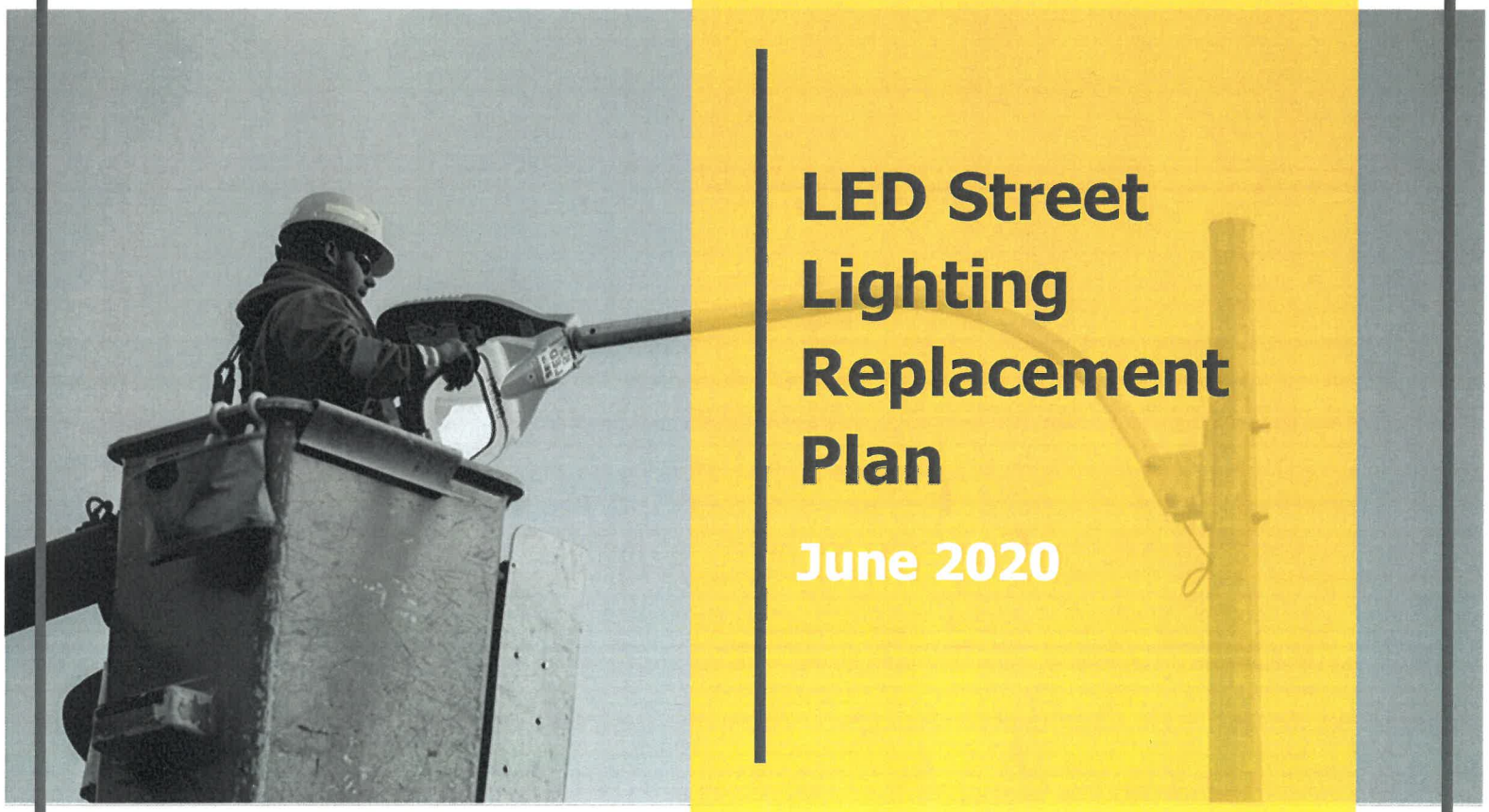
General Property *Five-Year Capital Plan: 2021-2025* ($000s)					
Project	**2021**	**2022**	**2023**	**2024**	**2025**
Tools and Equipment	$486	$491	$496	$501	$507
Additions to Real Property	598	527	532	616	541
Renovations Company Buildings	1,392	1,982	2,570	1,840	850
Physical Security Upgrades	300	300	300	300	300
Total	**$2,776**	**$3,300**	**$3,898**	**$3,257**	**$2,198**

Transportation *Five-Year Capital Plan: 2021-2025* ($000s)					
Project	**2021**	**2022**	**2023**	**2024**	**2025**
Replace Vehicles and Aerial Devices	$4,032	$4,108	$4,185	$4,262	$4,341
Total	**$4,032**	**$4,108**	**$4,185**	**$4,262**	**$4,341**

Telecommunications *Five-Year Capital Plan: 2021-2025* ($000s)					
Project	**2021**	**2022**	**2023**	**2024**	**2025**
Replace/Upgrade Communications Equipment	$112	$114	$116	$117	$119
Fibre Optic Cable	350	300	328	365	431
SJN Teleprotection Upgrade	-	1,200	-	-	-
VHF Radio System Replacement	-	-	1,750	-	-
Total	**$462**	**$1,614**	**$2,194**	**$482**	**$550**

Unforeseen Allowance *Five-Year Capital Plan: 2021-2025* ($000s)					
Project	**2021**	**2022**	**2023**	**2024**	**2025**
Allowance for Unforeseen	$750	$750	$750	$750	$750
Total	**$750**	**$750**	**$750**	**$750**	**$750**

General Expenses Capitalized *Five-Year Capital Plan: 2021-2025* ($000s)					
Project	2021	2022	2023	2024	2025
GEC	$6,500	$6,500	$6,500	$6,500	$6,500
Total	**$6,500**	**$6,500**	**$6,500**	**$6,500**	**$6,500**



LED Street Lighting Replacement Plan

June 2020

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Executive Summary

The vast majority of customers served by Newfoundland Power Inc. ("Newfoundland Power" or the "Company") reside in communities with street lighting service.

The Company's customers are currently served by a mix of Light-Emitting Diode ("LED") street lights and High-Pressure Sodium ("HPS") street lights. LED street lights are more energy efficient and reliable than HPS street lights. This, in turn, results in lower customer rates.

LED street lights were introduced as a service option for Newfoundland Power's customers in 2019. The Company currently installs LED fixtures for new street lighting installations or when HPS fixtures fail. Following this approach, customers would continue to pay the higher rates of HPS street lights for over 30 years.

The *LED Street Lighting Replacement Plan* will accelerate the installation of LED street lights for customers. The plan will commence in 2021 and ensure all customers are provided with the lower rates of LED street lights within 6 years.

The total cost of executing the plan is estimated at approximately $32.8 million.

An economic analysis determined the plan will reduce energy and maintenance costs to customers by approximately $52 million over 20 years. This results in lower overall costs for customers over the long term.

Newfoundland Power's plan is consistent with the delivery of least-cost, reliable service to customers and current Canadian utility practice. Ten of 12 Canadian utilities surveyed have implemented replacement programs to install LED street lights.

The plan has received the support of the largest municipal organization in the province, Municipalities Newfoundland and Labrador.

2.0 Background

2.1 Customer Benefits of LED Street Lights

Newfoundland Power provides street lighting service to approximately 11,000 customers, including municipalities and businesses. The vast majority of customers served by the Company live in a community with street lighting service.[1] Newfoundland Power is required to provide this service in a manner that is efficient, reliable, and least-cost for its customers.

Newfoundland Power changed its street lighting standard from HPS fixtures to LED fixtures in 2019. This change in standards followed the approval of a new service option for customers in Order No. P.U. 2 (2019). The Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") approved this service option on the basis that it "*would be beneficial to customers and would offer lower rates compared to the HPS rates.*"[2]

Newfoundland Power assessed the customer benefits of LED street lights over multiple years.[3] The assessment included: (i) trial installations of 240 LED street lights to evaluate products from different manufacturers; [4] (ii) a survey of 266 customers living in close proximity to the trial installations;[5] and (iii) an engineering review completed with the assistance of CBCL Limited.[6]

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1 As of June 2020, approximately 88% of Newfoundland Power's 258,000 Domestic and General Service customers live in a municipality or unincorporated community with street lighting service.

2 See Order No. P.U. 2 (2019), page 8, lines 19-20.

3 The detailed results of the assessment were provided in the *2019/2020 General Rate Application, Volume 2, Supporting Materials, Reports, Tab 7, LED Street Lighting* (the "2019 LED Street Lighting Report").

4 Between 2009 and 2019, Newfoundland Power completed trial installations of fixtures from 6 LED street light manufacturers in 28 separate locations throughout its service territory. Applications included residential subdivisions, roadways, roundabouts, coastal locations, commercial areas, and recreational areas.

5 The detailed results of the customer survey were provided as Appendix A to the 2019 LED Street Lighting Report.

6 In 2018 and 2019, CBCL Limited developed *Recommended Street Lighting Design Criteria* for Newfoundland Power to ensure adequate and uniform lighting levels for driver and pedestrian safety. The criteria are based on various national and international standards. These include, as examples: (i) the American National Standards Institute ("ANSI") / Illuminating Engineering Society ("IES") RP-8 American *National Standard Practice for Design and Maintenance of Roadway and Parking Facility Lighting*; (ii) IES RP-33 *Lighting for Exterior Environments*; (iii) the American Association of State Highway and Transportation Officials ("AASHTO") *Roadway Lighting Design Guide*; and (iv) the Canadian Standards Association ("CSA") CSA C22.1 – Canadian Electrical Code.

The assessment concluded that LED street lights provide 3 principal customer benefits:

(i) **Lower overall costs.** The capital cost of a installing an LED fixture is approximately twice that of an HPS fixture.[7] However, in comparison to HPS fixtures, LED fixtures require ⅓ the number of maintenance visits[8] and each maintenance visit is less than ½ the cost.[9] LED street lights also consume an average of 60% less energy than their HPS equivalents.[10] These reduced maintenance and energy costs more than offset the higher capital cost of LED fixtures, resulting in lower customer rates.

As shown in Table 1, current customer rates for LED street lights are between 9% and 39% less than equivalent HPS rates depending on the lighting output required.[11]

Table 1:
Street Lighting Rates
(October 1, 2019)

Type[12]	100	150	250	400
HPS	$17.89	$22.02	$30.55	$41.87
LED	$16.20	$17.70	$22.68	$25.71
Difference	9%	20%	26%	39%

7 The average installed capital costs are approximately $604/LED fixture and $297/HPS fixture, including materials and labour ($604 / $297 = 2.0).

8 Maintenance is required approximately 3 times over the 20-year service life of an HPS street light, primarily to replace failed bulbs. The Company expects an LED street light to require 1 maintenance visit over its 20-year service life.

9 Estimated maintenance costs are $107/LED fixture and $224/HPS fixture ($107 / $224 = 0.48).

10 Newfoundland Power's street lights operate for approximately 350 hours per month. This translates into energy savings of between 20 to 108 kWh/month, depending on the lighting output required.

11 See Order No. P.U. 31 (2019), Schedule A, Page 28 of 34.

12 Newfoundland Power's Street and Area Lighting Service includes 4 types of Sentinel/Standard HPS fixtures that are classified according to wattage and light output. The 4 types are: 100W (8,600 lumens); 150W (14,400 lumens); 250W (23,200 lumens); and 400W (45,000 lumens). As of March 1, 2019, the Company's Street and Area Lighting Service includes 4 LED fixture types that provide equivalent lighting to the HPS fixtures. These are LED 100, LED 150, LED 250, and LED 400. The number of each LED fixture corresponds to the wattage of an equivalent HPS fixture. For example, LED 100 provides the equivalent lighting output of a 100W HPS fixture.

(i) **Improved service reliability.** LED street lights are over 3 times as reliable as HPS street lights. LED street lights are designed to operate for up to 100,000 hours without the need to replace components. This equates to an outage every 20 or more years. By comparison, the bulbs used in HPS street lights have an average service life of approximately 24,000 hours. This equates to an outage every 6 years.[13]

(ii) **Better lighting quality.** The light emitted by LED street lights appears white, whereas the light emitted by HPS street lights appears orange. The white light of LED street lights provides a more accurate representation of colours at night. This improves nighttime visibility. LED street lights are also directional, whereas HPS street lights are not. The directional nature of LED street lights prevents light from spilling onto areas not intended to be lit, such as a customer's residence and the night sky.[14]

These customer benefits are consistent with Newfoundland Power's obligation to provide reliable service to customers at least cost.[15]

A customer survey conducted in 2018 confirmed that LED street lights are the preferred service option among Newfoundland Power's customers.[16]

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[13] 20 years / 6 years = 3.3.

[14] Newfoundland Power's LED street lighting fixtures have received the International Dark-Sky Association's ("IDA") *Fixture Seal of Approval*. The IDA is a recognized not-for-profit organization focused on protection of the night sky. The *Fixture Seal of Approval* program provides objective, third-party certification for luminaires that minimize glare, reduce light trespass, and do not pollute the night sky.

[15] See Section 3(b)(iii) of the *Electrical Power Control Act, 1994.*

[16] In February 2018, a total of 266 customers were surveyed on their opinion of trial LED street light installations. Of the customers who noticed the LED fixtures in their area: (i) 88% preferred the white light produced by LED fixtures; (ii) 74% indicated LED fixtures were brighter; and (iii) 78% indicated LED fixtures provided improved visibility in their area. For more information, see the 2019 LED Street Lighting Report, Appendix A.

2.2 Current Installation Approach

Newfoundland Power currently installs LED street lights for customers' new service requests and when existing HPS street lights fail and cannot be repaired. When feasible, HPS street lights are repaired by replacing parts such as the bulb, photocell or wiring.

Under Newfoundland Power's current installation approach, approximately 1,700, or 3% of all HPS street lights, are replaced annually with LED equivalents.

Table 2 provides the percentage of LED street lights throughout Newfoundland Power's service territory as of June 2020.

Table 2:
Current Street Light Installations by Fixture Type
(June 2020)

Type[14]	HPS	LED	Total	Percentage LED
100	52,012	3,476	55,488	6%
150	6,412	510	6,922	7%
250	1,580	186	1,766	11%
400	474	77	551	14%
Total	**60,478**	**4,249**	**64,727**	**7%**

LED street lights account for 7% of all street lights serving Newfoundland Power's customers.

Based on Newfoundland Power's current installation approach, it would require over 30 years to provide the LED street lighting service to all customers.[17] Street lighting customers would continue to pay the higher rates of HPS street lights over this period.

[17] 60,478 total HPS street lights / 1,700 annual replacements = approximately 36 years.

2.3 Current Canadian Utility Practice

The majority of Canadian utilities have adopted LED street lights as their service standard.[18]

Newfoundland Power completed a survey of current Canadian utility practice for installing LED street lights in 2020.

The survey determined that current Canadian utility practice is to implement a replacement program to install LED street lights. Replacement programs are effectively designed to provide the benefits of LED street lights to customers by replacing existing, less efficient street lights over a defined period of time.

Of 12 Canadian utilities included in the survey, 10 have implemented replacement programs to install LED street lights.[19] One additional utility plans to implement a replacement program in 2020 following approval of a proposal to adopt LED street lights as its service standard.[20]

Utilities' replacement programs range in duration from 3 to 12 years. These programs are in varying stages of execution. For example, 3 utilities have fully executed their replacement programs, while 1 utility has a new program that is 10% complete.

The detailed results of the survey are provided in Appendix A.

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[18] Based on a survey completed in 2020, 11 of 12 Canadian utilities have adopted LED street lighting as their service standard. The other utility, BC Hydro, intends to file an application with the British Columbia Utilities Commission in 2020 to adopt LED street lights. For more information, see Appendix A to this report.

[19] The 10 Canadian utilities with replacement programs for LED street lights are: Nova Scotia Power, New Brunswick Power, Maritime Electric, Manitoba Hydro, SaskPower, FortisAlberta, ATCO, ENMAX, EPCOR, and FortisBC. These results do not include the over 60 utilities operating in Ontario, many of which also have accelerated installation programs for LED street lights (e.g. Ottawa Hydro, Kitchener-Wilmot Hydro, St. Catherine's Hydro, and Guelph Hydro Electric Systems).

[20] BC Hydro intends to implement a replacement program for LED street lights in 2020 following the approval of customer rates for LED street lights by the British Columbia Utilities Commission.

3.0 Assessment of Alternatives

3.1 Methodology

3.1.1 Description of Alternatives

Newfoundland Power analyzed whether a replacement program to accelerate the installation of LED street lights would provide an economic benefit to its customers. The analysis is based on 2 alternatives:

Alternative 1: Current Approach

Alternative 1 involves continuing Newfoundland Power's current approach of installing an LED fixture when an HPS fixture fails and cannot be repaired. The Company's maintenance program for HPS street lights would continue under this alternative. Approximately 1,700 HPS street lights would be replaced with LED equivalents annually.

Alternative 2: Replacement Program

Alternative 2 is a replacement program to accelerate the installation of LED street lights. It suspends the current maintenance program by installing an LED fixture in response to any required maintenance visit for an HPS street light.

On average, Newfoundland Power's HPS street lights require maintenance every 6 years to replace parts or repair components. Alternative 2 assumes that all HPS street lights will be removed from service and replaced with LED equivalents over 6 years. Approximately 10,000 HPS street lights would be replaced with LED equivalents annually.

From an economic perspective, eliminating the maintenance of HPS street lights would provide operating efficiencies in serving customers.

From a public policy perspective, aligning the timing and location of LED street light installations with HPS street light maintenance would ensure fairness in customers' access to the lower rates provided by the LED service option.[21]

3.1.2 Comparison of Alternatives

Table 3 provides the forecast number of LED street lights installed under both alternatives at year end for the period 2020 to 2026.[22]

Table 3:
Comparison of Alternatives
Street Light Installations

Year	Alternative 1: Current Approach			Alternative 2: Replacement Program		
	HPS	LED	Percentage LED	HPS	LED	Percentage LED
2020	60,068	1,700	3%	60,068	1,700	3%
2021	58,368	3,400	6%	50,057	11,711	19%
2022	56,668	5,100	8%	40,045	21,723	35%
2023	54,968	6,800	11%	30,034	31,734	51%
2024	53,268	8,500	14%	20,023	41,745	68%
2025	51,568	10,200	17%	10,011	51,757	84%
2026	49,868	11,900	19%	0	61,768	100%

Under Newfoundland Power's current approach, LED street lights would account for only 19% of all street lights serving customers by year end 2026. Under the replacement program, customers would be served exclusively by LED street lights by year end 2026.

[21] Section 3(a)(i) of the *Electrical Power Control Act, 1994* requires that rates to be charged to customers should be reasonable and not unjustly discriminatory. LED street lights provide lower customer rates in comparison to HPS street lights. Aligning the installation of LED street lights with Newfoundland Power's maintenance program for HPS street lights will ensure fairness among customers in accessing the lower rates.

[22] The quantities of LED fixtures in Table 2 and Table 3 include replacement fixtures only and do not include LED fixtures installed as a result of new street lighting requests.

3.1.3 Economic Analysis of Alternatives

Newfoundland Power conducted a Net Present Value ("NPV") analysis to determine whether the replacement program to accelerate the installation of LED street lights would provide an economic benefit to its customers.

The NPV analysis seeks to determine whether the reduced electricity costs and maintenance costs of LED street lights would exceed the increased capital costs of installing a larger volume of street lights annually. The analysis considers forecast costs over a 20-year period.[23] It is based on the most recent marginal costs provided by Newfoundland and Labrador Hydro ("Hydro"). [24]

A sensitivity analysis was also conducted to determine whether the replacement program would continue to be economic for customers if marginal costs were to decrease.

Appendix B provides the detailed inputs and assumptions used in the analysis.

All inputs and assumptions were reviewed by CBCL Limited. CBCL Limited found Newfoundland Power's inputs and assumptions are valid and within a reasonable margin of error.[25] Appendix C provides the results of CBCL Limited's review.

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[23] A 20-year time horizon approximates the expected life of an LED fixture. This approach is consistent with the *Street and Parking Facility Lighting Retrofit Financial Analysis Tool* developed by the United States Department of Energy Municipal Solid-State Street Lighting Consortium, the Federal Energy Management Program, and the Better Buildings Initiative.

[24] Based on Hydro's 2020 marginal cost update as provided to Newfoundland Power on April 9, 2020. See Appendix B for more information.

[25] See Appendix C, page 16.

3.2 Results

The NPV analysis provides the cost of each alternative to customers over the next 20 years, including capital and operating costs. A lower NPV result indicates a lower cost to customers.

Table 4 provides the NPV result for each alternative based on the most recent marginal costs provided by Hydro.

Table 4:
NPV Result
($000s)

	Capital Expenditures	Retirement	Taxes and Net Salvage	Maintenance Costs	Avoided Electricity Costs	Total Cost	NPV
Alternative 1 – Current Approach	21,675	5,823	5,334	31,723	-15,936	48,619	31,854
Alternative 2 – Replacement Program	38,499	9,666	9,344	8,111	-44,175	21,445	27,000
Difference	**16,824**	**3,843**	**4,010**	**-23,612**	**-28,239**	**-27,174**	**-4,854**

In comparison to Newfoundland Power's current installation approach, the replacement program would reduce overall costs to customers by approximately $27.2 million over 20 years. This includes: (i) increased capital expenditures, retirement costs and taxes of approximately $24.7 million; less (ii) reduced maintenance and electricity costs of approximately $51.9 million.

When calculated on an NPV basis, the replacement program reduces costs to customers by approximately $4.9 million over 20 years.

Newfoundland Power conducted a sensitivity analysis to test the NPV result against changes in marginal energy and capacity costs. The Company used a 20% and 40% reduction in marginal energy and capacity costs to assess the alternatives.[26]

Table 5 provides a sensitivity analysis that adjusts the NPV results based on 20% reductions in marginal energy and capacity costs.

Table 5:
Sensitivity Analysis
(20% Reduction in Marginal Costs)

Marginal Cost	Base Case	20% Reduction	NPV		Difference (millions)
			Alternative 1 (millions)	Alternative 2 (millions)	
Energy (2020 to 2040)	4.2¢/kWh – 6.7¢/kWh	3.4¢/kWh – 5.3¢/kWh	$32.4	$28.7	$3.7
Capacity (2020 to 2040)	$319/kW – $485/kW	$255/kW – $388/kW	$32.8	$30.1	$2.7

The replacement program is sufficiently economic to withstand a reduction in marginal costs of 20%. On an NPV basis, the economic benefit to customers of the replacement program would be approximately: (i) $3.7 million over 20 years assuming a 20% reduction in marginal energy costs; and (ii) $2.7 million over 20 years assuming a 20% reduction in marginal capacity costs.

[26] A 20% reduction corresponds to a mid-level sensitivity threshold for avoided costs used in the 2020-2034 Conservation Potential Study ("CPS") prepared by Dunsky Energy Consulting. A 40% reduction corresponds to a low-level sensitivity threshold for avoided costs used in the CPS. The CPS was provided as Attachment A to response to Information Request PUB-NP-104 filed in relation to the Board's Rate Mitigation Options and Impacts Reference.

Table 6 provides a sensitivity analysis that adjusts the NPV results based on 40% reductions in marginal energy and capacity costs.

Table 6: Sensitivity Analysis (40% Reduction in Marginal Costs)					
			NPV		
Marginal Cost	Base Case	40% Reduction	Alternative 1 (millions)	Alternative 2 (millions)	Difference (millions)
Energy (2020 to 2040)	4.2¢/kWh – 6.7¢/kWh	2.5¢/kWh – 4.0¢/kWh	$32.9	$30.4	$2.5
Capacity (2020 to 2040)	$319/kW – $485/kW	$192/kW – $291/kW	$33.8	$33.2	$0.6

The replacement program is sufficiently economic to withstand a reduction in marginal costs of 40%. On an NPV basis, the economic benefit to customers of the replacement program would be approximately: (i) $2.5 million over 20 years assuming a 40% reduction in marginal energy costs; and (ii) $0.6 million over 20 years assuming a 40% reduction in marginal capacity costs.

4.0 Project Description

Newfoundland Power is proposing a plan to accelerate the installation of LED street lights for customers throughout its service territory (the "*LED Street Lighting Replacement Plan*").

The *LED Street Lighting Replacement Plan* is consistent with Alternative 2 as described in Section 3.0. The plan will provide the LED service option to all street lighting customers within 6 years. This approach is consistent with current Canadian utility practice.[27]

An economic analysis confirmed the *LED Street Lighting Replacement Plan* will reduce overall costs to customers over the long term.

[27] The survey provided as Appendix A shows that utilities' replacement programs for LED street lights range from 3 to 12 years. Newfoundland Power's 6-year plan is consistent with this range.

In the absence of this plan, it would require over 30 years to provide the lower rates of LED street lights to all customers.

Newfoundland Power's plan aligns the timing and location of LED street light installations with maintenance visits to HPS street lights. In addition to providing operating efficiencies, this approach will ensure fairness in providing the LED service option to customers.

Approximately ¾ of Newfoundland Power's street lights provide service to municipal customers. In developing its plan, the Company consulted with the largest municipal organization in the province, Municipalities Newfoundland and Labrador ("MNL"). MNL has provided a letter of support for Newfoundland Power's plan. MNL's letter states:

> *"MNL fully supports Newfoundland Power's proposed LED Streetlight Replacement Program and believes it will result in a fair and reasonable deployment of LED streetlights to the municipalities it serves."*

Appendix D provides the letter of support from MNL.

Overall, the *LED Street Lighting Replacement Plan* is consistent with Newfoundland Power's obligation to provide reliable service to its customers at least-cost.

5.0 Project Costs

Table 7 provides the annual estimated cost of the *LED Street Lighting Replacement Plan*.

Table 7: Project Costs (000s)	
Year	Costs
2021	$5,402
2022	$5,428
2023	$5,452
2024	$5,478
2025	$5,503
2026	$5,529
Total	**$32,792**

The total estimated cost of the *LED Street Lighting Replacement Plan* is approximately $32.8 million over 6 years. This includes expenditures of approximately $5.4 million in 2021.

Newfoundland Power will file an update to the *LED Street Lighting Replacement Plan* as part of its annual capital budget application to seek approval of expenditures for the upcoming year.

Appendix A

Survey of Canadian Utility Practice

Table A-1: Survey LED Street Light Installation Approaches[28]				
Utility	Approved LED Rate	LED Street Light Replacement Program		
		Replacement Program	Program Duration	Complete (%)
Nova Scotia Power	Yes	Yes	8 years	100%
New Brunswick Power	Yes	Yes	6 years	100%
Maritime Electric	Yes	Yes	10 years	60%
Hydro Quebec	Yes	No	--	--
Manitoba Hydro	Yes	Yes	6 years	97%
SaskPower	Yes	Yes	10 years	10%
FortisAlberta[29]	Yes	Yes	Various	Various
ATCO[30]	Yes	Yes	Various	Various
ENMAX[31]	Yes	Yes	4 years	100%
EPCOR	Yes	Yes	12 years [32]	42%
FortisBC	Yes	Yes	3 years	66%
BC Hydro[33]	No	Planned	3 years	0%

28 The results shown in Table A-1 do not include utilities in Ontario. There are over 60 local distribution companies ("LDCs") in Ontario, most of which are owned by municipalities. Numerous LDCs have commenced LED street light replacement programs including Ottawa Hydro, Kitchener-Wilmot Hydro, St. Catherine's Hydro, and Guelph Hydro Electric Systems. These results were excluded to ensure a representative view of overall Canadian utility practice.

29 FortisAlberta has a conversion program available to its municipal customers to help customers convert to LED street lights with no upfront capital investment. As of February 5, 2018 approximately 85% of the communities served by FortisAlberta have requested the street light conversion option.

30 ATCO's LED street light conversion program is dependent upon its street lighting customers. ATCO offers municipalities an option for full-scale conversion of street lights using an *LED Conversion Multiplier*. ATCO expects to offer this option until most of the street lights in the communities it serves have been converted from HPS to LED. ATCO currently expects this will take 3-5 years.

31 The City of Calgary owns the street lights and contracts Enmax Power Services Corporation to maintain or repair them. ENMAX and its subsidiaries are owned by the City of Calgary.

32 EPCOR replaced 53,000 HPS street lights with LEDs from 2011 to 2019. It plans to replace an additional 46,000 HPS street lights to LEDs by 2022. The goal is to have 103,000 out of 126,000 streetlights, or 82%, of Edmonton's streetlight system operating as LEDs by the end of their conversion project.

33 BC Hydro is planning to file a proposal with the British Columbia Utilities Commission in 2020 to adopt LED street lights as its service standard. BC Hydro is planning to adopt an accelerated installation program for LED street lights following approval of that proposal.

Appendix B

Net Present Value Analysis

1.0 Inputs and Assumptions

1.1 General

A number of factors require consideration in conducting the NPV analysis of the alternatives described in this report. These factors include differences in energy costs, maintenance costs and capital costs between the 2 alternatives.

1.2 Energy Costs

The NPV analysis accounts for the differences in the energy requirements for HPS street lights and LED street lights.

Table B-1 provides a comparison of the electricity required to operate HPS and LED fixtures.

Table B-1:
Electricity Demand (W) and Consumption (kWh/month)

	100		150		250		400	
	W	kWh/month	W	kWh/month	W	kWh/month	W	kWh/month
HPS	108	38	170	60	300	105	465	163
LED	52	18	69	24	113	40	158	55
Reduction	56	20	101	36	187	65	307	108
Reduction (%)	52%	53%	59%	60%	62%	62%	66%	66%

On average, LED fixtures consume approximately 60% less energy than HPS fixtures. Replacing all of the Company's remaining HPS fixtures with LED fixtures represents a reduction in energy requirements of approximately 16.8 GWh and a 4.0 MW reduction in capacity.[34]

[34] The reduction of energy and demand provided by an accelerated adoption of LED fixtures is consistent with the Board's comments in its February 7, 2020, *Reference to the Board – Rate Mitigation Options and Impacts – Muskrat Falls Project – Final Report.* At page 74 of its report, the Board found *"it is also important to include CDM programs and consider rate design and to better manage the system peak demand to prevent a need for future capital investment and also allow for additional export sales."*

An estimate of the marginal cost of electricity is required to determine the financial benefit associated with the reduction in energy requirements. Based on the most recent update from Hydro, marginal cost estimates for energy are forecast to be 4.2¢/kWh in 2021 to 6.7¢/kWh in 2040. Marginal cost estimates for capacity are forecast to be $319/kW in 2020 to $485/kW in 2040.[35]

1.3 Maintenance Costs

The NPV analysis accounts for differences in maintenance requirements for HPS street lights and LED street lights.

Maintenance costs for HPS street lights are primarily driven by the failure of the bulb. HPS bulbs have an expected service life of approximately 24,000 hours, or approximately 6 years.[36] Other maintenance activities include replacing photocells, wiring and connections.[37]

Over the 2017 to 2019 period, Newfoundland Power completed an average of approximately 10,700 maintenance visits per year for HPS fixtures.[38] The average cost of completing this maintenance was approximately $216/HPS fixture. For 2021, Newfoundland Power estimates an average maintenance cost of $224/HPS fixture based on inflationary increases.[39]

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[35] Based on Hydro's 2020 marginal cost update as provided to Newfoundland Power from Hydro on April 9, 2020. Estimates of marginal capacity costs include the cost for additional generation as well as marginal capacity costs related to the distribution and transmission systems.

[36] Based on operating for 4,200 hours per year. (24,000 hours / 4,200 hours per year) = 5.7 years.

[37] In 2019, 78% of all street lighting outages involved the replacement of the HPS bulb and/or photocell, 15% involved the replacement of HPS fixtures, and the remaining 7% involved repairing other issues such as failed wiring and connections.

[38] This excludes street light outages that result in the replacement of a failed HPS fixture.

[39] Inflationary increases in 2020 and 2021 are 2% in each year. This reflects labour increases associated with the collective agreement between Newfoundland Power and its unionized employees, effective October 1, 2017 to June 30, 2022.

LED fixtures are designed to operate for up to 100,000 hours without the need to replace any components. The Company expects an LED fixture to require 1 scheduled maintenance visit over a service life of 20 years.[40] For 2021, the estimated cost is $107/LED fixture.[41]

The NPV analysis accounts for the possibility of premature failure of LED fixtures. A conservative failure rate estimate of 1% was used in the analysis.[42] In Newfoundland Power's experience, premature failure rates of LED fixtures have been lower, at approximately 0.1%.[43]

1.4 Capital Costs

The capital costs of LED fixtures include equipment costs and installation costs. Installation costs include labour, vehicle, and traffic control costs.

Under Alternative 1, Newfoundland Power would install approximately 1,700 LED fixtures per year over more than 30 years. Under Alternative 2, the Company would install approximately 10,000 LED fixtures per year over 6 years. Alternative 2 has a higher annual capital cost due to the higher equipment and installation requirements.[44]

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[40] Repairs associated with wiring and connection failures are common for both HPS and LED fixtures. As a result, the Company expects that unscheduled maintenance associated with these types of failures will continue to occur regardless of the lighting technology being used.

[41] Scheduled maintenance associated with LED fixtures primarily involves cleaning to ensure the fixture continues to provide adequate lighting throughout its service life. The labour cost associated with performing scheduled maintenance work for LED street lights is lower than the labour cost associated with HPS maintenance since scheduled maintenance can be performed in one geographic area, such as a neighbourhood, whereas HPS maintenance is driven by street light outages which can occur sporadically throughout the Company's service territory or operating region.

[42] Newfoundland Power's scheduled maintenance and 1% failure rate assumptions are consistent with the *Street and Parking Facility Lighting Retrofit Financial Analysis Tool* developed by the United States Department of Energy Municipal Solid-State Street Lighting Consortium, the Federal Energy Management Program, and the Better Buildings Initiative.

[43] As of March 1, 2020 Newfoundland Power had a total of 3,984 LED fixtures installed. This included the Company's trial LED fixtures, new installations, and replacement of HPS street lights that had reached end of life. The Company recorded 5 failures of in-service LED fixtures over the period March 1, 2019 to March 1, 2020 which reflects a failure rate of approximately 0.1% (5 / 3,984 = 0.0013).

[44] In accordance with the Company's Capitalization Policy, labour costs associated with replacing a street light fixture are charged 50% to capital and 50% to retirement.

The equipment costs of LED fixtures are based on the Company's existing pricing. This pricing was obtained through a competitive Request for Proposals ("RFP") process.[45] An additional 2% volume discount was factored into the NPV analysis based on an increase in the quantity of equipment purchased annually.[46]

Installation costs are estimated to be $252/LED fixture.[47]

2.0 Detailed Results

The detailed results of the NPV analysis of Alternative 1 and Alternative 2 are provided in the 2 tables that follow.

[45] Newfoundland Power issued a Request for Proposals for LED street light fixtures in December 2018. The Company's current agreement for LED fixtures came into effect on December 2019 and included a price reduction of between 1-2%.

[46] The volume discount is included based on a commitment from the Company's LED fixture supplier. Fixture costs based on volume discounts will not be finalized until the proposed accelerated street light replacement program is approved by the Board.

[47] The estimated installation cost per fixture is based on the average cost of a street light maintenance visit, plus additional labour costs to reflect the additional time required to install a fixture.

Table B-2: NPV Analysis Alternative 1: Current Approach								
Year	Capital Expenditures	Retirement	Taxes and Net Salvage	Maintenance Costs	Avoided Electricity Costs	Total Cost	Net Present Value	Cumulative Present Value
2021	945,857	222,021	226,568	1,892,223	(57,381)	3,229,289	3,229,289	3,229,289
2022	959,704	228,630	230,537	1,862,421	(117,298)	3,163,993	2,987,154	6,216,442
2023	973,663	235,350	234,548	1,830,012	(171,227)	3,102,346	2,765,249	8,981,691
2024	987,684	242,133	238,584	1,795,069	(233,329)	3,030,140	2,549,933	11,531,625
2025	1,001,760	248,971	242,642	1,757,090	(298,362)	2,952,100	2,345,412	13,877,037
2026	1,015,901	255,873	246,724	1,716,411	(371,887)	2,863,023	2,147,509	16,024,546
2027	1,030,130	262,864	250,841	1,673,201	(445,164)	2,771,872	1,962,932	17,987,478
2028	1,044,524	270,019	255,021	1,628,181	(528,976)	2,668,770	1,784,289	19,771,768
2029	1,059,075	277,332	259,263	1,580,713	(624,454)	2,551,928	1,610,811	21,382,579
2030	1,073,738	284,757	263,548	1,531,014	(707,714)	2,445,343	1,457,263	22,839,842
2031	1,088,614	292,394	267,916	1,702,226	(794,057)	2,557,092	1,438,688	24,278,530
2032	1,103,629	300,171	272,337	1,651,638	(883,580)	2,444,194	1,298,309	25,576,839
2033	1,118,802	308,106	276,820	1,598,663	(976,313)	2,326,078	1,166,510	26,743,350
2034	1,134,143	316,208	281,368	1,543,568	(1,072,454)	2,202,833	1,042,961	27,786,310
2035	1,149,654	324,481	285,982	1,485,730	(1,172,039)	2,073,808	926,994	28,713,304
2036	1,165,387	332,975	290,682	1,425,883	(1,275,133)	1,939,794	818,627	29,531,932
2037	1,181,250	341,600	295,433	1,362,960	(1,381,934)	1,799,308	716,899	30,248,831
2038	1,197,350	350,461	300,275	1,297,623	(1,492,482)	1,653,228	621,881	30,870,711
2039	1,213,586	359,459	305,171	1,229,410	(1,606,875)	1,500,751	532,973	31,403,684
2040	1,230,090	368,726	310,170	1,159,025	(1,725,328)	1,342,683	450,186	31,853,871

Table B-3: NPV Analysis Alternative 2: Replacement Program								
Year	Capital Expenditures	Retirement Costs	Taxes and Net Salvage	Maintenance Costs	Avoided Electricity Costs	Total Cost	Net Present Value	Cumulative Present Value
2021	5,402,313	1,287,748	1,297,872	0	(333,029)	7,654,904	7,654,904	7,654,904
2022	5,481,788	1,326,078	1,320,726	0	(680,775)	7,447,816	7,031,549	14,686,453
2023	5,561,913	1,365,057	1,343,832	0	(993,769)	7,277,034	6,486,321	21,172,774
2024	5,642,399	1,404,397	1,367,078	0	(1,354,194)	7,059,681	5,940,885	27,113,659
2025	5,723,205	1,444,058	1,390,449	0	(1,731,636)	6,826,076	5,423,245	32,536,904
2026	5,805,483	1,484,377	1,414,233	0	(2,158,437)	6,545,655	4,909,794	37,446,698
2027	338,224	86,303	82,358	0	(2,214,634)	(1,707,749)	(1,209,362)	36,237,336
2028	339,745	87,824	82,948	0	(2,302,641)	(1,792,124)	(1,198,181)	35,039,155
2029	341,288	89,367	83,547	0	(2,416,227)	(1,902,025)	(1,200,584)	33,838,571
2030	342,838	90,918	84,149	0	(2,464,549)	(1,946,644)	(1,160,072)	32,678,500
2031	344,428	92,508	84,766	1,294,524	(2,513,849)	(697,623)	(392,501)	32,285,999
2032	346,033	94,113	85,388	1,316,981	(2,564,158)	(721,643)	(383,323)	31,902,676
2033	347,658	95,738	86,019	1,339,726	(2,615,325)	(746,184)	(374,205)	31,528,471
2034	349,307	97,386	86,658	1,362,790	(2,667,662)	(771,521)	(365,287)	31,163,184
2035	350,978	99,057	87,307	1,386,175	(2,721,014)	(797,496)	(356,482)	30,806,702
2036	352,687	100,767	87,970	1,410,376	(2,775,336)	(823,536)	(347,546)	30,459,156
2037	354,406	102,485	88,637	0	(2,830,859)	(2,285,331)	(910,545)	29,548,610
2038	356,166	104,245	89,320	0	(2,887,464)	(2,337,733)	(879,365)	28,669,245
2039	357,936	106,016	90,007	0	(2,945,157)	(2,391,199)	(849,204)	27,820,041
2040	359,755	107,835	90,712	0	(3,004,150)	(2,445,848)	(820,064)	26,999,977

3.0 Additional Notes

Capital Expenditures

Capital expenditures include all equipment and installation costs, as described in Section 1.4 of this appendix. This includes capital expenditures associated with a 1% annual failure rate of LED fixtures.

Retirement Costs

Labour costs associated with fixture replacement are charged 50% to retirement and 50% to capital in accordance with the Company's Capitalization Policy.

Taxes and Net Salvage

Income tax and net salvage costs are associated with financing and the eventual retirement of street light assets. Net Salvage costs are as detailed in the Company's *2014 Depreciation Study*.

Maintenance Costs

Maintenance costs for each alternative were estimated on per-fixture basis, as described in Section 1.3 of this appendix. Maintenance costs that are common between both alternatives, such as wiring issues, are not included in the analysis.

Avoided Electricity Costs

Avoided electricity costs are based on marginal cost estimates for energy and capacity, as described in Section 1.2 of this appendix.

Discount Rate

A discount rate of 5.92% is used based upon a 3.815% cost of debt, an 8.50% cost of equity, and the Company's existing capital structure of 55% debt and 45% equity.

Net Present Value

The calculated net present value of each alternative is shown in 2021 dollars for the period 2021 to 2040.

Cumulative Net Present Value

The cumulative net present value for the particular year is the sum of the present value for the year and the preceding years in 2021 dollars.

Appendix C

CBCL Limited Report

Newfoundland Power

LED Street Lighting Adoption Review

CBCL

NEWFOUNDLAND POWER
A FORTIS COMPANY

203016.00 • Final Report • June 2020

Contents

Chapter 1 Introduction

1.1 Scope of Document

As part of Newfoundland Power's 2021 Capital Budget Application (2021 CBA), the company proposes a multi-year plan to replace its existing High-Pressure Sodium (HPS) luminaires with new LED luminaires.

This report serves as a technical review of Newfoundland Power's approach for the adoption of LED street lighting technology. CBCL Limited's scope included a review of Newfoundland Power's process leading up the 2021 CBA, as well as their proposed implementation strategy for luminaire replacement.

1.2 Definitions

The following definitions apply to terms used within this document:

- ANSI: American National Standards Institute.
- Ballast: A device used with an electric-discharge lamp to provide the necessary circuit conditions (voltage, current, and wave form) for starting and operating.
- CCT: Correlated Colour Temperature. The absolute temperature of a blackbody whose chromaticity most nearly resembles that of the light source.
- CRI: Colour Rendering Index. A measure of the degree of color shift that objects undergo when illuminated by the light source, as compared with the color of those same objects when illuminated by a reference source of comparable color temperature.
- CSA: Canadian Standards Association.
- Efficacy: The quotient of the total luminous flux emitted by the total lamp power input. It is expressed in lumens per watt (lm/W).
- EPA: Effective Projected Area. A coefficient used to determine how much force a luminaire will apply to the mounting brackets or pole at a given wind velocity.
- Fixture: See "Luminaire".
- Fluorescent Lamp: A low-pressure mercury electric-discharge lamp in which a fluorescing coating (phosphor) transforms some of the ultraviolet energy generated by the discharge into light.
- HID Lamp: An electric discharge lamp in which the light-producing arc is stabilized by bulb wall temperature and in which the arc tube has a bulb wall loading in excess of 3 W/cm^2. HID lamps include groups of lamps known as mercury, metal halide, and high pressure sodium.
- IES: Illuminating Engineering Society.

- Illuminance: The areal density of the luminous flux incident at a point on a surface.
- LED: Light Emitting Diode. A p-n junction semiconductor device that emits incoherent optical radiation when forward biased. The optical emission may be in the ultraviolet, visible, or infrared wavelength regions.
- LED Array: An assembly of LED packages (components), or dies on a printed circuit board or substrate, possibly with optical elements and additional thermal, mechanical, and electrical interfaces that are intended to connect to the load side of an LED driver.
- LED Driver: A device composed of a power source and light emitting diode (LED) control circuitry designed to operate an LED package (component), an LED array (module), or an LED lamp.
- Lumen (lm): SI unit of luminous flux
- Luminaire: A complete lighting unit consisting of a lamp(s) and ballast(s) (when applicable), in conjunction with the parts designed to distribute the light, to position and protect the lamps, and to connect the lamps to its power source. Also known as a light fixture.
- Luminance: Visual brightness of a surface.
- Photocell: A photoelectric switch that controls lighting by the level of daylight illuminance.
- Road: Generally refers to both *streets* and *highways*, interchangeably.
- TAC: Transportation Association of Canada.

1.3 Reference Standards

The following reference standards are relevant for the implementation of LED street and area lighting design:

- ANSI C136.31– American National Standard for Roadway and Area Lighting Equipment – Luminaire Vibration
- ANSI C62.41 – IEEE Recommended Practice for Surge Voltages in Low-Voltage AC Power Circuits
- IES LM-79 – Optical and Electrical Measurements of Solid-State Lighting Products
- IES LM-80 – Measuring Luminous Flux and Color Maintenance of LED Packages, Arrays and Modules
- ANSI/IES RP-16 – Nomenclature and Definitions for Illuminating Engineering
- ANSI/IES RP-8 – Roadway Lighting
- ASTM B117 – Standard Practice for Operating Salt Spray (Fog) Apparatus
- CSA C22.1 – Canadian Electrical Code Part 1
- IES TM-21 – Projecting Long Term Lumen, Photon, and Radiant Flux Maintenance of LED Light Sources
- NEMA SSL 3 – High-Power White Binning for General Illumination
- TAC Guide for the Design of Roadway Lighting

1.4 About CBCL Limited

With over 300 employees, CBCL Limited is the leading employee owned multidisciplinary engineering and environmental consulting firm in Atlantic Canada. In business since 1955, and with branches located across all four Atlantic Canadian Provinces and in Ontario, CBCL Limited provides professional consulting services in a number of sectors, including Municipal Services, Water and Wastewater, Buildings, Industry and Manufacturing, Energy and Power, Oil and Gas, Marine, Transportation and Bridges and Environment and Planning.

CBCL Limited has developed an extensive lighting project portfolio throughout the years. Several of our employees are members of the Illuminating Engineering Society (IES) and have been on IES executive committees both on the local Section and Society levels.

Our lighting designers have worked on many different commercial, industrial, institutional, and infrastructure lighting projects including studies and evaluations, lighting upgrades and retrofits, lighting designs for new construction projects and renovations, daylighting analysis for buildings, obtrusive light, and light trespass calculations.

One of our most relevant projects applicable to this report is our work related to the large-scale replacement of LED Street lights in Halifax, Nova Scotia. This project involved the replacement of approximately 44,000 HPS luminaires across over 5,000 km of roadway, within the Halifax Regional Municipality. CBCL's role involved establishing lighting design criteria in accordance with IES recommendations and detailed lighting calculations and associated documentation to select an appropriate replacement luminaire to be installed by their construction partner.

Chapter 2 Approach to Adopting LED Street Lighting Technology

2.1 History of LED Lighting

Touted for its long life and high efficacy, LED lighting technology for general illumination became commercially available in the late 2000's and its industry growth has been exponential to the point in which it is currently the industry standard for all interior and exterior lighting applications.

For decades prior to this, commercial lighting generally consisted of fluorescent and high-density discharge lighting technology which incorporated lamps and ballasts into luminaires and each component was evaluated independently for its intended purpose. The luminaire was evaluated for its physical characteristics such as its construction, finish, lighting distribution, and efficiency; the lamp was evaluated for its performance such as mean lumen output, CRI value, colour temperature, and average rated life; and the ballast was evaluated based on its operating characteristics such as power factor and total harmonic distortion. As these three components were not totally reliant on each other, they could each be evaluated on their own merits. Improvements in lamp and ballast technology were typically backwards compatible with existing luminaires as their shapes and base form factors were standardized. Though there are still three (3) main components in LED luminaires (LED Engine, Driver and Housing), they are produced as a complete system and must be evaluated that way.

In the early phases of LED adoption, the lighting industry was struggling to adapt to the rate of technological improvements. New luminaires were becoming available from start-up companies with brochures promoting long life and high-efficacy; however, there were no procedures or documents developed to validate these claims. This, in addition to significant cost premiums, led to a slow and cautioned uptake of LED technology within the lighting industry. This began to change in 2008 when the IES published LM-79 and LM-80; its first two LED specific guides for measuring lumen output and depreciation of LED luminaires. TM-21 followed in 2011 to establish a standard method of projecting the useful life of an LED luminaire based on LM-80 test data. By 2011, the course was set for LED lighting technology as price points started to descend and simple paybacks became more favorable. By 2013, LED lighting was the industry standard for the majority of exterior applications and this also became the case for interior lighting by 2015. As of 2020, price points for the majority of LED luminaires have stabilized to the point that HID and fluorescent products are being phased out by lighting manufacturers.

2.2 Newfoundland Power LED Street Lighting Adoption

Newfoundland Power began evaluating LED lighting for its street lighting services in 2009 by installing LED luminaires from various manufacturers in its service territory on a trial basis. Following this, the company began its assessment and business case for adopting LED lighting as its new standard. This process encompassed several tasks, including:

- An assessment of LED technology compared to HPS technology.
- A net present value analysis comparing HPS luminaires to LED luminaires.
- A customer survey.
- A review of industry trends including other Utility practices.
- Development of a LED Street Lighting Luminaire Specification.

A report with findings on this assessment was produced in June of 2018 and was included in the 2019/2020 General Rate Application (GRA). The GRA proposed new rates for LED street and area lighting that were approved by the Newfoundland and Labrador Public Utilities Board.

As of March 1, 2019, LED luminaires have become standard for all new installations and for end-of-life HPS replacements.

2.3 LED Street Lighting Luminaire Specification

Newfoundland Power developed its LED Street Lighting Luminaire Specification with criteria applicable to its service territory. This specification was developed based on their review of the trial installations and input from engineering consultants and manufacturers.

This specification was included in a request for proposal for the procurement of LED street lighting luminaires. Newfoundland Power engaged CBCL Limited to aid in evaluating the proposals and subsequently entered into a contract for the supply of these luminaires.

Knowing the needs of the application and having an appropriate specification to meet those needs is crucial when procuring any product; however, this is especially true when these products will be purchased in bulk such as LED roadway luminaires. Procuring a product that is inferior to the needs of the application can result in immediate or long-term issues which will ultimately lead to additional expenditure and client dissatisfaction.

The two main considerations when specifying street lighting luminaires are their reliability, and their performance. This is especially true for large or remote service areas with relatively low population densities as the labour associated with maintenance calls can far

outweigh the cost of repair or replacement of a product. Another important factor is ease of service.

Items 2.3.1 through 2.3.3 describe the most important considerations related to reliability, performance, and serviceability, in addition to how Newfoundland Power's LED Street Lighting Luminaire Specification addresses them. A less robust specification would reduce the reliability and performance of the equipment potentially leading to higher maintenance cost for very little savings on the initial procurement cost.

2.3.1 Reliability

LED technology is often synonymous with low-maintenance and high reliability, due to its long life; however, this claim is contingent on the product being suitable for the environment in which it is installed. Newfoundland and Labrador's weather can be harsh on several aspects including:

High Winds:

The most obvious effect of a high-wind condition would be mounting hardware failure causing the luminaire or its arm to come out of alignment or fall down completely.

High winds can generate oscillations and vibrations within the lighting assembly; this could lead to loose internal connections resulting in premature equipment failure.

Among other weather conditions such as snow, ice and rain, heavy winds and lightning can cause power outages which can cause surges and damage sensitive electronics within the luminaires.

Heavy Snow, Rain and Ice:

Luminaires and their internal components must be properly protected (sealed) against the ingress of water/moisture to avoid premature failure.

The luminaire's construction, and its geometry, should be designed to avoid the build-up of snow and ice to maintain the intended optical and thermal performance of the luminaire. Additionally, this would avoid an undue increase in luminaire weight and/or EPA.

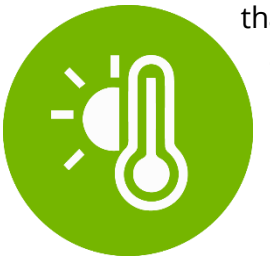
Coastal and Corrosive Environments:

Many areas in Newfoundland and Labrador are near salt water. Salt is also used for snow clearing operations which can lead to the corrosion of equipment and hardware. This can drastically reduce the anticipated useful life of a product if it is not designed for such a purpose.

Birds can often be observed atop pole mounted luminaires and their droppings can damage finishes causing the paint to peel off. The housing should be properly pre-treated and painted with a durable finish. Luminaires installed in problematic areas (near coastlines) could be fitted with bird spikes.

Temperature Extremes:

Generally speaking, LED luminaires are much less affected by extreme cold temperatures than they are with extreme heat, which is favourable for Newfoundland and Labrador's climate; however, extreme cold can have an effect on a luminaire's ability to rid itself of accumulated snow or ice.



The technical requirements included in Newfoundland Power's LED Street Lighting Luminaire Specification addresses all of these factors by specifying the appropriate construction, finish, and testing per industry standards. These include:

- Salt spray testing
- 3G vibration
- Enclosed and gasketed housing
- Passive heat sink
- Treated and Painted Finish
- Surge Protection
- 10-year warranty

2.3.2 Performance

Similar to the relationship between the installed conditions and reliability, the performance of a luminaire/lighting design must be tailored to the application it is meant to serve. The following performance criteria should be considered when executing a design and specifying a luminaire.

Lumen Output, Depreciation and Distribution Pattern:

The most apparent factors in a quality lighting design/luminaire selection is the lumen output and distribution pattern. Proper selection of these will ensure appropriate light levels are achieved in the designated areas.

Mounting options are also important considerations for field aiming where necessary.

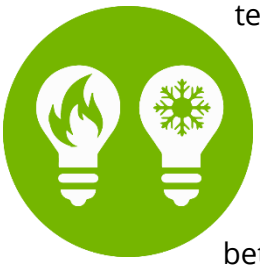
Lumen depreciation over time must also be considered to ensure the basis of design illuminance is achieved over the useful life of the product.

Efficacy:

Expressed in lumens per watt, efficacy is a ratio of how much light is produced and the power required to produce it. The higher the efficacy value, the higher the energy savings will be.

Correlated Colour Temperature:

The majority of LED roadway lighting installations to date utilise a cool-white colour temperature of 4000°K to 6000°K that most closely resembles daylight. Early adopters of LED for roadway and street lighting gravitated to these higher colour temperatures to capitalize on the higher efficacy values associated with high CCT.



More recently, colour temperature trends have gravitated to values between 3000°K and 4000°K which produces a warmer light than LED roadway luminaires with higher correlated colour temperatures.

Another factor related to this is the CCT variation between each chip. This is commonly known as the LED binning process. These variations should not be apparent at the street level, and only slight variations should be noticeable when looking directly at the source.

Colour Rendering Index:

CRI and spectral power distribution are methods of determining the ability of a luminaire source to depict the true colour of an object. Commercial LED's typically have CRI values ranging between 70 and 90. Though on the low-end of colour rendering for commercial, retail or interior lighting applications, a CRI value of 70 is common and reasonable for exterior street and area lighting. By comparison, the typical CRI value of an HPS light source is in the range of 20-25.

Controls:

Street and area lighting controls must be considered when specifying a luminaire. Control of exterior lighting can be fulfilled in several different ways including:

- Group control via a time clock or photocell and lighting contactors.
- Individual control via on-board photocell.
- Individual or group control via on-board wireless mesh network nodes.
- Control based on occupancy or motion sensing.
- Dimming controls for pre-curfew and post curfew scenarios.

Most roadway lighting applications use individual control via an on-board photocell. This reduces the likelihood of group failures due to a faulty control device and also reduces the amount of distribution equipment required.

The Newfoundland Power LED street Lighting Luminaire Specification addresses all of these performance factors. This includes:

- Colour temperature of 3000°K with binning per NEMA SSL 3
- CRI value of 70 or greater
- Luminaire mounted photocell
- Lumen output and distribution options
- 100,000 rated life to L85 based on IES TM-21
- Luminaire tilt adjustment

2.3.3 Serviceability

Several factors can improve the ease of service of a luminaire and reduce time spent on service calls. These include:

Tool-less Access and Common Hardware:

The luminaire should be easily accessed and hardware should be captive to avoid dropping or losing items. This could involve a hinged lens with captive screws or a secured handle to access replaceable parts. Hardware configurations should also be common to avoid multiple screw drivers or wrench sizes/styles.

Easily Replaceable Parts:

Main components of luminaires such as drivers, photocells and LED array should be easy to access and remove. This may include receptacle-based photocells, quick connectors for components and common hardware configurations.

Visible and Durable Labelling:

Luminaire types, ID's, distributions and outputs should be visible from the ground to avoid multiple trips up the pole to remove and replace luminaires/components.

The Newfoundland Power LED street light Luminaire Specification addresses all of these serviceability factors. This includes:

- Receptacle based lighting controller (photocell)
- Toolless Access
- Labelling visible from the Ground
- Labelling on exterior of packaging
- Modularly replaceable LED array
- Quick disconnect and easy access for LED driver

2.4 Recommended Street Lighting Criteria

The *Recommended Street Lighting Design Criteria* was developed by CBCL Limited for Newfoundland Power. This document was based on industry best practices, as well as CBCL's experience with Street Lighting designs in several markets. This document further included extensive research on policies, procedures, and codes from other jurisdictions throughout North America. Recommended practices and guidelines from the Transportation Association of Canada (TAC) and the Illuminating Engineering Society (IES) were also incorporated into the report.

The *Recommended Street Lighting Design Criteria* is intended to be used to assist Newfoundland Power and its customers in establishing the appropriate lighting design criteria to provide adequate and uniform lighting levels for a variety of roadway applications and areas including streets, highways, intersections, roundabouts, crosswalks and sidewalks.
The document generally identifies factors which affect and dictate the required illuminance, luminance, and uniformity values for a given application. These factors include pavement classification, street and highway classification, pedestrian conflict, intersection classification, urban versus rural areas, obtrusive light, and light trespass.

2.5 Street Lighting Design Guide

The *Street Lighting Design Guide* was also developed by CBCL Limited for Newfoundland Power. As with the previous document, the *Street Lighting Design Guide* was based on industry best practices, project experience, and recommended practices from TAC and the IES.

This document is intended to be used by Newfoundland Power engineering and field staff in order to have a consistent design approach for a variety of scenarios in an effort to achieve the values identified in the recommended street lighting design criteria document.

The document identifies a number of parameters which must be accounted for when performing a design such as light loss factors, pole/luminaire spacing, luminaire distribution pattern options, lumen output options, pole setback, mounting arm length, luminaire tilt options, light trespass reduction techniques, and luminaire mounting heights.

The document also provides fifteen (15) potential design scenarios with associated design criteria and calculation summaries identifying areas of compliance or non-compliance with previously established recommendations. These typical scenarios will offer guidance for most applications encountered by Newfoundland Power's engineering and field staff.

Chapter 3 Newfoundland Power's Street Lighting Replacement Program

3.1 Overview of Proposed Implementation

Presently, Newfoundland Power is only proceeding with the installation of new LED luminaires for new installations or when an existing luminaire has reached the end of its service life. Existing HPS luminaires requiring lamp or ballast replacements are being serviced as usual.

As part of the 2021 CBA plan, the Company intends to carry out an accelerated replacement of its existing HPS street lighting luminaires over a multi-year timeframe. The intent behind this is to expedite the adoption of LED technology and lighting service.

In general, similar organisations have opted for accelerated replacement programs as they appear to be the most practical means of adopting LED technology. Though this approach results in higher capital investment early-on, it is beneficial for several reasons including:

- Consistent lighting patterns, colour temperature, CRI, and luminaire appearance in a shorter timeframe.
- Less maintenance requirements and fewer street light outages.
- Preventative maintenance schedules could be established and tracked more reliably.
- Lower cost relating to electricity consumption.
- Common rates and lighting results for all customers within a shorter timeframe.

A long-term end-of-life only replacement strategy could lead to unused inventory, inconsistent lighting results, and customer complaints due to higher rates. Additionally, HPS technology will become costlier and more difficult to source over time whereas pricing for LED luminaires has stabilized.

3.2 2021 CBA Plan Assumptions

The Net Present Value (NPV) analysis in Newfoundland Power's 2021 CBA Plan compares status quo (End-of-Life replacement only) against an accelerated replacement program. The NPV analysis estimates a $4.9M savings by selecting the accelerated replacement option. Electricity requirements (energy savings), maintenance cost, and

equipment/installation cost are the three key factors evaluated to determine the NPV of either scenario.

3.2.1 Electricity Requirements (Energy Savings)

The analysis assumes an average operation of 11.5 hours per day and an energy savings of 52% to 66% by converting to LED depending on the lumen output required. Greater source efficacy is the only factor that will affect energy consumption for this application as operating hours and controls are the same for both options. As can be expected, greater energy savings are achieved with the accelerated replacement program. It is possible to see slight increases in efficacy over time; however, these savings would likely be negligible when compared against the savings achieved by adopting LED technology at an earlier stage.

3.2.2 Maintenance Cost

The maintenance cost associated with HPS luminaires was determined based on historical data from 2017-2019 and generally consisted of HPS lamp replacements. This includes an average material cost of $10 for a lamp and $205 for responding to the outage (labour, vehicle and traffic control). It was assumed that this would have to be completed every six (6) years (24,000 operating hours) and an inflation factor was added to this cost resulting in an average maintenance cost of $224 per luminaire at six (6) year intervals.

The maintenance cost associated with the accelerated replacement program is estimated at $107 per luminaire and assumes one visit to perform cleaning activities as part of a preventative maintenance program. The result is a much lower maintenance cost per luminaire as there are significant labour efficiencies associated with preventative maintenance programs. Maintenance teams are not dispatched on a case-by case basis.

The NPV analysis also assumes a 1% annual failure rate which would be addressed as a maintenance exercise. This conservative assumption appears to be in-line with industry standards.

Additionally, the specified ten (10) year warranty will help minimize material cost associated with premature component failures.

3.2.3 Equipment/Installation Cost

The NPV analysis for the accelerated replacement program assumes a stable cost for the LED luminaires plus a 2% volume discount. This input appears to be reasonable as it is not likely to see a reduction in material cost since costs for standard LED technology has now stabilized.

The NPV analysis also assumes a $39 labour premium for installing an LED luminaire compared to servicing/relamping an HPS luminaire. This allows for additional time to remove the existing HPS luminaire and install the new LED Luminaire.

Chapter 4 Conclusion

4.1 Summary of Review

As demonstrated in the body of this report, CBCL Limited have reviewed Newfoundland Power's intent with regards to the adoption of LED lighting as a standard for street lighting applications and feel that the approach is consistent with industry standards. The inputs used in the NPV analysis comparing status quo against the accelerated replacement program appear to be valid within a reasonable margin of error.

In addition to their own field testing and multiple and NPV analyses, Newfoundland Power have consulted with other utilities on their policies, reached out for feedback from their own customers, and engaged consulting engineers actively involved in the exterior lighting industry for professional guidance.

Their timing in adopting LED as a standard has allowed for making educated decisions as the LED lighting industry continues to mature. Examples of this includes the development of standards for evaluating the performance and reliability of LED luminaries, as well as selecting a lower luminaire colour temperature than early adopters based on lessons learned. This has demonstrated a thorough vetting process in making the appropriate decision for its stakeholders and clients.

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Appendix D

MNL Correspondence

June 9, 2020

Mr. Byron Chubbs
Vice President, Energy Supply & Planning
Newfoundland Power
55 Kenmount Road
P.O. Box 8910
St. John's, NL A1B 3P6

Dear Mr. Chubbs:

Municipalities Newfoundland and Labrador (MNL) and its members have been engaged with Newfoundland Power for a number of years regarding the ongoing assessment and evaluation of LED streetlights in the province. We were pleased to learn at last year's MNL Conference that Newfoundland Power had received approval to adopt LED streetlight as its new lighting standard. Our municipal leaders were also encouraged that planning was well underway to replace all High-Pressure Sodium (HPS) streetlights with LED streetlights.

We understand that LED streetlights are more reliable, use less energy and require less maintenance than existing HPS streetlights currently in service throughout our municipalities. In addition, LED streetlight rates are between 9% and 39% less than those of HPS streetlights. Transitioning from HPS to LED provides many tangible benefits to our municipalities, including lower costs, less outages and better lighting quality.

A recent presentation by Newfoundland Power outlined its proposed LED Streetlight Replacement Program. The approach to install an LED streetlight whenever a HPS streetlight outage occurs, resulting in all HPS streetlights being replaced over a 6-year period, provides a reasonable timeframe that will work well for municipalities.

Street lighting is an important service for all municipalities in the province. Managing the costs associated with this service will be extremely beneficial to many municipalities who face economic uncertainty at this time. Newfoundland Power's replacement program will ensure municipalities receive the benefits of reduced costs and improved reliability that come with LED streetlights.

Therefore, MNL fully supports Newfoundland Power's proposed LED Streetlight Replacement Program and believes it will result in a fair and reasonable deployment of LED streetlights to the municipalities it serves.

Sincerely,

Sheila Fitzgerald

Sheila Fitzgerald, President

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Customer Service Continuity Plan

June 2020

NEWFOUNDLAND POWER
A FORTIS COMPANY

TABLE OF CONTENTS

1.0 Executive Summary

Least-cost customer service delivery is a principal objective of Newfoundland Power Inc. ("Newfoundland Power" or the "Company"). The Company serves more customers and responds to nearly triple the number of customer enquiries today in comparison to 20 years ago. Customer service costs are 43% lower today than 20 years ago on an inflation-adjusted basis.

All essential customer service functions are supported by Newfoundland Power's Customer Service System. This system was implemented in 1993 with an expected service life of 20 years. The Company plans to replace the system by 2023 following 30 years of operation.

Replacement of this system is necessary to ensure continuity in customer service delivery. An assessment by Ernst & Young LLP ("EY") in 2018 determined Newfoundland Power is the last mid-to-large Canadian utility operating a legacy system with no upgrade path provided by the original vendor. EY concluded, in effect, that Newfoundland Power's system is facing risk of obsolescence and recommended the Company explore modernization options.

An independent assessment of alternatives has confirmed that implementing a modern Customer Information System is the only viable alternative to ensure continuity in Newfoundland Power's customer service delivery. A modern Customer Information System would support the Company's existing business processes, provide opportunities to improve the customer experience, and align the Company with current industry practice.

Newfoundland Power plans to implement a modern Customer Information System over 3 years at a total cost of approximately $31.6 million. These costs are comparable to the experience of other utilities implementing similar projects.

The Company's plan for implementing a modern Customer Information System is consistent with the recommendations of EY and industry best practices. Implementing this plan will enable Newfoundland Power to continue providing responsive and least-cost service to its customers over the long term.

2.0 Background

2.1 Customer Service Delivery

Newfoundland Power serves approximately 87% of all electricity customers in Newfoundland and Labrador. Customer service delivery is a principal business function of the Company.

Newfoundland Power's customer service delivery includes:

(i) **Program and service delivery**, which includes customer conservation programs, customer financing programs, and requests for field work, such as new service connections. Over 50,000 on-bill conservation rebates have been provided to customers since 2009.[1] The Company has also provided over $9 million in customer financing programs over this period.

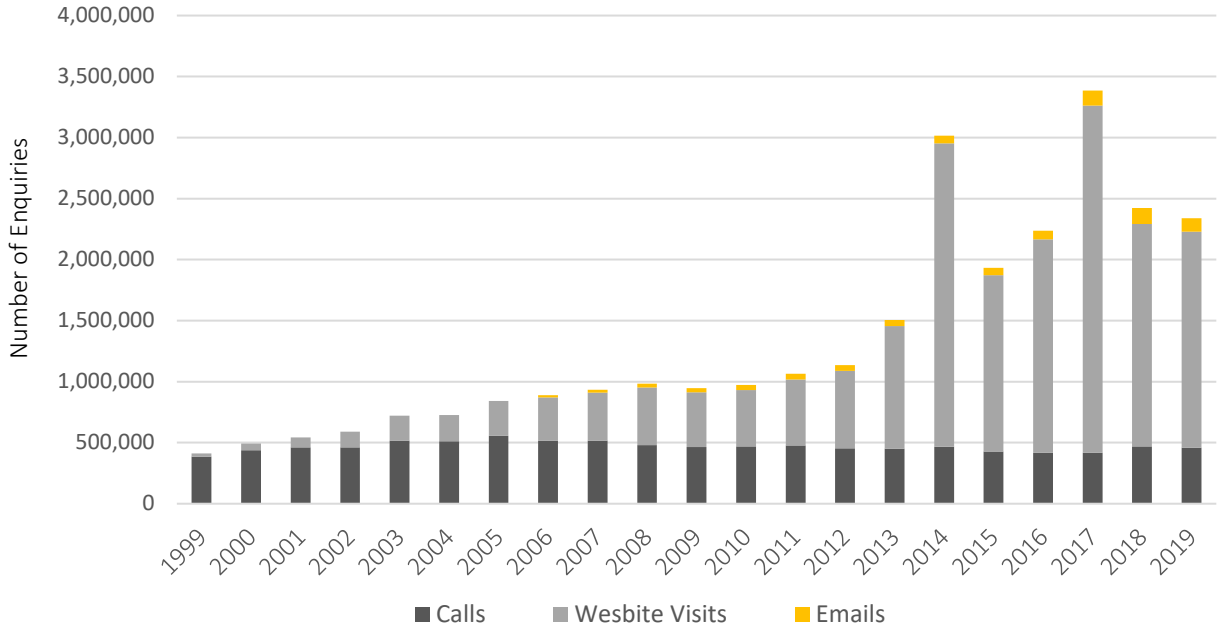
(ii) **Account management and billing**, which requires reading approximately 258,000 customer meters, issuing over 3 million customer bills annually, and managing all customer payments. The Company's approach to account management and billing has evolved over time to include options for customers such as paperless billing ("ebills"), the Equal Payment Plan, and online self-service options.

(iii) **Communications and contact management**, which requires managing customers' enquires via telephone, email and the customer website. Customers expect to receive timely and accurate information. Digital communication channels are increasingly used by customers to obtain information on their accounts, outages, and available programs and services.

[1] On-bill conservation rebates are provided for energy-efficient products, such as programmable thermostats and insulation. For more information, see Newfoundland Power's *2019 Conservation and Demand Management Report,* filed with the Newfoundland and Labrador Board of Commissioners of Public Utilities Board ("the Board") on April 2, 2020.

Figure 1 shows the number of customer enquiries received annually via phone, website and email over the 20-year period 1999 to 2019.

Figure 1:
Customer Enquiries
(1999 to 2019)



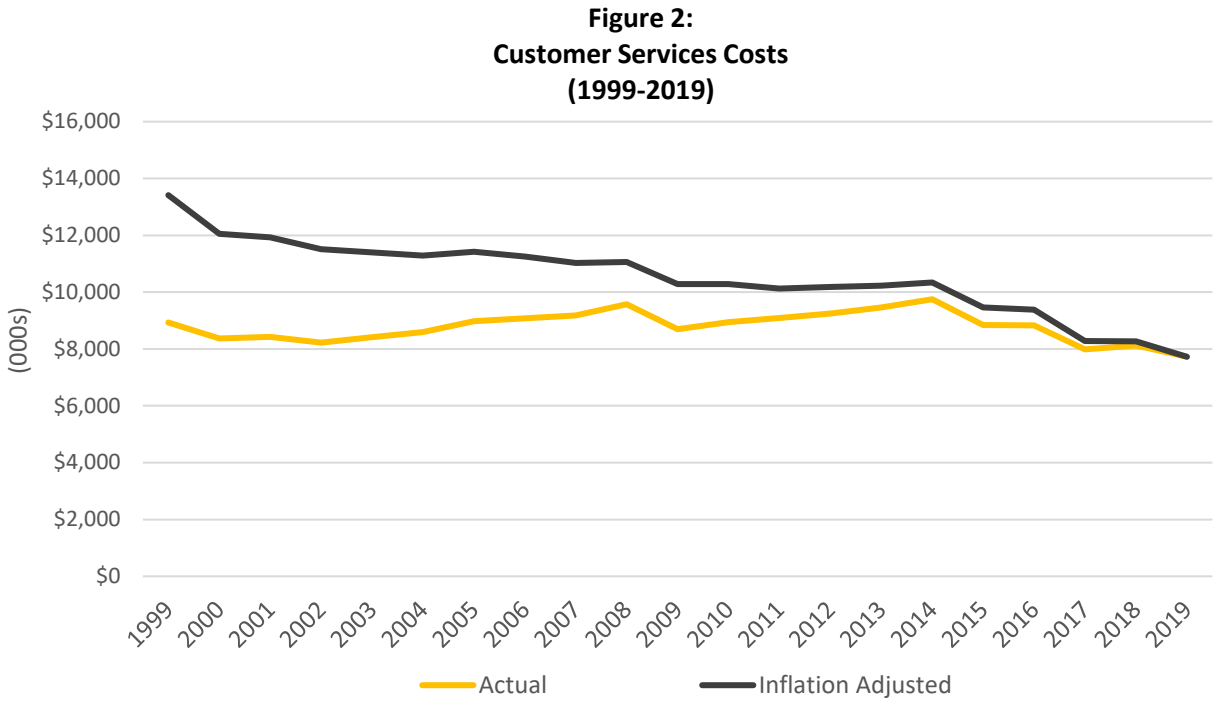
Enquiries from customers nearly tripled over the last 2 decades. An average of approximately 2 million customer enquiries were responded to annually over the most recent decade. This compares to an average of approximately 700,000 customer enquiries annually over the previous decade.

This increase in customer enquires occurred exclusively via digital communication channels. The number of visits to the customer website quadrupled in 2019 compared to 2009.[2] The number of customer emails tripled over the same period.[3]

[2] There were approximately 450,000 visits to the customer website in 2009 and approximately 1.8 million in 2019 (1.8 million / 450,000 = 4.0).

[3] Approximately 34,000 customer emails were received in 2009 and approximately 109,000 in 2019 (109,000 / 34,000 = 3.2).

Figure 2 shows the total annual cost of Newfoundland Power's customer service delivery over the 20-year period 1999 to 2019.[4]



Newfoundland Power provided customer service at a lower total cost in 2019 than in 1999. On an actual basis, customer service costs were 13% lower in 2019 than in 1999. When adjusted for inflation, costs were 43% lower over the same period.[5]

While customer service costs were reduced, the number of customers served by Newfoundland Power increased by 55,000, or 26%, from 1999 to 2019.

Customers have indicated a reasonable level of satisfaction with the Company's service delivery. Customer satisfaction averaged approximately 88% over the 20-year period 1999 to 2019.

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4 Excludes costs associated with customer conservation programs and uncollectible bills expense.

5 Customer service costs were approximately $8.9 million in 1999 and $7.7 million in 2019 (($7.7 million - $8.9 million) / $8.9 million = -0.13, or -13%). In 2019 dollars, customer service costs were approximately $13.4 million in 1999 (($7.7 million - $13.4 million) / $13.4 million = -0.43, or -43%).

Overall, Newfoundland Power's approach to customer service delivery is efficient and responsive to customers' service expectations.[6]

2.2 Customer Service Technology

System Functionality

The Customer Service System ("CSS") is the primary technology underpinning Newfoundland Power's customer service delivery. CSS supports account management and billing, customer communication and contact management, and program and service delivery.

CSS was developed and implemented in 1993 at a total cost of approximately $10.2 million. The system modernized customer service delivery at Newfoundland Power. It allowed manual billing and account management processes to be eliminated and enabled the Company to centralize its customer service function. This modernization supported the long-term service efficiencies shown in Figure 2.

CSS was developed with an expected service life of 20 years. The system continues to support all essential customer service functions today by:

(i) Storing and maintaining information related to over 269,000 active customer accounts and over 1 million inactive accounts;

(ii) Processing monthly metering data to automatically generate virtually all customer bills, including the automatic issuance of ebills to customers;

(iii) Tracking and applying customer payments and payment arrangements, including generating automatic correspondence and calls to customers;

(iv) Connecting directly with the customer website and telephone system to provide self-service options, including the ability for customers to view account balances, request payment arrangements, and report outages online;

[6] An assessment of the overall effectiveness of Newfoundland Power's operations in meeting customers' service expectations is provided in Attachment B, Customer Experience Report.

(v) Providing a record of customers' service history and previous contacts with Newfoundland Power to facilitate responding to customers' enquiries;

(vi) Facilitating the delivery of programs and services to customers, including all on-bill customer conservation rebates and customer financing programs; and

(vii) Logging and tracking day-to-day work queues for customer service staff, such as customer billing adjustments, high billing enquiries, and energy conservation requests.

This functionality is essential to providing service to customers. Much of this functionality has evolved over the last 2 decades in response to changing customer expectations, industry practices and regulatory requirements.[7] These modifications have resulted in a highly customized and complex system that is unique to Newfoundland Power.

Risks to Continued Operation

The Company has monitored the risks facing CSS as part of its routine technology planning. Risk assessments were completed in 1996, 2003 and 2013. These assessments have contributed to the extension of the system's service life.

A risk assessment by EY in 2018 examined the current technical and functional risks facing CSS.[8] The assessment determined, in effect, that CSS is facing risks of becoming both technologically and functionally obsolete.

The risk assessment examined the vendor market share and vendor health of CSS, which are indicators of technology obsolescence. As product sales decline and vendor investment dwindles, it is increasingly likely that a technology will no longer be upgraded or supported by its vendor.

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[7] For example, CSS was upgraded in 2003 to support the Equal Payment Plan for customers, in 2011 to deliver the Provincial Government's residential energy rebate, and in 2016 to deliver the Rate Stabilization Plan ("RSP") Refund to customers.

[8] Technical risks relate to the performance and security of the underlying technology and infrastructure. Functional risks relate to the ability to deliver the required customer service business functions.

A survey conducted as part of the risk assessment determined that Newfoundland Power is the last mid-to-large Canadian utility operating a legacy system with no upgrade path provided by the original vendor.[9] The market share of the technologies underlying the system has diminished and individuals with the skills to support these technologies are in short supply.[10] In many cases, vendor investment in these technologies has either ended or is uncertain.[11]

Functional obsolescence was assessed based on the ability of CSS to deliver key customer service functions. The risk assessment determined that the functionality provided by CSS is "manageable," but the ability to upgrade and enhance the system is inadequate.[12] Some functional limitations have already materialized. For example, the billing of net metering and some large general service customers cannot cost-effectively be delivered through CSS. These functional limitations are expected to increase over time as customers' service expectations evolve.[13] CSS could not, for example, be customized to deliver time-of-use rates.

The assessment further determined that CSS has moderate support risk. CSS has been supported using internal expertise since 1998.[14] Support capacity is expected to diminish over time due to employee retirements.[15] The skills necessary to replace this expertise are not commonplace in the labour market and are no longer offered as part of postsecondary programs.[16] Diminished support capacity increases the risks of both technological and functional obsolescence.

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9 See EY, *CSS Technical Risk Assessment,* June 2018, pages 9-10.
10 See EY, *CSS Technical Risk Assessment,* June 2018, pages 7-9.
11 See EY, *CSS Technical Risk Assessment,* June 2018, pages 12-14.
12 See EY, *CSS Technical Risk Assessment,* June 2018, pages 17-18.
13 See EY, *CSS Technical Risk Assessment,* June 2018, page 19.
14 The CSS vendor, Andersen Consulting, notified the Company it was discontinuing support of the CSS in 1997. Newfoundland Power subsequently upgraded the system architecture to allow the system to be supported internally. This architecture remains the basis upon which the CSS operates today.
15 Two employees with a high level of expertise in CSS will be eligible to retire by 2023. Three additional employees with a high level of expertise will be eligible to retire by 2028. At the time of the assessment, the average age of these 5 employees was 53 years.
16 See EY, *CSS Technical Risk Assessment,* June 2018, page 14.

Obsolete technology faces a higher risk of failure. Critical failure of CSS would effectively preclude the delivery of efficient and responsive service to customers. Considerable manual effort would be required to maintain minimum service levels. This would include the manual processing of thousands of customer bills, payments, enquiries and service requests each month.

Based on the 2018 risk assessment, EY recommended that: *"Newfoundland Power formalize and deepen its examination of CSS modernization options to include a thorough evaluation of the costs and benefits of replacement and deployment options."*[17]

Newfoundland Power commenced a 3-year assessment and planning project in 2018 to mitigate the risks facing its customer service delivery.

2.3 Assessment and Planning Framework

Newfoundland Power provided an assessment and planning framework to ensure continuity in customer service delivery as part of its *2019/2020 General Rate Application*.[18] The framework was developed based on industry best practices and included 4 milestones:

(i) **Current state assessment** detailing the business processes behind how Newfoundland Power currently delivers customer service, the technology supporting these processes, and the strengths and weaknesses of the current approach;

(ii) **Target state assessment** outlining how Newfoundland Power will continue to provide customer service over the longer term, including the functional and technical requirements for the replacement technology;

(iii) **Application development planning** to identify how Newfoundland Power will implement a replacement solution that meets all business requirements; and

(iv) **Data assessment** to support a successful transition of all necessary customer data to the replacement solution.

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[17] See EY, *CSS Technical Risk Assessment*, June 2018, page 21.

[18] See Attachment A to response to Request for Information PUB-NP-008 filed as part of Newfoundland Power's *2019/2020 General Rate Application.*

Newfoundland Power executed the assessment and planning framework from 2018 to 2020. Execution of the framework included independent expert assessments of the Company's operations, site visits with utilities who have recently completed similar projects,[19] vendor product demonstrations,[20] customer focus groups and surveys,[21] and other industry research.

This report outlines Newfoundland Power's plan for ensuring continuity in customer service delivery based on the results of its assessment and planning work.

3.0 Assessment of Continuity Options

3.1 Overview

EY was selected through a competitive tendering process to assist Newfoundland Power in developing a plan to ensure continuity in customer service delivery.[22]

EY assessed what alternatives are available to provide continuity in Newfoundland Power's customer service delivery. Alternatives were identified based on industry trends and its experience working with other utilities. Each alternative was assessed on the basis of whether it would mitigate the technical and functional risks associated with CSS. The recommended alternative was then assessed in detail to understand the potential impact on Newfoundland Power's operations and to develop planning recommendations.

This section summarizes the results of these assessments.

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[19] Newfoundland Power completed site visits with 5 utilities who had recently replaced their customer service technology: Hydro Ottawa, Consolidated Edison (Orange and Rockland), Central Hudson and Arizona Public Service. These site visits allowed Newfoundland Power to gain an understanding of current best practices in implementing replacement projects of this magnitude.

[20] Product demonstrations were held with 6 commercial software vendors to understand the technical and functional capabilities of their products and whether they could deliver Newfoundland Power's requirements.

[21] See Attachment B to the plan for more information on customer focus groups and surveys conducted to date.

[22] The results of EY's work, *Customer Information System: Assessment Results and Planning Recommendations*, March 2020 (the "EY Report"), are provided as Attachment A to this plan.

3.2 Assessment of Alternatives

The 4 alternatives assessed by EY were: (i) maintaining the status quo; (ii) extending CSS with bolt-on applications; (iii) re-platforming CSS; and (iv) replacing CSS with a modern, commercially available solution.

According to EY, the risks facing CSS are not static and will increase over time. Maintaining the status quo would not address the technical or functional risks facing the existing system. Certain functionality, such as time-of-use rates, could not be delivered within CSS. Diminishing support capacity and vendor investment will continue to present risks to the underlying system infrastructure.[23]

The assessment therefore concluded that maintaining the status quo is not a sustainable option.[24]

Bolt-on applications are software applications that are integrated with the existing system to provide specific business functions, such as a time-of-use rates engine. The assessment determined that bolt-on applications would not address limitations with core CSS functionality, would be technically complex to implement and would not address the technical risks facing the current system.[25]

Re-platforming CSS would require automating the migration of the existing code to a modern, supported programming language. The assessment determined that re-platforming is not standard industry practice, would mitigate certain technical risks while increasing others, and would not mitigate any functional risks facing the current system.[26]

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[23] See the EY Report, pages 7-8.
[24] See the EY Report, page 8.
[25] See the EY Report, pages 8-9.
[26] See the EY Report, page 9.

The assessment determined that neither bolt-on applications nor re-platforming CSS are viable alternatives.[27]

EY concluded the only viable alternative to provide continuity in Newfoundland Power's customer service delivery is to replace CSS with a modern, commercially available solution.[28] A modern, commercially available solution would mitigate both the functional and technical risks facing the current system.[29]

According to EY, modern Customer Information Systems ("CIS") have core functionality included in the base products and dedicated upgrade strategies to ensure system functionality can address changing business requirements and customer expectations. Modern CIS solutions include vendor support resources, proactive upgrades and streamlined IT environments to reduce complexity.[30]

EY confirmed that implementing a modern CIS would align Newfoundland Power with current industry practice. Newfoundland Power is the last remaining mid-to-large Canadian utility operating a legacy system with no upgrade path provided by the original vendor.[31] Current industry practice is to implement a modern CIS from a commercial software vendor.[32]

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[27] See the EY Report, pages 8-9.

[28] EY states: "*EY recommends replacing Newfoundland Power's CSS with a modern CIS as it is the only viable alternative that mitigates the functional and technical risks facing Newfoundland Power.*" See pages 10-11.

[29] Ibid.

[30] Ibid.

[31] See the EY Report, page 4.

[32] See the EY Report, page 13.

3.3 Detailed Assessment

EY assessed how a modern CIS would fit within Newfoundland Power's operations. The assessment included:

(i) An analysis of current industry trends in implementing modern CIS solutions, including a survey of 120 North American utilities and a subset of 28 peer utilities;[33]

(ii) Process maps outlining the workflows and related technologies of 43 key customer service functions that would be supported by a replacement solution;[34]

(iii) An examination of opportunities to improve customer service delivery in the future;[35]

(iv) A review of how a solution would fit technically among 56 other applications in Newfoundland Power's IT environment;[36] and

(v) A data quality assessment to identify and help address any issues with transitioning customer and Company information to a replacement solution.[37]

EY determined that a modern CIS would fit well in Newfoundland Power's operations.

From a functional perspective, EY assessed that Newfoundland Power's customer service business processes are similar to those of other utilities. Approximately 80% of customer service business processes are common across utilities. These processes are readily delivered in a modern CIS through the base package or standard configuration.[38]

EY assessed that the functionality provided by a modern CIS would provide opportunities for Newfoundland Power to improve the customer experience and streamline existing business processes. Further discussion of potential future enhancements to customer service delivery is provided in Section 5.0 and Attachment B to this plan.

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[33] See the EY Report, Appendix A: Market Analysis.
[34] See the EY Report, Appendix D: Business Process Mapping.
[35] See the EY Report, Appendix B: Customer Journey Mapping.
[36] See the EY Report, Appendix D: Edge Application Disposition.
[37] See the EY Report, Appendix E: Data Quality Assessment.
[38] See the EY Report, page 17.

From a technical perspective, EY assessed that a modern CIS would streamline Newfoundland Power's IT environment. Of 56 essential business applications interfacing with CSS, 36% could be retired with the implementation of a modern CIS. Retiring applications provides efficiencies by reducing the overall complexity of the IT environment and associated support and maintenance requirements.[39]

In assessing the level of effort required to transition customer and Company data to a replacement solution, EY assessed Newfoundland Power's data quality to be "very good" relative to industry standards. A data quality framework will be implemented to ensure a seamless transition of customer and Company information to a replacement solution.[40]

These assessment results informed the development of EY's planning recommendations for Newfoundland Power. The project scope, benefits, costs and schedule outlined in this plan are consistent with EY's recommendations.

4.0 Project Scope

Newfoundland Power is proposing to implement a modern CIS. This once-in-a-generation project is necessary to ensure continuity in customer service delivery. The magnitude and complexity of this project requires resources and expertise above the Company's day-to-day-operational requirements. Third party advisory and implementation support will therefore be required throughout the project, as detailed in this section.

[39] See the EY Report, page 15.
[40] See the EY Report, page 17.

The Company plans to approach the project in 3 stages: (i) Pre-Implementation; (ii) Implementation; and (iii) Post-Implementation. A multi-stage approach is consistent with industry best practices.[41]

The Pre-Implementation stage focuses on procuring a replacement solution from an established vendor. Newfoundland Power will contract a third-party Procurement Advisor to assist in undertaking a competitive Request for Proposals process. The Procurement Advisor will provide expertise in developing hundreds of functional and technical specifications for the replacement solution. The Procurement Advisor will also provide best practices and lessons learned in evaluating vendors' proposals and contract negotiations. This expertise will mitigate project execution risks.

Newfoundland Power plans to complete procurement in 2 phases. The first phase will focus on procuring a commercial solution from an established software vendor. The second phase will focus on contracting a third-party System Integrator to provide the technical expertise required to implement the solution. A two-phase procurement approach is consistent with industry best practice.[42]

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[41] In 2018, as part of its assessment framework, Newfoundland Power noted a broad degree of commonality among replacement methodologies recommended by industry experts. For example, Cognizant, a multinational information technology services company, outlines a methodology with 4 steps: (i) Business Case and Roadmap Definition; (ii) Pre-Implementation; (iii) System Development and Implementation; and (iv) Post Implementation (see Cognizant, *CIS Transformation: Unlocking the Value of Utilities' Customer Information Systems*, December 2013, page 5). TMG Consulting outlines a 4-step methodology that includes: (i) Planning; (ii) Procurement; (iii) Implementation; and (iv) Stabilization (see TMG Consulting, *CIS Replacement Risk Mitigation,* April 2016, page 2). Newfoundland Power's approach is consistent with these methodologies and the recommendations of EY.

[42] For example, TMG Consulting, an independent IT advisory service, states: *"TMG believes that CIS procurements should take a two-phase approach; the first phase being the software followed by a SI [System Integrator]."* See TMG Consulting, *CIS Procurement Risk Mitigation*, December 2015.

The Implementation stage encompasses all activities required to ensure the replacement solution is configured to deliver Newfoundland Power's customer service requirements. The implementation stage has 6 phases:

(i) **Initiation**, which requires establishing the project team and associated work plans;

(ii) **Design**, which involves finalizing the functional and technical requirements to be delivered by the replacement solution;

(iii) **Development**, which includes configuring the solution to deliver the identified requirements and migrating customer and Company data;

(iv) **Testing**, which includes testing system functionality, interface, security and performance to ensure the replacement solution operates as required;

(v) **Training**, which includes train-the-trainer and end-user training to ensure employees are skilled in serving customers using the replacement solution; and

(vi) **Deployment**, which focuses on final cutover activities and launch of the solution.

The third-party System Integrator will work directly with the software vendor and Newfoundland Power throughout the Implementation stage to deliver the Company's functional and technical requirements.

The Post-Implementation stage is designed to manage any issues that arise following launch of a replacement solution. Technical issues will be addressed with the software vendor as they occur. Additional resources will be made available to employees as they gain experience serving customers using the new system.

Overall, this project scope is consistent with EY's planning recommendations, industry best practices, and Newfoundland Power's assessment and planning framework provided to the Board in 2018.

5.0 Project Benefits

5.1 Provide Service Continuity

A modern CIS will provide continuity in Newfoundland Power's customer service delivery over the long term.

A modern CIS will mitigate the functional risks facing the existing system. A modern CIS will support the Company's existing customer service business processes either through the base product or standard configuration. Upgrade strategies will ensure the solution can adapt to meet changing customer expectations, industry trends and regulatory requirements.

A modern CIS will mitigate the technical risks facing the existing system. A modern CIS will reduce the complexity of Newfoundland Power's IT environment. Vendor support will be available to address technical issues as they arise. This will ensure a high level of system availability and performance.

Mitigating these functional and technical risks will enable Newfoundland Power to continue providing responsive service to customers over the long term.

5.2 Maintain Service Efficiency

Newfoundland Power has improved the efficiency of its customer service delivery over the last 2 decades. CSS was essential to achieving existing levels of service efficiency.

However, CSS can no longer effectively deliver all required customer service functionality. This creates inefficiencies in serving customers. For example, manual processes are currently required because CSS cannot be customized to complete the billing of net metering customers. The system could also not be customized to provide time-of-use rates or any new complex rate designs in the future.

A modern CIS would allow Newfoundland Power to maintain the overall efficiency of its customer service delivery over the long term.

From a customer perspective, several of the opportunities identified to improve the customer experience are expected to have efficiency benefits. These opportunities are described in the next section and include: (i) further automating processes, such as customer notifications and service transfers; (ii) expanding self-service options and online tools via the customer website; and (iii) providing employees with better information to efficiently respond to customers' enquiries. Potential efficiencies will be assessed over the short, medium and long term, as described in the next section.

From an internal operations perspective, a modern CIS is expected to provide efficiencies in user training. Newfoundland Power's Customer Service Representatives undergo multiple weeks of classroom training to understand the processes and technologies used to serve customers, followed by months of on-the-job training.[43] A modern CIS would provide reduced user complexity and provide more effective and efficient agent training. [44]

From a technical perspective, a modern CIS would allow a number of existing applications to be retired. Generally, these applications were internally developed and are supported using internal expertise. Retiring these systems will provide more effective and efficient management of Newfoundland Power's IT environment.

Overall, the capabilities and efficiencies provided by a modern CIS will ensure Newfoundland Power can continue providing responsive service to customers at least cost.

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[43] Newfoundland Power's expects that a modern Customer Information System would reduce the training time for new Customer Service Representatives by up to 10%.

[44] See the EY Report, page 17.

5.3 Enhance Customer Experience

Customers' service expectations evolve over time. The Company's customer service delivery must routinely adapt to meet these evolving expectations.

A modern CIS will provide opportunities to improve the customer experience both upon implementation of the solution and over time. As part of executing its assessment and planning framework, Newfoundland Power examined the strengths and weaknesses of its current approach to customer service delivery and opportunities to better serve customers once a modern CIS is implemented.

A total of 29 potential future enhancements in customer service delivery were identified.[45] These include:

(i) 8 enhancements to the customer website, such as increased real-time customer account information, enhanced self-service capabilities for commercial customers, and an online calculator for customers to estimate bills between meter reads;

(ii) 7 enhancements to customer communication, such as more proactive notifications for customers, the ability to personalize communication via preferred channels, and an online customer chat option;

(iii) 5 opportunities to streamline existing business processes, such as automated service transfers and electronic identity verification for customers establishing a new service;

(iv) 5 new or expanded service offerings, such as the ability to set call-back times or more flexible account management options for commercial customers; and

[45] See the EY Report, Appendix B: Customer Journey Mapping.

(v) 4 opportunities to provide better information to employees serving customers, such as the ability to flag accounts associated with small businesses and a 360° view of the customer when responding to enquiries.[46]

The majority of these enhancements are driven by new functionality that would be provided by a modern CIS. The specific costs, customer benefits and timing of these enhancements will depend, in large part, on the solution that is implemented.

EY recommended Newfoundland Power prioritize these enhancements for further assessment. Attachment B provides a complete list of the enhancements identified and the priority assigned to each. It shows over ½ of potential enhancements will be assessed over the short term as part procuring a replacement system.

Attachment B also provides customer feedback received during focus groups and surveys conducted in winter 2020.

6.0 Project Costs and Schedule

6.1 Costs

Newfoundland Power proposes to implement a modern CIS over 3 years at a total estimated cost of $31.6 million.

[46] Newfoundland Power's CSS follows a premises-based model. Under this model, information for a customer with multiple services may be recorded across multiple accounts. Each account must be reviewed individually when responding to a customers' enquiry, which can add to the time and complexity required to resolve a particular issue. Modern CIS solutions follow a customer-centric model that provides a 360° view of the customer. This ensures all information related to a customer's services is available when responding to an enquiry.

This cost estimate is consistent with the planning recommendations of EY and the Project Scope outlined in Section 4.0.[47] Based on EY's analysis, these costs are comparable to the experience of other utilities who have completed similar implementations.[48]

Table 1 provides a breakdown of project costs by year.

Table 1: Project Costs ($000s)			
Cost Category	**2021**	**2022**	**2023**
Material	7,186	10,358	3,685
Labour – Internal	1,934	4,132	1,237
Other	783	1,336	995
Total	**9,903**	**15,826**	**5,917**

Material costs in 2021 include the services of a Procurement Advisor to assist in the Request for Proposals process and procurement of the required hardware and software to implement a modern CIS. Material costs in 2022 and 2023 include the services of a System Integrator and the selected software vendor to design, deliver and implement the solution in a manner that meets Newfoundland Power's requirements.

Internal labour costs include resources from Newfoundland Power's Customer Relations and Technology departments. Internal labour costs in 2021 and 2022 reflect the resources required to procure and design a replacement solution. Internal labour costs in 2023 reflect the

[47] See the EY Report, page 23.

[48] EY referred to common industry benchmarks, such as cost-per-customer figures cited by Gartner, to validate that the projections were in an acceptable range for a CIS implementation of this size and complexity. EY states: *"Industry guidance for CIS replacement initiatives, based on market experience, places implementation costs between $65 and $137 per customer, gaining economies of scale with larger utilities. Newfoundland Power is within that range, estimated at $106 per customer."* See the EY Report, page 23.

resources required to finalize data conversion requirements, test and deploy the solution, and train employees in serving customers using the new technology.

Other costs include facilities costs necessary to provide space for the project team and an Allowance for Funds Used During Construction ("AFUDC").

Newfoundland Power has assessed the accounting treatment of the proposed project costs based on generally accepted accounting principles in the United States ("U.S. GAAP"). Attachment C provides the results of this assessment.

6.2 Schedule

Table 2 provides the schedule for implementing a modern CIS.

Table 2:
Project Schedule

Stage/Phase	Timeframe
Pre-Implementation	Q4 2020 to Q2 2021
Procurement	*8 months*
Implementation	Q3 2021 to Q1 2023
Initiation	*2 months*
Design	*5 months*
Development	*7 months*
Testing and training	*9 months*
Deployment	*2 months*
Post Implementation	Q2 2023 to Q3 2023
Stabilization	*4 months*

The project is scheduled to commence in Q4 2020, following Board approval. A replacement solution is expected to be implemented by Q3 2023. This schedule will help mitigate project

execution risks by avoiding deployment during the winter period, when the majority of customer outages occur.

Overall, the project schedule shown in Table 2 is consistent with the project scope outlined in Section 4.0 and the planning recommendations of EY.[49]

[49] See the EY Report, page 21.

Attachment A

Ernst & Young LLP Customer Information System: Assessment Results and Planning Recommendations

Customer information system

Assessment results and planning recommendations

March 2020

EY
Building a better working world

Table of contents

Appendices

1. Executive summary

Newfoundland Power's Customer Service System ("CSS") is a 27-year old application that supports the majority of customer service delivery functions. CSS has exceeded its anticipated useful life and there are significant functional and technical risks associated with continuing to operate and maintain the application. In 2019, Newfoundland Power embarked on a multi-year assessment and planning effort to explore modernization options and implementation approaches.

Through a competitive tendering process, EY was selected to assist Newfoundland Power in:

- Identifying and assessing modernization alternatives
- Reviewing existing customer service business processes and determining how the recommended alternative would fit in Newfoundland Power's environment
- Outlining recommendations for developing and implementing a replacement solution

EY used its standard industry methodologies for conducting the CSS assessment and developing planning recommendations.

EY identified a set of modernization alternatives based on its experience working with other utilities and what is typically seen in the industry. Each alternative was evaluated to determine its viability for Newfoundland Power. Modernization alternatives considered as part of the analysis were:

- Maintain the status quo - Maintaining the status quo involves continuing Newfoundland Power's practice of supporting and enhancing the CSS through approved capital and operating investments.
- Extend CSS with bolt-on applications - Extending CSS with bolt-on applications involves purchasing software applications that provide specific business functions and integrating them with the existing CSS.
- Re-platform the existing CSS - Re-platforming the existing CSS application requires automating the migration of the existing code to a modern, supported programming language.
- Replace the existing CSS - Replacing the existing CSS application with a modern Customer Information System ("CIS") solution from an established software vendor.

EY recommends replacing Newfoundland Power's CSS with a modern CIS as the only viable modernization alternative to mitigate the functional and technical risks facing Newfoundland Power.

Maintaining the status quo would continue to increase complexity and not mitigate the technical and functional risks facing Newfoundland Power. A bolt-on strategy would continue to increase the complexity of CSS, limit functional capabilities and would not address technical risks. A re-platforming strategy is not industry standard, would mitigate certain technical risks while increasing others and would not mitigate any risks associated with functional obsolescence.

Based on this recommendation, EY assessed how a modern CIS would fit within Newfoundland Power's customer service environment incorporating four perspectives:

- Market - A modern CIS solution would align Newfoundland Power with current industry practices as over 90% of surveyed utilities have already implemented, are presently implementing or plan to implement modern CIS solutions from one of two CIS solution providers.
- Customer – A modern CIS solution would provide Newfoundland Power functionality to improve customer experience (e.g., automated proactive customer communications, real-time updates, improved self service, etc.) and keep pace with evolving customer expectations and industry changes.
- Product – A modern CIS solution would allow Newfoundland Power to retire 20 customized, home-grown applications currently interfacing with CSS, significantly decreasing technical complexity as well as simplifying ongoing support and maintenance.
- Internal - A modern CIS solution would meet the majority of Newfoundland Power's requirements with minimal customization, thereby decreasing the risk of a CIS replacement project. Additionally, Newfoundland Power's CSS is well positioned for data migration to a replacement solution.

A modern CIS solution would fit well functionally and technically in Newfoundland Power's business environment. EY has developed planning recommendations to move forward with implementation of a modern CIS solution in stages over a multi-year effort utilizing industry best practices. EY's planning recommendations include schedule, resource and cost baselines. The estimated costs to procure, implement, and stabilize a modern CIS replacement solution is estimated at approximately $31.6 Million over an 8-month pre-implementation period, a 21-month implementation period, and a 4-month post-implementation period. Following this approach should position Newfoundland Power for a successful CIS replacement.

2. Background

Newfoundland Power's CSS is the primary application used to support its billing and customer service delivery, performing critical meter-to-cash functionality.

CSS went live in 1993 and belongs to the family of Customer/1 billing systems. CSS has been a stable application meeting Newfoundland Power's business requirements for decades, well beyond its original expected service life. Failure of CSS would negatively impact Newfoundland Power's ability to bill customers and deliver responsive and efficient customer service.

Newfoundland Power is the last remaining mid-to-large size Canadian utility operating a legacy CIS application with no upgrade path provided by the original vendor. CSS has been extended to its maximum life and is now reaching technical and functional obsolescence.

In 2018, Newfoundland Power engaged EY to perform an assessment of the risks associated with the foundational technologies that support CSS. The results from EY's assessment concluded that, while CSS does not pose an immediate operational risk to Newfoundland Power, there are significant functional and technical risks associated with continuing to operate and maintain the application.[1]

Newfoundland Power's CSS is at risk of becoming functionally obsolete. Functionality essential for providing service to customers has evolved over the last two decades in response to changing customer expectations, industry practices and regulatory requirements. Enhancing CSS to keep pace with this evolution has resulted in a highly customized, complex system, often making further enhancements cost prohibitive or difficult to deploy. At this time, even minor enhancements to the CSS can be time consuming and cost prohibitive given the application's complex, highly customized architecture. This increases the need for manual business processes and limits Newfoundland Power's ability to improve the customer experience.

CSS has been extended to its maximum life and is becoming technically obsolete. Newfoundland Power faces declining support as individuals with the necessary technical skills are in short supply. Over the last 27 years, CSS customizations have created a highly complex application which is very difficult to maintain. CSS as a software product has had no vendor investments for decades and commitment to future vendor investment for the foundational technologies is uncertain. Lack of vendor investment increases the risk of critical failure of the application.

These risks are not static and will increase over time.

The primary recommendation arising from EY's 2018 Technical Risk Assessment was that Newfoundland Power should formalize and deepen its examination of CSS modernization

options to include a thorough evaluation of the costs and benefits of replacement and deployment options.

Newfoundland Power has undertaken a structured approach to explore modernization options and embarked on a multi-year assessment and planning effort to determine the appropriate solution for its operations.

In 2019, through a competitive tendering process, EY was selected to assist Newfoundland Power in:

- Identifying and assessing modernization alternatives
- Reviewing existing customer service business processes and determining how the recommended alternative would fit in Newfoundland Power's environment
- Outlining recommendations for developing and implementing a replacement solution

EY's Power and Utilities ("P&U") practice conducted this work based on its established approaches, methodologies and industry expertise. EY's P&U practice has worked with over 200 North American utilities on more than 250 customer and strategic system-related initiatives.

Richard Charles, EY's P&U Customer Leader, was the primary advisor for conducting the assessment and planning work for Newfoundland Power. Richard led an experienced project team including senior resources from EY's US and Canadian practices. Richard and his team members have conducted over 20 similar assessments for utilities throughout North America.

EY resource qualifications is Appendix F.

3. Approach

EY conducted its assessment between March and November 2019. EY began its work by documenting how Newfoundland Power currently delivers customer service through key stakeholder interviews, workshops, and documentation reviews. This work provided EY with an in-depth understanding of customer service delivery at Newfoundland Power and was used to inform EY's assessment and planning activities.

EY identified a set of modernization alternatives based on its experience working with other utilities and what is typically seen in the industry. Each alternative was evaluated to determine its viability for Newfoundland Power.

Section 4 outlines EY's assessment of modernization alternatives.

With the recommended modernization alternative, EY further assessed the functional and technical requirements to provide continuity in Newfoundland Power's customer service delivery. This work included:

- Market analysis (Appendix A)
- Customer journey mapping (Appendix B)
- Edge application disposition (Appendix C)
- Business process mapping (Appendix D)
- Data quality assessment (Appendix E)

Section 5 outlines EY's assessment of technical and functional requirements to provide a successful fit for Newfoundland Power's environment.

Working with Newfoundland Power, EY developed recommendations to inform an application development plan. This includes recommendations for project scope, estimated costs, anticipated timelines and estimated resourcing effort.

Section 6 outlines EY's planning recommendations.

4. Assessment of modernization alternatives

4.1 Approach

CSS and supporting systems are facing increasing levels of risk due to technical and functional obsolescence. Mitigating these risks through modernization is necessary to provide continuity of customer service delivery.

EY identified modernization alternatives based on its experience working with other utilities and what is typically seen in the industry.

Modernization alternatives considered as part of the analysis were:

- Maintain the status quo
- Extend CSS with bolt-on applications
- Re-platform the existing CSS
- Replace the existing CSS

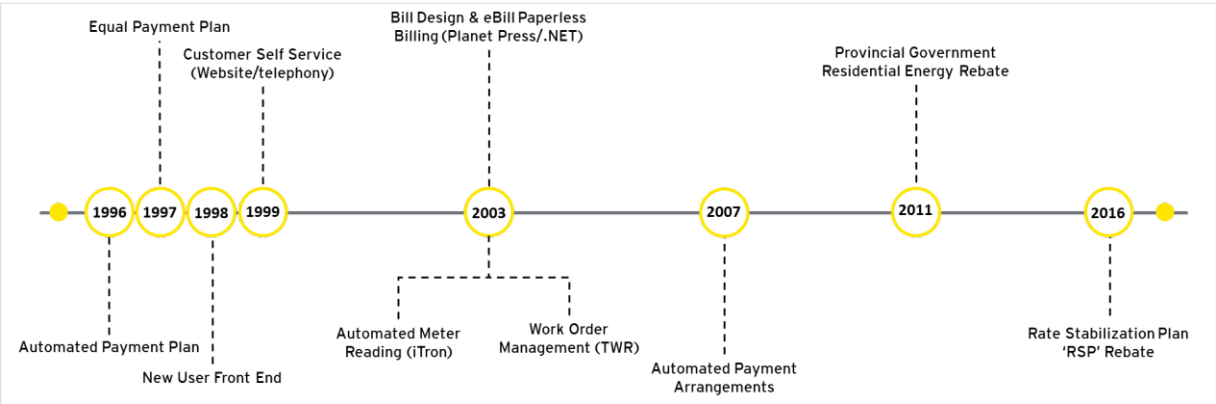
EY assessed each alternative to determine whether it would mitigate the technical and functional risks currently facing Newfoundland Power.

4.2 Findings

Option 1: Maintain the status quo

Maintaining the status quo would involve continuing with Newfoundland Power's practice of supporting and enhancing the CSS through approved capital and operating investments. As shown in Figure 4.1, Newfoundland Power has strategically extended the useful life of the CSS by 50% through implementation of functional and technical enhancements.

Figure 4.1 – CSS Enhancement and Extension Examples



Maintaining the status quo would not address the functional risks within the current CSS. While implementing functional enhancements has provided positive customer satisfaction, increasing customer expectations and changes in the market require new features which cannot be provided within the current CSS. Newfoundland Power is routinely mandated to develop regulatory driven customer service functionality that a system designed nearly 30 years ago would not have anticipated, such as net metering which is currently delivered outside of CSS. Certain other functionality, if required in the future, could simply not be delivered in CSS such as time of use rates.

Maintaining the status quo would not address the technical risks within the current CSS. Vendor support in key underlying infrastructure is decreasing and future vendor investment is uncertain. Technical expertise to support aging technologies is difficult to source. Aging infrastructure increases integration and cybersecurity risks and becomes costlier to maintain as talent acquisition/retention scarcity increases. Additionally, several home-grown custom applications are nearing the end of their useful life and will require significant investment or replacement (e.g., Meter Equipment System, Street Light Management System, and Handheld Meter Reading Reporting).

These risks are not static and will increase over time. Maintaining the status quo will continue to increase complexity and not mitigate the technical and functional risks facing Newfoundland Power.

In EY's opinion, this is an unsustainable option.

Option 2: Extend CSS with bolt-on applications

Extending CSS with bolt-on applications involves purchasing software applications that provide specific business functions and integrating them with the existing CSS. Traditionally, a bolt-on application provides missing or improved functionality that can be integrated into the existing CIS application. Common examples of bolt-on applications include complex rate engines, real-time self-service functions, and bill print capabilities.

Extending CSS with bolt-on applications would not fully mitigate the functional risks within the current application and would continue to increase the application's functional complexity. While bolt-on applications would allow Newfoundland Power to meet specific business requirements, the ability to improve and enhance broader core CSS functionality would remain unchanged with the existing premise-based data model limiting the ability to be customer centric.

To effectively implement a bolt-on application, the CSS foundational technologies would need to support a modern integration framework. Modern bolt-on applications have a 'plug and play' capability that work seamlessly with a modern CIS. However, CSS would require a customized design integration to implement a bolt-on application, further increasing the technical complexity to implement and support as well as the overall risk of this option.

Overall, a bolt-on strategy would continue to increase the complexity of CSS, limit functional capabilities and would not address technical risks.

In EY's opinion, this is not a viable modernization alternative.

Option 3: Re-platform the existing CSS

Re-platforming CSS would require automating the migration of the existing code to a modern, supported programming language. In EY's experience, this option is not standard industry practice.

Re-platforming CSS would mitigate certain technical risks. Newfoundland Power's current CSS is hosted on an Open VMS operating system and is custom developed using COBOL and Powerhouse programming languages. The hardware for CSS is from Hewlett Packard Enterprises ("HPE") and hosted on HPE Integrity Blade Servers. These components are unique to CSS and would require a technical migration expert to design a custom toolset to migrate the CSS software. Additionally, CSS is integrated with over 50 custom designed edge applications. A re-build/re-design of every edge application interface to CSS would be necessary.

While re-platforming CSS would mitigate certain technical risks, a re-platforming of this magnitude would be a high-risk option due to the unknowns associated with a new toolset creation and the complexity associated with operating CSS in this new environment. EY is not aware of any North American utilities comparable to Newfoundland Power that are pursuing this option.

Re-platforming would not mitigate any risks associated with functional obsolescence.

In EY's opinion, this is not a viable modernization alternative.

Option 4: Replace the existing CSS

This option involves replacing the existing CSS application with a modern, commercial off-the-shelf solution from an established software vendor. Modern CIS solutions are designed to meet the majority of core meter to cash customer service requirements with little to no customization.

Implementing a modern CIS solution would mitigate the risk of functional obsolescence facing Newfoundland Power's current CSS.

Modern CIS solutions keep pace with ever-changing markets. Modern CIS solutions have core business processes incorporated into the base packages and dedicated upgrade strategies to address changing industry and customer expectations. Functionality changes such as advanced metering infrastructure, complex rates, electric vehicles, and electrification of the grid are easily supported by configurations available in modern CIS solutions. Implementing a modern CIS would allow Newfoundland Power to meet evolving customer and industry

requirements in a timely manner and mitigate risks.

Modern CIS solutions provide functionality that would allow Newfoundland Power to improve customer experience. For example, customer contact information is currently stored in multiple locations within CSS and supporting business applications. This requires contact centre agents to search for prior customer contacts across multiple applications to help resolve the query. Modern CIS solutions offer standard features that provide a 360-degree view of the customer. These features aggregate all critical customer contact information and present the information in real-time in the CIS solution. This capability would allow contact centre agents to be more responsive to customer inquiries.

Modern CIS solutions provide functionality that would allow Newfoundland Power to streamline existing processes. For example, due to current CSS limitations, customer self-service requests on Newfoundland Power's website frequently generate emails that require manual intervention by contact centre agents. When a customer visits Newfoundland Power's website to request a transfer of their electric service to a new location, an email is sent to the contact centre. A contact centre agent completes the request for transfer of service in CSS using the information that was provided via the email. Modern CIS solutions are built to fully integrate customer self-service functions, eliminating the need for manual intervention by contact centre agents.

Implementing a modern CIS solution would mitigate the risk of technical obsolescence facing Newfoundland Power's current CSS.

Modern CIS solutions support and proactively deliver technology upgrades through package releases which extend the useful life of the solution and its foundational technologies. Skills required to maintain and use a modern CIS can be readily acquired through formalized training and certification programs for technical and business employees. This increases the number of available skilled resources to support a modern CIS.

Modern CIS solutions provide an integrated platform that will streamline the IT environment and reduce complexity. Over the years, CSS has been extended with over 50 edge applications and integrations to provide the necessary functionality. Modern CIS solutions are configuration-based which would allow Newfoundland Power to incorporate the majority of its business requirements into a CIS without customization. This also removes the necessity for complex integrations, minimizes the requirements for numerous edge applications, and allows for the retirement of home-grown applications.

In EY's opinion, replacement of the CSS is the only viable option to mitigate the technical and functional risks facing Newfoundland Power.

4.3 Conclusion

CSS and supporting systems are facing increasing levels of risk due to technical and functional obsolescence. These risks are not static and will increase over time. Mitigating these risks through modernization is necessary to provide continuity of customer service delivery.

EY identified four modernization options based on industry experience then assessed each alternative to determine whether it would mitigate the technical and functional risks currently facing Newfoundland Power.

Maintaining the status quo will continue to increase complexity and not mitigate the technical and functional risks facing Newfoundland Power. In EY's opinion, this is an unsustainable option.

Extending CSS with bolt-on applications would allow Newfoundland Power to meet specific business requirements but would continue to increase the complexity of CSS, limit other functional capabilities and would not address technical risks. In EY's opinion, this is not a viable modernization alternative.

Re-platforming CSS would mitigate certain technical risks. However, a re-platforming of this magnitude would be a high-risk option. EY is not aware of any North American utilities comparable to Newfoundland Power that are pursuing this option. Re-platforming would not mitigate any risks associated with functional obsolescence. In EY's opinion, this is not a viable modernization alternative.

EY recommends replacing Newfoundland Power's CSS with a modern CIS as it is the only viable alternative that mitigates the functional and technical risks facing Newfoundland Power. Implementing a modern CIS would provide continuity of customer service delivery in the long-term.

5. CIS solution assessment

5.1 Approach

Based on the recommended modernization alternative, EY assessed how a modern CIS would fit within Newfoundland Power's customer service environment. EY conducted this assessment based on its evaluation framework, which covers four perspectives:

Market Perspective provides an understanding of CIS trends in the marketplace and strategies of comparable utilities.

Customer Perspective provides an understanding of the functionality required to address current and future customer needs and what makes a successful customer experience.

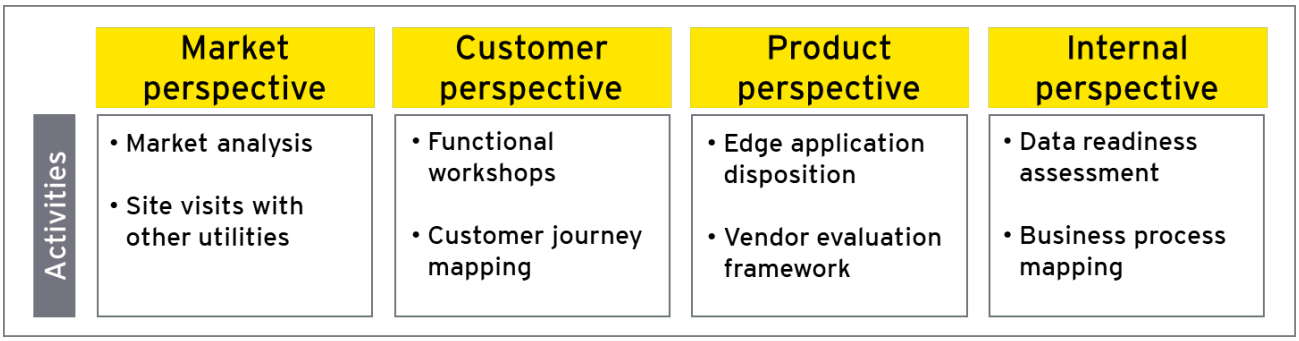
Product Perspective provides an understanding of available functionality, technical requirements, and vendor capabilities.

Internal Perspective provides an understanding of the key customer service business processes and an understanding of data readiness to prepare for a CIS replacement.

The use of these four perspectives provides a comprehensive and structured approach to assessing the current CSS environment, identifying gaps and opportunities for improvement and developing a roadmap for moving forward. EY uses this evaluation framework to provide informed application planning recommendations.

These perspectives were captured through a series of workshops with over 50 employees across Newfoundland Power. Figure 5.1 outlines the activities that were conducted in order to capture each perspective.

Figure 5.1 - Assessment and Planning Activities



5.2 Key Findings

Market perspective findings

The majority of utilities have implemented, are presently implementing or plan to implement modern CIS solutions from one of two CIS solution providers.

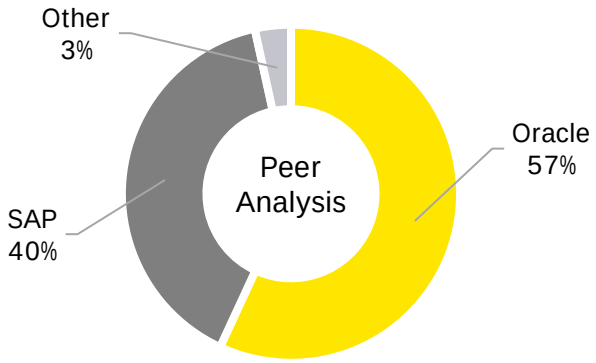
A market analysis consisting of 120 North American utilities that have recently implemented or are in the process of implementing new CIS solutions was conducted in July 2019. The findings show that 93% of the utilities in the analysis have selected one of two software providers: Oracle or SAP.

A subset of 28 peer utilities was identified from the broader market dataset to show greater applicability to Newfoundland Power. EY identified these peer utilities based on two criteria:

- Number of customers - Utilities who serve between 150,000 - 450,000 customers
- Service type - Electric utilities

As shown in Figure 5.2 below, the peer analysis findings mirror the broader market. The number of utilities that are implementing modern CIS solutions from one of two software providers increases from 93% in the broader market to 97% in the peer group.

Figure 5.2 – % of installs by vendor



Other industry research validates these findings. Per Gartner Inc., an IT research and advisory firm: "SAP CR&B and Oracle Utilities CC&B (C2M) have achieved leadership positions and continue to break away from the rest of the pack. This effectively forces this market into a 'duopoly' mode." [2]

The detailed market analysis is Appendix A.

The market perspective also included on-site visits to North American utilities with active or recently completed CIS replacement projects. Site visits were conducted at Hydro Ottawa, ConEdison (Orange & Rockland), Central Hudson Gas and Electric, and Arizona Public Service

Electric Company ("APS"). Each of these utilities has selected either SAP or Oracle as their replacement CIS. Information collected during the site visits included deployment strategies, lessons learned and implementation timeframes.

This information was used to inform the application planning recommendations outlined in Section 6.

Customer perspective findings

Modern CIS solutions more readily provide the ability to enhance customer experience as compared to legacy CSS applications.

EY conducted functional workshops to understand how Newfoundland Power currently meets customer expectations. A customer journey mapping exercise was then conducted. Customer journey mapping allowed Newfoundland Power employees to step into the 'customer's shoes' to understand the broader experience from the customer perspective, rather than focusing on individual business functions or processes. The purpose of the customer journey mapping was to document key customer interactions and identify strengths and challenges of the current approach to customer service delivery.

Evaluating customer journey maps highlighted opportunities to improve customer experience. EY's industry knowledge and analysis of the customer journey maps concluded that modern CIS solutions would provide functionality to improve customer experience at Newfoundland Power. Examples of potential improvements include:

- Automating proactive customer communications to send notifications to specific customer segments via preferred channels (e.g., notifications in relation to program eligibility, payment reminders, and payment arrangement options).
- Expanding online self-service capabilities to provide real-time updates for customers (e.g., real-time updates on outages, payments, and account balances).
- Providing a single 360-degree view of the customer. This would allow agents to better analyze and understand customer needs and be more responsive to customer inquiries.
- Implementing advanced contact routing so customers will get the same agent, if possible. This would allow customer inquiries to be addressed in a consistent and timely manner.
- Implementing options (e.g., Facetime, Skype, etc.) for remote identity verification. This would avoid customers having to present ID in person at a Newfoundland Power location.

Further assessment of these opportunities is required by Newfoundland Power to prioritize capabilities that could be actioned in the short, medium and long-term.

A detailed output of the customer journey mapping sessions is Appendix B.

Product perspective findings

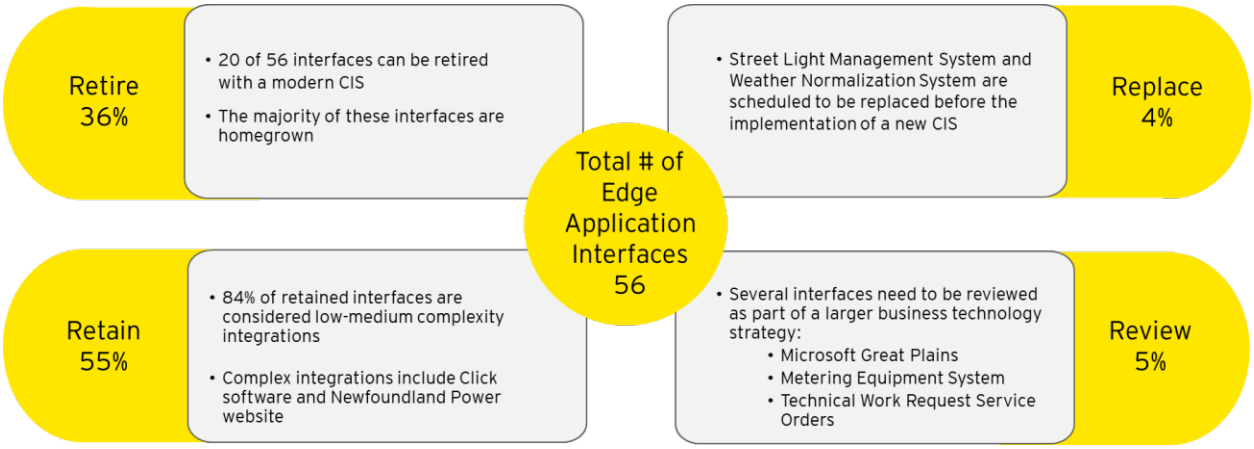
Many customized, home-grown applications currently interfacing with CSS could be retired with a modern CIS.

CSS interfaces with 56 essential business applications, referred to as "edge applications." Examples of these applications include Newfoundland Power's customer self-service website, the financial application MS Great Plains, the workforce management application Click, and the Avaya contact centre solution. Many of these edge applications are highly customized which increases the complexity of the CSS operating environment.

A technical assessment and edge application disposition review was conducted to identify current CSS edge applications and provide a high-level view of potential future-state dispositions, including applications to be retired, retained, replaced or reviewed in the future.

As shown in Figure 5.3, 36% of edge applications could be retired with the implementation of a modern CIS solution, that provides similar functionality either in the base package or via standard configuration. The retirement of these mostly home-grown edge applications would significantly decrease complexity as well as simplify ongoing support and maintenance.

Figure 5.3 – Edge application disposition



The review also found that 55% of edge applications could be retained, a manageable number based on EY's experience. The majority of these edge applications are low to medium complexity.

The remaining edge applications are expected to be replaced as part of the existing technology plan or require further review as part of Newfoundland Power's broader technology strategy.

The detailed results of the edge application disposition review is Appendix C.

Newfoundland Power will need to ensure that any new CIS can deliver similar functionality to these current edge applications to provide continuity in business operations. The final disposition strategy will ultimately depend on the CIS that is implemented.

Pre-screening modern CIS alternatives is an effective method to ensure only solutions that are a good fit for Newfoundland Power are further considered during procurement.

EY recommends evaluating vendor and product capabilities of available replacement CIS solutions across the following criteria:

- Vendor health – Assessment of vendor profile including ownership structure and financial stability.
- Vendor qualifications – Assessment of vendor experience implementing similar size projects for electric utilities in representative geographic areas.
- Product roadmap and strategy – A review of vendor investment, commitment, and strategic planning to remain current in the market (e.g., functionality, infrastructure, release schedule, etc.).
- Resource availability – Vendor resource availability and strategic partnerships in the market to successfully deploy and support the product.
- Functional fit/completeness – Assessment of the software product capability to meet key business requirements.
- Technical fit/completeness – Assessment of the software product capability to meet current and future technical requirements (e.g., shared services, integration, support, audit, testing, cyber security etc.).
- Customer experience – Assessment of the software product capability to support changing customer needs (e.g., digital interactions).
- Implementation costs – Assessment of the accuracy of the budgetary guidance provided by the vendor of the total cost and effort to successfully implement the solution.
- Ongoing support costs – Assessment of the accuracy of the budgetary guidance provided by the vendor of the total recurring costs to license, maintain, and support the solution.

By applying this methodology, each potential solution will have to meet critical success criteria before Newfoundland Power engages the vendor in a detailed procurement process.

Internal perspective findings

Newfoundland Power's business processes are similar to other utilities and can be implemented with a modern CIS solution with minimal customization.

EY conducted "as-is" business process mapping to establish how Newfoundland Power currently delivers key customer service processes. Business process mapping helps determine future CIS requirements and mitigates risk through a complete understanding of key processes. A total of 43 business processes were mapped as part of this assessment. These processes were prioritized based on customer impact and incidence.

In EY's experience, 80% of business processes are common across utilities and can be implemented with out-of the-box functionality from a modern CIS solution.[3] Based on EY's review of the key business process maps produced, this commonality applies to Newfoundland Power.

The high degree of commonality in business processes would indicate that a modern CIS solution would meet Newfoundland Power's requirements with minimal customization. This would decrease the risk of a CIS replacement project. The reduced requirement for customization would also reduce the complexity of future upgrades and on-going support and maintenance requirements. It would also facilitate more effective and efficient agent training and provide Newfoundland Power with additional opportunities to leverage industry best practices and experiences from other utilities who utilize commercial CIS solutions.

Detailed findings from the business process mapping is Appendix D.

Data quality findings scored above average when evaluated against utilities in comparable replacement scenarios.

A data quality assessment was conducted to ascertain the current state of Newfoundland Power's customer data and its readiness for migration to a modern CIS. EY performed this assessment by conducting a series of sample queries against data and expected values. The assessment helped capture indicative sizing of any data quality problems.

Data quality findings scored above average when evaluated against utilities in comparable replacement scenarios. Overall data quality was seen to be "very good" relative to the industry standards. Industry standards include: consistency within cardinality rules (i.e. unique IDs), limited presence of intelligent keys (i.e., primary keys), and prior remediation efforts indicating active interest in data cleansing.

Based on the results of the data assessment, Newfoundland Power implemented additional remediation efforts to facilitate data migration to a CIS replacement solution. These remediation efforts included three data cleansing activities – service address validation, phone number format standardization, and name/address hygiene. A data quality framework

was also provided to Newfoundland Power to support future remediation efforts.

Detailed findings of the data quality assessment is Appendix E.

5.3 Conclusion

A modern CIS solution would fit well in Newfoundland Power's business environment from a functional and technical perspective. Implementing a modern CIS solution would align Newfoundland Power with current industry practice. The majority of Newfoundland Power's business processes can be delivered through using a modern CIS with minimal customization and a significant number of applications could be retired. A modern CIS would also provide several opportunities to improve customer experience in the short, medium and long term. Additionally, Newfoundland Power's CSS data is well positioned for migration to a replacement solution.

6. CIS planning recommendations

6.1 Approach

EY developed a recommended project scope and implementation approach based on its standard CIS implementation methodology.

EY then utilized its resourcing and cost approximation framework as a reference for financial and resource projections. This framework has been refined based on similar CIS implementations of utilities that EY has worked with. Using this framework, EY developed a recommended project schedule, resourcing effort and cost baselines for Newfoundland Power. EY reviewed its initial assumptions with Newfoundland Power and then adjusted the results to account for Newfoundland Power's internal staffing model and the assessment results as described in this report.

Additionally, EY referred to common industry benchmarks such as cost-per-customer figures, cited by Gartner, to validate that the projections were in an acceptable range for a CIS implementation of this size and complexity.

6.2 Project Scope

Project description

EY has developed planning recommendations to assist Newfoundland Power in moving forward with implementation of a modern CIS solution. The overarching project goal is selecting a solution that will provide continuity in Newfoundland Power's key pillars of customer service: (i) account management and billing, (ii) communication and contact management, and (iii) program and service delivery.

Industry methodologies for implementing CIS solutions are generally approached in stages over a multi-year effort. EY recommends a replacement methodology based primarily on industry leading practices, which includes Pre-Implementation, Implementation, and Post-Implementation stages. The following provides a high-level overview of the noted stages, with a detailed project plan covering all three stages to be prepared between Newfoundland Power and the selected solution provider.

Pre-Implementation

Pre-Implementation activities focus on preparing Newfoundland Power for the Request for Proposal ("RFP") process to select software vendors that can partner with Newfoundland Power to successfully deliver the necessary technical/functional requirements to meet current/future customer service needs, as documented in the assessment and planning evaluation.

EY recommends Newfoundland Power's procurement plan follow industry leading practices in contracting a third-party procurement advisor experienced with similar-sized utilities. This approach helps mitigate risks, provides fair and transparent evaluation of vendors, and safeguards that contract negotiations select the least cost vendor that best meets business requirements for future success.

CIS procurement advisors have deep experience and qualifications working with many utilities across the globe on CIS replacement efforts to:

- Develop business and technical solution requirements for inclusion in the RFP
- Evaluate vendor proposals based on industry expectations
- Provide targeted short-list guidance based on procurement findings
- Guide the overall solution procurement process
- Provide industry specific guidance during contract negotiations

Implementation

Based on industry leading practices, EY recommends a five-phased implementation approach for Newfoundland Power consisting of Initiation, Design, Development, Testing/Training, and Deployment. Each phase has well-defined activities and contributes to a structured deployment in the 21-month target timeframe.

Initiation – A small team of key project resources is established to finalize preparations for the deployment including establishing temporary project facilities, refining resourcing and logistics plans with selected vendors, and finalizing the overall project plan activities and timeline.

Design – The team increases in size to capture functional requirements across all business areas, map business processes to the new solution, and document the testing strategy. In addition, IT environments are built out and software installation takes place.

Development – Design transitions into software product configuration and development based on the defined business requirements. The team resourcing efforts increase as data conversion activities and detailed test planning begin.

Testing/training – Multiple iterations of functionality, interface, security, performance, and parallel testing will be executed to validate both system and operational readiness. Training materials will be developed, train-the-trainer training will be executed, and end users will receive between 80 and 120 hours of specialized training on the new system. Team size peaks during end-user training.

Deployment – Cutover planning, data conversion, implementation dress rehearsals, and final cutover activities will be conducted to prepare for a successful go-live.

Post-implementation

The stabilization period following solution deployment mitigates potential negative impacts to customer service and transitions operations to business as usual.

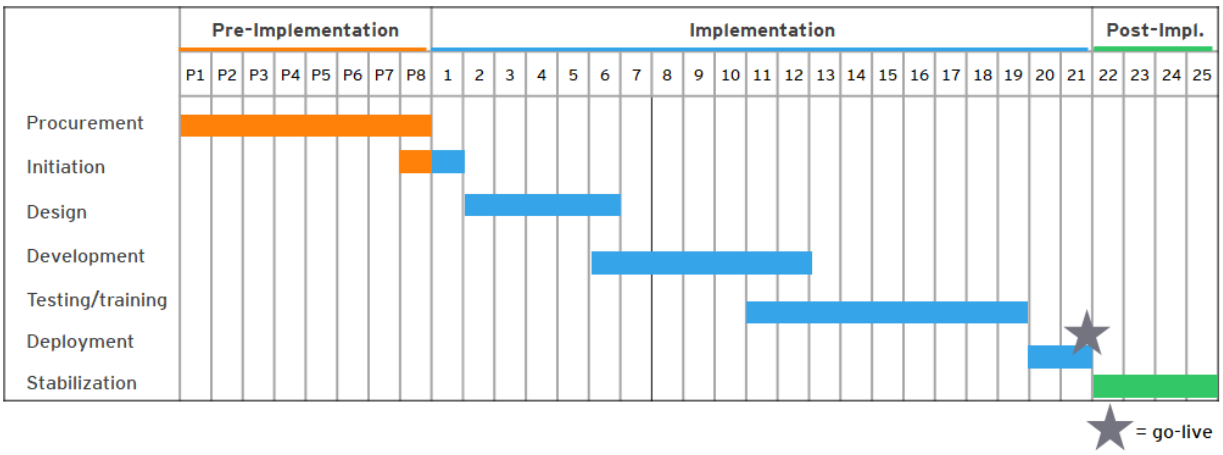
Extra staff on call, power users walking the floor to provide immediate support as needed, and vendor attention are required immediately post go-live to account for a period of decreased efficiency as users learn to effectively use the new CIS solution in a real-world environment. With the implementation of a modern CIS solution, call centre agents will now need to handle thousands of calls a week while continuing to gain experience and efficiency. Industry data supports this period of inefficiency and while classroom training provides technical solution proficiency, time is needed to become comfortable in real world scenarios with customers.

During the four-month stabilization period, as Newfoundland Power call centre agents become more comfortable and proficient with the solution, vendor responsibilities will naturally transition to Newfoundland Power and operations will return to business as usual

6.3 Project schedule

Figure 6.1 provides the recommended project schedule.

Figure 6.1 - Suggested replacement timeline



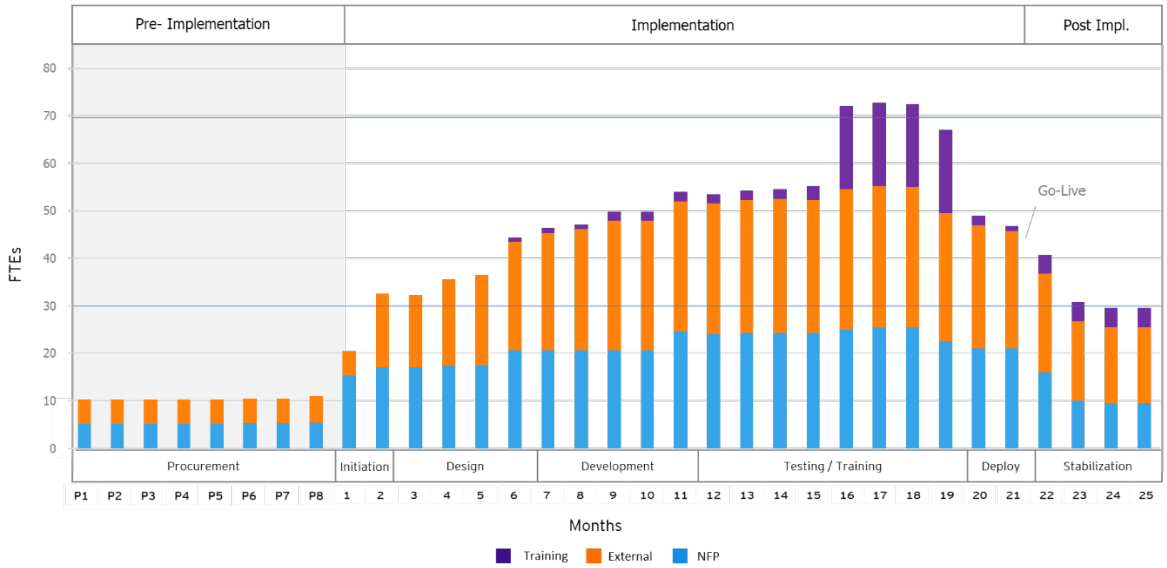
Pre-implementation activities are anticipated to take 8 months for vendor procurement activities and early initiation planning. Industry ranges for CIS implementations of similar sized utilities can vary from 18 to 24 months. [4,5] Based on information gathered during the assessment and planning effort and EY's experience with other implementations, a 21-month implementation is recommended for Newfoundland Power. This implementation baseline should be reviewed with selected vendors during contract negotiations.

A 4-month period of post go-live support will follow the implementation to stabilize the new system and successfully transition solution ownership to Newfoundland Power.

6.4 Project resourcing effort

A baseline resource model was formulated as shown in Figure 6.2. The model was based on vendor provided resourcing estimates, EY's and industry leading practices for similar projects, Newfoundland Power's core requirements and internal resource availability. The model identified target monthly resourcing levels (internal and third-party) to successfully deliver a replacement project of this size and scope.

Figure 6.2 - Projected resourcing effort model



A team of key Newfoundland Power and vendor resources will manage procurement, contract negotiation, and initiation planning. Resources will ramp up during design, development, and testing to peak to over 70 FTEs during end-user training. Upon training completion, the project team will ramp down during deployment preparation/execution and stabilize during post go-live support until users gain real world proficiency in the new CIS solution.

Further refinement of the resource estimates should be conducted with the selected vendor during procurement and initiation based upon the final negotiated scope.

6.5 Project cost

Implementation Costs

During the procurement process, Newfoundland Power will select the option that effectively meets its business, technical, cost, and timeline expectations. Estimated costs for replacement, as depicted in Figure 6.3, will be allocated annually over the duration of the engagement.

Figure 6.3 - Estimated Cost for Replacement

Implementation Cost (000's)		
Consultant Implementation Fees/Expenses	$	17,170
NFP - Implementation Labour	$	6,864
NFP - Facilities/Hardware	$	1,890
Software License	$	2,090
3rd Party - Quality Assurance Fees/Expenses	$	268
AFUDC	$	2,325
3rd Party – Procurement Fees/Expenses	$	600
NFP Procurement Costs	$	438
Total	$	31,645

The projected all-inclusive cost for Newfoundland Power to properly procure, implement, and stabilize a modern CIS replacement solution is estimated at $31.6M over an 8-month pre-implementation period, a 21-month implementation period, and a 4-month post-implementation period.

Industry guidance for CIS replacement initiatives, based on market experience, places implementation costs between $65 and $137 per customer[6], gaining economies of scale with larger utilities. Newfoundland Power is within that range, estimated at $106 per customer.[7]

Sustaining Costs

Sustaining costs fall under two categories: Annual Maintenance and Support and Software Upgrades. Both are comprised of third-party consultant, hardware, and internal labour costs.

Recurring annual maintenance and support costs are estimated at $1.3M per year. These costs cover software licensing fees, vendor support, hardware maintenance, and internal labour.

To maintain vendor software support and implement major software functionality enhancements, vendors mandate software upgrades every 3-4 years. A minor upgrade in year four is estimated at $2.1M with a larger upgrade/hardware refresh in year eight estimated at $4.0M.

The sustaining costs depicted above are not inclusive of annual inflation increases.

6.6 Conclusion

The project scope, schedule, resourcing effort and costs are consistent with standard industry practice for modern CIS implementations. In EY's opinion, following these recommendations will position Newfoundland Power for a successful CIS implementation.

References

[1] EY: “CSS Technical Risk Assessment,” June 2018.

[2] Gartner Inc: An American research and advisory firm providing IT related data, analysis and performance indicators for IT and business leaders. “Magic Quadrant for Utilities Customer Information Systems”, Gartner June 2018, Pages 2-4.

[3] EY leveraged its proprietary Power and Utilities Maturity Model and Architecture “PUMMA” framework. PUMMA is a repository of the processes commonly found in global utility organizations and enables EY to assess our client’s business processes, compare performance against peers and identify opportunities for improvement.

[4] Gartner Inc: “Based on our interaction with Gartner Utility clients, the average CIS implementation duration is in the 18- to 24-month range.” “Strategic Roadmap for Utility Customer Information Systems”, November 2018, page(s) 11.

[5] EY: Proprietary CIS Market Implementation Database. Accessed August 2019.

[6] Gartner Inc: “With an average 18- to 24-month implementation duration … a $50USD to $100USD per-meter cost.” (USD converted to CAD at 1.30 Rate). “Strategic Roadmap for Utility Customer Information Systems”, November 2018, page(s) 12.

[7] EY: Cost per customer implementation costs do not include procurement or AFUDC costs.

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Appendix A: Market analysis for Newfoundland Power

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1.0 Introduction

Newfoundland Power's Customer Service System ("CSS") was developed and implemented in 1993 and has been the foundation for customer service delivery for over 25 years. Since then, the utility industry has seen significant transformation with a number of major trends impacting the need to evolve legacy Customer Information System ("CIS") infrastructure across utilities globally:

A changing customer - Influenced by digital experiences in other industries (e.g. Bell), customers are more informed, connected and accustomed to high quality, personalized and on-demand service. As a result, customers are demanding new levels of experience from their utilities.

Emerging technology - A combination of new digital technologies is changing how energy infrastructure is managed and altering how customers interact with their providers. At the same time, the impact of technology, particularly on customer service, is disrupting the skills needed in the workforce of today's utilities. It has become essential to be adaptive and responsive to new technologies not only to meet customer expectations, but also to increase operational performance and management capabilities.

An evolving energy sector - Utilities need to meet higher demands from better-informed stakeholders. Regulatory scrutiny has increased, consumer pressure over rising prices is growing and environmental demands are tougher.

When embarking on such a significant project like a CIS replacement, it is important to understand what similar utilities are doing to gain insight on CIS market trends. The objective of the market analysis was to identify on-going and recently completed CIS planning and implementation efforts of comparable utilities across North America.

2.0 Approach

The market analysis was conducted in June 2019. As the primary data source, EY leveraged its own proprietary database of utilities who have recently implemented or are undergoing a CIS implementation within the last 5-7 years [1]. Information extracted from the database included:

a. Utility name
b. Location
c. Total number of customers
d. Commodity type (i.e. Electricity, Gas, Water)
e. Current CIS Vendor

The two-part analysis of North American and peer group utilities included:

1. In total, 120 North American utilities were included as part of the analysis. The utilities are distributed across Canada and the United States as illustrated in Figure 2.1. A detailed list of these utilities can be found in Section 5.

Figure 2.1 – Distribution of utilities included in analysis

2. A subset of peer utilities was identified from the broader market dataset to show greater applicability to Newfoundland Power. The results were filtered based on two criteria:

   - Number of customers- Utilities who serve between 150,000-450,000 customers
   - Service type- Electric Utilities

By filtering by this criteria, 28 peer utilities were identified. EY also conducted a jurisdictional scan of Canadian utilities who serve more than 100,000 electric retail customers to gather a view of market activity within Canada.

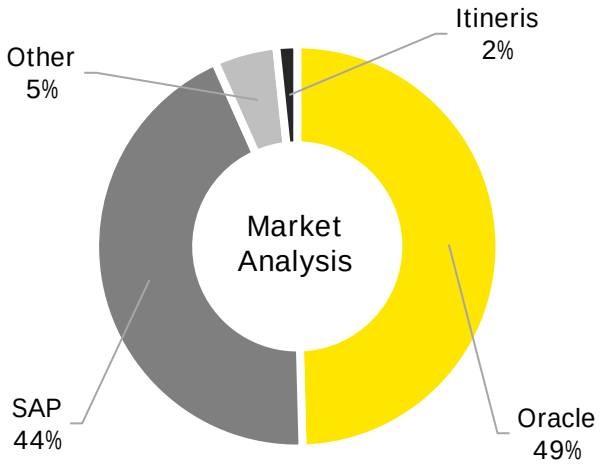
[1] EY has collected this data over the last 5 years and while the majority of the customer numbers and CIS vendors were refreshed as part of this analysis some data could differ based on changes since June 2019.

3.0 Findings

3.1 North American Market Analysis

The analysis confirms that within the North American market the majority of utilities are implementing modern CIS solutions from one of two CIS vendors, Oracle or SAP.[2] As shown in Figure 3.1 below, 93% of North American utilities included in the analysis selected one of these two vendors.

Figure 3.1 – % of North American installs by vendor



These findings are consistent with other industry research. For example, Gartner produces an annual "Magic Quadrant for Utilities Customer Information Systems" report which evaluates CIS vendors in the sector and provides key insights for utilities considering replacing or upgrading their CIS system. Since 2008, Gartner has consistently ranked SAP and Oracle as leaders in the CIS market. [3]

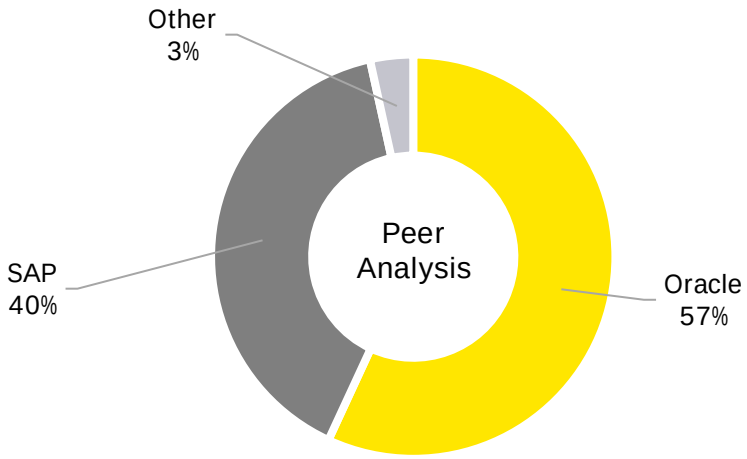
3.2 Peer Market Analysis

The peer group mirrors the greater market, as shown in Figure 3.2, with 97% of the identified comparable utilities replacing their legacy CIS with products from one of the two market leaders.

[2] These findings are consistent with other industry analysis. See Gartner Inc: An American research and advisory firm providing IT related data, analysis and performance indicators for IT and business leaders. "Magic Quadrant for Utilities Customer Information Systems", Gartner June 2018, Pages 2-4.

[3] See Gartner Inc: "SAP CR&B and Oracle Utilities CC&B (C2M) have achieved leadership positions and continue to break away from the rest of the pack. This effectively forces this market into a 'duopoly' mode." Magic Quadrant for Utilities Customer Information Systems", Gartner June 2018, Page 22.

Figure 3.2 – % of installs in peer group by vendor



3.3 Canadian Market Analysis

Newfoundland Power is the last remaining mid-large size Canadian utility operating a legacy CIS application with no upgrade path provided by the original vendor. The majority of peer Canadian utilities have already replaced or are in the process of replacing their legacy CIS systems as shown in Table 3.1 which provides a list of Canadian utilities that serve more than 100,000 customers with their current CIS vendors.

Table 3.1 – Canadian Utility CIS Scan[4]

Utility	Province	Current CIS Vendor
Newfoundland Power	NL	Legacy (Customer/1)
Nova Scotia Power (Emera)	NS	Harris
New Brunswick Power	NB	SAP
Hydro Quebec	QC	SAP
Hydro One	ON	SAP
Toronto Hydro	ON	Oracle
Alectra	ON	Oracle
London Hydro	ON	SAP
Peel Water	ON	Oracle
Durham Water	ON	Oracle

[4] EY: "CSS Technical Risk Assessment," June 2018. Information was obtained from EY's proprietary database and updated as of November 2019.

Utility	Province	Current CIS Vendor
Algonquin Power	ON	SAP (In progress)
Manitoba Hydro	MB	Hansen
SaskPower	SK	SAP
ENMAX	AB	SAP
EPCOR	AB	SAP (In progress)
ATCO	AB	Oracle (In progress)
BC Hydro	BC	SAP

4.0 Conclusion

The majority of comparable utilities to Newfoundland Power have completed or are currently in the process of a modern CIS implementation and have chosen Oracle or SAP. Of the utilities in the analysis, Newfoundland Power is the last mid to large size utility using a legacy system with no upgrade path provided by the original vendor.

5.0 Attachments

The table below provides the list of the 120 North American utilities that were included in the analysis; those highlighted in grey identify utilities included as part of the peer group.

Utility	Services	Customers	Location
Albuquerque Bernalillo County Water Utility	Water	700,000	USA
Algonquin Power & Utilities Corp.	Electric, Gas, and Water	768,000	Canada
American Water	Water	5,000,000	USA
Arizona Public Service Company	Electric	1,200,000	USA
Artesian Water	Water	86,500	USA
ATCO Electric	Electric & Gas	227,000	Canada
Atlantic City Electric Company	Electric	556,000	USA
Atmos Energy Corporation	Gas	3,000,000	USA
Avista	Electric & Gas	600,000	USA
Baltimore Gas & Electric	Electric & Gas	1,900,000	USA
Black Hills Energy	Electric & Gas	1,200,000	USA
Boston Water	Water	850,000	USA
Burbank Power	Electric & Water	51,000	USA
CalWater	Water	484,900	USA
Centerpoint Energy	Electric & Gas	5,500,000	USA
Central Hudson	Electric & Gas	380,000	USA
Citizens Gas Fuel Company	Gas	17,000	USA
City of Baltimore Water	Water	410,000	USA
City of Long Beach	Gas & Water	177,000	USA
City of Lubbock	Electric & Water	193,000	USA
City of Phoenix Water	Water	1,500,000	USA
City of Sacramento	Electric	628,900	USA
City of Seattle	Electric	454,000	USA
CLECO	Electric	290,000	USA
Cleveland Public Power	Electric	80,000	USA
Cleveland Water Department	Water	427,000	USA
Cobb EMC	Electric	200,000	USA
Colorado Springs Utilities	Electric, Gas & Water	600,000	USA
Commonwealth Edison Company	Electric	4,000,000	USA
Consolidated Edison Company of New York	Electric & Gas	4,300,000	USA
Consumers Energy	Electric & Gas	3,500,000	USA

Utility	Services	Customers	Location
Dayton Power & Light	Electric	525,000	USA
Delmarva Power	Electric & Gas	660,000	USA
DTE Energy	Electric	3,500,000	USA
Duke Energy	Electric & Gas	9,300,000	USA
Duquesne Light Company	Electric	600,000	USA
Durham Water	Water	250,000	USA
El Paso Electric	Electric	400,000	USA
Energie NB Power	Electric	390,000	Canada
Enersource	Electric	220,000	Canada
ENMAX	Electric & Gas	900,000	Canada
Entergy Arkansas	Electric	711,000	USA
Entergy Louisiana	Electric & Gas	1,173,000	USA
Entergy Mississippi	Electric	450,000	USA
Entergy New Orleans	Electric & Gas	309,000	USA
Entergy Texas	Electric	454,000	USA
Epcor Electric	Electric, Gas & Water	2,000,000	Canada
Fortis Alberta	Electric	564,000	Canada
Fortis BC Electric	Electric	176,000	Canada
Fortis BC Gas	Gas	1,030,000	Canada
Fortis Ontario	Electric	66,000	Canada
Gas South	Gas	300,000	USA
Gulf Power	Electric	428,000	USA
Hawaii Electric Light Company	Electric	400,000	USA
Horizon Utilities	Electric	300,000	Canada
Hydro One	Electric	1,400,000	Canada
Hydro One Brampton	Electric	160,000	Canada
Hydro Ottawa	Electric	331,000	Canada
Hydro Quebec	Electric	4,300,000	Canada
Idaho Power	Electric	560,000	USA
Indianapolis Power & Light	Electric	470,000	USA
Interstate Power and Light Company	Electric & Gas	764,000	USA
Jersey Central Power and Light	Electric	1,100,000	USA
Kansas City Light and Power	Electric	800,000	USA

Utility	Services	Customers	Location
Kansas Gas Service	Gas	639,000	USA
Kentucky Utilities Company	Electric	553,000	USA
LA DWP	Electric & Water	2,181,000	USA
Las Vegas Valley Water District	Water	400,000	USA
London Hydro	Electric & Water	157,000	Canada
Louisville Gas and Electric Company	Electric & Gas	737,000	USA
Louisville Water	Water	603,000	USA
Madison Gas & Electric	Electric & Gas	309,000	USA
Manitoba Hydro	Electric & Gas	580,000	Canada
Maritime Electric	Electric	81,000	Canada
Met-Ed (Metropolitan Edison)	Electric	560,000	USA
Middlesex Water	Water	363,000	USA
Minnesota Power	Electric	145,000	USA
Mon Power	Electric	385,000	USA
Nashville Electric Service	Electric	370,000	USA
National Grid	Electric	5,000,000	USA
New York State & Electric Gas	Electric & Gas	1,160,000	USA
Nova Scotia Power	Electric	500,000	Canada
Oakville Hydro	Electric	64,000	Canada
Ohio Edison	Electric	1,000,000	USA
Oklahoma Gas & Electric	Electric & Gas	843,000	USA
Oncor	Electric	3,600,000	USA
Orange and Rockland Utilities	Electric & Gas	430,000	USA
PECO	Electric & Gas	2,111,000	USA
Pedernales Electric Cooperative	Electric	288,000	USA
Peel Water	Water	350,000	Canada
Penelec	Electric	600,000	USA
Penn Power	Electric	160,000	USA
Pepco	Electric	883,000	USA
PG&E Corporation	Electric & Gas	9,700,000	USA
Philadelphia Gas Works	Gas	500,000	USA
Portland General Electric	Electric	875,000	USA
Potomac Edison	Electric	400,000	USA

Utility	Services	Customers	Location
PowerStream	Electric	250,000	Canada
PSEG Long Island	Electric & Gas	1,100,000	USA
Puget Sound Energy	Electric & Gas	1,940,000	USA
Saint John Energy	Electric	36,000	Canada
San Diego Gas & Electric	Electric & Gas	2,273,000	USA
San Francisco PUC	Electric & Water	1,900,000	USA
San Jose Water	Water	216,000	USA
SaskPower	Electric	522,000	Canada
South Jersey Industries	Gas & Water	690,000	USA
Southern California Edison	Electric	5,000,000	USA
Southern Company Gas	Gas	774,000	USA
Southwest Gas	Gas	2,000,000	USA
Spire Inc	Gas	1,560,000	USA
Superior Water, Light and Power Company	Electric, Gas & Water	38,000	USA
TECO (Tampa Electric Company)	Electric	765,000	USA
The Illuminating Company	Electric	700,000	USA
Toledo Edison	Electric	300,000	USA
Toronto Hydro	Electric	772,000	Canada
Tucson Electric	Electric	420,000	USA
UniSource Energy Services	Electric & Gas	243,000	USA
Washington Gas	Gas	1,100,000	USA
West Penn Power	Electric	720,000	USA
Wisconsin Power and Light	Electric & Gas	639,000	USA

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Appendix B: Customer Journey Mapping Newfoundland Power

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1.0 Introduction

Improving customer experience is often cited as one of the primary drivers by utilities for replacing/upgrading their legacy CIS platforms.[1] Customer expectations have shifted as emerging technologies continue to change how customers interact with their utility, and social media usage highlights the importance of positive customer experiences. Customers expect more digital interactions and service at any hour of the day, in part due to higher standards being set in other industries. Customers want to embrace greater energy efficiency and increasingly expect their utility to be "Energy Advisors". On an operational level, anticipating customer needs and being able to address them proactively reduces interactions and complaints.

Customer journey mapping allows Newfoundland Power employees to step into the 'customer's shoes' to understand the broader experience from the customer perspective rather focusing on individual business functions or processes.

The objective of customer journey mapping is to better understand what customers currently experience vs. what they want and expect. Customer journey maps provide a comprehensive overview of key interactions a customer may have with Newfoundland Power over time via different channels. They show an aggregated customer-centric experience, rather than individual functions/processes. They also document potential future state capabilities for a CIS replacement to ensure continued good customer experience.

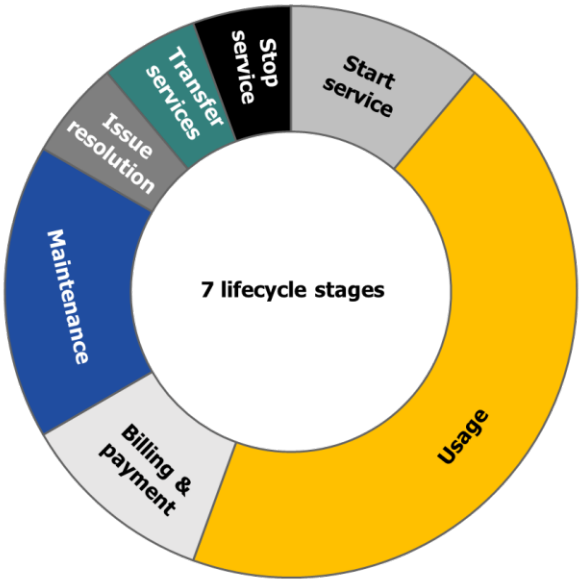
2.0 Approach

EY conducted customer journey mapping workshops in June 2019 with Newfoundland Power employees from the customer contact centre who work with customers on a day-to-day basis, as well as IT and other back office departments, to bring both a customer and internal business perspective.

Typically, there are 7 key customer lifecycle stages that every customer goes through with their utility provider as shown in Figure 2.1. Within these lifecycle stages, there are multiple customer journeys that define the customer experience and satisfaction. Customer journeys break the customer experience into manageable focus areas to identify improvement opportunities and define future-state experience.

[1] Gartner Inc: "Automating customer service with virtual agents and tailoring suppliers to consumers' preferences increase customer satisfaction while lowering customer service costs." See Top 10 Trends in 2018 Driving the Utility Industry Toward a Decarbonized, Distributed, Digital and Democratized Future, April 2018, page(s) 17.

Figure 2.1- Typical customer lifecycle stages



The majority of customers won't experience every journey throughout their lifetime as a Newfoundland Power customer. Through a prioritization exercise, the team identified 5 key customer journeys based on customer impact and incidence. Table 2.1 describes the five customer journeys that were prioritized as part of this exercise.

Table 2.1 – Customer journey prioritization results

Journey	Why was this journey chosen?
Sign up as a customer for this first time	• Signing up as a customer is one of the first (and maybe only) personal interaction points that they will have with Newfoundland Power.
Understand and pay my bill	• Frequent questions about abnormally high bills, Equal Payment Plan ("EPP"), and estimated bills have high impact on customer satisfaction.
Pay my past due bill	• Represents a high volume of calls to Contact Centre and high fiscal impact for Newfoundland Power.
Maintenance issue/outage	• Critical importance to customer to resolve any outage/maintenance issues.[2]
Transfer service	• High customer importance because any setback in the transfer will result in customer dissatisfaction as customers expect a smooth transition of power.

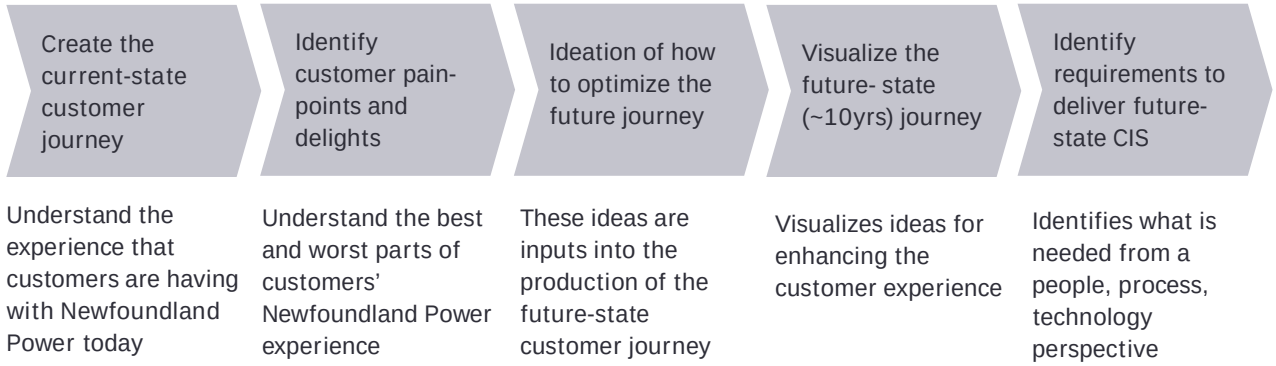
[2] Outages are one of the critical interactions that a customer will have with Newfoundland Power so while Responder (Newfoundland Power's Outage Management System) is the primary technology supporting the outage process the team felt it was important to map this journey to understand areas where CSS/Responder would overlap.

In order to explore how each customer segment will behave and what they expect, a persona is required. A persona is focused around a fictional individual who is representative of a specific customer segment. The persona hypothetically describes a real person and includes their background story, attributes, needs, and expectations. Personas enable workshop attendees to adopt the personality of a customer to better understand how they would interact with Newfoundland Power throughout their entire lifecycle.

Prior to the workshops, 8 personas were created by Newfoundland Power's Customer Relations Team. They were derived from statistical customer base segmentation work. Further detail on each persona can be found in Section 5. Personas were then assigned to a journey based on relevance and customers needs/wants.

The approach for customer journey mapping was broken out into 5 distinct stages, as shown in Figure 2.2.

Figure 2.2- EY's Customer Journey Mapping Methodology



Customer journey maps are compact visualizations of a customer's experience at various touch points during their lifecycle with Newfoundland Power. A customer journey map is built entirely from a customer's point of view. This allows employees to explore what customers' pain points and expectations are, and the emotions and opinions following the experience. For this exercise, EY leveraged the experience of front-line customer facing staff to walk through each journey to determine a list of potential outcomes.

Once completed, each journey map was analyzed to determine what would be required to enable the desired future-state customer experience. From each journey map, potential future state capabilities were identified and documented for Newfoundland Power to consider evaluating further in a CIS replacement. A detailed output of the journey mapping sessions, including terminology, can be found in Section 5.

3.0 Findings

In total, 8 current state customer journey maps were produced with associated customer delights and pain points. Potential future state capabilities were aggregated into three categories: People, Process and Technology. People refers to capabilities that impact individuals or groups (internal and external). Process refers to capabilities that impact business processes. Technology refers to capabilities that impact technology and/or data.

Further assessment of these findings is required by Newfoundland Power to prioritize capabilities that could be actioned in the short, medium and long-term. Additional analysis will be required to determine the operational costs and validate the customer benefits needed to implement any of the capabilities identified.

Future-state capabilities were grouped into one of three categories.

Examples of capabilities for further evaluation in the People category include:

- Expand and automate proactive customer communications to send notifications to specific customer segments via preferred channel for program eligibility, takeCHARGE initiatives, payment reminders, payment arrangement options, etc.
- Integrate automated workflows and scripting tools to help employees improve customer experience by providing consistent messaging across all channels. Guided workflows will also allow Newfoundland Power to train agents effectively and faster.
- Explore options (Facetime, Skype, etc.) for identity verification to avoid customers having to present ID in person at a Newfoundland Power location.

Examples of capabilities for further evaluation in the Process category include:

- Customers want to avoid being surprised by a high bill. A customer-initiated usage/charges tool could be created to better understand consumption between reads (i.e. input customer read into online calculator to show estimated current charges to date as well as projected cost on next bill date).
- Reduce manual paper-based forms and increase program enrollment by setting up MyAccount automatically at time of service sign up/transfer and allow customers to initiate all programs (e.g. Automatic Payment Plan (“APP”), EPP, Outage Alerts) at the same time.

Examples of capabilities for further evaluation in the Technology category include:

- Provide a single view of the customer and move away from a premise-based data model to better analyze and understand customer needs/wants, allowing for a more personalized customer experience.
- Bill redesign so customers can better understand the components of their bill. Present enhanced visual representations (graphs, charts etc.) of usage and charges on the bill and in MyAccount with clear definitions and additional details (e.g. weather info).
- Develop self-service options for General Service customers (e.g. web portal) so they can manage, report and inquire about their services including the ability to designate a facility manager or management company.
- Simplify complex services such as move-in / move-out.
- Provide real-time updates for all account changes including personalized outage tracking and reporting.
- Ensure advanced contact routing so customers will get the same Customer Service Representative ("CSR") to provide consistent customer service.

4.0 Conclusion

Customers' expectations continue to increase. Commercial and Residential customers alike expect prompt, efficient service at any hour of the day or night. Based on the findings from the customer journey mapping workshops, it is evident that opportunities exist to enhance customer experience with a CIS replacement. Many of the capabilities identified in these sessions are available in modern CIS solutions such as increased self-service options and tailored communications to individual preferences (e.g., email, SMS).

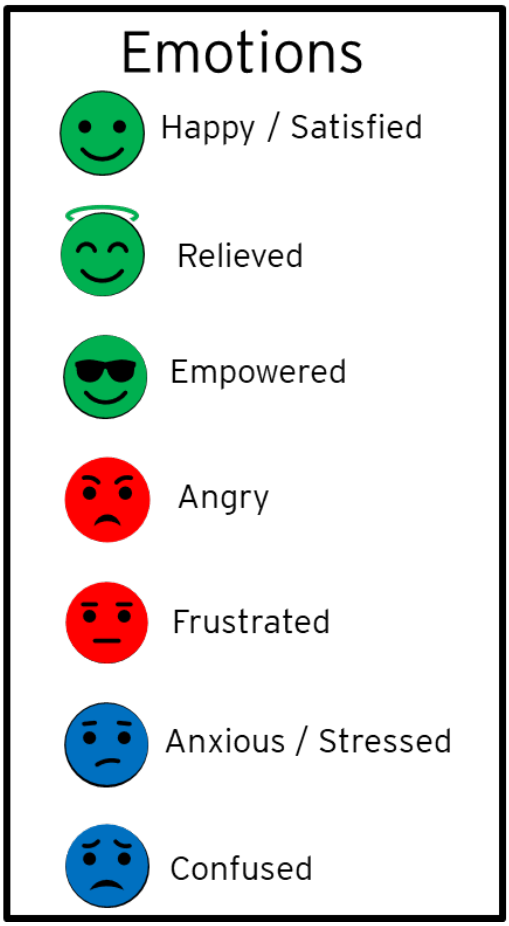
Newfoundland Power should further evaluate, identify and prioritize any capabilities that will eventually be incorporated into the CIS system requirements during a procurement phase.

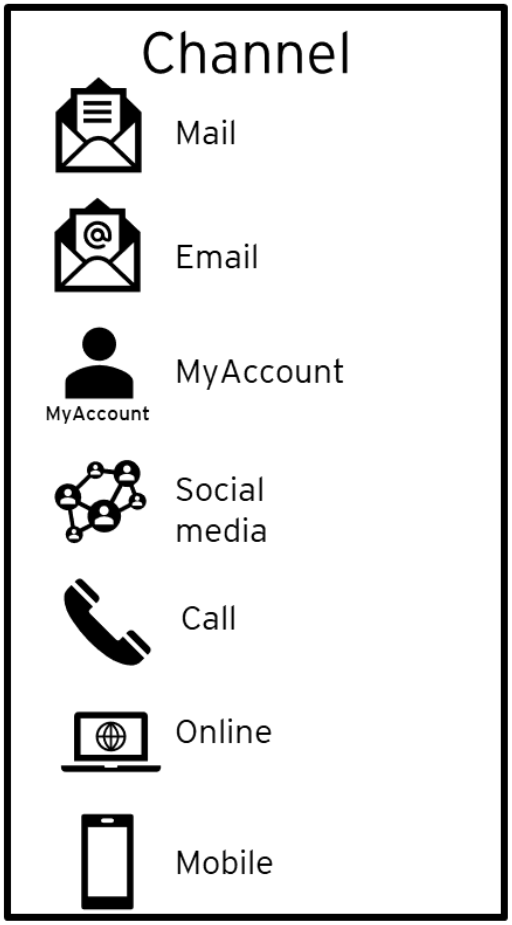
5.0 Attachments

- Customer Journey Maps

Legend -CJM terminology and outputs

Dimension	Definition
Persona	• The customer persona is the personality taken through the journey mapping process. These 8 personas were created by the Newfoundland Power Customer Relations Team
Scenario	• This is the particular scenario in which the persona individual encounters
Journey steps	• The sequence of interactions a customer will have on the journey that they are taking. These could be solo or interacting directly with Newfoundland Power
Emotions	• The emotions a customer feels at each step (e.g., are they satisfied, confused or frustrated?)
Channel interaction	• Highlights which of the possible communication mediums is leveraged in the interaction.
Pain points	• Which steps does the customer perceive negatively or cause unnecessary inconvenience for the customer
Delights	• Which customer steps are perceived positively and are emotionally important for a customer
Future-state capabilities	• List of possible operational (people, process, and technology) capabilities needed to deliver the "To-be" journey





Customer Journey Map | Pay my past due bill

Carl

Scenario

Carl has made and broken several payment arrangements resulting in numerous disconnections. He prefers to speak with a CSR instead of using online tools. He has received AESL assistance and NLHC subsidy in the past.

Journey Steps	Receive my bill, but do not pay it	Consider my options and contact NF Power	Discuss payment arrangement with NF Power	Agree to payment arrangements	Pay bill
Customer Journey Steps	1.1 Carl receives his bill and it's higher than he expected.	2.1 Carl doesn't think he has the money to pay his monthly bill.	3.1 Carl is given his payment arrangement options. 3.2 Carl is also given some possible reasons why his demand is higher than usual.	4.2 Carl agrees to payment terms and is encouraged to keep his account up to date.	5.1 Carl goes to the bank to make his payment.
Emotions/ Expectations					
Channel					
Pain Points	• Customers have no visibility of charges prior to receiving their bill • Customers who call multiple times could get a different CSR each time and receive inconsistent service	• Customers feel the payment terms can be too short • Payment term definitions and calculations may not be clearly understood by the customer			• Customers still like to walk into the bank and pay their bill
Delights			• Customers usually are able to make a payment arrangement and avoid disconnection		
Potential Future-State Capabilities – People		• Workflows and scripts to provide consistent messaging across all channels			
Potential Future-State Capabilities – Process	• Proactive notifications (e.g. payment reminders, payment arrangement options, APP)			• Personalized communication (i.e. via preferred channels, on specific topics)	• Proactive notifications (e.g. confirmation of payment)
Potential Future-State Capabilities – Technology	• Advanced contact routing • Online calculator for estimating bills between meter reads	• 360° view of the customer	• Improve internal system notes/history for CSRs (e.g. reason for high bill)		

Customer Journey Map | Pay my past due bill

Donna

Scenario

Donna runs her consulting business from her home. She has been behind in her payments and has made payment arrangements to avoid disconnection. She uses ebills and MyAccount but still prefers to call the company to better understand her usage.

Journey Steps	Receive my bill, but do not pay it	Consider my options and contact NF Power	Discuss payment arrangement with NF Power	Agree to payment arrangements	Pay bill
Customer Journey Steps	1.1 Donna receives her bill and it's higher than she expected.	2.1 Donna doesn't think she has the money to pay her monthly bill.	3.1 Donna is given her payment arrangement options. 3.2 Donna is also given some possible reasons why her demand is higher than usual.	4.1 Donna receives confirmation of her payment arrangement via email.	5.1 Donna pays the bill via online banking.
Emotions/ Expectations					
Channel					
Pain Points	• Customers have no visibility of charges prior to receiving their bill	• Customers feel the payment terms can be too short • General Service customers cannot make payment arrangements online and cannot make an aggregated payment arrangement for multiple accounts online		• Customers do not receive notifications of payment arrangements made over the phone/in person	• Once disconnected, payment arrangement options are limited for customers
Delights		• Customers can make a payment arrangement online	• Customers usually are able to make a payment arrangement and avoid disconnection	• Minimum payments are flexible	• Report a payment online
Potential Future-State Capabilities: People	• Dedicated CSRs for commercial customers	• Workflows and scripts to provide consistent messaging across all channels			
Potential Future-State Capabilities: Process	• Leverage customer touch points to ensure up-to-date/complete information • Proactive notifications (e.g. payment reminders, payment arrangement options)	• Ability to pick your own due date (e.g. 1st of month)	• Semi-annual review/touch point for small businesses	• Increased promotion of takeCHARGE programs for commercial customers	
Potential Future-State Capabilities: Technology		• Ability to identify accounts associated with small businesses		• Online calculator for estimating bills between meter reads	

Customer Journey Map | Understand and Pay My Bill

Mike

Scenario

Mike is a good credit customer. He owns and operates a bakery. He has multiple demand meters and reviews his usage every month in detail. He uses MyAccount but still receives a paper bill. He would prefer to talk to Newfoundland Power via electronic communication.

Journey Steps	Receive my bill	Read and analyze bill	Need help with a component of the bill	Contact NP to discuss bill	Pay bill
Customer Journey Steps	1.1 Mike receives his paper bill.	2.1 Mike's bill is higher than he expected. He looks for bill component definitions on the paper bill because he's not sure what the numbers mean and is questioning their accuracy.	3.1 Finding no answer on the paper bill, Mike goes into MyAccount as he needs a better understanding of how much power he used this month. 3.2 There's a little more detail, but he still doesn't understand and has trouble finding the reference material.	4.1 Mike has to call to get a more detailed explanation of his consumption/charges.	5.1 Mike wishes he could pay by credit card without the extra fees so he could get points.
Emotions/ Expectations					
Channel		MyAccount	MyAccount		
Pain Points	• The paper bill doesn't give much detail about why demand was high for that month • The paper bill has an outdated section showing meter dials • The definition and calculations are not in simple terms	• Difficulty understanding the definitions and calculations on the bill • No weather information • No calculator/definition guide	• Customers don't fully understand demand • A bill account can only be associated with one MyAccount profile • Statement of accounts is not online	• Customers usually need to speak to a CSR to get information related to their demand/usage	• Customers would like to pay by credit card without extra charges and without being transferred to a third party
Delights	• Customers receive their bill through their preferred method (email/paper/online)	• Shows charges for the same month last year for comparability		• Customers receive information about energy efficiency programs	• Customers like the discount date and notification reminder
Potential Future-State Capabilities: People			• Dedicated CSRs for commercial customers		
Potential Future-State Capabilities: Process	• Improve internal system notes/history for CSRs (e.g. reason for high bill)			• Increased promotion of takeCHARGE programs for commercial customers • Proactive notifications (e.g. promote bills enrollment) • Semi-annual review/touch point for small businesses	
Potential Future-State Capabilities: Technology	• 360° view of the customer	• Bill redesign (e.g. to provide more detail on usage, make more user friendly) • Online calculator for estimating bills between meter reads	• Allow multiple bill accounts for a single MyAccount profile • Live online chat during business hours • Automated online chat after hours	• Online tools to help customers understand historical usage patterns	• Pre-population of information when transferring to another agent or supervisor

Customer Journey Map | Understand and Pay My Bill

Thelma

Scenario

Thelma has fluctuating credit history with the company and is enrolled in EPP to help her better manage her monthly payments. She rarely pays on time and usually pays what she can. She frequently calls Newfoundland Power to discuss her bill and complains about the cost of electricity.

Journey Steps	Receive my bill	Read and analyze bill but needs help with component of the bill	Contacts NF Power to discuss bill	Consider / discuss payment options and pay bill
Customer Journey Steps	1.1 Thelma receives her bill and thinks it's too high.	2.1 Thelma notices that her EPP has gone up slightly. 2.2 Thelma reviews the true-up information and the deferred balance, but doesn't understand how it's calculated. 2.3 Thelma needs help understanding how EPP works.	3.1 Thelma calls to get help understanding her usage and what the deferred balance means 3.2 Thelma wants clarification of why it was reviewed. 3.3 CSR explains the calculation and also provides additional detail on weather patterns and household factors that could be the cause.	4.1 Thelma can only afford to pay her current arrears. 4.2 The CSR must explain that she must keep up to date with EPP or risk being removed from the program. 4.3 Thelma receives some takeCHARGE program information that may be useful to help reduce her usage and bill.
Emotions/ Expectations				
Channel				
Pain Points	• Difficult to understand what everything on the bill means • Can miss bill messages when receiving online bills	• Definitions and calculations are not in simple terms • No weather information on the bill	• Customers often have to call Newfoundland Power to get more detailed explanation of consumption/charges	• The payment timing can be confusing for customers already in arrears • Customers cannot pick their due date
Delights	• Customers like the stability of EPP • Customers receive their bill through their preferred method (email/paper/online)	• ebills are provided as email attachments • Customers can view year-over-year usage		
Potential Future-State Capabilities – People		• Workflows and scripts to provide consistent messaging across all channels		
Potential Future-State Capabilities – Process	• Proactive notifications (e.g. change in EPP)			
Potential Future-State Capabilities – Technology		• Increased EPP information on website • Online tools to help customers understand historical usage patterns • Bill redesign (e.g. to provide more detail on EPP, make more user friendly)		

Customer Journey Map | Understand and Pay My Bill

Cory

Scenario

Cory is an Accounts Payable Manager based out of Toronto. He is responsible for making payments for ABC superstores in NL. His company uses Consolidated Billing. He prefers electronic communication.

Journey Steps	Receive my bill	Makes payment on current bill	Receives next bill	Contact NP to discuss bill	Settle account
Customer Journey Steps	1.1 Cory receives his bill via email. 1.2 ABC Superstore accounts are listed in a summary PDF and a spreadsheet is attached.	2.1 Cory reviews his bill in detail but makes the payment on the incorrect master account.	3.1 Cory receives his next bill and only then realizes his error.	4.1 Cory calls and explains his error and asks Newfoundland Power to reconcile the issue for him. 4.2 CSR tells him that they will take it offline and someone will have to call him back. 4.3 He receives a call back informing him that his issue is resolved.	5.1 Cory receives his next bill, which shows adjustments in PDF/ spreadsheet.
Emotions/ Expectations					
Channel		MyAccount			
Pain Points	• Unable to immediately compare this month's bill to the past month • Summary PDF can be lengthy as customers can have multiple master accounts	• Customers on consolidated billing may have issues trying to reconcile bills and payments • Can't see consolidated bill online, only individual accounts • Website not designed for General Service customers with multiple accounts • Only one customer web profile can view an account; an account cannot be managed or viewed by more than one customer	• Large General Service customers have differing processes for paying accounts and payments can often be delayed • Interest charges can be significant for this type of error	• Must call in to resolve issue • Can be a lengthy process to reconcile	
Delights	• Flexible account management options for commercial customers (e.g. flexible bill formatting)				
Potential Future-State Capabilities: People				• Dedicated CSRs for commercial customers	
Potential Future-State Capabilities: Process		• Proactive notifications (e.g. mismatch in payment amounts)		• Flexible account management options for commercial customers	
Potential Future-State Capabilities: Technology	• 360° view of the customer	• Improve self-service options for commercial customers (e.g. allowing more transactions to be completed online) • Allow multiple bill accounts for a single MyAccount profile	• 360° view of the customer		• Improve self-service options for commercial customers (e.g. ability to make billing inquiries online)

Customer Journey Map | Sign up as a new customer

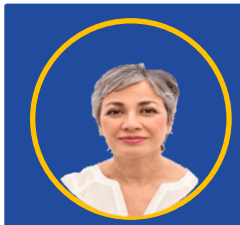
Mel

Scenario

Mel rents an apartment and lives with a roommate. She uses ebills and MyAccount to receive and review her bill. She prefers electronic means of communication and rarely calls Newfoundland Power unless absolutely necessary.

Journey Steps	Research	Initiates Contact	Process and Approve	Connect
Customer Journey Steps	1.1 Mel has no idea which company provides electricity, so she googles "Newfoundland Power" 1.2 She wonders how much her monthly cost will be at her new apartment and tries to find out what her monthly average bill would be.	2.1 She opens the web application form but doesn't have all the info she needs to complete the form, so she closes out the form and loses the information she already spent 20 minutes typing in.	3.1 The next day, she completes the form online. 3.2 She is prompted to sign up for available programs (e.g. APP, ebills). 3.3 An email is sent to her landlord notifying of her move-in date. 3.4 Mel is told that her and her roommate must present ID physically at Duffy Place.	4.1 Mel moves into her new apartment.
Emotions/ Expectations				
Channel				
Pain Points	• There's no online tool to estimate usage	• Forms can't be saved while in progress	• Customers must physically present ID when setting up a new service if renting • A customer could be disconnected if their roommate is in arrears • Additional documentation must be presented to enroll in APP • Landlords may have to verify tenants before a transfer of service	
Delights			• Landlords receive notifications when tenants move in and out of the premise	
Potential Future-State Capabilities: People				• Workflows and scripts to provide consistent messaging across all channels
Potential Future-State Capabilities: Process	• Enhance self-service capabilities (e.g. automation of processing Move In/Move Out requests)	• Leverage customer touch points to ensure up-to-date/complete information • Improve real-time information on MyAccount (e.g. immediate activation of MyAccount profile)		• Proactive notifications (e.g. "welcome home" kit with energy saving tips) • Personalized communication (i.e. via preferred channels, on specific topics)
Potential Future-State Capabilities: Technology	• Online calculator for estimating bills between meter reads	• Live online chat during business hours • Automated online chat after hours • 360° view of the customer	• Ability to save website forms while in progress • Ability to verify identity electronically	

Customer Journey Map | Transfer Service



Stella

Scenario

Stella is a good credit customer and is enrolled in EPP to help her better manage her monthly finances. She also uses APP and ebills for convenience. Her son has special needs and is on the Company's Special Care Customer List. She prefers to use email to contact Newfoundland Power.

Journey Steps		Initiates Contact	Process and Approve	Connect
Customer Journey Steps		1.1 Stella emails to transfer services.	2.1 The next day, she receives an email with the new account number and service date.	3.1 Stella moves into her new home.
Emotions/ Expectations				
Channel				
Pain Points		• General Service application for service cannot be completed online	• New account number is generated every time a customer moves • Service addresses can be difficult to find (e.g. Main Rd) • Insufficient customer information logged in current database	
Delights		• Ability to set up an account through email/online	• Quick and easy transfer process • Can sign up for Equal Payment Plan at the time of sign-up	
Potential Future-State Capabilities	People	• Workflows and scripts to provide consistent messaging across all channels		
	Process		• Leverage customer touch points to ensure up-to-date/complete information • Automated transfer of all programs (e.g. APP, EPP) when transferring service	• Proactive notifications (e.g. confirmation of service transfer, "welcome home" kit with energy saving tips)
	Technology	• Online calculator for estimating bills between meter reads • Ability to set call back times	• Live online chat during business hours • Automated online chat after hours • 360° view of the customer • Integrate with Geographic Information System ("GIS")	

Customer Journey Map | Unplanned Outage

Nick

Scenario

Nick is a good credit customer and uses ebills and MyAccount. He is aware of the TakeCHARGE programs and applied for rebate programs online. He never calls Newfoundland Power and prefers to interact with the company in a real-time digital environment.

Journey Steps	Customer's power goes out	Customer contacts NF Power	Customer explains issue	Restoration time is given	Power is back
Customer Journey Steps	1.1 Nick checks his Facebook/Twitter and the Newfoundland Power website to see if the outage is listed online, but it's not.	2.1 Nick checks the website again 15 minutes later but there's still no information available. 2.2 Nick reports the outage online	3.1 Nick continually checks social media and the website for updates. 3.2 Nick signs into MyAccount and selects to receive outage alerts via text.	4.1 Nick receives an Estimated Time of Restoration via text.	5.1 Nick's power is restored.
Emotions/ Expectations					
Channel					
Pain Points	• Outages are only pushed out to social media if they are planned or major • May not know the reason for the outage or where to look to see if the meter is damaged, etc. • Must sign up for outage alerts (not automatic)	• Outages will only link to a premise if logged into MyAccount • Depending on the size of the outage, customers could experience longer handle times if they call early in the outage • Customers may not understand power restoration priorities/procedures when multiple outages occur	• Customers are only notified if they are signed up for alerts or logged into MyAccount	• Multiple outages can occur at once	
Delights	• Customers can sign up to receive outage alerts via their preferred channel through MyAccount • Customers can sign up to receive outage alerts on multiple accounts	• Ability to report an outage online • Information provided via IVR/Outage Line • Newfoundland Power frequently updates its website/social media for major power outages	• Key accounts will receive personalized contact if power goes out	• Generally, power is restored when Newfoundland Power estimates • Customers generally feel their service is reliable	
Potential Future-State Capabilities: People					
Potential Future-State Capabilities: Process	• Proactive notifications (e.g. automated sign-up for outage alerts)	• Leverage customer touch points to ensure up-to-date/complete information			• Proactive notifications (e.g. confirmation of power restoration)
Potential Future-State Capabilities: Technology		• Live online chat during business hours • Automated online chat after hours			

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Appendix C: Edge Application Disposition for Newfoundland Power

Building a better working world

Contents

1.0 Introduction

Newfoundland Power's Customer Service System ("CSS") is the Company's primary source of account and customer data. CSS integrates with nearly 60 other operational applications including the Company's Financial Enterprise Resource Planning ("ERP") System, Meter Asset Management System and Outage Management System. It is critical to understand how these 'edge applications' interact with CSS to determine how a CIS could fit functionally and technically in Newfoundland Power's environment.[1]

Typically, modern CIS solutions have built-in core utility business processes in their standard product offerings allowing many legacy edge applications to be replaced or retired as part of a new CIS implementation. In addition, CIS vendors work closely with the utilities across the sector to anticipate and develop capabilities within their base packages to meet changing market demands. These new requirements are incorporated into product releases during the normal upgrade process, providing access to integrated product enhancements used by other utilities without having to build and support complex CSS customizations. Reducing the number of edge applications will decrease complexity and minimize the support required to maintain the future CIS.

The objective of the analysis was to identify current CSS edge applications in order to provide a high-level view of potential future-state dispositions including applications to be retried, retained, replaced or reviewed in the future.

It is important to note that the disposition strategy may change based on the software product selected and design decisions during the procurement and application design phases. Newfoundland Power will need to ensure that any new CIS meets the technical and functional requirements needed to deliver similar functionality that these current edge applications provide to ensure continuity in business operations.

[1] Within the commercial marketplace, Newfoundland Power's CSS is referred to as a Customer Information System or "CIS".

2.0 Approach

EY's Technical Architect, experienced in implementing various CIS software products, conducted a preliminary workshop with key Newfoundland Power IT personnel to gain an understanding of the current CIS landscape. An application diagram provided by Newfoundland Power, as found in Section 5, was used as a starting point. EY then documented each application that interfaces to the CSS in order to gather detailed information for each application.

Data collected included:

a. Application description
b. Application type (e.g. file transfer protocol, manual, directly queries CSS etc.)
c. Frequency of data transfer (e.g. daily, weekly, ad-hoc etc.)
d. Data direction (i.e. data transfer in and/or out of CSS)
e. Related business process (e.g. Payments, Meter and Asset Inventory, Collections etc.)
f. Complexity of integration (High, Medium, Low)
g. Application monitoring and error handling (i.e. how data errors are identified)
h. Current mechanism and any technology pain points

Based on the information reviewed in the workshop, EY developed the edge application inventory and categorized similar applications into functional groupings, as noted in Table 3.1, to highlight common operational areas associated with current edge applications.

EY then identified application interfaces and where there could be duplication or gaps in functionality between legacy CSS architecture and what modern CIS solutions provide, as seen in other similar utilities. Individual applications were then assigned dispositions based on four categories.

- Retire - The interface can be eliminated or new CIS functionality will be able to replace it.
- Retain - The interface/functionality will be incorporated into the new CIS via configuration or customization.
- Replace - The interface is scheduled to be replaced as part of the existing technology plan.
- Review - The interface requires continued consideration as part of a broader technology strategy.

EY confirmed and refined its initial disposition strategy with feedback from Newfoundland Power. A summary of identified dispositions, and key application attributes is included in Section 3.

3.0 Findings

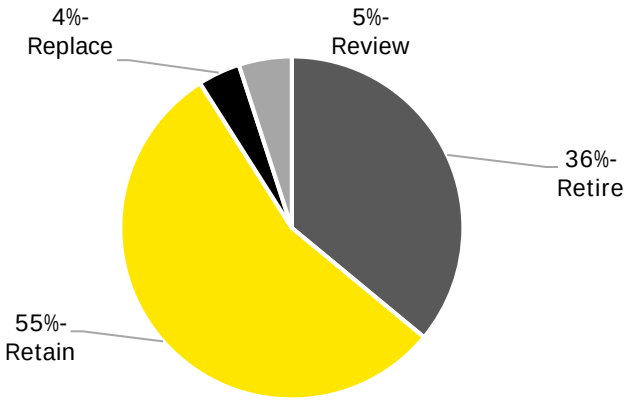
The assessment identified 56 edge applications that interact with CSS which were categorized into 10 functional groupings. When grouped by function, as shown in Table 3.1, it becomes clear that CSS application architecture impacts many critical business functions across Newfoundland Power.

Table 3.1- Functional Groupings of Edge Applications

Functional Group	Description	Number of Applications
Customer Information Management	Applications that support recording and storing customer information.	17
Meter and Meter Asset Inventory	Applications used to provide enhanced analytics and management of metering data and meter reading functions.	10
Payments	Applications that support receiving, processing and reviewing customer payments.	9
Other	Applications that have been created to fill functions that CSS or other edge applications could not.	7
Collections	Applications that support credit and collection activities.	3
Reports	Applications that provide various reports or aggregate customer information.	2
Field Orders	Applications that support technical work requests and mobile workforce management.	2
Billing	Applications that allow for special billing files to be received outside of CSS.	2
Customer Communications	Applications that generate customer correspondence.	2
Financials	Applications that support financial reporting.	2

Based on EY's knowledge of modern CIS solutions in the market today, edge applications were assigned a future state disposition type (Retain, Retire, Replace and Review) as illustrated in Figure 3.1 below.

Figure 3.1 – Assigned future-state disposition (% of total edge applications)



3.1. Future state disposition - Retire

The analysis indicates that 36% of the current edge applications, as shown in Table 3.2, could be retired with a modern CIS. The majority of these applications have been developed by Newfoundland Power to meet a specific business or technical requirements due to limitations in the existing CSS. Modern CIS solutions contain much of the same functionality, either in the base package or via standard configuration.

Most of these homegrown applications are low complexity and currently require data to be manually inputted. Complexity was based on the estimated level of effort required to incorporate the legacy functionality into a CIS replacement.

Table 3.2- Edge Applications that could be retired with a modern CIS

Application Name	Description	Complexity
APPModifier	An application built in-house that provides designated Customer Service staff ability to modify details in the Automatic Payment Plan file before the file is sent to the bank.	Low
Cash File Append	A function built in-house and used by Newfoundland Power's Cash Services staff to merge/append payment files from various sources and prepare them for CSS processing.	Low
Collection Agency Analysis	An application/process created in-house that queries CSS data and prepares information to send to Collection Agencies. Microsoft Access is used as part of this process.	Low

Application Name	Description	Complexity
Correspondence Tracking	Correspondence requests from customers (e.g. re-send customer last bill again) are compiled and documented with this application.	Low
Credit Reporting	Data warehouse that extracts data from CSS nightly and summarizes information for customers who are in arrears to facilitate analysis and follow up.	Medium
Customer Inquiry	In-house designed .NET application that allows agents to lookup customer data using information pushed from CSS to a database designed to support website self-service.	Medium
Disconnect for Debt	An application built in-house (written in .NET) that summarizes key information about customers who have had their electricity disconnected and presents it in an easy to use interface for after hours use by Operators in the System Control Centre (SCC).	Low
EPP Review	An in-house designed Equal Payment Plan (EPP) calculator used by agents to simplify some EPP calculations.	Low
Handheld Meter Reading Analysis	Homegrown analytical tool that uses meter reading data for meter route analysis and management.	Low
Key Customer	A SharePoint list that stores key contacts for large commercial customers.	Low
LEED Tools	Used by agents to manually reproduce a customer bill for special or extenuating circumstances.	Low
Meter Pictures	An in-house designed application that collects and organizes pictures of meters taken by Meter Readers (if required).	Low
Meters Requiring Keys	A SharePoint list of customer meters that requires keyed access.	Low
Metering Spreadsheets	Set of Excel spreadsheets that move meter data to/from CSS, such as missing reads with reasons and counts for further analysis or follow up.	Medium
NewCust_TR	An in-house designed application used to manually insert Automated Payment Plan transaction entries under special or extenuating circumstances.	Low
Operator Database	An in-house designed application used by computer room operators to record information related to previous night's batch key statistics.	Low
Service Order Spreadsheets	Set of Excel spreadsheets that pull data from CSS and push data to CSS to help with managing of service orders related to metering functions (e.g. meter change, check read).	Medium

Application Name	Description	Complexity
Special Bills	An Excel application used to calculate and produce an electricity bill that is unable to be billed directly from CSS.	Medium
VMS Scheduler	A VMS Operating System application used for CSS batch scheduling of core CSS functions and report generation.	Medium
Web to CSS Schedule	A VB.NET in-house designed application that moves e-bill sign-up and e-bill cancellation requests from self-service requests to CSS.	Low

3.2. Future state disposition- Retain

The analysis indicates that 55% of the current edge applications, as shown in Table 3.3, would be retained with a modern CIS. Furthermore, 84% of the applications to be retained are considered low-medium complexity, which could reduce risks associated with integration with a modern CIS solution.

From EY's experience, this is a manageable number of applications to be retained and the functionality provided by these applications could be successfully integrated with a modern CIS.

Table 3.3- Edge Applications that could be retained with a modern CIS

Application Name	Description	Complexity
Advanced Education, Skills, and Labour (AESL)	An in-house designed application that facilitates the redirection of some funds from customers on income support for payment to Newfoundland Power. This amount is deducted directly from AESL and remitted to Newfoundland Power twice a month.	Low
Avaya Contact Center	An Interactive Voice Response ("IVR") application that uses customer-supplied information, such as telephone or account information to offer multiple self-service capabilities such as account balance inquiry, submit a meter reading, and submit a payment arrangement.	Low
Avaya Experience Portal	Combines customer telephone information. Pulls information from CSS (e.g. Account balance).	Medium

Application Name	Description	Complexity
Biztalk	Microsoft Middleware application that polls Newfoundland Power's website database for customer self-service requests and integrates with (triggers an action in) another database.	Low
Address Complete	A Canada Post application that Newfoundland Power uses on the customer website to offer advanced search methods and enhanced address correction data. This increases accuracy of customer supplied addresses.	Low
Remittance Processor	A hardware appliance used in Cash Services to process customer payment (cheque) stubs.	Low
Contributions in aid of Constructions (CIAC)	An in-house designed application used to calculate customer payment for electrical infrastructure and design for customers requesting power in areas where it is cost prohibitive for Newfoundland Power to offer service.	Low
Click	Click mobile workforce management system used for scheduling field work.	High
Credit Unions	A process used by case services to download a payment transaction file from the Credit Union.	Low
Customer Rebate Tracking (takeCHARGE)	An in-house built application that Newfoundland Power's takeCHARGE team uses to create energy efficiency rebates for items such as thermostats, heat exchangers and insulation for customers. The information is passed to CSS so the rebate can be applied to the customer's bill.	Low
Email MgMt AVAYA	An agent documents a confirmation in CSS that the email was sent or received. Action will be taken based on the request (e.g. move in, payment arrangement)	Medium
Email Verification	A process that validates email addresses supplied by a customer on the website or through other means.	Low
Field Collection System	Itron Field Collection System to collect meter reads.	Medium
GIS (Geographic Information System)	Various integrations with ESRI GIS to link location data to corresponding customer information.	Medium
Itron MV90	A utility meter software solution for interval data collection, management and analysis. Special MV90 meters are installed at some large commercial customer locations to allow Newfoundland Power to capture metering data via MV90.	Low

Application Name	Description	Complexity
Itron MCLite	A meter reading device (tablet) that provides drive-by capabilities to allow for meter read collection while driving.	Medium
Mobile Application	A Kubra hosted application that allows some strategic self-service options to be offered to customers on an IOS or Android device.	Medium
Outage	A preference-based notification application to allow customers to sign up for alerts. Currently used for outage alerts.	Medium
Newfoundland Labrador Housing Corporation (NLHC)	NLHC offers some of their customers a subsidy allowance to be applied to their electric bill. Newfoundland Power receives the subsidy data from NLHC, three times per month. This data is used by Newfoundland Power's billing process in the calculation of electric charges due.	Medium
PlanetPress	A third-party software application for automation, such as generating PDF, emails, printing bills, and Ebills.	Medium
Pitney Bowes StreetSweeper	A third-party address correction software used by CSS to validate addresses entered.	Low
Plastiq Credit Card	A third-party online payment system for credit cards. Customers may avail of this third-party payment option via a link provided on the customer service website.	Low
Residential Loan Application	An in-house built application for tracking/managing customer loan applications (e.g., hot water tanks, heat pumps)	Low
Responder	A Schneider Electric Outage Management System.	Low
Revenue Accrual	A Microsoft SQL Server based application used to estimate portion of revenue to be accrued each reporting period.	High
ScotiaConnect	Scotiabank software is the payment aggregator for Electronic Funds Transfer ("EFT") payments.	Low
Customer Self Service Website	Newfoundland Power's corporate website that offers customer self-service features. The website was originally created in-house (written in .NET) and later migrated to SiteCore CMS.	High
Stats Canada	An in-house suite of reports designed to pull customer billing and demographic data on a monthly basis.	Low
TeleVox	A third-party remote dialer application integrated to CSS to relay overdue account balance information to customers. The phone call will alert customers of the amount of payment that is necessary to stop further collection escalations.	Medium

Application Name	Description	Complexity
Tendril	A third-party application that uses customer billing data nightly to help promote customer energy conservation and usage.	Low
High Volume Call Answering (HVCA)	High call volume notification/outage reporting system.	Medium

3.3. Future state disposition- Replace

The analysis indicates that 4% of the current edge applications, as shown in Table 3.4, are scheduled to be replaced as part of Newfoundland Power's current technology plan prior to the implementation of a replacement CIS (within the next 2 years). Newfoundland Power is already taking into consideration the timing of these implementations to ensure they align with the overall CSS replacement timeline and that functionality will be properly integrated.

Table 3.4- Edge Applications scheduled to be replaced prior to CIS

Application Name	Description	Complexity
Street Light Management System	In-house system for management of street light assets.	Medium
Weather Normalization System	Homegrown system that tracks/summarizes manually keyed weather information and provides information for meter reading estimation.	Low

3.4. Future state disposition- Review

The analysis indicates that 5% of the current edge applications, as shown in Table 3.5, would require further discussion as part of a longer-term business and technology strategy. Some modern CIS solutions offer a large product suite footprint that can be the foundation for other supporting business requirements, such as Enterprise Resource Planning ("ERP") and Meter Asset Management applications.

Table 3.5- Edge Applications to be reviewed

Application Name	Description	Complexity
Financials "MS Great Plains"	Financial management application with modules to manage Payroll, Accounts Payable, General Ledger etc.	High
Metering Equipment System (MES)	An application written in .NET that manages customer meter information such as multipliers and specification codes used to determine billing. MES Extensions is a separate but related process that allows the ability to upload Encoder Receiver Transmitters ("ERT") and Probe meters into MES.	Medium

Application Name	Description	Complexity
Technical Work Request (TWR)	An in-house built system for managing customer requests such as installation/moving of poles, requests for tree trimming, installation of a new meter, and connection of a new service.)	Medium

4.0 Conclusion

Over the last 20 years, Newfoundland Power has had to adapt to changing customer and regulatory requirements by developing some functionality in edge applications outside of CSS. In EY's experience, it is fairly common for utility billing systems from the 1990s to have a large number of interfaces to other applications. While creating these edge applications allows for delivery of essential business functions, it has resulted in a highly customized and complex CSS architecture. As CSS approaches end of life, maintaining and supporting many edge applications increases possible critical failure risks of some of Newfoundland Power's systems.

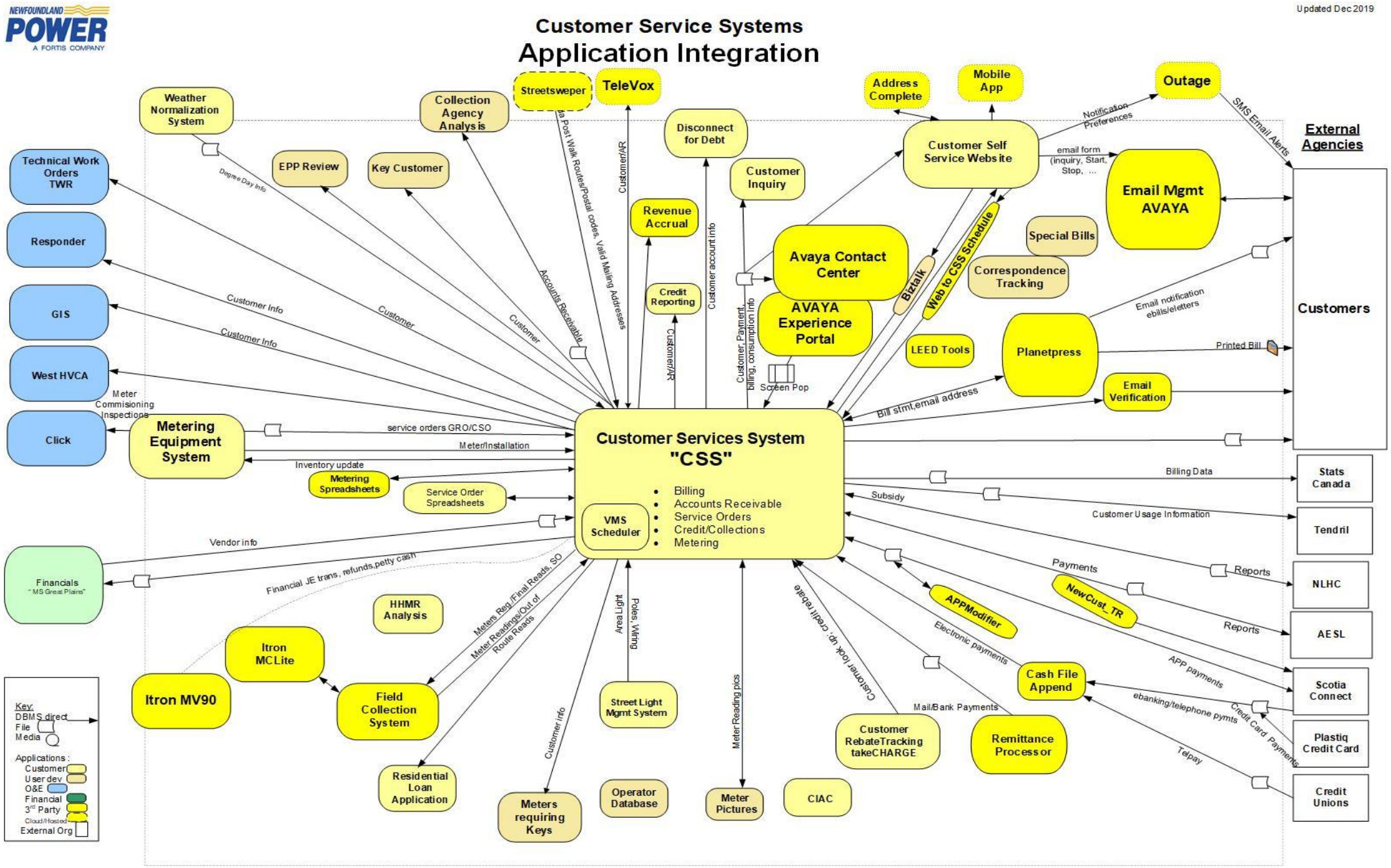
A significant number of edge applications could be retired with the implementation of a new CIS as the functionality provided would likely be incorporated in the base package of most modern CIS software products. Retiring these homegrown applications would minimize complexity and risk when implementing a new CIS by reducing the number of application integrations and simplifying ongoing support and maintenance.

Based on the findings, the number of edge applications that will be retained and interface with a new CIS is manageable and comparable with similar sized utilities that EY has worked with. The functional and technical requirements that these applications currently provide would need to be reviewed during the procurement phase to document product-specific details on how the functionality would be integrated with the new CIS. Typically, an integration approach would be finalized during the design phase to ensure that the essential business functionality that these applications provide will not be lost during a new CIS implementation.

5.0 Attachments

The application interface diagram, as shown in Figure 5.1, illustrates the 56 edge applications and how they interact with CSS.

Figure 5.1- Edge application interface diagram



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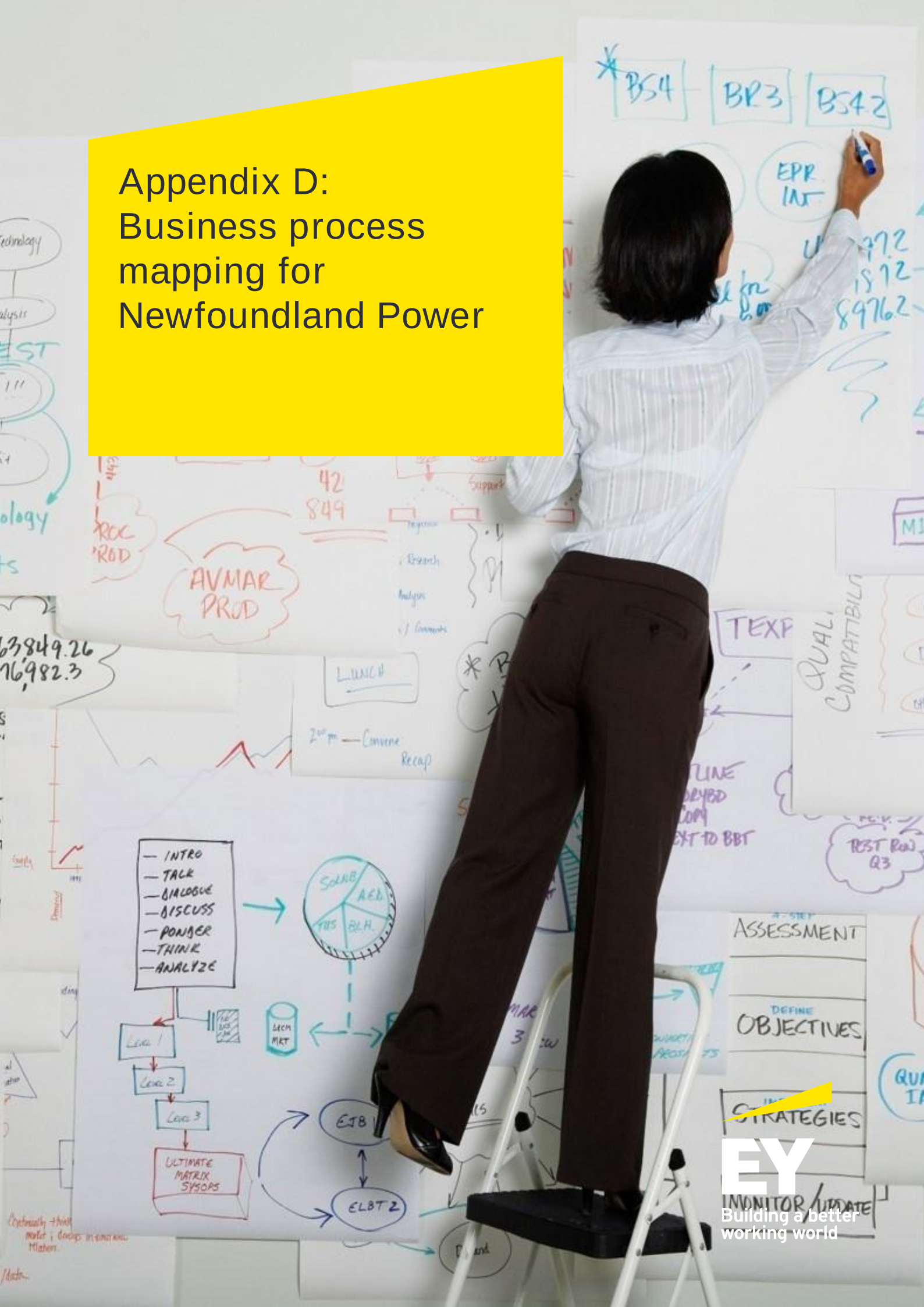
Appendix D: Business process mapping for Newfoundland Power



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Contents

1.0 Introduction

Newfoundland Power's Customer Service System ("CSS") is the Company's primary source of account and customer data. CSS supports all key customer service business processes such as customer account set-up and maintenance, transfer of service, customer payments, etc. The purpose of documenting Newfoundland Power's key "As-is" business processes is to better understand how each process relates to CSS and customer service delivery then collaboratively create process maps detailing the who, what, where and why for each task in the process.

"As-is" process mapping is an important step in establishing how Newfoundland Power's business processes currently map to its CSS. It also helps determine future requirements for a CIS replacement and mitigates risk through a complete understanding of key processes to identify gaps or interdependencies when designing the business process requirements for a replacement system. This documentation will be provided to prospective vendors during the procurement process.

2.0 Approach

Through a prioritization exercise with Newfoundland Power employees, key business processes were identified based on customer impact and incidence. EY conducted "As-is" process mapping workshops from March - October 2019. Workshop attendees included over 30 Newfoundland Power personnel from multiple departments including Customer Relations, Customer Contact Centre, IT, Finance and Metering to ensure the end-to-end process were captured across various business units involved with each process.

EY supplied its own process templates based on common industry practices to document each process flow and process narrative. These templates provided standard naming, language and level of detail for consistency. Process flows need to contain detailed information so that individuals not familiar with a process such as a software vendor, can clearly read and understand the activities and decisions made within that given process.

In general, each 'As-is' process document included the following:

- Process Name
- Process Description
- Process Owner(s)
- Process Frequency and Volumes
- Related Business Process
- Related Applications
- Process flow or visual representation that contains information about a process, including; what steps are taken, what decisions are made, or conditions are met, who performs the activities, and other high-level information.

3.0 Findings

Of the 182 documented business processes, 43 of the most critical processes were mapped with associated narratives which were categorized into 9 functional groupings as shown in Table 3.1 below. EY and Newfoundland Power prioritized the key processes to be documented based on customer impact, transaction volume, and processes that would be considered unique to Newfoundland Power. Business process documentation is provided in Section 5.

Table 3.1- Functional Groupings of Business Processes

Functional Group	# of processes mapped	Processes
Accounts Receivable (A/R) Maintenance	2	• Cancel/rebill requests • Transfer credits
Billing	12	• Residential bill calculation • Consolidated billing • E-Correspondence (ebills) • Equal Payment Plan ("EPP") set-up • EPP maintain/settle/end • Financing plans • High bill complaint/inquiry • Manage billing exceptions • Mortgagee in possession • Newfoundland Labrador Housing Corporation ("NLHC") billing • Other accounts receivable ("OAR") • Rate change process
Cash Processing	4	• Automatic Payment Plan "(APP") • Retrieving missing customer payments • Processing payments • Process returned payments

Functional Group	# of processes mapped	Processes
Credit and Collections	8	• Customer Credit Analysis ("CAA") codes • Collection agency placement • Credit and Collection (Residential) • Credit and Collection (General Service) • Customer escalations (Credit) • Payment arrangements for debt • Security deposits • Restriction on disconnection
General Maintenance	4	• Enrol in MyAccount • Estate and trusts • Manage customer subscriptions • Sensitive customer protocol
Meter Reading	3	• Meter readings (regular cycle) • Out of route reads ("ORR") • Revenue protection/theft of service
Pre-Billing	1	• Pending work queue
Service Orders	6	• Disconnect/reconnect for debt • Establish new service (Residential and General Service) • Landlord agreements • Move in/move out • New customer set-up • Service orders
System Controls	3	• Batch scheduling • Date constants and schedule • Unmatched queue

Newfoundland Power also conducted product awareness sessions with six established vendors of commercial CIS solutions to validate the capabilities offered by modern systems. These sessions demonstrated that modern CIS solutions met the majority of Newfoundland Power's current and future needs in terms of functional fit and customer experience capabilities; important markers to keep pace in an ever-changing market and provide the ability to meet enhanced customer expectations.

Modern CIS solutions have core business processes incorporated into base packages and dedicated upgrade strategies to address changing industry and customer expectations. In EY's experience, 80% of business processes are common across utilities and can be implemented with out-of the-box functionality from a modern CIS solution.[1] Based on the findings, the majority of Newfoundland Power's business processes are relatively similar to other peer utilities.

4.0 Conclusion

As required, Newfoundland Power will consider modifying its existing processes and procedures to align with industry leading practices which would allow it to utilize a CIS base product with minimal customization required. The standardization of processes will facilitate more effective and efficient agent training and provide Newfoundland Power with additional opportunities to leverage industry best practices and experiences from other utilities who use commercial CIS solutions.

Modifying business processes to minimize customizations would significantly decrease the risk of a CIS replacement project by reducing customizations to configure, build, test, and train, while simplifying the complexity of future upgrades.

5.0 Attachments

The section provides further detail of the key business processes that were mapped as part of this exercise with associated descriptions and process flows.

[1] EY leveraged its proprietary Power and Utilities Maturity Model and Architecture "PUMMA" framework. PUMMA is a repository of the processes commonly found in global utility organizations and enables EY to assess our client's business processes, compare performance against peers and identify opportunities for improvement.

Process Name: Automatic Payment Plan (“APP”)

Process Description: This is a payment plan that allows customers (both Residential and Commercial) to pay their monthly bills automatically through direct debit from their bank accounts on a specified date.

Process Owner(s):

Group: Cash Processing

Frequency: Daily

Volume: 44,500 accounts use APP

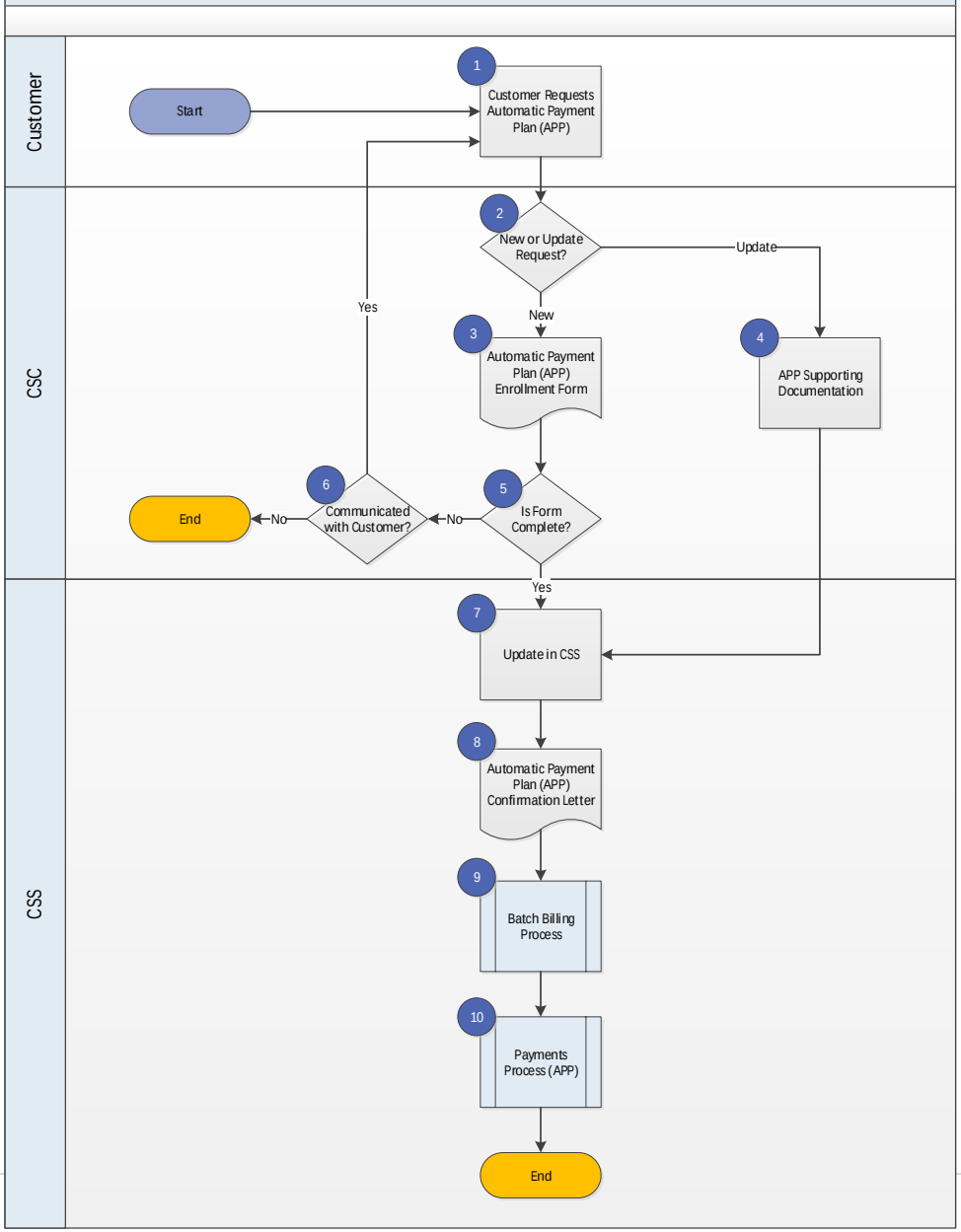
Related Process:

- Process Payments
- Nightly Batch
- Equal Payment Plan (EPP)
- Consolidated Billing
- Landlord Agreements

Applications:

- Customer Service System (CSS)
- Planet Press
- Newfoundland Power website

Figure 5.1 - Automatic Payment Plan (APP)



Process Name: Nightly Batch

Process Description: The process that occurs after hours for account updating, data exporting, bill generation and reporting. Batch processes close the current business day and initialize for the next business day.

Process Owner(s):

Group: Core Team

Frequency: Daily

Volume: Approximately 270,000 customer accounts

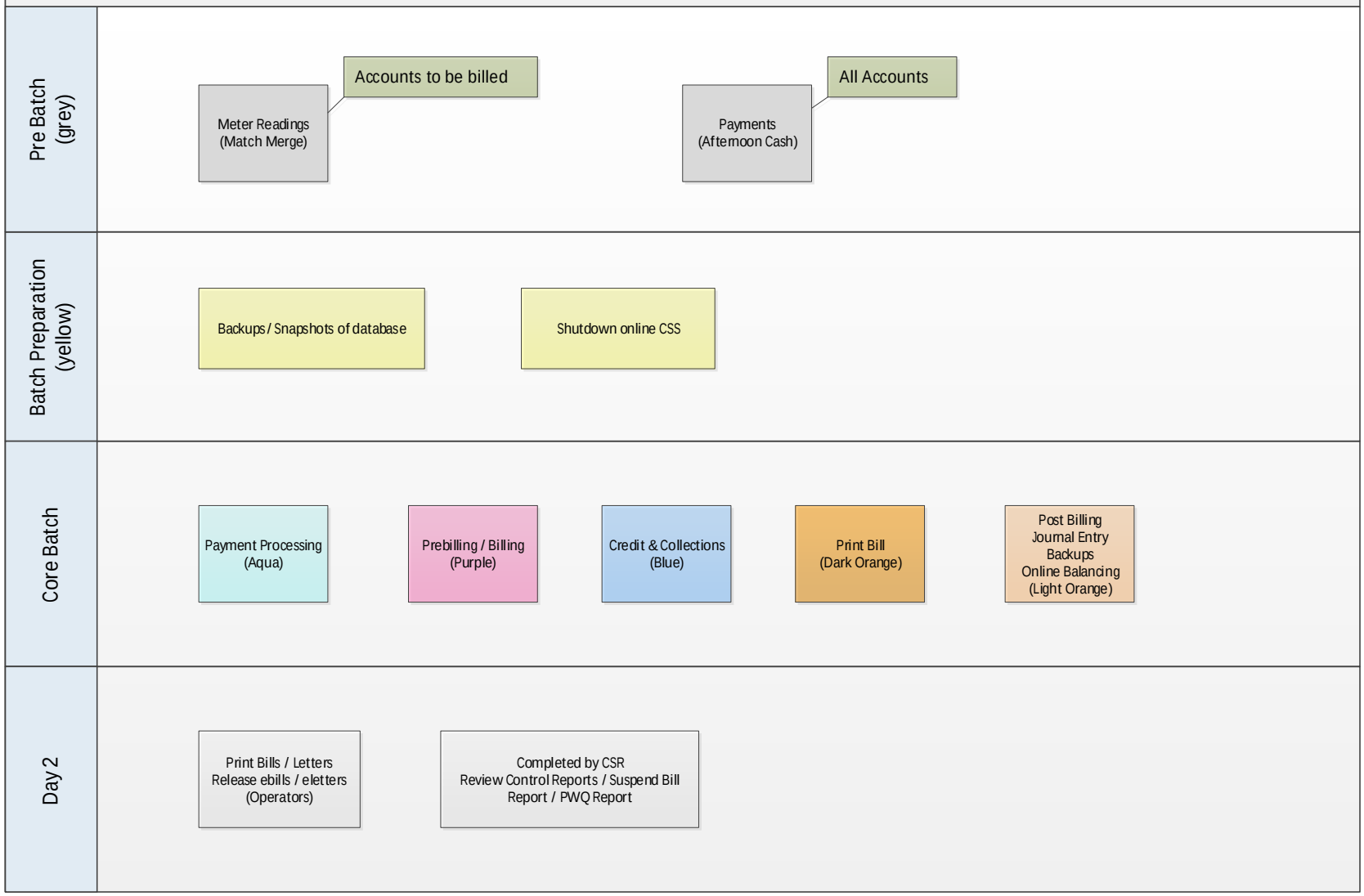
Related Process:

- Bill Calculation
- Meter Reading
- Process Payments
- Credit and Collections – General Service
- Credit and Collections - Residential
- Service Orders
- Pending Work Queue
- Equal Payment Plan (EPP)

Applications:

- Customer Service System (CSS)
- Itron
- Technical Work Request (TWR)
- Planet Press
- CashFile Append

Figure 5.2 - Nightly Batch



Process Name: Bill Calculation

Process Description: The process used by billing to calculate total amount due on bill.

Process Owner(s):

Group: Customer Relations, Core Team

Frequency: Daily

Volume: Approximately 13,000 residential bills per night

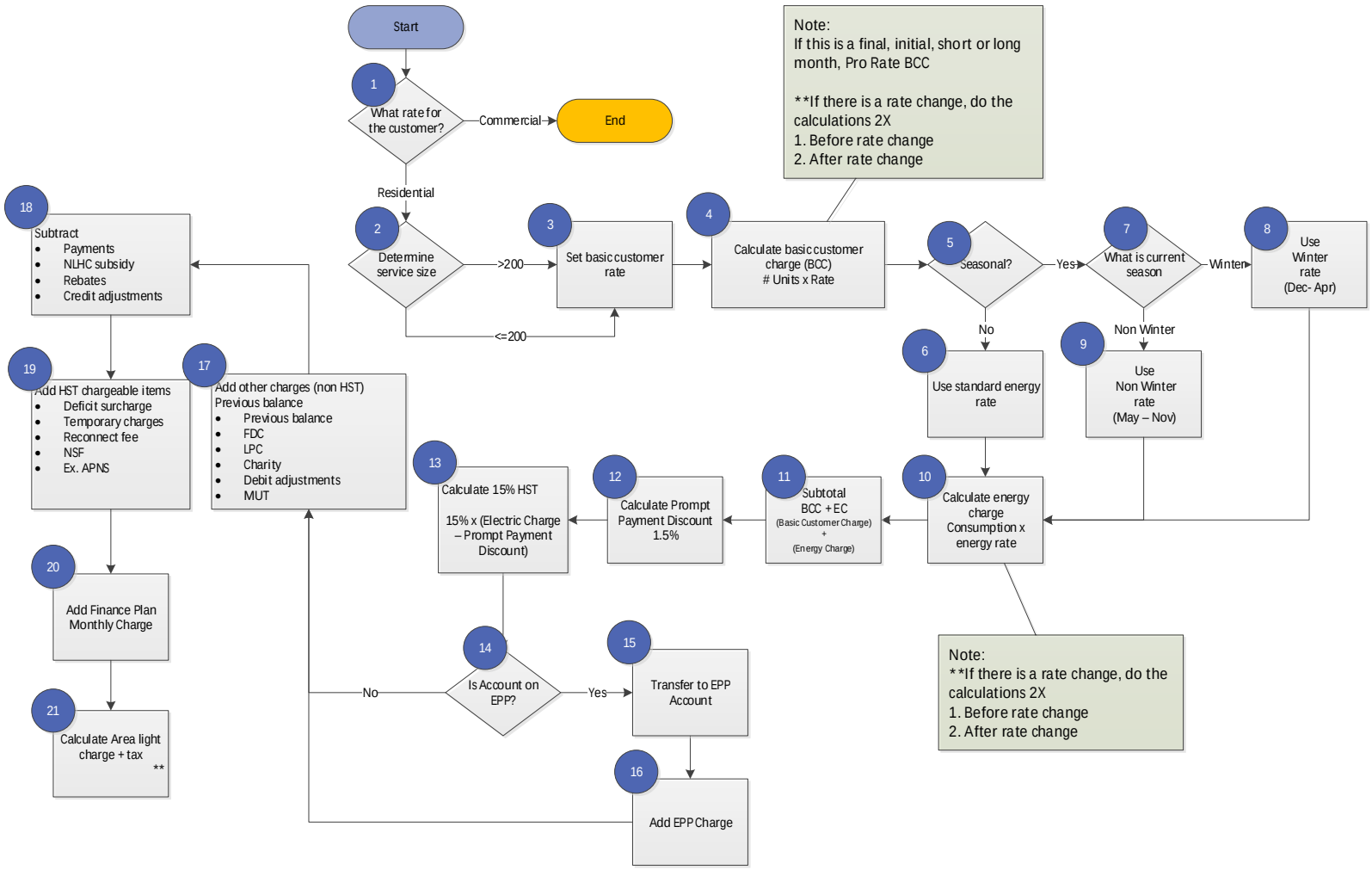
Related Process:

- Nightly Batch

Applications:

- Customer Service System (CSS)

Figure 5.3 - Bill Calculation



Process Name: Customer Credit Analysis (“CAA”) Codes

Process Description: Each customer account is assigned a 12-character credit analysis code or internal credit rating. (e.g., XXXXXXXXXXCD) that represents a customer credit history over the last 12 months.

Process Owner(s):

Group: Core Team

Frequency: Daily/Monthly

Volume: 10,000 - 15,000 nightly

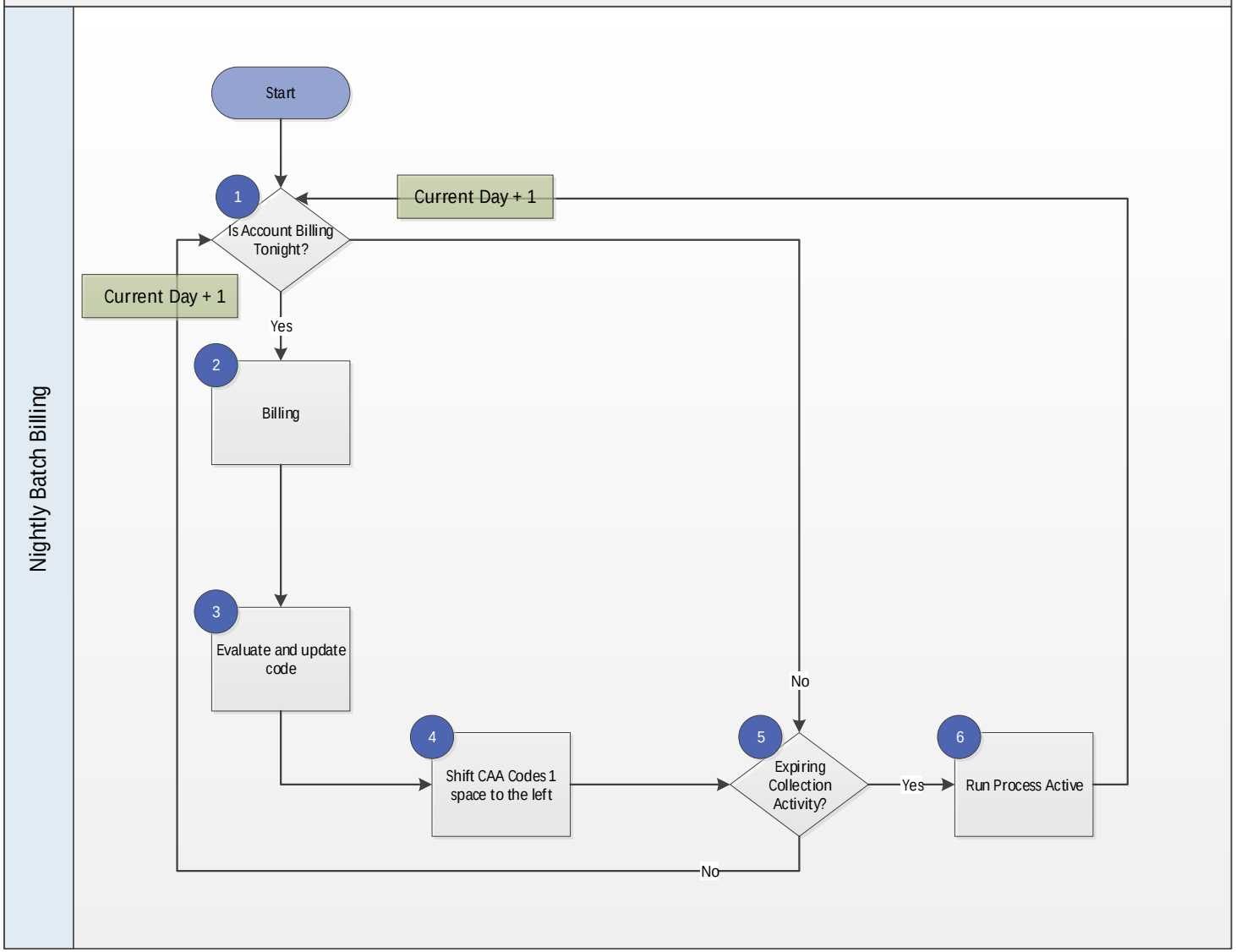
Related Process:

- Credit and Collections – General Service
- Credit and Collections - Residential
- Disconnect/ Reconnect for Debt
- Finance Plans
- Security Deposits

Applications:

- Customer Service System (CSS)

Figure 5.4 – Customer Credit Analysis (CAA) Codes



Process Name: Cancel/Rebill

Process Description: Occasionally, for instances such as an account is estimated or was billed on an outlier read, CSS provides the option to cancel the current bill outstanding and to reissue the same bill using a new reading. Requests would be taken from the pending work queue ("PWQ") or the customer may call in after the bill is issued.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: 100 per month

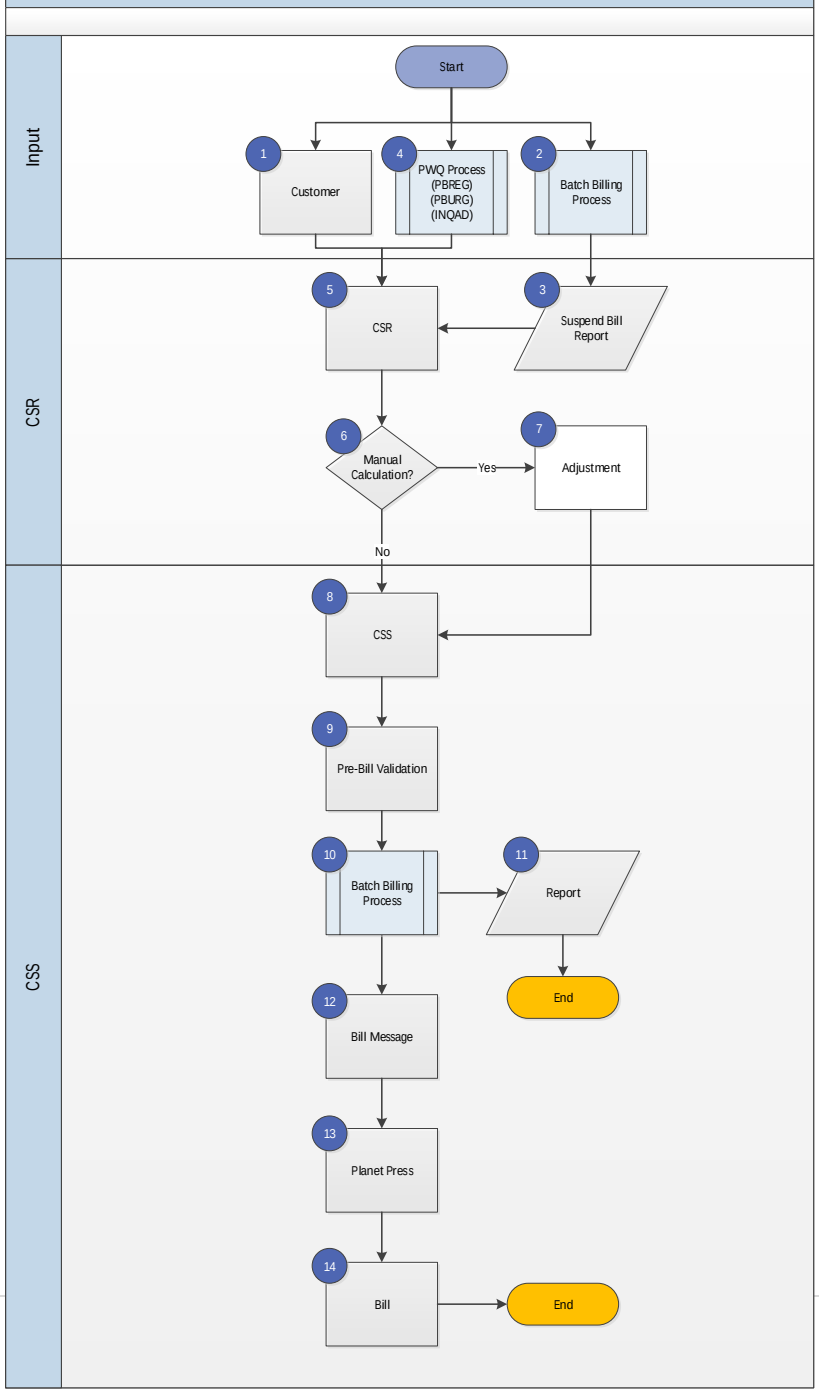
Related Process:

- Bill Calculation
- Service Orders
- Pending Work Queue
- Nightly Batch
- Cancel/Rebill

Applications:

- Customer Service System (CSS)
- Planet Press
- Webster (Billing adjustment spreadsheets)
- Itron

Figure 5.5 – Cancel/ Rebill



Process Name: Restriction on disconnection

Process Description: Customers will not be disconnected for non-pay between December 15 – January 1 each year (approximately). This only applies to residential and small business customers (under 10kW).

Process Owner(s):

Group: Customer Relations

Frequency: Yearly

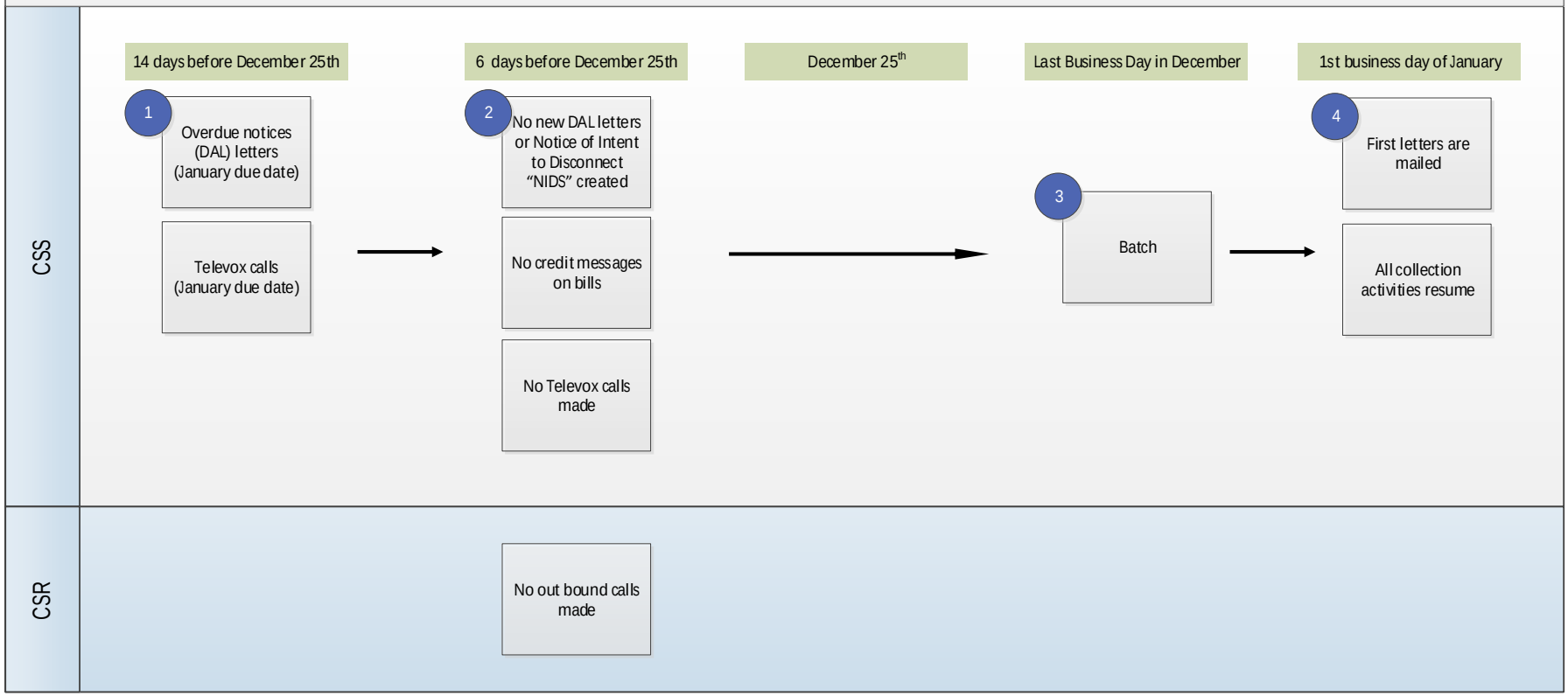
Related Process:

- Credit and Collections – General Service
- Credit and Collections - Residential
- Payment Arrangements for Debt
- Disconnect/Reconnect for Debt
- Final/Reserve Outstanding (FRO)
- Confirm Customer Identity

Applications:

- Customer Service System (CSS)
- Televox

Figure 5.6 - Restriction on disconnection



Process Name: Consolidated Billing

Process Description: Consolidated Billing is a solution offered to Residential and Commercial customers who have multiple accounts and would like to reduce the number of invoices they receive from Newfoundland Power.

Note: This process only covers the setup of a Consolidated Billing customer. Consolidated Billing Maintenance and Batch Billing will be shown separately.

Process Owner(s):

Group: Customer Relations

Frequency: Automated Payment Plan (“APP”) = Weekly

Electronic Funds Transfer (“EFT”) = Monthly fixed cycles (5, 10, 15, 19)

Volume: Approximately 250 customers with over 7000 accounts

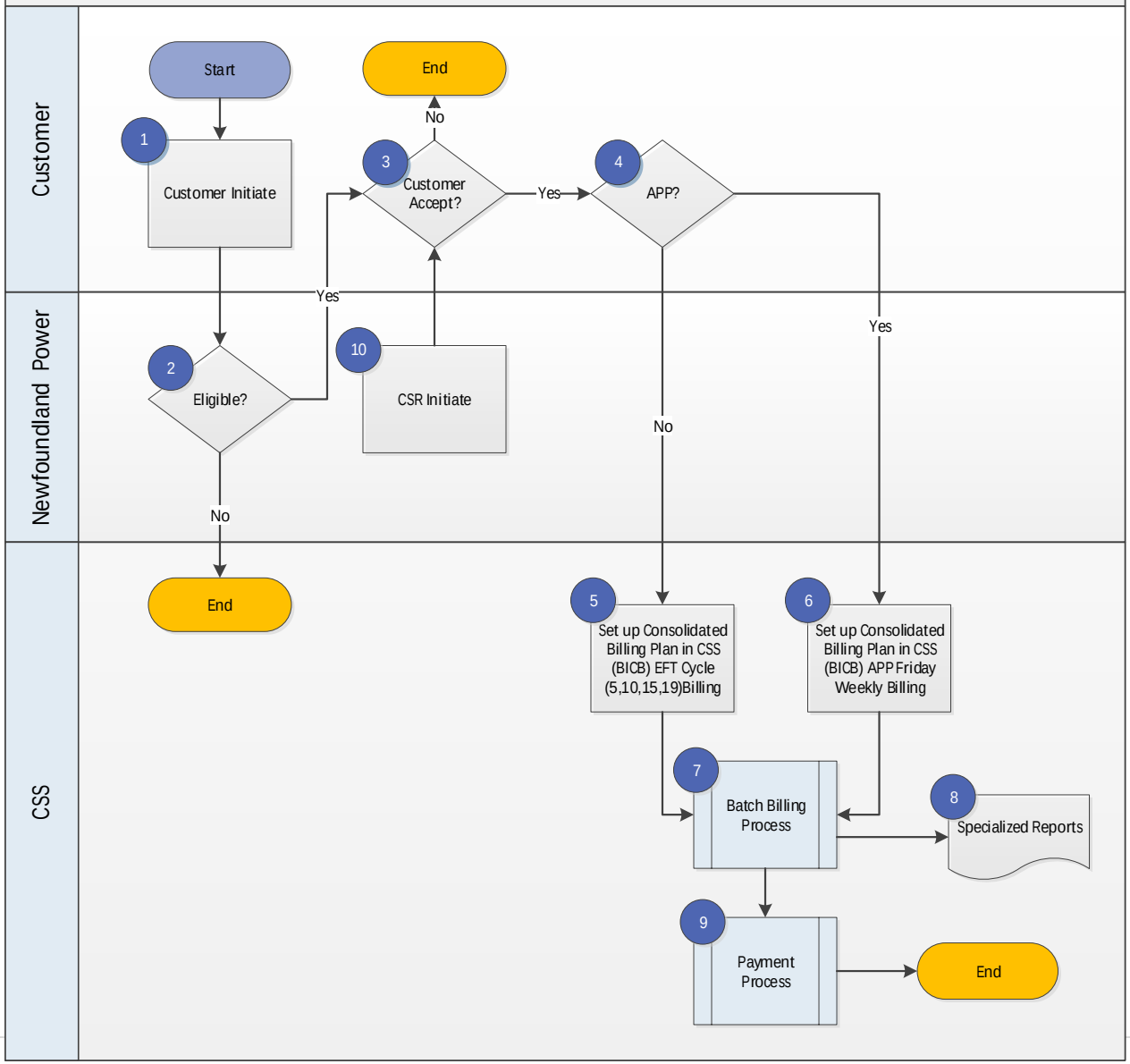
Related Process:

- Process Payments
- Nightly Batch
- Consolidated Billing

Applications:

- Customer Service System (CSS)
- Planet Press

Figure 5.7 - Consolidated Billing



Process Name: Collection Agency Placement

Process Description: The process of how accounts are placed with collection agencies when a customer has an unpaid final bill.

Process Owner(s):

Group: Customer Relations

Frequency: Weekly (Transfer to Collection Agencies)

Volume: 4,000 accounts were sent to Reserve (2018)

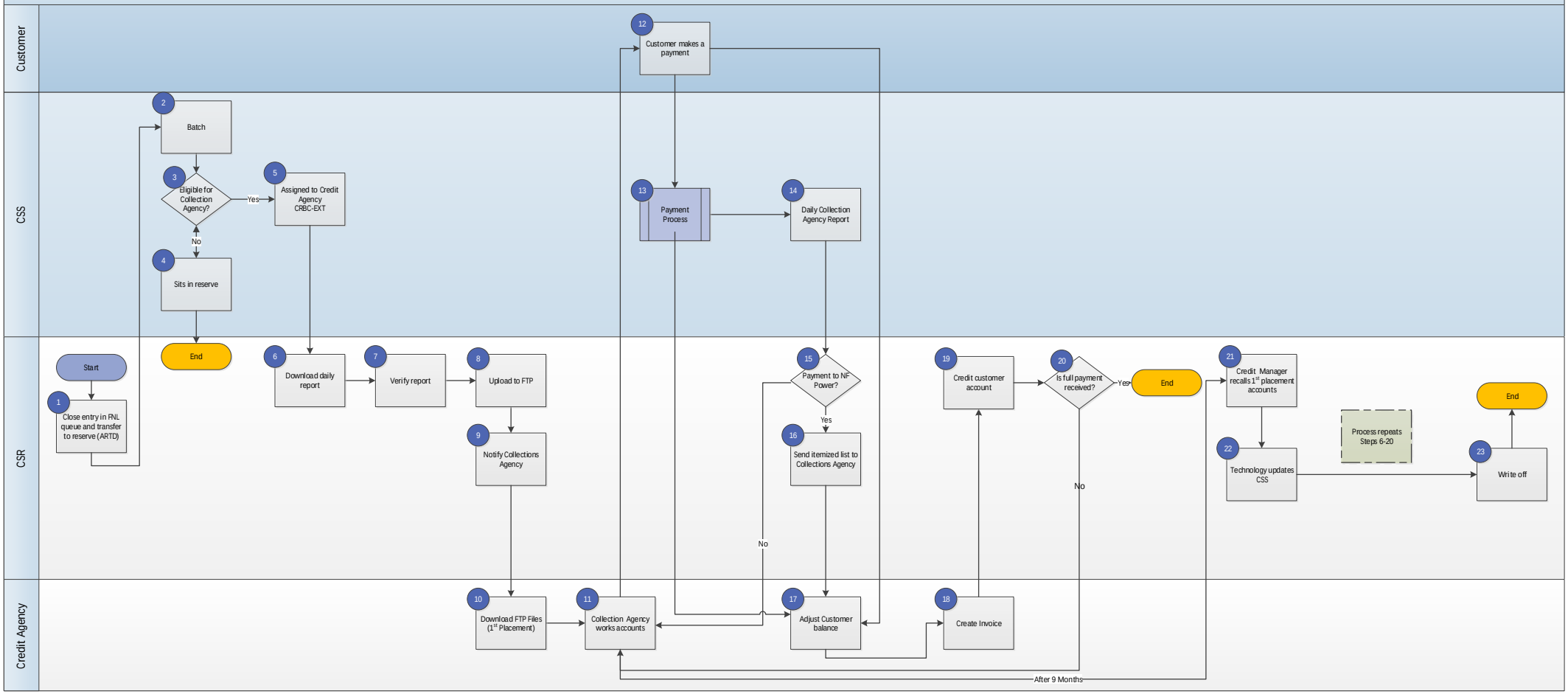
Related Process:

- Credit & Collections – General Service
- Credit & Collections - Residential
- Payment Arrangements for Debt
- Disconnect/Reconnect for Debt
- Pending Work Queue
- Move in/Move out

Applications:

- Customer Service System (CSS)
- MS Access
- MS Great Plains

Figure 5.8 - Collection Agency Placement



Process Name: Credit and Collections - General Service

Process Description: The collection of General Service (Commercial) account to notify and collect overdue balances using bills, credit letters and outbound calling.

*Note: At any point during the process depicted within the Process Flow diagram if the customer pays the full balance then the process would end. If the customer makes only the minimum payment, then the process re-starts at Batch Billing.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: 1,200 GSA collection activities per month

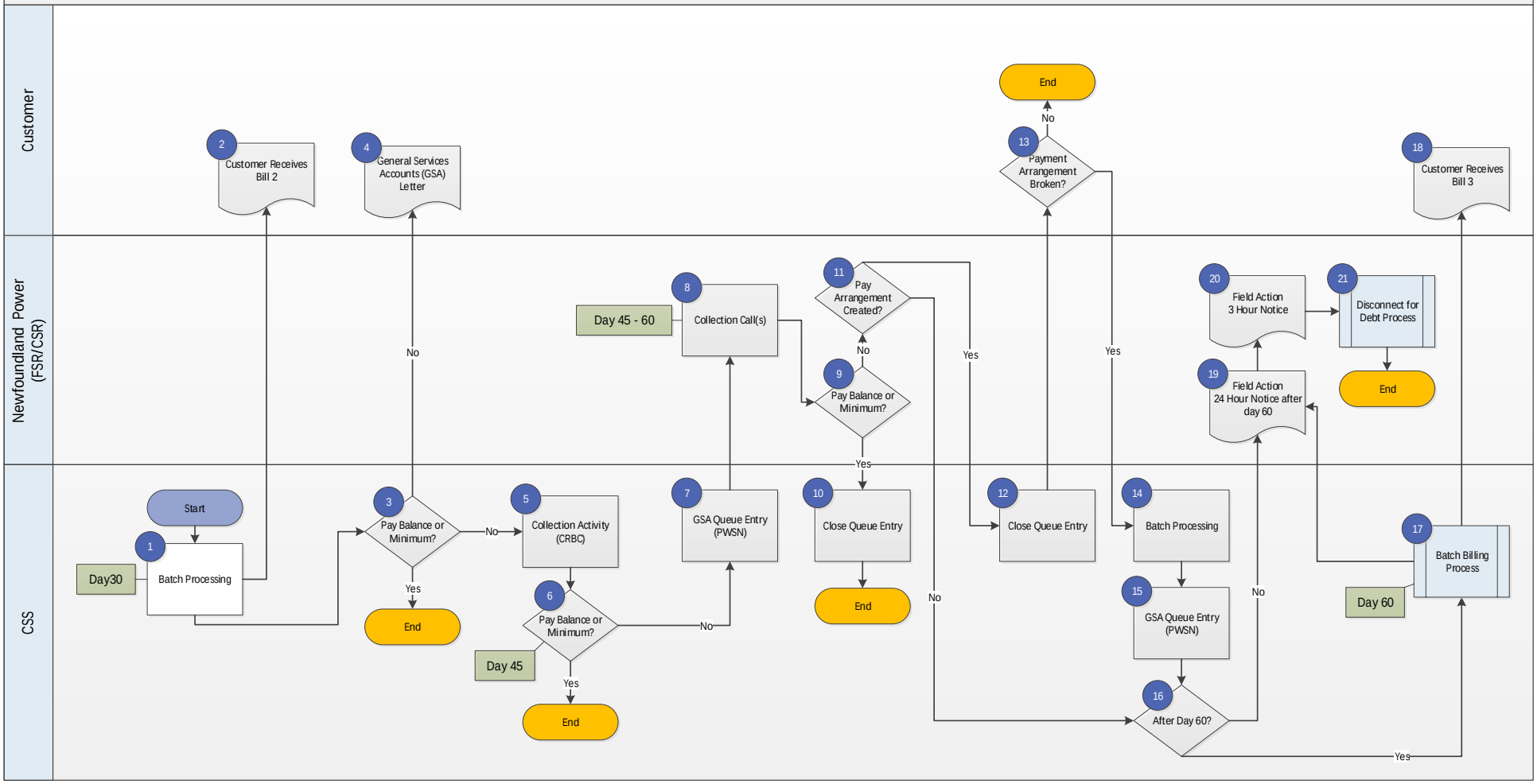
Related Process:

- Process Payments
- Payment Arrangements for Debt
- Nightly Batch
- Security Deposits
- Collection Agency Placement
- Disconnect/Reconnect for Debt

Applications:

- Customer Service System (CSS)
- External reporting (Pivots)
- Credit Cube

Figure 5.9 - Credit and Collections Process - General Service



Process Name: Credit and Collections - Residential

Process Description: The collection of residential accounts to notify and collect overdue balances using bill messages, credit letters, Televox messages, outbound calling and where appropriate Newfoundland Power visits and leaves a card.

*Note: At any point during the process depicted within the Process Flow diagram, the customer pays the full balance then the process would end. If the customer makes only the minimum payment, then the process re-starts at Batch Billing.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: 20,000/month

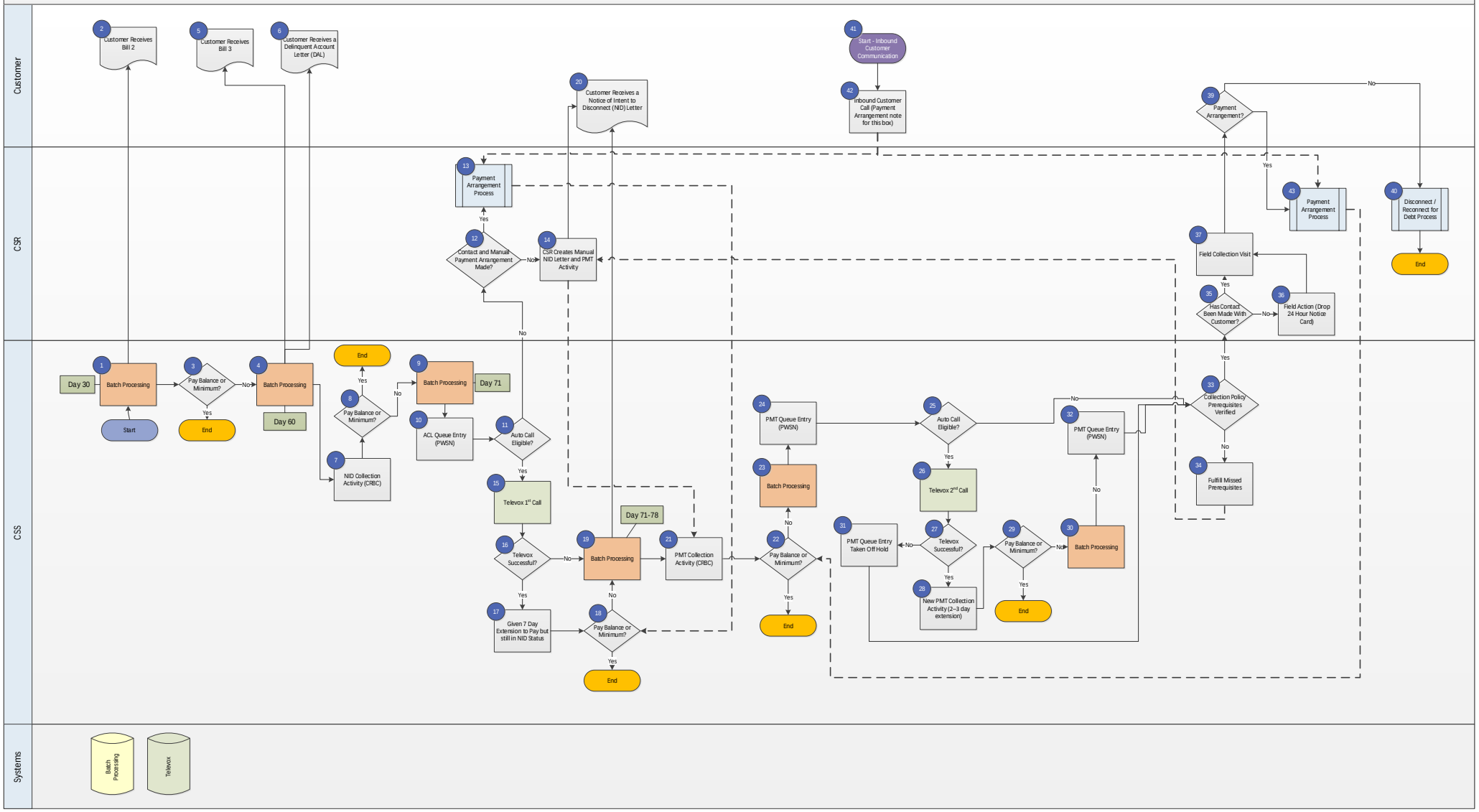
Related Process:

- Process Payments
- Payment Arrangements for Debt
- Nightly Batch
- Equal Payment Plan (EPP)
- AESL Redirects
- Disconnect/Reconnect for Debt

Applications:

- Customer Service System (CSS)
- Televox
- External reporting (Pivots)
- Credit Cube

Figure 5.10 - Credit and Collections Process - Residential



Process Name: Customer Escalation Process - Credit

Process Description: If a customer query cannot be resolved at first point of contact with the CSR an escalation is needed. Different channels are used to resolve the query/issue.

*Note: The process flow only depicts an example of a credit escalation phone call.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Credit drives the highest volumes of escalations

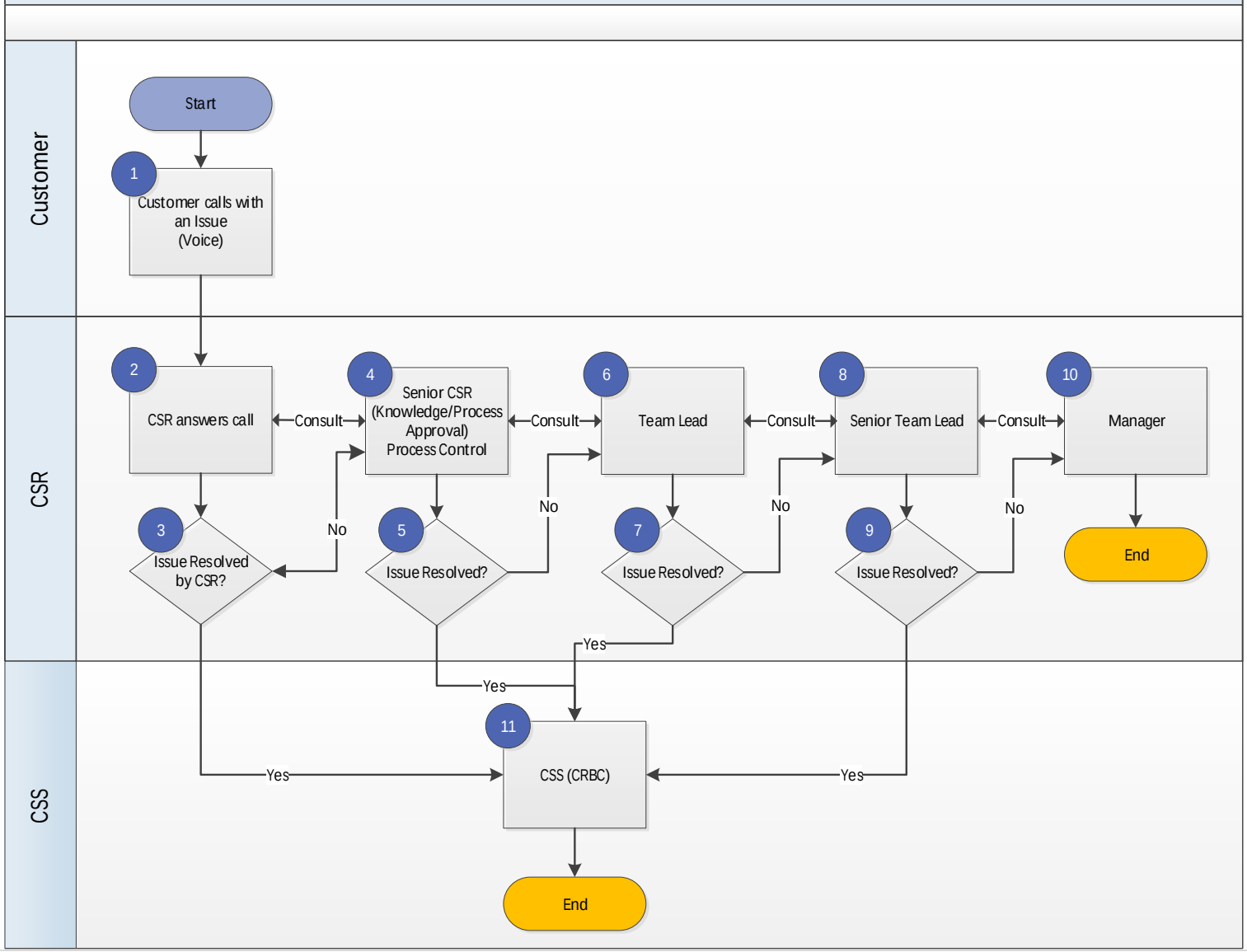
Related Process:

- Pending Work Queue
- Service Orders
- Credit and Collections – General Service
- Credit and Collections - Residential

Applications:

- Customer Service System (CSS)
- Technical Work Requests (TWR)
- Sharepoint (Webster)

Figure 5.11 - Customer Escalations - Credit



Process Name: Date Constants and Schedule

Process Description: The process to determine the discount and interest dates annually based on the approved meter reading schedule.

Process Owner(s):

Group: Customer Relations

Frequency: Annual. Meter reading schedule is completed Q1 for the following year and date constants is completed Q4 for the following year.

Volume: N/A

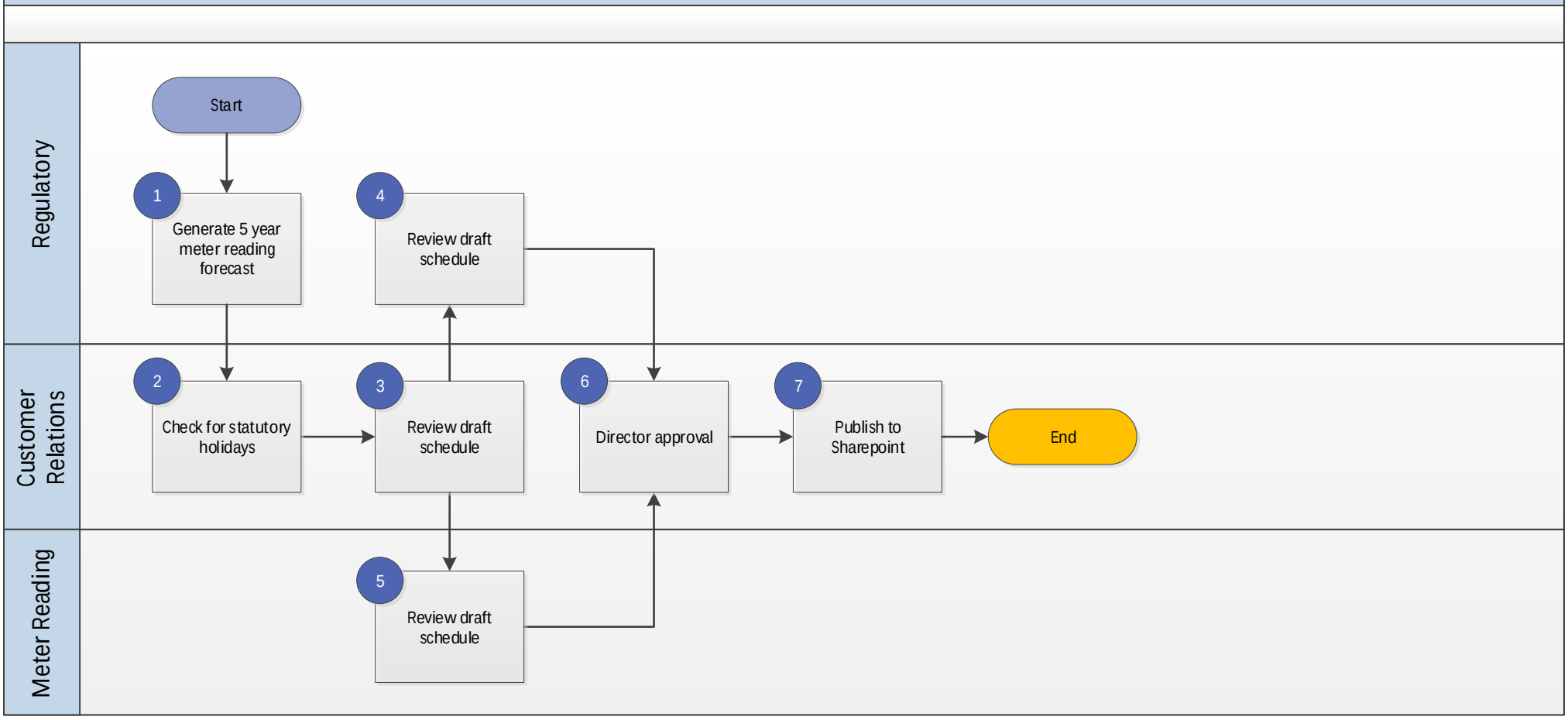
Related Process:

- Bill Calculation
- Meter Reading
- Credit and Collections – General Service
- Credit and Collections - Residential
- Month End Close
- Service Orders

Applications:

- Customer Service System (CSS)
- Weather Normalization System (WNS)
- Newfoundland Power website

Figure 5.12 - Date Constants and Schedule



Process Name: Disconnect/Reconnect for Debt

Process Description: When collection efforts fail the customer is disconnected for insufficient payment. Reconnection can only take place if all issues (e.g. outstanding debt, IDs, etc.) with the customer's account are resolved.

*Note: At any point during the process, depicted within the Process Flow diagram, if the customer pays their outstanding balance, then the process will end, and the customer be reconnected (if the disconnect had already taken place). Because of this, the Process Flow diagram will only depict a typical disconnect.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: 2,000 per year

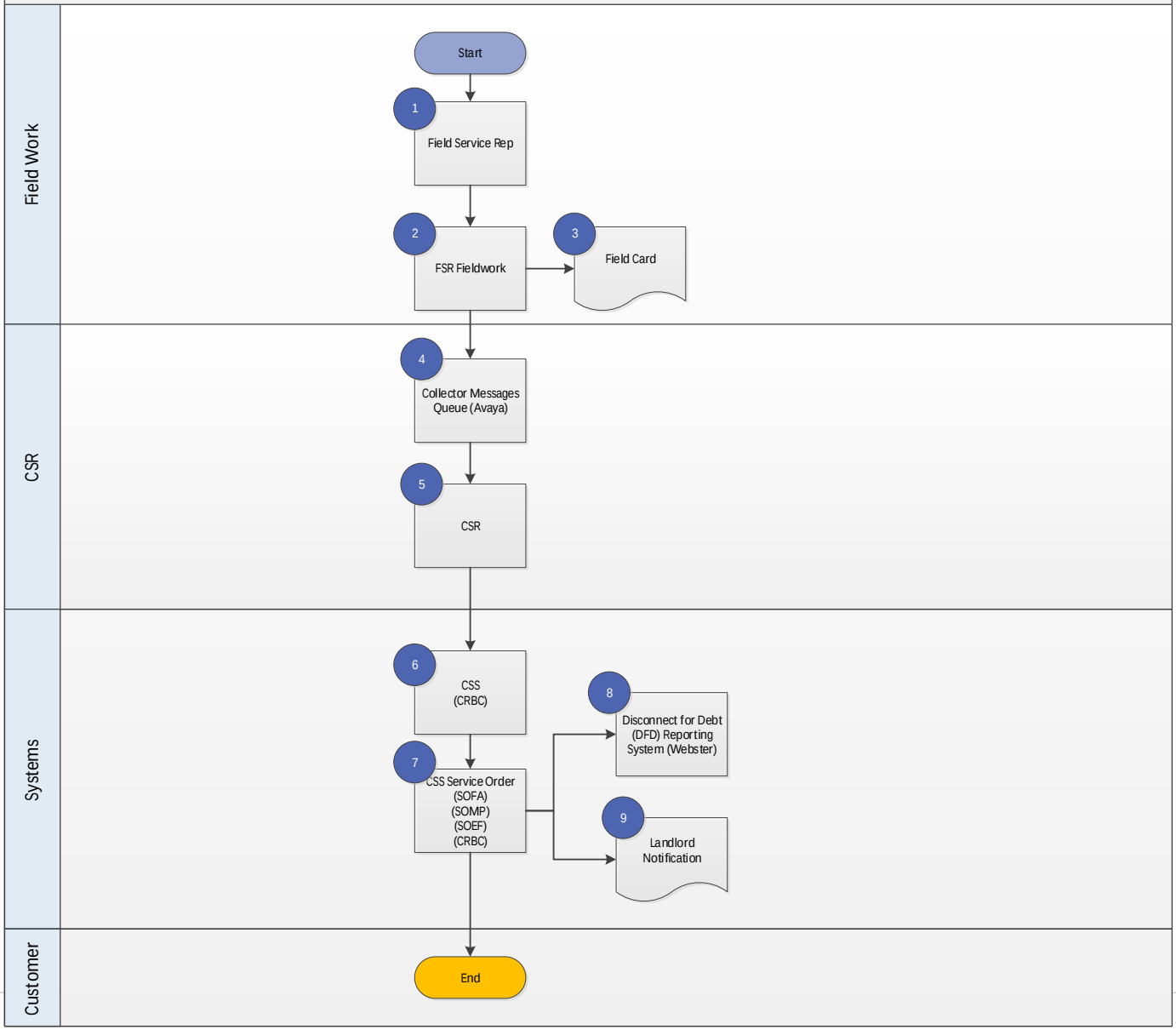
Related Processes:

- Service Orders
- Credit and Collections – General Service
- Credit and Collections - Residential
- Credit Activity Analysis (CAA) Codes

Applications:

- Customer Service System (CSS)
- Disconnect for Debt System (Webster)
- Avaya
- Planet Press

Figure 5.13 - Disconnect / Reconnect For Debt



Process Name: Customer Electronic Correspondence

Process Description: The process of managing customer electronic correspondence from Newfoundland Power (Bills and Letters).

Process Owner(s):

Group: Core Team

Frequency: Daily

Volume: Approximately, 125,000 customers enrolled on e-correspondence. 8,000 additions and deletions over the past 12 months (2019)

Related Process:

- Nightly Batch
- Credit and Collections – General Service
- Credit and Collections - Residential
- Service Orders
- Move In/Move Out
- New Customer Set-up

Applications:

- Customer Service System (CSS)
- Newfoundland Power website

Figure 5.14 - Customer Electronic Correspondence - Call

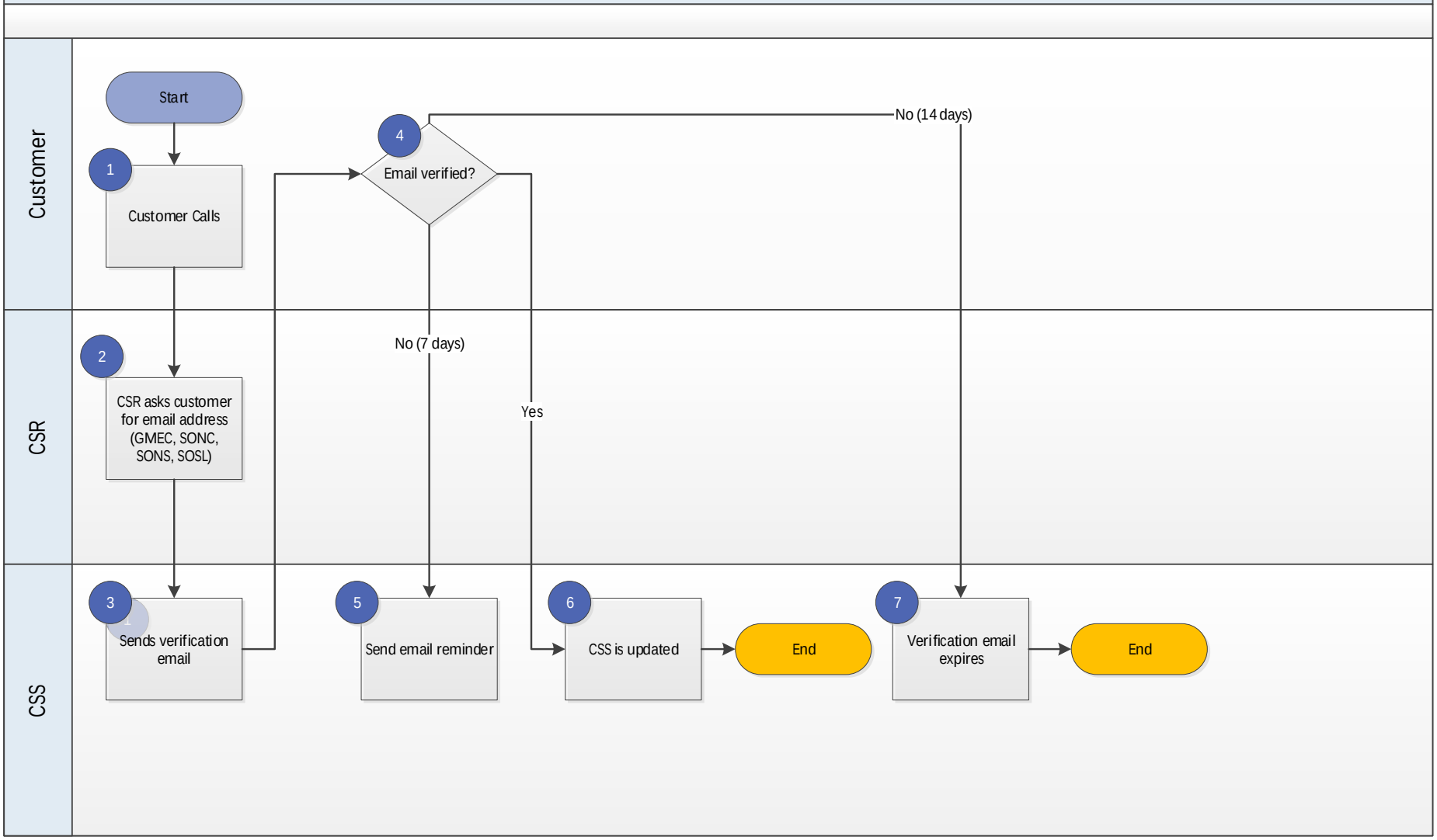
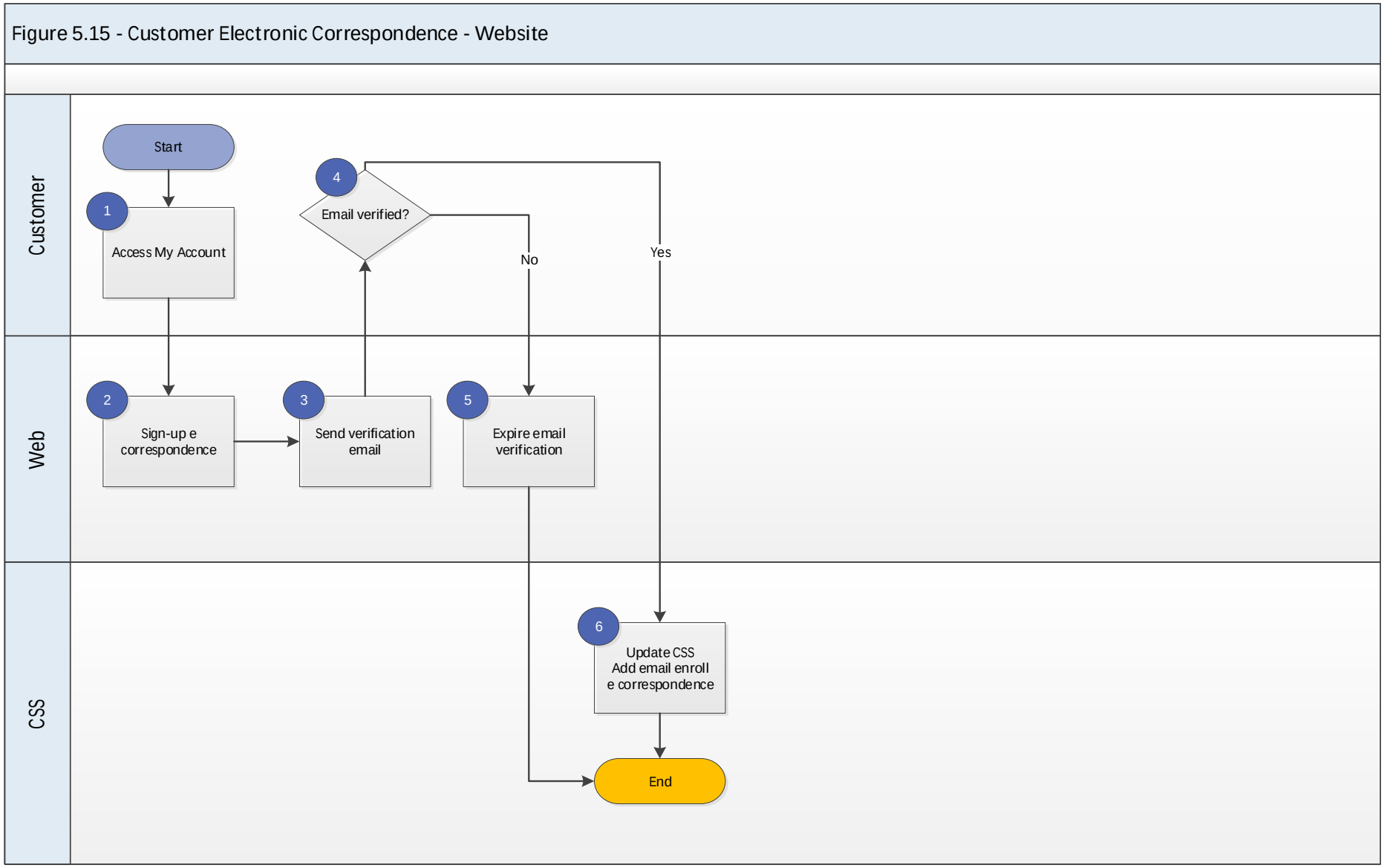


Figure 5.15 - Customer Electronic Correspondence - Website



Process Name: Enroll in MyAccount

Process Description: The process of how customer can sign up for MyAccount on the Newfoundland Power website.

Process Owner(s):

Group: Core Team

Frequency: Daily

Volume: 73,000 active profiles.

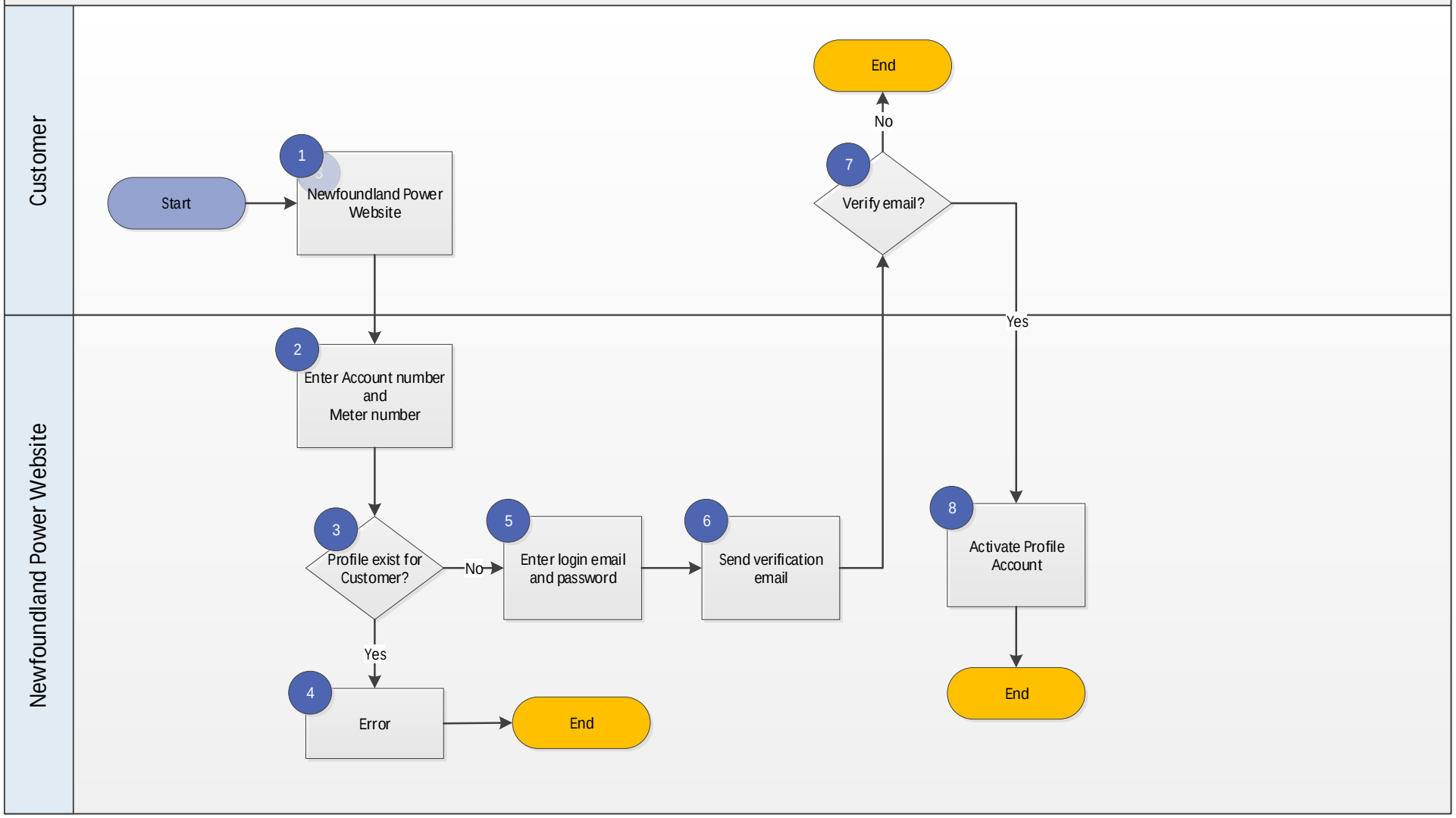
Related Process:

- All self-service offerings

Applications:

- Customer Service System (CSS)
- Newfoundland Power website

Figure 5.16 - Enroll in My Account



Process Name: Equal Payment Plan (“EPP”) Set-up

Process Description: EPP allows a customer to pay the same amount over a 12-month period while tracking their actual usage. All EPP accounts are reviewed every 6 months with quarterly reviews performed as needed.

Note: This process only covers the setup of an EPP customer. EPP Maintenance will be documented as a separate process.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Approximately 44,500 accounts on EPP. There were 6,200 accounts set up on EPP in 2018.

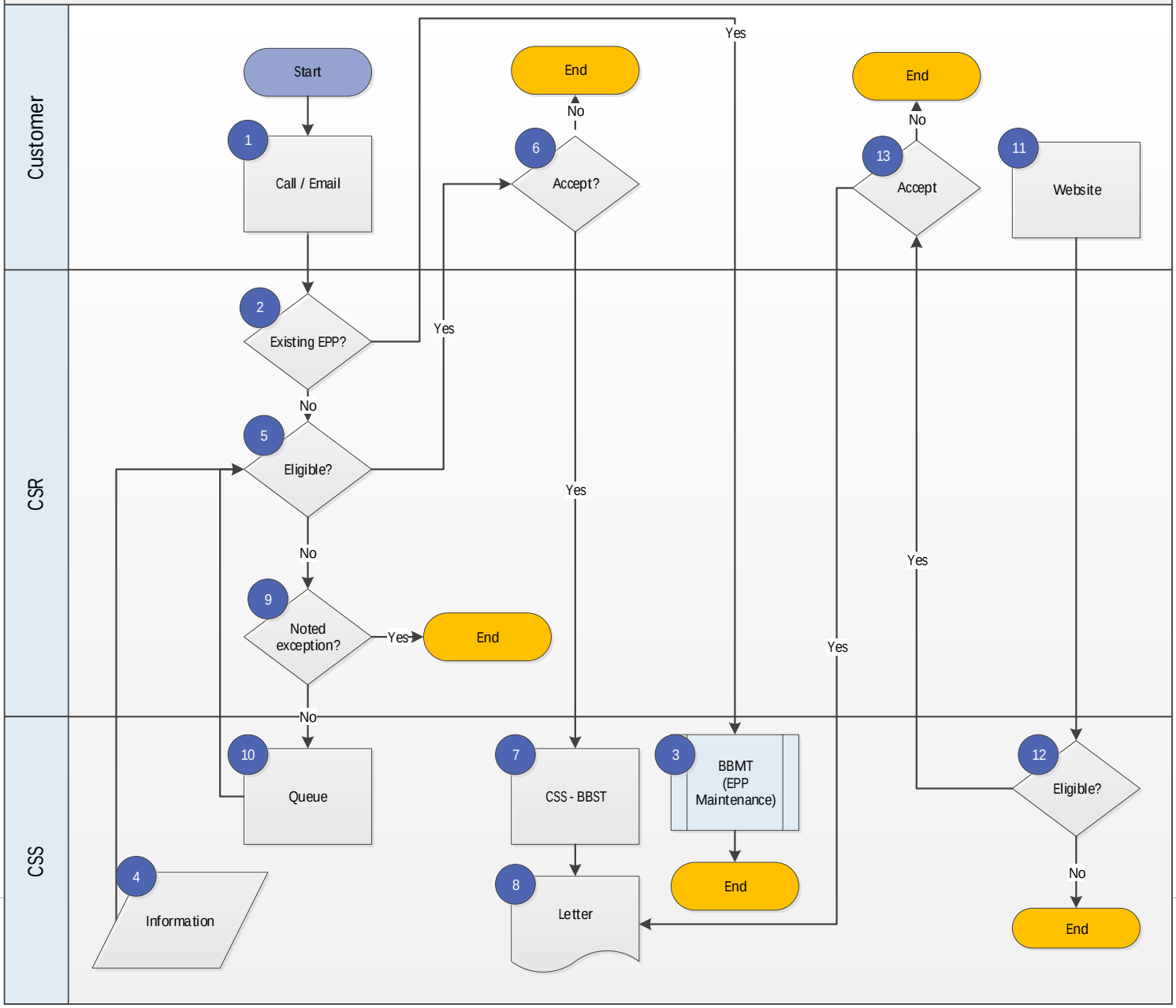
Related Process:

- Equal Payment Plan (EPP)
- Pending Work Queue
- Nightly Batch
- Process Payments

Applications:

- Customer Service System (CSS)
- Newfoundland Power website
- Planet Press

Figure 5.17 - Equal Payment Plan (EPP) Set-Up



Process Name: Equal Payment Plan (EPP) Maintenance – Customer Initiated

Process Description: The process of maintaining and reviewing Equal Payment Plans. EPP is reviewed every 6 months with quarterly reviews every 3 and 9 months (if necessary). A customer can choose to maintain, settle or stop their EPP.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Approximately 45,000 annually

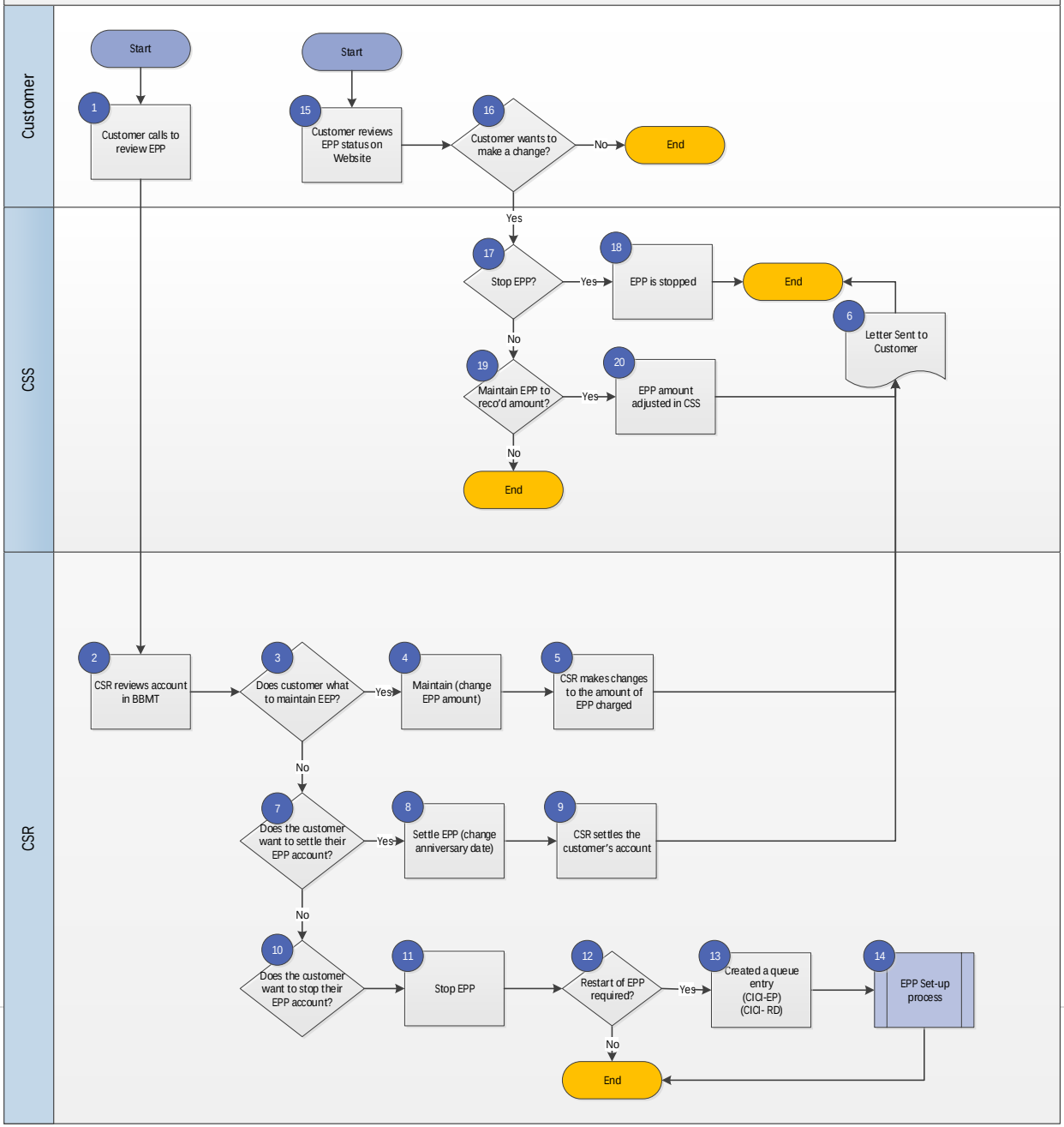
Related Process:

- Equal Payment Plan (EPP)
- Bill Calculation
- AESL Redirects
- Credit and Collections – General Service
- Credit and Collections - Residential
- Payment Arrangements for Debt

Applications:

- Customer Service System (CSS)

Figure 5.18 - Equal Payment Plan (EPP) Maintenance – Customer Initiated



Process Name: Equal Payment Plan (EPP) Maintenance – CSS

Process Description: The process of maintaining and reviewing Equal Payment Plans. CSS automatically processes annual settlements and letters to customers. During a rate change, IT will run scripts in CSS to review an anticipated EPP bump before the rate change date.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: 45,000 annually

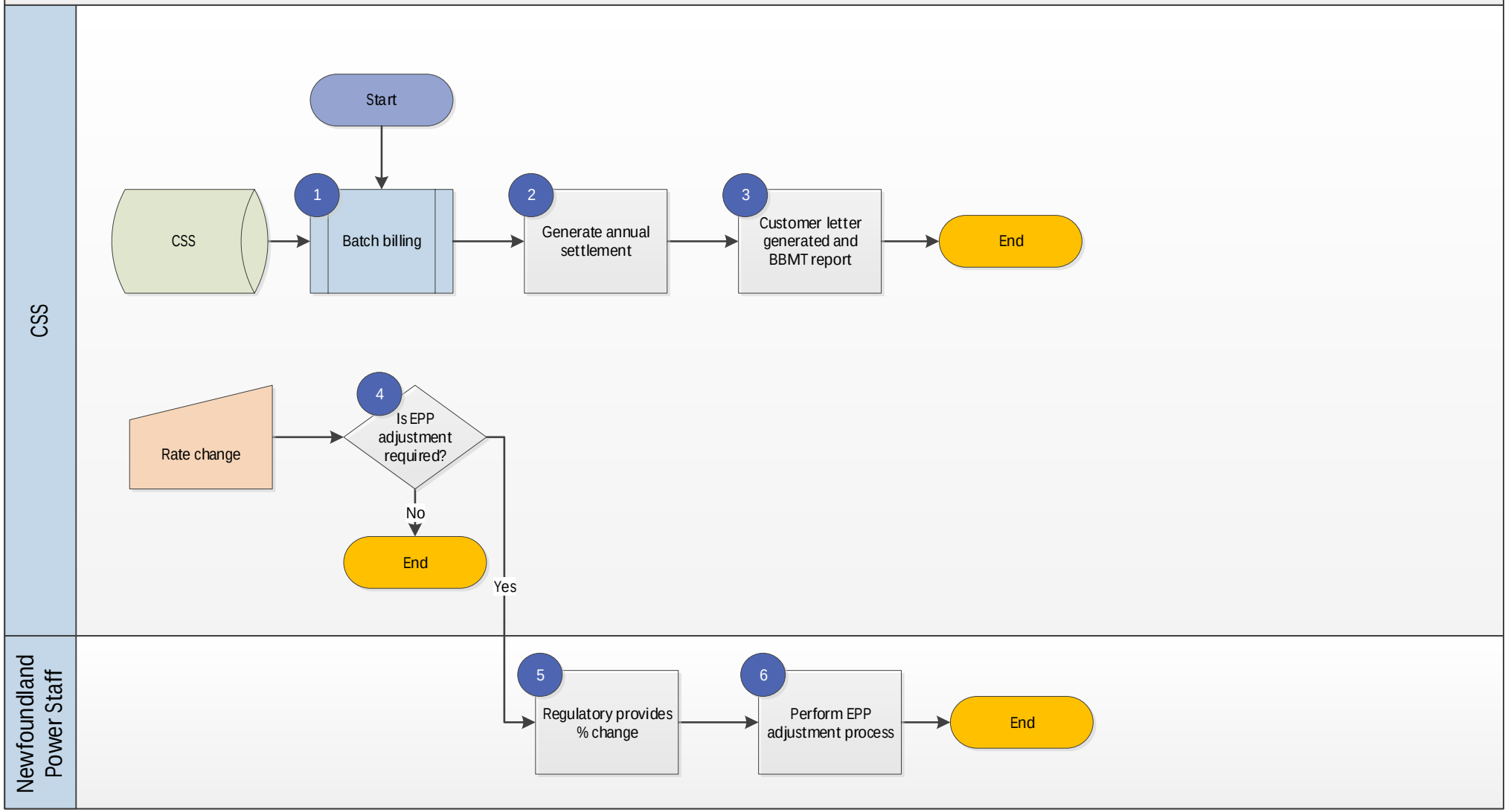
Related Process:

- Equal Payment Plan (EPP)
- Bill Calculation
- AESL Redirects
- Credit and Collections – General Service
- Credit and Collections - Residential
- Payment Arrangements for Debt
- Rate Change Implementation

Applications:

- Customer Service System (CSS)

Figure 5.19 - Equal Payment Plan (EPP) Maintenance – CSS



Process Name: Equal Payment Plan (EPP) Maintenance - Quarterly Reviews

Process Description: The process of maintaining and reviewing Equal Payment Plans. EPP is reviewed every 6 months with quarterly reviews every 3 and 9 months (if necessary).

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: 45,000 (3 times a year)

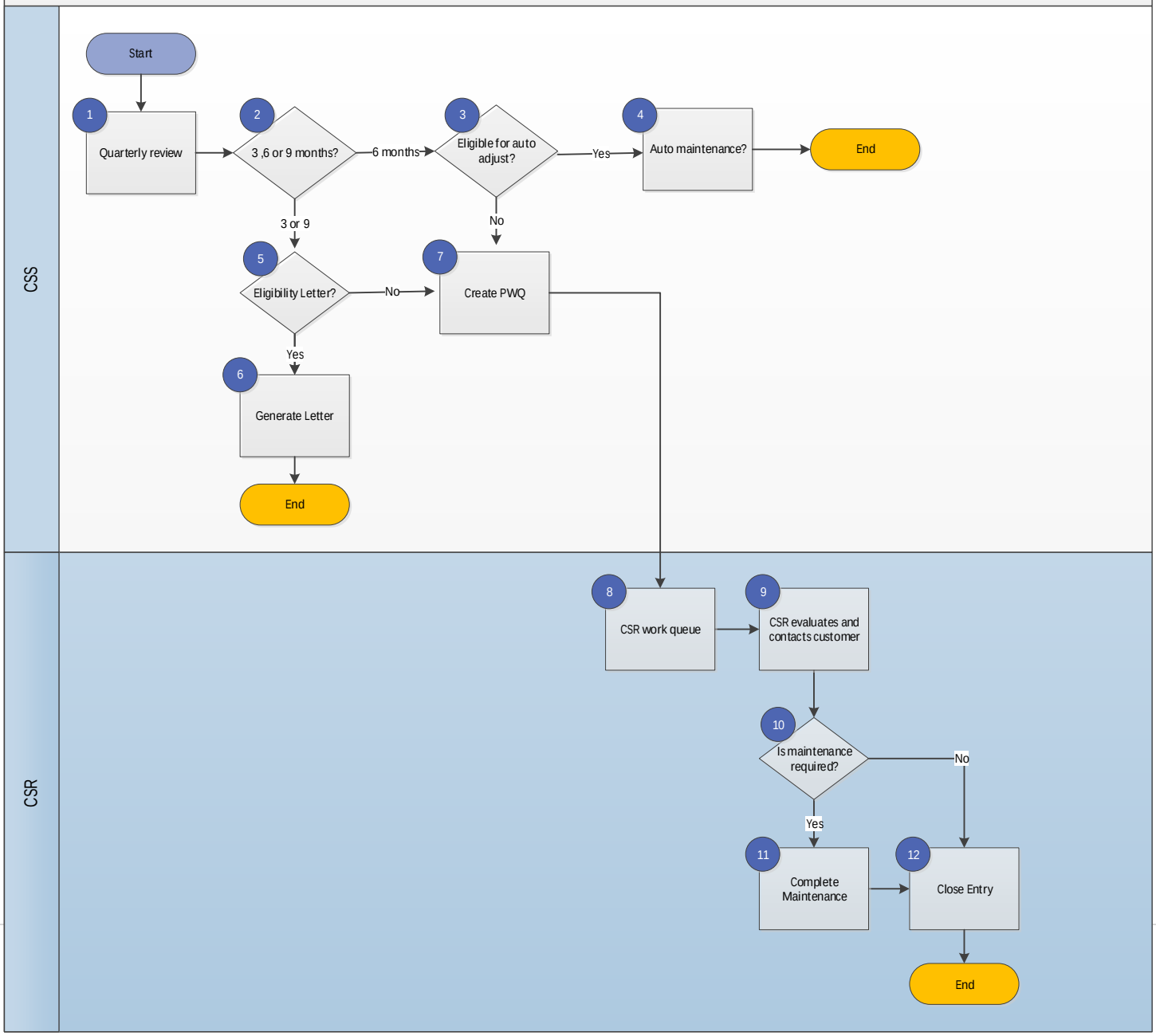
Related Process:

- Equal Payment Plan (EPP)
- Bill Calculation
- AESL Redirects
- Credit and Collections – General Service
- Credit and Collections - Residential
- Payment Arrangements for Debt

Applications:

- Customer Service System (CSS)

Figure 5.20 - Equal Payment Plan (EPP) Maintenance - Quarterly Reviews



Process Name: Establish New Service

Process Description: The process of setting up a new service at a premise that has never had service at that location before.

Process Owner(s):

Group: Customer Service

Frequency: Daily

Volume: 2,500 annually.

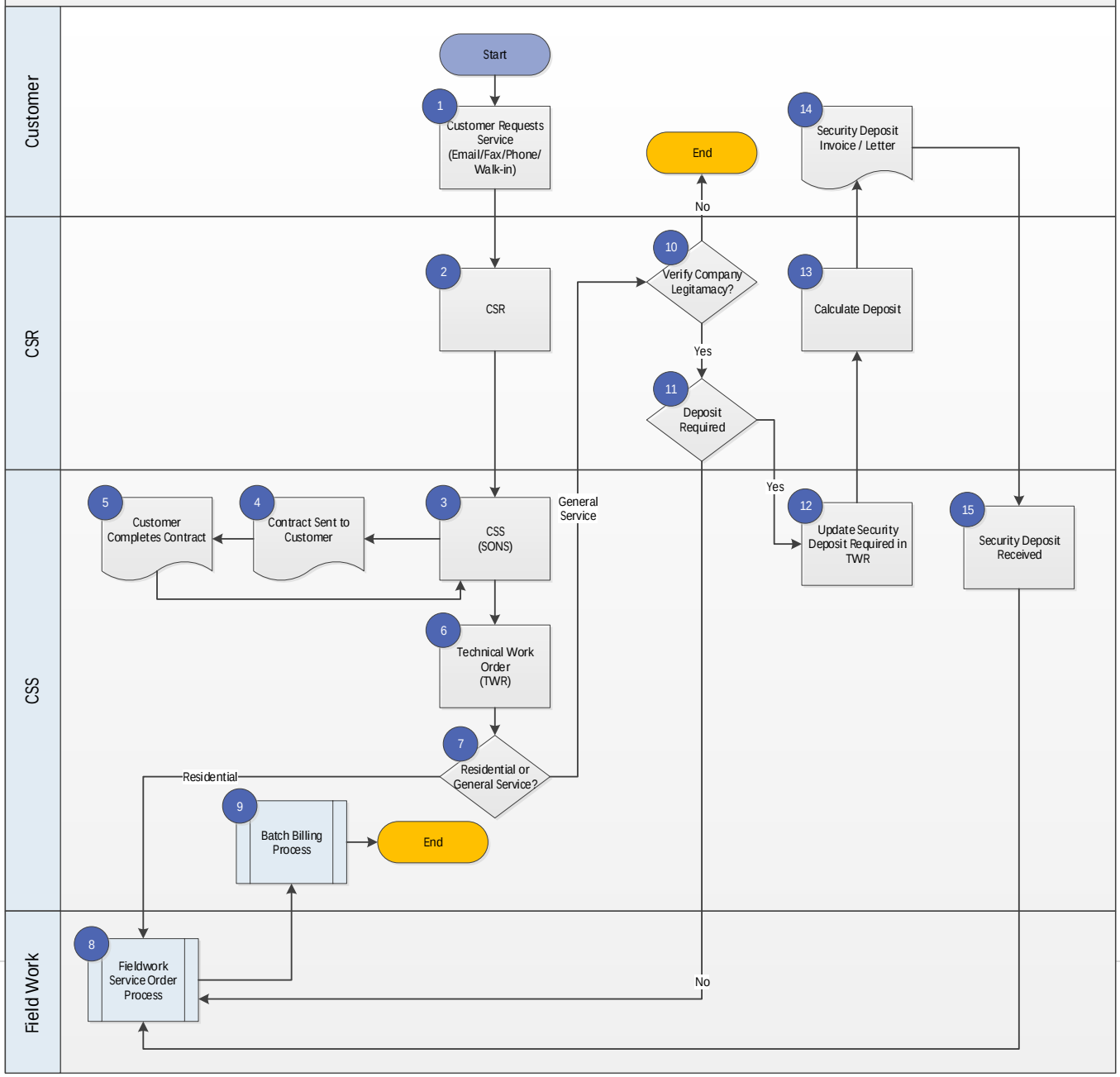
Related Process:

- Nightly Batch
- Service Orders
- Process Payments
- Final/Reserve Outstanding (FRO)

Applications:

- Customer Service System (CSS)
- Technical Work Requests (TWR)
- Click (dispatch)
- Click (mobile)
- Sharepoint
- Street Light Management System (SLMS)
- Planet Press

Figure 5.21 - Establish New Service



Process Name: Estates and Trusts

Process Description: The process of updating a deceased customer's account information to identify if it is in estate or trust.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Approximately 500 customers annually (Estates)

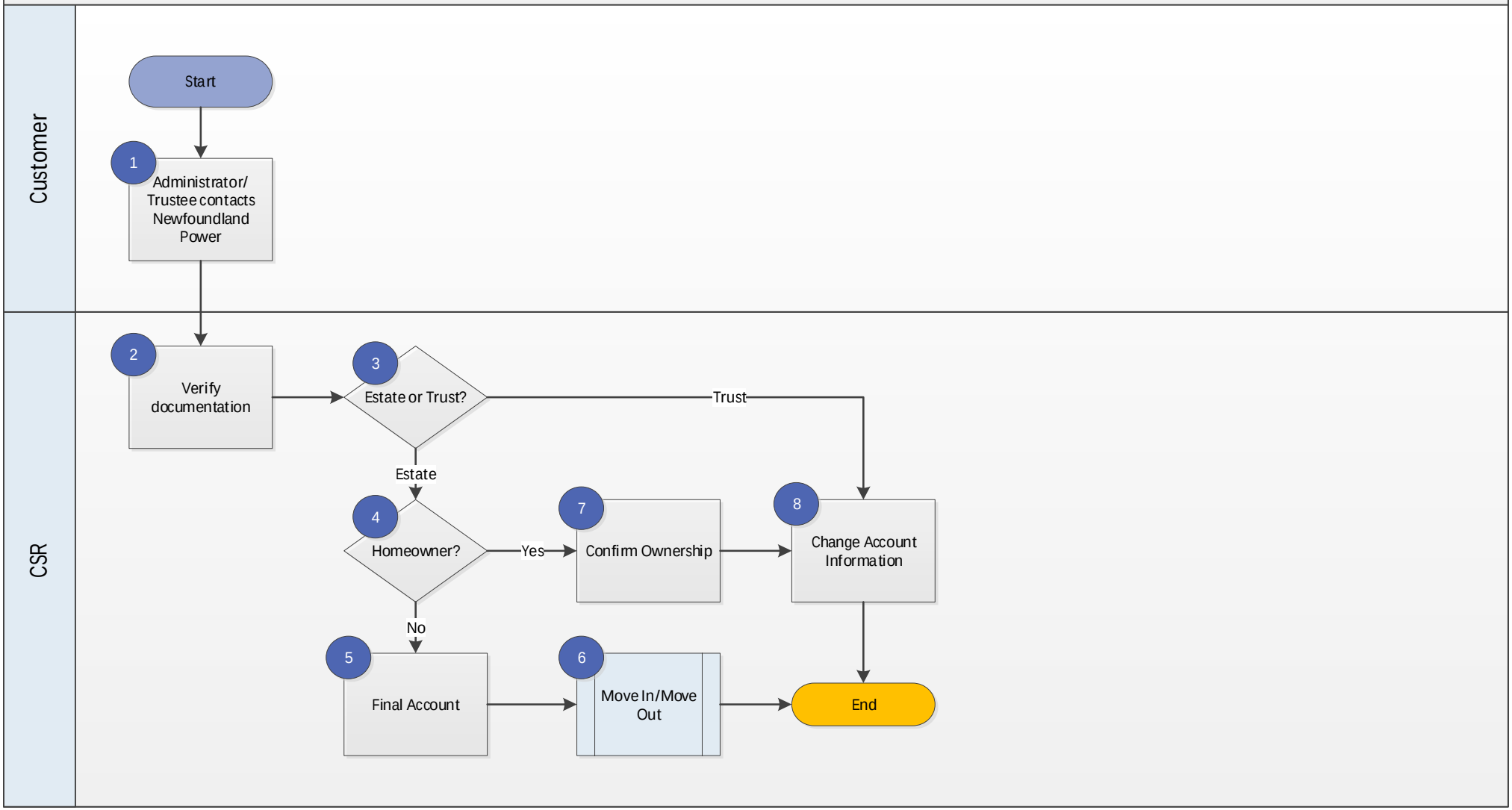
Related Process:

- Credit and Collections – General Service
- Credit and Collections - Residential
- Landlord Agreements
- Move in/Move out

Applications:

- Customer Service System (CSS)
- Avaya

Figure 5.22 - Estate and Trusts



Process Name: Finance Plans

Process Description: Newfoundland Power finances various convenience programs such as: electric heating systems, windows, insulation, electrical upgrades, hot water tanks and energy efficient electric thermostats, to a maximum $10,000. Newfoundland Power does not supply or install any of the products only allow customer's the option of financing on their bill pending credit approval.

Process Owner(s):

Group: Credit and Collections

Frequency: Daily

Volume: 776 approved over previous year (38 Contribution in aid of Constructions - CIACs)

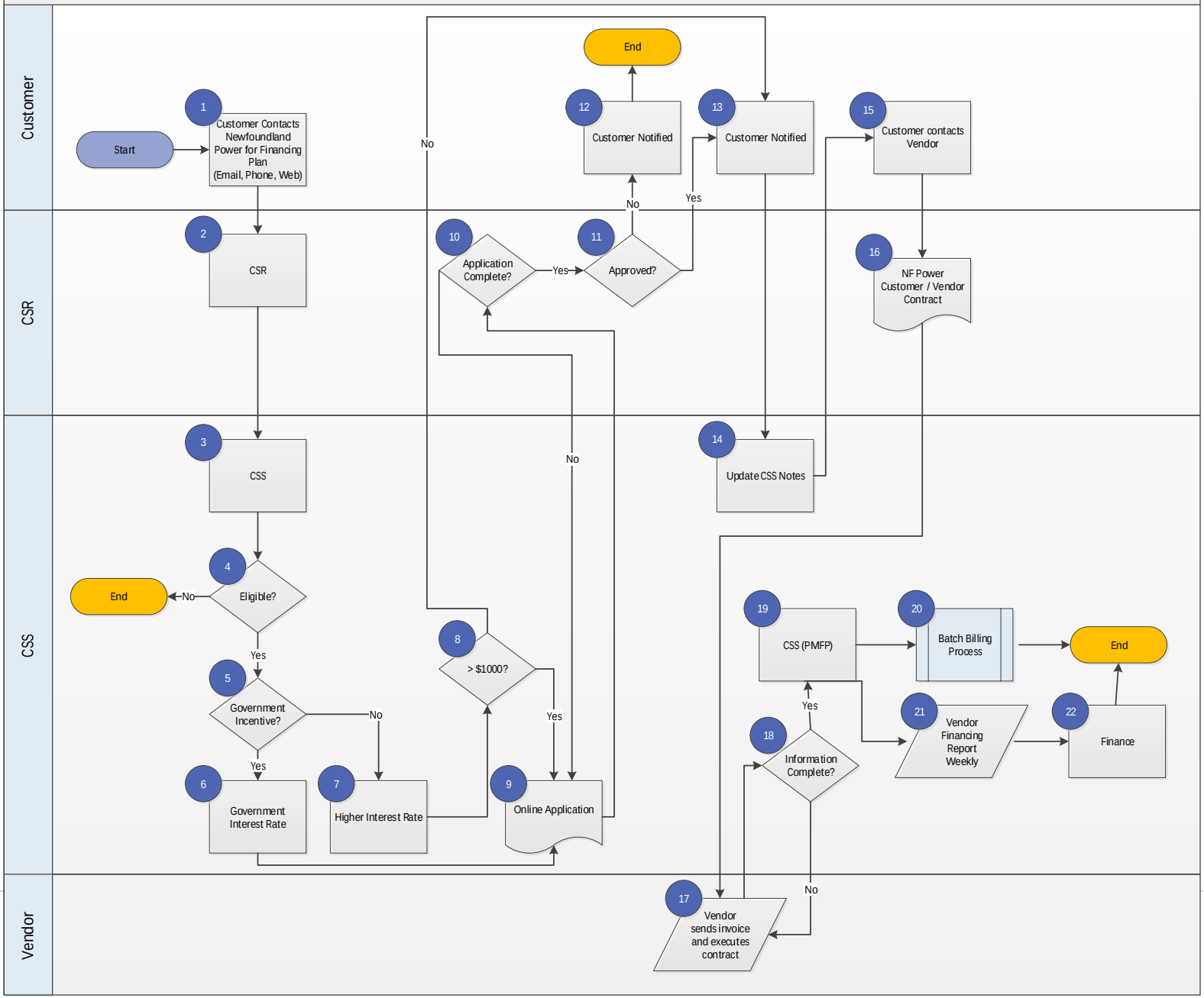
Related Process:

- Nightly Batch
- Credit and Collections – General Service
- Credit and Collections - Residential
- Process Payments
- TakeCHARGE

Applications:

- Customer Service System (CSS)
- Residential Loan Application (.net solution)
- Planet Press
- Webster (calculators)
- External Credit Reporting Agencies (Transunion)

Figure 5.23 – Finance Plans



Process Name: High Bill Complaint

Process Description: The process of resolving a customer inquiry or complaint for a high bill.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Seasonal

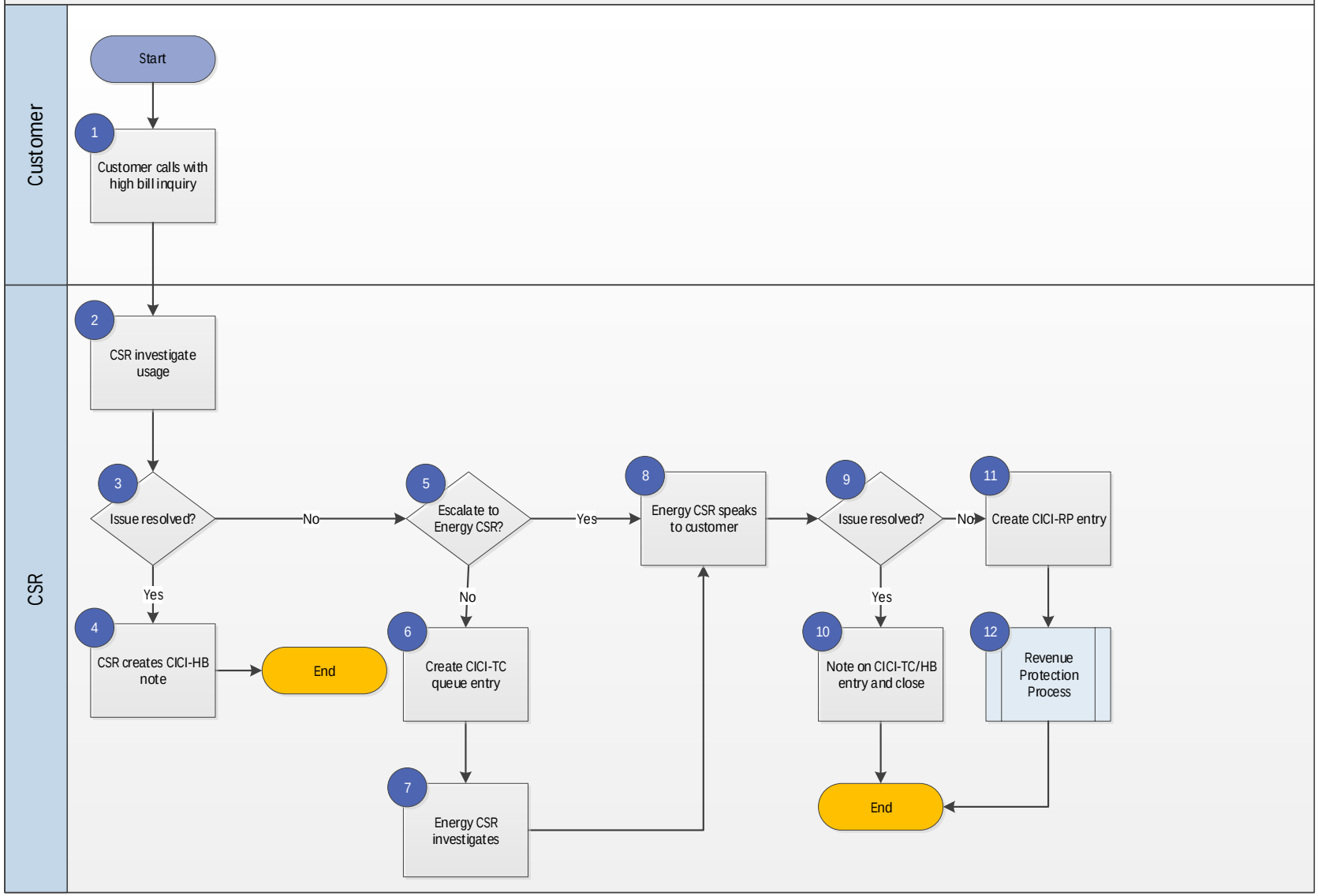
Related Process:

- High Bill Complaint
- Credit and Collections – General Service
- Credit and Collections - Residential
- Equal Payment Plan (EPP)

Applications:

- Customer Service System (CSS)
- Webster (Energy Manual/Calculator sheets)
- takeCHARGE
- Newfoundland Power website
- Metering Equipment System (MES)

Figure 5.24 - High Bill Complaint



Process Name: Landlord Agreements

Process Description: Agreement attached to a customer (landlord) where service can be automatically transferred/disconnected between tenant to landlord for one or more premises.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Total number of Landlord Agreements with at least 1 premise attached is approximately 24,000

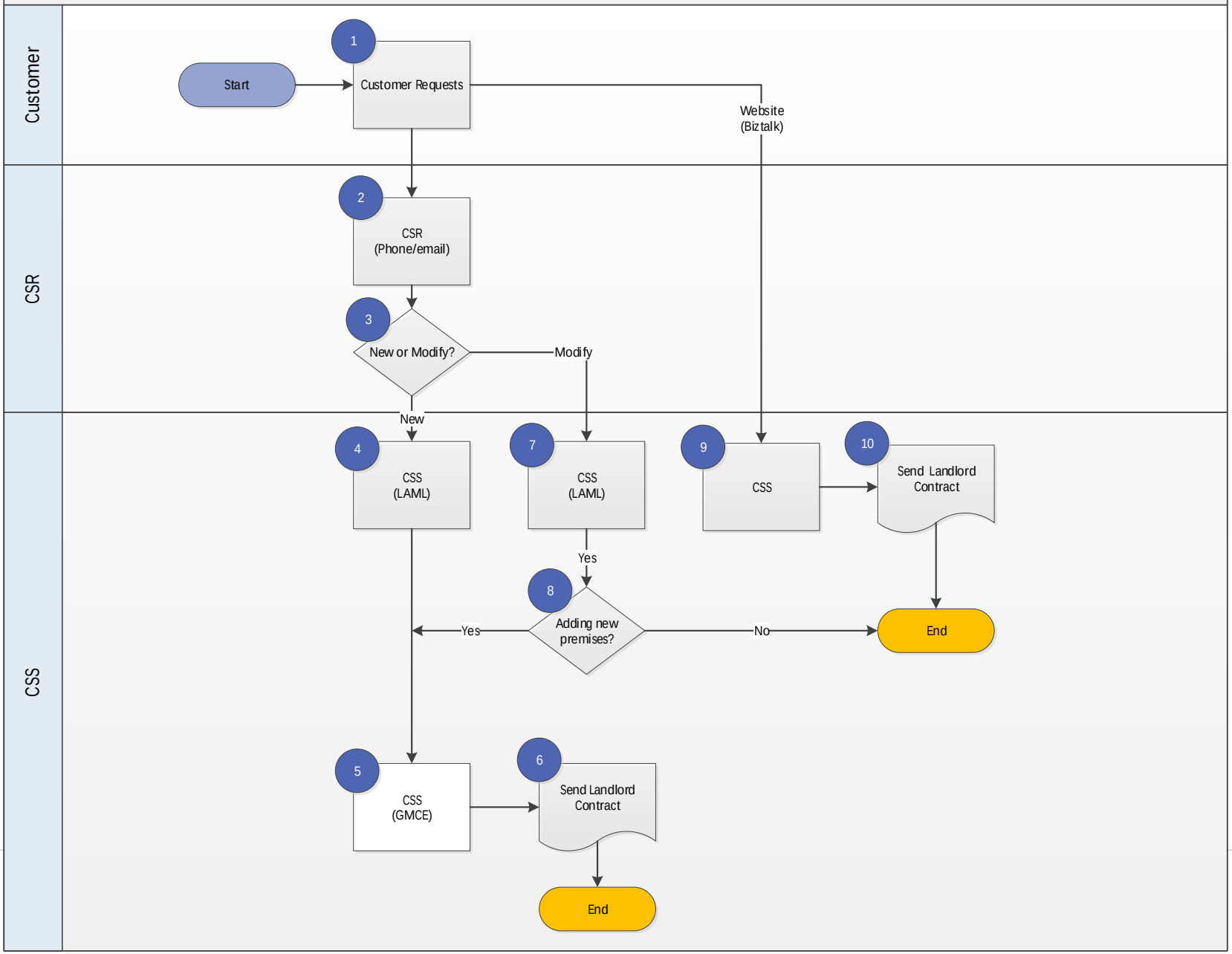
Related Process:

- Consolidated Billing
- Process Payments
- Automatic Payment Plan (APP)
- Customer Electronic Correspondence
- Move in/Move out
- New Customer Set-up
- Service Orders

Applications:

- Customer Service System (CSS)
- Newfoundland Power website
- Planet Press
- Biztalk

Figure 5.25 - Landlord Agreements



Process Name: Manage Billing Exceptions

Process Description: The process of managing billing exceptions that are generated by CSS (PWQ, suspended bill reports). These would stop billing for an individual account.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Approximately 60-80/day (St. John's)

Related Process:

- Pending Work Queue
- Nightly Batch
- Service Orders
- Meter Reading
- Cancel/Rebill
- Revenue Protection

Applications:

- Customer Service System (CSS)
- Technical Work Requests (TWR)
- Responder
- LEAD tools
- Excel spreadsheets for adjustments

Figure 5.26 - Managing Billing Exceptions

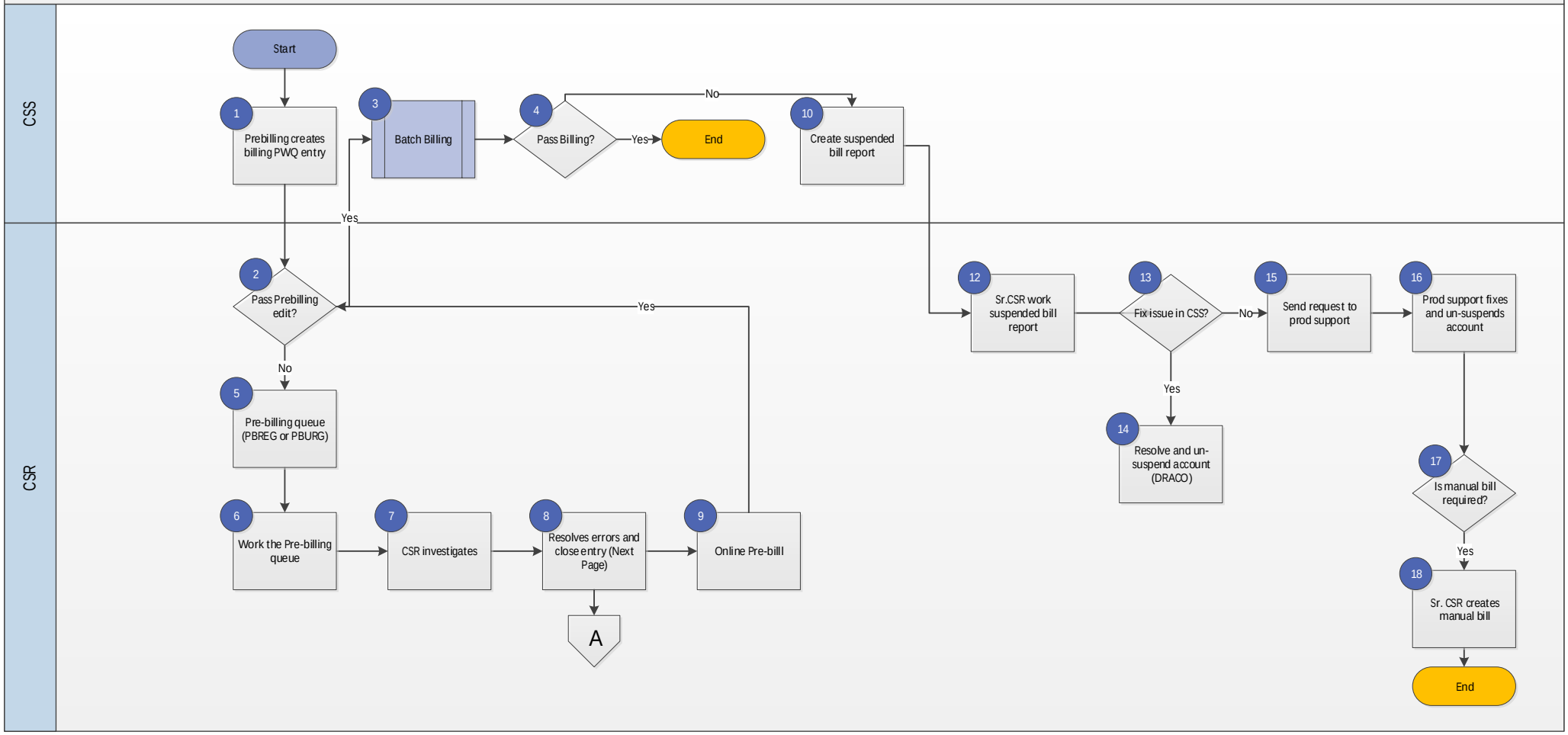
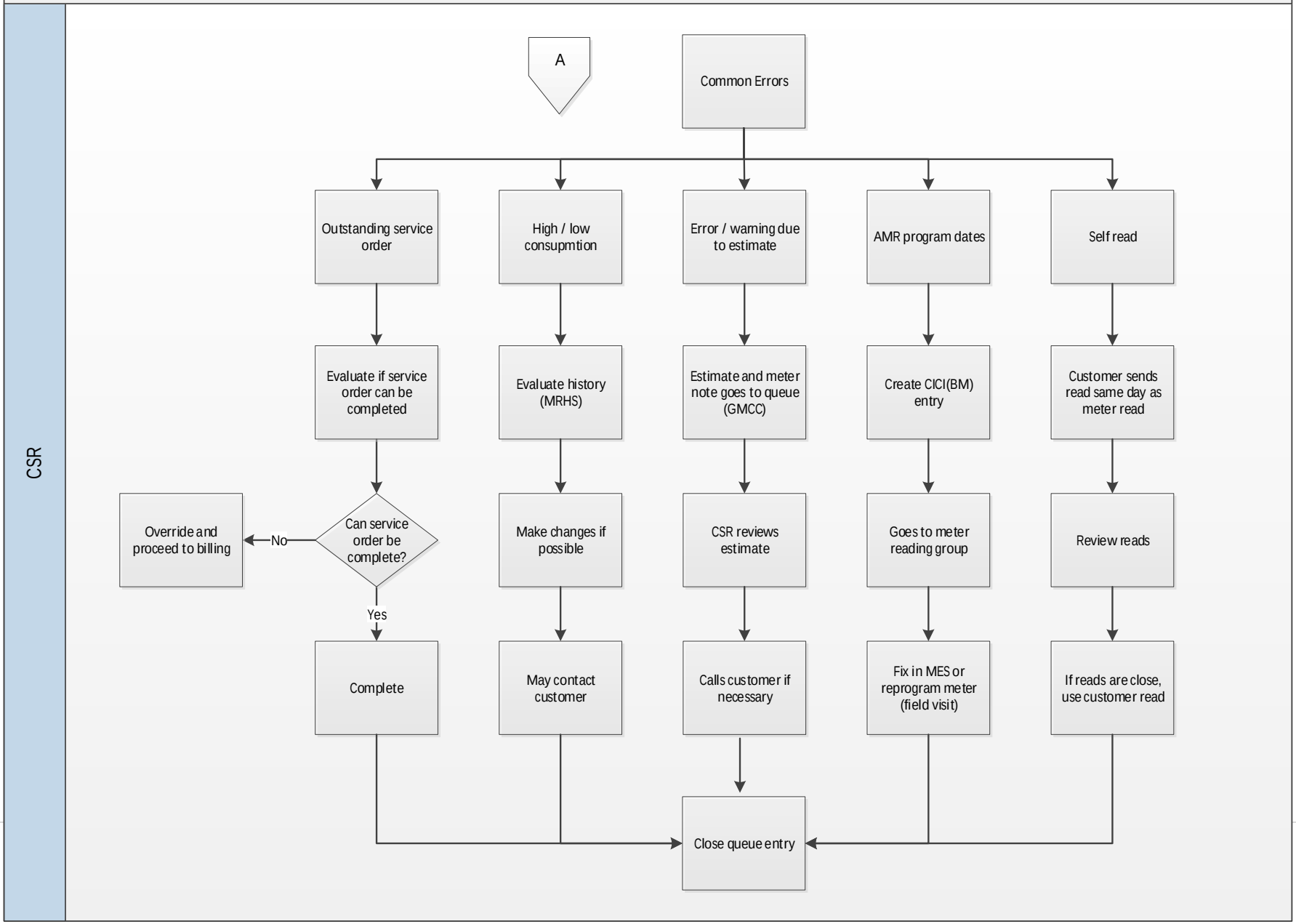


Figure 5.27 - Common Errors and Resolutions



Process Name: Manage Customer Subscriptions

Process Description: The process of collecting and managing customer information for Newfoundland Power's program and services to adhere to Canada's Anti-Spam Legislation.

Process Owner(s):

Group: Core Team

Frequency: Daily

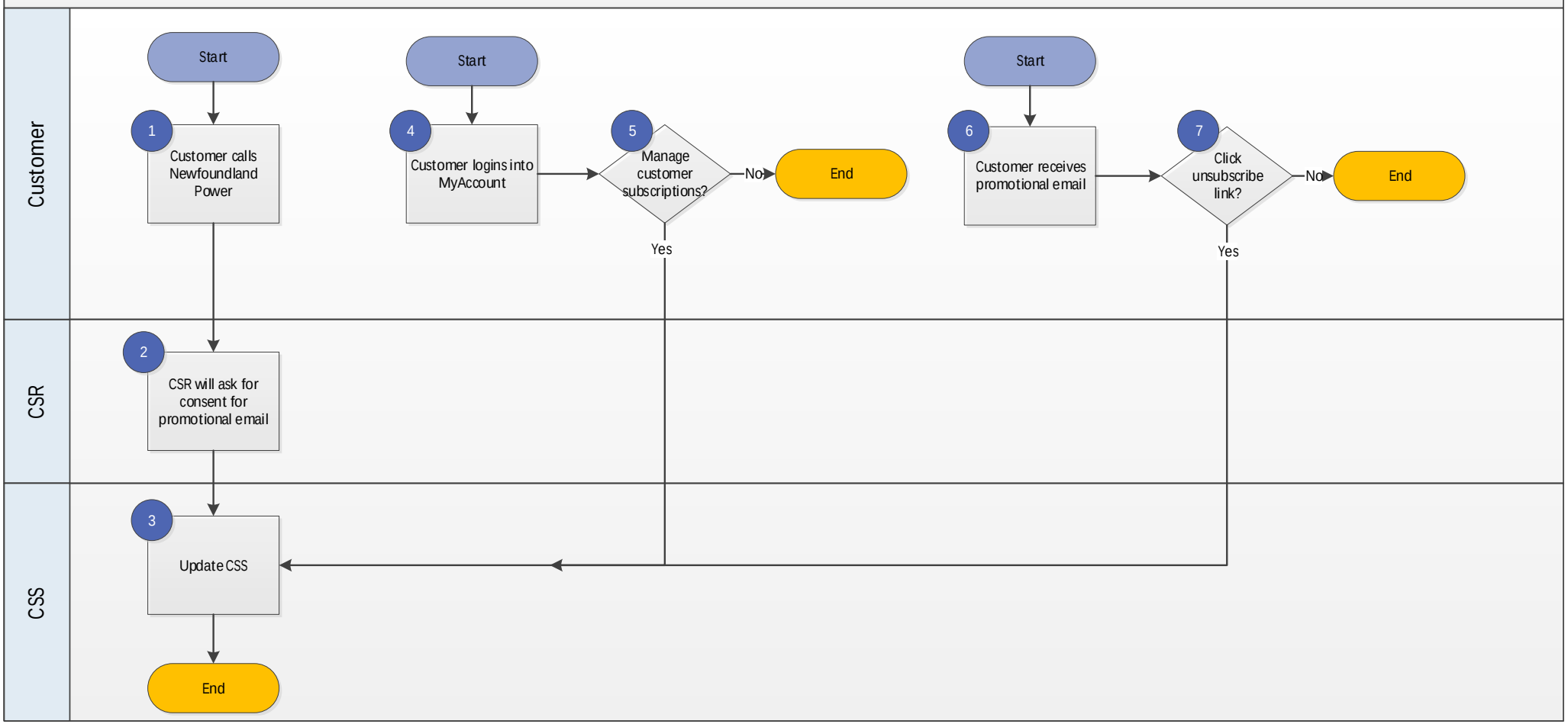
Related Process:

- New Customer Set-up
- Service Orders
- Move in/Move out
- Automatic Payment Plan (APP)
- Equal Payment Plan (EPP)

Applications:

- Customer Service System (CSS)
- Newfoundland Power website
- Email Campaigns

Figure 5.28 - Manage Customer Subscriptions



Process Name: Meter Reading

Process Description: Meter readers pick up their mobile devices loaded with their assigned work each day at one of the 8 area offices and return the device at the end of day. The readings are transmitted electronically back to CSS where they are processed for billing.

Process Owner(s):

Group: Customer Relations

Frequency: Daily (end of day)

Volume: Over 250,000 meters are read monthly across 19 cycles

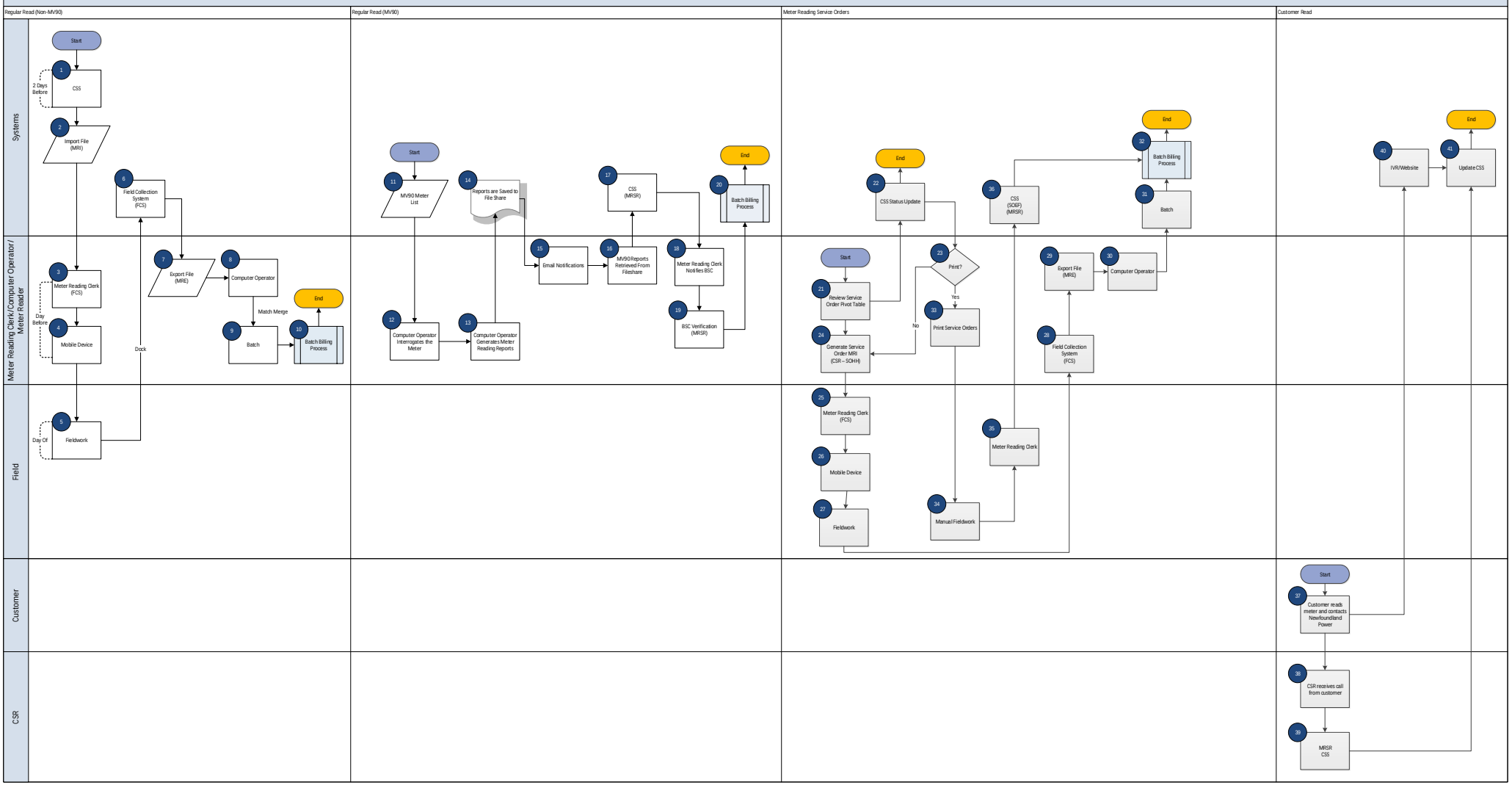
Related Process:

- Nightly Batch
- Service Orders
- Meter Maintenance

Applications:

- Customer Service System (CSS)
- MV-90
- PC Pro+ Advanced
- Itron (Field Collection System)
- MES/MES extensions
- Meter Reading Pivot Table, Service Order Spreadsheets

Figure 5.29 - Meter Reading



Process Name: Missing Customer Payments

Process Description: The process of finding missing customer payments.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Less than 100 per month

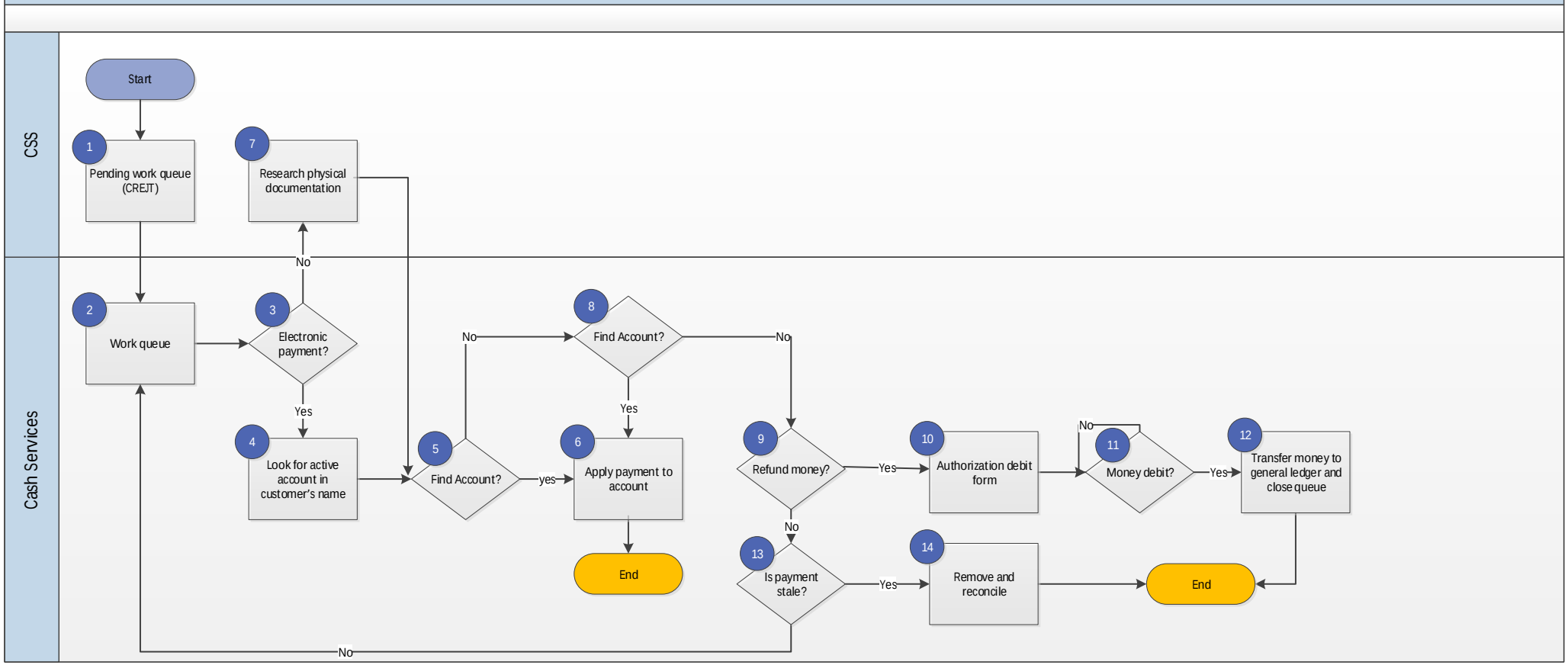
Related Process:

- Process Payments
- Pending Work Queue
- Nightly Batch
- Credit and Collections – General Service
- Credit and Collections - Residential
- Transfer Credits

Applications:

- Customer Service System (CSS)
- ScotiaConnect - MS Access and File (Receivables look up file)
- ScotiaConnect - Payment Statement

Figure 5.30 - Finding Missing Payments



Process Name: Mortgagee in Possession

Process Description: The process of settling a customer account when the bank takes possession of the premise.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

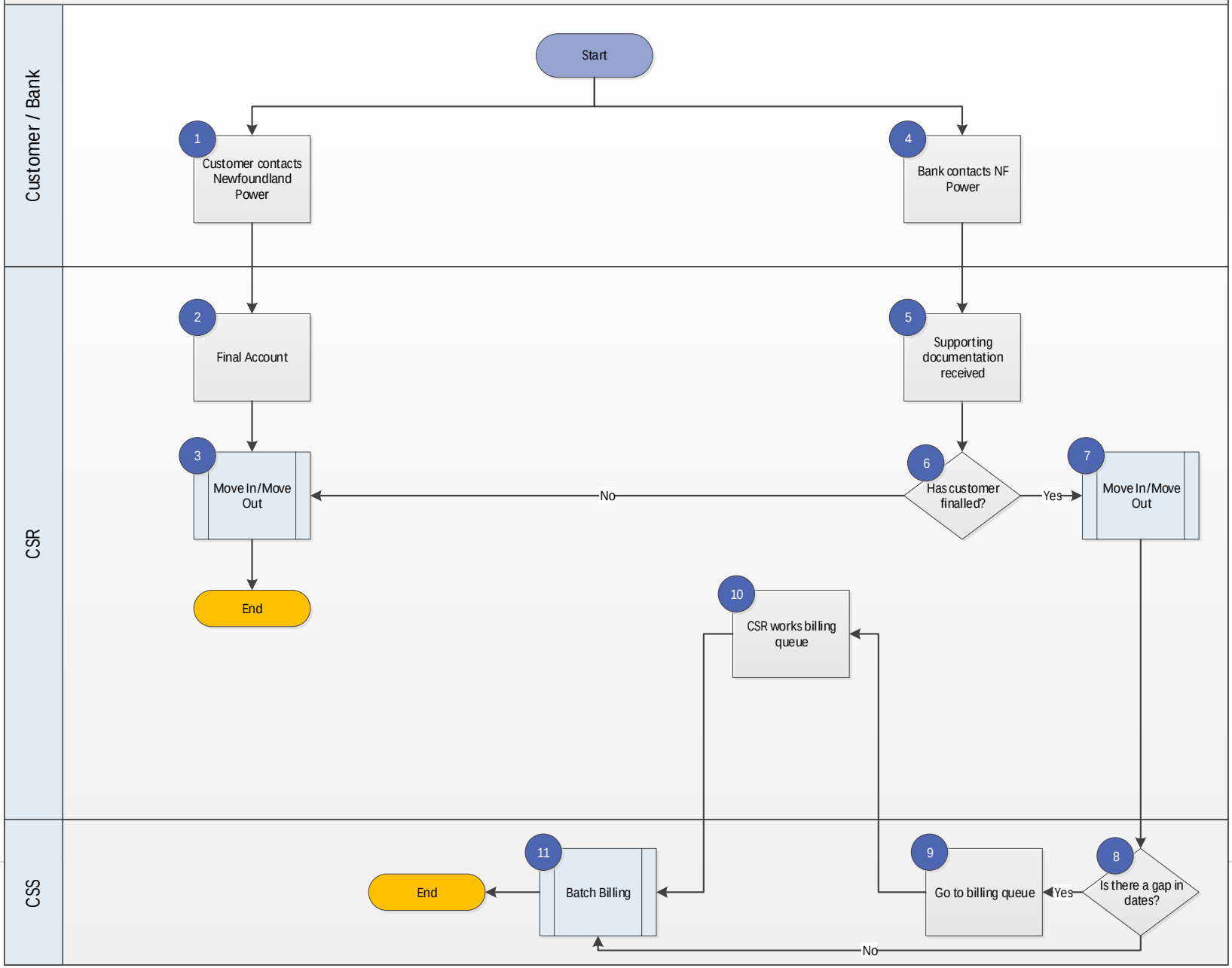
Related Process:

- Move in/Move out
- Credit and Collections for Debt
- Disconnect/Reconnect for Debt

Applications:

- Customer Service System (CSS)
- Avaya
- Webster (Mortgagee in Possession Form)

Figure 5.31 - Mortgagee in Possession



Process Name: Move in/Move out

Process Description: A customer is either 1) moving from one premise to another 2) moving out and not transferring service or 3) moving into a premise for the first time.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Average 3,500 move outs and 3,400 move ins per month.

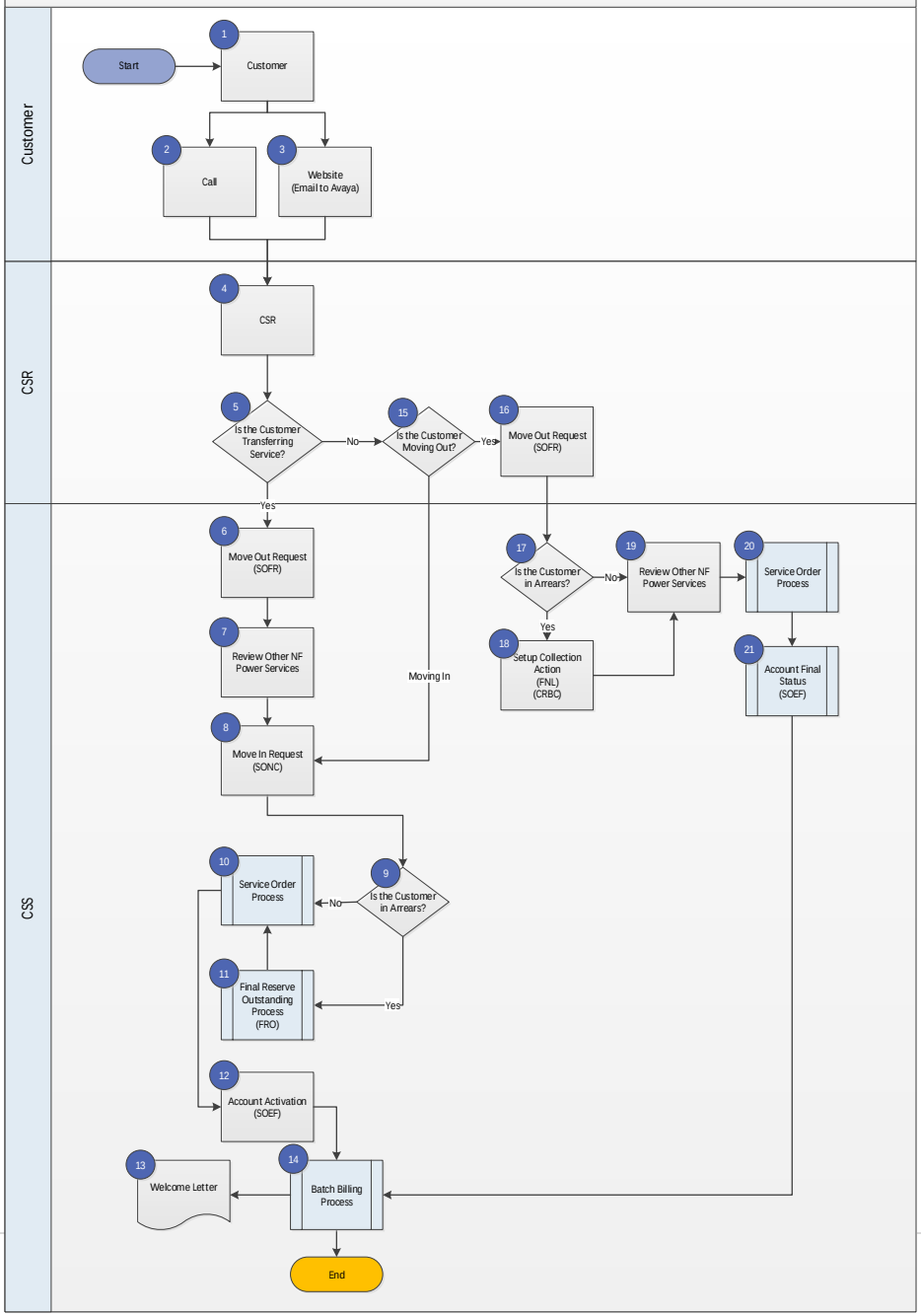
Related Process:

- Nightly Batch
- Credit and Collections – General Service
- Credit and Collections - Residential
- Equal Payment Plan (EPP)
- Service Orders
- Finance Plans
- Automatic Payment Plan (APP)
- Landlord Agreements
- Outages
- Customer Electronic Correspondence

Applications:

- Customer Service System (CSS)
- Newfoundland Power website
- Avaya
- Planet Press

Figure 5.32 - Move In / Move Out



Process Name: New Customer Set-Up

Process Description: The process of setting up a new customer. Customers must present their ID in person at a Newfoundland Power location.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Approximately 9,000 annually (2018)

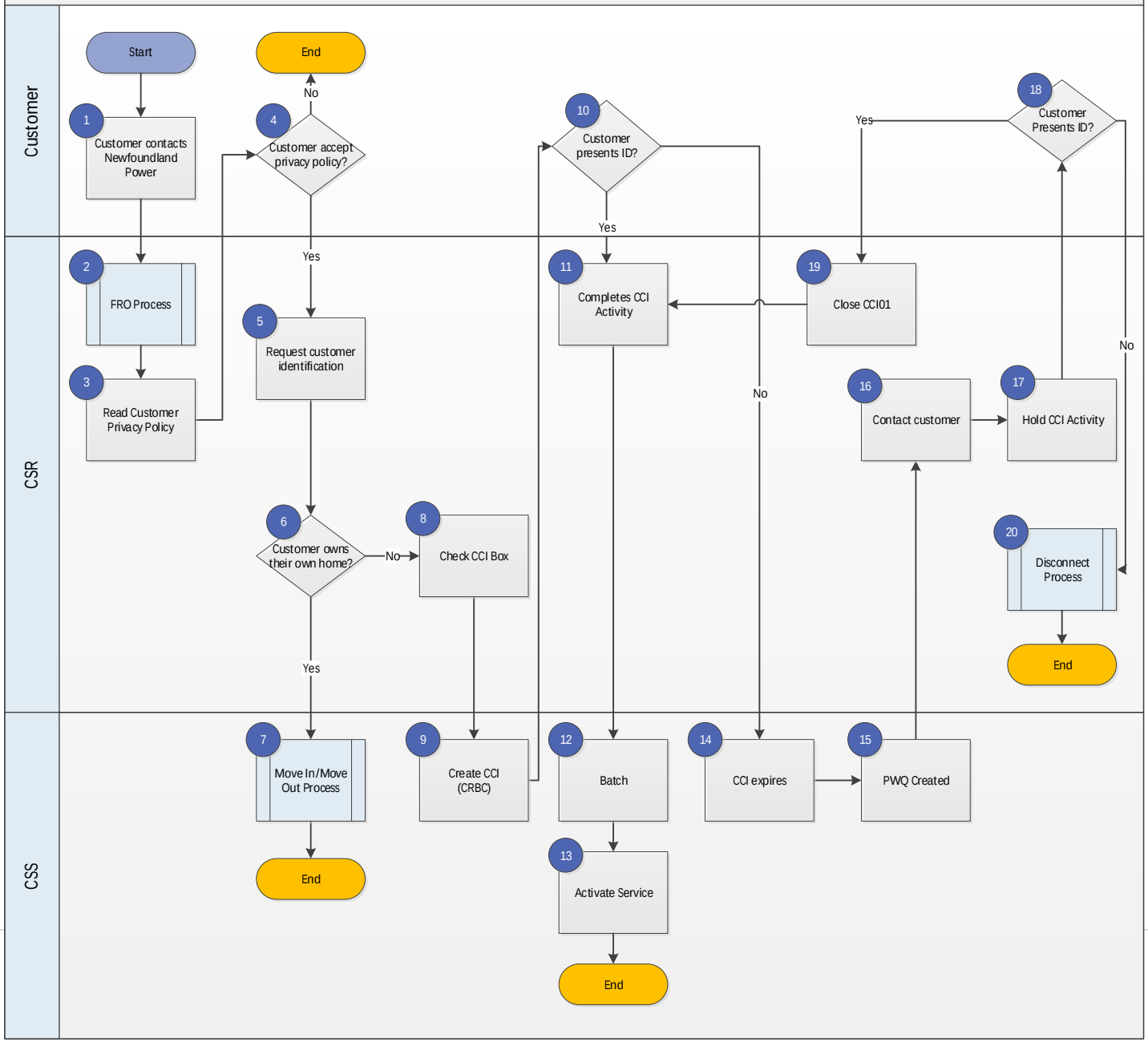
Related Process:

- New Customer Set-up
- Service Orders
- Move In/Move Out
- Disconnect/Reconnect for Debt
- Final/Reserve Outstanding (FRO)

Applications:

- Customer Service System (CSS)

Figure 5.33 - New Customer Set-Up



Process Name: Newfoundland and Labrador Housing Corporation (“NLHC”) Subsidy

Process Description: NLHC provides a heating subsidy to assist its tenants. NLCH determines which premises are eligible and the amount. It is based on the premise not the customer. The program rolls over each November and the balance is updated throughout the year. The subsidy amount is displayed on the bill.

*Note: Occasionally, a customer is both an AESL client and receives the NLHC subsidy.

Process Owner(s):

Group: Customer Relations

Frequency: 3 times per month on cycles 1, 7, and 13

Volume: 5,325 premises

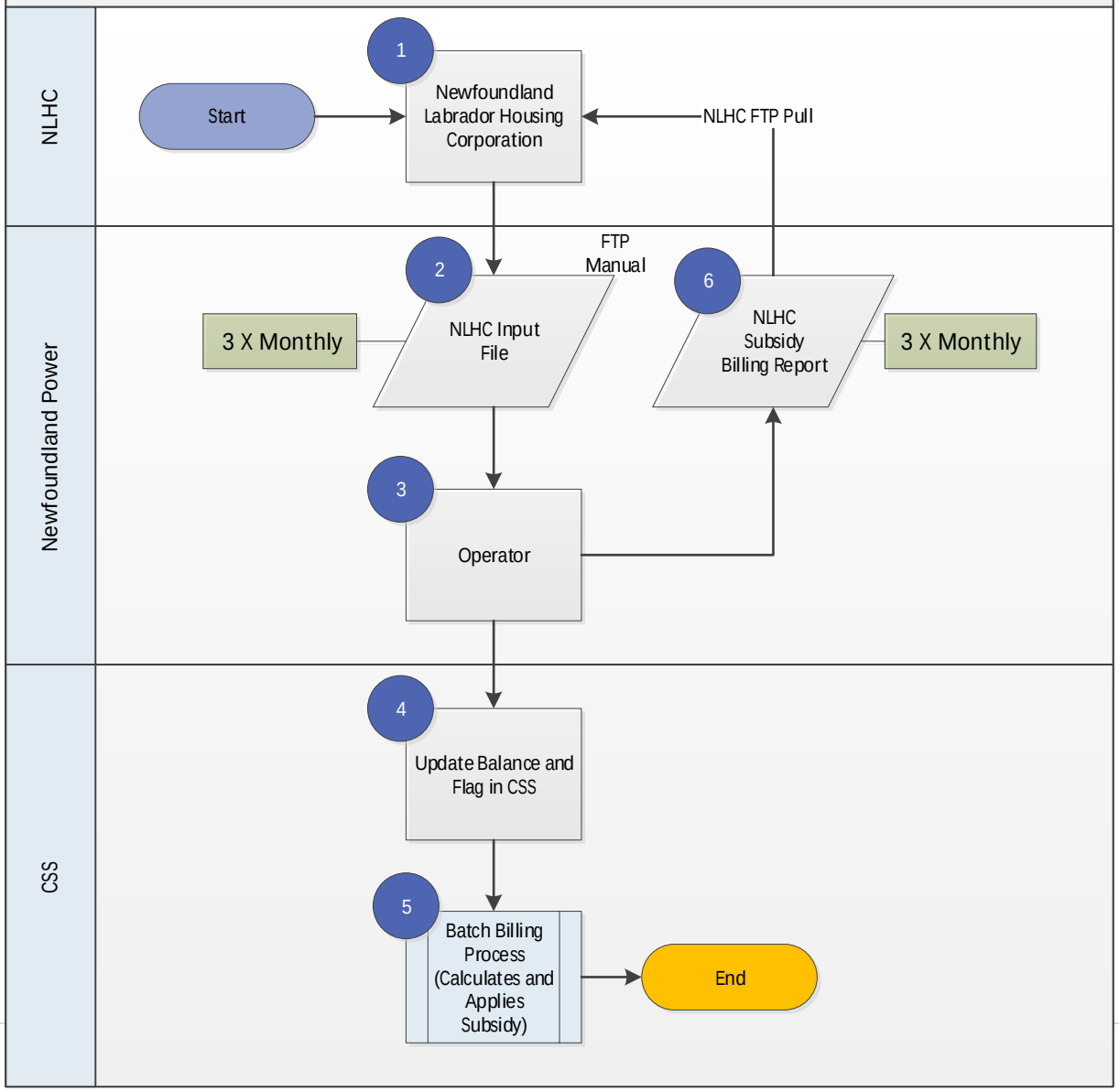
Related Process:

- Nightly Batch
- Process Payments
- Pending Work Queue
- AESL Redirects

Applications:

- Customer Service System (CSS)
- FTP (NLHC)

Figure 5.34 - Newfoundland and Labrador Housing Corporation (NLHC) Subsidy



Process Name: Other Accounts Receivable (“OAR”)

Process Description: Billing for ancillary services (i.e. pole move, engineering services) that are not included on a normal customer bill.

Process Owner(s):

Group: Finance

Frequency: Daily

Volume: Approximately 100 vendors are defined for reoccurring invoices (can fluctuate based on market demands)

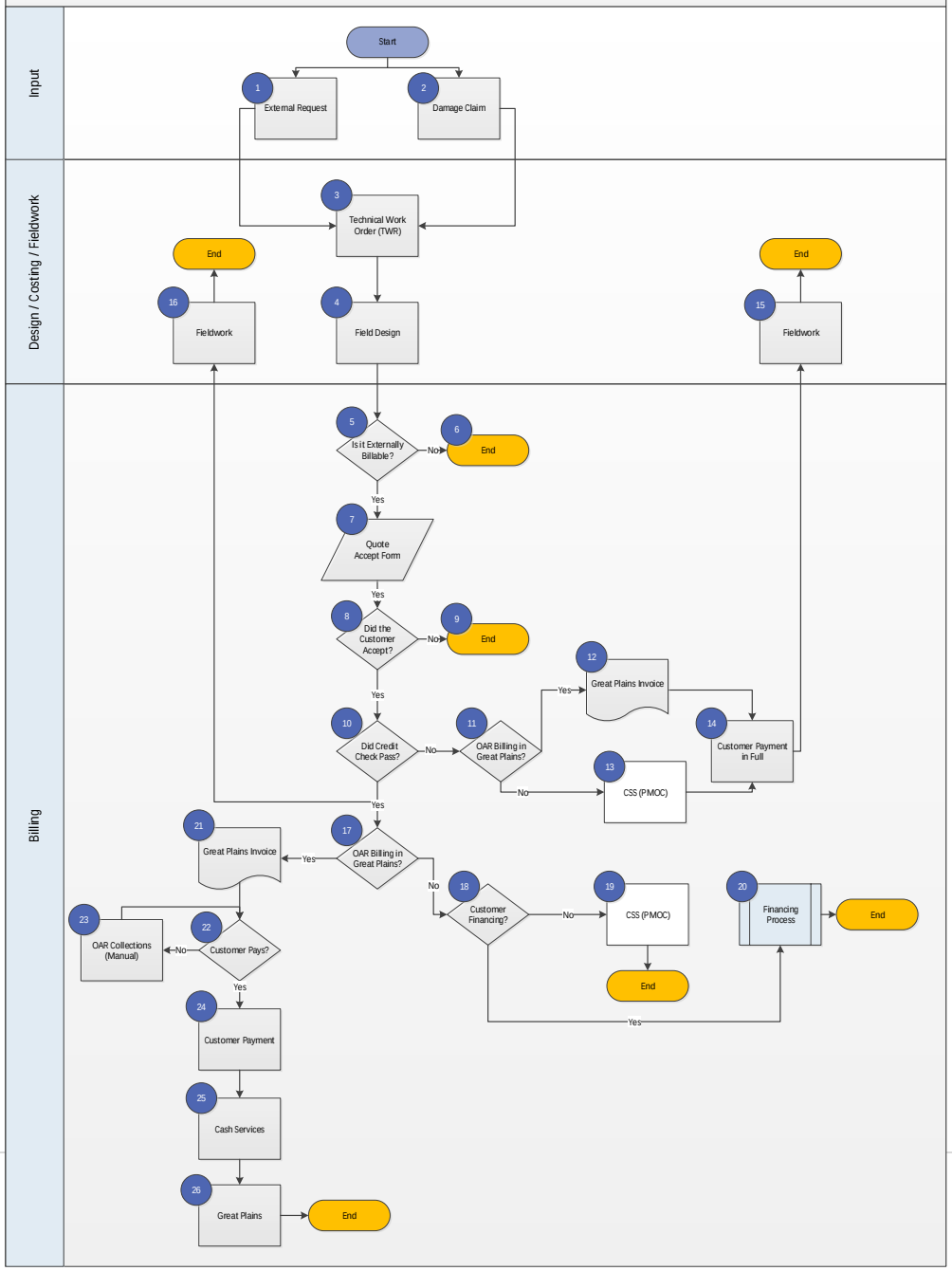
Related Process:

- Process Payments
- Nightly Batch
- Service Orders
- Credit and Collections – General Service
- Credit and Collections - Residential

Applications:

- Customer Service System (CSS)
- MS Great Plains
- Technical Work Requests (TWR)
- Engineering (source)
- Webster (Finance)

Figure 5.35 - Other Accounts Receivable (OAR)



Process Name: Out of Route (“ORR”) Reads

Process Description: The FC300 meter reading handheld has the capability to capture reads from Automated Meter Read (AMR) meters that are not in the route assignments loaded on the Handheld; hence the term Out of Route reads.

Process Owner(s):

Group: Core Team

Frequency: Daily

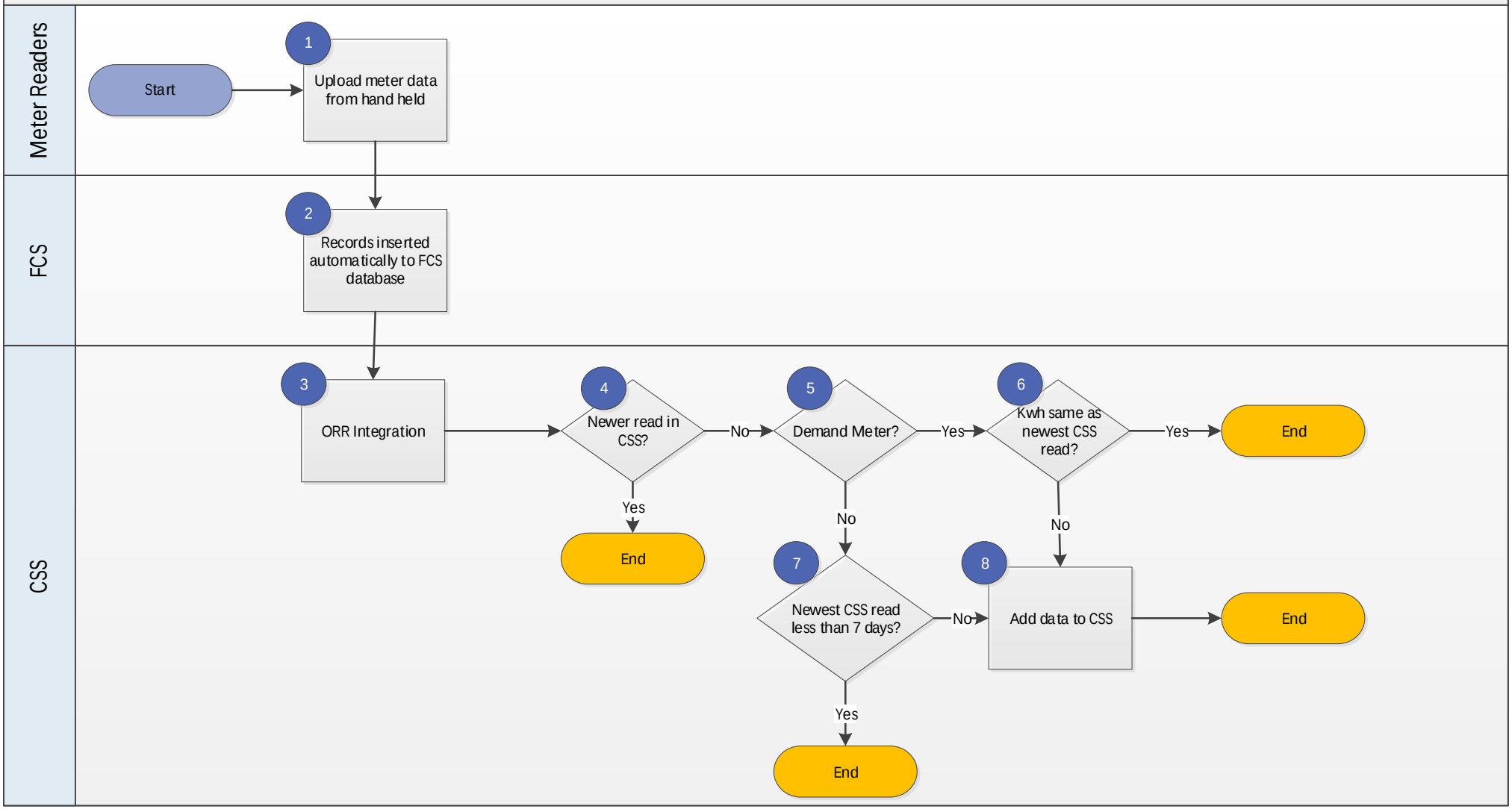
Related Process:

- Meter Reading
- Nightly Batch
- Service Orders
- Pending Work Queue
- New Customer Set-up
- Service Orders
- Final/Reserve Outstanding (FRO)

Applications:

- Customer Service System (CSS)
- Itron (Field Collection System)

Figure 5.36 - Out Of Route (ORR) Reads



Process Name: Payment Arrangements for Debt

Process Description: If the customer indicates that they have financial hardships, a payment arrangement can be made through the CSR, website, or IVR. Payment arrangements are for specific amounts, through specific payment channels on a specific date.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Average of 9,500 payment arrangements per month (excluding automated collection activities)

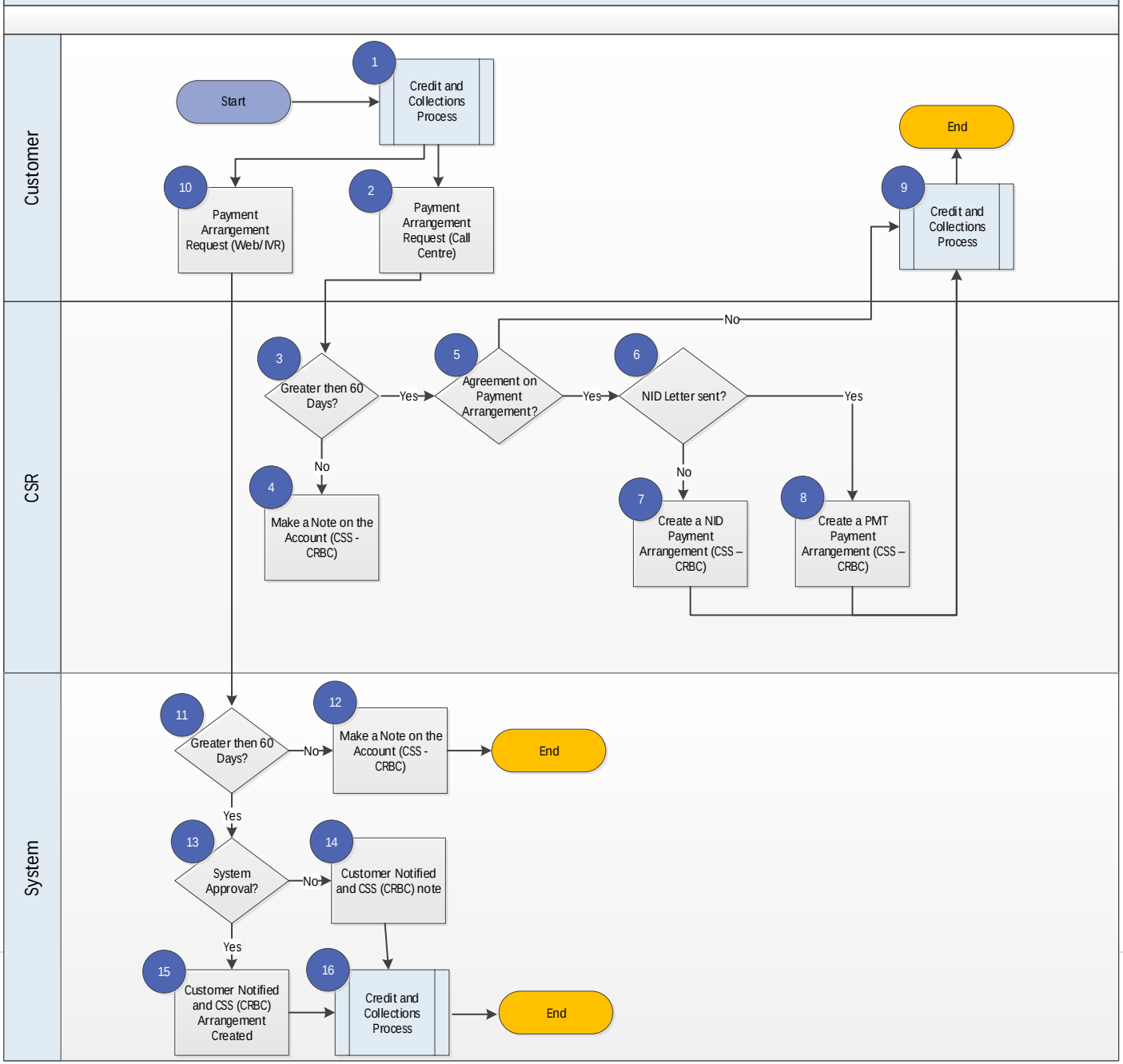
Related Process:

- Credit and Collections – General Service
- Credit and Collections - Residential
- Process Payments
- Nightly Batch
- AESL Redirects
- Collection Agency Placement
- Disconnect/Reconnect for Debt

Applications:

- Customer Service System (CSS)
- Avaya
- Newfoundland Power website

Figure 5.37 - Payment Arrangements for Debt



Process Name: Pending Work Queue

Process Description: Tasks within the Pending Work Queue (“PWQ”) can be generated by a User, or through CSS, and are then assigned to employees based on the type of work needed to be completed.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Total queue volume average 100+ and is made up of multiple different queue types

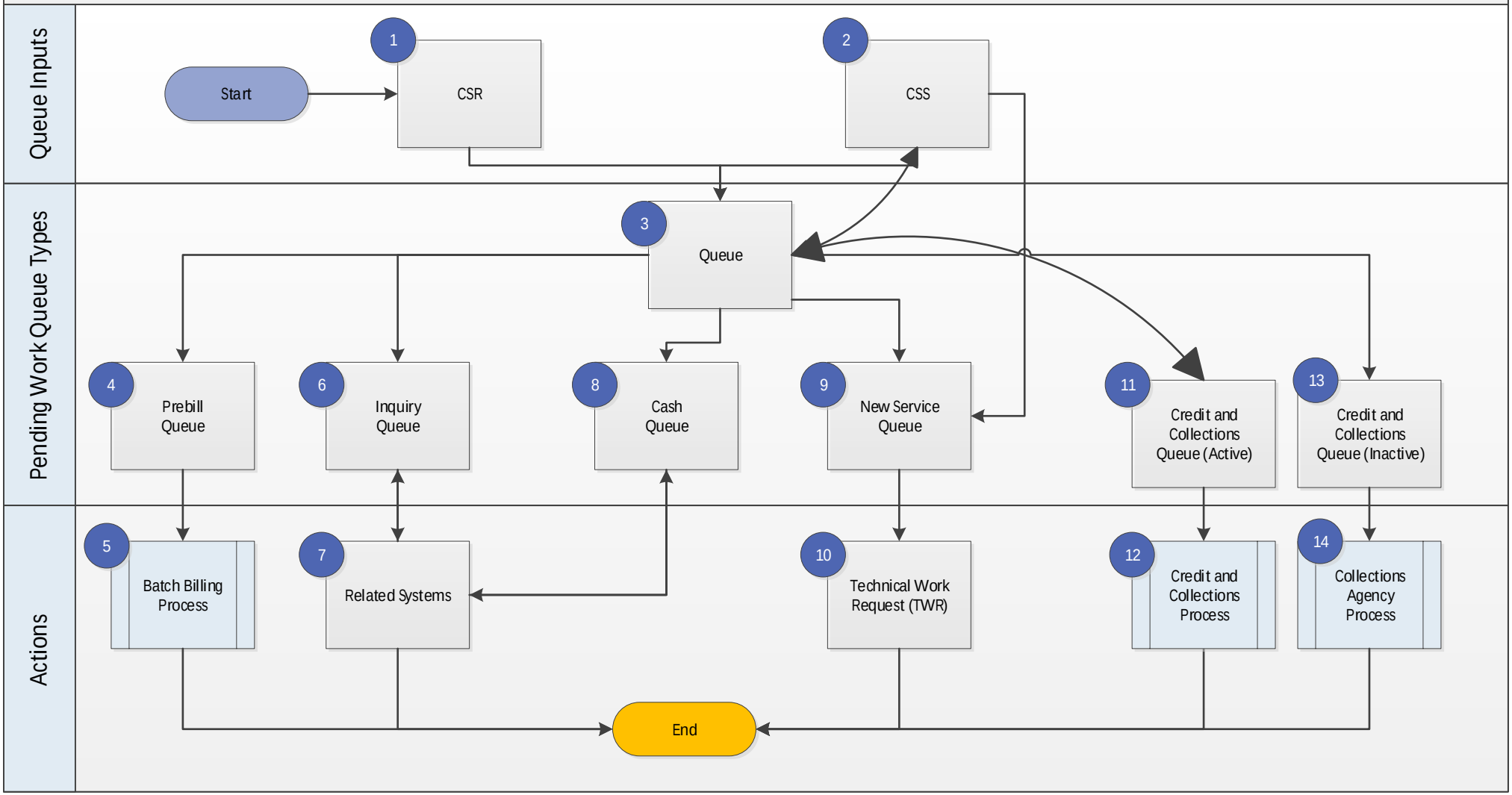
Related Processes:

- Process Payments
- Nightly Batch
- Credit and Collections – General Service
- Credit and Collections - Residential
- Collections Agency Placement

Related Applications:

- Customer Service System (CSS)
- Technical Work Requests (TWR)
- TeleVox
- Planet Press
- Responder
- Metering Equipment System (MES)
- takeCHARGE (Customer Rebate Tracking)
- Webster

Figure 5.38 - Pending Work Queue



Process Name: Process Payments

Process Description: Customers can make payments through a variety of different methods which are aggregated daily through Afternoon Cash and reconciled through CSS Batch Billing.

Process Owner(s):

Group: Cash Processing

Frequency: Daily

Volume: Approximately 3 million payments per year

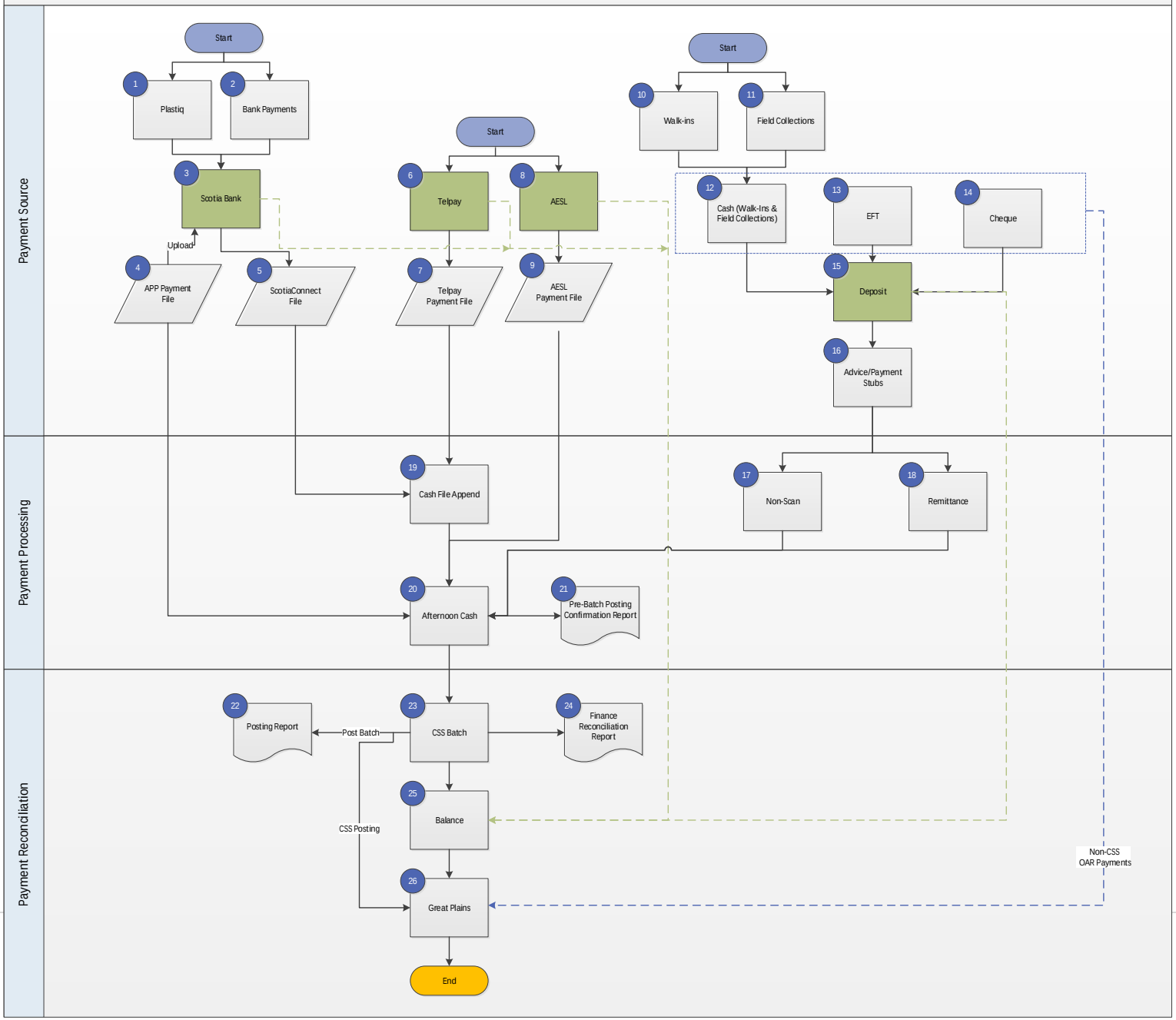
Related Process:

- Nightly
- Batch
- Credit and Collections – General Service
- Credit and Collections - Residential
- Consolidated Billing
- Automatic Payment Plans (APP)
- AESL Redirects
- Other Accounts Receivable (OAR)

Applications:

- Customer Service System (CSS)
- MS Great Plains
- Telepay
- ScotiaConnect
- Plastiq Credit Card

Figure 5.39 - Process Payments



Process Name: Rate Change Implementation

Process Description: The process of testing and implementing changes of rate structure, dollar value and/or introduction of a new rate class.

Please note: CSS is not able to handle changes in rate structure through configuration therefore this process will document rate change implementation only.

Process Owner(s):

Group: Customer Relations

Frequency: Annual or as needed

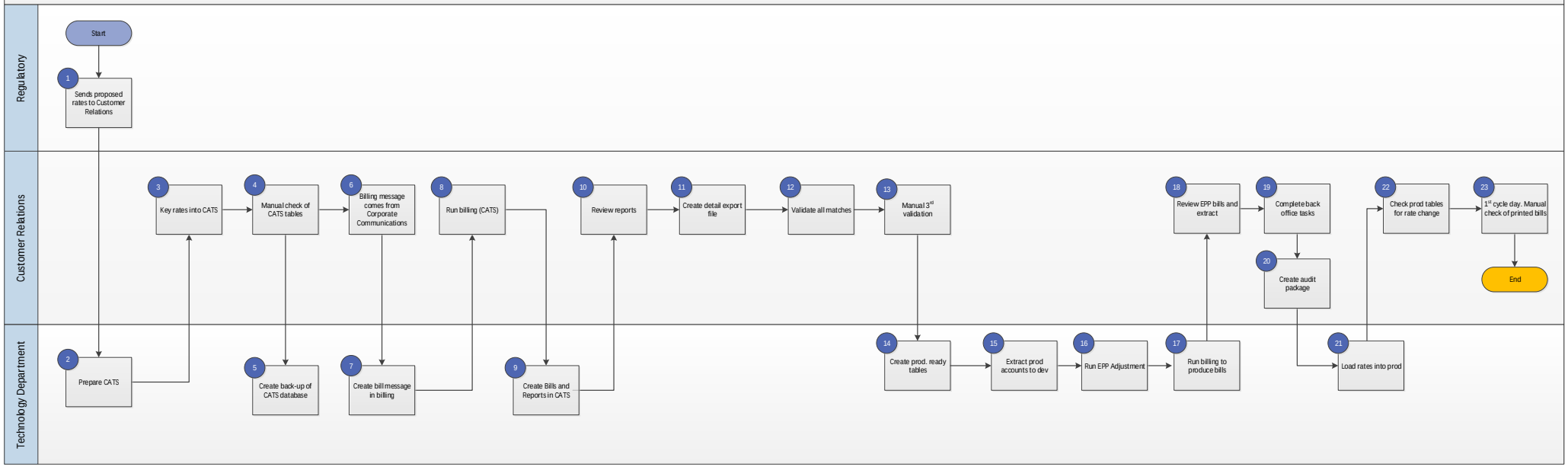
Related Process:

- Nightly Batch
- Bill Calculation
- Equal Payment Plan (EPP)
- Customer Electronic Correspondence

Applications:

- Customer Service System (CSS)
- Billing spreadsheets (Webster)
- Customer Accounting Testing System (CATS)
- Revenue Accrual
- Planet Press

Figure 5.40 - Rate Change Implementation



Process Name: Returned Payments

Process Description: The process of managing returned payments (e.g. Non-Sufficient Funds (NSF), stop payment, account closed).

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Approximately 20 per day

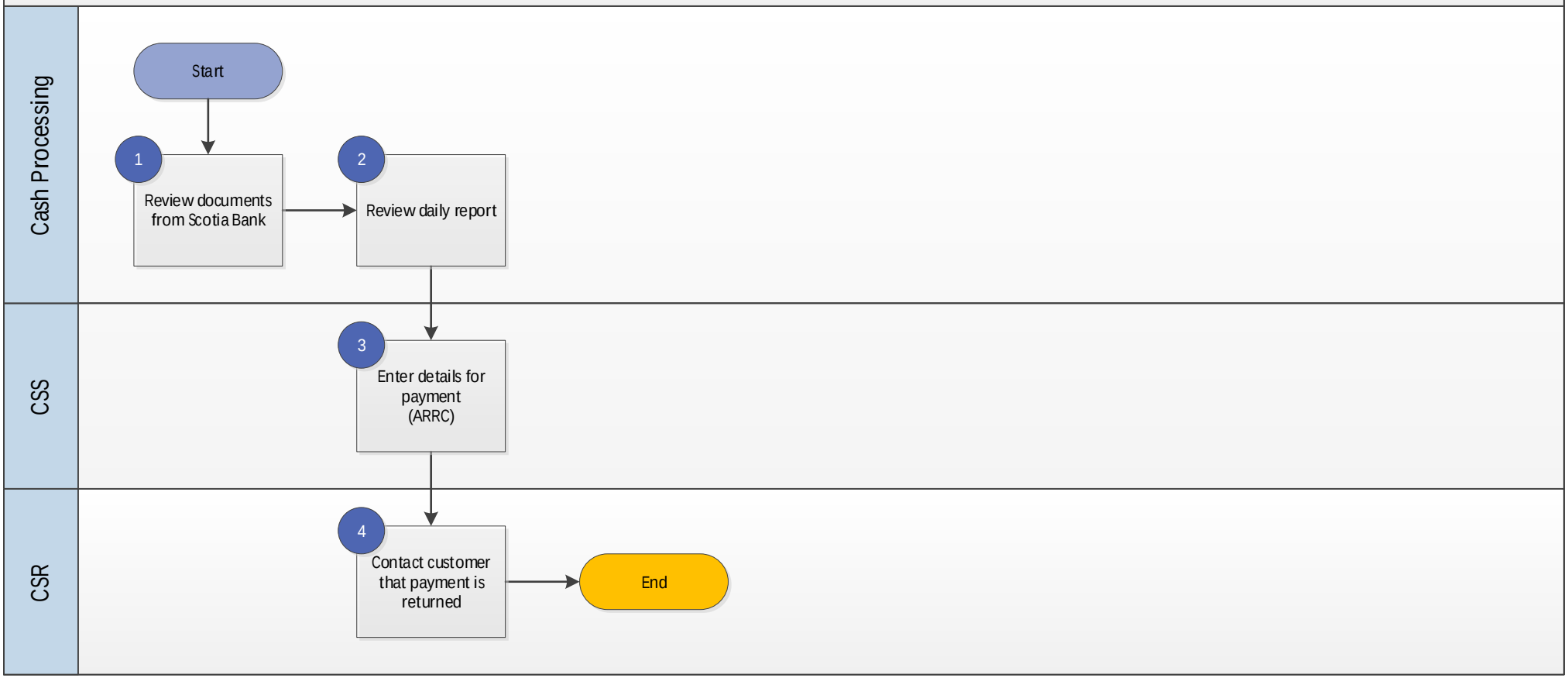
Related Process:

- Credit and Collections – General Service
- Credit and Collections - Residential
- Nightly Batch
- Process Payments
- Pending Work Queue
- Transfer Credits

Applications:

- Customer Service System (CSS)
- MS Great Plains
- ScotiaConnect

Figure 5.41 - Returned Payments



Process Name: Revenue Protection

Process Description: The process of identifying and preventing loss of revenue from technical (equipment failure) and/or non-technical (meter tampering) issues.

Process Owner(s):

Group: Customer Relations

Frequency: Daily/Monthly

Volume: Approximately 800 (2018)

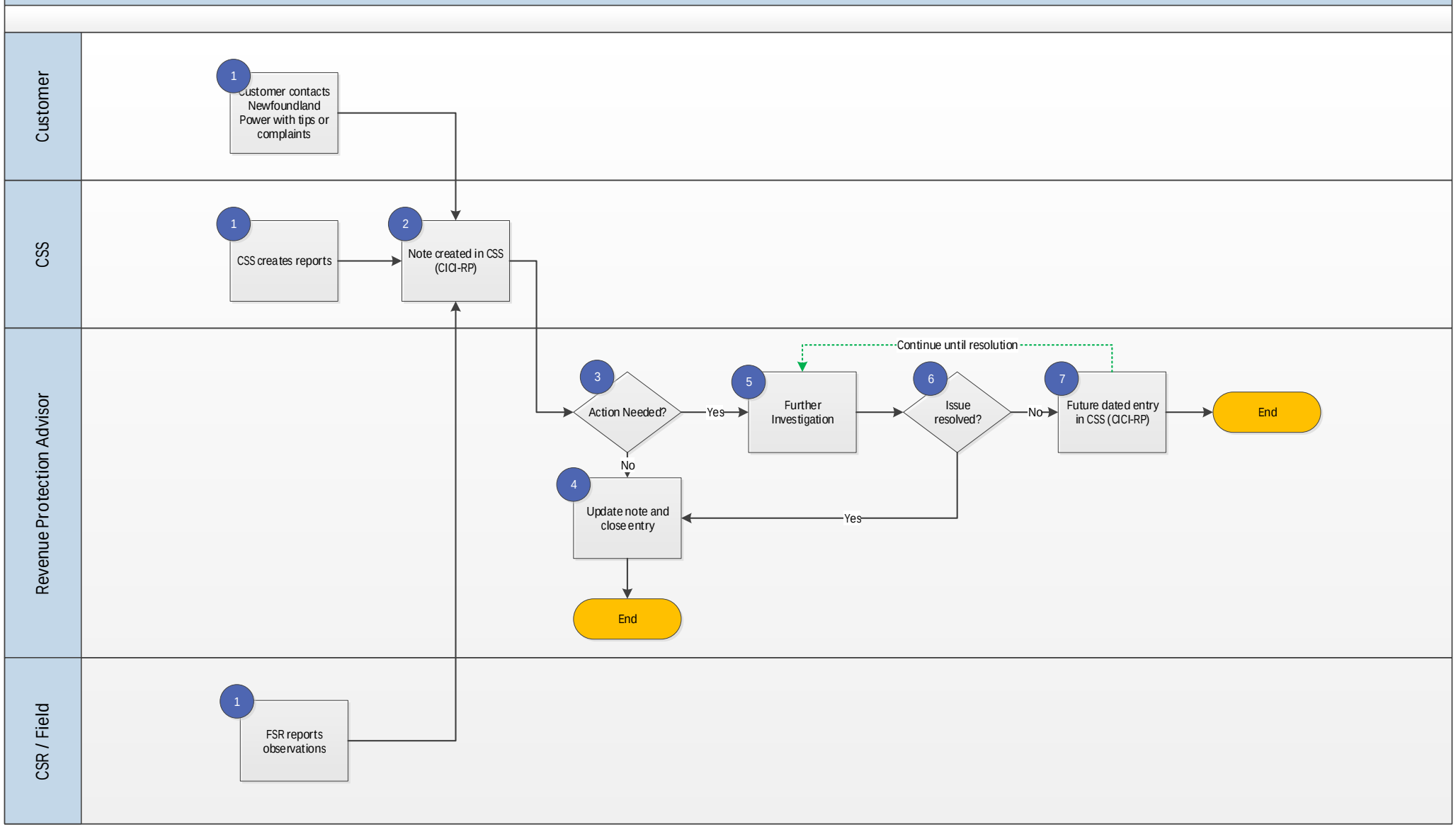
Related Process:

- Credit and Collections – General Service
- Credit and Collections - Residential
- Disconnect/Reconnect for Debt
- Service Orders
- Meter Reading
- New Customer Set-up
- Move in/Move out
- Pending Work Queue

Applications:

- Customer Service System (CSS)
- Metering Equipment System (MES)
- Meter Reading Spreadsheets
- Access Control Language (ACL) Reports
- Service Order Spreadsheets
- Technical Work Requests (TWR)
- Responder
- Meter log book

Figure 5.42 - Revenue Protection



Process Name: Security Deposits

Process Description: The process of initiating, approving, maintaining and refunding security deposits for customers. Security deposits are applied to: a) General Service Rate or b) a Limited Liability Company (LLC) that is responsible for a domestic rate.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: 650 (2018)

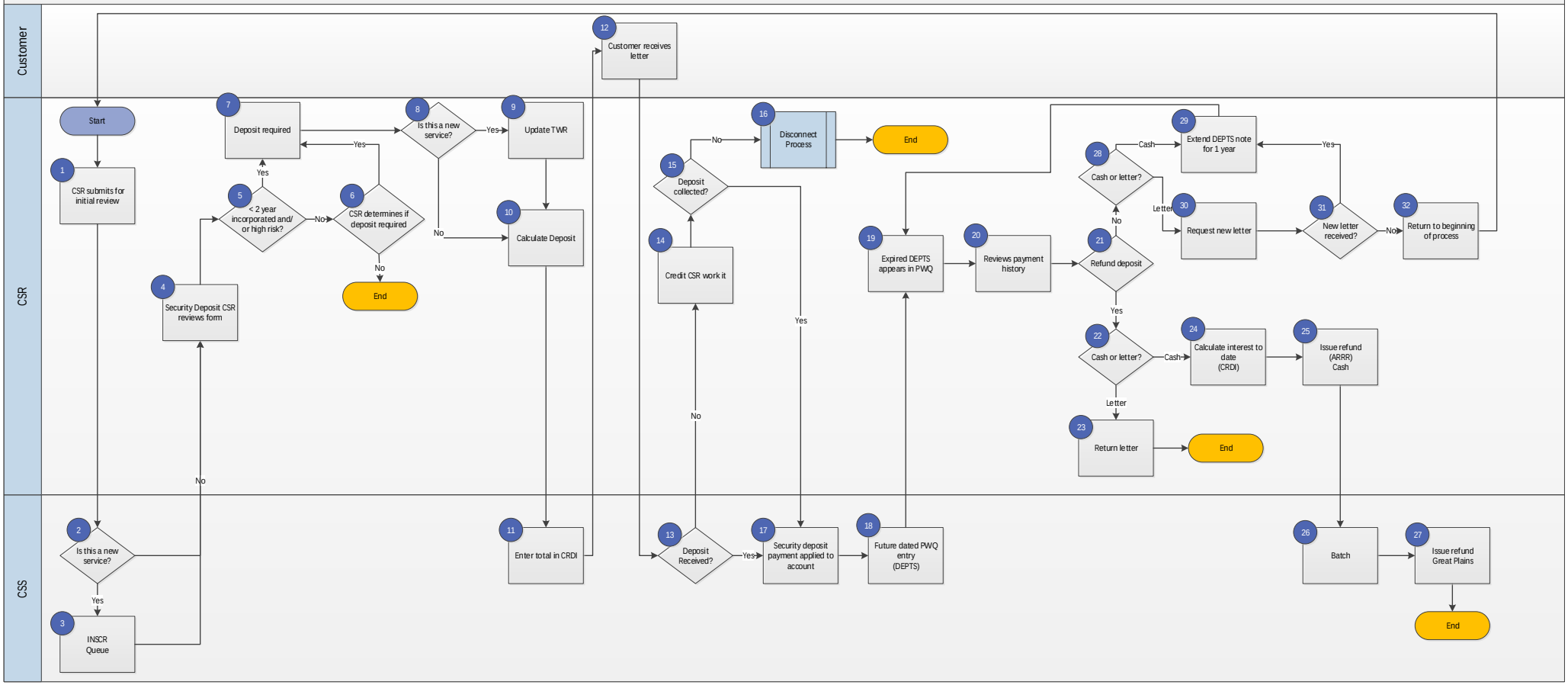
Related Process:

- New Customer Set-up
- Service Orders
- Credit and Collections - General Service
- Credit and Collections - Residential
- Move in/Move out
- Landlord Agreements
- Pending Work Queue
- Nightly Batch

Applications:

- Customer Service System (CSS)
- Technical Work Requests (TWR)
- Security Deposit Calculator Spreadsheets
- Webster – Sharepoint Form
- MS Great Plains

Figure 5.43 - Security Deposits



Process Name: Sensitive Customer Protocol

Process Description: The process of identifying the level of risks of a customer and/or premise to ensure the safety of Newfoundland Power employees.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Low (Approximately 135 customers)

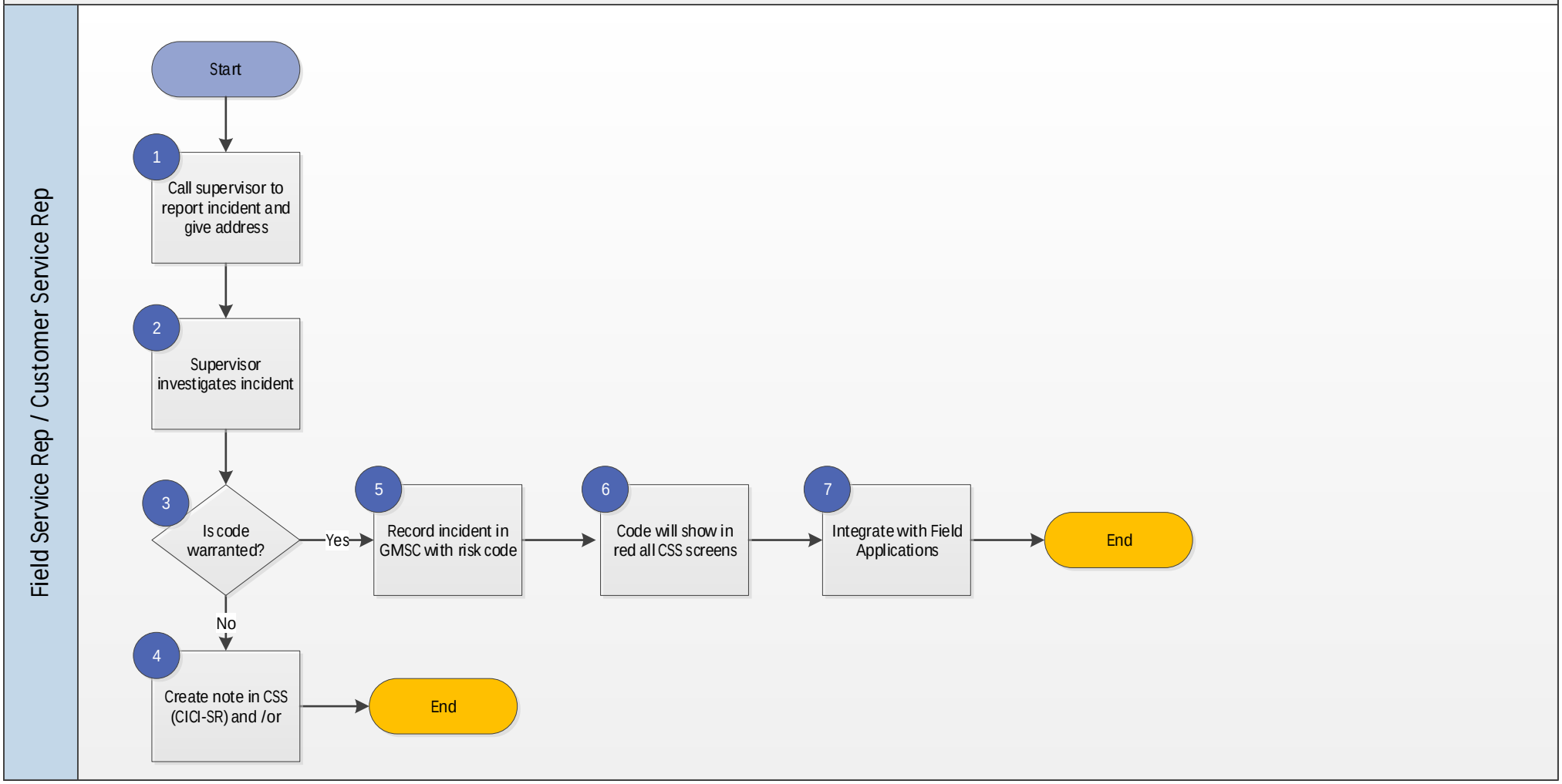
Related Process:

- Credit and Collections – General Service
- Credit and Collections - Residential
- Service Orders
- Disconnect/Reconnect for Debt

Applications:

- Customer Service System (CSS)
- Responder

Figure 5.44 - Sensitive Customer Protocol



Process Name: Service Orders

Process Description: Service orders represent tasks to be completed by CSRs and field staff and are broken down into three major categories:

CSS Service Order (CSSSO) – Orders completed inside CSS if field information is already available or not needed to process request

Field Work Service Order (FWSO) – Orders requiring action by non-customer service staff (line crew, technical designers, etc.)

Customer Service Service Order (CSSO) - Orders requiring action by Customer Service staff (meter readers, field staff, etc.)

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Approximately 95,000 annually

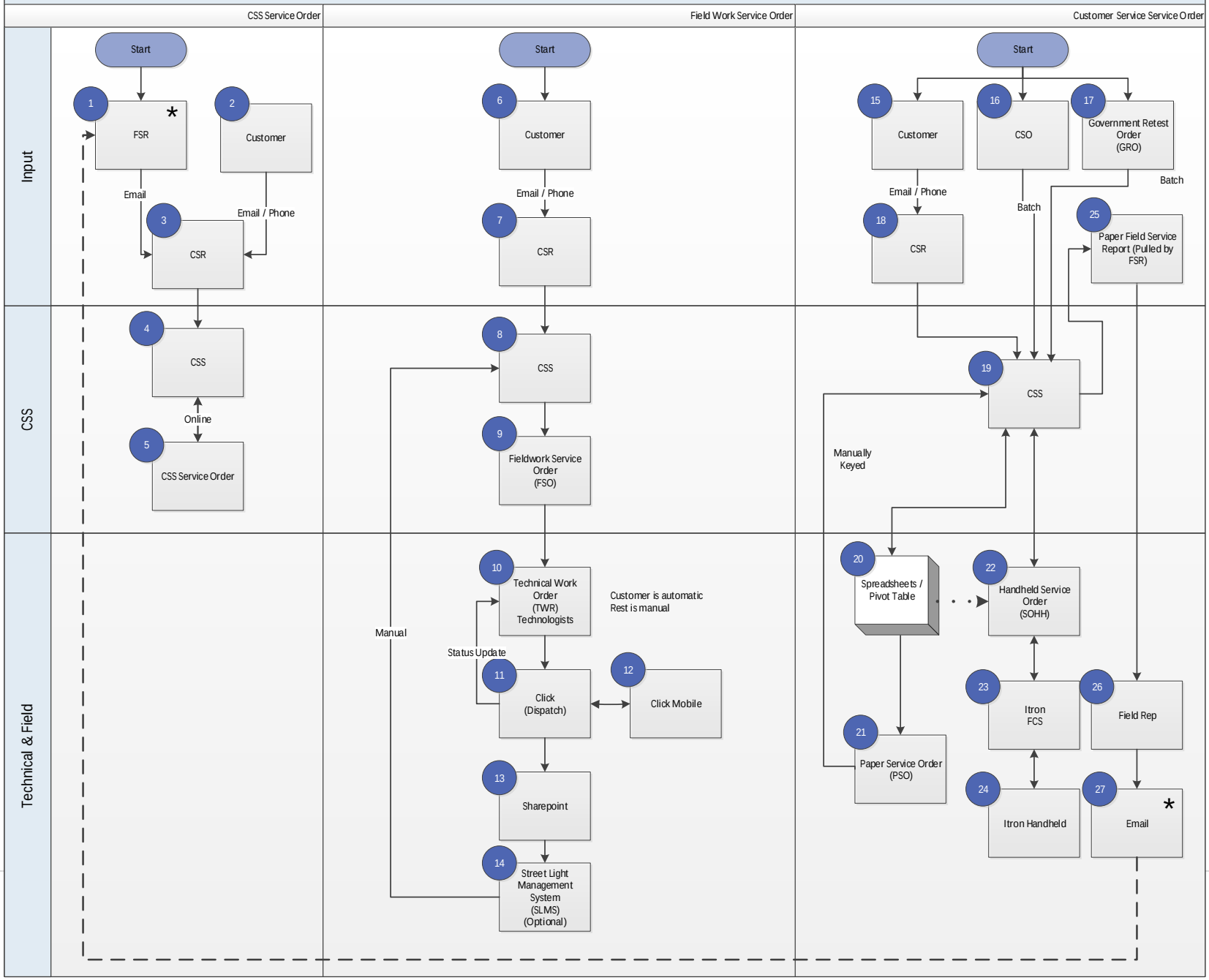
Related Processes:

- Nightly Batch
- Process Payments

Related Applications:

- Technical Work Requests (TWR)
- Click
- Click Mobile
- Sharepoint
- Itron (Field Collection Services)
- Spreadsheets/Pivot Tables

Figure 5.45 - Service Orders



Process Name: Transfer Credits

Process Description: The process of transferring credits from one account to another or to the General Ledger (GL) such as misapplied payments, customer requests adjustment, etc.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Approximately 1,600 annually

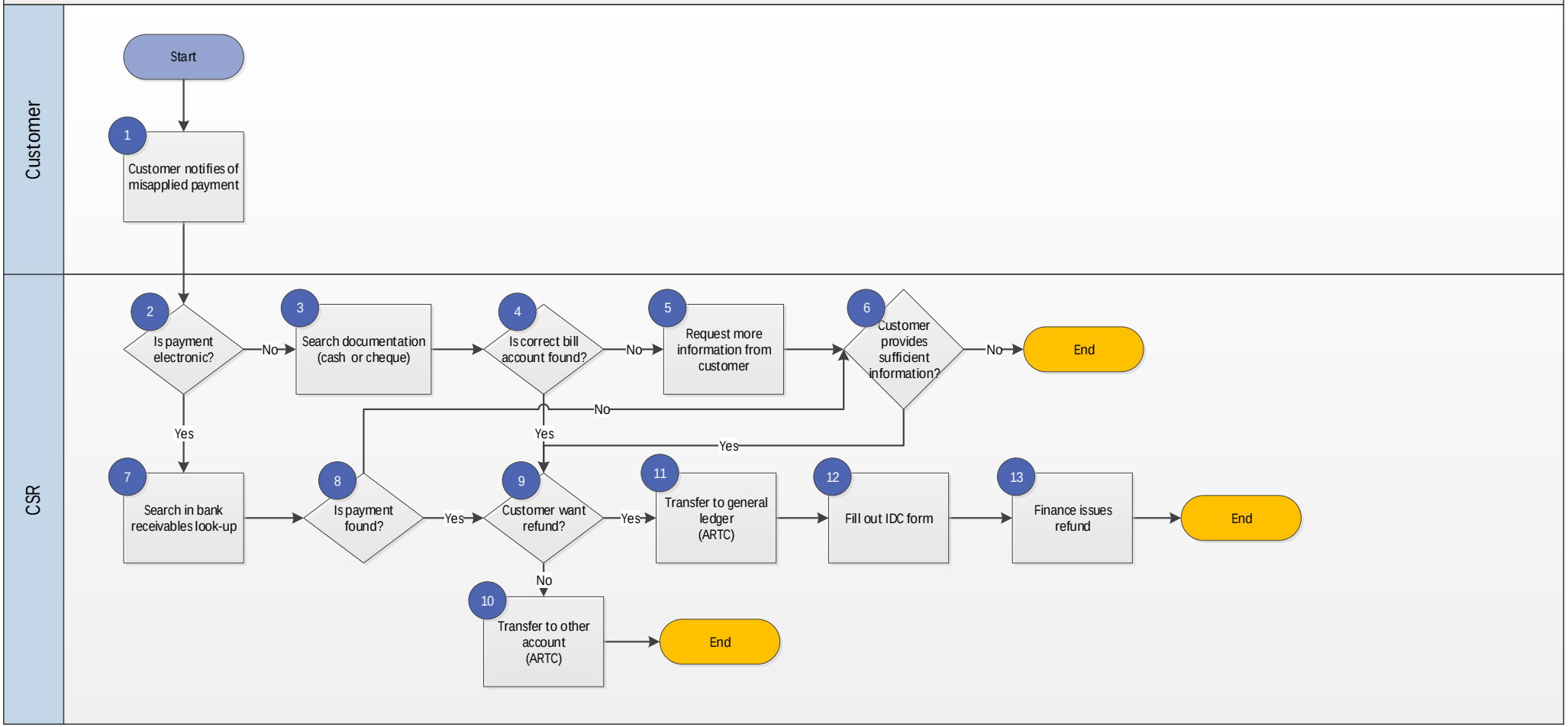
Related Process:

- Bill Calculation
- Process Payments
- Pending Work Queue

Applications:

- Customer Service System (CSS)
- MS Great Plains

Figure 5.46 - Transfer Credits



Process Name: Unmatched Queue

Process Description: Unmatched is referred to when one customer is finalled and there is no other customer assigned to the active premise.

Process Owner(s):

Group: Customer Relations

Frequency: Daily

Volume: Unmatched queue/inquiries annually – Residential 3,200 and General Service 300

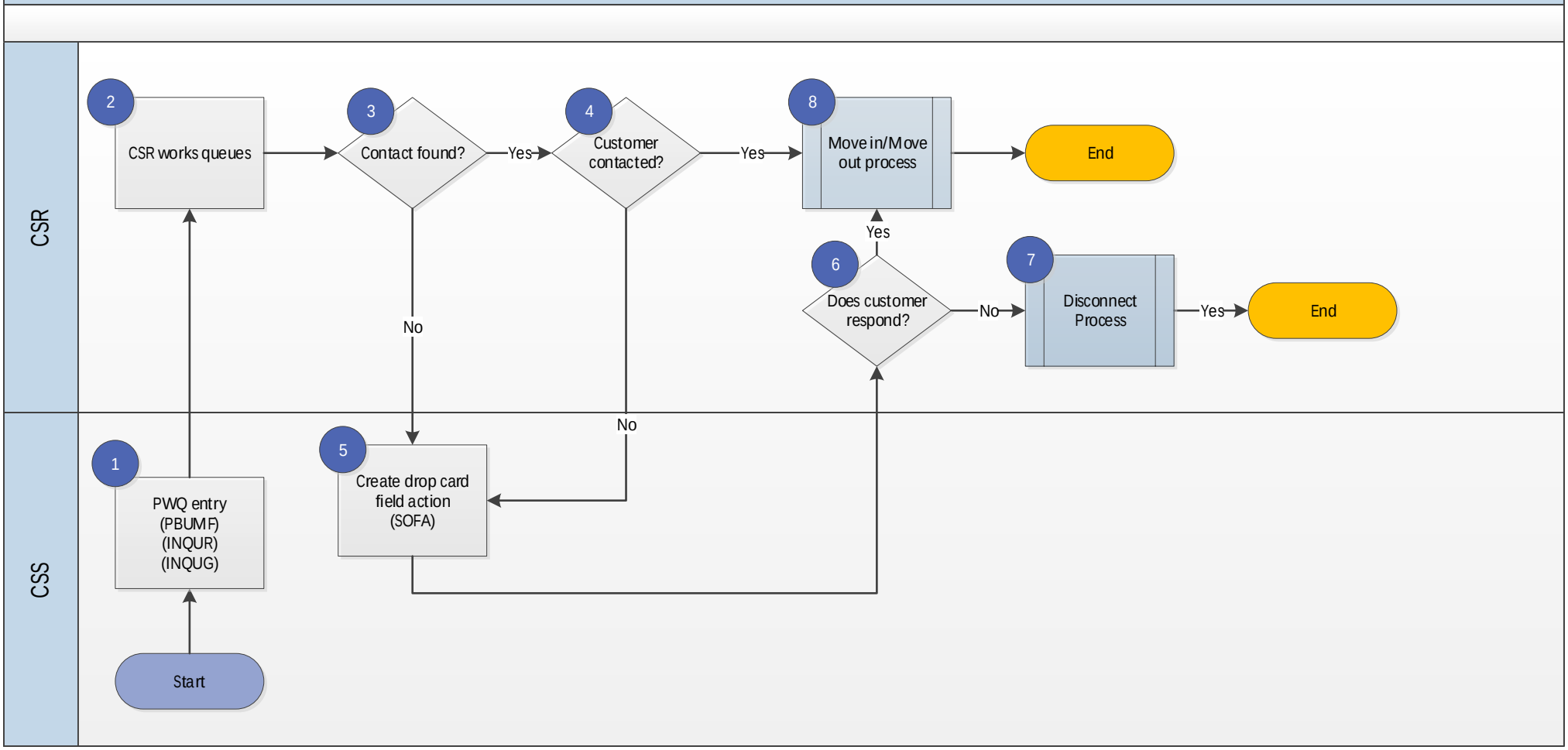
Related Process:

- Move in/Move out
- Credit and Collections – General Service
- Credit and Collections - Residential
- Disconnect/Reconnect for Debt
- Final/Reserve Outstanding (FRO)
- New Customer Set-up

Applications:

- Customer Service System (CSS)

Figure 5.47 - Unmatched Queue



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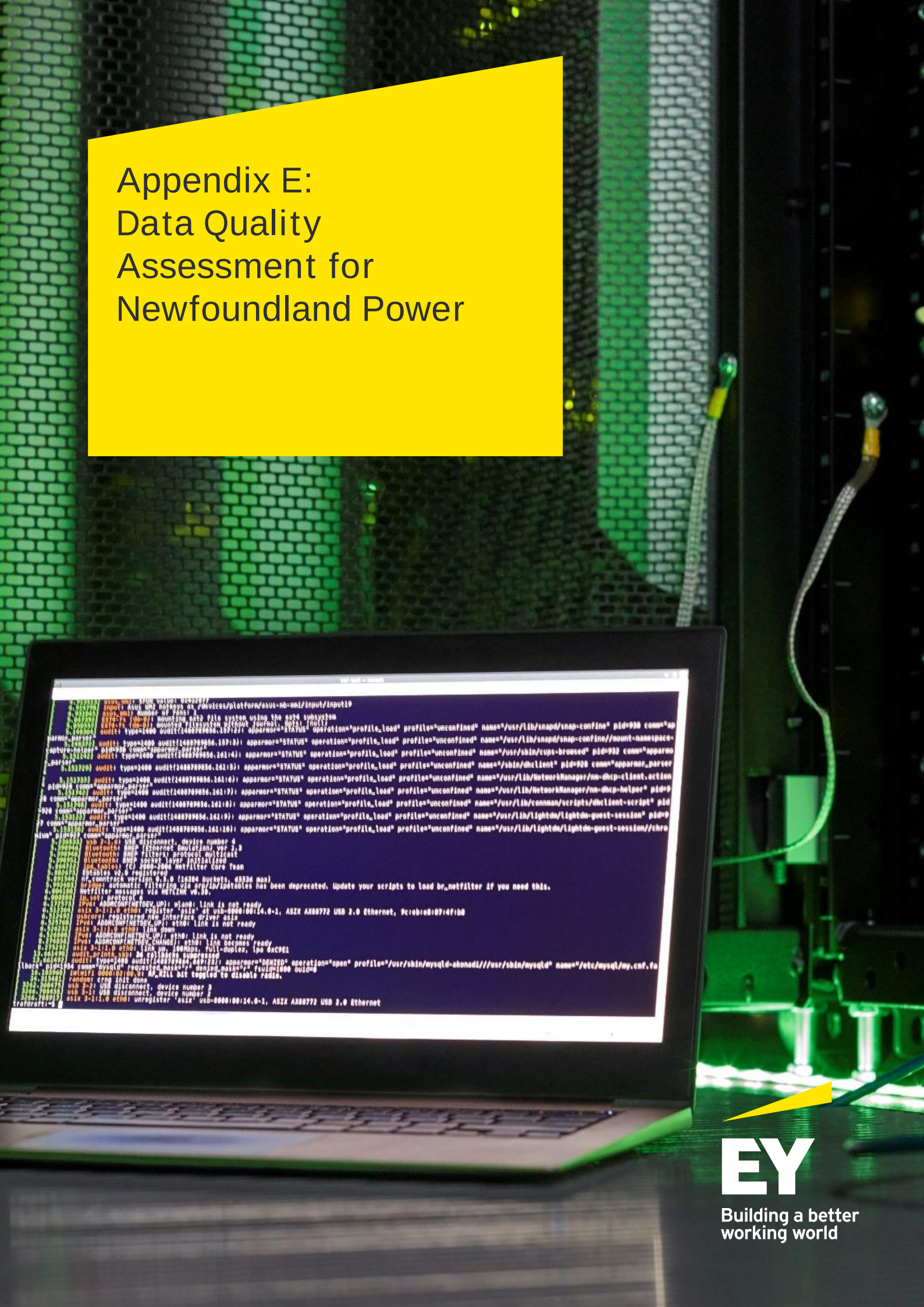
Appendix E: Data Quality Assessment for Newfoundland Power



Building a better working world

Contents

1.0 Introduction

Newfoundland Power's Customer Service System ("CSS") is its primary source of account, customer, premise and meter data. Since the implementation of CSS in 1995, an evolution has occurred in how data is oriented in customer platforms. Customer-centric views of data models in the latest CIS solutions dictate changes in data collection processes and content management. To properly consider the complexity of future state data conversion requirements, it is important to understand current data quality measurements as seen through the lens of a modern CIS.

In EY's experience, an assessment of data quality is a high-value pre-implementation activity to initiate required remediation in advance of a replacement system to reduce execution project risks. The purpose of the data assessment was to quantify and prioritize the business impacts of data quality issues within CSS to support a future CIS replacement. Examples of data quality issues may include multiple versions of the same data, invalid or missing data, out-of-date data, or data that falls outside expected ranges.

2.0 Approach

EY's Data Conversion Specialist, experienced in implementing various CIS software products, conducted a multi-day workshop with key Newfoundland Power IT personnel to understand the current data architecture and active data remediation activities that have been completed or are in the process of being completed by Newfoundland Power. These workshops were held in May 2019.

The data assessment approach consisted of four stages, as shown below in Figure 2.1, and has been used at multiple utilities evaluating potential replacement options.

Figure 2.1- EY's Data assessment approach

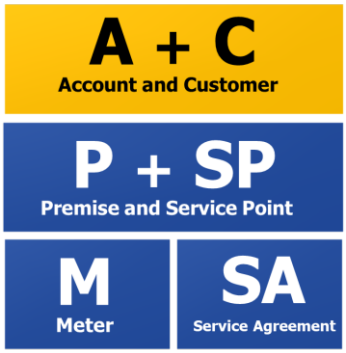
Data Quality Audit	Established Data Ownership and Accountability	Short-term Data Quality Improvement	Longer-term Action Plan
Performed audit to identify data issues by conducting a series of sample queries against data and expected values. The audit also helped capture indicative sizing of any data quality problems and enables Newfoundland Power to understand the extent and potential impact.	Identified data ownership and responsibility for data cleansing. In doing so, Newfoundland Power can prioritize and answer key questions, such as data usage, importance, ownership, validity, etc.	Developed a tactical plan to resolve data quality issues that can be addressed through short-term or end-user-oriented solutions. For example, and where practical, this may be re-keying key customer data or inserting or updating large amounts of data with missing information.	Documented a long-term data cleansing approach, stakeholders and accountability for any data cleansing or remediation tasks, risks and potential impacts.

Source cleaning, such as data quality and integrity, are preliminary indicators of data readiness. Data quality focuses on issues such as inaccurate addresses, duplicate customers, or invalid dates. Data integrity focuses where referential integrity has not been adhered to, such as accounts present with no customer information.

Three main activities were conducted as part of the abridged data quality audit:

- Identified source content for review – EY's approach defined a set of four key elements of data content within legacy CIS platforms as shown in Figure 2.2. Within the scope of the initial assessment efforts, the focus was on Account and Customer data elements. Newfoundland Power will address the remaining data elements as part of the CIS replacement project.

Figure 2.2- Typical CIS Data Elements



- Executed data integrity reports on source data – Newfoundland Power executed 377 queries on customer and account tables to produce data sets used for identification of anomalies.
- Performed analysis on the data integrity reports – EY's Data Conversion Specialist analyzed the results from the reports using two primary methods: data profiling (i.e., identified missing, duplicate, and outlier values) and pattern matching (i.e., identified actual versus expected formats).

3.0 Findings

Based on EY's experience, data quality audit findings for Newfoundland Power scored above average when evaluated against utilities in comparable replacement scenarios. Overall data quality was seen to be "very good" relative to the industry standards that are to be expected for a 25+ year old CSS with elements of specific master data content at levels that approach or exceed "Excellent". Industry standards include: (i) consistency within cardinality rules (i.e., unique IDs), (ii) limited presence of intelligent keys (i.e., primary keys), and (iii) prior remediation efforts indicate active interest in data cleansing.

The initial audit identified a number of items that should be reviewed by Newfoundland Power and EY has suggested short-term remediation activities as shown in Table 3.1 and Table 3.2. EY recommends that Newfoundland Power review and consider remediation activities from the data quality audits.

Table 3.1- Findings from customer data elements

Findings (Customer Data Elements)	Suggested Remediation
• Customer records with no name, 'Individual' customers with company type, 'General Service' customers without company type	• Execute a review of anomalies found and cleanse such that current rules for customer designation are enforced on a universal basis
• Records with birth years more than 100 years ago	• External approach: Use public records to validate customer name against Date of Birth ("DOB") • Internal approach: Add request to validate DOB to standard Customer Service Representative ("CSR") customer contact
• Free form customer title field increases duplicate values (Bishop, Judge, Captain etc.)	• Define a set of standards to be applied for customer title and enforce said standards via data cleansing
• Customers with no active account status	• Review customer number for presence of account activity, and update data records accordingly. Where active status is truly In-Active or Closed, mark data as such
• Potential customer duplication	• Review potential duplicates, using an industry level scoring algorithm to identify true duplication, then use selection to define non-duplicated values

Table 3.2- Findings from account data elements

Findings (Account Data Elements)	Suggested Remediation
• Future dated final read dates/past dated next bill dates • Formatted date fields have dates that are outside of expected ranges	• Perform detailed data analysis to identify correct dates and cleanse or else purge records from database
• Current data fields support latitude/longitude and not GPS	• Use industry standard formatting for defining fields for GPS position content
• Incorrect Standard Industry Classification ("SIC") codes and other meter content	• Reload SIC codes for ANSI standard database environments for manufacturer, model and other demographic device content
• Incorrect country code formatting on phone numbers	• Enforce via backend process to screen capture for customer phone number, correct formatting for international (+) dialing

In addition to the findings above, Newfoundland Power has proactively initiated three data cleansing activities to address CSS data architecture challenges – service address validation, phone number format standardization, and name/address hygiene.

To support ongoing data cleansing activities in preparation for a potential CIS replacement, EY recommends that Newfoundland Power continue its cleansing efforts on the customer and account data elements and execute and analyze queries on the remaining data elements (e.g., Premise, Service Point, Meter, and Service Agreement). This will help to remediate anticipated challenges common to CIS replacement initiatives.

Upon selection of a CIS software product, Newfoundland Power should further assess:

- Data complexity (i.e., difficulty of transforming present data into a state usable by the future solution)
- Data completeness (i.e., areas where data critical to the future solution are absent)
- Data uniqueness (i.e., data utilized for processes unique to Newfoundland Power)

Additional data quality best practice activities that should be considered in CSS and during migration are ETL (Extract, Transform, Load) code rationalization, system of record optimization, data archival and retention, and data re-orientation to meet the needs of a customer-centric CIS solution. EY provided a best practice framework, which is provided in Section 5.

4.0 Conclusion

Current state data quality is “very good” relevant to peer utilities. However, consistent with industry experience for CIS implementations, considerable change is still needed to efficiently migrate to a modern CIS platform. In EY’s experience, leveraging a data quality framework to further analyze data quality is a critical success factor for a CIS replacement project. By focusing on data readiness to identify and mitigate potential issues now, Newfoundland Power is taking a prudent step to de-risk a future CIS implementation.

Data requirements cannot be fully addressed until a software product is selected. At that time, further data readiness activities to determine how the chosen solution will address Newfoundland Power’s data complexity, data completeness and data uniqueness will need to be conducted.

5.0 Attachments

Table 5.1- Best practices for data quality continuance effort

Source Cleaning	1. Name & Address Hygiene An independent data quality initiative performed within the existing CIS environment to provide a common format for customer contact and primary identification data content.
	2. Customer De-Duplication and 3. Identity Resolution An independent data quality initiative performed within the existing CIS environment to address issues determined to exist regarding duplicated customer data.
Platform Optimization	4. Code Rationalization & Simplification An activity performed during the extraction from the legacy source applications to address primary formulaic transformation.
Source of Truth Inventory	5. Becomes a Single Source of Truth Platform becomes the central repository for customer information.
	6. Determination of System of Record Inventory Includes auxiliary platform optimization (edge apps) system inventory.
Data Remediation	7. Archival Cleansing An initiative performed in order to create a common source where old data, that should no longer be stored, is removed from data storages.
	8. Data Retention Policy Performed as a secondary common source task to define rules on what data should be retained and deleted moving forward.
Post Cleaning	9. Customer Data Re-Orientation An initiative performed to reorient data content to represent a customer facing view, rather than the current premise centric view.
Future State	10. Financial Data Re-Orientation Initiative performed to build the modern database view of the aggregate customer and rates related data from a financial perspective in accordance modern utility data practices.

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Appendix F- EY resource qualifications

Building a better working world

Richard Charles
Principal
Leader, Customer and Enabling Technology in Power & Utilities Advisory Services

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Avista Energy
Central Hudson Gas & Electric
Cleveland Water
Consolidated Edison
Direct Energy
Duke Energy
Eversource Energy
Madison Gas & Electric
Newfoundland Power
San Diego Gas & Electric
WEC Energy

Education
B.S, Electrical Engineering – Northwestern University
M.B.A. – Kellogg Graduate School of Management

Professional experience summary

Richard is a Principal in the Advisory Services practice of Ernst & Young LLP focused on the Power and Utilities sector. He leads EY's Customer and Billing Transformation solution for Power and Utilities, focused on the processes, skills and enabling technologies required to improve customer satisfaction and engagement. He has more than 30 years of experience working with utilities, energy retailers and suppliers to the industry. This breadth of experience has given him a deep understanding of utility operations, regulatory and compliance regimes, and the key trends shaping the industry today.

Since 2000, his primary focus has been the intersection of the customer and technology within investor-owned and municipal utilities. Richard has worked with over 12 large investor-owned utilities to develop CIS strategies (e.g., risk mitigation, extension and replacement).

He is a frequent author and speaker on IT and CIS strategy. Richard has provided regulatory testimony support in the US and Canada to justify CIS initiatives.

Relevant engagement experience

- Currently co-leads the CIS implementation project at Central Hudson Gas & Electric.
- Conducted the CSS risk review for NL Power in 2018, which documented the risks associated with the foundational technologies used to implement the current in-house supported and maintained CSS.
- Led the CIS business case evaluation and CIS pre-implementation projects at Central Hudson Gas & Electric. Workstreams included developing the governance model, evaluation the data quality, assessing change management impacts, creating customer journey maps, and developing future business requirements.
- Led an initiative to transform a large retail energy provider's customer care and billing operations through the evaluation and selection of a new CIS, the supporting technologies, and the systems integrator; provided regulatory support and ongoing executive coaching during the implementation.
- Helped develop a CIS extension and mitigation strategy for a large northeast utility serving over 4 million electric, gas and steam customers.
- Led the meter-to-cash evaluation for a large multi-state gas retailer, which included developing requirements, creating the RFP, evaluating responses and assisting with negotiations.
- Helped developed a CIS roadmap for a large midwestern utility serving over 6 million electric and gas customers.
- As president of Five Point, nurtured the development of its Advisory services practice into a leading IT strategy provider, focused predominantly on CIS/CRM; these capabilities, along with the balance of Five Point's utilities practice were successfully transitioned to EY in May 2014.
- As Head of Client Services at Vertex Business Services, was responsible for the delivery of meter-to-cash services to a portfolio of over 50 utility clients.

Chris Balish
Senior Manager
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Cobb EMC
ConEdison
Direct Energy
Exelon
Gas South
Georgia Natural Gas
Newfoundland Power
Sask Power
USG&E

Education
B.S Finance – Virginia Tech
M.B.A. – George Mason University

Certification(s)
Project Management Professional (PMP))

Professional experience summary

Chris Balish is a Senior Manager in the Advisory Services practice of Ernst & Young LLP, with over 15 years of experience in the Power and Utilities industry.

Chris has strategic advisory, implementation, and managed services experience in both regulated and deregulated markets with significant Customer Information System (CIS) and Solution Procurement experience across multiple platforms and products.

Relevant engagement experience

- Led deployment strategy of a global SAP Enterprise Resource Planning (ERP) system to 138 countries, including methodology development, deployment planning and readiness, and PMO engagement management activities.
- Led PMO activities of a highly complex $60M+ risk remediation healthcare engagement, including commercial contracting, resourcing, financial reporting, risk management, and invoicing.
- Led the multi-jurisdiction implementation of an Oracle Customer Care and Billing (CC&B) customer information system at one of the largest water utilities in the US; responsible for all aspects of the engagement including contract negotiation, project delivery, issue resolution, and P&L management.
- Led the evaluation and selection process of a retail energy software suite solution for a natural gas and electricity energy service company (ESCO) retailer operating in 11 states and 54 markets nationwide.
- Managed the strategic CIS application planning services of a multiple operating company, multi-million customer electric and natural gas investor owned utility to evaluate replacement strategies and recommend a consolidated solution.
- Led the evaluation and procurement of a modern CIS system for a multi-jurisdictional electric and natural gas investor owned utility serving over 1.4 million customers.
- Managed quality assurance activities for a three-year modern CIS implementation initiative.
- Co-managed the evaluation and selection process of an international multi-million customer electric and natural gas energy marketer to replace their legacy CIS system and negotiate a full BPO outsourcing agreement.
- Conducted a pre-implementation go-live readiness assessment for a 460,000-customer electric utility to provide validation that its new SAP CIS was positioned for a successful implementation.
- Managed an expedited evaluation and selection process of a global CIS to replace the legacy and shared systems for a multi-million customer natural gas utility.
- Managed full Business Process Outsourcing (BPO) relationship of a multi-year outsourcing agreement on the Nexant Revenue Manager platform in the Texas deregulated electric market with P&L responsibility for $20M in annual revenue.
- Led business integration effort to assimilate a 160,000-customer natural gas utility onto a new Oracle based CIS with negotiated outsourcing services.
- Directed the day-to-day CIS Operations of a 500,000-customer natural gas retailer, including application development, defect management, and system operations.

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Cobb EMC
California Water
Cleveland Water
City of Long Beach
City of Phoenix
Southern Company
Albuquerque Water Authority
Madison Gas & Electric
AQUA

Education
B.Sc, Major Biology (Meerut / Chaudhary Charan Singh University
B.Ed, Bachelor in Education (MDU Rohtak , Haryana , India)
M.Ed, Master in Education) (MDU Rohtak, Haryana, India)

Certification(s)
Oracle Certified Associate
Project Management Professional

Professional experience summary

Sukanya Sirohi is a Manager in the Technology Solution Delivery practice of Ernst & Young LLP with over 15 years of providing technical advisory to utilities on wide variety of CIS implementations including architecture design, infrastructure set up, installations and development.

Sukanya has strong development skills where she has done extensive work using varying languages including SQL, PL/SQL, ABAP (ECC 6.0 IS-U 600), Shell Scripting using Unix and ant, python, wlst, C++, Pascal, crystal reports, SOA Suite BPEL composites.

Sukanya has expertise in implementing various CIS solutions including Oracle, SAP and Banner (Advantage).

Relevant engagement experience

- Technical Architect supporting a Northeast utility helping with the conversion of their legacy CIS system to Oracle CC&B as well as MDM, SOM and ODM capabilities of Oracle C2M. She is responsible for analyzing and building the system architecture, installing and patching the edge applications, setting multiple environments, performance tuning the solution and other components of the technical aspects of the implementation.

- Technical Lead at a large Electric/Gas utility company in the Southeast in their CIS Consolidation project. Responsible for analyzing and building the architecture environment, installing and patching the applications and managing all environment related issues.

- Technical Lead for a Southwest water utility where she was responsible for setting up the Oracle Utilities Field Work PIP 12.1 between CCB 2.4 and MWM 2.1. She was responsible for installing, configuring the PIP (12.1) environments, customizing the SOA composites, performance tuning and resolving any issues in the integration.

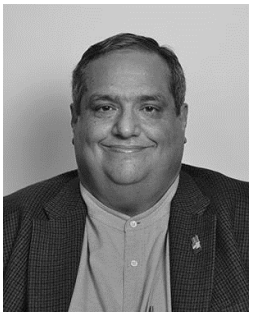
- Technical Lead for Northeast utility and installed and integrated their WAM systems to the Oracle ERP systems.

- Technical team member at a Westcoast water utility where EY upgraded their CCB system from 2.3 to version 2.5 from windows platform to Linux and database version from 11g to 12c.

- Technical Architect supporting a Westcoast utility in their final last months of upgrade to Oracle CCB 2.4. Helped in resolving performance issues for go live. Supported with SQL and PL/SQL stored procedure issues.

- Technical team member for a gas utility company which implemented the SCT Banner (advantage) product when the market deregulated.

- Technical team member for water utility organization as part of the implementation of SAP that replaced their legacy product. She was responsible correcting defects in their production system and performing other development activities and managing projects.



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Madison Gas & Electric
ConEdison
ONCOR
California Water Services
Irvine Ranch Water District
Golden State Water Company
Exelon
Terasen Gas (2010)
TRUenergy
Xcel Energy
Arizona Public Service
Disney Corporation
Atmos Energy
Golden State Water Company
ASIC - Australian Securities Investment Commission
TimeWarner/AOL

Education
B.S Natural Sciences and Mathematics- SUNY at Buffalo
M.B.A. – University of Houston

Professional experience summary

Steve Shavel is a Manager in the Technology Solution Delivery practice of Ernst & Young LLP with a significant emphasis on the delivery of data conversion solutions for CIS implementations.

Steve has been a Data Conversion Analyst for over 20 years with primary experience in the Oracle Customer to Meter (C2M) platform (formerly CC&B) data conversion for 18 separate CIS projects.

Relevant engagement experience

- Data Conversion Lead for implementation of C2M at MGE in Madison, WI. This is an ongoing project delivery effort, with a total of 7 Mocks having been planned for including the pre-project delivery of Mock Zero, (Sep 2019) which allowed access to customer data inside of CC&B within 3 months of project inception.

- Data Conversion Lead for a Tier-1 water utility in the San Francisco Bay Area. Developed the data conversion strategy for CC&B deployment, including the execution of 10 separate mock conversions, Dress rehearsal and final conversion cutover. Data quality for conversion of over 1.4 billion records.

- Functional Conversion Advisor for a mid-market water utility in southern California. Developed data conversion strategy for CC&B deployment and helped to provide supervisory assistance for a team of offshore and onshore resources; target was Oracle CC&B v2.4.1.

- Data Conversion Lead for a large western US based electrical Utility during their platform consolidation and system transformation in support of the retail electricity market in the 9 US states that they provide customer service in.

- Data Conversion Lead for large Northeastern based Electric and Gas Utility during its platform consolidation across 5 NE states.

- Data Conversion Lead for a large southern utility during its asset management system transformation across 14 power plant and other generation support systems consolidation.

- Data Conversion Lead for a large Boston-based municipal Electric and Gas Utility during its systems consolidation following merger with its primary competitor.

- Data Conversion Lead for multi-national European electrical provider.

- Data Conversion Lead for a large Midwestern Electric and Gas provider during its systems consolidation.

- Data Conversion Lead and on-site project manager for a large utility delivery in Melbourne, Australia; target was Oracle CC&B v2.2.1.

- Data Conversion Lead for a large Texas based natural gas provider in their acquisition of legacy customer population and its subsequent conversion into their target CIS platform; target was Banner / CIS v4.x

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Attachment B

Newfoundland Power Inc. Customer Experience Report

Customer Experience Report

June 2020

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Executive Summary

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") existing customer service technology is at risk of becoming obsolete. The Company is proposing to replace this technology with a modern Customer Information System.

A modern Customer Information System will provide long-term continuity in Newfoundland Power's customer service delivery. As part of developing its *Customer Service Continuity Plan*, the Company assessed the overall effectiveness of its service delivery in meeting customers' expectations and opportunities to better serve customers in the future.

The overall effectiveness of Newfoundland Power's customer service delivery was assessed based on 8 key performance metrics. These metrics show: (i) the Company provides a timely response to customers' service requests and enquiries; (ii) customers are satisfied with Newfoundland Power's service delivery; and (iii) costs per customer have been reduced by 31% over the last 2 decades.

In Newfoundland Power's view, this performance is consistent with meeting customers' service expectations at least cost.

Customers' service expectations evolve over time. Enhancing the information and services available to customers is necessary to continue meeting their expectations.

Newfoundland Power has identified a total of 29 potential future enhancements to its customer service delivery. These include enhancements to customer communications and services available on the customer website, among others. Many of these enhancements are the direct result of the capabilities provided by a modern Customer Information System.

The costs and customer benefits of these enhancements will be assessed over multiple time horizons. Over ½ of the identified enhancements will be assessed over the short term as part of procuring a replacement system.

2.0 Background

Customer service delivery is a principal business function of Newfoundland Power. The primary technology underpinning the Company's customer service delivery is its Customer Service System ("CSS"). CSS supports all essential customer service functions, including: (i) program and service delivery; (ii) account management and billing; and (iii) customer communications and contact management.[1]

CSS is facing risks of becoming both technologically and functionally obsolete.[2] Newfoundland Power developed a framework to assess and plan for replacing CSS in 2018.[3] Among other provisions, the framework outlined a requirement to review existing customer service business processes and opportunities to better serve customers in the future.[4]

Newfoundland Power executed the assessment and planning framework over the period 2018 to 2020. The Company reviewed its customer service business processes,[5] assessed the overall effectiveness of its service delivery in meeting customers' expectations, and identified opportunities to better serve customers.

The overall effectiveness of Newfoundland Power's service delivery in meeting customers' expectations was assessed based on key performance metrics. Section 3.0 provides the results of this assessment.

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1 For more information on customer service delivery at Newfoundland Power, see Section 2.1 of the *Customer Service Continuity Plan.*

2 For more information on the technical and functional risks facing CSS, see Section 2.2 of the *Customer Service Continuity Plan.*

3 This assessment and planning framework was provided as Attachment A to Request for Information PUB-NP-008 filed as part of Newfoundland Power's *2019/2020 General Rate Application.*

4 See Request for Information PUB-NP-008 (Newfoundland Power's *2019/2020 General Rate Application*), Attachment A, page 13, *et seq.*

5 See Appendix D to Ernst & Young LLP's *Customer Information System: Assessment Results and Planning Recommendations*.

A structured Customer Journey Mapping exercise was facilitated by Ernst & Young LLP ("EY") to identify specific opportunities to better serve customers in the future.[6] EY recommended Newfoundland Power prioritize these opportunities for further assessment over the short, medium and long term.[7] Section 4.0 summarizes the opportunities identified and the priority assigned to each.

Appendix 1 to this report provides the results of customer focus groups and interviews completed as part of this assessment and planning work.

3.0 Overall Effectiveness of Customer Service Delivery

3.1 General

Newfoundland Power evaluated 8 metrics across 3 dimensions to assess the overall effectiveness of its service delivery in meeting customers' expectations. These include: (i) 3 metrics in relation to service responsiveness; (ii) 4 metrics in relation to customer satisfaction; and (iii) and 1 metric in relation to overall service efficiency.

3.2 Service Responsiveness

Service responsiveness describes the timeliness of Newfoundland Power's response to customers when issues arise. Metrics assessed in relation to service responsiveness include: (i) response time to customers calls; (ii) response time to new service connections; and (iii) restoration time in response to customer outages.

Newfoundland Power aims to respond to 80% of customer calls within 60 seconds. This target is designed to ensure a reasonable level of responsiveness to customers' enquiries.

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[6] The results of the Customer Journey Mapping exercise are provided as Appendix B to EY's *Customer Information System: Assessment Results and Planning Recommendations.*

[7] EY assessed that modern Customer Information Systems ("CIS") *"more readily provide the ability to enhance customer experience as compared to legacy CSS applications."* See EY's *Customer Information System: Assessment Results and Planning Recommendations*, pages 14-15.

Table 1 provides the total customer calls answered annually and the percentage answered within 60 seconds.

Table 1: Customer Calls (2015-2019)		
Year	Total Number of Calls	Answered in 60 Seconds
2019	458,000	77%
2018	470,000	81%
2017	580,000	80%
2016	418,000	82%
2015	427,000	82%

The Company's contact centre responds to approximately 470,000 customer calls annually.[8] On average, approximately 80% of customer calls have been answered within 60 seconds over the last 5 years. This is consistent with the Company's target for ensuring responsiveness to customers' enquiries.

Newfoundland Power aims to complete 85% of new service connections within 10 days. This target is designed to ensure a timely response to connecting new customers.

[8] Reflects the average number of customer calls received annually over the period 2015 to 2019.

Table 2 provides the total number of new service connections completed annually and the percentage completed within 10 days.

Table 2: New Service Connections (2015-2019)		
Year	Total Number Connections	Completed within 10 Days
2019	2,379	85%
2018	2,781	87%
2017	3,271	90%
2016	3,528	87%
2015	3,786	85%

Newfoundland Power completes approximately 3,100 new service connections annually.[9] Approximately 87% of new service connections have been completed within 10 days over the last 5 years. This is consistent with the Company's target for connecting new customers.

Newfoundland Power aims to ensure a reasonable level of responsiveness to customer outages. The Company compares its responsiveness to other utilities using the Customer Average Interruption Duration Index ("CAIDI"). CAIDI measures the average time it takes to restore service to customers following an unscheduled outage.[10]

[9] Reflects the average number of new service connections completed annually over the period 2015 to 2019.

[10] CAIDI is the restoration time measure used by the Canadian Electricity Association. In arithmetic terms, CAIDI is expressed as outage duration ("SAIDI") / outage frequency ("SAIFI").

Table 3 compares Newfoundland Power's CAIDI to the Canadian Electricity Association average for the period 2015 to 2019.[11]

Table 3: CAIDI (2015-2019)		
Year	Newfoundland Power	Canadian Average
2019	1.5	2.9
2018	1.5	2.4
2017	1.4	2.6
2016	1.7	2.2
2015	1.4	2.2

Newfoundland Power's CAIDI has been approximately 40% less than the Canadian average over the most recent 5-year period.[12]

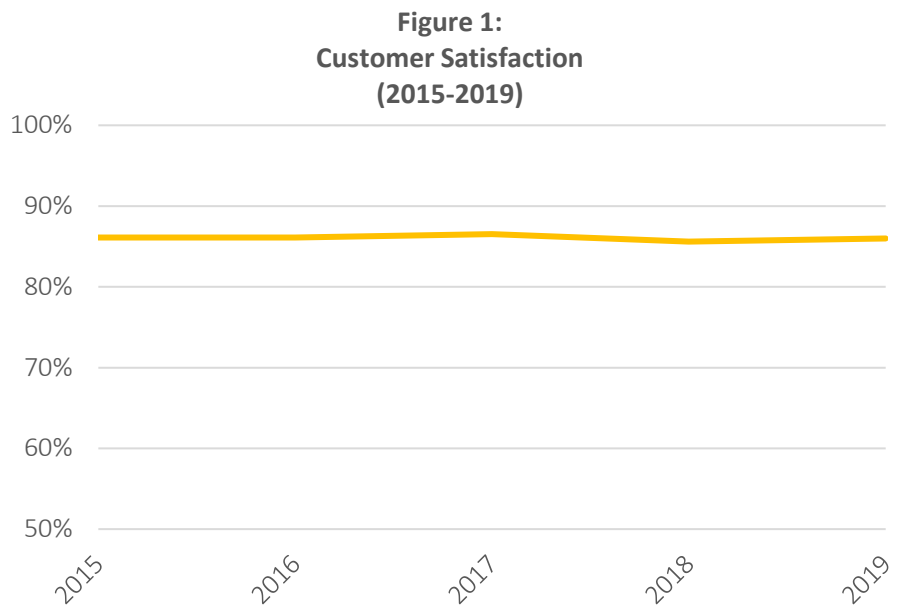
3.3 Customer Satisfaction

Newfoundland Power surveys its customers quarterly to obtain a broad indication of customers' satisfaction with the Company's service delivery. Approximately 1,800 customers are surveyed each quarter. These include customers who recently interacted with Newfoundland Power and those who had no contact with the Company. This approach permits satisfaction to be measured both overall and on a transactional basis.

[11] The Canadian Electricity Association average reflects Region 2 utilities. Region 2 utilities include Canadian utilities that serve a mix of urban and rural markets.

[12] Over the period 2015 to 2019, Newfoundland Power's average CAIDI was 1.5 and CEA average was 2.5 ((1.5 – 2.5) / 2.5 = -0.40, or -40%).

Figure 1 shows customers' overall satisfaction level with Newfoundland Power's service delivery over the period 2015 to 2019.



Customers' overall satisfaction with the Company's service delivery has averaged approximately 86% annually over the last 5 years. This is consistent with longer-term trends.[13]

Transactional satisfaction is measured by surveying customers who recently interacted with the Company via the phone, website or in the field.

Satisfaction is higher among customers who recently interacted with Newfoundland Power. Over the same 5-year period, satisfaction levels averaged approximately: (i) 92% for customers who interacted with Newfoundland Power via the phone; (ii) 89% for customers who interacted with the website; and (iii) 92% for customers who interacted with employees in the field.

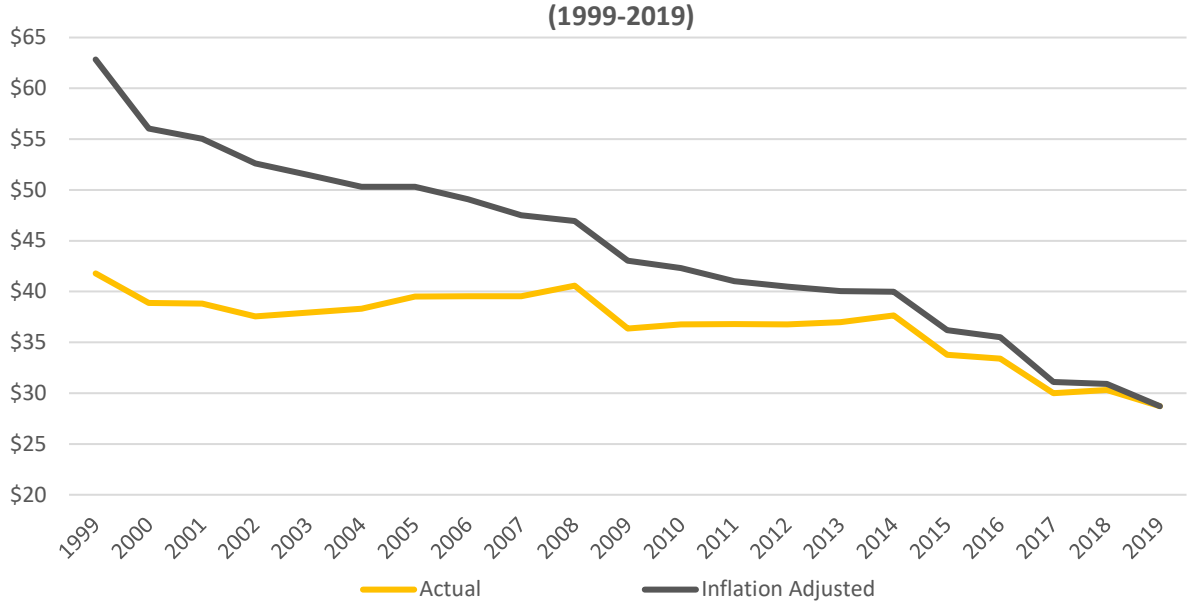
[13] Overall satisfaction with Newfoundland Power's service delivery averaged approximately 86% over the last decade (2010 to 2019).

3.4 Overall Service Efficiency

Newfoundland Power assessed trends in its Customer Service costs per customer over 2 decades to assess its overall service efficiency.

Figure 2 shows Newfoundland Power's Customer Service costs per customer over the period 1999 to 2019.[14]

Figure 2:
Customer Service Costs per Customer
(1999-2019)



On a per-customer basis, Newfoundland Power's Customer Service costs were 31% lower in 2019 compared to 1999. When adjusted for inflation, per-customer costs were 54% lower over the same period.[15]

[14] Customer Service costs, as shown in Figure 2, do not include costs associated with uncollectible bills expense or customer conservation programs.

[15] Customer service costs were approximately $41.8/customer in 1999 and $28.7/customer in 2019 (($41.8 - $28.7) / $41.8 = 0.31, or 31%). In 2019 dollars, customer service costs were approximately $62.9/customer in 1999 (($62.9 - $28.7) / $62.9 = 0.54, or 54%)

3.5 Observations

Newfoundland Power's current approach to customer service delivery is consistent with meeting customers' service expectations.

The Company's operations are responsive to customers. Targets for service responsiveness within the Customer Contact Centre and field operations are consistently achieved. The restoration time following customer outages is approximately 40% less than the Canadian average.

Customer satisfaction with Newfoundland Power's service delivery remains consistent. Satisfaction is higher among customers who recently interacted with the Company via the telephone, website or in the field.

Newfoundland Power's customer service delivery is efficient. The Company reduced its Customer Service costs per customer by ½ on an inflation-adjusted basis over the last 2 decades

4.0 Enhancements to Customer Service Delivery

4.1 General

Newfoundland Power reviewed the strengths and weaknesses of its current approach to customer service delivery through a Customer Journey Mapping exercise facilitated by EY.

The Customer Journey Mapping exercise examined key customer service business processes by:

(i) Completing functional workshops to provide EY with a detailed understanding of customer service delivery at Newfoundland Power;

(ii) Developing "customer journeys" based on interactions that are most common and impactful for customers, such as outage enquiries and payment arrangements;

(iii) Identifying the most likely outcomes for each customer journey based on statistical data and internal expertise, including pain points and delights for customers[16]; and

(iv) Identifying potential future enhancements to customer service delivery based on the customer experience of each journey.

A total of 29 potential future enhancements to customer service delivery were identified by Newfoundland Power. EY recommended the Company prioritize further assessment of these enhancements over the short, medium and long term.

Consistent with EY's recommendation, Newfoundland Power has prioritized all 29 potential enhancements as either:

(i) **Short-term enhancements** that will be assessed during the procurement of a new CIS. Short-term enhancements generally relate to functionality that is standard within a modern CIS. Certain short-term enhancements that do not depend on the implementation of a new CIS are currently being assessed or implemented, as practical.

(ii) **Medium-term enhancements** that will be assessed within 2 years of implementing a replacement CIS. Medium-term enhancements are generally supported by a modern CIS, but would rely heavily on enhancements to other Company systems (e.g. customer website, contact management system).

(iii) **Long-term enhancements** that will be assessed within 2 to 5 years of implementing a modern CIS. Long-term enhancements are expected to have higher complexity based on the potential impact on business processes and other supporting technologies. High-complexity enhancements would be expected to increase the overall risk of a CIS implementation.

[16] Statistical data was used to develop customer personas that serve as representative samples of common customer needs and expectations.

Prioritization of these enhancements included focus groups and interviews with residential and commercial customers in 2020. Additional consultation with customers is planned as part of further assessing these enhancements.

Tables 4 through 6 identify the priority assigned to each potential future enhancement identified through the Customer Journey Mapping exercise.

4.2 Short-Term Enhancements

In total, 16 of 29 (or 55%) of potential future enhancements were prioritized for further assessment over the short term.

Table 4 describes the enhancements to be assessed over the short term.

Table 4:
Potential Future Enhancements
(Short Term)

Enhancement	Description
Live online chat during business hours	Implementation of live online chat commenced in 2020. For more information, see Newfoundland Power's *2020 Capital Budget Application, Report 6.1 Application Enhancements.*
Improved promotion of takeCHARGE programs for commercial customers	Improved promotion of takeCHARGE programs commenced in 2019 with the development of new educational resources for businesses. For more information, see Newfoundland Power's *2019 Conservation and Demand Management Report.*
Increased EPP information on website	The Equal Payment Plan ("EPP") averages customers' monthly bill payments over 12 months so that customers pay the same amount each month. Increasing the information available on this program requires minor enhancements to the customer website.

Table 4: Potential Future Enhancements (Short Term)	
Enhancement	**Description**
Workflows and scripts to provide consistent messaging across all channels	This capability is standard within modern CIS solutions. Workflows and scripts will promote efficiency and consistency in responding to customers' enquiries.
Improve internal system notes/history for CSRs (e.g. reason for high bill)	This capability is standard within modern CIS solutions. Improved internal system notes/history will provide Customer Service Representatives ("CSRs") with better information and promote efficiency when responding to customers' enquiries.
Leverage customer touch points to ensure up-to-date/complete information	This capability is standard within modern CIS solutions. Leveraging customer touch points is an efficient means to ensure up-to-date and complete information for customers' accounts. Up-to-date and complete information ensures accuracy when responding to customers' enquiries.
Real-time information on MyAccount	This capability is standard within modern CIS solutions. The importance of real-time information was noted by customers during focus group sessions. An example would include immediately updating a customer's account balance when a payment is received. Implementing this functionality will require enhancement of the customer website.
Improve MyAccount to allow multiple profiles for each bill account	This capability is standard within modern CIS solutions. Improving MyAccount to allow multiple profiles for each bill account will provide ease of access for customers. Implementing this functionality will require enhancement of the customer website.
Proactive notifications (range of topics identified)	This capability is standard within modern CIS solutions. Proactive notifications, particularly for essential information (e.g. outages) were supported by customers during focus group sessions. Certain proactive notifications are available now as an efficient means of providing information to customers (e.g. outage alerts). Options for increased notifications include changes in customers' usage and new programs.

Table 4: Potential Future Enhancements (Short Term)	
Enhancement	Description
Personalized communication	This capability is standard within modern CIS solutions. Customers indicated a preference for personalized communication during focus group sessions. Personalized communication ensures customers receive information relevant to them via their preferred channel.
360° view of the customer	This capability is standard within modern CIS solutions. A 360° view of the customer ensures CSRs have all relevant information when responding to customers' enquiries. This differs from the current premise-based model of CSS, where relevant customer information can be spread across multiple accounts. A 360° view of the customer will promote an effective and efficient response to customers' enquiries.
Ability to pick your own due date	This capability is standard within modern CIS solutions. The option for customers to select a specific due date for their payments will provide greater billing flexibility to customers.
Automated transfer of all programs when transferring service	This capability is standard within modern CIS solutions. Currently, when a customer transfers their electric service, many programs and services (e.g. Automatic Payment Plan, Customer Outage Notifications) must be transferred individually. This increases the amount of time required to complete a transfer request. Implementing this capability will provide efficiencies as all programs and services would be transferred using automated tools.
Ability to identify accounts associated with small businesses	This capability is standard within modern CIS solutions. Domestic Rate 1.1 includes both residential and small business customers. The current system does not permit accounts for small businesses to be identified. Identifying accounts associated with small businesses will allow CSRs to have better information and be more responsive when addressing customers' enquiries.

Table 4: Potential Future Enhancements (Short Term)	
Enhancement	**Description**
Integrate with Geographic Information System ("GIS")	This capability is standard within modern CIS solutions. The GIS provides location information for electrical system assets and customer premises. Integrating a modern CIS with Newfoundland Power's GIS will provide better information when responding to customers' enquiries, such as outages and customer-driven work requests.
Enhance self-service capabilities (e.g. automation of Move In/Move Out requests)	This capability is standard within modern CIS solutions. Self-service options are an efficient means of responding to customers' enquiries and are consistent with meeting customers' expectations. Currently, certain self-service options require manual intervention from CSRs. This includes Move In/Move Out requests completed via the customer website, which generate an email for further action by CSRs before being completed. Enhancing self-service capabilities will promote further efficiency and responsiveness in customer service delivery. Implementing this capability will require enhancement of the customer website.

4.3 Medium-Term Enhancements

In total, 10 of 29 (or 34%) of potential future enhancements were prioritized for further assessment over the medium term.

Table 5 describes the enhancements to be assessed over the medium term.

Table 5: Potential Future Enhancements (Medium Term)	
Enhancement	**Description**
Online calculator for estimating bills between meter reads	The importance of real-time information was noted by customers during focus group sessions. An online calculator for estimating customers' bills between meter reads will improve access to real-time usage information for customers. This capability will require enhancements to the customer website.

Table 5: Potential Future Enhancements (Medium Term)	
Enhancement	**Description**
Online tools to help customers understand historical usage patterns	The importance of usage-related information to customers was noted during focus group sessions. An online tool to help customers understand historical patterns will provide improved usage-related information to customers. Implementing this capability will require enhancements and CIS integrations to the customer website.
Automated online chat after hours	This capability is an extension of the live online chat feature being implemented in 2020. Implementing an automated online chat feature after business hours would provide an additional means of digital communication for customers. Digital communication channels are consistent with customers' service expectations. This capability will require enhancements to the customer website and Avaya contact centre technology.
Advanced contact routing	Advanced contact routing ensures customers have the option of reaching the same CSR each time they enquire about a particular issue. The importance of reaching a CSR that is already familiar with an issue was noted by customers during focus group sessions. Implementing advanced contact routing will require modifications to the Avaya contact management system.
Pre-population of information when transferring to another agent or supervisor	This capability is standard within modern CIS solutions. Pre-population ensures CSRs and supervisors have ready access to customers' information upon being transferred an enquiry. This capability mitigates the need for customers to repeatedly provide the same details. This is consistent with customers' service expectations, as noted during focus group sessions. Implementing this functionality will require modifications to the Avaya contact management system.
Dedicated CSRs for commercial customers	Currently, CSRs receive training to respond to enquiries from both residential and commercial customers. Introducing CSRs dedicated to serving commercial customers would involve the creation of new positions within Newfoundland Power's operations. It would also require certain business processes to be redesigned and enhancements to the Avaya contact management system.

Table 5: Potential Future Enhancements (Medium Term)	
Enhancement	**Description**
Flexible account management options for commercial customers	This capability is standard within modern CIS solutions. Flexible account management provides commercial customers with multiple accounts the ability to group their electric services by geographic location, business unit, responsible employee or many other characteristics that aid with the management of their electrical service. Implementing this functionality would require changes to existing business processes and enhancements to the customer website.
Enhance self-service options for commercial customers	Current self-service options primarily target residential customers. Self-service options create efficiencies in serving customers and are consistent with customers' service expectations. Opportunities to enhance self-service options for commercial customers include the ability to handle complex aggregation of services and the ability to have multiple website logins with access to specific segments of services. Enhancing self-service options for commercial customers would require enhancements to the customer website.
Semi-annual review/touch point for commercial customers	A semi-annual review/touch point would provide an opportunity to ensure commercial customers' account information is complete and up-to-date. Implementing this capability would involve the creation of a new business process.
Ability to verify identification electronically	Currently, customers are required to present identification in-person at a Company office when setting up a new service. Electronic identity verification would involve using new technology, such as Facetime or Skype, to connect customers with CSRs. This capability would be consistent with customers' expectations for digital communication. Implementing this capability would require enhancement to the customer website and integration to the Avaya contact management system.

4.4 Long-Term Enhancements

In total, 3 of 29 (or 10%) of potential future enhancements were prioritized for further assessment over the long term.

Table 6 describes the enhancements to be assessed over the long term.

Table 6:
Potential Future Enhancements
(Long Term)

Capability	Explanation of Priority
Ability to save website forms while in progress	Forms completed via the website, such as a new service request form, cannot be saved in progress. Customers can be required to input information more than once if a form cannot be completed in its entirety the first time. Implementing this capability would require complex enhancements to the customer website. For example, inputted information would have to be temporarily saved in a database for later retrieval by the customer. This information would have to be linked to a customer's self-service profile and secured so that no other website user would have access to the information.
Ability to set call back times	Implementing this capability would require complex enhancements to the customer website and Avaya contact management system.
Bill redesign (e.g. provide more detail on usage, more user friendly)	The format of Newfoundland Power's customer bills was designed in 2004. The bills are limited in the usage information provided to customers and certain aspects are outdated, such as visuals showing obsolete metering technology. Implementing a bill redesign would permit the opportunity to update the information provided to customers with their bills. This capability would be complex to implement and would require significant modification or replacement of PlanetPress bill imaging and printing technology provided by Objectif Lune.

4.5 Next Steps

Newfoundland Power will further assess potential short-term enhancements to its customer service delivery as part of procuring a modern CIS solution.

Each enhancement will be assessed based on the potential customer benefits, costs to implement, and risk to the overall system replacement project. The costs and benefits of each enhancement will depend, in part, on the solutions proposed by software vendors during the Request for Proposals process.

Potential customer benefits will continue to be validated through customer focus groups and interviews, as required.

Appendix 1

Customer Service Qualitative Research

February, 2020

Customer Service Qualitative Research

Prepared for: NF Power

MQO RESEARCH RECHERCHE

NEWFOUNDLAND POWER
A FORTIS COMPANY

Topline Summary

MQO RESEARCH RECHERCHE

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Customer Service Qualitative Research

SECTION 1: INTRODUCTION

INTRODUCTION

Background

Newfoundland Power (NF Power) recently engaged in a journey mapping process for their residential and commercial customer base in anticipation of implementing a new Customer Information System (CIS). Prior to making a final decision on the implementation of a new system, Newfoundland Power sought to obtain an in-depth understanding of the customer experience and certain opportunities to improve customer service delivery.

INTRODUCTION

Methodology

MQO was contracted to conduct qualitative research to gain insights from commercial and residential customers of NF Power.

Seventeen residential customers took part in two focus groups that were held in St. John's (9 participants) and Clarenville (8 participants) on January 27th and 28th, 2020. Nine commercial customers of various sizes were also selected to participate in interviews that took place from January 31st and February 7th, 2020

Customer Service Qualitative Research

SECTION 2: PROACTIVE COMMUNICATION

PROACTIVE COMMUNICATION

Customers were asked to recall what types of proactive communication they received from NF Power, how satisfied they were with that information, and what information they would like to receive from NF power.

Information Customers Recall Receiving From NF Power

For residential and commercial customers, **billing information** was cited as the primary communication received from NF Power with **usage information and outage notifications or alerts** also frequently mentioned. Some customers noted receiving information on **energy saving tips, rebate programs and usage history** such as year over year usage comparisons.

Of those that were interested in receiving more information than they currently got, most were interested in receiving information on various programs/rebates and any deals offered, ways to be more energy efficient as well as detailed usage activity reports, outage alerts and service issues.

Proactive communication *is the act of communicating ideas, information, or news in anticipation of a customer's future needs.*

NF Power Customers Recalled Receiving…

- Monthly bills
- Usage information
- Energy saving tips
- Information on rebate programs
- Outage alerts
- Notification of planned outages
- Historical comparisons

PROACTIVE COMMUNICATION

Information Customers *Want* to Receive From NF Power in the Future

Some customers[1] were only interested in the total on their bill and were happy with the amount of information they currently receive from NF Power.

"It's not important to me. I get a light bill, I pay it."

However, many customers did indicate an interest in receiving more information from NF Power. Most customers who wanted additional information were interested in information that would allow them to better understand and control their energy consumption and costs. Much of the discussion around information that customers would like to see in the future fell into the following themes:

- **More detailed/real time usage information**
- **Alerts concerning changes or anomalies in typical usage or bills**
- **Outage alerts/service issues**
- **Customer specific information on rebate programs and energy efficiency tips**

[1] 11 of 17 residential customers who participated in the focus groups and 7 of 9 commercial customers interviewed indicated they would be interested in receiving more information from NF power.

NF Power Customers Want to Receive…

Residential:

- Real time usage information
- Changes in typical usage or bills (e.g. usage anomalies)
- Personalized information

Commercial:

- Rebate programs
- Energy efficiency recommendations
- Detailed usage reports
- Outage alerts

PROACTIVE COMMUNICATION

Information Customers *Want* to Receive From NF Power in the Future:

More Detailed/Real Time Usage Information

Some residential customers indicated a desire to be able to pinpoint the usage of certain appliances for specific time periods during the day, many expressed an interest in real time usage data, similar to real time data usage reports that are available for cell phones. Commercial customers also expressed a desire for more detailed usage activity reports.

"One thing I would like to see is real time energy usage data…if I could have that data it would be very useful."

Alerts Concerning Changes or Anomalies in Typical Usage or Bills

Residential customers indicated a desire for NF Power to notify customers about anomalies in usage or billing patterns. For example, if a usage spike occurred where usage was considerably higher than the same time the previous year, customers would be notified so they would have the opportunity to examine why.

" A notification just like with credit cards where they noticed an anomaly in your service."

PROACTIVE COMMUNICATION

Information Customers *Want* to Receive From NF Power in the Future:

Outage Alerts/Service Issues

Both residential and commercial customers indicated that they would like to receive notification about outages and service issues. Although this is a service that is currently available, many customers were unaware of this service, or were not using it.

Residential customers want information that is communicated in a simple and easy to understand way.

Customer-Specific Information on Rebate Programs and Energy Efficiency Tips

Residential customers were very invested in ensuring that information they receive on rebate programs, energy efficiency tips and services were personalized and relevant to their situation. Residential customers suggested an app that would allow them to personalize the type of information and notifications that they receive. Commercial customers indicated an interest in receiving information on programs and rebates or any deals offered, as well as recommendations on ways to be more energy efficient.

"Don't tell me all about these wonderful rebate programs and then I go through all the steps and find out it doesn't apply to me."

"App that is user unique and specific…"

COMMUNICATION METHODS

Receiving Information from NF Power

Essential Information: Most residential customers indicated that they wanted to receive essential information by text[2], although email was also acceptable. Residential customers considered essential information to be time sensitive, such as bills and outage alerts. Commercial customers indicated a preference to receive information by email.[3]

Non-Essential Information: For non-essential information such as information about rebate programs and energy saving tips, residential customer preferences varied from emails and social media posts to mail outs, bill inserts and TV ads. Most commercial customers indicated that they would prefer to receive non-essential information along with the bill or by email.

The importance of personalization in meeting customer needs was an ongoing theme throughout the focus group discussions. Residential customers discussed differences in the type of information they use and how they prefer to communicate and be communicated with.

[2] 12 of 17 residential customers indicated that they would prefer essential information to be communicated by text.

[3] 6 of 9 commercial customers indicated that they would prefer essential information to be communicated by email.

COMMUNICATION METHODS

Reaching out to NF Power

Residential customers want to be able to reach out to NF Power in a variety of ways including over the phone, by online chat and in person. It was important for NF Power customers to be able to reach someone who was well informed, regardless of how they reached out to NF Power.

Commercial customers, for the most part said they prefer not to reach out to NF Power, preferring everything to run smoothly. However if there is an issue, interview responses indicated that reaching an individual who is already familiar with their issue would be incredibly valuable.

OPT-IN vs OPT-OUT

Residential

In general, residential customers were uncomfortable with the idea of 'opt-out' services or features. Some participants were open to opt-out options for essential services, such as e-bills and outage alerts, otherwise an opt-in approach was preferred.

"It's [opt-out] a slippery slope."

Commercial

Commercial customers were in favour of automatically being signed up for programs or information and then being able to 'opt-out' if unwanted.

"I think an automatic opt-in for e-bills or outage alerts would make sense. If I didn't want it I could just unsubscribe."

Customer Service Qualitative Research

SECTION 3: ONLINE TOOLS

ONLINE TOOLS

Current Use of Online Tools

Although many customers had seen and used the outage map or MyAccount, very few individuals suggested they regularly use these tools from NF power. Some participants did comment that it was difficult to find information on the website. Additionally, awareness and use of the NF Power app was very low.

"I installed the app then I uninstalled it because it was identical to logging into my account on the website."

Most customers did indicate that they use at least one app from other organizations. Apps for banking, news apps and points or loyalty apps (e.g. Optimum, Airmiles) were among some of the most frequently mentioned apps.

Future Use of Online Tools

Residential customers expressed a variety of preferences in terms of the type of information they wished to receive and how they preferred to receive it. All residential customers discussed the value of a personalized portal or app that would allow customization of the information and notifications they would receive.

"When I log in with my unique ID it gives me information that I've been able to customize."

NEWFOUNDLAND POWER APP

Future Use of Online Tools – NF Power App

Residential customers discussed at length the idea of being able to choose what, where, how and when they receive information. Customers discussed possible features of the app, including:

- ‘Portal’ style design that allowed you to login and would save your settings and preferences
- Real time data usage
- The ability to turn notifications on and off and choose the type of notification (text, email, call)
- Personalized information on rebates and energy efficiency (e.g. only rebate programs that a customer was eligible for would appear)
- Provide historical usage comparisons
- Provide other tools, for example appliance energy usage, tools to calculate energy costs to date
- Future trends and weather
- Bill and ability to pay bill

“App that is user unique and specific but would also have nice to know information and links”

Customer Service Qualitative Research

SECTION 4: STREAMLINED PROCESSES

IMPROVING CUSTOMER EXPERIENCE

In general, both residential and commercial customers are happy with the service provided by NF Power. Few additional recommendations were offered on how to streamline processes beyond what was previously discussed. However, residential customers did support the idea of a 'single view of the customer' with customer or account information tied to an individual instead of an address. Residential customers also discussed the value of a reaching an individual who is knowledgeable and can solve your problem without being bumped to several other individuals.

Similarly, commercial customers felt that an advanced contact routing system would improve customer service for commercial customers. This system would put you in touch with the same person when you called with a concern or issue.

"Yes, because there's nothing worse than having to repeat yourself every time you call."

"…in the past if I call with an issue and say 20-30 minutes, I call back I don't get the same person but you have to run through the conversation and second and third time."

Customer Service Qualitative Research

SECTION 5: SUMMARY OF FINDINGS

Summary of Findings

1. **Proactive Communication**

   There were commercial and residential customers who expressed a desire for proactive communication from NF Power that would allow them to better understand and control their energy consumption, costs and alert them about outages and service issues.

   Both residential and commercial customers indicated an interest in more detailed usage information, as well as outage or service alerts. Residential and commercial customers were also interested in receiving information on programs, rebates and recommendations on ways to be more energy efficient that would be relevant to their situation or business.

   Residential customers were also interested in alerts that would notify customers about anomalies in usage or billing patterns.

2. **Provide access to more detailed or real time usage information**

   Residential and commercial customers expressed a desire to have access to more detailed or real time usage information that will help them better understand their power usage and highlight opportunities to reduce energy and cut costs.

Summary of Findings

3. **Provide customers with the opportunity to personalize their NF Power communications**
   Customers want to have control over the information they receive. Customers like the idea of being able to choose what, where, how and when they receive information. Allowing for personalization of what information is received and how customers receive it meets the needs of the individuals and businesses who just want to know the total on their bill as well as those who review usage history, read about energy efficiency or get more information on available rebate programs.

4. **Increase functionality of the NF Power App**
   NF Power residential customers indicated a desire for an app that would provide self service functions and a personalized user experience. Customers suggested that in addition to basic billing information, the app could offer account specific information on rebates and energy efficiency. The app could also allow users to personalize the information they want to receive, as well as notifications. The app would provide customers more control over what information they receive, when they receive it and how it is received.

Summary of Findings

5. **Commercial customers cited a preference for 'opt-out' programs while most residential customers indicated a preference for 'opt-in'.**

   Based on the in-depth interviews, commercial customers are generally in favour of automatically being signed up for programs or information and then being able to 'opt-out' if unwanted. Most residential customers are still uncomfortable with the idea of automatically being signed up for programs and generally prefer to 'opt-in', however, some residential customers were comfortable with 'opt-out' when it came to essential information.

6. **Provide Online Chat - Customers want a variety of options to reach out to NF Power**

   In addition to being able to reach out to NF Power over the phone and by email, residential customers indicated a desire to be able to utilize online chat to meet their customer service and support needs.

7. **Implement Advanced Contact Routing**

   Regardless of how customers reached out to NF power, it was important for customers to be able to reach someone who was well informed and able to resolve their issue. For commercial customers in particular, customers want issues to be resolved quickly and do not want to have to re-examine their issue.

Attachment C

Newfoundland Power Inc. Accounting Assessment

Accounting Assessment

June 2020

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") accounting practices follow generally accepted accounting principles in the United States ("U.S. GAAP").[1] U.S. GAAP is established by the Financial Accounting Standards Board ("FASB"). The FASB Accounting Standards Codification ("ASC") provides guidance on the recognition of software costs.

Newfoundland Power assessed this guidance to determine the proper accounting treatment of costs associated with implementing a modern Customer Information System ("CIS"). Determining the proper accounting treatment is necessary to ensure the Company's compliance with U.S. GAAP.

2.0 Applicable Accounting Standards

Two sections of U.S. GAAP provide meaningful guidance on the accounting treatment of CIS implementation costs: (i) *ASC 350-40 Internal-Use Software ("ASC 350-40");* and (ii) *ASC 980 Regulated Operations ("ASC 980")*.

ASC 350-40 provides guidance on accounting for the cost of computer software developed or obtained for internal use. This includes guidance on which costs should be capitalized and which are more general in nature and should be expensed.

According to ASC 350-40, capital costs include those required to integrate a new software solution with on-premise software, as well as coding, configuration and customization costs.[2] General costs that should be expensed include data conversion and employee training.[3]

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[1] In Order No. P.U. 27 (2011), the Newfoundland and Labrador Board of Commissioners of Public Utilities ("the Board") approved the adoption of U.S. GAAP by Newfoundland Power for general regulatory purposes, effective January 1, 2012.

[2] See *ASC 350-40 Internal-Use Software*, paragraph 350-40-55-3.

[3] See *ASC 350-40 Internal-Use Software*, paragraphs 350-40-25-4 and 350-40-25-5.

ASC 980 provides guidance on accounting and financial reporting for entities with regulated operations. Regulators may approve allowable costs for rate-making purposes in a different period than the costs would be charged to expense by an unregulated entity.[4] ASC 980 permits the creation of assets and liabilities to reflect the economic impact of these rate-regulated activities.[5]

3.0 Assessment Results

Newfoundland Power is proposing to implement a modern CIS over 3 years at a total cost of approximately $31.6 million.

The Company has assessed the accounting treatment of CIS project costs in relation to ASC 350-40. The assessment determined that approximately $28.7 million, or 91% of the total project cost, should be capitalized in accordance with this guidance. This includes integration, coding, configuration and customization costs.

According to ASC 350-40, the remaining costs of approximately $2.9 million are more general in nature and should be expensed as incurred.[6] This includes costs related to data conversion and employee training, and certain activities related to the Request for Proposals ("RFP") process (collectively, "general project costs").[7]

Newfoundland Power has also assessed the accounting treatment of CIS project costs in relation to ASC 980. The assessment determined that ASC 980 could apply to the general project costs of $2.9 million, if approved by the Board.

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[4] For example, *Electric Plant Instruction 4. Overhead Construction Costs* of the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts provides for the capitalization of all overhead construction costs, such as engineering, supervision and general office salaries and expenses.

[5] See *ASC 980 Regulated Operations*, paragraph 980-05-5.

[6] The general project costs of $2.9 million are about 9% of the total CIS project costs of $31.6 million.

[7] Given the magnitude of the project, the RFP is expected to include processes not typically completed in a standard RFP. This includes general work associated with determining the existence of needed technology to include in the RFP and an extended process to evaluate multiple vendors. Costs associated with these general activities would typically be expensed in accordance with ASC 350-40.

Newfoundland Power is proposing to have ASC 980 apply to the general project costs of $2.9 million. This would result in the total $31.6 million CIS project costs being capitalized and recovered from customers over the life of the system.[8]

The reasonableness of having ASC 980 apply to the general project costs was assessed on the basis of 2 key regulatory principles: (i) customer rate stability; and (ii) intergenerational equity.

Rate stability is an established regulatory principle of the Board. According the Board:

> *Rates and revenues should be stable and predictable from year to year with a minimum of unexpected changes seriously adverse to either ratepayers or utility companies. This principle may justify smoothing out increases to avoid sharp rate climbs or temporary fluctuations.*[9]

The principle of intergenerational equity has also been recognized by the Board.[10] According to this principle, customers in a given period should pay only the costs necessary to provide them with service in that period. They should not be required to pay for costs incurred to provide service to customers in another period. This is consistent with just and reasonable customer rates.[11]

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[8] This treatment is similar to the Company's treatment of General Expenses Capitalized ("GEC"). Order No. P.U. 3 (1995-96) provides for the capitalization of general expenses that arise in connection with capital expenditures but cannot, from their nature, be charged to a specific item or project. Those general expenses are then amortized over the estimated service life of the related assets. Without the GEC account, the costs would likely be expensed in the year they were incurred. The Company's GEC account is consistent with *Electric Plant Instruction 4. Overhead Construction Costs* of the FERC Uniform System of Accounts.

[9] See, for example, Order No. P.U. 14 (2004), page 24.

[10] For example, Order No. P.U. 14 (2015) states: *"The Board is directed to apply tests which are consistent with generally accepted sound public utility practice, which would include consideration of principles such as fair return, rate stability, rate shock, predictability, certainty, fair cost apportionment, appropriate price signals and intergenerational equity"* (see page 12).

[11] Section 37(1) of the *Public Utilities Act* requires a public utility to provide service and facilities that are reasonably safe and adequate and just and reasonable.

Implementing a modern CIS is a once-in-a-generation effort. If general project costs were expensed as incurred, it would result in a temporary fluctuation in customer rates. This is inconsistent with rate stability for customers.

A modern CIS is expected to provide long-term continuity in Newfoundland Power's customer service delivery. Expensing general project costs as incurred would require current customers to assume the full burden of these costs. Future customers, who would also benefit from this project, would not bear any of these costs. This is inconsistent with the principle of intergenerational equity and just and reasonable customer rates.

Having ASC 980 apply to the general project costs of $2.9 million will allow all CIS project costs to be recovered from customers over the life of the system. In Newfoundland Power's assessment, this consistent with stable, just and reasonable customer rates.

4.0 Conclusion

Based on this accounting assessment, all costs required to implement a modern CIS should be included in the proposed capital budget for this project. This treatment is consistent with U.S. GAAP, established regulatory principles of the Board, and just and reasonable customer rates.