Electrification and deep decarbonization of Canada's energy system with small-scale residential prosumers: A case study of Ontario

Contribution to the Canadian Energy Modelling Initiative

Dr. Elizaveta Kuznetsova

Kuznetsova.Elizaveta@gmail.com

Prof. Miguel F. Anjos

Miguel.F.Anjos@ed.ac.uk

March 18, 2021

This report has been submitted to a peer-reviewed journal.
Suggested citation: E. Kuznetsova, M.F. Anjos (March 2021). Electrification and deep decarbonization of Canada's energy system with small-scale residential prosumers: A case study of Ontario. Technical report, Energy Modelling Initiative, Institut de l'énergie Trottier, Polytechnique Montréal, Canada.

Abstract

There is a lack of modeling capacity to identify the true capabilities of residential prosumers (households consuming and generating electricity) to contribute to deep decarbonization and electrification of large-scale energy systems. As a step to bridge this gap, we propose an integrated simulation model to assist a policy-maker in the definition of optimal tariff policies for residential prosumers. Using artificial intelligence and optimization methods, the model simulates the transformation of conventional consumers into prosumers under a given energy policy for a given jurisdiction. The model is geographically scalable and can cover a jurisdiction of national, provincial or municipal level, depending on a policy-maker needs. We apply the model to the case of Ontario and obtain a quantification of different indicators resulting from the integration of photovoltaic generation and battery storage in households for a long-term horizon from 2021 to 2050. The model quantifies total installed capacities of renewable energy sources and batteries, total renewable energy generation by prosumers, carbon savings, electricity affordability, and system reliability.

Resumé

Un des défis actuels est l'absence de modèles capables d'identifier le vrai potentiel des auto-consommateurs résidentiels (ménages consommateurs et producteurs d'électricité) pour contribuer à la profonde décarbonisation et à l'électrification des systèmes énergétiques. Comme un pas pour combler cet écart, nous proposons un modèle de simulation intégré pour aider un décideur politique dans la définition des tarifs optimaux pour des consommateurs résidentiels. En appliquant des méthodes d'intelligence artificielle et d'optimisation, le modèle simule la transformation des consommateurs conventionnels en auto-consommateurs sous une politique énergétique donnée et pour une juridiction donnée. Le modèle est géographiquement évolutif et est capable de couvrir une juridiction du niveau national, provincial ou municipal en fonction de besoins du décideur politique. Le modèle appliqué à la province d'Ontario aide à évaluer différents indicateurs résultant de l'intégration des sources d'énergie renouvelable et du stockage dans les ménages pour un horizon à long terme de 2021 au 2050. Le modèle quantifie les capacités totales de sources d'énergie renouvelable et de stockage, l'énergie totale renouvelable générée par des auto-consommateurs, la quantité d'émissions de carbone évitée, l'accessibilité financière de

l'électricité et la fiabilité du système.

Elizaveta Kuznetsova is acting in this project as an independent researcher and modeler. She holds the M.S. in Mechanical Engineering from the Moscow Technical State University (Russia), in Fluid Mechanics from the ENSEEIHT of Toulouse and in Sustainable Engineering from University of Versailles Saint-Quentin-en-Yvelines (France). In 2014 she received her Ph.D in Economics completed in the Industrial Engineering Research Department of CentraleSupélec (France). During her career Elizaveta has worked in France, Singapore and Canada on the development of decision-making methodologies to support sustainable design and operations of industrial systems. She was involved in projects on dynamic management of Smart grids, design of Eco-Industrial Parks and planning of national waste-to-energy infrastructure. Most recently she worked at Polytechnique Montreal on the integration of small-scale prosumers into an economic arrangement framework.

Miguel F. Anjos holds the Chair of Operational Research at the School of Mathematics, University of Edinburgh, and an Inria International Chair. He is the Schöller Senior Fellow for 2020 at the University of Erlangen-Nuremberg. He was previously on the faculty of Polytechnique Montreal, the University of Waterloo, and the University of Southampton. He is the Founding Academic Director of the Trottier Institute for Energy at Polytechnique Montreal. He served on the Mitacs Research Council since its creation in 2011 until 2017, and is now an Emeritus member. He is a Fellow of the Canadian Academy of Engineering. His allocades include IEEE Senior Membership, a Canada Research Chair, the NSERC-Hydro-Quebec-Schneider Electric Industrial Research Chair, the Méritas Teaching Award, a Humboldt Research Fellowship, the title of EUROPT Fellow, and the Queen Elizabeth II Diamond Jubilee Medal. His research interests are in the theory, algorithms and applications of mathematical optimization. He is particularly interested in the application of optimization to problems in power systems management and smart grid design. He is the current President of the INFORMS Section on Energy, Natural Resources, and the Environment. He is a member of the of the ORS Research Committee, of the Managing Board of EUROPT, the European working group on continuous optimization, and of the Management Committees of the International Centre for Mathematical Sciences and the Isaac Newton Institute for Mathematical Sciences.

Contents

Abbreviations

ABM	Agent-based model
AEF	Average Emission Factor
AI	Artificial Intelligence
DRL	Deep reinforcement learning
EMI	Energy Modelling Initiative
EoS	Economies of scale
FIT	Feed-in-tariff
GA	Global adjustment
GHI	Global horizontal irradiation
IA	Intelligent agent
KPI	Key performance indicators
LDC	Local distribution company
OEB	Ontario Energy Board
OER	Ontario Electricity Rebate
PDF	Probability distribution function
PV	Photovoltaic
RES	Renewable energy sources
SOC	State of charge
TOU	Time-of-use

1 Policy-maker decision-support framework

The integrated decision-support framework used in this work is described in Figure 1a. It is based on an agent-based model (ABM) of the energy system (Figure 1b). The framework guides a policy-maker through these various steps from inputs definition and data collection to an analysis of various models outcomes. The policy pathway refers here to the economic and financial measures, i.e, electricity tariffs (rates and charges), subsidies, incentives, renewable energy sources (RES) operation plans, which affect the electricity bill or RES installed and operation costs.

As a preliminary step, a user (policy-maker) defines global energy system objectives by relying on a long-term vision. The focus of this report is on the energy system electrification and deep decarbonization. The framework helps a policy-maker to assess potential contributions of small-scale residential prosumers in achieving this long-term vision. A policy-maker may simulate the impact of different tariffs (rates and charges), subsidies, incentives and RES connection plans on prosumers of a given jurisdiction prior to the policy implementation in situ. At Step 1, a potential policy pathway is proposed. At Step 2, the required data is collected from the available databases. The inputs from both steps are used to feed the decision-support model and to obtain results. At Step 3, results are analyzed from a policy-maker's perspective of global objectives for energy system electrification and decarbonization goals. A policy pathway, defined at Step 1, may stimulate prosumers to invest in RES and contribute to the vision of energy system electrification and deep decarbonization. However, a policy pathway may also lead to some undesirable effects, such as high policy cost, electricity affordability and reliability issues, over the development of RES capacities and eventual prosumers' disconnection from the grid. In this report we focus on model outcomes quantified through KPI illustrated in Figure 1a and discussed in Section 4 . Note that for analysis with different focus these KPI may account for other social, economic and environmental indicators. The model generates detailed maps of the jurisdiction showing year-by-year evolution of households strategies, i.e., transformation of conventional consumers into prosumers in different locations. If some sensitive locations in a considered jurisdiction are identified, the local impact of a given policy may be evaluated closely. The decision-making pattern of a typical household in each location is accessible and can be further analyzed to address the following questions: When will a household deploy RES and storage technologies, with which capacity, and under what conditions? How will these capacities be used, i.e., what is the optimal power dispatch in a household? Eventually, if the simulation results do not contribute to the global objectives, a policy-maker may adjust the policy pathway and repeat the simulation.

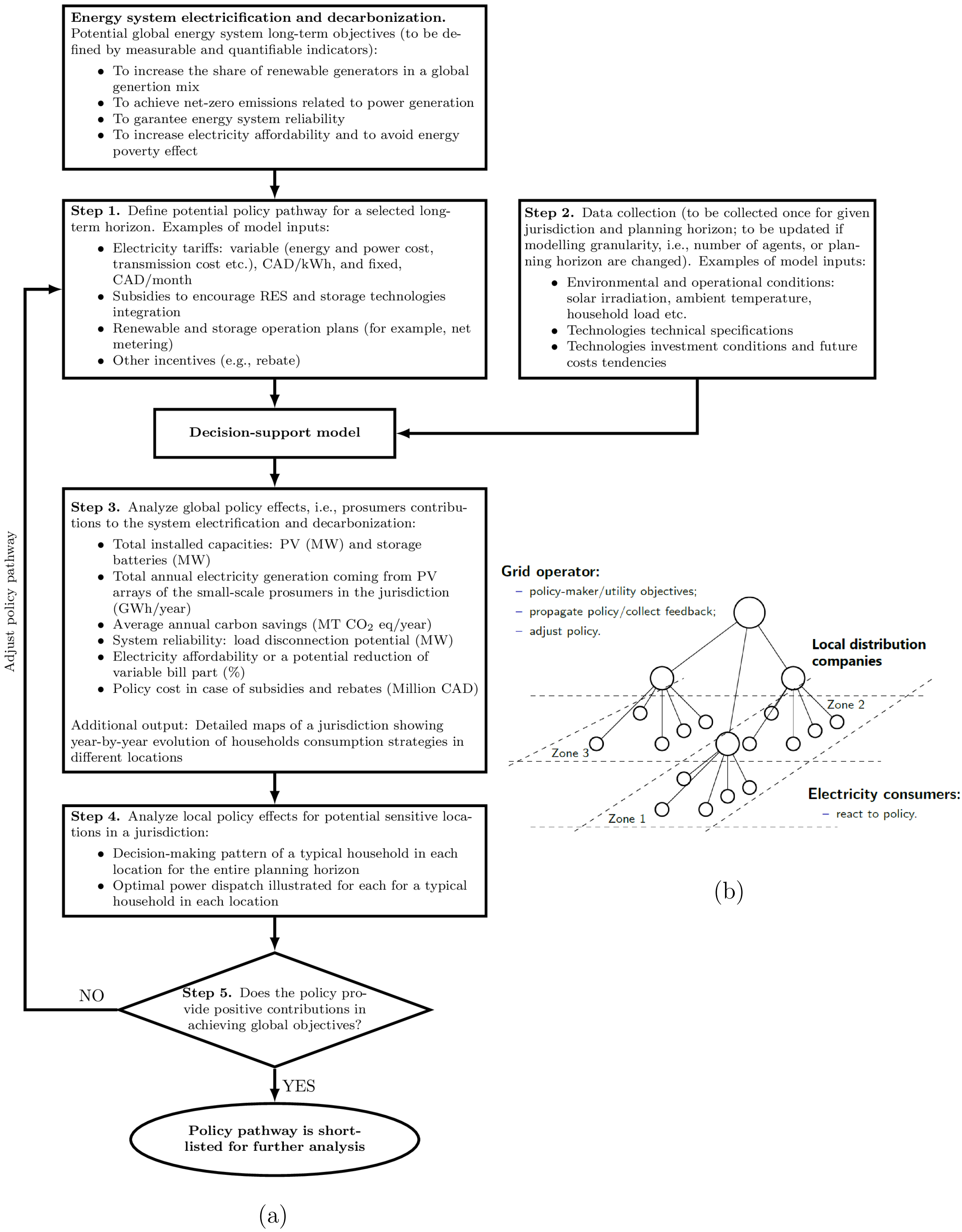


Figure 1: Policy-maker integrated decision-support framework: a) abstract representation of energy system modeled with ABM and b) procedure for policy optimality check.

The ABM is built using an artificial intelligence technique known as an intelligent agent (IA). IAs can sense the operational conditions, interact with their environment, communicate with other stakeholders, and make autonomous decisions. The IA is thus a perfect virtual representation of an individual decision-maker, such as a household. In this study, local distribution company (LDC) and the grid operator are used only to communicate policy decisions (tariffs) to consumers defined by a model user. The implementation of the decision-making process in models of LDCs and the grid operator may be done as a future extension (see Section 6 for more details).

The household decision-support model combines strategic and operational planning. The detailed mathematical model is presented in Appendix B.2. It uses inputs defined by a policy-maker to simulate a progressive transformation of household conventional consumer into prosumer through the following stages: (i) a conventional consumer, (ii) a prosumer with photovoltaic (PV) arrays (and its progressive expansion), (iii) a prosumer with integrated electric battery for higher self-sufficiency and, finally, (iv) an off-grid prosumer with seasonal storage (Figure 2).

The consumer decision-support model is based on the minimization of total household expenses for electricity over a long-term planning horizon typically of several decades. The household expenses include two types of costs. Capital investments for the deployment of on-site technologies (such as PV modules, electric battery and hydrogen seasonal storage), technologies maintenance and potential replacement costs are decided by the strategic decision model. The electricity bill and avoided costs (i.e., electricity costs avoided due to self-generation and self-consumption) are decided by the operational planning model. The operational model optimizes household power dispatch depending on the available on-site technologies while ensuring a power balance. For an on-grid household it optimizes on an hourly basis the optimal power to be purchased from the grid, used from the locally installed PV array, and/or charged and discharged to/from the battery. If the strategic model decides to deploy a seasonal storage and go off-grid, the operational model takes care of the seasonal storage dispatch. The decision-support model accounts for the economies of scale (EoS), i.e., the potential reduction in investment and operational cost based on the PV capacity expansion, and the discount factor to define the value of future cash flows.

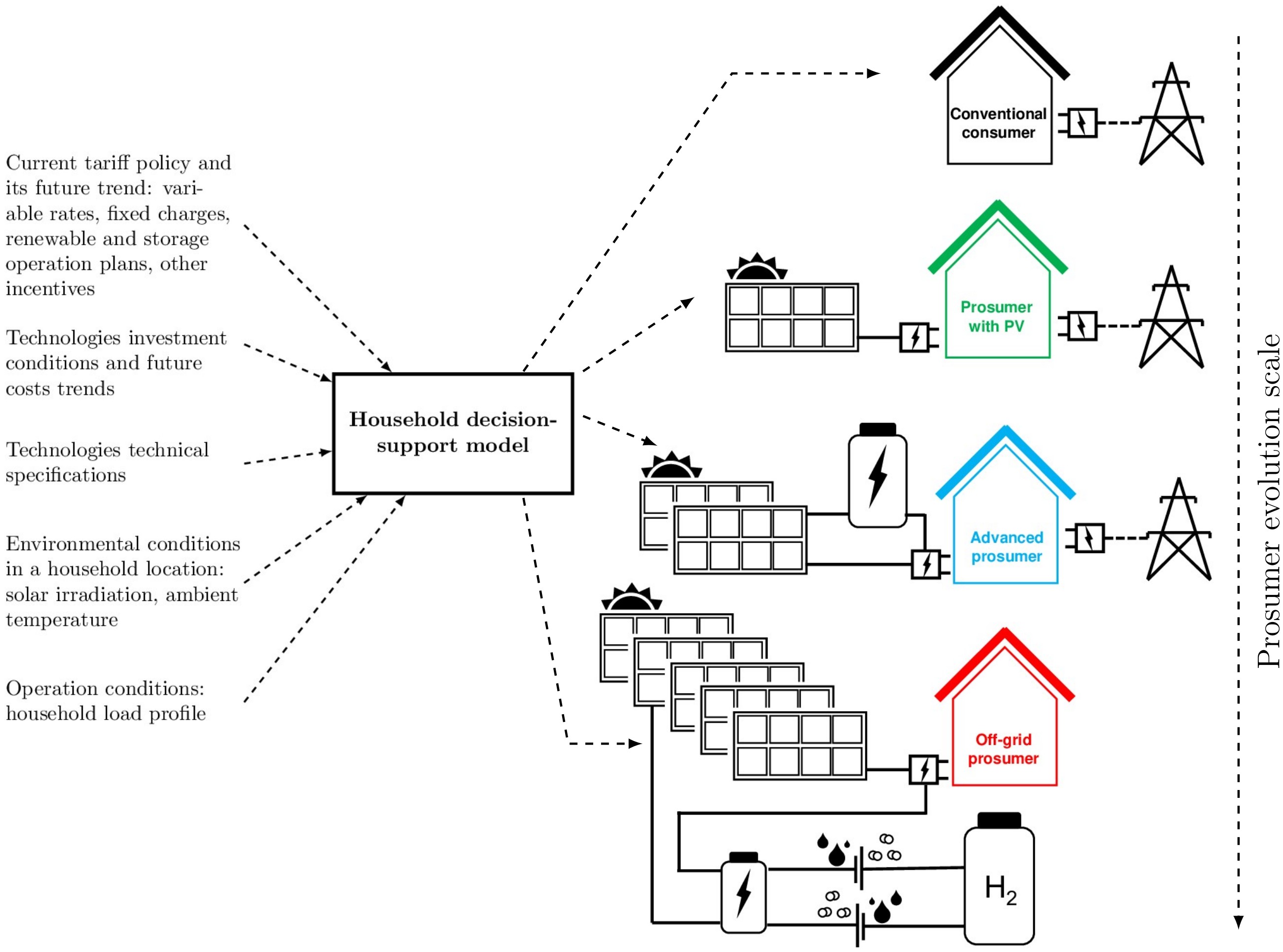


Figure 2: Household decision-support model inputs and results.

2 History of pricing policy for residential consumers in Ontario

This section provide a policy context for Ontario. The pricing policy of a jurisdiction defines the total electricity bill that a consumer pays each month. In Ontario, a monthly electricity bill has the following structure:

$$Electricity\ bill = \Big[\underbrace{Consumption \cdot Electricity\ rate}_{\text{energy and power cost}} + \underbrace{Consumption \cdot Transmission\ rate}_{\text{transmission cost}}$$
$$+ \underbrace{Fixed\ service\ charges + Consumption \cdot Distribution\ rate}_{\text{distribution cost}} - Rebate\Big] + Taxes \quad (1)$$

The bill is composed of energy, transmission and distribution costs. These amounts depend on the annual charges and rates adopted by electricity retailers and the Ontario Energy Board (OEB). This section discusses current trends for different rates and charges. The detailed analysis of different costs contributions to the total electricity bill may be found in [1].

2.1 Cost of energy

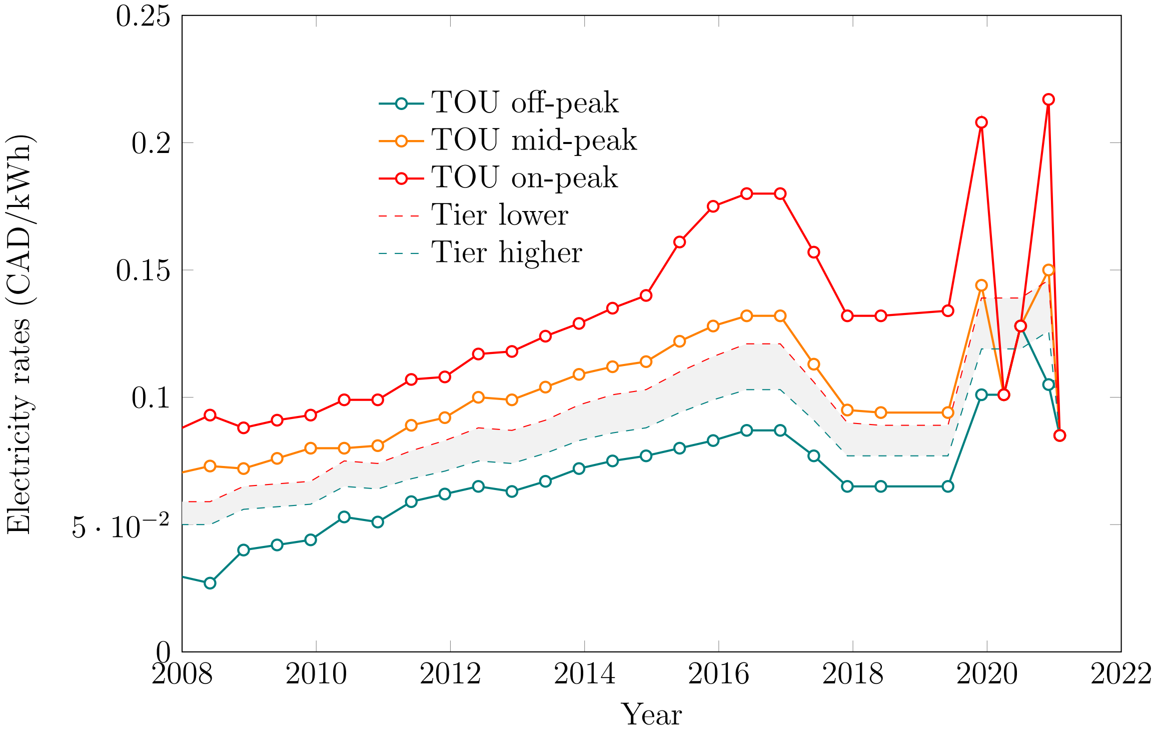


Figure 3: Historical electricity rates in Ontario [2].

Figure 3 presents the evolution of Ontario's time-of-use (TOU) and tier rate for the last 12 years. From July 2017 to April 2018 the government subsidized an "artificial" reduction of electricity rates while the OEB reset electricity rates"in a way that holds increases to the rate of inflation" (the rate drop, stagnation and increase can be seen in Figure 3). The effect of the Ontario Fair Hydro Plan Act, 2017, ended on October 31, 2019, generating a sudden increase in electricity rates. The TOU rates were 0.101, 0.144 and 0.208 CAD/kWh for off-, mid- and on-peak, respectively [2]. To offset this increase the Government of Ontario introduced the Ontario Electricity Rebate (OER), a 31.8% reduction applied to the pre-HST amount of eligible consumer's bills (lower rebates applied from January 1, 2017 to October 31, 2019 (8%) and from 2011 through 2015 (10%)) [2].

The rates in the period between spring 2020 and winter 2021 were affected by the COVID-19 measures [2]. During the first wave, temporary relief in the form of a fixed electricity price to support Ontario's households was introduced on March 24, 2020. On June 1, 2020 a fixed electricity price was made effective to support consumers while planning the safe and gradual re-opening of the province. Following the re-opening, the electricity rates skyrocketed overcoming the rates of November 2019 with on-peak rate reaching 0.217 CAD/kWh [2]. The second wave of the pandemic brought back down these rates with the introduction of another temporary relief on the form of fixed rates effective since January 1, 2021.

2.2 Grid fixed and variable charges

Grid fees are subject to the different tariff schemes adopted by different LDCs responsible for distributing power from transmission lines to the final consumers. These LDCs usually provide power in a specific service area around a city or a community and its neighborhood. In addition, a large power distribution provider with over 1.1 million customers covers the rest of the province and supplies electricity to low-density and remote areas. Figure 4 reports the cities, communities and districts associated with different LDCs (and different tariff schemes).

2.2.1 Transmission cost

Transmission cost is the sum of two rates: the network service rate, and the line and transformation connection service rate. On average, the network rate and the connection rate increased by 24% and 4.2%, respectively, for the last 12 years [3].

2.2.2 Distribution cost

Distribution fees are mostly composed of the fixed service charge (Figure 5a) and the distribution volumetric rate (Figure 5b). While the transmission rates are almost the same for all residential consumers in Ontario, the delivery rates vary by different LDCs. Figure 5 presents average residential year-round rates, and several rates for medium- and low-density areas for cities and communities in Ontario [3].

Starting in 2015 an important charge was observed in the delivery rate tariff scheme: fixed service charges start to increase while variable charges decrease. This trend becomes pronounced after 2015. On average, during last 12 years fixed service charge gained around 40% (that represents around 3% of annual increase), while variable charges decreases by 25%. Note that the fixed charges alone represent between 13% and 35% of

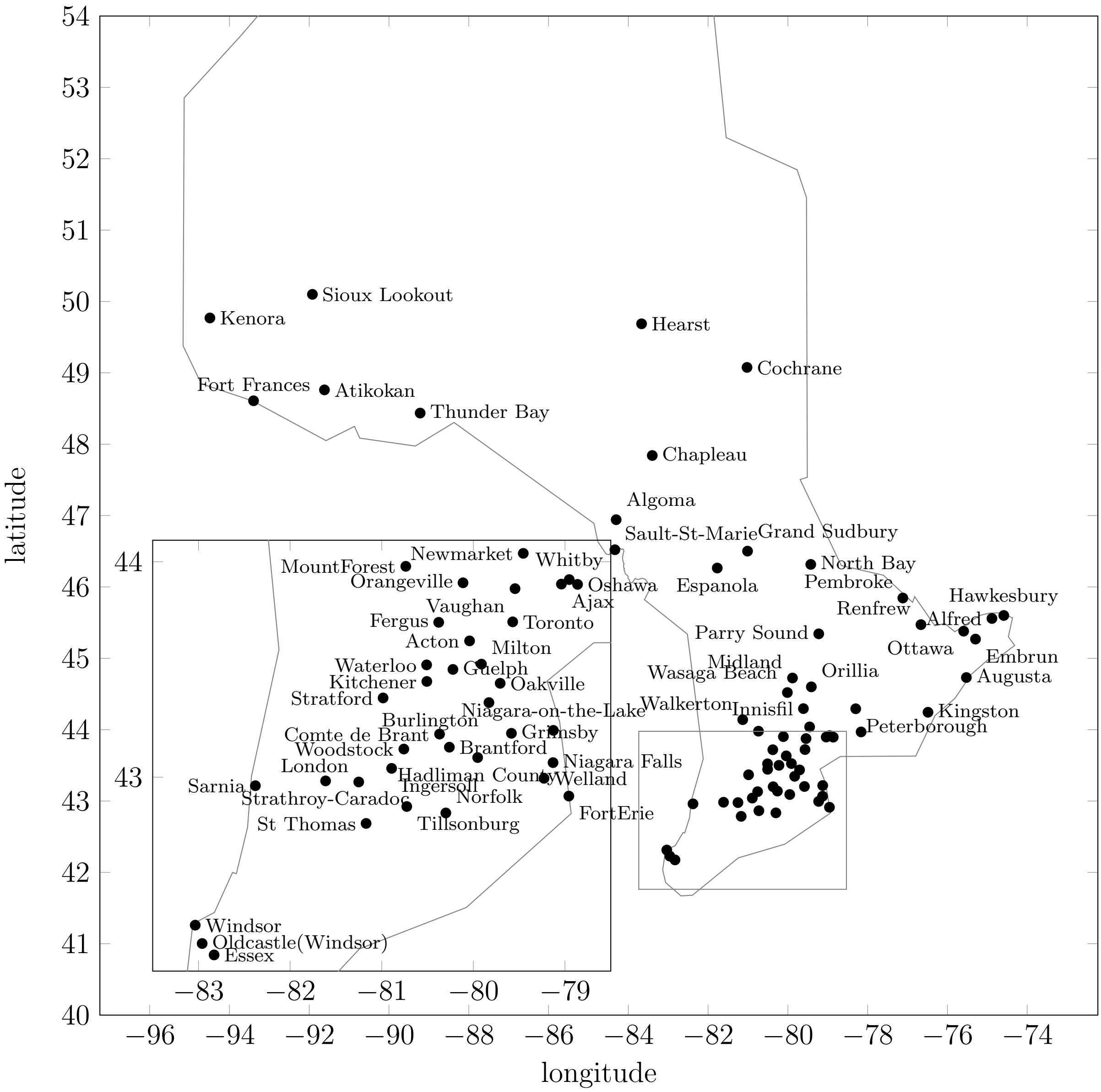


Figure 4: Cities, communities and districts associated with different electricity distribution areas for 2018.

the total electricity bill in different distribution areas.

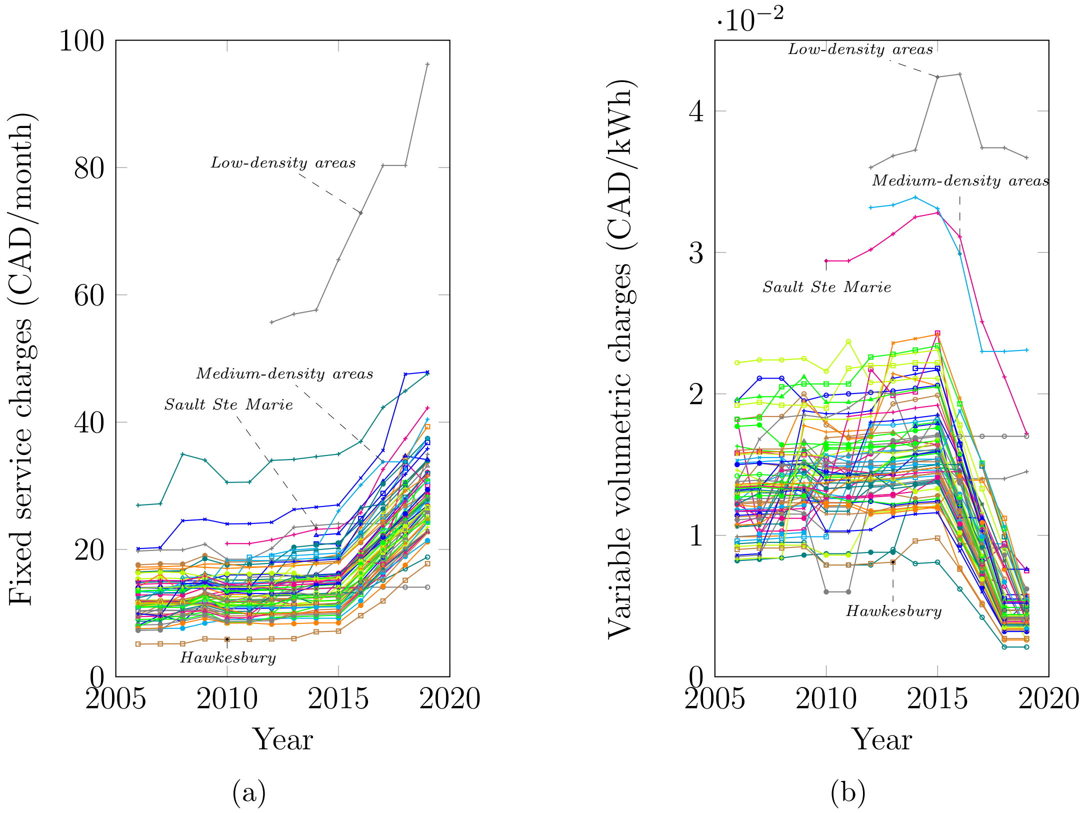


Figure 5: Historical distribution grid fees for residential consumers in cities and communities of Ontario for the period 2006-2019 [3] for a) monthly fixed service charges and b) variable volumetric charges.

2.3 Distributed renewable energy sources - options for prosumer

According to the OEB, the final feed-in-tariff (FIT) application period was held in 2016 after which the Independent Energy System Operator (IESO) ceased accepting applications [4]. The net metering scheme became the alternative to FIT allows to send the local difference between RES generated energy and consumed energy back to the grid in exchange for credits that can be carried over to future bills for up to 12 months [5]. Typically 1 kWh of PV generation injected in the grid is granted a credit of 1 kWh of utility generated electricity in future bills. To participate in this scheme residential consumers are switched from TOU rates to tier rates for both kWhs injected and used to/from the grid (see Figure 3) [6].

2.4 Ad hoc changes in legislation

The continuously increasing electricity rates and consequent impossibility for growing number of consumers to pay their bills forced energy legislation onto the Ontario government agenda. The major updates introduced through the Fair Hydro Plan starting from July 2017 [7] are concerned with the reduction of electricity rates, the application of various reliefs and rebates [7], and the introduction of tax-credit programs [8]. The Fair Hydro Plan was funded through a refinancing of a portion of the global adjustment (GA) cost, which in turn is to be recovered through a new charge on electricity bills called Clean Energy Adjustment (to appear in 2020) [7]. The Fair Hydro Plan added approximately 4 billion CAD in borrowing costs to Ontario and in 2019 the new government aims to improve relief rate structure and billing transparency [9]. One of the new legislative intentions is to hold the average bill increase to the rate of inflation starting from May 1, 2019 [9]. This is achieved by the introduction of a new OER, mentioned in Section 2.1, which is subject to a regular reevaluation. For example, on November 1, 2020, it was increased from 31.8% to 33.2% [10] and on January 1, 2021, the rebate regulation was amended by striking out "33.2 per cent" and substituting "21.2 per cent" [11].

2.5 Assumptions

The assumptions for this study and report are the following:

- "Conventional consumer" refers to the classical consumer without locally installed RES and connected to the grid. "Prosumer" is the consumer with locally installed RES (in our case, PV array) and connected to the grid under net metering scheme [6]. "Advanced prosumer", is a consumer with locally installed PV and electric battery, and also connected to the grid under net metering scheme. For simplicity the term "on-grid" is also used. The terms "off-grid" and "disconnection" are both used in this report to mean the physical disconnection from the grid. The "off-grid prosumer" therefore entirely relies on PV array, as well as electric battery and hydrogen seasonal storage.

- The focus of this report is on consumers in urban, suburban, rural and remote areas under year-round tariff under the following service classifications: urban residential, residential, R1 and R2 residential [3]. This study considers a typical natural-gas heated household.

- It is assumed that the electricity bill structure presented in Section 2 remains unchanged in the future, and that the Ontario government and the OEB will pursue their current energy policy strategy.

- It is assumed that in line with other jurisdictions, Ontario exited FIT program and net metering is the only rewarding scheme available for prosumers.
- Legal and technological issues behind the novel way of system operation are not considered. This means that it is assumed that there are no limitations to enablers of prosumers creation, such as implementation of RES, storage technologies and smart metering technologies.
- No temporary COVID-19-related measures were considered. The report assumes that the electricity rates are at their pre-pandemic level with mid-peak and tier rates around 0.1 CAD/kWh. In addition, no local fixed or variable adjustments, such as deferrals or variances of any kind, were considered.

3 Representation of all households in a jurisdiction by typical household consumers

To evaluate how residential consumers may contribute to the global performance indicators of the entire jurisdiction, it is essential to model an appropriate number of representative household agents and to identify how many households will act in the similar way.

3.1 Number of intelligent household agents

The important question is how many household agents must be included in the energy system model of a jurisdiction (Figure 1a) to realistically represent policy impacts. The choice of the number of agents depends on environmental conditions, tariff policies and household load profiles in a jurisdiction. For example, in a municipality, electricity tariffs, environmental conditions (solar irradiation, ambient temperature) and type of appliances used in households are usually very similar. In this case, one household agent may be sufficient to represent most household. In larger jurisdictions, such as province or country, tariffs are different in different distribution areas; environmental conditions change depending on latitude, air masses and wind, elevation, relief and ocean current; electric appliances in households and their use may be different (for example, a strong reliance on air conditioners in south). In this case, for large jurisdictions the number of household agents must be increased to account for these differences. For Ontario we follow the approach currently used by the OEB: policy impact on a household bill is evaluated for each distribution area through a household with a typical monthly consumption [12]. This typical consumption represents an average consumption calculated based on all Ontario households. It is defined using data for several years: the previous annual consumption reported by residential users and the total number of customers each year [13]. In 2020 the standard level of consumption for an Ontario household was determined to be 700 kWh/month [10]. Our model uses 67 typical household agents corresponding to the 67 distribution areas (Figure 4) of service classification stated in our assumptions (Section 2.4).

3.2 Strategic decisions of households with different average monthly consumption

To evaluate results of collective behavior of Ontario's households it is important to identify how many households will behave in a same way. The OEB uses the typical household per distribution area to evaluate policy impact on the electricity bill [13]. However, in our case households with different average monthly consumption may behave differently in terms of strategic decisions for deployment of technologies. We conducted a sensitivity analysis by considering a household in Atikokan. We considered a basic scenario of 2% technology investment costs increase (Appendix C). We vary average monthly electricity consumption levels from 400 to 1,000 kWh/month and, as a consequence, an annual power peak of a household load model from 0.9 to 2.25 kW (see Appendix C and [14] for more information about the load model). The strategic investment and operational decisions are simulated with the optimization model presented in Appendix B.2 for a 30-year horizon. At the end of this simulation horizon an Atikokan household may remain a conventional consumer (in white on Figure 6), become a prosumer by deploying a PV array (in green on Figure 6) or an advanced prosumer with a PV array and an electric battery (in blue on Figure 6). Ultimately, a household may decide to go off-grid by deploying a sufficient PV capacity and a seasonal storage (in red in Figure 6). The household strategy changes with the increase of total variable rates and fixed charges: a household starts to invest in technologies to move from a conventional consumer towards a prosumer. The household strategy also changes with the increase of average monthly consumption: higher consumption combined with higher increase of variable rate pushes household to disconnect. We use x_{min} and x_{max} to denote the size of the consumption window around 700 kWh/month where households will behave in the same way. For example, for 2% of variable rate and fixed charges increase, x_{min} is equal to -200 kWh/month and x_{max} is equal to 300 kWh/month; for 4% of variable rate and fixed charges increase, x_{min} is equal to -300 kWh/month and x_{max} is equal to 50 kWh/month.

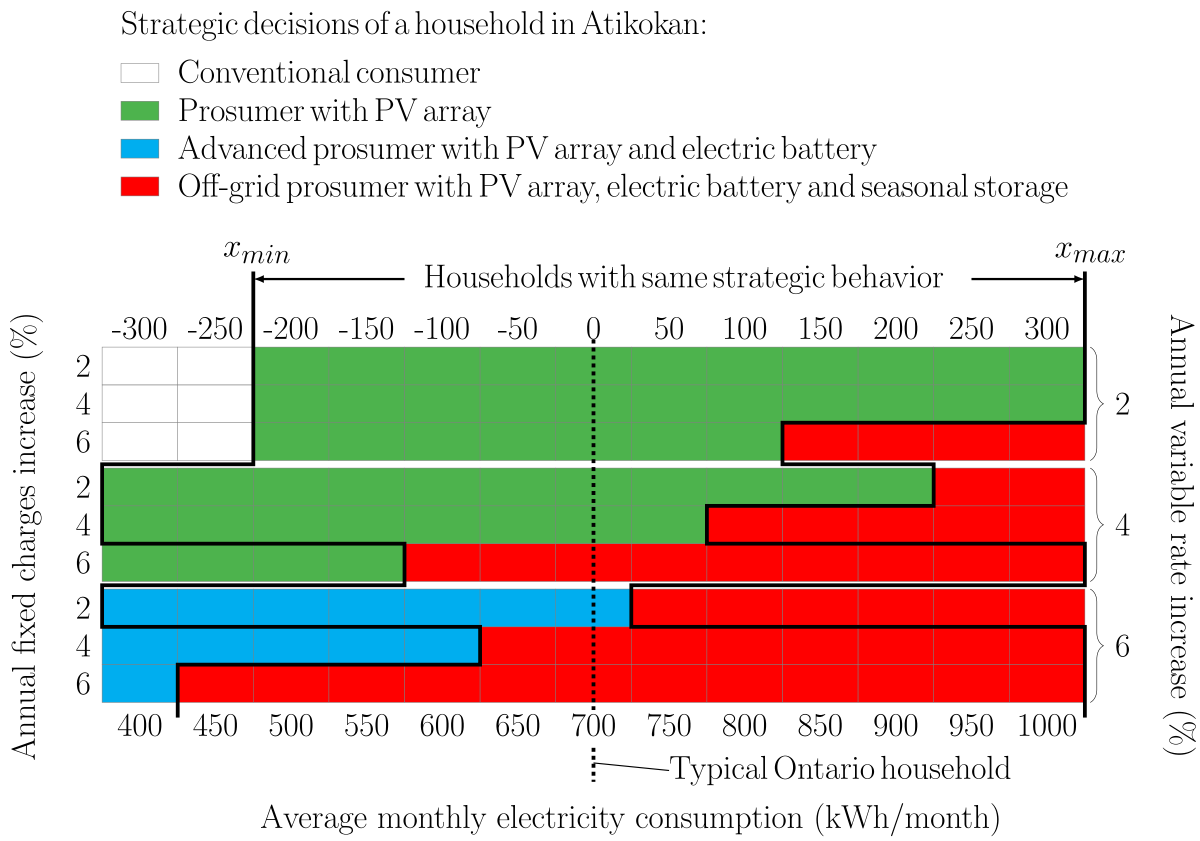


Figure 6: Strategic decisions of an Atikokan household depending on the average monthly consumption, annual increase of fixed charges and variable rates.

Note that this aspect requires a more extended analysis in the future since the size of a consumption window where consumers behave in a same way may also change by distribution area.

3.3 Number of households with the same strategic decisions

The last step is to define how many real households are represented by each of these typical consumers. In the absence of access to the OEB consumption measurement data we rely on the study of probability distribution functions (PDF) of electricity use in detached houses in Sweden [15]. This study shows that a Weibull PDF has a reasonable overall goodness of fit both in terms of electricity use and standard deviation. We therefore assumed that Ontario consumption data for single-detached households is distributed in the same way as in Sweden.

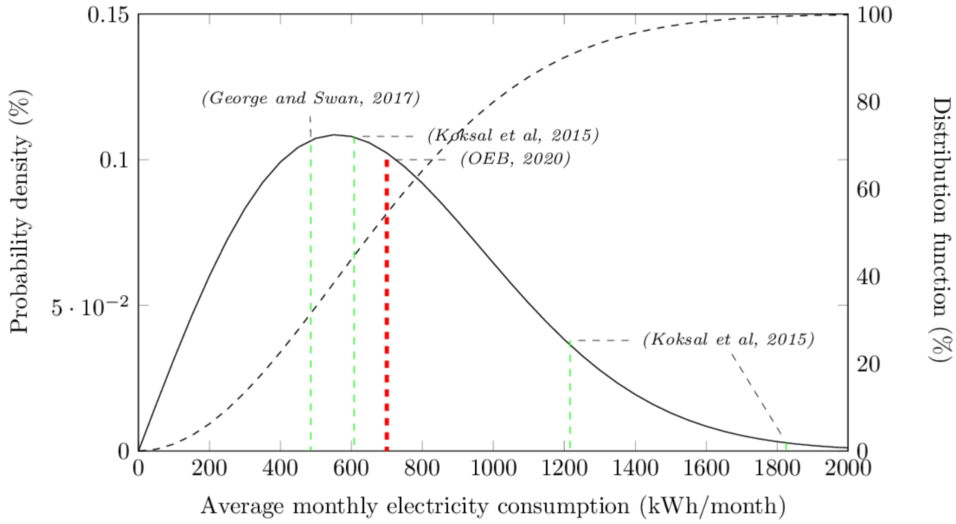


Figure 7: Weibull distribution of average monthly electricity consumption levels of households in Ontario.

To construct a Weibull distribution of household electricity consumption in Ontario, we used various available measurements. The available data from 25 households monitored in the Greater Toronto Area from [16] shows that the average monthly usage of the majority of households ranges between 608 and 1,216 kWh/month. Despite one household with average monthly consumption above 1,825 kWh/month, the average daily electricity consumptions of the households in each category are not widely distributed. Another study [17] reports (based on 23 households in Ottawa) the maximum annual peak to be less than 1.1 kW which is equivalent to a typical consumption of less than 486 kWh/month. By using this data, we adjusted Weibull distribution parameters to obtain a PDF with a mean of 700 kWh/month (Figure 7).

We calculated cumulative distribution functions $F(x_{\max})$ and $F(x_{\min})$ for each tariff scenario (illustrated in Figure 6) and identified Delta, the percentage of the consumption data lying in this interval. In general, the percentage of the households behaving as a typical household varies between 31% to 52%. For our analysis we assume $Delta = 40\%$.

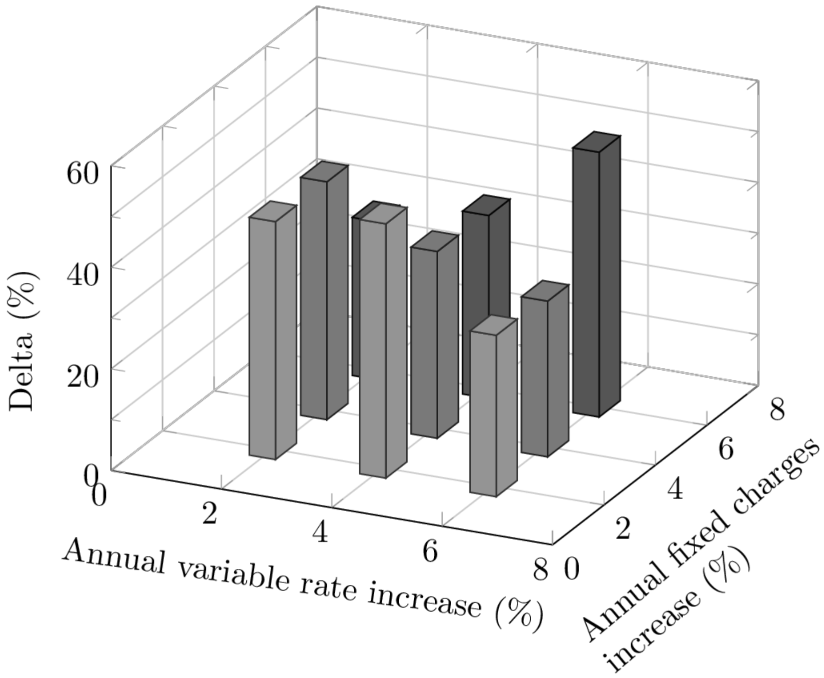


Figure 8: Percentage of the single-detached households behaving similar to a typical household.

According to the 2016 census [18], Ontario has 2,806,862 of private single-detached houses, from which 40% or 1,122,744 units may behave as a typical household. In the absence of the exact number of consumers living in private single-detached houses in each municipality we assume that they are distributed proportionally to the number of private dwelling in these municipalities. This assumption gives the distribution of private single-detached houses by Ontario's municipalities presented in Appendix A. The global performance indicators for different policy pathways are calculated based on these numbers.

4 Global performance KPI

The global KPI used by a policy-maker to evaluate performance of the energy policy pathways in terms of their contribution to deep decarbonization and electrification of the Ontario energy system are:

- Total installed non-hydro renewable capacity (net metering), MW
- Total installed battery storage capacity (net metering), MW

- Average total annual PV generation (net metering), GWh/year
- Annual CO_2 emissions savings in power generation (net metering), megaton CO_2 eq/year
- Load disconnected from the grid, MW
- Average reduction of variable electricity bill part (net metering), %
- Policy cost in rebates for all typical households of a jurisdiction, Million CAD

We rely on the Evolving scenario from the report on Canada's Energy Future 2020 [19] to define potential 2050 goals of Ontario's power system. This scenario advises that by 2050, total non-hydro renewable capacity including solar, wind and biofuels in Canada will be more than triple the 2018 levels [19]. This implies that Ontario non-hydro renewable capacity of 8,125 MW recorded for 2020 (combines systems at transmission and distribution levels) may reach 24,400 MW in 2050 (from which around 8,000 MW may be solar capacity). By considering the average Ontario solar production of 1,166 kWh/kW/year [20], this solar capacity may generate annually around 9,250 GWh. The Evolving scenario expects a considerable increase of utility scale battery storage to support large additions of solar by 2050. Under the assumption that battery storage capacity must represent around 40% - 50% of the solar capacity to efficiently mitigate various load variations [21], the total battery storage capacity in Ontario must reach around 4,000 MW in 2050. We assume that CO_2 emissions from Ontario's electricity sector in 2050 will remain the same as recorded in 2017, i.e., 2 Mt of CO_2 eq/year or 3% of total Canadian GHG emissions attributable to power generation [22]. Indicators, such as load disconnected from the grid, average reduction of variable electricity bill part and policy cost in rebates do not have specific 2050 targets. The reference net metering in indicators' titles indicates that these KPI are evaluated only for the grid-connected prosumers. Formulas for calculating different indicators are presented in Appendix B.3.

5 Application

5.1 Step 1. Selected policy pathways for the long-term

The simulation model separately takes into account fixed services charges and variable rate. Variable rate represents a sum of electricity rate, as well as per kWh costs for distribution, transmission and connection. Rates and charges for the beginning of the planning horizon are those from 2019 [3]. The important question is "How to set the annual increases of total variable rates and fixed charges?"

According to our study, starting from 2006 the total electricity bills in Ontario increases in average by 5.5% every year (before the addition of OER) for the same average consumption (transition years when the OEB decreased the average consumption of Ontario's households are not considered). This bill increase can be obtained by different combinations of annual increases for variable rates and fixed charges. Figure 9 shows the Pareto front of tariffs' increase identified for a household in Atikokan. If the annual bill increase represents 4% then the Pareto front will move to the left, whereas an increase of the bill below 5.5% will move the Pareto front to the right (not illustrated in Figure 9).

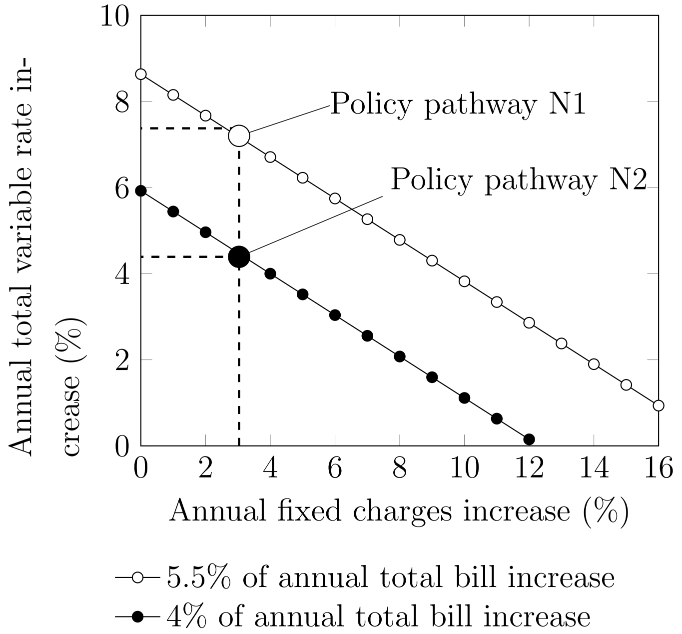


Figure 9: Pareto front of possible annual variable rates and fixed charges increase.

In this report we test two policy pathways shown in Table 1. Policy pathway N1 is similar to the current Ontario policy leading to the 5.5% of annual bill increase and 2% increase after the application of rebate. In the absence of clear directives about the OER program, it is assumed that the rebate will be active for the first five years of the planning horizon, and that afterwards the increase of the electricity bill will be 5.5% every year. Annual increases of fixed charges and variable rate are also selected close to real situation in Ontario, where fixed charges gain around 3% each year. This makes the annual increase of variable rates equal to 7.2%.

Policy pathway N2 assumes that the increase of the electricity bill can be contained by some means to a 4% of annual increase. The annual increase of fixed charges is 3% as for the policy pathway N1, and the annual increase of variable rates is 4.5%. Section 5.5

provides examples of possible mechanisms that can be used to decrease the electricity bill.

The duration of the planning horizon is 30 years, from 2020 to 2050.

Table 1: Tariff policy pathways.

Details	Policy pathway N1 - **Actual pricing with rebate**	Policy pathway N2 - **Alternative pricing without rebate**
Average annual increase of the actual bill, %	5.5[1]	4[1]
Rebate, % of the actual bill	21.2 (5 years)	none
Annual rebate increase, %	2	none
TOU mid-peak/average tier, CAD/kWh	0.1	0.1
Annual fixed charges increase, %	3[1]	3[1]
Annual total variable rate increase, %	7.19[1]	4.48[1]
Deployment of technologies	PV array, electric battery & hydrogen seasonal storage	PV array, electric battery & hydrogen seasonal storage
PV integration scheme	net metering	net metering

[1] From Figure 9.

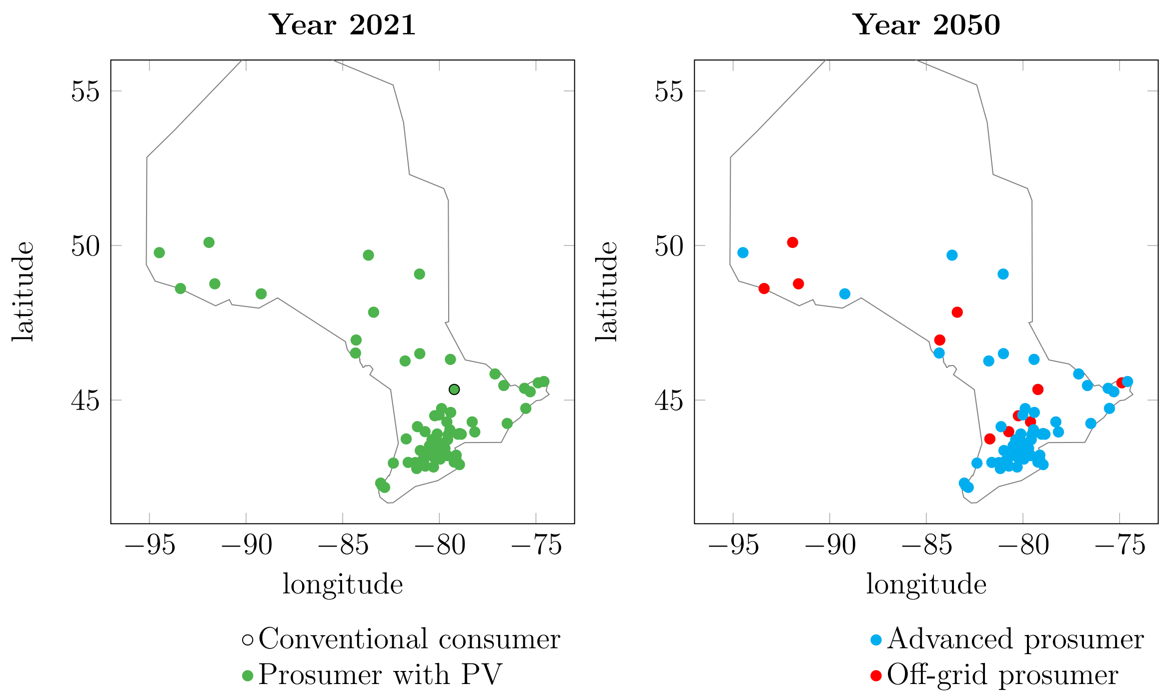
5.2 Step 2. Data collection

The simulation relies on the open-source data related to the electricity rates and charges, technical specifications and costs of the commercially available technologies, and environmental and operational conditions for various locations in Ontario. The details about each type of data and its origin are given in Appendix C.

5.3 Step 3. Global effects for Ontario

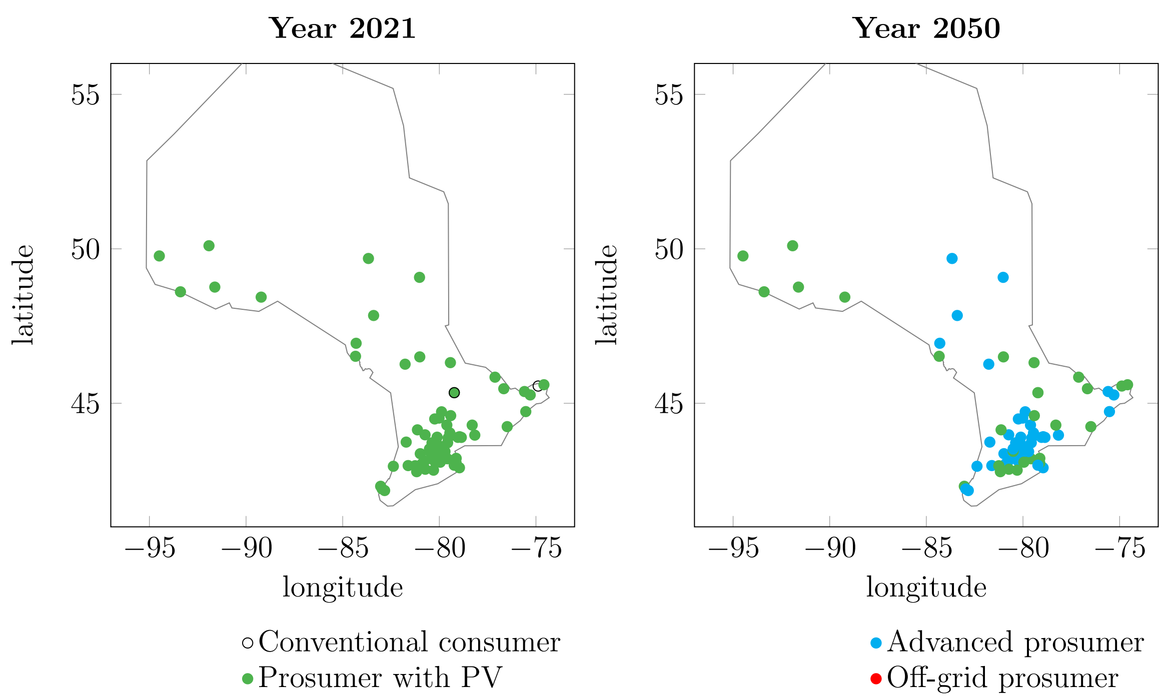
At different times of the planning horizon and depending on tariff policy, households may select a different consumption strategy among the following: conventional consumers, prosumers with PV array, advanced prosumers with PV array and electric battery, and off-grid prosumers with PV array. Figure 10a shows the results for the pathway N1. Already in 2021 it becomes interesting for Ontario's households to invest in PV and become prosumers. By 2050 it becomes economically rational for the majority of households to increase its self-generation and self-consumption: PV would be expanded and electric battery installed (Figure 10b). Furthermore, in some sensitive locations the model suggests that the physical disconnection may be considered by households as a possible option. These locations are characterized by particularly high fixed costs and variable charges. Similarly, under the pathway N2 the simulation model suggests a development of PV prosumers already in 2021 all around Ontario (Figure 11a). By 2050, all households rely on prosumer strategies but remain connected to the grid due to a more moderate rates increase (Figure 11b).

Figure 12 illustrates potential contributions of both policy pathways to the global 2050 goals for Ontario's power system (defined in Section 4). Both policies may add around 28% to the total installed non-hydro renewable capacity in Ontario by 2050. The installed PV in households may provide around 55% of the total expected annual PV generation in 2050. Self-generation and self-consumption with small-scale PV generators may contribute around 8% of the target for net-zero emissions in Ontario's power generation. More than 55% of the desired battery storage capacity in the province may be achieved via small-scale prosumers with the policy pathway N1, while pathway N2 may provide 46.5% of that battery storage capacity.



(a) (b)

Figure 10: Households consumption strategies for the policy pathway N1 in 2021 and 2050.



(a) (b)

Figure 11: Households consumption strategies for the policy pathway N2 in 2021 and 2050.

Both policies reduce the variable portion of the electricity bill. Pathway N1 requires more than CAD 1,560 Million for rebate payments and it may lead to the physical disconnection of 6,150 households or around 7.38 MW from the grid.

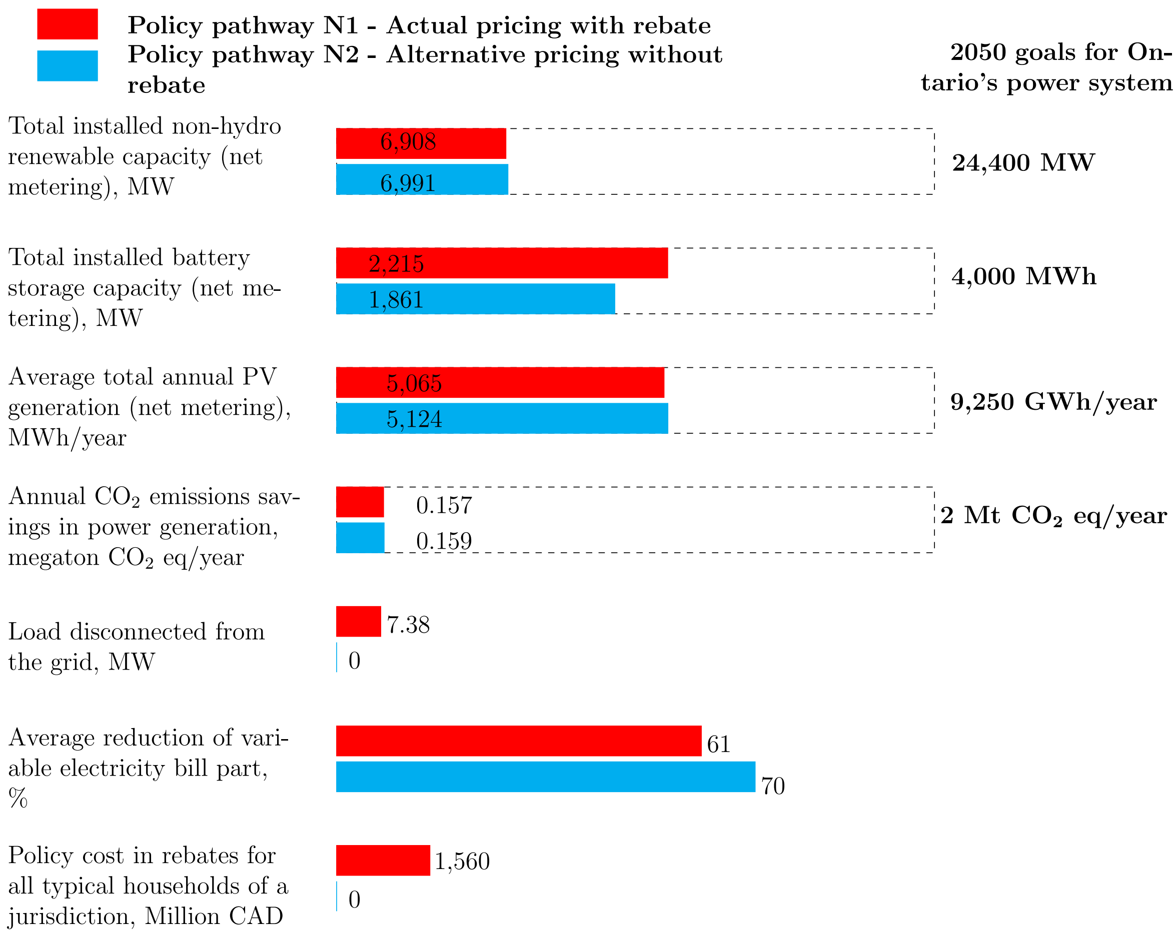
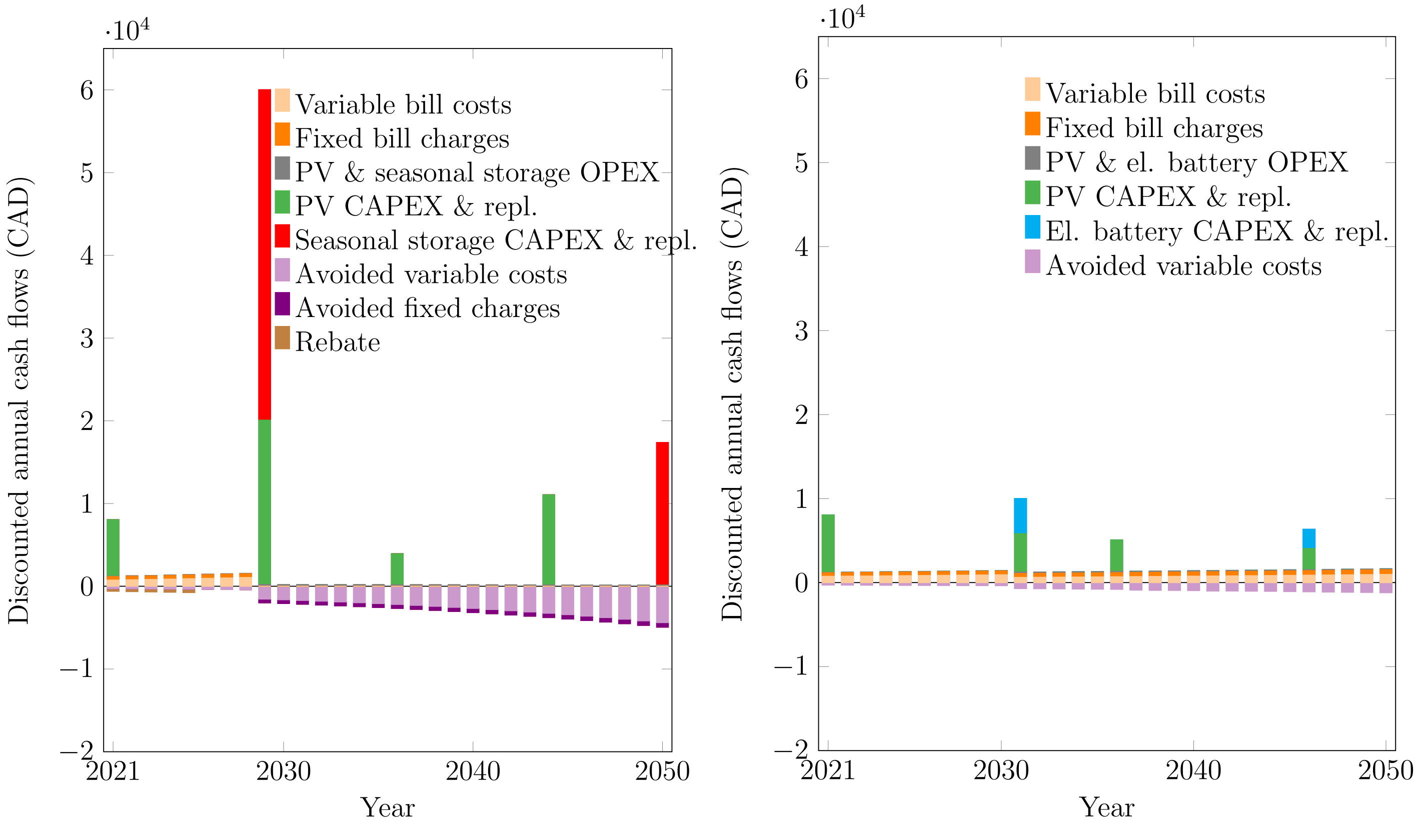


Figure 12: Contributions of policy pathways to the global 2050 goals for the Ontario's power system.

5.4 Step 4. Policy effects for sensitive locations

We illustrate the effect of the two policy pathways for Chapleau, a township situated in Sudbury District (Table 2). Figure 13 illustrates the decisions for a Chapleau household in terms of annual cash flows. Under pathway N1 a typical household in this location will tend to invest in a large PV system and seasonal storage to disconnect physically from the grid (Figure 13a). This disconnection may happen only few years after the rebate program is terminated, and the grid rates and charges start to generate excessive electricity costs in a grid-connected mode. Even under the assumption that technologies may generate additional expenses related to their maintenance and replacement (in case of major failure), the option to disconnect and rely on its own power generation seems to be more interesting for a typical Chapleau household (Figure 14a). If the increase of grid rates is not so fast and limited to 4% as in pathway N2, households in this location will more likely remain on-grid (Figure 13b). In this case, it becomes advantageous for a household to deploy a PV array which will be slightly expended around year 2030. At the same time a household may invest in an electric battery to increase its self-consumption and decrease the variable part of the remaining bill (Figure 14b).



(a) Pathway N1

(b) Pathway N2

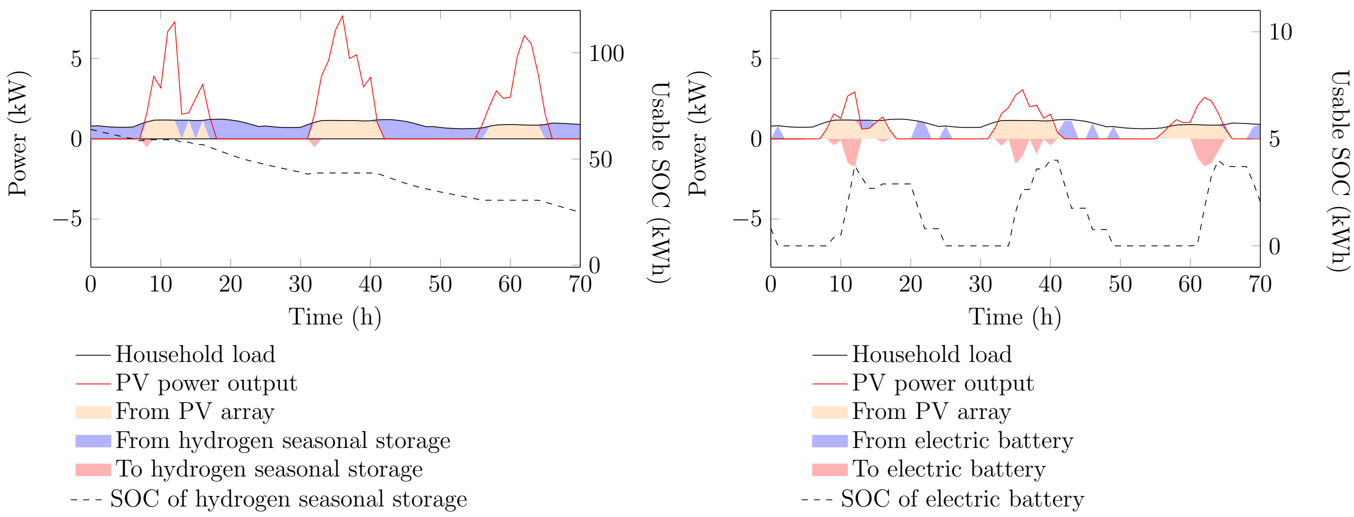
Figure 13: Annual investment and operation cash flows for a typical Chapleau household under each policy pathway.

Table 2: Simulation results for Chapleau household.

Details	Policy pathway N1 - **Actual pricing with rebate**	Policy pathway N2 - **Alternative pricing without rebate**
Deployment of technologies	5 PV modules, hydrogen seasonal storage	2 PV modules, electric battery
Prosumer total cash flows over 2021-2050 period		
Electricity bill, 10^3 CAD	10.64 (8 years)	38.5
Investments, 10^3 CAD	102.76[1]	27.49[1]
Avoided costs, 10^3 CAD	75.9[2]	22.3
Balance, 10^3 CAD	37.5	43.7
Benchmark - conventional consumer over 2021-2050 period		
Electricity bill, 10^3 CAD	120.56	83.6

[1] Installed, maintenance and replacement costs.

[2] Including rebates.



(a) Pathway N1

(b) Pathway N2

Figure 14: Example of power dispatch for a typical Chapleau household for the same three days in March after year 2030 under each policy pathway.

5.5 Step 5. Critical analysis and policy implications

Both policy pathways achieve similar results by 2050 in terms of total installed non-hydro renewable and battery storage capacities, average annual PV generation, and annual CO_2 emissions savings. However, pathway N1 reveals multiple sensitive locations in Ontario where prosumers may tend to disconnect by 2050 to rely on their own generators and storage. The important observation is that these disconnections may occur almost simultaneously in various province's locations only a few years after the rebate program is terminated. This may generate an important shock for Ontario's energy system. This policy is similar to the current Ontario policy: to allow important annual increases of variable rates and fixed charges in different distribution areas, and to mitigate the total annual bill increase by the application of rebates. The duration of this relief program which requires considerable expanses is not clear, but it seems that these costs will be paid back (at least partly) in the near future by consumers themselves through the GA.

If policy actions focus on the prevention of rapid bill increases then prosumers disconnection may be avoided. Alternatively the relief budget could be used partly to help LDCs diversify their service offers, to help build micro grids for remote municipalities (where rates are typically high), to develop new business models to stimulate the local RES and storage markets, and to involve prosumers in providing demand response to make them active and valuable players of Ontario's energy system. If rates and charges increase as in pathway N2, a policy-maker may achieve a considerable contribution to the deep decarbonization and electrification goals of Ontario via grid-connected small-scale prosumers. Not only the total RES installed capacity may be expanded, but also a large electric storage capacity at residential level and prosumers involvement with demand response may help further RES integration.

Prosumers disconnection is modeled with hydrogen seasonal storage (power-to-hydrogen-to-power technology) already commercially available for household application in Germany (see Appendix C for details). This type of technology may be potentially included in Ontario low-carbon hydrogen strategy [23]. In this view, a policy-maker may stimulate (through LDCs and appropriate policies) the deployment of such technology not as the ultimate solution for prosumers disconnection but rather in support of grid-connected prosumers. Power-to-hydrogen storage may help to address inter-seasonal and inter-annual load variability and power-to-hydrogen-to-power may become a new type of low-carbon dispatchable capacity providing reserve to the grid.

This study raised an important question about the accuracy of a typical household concept for an optimal policy definition. The analysis in Section 3 showed that households with different average monthly consumption will react differently to policies, and the number of typical households in a jurisdiction will be less than 50%. A potential solution may be to no longer rely on one typical household of 700 kWh/month, but to analyze policy impact for a few households with each one representing a typical consumption range (for example, from 0 to 500 kWh/month, from 500 kWh/month to 1,000 kWh/month and more than 1,000 kWh/month).

6 Model analysis and future developments

The presented model may be used directly by a policy-maker to design an optimal tariff policy for residential consumers. For the moment the model is only accessible by authors, however, we intend to work on model transfer and application to advice policy-makers on real-life cases. Regarding model transparency, its structure, equations, parameter values, and assumptions were made available through scientific publications, such as [24], and workshops. These communications give general understanding of how the model works, as well as provide technical information to evaluate the model at higher level of mathematical and programming detail. The benefits and limitations of the model are as follows:

- The present model is applicable to different jurisdictions. The number of agents (typical households) and their locations must be adjusted. For example, to test implications of different policies in Quebec, where all residential consumers pay the same tariff, typical households and their number would be more likely selected based on the difference in weather conditions (which will affect PV output).
- The present model is deterministic, it does not take into account possible uncertainties related to the emergence of new technologies or other events. The introduction of stochastic or robust models for uncertainty modeling may considerably affect calculation time and required capacity. This may be not convenient for a policy-maker. If the model remains deterministic a policy-maker may want to repeat the policy simulation at least once per year to verify that the results are consistent with recent developments.
- The present simulations were carried out considering linear variations in the tariff and capital costs. Note that the inputs of policy pathways may be defined depending on the policy-makers needs. For example, a policy-maker may define the input values "manually" predefining annual cost drops or increases. Eventually, these inputs can come from prediction models, such as methods for learning curve estimation (dependence of capacity deployment and cost decrease) [25].

- All inputs currently simulated with specific modeling toolboxes for our convenience (e.g., household load, PV power output) could be replaced by data sets defined by a policy-maker. In this case, a policy-maker will need only to respect data horizon, time step and measurement units.

- The present simulation accounts only for PV panels as a renewable source. This was guided by the choice of Ontario as a case study where wind resource in not generally sufficient to power residential turbines of smaller height. Large capacity onshore and offshore turbines, situated mainly in the South coastal area of Ontario, are about four times higher accessing faster wind speeds at higher altitudes. Note that a model for a wind turbine is available and could easily be integrated in the prosumer decision-making model if desired.

Future developments are evisaged in three thrusts: scientific communication, model licensing and technology transfer, and improvement of the algorithm and model.

First, we intend to publish the results of this study in a scientific paper. In addition to making the study widely available, this publication will provide additional visibility for the Energy Modelling Initiative (EMI) initiative. We are targeting the special issue of Energy Strategy Reviews entitled "Energy Modelling Platform for North America (EMP-NA) – Open Modelling Projects". This special issue aims to publish papers related to open source modeling efforts, policy implications and analysis techniques, including open data resources, that will benefit both academic researchers and policy makers in developing sustainable energy pathways. Our abstract for this study has been accepted and we were invited to submit a full-length scientific paper.

Second, we are exploring our options for model licensing and technology transfer. In particular, we are keen to develop direct contacts with policy-makers in the provinces and municipalities who may benefit from using our model to explore the implications of different tariff policies,

Finally, several directions related to different aspects of the model could be integrated in the agenda of the EMI initiative and developed during the next few years. First, we can work on improving the algorithm itself. The iterative process required when a policy-maker needs to manually adjust the policy and repeat the simulation (backward arrow on flow chart of Figure 1a) could be replaced by an automatic policy search approach. To do so, we would use a deep reinforcement learning (DRL) method. Starting with the initial policy, DRL will call the existing household agents to simulate their responses and will automatically evaluate whether the results meet criteria predefined by a policy-maker (such as the installed capacities and carbon savings). If these criteria are not met, DRL will automatically adjust the initial policy by learning from this feedback, run the simulation again, and evaluate the results. This process is iterated until a satisfactory optimal policy is found. Second, it would be important to make our model more realistic without increasing computational resources and time. In this direction, we could explore further assumptions and simplifications for greater model scalability, such as how many households must be modelled to realistically represent jurisdictions of different sizes at municipal, provincial and national levels (see observation in Section 5.5). Third, the model components could be further integrated and a user-friendly interface provided to facilitate their use by policy-makers. Via this interface, a policy-maker would: 1) select databases (already available online) to collect the inputs and automatically convert them to the model format, 2) set up criteria for evaluating the results for a given policy and determine if it is satisfactory, and 3) launch the simulation and automatically obtain the results in the desired format.

References

[1] Elizaveta Kuznetsova and Miguel F Anjos. "Challenges in energy policies for the economic integration of prosumers in electric energy systems: A critical survey with a focus on Ontario (Canada)". In: *Energy Policy* 142 (2020), p. 111429.

[2] OEB. *Bill calculator*. Tech. rep. Ontario Energy Board, 2021. URL: https://www.oeb.ca/rates-and-your-bill/bill-calculator.

[3] OEB. *Electricity distribution rates*. 2019. URL: https://www.oeb.ca/industry/applications-oeb/electricity-distribution-rates (visited on 04/23/2019).

[4] IESO. *Feed-in Tariff Program*. 2019. URL: http://www.ieso.ca/Sector-Participants/Feed-in-Tariff-Program/FIT-Archive (visited on 04/23/2019).

[5] Government of Ontario. *Save on your energy bill with net metering*. 2019. URL: https://www.ontario.ca/page/save-your-energy-bill-net-metering.

[6] HydroOttawa. *Net Metering*. 2019. URL: https://hydroottawa.com/accounts-and-billing/generation/net-metering.

[7] OEB. *The Fair Hydro Act, 2017*. 2017. URL: https://www.oeb.ca/newsroom/2017/fair-hydro-act-2017.

[8] Government of Ontario. *Find programs to reduce your electricity bill*. 2017. URL: https://www.ontario.ca/page/find-programs-reduce-electricity-bill (visited on 06/26/2019).

[9] Government of Ontario. *Keeping electricity affordable and improving transparency*. 2019. URL: https://news.ontario.ca/mndmf/en/2019/03/keeping-electricity-affordable-and-improving-transparency.html (visited on 06/26/2019).

[10] OEB. *Historical electricity rates*. 2020. URL: https://www.oeb.ca/newsroom/2020/ontario-energy-board-sets-new-electricity-prices-households-and-small-businesses (visited on 01/03/2020).

[11] Government of Ontario. *Ontario Rebate for Electricity Consumers Act, 2016, ONTARIO REGULATION 363/16, Last amendment: 736/20*. Tech. rep. Government of Ontario, 2021. URL: https://www.ontario.ca/laws/regulation/160363/v10.

[12] OEB. *Electricity distribution rates - Estimated Total Bill Impacts*. Tech. rep. Ontario Energy Board, 2018. URL: https://www.oeb.ca/industry/applications-oeb/electricity-distribution-rates.

[13] OEB. *Defining Ontario's Typical Electricity Customer*. Tech. rep. Ontario Energy Board, 2016, pp. 1–10. URL: https://www.oeb.ca/sites/default/files/uploads/Report_Defining_Typical_Elec_Customer_20160414.pdf.

[14] Elizaveta Kuznetsova and Miguel F Anjos. "Prosumers and energy pricing policies: When, where and under which conditions will prosumers emerge ? A case study for Ontario (Canada)". In: *Energy Policy* 149 (2021), p. 111982.

[15] Joakim Munkhammar, Jesper Rydén, and Joakim Widén. "Characterizing probability density distributions for household electricity load profiles from high-resolution electricity use data". In: *Applied Energy* 135 (2014), pp. 382–390. DOI: 10.1016/j.apenergy.2014.08.093. URL: http://dx.doi.org/10.1016/j.apenergy.2014.08.093.

[16] Merih Aydinalp Koksal, Ian H Rowlands, and Paul Parker. "Energy, cost, and emission end-use profiles of homes : An Ontario (Canada) case study". In: *Applied Energy* 142 (2015), pp. 303–316. ISSN: 0306-2619. DOI: 10.1016/j.apenergy.2014.12.077. URL: http://dx.doi.org/10.1016/j.apenergy.2014.12.077.

[17] Dane George and Lukas G Swan. "A method for distinguishing appliance , lighting and plug load profiles from electricity ' smart meter ' datasets". In: *Energy and Buildings* 134 (2017), pp. 212–222. ISSN: 0378-7788. DOI: 10.1016/j.enbuild.2016.10.048.

[18] Statistics Canada. *Analytical products, 2016 Census*. 2016. URL: https://www12.statcan.gc.ca/census-recensement/2016/as-sa/98-200-x/2016005/98-200-x2016005-eng.cfm.

[19] Canada Energy Regulator. *Canada's Energy Future 2020*. Tech. rep. Canada Energy Regulator, 2020. URL: https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2020/index.html.

[20] EnergyHub. *Cost of Solar Power In Canada 2019*. 2019. URL: https://energyhub.org/cost-solar-power-canada/ (visited on 05/29/2019).

[21] IRENA. *Utility-scale batteries*. Tech. rep. International Renewable Energy Agency, 2019, pp. 1 –24. URL: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Utility-scale-batteries_2019.pdf.

[22] Canada Energy Regulator. *Provincial and Territorial Energy Profiles – Ontario*. Tech. rep. Canada Energy Regulator, 2021. URL: https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-ontario.html.

[23] ERO. *Ontario Low-Carbon Hydrogen Strategy - discussion paper*. Tech. rep. Environmental Registry of Ontario, 2020, pp. 1 –20. URL: https://prod-environmental-registry.s3.amazonaws.com/2020-11/Ontario%20Low-Carbon%20Hydrogen%20Strategy%20-%20discussion%20paper%20%28November%202020%29.pdf.

[24] Elizaveta Kuznetsova and Miguel F Anjos. "Combined Strategic Planning and Power Dispatch Optimization Framework to Simulate the Emergence of Small-Scale Residential Prosumers". In: *2020 IEEE Power and Energy Society General Meeting (PESGM)*. 2020, pp. 1 –5.

[25] Amro M. Elshurafa, Shahad R. Albardi, Simona Bigerna, and Carlo Andrea Bollino. "Estimating the learning curve of solar PV balance–of–system for over 20 countries: Implications and policy recommendations". In: *Journal of Cleaner Production* 196 (2018), pp. 122–134. DOI: 10.1016/j.jclepro.2018.06.016. URL: https://doi.org/10.1016/j.jclepro.2018.06.016.

[26] The Atmospheric Fund. *A Clearer View on Ontario's Emissions. Electricity emussions factors and guidlines*. Tech. rep. 2019, pp. 1–26. URL: https://taf.ca/wp-content/uploads/2019/06/A-Clearer-View-on-Ontarios-Emissions-June-2019.pdf.

[27] Government of Canada. *Comprehensive Energy Use Database. Energy Use Data Handbook*. 2019. URL: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm (visited on 07/19/2019).

[28] IRENA. *Electricity storage and renewables: Costs and markets to 2030*. Tech. rep. October. Abu Dhabi: International Renewable Energy Agency, 2017, pp. 1 –132. URL: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf.

[29] Danielle Muoio. *10 home batteries that rival Tesla's Powerwall 2*. 2017. URL: https://www.businessinsider.com/rechargeable-battery-options-compete-tesla-2017-5 (visited on 05/29/2019).

[30] Energy Sage. *Solar batteries for home use*. 2018. URL: https://www.energysage.com/solar/solar-energy-storage/.

[31] Jason Deign. *Seasonal Storage for Homes ? German Firm Sells Residential Batteries Tied to Fuel Cells*. 2018. URL: https://www.greentechmedia.com/articles/read/fuel-cell-batteries-for-your-home#gs.qvtscn.

[32] O Schmidt, A Gambhir, I Staffell, A Hawkes, J Nelson, and S Few. "Future cost and performance of water electrolysis : An expert elicitation study". In: *International Journal of Hydrogen Energy* 42.52 (2017), pp. 30470–30492. ISSN: 0360-3199. DOI: 10.1016/j.ijhydene.2017.10.045. URL: https://doi.org/10.1016/j.ijhydene.2017.10.045.

[33] Eleonora Ruffini and Max Wei. "Future costs of fuel cell electric vehicles in California using a learning rate approach". In: *Energy* 150 (2018), pp. 329 –341. DOI: 10.1016/j.energy.2018.02.071.

[34] Sunceco. *Solar modules*. URL: http://sunceco.com/solar-modules/.

[35] Timothy Dierauf, Aaron Growitz, Sarah Kurtz, Jose Luis Becerra, Evan Riley, and Clifford Hansen. *Weather-Corrected Performance Ratio*. Tech. rep. National Renewable Energy Laboratory, 2013, pp. 1–22. URL: https://www.nrel.gov/docs/fy13osti/57991.pdf.

[36] HPS. *HPS System – Picea*. 2019. URL: http://www.homepowersolutions.de/en/product#content.

[37] FuelCellsWorks. *Wystrach and Picea to Cooperate on Home Power Solutions with Hydrogen Storage*. 2019. URL: https://fuelcellsworks.com/news/wystrach-and-picea-to-cooperate-on-home-power-solutions-with-hydrogen-storage/.

[38] PV Europe. *100 percent energy-autonomous passive house*. 2019. URL: https://www.pveurope.eu/News/Solar-Generator/100-energy-autonomous-passive-house (visited on 07/31/2019).

[39] NREL. *Hydrogen Station Compression, Storage, and Dispensing Technical Status and Costs*. Tech. rep. National Renewable Energy Laboratory, 2014, pp. 1 –74. URL: https://www.hydrogen.energy.gov/pdfs/58564.pdf.

[40] S Mekhilef, R Saidur, and A Safari. *Comparative study of different fuel cell technologies*. 2012. DOI: 10.1016/j.rser.2011.09.020. URL: http://dx.doi.org/10.1016/j.rser.2011.09.020.

[41] NRC. *Solar resource data available for Canada*. 2016. URL: https://www.nrcan.gc.ca/energy/energy-sources-distribution/renewables/solar-photovoltaic-energy/solar-resource-data-available-canada/14390.

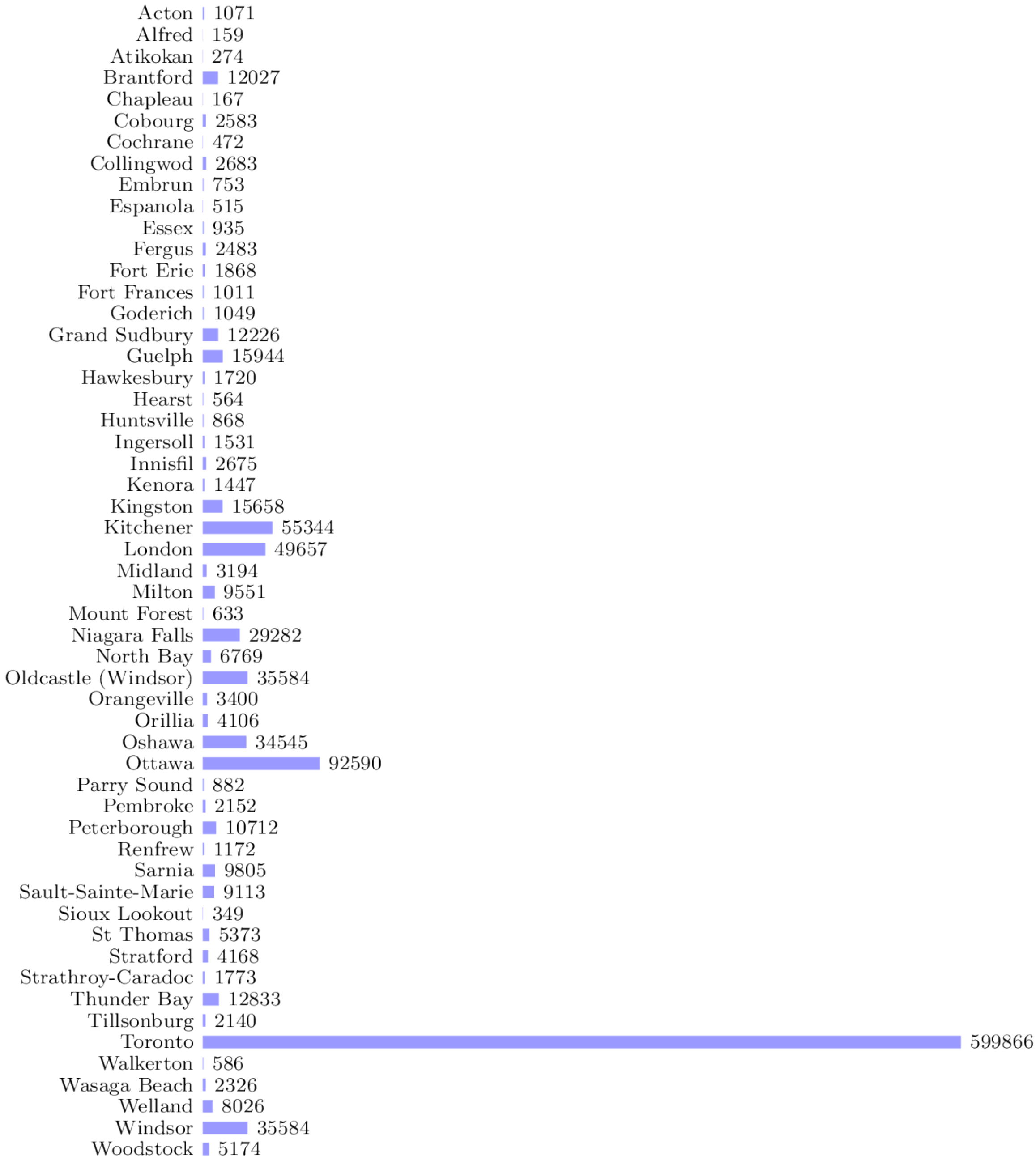
[42] Weatherstats. *Canada Weather Stats*. 2019. URL: https://www.weatherstats.ca/ (visited on 04/24/2019).

[43] Y M Atwa, M M A Salama, and R Seethapathy. "Optimal renewable resources mix for distribution system energy loss minimization". In: *IEEE Trans. on Power Syst.* 25.1 (2010), pp. 360–370. DOI: 10.1109/TPWRS.2009.2030276.

[44] M Mattei, G Notton, C Cristofari, M Muselli, and P Poggi. "Calculation of the polycrystalline PV module temperature using a simple method of energy balance". In: *Renewable Energy* 31 (2006), pp. 553–567. DOI: 10.1016/j.renene.2005.03.010.

[45] C. Grigg, P. Wong, P. Albrecht, R. Allan, M. Bhavaraju, R. Billinton, Q. Chen, C. Fong, S. Haddad, S. Kuruganty, W. Li, R. Mukerji, D. Patton, N. Rau, D. Reppen, A. Schneider, M. Shahidehpour, and C. Singh. "The IEEE Reliability Test System - 1996". In: *IEEE Trans. on Power Syst.* 14.3 (1999), pp. 1010–1020.

Appendix A Number of single-detached houses per municipality



Appendix B Decision-support model and KPI

B.1 Nomenclature

	Sets
$d \in J$	Distribution area d in a jurisdiction J
$h \in H$	Power dispatch time step (h)
$u \in U^{PV}$	PV unit
$y \in Y$	Strategic planning time step ($year$)
	Parameters
$\eta^{bat/seas,ch}$	Charging efficiencies of electric battery and hydrogen seasonal storage (including electrolyzer, compression and storage stages)
$\eta^{bat/seas,disch}$	Discharging efficiencies of electric battery and hydrogen seasonal storage (including fuel cell)
AEF_J	Average Emission Factor (AEF) in a jurisdiction J ($g\ CO_2eq/kWh$)
$Bill\ reduction_{J,y}$	Average reduction of a variable bill part (%)
$c^{el}_{h,y}$	Electricity load of the consumer at time step h at year y (kW)
$c^{el.\Delta}_{h,y}$	Average electricity load of the consumer at time step h at year y (kW)
$C^{avoided}_{y}$	Total cost related to gains and avoided payments in electricity bill at year y (CAD)
$Capacity^{bat}_{J}$	Total installed capacity of electric batteries in jurisdiction J (MW)
$Capacity^{PV}_{J}$	Total installed PV capacity in jurisdiction J (MW)
$Capacity^{bat}_{d}$	Total installed capacity of electric batteries in distribution area d (MW)
$Capacity^{PV}_{d}$	Total installed PV capacity in distribution area d (MW)
$CAPEX_y$	Total capital investments in RES technologies at year y (CAD)
$Capex^{PV}_{u,y}$	Installed cost of PV unit u at year y (CAD)
$Capex^{bat/seas}_{y}$	Installed costs of electric battery and hydrogen seasonal storage at year y (CAD)
$Capex^{PV,repl}_{u,y}$	Replacement cost of PV unit u at year y (CAD)
$Capex^{bat/seas,repl}_{y}$	Replacement costs of electric battery and hydrogen seasonal storage at year y (CAD)

$d^{PV/bat/seas}$	Technologies' warranty periods ($year$)
$Disconnection\ potential_J$	Total load disconnection potential in a jurisdiction J (MW)
EB_y	Yearly household electricity bill (CAD)
EoS^{PV}	EoS rate of PV technology
f_y^{disc}	Discount factor at year y
$f_y^{disc,repl}$	Discount factor for technology replacement at year y
$f_u^{EoS,PV}$	Factor of PV costs decrease due to EoS at year y
Fix_y	Fixed charges at year y (CAD/kWh)
$Generation_{J,y}^{PV}$	Total annual PV generation in a jurisdiction J at year y ($GWh/year$)
H_d	Number of typical households in distribution area d
$H_d^{x_y^{Off}}$	Number of typical households prompt to disconnect in distribution area d
$OPEX_y$	Total operation cost of RES technologies at year y (CAD)
$Opex_{u,y}^{PV}$	Operation cost of PV unit u at year y (CAD)
$Opex_y^{bat/seas}$	Operation costs of electric battery and hydrogen seasonal storage at year y (CAD)
$p_{h,y}^{PV}$	Available PV power at time step h at year y (kW)
$Policy\ cost_J$	Total policy cost for a jurisdiction J ($MillionCAD$)
r	Discount rate
$R_{h,y}^{bat/seas}$	state of charge (SOC)s of electric battery and hydrogen seasonal storage (in energy content equivalent) at the time step h at year y (kWh)
$R^{bat/seas,Min/Max}$	Minimum and maximum acceptable levels of charge of electric battery and hydrogen seasonal storage kWh
$R^{bat/seas,ch,Min/Max}$	Minimum and maximum power to be charged to electric battery and hydrogen seasonal storage (kW)
$R^{bat/seas,disc,Min/Max}$	Minimum and maximum power to be discharged from electric battery and hydrogen seasonal storage (kW)
$Rebate_y$	OER at year y (CAD)
$REPLACE_y$	Total replacement cost of RES technologies at year y (CAD)
$Savings_{J,y}^{CO_2}$	Total annual CO_2 savings in a jurisdiction J at year y ($GWh/year$)
Var_y	Total variable electricity rate at year y (CAD/kWh)
Var_y^{NM}	Total variable electricity rate that may be credited under net metering scheme at year y (CAD/kWh)

Variables

$\delta_{h,y}^{bat/seas,ch/disch}$	Binary decision variables for charging and discharging of electric battery and hydrogen seasonal storage at time step h at year y
$b_{h,y}$	Power from the grid at time step h at year y (kW)
$l_{h,y}^{PV}$	Power used from PV at time step h at year y (kW)
$R_{h,y}^{bat/seas,ch/disch}$	Power charged or discharged from electric battery and hydrogen seasonal storage at time step h at year y (kW)
$w_{h,y}^{PV}$	PV power excess at time step h at year y (kW)
$x_{u,y}^{PV}$	Binary decision variable for deployment of PV unit u at year y
$x_{y}^{bat/seas}$	Binary decision variables for deployment of electric battery or hydrogen seasonal storage at year y
x_{y}^{Fix}	Binary decision variable to ensure that fixed charges and rebate are paid in the on-grid mode at year y
x_{y}^{Off}	Binary decision variable eliminating fixed charges and rebate in the off-grid mode at year y

B.2 Optimization model

The decision-making model is based on the consumer objective of total expenses minimization over a long-term planning horizon Y (Figure 15). This model, first presented during the General Meeting of PES IEEE in August 2020 and published in [24], was specifically upgraded for this report. The present model is now able to simulate the entire transformation pathway from a conventional on-grid consumer to an off-grid prosumer with seasonal storage. Indexes h and y state for hour and year, respectively, so $h \in [0, ..., H]$ and $y \in [0, ..., Y]$. Index $u \in [0, ..., U^{PV}]$ states for PV unit to deploy. The total objective function is defined as the sum of annual electricity bills EB_y, capital investments $CAPEX_y$ in technologies, operational expenses $OPEX_y$ to operate and maintain these technologies and annual avoided costs $C_y^{avoided}$ Eq. (2).

$$Minimize \sum_{y \in Y} f_y^{disc} \Big[EB_y + CAPEX_y + REPLACE_y + OPEX_y - C_y^{avoided} \Big] \tag{2}$$

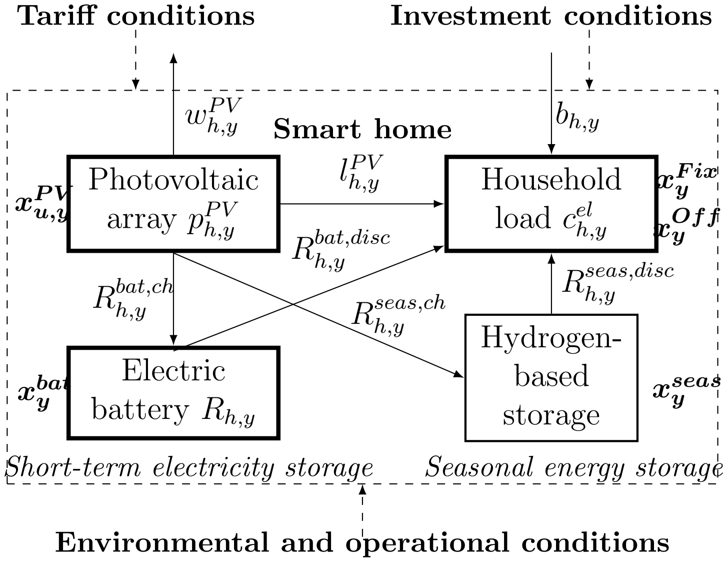


Figure 15: Prosumer abstract scheme updated from [24].

B.2.1 Strategic planning

$CAPEX_y$ including investments in PV array $Capex^{PV}_{u,y}$, in electric battery $Capex^{bat}_y$ and in seasonal storage $Capex^{seas}_y$ has been divided into two terms: *(i)* initial investment cost at $y = 0$ (3) and *(ii)* deployment cost for the remaining future planning horizon for $y = 1, ..., Y$ (4). The deployment decision is made by taking into account one replacement by an equivalent technology of the same capacity and performance at the end of technology lifespan. Lifespans of the PV array, electric battery and seasonal storage are denoted d^{PV}, d^{bat} and d^{seas}, respectively (5) - (6). If the potential replacement time falls after the end of the total planning horizon Y, it is assumed that the replacement cost is equal to the technology cost at $y = Y$ (7). Similar to the capital investments, the operational expenses $OPEX_y$ accounts for PV $Opex^{PV}_{u,y}$, electric battery $Opex^{bat}_y$ and seasonal storage $Opex^{seas}_y$ maintenance (8).

The consumer minimizes his expenses by making strategic annual decisions on deployment of PV array units, electric battery and seasonal storage represented by binary decision arrays $x^{PV}_{u,y}$, and decision variables x^{bat}_y and x^{seas}_y, respectively (9). Constraint (10) ensures that if a seasonal storage for the off-grid scheme is deployed the optimization model deploys enough PV capacity for the consumer to be self-sufficient. Consumer may decide to progressively expand his renewable capacities by adding additional units to already existing units. Constraint (11) ensures that the deployed capacity cannot be reduced in future. Constraint (12) stipulates that the deployment is progressive. The Economy of Scale (EoS) factors $f^{EoS,PV}_u$ accounts for the potential reduction in investment and operational cost based on the capacity expansion (13). The discount factor serves to define the value of future cash flows (14). In the case of replacement cost, the calculation accounts for the year of reinvestment (15).

$$CAPEX_y = \sum_{u \in U^{PV}} Capex^{PV}_{u,y} \cdot f^{EoS,PV}_u \cdot x^{PV}_{u,y} + Capex^{bat}_y \cdot x^{bat}_y + Capex^{seas}_y \cdot x^{seas}_y, y = 0 \tag{3}$$

$$CAPEX_y = \sum_{u \in U^{PV}} Capex^{PV}_{u,y} \cdot f^{EoS,PV}_u \cdot (x^{PV}_{u,y} - x^{PV}_{u,y-1}) + Capex^{bat}_y \cdot (x^{bat}_y - x^{bat}_{y-1}) + Capex^{seas}_y \cdot (x^{seas}_y - x^{seas}_{y-1}), y = 1, ..., Y, \forall y \tag{4}$$

$$REPLACE_y = \sum_{u \in U^{PV}} Capex^{PV,repl}_{u,y} \cdot f^{EoS,PV}_u \cdot x^{PV}_{u,y} + Capex^{bat,repl}_y \cdot x^{bat}_y + Capex^{seas,repl}_y \cdot x^{seas}_y, y = 0 \tag{5}$$

$$REPLACE_y = \sum_{u \in U^{PV}} Capex^{PV,repl}_{u,y} \cdot f^{EoS,PV}_u \cdot (x^{PV}_{u,y} - x^{PV}_{u,y-1}) + Capex^{bat,repl}_y \cdot (x^{bat}_y - x^{bat}_{y-1}) + Capex^{seas,repl}_y \cdot (x^{seas}_y - x^{seas}_{y-1}), y = 1, ..., Y, \forall y \tag{6}$$

$$Capex^{PV/bat/seas,repl}_{u,y} = \begin{cases} Capex^{PV/bat/seas}_{u,y+d^{PV/bat/seas}}, & \text{if } y \leqslant Y - d^{PV/bat/seas} \\ Capex^{PV/bat/seas}_{u,Y}, & \text{otherwise} \end{cases} \tag{7}$$

$$OPEX_y = \sum_{u \in U^{PV}} Opex^{PV}_{u,y} \cdot f^{EoS,PV}_u \cdot x^{PV}_{u,y} + Opex^{bat}_y \cdot x^{bat}_y + Opex^{seas}_y \cdot x^{seas}_y, \forall y \tag{8}$$

$$0 \leqslant x^{PV}_{u,y} \leqslant 1, 0 \leqslant x^{bat}_y \leqslant 1, 0 \leqslant x^{seas}_y \leqslant 1, \forall u, y \tag{9}$$

$$0 \leqslant x^{seas}_y \leqslant x^{PV}_{u,y}, \forall u, y \tag{10}$$

$$x^{PV}_{u,y-1} \leqslant x^{PV}_{u,y}, x^{bat}_{y-1} \leqslant x^{bat}_y, x^{seas}_{y-1} \leqslant x^{seas}_y, \forall u, y \tag{11}$$

$$x_{u,y}^{PV} \leqslant x_{u-1,t}^{PV}, \forall u, y \tag{12}$$

$$f_u^{EoS,PV} = u^{EoS^{PV}} - (u-1)^{EoS^{PV}}, \forall u = 1, ..., U^{PV} \tag{13}$$

$$f_y^{disc} = \frac{1}{(1+r)^y}, \forall y \tag{14}$$

$$f_y^{disc,repl} = \begin{cases} 1/(1+r)^{y+d^{PV/bat/seas}}, & \text{if } y \leqslant Y - d^{PV/bat/seas} \\ 1/(1+r)^Y, & \text{otherwise} \end{cases} \tag{15}$$

B.2.2 Operation planning

The annual electricity bill (16) and avoided costs (17) depend on the variable rates (CAD/kWh) and fixed monthly charges (CAD). The annual electricity bill also includes possible $Rebate_y$ (OER) offered by the electricity provider. Var_y agglomerates all variable costs including energy and power rate, and distribution and transmission rates. Fix_y represents fixed service charges. The annual avoided cost also includes a variable rate Var_y^{NM} used to simulate a Met Metering scheme. The binary decision variable x_y^{Fix} ensures that fixed charges are paid when the consumer is physically connected to the grid (18). These fixed charges may be eliminated only if the seasonal storage is deployed (which supposes a possibility for physical disconnection from the grid). It is achieved with a binary decision variable x_y^{Off} (19). Similar to the fixed charges, the consumer receives $Rebate_y$ when he is connected to the grid; this rebate is eliminated from the equation when he disconnects. The operation planning model optimizes power dispatch at hourly basis by deciding the optimal power $b_{h,y}$ purchased from the grid, $l_{h,y}^{PV}$ used from the locally installed PV array, $R_{h,y}^{bat/seas,ch}$ and $R_{h,y}^{bat/seas,disc}$ charged and discharged to/from the electric battery or hydrogen seasonal storage. The remaining $w_{h,y}^{PV}$ is used as a credit in net metering. Equations (20) - (23) are power balance equations for power dispatch at each time h. Equations (24) and (25) provide dynamics for electric battery and seasonal storage charge and discharge, where $R_{h,y}^{bat/seas}$ is the level of charge at time h, and $\eta^{bat/seas,ch}$ and $\eta^{bat/seas,disc}$ are charging and discharging efficiencies. Charging and discharging power is bounded by minimum and maximum charging ($R^{bat/seas,ch,Min}$ and $R^{bat/seas,ch,Max}$) and discharging ($R^{bat/seas,disc,Min}$ and $R^{bat/seas,disc,Max}$) power in (26) and (27). Binary decision arrays $\delta_{h,y}^{bat/seas,ch}$ and $\delta_{h,y}^{bat/seas,disc}$ ensure that the battery cannot be charged and discharged at the same time h if the battery is available (28) and (29). To ensure a power flow conservation, battery charge at the end of the operational period must be higher or equal to the initial battery charge (30).

$$EB_y = \sum_{h \in H} b_{h,y} \cdot Var_y + Fix_y \cdot (x_y^{Fix} - x_y^{Off}) - Rebate_y \cdot (x_y^{Fix} - x_y^{Off}), \forall h, y \tag{16}$$

$$C_y^{avoided} = \sum_{h \in H} \left[(l_{h,y}^{PV} + R_{h,y}^{bat,disc}) \cdot Var_y + w_{h,y}^{PV} \cdot Var_y^{NM} \right] + x_y^{Off} \cdot Fix_y, \forall h, y \tag{17}$$

$$0 \leqslant x_y^{Fix} \leqslant 1, x_y^{Fix} \geqslant 1, \forall y \tag{18}$$

$$0 \leqslant x_y^{Off} \leqslant 1, x_y^{Off} \leqslant x_y^{seas}, \forall y \tag{19}$$

$$0 \leqslant l_{h,y}^{PV} \leqslant c_{h,y}^{el}, 0 \leqslant w_{h,y}^{PV} \leqslant p_{h,y}^{PV}, 0 \leqslant b_{h,y} \leqslant c_{h,y}^{el}, \forall h, y \tag{20}$$

$$p_{h,y}^{PV} \cdot \sum_{u \in U^{PV}} x_{u,y}^{PV} - c_{h,y}^{el} \geqslant w_{h,y}^{PV} - b_{h,y} - R_{h,y}^{bat,disc} + R_{h,y}^{bat,ch} - R_{h,y}^{seas,disc} + R_{h,y}^{seas,ch}, \forall h, y \tag{21}$$

$$p_{h,y}^{PV} \cdot \sum_{u \in U^{PV}} x_{u,y}^{PV} \geqslant l_{h,y}^{PV} + w_{h,y}^{PV} + R_{h,y}^{bat,ch} + R_{h,y}^{seas,ch}, \forall h, y \tag{22}$$

$$c_{h,y}^{el} \leqslant l_{h,y}^{PV} + b_{h,y} + R_{h,y}^{bat,disc} + R_{h,y}^{seas,disc}, \forall h, y \tag{23}$$

$$R_{h,y}^{bat/seas} \leqslant R_{h-1,y}^{bat/seas} - \frac{R_{h,y}^{bat/seas,disc}}{\eta^{bat/seas,disc}} + \eta^{bat/seas,ch} \cdot R_{h,y}^{bat/seas,ch}, \forall h, y \tag{24}$$

$$R^{bat/seas,Min} \cdot x_y^{bat/seas} \leqslant R_{h,y}^{bat/seas} \leqslant R^{bat/seas,Max} \cdot x_y^{bat/seas}, \forall h, y \tag{25}$$

$$\delta_{h,y}^{bat/seas,ch} \cdot R^{bat/seas,ch,Min} \leqslant \eta^{bat/seas,ch} \cdot R_{h,y}^{bat/seas,ch} \leqslant \delta_{h,y}^{bat/seas,ch} \cdot R^{bat/seas,ch,Max}, \forall h, y \tag{26}$$

$$\delta_{h,y}^{bat/seas,disc} \cdot R^{bat/seas,disc,Min} \leqslant \frac{R_{h,y}^{bat/seas,disc}}{\eta^{bat/seas,disc}} \leq c_{h,y}^{el}, \forall h, y \tag{27}$$

$$0 \leqslant \delta_{h,y}^{bat/seas,ch} \leqslant 1, 0 \leqslant \delta_{h,y}^{bat/seas,disch} \leqslant 1, \forall h, y \tag{28}$$

$$\delta_{h,y}^{bat/seas,ch} + \delta_{h,y}^{bat/seas,disch} \leqslant x_y^{bat/seas}, \forall h, y \tag{29}$$

$$R_{h=0,y} \cdot x_y^{bat/seas} \leqslant R_{h=H,y}, \forall y \tag{30}$$

B.3 KPI for policy pathways assessment

Total installed PV capacities $Capacity_J^{PV}$ (in MW) and battery storage $Capacity_J^{bat}$ (in MW) in a jurisdiction J at the end of planning horizon are calculated as a sum of installed capacities in a typical household $Capacity_c^{PV}$ in each distribution area d multiplied by H_d number of typical households in each area.

$$Capacity_J^{PV} = \sum_d^J [Capacity_c^{PV} \cdot H_d] \cdot 10^{-3} \tag{31}$$

$$Capacity_J^{bat} = \sum_d^J [Capacity_c^{bat} \cdot H_d] \cdot 10^{-3} \tag{32}$$

Average annual PV generation $Generation_J^{PV}$ (in GWh/year) in a jurisdiction J is calculated for the last year of the planning horizon as a sum of useful generation $l_{h,y}^{PV}$ from PV system and $R_{h,y}^{disc}$ electric battery in a typical household in each distribution area multiplied by H_d number of typical households in each area.

$$Generation_{J,y}^{PV} = \sum_d^J [\sum_h^H (l_{h,y}^{PV} + R_{h,y}^{disc}) \cdot H_d] \cdot 10^{-6} \tag{33}$$

Total annual CO_2 savings (in Mt CO_2 eq per year) in a jurisdiction J is calculated for last year of the planning horizon as a sum of avoided CO_2 emissions achieved with $l_{h,y}^{PV}$ from PV system and $R_{h,y}^{disc}$ electric battery in a typical household in each distribution area multiplied by H_d number of typical households in each area. Possible CO_2 reduction per kWh is evaluated with AEF equal to 31 g CO2 eq per kWh [26].

$$Savings_{J,y}^{CO_2} = \sum_{d}^{J}[\sum_{h}^{H}(l_{h,y}^{PV} + R_{h,y}^{bat,disc}) \cdot AEF_J \cdot H_d] \cdot 10^{-6} \tag{34}$$

Electricity affordability provides estimation of average reduction % for a variable part of an annual electricity bill for a typical household in a province at the end of a planning horizon. The monetary equivalent of an electricity bill may be calculated further for each distribution area depending on local rates and charges.

$$Bill\ reduction_{J,y} = \sum_{d}^{J}[\sum_{h}^{H}\frac{(l_{h,y}^{PV} + R_{h,y}^{bat,disc})}{c_{h,y}^{el}} \cdot H_d] \tag{35}$$

Policy cost (in Million CAD) evaluates the expenses for rebates paid to typical consumers over the entire planning horizon.

$$Policy\ cost_J = \sum_{d}^{J} Rebate_y \cdot H_d \cdot 10^{-6} \tag{36}$$

We evaluate contributions of changing household behavior to the Ontario's energy system reliability for a worst case scenario of household physical disconnection from the grid. Disconnection potential (MW) is a sum of $H_d^{x_y^{Off}=1}$ households prompt to disconnect per distribution area multiplied by an average household load $c_y^{el.\Delta}$.

$$Disconnection\ potential_J = \sum_{d}^{J} c_y^{el.\Delta} \cdot H_d^{x_y^{Off}=1} \cdot 10^{-3} \tag{37}$$

Appendix C Data and model inputs

Model input	Description	Sources
Electricity tariffs		
Variable rates, CAD/kWh	The report considers pre pandemic TOU rates. Other variable transmission and distribution rates for different municipalities are those from 2020 reported by the OEB.	• Historical electricity rates, i.e., TOU and tired tariffs [2] • Electricity transmission and distribution rates [3]
Fixed charges, CAD	Fixed service charges for different municipalities are those from 2020 reported by the OEB.	• Electricity transmission and distribution rates [3]

Model input	Description	Sources
	Technologies installed costs and future tendencies	
PV module, CAD/kW	The Government of Canada reports that the cost of residential PV installation in Canada was 3,197 CAD/kW in 2019 and may decrease within ten years to 2,252 CAD/kW in an optimistic scenario (a cost reduction of approximately 30%) [27]. Furthermore, government of Canada [27] states that the residential PV installation cost in provinces with experience in solar installations (such as Ontario) is already equal to the installed cost of an optimistic scenario. This is confirmed by [20], which records that in 2019 Ontario had the lowest installed costs of any Canadian province: 2,280 - 2,780 CAD/kW. This report considers the installed PV cost of 2,280 CAD/kW and 2% of annual cost decrease.	• Comprehensive energy use database [27] • Cost of solar power in Canada [20] • Detailed analysis of PV cost trends [14]
Electric battery, CAD/kWh	Based on the detailed analysis of seven commercially available residential batteries the investment cost is assumed to be 1,560 CAD/kWh. Following the most optimistic trend, the battery installation cost may decrease by approximately 35% between 2019 and 2030 [28]. This report considers an average 2% of annual cost decrease.	• Market available residential batteries with indicative costs [29, 30] • Detailed analysis of electric batteries cost trends [14]

Model input	Description	Sources
Hydrogen seasonal storage	The hydrogen-based seasonal storage technology that can deliver up to 6 MWh of energy (electricity plus thermal) is commercialized for around 80,000 CAD since 2018 [31]. In report we consider only the electricity component, therefore only the storage cost share of around 55,000 CAD was considered. Experts estimate that costs of different equipment may be reduced by at least 17% by 2030 [32, 33]. This report considers an average 2% of annual cost decrease.	• Market available hydrogen-based storage [31] • Detailed analysis of hydrogen equipment cost trends [14]
Technologies technical specifications		
PV array	3 kW mono-crystalline module, up to 5 modules to be deployed at one household premises	• Market available modules and their technical specifications [34] • Weather-corrected PV module performance [35]
Electric battery	Electric battery of 4 kWh usable capacity and fast charging/discharging technology.	• Market available residential electric batteries [29, 30]

Model input	Description	Sources
Hydrogen seasonal storage	Hydrogen-based seasonal storage which allows power-to-gas and gas-to-power conversion. The technology includes two types of installations, i.e., energy center (including electric battery, power electronics, ventilation unit, electrolyzer and fuel cell) and seasonal energy storage (including compact compressor unit and hydrogen storage). It requires in total around 6.3 m^3 to install 4.6 t of equipment. The off-grid scheme for a household situated in Atikokan would require approximately 2,600 kWh hydrogen-based seasonal storage powered by a 15 kW PV array.	• Market available hydrogen-based seasonal storage [36, 37] • Example of a real-life application [38] • Conversion efficiency of different equipment [32, 39, 40]
Environmental and operational conditions		
Solar irradiation, kW/m^2	GHI is used to represent a typical hourly solar availability	• Solar resources for different Canada's municipalities [41]
Ambient temperature, °C	Typical hourly ambient temperature in a household location over a year.	• Weather statistics for Canada [42]

Model input	Description	Sources
PV power output, kWh	The output from the PV array is calculated using the mathematical model accounting for the technical characteristics of the panels, the GHI and the loss of module efficiency with the increase of ambient temperature.	• First model presentation and justification [43, 44] • Model application and analysis for a case study of Atikokan (Ontario) [14]
Household load, kW	To simulate the load profile, the top-down approach, based on detailed chronological collection of overall electricity demand, is used. The model relies on the maximum hourly peak load over a year set to 1.58 kW which corresponds to 700 kWh of average monthly household electricity consumption in Ontario. Note, the load model provides an average smooth load profile, which will differ from the real-time measurements of a single household.	• Detailed presentations of load model [45] • Load profile analysis and model calibration for Ontario household [14]