BC Hydro
Power smart

6911 Southpoint Drive (B03)
Burnaby, BC
V3N 4X8

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #1 – [redacted] – Interconnection Feasibility Study

Dear [redacted]

Enclosed is the Interconnection Feasibility Study for the proposed Interconnection Request (IR), [redacted], submitted under Attachment M-2: Transmission Service and Interconnection Service Procedures for Competitive Electricity Acquisition Process (CEAP) of the Open Access Transmission Tariff (OATT). This letter provides a non-binding good faith estimate of the cost and time to construct the facilities required to interconnect your project to BC Hydro's Transmission System, being the Network Upgrades, based on the findings of the Interconnection Feasibility Study.

Open Access Transmission Tariff

The OATT defines Network Upgrades as additions, modifications, and upgrades to BC Hydro's Transmission System required at or beyond the Point of Interconnection to accommodate the interconnection of the Generating Facility to the BC Hydro's Transmission System. Pursuant to the OATT, BC Hydro will design, procure, construct, install, and own the Network Upgrades. While BC Hydro will pay the costs for the Network Upgrades, the Interconnection Customer provides security for such costs.

Interconnection Study Costs

The Interconnection Customer is responsible for paying the full cost of all Interconnection Studies in cash. Interconnection Study costs vary depending on the scope, complexity, and other factors such as whether any scope is shared with another Interconnection Customer (not applicable to this Interconnection Feasibility Study). The deposit amounts specified in the OATT are not proxy Interconnection Study costs. If actual Interconnection Study costs exceed the deposit amount, the Interconnection Customer must pay the remaining balance in cash. Please refer to the answer for question no. 53 in the posted Questions & Answers for 2025 Call for Power for typical study cost ranges.

Cost Estimate

Based on the Interconnection Feasibility Study, the non-binding good faith estimated cost (typical accuracy range of +150%/-50%) for Network Upgrades required to interconnect your project is $0.4 M.

Major Scope of Work Identified:

- Supply and install required Protection, Control and Telecommunications equipment

Exclusions:

- GST
- Permits
- Right-of-Way & property costs

Key Assumptions:

- Construction by contractor
- 6 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- Impact Benefit Agreements with First Nations are not considered
- [redacted] project is assumed to be in-service in July 2031

Key Risks:

- No defined supply chain strategy; construction costs may increase depending on delivery method
- Project schedule may be longer than expected, leading to increased overhead costs
- Ground improvements may be required leading to increased construction costs
- Contaminated soil may be encountered leading to increased construction costs
- Cost of materials and major equipment may be affected by market conditions and escalation

Indirect Interconnection

Your IR involves an indirect interconnection to the BC Hydro Transmission System. Under the OATT Attachment M-1: Standard Generator Interconnection Procedures (SGIP) and the Standard Generator Interconnection Agreement (SGIA), the party executing the SGIA must be the owner of the Interconnection Customer Interconnection Facilities up to the Point of Interconnection. Depending on the scope of required Network Upgrades, this execution may occur years before the Commercial Operation Date.

Study Limitations and Exclusions

Protection, Control, and Telecommunications

The Interconnection Feasibility Study does not include a detailed review of the protection, control, and telecommunications system requirements specific to your Interconnection Request. Based on a high-level review, we have identified proxy costs for protection, control, and telecom Network Upgrades drawn from comparable interconnection projects with similar scope and complexity; these proxy costs have been included solely for indicative budgeting purposes. The relative interconnection cost determined by the Interconnection Feasibility Study includes a telecommunications component based on an assumed solution to deliver teleprotection and telecontrol circuit requirements necessary for the Interconnection Request. Protection, control, and telecommunications system requirements will be reviewed in detail in the System Impact Study if you are a successful participant of the CEAP and meet applicable requirements.

For Interconnection Feasibility Study purposes, it is assumed that any applicant-proposed works that could obstruct or impair the performance of existing BC Hydro microwave systems or new links from the proposed Interconnection Customer Interconnection Facilities (ICIF) to the BC Hydro microwave system would be identified and either relocated or repositioned as determined in a System Impact Study if you are a successful participant of the CEAP and meet applicable requirements. Such works may include, but are not limited to, towers, turbines, dams, support structures, panels, surface materials deposited or redistributed, water surface changes, or vegetation.

Generation Shedding/Curtailment Scheme and Electromagnetic Transient (EMT) Studies

The generation shedding/curtailment scheme reviews (e.g., Remedial Action Scheme (RAS), and a direct transfer trip for anti-islanding scheme) and EMT studies are completed in a System Impact Study. The outcomes of these studies may result in additional requirements, which could include Network Upgrades or ICIF. Any costs associated with completion of these studies, and resulting requirements, are not included in the Interconnection Feasibility Study cost estimate.

Revenue Metering

Please note that revenue metering requirements have not been determined with the Interconnection Feasibility Study. As such, any costs associated with revenue metering and other interconnection components are not included in the cost estimate provided above. Once these requirements are defined, costs that are attributable to the Interconnection Customer are to be paid in cash. For more details on revenue metering requirements and responsibilities, please refer to:

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/distribution/standards/ds-rmr-complex-revenue-metering.pdf.

Schedule

Based on the Interconnection Feasibility Study, the non-binding good faith estimated in-service date for your Interconnection Request's Network Upgrades is Quarter 3 2031 (calendar year). To achieve this timeline, we may need to expedite certain activities, including engineering design and procurement of long-lead equipment.

Timely actions required from you to minimize risks to the schedule:

- Submission of additional technical data required for the System Impact Study and Facilities Study
- Submission of any required information or document such as demonstration of Site Control
- Execution of Combined Study Agreement and Standard Generator Interconnection Agreement
- Financial commitments and securities

Please note that changes to your Interconnection Request or delays in data submission or financial commitments may also impact the target in-service date.

If you have any questions, please contact the BC Hydro CEAP team at ceap2025@bchydro.com.

Sincerely,

[redacted]

[redacted]

Manager, Customer Interconnections

BC Hydro

Encl.: CEAP_2025_IR1_[redacted]_Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR #1

Prepared for: [redacted]

Prepared by: [redacted]

[redacted]
Sr. Engineer, Transmission Planning

Reviewed by: [redacted]

Technical Strategic Principle, Transmission Planning

Accepted by: [redacted]

Division Manager, Transmission Planning

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Revision	Date	Description
0	2025 Nov	Initial release

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The following accept responsibility for the content in the specified sections. Professionals apply their signature and/or seal as appropriate.

Section: **Discipline:**

Entire report except listed below — Transmission Planning

Contributed by:

[redacted] [redacted]

Sr. Engineer, Transmission Planning

Section: **Discipline:**

5.2, 5.3 — Stations Planning

Contributed by:

[redacted] [redacted]

Specialist Engineer, Station Planning

Executive Summary

[redacted]., the Interconnection Customer (IC), requests to interconnect its [redacted] wind project (2025 CEAP IR #1) to BC Hydro (BCH) transmission system. [redacted] wind project has nine (9) [redacted] type-4 wind turbine generators (WTG), adding a total installed capacity of 63 MW with a maximum power injection of 61 MW into the BC Hydro system at the Point of Interconnection (POI). The IC has proposed to connect their wind project to BC Hydro transmission system at the same POI as the planned [redacted] wind project, at the 230 kV bus of the planned [redacted] Terminal Station (temporarily designated as "[redacted] located approximately 43 km from Barlow Substation (BLW) on the BC Hydro transmission line 2L96.

The IC's Phase II project will be connected to the planned customer-owned 230 kV [redacted] Generating Station (temporarily designated as "[redacted] which will be constructed under 2024 CEAP and radially supplied by a new approximately 25 km 230 kV customer-built transmission line from the proposed POI. The IC's proposed commercial operation date (COD) is December 1, 2030.

To interconnect [redacted] wind project and its facilities to the BCH Transmission System at the proposed POI, this Feasibility Study has made the recommendations and conclusions as follow:

1. The proposed POI, at the 230 kV bus of the planned [redacted] switching station on 2L96 is acceptable to interconnect the IC's generating project to the BCH system.

2. There is no thermal or voltage violations discovered for system normal operation scenarios.

3. The study identifies potential thermal overload constraints on 2L95A and 2L354 under system contingency operating conditions as a result of the connection of [redacted] project.

   A new generation shedding Remedial Action Scheme (RAS) is required to mitigate the potential overloads on 2L95A and 2L354 under single contingencies.

The connection of IC's wind project will exacerbate the existing thermal overloads on the 500 kV lines 5L11, 5L12 and 5L13 under single contingencies. These overloads can be mitigated by the existing G.M. Shrum (GMS) Area Gen Shedding RAS. Therefore, [redacted] project is required to participate in the existing GMS Area Generation Shedding RAS to trip IC's generations at [redacted] under single contingencies.

4. The IC's wind project would be islanded with the existing or future loads for the multiple contingencies.

   A Direct Transfer Trip (DTT) protection scheme is required to isolate the IC's wind project at the [redacted] to avoid potential islanding operations with the existing or future loads. The DTT requirement will be further confirmed during the next study stage.

5. Anti-islanding protection is required for the [redacted] project and shall be configured in the manner that does not compromise the required ride-through performance.

6. The proposed [redacted] project is required to have the dynamic reactive power capability at a minimum of +/- 33% of its MPO from the plants at the high-voltage side of the switchyard over the full MW operating range, per BC Hydro's TIR Section 6.4.2. Based on the IC-submitted PSS/E model, the proposed [redacted] project meets the reactive capability requirement above.

7. The "STATCOM option" for the proposed 7.0 MW type-4 WTGs is required so that each turbine can provide reactive power capability at zero MW output including during turbine standstill.

   Voltage controls of Phase I ([redacted]) and Phase II ([redacted]) wind turbines are required to be coordinated.

8. Per BC Hydro's TIR Section 6.4.5, the [redacted] wind project shall have the capability of providing Fast Frequency Response (FFR) to help improve the system frequency response performance. For typical performance metrics of the FFR provided by WTG based IBR plants, please refer to Section 6.2.3 of IEEE Standard 2800-2022. BC Hydro will

work with the IC to establish the detailed FFR performance requirements under System Impact Study (SIS) stage.

The above conclusions are made based on the IC's input data and study assumptions listed in Section 4, which represent the best available information on October 14, 2025.

A non-binding good faith cost for required network upgrades and estimated schedule for construction are included in a separate letter to the IC.

Please note that, this Feasibility Study report does not include the descriptions of Protection, Control, and Telecommunications requirements and the associated upgrade scopes; however, as discussed in Section 2 “Purpose and Scopes of Study”, the associated cost implications are captured and delivered in the cover letter to the IC.

Contents

Appendices

Acronyms

The following are acronyms used in this report.

BCH	BC Hydro
CEAP	Competitive Electricity Acquisition Process
COD	Commercial Operation Date
DTT	Direct Transfer Trip
ERIS	Energy Resource Interconnection Service
IBR	Inverter-Based Resources
IC	Interconnection Customer
IR	Interconnection Request
LAPS	Local Area Protection Schemes
MPO	Maximum Power Output
NERC	North American Electric Reliability Corporation
NRIS	Network Resource Interconnection Service
OATT	Open Access Transmission Tariff
POI	Point of Interconnection
RAS	Remedial Action Scheme
TIR	BC Hydro “60 KV to 500 kV Technical Interconnection Requirements for Power Generators”
WECC	Western Electricity Coordinating Council
WTG	Wind Turbine Generator

1 Introduction

Table 1-1 below summarizes the project reviewed in this Feasibility Study.

Table 1-1 Summary of Project Information

Project Name	[redacted]	
Name of Interconnection Customer (IC)	[redacted]	
Point of Interconnection (POI)	[redacted] Switching Station on 2L96, 43 km from BLW	
IC's Proposed COD	Dec 1, 2030	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	61 MW (Summer)	61 MW (Winter)
Number of Turbines	9 x 7 MW	
Plant Fuel	Wind	

[redacted]., the Interconnection Customer (IC), requests to interconnect its [redacted] Wind project (2025 CEAP IR #1) to the BC Hydro (BCH) transmission system. [redacted] wind project has nine (9) [redacted] type-4 wind turbine generators (WTG), adding a total installed capacity of 63 MW with a maximum power injection of 61 MW into the BC Hydro system at the Point of Interconnection (POI). The IC has proposed to connect their wind project to BC Hydro transmission system at the same POI as the planned [redacted] wind project, at the 230 kV bus of the planned [redacted] Terminal Station (temporarily designated as "[redacted] located approximately 43 km from Barlow Substation (BLW) on the BC Hydro transmission line 2L96.

The IC's [redacted] project will be connected to the planned customer-owned 230 kV [redacted] Generating Station (temporarily designated as "[redacted] which will be constructed under 2024 CEAP and radially supplied by a new approximately 25 km 230 kV customer-built transmission line from the proposed POI. With the addition of the Phase II project, the total installed capacity of the [redacted] project will be 207 MW. The Phase II project will upgrade the main generation transformer capacity to 300 MVA. The IC's proposed commercial operation date (COD) is December 1, 2030.

Figure 1-1 shows the Central Interior region 230 kV transmission system simplified one-line diagram. [redacted] project (Phase I and II) is to be connected at a new 230 kV switching station [redacted] on 2L96.

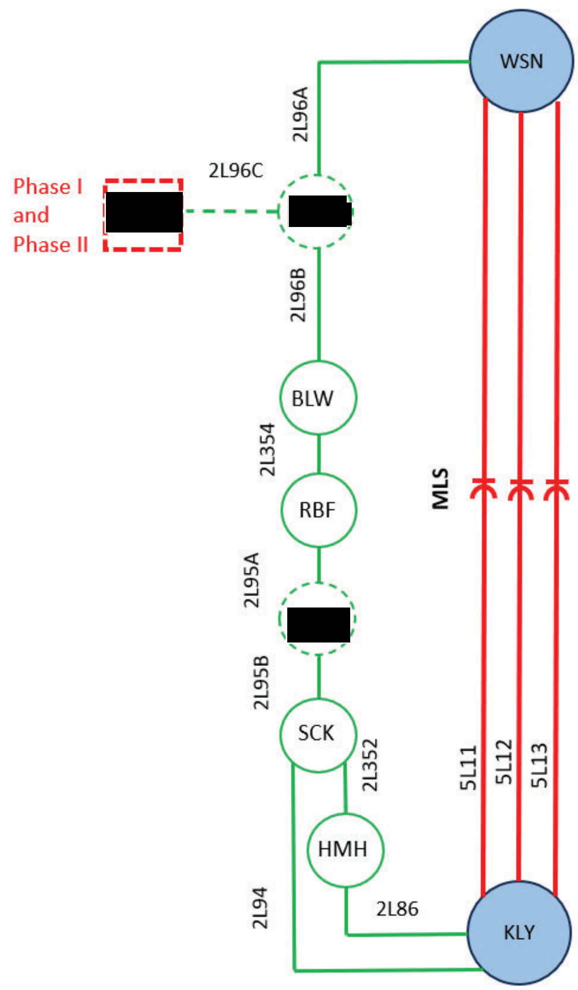

Figure 1-1: Central Interior Region 230 kV Transmission System One-line Diagram

2 Purpose and Scopes of Study

This Feasibility Study is a preliminary evaluation of the system impact of interconnecting the proposed project to the BC Hydro system based on power flow and short circuit analysis in accordance with BCH's Open Access Transmission Tariff (OATT) and produces the estimated cost of required Network Upgrades and the implementation schedule.

Per OATT, the Feasibility Study is performed individually for each of the participating projects in the CEAP process and focuses specifically on the BCHydro regional transmission system where the proposed generating project is connected and affects.

This is a "limited scope" study which is restricted to power flow studies of P0, P1 and P2 planning events as defined in TPL-001-4 and short circuit analysis. The study does not address other technical aspects such as transient stability and switching transients and impact of multiple contingencies. These subjects will be addressed in subsequent System Impact Study if the project proceeds further. In addition, any potential impacts to the adjacent external systems to BC Hydro would be addressed in subsequent detailed and coordinated studies with the relevant adjacent entities if the proposed generator project proceeds further.

Please note that, due to the compressed study timeline for CEAP 2025 Feasibility Study, this report does not include the descriptions of the Protection, Control, and Telecommunication requirements and the associated upgrade scopes. Instead, the network upgrades associated with Protections, Controls and Telecommunications are incorporated with cost estimates in a separate cover letter to the IC.

3 Standard and Criteria

The Feasibility Study is performed in compliance with the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards, and the BCH interconnection requirements in the TIR, and upon the ratings of the existing BCH transmission facilities described in Operating Orders, specifically:

- NERC standards: TPL-001-4 and FAC-002-3 relevant to the scope of this Feasibility Study.
- WECC criteria TPL-001-WECC-CRT-4 Transmission System Planning Performance, July 1, 2023.
- BC Hydro's 60 kV to 500 kV Technical Interconnection Requirements for Power Generators, Rev 2.1.1, Effective: Sept 22, 2025.
- BC Hydro Operating Order 5T-10, Ratings for All Transmission Circuits 60 kV or Higher, Sept 17, 2025.
- BC Hydro Operating Order 5T-14, Ratings for All Transmission and Distribution Transformer, Sept 22, 2025.
- BC Hydro System Operating Order 7T-22 System Voltage Control, Sept 19, 2023.

4 Assumptions and Conditions

This Feasibility Study is performed based on the IC's submitted data and information available to BC Hydro on October 14, 2025 for the study purpose. Assumptions are made wherever the IC's input is unavailable. Appendix A shows the schematic diagram of the IC's Project IC's project used in the study model.

The power flow study cases used in this Feasibility Study are established based upon the BC Hydro's base resource plan and load forecasts available at the time of performing the study, which includes existing and future generators, transmission facilities, and loads in addition to the subject interconnection project in this study. Applicable seasonal conditions and the appropriate study years for the study planning horizon are also incorporated. Additional assumptions are listed as follows.

- The generation in the study area are dispatched to the patterns that stress the transmission system in the study area. In these patterns, the associated generators are typically set to their Maximum Power Outputs (MPO) unless otherwise specified.
- The 2024 Distribution Substation Load Forecast, 2025 Transmission Voltage Customer (TVC) Load Forecast and 2025 System Peak Forecast are used.
- September 2024 Base Resource Plan.
- 144 MW [redacted] [redacted] project will be in service on December 1, 2030.
- 31HW, 32HS and 32LS are used as base case in the study to evaluate system impact after [redacted] [redacted] wind project interconnection.
- All new TVC load interconnection and associated system reinforcements are considered in this study.

5 System Studies and Results

5.1 Power Flow Study Results

Power flow studies were performed to evaluate whether the IC's generating project would cause any unacceptable system performance (e.g., equipment overloads, steady-state voltage violation and voltage instability) and to determine the system reinforcement requirement based on steady state performance analysis.

Steady-state power flow studies have been conducted with the focus on the 32LS system condition, taking into considerations of factors such as load conditions, seasonal variation in ambient temperatures, and generation patterns that stress the transmission system. The 31HW and 32HS cases are also checked to capture any performance violations under high load conditions.

The studies are performed for system normal conditions and under critical system contingencies specified in the P1 and P2 events by NERC TPL-001-4. Study results are summarized below.

5.1.1 Thermal Overload Analysis

There is no thermal overloading discovered under system normal operation scenarios.

Thermal overloads on 2L95A and 2L354 have been identified under single contingencies of loss 5L11 (or 5L12, 5L13) in light summer season.

A new generation shedding Remedial Action Scheme (RAS) is required to mitigate the potential overloads on 2L95A and 2L354 under single contingencies.

The connection of IC's wind project will exacerbate the existing thermal overloads on the 500 kV lines 5L11, 5L12 and 5L13 under single contingencies. These overloads can be mitigated by the existing G.M. Shrum Area Gen Shedding RAS. Therefore, [redacted] project is required to participate in the existing GMS Area Generation Shedding RAS to trip IC's generation at [redacted] under single contingencies, loss one of 500 kV lines, 5L11 or 5L12 or 5L13.

Details of the thermal overload analysis are provided in Appendix B.

5.1.2 Steady-State Voltage Analysis

With the connection of the IC's project, the stead-state voltage performance under system normal and single contingency conditions is acceptable for all the three study scenarios (32LS, 32HS, 31HW). Appendix B shows the details in the steady-state voltage study results.

5.1.3 Reactive Power Capability Evaluation

The BCH TIR requires IBR generators have the dynamic reactive power capability at a minimum of +/- 33% of its Maximum Power Output (MPO) at the high voltage side of the IC's switchyard over the full MW operating range. This translates to a minimum reactive power range of +/-68.3 MVAr at the high side of the main power transformer.

Based on the PSS/E power flow data submitted for this project, the study finds that the proposed generating project can meet the BC Hydro's reactive capability requirement.

It is noticed that Phase II project is using [redacted] wind turbines, which are different from the [redacted] wind turbines selected in Phase I. Voltage controls of two different wind turbines are required to be coordinated.

5.1.4 Anti-Islanding Requirements

[redacted] wind project is not arranged for islanded operation. In addition, the IC is required to install anti-islanding protection within its facility to disconnect the IC's wind farm from the grid when an inadvertent island with the local load forms.

A Direct Transfer Trip (DTT) protection scheme is required to isolate the IC's wind project at the [redacted] to avoid potential islanding operations with the existing or future loads.

5.1.5 Other Performance Requirements

Fast Frequency Response (FFR), as per BCH TIR Section 4.6.5, is required at the [redacted] wind project. The proposed wind turbine generators, when the FFR function is enabled, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The FFR settings should be determined in coordination with BC Hydro in the later stage of the interconnection process.

5.2 Fault Analysis

The short circuit analysis in the Feasibility Study is based upon the latest BC Hydro system model, which includes the generating facility information and associated impedance data provided by the IC. A more detailed study will be performed at the system impact study stage if needed.

5.3 Stations Requirements

No substation work is required for this IC's interconnection.

5.4 Transmission Line Requirements

No transmission line engineering scope of work is identified for this project.

6 Cost Estimate and Schedule

The non-binding good faith estimated cost and time to construct the Network Upgrades required to interconnect the proposed project will be provided in a separate letter to the IC.

7 Conclusions

To interconnect the [redacted] project and its facilities to the BCH Transmission System at the POI, this Feasibility Study has identified the following conclusions and requirements:

1. The proposed POI, at the 230 kV bus of the planned [redacted] switching station on 2L96 is acceptable to interconnect the IC's generating project to the BCH system.
2. There is no thermal or voltage constraints violations identified for system normal operation conditions.
3. The study identifies potential thermal overload constraints on 2L95A and 2L354 under system contingency operating conditions as a result of the connection of [redacted] project.

   A new generation shedding RAS is required to mitigate the potential overloads on 2L95A and 2L354 under single contingencies.

   [redacted] project is required to participate in the existing GMS Area Generation Shedding RAS for 500 kV contingencies to trip IC's generation at [redacted] under single contingencies.
4. A DTT protection scheme is required to isolate the IC's wind project at the [redacted] to avoid potential islanding operations with the existing or future loads. The DTT requirement will be further confirmed during the next study stage.
5. Anti-islanding protection is required for the [redacted] project and shall be configured in the manner that does not compromise the required ride-through performance.
6. The proposed [redacted] project is required to have the dynamic reactive power capability at a minimum of +/- 33% of its MPO from the plants at the high-voltage side of the switchyard over the full MW operating range, per BC Hydro's TIR Section 6.4.2. Based on the IC-submitted PSS/E model, the proposed [redacted] project meets the reactive capability requirement above.

7. The “STATCOM option” for the proposed 7.0 MW type-4 WTGs is required so that each turbine can provide reactive power capability at zero MW output including during turbine standstill.

   Voltage controls of Phase I ([redacted]) and Phase II ([redacted]) wind turbines are required to be coordinated.

8. Per BC Hydro’s TIR Section 6.4.5, the [redacted] project shall have the capability of providing Fast Frequency Response (FFR) to help improve the system frequency response performance. For typical performance metrics of the FFR provided by WTG based IBR plants, please refer to Section 6.2.3 of IEEE Standard 2800-2022. BC Hydro will work with the IC to establish the detailed FFR performance requirements under System Impact Study stage.

Appendix A

Schematic Diagram of the IC’s Project

Figure A-1 shows the schematic diagram for the [redacted] project.

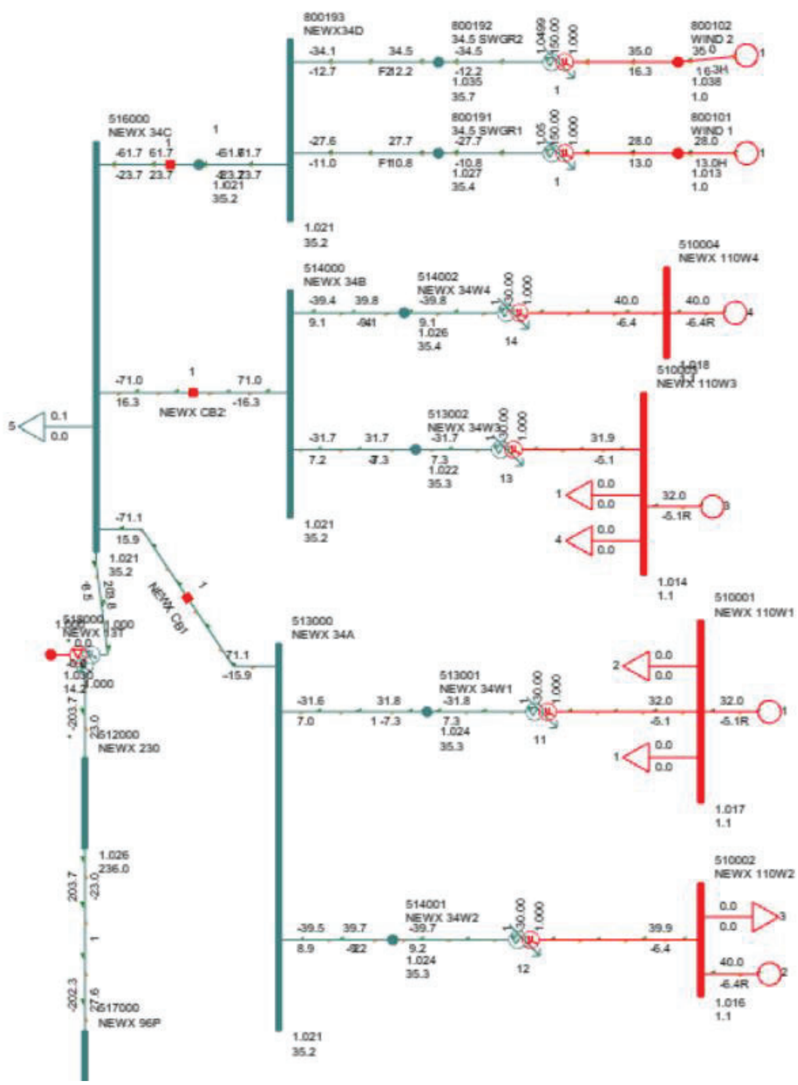

Figure A-1: [redacted] Project (Phase I and II) Plant Schematic Diagram.

Appendix B
Power Flow Study Results

Base Scenario (31HW/32HS/32LS)

Table B-1: Thermal Overload Study Results

Cases	IC's Gen Output (MW)	Contingency Identified		Branch Loading (Amp/%rating)				
				2L96A	2L96B	2L354	2L95 A	2L95B
		Cate.	Description	WSN-P79T	P79T-[redacted]	BLW-RBF	RBF-[redacted]	[redacted]-SCK
Winter Ratings				1184 A	1184 A	800 A	800 A	800 A
31HW	Max	P0	System Normal	201 17%	699 59%	484 61%	413 52%	254 32%
		P1	2L96A	N/A	505 43%	290 36%	220 27%	80 10%
		P1	2L96B	513 43%	N/A	222 28%	297 37%	460 58%
		P1	2L354	306 26%	223 19%	N/A	83 10%	299 37%
		P1	KLY-T4	205 17%	699 59%	513 64%	438 55%	279 35%
		P1	5L11	332 28%	810 68%	593 74%	514 64%	354 44%
Summer Ratings				817 A	817 A	574 A	515 A	515 A
32HS	Max	P0	System Normal	156 19%	652 80%	444 77%	399 77%	238 46%
		P1	2L96A	N/A	508 62%	299 52%	255 50%	100 19%
		P1	2L96B	515 61%	N/A	206 36%	255 50%	415 81%
		P1	2L354	315 38%	217 27%	N/A	51 10%	211 41%
		P1	2L95A	268 33%	257 31%	49 9%	N/A	60 31%
		P1	5L11	282 35%	767 94%	558 97%	508 99%	347 67%
32LS	Max	P0	System Normal	138 17%	631 77%	465 81%	429 83%	288 56%
		P0	Add TVC load	217 27%	719 88%	548 95%	509 99%	144 68%
		P1	2L96A	N/A	505 62%	337 59%	302 59%	161 31%
		P1	2L96B	516 63%	N/A	175 31%	219 43%	344 67%
		P1	2L354	357 44%	192 23%	N/A	60 11%	185 36%
		P1	2L95A	320 39 %	218 27%	38 7%	N/A	160 31%
		P1	2L95B	175 21%	350 43%	184 32%	150 29%	N/A
		P1	KLY T4	163 20%	663 81%	491 86%	457 89%	296 57%
		P1	5L11	280 34%	768 94%	595 104%	551 107%	391 76%

Table B-2: Steady-State Voltage Study Results

Case	IC's Generator Output (MW)	Contingency		Bus Voltage (PU)				
		Cate.	Description	WSN230	[redacted] 230	BLW 230	SCK 230	KLY 230
31HW	Max	P0	System Normal	1.02	1.02	1.03	1.03	1.05
		P1	2L96A	1.02	1.03	1.04	1.03	1.05
		P1	2L96B	1.01	1.02	1.01	1.00	1.04
		P1	2L354	1.01	1.03	1.04	1.06	1.06
		P1	KLY T4	1.02	1.02	1.03	1.03	1.05
		P1	5L11	1.00	1.02	1.02	1.03	1.06
32HS	Max	P0	System Normal	1.02	1.03	1.03	1.04	1.06
		P1	2L96A	1.02	1.03	1.04	1.05	1.06
		P1	2L96B	1.01	1.02	1.06	1.04	1.05
		P1	2L354	1.02	1.03	1.04	1.04	1.05
		P1	5L11	1.01	1.02	1.03	1.03	1.05
32LS	Max	P0	System Normal	1.02	1.03	1.03	1.03	1.05
		P1	2L96A	1.02	1.03	1.04	1.04	1.05
		P1	2L96B	1.01	1.02	1.06	1.03	1.05
		P1	2L354	1.02	1.03	1.04	1.03	1.06
		P1	2L95A	1.02	1.03	1.04	1.05	1.06
		P1	WSN T4	1.02	1.03	1.04	1.05	1.06
		P1	5L11	1.01	1.02	1.04	1.04	1.06