Optimal Deployment of Green Hydrogen Plants in Ontario Electricity System

Part II: Feasibility Study at Keele Campus

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This project is supported by the financial contribution of the Independent Electricity System Operator (IESO), through its Hydrogen Innovation Fund. However, the views, opinions and learnings expressed in this report are solely those of the York University.

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1. Executive Summary:

This report provides a techno-economic feasibility study for the application of Green Hydrogen Plants (GHPs) to partially decarbonize the electricity system at Keele Campus of York University via phasing out its existing natural gas-powered co-generation units (Co-gens). The application of the GHP is compared to that of the Battery Storage Systems (BSSs). The feasibility study for deployment of GHPs include various applications such as energy shifting, arbitrage utilization, and provision of grid services. To that end, a detailed mathematical model is developed and coded to conduct the feasibility study. The study considers five possible operation scenarios: 1) Baseline when the campus is supplied only from the grid, 2) Grid & Co-gen, 3) Grid & BSS, 4) Grid & GHPs and 5) Grid & solar photovoltaic (PV). Historical operating data of the Keele Campus electricity demand and costs, for the period of May 2022 to May 2023, are used for simulation studies.

The study in this report aims to provide the Ontario Independent Electricity System Operator (IESO), I&C facility owners, and other stakeholders with the necessary information to make well-informed decisions regarding the investment in on-site hydrogen generation and storage plants in I&C facilities.

The key discussions and findings from this feasibility study report can be summarized as follows:

- **Grid Only**: The baseline average electric demand of Keele Campus is 7 MW during the summer and 5.8 MW during the winter, with peak loads of 16 MW in the summer and 13 MW in the winter. This demand results in an annual electricity bill of $8.67 million if supplied directly and fully by the grid. Additionally, the campus demand causes indirect GHG emissions of 3,221 tons per year from grid-supplied electricity (as per the baseline case).
- **Grid & Co-gen**: Compared to the baseline electricity cost, existing on-site co-generation units reduce the total campus annual electricity cost to $6.27 million resulting in 28% saving. The co-gens lower the electricity costs by (1) providing on-site energy at one-third the grid electricity price, and (2) reducing peak demand chargers. Environmentally, co-gens have the highest negative impact, increasing GHG emissions up to three times the baseline case, with over 85% of emissions generated directly on campus. To maximize the costs saving, the facility operator runs the co-gens at full capacity when the grid electricity prices are higher than the co-gen price and scale down when grid prices are lower.
- **Grid & BSS**: The study concludes that BSS is financially feasible at Keele Campus. BSS arbitrage against real-time pricing and maintains the campus peak within certain limits, reducing both electricity and delivery charges. Additionally, BSS helps decrease indirect GHG emissions from the grid by storing energy during off-peak times (less reliance on gas-fired engines) and discharging during peak times (reliance on gas-fired engines). However, BSS faces high storage capacity costs, making it suitable for short-term (daily) energy storage. Due to degradation at high states of charge (SoC), BSS avoids maintaining high SoC for extended periods, resulting in a higher number of charge and discharge cycles.
- **Grid & GHP**: The study concludes that deployment of GHPs, acting as on-site energy storage solution, are financially feasible at Keele Campus under certain conditions. Due to the low efficiency of P2H and H2P conversions, GHPs can only arbitrage at very low and high electricity prices to reduce electricity charges. However, thanks to the inexpensive storage capacity

(hydrogen tanks), GHPs can store large amounts of energy for extended periods, enhancing its peak reduction capabilities. Despite this, GHPs have the lowest cost-saving impact on the electricity bill due to high CAPEX and low efficiency. From the environmental perspective, both BSS and GHPs have similar impacts. However, the GHP performs fewer charge and discharge cycles compared to BSS, indicating a lower potential for degradation.

- **Grid & PV**: The study concludes that rooftop solar PV systems are financially viable for York University's Keele Campus and can significantly reduce GHG emissions by providing a source of affordable and clean energy. The cost-effectiveness of PV energy depends primarily on the system's CAPEX and lifespan; with lower CAPEX and extended lifespans, PV energy becomes more affordable than co-generation systems, delivering cleaner energy. Across various price ranges and system lifespans considered in the market, PV energy consistently proves to be more cost-effective than energy from the electric grid. Therefore, PV systems stand out as a strong solution for advancing decarbonization efforts at Keele Campus.
- Providing grid services in the form of Demand Response (DR) improves the financial aspects of both BSS and GHP without impacting GHG emission levels. However, both systems perform more charge and discharge cycles during participation in DR. This increased activity is due to the need to prepare for DR activation by storing energy and then discharging during the activation periods, which accelerates the rate of degradation.
- Unlike BSS, GHPs can supply hydrogen to the market and meet hydrogen demand for several applications such as hydrogen powered vehicles. The results show that the minimum hydrogen selling price to make the investment in GHPs financially feasible is \$5.7/kg. The results also show that at hydrogen price of \$7/kg, the GHP outperforms BSS in cost savings. The results are yielded assuming the on-site GHP supplies a hydrogen refueling station with an average of 600 kg/day. It is noteworthy that this result is contingent on the demand for hydrogen materializing as projected. If hydrogen offtakes do not emerge or the demand for hydrogen is lower than anticipated, the financial viability of the GHP option could be at risk. The costs associated with the underutilization of the system should be quantified and accounted for, as the GHP could face financial losses if it is unable to secure sufficient hydrogen offtakes. This risk should be considered when evaluating the long-term profitability of the GHP solution.

1.1 Report Organization

After the executive summary, this report is structured into five sections investigating the five operating scenarios (Baseline, Grid & Co-gen, Grid & BSS, Grid & GHP, and Grid & PV). Section 2 introduces the Keele campus, detailing its system structure, electrical demand, and electricity bill components. It also discusses the contributions of the co-gen units, highlighting their environmental and financial impacts when compared to the baseline. Additionally, the section provides an in-depth understanding of the challenges faced by the campus and outlines future directions for York University to decarbonize its campus. Section 3 explores the financial and environmental impacts of utilizing the BSS instead of co-gens, highlighting the associated benefits and drawbacks. Additionally, this section examines the potential for the BSS to provide grid services, such as DR, to propel its financial outcomes. Section 4 discusses the potential of using a GHP, comprising an electrolyzer, fuel cell, and hydrogen storage tank, to reduce dependence on co-gens. It also explores the financial and environmental impacts of utilizing the GHP instead of co-gens, highlighting the associated benefits and drawbacks. Additionally, it examines the potential for participation in DR grid services and the hydrogen market by selling the produced hydrogen to other sectors such as transportation and industrial facilities. In section 5, a comparison between the performance of the BSS and the GHP, highlighting the advantages and disadvantages of each solution is provided. The section presents a sensitivity analysis to shed the light on the impacts of GHPs design parameters on the financial and environmental outcomes. Section 6 highlights the role of PV systems and their integration with BSS and GHP. It discusses the potential rooftop PV capacity along with the financial and environmental impacts of implementing PV systems.

2. Keele Campus Energy Profile

Keele is the main campus of York University, located in the North York district of Toronto, Ontario, Canada. Covering approximately 1 square kilometer, it is bounded by Jane Street to the west, Keele Street to the east, Steeles Avenue West to the north, and Finch Avenue West to the south. As the largest post-secondary campus in Canada, it spans 457 acres (185 hectares) and includes around 100 buildings, including libraries, student centers, and both graduate and undergraduate residential buildings. The campus hosts approximately 55,700 students and 7,000 faculty and staff.

This section offers an overview of the Keele's campus electricity system, along with the collected information necessary for conducting the feasibility analysis. It includes details about the required parameters and the sources from which the relevant data was gathered. Additionally, the section covers the process of electricity bill calculation at Keel campus under two operating scenarios: baseline without local generation and storage (Grid only) and when the existing co-gens are running (Grid & Co-gen). The purpose of this section is to furnish readers with a comprehensive understanding of the problem's context and formulation, facilitating comprehension of the key calculations and procedures involved. Additionally, it discusses the financial and environmental impacts of the existing co-generation units.

2.1 Electricity Demand at Keele Campus

Figure 1 depicts the system configuration of the baseline scenario (without local generation and storage) for the Keele Campus. The campus receives power from Toronto Hydro through a dual parallel power source system, each with a capacity of up to 26 MVA. The average electrical demand of the campus is 7 MW during the summer and 5.8 MW during the winter, with maximum recorded loads of 16 MW in summer and 13 MW in winter.

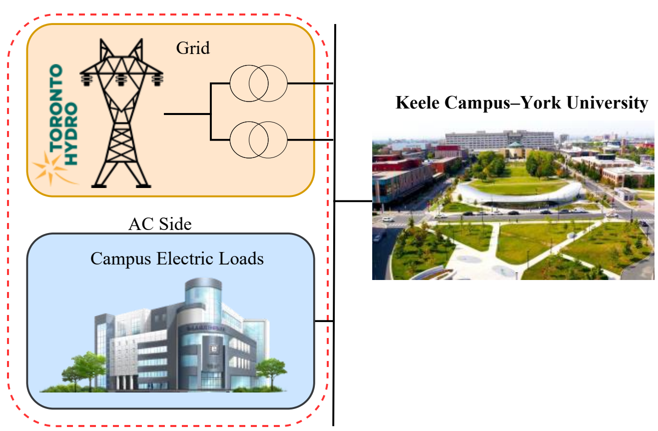
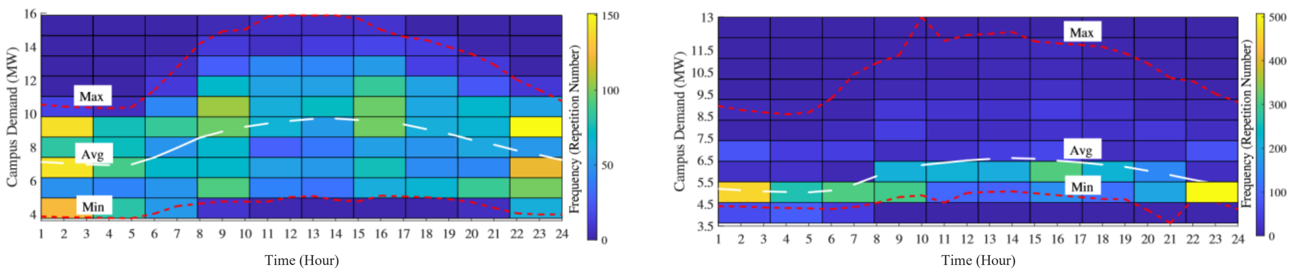


Figure 1| Keele Campus Supplied from Toronto Hydro Substations

Table 1 | Minimum, maximum, and average power demand during the studied period

Month	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Year	2022	2022	2022	2022	2022	2022	2022	2022	2023	2023	2023	2023	2023
Maximum Demand (MW)	15.01	15.87	13.94	13.76	10.99	12.55	11.89	8.87	6.7	8.94	6.72	9.56	12.99
Minimum Demand (MW)	7.07	8.45	4.99	3.74	4.29	4.32	4.3	4.27	4.52	4.46	4.48	4.49	3.63
Average Demand (MW)	10.23	11	8.61	7.7	6.16	6.51	5.97	5.34	5.28	5.29	5.4	5.6	7.9



(a) Campus Summer load profile

(b) Campus Winter load profile

Figure 2| Keele Campus Load Profiles in the duration of May-2022 until May-2023.

Figure 2 above depicts the hourly campus load profile and its frequency of occurrence during both Summer and Winter in the period of May 2022 to May 2023. The horizontal axis (x axis) represents the time of day, the vertical axis (y axis) shows the possible demand values at each hour of the day, and the color pars indicate the frequency of occurrence for each power demand range at each hour of the day. As depicted in the figure, the power demand starts to gradually increase from 6:00 AM and reaches its peak between 12:00 PM- 5:00 PM in most of the days.

Table 1 presents the maximum, minimum, and average power demands in MW for each month of the studied period. It is observed that the difference between the maximum and minimum loads is higher during the summer season compared to winter, indicating greater variance and higher demand during certain periods.

2.2 Electricity Bill Breakdown

Gaining insight into various components of the electricity bill paid by York University is crucial for assessing the extent of electricity bill reduction and possible cost saving from the installation of the co-gens, BSS, and GHPs. With the installation of distributed energy resources, York University will be empowered to generate cheaper electricity onsite or store electric energy during periods of low market prices and utilize it during times of high market prices. This approach serves to 1) decrease the cost of energy supplied to the campus and 2) mitigate the peak load on the campus, ultimately leading to the reduced electricity expenses, as elaborated in this sub-section.

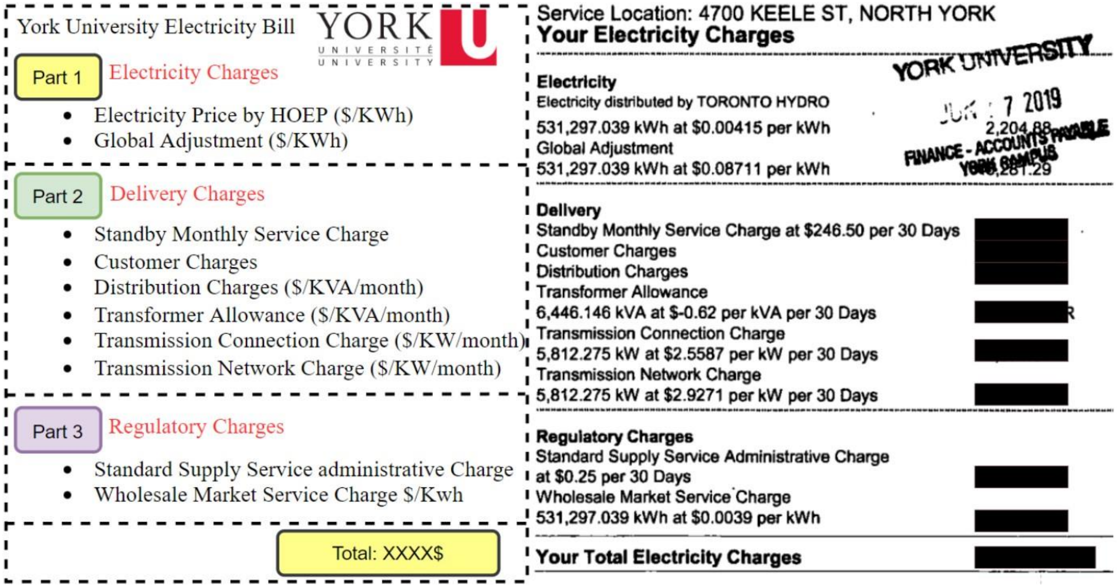


Figure 3| York University Electricity Bill Structure.

Figure 3 shows the Keele campus electricity bill breakdown. This electricity bill represents the "Interval meter sample bill" from Toronto Hydro for electric demand higher than 50 KW. The bill comprises three main parts.

The first part is the electricity charges, representing the cost of the electric energy consumed by the campus. This part of the bill comprises two main components including hourly Ontario energy prices (HOEPs) and global adjustment (GA) fees. The mathematical expression of the electricity charges is given by equation (1).

$$Electricity{\sim}Charges = \sum_{t=1}^{T_{month}} P_{grid}(t) \times \mathrm{HOEP}(t) + \sum_{t=1}^{T_{month}} P_{grid}(t) \times GA(t) \quad (1)$$

The second part of the electricity bill is the GA charges, primarily determined by the peak apparent power and active power consumption of the campus during a month. This section reflects the campus's contribution to the overall burden on Ontario's electricity system. The delivery charge comprises six components as follows:

1) Standby Monthly Service Charge (fixed term per month).

2) Customer Charges (approximately fixed value around $4400-4600/month).

3) Distribution Charges ($7.2/KVA/month $\times Peak_{apparent}\, KVA$).

4) Transformer Allowance ($0.62/KVA/month $\times Peak_{apparent}\, KVA$).

5) Transmission Connection Charge ($2.5587/KW/month $\times Peak_{active}\, KW$).

6) Transmission Network Charge ($2.9271/KW/month $\times Peak_{active}\, KW$).

Table 2 | Delivery Charge Components

Term	Equation ($/Month)
$P_{peak} = max(P_{grid}(t), \sim\forall t \in T_{month}), S_{peak} = \frac{P_{peak}}{P.F = 0.9}$	
Standby Monthly Service Charge	$254.72 (constant)
Customer Charges	$4,500 (approximately Constant)
Distribution Charges	$7.2×$S_{peak}(KVA)$
Transformer Allowance	$0.62×$S_{peak}(KVA)$
Transmission Connection Charge	$2.5587×$P_{peak}(KW)$
Transmission Network Charge	$2.9271×$P_{peak}(KW)$

To calculate the peak apparent power of the campus, the average power factor of 0.9 lagging is used after estimating the peak active power. Table 2 provides a summary of the values and mathematical equations for the components of the delivery charges. The cost coefficients in the table are estimated based on the historical bill charges provided for the fiscal year 2019-2020.

The third part of the electricity bill comprises the regulatory charges, consisting of two components. The first component is the Standard Supply Service Administrative Charge, which remains constant at $0.26/ month. The second component is the Wholesale Market Service Charge, which amounts at $0.0039 /kWh consumed. The calculation for regulatory charges can be accomplished using Equation (2).

$$RegulatoryCharges = 0.0039 \frac{\$}{Kwh} \sum_{t=1}^{T_{month}} P_{grid}(t) + 0.2 \quad (2)$$

The total electricity bill is computed by summing the electric power costs of the three main parts of the bill along with other components considered in the analysis [1].

2.2.1 Cost and Environmental Analysis for the First Scenario (Baseline)

Table 3 presents the monthly electricity bill breakdown for the baseline Scenario where the total campus load is supplied only from the power grid. To meet its electricity needs exclusively from the power grid, York University incurs an annual bill of approximately $8.68 million. Of this total, 74% is allocated to the electricity/energy charge component, 23% to the delivery charge, and 3% to the regulatory charge, as illustrated in Figure 4. In this baseline scenario, the electricity grid generates around 3,221 ton of GHG emissions during the year. This value is calculated based on the contribution of generation power utilized by the IESO during each hour (more information about the method of calculation is given in Appendix C of this report).

Table 3 | Keele Campus Electricity Bill Breakdown for the Baseline Scenario

Month	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Year	2022	2022	2022	2022	2022	2022	2022	2022	2023	2023	2023	2023	2023
Consumption (GWh)	7.61	7.92	6.41	5.73	4.43	4.84	4.3	3.97	3.93	3.55	4.02	4.03	5.88
Peak Load (MW)	15.01	15.87	13.94	13.76	10.99	12.55	11.89	8.87	6.7	8.94	6.72	9.56	12.99
Electricity Charge (K$)	896.81	920.11	632.16	511.59	422.49	494.77	435.45	351.15	344.69	375.25	423.33	481.64	686.88
Delivery Charge (K$)	217.64	229.71	202.44	199.88	160.62	182.78	173.36	130.58	99.84	131.49	100.04	140.32	188.94
Regulatory Charge (K$)	29.69	30.9	24.99	22.35	17.3	18.9	16.77	15.49	15.33	13.87	15.69	15.73	22.94
Total Electricity Bill (K$)	1144.14	1180.73	859.6	733.83	600.42	696.46	625.58	497.23	459.88	520.62	539.06	637.7	898.77
GHG From Grid (Ton)	323.37	344.77	424.1	390.81	260.7	277.16	210.66	271.81	227.09	167.6	194	152.02	244.78

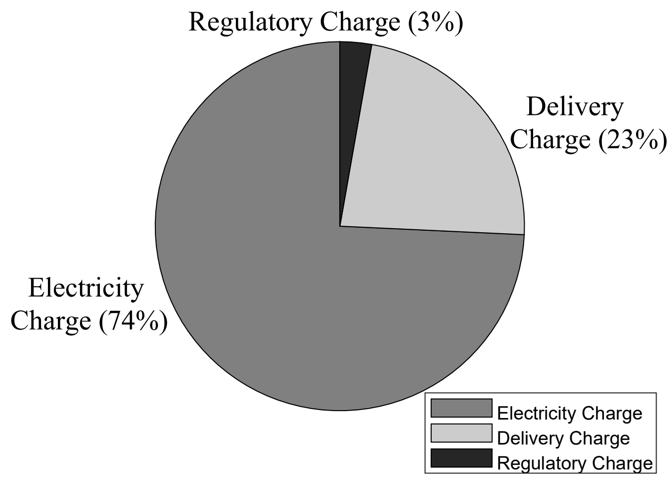


Figure 4| Campus Electricity Bill Breakdown for the Baseline Scenario.

2.2.2 Cost and Environmental Analysis for the Second Scenario (Grid & Co-gens)

To improve the financial aspect and mitigate high electricity bills, York University has two on-site co-generation units (Co-gens) on campus. These units reduce the energy provided by the electric grid and are also used for heating water within the campus. Figure 5 shows the system structure with the Co-gens in place, while Table 4 provides detailed information about these Co-gens. Both Co-gens together can provide a total rated power of up to 10.4 MW, though only 38% (3.95 MW) are used for electricity purposes while other remaining 62% is used for water heating purposes. Each MWh of energy produced on-site costs approximately $29.91 in fuel and generates about 0.36 tons of GHG emissions. The capital and maintenance costs for each Co-gen are around $775,000, covering both electricity generation and water heating purposes, and only 38% of this cost is included in the analysis to represents the focus of this study on the Co-gen electric contribution. The mathematical modeling discussed in Appendix B is utilized in this study to yield the optimal management of the Co-gens and the maximum cost-saving achieved compared to the baseline. It is noted that the model takes the carbon taxes for the years of 2022 and 2023 into account, i.e., is $30 and $40 per ton, respectively. The optimization problem is solved using the Gurobi optimizer and covers the entire 13-month period of the study considering a simulation step of one hour.

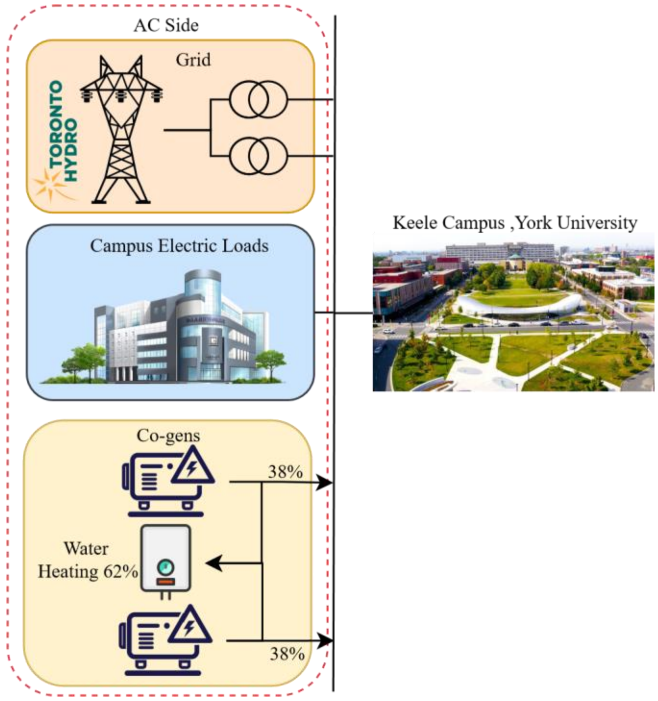


Figure 5| Existing Keele Campus System Structure with Co-gens (Scenario 2)

Table 4 | Information about the Campus Co-generation units

Name	Duration	Type	Importance	Value
Number of Co-gen units	2022	Private	High	2
Co-gen rates	2022	Private	High	5.2 MW
Electric Load share percentage	2022	Private	High	38%
Operation limits (Max., Min) rate	2022	Private	High	5.2 MW, 2.3MW
Fuel Cost $/MWh	2022	Private	High	29.91
Generated GHG ton/MWh	2022	Private	High	0.3557
Capital +Maintenance cost $/Year	May 2022-2023	Private	High	775,000
Maintenance Period	May 2022-2023	Private	High	3 weeks per year
Historical scheduling profile	May 2022-2023	Private	High	NA
Co-gen Carbon Tax $/ton	2023	Private	High	(2023:50$,2022:40$,2021:30$ 2020:20$,2030:270$)

Table 5 | Cost and Environmental Breakdown for the Second Scenario (Grid & Co-gens)

Month	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Year	2022	2022	2022	2022	2022	2022	2022	2022	2023	2023	2023	2023	2023
Energy From Grid (GWH)	4.672	5.078	3.5	3.071	1.753	1.907	1.454	1.169	0.992	0.9	1.083	1.189	2.944
Peak Load (MW)	11.06	11.91	9.99	9.81	7.04	8.6	7.94	4.92	2.75	4.98	2.77	5.61	9.04
Total Electricity Bill (K$)	737.45	790.64	506.02	421.94	280.73	329.09	273.44	176.63	136.44	174.96	162.61	231.97	489.72
Energy From Co-gens (GWH)	2.94	2.845	2.909	2.661	2.684	2.94	2.845	2.803	2.94	2.655	2.94	2.845	2.94
Fuel Cost (K$)	87.94	85.1	87.02	79.59	80.29	87.94	85.1	83.85	87.94	79.43	87.94	85.1	87.94
Carbon Tax (K$)	52.29	50.6	51.74	47.32	47.74	52.29	50.6	49.86	52.29	47.23	52.29	50.6	52.29
Co-gens CAPEX and OPEX (K$)	164.77	160.25	163.3	151.46	152.58	164.77	160.25	158.26	164.77	151.2	164.77	160.25	164.77
Total Cost (K$)	902.23	950.9	669.32	573.4	433.31	493.87	433.69	334.89	301.22	326.17	327.39	392.22	654.5
Cost Saving With Respect to The Baseline Case (K$)	241.91	229.83	190.28	160.43	167.11	202.59	191.89	162.34	158.66	194.45	211.67	245.48	244.27
GHG From Grid (Ton)	204.16	227.6	237.21	207.05	110.18	110.4	72.32	74.64	60.65	43.95	53.88	47.23	125.76
GHG From Co-gens (Ton)	1045.86	1012.12	1034.88	946.54	954.89	1045.86	1012.12	997.25	1045.86	944.64	1045.86	1012.12	1045.86
Total GHG (Ton)	1250.02	1239.73	1272.09	1153.6	1065.07	1156.26	1084.44	1071.9	1106.51	988.59	1099.74	1059.35	1171.62

Table 5 presents the electricity costs and GHG emissions when Co-gens are running. As shown in the table, the installation of Co-gens reduces the total annual electricity bill from $8.68 million to $4.35 million, resulting in cost savings of approximately $4.33 million per year. However, the CAPEX and OPEX of the Co-gens add an additional cost of $2.08 million per year (38% of the total installation and running cots, fuel cost and carbon tax), leading to a net cost saving of $2.41 million, i.e., 28%. These savings are primarily due to the reduction in peak load, which lowers the demand charge and allows energy generation from Co-gens at a cheaper rate of around $56/MWh compared to the average grid price of $162/MWh. Figure 6 shows the share percentage of each cost component between the electricity bill and the co-gens. As depicted, the co-gens provide significant cost saving to the electricity bill. However, from the environmental side, the co-gens increase the GHG emissions from 3,221 tons in the baseline to 13,587 tons per year, representing an approximately 300% rise. Figure 7 presents the energy contributions of both the co-gens and the power grid to the campus and their respective impacts on the GHG emissions. As shown, the Co-gens supply approximately 60% of the total campus electrical demand due to their cost-effective energy production, operating nearly 24/7. Despite providing 60% of the campus's electric energy, Co-gens are responsible for about 90% of the GHG emissions for the electrical demand. Hence, it is essential to find a solution to phase out the co-gens or reduce its operating hours to decarbonize Keele campus.

Figure 8 shows the optimal operation dispatch of the existing co-gens in response to the changes on the grid electricity prices over the studied period. As shown, the optimization algorithm devises a straightforward plan where co-gens operate at full capacity when the grid HOEP+GA ($/MWH) exceeds the average MWh cost of the Co-gens. Conversely, their output is minimized to the lower limits set by the management team when prices are lower.

2.2.3 Keele Campus Decarbonization Initiative

The current saturation of GHG levels compels York University to take immediate action to reduce its dependence on the Co-gens. Starting Fall 2024, the university's operation and management team will prioritize GHG reduction, placing less emphasis on financial aspects. As a result, the number of operation hours for Co-gens will be limited to 500, down from 8,500 hours this year. This is projected to reduce CO_2 levels by 84.7%, but it will also increase the annual electricity bill by $1.95 million.

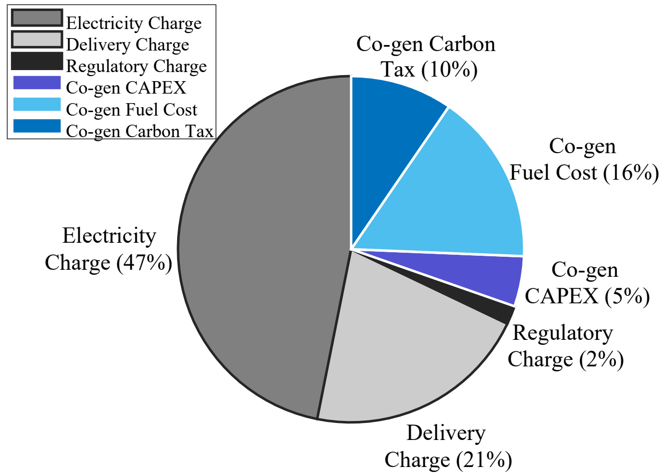


Figure 6| Power Utility Charges and Co-gen Annual Cost Distribution.

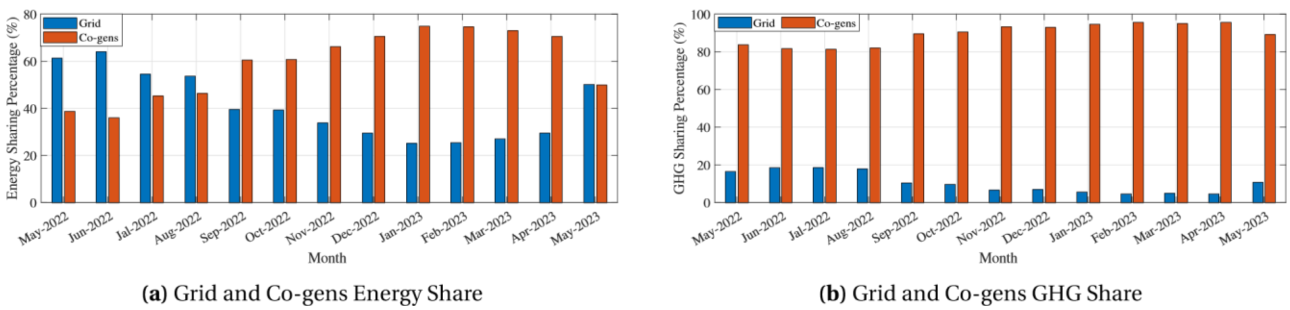


Figure 7| Energy and GHG Contributions of both Grid and Co-gens.

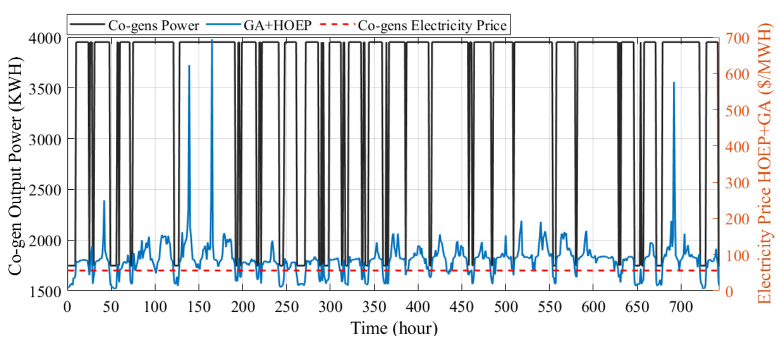


Figure 8| Co-gen Output Power Based on an Optimal Scheduling Strategy

Therefore, integrating short and long-term storage units, such as BSS and GHP, alongside PV are currently investigated to facilitate a smooth Co-gen shutdown, enhancing environmental sustainability, and mitigating negative financial impacts. The following sections will discuss the integration of these short and long terms energy storage systems and outline the possible pathways of the campus energy decarbonization.

3. Deployment of Battery Energy Storage System

This section investigates the role of BSS in reducing the total electricity bill of Keele campus if Co-gens are fully phased out. It also explores the potential of using the BSS to provide grid services in the form of DR to further enhance the cost savings. Figure 9 depicts a schematic diagram of Keele Campus with the integration of BSS. As shown, the BSS is connected to the campus AC system via a Bi-directional Power Conversion System (PCS). The primary role of the BSS is to reduce the electricity bill by avoiding high peaks, thus lowering the high delivery charges, and acting as an arbitrage agent against real-time pricing (HOEP) to reduce the electricity charge.

Obtaining accurate information regarding the costs of deploying BSS on campus is crucial for a detailed assessment. This includes the cost of the BSS system itself, the expected lifetime of the system, and the installation and maintenance costs associated with its implementation. In this study, different BSS models are adopted from the market to estimate the average cost, efficiency, and lifespan of the project. Table 6 provides a summary of essential details for both the BSS and PCS components, along with their corresponding costs and operating parameters.

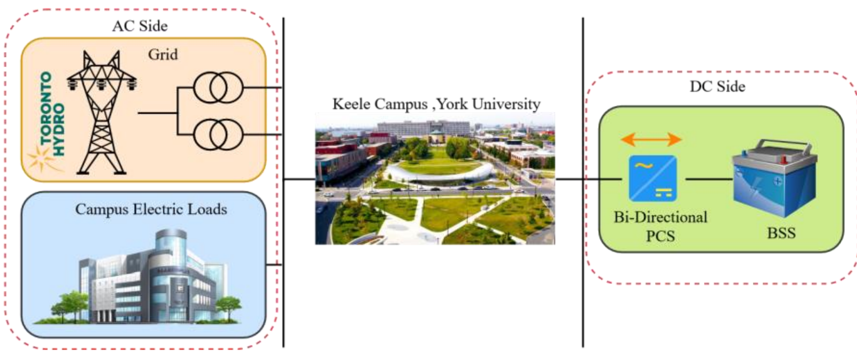


Figure 9| Schematic Diagram of Keele Campus with BSS Integration.

Table 6| Required Information of BSS and PCS [3-6]

Name	Duration	Type	Importance	Value
BSS and PCS Installation Cost	2023	Public	Medium	\$10K/lifetime
BSS and PCS Capital Cost	2023	Public	Medium	\$200/KWh (BSS) \$470/KW (PCS)
BSS and PCS Maintenance Cost	2023	Public	Medium	\$11.31k/year
BSS and PCS life-time	2023	Public	Medium	20 years with warranty
BSS Charge and Discharge Efficiency	2023	Public	Medium	92%
BSS Degradation Model	2023	Public	Medium	Discussed in Appendix B
PCS efficiency	2023	Public	Medium	92%
Candidate Location for Points of Connection	2023	Private	Medium	If 600V, 800A per breaker pf. 95% and 80% loading (630 KW per breaker)
Candidate Location for Points of Connection	2023	Private	Medium	If 13.8 KV, 1200A per breaker pf. 95% and 80% loading (5MW per breaker)

3.1 Electricity Bill with BSS Integration

To find the optimal design for the BSS size and PCS rate, the optimization problem detailed in Appendix B is solved using the Gurobi optimizer. The BSS size and PCS rated power are set to range from 0.5 MWh to 20 MWh and 0.5 MW to 5 MW, respectively, with increments of 0.25 MWh/MW. The optimization model yielded 14.5 MWh for the BSS size, and 3.25 MW for the PCS rated power.

Table 7 presents the economic and environmental results of the campus electricity with consideration of the BSS. Figure 10 shows the share percentage of each cost component between the electricity bill and the BSS. The results show that the installation of the BSS reduces the total annual electricity bill from \$8.68 million to \$8.25 million, resulting in cost savings of approximately \$430 thousand per year. However, the CAPEX and OPEX of the BSS add an additional cost of \$252 thousand per year, leading to a net cost saving of \$178 thousand per year, i.e., only 2%. These savings are primarily due to the reduction in peak load, which lowers the demand charge, and arbitrage against real-time pricing. The last row in the table shows the number of charge and discharge cycles of the BSS completed each month, indicating the level of degradation in its lifetime. Overall, the BSS completed approximately 1,090 cycles in the studied year. BSS, however, helps reduce the indirect GHG emissions from the grid, by providing power to the campus at peak times, which reduces the dependence on the grid gas fired generation. The BSS reduced the annual GHG from 3,221 tons to 3,162 tons compared to the baseline, and by 76% compared to the case with Co-gens in place.

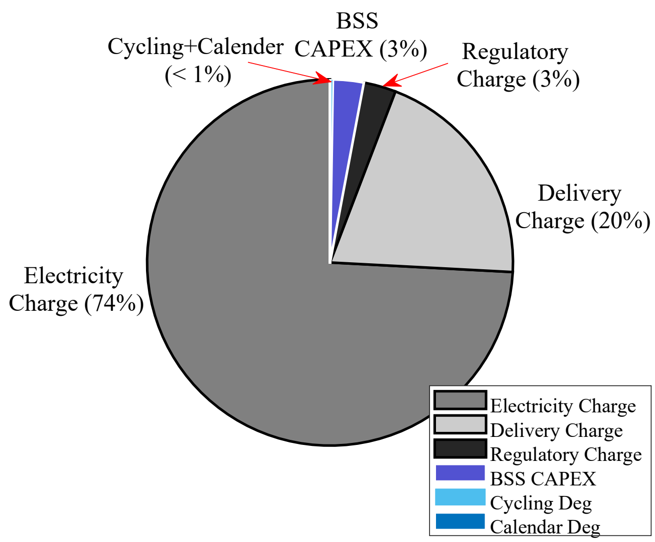


Figure 10| Electricity Bill and BSS Annual Cost Distribution.

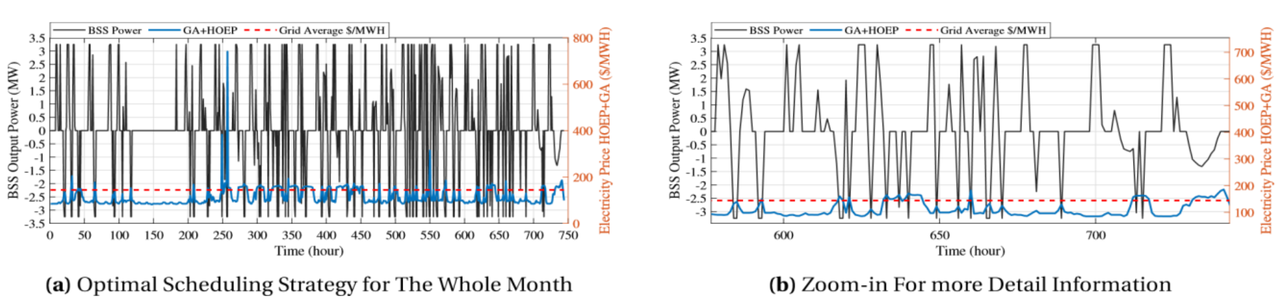


Figure 11| BSS Output Power Management and Optimal Scheduling Strategy.

Table 7| Cost and Environmental Breakdown for Scenario 3 (Grid & BSS) without DR

BSS=14.5MWH, PCS=3.25MW													
Month	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Year	2022	2022	2022	2022	2022	2022	2022	2022	2023	2023	2023	2023	2023
Energy From Grid (GWH)	7.67	7.98	6.46	5.8	4.5	4.9	4.35	4.03	3.96	3.59	4.05	4.06	5.91
Peak Load (MW)	13.7	14.31	10.72	11.35	9.62	10.24	10.7	7.98	5.81	7.55	5.72	7.27	10.73
Total Electricity Bill (K$)	1108.97	1142.81	801.11	669.92	564.64	653.07	600.04	468.52	443.89	497.23	524.39	600.3	865.08
BSS Calendar Cost ($)	8.33	10.07	13.41	13.12	6.3	3.55	1.92	1.49	0.9	0.89	1.44	2.79	5.65
BSS Cycling Cost (K$)	1.92	1.91	1.99	2.24	1.87	1.76	1.73	1.84	1.51	1.44	1.6	1.49	1.53
BSS CAPEX and OPEX (K$)	21.16	21.16	21.24	21.49	21.12	21.01	20.97	21.08	20.75	20.68	20.84	20.73	20.77
Total Cost (K$)	1130.14	1163.97	822.35	691.41	585.76	674.08	621.02	489.6	464.65	517.91	545.24	621.04	885.86
Cost Saving With Respect to The Baseline Case (K$)	14	16.76	37.25	42.42	14.66	22.38	4.56	7.63	-4.77	2.71	-6.18	16.66	12.91
GHG From Grid (Ton)	319.53	338.77	414.29	378.32	255.03	272.82	206.74	267.48	222.78	165.57	192.89	150.51	241.63
Charge and Discharge Cycle	109	95	99	135	127	107	97	101	65	69	61	73	43

Figure 11 above illustrates the optimal scheduling and management strategy yielded from the solution of the optimization problem. As shown, the BSS charges when the electricity prices are low and discharges when the prices exceed the average value, to arbitrage against real-time pricing. Additionally, the BSS discharges during peak load times to keep the peak value below a certain limit throughout the month, thereby avoiding high delivery charges. Figure 11b presents the BSS cycling behavior in the last week of May 2022. As the month progresses and summer approaches, peak values on campus start to rise due to increased temperatures and the use of cooling systems. To avoid high delivery charges from these elevated peaks at the end of the month, the BSS discharges in a distributed manner to prevent peak values from exceeding a certain limit. This behavior, where the BSS charges and discharges in a distributed manner to manage peaks, is not observed throughout the month. In normal days, the BSS typically charges and discharges for arbitrage during periods of low demand. Moreover, the figure shows how frequently the BSS charges and discharges within the same day, performing around three cycles daily.

3.2 Utilization of BSS for Electricity Bill Reduction and Provision of DR

To propel the economic viability of the BSS there is a need to utilize it for the provision of grid services. This section revises the analysis carried out in the previous subsection when BSS participates in the provision of DR service. The mathematical formulation of the DR is incorporated into the general optimization problem as discussed in Appendix C. The DR activation signals are selected based on the three days with the highest grid generation levels (indicating the grid's need for energy due to high demand). Each activation is set for four consecutive hours.

Table 8 shows the performance of the BSS when participating in DR programs. The annual operating cost decreased from \$8.5 million to \$8.33 million per year. Participating in the DR programs provides an incentive payment of \$170 thousand per year, i.e., additional 2% cost saving. Other parameters, such as peak load and electricity bill, remain almost the same. However, the number of charge cycles increased to 1,105 cycles per year (1.37% increase). This is due to the need to charge before the DR event and discharge during the DR activation, increasing the overall cycling frequency.

Figure 12 shows the optimal scheduling and management strategy of the BSS when it participates in DR. During normal operation without DR activation, the BSS charges and discharges based on the load profile peaks and real-time prices, as discussed previously. However, Figure 12b depicts the BSS behavior during a DR event. Before the DR event, the BSS charges up to 90% of the SOC (the upper limit allowed). During the DR event, the BSS discharges at a constant power equal to: $C_B.\eta^{PCS} \times \frac{\overline{SoC}-\underline{SoC}}{DR\_Window}$.

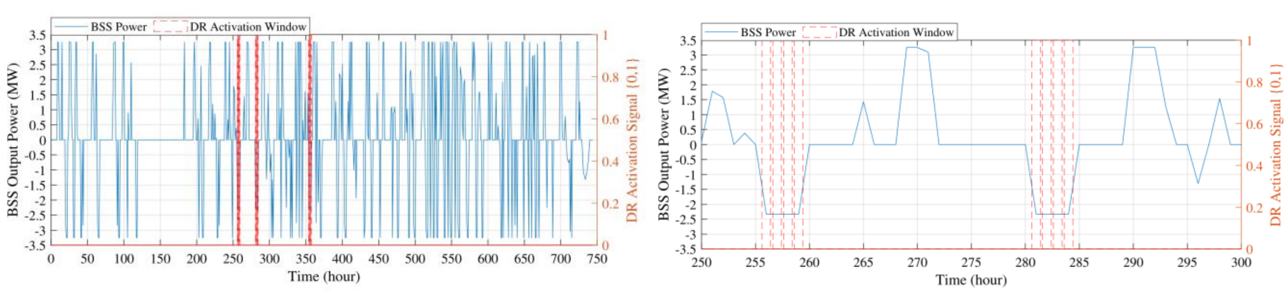
This strategy ensures that the minimum power reduction during the DR events is uniform and thus maximizing the payment from participating in DR. Since DR events pay based on the lowest DR participation level (power reduction), ensuring a uniform power discharge maximizes the minimum power reduction.

It is important to highlight that the DR clearing price used in this study is estimated using a linear regression model based on projected DR prices for the 2025/2026 period. While this price affects only the expected DR payment and total cost rows, it does not impact the optimal scheduling, or the parameters presented in Table 8. The recalculation of these two values involves adjusting the DR payment according to the ratio of the new to old clearing price and updating the total cost by subtracting the old DR payment and adding the new DR payment at the updated clearing price.

Table 8 | Cost and Environmental Analysis for Scenario 3 when BSS Participates in DR

BSS=14.5MWH, PCS=3.25MW, DR Payment 600$/MW/Business Day

Month	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Year	2022	2022	2022	2022	2022	2022	2022	2022	2023	2023	2023	2023	2023
Energy From Grid (GWH)	7.67	7.98	6.46	5.8	4.5	4.9	4.35	4.03	3.96	3.59	4.05	4.06	5.91
Peak Load (MW)	13.7	14.31	11.28	11.35	10.77	10.24	10.7	7.98	5.81	7.55	5.72	7.27	10.73
Total Electricity Bill (K$)	1109.7	1143.27	808.55	670.54	580.97	653.18	600.04	468.52	443.89	497.23	524.39	600.3	865.26
BSS Calendar Cost ($)	8.5	10.07	13.41	13.12	6.3	3.55	1.92	1.49	0.9	0.89	1.44	2.79	5.65
BSS Cycling Cost (K$)	1.96	1.93	2.04	2.23	1.93	1.79	1.73	1.84	1.51	1.44	1.6	1.49	1.57
BSS CAPEX and OPEX (K$)	21.21	21.18	21.29	21.49	21.17	21.04	20.97	21.08	20.75	20.68	20.84	20.73	20.81
DR Power Reduction (MW)	2.34	2.34	1.88	2.34	2.34	2.34	-0.21	-1.29	-0.64	-0.76	-0.54	-0.91	2.34
DR Payment (K$)	-32.22	-30.82	-25.93	-32.22	-30.82	-32.22	0	0	0	0	0	0	-32.22
Total Cost (K$)	1098.7	1133.64	803.92	659.81	571.33	642	621.02	489.6	464.65	517.91	545.24	621.04	853.86
Cost Saving With Respect to The Baseline Case (K$)	45.44	47.09	55.68	74.02	29.09	54.46	4.56	7.63	-4.77	2.71	-6.18	16.66	44.91
GHG From Grid (Ton)	319.46	338.82	414.18	378.31	255.04	272.55	206.74	267.48	222.78	165.57	192.89	150.51	241.54
Charge and Discharge Cycle	111	95	101	135	133	107	97	101	65	69	61	73	49



(a) Optimal Scheduling Strategy for The Whole Month

(b) Zoom-in For DR Events scheduling and Operation

Figure 12 | BSS Output Power Management and Optimal Scheduling Strategy During DR Events

4. Deployment of Green Hydrogen Plant

This section studies the costs of electricity at Keele Campus when GHP is deployed. The study discusses the capability of GHPs to 1) provide peak reduction and arbitrage against real-time pricing, 2) participate in the provision of grid services in the form of DR, and 3) supplying 600 kg of hydrogen to application such as hydrogen refueling stations.

Figure 13 shows a schematic diagram of Keele Campus with the integration of GHP. As shown, the GHP comprises three main elements: 1) an electrolyzer that converts power to hydrogen (P2H), 2) a fuel cell that converts hydrogen to power (H2P), and 3) a hydrogen tank that stores the generated hydrogen for either fuel cell uses or to meet a pre-specified hydrogen demand. Both the electrolyzer and fuel cell are associated with unidirectional converters. The GHP's hydrogen demand is represented by a hydrogen refueling station with a daily demand of 600 kg. The primary roles of the GHP are to reduce the electricity bill by avoiding high peaks and thus lowering delivery charges–acting as an arbitrage agent against real-time pricing (HOEP) to reduce electricity charges, provide grid services, and meet the hydrogen demand.

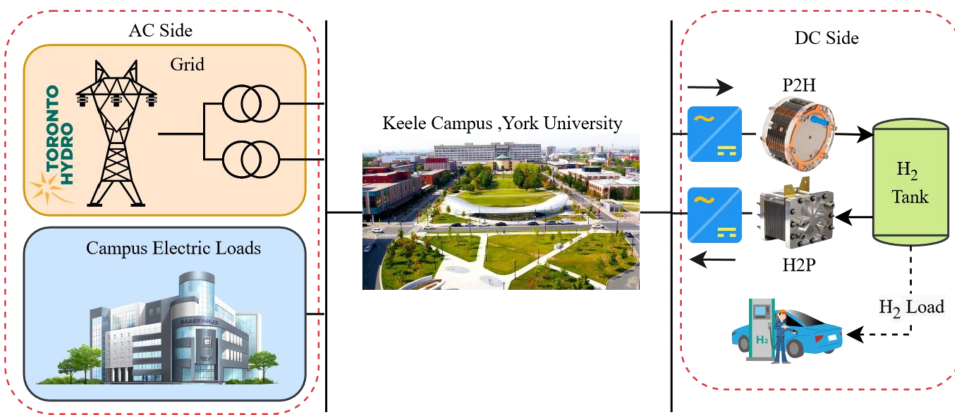


Figure 13 | Structure of Keele Campus with GHP Integration (Scenario 4).

Table 9 | Required Information of the GHP [7-9]

Name	Duration	Type	Importance	Value
Electrolyzer Capital and Operation Cost	2023	Public	Medium	\$850/KW
Fuel Cell Capital and Operation Cost	2023	Public	Medium	\$540 /KW
Electrolyzer Efficiency	2023	Public	Medium	60%
Fuel Cell Efficiency	2023	Public	Medium	50%
H_2 Tank Capital and Operation Cost	2023	Public	Medium	\$33.37/m^3
H_2 Tank Dissipation Factor	2023	Public	Medium	0.006%
Hydrogen System Life Span	2023	Public	Medium	12 years

Information related to the hydrogen system encompasses the capital, operational, and maintenance costs of the electrolyzer, hydrogen tank, and fuel cell. Additionally, it includes factors such as the hydrogen tank's dissipation and the project's lifetime. Table 9 provides the information of the GHP.

4.1 Cost and Environmental Analysis with GHP Integration

To determine the optimal design for the GHP electrolyzer and fuel cell rated power, as well as the hydrogen tank size, the optimization problem detailed in Appendix B was solved using the Gurobi optimizer. The electrolyzer and fuel cell size rates were set to range from 0.5 MW to 5 MW, with increments of 0.25 MW. The tank size range was set from 1,000 to 20,000 m^3. The optimal design was found to be 0.5 MW for the electrolyzer, 2 MW for the fuel cell, and 12,000 m^3 for the hydrogen tank when no hydrogen demand was considered. When the hydrogen demand was represented by a hydrogen refueling station with a daily demand of 600 kg, the optimal design changed to 2 MW for the electrolyzer and 1.5 MW for the fuel cell, while the hydrogen tank size remained the same. The increase in the electrolyzer size is due to the additional demand that needs to be met by the GHP.

Table 10 presents an analysis of the system with the GHP installed. As shown, the GHP installation reduces the total annual electricity bill from $8.68 million to $8.44 million, resulting in cost savings of approximately $240,000 per year. However, the CAPEX and OPEX of the GHP add an additional cost of $158,780 per year, leading to a net cost saving of $81,260, i.e., 0.9% saving. These savings are primarily due to the reduction in peak load, which lowers the demand charge, and arbitrage against real-time pricing. The last row shows the number of cycles the GHP completed each month, indicating the level of degradation in its lifetime. Overall, the GHP completed approximately 125 cycles per year, which is almost 9 times fewer than the BSS. Figure 14 shows the share percentage of each cost component between the electricity bill and the GHP. Financially, the GHP is slightly above its break-even. From an environmental standpoint, the GHP causes indirect GHG emissions of 3,229 tons per year, resulting in an increase of the GHG emissions compared to the baseline due to its lower efficiency compared to the BSS. The increased energy consumption from the grid, due to losses in hydrogen generation, leads to higher indirect GHG emissions. However, compared to the Co-gens, the GHP helps in reducing approximately 74% of the GHG emissions.

Table 10| Cost and Environmental Analysis Breakdown for Scenario 4 (Grid & GHP)

Electrolyzer=0.5MW, Fuel Cell=2MW, Hydrogen Tank= 12,000 m3

Month	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Year	2022	2022	2022	2022	2022	2022	2022	2022	2023	2023	2023	2023	2023
Energy From Grid (GWH)	7.66	8	6.42	5.8	4.49	4.85	4.33	4.01	3.98	3.59	4.04	4.05	5.95
Peak Load (MW)	13.44	13.92	11.94	11.76	9.42	11.44	10.19	8.59	5.97	6.94	6.37	7.56	10.99
Total Electricity Bill (K$)	1123.61	1157.38	831.47	702.88	583.29	679.99	603.6	490.82	452.84	494.94	535.81	611.59	877.82
GHP CAPEX and OPEX (K$)	13.23	13.23	13.23	13.23	13.23	13.23	13.23	13.23	13.23	13.23	13.23	13.23	13.23
Total Cost (K$)	1136.84	1170.61	844.7	716.11	596.52	693.22	616.83	504.05	466.07	508.18	549.04	624.83	891.06
Cost Saving With Respect to The Baseline Case (K$)	7.3	10.12	14.9	17.72	3.9	3.24	8.75	-6.82	-6.19	12.44	-9.98	12.87	7.71
GHG From Grid (Ton)	323.86	345.06	424.14	392.02	262.84	277.17	211.49	272.01	228.45	168.14	194.53	152.37	246.45
Charge and Discharge Cycle	8	14	12	14	6	3	2	10	19	2	27	4	14

Figure 15 illustrates the optimal scheduling and management yielded from the optimization problem. As given, the GHP charges only when electricity prices are very low and discharges when they exceed at least twice the average value to arbitrage against real-time pricing. This behavior is due to the low efficiency, where the actual cost of 1 MWh is equivalent to the cost of $\frac{1MWh}{\eta^{EL}\times\eta^{FC}} = 3.3MWh$.

In this scenario, to effectively arbitrage against real-time pricing, the GHP charges at very low prices and discharges at very high prices, ensuring the gap is more than 3.3 times the average price to guarantee cost savings. This explains the relatively modest cost savings of the GHP compared to the BSS. Additionally, the GHP discharges during peak load times to keep the peak value below a certain limit throughout the entire month, thereby avoiding high delivery charges. Figure 15b provides a detailed view of the GHP behavior in the last two weeks of May 2022. As the month progresses and summer begins, peak values start to rise on campus. In response, the GHP discharges in a distributed manner to prevent peak values from exceeding a certain limit–a behaviour that was not seen in the whole month. Moreover, the figure shows how frequently the GHP charges and discharges, which is fewer than BSS cycles. The GHP completes approximately three cycles per week, whereas the BSS performs around three cycles daily.

In order to propel the economic viability of the GHP there is a need to consider options such as providing grid services or supplying hydrogen to the available market. The next subsections will analyze the GHP's performance when it is utilized at Keele Campus to provide DR and/or supply produced hydrogen to a hydrogen market.

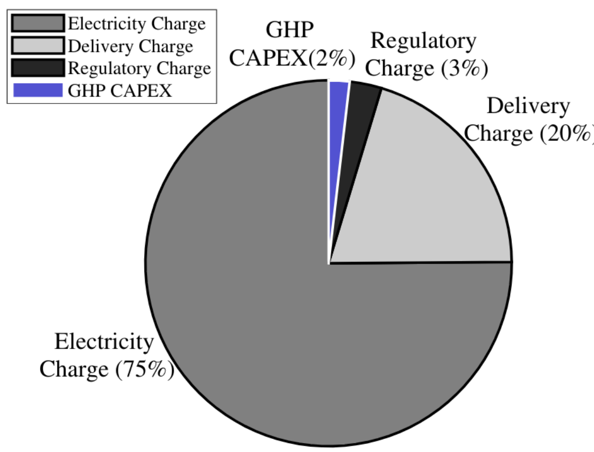
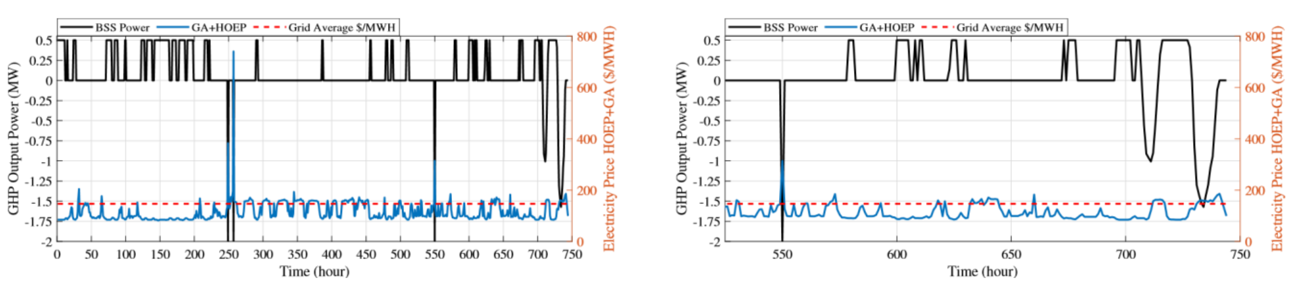


Figure 14| Electricity Bill and GHP Annual Cost Distribution.



(a) Optimal Scheduling Strategy for The Whole Month

(b) Zoom-in For more Detail Information

Figure 15| GHP Output Power Management and Optimal Scheduling Strategy.

4.2 Utilization of GHP for Electricity Bill Reduction and Provision of DR

The mathematical formulation of the DR is incorporated into the general optimization problem as discussed in Appendix C. The DR activation signals are selected based on the three days with the highest grid generation levels (indicating the grid's need for energy due to high demand). Each activation is set for four consecutive hours.

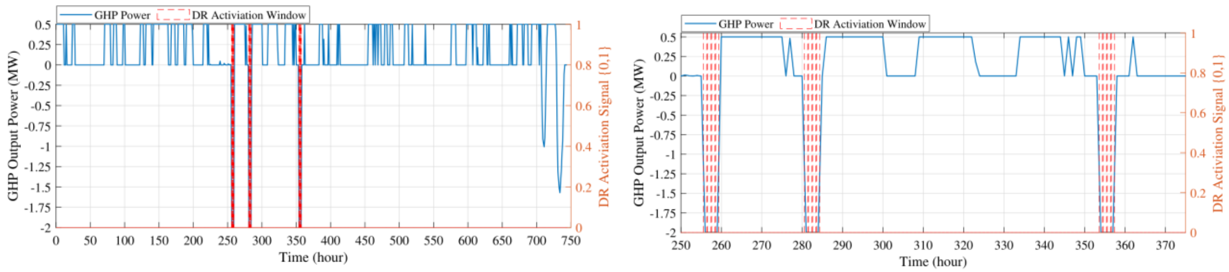
Table 11 shows the performance of the GHP when participating in DR programs. The annual operating cost decreased from \$8.6 million (In case when GHP does not participate in DR) to \$8.48 million per year. Participation on the DR programs provides an incentive payment of \$120 thousand per year, i.e., additional 1.3% saving. Other parameters, such as peak load and electricity bill, remain almost the same. However, the number of charge cycles increased to 155 cycles per year, compared to 125 cycles when GHP does not participate in the DR. This is due to the need to charge before the DR event and discharge during the DR activation.

Figure 16 depicts the optimal scheduling and management strategy of the GHP when it participates in DR. During normal operation without DR activation, the GHP charges and discharges in accordance with the peak load profile and real-time prices, as previously discussed. However, Figure 16b captures the GHP's behavior during a DR event. Unlike the BSS, the GHP can store hydrogen in the tank for extended periods. Consequently, during a DR event, the GHP can utilize the full capacity of the electrolyzer throughout the entire period, thanks to the available hydrogen tank capacity at a low price. Since DR events compensate based on the lowest level of DR participation (power reduction), maintaining a uniform power discharge optimizes the minimum power reduction.

Table 11| Cost and Environmental Analysis when GHP participates in DR

Electrolyzer=0.5MW, Fuel Cell=2MW, Hydrogen Tank= 12,000 m3, DR Payment 600\$/MW/Business Day

Month	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Year	2022	2022	2022	2022	2022	2022	2022	2022	2023	2023	2023	2023	2023
Energy From Grid (GWH)	7.7	8	6.47	5.84	4.5	4.89	4.33	4.01	3.98	3.59	4.04	4.05	5.99
Peak Load (MW)	13.44	14.36	11.94	11.76	10.35	11.44	10.19	8.59	5.97	6.94	6.37	7.56	11.06
Total Electricity Bill (K\$)	1127.88	1164.85	834.84	706.29	596.66	681.55	603.6	490.82	452.84	494.94	535.81	611.59	882.67
GHP CAPEX and OPEX (K\$)	13.23	13.23	13.23	13.23	13.23	13.23	13.23	13.23	13.23	13.23	13.23	13.23	13.23
DR Power Reduction (MW)	2	1.27	2	1.6	1.9	2	0	0	0.01	0	0.01	0	1.71
DR Payment (K\$)	27.6	16.66	27.6	22.01	25.03	27.6	0	0	0	0	0	0	23.57
Total Cost (K\$)	1113.52	1161.42	820.47	697.52	584.87	667.19	616.83	504.05	466.07	508.18	549.04	624.83	872.34
Cost Saving With Respect to The Baseline Case (K\$)	30.62	19.31	39.13	36.31	15.55	29.27	8.75	-6.82	-6.19	12.44	-9.98	12.87	26.43
GHG From Grid (Ton)	324.32	345.83	425.29	394.77	263.01	277.03	211.49	272.01	228.45	168.14	194.53	152.37	246.46
Charge and Discharge Cycle	10	16	18	18	6	5	2	10	19	2	27	4	18



(a) Optimal Scheduling Strategy for The Whole Month **(b)** Zoom-in For DR Events scheduling and Operation

Figure 16| GHP Output Power Management and Optimal Scheduling Strategy During DR Events.

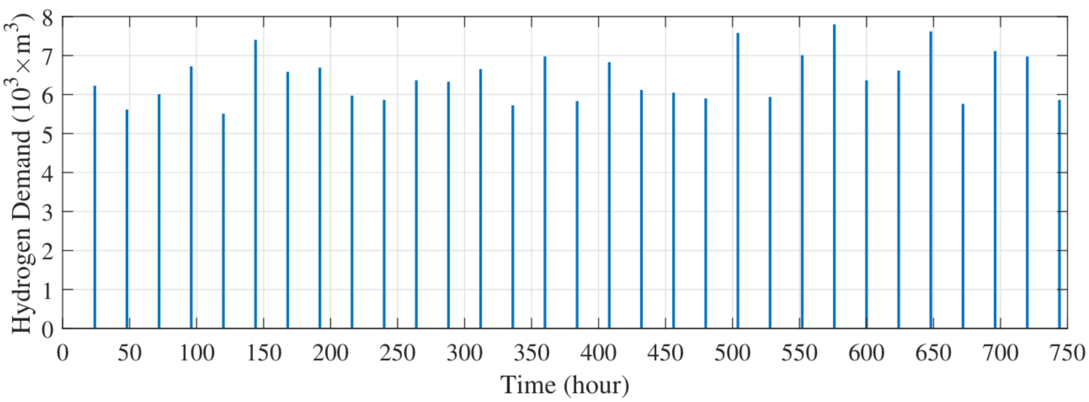


Figure 17| Hydrogen Demand Profile for May 2022.

4.3 Utilization of GHP for Electricity Bill Reduction and Participation in Hydrogen Market

Unlike BSS, the GHP can provide hydrogen for market, which could improve the cost saving aspects. In this case, the GHP is assumed to supply hydrogen to a refueling station with an average capacity of 600Kg/day. Figure 17 shows the monthly load profile of the hydrogen refueling station for May 2022. The GHP produces the hydrogen and store it in the hydrogen tank. Then, at 12:00 AM, hydrogen is shipped to the hydrogen refueling station.

The price of hydrogen varies depending on its type. The cost of hydrogen can be categorized as follows: gray hydrogen costs 0.98-2.93 $/Kg, blue hydrogen costs 1.8-4.7 $/Kg, and green hydrogen costs 4.5-12 $/Kg. However, the commercial price of hydrogen at fuel stations generally ranges from 13-16 $/Kg. For the purposes of this study, the hydrogen price is assumed to be 3.82 $/Kg, which falls within the blue hydrogen price range. The primary objective of this study is to evaluate the performance and behavior of the GHP when it is used to supply hydrogen to a refueling station.

It is important to note that the previous design of the electrolyzer and fuel cell could not meet the required hydrogen demand. Therefore, the optimization method was revised to consider hydrogen demand as a constraint that must be met. As a result, the new optimal design specifies 2 MW for the electrolyzer and 1.5 MW for the fuel cell, while the hydrogen tank capacity remains unchanged at 12,000 m3.

Table 12| Cost and Environmental Analysis when GHP Supplies a Hydrogen Demand

Electrolyzer=2MW, Fuel Cell=1.5MW, Hydrogen Tank= 12,000 m3, H2 selling Price=3.83 $/kg

Month	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Year	2022	2022	2022	2022	2022	2022	2022	2022	2023	2023	2023	2023	2023
Energy From Grid (GWH)	8.55	8.83	7.34	6.68	5.36	5.77	5.18	4.92	4.85	4.41	4.97	4.9	6.81
Peak Load (MW)	14.24	14.89	12.44	12.26	10.31	11.61	11.04	9.28	6.83	7.74	6.85	8.06	11.49
Total Electricity Bill (K$)	1229.22	1259.36	923.17	776.03	667.38	771.07	694.53	576.92	540.62	591.63	642.37	716.91	983.26
GHP CAPEX and OPEX (K$)	20.21	20.21	20.21	20.21	20.21	20.21	20.21	20.21	20.21	20.21	20.21	20.21	20.21
H2 Supply Payment (K$)	64	60.98	64.01	63.23	63.05	63.9	60.28	65.12	63.23	58.15	65.61	59.58	62.32
Total Cost (K$)	1185.43	1218.59	879.37	733	624.53	727.38	654.45	532	497.59	553.69	596.96	677.54	941.15
Cost Saving With Respect to The Baseline Case (K$)	-41.29	-37.86	-19.77	0.83	-24.11	-30.92	-28.87	-34.77	-37.71	-33.07	-57.9	-39.84	-42.38
GHG From Grid (Ton)	354.4	375.23	473.03	440.09	304.34	322.17	246.28	328.62	271.97	201.24	236.21	179.19	274.62
Charge and Discharge Cycle	6	6	4	10	6	4	2	2	2	4	0	4	12

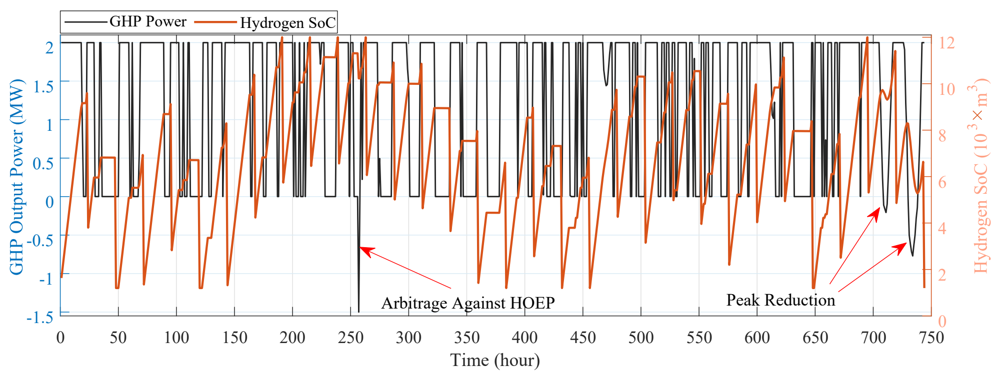


Figure 18| GHP Output Power Management and Optimal Scheduling for Hydrogen Supply.

Table 12 presents an analysis of the cost and environmental aspects of when GHP is utilized to supply hydrogen to a fueling station. As depicted in the table, the electricity bill has increased to $9.57 million per year, compared to $8.68 million per year for the baseline case. This increase is due to the higher energy consumption by the GHP to produce hydrogen, which adds additional electric demand on the campus. This aspect is highlighted in the first row of the table, where the total energy in GWH has increased, leading to higher electricity charges. Moreover, the monthly peak load has also risen due to the need to meet hydrogen demand, preventing the GHP from frequently utilizing the fuel cell to reduce peaks. This is reflected in the reduction of charge and discharge cycles to about 57 per year. The increase in peak load results in a higher delivery charge on the electricity bill. Moreover, from an environmental perspective, the GHG levels from the grid increased due to the higher energy consumption driven by the additional hydrogen demand.

In addition to the cost and environmental analysis, it is important to address the safety considerations associated with the use of hydrogen. Hydrogen, while offering numerous benefits in terms of decarbonization, presents unique safety challenges due to its high flammability and low ignition energy [10]. The management of hydrogen gas requires strict safety protocols, such as, the use of advanced leak detection systems, which can quickly identify hydrogen leaks through infrared or ultrasonic technology, providing early warnings since hydrogen is odorless and colorless. Proper ventilation is essential, as hydrogen, being lighter than air, rises rapidly when released. This is particularly important in enclosed spaces where ventilation systems allow the gas to dissipate safely in the event of a leak. Explosion-proof equipment, including spark-free tools and specially designed electrical components, is also necessary to prevent ignition in areas where hydrogen is stored or used. Additionally, pressure relief valves are employed to avoid overpressurization in tanks or pipelines, reducing the risk of rupture or explosion. Flame arrestors are installed to stop flames from spreading back into the hydrogen system in case of fire, preventing further damage. Finally, emergency shutoff systems—both automatic and manual—are essential to quickly halt hydrogen flow during emergencies, integrating with control systems to react swiftly to any detected leaks or abnormalities. leak detection systems, proper ventilation, and adherence to safety standards in storage and transportation. Compared to the BSS, which relies on Energy Management System to maintain suitable operation temperature for the BSS and managing the maximum charge/discharge current, the GHP system must incorporate advanced safety mechanisms to mitigate the risks of hydrogen handling. These safety measures ensure that hydrogen can be safely integrated into the energy infrastructure, but they also contribute to the complexity and operational considerations of the system.

Figure 18 illustrates the management and optimal scheduling of GHP operations for hydrogen supply. The fuel cell (negative power in the figure) is utilized three times during the month: once for arbitrage against real-time pricing and twice for peak reduction purposes. The figure also displays the state of charge (SoC) of the hydrogen level in the tank, showing that hydrogen is supplied daily, and the electrolyzer is used to generate hydrogen for the following day.

Overall, selling hydrogen provides an additional cost saving of about $751,000 per year. However, while this saving can offset the CAPEX of the hydrogen system, it does not cover the increased electricity bill. The use of the GHP to meet hydrogen demand adds an extra annual cost of around $890,000 to the system. This analysis indicates that selling hydrogen at $3.83/kg is not economically feasible. A sensitivity analysis is necessary to determine the feasible and economic range for selling hydrogen that allows the GHP to supply the market effectively. For example, 1 MWh from the grid costs around $145 and can generate $(\eta=0.6)\times360(m^3/MWh)\times1MWh = 216m^3 = 18kg$ of hydrogen. At a selling price of $3.83/kg, the revenue from hydrogen generated by 1 MWh is $69, which is less than the electricity cost, even without considering the GHP CAPEX. These aspects will be discussed in section 5, where a comparison between the BSS and GHP is added beside a sensitivity analysis.

4.4 Impacts of Electrolyzer and Fuel Cell Costs on the Optimal Design and Economic Feasibility of GHP:

A key factor in assessing the feasibility of the GHP is the cost of its main components, particularly the electrolyzer and fuel cell. The prices of these units vary widely, making it essential to understand how changes in electrolyzer and fuel cell costs impact the GHP's optimal design and determine the economic and feasible cost range. Additionally, it is important to understand how this feasible cost range shifts when providing different services, such as (1) grid services like DR and (2) hydrogen supply to the commercial hydrogen market. This section, therefore, presents a sensitivity analysis to examine the optimal GHP design and economic feasibility across various electrolyzer and fuel cell cost scenarios. Here, the costs of electrolyzer and fuel cell units are assumed to range from $500 to $3500 per kW, covering the full spectrum of technologies—Alkaline (AWE), Proton Exchange Membrane (PEM), and Solid Oxide Electrolysis Cell (SOEC).

The optimization problem was solved over a 13-month period with one hour step, involving 90,000 decision variables (spanning planning and management) and subject to 900,000 linear and non-linear constraints. The Gurobi optimizer was used for this purpose via cloud computing, achieving optimality scores exceeding 99.99% for all studied cases.

4.4.1 GHP Optimal Design and Economic Feasibility without Participation in DR and Hydrogen Market

Figures 19(a)–(c) present a sensitivity analysis for the optimal sizing of the electrolyzer and fuel cell units at different ranges for their costs, where the color of each square refers to the Z axis value and the color par gives the numerical value (optimal size in kW) for each color. This representation of the output data from the optimization model enables a direct estimation of the optimal size of GHP components for any specified electrolyzer and fuel cell costs. By drawing a vertical line at the desired electrolyzer cost and a horizontal line at the corresponding fuel cell cost, the intersection point on the color scale indicates the optimal size of the GHP unit. This color value can then be referenced against the color par to obtain the numerical value of the optimal size. Also, the dashed red line in the figure represents the threshold between the feasible and infeasible economic regions of the GHP.

In Figure 19(a), the optimal electrolyzer size is shown, with values ranging from 50 to 500 kW. The analysis reveals that fuel cell cost plays a crucial role in the financial feasibility, as the GHP becomes economically unviable when the fuel cell price exceeds $2000/kW. This is largely because a higher-capacity fuel cell is needed to achieve profitable peak shifting, which helps offset both CAPEX and OPEX. In contrast, the electrolyzer benefits from low-cost energy availability during night-time, enabling extended hydrogen storage and utilization over shorter peak periods for cost-effective reduction.

Figure 19(b) displays the optimal fuel cell size, which ranges between 0.5 and 2.5 MW. Once the fuel cell cost surpasses $2000/kW, the optimization algorithm immediately reduces the optimal fuel cell size to zero, indicating financial infeasibility. Additionally, as the electrolyzer cost rises, the optimal fuel cell size decreases slightly. This is primarily due to the operational flexibility of the electrolyzer, which can store energy throughout the extended night hours, whereas the fuel cell is limited to brief peak periods for offsetting demand and generating net savings.

Figure 19(c) presents the optimal size of the hydrogen tank, which ranges between 3 and 16 thousand m^3. Once the fuel cell reaches the critical limits of $2000/kW, the hydrogen tank size becomes zero indicating no feasibility from the economic perspective.

Figure 19(d) depicts the annual net savings achieved by the GHP. It is evident that net savings drop to zero when the fuel cell cost exceeds $2000/kW, signaling the GHP's economic infeasibility. In contrast, variations in the electrolyzer cost reduce the annual net savings due to the increased CAPEX for the electrolyzer, though this does not directly impact savings from campus peak reduction. The range of net cost savings spans from $10,000 to $110,000 per year.

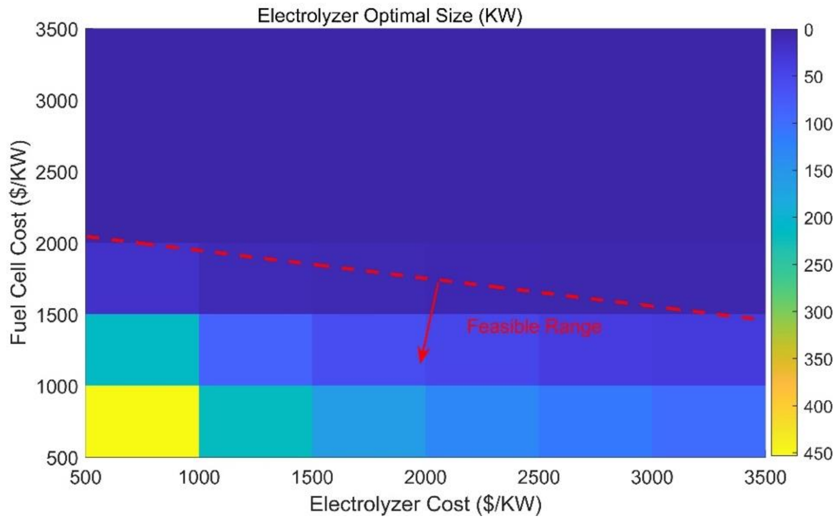


Figure 19 (a)| Optimal Electrolyzer Size Without Considering DR and Hydrogen Market Participation at a Range of Prices for Fuel Cell and Electrolyzers.

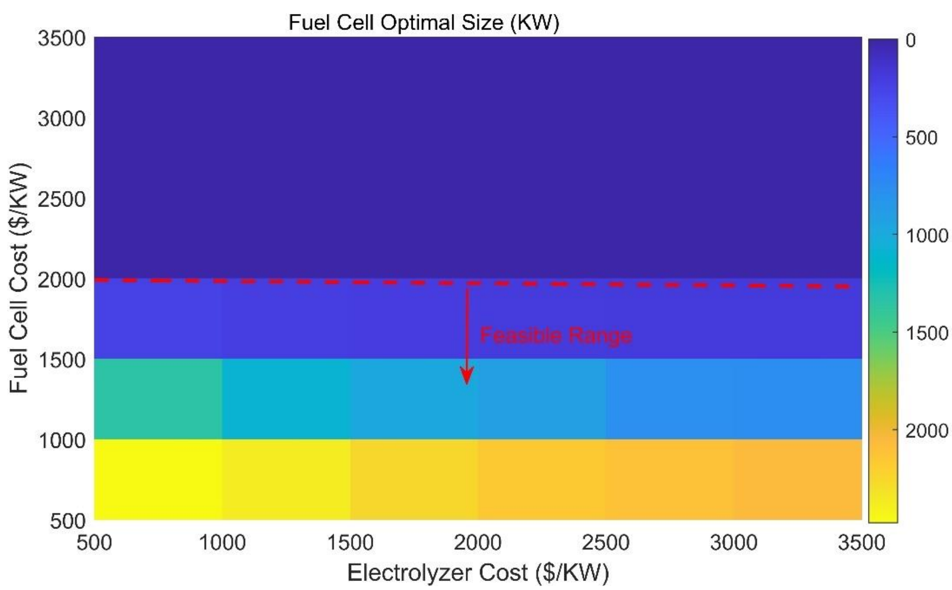


Figure 19 (b)| Optimal Fuel Cell Size without Considering DR and Hydrogen Market Participation.

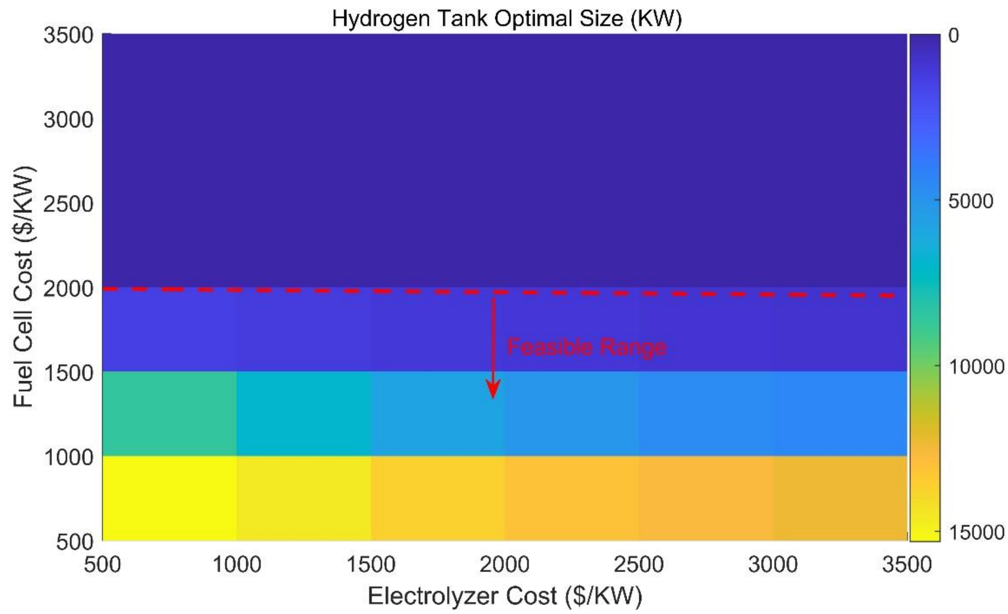


Figure 19 (c)| Optimal Hydrogen Tank Size without Considering DR and Hydrogen Market Participation.

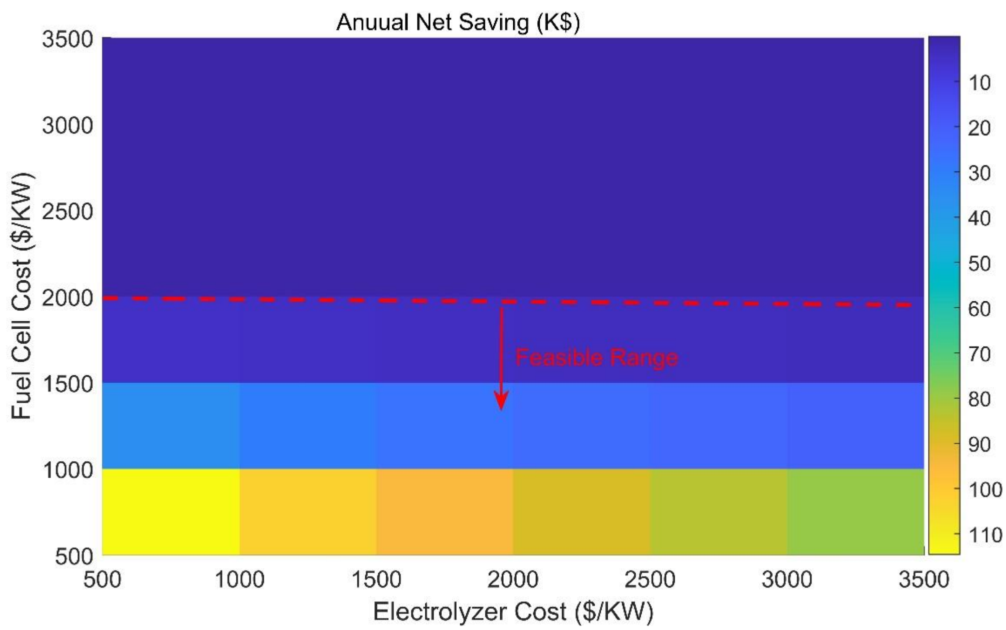


Figure 19 (d)| Annual Net Saving without Considering DR and Hydrogen Market Participation.

4.4.2 GHP Optimal Design and Economic Feasibility with Participation in DR

Figures 20(a)–(c) present the sensitivity analysis for the optimal sizing and economic feasibility of the GHP when it participates in the provision of DR. Compared to the previous case study (without DR participation), the optimal electrolyzer size range increases to 200–1600 kW, and the fuel cell range is expanded to 0.5–5 MW. Additionally, the optimal hydrogen tank size increases to 10,000–40,000 m³. The changes in the sizing ranges of the GHP components result from the GHP's ability to generate higher profits through DR participation, requiring a larger hydrogen tank to store additional energy and a higher capacity electrolyzer to produce sufficient hydrogen. From the cost perspective, a fuel cell price of $3000/kW renders the system economically infeasible due to high capital costs. Moreover, rising electrolyzer costs have a pronounced impact on the system financial feasibility, as the electrolyzer's role becomes crucial in maintaining sufficient hydrogen supply for effective DR participation. Figure 20(d) illustrates the annual net cost savings achieved by the GHP when participating in DR. The net savings increase to a range of $50,000–$350,000, primarily due to DR participation. Notably, as GHP unit costs rise, the optimal size decreases, reducing the GHP's capacity auction and resulting in lower DR payments. Thus, higher costs have a dual impact: they elevate CAPEX while also reducing DR income, underscoring the importance of managing GHP unit costs to ensure profitability in grid service applications.

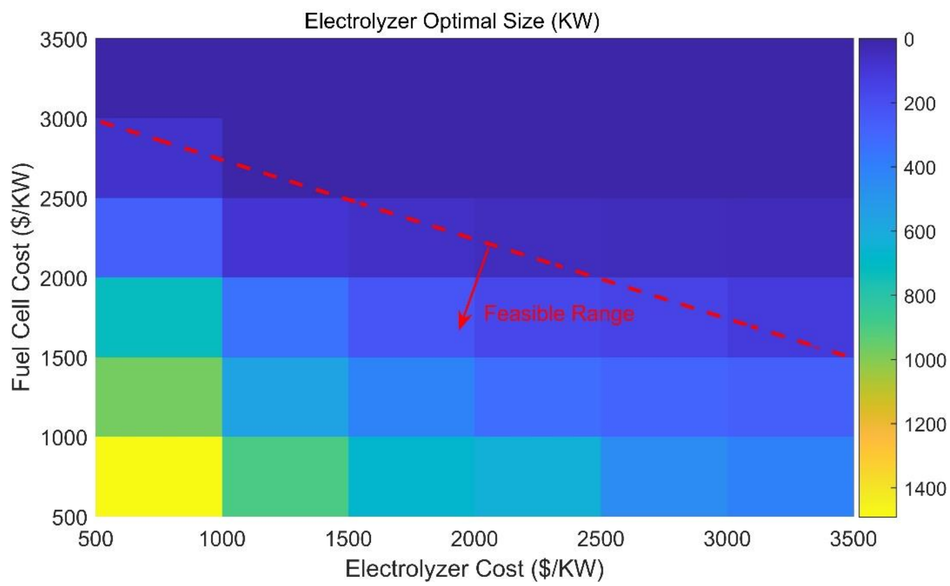


Figure 20 (a)| Optimal Electrolyzer Size Considering DR Participation.

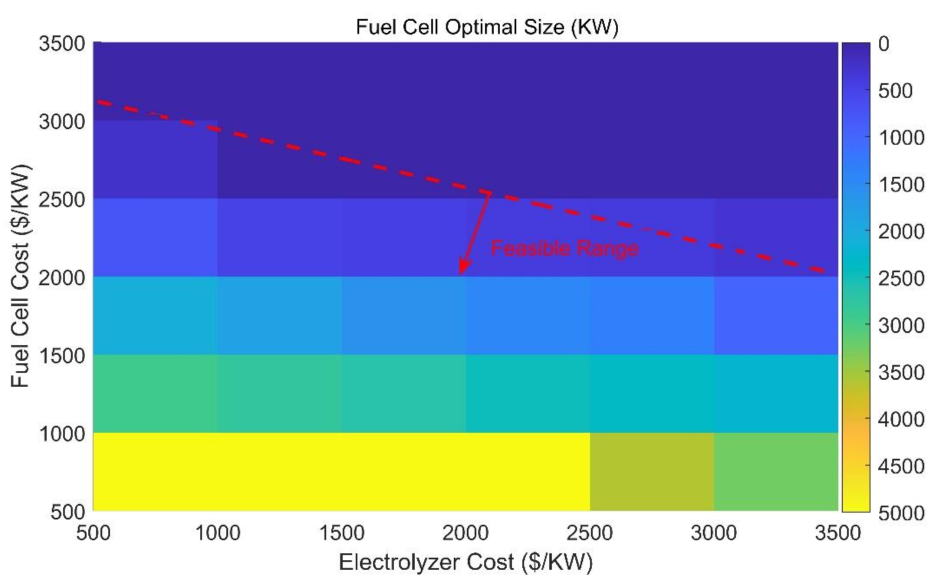


Figure 20 (b)| Optimal Fuel Cell Size Considering DR Participation.

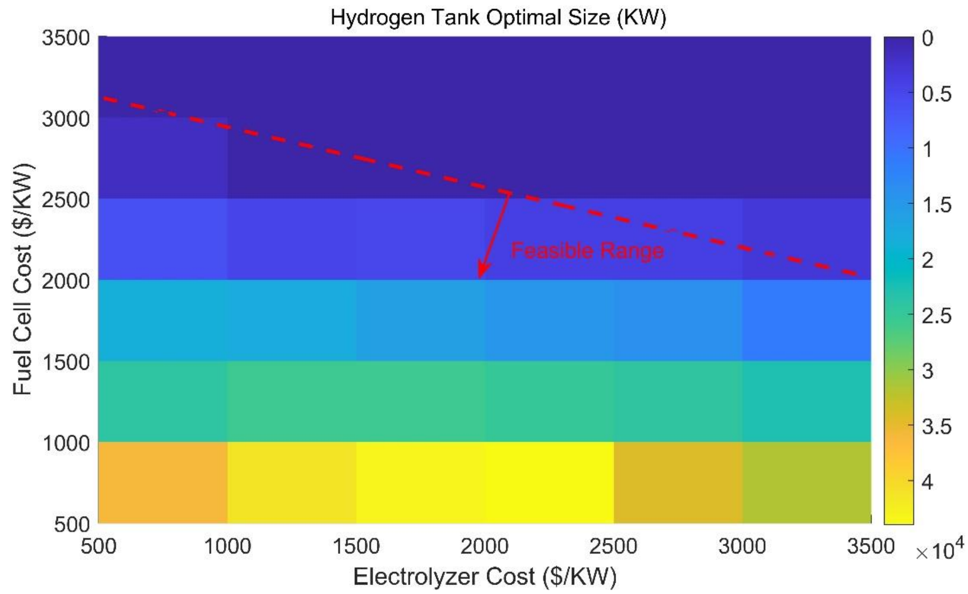


Figure 20 (c)| Optimal Fuel Hydrogen Tank Size Considering DR Participation.

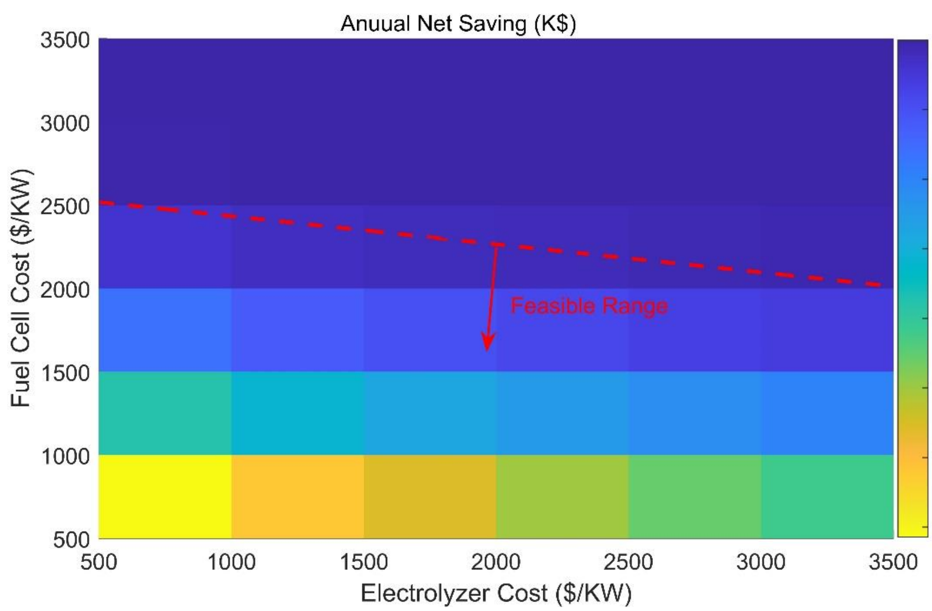


Figure 20 (d)| Annual Net Saving Considering DR Participation.

4.4.3 GHP Optimal Design and Economic Feasibility with Participation in the Hydrogen Market

Figures 21(a)–(c) display the optimal sizing of the GHP components when the GHP participates in the hydrogen market, where the GHP supplies 600 kg/day of hydrogen to a refueling station. Unlike previous cases, where the GHP components sizing are set to zero if economically infeasible, the electrolyzer and hydrogen tank cannot be reduced to zero due to the continuous hydrogen demand (i.e., set as a hard constraint to be met in the optimization model). For this reason, the economic feasibility in this case is assessed through net cost savings, with positive values indicating feasibility and negative values indicating infeasibility. Figures 21(a) and (c) reveal that a minimum of 1.4 MW for the electrolyzer and 12,000 m^3 for the hydrogen tank are required to meet the hydrogen demand. In contrast, Figure 21(b) shows that the fuel cell size can drop to zero, as it is not essential for hydrogen production. Thus, if the fuel cell's CAPEX exceeds the savings from arbitrage and peak reduction, the optimization algorithm sets its optimal value to zero.

It is also noted that the impact of the electrolyzer cost becomes increasingly significant for its optimal sizing. This is primarily due to the larger electrolyzer size required to meet hydrogen demand, making cost increases more influential in determining its optimal design. In contrast, the fuel cell size is less affected by electrolyzer costs, as it plays no role in fulfilling the hydrogen demand. Instead, fuel cell sizing is determined by whether the potential profits from arbitrage and peak reduction can offset its CAPEX. In summary, for hydrogen market participation, the electrolyzer's optimal size is directly constrained by the targeted hydrogen demand and is highly sensitive to its own cost, while the fuel cell's optimal size depends on its ability to generate sufficient returns to cover its costs.

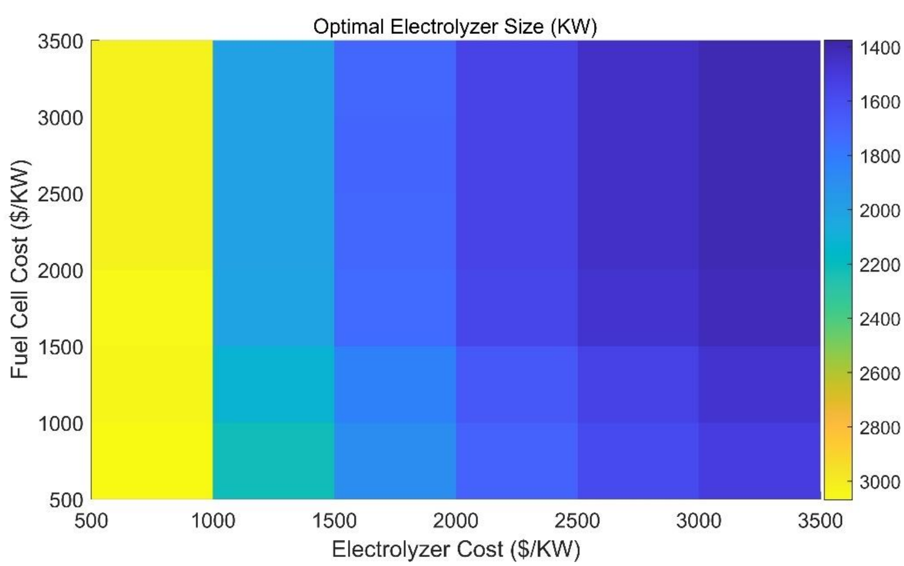


Figure 21 (a)| Optimal Electrolyzer Sizing with Hydrogen Market Participation.

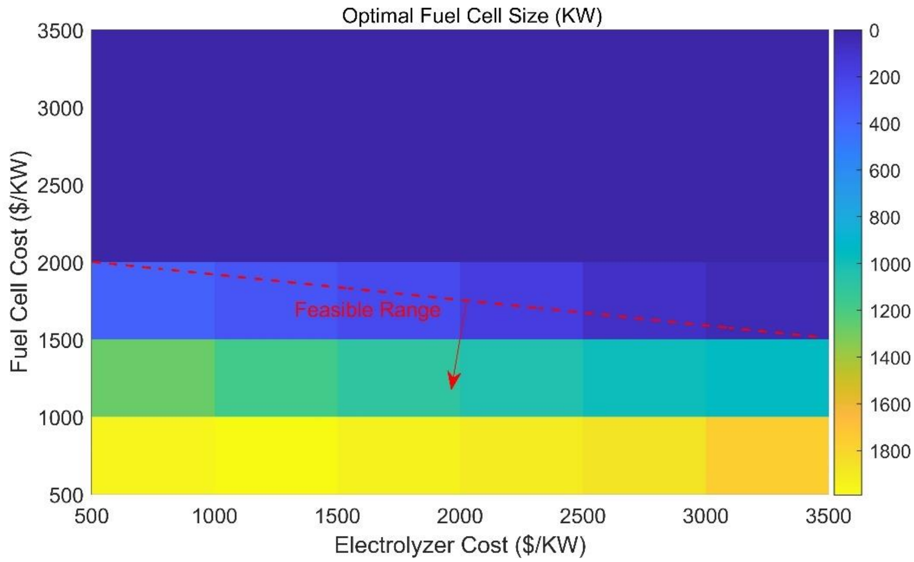


Figure 21 (b)| Optimal Fuel Cell Sizing with Hydrogen Market Participation.

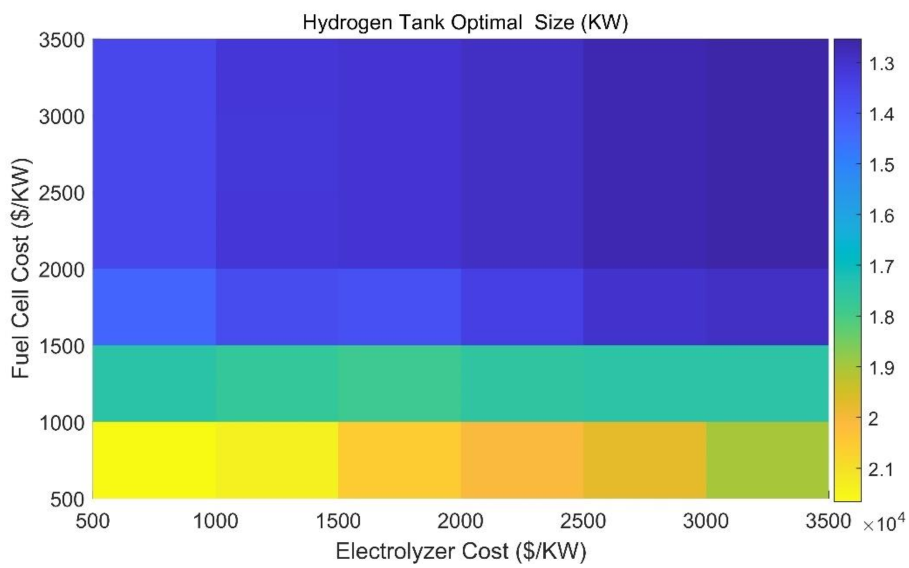


Figure 21 (c)| Optimal Fuel Hydrogen Tank Sizing with Hydrogen Market Participation.

Another key observation is that the optimal sizing of the GHP components remains unaffected by the hydrogen price. This is because profits from hydrogen sales are a constant component of the overall objective function, calculated as the product of hydrogen demand and selling price. As a result, hydrogen price does not directly impact optimal planning or sizing parameters but influences only the economic feasibility of the GHP. Higher selling prices enhance the economic viability of the GHP, making it more financially feasible.

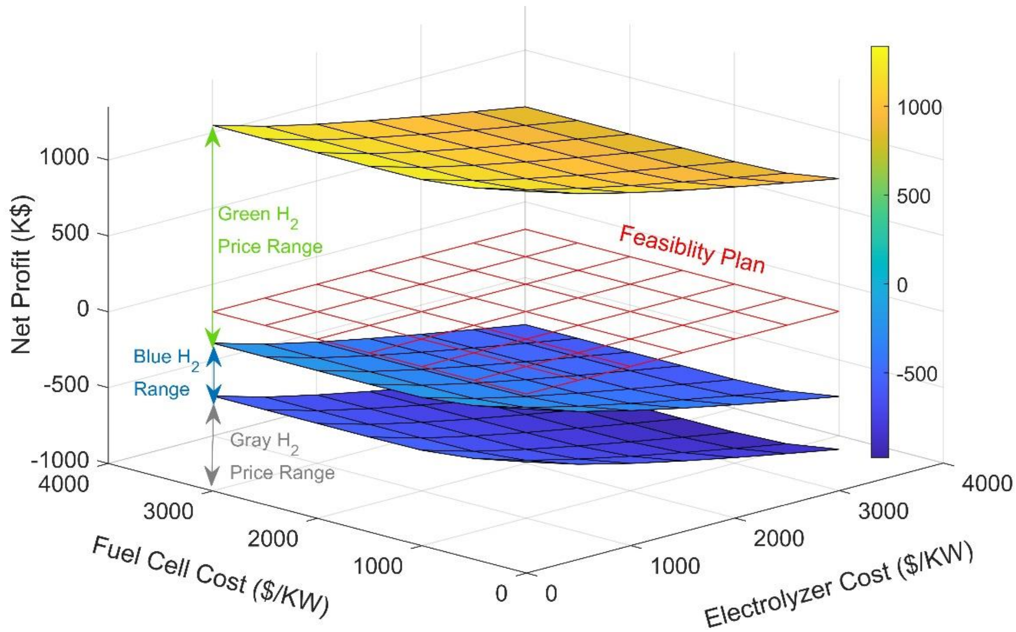


Figure 21 (d)| Annual Net Saving with Hydrogen Market Participation.

Figure 21(d) displays the projected annual net savings from the GHP at various hydrogen selling prices—Gray, Blue, and Green. The figure shows that as hydrogen selling prices rise, the overall net profit plan shifts by a constant amount, depending on GHP unit costs. The line where net savings equal zero marks the boundary between feasible and infeasible hydrogen prices. It is evident that only the green hydrogen market is economically viable for the GHP, while Gray and Blue hydrogen markets are not feasible under current conditions. Table 13 summaries the results of the cost sensitivity analysis and highlights the GHP units optimal sizing based on the used technology and identified cost range.

Table 13| Summary of the GHP Cost Sensitivity Analysis under Different Case Studies

Services	Hydrogen Technology Price Range ($/KW)	**AWE** 850-1400	**PEM** 1500-2000	**SOCE** 2500-3500
Without DR and Hydrogen Market Participation	Electrolyzer Optimal Size Range (MW)	0.01-0.45	0.01-0.05	Infeasible
	Fuel Cell Optimal Size Range (MW)	0.5-2.5	0.5-0.01	Infeasible
	Hydrogen Tank Optimal Size Range (1000 m3)	7-15	<5	Infeasible
	Expected Annual Cost Saving (K$)	80-50	<30	Infeasible
With DR Participation	Electrolyzer Optimal Size Range (MW)	0.6-1.5	0.1-0.4	<0.1
	Fuel Cell Optimal Size Range (MW)	3-5	1-2	<0.8
	Hydrogen Tank Optimal Size Range (1000 m3)	25-50	15-20	<5
	Expected Annual Cost Saving (K$)	180-360	50-100	<5
With Hydrogen Market Participation	Electrolyzer Optimal Size Range (MW)	2.2-3.2	1.8-1.2	1.4
	Fuel Cell Optimal Size Range (MW)	1.3-2	0.6-1	Infeasible
	Hydrogen Tank Optimal Size Range (1000 m3)	18-22	14-15	13
	Expected Annual Cost Saving (K$)	**Depends on the hydrogen selling price and only economically feasible for the green hydrogen price range.**		

5. Comparative Analysis Between the Different Scenarios

This section compares the financial and environmental outputs yielded from the four studied scenarios (Baseline, Grid & Co-gen, Grid & BSS, and Grid & GHP). It also includes a sensitivity analysis on the variation of GHP performance/technical parameters and their impact on the financial and environmental aspects, such as CAPEX, efficiency, hydrogen selling price, and GHG emissions.

5.1 Financial and Environmental Comparative Analysis

Table 14 summarizes the financial and environmental outputs yielded from the studied four scenarios. As shown in the table, the most economic scenario is to run the Keele Campus with existing co-gens, which reduces the total annual electricity cost by $2.4 million (compared to the baseline), outperforming all other scenarios. This is because co-gens generate electricity at one-third the cost of the grid. Additionally, Co-gens have a substantial effect on reducing the campus peak demand charges as, unlike storage units, there are no restrictions on the time and duration they can be utilized for peak reduction. However, Co-gens have the worst environmental impact compared to other scenarios, generating an additional 10,370 tons of direct GHG emissions per year on campus.

Both BSS and GHP scenarios have moderate to poor financial performance compared to the baseline scenario, being economically feasible with limited impact on the total electricity bill. However, BSS outperforms GHP due to its lower CAPEX and higher efficiency, allowing it to profit from smaller differences in electricity costs between charging and discharging events. The high efficiency of BSS also results in smaller energy losses, reducing the electricity charge component of the bill. Despite these advantages, the BSS cost increases significantly with the increase of its energy capacity. BSS typically aims for a smaller energy capacity compared to GHP, which can have a much larger capacity due to the low cost of hydrogen tanks. This behavior is reflected in the number of charge and discharge cycles, with BSS cycling more frequently. Additionally, BSS experiences degradation at high SoC, leading to increased internal losses and avoidance of maintaining a high SoC for long duration. These limitations do not affect GHP, making it suitable for long-term storage, whereas BSS is better suited for short-term storage. Moreover, from a degradation perspective, BSS is likely to degrade at a faster rate compared to GHP. This is due to the stress placed on its components during frequent charge and discharge cycles.

Table 14| Comparison of Financial and Environmental Outputs for the Different Scenarios

Case		Annual Demand (GWH)	Average Peak (MW)	Annual Electricity Bill (Million $)	Annual Total Cost (Million $)	Total GHG ($Ton \times 10^3$)	Charge/Discharge Cycles
Baseline		61.54	11.37	8.67	8.67	3.22	-
Co-gens		Total =61.54 Grid= 27.43, Co-g=34.1	7.42	4.35	6.27	13.59	0
BSS	No Services	62.12	9.67	8.25	8.5	3.16	1090
	With DR	62.12	9.80	8.27	8.32	3.16	1105
GHP	No Services	62.06	9.89	8.44	8.6	3.22	125
	With DR	62.26	10	8.47	8.47	3.23	155
	With H2 Demand	72.57	10.54	9.57	9.06	3.69	57

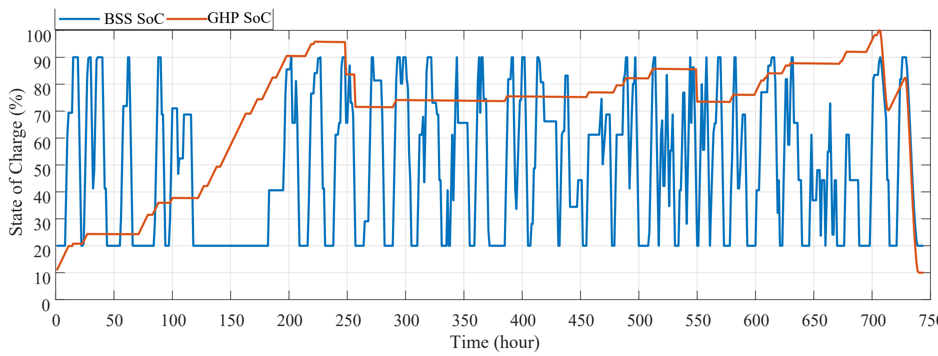


Figure 22| BSS and GHP operation cycles at Keele Campus.

Additionally, it was evident that grid services in the form of DR response can improve the financial aspects without significantly impacting GHG levels. However, it is also noted that participating in DR causes both BSS and GHP to perform a higher number of charge and discharge cycles, which increases system degradation and operational stress.

Unlike BSS, GHP can provide additional services by supplying hydrogen to the market. However, it is important to understand the profitability under different selling prices. The lower bound of profitability is reached when the hydrogen price compensates for the electricity cost used during hydrogen generation, in addition to covering the GHP CAPEX. This sensitivity analysis will be highlighted in section 5.3.

5.2 Comparison of Energy Management and Optimal Operation Strategy

Beside comparing the financial and environmental aspects of the four scenarios, it is also important to understand the energy management and optimal operation strategy of the BSS and GHP. For arbitrage against real-time pricing to be effective, the storage system needs a price difference between charge and discharge times such that $\Delta(HOEP + GA)|_{CH}^{\text{Disch}} \geq 1MWh \times \left(\frac{1}{(\eta^{ch} \times \eta^{disch})} - 1\right) \times \text{Avg}(HOEP + GA)$.

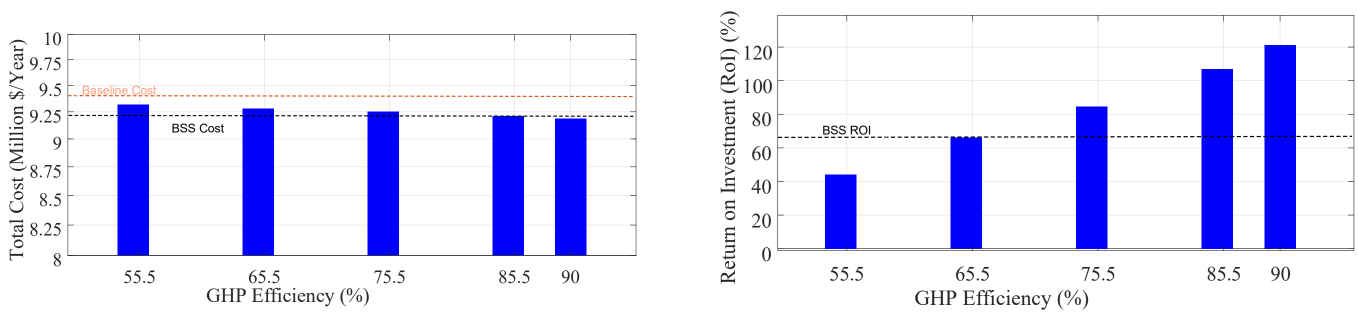
Moreover, for peak reduction purposes, the energy storage discharges during high demand peaks to maintain reduction using the storage system, ensuring this limit is maintained throughout the month. Figure 22 illustrates the differences in operation and management between BSS and GHP for the same target. Due to factors such as 1) small energy capacity, 2) high degradation at high SoC, and 3) a lower charge and discharge price gap, BSS is used for short-term storage and undergoes daily charge and discharge cycles. In contrast, GHP provides long-term storage due to its 1) larger energy capacity with inexpensive hydrogen tanks, 2) minimal degradation, and 3) higher electricity price gap requirement. As the figure shows, GHP stores hydrogen for extended periods.

5.3 Sensitivity Analysis of the GHP Parameters

The impact of the main parameters affecting the economic viability of the GHP including efficiency, capital expenditure (CAPEX), and hydrogen sale prices are factored in as discussed hereunder. For calculation of the return on investment (ROI), the cost saving resulted from BSS or GHP deployment has been computed by subtracting the total system cost before and after the BSS or GHP deployment. The cost saving percentage over the system CAPEX is then given as the ROI.

5.3.1 Impact of GHP Efficiency on Its Feasibility

The economic viability of the GHP is highly tied to its efficiency. As the electrolysis technology materializes, higher efficiency values can be achieved, thereby positively impacting the economic viability of the GHP deployment. The impact of the electrolysis efficiency on the total system cost and ROI, without and with contribution to the DR services are evaluated, and the results are given in Figures 23 and 24, respectively.



(a) **(b)**

Figure 23| Impact of the electrolysis efficiency on the a) total system cost and b) ROI, without contribution to DR.

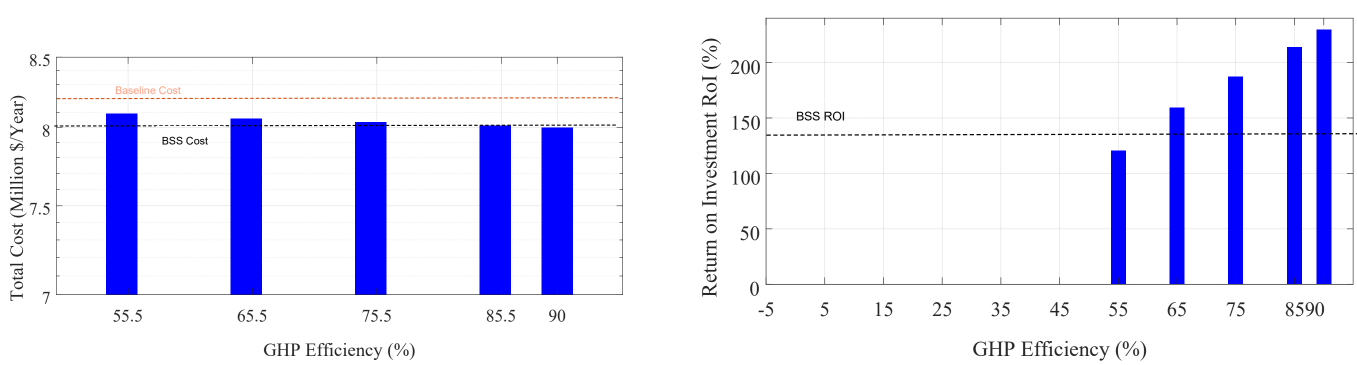


Figure 24| Impact of the electrolysis efficiency on the left) total system cost, and right) ROI, with contribution to DR.

The following can be observed from Figures 23 and 24:

- Both the GHP and the BSS offer financial benefits compared to the baseline where no facility is used for energy shifting and serving the grid.
- At the existing efficiency value of 55% in average for the GHP units (60% and 50% for electrolyzer and fuel cell, respectively) and with overall efficiency almost 30%, the GHP is not on par with the BSS from the financial perspective, since the benefits from the BSS can outweigh the GHP benefits.
- As the efficiency of the GHP increases, the total system cost decreases and the ROI increases. At the efficiency value of 75% for a GHP units (overall efficiency 56.25%), the system cost of the BSS and GHP become comparable as shown in Figure 23 (a). As the efficiency value increases further, the GHP offers more cost savings than the BSS. In addition, Figure 23 (b) shows that at efficiency values greater than 65%, the GHP starts producing a higher ROI than the BSS.
- The results in Figure 24 show that when the BSS or GHP is used for provision of DR services to the grid, they both offer greater financial benefits. However, the BSS and GHP comparative observations are on par with the above-mentioned findings from Figure 23.

5.3.2 Impact of GHP CAPEX on Its Feasibility

Similar to the impact of efficiency variation, the economic viability of a GHP is impacted by its CAPEX. As the electrolysis technology materializes, the plant CAPEX is expected to go down, thereby enhancing its economic viability. The impact of the GHP CAPEX variation on the total system cost, without and with contribution to DR are assessed, and the results are depicted in Figure 25.

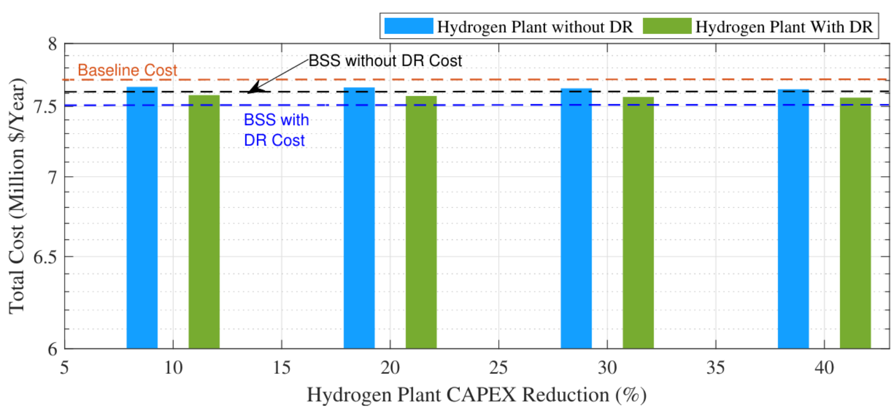


Figure 25| Impact of the GHP CAPEX variation on the total system cost.

The following observations can be made from Figure 25:

- Both the GHP and BSS present financial benefits compared to the baseline where no facility is used for energy shifting and serving the grid.
- Unlike the efficiency, CAPEX variation does not cause a significant change to the total system cost. This is because the total system cost is composed of CAPEX, OPEX, and electricity bills, where CAPEX does not make up a major component of the total cost. However, when the CAPEX reduces by about 40%, the GHP becomes comparable to the BSS from the economic perspective.

- The results also demonstrate that when the BSS or GHP is used for the provision of DR services to the grid, they can offer enhanced financial benefits compared to the case where they do not provide any DR services to the grid.

5.3.3 Impact of Hydrogen Sale Price on the GHP Feasibility

Hydrogen sale prices can directly impact the profitability of the investment in a GHP. The impact of hydrogen sale prices on the system total cost is evaluated, and the results are given in Figure 26.

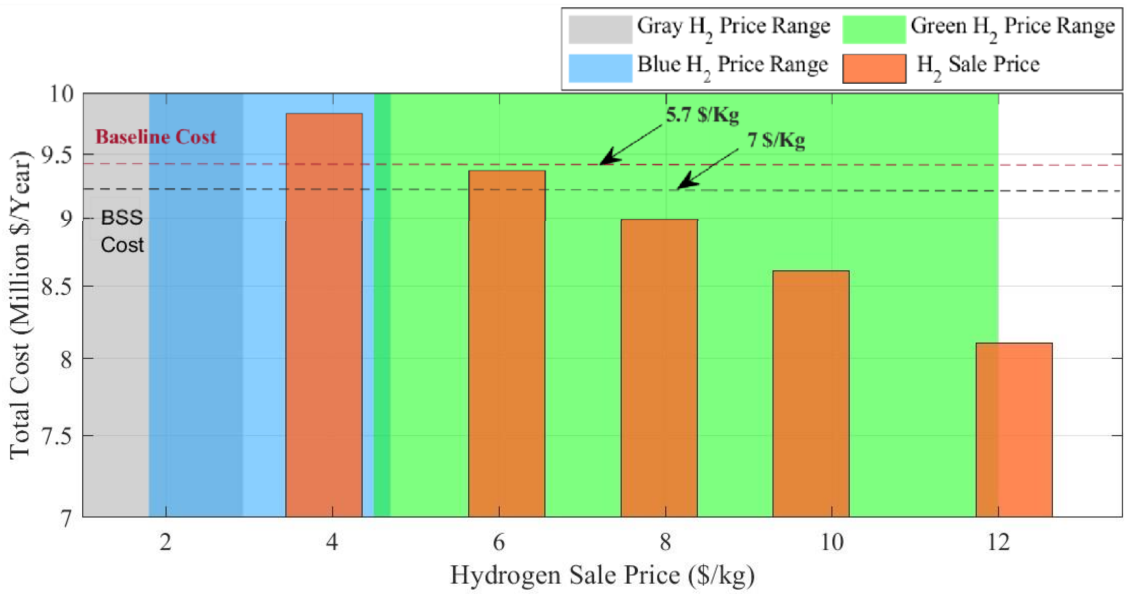


Figure 26| Impact of hydrogen sale price on the total system cost.

The following observations can be made from Figure 26:

- At the lower bound of hydrogen sale prices, i.e., less than 3.9$/kg, the GHP is less economical than the baseline. This is indicated in the figure by the blue region.
- Once the hydrogen sale price is set at 5.7$/kg or higher, the plant starts becoming economical feasible compared to the baseline, which is indicated in the figure by the green range.
- When the hydrogen sale priced at 7$/kg or higher, the GHP outweighs the BSS from the economic perspective.

5.3.4 Summary of the Comparative analysis

- In general, the application of the GHP for arbitrage utilization does not economically justify its significant CAPEX. For this application, a BSS can provide similar services at a more economical rate. The economic viability of the GHP, however, is impacted by various parameters including its efficiency, CAPEX, and hydrogen sale prices.
- At the existing efficiency value of 55%, the economic viability of a GHP is not on par with that of a BSS since BSS benefits can outweigh the GHP benefits. As the efficiency of the GHP increases, the total system cost decreases and the ROI increases. When the efficiency of the GHP units reaches 75% or higher (75% for both the electrolyzer and fuel cell with overall GHP efficiency of 56.25%), the system cost of the BSS and GHP become comparable. As the

efficiency increases further, the GHP offers more cost savings than the BSS. At 65% efficiency, the GHP starts producing a higher ROI than the BSS.

- If a GHP is used for DR provision, it presents a better economic profile compared to the case where it is only used for arbitrage and energy shifting.
- As the electrolysis technology materializes and its CAPEX reduces, GHP becomes more economical. When the CAPEX is reduced by about 40%, the GHP becomes comparable to the BSS from the economic perspective.
- At the lower bound of hydrogen sale price, i.e., 3.9$/Kg, the GHP is less economical than the baseline. Once the hydrogen sale price reaches 5.7$/Kg, the plant starts becoming economical compared to the baseline. When hydrogen sale is priced at or above 7$/Kg, the GHP outweighs the BSS from the economic perspective.
- Phasing out co-gen units and replacing them with GHPs results in significant reduction of the GHG emissions, making the GHP a promising solution to reduce the adverse environmental impacts of conventional generator units. In such a case, policy makers and regulatory bodies can incentivize the deployment and operation of GHPs to enhance their economic profile and promote private investment in their technologies.

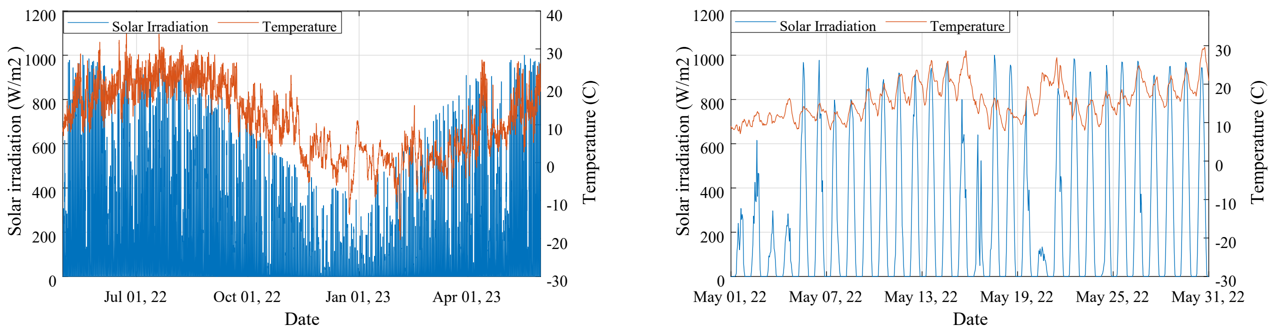
6. Deployment of Rooftop PV

On-site Photovoltaic (PV) installation could enhance the cost savings and reduce the additional costs associated with limiting and/or phasing out the Co-gens contributions. This section analyzes the integration of PV with the BSS or GHP and examines the limitations of Co-gens contributions. Solar irradiation and temperature profiles of York University's Keele campus are studied over the period from May 2022 to May 2023. The expected energy generation and the corresponding price of solar energy are calculated. The study also includes participation in DR programs to further improve cost-saving outcomes.

6.1 Estimated Solar Energy and Costs

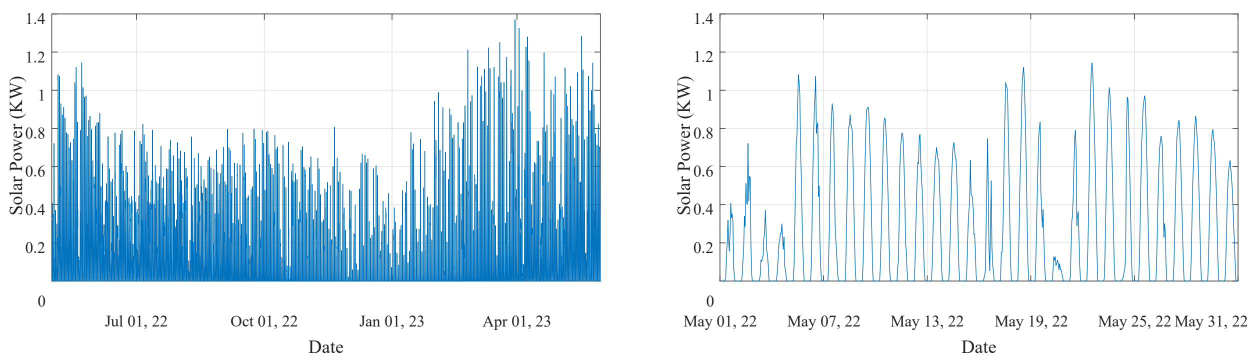
To estimate the energy output of a 1 kW PV system, it is crucial to consider weather profiles, particularly solar irradiation and temperature, due to their significant impact on PV power generation. Figure 27 displays these profiles for the study period, with a detailed view for May 2022. During the summer, both solar irradiation and temperature are high, while in winter, both values are low. January exhibits the lowest irradiation and temperature values. Higher solar irradiation increases PV power output, whereas higher temperatures negatively affect PV energy generation. Figure 28 illustrates the expected output power from a 1 kW PV system installed on campus. The highest power generation occurs in March and April, when irradiation is high and temperatures are moderate, providing optimal conditions for PV output. Figure 28b shows a reduction in PV power from May 7 to May 13, 2022, despite stable irradiation levels (see Figure 27b), due to rising temperatures causing a drop in PV output power.

A 1 kW PV system is expected to generate approximately 1.46 MWh of energy per year. The total cost for such a system, including CAPEX, installation, and maintenance, ranges from \$2,000 to \$3,600. The expected lifetime of the PV system is between 20 and 30 years, with an annual performance degradation of 0.5%. Consequently, the cost of energy generated from the PV system depends on the system's cost and lifespan. Figure 29 illustrates the expected energy cost per MWh for a 1 kW PV system installed at York Campus, factoring in both the projected lifetime and overall cost of the system. These energy cost values assume a 0.5% annual reduction in PV efficiency. In the best-case scenario, a PV system generates solar energy at a price of \$49.25/MWh, assuming a lifespan of 30 years and a total system cost of \$2,000. This energy price is lower than the Co-gen energy cost of \$56/MWh, assuming 100% contribution with no limitation on working hours. In the worst-case scenario, a PV system provides energy at \$129.4/MWh, given a 20-year lifespan and a total system cost of \$3,600. This price is still lower than the Co-gen energy cost when its contribution is limited below 10%. However, this analysis does not account for the potential cost savings from peak reduction and real-time arbitrage when integrating the PV system with the BSS or the GHP. It is also noted that even under worst case, PV energy is cheaper than the grid average energy.



(a) The Duration of May-2022 May-2023. **(b)** The Month of May-2022.

Figure 27| Solar irradiation and Temperature at York University, Keele Campus.



(a) The Duration of May-2022 May-2023. **(b)** The Month of May-2022.

Figure 28| Expected Output Power of 1KW PV System.

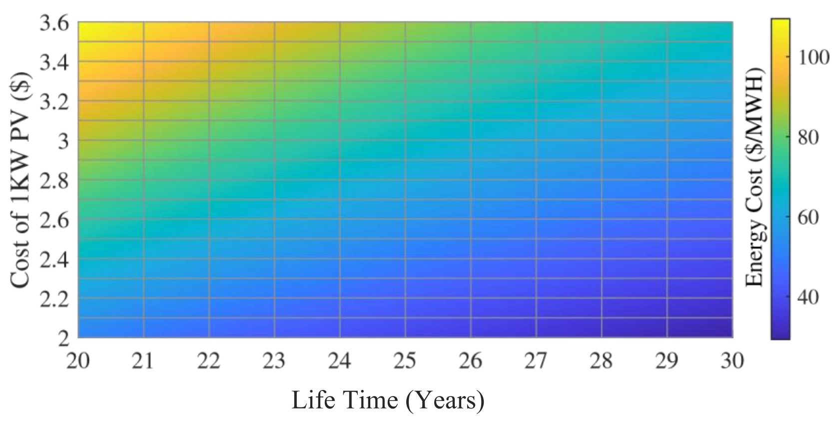


Figure 29| PV Energy Cost ($/MWh) as Function of Lifetime and CAPEX for 1KW system.

In the next sub-section, we analyze each building at Keele Campus to estimate the campus's solar energy capacity using rooftop PV systems.

6.2 Analysis of the Keele Campus Capacity of Top-roof PV System

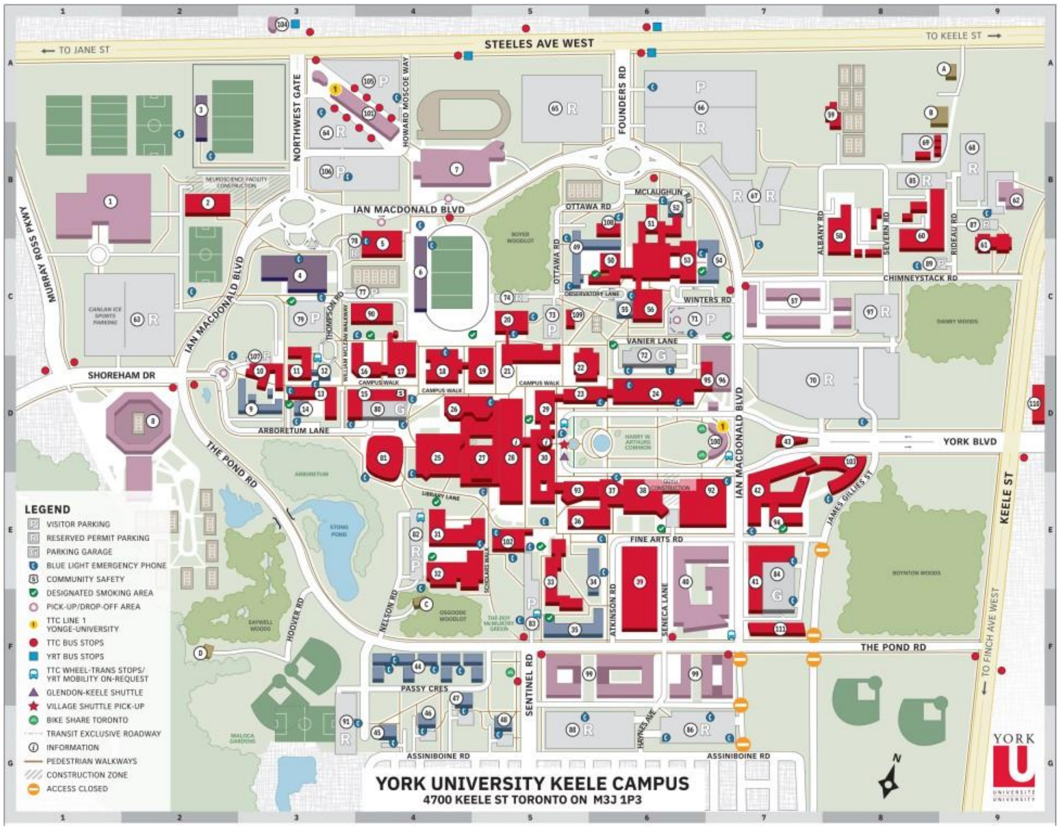


Figure 30|: The Keele Campus Map

Figure 30 illustrates the Keele campus map with identification number given for each building, while Table 15 presents the estimated solar PV capacity of each building. The rooftop analysis is based on evaluating the available roof area of each building that can be utilized for PV installation. Using Google Earth satellite images, the total effective area was measured by excluding areas with obstacles, sharp curves, and insufficient solar irradiation. The analysis identified 37 candidate buildings across the university, with a total rooftop PV capacity of 8.1 MW. Notably, 28 buildings can support a PV system with a capacity greater than 100 kW, 15 buildings with more than 200 kW, and 9 buildings with over 300 kW. The Bennett Centre for Student Services / Admissions (BCS) has the highest potential, with a rooftop PV capacity of 988 kW. This analysis is crucial for York's operations and management team, as it helps prioritize buildings for rooftop PV installations based on capacity. Prioritizing buildings with higher capacities is preferred to centralize PV installations, thereby minimizing installation and maintenance costs.

Table 15| Estimated PV Energy for Campus Buildings

Building index	Building Name	Roof Area	Roof Effective Area for PV Installation (m²)	PV Power (KW)	Min PV Energy (MWh)	Max PV Energy (MWh)
1	190 Albany Road	484.01	255	51	1418	2071.2
2	4747 Keele Street, York University Finance Department	4,830.78	2511	502.2	13963	20395
3	Accolade East (ACE)	8,228.38	3505	701	19490	28468
4	Accolade West (ACW)	2,297.11	1619	323.8	9002.9	13150
5	Atkinson (ATK)	1,787.22	458	91.6	2546.8	3720
6	Behavioural Science Building (BSB)	2,890.56	788	157.6	4381.9	6400.3
7	Bennett Centre for Student Services / Admissions (BCS)	11,154.91	4942	988.4	27481	40140
8	Bergeron Centre for Engineering Excellence	3,435.50	334	66.8	1857.3	2712.8
9	York Lanes (YL)	7709	1745	349	9703.5	14173
10	Calumet College (CC)	1180	0	0	0	0
11	Central Utilities Building (CUB)	3039	864	172.8	4804.5	7017.6
12	Centre for Film & Theatre(CFT)	4,697.26	1047	209.4	5822.1	8504
13	Chemistry (CB)	2,095.71	141	28.2	784.1	1145.2
14	CMiC (CMB)	1130	524	104.8	2913.8	4256
15	Curtis Lecture Halls (CLH)	3326	1241	248.2	6900.9	10080
16	Dezsö J. Horváth Executive Learning Centre (ELC)	1492.48	606	121.2	3369.8	4922.1
17	Farquharson Life Sciences (FRQ)	3100	832	166.4	4626.6	6757.7
18	First Student Centre (FSC)	2,524.97	629	125.8	3497.7	5108.9
19	Founders College (FC)	1,178.37	1026	205.2	5705.3	8333.4
20	Health, Nursing & Environmental Studies (HNE)	3821	2414	482.8	13424	19607
21	Ignat Kaneff Building+ Osgoode Hall Law School (OSG)	6,786.83	1189	237.8	6611.7	9657.3
22	Joan & Martin Goldfarb Centre for Fine Arts (CFA)	3,197.42	780	156	4337.4	6335.3
23	Kaneff Tower (KT)	4,538.94	2228	445.6	12389	18096
24	Kinsmen (K)	1,176.72	539	107.8	2996.8	4377.7
25	Lassonde Building (LAS)	3,105.81	0	0	0	0
26	Leonard G. Lumbers Building (LUM)	2604	822	164.4	4570.3	6676.2
27	Life Sciences Building (LSB)	4,036.02	1698	339.6	9440.8	13791.1
28	Lorna R Marsden Honour Court & Welcome Centre (HC)	304	0	0	0	0
29	McLaughlin College (MC)	3474	987.4	197.4	5487.7	8016.4
30	Norman Bethune College (BC)	2,157.32	880	176	4892.8	7147.3
31	Petrie Science & Engineering (PSE)	2,976.43	592	118.4	3291.5	4808.2
32	Physical Resources Building (PRB)	4,745.90	2007	401.4	11158.9	16300.8
33	Rob & Cheryl McEwen Graduate Study & Research Building (MB)	2,455.70	317	63.4	1762.5	2574.6
34	Ross Building (R)	4,118.50	1168	233.6	6494	9486.4
35	School of Continuing Studies (SCS)	2,038.39	861	172.2	4787.1	6993
36	Scott Religious Centre (SRC)	1,237.42	0	0	0	0
37	Second Student Centre (SSC)	4,296.22 m²	1071	214.2	5954.7	8698.6

6.3 Rooftop PV With BSS

The adoption of PV can significantly improve the financial outcomes and lead to substantial cost savings, enabling the York development and management team to expedite phasing out the Co-gens. As highlighted in Section 6.1, PV energy is identified as a promising solution for providing a green and inexpensive energy source. Consequently, this section delves into the analysis of the impact the adoption of a PV Energy System could have on the decarbonization of the energy profile at Keele campus.

To determine the optimal planning parameters for the BSS size, PCS rate, and PV solar energy size, the PV system is assumed to have an average cost of $2,500 per kW. This cost includes capital, maintenance, and operation expenses. The lifespan of the PV system is estimated at an average of 25 years and the upper PV capacity is kept to 5000 KW. The optimization problem is then solved for the entire 13-month period, with the planning parameters as decision variables. The Gurobi optimizer is used to solve the problem, which covers 9504 optimization hours and involves 90,000 decision variables. To reduce computational time, the problem is solved using large-scale parallel computation on a cloud server.

The optimal planning parameters were found to be 13.75 MWh for the BSS size, 3.127 MW for the PCS rate, and a full 5 MW capacity for the PV system, indicating that the PV system is highly beneficial for cost savings. Table 16 provides an in-depth analysis of the financial and environmental aspects of integrating BSS and PV at Keele campus, with and without the provision of grid services assuming Co-gens existed in all cases, which simulates the current scenario at Keele Campus. The results show that the average monthly reduction/cost savings with BSS and PV integration increased to $47.3K compared to $28.4K without PV integration, resulting in an expected total cost saving of $11.35M over a 20-year project lifespan. When the BSS is used for grid services, the average monthly cost savings increased to $62.23K, leading to an expected total cost saving of $14.94M over the system lifespan. The BSS and PCS have a combined cost of approximately $4.41M (20-years) for capital, maintenance, and installation. On the other hand, the PV system costs around $12.5M (25-years), covering capital, maintenance, installation, and operation expenses. Despite the high cost of the PV, unlike the BSS, which achieves cost savings through peak reduction and arbitrage, the PV system acts as an energy source that supplies lower-cost energy to the campus and contributes to peak reduction during peak hours.

In the case of PV integration, total cost savings are derived from three main components: 1) electricity bill savings (from peak reduction and arbitrage), 2) the PV energy source, and 3) payments from the DR program. In the first case, where the BSS and PV do not participate in DR, the monthly cost savings in electricity bills is $108.08K. The average peak demand reduction is 2.494 MW, resulting in a $40.1K decrease in the electricity bill. The PV system provides an average of 547 MWh per month, with an average electricity price of $89.9/MWh, contributing $49.2K to the cost savings. The final component of the cost savings comes from the BSS arbitrage and peak reduction, which increases to $18.87K per month. This increase in the cost saving is due to the inexpensive energy from the PV system, which is stored in the BSS and discharged during periods of high energy prices. The cost-saving components remain nearly the same in the case of BSS and PV participation in DR, but an additional saving comes from DR payments, which add an average of $16.25K per month. Financially, it is evident that the PV system significantly enhances cost savings and helps the system move closer to achieving net zero.

From the environmental perspective, integrating the PV system reduces the campus reliance on the grid energy during peak times when power systems typically depend on gas-fired generators. This would, in turn, contribute to the reduction of the indirect GHG emissions from the grid. On average, the PV system was responsible for supplying 10.7% of the total campus energy, resulting in an annual reduction of 454 tons of GHG emissions. While the addition of PV helps decrease indirect GHG emissions from the grid, it does not directly affect the scheduling of the Co-gens or their associated GHG emissions, making direct efforts to phase out the Co-gens necessary. However, the combined BSS and PV system contributes additional cost savings that can be used to reduce the Co-gens' contribution, thereby avoiding the significant extra costs associated with limiting Co-gens energy output.

Table 16| Impacts of PV Integration with BSS and with/without DR.

Parameters: 201$/KWh , $469/KW, Initial SoC 20%, and, PV $2500/KW DR payment $0.6/KW/day (BSS: 13.75 MWh, PCS: 3.127 MW, PV: 5000 KW)

Month		May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	April	May	Sum
Year		2022	2022	2022	2022	2022	2022	2022	2022	2023	2023	2023	2023	2023	
Total Cost K$	Without BSS+PV	902.23	950.9	669.32	573.4	433.31	493.87	433.69	334.89	301.22	326.17	327.39	392.22	654.5	6613.63
	BSS+PV No DR	794.19	877.02	592.14	513.69	400.61	452.31	437.61	337.48	318.42	302.87	286.7	319.79	545.37	6423.12
	BSS+PV With DR	764.4	848.27	564.22	483.32	383.72	421.87	437.65	337.5	318.42	302.92	286.7	319.8	514.97	5983.76
Reduction K$	BSS+PV No DR	108.03	73.87	78.57	57.67	31.28	41.56	-3.92	0.8	-17.2	23.3	40.48	71.35	109.12	614.97
	BSS+PV With DR	137.83	102.62	105.1	90.07	49.58	71.99	-3.96	-2.62	-17.2	23.24	40.69	72.41	139.52	809.27
Electricity Bill K$	Without BSS+PV	737.45	790.64	506.02	421.94	280.73	329.09	273.44	176.63	136.44	174.96	162.61	231.97	489.72	4711.7
	BSS+PV No DR	567.06	654.6	365.2	301.82	187.21	225.31	215.29	113.79	91.35	89.72	60.09	98.48	318.17	3288.12
	BSS+PV With DR	567.79	655.04	367.71	301.98	201.63	225.38	215.29	113.79	91.35	89.72	60.09	98.48	318.33	3306.58
Reduction K$	BSS+PV No DR	170.39	136.04	140.81	120.11	93.51	103.78	58.15	62.83	45.08	85.24	102.52	133.49	171.55	1423.57
	BSS+PV With DR	169.66	135.6	138.3	119.95	79.09	103.71	58.15	62.83	45.08	85.24	102.52	133.49	171.39	1405.01
Peak Value MW	Without BSS+PV	11.06	11.91	9.99	9.81	7.04	8.6	7.94	4.92	2.75	4.98	2.77	5.61	9.04	-
	BSS+PV No DR	8.08	8.84	5.72	7.17	5.05	5.32	6.75	3.36	1.53	2.72	1.14	2.39	4.82	-
	BSS+PV With DR	8.08	8.84	5.93	7.17	5.93	5.32	6.75	3.36	1.53	2.72	1.14	2.39	4.82	-
DR Power Reduction MW	BSS+PV No DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BSS+PV With DR	2.22	2.22	2.22	2.22	2.22	2.22	0	0	0	0	0	0	2.22	-
Achievable DR Payment $/Day	BSS+PV No DR	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	BSS+PV With DR	1332	1332	1332	1332	1332	1332	0	0	0	0	0	0	1332	-
Actual DR Payment $/Day	BSS+PV No DR	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	BSS+PV With DR	1332	1332	1332	1332	1332	1332	0	0	0	0	0	0	1332	-
BSS Cost K$	BSS+PV No DR	20.68	20.5	20.57	20.77	20.56	20.55	20.4	20.36	20.61	20.27	20.37	20.46	20.76	266.93
	BSS+PV With DR	20.68	20.5	20.57	20.77	20.56	20.55	20.4	20.36	20.61	20.27	20.37	20.46	20.76	266.86
PV Cost K$	BSS+PV No DR	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	541.66
	BSS+PV With DR	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	541.58
PV Energy TWH	BSS+PV No DR	0.86	0.61	0.6	0.5	0.48	0.44	0.29	0.24	0.26	0.45	0.71	0.71	0.89	7.11
	BSS+PV With DR	0.86	0.61	0.6	0.5	0.48	0.44	0.29	0.24	0.26	0.45	0.71	0.71	0.89	7.04
Co-Gens Energy TWH	Without BSS+PV	2.94	2.84	2.9	2.66	2.68	2.94	2.84	2.8	2.94	2.65	2.94	2.84	2.94	36.91
	BSS+PV No DR	2.94	2.84	2.93	2.61	2.65	2.94	2.84	2.87	2.94	2.65	2.93	2.82	2.94	36.95
	BSS+PV With DR	2.94	2.84	2.93	2.61	2.6	2.94	2.84	2.87	2.94	2.65	2.93	2.82	2.94	36.85
Co-Gens GHG Ton	Without BSS+PV	1045.86	1012.12	1034.88	946.54	954.89	1045.86	1012.12	997.25	1045.86	944.64	1045.86	1012.12	1045.86	13143.9
	BSS+PV No DR	1045.86	1012.12	1045.27	931.42	944.34	1045.86	1012.12	1022.6	1045.86	944.64	1044.29	1004.13	1045.86	13144.41
	BSS+PV With DR	1045.86	1012.12	1045.11	931.38	928.32	1045.86	1012.12	1022.6	1045.86	944.64	1044.29	1004.13	1045.86	13128.15
Grid Energy TWH	Without BSS+PV	4.67	5.07	3.5	3.07	1.75	1.9	1.45	1.16	0.99	0.9	1.08	1.18	2.94	29.71
	BSS+PV No DR	3.86	4.51	2.91	2.68	1.36	1.51	1.2	0.9	0.74	0.47	0.38	0.52	2.07	23.18
	BSS+PV With DR	3.86	4.51	2.91	2.68	1.4	1.51	1.2	0.9	0.74	0.47	0.38	0.52	2.07	23.15
Grid GHG ton	Without BSS+PV	204.16	227.6	237.21	207.05	110.18	110.4	72.32	74.64	60.65	43.95	53.88	47.23	125.76	1575.03
	BSS+PV No DR	157.72	190.88	178.98	153.84	72.74	78.28	49.33	48.13	39.25	16.06	16.29	18.33	79.34	1099.24
	BSS+PV With DR	157.66	190.94	178.12	153.86	73.68	77.95	49.35	48.13	39.25	16.06	16.29	18.25	79.34	1098.88
GHG Reduction	BSS+PV No DR	46.44	36.72	47.83	68.33	47.98	32.11	22.98	1.16	21.4	27.88	39.15	36.88	46.42	475.33
	BSS+PV With DR	46.49	36.65	48.85	68.35	63.06	32.44	22.96	1.16	21.4	27.89	39.15	36.96	46.41	491.84

6.3 Rooftop PV With GHP

This section evaluates the impact of adopting a PV system integrated with the GHP on the decarbonization of Keele Campus's energy profile. Optimal sizing parameters were identified as follows: a 221.6 kW electrolyzer, a 2.534 MW fuel cell, a hydrogen tank capacity of 12,425 m^3, and a full 5 MW PV system capacity, highlighting the PV system's significant potential for cost savings. Table 17 provides an analysis of the financial and environmental effects of integrating GHP and PV systems at Keele Campus, both with and without grid service provisions, assuming Co-gens are consistently present, representing the current scenario at Keele Campus. Results indicate that the average monthly savings with GHP and PV integration reached $42,000, compared to $6,700 without PV integration, leading to an anticipated total cost saving of $10.08 million over a 20-year project span. When GHP services are used for grid applications, monthly savings increase to $48,750, translating to a projected total cost saving of $11.7 million over the system's life. The combined capital, maintenance, and installation costs of the GHP system amount to approximately $3.285 million (over 20 years), while the PV system's expenses, including capital, maintenance, installation, and operational costs, total around $12.5 million (over 25 years). Despite the PV system's high initial cost, it serves as a consistent energy source, supplying the campus with lower-cost energy and supporting peak demand reduction, unlike the GHP, which achieves cost savings primarily through peak reduction and energy arbitrage.

From the environmental perspective, the integration of the PV system reduces Keele Campus's reliance on grid energy during peak hours, which are often supplied by gas-fired generators. This shift contributes to reducing the campus's indirect GHG emissions associated with grid electricity. The PV system alone supplied an average of 10.7% of the campus's total energy demand, resulting in an annual reduction of approximately 513 tons of GHG emissions. Additionally, the GHP system aids in reducing GHG emissions by storing hydrogen over extended periods. This capability enables GHP to store hydrogen during nights and low-emission periods, allowing for more efficient use during high-demand times. However, neither the GHP nor the PV system directly impacts the Co-gen units or their associated emissions. The Co-gen units' operational schedules and GHG emissions remain unaffected by these integrations, underscoring the need for direct measures to phase out or limit Co-gens to achieve significant emissions reductions. Nonetheless, the cost savings generated by the combined GHP and PV systems can help offset Co-gen contributions, reducing the financial burden that would come with restricting Co-gens' energy output.

Table 18 details the financial parameters for the integrated PV and BSS/GHP system, comparing all discussed scenarios. The data shows that the inclusion of a PV system significantly enhances net profit—by a factor of 2 to 3—relative to scenarios utilizing only BSS/GHP. The break-even period for the BSS and PV system is 11.19 years when not engaged in DR, which reduces to 9.83 years when DR participation is included. Similarly, for the GHP, the break-even period is 11.4 years without DR and drops to 10.6 years with DR. In terms of return on investment, the integrated BSS and PV system can reach up to 100% profit, while the combination of GHP and PV achieves up to 86%. These findings highlight the considerable financial advantage of incorporating an on-site PV system alongside both short-term and long-term storage solutions offered by the BSS and GHP systems.

Table 17| Impacts of PV Integration with GHP and with/without DR.

Parameters: Electrolyzer 850$/KW , Fuel Cell 540 $/KW, H_2 tank: 33.37 $/m3, Initial SoC 10%, and, PV $2500/KW DR payment $0.6/KW/day (Elc: 221.6 KW, FC: 2.53 MW, Tnk: 12,425 m^3 , PV: 5000 KW)

Month		May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	April	May	Sum
Year		2022	2022	2022	2022	2022	2022	2022	2022	2023	2023	2023	2023	2023	
Total Cost K$	Without GHP+PV	902.23	950.9	669.32	573.4	433.31	493.87	433.69	334.89	301.22	326.17	327.39	392.22	654.5	6613.63
	GHP+PV No DR	800.93	885.54	606.48	529.12	405.49	462.37	432.6	352.72	318.17	295.24	292.11	315.68	550.19	6246.64
	GHP+PV With DR	783.66	880.71	589.81	523.55	397.97	440.89	434.48	352.72	318.17	295.24	292.11	315.71	534.01	6159.03
Reduction K$	GHP+PV No DR	101.3	65.36	62.84	44.28	27.82	31.5	1.09	-17.83	-16.95	30.93	35.28	76.54	104.31	367
	GHP+PV With DR	118.57	70.19	79.51	49.85	35.34	52.98	-0.79	-17.83	-16.95	30.93	35.28	76.51	120.49	454.6
Electricity Bill K$	Without GHP+PV	737.45	790.64	506.02	421.94	280.73	329.09	273.44	176.63	136.44	174.96	162.61	231.97	489.72	4711.7
	GHP+PV No DR	580.8	669.93	387.58	330.6	202.51	242.24	216.99	140.21	98.03	88.68	71.98	100.07	330.05	3459.7
	GHP+PV With DR	584.26	684.93	391.65	347.11	215.81	241.49	218.87	140.21	98.03	88.68	71.98	100.1	334.61	3517.73
Reduction K$	GHP+PV No DR	156.65	120.71	118.44	91.34	78.22	86.85	56.45	36.42	38.41	86.28	90.63	131.9	159.67	1251.97
	GHP+PV With DR	153.19	105.71	114.37	74.83	64.92	87.6	54.57	36.42	38.41	86.28	90.63	131.87	155.11	1193.97
Peak Value MW	Without GHP+PV	11.06	11.91	9.99	9.81	7.04	8.6	7.94	4.92	2.75	4.98	2.77	5.61	9.04	-
	GHP+PV No DR	7.74	8.57	6.24	6.85	4.75	5.92	6.22	3.96	1.68	2.31	1.6	2.47	5.21	-
	GHP+PV With DR	7.69	9.69	6.24	7.85	5.61	5.92	6.22	3.96	1.68	2.31	1.6	2.47	5.21	-
DR Power Reduction MW	GHP+PV No DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GHP+PV With DR	1.51	1.51	1.51	1.51	1.51	1.51	-	-	-	-	-	-	1.51	-
Achievable DR Payment $/Day	GHP+PV No DR	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	GHP+PV With DR	906	906	906	906	906	906	0	0	0	0	0	0	906	-
Actual DR Payment $/Day	GHP+PV No DR	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	GHP+PV With DR	906	906	906	906	906	906	0	0	0	0	0	0	906	-
GHP Cost K$	GHP+PV No DR	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	177.84
	GHP+PV With DR	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	177.84
PV Cost K$	GHP+PV No DR	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	541.66
	GHP+PV With DR	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	41.66	541.58
PV Energy TWH	GHP+PV No DR	0.86	0.61	0.6	0.5	0.48	0.44	0.29	0.24	0.26	0.45	0.71	0.71	0.89	7.11
	GHP+PV With DR	0.86	0.61	0.6	0.5	0.48	0.44	0.29	0.24	0.26	0.45	0.71	0.71	0.89	7.04
Co-Gens Energy TWH	Without GHP+PV	2.94	2.84	2.9	2.66	2.68	2.94	2.84	2.8	2.94	2.65	2.94	2.84	2.94	36.91
	GHP+PV No DR	2.94	2.84	2.91	2.48	2.58	2.94	2.84	2.78	2.94	2.65	2.94	2.84	2.94	36.62
	GHP+PV With DR	2.94	2.84	2.91	2.45	2.55	2.94	2.84	2.78	2.94	2.65	2.94	2.84	2.94	36.56
Co-Gens GHG Ton	Without BSS+PV	1045.86	1012.12	1034.88	946.54	954.89	1045.86	1012.12	997.25	1045.86	944.64	1045.86	1012.12	1045.86	13143.9
	GHP+PV No DR	1045.86	1012.12	1036.65	884.67	917.86	1045.86	1012.12	988.99	1045.86	944.64	1045.86	1012.12	1045.86	13038.47
	GHP+PV With DR	1045.86	1012.12	1036.61	874.58	910.58	1045.86	1012.12	988.99	1045.86	944.64	1045.86	1012.12	1045.86	13021.06
Grid Energy TWH	Without GHP+PV	4.67	5.07	3.5	3.07	1.75	1.9	1.45	1.16	0.99	0.9	1.08	1.18	2.94	29.71
	GHP+PV No DR	3.86	4.52	2.94	2.81	1.41	1.47	1.16	1.01	0.76	0.46	0.4	0.48	2.09	23.37
	GHP+PV With DR	3.89	4.52	2.98	2.84	1.43	1.47	1.19	1.01	0.76	0.46	0.4	0.48	2.13	23.56
Grid GHG Ton	Without GHP+PV	204.16	227.6	237.21	207.05	110.18	110.4	72.32	74.64	60.65	43.95	53.88	47.23	125.76	1575.03
	GHP+PV No DR	162.78	197.34	189.35	173.15	81.13	82.74	54.62	57.19	43.14	18.59	17.9	18.66	83.7	1180.29
	GHP+PV With DR	163.18	197.35	191.56	173.87	81.83	81.76	55.37	57.19	43.14	18.59	17.9	18.67	84.07	1184.48
GHG Reduction	GHP+PV No DR	41.38	30.27	46.08	95.78	66.07	27.66	17.69	25.72	17.51	25.35	35.98	28.57	42.06	500.12
	GHP+PV With DR	40.98	30.25	43.91	105.14	72.65	28.64	16.95	25.72	17.51	25.35	35.98	28.56	41.69	513.33

Table 18| Financial Parameters of Integrated BSS/GHP and PV System

Case	Initial Investment ($)	Average Monthly BSS/GHP Expenses ($)	Average Monthly Cost Saving ($)	Average Monthly Profit ($)	Gross Income ($)	Net Income ($)	Net Profit ($)	Break Even Time (years)	Return of Investment (%)
1	4,457,190	1,765.69	34,817.24	33,051.55	835,613,8	7,932,372	3,475,182	11.24	77.97
2	14,409,611	2,159.91	109,505.67	107,345.76	26,281,361	25,762,983	11,353,372	11.19	78.79
3	4,457,190	1,784.35	49,485.82	47,701.47	11,876,597	11,448,353	6,991,163	7.79	156.85
4	14,409,611	2,194.17	124,330	122,135.82	29,839,196	29,312,596	14,902,985	9.83	103.42
5	2,937,553	992.42	19,075.84	18,083.423	4,578,203	4,340,023	1,402,470	13.53	47.74
6	13,038,951	1026.67	96,304.52	95,277.85	23,113,086	22,866,684	9,827,734	11.4	75.37
7	2,937,553	992.42	29,209.42	28,217	7,010,260	6,772,080	3,834,527	8.67	130.53
8	13,038,951	1026.67	102,864.54	101,838	24,687,492	24,441,091	11,402,110	10.66	87.44
9	4,493,033	1,517.92	51,346.41	49.828.5	12,323,138	11,958,838	7,465,805	7.51	166.2

Case 1: BSS without DR. Case 2:BSS+PV without DR. Case 3: BSS with DR. Case 4: BSS+PV with DR, Case 5: GHP no DR or Hydrogen Market, Case 6: PV+GHP no DR or Hydrogen Market, Case 7: GHP with DR, Case 8: PV+GHP with DR, Case 9: GHP with market participation, hydrogen Price 6.5 $/Kg.

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Appendix A – Nomenclature

Acronyms

BSS Battery Storage System.

PCS Power Conversion System.

DC/AC Direct/Alternating Current.

$Co-gen$ Co-generation.

GHG Green House Gases.

$HOEP$ Hourly Ontario Electricity Prices.

GA Global Adjustment.

SoC State of Charge.

DR Demand Response.

ROI Return on Investment.

Notations

$\underline{X}/\overline{X}$ Upper and lower limit of X.

Indices

t Index of time interval.

i Index of Co-gen.

Sets

T_{month} Set of hours within the studied month.

T_{year} Set of hours within the studied year.

Constant

a, z Storage cycling cost constant parameters.

$A1 : A5$ Storage calendar cost constant parameters.

K Boltzmann constant.

RC Storage residual cost.

C_{B+P}^{Cap} Storage and PCS capital cost.

C_{B+P}^{Ins} Storage and PCS installation cost.

C_{B+P}^{Main} Storage and PCS maintenance cost.

$C_{B}^{cyc,D}$ Storage cycling degradation cost.

$C_{B}^{cal,D}$ Storage calendar degradation cost.

$\eta_{B}^{ch,Dch}$ Average charge and discharge efficiency of storage.

C_{co}^{Cap} Co-gens capital cost.

C_{co}^{Main} Co-gens maintenance cost.

E_{co}^{GHG} GHG tax for the co-gen fuel \$/ton.

E_{fuel} Co-gens fuel cost.

η_P Efficiency of the PCS.

$\overline{P_{PCC}}$ Maximum thermal capacity of the point of connection of the PCS.

Variables

$P_{grid}(t)$ Grid power provided to the campus at time t.

$E_{grid}(t)$ Grid energy provided to the campus at time t.

P_{peak} Grid peak active power.

S_{peak} Grid peak apparent power.

N_B Number of storage units.

$X_{co}(t)$ Decision variable of co-gens output power at time t.

$t_B^{ch}(t)$ Charge/discharge duration of the storage at time t.

$SoC_B(t)$ State of charge of the storage at time t.

$Temp(t)$ Surrounding temperature at time t.

δt Calendar time.

Parameters

PF Average power factor of the campus during the month.

C_B Capacity of storage KWh.

C_P Rate of storage PCS KW.

N_{Co} Number of Co-gen units.

Δt Time step.

Appendix B – Modeling and Theories

In this section the mathematical model and the financial analysis of GHP and BSS are discussed.

Mathematical Model and Optimization Problem Description

The mathematical model can be formulated as an optimization problem, aiming to determine the optimal size and scheduling of the GHP and BSS.

Decision Variables

The optimization decision variables can be defined as follows:

The number of battery units installed, denoted as NB, the storage capacity of the BSS, represented by CB, and the rated power of the PCS denoted by CP, measured in megawatts (MW). These quantities can be defined using equation (3). The charger rate depends on the specific battery model chosen, considered as 1 MW or 2 MW.

$$C_B = N_B \times 3.9(MWh/unit), C_P = N_B \times 1\ or\ 2(MW) \tag{3}$$

The Co-gen units scheduling is represented as a vector of length Tmonth, describing the rated power of each Co-gen unit at various operation hours throughout the billing cycle. It is essential to note that the optimization problem is solved using one-hour time steps. The decision variable for this component can be defined using Equation (4). The constraints in the equation define the upper and lower operational limits of the Co-gen units, which are bounded by the Co-gen's minimum and maximum rated powers. These constraints ensure that the Co-gen units operate within their specified power range.

$$X_{co}^{i} = \left[x_{co}^{i}(1) \dots x_{co}^{i}(T_{month})\right], \forall\, i \in N_{co}, wehre\ \underline{X^{i}}_{co} \le x_{co}^{i}(t) \le \overline{X^{i}}_{Co}, \forall\, t \in T_{month} \tag{4}$$

The BSS scheduling is represented as a vector of length Tmonth, which specifies the duration of charge and discharge operations for each hour of the month. This decision variable can be defined using Equation (5). The constraints in the equation set the upper and lower operational limits for the charging time as a positive value (indicating charging the BSS for one hour) and negative value (representing discharging the BSS for one hour). These constraints ensure that the BSS operates within its charging and discharging capabilities during each hour of the month.

$$T_B^{Ch} = \left[t_B^{Ch}(1) \dots t_B^{Ch}(T_{month})\right], wehre\ -\Delta t \le t_B^{Ch}(t) \le \Delta t\ , \forall\, t \in T_{month} \tag{5}$$

The GHP decision variables including PtH power, representing the power consumption of the electrolyzer and the HtP power, representing the electric power generated by the fuel cell as as follows:

$$\begin{aligned} P^{P2H} &= [P^{PtH}(1) \dots P^{PtH}(T_{month})],\ wehre\ 0 \le P^{PtH}(t) \le \overline{P^{P2H}}, \forall\, t \in T_{month} \\ P^{H2P} &= [P^{HtP}(1) \dots P^{HtP}(T_{month})],\ wehre\ 0 \le P^{HtP}(t) \le \overline{P^{H2P}}, \forall\, t \in T_{month} \end{aligned} \tag{6}$$

Grid Supplied Energy

Upon measuring the electric power generated by the Co-gen units and the charge or discharging energy of the BSS and GHP, it becomes possible to calculate the energy required to be supplied from the grid. In this case, the grid energy at a specific hour t is obtained by subtracting the power generated by the Co-gen units from the campus load, and then adding the energy needed to input power of the BSS/GHP or subtracting the energy output from the BSS/GHP. Mathematically, the grid energy can be described using equation (7). This equation outlines the relationship between the various energy components and determines the net energy exchange with the grid at each hour of operation.

$$E_{grid}(t) = \left(P_L(t) - P^{HtP}(t) + P^{PtH}(t)\right).\Delta t - \sum_{i=1}^{N_{co}} X_{co}^{i}(t)\,.\Delta t + t_B^{ch}(t).\,C_P, \sim\forall t \in T_{month} \tag{7}$$

Cost Estimation

The overall payment per year is divided into three different components. The first component is the BSS/GHP cost, which encompasses the annual capital cost of the plant, the yearly installation cost, the annual maintenance cost, and the cost associated with the plant degradation. This is expressed mathematically by equation (8).

$$C(B+P) = \frac{C_{B+P}^{Cap} + C_{B+P}^{Ins}}{Lifetime} + C_{BCC+P}^{Main} + \sum_{t=1}^{T_{year}}\left[C_B^{cyc,D}(t) + C_B^{cal,D}(t)\right] \tag{8}$$

The cycle degradation cost $C_B^{cyc,D}(t)$ can be defined as follow:

$$C_B^{cyc,D}(t) = \left(C_B^{Cap} - RC_B\right).\,Q_B^{cyc}(t), wehre \tag{9}$$

$$Q_B^{cyc}(t) = DoD_B(t) \times C_B \times ACC_B(t) \times \eta_B^{ch,Dch}$$

$$DoD_B(t) = 1 - SoC_B(t), and ACC_B(t) = \frac{a}{[DoD_B(t)]^z}$$

The calendar degradation cost $C_B^{cal,D}(t)$ can be defined as follow:

$$C_B^{cal,D}(t) = \left(C_B^{Cap} - RC_B\right).\,Q_B^{cal}(t), wehre \tag{10}$$

$$Q_B^{cal}(t) = C_B \times \left[A_1 e^{\left(\frac{-A_2 + A_3.DoD_B(t)}{K \times Temp(t)} + A_4.DoD_B(t)\right)} - A_5\right].\,\delta t$$

The parameter of the cycle and the calendar degradation are obtained from previous research and The parameter of the cycle and the calendar degradation are obtained from previous research and Table 18 summarizes the values of these parameters.

The second component is the Co-gen units cost, which includes: 1) the capital and maintenance costs per year, 2) fuel cost incurred for generating electric energy, and 3) the carbon tax attributed to the greenhouse gas emissions produced by Co-gen units. This cost is mathematically represented by Equation (11). This equation outlines the relationship between the fuel cost, the carbon tax, and the electric energy generated by Co-gen units, providing a comprehensive representation of the associated expenses.

Table 19 | Cycle and Calendar Degradation parameters

Cycle Parameters	Calendar Parameters
$RC = 20C_{BCC}^{Cap}\%$, a=2744, z=1.665	$A_1 = 2.563 \times 10^5 \%/day$, $A_2 = 0.5531ev$, $A_3 = -0.3672ev$, $A_4 = 12.34$, $A_5 = 0\%/day$ and $k = 1.38 \times 10^{-23} J/K$

$$C(Co-gen) = \frac{C_{co}^{Cap} + C_{co}^{Main}}{Co-gen\sim Lifetime} + \left[E_{fuel} + E_{co}^{GHG}\right] \times \sum_{m=1}^{Year} \sum_{t=1}^{T_{month(m)}} \sum_{i=1}^{N_{co}} X_{co}^{i}(t) \,.\, \Delta t \tag{11}$$

The hydrogen system cost can be defined as the sum of the electrolyzer, fuel cell and tank costs, defined by the $/KW and $ m3 value. This cost can be expressed as follow:

$$C(H_2) = \frac{Size(PtH) \times C^{PtH} + Size(HtP) \times C^{HtP} + Size(tank) \times C^{tank}}{H_2\sim Lifetime} \tag{12}$$

The third component is the electric power grid bill/cost, encompassing the payment components. The bill is calculated on a monthly basis and is mathematically represented by Equation (13). This equation captures the relationship between various elements of the grid bill and provides a comprehensive representation of the associated costs incurred by the campus in its electricity consumption.

$$C(grid) = \sum_{m=1}^{year} \Big[\& \sum_{t=1}^{T_{month}} P_{grid}(t) \times \big(HOEP(t) + GA(t)\big) + \big(254.72 + 4500 + (7.2 + 0.62).S_{peak} + (2.5587 + 2.9271).P_{peak}\big) + \big(0.0039 \times \sum_{t=1}^{T_{month}} P_{grid}(t) + 0.26\big)\Big] \tag{13}$$

Optimization Problem Constraints

The constraints of the optimization problem are carefully formulated to guarantee that the output solution, obtained after solving the optimization problem, is valid and realistic. These constraints serve the following purposes:

Prevent overcharging or discharging of the storage, which could lead to potential damage and negatively impact its lifespan. To address this issue, the first constraint is added to restrict the State of Charge (SoC) of the BSS within the maximum and minimum limits. For this study, the maximum and minimum limits are set at 90% and 20%, respectively. These constraints ensure that the BSS operates within the safe and sustainable charging and discharging ranges.

The SoC can be measured at each time t by equation (14):

$$SoC_B(t+1) = SoC_B(t) + \beta_P \frac{t_B^{ch}(t) \times C_P}{C_B}, where\ \beta_P = \begin{cases} \eta_P\ if\ t_B^{ch}(t) \geq 0 \\ \frac{1}{\eta_P}\ if\ t_B^{ch}(t) < 0 \end{cases} \tag{14}$$

$$SoC_B(1) = k\%\ it\ is\ assumed\ to\ be\ 55\%\ at\ the\ initial\ stage$$

Then, the SoC constraints is formulated as:

$$\underline{SoC_B} \leq SoC_B(t) \leq \overline{SoC_B} \tag{15}$$

Similarly, the SoC of the hydrogen storage can be measured during the optimization process as hydrogen is being produced and stored by the PtH unit minus the hydrogen that is used by the HtP unit and the hydrogen consumers:

$$SoC_{H_2}(t+1) = \left(1 - \gamma^{Dis}\right)SoC_{H_2}(t) - H_2^L + \eta^{PtH} \times \zeta^{PH} \times P^{PtH}(t) - \frac{\zeta^{PH} \times P^{HtP}(t)}{\eta^{HtP}} \tag{16}$$

Then, the hydrogen storage SoC range is expressed as follows:

$$0 \leq SoC_{H_2}(t) \leq Size(tank) \tag{17}$$

Another constraint is imposed to ensure that the rated power of the PCS charger does not exceed the thermal capacity of the point of common coupling. In other words, the power provided by the PCS charger can be accommodated by the point of common coupling without causing any stability issues and remains within the capacity that the breaker can handle. This constraint is mathematically defined by Equation (18). It guarantees that the charging operation remains within the safe operating limits of the point of common coupling and avoids any potential overheating or instability problems.

$$C_P \leq \overline{P}_{PCC} \tag{18}$$

A constraint is added to limit the decision variables within the operation ranges for co-gen units and the BSS charging and discharging quantities.

$$\underline{X_{co}^{i}} \leq X_{co}^{i}(t) \leq \overline{X_{co}^{i}}, \forall t \in T_{year}, \ \cap -\Delta t \leq t_B^{ch}(t) \leq \Delta t, \ \forall t \in T_{year} \tag{19}$$

Appendix C – Class A Demand Response Program

This section emphasizes the potential enhancement of the BSS and GHP economic viability at the Keele Campus, York University campus by integrating its core functionalities with the DR programs. Additionally, it explores the indirect application of the BSS and GHP to support the grid during peak periods, steering clear of peaker generators like natural gas and biomass gas-fired generators, resulting in an indirect reduction of GHG emissions. This section aims to briefly introduce DR rules, activation times, power reduction calculations, payment and charge rules. It underscores the indirect GHG reduction achieved through participation in DR programs.

Demand Response Program Rules

IESO issues the Market Manual outlining the key rules governing the DR programs. The initiation of this involves a list of candidates expressing interests in participating in the DR program. Each candidate provides two essential pieces of information: 1) the amount of power reduction during the DR event (KW), and 2) the capacity price, denoting the incentive payment received from the IESO/Toronto Hydro ($/MW) for reducing the power demand. IESO then arranges the candidates based on the capacity price, selecting participants from the lowest to the highest suggested price until the required amount of the DR capacity is fulfilled. The clearing price is subsequently determined based on the highest price among the last selected participants, as shown in Figure 31 [2].

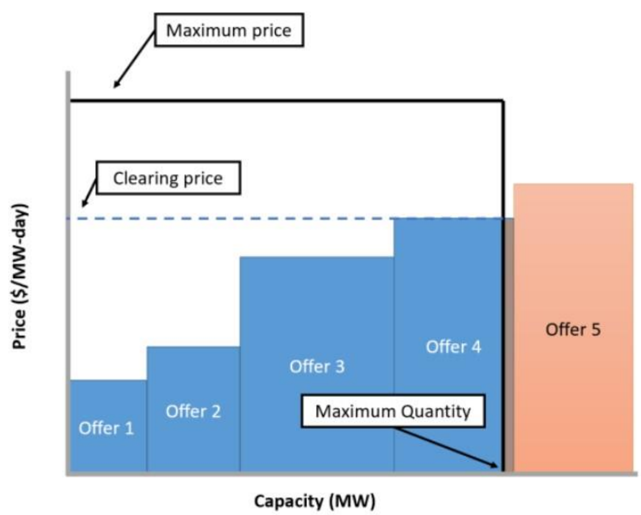

Figure 31 | Process of selecting the DR participant and determining the clearing price based on the IESO/Toronto Hydro required capacity.

Participants face a trade-off, aiming for maximum cost savings by increasing the capacity price while staying within an acceptable range to ensure selection.

To qualify for participation in the DR program, York University must adhere to the following eligibility criteria:

- Geographical Location: Participating loads must be situated within the service areas of either Manby TS or Horner TS.
- Resource Capacity: The combined resource capacity must be a minimum of 500 kW. This capacity can be derived from a single facility or aggregated from multiple contributors. From here, it is clear that the minimum size for the PCS is 500 KW and the minimum storage size is five times this value to ensure meeting the DR 4 hours activation window.
- Aggregation of DR Resources: Aggregation of DR resources is allowed, provided that individual contributors are located within the service areas of Manby TS or Horner TS. Aggregators can pool capacity across both stations, encompassing loads served by either.
- Market Capacity Usage: The Participants in the program cannot simultaneously use the same capacity in the IESO markets as well as Toronto Hydro.
- Exclusion of Individual Residential Customers: The program is exclusively available to entities falling under the General Service (GS) rate class, excluding individual residential customers.

As York University fulfills the minimum power criteria required by the market, it stands a strong contender for participation in DR programs, thereby enhancing cost-saving opportunities through the efficient operation of the GHP and BSS.

Demand Response Management: Preparation for Demand Response Event

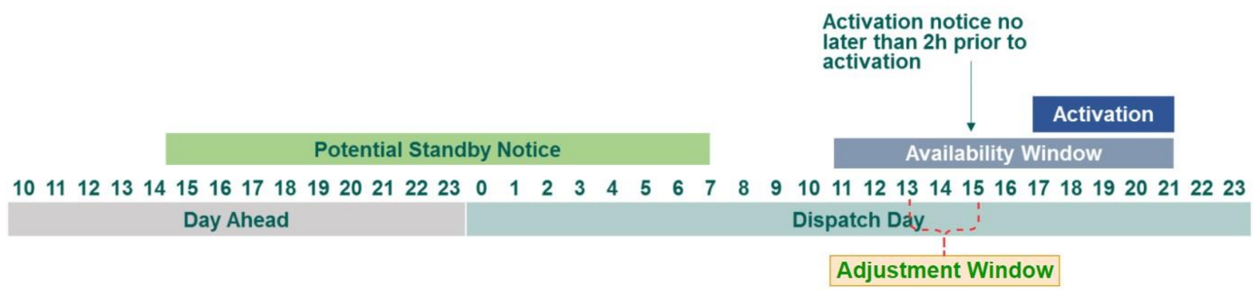

Figure 32| DR activation timeline and important window of analysis.

Once York University is designated as a participant in the DR program, collaboration ensues between the IESO/Toronto Hydro and the university to facilitate seamless operations during DR events. The management process initiated by the IESO involves issuing standby notices via email or calls, commencing from 14:00 the day before up to 7:00 on the DR event day. In extreme cases, the standby notice may be received as late as 3 hours before the DR event. The DR events can transpire anytime between 11:00 and 21:00, constituting the activation window, with each DR event lasting any cascaded four-hour period within this time frame. Participants receive an activation notice no later than 2 hours before the activation. Figure 32 illustrates a timeline of the DR process activation, showcasing different key windows.

In this example, a DR activation occurs at 17:00 and concludes at 21:00. Participants receive the activation notice no later than 15:00 and the standby notice no later than 7:00 on the same day. Another critical window is the adjustment window, which spans the past 3 hours (from 13:00 to 15:00 in this example), one hour before the activation. The adjustment window is crucial for calculating the baseline of the load profile to ensure the fulfillment of the agreed MW reduction during DR activation. It is essential to note that only one DR event can occur per day. According to historical IESO records, York University anticipates receiving only six DR activation events between May 1, 2024, and October 31, 2024.

Demand Response Management: Payment and Charges Process

The ultimate cost savings achieved through the DR programs are contingent on effectively meeting the contracted MW reduction. This outcome comprises two key components: 1) Incentive payment, earned by adhering to the DR event contract stipulations, and 2) charges for the sub-optimal performance, categorized into dispatch and capacity charges. The monthly payment for participating in the DR event is determined by multiplying the clearing price ($/MW), the agreed-upon MW reduction, and the number of business days in the month, as illustrated by equation (20), where the negative sign indicates saving.

$$C(DR) = -P_{DR}^{IESO} \times CP_{DR} \times N_{BD} \tag{20}$$

The dispatch charges are levied in the event of falling short of 85% of the agreed MW reduction for one activation event. These charges are computed by multiplying the clearing price ($/MW), the agreed-upon MW reduction, and a Non-performance factor ranging between 1 and 2, contingent on the month in which the failure occurs. Equation (21) explains the calculation of dispatch charges. Notably, dispatch charges compensate for approximately one or two business days' worth of payment. The NP factor is defined as follows: {May: 1.0, June: 1.5, July: 2.0, August: 2.0, Sept: 2.0, October: 1.0}.

$$Dis^{ch} = P_{DR}^{IESO} \times CP_{DR} \times NP \tag{21}$$

The capacity charges are deemed particularly detrimental as they directly offset the DR payment to zero. These charges are imposed in instances where the achieved MW reduction falls below 80% of the agreed-upon amount for any test activation events. The calculation of capacity charges involves multiplying the clearing price ($/MW), the agreed-upon MW reduction, and the number of business days in the month during which the failure transpires as formulated in the following:

$$Cap^{ch} = -C(DR) = P_{DR}^{IESO} \times CP_{DR} \times N_{BD} \tag{22}$$

Demand Response Management: Measurement of Baseline and verification of the MW Reduction

Comprehending how IESO/Toronto Hydro evaluates the reduction during DR activation holds utmost significance in determining whether York University has achieved the agreed MW reduction or encountered failure. This understanding is crucial for assessing the percentage of failure and the associated charges. IESO establishes a standardized baseline for reduction calculation, measuring the reduction as the variance between this baseline and the power supplied to the campus from the grid throughout the DR activation window. Equation (23) provides the mathematical expression illustrating this process, where DR(t) is a binary variable indicating whether a DR event exists at time t.

$$P_{DR}(t) = \left(P_{BL}(t) - P_{grid}(t)\right) \times DR(t) \tag{23}$$

The baseline for each hour t is determined by the multiplication of two components: 1) The standard baseline and 2) in-day adjustment factor, as illustrated by equation (24).

$$P_{BL}(t) = P_{Standrd-BL}(t) \times AF_{grid}(t) \tag{24}$$

The standard baseline is calculated as the average of the highest 15 measurement data values for the corresponding hour, considering the last 20 applicable business days preceding the activation. This can be expressed mathematically as follows:

$$P_{Standrd-BL}(t) = \frac{\sum_{v=1}^{v=15} P_{grid}^{v}(t)}{15} . P_{grid}^{v}(t) = Max\left(\{P_{grid}(t) : t \in past\ 20\ Business\ days\}\right) \tag{25}$$

The in-day adjustment factor is determined as the ratio between the energy consumption during the adjustment window on the day of activation (refer to Figure 32) and the energy consumption of the standard baseline during the corresponding adjustment window. Mathematically, this can be expressed as follows:

$$AF_{grid}(t) = \frac{\sum_{t_{activation}-4}^{t_{activation}-2} P_{grid}(t)}{\sum_{t_{activation}-4}^{t_{activation}-2} P_{Standrd-BL}(t)} . S.T\ 0.8 \le AF_{grid}(t) \le 1.2 \tag{26}$$

The in-day adjustment factor is constrained to fall within the range of 0.8 to 1.2. Its purpose is to fine-tune the baseline, aligning it with the load consumption pattern on the day of activation. This adjustment ensures fairness for both the utility and the DR participant.

Impact on Greenhouse Gas Reduction

Table 20| Fuel Types Used in Electric Power Generation and their Contribution to the CO2 Generation

Type	NUCLEAR	GAS	HYDRO	WIND	SOLAR	BIOFUEL	Total Output
TWH	78.8	15.2	38	13.8	0.75	0.3	146.85
% Generation	53.7	10.4	25.9	9.4	<1	<1	100
Co2 Ton/TWH	12	400	24	11.5	45	230	-
Co2 Ton	945.6	6080	912	158.7	33.75	69	8199.05
% Co2	11.53	74.15	11.12	1.93	0.41	0.84	100

One advantage of participating in DR programs is providing support to the utility during high energy demands or peak periods. These peaks are typically addressed by a peaker generation unit, offering a rapid response to electric demands. However, these peaker generation facilities often rely on natural gas and bio-fuel, causing increased GHG emissions. Table 19 provides a summary of the types of electric power generation used by the IESO, the total generated power for 2022, and the corresponding CO2 emissions in tons produced by each source.

Notably, natural gas accounts for approximately 400 tons per terawatt-hour (Ton/TMW), making it the highest GHG-emitting source, followed by bio-fuel, generating around 230 ton/TMW of CO2. Despite natural gas contributing to only 10.4% of the total generation, it is responsible for approximately 74.15% of the total CO2 emissions, resulting in 6080 tons annually, with the figure expected to rise in 2023.

The use of peaker generation during peak hours causes fluctuations in the hourly CO2 emissions, determined by the contribution of each type of electric power generation. Essentially, the time span during the day that relies on natural gas and bio-fuel exhibits higher GHG emissions. Figure 31 illustrates the average hourly CO2 generated in kilograms per megawatt during a day in March 2022.

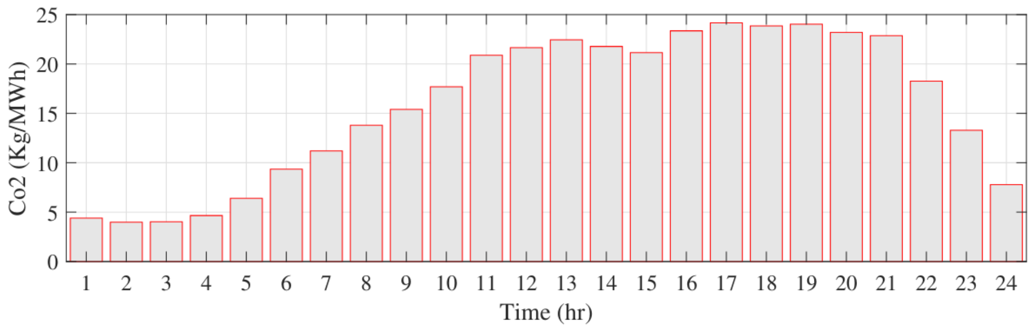

Figure 31| Amount of Co2 Generated in Kg/MWh at Different Time of The Day for Mar 2022.

It is evident that for the same amount of energy (1 MWh), the CO2 emissions in kilograms vary significantly. The CO2 emissions reach their highest values during the period from 11:00 to 21:00, aligning with the availability window of DR events. The primary role of the BSS is to store electric energy during periods of lower emissions and release this energy during DR activation events to reduce CO2 emissions. The amount of Co2 generated by the grid in order to provide the electric power needed by the campus is defined by equation (27).

$$Co2_{grid} = \sum_{m=1}^{Year} \sum_{t=1}^{T_{month(m)}} P_{grid}(t) \times Co2(t) \tag{27}$$