ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998 c.15 (Schedule B), s. 78.

AND IN THE MATTER OF an application by Hydro One Networks Inc. to raise its electricity distribution rates effective January 1, 2018 and continuing each year for another 4 years, until December 31, 2022.

EB-2017-0049

CROSS-EXAMINATION COMPENDIUM

PANEL 7

ENERGY STORAGE CANADA

June 28, 2018

TAB 1

UNDERTAKING – JT 3.15

Undertaking

To review the white paper referred to in Anwaatin 2 and provide a summary of its content.

Response

See Attachment 1.

Witness: GARZOUZI Lyla

EPRI-Hydro One Energy Storage Project

Introduction

With advances in energy storage and the drop in related costs, energy storage shows promise in supporting the energy needs of electricity customers. The following provides a brief description of the EPRI-Hydro One Energy Storage Project.

Project Description

This project aims to advance distribution planning methods when considering energy storage as one element within a Distributed Energy Resources (DER) portfolio.

- Key elements of this project include:
    - Developing a Distribution needs assessment to identify, define, and quantify the value of services that energy storage systems can provide across a utility service.
    - Developing methods to identify energy storage system requirements to adequately address distribution needs within any identified operational constraints.
    - Developing energy storage deployment scenarios:
        - Where to apply energy storage systems along the Distribution feeders;
        - Determining how much storage can be installed when the distribution feeder is already constrained due to reliability/power quality levels.

  Figure 1 below provides the project framework.

- The creation of a formal process will facilitate a better understanding of the potential grid impacts of various deployment scenarios and the opportunities of energy storage (utility-connected as well as customer sited) along the distribution system.
- A methodology will be developed for conducting the technical and cost/benefit analysis of potential solutions involving energy storage.
- Software will be produced so that Hydro One can conduct these siting and sizing analyses. EPRI will also provide training in how to use these tools.
- Traditional distribution planning techniques rely heavily on static power flow data for a selected loading condition – usually the peak power demand forecasted for a selected planning period. This does not give an accurate representation of variable resources such as wind and photovoltaic (PV) generation and limited duration distributed energy resources like energy storage. This project will determine how to use time dependent load flows.

Who is involved:

- Electric Power Research Institute (Principal Investigator)
- Hydro One Networks Inc. (Distribution Planning, Distribution Automation, Operations, RD&D/Strategy & Integrated Planning)

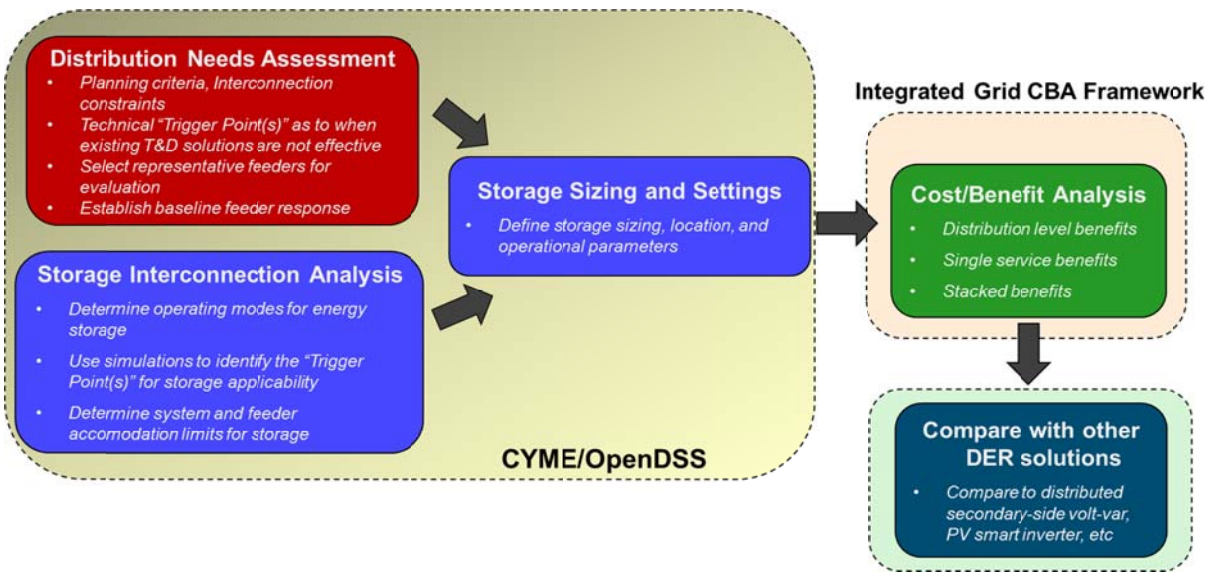
When it will be completed and ready for use:

- September 2018.

Benefits:

- Energy storage (ES) technology has potential benefits for utilities, system operators, and end users to increase reliability and reduce the cost of electricity.
- Hydro One believes storage may be used in Ontario in a number of applications, including frequency regulation, energy security/outage management, power quality, voltage VAR management, and peak shaving.
- It may be especially important as a flexibility asset to address the integration of variable generation resources such as wind and solar.
- Hydro One is also interested in better understanding the potential for energy storage to be a solution for providing service to remote communities.
- Storage may also be a tool to improve asset utilization at the distribution level, and if costs are low enough, it can be used for diurnal energy arbitrage.

Figure 1: EPRI Energy Storage Locational Analysis Framework on Distribution



TAB 2

Energy Storage Canada Interrogatory # 2

Issue:

Issue 51: Are the revenue-to-cost ratios for all rate classes over the 2018 – 2022 period appropriate?

Reference:

H1-02-03 Sections:

- 1.1.10.2 (Connection Impact Assessments – Embedded LDC Generators (Rate Code 45B)),
- 1.1.10.3 (Connection Impact Assessments – Small Projects <= 500 kW (Rate Code 45C);
- 1.1.10.5 (Connection Impact Assessments – Greater Than Capacity Allocation Exempt Projects – Capacity Allocation Required Projects (Rate Code 45E); and
- 1.1.10.6 (Connection Impact Assessments – Greater Than Capacity Allocation Exempt Projects – TS Review for LDC Capacity Allocation Required Projects (Rate Code 45F).

Interrogatory:

a) Please explain, in detail, and provide example calculations for Hydro One's method of determining and calculating Connection Impact Assessment charges for customers (including, without limitation, any energy storage customers), in the following rate codes:

   i. 45B (Connection Impact Assessments – Embedded LDC Generators)
   ii. 45C Connection Impact Assessments – Small Projects <= 500 kW)
   iii. 45E (Connection Impact Assessments – Greater Than Capacity Allocation Exempt Projects – Capacity Allocation Required Projects)
   iv. 45F (Connection Impact Assessments – Greater Than Capacity Allocation Exempt Projects – TS Review for LDC Capacity Allocation Required Projects)

b) Please describe how the system benefits provided by energy storage facilities are considered in the Connection Impact Assessment charges for energy storage facilities in the following rate codes:

   i. 45B (Connection Impact Assessments – Embedded LDC Generators);
   ii. 45C Connection Impact Assessments – Small Projects <= 500 kW);

iii. 45E (Connection Impact Assessments – Greater Than Capacity Allocation Exempt Projects – Capacity Allocation Required Projects); and
iv. 45F (Connection Impact Assessments – Greater Than Capacity Allocation Exempt Projects – TS Review for LDC Capacity Allocation Required Projects).

c) Please update Table 16, Table 17, Table 19, and Table 20 to show calculations for charges to:

i. distribution-connected energy storage; and
ii. BTM energy storage.

d) Please explain why energy storage facilities are included in Rate Code 45 (Small Projects <= 500 kW).

e) Please explain why Small Vehicle Time is included as part of the Connection Impact Assessment charges for energy storage facilities in:

i. Rate Code 45B (Embedded LDC Generators); and
ii. Rate Code 45C (Small Projects <= 500 kW).

Response:

a) Connection Impact Assessment ("CIA") charges for generators including energy storage customers, are derived by the time and TWE required to perform the studies, as shown in Exhibit H1-02-03, Attachment 1, Tables 41, 42, 44, and 45.

b) An energy storage facility acts as a load while charging from the grid and act as a generator, similar to a solar DG project, while injecting energy back into the grid. The effort and time required to complete a CIA study for an energy storage facility is the same as any other generation facility.

c) Refer to b) above.

d) Refer to b) above.

e) Small Vehicle Time and Field Staff (ADET) expenses are required to complete the Site Assessment. The site assessment determines the estimated cost to connect the customer owned tap line to the Hydro One distribution system.

i. Due to an administrative error, in Rate Code 45 (b), Embedded LDC Generators, Table 16 in H1-02-03, Direct Field Staff Labour (ADET) and Small Vehicle Time was included. The Field Staff Labour (ADET) and Small Vehicle Time costs should be omitted from this table.

ii. Rate Code 45 (c) (Small Projects ≤ 500 kW) - Small Vehicle Time and Field Staff (ADET) expenses are applicable

Due to an administrative error, in Rate Code 45 (e), Greater than Capacity Allocation Exempt Projects, Table 19 in Exhibit H1-02-03, Direct Field Staff Labour (ADET) and Small Vehicle Time was excluded. The Field Staff Labour (ADET) and Small Vehicle Time costs should be included in this table.

TAB 3

UNDERTAKING – JT 3.27

Undertaking

To provide corrected data for IR Response Exhibit I, Tab 51, Schedule ESC 2, table 16 and table 19.

Response

Refer to Attachment 1 for the updated Table 16 – Rate Code 45b - Connection Impact Assessments – Embedded LDC Generations

Refer to Attachment 2 for the updated Table 19 – Rate Code 45e – Connection Impact Assessments – Greater than Capacity Allocation Exempt Projects

Witness: BOLDT John

Year	Rate Code	Specific Service Charge Description	Labour Description	Rate Amount	Hours/Units	Overtime Factor	Calculated Total	Payroll Burdens	Total Labour	Other Description	Rate Amount	Hours/Units	Calculated Total	Total Other	Total
2018	45b	Connection Impact Assessments - Embedded LDC Generators	Direct Labour - Clerical	$80.08	0.87		$69.67	$37.34	$107.01						
			Direct Labour - MP4	$117.84	1.25		$147.30	$78.95	$226.25						
			Direct Labour - Technician (GR64)	$89.20	1.58		$140.94	$75.54	$216.48						
			Direct Labour - MP2	$105.47	10.66		$1,124.31	$602.63	$1,726.94						
			Payroll Burden	53.60%					**$2,276.68**						**$2,276.68**
2019	45b	Connection Impact Assessments - Embedded LDC Generators	Direct Labour - Clerical	$81.00	0.87		$70.47	$38.27	$108.74						
			Direct Labour - MP4	$119.24	1.25		$149.05	$80.93	$229.98						
			Direct Labour - Technician (GR64)	$90.07	1.58		$142.31	$77.27	$219.59						
			Direct Labour - MP2	$106.92	10.66		$1,139.77	$618.89	$1,758.66						
			Payroll Burden	54.30%					**$2,316.97**						**$2,316.97**
2020	45b	Connection Impact Assessments - Embedded LDC Generators	Direct Labour - Clerical	$81.96	0.87		$71.31	$39.15	$110.45						
			Direct Labour - MP4	$120.69	1.25		$150.86	$82.82	$233.69						
			Direct Labour - Technician (GR64)	$91.00	1.58		$143.78	$78.94	$222.72						
			Direct Labour - MP2	$108.43	10.66		$1,155.86	$634.57	$1,790.43						
			Payroll Burden	54.90%					**$2,357.29**						**$2,357.29**
2021	45b	Connection Impact Assessments - Embedded LDC Generators	Direct Labour - Clerical	$82.92	0.87		$72.14	$40.11	$112.25						
			Direct Labour - MP4	$121.49	1.25		$151.86	$84.44	$236.30						
			Direct Labour - Technician (GR64)	$91.92	1.58		$145.23	$80.75	$225.98						
			Direct Labour - MP2	$109.27	10.66		$1,164.82	$647.64	$1,812.46						
			Payroll Burden	55.60%					**$2,386.99**						**$2,386.99**
2022	45b	Connection Impact Assessments - Embedded LDC Generators	Direct Labour - Clerical	$84.20	0.87		$73.25	$40.73	$113.98						
			Direct Labour - MP4	$122.77	1.25		$153.46	$85.33	$238.79						
			Direct Labour - Technician (GR64)	$93.20	1.58		$147.26	$81.87	$229.13						
			Direct Labour - MP2	$110.56	10.66		$1,178.57	$655.28	$1,833.85						
			Payroll Burden	55.60%					**$2,415.76**						**$2,415.76**

Year	Rate Code	Specific Service Charge Description	Labour Description	Rate Amount	Hours/Units	Overtime Factor	Calculated Total	Payroll Burdens	Total Labour	Other Description	Rate Amount	Hours/Units	Calculated Total	Total Other	Total
2018	45e	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - Capacity Allocation Required Projects	Direct Labour - Clerical	$80.08	0.62		$49.65	$26.61	$76.26	Small Vehicle Time	$10.00	1.81	$18.10		
			Direct Labour - MP2	$105.47	11.10		$1,170.72	$627.50	$1,798.22						
			Direct Labour - Intern	$67.06	28.71		$1,925.29	$1,031.96	$2,957.25						
			Direct Labour - MP4	$117.84	20.37		$2,400.40	$1,286.61	$3,687.02						
			Direct Labour - Field Staff (ADET)	$84.64	4.08		$345.33	$185.10	$530.43						
			Payroll Burden	53.60%					**$9,049.18**					**$18.10**	**$9,067.28**
2019	45e	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - Capacity Allocation Required Projects	Direct Labour - Clerical	$81.00	0.62		$50.22	$27.27	$77.49	Small Vehicle Time	$10.00	1.81	$18.10		
			Direct Labour - MP2	$106.92	11.10		$1,186.81	$644.44	$1,831.25						
			Direct Labour - Intern	$67.39	28.71		$1,934.77	$1,050.58	$2,985.35						
			Direct Labour - MP4	$119.24	20.37		$2,428.92	$1,318.90	$3,747.82						
			Direct Labour - Field Staff (ADET)	$85.54	4.08		$349.00	$189.51	$538.51						
			Payroll Burden	54.30%					**$9,180.42**					**$18.10**	**$9,198.52**
2020	45e	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - Capacity Allocation Required Projects	Direct Labour - Clerical	$81.96	0.62		$50.82	$27.90	$78.71	Small Vehicle Time	$10.00	1.81	$18.10		
			Direct Labour - MP2	$108.43	11.10		$1,203.57	$660.76	$1,864.33						
			Direct Labour - Intern	$67.77	28.71		$1,945.68	$1,068.18	$3,013.85						
			Direct Labour - MP4	$120.69	20.37		$2,458.46	$1,349.69	$3,808.15						
			Direct Labour - Field Staff (ADET)	$86.48	4.08		$352.84	$193.71	$546.55						
			Payroll Burden	54.90%					**$9,311.59**					**$18.10**	**$9,329.69**
2021	45e	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - Capacity Allocation Required Projects	Direct Labour - Clerical	$82.92	0.62		$51.41	$28.58	$79.99	Small Vehicle Time	$10.00	1.81	$18.10		
			Direct Labour - MP2	$109.27	11.10		$1,212.90	$674.37	$1,887.27						
			Direct Labour - Intern	$68.78	28.71		$1,974.67	$1,097.92	$3,072.59						
			Direct Labour - MP4	$121.49	20.37		$2,474.75	$1,375.96	$3,850.71						
			Direct Labour - Field Staff (ADET)	$87.42	4.08		$356.67	$198.31	$554.98						
			Payroll Burden	55.60%					**$9,445.55**					**$18.10**	**$9,463.65**
2022	45e	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - Capacity Allocation Required Projects	Direct Labour - Clerical	$84.20	0.62		$52.20	$29.03	$81.23	Small Vehicle Time	$10.00	1.81	$18.10		
			Direct Labour - MP2	$110.56	11.10		$1,227.22	$682.33	$1,909.55						
			Direct Labour - Intern	$70.06	28.71		$2,011.42	$1,118.35	$3,129.77						
			Direct Labour - MP4	$122.77	20.37		$2,500.82	$1,390.46	$3,891.28						
			Direct Labour - Field Staff (ADET)	$88.70	4.08		$361.90	$201.21	$563.11						
			Payroll Burden	55.60%					**$9,574.94**					**$18.10**	**$9,593.04**

UNDERTAKING – JT 3.28

Undertaking

To update the response to part C of Exhibit I, Tab 51, Schedule ESC 2.

Response

The effort and time required to complete a CIA study for an energy storage facility is the same as any other generation facility. Therefore, the charges in Table 16, Table 17, Table 19, and Table 20 found in H1-02-03 Appendix B would apply to an energy storage facility greater than 10kW.

An energy storage facility equal to or less than 10kW would apply under the micro-embedded generation process for which there is no charge for the assessment/screening.

Witness: BOLDT John

TAB 4

SPECIFIC SERVICE CHARGES

1. INTRODUCTION

Specific Service Charges are charges for specific services over and above the standard level of service as defined by the Distribution System Code. Each miscellaneous service has an OEB-approved fixed rate and is charged to a customer based on a customer's request or as the result of a customer's action or inaction that would impose a cost on Hydro One.

In its last distribution rate filing (EB-2013-0416), Hydro One proposed rates for miscellaneous services in Exhibit G2, Tab 5, Schedule 1 of that application. The rationale was that regular distribution rates only recover costs of providing standard distribution services. In its Decision issued on March 12, 2015 in relation to EB-2013-0416, the OEB directed Hydro One to file with this Application a study assessing whether its Specific Service Charges reflect its underlying costs to perform those services ("the Time Study") and propose changes accordingly. Hydro One has completed the Time Study and proposes the new charges detailed in this Exhibit.

2. THE STUDY

In response to the OEB's direction, with the support of Elenchus Research Associates Inc., Hydro One completed a year-long time study of the tasks involved in providing miscellaneous services and the associated costs, including labour rates and burdens, fleet costs, material costs and pass-through charges. The charges studied included those included in Chapter 11 of the OEB's *2006 Electricity Distribution Rate Handbook* (the "Rate Handbook").

Hydro One used the approaches found in Chapter 11 of the Rate Handbook to define the level of the charge to bill the customer. The Study details its context and methodology and is includeded as Attachment 1 to this Exhibit.

3. THE PROPOSED SPECIFIC SERVICE CHARGES

A summary of all the proposed 2018-2022 charges can be found in Table 1 of this Exhibit (Schedule 11-1 of the Rate Handbook). Descriptions of the miscellaneous services (as found in Attachment 1 of this Exhibit) and details of the methodology used to determine the charges are provided in Appendices A and B to this Exhibit. Except where identified, the proposed charges align with the associated labour and materials identified in the Time Study.

In Appendices A and B, the Specific Service Charge for each service is based on average elapsed hours required to carry out the work, as well as burdened labour rates, vehicle costs, and material. Refer to Exhibit E1, Tab 1, Schedule 2, and Table 2 of this Exhibit ("Capital Contributions") for a summary of the historical volumes along with 2018-2022 forecasted volumes and projected revenues for each service.

Appendix A: Charges listed in Chapter 11 of the 2006 Rate Handbook and updated as per the Time Study.

Appendix B: Hydro One-specific charges, primarily calculated based on labour, as per the Time Study.

Appendix C: Hydro One-specific charges, calculated as per previously approved OEB methodology.

For the services listed in Appendix C, Specific Service Charges are determined by methodologies that take into account the value of assets, volumes of those assets and the costs associated with the maintenance of those assets.

1.1.10 CONNECTION IMPACT ASSESSMENTS

Renewable generation development and the subsequent connection process involve a number of stages, including technical assessments. Hydro One assesses the technical impact of the renewable generation connection to its distribution system through a Connection Impact Assessment ("CIA"). A CIA is a more detailed assessment of a project's impact on the distribution system. The results include a technical report outlining project feasibility, technical specifications needed for the project and the impact the project would have on the distribution grid and any of its customers, in accordance with Section 6.2.14 of the DSC.

1.1.10.1 CONNECTION IMPACT ASSESSMENTS – NET METERING (RATE CODE 45A)

A net metering generator, as defined in section 7(1) of the Net Metering Regulation (O. Reg. 541 / 05), generates electricity primarily for its own use from a renewable generation facility. Net metering involves the measurement of the quantity of electricity a generator uses against the quantity of electricity it generates resulting in a net total. Net metering projects include those which have a capacity greater than 10 kW but less than or equal to 500 kW that wish to connect to Hydro One's distribution system.

1.1.10.3 CONNECTION IMPACT ASSESSMENTS – SMALL PROJECTS < =500 KW (RATE CODE 45C)

This category covers CIA completed for CAE-sized DG projects, including load displacement and energy storage facilities, proposed for connection to Hydro One distribution system. When no LDC is involved, this type of CIA is completed by Hydro One at the request of an applicant.

1

Table 17: Connection Impact Asssessments – Small Projects <=500 kW

Year	Rate Code	Specific Service Charge Description	Labour Description	Rate Amount	Hours/Units	Overtime Factor	Calculated Total	Payroll Burdens	Total Labour	Other Description	Rate Amount	Hours/Units	Calculated Total	Total Other	Calculated Total Charge	Proposed Charge
2018	45c	Connection Impact Assessments - Small Projects <=500 kW	Direct Labour - Clerical	$80.08	0.87		$69.67	$37.34	$107.01	Small Vehicle Time	$10.00	1.81	$18.10			
			Direct Labour - MP4	$117.84	3.42		$403.01	$216.01	$619.03							
			Direct Labour - Technician (GR64)	$89.20	10.85		$967.82	$518.75	$1,486.57							
			Direct Labour - Field Staff (ADET)	$84.64	4.08		$345.33	$185.10	$530.43							
			Direct Labour - MP2	$105.47	2.81		$296.37	$158.85	$455.23							
			Payroll Burden	53.60%					**$3,198.27**					**$18.10**	**$3,216.37**	**$3,216.37**

2

Year	Rate Code	Specific Service Charge Description	Labour Description	Rate Amount	Hours/Units	Overtime Factor	Calculated Total	Payroll Burdens	Total Labour	Other Description	Rate Amount	Hours/Units	Calculated Total	Total Other	Calculated Total Charge	Proposed Charge
2019	45c	Connection Impact Assessments - Small Projects <=500 kW	Direct Labour - Clerical	$81.00	0.87		$70.47	$38.27	$108.74	Small Vehicle Time	$10.00	1.81	$18.10			
			Direct Labour - MP4	$119.24	3.42		$407.80	$221.44	$629.24							
			Direct Labour - Technician (GR64)	$90.07	10.85		$977.26	$530.65	$1,507.91							
			Direct Labour - Field Staff (ADET)	$85.54	4.08		$349.00	$189.51	$538.50							
			Direct Labour - MP2	$106.92	2.81		$300.45	$163.14	$463.59							
			Payroll Burden	54.30%					**$3,247.97**					**$18.10**	**$3,266.07**	**$3,266.07**

Year	Rate Code	Specific Service Charge Description	Labour Description	Rate Amount	Hours/Units	Overtime Factor	Calculated Total	Payroll Burdens	Total Labour	Other Description	Rate Amount	Hours/Units	Calculated Total	Total Other	Calculated Total Charge	Proposed Charge
2020	45c	Connection Impact Assessments - Small Projects <=500 kW	Direct Labour - Clerical	$81.96	0.87		$71.31	$39.15	$110.45	Small Vehicle Time	$10.00	1.81	$18.10			
			Direct Labour - MP4	$120.69	3.42		$412.76	$226.61	$639.36							
			Direct Labour - Technician (GR64)	$91.00	10.85		$987.35	$542.06	$1,529.41							
			Direct Labour - Field Staff (ADET)	$86.48	4.08		$352.84	$193.71	$546.55							
			Direct Labour - MP2	$108.43	2.81		$304.69	$167.27	$471.96							
			Payroll Burden	54.90%					**$3,297.73**					**$18.10**	**$3,315.83**	**$3,315.83**
2021	45c	Connection Impact Assessments - Small Projects <=500 kW	Direct Labour - Clerical	$82.92	0.87		$72.14	$40.11	$112.25	Small Vehicle Time	$10.00	1.81	$18.10			
			Direct Labour - MP4	$121.49	3.42		$415.50	$231.02	$646.51							
			Direct Labour - Technician (GR64)	$91.92	10.85		$997.33	$554.52	$1,551.85							
			Direct Labour - Field Staff (ADET)	$87.42	4.08		$356.67	$198.31	$554.98							
			Direct Labour - MP2	$109.27	2.81		$307.05	$170.72	$477.77							
			Payroll Burden	55.60%					**$3,343.36**					**$18.10**	**$3,361.46**	**$3,361.46**

Year	Rate Code	Specific Service Charge Description	Labour Description	Rate Amount	Hours/Units	Overtime Factor	Calculated Total	Payroll Burdens	Total Labour	Other Description	Rate Amount	Hours/Units	Calculated Total	Total Other	Calculated Total Charge	Proposed Charge
2022	45c	Connection Impact Assessments - Small Projects <=500 kW	Direct Labour - Clerical	$84.20	0.87		$73.25	$40.73	$113.98	Small Vehicle Time	$10.00	1.81	$18.10			
			Direct Labour - MP4	$122.77	3.42		$419.87	$233.45	$653.32							
			Direct Labour - Technician (GR64)	$93.20	10.85		$1,011.22	$562.24	$1,573.46							
			Direct Labour - Field Staff (ADET)	$88.70	4.08		$361.90	$201.21	$563.11							
			Direct Labour - MP2	$110.56	2.81		$310.67	$172.73	$483.41							
			Payroll Burden	55.60%					**$3,387.28**					**$18.10**	**$3,405.38**	**$3,405.38**

1.1.10.6 CONNECTION IMPACT ASSESSMENTS – GREATER THAN CAPACITY ALLOCATION EXEMPT PROJECTS – TS REVIEW FOR LDC CAPACITY ALLOCATION REQUIRED PROJECTS (RATE CODE 45F)

The Transformer Station ("TS") review CIAs are completed for all DG projects greater than 500 kW, including load displacement and energy storage facilities, connecting to LDC dedicated feeders. TS review CIAs are performed to determine if any upgrades are required at an upstream TS in order to facilitate connection of the DG projects to the distribution system. Changes in the feeder protection schemes such as transfer trip, low set block signal, and distributed generator end open signal are evaluated to ensure adequate protection of the equipment in the event of a contingency on the system.

Table 20: Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - TS Review for LDC Capacity Allocation Required Projects

Year	Rate Code	Specific Service Charge Description	Labour Description	Rate Amount	Hours/Units	Overtime Factor	Calculated Total	Payroll Burdens	Total Labour	Other Description	Rate Amount	Hours/Units	Calculated Total	Total Other	Calculated Total Charge	Proposed Charge
2018	45f	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - TS Review for LDC Capacity Allocation Required Projects	Direct Labour - Clerical	$80.08	0.62		$49.65	$26.61	$76.26							
			Direct Labour - MP2	$105.47	14.90		$1,571.50	$842.33	$2,413.83							
			Direct Labour - Intern	$67.06	10.44		$700.11	$375.26	$1,075.36							
			Direct Labour - MP4	$117.84	11.45		$1,349.27	$723.21	$2,072.48							
			Payroll Burden	53.60%					**$5,637.93**					**$0.00**	**$5,637.93**	**$5,637.93**

Year	Rate Code	Specific Service Charge Description	Labour Description	Rate Amount	Hours/Units	Overtime Factor	Calculated Total	Payroll Burdens	Total Labour	Other Description	Rate Amount	Hours/Units	Calculated Total	Total Other	Calculated Total Charge	Proposed Charge
2019	45f	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - TS Review for LDC Capacity Allocation Required Projects	Direct Labour - Clerical	$81.00	0.62		$50.22	$27.27	$77.49							
			Direct Labour - MP2	$106.92	14.90		$1,593.11	$865.06	$2,458.17							
			Direct Labour - Intern	$67.39	10.44		$703.55	$382.03	$1,085.58							
			Direct Labour - MP4	$119.24	11.45		$1,365.30	$741.36	$2,106.65							
			Payroll Burden	54.30%					**$5,727.89**					**$0.00**	**$5,727.89**	**$5,727.89**
2020	45f	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - TS Review for LDC Capacity Allocation Required Projects	Direct Labour - Clerical	$81.96	0.62		$50.82	$27.90	$78.71							
			Direct Labour - MP2	$108.43	14.90		$1,615.61	$886.97	$2,502.58							
			Direct Labour - Intern	$67.77	10.44		$707.52	$388.43	$1,095.95							
			Direct Labour - MP4	$120.69	11.45		$1,381.90	$758.66	$2,140.56							
			Payroll Burden	54.90%					**$5,817.80**					**$0.00**	**$5,817.80**	**$5,817.80**

Year	Rate Code	Specific Service Charge Description	Labour Description	Rate Amount	Hours/Units	Overtime Factor	Calculated Total	Payroll Burdens	Total Labour	Other Description	Rate Amount	Hours/Units	Calculated Total	Total Other	Calculated Total Charge	Proposed Charge
2021	45f	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - TS Review for LDC Capacity Allocation Required Projects	Direct Labour - Clerical	$82.92	0.62		$51.41	$28.58	$79.99							
			Direct Labour - MP2	$109.27	14.90		$1,628.12	$905.24	$2,533.36							
			Direct Labour - Intern	$68.78	10.44		$718.06	$399.24	$1,117.31							
			Direct Labour - MP4	$121.49	11.45		$1,391.06	$773.43	$2,164.49							
			Payroll Burden	55.60%					**$5,895.15**					**$0.00**	**$5,895.15**	**$5,895.15**
2022	45f	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - TS Review for LDC Capacity Allocation Required Projects	Direct Labour - Clerical	$84.20	0.62		$52.20	$29.03	$81.23							
			Direct Labour - MP2	$110.56	14.90		$1,647.34	$915.92	$2,563.27							
			Direct Labour - Intern	$70.06	10.44		$731.43	$406.67	$1,138.10							
			Direct Labour - MP4	$122.77	11.45		$1,405.72	$781.58	$2,187.29							
			Payroll Burden	55.60%					**$5,969.89**					**$0.00**	**$5,969.89**	**$5,969.89**

TAB 5

Energy Storage Canada Interrogatory # 1

Issue:

Issue 49: Are the inputs to the cost allocation model appropriate and are costs appropriately allocated?

Issue 51: Are the revenue-to-cost ratios for all rate classes over the 2018 – 2022 period appropriate?

Reference:

H1-02-03

Interrogatory:

a) Please explain, in detail, and provide supporting calculations, for Hydro One's method of determining and calculating demand charges for:

   i. licensed energy storage providers that are connected to the distribution system, licensed pursuant to an Ontario Energy Board license in the form of a facility that is connected to a distribution system and is capable of withdrawing electrical energy from distribution system (i.e. charging), and then storing such energy for a period of time, and then re-injecting only such energy back into the distribution system, minus any losses (i.e. discharging); and

   ii. customers, including large industrial, all commercial, and all residential customers that have energy storage equipment behind their distribution meter (BTM).

Response:

i) Hydro One classifies licensed energy storage providers that are directly connected to the distribution system as Distributed Generation ("DG") customers.

   When these facilities withdraw electrical energy from the distribution system, they incur demand charges, as specified in the Hydro One rate schedules listed in Exhibit H1, Tab 2, Schedule 1 and Schedule 2.

   Demand charges for DG customers are determined using the following steps:

   1. Hydro One's 2018 revenue requirement is allocated to all Hydro One rate classes using the OEB's 2018 Cost allocation model. Exhibit G1 in this application provides more information on the cost allocation process.

2. Hydro One's proposed rates for each rate class (including demand charges) are determined by dividing the costs allocated to each rate class by the forecast charge determinants (i.e. number of customers for monthly fixed charges, and kWh or kW for volumetric charges) for each rate class. Demand charges for DG customers are on a $ per kW basis. Exhibit H1, Tab 1 and Tab 2 in this application provides more information on the rate design process.

ii) Hydro One classifies large industrial, all commercial and all residential customers that have energy storage equipment behind their distribution meter (BTM) as load customers. Industrial and commercial load customers can be classified as General Service Energy, General Service Demand, Urban General Service Energy, Urban General Service Demand or Sub-Transmission ("ST"), depending on the usage level, density, connection voltage and transformer ownership. Residential customers can be classified as medium density, low density or urban density year-round customers, or as seasonal customers.

Demand charges only apply to General Service Demand, Urban General Service Demand and ST customers. Demand charges for these customer classes are derived using the same steps as described in Hydro One's response to part i) above. All other classes listed above have volumetric charges based on kWh.

Hydro One also notes that the distribution volumetric charges for all customers (except ST customers) with a BTM load displacement generator or energy storage equipment are based on the net usage (i.e. the usage measured at the meter). ST customers with a BTM load displacement generator or energy storage equipment, installed after October 1998 at 1 MW or above, or at 2 MW or above for renewable generation are subject to "gross demand" billing[1] on their distribution volumetric charges.

[1] For more information on "gross demand" billing, please see Hydro One's current rate schedule in Exhibit H1, Schedule 2, Tab 1, page 10 and page 19, note (13).

TAB 6

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2017-0049**	**Hydro One Networks Inc.**

VOLUME: **Technical Conference**

DATE: **March 5, 2018**

EB-2017-0049

THE ONTARIO ENERGY BOARD

Hydro One Networks Inc.

Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Monday, March 5, 2018,
commencing at 9:06 a.m.

TECHNICAL CONFERENCE

---

out this over several years -- or you haven't decided yet?

MR. ANDRE: Yes, so I don't think we have made a decision. You know, if at the time that the decision is made and we are preparing the draft rate order, if these were the impacts that were to materialize, clearly we would have to do something as they are above the 10 percent limit and, you know, I would imagine there's options in terms of recovering over a longer period, doing some sort of individual bill impact mitigation.

So we would take some action to bring those impacts on a typical customer down below 10 percent. But we haven't made any decision at this point what that would be.

MR. LADANYI: Thank you, Mr. Andre, these are all my questions.

MR. SIDLOFSKY: Thanks, Mr. Ladanyi. Finally, Mr. Ferguson. Are you going to be asking questions for both Anwaatin and ESC?

MR. FERGUSON: Right now, it's just ESC, Energy Storage Canada.

MR. SIDLOFSKY: Okay, thank you. Go ahead.

QUESTIONS BY MR. FERGUSON:

MR. FERGUSON: Good evening, panel. My name is Cary Ferguson and I am here on behalf of Energy Storage Canada. I have questions on your interrogatory responses to ESC 1 and ESC 2. We will start with ES C2, and that's Exhibit I, tab 51, schedule ESC 2, and we will start on page 3.

In your response to our interrogatory E there, you have noted that there were administrative errors in table

16 and table 19, and I just hope -- I am just wondering if you can undertake to update those tables to correct those administrative errors.

MR. BOLDT: Yes, we can do that.

MR. FERGUSON: Thank you.

MR. SIDLOFSKY: Undertaking JT3.27.

UNDERTAKING NO. JT3.27: TO PROVIDE CORRECTED DATA FOR IR RESPONSE EXHIBIT I, TAB 51, SCHEDULE ESC 2, TABLE 16 AND TABLE 19

MR. FERGUSON: If you could scroll up to page 2, the response to interrogatory B, we had asked that you describe how the system benefits provided by Energy Storage facilities were considered in CIA, connection impact assessment charges, for energy storage facilities.

And I've read your answer and I just want to confirm, does your answer -- should I take from that that you do not consider system benefits in the CIA charges for energy storage facilities? Those are not taken into consideration?

MR. BOLDT: In the calculation for the CIA or the work that's done -- excuse me -- the energy storage device, it's based or it's connected to the system based on the nameplate size of the device. And it doesn't, it doesn't take into effect not the X megawatt-hours of storage that it has. So it treats it as a load when it's connecting it.

MR. FERGUSON: So just as a load; no consideration of those other benefits that it might provide?

MR. BOLDT: Correct.

MR. FERGUSON: Thank you. And then I saw in response to C and D you said to refer to B above. I understand that makes sense in the context of question D, but our question C had been to update tables to show calculations for distribution connected energy storage and behind the meter energy storage. And so I was just hoping you could either undertake to update those tables, as we have had asked in interrogatory C. I just didn't understand how B applied to C in this case.

MR. BOLDT: Yeah, we can take a look at it and give you the taking.

MR. FERGUSON: Thank you.

MR. SIDLOFSKY: JT3.28.

UNDERTAKING NO. JT3.28: TO UPDATE THE RESPONSE TO PART C OF EXHIBIT I, TAB 51, SCHEDULE ESC 2

MR. FERGUSON: And now if we can, if I can have you turn to ESC 1. That's Exhibit I, tab 49, Schedule ESC 1, and go to page 2 of 2 there, please.

MR. ANDRE: Yes, I am there.

MR. FERGUSON: Great. This is for Mr. Andre. In response to number 2 there on lines 8 to 14, you're describing how you classify different customer groups, and on line 10 you say:

"Industrial and commercial load customers can be classified as general service energy, general service demand, urban general service energy, urban genera service demand, or sub transmission, depending on the usage level, density, connection voltage, and transformer ownership."

I was hoping you would be able to provide a table listing the thresholds and when those classifications change for each of those factors.

MR. ANDRE: So our rate schedules that are included in evidence would -- at the top, it would describe what is required to fit into each of those categories. The usage level, I mean, I can -- general service energy is where demand is less than 50 kilowatt-hours, and then demand is when demand is greater than 50 kilowatts -- not kilowatt-hours, sorry, kilowatts. So is that's the usage.

Density -- I think that's evident in the name. The urban ones are the density; the ones that don't say urban are the regular. And then connection voltage and transformer ownership refers to subtransmission customers, so subtransmission customers have to be connected above 13.8 kV connected to a facility that's at that voltage or higher and they have to own their own transformer.

MR. FERGUSON: You anticipated my next question, Mr. Andre, thank you. So all those factors --

MR. ANDRE: Requirements.

MR. FERGUSON: -- requirements, thank you -- are in the rate codes?

MR. ANDRE: They are in the rate schedules, yes.

MR. FERGUSON: Sorry, the rate schedules.

MR. ANDRE: Yes.

MR. FERGUSON: Thank you. Just going through this in terms of going kind of back to the system benefits discussion we just had. I just want to confirm that there's no consideration in terms of when we are classifying energy storage. It's based on those factors in that paragraph we just discussed, Mr. Andre. There's no consideration of the system benefits?

MR. ANDRE: No.

MR. FERGUSON: No? Or the avoided or deferred benefits that they provide?

MR. ANDRE: No.

MR. FERGUSON: No consideration?

MR. ANDRE: No? I am aware that that has come up in some Board working groups in terms of the appropriate rates to set for energy storage. These aren't specific to energy storage. We are trying to fit, make use of existing rate classes, and so the existing rate classes there, it's sort of like fitting customers into one of those existing rate classes and there is no consideration of benefits.

MR. FERGUSON: Right; so it's not there yet?

MR. ANDRE: No.

MR. FERGUSON: Thank you. And how is net metering considered in these? How would net metering be considered in this?

MR. ANDRE: I think the last paragraph clarifies that.

MR. FERGUSON: Yeah.

MR. ANDRE: So, you know, if there -- if customers have a behind the meter, the BTM refers to behind the meter generation, then it's the metered generation on which customers are billed. So net metering is automatically considered for customers that are in the general service or general service demand or energy classes. And then for ST customers, behind the meter generation is actually added back because those customers are gross-load billed.

MR. FERGUSON: Thank you. I am just curious about the qualification here with October 1998. So ST customers with a BTM load displacement generator, or energy storage equipment installed after October 1998 at one megawatt or above, et cetera. Why the cutoff at October 1998?

MR. ANDRE: So that was the time that the energy market was opened. That's the time that Hydro One was not -- Ontario Hydro was broken up into the various component companies, and so as part of the application to set those first set of rates, the decision by the Board made at the time was that any generation that existed at this point in time would be grandfathered as being part of the base load.

So if they already had that generation in there, the load that you were seeing, the net load that you were seeing represented what that customer has historically provided. So basically they were grandfathered and it had to do with the opening up of the market and the breaking up of Ontario Hydro.

MR. FERGUSON: Thank you, that's very clarifying. Just one last question here. I am just trying to wrap my head around where storage fits into all these. Admittedly there's a lot of different factors at play here, so correct me where I am going wrong here, if I am going wrong.

The storage could be general service demand? Could fall into that category, energy storage?

MR. ANDRE: So, energy -- I mean, energy storage is, shall I say there's a lack of clarity on how energy storage customers should be treated. We have a distribution generation -- distributed generation class, and so there's some thought that they should be part of that class. Or, as Mr. Boldt just said, energy storage can be thought of as load customers. So if they are thought of as load customers, then any one of these classes could apply as well.

But I will be frank: There is some lack of clarity around -- I mean, it's so new, there is a bit of a lack of clarity around how to treat them. From a rates perspective, the thought or notion of treating them as load customers and having one of these classes apply to them, that represents our current thinking right now.

MR. FERGUSON: Right, so it could be in the demand category by not the energy category; right?

MR. ANDRE: It depends on the size of the energy storage.

MR. FERGUSON: And it would depend on those factors in the paragraph we discussed?

MR. ANDRE: Right. Correct.

MR. FERGUSON: Usage level, density, connection voltage and transfer ownership?

MR. ANDRE: Correct, correct.

MR. FERGUSON: Okay. Thank you, those are my questions.

TAB 7

Energy Storage Canada Interrogatory # 3

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Issue 29: Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?

Reference:

Ontario Energy Board, Filing Requirements for Electricity Transmission and Distribution Applications (the Filing Requirements), Chapter 5: Consolidated Distribution System Plan Filing Requirements, section 5.0.4.3 at page 4 and section 5.4.1 at page 15.
Exhibit B1, Tab 1, Schedule 1
Exhibit B1, Tab 1, Schedule 1, Section 1.3, Attachment 1
Exhibit B1, Tab 1, Schedule 1, Section 3
Exhibit C1, Tab 1, Schedule 3, page 8.

Interrogatory:

Preamble:
The Filing Requirements require that Hydro One's distribution system plan (DSP) include the consideration(s) Hydro One has given to the investments necessary to facilitate the integration of distributed generation and customers with energy storage capability.

Exhibit B1, Tab 1, Schedule 1, Section 1.3, Attachment 1 shows that 9%-16% of Hydro One customers prioritize upgrading the system to connect new customers, including those using energy storage.

Hydro One describes energy storage at Exhibit C1, Tab 1, Schedule 3, page 8, as one of "the most impactful disruptive technologies affecting utilities over the coming decade due to rapidly declining cost and mass production" and that it "has potential benefits to utilities in terms of peak load shifting (thereby having a positive effect on deferring asset replacement), frequency regulation (improving power quality for customers), reserve capacity (providing better reliability), and improved voltage support".

a) Please describe how Hydro One has considered and implemented energy storage planning and investment into its DSP. Please provide a chart showing:

   i. all instances where Hydro One has considered energy storage (as a solution, alternative to a wires investment, or otherwise);
   ii. whether or not the energy storage project was implemented;
   iii. if the energy storage project was not implemented, the reasons why it was not implemented;
   iv. if the energy storage project was implemented, the quantified system benefits, the deferred distribution investment, and the customer rate impact of the project; and
   v. all instances where Hydro One has considered and/or incorporated energy storage in its capital planning decision-making processes.

Response:

i. Hydro One is in the feasibility stage of evaluating energy storage for three different applications:
   - Reliability improvement
   - Power quality
   - Deferring other capital investments required to supply load growth

ii.-iv. As these projects are in the feasibility stage, the decision to implement has not been made. The expected system benefits and rate impacts are currently being investigated.

ii. Hydro One has not begun incorporating energy storage in its capital planning process at this time. Should the applications listed above provide meaningful grid benefits in a cost effective manner, Hydro One will move to incorporate energy storage more fully into the planning process.

In addition to the discussion above, please refer to Exhibit I-23-OEB Staff-87 for further energy storage projects considered under the Advanced Distribution System project (see Exhibit B1, Tab 1, Schedule 1, section 3.8, Investment Summary Document SS-07).

TAB 8

Hydro One Networks Inc.
7th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5680
Cell: (416) 568-5534
frank.dandrea@HydroOne.com

Frank D'Andrea
Vice President
Regulatory Affairs

BY COURIER

June 15, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON, M4P 1E4

Dear Ms. Walli,

EB-2017-0049 - Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application (the "Application") Settlement Proposal regarding Hydro One Transmission/ Anwaatin Motion to Review and Vary (EB-2016-0160 / EB-2017-0335)

Please find enclosed the Settlement Proposal between Hydro One and Anwaatin Inc. regarding EB-2017-0335 Anwaatin Inc.'s Motion to Review and Vary the Ontario Energy Board Decision in EB-2016-0160.

The Settlement Proposal was provided during the Oral Hearing on June 15th, 2018 and was entered into the evidentiary record as Exhibit K4.4.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Enc.

SETTLEMENT PROPOSAL

ANWAATIN INC.

Motion to Review and Vary the Ontario Energy Board's Decision
on Hydro One Network Inc.'s Transmission Rates in EB-2016-0160

EB-2017-0335

June 15, 2018

Table of Contents

Anwaatin Inc.
EB-2017-0335

SETTLEMENT PROPOSAL

A. PREAMBLE

This Settlement Proposal is filed with the Ontario Energy Board (the "**OEB"**) in connection with the Anwaatin Inc. ("**Anwaatin"**) Motion to Review and Vary the Ontario Energy Board's Decision on Hydro One Networks Inc.'s ("**HONI"**) Transmission Rates in EB-2016-0160 (the "**Decision"**) through the EB-2017-0335 proceeding (the "**Anwaatin MRV"**). It follows settlement discussions that took place after the Anwaatin MRV was argued and before the OEB rendered a decision in the Anwaatin MRV. The settlement discussions were predominantly between Anwaatin and HONI, with limited involvement of a distributed energy resource developer, Abundant Solar Inc. ("**Abundant"**), and the two intervenors in the Anwaatin MRV, (Schools Energy Coalition "**SEC**") and Vulnerable Energy Consumers Coalition "**VECC**") in a manner that was guided by the process contemplated in the OEB''s Practice Direction on Settlement Conferences, as amended (the "**Practice Direction**"). OEB staff were also informed of the settlement discussions, but in accordance with the Practice Direction OEB Staff is neither a Party nor a signatory to this Settlement Proposal. Nonetheless, OEB Staff who were apprised of the developments in and around the settlement discussions are bound by the same confidentiality provisions that apply to all of the above-mentioned Parties and entities. The communities Anwaatin represents for the Anwaatin MRV and this Settlement Proposal ("**the Anwaatin First Nations**") include Aroland First Nation, MoCreebec Eeyoud, and Waaskiinaysay Ziibi Inc. Development Corporation ("**WZI**"), an economic development corporation representing five First Nations in the Lake Nipigon watershed: Animbiigoo Zaagiigan Anishinaabek, Bingwi Neyaashi Anishinaabek, Biinjitiwaabik Zaaging Anishinaabek. Red Rock Indian Band, and Whitesand First Nation.

This Settlement Proposal is subject to the following conditions subsequent:

(i) Acceptance of the Settlement Proposal by the OEB in its entirety, and in a manner that allows for implementation of its terms;

(ii) The Pilot Project satisfies the OEB and Ministry of Energy's Impact Assessment Requirements:

   a. System Impact Assessment conducted by the IESO; and

   b. Connection Impact Assessment conducted by HONI.

(iii) Obtaining any approvals required by Abundant and Anwaatin/Anwaatin First Nations, if any, regarding the repurposing of existing FIT contracts if included or required to facilitate reliability as part of the Pilot Project.

(iv) Decisions made by HONI to proceed with Phase 1 and 2 investments as described in Paragraph 1.5(c) below.

(collectively, the "**Conditions Subsequent**").

Unless amended on the written consent of Anwaatin and HONI, all Conditions Subsequent must be fulfilled by no later than December 31, 2021, failing which this Settlement Proposal is null and void and of no further effect.

In entering this agreement, the Parties understand and agree that, pursuant to the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B) (the "Act") the OEB has the exclusive initial jurisdiction with respect to the interpretation and enforcement of the terms hereof.

B. DESCRIPTION OF SETTLEMENT

1.1 The Parties

Anwaatin and HONI were the central parties to the Anwaatin MRV and are the signatories to this Settlement ("**Parties**"). Two other interveners participated in the Anwaatin MRV in a limited manner. SEC intervened in the Anwaatin MRV for the limited purpose of requesting that any cost consequences to the Decision be reviewed. VECC intervened in the Anwaatin MRV in support of Anwaatin. Abundant was involved in the settlement discussions in order to ensure that the proposed solutions were technically feasible and able to be implemented in a timely manner.

1.2 Confidentiality

The Parties agree that the settlement discussions shall be subject to the rules relating to confidentiality and privilege contained in the Practice Direction. The Parties acknowledge that confidentiality in that context does not have the same meaning as confidentiality in the OEB's Practice Direction on Confidential Filings, and the rules of that latter document do not apply. The Parties interpret the Practice Direction to mean that the documents and other information provided, the discussion of each issue, any offers and counter-offers, and the negotiations leading to settlement of each issue during the course of the settlement discussions are strictly confidential between the Parties and were undertaken on a without prejudice basis. None of the foregoing settlement discussions and processes leading to this Settlement Proposal are admissible as evidence in this or any other proceeding, or otherwise, except where the filing of such settlement information is necessary to implement the Settlement Proposal and/or resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal and subject to the direction of the OEB. In such case, only the settlement information that is necessary for the purpose of implementing and interpreting the settlement proposal shall be filed and such information shall be filed using the appropriate protections afforded under the relevant legislation and OEB instruments. These obligations shall not impede the filing of this Settlement Proposal itself or its use as evidence in subsequent proceedings including, without limitation, the EB-2017-0049 proceeding.

Further, the Parties have a positive and ongoing obligation not to disclose settlement information to persons who were not involved in the settlement discussions.

1.3 Parameters of Proposed Settlement

All of the elements of this Settlement Proposal have been settled by the Parties as a package, and none of the provisions of this Settlement Proposal are severable. Numerous compromises were made by Anwaatin and HONI with respect to various matters to arrive at this Settlement Proposal. The distinct issues and elements addressed in this Settlement Proposal are inextricably interrelated, and changes in the agreed parameters are likely to have consequences in other areas of this Settlement Proposal, which may be unacceptable to one or more of the Parties. If the OEB does not accept this package in its entirety, then there is no settlement (unless HONI and Anwaatin agree in writing that any portion of the package that the OEB does accept may continue as part of a valid Settlement Proposal).

If the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but neither Anwaatin nor HONI will be obligated to accept any proposed revision. The Parties agree that Anwaatin and HONI must agree with any revised Settlement Proposal prior to its re-filing with the OEB.

None of the Parties can withdraw from this Settlement Proposal except in accordance with the terms contemplated herein (including satisfaction of the Conditions Subsequent) and with Rule 30.05 of the OEB's Rules of Practice and Procedure.

1.4 Full Settlement of Parties

a) HONI will undertake a pilot project that is intended to explore the feasibility of implementing non-wires distributed energy projects (**"Pilot Project")** in and around the Anwaatin First Nations communities as a means to improve reliability in remote and radial areas of HONI's system. The Pilot Project is intended to provide HONI with an opportunity to assess whether similar and repeatable approaches may be used in other remote areas of its system that are experiencing poor reliability conditions.

b) HONI's investment in the Pilot Project shall not exceed $5 million and shall be funded from HONI's distribution capital investment plan.

c) Anwaaatin and HONI agree to work together in an effort to offset or augment this investment amount by obtaining government funding through subsidies or grant programs.

d) The Parties acknowledge that any further funding of this initiative is dependent on (i) the feasibility of the Pilot Project and (ii) further review and approval by the OEB to increase HONI's approved capital investment envelope and recovery through rates of the additional funding requirements.

e) Anwaatin/Anwaatin First Nations communities and Abundant plan to jointly develop and implement up to 45 MW of FIT contracted solar generation in the following repurposed locations:

   a. Longlac M2/Nakina DS: maximum size 5 MW
   b. Moosonee: maximum size 10 MW
   c. Longlac M1/Longlac East DS: maximum size 9 MW
   d. Longlac TS LV bus: maximum size 10 MW
   e. Beardmore DS: maximum size 1.1 MW
   f. Jellicoe DS: maximum size 0.9 MW
   g. Red Rock: maximum size 9 MW.

f) HONI will consider the technical feasibility of having Abundant/Anwaatin First Nation solar generation be used as a source of supply to the energy storage facilities as part of the Pilot Project.
g) HONI commits to processing all connection impact assessment applications made by Anwaatin/Anwaatin First Nations and Abundant in a timely manner, taking into account all other existing connection impact assessment applications HONI has received.
h) The first phase of the Project will complete the technical assessment of energy storage facilities that may improve reliability in the communities served by HONI's F2 Feeder that serves the Nakina area. Energy storage facilities for Phase 1 are targeted to be in-service by March 31, 2019.
i) The design, size and load to be served by Phase 1 facilities are matters not yet determined and will be dependent upon further technical review. HONI will continue to regularly consult with Anwaatin regarding the status of the Phase 1 design.
j) A technical review of Phase 1 implementation is targeted for completion within six months of in-service timing. This information is intended to be used to inform the approaches, design, and viability of Phase 2.
k) During the EB-2017-0049 proceeding, Anwaatin and HONI will provide the OEB with an update on the Project, including any preliminary information regarding sizing of energy storage, siting alternatives and preliminary cost estimates. As part of this update, Anwaatin and HONI may file this Settlement Proposal.
l) The Project shall have no retrospective financial or cost consequences that will require revisiting the amounts assessed and determined by the Board in the EB-2016-0160 Decision.
m) Anwaatin and HONI will consult and cooperate on any other longer-term wires and/or non-wires electricity reliability proposals and solutions affecting the Anwaatin First Nations communities and may jointly pursue other projects intended to improve reliability in other regions served by HONI.

1.5 Description of Project

(a) **Phase 1** is focussed on improving reliability to the communities served by HONI's F2 Feeder situated in the Nakina region. The objective is to provide measurable improvement to the reliability of supply to these communities and as compared to the five-year historical average SAIDI and SAIFI values applicable to these communities. Anwaatin/Anwaatin First Nations, Abundant and HONI intend to achieve this objective through designing and implementing energy storage facilities in close proximity to the referenced communities and the option of having solar generation used to recharge the storage facilities in times of outages.

Anwaatin/Anwaatin First Nations, Abundant and HONI will take reasonable steps to find suitable off-reserve locations in proximity to HONI's feeder distribution facilities to site both solar generation and energy storage facilities at locations in close proximity to local community distribution load.

All constructed Phase 1 energy storage facilities will initially be owned and operated by HONI. HONI agrees to explore in good faith the possibility of Anwaatin First Nations obtaining a minority, non-operating ownership interest in the Phase 1 facilities, should the said facilities proceed to development. The valuation of this interest will be based on HONI's actual investment cost incurred to the date that such interest is acquired by Anwaatin First Nations.

HONI's design of the Phase 1 energy storage facilities will take into account, among other technical factors, historic load levels in the Aroland community. Anwaatin agrees to work with HONI in assessing ways to prioritize distribution service during times of an outage so that stored energy may be used for essential services in the communities.

HONI will consult with Anwaatin/Anwaatin First Nations and Abundant regarding design and sizing of the energy storage facilities.

Anwaatin/Anwaatin First Nations and Abundant intend to jointly develop and implement solar generation facilities in close proximity to all identified energy storage facilities so that the solar generation facilities may be used to supply the energy storage facilities at times when outages occur in the Aroland community.

The targeted timelines for Phase 1 are as follows:

- Scope of work completed and storage partner selected by July 15, 2018
- Siting locations determined and community engagement completed by July 31, 2018
- Completion of all detailed engineering and financial viability review completed by September 30, 2018
- Civil work completed by November 30, 2018

- In-service of energy storage facilities by March 31, 2019.

Anwaatin/Anwaatin First Nations and Abundant acknowledge that targeted timelines may require adjustments, given acquisition timing of requisite land rights, remoteness of worksite locations, workforce availability and the season in which construction work occurs.

(b) **Phase 2:** is focussed on Waaskiinaysay Ziibi Inc. (an economic development corporation representing Rocky Bay First Nation, Bingwi Neyaashi Anishinaabek, Red Rock Indian Band, Whitesand First Nation, and Animbiigoo Zaagiigan Anishinaabek and other smaller First Nations along HONI's A4L transmission line) (collectively, **"WZI"**).

The Phase 2 objective is complete technical assessments of potential non-wires solutions for WZI communities in order to determine whether cost-effective and technically feasible ways may be used through the use of non-wires solutions to improve reliability to levels consistent with HONI's current average SAIDI and SAIFI metrics for its northern rural distribution customers and by deploying similar approaches and measures described in Phase 1. The results of Phase 1 are intended to inform and be used in the technical assessments contemplated for Phase 2.

In Phase 2, HONI and Anwaatin will also work together to identify and evaluate critical loads in MoCreebec Eeyoud locations served by HONI's F1 and F3 feeders and assess whether cost effective and technically feasible non wire energy storage facilities could be implemented to significantly improve reliability for identified critical loads.

Anwaatin will facilitate meetings between HONI, Abundant, WZI and other smaller interested First Nations served by the A4L line in order to describe, explain, and assess solar/storage reliability solutions.

HONI's Phase 2 commitments are limited to preparing technical assessments that consider deployment of energy storage facilities in the WZI communities in the same manner as carried out for Phase 1 and which technical assessments have been filed as part of Exhibit I-6-1(c) in OEB Hearing EB-2017-0049.

Once the technical assessments for Phase 2 are completed, HONI and Anwaatin/Anwaatin First Nations, Abundant and WZI will meet and discuss all technical, operational and financial viability issues that would need to be addressed before any further steps are taken to initiate potential investments. This discussion is intended to explore possible joint development opportunities to implement energy storage and solar generation facilities so that they may be used in an effective and feasible way to provide a means of back-up supply in times of outages for small communities along the A4L route, while maintaining feeder integrity.

(c) **Final Decisions to Proceed with Phase 1 Investments.** HONI's decision to proceed with the work execution and installation of Phase 1 is subject to: (1) investment requirements to not exceed the amounts or outcomes described in paragraph 1.4(b)-(d) above, (2) HONI's technical review and its acceptability to HONI of the final design of the facilities, (3) the level of reliability improvement expected from Phase 1 is reasonably achievable as determined by HONI, and (4) Phase 1 facilities are expected to provide a repeatable outcome for development in other areas of HONI's system. HONI will consult with Anwaatin on the ongoing status of these conditions throughout Phase 1.

1.6 Other Matters

(a) **Ongoing HONI Communications with the Anwaatin First Nations Communities.** HONI and Anwaatin agree to develop and implement a communications plan to facilitate regular communications between them and the First Nations communities to discuss and assess the progress and success of the Pilot Project.

(b) **Pilot for Future HONI/Indigenous Community Cooperation.** If the Pilot Project is successful, HONI and Anwaatin agree to work together and promote the Pilot Project as a potential reliabilty solution in other Indigenous and similarily situated communities.

(c) **Conditions Precedent.** The final form of the Settlement Proposal is subject to the approval of the Band Councils and/or the applicable First Nation governing body(ies).

(d) **Conditions Subsequent.** This Settlement Proposal is subject to the Conditions Subsequent listed in Part A (Preamble) above.

ACCEPTED AND AGREED TO THIS 15 DAY OF JUNE 2018

Ferio Pugliese, Executive Vice President
Customer Care and Corporate Relations
Hydro One Networks Inc.

Larry Sault, President and Chief Executive Office
Anwaatin Inc.

TAB 9

Hydro One Networks Inc.
7th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5680
Cell: (416) 568-5534
frank.dandrea@HydroOne.com

Frank D'Andrea
Vice President
Regulatory Affairs

hydro one

BY COURIER

June 15, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON, M4P 1E4

Dear Ms. Walli,

EB-2017-0049 - Interrogatory Response Update in Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application (the "Application")

Please find enclosed the updated interrogatory I-06-Anwaatin-001 for Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application. This update takes into account a new pilot project initiative that Hydro One is evaluating in the area that serves Anwaaatin communities.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Enc.

Anwaatin Inc. Interrogatory # 1

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

A-04
A-04-02

Preamble:

Hydro One's distribution business serves the majority of the First Nations and Métis communities in Ontario.

In the Application, Hydro One states that it will be implementing a three-pronged strategy that is intended to increase system reliability within First Nations communities (increasing capital investments and replacing equipment that affects reliability; leveraging technology to allow Hydro One to better detect, limit the scope, and remotely respond to certain types of outages; and reducing planned outages by bundling work).

Hydro One indicates that, through its First Nations and Métis Strategy (Exhibit A, Tab 4, Schedule 2), communities would like to see an increase in procurement, investment/ownership opportunities, and other business partnership opportunities for Aboriginal businesses. Hydro One further indicates that First Nations communities have raised concerns about the high frequency and duration of power outages, particularly in Northern Ontario. Some communities have also indicated that the electricity supply is not sufficiently reliable to serve businesses on reserve and are concerned about degrading Hydro One asset conditions on reserve.

Hydro One also notes that First Nations communities and customers feel they are disproportionately impacted by high electricity costs. Many have raised concerns that their delivery charge is higher than their electricity consumption. In addition, First Nations customers are most sensitive to cost and place the greatest importance on cost over improvements in the service they receive.

Hydro One indicates that it hopes to address many of the Indigenous concerns with reliability and distributed energy resources, including Indigenous investment and ownership, and is developing a consolidated framework to guide First Nations and Métis relations and engagement across all lines of business.

Interrogatory:

a) Please describe how Hydro One consulted First Nations on any and all investment/ownership opportunities and other business partnership opportunities related to DERs in grid-connected communities, and what resulted from these consultation efforts.

b) Please describe in detail and provide all reports, notes, memos and documents related to:

   i. all processes Hydro One undertook to consult with Indigenous communities on this distribution rate application; and
   ii. the outcome of those consultations.

c) Please list each and all distributed energy resources that:

   i. Hydro One considered for Indigenous communities;
   ii. Hydro One consulted with First Nations on;
   iii. Hydro One implemented or intends to implement for Indigenous communities;
   iv. the Hydro One actions that result from them; and
   v. the quantified improvements in reliability and service that result from them.

d) Since First Nations in Ontario have now acquired or will soon acquire more than 14 million shares of Hydro One (representing 2.4% of the outstanding common shares of Hydro One), please describe how Hydro One will address the significant concerns of Indigenous shareholders relating to the high frequency and duration of power outages in Indigenous communities and the disparate reliability afforded to this class of shareholder.

Response:

a) Hydro One engages First Nations on investment/ownership opportunities on a project by project basis such as the Bruce to Milton Transmission Project and the Niagara Reinforcement Project. At this time, Hydro One has not yet engaged First Nations on any investment/ownership opportunities and other business partnership opportunities related to distributed energy resources (DERs) in grid-connected communities. Hydro One has recently begun exploring opportunities to partner with interested First Nation communities and to leverage federal and provincial government funding to support green energy and greenhouse gas reducing energy projects.

b)

i) Hydro One regularly engages with First Nations and Métis communities about various issues of concern.

As part of its review of customer needs and preferences, Hydro One conducted a telephone survey in August 2016 of a random and representative sample of 300 First Nations customers. A key finding was that First Nations customers are most sensitive to cost and place the greatest importance on cost over improvements in the service they receive. A copy of the telephone survey results with First Nations customers can be found EB-2017-0049, Exhibit B1-1-1, Section 1.3, Attachment 1, pages 1562 to 1570.

In addition, Hydro One also held engagement sessions with (a) the 88 First Nation communities it serves on February 9 and 10, 2017, the session reports for which are provided as Attachment 4 to section 1.3 of the DSP (Exhibit B1, Tab 1, Schedule 1) and (b) the 29 Métis Councils represented by the Métis Nation of Ontario on May 13, 2017. The purpose of the sessions was to engage on Application as well as to share information on various programs and initiatives benefiting Indigenous communities and to hear about issues and concerns expressed by participants as they related to Hydro One. Please find enclosed reports, presentations, and notes related to these engagement sessions as Attachments 1 to 9.

Hydro One will be hosting a second First Nations Engagement Session on February 21, 2018 which will be open to representatives of the 88 First Nations communities it serves. A similar engagement session will be offered to the Métis Nation of Ontario in 2018.

ii) For the most part, Hydro One had existing initiatives in place to address the concerns raised in these engagement sessions. Hydro One made 35 specific commitments at the

February 9 and 10, 2017 First Nation engagement session and 95% of these commitments were addressed throughout the year. Hydro One made 10 specific commitments at the May 13, 2017 engagement session with the Métis Nation of Ontario. Attachment 10 lists the 10 questions asked by the Métis Nation of Ontario and includes Hydro One responses.

The outcomes of these engagement sessions was the development of additional strategies and plans responsive to the key issues and concerns expressed by participants as they related to the transmission and distribution system.

To improve affordability, Hydro One implemented an outreach plan to ensure all eligible First Nation customers benefit from the First Nations Delivery Credit announced as part of the Ontario Fair Hydro Plan and which came into effect on July 1, 2017. Hydro One also adjusted a plan to implement the First Nations Conservation Program (FNCP) in new First Nation communities in 2018. The FNCP is a follow-up program to the Aboriginal Conservation Program which was implemented by the Independent Electricity System Operator (IESO) and ended in 2015 after providing services to 39 communities. The FNCP is designed to serve the communities not served by the IESO’s earlier program.

In addition, Hydro One also implemented the Get Local Initiative to help customers by providing information about conservation programs and resources that may assist low-income customers and ensuring that qualifying customers are aware of and accessing the Province of Ontario's Ontario Electricity Support Program. Finally, in 2018 Hydro One started to roll-out the Affordability Fund to improve First Nations’ home energy efficiency by providing free energy-saving upgrades, which can lower home energy use and, correspondingly, a customer’s electricity bill over the long term.

In order to improve reliability and in response to complaints raised at the engagement sessions, Hydro One has revised its vegetation management policy whereby it will increase the frequency of forestry maintenance work on reserve. In addition, on measures to improve reliability, please see parts c) i), ii), and iii) of Exhibit I-6-Anwaatin-2.

On liability and access, Hydro One responded to feed-back committing to notify or seek permission as applicable from First Nation communities when conducting reconnection work on reserve in the context of its distribution business.

c) In its February 12, 2018 response to Exhibit I-6-Anwaatin-001 c), Hydro One stated that it had not yet considered distributed energy resources related to Indigenous communities. Hydro One has recently begun exploring opportunities to partner with interested First Nation communities and to leverage federal and provincial government funding to support green energy and greenhouse gas reducing energy projects.

By way of update, in April 2018, Hydro One commenced preliminary discussions with Anwaatin regarding renewable sourced generation interconnection capacity and energy storage capacity at distribution station locations in proximity to Anwaatin communities. These discussions have evolved into assessing whether an energy storage pilot project could be developed in a remote region of the distribution system serving Anwaatin communities and tested to determine reliability improvement and whether this approach could be used as a repeatable approach in other regions of the system.

More technical information is now available regarding this initiative. Hydro One's current technical assessment has focused on the three distribution feeder lines that serve the Nakina and Moosonee communities (referred to as Moosonee F1 and F3, and Nakina F2).

These assessments, included in Attachment 11, provide information regarding the following:

- the historical reliability of these feeders;
- three potential energy storage solutions that are in the process of evaluation;
- expected levels of costs of each solution; and
- the potential reliability improvement.

The assessments are continuing. Completion of all detailed engineering and financial viability review is targeted by September 30, 2018. Forecast investment for this new pilot project will not exceed $5 million. Government grants and funding may also provide a source of funds. One of the key objectives with this pilot project is assessing scalability to meet similar reliability concerns in other communities served by Hydro One.

At this time, issues affecting pilot project feasibility include, but are not limited to, the following:

- Installation of energy storage facilities on a radial line will result in the "islanding" of an area, with the consequence that during the outage, this load would be served by non-wires storage. This technical design and approach are not found on any other part of the Hydro One Distribution system and will require careful operational scrutiny.

- Estimated capital costs set out in the attached technical assessments are preliminary and subject to further review. Investment estimates depend on a variety of factors, including battery sizing, variability of load, and availability of government funding programs.

- Cost/benefit analysis of the potential reliability improvement must also be considered by a comparison to other potential ways to improve reliability, such as changes in vegetation management and prior transmission investments that have been made in the area.

d) Hydro One will continue to invest in its assets according to asset condition assessments without regard to preferences of specific shareholders.

Nakina DS F2 & Moosonee DS F1/F3 Energy Storage Reliability Overview

June 15, 2018

Assumptions and Context

- HONI has recently explored Non-Wires Alternatives (NWA) to improve reliability to Anwaatin communities.
- Key issues associated with NWA include storage sizing, location, cost, and "islanding" operational concerns.
- This analysis is based on total community load. Variability in load may impact the battery backup duration to the community.
- Targeting critical loads for backup would reduce the battery size required, and hence the total cost.
- Cost estimates are based on informal vendor discussions, and publicly available information plus contingency due to remote access/unknown variables.
- Optimal location of the battery is in close proximity to the community to maximize the reliability benefit.

Feeder Supply to Anwaatin Communities

- Nakina DS F2 – supplies Aroland First Nations
- Moosonee DS F1 & F3 – supplies Mocreebec First Nations

Reliability Ranking of Supply Feeders

Ranking without Transmission Loss of Supply*

	SAIDI Ranking	SAIFI Ranking
Nakina DS F2	1988	2146
Moosonee DS F1	498	549
Moosonee DS F3	1134	1184

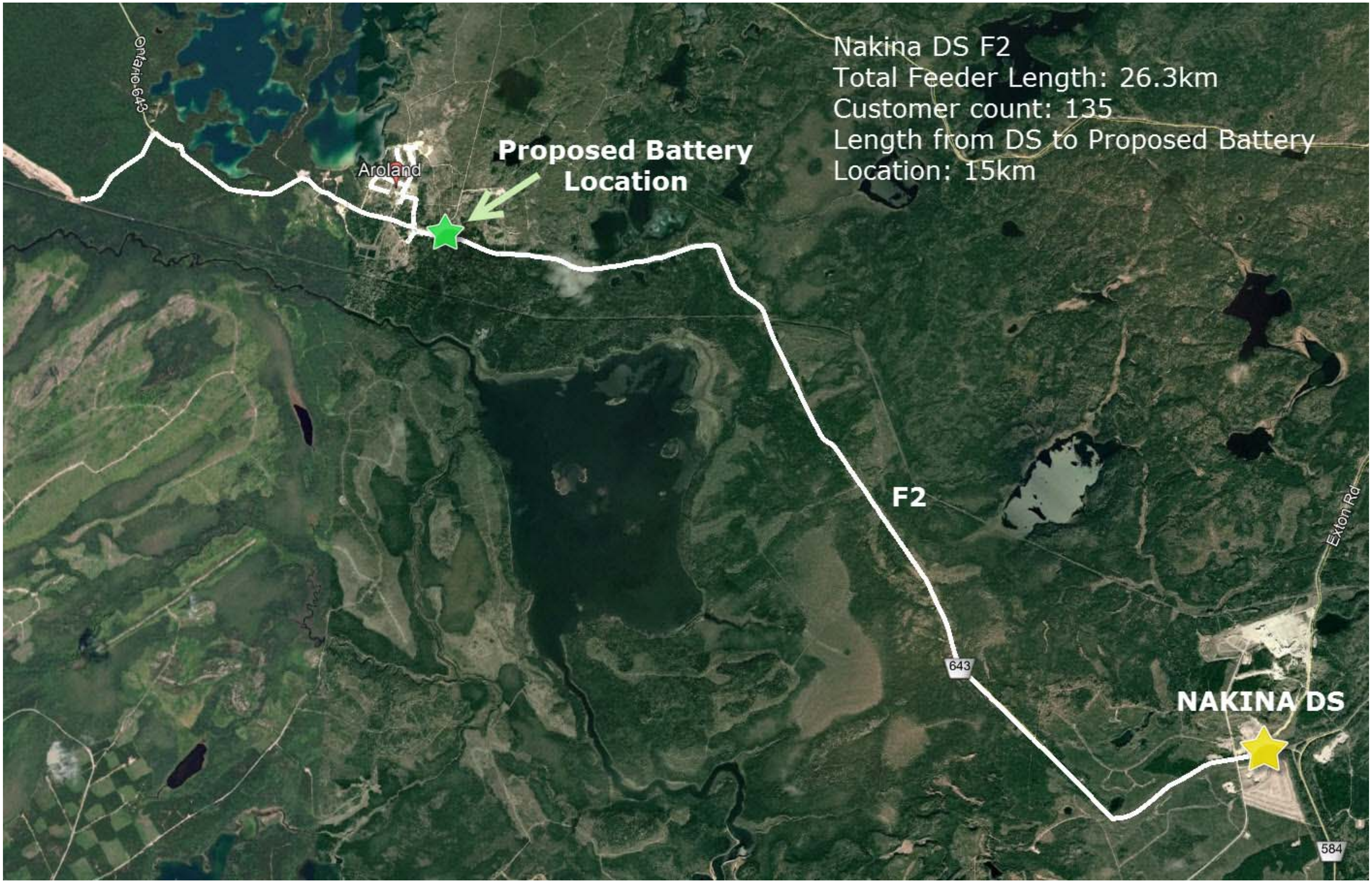
Ranking with Transmission Loss of Supply*

	SAIDI Ranking	SAIFI Ranking
Nakina DS F2	2022	2183
Moosonee DS F1	431	412
Moosonee DS F3	864	678

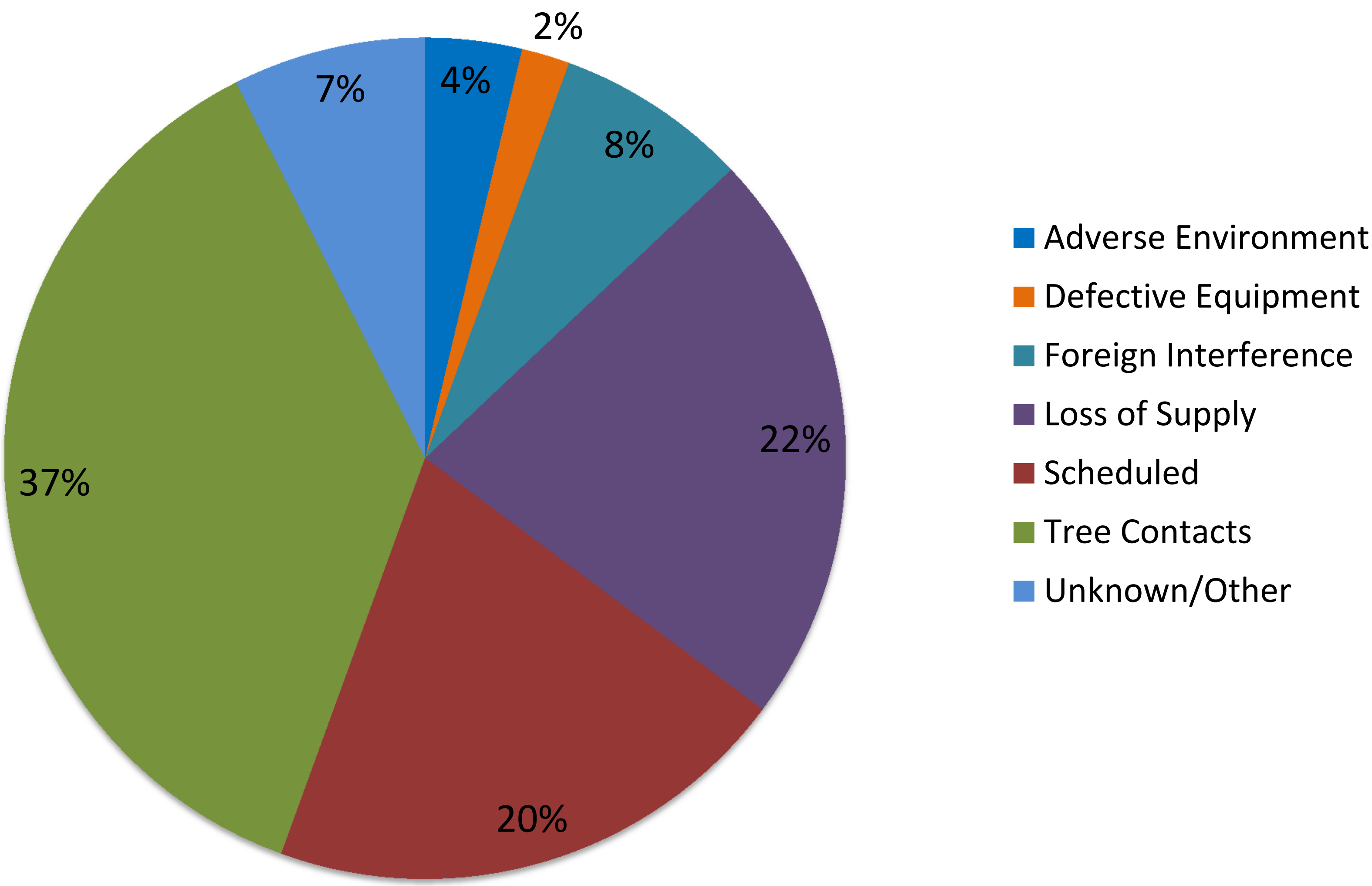
*Ranking based on 2015-2017 average data, out of approximately 3300 feeders. Feeder ranking is from worst to best, with "1" being the worst.

Nakina DS F2
Energy Storage
Reliability Overview

Nakina DS F2

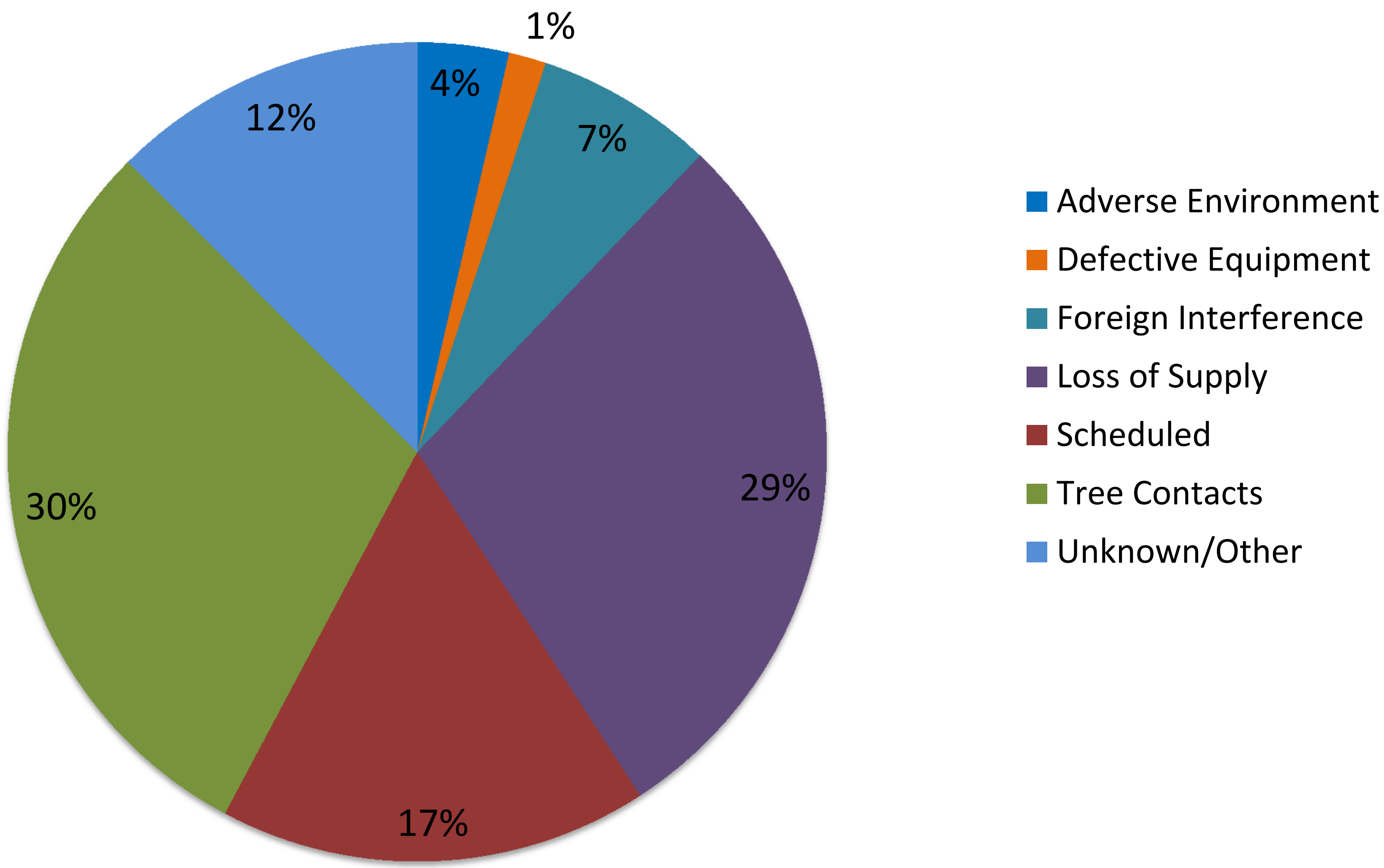

Nakina DS F2
Total Feeder Length: 26.3km
Customer count: 135
Length from DS to Proposed Battery
Location: 15km
Proposed Battery
Location
Aroland
Ontario 643
F2
643
NAKINA DS
Exton Rd
584

Nakina DS F2 - Frequency of Upstream Outages by Cause (5 years)



*Vegetation management will improve by 20-40% over the planning period.

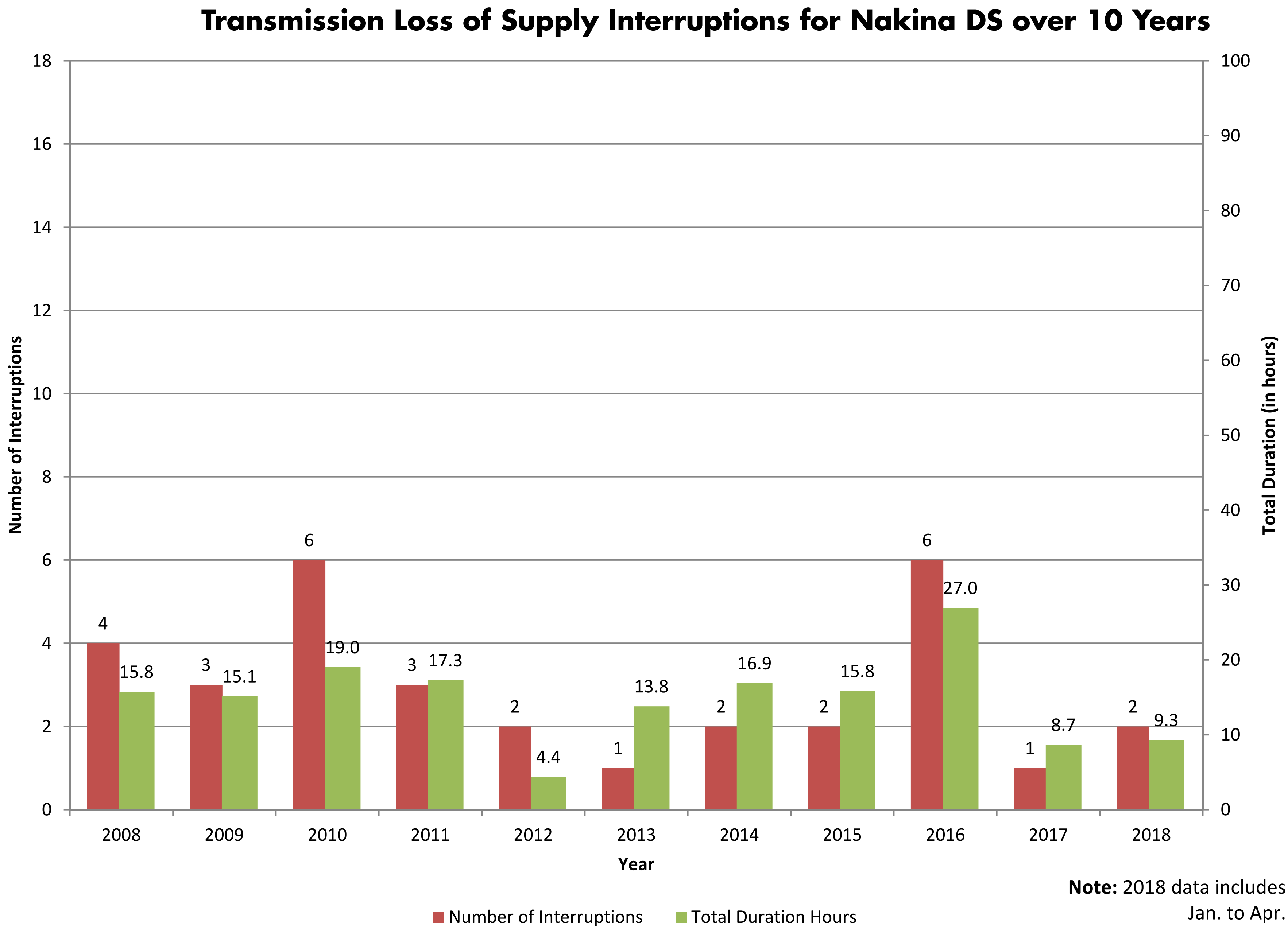
Nakina DS F2 - Duration of Upstream Outages by Cause (5 Years)



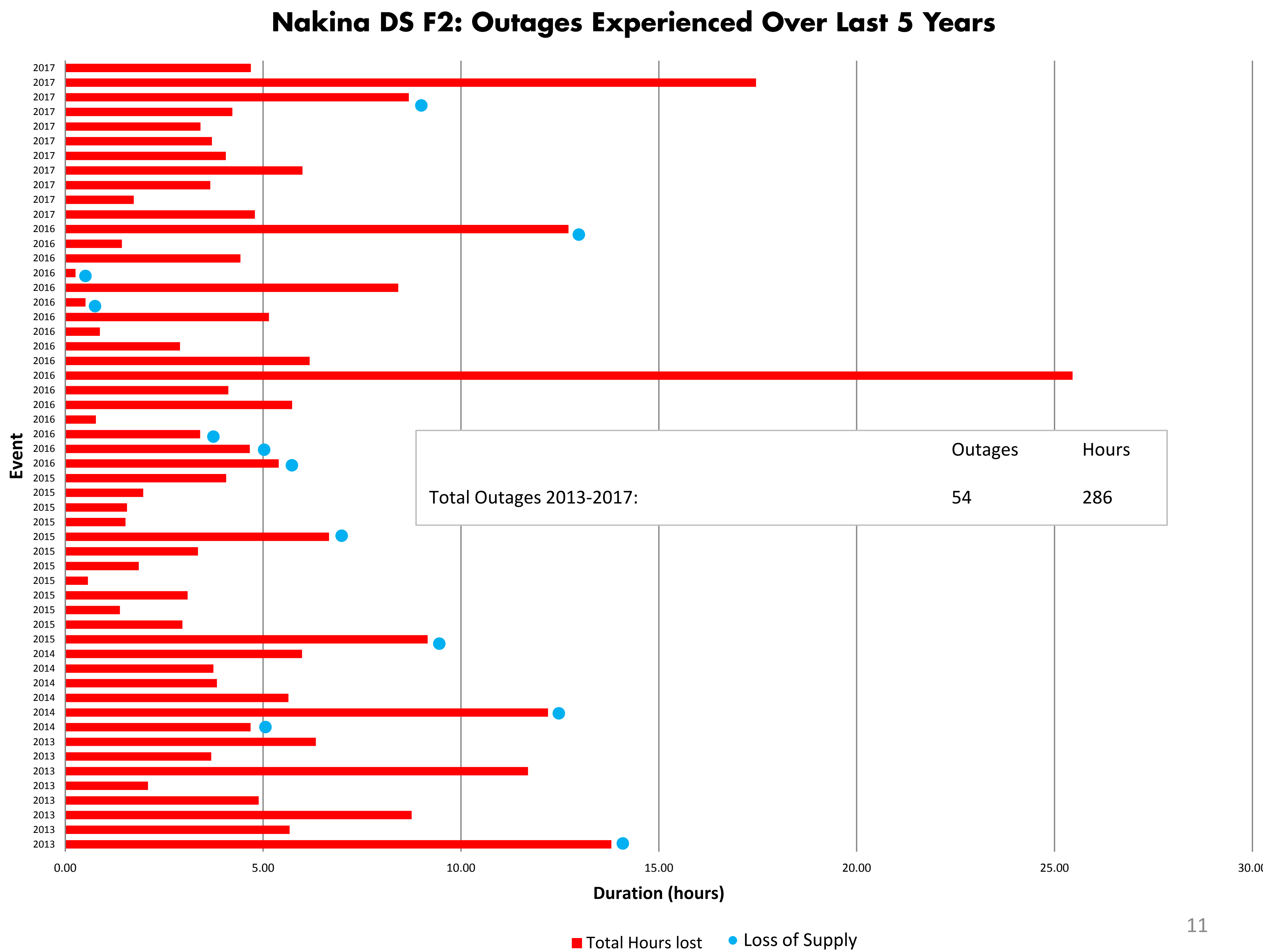
*Vegetation management will improve by 20-40% over the planning period.

Nakina DS F2 - Number and Total Duration of Outages by Year

Year	Number of Outages	Total Duration of Outages (Hours)
2013	8	57
2014	6	36
2015	12	38
2016	17	92
2017	11	62

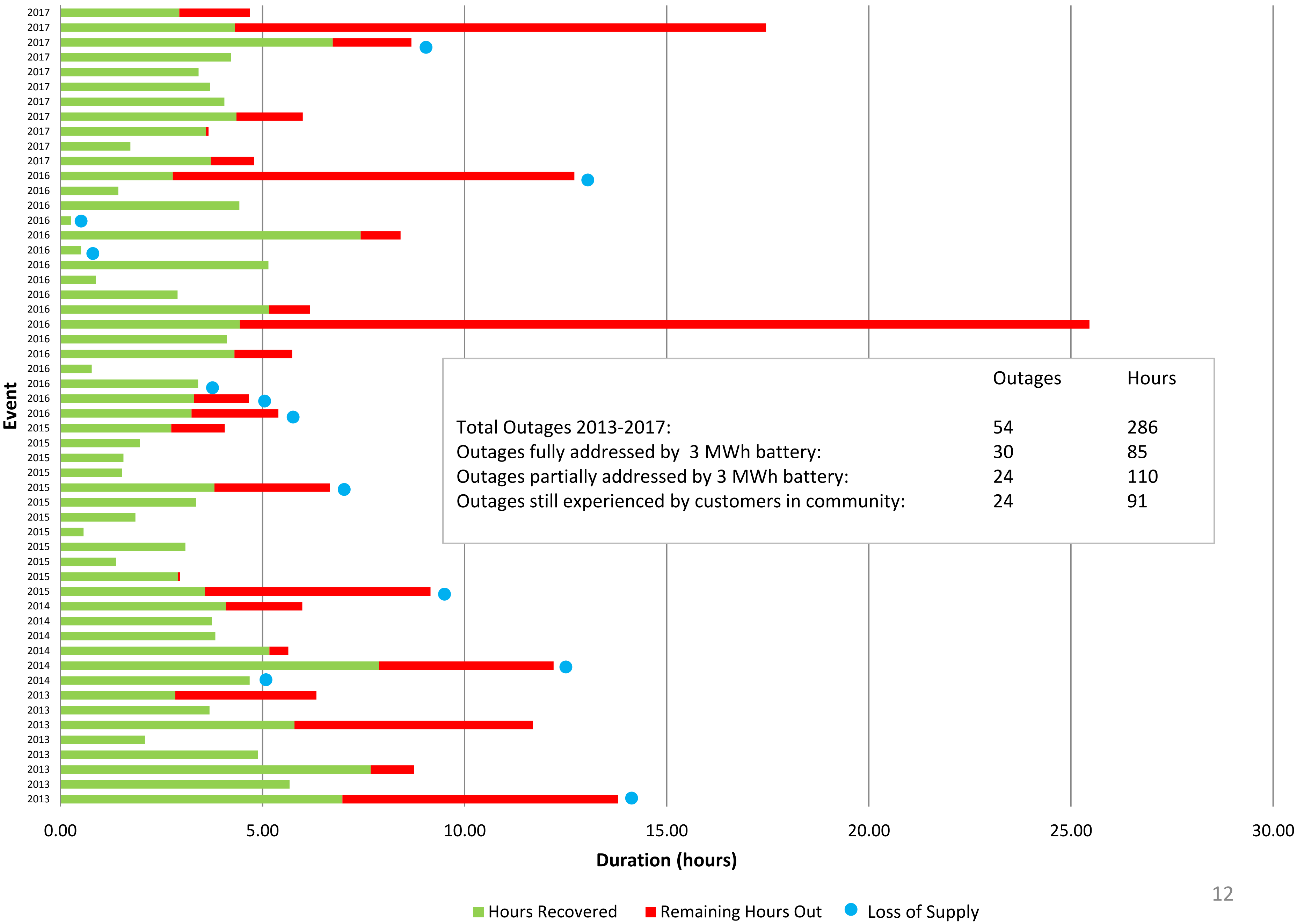


Note: 2018 data includes Jan. to Apr.

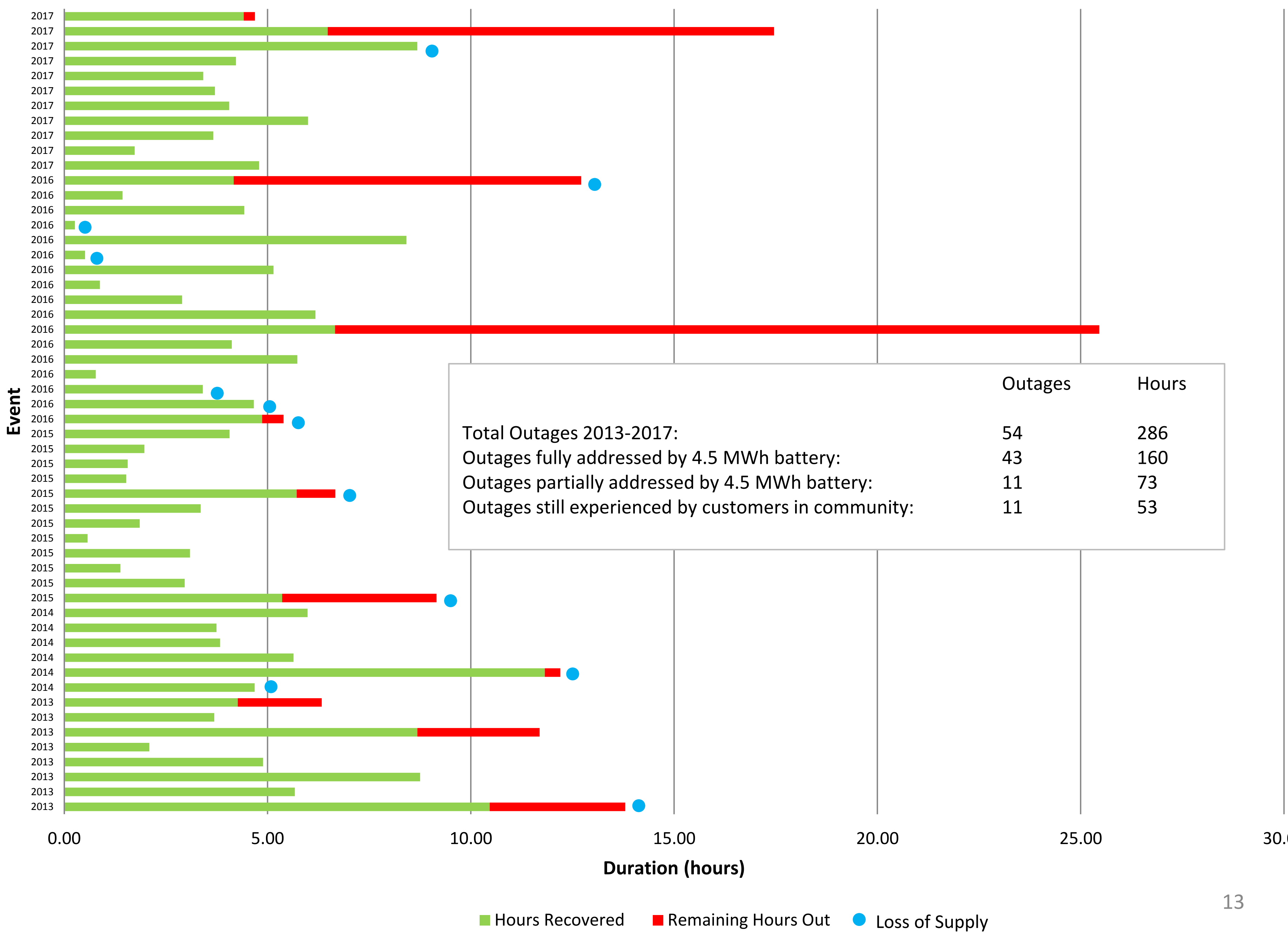


Nakina DS F2: Outages Experienced Over Last 5 Years
Event
Duration (hours)
0.00
5.00
10.00
15.00
20.00
25.00
30.00
2017
2016
2015
2014
2013
Outages
Hours
Total Outages 2013-2017:
54
286
Total Hours lost
Loss of Supply

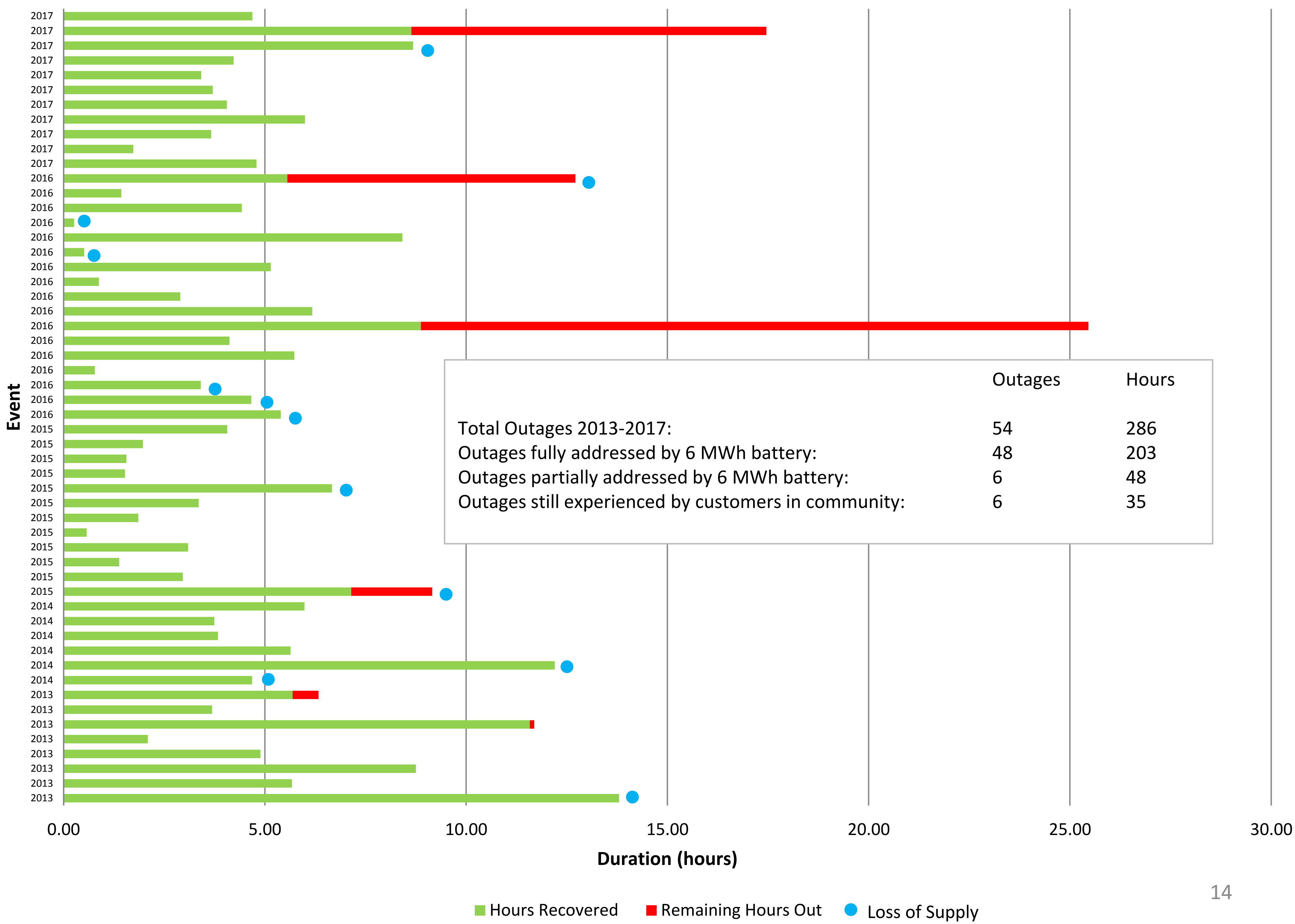
Nakina DS F2: Outage Impact with 1.5MW, 3MWh energy storage ($4.5M)



Nakina DS F2: Outage Impact with 1.5MW, 4.5MWh energy storage ($6.8M)

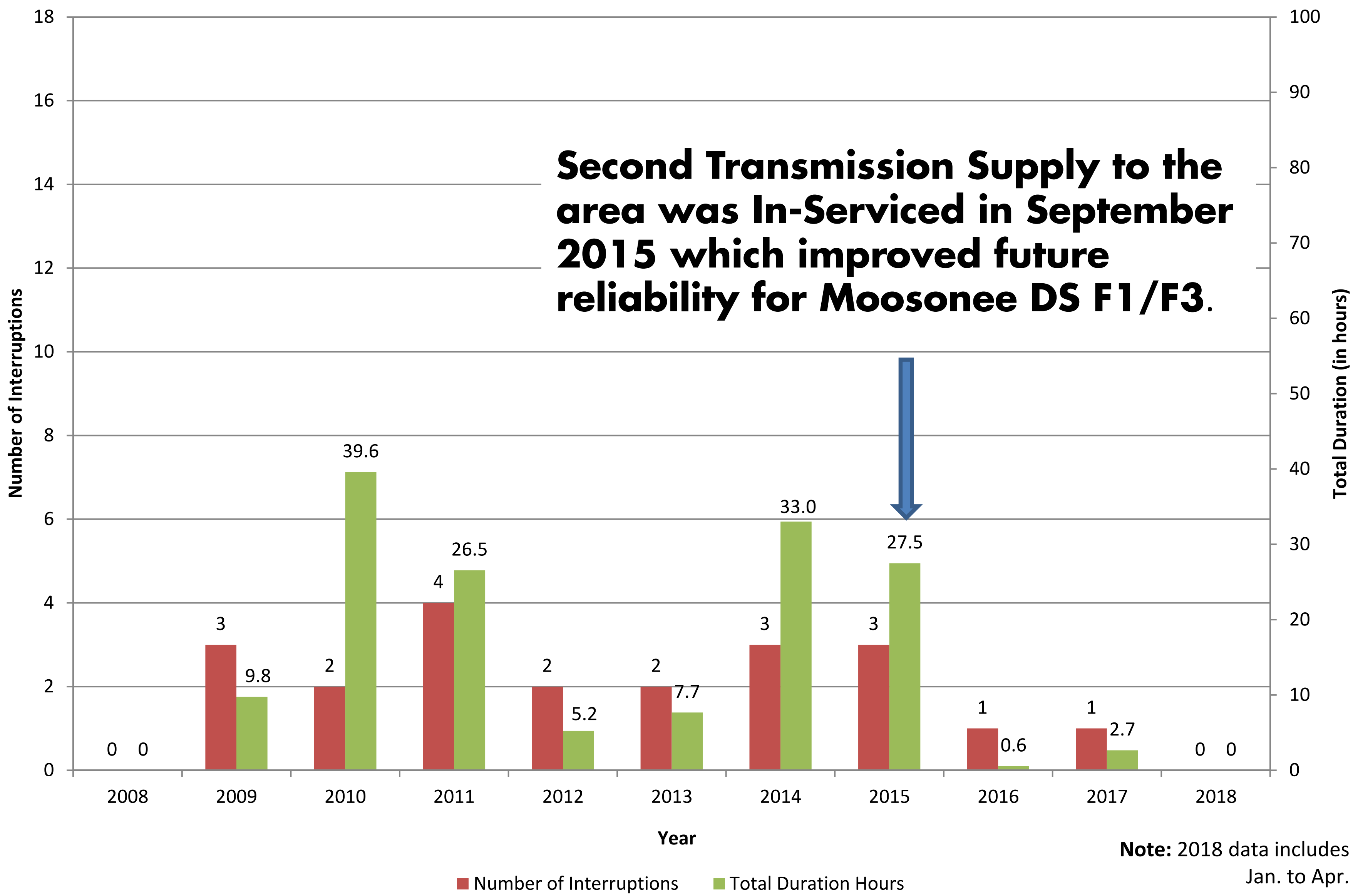


Nakina DS F2: Outage Impact with 1.5MW, 6MWh energy storage ($9M)



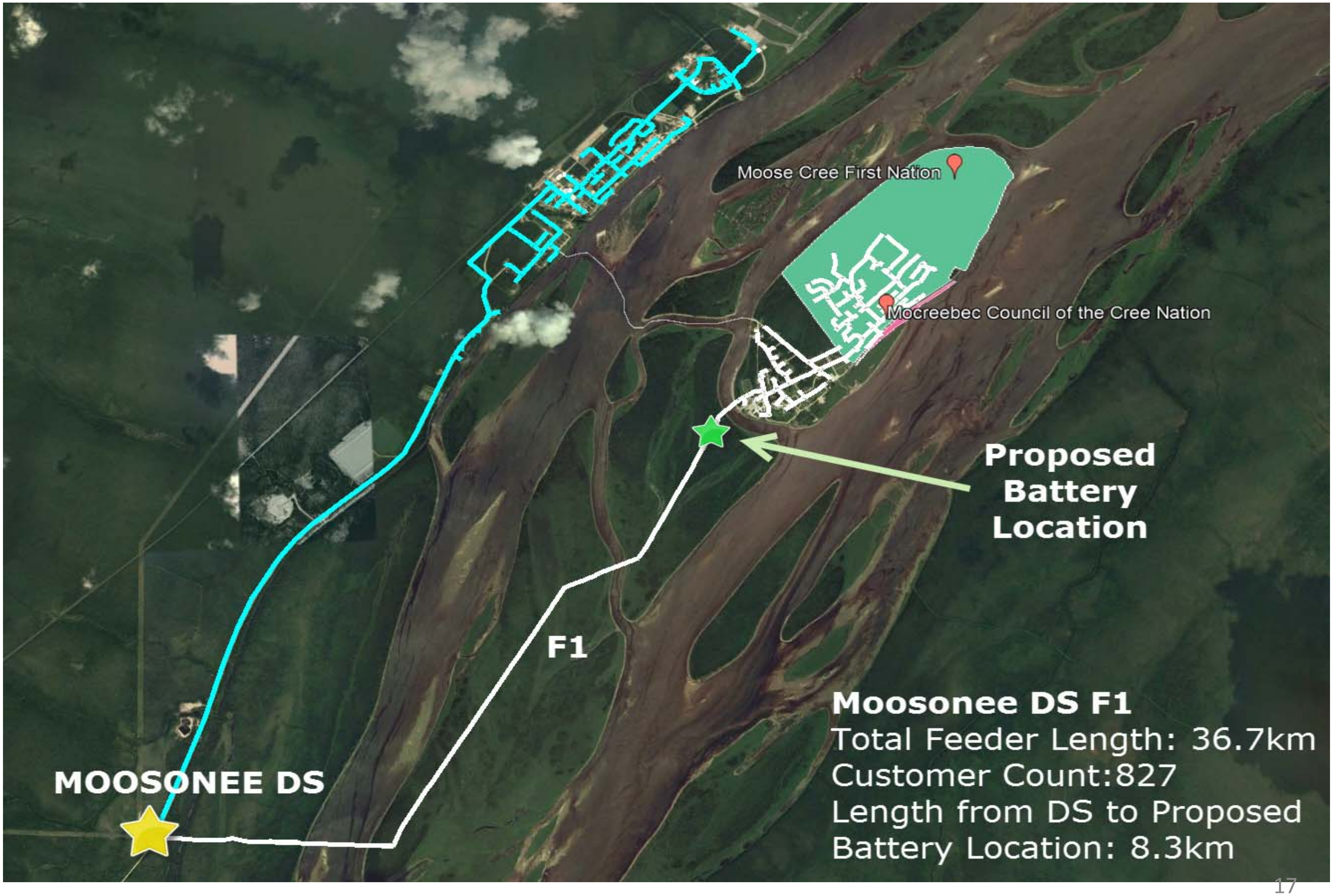
Moosonee DS F1/F3 Energy Storage Reliability Overview

Transmission Loss of Supply (LOS) Interruptions for Moosonee DS F1/F3 over 10 Years

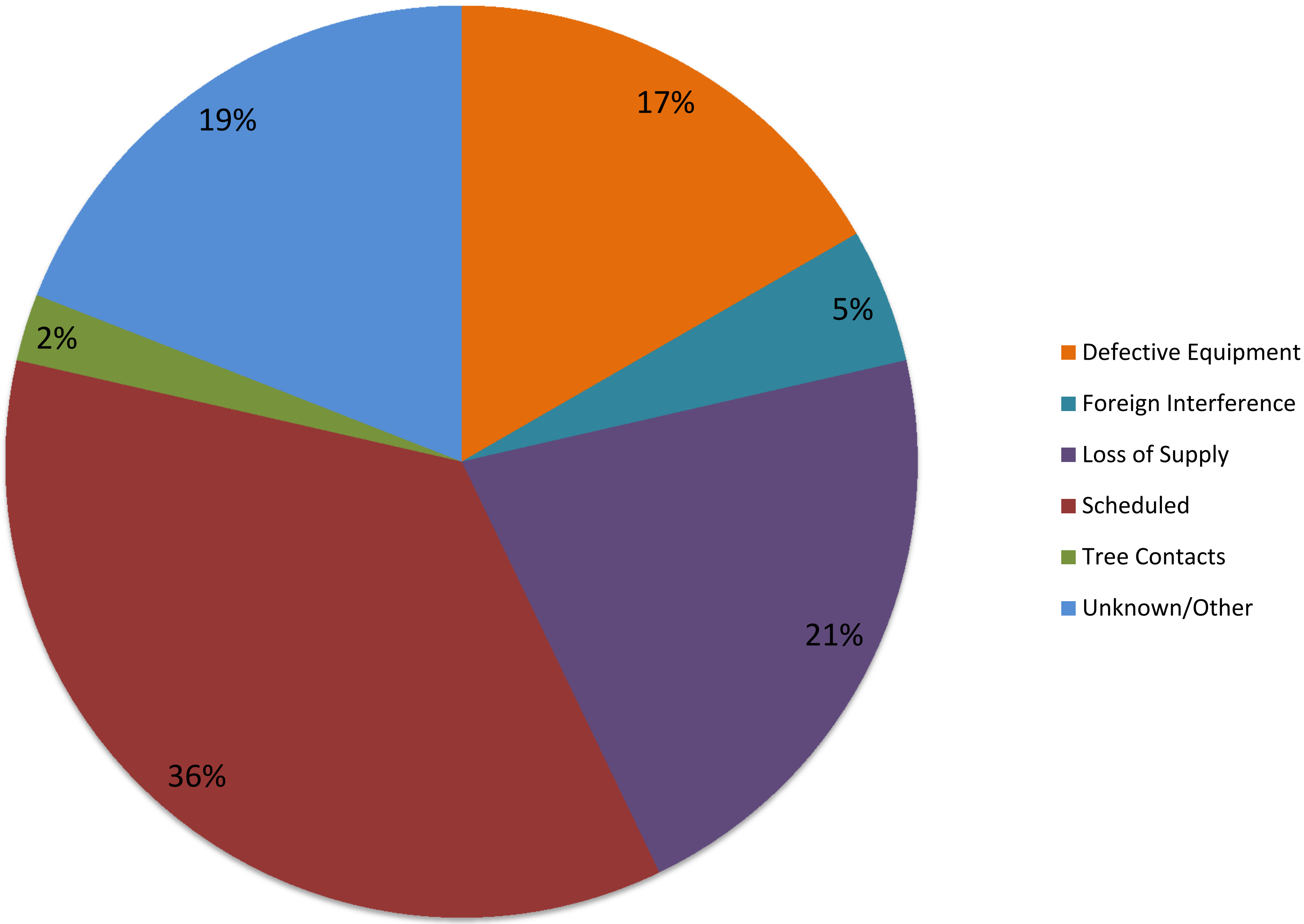


Note: 2018 data includes Jan. to Apr.

Moosonee DS F1



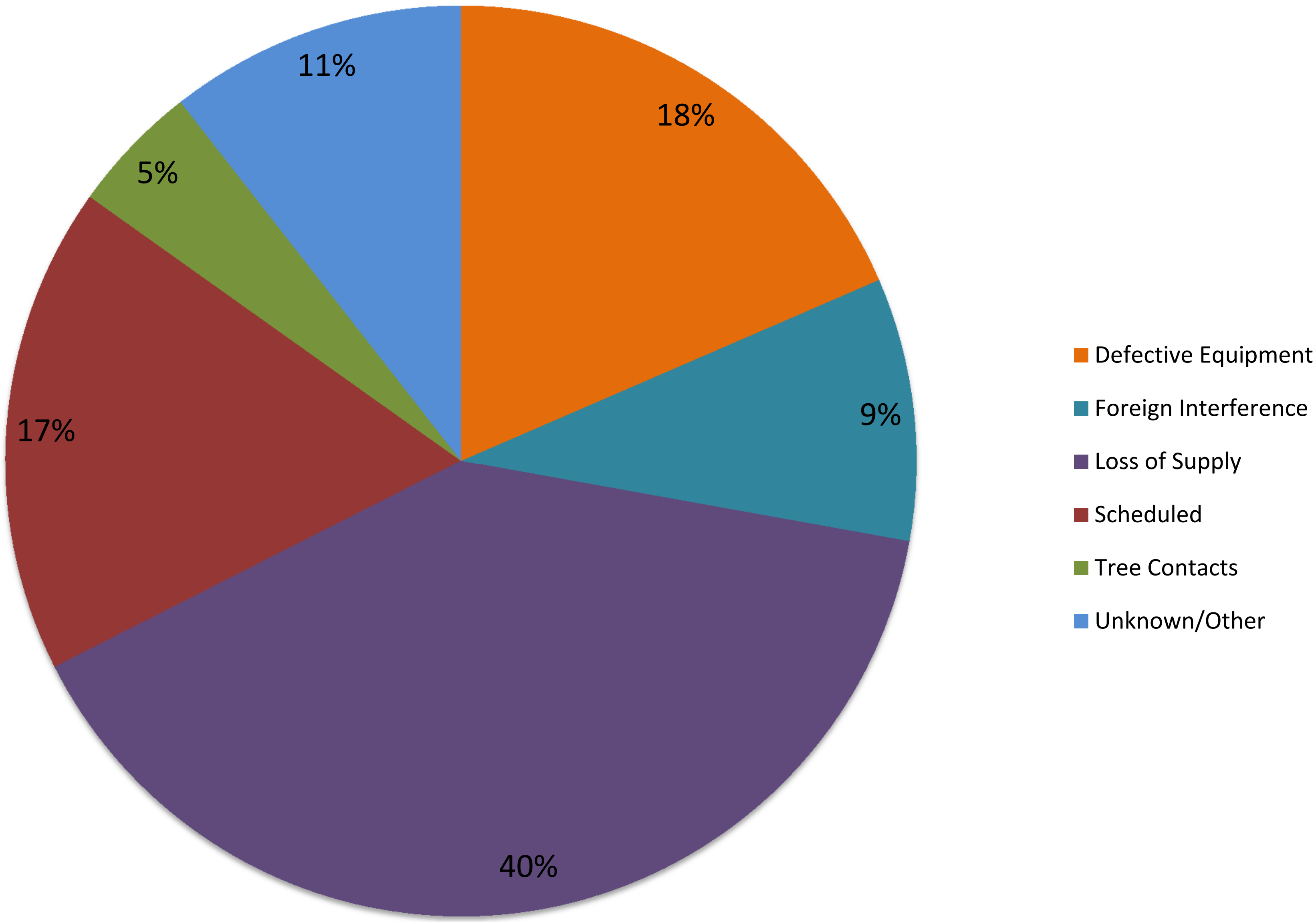
Moosonee DS F1: Frequency of Upstream Outages by Cause (5 years)



*Vegetation management will improve by 20-40% over the planning period.

** Reduction in frequency of Loss of Supply is expected due to upstream transmission investments.

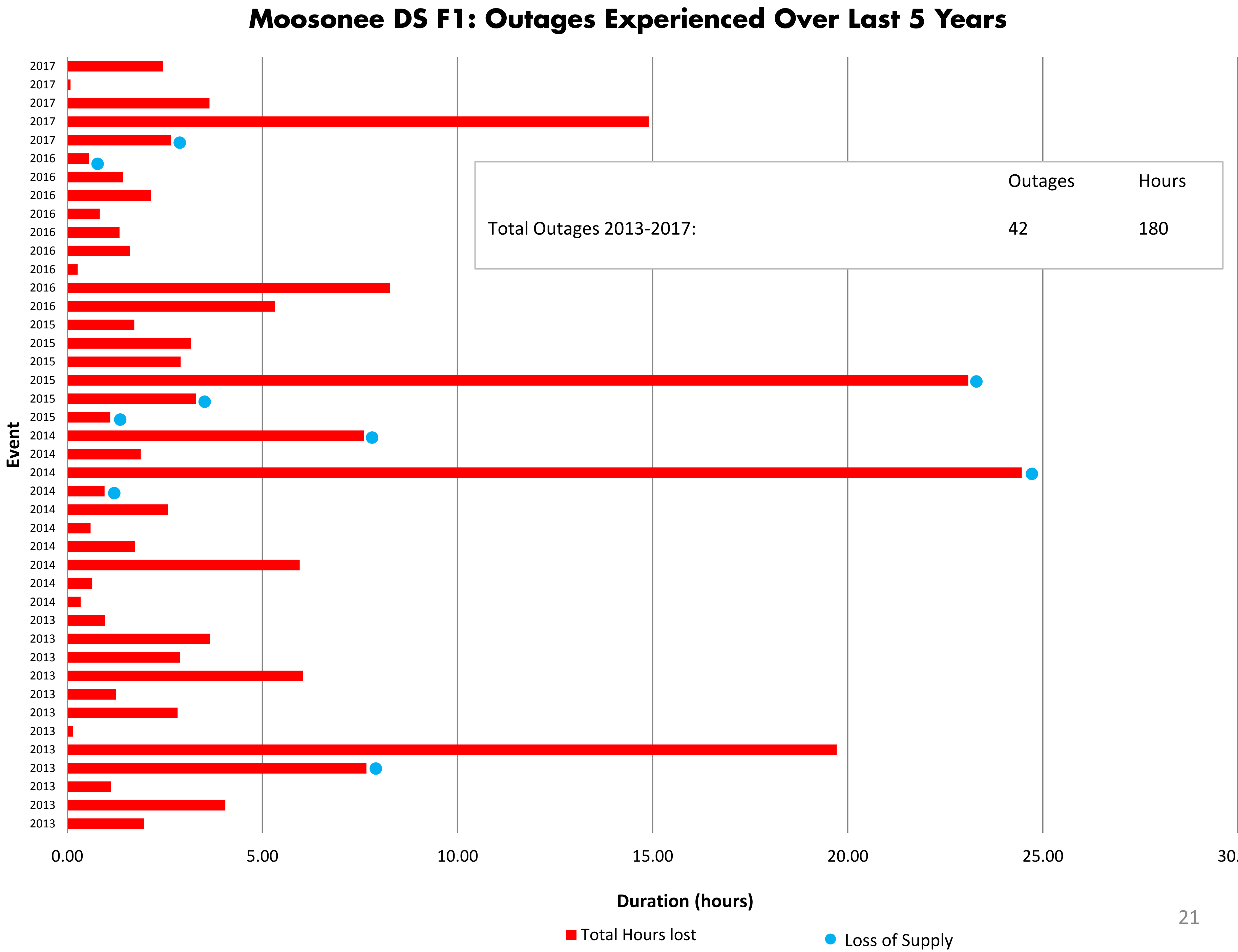
Moosonee DS F1: Duration of Upstream Outages by Cause (5 years)



*Vegetation management will improve by 20-40% over the planning period.
** Reduction in frequency of Loss of Supply is expected due to upstream transmission investments.

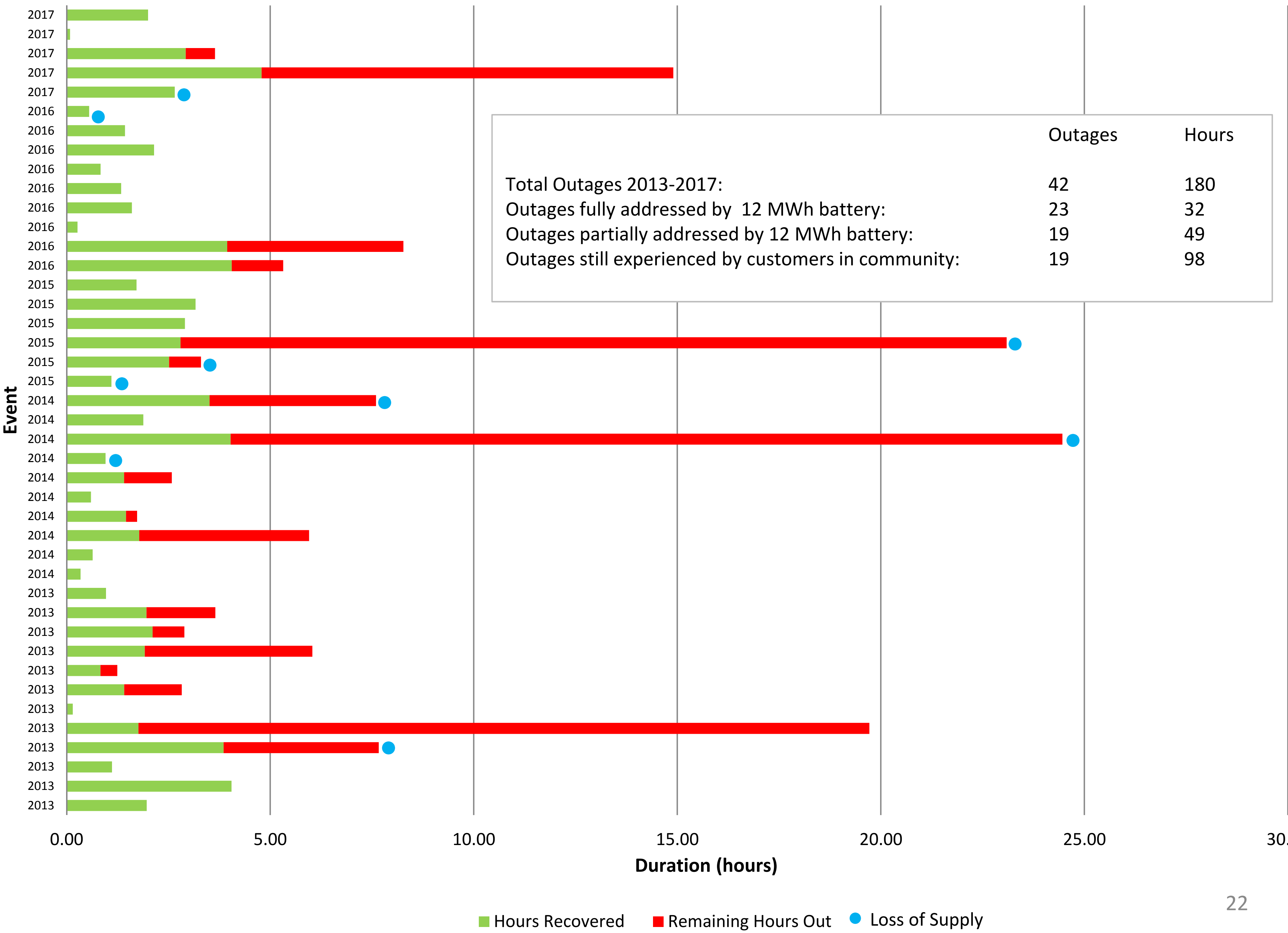
Moosonee DS F1 - Number and Total Duration of Outages by Year

Year	Number of Outages	Total Duration of Outages (Hours)
2013	12	52
2014	10	47
2015	6	35
2016	9	22
2017	5	24

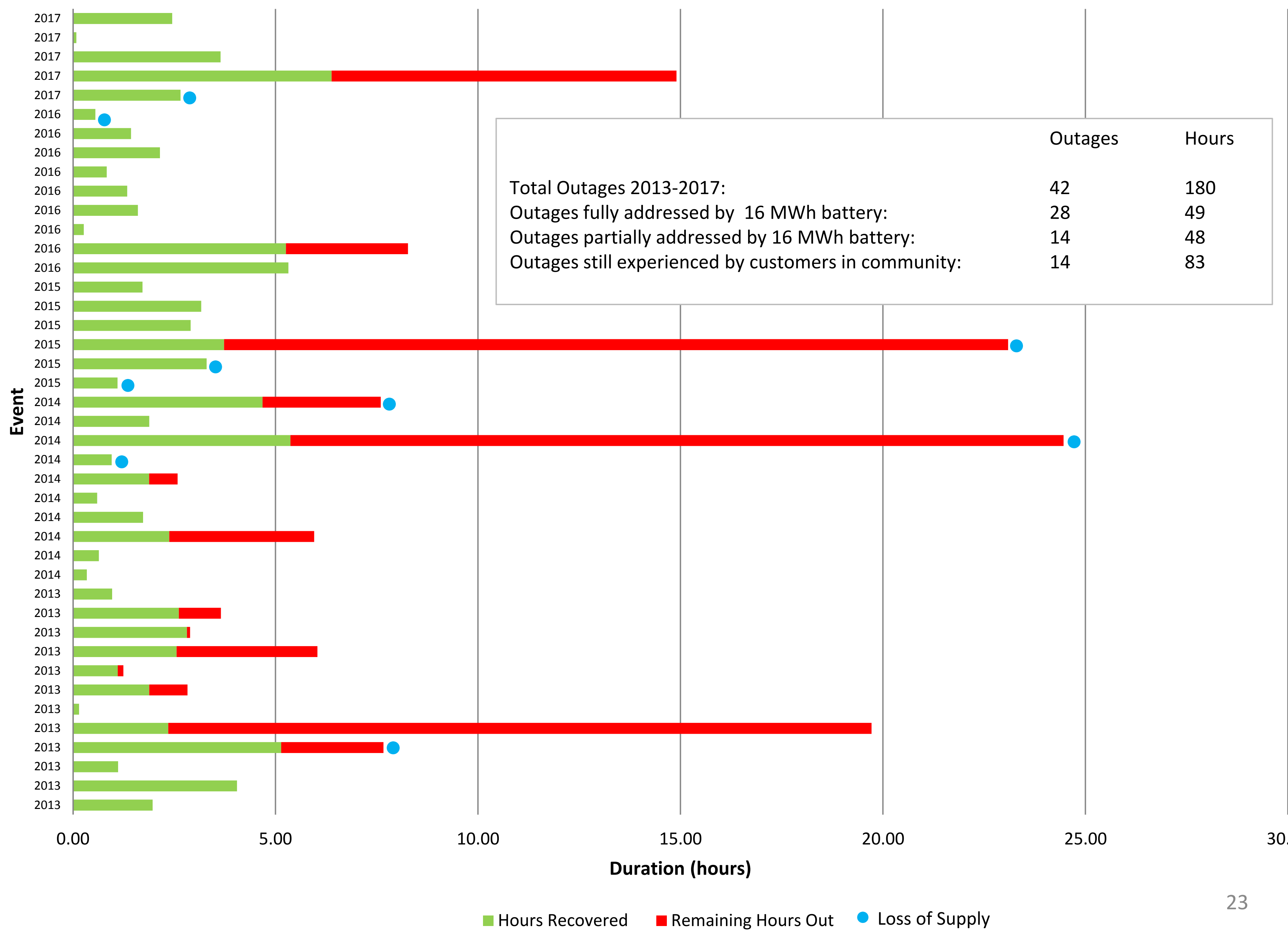


Moosonee DS F1: Outages Experienced Over Last 5 Years
Outages
Hours
Total Outages 2013-2017:
42
180
Event
2017
2016
2015
2014
2013
0.00
5.00
10.00
15.00
20.00
25.00
30.00
Duration (hours)
Total Hours lost
Loss of Supply

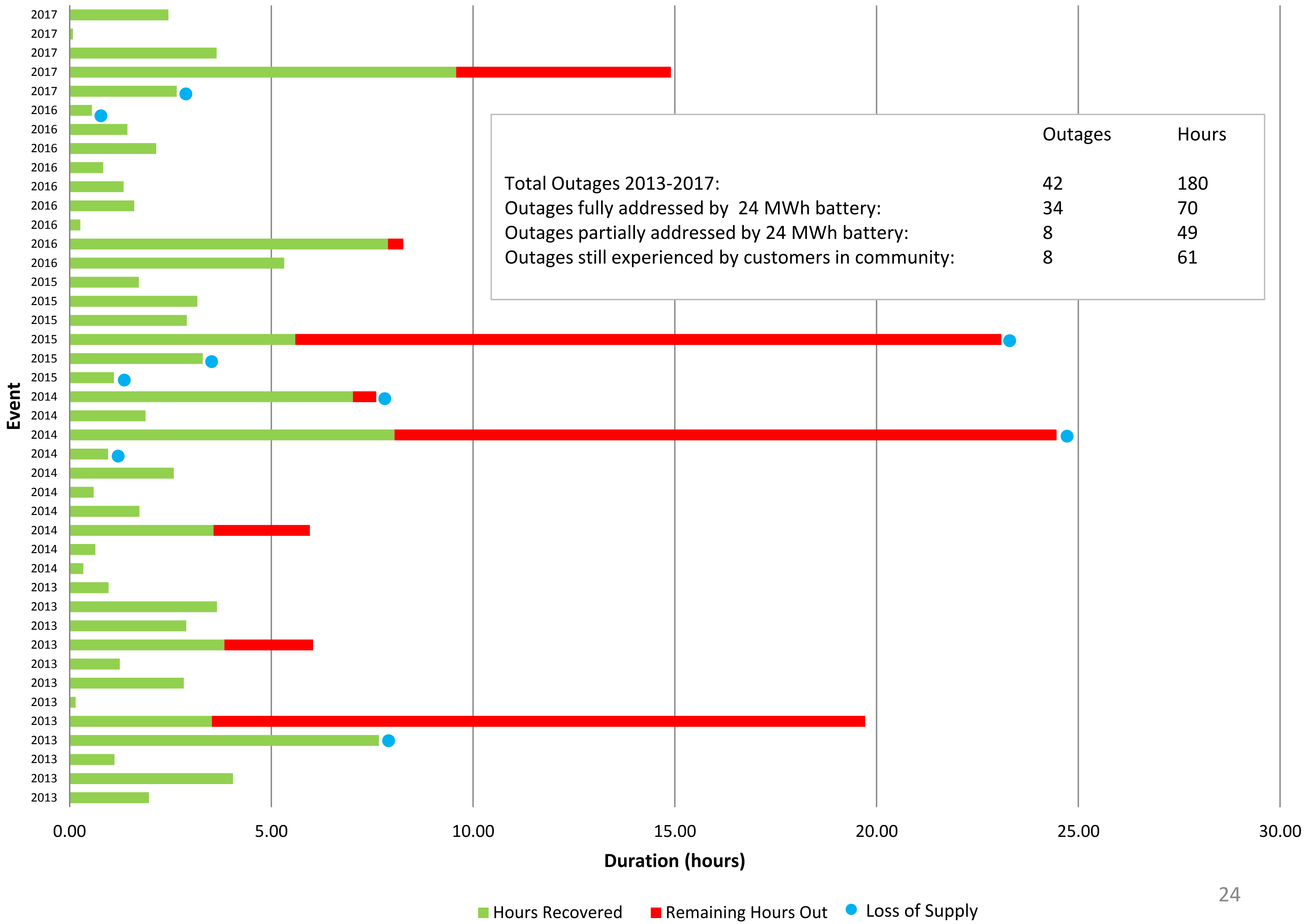
Moosonee DS F1: Outage Impact with 8MW, 12MWh energy storage ($18M)



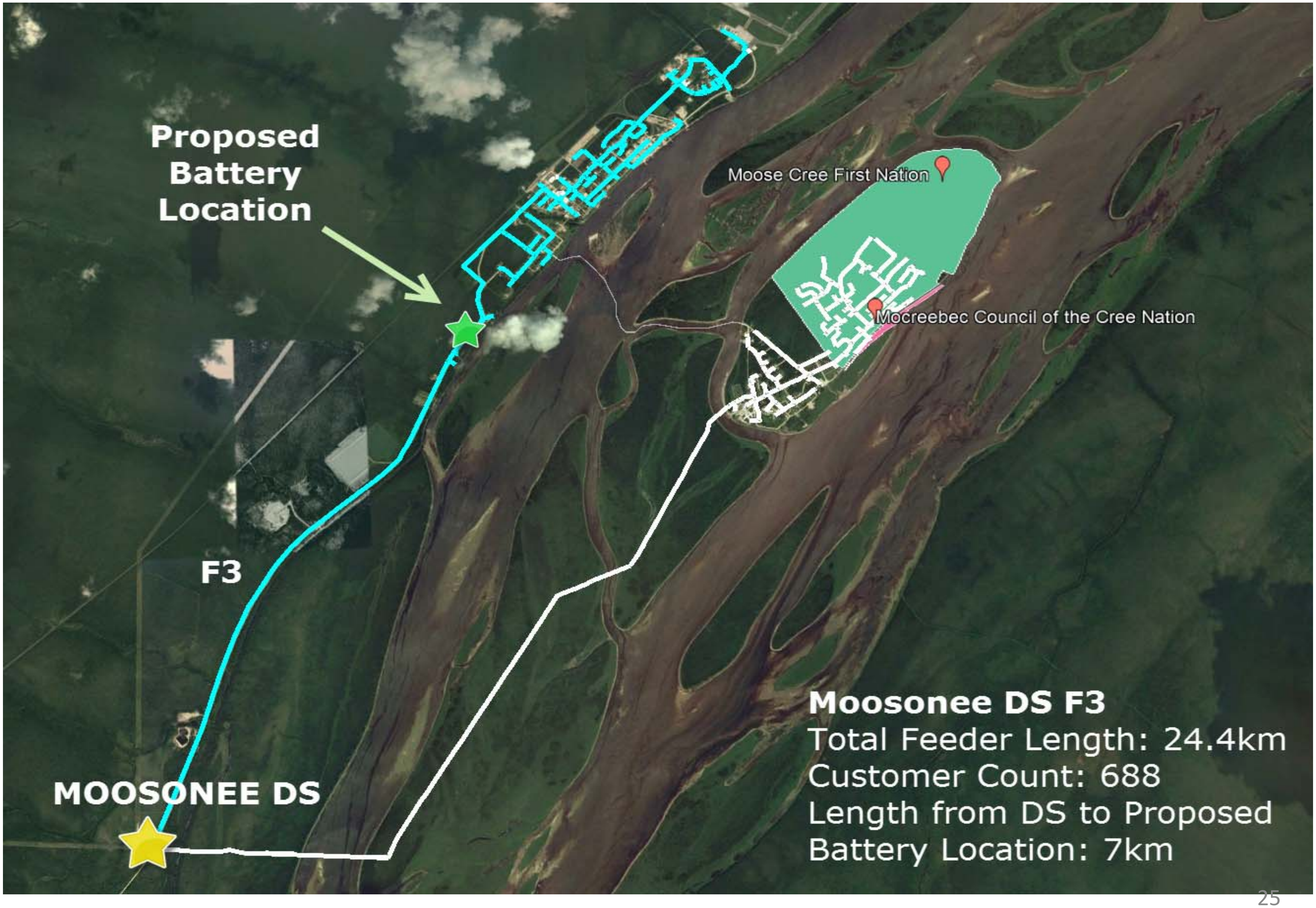
Moosonee DS F1: Outage Impact with 8MW, 16MWh energy storage ($24M)



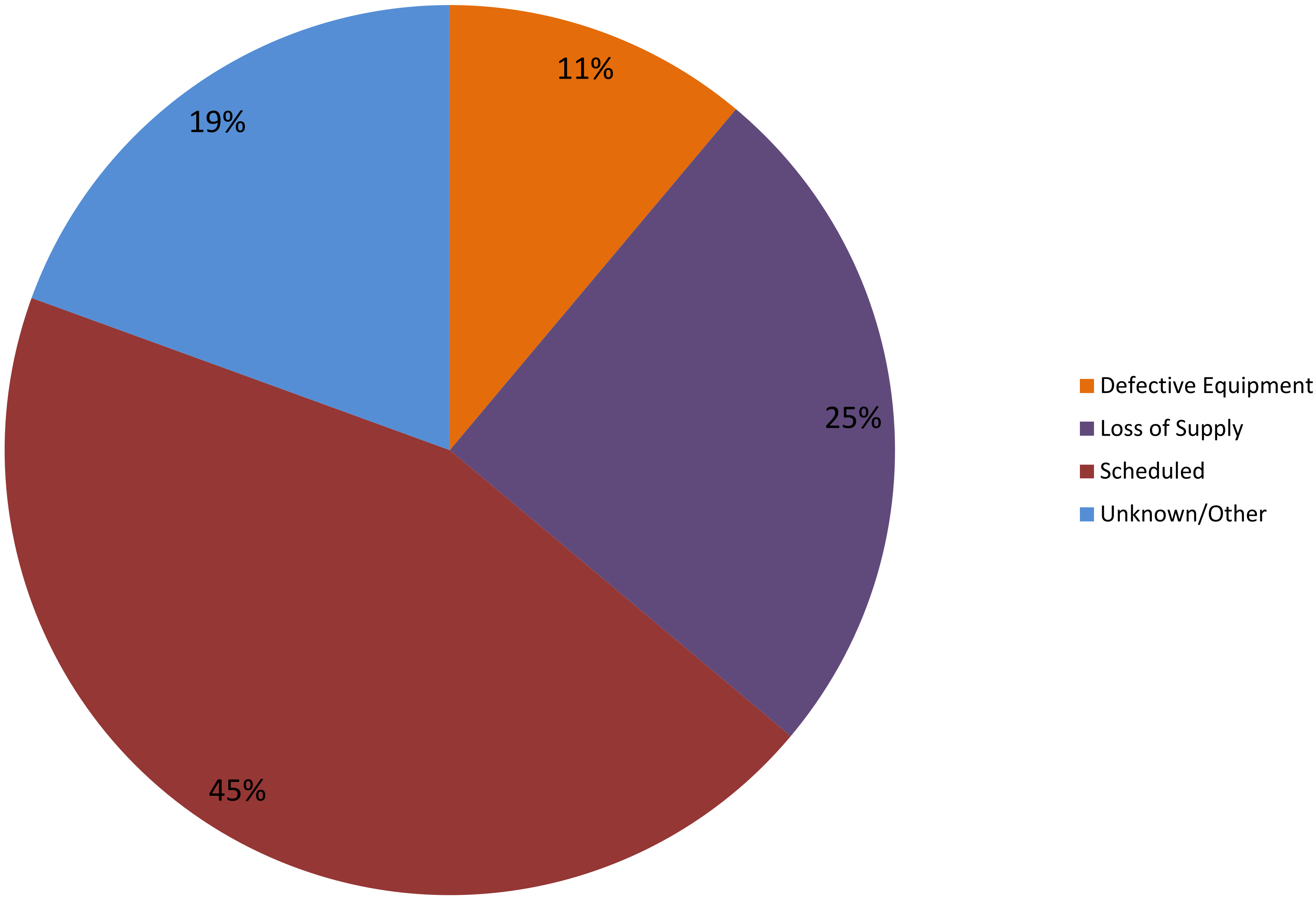
Moosonee DS F1: Outage Impact with 8MW, 24MWh energy storage ($36M)



Moosonee DS F3

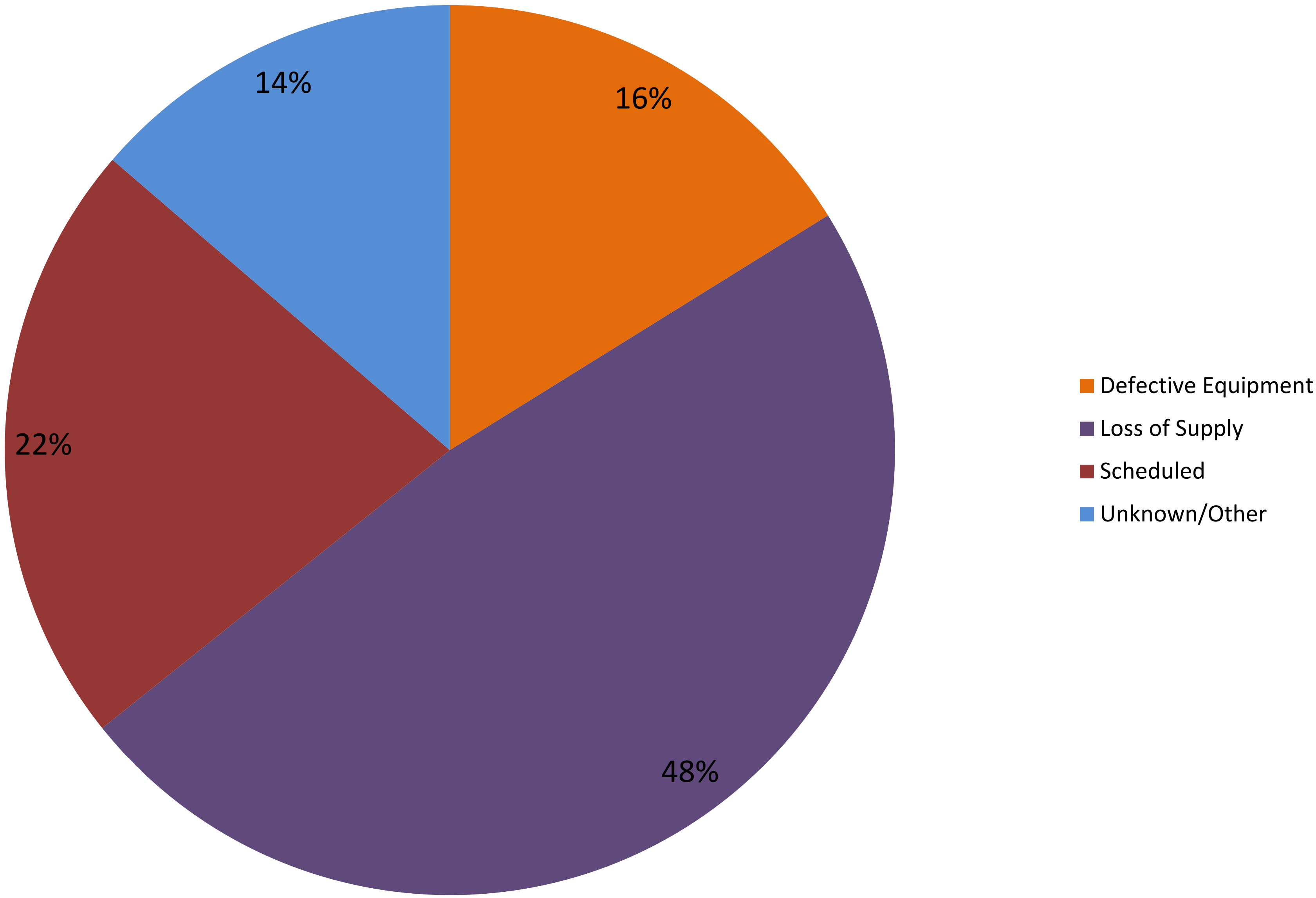


Moosonee DS F3: Frequency of Upstream Outages by Cause (5 years)



* Reduction in frequency of Loss of Supply is expected due to upstream transmission investments.

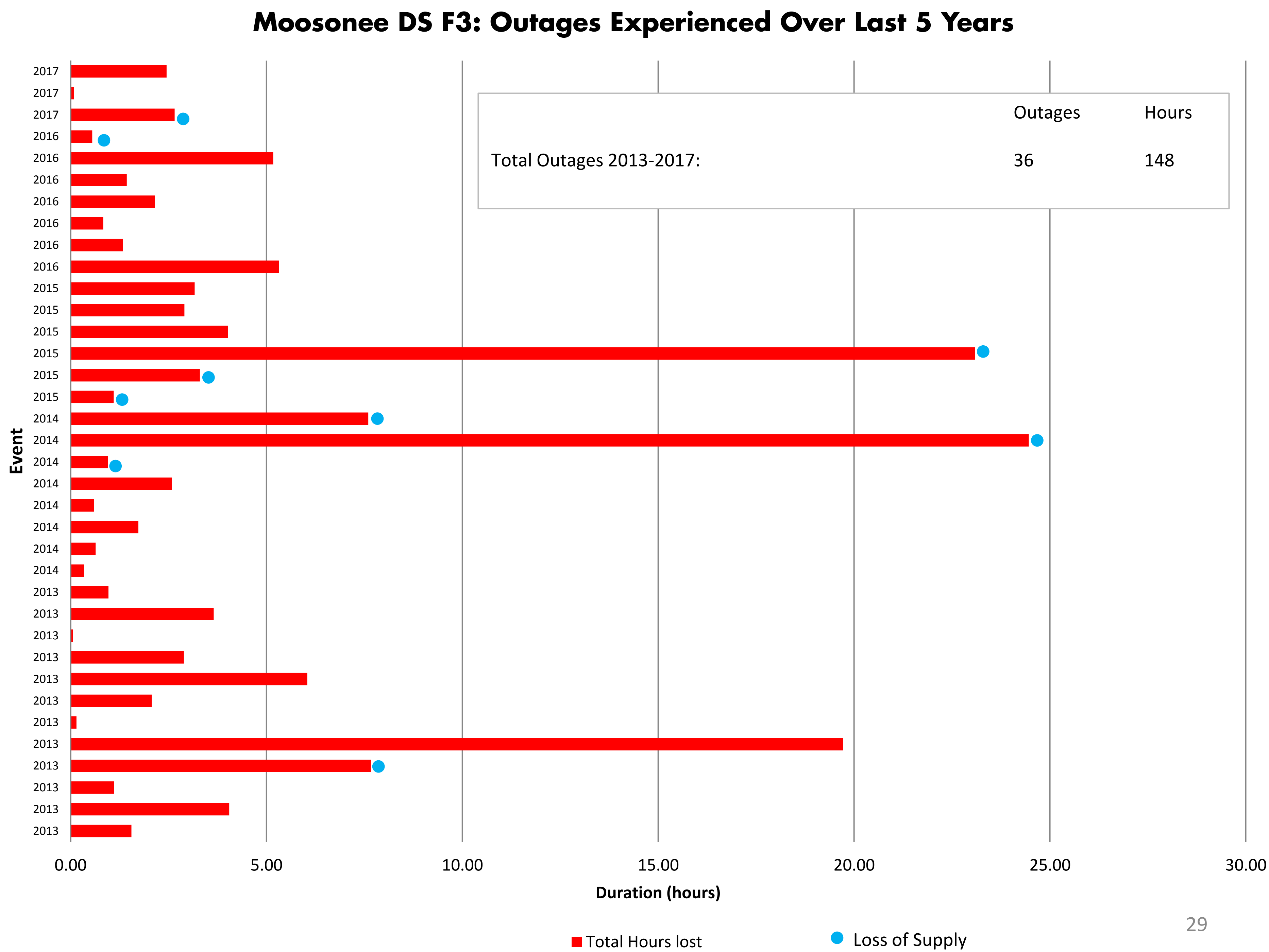
Moosonee DS F3: Duration of Upstream Outages by Cause (5 years)

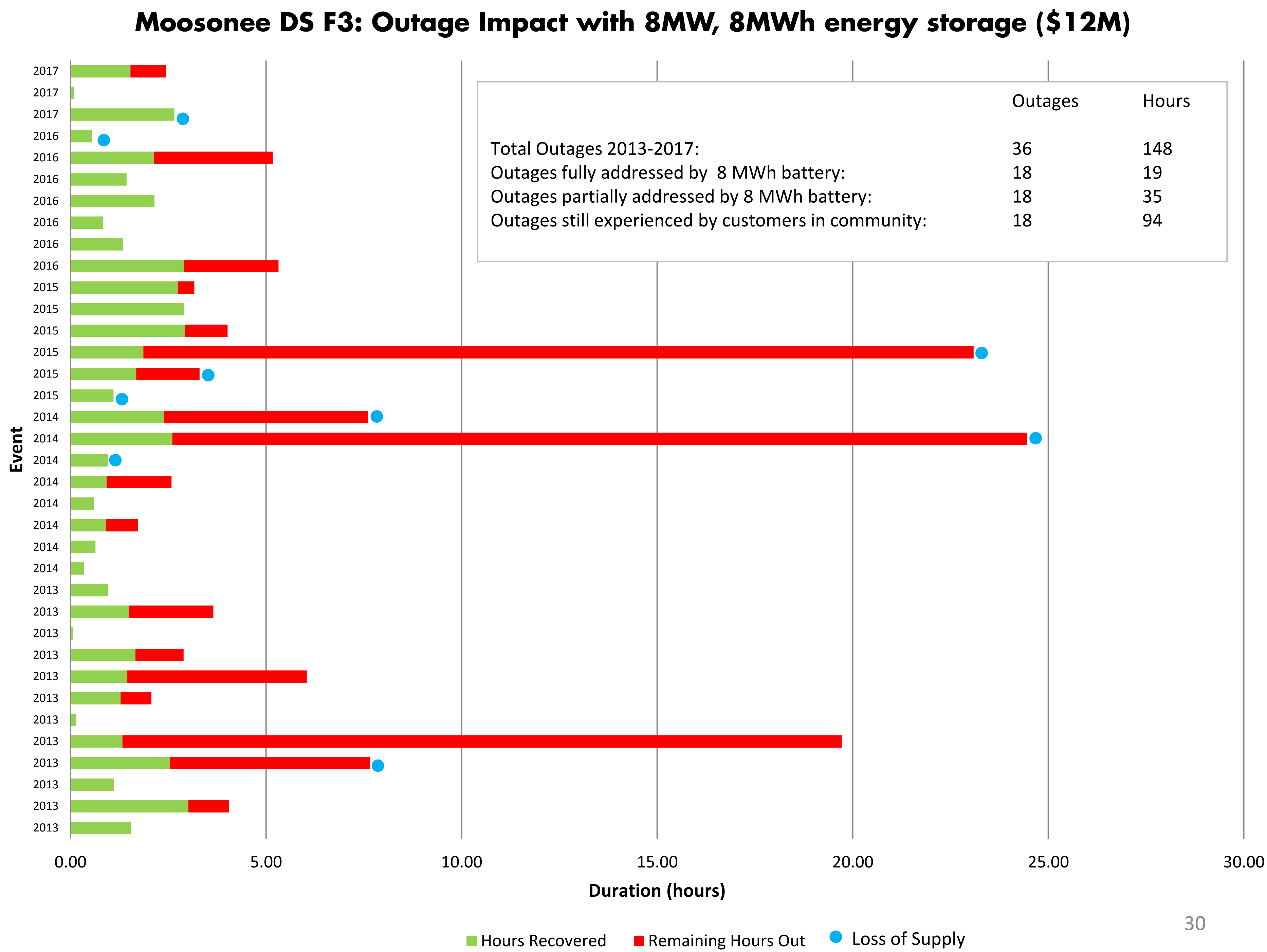


* Reduction in frequency of Loss of Supply is expected due to upstream transmission investments.

Moosonee DS F3: Number and Total Duration of Outages by Year

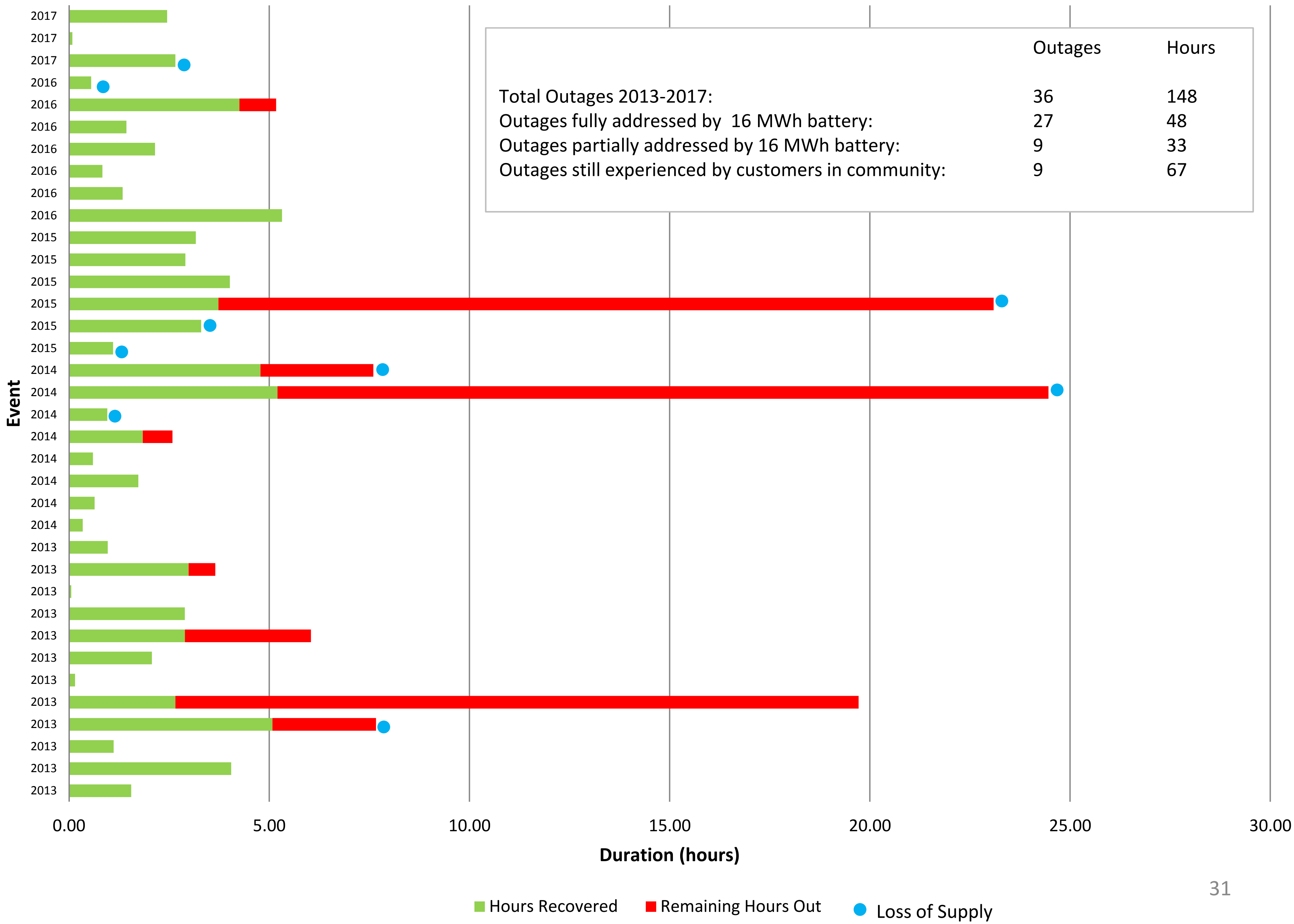
Year	Number of Outages	Total Duration of Outages (Hours)
2013	12	50
2014	8	39
2015	6	38
2016	7	17
2017	3	5


Moosonee DS F3: Outages Experienced Over Last 5 Years
Outages
Hours
Total Outages 2013-2017:
36
148
Event
2017
2017
2017
2016
2016
2016
2016
2016
2016
2016
2015
2015
2015
2015
2015
2015
2014
2014
2014
2014
2014
2014
2014
2014
2013
2013
2013
2013
2013
2013
2013
2013
2013
2013
2013
2013
0.00
5.00
10.00
15.00
20.00
25.00
30.00
Duration (hours)
Total Hours lost
Loss of Supply

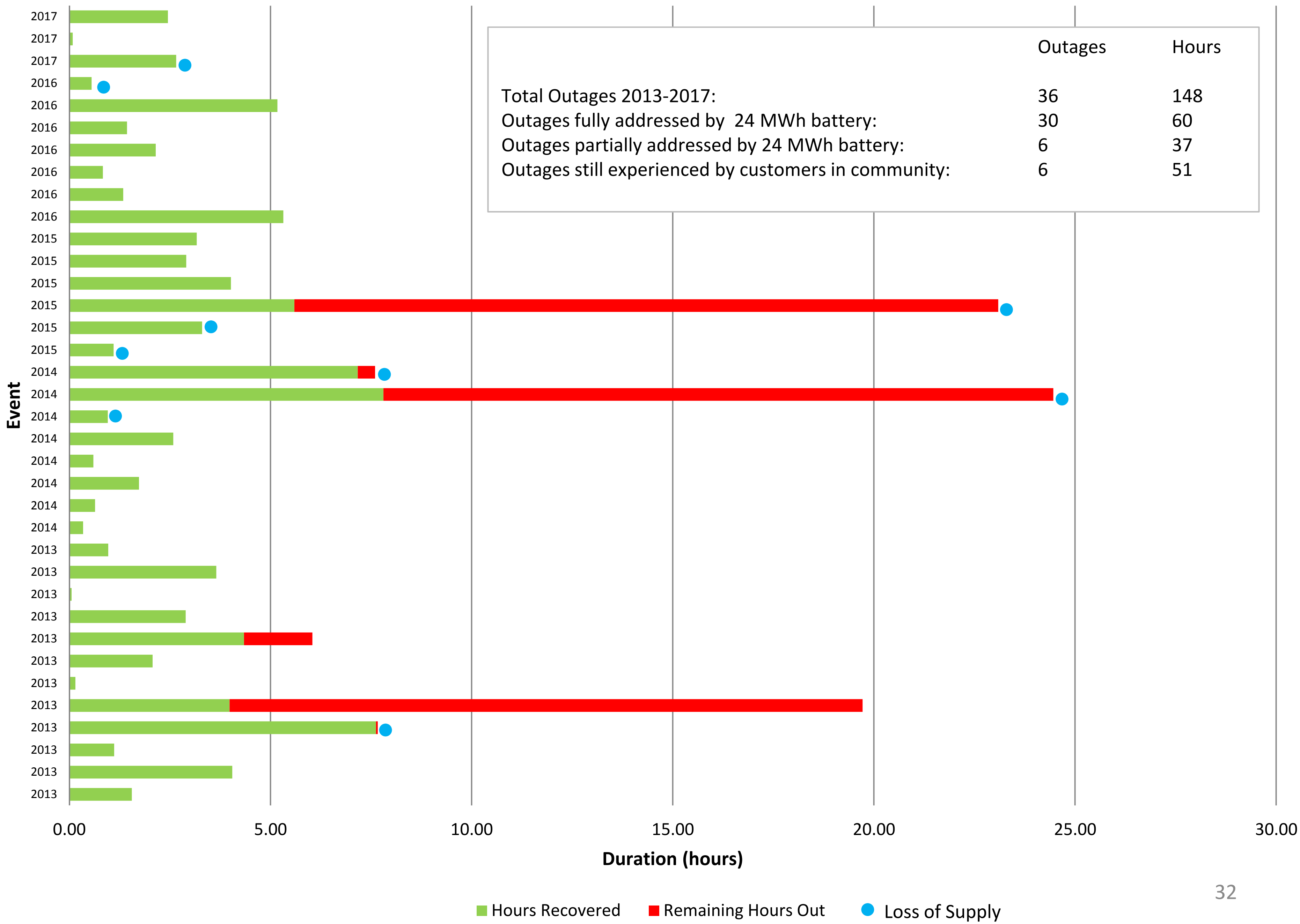


Moosonee DS F3: Outage Impact with 8MW, 8MWh energy storage ($12M)
Outages
Hours
Total Outages 2013-2017: 36 148
Outages fully addressed by 8 MWh battery: 18 19
Outages partially addressed by 8 MWh battery: 18 35
Outages still experienced by customers in community: 18 94
Event
2017
2017
2017
2016
2016
2016
2016
2016
2016
2016
2015
2015
2015
2015
2015
2015
2014
2014
2014
2014
2014
2014
2014
2014
2013
2013
2013
2013
2013
2013
2013
2013
2013
2013
2013
2013
0.00
5.00
10.00
15.00
20.00
25.00
30.00
Duration (hours)
Hours Recovered
Remaining Hours Out
Loss of Supply

Moosonee DS F3: Outage Impact with 8MW, 16MWh energy storage ($24M)



Moosonee DS F3: Outage Impact with 8MW, 24MWh energy storage ($36M)



Investment Prioritization

- Retention of an experienced storage and engineering partner is underway.
- The detailed engineering and financial viability review is targeted by September 30, 2018.
- There may be additional value due to scalability.
- Pilot project funding sourced through redirection ($5M) and may be offset or augmented by government funding programs.