

Business Case for
GrandBridge Energy's
Non-Wires Alternatives (NWA) Program

Executive Summary

GrandBridge Energy (GBE) is seeking funding under the Smart Renewables and Electrification Pathways (SREP) Program – Utility Support Stream to implement its Non-Wires Alternatives (NWA) Program—a proactive solution to address critical grid capacity challenges, enhance system resiliency, and advance Ontario's energy transition.

By the end of 2027, three key transformer stations in Cambridge—Preston TS, Galt TS, and MTS1—is forecasted to reach approx. 88% of their aggregated rated capacity, driven by:

- Rapid data center connections, particular around Artificial Intelligent
- Commercial sector growth in regions around Highway 401 and Highway 403 (two major roadways serving Ontario)
- New residential subdivision growth and urban densification, and
- Fleet electrification, especially the adoption of Level 3 chargers

This trend is also seen across Ontario, where the provincial electricity demand is projected to increase by 75% increase in electricity demand by 2050, per the Independent Electricity System Operator [IESO] latest forecast released on Oct. 16, 2024, rising from 151 terawatt-hours (TWh) in 2025 to 263 TWh in 2050.

As a mid-sized utility serving 113,000 customers, GBE lacks the capital and personnel resources of Ontario's largest utilities (1M+ customers). Without funding support, the cost of running the NWA program would need to be fully recovered through electricity rates. The SREP funding is crucial to ensuring the program is cost-effective for ratepayers while advancing a more flexible, resilient, and sustainable energy system.

Ontario's regulatory landscape is supportive of NWA solutions, as reflected in:

- Ontario Energy Board (OEB) policies, such as the Non-Wires Solution Guidelines and Benefit-Cost Analysis (BCA) Framework, which encourage utilities to adopt innovative grid solutions.
- The government's broader ambition to accelerate new connections and keep electricity costs affordable.

If no action is taken, capacity constraints will force GBE to delay or deny new customer connections, contradicting our regulatory obligation to serve all customers, and causing:

- Economic stagnation, as businesses may take their investments elsewhere, potentially outside of Canada.
- Loss of trust with customers and the local community.
- Higher costs for ratepayers, as traditional infrastructure upgrades are far more expensive than NWA solutions.

With successful SREP funding, the GBE NWA Program will:

- Ensure customers are connected faster, without waiting years for infrastructure expansion before they can connect.
- Empower customers to participate in grid management and reduce their electricity costs.
- Enhance energy reliability and grid resiliency, reducing outage risks.
- Support local job creation and investment in clean energy technologies.

The Problem: Grid Capacity Constraints & Economic Risks

Transformer Station Overload & Reliability Challenges

By the end of 2027, Preston TS, Galt TS, and MTS1 is forecasted to reach an average of 87.8% of their combined rated capacity, causing:

- Severe grid constraints, limiting the ability to transfer loads between stations.
- Reduced system resiliency, making outages more difficult to manage.
- Delayed or denied new customer connections, hindering economic growth.

The table below is the Limited Time Rating (LTR) for Preston TS, Galt TS, and MTS1. Figures are in Mega Volt-Amperes (MVA).

Station	LTR
MTS#1	102
Galt TS	169
Preston TS	180
Total	451

The table below is the forecasted load for Preston TS, Galt TS, and MTS1 from 2024 to 2027. Figures are in MVA.

Station	2024	2025	2026	2027
MTS#1	82.9	100.4	97.9	99.9
Galt TS	129.5	132.5	135.5	138.6
Preston TS	88.5	89.1	155.4	157.5
Total	300.9	322.0	388.8	396.0
% of Total LTR	66.7%	71.4%	86.2%	87.8%

If GBE is forced to turn away customers due to grid limitations, this would:

- Contradict our regulatory obligation to serve all customers.
- Damage GBE's reputation and erode trust with the community.
- Result in lost commercial and industrial investments for the City of Cambridge.

Rising Electricity Costs & Infrastructure Investment Pressure

Traditional solutions—such as building new transformer stations and new distribution infrastructure—are costly and take years to complete, leading to:

- Higher electricity rates for ratepayers, as these capital costs are passed down.
- Delays in connecting businesses and residents, slowing economic growth.
- Missed opportunities to integrate cleaner, more efficient energy solutions.

Based on GrandBridge Energy's latest Key Performance Indicator (KPI) metrics:

- The average cost of a traditional single-circuit, three-phase overhead line expansion is approximately \$400 per meter. Constructing a 5 km distribution line would cost \$2 million and provide approximately 20MVA of additional distribution capacity.
- The estimated cost of a new substation is approximately \$50 million for a 100MVA station.

Since GBE is already running near maximum available station capacity in the City of Cambridge (87.8% by the end of 2027), enabling 20 MVA of additional capacity would very likely require a new overhead line and a new substation. The price tag for this new infrastructure would be approximately \$52 million, an expense that would ultimately be recovered through electricity rates paid by ratepayers.

The Ontario Energy Board (OEB) expects utilities to actively explore Non-Wires Alternatives (NWA) solutions as part of their planning and investment strategies. In alignment with this regulatory direction, GrandBridge Energy (GBE) is committed to:

- Minimizing costs for ratepayers by leveraging demand-side solutions as a cost-effective alternative to traditional infrastructure expansion.
- Accelerating customer connections through innovative approaches that reduce wait times for new capacity.
- Enhancing grid reliability by integrating flexible, scalable solutions rather than relying solely on costly infrastructure upgrades.

The Solution: GrandBridge Energy's NWA Program

Program Overview

The GBE NWA Program is designed to relieve capacity constraints, defer infrastructure investments, and enhance grid resiliency through:

- Leveraging existing local Demand Response (DR) resources: Participants are incentivized to reduce load during peak hours
- Leveraging existing local Distributed Energy Resources (DERs): Incentivizing behind-the-meter (BTM) solar, battery storage, and smart energy solutions in a load displacement configuration to reduce their demand on the grid during peak hours
- Market Participation: Running a capacity auction for DR and DER capacity allows for pricing competitiveness and ensures the utility is obtaining these resources in a cost-effective manner for its ratepayers.

As alluded to in the previous section, the cost of enabling 20 MVA of capacity using traditional infrastructure (i.e., a new transformer station and new overhead distribution lines) is approximately \$52 million. The GBE NWA Program is expected to procure existing DR or DERs more cost-effectively. For comparison, the current IESO Demand Response market pays up to approximately \$45,000 per MVA per year, which translates into a \$900k per year payment for 20 MVA of capacity. Using the OEB's BCA framework and factoring in running costs, interest costs, etc., the total net present value savings to ratepayers is approximately \$4.9 million, assuming the traditional infrastructure investment can be deferred by 5 years — which assumes a growth of about 4 MVA per year (20 MVA divided by 5 years). The net present value savings will be even higher if a deferral period greater than 5 years is achieved. Please note that it is GBE's opinion that the NWA Program can only defer traditional infrastructure investments but cannot completely replace them. However, the deferral will help achieve savings for our ratepayers as described above.

Key Program Benefits

- Defers costly transformer station and distribution system expansions, reducing ratepayer impacts.
- Accelerates business and residential connections, avoiding long wait times.
- Enhances grid resiliency, mitigating power outage risks.
- Supports economic growth, enabling new commercial and industrial development.
- Empowers customers with energy choices, enhancing participation in Ontario's clean energy transition.

By implementing these solutions, GrandBridge Energy will:

- Align with OEB's regulatory framework for cost-effective grid planning.
- Keep electricity costs stable for ratepayers while improving reliability.
- Enable the transition towards a future Distributor System Operator (DSO) model, similar to the shift currently occurring in European markets, by integrating DERs into core grid decision-making.

Alignment with Regulatory & Policy Goals

Supporting Ontario's Grid Modernization & Affordability Targets

The OEB's Non-Wires Solution Guidelines encourage utilities to:

- Minimize infrastructure investments through demand-side solutions.
- Promote DER integration for a smarter, more cost-effective grid.
- Ensure affordability for ratepayers by reducing capital expenditures.

The GBE NWA Program aligns with these mandates, ensuring regulatory compliance while delivering tangible benefits to ratepayers.

Positioning Ontario for a Future DSO Model

Jurisdictions like Europe, Northeastern U.S., and Australia have successfully integrated DR and DERs into grid planning through advanced DSO models. While Canada lags behind, implementing NWA is a critical first step toward evolving into a modern DSO by:

- Leveraging customer-sited resources to support the grid.
- Shifting from centralized infrastructure investment to a decentralized, flexible model.
- Demonstrating leadership in grid modernization, inspiring future talent and investment.

Why SREP Funding is Crucial to Program Success

Unlike larger Ontario utilities (1M+ customers), GBE is a mid-sized utility (113,000 customers) with limited capital and personnel resources. SREP funding is essential to:

- Reduce program costs that would otherwise be recovered through electricity rates, ensuring the program remains cost-effective for ratepayers.
- Support program deployment without financial strain, accelerating clean energy adoption.
- Ensure that mid-sized utilities like GBE can lead in energy innovation, rather than only larger utilities with greater resources.

Conclusion

Without immediate action, growing capacity constraints will lead to:

- Denied customer connections, harming economic growth and community trust.
- Higher electricity rates, due to reliance on more expensive, traditional electricity infrastructure expansions.
- Greater reliability risks, with increased grid congestion and outage potential.

With SREP funding, the GBE NWA Program will:

- Provide a cost-effective, innovative solution to grid challenges vs. sole reliance on traditional electricity infrastructure.
- Ensure customers can connect to the grid faster and more affordably, increasing additional economic investments and ensuring economic prosperity.
- Support Ontario's clean energy transition, creating additional green jobs and local investments.

By supporting the GBE NWA Program, Canada can drive sustainable economic growth, accelerate electrification, and modernize Ontario's grid—all while keeping electricity affordable, reliable, and customer-centric.

SREP FPP - Project Budget

Eligible Expenditures	Apr 2025 - Mar 2026	Apr 2026-Mar 2027	Apr 2027-Mar 2028	Apr 2028 - Mar 2029	Total	Comments
Salaries and Benefits	\$125,000	\$125,000	\$125,000	\$125,000	\$500,000	Salaries and Benefits, including overheads of GBE Employees
Professional, Scientific and Contracting Services	\$575,000	\$50,000	\$50,000	\$50,000	\$725,000	GridS2's services and technology implementation contract fee + third-party services for regulatory and legal support.
Travel, including meals and accommodations	-	-	-	-	\$0	No travel and other associated expenses are expected during the lifecycle of this project
Capital Expenditures for Equipment and Products	-	\$208,840	\$417,680	\$835,360	\$1,461,880	The payment to DR market participants. This is based on a cost of \$41,768/MW as calculated in the Network Analysis Report, and a phased procurement plan - 5 MW in 2026, 10 MW in 2027 and 20 MW in 2028.
Expenses for Indigenous Organizations	-	-	-	-	\$0	No expenses for indigenous organizations are expected during the lifecycle of this project
Total by Fiscal Year	\$700,000	\$383,840	\$592,680	\$1,010,360		
Total Eligible Expenditures					\$2,686,880	
In-Eligible Expenditures	Apr 2025 - Mar 2026	Apr 2026-Mar 2027	Apr 2027-Mar 2028	Apr 2028 - Mar 2029	Total	Comments
Not Applicable	-	-	-	-	\$0	No In-Eligible Expenditures are expected during the lifecycle of this project
Total In-Eligible Expenditures					\$0	
In-Kind Costs	Apr 2025 - Mar 2026	Apr 2026-Mar 2027	Apr 2027-Mar 2028	Apr 2028 - Mar 2029	Total	Comments
Not Applicable	-	-	-	-	\$0	No In-Kind Costs are expected during the lifecycle of this project
Total In-Kind Costs					\$0	
Total Project Costs					\$2,686,880	



ABSTRACT

The cost of demand response for GBE in aggregate across the three constrained transformer stations is \$41,768 per MW.

**NETWORK
ANALYSIS REPORT**

April 2025

GBE Demand Response Analysis Report for Preston, Galt and MTS1 TS

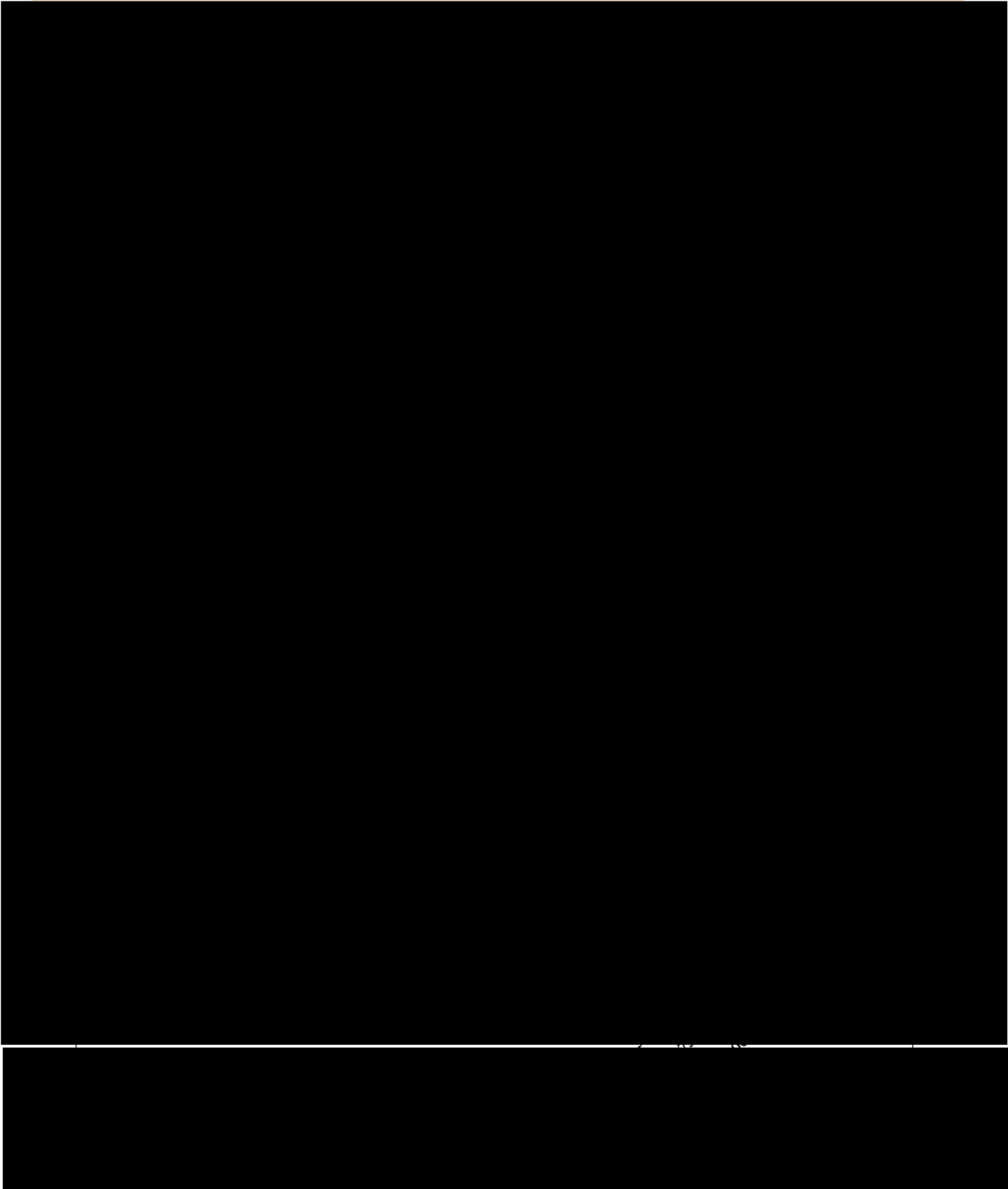
1. Introduction

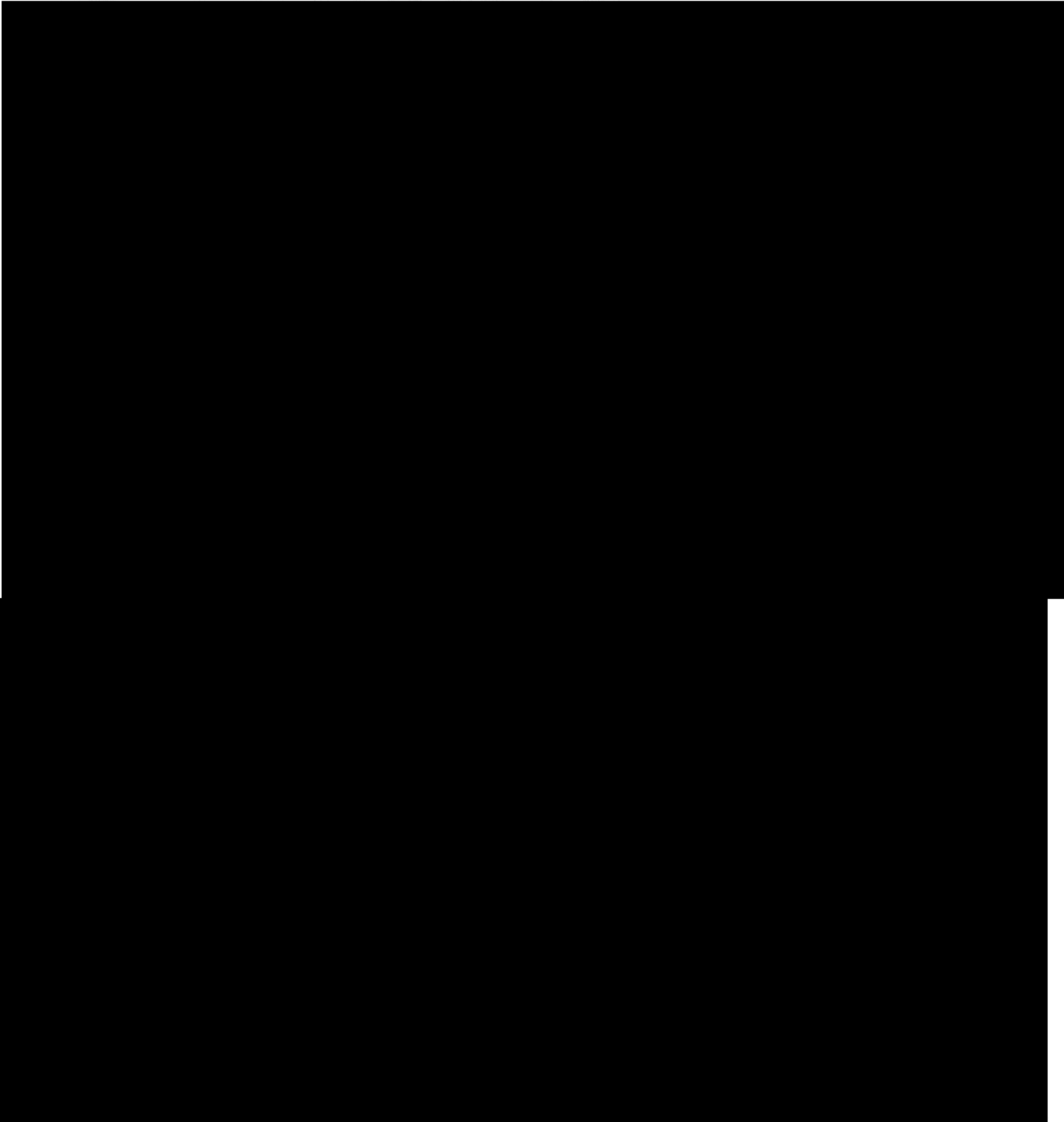
Transformer Stations (TSs) in GrandBridge Energy's (GBE's) service territory are witnessing substantial load growth. To contend with this load growth, Demand Response (DR) is a solution the GBE is implementing. To define the requirements of the DR program, load profiles for the three constrained TSs - Preston TS, Galt TS and MTS1 were studied for calendar years 2023, and 2024. These studies and their reports are presented in appendices A1, A2, and A3.

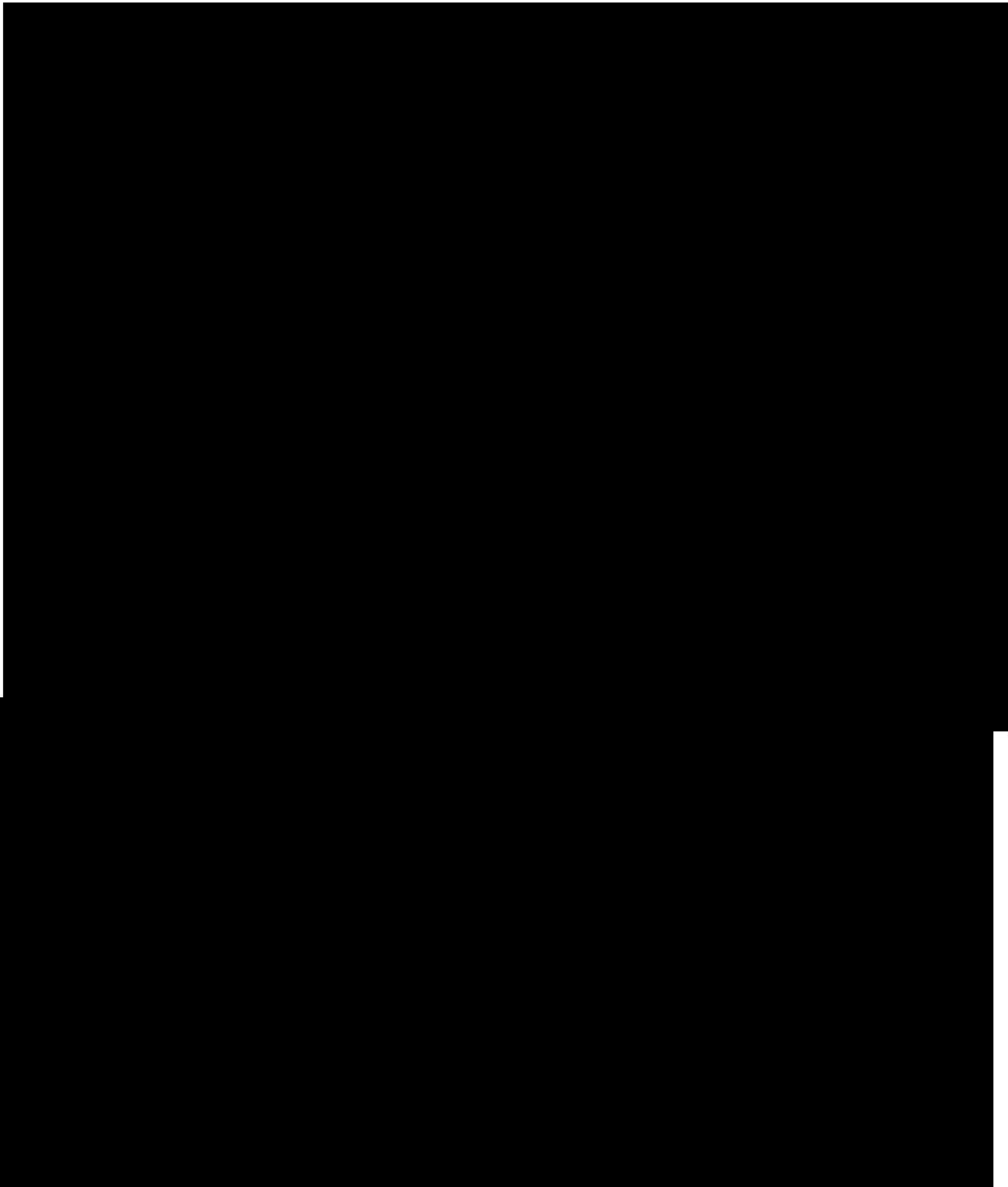
2024 data was used to explore their load duration curves that show their peak demand incidences. Tables 1, 2 and 3, in the following pages, provide sensitivity analysis for various capacity auction settlement values in terms of \$/MW-day and number of calls per month, at each TS. Similarly Figures 1, 2 and 3 provide a graphical representation of this analysis.

Tables 4 and Figure 4 aggregate these results to show the effect across the three TSs for GBE.

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2. Conclusion

Considering **2 calls / month** at **\$500 per MW-day**, the total costs for **19.85 MW** of DR for GBE costs **\$829,193 per year**. It comprises \$516,590 as capacity costs which are fixed, and \$312,603 as performance costs which are variable.

In summary, the cost of demand response for GBE in aggregate per MW equals: $\$829,193 / 19.85208 = \$41,768/\text{MW}$.

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Appendix A1 – GBE Demand Response Analysis Report for Preston TS

A1.1. Introduction

The Preston TS had a peak demand of 87.01 MW in 2023, and 96.25 MW in 2024. It is about a 10% annual growth. This rate of growth is sometimes unanticipated. Demand response is an apt tool in the utility tool chest to efficiently operate distribution networks and manage rapid growth of demand while planning for new assets to facilitate this increased demand.

Figure A1.1 shows the demand for Preston TS for years 2023 and 2024.

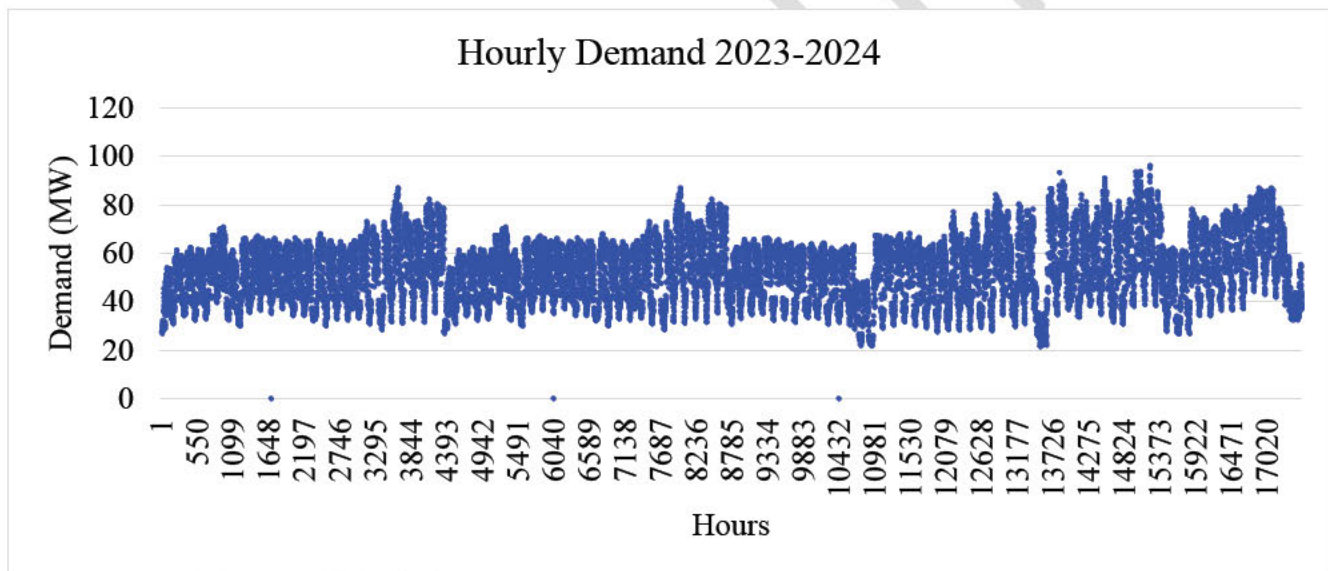


Figure A1.1 – Preston TS MW demand for 2023 and 2024

The demand is usually between 30 MW and 100 MW. Peak demand growth can be seen from 2023 to 2024 via visual inspection. Numerical details are shown in the following sections.

A1.2. Technical Analysis of Preston TS Loading

The load duration for 2024 is now analyzed to explore effects of demand response (DR), see Figure A1.2. From the graph, it is clear that year peak demand has grown from 87.01 MW to 96.25 MW from 2023 to 2024, amounting to a 10% year-on-year increase. Such a dramatic increase is an apt place for use of tools such as demand response, while waiting for new build to supply such a sustained demand.

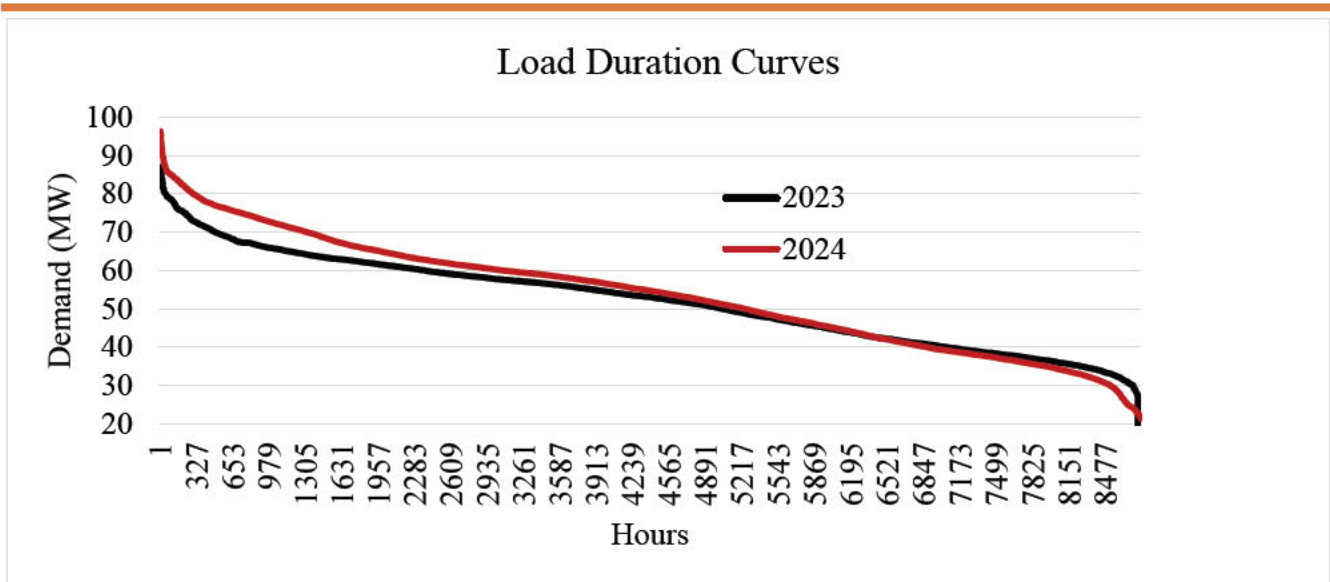
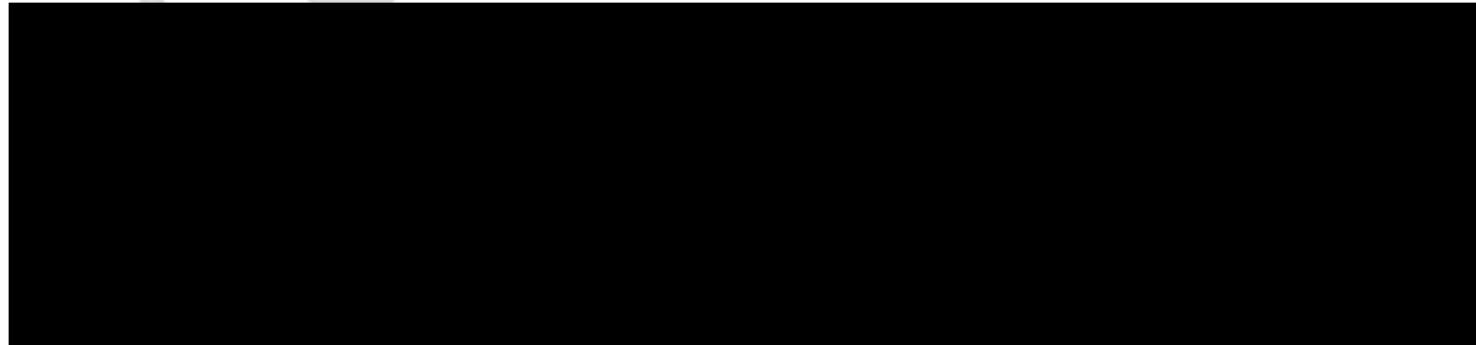
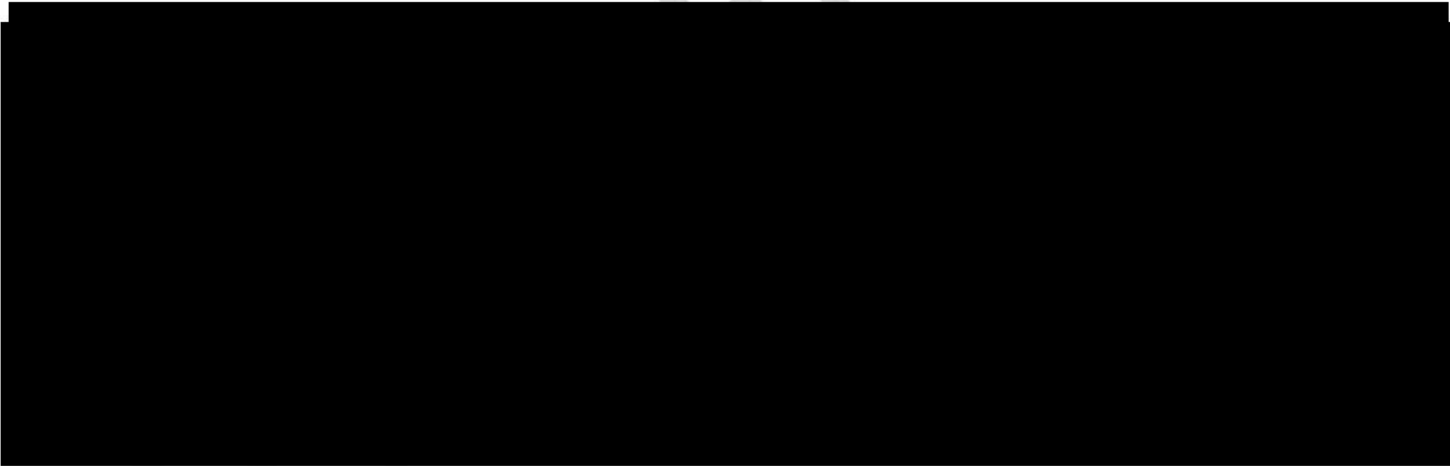
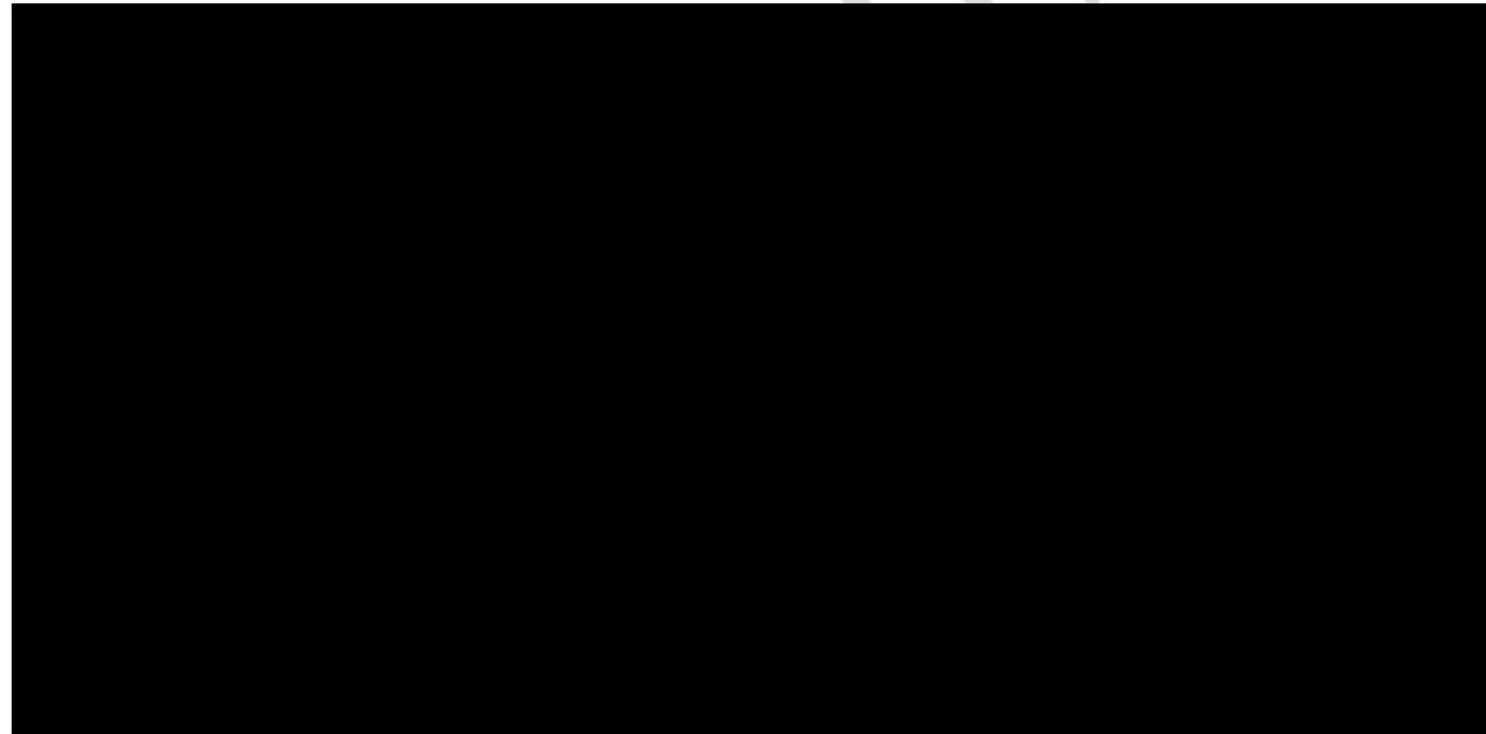
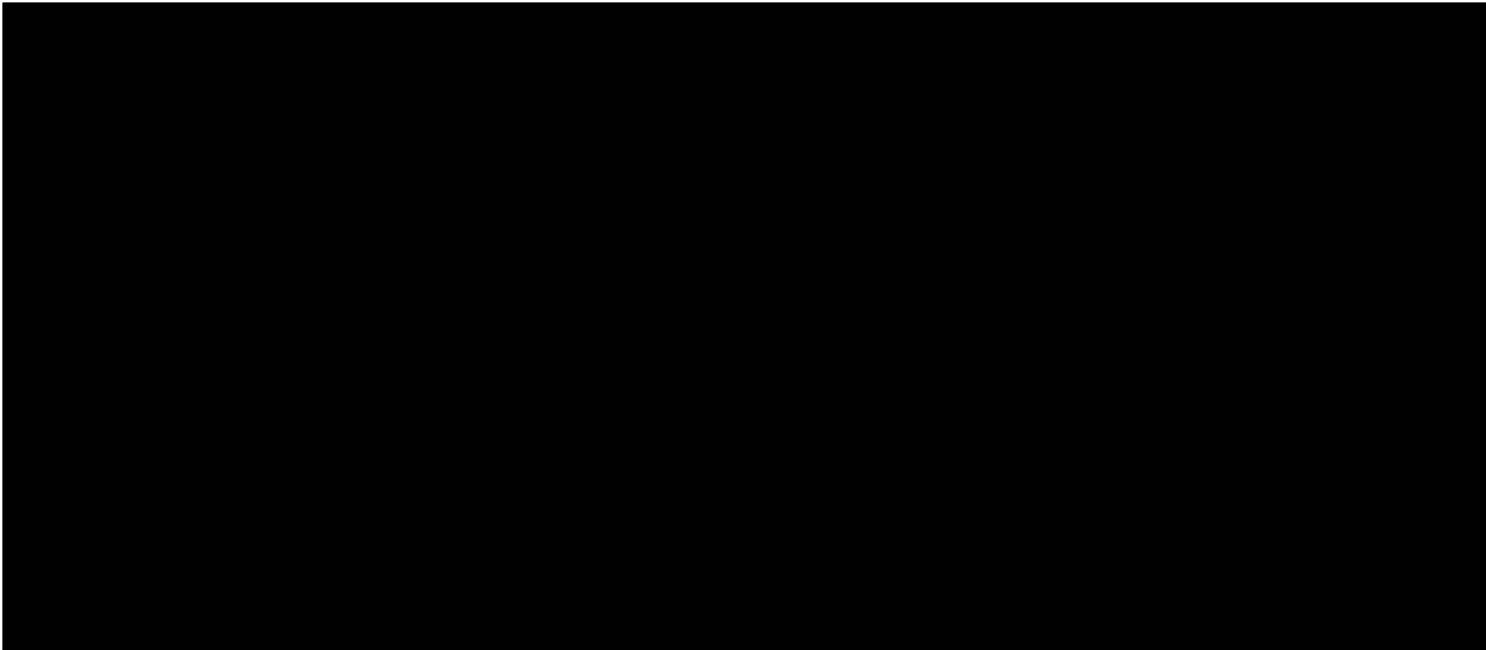
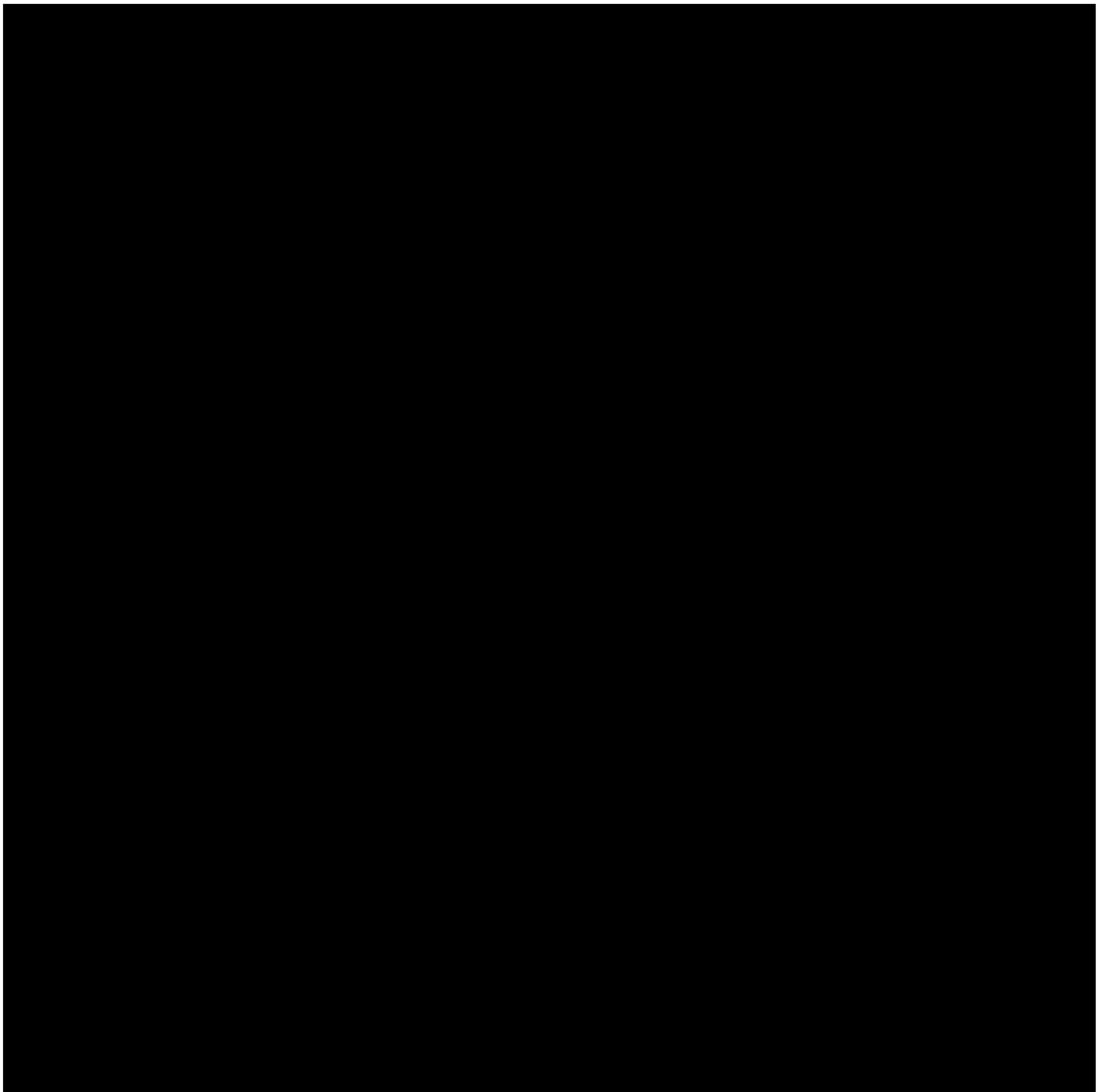


Figure A1.2 – Load Duration Curves for Preston TS considering years 2023 and 2024.

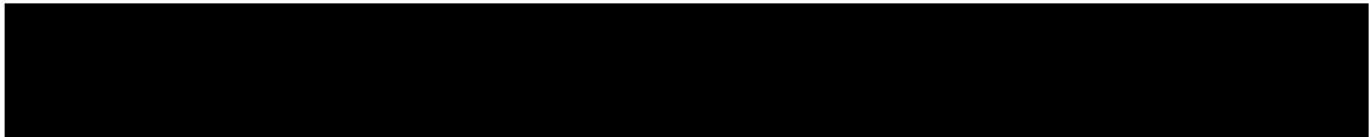
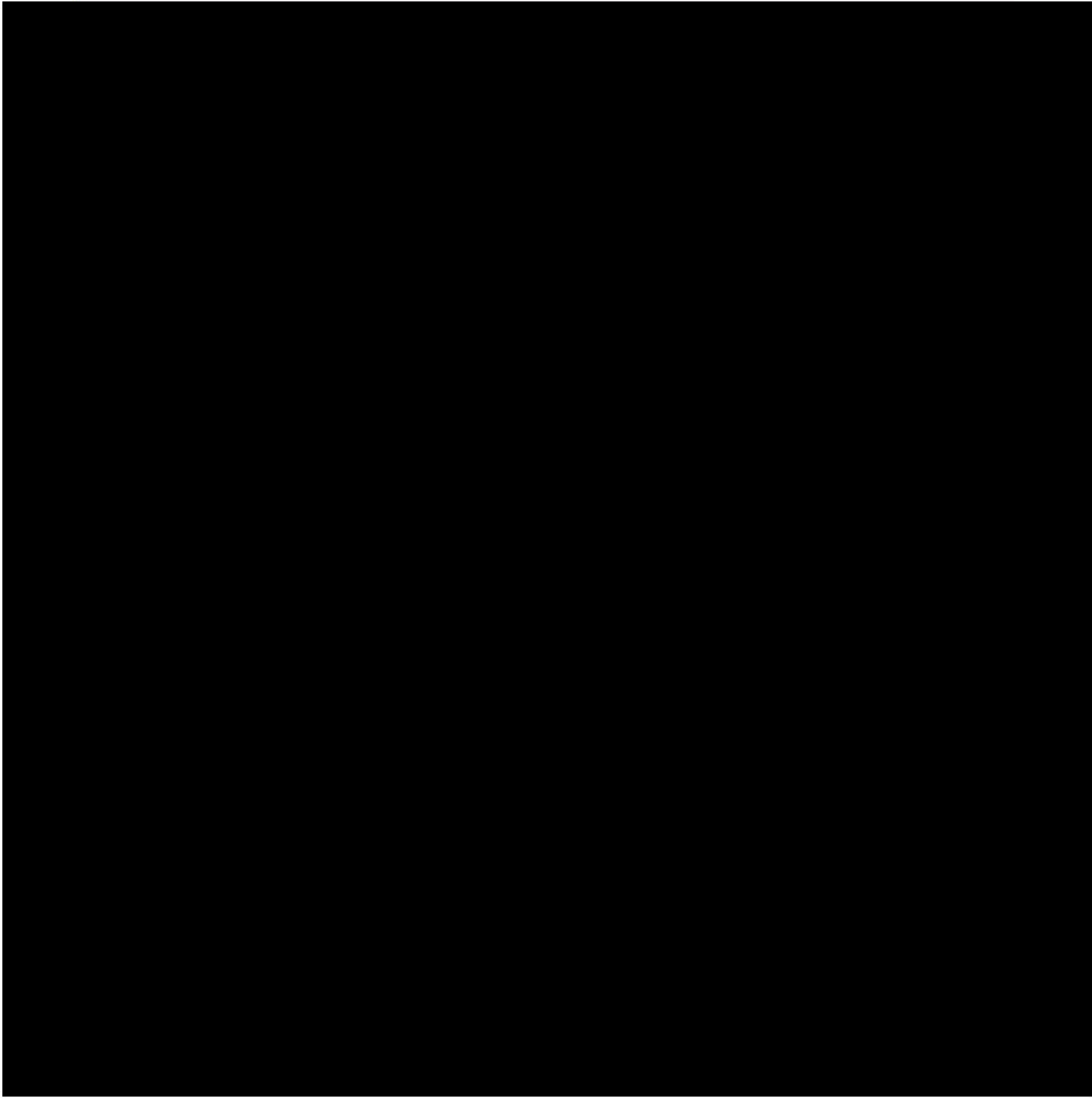
To curtail peak demand to a percentage of the actual peak demand, a utility may resort to demand response. The load duration curve shows the number of times DR should be called to achieve the required peak reduction. This is computed and reported in Table A1.1.

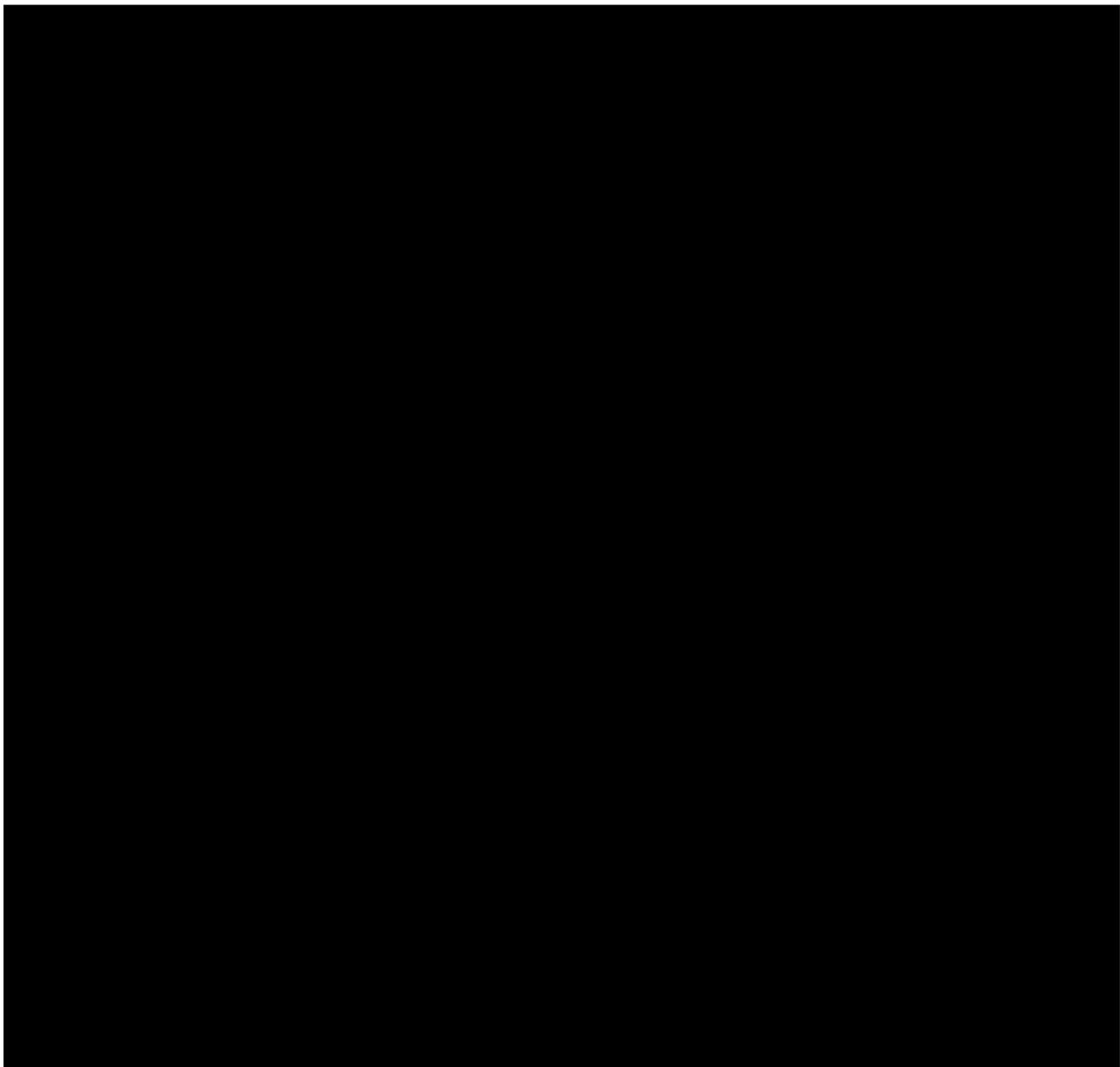


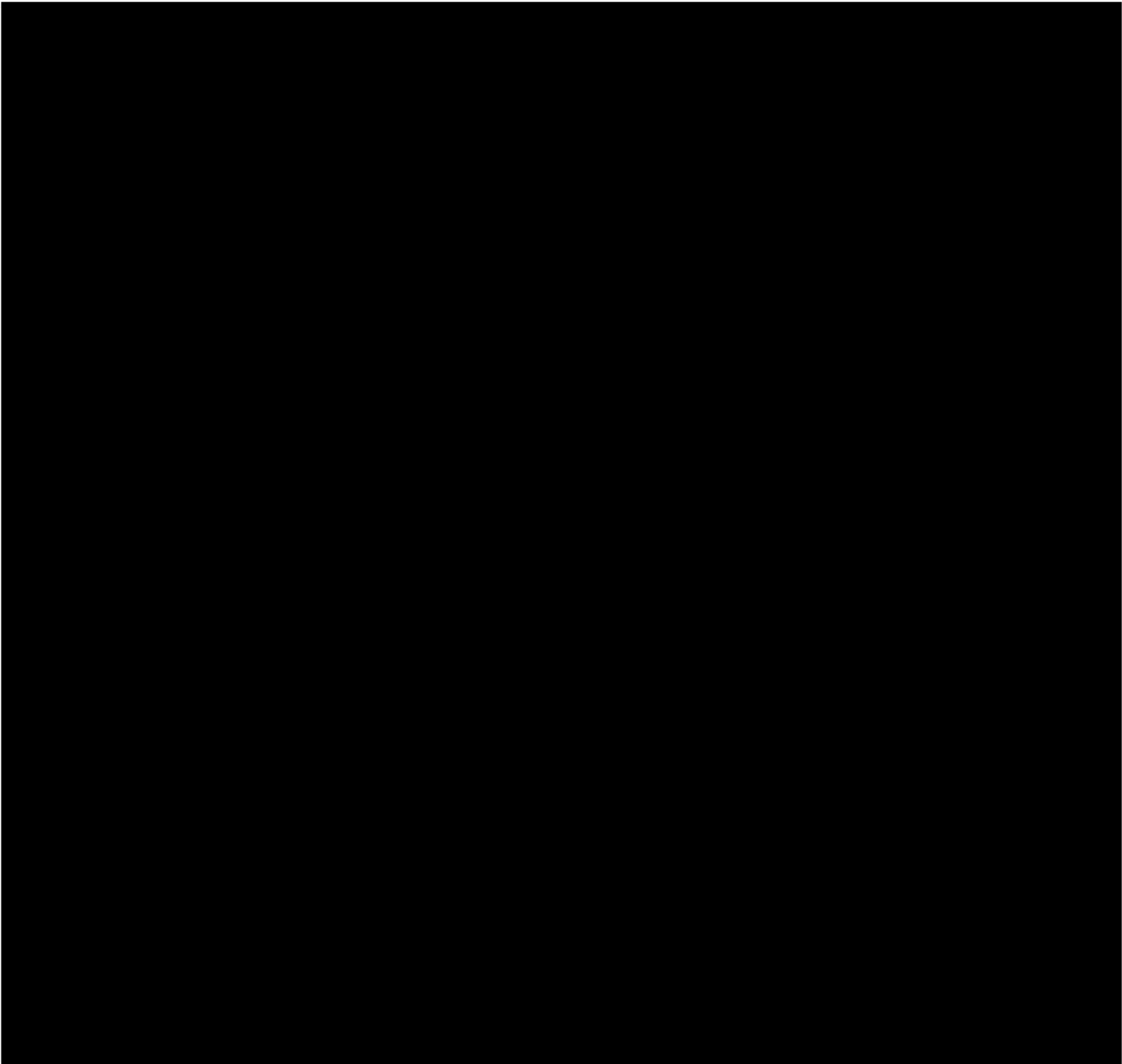












Appendix A2 – GBE Demand Response Analysis Report for Galt TS

A2.1. Introduction

The Galt TS had a peak demand of 110.13 MW in 2023, and 148.17 MW in 2024. It is about a whopping 34.54% annual growth. This rate of growth is sometimes unanticipated. Demand response is an apt tool in the utility tool chest to efficiently operate distribution networks and manage rapid growth of demand while planning for new assets to facilitate this increased demand.

Figure A2.1 shows the demand for Galt TS for years 2023 and 2024.

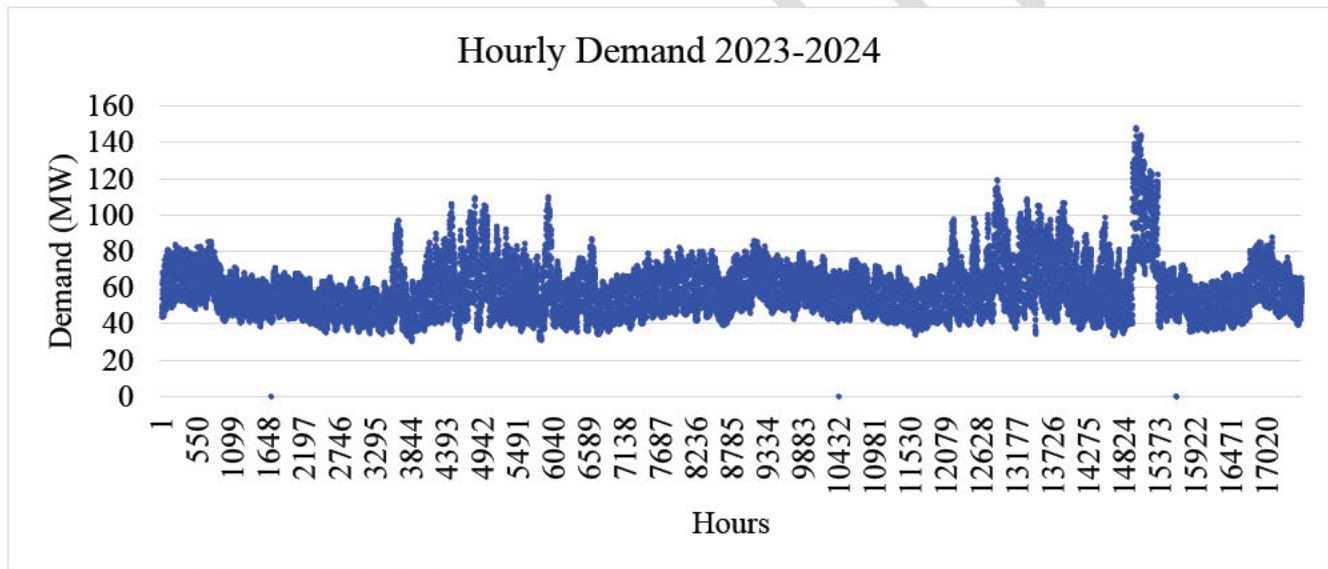


Figure A2.1 – GaltTS MW demand for 2023 and 2024

The demand is usually between 30 MW and 150 MW. Peak demand growth can be seen from 2023 to 2024 via visual inspection. Numerical details are shown in the following sections.

A2.2. Technical Analysis of Galt TS Loading

The load duration for 2024 is now analyzed to explore effects of demand response (DR), see Figure A2.2. From the graph, it is clear that year peak demand has grown from 110.13 MW in 2023, to 148.17 MW in 2024, amounting to a 34.54% year-on-year increase. Such a dramatic increase is an apt place for use of tools such as demand response, while waiting for new build to supply such a sustained demand.

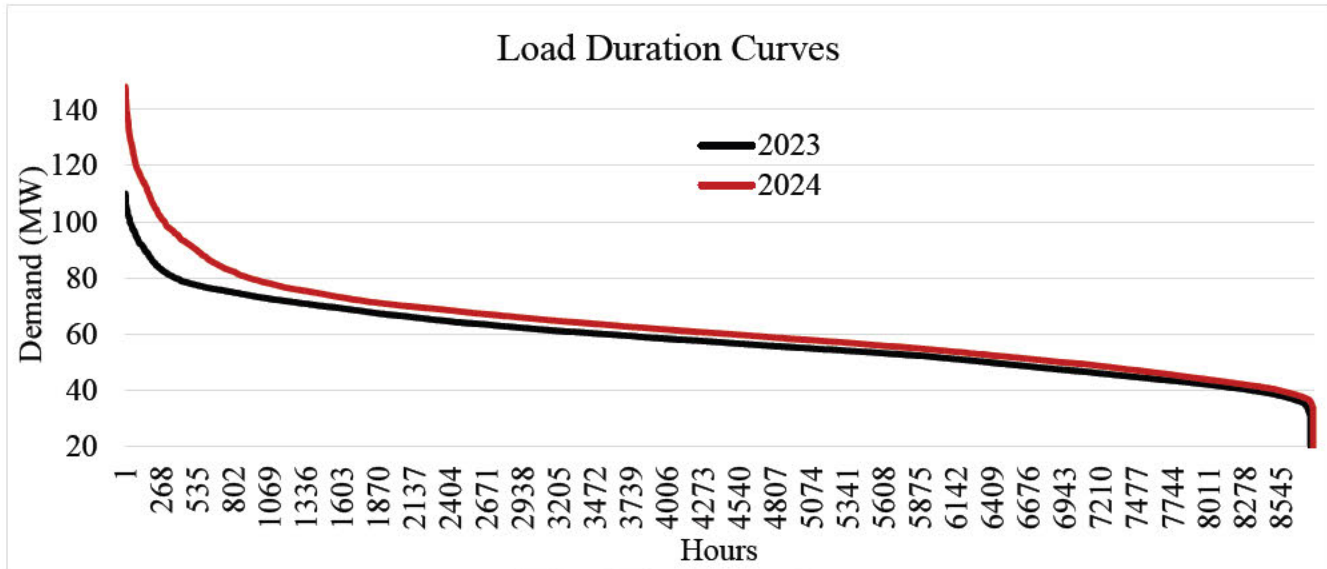
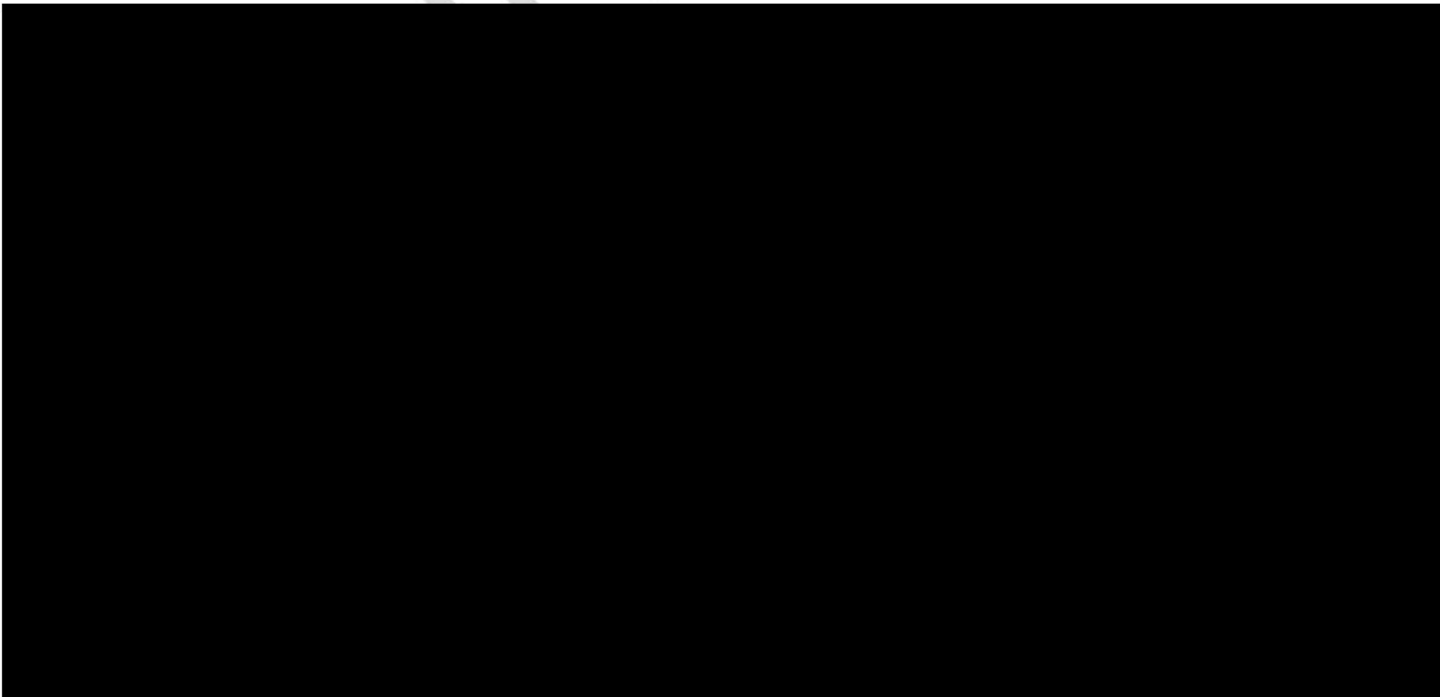
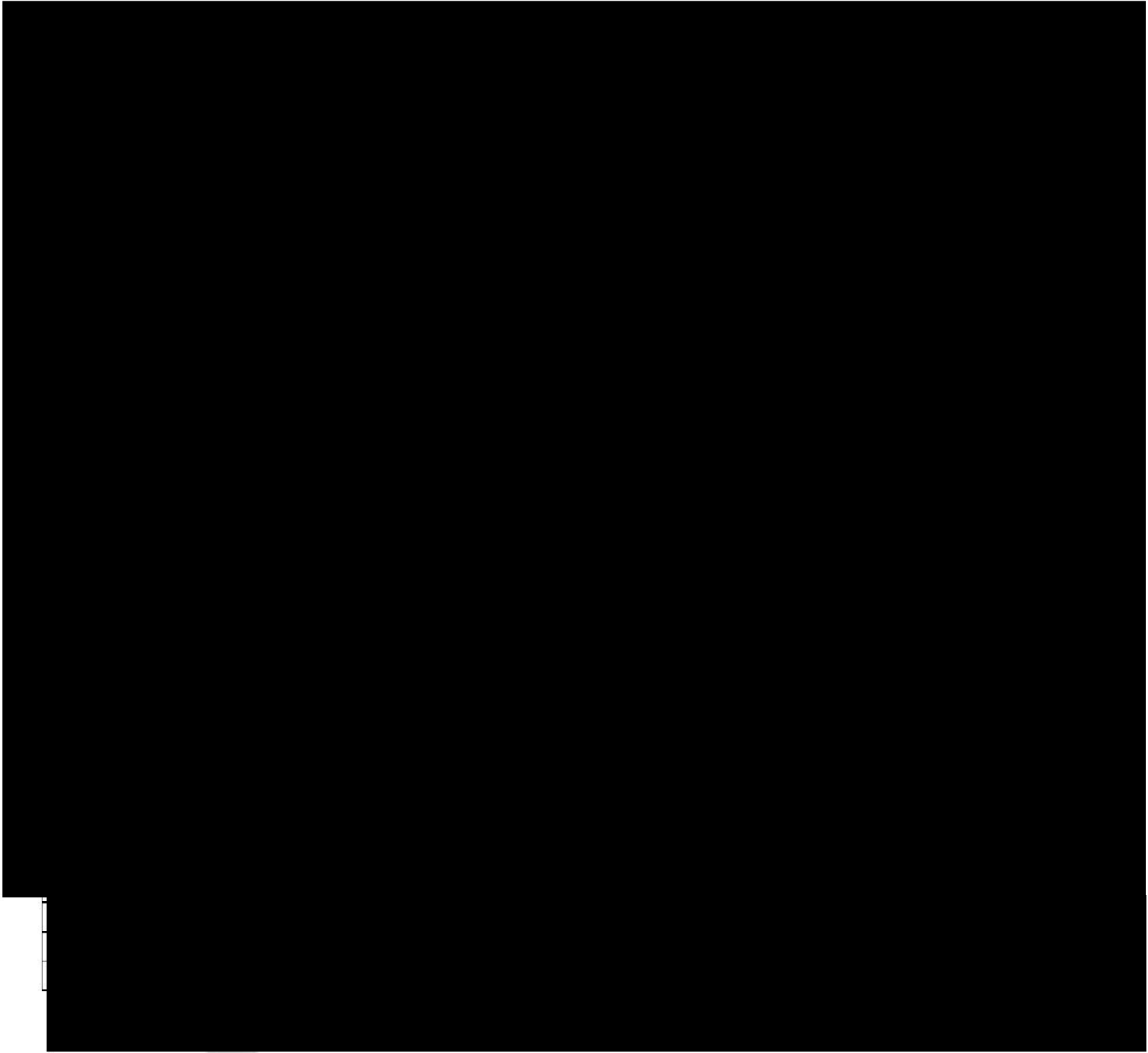
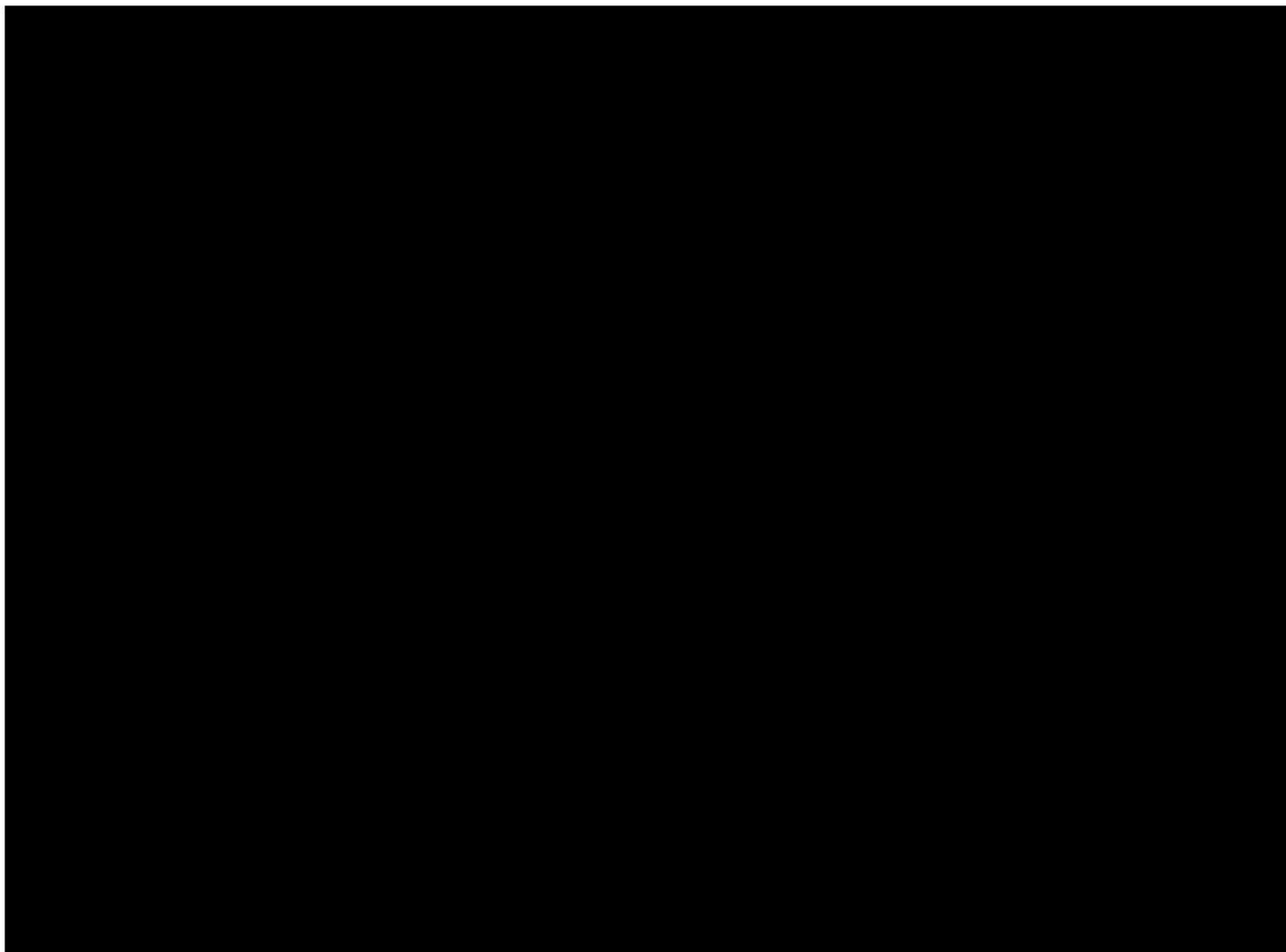


Figure A2.2 – Load Duration Curves for Galt TS considering years 2023 and 2024.

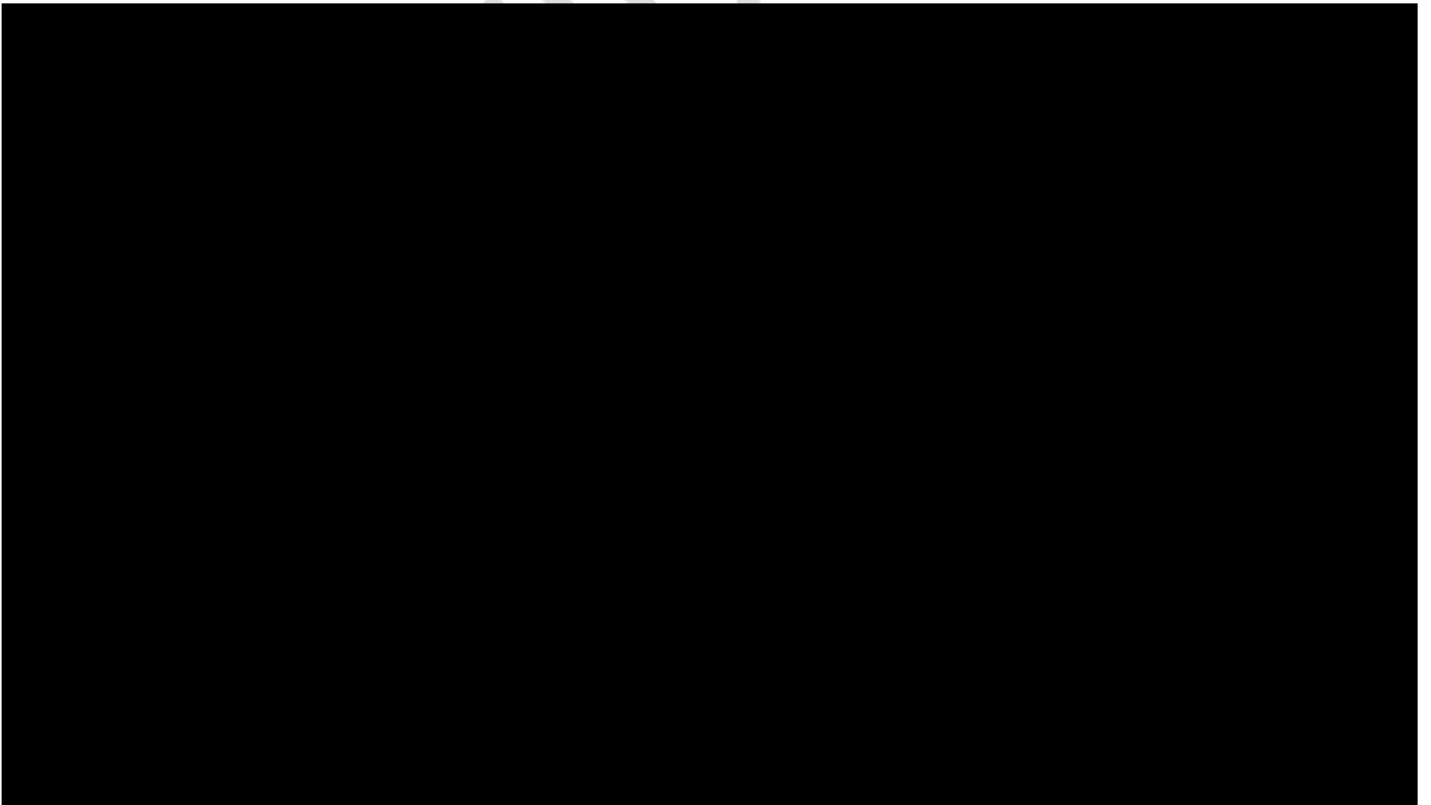
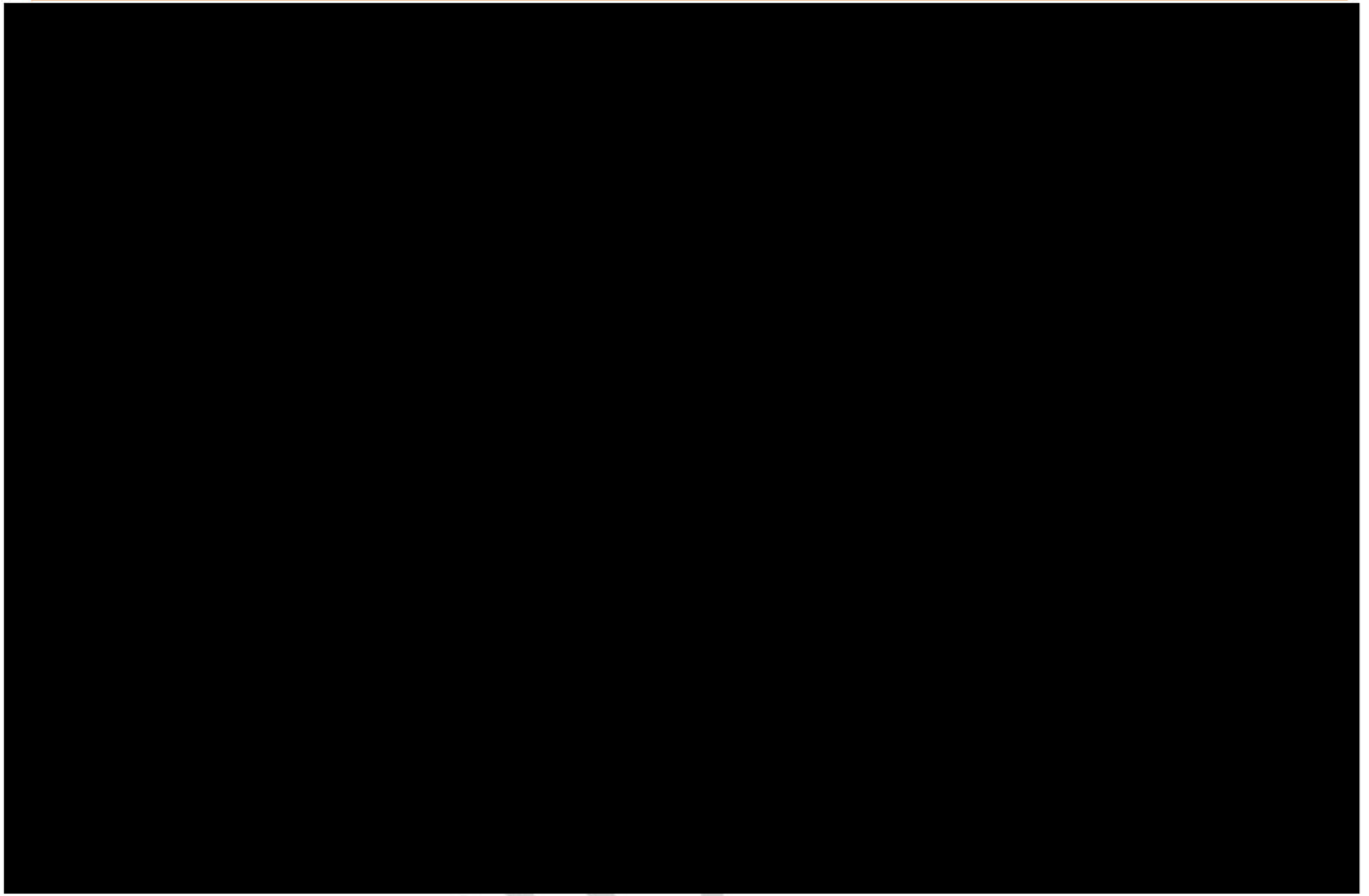
To curtail peak demand to a percentage of the actual peak demand, a utility may resort to demand response. The load duration curve shows the number of times DR should be called to achieve the required peak reduction. This is computed and reported in Table A2.1.

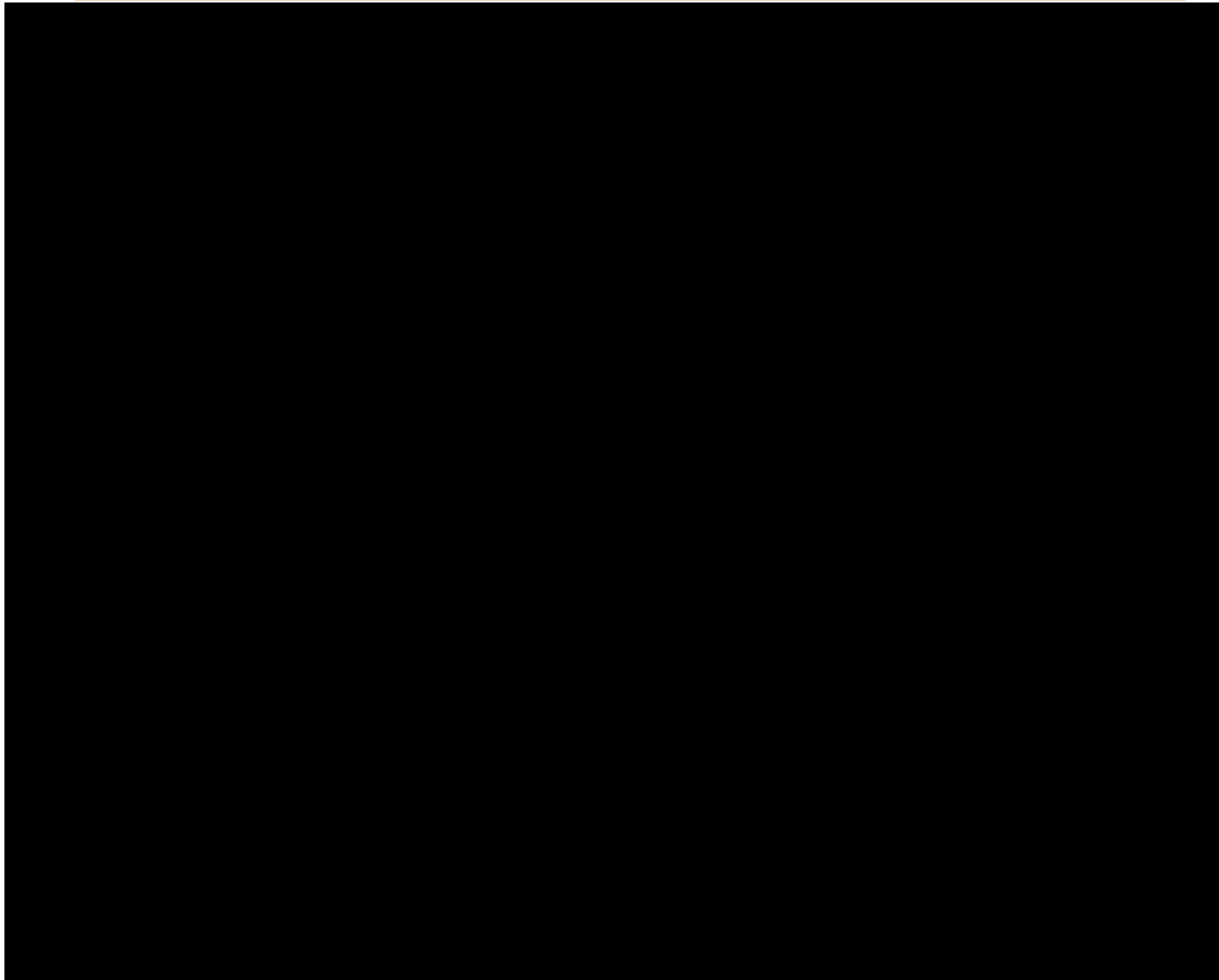


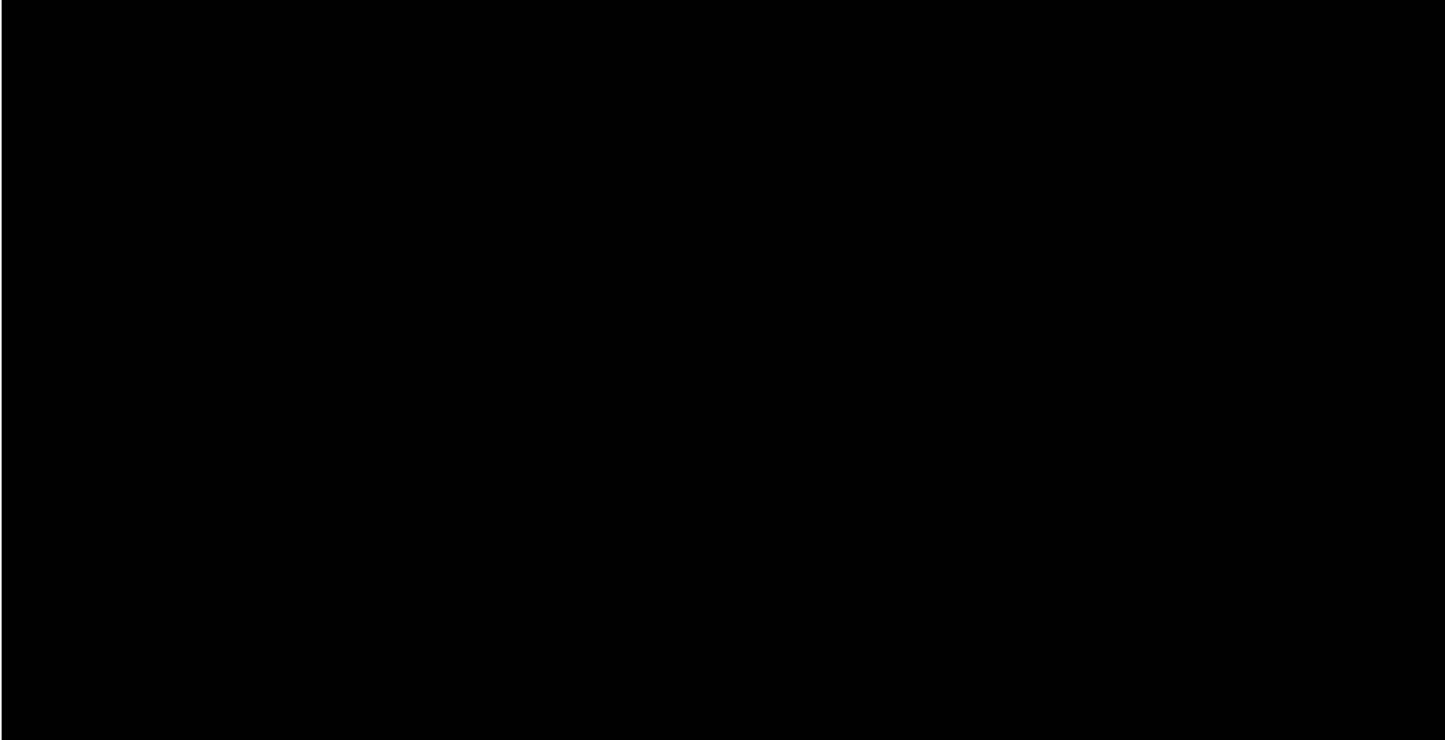
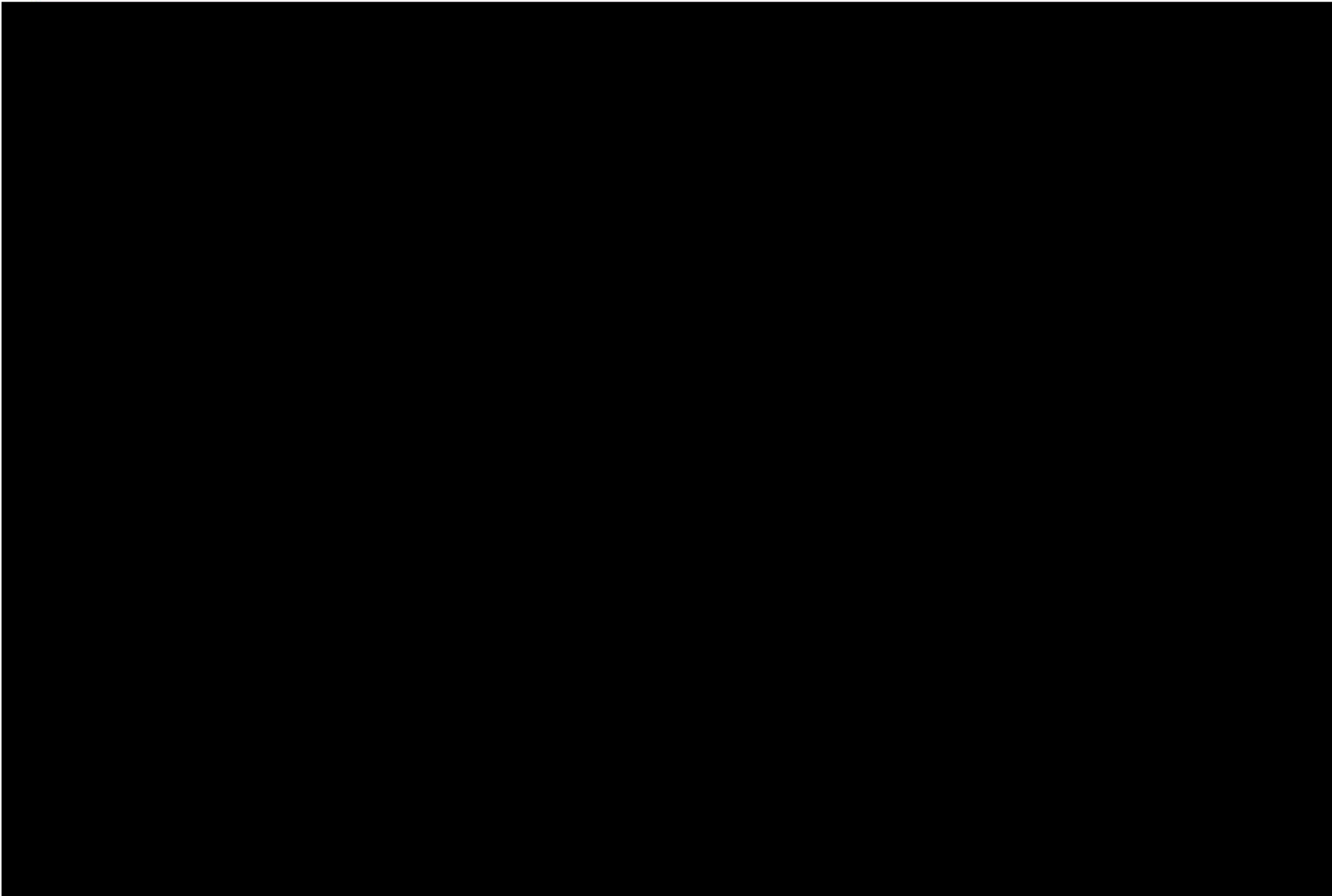


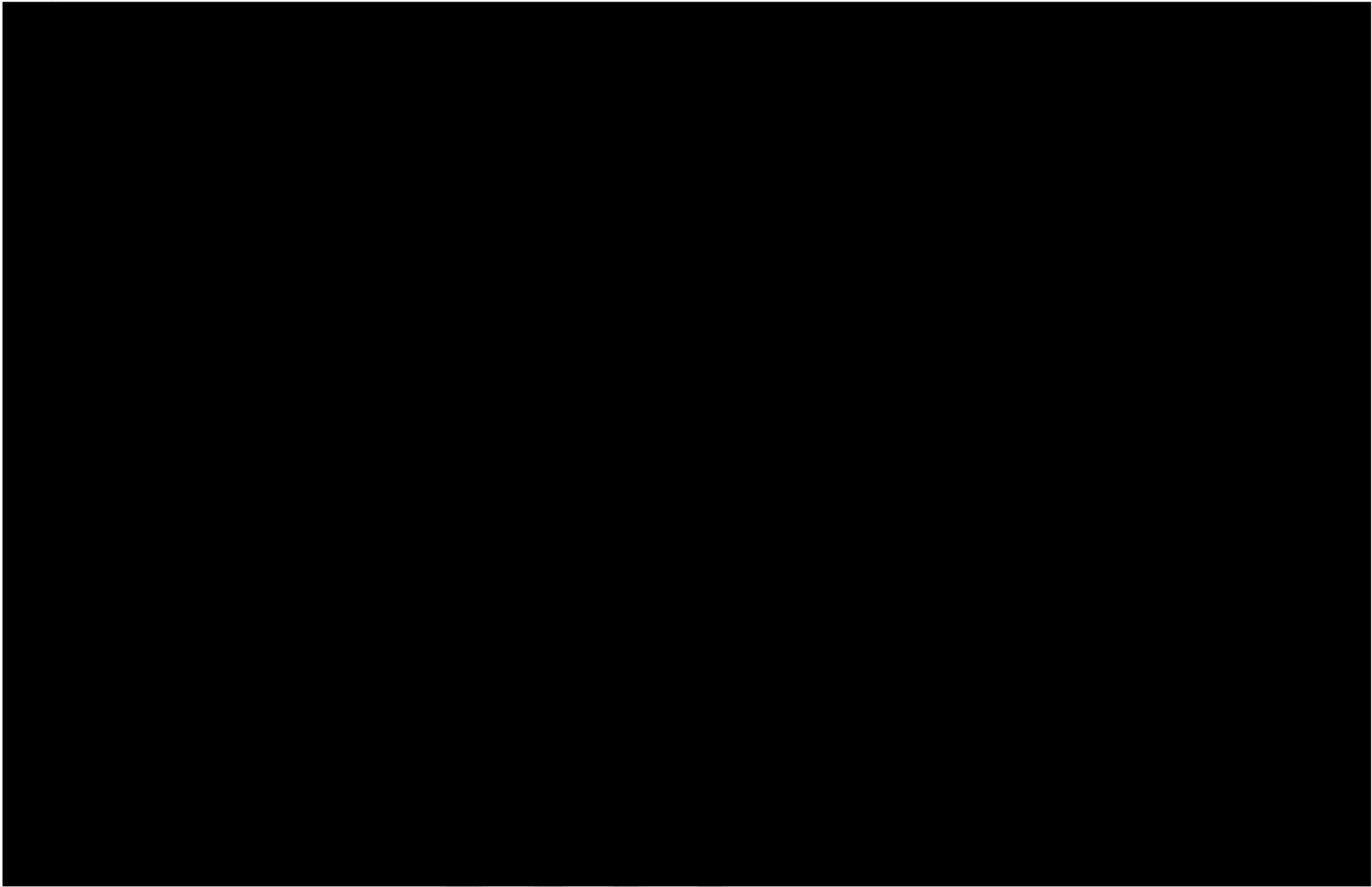


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Appendix A3 – GBE Demand Response Analysis Report for MTS1 TS

A3.1. Introduction

The MTS1 TS had a peak demand of 95.36 MW in 2023, and 86.45 MW in 2024. There isn't any annual growth. While there isn't any load growth, demand response may be explored to check possible peak demand growth.

Figure A3.1 shows the demand for MTS1 TS for years 2023 and 2024.

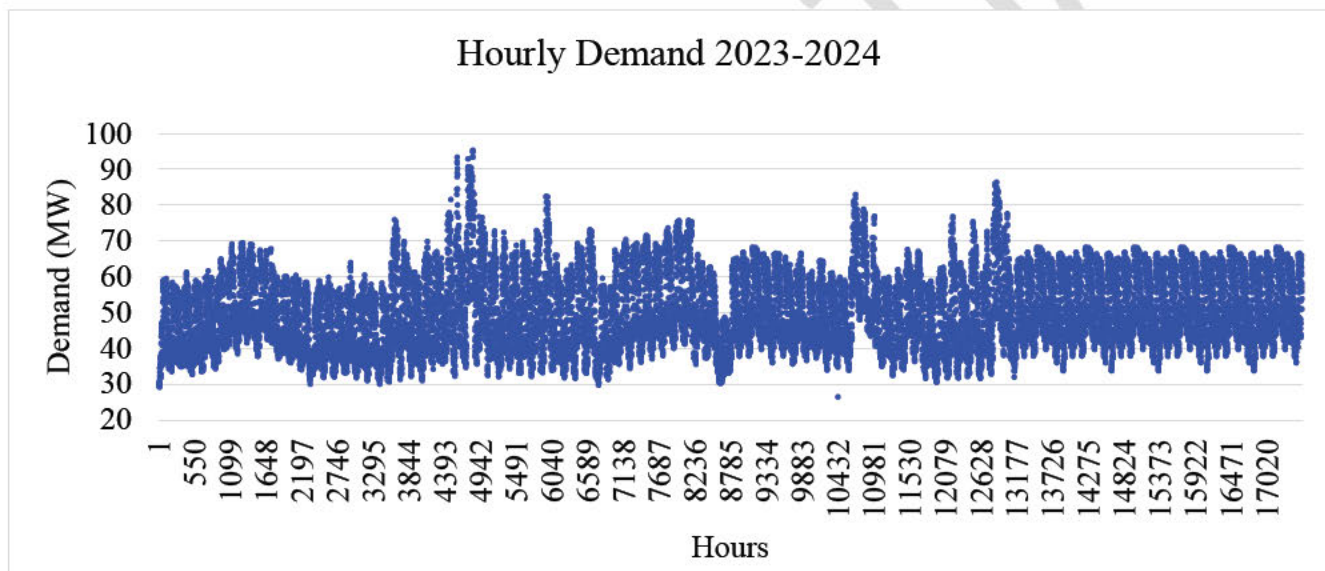


Figure A3.1 – MTS1 TS MW demand for 2023 and 2024

The demand is usually between 25 MW and 100 MW. Peak demand can be seen from 2023 to 2024 via visual inspection. Numerical details are shown in the following sections.

A3.2. Technical Analysis of MTS1 TS Loading

The load duration for 2024 is now analyzed to explore effects of demand response (DR), see Figure A3.2. From the graph, it is clear that year peak demand hasn't grown.

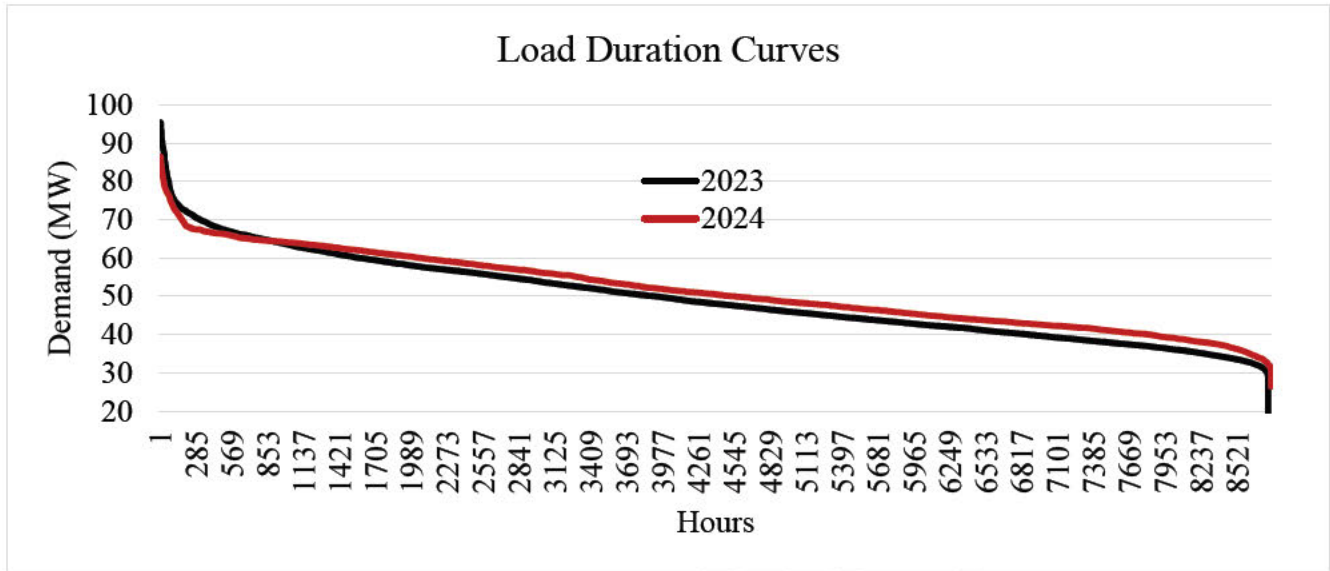
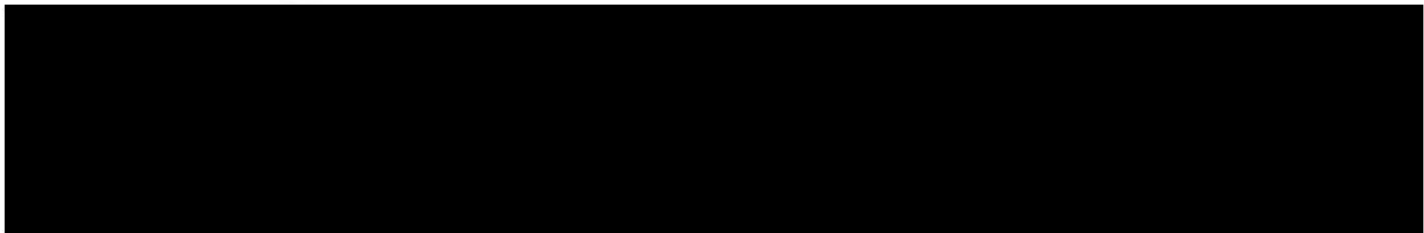
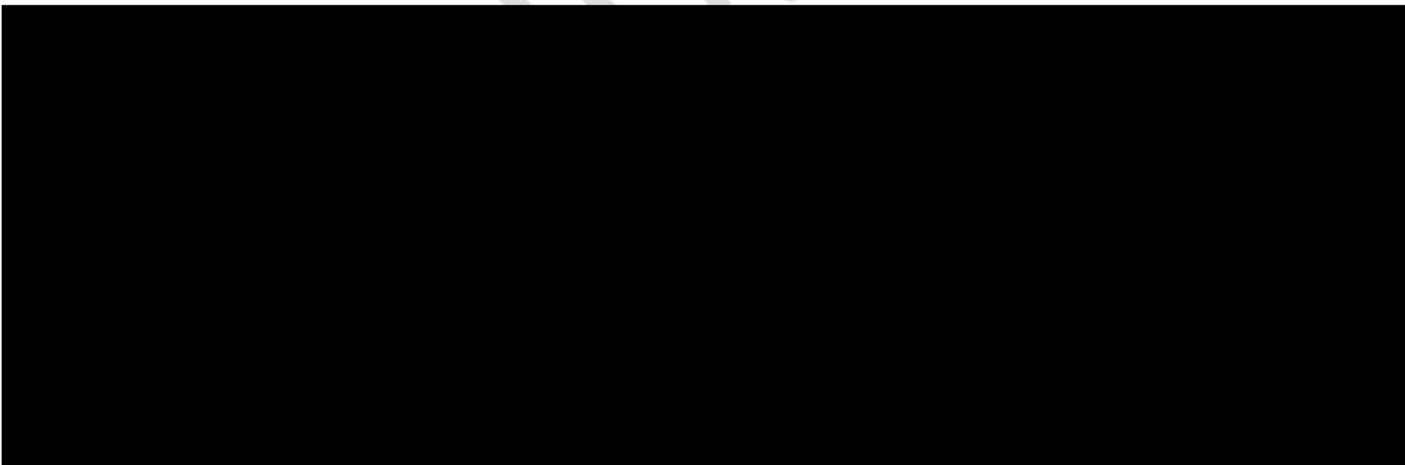
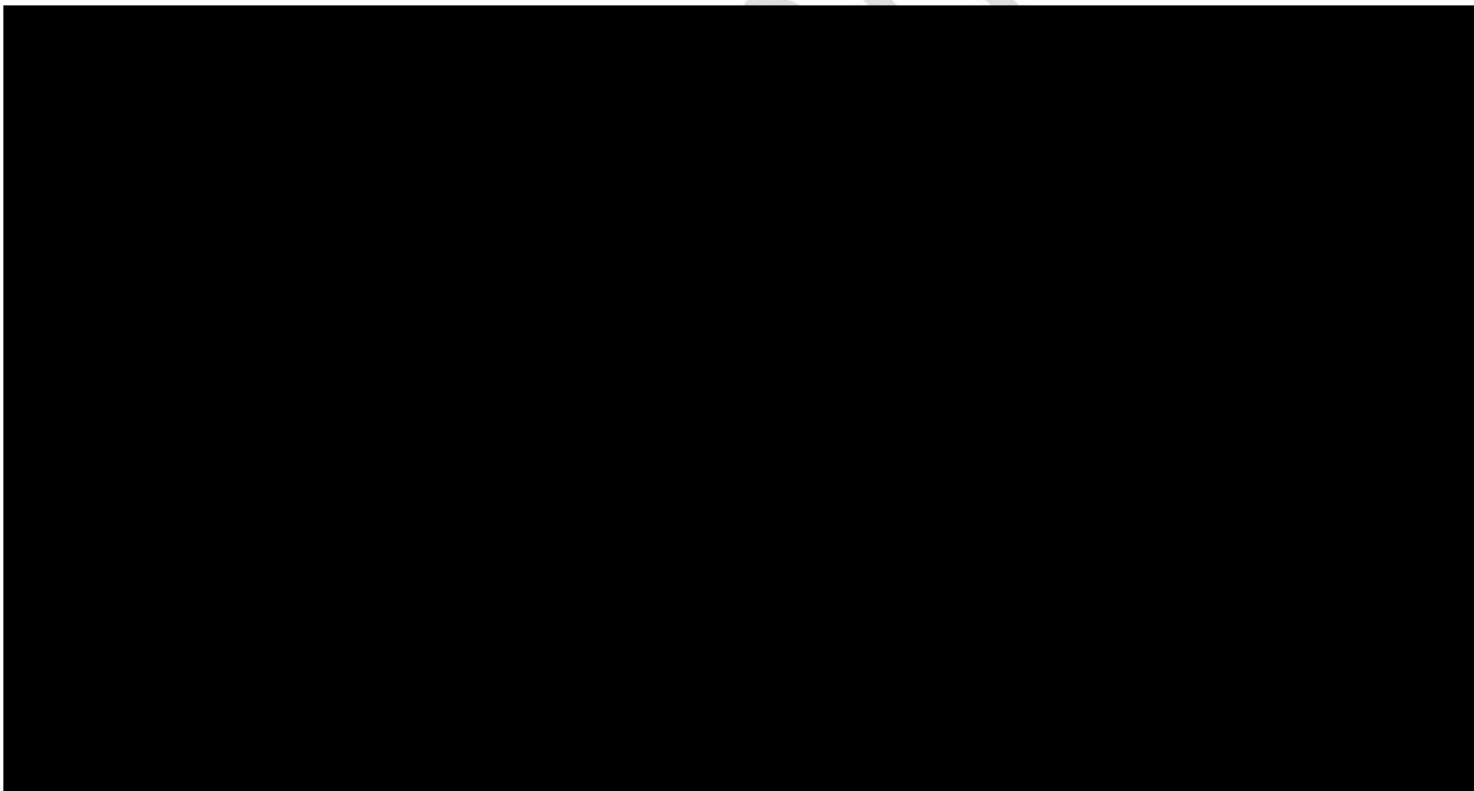


Figure A3.2 – Load Duration Curves for MTS1 TS considering years 2023 and 2024.

To curtail peak demand to a percentage of the actual peak demand, a utility may resort to demand response. The load duration curve shows the number of times DR should be called to achieve the required peak reduction. This is computed and reported in Table A3.1.





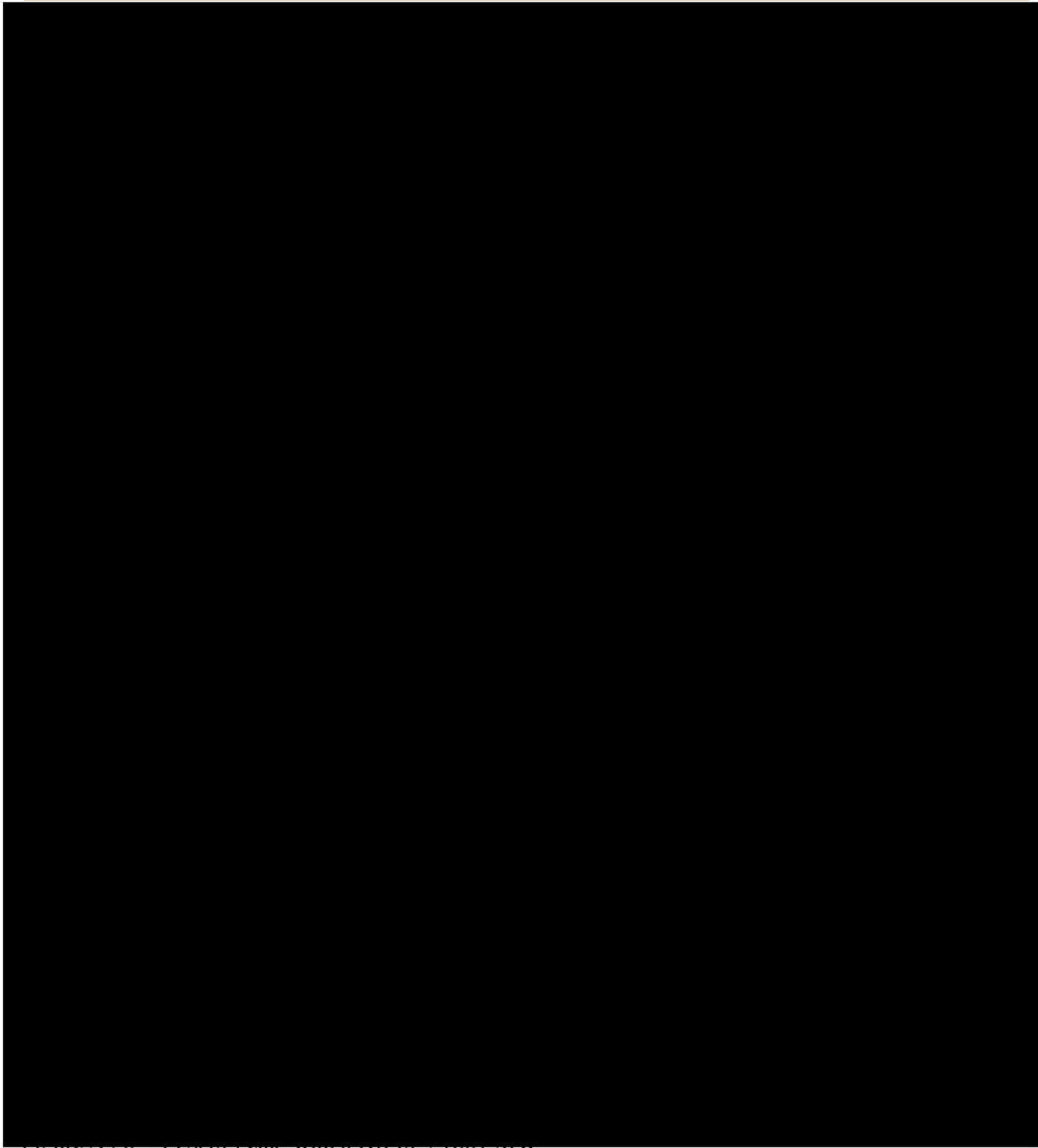
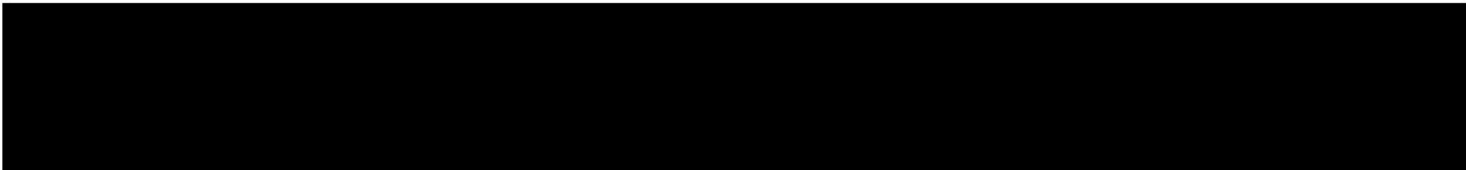
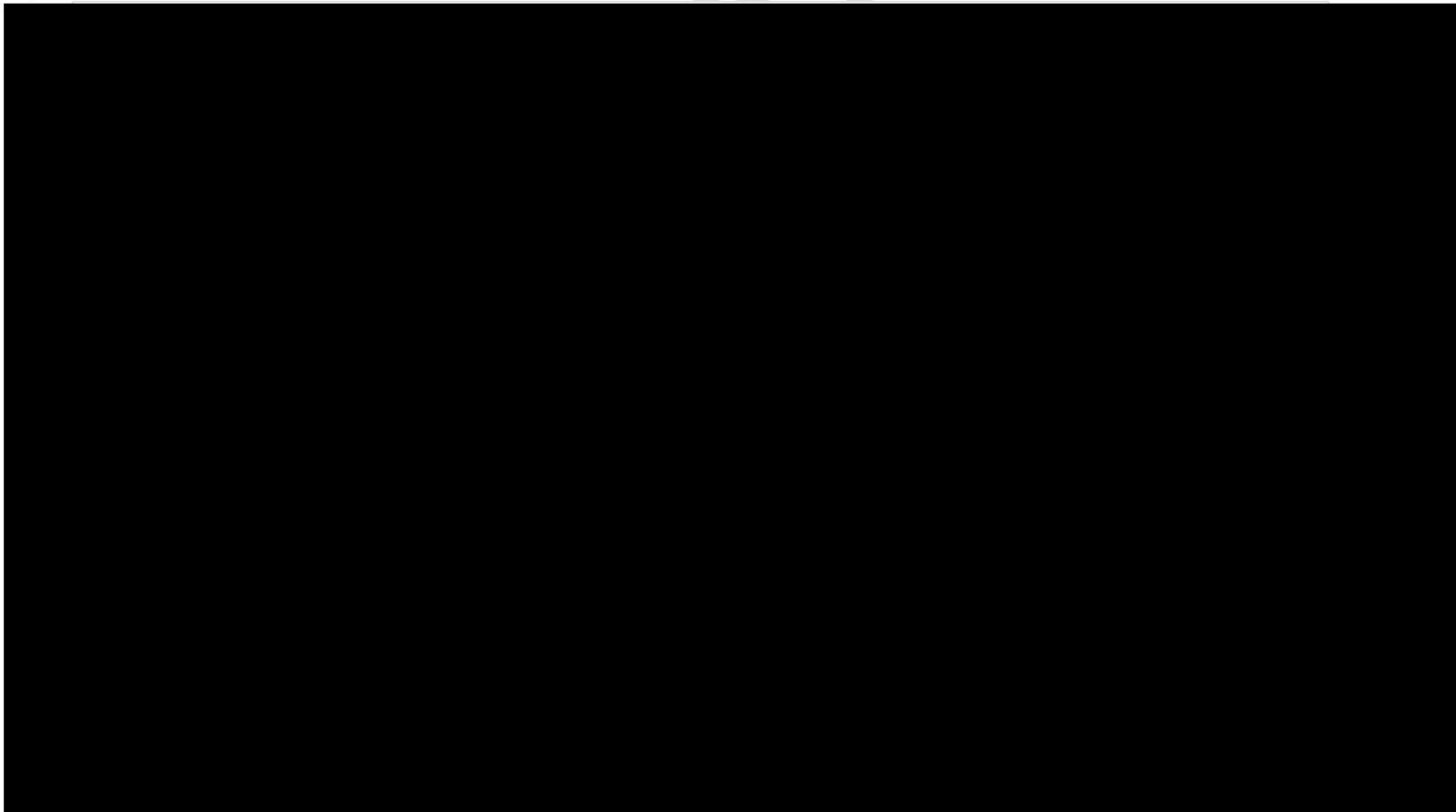


Figure 15.6 - 5.1% of Peak, with a DR of 5.1667 MW







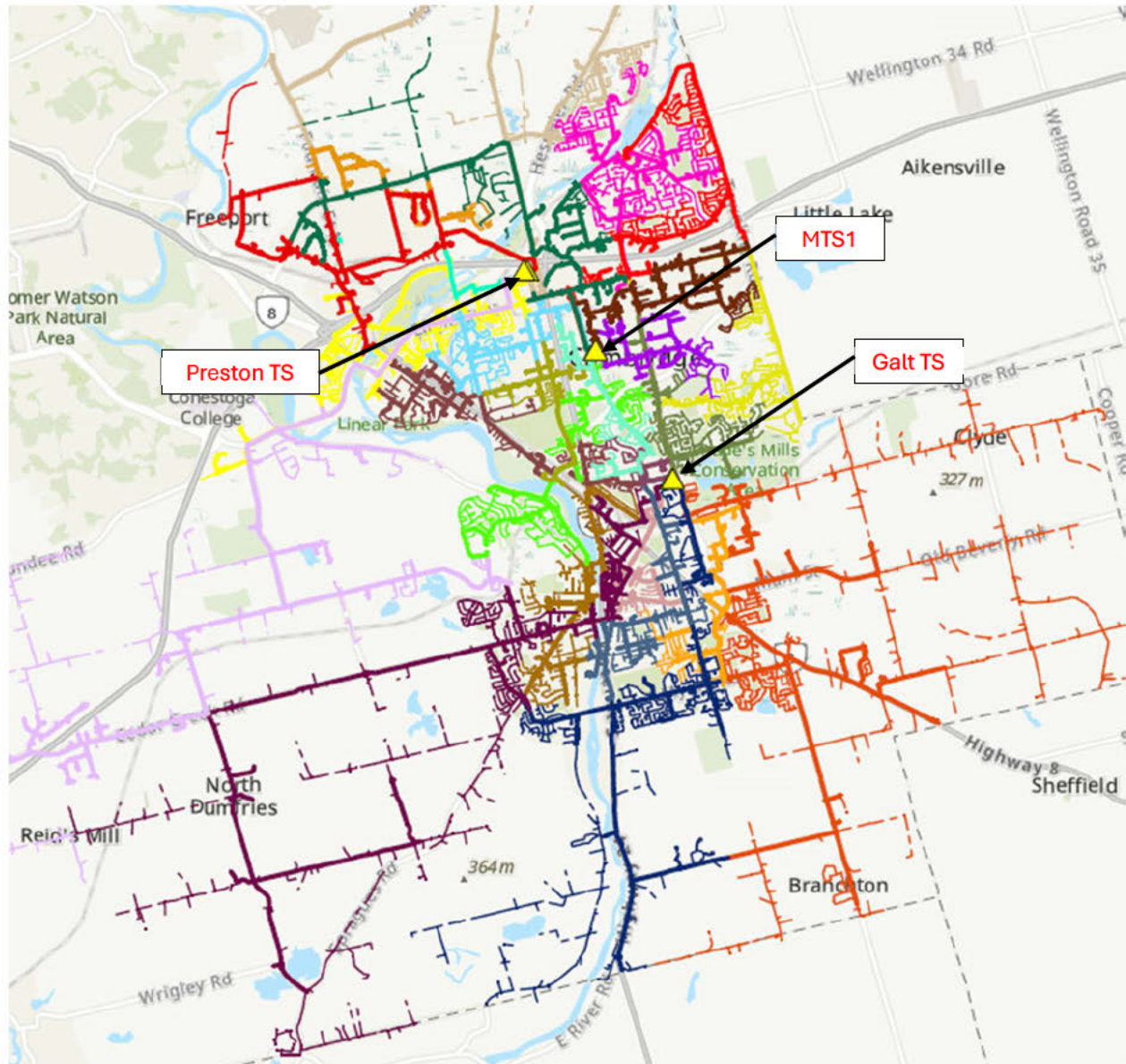
Project Diagram

The proposed project will leverage existing behind-the-meter resources already connected at GBE customer sites, by incentivizing those resources to participate in the DR Program. As such, no new field equipment is required. Therefore, no new or edits to existing diagrams line single line drawings are required. A network diagram showing the three Transformer Stations, feeders and service area where the DR Program will be implemented is shown on page 2.

The only new system that will be incorporated as part of this project is GridS2's transactive energy platform – this is a stand-alone system that will be installed on a dedicated computer at the GBE office premises.

The process diagram for GBE's DR Program, including Procurement, Operations and Settlement, is presented on page 3.

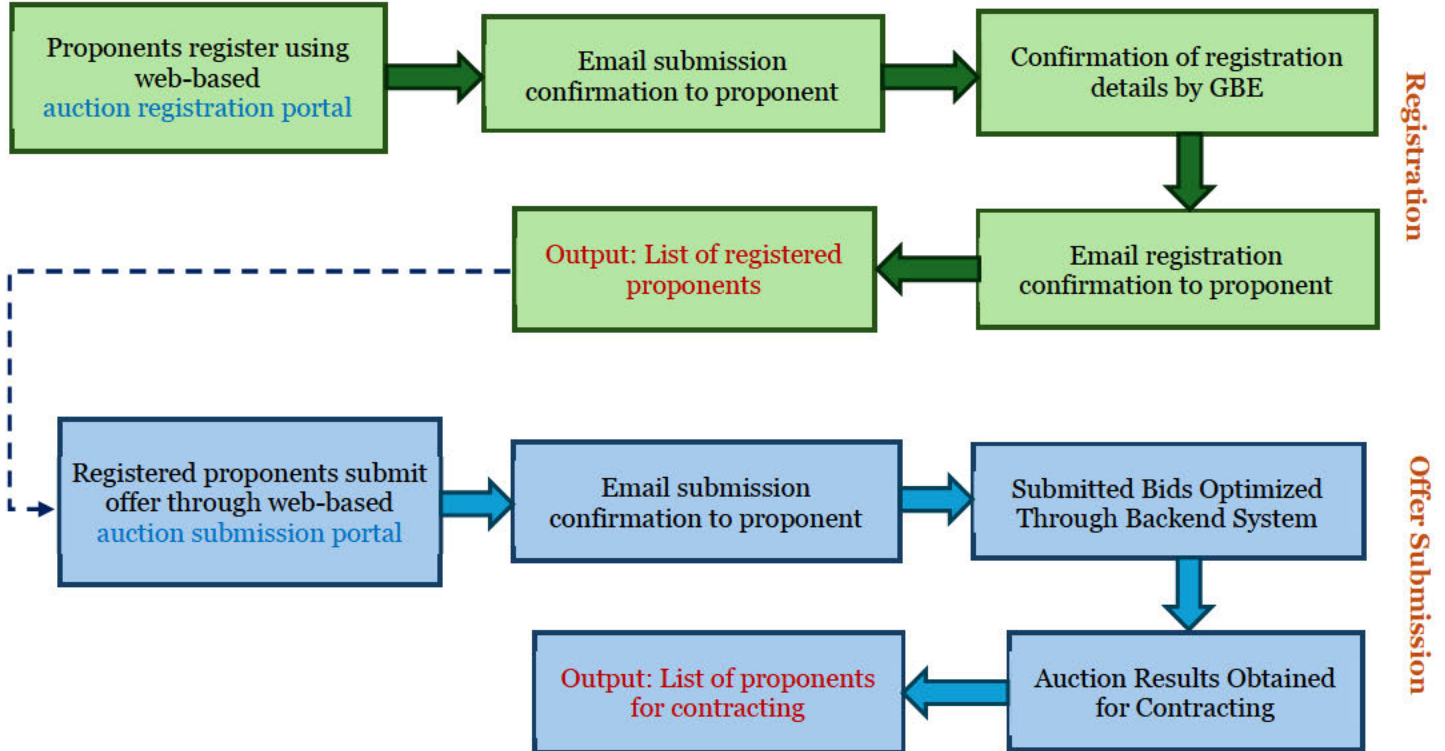
GBE's DR Program – Network Diagram



GBE's DR Program – Procurement to Settlement

Step 1: Procurement (Annual)

Annual Capacity Auction to procure required capacity over the peak loading period per Transformer Station (TS). This step will have 2 phases – registration and offer submission.



Step 2: Operations (Daily):

- Forecast load at the TS level for Preston TS, MTS#1 and Galt TS for the next 72 hours.
- Create and issue Standby and Activation notices as required to Market Participants



Step 3: Settlement (Monthly):

Calculate payments for all dispatched resource(s) at the end of each month, ensuring compliance with market rules.



March 31, 2025

Natural Resources Canada (NRCan)

Subject: Letter of Support for GrandBridge Energy's Application to the Smart Renewables & Electrification Pathways, Utility Support Stream – Deployment Project call for proposals

Dear Review Committee Members,

I am writing on behalf of GridS2 to express our enthusiastic support for GrandBridge Energy's (GBE's) NRCan application requesting support for the on-going implementation of their Demand Response (DR) Program to address immediate grid capacity constraints in the City of Cambridge, Ontario.

GridS2, **an Ontario based, Canadian cleantech technology provider**, is excited to play a central role as the subject matter expert and technology provider for this project. Our **expertise in designing electricity markets, understanding of the utility business model and regulatory space, power networks and advanced optimization algorithms**, positions us to contribute significantly to the success of this time-critical initiative for GBE. We are confident that our program design and platform will contribute significantly to GBE's Grid Modernization plans, create customer value and lead to multiple societal benefits.

This project speaks directly to **GBE's vision of leading the energy transition** by enabling their communities to achieve a sustainable energy future and resonates with our own commitment of transforming the energy landscape to create a more sustainable ecosystem. We believe that the collaboration between GBE and GridS2 will result in a robust and market-driven energy future that aligns with the goals of NRCan.

Our team has **already begun working with GBE on this project and has completed the network analysis** of the three constrained transformer stations, allowing the project team to better define the objectives of the DR Program. GridS2 is committed to supporting GBE throughout the implementation of the project - from the present design stage to the close out phase. We are eagerly working towards bringing our expertise and working collaboratively with all stakeholders to achieve the project's objectives.

Thank you for considering our letter of support for GBE's application. We look forward to the opportunity to contribute to the success of this transformative project and the advancement of Canada's energy sector.

Sincerely,

Nimish Bhatnagar

Nimish Bhatnagar
CEO and Co-founder, GridS2 Inc.
NimishB@GridS2.com

ASCENT TOR1
17 Vondrau Dr,
Cambridge, Ontario,
N3E 1B8

March 27, 2025

Subject: Letter of Support for GrandBridge Energy's Non-Wires Alternatives (NWA) Program – SREP Funding Application

Dear SREP Program Review Committee,

On behalf of **ASCENT TOR1**, I am pleased to express our support for GrandBridge Energy's funding application under the Smart Renewables and Electrification Pathways (SREP) Program – Utility Support Stream to advance its Non-Wires Alternatives (NWA) Program.

As an **commercial organization**, we are committed to energy efficiency, sustainability, and grid modernization. GrandBridge Energy's NWA Program presents an innovative and cost-effective approach to addressing electricity demand growth, combating grid constraints, integrating distributed energy resources (DERs), and enhancing grid reliability for managing grid demand.

Through its demand response and DER integration strategies, this initiative will:

- Stabilize electricity costs for customers by lowering peak demand and deferring costly grid upgrades.
- Improve reliability and resiliency, particularly for end-of-line communities and businesses vulnerable to power disruptions.
- Support Canada's decarbonization goals by reducing reliance on fossil-fuel-based peaker plants and facilitating greater renewable energy integration.
- Expand customer participation in the energy transition by providing financial incentives and new revenue opportunities for flexible energy use.

As a potential participant in this program, **ASCENT TOR1** is eager to explore the benefits of demand-side management and distributed energy participation. This program represents a significant opportunity to enhance grid reliability, economic efficiency, and environmental sustainability for businesses and communities across Canada.

We strongly encourage Natural Resources Canada to approve this funding request, as it will accelerate the transition to a modernized, low-carbon electricity system while delivering significant cost savings and resilience benefits for GrandBridge Energy's customers.

Sincerely,



Tyler Pamer
Sr. Critical Facilities Manager
Ascent TOR 1
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SMART RENEWABLES AND ELECTRIFICATION PATHWAYS

Full Project Proposal Application Form

Utility Support Stream – Deployment Projects

Project Proposal Package Overview

Applicants are advised to read the Smart Renewables and Electrification Pathways Program (SREPs) Applicant Guide – Utility Support Stream – Deployment Projects prior to completing a Full Project Proposal (FPP). The Applicant Guide was developed to assist applicants in preparing their submissions to SREPs. It provides guidance on the type of information to be included in this application form and describes the additional documents that are required to make up a FPP package. It also explains how SREPs will evaluate submissions and how the program will communicate with applicants at different stages of the process.

This form is broken down into four (4) major parts followed by annexes, attestations, and a submission checklist:

- Part 1: Project Details 4
- Part 2: Project Impact..... 5
- Part 3: Strategic Value 9
- Part 4: Project Feasibility..... 12
- Annex A: Risks and Mitigation Measures 18
- Annex B: Project Funding..... 19
- Annex C: Key Equipment List 20
- Annex D: Description of Work 21
- Attestations..... 22
- Project Proposal Package Checklist 24

Applicants are required to complete all sections of this application form, annexes, and mandatory attachments and submit the project proposal package through the [Natural Resources Canada \(NRCAN\) Funding Portal](#). Please use the *Project Proposal Package Checklist* at the end of this document to confirm that all mandatory attachments are included. **Incomplete project proposal packages will not be reviewed.**

Notes to Applicants:

1. It is the responsibility of the applicant to ensure that the character limits are respected for each question. The box sizes in this form do not necessarily reflect the character limit; you may wish to use the “Word Count” tool in your word processor (e.g., in Microsoft Word: Review Tab > Proofing Section > Word Count Tool.)
2. Completion and submission of the Full Project Proposal package to SREPs does not mean that the proposed project will be approved by the program.
3. This form is confidential when completed except for marked fields that may be made public.
4. Applicants must submit all information specified in this application form. Failure to provide the necessary information may lead to the rejection of the project proposal.
5. It is the responsibility of the applicant to ensure that the project proposal clearly and thoroughly demonstrates how each criterion is met. The mandatory annexes are required to support the information in this application form
6. The applicant should provide information concisely while still providing sufficient details to ensure complete understanding by reviewers.
7. Priority may be given to projects demonstrating a need for support, and that are able to initiate project spending before the end of the following fiscal year. Projects that do not anticipate spending within that timeline are encouraged to apply to a future intake.

PART 1: PROJECT DETAILS

1.1 Project Activities Update

Provide a bullet point summary of activities completed since the Expression of Interest (EOI) submission. (2,500-character maximum):

- Secured Main Program Consultant: Contract signed, and PO issued to GridS2 Inc, which will provide program design, technology development, deployment, advisory, and project management services.
- NWA Project Team Formation: Established project team at GBE, identified key project phases and tasks, and developed a master project schedule.
- Regulatory Application Development: Engaged regulatory consultant (Utilis) to develop a rate application supporting the NWA program. Targeting submission of an interim rate rebasing application in June/July 2025 to secure funding through utility rates.
- Technical Network Analysis Conducted:
 - a. Analyzed hourly peak demand data at Preston TS, Galt TS, and MTS1 to assess grid constraints.
 - b. Performed sensitivity analysis to refine demand response strategy.
- Drafted Program Design: Determined capacity requirements, pricing structure, and operational parameters for running the program. To be reviewed and approved by GBE team in June/July 2025.
- Refined Financial Requirements: Conducted updated program costing analysis to ensure accurate financial planning and funding needs.

These activities have laid the foundation for program implementation, ensuring regulatory alignment, financial viability, and technical readiness.

1.2 Changes to Project

Have there been any changes to the project scope since the time of EOI submission?

For example: proplead, funding requested, project activities, project partners, timelines, etc.

Yes No

If yes, describe the changes. For each change, explain the rationale for the change and the impact that it will have on the project. NRCan reserves the right to disqualify a project that is deemed materially different than what was presented in the EOI. (2,500-character maximum):

Project Budget Adjustment and Rationale

Following a detailed network analysis assessing the loading conditions at the three Transformer Stations, along with refinements to GBE's NWA program design, we have determined the need to increase the total project budget by 45% compared to the EOI. While GBE will be increasing our cash contribution to match this added budget, we are requesting an equivalent increase in NRCan's contribution to the project. The key driver behind this increase is the higher-than-anticipated costs of incentivizing market participants and procuring 20 MW of DR capacity to effectively mitigate grid constraints. The updated budget reflects a more precise and data-driven approach, ensuring that the project meets its technical and operational objectives.

Key Changes and Their Impact:

1. Revised Capacity Requirements

- a. Rationale: The network analysis provided granular insights into capacity constraints at each TS, refining the frequency and duration of DR events and/or when DER capacity is needed.
- b. Impact: To ensure grid reliability, the program requires higher market participation, increasing procurement costs.

2. Increased Customer Incentives for Participation

- a. Rationale: Insights from similar Ontario projects informed more refined pricing and incentive structures to drive participation.
- b. Impact: Higher financial commitments from GBE are necessary to attract sufficient market engagement during peak demand periods.

3. Enhanced DER Market Development & Engagement

- a. Rationale: More targeted customer outreach & regulatory/legal support are required.

b. Impact: Additional budget is needed for customer education, stakeholder engagement, contract structuring, & rate application to support expanded procurement.

Commitment to Project Success & Budget Flexibility

GBE remains committed to the successful execution of this project and recognizes that the increased budget request may require adjustments. Should NRCan find the revised budget to be beyond its scope, GBE is prepared to:

- Contribute additional funds, beyond the already committed 50%, to cover part of the increased cost.
- Adjust the procurement target, reducing the total MW procured while maintaining the core objectives of the project.

GBE is open to discussions to align the project scope and funding requirements, ensuring both feasibility and impact while balancing financial constraints.

Note: Technical Network Analysis Report is attached to this application for reference.

1.3 Indigenous Ownership and Participation

Indicate which of the following applies to your project:

- Ownership:** Project ownership by Indigenous entities.
- Participation:** Project participation of Indigenous entities. Participation can include, but is not limited to, regular communication, consultation, and participation in project-related activities (planning, review, employment, etc.).
- None of the above.**

Note: For the purposes of this form, the term "Indigenous" is understood to include Inuit, Métis, and First Nations. Entities include Indigenous communities and governments, Tribal Councils, National and regional Indigenous councils or organizations, and Indigenous for-profit and not-for-profit organizations (majority of voting shares owned and de facto controlled by Indigenous Peoples.)

Provide a detailed description of how your project supports Indigenous ownership or participation, including:

- Name(s) of Indigenous owners, and/or entity(ies) involved or participating.
- A description of the project's level of Indigenous ownership or participation.
- Details of engagement with the Indigenous entity(ies), including timelines and methods.
- The status of the partnership agreement, if applicable.

(1,500-character maximum):

N/A

1.4 Past Support

Has your company received funding from NRCan in the last 5 years? Yes No

If yes, specify the name of the program:

N/A

PART 2: PROJECT IMPACT

2.1 Grid Modernization

The program is seeking projects that:

- propose clear and impactful improvements to the Canadian electricity system,
- justify the impacts through supporting evidence,
- provide unique solutions (where appropriate,)
- propose meaningful results,
- utilize meaningful metrics to measure project impacts, and
- demonstrate sound methodology and assumptions.

Where appropriate, consider referencing the mandatory attachments to support responses (see Project Proposal Package Checklist).

2.1.1 Indicate which of the following areas will be advanced through the implementation of the project (select all that apply):

- Improving the utilization and efficiency of existing assets.
- Increasing the reliability, resiliency, and flexibility of the power system
- Increasing the integration and use of renewable resources and non-conventional infrastructure solutions.

2.1.2 Describe how the project is expected to advance outcomes related to each of the areas selected above. Consider the gap the project will bridge, how outcomes will be achieved, and evidence that supports the likelihood of success. Direct and indirect benefits should be differentiated. (3,000-character maximum):

1) Improving Utilization & Efficiency of Existing Assets

Gap Bridged: Traditional grid expansion can be costly and inefficient, addressing peak loads lasting only 2–4 hours per day, leaving assets underutilized.

How Outcomes Will Be Achieved:

- Peak Demand Reduction: Activating voluntary DR events and behind-the-meter Distributed Energy Resources (DERs) to manage peak loads lasting only 2-4 hours per day.
- Deferral of Infrastructure Investments: Reducing peak loads to delay or avoid costly upgrades.
- Benefit Stacking: Improving efficiency across distribution, transmission, and bulk power markets.

Evidence Supporting Success:

- Toronto Hydro’s Local DR Program reduced demand by approx. 10 MW at two stations in downtown Toronto.
- Alectra & Essex Powerlines’ NWA Programs deferred infrastructure expansion.

Direct Benefits:

- Higher asset utilization, reducing infrastructure needs.
- More efficient grid operations, minimizing congestion.

Indirect Benefits:

- Lower electricity costs by avoiding capital expenditures.
- Increased customer engagement in demand-side solutions.

2) Increasing Grid Reliability & Flexibility

Gap Bridged: Rising demand, extreme weather, and aging infrastructure increase outage risks. Traditional solutions lack real-time flexibility.

How Outcomes Will Be Achieved:

- On-Call Demand Response: Participants reduce load during system stress periods.
- Automated Dispatch: Real-time activation optimizes supply-demand balance.
- Dual Market Participation: DR supports local and system-wide reliability.

Evidence Supporting Success:

- Global DR Programs enhance resiliency and reduce blackouts.
- European DSO Models integrate DR to minimize service disruptions.

Direct Benefits:

- Faster response to contingencies, reducing outage risks.
- Increased grid resilience in constrained areas.

Indirect Benefits:

- Greater regulatory support for demand-side solutions.
- Lower operational costs by reducing reliance on emergency power.

3) Enhancing Renewable Integration & Non-Wires Alternatives

Gap Bridged: Solar and wind intermittency challenges grid stability. Without flexible solutions, excess renewable energy is curtailed.

How Outcomes Will Be Achieved:

- Load Shaping for Renewables: Aligning demand with high renewable output and minimizing usage of fossil fuel based generation such as gas peaker plants.
- Behind-The-Meter (BTM) Resource Integration: Batteries and smart loads smooth renewable intermittency.

Evidence Supporting Success:

- Ontario's IESO DR Programs integrate renewables to reduce fossil fuel use.
- Ontario's "Prosumer" Growth: Net metering and DER participation increase local energy self-sufficiency.

Direct Benefits:

- Greater renewable energy utilization, reducing fossil reliance.
- More opportunities for DER owners to generate revenue.

Indirect Benefits:

- Faster clean energy transition, reducing emissions.
- Smart grid investments improving long-term stability.

2.1.3 Describe the metrics that will be used to assess project performance in each area identified above. Metrics should be specific, measurable, and time bound. Provide an explanation of how metrics will be measured, the targeted results, and any assumptions used. (2,000-character maximum):

1) Optimizing Utilization and Efficiency of Existing Assets

Metrics:

Peak Load Reduction (%): Reduction at Galt TS, MTS#1, and Preston TS.

Target: 5-10% reduction, aggregating to 20 MW at the end of 2029.

Deferred Infrastructure Investments (\$): Avoided upgrade costs.

Target: At least \$5 million in CAPEX

Load Factor Improvement: Better utilization of grid assets.

Target: 3-5% improvement.

Measurement Approach:

- Track peak demand reduction using historical grid data, smart meters, and SCADA.
- Compare projected infrastructure costs with demand response savings.

Assumptions:

- Participants adhere to commitments.
- Peak demand trends remain stable.

2) Enhancing Grid Reliability, Resiliency, and Flexibility

Metrics:

Activations: DR (including BTM DERs) events during grid stress.

Target: At least 5 activations per participating transformer station.

Response Time to Grid Stress (Minutes): Speed of load reduction.

Target: <2 hours for 90% of events.

Measurement Approach:

- Use event logs and smart meter data to track activations and response times.
- Estimate outage prevention impact from curtailment effectiveness.

Assumptions:

- Participants comply with activations.
- Grid stress occurs as predicted.

3) Expanding Renewable Energy Integration and Non-Conventional Solutions

Metrics:

Load Curtailment (%): DR events involving load reduction.

Target: 30% of activations.

Load Displacement via BTM Batteries or Renewable DERs (%): DERs supporting demand.

Target: 20% of activations.

Growth in Enrolled NWA Capacity (MW): Expansion in DR/DER enrollments.

Target: At least 10 MW increase from 2025 to 2029.

Measurement Approach:

- Analyze renewable generation and curtailment data against DR activations.
- Track DER participation through enrollment records.

Assumptions:

- DR aligns with renewable generation availability.
- DER participants actively engage.

2.2 Customer Value

The program is seeking projects that:

- clearly demonstrate that ratepayers will benefit from implementation,
- justify the impacts through supporting evidence,
- address a clear gap or need,
- propose significant results,
- utilize meaningful metrics to measure project impacts, and
- demonstrate sound methodology and assumptions.

Where appropriate, consider referencing the mandatory attachments to support responses.

2.2.1 Describe how the project addresses value for ratepayers. For example, consider how the project will improve affordability, increase market access, improve electricity reliability for customers, improve customer satisfaction, or deliver non-energy benefits. Direct and indirect benefits should be differentiated. (3,000-character maximum):

1) Improving Affordability and Reducing Costs

Direct Benefits:

- Lower System Costs: Reducing peak demand defers costly infrastructure upgrades, preventing rate

increases and yielding long-term net present value savings.

- Demand Reduction Incentives: Participants receive capacity and activation payments, directly lowering their electricity costs.
- Avoided Peaker Plant Costs: Demand response decreases reliance on expensive, carbon-intensive peaker plants, reducing wholesale electricity prices.

Indirect Benefits:

- Long-Term Rate Stability: Reducing infrastructure costs helps maintain stable electricity rates.
- Lower Market Price Volatility: Managing peak demand alleviates grid strain, stabilizing energy prices.

2) Expanding Market Access for Customers

Direct Benefits:

- New Revenue Streams: Businesses can monetize flexible energy use, turning demand management into a financial asset.
- Participation in Evolving Markets: Customers engage with demand response and DERs, preparing for future market opportunities.
- Meeting Customer Expectations: Utilities support the growing demand for "prosumers".

Indirect Benefits:

- Empowering Consumers: Demand-side solutions provide greater control over electricity costs and usage.
- Encouraging Smart Energy Investments: Businesses recognizing load flexibility benefits are more likely to invest in battery storage and energy-efficient technologies.

3) Strengthening Electricity Reliability and Resilience

Direct Benefits:

- Reduced Risk of Outages: Demand response enhances grid stability by enabling rapid load reductions during emergencies.
- Enhanced Grid Flexibility: A diversified portfolio of customer resources allows operators to manage demand efficiently.

Indirect Benefits:

- Resilient Local Communities: Demand response participation strengthens local grid stability, preventing disruptions.
- Reduced Strain on Aging Infrastructure: Optimizing grid assets extends equipment lifespan, reducing upgrade costs.

4) Delivering Non-Energy Benefits

Direct Benefits:

- Environmental Impact Reduction: Shifting demand to align with renewable generation lowers emissions and fossil fuel reliance.
- Policy Alignment: Supports regulatory goals for grid modernization, sustainability, and DER integration.

Indirect Benefits:

- Job Creation & Economic Growth: Expanding demand response benefits local energy service providers and technology firms.
- Enhanced Customer Satisfaction: Businesses benefit from cost savings and greater market participation, increasing engagement.

2.2.2 Describe the metrics that will be used to assess project performance impacts on customer value. Metrics should be specific, measurable, and time bound. Provide an explanation of how metrics will be measured, the targeted results, and any assumptions used. (2,000-character maximum):

1) Cost Savings and Affordability

Metrics:

- Participant Revenue / Cost Savings (\$): Total capacity payments received.

Target: Up to \$1,461,880 in participant payments from Apr 2026 to Mar 2029.

- Deferred Infrastructure Costs (\$): Estimated savings from avoided grid upgrades.

Target: At least \$5 million in traditional infrastructure deferred.

Measurement Approach:

- Track payments via financial records and settlement statements.
- Compare projected infrastructure costs with and without demand response.

Assumptions:

- Demand response activations occur as planned.
- Participants meet load reduction commitments.

2) Customer Participation and Market Access

Metrics:

- Enrolled Demand Response Capacity (MW): Total committed flexible load.

Target: 20 MW by 2029.

- Participating Customers: Total enrolled businesses/organizations.

Target: At least 10.

- Customer Retention Rate (%): Percentage of continued participation.

Target: 75% retention annually.

Measurement Approach:

- Track enrollment and capacity commitments.
- Conduct participant surveys to assess satisfaction.

Assumptions:

- Customers find value in participation and remain engaged.
- Market conditions support continued involvement.

3) Reliability and Resiliency Benefits

Metrics:

- Reduction in Outage Risk (%): Estimated decrease in outages.

Target: Up to 10% reduction in affected areas.

- Response Time to Grid Events (Minutes): Time from activation to load reduction.

Target: <2 hours for 90% of activations.

Measurement Approach:

- Use smart meters and grid monitoring to track demand and outage frequency.
- Analyze event logs for response time data.

Assumptions:

- Activations align with peak grid stress.
- Participants meet response expectations.

2.3 Job Creation

The program is seeking projects that:

- increase employment in the electricity sector, and
- demonstrate that the numbers presented are reasonable, estimated through a sound methodology, and likely to be achieved.

Where appropriate, consider referencing the mandatory attachments to support responses. (see Project Proposal Package Checklist).

2.3.1 Number of temporary jobs created during construction and/or implementation of the project:	0
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2.3.2 Number of operational jobs created as a direct result of the project over the project's useful life:	3
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2.3.3 Describe the methodology and assumptions used to obtain the above results. Applicants may consider specific teams that will need to be expanded, key project activities that will create jobs, etc. (1,000-character maximum):

The job creation estimates are based on the key roles required to implement and operate the program:

- At GBE, at least one new full-time role – a Grid Innovation specialist – will be created and needed to manage program implementation, oversee stakeholder engagement, and coordinate with the GridS2.
- GridS2 will add two new full-time employees for platform integration, system support, and ongoing optimization.
- Additionally, market participants, including DER aggregators and local service providers, will require personnel for DER deployment, asset monitoring, and market operations, creating additional jobs.

Assumptions are based on similar demand response and DER integration programs, where program management, technical support, and market participation drive job creation. As the program scales, further employment opportunities may emerge in engineering, customer support, and energy market operations, ensuring long-term economic benefits.

2.4 Emissions Reduction

The program is seeking projects that:

- lead to direct and/or enabled emissions reduction, and
- provide sound methodology and assumptions for the expected results.

Where appropriate, consider referring to the mandatory attachments to support the response.

2.4.1 Describe the greenhouse gas emissions reduction expected from the implementation of the project. Identify if the project will result in direct emissions reduction or if it will enable emissions reduction through subsequent investment (i.e., this project is a prerequisite for a future project that will directly reduce emissions). In both cases, indicate how the emissions reduction will be realized. For any quantified responses, include a description of the methodology and assumptions used. (2,000-character maximum):

1) Direct Emissions Reduction

How It's Achieved:

- Peak Load Shifting: DR activation reduces reliance on carbon-intensive natural gas peaker plants.
- Avoided Transmission Losses: Optimizing local energy use minimizes long-distance transmission losses and associated emissions.

Estimated Reduction:

- Assuming 50% of the 20 MW target is met through non-emitting resources (load reduction, battery storage, renewables), replacing gas peaker generation, and using an emissions factor of 0.43 tCO₂/MWh, the estimated reduction is 172 metric tons of CO₂ annually (10 MW x 20 calls/year x 2 hours/call).

2) Enabled Emissions Reduction

How It's Achieved:

- Supporting DER Investment: The program encourages adoption of energy storage and behind-the-meter renewables, reducing long-term grid reliance.
- Deferring Carbon-Intensive Infrastructure: DR alleviates congestion, delaying or avoiding new natural gas generation.

Estimated Reduction:

- Over five years, increased renewable integration and DER adoption could enable up to 1,000 metric tons of CO₂ savings through reduced peaker plant use and improved grid efficiency.

Methodology & Assumptions

- Emission Factor: 0.43 tCO₂/MWh, based on regional natural gas plant data.
- DR Impact: Assumed 40 activation hours/year at 10 MW capacity.
- Renewable Integration: Estimated 5–10% increase in renewable utilization due to reduced curtailment.

2.5 Societal Benefits

The program is seeking projects that provide societal benefits (i.e., those that add value for disproportionately impacted and/or marginalized populations) across Canada. Examples of these populations include, but are not limited to, high-density housing, end-of-line communities, and those experiencing energy poverty. These benefits are distinct from those in *Section 2.2 Customer Value* which are experienced generally by system ratepayers. Project benefits in this section are separated into direct and enabled societal benefits.

Direct societal benefits result in disproportionately impacted and/or marginalized populations gaining firsthand value from the proposed project construction, implementation, or completion. Examples include supporting affordable and secure energy, creating employment or training for local community members, and creating revenue opportunities for distributed energy resources. Community ownership in the project is also considered a direct societal benefit.

Enabled societal benefits address barriers that customers and communities face in accessing information related to electricity projects and receiving direct societal benefits. Enabled benefits may include increasing access to project information, reducing the burden of participation, and increasing opportunities for engagement or feedback through various phases of the project (e.g., planning and design). Enabled benefits may also be achieved when the proposed project is necessary for a future investment that will create direct societal benefits (e.g., a grid modernization project that is necessary for a clean energy generation project that will benefit a marginalized community).

The program is seeking projects that:

- demonstrate clear and impactful improvements for disproportionately impacted and/or marginalized populations across Canada,
- justify the impacts through supporting evidence,
- address a clear gap or need,
- propose significant results,
- utilize meaningful metrics to measure project impacts (as applicable), and
- demonstrate sound methodology and assumptions.

Where appropriate, consider referencing the mandatory attachments to support responses. (see Project

2.5.1 Describe the direct societal benefits of the project. Consider the problem, gap, or opportunity presented and how the project implementation will address the identified issue. Applicants are encouraged to consider how the target stakeholders will benefit from key project activities. (2,500-character maximum):

1) Addressing Energy Affordability & Energy Poverty

Problem: Many marginalized households spend a high percentage of income on electricity and lack access to cost-saving programs.

How the Project Helps:

- **Stabilize Energy Bills:** The NWA program reduces peak electricity costs, stabilizes rates, and provides financial incentives to participants.
- **Avoiding Rate Increases:** Deferring costly grid upgrades prevents infrastructure expenses from being passed to ratepayers, particularly benefiting low-income households.

Expected Impact:

- Up to 20 MW of NWA capacity deployed by 2029, reducing peak demand and stabilizing prices.
- Direct bill reductions for participating customers through incentive payments.

2) Increasing Economic Opportunities & Market Participation

Problem: Marginalized communities often lack access to demand-side programs and revenue-generating Distributed Energy Resources (DERs).

How the Project Helps:

- **Revenue for Local Businesses & Housing Providers:** Housing cooperatives, community centers, and small businesses can monetize energy flexibility by reducing peak demand when needed by GBE.
- **Job Creation & Workforce Development:** Expanding demand response fosters jobs in energy efficiency, smart grid tech, and demand-side management.

Expected Impact:

- New income streams for community organizations and small businesses in demand response.
- Increased DER investment (e.g., community battery storage) in underserved areas, creating local jobs and economic activities.

3) Enhancing Grid Reliability & Resiliency for Vulnerable Populations

Problem: End-of-line communities and system constrained areas are more vulnerable to outages due to infrastructure limitations.

How the Project Helps:

- **Reducing Outage Risks:** NWAs provide real-time load reductions, reducing strain on local substations and preventing brownouts.
- **Enhancing Energy Security:** Community-owned resources (e.g., battery storage, microgrids) can join the NWA program, creating resiliency hubs during grid disruptions.

Expected Impact:

- Up to 10% reduction in outages in targeted areas.
- Increased local energy security through demand-side resource deployment.

2.5.2 Describe the metrics that will be used to assess direct societal benefits. Metrics should be specific, measurable, and time bound. Provide an explanation of how metrics will be measured, the targeted results, and any assumptions used. (2,000-character maximum):

1) Energy Affordability & Cost Savings

Metrics:

- **Total Financial Incentives Paid (\$):** Payments to participants for demand response activations. Target: Up to \$1,461,880 from Apr. 2026 to Mar. 2029.
- **Reduction in Peak-Time Energy Costs (%):** Decrease in energy costs for participating communities. Target: Limit distribution rate increases to Canadian inflation/CPI values from Apr. 2026 to Mar. 2029.

Measurement Approach:

- Settlement/payment records track incentive distributions.
- Energy cost savings assessed using pre- and post-participation billing data.

Assumptions:

- Participants respond to demand response activations.
- Peak-time cost reductions benefit participating communities.

2) Economic Participation & Job Creation

Metrics:

- **Number of Participants:** Tracks low-income housing, community organizations, and small businesses. Target: At least 3 participants each year.
- **New Revenue from Community-Owned DERs (\$):** Earnings from local battery storage or DERs. Target: Up to \$250,000 from Apr. 2026 to Mar. 2029.

Measurement Approach:

- Enrollment records track participant demographics.
- Revenue monitored through energy market reports.

Assumptions:

- Community organizations and businesses actively participate.
- Market conditions support community-owned DER involvement.

3) Grid Reliability & Resilience

Metrics:

- **Reduction in Outage Frequency (%):** Tracks reliability improvements in targeted communities. Target: Up to 10% reduction in outages.
- **Response Time to Grid Events (Minutes):** Measures speed of demand response activations. Target: <2 hours for 90% of activations.

Measurement Approach:

- Utility outage data and grid monitoring assess outage reductions.
- Event logs track response times.

Assumptions:

- Demand response aligns with peak grid stress.
- Participants reduce load as expected.

2.5.3 Describe the enabled societal benefits of the project. Consider the problem, gap, or opportunity presented and how the project implementation will address the identified issue for the target stakeholders. (1,500-character maximum):

1) Increasing Access to Energy Programs & Information

Problem: Underserved communities often lack awareness or knowledge of demand response opportunities.

Solution: Targeted outreach, simplified enrollment, and educational resources improve accessibility.

2) Reducing the Burden of Participation

Problem: Complex processes and upfront costs prevent customer engagement in energy-saving programs.

Solution: Streamlined enrollment and no-cost participation options, such as load curtailment instead of DER investments, ensure equitable access.

3) Creating Pathways for Future Community Investments

Problem: Many communities lack access to DERs, battery storage, or microgrids due to limited integration with grid programs.

Solution: This project facilitates demand response participation, laying the groundwork for future community-owned energy initiatives and enhanced resilience.

PART 3: STRATEGIC VALUE

3.1 Priority Support

The program is seeking projects that:

- demonstrate strategic use of federal funding, and
- provide sound justification.

3.1.1 Indicate which of the following applies to the proposed project (select all that apply):

- X Implementation of the project represents a key decarbonization opportunity based on location (e.g., fossil fuel-dependent region, end-of-line community).
- X Implementation of the project represents infrastructure modernization to support the integration of diverse generation technologies or the interconnection with existing systems.
- X Implementation of the project will require support to overcome regulatory approval challenges needed to implement the proposed solution.
- X The project is incorporated into a long-term corporate strategy for decarbonization, reliability, and affordability.

3.1.2 Provide a justification for each of the selection(s) made above. If there are any other aspects of strategic value for the proposed project, describe those here. For example, applicants may consider how the project addresses system or regional priorities or challenges. (1,500-character maximum):

Decarbonization & Grid Efficiency: Reduces reliance on fossil-fuel-based peaker plants by shifting demand during peak hours, cutting emissions. Enhances grid reliability for end-of-line communities, improving access to clean energy.

Infrastructure Modernization: Integrates demand response (DR) with Distributed Energy Resources (DERs) like battery storage and renewables, enabling flexible, decentralized grid solutions and maximizing renewable use.

Regulatory Challenges & Market Barriers: Current market structures favor and incentivizes traditional infrastructure expansion over demand-side solutions. This project collaborates with regulators to enable demand response participation, create new incentives, and support dual participation in local and system-wide markets.

Long-Term Decarbonization & Affordability: Aligns with corporate goals to cut emissions, enhance reliability, and lower costs through demand-side management, serving as a scalable model for future clean energy projects.

Strategic Value

Supports peak demand reduction, energy equity, and infrastructure cost deferral while accelerating Canada's clean energy transition and improving affordability for underserved communities.

3.2 Need for Support

The program is seeking projects that:

- show a clear need for support,
- demonstrate that support will be impactful,
- provide value for money,
- provide sound justification, and
- demonstrate leveraging of funds.

3.2.1 Explain why SREPs funding is necessary for project success. Consider the following questions:

- What is the internal minimum rate of return and is funding required for the project to meet it?
- Is the project in competition with other internal projects?
- What is the gap between project costs and benefits for consideration of regulatory approval?
- Are there timing considerations for the funding need? Why is funding needed now?

(2,000-character maximum):

1) Financial Viability & Rate of Return

- Ontario utilities earn up to 9.21% return on equity, typically from capital expenditures like grid expansions, which have predictable cost recovery over 20+ years.
- NWA programs rely on operating costs rather than capital investments, making them less financially viable under traditional utility models.
- SREP funding is needed to offset costs and make NWA adoption financially feasible.

2) Competition with Other Internal Projects

- Traditional grid expansions receive higher priority due to established financial models and rate of return certainty.
- Without funding, utilities may default to capital-intensive solutions (e.g., poles and wires, substations) instead of more cost-effective non-wires alternatives (NWA).

3) Regulatory Barriers & Cost-Benefit Challenges

- Regulatory frameworks have traditionally favored infrastructure expansion over demand-side solutions.
- However, the 2024 Ontario Benefit-Cost Analysis (BCA) Framework & Non-Wires Solution Guidelines (NWS) now mandate utilities to consider NWAs for cost-effective capacity solutions.
- Funding will demonstrate the financial and environmental benefits of demand response (DR), supporting its long-term viability.

4. Timing Considerations

- Urgent action is required to address capacity constraints in Cambridge, where substations will reach 87.8% capacity by end of 2027.
- The Ontario Energy Board (OEB) expects grid modernization to improve resiliency against climate change and support new capacity required by economic growth.
- Ratepayers demand cost stability, especially amid tariff uncertainties that could impact the economy.

3.2.2 Explain how SREPs funding would be used to progress the project (e.g., expand the scope, accelerate implementation, improve outcomes, secure approval, etc.). (2,000-character maximum):

SREPs funding is essential to expanding scope, accelerating implementation, improving outcomes, and securing regulatory approval for this GBE's NWA Program. Without financial support, the program's scale, effectiveness, and long-term impact would be significantly limited.

1) Expanding Scope & Participation

- Funding supports outreach to marginalized communities, small businesses, and distributed energy resource (DER) owners who face financial or informational barriers.
- Enables higher capacity procurement, increasing total DR resources and maximizing grid efficiency and emissions reductions.

2) Accelerating Implementation

- Without funding, the project faces more challenging internal financial approvals.
- SREP funding improves the financial viability of the project by potentially being able to pay a higher incentive amount for participants, increasing market participations.

3) Improving Outcomes & Effectiveness

- Enables investment in grid automation, real-time monitoring, and advanced analytics for more precise and reliable DR and DER activations.
- Supports enhanced measurement and verification (M&V) for transparent, data-driven impact assessments.

4) Securing Regulatory Approval

- While the project aligns with OEB's NWS guidelines and does not require approval, GBE plans to file a rate application to support its NWA Program.
- SREPs funding minimizes rate impacts for ratepayers, easing regulatory approval and supporting future DR expansion.

3.3 Business Value

The program is seeking projects that:

- demonstrate alignment of the project with a business need,
- provide a strong business case with supporting evidence,
- utilize meaningful metrics to measure project impacts, and
- demonstrate sound methodology and assumptions.

3.3.1 Provide an overview of the project's business case (mandatory attachment). This may be an executive summary, or applicants may choose to highlight critical aspects with reference to specific sections of the attachment. (2,500-character maximum):

GrandBridge Energy (GBE) seeks funding under the Smart Renewables and Electrification Pathways (SREP) Program – Utility Support Stream to implement its Non-Wires Alternatives (NWA) Program, a proactive solution to address grid capacity challenges, enhance resiliency, and advance Ontario's energy transition.

By 2026, three key transformer stations in Cambridge—Preston TS, Galt TS, and MTS1—will reach 88% of their aggregated rated capacity, driven by:

- Rapid data center growth, particularly in AI applications
- Commercial sector expansion along Highways 401 and 403
- Residential subdivision growth and urban densification
- Fleet electrification, including Level 3 EV chargers

This reflects a broader Ontario trend, with electricity demand projected to rise 75% by 2050 (151 TWh in 2025 to 263 TWh in 2050, per the IESO's Oct. 16, 2024, forecast).

As a mid-sized utility serving 113,000 customers, GBE lacks the capital and resources of Ontario's largest utilities. Without SREP funding, the NWA program's costs would be passed to ratepayers, limiting affordability and scalability.

Ontario's regulatory framework supports NWA adoption:

- The Ontario Energy Board (OEB) promotes innovative grid solutions via its Non-Wires Solution Guidelines and Benefit-Cost Analysis (BCA) Framework.
- The provincial government aims to accelerate new connections and keep electricity affordable.

Without action, capacity constraints will force GBE to delay or deny new customer connections, violating its regulatory obligation to serve all customers. This could lead to:

- Economic stagnation, as businesses may relocate investments outside Canada.
- Loss of customer and community trust.
- Higher costs for ratepayers, as traditional infrastructure upgrades are significantly more expensive than NWAs.

SREP funding will ensure the GBE NWA Program can:

- Accelerate customer connections without long delays for grid expansion.
- Enable "prosumer" participation in grid management and modernization
- Enable new revenue opportunities for businesses
- Improve reliability and resiliency, lowering outage risks.
- Drive local job creation and clean energy investment.

3.3.2 Describe the metrics that will be used to assess project performance related to the business solution and needs, including cost-benefit analysis of the project. Metrics should be specific, measurable, and time bound. Provide an explanation of how metrics will be measured, the targeted results, and any assumptions used. (2,000-character maximum):

1) Peak Demand Reduction & Grid Efficiency

Metric: Reduction in peak demand (MW)

Target: Up to an aggregated 20 MW reduction by 2029 through NWAs

Measurement Approach: Smart meter and SCADA data will track demand reductions during demand response (DR) activations.

Assumptions: Participants consistently reduce load when called upon.

2) Financial Savings for Ratepayers

Metric: Cost savings from avoided infrastructure investments (\$)

Target: At least \$5M in deferred infrastructure upgrades over project period

Measurement Approach: Cost-benefit analysis comparing traditional infrastructure costs vs. NWA program costs.

Assumptions: Regulatory approval supports NWA deployment over capital-intensive grid expansion.

3) Customer Participation & Economic Inclusion

Metric: Number of participants enrolled

Target: At least 10 local participants enrolled by end of 2029

Measurement Approach: Enrollment records and customer engagement reports.

Assumptions: Awareness campaigns drive participation, and financial incentives remain competitive.

4) Energy Cost Reduction for Participants

Metric: Total financial incentives paid to participants (\$)

Target: Up to \$1,461,800 in incentives distributed from Apr. 2026 to Mar. 2029

Measurement Approach: Settlement and billing records will track payments.

Assumptions: DR activations occur as expected, and incentives offset peak-time costs.

5) Grid Reliability & Resiliency

Metric: Reduction in outage frequency (%)

Target: Up to 10% reduction in outage incidents in City of Cambridge

Measurement Approach: Utility outage reports and grid monitoring data.

Assumptions: Demand response activations effectively alleviate local grid stress.

PART 4: PROJECT FEASIBILITY

4.1 Project Budget			
<p>The program is seeking projects that:</p> <ul style="list-style-type: none"> • provide detailed and defensible budgets, • demonstrate sound cost planning practices, • have contingency plans in place for any unsecured funds, and • demonstrate strong risk identification and mitigation measures. <p>The evaluation of this section will also consider <i>Annex A: Risks and Mitigation Measures</i>, <i>Annex B: Project Funding</i>, and the project budget (mandatory attachment).</p>			
4.1.1 Sources of Funding:			
Name of Organization	Cash	In-kind	Confirmed (Yes/No)
SREPs	\$ 1,343,440	N/A	N/A
Applicant	\$ 1,343,440	\$	Yes
[Other Partner]	\$	\$	
[Other Government]	\$	\$	
Total Project	\$ 2,686,880	\$	
4.1.2 How have capital and project cost estimates been established? Note the estimate must be within a ±20% degree of accuracy. (1,000-character maximum):			
<p>The capital and project cost estimates were developed using a bottom-up approach, considering:</p> <ul style="list-style-type: none"> - Procuring DR capacity – based on network analysis and Ontario LDC/IESO DR program costs. - Program Design & Platform Integration – fixed-price contract with GridS2. - Regulatory, Legal & Marketing Support – estimated using past vendor engagements. - GBE Labour Costs – derived from internal cost modeling. - Contingency – included for procurement and labor costs to ensure financial flexibility. <p>This approach ensures financial viability while maintaining adaptability for unforeseen expenses.</p>			
4.1.3 How will any potential cost overruns/underruns be managed? (1,000-character maximum):			
<p>GBE has a fixed-price contract with GridS2 for platform integration, network analysis, and market design. Internal costs are based on existing models and remain stable, while third-party costs are based on past vendor pricing. The only potential variance is in demand response (DR) capacity procurement costs.</p> <p>A contingency budget ensures financial flexibility for unforeseen expenses. Additionally, the competitive procurement process is expected to reduce DR capacity costs, maximizing value.</p> <p>If cost underruns occur, surplus funds will be reallocated to enhance project outcomes. As a regulated entity, GBE ensures transparent financial reporting and accountability in meeting project objectives.</p>			
4.1.4 For any unsecured funding (other than SREPs), what is the contingency plan in the event funding is not secured in time to start the project? (1,000-character maximum):			
<p>Funding has already been allocated and committed for both the technology platform, and internal resourcing.</p> <p>For funding additional to that anticipated from SREP, that will be used to payout the market participants, GBE is putting in a rate application with the OEB. The probability of the rate application not being approved before the start of the operational phase of this project – which is May 2026 – is unlikely. Yet, in the event that the application approval is delayed, GBE can either reduce their procurement target for year 1 (2026), or payout</p>			

through other internal budgeting mechanisms such as deferral accounts.

4.2 Technical Advancement

The program is seeking projects that have strong technical feasibility as demonstrated by:

- credible and relevant past work,
- a methodological approach in addressing the technical challenge or need,
- the technical merit of the proposed solution,
- a sound pathway to project implementation,
- a credible feasibility study or engineering report, and
- strong risk identification and mitigation measures (in Annex A: *Risks and Mitigation Measures*).

4.2.1 Describe the technical challenge or need the project addresses. (1,500-character maximum):

Technical Challenge/Project Need: Distribution System Capacity Constraint, that cannot be immediately and cost-effectively solved through traditional infrastructure upgrades.

Proposed Solution: Obtain additional capacity during peak periods by incentivizing DERs, through a NWA Program.

Past Work: GridS2's team played a key role in delivering Toronto Hydro's Demand Response (DR) program, and the solution proposed for this project builds upon and enhances the technology currently in use there. Additionally, GBE is incorporating key insights from other leading projects in Ontario to refine and strengthen the program's design and implementation.

Methodological Approach: GBE will implement a transactive energy platform that will allow it to forecast short-term load, optimize DER dispatch and thereby alleviate peak demand stress on constrained infrastructure.

Technical Merit: The project's technical merit lies in its ability to maximize existing infrastructure while utilizing advanced grid management techniques. The platform enables accurate load forecasting, dynamic DER coordination, and dispatch, ensuring reliability without costly upgrades.

Implementation: A flexible program design, customizable technology platform and phased procurement of DR resources - all ensure minimization of risk while allowing continuous optimization based on operational performance and feedback.

Engineering Report: See attached.

Risks & Mitigation: See Annex A

4.2.2 Describe the research or analysis completed to arrive at the proposed solution. Consider the following questions:

- ❓ What specific work has your organization completed to inform the proposed project approach? For example, studies, analyses, prior project learnings/experience, etc.
- ❓ What external sources has your organization referenced to inform the proposed project approach? For example, learnings from other jurisdiction, standards, studies, etc.

(2,500-character maximum):

Our technology partner, GridS2's team has utilized the theoretical background of an Incremental Capacity Auction (ICA)¹ to develop their proprietary transactive energy platform. The theoretical model requires bids to buy asset capacities from various loads. The model sources offers-to-sell asset capacities from various vendors. It settles the auction by maximizing social welfare, while satisfying network requirements. This mechanism has since been further developed and implemented for an actual procurement of Demand

Response (DR) in a pilot project with Toronto Hydro, in a project funded by IESO and OEB's Grid Innovation Fund. This project uses DR for dual participation in distribution and bulk systems, simultaneously.

For the proposed project, with data provided by GBE, the GridS2 team conducted detailed network analysis, for the three transformer stations (TSs) under consideration - Preston TS, Galt TS and MTS#1. Load curves for 2023 and 2024 were modelled to show peak demand periods. Thereafter, sensitivity analysis was conducted based on factors such as percentage load reduction, fixed cost of obtaining DR capacity (\$/MW-day), variable cost of obtained DR capacity (\$/MWh) and number of calls per month when DR resources will be called upon. This analysis has provided the granular insights on which months during the year, for how many days in a month, and for how many hours on each of those days, at each of the three TSs would GBE need to call upon a DR resource to obtain the targeted peak load reduction. This data driven approach has been used to define the project budget and implementation plan.

Also, the GBE project team has had detailed conversations with other project teams that have conducted similar programs in Ontario – namely Toronto Hydro's Local DR Program, Essex Power's PowerShare, and Alectra's Non-Wires Alternatives initiative. These discussions have led to a better understanding of the requirements of implementing GBE's DR program.

1 A. A. Mohamed, C. Sabillon, A. Golriz, M. Lavorato, M. J. Rider and B. Venkatesh, "Deregulated Distribution System Planning - Incremental Capacity Auction Mechanism with Transactive DERs," in IEEE Transactions on Power Delivery, vol. 37, no. 6, pp. 4515-4526, Dec. 2022.

4.2.3 Describe the technology/solution proposed by the project, justify its technical merit, and the reason for its selection. Consider the following questions:

- How does the proposed approach address this challenge or need?
- How does the proposed solution compare to alternative solutions?
- What are the key pieces of equipment necessary for project implementation? Have specific products been selected? Note that a list of key equipment is required as per *Annex C: Key Equipment List*.

(2,500-character maximum):

Proposed Solution: Market-Based Demand Response Procurement

Selected Technology: Transactive Energy Platform – short-term load forecasting, DR dispatch scheduling, and settlement capabilities.

Technical Merit (How It Addresses the Challenge/Need):

Granular Load Forecasting & Optimization

- Analyzes actual and historical load data for accurate peak demand forecasting.
- Ensures DR resources are dispatched precisely when and where needed, targeting transformer station constraints.

Market-Based Efficiency & Scalability

- Competitive procurement selects cost-effective DR resources, reducing program costs.
- Scalable across multiple feeders and transformer stations with minimal operational changes.

Regulatory Alignment & Grid Modernization

- Supports OEB's NWS framework, showcasing market-based capacity management.
- Advances grid modernization with dynamic, data-driven decision-making over static contingency planning.

Why This Solution Was Selected Over Alternatives:

Alternative 1: Traditional Infrastructure Expansion

Issue: Building a new transformer station requires 3–5 years and significant capital.

Advantage of Proposed Solution: Faster, cost-effective peak load management.

Alternative 2: Conventional DR Programs (Static Dispatch Rules)

Issue: Limited flexibility, lacks market-driven efficiency.

Advantage of Proposed Solution: Dynamic transactive energy platform enables precise load forecasting and optimized DR dispatch for better grid management.

Key Equipment & Services, Product Selection:

- Transactive Energy Platform – Provided by GridS2, the only vendor offering a full end-to-end solution with a proven track record.
- Demand Response Capacity – Procured through market-based mechanisms, leveraging behind-the-meter resources in GBE's service territory.

4.2.4 What remaining engineering design and/or technical studies are required to initiate the project? Have engineering firm(s) been identified or retained to perform these studies? What are the associated timelines?

Projects with no outstanding design or technical work may provide additional details of study findings not captured under *Question 4.2.2* or may mark the question as not applicable. (1,000-character maximum):

- Network Analysis – completed by GridS2 (see attached as feasibility/engineering report)
- Program Design – on-going, target completion 2025/08. GridS2 awarded contract.

Since existing behind-the-meter DR resources will be leveraged, no new construction or connection impact assessments are required, and therefore no other major engineering design and/or technical studies are required as part of this project.

4.3 Project Team

The program is seeking projects that are led by teams that have:

- relevant experience,
- subject matter expertise,
- appropriate partnerships for project success, and
- corporate and individual project management experience.

4.3.1 Describe your organization’s experience completing projects of similar scale and complexity. (1,250-character maximum):

GBE has a strong track record in large-scale infrastructure projects, including multi-million-dollar distribution feeder and transformer upgrades. Our in-house technical team specializes in SCADA, grid modernization, and DER integration, supporting advanced grid solutions and the adoption of an NWA/DSO model.

Our Innovation & Continuous Improvement Team focuses on integrating NWA and DSO models into core operations while enhancing efficiency and reliability. The NWA project team brings expertise in utility DSO transition roadmaps, electrification strategies, and Smart Grid deployments across North America. Our executive sponsor has led industry innovation initiatives, including chairing GridSmartCity’s New Technologies Committee and developing strategic roadmaps to ensure industry alignment.

Backed by executive leadership and shareholders, GBE’s NWA Program is built for success. Looking ahead, we remain committed to innovation, collaboration, and continuous improvement to deliver reliable, cost-effective solutions for our customers.

4.3.2 Provide information for key project team members:			
Name	Organization	Project Role and Responsibilities	Relevant Experience/ Expertise
Umar Waqas, Vice President, Grid Modernization	GrandBridge Energy	Executive Sponsor: Provide strategic oversight, secure funding, and ensure project alignment with corporate objectives.	Results-driven Vice President with a proven track record in engineering leadership and continuous improvement within the energy sector. Strategic thinker with experience in capital budgeting, distribution system planning, merger integration, renewable energy generation, and innovation.
Prescott Davis, Director, Engineering & Planning	GrandBridge Energy	Project Director: Oversee project execution, manage stakeholder engagement, and ensure compliance with regulatory and funding requirements.	A strategic and goal-oriented leader, who develops processes and productivity improvements to achieve results. Possesses strong skills in short- and long-range planning, operational analysis and forecasting while developing strong working relationships.
Allen Chan, Manager, Engineering & Innovation	GrandBridge Energy	Project Manager, GBE: Manage day-to-day project activities, coordinate teams, and track milestones and deliverables.	Demonstrated strong success in leading engineering teams, planning projects, and managing budgets. Robust grasp of business, technical, and regulatory facets in the utility industry. Experienced Previously developed strategic roadmaps for utility transition to the Distribution System Operator (DSO) model and electrification initiatives, assessing operational readiness, identifying gaps, and aligning with sustainability goals.
TBD, Innovation Specialist	GrandBridge Energy	Project Lead: Lead technical implementation & market operations, support procurement, and facilitate engagement with market participants.	GrandBridge Energy is hiring for this role in May 2025. The role requires 4–6 years of experience in the electric utility, technical consulting, or a related industry, along with at least 3 years in project management, facilitation, and stakeholder engagement. Candidates should have expertise in project coordination, organizational change initiatives related to technology adoption, and cross-functional team collaboration. Experience with digital tools, data analytics platforms, and funding application development is an asset, along with a strong technical and analytical mindset.
Nimish Bhatnagar, CEO & Co-founder	GridS2	Project Manager, GridS2: Ensure technology integration, oversee software deployment, and coordinate with GBE's project team.	20+ years of relevant industry experience with multiple North American distribution utilities and large electricity consumers. With a deep understanding of the utility business model, has assisted utilities in submitting regulatory filings and reviewing system plans. Has led multiple technical and financial analysis involving both in front of and behind

			the meter distribution energy resources projects.
Bala Venkatesh, CTO & Co-founder	GridS2	Technology Lead: Guide technical architecture, ensure platform scalability, and oversee market design & implementation.	Leader in the field of Power System Analysis and Optimization. He has led the development of integrating storage in incremental capacity auction design for electricity markets in Ontario, has developed fundamental algorithms for power system analysis, including holding a patent for a line-wise power flow. Technology lead for Toronto Hydro's DR Program.
TBD, Software Engineer	GridS2	Platform Integration: Customize and configure the web-based auction platform as well the transactive energy platform, implement automation features, and troubleshoot system issues.	Experienced full-stack developer, proficiency in developing web-based applications. Stack expertise includes MongoDB, Next.JS, React, Node.JS and cloud platforms such as Azure and AWS.
TBD, Electrical Engineer	GridS2	Program Design & Implementation: Lead program design and validation, ensure platform compatibility with grid operations, validate DR capacity models, and support network analysis.	Experienced electrical engineer with a graduate degree in Power System Engineering, having a mix of industry and research expertise. Proficiency with utility platforms like SCADA, GIS, ADMS, DERMS and an in-depth understanding of DERs including Solar PV, Battery Storage and EVs.
Other Subject Matter Experts (SMEs)	GrandBridge Energy & GridS2	SMEs – Regulatory, Finance, Metering etc.	SMEs for specific integration and/or implementation tasks, as required, through the life of the project.

4.3.3 Provide information for project partners. If you have more than one project partner, repeat the below sections for each. Documentation must be attached to validate each partnership claim.

Note: "Project partner" refers to an entity providing in-kind or cash contributions to the project and may not necessarily constitute a legal partnership. Project partner involvement should be reflected in information provided in *Annex B: Project Funding* and *Annex D: Description of Work*.

Legal name of partner:	GridS2 Inc.
Business sector of organization:	Technology
Website:	https://www.grids2.com
Primary contact:	Nimish Bhatnagar
Title (e.g., Senior	CEO & Co-founder
Email:	NimishB@GridS2.com
Phone number:	416-662-8782
Address:	4187 Trellis Crescent, Mississauga, ON L5L 2M1

Describe how this partnership benefits the project (e.g., project role and responsibilities, technical expertise, in-kind/cash contribution, etc.). (500-character maximum):

The partnership leverages GBE's grid operations expertise and GridS2's advanced transactive energy platform. GBE will oversee program implementation, DER procurement, and operations, while GridS2 provides the platform, technical support, in addition to the market design and subject matter expertise. This collaboration ensures seamless deployment, enhances system efficiency, and maximizes the project's impact on capacity management.

Legal name of partner:	
Business sector of organization:	
Website:	
Primary contact:	
Title:	
Email:	
Phone number:	
Address:	

Describe how this partnership benefits the project (e.g., project role and responsibilities, technical expertise, in-kind/cash contribution, etc.). (500-character maximum):

4.4 Timing

The program is seeking projects that demonstrate:

- defensible project timelines,
- an ability to begin project activities in the near term, and
- strong risk identification and mitigation measures.

The evaluation of this section will also consider *Annex A: Risks and Mitigation Measures*, *Annex D: Description of Work*, and the Project Schedule (mandatory attachment).

Indicate which of the following are in place for the project as of the date of your FPP submission (select all that apply):

Construction-ready engineering and costing studies.

Required permitting and environmental assessments have been applied for and approved or are pending approval and will be issued according to the project schedule.

A confirmed project site with the required infrastructure in place

Third-party funding is confirmed.

Project internally approved for spending.

Service contract secured (if applicable).

Regulatory approval for project implementation has been applied for and is pending approval according to the project schedule

Regulatory approval for project implementation has been received or is not necessary for implementation.

None of the above are in place as of the time of the submission.

Note: It is not required to have completed all items to date. If the project is selected, further information will be obtained as part of due diligence.

4.5 Permits, Approvals, and Regulatory

The program is seeking projects that demonstrate:

- a strong understanding of permitting, approvals, or regulatory impacts,
- the ability to resolve outstanding issues, and
- strong risk identification and mitigation measures (in *Annex A: Risks and Mitigation Measures*).

4.5.1 Complete the table with any required permits or third-party approvals required prior to construction or project commissioning:			
Permit/Approval Name	Expected Date to Obtain	Short Description/ Impact on Project	Issuing Body
Not Applicable			
4.5.2 Identify any permits, approvals, or regulations that pose a risk to the design, implementation, or timing of the project. Describe how the risk will be mitigated and how the project may be altered if the risk cannot be mitigated. (2,000-character maximum):			
<p>No Permits and/or Approvals, regulatory or otherwise are needed for the project implementation.</p> <p>GBE is in the process of submitting a rate-application related to the DR program payments to Market Participants for two purposes:</p> <ol style="list-style-type: none"> 1. As a mitigation strategy to this SREP application not being approved 2. As a strategy of ensuring program implementation post the SREP funding period <p>Given OEB's NWS framework and directive to implement innovative and cost-effective solutions to solving grid constraints, along with a strong business case supporting this project, GBE is confident of receiving the required approval from OEB to rate base future payments of this program.</p>			

ANNEX A: RISKS AND MITIGATION MEASURES

Using the table below, outline the risks that will impact the implementation of the project according to *Annex D: Description of Work* and the Project Budget (mandatory attachment). For each risk, provide the following:

- ❑ the relative probability of occurrence (high, medium, low)
- ❑ the estimated risk impact (high, medium, low), and
- ❑ the risk mitigation and response strategies to reduce the probability and/or impact of the risk.

Key Risks	Probability	Impact	Risk Mitigation Strategies
Technical Risks			
Technology Platform Performance	Low	High	GBE awarded the contract of to GridS2 because, their technology for all three modules – load forecasting, DR Scheduling and Settlement – has been tested and is currently in operation within a utility environment. Also, by awarding the contract to GridS2 early and for the complete life of the project, GBE has ensured any technical challenges will be addressed by GridS2’s team directly and promptly.
Regulatory and Permitting Risks			
Regulatory changes affecting DR programs or non-wire solutions	Low	High	Considering that the OEB recently introduced the Non-Wires Solutions (NWS) Guidelines and the supporting Benefit-Cost Analysis (BCA) framework to evaluate NWS projects, it is highly unlikely that the regulatory environment would change to discourage such solutions. On the contrary there is every indication that the regulations will continue to evolve more favourably for such projects.
Budget and Financing Risks			
Cost overruns due to unforeseen technical challenges.	Low	Medium	GBE has signed a fixed price contract with GridS2, minimizing the risk of any cost escalations due to technical challenges of the platform.

Delay in securing external funding	Medium	High	While GBE has earmarked certain budget for technology integration, the funding for making the program becomes operational, i.e. to pay market participants is anticipated in part through the SREP funding. As a mitigation measure and to ensure long-term viability of the program, GBE's regulatory team is in the process of developing a rate application to be submitted to the OEB, supporting the program.
Project Plan and Timeline Risks			
Delays in Market Participant Onboarding	Medium	Medium	GBE is committed to conducting early stakeholder engagement, streamlining the on-boarding process and potentially offering incentives for early participation. GBE's experience with implementing Conservation & Demand Management (CDM) programs will be leveraged to ensure appropriate and timely on-boarding.
Business Model and Business Plan Risks			
Lower-than-expected participation from DER owners	Medium	Medium	GBE has already on-boarded a key-accounts executive and involved their communications team. Appropriate education to these personnel will be provided so they may appropriately understand and communicate the value proposition of participating in the program to our customers. The program is being designed to offer competitive incentives and is based on learnings from other such programs. In the event that desired participation is not received, the program has the flexibility to alter the program design based on market feedback.
Uncertainty in long-term program viability.	Medium	Medium	To ensure the program remains sustainable beyond the SREP project timeframe, GBE is engaging the OEB through a rate application that can be used to fund the program in part during the SREP funding period, and in full beyond 2029.

Other Risks			
Lower or higher than expected load growth.	Low	Low	<p>The program design is for annual procurement, and therefore the targets for DR capacity can be altered based on the real requirements of the system.</p> <p>Since the program is being implemented on transformer stations that are already constrained, even if the forecasts around future load growth are lower than expected, the program will still lead to useful grid management options.</p> <p>In the event the growth is lower or higher than forecasted, the capacity procurement targets under the program can be altered accordingly.</p>
Inadequate staff training or turnover.	Low	Low	<p>As part of this project, staff will be trained in all aspects of the technology as well as market operations. Also, as this project is of strategic importance to GBE, the executive leadership will continue to be involved in the lifecycle of the project, mitigating any risks of staff turnover at the operational level.</p>

ANNEX B: PROJECT FUNDING

Provide a cost breakdown for the proposed project, by cost category and fiscal year. Note: Government fiscal years run from April 1 to March 31 (e.g., April 1, 2024 to March 31, 2025). Refer to Section 2.5.2 of the *Applicant Guide* for detailed Eligible Expenditures categories.

For GST, PST or HST, only the unrebated tax portion of project costs is eligible for reimbursement and can be included in the budget table below.

The Program (NRCan Contribution) - Approved Budget (\$)

<u>2024-25</u>	<u>2025-26</u>	<u>2026-27</u>	<u>2027-28</u>	<u>2028-29</u>	<u>2029-30</u>	<u>Total</u>
\$0.00	\$350,000.00	\$191,920.00	\$296,340.00	\$505,180.00	\$0.00	\$1,343,440.00

Total NRCan Contribution

\$1,343,440.00

Eligible Expenditures

<u>Eligible Expenditure</u>	<u>2024-25</u>	<u>2025-26</u>	<u>2026-27</u>	<u>2027-28</u>	<u>2028-29</u>	<u>2029-30</u>	<u>Total (\$)</u>
Salaries and benefits	\$0.00	\$125,000.00	\$125,000.00	\$125,000.00	\$125,000.00	\$0.00	\$500,000.00
Professional, scientific and contracting services	\$0.00	\$575,000.00	\$50,000.00	\$50,000.00	\$50,000.00	\$0.00	\$725,000.00
Capital expenditures for equipment and products	\$0.00	\$0.00	\$208,840.00	\$417,680.00	\$835,360.00	\$0.00	\$1,461,880.00

Total Eligible expenditures 2024-25	Total Eligible expenditures 2025-26	Total Eligible expenditures 2026-27	Total Eligible expenditures 2027-28
\$0.00	\$700,000.00	\$383,840.00	\$592,680.00

Total Eligible expenditures 2028-29	Total Eligible expenditures 2029-30
\$1,010,360.00	\$0.00

Total Eligible expenditures
\$2,686,880.00

ANNEX C: KEY EQUIPMENT LIST

Complete the table below with the most current information available. Where information is not available, mark as N/A.

Equipment Name	Description of Equipment	Capacity/ Design Rating	Make and Model	Supplier/ Potential Supplier	Quotes Received? (Y/N)	Estimated Cost in CAD
Auction Platform & Transactive Energy Platform	<p>Auction Platform: Web-based platform to allow market participants to register and submit offers.</p> <p>Technology platform that would enable the implementation of the DR Program – to include:</p> <p>Short-term Load Forecasting: allows GBE to anticipate days and times when DR activation would be needed.</p> <p>DR Scheduling: ability to schedule and send activation notices (non-operational) to market participants.</p> <p>Settlement: validate and calculate payments to be made out to market participants in line with terms of the market rules and contracts.</p>	Not applicable	qEx	GridS2	Y	\$625,000
DR Capacity	Capacity to be procured from DR resources to enable peak load management and thereby resolve capacity constraints.	20 MW	DR Events and DER Capacity	Multiple Market Participants	N	\$1,461,880

ANNEX D: DESCRIPTION OF WORK

Complete a Description of Work for the project, including major tasks and key activities required to complete those tasks. Describe deliverables and timelines. The major activities must adequately reflect the scope of the work of the proposed project and show progress throughout the project.

The Description of Work will form the basis of the scope of the contribution agreement. The following general tasks may be considered; however, applicants are encouraged to use tasks that best align with the proposed project:

- ☐ Securing final permits and approvals
- ☐ Project management and engineering
- ☐ Equipment procurement and installation
- ☐ Civil and structural installation
- ☐ Mechanical installation
- ☐ Electrical and instrumentation installation
- ☐ Commissioning
- ☐ Trials and optimization

Task name	Task Activities/ Description	Start Date (YYYY/MM)	Completion Date (YYYY/MM)	Deliverables / Outputs	Estimated Cost (\$)
1. Network Analysis	<p>Perform an analysis of GBE’s network to identify specific DR capacity requirements and the timing of demand reductions. This includes evaluating historical and projected load data to pinpoint when and where capacity constraints are most critical, ensuring the program is both targeted and effective.</p> <p>Task Lead: GridS2 Task Support: GBE</p>	2025/03	2025/04	Network Analysis Report: A report summarizing the findings from the network analysis, including identified capacity requirements, timing of DR needs, and recommendations for program design.	\$72,500

Task name	Task Activities/ Description	Start Date (YYYY/MM)	Completion Date (YYYY/MM)	Deliverables / Outputs	Estimated Cost (\$)
2. Develop Program Rulebook	<p>Develop a comprehensive Program Rulebook that establishes the framework for the DR Program, including:</p> <ul style="list-style-type: none"> • Eligible Technologies: Define acceptable technologies such as renewable energy systems, battery storage, and load curtailment mechanisms that participants can use. • Customer Eligibility: Outline criteria for customer participation, such as being a commercial or industrial entity, residing in a specific geographic area, or meeting certain load requirements. • Stakeholder Roles and Responsibilities: Clearly delineate the responsibilities of GBE and DR participants to ensure smooth program operation. • Market Mechanisms: Specify bidding processes, dispatch procedures, and settlement rules, ensuring transparent and efficient market operations. <p>Task Lead: GridS2 Task Support: GBE</p>	2025/04	2025/08	Program Rulebook: A finalized document detailing program eligibility criterion, market rules, bidding and dispatch procedures, and roles and responsibilities of all stakeholders. Also included will be validated test cases demonstrating program feasibility.	\$220,000

Task name	Task Activities/ Description	Start Date (YYYY/MM)	Completion Date (YYYY/MM)	Deliverables / Outputs	Estimated Cost (\$)
3. Develop & Deploy Auction Platform	<p>Design and deploy a user-friendly web-based portal for the DR auction process. This platform will allow market participants to:</p> <ul style="list-style-type: none"> • Register and review program guidelines. • Submit bids during the auction phase. • Access real-time updates and results once the auction concludes. <p>Based on the bids offered and GBE's network requirements, the backend system will then create the most cost-effective DR participant portfolio. <i>(See schematic of DR procurement process in the attached Project Diagrams section)</i></p> <p>Task Lead: GridS2 Task Support: GBE</p>	2025/06	2025/10	Auction Platform: A fully operational web-based portal for conducting DR auctions. The platform will enable participant registration, bid submission, and result visualization, with a robust backend for auction settlement.	\$143,750
4. Technology Integration	<p>Customization, Installation & Testing of GridS2's Transactive Energy Platform, featuring:</p> <ul style="list-style-type: none"> • Short-Term Load Forecasting Module: Provides precise forecasts to support operational decisions. • DR Module: Creates and sends appropriate standby and activation notices to participants, based on approved rules. • Settlement Module: Automates participant compensation processes, ensuring accuracy and timeliness. <p>Task Lead: GridS2 Task Support: GBE</p>	2025/06	2026/02	Transactive Energy Platform: An on-premises platform with integrated modules for load forecasting, DR notification, and settlements, tailored to meet GBE's operational requirements.	\$240,000

Task name	Task Activities/ Description	Start Date (YYYY/MM)	Completion Date (YYYY/MM)	Deliverables / Outputs	Estimated Cost (\$)
5. Training	<p>Staff Training: GridS2 will deliver tailored training sessions for up to two GBE staff members, equipping them with the skills to operate the Auction Platform and Transactive Energy Platform effectively. Training will include hands-on sessions and address any specific concerns.</p> <p>Task Lead: GridS2 Task Support: GBE</p>	2026/02	2026/03	<p>Training Sessions: Hands-on training sessions for up to two GBE staff members, ensuring they are fully equipped to operate and manage the deployed platforms.</p>	\$73,750
6. Technology Support / Licensing	<p>Ongoing Support: GridS2's scope includes an annual licensing fee that covers regular software updates, platform enhancements, and up to 40 hours of technical support per year. This ensures the program remains operational and evolves with GBE's needs.</p> <p>Task Lead: GridS2 Task Support: GBE</p>	2026/04	2029/03	<p>Annual Support Package: Ongoing support including software updates, enhancements, and up to 40 hours of technical assistance annually as part of the licensing agreement.</p>	\$150,000

Task name	Task Activities/ Description	Start Date (YYYY/MM)	Completion Date (YYYY/MM)	Deliverables / Outputs	Estimated Cost (\$)
7. Auction & Contracting	<p>Procurement Auction: Conduct auction to receive offers from potential market participants. Auction platform will process the submissions to determine winners and clearing price. This task will have the following steps:</p> <ul style="list-style-type: none"> • Open registration portal to public. • Offers portal open to registered participants. • Auction Settlement results obtained. <p><i>(See schematic of DR procurement process in the attached Project Diagrams section)</i></p>			<p>Executed contracts with qualified market participants: Binding agreements with Market Participants ensuring compliance with market rules.</p>	
	<p>Contracts with Market Participants: Formalize legal agreements with selected market participants based on terms defined in the Program Rulebook. Third-party contractors for Regulatory/Legal oversight might be engaged. This task will have the following steps:</p>	2026/01	2026/03		\$41,666
	<ul style="list-style-type: none"> • Contract negotiations with qualified participants. • Execute contracts with qualified market participants. 	2027/01	2027/03		\$41,667
	<ul style="list-style-type: none"> • Execute contracts with qualified market participants. <p><i>Note: Both the above tasks will be done on an annual basis, over a 3-month auction & contracting period.</i></p> <p>Task Lead: GBE Task Support: GridS2</p>	2028/01	2028/03		\$41,667

Task name	Task Activities/ Description	Start Date (YYYY/MM)	Completion Date (YYYY/MM)	Deliverables / Outputs	Estimated Cost (\$)
8. Market Operations & Reporting	<p>Market Operations: Manage day-to-day operations of the DR market, including daily load forecasting, dispatch scheduling, and monthly settlements for participating resources during the contracted period for each of the 3 TSs, as applicable. This task will include the following steps:</p> <ul style="list-style-type: none"> • Daily: Forecast the load on at each TS for 72 hours. • Daily: Create an optimized 24-hour schedule for the dispatch of participating resources and send schedule (excludes control) to the market participants. • Monthly: Calculate the settlement for the dispatched resources at the end of each month and include in invoice. <p>At this time, we anticipate the program will first be rolled out at Preston TS, to procure 5 MW in 2026. Galt TS will be included in 2027, for a total procurement of 10 MW. And the program will be rolled out to all 3 TSs in 2028, with a total procurement target of 20 MW.</p> <p><i>(See schematic of DR market operations in the attached Project Diagrams section)</i></p> <p><i>Note: Market Operations will be conducted annually during the contracted period for each TS. The timelines mentioned are based on the historical load profiles and may be modified annually for each TS depending on real load growth. See attached engineering report for further details.</i></p> <p>Reporting: During and post market operations each year, the results will be analyzed and metrics as mentioned in Sections 2 & 3 to measure both project impact and strategic value will be quantified. This will be done for each TS, as applicable.</p>	<p>Market Operations</p> <p>Preston TS: 2026/07 2027/07 2028/07</p> <p>Galt TS: 2027/09 2028/09</p> <p>MTS#1: 2028/03</p> <p>Reporting</p> <p>2026/06 2027/06 2028/04</p>	<p>Market Operations</p> <p>Preston TS: 2026/09 2027/09 2028/09</p> <p>Galt TS: 2027/09 2028/09</p> <p>MTS#1: 2028/06</p> <p>Reporting</p> <p>2026/12 2027/12 2028/12</p>	<p>Operational NWA through DR Procurement: Reduction in peak demand, leading to deferment of traditional infrastructure and grid optimization.</p> <p>Market Reports: Annual data driven reports based on the analysis of market operations for each TS.</p>	<p>2026: \$233,840</p> <p>2027: \$492,680</p> <p>2028: \$935,360</p>

(add rows as necessary)

ATTESTATIONS

Please PRINT, SIGN, and SCAN this section and include it as a PDF in your project proposal submission.

Applicant name: _____

Project title: _____

Date submitted (YYYY/MM/DD): _____

By submitting this proposal, the project applicant:

1. Attests they have read and understand all the terms and conditions of the Smart Renewables and Electrification Pathways Program (SREPs) set out in this project proposal and the *Applicant Guide*.
2. Attests that, before receiving funding, the organization will be legally registered or incorporated in Canada.
3. Attests that the information provided is true and accurate to the best of their knowledge.
4. Attests that approval, from any affected parties, has been obtained to share any confidential information that is included in the project proposal.

Please note that federal reviewers are bound by the requirements of the *Access to Information Act* and the *Privacy Act* regarding the treatment of confidential information.

5. Understands that, if the project is accepted under SREPs, no liability and no obligation exists on the part of Natural Resources Canada to make a financial contribution to the project until a written contribution agreement is signed by both parties.
6. Understands that project costs presented in this project proposal must be estimated with a degree of accuracy of plus or minus 20%.
7. Agrees, by checking below, that Natural Resources Canada may share information provided with other funding agencies in cases where this may be of benefit to the project or applicant. Natural Resources Canada will safeguard personal information according to federal information protection standards under the *Privacy Act* and other applicable provincial or territorial privacy legislation of relevance.

Funding entities of the Government of Canada:

Yes, information can be shared

No, information cannot be shared

Provincial, territorial, or municipal governments:

Yes, information can be shared

No, information cannot be shared

The not-for-profit sector, such as Sustainable Development Technology Canada and the Green Municipal Fund:

Yes, information can be shared

No, information cannot be shared

Please sign below to confirm these attestations:

Signature	Date
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Name of Duly Authorized Officer for Applicant	Title
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By signing this document, the officer attests that they have provided all necessary documentation to constitute a completed project proposal and have the necessary authority to apply to the SREPs in the name of their company.

PROJECT PROPOSAL PACKAGE CHECKLIST

In addition to this application form, the supplemental documents listed below are required for a complete project proposal package.

Please complete the following checklist to confirm that your project proposal package is complete. Document file names should follow the presented file naming convention while incorporating the name of your organization.

Project Proposal Checklist	Included	Not Included	File Naming Convention
Application Form including Annexes: <ul style="list-style-type: none"> • <i>Annex A: Risks and Mitigation Measures</i> • <i>Annex B: Project Funding</i> • <i>Annex C: Key Equipment List</i> • <i>Annex D: Description of Work</i> 	<input type="checkbox"/>	<input type="checkbox"/>	00-USSD-Organization-Application
Attestations – signed PDF (2 pages)	<input type="checkbox"/>	<input type="checkbox"/>	00-USSD-Organization-Attestations
Mandatory Attachments			
1. Business case	<input type="checkbox"/>	<input type="checkbox"/>	01-USSD-Organization-Business
2. Project budget	<input type="checkbox"/>	<input type="checkbox"/>	02-USSD-Organization-Budget
3. Feasibility study or engineering report	<input type="checkbox"/>	<input type="checkbox"/>	03-USSD-Organization-EngReport
4. Project schedule	<input type="checkbox"/>	<input type="checkbox"/>	04-USSD-Organization-Schedule
5. Project diagram	<input type="checkbox"/>	<input type="checkbox"/>	05-USSD-Organization-Diagram
Optional Attachments, if applicable to the proposed project			
6. Results from studies or trials	<input type="checkbox"/>	<input type="checkbox"/>	06-USSD-Organization-StudyResults
7. Letters of support	<input type="checkbox"/>	<input type="checkbox"/>	07-USSD-Organization-SupportLetters

Any documents that you wish to include in your submission that are not listed above will require justification for inclusion and must be referenced within this application form.

Document Included	Brief Description and Justification for Inclusion	File Naming Convention
8. Document Name		08-USSD-Organization-DocName
9. Document Name		09-USSD-Organization-DocName

ATTESTATIONS

Please PRINT, SIGN, and SCAN this section and include it as a PDF in your project proposal submission.

Applicant name: GrandBridge Energy Inc.

Project title: Leveraging Demand Response and DER Integration to Address Immediate Grid Capacity Constraints

Date submitted (YYYY/MM/DD): 2025/04/02

By submitting this proposal, the project applicant:

1. Attests they have read and understand all the terms and conditions of the Smart Renewables and Electrification Pathways Program (SREPs) set out in this project proposal and the *Applicant Guide*.
2. Attests that, before receiving funding, the organization will be legally registered or incorporated in Canada.
3. Attests that the information provided is true and accurate to the best of their knowledge.
4. Attests that approval, from any affected parties, has been obtained to share any confidential information that is included in the project proposal.

Please note that federal reviewers are bound by the requirements of the *Access to Information Act* and the *Privacy Act* regarding the treatment of confidential information.

5. Understands that, if the project is accepted under SREPs, no liability and no obligation exists on the part of Natural Resources Canada to make a financial contribution to the project until a written contribution agreement is signed by both parties.
6. Understands that project costs presented in this project proposal must be estimated with a degree of accuracy of plus or minus 20%.
7. Agrees, by checking below, that Natural Resources Canada may share information provided with other funding agencies in cases where this may be of benefit to the project or applicant. Natural Resources Canada will safeguard personal information according to federal information protection standards under the *Privacy Act* and other applicable provincial or territorial privacy legislation of relevance.

Funding entities of the Government of Canada:

Yes, information can be shared No, information cannot be shared

Provincial, territorial, or municipal governments:

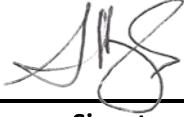
Yes, information can be shared No, information cannot be shared

The not-for-profit sector, such as Sustainable Development Technology Canada and the Green Municipal Fund:

Yes, information can be shared

No, information cannot be shared

Please sign below to confirm these attestations:



April 1, 2025

Signature

Date

Sarah Hughes

President & CEO

Name of Duly Authorized Officer for Applicant

Title

By signing this document, the officer attests that they have provided all necessary documentation to constitute a completed project proposal and have the necessary authority to apply to the SREPs in the name of their company.