

PATHWAY TO DECARBONIZATION FEASIBILITY STUDY

CITY OF TEMISKAMING SHORES

CITY HALL
325 Farr Drive, Haileybury, ON

WalterFedy Project No: 2023-0734-10

July 21, 2025



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Project Number: 2023-0734-10

July 21, 2025

Mathew Bahm
Director of Recreation
City of Temiskaming Shores
325 Farr Drive
Haileybury, ON POJ 1K0

Dear Mathew,

RE: Pathway to Decarbonization Feasibility Study

WalterFedy is pleased to submit the attached Pathway to Decarbonization Feasibility Study report to the City of Temiskaming Shores. This study covers the agreed-upon scope and provides a Pathway to Decarbonization Feasibility Study for the City Hall, which is located at 325 Farr Drive in Haileybury, ON. Certain parts of this report are designed to be viewed in digital/PDF format. This approach will enable the reader to zoom in on images and navigate the document using the provided hyperlinks.

The report was completed based on the information provided by the City of Temiskaming Shores, using the supplied and collected data, engineering judgment, and various analysis tools to arrive at the final recommendations.

All of which is respectfully submitted,

WALTERFEDY



Jordan Mansfield, P.Eng., M.Eng., CEM, CMVP
Energy Engineer
Energy and Carbon Solutions

jmansfield@walterfedy.com
519 576 2150 x 336

Contents

	Page
EXECUTIVE SUMMARY	1
1 INTRODUCTION	5
1.1 Overview	5
1.2 Background	5
1.2.1 Corporate Greenhouse Gas Reduction Plan	5
1.2.2 Asset Management Plan	5
1.3 Contact information	6
2 FACILITY DESCRIPTION	7
2.1 Facility description methodology	7
2.2 Facility overview	7
2.3 Building information	8
2.4 Space use	10
2.5 Building Envelope	12
2.6 HVAC	15
2.7 Domestic hot water	24
2.8 Lighting	25
2.9 Process and plug loads	28
2.10 Water fixtures	29
2.11 Utility services	30
2.12 Onsite energy sources	31
2.13 Electrical infrastructure	32
3 UTILITY USE ANALYSIS	34
3.1 Utility analysis methodology	34
3.2 Utility analysis assumptions	36
3.3 Electricity metered utility use	37
3.4 Natural gas metered utility use	39
3.5 Utility use baseline	40
3.6 Benchmarking analysis	41
3.7 ENERGY STAR Portfolio Manager benchmarking analysis	43
3.8 Utility use analysis discussion	44
4 ENERGY MODEL DEVELOPMENT	45
4.1 Energy model development methodology	45
4.2 Hourly utility use profiles	46
4.3 Monthly utility use profiles	49
4.4 Calibration analysis	50
4.5 End use analysis	54
5 MEASURE ANALYSIS	55
5.1 Measure analysis methodology	55
5.2 Measure analysis assumptions	57
5.3 Measure identification	60
5.4 Boiler plant to ASHP	61
5.5 Boiler plant to ASHP hybrid	64
5.6 Carbon offsets 20	67
5.7 Geothermal deep retrofit with Lake Loop	69
5.8 HVAC re-commissioning	73
5.9 Interior LED lighting upgrade	76

5.10	Roof upgrade to high performance	78
5.11	RTUs to ASHP with electric backup	80
5.12	RTUs to ASHP with natural gas backup	83
5.13	Solar PV canopy	86
5.14	Solar PV rooftop	89
5.15	Wall upgrade to high performance	92
5.16	Windows and doors to high performance	94
5.17	Measure risk analysis	96
5.18	Measure analysis summary	98
6	SCENARIO ANALYSIS	99
6.1	Cluster scenario analysis methodology	99
6.2	Cluster scenario objectives	99
6.3	Cluster scenario composition	100
6.4	Cluster scenario performance analysis	101
6.5	Plan scenario development	111
6.6	Plan performance analysis	115
6.7	Plan performance summary	119
6.8	Scenario analysis discussion	120
7	END	121

List of Figures

1	Recommended plan scenario composition, indicating which measures are implemented when and at what cost in each plan scenario	2
2	Recommended scenario performance	3
3	City Hall aerial view	7
4	City Hall - Floor Plan - Level 1	11
5	City Hall - Floor Plan - Level 2	11
6	Brick veneer	13
7	The curtain wall on the east elevation	13
8	East elevation of office area	13
9	Front entrance doors with glazing	13
10	The hollow metal door on the south elevation	13
11	Insulation above the ceiling in the Receiver room	13
12	Laminated wood architectural feature in poor condition	13
13	Metal panelling on the west elevation	13
14	North elevation	13
15	Overhead in the Receiver room	13
16	Roof hatch for access to Northern roof	13
17	The roof membrane on the north section	13
18	South elevation	14
19	Underside of the roof	14
20	West elevation of office area	14
21	Window shades in the boardroom	14
22	B1	19
23	BP1	19
24	B2	19
25	BP2	19
26	B3	19
27	BP3	19
28	Ductless split unit	19

29	Ductless split unit in the IT room	19
30	ERV1 BAS graphic	19
31	ERV1 Trends	19
32	ERV1	19
33	ERV2	19
34	ERV2 Schedule	20
35	ERV2 is located in the ceiling space above the Storage room	20
36	ERV2 Trends	20
37	Electric baseboard heater in janitor closet	20
38	Electric duct heater	20
39	Exhaust fan timer in the boardroom	20
40	The exhaust fan is controlled via a thermostat in the elevator room	20
41	HU1	20
42	HU2	20
43	Heat wheel motor on ERV1	20
44	Hot water loop	20
45	Hot water loop - Boilers	20
46	Hot water loop - Pump trends	20
47	Hot water loop - Temperature July	20
48	Hot water loop - Temperature June	20
49	Hydronic cabinet heater	21
50	In-slab heating - Manifold 3, 4, and 5	21
51	In-slab heating - Manifold 1 and 2	21
52	Lighting control and trap seal	21
53	MP1	21
54	MP3 and MP4	21
55	Main Menu	21
56	Manifold 4 in the Receiver room	21
57	P1, P2, and PC	21
58	PB3	21
59	RTU1	21
60	RTU1	21
61	RTU1 Humidity Trends	21
62	RTU1 Schedule	21
63	RTU1 SPST trends - 6 months	21
64	RTU1 Temperature trends - 1 year	22
65	RTU1 Temperature trends - 1 month	22
66	RTU1 Trends	22
67	RTU2 - Humidity trend	22
68	RTU2 - Temperature trend	22
69	RTU2 - Temperature trend - 1 month	22
70	RTU2	22
71	RTU2	22
72	RTU2 is in hand to be ON continuously	22
73	RTU2 Schedule	22
74	RTU3	22
75	RTU3	22
76	RTU3 filters are clean	22
77	RTU3 Schedule	22
78	RTU3 Temperature trend	22
79	RTU4	23
80	RTU4	23
81	RTU4 Schedule	23
82	RTU4 Trends	23

83	Room Control - Level 1	23
84	Room Control - Level 2	23
85	The thermostat in the boardroom	23
86	The thermostat in the council chambers	23
87	VAV - Main Foyer	23
88	VAV - Art Gallery	23
89	VAV - Office RM06	23
90	VAV - Office RM09	23
91	Electric DHW tank in the Receiver room	24
92	Electric DHW tank in the mechanical room	24
93	Ceiling-mounted occupancy sensor in the meeting room	26
94	Contactor for northern parking lot lights that connect to the BAS	26
95	Switched-mounted occupancy sensor in the receiver room	26
96	Switched-mounted occupancy sensor in the men's washroom	26
97	Type A2 and G in the boardroom	26
98	Type C fixture in the north corridor	26
99	Type C fixtures in the storage room	26
100	Type C fixtures in the receiver room	26
101	Type C fixtures in the men's washroom	26
102	Type E fixture in the mechanical room	26
103	Type G fixture on the second floor	26
104	Type H1 fixtures in the lobby	26
105	Type H2 fixtures in the art gallery	27
106	Type H fixtures in the council chambers	27
107	Type J fixture in the parking lot	27
108	Type L fixture on the north elevation	27
109	Electric air dryer in the men's washroom	28
110	Elevator	28
111	IT equipment	28
112	IT equipment for the council chambers - 1	28
113	IT equipment for the council chambers - 2	28
114	Kitchenette appliances	28
115	Kitchenette in the first-floor office area	28
116	TV in the boardroom	28
117	Typical office equipment	28
118	Kitchenette sink	29
119	Motion-activated handwashing faucet	29
120	Sink in the first-floor office area	29
121	Slop sink	29
122	Urinal rated for 3.8 lpf	29
123	Electricity meter	30
124	Natural gas meter for the building	30
125	Natural gas meter serving the generator	30
126	Natural gas generator	31
127	75 kVA transformer to panel PP-A	32
128	75 kVA transformer for RTU1 and RTU2	32
129	Main service disconnect	32
130	Panel DP1	33
131	Panel D	33
132	Panel IG-E	33
133	Panel IG-PC, B, and DP-2 in the Receiver room	33
134	Transfer switch	33
135	Two 45 kVA transformers in the Receiver room	33
136	Hourly electricity use	37

137	Hourly electricity use hairball plot	37
138	Monthly electricity use	38
139	Monthly natural gas use	39
140	Electricity use intensity benchmarking analysis comparison	41
141	Natural gas use intensity benchmarking analysis comparison	41
142	Total energy use intensity benchmarking analysis comparison	42
143	GHG emissions intensity benchmarking analysis comparison	42
144	Energy Star energy performance scorecard.	43
145	Hourly electricity utility use by end use (made by calibrated energy model)	47
146	Hourly natural gas utility use by end use (made by calibrated energy model)	48
147	Monthly utility use profiles for each modelled utility	49
148	Electricity calibration analysis (metered vs modelled utility use)	50
149	Natural gas calibration analysis (metered vs modelled utility use)	51
150	Electricity end use breakdown (calculated by calibrated energy model)	54
151	Natural gas end use breakdown (calculated by calibrated energy model)	54
152	Utility cumulative use sensitivity analysis	96
153	GHG cumulative emissions and life cycle cost sensitivity analysis	97
154	Scenario composition	100
155	Electricity utility use expected yearly for each scenario by end use	103
156	Natural gas utility use expected yearly for each scenario by end use	104
157	Equivalent energy use expected yearly for each scenario by end use	105
158	GHG emissions expected yearly for each scenario by end use	106
159	Utility costs expected yearly for each scenario by end use	107
160	Project cost expected for each scenario by measure	108
161	Life cycle cost expected for each scenario by cost item	109
162	GHG cumulative reduction per life cycle cost (LCC) dollar expected for each scenario by utility	110
163	Plan scenario composition, indicating which measures are implemented when and at what cost in each plan scenario	112
164	Electricity yearly utility use projection for each scenario	115
165	Natural gas yearly utility use projection for each scenario	116
166	GHG yearly emissions projection for each scenario	117
167	Life cycle yearly cost (after discounting to present value) projection for each scenario	118

List of Tables

1	Recommended plan scenario performance summary	4
2	Asset management summary for this facility	6
3	Contact information	6
4	Facility overview	7
5	Space use summary	10
6	Building envelope summary	12
7	Air distribution systems summary	15
8	Water distribution systems summary	15
9	Heating systems summary	16
10	Cooling systems summary	16
11	Lighting systems summary	25
12	Water fixture summary	29
13	Baseline performance data source for each utility	34
14	GHG emissions factor assumptions	36
15	Utility cost rate assumptions for the baseline year (2023)	36
16	Baseline utility use performance	40
17	Utility and end use summary and definitions	45
18	Statistical calibration analysis summary	52

19	Utility cost rate future assumptions	57
20	Financial incentive assumptions	58
21	Life cycle cost analysis assumptions	58
22	Risk parameter and case definitions	58
23	Measure identification and triaging summary	60
24	Project cost estimate (Boiler plant to ASHP)	62
25	Boiler plant to ASHP analysis results summary	63
26	Project cost estimate (Boiler plant to ASHP hybrid)	65
27	Boiler plant to ASHP hybrid analysis results summary	66
28	Carbon offsets 20 analysis results summary	68
29	Project cost estimate (Geothermal deep retrofit with Lake Loop)	71
30	Geothermal deep retrofit with Lake Loop analysis results summary	72
31	Project cost estimate (HVAC re-commissioning)	74
32	HVAC re-commissioning analysis results summary	75
33	Project cost estimate (Interior LED lighting upgrade)	77
34	Interior LED lighting upgrade analysis results summary	77
35	Project cost estimate (Roof upgrade to high performance)	79
36	Roof upgrade to high performance analysis results summary	79
37	Project cost estimate (RTUs to ASHP with electric backup)	81
38	RTUs to ASHP with electric backup analysis results summary	82
39	Project cost estimate (RTUs to ASHP with natural gas backup)	84
40	RTUs to ASHP with natural gas backup analysis results summary	85
41	Project cost estimate (Solar PV canopy)	87
42	Solar PV canopy analysis results summary	88
43	Project cost estimate (Solar PV rooftop)	90
44	Solar PV rooftop analysis results summary	91
45	Project cost estimate (Wall upgrade to high performance)	93
46	Wall upgrade to high performance analysis results summary	93
47	Project cost estimate (Windows and doors to high performance)	95
48	Windows and doors to high performance analysis results summary	95
49	Measure analysis summary	98
50	Scenario objectives	99
51	Cluster composition	101
52	Scenario analysis summary	102
53	Plan scenario identification and objectives	111
54	Scenario composition summary	113
55	Minimum performance scenario measure implementation timeline	113
56	Aggressive deep retrofit measure implementation timeline	113
57	Comprehensive measure implementation timeline	114
58	Organizational goal alignment measure implementation timeline	114
59	Business as usual measure implementation timeline	114
60	Plan performance summary	119

EXECUTIVE SUMMARY

WalterFedy was engaged by the City of Temiskaming Shores to complete a Pathway to Decarbonization Feasibility Study for the City Hall. The objective of this engagement is to identify and analyze measures that reduce utility use, GHG emissions, and utility costs at the City Hall, and to analyze various GHG Reduction Pathways consisting of combinations of measures. Based on these analyses, the objective is also to recommend the preferred GHG Reduction Pathway for implementation. To achieve this objective, the following steps were taken.

1. **Facility description.** The existing conditions of the facility were reviewed through available documentation and a site survey completed on 2024-04-16 to gain an understanding of the facility and its operations. A facility description, summarizing findings, is provided in Section 2.
2. **Utility use baseline.** Metered utility data provided by the City of Temiskaming Shores was reviewed to understand historical utility use trends, and to establish the utility use baseline for the City Hall. Findings are documented in Section 3.
3. **Energy model development.** A calibrated energy model was developed from a bottom-up hourly analysis considering historical weather patterns, and the insight gained from reviewing the facility's existing conditions and historical utility use data. Findings are documented in Section 4.
4. **Measure analysis.** Measures intended to achieve the City of Temiskaming Shores's goals were identified and analyzed. Analysis includes conceptual design development and utility analysis quantifying utility use impacts, GHG emissions and utility costs for each measure. Findings are documented in Section 5.
5. **Scenario analysis.** Scenario analysis was completed to estimate the costs and benefits expected from implementing various combinations (i.e. scenarios) of the measures that were individually analyzed in Section 5, accounting for the interactive effects between measures within each scenario. Findings are documented in Section 6.

All analysis was completed using the calibrated energy model, which matches metered yearly electricity and natural gas utilities used by the City Hall by precisely capturing existing conditions of the building within the model. The model tracks each utility end use for every hour of a complete year.

Based on the analysis completed and discussions with the client, the GHG reduction pathway that is recommended for implementation is as follows.

- **Minimum performance scenario**

The recommended plan scenario composition is presented in Figure 1, which is a measure implementation timeline plot indicating which measures were assumed to be implemented in which plan scenarios and when, and the estimated project cost of each measure. The measures are also colour-coded according to measure group.

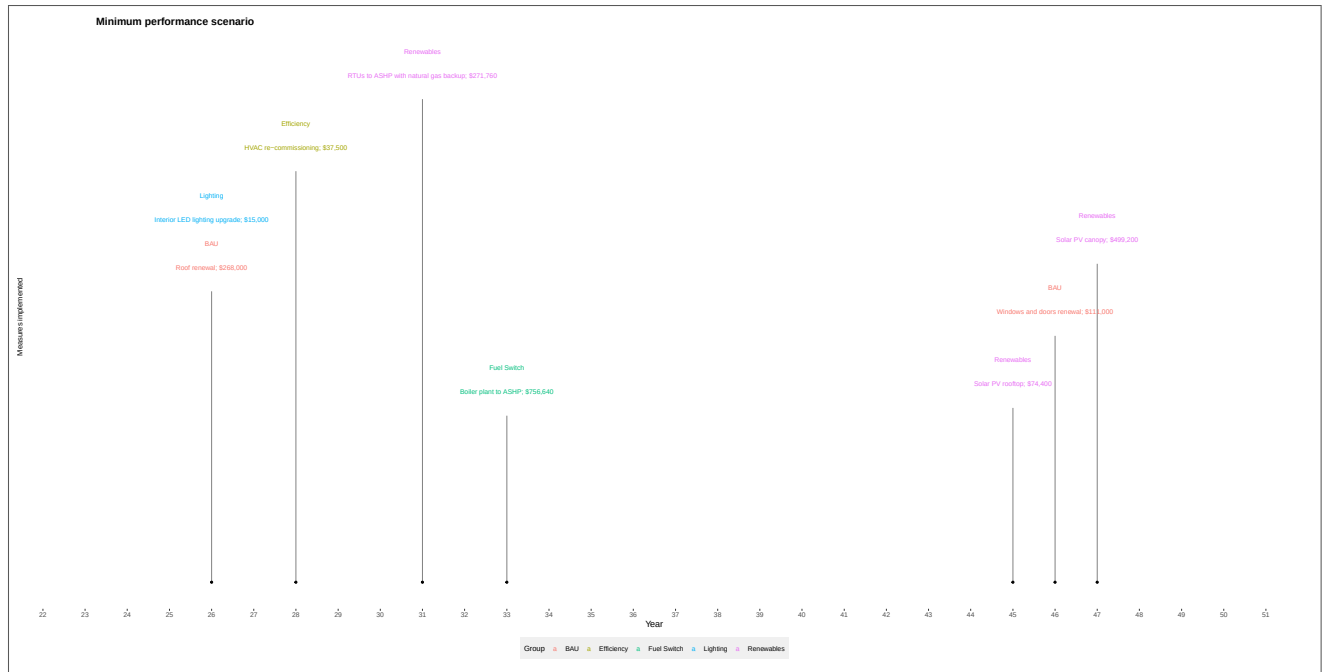


Figure 1: Recommended plan scenario composition, indicating which measures are implemented when and at what cost in each plan scenario

The following plots in Figure 2 show the results for the recommended GHG reduction pathway.

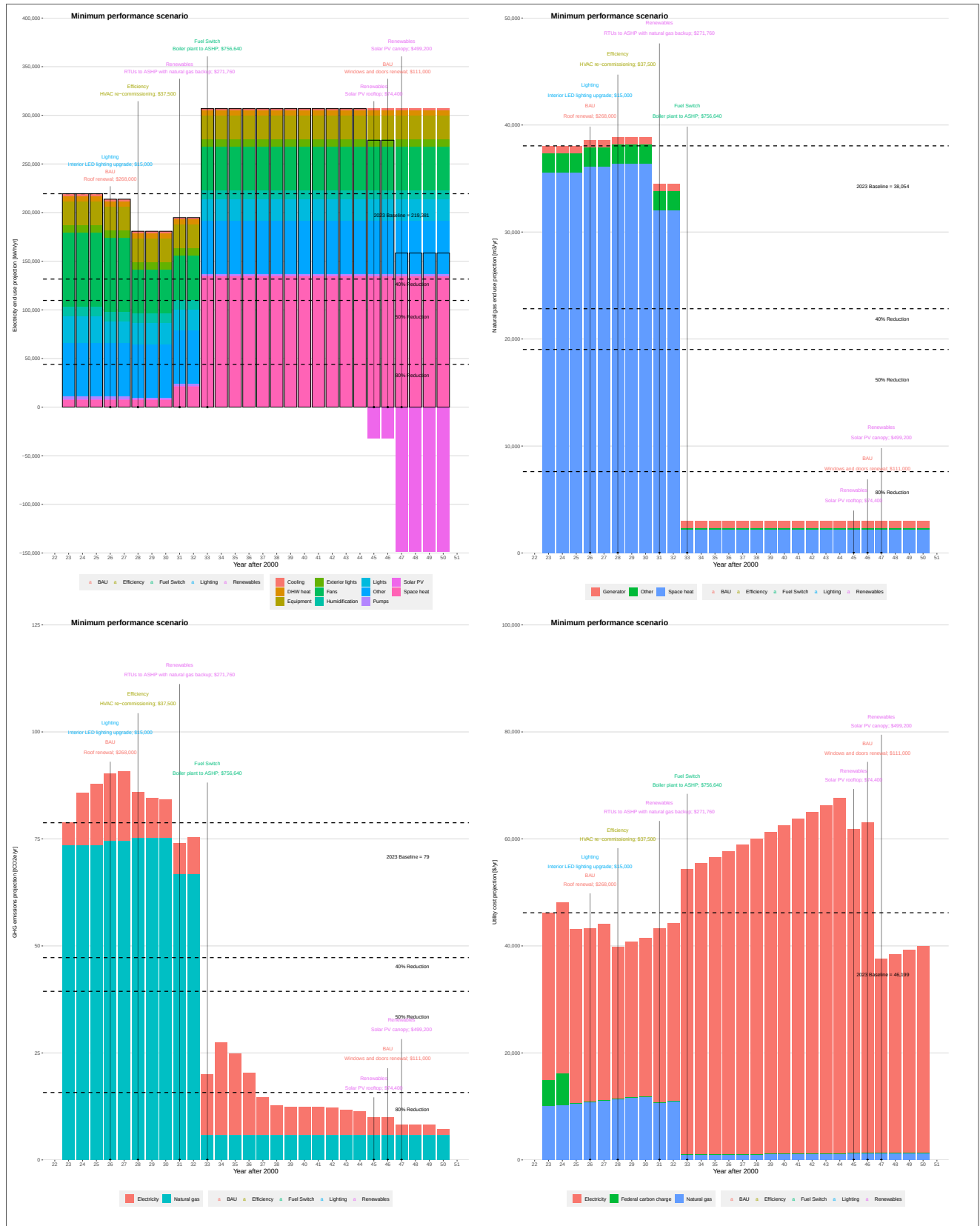


Figure 2: Recommended scenario performance

Table 1 summarizes the performance of all the plan scenarios with respect to utility use, GHG emissions, utility cost, and financial metrics. The recommended plan scenario is in **bold**. The first half of Table 1 represents the estimated performance in the final year (2050) of the evaluation period. The second half of Table 1 represents the estimated cumulative performance across the entire evaluation period (present to 2050). All final year dollar values are in the value of today's currency. All cumulative dollar values presented in Table 1 are calculated as the simple sum of expenditures over the evaluation period, except for the life cycle cost, which is discounted to present value (as illustrated in Figure 2).

Table 1: Recommended plan scenario performance summary

Section	Description	Unit	Minimum performance scenario	Aggressive deep retrofit	Comprehensive	Organizational goal alignment	Business as usual
Utility use final	Electricity use	[kWh/yr]	158,404	158,404	83,364	158,404	219,381
	Electricity monthly peak (av)	[kW]	77.5	77.5	55.4	77.5	40.7
	Electricity yearly peak (max)	[kW]	114	114	86	114	48
	Natural gas use	[m3/yr]	2,996	2,996	2,473	2,996	38,054
GHG emissions final	Electricity GHGs	[tCO2e/yr]	1.5	1.5	0.8	1.5	2.1
	Natural gas GHGs	[tCO2e/yr]	5.8	5.8	4.8	5.8	73.5
	Carbon offsets GHGs	[tCO2e/yr]	0.00	0.00	0.00	0.00	0.00
	Total GHGs	[tCO2e/yr]	7.3	7.3	5.6	7.3	75.6
Utility cost final	Electricity utility cost	[\$/yr]	38,619	38,619	20,324	38,619	53,485
	Natural gas utility cost	[\$/yr]	1,356	1,356	1,119	1,356	17,223
	Carbon offsets utility cost	[\$/yr]	0.00	0.00	0.00	0.00	0.00
	Federal carbon charge	[\$/yr]	0.00	0.00	0.00	0.00	0.00
	Total utility cost	[\$/yr]	39,975	39,975	21,444	39,975	70,709
Utility use cumulative	Electricity use	[kWh]	6,882,257	4,937,544	5,667,049	6,882,257	6,142,665
	Natural gas use	[m3]	430,878	224,947	430,193	430,878	1,065,526
GHG emissions cumulative	Electricity GHGs	[tCO2e]	249	193	220	249	225
	Natural gas GHGs	[tCO2e]	833	435	831	833	2,059
	Carbon offsets GHGs	[tCO2e]	0.00	0.00	0.00	0.00	0.00
	Total GHGs	[tCO2e]	1,082	628	1,051	1,082	2,284
Utility cost cumulative	Electricity utility cost	[\$]	1,303,478	914,748	1,048,564	1,303,478	1,161,052
	Natural gas utility cost	[\$]	130,031	67,985	129,151	130,031	373,866
	Carbon offsets utility cost	[\$]	0.00	0.00	0.00	0.00	0.00
	Federal carbon charge	[\$]	10,663	10,663	10,663	10,663	10,663
	Total utility cost	[\$]	1,444,171	993,395	1,188,377	1,444,171	1,545,580
Financial cumulative	Project cost	[\$]	3,090,292	2,608,687	14,635,911	3,090,292	847,008
	Replacement cost	[\$]	1,260,155	1,154,769	38,147	1,260,155	442,000
	Life cycle cost	[\$]	2,128,660	2,514,555	2,516,665	2,128,660	1,478,467

1 INTRODUCTION

1.1 Overview

WalterFedy was engaged by the City of Temiskaming Shores to complete a Pathway to Decarbonization Feasibility Study for the City Hall. This engagement aims to identify a recommended Greenhouse gas (GHG) reduction pathway by examining GHG reduction measures and various scenario developments. Based on a review of the Request For Proposal Document, the City's Corporate Greenhouse Gas Reduction Plan (GHGRP), and the Federation of Canadian Municipalities (FCM) Community Buildings Retrofit (CBR) funding program, the following scenarios will be developed:

- **Business as usual:** To follow the existing capital renewal plan and replace equipment at the end of its life with like-for-like equipment, meeting minimum energy-efficiency requirements of ASHRAE 90.1.
- **Minimum performance:** To achieve a 50% reduction in operational GHG emissions within 10 years and 80% within 20 years. This scenario addresses the minimum performance scenario of FCM's CBR program.
- **Aggressive deep retrofit:** Implement the same measures as in the minimum performance scenario but achieve an 80% reduction in GHG emissions within five years. This scenario addresses the additional scenario requirement of FCM's CBR program.
- **Organizational goal alignment:** To reduce emissions by 40% GHG emissions from 2019 levels by 2033 and 80% reduction by 2050 of on-site emissions. The remaining 20% is to be addressed through carbon offsets, as noted in the City's GHGRP.
- **Comprehensive:** To understand the limit of GHG reductions possible by implementing all measures with the greatest reduction on GHG emissions that are mutually exclusive.

1.2 Background

1.2.1 Corporate Greenhouse Gas Reduction Plan

The City of Temiskaming Shores has been dedicated to taking a leading role in the battle against climate change. As a committed member of the Partners for Climate Protection (PCP) program, they achieved Milestone 3 in May 2023 by creating the City's Corporate Greenhouse Gas Reduction Plan. The plan includes ambitious targets, aiming for a 40% reduction below 2019 levels by 2033 and striving for net zero emissions operations by 2050. After conducting an inventory of its greenhouse gas (GHG) emissions in 2019, the City discovered that its buildings and facilities accounted for 813 tCO₂e, representing 41.6% of its total GHG emissions inventory. A significant portion of these GHG emissions comes from natural gas, which makes up 41.7% of all energy sources for the City. To reach these sustainability goals, the City has implemented several measures, including:

- Establishing a Climate Action Committee
- Implementing a Climate Lens with regular reporting
- Utilizing a combination of EnergyCAP and ENERGY STAR Portfolio Manager to monitor and report building utility use, including electricity, natural gas, and propane
- Transitioning its fleet to biodiesel
- Initiating decarbonization studies of its buildings

This study will contribute to the decarbonization studies of its buildings. The City Hall is one of fourteen buildings being examined. Of these fourteen buildings, they represent over 77% of the buildings and facilities GHG emissions. In particular, the City Hall represented 57 tCO₂e in 2019, or 2.9% of the overall inventory.

1.2.2 Asset Management Plan

The City of Temiskaming Shores released Version 1.2 of their Asset Management Plan in 2024, providing a framework for prioritizing and optimizing asset management efforts from 2024 to 2034. The building and facility assets are estimated to have a total replacement cost of \$76,178,722, with City Hall alone having an estimated

replacement cost of \$8,613,308. The average annual financial requirements, including capital and operational expenditures, is \$2,153,014. Furthermore, the 2031 budget will see a significant increase in capital needs, nearing \$44 million. In 2032, this figure will exceed \$25 million, and in 2033, it will be more than \$5 million. Figure 2 summarizes the asset management data for the City Hall.

Table 2: Asset management summary for this facility

Group	Metric	Unit	Value
Financial	Content Value Estimated	[\$]	1,247,153
	Building Land Tank	[\$]	8,799,409
	Replacement Cost	[\$]	10,046,562
Information	Install Date	[yr]	2007
	Age	[yrs]	18
Condition Rating	Structure Condition Score	[-]	4.4
	Final Condition Score	[-]	4.4
Risk	Probability of Failure	[-]	1
	Consequence of Failure	[-]	5
	Risk Score	[-]	1.8

1.3 Contact information

Contact information for WalterFedy (the Consultant) and City of Temiskaming Shores (the Client) is provided in Table 3.

Table 3: Contact information

Description	Consultant	Client
Organization	WalterFedy	City of Temiskaming Shores
Address	Suite 111, 675 Queen St South	325 Farr Drive
Location	Kitchener, ON	Haileybury, ON
Postal code	N2M 1A1	P0J 1K0
Contact name	Jordan Mansfield	Mathew Bahm
Credentials	P.Eng., M.Eng., CEM, CMVP	-
Title	Energy Engineer	Director of Recreation
Phone	519 576 2150 x 336	705 672 3363 x 4106
Email	jmansfield@walterfedy.com	mbahm@temiskamingshores.ca

2 FACILITY DESCRIPTION

2.1 Facility description methodology

The facility was reviewed and described according to the following methodology. The intent of reviewing and describing the facility is to understand the pertinent operations and systems in the facility that use utilities so that the baseline (i.e. existing) utility use can be accurately quantified.

1. **Facility document review.** Facility documents from the following list were reviewed, if available. Further information on available documentation are available in Section 2.3.
 - Building drawings.
 - Building automation system graphics and points lists.
 - Previously completed Engineering studies, including Energy Audits, Feasibility Studies, and Building Condition Assessments.
 - Historical utility use data.
 - Other documentation made available by the City of Temiskaming Shores.
2. **Site survey.** A site survey was completed on 2024-04-16 to review the energy systems applicable to the desired retrofit scenario.

2.2 Facility overview

An overview of the City Hall is provided in Table 4.

Table 4: Facility overview

Description	Unit	Value
Name	[-]	City Hall
Address	[-]	325 Farr Drive
Location	[-]	Haileybury, ON
Type	[-]	Administration
Construction year	[-]	1999
Gross floor area	[m2]	1,468
Gross floor area	[ft2]	15,800

An aerial view of the City Hall is provided in Figure 3.

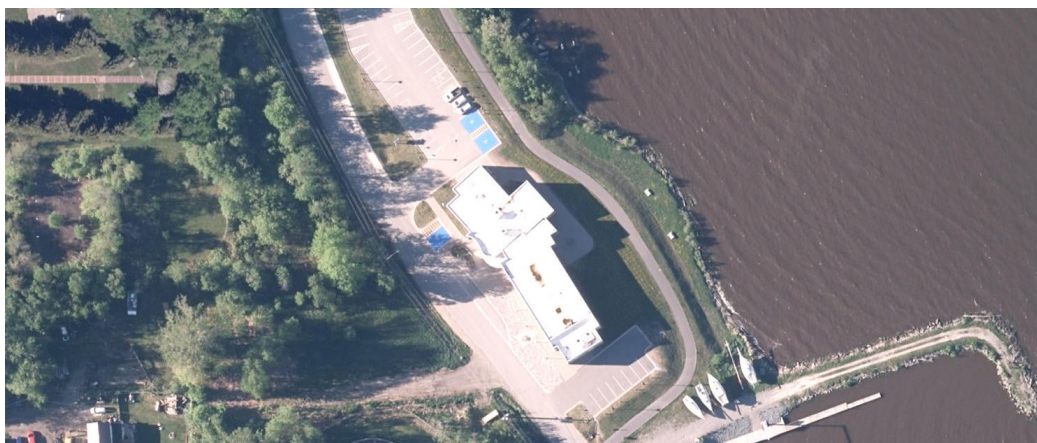


Figure 3: City Hall aerial view

2.3 Building information

Renovations

The following renovations are known:

- **HVAC renovation (2012):** underwent a renovation to the hot water heating and HVAC system. The City replaced RTU1, RTU2, RTU3, and RTU4, added new electric duct heaters to spaces served by RTU1 and RTU2, added new hydronic reheat coils to zones served by RTU3 and RTU4, added B3, added circuit balancing valves (CBVs) to in-floor heating manifolds, and updated the sequence of operation (SOO) of its Building Automation System (BAS).
- **Lighting retrofit (2016):** 411 LED lamps were purchased to replace existing T8 fluorescent lamps. This project did not include other fixture types.

Additions

There have been no additions to this building.

Energy use not within the gross floor area

The following energy use is located outside the gross floor area of this building:

- Building-mounted exterior light fixtures.
- Parking lot pole lighting.
- Natural gas-fired generator.

Utility bill responsibility

Utility bill responsibility is as follows:

- Natural gas meters: the City
- Electricity meter: the City

Commissioning history

No commissioning history has been documented.

Previous studies

The following is a summary of known previous studies:

- Energy audits: None
- Engineering studies: Roof inspection by SRP Building Products Inc.
- Building condition assessments: None

Documentation availability

In conjunction with the site survey, the following documents are being used to help us better understand this facility:

- Architectural drawings were not made available. The overall R-Value of building envelope assemblies and area take-offs (e.g., window area) will be estimated.
- Electrical drawings, E01-E05, dated March 22, 2007.
- Floor plans, no date provided.

- Controls drawings, pulled from the BAS.
- Mechanical drawings: no original drawing set was provided.
- 2012 Renovation includes mechanical (M-1 to M-7) and electrical (E-1) drawing sets.

2.4 Space use

Type summary

The following spaces were identified during the site survey and documentation review.

- Computer/Server room
- Meeting room
- Electrical/Mechanical room
- Lobby
- Receiver room
- Office, enclosed and open
- Washroom
- Art gallery
- Council chamber
- Storage
- Lunchroom

All spaces are being used as originally intended.

Occupancy scheduling

The facility operation hours are as follows:

- **Municipal hours:** 08:30-16:30 Monday to Friday based on the City's website.
- **Gallery hours:** 10:00-16:00 Monday to Friday based on the Art Gallery's website.

Based on the GFA, it is assumed that this building has a peak occupancy of 40 people.

Space use breakdown

A space use breakdown, which was estimated via calibrated measurements performed on available facility floor plans, is presented in Table 5.

Table 5: Space use summary

Space name	Floor area of space	HVAC System	Data source
-	[m2]	-	-
1st and 2nd floor east side	462	RTU1	BAS.
1st and 2nd floor west side	462	RTU2	BAS.
Council chambers, office, storage, and boardroom	301	RTU3	BAS.
Art gallery offices, Art gallery, and lobby	243	RTU4	BAS.

Space use documentation

Space use documentation, including available drawings and photos taken during the site survey, is provided in the following images. Most drawings in this report are high-quality, embedded PDF documents, enabling the reader to review details by zooming in on the figures.

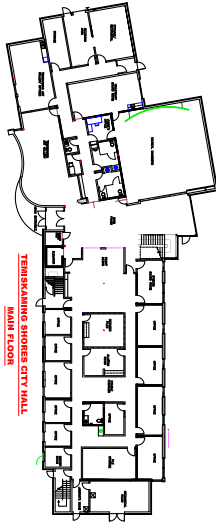


Figure 4: City Hall - Floor Plan - Level 1

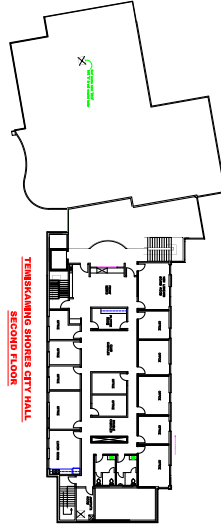


Figure 5: City Hall - Floor Plan - Level 2

2.5 Building Envelope

Building envelope area data summary

Building envelope areas are summarized in Table 6.

Table 6: Building envelope summary

Area of roof	Area of exterior walls net	Area of exterior walls	Area of exterior windows	Area of exterior doors
[m2]	[m2]	[m2]	[m2]	[m2]
1,031	2,882	3,022	140	7.2

Overview

No architectural drawings were available, and therefore no detailed information on building assemblies. All overall R-Values are based on the requirements listed in the Model National Energy Code of Canada for Buildings, 1997.

Roof

- The roof exterior layer consisted of a white roof membrane with wood structural decking observed above the finished ceiling. Using the roof hatch as a reference, it appears that there is an average of inches of insulation.
- The overall R-Value is assumed to be R32.
- The roof condition was fair, as it is approaching its end of life (approximately 20 years).

Opaque Walls (above ground)

- The exterior walls comprised either an outer layer of veneer brick, metal siding, or metal panelling. The west elevation also has an architectural wood laminated feature.
- The overall R-Value is assumed to be R12.
- The wall condition was excellent, except for the architectural feature on the west elevation.

Fenestration

Windows

- The facility has aluminum-framed, double-pane picture windows and a double-pane curtain wall.
- Windows appeared to be in excellent condition, including sealant around windows.
- The overall R-Value is assumed to be 0.625 Btu/hr.ft².F for the window system with a SHGC of 0.35.

Doors

- The facility has swing doors with glazing, hollow metal, and one small overhead door.
- The front entrance door suggested that new weatherstripping is required. However, overall, the doors appear to be in excellent condition.
- The front entrance door on the west elevation had a gap in the door, presenting an opportunity for infiltration.
- The overall fenestration-to-wall ratio is estimated to be 5%, as elevation drawings were not made available.

Overall Enclosure Tightness

It is difficult to determine a building's infiltration rate without performing a blower door test. However, an infiltration rate is required for energy modelling purposes. Based on the site survey, an infiltration rate of 0.35 Lps/m² of the above-grade building envelope area will be assumed here.

Building Envelope documentation

Building envelope documentation, including available drawings and photos from the site survey, is provided in the following images.



Figure 6: Brick veneer



Figure 7: The curtain wall on the east elevation



Figure 8: East elevation of office area



Figure 9: Front entrance doors with glazing



Figure 10: The hollow metal door on the south elevation



Figure 11: Insulation above the ceiling in the Receiver room



Figure 12: Laminated wood architectural feature in poor condition



Figure 13: Metal panelling on the west elevation



Figure 14: North elevation



Figure 15: Overhead in the Receiver room



Figure 16: Roof hatch for access to Northern roof



Figure 17: The roof membrane on the north section



Figure 18: South elevation



Figure 19: Underside of the roof



Figure 20: West elevation of office area



Figure 21: Window shades in the boardroom

2.6 HVAC

HVAC equipment summary

HVAC systems are summarized in Table 7, Table 8, Table 9, and Table 10.

Table 7: Air distribution systems summary

Tag	Make	Model	Serves	Design flow	Motor output	Data source
-	-	-	-	[cfm]	[hp]	-
RTU1	AAON	RN-011-8-0-EA09-3G9	1st and 2nd floor east side	4,000	5.00	Namplate.
RTU1_exh	AAON	RN-011-8-0-EA09-3G9	1st and 2nd floor east side	4,000	2.00	Namplate.
RTU2	AAON	RN-011-8-0-EA09-3G9	1st and 2nd floor east side	4,000	5.00	Namplate.
RTU2_exh	AAON	RN-011-8-0-EA09-3G9	1st and 2nd floor east side	4,000	2.00	Namplate.
RTU3	AAON	RN-006-8-0-EA09-3L9	Council chambers, office, storage, and boardroom	2,600	2.00	Namplate.
RTU3_exh	AAON	RN-006-8-0-EA09-3L9	Council chambers, office, storage, and boardroom	2,600	2.00	Namplate.
RTU4	AAON	RQ-005-8-V-EA09-359	Art gallery offices, Art gallery, and lobby	2,100	2.00	Namplate.
RTU4_exh	AAON	RQ-005-8-V-EA09-359	Art gallery offices, Art gallery, and lobby	2,100	1.00	Namplate.
ERV1	Greenheck	ERH-20H-30-15-ES	RTU1 and RTU2	2,000	1.50	Namplate.
ERV1_exh	Greenheck	ERH-20H-30-15-ES	RTU1 and RTU2	2,000	1.50	Namplate.
ERV1_htwhl	Greenheck	ERH-20H-30-15-ES	RTU1 and RTU2	2,000	0.05	Namplate.
ERV2	-	-	RTU4	1,000	0.50	Assumption.
ERV2_exh	-	-	RTU4	1,000	0.50	Assumption.

Table 8: Water distribution systems summary

Tag	Serves	Flow	Head	Motor output	Data source
-	-	[gpm]	[ft]	[hp]	-
PM1	Manifold 1; in-floor heating	-	-	0.11	Assumption.
PM2	Manifold 2; in-floor heating	-	-	0.11	Assumption.
PM3	Manifold 3 and 5; in-floor heating	9.7	9.5	0.12	Nameplate
PM4	Manifold 4; in-floor heating	5.8	15.0	0.12	Nameplate
PB1	Boiler 1	-	-	0.17	Nameplate
PB2	Boiler 2	-	-	0.26	Nameplate
PB3	Boiler 3	-	-	0.26	Nameplate
P1	Hot water loop	39.3	32.0	1.50	Nameplate
P2	Hot water loop	39.3	32.0	1.50	Nameplate
PC	Hot water coils	8.0	17.0	0.40	Nameplate

Table 9: Heating systems summary

Tag	Serves	Utility	Efficiency	Output	Data source
-	-	-	[decimal]	[btuh]	-
B1	Hot water loop	Natural gas	0.90	207,000	Assumption.
B2	Hot water loop	Natural gas	0.90	207,000	Assumption.
B3	Hot water loop	Natural gas	0.90	207,000	Nameplate.
RTU1_HEAT	1st and 2nd floor east side	Natural gas	0.80	234,000	Nameplate.
RTU2_HEAT	1st and 2nd floor west side	Natural gas	0.80	234,000	Nameplate.
RTU3_HEAT	Council chambers, office, storage, and boardroom	Natural gas	0.80	168,000	Nameplate.
RTU4_HEAT	Art gallery offices, Art gallery, and lobby	Natural gas	0.81	113,400	Nameplate.
RHC31	Lobby	Electricity	1.00	27,297	Drawings.
RHC32	Art gallery	Electricity	1.00	8,530	Nameplate.
RHC33	Art gallery offices	Electricity	1.00	8,530	Drawings.
RHC34	Judge's office	Electricity	1.00	3,412	Drawings.
HU1	RTU1	Electricity	1.00	38,898	Nameplate.
HU2	RTU2	Electricity	1.00	38,898	Nameplate.
HU3	RTU3	Electricity	1.00	-	Assumption.
HU4	RTU4	Electricity	1.00	-	Assumption.
DHW1	South DHW	Electricity	1.00	10,236	Nameplate.
DHW2	North DHW	Electricity	1.00	5,118	Nameplate.

Table 10: Cooling systems summary

Tag	Serves	Efficiency	Output	Data source
-	-	[decimal]	[ton]	-
RTU1_COOL	1st and 2nd floor east side	4	10	Drawings.
RTU2_COOL	1st and 2nd floor west side	4	10	Drawings.
RTU3_COOL	Council chambers, office, storage, and boardroom	4	6	Drawings.
RTU4_COOL	Art gallery offices, Art gallery, and lobby	4	5	Drawings.
DS_1	IT server room	4	2	Drawings.

System type

The facility utilizes four RTUs coupled with two ERVs to serve the building. A summary of this system is as follows:

- Each RTU is a variable-volume unit coupled with VAV boxes. All supply fans are equipped with VFDs; however, exhaust/return fans appear not to be.
- All RTUs are natural gas-fired units completed with DX cooling.
- All RTUs are equipped with electric humidifiers. The humidifiers for RTU3 and RTU4, which are located in an alcove of the men's washroom, were not observed during the site visit. The humidifiers for RTU1 and RTU2 are located in the mechanical room.
- RTU1 and RTU2 utilize hydronic reheat coils, while RTU3 and RTU4 utilize electric ones.
- RTU1 and RTU2 are interlocked with ERV1, while RTU4 is interlocked with ERV2.

- RTU3 was initially specified to be coupled with an ERV unit; however, after a site survey and reviewing product literature, it was confirmed that RTU3 has no heat recovery. The unit instead uses demand-control ventilation based on space CO₂ levels. When the CO₂ levels are satisfied, it operates in full recirculation mode.
- ERV1 is located in the mechanical room. We were unable to obtain the flow rates for this unit.
- ERV2 is located in the plenum space above the storage room on the north side of the building. We were unable to obtain nameplate information on this unit.
- All RTUs operate with an economizer mode.
- The server room has supplemental cooling through a ductless split application with the condenser unit located on the roof.
- All ventilation equipment appeared to be in excellent condition, as the majority was replaced in 2012.
- Only two electric baseboard heaters were documented during the site visit. They were located in the elevator machine room and the janitor closet.

Central Plant

- Three condensing boilers provide hot water to reheat coils and in-floor heating. The in-floor heating is divided into five manifolds and further into 17 zones.

Distribution system

A total of 10 pumps circulate the working fluid throughout the building. They serve the following:

- Three pumps serve the primary boiler loop. Each pump is interlocked with a corresponding boiler.
- Three pumps serve the secondary hot water loop. Two operate in a lead/lag configuration, which serves the in-floor heating, and the third pump serves the reheat coils.
- The remaining four pumps serve the five in-floor manifolds. Manifolds 3 and 5 share the same pump (MP3).

The air distribution throughout the building uses a single-duct approach to VAV boxes serving individual zones.

Controls

RTU1 and RTU2

- RTU1 and RTU2 is in cooling mode when the outdoor air temperature (OAT) exceeds 55F for 15 minutes. The supply air temperature (SAT) starts at 55F and decreases at 0.2F/min if any temperature in a zone exceeds 3.5F of the setpoint. It increases by 0.2F/min if it is below 3.5F. When satisfied, SAT resets to 55F.
- RTU1 and RTU2 is in heating mode when the OAT is less than 55F for 15 minutes. SAT starts at 55F and increases at 0.2F/min if any temperature in a zone drops below 3.5F of the setpoint. Decrease by 0.2F/min if above by 3.5F. When satisfied, the temperature resets to 55F.
- A static pressure signal tells the supply fan to increase speed to meet the setpoint. The module is based on duct static pressure in the zone. However, the setpoint is set to hold at 190 Pa, and the supply fan VFD is set to 75%. This approach overconstrains the system and does not allow it to function as intended.
- When humidity drops below 35%, and the supply duct high limit and airflow switch are in contact, the humidifier modulates to maintain 45% RAH. The humidifier modulates with the VFD to avoid condensation inside the supply duct. The unit is off and on hold as of July 2024.
- The factory controls enable the economizer, cooling stages, and heating stages to maintain the supply air temperature setpoint (SATSP).
- RTU2 operating in hand (i.e., continuously).
- RTU1's humidifier appears to not be in operation.

ERV1

- ERV1 is interlocked with RTU1 and RTU2. If one or more is enabled, then ERV1 is on. Given that RTU2 is in hand, this unit is also running continuously.
- On the supply discharge side, there is a reheat coil. It's a three-way valve that modulates to maintain 55F.

RTU3

- The drawings indicate that an ERV3 is dedicated to RTU3. However, no ERV3 is present at the site.
- The SATSP is based on the council chamber room temperature and setpoint.
- The BAS enables cooling if the space temperature setpoint is higher than 74F. The unit will determine the cooling staging and economizer mode.
- If the space temperature setpoint is lower than 72F, heating is enabled. The discharge air temperature (DAT) is set to 95F. The boardroom has a dedicated electric duct heater that will modulate.
- If no heating or cooling is present, the SAT is set to the temperature setpoint in the space.
- When humidity drops below 35%, the supply duct high limit and airflow switch is in contact, and the humidifier modulates to maintain 45% RAH.
- Demand-control ventilation is controlled via a CO2 sensor in the council chamber and boardroom. If the CO2 ppm level exceeds 900 ppm, the OA damper modulates open. Once the CO2 ppm levels are satisfied, the unit is in full recirculation mode.

RTU4

- RTU4 follows a similar sequence of operation as RTU1 for heating and cooling.
- The ductwork is not reaching the static pressure setpoint. This can be caused by several issues, including the VFD's fixed setting of 75%, the static pressure setpoint being too high, or the location of the static pressure sensor needing to be relocated.
- Humidity is controlled similarly to RTU1 and RTU2. The VFD signal is interlocked with the humidifier modulation.

ERV2

- ERV2 is interlocked with RTU4.

Hot water loop

- When the OAT drops below 70F, the hot water system is enabled, and the circulation pumps (P1, P2, and Pcoils) are all enabled.
- The boiler plant is a lead-lag configuration (2-week lead period) and operates on an OAT reset schedule. The supply water temperature (SWT) ranges from 110F to 180F, corresponding linearly to an OAT of 70F to -15F.
- P1 and P2 operate in a lead-lag configuration, changing every other week.

In-slab heating

- All four manifold pumps are interlocked with the hot water loop system.
- Each manifold has a 3-way valve that modulates the supply temperature setpoint. SWT ranges from 90F to 139F, corresponding linearly to an OAT of 68F to -22F.
- Each zone has a thermal valve that cycles to maintain the zone slab temperature setpoint as reset by room temperature.
- Manifold 1 is responsible for Zones 1 through 4 (Rooms 7, 8, 9, 10, 12, and 13). Zone 7 is also on this circuit. However, it does not have a temperature sensor. Room 13 temperature sensor is used.

- Manifold 2 is responsible for Zones 5, 6 and 8 (Rooms 3, 4, 5, 6, 15, 16, and 17).
- Manifold 4 is responsible for Zone 13-17 (Rooms 27, 35, 36, 37, and 38).
- Manifold 3 is responsible for Zones 9-11 (Rooms 25 north, 25 south, and 34).
- Manifold 5 is responsible for Zone 12 (Room 26).

VAV Zone Control

- The VAV box is turned off in unoccupied mode. Perimeter radiation maintains a nighttime setback of 65F.

HVAC system documentation

HVAC system documentation, including available drawings and photos from the site survey, is provided in the following images.



Figure 22: B1

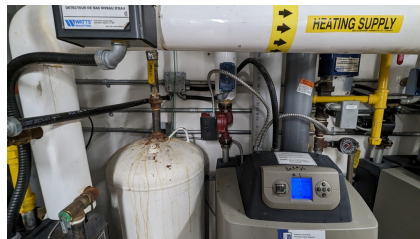


Figure 23: BP1



Figure 24: B2



Figure 25: BP2



Figure 26: B3



Figure 27: BP3



Figure 28: Ductless split unit



Figure 29: Ductless split unit in the IT room



Figure 30: ERV1 BAS graphic

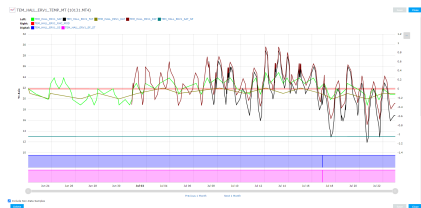


Figure 31: ERV1 Trends



Figure 32: ERV1



Figure 33: ERV2

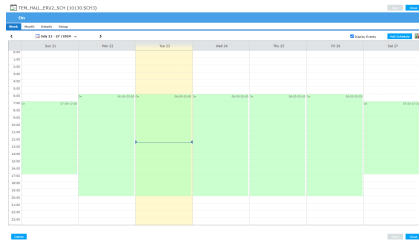


Figure 34: ERV2 Schedule



Figure 35: ERV2 is located in the ceiling space above the Storage room

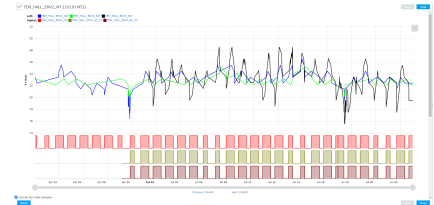


Figure 36: ERV2 Trends



Figure 37: Electric baseboard heater in janitor closet

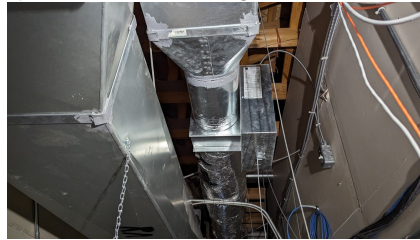


Figure 38: Electric duct heater

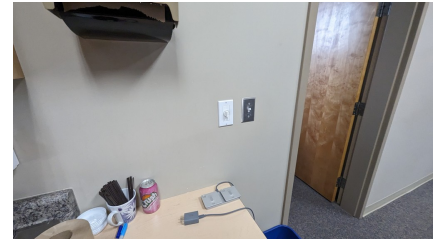


Figure 39: Exhaust fan timer in the boardroom



Figure 40: The exhaust fan is controlled via a thermostat in the elevator room



Figure 41: HU1



Figure 42: HU2



Figure 43: Heat wheel motor on ERV1

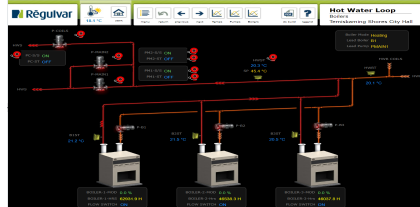


Figure 44: Hot water loop

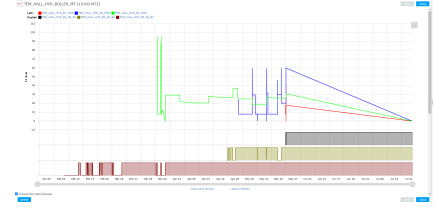


Figure 45: Hot water loop - Boilers

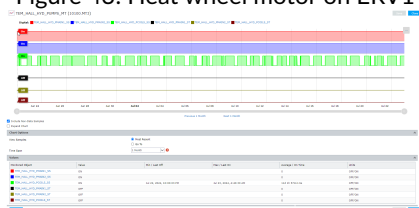


Figure 46: Hot water loop - Pump trends

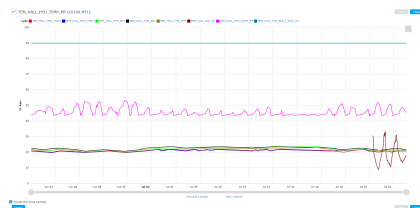


Figure 47: Hot water loop - Temperature July

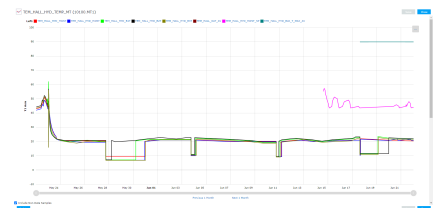


Figure 48: Hot water loop - Temperature June



Figure 49: Hydronic cabinet heater



Figure 50: In-slab heating - Manifold 3, 4, and 5

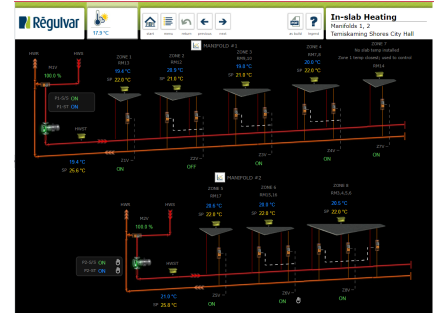


Figure 51: In-slab heating - Manifold 1 and 2

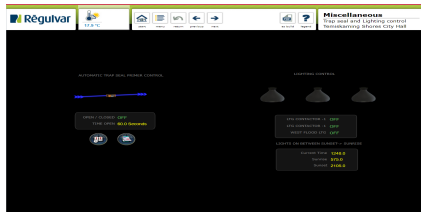


Figure 52: Lighting control and trap seal

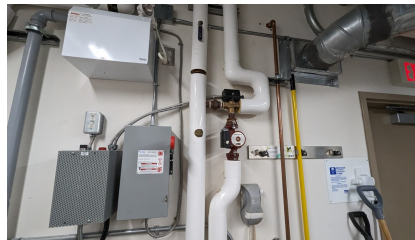


Figure 53: MP1



Figure 54: MP3 and MP4

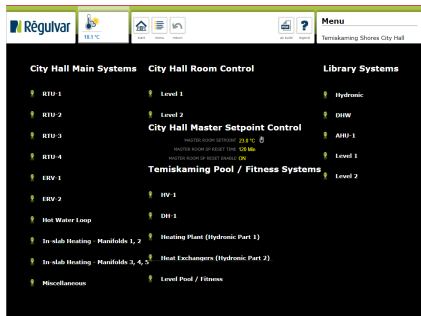


Figure 55: Main Menu

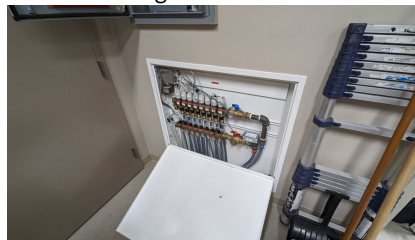


Figure 56: Manifold 4 in the Receiver room

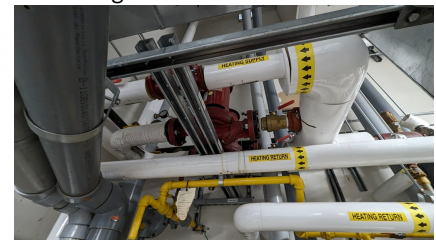


Figure 57: P1, P2, and PC

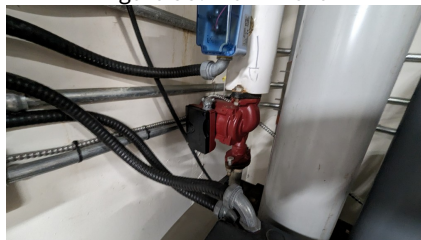


Figure 58: PB3



Figure 59: RTU1

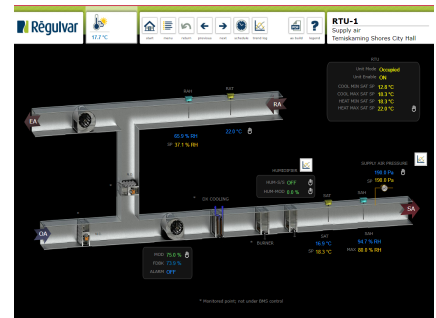


Figure 60: RTU1

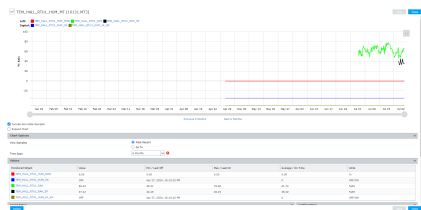


Figure 61: RTU1 Humidity Trends

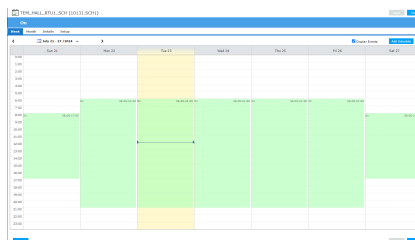


Figure 62: RTU1 Schedule

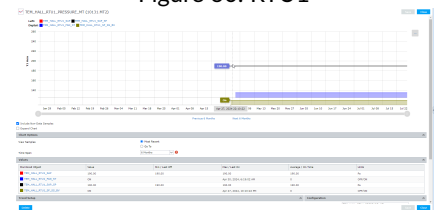


Figure 63: RTU1 SPST trends - 6 months



Figure 64: RTU1 Temperature trends - 1 year



Figure 67: RTU2 - Humidity trend

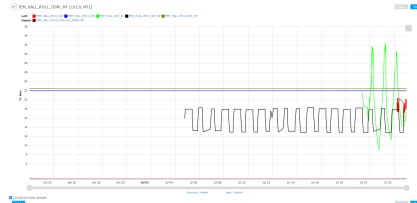


Figure 65: RTU1 Temperature trends - 1 month

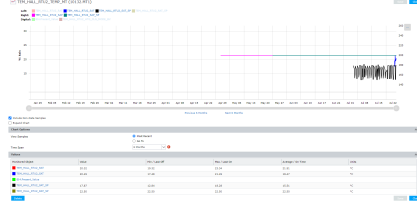


Figure 68: RTU2 - Temperature trend

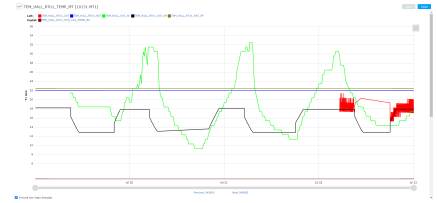


Figure 66: RTU1 Trends

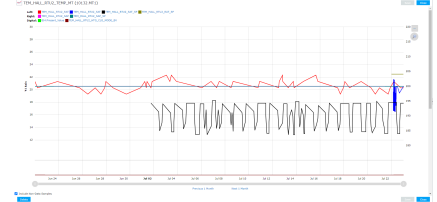


Figure 69: RTU2 - Temperature trend - 1 month



Figure 70: RTU2

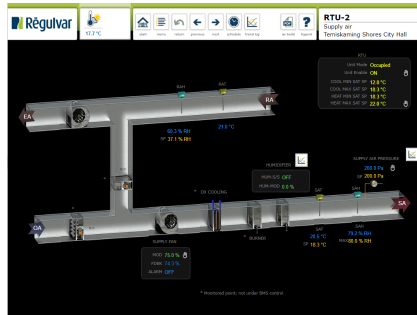


Figure 71: RTU2

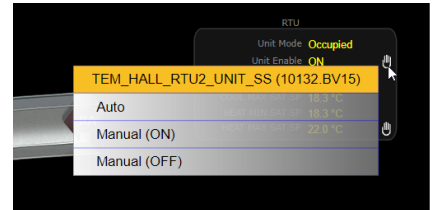


Figure 72: RTU2 is in hand to be ON continuously

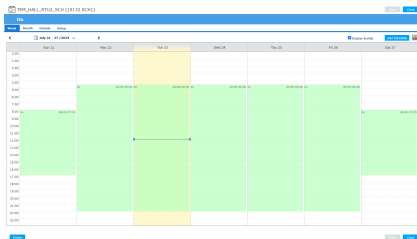


Figure 73: RTU2 Schedule



Figure 74: RTU3

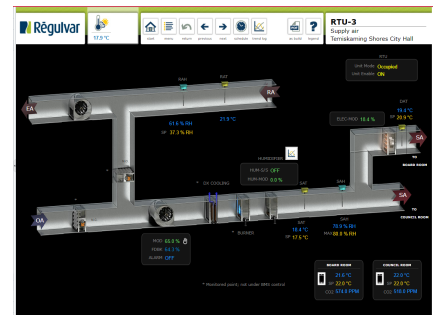


Figure 75: RTU3



Figure 76: RTU3 filters are clean

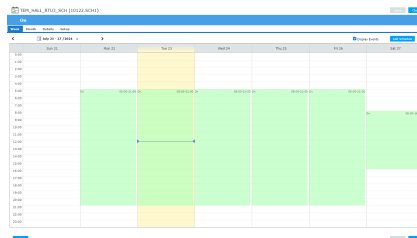


Figure 77: RTU3 Schedule



Figure 78: RTU3 Temperature trend



Figure 79: RTU4

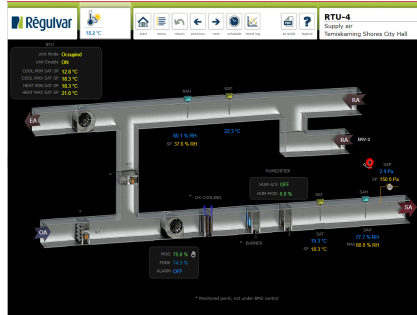


Figure 80: RTU4

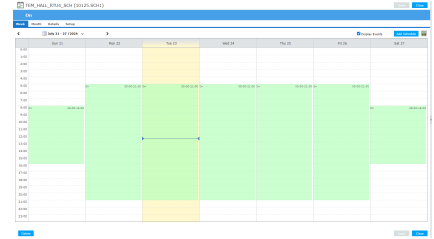


Figure 81: RTU4 Schedule



Figure 82: RTU4 Trends



Figure 83: Room Control - Level 1



Figure 84: Room Control - Level 2



Figure 85: The thermostat in the boardroom



Figure 86: The thermostat in the council chambers



Figure 87: VAV - Main Foyer



Figure 88: VAV - Art Gallery

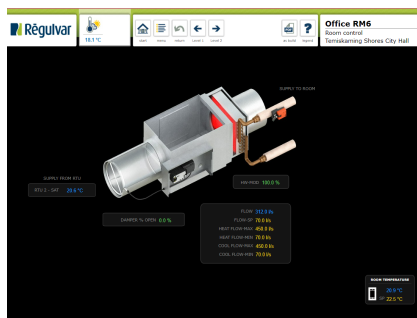


Figure 89: VAV - Office RM06

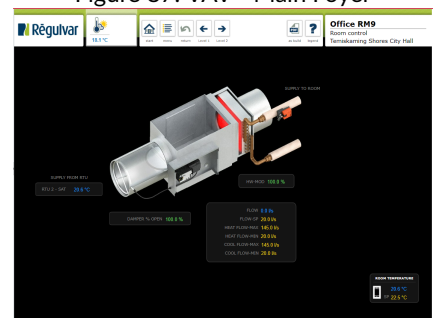


Figure 90: VAV - Office RM09

2.7 Domestic hot water

Overview

Two electric DHW heaters are serving this building. The first tank is located in the mechanical room and serves the washrooms and sinks on the south side of the building. The second tank is located in the north storage room and serves the washrooms and kitchenette in the boardroom. DHW1 and DHW2 capacities are 12 USG and 48.6 USG, respectively.

Domestic Hot Water documentation

Domestic Hot Water documentation, including available drawings and photos from the site survey, is provided in the following images.

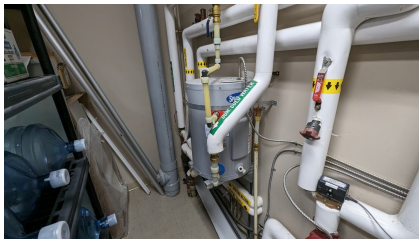


Figure 91: Electric DHW tank in the Receiver room



Figure 92: Electric DHW tank in the mechanical room

2.8 Lighting

Lighting system summary

Lighting systems are summarized in Table 11.

Table 11: Lighting systems summary

Space name	Floor area of space	Light power density	Light power input	Data source
-	[m ²]	[W/m ²]	[W]	-
1st and 2nd floor east side	462	8.8	4,066	Takeoff.
1st and 2nd floor west side	462	8.8	4,066	Takeoff.
Council chambers, office, storage, and boardroom	301	8.8	2,649	Takeoff.
Art gallery offices, Art gallery, and lobby	243	8.8	2,138	Takeoff.

Interior lighting

Fixtures

The following interior light fixtures were observed during the site survey:

- Type A: 2'x4' recessed, 3 lamp, 347V, LED lamp retrofitted
- Type A1: 2'x4' recessed, 2 lamp, 347V, LED lamp retrofitted
- Type A2: 2'x4' recessed, 3 lamp, 120V, LED lamp retrofitted
- Type B: 2'x4' recessed, 4 lamp, 347V, LED lamp retrofitted
- Type C: 1'x4' recessed, 2 lamp, 347V, LED lamp retrofitted
- Type E: strip suspended, 2 lamp, 347V, LED lamp retrofitted
- Type G: Recessed 6" horizontal CFL downlight, 1 lamp, 347V
- Type H: Pendant, suspended, 6 x F40 CFL lamps, dimming
- Type H1: Pendant, suspended, 6 x F40 CFL lamps, non-dimming
- Type H2: Pendant, suspended, 4 x F36 CFL lamps, non-dimming

Controls

Interior lighting control is done through switch-mounted occupancy sensors, ceiling-mounted occupancy sensors, and manual switches. The lights are typically on from 07:00 to midnight, at which point the janitorial staff turns off all lights. A few lights are left on continuously as they are not controlled by a switch. Based on takeoffs, this load equates to approximately 1 kW an hour.

Exterior lighting

Fixtures

The following exterior light fixtures were observed during the site survey:

- Type J: Pole, 15', 150 W HPS lamp
- Type L: Wall pack, LED, 30 W
- Type P: Recessed 6" MH downlight, 1 lamp, 347V

Controls

The BAS controls exterior lighting set to turn on at sunset and off at sunrise.

Lighting system documentation

Lighting system documentation, including available drawings and photos taken during the site survey, is provided in the following images.



Figure 93: Ceiling-mounted occupancy sensor in the meeting room



Figure 94: Contactor for northern parking lot lights that connect to the BAS



Figure 95: Switched-mounted occupancy sensor in the receiver room



Figure 96: Switched-mounted occupancy sensor in the men's washroom



Figure 97: Type A2 and G in the boardroom



Figure 98: Type C fixture in the north corridor

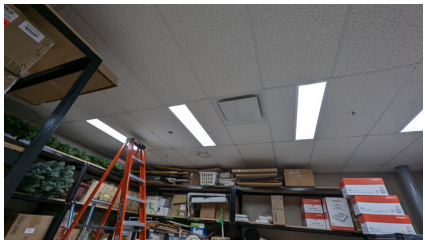


Figure 99: Type C fixtures in the storage room



Figure 100: Type C fixtures in the receiver room



Figure 101: Type C fixtures in the men's washroom



Figure 102: Type E fixture in the mechanical room



Figure 103: Type G fixture on the second floor



Figure 104: Type H1 fixtures in the lobby floor



Figure 105: Type H2 fixtures in the art gallery



Figure 106: Type H fixtures in the council chambers



Figure 107: Type J fixture in the parking lot



Figure 108: Type L fixture on the north elevation

2.9 Process and plug loads

Process

Various process loads are present at the facility, including:

- Elevator
- IT equipment
- Hand dryers

Plug loads

Various plug loads are present at the facility, including:

- Office equipment (photocopier, plot printer, etc.)
- Personal computers
- Appliances (e.g., dishwasher, kettle, etc.)

Process and plug loads documentation

Process and plug loads documentation, including available drawings and photos from the site survey, is provided in the following images.



Figure 109: Electric air dryer in the men's washroom



Figure 110: Elevator



Figure 111: IT equipment



Figure 112: IT equipment for the council chambers - 1

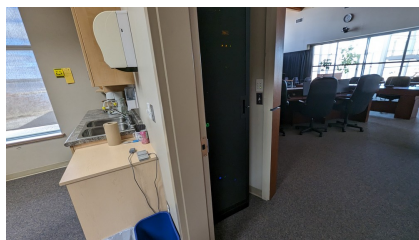


Figure 113: IT equipment for the council chambers - 2

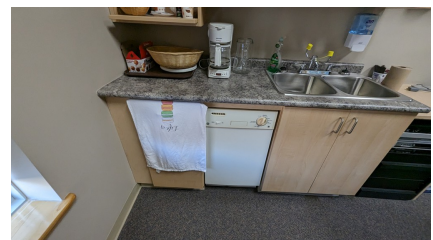


Figure 114: Kitchenette appliances



Figure 115: Kitchenette in the first-floor office area



Figure 116: TV in the boardroom

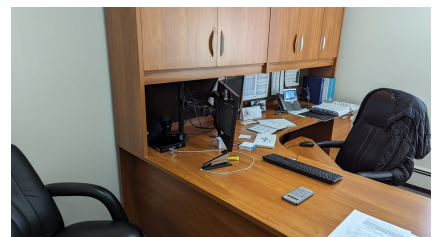


Figure 117: Typical office equipment

2.10 Water fixtures

Water fixture summary

Water fixtures at City Hall are summarized in Table 12.

Table 12: Water fixture summary

Serves	Unit count	Flow	Volume	Data source
-	-	[gpm]	[gpc]	-
Kitchen faucets	3	2.20	-	Assumption.
Washroom faucets	6	0.50	-	Assumption.
Toilets	11	-	1	Assumption.
Urinals	2	-	1	Assumption.

Overview

A summary of water fixtures is as follows:

- Six handwashing faucets. They are equipped with motion sensors and are low-flow.
- Three kitchen sinks.
- Two slop sinks.
- 11 toilets.
- 2 urinals.

Water fixture documentation

Water fixture documentation, including available drawings and photos taken during the site survey, is provided in the following images.



Figure 118: Kitchenette sink



Figure 119: Motion-activated handwashing faucet



Figure 120: Sink in the first-floor office area



Figure 121: Slop sink



Figure 122: Urinal rated for 3.8 lpf

2.11 Utility services

Utility services summary

Overview

The building utilizes electricity from Hydro One Networks Inc. and natural gas from Enbridge.

The one electricity meter operates on a General Energy rate structure. However, it was previously on a General Demand rate structure. The change occurred as there were more than 12 consecutive months of real demand being less than 50 kW.

There are two natural gas meters at this facility. The first serves the whole building, and the second is dedicated to the natural gas-fired emergency generator.

Utility services documentation

Utility services documentation, including available drawings and photos from the site survey, is provided in the following images.



Figure 123: Electricity meter



Figure 124: Natural gas meter for the building



Figure 125: Natural gas meter serving the generator

2.12 Onsite energy sources

Overview

This site has one 150 kW natural gas-fired emergency generator. Per staff, the unit is operated weekly to ensure it is in working order.

There are no renewable energy systems present at this facility.

Onsite energy sources documentation

Onsite energy sources documentation, including available drawings and photos from the site survey, is provided in the following images.



Figure 126: Natural gas generator

2.13 Electrical infrastructure

Overview

The building is fed from a pole-mounted transformer bank across the road near the generator. The feed travels underground to the mechanical room via 4-500 MCM into the main 600 V/347 V switchgear, with a 400A main disconnect. The building is equipped with an auto transfer switch (ATS) rated at 400A, 347/600V. There are seven panels throughout the building.

The existing systems is 400A at 600V service running at a maximum load of 17.594 kW, which is approximately 46

The peak hourly electrical load of the building since 2020 is 51.84 kVA. However, this load occurred in 2019, and since then, the building has had 12 consecutive months of demand below 50 kW, allowing it to transition from a General Demand rate structure to a General Energy rate structure. Even with the 51.84 kVA, there is an estimated free capacity of nearly 88%.

Panel summary

The seven panels at this site are summarized below:

- Panel IG-C, 120/208V, three ph, 4W. Serves receptacles in the council chambers.
- Panel B, 120/208V, three ph, 4 W. Serves exterior west parking receptacles, exterior lighting, reheat coils, Panel IG-C, art gallery receptacles and lights, hand dryers, electric heater in the elevator machine room, hot water heater.
- Panel DP-2, 347/600V, three ph, 4 W. Serves lighting and humidifiers in RTU-3 and RTU-4, Panel B via a 45 kVA transformer, elevator motor, and 45 kVA transformer for RTU 3,4.
- Panel IG-E, 120/208V, 3ph, 4W. It serves receptacles, photocopiers, heat tracers, security systems, and UPS.
- Panel DP1, 347/600V, 3ph,4W. Serves lighting, humidifiers 1 and 2, panel PP-A, ERV1, and RTU 1 and 2.
- Panel PP-A, 120/208V, 3ph,4W. Serves receptacles, lighting, pumps, hand dryers,
- Panel D, 120/208V, 3ph, 4W. Serves receptacles, hand dryers, and lights.

Electrical infrastructure documentation

Electrical infrastructure documentation, including available drawings and photos from the site survey, is provided in the following images.



Figure 127: 75 kVA transformer to panel PP-A



Figure 128: 75 kVA transformer for RTU1 and RTU2

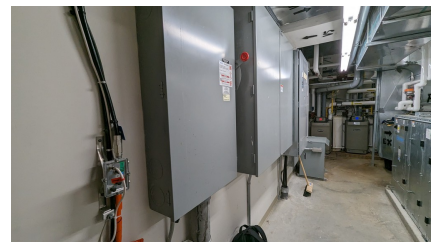


Figure 129: Main service disconnect



Figure 130: Panel DP1



Figure 131: Panel D



Figure 132: Panel IG-E



Figure 133: Panel IG-PC, B, and DP-2 in the Receiver room



Figure 134: Transfer switch



Figure 135: Two 45 kVA transformers in the Receiver room

3 UTILITY USE ANALYSIS

3.1 Utility analysis methodology

The utility use analysis was completed according to the following methodology. Note that the results achieved from applying this methodology are presented in the same order in Sections 3.2 through 3.8.

1. **Utility analysis assumptions.** Assumptions applied in the utility use analysis were identified and summarized in Section 3.2.
2. **Metered utility use.** Metered utility use data, as available, were analyzed and summarized in a subsection corresponding to the utility. Metered utility use data were available for the following utilities for City Hall.
 - Electricity; see Section 3.3.
 - Natural gas; see Section 3.4.
3. **Utility use baseline.** The utility use baseline was summarized in Section 3.5, and includes the following.
 - **Baseline year:** A baseline year was determined as the most recent year with the fewest anomalies in facility operations and utility metering. The baseline year was used to establish the historical weather data used for the energy model development, as explained in Section 4.1. If valid metered utility data was available for the baseline year, then the metered utility use data for the baseline year was used to establish baseline performance and for energy model calibration.
 - **Baseline performance:** Yearly utility use, GHG emissions and utility costs. For each utility, the baseline performance was derived from the metered utility use for the baseline year if available for that utility, or from the energy model described in Section 4 if metered data were unavailable or invalid for that utility. Table 13 summarizes the data source of the baseline performance for each utility.

Table 13: Baseline performance data source for each utility

Utility	Source
Electricity	Meter
Natural gas	Meter

4. **Benchmarking analysis.** The yearly baseline energy use and GHG emissions of City Hall was compared with those of similar facilities in Section 3.6. Data for similar facilities were obtained from the Government of Ontario's website, made available for the Broader Public Sector (BPS) through O. Reg. 25/23. The list below includes all municipalities considered for the benchmarking process. If this building is the only one presented, it indicates that similar buildings are not being reported to the database.
 - City of Greater Sudbury
 - City of North Bay
 - City of Temiskaming Shores
 - City of Timmins
 - Municipality of Temagami
 - Municipality of West Nipissing
 - Town of Iroquois Falls
 - Town of Kirkland Lake
 - Township of Armstrong
 - Township of Black River-Matheson
 - Township of Brethour
 - Township of Casey
 - Township of Chamberlain

- Township of Gauthier
 - Township of Harley
 - Township of Harris
 - Township of Hilliard
 - Township of Hudson
 - Township of James
 - Township of Kerns
 - Township of Larder Lake
 - Township of Matachewan
 - Township of McGarry
5. **Portfolio benchmarking analysis.** A portfolio benchmarking analysis was also performed, where Energy Star Portfolio Manager was used to benchmark the energy analysis of City Hall.
6. **Utility use analysis discussion.** Results of the utility use analysis were studied and discussed in Section 3.8.

3.2 Utility analysis assumptions

Assumptions applied throughout the methodology are summarized as follows.

- GHG emissions factors were assumed as per Table 14.

Table 14: GHG emissions factor assumptions

Utility	Unit	Value	Source
Electricity	[tCO ₂ e/kWh]	0.0000239	Environment and Climate Change Canada Data Catalogue, Electricity Grid Intensities-1
Natural gas	[tCO ₂ e/m ³]	0.0019324	National Inventory Report, 1990-2023, Table 1-1, Table A61.1-1 and Table A61.1-3

- Utility cost rates for the baseline year of 2023 were assumed as per Table 15. Electricity utility cost rates were assumed based on typical wholesale rates for the General Service Energy billing structure. Throughout this document, the Federal Carbon Charge ("FCC") was treated separately with respect to applicable fuels, rather than being blended into the utility cost rate for those fuels. As such, all other utility cost rates exclude the federal carbon charge. The Federal Carbon Charge was removed on April 1, 2025, as such, this document has been updated to have the FCC set to \$0/tCO₂e for 2025 and onward.

Table 15: Utility cost rate assumptions for the baseline year (2023)

Utility	Line item	Unit	Value
Electricity	Electricity consumption - Class B	[\$/kWh]	0.0200
Electricity	Global adjustment - Class B	[\$/kWh]	0.0735
Electricity	Regulatory	[\$/kWh]	0.0057
Natural gas	Natural gas (blended)	[\$/m ³]	0.2600
GHG emissions	Federal carbon charge	[\$/tCO ₂ e]	50.0000

3.3 Electricity metered utility use

Hourly electricity use is plotted in Figure 136.

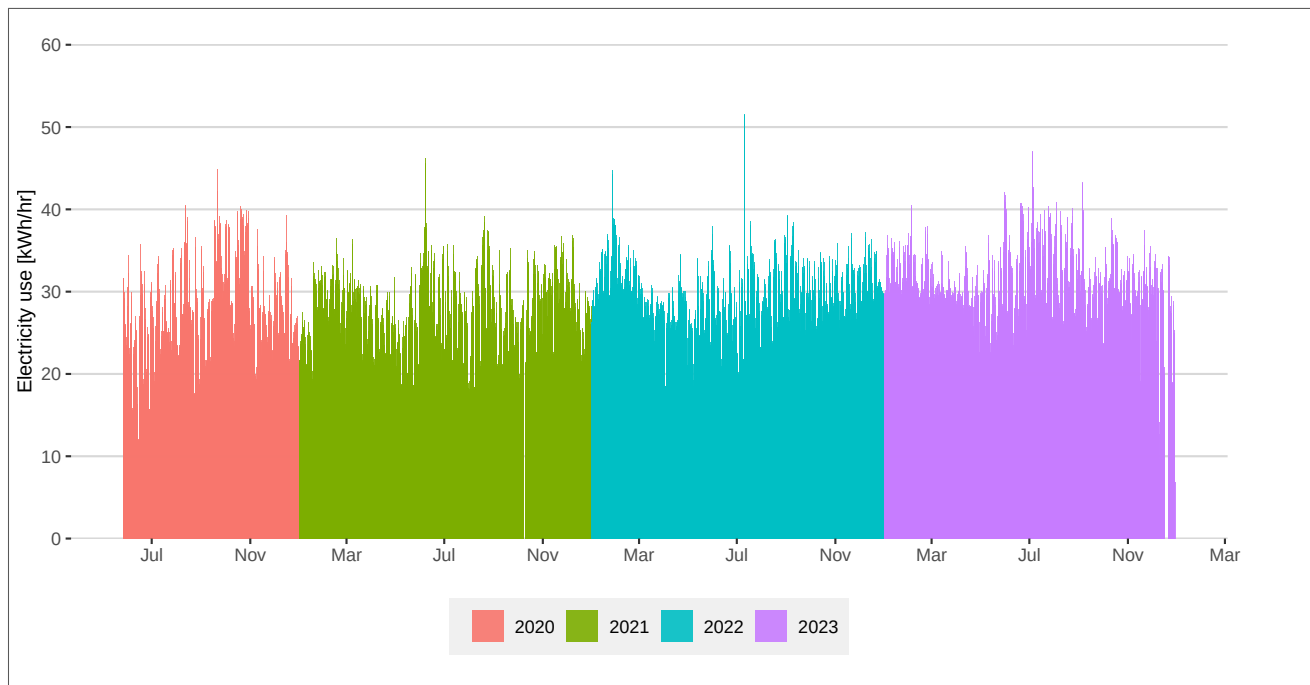


Figure 136: Hourly electricity use

The same hourly electricity use data is plotted in Figure 137, which highlights how electricity use is influenced by year, season, day of week and hour of day. The vertical axis on Figure 137 may be rescaled relative to in Figure 136 for greater resolution.

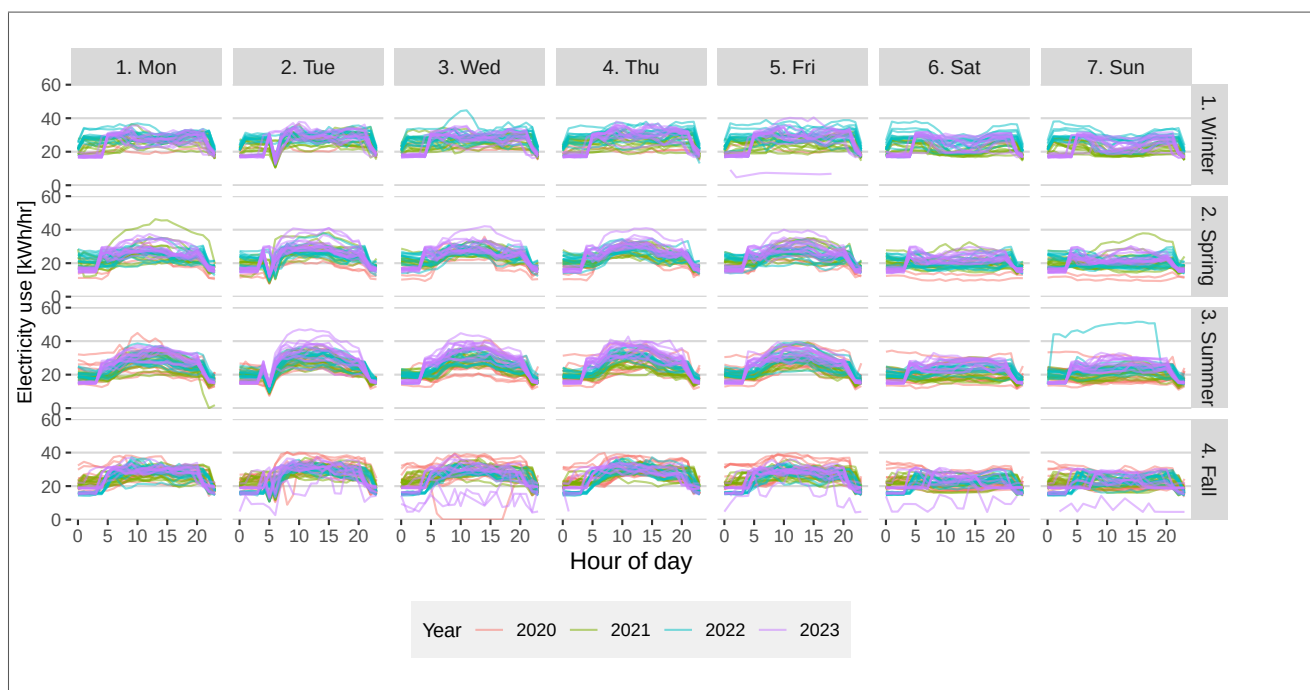


Figure 137: Hourly electricity use hairball plot

Monthly electricity use is plotted in Figure 138.

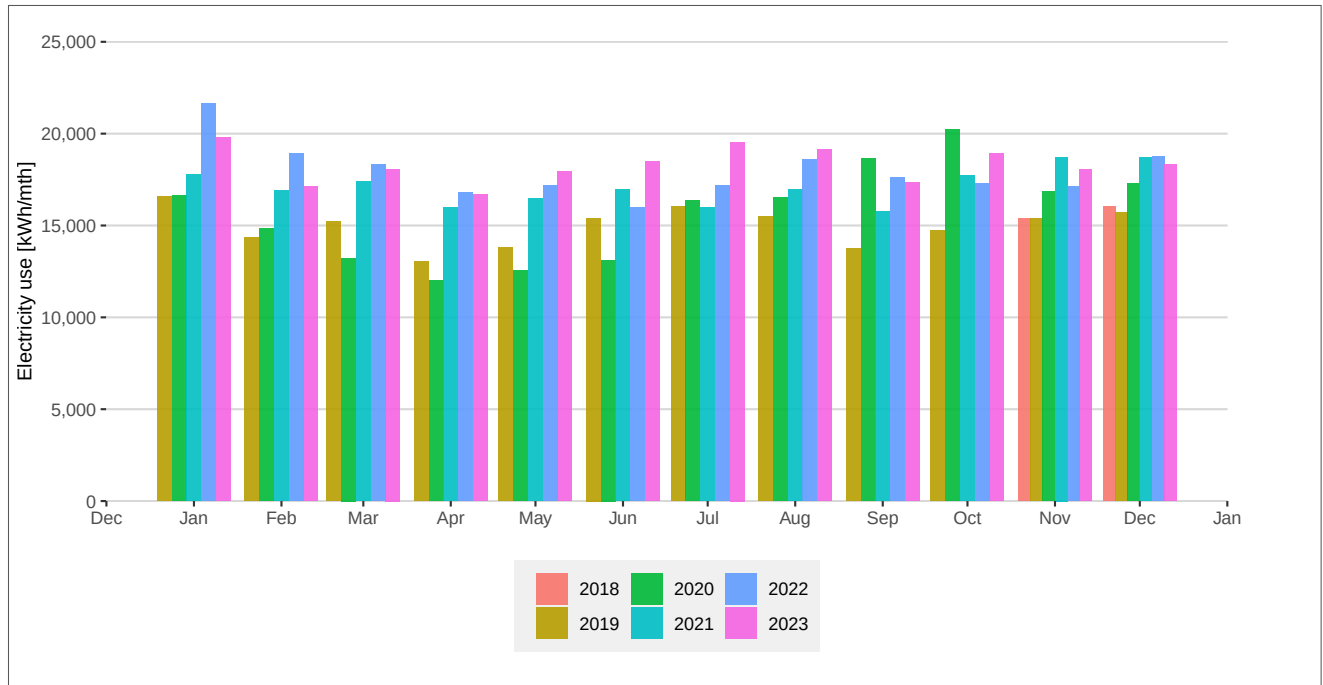


Figure 138: Monthly electricity use

3.4 Natural gas metered utility use

Monthly natural gas use is plotted in Figure 139.

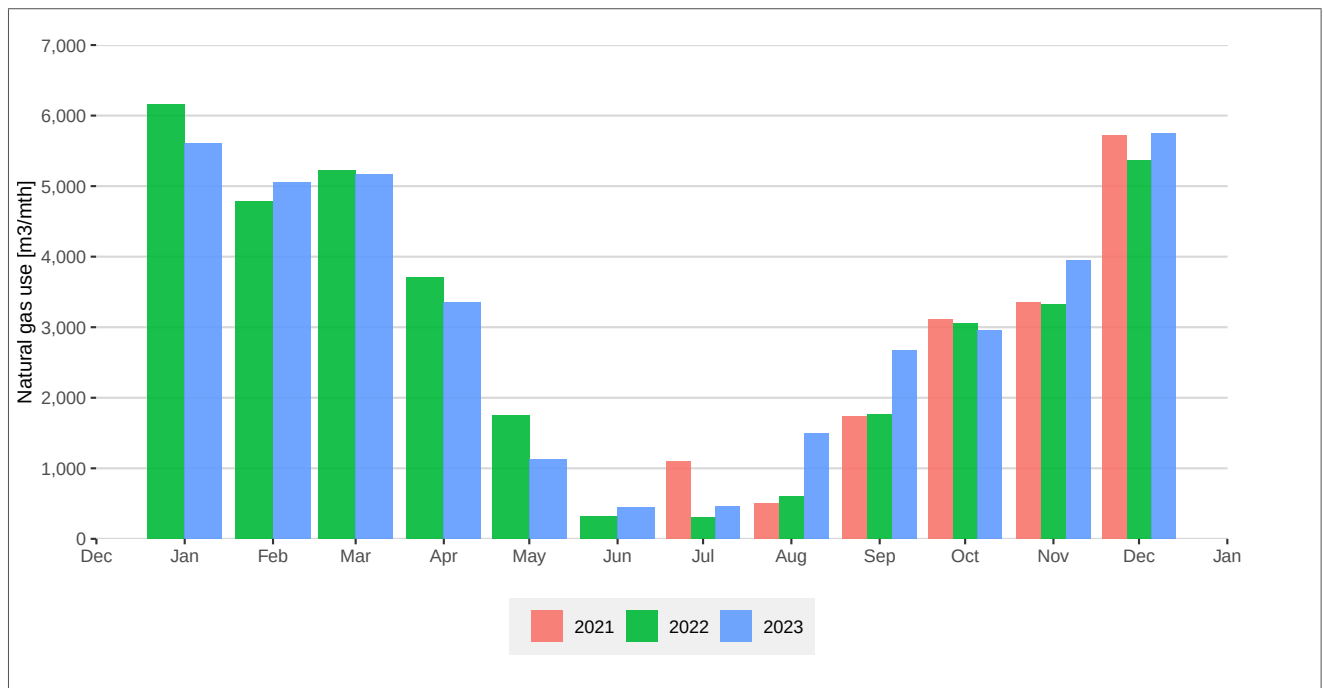


Figure 139: Monthly natural gas use

3.5 Utility use baseline

Baseline year

The baseline year for City Hall, which is used to establish the baseline performance through the metered utility use data from that year, is as follows.

- **Baseline year:** 2023.

Baseline performance

Baseline utility use performance for the baseline year of 2023 is summarized in Table 16.

Table 16: Baseline utility use performance

Category	Utility	Unit	Value
Utility use	Electricity use	[kWh/yr]	219,381
	Natural gas use	[m3/yr]	38,054
	Carbon offset use	[tCO2e/yr]	0
Equivalent energy use	Electricity energy	[kWh/yr]	219,381
	Natural gas energy	[kWh/yr]	401,730
	Total energy	[kWh/yr]	621,111
GHG emissions	Electricity GHGs	[tCO2e/yr]	5
	Natural gas GHGs	[tCO2e/yr]	74
	Carbon offsets GHGs	[tCO2e/yr]	0
	Total GHGs	[tCO2e/yr]	79
Utility cost	Electricity utility cost	[\$/yr]	21,763
	Natural gas utility cost	[\$/yr]	9,894
	Carbon offsets utility cost	[\$/yr]	0
	Federal carbon charge	[\$/yr]	3,677
	Total utility cost	[\$/yr]	35,333

3.6 Benchmarking analysis

Benchmarking analysis results are presented in the following figures.

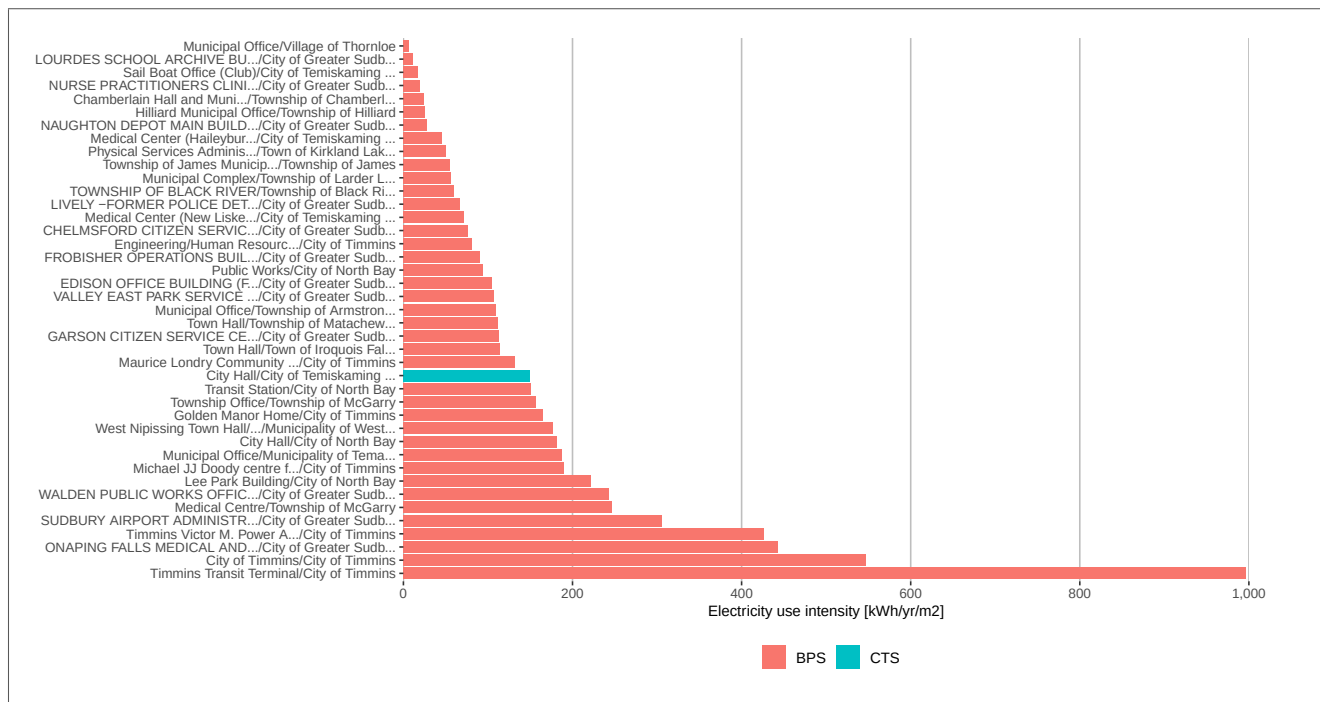


Figure 140: Electricity use intensity benchmarking analysis comparison

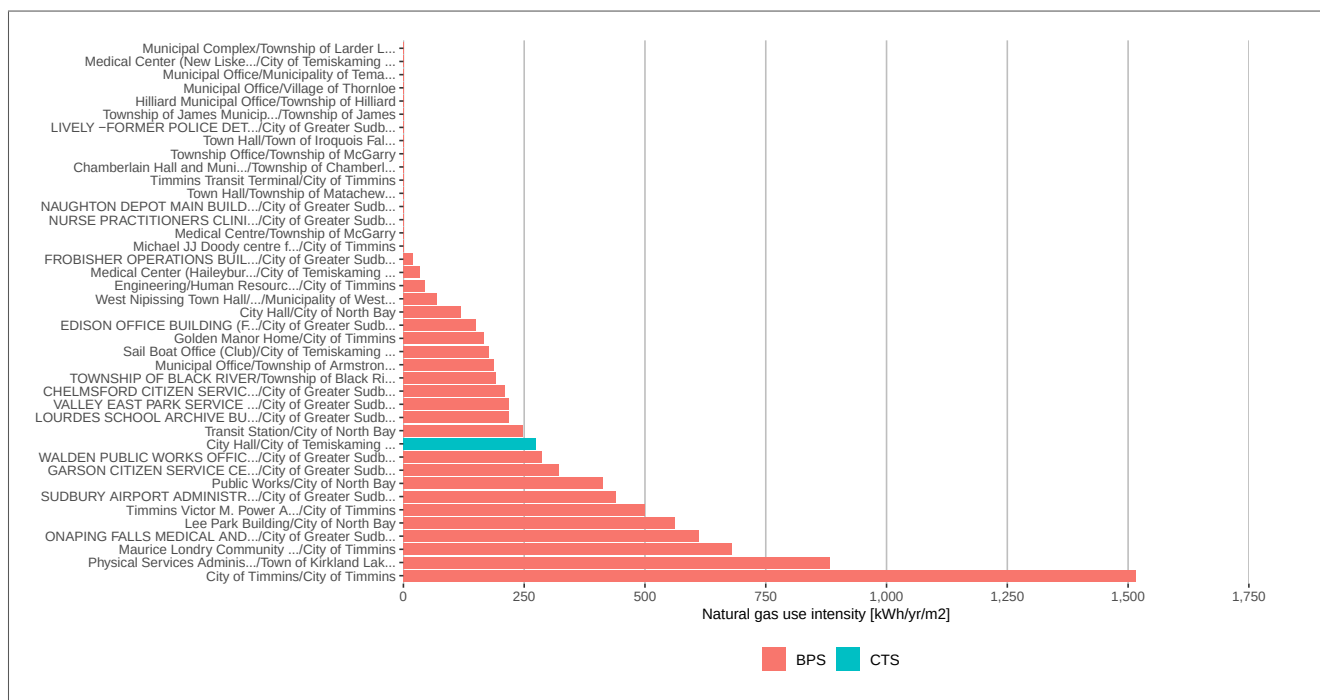


Figure 141: Natural gas use intensity benchmarking analysis comparison

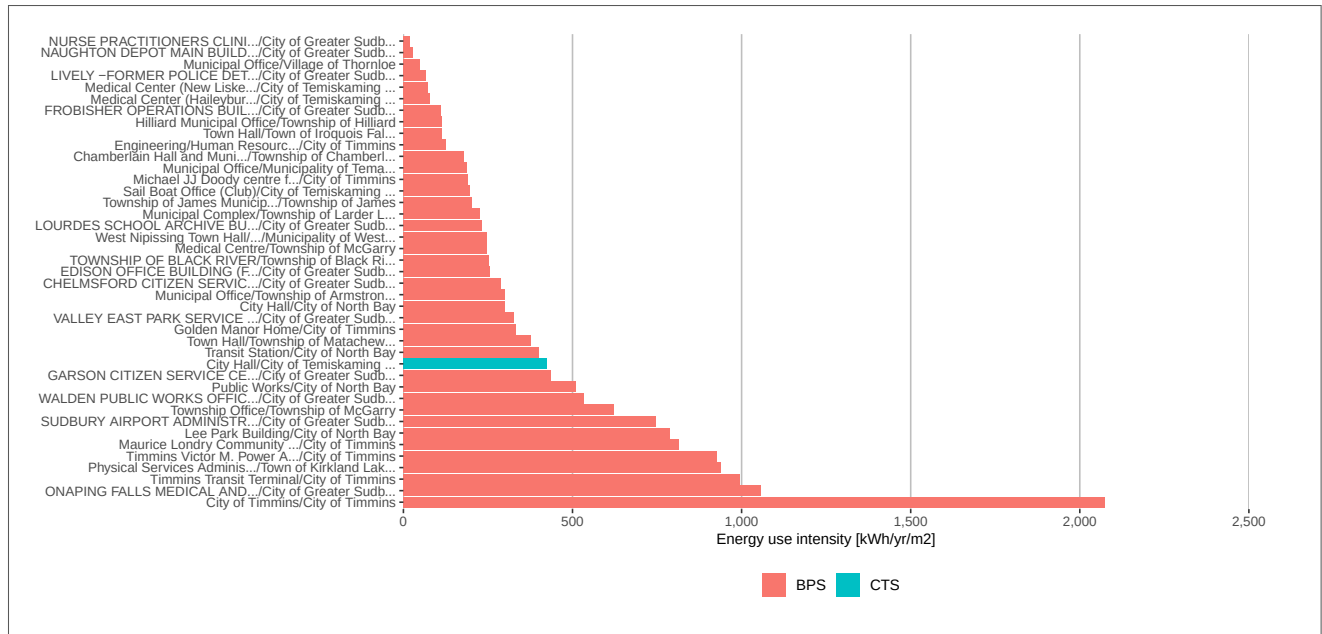


Figure 142: Total energy use intensity benchmarking analysis comparison

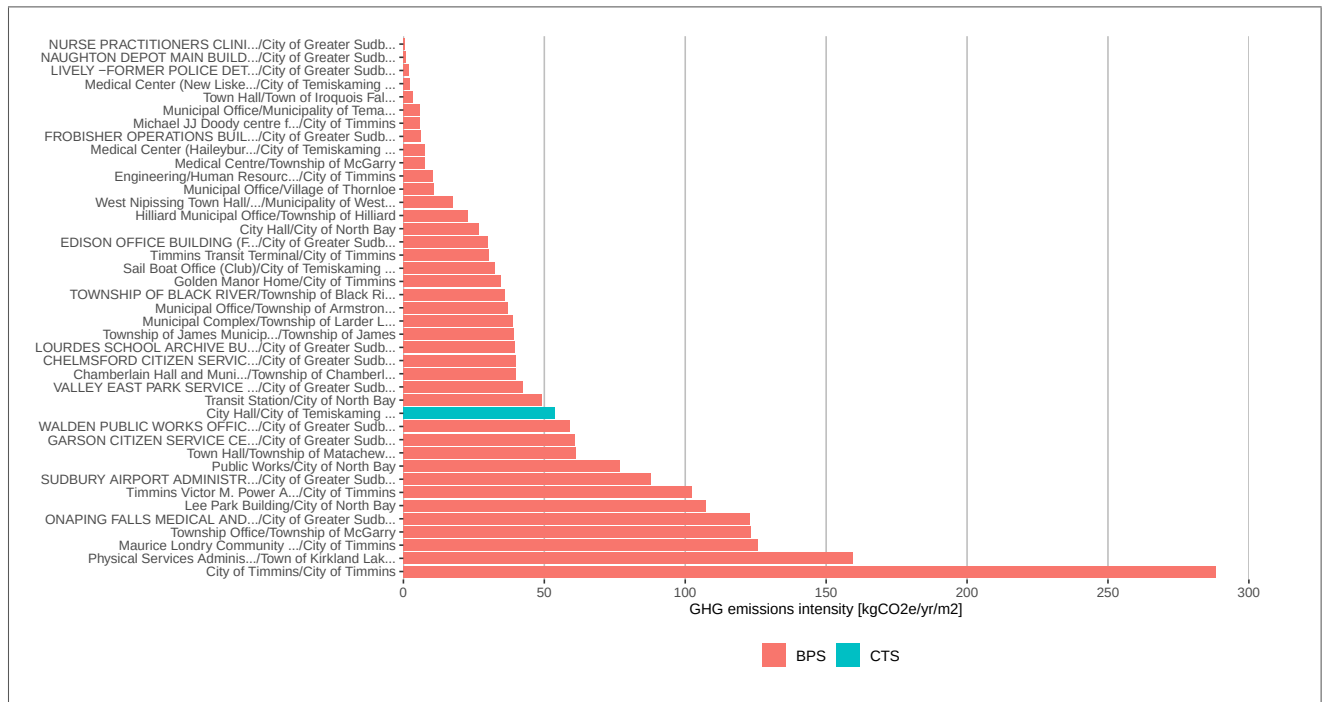


Figure 143: GHG emissions intensity benchmarking analysis comparison

3.7 ENERGY STAR Portfolio Manager benchmarking analysis

The scorecard is shown in Figure 144.

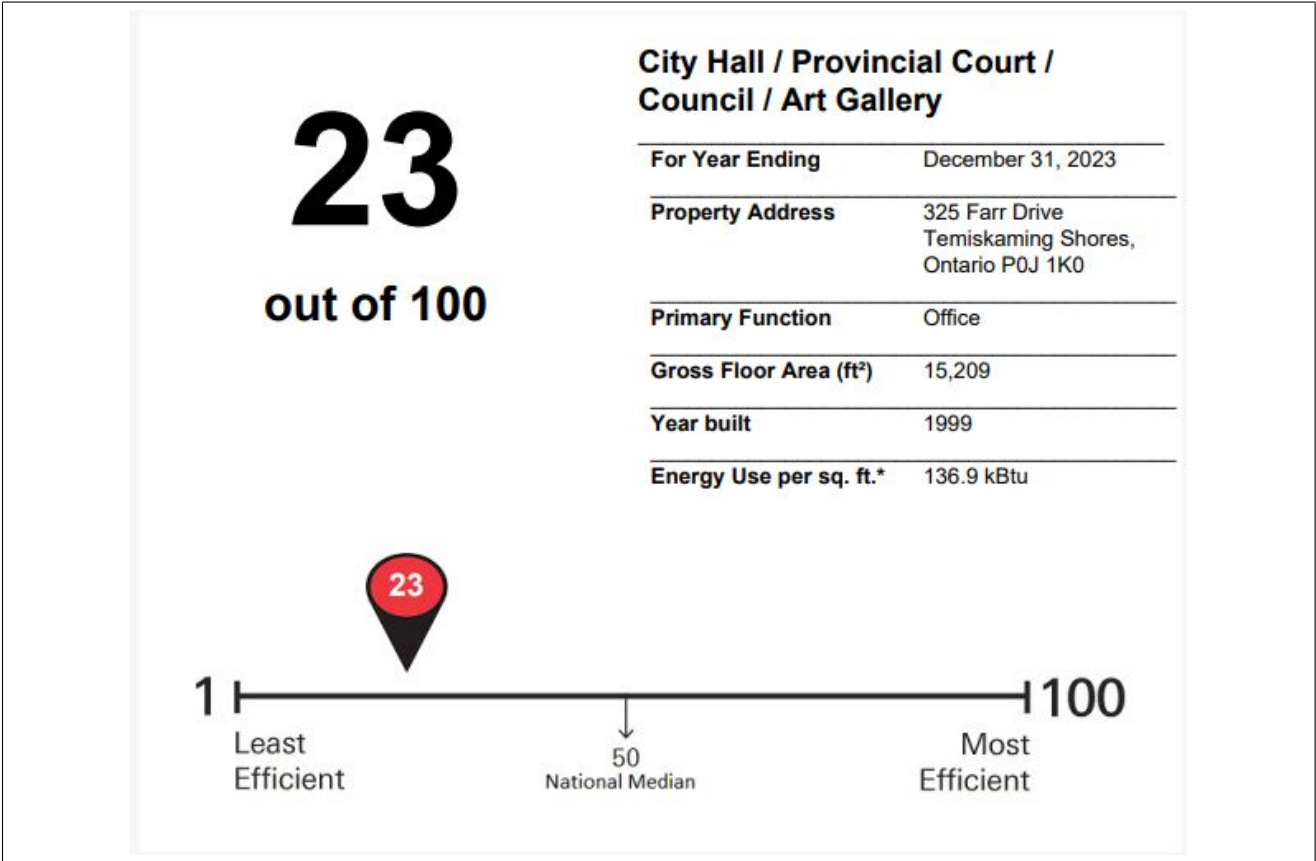


Figure 144: Energy Star energy performance scorecard.

3.8 Utility use analysis discussion

General

The following discussion seeks to explain utility use trends observed in the metered data, based on the understanding of the building systems and their operations presented in Section 2.

Electricity - Hourly

- Hourly electricity consumption typically peaks during the summer, most likely due to cooling.
- Hourly consumption is typically under 40 kWh and above 15 kWh.
- An "S-shape" profile suggests heating in the winter and cooling in the summer.
- Hourly consumption during unoccupied hours is around 15-20 kWh. This amount is attributed to the RTU2 and ERV1 being on continuously, along with exterior lighting, interior emergency lighting, and most likely plug loads.

Electricity - Monthly

- **2018:** The dataset provided started in November 2018 and did not allow for a full year of comparison. However, November and December for this year were notably less than in future years.
- **2019:** Peak consumption in January and July and low overall consumption compared to future years.
- **2020:** There was a noticeable dip in consumption from March through June. This observation is consistent with other similar buildings due to the pandemic. However, consumption ramped up again in July, and September and October had the highest consumption for their respective months of that year. This observation is most likely do to adjustments to the HVAC system.
- **2021:** Minimum change in monthly consumption throughout the year.
- **2022:** January 2022 had the highest monthly consumption of the dataset.
- **2023:** Shows the highest consumption overall, especially during May to August.

Natural gas

- Natural gas consumption has maintained a consistent profile year over year. It is highest during the heating season and very low during the cooling season.
- There appears to be a spike in the monthly natural gas use in July 2021, which is thought to be an adjustment for underestimated data in previous months.
- This building has two end uses: space heating and the generator. Based on a review of the generator account, the consumption represents approximately 650m³ annually.
- Natural gas consumption in the summer is likely due to the RTUs and reheating of supply air to zones.
- Of the thirty data points available for monthly natural gas consumption, only 12 were actual readings, not estimates. This observation can lead to calibration issues, as the model may not pass ASHRAE Guideline 14.

4 ENERGY MODEL DEVELOPMENT

4.1 Energy model development methodology

The utility use profile was developed from an hourly analysis, spanning one year, of the following energy systems. The analysis reflects the existing conditions of the facility as documented in Section 2.

The energy model was created in eQUEST v3.65, build 7175, using the DOE2.3 engine. The inputs were established to match the existing conditions as closely as possible. The following sources were used as background information to inform energy model inputs:

- Observations from site survey and conversations with facility staff.
- Schedules and setpoints from the BAS. As-built drawings provided by the City of Temiskaming Shores.
- References from the Ontario Building Code (OBC) SB-12, ASHRAE90.1, and NECB where the above data was not available.

1. **Hourly utility use profiles.** An hourly utility use profile for each utility was developed according to the following methodology. Results were presented in Section 4.2.

- (a) *Utilities and end uses.* Hourly utility use profiles developed through this analysis were assigned to both utilities and end uses. The utilities and end uses that were modelled are summarized in Table 17.

Table 17: Utility and end use summary and definitions

Utility	End use	Definition of end use
Electricity	Cooling	Cooling energy use.
	DHW heat	Domestic hot water heating energy use.
	Equipment	Equipment energy use.
	Exterior lights	Exterior lighting energy use.
	Fans	Fan motor energy use.
	Humidification	Humidification energy use.
	Lights	Lighting energy use.
	Other	Metered use less modelled use.
	Pumps	Pump motor energy use.
	Space heat	Space heating energy use.
Natural gas	Generator	Generator energy use.
	Other	Metered use less modelled use.
	Space heat	Space heating energy use.

- (b) *Weather data.* Hourly weather data was obtained from the Earlton-Cimate weather station, ID 712130S.
- (c) *Facility spaces.* Facility spaces were grouped according to activities in the spaces and HVAC systems serving them. The thermal characteristics of the exterior building envelope components for each space were assumed based on findings documented in Section 2.7. Thermal loads within each space were calculated based on assumed space temperature and humidity setpoints, hourly weather data, and activities in the space that affect thermal conditions (e.g. lighting or equipment that generates heat).
- (d) *Primary systems.* Primary systems are defined as systems whose utility use can be predicted independent from other systems; examples include lighting, equipment (e.g. office and process equipment), pumps, etc. The hourly utility demand of primary systems was modelled based on assumed time-of-day operating schedules, peak power input and average loads relative to the peak power input. Peak power input was estimated from findings documented throughout Section 2, including lighting power or power density, nameplate horsepower of motors, etc.
- (e) *HVAC systems.* HVAC system energy use was modelled based on hourly weather data and space condition setpoints defined for the various spaces. The analysis also accounted for system-specific ventilation controls and activities and primary systems that have thermal influences on spaces

(e.g. occupancy, lighting, equipment, processes that add heat to spaces). The analysis quantified hourly energy use of fans, heating (e.g. sensible, humidification, reheat) and cooling (e.g. sensible, dehumidification).

- (f) *Generators*. The utility use and generation of on-site systems that generate energy or utilities was modelled based on the assumed capacities and operations of those systems according to findings documented in Section 2; examples include solar PV, CHP, etc. Utilities generated on site were treated as negative utility consumption relative to utilities consumed on site so that the consumption, generation and the aggregate use of utilities could be tracked accordingly.
 - (g) *Other*. For each utility having valid metered utility use data available for the baseline year, the Other end use was modelled from the top down to reconcile results of the above utility-consuming systems that were modelled from the bottom up with metered utility use data for the baseline year. This end use was called Other.
2. **Monthly utility use profiles**. A monthly utility use profile for each utility was developed by grouping and summing up the hourly utility use profiles by end use and by month. Results were presented in Section 4.3.
 3. **Calibration analysis**. After explicitly modeling the above systems, the model was calibrated for each of the following utilities (utilities for which valid metered data for the baseline year was available) through the Other end use, which was calculated as the difference of metered and modeled utility use. The above modeling steps were iterated as required to achieve reasonable calibration.
 - Electricity
 - Natural gas
 4. **End use analysis**. An end use analysis of each utility was completed. Since the hourly utility use profiles already track the hourly utility use by each end use, the end use analysis involved summarizing data from the hourly utility use profiles to obtain yearly utility use by each end use. Results were presented in Section 4.5.

4.2 Hourly utility use profiles

The hourly utility use profiles are presented graphically in this Section 4.2 in a format called a stacked bar plot. For each hour of the year, the utility use for all end uses active during that hour is presented in a single bar pertaining to that hour. The end uses are identified by colour, and all end uses are “stacked” on top of each other within each hour-specific bar such that the total height of each bar represents the total utility use of all end uses combined in that hour.

Electricity

The hourly electricity utility use profile by end use made by the energy model is plotted in Figure 145. See Table 17 for end use definitions.

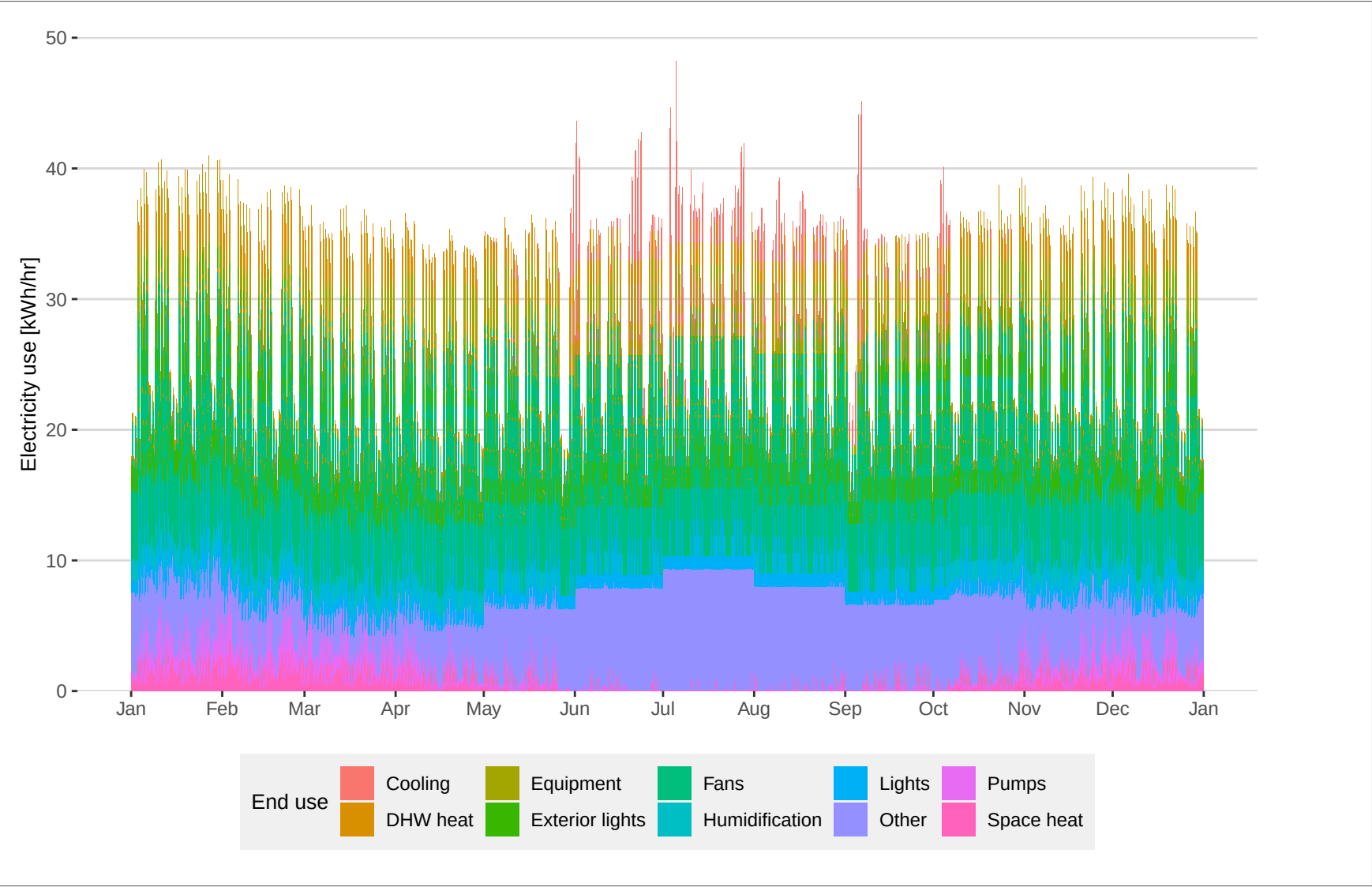


Figure 145: Hourly electricity utility use by end use (made by calibrated energy model)

Natural gas

The hourly natural gas utility use profile by end use made by the energy model is plotted in Figure 146. See Table 17 for end use definitions.

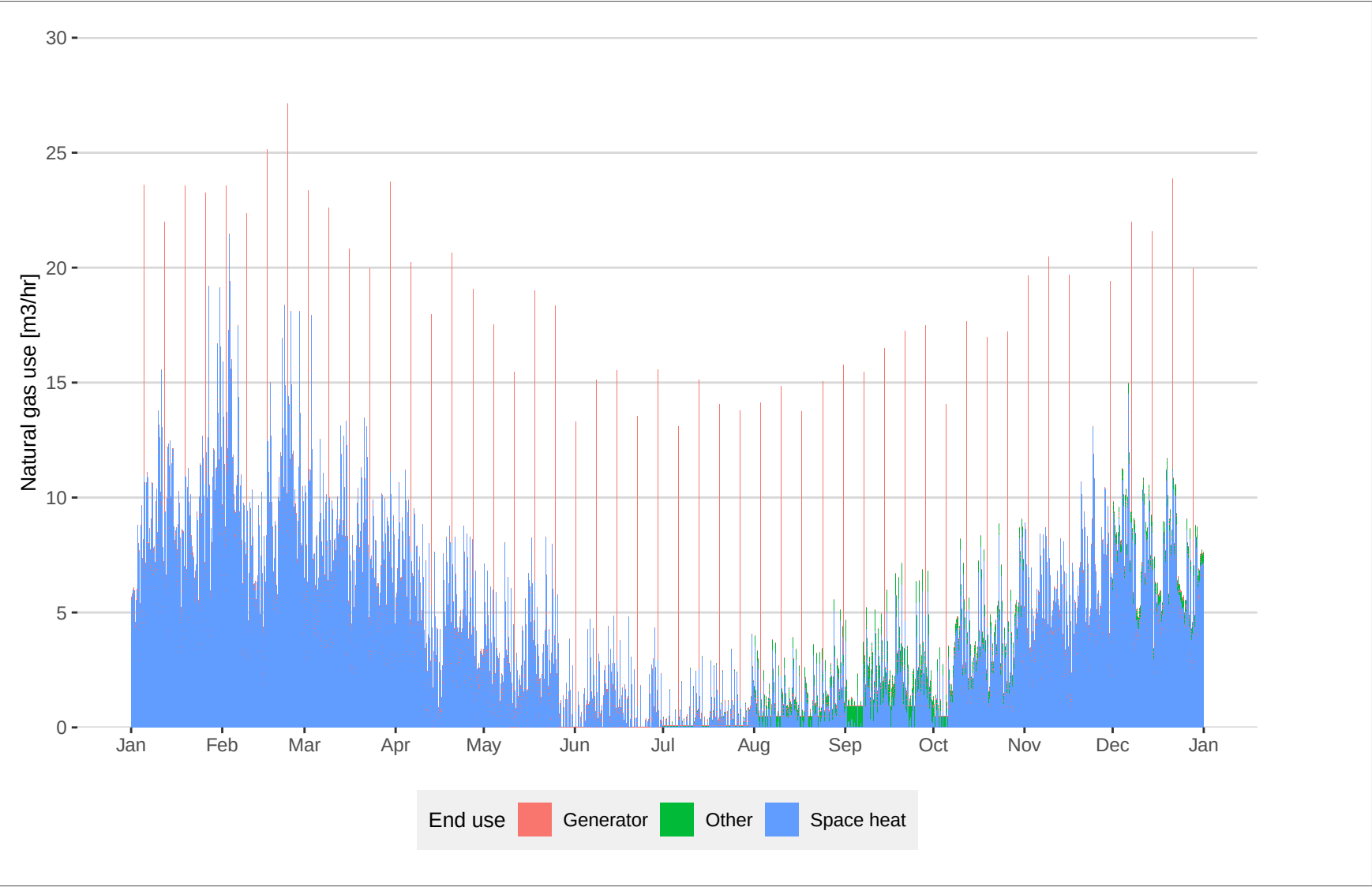


Figure 146: Hourly natural gas utility use by end use (made by calibrated energy model)

4.3 Monthly utility use profiles

Monthly utility use profiles for each modelled utility are presented in Figure 147.

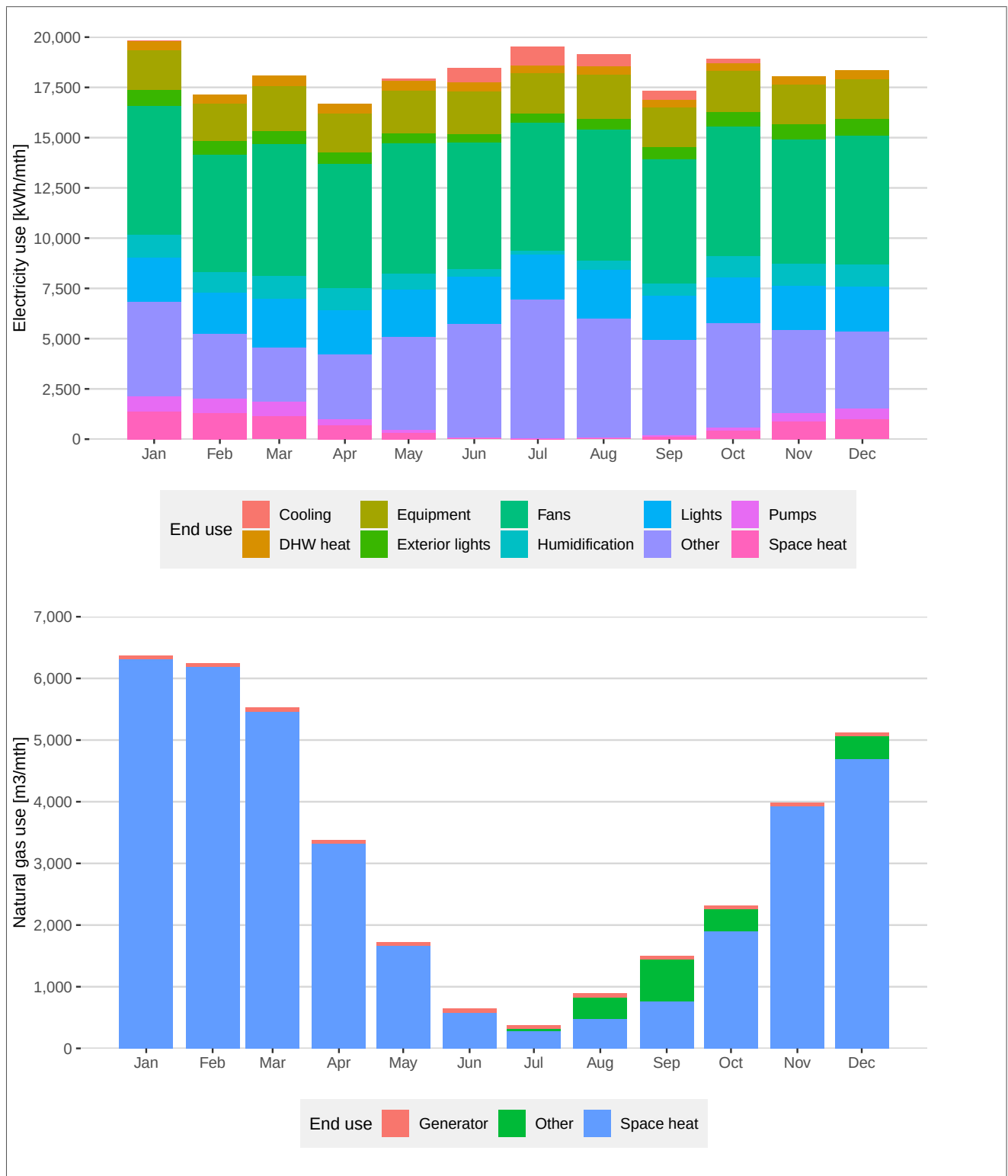


Figure 147: Monthly utility use profiles for each modelled utility

4.4 Calibration analysis

Electricity

Figure 148 compares the metered utility use with the modelled use to check how well the model is calibrated.

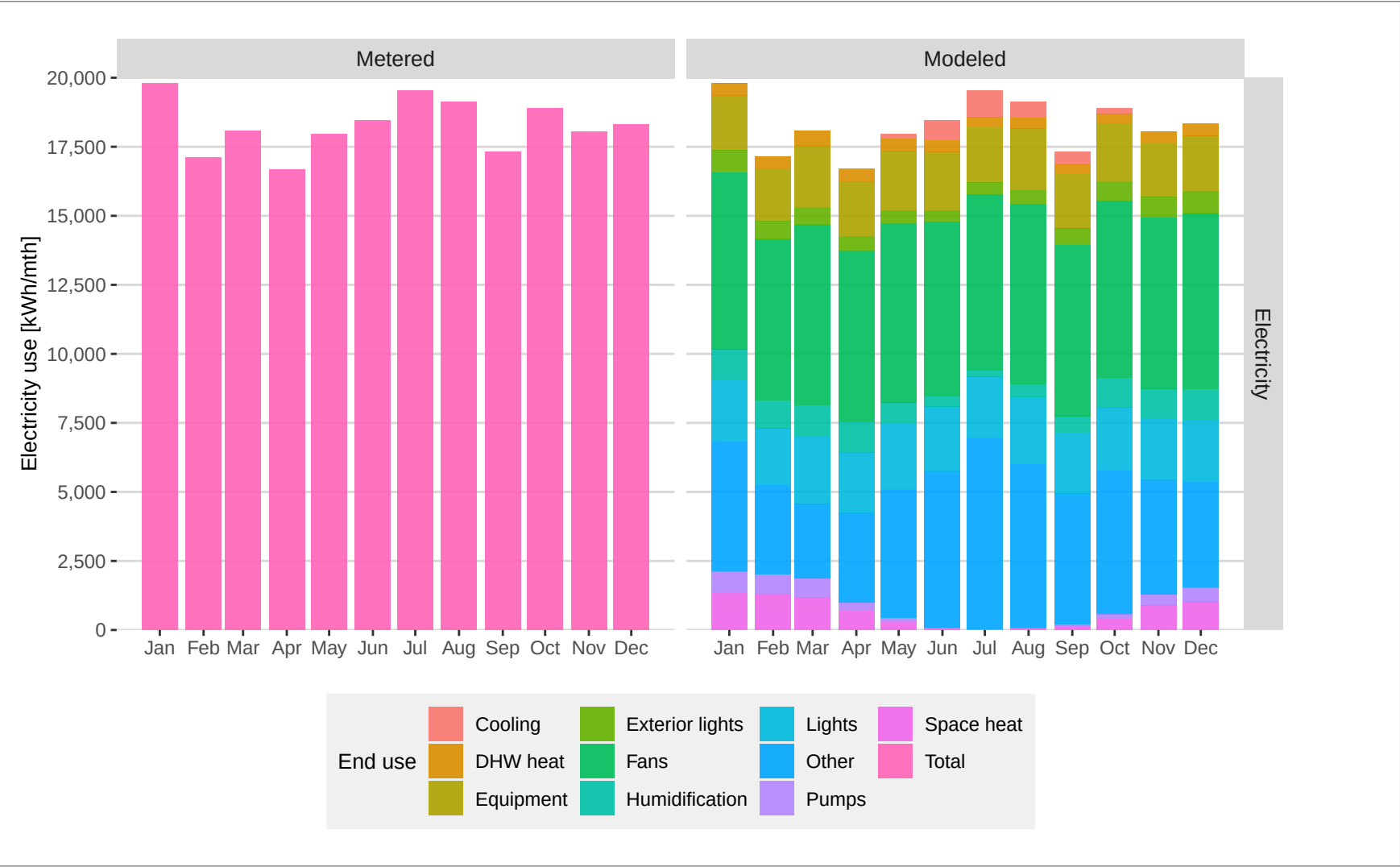


Figure 148: Electricity calibration analysis (metered vs modelled utility use)

Natural gas

Figure 149 compares the metered utility use with the modelled use to check how well the model is calibrated.

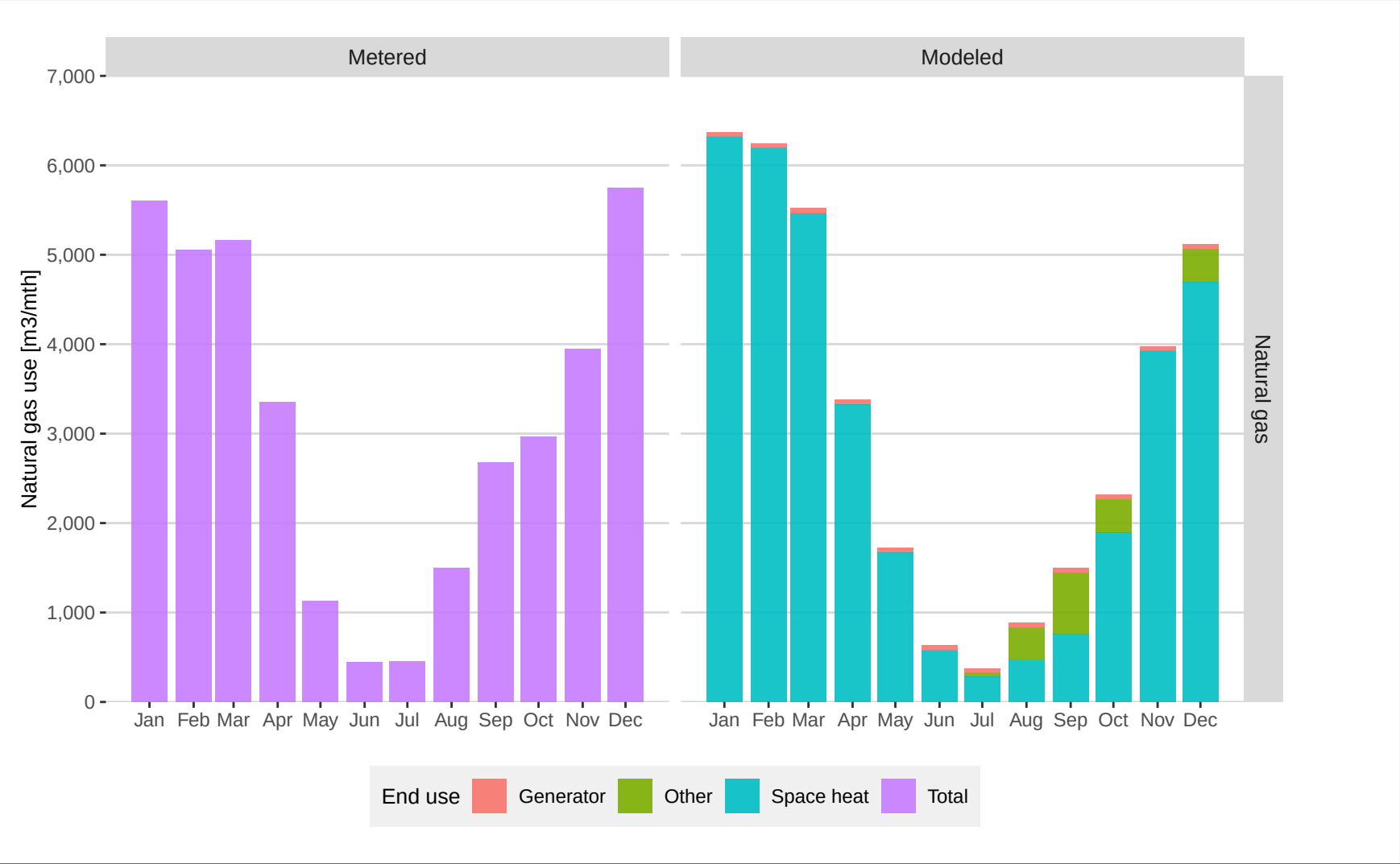


Figure 149: Natural gas calibration analysis (metered vs modelled utility use)

Statistical calibration analysis

ASHRAE Guideline 14 suggests maximum allowable values for the mean bias error, and the root mean bias error, which are defined as follows with respect to energy model calibration.

- **Mean bias error (MBE).** The average monthly error between modelled and metered utility use as a percentage of the mean monthly metered utility use. This metric indicates the ability of the model to accurately predict yearly utility use, despite month-to-month errors, by capturing the direction of all month-to-month errors.
- **Root mean square error (RMSE).** The square root of the sum of all squared monthly errors as a percentage of the mean monthly metered utility use. This metric indicates the ability of the model to accurately predict month-specific utility use.

Statistical calibration analysis results were calculated and are summarized in Table 18.

Table 18: Statistical calibration analysis summary

Utility	Description	Unit	ASHRAE 14	Model	Pass/Fail
Electricity	Mean bias error	[%]	< +/- 5	-0.0	Pass
	Root mean square error	[%]	< 15	0.0	Pass
Natural gas	Mean bias error	[%]	< +/- 5	0.0	Pass
	Root mean square error	[%]	< 15	21.5	Fail

It should be noted that the root mean square error test suggested by ASHRAE Guideline 14 places undue emphasis on months that have relatively little utility use (e.g. natural gas or steam use in the summer). This is because the root mean square error test is calculated based on relative errors between monthly metered and modelled utility use. Because of this, a small absolute error between metered and modelled utility use for a certain month may also be a large relative error, causing a significant increase in the root mean square error. Practically, though, the ability of the energy model to accurately quantify utility use overall has little dependence on its ability to quantify utility use in months with relatively little metered use, because overall utility use is more heavily influenced by those months with greater utility use. Therefore, it may not always be suitable for the model to pass the root mean square error test, provided that it reasonably captures utility use in the months of greater use.

A discussion of the energy model calibration analysis is as follows.

- Figures 148 and 149 both demonstrate a strong agreement between monthly trends observed in the metered utility use data and the monthly utility use predicted by the calibrated energy model.
- Electricity use was successfully calibrated according to the standards of ASHRAE Guideline 14. Note that the mean bias error is zero for electricity and natural gas because the Other end-use ensures that the yearly modelled utility use matches the yearly metered utility use. This process also maintains consistency between the baseline utility use derived from the metered utility data and all measure and scenario analyses.
- Natural gas consumption fails to follow Guideline 14 on the root mean square error. Some notable issues are that consumption is higher in the model from January through May and December. There is also a discrepancy in the summer months as well. Another note is that only 4 of 12 natural gas readings are actual readings. This issue makes it difficult to calibrate the model, especially against estimated data that the LDC typically underestimates.
- The successful energy model calibration is largely due to the methodology used in developing the calibrated energy model. Under this methodology, the major systems affecting utility use were studied in detail (see Section 2), including their operations and control sequences from analyzing the building automation system (BAS), so that these systems could be explicitly modelled one-to-one, precisely reflecting the unique operations associated with each system. Examples of such major systems include all air handling systems

(HVAC1, HVAC2, AC1-AC4) and the natural gas fireplace. The methodology also integrates the Other end-use category, which reflects the exact difference between metered and modelled utility use in a top-down calculation after all systems have been modelled from the bottom-up.

- Therefore, there can be confidence that the utility use impacts quantified in the various measure and scenario analyses under this report are reasonable.

Electricity

- Figure 148 indicates strong agreement between modelled and metered data.
- The peak and trough hourly consumption align with the metered interval data.
- The large fan load is due to RTU2 and ERV1 running continuously. Furthermore, even though this system is a variable volume system, the fixed speed on the RTUs causes it to operate as a constant volume system.

Natural gas

- Figure 149 indicates good agreement between modelled and metered data.
- The annual amount of natural gas consumption in the model is very close to the annual amount of the metered data. However, there are variances within several months. That being said, there are several estimated readings for this particular dataset.

4.5 End use analysis

Electricity

The yearly electricity end use breakdown calculated by the energy model is plotted in Figure 150. See Table 17 for end use definitions.

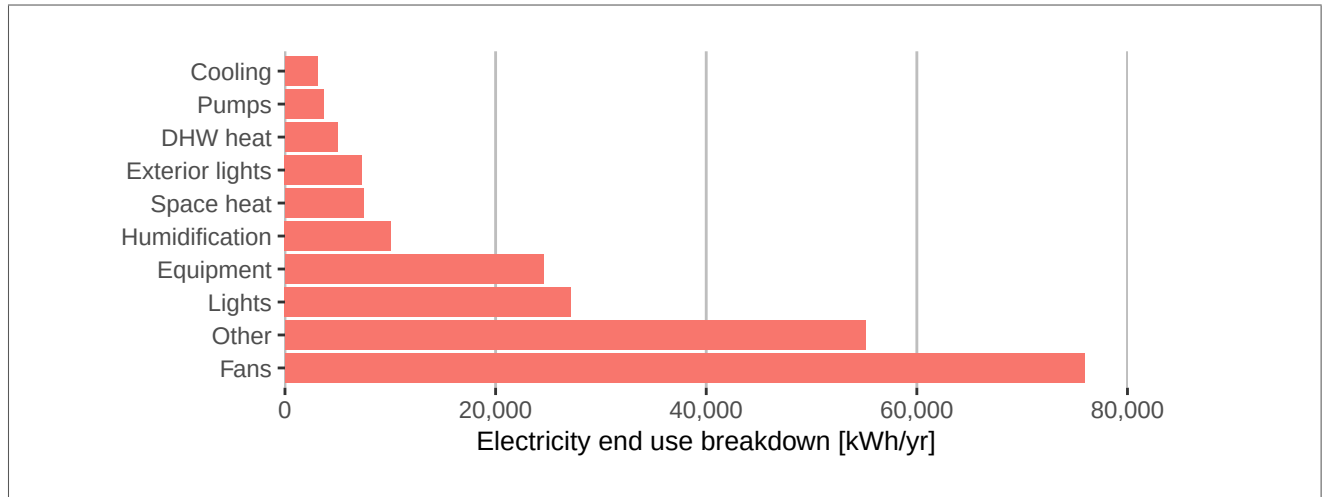


Figure 150: Electricity end use breakdown (calculated by calibrated energy model)

Natural gas

The yearly natural gas end use breakdown calculated by the energy model is plotted in Figure 151. See Table 17 for end use definitions.

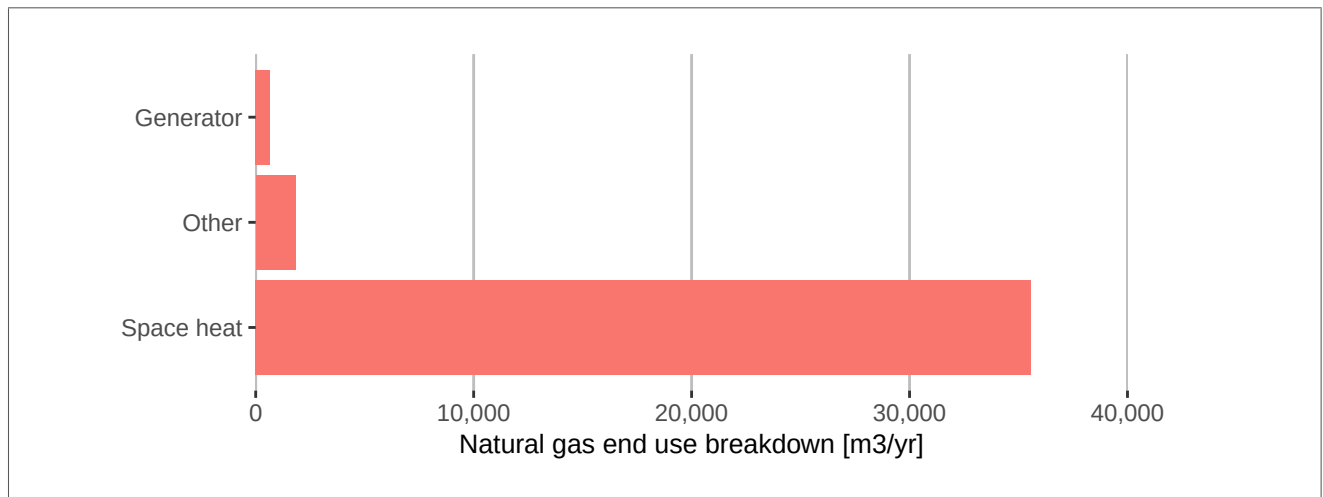


Figure 151: Natural gas end use breakdown (calculated by calibrated energy model)

5 MEASURE ANALYSIS

5.1 Measure analysis methodology

The measure analysis was completed according to the following methodology.

1. **Measure identification and triaging.** Measures that could be implemented to help achieve City of Temiskaming Shores's goals were identified based on the findings documented in Sections 2 and 3. Identified measures were triaged by labeling each one as either 'Analyzed' or 'Not analyzed'. The intent of triaging was to focus efforts on analyzing measures for which analysis was considered most valuable (typically for measures that are more complex or more impactful). Results are summarized in Section 5.3.
2. **Measure analysis.** For each 'Analyzed' measure, the analysis completed for that measure was summarized in a dedicated sub-section named after that measure (see Sections 5.4 through 5.16). In each sub-section, the following was documented.
 - *Measure description.* The relevant existing condition was summarized, an opportunity for improving the stated existing condition was described, and the intended utility-savings mechanism associated with the opportunity was described.
 - *Design description.* A conceptual design description was provided, including a written description of the proposed design concept and the associated project cost estimate.
 - *Utility analysis.* A utility analysis was completed using the energy model introduced in Section 4. Measure-specific assumptions applied in calculating the impacts on utility use were provided for each measure. For each measure, the expected GHG emissions, utility costs and financial incentives associated with implementing the measure were calculated based on utility use, using the assumptions outlined in Section 5.2. A life cycle cost analysis was completed, applying the assumptions summarized in Tables 15 and 21 according to the following methodology.
 - (a) The life cycle cost for each measure was calculated based on the assumed implementation year of 2026 for each measure. The life cycle cost for each measure was calculated as the sum of the following future financial cost expenditures, discounted back to present value using the discount rate from Table 21, over the evaluation period of present to 2050.
 - (b) Project costs: The future value of project costs was calculated based on the project cost estimate of each measure, inflated to future value associated with the assumed implementation year using the general inflation rate from Table 21. In the life cycle cost calculation, the project cost was amortized over the expected life of the measure such that the yearly present value is constant over every year of the expected life of the measure. This results in the net present value of the project cost being equal to what it would be if the owner was to pay for it via lump sum in the implementation year for that measure.
 - (c) Replacement costs: The future value of replacement costs was calculated assuming that a financial cost was incurred to replace equipment associated with each measure at the end of the expected life of that measure equal to 50% of the initial project cost, inflated to future value associated with the estimated time of replacement using the general inflation rate from Table 21. The same amortization approach as for project costs was used.
 - (d) Utility costs: The future value of yearly utility costs of the entire facility was accounted for in the life cycle cost calculation for each measure. The future value of yearly utility costs was calculated by applying the future utility cost rates from Table 19 to the utility use of the entire facility for that year as predicted by the calibrated energy model for each measure and scenario.
3. **Measure risk analysis.** A risk analysis of each individual measure was completed to test how the performance of that measure might be affected by changes to certain risk parameters. In this risk analysis, each of the risk parameters defined in Table 22 was tested under each risk case also defined in Table 22 for that risk parameter. For each risk case of each risk parameter, the expected performance of each measure was quantified, and the results were summarized using box and whisker plots indicating the range over

which performance might be expected to vary. Findings from the risk analysis were summarized in Section 5.17.

4. **Measure analysis summary.** Measure analysis results for all measures were summarized in table format in Section 5.18.

5.2 Measure analysis assumptions

Assumptions general to all measures are as follows.

- GHG emissions factor assumptions are summarized in Table 14, in Section 3.2.
- Utility cost rate assumptions applied to quantify yearly utility cost impacts relative to the baseline are summarized in Table 15, in Section 3.2. Utility cost rate future assumptions applied in the life cycle analysis for each measure are summarized in Table 19. Note that throughout this Pathway to Decarbonization Feasibility Study the Federal Carbon Charge is treated separately (if applicable) with respect to associated fuels (rather than being accounted for within the rates of the applicable fuels, the federal carbon charge line item is calculated separately based on the estimated yearly GHG emissions for that fuel). As such, all other utility cost rates exclude the federal carbon charge.

Table 19: Utility cost rate future assumptions

Year	Natural gas	Federal carbon charge	Carbon offsets	Class B HOEP	Class B GA	Class B regulatory
-	[\$/m3]	[\$/tCO2e]	[\$/tCO2e]	[\$/kWh]	[\$/kWh]	[\$/kWh]
2023	0.2652	65	30	0.0204	0.075	0.0058
2024	0.2705	80	30.6	0.0208	0.0765	0.0059
2025	0.2759	0	31.21	0.0212	0.078	0.006
2026	0.2814	0	31.84	0.0216	0.0796	0.0061
2027	0.287	0	32.47	0.022	0.0812	0.0062
2028	0.2927	0	33.12	0.0224	0.0828	0.0063
2029	0.2986	0	33.78	0.0228	0.0845	0.0064
2030	0.3046	0	34.46	0.0233	0.0862	0.0065
2031	0.3107	0	35.15	0.0238	0.0879	0.0066
2032	0.3169	0	35.85	0.0243	0.0897	0.0067
2033	0.3232	0	36.57	0.0248	0.0915	0.0068
2034	0.3297	0	37.3	0.0253	0.0933	0.0069
2035	0.3363	0	38.05	0.0258	0.0952	0.007
2036	0.343	0	38.81	0.0263	0.0971	0.0071
2037	0.3499	0	39.58	0.0268	0.099	0.0072
2038	0.3569	0	40.38	0.0273	0.101	0.0073
2039	0.364	0	41.18	0.0278	0.103	0.0074
2040	0.3713	0	42.01	0.0284	0.1051	0.0075
2041	0.3787	0	42.85	0.029	0.1072	0.0077
2042	0.3863	0	43.7	0.0296	0.1093	0.0079
2043	0.394	0	44.58	0.0302	0.1115	0.0081
2044	0.4019	0	45.47	0.0308	0.1137	0.0083
2045	0.4099	0	46.38	0.0314	0.116	0.0085
2046	0.4181	0	47.31	0.032	0.1183	0.0087
2047	0.4265	0	48.25	0.0326	0.1207	0.0089
2048	0.435	0	49.22	0.0333	0.1231	0.0091
2049	0.4437	0	50.2	0.034	0.1256	0.0093
2050	0.4526	0	51.21	0.0347	0.1281	0.0095

- Financial incentive assumptions are summarized in Table 20.

Table 20: Financial incentive assumptions

Incentive program	Incentive calculation rules
Enbridge custom	0.25 \$/m3/yr of natural gas reduction Up to a maximum of 50% of eligible project costs Up to a maximum of \$100,000
FCM CBR GHG reduction pathway grant	Up to 80% of project costs (grant + loan) Up to \$5 million (grant + loan) Up to 25% of funding can be grant

- Life cycle cost analysis assumptions are summarized in Table 21.

Table 21: Life cycle cost analysis assumptions

Description	Unit	Value
General cost inflation	[%]	2
Discount rate	[%]	5

- Risk analysis assumptions, including risk parameters and risk cases that were tested in the measure risk analysis are summarized in Table 22.

Table 22: Risk parameter and case definitions

Parameter	Description	Methodology	Case	X	Unit
Project cost	Project cost may differ from the estimated values.	The case project cost = x TIMES the initial project cost estimate.	Very low Low High Very high	0.75 0.9 1.1 1.25	[decimal]
Replacement cost	Replacement cost may differ from the estimated values.	The case replacement cost = x TIMES the initial replacement cost estimate.	Very low Low High Very high	0.75 0.9 1.1 1.25	[decimal]
Utility use change	Changes to utility use and thermal energy demand in a measure or scenario may differ from reality.	The case utility use profile is the baseline profile plus x TIMES the difference between the initial proposed profile and the baseline profile.	Very low Low High Very high	0.75 0.9 1.1 1.25	[decimal]
Electricity GHG factor	Future GHG factors for electricity may differ than those assumed.	For each year for which the GHG factor is projected, the case GHG factor for that year = the current year factor PLUS (x TIMES the difference between the initial value for that year, and the factor for the current year).	Very low Low High Very high	0.75 0.9 1.1 1.25	[decimal]
Incentive rates	Actual incentives may be different from estimated ones. While project cost and utility use affects incentive amounts, this risk parameter seeks to identify the risk in changes to the financial rates used in incentive amount calculations (e.g., if saveon energy provides incentives at 0.05 \$/kWh rather than 0.04 \$/kWh, etc).	For each financial rate used in incentive amount calculations, the case rate is x TIMES the initial rate.	Very low Low High Very high	0.75 0.9 1.1 1.25	[decimal]
Federal carbon charge	Future federal carbon charge rates may differ than those assumed.	The default federal carbon charge increases to 170 \$/tCO2e by 2030 and to 300 \$/tCO2e by 2050. The case federal carbon charge follows the default trend but limited to a maximum value of x.	Very low Low High Very high	0 100 240 300	[\$/tCO2e]
Utility cost inflation	Future utility cost rates may differ than what was assumed.	The case utility cost inflation rate for all utilities is x (as a decimal) compounded yearly.	Very low Low High Very high	0.01 0.015 0.025 0.03	[decimal]
General cost inflation	General cost inflation may differ from what was assumed. Note that general cost inflation is applied ONLY to project costs, replacement costs, and maintenance costs (future utility cost rates are handled separately).	The case general cost inflation rate is x.	Very low Low High Very high	0.01 0.015 0.025 0.03	[decimal]
Discount rate	It is worth testing the sensitivity of the discount rate on life cycle cost / net present value calculations.	The case discount rate is x.	Very low Low High Very high	0.05 0.06 0.08 0.09	[decimal]

- This building has not undergone a building condition assessment, and therefore, business as usual (BAU) measures were not available. WalterFedy utilized previous reports to gauge the potential costing of BAU renewal measures. These measures are provided for reference only and are not intended for use in budgetary

requirements. It's recommended that the City of Temiskaming Shores undertake a Building Condition Assessment of this building.

5.3 Measure identification

Results of the measure identification and triaging process are summarized in Table 23.

Table 23: Measure identification and triaging summary

Measure name	Triage for analysis
Baseline	
Boiler plant to ASHP	Analyzed.
Boiler plant to ASHP hybrid	Analyzed.
Carbon offsets 20	Analyzed.
Geothermal deep retrofit with Lake Loop	Analyzed.
HVAC re-commissioning	Analyzed.
Interior LED lighting upgrade	Analyzed.
Roof upgrade to high performance	Analyzed.
RTUs to ASHP with electric backup	Analyzed.
RTUs to ASHP with natural gas backup	Analyzed.
Solar PV canopy	Analyzed.
Solar PV rooftop	Analyzed.
Wall upgrade to high performance	Analyzed.
Windows and doors to high performance	Analyzed.
Boiler renewal	Business as usual.
Exterior walls renewal	Business as usual.
Interior lighting renewal	Business as usual.
Roof renewal	Business as usual.
RTUs renewal	Business as usual.
Windows and doors renewal	Business as usual.
DHW to ASHP	Not analyzed: DHW is already electric.
Generator replacement	Not analyzed: minimal consumption to justify replacement.

5.4 Boiler plant to ASHP

Measure description

Existing condition

Three gas-fired condensing boilers provide hot water to reheat coils and in-floor heating. The in-floor heating is divided into five manifolds and further into 17 zones.



Opportunity

Convert the entire boiler plant to air-source heat pumps (ASHPs) as the primary heat source.

Utility-savings mechanism

The primary intent of this measure is to reduce GHG emissions by converting the fuel used for heating from natural gas to electricity. Reduced natural gas use and increased electricity use would be expected as a result.

Design description

Overview

One boiler is replaced with an air source heat pump system in this measure. The heat pump system is designed to handle the entire hydronic heating load of the building, but one boiler is retained for backup and emergency conditions. To obtain the required temperature output from the heat pump system to properly serve the high-temperature heating loop, we have selected a cascading heat pump system. The basis of the design is to utilize Transom heat pumps, a heat pump manufacturer located in Barrie, Ontario, familiar with the design conditions of the area.

Two Hatch air-to-water heat pumps installed on the roof generate low-temperature heat utilizing heat extracted from the ambient air. This heat is then transferred to a Severn water-to-water heat pump located in the mechanical room at the existing boiler location. A new glycol loop is installed to connect these two heat pumps. The Severn

unit is connected to the boiler loop in the same location as the boiler that was removed. Using this cascading approach, the heat pump can generate the heating water temperature required on the coldest design days. This system has been selected to deliver 170F water with a return water temperature of 150F. The Hatch heat pump generates 100F glycol that is sent to the Severn unit. This unit has integral backup electric resistance heating, but even at design heating days (-9F), the unit can still provide approximately 63% of the heating from the heat pump.

The new heat pump system shall be integrated into the BAS. The BAS shall provide the following commands to the Severn Heat pump:

- Heat Pump Enable
- Heat Pump Supply Water Setpoint

The Transom system shall modulate the Severn and Hatch heat pumps as required to provide the leaving hot water at the desired setpoint. The following points shall be monitored on both heat pumps at a minimum:

- Heat Pump status
- Heat Pump entering and leaving water/glycol temperature
- Heat Pump modulation percentage
- General alarm

The heat pump system shall operate as primary heating for the facility, and the sequence shall be as follows:

- The BAS shall enable the heating plant according to the original control sequence.
- The BAS shall enable the heat pump system and send it a supply water setpoint according to the current control sequence and reset schedule.

It should be noted that although, in this measure, the ASHP has been sized to accommodate the entire hydronic heating load of the building, one boiler could be retained to provide backup heating in case of failure.

Costs provided below include the equipment, electrical contractor and costs to the electrical distribution company. The vault or new electrical room construction would be additional.

Electrical

The ASHP will add approximately 58.5 kW of power to the existing system, which will put the system at 110.34 kW, which is approximately 33% of the full load of the building's electrical capacity.

Project cost estimate

Table 24: Project cost estimate (Boiler plant to ASHP)

Category	Line item	Unit	Value
Construction	Transom 400MBH Cascade Heat Pump System (Hatch HBV210 (1) and Severn SBH100 (1))	[\$]	230,000
	BAS Integration, Programming, and Commissioning	[\$]	25,000
	Installation of Heat Pumps, Glycol Loop, Integration to Heating Plant	[\$]	200,000
	New Electrical Distribution to Heat Pumps	[\$]	24,000
	General requirements (25%)	[\$]	119,800
Contingency	Subtotal after Construction	[\$]	598,800
	Design Contingency (25%)	[\$]	149,700
	Construction Contingency (10%)	[\$]	59,900
Design, Contractors, PM	Subtotal after Contingency	[\$]	808,400
	Engineering Design and Field Review (10%)	[\$]	80,800
	Contractor Fee (7%)	[\$]	56,600
Total	Total	[\$]	945,800

Utility analysis

Utility analysis methodology

The following assumptions were applied to the energy model to estimate utility use impacts.

- **Baseline.** The boilers have a thermal efficiency of 90%.
- **Proposed.** Boilers are replaced by air-source heat pumps with an average heating COP of 3.

Utility analysis results

Table 25: Boiler plant to ASHP analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	219,381	328,257	-108,876	-49.6
	Natural gas use	[m3/yr]	38,054	7,321	30,734	80.8
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	219,381	328,257	-108,876	-49.6
	Natural gas energy	[kWh/yr]	401,730	77,281	324,450	80.8
	Total energy	[kWh/yr]	621,111	405,538	215,573	34.7
GHG emissions	Electricity GHGs	[tCO2e/yr]	5.2	7.8	-2.6	-49.6
	Natural gas GHGs	[tCO2e/yr]	73.5	14.1	59.4	80.8
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	78.8	22.0	56.8	72.1
Utility cost	Electricity utility cost	[\$/yr]	21,763	32,563	-10,801	-49.6
	Natural gas utility cost	[\$/yr]	9,894	1,903	7,991	80.8
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	3,677	707	2,969	80.8
	Total utility cost	[\$/yr]	35,333	35,174	160	0.45
Financial	Assumed life	[yrs]	15	15	—	—
	Project cost	[\$]	0	945,800	—	—
	Incentive amount	[\$]	0	189,160	—	—
	Incremental project cost	[\$]	0	756,640	—	—
	Life cycle cost	[\$]	892,915	1,961,207	—	—
	Net present value	[\$]	0	-1,068,292	—	—
	Project cost per GHG reduction	[\$/tCO2e]	—	13,324	—	—
	Simple payback period	[yr]	—	>20	—	—

5.5 Boiler plant to ASHP hybrid

Measure description

Existing condition

Three gas-fired condensing boilers provide hot water to reheat coils and in-floor heating. The in-floor heating is divided into five manifolds and further into 17 zones.



Opportunity

Convert the boiler plant to a hybrid ASHP and natural gas-fired boiler plant, in which ASHP is the primary heat source, and natural gas is the backup. This option is considered a potentially more cost-efficient option for GHG abatement than complete conversion to ASHP.

Utility-savings mechanism

The primary intent of this measure is to reduce GHG emissions by converting the fuel used for heating from natural gas to electricity. Reduced natural gas use and increased electricity use would be expected as a result.

Design description

Overview

One boiler is replaced with an air source heat pump system in this measure. The heat pump is sized to accommodate the lower temperature in-floor radiant heating loop. The one boiler is retained for backup and to serve the higher temperature baseboard rads and hydronic coils. The existing piping will need to be modified to accommodate the change.

One 20T Aermec ASHP shall be provided with a buffer tank to serve the in-floor heating load.

The new heat pump system shall be integrated into the BAS.

- The infloor heating loop shall operate on an Outdoor reset schedule to optimize the operating temperature and efficiency of the heat pump system.
- An injection loop and pump shall be controlled to provide second stage heating to the heat pump loop.

Costs provided below include the equipment, electrical contractor and costs to the electrical distribution company. The vault or new electrical room construction would be additional.

Electrical

The ASHP will add approximately 30 kW of power to the existing system, which will put the system at 81.84 kW, which is approximately 25% of the full load of the building's electrical capacity.

Project cost estimate

Table 26: Project cost estimate (Boiler plant to ASHP hybrid)

Category	Line item	Unit	Value
Construction	Heat Pump Supply	[\$]	80,000
	BAS Integration, Programming, and Commissioning	[\$]	25,000
	Installation of Heat Pumps, Glycol Loop, Integration to Heating Plant	[\$]	120,000
	New Electrical Distribution to Heat Pumps	[\$]	16,000
	General requirements (25%)	[\$]	60,200
Contingency	Subtotal after Construction	[\$]	301,200
	Design Contingency (25%)	[\$]	75,300
	Construction Contingency (10%)	[\$]	30,100
Design, Contractors, PM	Subtotal after Contingency	[\$]	406,600
	Engineering Design and Field Review (10%)	[\$]	40,700
	Contractor Fee (7%)	[\$]	28,500
Total	Total	[\$]	475,800

Utility analysis

Utility analysis methodology

The following assumptions were applied to the energy model to estimate utility use impacts.

- **Baseline.** The boilers have a thermal efficiency of 90%.
- **Proposed.** Most boilers are replaced by air-source heat pumps with an average heating COP of 3. Backup heating is provided through natural gas when the outdoor air temperature is below -15 C.

Utility analysis results

Table 27: Boiler plant to ASHP hybrid analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	219,381	287,642	-68,262	-31.1
	Natural gas use	[m3/yr]	38,054	14,047	24,007	63.1
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	219,381	287,642	-68,262	-31.1
	Natural gas energy	[kWh/yr]	401,730	148,290	253,440	63.1
	Total energy	[kWh/yr]	621,111	435,933	185,179	29.8
GHG emissions	Electricity GHGs	[tCO2e/yr]	5.2	6.9	-1.6	-31.1
	Natural gas GHGs	[tCO2e/yr]	73.5	27.1	46.4	63.1
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	78.8	34.0	44.8	56.8
Utility cost	Electricity utility cost	[\$/yr]	21,763	28,534	-6,772	-31.1
	Natural gas utility cost	[\$/yr]	9,894	3,652	6,242	63.1
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	3,677	1,357	2,320	63.1
	Total utility cost	[\$/yr]	35,333	33,544	1,790	5.1
Financial	Assumed life	[yrs]	15	15	—	—
	Project cost	[\$]	0	475,800	—	—
	Incentive amount	[\$]	0	95,160	—	—
	Incremental project cost	[\$]	0	380,640	—	—
	Life cycle cost	[\$]	892,915	1,424,151	—	—
	Net present value	[\$]	0	-531,236	—	—
	Project cost per GHG reduction	[\$yr/tCO2e]	—	8,504	—	—
	Simple payback period	[yr]	—	>20	—	—

5.6 Carbon offsets 20

Measure description

Existing condition

The facility is currently purchasing no carbon offsets.

Opportunity

After implementing other measures, purchase carbon offsets to offset 20% of the remaining GHG emissions.

Utility-savings mechanism

Energy use is not affected by purchasing carbon offsets. Yearly GHG emissions accounted against the facility will be reduced by the same quantity as those purchased for that year.

Design description

Net zero definition

The Canadian Green Building Council (CaGBC) defines net carbon emissions for a facility as in the following formula.

$$\text{Net emissions} = \text{Embodied carbon} + \text{Operational carbon} - \text{Avoided emissions}$$

The terms of this formula are defined as follows.

- **Embodied carbon.** GHG emissions associated with the construction, maintenance and final end-of-life disposal of the facility.
- **Operational carbon.** GHG emissions associated with the use of energy of the facility while in operation.
- **Avoided emissions.** GHG emissions avoided through activities such as exporting green power to local grids, or the purchase of carbon offsets.

Net Zero emissions as achieved when the Net emissions from this formula is zero or less.

This measure focuses on the on-going use of avoided emissions (as defined above) to offset operational carbon associated with ongoing energy use at the facility. Note that embodied carbon emissions tend to be a one-time event, in contrast to the on-going emissions associated with operations, which must also be accounted for through avoided emissions.

Renewable energy certificates

As defined above, emission avoidance activities recognized by the CaGBC definition of Net-Zero include exporting green power, or the purchase of carbon offsets. Green power exports include the exporting of on-site renewable energy, as well as the injection of renewable energy into local grids through off-site renewable energy generation facilities. The latter approach is typically accomplished through the purchase of Renewable Energy Certificates (RECs). RECs are utility-specific and are purchased by unit energy of the utility in question (e.g. kWh for electricity, or m³ for natural gas), and can only be used to offset GHG emissions associated with the specific utility in question. For example, electricity RECs can be purchased to offset up to 100% of electricity used by the building, but cannot be used to offset natural gas used by the building (and vice versa). RECs are typically considered best practise because they facilitate an immediate injection of renewable energy into grids. RECs can be purchased through REC providers such as Bullfrog Power.

Carbon offsets

The purchase of carbon offsets is the second approach for avoided emissions recognized by CaGBC. Carbon offsets are purchased per tonne of GHG emissions, and can be used to offset either direct (e.g. natural gas combustion on-site) or indirect (e.g. electricity use on-site, which is generated offsite) GHG emissions. Carbon offsets must be certified as stipulated within the CaGBCs Zero Carbon Building Standard, which is required to

uphold quality standards of the carbon offsets. Carbon offsets can be purchased through certified providers such as Less Emissions Inc.

Cost rates

Cost rates for RECs and carbon offsets are summarized as follows.

- Electricity REC cost rate (Bullfrog Power): 0.025 \$/kWh.
- Natural gas REC cost rate (Bullfrog Power): 0.186 \$/m3.
- Carbon offset cost rate (Less Emissions Inc.): 30 \$/mtCO₂e.

Utility analysis

Utility analysis methodology

Energy use is not affected by purchasing carbon offsets. Yearly GHG emissions accounted against the facility will be reduced by the same quantity as those purchased for that year.

Baseline. It is assumed that no carbon offsets are purchased.

Proposed. Carbon offsets are assumed to be purchased in the quantity equal to 20% of remaining GHG emissions. Note that as an individual measure, the analysis indicates the impact of offsetting baseline GHG emissions with carbon offsets. When considered as part of the scenario analyses in Section 6, this measure will cause 20% of remaining GHG emissions to be offset.

Utility analysis results

Table 28: Carbon offsets 20 analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	219,381	219,381	0	0
	Natural gas use	[m3/yr]	38,054	38,054	0	0
	Carbon offset use	[tCO ₂ e/yr]	0	15.8	-15.8	—
Equivalent energy use	Electricity energy	[kWh/yr]	219,381	219,381	0	0
	Natural gas energy	[kWh/yr]	401,730	401,730	0	0
	Total energy	[kWh/yr]	621,111	621,111	0	0
GHG emissions	Electricity GHGs	[tCO ₂ e/yr]	5.2	5.2	0	0
	Natural gas GHGs	[tCO ₂ e/yr]	73.5	73.5	0	0
	Carbon offsets GHGs	[tCO ₂ e/yr]	0	-15.8	15.8	—
	Total GHGs	[tCO ₂ e/yr]	78.8	63.0	15.8	20.0
Utility cost	Electricity utility cost	[\$/yr]	21,763	21,763	0	0
	Natural gas utility cost	[\$/yr]	9,894	9,894	0	0
	Carbon offsets utility cost	[\$/yr]	0	473	-473	—
	Federal carbon charge	[\$/yr]	3,677	3,677	0	0
	Total utility cost	[\$/yr]	35,333	35,806	-473	-1.3
Financial	Assumed life	[yrs]	15	20	—	—
	Project cost	[\$]	0	—	—	—
	Incentive amount	[\$]	0	0	—	—
	Incremental project cost	[\$]	0	—	—	—
	Life cycle cost	[\$]	892,915	901,535	—	—
	Net present value	[\$]	0	-8,620	—	—
	Project cost per GHG reduction	[\$/tCO ₂ e]	—	—	—	—
	Simple payback period	[yr]	—	—	—	—

5.7 Geothermal deep retrofit with Lake Loop

Measure description

Existing condition

Three gas-fired condensing boilers supply hot water to reheat coils and in-floor heating systems. The in-floor heating is organized into five manifolds, which are further divided into 17 zones. The facility features four rooftop units (RTUs) supported by two energy recovery ventilators (ERVs) to serve the building. Each RTU is a variable-volume unit connected to variable air volume (VAV) boxes. Additionally, each RTU is natural gas-fired and equipped with direct expansion (DX) cooling.

Opportunity

Provide a 72T lake-based geothermal system to serve the replacement of RTUs and Boilers with water source heat pump equipment.

Utility-savings mechanism

The primary intent of this measure is to reduce GHG emissions by converting the fuel used for heating from natural gas to electricity due to electricity having a lower GHG intensity than natural gas. Reduced natural gas use and increased electricity use would be expected as a result.

Design description

Overview

Provide a 72T lake-based geothermal system to serve the replacement of RTUs and Boilers with water source heat pump equipment.

Lake loop

Geothermal systems are subject to several municipal regulations and provincial codes. These include requirements under the Ontario Building Code, The Clean Water Act, 2006, and Ontario Regulation 98/12. The following is a review of the regulations specific to City Hall.

- The site does not fall within a source water protection or intake protection zone.

Every geothermal system needs to be designed and placed with careful consideration of the geology and planned building at the site. In the case of a lake-based system, knowledge of the depth and material at the bottom of the body of water is essential. Lake systems are sized based on the peak connected load and are placed to take advantage of seasonal stratification in the lake. Water is densest at 40F and as such, the water surrounding the lake loop can be expected to be 40F with sufficient depth.

The lake-based heat exchanger will consist of a header trench extending from the building to the lake. Six pairs of 2-inch HDPE pipe will be separated into four runs of 1.25-inch pipe where the lake depth reaches 15 feet or deeper. Each circuit of 1.25 inch pipe will run 750 feet.

The pipe will be weighed to the bottom of the lake using a system of 0.25-inch aircraft cable wrapped around the pipe and strategically located cinder blocks. The intent of this system is for the piping system to be bouyant when filled with air, but will sink to the bottom when filled with fluid.

Inside the building, the geothermal system will be connected to the new WSHPs in a primary-secondary arrangement. A pair of 5HP pumps circulating pumps with integral VFDs will provide flow through the lake side of the loop, and individual circulators will be provided at each heat pump.

Boiler Replacement

One boiler is replaced with a pair of water source heat pumps. The heat pump system is designed to handle the entire hydronic heating load of the building, but one boiler is retained for backup and emergency conditions. The heat pump will be selected to achieve temperatures suitable for the hot water loop.

The new heat pump system shall be integrated into the BAS. The BAS shall provide the following commands:

- Heat Pump Enable
- Heat Pump Supply Water Setpoint

The heat pump system shall operate as primary heating for the facility, and the sequence shall be as follows:

- The BAS shall enable the heating plant according to the original control sequence.
- The BAS shall enable the heat pump system and send it a supply water setpoint according to the current control sequence and reset schedule.

The WSHP will add approximately 58.5 kW of power to the existing system, bringing the total to 110.34 kW, which is approximately 33% of the building's full electrical load.

Costs provided below include the equipment, electrical contractor and costs to the electrical distribution company. The vault or new electrical room construction would be an additional expense.

RTU Replacement

This measure involves replacing the current rooftop units with packaged water source heat pumps (WSHP) model equipped with electric resistance heating. As an initial selection, a ClimateMaster 10-ton rooftop unit, similar to the model TRE120, was considered for this application. It should be noted that other manufacturers also provide similar models.

The units are to be equipped with the following features:

- ECM variable speed supply fan motors
- Full economizer for free cooling
- Electric heating section
- Full controls

The new rooftop unit can be installed in the same location as the existing unit and integrated into the existing ductwork distribution. The electrical distribution to the unit will have to be upgraded to account for the extra load imposed by the electric resistance heating (typically this is a separate feed to the electric resistance section).

The rooftop unit is provided with integral controls to efficiently control the heat pump, free cooling economizer, and electric heating. The space thermostat will be located within the facility in the same location as the current thermostat for the existing rooftop units. Thermostats and controls should be programmed to allow for scheduling, including temperature setpoint setbacks during unoccupied periods. The thermostat for the rooftop unit would be used to control the unit itself, while the existing thermostats within the individual zones would control the existing bypass dampers as required.

The following units are noted for this project:

- RTU-1 - 10T with 15kW backup
- RTU-2 - 10T with 15kW backup
- RTU-3 - 6T with 10kW backup
- RTU-4 - 5T with 10kW backup

The WSHP with electric backup will add approximately 105.5 kW of power to the existing system, bringing the total to 158.34 kW, which is approximately 48% of the building's full electrical load. A new 200A panel is recommended to power all the new equipment, as DP-1 will not have enough physical breaker space.

Project cost estimate

Table 29: Project cost estimate (Geothermal deep retrofit with Lake Loop)

Category	Line item	Unit	Value
Construction	Supply - RTUs	[\$]	93,000
	Installation - RTUs	[\$]	60,000
	Electrical distribution to RTUs	[\$]	59,000
	Supply - Two 20T Water Source Heat Pumps	[\$]	160,000
	Installation of Heat Pumps, Glycol Loop, Integration to Heating Plant	[\$]	150,000
	New Electrical Distribution to Heat Pumps	[\$]	24,000
	Geothermal Loop Supply and Install (\\$2,500 per Ton): includes piping, manifolds, installation into new mech room.	[\$]	180,000
	Civil Works/Landscaping repair	[\$]	10,000
	Circulating Pumps VFD and Accessories (Estimated)	[\$]	15,000
	Interior Manifold	[\$]	30,000
	BAS Integration, Programming, and Commissioning	[\$]	25,000
	General requirements (25%)	[\$]	201,500
Contingency	Subtotal after Construction	[\$]	1,007,500
	Design Contingency (25%)	[\$]	251,900
	Construction Contingency (10%)	[\$]	100,800
Design, Contractors, PM	Subtotal after Contingency	[\$]	1,360,200
	Engineering Design and Field Review (10%)	[\$]	136,000
	Contractor Fee (7%)	[\$]	95,200
Total	Total	[\$]	1,591,400

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline:** The RTUs provide space heating and cooling through natural gas-fired burners and DX, respectively. The existing heating efficiency and cooling COP are 80% and 4, respectively. The boilers have a thermal efficiency of 90%.
- **Proposed:** The RTUs provide space heating and cooling through water-source heat pumps. The proposed average heating and cooling COPs are 4 and 6 (20.5 EER), respectively. Backup heating is provided through electric resistance. Most boilers are replaced by water-source heat pumps with an average heating COP of 4. Backup heating is provided through natural gas when the geothermal loop cannot reach temperature.

Utility analysis results

Table 30: Geothermal deep retrofit with Lake Loop analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	219,381	305,887	-86,506	-39.4
	Natural gas use	[m3/yr]	38,054	2,473	35,581	93.5
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	219,381	305,887	-86,506	-39.4
	Natural gas energy	[kWh/yr]	401,730	26,110	375,620	93.5
	Total energy	[kWh/yr]	621,111	331,997	289,114	46.5
GHG emissions	Electricity GHGs	[tCO2e/yr]	5.2	7.3	-2.1	-39.4
	Natural gas GHGs	[tCO2e/yr]	73.5	4.8	68.8	93.5
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	78.8	12.1	66.7	84.7
Utility cost	Electricity utility cost	[\$/yr]	21,763	30,344	-8,581	-39.4
	Natural gas utility cost	[\$/yr]	9,894	643	9,251	93.5
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	3,677	239	3,438	93.5
	Total utility cost	[\$/yr]	35,333	31,226	4,107	11.6
Financial	Assumed life	[yrs]	15	40	—	—
	Project cost	[\$]	0	1,591,400	—	—
	Incentive amount	[\$]	0	318,280	—	—
	Incremental project cost	[\$]	0	1,273,120	—	—
	Life cycle cost	[\$]	892,915	1,719,173	—	—
	Net present value	[\$]	0	-826,257	—	—
	Project cost per GHG reduction	[\$/tCO2e]	—	19,091	—	—
	Simple payback period	[yr]	—	>20	—	—

5.8 HVAC re-commissioning

Measure description

Existing condition

There are items which can be addressed to reduce energy consumption, including:

- RTU1: Return air temperature is in a hold at 22C, VFD on supply fan is on hold at 75%, and the supply air SP is set to 190 kPa. The humidifier is also in hand but that is most likely due to it being summer. The heat max SAT setpoint is at 22C and in hand. Cooling max SATSP is 18.3 and goes down to 12.8C.
- RTU2: Supply fan is set to 75% in hold. Supply air SP set to 190 kPa. RTU2 unit is enabled in hand.
- RTU3: Supply fan is set to 65% in hold. Supply air SP set to 200 kPa. OAT is 17.9C and burner is firing. The electric duct heater is also on at 20.7%. RAH has a SP of 37.5%. The trend shows it on most of the time.
- RTU4: Supply fan is set to 75% in hold. Burner on when OAT is 18.2. SAP is at 3 and setpoint is 150 Pa. The SAP SP is 150 PA and RATSP is at 22.5.
- Hot water loop: P1 and P2 are running. P2 is in auto.

Opportunity

The City is recommended to undergo a formal re-commissioning program to optimize existing BAS controls.

Utility-savings mechanism

Implementing this measure will save natural gas and electricity by optimizing BAS controls.

Design description

Overview

Conduct a retro-commissioning exercise for the HVAC systems serving the facility.

It is recommended that the commissioning exercise be conducted according to the following steps.

- Meet with the users of the space and the building operators to identify and document the specific requirements of the spaces in terms of occupancy, setpoints, and airflow requirements.
- Investigate the existing project documentation, including design drawings, controls as-builts, testing and balancing information, and commissioning reports to learn how the systems were originally set up to operate.
- Execute virtual functional testing on the systems to confirm the proper operation of individual components and overall systems.
- Identify opportunities for the repair of failed components and for the improvement of control sequences with respect to energy efficiency and to better meet the goals of the facility.
- Implement agreed-upon measures with the assistance of a controls contractor and other contractors as required.
- Ensure that the building operators and occupants are trained on changes that are implemented and trained on how to optimally operate the systems and make required changes.

As part of the process, the following items are to be optimized at a minimum:

- Scheduling of air handling units according to user requirements
- Limiting the OA provided at each air handler to the unit to the occupancy requirements
- Coordination of heating and cooling setpoints between adjacent units to prevent simultaneous heating and cooling
- Setback of temperature setpoints during unoccupied periods.
- Economizer control on air handling units.

- Boiler supply water reset schedules.
- Boiler cycling periods.

The costing provided below is an estimate for the investigation phase of the work. Costs for implementing any energy-saving measures would be in addition to the pricing below. Pricing is based on a virtual review of the existing BAS, and must include the recommissioning measures noted in the Waterfront Pool and Fitness Centre and Temiskaming Shores Library reports.

- Virtual meeting with the controls contractor supplied by the City.
- Provide action items in a brief report to be provided to the controls contractor.
- Virtual meeting with the controls contractor to clarify any issues.

Exclusions:

- This work does not include pricing for the controls contractor or replacement parts.
- Does not include a site visit by the controls engineer.

Project cost estimate

Table 31: Project cost estimate (HVAC re-commissioning)

Category	Line item	Unit	Value
Materials and labour	EBCx Consultant Fee (Desktop review)	[\$]	5,000
	Allowance for Controls Contractor Assistance - Investigation Phase	[\$]	20,000
Contingency	Subtotal after Materials and labour	[\$]	25,000
	General Contingency (50%)	[\$]	12,500
Total	Total	[\$]	37,500

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- RTU2 is in hand, and all supply fan VFDs are set to a fixed speed.
- RTU2 can turn off during unoccupied hours if no demand exists and VFDs are free to fluctuate based on static pressure.

Utility analysis results

Table 32: HVAC re-commissioning analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	219,381	186,392	32,989	15.0
	Natural gas use	[m3/yr]	38,054	38,388	-334	-0.88
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	219,381	186,392	32,989	15.0
	Natural gas energy	[kWh/yr]	401,730	405,251	-3,521	-0.88
	Total energy	[kWh/yr]	621,111	591,644	29,468	4.7
GHG emissions	Electricity GHGs	[tCO2e/yr]	5.2	4.5	0.79	15.0
	Natural gas GHGs	[tCO2e/yr]	73.5	74.2	-0.64	-0.88
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	78.8	78.6	0.14	0.18
Utility cost	Electricity utility cost	[\$/yr]	21,763	18,490	3,272	15.0
	Natural gas utility cost	[\$/yr]	9,894	9,981	-86.7	-0.88
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	3,677	3,709	-32.2	-0.88
	Total utility cost	[\$/yr]	35,333	32,180	3,154	8.9
Financial	Assumed life	[yrs]	15	15	—	—
	Project cost	[\$]	0	37,500	—	—
	Incentive amount	[\$]	0	0	—	—
	Incremental project cost	[\$]	0	37,500	—	—
	Life cycle cost	[\$]	892,915	852,885	—	—
	Net present value	[\$]	0	40,030	—	—
	Project cost per GHG reduction	[\$/tCO2e]	—	260,489	—	—
	Simple payback period	[yr]	—	12	—	—

5.9 Interior LED lighting upgrade

Measure description

Existing condition

Some areas of the building currently operate with LED fixtures (e.g. boardroom, washrooms, and storage). The remaining areas of the building primarily utilize CFL lamps.



Opportunity

Replace remaining fixtures containing CFL lamps with new LED fixtures.

Utility-savings mechanism

Reduced interior lighting energy use with higher efficiency LED fixtures. However, heating energy use will increase to offset the reduction in internal heat gain from the fixtures, while cooling energy use will decrease.

Design description

Overview

The lighting system shall be designed to meet the latest ASHRAE 90.1 energy codes, IESNA standards, the City Hall standards and other applicable regulations and standards.

The existing site has gone through some recent LED upgrades. It will be proposed that all the remaining fluorescent fixtures will be replaced with new LED fixtures.

LED luminaires shall be provided with an expected service life of over 50,000 hours and be listed on the Energy Star Qualified Commercial Lighting List or the Design Lights Consortium List (DLC) for incentive eligibility from the IESOs Save on Energy Program.

With the extended lifespan associated with LED fixtures, the likelihood of a complete fixture failure is significantly less likely than previous fixture types. Rather, the user would witness a slow degradation of the lighting output of

the fixtures. It would be recommended that an annual lighting review is conducted to measure the lighting levels within each space of the facility. At the 70

Project cost estimate

Table 33: Project cost estimate (Interior LED lighting upgrade)

Category	Line item	Unit	Value
Materials and labour	Interior LED lighting upgrade	[\$]	10,000
Contingency	Subtotal after Materials and labour	[\$]	10,000
	General Contingency (50%)	[\$]	5,000
Total	Total	[\$]	15,000

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline:** It is assumed that there is an average lpd of 0.82 W/ft².
- **Proposed:** It is assumed that the average lpd is reduced to 0.656 W/ft². Operation schedules are maintained.

Utility analysis results

Table 34: Interior LED lighting upgrade analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	219,381	213,766	5,615	2.6
	Natural gas use	[m3/yr]	38,054	38,554	-499	-1.3
	Carbon offset use	[tCO ₂ e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	219,381	213,766	5,615	2.6
	Natural gas energy	[kWh/yr]	401,730	407,001	-5,271	-1.3
	Total energy	[kWh/yr]	621,111	620,767	344	0.06
GHG emissions	Electricity GHGs	[tCO ₂ e/yr]	5.2	5.1	0.13	2.6
	Natural gas GHGs	[tCO ₂ e/yr]	73.5	74.5	-0.96	-1.3
	Carbon offsets GHGs	[tCO ₂ e/yr]	0	0	0	—
	Total GHGs	[tCO ₂ e/yr]	78.8	79.6	-0.83	-1.1
Utility cost	Electricity utility cost	[\$/yr]	21,763	21,206	557	2.6
	Natural gas utility cost	[\$/yr]	9,894	10,024	-130	-1.3
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	3,677	3,725	-48.2	-1.3
	Total utility cost	[\$/yr]	35,333	34,955	379	1.1
Financial	Assumed life	[yrs]	15	20	—	—
	Project cost	[\$]	0	15,000	—	—
	Incentive amount	[\$]	0	0	—	—
	Incremental project cost	[\$]	0	15,000	—	—
	Life cycle cost	[\$]	892,915	896,294	—	—
	Net present value	[\$]	0	-3,379	—	—
	Project cost per GHG reduction	[\$/tCO ₂ e]	—	-18,060	—	—
	Simple payback period	[yr]	—	>20	—	—

5.10 Roof upgrade to high performance

Measure description

Existing condition

The roof exterior layer consisted of a white roof membrane with wood structural decking observed above the finished ceiling. Using the roof hatch as a reference, it appears that there is a minimum of four inches of insulation.



Opportunity

Upgrade upon the end of useful life or as required to meet scenario criteria.

Utility-savings mechanism

Reduced heating energy use through improved thermal performance of the roof.

Design description

Overview

The roof thermal performance varies from R31-R38 for roof types R1 and R2. This is very close to meeting the current OBC requirements (R32 for continuous insulation above a deck). We understand that the PVC roof is due for replacement, and we recommend that at least 8-9 inches of rigid insulation be provided prior to installation of the new roof membrane, which will bring the roof performance to R40-R46. The joints between walls and roof should be examined to ensure that there is no air leakage or thermal bridging occurring. Sealants and/or spray foam should be provided where leaks are occurring, as they can significantly affect thermal performance. The parapet flashing and membrane flashing may need to be reworked around the parapets in order to accommodate the extra roof insulation thickness.

Project cost estimate

Table 35: Project cost estimate (Roof upgrade to high performance)

Category	Line item	Unit	Value
Construction	Roof replacement	[\$]	332,800
	General requirements (25%)	[\$]	83,200
Contingency	Subtotal after Construction	[\$]	416,000
	Design Contingency (25%)	[\$]	104,000
	Construction Contingency (10%)	[\$]	41,600
Design, Contractors, PM	Subtotal after Contingency	[\$]	561,600
	Engineering Design and Field Review (10%)	[\$]	56,200
	Contractor Fee (7%)	[\$]	39,300
Total	Total	[\$]	657,100

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline.** An average roof U-value of 0.0313 BTU/hr.ft².F (R32) was assumed.
- **Proposed.** An average roof U-value of 0.025 BTU/hr.ft².F (R40) was assumed.

Utility analysis results

Table 36: Roof upgrade to high performance analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	219,381	219,201	180	0.08
	Natural gas use	[m3/yr]	38,054	37,550	504	1.3
	Carbon offset use	[tCO ₂ e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	219,381	219,201	180	0.08
	Natural gas energy	[kWh/yr]	401,730	396,409	5,321	1.3
	Total energy	[kWh/yr]	621,111	615,610	5,502	0.89
GHG emissions	Electricity GHGs	[tCO ₂ e/yr]	5.2	5.2	0.00	0.08
	Natural gas GHGs	[tCO ₂ e/yr]	73.5	72.6	0.97	1.3
	Carbon offsets GHGs	[tCO ₂ e/yr]	0	0	0	—
	Total GHGs	[tCO ₂ e/yr]	78.8	77.8	0.98	1.2
Utility cost	Electricity utility cost	[\$/yr]	21,763	21,745	17.9	0.08
	Natural gas utility cost	[\$/yr]	9,894	9,763	131	1.3
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	3,677	3,628	48.7	1.3
	Total utility cost	[\$/yr]	35,333	35,136	198	0.56
Financial	Assumed life	[yrs]	15	20	—	—
	Project cost	[\$]	0	657,100	—	—
	Incentive amount	[\$]	0	131,420	—	—
	Incremental project cost	[\$]	0	525,680	—	—
	Life cycle cost	[\$]	892,915	1,445,355	—	—
	Net present value	[\$]	0	-552,440	—	—
	Project cost per GHG reduction	[\$/tCO ₂ e]	—	537,307	—	—
	Simple payback period	[yr]	—	>20	—	—

5.11 RTUs to ASHP with electric backup

Measure description

Existing condition

The facility utilizes four RTUs coupled with two ERVs to serve the building. Each RTU is a variable-volume unit coupled with VAV boxes. Each RTU is natural-gas fired complete with DX cooling.



Opportunity

Replace the RTUs and use air-source heat pumps as the heating and cooling source with electric backup.

Utility-savings mechanism

The primary intent of this measure is to reduce GHG emissions by converting the fuel used for heating from natural gas to electricity due to electricity having a lower GHG intensity than natural gas. Reduced natural gas use and increased electricity use would be expected as a result.

Design description

Overview

This measure involves replacing the current rooftop units with a packaged air source heat pump (ASHP) model equipped with electric resistance heating for cold ambient conditions when the heat pump capacity would be insufficient for the entire heating load. For the initial selection of the unit, the heating and cooling capacities were selected to match the existing equipment. As an initial selection, a Daiken 10 ton rooftop unit similar to model DPS010A was considered for this application. It should be noted that other manufacturers also provide similar models.

The units are to be equipped with the following features:

- ECM variable speed supply fan motors

- Full economizer for free cooling
- Air source heat pump section
- Electric heating section
- Full controls.

The unit will control the economizer and the heat pump to satisfy cooling requests based on the space temperature setpoints. For heating, the unit can be configured to provide heating from the air-sourced heat pump. Once the heat pump is operating at capacity, the electric resistance will be enabled as a second stage of heat. Note that heat pump heating and electric resistance heating can be on simultaneously, allowing the heat pump to always contribute as much as possible to the heating.

The capacity of heating from the heat pump is dependent on the ambient outdoor conditions.

The new rooftop unit can be installed in the same location as the existing unit and integrated into the existing ductwork distribution. The electrical distribution to the unit will have to be upgraded to account for the extra load imposed by the electric resistance heating (typically this is a separate feed to the electric resistance section).

The rooftop unit is provided with integral controls to efficiently control the heat pump, free cooling economizer, and electric heating. The space thermostat will be located within the facility in the same location as the current thermostat for the existing rooftop units. Thermostats and controls should be programmed to allow for scheduling, including temperature setpoint setbacks during unoccupied periods. The thermostat for the rooftop unit would be used to control the unit itself, while the existing thermostats within the individual zones would control the existing bypass dampers as required.

The following units are noted for this project:

- RTU-1 - 10T with 20kW backup
- RTU-2 - 10T with 20kW backup
- RTU-3 - 6T with 20kW backup
- RTU-4 - 5T with 15kW backup

Electrical

The ASHP with the electric backup will add approximately 121.5 kW of power to the existing system, which will put the system at 173.34 kW, which is approximately 52% of the full load of the building's electrical capacity. A new 200A panel is recommended to power all the new equipment, as DP-1 will not have enough physical breaker space.

Project cost estimate

Table 37: Project cost estimate (RTUs to ASHP with electric backup)

Category	Line item	Unit	Value
Construction	Supply	[\$]	93,000
	Installation Cost	[\$]	60,000
	Electrical distribution to unit	[\$]	59,000
	General requirements (25%)	[\$]	53,000
Contingency	Subtotal after Construction	[\$]	265,000
	Design Contingency (25%)	[\$]	66,200
	Construction Contingency (10%)	[\$]	26,500
Design, Contractors, PM	Subtotal after Contingency	[\$]	357,700
	Engineering Design and Field Review (10%)	[\$]	35,800
	Contractor Fee (7%)	[\$]	25,000
Total	Total	[\$]	418,500

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline:** The RTUs provide space heating and cooling through natural gas-fired burners and DX, respectively. The existing heating efficiency and cooling COP are 80% and 4, respectively.
- **Proposed:** The RTUs provide space heating and cooling through air-source heat pumps. The proposed average heating and cooling COPs are 3 and 4.1 (14 EER), respectively. Backup heating is provided through electric resistance when the outdoor air temperature is below -15 C.

Utility analysis results

Table 38: RTUs to ASHP with electric backup analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	219,381	248,853	-29,472	-13.4
	Natural gas use	[m3/yr]	38,054	31,341	6,713	17.6
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	219,381	248,853	-29,472	-13.4
	Natural gas energy	[kWh/yr]	401,730	330,861	70,870	17.6
	Total energy	[kWh/yr]	621,111	579,714	41,398	6.7
GHG emissions	Electricity GHGs	[tCO2e/yr]	5.2	5.9	-0.70	-13.4
	Natural gas GHGs	[tCO2e/yr]	73.5	60.6	13.0	17.6
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	78.8	66.5	12.3	15.6
Utility cost	Electricity utility cost	[\$/yr]	21,763	24,686	-2,924	-13.4
	Natural gas utility cost	[\$/yr]	9,894	8,149	1,745	17.6
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	3,677	3,028	649	17.6
	Total utility cost	[\$/yr]	35,333	35,863	-530	-1.5
Financial	Assumed life	[yrs]	15	18	—	—
	Project cost	[\$]	0	418,500	—	—
	Incentive amount	[\$]	0	83,700	—	—
	Incremental project cost	[\$]	0	334,800	—	—
	Life cycle cost	[\$]	892,915	1,309,374	—	—
	Net present value	[\$]	0	-416,458	—	—
	Project cost per GHG reduction	[\$/tCO2e]	—	27,291	—	—
	Simple payback period	[yr]	—	—	—	—

5.12 RTUs to ASHP with natural gas backup

Measure description

Existing condition

The facility utilizes four RTUs coupled with two ERVs to serve the building. Each RTU is a variable-volume unit coupled with VAV boxes. Each RTU is natural-gas fired complete with DX cooling.



Opportunity

Replace the RTUs and use air-source heat pumps as the heating and cooling source with natural gas backup.

Utility-savings mechanism

The primary intent of this measure is to reduce GHG emissions by converting the fuel used for heating from natural gas to electricity due to electricity having a lower GHG intensity than natural gas. Reduced natural gas use and increased electricity use would be expected as a result.

Design description

Overview

This measure involves replacing the current rooftop units with a packaged air source heat pump (ASHP) model equipped with natural gas heating for during cold ambient conditions when the heat pump capacity would be insufficient for the entire heating load. For the initial selection of the unit, the heating and cooling capacities were selected to match the existing equipment. As an initial selection, a Daiken 10 ton rooftop unit similar to model DPS010A was considered for this application. It should be noted that other manufacturers also provide similar models.

The unit is to be equipped with the following features:

- ECM variable speed supply fan motors

- Full economizer for free cooling
- Air source heat pump section
- Natural gas heating section
- Full controls.

The unit will control the economizer and the heat pump to satisfy cooling requests based on the space temperature setpoints. For heating, the unit can be configured to provide heating from the air-sourced heat pump. Once the heat pump is operating at capacity, the natural gas heater will be enabled as a second stage of heat. Note that heat pump heating and the natural gas heating can be on simultaneously, allowing the heat pump to always contribute as much as possible to the heating.

The capacity of heating from the heat pump is dependent on the ambient outdoor conditions.

The new rooftop unit can be installed in the same location as the existing unit and integrated into the existing ductwork distribution.

The rooftop unit is provided with integral controls to efficiently control the heat pump, free cooling economizer, and natural gas heating. The space thermostat will be located within the facility in the same location as the current thermostat for the existing rooftop units. Thermostats and controls should be programmed to allow for scheduling, including temperature setpoint setbacks during unoccupied periods. The thermostat for the rooftop unit would be used to control the unit itself, while the existing thermostats within the individual zones would control the existing bypass dampers.

The following units are noted for this project:

- RTU-1 - 10T with 240MBH backup
- RTU-2 - 10T with 240MBH backup
- RTU-3 - 6T with 180MBH backup
- RTU-4 - 5T with 125MBH backup

The ASHP with the electric backup will add approximately 46.5 kW of power to the existing system, which will put the system at 98.34 kW, which is approximately 30% of the full load of the building's electrical capacity.

Project cost estimate

Table 39: Project cost estimate (RTUs to ASHP with natural gas backup)

Category	Line item	Unit	Value
Construction	Supply	[\$]	96,100
	Installation Cost	[\$]	60,000
	Electrical distribution to unit	[\$]	16,000
	General requirements (25%)	[\$]	43,000
Contingency	Subtotal after Construction	[\$]	215,100
	Design Contingency (25%)	[\$]	53,800
	Construction Contingency (10%)	[\$]	21,500
Design, Contractors, PM	Subtotal after Contingency	[\$]	290,400
	Engineering Design and Field Review (10%)	[\$]	29,000
	Contractor Fee (7%)	[\$]	20,300
Total	Total	[\$]	339,700

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline:** The RTUs provide space heating and cooling through natural gas-fired burners and DX, respectively. The existing heating efficiency and cooling COP are 80% and 4, respectively.
- **Proposed:** The RTUs provide space heating and cooling through air-source heat pumps. The proposed average heating and cooling COPs are 3.2 and 4.1 (14 EER), respectively. Backup heating is provided from the existing gas-fired furnaces when the outdoor air temperature is below -15 C.

Utility analysis results

Table 40: RTUs to ASHP with natural gas backup analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	219,381	235,065	-15,684	-7.1
	Natural gas use	[m3/yr]	38,054	33,434	4,620	12.1
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	219,381	235,065	-15,684	-7.1
	Natural gas energy	[kWh/yr]	401,730	352,958	48,772	12.1
	Total energy	[kWh/yr]	621,111	588,024	33,088	5.3
GHG emissions	Electricity GHGs	[tCO2e/yr]	5.2	5.6	-0.37	-7.1
	Natural gas GHGs	[tCO2e/yr]	73.5	64.6	8.9	12.1
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	78.8	70.2	8.6	10.9
Utility cost	Electricity utility cost	[\$/yr]	21,763	23,318	-1,556	-7.1
	Natural gas utility cost	[\$/yr]	9,894	8,693	1,201	12.1
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	3,677	3,230	446	12.1
	Total utility cost	[\$/yr]	35,333	35,242	91.7	0.26
Financial	Assumed life	[yrs]	15	18	—	—
	Project cost	[\$]	0	339,700	—	—
	Incentive amount	[\$]	0	67,940	—	—
	Incremental project cost	[\$]	0	271,760	—	—
	Life cycle cost	[\$]	892,915	1,213,508	—	—
	Net present value	[\$]	0	-320,592	—	—
	Project cost per GHG reduction	[\$/tCO2e]	—	31,775	—	—
	Simple payback period	[yr]	—	>20	—	—

5.13 Solar PV canopy

Measure description

Existing condition

There is no canopy solar PV. Some parking lot space is available.

Opportunity

Install a solar PV system on canopies in the parking lot where feasible. A net-metering agreement is recommended so that the reduced GHG emissions associated with the electricity generated by the system can be retained by the City of Temiskaming Shores or exported to the grid if on-site electricity consumption is fulfilled.

Utility-savings mechanism

The solar PV system will reduce the electricity use from the grid, GHG emissions, and utility costs.

Design description

Helioscope overview

Helioscope was used to determine a preliminary design concept for the proposed solar PV system. For this system, we consider one typical solar canopy (around 6.5m wide and 27m long). The Helioscope model is depicted in the following image.



Based on the results from the Helioscope model, the proposed solar PV system was assumed to have the following output capacity.

- Total system output capacity (DC) = 135 kW.

Proposed scope

Supply and install a canopy solar PV electricity generation system, including the following.

- Solar PV modules.
- Racking system to for mounting the solar panels onto.
- DC to AC inverters.
- Wiring, disconnects, meters, panels and transformers. AC output from inverters to be wired into a dedicated solar PV electrical panel before being connected to the main switchboard via a new breaker.
- Connection impact assessment, and other requirements to satisfy the utility provider for executing a Net Metering agreement.
- Installation of the above.

Electrical

With the existing system, the main panel is rated high enough to accommodate the additional 167kW of the solar to the roof and canopies.

Project cost estimate

Table 41: Project cost estimate (Solar PV canopy)

Category	Line item	Unit	Value
Materials and labour	Solar PV electricity system installed (assuming 135 kW at 3500 \$/kW)	[\$]	472,500
	Electrical upgrades	[\$]	7,500
Contingency	Subtotal after Materials and labour	[\$]	480,000
	General Contingency (20%)	[\$]	96,000
	Design Contingency (10%)	[\$]	48,000
Total	Total	[\$]	624,000

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline.** There is no solar PV present at this site.
- **Proposed.** The proposed solar PV electricity generation system described above was assumed to be implemented. Helioscope was used to model the hourly electricity output from the solar PV system. All electricity generated by the system was assumed to be used on-site, directly reducing grid electricity consumption, GHG emissions and utility costs.

Utility analysis results

Table 42: Solar PV canopy analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	219,381	99,782	119,599	54.5
	Natural gas use	[m3/yr]	38,054	38,054	0	0
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	219,381	99,782	119,599	54.5
	Natural gas energy	[kWh/yr]	401,730	401,730	0	0
	Total energy	[kWh/yr]	621,111	501,512	119,599	19.3
GHG emissions	Electricity GHGs	[tCO2e/yr]	5.2	2.4	2.9	54.5
	Natural gas GHGs	[tCO2e/yr]	73.5	73.5	0	0
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	78.8	75.9	2.9	3.6
Utility cost	Electricity utility cost	[\$/yr]	21,763	9,898	11,864	54.5
	Natural gas utility cost	[\$/yr]	9,894	9,894	0	0
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	3,677	3,677	0	0
	Total utility cost	[\$/yr]	35,333	23,469	11,864	33.6
Financial	Assumed life	[yrs]	15	30	—	—
	Project cost	[\$]	0	624,000	—	—
	Incentive amount	[\$]	0	124,800	—	—
	Incremental project cost	[\$]	0	499,200	—	—
	Life cycle cost	[\$]	892,915	985,484	—	—
	Net present value	[\$]	0	-92,569	—	—
	Project cost per GHG reduction	[\$/tCO2e]	—	174,642	—	—
	Simple payback period	[yr]	—	>20	—	—

5.14 Solar PV rooftop

Measure description

Existing condition

There is no solar PV on the roof. Some rooftop space is available.

Opportunity

Install a solar PV system on the remaining roof where feasible. A net-metering agreement is recommended so that the reduced GHG emissions associated with the electricity generated by the system can be retained by the City of Temiskaming Shores or exported to the grid if on-site electricity consumption is fulfilled.

Utility-savings mechanism

The solar PV system will reduce the electricity use from the grid, GHG emissions, and utility costs.

Design description

Helioscope overview

Helioscope was used to determine a preliminary design concept for the proposed solar PV system. The Helioscope model is depicted in the following image.



Based on the results from the Helioscope model, the proposed solar PV system was assumed to have the following output capacity.

- Total system output capacity (DC) = 32 kW.

Proposed scope

Supply and install a rooftop solar PV electricity generation system, including the following.

- Solar PV modules.
- Racking system for mounting the solar panels onto.
- DC to AC inverters.
- Wiring, disconnects, meters, panels and transformers. The AC output from inverters is to be wired into a dedicated solar PV electrical panel before being connected to the main switchboard via a new breaker.
- Connection impact assessment, and other requirements to satisfy the utility provider for executing a Net Metering agreement.
- Installation of the above.

Electrical

With the existing system, the main panel is rated high enough to accommodate the additional 167kW of the solar to the roof and canopies.

Project cost estimate

Table 43: Project cost estimate (Solar PV rooftop)

Category	Line item	Unit	Value
Materials and labour	Solar PV electricity system installed (assuming 32 kW at 2000 \$/kW)	[\$]	64,000
	Electrical upgrades	[\$]	7,500
Contingency	Subtotal after Materials and labour	[\$]	71,500
	General Contingency (20%)	[\$]	14,300
	Design Contingency (10%)	[\$]	7,200
Total	Total	[\$]	93,000

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline.** There is no solar PV present at this site.
- **Proposed.** The proposed solar PV electricity generation system described above was assumed to be implemented. Helioscope was used to model the hourly electricity output from the solar PV system. All electricity generated by the system was assumed to be used on-site, directly reducing grid electricity consumption, GHG emissions and utility costs.

Utility analysis results

Table 44: Solar PV rooftop analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	219,381	186,874	32,507	14.8
	Natural gas use	[m3/yr]	38,054	38,054	0	0
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	219,381	186,874	32,507	14.8
	Natural gas energy	[kWh/yr]	401,730	401,730	0	0
	Total energy	[kWh/yr]	621,111	588,604	32,507	5.2
GHG emissions	Electricity GHGs	[tCO2e/yr]	5.2	4.5	0.78	14.8
	Natural gas GHGs	[tCO2e/yr]	73.5	73.5	0	0
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	78.8	78.0	0.78	0.99
Utility cost	Electricity utility cost	[\$/yr]	21,763	18,538	3,225	14.8
	Natural gas utility cost	[\$/yr]	9,894	9,894	0	0
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	3,677	3,677	0	0
	Total utility cost	[\$/yr]	35,333	32,109	3,225	9.1
Financial	Assumed life	[yrs]	15	30	—	—
	Project cost	[\$]	0	93,000	—	—
	Incentive amount	[\$]	0	18,600	—	—
	Incremental project cost	[\$]	0	74,400	—	—
	Life cycle cost	[\$]	892,915	868,466	—	—
	Net present value	[\$]	0	24,450	—	—
	Project cost per GHG reduction	[\$/tCO2e]	—	95,763	—	—
	Simple payback period	[yr]	—	>20	—	—

5.15 Wall upgrade to high performance

Measure description

Existing condition

The exterior walls comprised either an outer layer of veneer brick, metal siding, or metal panelling. The west elevation also has an architectural wood laminated feature.



Opportunity

Upgrade upon the end of useful life or as required to meet scenario criteria.

Utility-savings mechanism

Reduced heating energy use through improved thermal performance of exterior walls.

Design description

Overview

The wall performance is less than required by the current building code (R20). In order for it to be improved, either the exterior cladding (stone or metal siding) would need to be removed and the insulation in the cavity increased, or an EIFS (insulated stucco) system would need to be applied to the face of the existing brick. (In the case of the metal siding, the only option is to have the EIFS system replace the siding along with the associated girts and insulation). Both of these options would be expensive but the performance of the wall could be increased to R30-40 if it made financial sense over a 10-20 year payback period. If the decision is taken not to add insulation to the exterior walls then we would recommend at least using thermal imaging and blower door testing to see if there are significant points of air leakage or thermal bridging that are compromising the performance of the walls and roof. These can be addressed locally with sealants and spray foam.

Project cost estimate

Table 45: Project cost estimate (Wall upgrade to high performance)

Category	Line item	Unit	Value
Construction	Wall upgrade	[\$]	4,008,530
	General requirements (25%)	[\$]	1,002,100
Contingency	Subtotal after Construction	[\$]	5,010,630
	Design Contingency (25%)	[\$]	1,252,700
	Construction Contingency (10%)	[\$]	501,100
Design, Contractors, PM	Subtotal after Contingency	[\$]	6,764,430
	Engineering Design and Field Review (10%)	[\$]	676,400
	Contractor Fee (7%)	[\$]	473,500
Total	Total	[\$]	7,914,330

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline.** An average wall U-value of 0.085 BTU/hr.ft².F (R12) was assumed.
- **Proposed.** An average wall U-value of 0.0333 BTU/hr.ft².F (R30) was assumed. Infiltration flow was assumed to be reduced by 10% in total relative to the Baseline for affected spaces.

Utility analysis results

Table 46: Wall upgrade to high performance analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	219,381	218,256	1,125	0.51
	Natural gas use	[m ³ /yr]	38,054	30,970	7,084	18.6
	Carbon offset use	[tCO ₂ e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	219,381	218,256	1,125	0.51
	Natural gas energy	[kWh/yr]	401,730	326,946	74,784	18.6
	Total energy	[kWh/yr]	621,111	545,202	75,910	12.2
GHG emissions	Electricity GHGs	[tCO ₂ e/yr]	5.2	5.2	0.03	0.51
	Natural gas GHGs	[tCO ₂ e/yr]	73.5	59.8	13.7	18.6
	Carbon offsets GHGs	[tCO ₂ e/yr]	0	0	0	—
	Total GHGs	[tCO ₂ e/yr]	78.8	65.1	13.7	17.4
Utility cost	Electricity utility cost	[\$/yr]	21,763	21,651	112	0.51
	Natural gas utility cost	[\$/yr]	9,894	8,052	1,842	18.6
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	3,677	2,992	684	18.6
	Total utility cost	[\$/yr]	35,333	32,696	2,638	7.5
Financial	Assumed life	[yrs]	15	75	—	—
	Project cost	[\$]	0	7,914,330	—	—
	Incentive amount	[\$]	0	1,250,000	—	—
	Incremental project cost	[\$]	0	6,664,330	—	—
	Life cycle cost	[\$]	892,915	3,013,703	—	—
	Net present value	[\$]	0	-2,120,788	—	—
	Project cost per GHG reduction	[\$/tCO ₂ e]	—	485,887	—	—
	Simple payback period	[yr]	—	>20	—	—

5.16 Windows and doors to high performance

Measure description

Existing condition

The facility has aluminum-framed, double-pane picture windows and a double-pane curtain wall. The facility has swing doors with glazing, hollow metal, and one small overhead door.



Opportunity

Upgrade upon the end of useful life or as required to meet scenario criteria.

Utility-savings mechanism

Reduced heating energy use through improved thermal performance of windows and doors.

Design description

Windows

We recommend replacing all windows with Passive House Certified Triple-glazed, thermally broken windows. These could be framed in aluminum, vinyl or fiberglass.

Doors

Doors are a significant source of heat loss and air infiltration. To minimize their impact, we recommend the following measures:

- **Hollow Metal Doors:** Replace existing hollow metal doors with insulated doors in thermally broken frames.
- **Glazed Entry Doors:** Should be triple-glazed and thermally broken as part of the curtain wall/window improvements.

Project cost estimate

Table 47: Project cost estimate (Windows and doors to high performance)

Category	Line item	Unit	Value
Construction	Window and door replacement	[\$]	327,400
	General requirements (25%)	[\$]	81,800
Contingency	Subtotal after Construction	[\$]	409,200
	Design Contingency (25%)	[\$]	102,300
	Construction Contingency (10%)	[\$]	40,900
Design, Contractors, PM	Subtotal after Contingency	[\$]	552,400
	Engineering Design and Field Review (10%)	[\$]	55,200
	Contractor Fee (7%)	[\$]	38,700
Total	Total	[\$]	646,300

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline.** The average U-value of all windows and doors was assumed to be 0.625 BTU/hr.ft².F and 2.08 BTU/hr.ft².F, respectively.
- **Proposed.** The average U-value of all windows and doors was assumed to be 0.125 BTU/hr.ft².F (R8). Infiltration flow was assumed to be reduced by 10% in total relative to the Baseline for affected spaces.

Utility analysis results

Table 48: Windows and doors to high performance analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	219,381	218,589	792	0.36
	Natural gas use	[m ³ /yr]	38,054	31,644	6,410	16.8
	Carbon offset use	[tCO ₂ e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	219,381	218,589	792	0.36
	Natural gas energy	[kWh/yr]	401,730	334,060	67,671	16.8
	Total energy	[kWh/yr]	621,111	552,649	68,463	11.0
GHG emissions	Electricity GHGs	[tCO ₂ e/yr]	5.2	5.2	0.02	0.36
	Natural gas GHGs	[tCO ₂ e/yr]	73.5	61.1	12.4	16.8
	Carbon offsets GHGs	[tCO ₂ e/yr]	0	0	0	—
	Total GHGs	[tCO ₂ e/yr]	78.8	66.4	12.4	15.7
Utility cost	Electricity utility cost	[\$/yr]	21,763	21,684	78.6	0.36
	Natural gas utility cost	[\$/yr]	9,894	8,228	1,667	16.8
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	3,677	3,057	619	16.8
	Total utility cost	[\$/yr]	35,333	32,969	2,365	6.7
Financial	Assumed life	[yrs]	15	40	—	—
	Project cost	[\$]	0	646,300	—	—
	Incentive amount	[\$]	0	129,260	—	—
	Incremental project cost	[\$]	0	517,040	—	—
	Life cycle cost	[\$]	892,915	1,173,774	—	—
	Net present value	[\$]	0	-280,859	—	—
	Project cost per GHG reduction	[\$/tCO ₂ e]	—	41,678	—	—
	Simple payback period	[yr]	—	>20	—	—

5.17 Measure risk analysis

Utility use sensitivity

Figure 152 indicates how sensitive cumulative electricity and natural gas use are to variations in each risk parameter.

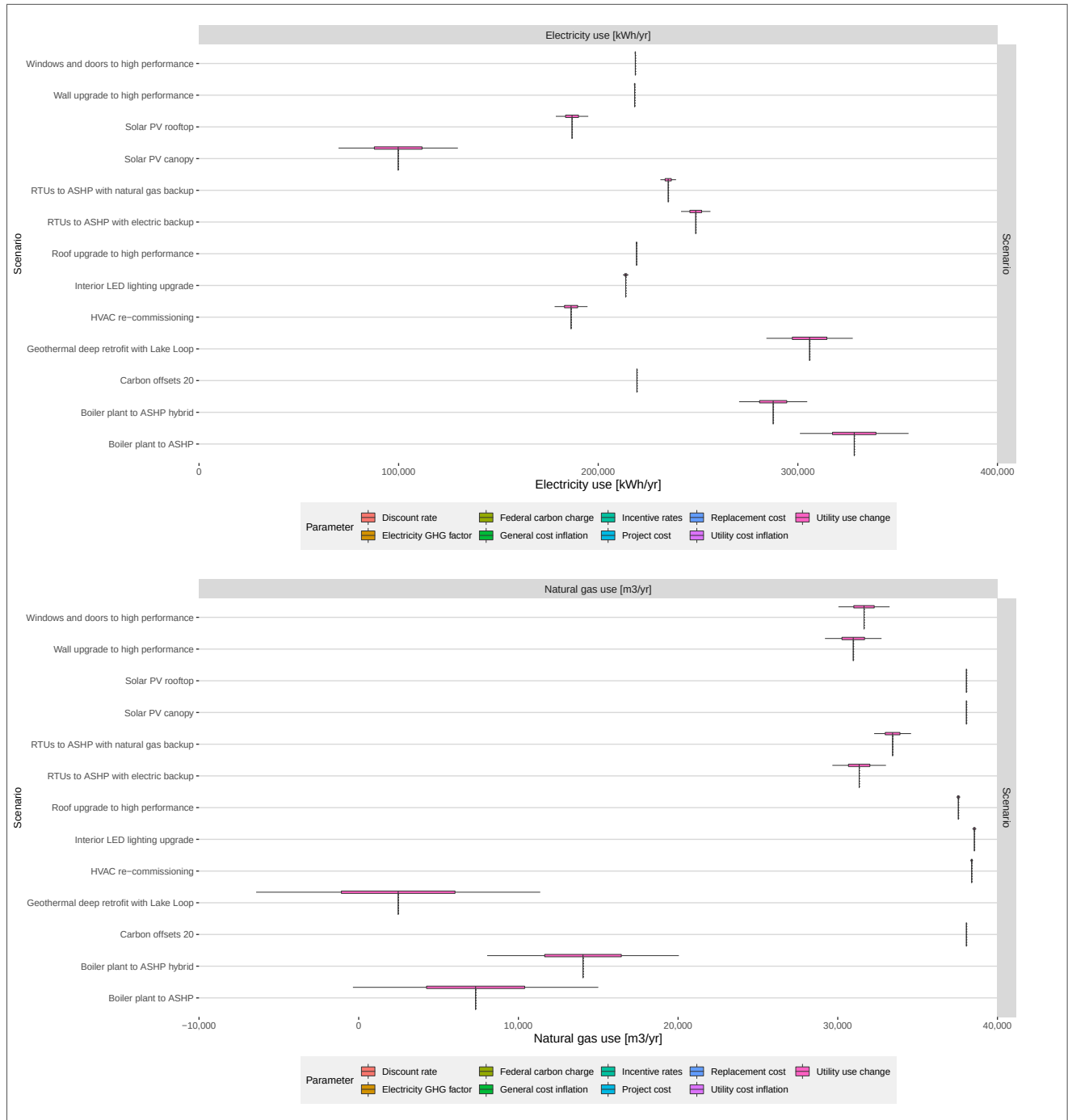


Figure 152: Utility cumulative use sensitivity analysis

GHG emissions and life cycle cost sensitivity

Figure 153 indicates how sensitive cumulative GHG emissions and life cycle costs are to variations in each risk parameter.

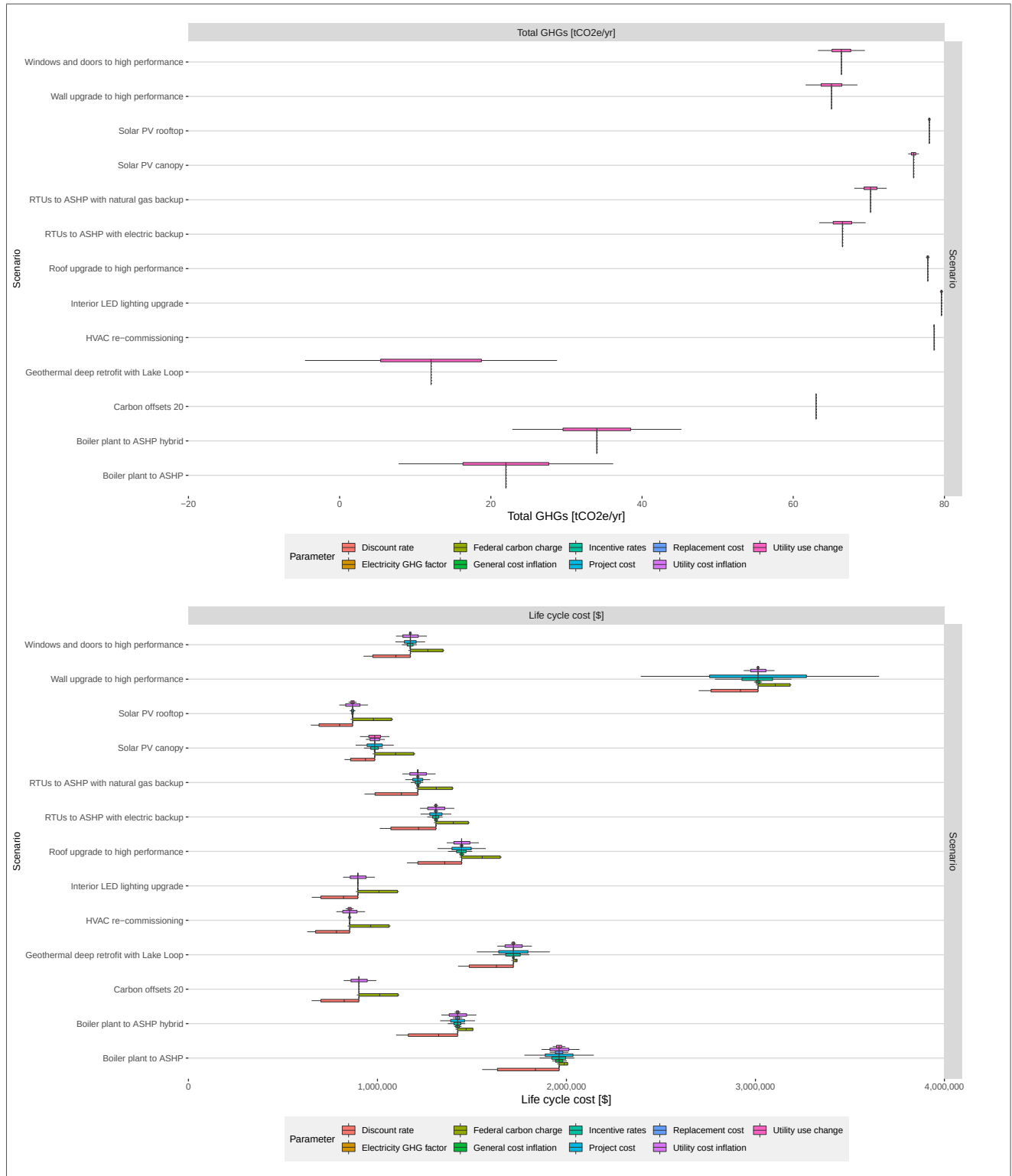


Figure 153: GHG cumulative emissions and life cycle cost sensitivity analysis

5.18 Measure analysis summary

For each analyzed measure, the analysis results are summarized in Table 49.

Table 49: Measure analysis summary

Measure ID	Utility use				Equivalent energy use		GHG emissions		Utility cost		Financial							
Measure name	Electricity use reduction	Electricity use reduction	Natural gas use reduction	Natural gas use reduction	Total energy reduction	Total energy reduction	Total GHG reduction	Total GHG reduction	Utility cost reduction	Utility cost reduction	Assumed life	Project cost	Incentive amount	Incremental project cost	Life cycle cost	Net present value	Project cost per GHG reduction	Simple payback period
-	[kWh/yr]	[%]	[m3/yr]	[%]	[kWh/yr]	[%]	[tCO2e/yr]	[%]	[\$/yr]	[%]	[yrs]	[\$]	[\$]	[\$]	[\$]	[\$]	[\$/tCO2e]	[yr]
Baseline	219,381	100.0	38,054	100.0	621,111	100.0	79	100.0	35,333	100.0	15	0	0	0	892,915	0	-	-
Boiler plant to ASHP	-108,876	-49.6	30,734	80.8	215,573	34.7	57	72.1	160	0.5	15	945,800	189,160	756,640	1,961,207	-1,068,292	13,324	4,737
Boiler plant to ASHP hybrid	-68,262	-31.1	24,007	63.1	185,179	29.8	45	56.8	1,790	5.1	15	475,800	95,160	380,640	1,424,151	-531,236	8,504	213
Carbon offsets 20	0	0.0	0	0.0	0	0.0	16	20.0	-473	-1.3	20	-	0	-	901,535	-8,620	-	-
Geothermal deep retrofit with Lake Loop	-86,506	-39.4	35,581	93.5	289,114	46.5	67	84.7	4,107	11.6	40	1,591,400	318,280	1,273,120	1,719,173	-826,257	19,091	310
HVAC re-commissioning	32,989	15.0	-334	-0.9	29,468	4.7	0	0.2	3,154	8.9	15	37,500	0	37,500	852,885	40,030	260,489	12
Interior LED lighting upgrade	5,615	2.6	-499	-1.3	345	0.1	-1	-1.1	379	1.1	20	15,000	0	15,000	896,294	-3,379	-18,060	40
Roof upgrade to high performance	180	0.1	504	1.3	5,502	0.9	1	1.2	198	0.6	20	657,100	131,420	525,680	1,445,355	-552,440	537,307	2,660
RTUs to ASHP with electric backup	-29,472	-13.4	6,713	17.6	41,398	6.7	12	15.6	-530	-1.5	18	418,500	83,700	334,800	1,309,374	-416,458	27,291	-632
RTUs to ASHP with natural gas backup	-15,684	-7.1	4,620	12.1	33,088	5.3	9	10.9	92	0.3	18	339,700	67,940	271,760	1,213,508	-320,592	31,775	2,964
Solar PV canopy	119,599	54.5	0	0.0	119,599	19.3	3	3.6	11,864	33.6	30	624,000	124,800	499,200	985,484	-92,569	174,642	42
Solar PV rooftop	32,507	14.8	0	0.0	32,507	5.2	1	1.0	3,225	9.1	30	93,000	18,600	74,400	868,466	24,450	95,763	23
Wall upgrade to high performance	1,125	0.5	7,084	18.6	75,910	12.2	14	17.4	2,638	7.5	75	7,914,330	1,250,000	6,664,330	3,013,703	-2,120,788	485,887	2,526
Windows and doors to high performance	792	0.4	6,410	16.8	68,463	11.0	12	15.7	2,365	6.7	40	646,300	129,260	517,040	1,173,774	-280,859	41,678	219
Total project cost	-	-	-	-	-	-	-	-	-	-	-	13,758,430	-	-	-	-	-	-
Boiler renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	30	37,000	0	37,000	922,868	-29,952	-	-
Exterior walls renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	75	17,000	0	17,000	898,420	-5,505	-	-
Interior lighting renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	20	20,000	0	20,000	913,704	-20,789	-	-
Roof renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	20	268,000	0	268,000	1,171,483	-278,568	-	-
RTUs renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	18	303,000	0	303,000	1,221,224	-328,309	-	-
Windows and doors renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	40	111,000	0	111,000	960,308	-67,393	-	-
BAU measure totals	-	-	-	-	-	-	-	-	-	-	-	756,000	-	-	-	-	-	-

6 SCENARIO ANALYSIS

6.1 Cluster scenario analysis methodology

A scenario analysis was completed to estimate the costs and benefits expected from implementing various combinations (i.e. scenarios) of the measures that were individually analyzed in Section 5. Whereas in Section 5, each measure was individually analyzed as though implemented by itself, in Section 6, scenarios of multiple measures being implemented together were analyzed, and the interactive effects between measures within each scenario were accounted for. The scenario analysis was completed according to the following methodology.

1. **Cluster scenario objectives.** All scenarios that were analyzed and their objectives were defined as summarized in Table 50.
2. **Cluster scenario composition.** Each scenario was composed by iteratively assigning measures to that scenario to achieve the objectives of that scenario as closely as possible. Results are presented in Section 6.3.
3. **Cluster scenario performance analysis.** Each scenario was analyzed using the energy model to estimate the overall performance that implementing all measures in that scenario would have on utility use, equivalent energy use, GHG emissions, utility costs and several financial performance metrics. Results are presented in Section 6.4.
4. **Cluster scenario analysis discussion.** Results of the scenario analysis were discussed in Section 6.4.

6.2 Cluster scenario objectives

The cluster scenarios that were analyzed and their objectives are summarized in Table 50.

Table 50: Scenario objectives

Scenario	Objectives
Control optimization	To estimate the impact of all control optimization measures combined.
Envelope upgrades	To estimate the impact of all envelope upgrade measures combined.
Load minimization	To estimate the impact of all controls optimization, envelope upgrades, and other measures intended to reduce the thermal and electrical load of the facility, which would ideally reduce the capacity requirements of new equipment.
Comprehensive cluster	To understand the limit of GHG reductions possible by implementing all measures that have the greatest reduction on GHG emissions.

6.3 Cluster scenario composition

In the scenario composition exercise, individual measures were assigned to each scenario in an iterative process to achieve the objectives of that scenario as closely as possible. Figure 154 and Table 51 present the results of this exercise, indicating which measures were assigned to which scenario.

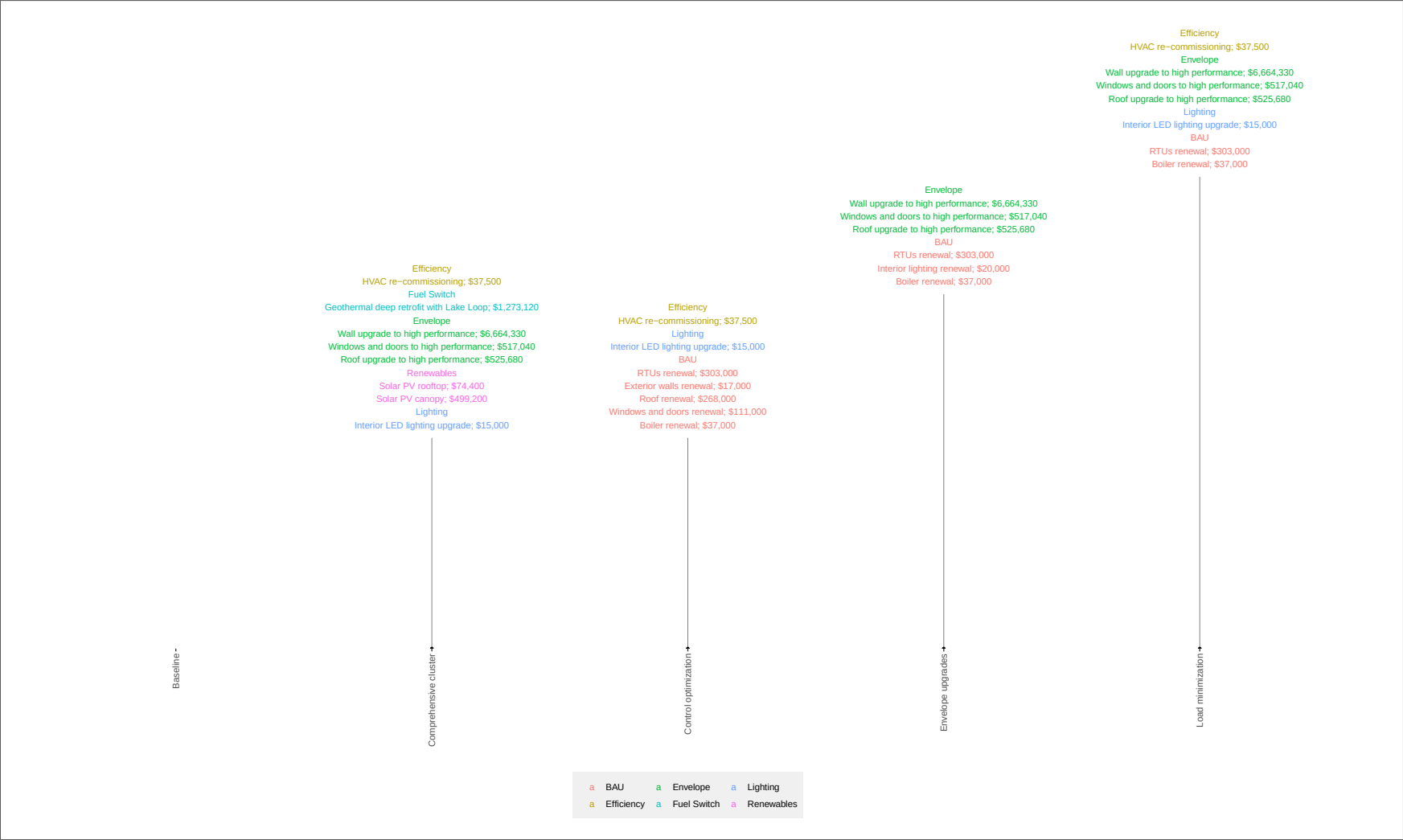


Figure 154: Scenario composition

Table 51: Cluster composition

Measure	Control optimization	Envelope upgrades	Load minimization	Comprehensive cluster
Boiler plant to ASHP	✗	✗	✗	✗
Boiler plant to ASHP hybrid	✗	✗	✗	✗
Carbon offsets 20	✗	✗	✗	✗
Geothermal deep retrofit with Lake Loop	✗	✗	✗	✓
HVAC re-commissioning	✓	✗	✓	✓
Interior LED lighting upgrade	✓	✗	✓	✓
Roof upgrade to high performance	✗	✓	✓	✓
RTUs to ASHP with electric backup	✗	✗	✗	✗
RTUs to ASHP with natural gas backup	✗	✗	✗	✗
Solar PV canopy	✗	✗	✗	✓
Solar PV rooftop	✗	✗	✗	✓
Wall upgrade to high performance	✗	✓	✓	✓
Windows and doors to high performance	✗	✓	✓	✓
Boiler renewal	✓	✓	✓	✗
Exterior walls renewal	✓	✗	✗	✗
Interior lighting renewal	✗	✓	✗	✗
Roof renewal	✓	✗	✗	✗
RTUs renewal	✓	✓	✓	✗
Windows and doors renewal	✓	✗	✗	✗

6.4 Cluster scenario performance analysis

The scenario performance analysis was completed by using the energy model (see Section 4) to determine the expected performance of implementing all measures in each scenario. Results are presented throughout Section 6.4.

Cluster scenario performance analysis summary

Results of the scenario analysis are summarized in Table 52, which indicates all individual measures that were considered to be implemented under each scenario, the measure-specific impacts that each measure was estimated to have if implemented by itself, and the combined impacts that implementing all measures in each scenario is expected to have, accounting for the interactive effects between measures within each scenario.

Table 52: Scenario analysis summary

Measure ID	Utility use					Equivalent energy use		GHG emissions		Utility cost		Financial							
Scenario	Measure name	Electricity use reduction	Electricity use reduction	Natural gas use reduction	Natural gas use reduction	Total energy reduction	Total energy reduction	Total GHG reduction	Total GHG reduction	Utility cost reduction	Utility cost reduction	Assumed life	Project cost	Incentive amount	Incremental project cost	Life cycle cost	Net present value	Project cost per GHG reduction	Simple payback period
-	-	[kWh/yr]	[%]	[m3/yr]	[%]	[kWh/yr]	[%]	[tCO2e/yr]	[%]	[\$/yr]	[%]	[yrs]	[\$]	[\$]	[\$]	[\$]	[\$]	[\$/tCO2e]	[yr]
Comprehensive cluster	Combined	136,017	62.0	35,581	93.5	511,637	82.4	72	91.4	26,182	74.1	-	11,578,630	1,972,360	9,606,270	4,442,828	-3,549,913	133,409	367
Comprehensive cluster	HVAC re-commissioning	32,989	15.0	-334	-0.9	29,468	4.7	0	0.2	3,154	8.9	15	37,500	0	37,500	852,885	40,030	260,489	12
Comprehensive cluster	Geothermal deep retrofit with Lake Loop	-86,506	-39.4	35,581	93.5	289,114	46.5	67	84.7	4,107	11.6	40	1,591,400	318,280	1,273,120	1,719,173	-826,257	19,091	310
Comprehensive cluster	Wall upgrade to high performance	1,125	0.5	7,084	18.6	75,910	12.2	14	17.4	2,638	7.5	75	7,914,330	1,250,000	6,664,330	3,013,703	-2,120,788	485,887	2,526
Comprehensive cluster	Windows and doors to high performance	792	0.4	6,410	16.8	68,463	11.0	12	15.7	2,365	6.7	40	646,300	129,260	517,040	1,173,774	-280,859	41,678	219
Comprehensive cluster	Roof upgrade to high performance	180	0.1	504	1.3	5,502	0.9	1	1.2	198	0.6	20	657,100	131,420	525,680	1,445,355	-552,440	537,307	2,660
Comprehensive cluster	Solar PV rooftop	32,507	14.8	0	0.0	32,507	5.2	1	1.0	3,225	9.1	30	93,000	18,600	74,400	868,466	24,450	95,763	23
Comprehensive cluster	Solar PV canopy	119,599	54.5	0	0.0	119,599	19.3	3	3.6	11,864	33.6	30	624,000	124,800	499,200	985,484	-92,569	174,642	42
Comprehensive cluster	Interior LED lighting upgrade	5,615	2.6	-499	-1.3	345	0.1	-1	-1.1	379	1.1	20	15,000	0	15,000	896,294	-3,379	-18,060	40
Control optimization	Combined	38,580	17.6	-826	-2.2	29,862	4.8	-1	-0.9	3,533	10.0	-	788,500	0	788,500	1,536,167	-643,252	-1,170,284	223
Control optimization	HVAC re-commissioning	32,989	15.0	-334	-0.9	29,468	4.7	0	0.2	3,154	8.9	15	37,500	0	37,500	852,885	40,030	260,489	12
Control optimization	Interior LED lighting upgrade	5,615	2.6	-499	-1.3	345	0.1	-1	-1.1	379	1.1	20	15,000	0	15,000	896,294	-3,379	-18,060	40
Control optimization	RTUs renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	18	303,000	0	303,000	1,221,224	-328,309	-	-
Control optimization	Exterior walls renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	75	17,000	0	17,000	898,420	-5,505	-	-
Control optimization	Roof renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	20	268,000	0	268,000	1,171,483	-278,568	-	-
Control optimization	Windows and doors renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	40	111,000	0	111,000	960,308	-67,393	-	-
Control optimization	Boiler renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	30	37,000	0	37,000	922,868	-29,952	-	-
Envelope upgrades	Combined	1,912	0.9	13,837	36.4	147,980	23.8	27	34.0	5,124	14.5	-	9,577,730	1,510,680	8,067,050	4,023,104	-3,130,189	301,203	1,574
Envelope upgrades	Wall upgrade to high performance	1,125	0.5	7,084	18.6	75,910	12.2	14	17.4	2,638	7.5	75	7,914,330	1,250,000	6,664,330	3,013,703	-2,120,788	485,887	2,526
Envelope upgrades	Windows and doors to high performance	792	0.4	6,410	16.8	68,463	11.0	12	15.7	2,365	6.7	40	646,300	129,260	517,040	1,173,774	-280,859	41,678	219
Envelope upgrades	Roof upgrade to high performance	180	0.1	504	1.3	5,502	0.9	1	1.2	198	0.6	20	657,100	131,420	525,680	1,445,355	-552,440	537,307	2,660
Envelope upgrades	RTUs renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	18	303,000	0	303,000	1,221,224	-328,309	-	-
Envelope upgrades	Interior lighting renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	20	20,000	0	20,000	913,704	-20,789	-	-
Envelope upgrades	Boiler renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	30	37,000	0	37,000	922,868	-29,952	-	-
Load minimization	Combined	40,741	18.6	12,800	33.6	175,868	28.3	26	32.6	8,606	24.4	-	9,610,230	1,510,680	8,099,550	3,969,575	-3,076,660	315,061	941
Load minimization	HVAC re-commissioning	32,989	15.0	-334	-0.9	29,468	4.7	0	0.2	3,154	8.9	15	37,500	0	37,500	852,885	40,030	260,489	12
Load minimization	Wall upgrade to high performance	1,125	0.5	7,084	18.6	75,910	12.2	14	17.4	2,638	7.5	75	7,914,330	1,250,000	6,664,330	3,013,703	-2,120,788	485,887	2,526
Load minimization	Windows and doors to high performance	792	0.4	6,410	16.8	68,463	11.0	12	15.7	2,365	6.7	40	646,300	129,260	517,040	1,173,774	-280,859	41,678	219
Load minimization	Roof upgrade to high performance	180	0.1	504	1.3	5,502	0.9	1	1.2	198	0.6	20	657,100	131,420	525,680	1,445,355	-552,440	537,307	2,660
Load minimization	Interior LED lighting upgrade	5,615	2.6	-499	-1.3	345	0.1	-1	-1.1	379	1.1	20	15,000	0	15,000	896,294	-3,379	-18,060	40
Load minimization	RTUs renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	18	303,000	0	303,000	1,221,224	-328,309	-	-
Load minimization	Boiler renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	30	37,000	0	37,000	922,868	-29,952	-	-

Utility use comparison

The following figures compare the total expected yearly utility use by end use between each scenario.

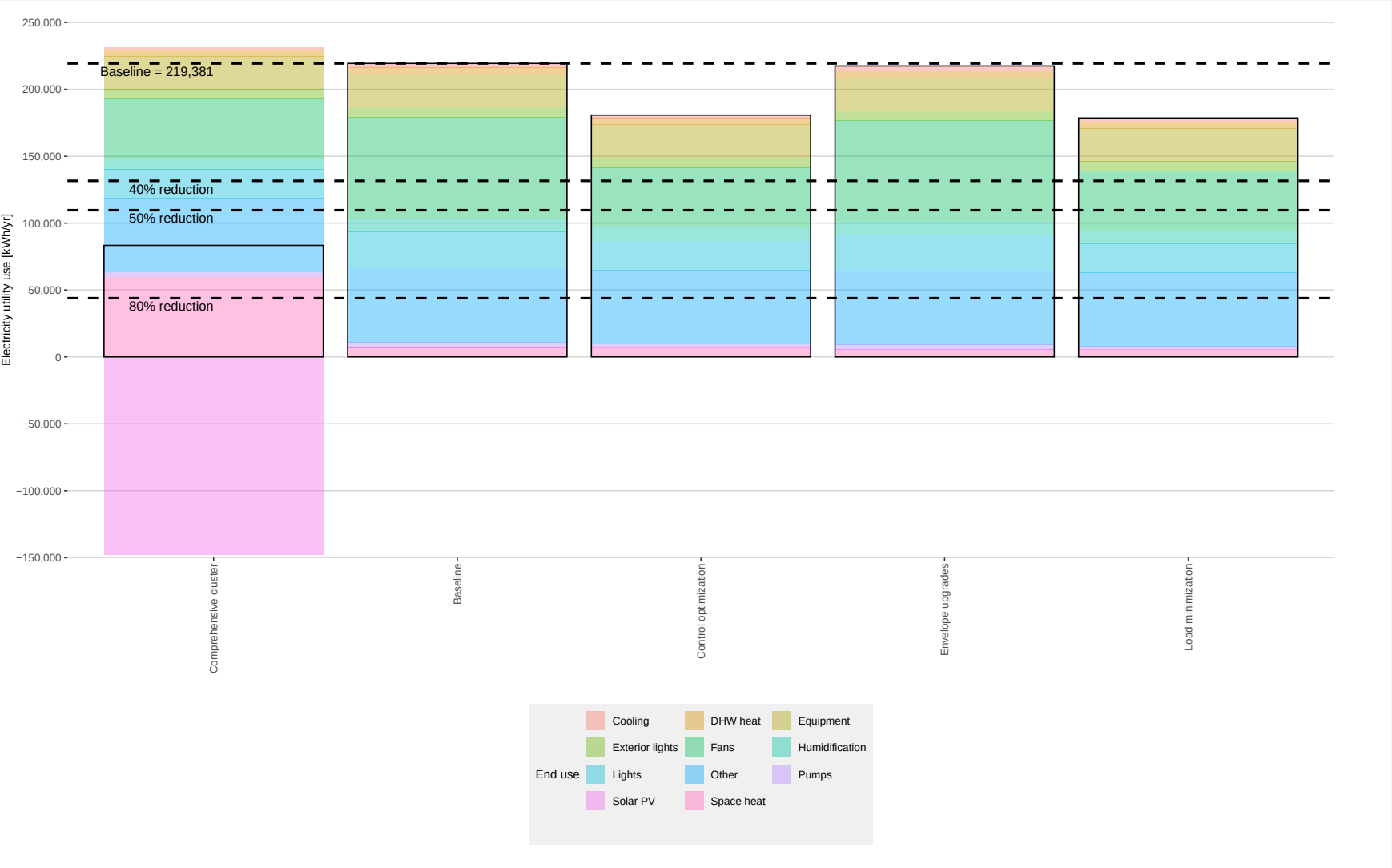


Figure 155: Electricity utility use expected yearly for each scenario by end use

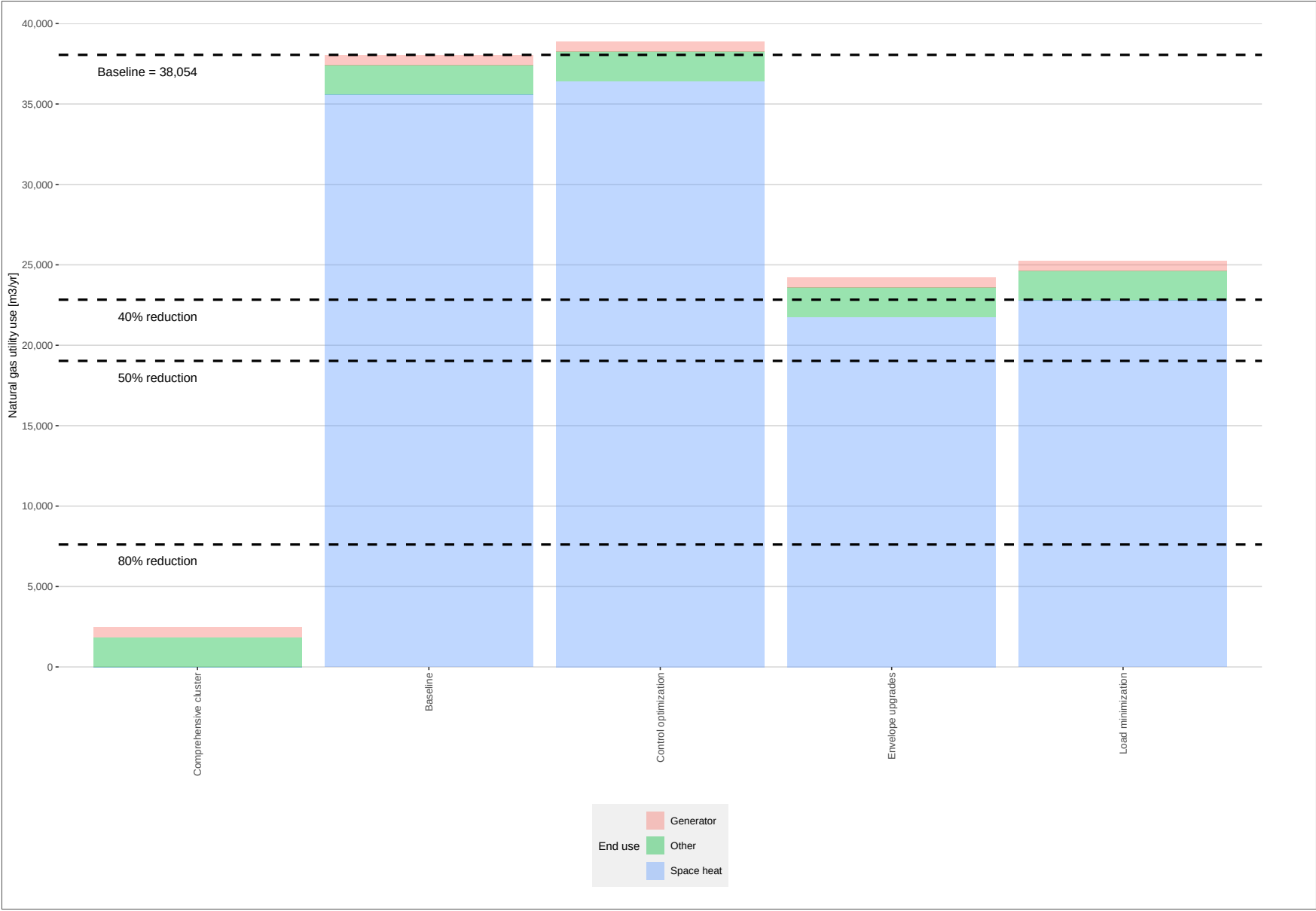


Figure 156: Natural gas utility use expected yearly for each scenario by end use

Energy, GHG and utility cost comparison

The following figures compare the total expected yearly equivalent energy use, GHG emissions and utility costs between each scenario.

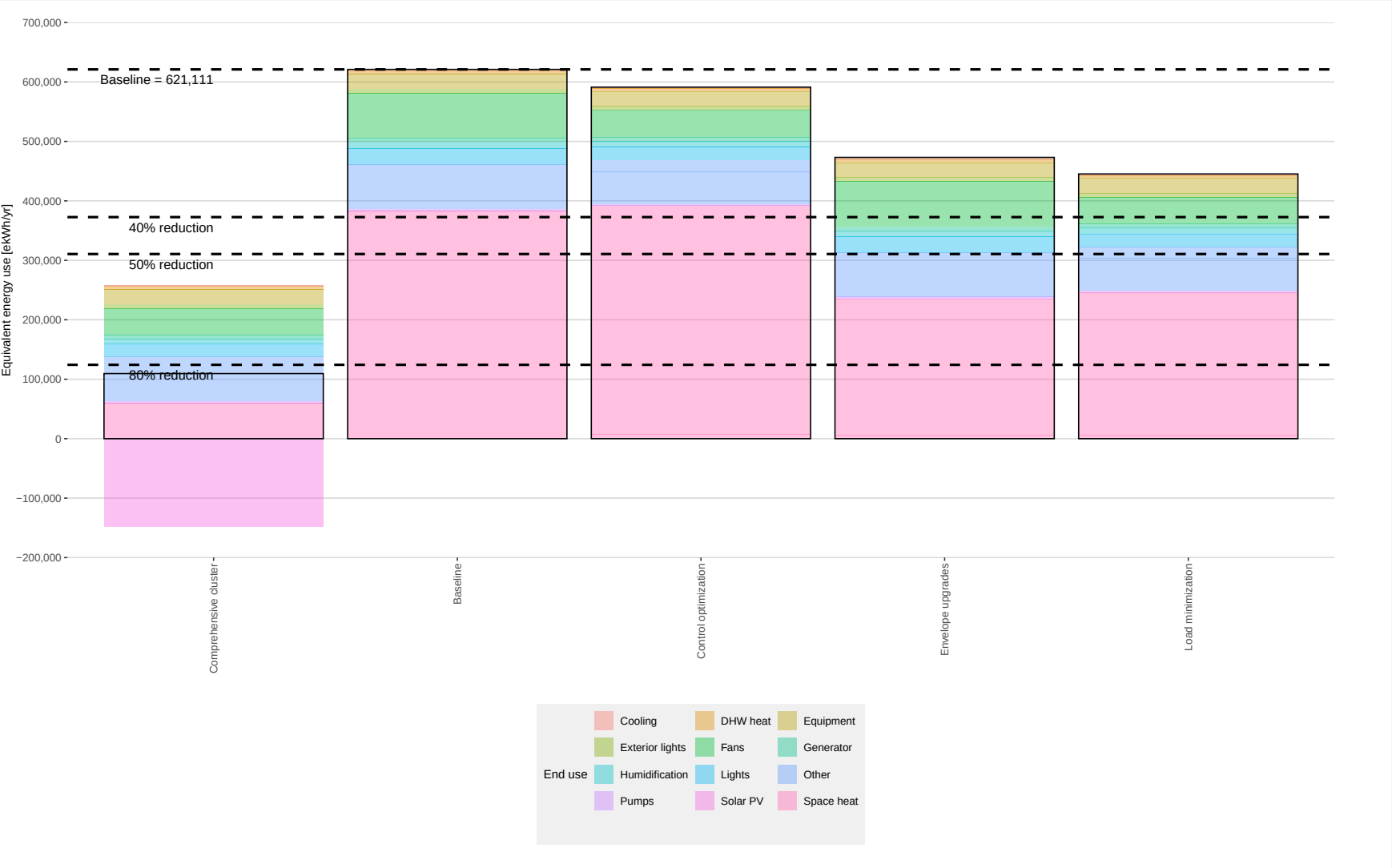


Figure 157: Equivalent energy use expected yearly for each scenario by end use



Figure 158: GHG emissions expected yearly for each scenario by end use

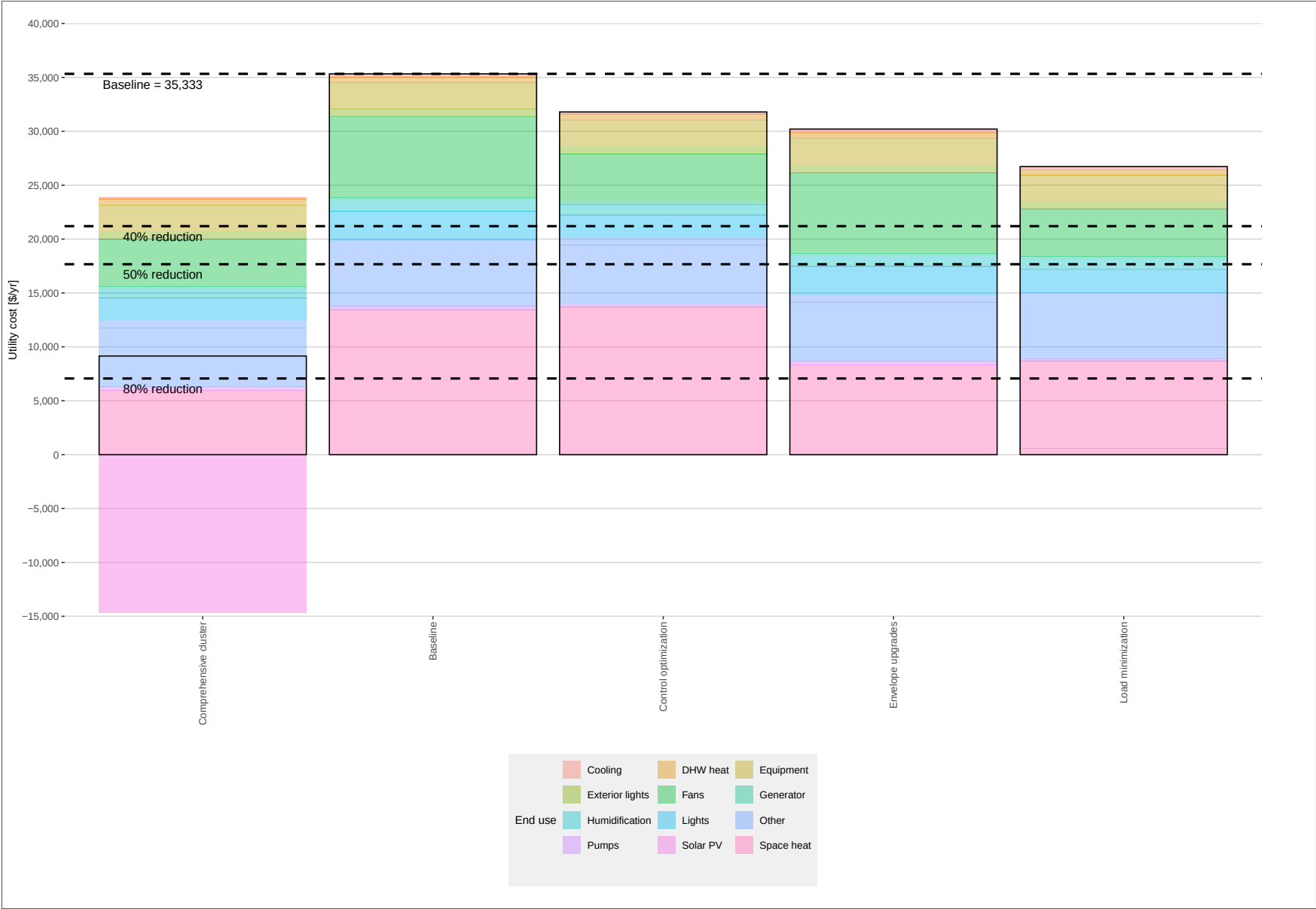


Figure 159: Utility costs expected yearly for each scenario by end use

Financial performance comparison

The following figures compare the financial performance between each scenario.

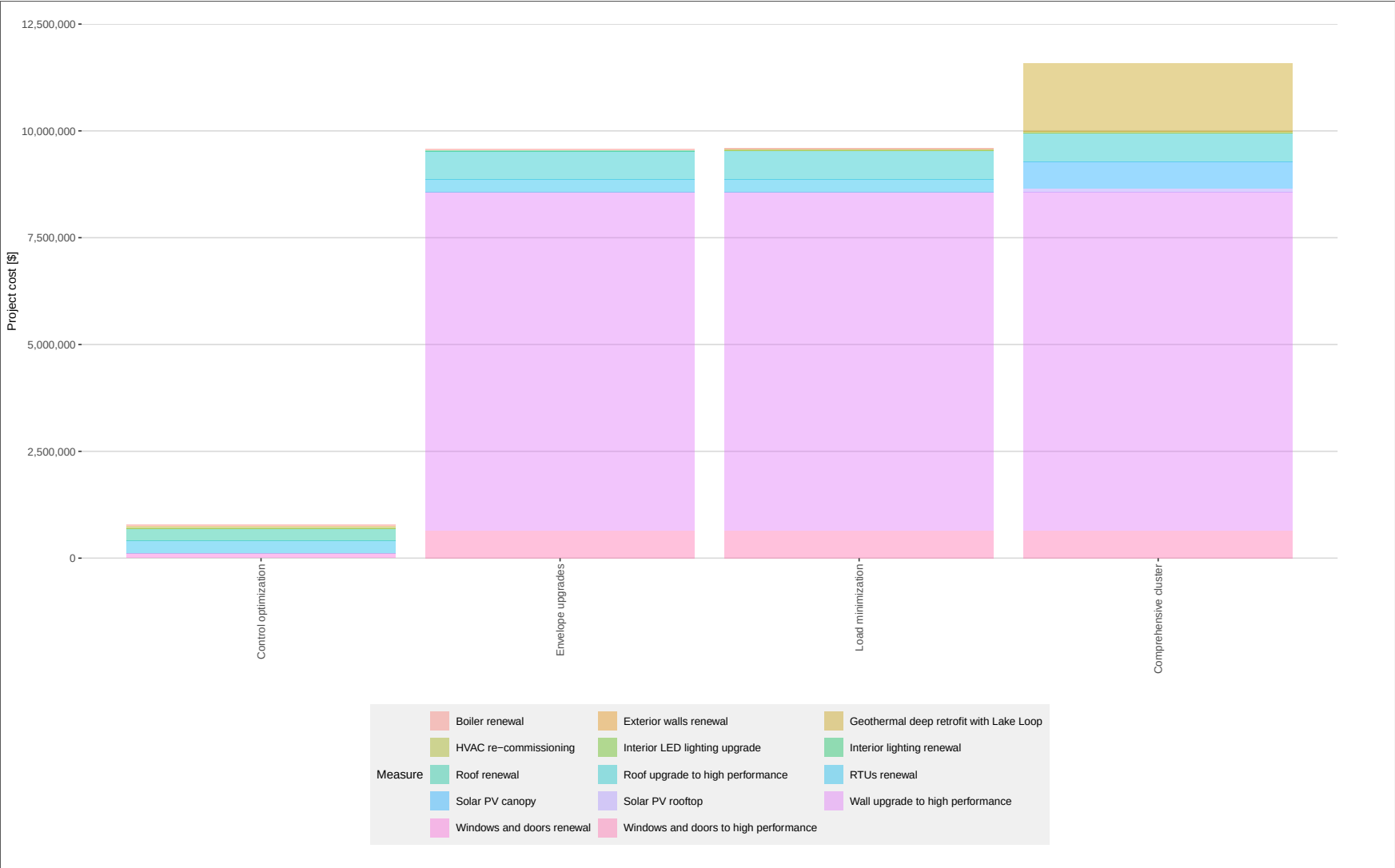


Figure 160: Project cost expected for each scenario by measure

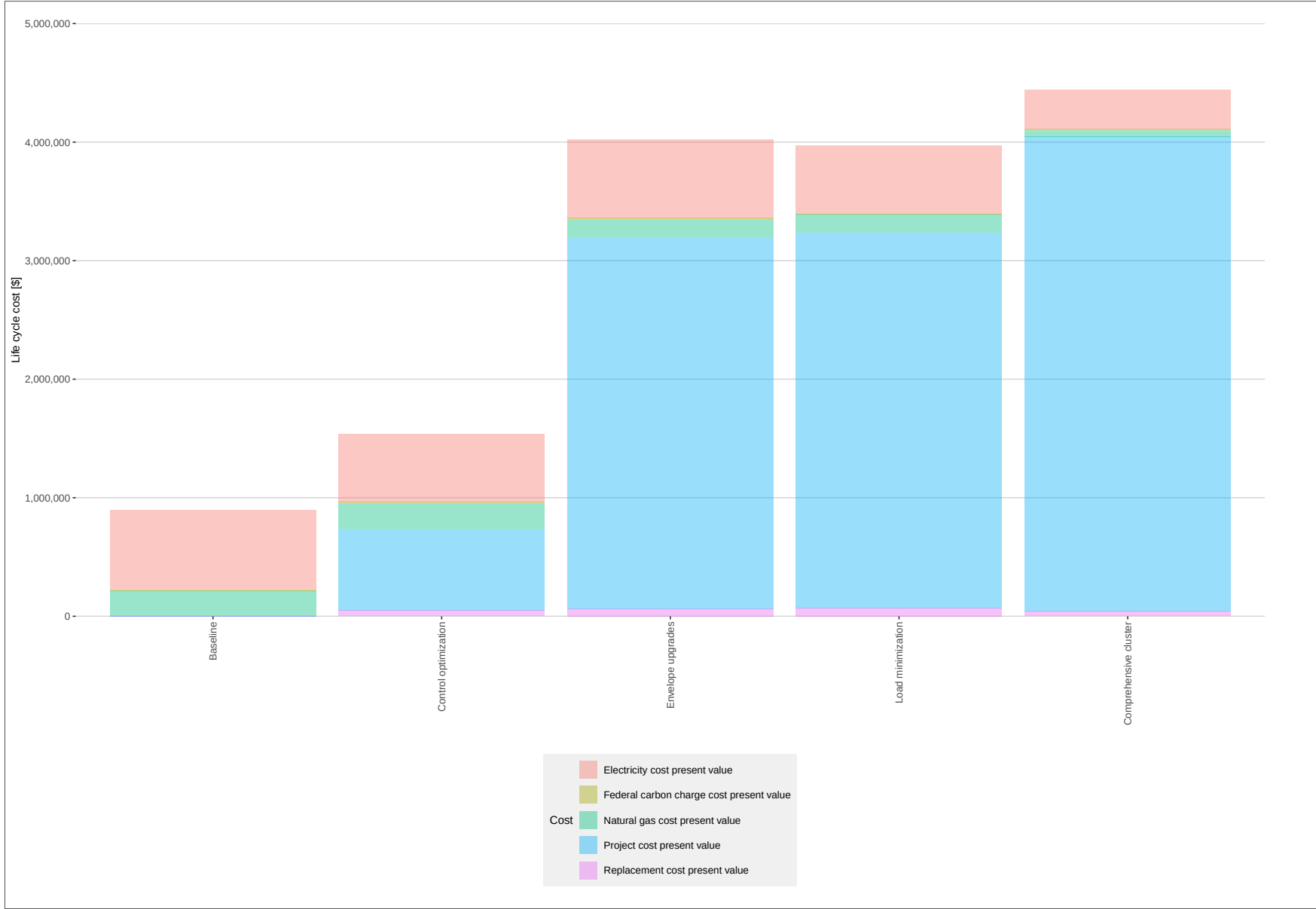


Figure 161: Life cycle cost expected for each scenario by cost item

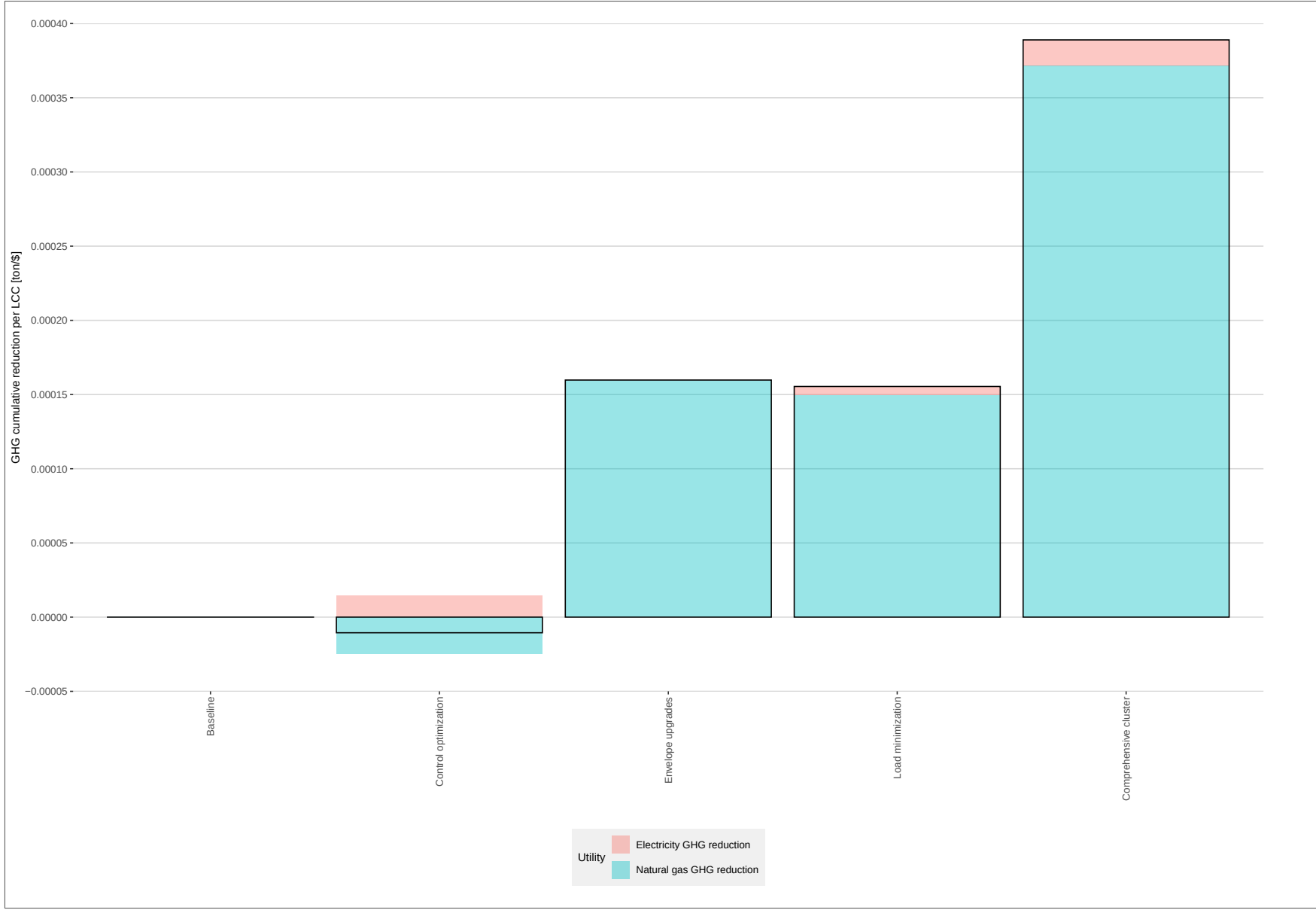


Figure 162: GHG cumulative reduction per life cycle cost (LCC) dollar expected for each scenario by utility

6.5 Plan scenario development

Plan scenario identification and objectives

The plan scenarios that were analyzed and their objectives are summarized in Table 53.

Table 53: Plan scenario identification and objectives

Plan scenario	Objectives
Minimum performance scenario	To achieve a 50% reduction in operational GHG emissions within 10 years and 80% within 20 years. This scenario addresses the minimum performance scenario of FCM's CBR program.
Aggressive deep retrofit	Implement the same measures as in the minimum performance scenario but achieve an 80% reduction in GHG emissions within five years. This scenario addresses the additional scenario requirement of FCM's CBR program.
Comprehensive	To understand the limit of GHG reductions possible by implementing all mutually exclusive measures that have the greatest reduction on GHG emissions and excluding the use of carbon offsets.
Organizational goal alignment	To reduce emissions by 40% GHG emissions from 2019 levels by 2033 and 80% reduction by 2050 of on-site emissions. The remaining 20% is to be addressed through carbon offsets, as noted in the City's Corporate Greenhouse Gas Reduction Plan (GHGRP).
Business as usual	To follow the existing capital renewal plan and replace equipment at the end of its life with like-for-like equipment, meeting minimum energy-efficiency requirements of ASHRAE 90.1.

Plan scenario composition

The plan scenarios were composed with the intent of achieving the objective of each plan scenario, as outlined in Table 53. Results of the plan scenario composition are presented in Figure 163, which is a measure implementation timeline plot indicating which measures were assumed to be implemented in which plan scenarios and when, and the estimated project cost of each measure. The measures are also colour-coded according to measure group. The same information is included in plan performance analysis results figures in Section 6.6 for ease of reference. The plan scenario composition is also presented in Tables 54 to 59.

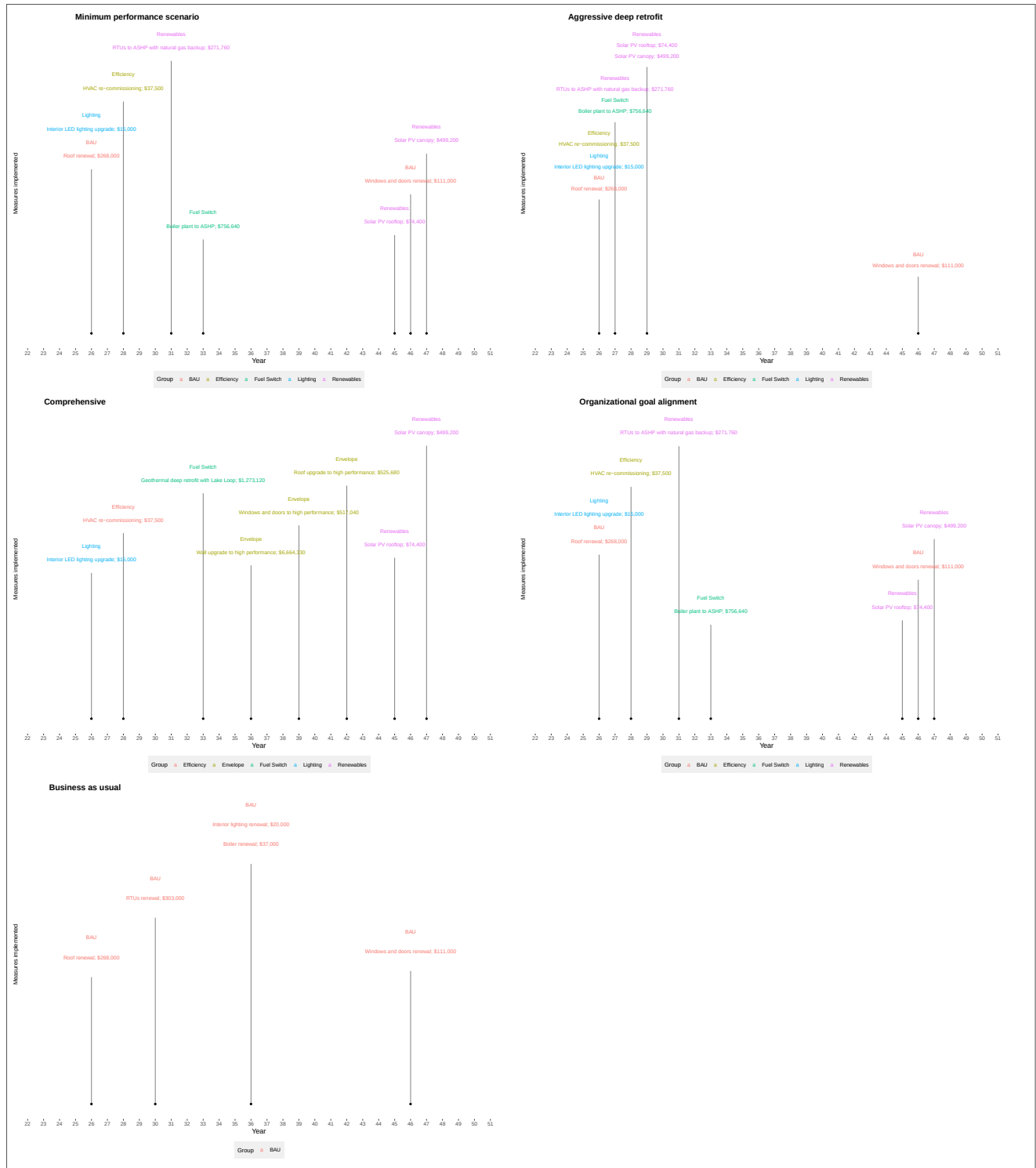


Figure 163: Plan scenario composition, indicating which measures are implemented when and at what cost in each plan scenario

Table 54: Scenario composition summary

Measure	Minimum performance scenario	Aggressive deep retrofit	Comprehensive	Organizational goal alignment
Boiler plant to ASHP	✓	✓	✗	✓
Boiler plant to ASHP hybrid	✗	✗	✗	✗
Carbon offsets 20	✗	✗	✗	✗
Geothermal deep retrofit with Lake Loop	✗	✗	✓	✗
HVAC re-commissioning	✓	✓	✓	✓
Interior LED lighting upgrade	✓	✓	✓	✓
Roof upgrade to high performance	✗	✗	✓	✗
RTUs to ASHP with electric backup	✗	✗	✗	✗
RTUs to ASHP with natural gas backup	✓	✓	✗	✓
Solar PV canopy	✓	✓	✓	✓
Solar PV rooftop	✓	✓	✓	✓
Wall upgrade to high performance	✗	✗	✓	✗
Windows and doors to high performance	✗	✗	✓	✗
Boiler renewal	✗	✗	✗	✗
Exterior walls renewal	✓	✓	✗	✓
Interior lighting renewal	✗	✗	✗	✗
Roof renewal	✓	✓	✗	✓
RTUs renewal	✗	✗	✗	✗
Windows and doors renewal	✓	✓	✗	✓

Table 55: Minimum performance scenario measure implementation timeline

Measure	Year
Interior LED lighting upgrade	2026
Roof renewal	2026
HVAC re-commissioning	2028
RTUs to ASHP with natural gas backup	2031
Boiler plant to ASHP	2033
Solar PV rooftop	2045
Windows and doors renewal	2046
Solar PV canopy	2047
Exterior walls renewal	2081

Table 56: Aggressive deep retrofit measure implementation timeline

Measure	Year
HVAC re-commissioning	2026
Interior LED lighting upgrade	2026
Roof renewal	2026
Boiler plant to ASHP	2027
RTUs to ASHP with natural gas backup	2027
Solar PV canopy	2029
Solar PV rooftop	2029
Windows and doors renewal	2046
Exterior walls renewal	2081

Table 57: Comprehensive measure implementation timeline

Measure	Year
Interior LED lighting upgrade	2026
HVAC re-commissioning	2028
Geothermal deep retrofit with Lake Loop	2033
Wall upgrade to high performance	2036
Windows and doors to high performance	2039
Roof upgrade to high performance	2042
Solar PV rooftop	2045
Solar PV canopy	2047

Table 58: Organizational goal alignment measure implementation timeline

Measure	Year
Interior LED lighting upgrade	2026
Roof renewal	2026
HVAC re-commissioning	2028
RTUs to ASHP with natural gas backup	2031
Boiler plant to ASHP	2033
Solar PV rooftop	2045
Windows and doors renewal	2046
Solar PV canopy	2047
Exterior walls renewal	2081

Table 59: Business as usual measure implementation timeline

Measure	Year
Roof renewal	2026
RTUs renewal	2030
Boiler renewal	2036
Interior lighting renewal	2036
Windows and doors renewal	2046
Exterior walls renewal	2081

6.6 Plan performance analysis

Figures 164 through 167 present the projected yearly electricity use, natural gas use, GHG emissions and life cycle costs associated with each plan scenario.



Figure 164: Electricity yearly utility use projection for each scenario

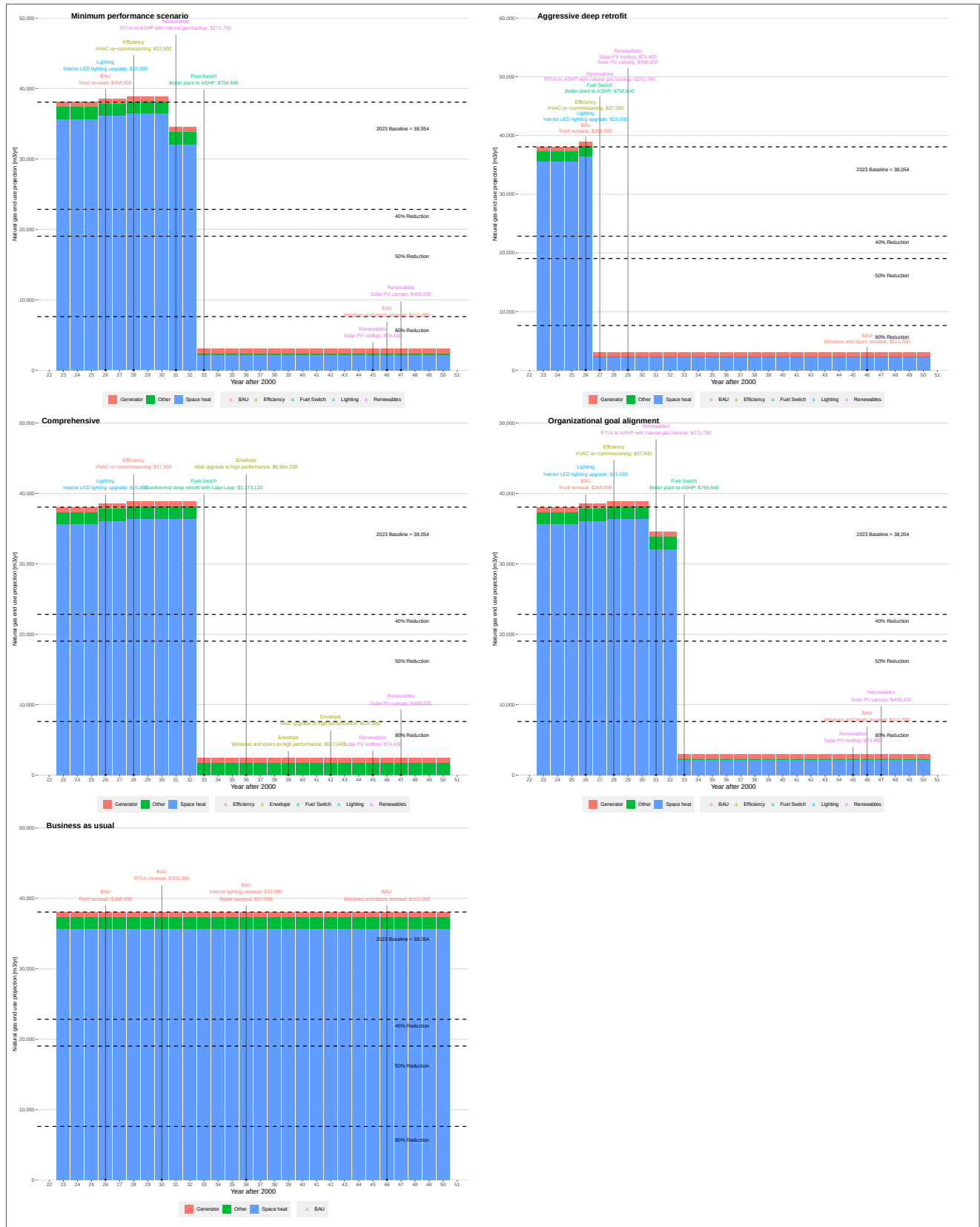


Figure 165: Natural gas yearly utility use projection for each scenario

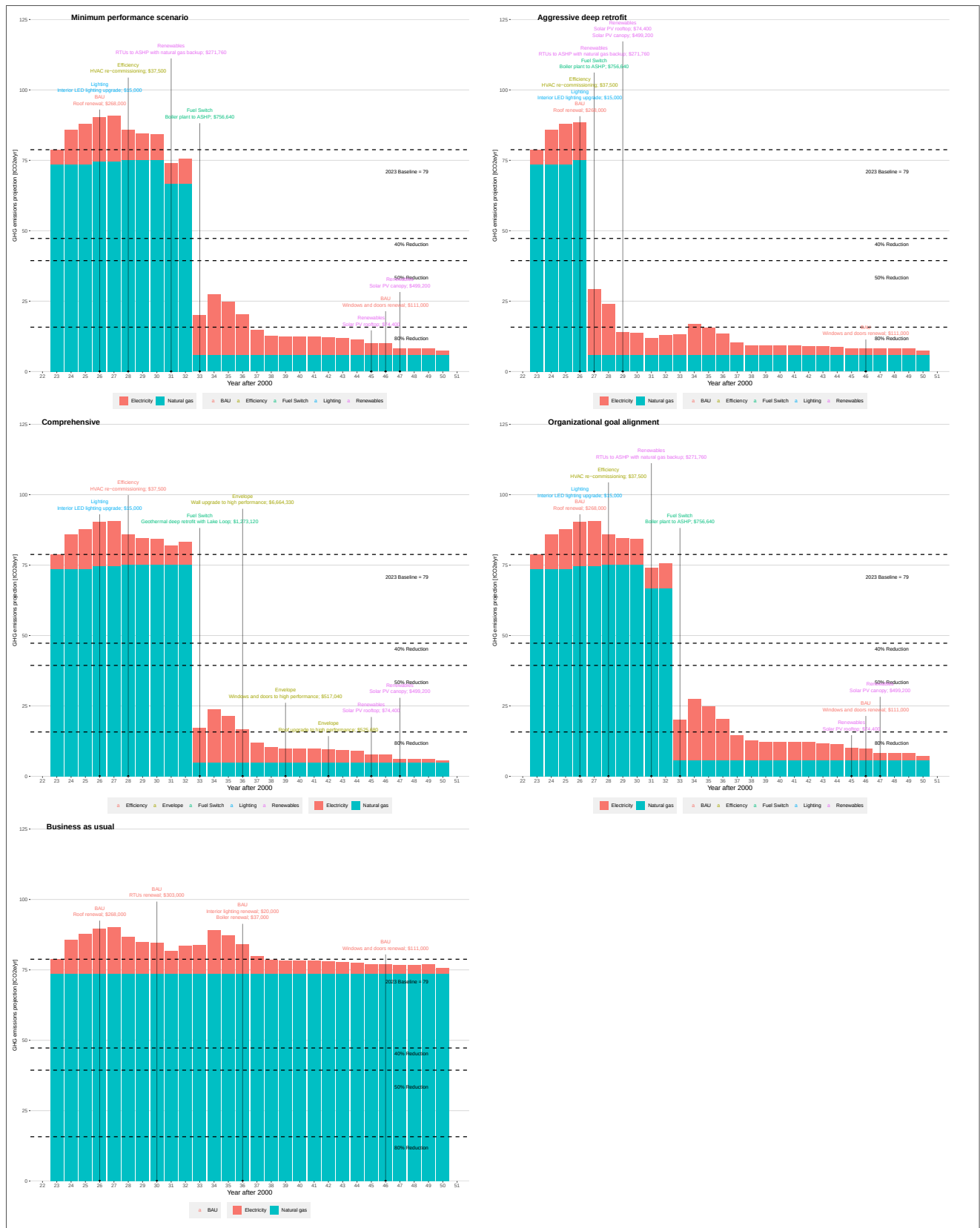


Figure 166: GHG yearly emissions projection for each scenario

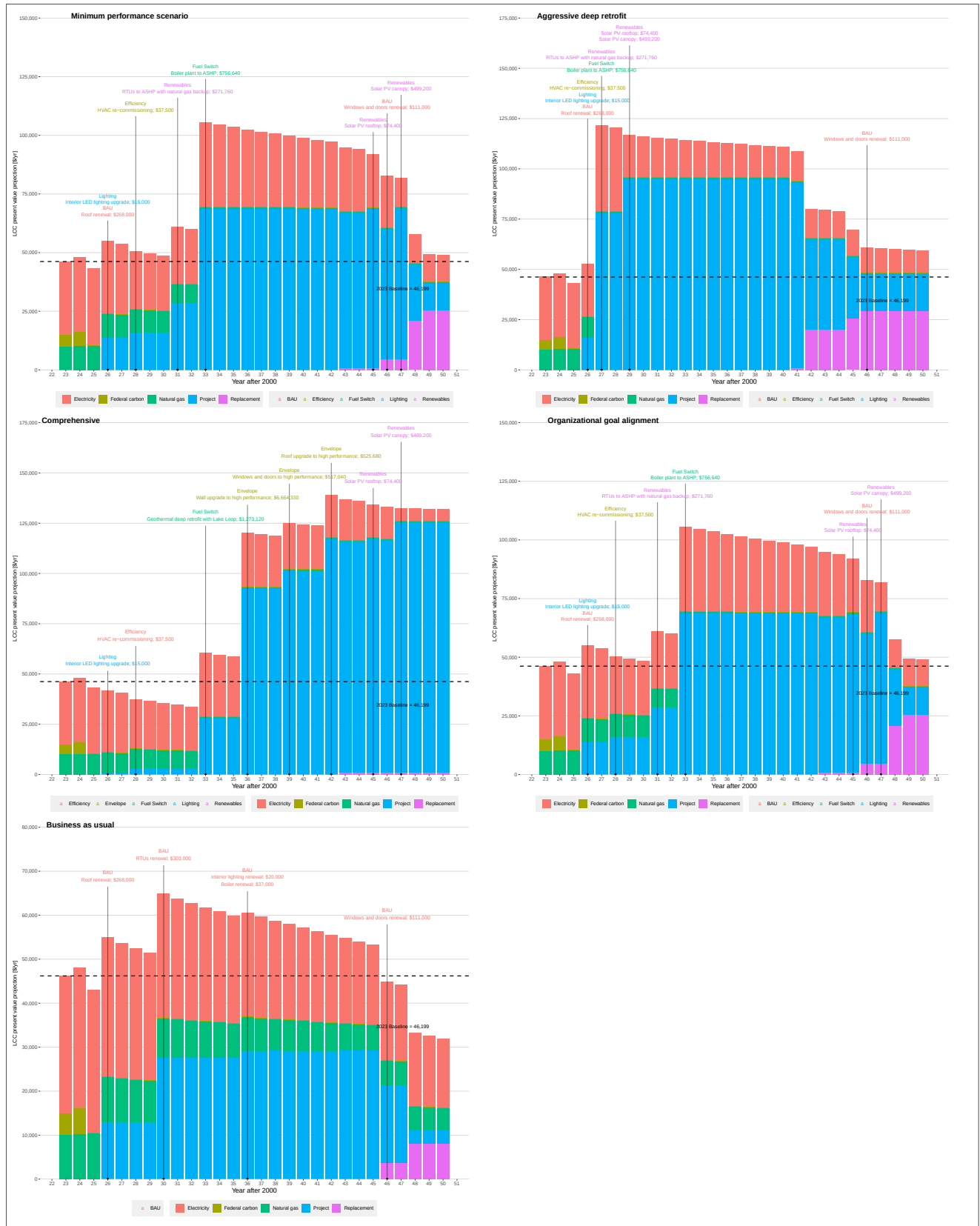


Figure 167: Life cycle yearly cost (after discounting to present value) projection for each scenario

6.7 Plan performance summary

Plan performance summary

Table 60 summarizes the performance of each plan scenario with respect to utility use, GHG emissions, utility cost, and financial metrics. The first half of Table 60 represents the estimated performance in the final year (2050) of the evaluation period. The second half of Table 60 represents the estimated cumulative performance across the entire evaluation period (present to 2050). All final year dollar values are in the value of today's currency. All cumulative dollar values presented in Table 60 are calculated as the simple sum of expenditures over the evaluation period, except for the life cycle cost, which is discounted to present value (as illustrated in Figure 167).

Table 60: Plan performance summary

Section	Description	Unit	Minimum performance scenario	Aggressive deep retrofit	Comprehensive	Organizational goal alignment	Business as usual
Utility use final	Electricity use	[kWh/yr]	158,404	158,404	83,364	158,404	219,381
	Electricity monthly peak (av)	[kW]	77.5	77.5	55.4	77.5	40.7
	Electricity yearly peak (max)	[kW]	114	114	86	114	48
	Natural gas use	[m3/yr]	2,996	2,996	2,473	2,996	38,054
GHG emissions final	Electricity GHGs	[tCO2e/yr]	1.5	1.5	0.8	1.5	2.1
	Natural gas GHGs	[tCO2e/yr]	5.8	5.8	4.8	5.8	73.5
	Carbon offsets GHGs	[tCO2e/yr]	0.00	0.00	0.00	0.00	0.00
	Total GHGs	[tCO2e/yr]	7.3	7.3	5.6	7.3	75.6
Utility cost final	Electricity utility cost	[\$/yr]	38,619	38,619	20,324	38,619	53,485
	Natural gas utility cost	[\$/yr]	1,356	1,356	1,119	1,356	17,223
	Carbon offsets utility cost	[\$/yr]	0.00	0.00	0.00	0.00	0.00
	Federal carbon charge	[\$/yr]	0.00	0.00	0.00	0.00	0.00
	Total utility cost	[\$/yr]	39,975	39,975	21,444	39,975	70,709
Utility use cumulative	Electricity use	[kWh]	6,882,257	4,937,544	5,667,049	6,882,257	6,142,665
	Natural gas use	[m3]	430,878	224,947	430,193	430,878	1,065,526
GHG emissions cumulative	Electricity GHGs	[tCO2e]	249	193	220	249	225
	Natural gas GHGs	[tCO2e]	833	435	831	833	2,059
	Carbon offsets GHGs	[tCO2e]	0.00	0.00	0.00	0.00	0.00
	Total GHGs	[tCO2e]	1,082	628	1,051	1,082	2,284
Utility cost cumulative	Electricity utility cost	[\$]	1,303,478	914,748	1,048,564	1,303,478	1,161,052
	Natural gas utility cost	[\$]	130,031	67,985	129,151	130,031	373,866
	Carbon offsets utility cost	[\$]	0.00	0.00	0.00	0.00	0.00
	Federal carbon charge	[\$]	10,663	10,663	10,663	10,663	10,663
	Total utility cost	[\$]	1,444,171	993,395	1,188,377	1,444,171	1,545,580
Financial cumulative	Project cost	[\$]	3,090,292	2,608,687	14,635,911	3,090,292	847,008
	Replacement cost	[\$]	1,260,155	1,154,769	38,147	1,260,155	442,000
	Life cycle cost	[\$]	2,128,660	2,514,555	2,516,665	2,128,660	1,478,467

6.8 Scenario analysis discussion

Baseline

- This scenario reflects existing conditions.

Minimum performance scenario

- To meet the FCM minimum performance scenario, significant capital retrofits would be required. Heating system electrification would be required.

Aggressive deep retrofit

- For the aggressive deep retrofit, the same measures as the minimum performance scenario need to be implemented, but on a shorter timeframe.

Organizational goal alignment

- To achieve the organizational goal alignment of 80% reduction in GHG emissions without carbon offsets, the heating systems must be electrified, although natural gas can be used as a backup heating source for RTUs.

Comprehensive

- The comprehensive scenario demonstrates the upper limit of energy-efficiency that City Hall could achieve, based on the measures that were analyzed under this Pathway to Decarbonization Feasibility Study.

7 END