Appendix B - Congestion Assessment

Congestion Assessment Report

Vauxhall Area Transmission Development

AESO Project Number: P7075

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1. Introduction

This Congestion Assessment Report provides information supplementary to the Vauxhall Area Transmission Development (VATD) Planning Report[1]. This report documents the methodology, assumptions, and results of the congestion assessment that was performed to support the VATD planning studies.

As described in the Planning Report, the planning studies focused on the 138 kV path from Taber 83S substation to Bowmanton 244S substation (the Study Area), located in the Alberta Electric System Operator (AESO) planning areas of Vauxhall (Area 52) and Medicine Hat (Area 4), referred to collectively as the Study Region. Thermal criteria violations have been observed in real-time operations in the Study Area due the 138 kV path serving as a transfer-out network for excess power produced in the area. The purpose of the congestion assessment was to estimate the probability of congestion after the energization of generation projects located in the Study Region that meet the AESO's project inclusion criteria[2]. The congestion assessment also considered scenarios with additional generation in the Study Region, based on projects that did not meet the AESO's project inclusion criteria at the time the studies were conducted. Congestion probability was calculated before and after the VATD project to examine the effectiveness of the Preferred Transmission Development proposed in the Planning Report. The results of the congestion assessment were also used to identify constrained hours and develop base cases for the planning studies.

2. Methodology

Congestion is identified to occur when the transmission system cannot accommodate all in-merit generation, because the resulting power flows would contravene reliability standards[3] and/or ISO rules,[4] and mitigation measures that affect the energy market are consequently needed.

The probability that congestion will occur was estimated using an integrated transmission system model using the AURORA[5] software–an energy market modeling software that integrates the production cost of generators and the transmission system network. AURORA determines hourly generator dispatches using load and generator production cost assumptions. AURORA then calculates the hourly power line flows that result from each dispatch using a direct current (DC) network model.

The calculated power flows were used to identify in which hours one or more transmission lines would have, or be at risk of having, loading above their facility rating(s).

Figure 1 illustrates the inputs and processes involved in this congestion assessment.

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[1] Filed under a separate cover in the AESO's *Needs Identification Document for the Vauxhall Area Transmission Development*..

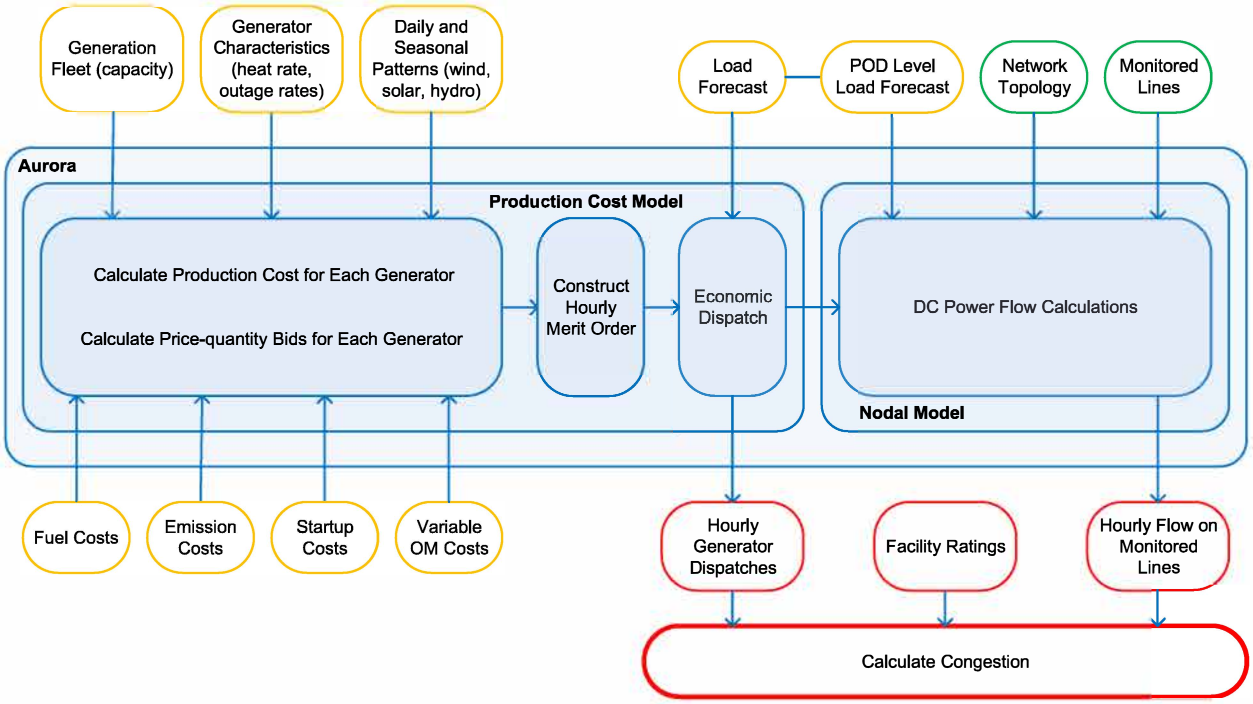
[2] The AESO's project inclusion criteria are available in *ID #2018-018T Provision of System Access Service and the AESO Connection Process*, on the AESO website.

[3] The reliability standards are available on the AESO website.

[4] The ISO rules are available on the AESO website.

[5] AURORA is an energy forecasting software developed by Energy Exemplar. Please refer to their website for more information: https://energyexemplar.com/solutions/aurora/

Figure 1 - Congestion Assessment Process



To understand the risk of congestion with different generation connection projects energizing in the Study Region, transmission line congestion was calculated for three scenarios, discussed in more detail in Section 3.2. Additionally, to evaluate the effectiveness of the Preferred Transmission Development, congestion was calculated with the proposed upgraded transmission line ratings (presented in Section 3.3) for the 138 kV transmission lines 610L and 879L.

2.1. Congestion Assessment under Category A

The assessment estimated congestion due to "Category A" thermal criteria violations. Category A (also known as N-0) congestion is defined as congestion that occurs when all system elements are in service. As such, in this assessment all system elements were assumed to be in service, and then the generation dispatch was determined as if the system had no transmission system constraints. Furthermore, the effects of contingency events, including post-contingency transmission line loading, were not considered. Given these assumptions, an hour was classified as congested whenever any monitored transmission line (listed in Section 3.3.2) in the Study Area had loading above its seasonal normal rating.

3. Modeling and Assumptions

The key inputs for congestion assessments include the load forecast, future generation capacity assumptions, generator production cost assumptions, generator physical characteristics, renewable generation production profiles, and transmission system assumptions. These inputs are discussed in the following sections.

The congestion assessment was performed for the full year of 2023 to understand the potential risks of congestion after the energization of connection projects that met the AESO's project inclusion criteria as of December 2021[6], and if other projects that did not meet the criteria were to energize.

3.1. Load Assumptions

The following subsections describe the historical load trend and the AESO's current outlook for load in the Study Region.

3.1.1. Historical Load

The Study Region consists primarily of residential, commercial, and agricultural load. The Study Region has historically been summer-peaking, and includes the municipalities of Vauxhall, Taber, and Medicine Hat.

In this section, the historical load statistics are reported based on a seasonal year[7] at the South Region coincident. Table 1 summarizes historical Summer Light (SL), Summer Peak (SP) and Winter Peak (WP) load levels in the Study Region over a 5 year period from 2017 to 2021.

Table 1 – Historical Load in the Study Region

Year	SL (MW)	SP (MW)	WP (MW)
2017	112	452	336
2018	188	465	359
2019	200	463	365
2020	176	403	358
2021	180	478	339

The Compound Annual Growth Rate (CAGR)[8] in the Study Region from 2017 to 2021 was 12.6% for the SL, 1.4% for SP, and 0.2% for WP. The SL load in 2017 was abnormally low, leading to a seemingly high CAGR. Over the past 10 years, the SL load in the Study Region has been flat to declining, averaging 195 MW since 2011 when 2017 is excluded.

[6] The AESO's Project List is available on the AESO website.

[7] The summer season is from May 1st to Oct 31st of the same year. The winter season is from Nov 1st to Dec 31st and Jan 1st to Apr 30th of the following year. The "peak" load represents the maximum load during the season; "light" load represents the minimum load during the season.

[8] $CAGR\ (\%) = \left(\left(\frac{Load_{t(n)}}{Load_{t(0)}}\right)^{\frac{1}{t(n)-t(0)}} - 1\right) \times 100, where\ t(0) = beginning\ period, t(n) = ending\ period$

3.1.2. *Forecast Load*

The load forecast used in the congestion assessment, as well as the planning studies in the Planning Report, covers the latest information in the Study Region that was considered in the AESO's *2021 Long-term Outlook*[9] (2021 LTO) Reference Case. The Reference Case load forecast represents the AESO's current expectations for long-term load growth given uncertainties facing the electricity industry. Using econometric models, the 2021 LTO provides hourly load forecasts at Alberta internal load (AIL), AESO Planning Region, AESO planning area, and Point of Delivery (POD) levels for the next 20 years[10].

The AESO South Planning Region consists of multiple industrial and commercial load types including pipelines, natural gas processing, manufacturing, farming and agriculture, meat and agri-food processing, and tourism and hospitality.

The 2021 LTO expects a recovery in load for the South Planning Region in the near-term (2023) from pandemic levels, and moderate load growth thereafter, offset in part by growth in rooftop solar generation and some distribution-connected resources. The 2021 LTO also forecasts some load growth in the City of Medicine Hat, driven by cryptocurrency mining and general population and economic growth.

The congestion assessment simulations used the weather-syncronized hourly POD level load forecasts for all the substations in the Alberta interconnected electric system (AIES). This approach captures the localized hourly load patterns and how this load diversity impacts the transmission system power flows. Table 2 summarizes the seasonal SL, SP, and WP load forecast for 2023, 2031, and 2041 in the Study Region.

Table 2 – Forecast Load in the Study Region

Year	SL (MW)	SP (MW)	WP (MW)
2023	245	523	364
2031	278	569	416
2041	295	566	420

The forecast CAGR of the load in the Study Region, from 2021 to 2041 is 2.5% for SL, 0.8% for SP, and 1.1% for WP.

The congestion assessment simulations were carried out for year 2023 only. The year 2023 was selected based on input from the planning studies and the earliest possible in-service year of the Preferred Transmission Development.

3.2. Generation Assumptions

The generation assumptions are discussed in two main sections: existing generation capacity and future generation capacity in the Study Region.

[9] The 2021 LTO is available on the AESO website.

[10] Please refer to the 2021 LTO, available on the AESO website, for more details on forecast methodology.

3.2.1. Existing Generation Capacity

As of December 2021, total existing generation capacity in the Study Region was 1,039 MW, comprised of 823 MW in Medicine Hat (Area 4), and 216 MW in Vauxhall (Area 52). Approximately 68% of the existing generation capacity in the Study Region comes from renewable generation (solar and wind), while the rest is waste heat or gas-fired generation. Table 3 details the existing generation in the Study Region.

Table 3 – Existing Generation Capacity in the Study Region

Asset	Type	Maximum Capability (MW)	Planning Area
Medicine Hat #1 (CMH1)	Combined Cycle	255	04-Medicine Hat
Cancarb Medicine Hat (CCMH)	Other	42	04-Medicine Hat
Ralston (NAT1)	Simple Cycle	20	04-Medicine Hat
Suffield (SUF1)	Solar	23	04-Medicine Hat
Rattlesnake Ridge Wind (RTL1)[11]	Wind	130	04-Medicine Hat
Whitla 1 (WHT1)	Wind	202	04-Medicine Hat
Whitla 2 (WHT2	Wind	151	04-Medicine Hat
Lethbridge Burdett (ME03)	Simple Cycle	7	52-Vauxhall
Lethbridge Taber (ME02)	Simple Cycle	8	52-Vauxhall
BRD1 Burdett (BRD1)	Solar	11	52-Vauxhall
BUR1 Burdett (BUR1)	Solar	20	52-Vauxhall
Hays (HYS1)	Solar	23	52-Vauxhall
Hull (HUL1)	Solar	25	52-Vauxhall
Vauxhall (VXH1)	Solar	22	52-Vauxhall
Westfield Yellow Lake (WEF1)	Solar	19	52-Vauxhall
Enmax Taber (TAB1)	Wind	81	52-Vauxhall
Total Generation Capacity		**1,039**	

3.2.2. Future Generation Capacity

To study the potential future generation capacity in the Study Region, three different study scenarios were developed. All the nodal simulations that were run for these scenarios were for year 2023, when all the projects that met the AESO's project inclusion criteria (as of December 2021) were expected to be in service. For each scenario, congestion was calculated using the current transmission line ratings for all the monitored transmission lines, described in Section 3.3. Then, congestion was calculated again but using the proposed upgraded transmission line ratings for the 138 kV transmission lines 610L and 879L. The three scenarios are:

[11] Rattlesnake Ridge Wind (RTL1) is listed as a project in the December 2021 AESO Project List. However, it energized and was added to the AESO's Current Supply & Demand page effective December 2, 2021. As such, it was included as "existing" generation in this report.

1. Base

A base scenario was developed in which all the existing generation plus the projects that met the AESO's project inclusion criteria were modeled.

2. Base + Taber DERs

Given the uncertainty around additional renewable generation projects that may meet the AESO's project inclusion criteria in the near term, an additional scenario was developed to examine the risk of congestion should some solar generation projects energize before 2023 as well. Those projects are the four Taber DER Solar projects listed in Table 5.

3. Base + Burdett Solar

The planning studies also included an assessment of generation integration capability to determine the additional amount of solar generation that could theoretically be connected at the Burdett 368S substation[12]. To help in that assessment, a third scenario included one simulation with 20 MW of hypothetical additional solar generation connected at the Burdett 368S substation.

There are several renewable generation projects in the Study Region that met the AESO's project inclusion criteria as of the December 2021 AESO Project List and are anticipated to energize before 2023. Besides the existing in-service generation, these projects that met the AESO's project inclusion criteria were also considered in the base scenario of the congestion assessment. Table 4 summarizes these projects in the Study Region.

Table 4 – Generation Connection Projects in the Study Region that Met the AESO's Project Inclusion Criteria

Project Name	Type	Maximum Capability (MW)	Planning Area	Anticipated In-Service Date
P1812 Suncor Forty Mile Granlea	Wind	200	04-Medicine Hat	May 2, 2022
P1918 FortisAlberta Conrad DER Solar 1	Solar	23	52-Vauxhall	Apr 15, 2022
P1959 FortisAlberta Conrad DER Solar 2	Solar	23	52-Vauxhall	Apr 15, 2022
P2122 Cypress Wind Project	Wind	202	04-Medicine Hat	Nov 1, 2022
P2362 Fortis Enchant 447S DER Solar[13]	Solar	23	52-Vauxhall	Dec 15, 2021
P2363 Fortis Enchant 447S DER Solar	Solar	18	52-Vauxhall	Dec 15, 2021
P2364 Fortis Enchant 447S DER Solar	Solar	10	52-Vauxhall	Dec 15, 2021
P2365 Fortis Enchant 447S DER Solar	Solar	24	52-Vauxhall	Dec 15, 2021
Total Additional Planned Generation		**523**		

[12] Further details are provided in Section 6.1.2 of the Planning Report.

[13] All four Enchant DER projects met the AESO's project inclusion criteria on December 1, 2021.

The generation additions sensitivities (scenarios 2 and 3) are provided in Table 5.

Table 5 – Generation Connection Sensitivities in the Study Region

Project Name	Scenario	Type	Maximum Capability (MW)	Planning Area	Anticipated In-Service Date
P2323 Fortis Taber 83S DER Solar 1	2	Solar	19	52-Vauxhall	Nov 1, 2022
P2324 Fortis Taber 83S DER Solar 2		Solar	16	52-Vauxhall	Nov 1, 2022
P2325 Fortis Taber 83S DER Solar 3		Solar	16	52-Vauxhall	Nov 1, 2022
P2326 Fortis Taber 83S DER Solar 4		Solar	14	52-Vauxhall	Nov 1, 2022
Hypothetical Solar Addition at Burdett 368S	3	Solar	20	52-Vauxhall	-

As of the writing of this report, the four Taber 83S DER projects were in Stage 2 of the AESO's connection process and did not meet the AESO's project inclusion criteria.

The 20 MW solar generation addition at Burdett 368S substation is not related to any project in the AESO's Project List. Instead, it is a hypothetical generation addition, to help investigate whether there is risk of observing additional congestion should another solar generation project energize at the Burdett 368S substation in the future.

Table 6 summarizes the three scenarios considered in this assessment.

Table 6 – Congestion Assessment Scenarios

Scenario No.	Scenario Name	Scenario Description
1	Base	Projects meeting AESO project inclusion criteria (PIC)
2	Base + Taber DERs	PIC + Four Taber DER Solar Projects
3	Base + Burdett Solar	PIC + Burdett 368S substation Solar Addition

3.3. Transmission System Assumptions

The transmission system assumptions are discussed in the following sections.

3.3.1. Network Topology

The AIES was modeled in its entirety. The transmission system's three interties, to British Columbia, Saskatchewan, and Montana, were modeled and the neighboring jurisdictions had simplified representations. Intertie available transfer capability was established based on historical performance. Flows on interties were predicted based on price differentials yielded by production cost modeling. The AIES was modeled as per the existing transmission system; no future transmission system projects were modeled. The model included the connection projects for the future generation capacity discussed in Section 3.2.12.

3.3.2. *Monitored Transmission Lines and Ratings*

The focus of this congestion assessment was on the 138kV transmission lines from the Bowmanton 244S substation, northeast of the City of Medicine Hat, to the Taber 83S substation, east of Lethbridge These paths serve to supply load and act as a transfer-out network for excess power produced in the area.

The normal ratings for the monitored transmission lines are listed in Table 7. AURORA uses a linearized DC model for power flow calculations which assumes a voltage of 1 p.u. at each bus. The thermal ratings of the transmission lines were adjusted accordingly. The ratings were converted from MVA to MW using a power factor of 0.95 to account for the capacity that might be used for reactive power flow.

Table 7 – Existing Ratings for Monitored Transmission Lines

Line	From Substation	To Substation	Voltage Class (kV)	Normal Rating (MVA)	
				Summer	Winter
610L	83S TABER	336S FINCASTLE	138	85	90
612L	336S FINCASTLE	368S BURDETT	138	85	90
879L	368S BURDETT	879AL TAP-POINT	138	85	90
879L	244S BOWMANTON	879AL TAP-POINT	138	85	90

The 138 kV transmission line 879L constitutes two segments, and they were modeled and analyzed individually. For a visual representation of these transmission lines, please refer to the Planning Report.

The Preferred Transmission Development identified in the Planning Report is to increase the ratings for the 138 kV transmission lines 610L and 879L to the values shown in Table 8. For the 138 kV transmission line 879L, only the segment from Bowmanton 244S substation to the 879AL tap-point would be upgraded. As such, only that segment is shown in this table.

Table 8 – Future Ratings for Select Transmission Lines

Line	From Substation	To Substation	Voltage Class (kV)	Normal Rating (MVA)	
				Summer	Winter
610L	83S TABER	336S FINCASTLE	138	173	214
879L	244S BOWMANTON	879AL TAP-POINT	138	118	145

The congestion statistics were calculated first with the current transmission line ratings, and again with these higher ratings, to observe the effectiveness of the Preferred Transmission Development.

3.3.3. *HVDC Dispatch*

The high voltage direct current (HVDC) transmission lines called Western Alberta Transmission Line and Eastern Alberta Transmission Line, were dispatched to minimize transmission system losses in the congestion assessment. A formula that estimates the minimum loss dispatch based on flows measured on certain alternating current transmission lines was used to determine the HVDC dispatch that should be used for each hour in the simulation.

4. Congestion Assessment Results

The congestion results for all three scenarios are discussed in the following section. To summarize from previous sections, the congestion assessment included one base scenario and two sensitivity scenarios. The nodal simulations for each scenario were run as if there were no transmission system constraints. Then, congestion statistics were calculated using the current transmission line ratings, and again with the higher proposed ratings described earlier.

4.1. Scenario Results

The following table presents the key congestion results for all the monitored transmission lines in the Study Area. The table shows the percentage (and number) of congested hours expected in 2023 under the three different scenarios, pre- and post-VATD.

Table 9 – Summary of Congestion Results Under All Scenarios Pre and Post VATD

	Base	Base + Taber DERs	Base + Burdett Solar
	Scenario 1	Scenario 2	Scenario 3
Pre-VATD Congestion Frequency	8.48% (743)	8.47% (742)	9.22% (808)
Post-VATD Congestion Frequency	0.05% (4)	0.10% (9)	0.10% (9)

4.1.1. Pre-VATD Results

In all three scenarios before VATD, congestion is observed mainly on the 138 kV transmission lines 610L and 879L. The frequency of congestion ranged from approximately 740 to 810 hours, or about 8-9% of all hours in 2023.

The simulations for the sensitivity scenarios showed that the energization of the four Taber DER projects did not significantly impact the amount of anticipated congestion, but that the energization of more solar generation at Burdett 368S would increase the probability of congestion in the Study Area by about 1% in the pre-VATD case.

To understand the magnitude of potential congestion, duration curves (sorted hourly line flows) for each of the monitored transmission lines in all scenarios pre-VATD are provided in Attachment B-1. The duration curves show that maximum loading in the pre-VATD case ranged from approximately 180% to 200% of certain monitored transmission lines ratings.

4.1.2. Post-VATD Results

In all three scenarios post-VATD, the expected frequency and magnitude of congestion are reduced to nearly zero. After the line rating upgrades for the two 138 kV transmission lines 610L and 879L no remaining congestion is observed on line 610L. In the Base scenario, only marginal congestion (4 hours) is observed on 138 kV transmission line 879L, while the sensitivity scenarios (Scenarios 2 and 3) show 9 hours and 7 hours with congestion, respectively.[14]

[14] In sensitivity Scenario 3, 2 hours with congestion are also observed on the 138 kV transmission line 612L. Should a scenario like this arise, the AESO will handle this congestion using real-time operation procedures.

Duration curves for each of the monitored transmission lines in all scenarios post-VATD are presented in Attachment B-2.

The duration curves show that maximum loading in the post-VATD case was reduced to approximately 115% of certain monitored lines ratings, mainly 138 kV transmission line 879L.

5. Conclusions

Congestion on the 138 kV transmission lines 610L and 879L is currently being observed in real-time operations. This assessment shows that congestion is expected to occur approximately 8 to 9 % of hours in 2023. This assessment also shows that the transmission development proposed in the VATD Planning Report, which is to increase the thermal ratings of the 610L and 879L transmission lines, would reduce the expected congestion to nearly zero percent of hours in 2023. A few hours of congestion that are still observed in the post-VATD scenarios will be managed using real-time operation procedures.

Attachment B-1

Figure 1_A - 610L_336S -- Summer Duration Curve

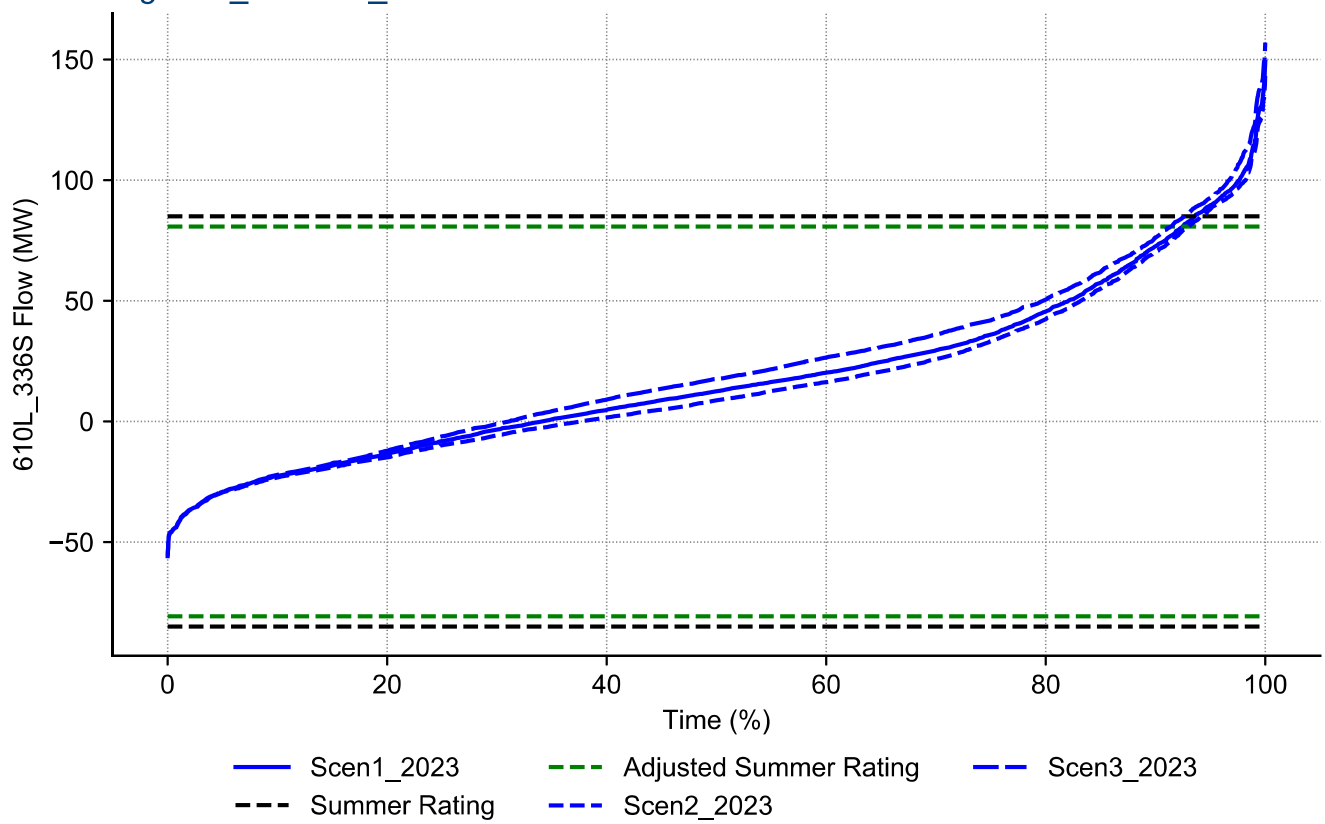


Figure 1_B - 610L_336S -- Winter Duration Curve

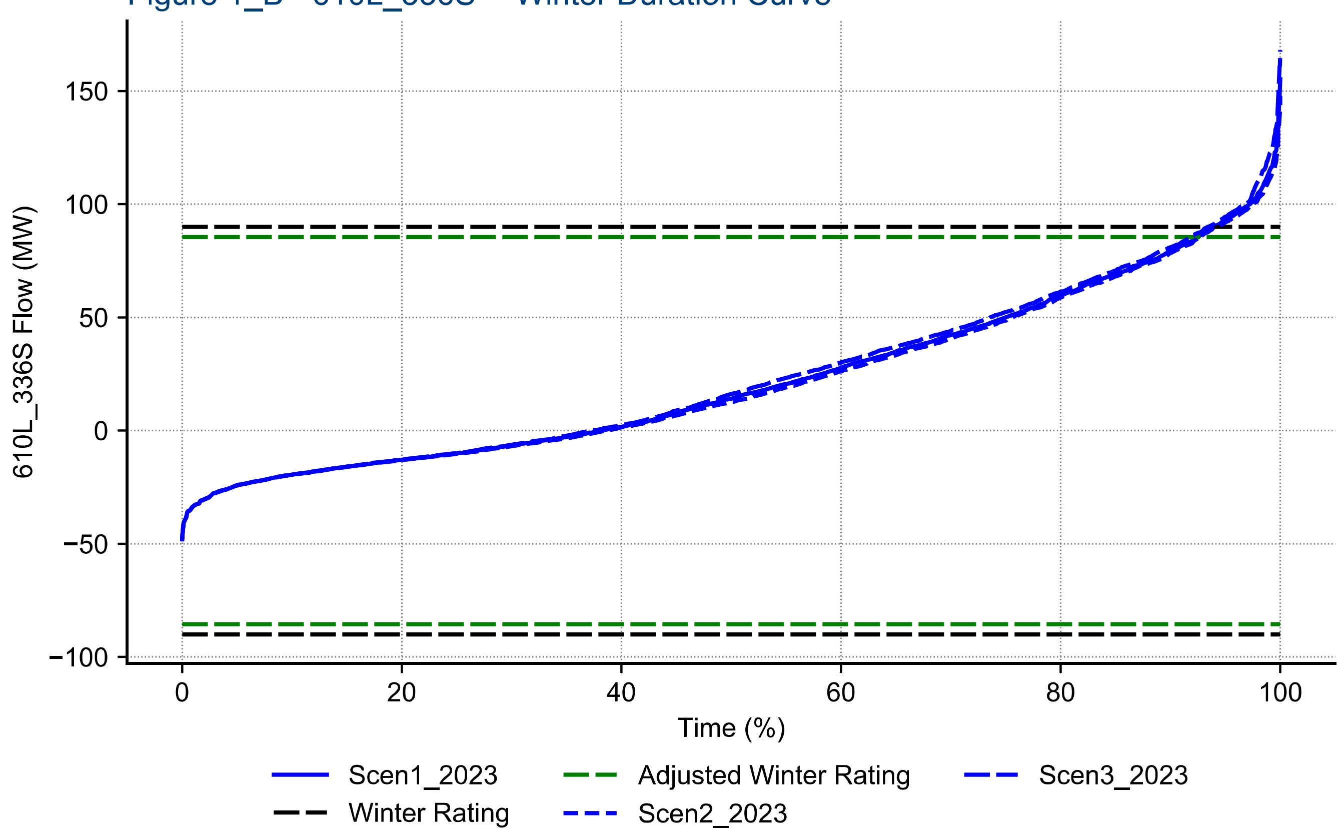


Figure 2_A - 612L_336S -- Summer Duration Curve

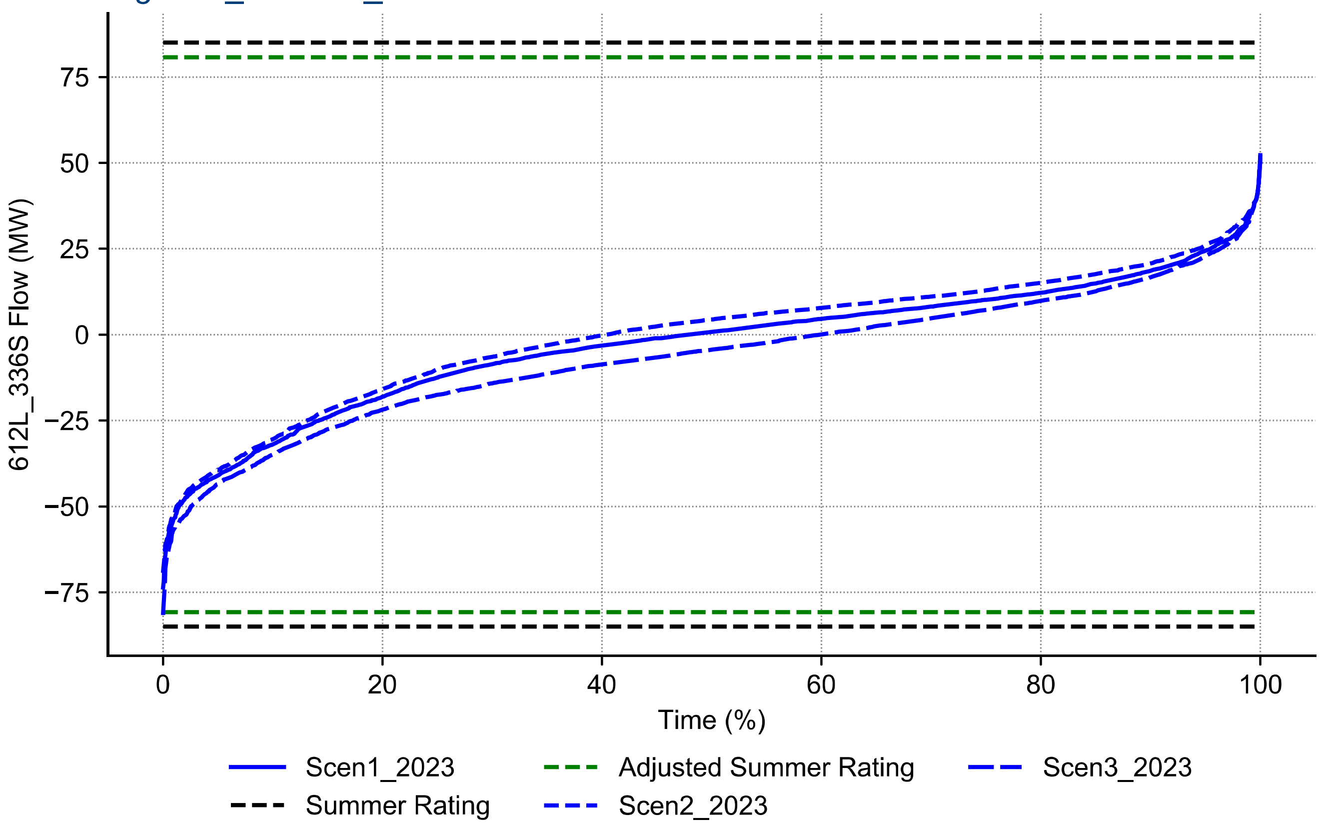


Figure 2_B - 612L_336S -- Winter Duration Curve

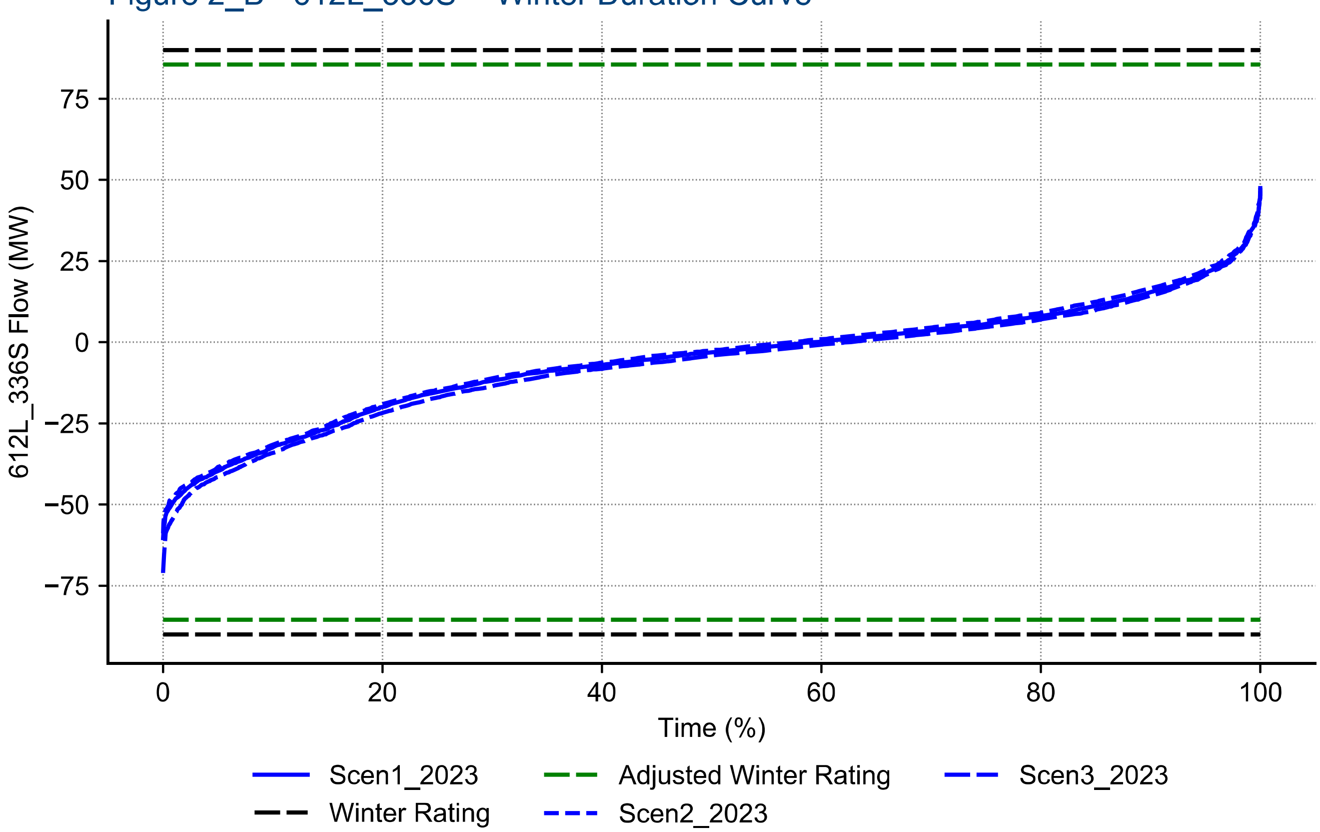


Figure 3_A - 879L_368S -- Summer Duration Curve

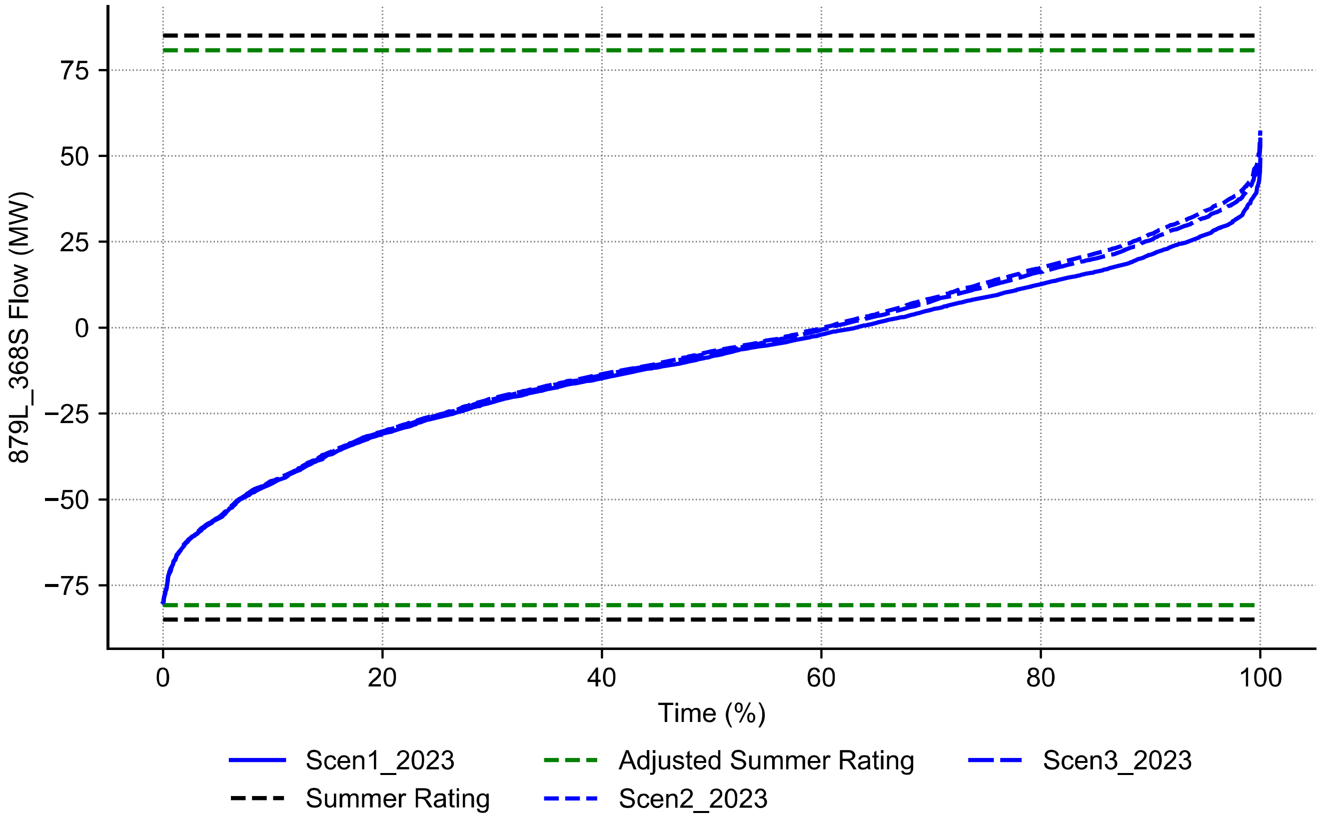


Figure 3_B - 879L_368S -- Winter Duration Curve

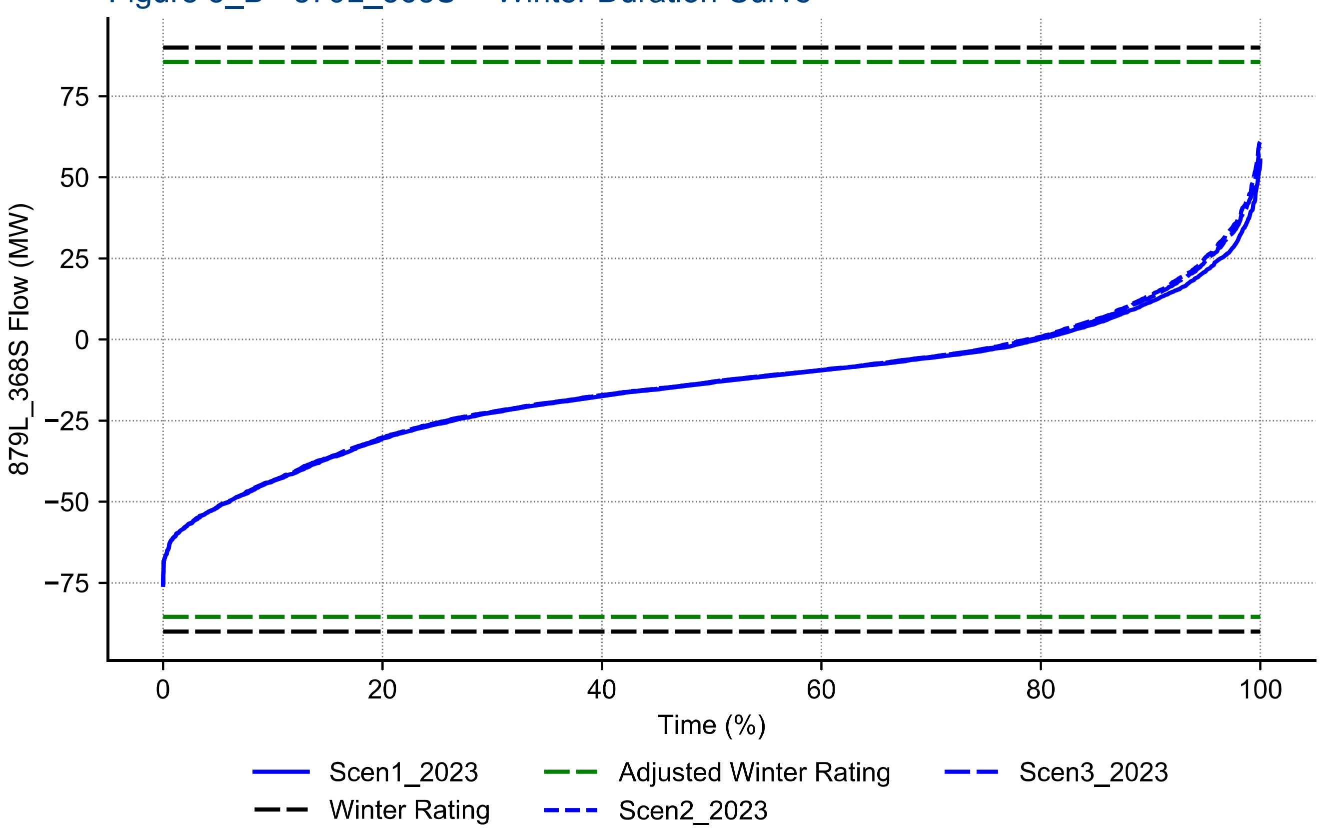


Figure 4_A - 879L_244S -- Summer Duration Curve

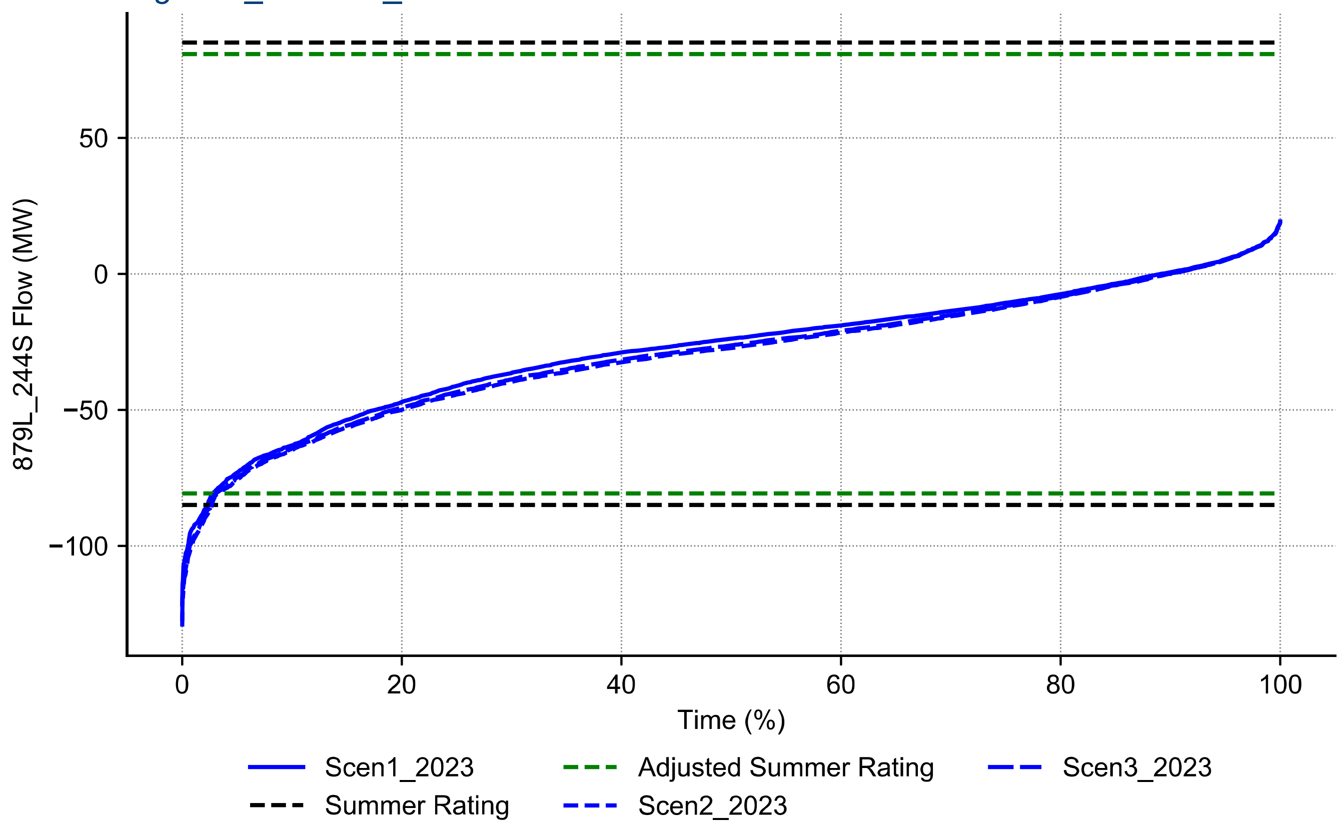
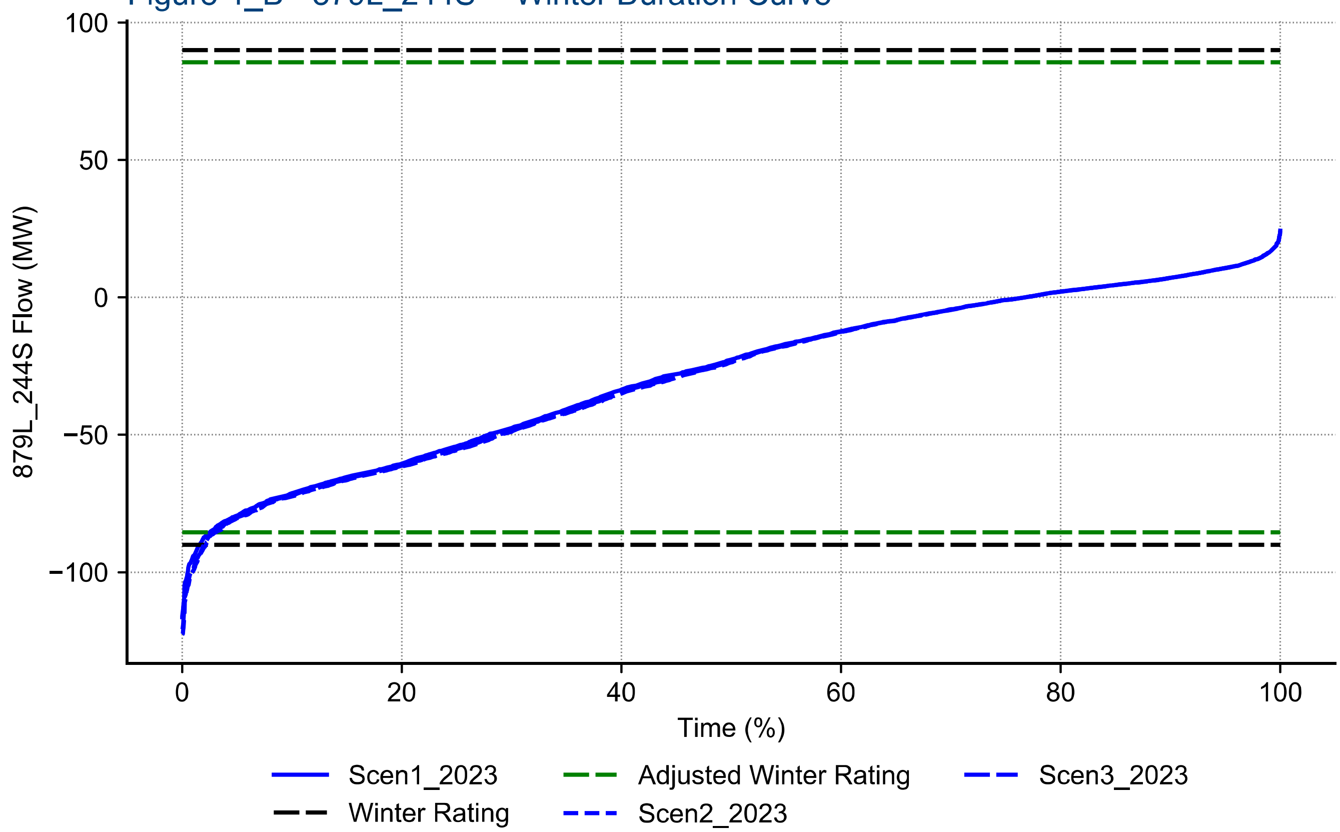


Figure 4_B - 879L_244S -- Winter Duration Curve



Attachment B-2

Figure 1_A - 610L_336S -- Summer Duration Curve

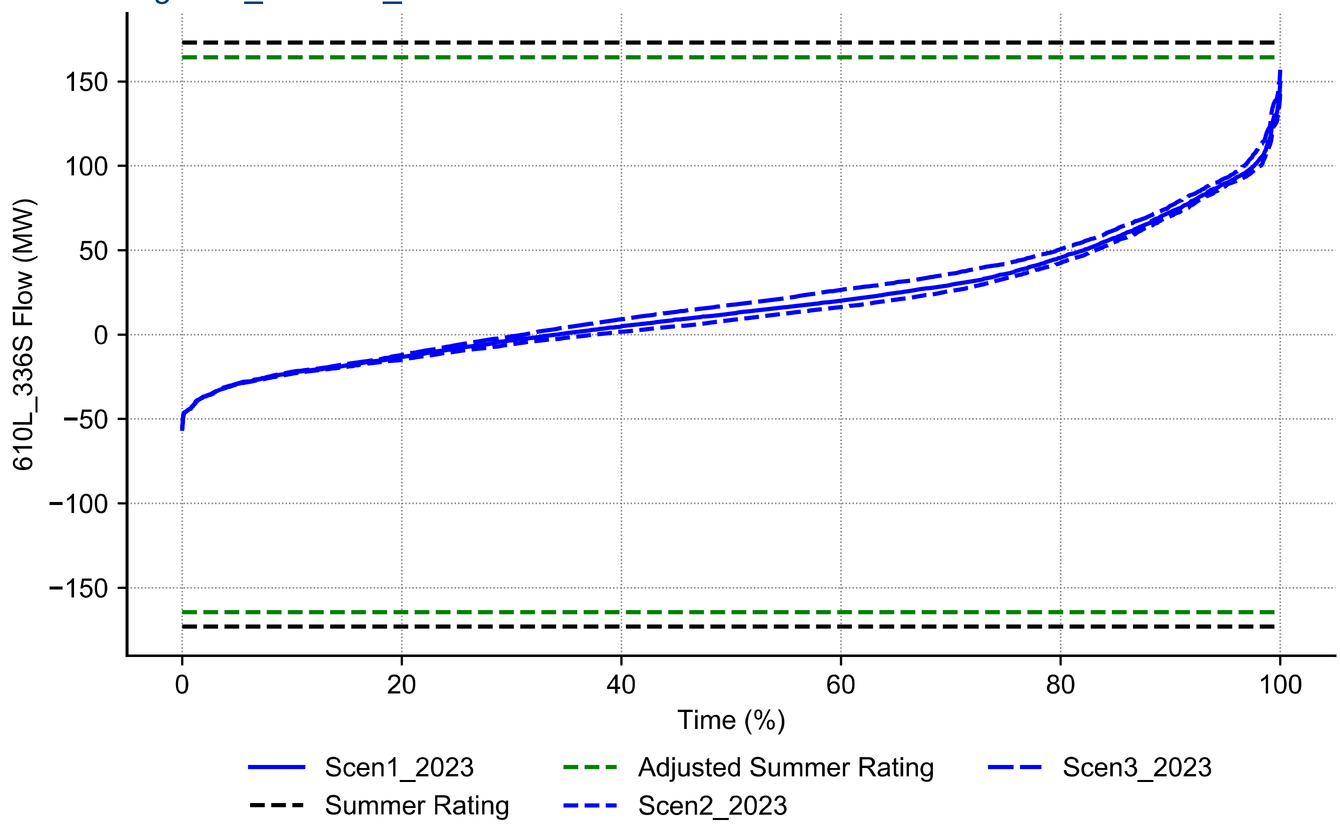


Figure 1_B - 610L_336S -- Winter Duration Curve

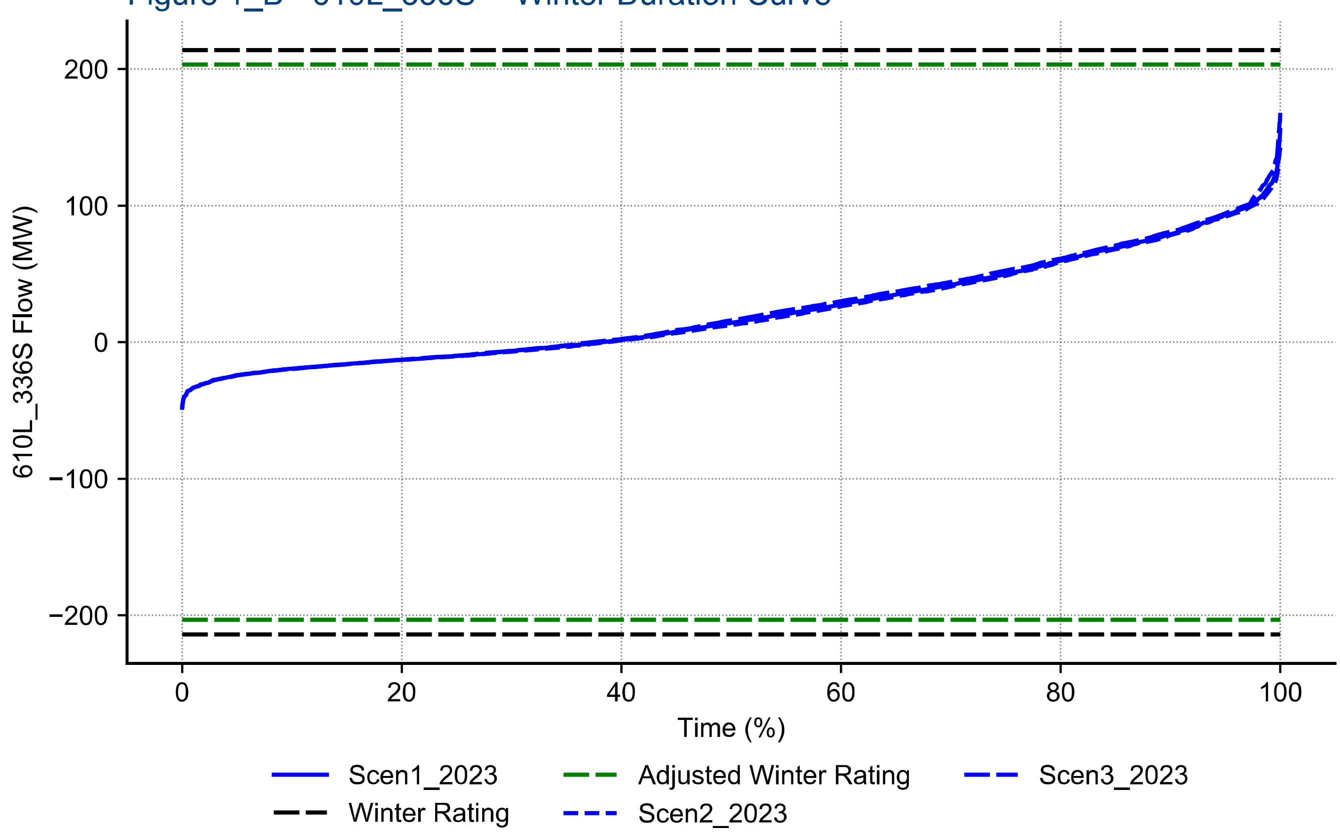


Figure 2_A - 612L_336S -- Summer Duration Curve

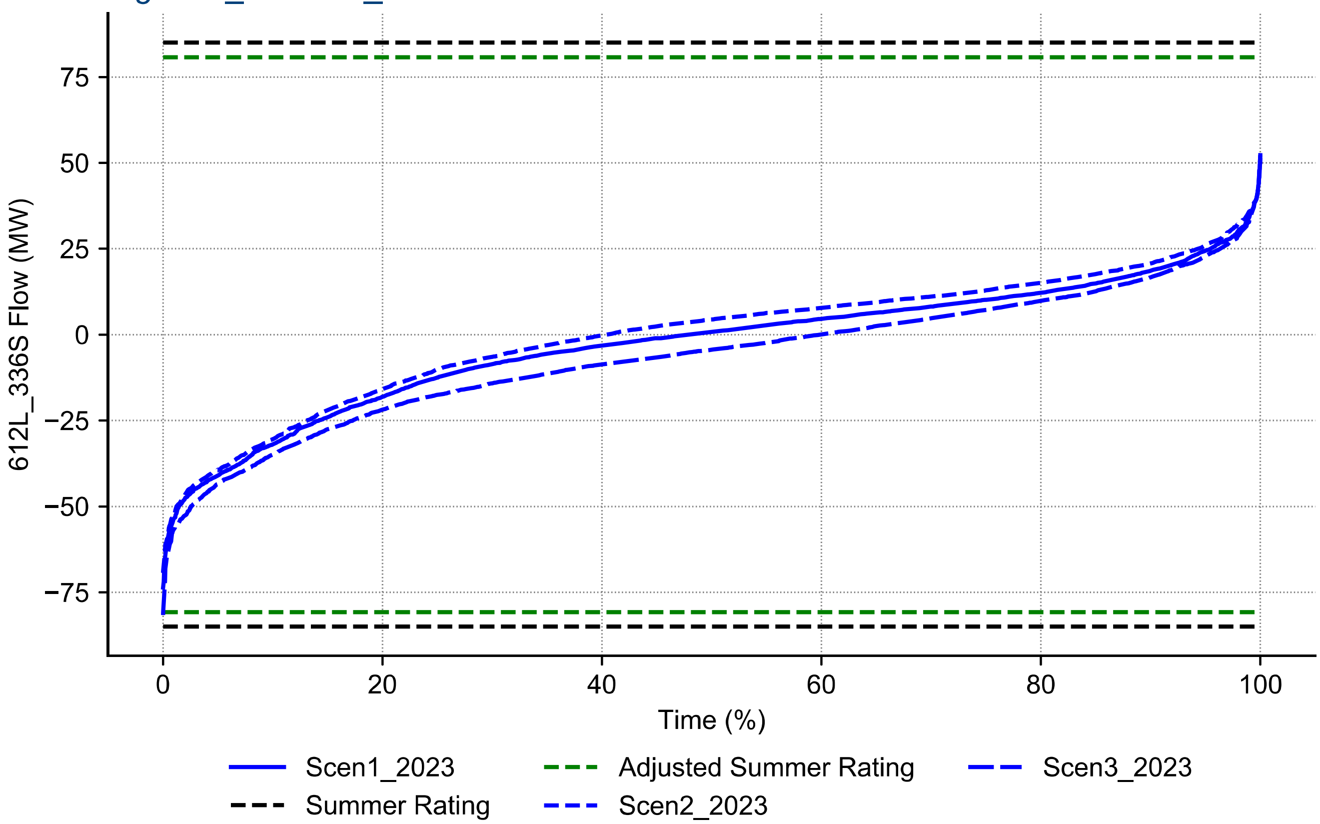


Figure 2_B - 612L_336S -- Winter Duration Curve

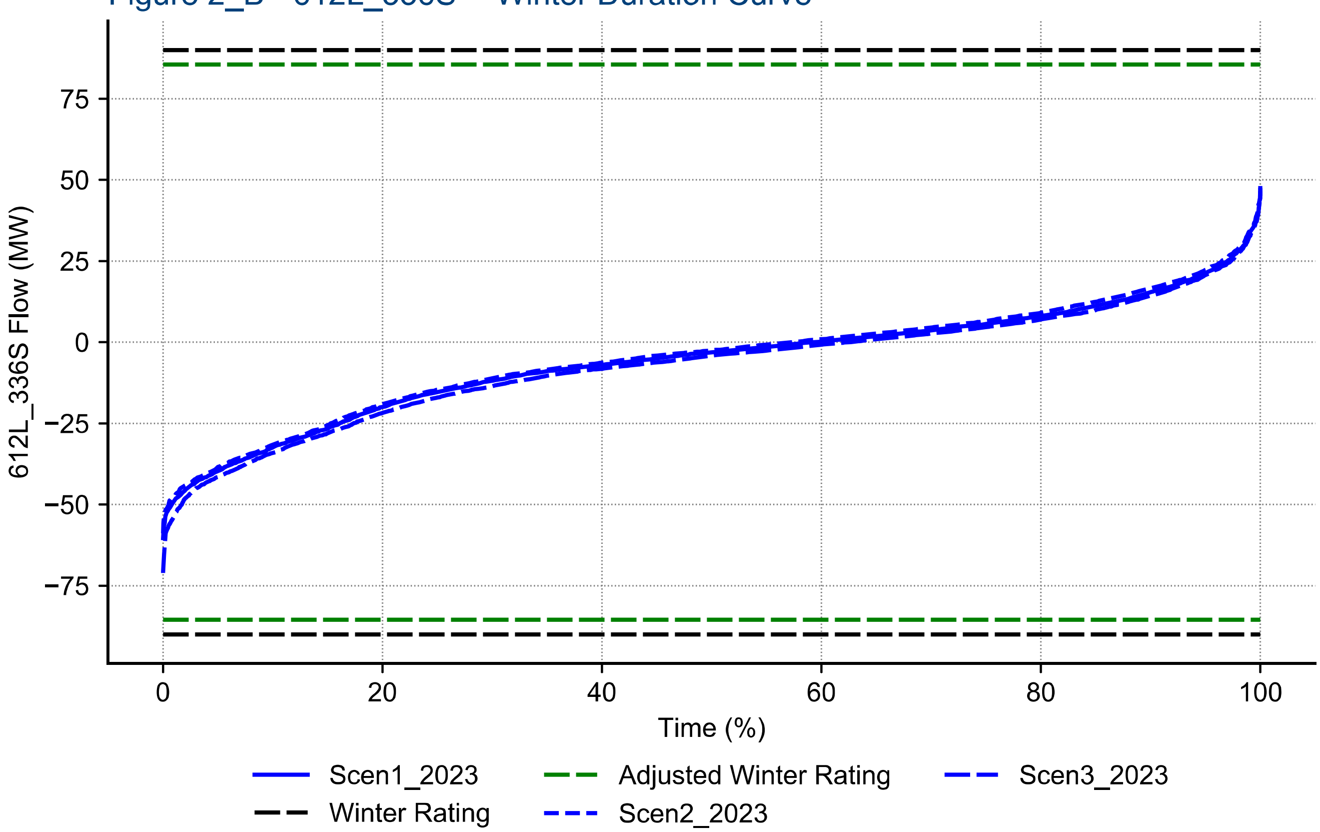


Figure 3_A - 879L_368S -- Summer Duration Curve

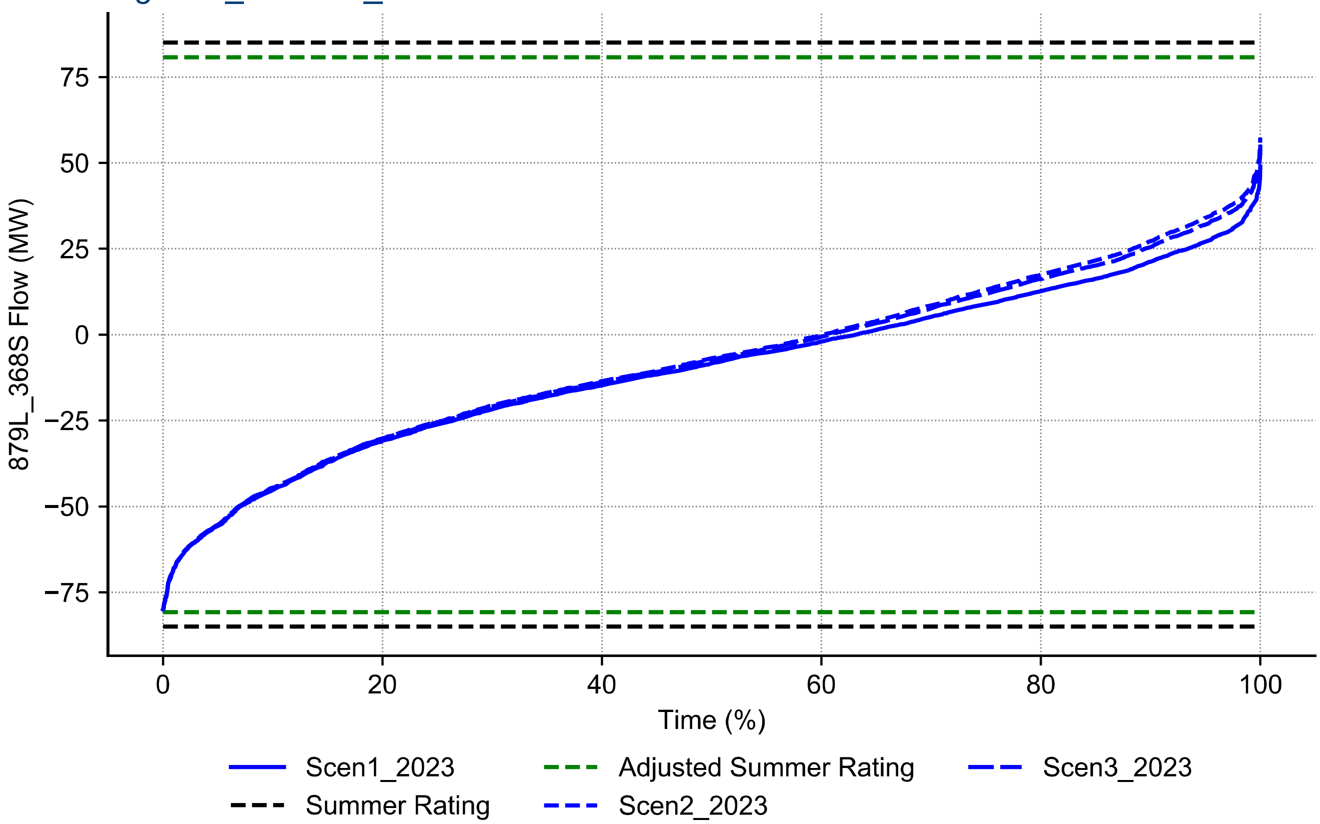


Figure 3_B - 879L_368S -- Winter Duration Curve

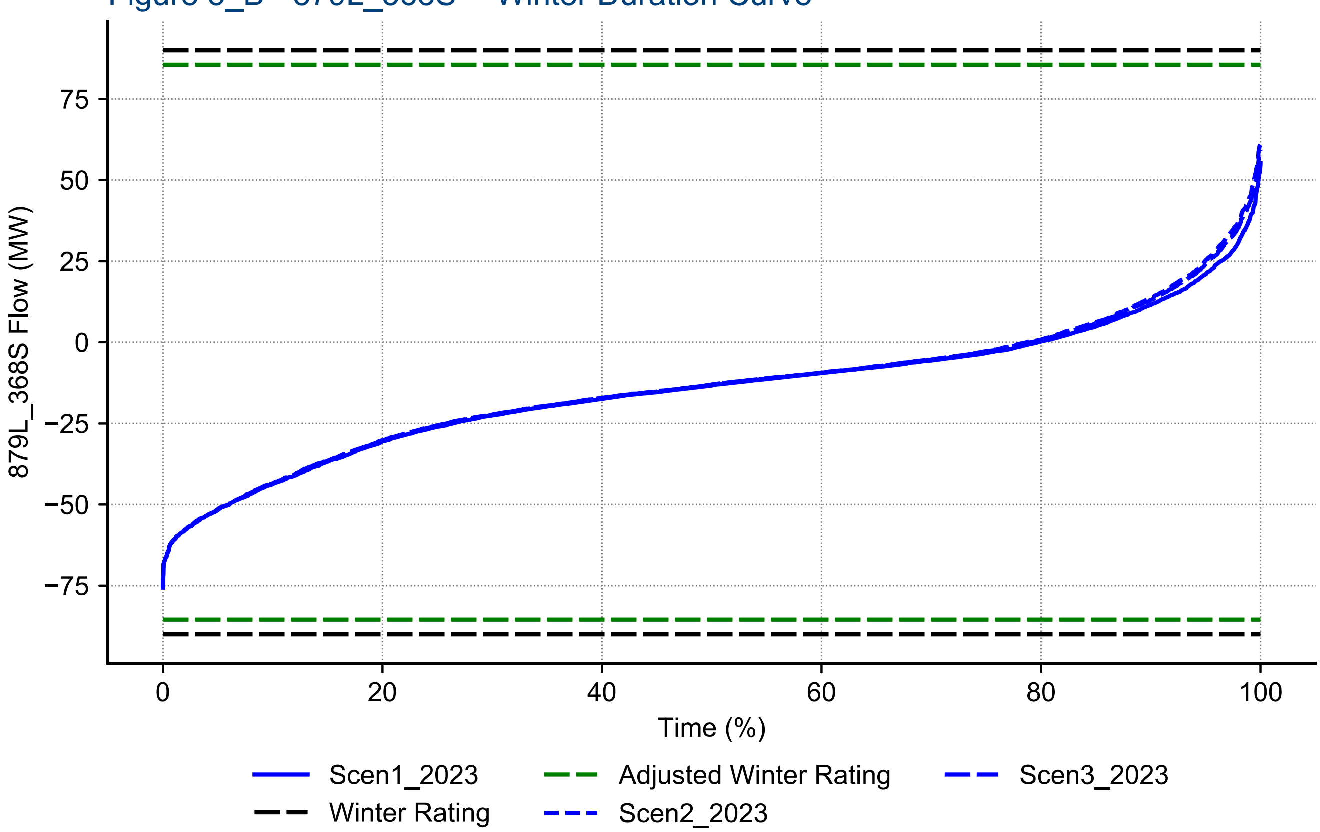


Figure 4_A - 879L_244S -- Summer Duration Curve

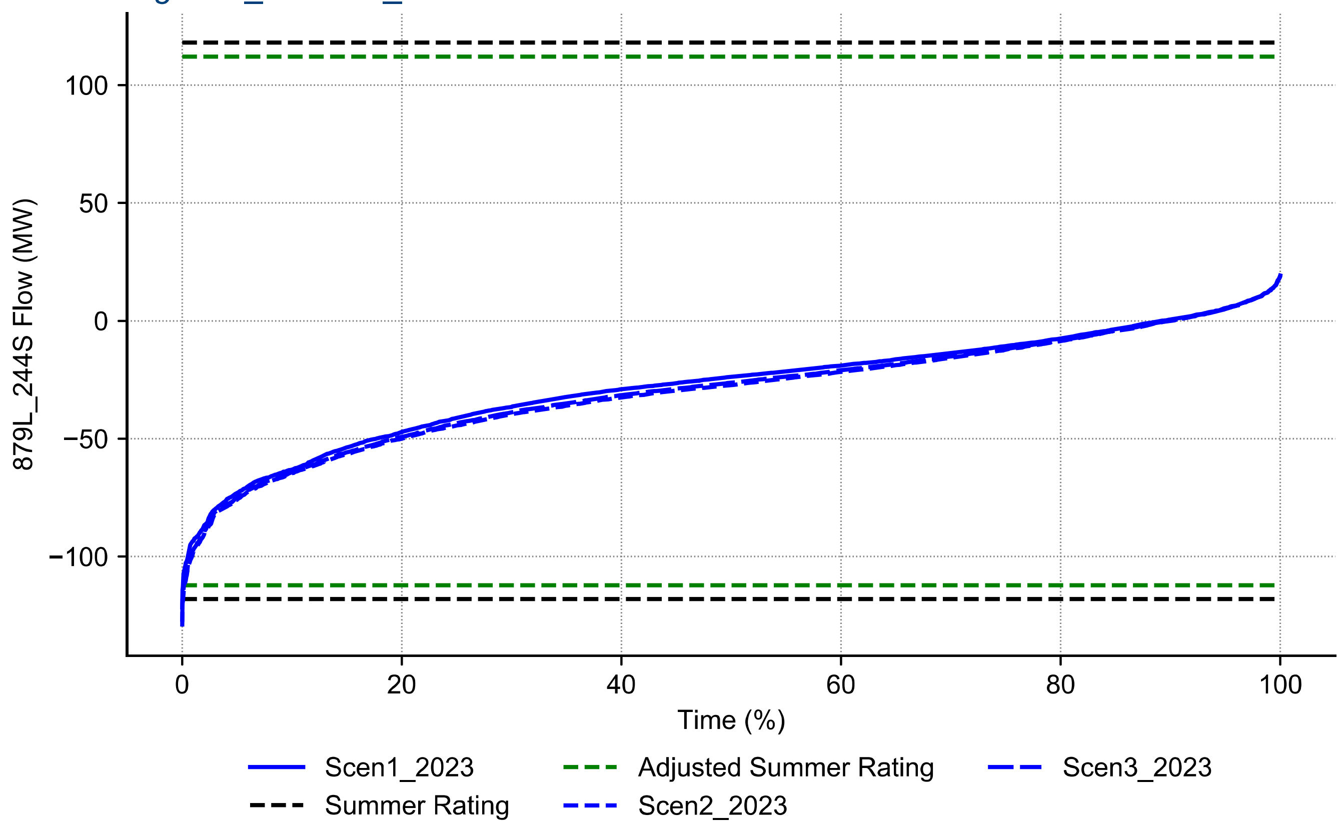


Figure 4_B - 879L_244S -- Winter Duration Curve