Yukon Energy Corporation
Application For

an Energy Project Certificate
and
an Energy Operation Certificate

Regarding The Proposed
Battery Energy Storage System Project

January 2021

TABLE OF CONTENTS

1.0 INTRODUCTION 1

2.0 APPLICANT 2

3.0 PROJECT DESCRIPTION 3

3.1 PROJECT SUMMARY DESCRIPTION 3

3.1.1 Existing Facilities and Project Components 3

3.1.2 Project Uses 5

3.1.3 Project Costs and First Nation Debenture Investment 16

3.2 ANTICIPATED TIMELINE 19

3.3 RELATED PROJECTS – WHITEHORSE INTERCONNECTION FACILITY 22

3.4 SUMMARY OF ENVIRONMENTAL AND SOCIO-ECONOMIC IMPACTS 22

4.0 PROJECT JUSTIFICATION 24

4.1 YUKON GRID CONTEXT 24

4.1.1 Yukon Grid Context 24

4.1.2 Evolving Grid Load Conditions 25

4.1.3 Forecast New Grid Capacity Required 25

4.2 NEED FOR AND ALTERNATIVES TO THE PROJECT 29

4.2.1 Alternatives to the Project 29

4.2.2 Alternative Ways of Undertaking Project & Preferred Alternative 31

4.2.3 Project Economics 36

4.3 RISKS AND POTENTIAL IMPACTS ON RATEPAYERS 39

5.0 CONSULTATION 41

5.1 YESAB PROCESS 42

6.0 OTHER APPLICATIONS AND APPROVALS 43

6.1 LIST OF APPROVALS, PERMITS AND LICENCES 43

6.2 CONDITIONS AFFECTING APPROVALS 44

LIST OF TABLES

Table 3-1: Estimated Annual Throughput for 20 MW/40 MWh BESS on YIS 6
Table 3-2: BESS Energy Capacity Peak Reduction Benefits – Range of Capacity Sizes 9
Table 3-3: BESS Operating Reserve Use & Thermal Generation Reduction (20 MW/40 MWh) 12
Table 3-4: Estimated Capital Costs for Project Facilities (2020$) 16
Table 3-5: Estimated Annual Operating Costs for Project Facilities (2020$) 17
Table 4-1: Forecast Non-Industrial Peak and Dependable Capacity under N-1 Capacity Planning Criterion: 2021/22-2030/31 Winter (MW) 28
Table 4-2: BESS Operating Reserve Use & Thermal Generation Reduction – Range of Sizes 35
Table 4-3: Annual Ratepayer Impacts from BESS (20 MW/ 40 MWh) 39
Table 6-1: Regulatory Authorizations Required for the Project 43

LIST OF FIGURES

Figure 3-1: YIS Load Profile (MW by hour) for 5 Peak Days in January 2020 7
Figure 3-2: BESS Energy Capacity (MWh), Max Power (MW) & Recharge for N-1 Capacity Reserve 8
Figure 4-1: Non-Industrial Peak & Dependable Capacity under N-1 Capacity Planning Criterion: 2021/22-2041/42 Winter 28

LIST OF APPENDICES

Appendix A Supporting Figures and Tables

Appendix B Hatch Report

1.0 INTRODUCTION

Yukon Energy Corporation ("**YEC**" or "**Yukon Energy**") hereby applies (the "**Application**") to the Minister of Justice (the "**Minister**") for an energy project certificate and an energy operation certificate (the "**Certificates**") for the proposed Battery Energy Storage System Project (the "**Project**"). The Project has been designated by OIC 2020/180 as a "regulated project" under Part 3 of *the Public Utilities Act*. It is understood that, as required by Part 3 of the *Public Utilities Act*, the Minister will refer this Application for the Certificates to the Yukon Utilities Board (the "**YUB**", or the "**Board**") for a review.

The Project will provide a containerized lithium ion battery energy storage system ("**BESS**") located on undeveloped Kwanlin Dun First Nation ("**KDFN**") Category B settlement land in Whitehorse near the intersection of Robert Service Way and the Alaska Highway, and connected by a transmission line to the Yukon Energy Whitehorse Rapids facility.

The Project will provide 40 MWh of energy storage capacity and 7.2 MW of dependable capacity (i.e., displace four 1.8 MW diesel rental units) to the Yukon Integrated System ("**YIS**") for 20 years, reducing Yukon Energy's need to rely on rental of diesel generators during the winter months to address N-1 capacity shortfalls. It will also provide operating reserve that reduces thermal generation requirements, opportunities for diesel-peak shifting, enhanced blackstart capability, and other system benefits.

The Project will be located on the overlapping Traditional Territory of Ta'an Kwach'an Council ("**TKC"**) and KDFN, and will also include an investment opportunity for both TKC and KDFN.

It is expected that a proposal for the Project activities will be submitted by March 31, 2021 to the Yukon Environmental and Socio-economic Assessment Board ("**YESAB**") under the *Yukon Environmental and Socio-economic Assessment Act*, and is subject to a screening by the Whitehorse Designated Office. This process will lead to a recommendation by the YESAB Designated Office, and a response by the decision bodies[1] in the form of a decision document. Any government authorizations issued in support of the Project, including any Energy Project Certificate or Energy Operation Certificate under Part 3 of the *Public Utilities Act*, will have to conform to the decision document.

On December 17, 2020, the Commissioner in Executive Council designated the Project as a regulated project under Part 3 of the *Public Utilities Act* pursuant to OIC 2020/180. As prescribed by OIC 2007/50, Yukon Energy's Application for the Certificates for the Project includes the following sections:

- Applicant;
- Project Description;
- Project Justification;
- Consultation; and
- Other Applications and Approvals.

[1] The decision bodies are expected to be KDFN under Kwanlin Dun First Nation Lands Act, 2020 and the Yukon Government.

2.0 APPLICANT

The required information on the Applicant is as follows:

Yukon Energy Corporation
P.O. Box 5920
Whitehorse, Yukon, Y1A 6S7
Telephone: (867) 393-5300; Fax: (867) 393-5323; Website: www.yukonenergy.ca

The person with whom correspondence should be made respecting the Application is:

Mila Milojevic
Vice President, Resource Planning and Regulatory Affairs
Telephone: (867) 393-5326; Fax: (867) 393-5323;
Email: Mila.Milojevic@yec.yk.ca

3.0 PROJECT DESCRIPTION

3.1 PROJECT SUMMARY DESCRIPTION

The Project will install a containerized lithium ion battery energy storage system ("**BESS**") on a 1.5 ha site that Yukon Energy will lease on undeveloped KDFN Category B settlement land located northeast of the intersection of Robert Service Way and the Alaska Highway. The BESS will be connected to the Yukon Energy Whitehorse Rapids facility by a new 1.7 km 34.5 kV transmission line that goes north of the KDFN site, following existing easements through forested crown land until it meets and follows the path of the existing ATCO 34.5 kV line to the Whitehorse Rapids facility (see Appendix A, Figure A-1 for a map of the BESS site, the Project transmission line connection to the Whitehorse Rapids facility, and the connection therein to the Riverside Substation).

The Project will involve a grid-sized BESS with 40 MWh of useful energy storage capacity and 20 MW of inverter and transformer capacity that together will provide 7.2 MW of dependable capacity (i.e., displace four 1.8 MW diesel rental units) to the YIS for 20 years, starting in the winter of 2022/23.

The 7.2 MW of dependable capacity provided by the Project will reduce Yukon Energy's need to rely on rental of diesel generators during the winter months to address capacity shortfalls. The BESS will also provide other benefits, including: operating reserve that reduces thermal generation requirements; enhanced blackstart capability; opportunities for diesel-peak shifting; and other system benefits.

The preliminary capital cost estimate (2020$, +/- 30% accuracy) is $31.7 million; after the $16.5 million funding from the Federal government's Investing in Canada Infrastructure Program ("ICIP"), the preliminary net capital cost estimate for Yukon Energy is $15.2 million.

The Project lies within the overlapping Traditional Territory of TKC and KDFN. Yukon Energy engaged both First Nations in Q2 2020 to form a trilateral committee for sharing Project information, assessing three alternative KDFN and TKC sites for the Project, and negotiating benefits for both First Nations from the Project. The Project Committee met regularly thereafter in 2020 with a particular focus on the work required to recommend a preferred site and to review a draft Term Sheet that evolved to include a debenture investment opportunity for both TKC and KDFN based on 25% of the equity portion of YEC's net rate base cost of the BESS project.

Hatch Engineering ("**Hatch**") in mid-August 2020 completed a feasibility study for the Project. A copy of the Hatch report, excluding appendices, is provided in Appendix B to support the Application.

3.1.1 Existing Facilities and Project Components

The Project is located near Yukon Energy's Whitehorse Rapids Generating Station built to supply electricity to the Whitehorse area starting in 1958. The Whitehorse Rapids facility is connected to the balance of the YIS through the 138 kV/ 69 kV/ 34.5 kV transmission grid, and currently includes the following components:

- Whitehorse hydro plants - Four units with combined installed capacity of 41.3 MW (the largest unit [WH4] has 21.3 MW) and dependable capacity of 27 MW;

- Whitehorse diesel plant - Four units with combined installed capacity of 10.8 MW and dependable capacity of 9.5 MW;
- Whitehorse natural gas / LNG plant - Three units with combined installed capacity of 13.2 MW and dependable capacity of 12.6 MW;
- Mobile / rented diesel units – In winter 2020/21, 10 of the 17 mobile 1.8 MW rented diesel units on the YIS are located at the Whitehorse Rapids facility (the balance of these units are located at the Faro diesel plant); and
- Substations – The main Whitehorse Substation (S150) is located within the existing site; the Riverside Substation (S171) is located across the Yukon River.

The main components of the proposed Project are as follows:

1. **KDFN Site Lease and Site Preparation** – The site for the BESS will be on a 1.5 ha site that Yukon Energy will lease on undeveloped KDFN Category B settlement land located northeast of the intersection of Robert Service Way and the Alaska Highway.
    a. **KDFN Site Preparation** – KDFN responsibilities under the lease include survey/ subdivision, zoning, and road access development (engineering, traffic impact assessment, development permit, construction) and any related YESAA submissions.
    b. **YEC Site Preparation** – Yukon Energy will be responsible for site geotechnical survey work, site clearing (currently forested), leveling (fill as needed to minimize any drainage issues), gravel pad development, site fence and gate, security measures (monitors, cameras, alarms), and any related YESAA submissions, permitting or other required site preparation activities.
2. **Containerized Battery System and Power Conversion System** – The containerized lithium ion battery energy storage system to be located on the leased site includes separate containers for the battery system and the power conversion system components (inverters, switch gear, transformer(s)). Final design, container size and number of containers will vary depending on the vendor selected and the final system design. Total area required for the system is likely to be accommodated within 0.35 ha, i.e., a small portion of the leased site.

    The container systems are supplied as pre-integrated modules. Thermal management system (typically HVAC system) and fire detection and suppression systems are pre-engineered by vendors. The containers would include insulated walls and roof.

    A sample layout for the Project with useable capacity of 20 MW/ 40 MWh to end of life[2] is provided in Figure A-2 (Appendix A) assuming 40 ft containers for the batteries (12 containers, 4 MWh/container), the inverters (6 containers, 3.4 MW/container), and the combiner and

[2] The energy storage is expected to require an overbuild due to the limited state-of-charge range and degradation over the Project life. The overbuild requirements will be confirmed during procurement process based on specific vendor recommendations. The conceptual layout in Figure A-2 assumes a 20% overbuild (total 48 MWh) for illustrative purposes.

transformer (provision for 2 x 20 MW if this level of redundancy is selected). The typical height of containers is about 9-10 ft (about 2.75-3.05 m), with a flat roof.

3. **Transmission Line Connection** – The BESS will be connected to the Yukon Energy Whitehorse Rapids facility by a new 1.7 km 34.5 kV transmission line that goes north of the KDFN site, following existing easements through forested crown land until it meets and follows the path of the existing ATCO Electric Yukon (AEY) 34.5 kV line to the Whitehorse Rapids facility (see Appendix A, Figure A-1 for a map of the BESS site, the Project transmission line connection to the Whitehorse Rapids facility, and the connection therein to the Riverside Substation).

   Final design will assess the final routing on crown land and the most cost-effective strategy for this connection related to the AEY line, e.g., either build double circuit poles with the existing AEY line or build another set of poles with a single circuit (if there is enough area in the easement). The Project transmission connection design will be part of Yukon Energy's Whitehorse Interconnection Project to adjust interconnection of YEC's existing and incoming generation assets at Whitehorse, with added transmission extension connection to the Riverside Substation.

In order to have the Project in service by November 2022 (i.e., available for winter 2022/23), long lead BESS and related equipment need to be ordered by approximately mid-2021 and initial site preparation activities also need to be completed in August 2021. Yukon Energy is proceeding with the necessary work to advance the Project to a final "go" decision point targeted for July 1, 2021. A competitive procurement process has been initiated to select battery vendors qualified to design a battery able to meet Yukon Energy's operational requirements and Yukon's northern climate; selected vendors will then be evaluated based on technical specifications, prices, and other components. Thermal management and heating of the system will be critical for Yukon Energy when selecting the BESS vendor.

A BESS life of 20 years is considered reasonable based on expected throughputs (see Section 3.1.2 on BESS uses). Assuming operation within specified state-of-charge ranges, it is estimated that 4,000-4,500 charge/ discharge cycles (throughput divided by useable energy storage capacity) for lithium ion batteries typically leads to a 20% capacity fade. Based on expected 20-year cycles for the Project (1,570 "typical year" cycles to 2,878 "worst case" scenario) as reviewed in Section 3.1.2 below, cycle related capacity fade over 20 years for the BESS is estimated between 7-8% and 13-15% (Hatch, page 76). A lifetime of 20 years therefore is reasonable with a modest overbuild or capacity augmentation at year ten. Yukon Energy will work with vendors to assess relevant options, including any appropriate added energy capacity overbuild.

At the end of life, many battery vendors will take back the battery modules – which ensures that the batteries are treated properly and places responsibility of disposal on the supplier.

3.1.2 Project Uses

The 7.2 MW of dependable capacity provided by the Project will reduce Yukon Energy's need to rely on rental of diesel generators during the winter months to address capacity shortfalls. This is the primary BESS use, given Yukon Energy's ongoing need to provide added dependable capacity for the YIS.

The BESS will also provide other benefits, including: an operating reserve that reduces thermal generation requirements; enhanced blackstart capability; opportunities for diesel-peak shifting;

opportunities for more stable hydro operation during periods of downstream winter ice formation; and other system benefits.

Estimated BESS throughout and charge/recharge cycles on the YIS for five of the BESS uses are summarized in Table 3-1 based on a typical recent year and a worst case scenario. Round trip efficiency for BESS charge/ recharge is assumed at 85%.

Table 3-1: Estimated Annual Throughput for 20 MW/40 MWh BESS on YIS[3]

	Typical Year		Worst Case	
BESS Use	**Frequency**	**BESS Use**	**Frequency**	**BESS Use**
N-1 Events (2 week event)	1 in 10 yrs	56 MWh	1 in 5 yrs	112 MWh
Operating Reserve	1/month	120 MWh	2/week	1,040 MWh
Blackstart Outage Restoration	53/yr	2,120 MWh	79/yr	3.160 MWh
Peak Shifting		244 MWh		244 MWh
Reduction in Load Shedding & Renewable Integration	100 cycles/yr, 15% discharge depth	600 MWh	200 cycles/yr, 15% discharge depth	1,200 MWh
Total Annual Throughput (MWh)		**3,140**		**5,756**
Total Throughput Useable Cycles		79		144
Cycles/365 days (cycles/day)		0.22		0.39
Estimated Cycles in 20 yrs (Cycles)		**1,570**		**2,878**

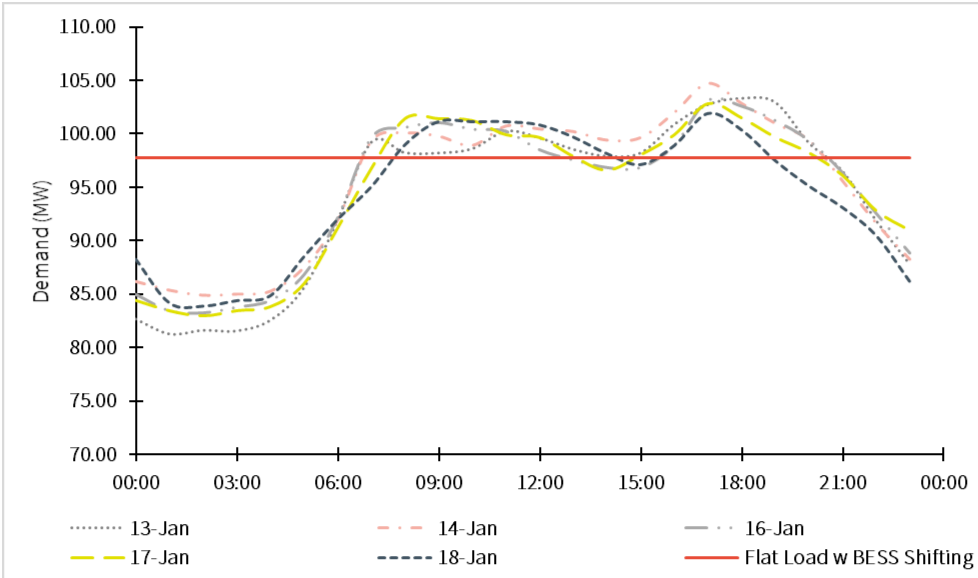
3.1.2.1 Primary BESS Use: N-1 Capacity Reserve

Yukon Energy must have sufficient dependable capacity under its N-1 Dependable Capacity Criterion to meet its winter non-industrial peak load without its largest generator (currently the 37 MW Aishihik Hydro connected to Whitehorse by transmission). For the BESS to contribute to this N-1 capacity reserve, it needs to be able to reduce the non-industrial peak demand during the day, and then be recharged overnight, for up to two weeks during the coldest winter months.

Figure 3-1 shows the YIS hourly load profile (MW demand for all loads) for the five peak days in January 2020 when Yukon Energy achieved its all time peak demand of almost 105 MW. It shows that the YIS daily peak load profile extended over many hours (from about 6 to 8 am until about 7 to 9 pm), and that the morning peak was greater and sustained longer on three of the five days (January 16, 17 and 18).

[3] Source: Hatch August 24, 2020 Report, Tables 8-1 and 8-2.

Figure 3-1: YIS Load Profile (MW by hour) for 5 Peak Days in January 2020[4]

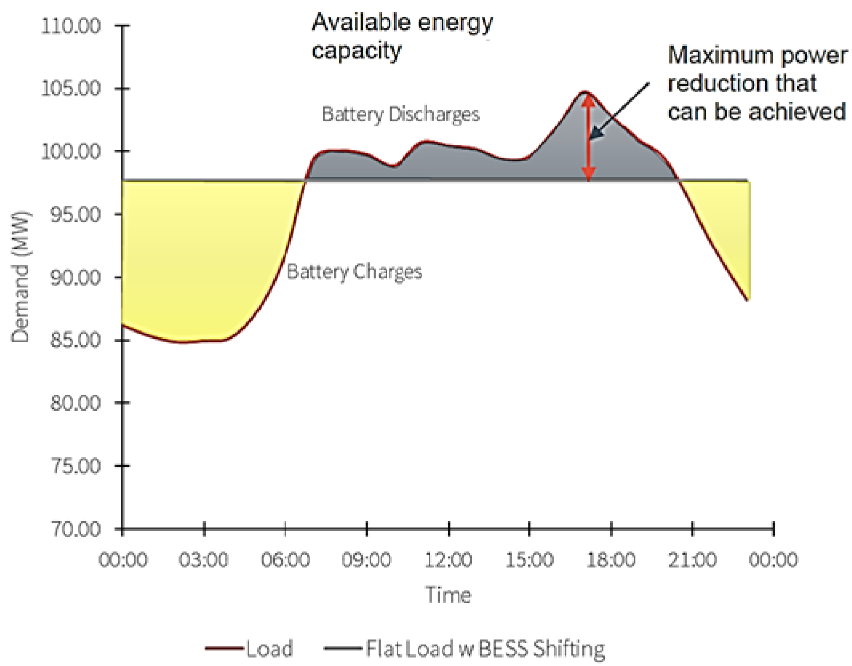


The purpose for the BESS in N-1 events is to reduce the daytime peaks. Given the extensive daily time period related to these peaks, the available energy capacity of the BESS will determine the maximum power reduction that can be achieved, since it will dictate the duration that energy can be supplied throughout the day. In the above figure, the BESS must supply energy over the entire period above the red "flat load" line to achieve 7.2 MW dependable capacity replacement associated with displacing four rented diesel units.

Figure 3-2 shows how the proposed BESS would work to reduce daytime peak.[5] The maximum power reduction shown in the figure reduces peak load from about 105 MW to 98 MW providing 7.2 MW dependable capacity. In all cases, the yellow area energy available to recharge the battery is in excess of the energy required to charge the battery (which includes the energy supplied during the day plus 15% for losses).

[4] Source: Hatch August 24, 2020 Report, Figure 6-2. Under an N-1 event the industrial load would be curtailed and only the non-industrial load would be supplied, i.e., overall YIS demand would be lower than shown in this figure. However, the load profile shown reflects the changes in non-industrial load requirements over the peak load days.
[5] Source; Hatch August 24, 2020 Report, Figure 6-1.

Figure 3-2: BESS Energy Capacity (MWh), Max Power (MW) & Recharge for N-1 Capacity Reserve



In summary, there are two factors that must be considered for the BESS to provide N-1 capacity reserve: the energy capacity (MWh) it can provide, and the power output (MW) it can provide.

The Hatch Report examined a range of BESS options to provide N-1 capacity reserve. For each BESS energy capacity size (MWh), the flattened load that can be achieved using the full capacity (taking into account 15% losses) was assessed and the resulting maximum power output reduction was determined. Other assumptions made in the analysis included the following:

- The BESS will be recharged overnight; and
- Round trip efficiency is 85%, thus the BESS must be charged with 15% excess energy overnight.

Recharging the BESS for N-1 event capacity reserve use is expected to be during the winter peak load period, using thermal generation. The 15% losses for round trip BESS operation each day reflect an added thermal generation requirement (fuel and other non-fuel opex costs) that would otherwise not be required for rented mobile gensets or new thermal generation options to provide the N-1 capacity reserve.

Table 3-2 shows peak reductions as estimated by Hatch for different battery useable energy capacity sizes, ranging from 30 MWh to 45 MWh (incremental capex for each 5 MWh energy capacity approximates $2.9 million)[6]. The optimal BESS energy capacity sizing for the peak day is shown to be either 35 MWh or 40 MWh, which result in a reduction of 4 diesel genset rentals (7.2 MW). The 30 MWh offering only results in a reduction of 3 diesel gensets (5.4 MW), therefore, adding the extra 5 MWh of energy capacity to the BESS has an advantage each year. However, moving to 45 MWh energy capacity does not result in any further reduction in rental diesel gensets with the current load profile.

Table 3-2: BESS Energy Capacity Peak Reduction Benefits – Range of Capacity Sizes[7]

Battery Energy Capacity Size	Peak Load - Generation Flat Load with BESS, MW	Generation Peak Reduced with BESS, MW	BESS Duration at Peak , hrs	Reduction in 1.8 MW Mobile Gensets
1	2	3	4=1/3	5
No BESS	104.7			
30 MWh	98.5	6.3	4.8	3
35 MWh	98.1	6.6	5.3	4
40 MWh	97.7	7.0	5.7	4
45 MWh	97.4	7.3	6.1	4

In summary, BESS use for N-1 capacity reserve enables Yukon Energy to save annual rental costs for 7.2 MW of mobile diesel. The only incremental YEC operating cost offset to this BESS use is the efficiency loss (15%) incurred when an N-1 event occurs and the BESS must be recharged using thermal generation (estimated on average to be less than $2,000/year).[8]

Using the BESS only to provide N-1 dependable capacity reserve would result in it being kept fully charged and idle to respond to one of these rare events, i.e., assumed once per 10 years. Given energy self-discharge of approximately 3-5% per month when charged and idle, the BESS would also need ongoing recharging under this scenario.

3.1.2.2 Other BESS Uses

The BESS has the capability to provide the following additional beneficial uses on the YIS:[9]

---

[6] See Table A-1, Appendix A and Hatch August 24, 2020 Report, page 28 and Table 5-2. Estimated capex includes added cost for 20% overbuild required due to the limited state-of-charge range (20%-100%, or 10% to 90%, depending on vendor recommendation). The energy shown for the BESS is the useable energy, with the installed energy capacity being 20% greater.

[7] Source: Hatch August 24, 2020 Report, Table 6-2 and Table 6-3.

[8] Table 3-1 shows 56 MWh as BESS throughput in a typical year for N-1 dependable capacity use (based on one event every 10 years), for which 15% efficiency loss equals 8.4 MWh. At the 2021 GRA diesel fuel price of $0.2051/kWh, the cost impact is $1,723/year.

[9] Source: Hatch August 24, 2020 Report, Sections 6.3 to 6.8 (pages 42-69).

- **Operating reserve:** The BESS can provide operating reserve for the grid when excess water is available, allowing diesel (and potentially LNG) thermal units to be turned off when hydro can meet the system load, and allowing hydro units to be run at higher efficiency;
- **Blackstart and outage restoration capability:** The BESS can be used to initiate grid re-energization after a blackout, improving outage restoration capability on the grid and reducing the length of outages;
- **Diesel peak shifting:** The BESS can be discharged in lieu of diesel generation during peak and recharged overnight with LNG generation or hydro generation, reducing thermal generation fuel costs and GHG emissions;
- **Grid Reliability & Ancillary Services:** The BESS can be used to respond to large frequency excursions, cover the loss of large generation units, and prevent "load shedding" events. Frequency excursions increase as more intermittent renewables are added to the grid[10];
- **Load loss stabilization:** The BESS can act as a load during a large loss of load event (e.g., loss of a mine load or a transmission line), and thereby prevent tripping generation on the grid, which improves grid stability and reliability; and
- **Reactive power support:** The BESS inverters can provide real and reactive power simultaneously to the grid. Providing reactive power support does not deplete the energy store and therefore does not impact the ability of the BESS to provide other services at a later period.

Rented or permanent thermal generation options to provide N-1 capacity reserve cannot provide these additional benefits. Operating reserve, diesel peak shifting, blackstart outage restoration, and grid reliability and ancillary service benefits are each reviewed in more detail below to describe operation requirements and potential benefits to YEC and/or improved customer reliability. Load loss events on the YIS are rare and short in duration, and this potential use is not discussed further. Significant reactive power compensation also is not typically required on the YIS, and this potential use is not discussed further.

Operating Reserve

Operating reserve is carried on the electric grid to accommodate variations in the load or to cover the loss of a generator. This is achieved by operating a hydro generator below its maximum capacity, to allow its output to be increased quickly, if required.

Hatch concluded that use of the BESS to provide supplementary reserve has the greatest economic benefit among the identified additional uses.[11] The benefits of the BESS use for operating reserve when excess water is available were noted to be two-fold:

[10] Yukon Energy is also exploring options for potential use of BESS to stabilize hydro operation during periods of downstream winter ice formation, reducing downstream winter flooding and icing problems and enhancing hydro unit efficiencies.

- A direct reduction in diesel and LNG genset operation hours and energy generation; and
- Improved efficiency of the hydro-turbines by operating them at their most efficient output more frequently, leading to more energy production with the same amount water flow.

The BESS can provide this operating reserve by remaining at a moderate to high state-of-charge (SOC) and acting as a backup to generation.

The BESS response time is very rapid, 150-200 ms to achieve full power output, and therefore can be brought online quickly to cover the load in the event of a loss of a generator. The BESS would need to maintain a minimum energy level at all times when operating reserve is provided to ensure it can cover the load for the time required to start-up a back-up thermal generator, which is typically 10-30 minutes.

- For example, the minimum useful energy storage required with a 10 MW/40 MWh BESS would be 5 MWh for 30 minute operating reserve discharge, thereby ensuring that the BESS can provide the necessary operating reserve without discharging below its minimum SOC.
- Depending on grid operation and response time of the units that will come online to replace the lost generation, BESS operating reserve in this case might be increased above 5 MWh (if a longer discharge period is to be covered) or reduced below 5 MWh (when there is significant excess hydro generation and no thermal units online).[12]
- There are several weeks in winter when no operating reserve benefits can be achieved due to water flow limitations.

For the BESS to discharge as part of the operating reserve application, an unplanned event needs to occur where generation trips or is insufficient. This is an infrequent event (estimate of one 30 minute event per month, with worst case of one event per week),[13] and in operating reserve use the BESS therefore will be primarily idling with sufficient energy stored to provide this operating reserve and not cycling frequently.

Based on 2019/2020 year YIS operation and average annual water flow, the average monthly operating reserve on hydro turbines ranges from 2 MW to 8 MW across the year (includes all months), with an annual average of 4.8 MW.[14] Based on this operating reserve and 2019/2020 YIS operations, the annual

---

[11] Hatch August 24, 2020 Report, page 68.
[12] See Hatch, August 24, 2020 Report, Page 71.
[13] Hatch, August 24, 2020 Report, Tables 8-1 and 8-2. Assuming 30 minute duration for recharge per event, estimated annual throughput equals 50% of option inverter capacity times number of events per year, e.g., 10 MW inverter capacity yields 60 MWh for estimated annual throughput (at 1 event per month) and 520 MWh for worst case (at 2 events per week). Recharging is assumed to use hydro generation that would otherwise not displace thermal generation. Thermal generation volume savings from BESS operating reserve significantly exceed the annual throughput for BESS recharging, reflecting the requirement to maintain operating reserve at all applicable times even though events requiring the reserve are infrequent.
[14] Hatch, August 24, 2020 Report, Figure 6-3 and pages 42-43. The assessment calculated the additional hydro generation that could displace LNG or diesel generation in each hourly timestep, based on average water year water flows. No benefits were included from Whitehorse Unit 4, and it was assumed that the unit could never run above its summer maximum output.

average amount of thermal generation that could be avoided by BESS use as an operating reserve has been estimated by Hatch for the 20 MW/40 MWh option at 1.8 GWh of diesel generation and 17.0 GWh of LNG generation (see Table 3-3).

Table 3-3: BESS Operating Reserve Use & Thermal Generation Reduction (20 MW/40 MWh)[15]

Battery Useable Power & Energy Capacity Size	Energy Used of Operating Reserve (30 min)	% of Useable Energy Capacity	Reduction in Diesel Generation (MWh/yr)	Reduction in LNG Generation (MWh/yr)
1	2=MW*1/2hrs	3=2/MWh	4	5
20 MW/ 40 MWh	10.0	25.0%	1,837	17,043

YEC cost saving and GHG reduction benefits from the BESS operating reserve use result from the reduction in thermal generation that otherwise is required when hydro units are used for operating reserve. Requirements to recharge the battery as a result of this use are infrequent, and would use excess hydro generation at minimal incremental YEC cost. Potential thermal generation reduction benefits from this BESS reserve use will be greater in years with higher water flows and lower in years with lower water availability.

Hatch also noted that using the BESS to supplement operating reserve will enable hydro plants to operate at higher efficiency (due to higher loading). A modest efficiency gain of 0.5-1% would translate to an additional 2.2-4.4 GWh of energy generated from the same volume of water which, if it can be directed to reduction in thermal generation, would provide opportunities for significant added thermal generation reduction beyond that estimated in Table 3-3.[16]

The Hatch analysis estimated potential reduction in direct thermal generation use to provide operating reserve by estimating when thermal generation was used in 2019/20 to provide operating reserve. However, the full benefits of the thermal displacement as estimated by Hatch are not expected to be realized given the relationship between thermal generation and subsequent hydro storage availability.[17] To be conservative, net thermal generation reduction from BESS operating reserve use is assumed to be

[15] Hatch, August 24, 2020 Report, Figure 6-6.
[16] Hatch, August 24, 2020 Report, page 47.
[17] The Hatch estimates for 2019/20 and 20 MW/ 40 MWh Project indicate 35% of thermal generation used for operating reserve occurred in spring (March-May), 35% in fall (September-November), 23% in winter (December-February) and 7% in summer (June-August). Thermal generation used for operating reserve during non-summer seasons [fall, winter and spring] can allow hydro units to run below capacity as needed for this reserve, and thereby enable added stored water at Aishihik and/or Mayo hydro facilities. Without BESS, this added stored water would normally be used subsequently to reduce future thermal generation, unless stored water is spilled during summer due to surplus water conditions. Normally, saved water storage in spring is mostly spilled due to freshet flows.

only one-third of the Hatch estimates.[18] Based on YEC's 2021 GRA fuel prices the annual thermal fuel cost savings from BESS operating reserve use for the 20 MW/ 40 MWh BESS is about $1.156 million.[19] The only incremental YEC operating cost offset to this BESS use is the efficiency loss (15%) incurred when an operating reserve event occurs and the BESS must be recharged using hydro or thermal generation (estimated on average to be less than $4,000/year).[20]

Blackstart & Outage Restoration

In the event of a significant grid outage, Yukon Energy must blackstart the grid. To do so, YEC sectionalizes the grid into smaller load segments, which are re-energized sequentially using smaller individual generators. This involves energizing the electrical equipment in the substation, then the hydro generation, in several increments. As the system is segmented into numerous load blocks, and some of the switching is of a manual nature that needs to be conducted by deploying resources to the field for restoration, this process can take up to 2 hours, depending on the extent and severity of the outage.

BESS use to initiate grid re-energization after a blackout can improve outage restoration ability on the grid and reduce the length of outages. As the grid is sectionalized in the event of a grid outage, the BESS will enable significantly larger load segments, e.g., 20 MW to be restored at once. The BESS thereby enables rapid pick up of the grid once the issue has been addressed, which is critical for customer reliability, particularly during winter. The BESS power capacity will be greater than the 5 MW hydro capacity currently used to blackstart, thus resulting in greater load segments that can be energized.

Connection point for the BESS is critical for the blackstart capabilities, since the connection point will determine the blackstart procedure. With the BESS at the selected site being connected into the Whitehorse substation, it is likely there will only be minor modifications to the blackstart procedure (i.e., which switches and transformers are energized first, since the exact connection point will differ).

Blackstart events are fairly rare, e.g., average 53 events per year based on average for 2014-2018 and 79 events per year estimated for worst case based on 2019 Annual Report with assumed maximum energy duration equal to the BESS energy capacity (35 or 40 MWh) per event.[21] However, blackstart outage restoration accounts for more than half of the estimated BESS annual throughput and cycles under typical and worst case scenarios.[22] BESS use for blackstart will incur operating efficiency losses of

[18] Reflects spring thermal generation displaced (35% of total) when saved water is mostly spilled, plus allowance for at least some net thermal reduction benefits in fall and winter seasons.
[19] One-third of the diesel and LNG generation reduction for the 20 MW/40 MWh option is about 612 MWh/year diesel and 5,681 MWh LNG. With 2021 GRA fuel prices [$0.2051/kWh diesel and $0.1814/kWh LNG] the annual thermal cost savings approximate $1.156 million.
[20] Table 3-1 shows 120 MWh as BESS throughput in a typical year for operating reserve use (based on one event per month), for which 15% efficiency loss equals 18 MWh. Assuming in the extreme that recharging either directly uses diesel generation, or uses hydro storage that in future results in added diesel generation, the cost impact is $3,692/year assuming the 2021 GRA diesel fuel price of $0.2051/kWh.
[21] See Table 3-1.
[22] See Table 3-1.

15% on the throughput; however, it is assumed that overall savings from enhanced system restart will more than offset any efficiency loss costs.

The Hatch Report notes the following (at page 41):

> Having the larger BESS (10 MW/40 MWh, 13 MW/40 MWh or 20 MW/40 MWh) will increase the power capacity of the load segments during blackstart, thus reducing the time required to re-energize the grid. As well, the higher energy capacity will increase the infrastructure and power generation that can be re-energized with the BESS. Particularly, the 20 MW power capabilities provides Yukon Energy with increased flexibility to significantly increase the segments that can be picked up during the blackstart process, which reduces the time. This 20 MW inverter capability can also cover the loss of Whitehorse Hydro Unit #4. It also has the highest operating factor (capacity factor) of all of Yukon Energy's generation, therefore, and outage of Whitehorse Hydro Unit #4 can lead to critical outages on the grid. Based on discussions with Yukon Energy, this hydro unit is the cause of many system outages.

Diesel Peak Shifting

The BESS can be discharged in lieu of diesel generation during peak and recharged overnight with LNG (75% estimated) or hydro (25% estimated), reducing thermal fuel costs and GHG emissions.

Hatch estimates (based on 2019 operations – results summary page 56) that the BESS has the potential on average to shift between 108-244 MWh per year of diesel generation between Whitehorse and Faro diesel (108 MWh for 1-3 hr events in Whitehorse only, 244 MWh for 1-4 hr events at Whitehorse + Faro), representing 3-6% of total annual diesel generation at the two sites. All but one of the 1-4 hour events can be served by the 6.6 MW/35 MWh and 7 MW/40 MWh BESS, and the 10 MW/40 MWh BESS is capable of shifting all of the diesel peaks based on 2019 operations.[23]

As grid load grows, diesel peaks will likely increase, and 20 MW BESS power capability will increase flexibility of future operations sufficiently to cover the entire output capacity of the natural gas generating plant [13 MW] or the Whitehorse Hydro Unit #4 [20 MW].

If the BESS is also providing operating reserve during these periods, a priority must be set for BESS operation. Estimated net cost savings from BESS diesel peak shifting based on 2019 operations indicate relatively small net economic benefits approximating $10,600/year (see Table A-2. Appendix A) after consideration of LNG and hydro operating costs for recharging of BESS.

Grid Reliability and Ancillary Services

The BESS responds to large frequency excursions, covers the loss of large generation units, prevents "load shedding" events, and improves power quality and customer reliability through the provision of

[23] Table A-2 in Appendix A shows 244 MWh diesel savings with the BESS size options reviewed.

additional ancillary grid services. The BESS will reduce load shedding resulting from frequency excursions. Large frequency excursion events are relatively infrequent (8-18 events per year [Hatch, page 69] and do not provide significant economic benefit to YEC (no economic impact estimates provided by Hatch).[24] However, these events directly impact customer reliability, particularly in the commercial sector, which can drive outage-related customer costs. Reduction in load shedding would result in increased customer reliability.

The Hatch Report also notes the following (at page 41):

> This 20 MW inverter capability can also cover the loss of Whitehorse Hydro Unit #4. It also has the highest operating factor (capacity factor) of all of Yukon Energy's generation, therefore, and [sic] outage of Whitehorse Hydro Unit #4 can lead to critical outages on the grid. Based on discussions with Yukon Energy, this hydro unit is the cause of many system outages.

Outages caused by the loss of Whitehorse Hydro Unit #4 have occurred approximately once per year.[25] Given the larger size of this unit, the resulting load shedding is more extensive. This is particularly true in the summer when WH#4 is providing a larger portion of generation on the grid.

Frequency excursions are likely to increase as more intermittent renewables are added to the grid, increasing potential BESS benefits from this use in future years. Reduction in load shedding and renewable integration accounts for 19% to 22% of the estimated BESS annual throughput and cycles under typical and worst case scenarios (see Table 3-1). No estimates have been developed of potential YIS cost savings related to this BESS use.

The BESS can also act as a load during a large loss of load event (e.g., loss of a mine load or a transmission line) and thereby prevent tripping generators on the grid, which also improves grid stability and reliability.

Yukon Energy is also exploring other options such as BESS use for stabilizing hydro operation during periods of downstream winter ice formation, reducing downstream winter flooding and icing problems and enhancing hydro unit efficiency. During periods of downstream winter ice formation daily fluctuation in hydro generation in response to load will lead to fluctuations in downstream flows that can hamper effective ice formation and cause related downstream flooding and over-bank ice conditions. Constraining hydro operation to prevent such impacts can require increased thermal generation. BESS use to stabilize hydro operation at this time facilitates the desired stabilizing of downstream flows without incurring added thermal generation costs, and concurrently also has the potential to enhance hydro unit efficiency.

[24] Table 3-1 estimates 100 cycles per year under average conditions and 200 cycles per year under worst case conditions, with 15% depth of discharge (5.25 MWh per cycle with 35 MWh capacity and 6 MWh per cycle with 40 MWh capacity).
[25] From 2016 through 2020 after work was done on the governor to reduce outage problems, three Whitehorse Hydro Unit #4 outages occurred (July 2016, February 2017, and February 2020).

3.1.3 Project Costs and First Nation Debenture Investment

Project Costs

Table 3-4 provides a summary of preliminary estimated Project capital costs of $31.7 million (2020$, +/-30% accuracy), developed from the Hatch feasibility report and Yukon Energy estimates for planning and owner's costs. The estimates include a 15% contingency. The battery price has the greatest impact on the Project economics as it accounts (with contingency included) for about 72% of the total project capital cost.

The preliminary net capital cost estimate for Yukon Energy, after the $16.5 million funding from the Federal government's "Investing in Canada Infrastructure Program ("ICIP"), is $15.2 million.

Table 3-5 provides a summary of preliminary estimated Project annual operating costs of $0.629 million (2020$), developed from the Hatch feasibility report and Yukon Energy estimates for transmission O&M and site lease costs. The Hatch estimates include annual preventive maintenance costs for the battery, based on vendor site visits and an allocation for parts. Recharging costs are excluded as these are not included in Table 3-5, and are addressed subsequently when assessing specific Project uses (see Section 4).[26]

Table 3-4: Estimated Capital Costs for Project Facilities (2020$)

Activity	Estimated Costs ($000)	% Total Costs
Planning Costs	445	1%
Engineering Services & Project Management	590	2%
Battery System	19,985	63%
Power Conversion System	3,600	11%
Grid Connection	595	2%
Site Preparation Costs	335	1%
Owner's Costs	2,382	8%
Contingency	3,766	12%
Total	**31,698**	**100%**

Notes:
1. Hatch preliminary cost estimates for all activities at KDFN selected site excluding Planning Costs and Owner's Costs.
2. Planning Costs are YEC costs to the end of October 2020.
3. Owner's Costs include final planning prior to final "go" decision targeted for July 1, 2021 and Owner's Costs during construction (including site development KDFN lease charge).

[26] Hatch estimates for recharging costs included in opex costs only addressed estimated costs related to diesel peak shifting use (at $57k/year); however, this use is estimated by Hatch to yield benefits that exceed the recharging costs through thermal fuel costs displaced by BESS use.

Table 3-5: Estimated Annual Operating Costs for Project Facilities (2020$)

Activity	Estimated Annual Costs ($000)	% Total Costs
Site Lease[3]	55	9%
Annual Opex[1,2]	230	37%
Property Tax[1]	297	47%
Insurance[1]	40	6%
Transmission O&M	7	1%
Total Annual Operating Costs (ex.recharging)	**629**	**100%**

Notes:

1 Hatch preliminary cost estimates for selected KDFN site, 20 MW/ 40 MWh size.

2 Opex annual cost includes annual preventive maintenance costs for the battery ($60k/year for two technicians, twice per year; plus $2.25/kWh/yr and $4/kW/yr for parts and preventive maintenance).

3 KDFN annual lease costs, escalates at 1% per year over 25 year term.

The levelized cost of capacity ("**LCOC"**) provides an economic metric to evaluate the cost of the primary use of the BESS (provision of 7.2 MW of dependable capacity, equal to displacement of four diesel rental units). The estimated net capital cost for Yukon Energy of $15.2 million equals $2.11 million per MW of dependable capacity (7.2 MW) provided by the Project. The Project LCOC (2022$), which does not account for YEC thermal fuel cost savings from the other BESS uses, is $235/kW-year based on the estimated capital cost and operating cost (Tables 3-4 and 3-5, escalated where relevant 2% per year for two years of inflation), provision for ongoing recharging losses and idling with only N-1 dependable capacity use,[27] and Yukon Energy's updated weighted average cost of capital (WACC) of 4.794% nominal (2.739% real assuming 2% annual inflation).[28] The Project LCOC is higher than the LCOC for rented diesel units[29] and new diesel units.[30] However, as reviewed in section 4.2.3 of this Application, the Project results in a net present value benefit to ratepayers due to the cost savings resulting from the avoidance

[27] Estimated approximately $5,000 per year (2020$), assuming 8.4 MWh per year for recharging losses (Table 3-1 annual average throughput for 7.2 MW N-1 dependable capacity use times 15% for losses), 14.4 MWh per year for idling losses (3% per month times 40 MWh capacity), and 2021 GRA diesel fuel generation costs at $0.2051/kWh for all of this throughput (conservative assumption that overstates likely costs).

[28] The 2021 GRA includes 8.70% return on equity (40% of capital) and 2.19% interest on new long-term debt (60% of capital).

[29] LCOC for rented diesel units with the same WACC and over the same 20 year life is $211/kW-year (2022$) assuming diesel rental costs of $162,400/MW connected [includes cost of spares] estimated (2021$) for winter 2021/22, 4% year escalation of diesel rental costs, and $11/kWh for variable non-fuel O&M. Infrastructure capital costs for diesel rental at $3.5 million (2022$) for 27 MW capacity based on infrastructure capital costs for the existing rentals [inflated at 2%/year].

[30] LCOC for 12.5 kW new diesel at Takhini estimated at approximately $186/kW-year (2022$), based on Midgard estimate (2019$) of capex and opex for 12.5 MW Takhini diesel plant, 40 year life (WACC at 4.92%), escalated for inflation at 2% per year to 2022.

of four rental diesel generators, and the avoided thermal generation from the other use cases as shown in Table 4-3.

In summary, it is concluded that the specified need to meet near term forecast requirements for reliable and flexible new capacity on the Yukon grid would best be met through development of the Project. Compared to the feasible and best alternative available today (i.e., diesel rental), at forecast grid loads the Project provides a cheaper and renewable focused energy option for Yukon Energy and Yukon ratepayers.

First Nation Debenture Investment

The Project lies within the overlapping Traditional Territory of TKC and KDFN. Yukon Energy engaged both First Nations in Q2 2020 to form a trilateral committee for sharing Project information, assessing three alternative KDFN and TKC sites for the Project, and negotiating benefits for both First Nations from the Project. The Project Committee met regularly thereafter in 2020 with a particular focus on the work required to recommend a preferred site and to review a draft Term Sheet that evolved to include a debenture investment opportunity for both TKC and KDFN based on 25% of the equity portion of YEC's net rate base cost of the BESS project.

The First Nation debenture investment for the Project would follow precedents established to enable First Nation debenture investments related to earlier Yukon Energy projects, i.e., the Mayo-Dawson Transmission Line Project, the Mayo B Hydro Project, and the LNG Project. In the past, however, these debenture investments were made with YDC and were not subject to YUB review – while the debenture investment for the Project will be made with Yukon Energy, and therefore will be subject to YUB review when approving future YEC rates. As was the case with earlier precedents, there is no legal requirement to provide any First Nation with an investment opportunity related to the specified Yukon Energy projects – the investment opportunity in each instance has been, or is, provided as part of First Nation engagement, involvement and support for the project's development.

The key terms for the First Nation debenture investment opportunity related to the Project include the following:

1. KDFN and TKC will each be offered the opportunity to provide a loan to YEC in accordance with the following principles:
    a. YEC's Net Rate Base Cost for the Project is YEC's final capital cost for developing the Project less any funding contributions to YEC for the Project and any costs disallowed by the YUB from inclusion in rates.
    b. The BESS Equity Cost is 40% of the Net Rate Base Cost, and reflects the portion of the Net Rate Base Cost that is financed by YEC equity.
    c. KDFN and TKC will each be offered the opportunity to provide a Loan Investment of up to 25% of the BESS Equity Cost. The following example outlines the process, assuming a final BESS net rate base cost of $15.2 million after grants:

i. Assuming YUB approval of these costs, YEC's Net Rate Base Cost would be $15.2 million and this would be funded by 40% equity [the BESS Equity] of $6.1 million and by 60% long-term debt of $9.1 million.

ii. KDFN and TKC would each have the opportunity to provide a Loan Investment of up to $1.52 million, i.e., each up to 25% of the $6.1 million BESS Equity Cost.

2. The Loan Investment opportunity will be available for a specified period after the Project is in service and YEC's final net rate base (after contributions and YUB review) is determined by YEC and communicated to KDFN and TKC.
3. The term for each Loan Investment will be based on the remaining portion of the expected asset life.
4. YEC will provide the following annual payments to KDFN and TKC with regard to each of KDFN and TKC's Loan Investment:
    a. Repayment of principal at equal annual amounts over the Term; and
    b. An annual return on the Loan Investment balance then applicable times YEC's actual final rate of return on equity (actual percentage return for a completed fiscal year) for YEC's utility regulatory income for the completed fiscal year most recently filed with the YUB (YEC's last approved equity return included in rates is 8.70%).

In accordance with current accounting regulations, the Project First Nation debentures would be treated as long term debt given the nature of the financial instrument. However, the equity return paid on this instrument is well above the market rate for long term debt that Yukon Energy would expect to pay. Therefore, for the purposes of rate-making (i.e., revenue requirement determination by the YUB), Yukon Energy proposes to treat this investment as equity for the purpose of maintaining the 60:40 debt to equity capital structure for Yukon Energy as approved by the YUB. To the extent that the outstanding balance of the First Nation investment affects this ratio, Yukon Energy will execute the necessary transactions with Yukon Development Corporation (dividend or equity injection) to maintain this ratio on an annual basis. As well, any rate applications to the YUB will show this debenture as a component of equity for revenue requirement determination; in this way, there is no net impact to ratepayers from this transaction.

3.2 ANTICIPATED TIMELINE

Yukon Energy is undertaking all required planning, environmental and socio-economic review and permitting, engineering design, contracting and other related activities to obtain authorizations and approvals necessary for procurement to be initiated by July 2021 and to allow for initial civil construction work for the Project to commence by August 2021. The schedule is driven by the requirement to have the battery in service by November 2022 in order to ensure dependable capacity is available to meet N-1 contingency requirements for winter 2022/23.

In order to meet the target in service date, initial long lead equipment must be ordered from a supplier selected and committed by July 2021. The YESAA review process, Part 3 Application process with the YUB, and any related permitting requirements are the key critical path elements currently affecting the required start of civil construction work by August 2021, and subsequent project in service by fall 2022.

A more detailed review of key timeline elements is provided below:

- **Permitting and Approvals:** The schedule anticipates completion of the YESAB review, Part 3 review, issuance of Decision Documents, and securing all needed permits and approvals to commence construction in July 2021. Section 6.1 contains a detailed list of all requested permits and authorizations for the Project.
  - **The Designated Office assessment process** includes, at a minimum the following major steps:
    - **A pre-screening adequacy review** – Yukon Energy plans to file a project proposal by March 31, 2021; it is assumed that the adequacy review will be completed by April 15, 2021.
    - **Seeking Views and Information** – Public comment on the project proposal is assumed to be completed by May 3, 2021.
    - **Recommendation or Referral** – It is assumed that the proposal will then move to the recommendation or referral process and that a report and recommendations will be provided by the Designated Office by June 1, 2021. The schedule assumes Decision Documents will be issued within 15-30 days of issuance of the Report and Recommendations.
  - **Part 3 Review process by the YUB** as required for the Application is expected to involve a public hearing and issuance of the Board's report to the Minister by the date in the Minister's Terms of Reference.
  - **Permits and Approvals** can be issued by regulatory authorities only after release of the Designated Office Report and Recommendations and after each Decision Body has issued a Decision Document accepting, rejecting or varying the Designated Office Recommendations.
- **Other Project Planning** – Other planning phase work to be completed prior to July 2021 relates to procurement and contracting, First Nations agreements, preliminary engineering, and related investigations.
  - **Finalize Lease for KDFN Site** – The finalized lease is required to enable work to proceed and to ensure that KDFN proceeds with the site development work that it is responsible for carrying out.
  - **Procurement Process and Preliminary Engineering** – This includes defining First Nation guidelines; carrying out battery vendor procurement process and related contract

negotiations (a two stage process has been initiated to identify eligible and interested vendors); procuring and contracting an owner's engineer; preliminary engineering for the engineering, procurement and construction (EPC) procurement for the Balance of Plant/Civil/ Interconnection work; and procurement for this EPC contractor.

- **Related Other Investigations and Agreements** – This includes completing a system impact study; and completing a geotechnical site investigation (after completing the related YESAA process). The geotechnical assessment will provide information needed to advance civil engineering and is not expected to identify any material issues that would prevent proceeding with the Project. This also includes finalizing route and planning as required for transmission connection, and related work planning; and finalizing a Project Agreement (including benefits arrangements) with KDFN and TKC.

- **Project Construction** – The construction phase that is scheduled to start in July 2021 comprises a variety of tasks and activities, including site preparation, sourcing of required materials, construction of supporting infrastructure as well as primary facilities, management of fuel and hazardous waste, and the management of necessary work crews.
  - **Long-lead equipment orders** – Long lead equipment orders (particularly for the BESS, as well as key transmission equipment) will be issued, based on the completed procurement process.
  - **Initial site preparation and civil works** – Civil work is required to start in Q3 2021 in order to ensure that the site is ready to receive delivery of the battery in May 2022.
    - Following completion of a YESAA DO assessment as required to undertake KDFN and YEC site preparation and civil works, the access road, site clearing, gravel pad placement, fencing and other site preparation work will proceed.
    - Site preparation as required for the transmission connection will proceed as required.
  - **Installation of Equipment** – Installation of BESS-related equipment is expected to take approximately 5 months. The lead time for the battery and transformer is approximately 10-12 months. As such, procurement of this equipment must commence in July 2021 to ensure that the equipment can be delivered by May 2022 and installation can be completed by mid-August 2022. The transmission connection installation will proceed as required.
  - **Commissioning** – Commissioning is planned to commence by mid-August 2022 and be completed by November 2022.
- **Project Operation** – The Project is planned to be in service by November 2022.

3.3 RELATED PROJECTS – WHITEHORSE INTERCONNECTION FACILITY

As discussed in Section 4 below, the 10-Year Renewable Electricity Plan outlines a number of new projects being planned over the next decade to meet Yukon's growing electricity needs. Many of these projects connect to the grid via the Whitehorse Rapids facility, including the BESS, diesel retirement replacement, hydro uprating projects, and the rental diesel units required to meet N-1 planning criterion. Accordingly, YEC is undertaking the Whitehorse Interconnection Project to facilitate the connection of these required capacity resources to the grid in the Whitehorse area.

The Whitehorse Interconnection Project will require design and engineering to change the interconnection configuration for generation assets at Whitehorse to avoid creation of a new N-1 contingency at the S-150 substation. This will likely include routing several connections to the Riverside substation. Completion of this project will facilitate the connection of the BESS and the other identified generation projects to the Whitehorse Rapids facility.

3.4 SUMMARY OF ENVIRONMENTAL AND SOCIO-ECONOMIC IMPACTS

An assessment by the Yukon Environment and Socio-economic Assessment Board (YESAB) Designated Office (DO) is required under the Yukon Environmental and Socio-economic Assessment Act (YESAA) related to specific land use activities required to construct and operate the Project. Land use assessments by NAV Canada and Transport Canada for aviation safety will also be required.

The YESAA assessment has not been initiated at this time. Yukon Energy is undertaking procurement to select a contractor to complete desktop studies required to complete the baseline studies and effects assessment as required to complete the YESAA Project Proposal. This work is targeted to be completed in March 2021 with the Project Proposal filing with the DO by March 31, 2021. The YESAA assessment process is expected be completed and Decision Documents issued by Decision Bodies before the end of June 2021.

As outlined in Figure A-1 (Appendix A), the Project will be located on a greenfield site on land zoned for utility use at the northeast corner of the Alaska Highway and Robert Service Way (south access road) on KDFN Category B Settlement land within an existing environmental and socio-economic setting that has seen commercial and industrial development activities over a sustained period of time. Most of the proposed 1.7 km transmission line connecting the Project to Yukon Energy's LNG plant will follow a pre-existing trail and cutline. A new access road will be built by KDFN to access the site.

The forested ecosystems observed in the area are all common types for the Boreal Low bioclimate zone of Yukon and rare plants are not typically associated with these ecosystems. An evaluation of environment conditions at the site undertaken in August 2020 indicated no especially productive wildlife habitats or concentrations of wildlife sign. Effects to water are limited to site runoff and would be of minimal concern after application of standard mitigation measures; and there would be no direct effects to fish-bearing water bodies. While there is potential for invasive species spread from disturbed areas into other surrounding forest habitat due to construction activities – such effects can also be mitigated using standard mitigation measures. In summary, the initial environmental scan identified no environmental values of material concern that could be potentially significantly affected by construction or operation of the Project.

A public engagement process was undertaken by Yukon Energy in fall 2020, including review of three site alternatives, and identified potential public issues and concerns related to project attributes (e.g., site location, noise levels, aesthetics, cost). These concerns were taken into consideration in site selection and will also inform project engineering and design, where appropriate. Other potential socio-economic effects considered included potential impacts related to noise pollution, light pollution and aesthetics. Mitigation measures have been or will be applied, where appropriate, as part of site selection, project engineering and design. Yukon Energy will also develop a comprehensive fire and emergency response plan and provide training to local firefighters to address concerns related to fire or emergency situations as part of project implementation.

As the site is in proximity to the Whitehorse International Airport and/or flight paths it is expected to require a NAV CANADA Land Use Assessment and a Transport Canada Aeronautical Obstruction Clearance. NAV CANADA must assess all projects with land use near airports and air navigation infrastructure before construction begins to ensure air navigation system safety and efficiency are not compromised. Given there is no exhaust plume and the low height of the containers for the battery – no issues are expected. The Project's height, electromagnetic interference, glare and lighting are the main elements that will be examined. Standard mitigations are expected to be implemented with no significant added cost, if required.

While the assessment and YESAA review is yet to be completed – due to the nature of the Project and due to the outcomes of consultation and site selection processes undertaken to date, the Project is not expected to have any significant environmental effects (e.g., impacts on aquatic environment, vegetation, wildlife or wildlife habitat) or socio-economic effects (e.g., recreation, human health, aesthetic quality, transportation, economy and ratepayers). This conclusion reflects careful consideration of the Project design, as well as consideration of standard mitigation measures that reduce or eliminate potential adverse effects. Some residual effects will occur (e.g., physical presence of the facilities will result in an altered landscape and other changes as long as the facilities are in place), but these are not expected to be significant given the developed and industrial nature of the immediate surroundings that have been persistent on the landscape for the last 55 years or more. The selected site is sheltered from related roadways and is not adjacent to any potentially non-compatible land use.

The Project will also have positive environmental and socio-economic effects. Notably, the Project is expected to provide for reduced greenhouse gas and particulate emissions resulting from the displacement of thermal generation emissions, reduced impacts from YIS disruptions, and enhanced ability to integrate new renewable generation. Other positive effects include the potential for local jobs and business activity during the construction period (including opportunities for KDFN and TKC), savings for Yukon ratepayers compared to what would be required with continued reliance on diesel rentals, and potential business, employment and investment opportunities for KDFN and TKC.

4.0 PROJECT JUSTIFICATION

4.1 YUKON GRID CONTEXT

4.1.1 Yukon Grid Context

YEC owns and operates the Yukon Integrated System (YIS), generating almost all of the electricity on this isolated electric grid. Yukon Energy is the electric utility with primary responsibility for planning and development of new generation and transmission facilities for the YIS.

Under long-term average water conditions, 84% of YEC's 2021 forecast generation for the YIS will be supplied by hydroelectric generation with almost all of the balance of this generation to be supplied by diesel and LNG fueled thermal generation.[31] Unlike other hydro based systems in southern Canada, however, Yukon's isolated grid must self-supply all its own capacity and energy, including securing reserve capacity in order to meet grid loads during winter peak periods, as it has no access to any external North American power grid to secure extra power when it is needed, or to sell surplus renewable generation when it occurs.

Seasonal generation constraints also present additional challenges to the YIS.[32] Electricity demand on the YIS is highly variable with seasonal mismatch between the timing of maximum available electricity production from renewable generation (which peaks in the summer months) and maximum customer demand (which peaks during a cold period during winter months). The result is surplus renewable generation during summer (which cannot be used or sold to other jurisdictions) and reliance on thermal generation to supply peak load requirements during winter.

Yukon Energy's generation capacity planning criterion for the YIS is based on the single contingency (N-1) dependable capacity criterion, under which the YIS is required to have enough dependable capacity to supply the forecast non-industrial peak winter demand (i.e., excluding major industrial demand) under the largest single contingency. The YIS's current largest single contingency corresponds to the loss of the 37 MW Aishihik Generation Station, either through an outage of the generating station itself or an outage of the L171 transmission line that interconnects the Aishihik Generating Station to the Takhini Substation and the Whitehorse Substation.

Inability to supply the non-industrial peak winter demand, which is expected to occur during a period of the coldest winter temperatures, presents an obvious and acute risk to human health and safety and public and private infrastructure.

---

[31] YEC 2021 GRA, Table 2.2. A small amount of solar IPP generation is also forecast for 2021.

[32] Seasonal water storage is typically needed for hydro facilities to be fully utilized in winter. In Yukon, controlled seasonal storage exists at Aishihik and to a much lesser extent at Mayo, but is largely unavailable at Whitehorse. As a result, there is an increasing need to rely on thermal generation to meet baseload energy loads in winter and early spring when grid loads are highest and hydro water flows are constrained. There are also winter flow constraints due to icing issues [Whitehorse Rapids GS winter flows are restricted at max 170 cms which provides about 27 MW out of 40 MW installed capacity; Mayo GS winter flows are restricted at max 15 cms which provides about 6.5 MW out of 15 MW installed capacity].

4.1.2 Evolving Grid Load Conditions

Demand for electricity is growing in Yukon. With the 1998 closure of the Faro mine and resulting decline in Yukon grid loads, there were no material requirements for the diesel generating units. However, since then the YIS load has increased considerably, with YIS non-industrial sales increasing by about 50% over the last 15 years, and with new industrial mine loads at the Minto, Alexco and Victoria Gold mines. Despite the efforts to increase renewable energy generation capacity, including completion of the Mayo B Hydro Enhancement Project and the Aishihik Third Turbine, thermal generation has once again become the default option to meet current and growing dependable capacity requirements on the YIS. Yukon Energy in recent years has used rented mobile diesel units to address a growing dependable capacity shortfall related to the N-1 dependable capacity planning criterion.

As reviewed in Yukon Energy's 2016 Resource Plan as well as the current 10-Year Renewable Electricity Plan, Yukon Energy continues to pursue new renewable energy developments to displace growth in thermal generation requirements, and also to implement a Demand Side Management (DSM) program aimed to reduce load growth, especially peak demand reductions. These activities will allow YEC to continue meeting Yukoners' growing demands for renewable electricity, while also supporting Yukon government's emission reduction targets.

The 10-Year Renewable Electricity Plan includes updated firm generation load forecasts for 2020 to 2030 as well as updates for potential new renewable generation for this period. The updated firm load forecasts include the impact of several electrification policies and actions being introduced by the Yukon government in support of its emission reduction targets. Ongoing generation projects include: Whitehorse Hydro uprates at WH2 and WH4, the BESS, renewable energy purchases from Independent Power Producers (IPP) through the Standing Offer Program, solar energy from the Micro-Generation program, the Southern Lakes and Mayo Lake enhanced storage projects, replacement of diesel generators as they retire, and DSM programs. The three major new projects YEC is proposing in the 10-Year Renewable Electricity Plan are: electricity purchases from the planned Atlin Hydro Expansion Project, construction of a pumped storage facility at Moon Lake, and upgrading and expansion of the Southern Lakes Transmission Network to facilitate the Moon Lake project and other potential improvements.

Although Yukon Energy is aiming to displace thermal energy generation over the next decade with the planned new renewable generation projects, not all of the added renewable generation sources will provide dependable capacity. For example, no dependable capacity will be provided by the expected IPP purchases under the Standing Offer Program as these are intermittent rather than dispatchable renewables; and enhanced storage projects displace thermal energy generation with no added dependable capacity. As a result, Yukon Energy is placing a high priority on new projects that can address the YIS dependable capacity requirements without reliance on new fossil fuel thermal generation or rented mobile diesel units.

4.1.3 Forecast New Grid Capacity Required

The 2016 Resource Plan identified an N-1 dependable capacity shortfall for the YIS reaching about 25 MW by 2021 and about 40 MW by 2030. Yukon Energy's 2016 Resource Plan included action plans focusing on short and long-term options to reduce these capacity shortfalls, including a new 20 MW diesel plant.[33]

Since the 2016 Resource Plan, there have been changes to the measures recommended in action plans as well as changes in forecast grid loads:

- First, based on feedback received from Yukoners as well as discussion with Yukon Government, in October 2019 Yukon Energy's Board of Directors decided to look at ways to avoid building a new 20 MW thermal generation facility and will now look at options to replace capacity at Yukon Energy's existing generation facilities as diesel engines reach end-of-life.[34]
- Second, YEC in January 2020 provided information on its new 10-Year Renewable Electricity Plan[35] to address impacts of the Yukon government Climate Change Strategy, YEC's Board Strategic Plan and the decision not to pursue a new 20 MW thermal plant at this time, and other updated information. YEC has subsequently released its completed 10-Year Renewable Electricity Plan.[36]

The updated 10-Year Renewable Electricity Plan shows a growing YIS non-industrial peak load between 2021 and 2030, with a continuing need to address a growing capacity shortfall on the YIS absent reliance on rented diesel units as shown in Table 4-1 and Figure 4-1.

Table 4-1 and Figure 4-1 show 2021-2030 forecast non-industrial peak load and the forecast dependable capacity excluding mobile rented diesel units. New capacity supply renewable options currently committed or in final planning include: DSM measures expected to reduce peak demand by 2.2 MW in 2021/22 increasing to 7.0 MW by 2030/31;[37] the Whitehorse GS Unit #2 uprate expected to add 0.6 MW dependable capacity starting in 2021/22; the Atlin Hydro Expansion Energy Purchase Agreement (EPA) with approximately 8.5 MW dependable capacity starting in 2024/25; and the BESS Project expected to provide 7.2 MW dependable capacity support starting in November 2022 [available for 2022/23 winter]. In addition to these new renewable capacity options, the 10-year plan includes the potential Moon Pump Storage Phase 1 with 35 MW winter capacity starting in 2028/29 as illustrated in Figure 4-1. The planned new capacity options also include 12.5 MW of new diesel units to replace retiring generation in Whitehorse, Faro and Dawson.

In summary, Table 4-1 and Figure 4-1 show the forecast N-1 capacity shortfall related to non-industrial YIS load after DSM and the WH2 uprate for 2021/22 at 26.4 MW requiring 15 diesel rental units (plus any spares needed to support these units); without new resources beyond DSM and the WH2 uprate, this

[33] 2016 Resource Plan, Executive Summary, Table 2 and Appendix 8.1 and Table 4.5 (assumes Medium Industrial Activity load forecast). After 2030 the dependable capacity shortfall declined slightly (38 MW by 2035).
[34] https://yukonenergy.ca/energy-in-yukon/projects-facilities/new-thermal-generation [accessed On April 22, 2020].
[35] YEC, "10-Year Renewable Electricity Plan", power point presentation on January 29, 2020 to the Building Partnerships Program Conference in Whitehorse.
[36] https://yukonenergy.ca/energy-in-yukon/electricity-in-2030/our-draft-10-year-plan
[37] In order to simplify illustration in this analysis, DSM was added as a new supply option instead of showing as a reduction in peak demand.

dependable capacity N-1 shortfall is forecast to increase to 39.9 MW in 2025/26 and 61.2 MW in 2030/31.[38]

The new supply resources in Table 4-1 (including DSM and WH2 uprate) are expected to add between 2.8 MW [2021/22] and 70.7 MW [2030/31] of dependable capacity. Due to timing of the supply resources, the N-1 capacity shortfall is forecast to continue through 2028/29 requiring from 4 to 15 diesel unit rentals (7 to 27 MW), plus spares as required, each year until the proposed 35 MW Phase 1 Moon Lake Pump Storage is in-service (forecast in 2028/29). Figure 4-1 shows the 10 MW Phase 2 Moon Lake Pump Storage project proposed in 2031/32 to address ongoing N-1 dependable capacity requirements.

In considering new dependable capacity resources for the YIS it is important to re-iterate that the requirement is based on non-industrial load forecasts. Unlike energy resources, where a loss of mine loads can quickly create surplus resource conditions, the forecast peak winter load requirement continues to grow well beyond the next 10 to 20 years.

[38] YEC also uses Loss of Load Expectation (LOLE) as system capacity planning criteria where the system is planned not to exceed a LOLE of 2 hours/year. The LOLE criterion includes industrial loads as part of the assessment. At the forecast industrial load, however, the LOLE criterion was satisfied in forecast years so long as the single contingency, N-1, criterion was met.

Figure 4-1: Non-Industrial Peak & Dependable Capacity under N-1 Capacity Planning Criterion: 2021/22-2041/42 Winter

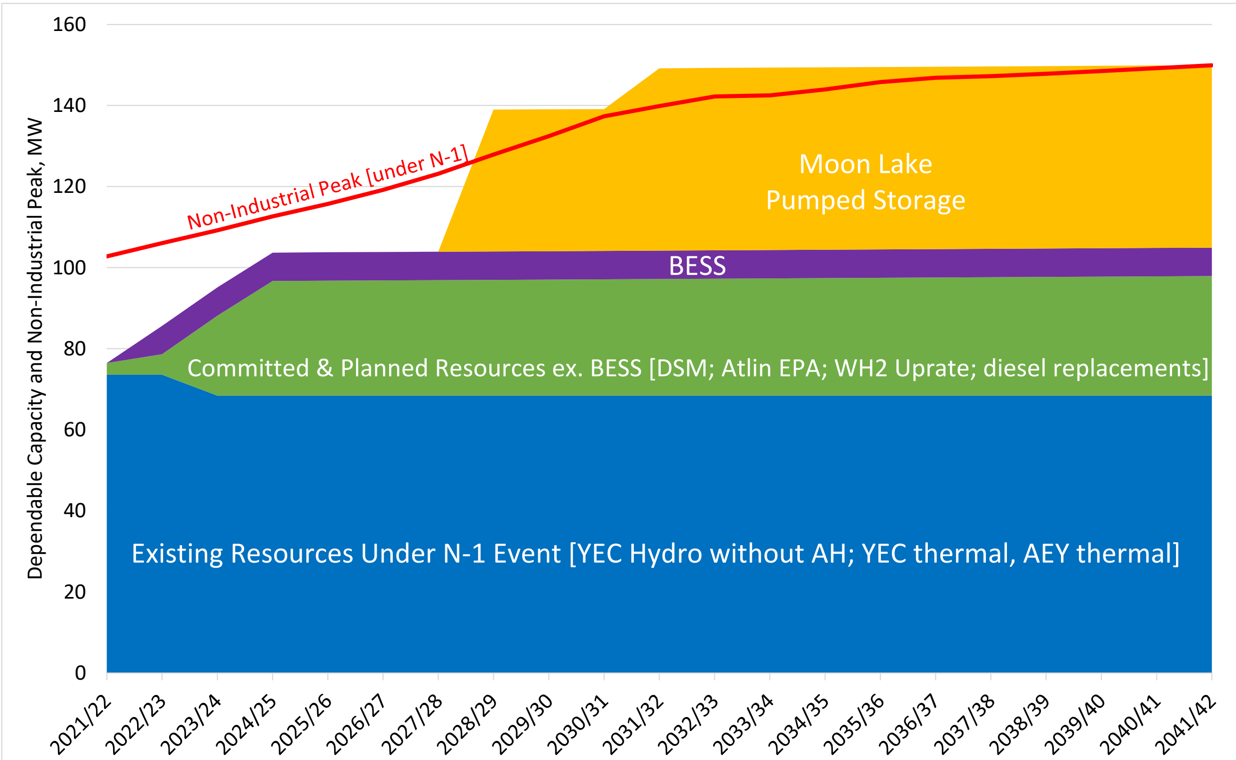


Table 4-1: Forecast Non-Industrial Peak and Dependable Capacity under N-1 Capacity Planning Criterion: 2021/22-2030/31 Winter (MW)

	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Non-industrial Peak	**104,102**	**107,372**	**110,546**	**113,952**	**117,030**	**120,515**	**124,517**	**129,214**	**133,769**	**138,676**
Non-industrial Peak	*103,284*	*106,277*	*109,078*	*111,985*	*114,393*	*116,982*	*119,783*	*122,870*	*125,268*	*127,285*
EV Peak	*818*	*1,096*	*1,468*	*1,968*	*2,637*	*3,533*	*4,734*	*6,344*	*8,501*	*11,391*
Existing Resource Dependable Capacity	**112,100**	**112,100**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**
YEC Hydro	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*
YEC Thermal	*36,050*	*36,050*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*
AEY Thermal	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*
N-1 Event [Lost of AH GS or L171]	**-37,195**	**-37,194**	**-37,193**	**-37,192**	**-37,191**	**-37,190**	**-37,189**	**-37,188**	**-37,187**	**-37,186**
Loss of AH GS	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*
Loss of AEY Haines Junction diesel	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*
Haines Junction peak	*1,305*	*1,306*	*1,307*	*1,308*	*1,309*	*1,310*	*1,311*	*1,312*	*1,313*	*1,314*
Capacity Shortfall/Surplus under N-1	**-29,197**	**-32,466**	**-40,839**	**-44,244**	**-47,321**	**-50,805**	**-54,806**	**-59,502**	**-64,056**	**-68,962**
Committed and Planned Supply Options	**2,843**	**12,047**	**26,752**	**35,318**	**35,385**	**35,452**	**35,521**	**70,589**	**70,659**	**70,729**
Diesel Replacements	*0*	*0*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*
Whitehorse #2 Uprate	*638*	*638*	*638*	*638*	*638*	*638*	*638*	*638*	*638*	*638*
BESS	*0*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*
Atlin Hydro EPA	*0*	*0*	*0*	*8,500*	*8,500*	*8,500*	*8,500*	*8,500*	*8,500*	*8,500*
DSM	*2,205*	*4,409*	*6,614*	*6,680*	*6,747*	*6,814*	*6,883*	*6,951*	*7,021*	*7,091*
Moon Lake Pump Storage Phase 1	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*35,000*	*35,000*	*35,000*
Capacity Shortfall/Surplus under N-1	**-26,355**	**-20,419**	**-14,087**	**-8,926**	**-11,936**	**-15,352**	**-19,285**	**11,087**	**6,603**	**1,767**

4.2 NEED FOR AND ALTERNATIVES TO THE PROJECT

The Project responds to the current need for dependable capacity to address the N-1 dependable capacity shortfall that requires reliance on rented mobile diesel units to meet YIS reliability requirements.

As reviewed in Section 4.1.3, the N-1 capacity shortfall related to non-industrial YIS load after DSM and the WH2 uprate is forecast for 2021/22 at 26.4 MW requiring 15 diesel rental units (plus two spares needed to support these units); without new resources, this shortfall is forecast to increase significantly in subsequent years.

Under a "status quo" or "do nothing" alternative, YEC would continue to rely on rented diesel units which would increase each year as non-industrial load growth and dependable capacity reduces with planned retirements of existing diesel units.[39] Aside from added costs, reliance on rented diesel units can create risks as to continuing availability, acceptable performance and the ability to accommodate the required units.[40] This may expose all grid customers to unreliable generation capacity as well as undermine the efforts to achieve goals outlined in Yukon government's draft "Our Clean Future: A Yukon strategy for climate change, energy and a green economy".[41]

In summary, the "status quo" option is not a feasible alternative today. Permanent solutions are needed rather than relying upon temporary options such as rented diesel generators. The sections below also confirm that the Project is the least cost new resource alternative available today for Yukon Energy to supply this required dependable capacity.

4.2.1 Alternatives to the Project

Yukon Energy's 10-Year Renewable Electricity Plan examined a wide range of near-term resource supply options[42] to address forecast energy and capacity shortfalls. Many of these options do not provide dependable capacity; and the new resources that will provide dependable capacity would generally not displace what the BESS option can provide, i.e., the identified permanent resource capacity options are generally all needed to remove reliance on rented diesels for addressing the forecast capacity shortfall reviewed in Table 4-1. Moon Lake pumped storage, when developed, is the only identified resource option aside from default new thermal fossil fuel generation that has the capability to remove the forecast N-1 dependable capacity shortfall.

---

[39] As reviewed in 10-Year Renewable Electricity Plan, YEC anticipates the retirement of the sole remaining Mirrlees diesel engine in Faro (FD1) and two diesel engines from the Dawson Diesel Plant (DD2 and DD5) in 2023 which would reduce dependable capacity by 5.2 MW. https://yukonenergy.ca/media/site_documents/YEN20093rpt_Technical_web2_compressed.pdf page 32.
[40] For example, without new resources the N-1 shortfall would grow to 64.1 MW by 2030 which would require 36 diesel rental units. In additional to the challenges finding this number of rental diesels, YEC would also face location and connection issues to safely connect diesel rental units to YIS.
[41] Yukon government's draft "Our Clean Future: A Yukon strategy for climate change, energy and a green economy" also mandates that an average of 93% of electricity generated on the grid must be produced from renewable sources, and includes specific actions to electrify the territory's transportation and heating sectors. This climate change strategy further increases non-industrial peak demand beyond the 2030 planning period and the need for additional renewable resources.
[42] See Section 5.1 of 10-Year Renewable Electricity Plan, December 2020.
https://yukonenergy.ca/media/site_documents/YEN20093rpt_Technical_web2_compressed.pdf

The reviewed new resource portfolio options to the BESS in the 10-Year Renewable Electricity Plan include the following:

- **Standing Offer Program (SOP) and Micro-Generation Program:** The SOP is outlined in the Independent Power Production (IPP) Policy of the Yukon territorial government issued in 2015. The SOP is included in the 10-Year Renewable Electricity Plan with 40 GWh/year of energy delivered by the IPP sector by the year 2024. The Micro-Generation Policy issued by the Yukon government in October 2013 is applicable to projects up to 50 kW. The micro-generation included in the 10-Year Renewable Electricity Plan envisions 6.5 GWh/year of delivered energy by the year 2024. However, no dependable capacity is available from SOP and micro-generation projects because they will be comprised of intermittent renewable resources such as wind and solar.
- **Whitehorse Hydro #2 (WH2) and Whitehorse Hydro #4 (WH4) Uprate Projects:** The Whitehorse Hydro WH2 Uprate Project will increase the efficiency and maximum capacity of the WH2 generation unit, resulting in more generated electricity for the same water throughput providing 6.2 GWh of annual energy and 0.64 MW of dependable capacity. The Whitehorse Hydro WH4 Uprate Project will increase the maximum water flow providing 0.9 GWh of annual additional energy, however, due to downstream Yukon River system ice flow restrictions this project does not provide additional dependable capacity.
- **Potentially Available Near-term Enhanced Hydro Storage Projects:** The Southern Lakes Enhanced Storage Project (SLESP) will expand the storage range on the Southern Lakes system potentially providing an additional 6.5 GWh of electricity each year at the Whitehorse Hydro facility. The Mayo Lake Enhanced Storage Project (MLESP) seeks to enhance water storage at Mayo Lake by lowering its current licensed minimum level by up to one metre potentially providing an additional 4 GWh of electricity each year. However, both hydro storage enhancement projects would not affect grid requirements for new dependable capacity.
- **Demand Side Management (DSM):** DSM involves using incentives, electricity rate structures, and building and appliance codes and standards to encourage customers to reduce the amount of electricity they use. The current focus of the DSM programs is on measures that deliver peak capacity savings (i.e., reductions in peak electricity consumption). The DSM programs are expected to reduce peak demand by 7 MW by 2030/31.
- **Diesel Replacement:** By replacing retired diesel generator units at existing generation facilities, YEC can reduce the need for added rental diesel generators. The total replacement diesel currently assumed is 12.5 MW. However, this does not fully address the capacity shortfall.[43]
- **The Atlin (Pine Creek) Hydro Expansion Project:** This was identified as a key project in the 10-Year Renewable Electricity Plan given its relatively advanced stage of development as a brown-field expansion project when compared to other potential greenfield hydro developments.

[43] In compliance with Yukon government Climate Change Strategy, YEC's Board decided not to pursue a new 20 MW thermal plant at this time.

In 2020, YEC engaged in discussions with Xeitl Limited Partnership (Xeitl LP) (Taku River Tlingit development corporation) regarding the Atlin project being planned by Xeitl LP, and key principles and terms for an Agreement-in-Principle (AIP) for an Electricity Purchase Agreement. Federal funding has been identified as a key requirement for this project to proceed. The objective is for this project to provide 8.5 MW of dependable capacity by 2024/25.

- **Tutshi-Moon Pumped Storage Project – Phase 1:** The 10-Year Renewable Electricity Plan identified the development of a pumped storage hydro project as a key priority that would provide renewable capacity to address the existing and forecast capacity shortfall under the N-1 planning criterion.[44] Yukon Energy completed an updated evaluation of pumped storage sites as part of the 10-Year Renewable Electricity Plan, and the Moon-Tutshi project was identified as the preferred site. This could potentially provide 35 MW dependable winter capacity starting in the 2028/29 winter season. Federal funding was identified as a critical requirement for this to be affordable for customers and to minimize risks.
- **New 20 MW Wind Project:** The High Case scenario of the 10-Year Renewable Electricity Plan identified a new 20 MW wind resource in 2025/26 to meet the higher energy requirements over the planning period. However, this potential resource option would not provide any dependable capacity as it is an intermittent resource.

In summary, no feasible renewable resource alternatives to the Project have been identified within the relevant time period. Aside from the potential Moon Lake pumped storage project in the future, the temporary rental diesel option or permanent new diesel development remain the only feasible alternatives that would provide dependable capacity required to address the N-1 shortfall.

The Project provides a net benefit to ratepayers compared to the rented diesel option to address the N-1 dependable capacity shortfall, as detailed in Section 4.2.3. Key additional features of the BESS Project compared to the diesel rental option are the added beneficial uses that it can provide to the YIS in addition to providing needed N-1 dependable capacity, including renewable operating reserve, enhanced blackstart capability, diesel peak shifting, and load shedding reduction/ frequency regulation that can assist integration of intermittent renewables as currently planned with the SOP.

4.2.2 Alternative Ways of Undertaking Project & Preferred Alternative

Alternative ways of undertaking the BESS Project include different technologies, installation options, and sites as well as different sizes for the Project. Each of these alternatives are reviewed below relative to the preferred option proposed for the Project, i.e., a containerized 20 MW/ 40 MWh lithium ion BESS on a 1.5 ha site that Yukon Energy will lease on undeveloped KDFN Category B settlement land located northeast of the intersection of Robert Service Way and the Alaska Highway.

[44] The pumped storage project would also allow for at least some of the spilled summer energy from IPP and SOP and YEC's surplus summer hydro to be captured and stored for use during the winter months.

Energy Storage Technology Options

There are various energy storage technologies available. Yukon Energy completed a comprehensive review of the available energy storage technologies for the 2016 Resource Plan. This study concluded that batteries, and lithium ion batteries specifically, were the best energy storage option for the YIS context. The use required by Yukon Energy involves low cycling, with a need for reliable and quick response in a northern climate location.

The Hatch Report notes that lithium-ion batteries (LIBs) are the most established and versatile energy storage technology on the market today outside of pumped hydro; and LIB technology is considered reliable, lower risk, and has established previous installations compared to other less established energy storage technologies. The Hatch comparison shows that the LIBs have higher round trip efficiency compared to other battery energy projects, faster response capability, and similar or better expected lifetime.[45]

During the review of YEC's 2017/18 GRA the YUB noted a concern that the technology used for battery storage has not been tested in a northern climate.[46] Small scale lithium ion battery energy storage facilities have been successfully applied in the northern regions, including the Raglan Mine [Nunavik, Northern Quebec] completed in 2015;[47] and Colville Lake completed by Northwest Territories Power Corporation in 2016.[48]

The Hatch Report also notes the following features for LIBs:[49]

- LIBs are generally regarded as the most versatile BESS technology, offering both high power and high energy capacities and they have the greatest energy density of battery technologies, making them ideal for locations with limited available space for installation.
- The cost of LIBs is continuously decreasing and is expected to continue to decrease over the next several years.
- LIBs are relatively easy to maintain compared to other BESS technology, with 1-2 maintenance visits from the vendor each year.

The Hatch Report notes that thermal management and heating of the system will be critical for Yukon Energy when selecting the BESS vendor, and reviews the ways in which vendor systems address climate considerations as well as safety considerations (e.g., fire risk).[50]

[45] Page 17 and Table 4-1 of Hatch August 2020 report. Table 4-1 of this report compares seven energy storage technologies (pumped storage, compressed air, flywheel, lithium ion battery, flow battery, lead-acid battery, and supercapacitor) and shows LIBs have 80-90% round trip efficiency compared to 60-85% for flow battery and 65-90% for lead-acid battery; LIBs respond in milliseconds compared to seconds for the other batteries, and have projected lifetime of up to 20 years versus only 10 years for lead-acid battery. At page 21, Hatch also notes that LIBs experience a slow self-discharge of 3-5% per month.
[46] YUB Order 2018-10, paragraph 463.
[47] https://www.nrcan.gc.ca/science-and-data/funding-partnerships/funding-opportunities/current-investments/glencore-raglan-mine-renewable-electricity-smart-grid-pilot-demonstration/16662 [accessed on January 7, 2020].
[48] https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2016/market-snapshot-batteries-dominate-early-stage-testing-energy-storage-in-canada.html [accessed on January 7, 2020].
[49] Hatch August 2020 Report, page 17.

There are three common utility scale lithium ion battery technologies: nickel manganese cobalt lithium (NMC), nickel cobalt aluminum lithium (NCA), and lithium iron phosphate (LFP). Yukon Energy will consider vendor proposals for all three technologies in order to ensure a competitive process with sufficient bidders and the ability to select the specific solution based on both technical compliance and price.[51]

Installation Options

The Hatch Report notes that most battery vendors offer their system in a containerized offering, typically with standard 40 ft or 20 ft shipping containers; however, for utility scale a building option may also be possible.

Although the building option offers some benefits over a containerized option [such as easier maintenance within the sheltered building, and more efficient thermal management in a single structure], there are more disadvantages with the building option:[52]

- Building design, heating/cooling system design, and fire suppression system design all must be done by a 3rd party which leads to higher engineering costs. Overall project cost may also be higher due to cost of the building.
- Building size limits expandability of the project in the future.
- Longer onsite construction since the building needs to be erected before batteries can be installed.
- Batteries, inverters and transformers need to be integrated on-site, increasing commissioning time and risk of complications.
- Integrated FAT testing is not possible at vendor site, thus increasing the risk of communication, synchronization, and timing challenges that arise during commissioning or after the vendor has left.
- The building will be taller, thus more visible to residents.

Batteries within the container can be integrated at the vendor's factory, reducing the on-site installation and commissioning time as they are supplied as pre-integrated modules. This reduces the risk during the installation and commissioning and also is less costly compared to the building option.

---

[50] Hatch August 2020 Report, Section 4.2.1 at page 22 and Section 4.2.2 at page 23. YEC will require vendor demonstrated capability to support operation in Whitehorse winter climate conditions. Hatch notes that the risk of fire in a battery energy storage system is very low.

[51] See Hatch, pages 8 and 18. The most common chemistry is NMC which is offered by many vendors and typically has the lowest cost. NCA tends to be a niche offering, typically geared towards high power applications with a higher cost. LFP technology is becoming increasingly common as it is low cost and considered inherently safer, although it typically has a larger footprint. Since the footprint is not significantly limited for YEC's application, Hatch's initial view is that the LFP will be the preferred chemistry for the lithium ion BESS as it is safer and tends to be low cost.

[52] See Hatch Report, Section 10 (for comparison of container and building options).

Project Site Options

Three separate battery location options were considered as part of project planning – each was selected for evaluation based on proximity to YEC's existing grid infrastructure in the Whitehorse area:

1. Site on TKC Settlement Land across from Yukon Energy's LNG Plant on Robert Service Way (South Access Road);
2. Site on KDFN Settlement Land on northeast corner of the Alaska Highway and Robert Service Way (South Access Road); and
3. Site on KDFN Settlement Adjacent to the Takhini Substation on the North Klondike Highway.

Features for each site option were reviewed by Hatch[53] and were also the focus of the public consultation and stakeholder engagement on the Project (see Section 5 of this Application).

As reviewed in Section 5, the public consultation indicated general support for the Project but strong opposition to it being located at the site option adjacent to the Takhini Substation. This site option offered lower ongoing O&M costs due to the absence of property taxes but had various issues in addition to strong public opposition, e.g., need for noise controls (due to proximity of residents), access was more challenging than at other sites, the site is not flat, and limited flexibility as to container output. Based on these considerations, this site option was not selected and would no longer be considered an option.

The two remaining site options located within Whitehorse for connection to the Whitehorse rapids substation facility generally offered relatively equivalent benefits and costs, including the cost of property taxes. Yukon Energy received lease proposals from both KDFN and TKC for these two sites and selected the KDFN site in this area as the preferred site option based on the lease rates offered. The schedule is now dependent on proceeding with this selected site option.

BESS Size Options

The proposed BESS has two fundamental ratings: the power capability, in MW; and the energy capacity, in MWh. The ratio of energy to power provides the duration for which the battery can supply electricity at its rated power capability.

The Hatch Report reviewed different sizing options for BESS from 30 MW.h and 45 MW.h energy capacity options, and power capability options ranging between 6.6 MW and 20 MW.

- **N-1 Dependable Capacity Use** – As reviewed earlier in Section 3.1.2 and Table 3-2, different battery useable energy capacity sizes were examined ranging from 30 MWh to 45 MWh.
- **Operating Reserve Use** – Based on 2019/2020 YIS operations, the annual average amount of thermal generation that could be reduced or turned off by BESS use as a supplementary

[53] See Hatch Report, Section 9 and summary comparison of site options at Table 1-2, starting page 4 and Table 9-1 starting page 87.

operating reserve has been estimated by Hatch at between 1.7-1.8 GWh of diesel generation and 13.5-17.0 GWh of LNG generation for size ranges in Table 4-2. Thermal generation reduction benefits from BESS use to supplement operating reserve increase with higher BESS power capacity with each of the energy capacity sizes, but show only marginal increases for power capacities in excess of 13 MW as shown in Table 4-2.

Table 4-2: BESS Operating Reserve Use & Thermal Generation Reduction – Range of Sizes[54]

Battery Useable Power & Energy Capacity Size	Energy Used of Operating Reserve (30 min)	% of Useable Energy Capacity	Reduction in Diesel Generation (MWh/yr)	Reduction in LNG Generation (MWh/yr)
1	2=MW*1/2hrs	3=2/MWh	4	5
6.6 MW/ 35 MWh	3.3	9.4%	1,728	13,480
7 MW/ 40 MWh	3.5	8.8%	1,731	13,691
8.8 MW/ 35 MWh	4.4	12.6%	1,777	16,062
10 MW/ 40 MWh	5.0	12.5%	1,813	16,410
13 MW/ 40 MWh	6.5	16.3%	1,837	16,995
20 MW/ 40 MWh	10.0	25.0%	1,837	17,043

Key conclusions from the review of these different BESS size options include the following:

- Overall, increasing inverter and transformer capacity [MW increase] has a relatively much smaller added cost impact than increasing battery cell capacity.[55]
- The optimal BESS energy capacity sizing for N-1 dependable capacity use to supply the peak day is either 35 MWh or 40 MWh, each of which result in a reduction of four diesel genset rentals, i.e., at 30 MWh capacity only three diesel genset rentals are removed and at 45 GWh the diesel rental genset reduction remains at four units.
    - o The 40 MWh BESS increases Yukon Energy capital costs by just under $3 million compared to the 35 MWh option.
    - o The 40 MWh capacity option enables Yukon Energy to maximize the benefits of all use cases simultaneously with each other, resulting in a net ratepayer savings as described in Section 4.2.3, while still allowing for the provision of N-1 dependable capacity. It also allows for greater operational flexibility.[56]

[54] Hatch, August 24, 2020 Report, Figures 6-5 and Figures 6-4 and 6-6. BESS sizes in the table each provide 7.2 MW N-1 dependable capacity reserve. The sizes with 8.8 MW or greater power capacity have 4 hour duration for full discharging or recharging.
[55] For example, the Hatch August 2020 Report page 38 notes increasing energy capacity from 35 MWh to 40 MWh adds about $3 million capital cost, while increasing power capacity from 10 MW to 20 MW adds about $1.8 million cost [Table 6-4 of Hatch Report]. See also Table A-2 in Appendix A to this Application.
[56] See Section 3.1.2.1 and Table A-1 of this Application and Hatch August 2020 Report, pages 37 to 39.

- Focusing on BESS inverter size options, the following features are noted for the potential BESS uses (see Section 3.1.2.2 and Table 4-2 of this Application and Tables A-1 and A-2 in Appendix A):
  - Increasing the power output of the BESS inverter to 20 MW allows the BESS to be recharged faster overnight, ensuring that it can be ready the next day to continue providing dependable capacity under the N-1 event.
  - As the load growth and peak demand increase, the higher power capabilities of a larger BESS inverter [13 MW or 20 MW] allow for more flexibility for future operation, especially for some secondary use cases.
  - Increased power and energy capacity increases BESS capability to provide blackstart benefits; in particular, the 20 MW power capabilities provide Yukon Energy with increased flexibility to significantly increase the size of the load segments that can be picked up during the blackstart process, which reduces the time required for grid restoration.
  - The 20 MW inverter capability can also cover the loss of Whitehorse Hydro Unit #4 which has the highest operating factor (capacity factor) of all of Yukon Energy's generation; therefore, an outage of Whitehorse Hydro Unit #4 can lead to critical outages on the grid. Outages caused by the loss of Whitehorse Hydro Unit #4 occur on average once per year, however, given the larger size of this unit the resulting load shedding is more extensive. This is particularly true in the summer when WH4 is providing a larger portion of generation on the grid.

YEC selected the 20 MW/40 MWh BESS system size in order to deliver the 7.2 MW of N-1 dependable capacity in combination with the other use cases, which result in a net benefit to ratepayers (as described in Section 4.2.3). This sizing ensures that provision of the N-1 dependable capacity does not limit YEC's ability to deploy the BESS for other uses and realize their benefits, enables faster recharging overnight, and provides greater operational flexibility to accommodate future changes in the configuration and operational needs of the grid as more intermittent renewable resources come online.

4.2.3 Project Economics

The BESS will provide 7.2 MW dependable capacity [reduction of four diesel rentals] to reduce Yukon Energy's need to rely on rental of diesel generators during the winter months to address N-1 capacity shortfalls. The BESS will also provide other benefits, including: an operating reserve that reduces thermal generation requirements; enhanced blackstart capability; opportunities for diesel-peak shifting; and other system benefits. These benefits result in net ratepayer savings when compared to the use of diesel rentals which would be necessary should the Project not proceed. The BESS is expected to assist in YIS grid stability and reduce thermal generation and GHGs – benefiting both the environment and Yukon ratepayers.

Capital and Operating Costs

As reviewed in Section 3.1.3, preliminary estimated capital costs (2020$) for BESS are $31.7 million (2020$, +/-30% accuracy) and include capital costs related to the equipment and installation costs as estimated by Hatch in the August 2020 Report, and Yukon Energy estimates for planning and owner's costs. The preliminary net capital cost estimate for Yukon Energy, after the $16.5 million funding from the Federal government's "Investing in Canada Infrastructure Program ("ICIP"), is $15.2 million.

Table 3-5 in Section 3.1.3 shows preliminary estimates for annual operating costs for BESS, including annual operating and maintenance costs of $0.230 million, annual property taxes at $0.297 million, insurance costs at $0.040 million and $0.007 million transmission O&M costs plus annual lease costs for selected site at $0.055 million to total annual costs at $0.629 million (2020$). The cost of recharge will vary based on use cases discussed below.

Net Ratepayer Cost Savings

Ratepayer cost savings related to thermal generation displacement from the Project are reviewed initially below by primary and other uses. Project costs over the Project 20-year life are then compared to these cost savings to provide net ratepayer cost savings over the Project life.

Primary Use

The primary use of the BESS is to provide N-1 dependable capacity reserve. Yukon Energy must have sufficient dependable capacity under its N-1 Dependable Capacity Criterion to meet its winter non-industrial peak load without its largest generator (currently the 37 MW Aishihik Hydro plant connected to Whitehorse by transmission). As reviewed in Section 4.1.3, the forecast N-1 capacity shortfall related to non-industrial YIS load for 2021/22 is 26.4 MW requiring 15 diesel rental units (plus any spares needed to support these units). Without new resources this dependable capacity N-1 shortfall is forecast to increase significantly by 2030/31.

The proposed BESS energy and power capacity sizing [20 MW/40 MWh] will provide 7.2 MW of dependable capacity. Based on displacing winter 2022/23 diesel rental costs of approximately $168,900/MW,[57] the year 1 (2022) annual savings in diesel rental costs approximates $1.216 million per year and these cost savings are assumed to escalate at 4% per year[58] over the 20-year Project.

[57] Forecast based on diesel rental costs per connected MW (includes costs for spares) for winter 2021/22 estimated at $162,400/MW, and escalated at 4% to forecast 2022/23 winter rental costs per MW.

[58] The 4% escalation reflects recent YEC experience on escalation of diesel rental costs at rates greater than overall consumer price inflation (consumer price inflation is assumed at 2% per year in the current analysis).

Other Use Cases

Operating Reserve

As discussed in Section 3.1.2.2., the Hatch August 2020 Report concluded that use of the BESS to provide operating reserve has the greatest economic benefit among the identified additional use cases with benefits of BESS use for operating reserve noted to be two-fold:

- A direct reduction in diesel and natural gas genset operation hours and energy generation; and
- Improved efficiency of the hydro-turbines by operating them at their most efficient output more frequently, leading to more energy production with the same amount of water flow.

Table 3-3 shows that when the 20 MW/40 MWh BESS is used as operating reserve it could save up to 1,837 MWh of diesel and 17,043 MWh of LNG, or $3.374 million, based on 2021 GRA fuel prices. Section 3.1.2.2. also notes that these estimates may not be fully realized due to water storage savings with the existing operations, and that net thermal generation reduction from BESS operating reserve use is approximately one-third of Table 3-3 estimates, i.e., the operating reserve annual net fuel cost saving is reduced to approximately $1.125 million (2022$).

Diesel Peak Shifting

As reviewed in Section 3.1.2.2, the estimated net cost savings from BESS diesel peak shifting based on 2019 operations indicate relatively small net economic benefits approximating $10,600/year (2022$) after consideration of LNG and hydro operating costs for recharging of BESS.

Other secondary use cases

The YIS will benefit from other secondary uses cases such as blackstart and outage restoration, reduction in load shedding (via frequency regulation) and renewable integration, load loss stabilization and reactive power support; however, the economic benefits from these use cases cannot be estimated [i.e., while there are no economic impact estimates provided in the Hatch Report, it is recognized that customers will receive benefits from reduced outage durations and other reliability benefits provided by the Project].

Net Ratepayer Cost Savings

Table 4-3 illustrates annual costs and savings from the Project, assuming for simplicity year 1 operation in 2022. The table shows that over the life of the Project the net present value (2022$) of the costs is $27.751 million compared to the net present value of benefits of $40.426 million. This indicates the Project will benefit Yukon ratepayers (present value savings of $12.676 million).

For each year of operation, ratepayers will see annual net savings from the Project: lower for initial years due to upfront capital costs and increasing year-by-year thereafter as illustrated in Table 4-3.

Table 4-3: Annual Ratepayer Impacts from BESS (20 MW/ 40 MWh)

$000	BESS Annual Costs ($000)				BESS Annual Savings ($000)				Net Annual Ratepayer Savings (Costs) ($000)
	Annual Capital Cost	Annual Operating Cost [excl. recharging]	Annual Net Recharging Cost [15% return loss plus 3% idling loss]	Total Annual Costs	Avoided Diesel Rental Costs	Annual Savings from Operating Reserve Use	Annual Savings from Peak Shifting	Total Annual Savings	
	A	B	C	D=A+B+C	E	F	G	H=E+F+G	I=H-D
Year 1	$1,530	$652	$82	$2,264	$1,216	$1,125	$11	$2,351	$87
Year 2	$1,492	$665	$84	$2,240	$1,265	$1,147	$11	$2,423	$182
Year 3	$1,454	$678	$85	$2,217	$1,315	$1,170	$11	$2,496	$280
Year 4	$1,416	$691	$87	$2,194	$1,368	$1,193	$11	$2,573	$379
Year 5	$1,378	$704	$89	$2,171	$1,423	$1,217	$12	$2,651	$481
Year 6	$1,340	$717	$91	$2,148	$1,480	$1,242	$12	$2,733	$585
Year 7	$1,302	$731	$92	$2,126	$1,539	$1,267	$12	$2,817	$691
Year 8	$1,264	$745	$94	$2,104	$1,600	$1,292	$12	$2,904	$801
Year 9	$1,226	$759	$96	$2,082	$1,664	$1,318	$12	$2,994	$912
Year 10	$1,189	$774	$98	$2,061	$1,731	$1,344	$13	$3,088	$1,027
Year 11	$1,151	$789	$100	$2,040	$1,800	$1,371	$13	$3,184	$1,144
Year 12	$1,113	$804	$102	$2,019	$1,872	$1,398	$13	$3,284	$1,265
Year 13	$1,075	$820	$104	$1,999	$1,947	$1,426	$13	$3,387	$1,388
Year 14	$1,037	$835	$106	$1,978	$2,025	$1,455	$14	$3,493	$1,515
Year 15	$999	$851	$108	$1,959	$2,106	$1,484	$14	$3,604	$1,645
Year 16	$961	$868	$111	$1,939	$2,190	$1,514	$14	$3,718	$1,779
Year 17	$923	$885	$113	$1,920	$2,278	$1,544	$15	$3,836	$1,916
Year 18	$885	$902	$115	$1,902	$2,369	$1,575	$15	$3,958	$2,057
Year 19	$847	$919	$117	$1,884	$2,463	$1,606	$15	$4,085	$2,201
Year 20	$810	$937	$120	$1,866	$2,562	$1,638	$15	$4,216	$2,350
NPV	**$16,318**	**$10,147**	**$1,286**	**$27,751**	**$22,647**	**$17,612**	**$167**	**$40,426**	**$12,676**

Notes:

1. **2021 assumed as Year 1. Capital costs (Table 3-4) and operating costs (Table 3-5) each escalated 2% for one year inflation.**
2. **YEC WACC at 4.794% per 2021 GRA (real WACC with 2% inflation at 2.739%) is used for all net present values (NPVs).**
3. **Annual Capital Cost includes depreciation (20 year life) and return on mid-year rate base at YEC WACC of 4.794%.**
4. **Annual Net Recharging Cost assumes diesel generation for N-1 dependable capacity and operating reserve recharge losses, 75% LNG and 25% hydro for other recharge losses (peak shifting saving already addresses these losses), and hydro for idling losses.**
5. **Avoided Diesel Rental Costs assumes $168,896 per MW (2022$) and 7.2 MW (4 rental units) of dependable capacity.**

In summary, based on review of the above investigations and analysis, it is concluded that the specified need to meet near term forecast requirements for reliable and flexible new capacity on the Yukon grid would best be met through development of the Project. Compared to the feasible and best alternative available today (i.e., diesel rental), at forecast grid loads the Project provides a cheaper and renewable focused energy option for Yukon Energy and Yukon ratepayers.

4.3 RISKS AND POTENTIAL IMPACTS ON RATEPAYERS

The Project technical, design and capital cost risks are considered to be manageable through selection of an experienced vendor able to address Yukon Energy's requirements. These risks are generally being addressed through an early vendor selection process, assisted by an owner's engineer with experience procuring battery vendors, in order to ensure a competitive process with sufficient bidders and the ability to select the specific solution based on both technical compliance and price, taking into consideration the Whitehorse climate conditions and Yukon Energy's specific requirements. Potential impacts on ratepayers relate to ultimate Project capital costs and the impact on rates, as well as any potential impacts on

Project performance and timing that enhance or reduce the expected BESS benefits related to reduced thermal generation and improved reliability for customers.

The other key risks relate to the timeline required to proceed in mid-2021 as needed to reduce rented diesel generation required for winter 2022/23. Delays in YESAA, YUB, or permitting are the main risks in this regard. Ratepayer impacts would relate to delay in securing Project benefits and potential added costs related to the process delays.

5.0 CONSULTATION

A public engagement process for the Project was undertaken in Q3 2020. The objectives of the engagement process were to:

1. Inform the public that YEC plans to install a battery in, or near, Whitehorse and explain why the project is happening, how the battery works, project benefits and how it relates to the 10-year Renewable Plan;
2. Gather public input on each of the three proposed site options for the battery project; and
3. Identify any potential questions or concerns about the project to ensure they can be addressed/ incorporated into project design where feasible.

Engagement activities were undertaken from late August to early September 2020 and included: two virtual community meetings; three in person community meetings; six stakeholder meetings; letters and information sheets to property owners and businesses located within 800 metres of each proposed site; and "door knocking" to each residence and business within this radius. Written comments were also accepted through an online form or by direct email.

A final "What we Heard" report[59] was developed summarizing the outcomes of the above engagement process. The majority of comments provided focused on the Takhihi site on the North Klondike Highway – and while there was general support for development of the Project, there was strong opposition to developing the Project at the Takhini location. General concerns identified regarding the Project related to potential noise and light pollution, impact of an industrial development in rural residential areas, fire and explosion safety, health impacts of radiation, electromagnetism, and gases, reduction in property values and impacts on insurance premiums, and contamination of agricultural land close to project in case of accidents and malfunctions. Many of these concerns are being addressed through a combination of site selection and selection of the battery technology and planned engineering.

Yukon Energy also engaged with both KDFN and TKC in 2020 through a tri-lateral Project Committee with a mandate to:

- Share information on the Project in an open and transparent manner;
- Make a recommendation to YEC regarding final site selection; and
- Structure and negotiate a benefits package for both First Nations that strives to share the available financial benefit arising from the project, recognizing the obligations of the Final Agreements.

[59] What We Heard: Response to the Yukon Energy Draft 10-Year Renewable Electricity Plan. Available at https://yukonenergy.ca/media/site_documents/FINAL_Yukon_Energy_What_We_Heard_Report_Draft_Renewable_10-Year_Elec..._.pdf [accessed on January 12, 2021].

The Project Committee met regularly over Q2 and Q3 2020 and focused on work required to recommend a preferred site. The negotiation of an associated lease agreement with KDFN is linked to the negotiation of a project investment and benefits agreement with both KDFN and TKC. Yukon Energy has also reviewed with KDFN and TKC a debenture investment opportunity for the Project (see Section 3.1.3 for more information).

5.1 YESAB PROCESS

The YESAA regulations do not include specific reference to battery electrical storage projects. As a result, the activity of storing and releasing electrical energy by a facility is not assessable under YESAA. Battery project activities that are assessable include the following:

1. Land use activities required for the construction and operation of the facility, including site clearing and grading, and long-term land tenure; and
2. Construction of a transmission line or distribution line, if it is outside an existing right of way for a road, railway, pipeline or powerline.

The Project is subject to a screening level assessment by the Whitehorse Designated Office, as it does not involve activities that would require an Executive Committee screening, (e.g., construction, decommissioning, abandonment of a hydroelectric generating station with a production capacity of 5 MW or more; or expansion of a hydroelectric generating station that would increase production capacity by 5 MW or more).[60]

Yukon Energy plans to submit its Project Proposal to the YESAB Designated Office in March 2021. The Designated Office will initiate a review process that will include a pre-screening process to review the adequacy of the Project Proposal and potentially include requests for supplementary information. The Project Proposal will also be placed onto the YESAB Registry and will be available for review by members of the public.

Following a determination of adequacy, the DO will proceed with a seeking views and information (SVI) process where members of the public will be able provide their views and comments regarding the Project. At the end of the SVI stage the DO will make a determination regarding whether it can proceed with its report and recommendations, whether further information is required, or whether a further SVI process is required.

As noted, the YESAA process is expected to be completed with Decision Documents issued by June 2021. KDFN will be a Decision Body for the assessment.

[60] Assessable Activities, Exceptions and Executive Committee Projects Regulations, SOR/2005-379, Schedule 1, Part IV (Energy and Telecommunications), Item 2; and Schedule 3, Section 25 and Section 26.

6.0 OTHER APPLICATIONS AND APPROVALS

6.1 LIST OF APPROVALS, PERMITS AND LICENCES

Table 6-1 lists the regulatory permits and approvals that have been identified as being potentially required for the Project.

Table 6-1: Regulatory Authorizations Required for the Project

Activity	Authorization Required	Act or Regulation
Construction of a project designated as an "energy project" under Part 3 of the *Public Utilities Act*	Energy Project Certificate	*Public Utilities Act*
Operation of a project designated as an "energy project" under Part 3 of the *Public Utilities Act*	Energy Operation Certificate	*Public Utilities Act*
Approvals for construction and development of the Project	OIC 1993/108	*Yukon Development Corporation Act, Financial Administration Act, Yukon Development Corporation Regulation*
Tenure/easement for Land Lease on settlement land	Authorizations through Land Lease	*KDFN Lands Regulations*
Construction on Yukon Government Land	Land Use Permit, Licence of Occupation or Easement Agreement	*Territorial Lands Act, Land Use Regulations*
Development of a Project within the City of Whitehorse	Development Permit, Building Permit.	*City of Whitehorse Zoning Bylaws*
New Infrastructure near Airports	NavCanada - Land Use Proposal Submission Form	*Land Use in the Vicinity of Airports*
Installation of Structures within 6 km of Center of an Aerodrome	Transport Canada Assessment Form for Obstacle Notice and Assessment	*Aeronautics Act - Canadian Aviation Regulations (CARs): TP 312 Standards and Recommended Practice and Standard 621 – Obstruction Marking and Lighting (CARs)*
Handling, Disposal, Generation or Storage of Special (Hazardous) Waste	Special Waste Permit (Environment Act)	*Environment Act, Special Waste Regulation*

Activity	Authorization Required	Act or Regulation
Storage and handling of Petroleum Products	Storage Tank Systems Permit, Land Use Permit	*Environment Act, Storage Tank Regulation* *Territorial Lands (Yukon) Act, Lands* *Act, Land Use Regulations*

Before any Yukon permit or approval can be issued, YESAB must complete its screening report and make recommendations to the relevant Decision Bodies under YESAA; and each Decision Body must issue Decision Documents accepting, varying or rejecting the YESAB recommendations. For the Project, the Yukon Government and KDFN are expected to be Decision Bodies.

6.2 CONDITIONS AFFECTING APPROVALS

YEC does not anticipate material risks of major design modifications resulting from the regulatory approvals and review process for this specific project. The Project will be built using conventional construction technologies suited for northern climate conditions and following all applicable construction and design practices for works of this nature, including building and electrical codes and adhering to industry best practices. Accordingly, no special added costs are anticipated at this time to be required to comply with anticipated material conditions in the approvals and permits.

The major regulatory risk remains material delays in schedule which could adversely affect the ability to procure equipment by July 2021, and complete civil construction work by fall 2021 as required to have the BESS operation by fall 2022.

APPENDIX A:
SUPPORTING FIGURES AND TABLES

Figure A-1: BESS Site Location (Leased KDFN Category B Settlement Land)

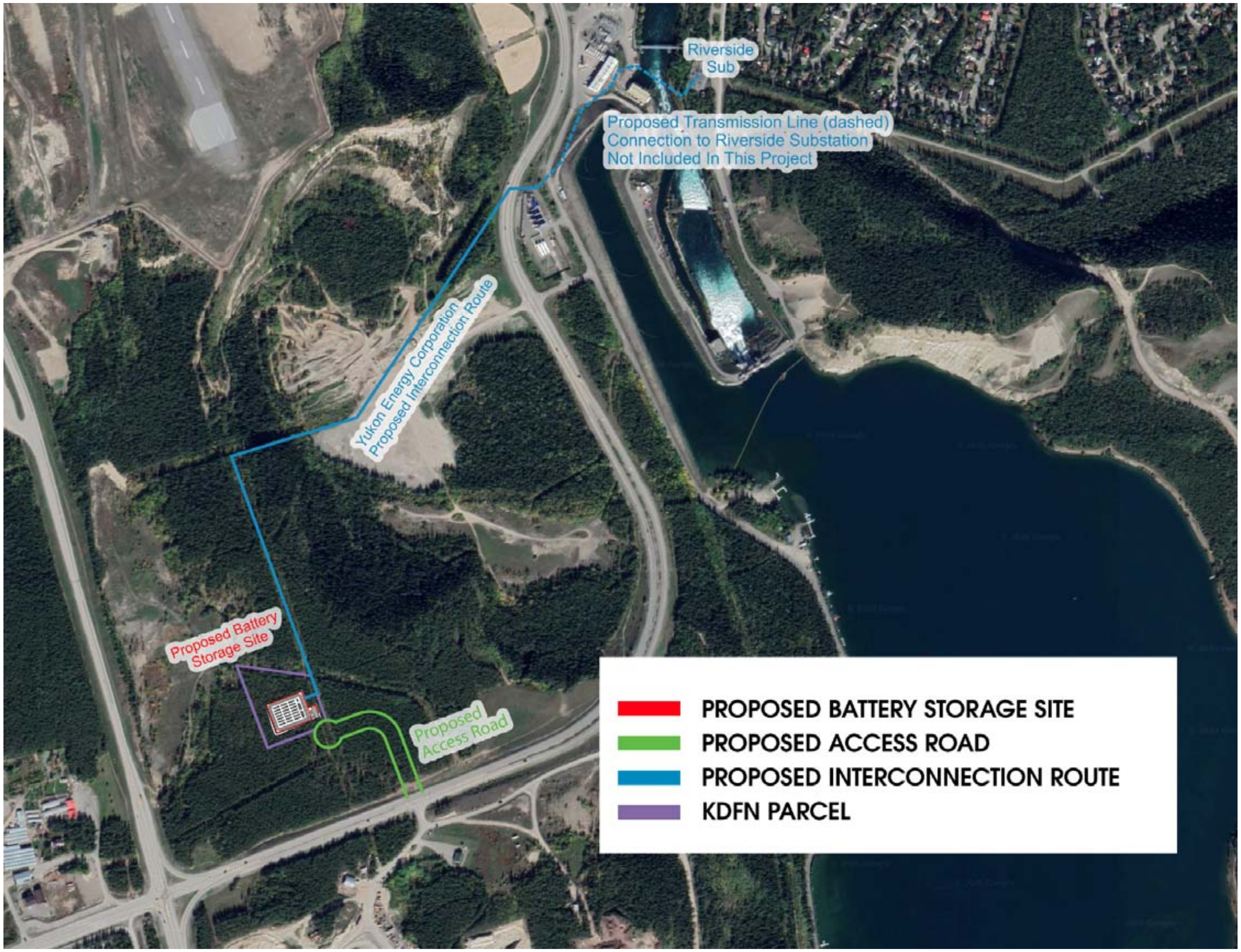


Figure A-2: Preliminary Layout for a 20MW/ 40 MWh BESS[1]

Table A-1: BESS Energy and Power Capacity Incremental Capital Costs for Selected Site (2020$)

Battery Useable Energy & Power Capacity Size	Estimated Capital Cost* ($million)	Incremental Capital Cost [each step] ($million)	Incremental Capital Cost compared to 35 MW.h/ 8.8MW	Incremental Capital Cost compared to 40 MW.h/ 10MW
35 MWh/6.6 MW	$23.83			
35 MWh/8.8 MW	$24.16	$0.33		
40 MWh/7 MW	$26.63	$2.47	$2.47	
40 MWh/10 MW	$27.09	$0.46	$2.93	
40 MWh/13 MW	$27.72	$0.63	$3.56	$0.63
40 MWh/20 MW	$28.88	$1.16	$4.72	$1.79

Source: Hatch Report, August 2020. Table 11-2 and 11-5

*Excludes YEC Planning Costs and Owner's Costs (with related contingency).

[1] Hatch Report, Figure 10-4. Includes 20% overbuild (48 MWh battery capacity). In this layout, an allocation for 2 transformers has been included. Depending on design and desired redundancy, a single 20 MW transformer may be used.

Table A-2: BESS Annual Savings for Operating Reserve & Diesel Peak Shifting with 2021 GRA Fuel Prices Prior to Considering Hydro Storage Impacts (2020$)[2]

Price of Diesel	0.2051	$/kWh
Price of LNG	0.1814	$/kWh
Hydro Operating Cost	0.005	$/kWh

		8.8 MW/35 MWh		**10 MW/40 MWh**		**13 MW/40 MWh**		**20 MW/40 MWh**	
Annual Savings	**Use Case**	**Savings**	**$/y**	**Savings**	**$/y**	**Savings**	**$/y**	**Savings**	**$/y**
	Annual Diesel Savings OR	1,777 MWh/yr	$ 364,463	1,813 MWh/yr	$ 371,754	1,837 MWh/yr	$ 376,769	1,837 MWh/yr	$ 376,769
	Annual LNG Savings OR	16,062 MWh/yr	$ 2,913,647	16,410 MWh/yr	$ 2,976,774	16,995 MWh/yr	$ 3,082,893	17,043 MWh/yr	$ 3,091,600
	Added Operating Costs for Hydro	17,839 MWh/yr	$ (89,195)	18,223 MWh/yr	$ (91,113)	18,832 MWh/yr	$ (94,160)	18,880 MWh/yr	$ (94,400)
Operating Reserve	***Total***		*$ 3,188,915*		*$ 3,257,416*		*$ 3,365,502*		*$ 3,373,969*
	Annual Diesel Savings PS	244 MWh/yr	$ 50,064	244 MWh/yr	$ 50,064	244 MWh/yr	$ 50,064	244 MWh/yr	$ 50,064
	Shift 75% to LNG, 25% to Hydro (PS)	287 MWh/yr	$ (39,429)	287 MWh/yr	$ (39,429)	287 MWh/yr	$ (39,429)	287 MWh/yr	$ (39,429)
Peak Shifting	***Total 75% to LNG, 25% to Hydro***		*$ 10,635*		*$ 10,635*		*$ 10,635*		*$ 10,635*
Total			***$ 3,199,550***		***$ 3,268,051***		***$ 3,376,137***		***$ 3,384,604***

[2] Hatch Report, Table 12-1 and Figure 6-4 (8.8 MW/ 35 MWh Operating Reserve), with adjusted fuel prices as per 2021 YEC GRA and corrected hydro operating cost. Operating Reserve thermal generation fuel cost savings are estimated prior to considering hydro storage impacts, i.e., thermal generation used without BESS to provide operating reserve enables added water storage for use subsequently to displace thermal generation.

APPENDIX B:
HATCH REPORT

Report

Utility Battery Feasibility Study Final Report - Phase 1

H362094-00000-200-006-0001

2020-08-24	0	Approved for Use	J. Zuliani	M. Carreau	J. Guilbaud	as Required
DATE	REV.	STATUS	PREPARED BY	CHECKED BY	APPROVED BY	APPROVED BY
				Discipline Lead	Functional Manager	Client

Notice to Reader

This report has been prepared by Hatch Ltd. (Hatch) for Yukon Energy Corporation (the "Client") for the purpose of assisting the Client with the development of a Utility Battery Feasibility Study.

This report contains opinions, conclusions and recommendations made by Hatch, using its professional judgment and reasonable care. Use of or the report or any information contained therein is subject to the following conditions:

1. The report must be read as a whole, with sections or parts thereof read or relied upon in context.
2. The conclusions and opinions contained in the report are based on conditions that may change over time (or may have already changed subsequent to the date of the report) due to natural forces or human intervention. Hatch takes no responsibility for the impact such changes may have on the accuracy, validity or the observations, conclusions and/or recommendations set out in the report.
3. The report is based on information made available to Hatch by the Client or by certain third parties on behalf of the Client. Unless expressly stated in the report, Hatch has not verified the accuracy, completeness or validity of such information, makes no representation regarding its accuracy and hereby disclaims any liability in connection therewith.

Any party receiving this report (Recipient) shall be deemed upon their use of the report or any information contained herein, to have accepted the following conditions precedent:

- Recipient acknowledges that they have been provided with a copy of the report on a non-reliance basis and that any use of the report or the information contained therein is at the Recipient(s) sole and exclusive risk.
- Recipient acknowledges that Hatch shall not have any liability to Recipient and Recipient waives and release Hatch from any liability in connection with its use of the Report or the information contained therein, irrespective of the theory of legal liability.
- Recipient shall not disclose the report, or any information contained therein, without the inclusion of this Notice to Reader.

Table of Contents

Notice to Reader ... i

1. Executive Summary ... 1

1.1 Background ... 1
1.2 Energy Storage Use Case Assessment ... 1
1.3 Site Selection ... 4
1.4 Capital and Operating Cost Estimate ... 6
1.5 Economic Assessment ... 7
1.6 Conclusions and Next Steps ... 8

2. Introduction ... 10

3. Yukon Energy Hydro Grid Overview ... 11

3.1 Electrical Grid ... 12
3.2 Generation and Demand ... 13

4. Energy Storage Overview ... 16

4.1 Lithium Ion Batteries ... 17
4.1.1 Power vs. Energy Battery ... 18
4.1.2 Battery Degradation ... 19
4.2 Lithium Ion Battery Operating Constraints ... 21
4.2.1 Climate Considerations for Yukon Energy ... 22
4.2.2 Safety Considerations for Battery Energy Storage Systems ... 23
4.3 Battery End of Life Considerations ... 25
4.3.1 Battery Return to Supplier ... 26
4.3.2 Lithium Ion Battery Recycling ... 26
4.3.3 Lithium Ion Battery Recycling Development ... 27

5. Use Case Definition ... 28

5.1 Primary Use Case: N-1 Capacity Reserve ... 28
5.2 Secondary Use Cases ... 30
5.2.1 Blackstart & Outage Restoration ... 30
5.2.2 Operating Reserve ... 31
5.2.3 Diesel Peak Shifting: Reduction in diesel generator usage ... 32
5.2.4 Reduce Load Shedding Events & Support Renewable Integration by reducing Large Frequency Excursions ... 33
5.2.5 Reduce Grid Instability in the Event of Load Loss ... 33
5.2.6 Reactive Power (Mvar) Support ... 34

6. Use Case Assessment and Ranking ... 35

6.1 Primary Use Case: N-1 Capacity Reserve ... 35

6.1.1 Methodology for Assessment ... 35
6.1.2 Results and Benefits ... 37
6.1.3 Important Technical Capabilities of BESS for N-1 Reserve Capacity ... 40
6.2 Blackstart and Outage Restoration ... 41
6.2.1 Methodology for Assessment ... 41
6.2.2 Results and Benefits ... 41
6.2.3 Important Technical Capabilities of BESS for Blackstart ... 41
6.3 Operating Reserve ... 42
6.3.1 Methodology for Assessment ... 42
6.3.2 Results and Benefits ... 44
6.3.3 Important Technical Capabilities of BESS for Operating Reserve ... 48
6.4 Diesel Peak Shifting ... 49
6.4.1 Methodology for Assessment ... 49
6.4.2 Results and Benefits ... 49
6.4.3 Important Technical Capabilities of BESS for Diesel peak shifting ... 57
6.5 Reduction in Load Shedding Events & Renewable Integration Support by Reducing Large Frequency Excursions ... 58
6.5.1 Methodology for Assessment ... 58
6.5.2 Results and Benefits ... 59
6.5.3 Important Technical Capabilities of BESS for Frequency Regulation ... 64
6.6 Act as a Load Bank during Load Loss ... 65
6.6.1 Important Technical Capabilities of BESS for Reactive Power Support ... 65
6.7 Reactive Power Support ... 67
6.7.1 Important Technical Capabilities of BESS for Reactive Power Support ... 67
6.8 Secondary Use Case Ranking ... 68
6.9 Battery Sizing ... 70

7. Operating Strategy Outline ... 71

7.1 Controls Considerations ... 72

8. Battery Chemistry and Lifespan Assessment ... 74

8.1 Battery Annual Throughput and Lifespan ... 74
8.2 Battery Chemistry ... 76

9. Location Assessment ... 78

9.1 Documents review ... 78
9.2 Geotechnical Review ... 78
9.2.1 TKC C-28B Property – Whitehorse Substation ... 78
9.2.2 KDFN C-34B Property at the intersection of the Alaska Highway and Robert Service Way ... 79
9.2.3 KDFN C-135B Property near Takhini Substation accessed off the Klondike Highway ... 79
9.2.4 Hatch Recommendation: ... 79
9.3 Proposed Layouts and Site-Specific Considerations ... 80

9.3.1 TKC C-28B Property – Whitehorse Substation ... 80
9.3.2 KDFN C-34B Property – Whitehorse Substation ... 81
9.3.3 KDFN C-135B Property - Takhini Substation ... 84
9.4 Preliminary Interconnection Plan ... 85
9.4.1 TKC C-28B Property – Whitehorse Substation ... 85
9.4.2 KDFN C-34B Property – Whitehorse Substation ... 86
9.4.3 KDFN C-135B Property - Takhini Substation ... 86
9.5 Summary ... 87

10. Preliminary Layout ... 91

10.1 Modular Containerized Installation ... 91
10.1.1 Higher Power BESS Layouts ... 93
10.2 Building Installation ... 95

11. Preliminary Cost Estimate ... 98

11.1 Capital Cost Estimate ... 98
11.1.1 Higher Power BESS ... 100
11.2 Annual Operating Costs ... 101

12. Preliminary Economic Assessment ... 104

13. Conclusions ... 111

13.1 Next Steps ... 111

Appendix A Project Execution Plan
Appendix B Site Visit Memo
Appendix C Noise Assessment Study
Appendix D Civil Layout Drawings
Appendix E Structured Decision-Making Workshop Memo
Appendix F Battery Performance Specifications (20 MW sizing)
Appendix G Battery Vendor List
Appendix H Blackstart Assessment for Takhini

List of Tables

Table 1-1: Summary of Potential Use Cases for the BESS on the Yukon Energy Grid 1
Table 1-2: Comparison of Three Potential Sites for the BESS Installation.. 4
Table 1-3: Estimated Capital Cost for Batteries for Various Sizes and at Various Sites (Class IV Estimate) 6
Table 1-4: Annual Operating Costs for Batteries of Various Sizes and at Various Sites (Class IV estimate) 7
Table 1-5 Economic Comparison of the Battery Sizes and at Different Sites... 7
Table 4-1: Summary of Various Energy Storage Technology Capabilities... 17
Table 6-1: N-1 Scenario with different BESS Sizing 38
Table 6-2: Estimated Capital Cost for Proposed BESSs.. 39
Table 6-3: Incremental and Total CAPEX to add additional MW to achieve 4 hr BESS rating.................. 39
Table 6-4: Incremental and Total CAPEX to add additional MW to a 40 MWh BESS.............................. 40
Table 6-5: Energy Used for OR and % of total BESS usable capacity.. 44
Table 6-6: Frequency Distribution of Diesel Operating Events at Whitehorse Diesel Plant, based on duration of genset operation 50
Table 6-7: Average Energy Generated by the Genset During Each Event at Whitehorse Diesel Plant 50
Table 6-8: Total Annual Generation for Events of Different Duration at Whitehorse Diesel Plant 51
Table 6-9: Maximum Generation from Whitehorse Diesel Plant in the South Grid based on duration of events 51
Table 6-10: Frequency Distribution of Diesel Operating Events at Faro Diesel Plant, based on duration of genset operation 52
Table 6-11: Average Energy Generated by the Genset During Each Event at Faro Diesel Plant 52
Table 6-12: Total Annual Generation for Events of Different Duration at Faro Diesel Plant..................... 53
Table 6-13: Maximum Generation from Faro Diesel Plant based on duration of events 53
Table 6-14: Frequency Distribution of Diesel Operating Events summed for Faro and Whitehorse Diesel, based on duration of genset operation.. 54
Table 6-15: Average Energy Generated by the Genset During Each Event at Faro Whitehorse Diesel Plant.. 54
Table 6-16: Total Annual Generation for Events of Different Duration at summed for Whitehorse and Faro Diesel Plant.. 55
Table 6-17: Maximum Generation from Whitehorse Diesel Plan and Faro Diesel Plant (together) based on duration of events 55
Table 6-18: Frequency Deviations at Whitehorse Substation. 60
Table 6-19: Frequency Deviations at McIntyre Substation... 61
Table 6-20: Frequency Deviations at Takhini Substation – Data Set 1 62
Table 6-21: Frequency Deviations at Takhini Substation – Data Set 2 63
Table 6-22: Assessment of BESS Energy Breakdown... 70
Table 8-1: Estimated Annual Throughput for the BESS, Typical Year 74
Table 8-2: Estimated Annual Throughput for the BESS, Worst Case Scenario 75
Table 9-1: Comparison of Three Potential Sites for the BESS Installation.. 87
Table 11-1: Estimated Capital Cost for 4 potential BESS Systems (for TKC Site)................................... 99
Table 11-2: Estimated Capital Cost for 4 potential BESS Systems (for KDFN Site near Whitehorse)...... 99
Table 11-3: Estimated Capital Cost for 4 potential BESS Systems (for KDFN Site near Takhini) 100
Table 11-4: Estimated Capital Cost for 3 potential 40 MWh BESS Systems configurations (for TKC Site) 100
Table 11-5: Estimated Capital Cost for 3 potential 40 MWh BESS Systems configurations (for KDFN Site near Whitehorse) 101

Table 11-6: Estimated Capital Cost for 3 potential 40 MWh BESS Systems configurations (for KDFN Site near Takhini) ... 101
Table 11-7: Annual Operating Cost Breakdown for Different BESS Sizes ... 103
Table 11-8: Annual Operating Cost Breakdown for Different BESS Sizes ... 103
Table 12-1: Summary of Annual Savings for 4 different power options for a 40 MWh BESS Size ... 107
Table 12-2: Summary of Economic Assessment for each BESS Size located at the TKC site ... 108
Table 12-3: Summary of Economic Assessment for each BESS Size Connected at KDFN Land near Whitehorse Substation ... 109
Table 12-4: Summary of Economic Assessment for each BESS Size Connected at KDFN Land near Takhini Substation ... 110

List of Figures

Figure 3-1: Map of Yukon's Electrical Grids 11
Figure 3-2: Yukon Energy Grid Infrastructure and Substations 12
Figure 3-3: All-time Peak Demand in January 2020, showing Yukon Energy (YEC) generation and ATCO generation combined to meet the demand between January 13 and 17, 2020. 14
Figure 3-4: Yukon Energy Generation between January 24, 2019 to January 23, 2020 15
Figure 4-1: Power vs Energy Storage Ranges of Typical Energy Storage Systems 16
Figure 4-2: Typical Degradation Curve of a Lithium Ion Battery based on Cycle Depth of Discharge, from Saft Battery System 20
Figure 4-3: Typical Calendar degradation of lithium ion battery, based on holding SOC and Temperature 21
Figure 4-4: Sample containerized battery system, showing HVAC, integrated inverter and lithium ion battery system. Qinous battery vendor 23
Figure 4-5: Sample of fire protection system, showing pressurized container of fire suppressant on left side, the fire/smoke detector in the container on the upper right, and the nozzle for dispensing the fire suppressant if required, on the bottom right. 24
Figure 4-6: Components of Lithium Ion Batteries for recycling, (Barik, Parbaharan, & Kumar, 2016) 26
Figure 5-1: Comparison of Forecasted Non-industrial Peak Demand to Yukon Energy's firm generation capacity (with the loss of 37 MW from Aishihik Hydro), for consideration of the N-1 reliability criterion. 29
Figure 5-2: Contribution of BESS to Capacity Reserve (Note: yellow area is the available energy to charge the battery, does not represent the charging profile of the battery) 30
Figure 5-3: Schematic of how a BESS can shift load off of the diesel generators 32
Figure 6-1: Illustration of the importance of energy capacity of the BESS in determining the potential capacity reduction that can be achieved. 35
Figure 6-2: Load profile for peak days in January 2020, showing hypothetical flat load with BESS shifting, and the impact of load profile on the power reduction. 36
Figure 6-3: Monthly average and maximum operating reserve (at hourly resolution) on Yukon Energy Grid 43
Figure 6-4: Reduction in Diesel Generation and LNG Generation as a result of OR supported by the BESS 45
Figure 6-5: Reduction of Annual Operating Hours on Diesel Gensets and LNG units. 45
Figure 6-6: Reduction in Diesel Generation and LNG Generation as a result of OR supported by the BESS, investigating different power outputs for a 40 MWh BESS. 46
Figure 6-7: Reduction of Annual Operating Hours on Diesel Gensets and LNG units, investigating different power outputs for a 40 MWh BESS. 46
Figure 6-8: Potential Increase in Average Unit Loading if OR is shifted to BESS. 47
Figure 6-9: Distribution of Frequency Excursions as a Deviation from 60 Hz. 60
Figure 7-1: Schematic of Optimal Dispatch and Battery Operation 73
Figure 9-1:TKC Site Layout Outline 80
Figure 9-2: KDFN Land Site near Whitehorse Substation – Option1 82
Figure 9-3: KDFN Land Site near Whitehorse Substation – Option 2. 83
Figure 9-4: KDFN Site Near Takhini. 85
Figure 10-1: Preliminary layout for a 10 MW/40 MWh containerized BESS with 20% overbuild (total capacity 10 MW/48 MWh). 92
Figure 10-2: Image of Containerized battery, based on Saft 20 ft standard LiB offering 93
Figure 10-3: Preliminary layout for a 13 MW/40 MWh containerized BESS with 20% overbuild (total capacity 13 MW/48 MWh). 94

Figure 10-4: Preliminary layout for a 20 MW/40 MWh containerized BESS with 20% overbuild (total capacity 20 MW/48 MWh). In this layout, an allocation for either 2 transformers has been included. Depending on the design and desired redundancy, a single 20 MW transformer may be used. 95
Figure 10-5 Preliminary layout for a 10 MW/40 MWh BESS with 20% overbuild (total capacity 10 MW/48 MWh) installed in a building. Each battery pack has a capacity of 210 kWh and the inverter has a capacity of 500 kW.......... 96
Figure 10-6: Image of Tesla Power Pack and Inverter Lineup 97

1. Executive Summary

1.1 Background

Yukon Energy completed an integrated resource plan in 2016, which identified a growing gap in the N-1 Reserve Capacity. Currently, Yukon Energy rents diesel gensets each year to cover the capacity gap during the peak load during the winter period. A battery energy storage system (BESS) was identified as one of several options to address this capacity gap and reduce the number of diesel gensets rented each year.

Yukon Energy aims to have the BESS installed and fully commissioned by Fall 2022.

Based on Yukon Energy's previous assessments, there are two proposed connection points on the Hydro Grid:

- Whitehorse Substation
- Takhini Substation

Both of these connection points are located near the grid's largest residential and commercial load center, Whitehorse. The proposed sites will be Yukon First Nation Land.

1.2 Energy Storage Use Case Assessment

The following table outlines the potential use cases for the battery energy storage system.

The four primary use cases are:

- N-1 Reserve Capacity
- Supplementary Operating Reserve
- Diesel Peak Shifting
- Blackstart/Outage Restoration.

Table 1-1: Summary of Potential Use Cases for the BESS on the Yukon Energy Grid

Use Case Ranking	Comments	Preferred Sizing
N-1 Reserve Capacity	• BESS will complete 1 full charge/discharge cycle per day during N-1 event	• 35 MWh- 40 MWh, to reduce genset rentals by 4 per year
Supplementary Operating Reserve	• BESS will act as reserve for the grid, allowing hydro units to run at higher loading when water is available • Improves efficiency and allows diesel gensets and/or LNG gensets to be	• 8.8 MW/35 MWh, 10 MW/40 MWh or 13 MW/40 MWh • Diminishing returns above 13 MW.

Use Case Ranking	Comments	Preferred Sizing
	turned off when hydro can meet the load • Operating Reserve requirements will likely increase in the future due to higher intermittent renewable penetration; the BESS can cover all or a portion of this OR requirement.	
Blackstart/Outage Restoration	• BESS is used to initiate grid re-energization	• Higher power leads to greater capability and flexibility –20 MW/40 MWh preferred
Diesel Peak Shifting	• The BESS would be used prevent the need to turn on one or more diesels for 1-4 hrs. • Battery would discharge during the peak and then be recharged overnight with LNG or hydro generation.	• Largest 4 hr peak is 7.01 MW peak, consuming 16.9 MWh. Therefore the 8.8 MW/35 MWh or 10 MW/40 MWh battery could serve this peak. • The larger energy capacity and higher power BESS provides more flexibility, particularly in the future. As the load grows, diesel peaks will likely increase, leading to higher demands. • The 13 MW/40 MWh battery has sufficient capacity to shift the LNG plant generation.
Load Shedding Reduction & Renewable integration through frequency excursion response	• The battery would respond to large frequency excursions, to prevent load shedding events. ◆ These events are likely to become more frequent as more intermittent renewables are integrated into the grid. ◆ The BESS can be used to support renewable integration by responding to frequency excursions.	• There are benefits to power quality and customer satisfactions. • The usage of the battery to reduce load shedding events must be weighed against the imposed degradation. • A larger BESS has greater benefit and allows these services to be provided without depleting the energy stored and impacting other

Use Case Ranking	Comments	Preferred Sizing
	• These large frequency excursions are fairly rare; however, preventing load shedding improves customer satisfaction. • It is not recommended to use the battery for grid frequency regulation continuously, as this will lead to high annual throughput and faster degradation.	usages (operating reserve, blackstart). • The 13 MW/40 MWh battery has sufficient capacity to cover the loss of the LNG generation plant.
Act as load during transmission line or load loss	• If a large load is lost or a transmission line goes out, there will be significant excess generation on the grid which needs to ramp down safely. • The battery can be charged during these events to improve grid stability and reduce wasted electricity.	• Tertiary benefit of the battery, since these events are relatively infrequent and short in duration. • Battery needs to be idled at partial state of charge to allow for recharging during these events. • Larger inverter allows for a higher charging rate and thus more excess electricity to be absorbed by the battery.
Reactive Power Support	• Inverters have the ability to provide both real and reactive power (can be provided simultaneously). • Most 4-quadrant inverters can operate within the entire power curve (+/- 1 pu leading/lagging). • Reactive power supply is based on inverter output, does not deplete the energy stored in the battery cells	• Tertiary use case, since Yukon Energy does not currently have reactive power concerns • Larger inverter provides more flexibility; therefore 10 MW, 13 MW or 20 MW/40 MWh BESS would have greater capabilities

1.3 Site Selection

There are three potential sites under consideration for the project:

- TKC Land across from Yukon Energy Headquarters – connection at Whitehorse substation
- KDFN Land near Whitehorse – connection at Whitehorse Substation
- KDFN Land adjacent to Takhini Substation – connection at Takhini Substation.

Table 1-2 compares the different site options across a variety of metrics.

Table 1-2: Comparison of Three Potential Sites for the BESS Installation

Parameter	TKC Land -Whitehorse	KDFN Land – Whitehorse	KDFN Land - Takhini
Connection Point	Whitehorse Substation	Whitehorse Substation	Takhini Substation
Ability to perform proposed use cases	No concern to perform all use cases	No concern to perform all use cases	Concern regarding Blackstart Capabilities, preliminary study in Appendix H
Maintenance and Yukon Energy Access	Site is easily accessible by Yukon Energy operations & maintenance team and Yukon Energy Staff as required	Site is easily accessible by Yukon Energy operations & maintenance team and Yukon Energy Staff as required	Site is about 20-30 min drive from Yukon Energy Headquarters in Whitehorse Takhini is unmanned site, unplanned events that require site presence would take longer to access
Electrical Interconnection			
Connection Voltage	34.5 kV	34.5 kV	34.5 kV
Transmission Line Length	1.2 km	1.7 km	70-150 m
Comments on Transmission Line Routing	Crosses recreational area – need taller poles Crosses Robert Service Way	Routes through forested crown land Crosses Robert Service Way	Routes down a sloped area into a valley between KDFN land and Takhini Substation fence line No roadway crossing
Site Preparation			
Land Area Available	More than sufficient land area available. Flexibility in installation layout and location of BESS containers	More than sufficient land area available. Flexibility in installation layout and location of BESS containers	Enough land area available, but limited flexibility in container layout and site configuration

Parameter	TKC Land -Whitehorse	KDFN Land – Whitehorse	KDFN Land - Takhini
Site Preparation Considerations	Land is generally flat and there is a cleared area that is likely large enough to accommodate the BESS containers. Land is hidden from highway by forested area	Land is not level and requires site clearing Site is hidden from highway	Site is not flat, requires grading There are abandoned structures, vehicles and storage barrels that must be cleaned up Land must be tested for contamination
Access Road	Existing access road at an intersection with lights, across from entrance to Yukon Energy Can use existing access road. Widening and strengthening of small access road to site required	There is an intersection with lights near the site, that can be used to build the access road. Access road must be built through forested area.	There is an existing access road with an intersection; however, there are no lights. Access is more challenging due to smaller available land area offering less flexibility
Expandability of BESS	Currently no identified limited for expandability	Currently no identified limited for expandability; however, additional clearing and grading will be required	Site can only accommodate a small expansion (2-3 times the energy)
Other Site Considerations	Site is a previous flood plain (not flooded in many years) and the ground becomes saturated with water during the spring as a result of snowmelt	Land is on the escarpment, so has relatively low flooding risk	Site is quite far from Yukon Energy Headquarters, less accessible for routine inspections
Site Preparation Costs	Lowest	Highest	Medium
Commercial Considerations			
Lease and Property Tax cost	City Taxes	City Taxes	Outside City Limits
Certainty to Development	Zoning concerns	No Zoning concerns	No Zoning concerns
Benefits to First Nation			
Site Lease	Yes	Yes	Yes
Social Risk			
Noise	<30 dB, no controls required	<40 dB no controls required	>50 dB controls required

1.4 Capital and Operating Cost Estimate

The estimated capital cost for the four different battery sizes located at the three different sites is presented in Table 1-3. The capital cost is the lowest for the 35 MWh option, due to the lower energy capacity. The marginal capital cost increases between the 10 MW/13 MW/20 MW battery options are based on added costs of the inverter and transformer, as well as the slightly larger land area required for the higher power systems.

Table 1-3: Estimated Capital Cost for Batteries for Various Sizes and at Various Sites (Class IV Estimate)

Battery Size	TKC Land (Whitehorse Connection)	KDFN Land (Whitehorse Connection)	KDFN Land (Takhini Connection)
8.8 MW/35 MWh	$23.84 M	$24.16 M	$23.59 M
10 MW/40 MWh	$26.78 M	$27.09 M	$26.52 M
13 MW/40 MWH	$27.39 M	$27.72 M	$27.24 M
20 MW/40 MWh	$28.55 M	$28.88 M	$28.41 M

The variation in capital cost between the three sites is driven by differing site preparation costs, access road requirements, noise abatement costs and transmission lines. The KDFN land near Takhini has a slightly lower capital cost due to the shorter road and transmission line, in spite of the noise abatement requirements. However, this variation is relatively modest, at about 2% of the total capital cost and is well within the error of these estimates. Additionally, the primary cost driver for the project is the battery, inverter and transformer, which are common to all sites. Therefore, capital cost is not a significant differentiator between sites.

The estimated annual operating costs is presented in Table 1-4. The first column shows the estimated annual preventative maintenance costs for the battery, based on vendor site visits and an allocation for parts. The total operating costs include an allocation for insurance, the property tax (as a function of CAPEX) for Whitehorse properties, and an allocation for maintenance of the transmission line.

The annual property taxes in Whitehorse are quite significant, between $275,000 - $300,000 depending on the size. The property taxes are estimated based on the cost of equipment and improvements to the site. This is a sizable contribution at over 50% of the total annual operating costs for the Whitehorse sites.

The length of the transmission line also impacts the operating costs; however, this is relatively modest, estimated at less than 10% of the battery only operating costs.

Table 1-4: Annual Operating Costs for Batteries of Various Sizes and at Various Sites (Class IV estimate)

Battery Size	Battery Only Operating Costs	TKC Land (Whitehorse Connection)	KDFN Land (Whitehorse Connection)	KDFN Land (Takhini Connection)
8.8 MW/35 MWh	$174,000	$496,000	$502,000	$215,500
10 MW/40 MWh	$190,000	$517,000	$523,000	$231,500
13 MW/40 MWH	$202,000	$535,000	$541,000	$243,500
20 MW/40 MWh	$230,000	$575,000	$581,000	$271,500

*Battery only operating costs is an estimated for the vendor preventative maintenance and parts allocation.

**total operating costs include battery maintenance, insurance, property tax for Whitehorse sites, and transmission line maintenance. They do not include recharging costs.

The property tax on the Whitehorse sites is a critical concern for these options, as it increases the total annual operating costs by over 50% each year. Further review is required to confirm this tax is necessary and that the value is correct as it can impact the site selection.

1.5 Economic Assessment

A preliminary economic comparison of the different battery sizes at the three sits is presented in Table 1-5. The levelized cost of capacity (LCOC) and the total cost of ownership were the two metrics selected as they are the most representative for this project. The trends between sites are driven by the operating cost differences, with the Takhini site having the lowest LCOC and Total Cost of Ownership by avoiding the annual taxes.

Table 1-5 Economic Comparison of the Battery Sizes and at Different Sites

Battery Size	TKC Land (Whitehorse Connection)		KDFN Land (Whitehorse Connection)		KDFN Land (Takhini Connection)	
	Levelized Cost of Capacity	Total Cost of Ownership (NPV 2020$)	Levelized Cost of Capacity	Total Cost of Ownership (NPV 2020$)	Levelized Cost of Capacity	Total Cost of Ownership (NPV 2020$)
8.8 MW/ 35 MWh	148 $/kW - yr	$15.6 M	152 $/kW - yr	$16.0 M	98 $/kW - yr	$11.2 M
10 MW/ 40 MWh	171 $/kW - yr	$18.9 M	174 $/kW - yr	$19.2 M	128 $/kW - yr	$14.4 M
13 MW/ 40 MWH	179 $/kW - yr	$19.7 M	183 $/kW - yr	$20.1 M	136 $/kW - yr	$15.2 M
20 MW/ 40 MWh	196 $/kW - yr	$21.5 M	199 $/kW - yr	$21.9 M	152 $/kW - yr	$16.8 M

The lowest cost of ownership is the 8.8 MW/35 MWh battery; however, this system also has the least flexibility of the preferred sizing options. The cost of ownership of the 20 MW/40 MWh BESS is approximately $6 M higher over the 20-year period; however, this system has the greatest flexibility. Additionally, the higher power capability is important for reactive power supply during blackstart/outage restoration.

1.6 Conclusions and Next Steps

The four key benefits of the proposed battery energy storage system for Yukon Energy identified in this study are:

1. Provide N-1 Reserve capacity to reduce the number of mobile diesel gensets rented each year
2. Provide operating reserve for up to 30 min at the rated power, to reduce the operating reserve carried on the hydro turbines and thus, reduce the amount of diesel fuel and LNG consumed each year
3. Provide blackstart/outage restoration support to reduce the length of outages
4. Supply generation instead of diesel peaking units, shifting consumption to LNG or Hydro overnight.

Additional benefits provided by the BESS include frequency regulation for large excursions to reduce load shedding events and support for future renewable integration, absorbing generation when there is a transmission line outages or load loss and providing reactive power support.

Recommended battery chemistry is lithium Ion, since the proposed duty cycle is relatively low and would not lead to accelerated cycle degradation of the BESS. Additionally, the higher round trip efficiency and lower auxiliary demands of lithium ion batteries make them more desirable for this application. Lithium Iron Phosphate (LFP) battery cell chemistry is preferred since it is inherently safer and has a lower capital cost. However, Yukon Energy should not limit vendors to only LFP suppliers in the RFP to get a full range of bids and confirm this assessment.

Preferred system sizing is 8.8 MW/35 MWh or 10 MW/40 MWh. Estimated capital cost for each of these options is $23.8 M and $26.8 M, respectively, if located on the TKC Land near Whitehorse Substation. Increasing power sizes from 10 MW/40 MWh to 20 MW/40 MWh leads to an increase in the CAPEX by approximately $1.7-1.8 M. This higher power BESS achieves the lowest LCOC.

Recommended immediate next steps are as follow:

- Conduct the Community Consultation to support site selection
- Preliminary Interconnection for Preferred Site
- Develop a procurement strategy for EPC & EPCM alternatives
- Confirm tax implications if BESS located within Whitehorse
- Conduct geotechnical campaigns for selected sites

2. Introduction

Yukon Energy Corporation (Yukon Energy), established in 1987, is the public electric utility wholly owned by the Yukon Government. Yukon Energy is a vertically integrated, regulated utility that owns and operates all major generation and owns and operates the transmission grid in the territory. The mandate of Yukon Energy is "to plan, generate, transmit and distribute a continuing and adequate supply of cost-effective, sustainable, clean and reliable electricity to customers in Yukon Territory." Yukon Energy sells electricity to ATCO Electric Yukon at wholesale pricing for distribution to retail customers in the larger communities.

Currently, the Yukon grid is powered primarily by three hydroelectric facilities, as well as liquified natural gas (LNG) generation and diesel gensets, when the hydro facilities cannot meet the load. Yukon Energy's planning includes the installation of new small hydro, wind and solar generation through the Yukon Government sponsored Independent Power Producers (IPP) Program. The IPP would own and operate the generation, with Yukon Energy as the off-taker. A 2 MW wind farm is currently being planned for operation in 2021.

Yukon Energy completed an integrated resource plan in 2016, which identified a growing gap in the N-1 Reserve Capacity. Currently, Yukon Energy rents diesel gensets each year to cover the capacity gap during the peak load during the winter period. A battery energy storage system (BESS) was identified as one of several options to address this capacity gap and reduce the number of diesel gensets rented each year.

Yukon Energy has received a grant from the Government of Canada, through the Green Infrastructure Stream of the Investing in Canada Infrastructure Program, to support the development of a grid connected BESS.

The BESS can also be used for many other secondary usages, such as operating reserve, diesel peak shifting, blackstart support, and frequency excursion response to reduce load shedding and for renewable integration support. The ability of the BESS to perform some or all of these services will be assessed and evaluated in this study.

Yukon Energy aims to have the BESS installed and fully commissioned by Fall 2022.

After a competitive procurement process, Yukon Energy retained Hatch to complete a feasibility assessment for the proposed BESS to be installed on the Yukon Energy Grid. The following study provides an overview of the Yukon Energy Grid today and the Energy Storage Technology landscape. The study outlines the potential use cases for the BESS and presents an assessment of the potential benefits of each use case, ranking them in terms of greatest benefits to the grid. Based on the use case, the preferred battery technology is proposed. The study assesses the three proposed locations for the BESS and presents the benefits and challenges for each. Finally, a preliminary cost estimate is prepared for 4 BESS sizes.

3. Yukon Energy Hydro Grid Overview

The Yukon Hydro Grid is isolated from the rest of the North American power grid. The entire load of all grid connected customers must be met using generation on the Yukon grid (as shown on Figure 3-1). It is critical for Yukon Energy to have the ability to match the generation to the load, as there is no alternative option to import or export power as required.

Yukon Energy must generate electricity to supply the over 21,000 electricity customers in the territory. Yukon Energy directly sells electricity to over 2,200 of these customers, most of whom live in and around Dawson City, Mayo and Faro. Yukon Energy serves most other Yukon communities through ATCO Electric Yukon (ATCO), by selling wholesale power to ATCO, who sells the electricity to retail customers in the territory. There are 4 other small diesel grids not connected to the main hydro grid that serve off-grid communities. These will not be considered in the scope of this study.

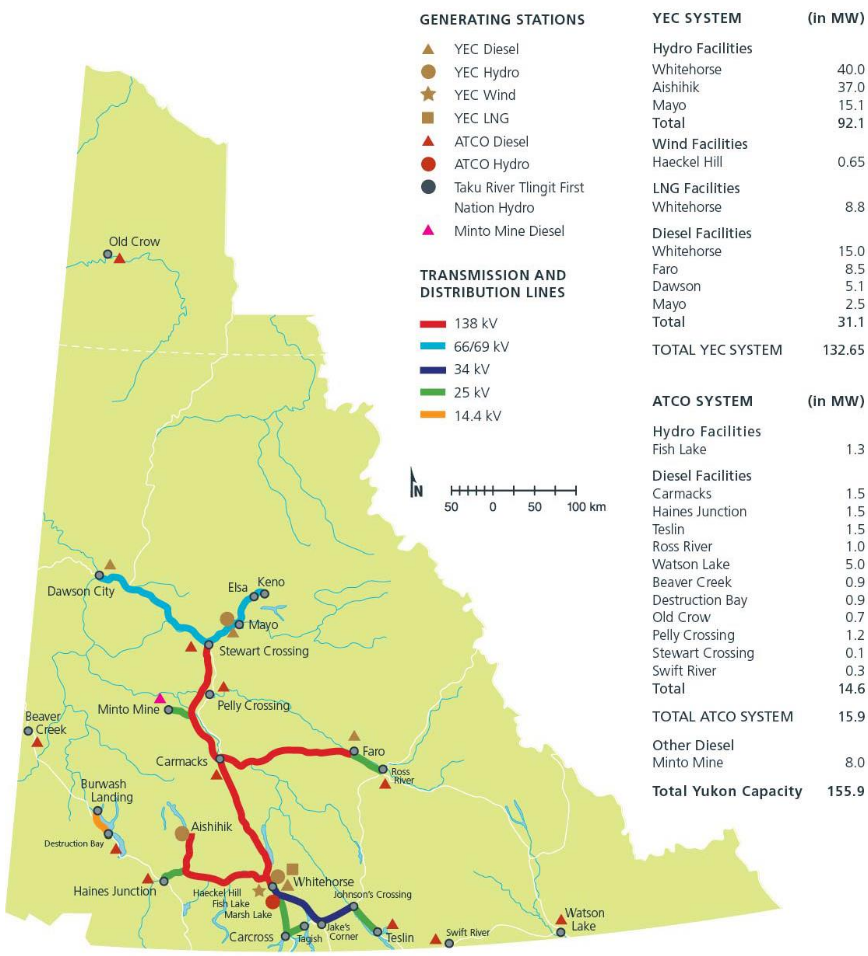


Figure 3-1: Map of Yukon's Electrical Grids

3.1 Electrical Grid

Yukon Energy's grid is served at a primary transmission voltage of 138 kV, which connects Whitehorse substation in the south to Aishihik Hydro and Substation Northwest of Whitehorse, Carmacks, Minto, and Stewart Crossing Substations north of Whitehorse, and Faro substation Northeast of Whitehorse. From the 138-kV transmission line, the grid has lower voltage transmission lines at 69 kV in the north, 34.5 kV in the south and 25 kV in the central region to transmit power to customer distribution load centers.

Currently there are 10 substations on the 138-kV grid, one steps down to 69 kV, three step down to 34.5 kV, four step down to 25 kV, the Faro Mine substation directly steps down to 4.16 kV to supply the mine and the Aishihik substation steps down to 13.8 kV to connect directly to the local hydroelectric generation. There are eight other substations which operate at 69 kV, 34.5 kV and 25 kV.

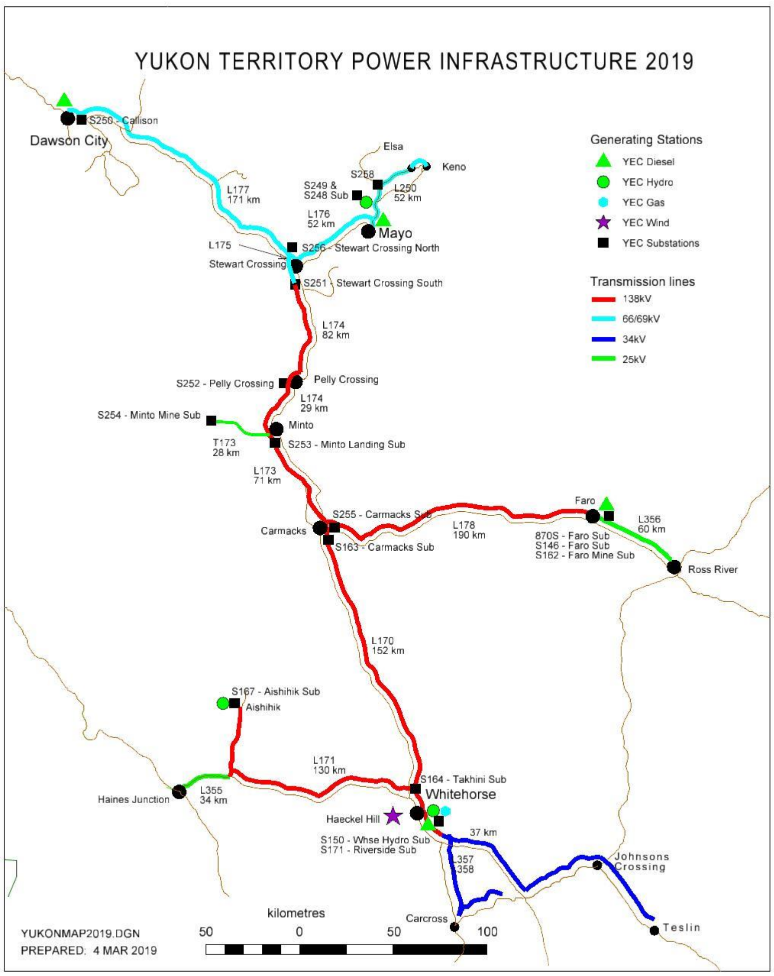


Figure 3-2: Yukon Energy Grid Infrastructure and Substations

Based on Yukon Energy's previous assessments, there are two proposed connection points on the Hydro Grid:

- Whitehorse Substation
- Takhini Substation

Both of these connection points are located near the grid's largest residential and commercial load center, Whitehorse.

It is proposed the BESS will be located on Yukon First Nation Land. There are two sites proposed near Whitehorse Substation, TKC Land and KDFN land, both with access off Robert Service Way. For the Takhini Substation connection, there is KDFN land to the south of the substation, which is accessed off the Klondike Highway. Further details on the location assessment are discussion in Section 9.

3.2 Generation and Demand

Yukon Energy currently owns and operates hydroelectric generators, diesel gensets, and natural gas gensets.

There are 3 hydroelectric facilities operated by Yukon Energy: one in Aishihik which has 3 turbines and an installed capacity of 37 MW, one in Mayo which has 4 operational turbines and an installed capacity of 12.5 MW, and one in Whitehorse which has 4 turbines and an installed capacity of 40 MW. In the summer, there is 86.6 MW of dependable hydro generation and in the winter, there is 72.5 MW of dependable hydro generation due to reduced water availability and flow restrictions due to icing, which is based on annual long-term average water inflows.

Yukon Energy operates 3 natural gas gensets located in Whitehorse, with a dependable capacity of 13.2 MW, each with a maximum capacity of 4.4 MW. The gas gensets are used as backup power, to provide energy during low water periods, and to meet peak demand in the winter.

Yukon Energy operates 4 diesel power plants: The Faro Diesel plant has 2 gensets, the Dawson City Diesel plant has 6 gensets, the Mayo Diesel plant has 3 gensets, and the Whitehorse Diesel plant has 4 gensets. The diesel gensets have a dependable capacity of 25.8 MW. Diesel generation is used as backup to meet the load and to cover peak demands, primarily in the winter when hydroelectric generation is lowest. The diesel gensets are also used for outage restoration.

ATCO owns several backup diesel generators connected to the grid that are used to supply local emergency power in the communities they are located in.

Yukon Energy generates over 90% of its energy needs using the 3 hydroelectric generation facilities; however, during peak periods the diesel and natural gas gensets need to be used to meet the demand. The natural gas units are dispatched to run before any diesel is run, due to their lower fuel cost and reduced GHG emissions.

As the Yukon is an Arctic climate, electricity demand peaks in the winter months and is lowest in the summer months. The primary driver of winter peaks is the use of electric heat for commercial and residential buildings. The all-time peak for the Yukon Grid was hit in January 2020, at 104.7 MW in an extended cold period. The demand for the 10-day period in January 2020 is shown in Figure 3-3.

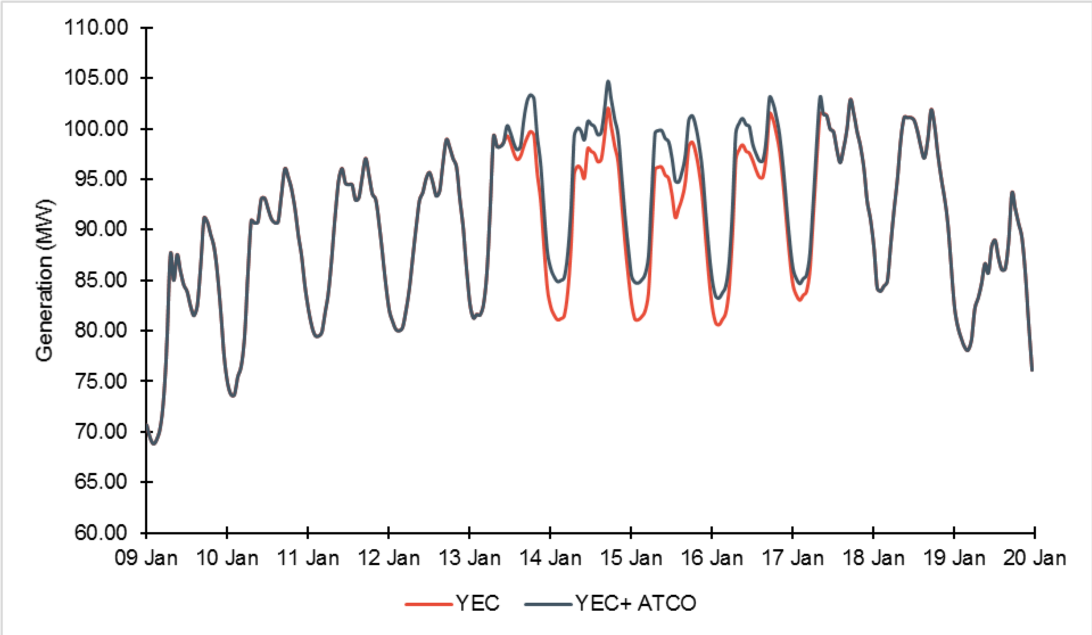


Figure 3-3: All-time Peak Demand in January 2020, showing Yukon Energy (YEC) generation and ATCO generation combined to meet the demand between January 13 and 17, 2020.

The yearly generation profile for Yukon Energy is shown in Figure 3-4, from January 24, 2019 to January 23, 2020. This profile shows the significant increase in demand in January 2020 compared to January 2019. The significant decline in demand in the summer is also shown in this figure, with daytime peaks dropping to below 50 MW during the warmer months. This significant reduction in demand in the summer months results in spilling of water at the hydro stations, as the energy that can be generated by this higher waterflow exceeds the current grid demand requirements.

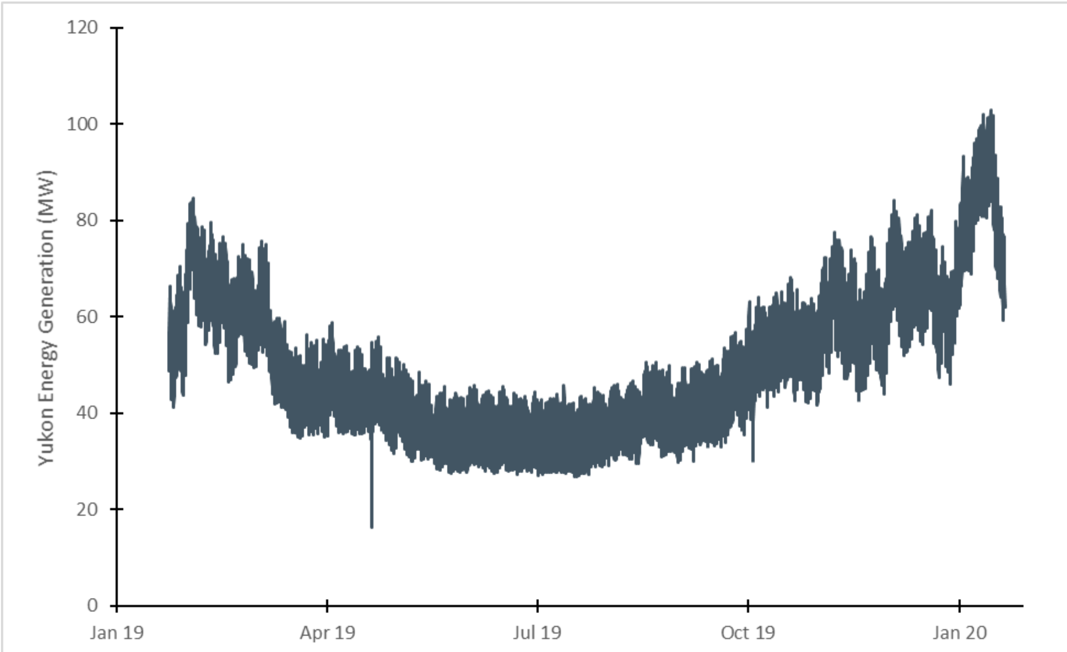


Figure 3-4: Yukon Energy Generation between January 24, 2019 to January 23, 2020

The background information provided in this section provides an overview of the Yukon Energy grid based on current 2019/2020 operation. It forms the basis for analysis of the potential benefits of the proposed BESS.

4. Energy Storage Overview

Energy storage systems (ESSs) are garnering increasing interest as their costs continue to decline and as there are increasing intermittent renewable generation sources deployed on power grids. Energy storage systems have many potential benefits and can often be used on a grid or microgrid to provide multiple services. In this section, an overview of available energy storage technologies is presented.

There is a wide array of energy storage technologies that are presently available on the market. Depending on the energy storage mechanism, the properties of the ESS will change. An overview of the power and energy capacity of the most common grid-scale energy storage systems is presented in Figure 4-1; additional details on the performance of these ESSs, including power output, energy output, response time, efficiency and projected lifespan, are presented in Table 4-1.

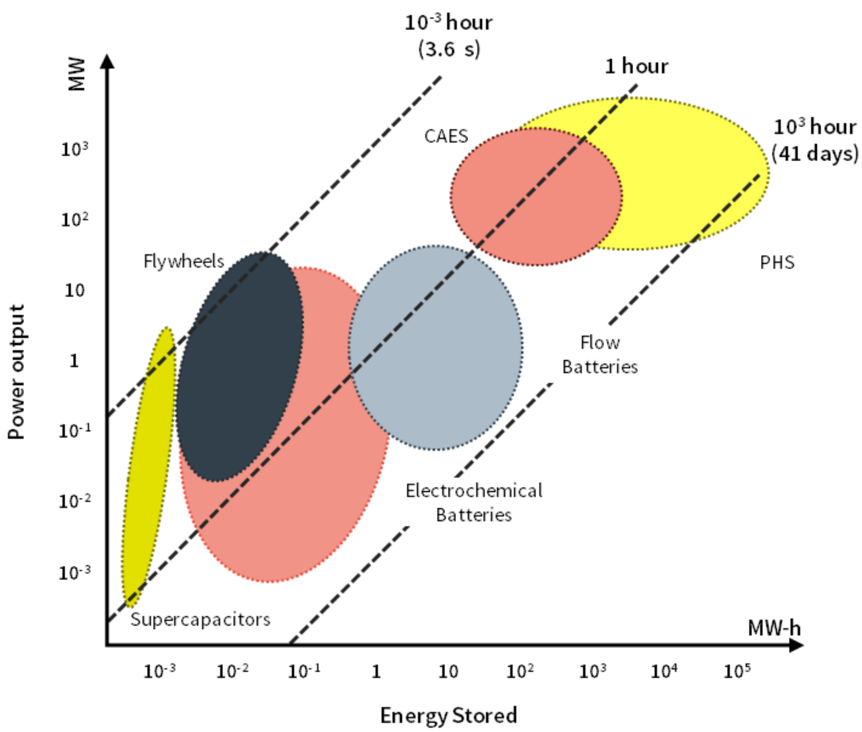


Figure 4-1: Power vs Energy Storage Ranges of Typical Energy Storage Systems

Table 4-1: Summary of Various Energy Storage Technology Capabilities

Technology	Typical Power Rating	Discharge Time	Round Trip Efficiency (%)	Response Time	Projected Lifetime
Pumped Hydro	100 MW-1000 MW	Hours-Days	75-80%	Seconds to Minutes	40-80 yrs.
Compressed Air	10 MW-1000 MW	Hours-Days	40-70%	Seconds to Minutes	20-30 yrs.
Flywheel	1 kW-10 MW	Seconds-Minutes	80-90%	Milliseconds	15-20 yrs.
Lithium-Ion Battery	100 kW -20 MW	Minutes-Hours	80-90 %	Milliseconds	5-20 yrs.
Flow Battery	100 kW-100 MW	Minutes-Hours	60-85%	Seconds	10-20 yrs.
Lead-Acid Battery	100 kW-50 MW	Minutes-Hours	65-90%	Seconds	5-10 yrs.
Supercapacitor	100 kW-5 MW	Seconds-Minutes	80-98%	Milliseconds	5-15 yrs.

All ESSs have two fundamental ratings: the power capability, in MW, and the energy capacity, in MWh. The ratio of energy to power provides the duration for which the battery can supply electricity at its rated power capability. The ESS can supply electricity for a longer period at a lower power rating (e.g. a 1 MW/4 MWh can supply 1 MW for 4 hrs or 0.5 MW for 8 hrs, or 0.25 MW for 16 hrs).

4.1 Lithium Ion Batteries

Lithium-ion batteries (LIBs) are the most established and versatile energy storage technology on the market today, outside of pumped hydro. The technology is considered reliable, reduces the risk and has established previous installations, compared to other less established ESS technologies.

There is a broad range of available LIB chemistries, each of which has its own niche applications. Generally, LIBs are regarded as the most versatile BESS technology, offering both high power and high energy capacities. They have the greatest energy density of battery technologies, making them ideal for locations with limited available space for installation. The cost of LIBs is continually decreasing and is expected to continue to decrease over the next several years. Finally, LIBs are relatively easy to maintain compared to other ESS technology, with 1-2 maintenance visits from the vendor each year.

However, there are some specific considerations and requirements for LIBs to operate safely and to ensure that they reach their specified lifespan. Lithium-ion batteries require accurate thermal management to ensure the battery cells are operating within the desired range. The system must be heated in the winter months and cooled in the summer months to prevent irreversible damage to the cells. LIB containers must have fire suppression systems; although the risk of thermal runaway is very low, since the cells are continually monitored and disconnected if there is any concern, a fire suppression system is required in the unlikely event of a thermal runaway. These challenges are commonly managed with the battery management system and controls provided in the containers. Finally, the lifespan of lithium-ion batteries can be maximized by maintaining the state of charge between 10% and 90%, which prevents over-charging and over-discharging. However, this results in the usable capacity being only 80% of the total capacity. Therefore, the battery system must be oversized in order to meet the specified requirements.

There are three common utility scale lithium ion battery chemistries typically used for grid scale storage applications.

The most common chemistry is a **nickel manganese cobalt lithium (NMC) battery**. This chemistry typically has the lowest capital cost. It is better suited for higher energy applications and has a limited power response.

Nickel cobalt aluminium lithium (NCA) batteries are also common for grid scale applications. These batteries provide higher power performance, making them better suited for applications with rapid response requirements. However, these batteries typically have higher costs compared to other options.

Lithium iron phosphate (LFP) batteries are used in grid scale applications. These batteries offer a blend of moderate power and energy capacity making them ideal for versatile applications. LFP batteries are also generally regarded as the safest technology and are therefore, typically used in indoor applications. LFP batteries are gaining increased popularity, with many vendors exploring this technology.

Each of these chemistries has its own capabilities and limitations, which need to be matched to the duty cycle and usage.

4.1.1 Power vs. Energy Battery

Battery cells can be configured in order to either favour high power capacity or high energy capacity, a power battery or an energy battery, respectively. For a power battery, the electrode configuration would be designed in such a fashion to support high currents and rapid reaction of the active lithium ions. This is typically achieved by using a thinner electrode, which allows the lithium ions to be transported more quickly between the active surface and electrolyte. However, the use of a thinner electrode, results in a reduced energy capacity, since the thinner electrodes have less available surface area, resulting in less “active sites” to allow for lithium ions insertion, thus a lower energy storage capacity. This power design configuration is required in order to allow for the LIB to sustain high power outputs for continuous operation, which enables complete charging and discharging times to be between 15 min and 1 hour. This is to allow for the lithium ions to diffuse rapidly into and out of the electrodes during charging and discharging by reducing the ion transport distance. As well, these thinner electrodes are used to prevent lithium plating on the electrode surface, which would lead to dendrite formation

By contrast, **an energy battery** is designed in order to favour energy capacity, by using an electrode material/design that has the ability to store more lithium ions. However, this often results in limitations on the rate of transport of the lithium ions to and from the electrolyte, which limits the power output. These batteries are typically limited to moderate power outputs and have complete charging and discharging times greater than 1 hour up to about 4 hours. These energy battery systems typically cannot withstand high power output for continuous operation.

These design configurations, along with specialized battery chemistries, will result in differing costs between power and energy batteries. This is a general description of the differences between power and energy batteries. In reality a battery cell manufacturer may have a wide array of cell types, each with different configurations to allow for different performance capabilities.

In addition to the discharge duration, the C-rate can be used to characterize the battery cells. The C-rate is the inverse of the duration (the power to energy ratio = MW/MWh). Therefore, a battery that can discharge in 30 min has a 2 C rating and a battery that discharges in 4 hrs has a ¼ C rating.

4.1.2 *Battery Degradation*

Lithium ion batteries experience two types of known capacity fade or degradation: degradation associated with cycling and calendar aging.

Cycle related degradation is a known and predictable phenomenon for LIBs. Cycle degradation is associated with loss of active lithium ions as a result of charge/discharge cycles. Typically, most LIBs have a capacity fade of approximately 20% after completing 4,000-4,500 full charge/discharge cycles; however, lithium iron phosphate (LFP) cell manufacturers claim a cycle life of over 6,000 full charge/discharge cycles. A typical degradation curve as a function of depth of discharge is shown in Figure 4-2.

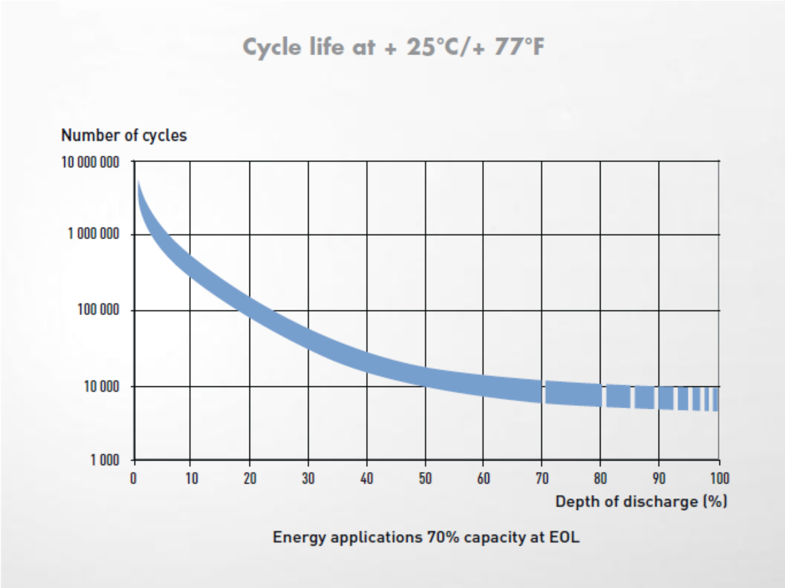


Figure 4-2: Typical Degradation Curve of a Lithium Ion Battery based on Cycle Depth of Discharge, from Saft Battery System

The cycle life of a LIB is dependent on its operating conditions; operating the cell within the vendor specified conditions, completing shallow cycling, at or below the rated power and within the specified temperature range will extended the lifespan of the BESS. However, accelerated degradation can occur if the BESS is operated outside the specified temperature range (degradation is worse if operated outside the range frequently or for extended periods, or under extreme hot or cold conditions), if charging or discharging rates are higher than the rated power, or if the LIB cells are charged above or below the recommended maximum/minimum state of charge. (SOC). A single excursion or event would not lead to significant degradation, unless it was extreme (e.g. charging at -40°C); however, routine or sustained operation outside the vendor specified bounds can lead to a shortened battery life.

Calendar aging is a relatively unstudied phenomena, as it is only becoming more apparent as lithium ion batteries are being used for newer applications (EVs, grid storage) where they are kept at high state of charge for extended periods (in contrast to personal electronics where batteries undergo regular cycling). Initial studies have shown that storing a battery cell at higher temperatures and higher state of charge can accelerate the calendar aging process.

Calendar aging have been attributed to the anode, which has a high lithium content during high SOC idling and thus has experienced expansion. The mechanism for calendar degradation is hypothesized to be a reduction of active lithium, since it is consumed in the formation of the solid-electrolyte-interphase layer on the anode. Formation of this interphase is accelerated when the anode is expanded to achieve 100% charging.

There has been indication that different lithium ion battery chemistries (Nickel Cobalt Aluminum, Nickel Manganese Cobalt, and Lithium Iron Phosphate) have different calendar aging properties. As the project moves into the next phases, it will be important to discuss calendar aging with the vendors and understand its impacts on their specific cell chemistry.

Additionally, based on the initial results, it appears important to keep the battery idling at modest temperatures, which will be particularly important during the summer months.

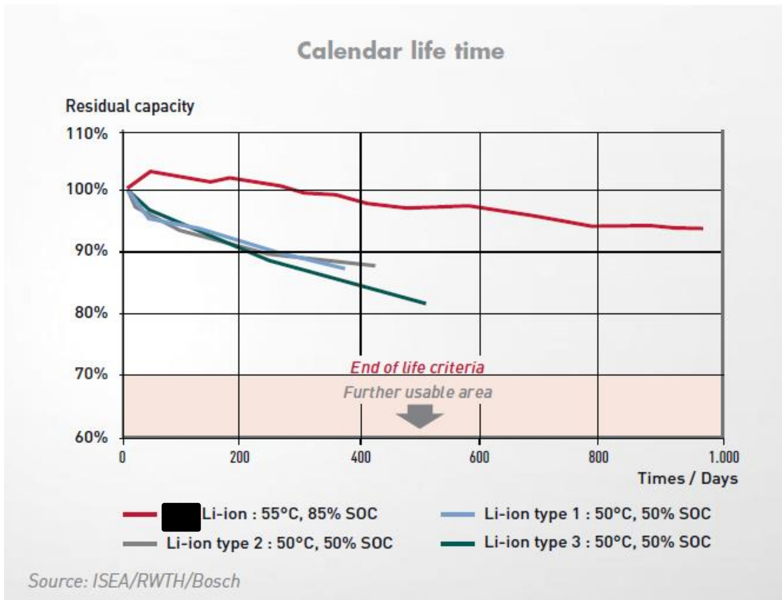


Figure 4-3: Typical Calendar degradation of lithium ion battery, based on holding SOC and Temperature

Given the proposed use cases for the Yukon Energy BESS, it is expected that it will experience both cycle and calendar aging associated capacity fade.

4.2 Lithium Ion Battery Operating Constraints

There are several operating considerations that must be addressed when deploying lithium ion batteries.

The main operational consideration is the round-trip efficiency and self-discharge of lithium ion batteries. Lithium ion batteries have one of the highest round-trip efficiencies of all energy storage technologies of approximately 85-90% round trip efficiency from AC input to AC output. Therefore, approximately 10-15% of the energy stored in LIBs is lost to inefficiencies and through electrical losses. In addition to the round-trip efficiency, LIBs experience a slow self-discharge. Self-discharge is the energy lost overtime when the energy storage system is kept idle for prolonged periods of time (several days or weeks). Typical self-discharge for LIBs is 3-5% per month, depending on the system design and idling conditions. Therefore, these inefficiencies and losses need to be considered when selecting the battery use case. The benefits of the BESS should outweigh the potential losses.

Controls and dispatching algorithms are another consideration. As it is assumed these will be un-manned stations, the BESS will be required to dispatch either based on an automated algorithm or based on a manual or system operator input command from a remote site. This controls system will need to be purchased and modified or designed for the specific requirements of the host grid. As well, interface between the BESS controls provided by the OEM, the dispatch controller and the overall grid controller will need to be considered when selecting and programming the dispatching controller.

4.2.1 Climate Considerations for Yukon Energy

Yukon Territory is an arctic climate and experiences extreme cold temperatures in the winter and temperate summers. **Thermal management and heating** of the system will be critical for Yukon Energy when selecting the BESS vendor. Ensuring the vendor has a robust cold weather offering with a proven track record will be important to ensure the BESS can operate reliably and efficiently in the winter months. Additionally, it is imperative to have sufficient thermal management to keep the cells cool during the summer months, during the charging and discharging process when there is heat generated.

Typically, LIBs are supplied in containerized systems; however, for this scale, a building option may also be possible, with cell modules and racks purchased and installed in the building. The containers would include insulated walls and roofs. The thermal management systems on LIBs are typically HVAC systems on the container walls to control the climate in the container. If Yukon Energy elects to use a building option, it will be important to ensure that the building is designed with appropriate heating, cooling and insulation for the climate and battery heat generation. Details on the benefits and challenges of both containerized and building options are presented in Section 10.

The thermal management system is activated through the battery management system based on temperature measurements of the cells and the ambient temperature measurements in the container.

Battery suppliers and integrators have strict controls on the battery temperature monitoring and regulation in order to prevent these failures and in order to maintain operation within the cell warranty requirements.

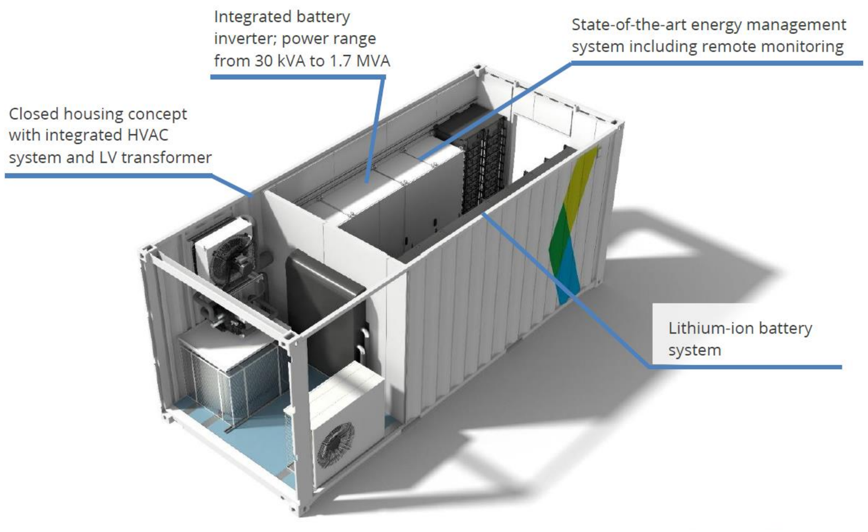


Figure 4-4: Sample containerized battery system, showing HVAC, integrated inverter and lithium ion battery system. Qinous battery vendor

4.2.2 Safety Considerations for Battery Energy Storage Systems

Fire Safety: While LIBs are generally considered safe technology and the risk of a fire in a battery energy storage system is very low, the lithium ion chemistry is known to have thermal runaway properties, which can lead to a fire if the system is operated incorrectly. The main safety concern with lithium ion batteries is the fire risk, associated with the flammable electrolyte. Depending on the cell configuration, separator design, and electrolyte additives, the risk of fire will vary based on the battery manufacturer. However, several safeguards have been designed to reduce this risk.

The most important strategies to reduce fire risk are:

- Selecting a qualified vendor with a proven and reputable battery system,
- Using qualified technicians to do the installation and commissioning,
- Maintaining the system in a good state-of-repair, with routine maintenance,
- Maintenance of the system is performed by a qualified technician,
- Fire suppression system is routinely checked and maintained as recommended by the vendor.

BESS suppliers have several mechanisms in place to prevent thermal runaway from occurring and to stop a fire if it occurs, operated through the automated battery management system (BMS). The BMS and battery controller are not located physically within the battery container, and thus remain accessible in an unexpected event.

The battery cell manufacturer and the module manufacturer design their battery to minimize the risk of thermal runaway, which includes battery material selection, battery separator design, and fire-retardant packing/module containers to prevent the spread of fire from pack to pack.

When the system is integrated into a series of racks, each battery cell in the system is constantly monitored to check that it is operating within the expected range. If the battery cell goes outside of the expected range or experiences abusive conditions (e.g. high temperature, high voltage, significant vibrations, flooding, etc.), the automated BMS will disconnect the cell or shutdown the system until the abusive conditions have been corrected.

The BMS is also responsible for maintaining the temperature within the container or building. If the temperature rises too high or drops too low, the BMS will trigger the HVAC heating/cooling system to return the temperature to within normal ranges.

Finally, all grid battery installations are outfitted with an integrated fire suppression system, in each container or within the building. The container is outfitted with a smoke/fume detector to trigger the BMS to report smoke to the owner, generate an audio and visual alarm to alert anyone nearby of the risk, and initiate the fire suppression system.

Figure 4-5: Sample of fire protection system, showing pressurized container of fire suppressant on left side, the fire/smoke detector in the container on the upper right, and the nozzle for dispensing the fire suppressant if required, on the bottom right.

The fire suppression system is comprised of special fluid suppressants, commonly Novak 1230 manufactured by 3M, designed to quickly extinguish the battery fire and safely absorb any heat generated preventing further reaction and fire. Novak 1230 is specially designed for electrical fire suppression. The containers/buildings are also outfitted with overpressure relief valves to allow gas to escape and avoid an explosion of the container/building.

Lastly, the containers should be installed a minimum of 3 m apart, in order to prevent propagation of a fire from container to container in the unlikely event that a full container fire occurs.

In addition to the safety measures put in place by the battery vendor, a fire response plan will be prepared by Yukon Energy and provided to the local fire department and emergency response staff. The fire department and emergency response staff will receive appropriate training on how to handle lithium ion battery fires.

Electrical Safety: Battery installations are charged units that hold voltages even when the system is completely shut off. This is an important consideration to take when handling and doing maintenance on these units. The typical voltage of a battery system is between 500-1000 V DC, which is present even if the battery system is disconnected from the power system. Therefore, it is critical to ensure that proper lock-out and disconnects are available to isolate the system during any maintenance, both of the battery system maintenance and maintenance of the substation or overhead line. Safety practices are required to ensure that the maintenance or work being done accounts for the ever-present voltage source. Typically, visible and lockable disconnect switches are required in order to isolate the battery system during any grid or substation maintenance.

4.3 Battery End of Life Considerations

The typical projected lifespan for a BESS is 10 – 20 years; the lifespan will be influenced by a variety of factors. The primary factors affecting the lifespan are the use case and the operating conditions. Maintaining operation within the vendor specifications is important to ensuring the lifespan is maximized. Additionally, the vendor design can impact the lifespan.

At the end of life, proper disposal of the BESS is critical, as it contains valuable materials which can be re-used, but can also be hazardous to the environment if improperly disposed. As the grid scale lithium ion battery industry is relatively nascent, the recycling and disposal processes are not fully developed presently.

There has been general interest in the re-use of spent electric vehicle lithium ion batteries as grid scale batteries. As EV batteries are typically taken out of service when the capacity has faded by 20%, these cells can still be used to in other applications where size and mass are not as critical. In the case of grid scale batteries, mass is less constrained, and thus a larger amount of battery cells can be compiled to achieve the desired pack capacity, duration and performance. While this plan extends the life of the battery cells, it does not address the disposal at the final battery cell end of life.

4.3.1 Battery Return to Supplier

Presently, many battery suppliers will take back the battery modules at the end of life. Some suppliers may also have incentives or credits associated with battery return, which can be used towards the next battery.

Grid scale BESSs are comprised of several different components, the container, any necessary thermal management and fire suppression systems, the battery module racks, and the battery modules and cells themselves. It may be possible that the container, fire suppression system and thermal management system be refurbished or repurposed for future uses. This could be done by working with the vendor to determine if they have a refurbishment or re-use program. Alternatively, these items could be sold at the end of life to other markets or recycled to recover valuable parts and materials.

By returning the batteries to the supplier, the supplier can then re-use the batteries, or process and recycle or dispose of the materials. This process ensures that the batteries are treated properly and do not cause environmental harm if improperly disposed. As well, returning the batteries to the supplier puts the responsibility of disposal on the supplier, instead of on the customer.

4.3.2 Lithium Ion Battery Recycling

Lithium ion batteries are particularly challenging to recycle due to their construction, with each cell individually packaged, then housed within a module. Therefore, there are many varied components and materials, all of which must be extracted and purified for future use. Some of the components of a lithium ion battery are shown in Figure 4-6.

Figure 4-6: Components of Lithium Ion Batteries for recycling, (Barik, Parbaharan, & Kumar, 2016)

Additionally, the battery racks could either be re-used or recycled for raw materials.

The battery modules and cells should be recycled if refurbishment is not possible. There are currently three processes for recycling lithium ion batteries, involving smelting, incineration, and cryogenic freezing and shredding. Special processes are required for lithium ion batteries recycling because the batteries remain partially charged at the end of life and due to the risks associated with the flammable electrolyte. Therefore, the cells typically cannot be punctured in atmospheric conditions.

All recycling processes require high energy inputs and have a high cost. With the current pricing and availability of the raw materials, recycling is not often economical. However, if the industry grows as projected, the greater demand for lithium and the greater volume of waste batteries will drive the need to commercialize an economical recycling process.

The most common process is smelting; this process recovers copper, nickel, iron and cobalt from the batteries; however, the lithium, aluminum and manganese are lost in the process. Additionally, the electrolyte and battery housing (plastic) are incinerated in the smelting process.

The second process is high temperature incineration; in this process, all organics, as well as plastics and lithium are incinerated and either scrubbed in off-gases or lost to the fly-ash. The process is designed to recover cobalt through secondary hydrometallurgy treatment.

The final process involves cryogenically freezing (-196°C) and shredding, the materials are then mixed with water, generating lithium hydroxide and hydrogen gas. Cobalt and aluminum are the primary recovery products of this process. The lithium hydroxide is converted to lithium carbonate; lithium carbonate can be recovered, with a recovery rate of 15 to 26%.

Therefore, the three available processes do not currently recover lithium from these batteries, primarily because the cost of lithium does not presently justify the recycle and re-use. However, there are currently several recycling processes under development, and as this industry grows, recycling will become more developed and increasingly important.

4.3.3 Lithium Ion Battery Recycling Development

Over the next several years, as the electric vehicle and grid scale energy storage industries continue to grow, end -of-life battery management is likely to develop into a key industry. The processes identified above are the current options available for lithium ion battery disposal. However, as the projected life of the BESS is between 10-20 years, it is likely that in this time, the battery refurbishment and recycle industry will develop significantly. There are several research programs and development companies currently investigating the various ways to recycle lithium ion batteries and recover the lithium for reuse.

Therefore, as the end-of-life of the BESS approaches, a review of the current practices should be completed to identify new opportunities. Additionally, upon purchase of the BESS, Yukon Energy should discuss with the supplier if they have a battery return or recycle program.

5. Use Case Definition

Through the initial battery use case workshop session, conducted during the first site visit, the primary use case was defined that the BESS should be sized to support the N-1 dependable capacity reserve.

Secondary use cases of interest that were identified are:

- Blackstart/Outage Restoration Support
- Provide Supplementary Operating Reserve
- Peak Shifting of Diesel Generator Peaks
- Reduction of Load Shedding Events and Support Future Renewable integration by Large Reducing Frequency Excursions
- Reduce Grid Instability in the Event of Load Loss
- Reactive Power (Mvar) Support.
- The following section will outline the use cases and Section 6 will present the assessment and ranking of the secondary use cases.

5.1 Primary Use Case: N-1 Capacity Reserve

Yukon Energy must meet the grid's non-industrial demand with firm generation, in the event of the loss of its largest generator. The largest generator is currently the Aishihik Hydroelectric Generation station or the L-171 138 kV transmission line, which connects Aishihik Hydro to Whitehorse Substation via Takhini and Riverside Substation. The loss of this line/generation facility would result with the loss of 37 MW of hydro capacity. Therefore, Yukon Energy must have sufficient firm generation to meet the load without this facility. This is known as the N-1 Capacity Reserve Criterion. A forecast of the dependable capacity gap under this N-1 planning criterion is shown in Figure 5-1. To meet this capacity gap, Yukon Energy currently rents mobile diesel gensets.

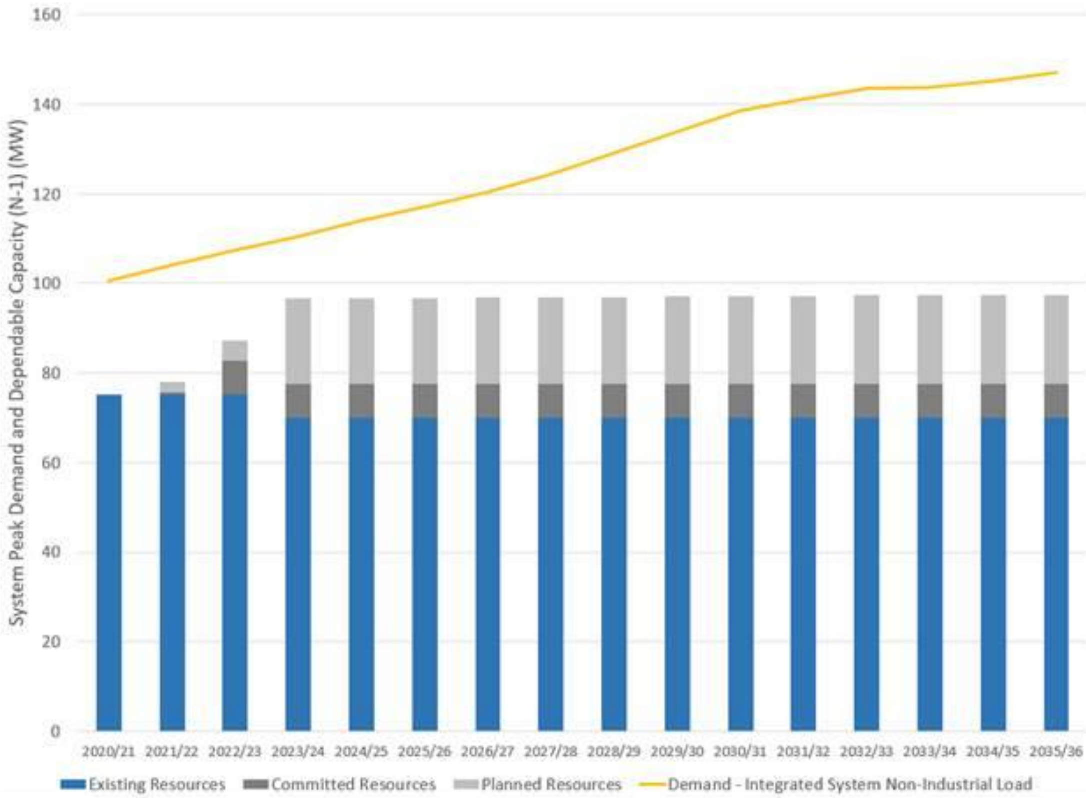


Figure 5-1: Comparison of Forecasted Non-industrial Peak Demand to Yukon Energy's firm generation capacity (with the loss of 37 MW from Aishihik Hydro), for consideration of the N-1 reliability criterion.

The primary use case for the BESS is to contribute to the N-1 Capacity Reserve on the Yukon Grid.

For the BESS to contribute to the capacity reserve, it needs to be able to reduce the peak demand during the day, and then be recharged overnight. A schematic of how the BESS would contribute to the capacity reserve is shown in Figure 5-2. The BESS discharges during the day, reducing the peak demand from 105 MW to 98 MW, and is recharged overnight. The BESS shown in this scenario reduces the number of rental engines by 4. **Note:** the yellow area represents the potential energy available to charge the battery. In all cases, this energy is in excess of the energy required to charge the battery. Thus, the battery does not need to be charged at full output.

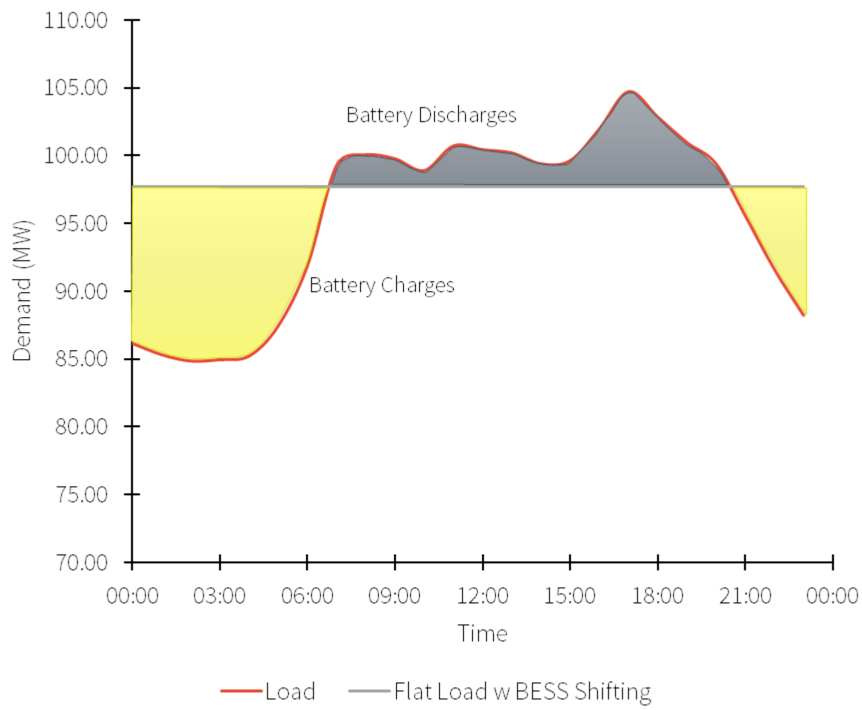


Figure 5-2: Contribution of BESS to Capacity Reserve (Note: yellow area is the available energy to charge the battery, does not represent the charging profile of the battery)

5.2 Secondary Use Cases

5.2.1 Blackstart & Outage Restoration

In the event of a significant grid outage, Yukon Energy must blackstart the grid. Currently, the hydroelectric turbines are used to blackstart the grid, by energizing the electrical equipment in the substation, then the hydro generation, in several increments. This process can take up to 2 hours, depending on the extent and severity of the outage. However, when Aishihik is unavailable to support blackstart, diesels are used to supplement load pickup. Blackstart events are generally infrequent.

A BESS has the capability to self-energize through the inverter, if the critical auxiliary loads (controls, HVAC, P&C, etc.) are drawn from the BESS itself (not a separate input from the grid). Therefore, after self—energizing the BESS can be used to support segmentation of the grid, such that portions can be energized. Segment size would be based on the power capabilities of the inverter and the inrush current of the segment. A BESS with blackstart capabilities is typically supplied with a UPS (uninterruptible power supply) which can supply the auxiliary loads for 1 hour. If necessary, a small backup diesel gensets could be integrated as backup to supply the HVAC/ P&C when the battery is self-energized. This would need to be determined based on discussions with the vendor, and their typical self-energization protocol and energy demand for the battery.

Connection point for the BESS is critical for the blackstart capabilities, since the connection point will determine the blackstart procedure. If the BESS is connected into the Whitehorse substation, it is likely there will be minor modifications to the blackstart procedure (i.e. which switches and transformers are energized first, since the exact connection point will differ). If the BESS is connected at Takhini Substation, a full blackstart energization plan will be required to determine which infrastructure at Takhini must be energized, the segmentation of the 138-kV transmission line between Takhini Substation and Whitehorse Substation. Additionally, consideration must be given to the energy capacity of the BESS to support energization of the transmission line, Takhini substation, and Whitehorse substation before reaching the hydro turbines.

Using the BESS to support blackstart provides two benefits. **The BESS capacity will be greater than the 5 MW hydro capacity currently used to blackstart, thus resulting in greater load segments that can be energized.** Reactive power requirements must be considered and a blackstart procedure should be developed to determine the maximum value of the load segments that can be picked up (See Blackstart Study in Appendix H).

5.2.2 Operating Reserve

Operating reserve is carried on the electric grid in order to accommodate variations in the load or to cover the loss of a generator. This is achieved by operating a generator below its maximum capacity, to allow its output to be increased quickly, if required. Yukon Energy carries operating reserve on its Hydro Turbines. The average operating reserve was 4.8 MW over the year. However, carrying this operating reserve on the hydro turbine reduces its efficiency and results in, on average, an additional 4.8 MW that needs to be supplied by natural gas or diesel generators, particularly during the winter season, when hydro generation cannot serve the entire load.

The BESS can provide this operating reserve, by remaining at a moderate to high state-of-charge (SOC) and acting as a backup to generation. The BESS response time is very rapid, 150-200 ms to achieve full power output, thus can be brought online quickly to cover the load. The BESS would need to maintain a minimum energy level at all times to ensure it can cover the load for the time required to start-up a generator, which is typically 10-30 min. Therefore, the BESS should not be discharged below 25-30% state-of-charge (~13 MWh) to ensure it can provide the necessary operating reserve without discharging below its minimum SOC. The exact minimum SOC will need to be determined based on the operating reserve being provided – this can also be varied throughput the year, with higher reserve kept in the winter and lower reserve kept in the summer.

The benefits of the BESS would be two-fold: 1) a direct reduction in diesel and natural gas genset operation hours and energy generation and 2) improved efficiency of the hydro-turbines by operating them at their most efficient output more frequently, leading to more energy production with the same amount water flow.

As more renewable generation is integrated into the mix, higher operating reserve will be required to manage the variability. The BESS can be used to support this operating reserve, ensuring the hydro turbines can continue to operate at high efficiency.

5.2.3 Diesel Peak Shifting: Reduction in diesel generator usage

During the fall, winter and spring, Yukon Energy is often required to start-up diesel generators for several hours to meet peak electricity demands. Starting and stopping the diesel generators leads to increased wear and tear, higher maintenance costs, and higher fuel consumption. Additionally, the units are not often loaded at high capacity factors during these discharge periods, thus leading to lower fuel efficiency.

The BESS can be used to shift short duration events where diesel generators need to be brought online for 1-4 hours to cover the load. As shown in Figure 5-3, the BESS can be used to cover these short periods where diesel generators need to come online to cover the load, shifting the energy consumption from peak period to overnight, when it can be supplied by natural gas or hydro generators. This function of the BESS results in lower diesel fuel consumption and higher loading and generation efficiency for the hydro and LNG units.

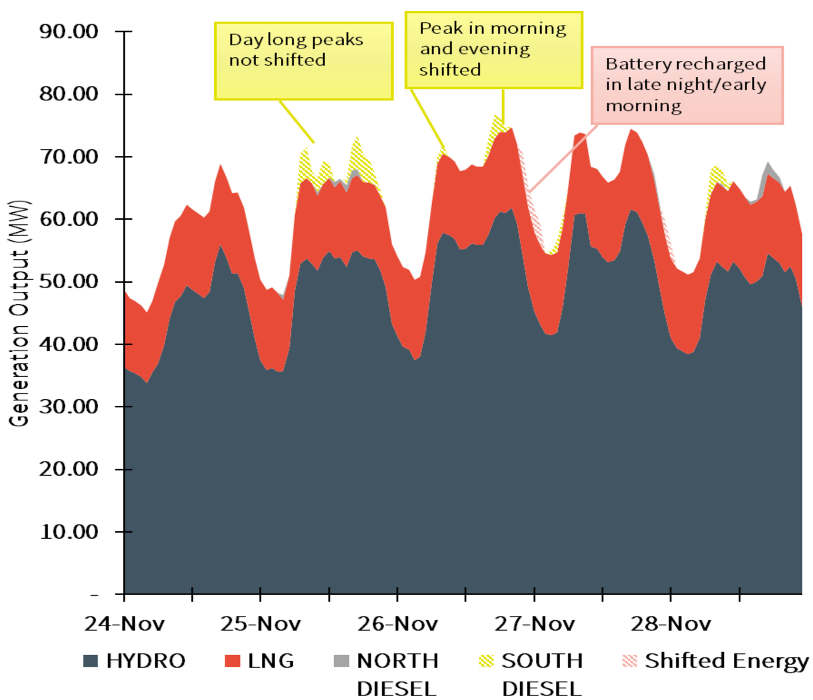


Figure 5-3: Schematic of how a BESS can shift load off of the diesel generators

5.2.4 *Reduce Load Shedding Events & Support Renewable Integration by reducing Large Frequency Excursions*

The frequency of electricity supplied in Yukon Territory is 60 Hz. The grid's frequency must be kept within a defined band, typically +/- 0.5 Hz. The grid's frequency will change as loads are turned on or turned off, which typically cause small deviations in the overall system's frequency. The hydro generators or thermal generators are ramped up and down slightly to manage these slight deviations.

However, occasionally, the deviation in grid frequency is outside the necessary band. If this deviation is sustained for an extended period (several milli-seconds), the Yukon Energy grid operators will initiate a load shedding procedure, where certain loads on the grid will be turned off to bring the grid back to the desired frequency. Causes of these deviations are typically a result of insufficient generation to manage the load (either from loss of generation or turning on a large load such as a motor), or the sudden loss of a transmission line which was supplying a portion of the generation. Either of these two events would result in a drop in frequency on the grid, which would trigger load shedding. The load shedding events are triggered automatically by the grid's protection and controls based on the rate of change of the grid frequency on various feeders. Load shedding is staged on the various feeders.

As the percentage of energy supplied by intermittent renewable generation (wind or solar generation) is increased on the Yukon Energy Grid, it is likely that the number of frequency excursion events (and consequently load shedding events) will increase. This is due to the inherent intermittency and potential for rapid drops in generation.

It is proposed that the BESS could respond to these significant deviations in grid frequency to prevent or reduce the amount of load that needs to be shed. Due to its rapid response and almost instantaneous ramp up, the battery can be brought online at full power output more quickly than other generating sources. The BESS can power the load until other generators can be brought online and ramped up, bringing the grid's frequency can be brought back within the desired band and customer loads can continue to be supplied without major interruption. **The benefits will further increase in the future, since the BESS can support ramp rate control from intermittent renewable generation, as more renewable generation comes online.**

5.2.5 *Reduce Grid Instability in the Event of Load Loss*

The grid needs to be able to exactly match the load and the generation at each instant in order to maintain grid stability. This is challenging for any grid operator but is particularly challenging in an isolated grid.

One of the unique scenarios, where energy storage can play a key role, is supporting the grid in the event of a load loss. When there is a load loss event, the grid will have excess generation, which can result in an increase in the frequency on the grid, outside of the typical operation band.

A significant drop in load can be triggered for many reasons, including a transmission line or substation outage or a large industrial mine turning off one or more of its major pieces of equipment. For the Yukon Energy grid, with relatively slow responding generation (hydro and natural gas), it may not be possible to ramp the generation down as quickly as the load is lost. In this case, the generation on the grid exceeds to demand, leading to instability and frequency and voltage excursions. Based on analysis of the Yukon Energy Load data, if there is a large load loss, the generation output needs to be quickly ramped down.

The battery can be charged during events of load loss with excess generation while it ramps down safely. This will reduce the extent and severity of the frequency/voltage excursions on the grid during these events.

5.2.6 Reactive Power (Mvar) Support

Utility scale energy storage devices can act as flexible AC transmission system (FACTS) devices by regulating the reactive power at their point of interconnection as a result of their inverter connection. For reactive power control mode, the remaining inverter capacity (i.e. the inverter capacity that is not being used for real power conversion – calculated using the following relationship $MVA^2 = MW^2 + Mvar^2$) can be used in a static synchronous compensator (STATCOM) mode of operation.

In addition to reactive power control, the real power controller for these devices can be tuned to further increase the stability of the power system by mimicking the response of a large-scale synchronous generator. By controlling the real power of an energy storage facility, utilities can further enhance the system inertia to increase the power system's stability. The control of real and reactive power of an ESS can be done in a decoupled manner and both can be used simultaneously. In comparison to conventional FACTS devices such as SVCs and STATCOMs, the decoupled control of real and reactive power of an ESS results in improved power system stability.

This option can be beneficial to Yukon Energy particularly in the winter months, since reactive power support is often necessary when Whitehorse Hydro Unit #4 is unavailable in cold weather.

6. Use Case Assessment and Ranking

6.1 Primary Use Case: N-1 Capacity Reserve

6.1.1 Methodology for Assessment

The BESS will make up part of the capacity reserve that will ensure electricity can continue to be reliably delivered to customers even if Aishihik Hydro is down for up to 2 weeks.

There are two factors that must be considered for the BESS to provide capacity reserve, the energy capacity (MWh) it can provide and the power output (MW) it can provide. As outlined in Section 5.1, the purpose for the BESS in these events is to reduce the daytime peaks, thus reducing the number of diesel gensets that must be rented each winter. Therefore, the available energy capacity of the BESS will determine the maximum power reduction that can be achieved, since it will dictate the duration that energy can be supplied throughout the day. Figure 6-1 shows that the defining factor in flattening the peak load is the area between the red – load curve and the grey flattened load line, represented by the blue shape. Therefore, in order to flatten the load, the BESS must supply energy for the entire period above the “flat load” value, without recharging. Thus, the energy capacity (and load shape) define the maximum reduction in power that can be achieved.

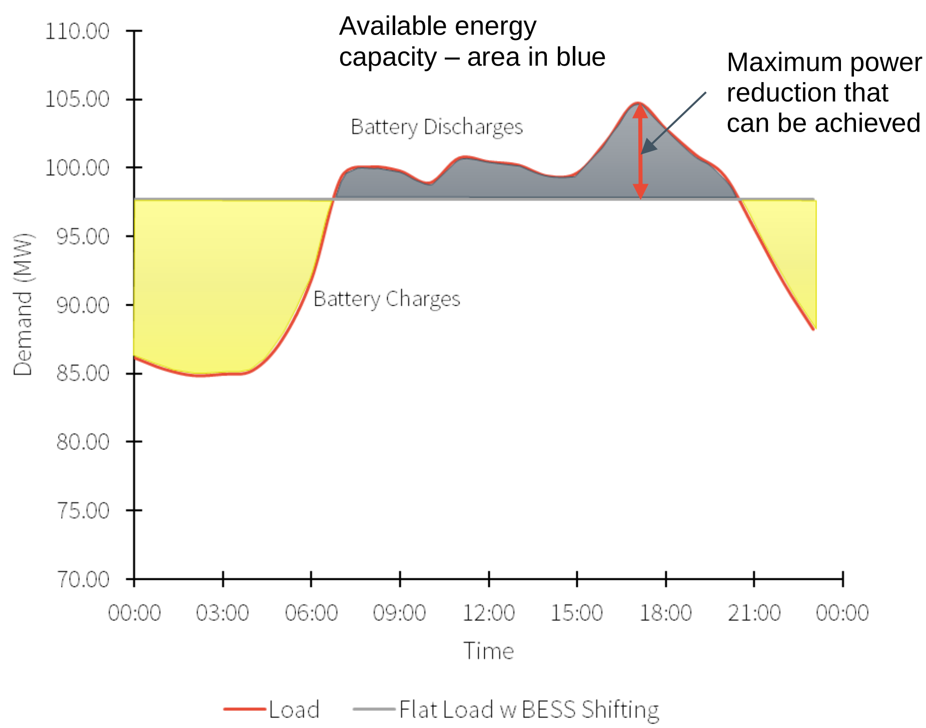


Figure 6-1: Illustration of the importance of energy capacity of the BESS in determining the potential capacity reduction that can be achieved.

In order to assess the potential benefits of the BESS, the maximum capacity reduction that could be achieved by batteries with a capacity of 30 MWh, 35 MWh, 40 MWh, and 45 MWh was calculated. Sizing was selected to allow for the BESS to have a CAPEX comparable to the allocated budget for the project. This analysis was completed for the 5 peak days in January 2020, when Yukon Energy achieved their all-time peak demand almost 105 MW.

The load profile for the 5 peak days in January 2020 is presented in Figure 6-2, January 13, 14, 16, 17, and 18. This figure shows the impact of load profile on the potential power capacity the BESS can provide. On January 17 and 18, the morning peak was greater and sustained for a longer period, thus lowering the amount of energy available for the afternoon peak.

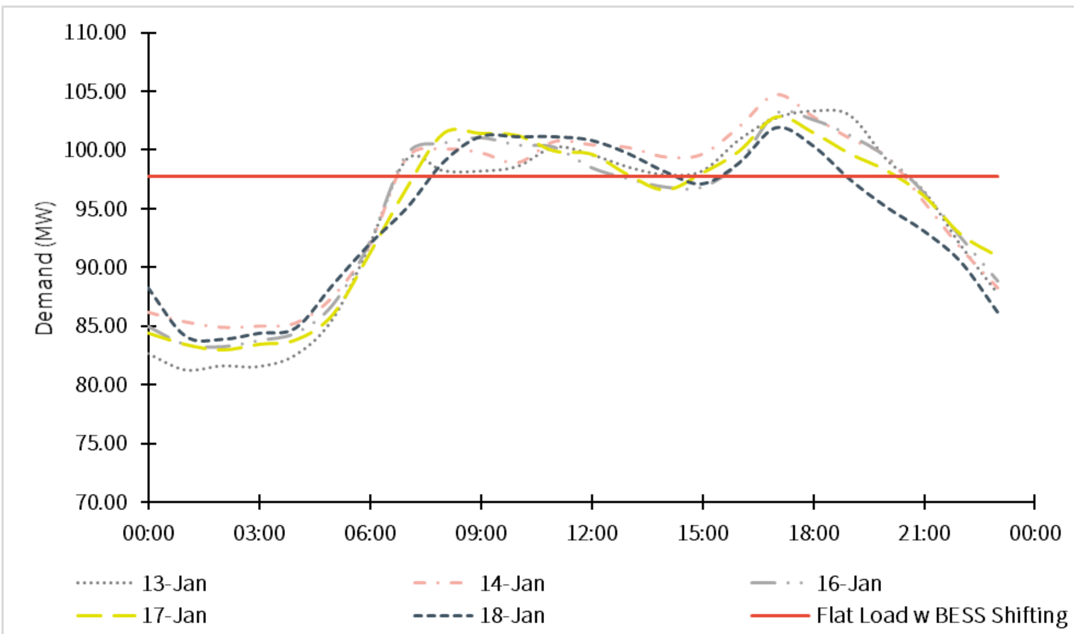


Figure 6-2: Load profile for peak days in January 2020, showing hypothetical flat load with BESS shifting, and the impact of load profile on the power reduction.

The following assumptions were made in the analysis:

- BESS will be recharged overnight.
- Round trip efficiency is 85%, thus BESS must be charged with 15% excess energy overnight.
- For each BESS size, the flattened load level that can be achieved using the full capacity (30, 35, 40 or 45 MWh) is assessed.

- Using the flat load estimate, the capacity of the BESS is calculated based on – peak daily demand – flat load = BESS capacity.
- Assessment includes both Yukon Energy and ATCO Electric Yukon generation.
- The firm capacity was calculated based on the firm winter hydro capacity and thermal generation capacity (106.55 MW) less Aishihik Hydro (37 MW) to a total of 69.55 MW. The number of rental units was calculated based on the different between the peak demand and the firm capacity (69.55 MW), divided by 1.8 MW, the size of each mobile genset.
- The difference between the peak and the flat load was used to calculate the potential reduction in rental gensets as a result of the BESS.

6.1.2 Results and Benefits

The results for the N-1 Reserve Capacity analysis are presented in Table 6-1 for the 4 different battery sizes. **The optimal sizing for the peak day is either 35 MWh or 40 MWh, which result in a reduction of 4 diesel genset rentals.**

The 30 MWh offering only results in a reduction of 3 diesel gensets, therefore, adding the extra capacity to the BESS has an advantage each year. Moving to 45 MWh increases the CAPEX but does not result in any further reduction in rental diesel gensets with the current load profile. Therefore, there are diminishing benefits to selecting the 45 MWh BESS.

From the perspective of this use case in isolation, the 35 MWh BESS is the optimal sizing, as it results in the same reduction in diesel genset rentals as the 40 MWh BESS. However, the 40 MWh BESS provides Yukon Energy with greater operational flexibility and allows for the potential to perform more secondary use cases since there are an additional 5 MWh of energy capacity.

Additionally, the overnight charging rate required to recharge the battery was estimated. This was done by determining the minimum charging rate required to recharge the battery from discharge, plus the additional energy required to accommodate for efficiency losses (assumed round trip efficiency of 85%). As required, the charging rate is also limited by the firm capacity (less the battery capacity) i.e. flat load level in Table 6-1.

Table 6-1: N-1 Scenario with different BESS Sizing

Date		13-Jan	14-Jan	16-Jan	17-Jan	18-Jan
No BESS	Peak	103.4	104.7	103.1	102.9	101.9
	Mobile Diesels Req	19	20	19	19	18
With 30 MWh BESS	Flat Load Level	97.7	98.5	97.8	97.7	97.2
	Mobile Diesels Req	16	17	16	16	16
	BESS Capacity to shed 30 MWh	5.6	6.3	5.3	5.2	4.6
	Minimum Overnight Charging Rate	3.8	3.6	3.8	3.5	3.1
With 35 MWh BESS	Flat Load Level	97.4	98.1	97.3	97.3	96.8
	Mobile Diesels Req	16	16	16	16	16
	BESS Capacity to shed 35 MWh	6.0	6.6	5.8	5.6	5.1
	Minimum Overnight Charging Rate	4.5	4.3	4.4	4.3	3.8
With 40 MWh BESS	Flat Load Level	97.0	97.7	96.9	96.9	96.4
	Mobile Diesels Req	16	16	16	16	15
	BESS Capacity to shed 40 MWh	6.3	7.0	6.2	6.0	5.5
	Minimum Overnight Charging Rate	5.2	5.0	5.3	5.1	4.6
With 45 MWh BESS	Flat Load Level	96.7	97.4	96.5	96.5	96.0
	Mobile Diesels Req	16	16	15	16	15
	BESS Capacity to shed 45 MWh	6.7	7.3	6.6	6.4	5.9
	Minimum Overnight Charging Rate	6.2	5.7	6.3	6.3	5.6

The estimated capital cost for the BESSs with the peak power capacity calculated from the N-1 reserve calculations is presented in Table 6-2. The CAPEX cost includes the added cost for the 20% overbuild required due to the limited state-of-charge range (20%-100% or 10% - 90% depending on the vendor recommendation). Therefore, the energy of the BESS is the usable energy, with the installed energy capacity being 20% greater. For comparison, the incremental capital cost to increase the power capacity to have a 4 hr duration BESS (which is a common size for lithium ion batteries) is presented in Table 6-3.

The capital cost for the 6.6 MW/35 MWh BESS is $24.9 million, increasing to $27.8 million for the 7.0 MW/40 MWh BESS. Therefore, the added flexibility of having a 40 MWh BESS results in an increased CAPEX of just under $3 million. As the secondary use cases are assessed, the impact of having a 35 MWh or 40 MWh BESS will be considered.

Table 6-2: Estimated Capital Cost for Proposed BESSs

BESS Energy Capacity	Power Capacity*	Duration	Flat Load	Number of Mobile Gensets	Genset reduction vs. base	Estimated Capital Cost
30 MWh	6.3 MW	4.8 h	98.5 MW	17	3	20.6 M$
35 MWh	6.6 MW	5.3 h	98.1 MW	16	4	23.5 M$
40 MWh	7.0 MW	5.7 h	97.7 MW	16	4	26.3 M$
45 MWh	7.3 MW	6.1 h	97.4 MW	16	4	29.2 M$

*reduction in peak demand achieved on peak day

The incremental cost of increasing the power output of the BESS to achieve a 4 hr duration is relatively minor, at only $300,000 - $500,000 for the preferred options. This is because increasing inverter and transformer capacity marginally is relatively minimal compared to increased battery cells. This option allows the BESS to be recharged faster overnight, ensuring that it can be ready the next day to continue providing diesel peak shifting services if the N-1 event continues.

The impact of these incremental benefits will also be assessed for the secondary use cases to determine their justification. However, given the modest capital cost increase, it seems reasonable to justify the 4 hr BESS, to allow for more flexibility.

Table 6-3: Incremental and Total CAPEX to add additional MW to achieve 4 hr BESS rating

BESS Energy Capacity	Power Capacity	Duration	Incremental Capital Cost	Estimated Total Capital Cost
30 MWh	7.5 MW	4.0 h	0.2 M$	20.8 M$
35 MWh	8.8 MW	4.0 h	0.3 M$	23.8 M$
40 MWh	10.0 MW	4.0 h	0.5 M$	26.8 M$
45 MWh	11.3 MW	4.0 h	0.7 M$	29.9 M$

Therefore, based on the N-1 reserve capacity assessment, the preferred sizing is 8.8 MW/35 MWh or 10 MW/40 MWh.

Additionally, Yukon Energy has requested that a 13 MW/40 MWh BESS and a 20 MW/40 MWh BESS is investigated to provided added flexibility for secondary use cases. Both of these battery sizes are sufficient to cover the complete loss of the LNG generation plant.

Table 6-4: Incremental and Total CAPEX to add additional MW to a 40 MWh BESS

BESS Energy Capacity	Power Capacity	Duration	Incremental Capital Cost	Estimated Total Capital Cost
40 MWh	10.0 MW	4.0 h	0 M$	26.8 M$
40 MWh	13.0 MW	3.1 h	0.6 M$	27.4 M$
40 MWh	20.0 MW	2.0 h	1.8 M$	28.6 M$

6.1.3 Important Technical Capabilities of BESS for N-1 Reserve Capacity

For this use case, the BESS will require the following technical capabilities:

- High Round trip efficiency (85% was assumed in the analysis)
- Low auxiliary demands
- Low self-discharge rate overnight
- High reliability and redundancy in design

6.2 Blackstart and Outage Restoration

6.2.1 *Methodology for Assessment*

While the blackstarting study has been performed, the outage restoration to study load pickup will be assessed using a Power System Model in PSCAD.

6.2.2 *Results and Benefits*

Results to be issued in a separate project memo. ***Full details on the Blackstart Study are found in Appendix H.***

Note: *having the larger BESS (10 MW/40 MWh, 13 MW/40 MWh or 20 MW/40 MWh) will increase the power capacity of the load segments during blackstart, thus reducing the time required to re-energize the grid. As well, the higher energy capacity will increase the infrastructure and power generation that can be re-energized with the BESS. Particularly, the 20 MW power capabilities provides Yukon Energy with increased flexibility to significantly increase the segments that can be picked up during the blackstart process, which reduces the time. This 20 MW inverter capability can also cover the loss of Whitehorse Hydro Unit #4. It also has the highest operating factor (capacity factor) of all of Yukon Energy's generation, therefore, and outage of Whitehorse Hydro Unit #4 can lead to critical outages on the gird. Based on discussions with Yukon Energy, this hydro unit is the cause of many system outages.*

6.2.3 *Important Technical Capabilities of BESS for Blackstart*

For this use case, the BESS will require the following technical capabilities:

- Ability to self-energize
- Low self-discharge rate while waiting for blackstart
- Inverter with grid forming capabilities (to maintain grid frequency and voltage)
- Low auxiliary demands

6.3 Operating Reserve

6.3.1 *Methodology for Assessment*

Currently, Yukon Energy carries operating reserve (OR) on its hydro turbines. However, this results in the turbines operating below their rated value and thus reduces the efficiency. As well, carrying this operating reserve on the hydro units, means that there is capacity not being used to generate electricity for customers, thus any shortfall in electricity is made up with LNG and diesel generation.

Therefore, by using the BESS to provide the operating reserve, when excess water is available, the hydro units can be run at higher loading and the diesel gensets and potentially the LNG gensets can be turned off. This reduces fuel consumption costs, as well as maintenance costs on these units.

The following assumptions were used in the assessment of the available operating reserve:

- Operating reserve was calculated based on 2019/2020 year compared to average annual water flow.
  - For each week of the year, the amount of energy generated by all hydro units was at or below the "average year's" water flow for this week. There are several weeks in the winter when no benefits can be achieved due to water flow limitations.
- Operating reserve was calculated using hourly data for 2019/2020.
- The maximum output from each site (Aishihik, Whitehorse, and Mayo) was estimated as the maximum output assuming average annual water for each week.
- If a hydro unit was off at any given timestep, it was not counted towards the reserve, nor was it turned on to add capacity
- Operating reserve was not carried on Whitehorse Turbine 4 – any benefits from this turbine were not allocated to the calculation
- Operating reserve was calculated using the following equation, with 25 MW, 24 MW, and 8 MW being the maximum output from each of the sites for this given week. These numbers were adjusted each week.
  - $\mathrm{OR(t)\ week\ 1} = \left(25 - \mathrm{WH1(t)} - \mathrm{WH2(t)} - \mathrm{WH3(t)} - \mathrm{WH4(t)}\right) + \left(24 - \mathrm{AH1(t)} - \mathrm{AH2(t)} - \mathrm{AH3(t)}\right) + \left(8 - MH1(t) - MH2(t) - MBH1\,(t) - MBH2\,(t)\right)$
  - It was assumed that the units could never run above their Summer Maximum Output; if the OR available was higher than this value, then the OR was reduced to ensure the units never ran above their summer maximum.
    - This has the greatest implications at Whitehorse, since it was assumed OR on WH4 should not be replaced by the BESS. (e.g. OR WH = 1.90 MW, but only

WH1 and WH4 are running. OR on WH1 = 1.04 MW, therefore, OR for this timestep is reduced to 1.04 MW, since OR on WH4 is not available.)

- Total weekly generation for each site with the new OR was calculated (WH generation + AH generation + MH generation + added generation from OR) and compared to average water total generation for the week. If the proposed total weekly generation was greater than the average water scenario, then the OR benefits were reduced until the weekly generation was equal to or below the average water year.
- The same was done for total annual generation from hydro units and for each site.

Based on this analysis, the additional available hydro generation that could replace LNG or diesel generation in each hourly timestep was calculated. The average OR and the maximum OR for each month on the Yukon Energy grid is presented in Figure 6-3. **The average operating reserve ranges from 2 MW to 8 MW across the year. The annual average is 4.8 MW of operating reserve.**

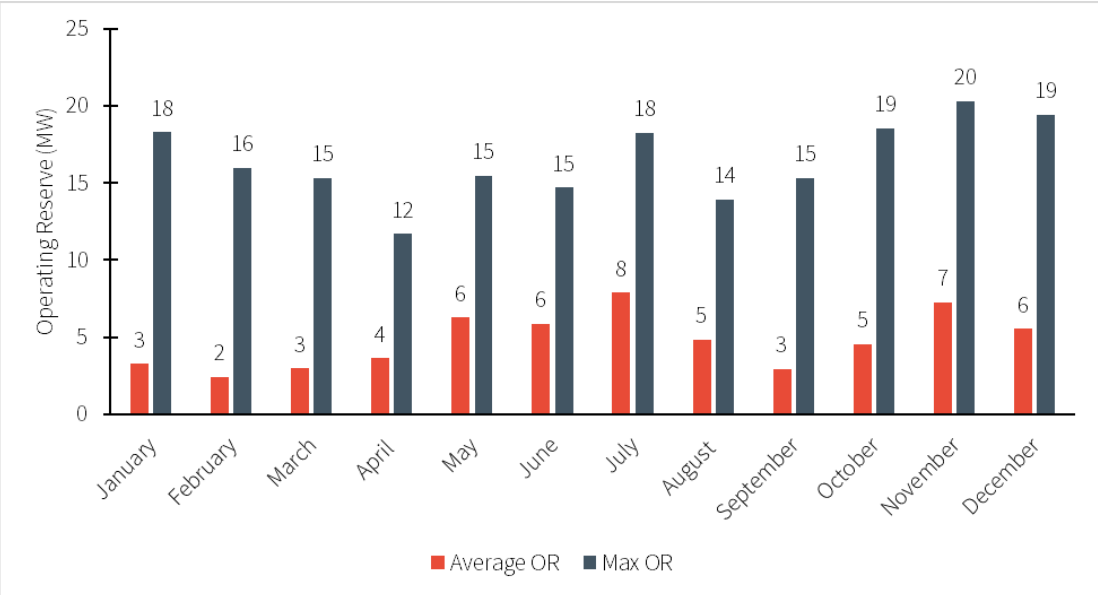


Figure 6-3: Monthly average and maximum operating reserve (at hourly resolution) on Yukon Energy Grid

Based on the available operating reserve, the amount of thermal generation that could be reduced or turned off was assessed. The following assumptions were used in this analysis:

- Diesel generation was turned off first
- If diesel units must remain on, the minimum amount of generation that must be carried is 400 kW (approximately 50% of the smallest genset at Dawson Diesel Plant).

- LNG units must be loaded at minimum 85%. Therefore, if there is OR available to reduce LNG output, there are two options:
  - Turn the generator off,
  - Reduce output to 85%.

6.3.2 Results and Benefits

The available energy to cover the OR is presented in Table 6-5, as well as the percentage of the total usable battery capacity that this energy represents. However, it is expected that the energy discharged from the BESS to provide operating reserve will be relatively low. For the BESS to discharge as part of the operating reserve application, an unplanned event where generation trips or is insufficient needs to occur. This is an infrequent event, as such in this use case the BESS will be primarily idling with sufficient energy stored to provide this operating reserve and not cycling frequently.

Table 6-5: Energy Used for OR and % of total BESS usable capacity

BESS Size	Energy Used for OR	% of total usable capacity
6.6 MW/35 MWh	3.3 MWh	9.4%
7 MW/40 MWh	3.5 MWh	8.8%
8.8 MW/35 MWh	4.4 MWh	12.6%
10 MW/ 40 MWh	5.0 MWh	12.5%
13 MW/ 40 MWh	6.5 MWh	16.3%
20 MW/ 40 MWh	10.0 MWh	25.0%

Table 6-5 assumes the battery will discharge at its rated power for 30 min, until another engine can be started. However, if necessary, the BESS can continue to discharge for longer periods, until the energy has been depleted. It should be noted that this may limit the BESS's ability to provide other services. The decision to discharge the BESS for longer than 30 min should be made based on available generation and the other necessary usages for the BESS in the near future.

The annual reduction in generation from diesel gensets and LNG units is presented in Figure 6-4. Adding the additional power capacity to shift to a 4-hr BESS results in a reduction of an additional 2,500-2,700 MWh of LNG; however, there is limited benefits to the diesel genset savings.

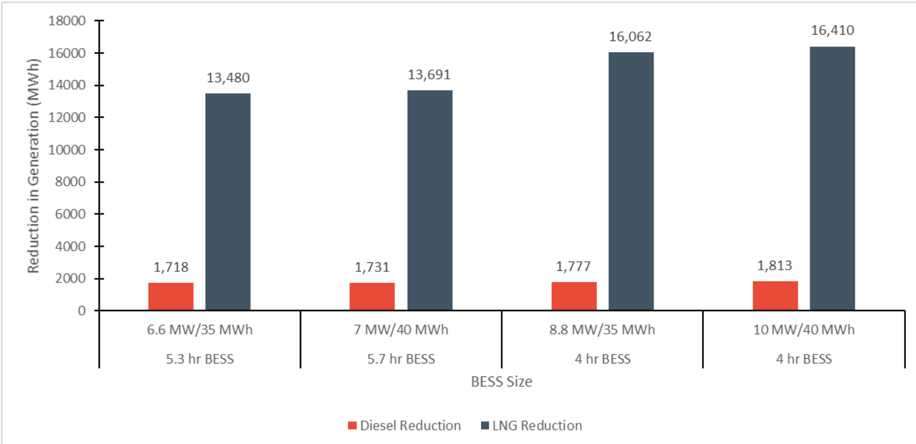


Figure 6-4: Reduction in Diesel Generation and LNG Generation as a result of OR supported by the BESS

The annual reduction in operating hours is presented in Figure 6-5. Again, moving to the 4 hr BESS shows a significant reduction in LNG unit operating hours, by over 700 hrs per year.

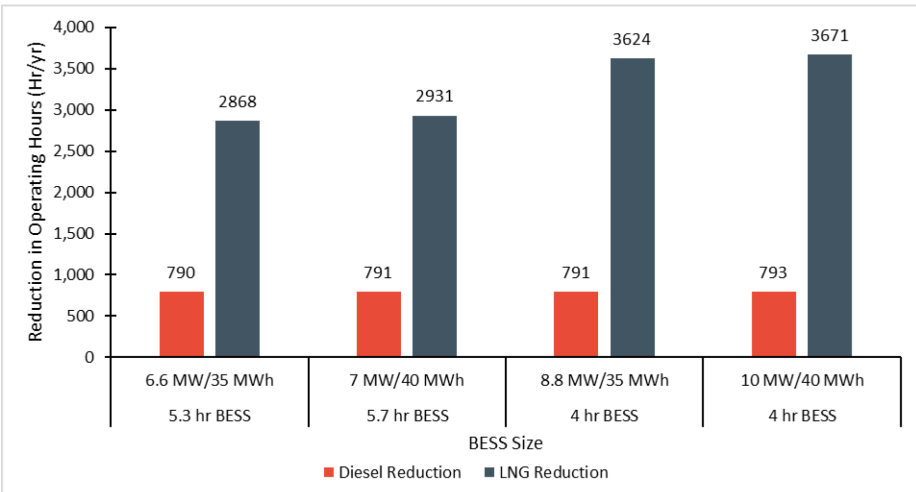


Figure 6-5: Reduction of Annual Operating Hours on Diesel Gensets and LNG units.

Further comparison is presented reviewing the 4 different power options for the 40 MWh BESS. Figure 6-6 compares the potential fuel savings based on power output of the BESS. Figure 6-7 compares the number of hours that either a diesel or natural gas genset can be turned off as a result of using the BESS for Operating reserve. The incremental increase in benefits in moving from 10 MW to 13 MW is a reduction of approximately 500 additional MWh of LNG and 150 more hours where one or more LNG units is turned off. The incremental savings of moving from a 13 MW to a 20 MW power capability are marginal. This is because there are few hours of the year where the available operating reserve on the hydro units is greater than 13 MW and there is over 13 MW of thermal generation that can be turned off.

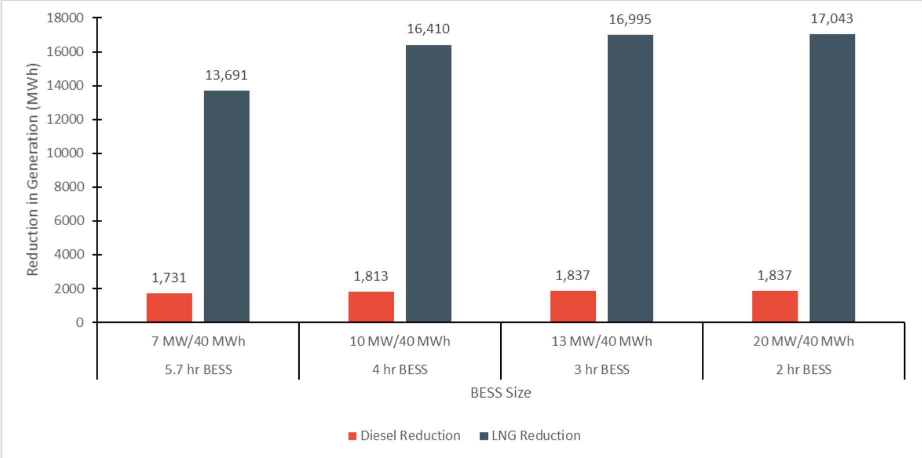


Figure 6-6: Reduction in Diesel Generation and LNG Generation as a result of OR supported by the BESS, investigating different power outputs for a 40 MWh BESS.

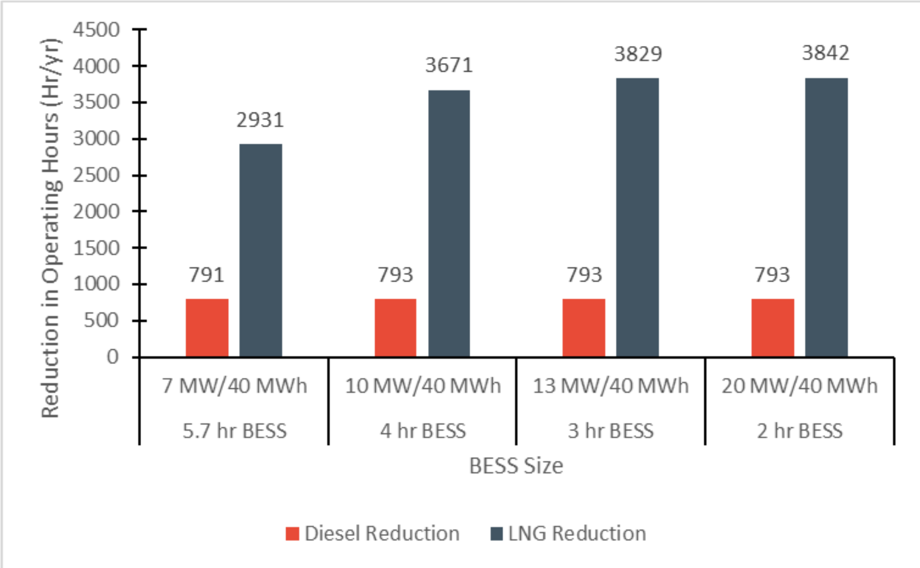


Figure 6-7: Reduction of Annual Operating Hours on Diesel Gensets and LNG units, investigating different power outputs for a 40 MWh BESS.

The potential benefits will vary year to year depending on water availability. Benefits will be greater in years with higher water flow volumes and will be lower in years with lower water availability. A preliminary economic assessment of these benefits is presented in Section 12.

The final benefit that can be gained by using the BESS as operating reserve is operating the hydroelectric plants at higher loading, which can increase their efficiency (i.e. more energy generated with the same amount of water flow). The potential increased average loading for each site is presented in Figure 6-8. The greatest potential gain is observed at Aishihik; however, this is because when extra generation was available it was provided by Aishihik first (as long as generation remained below the maximum weekly power output for the site).

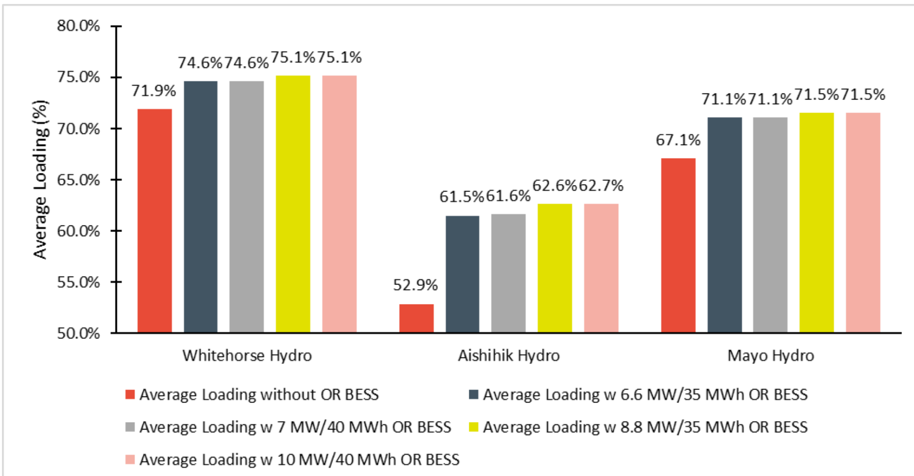


Figure 6-8: Potential Increase in Average Unit Loading if OR is shifted to BESS.

With the BESS providing supplementary operating reserve, there is potential for significant reduction in fuel consumption, which can provide meaningful savings to Yukon Energy. Additional savings are achieved with reduced variable maintenance on the gensets, since their operating hours are reduced each year. Finally, operating the hydro turbines at higher loading, on average, improves the efficiency, meaning more energy can be generated from the same amount of water. Newer turbines will have steeper efficiency curves, meaning the greatest benefits will be achieved by operating these units at higher loading first.[1]

For the Yukon Energy grid, there is a significant amount of energy generated with hydroelectric turbines. Even if there is a modest efficiency gain, of 0.5-1% in terms of improved efficiency, this translates to an additional 2.2-4.4 GWh of energy generated from the same volume of water. This higher generation from hydro is a significant savings opportunity if it can directly lead to a reduction in diesel genset and natural gas genset operation and fuel consumption.

[1] Efficiency curves for the hydro turbines were not available when the report was completed. The scale of this benefit should be assessed based on the turbine efficiency curve.

6.3.3 Important Technical Capabilities of BESS for Operating Reserve

For this use case, the BESS will require the following technical capabilities:

- Low self-discharge rate while acting as reserve
- Rapid and Automated Response
- Low auxiliary demands

6.4 Diesel Peak Shifting

6.4.1 *Methodology for Assessment*

The BESS could be used to reduce the number of events where diesel gensets are turned on for a short period of time (several hours). In order to assess the potential for diesel peak shifting events, the frequency of events was calculated for each generator based on event duration.

Analysis was conducted for each of the units for operating events of different durations (1 hr, 2 hr, 3 hr, 4 hr, 5 hr, 6 hr, 7 hr, 8 hr and >8 hr) to determine the number of times per year the unit comes on for each duration length, average energy generated within the events, and total annual generation within the events. This information provides insight into the amount of energy that can be shifted from the diesel gensets to LNG generators or hydro with the BESS.

The analysis was also completed for different combinations of units. Analysis was completed for Whitehorse diesel plant, Faro diesel plant, Whitehorse and Faro diesel plant combined, and Mayo and Dawson diesel plant combined. The combined analysis was done first by summing the generation across all gensets within the group. For example, for Whitehorse, a combined dataset was created for all 4 gensets at this plant; for Whitehorse and Faro together, a combined dataset consisting of all 6 gensets was prepared by summing the output from each unit.

The number of events, average generation during each event, and total annual generation based on event duration was then calculated for these combined data sets. Note, the output of this analysis is not a simple summation across the units, since sometimes the event duration would be increased if individual gensets come online at different hours within the same day.

The maximum power generated in a single hour, based on event duration, was also calculated for these data sets to determine the size of the BESS required to serve all of the combined events.

6.4.2 *Results and Benefits*

6.4.2.1 *Whitehorse Diesel*

The frequency distribution for diesel operation events for the Whitehorse diesel plant is presented in Table 6-6, showing that the majority of the events are 4 hours or less or greater than 8 hours.

Table 6-6: Frequency Distribution of Diesel Operating Events at Whitehorse Diesel Plant, based on duration of genset operation

Number of Events					
Duration of Event	Whitehorse				All South Grid
	WD 4	WD 5	WD 6	WD 7	
1 hr	10	6	3	6	9
2 hr	13	18	11	9	17
3 hr	10	11	11	4	10
4 hr	7	5	6	2	11
5 hr	0	1	3	0	4
6 hr	5	5	2	0	5
7 hr	3	4	5	1	2
8 hr	3	4	2	1	0
> 8 hr	18	17	16	4	20

The average energy generated by the gensets during these events is presented in Table 6-7, showing that each event that is 1-4 hrs in duration has a relatively small energy consumption, which can be supplied by the BESS. It is reasonable that the BESS could cover the all of the 1-4-hour peaks and some of the 5-hour peaks.

The single largest 4 hr and 5 hr generation events are 17 MWh, which will deplete roughly 50% of the BESS's total energy capacity. Therefore, Yukon Energy grid operators will need to make decisions on a case-by-case basis, based on grid operations at the time, if it is reasonable to shift these higher energy demand diesel generation events, to ensure the BESS is capable of performing other reliability duties.

Table 6-7: Average Energy Generated by the Genset During Each Event at Whitehorse Diesel Plant

Average Energy Generation Per Event					
Duration of Event	Whitehorse				All South Grid
	WD 4	WD 5	WD 6	WD 7	
1 hr	0.69 MWh	0.55 MWh	0.39 MWh	0.45 MWh	0.86 MWh
2 hr	2.22 MWh	2.13 MWh	1.72 MWh	1.55 MWh	2.83 MWh
3 hr	2.71 MWh	3.55 MWh	3.11 MWh	4.99 MWh	5.22 MWh
4 hr	6.33 MWh	5.93 MWh	6.30 MWh	6.38 MWh	9.37 MWh
5 hr	0.00 MWh	8.32 MWh	9.80 MWh	0.00 MWh	12.73 MWh
6 hr	10.36 MWh	7.90 MWh	11.31 MWh	0.00 MWh	13.41 MWh
7 hr	9.65 MWh	14.49 MWh	13.11 MWh	10.49 MWh	13.82 MWh
8 hr	15.85 MWh	16.60 MWh	15.36 MWh	15.64 MWh	0.00 MWh

The total annual generation from each genset and for the Whitehorse diesel plant as a whole is presented in Table 6-8. For the 1-4-hour events, the 4 Whitehorse diesel gensets generate 211 MWh of energy per year.

Table 6-8: Total Annual Generation for Events of Different Duration at Whitehorse Diesel Plant

Total Generation					
Duration of Event	Whitehorse				All South Grid
	WD 4	WD 5	WD 6	WD 7	
1 hr	6.89 MWh	3.28 MWh	1.17 MWh	2.68 MWh	7.76 MWh
2 hr	28.83 MWh	38.41 MWh	18.91 MWh	13.94 MWh	48.09 MWh
3 hr	27.12 MWh	39.05 MWh	34.18 MWh	19.97 MWh	52.22 MWh
4 hr	44.28 MWh	29.63 MWh	37.81 MWh	12.76 MWh	103.10 MWh
5 hr	0.00 MWh	8.32 MWh	29.39 MWh	0.00 MWh	50.91 MWh
6 hr	51.78 MWh	39.48 MWh	22.61 MWh	0.00 MWh	67.03 MWh
7 hr	28.96 MWh	57.97 MWh	65.54 MWh	10.49 MWh	27.64 MWh
8 hr	47.54 MWh	66.40 MWh	30.71 MWh	15.64 MWh	0.00 MWh

The maximum power output from the Whitehorse diesel plant, based on the duration of their operation, is presented in Table 6-9. For events for 1-4 hrs, there is a single event in the year where the demand is greater than 7 MW (the longer duration BESSs, with lower power capabilities)

Table 6-9: Maximum Generation from Whitehorse Diesel Plant in the South Grid based on duration of events

Maximum Output	
Duration of Event	All South Grid
1 hr	3.58 MW
2 hr	4.30 MW
3 hr	6.32 MW
4 hr	7.01 MW
5 hr	5.27 MW
6 hr	4.98 MW
7 hr	5.41 MW
8 hr	0.00 MW

6.4.2.2 Faro Diesel

The following tables complete the same analysis for Faro Diesel Plant. Faro diesel was separated from the rest of the North Grid as it is more centrally located on the main 138 kV line connecting the northern and southern communities in Yukon.

The frequency distribution of diesel operating events for Faro Diesel (for each unit and for the plant as a whole) is presented in Table 6-10. Again, the majority of the events are less than 4 hours in duration or greater than 8 hrs.

Table 6-10: Frequency Distribution of Diesel Operating Events at Faro Diesel Plant, based on duration of genset operation

Number of Events			
Duration of Event	Faro		
	FD1	FD2	FD Total
1 hr	5	2	2
2 hr	7	7	8
3 hr	1	3	3
4 hr	0	4	6
5 hr	0	4	4
6 hr	0	1	1
7 hr	0	1	1
8 hr	0	1	1
> 8 hr	3	12	11

The average energy generation per diesel operating event, based on duration, at Faro diesel is presented in Table 6-11,showing that for 1-4 hr events, the average energy generated by the Faro diesel plant is less than 5.5 MWh of energy. This represents a 13-16% of the total energy capacity of the BESS, depending on the size.

Table 6-11: Average Energy Generated by the Genset During Each Event at Faro Diesel Plant

Average Generation Per Event			
Duration of Event	Faro		
	FD1	FD2	FD Total
1 hr	0.71 MWh	0.72 MWh	1.39 MWh
2 hr	2.40 MWh	2.02 MWh	2.62 MWh
3 hr	3.52 MWh	2.89 MWh	3.64 MWh
4 hr	0.00 MWh	5.64 MWh	5.36 MWh
5 hr	0.00 MWh	8.31 MWh	8.31 MWh
6 hr	0.00 MWh	11.43 MWh	11.43 MWh
7 hr	0.00 MWh	15.33 MWh	15.33 MWh
8 hr	0.00 MWh	16.48 MWh	16.48 MWh

The total annual generation from each of the Faro Diesel gensets and the plant, based on the duration of generation is presented in Table 6-12. For the entire plant, events with a duration of 1-4 hrs represent 66.8 MWh of total generation each year.

Table 6-12: Total Annual Generation for Events of Different Duration at Faro Diesel Plant

Total Generation			
Duration of Event	Faro		
	FD1	FD2	FD Total
1 hr	3.54 MWh	1.44 MWh	2.79 MWh
2 hr	16.77 MWh	14.15 MWh	20.94 MWh
3 hr	3.52 MWh	8.67 MWh	10.91 MWh
4 hr	0.00 MWh	22.57 MWh	32.17 MWh
5 hr	0.00 MWh	33.24 MWh	33.24 MWh
6 hr	0.00 MWh	11.43 MWh	11.43 MWh
7 hr	0.00 MWh	15.33 MWh	15.33 MWh
8 hr	0.00 MWh	16.48 MWh	16.48 MWh

The maximum power output from the Faro diesel plant, based on the duration of their operation, is presented in Table 6-13. All events, the maximum demand is less than the 6.6 MW minimum BESS sizing, indicating that all diesel generating events less than 4 hrs in duration could be reasonably performed by the BESS.

Table 6-13: Maximum Generation from Faro Diesel Plant based on duration of events

Duration of Event	FD Total
1 hr	2.42 MW
2 hr	2.30 MW
3 hr	2.42 MW
4 hr	3.20 MW
5 hr	2.47 MW
6 hr	1.98 MW
7 hr	2.47 MW
8 hr	2.53 MW

6.4.2.3 Faro + Whitehorse

The following section explores the potential to shift both Whitehorse Diesel Plant and Faro Diesel plant generating events. Faro diesel was selected, since it is the closest diesel generating plant on the North Grid, therefore, the electrical losses would be lower compared to other diesel plants in the north.

In order to do this assessment, the total generation for each plant was summed, and the same analysis was completed on the summed data set (as was done for the totals for each plant).

Table 6-14 presents the frequency distribution for Whitehorse Diesel, Faro Diesel, and combined across the two sites. As expected, the majority of the events are less than 4 hrs in duration, thus have the potential to be powered by the BESS.

Table 6-14: Frequency Distribution of Diesel Operating Events summed for Faro and Whitehorse Diesel, based on duration of genset operation

	Number of Events		
Duration of	**WD**	**FD**	**Total**
1 hr	9	2	11
2 hr	17	8	21
3 hr	10	3	12
4 hr	11	6	14
5 hr	4	4	5
6 hr	5	1	5
7 hr	2	1	2
8 hr	0	1	0
> 8 hr	20	11	23

The average generation for each event is presented in Table 6-15. For events from 1-3 hrs, average generation between both sites is less than 5 MWh, which can be reasonably served by the BESS without impacting its ability to act as operating reserve.

The 4 hr events have an average consumption of 8.25 MWh, which is 20-25% of the total energy capacity of the BESS, depending on the size. Therefore, depending on the status of the grid, the state of charge of the BESS, and forecasted demands, some these events may be possible to shift with the BESS. The single largest 4 hr generation event is 17 MWh, which will deplete roughly 50% of the BESS's total energy capacity. Therefore, Yukon Energy grid operators will need to make decisions on a case-by-case basis, based on grid operations at the time, if it is reasonable to shift all 4 hr diesel generation events, to ensure the BESS is capable of performing other reliability duties.

Table 6-15: Average Energy Generated by the Genset During Each Event at Faro Whitehorse Diesel Plant

	Average Generation Per Event		
Duration of Event	**WD**	**FD**	**Total**
1 hr	0.86 MWh	1.39 MWh	0.96 MWh
2 hr	2.83 MWh	2.62 MWh	2.85 MWh
3 hr	5.22 MWh	3.64 MWh	4.86 MWh
4 hr	9.37 MWh	5.36 MWh	8.25 MWh
5 hr	12.73 MWh	8.31 MWh	10.78 MWh
6 hr	13.41 MWh	11.43 MWh	13.41 MWh
7 hr	13.82 MWh	15.33 MWh	13.82 MWh
8 hr	0.00 MWh	16.48 MWh	0.00 MWh

The total annual generation from each genset and for the Whitehorse and Faro diesel plants combined is presented in Table 6-16. **For the 1-4-hour events, the Whitehorse diesel**

gensets and Faro diesel gensets generate 244 MWh of energy per year. As identified above, it may be possible to shift all of this generation from diesel gensets to the BESS and recharge the BESS overnight with LNG or excess hydro power.

Table 6-16: Total Annual Generation for Events of Different Duration at summed for Whitehorse and Faro Diesel Plant

Total Generation			
Duration of	WD	FD	Total
1 hr	7.76 MWh	2.79 MWh	10.54 MWh
2 hr	48.09 MWh	20.94 MWh	59.76 MWh
3 hr	52.22 MWh	10.91 MWh	58.27 MWh
4 hr	103.10 MWh	32.17 MWh	115.52 MWh
5 hr	50.91 MWh	33.24 MWh	53.88 MWh
6 hr	67.03 MWh	11.43 MWh	67.03 MWh
7 hr	27.64 MWh	15.33 MWh	27.64 MWh
8 hr	0.00 MWh	16.48 MWh	0.00 MWh

Table 6-17 shows the maximum demand within each event, again the same single event at Whitehorse diesel is above the 7 MW capacity of the lower power BESSs.

Table 6-17: Maximum Generation from Whitehorse Diesel Plan and Faro Diesel Plant (together) based on duration of events

Duration of Event	WD + FD Total
1 hr	3.58 MW
2 hr	4.30 MW
3 hr	6.32 MW
4 hr	7.01 MW
5 hr	5.27 MW
6 hr	4.98 MW
7 hr	5.41 MW
8 hr	0.00 MW
> 8 hr	14.72 MW

6.4.2.4 Potential Diesel Peak Shifting Fuel Reductions

Based on this analysis, the most promising opportunity for the BESS to provide diesel peak shifting services is at Whitehorse diesel. Whitehorse diesel plant is close to both connection points, which reduces the losses associated with supplying energy by the BESS to replace the diesel genset output. Additionally, Whitehorse diesel represents a significant portion of the 1-4 hr generation (over 50% of total generation when gensets are operated for 1-4 hr in duration), thus can make a meaningful contribution to reduce diesel fuel consumption.

Faro diesel plant could also be included in the potential diesel peak shifting events, particularly for short duration events. The electrical losses associated with replacing Faro diesel generation with the BESS would need to be evaluated in order to ensure that electrical losses do not negate the benefits and that energy from the BESS can be delivered to the customers in this region efficiently.

The BESS has the potential to shift between 108 MWh – 244 MWh of diesel generation between Whitehorse diesel and Faro diesel. (108 MWh for 1-3 hr events at Whitehorse only, 244 MWh for 1-4 hr events at Whitehorse + Faro). The represents 3-6% of total annual diesel generation for the two plants. The longer duration events lead to greater overall energy consumption.

Adding in the 5 hr diesel operating events results in an additional 53 MWh of diesel offset, resulting is 297 MWh of diesel generation reduction at Faro and Whitehorse diesel plants.

All but one of the 1-4 hr events can be served by the 6.6 MW/35 MWh and 7 MW/40 MWh BESS; however, for the single largest event, generating 17 MWh of energy in 4 hrs, almost 50% of the total available energy in the BESS would be consumed to serve this event. The BESS's ability to perform other services that day and act as operating reserve would be reduced. Increasing the energy capacity of the BESS to 40 MWh allows for greater flexibility in shifting these longer duration events, while keeping a portion of the BESS reserved for backup/operating reserve.

Currently, the diesel peaks achieve a maximum at just over 7 MW of demand (from Whitehorse and Faro). Therefore, the 10 MW/40 MWh BESS is capable of shifting all of the diesel peaks based on 2019 operations. However, as the demand increases, these peaks will likely also increase in magnitude. **Increasing the power capabilities of the BESS to 13 MW or 20 MW allows for more flexibility for future operation, where diesel peaks may grow.**

Additionally, there may be times in the shoulder seasons (fall and spring) or summer period where the desire to shift natural gas generation exists due to spilled water. The 13 MW BESS is sufficient to cover the entire output capacity of natural gas generating plant. Again, though not necessarily applicable based on current operations, this capability may be beneficial for future operations as the load grows.

Note: If the BESS is also providing OR during these periods, a priority must be set. Typically, it is expected that operating reserve would take priority; however, if the grid is nearing capacity, shifting the diesel peak may be more beneficial.

In most cases, if it is assumed that OR discharge duration is 30 minutes at the rated power, for the 13 MW BESS we would need to conserve 6.5 MWh and the 20 MW BESS we would need to conserve 10 MWh. Therefore, under the current operation, the BESS would be capable of shifting the 17 MWh peak and retaining the 10 MWh required to provide OR.

However, if the BESS were partially discharged or if a diesel peak were larger, say 25 -27 MWh, one may select to run diesels to cover this peak instead of the battery to retain the operating reserve coverage of the BESS. However, that would need to be determined based on the stability of the grid, need for OR during that period.

6.4.3 Important Technical Capabilities of BESS for Diesel peak shifting

For this use case, the BESS will require the following technical capabilities:

- Low self-discharge rate
- Ability to be charged overnight at or near its rated power
- High round trip efficiency

6.5 Reduction in Load Shedding Events & Renewable Integration Support by Reducing Large Frequency Excursions

6.5.1 Methodology for Assessment

The BESS can be used to respond to large frequency excursions that would have otherwise led to load shedding events. It is expected that as the fraction of intermittent renewable generation increases on the grid, that these large frequency excursions will increase. Thus, by having the BESS designed to respond to under-frequency, due to low generation, it can also support renewable integration.

Frequency regulation with a BESS is most effective when the BESS is responding to frequency readings that are electrically close, which relates to the speed at which a signal can be received, and the BESS response can be observed on the grid.

If the BESS is configured to respond to frequency deviations that are at a great distance from the BESS, timing may be an issue due to delays between when the signal is read and when the BESS's response is sensed at the reading point. This can lead to the system "chasing its tail", with the response coming too late, leading to another frequency deviation.

The substation where the BESS is connected would be used as the monitoring point for the system frequency that would be used in any control algorithms related to frequency response from the battery. Depending on the inverter technology selected, the inverter may be capable of monitoring and responding to grid frequency deviations, without needing a separate measurement point.

Typically, the response time of a BESS is 150-250 ms depending on the controller and the inverter capabilities. In order to assess the potential for the BESS to support underfrequency events a frequency stability study would need to be done at a later phase. This study would assess the time it takes for the frequency excursion to be sensed by the BESS controller and for the BESS' response to be sensed at the point of concern and determine what (if anything) could occur in this time frame.

Therefore, for this analysis, it was assumed the BESS would respond to frequency deviations at/near the connection substation.

Yukon Energy's current load shedding protocol involves shedding ATCO's loads when the frequency drops below 59.5 Hz. Load shedding is triggered based on the rate of frequency drop (-1 to -2.6 Hz/s) for a defined period (e.g. duration 0.1-0.5 second or a number of cycles) Currently, load shedding occurs at McIntyre Substation on S170 – S6838, S170 – S6837 and Whitehorse Substation on S150-52-21 and S150-52-22.

In extreme events, load shedding at Takhini occurs on S164-52-7 if the frequency drops below 56.5 Hz for 6 consecutive cycles.

In all load shedding cases, customers on ATCO lines are impacted.

In order to assess the potential benefits of the BESS for frequency regulation and reducing load shedding, historic frequency data was assessed. Data was provided for 4.4 years, except on the L151, where data was provided for 2.9 years. Data was provided on 5 min time-step intervals.

A distribution of frequency deviations was prepared for each reading point.

Based on the distribution, the number of events were assessed. In some cases, the frequency deviation occurred for an extended period (lasting for hours to several days), each of these extended deviations were considered 1 event.

The following points were assessed:

- WH4 – Whitehorse Hydro
- L151 – Whitehorse LNG
- S170 – McIntyre Substation
- S164-L172 - Takhini to Riverside Substation
- S164 – L170 – Takhini to Carmacks Substation
- S164-L171 - Takhini to Aishihik Hydro
- S164-52-7 – 34.5 kV Takhini to ATCO Whistle Bend

6.5.2 Results and Benefits

The overall distribution of grid frequency deviations is presented in Figure 6-9, showing that there are very few deviations outside +/- 0.5 Hz, with the frequency moving outside this range less than 1% of the time. Therefore, though reducing load shedding is a benefit that can be achieved with the BESS, the annual requirement for this service is very low.

The following sections are a more detailed analysis of the potential reduction in load shedding at the different substations.

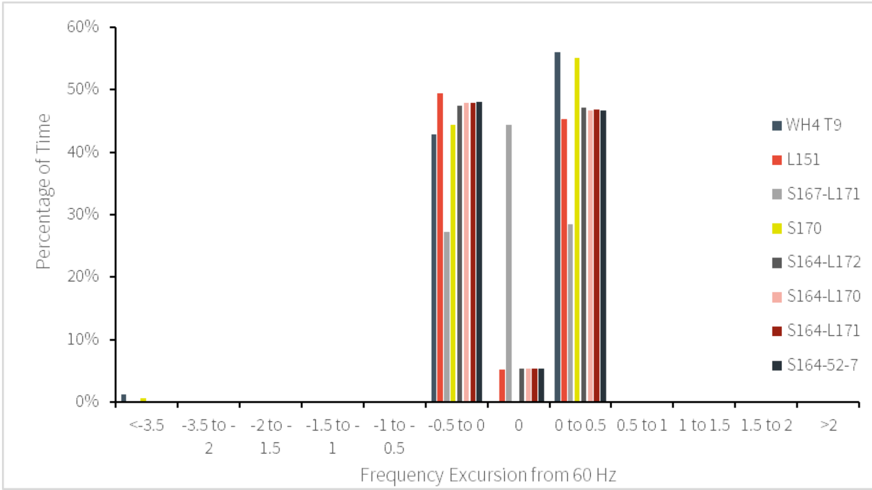


Figure 6-9: Distribution of Frequency Excursions as a Deviation from 60 Hz.

6.5.2.1 Whitehorse Substation Frequency Analysis

The distribution of frequency deviations at Whitehorse Substation on WH4 T9 and L151 are presented in Table 6-18. There were 8 major deviation events where the frequency dropped below 56.5 Hz for extended periods of time. Otherwise there were 33 deviations on WH4-T9 between 59.5 Hz and 56.5 Hz, and 32 deviations on L151.

The BESS could have responded to modest deviation events; thus, it is possible that the BESS could have reduced load shedding for 25 to 65 load shedding events over the past 4 years. It is unlikely the BESS could have avoided the significant frequency deviation events, below 56.5 Hz, which lasted for several hours.

Table 6-18: Frequency Deviations at Whitehorse Substation.

Frequency Excursion (deviation from 60 Hz)	WH4 – T9			L151		
	Number of data points in data set	Percentage Distribution	Number of total events	Number of data points in data set	Percentage Distribution	Number of total events
<-3.5	5517	1%	6 events	10	0%	2 events
-3.5 to -2	3	0%	3 events	3	0%	3 events
-2 to -1.5	2	0%	2 events	1	0%	1 event
-1.5 to -1	3	0%	3 events	11	0%	2 events
-1 to -0.5	26	0%	25 events	27	0%	26 events
-0.5 to 0	196465	43%	N/A	149525	49%	N/A
0	0	0%	N/A	15847	5%	N/A
0 to 0.5	257267	56%	N/A	137241	45%	N/A
0.5 to 1	18	0%	18 events	10	0%	10 events

Frequency Excursion (deviation from 60 Hz)	WH4 – T9			L151		
	Number of data points in data set	Percentage Distribution	Number of total events	Number of data points in data set	Percentage Distribution	Number of total events
1 to 1.5	6	0%	5 events	0	0%	0 events
1.5 to 2	1	0%	1 event	1	0%	1 event
>2	0	0%	0 event	6	0%	1 event
Total	459308	100%	N/A	302682	100%	N/A
Number of years	4.37			2.88		

6.5.2.2 McIntyre Substation Frequency Analysis

The distribution of frequency deviations at McIntyre Substation, for S170, are presented in Table 6-19. There were 9 major deviation events where the frequency dropped below 56.5 Hz for extended periods of time. Otherwise there were 33 deviations on S170 between 59.5 Hz to 56.5 Hz.

Since McIntyre substation is near Takhini and Whitehorse Substation, it may be possible for the BESS to respond to frequency deviations at this substation and avoid load shedding on the ATCO lines. However, it is imperative that the ability of the BESS to respond in a timely manner to avoid the system "chasing its tail".

The BESS could have responded to modest deviation events; thus, it is possible that the BESS could have reduced load shedding for 27 to 33 load shedding events over the past 4 years. It is unlikely the BESS could have avoided the significant frequency deviation events, below 56.5 Hz, which lasted for several hours.

Table 6-19: Frequency Deviations at McIntyre Substation.

Frequency Excursion (deviation from 60 Hz)	S170		
	Number of data points in data set	Percentage Distribution	Number of total events
<-3.5	2826	1%	9 events
-3.5 to -2	2	0%	2 events
-2 to -1.5	3	0%	3 events
-1.5 to -1	1	0%	1 event
-1 to -0.5	28	0%	27 events
-0.5 to 0	203494	44%	N/A
0	0	0%	N/A
0 to 0.5	252937	55%	N/A

Frequency Excursion (deviation from 60 Hz)	S170		
	Number of data points in data set	Percentage Distribution	Number of total events
0.5 to 1	16	0%	14 events
1 to 1.5	6	0%	2 events
1.5 to 2	1	0%	(incl. in 1 to 1.5 events)
>2	1	0%	1 event
Total	459315		
Number of years	4.37		

6.5.2.3 Takhini Substation Frequency Analysis

The distribution of frequency deviations at Takhini Substation on S164-L172 and S164-L170 are presented in Table 6-20 and on S164-L171 and S164-52-7 are presented in Table 6-21. Since this site is all connected on a ring bus, many of the deviation events are common across the 4 data sets.

Load shedding at Takhini is based on frequency excursions below 56.5 Hz, therefore, there was only 1-2 events over the past 4 years where the BESS would have reduced load shedding. However, the BESS may have been able to respond to these frequency excursions prior to reaching these significant undervoltage and avoided the excursion.

As well, the BESS could provide frequency support, responding to the deviations between 59.5 – 56.5 Hz as well, reducing their impact on power quality that is sent to the rest of the grid.

However, frequency control will lead to higher throughput of the BESS and faster degradation of the battery's capacity. Therefore, a balance must be struck between using the BESS to reduce the impacts of frequency excursions on the grid and degradation of the BESS.

Table 6-20: Frequency Deviations at Takhini Substation – Data Set 1

Frequency Excursion (deviation from 60 Hz)	S164-L172			S164-L170		
	Number of data points in data set	Percentage Distribution	Number of total events	Number of data points in data set	Percentage Distribution	Number of total events
<-3.5	1	0%	1 event	1	0%	1 event
-3.5 to -2	5	0%	3 events	8	0%	5 events
-2 to -1.5	0	0%	0 event	15	0%	2 events
-1.5 to -1	4	0%	4 events	3	0%	3 events
-1 to -0.5	26	0%	26 events	27	0%	27 events

Frequency Excursion (deviation from 60 Hz)	S164-L172			S164-L170		
	Number of data points in data set	Percentage Distribution	Number of total events	Number of data points in data set	Percentage Distribution	Number of total events
-0.5 to 0	217812	47%	N/A	219809	48%	N/A
0	24859	5%	N/A	24686	5%	N/A
0 to 0.5	216523	47%	N/A	214438	47%	N/A
0.5 to 1	22	0%	18 events	19	0%	13 events
1 to 1.5	4	0%	1 event	4	0%	1 event
1.5 to 2	1	0%	incl. in 1 - 1.5 Hz deviation	1	0%	incl. in 1 - 1.5 Hz deviation
>2	3	0%	3 events	1	0%	1 event
Total	459260	100%		459012	100%	
Number of years	4.37			4.37		

Table 6-21: Frequency Deviations at Takhini Substation – Data Set 2

Frequency Excursion (deviation from 60 Hz)	S164-L171			S164-L62-7		
	Number of data points in data set	Percentage Distribution	Number of total events	Number of data points in data set	Percentage Distribution	Number of total events
<-3.5	2	0%	2 events	1	0%	1 event
-3.5 to -2	6	0%	4 events	7	0%	4 events
-2 to -1.5	0	0%	0 event	1	0%	1 event
-1.5 to -1	18	0%	5 events	3	0%	2 events
-1 to -0.5	31	0%	31 events	26	0%	25 events
-0.5 to 0	219800	48%	N/A	220590	48%	N/A
0	24291	5%	N/A	24372	5%	N/A
0 to 0.5	214834	47%	N/A	214249	47%	N/A
0.5 to 1	25	0%	16 events	23	0%	19 events
1 to 1.5	5	0%	1 event	5	0%	1 event
1.5 to 2	1	0%	incl. in 1 - 1.5 Hz deviation	1	0%	incl. in 1 - 1.5 Hz deviation
>2	2	0%	2 events	2	0%	2 events
Total	459015	100%		459280	100%	
Number of years	4.37			4.37		

6.5.2.4 Benefits

As shown above, the greatest reduction in frequency excursion related load shedding events can be achieved at Whitehorse substation, since the load shedding occurs at 59.5 Hz instead of 56.5 Hz. **However, there is only on average 8-18 load shedding events per year, which is relatively infrequent.**

This frequency related response is a good added benefit of the BESS; however, would not be a main secondary use case for the system.

The higher the BESS discharge power capability, the more likely it will be able to prevent load shedding events, since a greater power capacity can be output to bring the grid back within the desired operating range. The BESS will be able to cover the load at its rated power for several minutes (the exact duration will depend on state of charge and the inverter power selected; however, should be at least 30 min assuming the BESS is also being used for operating reserve) until additional generation can be brought online, thus keeping the frequency within the desired bounds.

Specifically, the 13 MW/40 MWh BESS is the same capacity as the existing LNG plant. Therefore, if the LNG plant tripped, causing a frequency deviation and generation loss, the 13 MW and 20 MW BESS would be able to completely cover its generating capacity until diesel generation can be brought online. This is a significant added benefit, particularly in the winter months when the LNG plant operates at higher loading and more frequently.

However, as intermittent renewable generation increases on the Yukon Energy Grid, frequency excursions can potentially increase as well. Therefore, having the ability of the BESS to respond to these excursions may become increasingly beneficial.

6.5.3 Important Technical Capabilities of BESS for Frequency Regulation

For this use case, the BESS will require the following technical capabilities:

- Rapid and automated response
- Ability to switch between charging and discharging frequently

6.6 Act as a Load Bank during Load Loss

In the event that the load drops or a transmission or distribution line goes down, Yukon Energy may have significantly more generation online than load to consume it, creating an imbalance on the grid. The generation also needs to be ramped down safely, which can take several seconds. Therefore, the BESS could be used as a load in these short duration scenarios to recharge and store some of the excess generation.

This reduces wasted generation and helps the grid maintain stability and balance between generation and load.

These events are relatively short duration, lasting for a maximum of several seconds; as such, their impact cannot be modeled using hourly data. As well, this is likely a relatively infrequent event, and given it only lasts several seconds, will have limited overall financial benefits for the BESS.

However, this is a potential added secondary benefit of the BESS. As well, this functionality allows the BESS to be partially or fully recharged with generation that would otherwise be wasted. This benefit is only available if the BESS is partially charged at the time of the event.

Another consideration for this usage is that if the BESS has a higher power rating (and energy capacity) it can provide more benefits in terms of generation absorption during these scenarios. The higher power capacity will allow for faster charging of the BESS and the higher energy capacity will allow for more energy to be stored (assuming the BESS is partially charged). Thus, this secondary use case could be used to justify the 8.8 MW/35 MWh BESS or the 10 MW/40 MWh BESS. If the 40 MWh BESS is selected it could be idled at partial state of charge (e.g. 75-85% which is 30-34MWh of energy), and the remaining energy capacity could be charged during a load loss event.

Adding additional inverter capacity, shifting to the 13 MW or 20 MW BESS will also add additional capabilities to absorb more excess electricity during these load loss events. To maximize the benefits, the idling state-of-charge may be lowered.

Charging at higher power ratings can lead to faster capacity fade of the battery cells. Most vendors recommend charging times between 2-4 hours (which is 20 MW and 10 MW power, respectively). Therefore, it is not likely that the 20 MW charging would have a significant impact on degradation, particularly if it only occurs for a short duration and relatively infrequently. Idling at a lower state of charge (~65-75%) would also reduce the risk of overcharging the BESS. The exact configuration would need to be optimized based on the battery chemistry selected, the vendor’s specific cell design, and the overall use case priority.

6.6.1 Important Technical Capabilities of BESS for Reactive Power Support

For this use case, the BESS will require the following technical capabilities:

- Rapid and Automated Response

- Ability to charge quickly
- Potential short term (<1 min) inverter and BESS overloading capabilities to allow a higher portion of the excess generation to be stored

6.7 Reactive Power Support

Because of the inverter connection, the BESS has the capability to provide reactive power if required. Based on discussions with Yukon Energy, they currently only have reactive power compensation of about 8 Mvar on the grid. The excess inverter capacity at any given time can be used to provide reactive power support without depleting the battery's stored energy.

The Mvar capacity is calculated as follows:

$$Mvar\ (t) = \sqrt{MVA\ (t)^2 - MW\ (t)^2}$$

Therefore, if the BESS is providing no real power, the complete power range is available for reactive power compensation. In cases were the BESS is providing real power, the remaining portion of the MVA can be used to provide reactive power compensation as required.

However, increasing the power capacity of the BESS to achieve a 4 hr system allows for increased flexibility for Yukon Energy to use the BESS for reactive power supply. Under the case of the 10 MW/40 MWh BESS, if the BESS is providing 7 MW of real power, it can provide an additional 7.14 Mvar of reactive power simultaneously (for the 35 MWh system, the 8.8 MVA BESS can provide 6.6 MW of real power and 5.82 Mvar of reactive power simultaneously). Thus, for a relatively minor increase in CAPEX, there is significant added flexibility for the BESS. Using the BESS' inverter to improve reactive power management can reduce the overall system losses. Therefore, with lower system losses, less total generation is required to meet the customer load.

By comparison, a 20 MVA BESS can provide approximately 14 MW and 14 Mvar simultaneously. This configuration is also capable of providing 8 Mvar to the grid and approximately 18 MW of real power. Therefore, the larger BESS size can add significant flexibility to the reactive power support for the grid as needed.

The BESS can be used for reactive power support to allow the hydro units to run at an improved power factor, which will increase the efficiency of the generator (i.e. more electricity generated for the same water flow rate). Having the added flexibility of the larger inverter size (13 MW or 20 MW), allows for more flexibility in the reactive power support.

6.7.1 Important Technical Capabilities of BESS for Reactive Power Support

For this use case, the BESS will require the following technical capabilities:

- Rapid and Automated Response
- Inverter that can operating +/- 1 pu leading/lagging

6.8 Secondary Use Case Ranking

Based on the analysis, using the BESS to provide supplementary operating reserve has the greatest benefit as a secondary use case. This usage allows for the offset of between 1.7-1.8 GWh of diesel generation on average, and 13-17 GWh of LNG. This use case is the only secondary use case that results in significant reductions in LNG. Though the price of LNG is low, it may increase in the future, which adds additional economic benefits.

Operating reserve provides a great benefit to Yukon Energy without resulting in significant cycling or degradation of the BESS.

Diesel peak shifting is another excellent secondary use case for the BESS. Based on business as usual, diesel generation at Whitehorse and Faro diesel plants could be reduced by 108 – 244 MWh per year if 1-4 hr peaks are shifted, and 297 MWh if 1-5 hr peaks are shifted**. As the grid load increases, the diesel peaks will likely increase as well.** Having the higher power capabilities (13 MW or 20 MW) from the BESS will lead to increased flexibility for future operation. Additionally, these sizes allow for shifting of the LNG gensets, which may be potentially useful in the summer or shoulder seasons if there is excess water flow overnight.

If the BESS is used to provide operating reserve, the potential additional diesel fuel savings may be reduced, since there are likely already fewer peaks. However, any new 1-4 hr diesel genset operating events created by the changed operating strategy could also be shifted with the BESS. Based on a preliminary assessment of the new operating regime with the BESS providing 10 MW of OR, there remains 210 MWh of diesel operation within the grid for 1-4 hr events. A portion of this will be able to be shifted using the BESS to reduce diesel fuel consumption.

Blackstart or outage restoration is another key opportunity for the BESS to support the grid. Though blackstart events are fairly rare, rapid pickup of the grid once the issue has been addressed is critical for customer satisfaction. Therefore, in the event that a total or partial grid outage does occur, the BESS may support faster grid restoration. This is particularly beneficial in the winter. When the grid is down in the winter for extended periods, there is a higher load starting up due to heating requirements. **Therefore, the BESS can provide these blackstart support services as required which can be beneficial to reduce the grid outage time. However, though the benefits are important for blackstart capabilities, partial and total grid outages are rare events; therefore, the economic benefit of this use case is less than the benefits from the operating reserve and peak shaving use cases.**

Reduction in load shedding events through frequency regulation provides modest economic benefits to the Yukon Energy grid; however, has the potential to reduce load shedding events which impact customer satisfaction. From the customer/rate payer's perspective, a reduction in the frequency and duration of outages is highly beneficial.

Reviewing the load shedding protocol, load shedding begins at 59.5 Hz. The Yukon Energy grid is relatively stable, remaining within +/- 0.5 Hz band for 99% of typical operation over the last 3-4 years. Based on the assessment, there were approximately 39 – 73 load shedding events as a result of under frequency at Whitehorse substation in the last 3-4 years, which is only on average 8-18 load shedding events per year. There were 40 events on WH4 in the last 4 years and 34 events on L151 in the last 2.9 years, 8 of these events were major underfrequency events where frequency dropped below 56.5 Hz. Several of the major underfrequency events lasted for extended periods, one lasting for several days. Therefore, using the BESS to reduce load shedding due to underfrequency events improves customer power quality and reliability and is an added advantage of the system. However, based on the frequency excursion data, these events are relatively infrequent (8-18 events per year), thus, do not provide significant economic benefit alone to justify the BESS, but will also not lead to high usage impacting battery lifespan. Thus, this is a beneficial secondary use case for the BESS.

However, as more intermittent renewable generation (wind or solar PV) is integrated into the grid, the necessity for frequency regulation is likely to increase. Having the BESS capable of performing this secondary service is likely to become increasingly beneficial in future years.

Load loss events are rare and short in duration; however, these events represent an opportunity to charge the BESS with electricity that would have otherwise been wasted and to maintain grid stability.

Significant reactive power compensation is not typically required on the Yukon Energy grid. However, since most standard inverters can provide reactive power support, this is a tertiary benefit that has minimal added cost. Additionally, providing reactive power support does not deplete the energy stored, therefore does not impact the ability of the battery to perform other services at a later period.

6.9 Battery Sizing

Based on the primary use case, 6 potential BESS sizes were identified:

- 6.6 MW/35 MWh
- 7 MW/40 MWh
- 8.8 MW/35 MWh
- 10 MW/40 MWh.
- 13 MW/40 MWh
- 20 MW/40 MWh

All 6 of these sizes result in a reduction in 4 rental diesel gensets. However, the 10 MW/40 MWh, 13 MW/40 MWh and 20 MW/40 MWh BESSs provide added flexibility in operating strategy if there is sufficient CAPEX available.

A comparison of the 35 MWh and 40 MWh BESS is presented in Table 6-22. Though the 6.6 MW/35 MWh BESS technically meets all of the requirements for the 3 primary use cases, the 8.8 MW/35 MWh or 10 MW/40 MWh BESSs provide greater flexibility. For the 13 MW and 20 MW options, the worst-case available energy is lower than the 10 MW offering; however, this assumes the battery is always storing at least 30 min of energy capacity at its rated power. However, the operating reserve contribution can be reduced (and covered by other generation) if the BESS is required for other services.

Table 6-22: Assessment of BESS Energy Breakdown

Battery Size	Usable Capacity	Installed Capacity	Operating Reserve	Peak Shaving	Remaining Capacity (worst case)
6.6 MW/35 MWh	35 MWh	42 MWh	3.3 MWh	17 MWh	14.7 MWh
8.8 MW/35 MWh	35 MWh	42 MWh	4.4 MWh	17 MWh	13.6 MWh
7 MW/40 MWh	40 MWh	48 MWh	3.5 MWh	17 MWh	19.5 MWh
10 MW/40 MWh	40 MWh	48 MWh	5 MWh	17 MWh	18 MWh
13 MW/40 MWh	40 MWh	48 MWh	6.5 MWh	17 MWh	16.5 MWh
20 MW/40 MWh	40 MWh	48 MWh	10 MWh	17 MWh	13 MWh
Comments	Assuming 20% overbuild for operation between 10-90% SOC		30 min discharge at rated power	Largest 4 hr peak	

7. Operating Strategy Outline

Based on the above analysis, the three primary use cases are:

- Support N-1 Capacity, during loss of Aishihik Hydro
- Provide Operating Reserve to the Grid
- Peak shifting to avoid operating of diesel gensets for 1-4 hrs.

Since an N-1 event is a rare event, the BESS was sized to serve this purpose; however, based on discussions with Yukon Energy it is not desirable to keep the BESS fully charged to respond to one of these rare events.

Therefore, the primary two usages will be operating reserve and diesel peak shifting.

For the BESS to provide operating reserve, it must be able to discharge at its rated power for 30 min, at all times when it is providing operating reserve. In order to ensure the BESS can provide this operating reserve, a minimum of 30 min of energy capacity should be kept stored in the BESS above its minimum state of charge.

For example, the 10 MW/40 MWh BESS would have a minimum state of charge of 4 MWh (10%). An additional minimum of 5 MWh would need to be stored in the BESS at all times to provide 10 MW of OR discharge for 30 min. The new minimum energy storage capacity becomes 9 MWh (or 22.5% state of charge), ensuring the BESS is capable of providing the OR without discharging below its minimum state of charge. Depending on the grid operation and the response time of the units that will come online to replace lost generation, Yukon Energy may elect to have more than 5 MWh reserved for OR in this case. Conversely, in periods where there is significant excess generation and no thermal generation online, Yukon Energy may elect to reduce the amount of OR supplied by the battery (and shift it back to hydro units) such that the battery can provide other services.

For the BESS to perform diesel peak shifting, the BESS must be sufficiently charged to cover the energy that would have been generated by the diesel gensets, prior to the peak event. This requires a forecasting strategy to predict when the demand will exceed the hydro and LNG generation potential for a few hours and planning to ensure the BESS is sufficiently charged to perform this service. Based on the analysis, the maximum diesel generation in 4 hr was approximately 17 MWh, roughly 45-50% of the energy capacity of the BESS. The average energy generated in 1-4 hr peaks at Faro and Whitehorse diesel is 4.2 MWh, which is 10-12% of the BESS's energy capacity. After this energy is supplied by the BESS, it must be recharged in the coming hours with other generation sources. For Yukon Energy to effectively integrate the BESS as a diesel peak shifting tool, it must be incorporated into their order of merit (generator loading order), for both discharging and charging. Additionally, the minimum state of charge (as outlined above 10% + energy for OR) should be considered when dispatching the BESS to shift a diesel peak.

Another consideration is the desire to use the BESS for blackstart or outage restoration. A minimum energy capacity to support blackstart is also required and should be treated similar to the OR assessment. Based on the energy required to perform the blackstart process, for the most part, this energy should be continually stored in the BESS, if this is reasonably possible. Again, Yukon Energy may choose to vary the amount of energy required for blackstart throughout the year, since blackstart during the winter requires more load to be picked up compared to the summer. The energy requirements for the blackstart process will be evaluated in the Power System model study to assess the ability of the BESS to perform blackstart.

7.1 Controls Considerations

Currently, Yukon Energy operates with a blended manual and automated dispatch control system.

For the BESS to be effectively respond to frequency excursions, generation loss, over loading, excess generation, and reactive power compensation, it is typical to have an automated control system for dispatch.

Manual dispatch for peak shifting is possible as these operations are based on forecasted demand. Yukon Energy uses the ambient and forecasted temperature as a good indicator of their peak afternoon demand. Similarly, blackstart events are based on a manual command to restart the grid. This function can be initiated manually and then enter the load pickup protocol as done previously with the diesel gensets.

The benefit to Yukon Energy of having an automated control scheme with a manual override is they can adjust their dispatch based on the daily conditions. If the daily peak is high or the grid is unstable, Yukon Energy may elect to maintain a higher energy storage level and avoid diesel peak shaving or frequency excursion response, to keep the BESS fully charged for reserve applications. Similarly, on the coldest winter days, Yukon Energy may elect not to use the BESS for secondary applications (other than operating reserve), to keep it fully charged in case there is an N-1 event that cannot be covered without the BESS.

As Yukon Energy moves forward with the development of this project, the operating strategy for the BESS will need to be developed for both routine operation and extreme/rare scenarios.

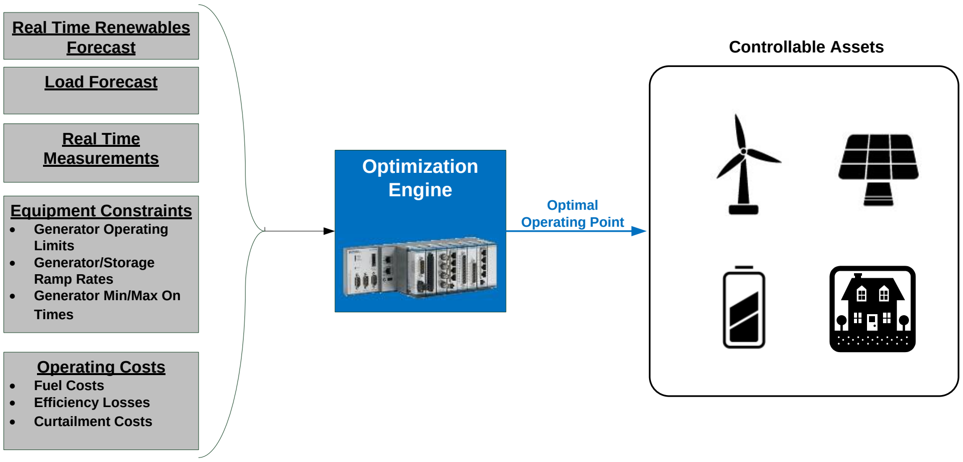


Figure 7-1: Schematic of Optimal Dispatch and Battery Operation

8. Battery Chemistry and Lifespan Assessment

8.1 Battery Annual Throughput and Lifespan

An estimation of the annual throughput of the BESS is presented in Table 8-1 for a typical year and Table 8-2 as a worst case scenario for the 8.8 MW/35 MWh, 10 MW/ 40 MWh, 13 MW/40 MWh, and 20 MW/40 MWh BESS.

Under the assumptions for a typical year, the BESS is estimated to perform approximately 0.21-0.22 cycles/day. Over a 20-year lifespan, this results in 1500-1600 cycles. Even with these very aggressive assumptions in the worst-case scenario, the estimated throughput is 0.35-0.40 cycles per day. Over a 20-year lifespan, the BESS would perform 2,600 to 2,900 cycles based on the assumptions below. These are both well below the typical rated cycle life for lithium ion batteries of 4,000 – 4,500 cycles. Thus based on the proposed duty cycle, there is not significant risk of accelerated battery degradation.

Table 8-1: Estimated Annual Throughput for the BESS, Typical Year

Battery Usage	Comments	Estimated Annual Throughput (8.8 MW/35 MWh BESS)	Estimated Annual Throughput (10 MW/40 MWh BESS)	Estimated Annual Throughput (13 MW/40 MWh BESS)	Estimated Annual Throughput (20 MW/40 MWh BESS)
N-1 Events	One (1) 2 week event every 10 years (490-560 MWh throughput per event, divided over 10 years)	49 MWh	56 MWh	56 MWh	56 MWh
Operating Reserve	One (1) events per month	53 MWh	60 MWh	90 MWh	120 MWh
Peak Shifting	Shift all 1-4 hr Whitehorse & Faro Diesel Peaks	244 MWh	244 MWh	244 MWh	244 MWh
Blackstart/ Outage Restoration	Fifty-three (53) events per year[2]	1,855 MWh	2,120 MWh	2,120 MWh	2,120 MWh
Reduction in Load Shedding & Renewable Integration	100 cycles per year, 15% depth of discharge	525 MWh	600 MWh	600 MWh	600 MWh

[2] Average outages for 2014 – 2018 based on annual reports
https://yukonenergy.ca/media/site_documents/2017_Annual_Report_Final_web_version.pdf
https://yukonenergy.ca/media/site_documents/2018_Annual_Report.pdf

Total Annual Throughput		**2,726 MWh**	**3,080 MWh**	**3,110 MWh**	**3,140 MWh**
Number of Cycles	Total Throughput/ Usable Capacity	78 cycles	77 cycles	78 cycles	79 cycles
Cycles per day	Cycles/365 days	0.21 cycles/day	0.21 cycles/day	0.21 cycles/day	0.22 cycles/day
Estimated Cycles in 10 years		779 cycles	770 cycles	778 cycles	785 cycles
Estimated Cycles in 20 years		1558 cycles	1540 cycles	1555 cycles	1570 cycles

Table 8-2: Estimated Annual Throughput for the BESS, Worst Case Scenario

Battery Usage	Comments	Estimated Annual Throughput (8.8 MW/35 MWh BESS)	Estimated Annual Throughput (10 MW/40 MWh BESS)	Estimated Annual Throughput (13 MW/40 MWh BESS)	Estimated Annual Throughput (20 MW/40 MWh BESS)
N-1 Events	One (1) 2 week event every 5 years (490-560 MWh throughput per event, divided over 5 years to get annual average)	98 MWh	112 MWh	112 MWh	112 MWh
Operating Reserve	Two (2) events per week	458 MWh	520 MWh	780 MWh	1,040 MWh
Peak Shifting	Shift all 1-4 hr Whitehorse & Faro Diesel Peaks	244 MWh	244 MWh	244 MWh	244 MWh
Blackstart/ Outage Restoration	Seventy-nine (79) events per year[3]	2,765 MWh	3,160 MWh	3,160 MWh	3,160 MWh
Reduction in Load Shedding & Renewable Integration	200 cycles per year, 15% depth of discharge	1,050 MWh	1,200 MWh	1,200 MWh	1,200 MWh
Total Annual Throughput		**4,615 MWh**	**5,236 MWh**	**5,496 MWh**	**5,756 MWh**

[3] Estimated from 2019 Annual Report – with 79 outages per year
https://yukonenergy.ca/media/site_documents/Yukon_Energy_2019_Annual_Report_web.pdf

Number of Cycles	Total Throughput/ Usable Capacity	132 cycles	131 cycles	137 cycles	144 cycles
Cycles per day	Cycles/365 days	0.36 cycles/day	0.36 cycles/day	0.38 cycles/day	0.39 cycles/day
Estimated Cycles in 10 years		1318 cycles	1309 cycles	1374 cycles	1439 cycles
Estimated Cycles in 20 years		2637 cycles	2618 cycles	2748 cycles	2878 cycles

Typically, 4,000 – 4,500 cycles lead to a 20% capacity fade. Based on the typical year duty cycle, the cycle related capacity fade will be 7-8% over 20 years. Based on the worst-case year duty cycle, the cycle related capacity fade will be 13-15% over 20 years. An additional allocation for calendar aging due to idling should also be included. **Based on this estimate, it is reasonable that the BESS will have a lifespan of 20 years with a modest overbuilt or capacity augmentation at year 10.**

For the 20 MW/40 MWh BESS, since the battery will be generally operating at a higher current on average, there is the potential that the degradation may be slightly faster than the lower power offerings. However, the 20 MW/40 MWh BESS is capped at 0.5 C, which is well within the typical capabilities of most lithium ion battery offerings.

In the next phase of the project, it will be imperative to work with the vendors based on the estimated duty cycle and calendar aging to select the appropriate capacity overbuild.

8.2 Battery Chemistry

The preferred battery chemistry for this project is lithium ion. Because of the low throughput of the proposed use cases, as well as the need to have low auxiliary power consumption and high round trip efficiency, lithium ion chemistry is preferred to flow batteries.

As such, the preferred option is lithium ion technology.

As outlined in Section 4.1, there are 3 common lithium ion chemistries:

- Lithium Nickel Manganese Cobalt (NMC)
- Lithium Nickel Aluminum Cobalt (NCA)
- Lithium Iron phosphate (LFP).

Each of the chemistries has its own benefits. The most common chemistry is the NMC chemistry, which will be provided by many integrators. The LFP chemistry is becoming increasingly common since it is lower cost, and inherently safer. However, the energy density is lower, thus for the same capacity, the footprint will be larger. The NCA chemistry is a more niche offering, typically geared towards higher power applications and typically has a higher cost.

Since the footprint is not significantly limited at this site, as an initial recommendation LFP would be the preferred chemistry since it is safer, tends to be low cost, and tends to have greater availability.

However, Yukon Energy should allow all vendors and all LIB chemistries to bid during the RFP, as long as they meet the performance requirements. This will ensure that Yukon Energy can select the solution based both on technical compliance and cost, as well as ensure there are sufficient bidders to have a competitive RFP.

9. Location Assessment

There are 3 proposed sites for the BESS, all on First Nation Settlement Land. One site is on Ta'an Kwach'an Council (TKC) land and two are on Kwanlin Dun First Nation (KDFN) land. The sites are:

- TKC C-28B Property near Whitehorse Substation accessed off Robert Service Way
- KDFN C-34B Property near Whitehorse Substation at the intersection of the Alaska Highway and Robert Service Way, accessed off Robert Service Way
- KDFN C-135B Property near Takhini Substation accessed off the Klondike Highway

9.1 Documents review

As part of the analysis to define de characteristics of each of the proposed sites, the following documents have been reviewed:

- Geotechnical report - TetraTech - YEC Thermal sites preliminary geotechnical evaluation – Whitehorse Yukon. March 2019 – Issued For Use
- Geotechnical Report - TetraTech – Geotechnical Evaluation – Liquid Natural Gas Power Generating Plant – EBA File W14103287-01, October 28, 2013 – Issued For Use.
- LNG and Natural Gas Power Generation Infrastructure Siting Study, Morrison Hershfield Project #512403300.02

The information presented below is been extracted from these reports and complemented for other public sources such as http://mapservices.gov.yk.ca/GeoYukon/ http://mapservices.gov.yk.ca/GeoYukon/

9.2 Geotechnical Review

9.2.1 TKC C-28B Property – Whitehorse Substation

No specific geotechnical information has been obtained for the site. Geotechnical information available for the LNG Power plant has been extrapolated to this site for proximity.

It is anticipated that the site will present in general the following characteristics:

- Subsurface soil conditions consisting of 5 to 8 m of gravel and sand overlying a layer of up to 4 m of sand underlain by bedrock
- Ground water is expected to be present on site due to its proximity with the Schwatka Lake
- Experience shows that bedrock is variant in the area from depths ranging from 8 to 15 m.
- Loose fine-grained sands with varying quantities of silt were encountered at depths of 4.5 m to 8.0 m bgs throughout the area and are considered potentially liquefiable.

Given the potential for soil liquefaction and the fact there has not been any specific geotechnical information at the site, it is anticipated that piling will be the preferred foundation method. However, an analysis of the weights and dimensions of the foundation shall be carried out to confirm the pressures induced to the ground. Given the type of infrastructure a layer of gravel might be able to offset the bearing pressures into the susceptible layers.

9.2.2 KDFN C-34B Property at the intersection of the Alaska Highway and Robert Service Way

No specific geotechnical information has been obtained for the site. Geotechnical information is assumed to be similar to the information presented for the TKC C-28B Property with the particularity that the site is located 50 m above. This site is divided in two proposed sites, one located in the greenfield area with vegetation and without access to it. And a second one proposed parallel to the Klondike Highway which is located in an old site that served as asphalt plant in the past.

Therefore, the second proposed site has an important constraint of contaminated soil to be evaluated.

9.2.3 KDFN C-135B Property near Takhini Substation accessed off the Klondike Highway

YEC's existing Takhini Substation, presents the following geotechnical conditions:

- Soil conditions at the site are expected to consist of eolian deposits of medium to fine sand and coarse silt that is well-sorted and noncompacted. The native soil at this site is likely frost susceptible and may also be susceptible to seismic liquefaction. Soft, fine-grained glaciolacustrine deposits may also be susceptible to long-term consolidation settlement.
- Ground water is anticipated at this location; however, the depth is unknown.
- Permafrost is not anticipated.
- Bedrock and till are identified on surficial geology maps to the west of the proposed area and may be encountered at depth. Depth to bedrock is likely shallowest in the western part of the site, and deepest to the east, however the actual depth to bedrock is unknown.
- Foundations types can vary greatly depending on the thickness of loose soils, from shallow strip footings to deep foundations.

9.2.4 Hatch Recommendation:

Given the lack of geotechnical information in the proposed sites, except for Takhini substation, Hatch recommends carrying out a geotechnical investigation program to understand the soil conditions and better define civil and foundation work for the proposed development. This campaign will ideally be carried out in the proposed permitted location, however in the absence of decision it will need to be carried out in the tree sites – if this is the case a preliminary campaign could be set up to understand any potential constraints that could impact the decision of the site location.

9.3 Proposed Layouts and Site-Specific Considerations

9.3.1 TKC C-28B Property – Whitehorse Substation

The TKC land near Whitehorse Substation and the proposed site layout is presented in Figure 9-1. The BESS would be connected to Whitehorse Substation using either an existing 34.5 kV switch or a new 34.5 kV switch (depending on if the LNG connection is moved). The site is accessible off the Robert Service Highway, with an existing access road into the adjacent recreation/snow storage area. As well, the land area is sufficiently large to accommodate the proposed BESS (as shown below).

The TKC land is approximately 127,700 m^2, while the battery footprint is 3,500 m^2 plus some surrounding area for the roadway and fencing. Therefore, the proposed battery would use less than 4% of the total site land area, plus some additional area for the access roadway. There is currently no concern about expandability for this site from an area perspective. Other factors, such as landlord interest, may limited the ability to expand the battery size in the future.

Figure 9-1:TKC Site Layout Outline

Other characteristics of the site present the following:

- Site is in a depression with a vertical difference elevation of 60 m with respect to the airport.
- Its proximity with the airport shall not present any problems given the difference in vertical elevation when it comes to visual obstacles. However, the materials used for the roofing of the proposed installations will need to be validated to be non-reflecting.
- The interference with the airport lake will also need to be validated.
- The interference with the airport for any electrical installation will need to be validated with the airport authority.

9.3.2 KDFN C-34B Property – Whitehorse Substation

There are two proposed layouts for the KDFN land near Whitehorse substation, shown in Figure 9-2 and Figure 9-3. Again, the BESS would be connected at Whitehorse substation at 34.5 kV. Again, the land area is more than sufficient to accommodate the BESS.

Option 1, in Figure 9-2, has the battery bank located near Robert Service Way, behind a large forested area. The advantages of this approximate location for the BESS are a shorter road length and the BESS is hidden behind a forested area, thus not visible from the highway. However, this area has greater sloping, thus would require additional site preparation and grading.

The KDFN land is approximately 107,300 m^2, while the battery footprint is 3,500 m^2 plus some surrounding area for the roadway and fencing. Therefore, the proposed battery would use less than 5% of the total site land area, plus some additional area for the access roadway. There is no concern about expandability for this site from an area perspective. Expanding the battery would require additional site clearing and potentially grading. Other factors, such as landlord interest, may limited the ability to expand the battery size in the future.

Figure 9-2: KDFN Land Site near Whitehorse Substation – Option1

Option 2, in Figure 9-3, has the battery bank located near the Alaska Highway, on existing cleared land. The advantages of this approximate location for the BESS are the land is cleared and it is known to be flatter in this area, reducing the site preparation and grading costs. However, the length of the roadway to access this site from Robert Service Way is approximately double Option 1. As well, this location is likely to be visible from the highway, making it more challenging for consultation or requiring that trees are planted to block the view. As well, locating the BESS here places it closer to the residential community on the other side of the Alaska Highway.

Figure 9-3: KDFN Land Site near Whitehorse Substation – Option 2.

The transmission line lengths are similar for both options.

Other characteristics of the site present the following:

- The site as an old Asphalt plant and there is potential for encountering contaminated soils.
- Site drainage is not favorable as it is located in a low area – 15 to 20 m below the highway alignment.
- Its proximity with the airport shall not present any problems given the difference in vertical elevation when it comes to visual obstacles. However, the materials used for the roofing of the proposed installations will need to be validated to be non-reflecting.

- The interference with the airport for any electrical installation will need to be validated with the airport authority.

9.3.3 KDFN C-135B Property - Takhini Substation

The third option is to locate the BESS on KDFN Land adjacent to Takhini Substation, as shown in Figure 9-4. There is a spare 34.5 kV connection point into the Takhini Substation which could be used to connect the BESS.

However, there are several challenges with this KDFN property. As shown in Figure 9-4, the land area is about one quarter of the area required for the BESS, leaving less potential area around the battery bank, as well as reducing the flexibility in the installation configuration or exact location of the battery containers. As well, based on the site visit, the land has several existing abandoned structures, vehicles, and storage barrels. These must be cleared from the land first, as well, the soil should be tested for contamination as the contents of the storage barrels is unknown. The site is also not level, thus requires grading. Finally, there is a residential property directly adjacent to the KDFN land.

The KDFN land near Takhini is approximately 18,300 m^2. The footprint of the batteries is approximately 3,500 m^2 plus additional area for a roadway surrounding the perimeter. This is approximately 25% of the total land area. Therefore, there is space to put an additional 2-3 additional 20 MW/40 MWh battery blocks. The exact configuration would need to be optimized to determine the exact sizing; however, there is some flexibility. Additionally, consideration would need to be given to the layout and location of the inverter to minimize the noise levels and their impact on nearby residents. However, the land is generally not level and would require grading for expansion of the battery size in the future. Additionally, landlord usage of the remainder of the property may also limit expansion prospects.

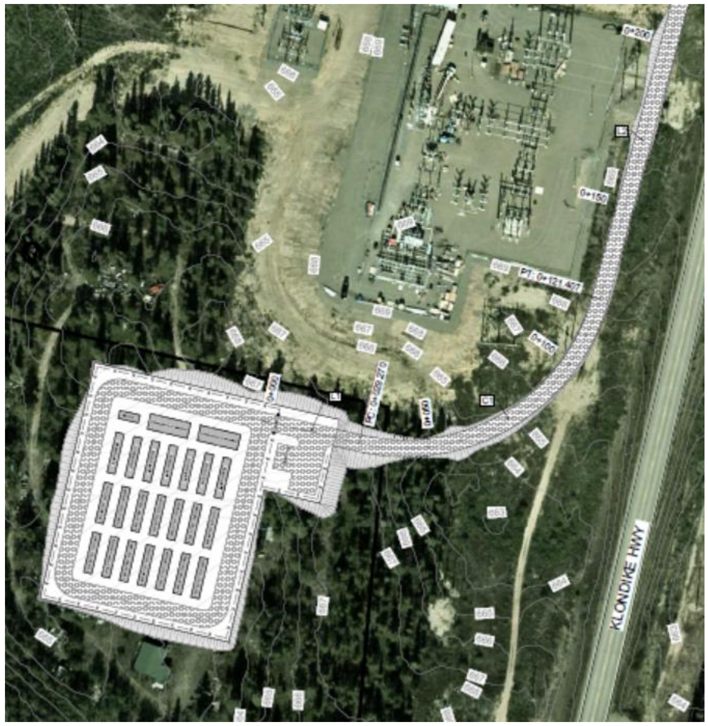


Figure 9-4: KDFN Site Near Takhini.

9.4 Preliminary Interconnection Plan

The following section outlines the proposed interconnection plan for each site.

9.4.1 TKC C-28B Property – Whitehorse Substation

If the BESS is located at this site, it will be connected to the Whitehorse Substation. As shown in Figure 9-1, the transmission connection line would run parallel to the existing ATCO 34.5 kV line, following the path to the 34.5 kV bus at the Whitehorse Substation.

The connection would be at 34.5 kV. Currently, it is proposed the BESS would replace the existing LNG connection on switch S150-52-13. It is planned to have the LNG connection re-routed to Riverside Substation to avoid having Whitehorse Substation become an N-1 Reliability Risk. This risk needs to be assessed to ensure the BESS does not create an N-1 reliability risk.

If this site is selected, a study would need to be conducted to determine the optimal strategy to connect the transmission line to determine the most cost-effective strategy: either build double circuit poles with the existing ATCO line or build another set of poles with a single circuit (if there is enough area in the easement).

Another consideration is the transmission line needs to cross the recreational area/snow storage area adjacent to the site – therefore, would likely require taller poles to avoid damage to the line.

9.4.2 KDFN C-34B Property – Whitehorse Substation

If the BESS is located at this site, it will be connected to the Whitehorse Substation. As shown in Figure 9-2 and Figure 9-3, the transmission connection line would need to follow existing easements through the forested crown land until it can meet the existing ATCO 34.5 kV line. After the transmission line meets the ATCO line, it would follow the path of this line to the 34.5 kV bus at the Whitehorse Substation.

The connection would be at 34.5 kV. Currently, it is proposed the BESS would replace the existing LNG connection on switch S150-52-13. It is planned to have the LNG connection re-routed to Riverside Substation to avoid having Whitehorse Substation become and N-1 Reliability Risk. This risk needs to be assessed to ensure the BESS does not create an N-1 reliability risk.

If this site is selected, a study would need to be conducted to determine the optimal strategy to connect the transmission line to determine the most cost-effective strategy: either build double circuit poles with the existing ATCO line or build another set of poles with a single circuit (if there is enough area in the easement).

As well, the exact routing of the transmission lines on crown land would need to be reviewed to ensure the easements are accessible and there is sufficient clearance for a 34.5 kV connection.

9.4.3 KDFN C-135B Property - Takhini Substation

If the BESS is located at this site, it will be connected to the Takhini Substation. As shown in Figure 9-4, the transmission connection line would run from the KDFN land down into the valley and back into the Takhini Substation.

The proposed connection point is currently the available 34.5 kV line, which was built for future connection. If this connection is available and approved for use, the BESS would connect to switch S164-52-8.

Since there is no other generation at Takhini, there is no risk of this substation becoming an N-1 Reliability Risk.

If this site is selected, the exact configuration of the connection would need to be assessed, because currently the connection point shares a 34.5 kV transmission line that serves ATCO. When the BESS is discharging, there would be reversed power flow along this line, which must be considered. The impact of this reversed power flow on the S164-T1 transformer must also be considered.

9.5 Summary

Table 9-1 compares the different site options across a variety of metrics.

Table 9-1: Comparison of Three Potential Sites for the BESS Installation

Parameter	TKC Land -Whitehorse	KDFN Land – Whitehorse		KDFN Land - Takhini
		Option 1	Option 2	
Connection Point	Whitehorse Substation	Whitehorse Substation		Takhini Substation
Ability to perform proposed use cases	No concern to perform all use cases, as the BESS would connect near the existing diesel gensets and LNG gensets which are used for these applications now	No concern to perform all use cases, as the BESS would connect near the existing diesel gensets and LNG gensets which are used for these applications now		BESS can perform primary use case and top two secondary use cases (operating reserve and diesel peak shifting) without major concern. There will be some minor electrical losses for the peak shifting. Load flow study for blackstart from Takhini included in Appendix H.
Maintenance and Yukon Energy Access	Site is easily accessible by Yukon Energy operations & maintenance team and Yukon Energy Staff as required	Site is easily accessible by Yukon Energy operations & maintenance team and Yukon Energy Staff as required		Site is about 20-30 min drive from Yukon Energy Headquarters in Whitehorse Takhini is unmanned site, therefore any unplanned events that require site presence would take longer to access
Electrical Interconnection				
Connection Voltage	34.5 kV	34.5 kV		34.5 kV To be confirmed this connection can be used
Transmission Line Length	1.2 km	1.7 km	1.7 km	70-150 m
Comments on Transmission Line Routing	Crosses recreational area – need taller poles Crosses Robert Service Way	Routes through forested crown land Crosses Robert Service Way		Routes down a sloped area into a valley between KDFN land and Takhini Substation fence line No roadway crossing

Parameter	TKC Land -Whitehorse	KDFN Land – Whitehorse		KDFN Land - Takhini
		Option 1	Option 2	
Transmission Connection Cost Estimate	Medium Long transmission line	Highest Longest Transmission line		Lowest, but higher risk in terms of connection point and cost Short transmission line, but need to confirm usage of 34.5 kV connection If the 34.5 kV connection cannot be used, connection at 138 kV would be costly
Site Preparation				
Land Area Available	More than sufficient land area available. Flexibility in installation layout and location of BESS containers	More than sufficient land area available. Flexibility in installation layout and location of BESS containers		Just enough land area available, limited flexibility in container layout and site configuration
Site Preparation Considerations	Land is generally flat and there is a cleared area that is likely large enough to accommodate the BESS containers. Land is hidden from highway by forested area	Land is not level and requires site clearing Site is hidden from highway	Land is level and clear, but visible from highway – likely requires re-forestation	Site is not flat, requires grading There are abandoned structures, vehicles and storage barrels that must be cleaned up Land must be tested for contamination
Access Road	Existing access road at an intersection with lights, across from entrance to Yukon Energy Can use existing access road. Widening and strengthening of small access road to site required	There is an intersection with lights near the site, that can be used to build the access road. Access road must be built through forested area.	Requires a longer access road – currently routed through the KDFN land, but could be routed around if necessary	There is an existing access road with an intersection; however, there are no lights. Widening, leveling and strengthening of small access road to site required. Access is more challenging due to smaller available land area offering less flexibility
Access Road Length	175 m	270 m	525 m	355 m
Expandability of BESS	Currently no identified limited for expandability	Currently no identified limited for expandability; however,	Currently no identified limited for expandability; however,	While there is additional area available, there is less land available as part of this property. However, the site may not be

Parameter	TKC Land -Whitehorse	KDFN Land – Whitehorse		KDFN Land - Takhini
		Option 1	Option 2	
		additional clearing and grading will be required	additional grading or decontamination may be required	able to accommodate a significant expansion (>2-3 times the energy)
Other Site Considerations	Site is a previous flood plain (not flooded in many years) and the ground becomes saturated with water during the spring as a result of snowmelt	Land is on the escarpment, so has relatively low flooding risk	Risk of Contamination of soil due to previous usage	Site is quite far from Yukon Energy Headquarters, less accessible for routine inspections
Site Preparation Costs	Lowest	Highest	Medium	Medium
Commercial Considerations				
Lease and Property Tax cost	City Taxes	City Taxes		Outside City Limits
Certainty to Development	Cultural significance of site to TKC First Nation and the land needs to be rezoned for utility usage	Zoning is correct, KDFN nation has historically engaged in lease agreements with Yukon Energy/ Yukon Government		Zoning is correct, KDFN nation has historically engaged in lease agreements with Yukon Energy/ Yukon Government
Operating Costs	Low	Low		Higher due to more remote location from Yukon Energy Headquarters
Benefits to First Nation				
Site Lease	Yes	Yes		Yes
Investment Opportunity	Potential	Ensured		Ensured
Contracting Opportunities	Medium	Medium		Medium
Social Risk				
Nearest Neighbors	Yukon River Tours 200 m from property line	Skookum Asphalt	Skookum Asphalt	Residence Adjacent to property line

Parameter	TKC Land -Whitehorse	KDFN Land – Whitehorse		KDFN Land - Takhini
		Option 1	Option 2	
	380 m from proposed location	120 m from property line 215 m from Option 1 location Residential community 150 m from property line 365 m from option 1 location	120 m from property line 420 m from Option 2 location Residential community 150 m from property line 220 m from option 2 location	30-50 m from proposed location
Noise	<30 dB, no controls required	<40 dB no controls required		>50 dB controls required
Other Social Risk	Site is fairly accessible, requires higher security Adjacent land is used for recreation – could lead to higher trespassing/undesired access to site	Site is fairly accessible, requires higher security		Site is more remote, less likely to be accessed by the public

10. Preliminary Layout

For this scale of BESS there are two potential layout options:

- Modular Containerized Installation,
- Building Installation.
- The benefits and challenges of these two options are presented below.

10.1 Modular Containerized Installation

Most battery vendors offer their system in a containerized offering, typically with standard 40 ft or 20 ft shipping containers. A sample layout of a containerized system with a usable capacity of 10 MW/40 MWh, using 40 ft containers and 20 ft inverter containers, is presented in Figure 10-1. It is recommended that lithium ion batteries are operated between 10% and 90% state-of-charge (or capacity); therefore, 20% of the installed capacity of the battery cannot be accessed to avoid degradation. Therefore, the installed capacity is 10 MW/48 MWh (2 extra containers). Additional overbuild may be necessary to accommodate degradation; however, has not been included at this stage, since the annual throughput of the system is relatively low.

Some vendors also offer their installations in 20 ft containers, which would result in double the number, slightly increasing the footprint by 20 ft in length (two additional 10 ft clearances).

The configuration below is preliminary and can be adjusted as required to work with the site topography and layout.

The estimated footprint for the containerized solution is 46 m x 62 m. Additional space within the fence line may be desired for 1-2 cars parking area, and additional clearance for ease of access. A land area of 50 x 70 m was used in the overall site layouts (in Section 9.3) to provide extra space if required.

The typical height of these containers is 9-10 ft (about 2.75 – 3.05 m), which is a flat roof. The structural suitability of these containers for the typical snow loading in Yukon should be reviewed. If necessary, slopped coverings could be integrated to reduce snow accumulation on the tops. As well, depending on the foundation design, containers may be raised a few feet off the ground, to prevent heating of the soil (typically for permafrost conditions).

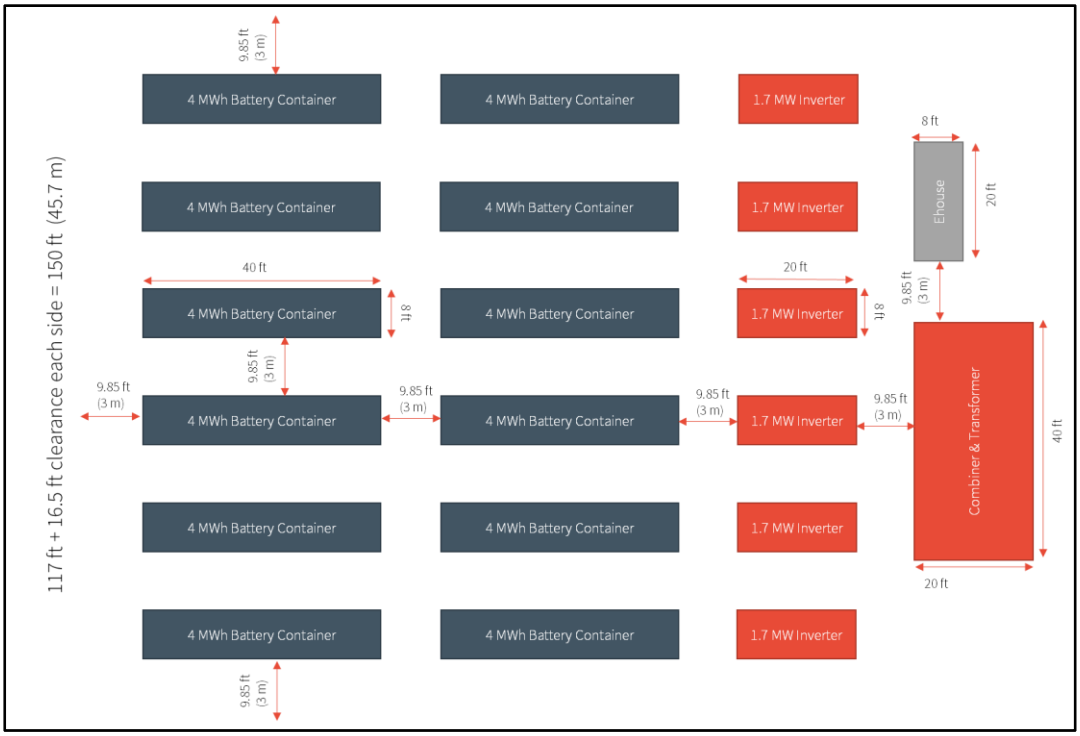


Figure 10-1: Preliminary layout for a 10 MW/40 MWh containerized BESS with 20% overbuild (total capacity 10 MW/48 MWh).

The advantages of the containerized system are:

- Containers are supplied as pre-integrated modules.
  - Batteries within the container can be integrated at the vendor’s factory, reducing the on-site installation and commissioning time. Initial coordination challenges can be identified in FAT testing.
  - Similarly, coordination between the battery management system, inverter and transformer can be done during FAT testing, reducing on-site commissioning and testing time, as well as return trips.
- Thermal management system (typically HVAC system) and fire detection and suppression systems have been pre-engineered by the vendors.
- The BESS can be expanded in the future to have a larger capacity if sufficient transformer capacity is available (transformer can be upgraded, or a second transformer can be added).

The disadvantages of the containerized system are:

- Many containers are co-located on site
- Each container has its own thermal management system, therefore, the overall auxiliary demands (heating) will likely be higher than a building system
- In the winter, maintenance workers won't have the same level of shelter
- It is less likely to be an on-site workstation, unless it is located in the eHouse
- Limits vendors to those with a cold weather package or those willing to design a cold weather package for this project. However, given the size, it is likely vendors will be willing to design a heating system for their containers for this project

Figure 10-2: Image of Containerized battery, based on Saft 20 ft standard LiB offering

10.1.1 Higher Power BESS Layouts

For the 13 MW and 20 MW batteries, larger inverter containers are required due to the higher power. These batteries required 40 ft standard inverter containers. The layouts are shown in Figure 10-3 and Figure 10-4 for the 13 MW/40 MWh and 20 MW/40 MWh options, respectively.

For the 20 MW/40 MWh option, the design below has 3.4 MW of inverter capacity per 40 ft container. Currently, vendors are offering 3.5 MW of inverter capacity in a 40 ft container; however, depending on the inverter vendor, one additional container may be required. Additionally, for this option space for a second transformer has been included. Once the interconnection point is selected, the electrical design will need to be completed. Consideration must be given to the amount of redundancy required for this operation (e.g. 2 x 10 MW transformer, 1 x 20 MW transformer, or 2 x 20 MW transformer for more reliability).

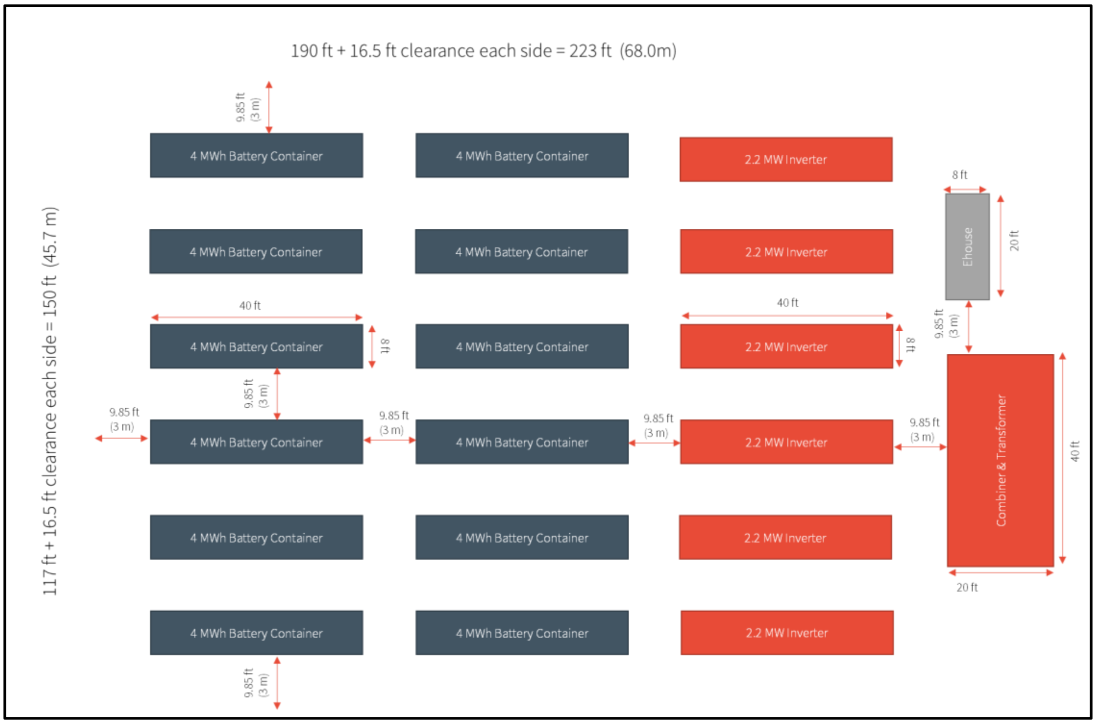


Figure 10-3: Preliminary layout for a 13 MW/40 MWh containerized BESS with 20% overbuild (total capacity 13 MW/48 MWh).

Figure 10-4: Preliminary layout for a 20 MW/40 MWh containerized BESS with 20% overbuild (total capacity 20 MW/48 MWh). In this layout, an allocation for either 2 transformers has been included. Depending on the design and desired redundancy, a single 20 MW transformer may be used.

10.2 Building Installation

Another option for this scale of system is to install a building, with battery modules and racks inside the building.

A sample layout of a building setup, based on Tesla Powerpacks, with a usable capacity of 10 MW/40 MWh, is presented in Figure 10-5. As above, 20% overbuild has been included to allow for the appropriate operating state-of-charge range; therefore, the installed capacity is 10 MW/48 MWh. Additional overbuild may be necessary to accommodate degradation; however, has not been included at this stage, since the annual throughput of the system is relatively low.

The building footprint is a minimum 33.3 m x 56.7 m. An allocation of 20 ft of clearance in all directions has been included; this clearance needs to be confirmed once the HVAC system has been designed. Again, the configuration of the packs can be varied slightly to accommodate different aspect ratios for the building.

Outside the building, additional clearance requirements will be necessary, which align with typical Yukon Building codes.

The building will need to have a ceiling that is 12.2 ft (3.7 m) (7.2 ft for the powerpack plus 5 ft of overhead clearance), plus additional 2.5-4 ft allocation for roof sloping. The building is expected to be 14.5 to 16.5 ft in height, depending on the roof sloping. If a roof with a slope greater than 4-7%, then the building will be taller.

If the building option is selected, an assessment of the roof slope required to accommodate snow loading should be completed. If a single building is too large for the snow loading to be reasonably accommodated, then a multiple building option could be explored. This is a design consideration, which could be assessed during the next phase; the optimization of the building design and system components within each building would be done at this stage as well.

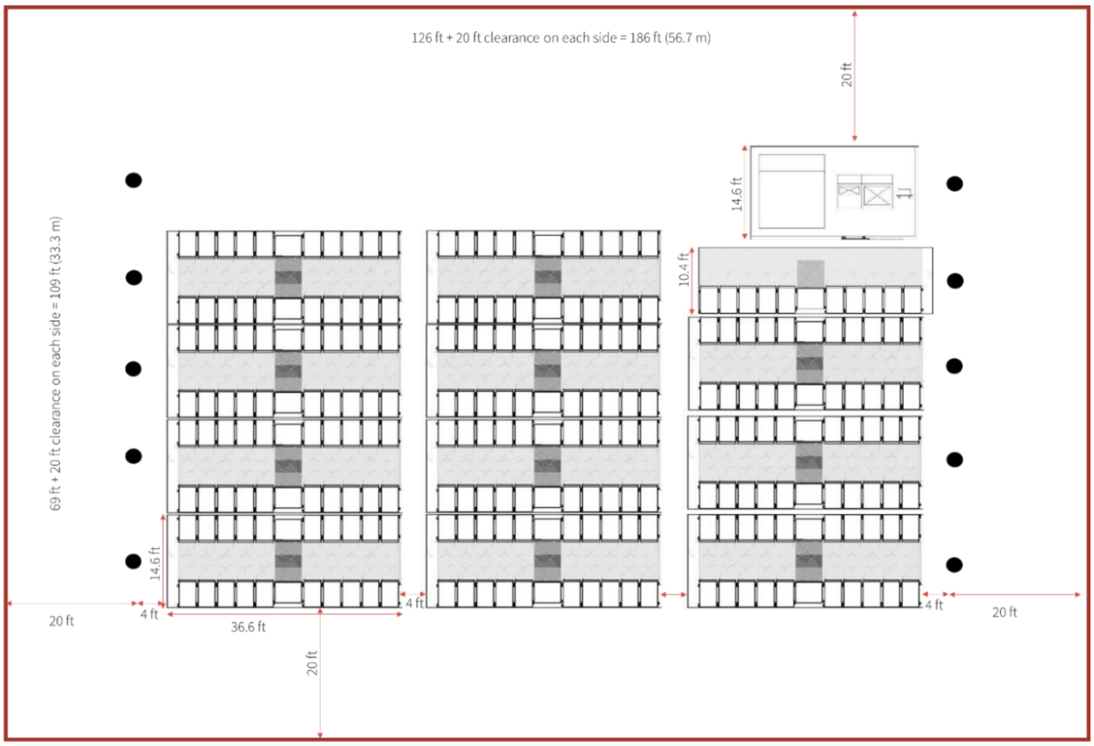


Figure 10-5 Preliminary layout for a 10 MW/40 MWh BESS with 20% overbuild (total capacity 10 MW/48 MWh) installed in a building. Each battery pack has a capacity of 210 kWh and the inverter has a capacity of 500 kW.

The advantages of the building installation are:

- Allows more vendors to participate since heating system is designed separately

- Vendors without a cold weather package can bid
- Building will be designed with appropriate sloping for snow loading
- Workers can perform maintenance within the sheltered building
- Thermal management is more efficient since it is a single structure
- There will be a workstation on-site
- The disadvantages of the building installation are:
- Building design, HVAC (heating/cooling) system design, and fire suppression system design all must be done by a 3rd party. This leads to higher engineering costs. Overall project cost may also be higher due to cost of the building.
- Building size limits expandability of project in future
- Longer onsite construction since building needs to be erected before batteries can be installed
- Batteries, inverters and transformers need to be integrated on-site, increasing commissioning time and risk of complications
- Integrated FAT testing is not possible at vendor site, thus increasing the risk of communication, synchronization, and timing challenges that arise during commissioning or after the vendor has left
- The building will be taller, thus more visible to residents.

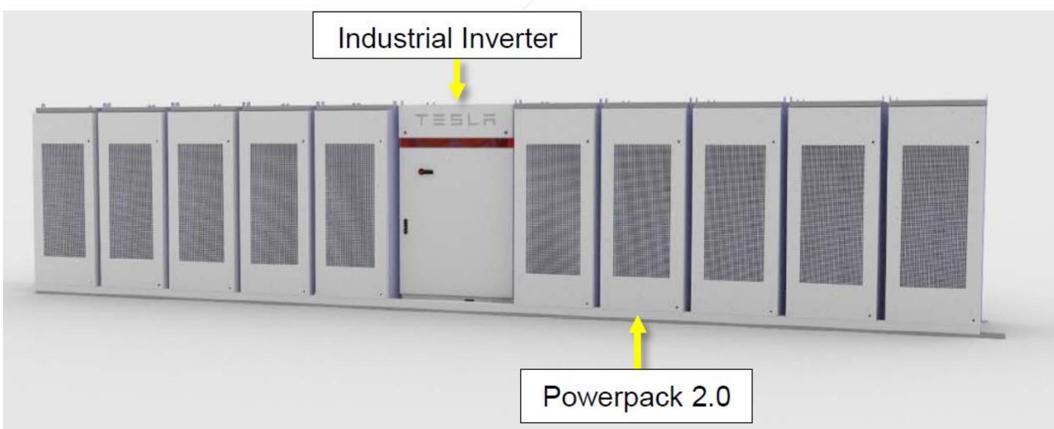


Figure 10-6: Image of Tesla Power Pack and Inverter Lineup

11. Preliminary Cost Estimate

11.1 Capital Cost Estimate

The capital cost for the four different battery systems evaluated is presented in Table 11-1 for the TKC site, Table 11-2 for the KDFN site near Whitehorse, and Table 11-3 for the KDFN site near Takhini.

The inverter and transformer CAPEX includes allocations for the inverter, transformer and other electrical switchgear. As well, when required, an allocation for noise controls has been included for the inverter and transformer.

The Battery CAPEX includes the capital cost of the batteries and an allocation for communications and controls.

Additionally, both CAPEX estimates include allocations for transportation to site and installation and commissioning.

The other CAPEX costs include:

- Site Preparation
- Engineering
- Surveying
- System impact studies
- Controls Integration
- Procurement and Project Management
- Project Controls
- Construction Management.

Allocations for owner's costs (e.g. permitting, administration, internal project management, etc.) have not been included in the estimate.

Table 11-1: Estimated Capital Cost for 4 potential BESS Systems (for TKC Site)

BESS Size	Overbuild	Discharge Duration	Inverter, Transformer, & interconnection CAPEX	BESS CAPEX	Other CAPEX	Total CAPEX
6.6 MW/ 35 MWh	20% (42 MWh)	5.3 hrs	$2.39 M	$20.23 M	$0.88 M	$23.51 M
8.8 MW/35 MWh	20% (42 MWh)	4 hrs	$2.72 M	$20.23 M	$0.88 M	$23.84 M
7 MW/40 MWh	20% (48 MWh)	5.7 hrs	$2.46 M	$22.98 M	$0.88 M	$26.32 M
10 MW/40 MWh	20% (48 MWh)	4 hrs	$2.92M	$22.98 M	$0.88 M	$26.78 M

Table 11-2: Estimated Capital Cost for 4 potential BESS Systems (for KDFN Site near Whitehorse)

BESS Size	Overbuild	Discharge Duration	Inverter, Transformer, & interconnection CAPEX	BESS CAPEX	Other CAPEX	Total CAPEX
6.6 MW/ 35 MWh	20% (42 MWh)	5.3 hrs	$2.60 M	$20.23 M	$0.99 M	$23.83 M
8.8 MW/ 35 MWh	20% (42 MWh)	4 hrs	$2.94 M	$20.23 M	$0.99M	$24.16 M
7 MW/ 40 MWh	20% (48 MWh)	5.7 hrs	$2.66 M	$22.98 M	$0.99 M	$26.63M
10 MW/ 40 MWh	20% (48 MWh)	4 hrs	$3.12 M	$22.98 M	$0.99 M	$27.09 M

Table 11-3: Estimated Capital Cost for 4 potential BESS Systems (for KDFN Site near Takhini)

BESS Size	Overbuild	Discharge Duration	Inverter, Transformer, & interconnection CAPEX	BESS CAPEX	Other CAPEX	Total CAPEX
6.6 MW/ 35 MWh	20% (42 MWh)	5.3 hrs	$2.06 M	$20.23 M	$0.96 M	$23.25 M
8.8 MW/ 35 MWh	20% (42 MWh)	4 hrs	$2.39 M	$20.23 M	$0.96 M	$23.59 M
7 MW/ 40 MWh	20% (48 MWh)	5.7 hrs	$2.12 M	$22.98 M	$0.96 M	$26.06 M
10 MW/ 40 MWh	20% (48 MWh)	4 hrs	$2.58 M	$22.98 M	$0.96 M	$26.52 M

*includes noise control measures in inverter & transformer CAPEX

The capital cost for the BESS ranges from $23.3 M to $27.1 M, depending on the energy capacity and site.

A contingency of 15% was used for all elements of the CAPEX estimate. The CAPEX estimate has an accuracy of -30% to +30%; the battery prices have the greatest impact on the total project CAPEX.

11.1.1 Higher Power BESS

Additionally, the option to increase the power capabilities of the 40 MWh BESS was investigated. This will add additional flexibility, particularly relating to the reliability use cases. The results for each of the three sites are shown in the following tables. The main drivers for the increased capital cost are the larger inverter and transformer, as well as a small increase in the site preparation costs due to additional land area requirements.

The battery costs are expected to stay relatively similar, since the same battery cell would be used regardless of 0.5 C or 0.25 C operation.

Table 11-4: Estimated Capital Cost for 3 potential 40 MWh BESS Systems configurations (for TKC Site)

BESS Size	Overbuild	Discharge Duration	Inverter, Transformer, & interconnection CAPEX	BESS CAPEX	Other CAPEX	Total CAPEX
10 MW/ 40 MWh	20% (48 MWh)	4 hrs	$2.92M	$22.98 M	$0.88 M	$26.78 M
13 MW/ 40 MWh	20% (48 MWh)	3.1 hrs	$3.47 M	$22.98 M	$0.94 M	$27.39 M
20 MW/ 40 MWh	20% (48 MWh)	2 hrs	$4.62 M	$22.98 M	$0.94 M	$28.55 M

Table 11-5: Estimated Capital Cost for 3 potential 40 MWh BESS Systems configurations (for KDFN Site near Whitehorse)

BESS Size	Overbuild	Discharge Duration	Inverter, Transformer, & interconnection CAPEX	BESS CAPEX	Other CAPEX	Total CAPEX
10 MW/ 40 MWh	20% (48 MWh)	4 hrs	$3.12 M	$22.98 M	$0.99 M	$27.09 M
13 MW/ 40 MWh	20% (48 MWh)	3.1 hrs	$3.67 M	$22.98 M	$1.07 M	$27.72 M
20 MW/ 40 MWh	20% (48 MWh)	2 hrs	$4.82 M	$22.98 M	$1.07 M	$28.88 M

Table 11-6: Estimated Capital Cost for 3 potential 40 MWh BESS Systems configurations (for KDFN Site near Takhini)

BESS Size	Overbuild	Discharge Duration	Inverter, Transformer, & interconnection CAPEX	BESS CAPEX	Other CAPEX	Total CAPEX
10 MW/ 40 MWh	20% (48 MWh)	4 hrs	$2.58 M	$22.98 M	$0.96 M	$26.52 M
13 MW/ 40 MWh	20% (48 MWh)	3.1 hrs	$3.12 M	$22.98 M	$1.13 M	$27.24 M
20 MW/ 40 MWh	20% (48 MWh)	2 hrs	$4.30 M	$22.98 M	$1.13 M	$28.41 M

*includes noise control measures in inverter & transformer CAPEX

As above, a contingency of 15% was used for all elements of the CAPEX estimate. The CAPEX estimate has an accuracy of -30% to +30%; the battery prices have the greatest impact on the total project CAPEX.

11.2 Annual Operating Costs

Annual operating costs for BESSs are relatively low.

Typically, there is one or two vendor inspections per year to conduct preventative maintenance on the BESS. Since this is a large BESS asset, it is likely Yukon Energy will have these two visits performed by the vendor for the first few years of operation. As the Yukon Energy staff gains experience operating and maintaining the BESS, it may be possible to reduce the frequency of the visits.

For the economic assessment, an allocation of $15,000 per visit per technician has been included, which includes time on site as well as travel costs and disbursements. It is assumed two technicians would be at each visit, totaling $60,000 per year.

Additionally, an allocation has been included for parts and preventative maintenance of $2.25/kWh installed for the battery cells and $4/kW installed per year for the inverter/transformer and switchgear.

The estimated annual maintenance costs for the BESS are between $165,000 - $230,000 per year depending on the size and duration of the BESS.

In addition to preventative maintenance costs, if the BESS is located within the Whitehorse city limits, property tax will need to be paid. This tax will apply to the TKC C-28B Property and the KDFN C-34B property, both located near the Yukon Energy headquarters.

Yukon Energy has estimated this property tax is at a rate of 1.636% per year. The tax is charged on 65% of the CAPEX of new equipment and 10% of the site upgrade costs. As an example, for the 20 MW/40 MWh BESS at TKC the tax is

$$Annual\ Property\ Tax = 1.636\%\ x\ \left(65\%\ x\ (\$4{,}620{,}000 + \$22{,}980{,}000) + 10\%\ x\ (\$940{,}000)\right) = \$295{,}036\ per\ year$$

For the KDFN and TKC land near Whitehorse, the property tax ranges from $242,000 - $297,500 per year, depending on the sizing and the site.

Finally, an allocation for recharging costs has been included in the annual operating cost. The recharging costs were based on the peak shaving use case, which has an annual throughput of 227 MWh for longer duration BESSs (6.6 MW/35 MWh and 7 MW/40 MWh BESS) and 244 MWh for the 4 hr BESSs (8.8 MW/35 MWh, 10 MW/40 MWh, 13 MW/40 MWh, and 20 MW/40 MWh BESS). The recharging cost is driven by diesel peak shifting for this assessment. Other usages (such as blackstart/outage restoration, discharging for operating reserve/frequency excursion, etc. will also contribute to this cost and will vary based on the battery power capabilities and year to year). Assuming 75% of this energy is replaced with LNG and 25% is replaced with hydro, this translates to approximately $53,000 - $57,000 per year.

Additionally, Yukon Energy will likely purchase insurance for the BESS to cover damage or failure due to rare events (e.g. vandalism, lightning strike, etc.). This will likely cost in the order of $20,000 - $40,000 per year, depending on the level of insurance desired.

A summary of the annual operating, property tax, and recharging costs for each BESS size is presented in Table 11-7.

Table 11-7: Annual Operating Cost Breakdown for Different BESS Sizes

BESS Size	Annual OPEX ($/yr)	Whitehorse Property Tax ($/yr)	Insurance Costs ($/yr)	Total Annual OPEX ($/yr)	Recharging Costs ($/yr)	Total OPEX with Recharging Cost ($/yr)
6.6 MW/35 MWh	$165,000	$242,000	$40,000	$447,000	$53,000	$500,000
7 MW/40 MWh	$178,000	$245,500	$40,000	$463,500	$53,000	$516,500
8.8 MW/35 MWh	$174,000	$272,000	$40,000	$486,000	$57,000	$543,000
10 MW/40 MWh	$190,000	$277,000	$40,000	$507,000	$57,000	$564,000
13 MW/40 MWh	$202,000	$283,000	$40,000	$525,000	$57,000	$582,000
20 MW/40 MWh	$230,000	$295,000	$40,000	$565,000	$57,000	$622,000

*note1 total annual operating cost for KDFN land near Takhini would not include the property tax payment.

**note2 property tax will be slightly more expensive for the KDFN land near Whitehorse due to the marginally higher capital cost (CAPEX ~0.8-1% greater)

In addition to the battery operating cost, there will be annual operating and maintenance costs for the transmission line to connect the BESS to the substation. It was estimated that this cost would be approximately 1% of the capital cost. Since the lines are relatively short, this will be a relatively modest cost. Additionally, Yukon Energy already has a maintenance program in place for its extensive transmission and distribution network, and thus this would be a modest increase to that maintenance program.

Table 11-8: Annual Operating Cost Breakdown for Different BESS Sizes

Site	CAPEX for Transmission Line ($) Including 15% contingency	OPEX for Transmission ($/yr)
TKC Land near Whitehorse	$483,000	$5,000
KDFN Land Near Whitehorse	$684,000	$7,000
KDF Land Near Takhini	$60,000	$600

Contingency was not included in the operating cost estimates.

12. Preliminary Economic Assessment

A preliminary economic assessment was done to compare the 4 different BESS options. The assessment compares the potential savings associated with reduced fossil fuel consumption as a result of the BESS providing operating reserve and as a result of the BESS peaking shifting diesel fuel consumption.

The following assumptions were used in this analysis:

- The annual OPEX for the BESS was calculated assuming there would be two vendor site visits each year ($30,000 per visit with 2 technicians) and the cost for preventative maintenance is $2.25/kWh installed for the batteries and $4/kW installed for the inverter/transformer.
- An allocation of $40,000 per year has been included for insurance.
- An allocation of 1% of CAPEX per year has been included for maintenance of the 34.5 kV connection line.
- For the two sites within the Whitehorse city boundaries, an annual property tax payment of 1.636% of a portion of the CAPEX was included.
- Long Term Avoided Cost of Diesel is $0.277/kWh.
- Long Term Avoided Cost of Natural Gas is $0.248/kWh.
- Hydro Turbine OPEX cost is $0.05/kWh.
- Fuel offset by Operating Reserve is replaced by Hydro generation.
- Diesel fuel offset by Peak Shavings is replaced 75% by natural gas and 25% by hydro.
- The Avoided Cost of Capacity is $2,000,000/MW – for a single rental unit this represents $3,600,000 (1.8 MW unit)
- The Avoided Cost of Capacity was distributed over the project lifespan (20 years) using the capital recovery factor, calculated with the real discount rate.
- A grant of $16.5 M was deducted from the CAPEX.
- Inflation was assumed to be 2% and the Nominal Discount rate was assumed to be 4.92%, this leads to a real discount rate of 2.86%.
- Project lifetime is 20 years.

For the 40 MWh BESS, increasing the power output to 13 MW and 20 MW results in an increase in the annual saves by over $121,000 and $130,000 respectively. The comparison of the four 40 MWh BESS options is shown in Table 12-1.

The economic metrics presented in this analysis are:

- Capital Cost ($)
- Annual Operating Cost ($/yr), including property tax where applicable but excluding recharging costs
- Levelized Cost of Energy ($/kWh) (LCOE), including recharging costs
- Levelized Cost of Capacity ($/kW-yr) (LCOC), excluding recharging costs
- Total Cost of Ownership ($), including recharging costs (net present cost including CAPEX, OPEX and recharging cost)
- Total Cost of Ownership per MW ($/MW), including recharging costs
- Net Present Value ($) (NPV) including the forecasted savings
- Internal Rate of Return (IRR)

In terms of site selection, the economics of the project are slightly more attractive when locating the BESS at Takhini, because of the slightly lower CAPEX and the elimination of the property tax (ranging between $242,000 - 297,000 per year). The elimination of the property tax results in a total savings over the lifespan of the project of approximately $3.6-4.5 M. However, there may be non-economic benefits which would justify the location of the BESS within the Whitehorse city boundaries.

In terms of sizing, the first comparison is between the 8.8 MW/35 MWh and 10 MW/40 MWh. Based on the financial analysis, the added diesel fuel savings do not alone justify increasing the BESS size from 8.8 MW/35 MWh to 10 MW/40 MWh. **Between these options, the 8.8 MWh/35 MWh BESS has the lowest LCOE and LCOC, and the highest IRR and NPV.**

However, the added flexibility that the larger sizes provides to Yukon Energy, which is not easily economically quantified (blackstart/outage restoration, frequency excursion response, etc.), may be a non-economic justification to increase the BESS size. For instance, it would allow for larger load segments during blackstart/outage restorations, more reactive power compensation capacity, a higher portion of excess generation that can be absorbed during a load loss, and a greater portion of the BESS dedicated to frequency excursion response.

Comparing the 10 MW/40 MWh, 13 MW/40 MWh and 20 MW/40 MWh sizing options. **The lowest LCOC a is achieved with the lowest power (10 MW/40 MWh) option;** additionally, the highest IRR and lowest cost of ownership and LCOE is achieved with the 10 MW/40 MWh BESS.

However, the 13 MW and 20 MW battery sizing have many benefits, and the LCOC is only approximately 8- 25$/kW-yr greater than the 10 MW BESS. The total cost of ownership for the 20 MW system is roughly $2.5-2.6 M greater, over 20 years, than the 10 MW system. The benefits of the higher power capabilities are not directly tangible from a diesel and LNG savings perspective; however, can be justified based on the added benefits relating to grid stability, reliability, and blackstart capabilities.

Table 12-1: Summary of Annual Savings for 4 different power options for a 40 MWh BESS Size

Use Case		7 MW/40 MWh		10 MW/40 MWh		13 MW/40 MWh		20 MW/40 MWh	
		Savings	$	Savings	$	Savings	$	$	$
N-1 Capacity	Avoided Cost of Capacity	4 units = 7.2 MW	$14,400,000	4 units = 7.2 MW	$14,400,000	4 units = 7.2 MW	$14,400,000	4 units = 7.2 MW	$14,400,000
	Total per year (20-year capital recovery factor)		$955,665		$955,665		$955,665		$955,665
Operating Reserve	Annual Diesel Savings	1,731 MWh/yr	$479,609	1,813 MWh/yr	$502,077	1,837 MWh/yr	$508,849	1,837 MWh/yr	$508,849
	Annual LNG Savings	13,691 MWh/yr	$3,395,368	16,410 MWh/yr	$4,069,680	16,995 MWh/yr	$4,214,760	17,043 MWh/yr	$4,226,664
	Added Operating Costs for Hydro	-15,422 MWh/yr	- $771,122	-18,223 MWh/yr	- $911,128	-18,808 MWh/yr	- $940,378	-18,856 MWh/yr	-$942,778
	Total		***$3,103,855***		***$3,660,629***		***$3,782,009***		***$3,791,513***
Peak Shifting	Annual Diesel Savings	227 MWh/yr	$62,936	244 MWh/yr	$67,615	244 MWh/yr	$67,615	244 MWh/yr	$67,615
	Added charging fuel costs (75% LNG, 25% Hydro)		- $53,059		-$57,004		-$57,004		-$57,004
	Total		***$9,877***		***$10,611***		***$10,611***		***$10,611***

Table 12-2: Summary of Economic Assessment for each BESS Size located at the TKC site

BESS Size	Location	CAPEX	Annualized OPEX	LCOE	LCOC	Total Cost of Ownership (NPV)	Levelized Cost of Ownership	NPV (with Savings)	IRR
		2020$	2020$/yr	$/kWh	$/kW-yr	2020$	2020$/MW	2020$	
6.6 MW/ 35 MWh	Whitehorse Connection	$23,510,000	$452,000	$4.27	$139	$14,620,000	$2,215,000	$45,519,000	51%
7 MW/ 40 MWh	Whitehorse Connection	$26,320,000	$468,500	$5.16	$160	$17,679,000	$2,526,000	$43,202,000	37%
8.8 MW/ 35 MWh	Whitehorse Connection	$23,840,000	$491,000	$4.24	$148	$15,597,000	$1,772,000	$52,321,000	55%
10 MW/ 40 MWh	Whitehorse Connection	$26,780,000	$512,000	$5.13	$171	$18,854,000	$1,885,000	$50,284,000	40%
13 MW/ 40 MWh	Whitehorse Connection	$27,390,000	$530,000	$5.37	$179	$19,735,000	$1,518,000	$51,205,000	39%
20 MW/ 40 MWh	Whitehorse Connection	$28,550,000	$570,000	$5.84	$196	$21,498,000	$1,075,000	$49,631,000	35%

Table 12-3: Summary of Economic Assessment for each BESS Size Connected at KDFN Land near Whitehorse Substation

BESS Size	Location	CAPEX	Annualized OPEX	LCOE	LCOC	Total Cost of Ownership (NPV)	Levelized Cost of Ownership	NPV (with Savings)	IRR
		2020$	2020$/yr	$/kWh	$/kW-yr	2020$	2020$/MW	2020$	
6.6 MW/ 35 MWh	Whitehorse Connection	$23,820,000	$456,000	$4.38	$143	$15,001,000	$2,273,000	$45,149,000	49%
7 MW/ 40 MWh	Whitehorse Connection	$26,630,000	$473,000	$5.27	$164	$18,057,000	$2,580,000	$42,834,000	35%
8.8 MW/ 35 MWh	Whitehorse Connection	$24,150,000	$495,000	$4.34	$152	$15,978,000	$1,816,000	$51,951,000	53%
10 MW/ 40 MWh	Whitehorse Connection	$27,090,000	$516,000	$5.23	$174	$19,224,000	$1,922,000	$49,924,000	39%
13 MW/ 40 MWh	Whitehorse Connection	$27,720,000	$534,000	$5.47	$183	$20,125,000	$1,548,000	$50,826,000	37%
20 MW/ 40 MWh	Whitehorse Connection	$28,880,000	$574,000	$5.95	$199	$21,888,000	$1,094,000	$49,252,000	34%

Table 12-4: Summary of Economic Assessment for each BESS Size Connected at KDFN Land near Takhini Substation

BESS Size	Location	CAPEX	Annualized OPEX	LCOE	LCOC	Total Cost of Ownership (NPV)	Levelized Cost of Ownership	NPV (with Savings)	IRR
		2020$	2020$/yr	$/kWh	$/kW-yr	2020$	2020$/MW	2020$	
6.6 MW/ 35 MWh	Takhini Connection	$23,250,000	$205,600	$3.11	$99	$10,647,000	$1,613,000	$49,381,000	57%
7 MW/ 40 MWh	Takhini Connection	$26,060,000	$218,600	$3.99	$122	$13,653,000	$1,950,000	$47,115,000	40%
8.8 MW/ 35 MWh	Takhini Connection	$23,590,000	$214,600	$3.04	$98	$11,183,000	$1,271,000	$56,613,000	61%
10 MW/ 40 MWh	Takhini Connection	$26,520,000	$230,600	$3.90	$128	$14,354,000	$1,435,000	$54,659,000	44%
13 MW/ 40 MWh	Takhini Connection	$27,240,000	$242,600	$4.15	$136	$15,254,000	$1,173,000	$55,561,000	42%
20 MW/ 40 MWh	Takhini Connection	$28,410,000	$270,600	$4.58	$152	$16,846,000	$842,000	$54,153,000	38%

Note: since the primary use case and the majority of the secondary use cases for the BESS are based on providing capacity to the grid (reserve capacity, operating reserve capacity) or for performing infrequent services (i.e. blackstart), the annual throughput in the LCOE metric is very low. This leads to an LCOE metric that is higher than typical and not necessarily representative of the true benefits of the BESS to the grid. As can be seen based on the NPV and IRR, there are considerable savings that can be achieved with this added capacity from the BESS, despite relatively low annual throughput.

13. Conclusions

The four key benefits of the proposed battery energy storage system for Yukon Energy identified in this study are:

1. Provide N-1 Reserve capacity to reduce the number of mobile diesel gensets rented each year
2. Provide operating reserve for up to 30 min at the rated power, to reduce the operating reserve carried on the hydro turbines and thus, reduce the amount of diesel fuel and LNG consumed each year
3. Provide blackstart/outage restoration support to reduce the length of outages
4. Supply generation instead of diesel peaking units, shifting consumption to LNG or Hydro overnight.

Additional benefits provided by the BESS include frequency regulation for large excursions and to support future intermittent renewable generation integration into the grid, absorbing generation when there is a transmission line outages or load loss, and providing reactive power support.

The recommended battery chemistry is lithium Ion, since the proposed duty cycle is relatively low and would not lead to accelerated cycle degradation of the BESS. Additionally, the higher round trip efficiency and lower auxiliary demands of lithium ion batteries make them more desirable for this application. Lithium Iron Phosphate (LFP) battery cell chemistry is preferred since it is inherently safer and has a lower capital cost. However, Yukon Energy should not limit vendors to only LFP suppliers in the RFP to get a full range of bids and confirm this assessment.

Estimated capital cost for the 8.8/35 MWh and 10 MW/40 MWh BESS is $23.8 M and $26.8 M, respectively, if located on the TKC Land near Whitehorse Substation. Increasing power sizes from 10 MW/40 MWh to 20 MW/40 MWh leads to an increase in the CAPEX by approximately $1.7-1.8 M. However, the higher BES has increased flexibility to provide grid stability and reliability services.

13.1 Next Steps

Recommended next steps are as follows:

- Conduct the Community Consultation (Yukon Energy) to support site selection
- Complete detailed system study for both Takhini and Whitehorse connection to determine the BESS's ability to energize back to Whitehorse Rapids, Whitehorse Hydro Units 1, 2, 3, and 4.

- Preliminary Interconnection for Preferred Site
- Prepare the procurement strategy document for EPC & EPCM alternatives
- Conduct geotechnical campaigns for selected sites
- Assessment of controls strategy and controls requirement to maximize benefits of the BESS. This should include review of both automated and manual operating strategies.