Greenhouse Gas Accounting for Distributed Energy Resources:

The SPEEDIER Project in Parry Sound, Ontario

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Author Note

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Abstract

As electrical utility grids move to reduce their greenhouse gas (GHG) emissions, the generation, transmission, and distribution infrastructures required are evolving toward a more decentralized, data-driven network model called the “smart grid” (Energy Independence and Security Act of 2007, 2020). This new structure enables electricity to be produced closer to the point of consumption using many small-scale Distributed Energy Resources (DER), which involve technologies like photovoltaic (PV) solar, wind turbines, hydroelectric generators, and Battery Energy Storage Systems (BESS). A Local Distribution Company (LDC) in Parry Sound, Ontario, Canada has initiated a pilot project called SPEEDIER — Smart, Proactive, Enabled Energy Distribution – Intelligently, Efficiently and Responsive, that seeks to demonstrate the economic and environmental benefits of DERs. In order to assess the project’s GHG impacts, the proponent engaged with the author through Georgian College’s Research and Innovation department and Royal Roads University to apply a recognized GHG accounting and reporting standard as a framework. The GHG Protocol for Project Accounting (GHG Protocol, 2005), and the Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects (GHG Protocol, 2007) were followed, with additional guidance provided by the ISO 14064-2:2019 standard (ISO, 2019). Following

the processes contained within the frameworks revealed the somewhat nascent state of accounting for GHG impacts and the very nuanced analyses required to verifiably quantify the results without excessive assumptions and limitations. It is hoped that the lessons learned may help to advance the art and science of GHG accounting and reporting, while providing insight into how DERs and related technologies might support a more sustainable energy future.

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1.0 Introduction

While the connection between abrupt changes in global climate systems and human emissions from economic activity has been widely debated in political circles, the 5th Assessment Report (AR5) from the Intergovernmental Panel on Climate Change (IPCC, 2014) has been unequivocal on the topic:

> Anthropogenic greenhouse gas emissions have increased since the pre-industrial era, driven largely by economic and population growth, and are now higher than ever. This has led to atmospheric concentrations of carbon dioxide, methane and nitrous oxide that are unprecedented in at least the last 800,000 years. Their effects, together with those of other anthropogenic drivers, have been detected throughout the climate system and are extremely likely to have been the dominant cause of the observed warming since the mid-20th century. (p. 4)

As such, the central tenet of the landmark *Paris Agreement* (UN, 2015) was the reduction or elimination of greenhouse gases (GHG) with the intention of maintaining the "global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels" (p. 3). As a signatory, Canada has committed to "nationally determined contributions" (NDCs) (UN, 2015, p. 3) of GHG emission reductions consistent with the *Paris Agreement* targets. The Pan-Canadian Framework on Clean Growth and Climate Change (Environment and Climate Change Canada, 2016) notes that as "Canada transitions to a low-carbon future, energy will play an integral role in meeting our collective commitment" (p. 5). With electricity generation representing "Canada's fourth-largest source of GHG emissions," the framework approach includes generating more electricity from “renewable and low-emitting sources,” improving access to “clean power,” and “modernizing electricity systems” (Environment and Climate Change Canada, 2016, p. 11).

In order to ensure the *efficacy* of the above improvements to Canada’s electricity systems from a GHG perspective, it is critical that accurate *accounting* and *reporting* of the net impacts of emissions is conducted. Such quantifications are necessary to gauge how certain technologies or strategies are performing with respect to initial estimates or projections, and also to guide continuous improvement activities or course corrections. Furthermore, the “pricing of carbon, implemented through tax, trading or regulation” (Stern, 2006, p. VIII) has long been recognized as a legitimate policy measure that promotes emission mitigation activities, but this is only possible when GHG inventories are “complete, consistent, accurate and transparent” (GHG Protocol, 2004, p. 62). With such accounting and reporting standards in place, along with “polic[ies] to support innovation and the deployment of low-carbon technologies” (Stern, 2006, p. VII), electrical utilities can begin to sustainably develop our energy infrastructure in a way that contributes to Canada’s NDCs under the *Paris Agreement* in the form of “economy-wide absolute emission reduction targets.” (UN, 2015, p. 4).

One strategy to reduce GHG emissions from the electricity sector is to transition away from traditional *centralized* generation and transmission models towards Decentralized Energy Systems (DES) — infrastructure that often incorporates Renewable Energy Technologies (RET) — to provide “a clean and inherently resilient approach towards reaching sustainable development goals” (Adil & Ko, 2015, p. 1026).

A popular emerging DES is the *microgrid*, defined by the U.S. Department of Energy as "a group of interconnected load and distributed energy resources (DER) within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from grid, operate in grid-connected or island mode" (Ton & Smith, 2012, p. 84). The benefits of such an arrangement include: deploying renewable energy to reduce *peak loads* and *transmission and distribution losses* by locating generation closer to the consumer; improving grid reliability locally with demand-side management at the community level; and improving the stability of the larger primary grid by addressing the variability of renewables with stored energy (Ton & Smith, 2012, p. 84-85). Although Canada's electricity generation capacity is relatively low-carbon, with 67% being derived from renewable sources (National Resources Canada, 2020), renewable energy can continue to displace GHG-emitting electricity generation to contribute further to national emission targets.

Bracebridge Generation Ltd. — an electrical power generator serving communities in the districts of Muskoka and Parry Sound — has recently embarked on a pilot project with the Town of Parry Sound to reduce electricity demand and offset power generation and emissions from the primary grid. This system uses a collection of renewable energy, battery storage, and demand management technologies. The company is a subsidiary of Lakeland Holding Ltd. in Huntsville, Ontario, which also owns and operates Lakeland Power Distribution Ltd., and Lakeland Energy. The project, installed within part of the distribution network supplying the town of Parry Sound, Ontario, is a "Smart Grid Demonstration and Deployment Program" called SPEEDIER

— “Smart, Proactive, Enabled Energy Distribution – Intelligently, Efficiently and Responsive” (Lakeland Holding Ltd., 2018, p. 3). The demonstration consists of a 2.5 MWh utility-scale battery energy storage system (BESS), a 500 kW photovoltaic (PV) solar array, 50 residential load-control managed hot water tanks (HWT), one 50 kW DC fast-charge (DCFC) electric vehicle (EV) charging station, three 7 kW AC (level 2) EV charging stations, and ten 13.5 kWh residential energy storage system (RBESS) units, all of which are managed by a distributed energy resource management system (DERMS). The large BESS, the PV array, the residential RBESS units and some of the HWT are connected within a microgrid network that can be operated independently of the primary utility grid (Lakeland Holding Ltd., 2018). In a recent press release, project partner Natural Resources Canada (2019) proclaimed:

> This investment will increase electricity grid reliability, defer costly upgrades, make better use of existing assets, help speed the adoption of electric vehicles and give residents greater control over how they use energy. This project will help the community significantly reduce its greenhouse gas emissions by 2030 and create jobs in an innovative and transformative field. (para. 3)

The above benefits touted by Natural Resources Canada will be achieved through a number of project strategies: peak demand, voltage, and outage response with dispatchable power from PV and industrial BESS; improved reliability and resiliency with feeder level microgrid configuration; curtailment of demand with controllable HWT and residential RBESS; potential for increased adoption of EVs; and enhanced visibility, control, data storage, security, and system optimization via a DERMS (SPEEDIER, 2019). While most of the project attributes are tangible, quantifying the purported GHG benefits will require that appropriate accounting and reporting systems are designed and implemented to verify net emission reduction impacts of identified project activities.

2.0 Research Question and Objectives

The technical and economic benefits of the SPEEDIER project notwithstanding, this applied research attempted to assess the *net impact* of the SPEEDIER project in Parry Sound on the Ontario electrical grid GHG emissions profile. The research used the internationally recognized *GHG Protocol for Project Accounting* (GHG Protocol, 2005), along with the supplementary *Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects* (GHG Protocol, 2007) as frameworks to help inform and structure the GHG assessment and reporting activities involved with the project. The requirements of the ISO 14064-2:2019 standard (International Standards Organization [ISO], 2019) were also consulted for further guidance. This case study explored the process of applying the framework to support the government-funded pilot project, contributing to the experiential and practical knowledge of involved stakeholders. It was anticipated that the findings from this research might also contribute to the regulatory reporting required by proponents of the Natural Resources Canada Smart Grid Demonstration and Deployment Program (Canada, 2017). The interpretation and application of the frameworks proved both challenging and somewhat more involved than originally anticipated. The process of arriving at a justifiable baseline scenario revealed many assumptions and complexities within *each* of the project activities that required extensive investigation and research in order to be reconciled within the GHG accounting system, providing the project team with invaluable insight and knowledge.

3.0 Literature Review

In order to help guide the process of accounting for and reporting the emission reductions attributable to the SPEEDIER project, a search for recent documented attempts to implement popular GHG frameworks was conducted to possibly provide proponents with additional insight. The following section contains a brief review of the most prominent frameworks and standards written to support this type of work, comparing and contrasting their respective approaches, and a short discussion of comparable efforts to implement such programs to account for and report on the resulting GHG emissions impacts.

3.1 Internationally Recognized GHG Accounting and Reporting Standard and Framework Developers

Currently there are a few notable organizations offering GHG accounting and reporting programs that are prominent on the world stage. The Greenhouse Gas Protocol is the product of a twenty-year partnership between the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD). Established in 1997, they have been working together as an “NGO-business partnership to address standardized methods for GHG accounting” (GHG Protocol, n.d., para. 8). Since 2001, the institution has been publishing “comprehensive global standardized frameworks” for countries, cities, companies, and organizations “to measure and manage greenhouse gas (GHG) emissions from private and public sector operations, value chains and mitigation actions” (GHG Protocol, n.d., para. 1). Another player in this space is the International Standards Organization (ISO) — an international, non-governmental organization consisting of a “membership of 165 national standards bodies” (ISO, n.d., para. 1). The members collaborate to develop “voluntary, consensus-based, market relevant International Standards” designed to support efforts to address the world’s greatest challenges (ISO, n.d., para. 2). Lastly, there is “The Climate Registry” — formerly known as the California Climate Action Registry (CCAR) — which was a California state-mandated organization developed to develop “protocols to guide emissions inventories” and to manage emission reporting data (The Climate Registry, n.d., para. 4). The current entity is a non-profit organization administered by participating Canadian provinces and U.S. states that exists to help North American enterprises “measure, report, and verify their carbon footprints” (The Climate Registry, n.d., para. 1). It is worth noting that *The Climate Registry General Reporting Protocol* specifically cites both the *GHG Protocol Corporate Accounting and Reporting Standard* and *ISO 14064-1:2018* as sources of what it considers to be best practice with respect to GHG accounting and reporting (The Climate Registry, 2019). Such cross-platform references reveal that these standards and frameworks are not developed in isolation. While there are indeed other groups working to develop tools to measure and disclose GHG emissions, the above organizations are the most frequently cited. Putting aside for the moment the organizations that developed the above-mentioned programs, it is necessary to consider *what type of entity* or *emission reduction project* these frameworks were devised to support.

3.2 Differentiating GHG Program Scopes

It is important to recognize the different scope and scale involved in devising systems to quantify the GHG emissions impacts from different types of operations. For example, GHG Protocol offers guidance for corporations, products, value chains, jurisdictions (countries, states, and cities), policy making, and individual projects (GHG Protocol, n.d.). The ISO maintains a number of standards under the direction of technical committee TC 207/SC 7 for the purposes of “quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements” at the organization level, at the project level, for products, for the purposes of GHG validation or verification, for climate change mitigation activities, or for communities and local government (ISO, n.d.). The Climate Registry offers the *General Reporting Protocol* (with supplementary guidance for small businesses, transit agencies, and oil and gas production), alongside the *Electric Power Sector Protocol*, the *Local Government Operations Protocol*, and the *Water-Energy GHG Metrics* for water and wastewater operations (The Climate Registry, n.d.). The different types of frameworks offered by these three parties are understandably varied — assessing the GHG impacts of a product through a life cycle analysis (LCA) is clearly a different undertaking than determining the GHG emission impacts of a new government transportation policy change, for example. Furthermore, the needs of the various stakeholders may be reflected in the different types of GHG programmes that have been developed — a manufacturer looking to be added to an approved supplier list through compliance with an environmental management system will have decidedly different needs for a framework than an oil and gas company looking to verify and validate emission reductions to sell on the international carbon market. Irrespective of the needs of stakeholders, there appears to be several mature, well-developed frameworks for just about any GHG accounting and reporting requirement, with other programs currently in development (ISO, n.d.).

3.3 Examples of Documented GHG Program Implementations

In order to benefit from the lessons learned from other parties attempting to use a GHG accounting framework to quantify the GHG impacts of a similar type of project, a search of academic and grey literature was conducted. The hope was to find a case study that might document an earlier attempt to implement one of the aforementioned *project-level* frameworks. The inclusion criteria consisted of academic journal articles from 2007 to 2020 that sought to assess the GHG emissions from DES or DER projects. A cursory search trying to find studies focused on GHG accounting, GHG emissions, and renewable energy or microgrid-related terms, after 2007 (the publication date of the GHG Protocol supplemental guidance specifically targeting grid-connected electricity projects) was conducted in Google Scholar (Table 3.3-1). This revealed *very few* promising results. The search then continued, using database subscriptions provided by both the Georgian College and Royal Roads University libraries (Table 3.3-2).

Table 3.3-1

Search Parameters Used for Cursory Search in Google Scholar

Keyword String	Date Range	Number of Results	Relevant Resources
"GHG emissions" "assessment" "renewable energy" "DER" "smart grid" "net impact"	2007-2020	22	0
"GHG emissions" "assessment" "renewable energy" "DER" "microgrid" "net impact"	2007-2020	7	0
"DER" "GHG accounting" "microgrid"	2007-2020	7	2

While these searches also revealed a shortage of specific material of this type, there were a few interesting examples of meaningful efforts to assess existing or planned

Table 3.3-2

Search Parameters Used for Search in Library Databases

Keyword String	Number of Results
kw:(GHG) AND kw:(emissions) AND kw:(renewable energy) AND kw:(accounting)	1206
kw:(GHG) AND kw:(emissions) AND kw:(renewable energy) AND kw:(accounting) AND (yr:2007..2020)	1186
kw:(GHG) AND kw:(emissions) AND kw:(renewable energy) AND kw:(accounting) AND fc:(GHG Protocol) AND (yr:2007..2020)	100
kw:(GHG) AND kw:(emissions) AND kw:(renewable energy) AND kw:(accounting) AND kf:(transmission and distribution) AND (yr:2007..2020)	40
kf:(GHG emissions) AND kf:(assessment) AND kf:(renewable energy) AND	24

kf:(DER) AND kf:(smart grid) AND kf:(net impact) AND (yr:2007..2020)	
kf:(GHG emissions) AND kf:(assessment) AND kf:(renewable energy) AND kf:(DER) AND kf:(microgrid) AND kf:(net impact) AND (yr:2007..2020)	6

electrical assets that provided some amount of insight into the process.

Perhaps the most helpful study was a 2013 masters project report by Judy Lai entitled “Evaluating Avoided Carbon Emission Benefits at the Santa Rita Jail”. The paper detailed the process of calculating GHG reductions as a result of the reconfiguration of various DERs including solar PV module arrays, natural gas-powered fuel cells, and wind turbines into a true microgrid facility to offer more reliable power to the fifth largest jail in the United States. The project in Dublin, California was led by Chevron Energy Services. The initiative enabled the facility to avoid enough emissions between 2007 and 2011 to produce a savings of “between $116,000 and $177,000” using “California’s recent cap and trade allowance auction settlement prices” (Lai, 2013, p. IV). This performance from a GHG perspective was compared with a baseline GHG and fiscal assessment of emissions that would have been produced if the electricity produced on site would have been purchased from the local utility instead. The study described how it used a specific formula and procedure from “The Greenhouse Gas Protocol: Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects” to determine “avoided grid generation” (Lai, 2013, p. 14). While this part of the paper was helpful, a curious decision was made by project proponents to omit the GHG emissions from the natural gas-powered fuel cell generators. This was a significant limitation of the case study in the present context because when the fuel cells were in operation, they produced more than half of the jail's energy demand (Lai, 2013). Such emissions would be captured as a *secondary effect* from a project activity under The GHG Protocol for Project Accounting, and due to the scale of the emissions, would have had a significant impact on the final numbers. Limitations aside, this paper was helpful as it described a real-world application of some aspects of the GHG Protocol framework.

Another relevant finding was an intriguing paper entitled "The contribution of renewable distributed generation in mitigating carbon dioxide emissions" (Labis et al., 2011), which sought to compare the GHG cost differences between a number of capacity addition proposals designed to serve a small island utility in the Philippines. The authors compared the differences between laying a new submarine transmission cable, installing a small coal or diesel generator, or deploying an array of DERs. It was curious that although the "Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Workbook" (Labis et al., p. 4894) was cited due to a lack of more locally specific emission factors, *no formal framework or methodology* to determine an emissions baseline was referred to. While the analysis certainly followed a logical progression that was similar in structure to the GHG Protocol, The Climate Registry, and the ISO 14064 standards, there did not appear to be the same rigour with respect to the *emissions analysis* in particular. Perhaps this could have been attributed to the focus on the *financial* aspects of the various options being considered — as revealed by the detailed Net Present Value (NPV) data for CO_2 abatement captured in the study (Labis et al., p. 4895, table 1) among other compelling economic arguments. Lack of a documented framework for the quantification of GHG emissions aside, this concise analysis concluded that renewable energy technologies offer a significant technological, economic, and environmental advantage over a submarine transmission cable or fossil fuel-powered local generation alternatives.

A third paper entitled “Sustainable Energy Options for Austin Energy” documented the assessment of a carbon footprint for the electrical utility, Austin Energy, which explicitly declared its use of The Climate Registry’s “General Reporting Protocol” along with supplementary guidance from the “Power/Utility Protocol” (Eaton, 2009, p. 66). The utility was bound to the use of The Climate Registry framework, as the GHG accounting and reporting was required *as a component* of the larger city-wide emissions assessment work which employed the *General Reporting Protocol* (Eaton, 2009). The report described the defining of assessment boundaries, the quantifying of direct, indirect, and fugitive emissions, and the inclusion of six greenhouse gases of concern that are consistent with ISO 16064-2:2019 and the GHG Protocol standards (CH_4, N_2O, SF_6, PFCs, and HFCs). Notably, the author of the report lamented that the GHG accounting and reporting frameworks “are silent as to whether an electric utility should calculate so-called life-cycle emissions” (Eaton, 2009, p 64), a source of confusion experienced also by project proponents of the present case study of the SPEEDIER project with respect to the manufacture, transport, deployment, and decommissioning of a number of new DERs.

3.4 Literature Review Closing Remarks

While the above studies offered some helpful insight into the effort to qualify and quantify the GHG impacts of their grid-connected project activities, the assessment of the emissions specifically were somewhat anecdotal, and did not offer a systematic review of how a particular GHG program was implemented. In defence of the cited studies, much of the documentation produced in the course of their respective assessments may have consisted of internal records that were inappropriate for public consumption. As such, the present study proceeded undeterred, resolving to rely heavily on guidance from the GHG Protocol programs and the ISO 14064-2:2019 standard, along with support from various project stakeholders and participants.

4.0 Methods

This research paper represents an *exploratory case study* of an application of the GHG Protocol accounting and reporting frameworks as they were used to assess the GHG emission reduction potential of the SPEEDIER project in Parry Sound, Ontario. The process involved the collaboration of the Local Distribution Company (LDC), Lakeland Holding Ltd., the Research and Innovation department of Georgian College, Natural Resources Canada, and the Town of Parry Sound. The case study followed "The GHG Protocol for Project Accounting" (GHG Protocol, 2005), with sector-specific guidance from "Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects" (GHG Protocol, 2007), developed collaboratively by the World Resources Institute (WRI) and the World Business Council for Sustainable

Development (WBCSD). Additional guidance was sought from “ISO 14064-2:2019 Greenhouse gases — Part 2: Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements” (ISO, 2019) where appropriate.

5.0 Results

The following section represents a systematic review of the implementation of the various steps required to define the GHG assessment boundary, identify project activities, determine build margin (BM) and operating margin (OM) effects, and establish GHG baseline scenarios for the various project activities that comprised the SPEEDIER project.

5.1 Establishing the GHG Assessment Boundary

The process of accounting for GHG began with delineating the various “project activities” (GHG Protocol, 2007, p. 26) to be included in the GHG assessment and reporting system. This foundational step also included the identification of primary (intended) and secondary (unintended) effects, plus any one-time impacts caused by the deployment and operation of project assets or activities (GHG Protocol, 2007, p. 27). Each of the project activities are accounted for in Table 5.1-1, which features technical details for each project activity and their respective primary and secondary

Table 5.1-1

Project Activities Comprising the Assessment Boundary, with Primary and Secondary Effects

Project Activity	Details	Primary Effect	Secondary Effect(s)
Utility-Scale Battery Energy Storage System (GBESS)	1257 kW / 1260 kVA / 2514 kWh 2-hour standard Tesla Megapack	Reduce combustion emissions from grid-connected power plants	Extraction of raw materials, manufacturing, transport, site preparations, installation, and decommissioning of BESS. Possible fugitive emissions from utility electrical components
Photovoltaic (PV) Solar Array	500 kW AC	Reduce combustion emissions from grid-connected power plants	Extraction of raw materials, manufacturing, transport, site preparations, installation, and decommissioning of PV modules and associated equipment. Possible fugitive emissions from utility electrical components
Load-Control Managed Hot Water Tanks (HWT)	40/60 gallon - 50 units	Reduce combustion emissions from grid-connected power plants	Extraction of raw materials, manufacturing, transport, installation, and decommissioning of HWT units
Electric Vehicle (EV) DCFC Public Charging Station	50 kW DC Fast Charger (DCFC) - 1 unit	Displace the consumption of GHG-emitting fuels used for transportation (these emissions may be outside of the assessment boundary, however)	Increased demand on the electrical grid. Extraction of raw materials, manufacturing, transport, site preparations, installation, and decommissioning of DCFC charging station and associated equipment
Electric Vehicle (EV) L2 Residential Charging Stations	7 kW AC Level 2 Chargers (L2) - 3 units	Displace the consumption of GHG-emitting fuels used for transportation (these emissions may be outside of the assessment boundary, however)	Increase demand on electrical grid. Extraction of raw materials, manufacturing, transport, site preparations, installation, and decommissioning of L2 charging station and associated equipment
Residential Battery Energy Storage Systems (RBESS)	5 kW / 13.5 kWh Tesla Powerwall - 10 units	Reduce combustion emissions from grid-connected power plants	Extraction of raw materials, manufacturing, transport, installation, and decommissioning of RBESS

effects. Lakeland Holding Ltd. provided a schematic diagram illustrating the SPEEDIER project components and how they were configured within the local distribution system in Parry Sound (Figure 5.1-1). All of the project activities listed in Table 5.1-1 can be

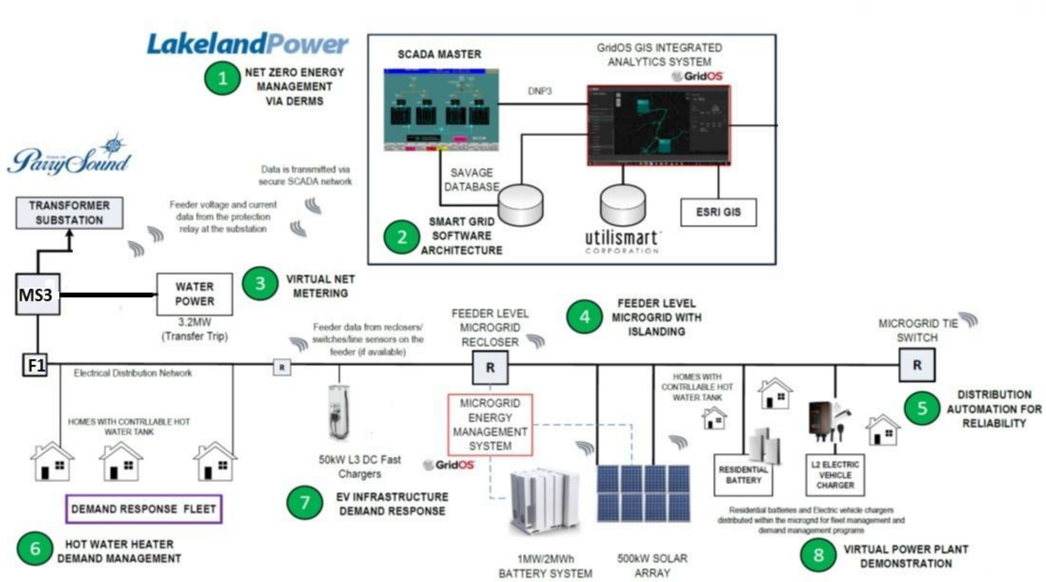

Figure 5.1-1. SPEEDIER project components. Used with permission (Lakeland Holding Ltd., n.d.).

located in Figure 5.1-1, along with the DERMS, the microgrid boundary, connections to the transformer station (TS), the local hydroelectric power plant, and the feeder connecting the various components inside the local distribution network. It was these mutually agreed-upon project activities that formed the basis of the analysis for the construction of a baseline emissions scenario, and the subsequent emission reduction estimates.

5.2 Determining the Extent of Build Margin and Operating Margin Effects

In the absence of the SPEEDIER project, the additional capacity that the initiative was planned to provide would otherwise have needed to be delivered from the construction of additional generation and transmission infrastructure. To what degree the project will impact decisions to build out new capacity needed to be assessed, which is referred to as the Build Margin (BM) effect (GHG Protocol, 2007, p. 13). The deployment of DER within SPEEDIER may also displace production from *existing* generation and transmission operations. The impact of new generation or electricity consumption reduction activities on current grid capacity is known as the Operating Margin (OM) effect and also needed to be quantified (GHG Protocol, 2007, p. 13). The respective impacts of *each project activity* on both the BM and OM effects needed to be determined in order to establish a factor for calculating each individual emission baseline (GHG Protocol, 2007, p. 30). Each project activity was carefully evaluated for their relative impact on the BM and OM effects using an algorithm provided by the GHG Protocol framework (Figure 5.2-1). These impacts were determined by deciding *first* whether there existed a demand for additional electrical energy capacity within the assessment boundary. Secondly, it needed to be determined whether the project activity met any new capacity needs. Thirdly, the quantity and type of any additional capacity (if applicable) needed to be determined, resulting ultimately in a factor for the BM impact (w), as a number from 0-1, with the difference representing the effect on the OM. The first two of the above steps were determined to be common to all project activities, and therefore needed to be addressed first.

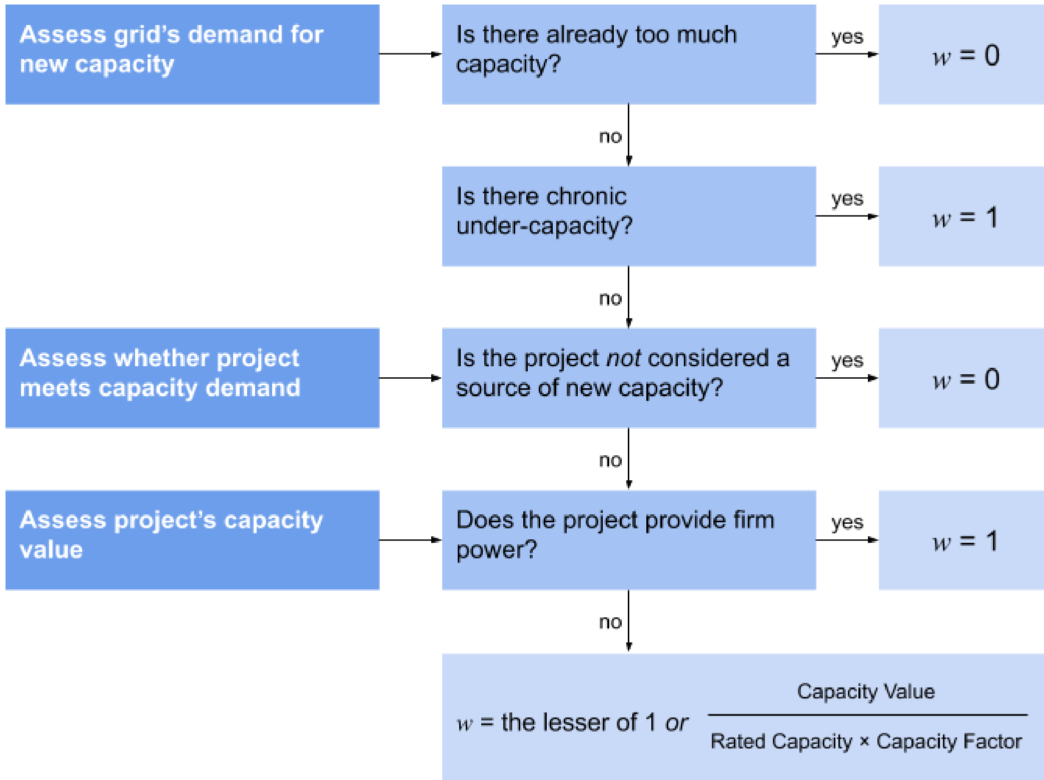

Figure 5.2-1. Flowchart detailing the process for determining an appropriate weight to the BM. Adapted from "Guidelines for Grid-Connected Electricity Projects," GHG Protocol, 2007, p. 31.

The Ontario Ministry of Energy's 2017 Long Term Energy Plan (LTEP) noted that the IESO was working with the local distribution company in Parry Sound-Muskoka "to determine whether targeted conservation initiatives [could] defer costly upgrades to specific local distribution and transmission infrastructure" (Ministry of Energy, 2017, p. 140). The impetus for the SPEEDIER project was the need to address increasing demand in Parry Sound that was constrained by a TS that was "overloaded, and [where] aging infrastructure [was] apparent" (Lakeland Holding Ltd., 2018, p. 5). This TS connected the community to the 230kV subsystem (Figure 5.2-2) of the

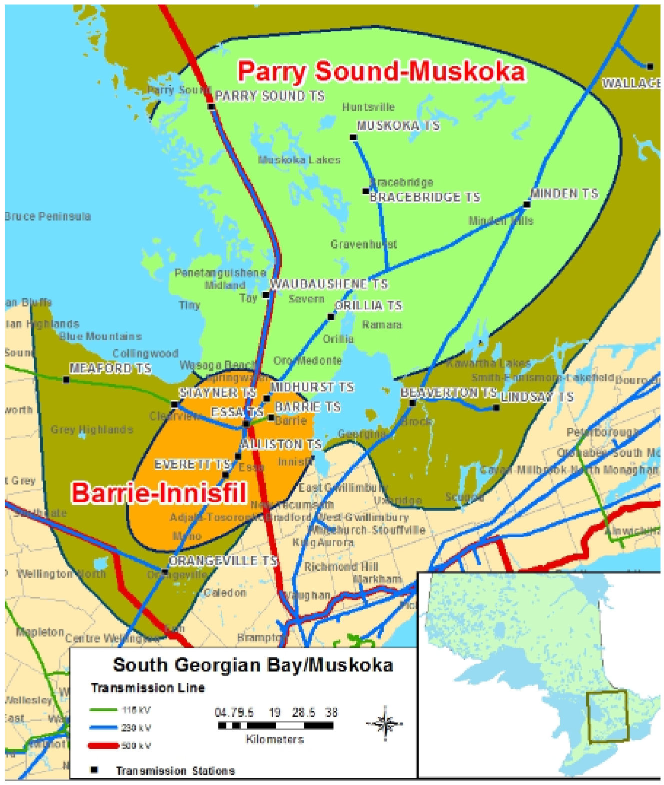

Figure 5.2-2. South Georgian Bay/Muskoka Region transmission network (Hydro One, 2017, p. 12).

provincial grid (Lakeland Holding Ltd., 2018). With the community's location on the bedrock of the Canadian Shield, development of natural gas infrastructure represented a significant challenge, meaning that growth in the area would rely heavily on electricity for energy needs (Community Futures Ontario, 2011). So while demand for capacity was growing in Parry Sound, due to the TS constraint, the area did not have adequate access to the provincial grid, which on average generated an annual net import-export surplus of 13.32 TWh over the last five years preceding this study (IESO, n.d.). Following the algorithm provided by GHG Protocol (Figure 5.2-1), while it was determined that there was indeed too much capacity on the grid, the *access* to this capacity was *inadequate*. Furthermore, as the IESO indicated that while there were indeed *imports* of energy into the grid — much larger exports notwithstanding — there were times when grid capacity could not fully address demand. As such, the answer to the first question was reasonably determined to be “no.” The second question inquired whether there was “chronic under-capacity” (Figure 5.2-1) — which from a *transmission* perspective might have been true in Parry Sound, but from a regional *generation* standpoint was *not*. Since the focus with the BM was the potential displacement of “power plant (or plants) that would have been built to meet demand for new capacity” (GHG Protocol, 2007, p. 88), it seemed that the answer to the second question might also have been “no.” Subsequent questions posed by the flowchart then needed to be determined for *each* project activity, which will be individually addressed next.

5.2.1 PV solar array.

The next step was to determine whether the 500 kW photovoltaic (PV) solar array would “[meet] capacity demand.” (GHG Protocol, 2007, Figure 5.1, p. 31). To make this determination, the framework flowchart (Figure 5.2-1) required the team to determine whether the project activity is *not* considered a source of additional capacity. As the PV solar array’s function is to generate additional electricity, the answer here was “no.” The assessment then proceeded to the determination of the *capacity value*, which is decided based on whether the project activity provides *firm* or *non-firm* generation. “Firm” capacity is defined by the framework as “power capacity that is reliably available, and is not intermittent or unpredictable” (GHG Protocol, 2007, p. 81). Renewable energy technologies like PV solar “cannot be consistently relied on when power is needed on the grid” (GHG Protocol, 2007, p. 81) and are classified therefore as “non-firm” with respect to their capacity. At this stage, the final step for determining the respective impact of the BM and the OM was to determine the value for w using the formula in Figure 5.2.1 (which represents the weight of the effect on the BM). The resulting value for the BM

$$w = min\left(1, \frac{CAP_{value}}{CAP_{rated} \cdot CF}\right)$$

Figure 5.2.1. Formula for assigning a weight value to the BM effect (w) (GHG Protocol, 2007).

would be the minimum of either 1, or the capacity value (CAP_{value}) divided by the product of the rated capacity (CAP_{rated}) and the capacity factor (CF). The *capacity value* is the power (in megawatts or MW) that can be reliably dispatched during times of peak demand. The *rated capacity* (sometimes called the *nameplate* capacity) is the maximum power output that the facility is capable of delivering under ideal conditions. The *capacity factor* is a “ratio of the net electricity generated, for the time considered, to the energy that could have been generated at continuous full-power operation during the same period” (U.S.NRC, 2020). The capacity value was conservatively assigned 0 MW, as peak demand in Parry Sound occurs in December (Lakeland Holding Ltd., 2018), when solar irradiance is at its lowest point in the year, and it is possible that there may be ice or snow covering the panels during this time. The rated capacity for the SPEEDIER PV solar module array is 0.5 MW (RESCo Energy Inc., 2020). A 2018 report by the Canadian Energy Research Institute suggested that the capacity factor value for a fixed (non-tracking) PV solar array located at the same latitude as Parry Sound would equate to a 37% summer utilization, and a 2.5% winter utilization (Doluweer et al., 2018, p. 49). Coincidentally, the mean of these two seasonal values (19.75%) was consistent with both the National Renewable Energy Laboratory (NREL) and the U.S. Department of Energy figures (NREL, n.d.). The project vendor's own performance simulations for the array produced a slightly more conservative value of 17.82% — predicting an annual generation of 780.59 MWh from a possible *theoretical* maximum of 4,380 MWh (RESCo Energy Inc., 2020). Using the formula in Figure 5.2.1 above, the value for the BM (w) therefore amounted to zero, leaving 100% of the weighted effect of the PV solar array's capacity to the OM (Table 5.2.1).

Table 5.2.1

Calculation of the Effect on the BM for the PV Solar Array Project Activity

Project Activity	Capacity Value (MW)	Rated Capacity (MW)	Capacity Factor	Assigned Weight for BM (w)
PV Solar Array	0	0.5	17.82%	0

5.2.2 Utility-scale (grid) battery energy storage system (GBESS).

Having already determined that the provincial grid did *not have too much capacity*, and also that there was *no chronic under-capacity* (see Section 5.2), the next step was to determine whether the 1.2645 MWh GBESS (Tesla Megapack) would meet capacity demand (Figure 5.2-1). While it was recognized that the GBESS project activity did *not* represent an additional source of power generation, it was decided, however that it *did* represent new capacity to deploy additional energy to the grid when required. Such facilities are deployed by utilities primarily to collect energy "from the grid or a power plant and then [to discharge] that energy at a later time to provide electricity or other grid services when needed" (Bowen et al., 2019, p. 1) — in effect *enabling* the alignment of variable capacity resources like PV solar with periods of high demand. Since the GBESS was therefore to be treated as a source of additional capacity, the next question to be answered was whether the project provided firm power (Figure 5.2-1). According to the International Renewable Energy Agency, utility-scale batteries represent "capacity firming" assets for solar PV and wind generators (IRENA, 2019, p. 9). As such, the GBESS project activity was characterized as a provider of firm power, meaning its marginal impact would be assigned entirely to the BM effect (w = 1).

For the sake of comprehensiveness, the *capacity value*, *rated capacity*, and *capacity factor* for the project activity were calculated notwithstanding (Table 5.2.2). Research by Xavier et al. (2019) described a similar configuration to the SPEEDIER GBESS with an associated 1.6% power loss, which permitted an estimation for its *capacity value*, based on the *rated capacity* of the resource at 1.257 MW (Lakeland

Holding Ltd., 2018). The *capacity factor* — representing the availability of the resource over a period of time — was unclear due to the undetermined (as of the time of writing) length of charging time required after a full discharge.

Table 5.2.2

Calculation of the Effect on the BM for the Utility-Scale GBESS

Project Activity	Capacity Value (MW)	Rated Capacity (MW)	Capacity Factor	Assigned Weight for BM (w)
Utility-Scale Batteries (BESS)	1.236888	1.257	undetermined	1

5.2.3 Residential battery energy storage systems (RBESS).

As with the Utility-Scale BESS, this particular project activity was also determined to be a source of additional capacity, affording the utility a fleet of energy storage devices, which when aggregated would function as a single asset that would better align grid capacity with local demand. The RBESS fleet, comprising ten 13.5 kWh Tesla Powerwall units managed by the DERMS (Lakeland Holding Ltd., 2018), was to provide capacity *firming* capabilities (IRENA, 2019) to the local distribution company (LDC) for the PV solar array (among other benefits). This characteristic, according to the GHG Protocol (Figure 5.2-1), would result in a value of *one* for its BM margin effect (w = 1). While not technically required to determine this project activity's marginal impact on the BM or the OM, the *capacity value*, *rated capacity*, and *capacity factor* for the RBESS is also presented here for comprehensiveness (Table 5.2.3). Similarly to the BESS, a 1.6% power loss was applied to the rated capacity in order to derive a plausible and justifiable capacity value (Xavier et al., 2019).

Table 5.2.3

Calculation of the Effect on the BM for the RBESS

Project Activity	Capacity Value (MW)	Rated Capacity (MW)	Capacity Factor	Assigned Weight for BM (w)
Residential Batteries (RBESS)	0.0492	0.05	undetermined	1

5.2.4 Load-control managed hot water tanks (HWT).

The HWT demand control project activity was unlike an efficiency optimization in that there was a limit to the potential reductions in demand that could be called upon at times of peak load. One or more of the HWT fleet could not be paused *indefinitely* as participating households would at some point require access to hot water. While the supplier that provided the HWTs and demand-management hardware and software were able to provide some aggregated performance data for a similar type of fleet in a load-control managed application (Packetized Energy, 2020), the construction of an energy model specific for the SPEEDIER fleet was not practical due to the complicated nature of the system, the lack of experimental controls, and the scarcity of resources available for such an effort. As a result, "determining a precise capacity value and/or expected capacity factor [was] not practical" (GHG Protocol, 2007, p. 33, Table 5-1). The *rated capacity* of the HWT fleet could be calculated however, using procurement documentation which described 50 units (with either a 184 L or 279 L tank), each equipped with a 3,000 watt heater element — equating to a theoretical 0.15 MW of demand reduction potential. While a lack of specifications and energy performance modelling confounded the team's effort to characterize this particular project activity, the *Guidelines for Grid-Connected Electricity Projects* helped to clarify the situation by noting that "[m]any (if not most) electricity reduction project activities will involve elements of predictability and unpredictability, analogous to both firm and non-firm power generation" (GHG Protocol, 2007, p. 33, Box 5.2). Considering the fact that there were controls available to participating residents that permitted the *override* of demand management control by the LDC (Lakeland Holding Ltd., 2018), and that hot water *availability* would likely have taken precedence over the utility's load reduction needs, it was reasonably concluded that the resource provided readily available (firm) capacity, but within operational parameters. For these reasons, it was decided that it would be both reasonable and conservative to assess this project activity as a provider of "[o]n-peak, baseload, or intermittent generation" with a low *capacity value*, resulting in an *equal weight* (Table 5.2.4) for its effect on both the BM (w) and the OM (GHG Protocol, 2007, p. 33, Table 5-1).

Table 5.2.4

Calculation of the Effect on the BM for the Load-Control Managed HWT Project Activity

Project Activity	Capacity Value (MW)	Rated Capacity (MW)	Capacity Factor	Assigned Weight for BM (w)
Load-Control Managed HWT	Undetermined	0.15	Undetermined	0.5

5.2.5 Electric vehicle (EV) DCFC public charging station.

Since the DCFC public charging station did not represent a source of additional generation capacity, but rather an *additional demand* on the local distribution system, it was determined that its effect would be limited solely to the OM, and the value for w should be set to *zero* (GHG Protocol, 2007, p. 31). For the sake of comprehensiveness, the *capacity value*, *rated capacity*, and *capacity factor* are presented herein (Table 5.2.5), albeit with negative values. While the specifications for the charging hardware were readily available, it was quickly realized that obtaining an accurate capacity factor would be a challenge. A recent white paper from The International Council on Clean Transportation attributed the inherent difficulty with forecasting EV charging network usage patterns to the fact that within the "rapidly evolving charging infrastructure industry, availability and access to accurate, up-to-date data can be limited in various markets" (Hall & Lutsey, 2017, p. 5). The project team found that Parry Sound, Ontario was no exception. Thankfully, a thorough economic analysis by the Rocky Mountain Institute proposed that a conservative 5% utilization rate could be used in the absence of any detailed consumer behavior modelling or data (Fitzgerald & Nelder, 2020), which was decided to be appropriate for the purposes of this part of the GHG analysis.

Table 5.2.5

Calculation of the Effect on the BM for the DCFC Public EV Charging Station

Project Activity	Capacity Value (MW)	Rated Capacity (MW)	Capacity Factor	Assigned Weight for BM (w)
DCFC Public EV Charging Station	0.045	0.05	5%	0

5.2.6 Electric vehicle (EV) L2 public charging stations.

As was the case with the public DCFC charging station, it was determined that the residential chargers as a group represented *additional load* on the electrical network, and as such, the framework was unambivalent in assigning such project activities with a value of *zero* for the BM effect (w = 0). While the fleet of 3 charging stations would be configured to support demand management features (Lakeland Holding Ltd., 2018), it was decided that this impact would not have a material impact on local demand, and therefore did not represent an energy-reduction activity. While the rated capacity was available for the three L2 charger units (7 kW AC) (Lakeland Holding Ltd., 2018), an efficiency rate that might account for any system losses was not available at the time of writing, rendering the capacity value *undetermined* (Table 5.2.6).

As was the case with the prior DCFC charging project activity, a conservative 5% utilization rate was also assumed (capacity factor).

Table 5.2.6

Calculation of the Effect on the BM for the L2 Residential EV Charging Stations

Project Activity	Capacity Value (MW)	Rated Capacity (MW)	Capacity Factor	Assigned Weight for BM (w)
L2 Residential EV Charging Stations	undetermined	0.021	5%	0

5.2.7 Assigned BM and OM weights.

As a result of the above assessments, each project activity was assigned a factor that represented the weighted effect of the resource on decisions that grid operators would likely make in the *absence* of each project activity, with respect to the construction of new generation sources or the operation of the current portfolio of energy assets. These weight factors (Table 5.2.7) represented the extent of BM and OM effects for the SPEEDIER project and would not need to change during the timeframe for GHG impact assessment (GHG Protocol, 2007). As a result of these analyses, it was concluded that *only* the load-control managed HWT project activity required the calculation of a BM emissions scenario. It was also concluded, however, that the *other* project activities might *also* require the identification of baseline candidates in order to demonstrate that the activities themselves did not represent "common practice," thereby satisfying the framework's requirement for *additionality* (GHG Protocol, 2007, p. 35, Box 6.1).

Table 5.2.7

Calculation of the Effect on the BM for the SPEEDIER Project Activities

Project Activity	Capacity Value (MW)	Rated Capacity (MW)	Capacity Factor	Assigned Weight for BM (w)	Assigned Weight for OM
PV Solar Array	0	0.5	19.75%	0	1
Utility-Scale GBESS	1.236888	1.257	undetermined	1	0
Load-Control Managed HWT	undetermined	0.15	undetermined	0.5	0.5
Residential Batteries (RBESS)	0.0492	0.05	undetermined	1	0
DCFC Public EV Charging Station (1)	0.045	0.05	5%	0	1
Level 2 Public EV Charging Stations (3)	undetermined	0.021	5%	0	1

5.3 Establishing a Method to Estimate Build Margin Emissions

The GHG Protocol for Project Accounting offers three different options to quantify the impact that the construction of new capacity would entail in the absence of an initiative like SPEEDIER (GHG Protocol, 2007). The first option is the project-specific procedure, where a single type of generation facility is identified to represent the BM. The second approach is the selection of a “conservative ‘proxy-plant’” (GHG Protocol, 2007, p. 35), which would be the lowest GHG-emitting baseline candidate. The third option consists of establishing a “blended emission rate” of suitable baseline candidates (GHG Protocol, 2007, p. 35), which can be applied to specific project activities or to the initiative as a whole. Since SPEEDIER was a *pilot* project, a significant part of the value obtained from the GHG accounting and reporting component was derived from the assessment of the emissions impact of *each* of the project activities in a disaggregated format, so that the effects could be better understood when applied *at scale*. Ultimately, it was decided that the most appropriate method to use — with due regard to the principles of relevance, consistency, transparency, accuracy, and conservativeness (GHG Protocol, 2007) was the determination of an appropriately blended rate of emissions using a number of carefully selected “representative type[s] of baseline candidate[s]” (GHG Protocol, 2007, p. 43).

As the PV solar array and the EV chargers only affected the OM (w = 0), they did not require an estimation of BM emissions (GHG Protocol, 2007, p. 35, Box 6.1). The BESS, the RBESS and the demand-response HWT fleet project activities however, required a thorough assessment of their proportional effects on the BM, and as such needed a justifiable baseline emissions scenario to be developed and defended.

5.4 Identifying Baseline Candidates for the Build Margin

In order to effectively establish a likely scenario that would have played out in the absence of the SPEEDIER project, infrastructure was required to be described that would represent “new capacity that might have been built in place of the project activity to provide the same generation” (GHG Protocol, 2007, p. 36). The procedure for each applicable project activity is detailed in Figure 5.4. Step one involved defining the

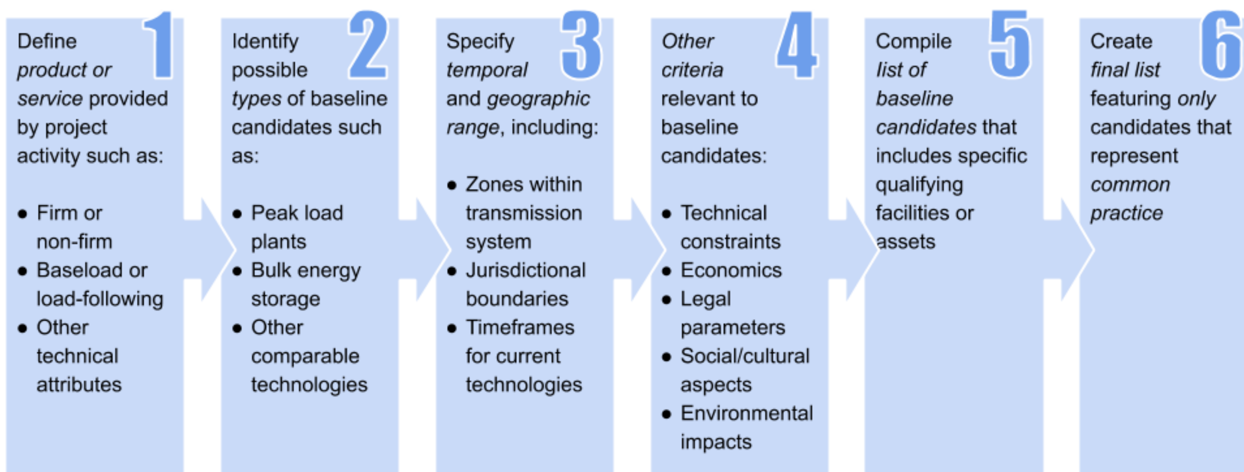

Figure 5.4. Steps involved in the production of a final list of baseline candidates for the BM. Adapted from Chapter 7 of “Guidelines for Grid-Connected Electricity Projects” (GHG Protocol, 2007).

product or service provided by the project activity, specifically the nature of the asset’s capacity, being firm or non-firm, baseload or load-following, and any other relevant characteristics. The next step was the identification of possible *types* of baseline candidates — comparable technologies that could provide equivalent services to the electrical grid, such as peak load power plants or bulk energy storage mechanisms. Thirdly, the *temporal and geographic range* needed to be specified, specifically focusing on physical regions of the transmission system where recent capacity has been or is likely to be added, within timeframes that facilities representative of current technology have been deployed. Next, due consideration needed to be given to other selection criteria that may apply to possible baseline candidates, such as relevant technical, legal, political, economic, environmental or social limitations that may preclude a prospect's inclusion. The fifth step was the compilation of a list of baseline candidates that named specific facilities or assets that satisfied the above criteria. To conclude, a final list was then produced that only included candidates that represented *common practice*. This excluded facilities that represented pilot projects or demonstrations, in favour of business-as-usual (BAU) developments or deployments.

5.4.1 Define the product or service provided.

Of the project activities that represented additional capacity, they were to function either as *baseload*, where they would operate "continuously (or nearly continuously) to meet base levels of power demand that [could] be expected regardless of the time of day or year" (GHG Protocol, 2007, p. 88), or as *load-following* services "whose output varies in response to fluctuations in load, and which [would operate] when generation is needed during times of peak demand" (GHG Protocol, 2007, p. 88). In addition, each activity's capacity needed to be characterized as either *firm*, where it could be

Table 5.4.1

Description of the Service Provided by Each SPEEDIER Project Activity

Project Activity	Function (baseload / load-following)	Character (firm / non-firm)	Details
Load-Control Managed HWT	load-following	firm	dispatchable, demand-response load reduction
PV Solar Array	baseload	non-firm	non-dispatchable, intermittent, variable generation
Residential Batteries (RBESS)	load-following	firm	dispatchable, load-matching, duration-constrained capacity
Utility-Scale GBESS	load-following	firm	dispatchable, load-matching, duration-constrained capacity

“consistently relied on when power is needed on the grid” (natural-gas fired generators, for example) or *non-firm*, where such activity could *not* be relied upon during periods of high demand, as is the case with renewable energy technologies (like wind turbines) which are intermittent by nature (GHG Protocol, 2007, p. 89). Table 5.4.1 classifies each of the SPEEDIER project activities accordingly (excluding the EV chargers as they did not represent a source of additional capacity). It was also noted that for the purposes of selecting baseline candidates, “electricity reduction and generation project activities [could] be treated analogously” (GHG Protocol, 2007, p. 19).

5.4.2 Identify types of baseline candidates.

With the SPEEDIER project activities then grouped into two categories (*firm, load-following* and *non-firm, baseload*), baseline candidates were then classified as either one of two types of facilities: *non-dispatchable*, *intermittent*, *variable* generation where capacity could not be reliably called upon during times of high demand; or *dispatchable*, *load-matching*, *duration-constrained* capacity where power could be called upon to respond to changes in demand, but where the amount of energy might be limited.

5.4.3 Specify geographic and temporal range.

In order to qualify as feasible baseline candidates, facilities of the previously mentioned types would need to be located either within the IESO-controlled transmission zone that serves the SPEEDIER assessment boundary area, or in adjacent grid-interconnected zones capable of supplying additional capacity when needed. Such facilities would and also have to exemplify reasonably recent technologies. The IESO transmission zone serving Parry Sound is called Essa, a load-constrained part of the Ontario grid (IESO, n.d.) which features connection interfaces with the *Northwest*, *Southeast*, and *Toronto* zones (Figure 5.4.3). There are three interfacing connection points; the Claireville North (CLAN) transfer, Flow East Towards Toronto (FETT) transfer,

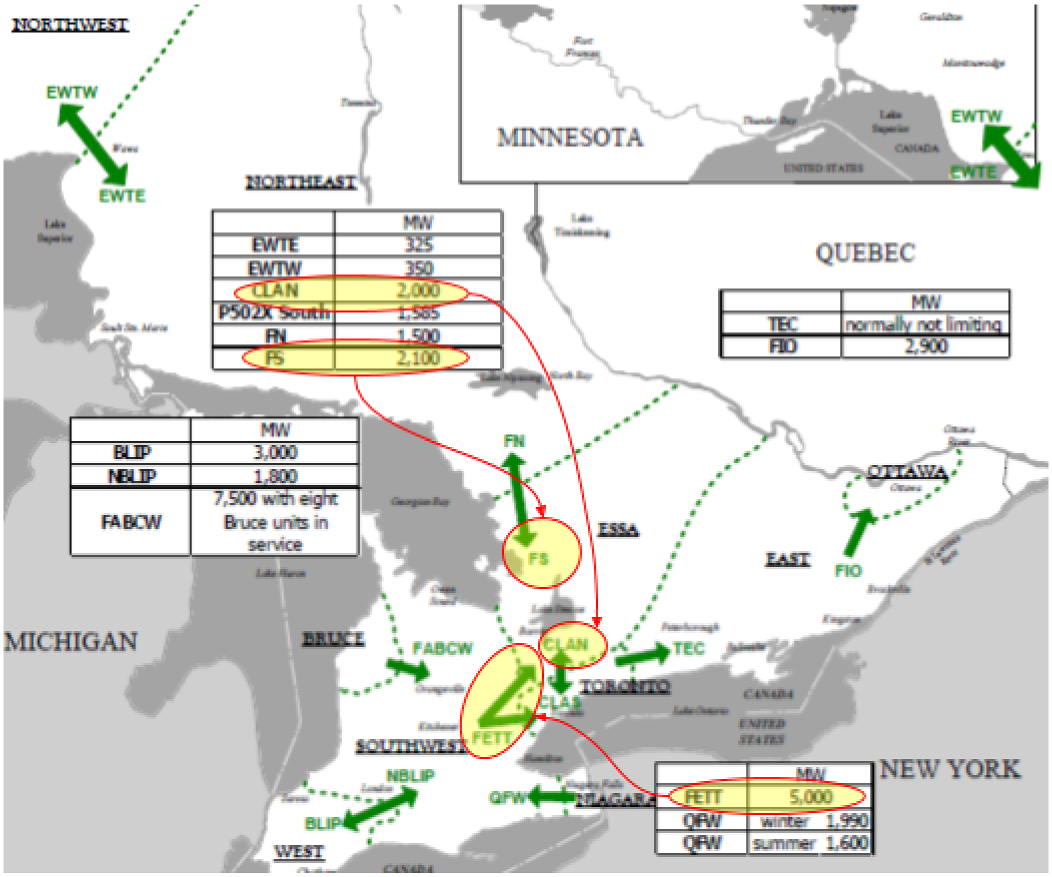

Figure 5.4.3. Modified image showing capacity and locations of Essa zone inbound grid interconnections with adjacent zones and their capacities (circled in red with yellow background) — adapted from IESO, 2018, Figure 3.3.1.

and the Flow South (FS) transfer (IESO, 2019). Each of these transfers permit the import of energy into the Essa zone at various capacities (IESO, 2018, p. 8, Figure 3.3.1). Beyond geographic considerations, the GHG Protocol framework noted that in order to produce a “sufficiently representative sample” of baseline candidates, the last twenty percent of additional capacity with respect to “total grid capacity” should be considered, with the *temporal range* not generally extending “beyond the most recent 5 to 7 years" (GHG Protocol, 2007, p. 40). The IESO conveniently (and regularly) provides what is called the "IESO Active Contracted Generation List" (IESO, 2019), which details current facilities providing capacity to the Ontario electrical grid, including their respective contractual timeframes. While the above geographical and temporal parameters further refined the list of qualified baseline candidates affecting the BM, there remained some other important considerations.

5.4.4 Determine other selection criteria.

Since the SPEEDIER project was designed to displace capacity provided via the Parry Sound TS (Lakeland Holding Ltd., 2018) — the point at which the assessment boundary area is connected to the provincial grid — all potential baseline candidates needed to be transmission-connected. To satisfy the GHG accounting principle of *conservativeness* (ISO, 2019), examples of various generation technologies to be considered needed to represent the lowest-emitting variants of their respective types. Furthermore, baseline candidates were required to be *unconstrained* with respect to their associated grid zone *interconnections* en route to the distribution system behind the Parry Sound TS. It is worth noting that for the purposes of this analysis, grid-connected baseline candidates would need to include upgrades to the Parry Sound TS as a matter-of-fact, which would incur one-time GHG impacts as a secondary effect.

5.4.5 Produce list of qualified baseline candidates.

Based on the function of each project activity presented earlier in Table 5.4.1, baseline candidates (alongside SPEEDIER project activities) were grouped as either *firm, load-following* (Table 5.4.5-1), or *non-firm, baseload* (Table 5.4.5-2) grid-connected assets. The firm, load-following baseline candidates that satisfied the selection criteria

Table 5.4.5-1

Qualifying Firm Load-following Baseline Candidates

Facility Name	Plant Type	Rated Capacity (MW)	Emissions Rate (t of CO_2e/MWh)	Built	IESO zone
SPEEDIER Load-Control Managed HWT	**demand reduction**	**0.15**	**0**	**2021**	**Essa**
SPEEDIER GBESS	**utility-scale battery energy storage**	**1.257**	**0**	**2021**	**Essa**
SPEEDIER RBESS	**residential battery energy storage**	**0.05**	**0**	**2021**	**Essa**
Brighton Beach Power Station	natural gas combined-cycle	580	0.379	2004	West*
Green Electron Power Plant	natural gas combined-cycle	314	no data	2017	West*
Greenfield Energy Centre	natural gas combined-cycle	1038	0.307	2008	West*
Napanee Generating Station	natural gas combined-cycle	900	no data	2020	East*
Portlands Energy Centre	natural gas combined-cycle	550	0.110	2009	Toronto
TransAlta Windsor	co-generation	72	0.533	1996	West*
West Windsor	natural gas combined-cycle	123	0.477	1996	West*

Facility Name	Plant Type	Rated Capacity (MW)	Emissions Rate (t of CO_2e/MWh)	Built	IESO zone
York Energy Centre	natural gas simple-cycle	200	0.643	2012	Essa
Ameresco Newmarket-Tay Energy Storage Facility	utility-scale battery energy storage	4	0	2019	Essa
Parry Sound Battery Storage Facility	utility-scale battery energy storage	2	0	2017	Essa
Milton Hydro Baseload Power Flow Battery Project	utility-scale battery energy storage	2	0	in-progress	Southwest
Goderich Advanced Compressed Air Energy Storage Facility	compressed air energy storage	2.2	0	2019	Southwest

Note. Data obtained from IESO (2019). SPEEDIER project activities appear in **boldface** for comparison.
* Not located in an adjacent IESO transmission zone.

Table 5.4.5-2

Qualifying Non-firm Baseload Baseline Candidates

Facility Name	Plant Type	Rated Capacity (MW)	Emissions Rate (t of CO_2e/MWh)	Built	IESO zone
SPEEDIER PV Solar Array	**solar PV array**	**0.5**	**0**	**2021**	**Essa**
Bow Lake Phase 1	wind turbine array	19.44	0	2015	Northeast
Bow Lake Phase 2b	wind turbine array	38.88	0	2016	Northeast
Goulais Wind Farm	wind turbine array	25	0	2015	Northeast
Grand Bend Wind Farm	wind turbine array	100	0	2015	Southwest
Henvey Inlet Wind	wind turbine array	300	0	2018	Essa
Nanticoke Solar	solar PV array	44	0	2019	Southwest
Southgate Solar	solar PV array	50	0	2016	Southwest

Note. Data obtained from IESO (2019). SPEEDIER project activities appear in **boldface** for comparison.

consisted of natural gas-powered “peaker” plants, utility-scale battery energy storage installations, and a compressed air energy storage facility.

The GHG Protocol framework noted that it is preferable that “identified plants will have been operational for *at least one year* and have a complete annual GHG emissions and generation data set” (GHG Protocol, 2007, p. 42). If these data were unavailable, they could be estimated using fuel consumption data, fuel and operational efficiency data, or “default capacity factors by plant type” (GHG Protocol, 2007, p. 42). The ISO 14064-2:2019 standard indicated that factors could be obtained from a variety of sources (ISO, 2016), but did not provide specific recommendations or direction. Obtaining emission factors for natural gas generator plants listed by the IESO presented a challenge. A detailed LCA study of electricity generators in Ontario (Mallia & Lewis, 2013) provided a table containing the GHG intensity (listed in tonnes of CO_2e/GWh) of combined-cycle natural gas electricity generation facilities that was cross-referenced with the IESO Active Contracted Generation List (IESO, 2019). In addition, the GHG intensity for the York Energy Centre was also located, from the Capital Power 2019 GRI Index (2019). These figures, along with corporate disclosures about the facilities, resulted in a compact list of seven Combined-Cycle Gas Turbines (CCGT) and one Simple-Cycle Gas Turbine (SCGT) peak-demand generators. While most of these were not built within the recommended 5-7 year temporal range, nor were they located in the appropriate IESO transmission zones, the combined data (Table 5.4.5.1) could be aggregated to produce a performance standard (GHG Protocol, 2007) for typical gas peaker plants for the purposes of BM emissions for the demand-response HWT fleet. The framework also declared that a "representative type of baseline candidate [could] be defined using the average efficiencies and operating characteristics of similar plants" (GHG Protocol, 2007, p. 42).

With respect to utility-scale bulk energy storage, it needed to be determined how GBESS power plants might suffice as baseline candidates. Like natural gas 'peaker' plants, such facilities offer *firm*, *load-following*, and quickly *dispatchable* capacity to the grid, but they also provide other valuable capabilities not possible with gas-powered generators. Such assets can improve system resilience while reducing costs (Wamsted, 2019), ease congestion in transmission and distribution, stabilize variable renewable generation, provide grid voltage and frequency regulation, and absorb surplus baseload generation (IESO, 2014). Such benefits can "[allow] utilities to defer, or even avoid, expensive system upgrades" (IESO, 2014, p. 1, Wamsted, 2019). Unlike gas-powered generation however, it was recognized that the *duration* of availability of such systems is constrained by installed battery capacity — measured in megawatt hours (MWh).

The project activity consisting of a 500kW PV solar module array represented additional *non-firm, baseload* capacity for which a number of baseline candidates were identified (Table 5.4.5.2). While not required for the estimation of BM emissions, the *Guidelines for Grid-Connected Electricity Projects* remarked that such a list might be needed for the purposes of justifying the baseline scenario "in order to demonstrate that the project activity is not ‘common practice’” (GHG Protocol, 2007, p. 35). As such, the SPEEDIER PV solar array along with the public EV charger installations were assessed with respect to their impact on the OM, rather than the BM.

5.4.6 Limit baseline candidates to those representing common practice.

With a plausible collection of baseline candidates assembled, the next step in the process was to pare down the list to those that represented “common practice” (GHG Protocol, 2007, p. 42) — or rather, examples of capacity that would *likely* have been built to address growing demand in the *absence* of the SPEEDIER project. The analysis proceeded to refine the list to include only the *firm*, *load-following* candidates, that would provide a baseline for the BM for SPEEDIER project activities of this type (Table 5.4.5-1).

Firstly, the gas-powered ‘peaker’ plants needed further examination. The York Energy Centre was purpose-built for peaking capacity, and while it is a less-efficient single-cycle gas turbine (SCGT), the simplicity of the technology enables the plant to respond more quickly to spikes in demand (Northland Power, n.d., para. 6). TransAlta Windsor was excluded because it is a *cogeneration* facility which also produces steam for the automotive sector (TransAlta, n.d.), and as such was not deemed to be typical of a gas ‘peaker’ plant in terms of its operation. Although the newer Green Electron Power plant and the Napanee Generating stations were identified as examples of current CCGT technology, neither facility provided any emissions or fuel consumption data and as such were excluded from the list.

Secondly, the list included a number of bulk energy storage facilities which were also reviewed. In 2012, the IESO began to investigate the benefits of bulk energy storage in Ontario with the Alternate Technologies for Regulation (ATR) procurement — adding 6 MW of capacity from two facilities (IESO, 2018). This was followed by a subsequent deployment of another 50 MW of capacity through the Energy Storage Procurement Framework to provide “regulation service or reactive support and voltage control (RSVC) service to support Ontario’s electricity system” (IESO, n.d.). In April of 2018, the IESO established the Energy Storage Advisory Group (ESAG) in order to help the organization to adapt its “policy, rules, processes and tools to better enable the integration of storage resources within the current structure of the IESO-administered markets” (IESO, 2018, p. 3). While this seemed significant, it appeared that the nature of the IESO’s foray into bulk energy storage was *demonstrative*, consisting of pilot projects and initiatives designed to further understand the impacts of the technology. A 2018 IESO report entitled “Removing Obstacles for Storage Resources in Ontario” disclosed why adoption of storage remains a challenge:

> The emergence of new energy storage technologies has changed the paradigm in a sector that has traditionally been operated with conventional resources that act as a load or a generator but not both. As a result, storage facilities are facing obstacles that limit both their ability to compete to provide services that they are otherwise capable of delivering, and to integrate into wholesale electricity markets and systems (IESO, 2018).

Due to the fundamental changes required for the integration into the transmission system of bulk energy storage, such assets could not be considered to be “common practice" (GHG Protocol, 2007, p. 41) at the time, and were therefore removed from the list of baseline candidates.

The resulting list (Table 5.4.6-1) was left with four CCGT 'peaker' plants, and one SCGT 'peaker' plant that represented "common practice" from a peak demand capacity

Table 5.4.6-1

Baseline Candidates - Firm, Load-following: Common Practice

Facility Name	Plant Type	Rated Capacity (MW)	Emissions Rate (t of CO_2e/MWh)	Built	IESO zone
SPEEDIER Load-Control Managed HWT	**demand reduction**	**0.15**	**0**	**2021**	**Essa**
SPEEDIER GBESS	**utility-scale battery energy storage**	**1.257**	**0**	**2021**	**Essa**
SPEEDIER RBESS	**residential battery energy storage**	**0.05**	**0**	**2021**	**Essa**
Brighton Beach Power Station	natural gas combined-cycle	580	0.379	2004	West*
Greenfield Energy Centre	natural gas combined-cycle	1038	0.307	2008	West*
Portlands Energy Centre	natural gas combined-cycle	550	0.110	2009	Toronto
West Windsor	natural gas combined-cycle	123	0.477	1996	West*
York Energy Centre	natural gas single-cycle	200	0.643	2012	Essa

Note. Data obtained from IESO (2019). SPEEDIER project activities appear in **boldface** for comparison.
* Not located in an adjacent IESO transmission zone.

perspective. It is important to note that the rated capacity of the plants are immaterial, as the candidates represent “the types of new capacity that *could be* displaced by the project activity” (GHG Protocol, 2007, p. 43). In order to further simplify the process of determining an appropriate baseline scenario, the four gas-fired plants were then reduced to a single “representative type of baseline candidate” (GHG Protocol, 2007, p. 43) by determining an average emission rate and plant capacity (Table 5.4.6-2). This final step was then subjected to an *assessment of barriers and benefits* as compared to the project activity itself during a justification of the baseline scenario and a characterization of the BM.

Table 5.4.6-2

Representative Baseline Candidates - Firm, Load-Following

Facility Name	Plant Type	Rated Capacity (MW)	Built	Emissions Rate (tCO_2e/MWh)
SPEEDIER Load-Control Managed HWT	**demand reduction**	**0.15**	**2021**	**0**
SPEEDIER GBESS	**utility-scale battery energy storage**	**1.257**	**2021**	**0**
SPEEDIER RBESS	**residential battery energy storage**	**0.05**	**2021**	**0**
Representative plant	natural gas combined-cycle	573	2004	0.318
York Energy Centre	natural gas single-cycle	200	2012	0.643

Note. SPEEDIER project activities appear in **boldface** for comparison.

5.5 Justifying the Baseline Scenario and Characterizing the Build Margin

In effect, this part of the process sought to demonstrate that in the *absence* of the project activity being analysed, the baseline scenario that would likely have played out would be the candidate that represented the *fewest barriers* to its implementation or the *greatest net benefits* — exclusive of any GHG emissions considerations. Such a scenario would represent the baseline from a GHG perspective, against which the project activity emissions were to be compared. For project activities deemed to affect the BM (in whole or in part), this step was used to “justify the baseline scenario and to identify a single baseline candidate to represent the BM” (GHG Protocol, 2007, p. 45). For those SPEEDIER project activities whose effects were determined to impact *only* the OM, this step served to “justify a baseline scenario consisting solely of OM generation” (GHG Protocol, 2007, p. 45). The process began with listing all possible barriers to the implementation of each project activity and any applicable baseline candidates. This activity was completed in collaboration with team members from Lakeland Holding Ltd. The findings — organized by categories suggested by *The GHG Accounting for Projects Protocol* (2005) — are presented below in Tables 5.5-1, 5.5-2, 5.5-3, and 5.5-4.

For each barrier, the *relative* significance of each challenge with respect to the other impediments for the same scenario were gauged by assigning a rating of either “H” (significant barrier), “M” (moderately significant barrier), or “L” (less significant barrier), as suggested in section 8.2 of the *The GHG Protocol for Project Accounting*

(2005). To further complete a “comparative assessment of barriers” (GHG Protocol, 2005, p. 52), each of the ratings were weighted appropriately, with an “H” equalling 3 points, an “M” valued at 2 points, and an “L” assigned 1 point. The resulting weighted totals for all project activities affecting the BM — alongside any comparable appropriate baseline candidates (Table 5.5-1) and the *do nothing* alternative (Table 5.5-4) — are presented in Table 5.5-5. This revealing — albeit *subjective* exercise illustrated the

Table 5.5-1

Barriers to Implementation for Project Activities that Affect the BM and their Alternative Baseline Candidates

Barrier Category	SPEEDIER Load-Control Managed HWT (demand reduction)	SPEEDIER RBESS	SPEEDIER Utility-Scale GBESS	Representative gas 'peaker' plant (CCGT)	York Energy Centre (SCGT)
Financial and Budgetary	• Early decommissioning of existing HWT fleet (M) • Cost of procurement of new network-enabled HWT fleet (H) • Up front Cost of DERMS to manage system (L) • Installation costs (H)	• Upfront capital costs for procurement, delivery, and installation of RBESS units (M) • Approvals and permitting (L)	• Upfront capital costs for design and build (L) • Hardware cost of utility-scale battery and related hardware (to provide equivalent service) (H) • Approvals and permitting (L)	• Upfront capital costs for design and build of new CCGT (M) • Hardware costs (H) • Approvals and permitting (M)	• Upfront capital costs for design and build of new SCGT (M) • Hardware costs (H) • Approvals and permitting (M)
Technology Operation and Maintenance	• Maintenance of IOT hardware / firmware / software (M) • Ongoing costs of training and personnel to maintain new system (L) • Technical support for end users (L) • Decommissioning of units (L)	• Operation is limited to battery capacity (H) • Asset does not produce additional energy - matches supply with demand (L) • Maintenance of IOT hardware / firmware / software (M) • Ongoing costs of training and personnel to maintain new system (L) • Technical support for end users (L) • Decommissioning costs (L) • Fuel (electricity) costs (L)	• Operation is limited to battery capacity - usually 2-4 hours (H) • Asset does not produce additional energy - matches supply with demand (L) • Maintenance and operational costs (L) • Decommissioning costs (M) • Fuel (electricity) costs (L)	• Maintenance and operational costs (M) • Decommissioning costs (M) • Fuel costs (L)	• Maintenance and operational costs (M) • Decommissioning costs (M) • Fuel costs (L)
Infrastructure	• Wireless and hard-wired network connectivity would need to be installed and configured (M)	• Modifications to residential panels and meter connections could be extensive and varied in nature (H) • Wireless and hard-wired network connectivity would need to be installed and configured (M)	• Siting appropriately for connection to local feeder and PV array (M)	• Connectivity to natural gas pipeline network (L) • Parry Sound TS would need to be upgraded to handle additional capacity (M)	• Connectivity to natural gas pipeline network (L) • Parry Sound TS would need to be upgraded to handle additional capacity (M)

Market Structure	• Consumer confusion with respect to economic benefits (M) • Consumer concern with respect to lack of control over domestic hot water supply (H) • Need to negotiate with local housing cooperative (L) • ROI is quite low for individual participants (H)	• Consumer confusion with respect to economic benefits (M) • Lack of clarity in market rules, OEB codes, and legislation and regulations (IESO, 2019) (H) • Net metering rules and regulations (M) • Consumer confusion with respect to economic benefits (M)	• Lack of clarity in market rules, OEB codes, and legislation and regulations (IESO, 2019) (H) • Natural gas prices in North America are relatively low (Carlson, 2017) (H)	• Infrequent operation of 'peaker' plant translates to a high cost per MWh (H) • IESO capacity auction could favour competing or subsidized technologies (L)	• Infrequent operation of 'peaker' plant translates to a high cost per MWh (H) • IESO capacity auction could favour competing or subsidized technologies (L)
Institutional / Social / Cultural / Political	• Consumer reluctance to trust new technology to provide reliable service (M) • Consumer fears regarding privacy of data or personal information (M) • Consumer skepticism of utilities (L) • Organizational inertia will favour incumbent technologies or approaches (M)	• Consumer reluctance to trust technology to provide reliable service (M) • Consumer fears regarding safeguarding of personal information (M) • Concerns about transferability of agreements to new owners (L) • Consumer skepticism of utilities (L) • Questions about impacts to property value (L)	• Community resistance (M) • Environmental assessments (L) • Demand peaking “capacity need through the mid-2020s can primarily be met by acquiring capacity from existing and available resources” (IESO, 2020, p. III) (M) • Business as usual processes favours incumbent technology (SCGT or CCGT) (H)	• Community resistance (H) • Environmental assessments (M) • Demand peaking “capacity need through the mid-2020s can primarily be met by acquiring capacity from existing and available resources” (IESO, 2020, p. III) (M) • Lengthy construction timeframes (M)	• Community resistance (H) • Environmental assessments (M) • Demand peaking “capacity need through the mid-2020s can primarily be met by acquiring capacity from existing and available resources” (IESO, 2020, p. III) (M) • Lengthy construction timeframes (M)
Resource Availability	• Possible supply chain issues (L) • Possible lack of qualified or available installers (L)	• possible supply chain issues (L) • possible lack of qualified or available installers (L)	• Long lead times for procurement or possible supply-chain issues (M) • Possible lack of qualified or available installers (L)	• Long lead times for procurement or possible supply-chain issues (L)	• Long lead times for procurement or possible supply-chain issues (L)
Barrier totals*	34 (H - 4, M - 7, L - 8)	34 (H - 3, M - 7, L - 11)	32 (H - 5, M - 5, L - 7)	29 (H - 3, M - 8, L - 4)	29 (H - 3, M - 8, L - 4)

* Barrier weighting: H = Significant barrier (3 points); M = Moderately significant barrier (2 points; L = Less significant barrier (1 point) (GHG Protocol, 2005)

Table 5.5-2

Barriers to Implementation for the PV Solar Array Project Activity

Implementation Barrier Category	Details
Financial and Budgetary	• Upfront capital costs for design and build • Costs of PV modules and related hardware
Technology Operation and Maintenance	• Maintenance and operational costs • Decommissioning costs
Infrastructure	• Acquisition of adequate land near to GBESS and local feeder • Appropriate zoning
Market Structure	• Government-sponsored Feed-In-Tariff (FIT) program has now expired
Institutional / Social / Cultural / Political	• Resistance from community with respect to aesthetics of PV Solar • Environmental assessments
Resource Availability	• Possible supply chain issues • Possible lack of qualified or available installers

Note. A comparative assessment and weighted scoring was not applied to the above barriers as this project activity was not deemed to affect the BM.

Table 5.5-3

Barriers to Implementation for the Public EV Charger Project Activities

Implementation Barrier Category	DCFC EV Charger	Level 2 EV Chargers
Financial and Budgetary	• Upfront hardware costs • Installation and configuration costs	• Upfront hardware costs • Installation and configuration costs
Technology Operation and Maintenance	• Maintenance and operational costs • Decommissioning costs	• Maintenance and operational costs
Infrastructure	• Costs of upgrading on-site infrastructure to support high-voltage DCFC service	• Modifications to residential panels and meter connections could be extensive and varied in nature
Market Structure	• Collecting payment for service can incur significant transactional costs for operators and customers	
Institutional / Social / Cultural / Political	• Resistance to allocating parking to EV only usage	• Consumer fears regarding safeguarding of personal information

Implementation Barrier Category	DCFC EV Charger	Level 2 EV Chargers
		• Concerns about adequacy of charging with demand-response
Resource Availability	• Local grid is already load-constrained • possible supply chain issues • possible lack of qualified or available installers	• Local grid is already load-constrained • possible supply chain issues • possible lack of qualified or available installers

Note. A comparative assessment and weighted scoring was not applied to the above barriers as this project activity was not deemed to affect the BM.

Table 5.5-4

Barriers to Implementation for the 'Do Nothing' Alternative

Implementation Barrier Category	Details
Financial and Budgetary	• Deferred upgrades or maintainance may create greater financial uncertainty for the local utility and grid operators (L)
Technology Operation and Maintenance	• Equipment outages may become a more frequent issue as increasing demand is placed on the current Parry Sound TS (M)
Infrastructure	• Ageing infrastructure at Parry Sound TS will soon become an issue as Essa transmission zone is "demand constrained" (IESO, n.d.) (H)
Market Structure	• This alternative ignores the fact that the Ontario grid's future needs will be "peaking in nature" (IESO, 2020, p. III) and additional generation and transmission capacity will be required (H)
Institutional / Social / Cultural / Political	• Economic growth and development in the local area may be impacted by current infrastructure capacity limitations (H)
Resource Availability	• No barriers determined
Barrier totals*	12 (H - 3, M - 1, L - 1)

* Barrier weighting: H = Significant barrier; M = Moderately significant barrier; L = Less significant barrier (GHG Protocol, 2005)

likelihood of a baseline scenario whereby additional peaking capacity was likely to be addressed by the continuation of current activities, which would quite possibly entail an upgrade to the transformer station serving the Parry Sound community (Hydro One,

2017) in order to facilitate the dispatch of additional energy during periods of peak demand. A net benefits analysis, which the GHG Protocol framework proposed when a comparative assessment of barriers failed to reveal the most likely scenario, was therefore not required (GHG Protocol, 2007). All that remained for this step then, was to explain how the barriers for the SPEEDIER project activities would be overcome.

Table 5.5-5

Comparative Assessment of Barriers for Project Activities and Alternatives

Baseline Scenario Alternatives	Significant Barriers (H)	Moderately Significant Barriers (M)	Less Significant Barriers (L)	Total Barriers	Weighted Total
SPEEDIER load-control managed HWT (demand reduction)	4	7	8	19	34
SPEEDIER RBESS	3	7	11	21	34
SPEEDIER utility-scale GBESS	5	5	7	17	32
Representative gas 'peaker' plant (CCGT)	3	8	4	15	29
York Energy Centre (SCGT)	3	8	4	15	29
Continuation of current activities (do nothing) alternative*	3	1	1	5	12

Supported by funding from Natural Resources Canada through the second phase of their Canada Green Infrastructure program, and also by an investment by Lakeland Holding Ltd. among other project partners, the SPEEDIER initiative represented an instance of the “Smart Grid Demonstration and Deployment Program” (Lakeland

Holding Ltd., 2018, p. 1). These significant resources provided equipment, software, training, and professional services that would address all of the aforementioned barriers and challenges posed by each of the project activities. In this sense, none of the activities were deemed to be indicative of “common practice” (GHG Protocol, 2005, p. 20) and would not have been viable options if not for the collective efforts and investments by project proponents. For the purposes of the GHG Protocol framework, the above considerations would satisfy the “additionality” requirements needed to qualify as activities that would produce verifiable greenhouse gas reductions (GHG Protocol, 2007, p. 88).

The continuation of current activities (Table 5.5-4) as an alternative also entailed barriers to its implementation. Hydro One, the regional IESO contracted transmission system operator, in its South Georgian Bay/Muskoka Regional Infrastructure Plan (2017) conceded that “based on the current load forecasts, additional transformation capacity relief is required for both Parry Sound TS and Waubaushene TS to accommodate the load growth and improve reliability in this sub-region” (Hydro One, 2017, p. 35). The report contained provisions for the *inevitable* upgrades to the Parry Sound transformer station or equivalent transmission system changes that would address the identified constraint, suggesting that the challenges captured in this assessment have been recognized and accounted for. It is important to note however, that while the IESO was confident that Ontario’s energy needs could “largely be met” with its “reliable baseload facilities like nuclear and hydroelectric, along with the combined cycle gas fleet,” a capacity shortfall of around 2,000 MW would occur sometime during 2023 (Figure 5.5) and would continue to grow past 2040 (IESO, 2020, p. III). The IESO further characterized this situation:

> This need is limited, occurring for a few short hours of peak demand each year, meaning future resource requirements are peaking in nature. The capacity need through the mid-2020s can primarily be met by acquiring capacity from existing and available resources, including demand response, imports, merchant generators, enhancements of current facilities (uprates), distributed energy resources (DERs) and, potentially, energy efficiency (IESO, 2020, p. III).

It was determined that it would be prudent to assume that additional "peaking" capacity *might* be needed in the near future, particularly when considering that "major planned outages" as a result of two to four nuclear generators were to be taken offline for

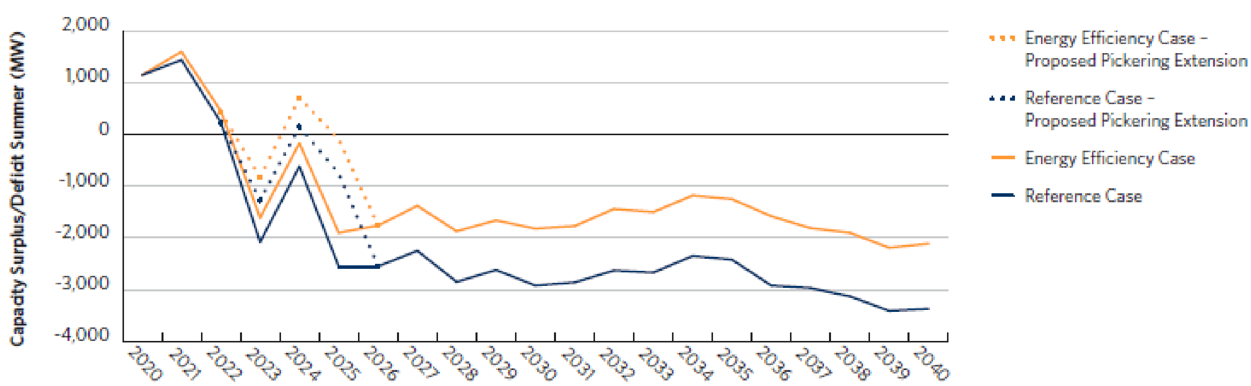

Figure 5.5. Summer capacity surplus/deficit with continued availability of existing resources (IESO, 2020, p. III).

refurbishment each year until 2029 (IESO, 2020, p. III). Adhering to the GHG Protocol guidance, which implored project proponents to "[u]se conservative assumptions, values, and procedures when uncertainty is high" (GHG Protocol, 2005, p. 24), it was considered sensible to consider that the more efficient (and lower-emitting) CCGT generators would likely employed to "provide needed flexibility in response to conditions on the power system" (IESO, n.d.). Such a baseline candidate could be represented by the representative gas 'peaker' plant characterized earlier in Table 5.4.6-2, even though it scored similarly in terms of comparative barriers than the higher-emitting York Energy Centre (Table 5.5-5). Adhering to the GHG Protocol's principle of conservativeness, the representative gas 'peaker' plant was also chosen because it featured a significantly lower GHG emission rate (0.318 tCO_2e/MWh) than the York Energy Centre (0.643 tCO_2e/MWh). This decision was further justified through research aimed at assessing the differences in operational costs between the two candidates. Calculation tools offered by the U.S. Energy Information Administration (2020, p. 6) suggested that the Levelized Cost Of Energy (LCOE) for the representative plant equated to $36.61/MWh, while the York Energy Centre would equal $68.71/MWh (in 2019 USD). The National Renewable Energy Laboratory evaluated the same plants at $34.09/MWh and $93.35/MWh respectively (NREL, n.d.). Thus, for the SPEEDIER project activities that were determined to affect the BM, the representative gas 'peaker' plant was chosen to represent the selected baseline scenario, while the remaining activities were to be compared with a baseline that impacted only the OM.

5.6 Estimating the Build Margin Emission Factor

The SPEEDIER demand-response HWT fleet and the GBESS and RBESS battery storage activities were both assessed as having material impacts on the BM, and were methodically aligned with the "most conservative, lowest-emitting baseline candidate” as the baseline scenario — the representative gas ‘peaker’ plant described in Table 5.4.6-2. This candidate was constructed using average characteristics of CCGT generators in Ontario (Mallia & Lewis, 2013) that best matched the baseline candidate selection criteria, while still representing common practice. The CCGT plants cited offered precise emission factors presented as tons of CO_2-equivalent per megawatt hour (tCO_2e/MWh). The representative plant was a 573 MW rated capacity combined-cycle natural gas generator built in 2004 with an emissions intensity of **0.318 tCO_2e/MWh**. According to the framework guidance, if an emission factor for the baseline candidate was available, this could be used to represent the *BM emission factor*. The remaining project activities’ baseline scenarios were assessed as affecting the OM instead, upon which the case study will now focus.

5.7 Estimating the Operating Margin Emission Factor

The next part of the undertaking required establishing the effect that the project would have on emissions produced by the OM. With the additional capacity provided by the SPEEDIER project activities, the OM emission factor represents an attempt to quantify the generation that could be sequentially shut down or displaced as demand is reduced on the grid (GHG Protocol, 2007, p. 54). The framework offered four different approaches to calculating the OM baseline emissions, each with increasing levels of accuracy that would each entail significantly greater effort and more granular data. With due consideration given to limitations of resources, the relatively comprehensive and rigorous “average marginal emissions” method was selected as an appropriate approach (GHG Protocol, 2007, p. 61).

The first step was to create a chart depicting a load duration curve, which plotted the electrical load (MW) for each hour of the year (8760 data points), stacked in order from hours with the highest demand down to the lowest (Figure 5.7-1). The second task

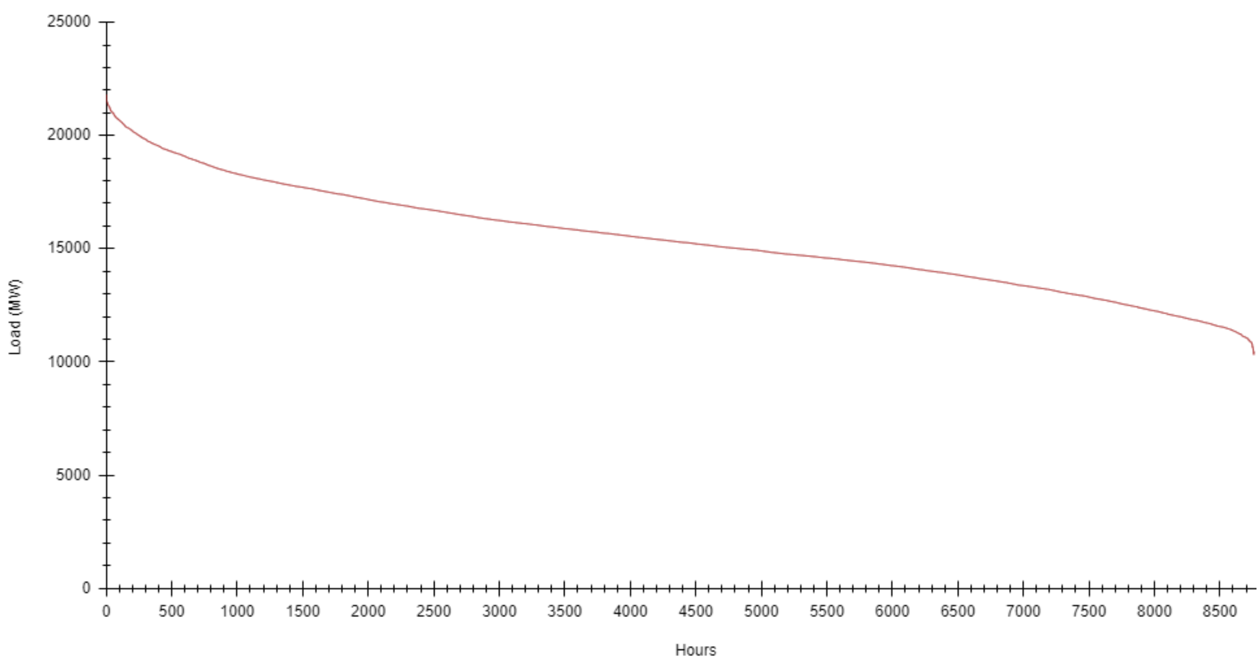

Figure 5.7-1. 2019 Ontario load duration curve. Generated using data provided by IESO (n.d.).

required obtaining an inventory of “total generation by resource type” (GHG Protocol, 2007, p. 61) for the time period being analysed (the baseline 2019 calendar year in this case). These data were offered by the IESO for both *transmission-connected*, and *distribution-connected* generation (IESO, n.d.). Since it was the effect that the project activities would have on the OM emissions from resources connected to the *transmission* grid that were needed, distribution generation was not relevant for these calculations (Table 5.7-1). This method for determining the OM emission factor included also accounting for any imported energy (later in the process) and treating it as "a distinct resource type" (GHG Protocol, 2007, p. 63). For this reason, energy imported to the Ontario grid in 2019 is also quantified in Table 5.7-1 (IESO, n.d.). The third step involved

Table 5.7-1

Total Transmission-Connected Grid Generation by Resource Type

	Nuclear	Hydro	Wind	Gas/Oil	Imported	Solar	Biofuel
Total transmission grid generation (MWh)	90,400,000	36,400,000	11,000,000	9,500,000	6,613,000	700,000	400,000
% of transmission grid generation	58.32%	23.48%	7.10%	6.13%	4.27%	0.45%	0.26%

Note: Figures were converted to MWh and represent totals for Ontario for the baseline year 2019 (IESO, n.d.)

the determination of the average operating cost for each resource type. The costs tabulated below in Table 5.7-2 represent an approximation of the "wholesale market

Table 5.7-2

Average Costs of Generation in Dollars Per MWh by Fuel Type

	Nuclear	Hydro	Gas/Oil	Wind	Biofuel	Solar	Imported
Cost per MWh	$66	$58	$173	$140	$131	$480	no data

Note: Data obtained from the Ontario Energy Board (2017, as cited by Ivey Business School, 2017) hourly spot price" and a cost-recovery mechanism called the *Global Adjustment (GA)*, which "reconciles the difference between the earned revenues in the wholesale market and the rates established via contract" (Ivey Business School, 2017, p. 7).

The fourth step in the procedure was a bit more involved, requiring resource types to be ordered from the least expensive, to the most costly fuel type — in effect stacking the generators in a *likely dispatch order* that the grid operator would logically follow as demand grew, with due consideration given to whether a given generation source was *dispatchable* (load-following), intermittent (variable), or baseload (non-load-following) in nature. These parameters resulted in the stacking order featured in Figure 5.7-2. It is important to note that hydroelectric and biofuel (biomass)

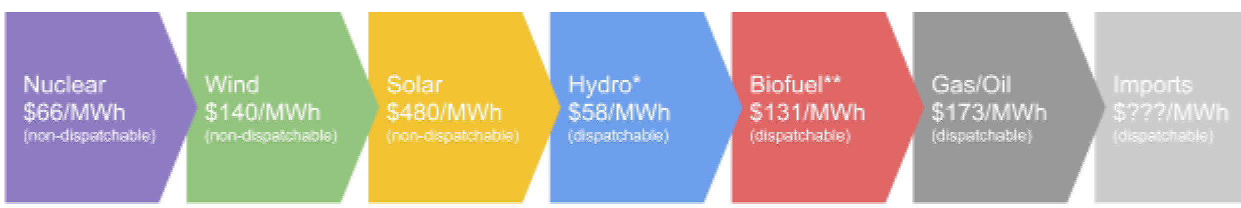

Figure 5.7-2. Dispatch order by resource type based on price and dispatch capability. *Hydroelectric generation is used in Ontario for *peaking* and intermediate generation with hydro pumped storage (IESO, n.d.). **Biofuel plants are also employed for peak demand generation (Murray, 2017).

generation would likely have followed the more expensive wind and solar generation facilities due to their dispatchable (load-following) capabilities. It was assumed that energy imported to the grid to address peak demand would be an instrument of last resort for grid operators (therefore last in the dispatch order) based on evidence that *imports increase* “when Ontario’s demand is high and Ontario’s gas fired generation is operating” (OSPE, 2017, p. 6). It was recognized that dispatch of generation types in response to demand *in practice* are determined by complicated algorithms embedded in proprietary software called Dispatch and Scheduling Optimization (DSO) (PwC, 2018). With due consideration to the relative volumes of energy from each generation source (Table 5.7-1), the demand curve was then filled from the bottom of the chart toward the top with a stacked bar, terminating at the point of highest demand. For each resource type, the horizontal bar intersected the load duration curve at both a lower and higher numbered hour along the x-axis — the difference between each pair of intersecting points represented the “number of hours that the resource type [was] on the margin” (GHG Protocol, 2007, p. 62). Each of these marginal values for each resource are presented in Figure 5.7-3 along the top of the chart, using a colour-coded legend.

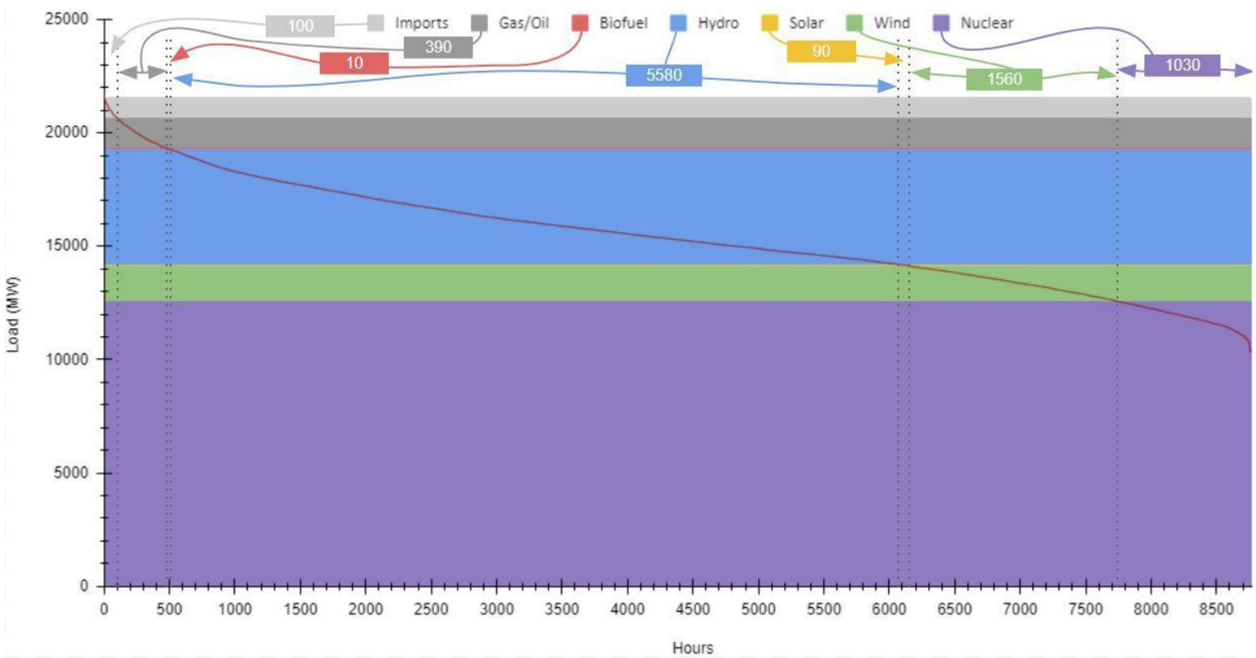

Figure 5.7-3. 2019 load duration curve (dark red) with generation by resource type in dispatch order, and number of hours each type is on the margin. The chart was generated using data provided by IESO (2019), and Ivey Business School (2017, p. 10).

For each generation type, an average emission factor was then required. Since the total amounts of GHG emissions were not found for the year 2019, average emission factors were obtained from research conducted on behalf of Ontario Power Generation (OPG) in 2016, along with data from the Canadian Energy Regulator (CER, 2020) and are presented below in Table 5.7-3. Notably, imported energy was assigned an emission

Table 5.7-3

Average Emission Factors for Various Electricity Generation Fuel Types

	Nuclear	Hydro	Gas/Oil	Wind	Biofuel	Solar	Imported
Emission rate (tCO_2e/MWh)	0.00015	0	0.525	0.00074	0.0165*	0.00615	0**

Note: Data was obtained from Intrinsik Corp. (2016)

*Biofuel (or biomass) emission factor derived from Canada's Renewable Power Landscape 2017 – Energy Market Analysis (CER, 2020)
**Conservative value of zero assigned by author (GHG Protocol, 2007, p. 63)

factor of zero. This was done in the place of a more thorough analysis to obtain an OM emission factor for the load-following component of the exporting grid (GHG Protocol, 2007), in adherence to the GHG Protocol's principle of conservativeness.

The last remaining step was to calculate the OM emission factor in preparation for the baseline emission estimation. The formula to determine this factor is described in Figure 5.7-4, along with descriptions for each variable involved. With the emission

$$OM_t = \frac{\sum_r \left(TM_{r,t} \times EF_{r,t}\right)}{HRS_t}$$

- OM_t is the operating margin emission factor for time period, t.
- $TM_{r,t}$ is the number of hours that resource type, r, was on the margin for time period, t.
- $EF_{r,t}$ is the average emission factor for resource type, r, for time period, t.
- HRS_t is the total number of hours in time period, t.

Figure 5.7-4. Formula to determine the "OM emission factor as a time-weighted average of the emission rates for marginal resource types" (GHG Protocol, 2007, p. 63).

factors for hydroelectric and imported generation being assigned a value of zero, and using the hours on the margin for each resource type as plotted along the load duration curve (Figure 5.7-3) the formula yielded the calculation rendered below in Figure 5.7-5.

$$OM_t = \frac{(204.75 + 0.0615 + 1.1544 + 0.1545 + 0.16524)}{8760} \cong 0.0235 \text{ t } CO_2e/MWh$$

Figure 5.7-5. Evaluation of the formula to determine the operating margin emission factor for the Ontario transmission grid for the 2019 year.

Yielding an emission factor for both the BM (0.318 t CO_2e/MWh - Section 5.6) and the OM (0.0235 t CO_2e/MWh - Figure 5.7-5), the framework then directed project proponents toward the task of producing a plausible *baseline emission scenario* against which to compare the future GHG performance of the project.

5.8 Estimating Baseline and Project Emissions

In order to produce a reasonable projection of the emission scenario that would have played out in the absence of the SPEEDIER project, each project activity was assigned a “combined margin emission rate derived from a weighted average of the BM and OM emission factors” (GHG Protocol, 2007, p. 66). Once this rate was determined for each project activity, the quantity of GHG emissions were estimated by factoring it with the anticipated electricity to be generated (or avoided) by each project activity over the time period required. Collectively and in aggregate, these baseline emission projections when compared with actual project activity GHG emissions data, would permit the project proponent to report on likely and plausible net reductions to GHG emissions that can be attributed directly to the SPEEDIER initiative.

5.8.1 Utility-scale battery energy storage system (GBESS).

The following section documents the analysis of the baseline emission projection completed for the GBESS project activity, followed by the anticipated project emissions over the course of a calendar year.

The baseline emission scenario for the GBESS project activity was represented by the equivalent services that would have needed to be provided to supplant the annual *discharge* phases of the battery system — which consisted of the timely dispatching of energy as a demand-response measure. The following discussion traces the energy transactions involved in a complete charge and discharge cycle, incorporating a number of logical or unavoidable assumptions.

The first of these assumptions was that the daily demand profile for the IESO Essa Zone of the Ontario grid for both the winter (Figure 5.8.1-1) and summer (Figure 5.8.1-2) seasons would approximate the character of the SPEEDIER project

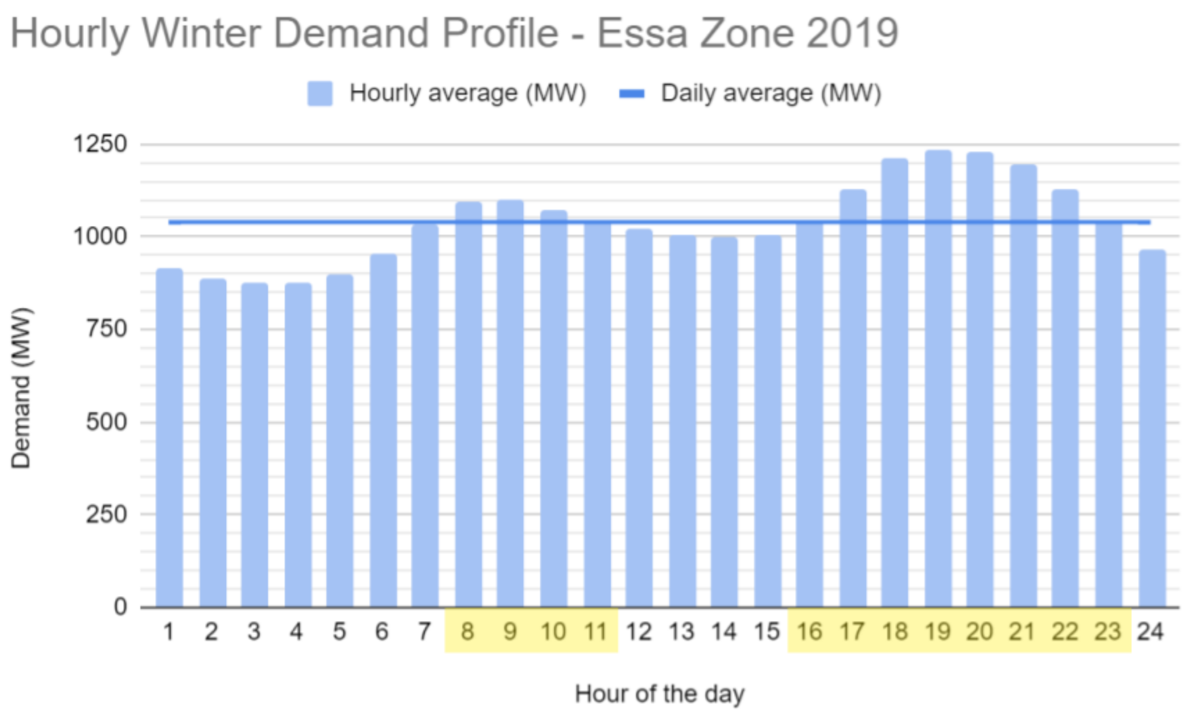

Figure 5.8.1-1. Hourly winter demand profile for Essa zone (2019). Hours in excess of daily mean demand are highlighted in yellow.

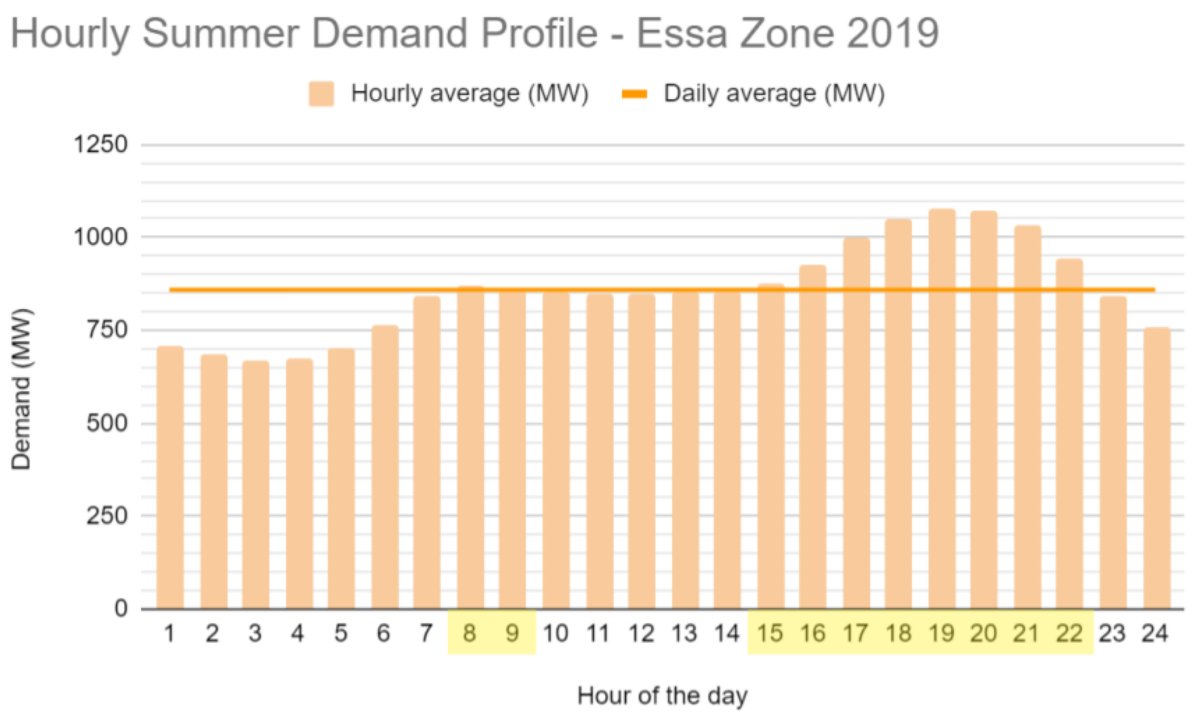

Figure 5.8.1-2. Hourly summer demand profile for Essa zone (2019). Hours in excess of daily mean demand are highlighted in yellow.

assessment boundary in Parry Sound, Ontario. The next assumption that was made was that any demand in excess of the daily mean (represented by a horizontal line in both Figure 5.8.1-1 and 5.8.1-2) constituted a *demand peak*, whereby the GBESS system would likely be called upon by the DERMS to dispatch energy to help *level out* the demand curve. While the winter demand profile *might have* appeared to offer both a morning and evening peak demand mitigation opportunity, the DERMS had been configured for only a *single charge-discharge event per day* (P. Ewald, personal communication, November 26, 2020), leaving all available GBESS capacity to be held in reserve to deploy during the evening peak event. With the DERMS being optimized to reduce GHG emissions, it was assumed that it would have very likely restricted charging events for the GBESS to periods of lower demand (from midnight to 7am). The final assumption made concerning this analysis was that while the GBESS could only deploy for two hours at full capacity, the DERMS would likely distribute the dispatch of energy over each peaking period in a way that maximized the effectiveness of the asset.

The first part of this analysis required accounting for all energy inputs needed to fully charge the GBESS. The DERMS was configured to limit the state of charge (SOC) to a minimum of 5% and up to a maximum of 90% (P. Ewald, personal communication, November 4, 2020), resulting in only 85% of the nameplate capacity of 2,514 kWh being available. Therefore, for baseline calculations, the battery consumed **2,136.9 kWh** (2,514 kWh * 0.85) for a single charge event. Since the energy to charge the battery was obtained from the primary grid, this amount needed to account for any applicable transmission and distribution losses (GHG Protocol, 2007, Section 3.3). This was referred to as a “Loss-Penalty Factor” and it equated to a factor of 1.01 for the baseline year 2019 (IESO, 2020). This additional factor resulted in a revised consumption of **2,158.269 kWh** (2,136.9 kWh * 1.01).

Next, it was required to factor in ½ of the losses associated with Round-Trip Efficiency (RTE). The RTE included all thermal system energy consumption and all internal Tesla Megapack control power consumption during a complete charge and discharge cycle (Tesla, n.d.). The battery RTE was specified by Tesla as 87%, which could alternatively be described as a 13% energy loss for a *full charge-discharge cycle*.

For the purposes of this analysis, *half* of these losses (6.5%) were attributed to the charge phase — amounting to a 93.5% efficiency for this specific process. Such losses could also be expressed as a *system loss factor* (similar to the Loss-Penalty Factor mentioned previously) of approximately 1.07 (1 ÷ 0.935). The additional energy required to accommodate these losses resulted in a total of **2,309.34783 kWh** (2,158.269 kWh * 1.07) required to charge the GBESS *once* from a 5% to a 90% SOC. The final step involved determining how much energy would be required over a typical calendar year, assuming one charging event per day — which amounted to **842,911.95795 kWh** or **842.91195795 MWh** (2,309.34783 kWh * 365 days). The above analysis is summarized below in Table 5.8.1-1. The above calculation is also presented as a formula in Figure 5.8.1-3.

Table 5.8.1-1

Annual GBESS Charging Analysis

	Capacity	SOC limits (effective capacity)	Loss-Penalty Factor (transmission and distribution losses)	½ RTE Losses (battery system loss factor)	Annual Charge Cycles
BESS	2,514 kWh	5% / 90%	1.01	1.07	365
Net Impact (kWh)	0	- 377.1	+ 21.369	+ 151.07883	N/A
Energy Consumed (kWh)	2,514	2,136.9	2,158.269	2,309.34783	842,911.95795

A similar accounting process was then required to determine the energy to be *dispatched* over the same amount of time. Assuming the GBESS was to begin with a 90% SOC — with a lower limit of 5% set by the DERMS, only 85% percent of the nameplate capacity was then available for dispatch. This left **2,136.9 kWh** (2,514 kWh * 0.85) of energy available for discharge. Similarly to the charging phase, it was required that ½ of the losses associated with the 87% RTE were factored into the equation here — amounting to a loss of 6.5% during the *discharge* portion of a full cycle. So, for baseline calculations, the battery *effectively* displaced **1,998.0015 kWh** (2,136.9 kWh * 0.935) of peak-demand generation. This energy also needed to include the "Loss-Penalty Factor" (IESO, 2020) as previously factored into the charge phase (GHG Protocol, 2007, Section 3.3), meaning that grid operators would have needed to procure *even more* energy from contracted generators *in order to provide the equivalent service*. This meant that in effect a full GBESS discharge would displace **2,017.981515 kWh** (1,998.0015 kWh * 1.01) from the grid. Finally, the amount of grid energy displaced by a single discharge then needed to be quantified over the course of a typical calendar year, assuming one discharge event per day — which amounted to **736,563.252975 kWh** or **736.563252975 MWh** (2,017.981515 kWh * 365 days). The above analysis is summarized below in Table 5.8.1-2.

Table 5.8.1-2

Annual GBESS Discharge Analysis

	Capacity	SOC Limits (effective capacity)	½ RTE Losses (battery system loss factor)	Loss-Penalty Factor (transmission and distribution losses)	Annual Discharge Cycles
BESS	2,514 kWh	5% / 90%	0.935	1.01	365
Net Impact (kWh)	0	- 377.1	- 138.8985	+ 19.980015	n/a
Energy Dispatched (kWh)	2,514	2,136.9	1,998.0015	2,017.981515	736,563.252975

The projected *net GHG emission reductions* afforded by the GBESS could then be represented by the GHG emissions that *would have* been produced by newly-built peak generation assets, *minus* the GHG emissions that *would be* incurred by all charging cycles during the year using existing assets. In effect, the GBESS would move some of the local peak demand from the times during the day when *new* peaking generators on the grid would be needed, to times when demand was much lower and *existing* lower-emissions generation would suffice.

The annual *baseline emissions* for the GBESS was therefore determined to be equivalent to the amount of energy dispatched over a typical year (in MWh), multiplied by the earlier determined baseline emission factor of 0.318 t CO_2e/MWh (section 5.2.2 and 5.6) — illustrated below in Figure 5.8.1-3.

$$bE_{GBESS} = \left(\sum_{i=1}^{d} e_i\right) \cdot slf \cdot lpf \cdot bEf$$

Where:
bE_{GBESS} = baseline emissions (tCO_2e) for the GBESS project activity
d = number of days to be quantified
e = total energy dispatched by the battery through *discharging* activities in each calendar day (mWh)
slf = system loss factor derived from the round-trip efficiency (RTE) of the GBESS
lpf = loss penalty factor (LPF) attributed to transmission and distribution losses
bEf = baseline emission factor (tCO_2e/MWh) attributed to the GBESS project activity

$$bE_{GBESS} = 2.1369 \text{ MWh x } 365 \text{ days} \times 0.935 \times 1.01 \times 0.318 \text{ tCO}_2\text{e/MWh}$$
$$bE_{GBESS} = 779.9685 \text{ MWh} \times 0.935 \times 1.01 \times 0.318 \text{ tCO}_2\text{e/MWh}$$
$$bE_{GBESS} = 729.2705475 \text{ MWh} \times 1.01 \times 0.318 \text{ tCO}_2\text{e/MWh}$$
$$bE_{GBESS} = 736.563252975 \text{ MWh} \times 0.318 \text{ tCO}_2\text{e/MWh}$$
$$bE_{GBESS} = \mathbf{234.227114446 \text{ tCO}_2\text{e/year}}$$

Figure 5.8.1-3. Formula and calculation of the annual baseline emissions for the GBESS project activity.

The annual *project emissions* were then calculated (Figure 5.8.1-4) based on the amount of energy consumed by the GBESS during charging activities (accounting for losses attributed to transmission, distribution, and internal battery systems), multiplied by the “grid electricity consumption emission factors” for Ontario in 2019 of 0.04 t CO2e/MWh (Environment and Climate Change Canada, 2017, as cited by Natural Resources Canada, n.d.).

$$pE_{GBESS} = \left(\sum_{i=1}^{d} e_i\right) \cdot lpf \cdot slf \cdot gEf$$

Where:
pE_{GBESS} = project emissions (tCO_2e) for the GBESS project activity
d = number of days to be quantified
e = total energy stored in the battery by *charging* activities in each calendar day (mWh)
lpf = loss penalty factor (LPF) attributed to transmission and distribution losses

slf = system loss factor derived from the round-trip efficiency (RTE) of the GBESS
gEf = grid electricity consumption emission factor (tCO_2e/MWh)

$$pE_{GBESS} = 2.1369 \text{ MWh} \times 365 \text{ days} \times 1.01 \times 1.07 \times 0.04 \text{ tCO}_2\text{e/MWh}$$
$$pE_{GBESS} = 779.9685 \text{ MWh} \times 1.01 \times 1.07 \times 0.04 \text{ tCO}_2\text{e/MWh}$$
$$pE_{GBESS} = 787.768185 \text{ MWh} \times 1.07 \times 0.04 \text{ tCO}_2\text{e/MWh}$$
$$pE_{GBESS} = 842.91195795 \text{ MWh} \times 0.04 \text{ tCO}_2\text{e/MWh}$$
$$pE_{GBESS} = \mathbf{33.716478318 \text{ tCO}_2\text{e/year}}$$

Figure 5.8.1-4. Formula and calculation of the annual project emissions for the GBESS project activity.

It was then projected that the GBESS project activity would likely result in a *net reduction* in annual GHG emissions (Table 5.8.1-3) amounting to the difference between the above two sums.

Table 5.8.1-3

GBESS Annual Net GHG Reductions

Baseline emissions (tCO_2e/year)	Project emissions (tCO_2e/year)	GHG reductions (tCO_2e/year)
234.227114446	33.716478318	200.510636128

5.8.2 Residential battery energy storage systems (RBESS).

The assumptions for the fleet of RBESS units were the same as those presented previously in section 5.8.1. The RBESS fleet would be treated by the DERMS as a single resource, albeit with some variability with respect to the specific demand and constraints imposed on each unit by the residence in which they were each installed. For the purposes of this baseline scenario projection, the array of RBESS units was treated as a single resource.

The analysis began with the accounting of all energy inputs required for the complete *charging* of a single RBESS unit. It was determined that the DERMS was configured to limit the minimum SOC to only 20%, but would allow for a 100% charge state (P. Ewald, personal communication, November 26, 2020). As such, each RBESS was assigned an *effective* capacity of **10.8 kWh** (13.5 kWh * 0.8). This slightly reduced capacity then needed to be subjected to a "Loss-Penalty Factor" (IESO, 2020) to account for appropriate transmission and distribution losses (GHG Protocol, 2007, Section 3.3). This meant that for a complete charge it would require **10.908 kWh** (10.8 kWh * 1.01) of electrical energy from the utility grid.

Next, it was necessary to account for ½ of the losses associated with the specified RTE of 90% (Tesla, n.d.) and apply them to the charging phase — an approximate energy loss of 10% for a *full charge-discharge cycle*. Like with the previous GBESS analysis, half of these losses (5% in this case) were associated with the charge phase — resulting in a 95% efficiency for this function of the RBESS. Expressed as a *system loss factor* of approximately 1.053 (1 ÷ 0.95), this would help quantify the additional energy needed to compensate for battery control processes and thermal losses associated with charging. Accounting for such losses meant that **11.486124 kWh** (10.908 kWh * 1.053) would be required for a single full charge of one RBESS unit from 20% to 100% SOC.

The next step involved quantifying the amount of energy consumed over an entire calendar year, assuming only a single charge event per day. The resulting annual total of **4,192.43526 kWh** (11.486124 * 365 days) would then need to be multiplied by the number of units included in the SPEEDIER fleet (10), which amounted to **41,924.3526 kWh** or **41.9243526 MWh**. The complete RBESS fleet annual charging analysis is summarized below in Table 5.8.2-1. The preceding calculations are also depicted as a formula in Figure 5.8.2-1.

Table 5.8.2-1

Annual RBESS Charging Analysis

	Capacity	SOC limits (effective capacity)	Loss-Penalty Factor (transmission and distribution losses	½ RTE Losses (battery system loss factor)	Annual Charge Cycles	RBESS Fleet (10 units)
RBESS	13.5 kWh	20% / 100%	1.01	1.053	365	10
Net Impact (kWh)	0	- 2.7	+ 0.108	+ 0.578124	N/A	N/A
Energy Consumed (kWh)	13.5	10.8	10.908	11.486124	4,192.43526	41,924.3526

Accounting for the energy transactions involved with annual *discharging* of the RBESS fleet followed much the same methodology as the GBESS analysis, beginning with the SOC limit of 100% to 20% imposed by the DERMS. With only 80% of the nameplate capacity available from each unit, this meant that only **10.8 kWh** (13.5 kWh * 0.8) was available for dispatch. As with the charging phase, the remaining ½ of the losses associated with the RTE needed to be assessed, amounting to 5% of the energy stored for discharge (a loss factor of 0.95). For the baseline calculations, each RBESS battery would therefore have displaced **10.26 kWh** (10.8 kWh * 0.95) of peak-demand energy from the provincial grid per discharge, but this also needed to factor in the associated transmission and distribution losses (GHG Protocol, 2007, Section 3.3). Therefore, a transmission and distribution loss factor of 1.01 was applied, representing a “Loss-Penalty Factor” of all generators on contract with IESO for the baseline year 2019 (IESO, 2020). This meant that grid operators and generators would have needed to provide even more energy to offer the *equivalent service* as one complete discharge, equating to **10.3626 kWh** (10.26 kWh * 1.01) per RBESS unit. Next, the amount of grid energy displaced by a single RBESS discharge event then needed to be considered over the course of a full year, which amounted to **3,782.349 kWh** (10.3626 kWh * 365 days). Finally, the assessment needed to account for 10 RBESS units included in the SPEEDIER fleet, for a total of **37,823.49 kWh** or **37.82349 MWh** (3,782.349 kWh * 10 units). The preceding analysis is captured below in Table 5.8.2-2.

Table 5.8.2-2

Annual RBESS Discharge Analysis

	Capacity	SOC Limits (effective capacity)	½ RTE Losses (battery system loss factor	Loss-Penalty Factor (transmission and distribution losses)	Annual Discharge Cycles	RBESS Fleet (10 units)
RBESS	13.5 kWh	20% / 100%	0.95	1.01	365	10
Net Impact (kWh)	0	- 2.7	- 0.54	+ 0.1026	N/A	N/A
Energy Dispatched (kWh)	13.5	10.8	10.26	10.3626	3,782.349	37,823.49

As with the GBESS, the *net GHG emissions reductions* made possible by the RBESS fleet could also be expressed as the GHG emissions that *would have* been produced by new peak generation assets, *minus* the GHG impacts of all charging cycles during the year using existing grid generation and transmission assets. The RBESS fleet was poised to shift local peak demand from periods during which higher-emitting generating assets would be deployed, to times when demand was much lower, and baseload supply was ample.

The yearly *baseline emissions* for the RBESS fleet was assessed as the quantity of energy deployed over the course of a year, multiplied by the previously assigned emission factor of 0.318 t CO_2e/MWh (section 5.2.3 and 5.6). The complete calculation procedure for annual baseline emissions for the RBESS project activity is illustrated below in Figure 5.8.2-1.

$$bE_{RBESS} = \left(\sum_{i=1}^{d} e_i\right) \cdot slf \cdot lpf \cdot n \cdot bEf$$

Where:
bE_{RBESS} = baseline emissions (tCO_2e) for the RBESS project activity
d = number of days to be quantified
e = total energy dispatched by the battery through *discharging* activities in each calendar day (mWh)
slf = system loss factor derived from the round-trip efficiency (RTE) of the RBESS
lpf = loss penalty factor (LPF) attributed to transmission and distribution losses
n = number of RBESS fleet units
bEf = baseline emission factor (tCO_2e/MWh) attributed to the RBESS project activity

$$bE_{RBESS} = 0.0108 \text{ MWh x } 365 \text{ days} \times 0.95 \times 1.01 \times 10 \text{ units} \times 0.318 \text{ tCO}_2\text{e/MWh}$$
$$bE_{RBESS} = 3.942 \text{ MWh} \times 0.95 \times 1.01 \times 10 \text{ units} \times 0.318 \text{ tCO}_2\text{e/MWh}$$
$$bE_{RBESS} = 3.7449 \text{ MWh} \times 1.01 \times 10 \text{ units} \times 0.318 \text{ tCO}_2\text{e/MWh}$$
$$bE_{RBESS} = 3.782349 \text{ MWh} \times 10 \text{ units} \times 0.318 \text{ tCO}_2\text{e/MWh}$$
$$bE_{RBESS} = 37.82349 \text{ MWh} \times 0.318 \text{ tCO}_2\text{e/MWh}$$
$$bE_{RBESS} = \mathbf{12.02786982 \text{ tCO}_2\text{e/year}}$$

Figure 5.8.2-1. Formula and calculation of the annual baseline emissions for the RBESS project activity.

The GHG emissions associated with this *project activity* (Figure 5.8.2-2) was then determined by multiplying the annual amount of energy consumed by the RBESS fleet during charging activities, multiplied by the “grid electricity consumption emission factors” for Ontario in 2019 of 0.04 t CO2e/MWh (Environment and Climate Change Canada, 2017, as cited by Natural Resources Canada, n.d.), as it was with the previous GBESS project activity calculation.

$$pE_{RBESS} = \left(\sum_{i=1}^{d} e_i\right) \cdot lpf \cdot slf \cdot n \cdot gEf$$

Where:
pE_{RBESS} = project emissions (tCO_2e) for the RBESS project activity
d = number of days to be quantified
e = total energy stored in the battery by *charging* activities in each calendar day (mWh)
lpf = loss penalty factor (LPF) attributed to transmission and distribution losses
slf = system loss factor derived from the round-trip efficiency (RTE) of the RBESS
n = number of RBESS fleet units
gEf = grid electricity consumption emission factor (tCO_2e/MWh)

$$pE_{RBESS} = 0.0108 \text{ MWh} \times 365 \text{ days} \times 1.01 \times 1.053 \times 10 \text{ units} \times 0.04 \text{ tCO}_2\text{e/MWh}$$
$$pE_{RBESS} = 3.942 \text{ MWh} \times 1.01 \times 1.053 \times 10 \text{ units} \times 0.04 \text{ tCO}_2\text{e/MWh}$$
$$pE_{RBESS} = 3.98142 \text{ MWh} \times 1.053 \times 10 \text{ units} \times 0.04 \text{ tCO}_2\text{e/MWh}$$
$$pE_{RBESS} = 4.19243526 \text{ MWh} \times 10 \text{ units} \times 0.04 \text{ tCO}_2\text{e/MWh}$$
$$pE_{RBESS} = 41.9243526 \text{ MWh} \times 0.04 \text{ tCO}_2\text{e/MWh}$$
$$pE_{RBESS} = \mathbf{1.676974104 \ tCO_2e/year}$$

Figure 5.8.2-2. Formula and calculation of the annual project emissions for the RBESS project activity.

Consequently, the difference between the RBESS baseline and the project activity was determined to result in a *projected net reduction* in annual GHG emissions as detailed below (Table 5.8.2-3).

Table 5.8.2-3

RBESS Annual Net GHG Reductions

Baseline emissions (tCO_2e/year)	Project emissions (tCO_2e/year)	GHG reductions (tCO_2e/year)
12.02786982	1.676974104	10.350895716

5.8.3 Load-control managed hot water tanks (HWT).

In a manner similar to both the GBESS and the RBESS systems, the DERMS was to be configured to defer heating of water until times when demand was lower, during periods when grid generation was supplied by lower-emitting sources. In order to calculate an annual baseline emission for the HWT fleet, the total amount of energy consumed in the process of heating water needed to be estimated with a reasonable degree of accuracy, and multiplied by the determined baseline emission factor (section 5.2.4). This baseline emission total was then compared with the project emissions — obtained by multiplying the total annual energy consumption by the “grid electricity consumption emission factors” for Ontario in 2019 (Environment and Climate Change Canada, 2017, as cited by Natural Resources Canada, n.d.) — as it was with the previous GBESS and RBESS project activities.

The vendor for the load-control managed HWT units, Packetized Energy, had provided Lakeland Holding Ltd. with average mean daily consumption data (in kWh) for their HWT fleet units for each day of the baseline year, 2019. However, the vendor noted that *not all* the units included in the data set were installed and reporting data for the entire 2019 calendar year. The 2019 data set was compared with a 2019-2020 data set to determine if the earlier months of the 2019 year were typical. The two data sets described a very similar consumption profile, with the exception of March, April, and May 2020, where average HWT energy consumption was slightly, but noticeably elevated (Figure 5.8.3-1). It is possible that this difference was a result of the COVID-19

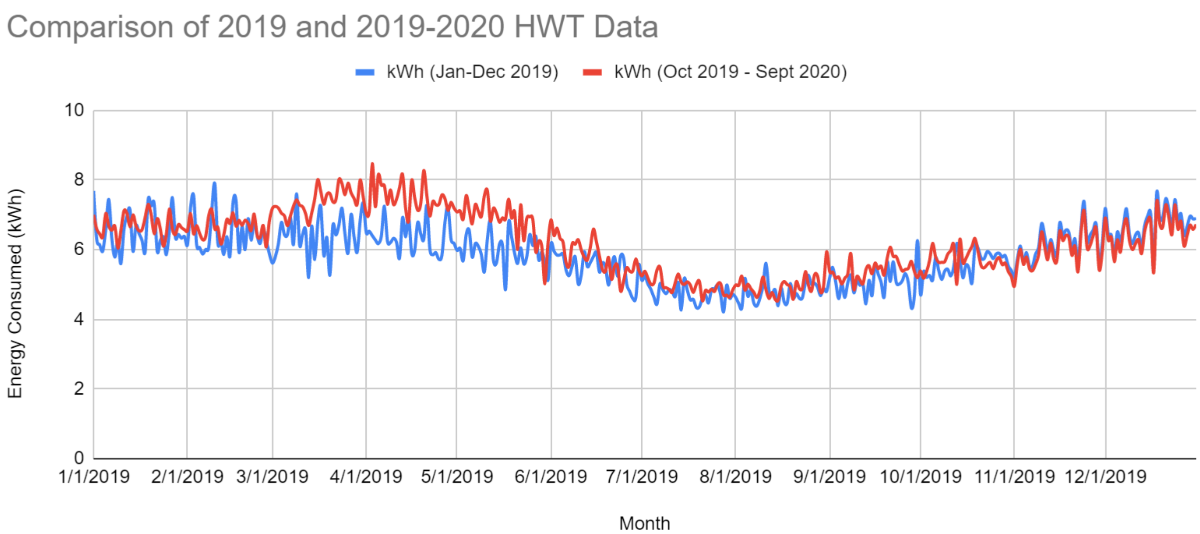

Figure 5.8.3-1. Comparison of 2019 and 2019-2020 mean daily energy consumption profiles for load-control managed HWT units (Packetized Energy, 2020).

lockdown and quarantine period when families spent more time at home during the daytime hours. The data was collected from the vendor’s existing fleet, consisting of tanks of either 184 or 279 litres (40 or 60 imperial gallons respectively), predominantly equipped with 4.5 kW heaters at 240 V (15-20 A) (meeting with Lakeland Holding Ltd. and vendor, October 15, 2020). Using the baseline 2019 year data, an *annual mean energy consumption* of **2,135.293447 kWh** for a single HWT unit of the type to be deployed in the SPEEDIER fleet was obtained for the purposes of determining a defensible *baseline scenario*.

To this end, and considering that the energy for the HWT fleet would be provided by the Ontario grid, a "Loss-Penalty Factor" of 1.01 (IESO, 2020) was applied to the previously mentioned mean energy consumption total, resulting in a slightly higher annual energy demand of **2,156.64638147 kWh** (2,135.293447 kWh * 1.01). With 50 HWT units in the SPEEDIER fleet, the annual energy consumption needed to be scaled accordingly, resulting in an annual consumption total of **107,832.319073 kWh** (2,156.64638147 kWh * 50 units) or **107.832319073 MWh**. The *baseline emissions* for the HWT fleet were then determined (Figure 5.8.3-2) by multiplying the above energy consumption value by the earlier determined emission factor of 0.17075 t CO_2e/MWh (section 5.2.4 and 5.6), which resulted in a total of **18.4123684818 tCO_2e/year** (107.832319073 MWh * 0.17075 tCO_2e/MWh).

$$bE_{HWT} = \left(\sum_{i=1}^{d} e_i\right) \cdot lpf \cdot n \cdot bEf$$

Where:
bE_{HWT} = baseline emissions (tCO_2e) for the HWT project activity
d = number of days to be quantified
e = total energy consumed by a single electric hot water tank in each calendar day (mWh)
lpf = loss penalty factor (LPF) attributed to transmission and distribution losses
n = number of HWT fleet units
bEf = baseline emission factor for the HWT project activity (tCO_2e/MWh)

$$bE_{HWT} = 2.135293447 \text{ MWh} \times 1.01 \times 50 \text{ units} \times 0.17075 \text{ tCO}_2\text{e/MWh}$$
$$bE_{HWT} = 2.15664638147 \text{ MWh} \times 50 \text{ units} \times 0.17075 \text{ tCO}_2\text{e/MWh}$$
$$bE_{HWT} = 107.832319073 \text{ MWh} \times 0.17075 \text{ tCO}_2\text{e/MWh}$$
$$bE_{HWT} = \mathbf{18.4123684818 \text{ tCO}_2\text{e/year}}$$

Figure 5.8.3-2. Formula and calculation of the annual baseline emissions for the HWT project activity.

Annual *project emissions* attributable to this project activity were then determined (Figure 5.8.3-3) using the same method as described above, but instead employing the 2019 Ontario grid emission factor of 0.04 tCO2e/MWh (Environment and Climate Change Canada, 2017, as cited by Natural Resources Canada, n.d.). It was thus

$$pE_{HWT} = \left(\sum_{i=1}^{d} e_i\right) \cdot lpf \cdot n \cdot gEf$$

Where:
pE_{HWT} = project emissions (tCO_2e) for the HWT project activity
d = number of days to be quantified
e = total energy consumed by a single electric hot water tank in each calendar day (mWh)
lpf = loss penalty factor (LPF) attributed to transmission and distribution losses
n = number of HWT fleet units
gEf = grid electricity consumption emission factor (tCO_2e/MWh)

$$pE_{HWT} = 2.135293447 \text{ MWh} \times 1.01 \times 50 \text{ units} \times 0.04 \text{ tCO}_2\text{e/MWh}$$
$$pE_{HWT} = 2.15664638147 \text{ MWh} \times 50 \text{ units} \times 0.04 \text{ tCO}_2\text{e/MWh}$$
$$pE_{HWT} = 107.832319073 \text{ MWh} \times 0.04 \text{ tCO}_2\text{e/MWh}$$
$$pE_{HWT} = \mathbf{4.31329276292 \text{ tCO}_2\text{e/year}}$$

Figure 5.8.3-3. Formula and calculation of the annual project emissions for the HWT project activity.

anticipated that the HWT project activity would result in a net reduction in annual GHG emissions amounting to the difference between the above two sums (Table 5.8.3).

Table 5.8.3

HWT Annual Net GHG Reductions

Baseline emissions (tCO_2e/year)	Project emissions (tCO_2e/year)	GHG reductions (tCO_2e/year)
18.4123684818	4.31329276292	14.0990757189

5.8.4 Photovoltaic (PV) solar array.

The calculation of the baseline emission scenario for this project activity relied on performance data from the solar module contractor for the specified array, which incorporated parameters about the specific latitude and climate in which the system would be deployed in a software-based simulation (RESCo Energy Inc., 2020). The amount of energy the system was expected to produce would be factored by the baseline emission rate determined earlier in this case study (sections 5.2.1 and 5.7). Any and all contributions to local energy demand were deemed to displace an equivalent amount of energy that would have otherwise been provided by Ontario grid generators and transmission system operators, as the PV solar module array would not produce any materially significant emissions during the service phase of the product life cycle.

The vendor conveniently assessed the *annual* aggregated energy output of the PV solar module array at **780,590 kWh**, conservatively factoring in “Collection Loss (PV-array losses)” and “System Loss” which includes inverter losses (RESCo Energy Inc., 2020, p. 4). The *baseline emissions* for this project activity also needed to include the aforementioned “Loss-Penalty Factor” (IESO, 2020) to account for appropriate transmission and distribution losses (GHG Protocol, 2007, Section 3.3), amounting to **788,395.9 kWh** (780,590 kWh * 1.01) or **788.3959 MWh**. There were no material energy consumption amounts to account for with the operation of the PV solar module array system. Any net GHG *emission reductions* that could be attributed to this project activity would have amounted to the emissions that *would have* been released by generation and transmission activities involved in producing energy of the character associated with the PV solar array — determined earlier in this study to be attributed wholly to the OM (section 5.2.1).

Annual *baseline emissions* for the PV solar array (Figure 5.8.4-1) were calculated using the annual energy production, plus applicable transmission and distribution losses, multiplied by the earlier decided baseline GHG emission factor of 0.0235 t CO_2e/MWh (section 5.7).

$$bE_{PV} = \left(\sum_{i=1}^{d} e_i\right) \cdot lpf \cdot bEf$$

Where:
bE_{PV} = baseline emissions (tCO_2e) for the PV solar array project activity
d = number of days to be quantified
e = total energy generated by the entire PV solar array in each calendar day (mWh)
lpf = loss penalty factor (LPF) attributed to transmission and distribution losses
bEf = baseline emission factor for the PV solar array project activity (tCO_2e/MWh)

bE_{PV} = 780.590 MWh × 1.01 × 0.0235 tCO_2e/MWh
bE_{PV} = 788.3959 MWh × 0.0235 tCO_2e/MWh
bE_{PV} = **18.52730365 tCO_2e/year**

Figure 5.8.4-1. Formula and calculation of the annual baseline emissions for the PV solar array project activity.

Annual *project emissions* could have included some one-time GHG emissions (GHG Protocol, 2007, p. 27) from construction and transportation activities associated with the installation of the array (amortized over the 5-year span of the GHG project), but these data were not available at the time of this assessment and were thus excluded. Net GHG reduction projections for this project activity are summarized below (Table 5.8.4).

Table 5.8.4

PV Solar Array Annual Net GHG Reductions

Baseline emissions (tCO_2e/year)	Project emissions (tCO_2e/year)	GHG reductions (tCO_2e/year)
18.52730365	0	18.52730365

5.8.5 Electric vehicle (EV) DCFC public charging station.

Recognizing that the DCFC public charging station project activity did not provide any generation capacity (section 5.2.5), and its operational impact *within the project assessment boundary* would have constituted additional demand, it was determined notwithstanding that it *enabled* the operation of electrified transportation that would displace the consumption of a quantifiable amount of gasoline (or possibly diesel fuel). While the GHG Protocol would have discounted the emissions displaced by the vehicles that might use the charging station (as they are outside the project assessment boundary), the Natural Resources Canada Smart Grid reporting template (Natural Resources Canada, n.d.) included the ability to quantify GHG emission reductions that were *indirectly made possible* by such project activities. This section of the paper describes the analysis that was used to quantify the net GHG impact of the operation of the DCFC charging station over a typical year, incorporating a number of fair and reasonable assumptions.

The initial task was to estimate the average energy to be consumed per day by a single charger unit of this type, at this particular geographical location. An extensive effort to obtain utilization data for a comparable facility revealed a significant scarcity of this type of information. This limitation necessitated the use of data from a different location and from a slightly different timeframe than the baseline year. In the absence of more precise utilization data, the Rocky Mountain Institute (Fitzgerald, 2020) recommended applying a 5% utilization rate for the purposes of establishing a fee structure for planned infrastructure of this type. A data set consisting of 3,432 hours or 143 days worth of data for the year 2020 provided by the project vendor (SWTCH Energy Inc., 2020) revealed a comparable utilization rate of 4.6162986%, corroborating the recommendation above by Fitzgerald (2020). The vendor’s data set was used to project conceivable annual usage for the SPEEDIER DCFC unit — resulting in a defensible (and conservative) *daily* energy consumption total of **32.18385594 kWh** (SWTCH Energy Inc., 2020). It was then necessary to determine the average efficiency of electric vehicles (EVs) available to Ontario drivers using combined city and highway data for the SPEEDIER baseline year which was **20.09428571 kWh/100km**, a figure publically available from Natural Resources Canada (2019). Using the above two numbers, it was then possible to calculate *how far on average a single DCFC station enabled a typical EV to travel in a day*. This involved converting the efficiency rate to kilowatt hours per kilometer (100km / 20.09428571 kWh = **4.97653917353 km/kWh**), then multiplying that by the (previously estimated) typical daily energy consumption demanded by the DCFC charging station. This calculation revealed that the DCFC charger enabled **160.1642198407858 km** of driving as an estimated daily average.

Next, it was required to calculate *how much gasoline* would be consumed (along with a commensurate amount of GHG emissions) *if a comparable gasoline-powered vehicle were to travel the same distance* determined in the previous step. This required consulting the average fuel economy figures for Canadian personal vehicles during the baseline 2019 year. The closest available data was obtained from the Canada Energy Regulator (2019) for the year 2017, which was 8.9 litres of gasoline per 100 kilometers (or **0.089 L/km**) of combined city and highway driving. This figure yielded a volume of **14.25461556582994 L** of gasoline (0.089 L/km * 160.1642198407858 km).

The final step in this analysis was to obtain and apply a conservative GHG emission factor for Canadian light-duty vehicles (Environment and Climate Change Canada, 2017, Table A6-12) for the combustion of the above quantity of fuel, in order to determine the daily emissions displaced by this project activity, reported in *grams* of CO_2e. At **2,317 gCO_2e/L**, the volume of gasoline being considered amounted to

33,027.94426602796 gCO2e per day (14.25461556582994 L * 2,317 gCO_2e/L). This was then converted to a quantity expressed in *tonnes* (rather than grams) of carbon dioxide equivalent produced over the course of a typical year — **12.055199657100210686 tCO_2e** (0.03302794426602796 tCO_2e/day * 365 days). The above baseline emissions calculations are illustrated below in Figure 5.8.5-1 and then summarized in Table 5.8.5-1.

$$bE_{DCFC} = \frac{\left(\sum_{i=1}^{d} e_i\right)\left(\frac{100}{ee_{EV}}\right)\left(\frac{ee_{ICE}}{100}\right)\cdot Ef_{ICE}}{1{,}000{,}000}$$

Where:
bE_{DCFC} = baseline emissions (tCO_2e) for the DCFC charging station project activity
d = number of days to be quantified
e = total energy consumed by charging sessions at the DCFC facility in each calendar day (kWh)
ee_{EV} = energy efficiency of a typical battery electric vehicle expressed in kilowatt hours per 100 km (kWh/100km)
ee_{ICE} = energy efficiency of a comparable vehicle powered by an internal combustion engine expressed in litres of gasoline per 100 kilometers (L/100km)
Ef_{ICE} = emission factor for light-duty internal combustion engine vehicles expressed in grams of carbon dioxide equivalent per litre of gasoline (gCO_2e/L)

bE_{DCFC} = 11,747.1074181 kWh × 4.97653917353 km/kWh × 0.089 L/km × 2,317 gCO_2e/L ÷ 1,000,000
bE_{DCFC} = 58,459.9402418 km × 0.089 L/km × 2,317 gCO_2e/L ÷ 1,000,000
bE_{DCFC} = 5202.93468152 L × 2,317 gCO_2e/L ÷ 1,000,000
bE_{DCFC} = 12,055,199.6571 gCO_2e ÷ 1,000,000
bE_{DCFC} = **12.0551996571 tCO_2e/year**

Figure 5.8.5-1. Formula and calculation of the annual baseline emissions for the DCFC charging station project activity.

Table 5.8.5-1

Calculation of Annual GHG Emissions Displaced by DCFC Project Activity

Mean daily EV charger energy consumption	Typical EV energy efficiency (combined city/hwy)	Daily Distance enabled by EV charger	Quantity of fuel consumed for equivalent distance (at 8.9L/100km)	Daily GHG emissions (at 2,317 g/L)	Annual GHG emissions (1 charger unit)
32.18385594 kWh	20.09428571 kWh/100km	160.1642198407858 km	14.25461556582994 L	33,027.94426602796 gCO_2e	12.055199657100210686 tCO_2e

In order to project what the net GHG reductions might be, any *project emissions* produced through the generation and transmission of energy demanded by the DCFC EV charger had to be subtracted from the emissions potentially displaced by the vehicle kilometers enabled by the facility. To start with, the daily energy consumption of the DCFC unit needed to be expanded to include the appropriate “Loss-Penalty Factor” (IESO, 2020) — a factor of 1.01 for the baseline year 2019. At the utilization rate determined earlier in this section, the *effective* DCFC facility daily consumption was therefore calculated to be **32.5056944994 kWh** (32.18385594 kWh * 1.01) when accounting for transmission and distribution losses. Annual GHG *emission* totals to be attributed to this project activity were then derived using the 2019 Ontario grid emission factor of 0.04 t CO2e/MWh (Environment and Climate Change Canada, 2017, as cited by Natural Resources Canada, n.d.), resulting in a potential **0.474583139691 tCO_2e** per year (0.0325056944994 MWh * 365 days * 0.04 tCO_2e/MWh). The above project emissions calculation is illustrated as a formula below (Figure 5.8.5-2).

$$pE_{DCFC} = \left(\frac{\sum_{i=1}^{d} e_i}{1,000} \right) \cdot lpf \cdot gEf$$

Where:
pE_{DCFC} = baseline emissions (tCO_2e) for the DCFC charging station project activity
d = number of days to be quantified
e = total energy consumed by charging sessions at the DCFC facility in each calendar day (kWh)
lpf = loss penalty factor (LPF) attributed to transmission and distribution losses
gEf = grid electricity consumption emission factor (tCO_2e/MWh)

pE_{DCFC} = (32.18385594 kWh × 365 days ÷ 1,000) × 1.01 × 0.04 tCO_2e/MWh
pE_{DCFC} = (11747.1074181 kWh ÷ 1,000) × 1.01 × 0.04 tCO_2e/MWh
pE_{DCFC} = 11.7471074181 MWh × 1.01 × 0.04 tCO_2e/MWh
pE_{DCFC} = 11.8645784923 MWh × 0.04 tCO_2e/MWh
pE_{DCFC} = **0.474583139691 tCO_2e/year**

Figure 5.8.5-2. Formula and calculation of the annual project emissions for the DCFC charging station project activity.

The resulting net GHG reduction projections for the DCFC EV charger project activity — the difference between the previously determined baseline emissions and the emissions attributed to the project activity — are summarized below (Table 5.8.5-2).

Table 5.8.5-2

DCFC EV Charger Annual Net GHG Reductions

Baseline emissions (tCO_2e/year)	Project emissions (tCO_2e/year)	GHG reductions (tCO_2e/year)
12.0551996571	0.474583139691	11.5806165174

5.8.6 Electric vehicle (EV) L2 charging stations.

Similarly to the DCFC project activity, the slower-charging Level 2 (L2) EVSE units did not represent additional energy production capacity, but rather an *additional demand* within the SPEEDIER assessment boundary. In accordance with the GHG Protocol guidance, while this project activity accounted for a new source of GHG emissions, the installation of these chargers *enabled* the displacement of a quantifiable volume of transportation fuel used by internal combustion engines. Like the DCFC facility, Natural Resources Canada sought to include the GHG emission reductions made possible by this new EV charging infrastructure. The remainder of this section documents the process used to determine both a baseline emissions scenario and a project emission estimate for the L2 chargers.

To begin with, an estimate of the average daily energy consumption to be attributed to a single L2 charger was required. As with the DCFC assessment, a data set from the hardware vendor (SWTCH Energy Inc., 2020) — from a site in Toronto, Ontario — was used to produce a reasonable estimate, based on 7,608 hours or 317 days worth of data for the year 2020. This data set revealed a utilization rate of 4.6163%, corresponding closely with the Rocky Mountain Institute’s recommendation to apply a 5% utilization rate (Fitzgerald, 2020) for the purposes of economic forecasting. This analysis began with a conservative value of **5.490716088 kWh** daily energy consumption for a single L2 charger. The following step involved obtaining the average energy economy rate for electric vehicles (EVs) in Ontario (Natural Resources Canada, 2019), as used in the previous DCFC project activity analysis (20.09428571 kWh/100km). The above two numbers then were used to determine *how far a single L2 charge station might enable a typical Ontario EV driver to travel in an average day*. This required the conversion of the efficiency rate to kilowatt hours per kilometer (100km / 20.09428571 kWh = **4.97653917353 km/kWh**), then multiplying that by the earlier estimated daily energy requirement for the L2 charging station. The resulting calculations indicated that the L2 charger enabled **27.3247637027 km** of driving per day ((100km ÷ 20.09428571 kWh) * 5.490716088 kWh).

The following step involved calculating how much gasoline would be required to drive the *same distance* using an internal combustion engine. Again, data from the Canada Energy Regulator (2019) offered a figure of 8.9L/100km (or **0.089L/km**) for 2017, which was used here again, as in the prior DCFC analysis. This resulted in a volume of **2.43190396954 L** of gasoline (0.089 L/km * 27.3247637027 km). Lastly, a conservative GHG emission factor needed to be applied to the combustion of the above volume of gasoline in order to calculate the daily emissions in *grams* of CO_2e. The combustion of the amount of fuel in question was determined to produce **5,634.72149742 gCO_2e** per day (2.43190396954 L * 2,317 gCO2e/L). This quantity was then converted to the number of *tonnes* of CO_2e emitted over the course of an entire year, by a fleet of *three* chargers deployed as part of the SPEEDIER initiative, for a grand total of **6.17002003967 tCO_2e** ((5,634.72149742 gCO2e ÷ 1,000,000) * 365 days * 3 units). The above baseline emission calculations are illustrated as a formula (Figure 5.8.6-1) and also summarized below in Table 5.8.6-1.

$$bE_{L2} = \frac{\left(\sum_{i=1}^{d} e_i\right)\left(\frac{100}{ee_{EV}}\right)\left(\frac{ee_{ICE}}{100}\right)\cdot Ef_{ICE}\cdot n}{1{,}000{,}000}$$

Where:
bE_{L2} = baseline emissions (tCO_2e) for the L2 charging station project activity
d = number of days to be quantified
e = total energy consumed by charging sessions at the L2 facilities in each calendar day (kWh)
ee_{EV} = energy efficiency of a typical battery electric vehicle expressed in kilowatt hours per 100 km (kWh/100km)
ee_{ICE} = energy efficiency of a comparable vehicle powered by an internal combustion engine expressed in litres of gasoline per 100 kilometers (L/100km)
Ef_{ICE} = emission factor for light-duty internal combustion engine vehicles expressed in grams of carbon dioxide equivalent per litre of gasoline (gCO_2e/L)
n = number of units comprising the L2 EVSE fleet

bE_{L2} = 2,004.11137212 kWh × 4.97653917353 km/kWh × 0.089 L/km × 2,317 gCO_2e/L × 3 units ÷ 1,000,000
bE_{L2} = 9,973.53875147 km × 0.089 L/km × 2,317 gCO_2e/L × 3 units ÷ 1,000,000
bE_{L2} = 887.644948881 L × 2,317 gCO_2e/L × 3 units ÷ 1,000,000
bE_{L2} = 2,056,673.34656 gCO_2e × 3 units ÷ 1,000,000
bE_{L2} = 6,170,020.03967 gCO_2e ÷ 1,000,000
bE_{L2} = **6.17002003967 tCO_2e/year**

Figure 5.8.6-1. Formula and calculation of the annual baseline emissions for the L2 charging station project activity.

Table 5.8.6-1

Calculation of Annual Emissions Displaced by Level 2 EV Chargers Project Activity

Mean daily EV charger energy consumption	Typical EV energy efficiency (combined city/hwy)	Daily Distance enabled by EV charger	Quantity of fuel consumed for equivalent distance (at 8.9L/100km)	Daily GHG emissions (at 2,317 g/L)	Annual GHG emissions (3 charger units)
5.490716088 kWh	20.09428571 kWh/100km	27.3247637027 km	2.43190396954 L	5,634.72149742 gCO_2e	6.17002003967 tCO_2e

To estimate the GHG reductions enabled by this project activity, the *difference* between the emissions produced by *supplying energy to the chargers* (project emissions) and the *emissions displaced by the electrically-powered kilometers driven* made possible by the facility (baseline emissions) would need to be calculated. In order to determine the *project emissions*, the energy dispatched to the L2 chargers needed to include any appropriate “Loss-Penalty Factor” (IESO, 2020) to account for transmission and distribution losses — specifically a factor of 1.01 for the year 2019. The required **5.54562324888 kWh** (5.490716088 kWh * 1.01) of energy needed per day from the Ontario grid then needed to be multiplied by the number of chargers in the fleet, for a total of **16.6368697466 kWh** (5.54562324888 * 3 units). This daily fleet consumption represented an *annual* amount of 6,072.45745752 kWh of energy or **6.07245745752 MWh**. The resulting GHG emissions produced by this project activity were then calculated using the 2019 Ontario grid emission factor of 0.04 tCO_2e/MWh as cited by Natural Resources Canada (n.d.) — for a total of **0.2428982983 tCO_2e** (6.07245745752

MWh * 0.04 tCO_2e/MWh). The preceding calculation is illustrated below in Figure 5.8.6-2.

$$pE_{L2} = \left(\frac{\sum_{i=1}^{d} e_i}{1{,}000} \right) \cdot lpf \cdot n \cdot gEf$$

Where:
pE_{L2} = baseline emissions (tCO_2e) for the L2 charging station project activity
d = number of days to be quantified
e = total energy consumed by charging sessions by the L2 fleet in each calendar day (kWh)
lpf = loss penalty factor (LPF) attributed to transmission and distribution losses
n = number of units comprising the L2 EVSE fleet
gEf = grid electricity consumption emission factor (tCO_2e/MWh)

pE_{L2} = (5.490716088 kWh × 365 days ÷ 1,000) × 1.01 × 3 units × 0.04 tCO_2e/MWh
pE_{L2} = (2,004.11137212 kWh ÷ 1,000) × 1.01 × 3 units × 0.04 tCO_2e/MWh
pE_{L2} = 2.00411137212 MWh × 1.01 × 3 units × 0.04 tCO_2e/MWh
pE_{L2} = 2.02415248584 MWh × 3 units × 0.04 tCO_2e/MWh
pE_{L2} = 6.07245745752 MWh × 0.04 tCO_2e/MWh
pE_{L2} = **0.242898298301 tCO_2e/year**

Figure 5.8.6-2. Formula and calculation of the annual project emissions for the L2 charging station fleet project activity.

The resulting net annual GHG reduction projections (baseline emissions minus the project emissions) for the Level 2 EV charger project activity are summarized below (Table 5.8.6-2).

Table 5.8.6-2

Level 2 EV Charger Annual Net GHG Reductions

Baseline emissions (tCO_2e/year)	Project emissions (tCO_2e/year)	GHG reductions (tCO_2e/year)
6.17002003967	0.242898298301	5.92712174137

5.8.7 Baseline and project emission totals.

With each of the project and baseline emissions assessments complete, determining the annual projected GHG reduction totals for the SPEEDIER initiative as a whole was achieved by calculating the *difference* between the sum of the projected annual *baseline emissions* and the sum of the estimated annual *project activity emissions*. The GHG reporting requirements from Natural Resources Canada (n.d.) also required that emission reductions that were *enabled* by project activities — namely the displacement of gasoline or diesel-fuelled vehicle travel by the EV charging stations — also be accounted for. These were tabulated separately, however, as the GHG Protocol framework placed these specific reductions *outside* of the assessment boundary for the project. The data below (Table 5.8.7) represent a relevant, consistent, transparent, accurate, and conservative assessment of the annual net GHG emission impacts of the SPEEDIER project, in keeping with the principles described in the GHG Protocol for Project Accounting (GHG Protocol, 2005) and also with due regard to the assumptions and limitations described herein.

Table 5.8.7

Projected Direct And Enabled GHG Emission Reductions For All Project Activities

Baseline Description	Emissions (tCO_2e/year)	Enabled Emissions (tCO_2e/year)
Photovoltaic solar array (PV) - 500 kW AC	18.52730365	
Grid-Scale Battery Energy Storage System (GBESS) - 2514 kWh	234.227114446	
Electric Vehicle DCFC Public Charging (DCFC) - 50 kW DC (1 unit)		12.0551996571
Electric Vehicle Level 2 Public Charging (L2) - 7 kW (3 units)		6.17002003967
Residential Battery Energy Storage System (RBESS) - 13.5 kWh (10 units)	12.02786982	
Load-Control Managed Hot Water Tanks (HWT) - 3 kW (50 units)	18.4123684818	
Total Baseline Emissions (Annual)	283.194656398	18.2252196968
Project Activity Description	Emissions (tCO_2e/year)	Enabled Emissions (tCO_2e/year)
Photovoltaic solar array (PV) - 500 kW AC	0	
Grid-Scale Battery Energy Storage System (GBESS) - 2514 kWh	33.716478318	
Electric Vehicle DCFC Public Charging (DCFC) - 50 kW DC (1 unit)		0.474583139691
Electric Vehicle Level 2 Public Charging (L2) - 7 kW (3 units)		0.242898298301
Residential Battery Energy Storage System (RBESS) - 13.5 kWh (10 units)	1.676974104	
Load-Control Managed Hot Water Tanks (HWT) - 3 kW (50 units)	4.31329276292	
Total Project Emissions (Annual)	39.7067451849	0.717481437992
	Emissions Reduction (tCO_2e/year)	Enabled Emissions Reduction (tCO_2e/year)
Annual project GHG emissions reduction (post commissioning)	243.487911213	17.5077382588

5.9 Monitoring and Quantifying GHG Emissions

After a baseline GHG emissions scenario was established to represent what would *likely* have occurred if the SPEEDIER project had not been implemented, the ongoing task of quantifying the GHG performance of the project activities was to begin (GHG Protocol, 2007, p. 68). This stage involved creating a plan to monitor each grid-connected project activity, and to quantify the respective net GHG emission reductions. The plan would detail the indirect monitoring of emissions, by describing what parameters were to be included, the monitoring frequencies, and any applicable quality assurance measures. Once the plan was designed and documented in collaboration with the LDC, data captured by the DERMS would be then used to quantify the effective GHG emissions that could be attributed directly to the primary and secondary effects of each project activity.

5.10 Reporting GHG Reductions

There were a number of stakeholders which would require GHG emission reports from the SPEEDIER project. Natural Resources Canada, as a financial supporter of the SPEEDIER initiative through the SmartGrid program, would require regulatory reporting of the GHG emissions in order to learn how investments in electrical grid modernization could help Canada to meet its GHG reduction commitments as a Paris Agreement signatory. The Town of Parry Sound would also need to communicate with the community some of the many benefits investment and participation in the SPEEDIER project was to provide. Lakeland Holding Ltd. would also need internal reporting to share the GHG emissions performance with internal stakeholders and project partners as part of a broader survey of the operational and economic benefits of the DER technology deployment. The specific reporting requirements were defined in the *The GHG Protocol for Project Accounting* (GHG Protocol, 2005), with additional requirements provided by the *Guidelines for Quantifying GHG Reductions from*

Grid-Connected Electricity Projects (2007). Natural Resources Canada also required regular reports designed to comply with the ISO 14064-2:2019 standard. It was hoped that many of the findings contained in this paper would inform the various internal and public-facing documentation that would need to be produced in the months and years to come.

6.0 Discussion

A complete assessment of the process involved in GHG accounting and reporting for the SPEEDIER project would be incomplete without a thoughtful consideration of both the benefits and the limitations of the procedure. The framework offered by *The GHG Protocol for Project Accounting* (2005), and the very sector-specific supplementary *Guidelines for Grid-Connected Electricity Projects* (2007) combined to delineate a very thorough, methodical, and relevant process for determining the GHG impacts of grid-connected electricity projects of this nature. The author and the project proponents are indebted to the many committed people and organizations that contributed to this indispensable guide, offered freely and without limitation. The following discussion is not a criticism of the GHG framework, but rather an examination of the assumptions, limitations, and benefits of its application specifically to a unique project deployed within a particular context and location during a specific period of time.

6.1 Disclosure of Assumptions

A number of assumptions were incorporated into the process that could have had a material impact on the final outcomes of the determination of the GHG baseline emission scenarios. Each of the following assumptions were made using supporting evidence from grid operators and independent research, with due regard to the principle of conservativeness (GHG Protocol, 2005).

Although part of the impetus for the SPEEDIER project was the possibility that the DERs could “defer, or even avoid, expensive system upgrades” (IESO, 2014, p. 1, Wamsted, 2019) like the aging Parry Sound TS, the present analysis was built on the assumption that the facility would be ultimately be upgraded *notwithstanding*. This assumption was not a criticism of SPEEDIER, but rather a pragmatic realization that as a *pilot project*, it did not offer sufficient *additional capacity* to address the TS load constraints, particularly during winter and summer peak demand. Furthermore, in constructing a feasible baseline scenario, it became clear that the continuation of current activities would need to include upgrading the current Parry Sound TS in order to facilitate increased imports from the Ontario grid (Hydro One, 2017). As Parry Sound would ultimately need a reliable interface to the provincial grid, this assumption was a fair and reasonable part of every scenario developed and considered.

Another significant assumption was that imports to the Ontario grid are generally the last resource to be dispatched during times of peak load. This presumption, if untrue, could have a material impact on the calculation of the OM emission factor as it would change the amount of time (and megawatt-hours) that various generation fuel types would be accounted for along the load-duration curve. Furthermore, to simplify the calculation of the effect of the OM on the baseline scenario, this imported energy was assigned an emission factor of zero, assuming that much of the capacity was supplied by Québec (OSPE, 2017) where 95% of the supply was provided by hydroelectric generators (CER, 2020), or by Manitoba (OSPE, 2017), where 87% of the installed capacity was also hydroelectric (CER, 2020).

One final assumption, with respect to the IESO's assertion that "through the mid 2020s" additional capacity will be "peaking in nature" (IESO, 2020, p. III), was that up until at least 2025, transmission-connected utility-scale GBESS would *not* be considered common practice. This represented a big assumption, as falling costs and technological improvements were beginning to show that GBESS were "well suited to serve as capacity reserves as they [could] discharge during peak hours, displacing peak generators and deferring further investment in peaking plants" (IRENA, 2019, p. 11). It remained to be seen how GBESS would be factored into the evolving Ontario electricity marketplace.

While these assumptions were understandable — if not unavoidable — there remained some significant limitations to the GHG accounting for the SPEEDIER project that should, in all fairness to project proponents and stakeholders, be disclosed.

6.2 Notable and Significant Limitations

There were a number of limitations worthy of discussion that either complicated or confounded the implementation of the framework. Some of these limitations were due to the subjectivity of some of the decision-making required, availability or scope of reliable data, or the very nature of the project itself — but they each represented factors that contributed to some of the inevitable uncertainty that goes along with analyses of this nature.

To start with, it was decided to use the “project specific” methodology to assess the BM emission effects, whereby each project activity would be assessed on its own merits. This disaggregation meant that the co-located PV solar array and the GBESS would *not be* considered together as one functional unit. The PV array would be treated as a *non-firm*, intermittent, variable source of additional capacity assigned to baseload, while the GBESS would be characterized as a *firm* (but limited), load-following, dispatchable resource. Considered in isolation, these two project activities had a certain effect on the BM and the OM, but when treated as a single asset, the *synergistic* effect of the GBESS re-defined the PV solar as a firm source of generation capacity, with a markedly different impact on grid operations. The decision to treat energy storage resources and co-located variable generation like renewable energy *as one distinct project activity* had the potential to plot a different emissions profile for the baseline calculations — particularly if applied at a larger scale.

A further limitation of this study was the emission impacts that potentially remained unaccounted for. Sulfur hexafluoride (SF_6) — a common gas used in utility-scale electrical components — has a global warming potential (GWP) of 23,500 times that of carbon dioxide (CO_2), over a 100-year time horizon (Myhre, G. et al., 2013). During the installation or decommissioning of such equipment, *fugitive emissions* of SF_6 could have an outsized impact on the GHG emissions profile of a project activity. While there are some provisions for the quantification of fugitive emissions as secondary effects, the deleterious nature of many of the synthetic gases involved underscores the importance of ensuring that unintentional leaks are properly accounted for (or preferably avoided). A similar possibility exists with the emission factors associated with natural gas generation. Significant emissions of methane (CH_4) are incurred during the "extraction, processing, transmission, storage, and distribution" (Spath & Mann, 2000) of natural gas. Methane has a GWP of 28 times that of CO_2 (Myhre, G. et al., 2013). As the second-highest gas emitted by CCGT generators, it is notable that 73% of those emissions arise from "fugitive emissions from natural gas production and distribution" (Spath & Mann, 2000, p. IV). If the emission factors for natural gas do not accurately reflect these upstream processes, or other fugitive emissions, then the GHG baselines determined by this study could be *overly conservative*.

Another notable limitation was the lack of ability at the *project level* to account for GHG emission reductions that would be achieved through the installation of the EV charging stations. Due to the fact that the provision of electricity to EVs would displace the consumption of diesel or gasoline, rather than generation capacity from the Ontario electrical grid, such emission reductions would reside *squarely outside* of the GHG *project assessment boundary* (GHG Protocol, 2007). If such activities were to be assessed at the *organizational level*, the reductions could be captured in another capacity, but as such, the EV chargers only served to *increase* attributable GHG emissions due to their effect on the OM. This was unfortunate, as the project offered additional resources for additional infrastructure that *enabled* the displacement of local transportation emissions. Thankfully, such potential for GHG emission mitigation was captured notwithstanding, as Natural Resources Canada recognized the *enabling* effect that these project activities would have on the transportation sector to displace hydrocarbon-based fuels and made provisions for the reporting of this data.

Yet another concern laid with the fact that as a pilot project, certain aspects of the project activities may not have met the *materiality thresholds* (GHG Protocol, 2005) for significance or inclusion with respect to impacts on the baseline emission scenarios. At a larger scale, it is possible that the effects of the DERs deployed by SPEEDIER could have produced more significant GHG reductions, but this insight could have been lost due to the somewhat experimental scale of the project activities.

One last concern with the present study surrounded the notion of *uncertainty*. The Ontario Society of Professional Engineers recently observed that the Ontario “electrical power system is the largest, most complex engineered system under the direction of decision-makers at Queen’s Park” (OSPE, 2017, p. 2). Given the unique and evolving characteristics of the Ontario grid, with its countless and unpredictable interactions, it should be noted that the *Guidelines for Grid-Connected Electricity Projects* specifically does *not* address uncertainty (GHG Protocol, 2007, p. 9). Perhaps with further work, both *high* and *low* baseline emission scenarios could have been established, but this would have been possible without significant additional resources.

Limitations aside, many tangible benefits could be extracted from the extensive work completed for the purposes of accounting for the GHG emission reductions made possible by the SPEEDIER project. These benefits will be discussed next.

6.3 Possible and Anticipated Benefits

While the above mentioned assumptions and limitations may have confounded and complicated the GHG emissions accounting process, the merits of the inquest made the effort a worthwhile endeavor.

It is possible that the lessons learned through this work could help LDCs, transmission grid operators, and generators avoid otherwise well-intentioned decisions (at a much larger scale) that could have unintended and detrimental effects from a GHG perspective. For example, it could be extrapolated that more numerous, smaller, distributed energy storage systems could address periods of peak demand with fewer emissions and at a lower cost than large capacity CCGT or SCGT 'peaker' plants. It might also be revealed that simple residential demand-reduction strategies could make more sense than upgrading transmission capacity to address growing local demand. There are other possible insights that could be gleaned through a study of this nature, which may inform other similar efforts to mitigate GHG emissions.

Much of the motivation for the SPEEDIER demonstration project came from the desire for electric utilities, generators, transmission and distribution companies, regulators, and policy makers to learn about the future impacts of DER deployment so that it might be done effectively and strategically. It may well be that in Ontario — as in other jurisdictions — it is determined that “renewable distributed generation units could greatly mitigate CO_2 emissions and are less costly to operate in the long run than fossil fuel based plants” (Labis et al., 2011, p. 4895).

Ultimately, efforts of this type may serve to lay the groundwork for improving the economic and transactional capacity for operators to *verifiably quantify* grid-connected GHG reductions in preparation to participate in the emerging carbon market, like the system that was already underway between Québec, California, and (briefly) Ontario (Montpetit, 2019). Frameworks like those offered by GHG Protocol were instrumental in establishing verification systems critical to the accurate pricing and trading of carbon credits. It is notable that none of the cited costs of generation using combustion technologies in this study factored in any discernible carbon pricing.

6.4 Final Thoughts

The GHP Protocol framework and guidance provided a rigorous and well-structured methodology that allowed the SPEEDIER project stakeholders to present a justifiable profile of the GHG emission impact potential of the project. Any limitations or necessary assumptions involved in such a process should not dissuade proponents from trying to assess the impact of emissions using a valuable tool like *The GHG Protocol for Project Accounting* (GHG Protocol, 2005), or the sector-specific *Guidelines for Grid-Connected Electricity Projects* (GHG Protocol, 2007).

7.0 Conclusions and Recommendations

Beyond the Natural Resources Canada requirements for Smart Grid GHG emissions reporting, it is hoped that this applied research work may help contribute to a growing body of knowledge and competencies that enable a “credible and transparent approach for quantifying and reporting GHG reductions from GHG projects” (GHG Protocol, 2005). The lessons learned through the implementation of the selected GHG accounting and reporting framework have improved the capacity of Lakeland Holding Ltd. and other project partners to help deploy additional DERs that can be configured to further reduce GHG emission impacts from the Ontario electricity system. The findings of this research may possibly be used by peer organizations to help continuously improve local, provincial, national, and global accounting and reporting tools and techniques for GHG emission mitigation. This investigative work was consistent with the Pan-Canadian Framework On Clean Growth And Climate Change (Environment and Climate Change Canada, 2016) mandate to increase the capacity of the electrical grid to provide access to “renewable and low-emitting” energy and to decarbonize and modernize electrical power generation and distribution systems (Environment and Climate Change Canada, 2016, p. 11). Research in this particular area is valuable because the move toward a clean-energy economy represents a significant opportunity for Canada to contribute meaningful emission reductions consistent with its *Paris Agreement* NDCs. Natural Resources Canada underscored both the economic and sustainability benefits of projects like SPEEDIER in a press release on the topic (2019):

> One of the greatest opportunities for Canada is the shift toward clean growth. By investing in smart grid technology, Canada is supporting better electricity systems that lower costs for families and create greener and more sustainable communities. (para. 1)

The work needed to move our energy systems toward a more sustainable model will require the *courage and imagination* of people who are willing to do things differently. Perhaps we might realize that “the true heroes of the renewables revolution may be a group that’s rarely recognized: accountants” (Fickling, 2017). Much of the work involved in quantifying the GHG impact of DERs — many of which are *renewable energy* technologies — is in fact an accounting exercise, where net changes in GHG emissions attributable to investments in grid-connected electricity projects are determined based on aggregated baseline emissions data generated using various GWP factors for a variety of gases. Existing accounting practices and regulatory bodies are poised to make meaningful contributions to this emerging market, if only the right incentives are in place.

This current study of a real-world attempt to account for GHG reductions has prompted the author to propose a number of key recommendations for proponents intending to apply *The GHG Protocol for Project Accounting* (GHG Protocol, 2005) either alone or perhaps in conjunction with supplementary sector-specific guidance:

- Make every effort to clearly delineate the assessment boundary — the subsequent assessments depend greatly upon the precision with which this is defined.

- Allocate significant time to the qualification and justification of project activity baseline scenarios — there are many hidden assumptions that quickly complicate this process and disrupt project timelines.
- Be prepared to be flexible with regard to supporting data to be used for the quantification of both baseline and project emissions — this can be exceedingly difficult to obtain or the data may be incomplete or of poor quality.

The breadth and scope of work involved in “smart grid” (Energy Independence and Security Act of 2007, 2020) applications and DERs with respect to decarbonizing the world’s electricity grids represents a significant undertaking. To this end, and with due regard to the ongoing effort to account for the GHG emission mitigation potential of specific projects, there are a number of important things that the author feels could merit further inquiry or research:

- Current GHG accounting and reporting frameworks will need to be expanded to better quantify and qualify *uncertainty* with respect to baseline emissions
- While factoring complete LCA emission assessments for individual project activities might be overly conservative, a more systematic assessment of *material one-time GHG impacts* could offer even greater precision to project accounting efforts of this type
- As jurisdictions begin to implement *carbon pricing*, it will need to be understood how the *principle of additionality* will be affected, as barriers to the implementation of baseline emission candidates will be more significant

- As GHG accounting systems continue to improve, *incorruptible methods for verifying and trading* emission reduction or carbon credits will need to be standardized using "robust accounting", to avoid the persistent issue of "double counting" (UN, 2015).

It is hoped that the experience and wisdom gained through this particular study might assist others with continuing work in this important field of applied research and innovation.

With much gratitude and appreciation for the many people who have worked so hard to advance the art and science of GHG accounting and reporting, the SPEEDIER project team, the department of Research and Innovation at Georgian College, and the countless others that have made this work so fulfilling and rewarding, the author humbly submits this case study to those committed to building more sustainable energy systems.

8.0 Summary of Changes to Second Version

As the work to quantify and qualify the GHG mitigation impacts of the SPEEDIER project continued beyond the first version of this case study, it became apparent that the document (and its intended audience) would benefit from some additional information regarding the ongoing work. In the spirit of the GHG accounting and reporting principles of relevance, completeness, consistency, transparency, accuracy, and conservativeness (GHG Protocol, 2005), this short section of the paper serves to summarize the changes made to the present case study since its first release on April 25, 2021.

The first significant update affected section 5.2.1, where some additional meetings with the vendor for the PV solar module array yielded a more accurate (and conservative) capacity factor for the asset (McCrindle, 2022, p. 31). This enabled the project proponent to cite a more defensible figure describing the capability of this particular project activity to contribute additional generation capacity.

Section 5.8 of the paper consisted of detailed descriptions of how both project and baseline emissions were estimated for *each project activity*. After proceeding to the monitoring stage of the GHG project, it became apparent that these calculations should be illustrated with *rendered formulae* to improve transparency with respect to the monthly and annual reporting to project stakeholders (and possibly auditors). Sections 5.8.1 - 5.8.6 were revised to include such formulae as detailed figures, complete with variable definitions and appropriate edits to each of the calculation descriptions to improve clarity and consistency.

With respect to the assessment of the GBESS and RBESS baseline and project emission calculations in sections 5.8.1 and 5.8.2, it was recognized that there was an opportunity to revise the formulae — where it accounted specifically for power losses attributable to the charging and discharging functions of the hardware itself. Originally, the approach was to use the vendor-supplied round-trip efficiency (RTE) factors for both the GBESS and RBESS units. This proved cumbersome, and it was inconsistent with the approach taken to account for other inefficiencies like transmission and distribution losses applied to energy delivered by the primary power grid — which uses a standard coefficient called a Loss-Penalty Factor (IESO, 2020). To improve the consistency of this calculation, the RTE factors were converted to simpler (and slightly more conservative) *system loss factors* (McCrindle, 2022, p. 75). This change resulted in the rendering of simpler and more understandable formulae to be used for the estimation and ongoing monitoring of project and baseline GHG emissions for battery energy storage systems.

As a result of a review of the various assessments in section 5.8, the table displaying the estimated baseline and project emission totals (Table 5.8.7) required an update. Some of the figures needed to be revised due to some rounding, and also as a result of the use of the simpler system loss factor for the GBESS and RBESS project activities. The resulting changes to these estimation totals reflected a slightly more conservative approach, and did not lead to any materially significant changes to anticipated GHG emission reductions.

At the time of writing, the monitoring of the various assets comprising the project was ongoing. The project proponents were actively involved in monitoring and reporting GHG mitigation performance, using elements of a GHG information system (GHGIS) developed with good practice guidance from ISO 14064-2:2019 (ISO, 2019), the GHG Protocol for Project Accounting (GHG Protocol, 2005), and the sector-specific Guidelines for Grid-Connected Electricity Projects (GHG Protocol, 2007).

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