Q. **Reference: Bay d'Espoir Unit 7 Additional Analysis Report, September 23, 2025, page 2, lines 20-23.**

"In this scenario, Unit 7 is uprated by approximately 20 MW to 174 MW rated capacity. As a result of system hydrology on the Bay d'Espoir system and the optimized maximum capacity addition to the system of 150 MW, the uprating of Unit 7 may necessitate lowering the nominal capacity of Unit 8 by approximately 20 MW to 130 MW."

a) Has Hydro completed any hydrology studies to confirm that the 20 MW uprate for Unit 7 would result in the lowering of the nominal capacity of Unit 8 by approximately 20 MW? If so, provide a copy of the study.

b) Has Hydro analyzed the benefits of an additional 20 MW from the Unit 7 uprate at a significantly lower cost on a per MW basis than the proposed Unit 8 project?

A. **a)** Newfoundland and Labrador Hydro ("Hydro") has not undertaken any dedicated studies to confirm that the 20 MW uprate for Bay d'Espoir Unit 7 would result in the lowering of the nominal capacity of Bay d'Espoir Unit 8 by approximately 20 MW. However, according to the 2025 Hydrology and Feasibility Study for Potential Bay d'Espoir Unit 8 ("2025 Hydrology and Feasibility Study"),[1] provided in the 2025 Build Application, and included herein as PUB-NLH-020, Attachment 1, Hatch Ltd. modelled 73 years of inflow and operational data to quantify the effect of adding a new unit. The study determined that the optimized increase in Bay d'Espoir Plant output was approximately 150.1 MW.

> The simulated hourly optimized generation capacity increase at the Bay d'Espoir plant is 150.1 MW with addition of Unit 8…because the model optimizes the total Bay d'Espoir plant output to meet the defined firm load while maximizing energy. The increase in simulated on-peak generation is at the expense of simulated off-peak generation.[2]

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[1] "Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8," Hatch Ltd., March 17, 2025.
[2] *Supra,* f.n. 1, Executive Summary, p. iv.

The 2025 Hydrology and Feasibility Study further explains that when the Bay d'Espoir system is modelled in isolation, its hydrology constrains total effective capacity. This outcome therefore suggests that the finite water supply and hydraulic head shared among all Bay d'Espoir units limit total plant output, which defines the optimized plant capacity. The report also notes, however, that marginal increases in total plant capacity beyond the 150.1 MW stated could likely be achieved through optimization of Hydro's broader energy resources.

Therefore, Hydro's position is that the Bay d'Espoir system hydrology presently supports approximately 150 MW of additional generating capacity as an optimized limit under current operating assumptions. That figure represents the amount of incremental capacity the system can efficiently utilize without reducing firm energy or overall efficiency.

b) The recommendation to construct Bay d'Espoir Unit 8 is part of a holistic expansion plan that meets all of Hydro's system planning criteria.[3] The Minimum Investment Required Expansion Plan was put forward to meet a planning reserve margin of 17.1% of peak, which equates to 360 MW of reserve requirements.[4] As part of this plan, the least-cost resources that meet the prescribed criteria result in an additional 384 MW to be added to the Island Interconnected System by 2035, of which Bay d'Espoir Unit 8 provides a firm capacity of 154.4 MW. Hydro did not further pursue the potential benefits of an additional 20 MW from the Unit 7 uprate for the reasons noted in the Life Extension Application and subsequent additional information requested by the Board of Commissioners of Public Utilities.[5] As a result of system hydrology on the Bay d'Espoir system and the optimized maximum capacity addition to the system of 150 MW, the uprating of Unit 7 may necessitate lowering the nominal capacity of Unit 8 by approximately 20 MW to 130 MW. A reduction to the capacity of Unit 8 to accommodate an increase in the capacity of Unit 7 would necessitate substantial re-engineering of Unit 8 and significant engineering investigations for Unit 7. It would also further compound delays in the implementation of both projects without resulting in any

[3] Considering the 2024 Slow Decarbonization load forecast and a highly reliable LIL (1% LIL bipole EqFOR).
[4] Based on the 2032 reference year.
[5] Please refer to "Bay d'Espoir Unit 7 Additional Analysis Report," Newfoundland and Labrador Hydro, rev. September 23, 2025 (originally filed September 22, 2025).

appreciable increase in the capacity of the system as a whole. There is no basis to assume that an additional 20 MW from Unit 7 will defer or delay the requirement for Bay d'Espoir Unit 8, due to the significant capacity requirements for the Island Interconnected System.

For further information on uprating Unit 7 by 20 MW, please refer to Hydro's response to PUB-NLH-021 of this proceeding.

HATCH

Newfoundland and Labrador Hydro
Hydrology and Feasibility Study for Potential Bay d'Espoir
Hydroelectric Generating Unit No. 8 2025 Update
H375556

Addendum Report

Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8

H375556-0000-2B0-230-0001

			Mathur, Pulkit		
2025-03-19	B	Client Review	T. Olason / P. Mathur	M. Rosales	T. Olason
2025-03-17	A	Internal Review	T. Olason / P. Mathur	M. Rosales	T. Olason
DATE	REV.	STATUS	PREPARED BY	CHECKED BY	APPROVED BY

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Executive Summary

The objective of the study was to update an earlier study by Hatch on the impact of the addition of Bay d'Espoir Unit 8 on the hydroelectric generation and operation of the Bay d'Espoir reservoir system. The scope of work included background data review; hydrological analysis; and power and energy model (Hatch Vista DSS) analysis. This study examined the effects of updated hydrology, the 2024 reference load forecast and recent data on frazil ice effects.

The study confirms the results of the earlier study, but the hydrology and load forecast caused a small decrease in firm and average energy estimates.

The firm energy estimate for the Bay d'Espoir system with Unit 8 is 294 MWc, down from the earlier estimate of 297.5 MWc.

The simulated average annual energy of the existing Bay d'Espoir system is 3,359.74 GWh. With the addition of Unit 8, it increases to 3,381.19 GWh, due to higher efficiency of the new unit and some spill capture.

The simulated average annual energy of the Bay d'Espoir plant is 2,613.56 GWh. The simulated average annual energy of the plant with the addition of Unit 8 is 2,646.46 GWh, an increase of 1.26 percent.

With the addition of Unit 8, the simulated hourly generation of the Bay d'Espoir plant increases 18.6 percent of the time and decreases 27.9 percent of the time. The increased generation occurs during on-peak hours while the decreased generation occurs during off-peak hours.

The study also confirmed the optimum utilization of the new unit. It will be the most efficient unit in the plant and should be base loaded.

The simulated hourly optimized generation capacity increase at the Bay d'Espoir plant is 150.1 MW with addition of Unit 8. This is less than the 154.4 MW capacity of the new unit because, although the model utilizes the full capacity of Unit 8, it optimizes the total Bay d'Espoir plant output to meet the defined firm load while maximizing energy. The increase in simulated on-peak generation is at the expense of simulated off-peak generation. This condition is a result of the Bay d'Espoir system being modelled in isolation for the purposes of this analysis. Through optimization of Hydro's full hydraulic resources, which was not simulated as part of this study, resources can likely be managed to fully mitigate the potential for energy shortfall from the Bay d'Espoir system to achieve an optimized increase in maximum generation equal to the full unit capability of 154.4 MW.

With addition of Unit 8, simulated Bay d'Espoir plant efficiency increases are in the range of 0.16 to 1.83 percent, with an average of 0.76 percent.

The North Salmon bypass spillway is used only 2.5 percent of the time in the simulation of the existing system, and 3.0 percent of the time with addition of Unit 8. The bypass may be used during periods of high inflow that exceed the capacity flow at the Upper Salmon plant and cannot be stored; periods when the Upper Salmon plant is shut down; and when necessary to delay water from reaching the Long Pong reservoir to provide more time to generate water out of the Long Pond reservoir when the Long Pond water level is high.

There is a slight loss of simulated efficiency at Upper Salmon plant with addition of Bay d'Espoir Unit 8. This loss occurred 17.98 percent of the time.

The information provided by Hydro on the hydromechanical equipment, head losses and tailwater does not indicate any physical restrictions to prevent Unit 8 from attaining 154.4 MW, or the Bay d'Espoir plant from attaining its full rated capacity, as long as there is water in the reservoir.

This study also re-examined the end-of-November elevation ranges and reconfirmed the range from the earlier study, that is, the large storage reservoirs in the system to optimize Bay d'Espoir system generation in the winter months while allowing room for possible early winter high flow.

- Victoria: 323.59 m to 325.39 m
- Meelpaeg: 271.72 m to 272.18 m
- Long Pond: 182.22 m to 182.25 m.

If levels at the end of November are lower than the recommended ranges, the system may not be able to do as much peaking in winter.

1. Introduction

In December 2020, Hatch Ltd. (Hatch) completed a hydrology and feasibility study for a potential new generating unit at the Bay d'Espoir Hydroelectric Generating Station for Newfoundland and Labrador Hydro (Hydro). In January 2025 Hydro asked Hatch to refresh the 2020 study with the most recent assumptions and hydrology, and to confirm its validity as Hydro has since determined the need to construct the new unit.

This addendum to the 2020 report documents the scope of work, background information, methodology, results, conclusions and recommendations from the 2025 update.

1.1 Objective

The objective of the current study is to update the 2020 study on the impact of the addition of Bay d'Espoir Unit 8 on the hydroelectric generation and operation of the Bay d'Espoir reservoir system.

1.2 Scope of Work

The scope of work includes the following components.

- Review and update assumptions and inputs used in the original 2020 study, including frazil ice assumptions, updated hydrology and Hydro's latest load forecasts.
- Re-run final set of 2020 runs to evaluate the impact.
- Review and recommend end of November targets water levels for major reservoirs in the Bay d'Espoir system.
- Addendum report.

For reference, the 2020 study considered the following issues.

- Potential operating procedure modifications, following the addition of Unit 8.
- Average annual energy of the Bay d'Espoir Hydroelectric Generating Station.
- Firm annual energy of the Bay d'Espoir Hydroelectric Generating Station.
- Average monthly energy on-peak and off-peak of the Bay d'Espoir Hydroelectric Generating Station.
- Firm monthly energy on-peak and off-peak of the Bay d'Espoir Hydroelectric Generating Station.
- Impact on the operation of Upper Salmon Hydroelectric Generating Station.
- Operations to control frazil ice at the generating stations in the system.

- Target storage of the Bay d'Espoir system reservoirs in advance of the winter operating season.
- Impact on efficiency for Bay d'Espoir Hydroelectric Generating Station.
- Inclusion of fish compensation requirements at Granite Canal Hydroelectric Generating Station and fisheries releases at Pudops Dam for Grey River and Burnt Spillway for White Bear River.

2. Data Review and Updates

Study inputs and assumptions are discussed in detail in the earlier report by Hatch (2020). For this update to the study, several key inputs and assumptions were revisited and updated. These are discussed in more detail below.

2.1 Unit Characteristics

The new facility will utilize the existing powerhouse forebay and does not require the construction of any additional dams. Unit 8 will use a draft tube-like Unit 7 with a minor modification to reduce head losses. The generating unit equipment will be designed to modern standards. As recommended by SLI (2018a) and as was modelled in the 2020 study, the unit will have a nominal combined efficiency of 0.916 and a transformer efficiency of 0.99. The penstock loss at capacity (154.4 MW) is 5.81 m. A comparison of the modelled efficiency curves for Unit 7 and the new Unit 8 is shown in Figure 2-1 below.

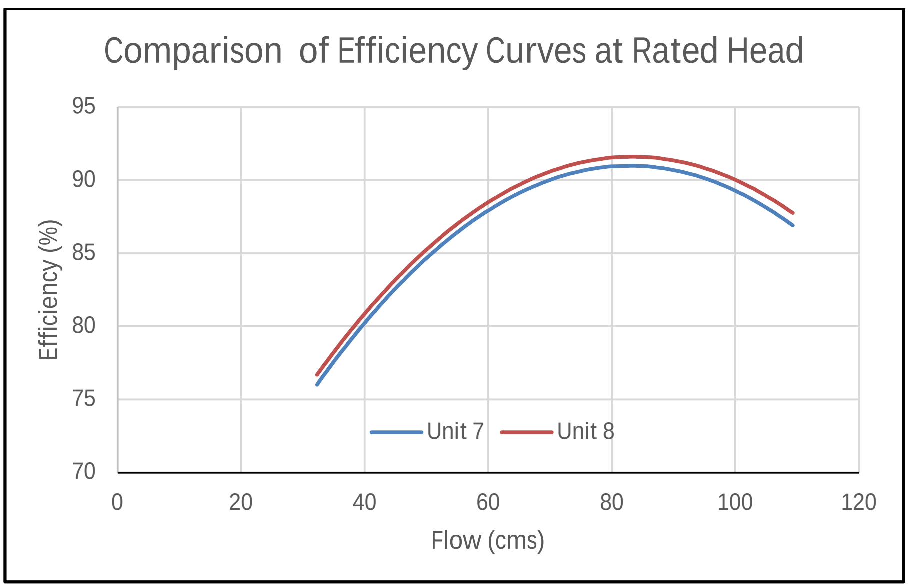

Figure 2-1: Comparison of Unit 7 and 8 Efficiency

2.2 Tailwater Curve

A tailrace channel expansion is recommended in the SLI (2018b) report, to minimize any increase in tailwater elevation that could result from increased plant discharge with the addition of Unit 8. In the 2020 study, it was assumed that the tailrace channel expansion recommended by SLI (2018b) with the addition of Unit 8 will be implemented. Therefore, the tailwater relationship in Vista was adjusted such that the tailwater level at the full discharge of the expanded plant is the same as the level at full discharge of the existing plant. The tailwater relationship used in the 2020 study will be used for the current study. A comparison of the modelled Long Pond tailwater curves for with and without Unit 8.is shown in Figure 2-2.

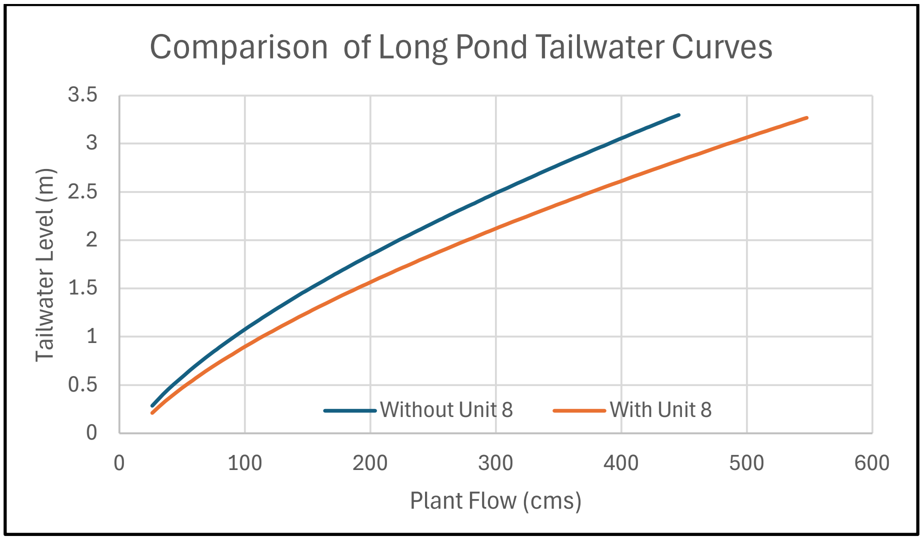

Figure 2-2:Tailwater Curve with and without Unit 8

2.3 Hydrology

Historic inflows for the Bay d'Espoir system are available from 1950. The method used to derive the inflows has changed over time, as the system was developed for hydroelectric power generation. The historic inflows, inflow calculation methods, trends, and inconsistencies in the inflow series were recently reviewed by Hatch (2024). Based on this review, the Bay d'Espoir inflow series were revised, and the revised inflows were used as the basis for this study for Unit 8. The hydrology used by Hatch in the 2020 study was based on an earlier version of the inflow dataset, covering 1950 to 2019. The total inflow upstream of BDE from the 2020 study hydrology and updated hydrology are shown in Figure 2-3, below. It is worth noting that the updated inflows are 3.8% lower than the inflows used in the 2020 study.

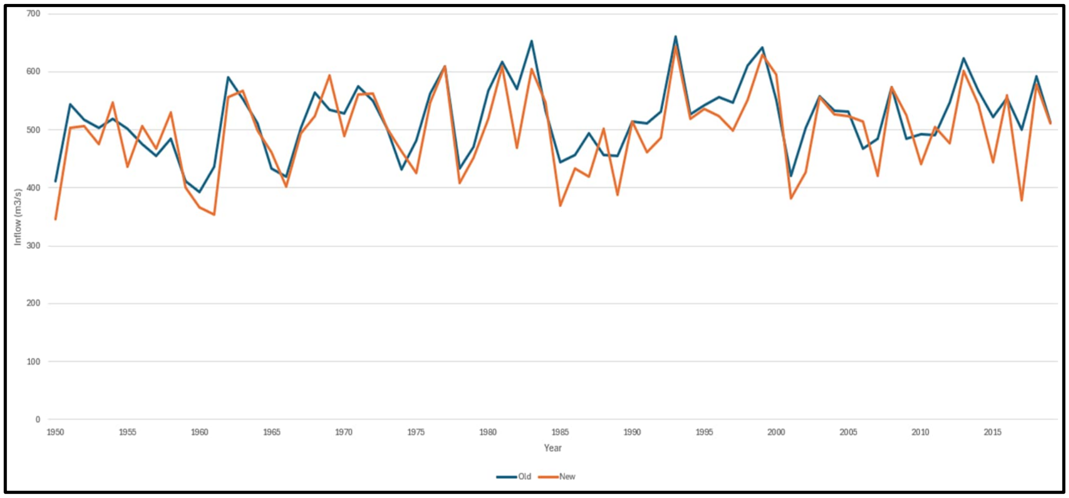

Figure 2-3: BDE Total Inflow Comparison

2.4 Frazil Ice Conditions

The Granite Canal and Upper Salmon plants are susceptible to frazil ice formation. During the winter months, Hydro would try to operate these plants in such a way that a stable ice cover forms on the headponds, and once it is in place these plants can be cycled during the day. However, in recent years winters have been warmer on average making it more difficult to form a stable ice cover. Without an ice cover and if a cold snap occurs, frazil ice formation can severely impact the operations, unless preventative measures are taken, such as reduction in generation.

In the 2020 study, the frazil ice limitation was assessed using operational data for the period 2010 to 2020. For this update, additional data for the period to 2024 was available. The frazil ice periods are summarized in Table 2-1 and Table 2-2.

Table 2-1: Frazil Ice Occurrences at Granite Canal

Year	Nr. Occurrences	Avg. Duration (Hours)	Avg. Generation (MW)
2010	1	14.3	0.0
2011	1	5.4	0.0
2012	1	44.4	0.0
2015	2	16.6	0.0
2018	3	7.2	0.0
2019	2	48.1	10.0
2021	1	106.0	15.0
2022	18	47.9	23.6
2023	11	81.4	27.3
2024	12	61.8	22.5

Table 2-2: Frazil Ice Occurrences at Upper Salmon

Year	Nr. Occurrences	Avg. Duration (Hours)	Avg. Generation (MW)
2010	7	19.7	0.0
2011	1	14.9	0.0
2012	2	6.9	0.0
2013	3	7.6	0.0
2014	5	7.7	0.0
2015	2	6.2	0.0
2016	1	10.4	0.0
2017	1	57.8	0.0
2018	5	17.1	4.0
2019	13	21.3	5.4
2020	3	18.7	33.3
2021	8	16.5	26.4
2022	16	26.2	52.5
2023	4	10.8	60.7
2024	11	39.6	49.6

There is a noticeable increase in occurrences in recent years, and Hydro's response has changed from shutting plants down, to reducing generation during the events. Considering the recent data and in consultation with Hydro, the decision was made to capture the frazil ice effect in this study update, by reducing the maximum generation at Granite Canal and Upper Salmon, for all hours in the December 15th to February 15th period, as follows:

- Granite Canal Plant limited to 56% of capacity.
- Upper Salmon Plant limited to 58.5 % of capacity.

2.5 Load Shape

The daily load shape is one of the Vista inputs for the firm energy analysis. In the 2020 study, the load shape derived from the 2020 Reference Case Load Forecast. For this update to previous study, Hydro provided the 2024 Reference Case load forecast.

2.6 Modelling Approach

Hatch used the same model and approach as in the 2020 study. This includes the proprietary Vista Decision Support System (DSS) model for the study of impacts of Unit 8 on the Bay d'Espoir system. The DSS has been implemented for Hydro assets including the Upper Churchill, Lower Churchill, Exploits River and the integrated Island systems. For this study, the model configuration is limited to the Bay d'Espoir system.

3. Model Analyses

The LT Vista module was used to perform the energy analyses in this study using all the 73 years of provided hydrologic record. LT Vista facilitates studies of long-term assessments and planning using long periods of hydrology.

The model was based on water-balance continuity where flow release decisions are constrained by physical limits and operating rules defined in the setup. The time step as defined in LT Vista is referred to as the period and is specified by the user. Typical period durations are months or weeks but can also be defined as multiples of a day or multiples of a week. The user also defines daily sub-periods within a week, i.e., on-peak, off-peak, shoulder-peak etc., hours for each day in a typical week and there could be as many sub-periods as desired. In model analyses, the average load and price over each period and sub-period are key drivers in the optimization, along with the defined constraints. In this assessment, the Island load profile provided by Hydro varies daily and over each sub-period (within the period). Therefore, the sub-periods should be selected so that derived energy is properly influenced by the provided load profile, i.e., higher generation during higher load sub-periods. The provided Island load for 2024 was analyzed to properly select the sub-periods. The following four sub-periods can be identified from the figure.

- Early hours/late night low load or off-peak period, longer for the weekend than the weekday.
- Morning, mid-day and night high load or shoulder-peak period.
- Morning higher load or peak-period, longer for the weekday than the weekend.
- Evening higher load or peak-period.

It can also be seen that the weekday non-off-peak loads are typically higher than the weekend values. Therefore, eight weekly sub-periods (4 for weekday and 4 weekend) were defined for this study as shown in Figure 3-1.

Hour	Mon	Tue	Wed	Thu	Fri	Sat	Sun
1	1	1	1	1	1	2	2
2	1	1	1	1	1	2	2
3	1	1	1	1	1	2	2
4	1	1	1	1	1	2	2
5	1	1	1	1	1	2	2
6	1	1	1	1	1	2	2
7	3	3	3	3	3	4	4
8	5	5	5	5	5	6	6
9	5	5	5	5	5	6	6
10	5	5	5	5	5	6	6
11	3	3	3	3	3	4	4
12	3	3	3	3	3	4	4
13	3	3	3	3	3	4	4
14	3	3	3	3	3	4	4
15	3	3	3	3	3	4	4
16	3	3	3	3	3	4	4
17	7	7	7	7	7	8	8
18	7	7	7	7	7	8	8
19	7	7	7	7	7	8	8
20	7	7	7	7	7	8	8
21	3	3	3	3	3	4	4
22	3	3	3	3	3	4	4
23	1	1	1	1	1	2	2
24	1	1	1	1	1	2	2

1 (2)	Off-Peak
3 (4)	Shoulder-Peak
5 (6)	Morning-Peak
7 (8)	Evening Peak

Figure 3-1: Modeled Weekly Sub-period Definition

3.1 Firm Energy Analysis

For a hydroelectric system, firm energy is the amount of electricity that can be generated over the most adverse sequence of hydrology, called the critical period. To determine the firm energy, simulations were carried out for the full hydrologic record. LT Vista run time depends on the model time step. The longer the time step, the shorter the run time. The run time increases exponentially as the time step decreases. Therefore, the analysis was carried out in two phases. In phase one, simulation was carried out over the full hydrologic records using a monthly time step to identify the critical period and an initial estimate of the firm energy. In phase two, a more detailed simulation was carried out using a daily time step to more accurately define the firm energy.

3.1.1 Critical Period Analysis

As in the earlier study, LT Vista was run in monthly time step to simulate operations over a 73-year continuous period with a fixed annual load for the existing system with the Upper Salmon bypass. The load shape is defined by the provided 2024 Island load. The annual load gradually increased until the system experienced failure to meet the load. For this analysis, the starting water levels in each reservoir in the system were assumed to be the maximum operating level (MOL) or upper rule curve for each reservoir and time of year, as specified in the Major Reservoir Operations Manual (Hydro, 2015). The total Bay d'Espoir system storage was monitored in order to establish system failure and determine the critical period.

The total system storage trajectories are illustrated in Figure 3-1. As shown in Figure 3-2, the total system storage drops to its minimum level in 1962. The LT simulation indicates that the critical sequence occurs between January 1959 (when system storage was full considering upper rule curves and maximum operating levels of the reservoirs) and March 1962 when the system storage drops to minimum.

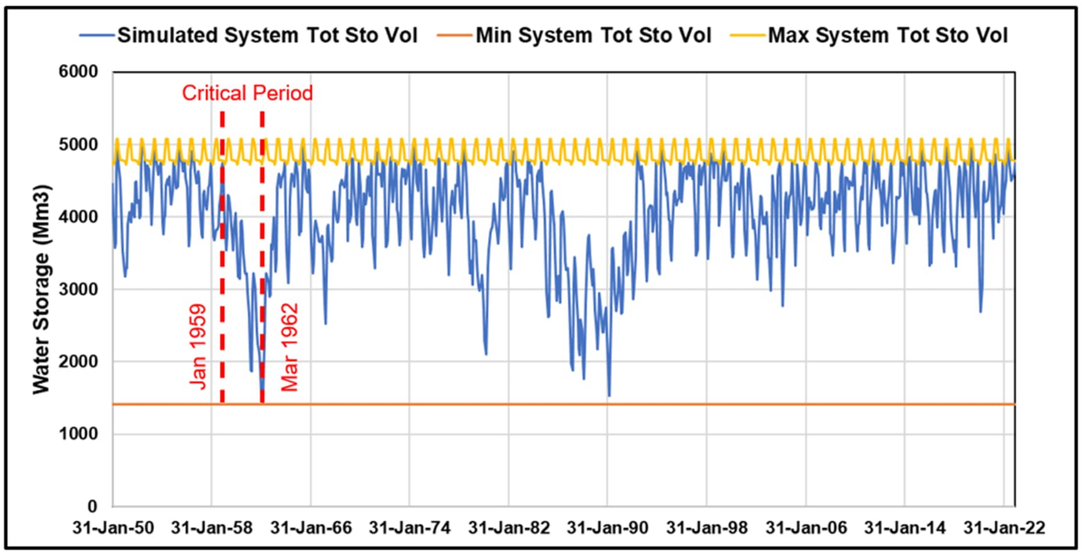

Figure 3-2: System Total Storage Trajectory

3.1.2 Detailed Analysis Using Daily Time Step

Once the critical period had been identified, LT Vista was run from January 1959 to December 1962 using a daily time step for trial annual loads close to 300 MWc. Again, the total system storage was monitored for each load trial to identify the smallest load value that would cause the storage, starting full, to be depleted in the critical period. The detailed analysis was performed for both the existing system with Upper Salmon bypass and the existing system plus Unit 8 and the Upper Salmon bypass.

The shape for each of the load trials is defined by the given 2024 Island load. The final estimate of the firm energy is:

- 294.0 MWc (with peak load of 545 MW) for the existing system and the existing system plus Unit 8.

Figure 3-3 shows the trajectory of the system storage under the existing system firm energy. Both the existing system and the existing system plus Unit 8 annual loads have the same

Figure 3-3 shows the trajectory of the system storage under the existing system firm energy. Both the existing system and the existing system plus Unit 8 annual loads have the same capacity factor of 0.5395 as the 2024 Island load. Figure 3-4 shows a comparison of the existing system's annual firm load with 2024 Island load. As such it can be determined that the addition of Unit 8 does not impact on the firm energy of the Bay d'Espoir plant.

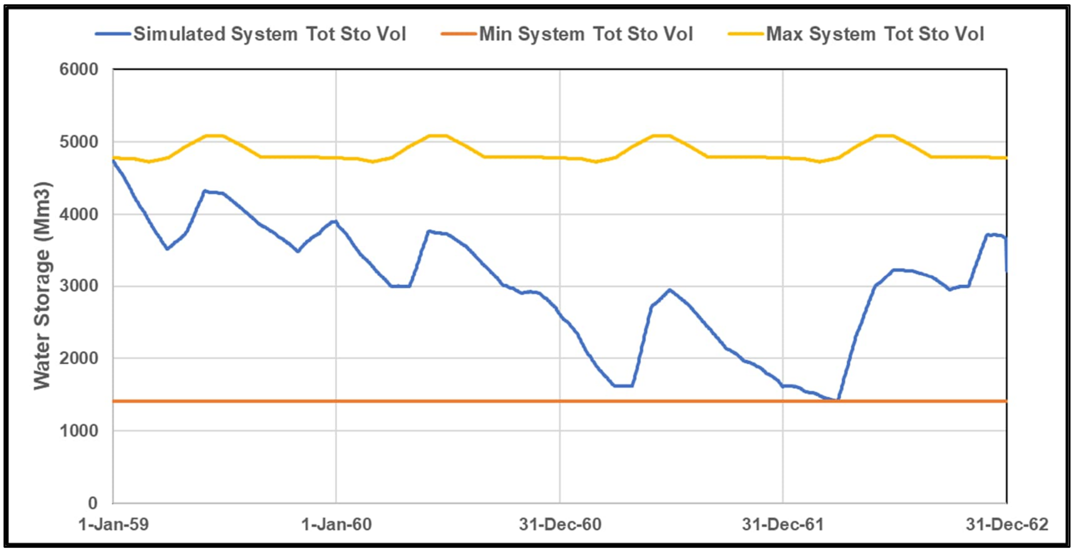

Figure 3-3: Simulated Firm Load System Total Storage Trajectory

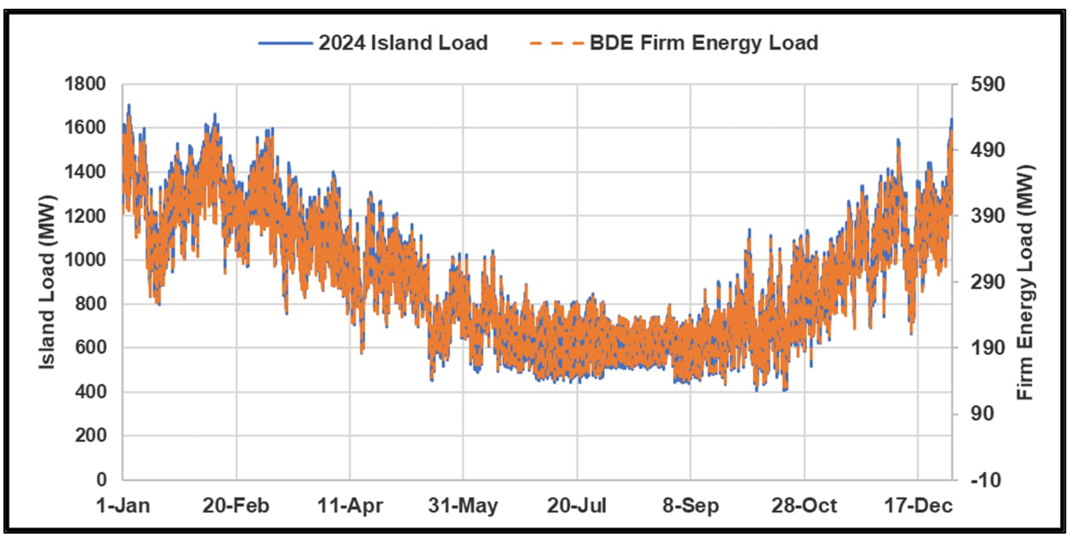

Figure 3-4: Comparison between Hourly 2024 Island Load and Hourly Bay d'Espoir Firm Energy Load

3.2 Energy Capability Analysis

To estimate the energy capability of the Bay d'Espoir system, LT Vista was run to optimize capacity while respecting the firm load requirement. For this purpose, the firm load established in Section 3.1 for the existing system was imposed on the system along with market opportunity to capture secondary energy. In order that the market price reflects the Island system load, and as such the capacity requirement, the hourly market price is set at the hourly load value of the 2024 Island load provided by Hydro.

In order to assess the impact of the potential addition of Bay d'Espoir Unit 8 on the hydroelectric generation and operation of the Bay d'Espoir reservoir system, LT Vista was run for the following four scenarios:

- Existing system with Upper Salmon Bypass.
- Existing system without Upper Salmon Bypass.
- Existing system plus Unit 8, with Upper Salmon Bypass.
- Existing system plus Unit 8, without Upper Salmon Bypass.

All the runs were conducted over the 73-year continuous period of available hydrology.

The results of the energy analysis are presented in Table 3-1 as average annual energy for the Bay d'Espoir system and the contribution from each plant, for each of the four scenarios. The difference and percent difference for the other three scenarios relative to the existing system with Upper Salmon bypass are also presented in the table. The following can be inferred from the table:

- Granite Canal plant average annual energy remains approximately 245 GWh for all four scenarios.
- There is only a very slight reduction in average annual energy for the existing system without Upper Salmon bypass.
- There is a similar level of increase, 0.64 percent, in the system average annual energy with the addition of Unit 8 with the Upper Salmon bypass.
- The average annual energy contributed by the Upper Salmon plant dropped by 2.32 percent and 1.71 percent with addition of Unit 8, with and without Upper Salmon bypass respectively.
- The average annual energy contributed by the Bay d'Espoir plant increased by 1.26 percent and 1.25 percent with addition of Unit 8, with and without Upper Salmon bypass respectively.

Table 3-1: Average Annual Energy for Bay d'Espoir System and the Contributing Plants

Scenario	Total System	Granite Canal Plant	Upper Salmon Plant	Bay d'Espoir Plant
Average Annual Energy (GWh/year)				
Existing System with Upper Salmon Bypass	3359.74	244.81	501.37	2613.56
Existing System without Upper Salmon Bypass	3359.47	244.76	501.21	2613.50
Existing System plus Unit 8, with Upper Salmon Bypass	3381.19	244.97	489.75	2646.46
Existing System plus Unit 8, without Upper Salmon Bypass.	3383.86	244.87	492.78	2646.22
Difference Relative to Existing System with Upper Salmon Bypass (GWh)				
Existing System without Upper Salmon Bypass	-0.28	-0.05	-0.16	-0.07
Existing System plus Unit 8, with Upper Salmon Bypass	21.45	0.17	-11.62	32.90
Existing System plus Unit 8, without Upper Salmon Bypass.	24.12	0.06	-8.59	32.65
Difference Relative to Existing System with Upper Salmon Bypass (%)				
Existing System without Upper Salmon Bypass	-0.01%	-0.02%	-0.03%	0.00%
Existing System plus Unit 8, with Upper Salmon Bypass	0.64%	0.07%	-2.32%	1.26%
Existing System plus Unit 8, without Upper Salmon Bypass.	0.72%	0.03%	-1.71%	1.25%

3.3 Detailed Model Results

Detailed model results are presented in the following subsections as tables, duration curves and monthly box plots. The centered-vertical line of the box plots extends from the minimum value to the maximum value. The horizontal line in the box is the median and the lower and upper ends of the box represents the 25th percentile and 75th percentile respectively. Where tables are presented for off-peak and on-peak values, the on-peak hours are hours 7 to 22 each day of the week, and the off-peak hours are hours 1 to 6, 23 and 24 each day of the week.

3.3.1 Firm Energy

Firm annual energy of the existing system and the existing system plus Unit 8 was estimated as 294.0 MWc. The system annual firm energy of the existing system of 294.0 MWc (2,543.66 GWh) is therefore adopted for the system. The corresponding annual firm energy for the Bay d'Espoir plant is 2,234.50 GWh. The corresponding total, on-peak and off-peak firm monthly energy for the system along with contributions from each plant are presented in Table 3-2.

Table 3-2: Firm Monthly Energy (GWh) for Bay d'Espoir System and the Contributing Plants

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	System			**Granite Canal Plant**		
January	268.96	81.68	187.27	15.22	4.97	10.25
February	277.13	85.36	191.77	15.43	4.93	10.50
March	267.23	81.72	185.51	17.99	5.10	12.89
April	221.47	66.20	155.27	19.63	6.10	13.53
May	188.30	56.55	131.76	28.40	9.54	18.86
June	159.20	46.03	113.17	15.71	5.69	10.01
July	151.94	43.34	108.60	13.22	6.24	6.98
August	149.62	44.30	105.32	13.43	5.42	8.01
September	154.10	44.06	110.04	15.82	6.20	9.62
October	181.93	50.64	131.30	18.85	6.74	12.12
November	235.39	68.73	166.66	20.80	6.88	13.92
December	288.40	85.42	202.97	17.38	5.92	11.46
	Upper Salmon Plant			**Bay d'Espoir Plant**		
January	19.01	6.51	12.50	234.73	70.20	164.52
February	22.81	7.90	14.91	238.89	72.53	166.36
March	24.40	8.24	16.17	224.83	68.38	156.45
April	9.29	4.47	4.82	192.55	55.64	136.92
May	7.32	3.31	4.01	152.58	43.69	108.89
June	2.95	1.27	1.67	140.55	39.06	101.48
July	0.75	0.16	0.60	137.96	36.94	101.02
August	0.59	0.10	0.49	135.59	38.78	96.81
September	0.50	0.19	0.31	137.78	37.66	100.11
October	0.80	0.28	0.52	162.28	43.62	118.66
November	3.67	1.74	1.94	210.91	60.11	150.80
December	5.17	1.45	3.73	265.85	78.06	187.79

3.3.2 Average Monthly Energy

The average annual energy for each scenario was presented in Table 3-1. The total, on-peak and off-peak average monthly energy for the system along with contributions from each plant, are presented in Table 3-3 to Table 3-6. It will be noted that there is a general increase in the on-peak generation and decrease in off-peak generation for the river system and Bay d'Espoir plant with addition of Unit 8. The monthly on-peak and off-peak generation at Granite Canal and Upper Salmon plants remain essentially the same with addition of Bay d'Espoir Unit 8. This change in distribution of generation at Bay d'Espoir plant is discussed further in Section 3.3.3 below.

Table 3-3: Average Monthly Energy (GWh) for Bay d'Espoir System

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	Existing System With Upper Salmon Bypass			**Existing System Without Upper Salmon Bypass**		
January	397.92	288.32	109.60	393.52	285.56	107.96
February	407.35	286.80	120.56	404.16	285.38	118.79
March	390.32	293.14	97.19	388.05	291.95	96.10
April	330.52	259.17	71.35	331.85	259.95	71.90
May	243.15	184.53	58.61	245.32	185.92	59.40
June	171.07	126.57	44.50	173.43	128.90	44.53
July	154.99	113.09	41.90	154.98	113.23	41.75
August	149.92	106.91	43.01	150.34	107.34	43.01
September	163.89	121.37	42.52	165.20	122.68	42.51
October	231.53	182.75	48.78	232.52	183.81	48.71
November	338.08	263.51	74.57	338.82	263.88	74.93
December	381.00	280.70	100.30	381.28	280.88	100.40
	Existing System Plus Unit 8, With Upper Salmon Bypass			**Existing System Plus Unit 8, Without Upper Salmon Bypass**		
January	413.62	312.50	101.12	403.06	305.48	97.58
February	449.69	327.22	122.47	441.98	323.07	118.91
March	387.51	299.29	88.22	383.67	296.86	86.81
April	327.51	261.39	66.12	332.23	265.44	66.79
May	229.87	172.98	56.89	236.28	178.70	57.58
June	163.24	118.80	44.45	167.40	122.92	44.48
July	153.71	111.95	41.77	153.62	111.86	41.76
August	149.60	106.59	43.01	149.72	106.71	43.01
September	158.10	115.60	42.50	161.31	118.80	42.51
October	220.29	171.65	48.64	224.01	175.34	48.66
November	337.72	267.72	70.00	339.25	269.17	70.08
December	390.31	291.31	99.00	391.33	292.31	99.02

Table 3-4: Average Monthly Energy (GWh) for Granite Canal Generating Station

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	Existing System With Upper Salmon Bypass			**Existing System Without Upper Salmon Bypass**		
January	17.40	11.82	5.58	17.40	11.82	5.58
February	20.95	14.18	6.76	20.96	14.18	6.78
March	27.56	19.26	8.30	27.66	19.31	8.34
April	24.06	17.37	6.69	24.05	17.36	6.70
May	25.04	18.24	6.80	25.09	18.31	6.79
June	17.49	14.47	3.02	17.58	14.58	3.00
July	15.60	11.30	4.30	15.33	11.46	3.87
August	14.80	10.32	4.48	14.80	10.34	4.46
September	15.61	11.21	4.40	15.56	11.42	4.14
October	20.56	14.55	6.01	20.65	14.72	5.93
November	24.54	17.44	7.10	24.46	17.47	7.00
December	21.20	14.89	6.31	21.21	14.89	6.31
	Existing System Plus Unit 8, With Upper Salmon Bypass			**Existing System Plus Unit 8, Without Upper Salmon Bypass**		
January	17.43	11.82	5.61	17.42	11.82	5.60
February	21.00	14.18	6.82	21.00	14.18	6.82
March	27.49	19.07	8.42	27.48	19.09	8.39
April	23.92	17.02	6.90	24.04	17.13	6.91
May	25.16	18.13	7.03	25.18	18.17	7.02
June	18.05	14.53	3.52	18.15	14.72	3.43
July	16.18	11.09	5.08	16.05	11.64	4.41
August	14.92	9.74	5.17	14.65	10.00	4.65
September	15.50	11.04	4.45	15.17	11.10	4.07
October	19.99	13.89	6.10	20.39	14.37	6.01
November	24.22	17.07	7.15	24.27	17.16	7.11
December	21.12	14.74	6.38	21.08	14.76	6.31

Table 3-5: Average Monthly Energy (GWh) for Upper Salmon Generating Station

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	Existing System With Upper Salmon Bypass			**Existing System Without Upper Salmon Bypass**		
January	34.83	23.22	11.61	33.68	22.50	11.17
February	43.07	28.71	14.35	42.44	28.29	14.15
March	61.33	40.93	20.40	61.22	40.81	20.41
April	57.10	38.33	18.77	57.03	38.34	18.69
May	53.63	37.09	16.53	53.27	36.69	16.57
June	42.72	30.42	12.31	42.91	30.52	12.39
July	28.55	22.92	5.63	29.35	22.69	6.66
August	20.53	15.99	4.54	21.32	16.57	4.75
September	23.55	19.42	4.13	24.11	18.88	5.23
October	36.61	28.57	8.04	36.54	28.08	8.47
November	53.13	36.57	16.56	53.16	36.41	16.76
December	46.32	30.96	15.36	46.20	30.88	15.32
	Existing System Plus Unit 8, With Upper Salmon Bypass			**Existing System Plus Unit 8, Without Upper Salmon Bypass**		
January	34.83	23.22	11.61	33.68	22.48	11.20
February	43.07	28.72	14.35	42.37	28.28	14.09
March	61.36	40.95	20.41	61.13	40.82	20.30
April	56.63	38.00	18.63	56.79	38.08	18.70
May	52.81	36.50	16.31	53.11	36.55	16.57
June	41.33	29.69	11.64	41.77	29.63	12.14
July	25.57	21.06	4.51	27.14	21.21	5.93
August	19.22	14.78	4.43	20.41	14.88	5.53
September	22.55	18.16	4.38	23.49	18.26	5.22
October	33.60	25.70	7.90	34.49	25.91	8.57
November	52.39	35.97	16.42	52.19	35.61	16.57
December	46.40	30.96	15.44	46.21	30.85	15.37

Table 3-6: Average Monthly Energy (GWh) for Bay d'Espoir Generating Station

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	Existing System With Upper Salmon Bypass			**Existing System Without Upper Salmon Bypass**		
January	345.68	253.27	92.40	342.44	251.24	91.20
February	343.34	243.90	99.44	340.76	242.91	97.86
March	301.43	232.94	68.49	299.18	231.83	67.35
April	249.36	203.47	45.89	250.77	204.25	46.52
May	164.48	129.20	35.28	166.96	130.92	36.04
June	110.86	81.69	29.18	112.94	83.80	29.14
July	110.84	78.87	31.97	110.30	79.08	31.22
August	114.59	80.60	33.99	114.23	80.43	33.80
September	124.73	90.74	33.99	125.52	92.38	33.14
October	174.36	139.63	34.73	175.33	141.02	34.31
November	260.41	209.50	50.91	261.19	210.01	51.18
December	313.49	234.85	78.63	313.88	235.10	78.77
	Existing System Plus Unit 8, With Upper Salmon Bypass			**Existing System Plus Unit 8, Without Upper Salmon Bypass**		
January	361.36	277.46	83.90	351.96	271.18	80.78
February	385.62	284.32	101.30	378.60	280.61	97.99
March	298.66	239.28	59.38	295.06	236.95	58.12
April	246.96	206.37	40.59	251.40	210.23	41.17
May	151.90	118.35	33.55	157.98	123.99	33.99
June	103.87	74.58	29.29	107.48	78.57	28.91
July	111.97	79.79	32.18	110.43	79.02	31.42
August	115.47	82.07	33.40	114.66	81.83	32.83
September	120.06	86.39	33.67	122.66	89.44	33.22
October	166.70	132.06	34.64	169.14	135.06	34.08
November	261.11	214.68	46.43	262.80	216.40	46.40
December	322.78	245.60	77.18	324.05	246.70	77.34

3.3.3 Impact on Distribution of Generation at Bay d'Espoir Generating Station

Figure 3-5 shows a comparison of the monthly box plot of the hourly generation at Bay d'Espoir plant. The following can be inferred from the figure:

- The optimized maximum hourly generation increased from near 600 MW for the existing plant to well over 700 MW, with the addition of Unit 8, in the fall to spring months of October to May.
- There is a significant increase in optimized maximum generation in June and September with the addition of Unit 8.

- There is a reduction in optimized maximum generation in July and August, with addition of Unit 8, an indication that energy is moved from these low load months to high load months.
- The 25th to 75th percentile spread in the winter months of December to March is much wider with the addition of Unit 8, an indication of significant energy movement from off-peak period to on-peak period in these high load months.

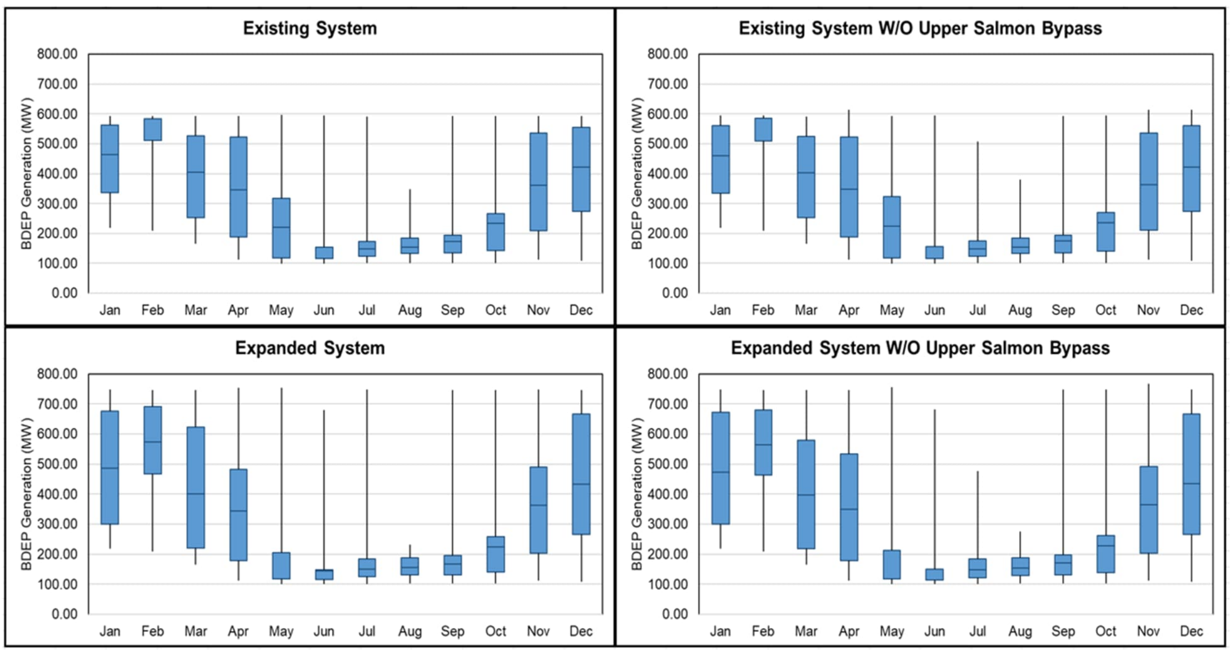

Figure 3-5: Variation in Hourly Bay d'Espoir Plant Generation by Month

Figure 3-6 shows a comparison of the hourly generation duration curves of the four scenarios. The curves for existing system with and without Upper Salmon bypass are identical. Similarly, the curves for existing system plus Unit 8 with and without Upper Salmon bypass are identical. The figure has the following distinct segments.

- A segment representing 18.6 percent of the time when generation with addition of Unit 8 is higher than that of the existing system. These are typically on-peak hours.
- A second segment representing 27.9 percent of the time when generation with addition of Unit 8 is lower than that of the existing system. These are off-peak hours from which energy is moved to the on-peak hours.

- A third segment representing 53.5 percent of the time when generation with the existing and system and the expanded systems are identical. These are hours when the committed firm load is just met.

The optimized maximum generation for the existing Bay d'Espoir plant is 597.3 MW which increased to 747.4 MW with addition of Unit 8. This is an optimized increase of 150.1 MW during some of the on-peak hours. It is less than the 154.4 MW capacity of Unit 8 because the gain in on-peak hour generation is at the expense of off-peak hour generation during which firm load must also be met. To increase on-peak hour generation to 154.4 MW will compromise meeting of firm load in some off-peak hours which will then have to be met from other resources.

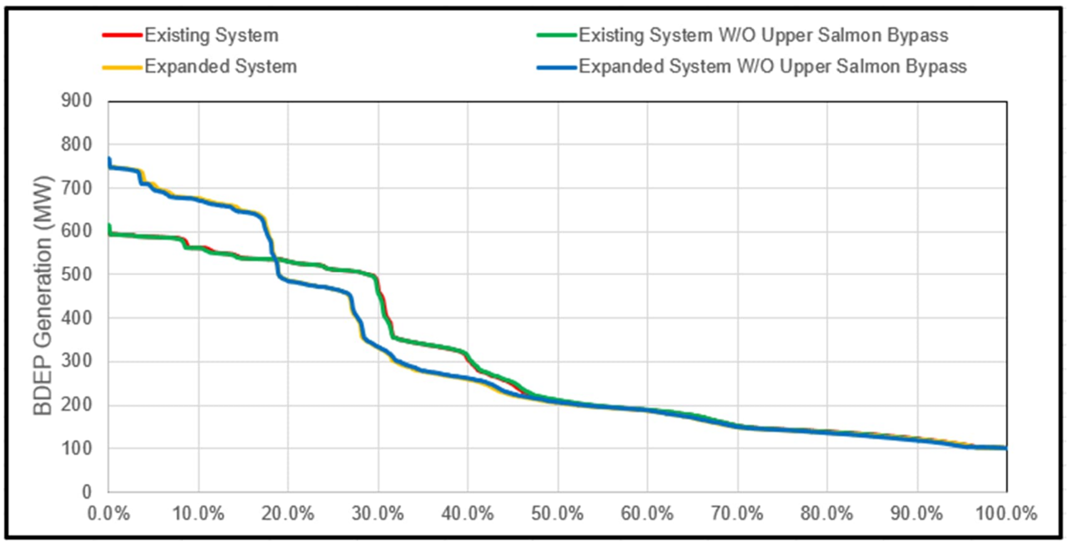

Figure 3-6: Duration Curves of Hourly Bay d'Espoir Plant Generation

The model does indeed employ Unit 8 at its full 154.4 MW capacity, being the first unit in scheduling order (discussed in the 2020 study). However, the model optimizes the total Bay d'Espoir plant output, with the objectives of meeting the defined firm every hour and maximizing average energy. Output at full rated capacity of the plant is possible, but there would be a tradeoff with reduced firm and average simulated energy. Likewise, increased duration of output in the high range (e.g., 700+ MW) is also possible, but with the tradeoff of reduced firm and average simulated energy. This condition is a result of the Bay d'Espoir system being modelled in isolation for the purposes of this analysis. Through optimization of Hydro's full hydraulic resources, which was not simulated as part of this study, resources can likely be managed to fully mitigate the potential for energy shortfall from the Bay d'Espoir system to achieve an optimized increase in maximum generation equal to the full unit capability of 154.4 MW. Hydro's intent is not to generate more from the Bay d'Espoir plant on an energy basis, but rather to shift generation from the off-peak hours and non-winter period to the on-peak hours and winter period (i.e., Labrador-Island Link deliveries and/or other on-island generation can be used to replenish the Bay d'Espoir system during the off-peak periods).

The information provided by Hydro on the hydromechanical equipment, head losses and tailwater do not indicate any physical restrictions to prevent Unit 8 from attaining 154.4 MW, or the Bay d'Espoir plant from attaining its full rated capacity, if there is water in the reservoir.

3.3.4 Impact on Efficiency of Bay d'Espoir Generating Station

The efficiency curve used for Unit 8 is the same as in earlier study and there is no change on BDE plant efficiency from earlier study.

3.3.5 Upper Salmon Bypass and West Salmon Spillway Usage

The Upper Salmon bypass (i.e., North Salmon spillway) is used to pass flows from the Upper Salmon reservoir to Long Pond while bypassing the Upper Salmon plant. According to Hydro, reasons for this may include periods of high inflow that exceed the capacity flow at the Upper Salmon plant and cannot be stored; periods when the Upper Salmon plant is shut down; and when necessary to delay water from reaching the Long Pong reservoir to provide more time to generate water out of the Long Pond reservoir when the Long Pond water level is high.

It was shown in Figure 3-6 that the duration curve of the Bay d'Espoir hourly generation is identical with or without Upper Salmon bypass. This suggests that the bypass is rarely needed to maintain peaking at the plant. So, it is desirable to examine the usage of the bypass and West Salmon spillway.

Figure 3-7 shows duration curves of hourly flows in the North Salmon Spillway and Figure 3-8 shows the duration curves of hourly flows in the West Salmon spillway. The North Salmon spillway is used 2.5 percent and 3.0 percent of the time for the existing and expanded systems respectively. West Salmon spillway is used only 0.2 percent of the time for both the existing and expanded systems when the North Salmon spillway is available. The spillway is used 10.1 percent and 11.8 percent of the time for the existing and expanded systems respectively without the bypass in the system. There are no spills at Long Pond in any of the scenarios as the capacity driven requirement for generation from Bay d'Espoir is higher than the capacity flow at the Upper Salmon plant.

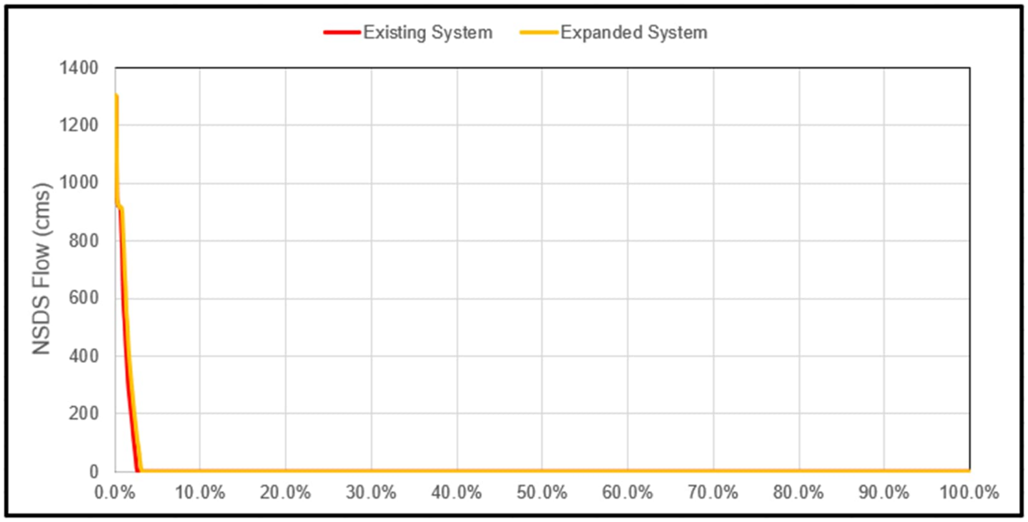

Figure 3-7: Duration Curves of Hourly Flows in the North Salmon Spillway

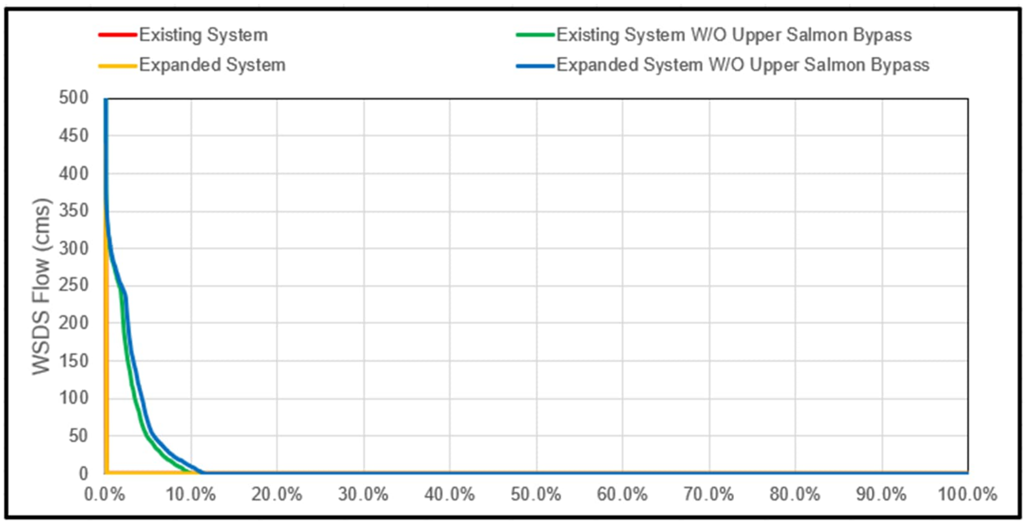

Figure 3-8: Duration Curves of Hourly Flows in the West Salmon Spillway

3.3.6 Impact on the Operation of Upper Salmon Hydroelectric Generating Station

Figure 3-9 shows the monthly box plot of the power flow at Upper Salmon. The impact on generation is very subtle and there are slight noticeable differences between the existing and expanded systems operation only in the high load months of January to March. Operations in the rest of the year are quite identical. Comparing the existing and expanded case with the bypass and focusing on the boxes in the box plot, power flows for the expanded case are slightly higher in January to March. In cases without the bypass, power flows are also higher in the expanded system than the existing system in January to March.

Figure 3-10 shows the duration curves of the hourly generation efficiency at the plant. It can be seen in the figure that, as a result of the January to March increased power flow in the expanded system, the plant is operated slightly less often, 80.8 percent of the time in the expanded system compared to 82.6 percent of the time in the existing system. There is also a loss of efficiency about 3.6 percent of the time in the expanded system compared to the existing system.

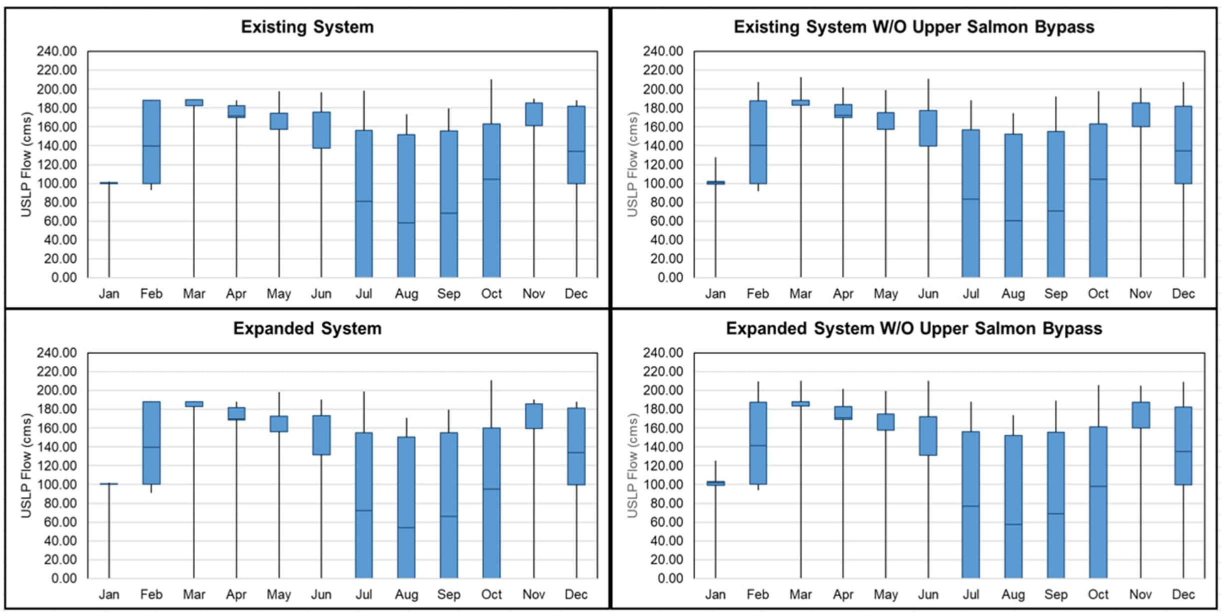

Figure 3-9: Variation in Hourly Upper Salmon Generation Flow by Month

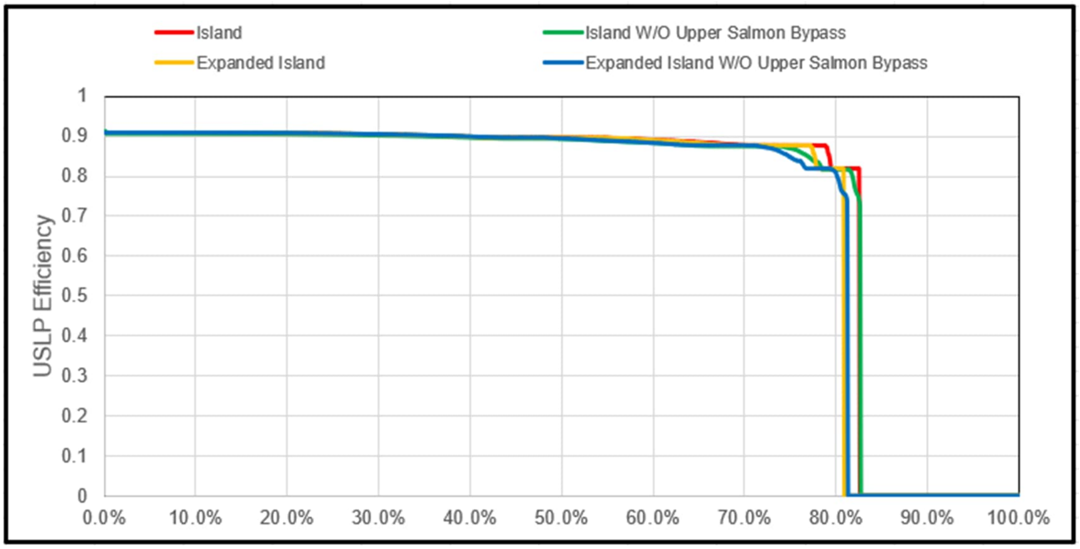

Figure 3-10: Duration Curves of Hourly Generation Efficiency at Upper Salmon Plant

3.3.7 Recommended Range of Storage of the Bay d'Espoir System Reservoirs in Advance of Winter Operating Season

The range of simulated monthly end elevations of the three large reservoirs are presented in the following sections. The optimization analysis in this study is for the Bay d'Espoir system alone. Therefore, these elevation ranges are those that maximize the economic benefits of the Bay d'Espoir system generation and not necessarily the overall Hydro generation system. With this recognition, ranges of end-of-November storage for each reservoir are recommended in this section, to maximize generation in the winter months and allow room for possible early winter high flow. If levels at the end of November are lower than the recommended ranges, the system may not be able to achieve as much peaking in winter. If reservoir levels at the end of November are lower than the recommended ranges, it is likely that energy can be sourced, such as from the LIL, to support reservoir storage.

3.3.7.1 Victoria Reservoir

Figure 3-11 shows the variation in monthly end elevation of Victoria Reservoir. The elevation ranges and variations are identical across all scenarios. An elevation range of 323.59 m to 325.39 m representing the 25th to the 75th percentiles is recommended at the end of November for Victoria Reservoir.

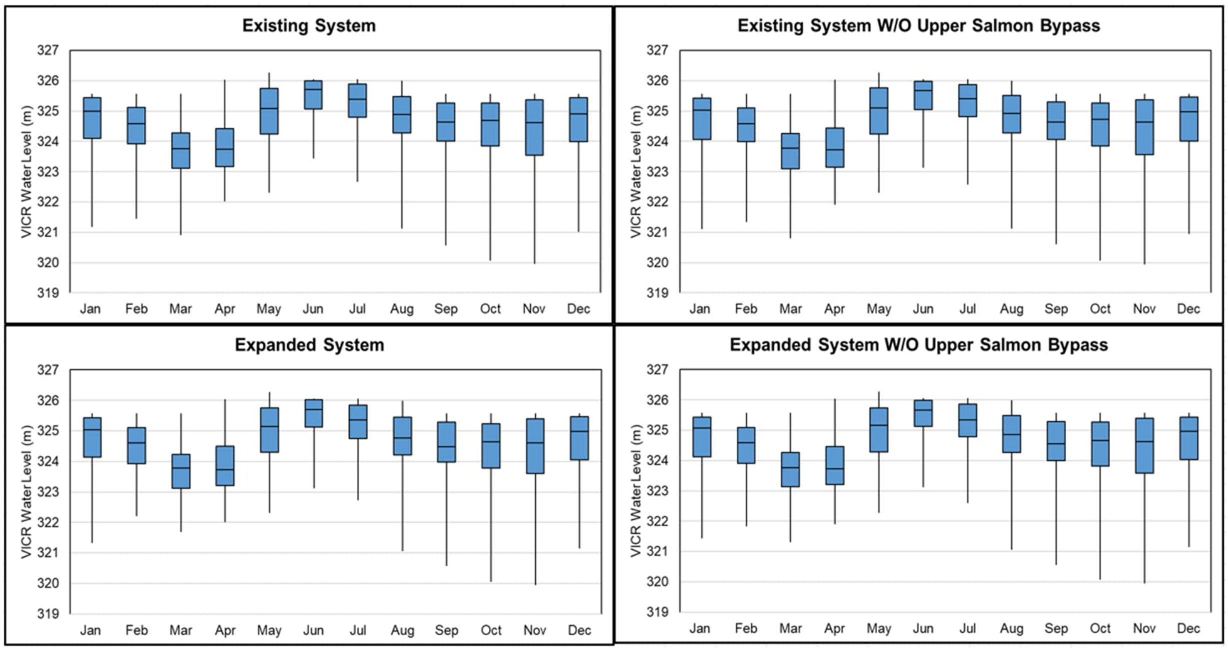

Figure 3-11: Variation in Victoria Reservoir Monthly End Elevation

3.3.7.2 Meelpaeg Reservoir

Figure 3-12 shows the variation in monthly end elevation of Meelpaeg Reservoir. The variation is different in the winter months of January to May for the expanded system. In these months, the 25th to 75th percentiles are both wider and lower for the expanded system than for the existing system. The minimum elevations for the expanded system are also lower in these months. However, the variation and range of elevations in November are identical across all scenarios. An elevation range of 271.72 m to 272.18 m representing the 25th to the 75th percentiles is recommended at the end of November for Meelpaeg Reservoir.

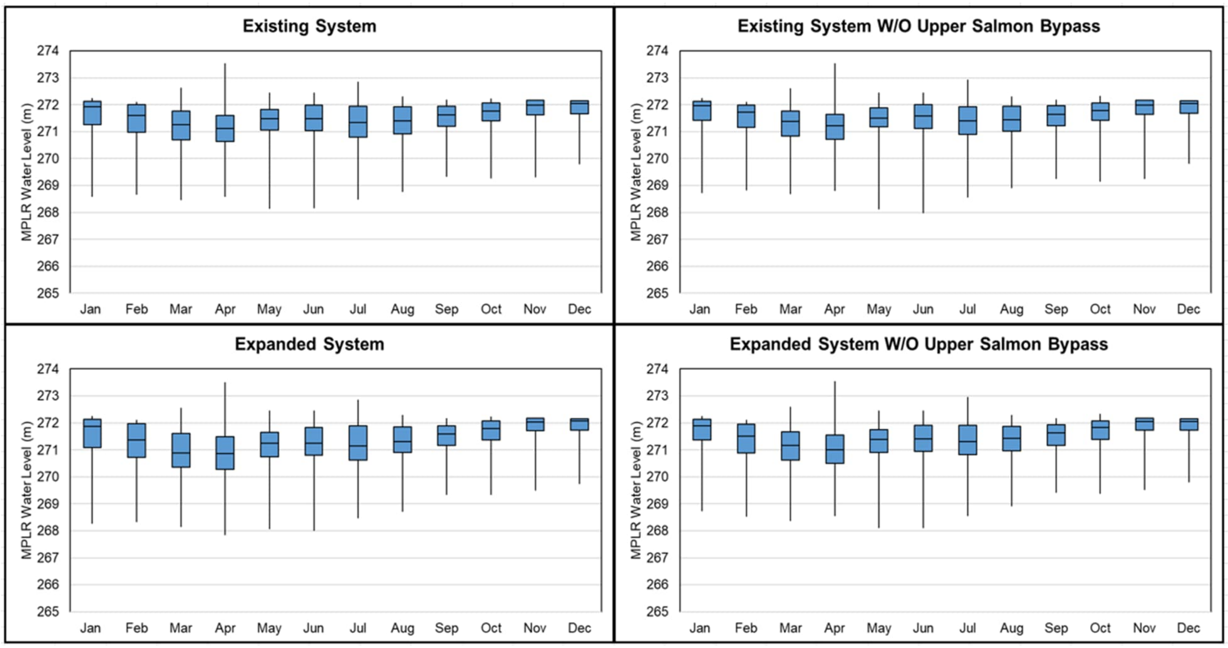

Figure 3-12: Variation in Meelpaeg Reservoir Monthly End Elevation

3.3.7.3 Long Pond Reservoir

Figure 3-13 shows the variation in monthly end elevation of Long Pond Reservoir. The elevation ranges and variations are identical across all scenarios from December to May with some differences in the remaining months of the year. The November elevation range is tight. This month has the highest minimum month end elevation in each of the scenarios to provide storage for optimum generation through winter. Therefore, an elevation range of 182.22 m to 182.25 m is recommended at the end of November for the Long Pond Reservoir. 182.22 m is the minimum end of November elevation of the four scenarios and 182.25 m is the 75th percentile of the November end elevation across all scenarios.

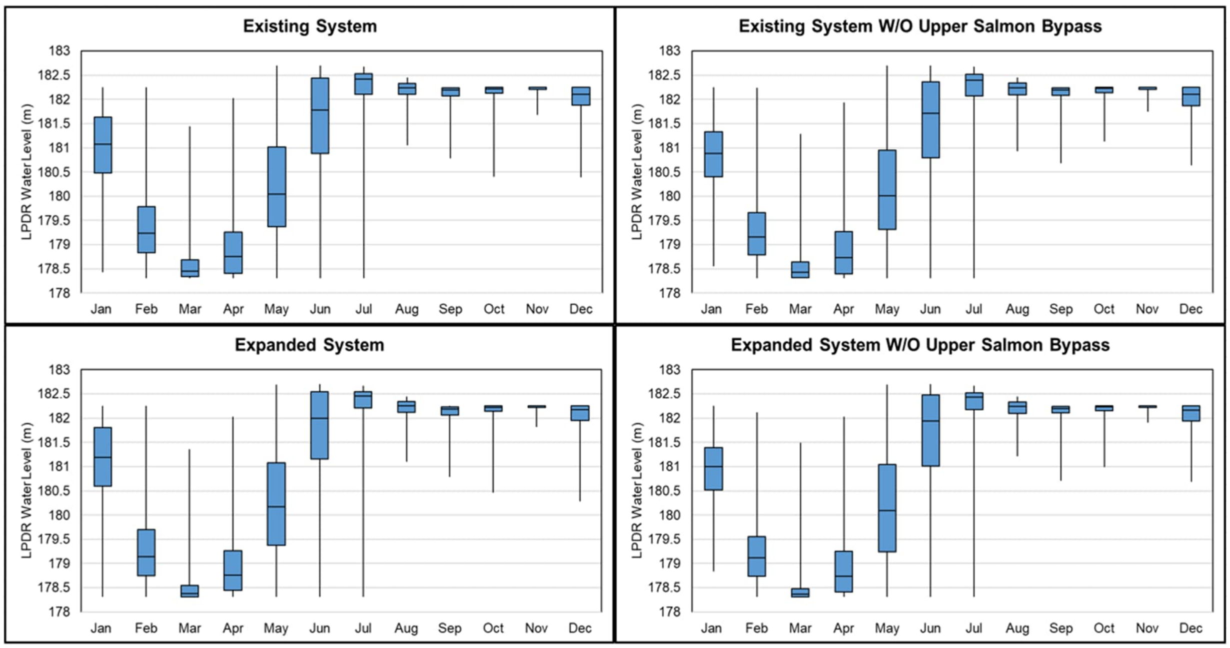

Figure 3-13: Variation in Long Pond Reservoir Monthly End Elevation

4. Conclusions

4.1 Conclusions

The conclusions of the update are as follows.

1. This update study confirms the results of the earlier study.
2. The firm energy estimate for the Bay d'Espoir system with Unit 8 is 294 MWc, down from the earlier estimate of 297.5 MWc. This reduction is attributed to the revised historic inflows and updated load forecast.
3. The simulated average annual energy of the existing Bay d'Espoir system is 3,359.74 GWh. With the addition of Unit 8, it increases to 3,381.19 GWh, due to higher efficiency of the new unit and some spill capture.
4. The simulated average annual energy of the Bay d'Espoir plant is 2,613.56 GWh. The simulated average annual energy of the plant with the addition of Unit 8 is 2,646.46 GWh, an increase of 1.26 percent.
5. With the addition of Unit 8, the simulated hourly generation of the Bay d'Espoir plant increases 18.6 percent of the time and decreases 27.9 percent of the time. The increased generation occurs during on-peak hours while the decreased generation occurs during off-peak hours.
6. The study also confirmed the optimum utilization of the new unit. It will be the most efficient unit in the plant and should be base loaded.
7. The simulated hourly optimized generation capacity increase at the Bay d'Espoir plant is 150.1 MW with addition of Unit 8. This is less than the 154.4 MW capacity of the new unit because, although the model utilizes the full capacity of Unit 8, it optimizes the total Bay d'Espoir plant output to meet the defined firm load while maximizing energy. The increase in simulated on-peak generation is at the expense of simulated off-peak generation. This condition is a result of the Bay d'Espoir system being modelled in isolation for the purposes of this analysis. Through optimization of Hydro's full hydraulic resources, which was not simulated as part of this study, resources can likely be managed to fully mitigate the potential for energy shortfall from the Bay d'Espoir system to achieve an optimized increase in maximum generation equal to the full unit capability of 154.4 MW.
8. With addition of Unit 8, simulated Bay d'Espoir plant efficiency increases are in the range of 0.16 to 1.83 percent, with an average of 0.76 percent.
9. The North Salmon bypass spillway is used only 2.5 percent of the time in the simulation of the existing system, and 3.0 percent of the time with addition of Unit 8. The bypass may be used during periods of high inflow that exceed the capacity flow at the Upper Salmon plant and cannot be stored; periods when the Upper Salmon plant is shut down;

and when necessary to delay water from reaching the Long Pong reservoir to provide more time to generate water out of the Long Pond reservoir when the Long Pond water level is high.

10. There is a slight loss of simulated efficiency at Upper Salmon plant with addition of Bay d'Espoir Unit 8. This loss occurred 17.98 percent of the time.
11. The information provided by Hydro on the hydromechanical equipment, head losses and tailwater does not indicate any physical restrictions to prevent Unit 8 from attaining 154.4 MW, or the Bay d'Espoir plant from attaining its full rated capacity, as long as there is water in the reservoir.
12. This study also re-examined the end-of-November elevation ranges and reconfirmed the range from the earlier study, that is, the large storage reservoirs in the system to optimize Bay d'Espoir system generation in the winter months while allowing room for possible early winter high flow.
    - Victoria: 323.59 m to 325.39 m
    - Meelpaeg: 271.72 m to 272.18 m
    - Long Pond: 182.22 m to 182.25 m.

    If levels at the end of November are lower than the recommended ranges, the system may not be able to do as much peaking in winter.

5. References

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