2024 Resource Adequacy Plan

Technical Conference #4: Expansion Plan, Insights and Next Steps

October 29, 2024

newfoundland labrador hydro

Safety Moment

Experts Present Today

- **Jennifer Williams,** President & CEO
- **Robert Collett,** Vice President, Engineering & NLSO
- **Gail Randell,** Director, Major Projects & Asset Management
- **John Walsh,** Sr. Manager, Major Projects & Engineering
- **Ryan Cooper,** Mechanical Engineer
- **Samantha Tobin,** Sr. Manager, Resource & Production Planning
- **David Goosney,** Team Lead, Long-Term Resource Planning
- **Phil DiDomenico,** Managing Consultant, Daymark (Virtual)

Opening Statement

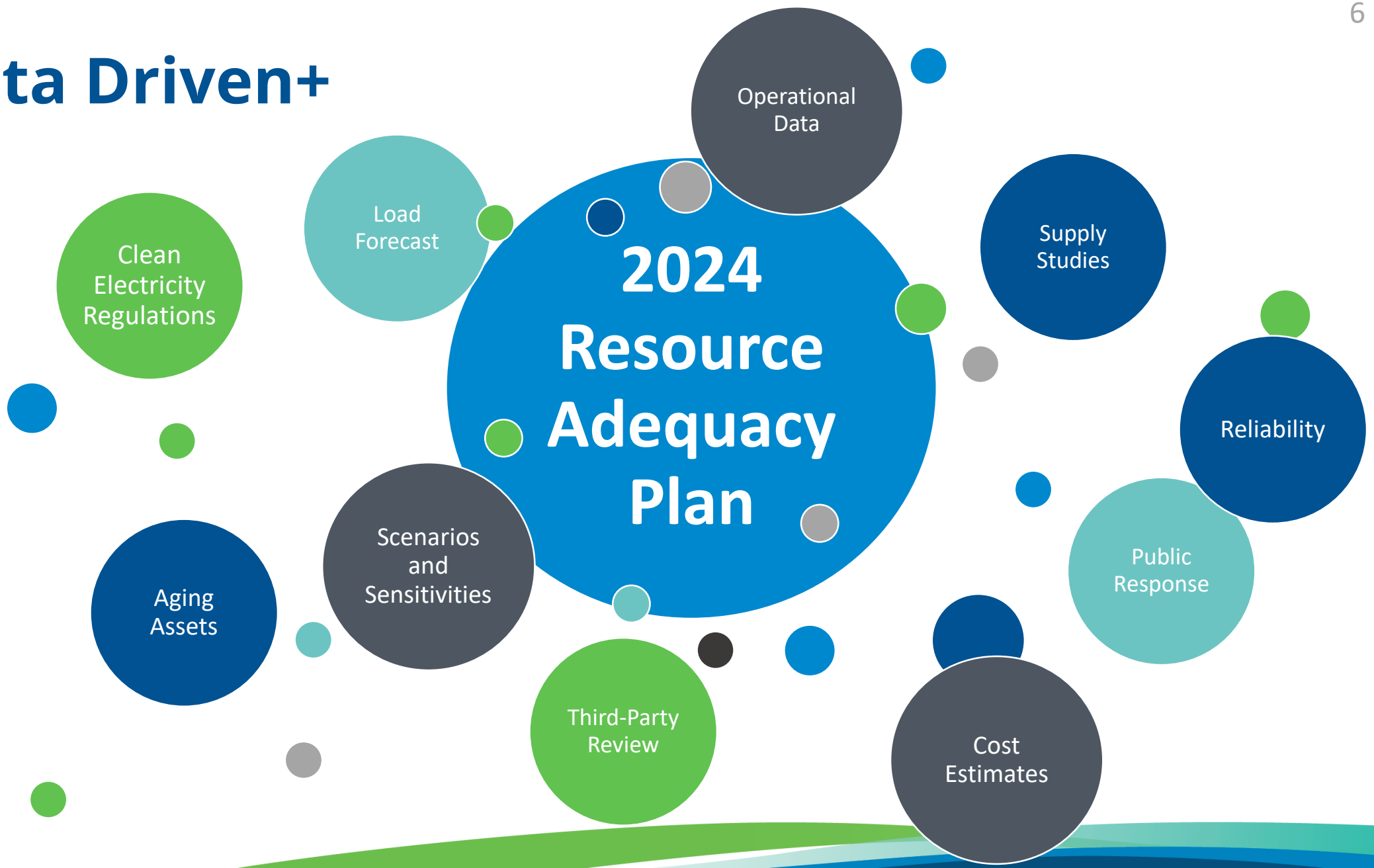
Takeaways

1. Our recommendations are **supported by data, experience, expertise, and customer feedback.**

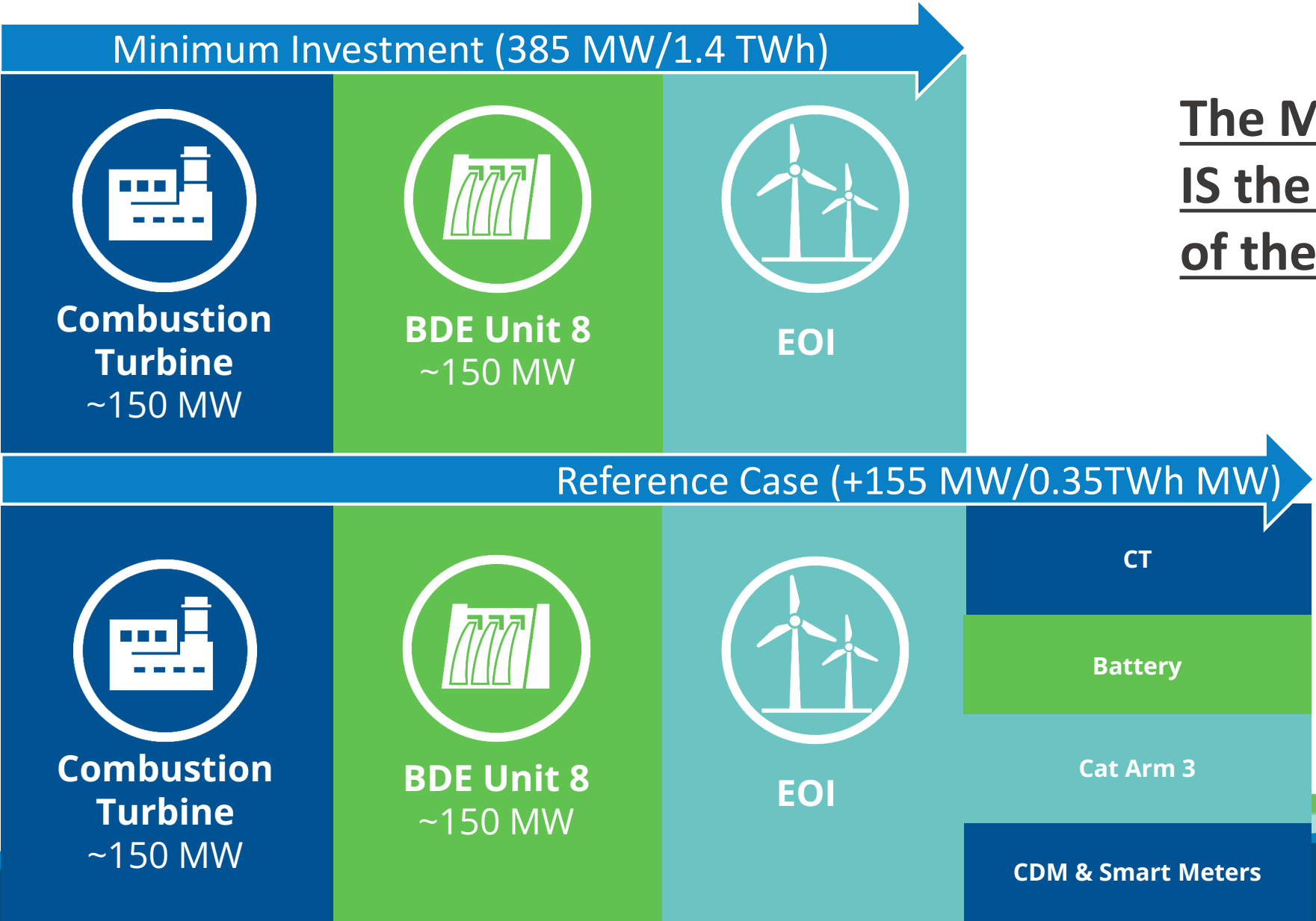
2. It isn't a question of Minimum Investment **vs.** Reference.

3. The Resource Adequacy Plan **is a living plan.**

1. Data Driven+



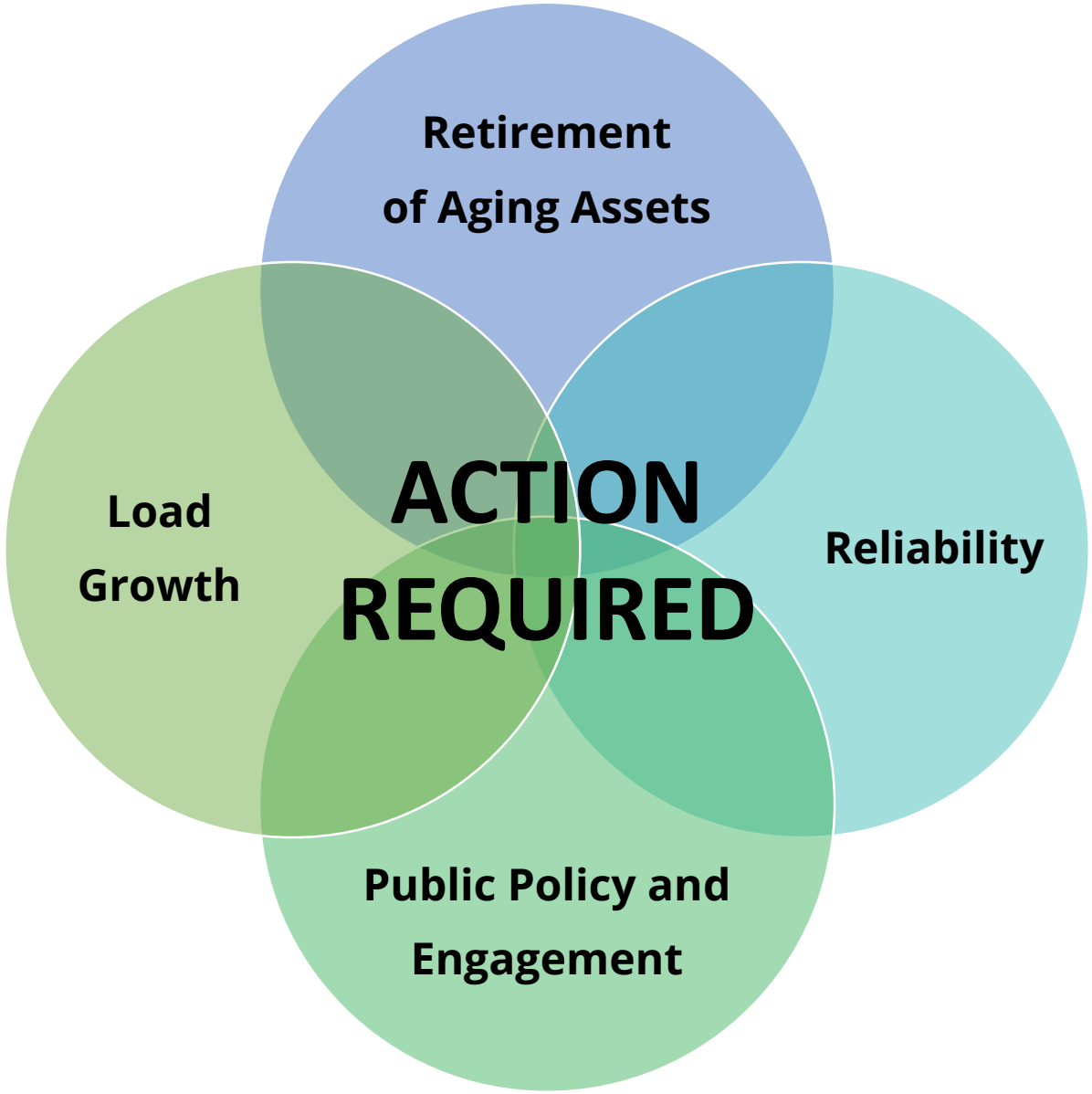
2. Minimum and Reference Investment Needs



The Minimum Case IS the first steps of the Reference Case.

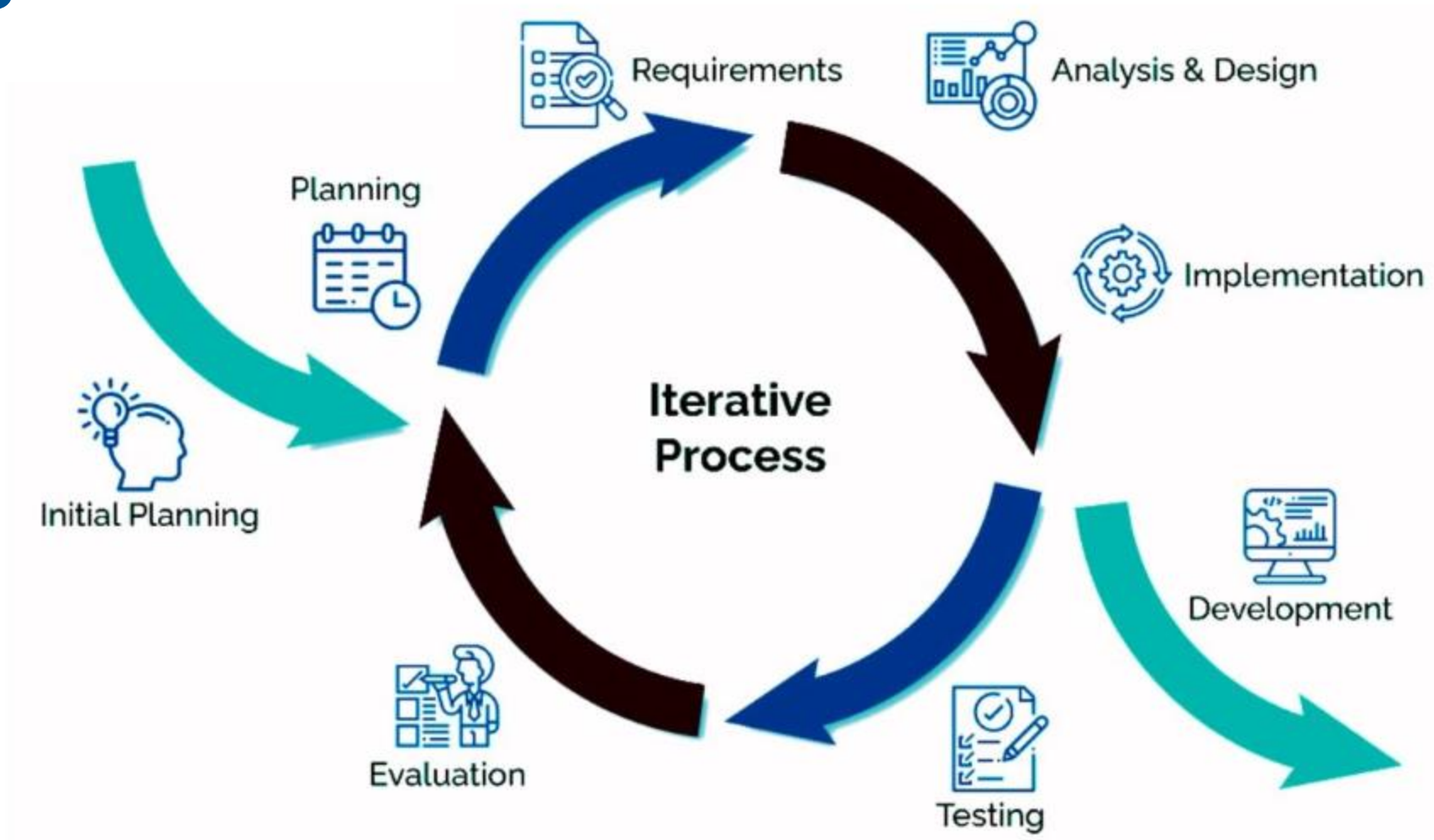
The gap is incremental – NOT different.

Supply options to fill this gap to be further refined and expected recommendations in 2026 filing.


Retirement
of Aging Assets
Load
Growth
ACTION
REQUIRED
Reliability
Public Policy and
Engagement

What We Know

3. A Living Plan



What If?

- **We see higher load growth?**
  - Extend assets beyond 2030 if necessary.
- **We see lower load growth?**
  - Minimum Investment is conservative and expected to materialize regardless of policy change.
  - Must plan for Labrador-Island Link (“LIL”) Shortfall Contingency and transition away from base-load thermal.
- **The LIL is more reliable (meaning LIL EqFOR <1%)?**
  - Must plan for LIL Shortfall Contingency even at a low equivalent forced outage rate (“EqFOR”).
- **We wait?**
  - Increased risks to cost, schedule and reliability.

“Rigour and speed are not incompatible.”

- Electricity Canada

2024 State of the Canadian Electricity Industry

Ready for What's Next

- We have the data we need to make informed decisions.
- Not Reference vs. Minimum – these first decisions are supported by both.
- This is a living plan.

Desired Conference Outcomes

Newfoundland and Labrador Hydro ("Hydro") aims to address parties' issues and questions and provide adequate information in relation to the 2024 Resource Adequacy Plan to achieve consensus amongst the parties on the following topics:

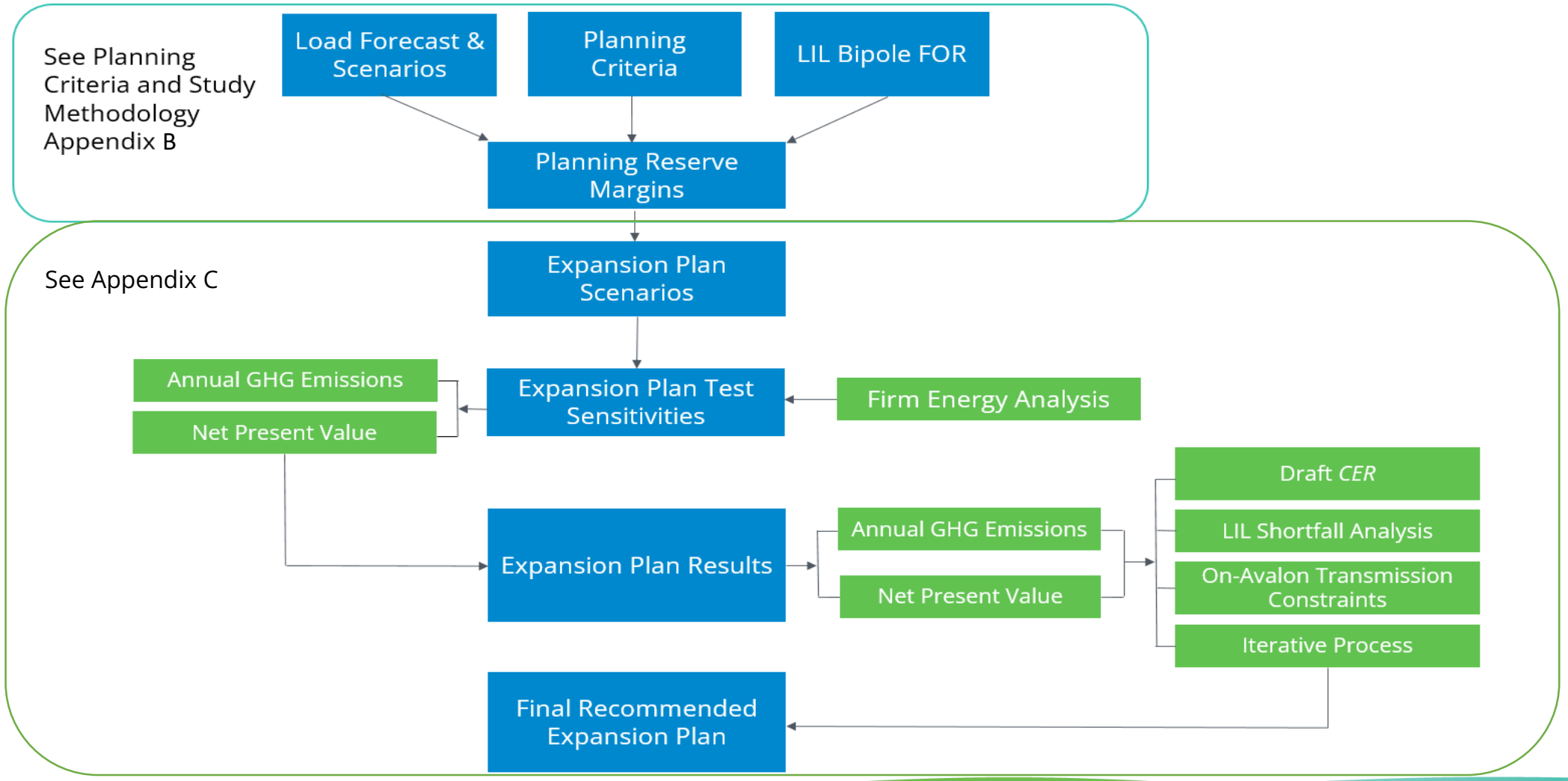
- Confirm that assumptions underlying Hydro's Minimum Investment Case are appropriate.
- Alignment on the selection of the Minimum Investment Required Expansion Plan.
- Understanding of how Hydro develops major project budgets as a result of cost estimates and risk analysis.
- Opportunity for feedback on the authorized spend approach to facilitate approval of future build applications.

Issue 7: Expansion Plan, Insights and Next Steps

Agenda: Expansion Plan, Insights and Next Steps

- Expansion Plan Results:
  - Expansion Plan Development Process
  - Additional Scenario Runs
  - Summary of Resource Selections
  - Minimum Investment Required Expansion Plan
- Next Steps
  - Major Projects Overview
  - Phased Approval Process
  - Cost Estimates
  - Risk Analysis and Project Budgets
  - Front-End Engineering Design (“FEED”)
  - Expression of Interest (“EOI”)
  - Risk Mitigation
  - 2025–2026 Next Steps

Expansion Plan Development Process



Expansion Plan Development Process

- The development process for the Expansion Plan was segmented into three steps:
  - Step 1: Development of Scenarios (Appendix C, Section 6.1)
    - Eight Expansion Plan scenarios that included variations of Island load forecast, LIL bipole EqFOR, and planning criteria.
  - Step 2: Development of Sensitivities (Appendix C, Section 6.2)
    - There were 11 sensitives identified to further test Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required) Expansion Plan scenarios.
    - The sensitivities considered parameters such as capital costs, fuel costs, limitations on certain resource options, variations in battery effective load carrying capacity (“ELCC”), etc.
  - Step 3: Further Analysis of Expansion Plans (Appendix C, Section 7.0)
    - Further analysis of the Expansion Plan was performed regarding the draft Clean Electricity Regulations, the LIL-shortfall analysis, On-Avalon transmission constraints, and an iteration between the rate, load forecast, and Expansion Plan requirements.

Expansion Plan: Wind

Assessment of 2024 Resource Adequacy Plan:

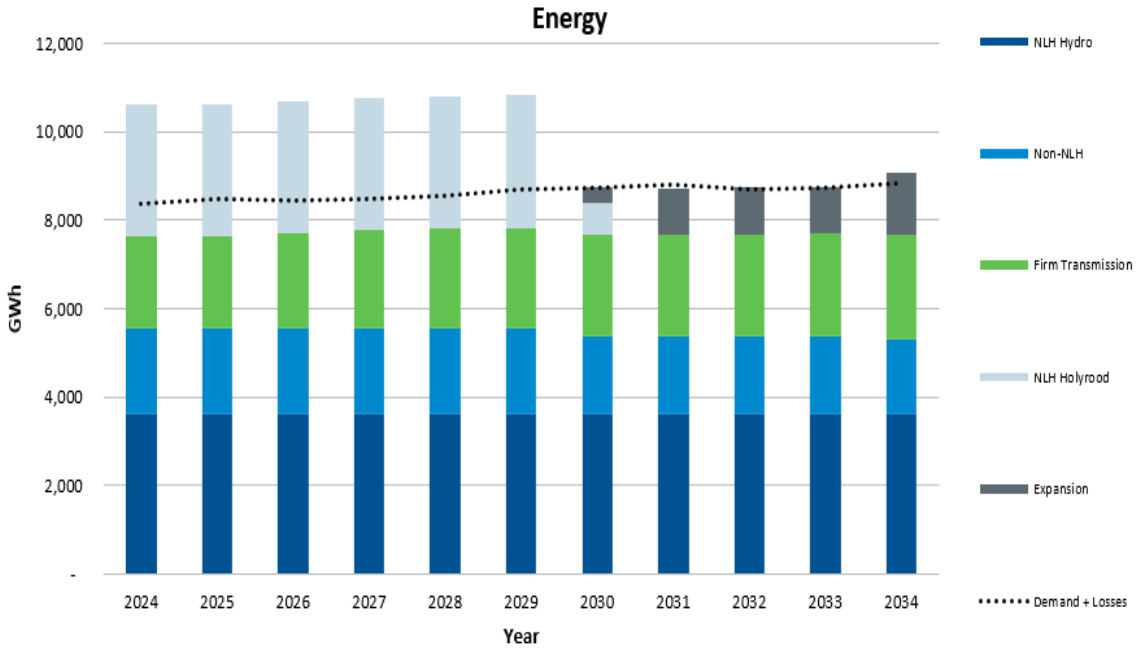
- *Clarify why the addition of wind in the lowest cost portfolios is later than in other portfolios, and confirm wind resource needs in 2030 (#55).*

Expansion Plan: Wind

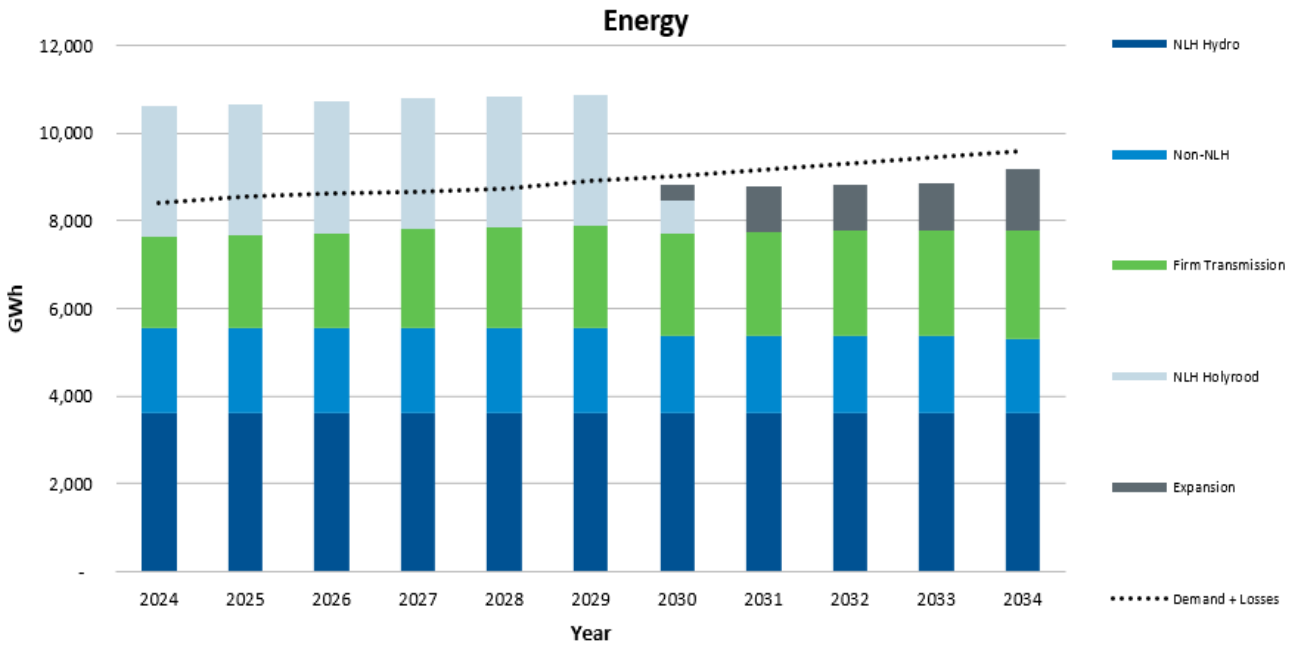
- Consistent amongst all load forecast scenarios, once the Holyrood Thermal Generating Station retires in 2030, the Island Interconnected System will no longer meet its firm energy criteria without expansion.
- The energy resource additions across scenarios varied only by the load forecast scenario applied.
  - **Slow Decarbonization:** Initial firm energy requirement totaling 100 MW of wind, escalating to a total of 400 MW of wind by the end of the study period, providing approximately 1.40 TWh of energy to the Island Interconnected System.
  - **Reference Case:** Initial firm energy requirement totaling 200 MW of wind, escalating to a total of 500 MW of wind by the end of the study period, providing approximately 1.75 TWh of energy.
  - **Accelerated Decarbonization:** Initial firm energy requirement totaling 300 MW of wind, escalating to a total of 700 MW of wind by the end of the study period, providing approximately 2.45 TWh of energy.

Expansion Plan: Wind

Energy Load Resource Balance: Slow Decarbonization



Energy Load Resource Balance: Reference Case



- The firm energy requirements to meet the Slow Decarbonization load forecast is 100 MW of wind which provides 350 GWh of firm energy in 2030.
- The firm energy requirements between the Slow Decarbonization and Reference Case load forecast is 350 GWh, or one 100 MW wind build by 2034.

Expansion Plan Results

Assessment of 2024 Resource Adequacy Plan:

- *Clarify whether BESS projects would be selected over a CT when CT costs are assumed to be higher than baseline (#56).*
- *Consider providing a LIL Shortfall Analysis assessment of a portfolio that included BESS (#58).*

Battery Energy Storage System ("BESS") Projects vs. CT

- New sensitivities were completed with the Combustion Turbine ("CT") capital cost increased by 50% combined with a range of battery ELCC (40%/60%/80%).
  - The table below describes each new sensitivity.
  - These sensitivities were applied to both Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required).

Sensitivity	Description
AB40H	Fixed wind profile to meet firm energy criteria, assumed battery ELCC of 40%, and increased CT capital costs by 50% in consideration of potential cost overruns
AH	Fixed wind profile to meet firm energy criteria, assumed battery ELCC of 60%, and increased CT capital costs by 50% in consideration of potential cost overruns
AB80H	Fixed wind profile to meet firm energy criteria, assumed battery ELCC of 80%, and increased CT capital costs by 50% in consideration of potential cost overruns

BESS vs. CT: Scenario 1 (Reference Case)

- Scenario 1AB40H: Reference Case, fixed wind, batteries at 40% ELCC and CT capital costs +50%.

	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
Bay d'Espoir ("BDE") Unit 8	154.4	0		1	1	1	1
Cat Arm ("CAT") Unit 3	68.2	0		1	1	1	1
LM6000 CT	141.6	0		1	1	1	2
Wind	22	350	2	4	5	5	5
Firm Capacity (MW)			44	452	474	474	616
Firm Energy (GWh)			700	1,400	1,750	1,750	1,750

- With a 40% ELCC for BESS, they are not chosen as the least-cost expansion option.

BESS vs. CT: Scenario 1 (Reference Case)

- Scenario 1AH: Reference Case, fixed wind, batteries at 60%, and CT capital costs +50%.

	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CAT Unit 3	68.2	0		1	1	1	1
Battery 50 MW	30	0		3	3	5	6
Wind	22	350	2	4	5	5	5
Firm Capacity (MW)			44	401	423	483	513
Firm Energy (GWh)			700	1,400	1,750	1,750	1,750

- With a 60% ELCC for BESS, they displace the CT as the least-cost expansion option, but not BDE Unit 8.

BESS vs. CT: Scenario 1 (Reference Case)

- Scenario 1AB80H: Reference Case, fixed wind, batteries at 80% ELCC and CT capital costs +50%.

	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CAT Unit 3	68.2	0					
Battery 50 MW	40	0		4	4	5	6
Wind	22	350	2	4	5	5	5
Firm Capacity (MW)			44	402	424	464	504
Firm Energy (GWh)			700	1,400	1,750	1,750	1,750

- With an 80% ELCC for BESS, batteries were chosen as the least-cost expansion option over both the CT and CAT Unit 3, but not BDE Unit 8.

BESS vs. CT: Scenario 4 (Minimum Investment Required)

- Scenario 4AB40H: Slow Decarbonization, fixed wind, batteries 40% ELCC and CT capital costs +50%.

	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CAT Unit 3	68.2	0					1
Wind	22	350	1	4	4	4	4
Firm Capacity (MW)			22	242	242	242	311
Firm Energy (GWh)			350	1,400	1,400	1,400	1,400

- Similar to 1AB40H With a 40% ELCC for BESS, they are not chosen as the least cost expansion option.

BESS vs. CT: Scenario 4 (Minimum Investment Required)

- Scenario 4AH: Slow Decarbonization, fixed wind, batteries at 60% ELCC and CT capital costs +50%.

	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
Battery 50 MW	30	0					1
Wind	22	350	1	4	4	4	4
Firm Capacity (MW)			22	242	242	242	272
Firm Energy (GWh)			350	1,400	1,400	1,400	1,400

- In 2034 the CT is replaced by one 50 MW battery with a firm capacity of 30 MW.

BESS vs. CT: Scenario 4 (Minimum Investment Required)

- Scenario 4AB80H: Slow Decarbonization, fixed wind, batteries at 80% ELCC and CT capital costs +50%.

	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
Battery 50 MW	40	0					1
Wind	22	350	1	4	4	4	4
Firm Capacity (MW)			22	242	242	242	282
Firm Energy (GWh)			350	1,400	1,400	1,400	1,400

- In 2034 the CT is replaced by one 50 MW battery with a firm capacity of 40 MW.

Shortfall Analysis: BESS vs. CTs

- In general, batteries provide a lower incremental reliability benefit as most of the supply shortage risk is during the winter period.
- A shortfall analysis scenario was included in the 2024 Resource Adequacy Plan to further analyze the reliability contribution of batteries as compared to CTs during a prolonged loss of the LIL in the winter (See Appendix C, Section 6.2.1.1.5).
- Four scenarios were completed where one 47.2 MW CT at a time was replaced with an equivalent 47.2 MW battery:
  - Scenario A: Three 47.2 MW CTs with no batteries;
  - Scenario B: Two 47.2 MW CTs with one 47.2 MW battery;
  - Scenario C: One 47.2 MW CTs with two 47.2 MW batteries; and
  - Scenario D: Three 47.2 MW batteries.
- Both four- and eight-hour batteries were analyzed.

Shortfall Analysis: BESS vs. CTs

Scenario	Description	Unserved Energy w/ Four- Hour Battery (GWh)	Increase in Unserved Energy (%)	Unserved Energy w/ Eight-Hour Battery (GWh)	Increase in Unserved Energy (%)
A	3, 47.2 MW CTs + No Batteries	1,752	-	1,752	-
B	2, 47.2 MW CTs + 1, 47.2 MW Battery	1,780	1.6	1,757	0.3
C	1, 47.2 MW CT + 2, 47.2 MW Batteries	1,921	9.6	1,881	7.3
D	No CTs + 3, 47.2 MW Batteries	3,036	73.3	2,894	65.2

Shortfall Analysis: BESS vs. CTs

- Batteries would have limited effectiveness in a shortfall situation but may be effective for capacities of up to 50 MW.
- Eight-hour batteries would have minimal incremental benefit in a shortfall situation.
  - Eight-hour batteries are double the cost of four-hour batteries.
- Due to uncertainty around the effectiveness of batteries in a shortfall scenario and uncertainty around the ELCC of batteries they are not part of Hydro's Minimum Investment Required Expansion Plan.
- Hydro expects that batteries do have a place on our system and will continue to study them as part of the 2025 ELCC Study and include them in the next Resource Adequacy Plan.

Sensitivities: Key Learnings

- For both scenarios tested, BDE Unit 8 is consistently being chosen by the model as the least-cost expansion option; however, CTs are cost-competitive to BDE Unit 8.
- When tested further, BDE Unit 8 remained the preferred expansion option if:
  - Fuel cost for CT increased by 50%.
  - The capital cost of the CT increased by 50%.
  - Both the CT fuel cost *and* the CT capital cost increased by 50%.
  - **The capital cost of the CT increased by 50% *and* batteries were not restricted.**
- When tested further, CT was the preferred expansion option if:
  - The forced annual burn-off was removed.
  - The capital cost of hydraulic expansion options increased by 50%.

Summary of Resource Selections

- The 2024 Resource Adequacy Plan provided results for 32 model runs.
- The table below has been updated to reflect the seven additional sensitivities completed for the technical conferences:
  - Scenario 1AH/AB40H/AB80H: Reference Case, fixed wind, batteries at 60%, 40% and 80% ELCC and CT capital costs +50%.
  - Scenario 4AH/AB40H/AB80H: Slow Decarbonization, fixed wind, batteries at 60%, 40% and 80% ELCC and CT capital costs +50%.
  - Scenario 4AEGH: Slow Decarbonization, fixed wind, no batteries, CT fuel costs +50% and CT capital costs +50%.

Resource Option	Runs Selected	% of Runs Selected
BDE Unit 8	33	85%
CT	29	74%
Cat Arm Unit 3	13	33%
BESS	9	23%

Summary of Resource Selections

- Scenario 1 (Reference Case)
  - Results for 13 model runs were included in the 2024 Resource Adequacy Plan.
  - An additional 3 were completed for these technical conferences, and the resource selection is summarized below.

Resource Option	Runs Selected	% of Runs Selected
BDE Unit 8	13	81%
CT	13	81%
Cat Arm Unit 3	6	38%
BESS	5	31%

Summary of Resource Selections

- Scenario 4 (Minimum Investment Required):
  - Results for 13 model runs were included in the 2024 Resource Adequacy Plan.
  - An additional 4 were completed for these technical conferences, and the resource selection is summarized below.

Resource Option	Runs Selected	% of Runs Selected
BDE Unit 8	14	82%
CT	10	59%
Cat Arm Unit 3	1	6%
BESS	4	24%

Expansion Plan - Minimum Investment Required

Assessment of 2024 Resource Adequacy Plan:

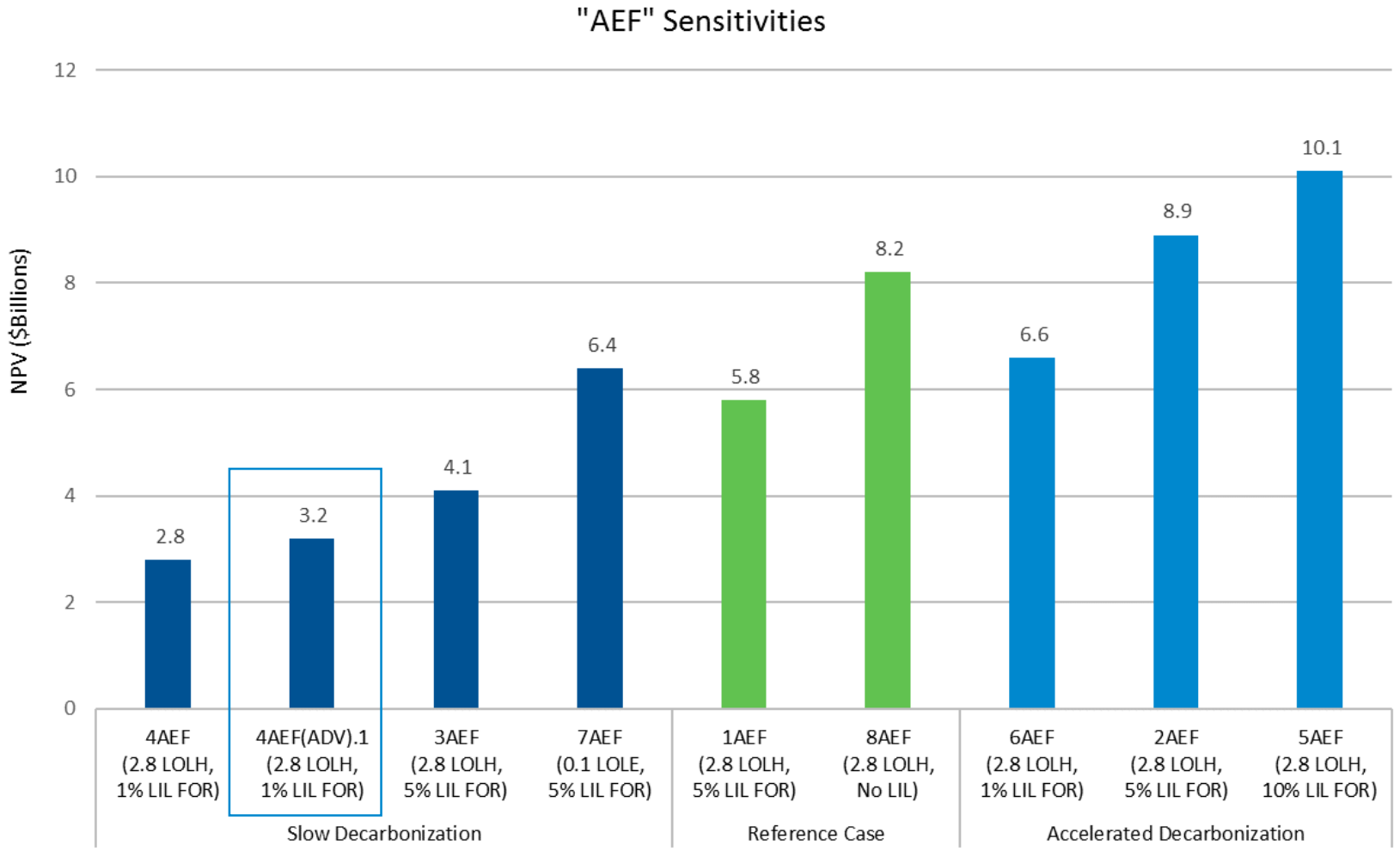
- *Specify the NPV of the 4AEF(ADV) project and the cost of moving the CT addition up to 2031 (#57).*

Minimum Investment Required Expansion Plan

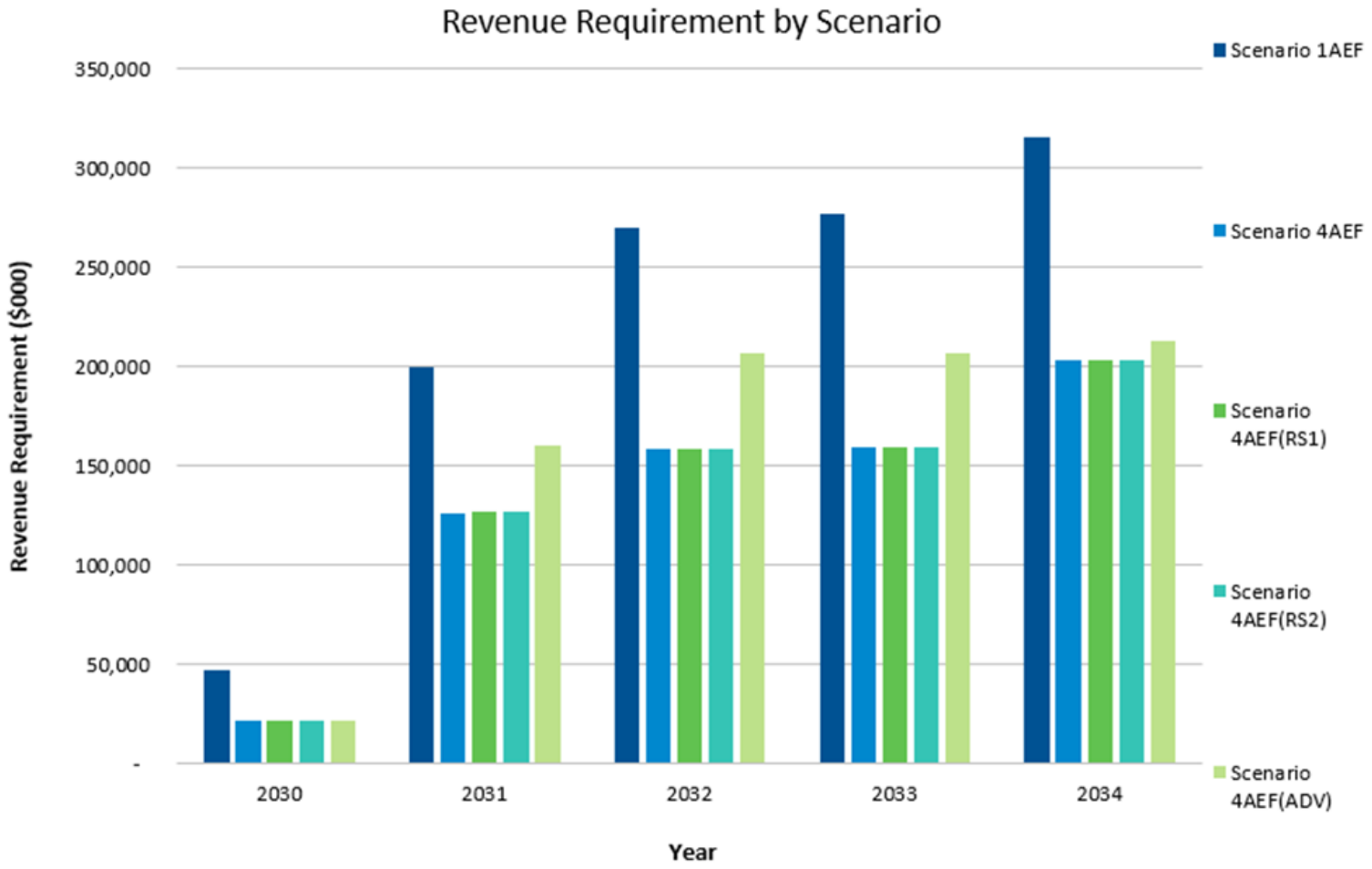
- The recommended Expansion Plan is referred to as Scenario 4AEF(ADV).1 (See Appendix C, Section 8.0).
  - Includes BDE Unit 8 and a CT coming into service in 2031 and up to 400 MW of wind energy by 2034.
  - Resulting in an additional 385 MW and 1.4 TWh added to the Island Interconnected System within the next ten years.

	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		1	1	1	1
Wind	22	350	1	3	3	3	4
Firm Capacity (MW)			22	362	362	362	384
Firm Energy (GWh)			350	1,050	1,050	1,050	1,400

CT Advanced to 2031: Net Present Value



CT Advanced to 2031: Revenue Requirement



- See Appendix C, Section 7.4.1 for additional information.

Expansion Plan - Minimum Investment Required

2024 Resource Adequacy Plan – Issues List:

NLH's "Minimum Investment Required Expansion Plan" does not meet all reliability requirements of the Reference Case. NLH proposes that in addition to the minimum investment (as a "first step"), it will monitor load growth and other factors to determine if more investment is needed. Is this reasonable, or should NLH be considering additional investment to meet the Reference Case scenarios?

Assessment of 2024 Resource Adequacy Plan:

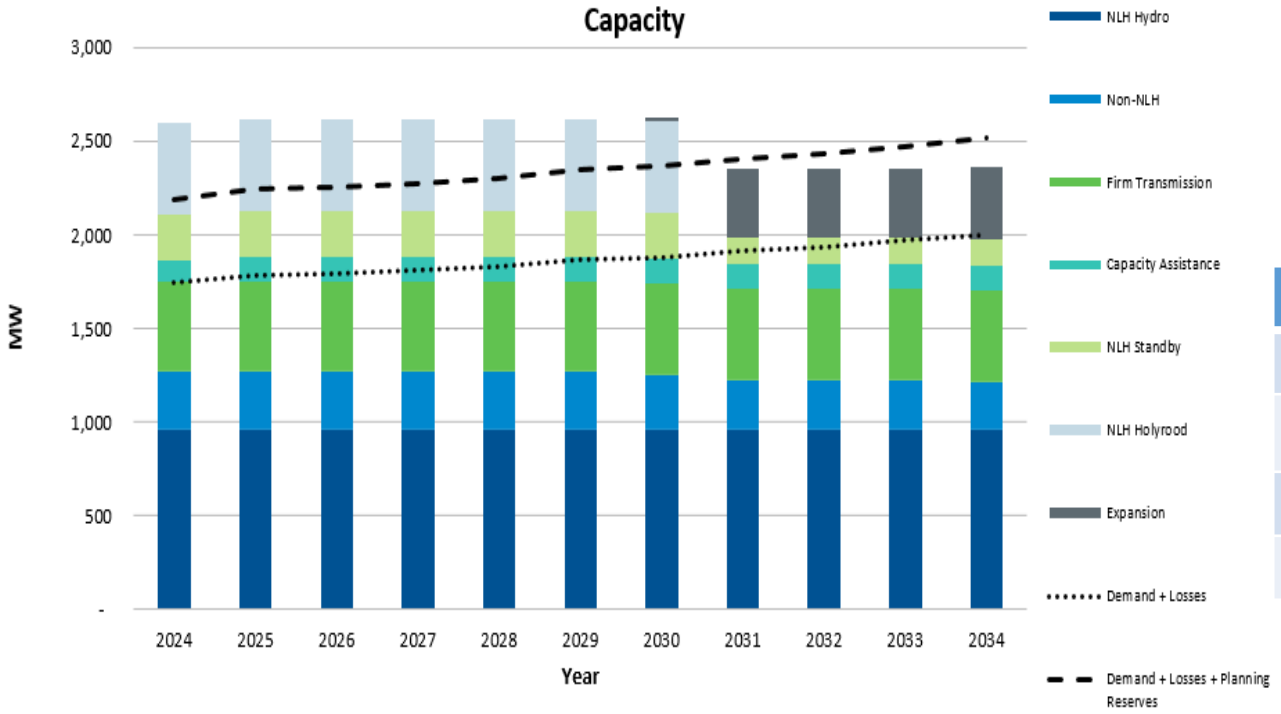
- *Vet and provide further details behind the recommended portfolio not meeting the reliability requirements of the reference case, not meeting the energy needs in the IIS load forecast, and the threat of prolonged LIL forced outage (#59).*

Recommended Expansion Plan: Resource Planning Criteria

- Hydro's Expansion Plan is driven by meeting three resource planning criteria:
  1. Probabilistic Capacity
     - The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours expectation target of not more than 2.8 hours per year.
  2. Firm Energy Requirement
     - The Island Interconnected System should have sufficient generating capability to supply all its firm energy requirements with firm system capability.
  3. LIL Shortfall Assessment
     - The Island Interconnected System should have sufficient generating capacity to limit the loss of load to a manageable level in the case of a LIL-shortfall event.

Recommended Expansion Plan: Probabilistic Capacity and LIL Shortfall Assessment

- Capacity Load Resource Balance Plot: Scenario 1 (Reference Case) versus Scenario 4 (Minimum Investment Required) expansion plan.
- The recommended resource options (in grey) meet both the probabilistic capacity requirements of the Minimum Investment Required expansion plan and the LIL shortfall criteria.

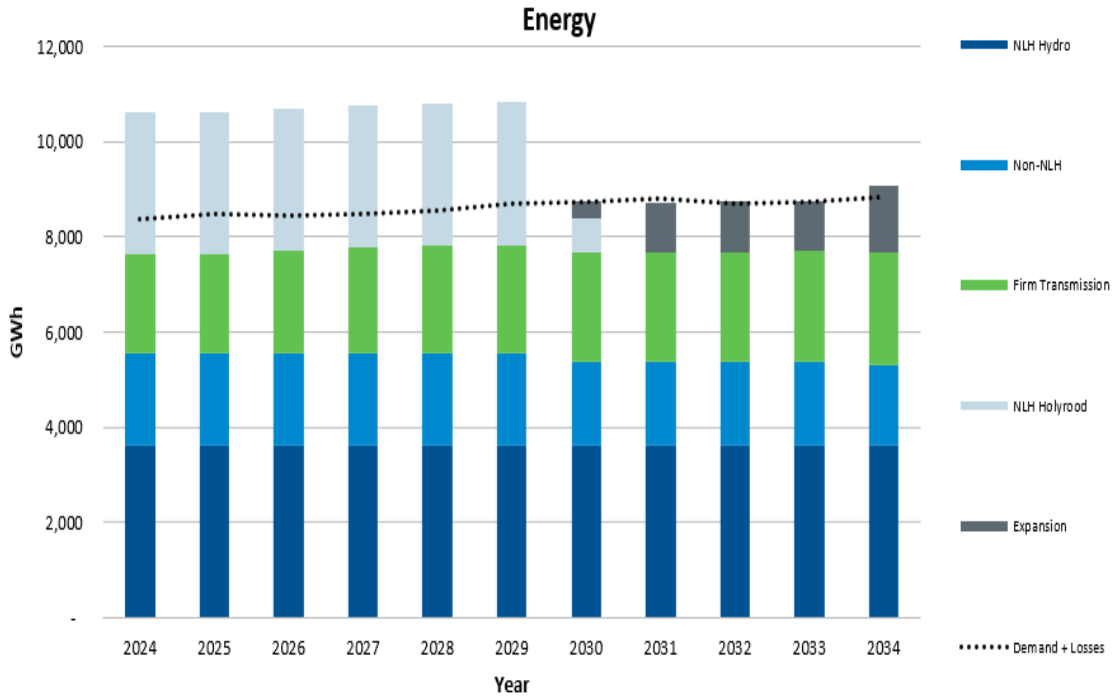


- The table reflects the annual capacity, including the capacity from the resources identified in the Minimum Investment Required Expansion Plan, compared to the additional capacity needed to meet the Reference Case.

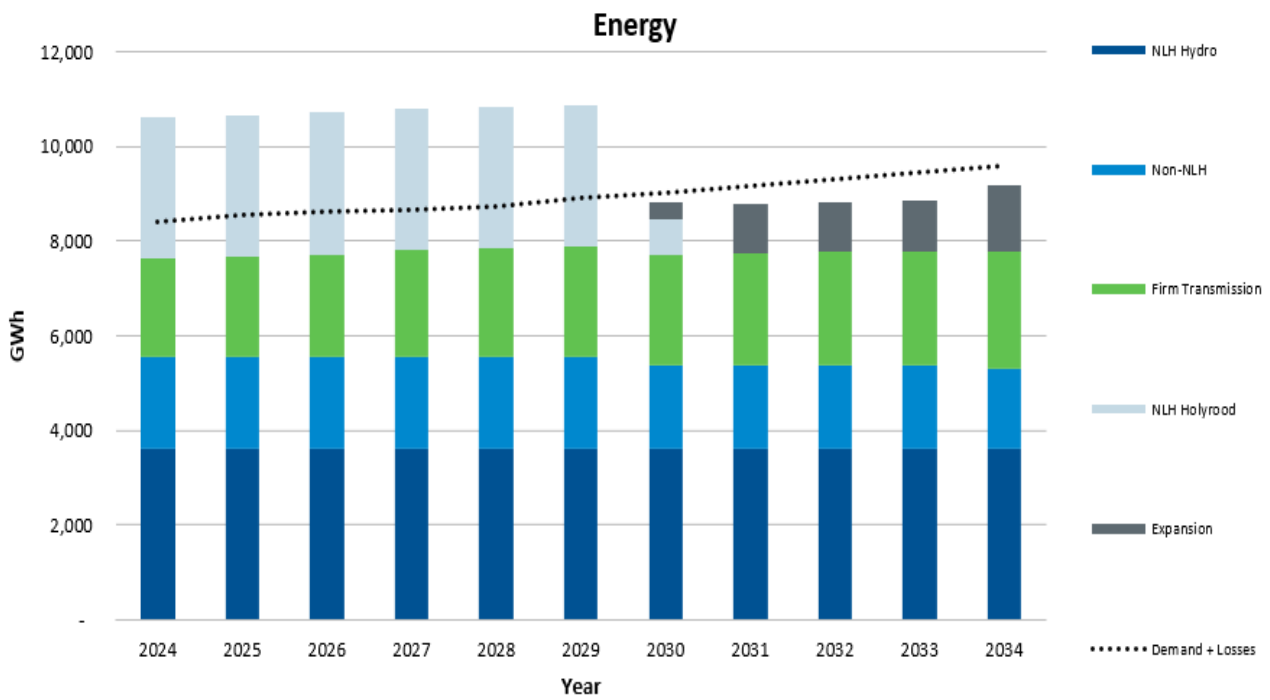
	Capacity Required per Year (MW)			
Scenario	**2031**	**2032**	**2033**	**2034**
4 (Minimum Investment Required)	2,347	2,347	2,347	2,361
1 (Reference Case)	2,408	2,437	2,475	2,515
Capacity Delta (MW)	**-61**	**-90**	**-128**	**-154**

Recommended Expansion Plan: Firm Energy Criteria

Energy Load Resource Balance: Slow Decarbonization



Energy Load Resource Balance: Reference Case



- The firm energy requirements between the Slow Decarbonization and Reference Case load forecast is 350 GWh in 2034 or one 100 MW wind build.

Recommended Expansion Plan

- The need for additional resources, even in the Minimum Investment Required, is substantial and Hydro considers this the first step.
- While the analysis shows the requirement for capacity in 2031, in reality, Hydro is working to advance both capacity resources as fast as possible to reduce the reliance on aging assets.
- Resource planning is a continuous process.
  - Hydro is actively working on next steps and evaluating the additional investment to meet the Reference Case.

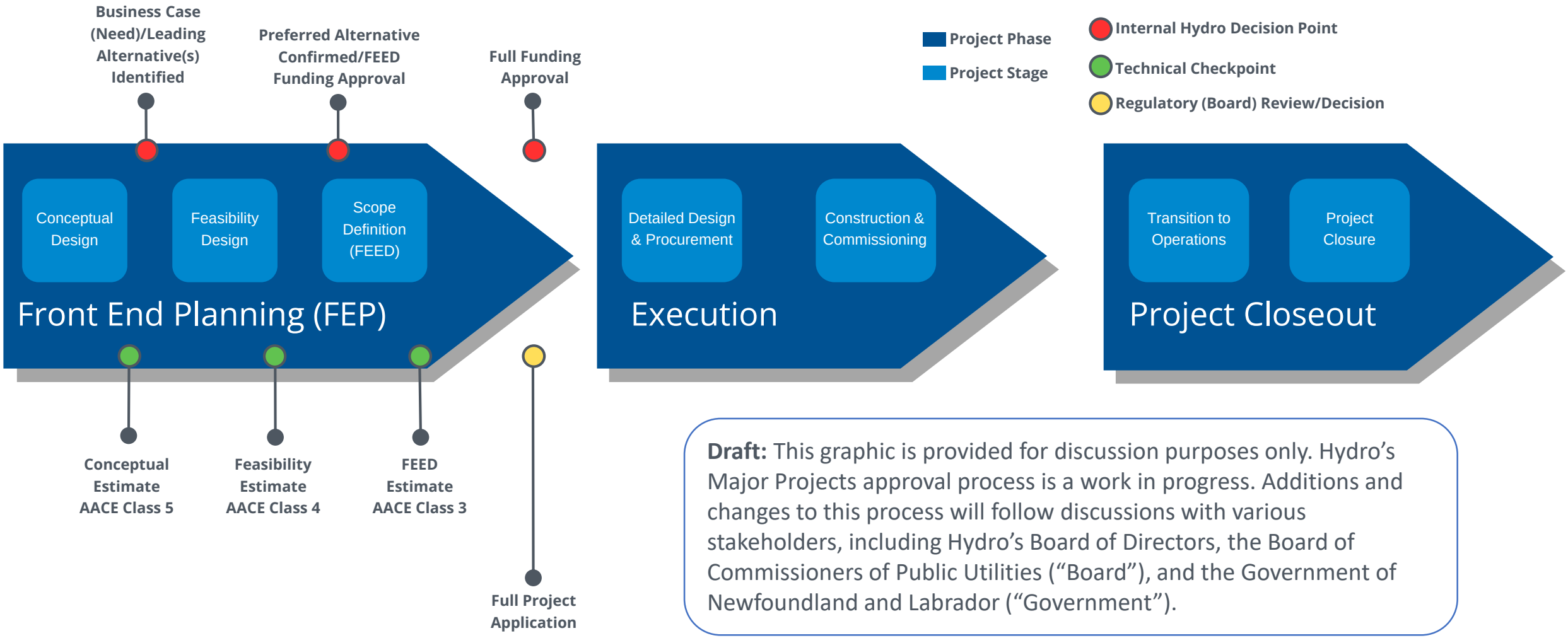
Next Steps

Next Steps: Major Project Department

- Hydro has implemented a new Major Projects Department. The department has two main goals:
  1. Get the organization ready for major projects.
  2. Execute major projects.

Key focus areas are implementing key governance structures including a staged approval process and maturing Hydro's cost estimating practices.

Next Steps: Phased Approval Process (DRAFT)



Draft: This graphic is provided for discussion purposes only. Hydro's Major Projects approval process is a work in progress. Additions and changes to this process will follow discussions with various stakeholders, including Hydro's Board of Directors, the Board of Commissioners of Public Utilities ("Board"), and the Government of Newfoundland and Labrador ("Government").

Next Steps: Cost Estimates

- Hydro has made significant steps to mature its cost estimating and project budget development skills including:
  - Improved front-end planning for major projects.
  - Training on industry practices for cost estimating and project budget development for all levels of the organization.
  - Engagement of senior estimating embedded contractors with major project experience.

Next Steps: Cost Estimates

How is Hydro improving its cost estimates?

1. Indirects and owner's costs.
2. Constructability reviews.
3. The Association for the Advancement of Cost Engineering's ("AACE") Guidelines for estimate accuracy including maturity matrices.
4. Quantitative risk analysis for project budget development.

Next Steps: FEED & AACE Maturity Matrices

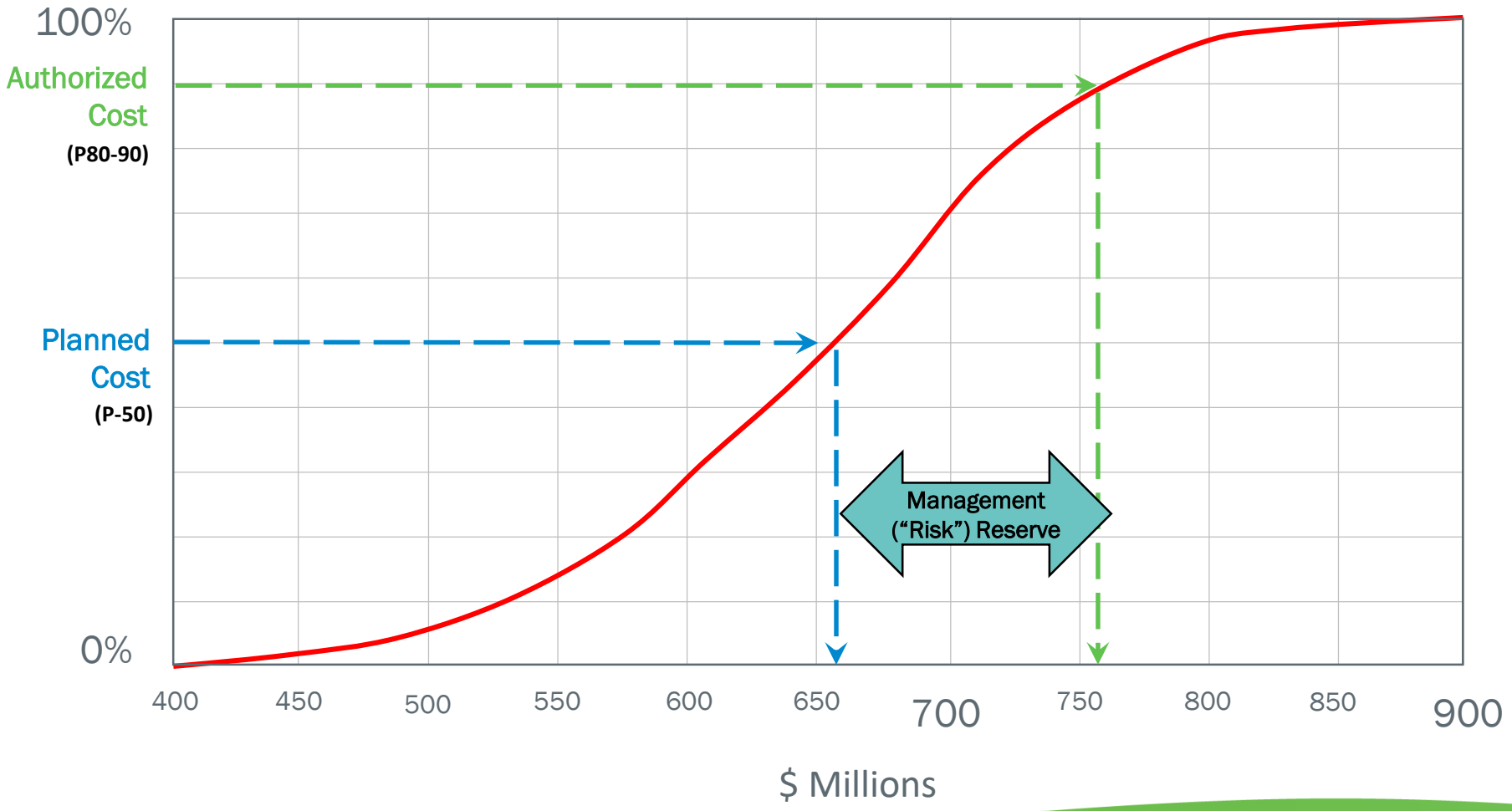
MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES	ESTIMATE CLASSIFICATION				
	CLASS 5	CLASS 4	CLASS 3	CLASS 2	CLASS 1
	0% to 2%	1% to 15%	10% to 40%	30% to 75%	65% to 100%
GENERAL PROJECT DATA:					
A. SCOPE:					
Project Scope of Work Description	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp etc.)	NR	P	D	D	D
B. CAPACITY:					
Facility Output / Production Profile	P	P	D	D	D
Electrical Power Requirements (when not the primary capacity driver)	NR	P	D	D	D
C. PROJECT LOCATION:					
Plant and Associated Facilities	P	P	D	D	D
D. REQUIREMENTS:					
Codes and/or Standards	NR	P	D	D	D
Communication Systems	NR	P	D	D	D
Fire Protection and Life Safety	NR	P	D	D	D
Environmental Monitoring	NR	NR	P	P	D
E. TECHNOLOGY SELECTION:					
N/A					
F. STRATEGY:					
Contracting / Sourcing	NR	P	D	D	D
Escalation	NR	P	D	D	D
G. PLANNING:					
Regulatory Approval & Permitting	P	P	D	D	D
Material Utilization (Borrow Sources)	P	P	P/D	D	D
Logistics Plan	P	P	P	D	D
Work Breakdown Structure	NR/P	P	P/D	D	D
Decommissioning Plan	NR	P	D	D	D
Integrated Project Plan[1]	NR	P	D	D	D
Project Code of Accounts	NR	P	D	D	D
Project Master Schedule	NR	P	D	D	D
Risk Register	NR	P	D	D	D
Stakeholder Consultation / Engagement / Management Plan	NR	P	D	D	D
Startup and Commissioning Plan	NR	P	P/D	D	D
H. STUDIES:					
Hydraulics	P	P	D	D	D
Topography and/or Bathymetry	P	P	P/D	D	D
Environmental Impact / Sustainability Assessment	NR	P	D	D	D
Environmental / Existing Conditions	NR	P	D	D	D
Soils and Hydrology	NR	P	D	D	D
Geotechnical Investigation	NR	P	P/D	D	D

AACE Maturity of Deliverables for Hydropower Projects

Not Required (NR)
Preliminary (P)
Defined (D)
Started (S)
Complete (C)

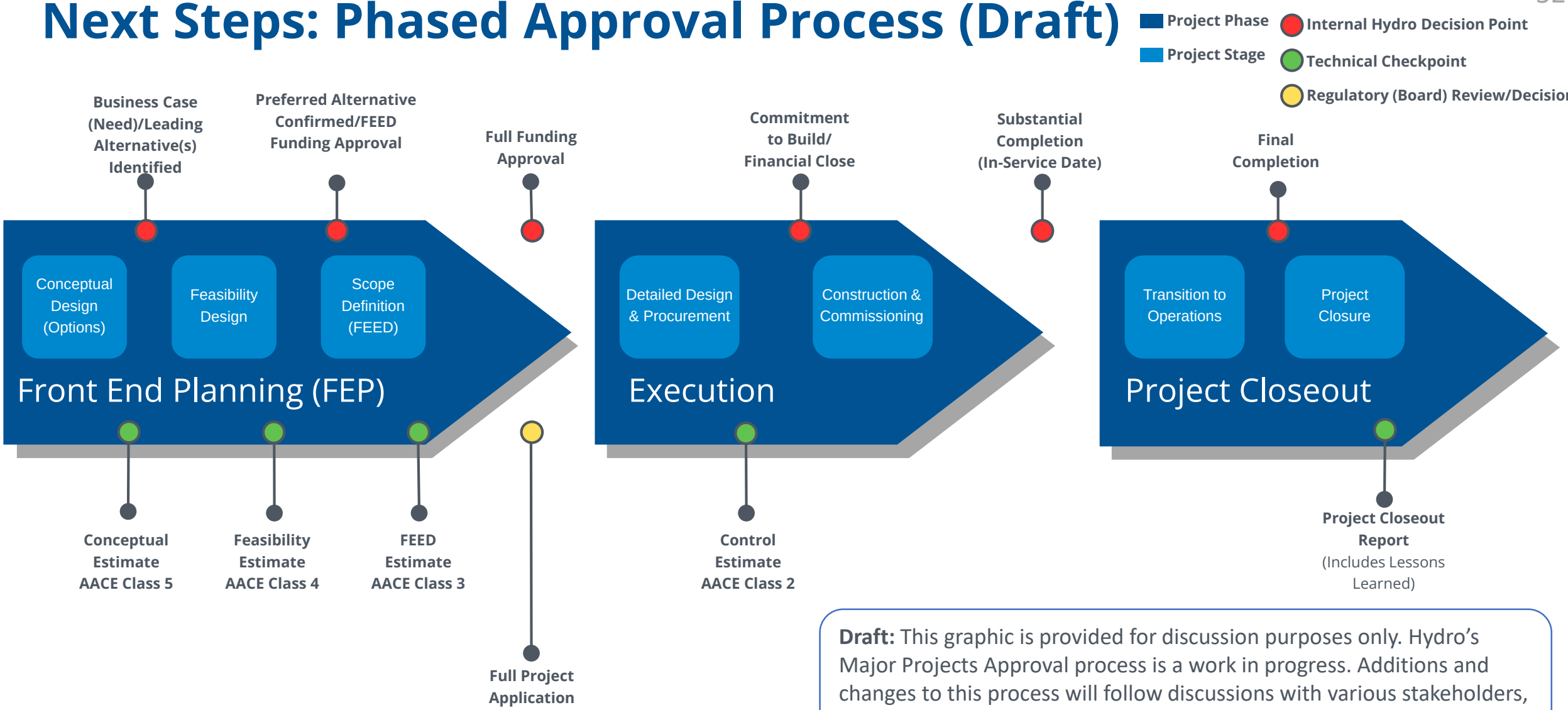
MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES	ESTIMATE CLASSIFICATION				
	CLASS 5	CLASS 4	CLASS 3	CLASS 2	CLASS 1
	0% to 2%	1% to 15%	10% to 40%	30% to 75%	65% to 100%
TECHNICAL DELIVERABLES:					
Block Flow Diagrams	S/P	C	C	C	C
Hydraulic Design and Probable Maximum Flood (PMF)	S	P	C	C	C
Equipment Datasheets	NR/S	P	C	C	C
Equipment Lists: Electrical	NR/S	P	C	C	C
Equipment Lists: Process / Utility / Mechanical	NR/S	P	C	C	C
Design Specifications	NR	S/P	C	C	C
Electrical One-Line Drawings	NR	S/P	C	C	C
General Equipment Arrangement Drawings	NR	S/P	C	C	C
Instrument List	NR	S/P	C	C	C
Construction Permits	NR	S/P	P/C	C	C
Civil / Site / Structural / Architectural Discipline Drawings	NR	S/P	P	C	C
Demolition Plan and Drawings	NR	S/P	P	C	C
Erosion Control Plan and Drawings	NR	S/P	P	C	C
Fire Protection and Life Safety Drawings and Details	NR	S/P	P	C	C
Mitigation Measures (Aquatic, Terrestrial, Avian, Clearing, Heritage etc.)	NR	S	P	C	C
Dam Design & Drawings	NR	S	P	P/C	C
De-Silting Basins	NR	S	P	P/C	C
Gates and Cranes Design & Drawings	NR	S	P	P/C	C
Intake Design & Drawings	NR	S	P	P/C	C
Penstock Design & Drawings	NR	S	P	P/C	C
Power House Design and Drawings	NR	S	P	P/C	C
Power Tunnel / Canal Design and Drawings	NR	S	P	P/C	C
Spillway Design & Drawings	NR	S	P	P/C	C
Turbine and Generator Design and Drawings	NR	S	P	P/C	C
Electrical Schedules	NR	NR/S	P	P/C	C
Instrument and Control Schedules	NR	NR/S	P	P/C	C
Instrument Datasheets	NR	NR/S	P	P/C	C
Spare Parts Listings	NR	NR	P	P/C	C
Electrical Discipline Drawings	NR	NR	S/P	P/C	C
Facility Emergency Communication Plan and Drawings	NR	NR	S/P	P/C	C
Information Systems / Telecommunication Drawings	NR	NR	S/P	P/C	C
Instrumentation / Control System Discipline Drawings	NR	NR	S/P	P/C	C
Mechanical Discipline Drawings	NR	NR	S/P	P/C	C
Auxiliary Electrical Design & Drawings	NR	NR	S	P	C
Auxiliary Mechanical Design & Drawings	NR	NR	S	P	C
Protection & Controls System Design & Drawings	NR	NR	S	P	C

Next Steps: Risk Analysis and Project Budgets



- Planned Cost is based on cost estimate plus contingency (around P50).
- Authorized Cost is based on risk analysis (around P80 - P90).
- Management ("Risk") Reserve = Authorized Cost - Planned Cost.
- The basis for the Planned and Authorized Costs will be outlined in the application.
- Hydro will seek Board approval of the Authorized Cost.
- Project team will be expected to deliver the project for the Planned Cost.
- Expansion Plan analysis will be done on the Planned Cost with Sensitivities using the Authorized Cost.

Next Steps: Phased Approval Process (Draft)



Draft: This graphic is provided for discussion purposes only. Hydro's Major Projects Approval process is a work in progress. Additions and changes to this process will follow discussions with various stakeholders, including Hydro's Board of Directors, the Board, and the Government.

Next Steps: Commitment to Build Decision

- A new Hydro decision point that addresses another recommendation from the Muskrat Falls Inquiry.
- Occurs:
  - After project approval.
  - Before construction when tender pricing for significant contracts is known.
  - Before financial close, if project-specific financing is used.
- Last decision point before major costs are committed.
  - Represents the moment that contractual commitments will be of the magnitude that project cancellation will likely be at considerable cost to the utility.
- Unique to each project, based on contracting strategy.

Collaboration with Canadian Utilities

- Canadian Electric Utilities Project Management Network
  - Consists of most major Canadian utilities.
  - Share lessons learned on governance, departmental structure, project planning criteria, contracting methodologies, estimating practices and execution risks/experiences.
- Similar Challenges and Sharing Solutions
  - Resources (internal and external).
  - Long lead items and Construction Market Changes.
  - Aging Utility Assets.
  - Share ideas on solutions (contracting strategy, planning criteria, etc.).
- Important for benchmarking and comparisons around Capital Programs
  - Portfolio Size, Regulatory Regimes, and complexities of each jurisdiction for project execution.

Next Steps – Decision to Progress FEED

2024 Resource Adequacy Plan – Issues List:

- *NLH states that it will "continue the advancement" of Bay d'Espoir Unit 8 and a 150 MW CT on Avalon, including "currently executing on FEED" studies on both projects. What issues should be considered regarding NLH's plan, including the cost and risk of moving these projects forward prior to regulatory application (let alone approval), the potential for alternative solutions, and the potential for supplemental resource adequacy modeling that may alter the recommended portfolio?*
- *In all cases, all existing thermal projects are retained until 2030, and no firm capacity additions are made prior to 2030. Is this a reasonable approach, or should NLH consider the impact of a pre-2030 asset retirement and new resource addition?*

Next Steps – Decision to progress FEED

- Hydro's supply stack consistently produced BDE Unit 8 and CT with a significant gap between those two solutions and other supply resource options.
- Hydro advanced FEED for these two supply options in order to produce a timely build application for review, considering the timeline for construction and commissioning to ensure adequate supply.
- Uncertainty is a reality within this process – Hydro must act on the best information available at this time, or risk insufficient supply for customers when increased demand arises.
- Hydro's analysis showed that a new generation is required in every scenario.
    - Mitigating risk of overspending by initial recommendation of Minimum Investment Required including the assets common to all scenarios.

Next Steps – FEED

2024 Resource Adequacy Plan – Issues List:

Regarding the FEED studies:

- *What is the planned timeline for each FEED study?*
- *Will the FEED studies resolve questions regarding the referenced fuel burn-off requirement for the CT prior to NLH's application?*

Assessment of 2024 Resource Adequacy Plan:

- *Provide detail on the planned timing for the FEED studies and clarify if these studies will resolve questions regarding the burn-off requirement (#61).*

Next Steps : FEED

- Significant work to progress both project planning and engineering design.
- Purpose is to develop a conceptual design of the project scope as a lead into detail design and full project execution. FEED assists the project team in understanding:
  - Costs
  - Schedule
  - Risks
  - Technical Challenges
- FEED Includes up-front engineering before sanction and execution.

Next Steps : FEED

FEED Deliverables

Avalon CT and BDE 8 Projects

- For the above FEED subject areas, both projects have approximately 110 documents/design deliverables for the ongoing FEED work.
- This constitutes months of early-stage design and project planning work in support of a proper plan, cost estimate and scope definition for each project.
- Engineering design completed to a substantial scope definition, information that will be carried forward and refined during detailed design.
- All this information is used to verify the class of estimate and as inputs to the project maturity matrix. FEED work for both projects will be completed in the fourth quarter of 2024 as a necessary input in the build applications.

Next Steps – Fuel Burn-Off

- Hydro's assumption is based on fuel degradation and aligns with the Fuel Market Study provided by Hatch Limited.
- Hydro has issued an EOI for fuel supply to better inform our strategy and the supply risk including the fuel degradation issue.
- The fuel burn-off issue will not be resolved in time for the build applications.
- Hydro will continue to look for ways to mitigate fuel degradation.
- Given the high cost of fuel, Hydro will continue to minimize the use of fuel whenever possible.

Next Steps – Build Application

2024 Resource Adequacy Plan – Issues List:

NLH appears to be moving toward an application where it will seek approval to develop and own assets with commercial operations dates in 2031.

- *Will NLH make such an application, seeking approval of a 2031 capacity addition?*
- *What near-term commitments and/or expenditures does NLH plan with respect to the proposed CT?*

Assessment of 2024 Resource Adequacy Plan:

- *Explain any near-term commitments and/or expenditures with respect to the proposed CT and BDE 8, prior to regulatory review and approval (#60).*

Next Steps – Build Applications

- Hydro plans to submit build applications for BDE Unit 8 and the Avalon CT in March 2025.
- Given the time to construct, applications will need to be submitted in 2025 to ensure the new generating facilities are in place by 2031.
- Commitments to date for FEED are **$2.6 million** for the Avalon CT and **$4.7 million** for BDE Unit 8.

Next Steps – Cost Recovery

2024 Resource Adequacy Plan – Issues List:

- *NLH identifies as next steps more refined cost estimates. How should NLH manage risks associated with capital cost estimates (and potential overruns)? Should customers take that risk, or should NLH's cost estimates be binding (with pre-determined allowances)?*
- *What happens to any CT-related costs if load growth does not materialize over, say, the next 5 years?*

Assessment of 2024 Resource Adequacy Plan:

- *Explain how cost recovery will be pursued and how risks will be managed (#62).*

Next Steps – Cost Recovery

- Hydro is improving its cost estimates in various ways such as constructability reviews; utilizing AACE's Guidelines for estimate accuracy and quantitative risk analysis for project budget development.
- Submitting planned costs and authorized costs with the application will allow for scrutiny of the risk reserve; expansion plan analysis will be done on the planned cost with sensitivities using the Authorized Cost.
- Commitment to build further manages risk, with an additional stage of review prior to incurring substantial costs.

Next Steps – Cost Recovery

- Existing Guidelines also serve to manage risks to customers:
  - Capital Budget Guidelines, Provisional, January 2022
    - **6. Multi-year Projects**

      The proposed expenditures for each year of a multi-year project will be considered together in the initial year of the application. Where a utility confirms in its capital budget application in subsequent years that the scope, nature and magnitude of the project continues to be consistent with the original approval, further approval of the project is not required. If there is a material change in a subsequent year the expenditures will be subject to further review. A change will be considered material if the nature or scope of the project changes such that that original rationale provided is no longer applicable or where the revised forecast expenditure exceeds the approved amount by 10% or more.

Next Steps: EOI

2024 Resource Adequacy Plan – Issues List:

- *To address firm energy needs, NLH proposes to pursue a wind expression of interest process. Is this a reasonable approach and what considerations should NLH address in designing the EOI process?*

Next Steps: EOI

- To begin the process of meeting firm energy requirements identified in 2030, Hydro will issue a Supply EOI by the second quarter of 2025.
- The information developed through the EOI will be used in evaluating candidates to receive potential future requests for proposals (“RFP”) for consideration for a power purchase agreement.
- Energy requests will be broad and not specific to wind to ensure all proposed options are evaluated.
- Development of the Supply EOI process is currently underway. However, some considerations include:
  - Engagement of a third party to assist Hydro with the RFP process;
  - Bidder-specific ELCC Studies;
  - Transmission Impact Studies; and
  - Regulatory considerations.
- The Supply EOI process will be continuous to meet the future energy needs of the Island Interconnected System.

Risk Mitigation

Risk Mitigation

2024 Resource Adequacy Plan – Issues List:

- *NLH identifies several "ongoing" resource adequacy efforts alongside its recommended portfolio (for which it is already taking steps to implement). These include potential changes to BESS and wind ELCCs, enhanced ECDM offerings, and potential increased output from existing hydro units, among others. How does NLH expect to manage the potential for material changes in the supply and demand landscape on its plans to pursue a portfolio of capacity and firm energy resources (and how should NLH do so)?*

Assessment of 2024 Resource Adequacy Plan:

- *Explain how NLH will track and act on material changes in the supply and demand landscape that may affect the optimality of the recommended portfolio (#63).*

Risk Mitigation

- The analysis behind the 2024 Resource Adequacy Plan and ultimately, the recommended expansion plan, was done with the understanding that the energy landscape is in a transition period.
    - However, immediate decisions are necessary to advance the planning, construction, and integration of new supply resources to ensure the retirement of aging thermal assets and to maintain the reliability of the Island Interconnected System.
- Hydro approached the analysis by developing eight scenarios with various combinations, thus providing a broad range of reasonable future scenarios.
- In addition, 11 sensitivities were applied to select scenarios for further testing of the expansion plans.
- All of this was done in a systematic approach to allow for better insight into the key drivers impacting change, should alternative futures materialize.
- This process enabled Hydro to narrow down the key drivers that could change the recommended expansion plan, thus reducing uncertainty with the plan that was put forward.

Risk Mitigation

- **Diversity of supply options is key in mitigating risk on all fronts.**

Risk	On-Avalon CT	BDE Unit 8	Wind
Load Growth materializes slower than Slow Decarbonization forecast	X	X	X
Load Growth materializes faster than Slow Decarbonization forecast	X	X	X
LIL EqFOR less reliable than anticipated (>1%)	X	X	X
LIL EqFOR more reliable than anticipated (<1%)	X	X	X
Future change to a more stringent planning criteria (i.e. to 0.1 LOLE)	X	X	X
Future requirement to further mitigate the risk of a prolonged bipole outage	X	X	X
Known diesel fuel restrictions on the Island	X	X	X
Extension of aging thermal assets beyond the bridging period (i.e. 2030)	X	X	X
Lack of outage flexibility to perform necessary life extension work		X	
Uncertainty around draft Clean Electricity Regulations	X	X	X

Risk Mitigation

- Hydro's aging thermal assets require replacement in the near term.
- Hydro has demonstrated that the system will require further reliability support in the circumstances of a LIL-shortfall during the winter period.
- Both capacity options highlighted in the recommended Minimum Investment Required Expansion Plan support both of these issues.
- The Supply EOI can scale requirements for additional energy to meet any changes in firm energy over the coming years.
- The load forecast will continue to be updated annually with the most recent information available.
    - The 2024 Load Forecast will provide input into the build applications for BDE Unit 8 and the 150 MW CT.
- Resource planning is a continuous process.
    - Hydro is actively working on the next steps (i.e., ELCC Study, Conservation and Demand Management ("CDM")) and evaluating the additional investment to meet the Reference Case.

2025–2026 Next Steps

- Submission of application for new generation.
  - BDE Unit 8 and On-Avalon CT.
- Understand availability of third-party energy and capacity:
  - 2025 Supply EOI
  - Followed by RFP.
- Advance feasibility work for next resource supply options, including but not limited to:
  - ELCC Study
    - Batteries/Wind/Solar.
  - Understand risk mitigation strategies for fuel supply
    - Fuel Supply Partnership Expression of Interest.
    - Holyrood Marine Terminal FEED.
  - Transmission upgrade requirements/Remedial Action Scheme/Dynamic Line Rating.
- 2025 Load Forecast Update.

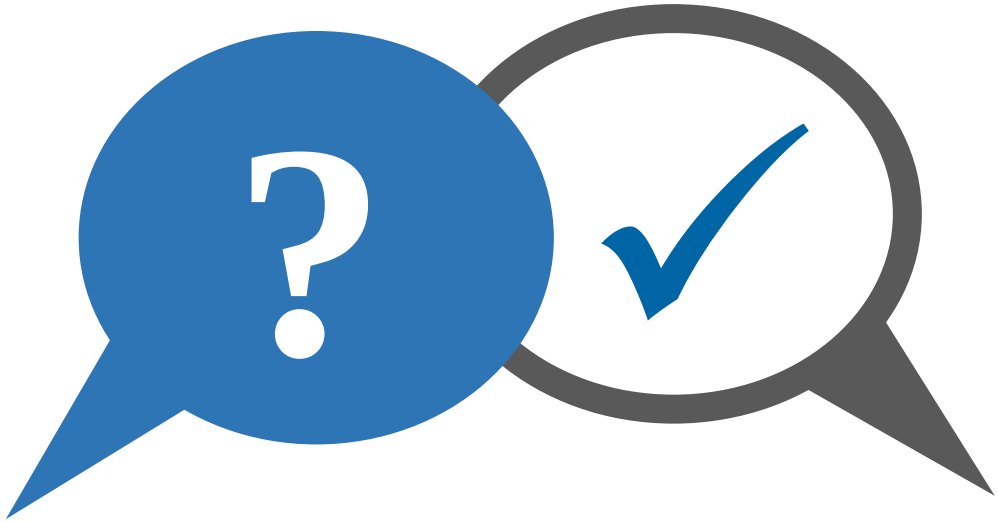
2025–2026 Next Steps

- Continue to monitor and refine LIL EqFOR assumptions.
- Evaluate further supply options to meet Reference Case.
  - CDM
  - Additional CT(s)
  - Cat Arm Unit 3
  - Batteries/Wind/Solar
- 2026 Resource Adequacy Plan.
- Build applications.

Expansion Plan, Insights and Next Steps: Hydro's Position

- Hydro firmly believes that the Minimum Investment Required Expansion Plan represents the first step to meet the Island Interconnected System reliability needs.
- Hydro continues to actively progress analysis to meet the incremental generation required for the Reference Case.
- Hydro will continue to annually update the load forecast and scenarios with new information, for both the Island Interconnected System and the Labrador Interconnected System to support all planning analysis for the province.
- Hydro will deliver its build application for BDE Unit 8 and On-Avalon CT in March 2025, as justified by the 2024 Resource Adequacy Plan analysis and based on industry best practice, lessons learned from the Muskrat Falls Project and in line with the approach of other Canadian Utilities for major projects.

Questions?



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