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Pearce, Joshua M.; Sommerfeldt, Nelson

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*Published in:*  
Energies

*DOI:*  
[10.3390/en14040834](https://doi.org/10.3390/en14040834)

Published: 01/02/2021

*Document Version*  
Publisher's PDF, also known as Version of record

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*Please cite the original version:*  
Pearce, J. M., & Sommerfeldt, N. (2021). Economics of Grid-Tied Solar Photovoltaic Systems Coupled to Heat Pumps: The Case of Northern Climates of the US and Canada. *Energies*, 14(4), Article 834.  
<https://doi.org/10.3390/en14040834>

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## Article

# Economics of Grid-Tied Solar Photovoltaic Systems Coupled to Heat Pumps: The Case of Northern Climates of the U.S. and Canada

Joshua M. Pearce<sup>1,2,3,\*</sup>  and Nelson Sommerfeldt<sup>1,4</sup> <sup>1</sup> Department of Material Science & Engineering, Michigan Technological University, Houghton, MI 49931, USA; nelson.sommerfeldt@energy.kth.se<sup>2</sup> Department of Electrical & Computer Engineering, Michigan Technological University, Houghton, MI 49931, USA<sup>3</sup> School of Electrical Engineering, Aalto University, FI-00076 Espoo, Finland<sup>4</sup> Department of Energy Technology, KTH Royal Institute of Technology, SE-100 44 Stockholm, Sweden

\* Correspondence: pearce@mtu.edu

**Abstract:** Solar photovoltaic (PV) technology is now a profitable method to decarbonize the grid, but if catastrophic climate change is to be avoided, emissions from transportation and heating must also decarbonize. One approach to renewable heating is leveraging improvements in PV with heat pumps (HPs). To determine the potential for PV+HP systems in northern areas of North America, this study performs numerical simulations and economic analysis using the same loads and climate, but with local electricity and natural gas rates for Sault Ste. Marie, in both Canada and U.S. Ground-mounted, fixed-tilt, grid-tied PV systems are sized to match 100% of electric loads considering cases both with and without air source HPs for residences with natural gas-based heating. For the first time the results show North American residents can profitably install residential PV+HP systems, earning up to 1.9% return in the U.S. and 2.7% in Canada, to provide for all of their electric and heating needs. Returns on PV-only systems are higher, up to 4.3%; however, the PV capacities are less than half. These results suggest northern homeowners have a clear and simple method to reduce their greenhouse gas emissions by making an investment that offers a higher internal rate of return than savings accounts, CDs and GICs in both countries. Residential PV and solar-powered heat pumps can be considered 25-year investments in financial security and environmental sustainability.

**Keywords:** photovoltaic; heat pumps; electrification; solar energy; renewable energy; northern climate; solar-assisted heat pumps; sustainable energy; net zero; greenhouse gas emissions



**Citation:** Pearce, J.M.; Sommerfeldt, N. Economics of Grid-Tied Solar Photovoltaic Systems Coupled to Heat Pumps: The Case of Northern Climates of the U.S. and Canada. *Energies* **2021**, *14*, 834. <https://doi.org/10.3390/en14040834>

Academic Editor: Gregorio García

Received: 15 January 2021

Accepted: 1 February 2021

Published: 5 February 2021

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## 1. Introduction

Solar photovoltaic (PV) technology costs have plummeted [1–3] due to a consistent and aggressive industrial learning curve [4–6]. PV prices are expected to continue to decrease another 60% in the short term [7]. Already at scales from residential to industrial, the levelized cost of electricity (LCOE) is lower than the net metered cost of grid electricity [8–10] and the value of solar (VOS) is even greater than net metering rates in the U.S. [11]. Simultaneously the PV technical community continues to drive improved performance [12] with black silicon [13,14] and bifacial PV modules [15,16] that will reduce solar electricity further [17]. Due to these trends, PV technology is the fastest growing electricity technology [18,19]. This is fortunate because PV has an excellent ecological balance sheet [20] and an established path to a sustainable future [21]. PV, which can be used as a distributed generation (DG) technology [22], also benefits the electrical system with (i) improved reliability [23–25], (ii) enhanced power quality [26], and (iii) reduced transmission and distribution losses [27]. These factors are all contributing to widespread deployment of PV and a reduction in the role of fossil fuels, and their concomitant greenhouse gas emissions (GHG) [28]. GHG emissions from electricity generation only account for about 1/3 of all

emissions [29], and if catastrophic climate change is to be avoided [30], emissions from transportation and heating must also transition to renewable energy sources. One method to transition to renewable heating is with solar-assisted heat pumps [31–33].

There are a considerable number of configurations and approaches to solar-assisted heat pumps considering both solar thermal and PV technologies [34,35]. It is easier to scale PV-powered heat pumps given that the systems can be installed and operated independently. It is also possible to install larger PV systems than the heating system requires, unlike solar thermal systems. Oversized PV systems thus provide more economic value to the building than solar thermal, because this additional solar electricity can be used to power a heat pump, appliances, lighting, and anything not used in the building can be sold to the grid, which has been demonstrated in Sweden [36]. Heat pumps can also be used to regulate PV generation both in the building and the grid using demand side management and storage [37,38] or the thermal mass of the building [39]. Heat pumps can also enable higher penetration of solar electricity in the power system, particularly when they are reversed for cooling [40].

In North America, distributed generation with PV is becoming widespread and offers to the potential to accelerate heat pump adoption. Historic economics of both solar and heat pumps demanded major policy interventions to make such systems financially possible. In this study, the economic viability of PV-powered heat pump is probed with no additional policy interventions using numerical simulations of commercial systems available now. To remain conservative all simulations assume replacing natural gas furnace, which is the current most widespread and largely perceived to be the lowest cost form of heating in the region. Economic analysis is performed for the following scenarios using the same load and local electricity and natural gas for Sault Ste. Marie, which straddles the Canadian and U.S. border (shown in Figure 1): (i) ground mount fixed tilt PV-grid tied to match 100% of electric load in Sault Ste. Marie, MI; (ii) ground mount fixed tilt PV-grid tied to match 100% of electric load in Sault Ste. Marie, Ontario; (iii) air source heat pump to meet all thermal load with grid electricity in Sault Ste. Marie, MI; (iv) air source heat pump to meet all thermal load with grid electricity in Sault Ste. Marie, Ontario; (v) ground mount fixed tilt PV-grid tied to match 100% of electric load and electrified thermal load assuming air source heat pump in Sault Ste. Marie, MI; and (vi) ground mount fixed tilt PV-grid tied to match 100% of electric load and electrified thermal load assuming air source heat pump in Sault Ste. Marie, Ontario. The results are compared for both countries to probe the impact of national policy on the economic viability for not only electrification of the heating sectors in cold climates but also the solar-powered electrification of heating. Policy recommendations are discussed to accelerate economically favorable carbon emission reductions.



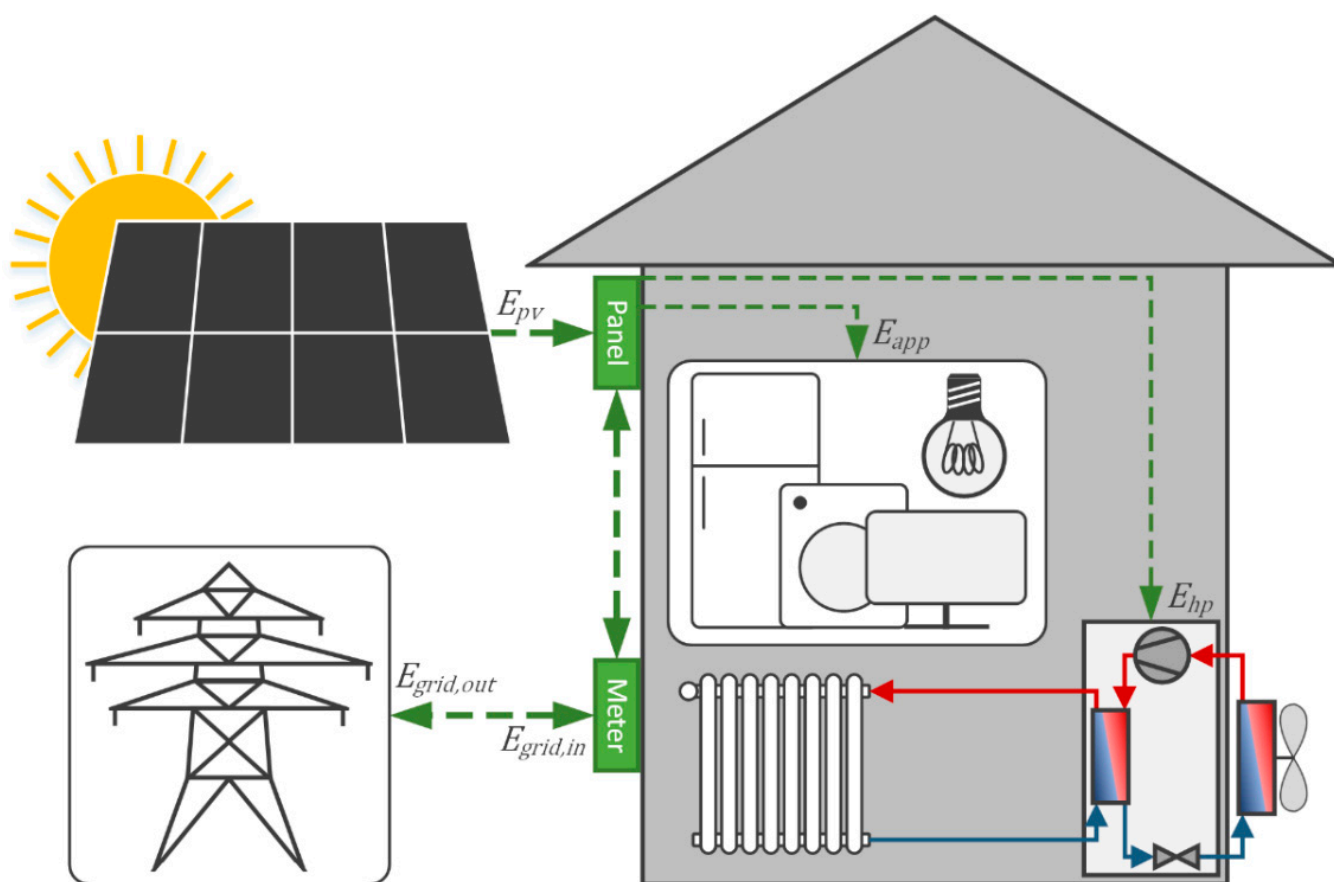
**Figure 1.** Sault Ste. Marie, located in western Ontario and the eastern part of the Upper Peninsula of Michigan, is shown context in North American OpenStreetMap.

## 2. Materials and Methods

A systems diagram of the building energy system is shown in Figure 2, with electricity flows in green and thermal flows in red/blue. It is a typical grid connected PV system, where PV generation ( $E_{pv}$ ) is used first to service loads in the building ( $E_{app}$ ,  $E_{hp}$ ) and excess is sold to the grid ( $E_{grid,out}$ ). During times of no PV generation, building loads are serviced with grid electricity ( $E_{grid,in}$ ). As the systems are net-zero energy, where the annual PV generation matches the annual demand,  $E_{grid,in}$  and  $E_{grid,out}$  are equal and opposite over the year. The configuration shown in Figure 2, which includes the heat pump, specifically maps to systems v/vi. Removing the PV system and relying only on electric grid supply represents systems iii/iv. Systems i/ii keep the PV but replacing the heat pump with gas heating supply, leading to smaller PV capacities to maintain net-zero energy.

### 2.1. Electric Rates

Table 1 summarizes the electric rates and natural gas rates for the utilities in Sault Ste. Marie, Ontario and Michigan. For the Public Utility Commission (PUC), all rates taken from the 11/2019 rate sheet, as 2020 rates were temporarily altered due to the pandemic. For PUC Time of Use Rate (TOU); Off-peak 7:00 pm–7:00 am plus weekends and holidays; Mid-peak 11:00 am–5:00 pm; On-peak 7:00 am–11:00 am; and 5:00 pm–7:00 pm.



**Figure 2.** Systems diagram of building energy system with PV generation ( $E_{pv}$ ), appliance loads ( $E_{app}$ ), heat pump loads ( $E_{hp}$ ), and a grid connection ( $E_{grid}$ ).

**Table 1.** All electric rates are from publicly available information found on utility websites as of 11/2020.

Electric	Location	Flat/Off-Peak	Mid-Peak	Peak	Customer Charge Per Month	
Cloverland Electric Coop [41]	MI	\$0.093			\$23.75	
PUC, Time of Use [42]	ONT	\$0.090	\$0.124	\$0.174	\$21.88	
		First 1000 kWh Oct-Apr	Balance			
		First 600 kWh May-Sept				
PUC, Tiered [42]	ONT	\$0.100	\$0.115		\$21.88	
Gas	Location	\$/100 Ccf				
DTE [43]	MI	\$0.667			\$12.25	
		\$/m <sup>3</sup> first 100 m <sup>3</sup>	100–200	200–500	500–1000	Over 1000
Union Gas [44]	ONT	\$0.248	\$0.246	\$0.243	\$0.240	\$0.238
						\$16.98

All rates are converted to US dollars with an exchange rate of 1 USD to 1.325 CAD [45].

## 2.2. Thermal Load Conversion to Heat Pump

The average Michigan residential annual energy consumption is 123 million BTUs ( $1.3 \times 10^{11}$  J) [46]. Space heating makes up 55% of this amount, meaning the average Michigan resident uses 67.65 million BTUs ( $7.1 \times 10^{10}$  J) for space heating [46]. Using the ten-year average monthly heating degree data for the eastern UP, the monthly space heating demand is approximated [47]. Then, the monthly fuel cost for a natural gas furnace of typical new modern high efficiency [48] is calculated. It should be noted that this is a conservative estimate for most home owners with 95% being on the high end, AFUE ratings still overpredicts real-world performance and the population in the region being economically depressed are likely to favor 80% efficiency non-condensing furnaces because of their lower capital costs [49]. For a regionally appropriate heat pump efficiency, the method determined by Faurey et al. (2004) [50] for calculating a local HSPF using

the ASHRAE 1% design temperature for Sault Ste. Marie [51] and a nameplate HSPF of 10 was used. Thus, the required electricity demand ( $E_{hp}$  in kWhs per month) given the required thermal demand (BTUs per month) was calculated. This additional electric load is then added and normalized to U.S. National Renewable Energy Lab's (NREL) load profile for Sault Ste. Marie, MI ( $E_{app}$ ) to determine monthly and annual cost for the three utility rate structures [52]. Finally, from personal communication with local plumbing contractors, the cost to replace a natural gas furnace with air source heat pump for a typical 2000 square foot (186 m<sup>2</sup>) home was estimated to be USD\$6000–7000.

### 2.3. Heat Pump Costs

The costs to electrify heating with a heat pump are summarized in Table 2. In Table 2, the weighted unit price for PUC Tiered is based on the proportion of electricity in each price bin for each month. Weighted unit for Union is the proportion gas in each price bin for each month. Cloverland and DTE are flat unit prices. Cost per year assumes 67.65 million British Thermal Units (BTU) ( $7.1 \times 10^{10}$  J) consumed in space heating in a year. BTU is the standard unit of thermal energy used in the U.S. Heating load by month determined by two-year average of heating degree days for Sault Ste. Marie. Cost per year for heat pumps does not include monthly customer charge as residents would be paying for this already. Cost per year for furnaces does include monthly customer charge as replacing a furnace with a heat pump could mean discontinuing natural gas service. The heating seasonal performance factor (HSPF) is used as a measure of the efficiency of air source heat pumps and is defined as the ratio of heat output (measured in BTUs as is standard in the industry in North America) over the heating season to electricity used (measured in watt-hours). In parenthesis with HSPF is the same metric considering heat output and electricity used both in kilowatt-hours. For the furnaces, the thermal efficiency used was the annual fuel utilization efficiency (AFUE) that represents the actual, season-long, average efficiency of the furnace and is the ratio of useful energy output to energy input.

**Table 2.** Weighted unit price for PUC TOU is the weighted average of the prices given the number of hours they occur per week, excluding holidays.

Utility	Unit	Weighted Price Per Unit	BTU Content Per Unit	Heating Type	Type of Efficiency Rating	Efficiency Rating	Cost Per Million BTU	Cost Per Year
Cloverland, MI	kWh	\$0.093	3412	Heat Pump	HSPF	5.9 (1.73)	\$15.85	\$1072.00
PUC, ONT TOU	kWh	\$0.111	3412	Heat Pump	HSPF	5.9 (1.73)	\$18.81	\$1271.00
PUC, ONT Tiered	kWh	\$0.107	3412	Heat Pump	HSPF	5.9 (1.73)	\$18.19	\$1365.00
DTE, MI	Ccf	\$0.667	102,800	Furnace	AFUE	0.95	\$6.83	\$609.04
Union, ONT	M <sup>3</sup>	\$0.246	35,078	Furnace	AFUE	0.95	\$7.38	\$703.18

### 2.4. Numerical Simulations

PV generation and economic analysis was conducted with the National Renewable Energy Lab's open source System Advisor Model (SAM) software [53] using the input parameters found in Table 3. The region is relatively flat and all systems were assumed to be on level ground and unshaded. All systems were ground mounted, fixed tilt, and grid tied to eliminate complexities of roof suitability and nuances. Similarly, all heat pumps (HP) were air source so that local conditions would not play a factor in the installation of a ground source heat pump. The six systems simulated include:

1. ground mount fixed tilt PV-grid tied sized to match 100% of electric load in Sault Ste. Marie, MI;
2. ground mount fixed tilt PV-grid tied sized to match 100% of electric load in Sault Ste. Marie, Ontario;
3. air source heat pump to meet all thermal load with grid electricity in Sault Ste. Marie, MI;
4. air source heat pump to meet all thermal load with grid electricity in Sault Ste. Marie, Ontario;



5. ground mount fixed tilt PV-grid tied to match 100% of electric load and electrified thermal load assuming air source heat pump in Sault Ste. Marie, MI; and
6. ground mount fixed tilt PV-grid tied to match 100% of electric load and electrified thermal load assuming air source heat pump in Sault Ste. Marie, Ontario.

**Table 3.** System Advisor Model Version 2020.2.29 [53] simulation parameters, inputs, and sources.

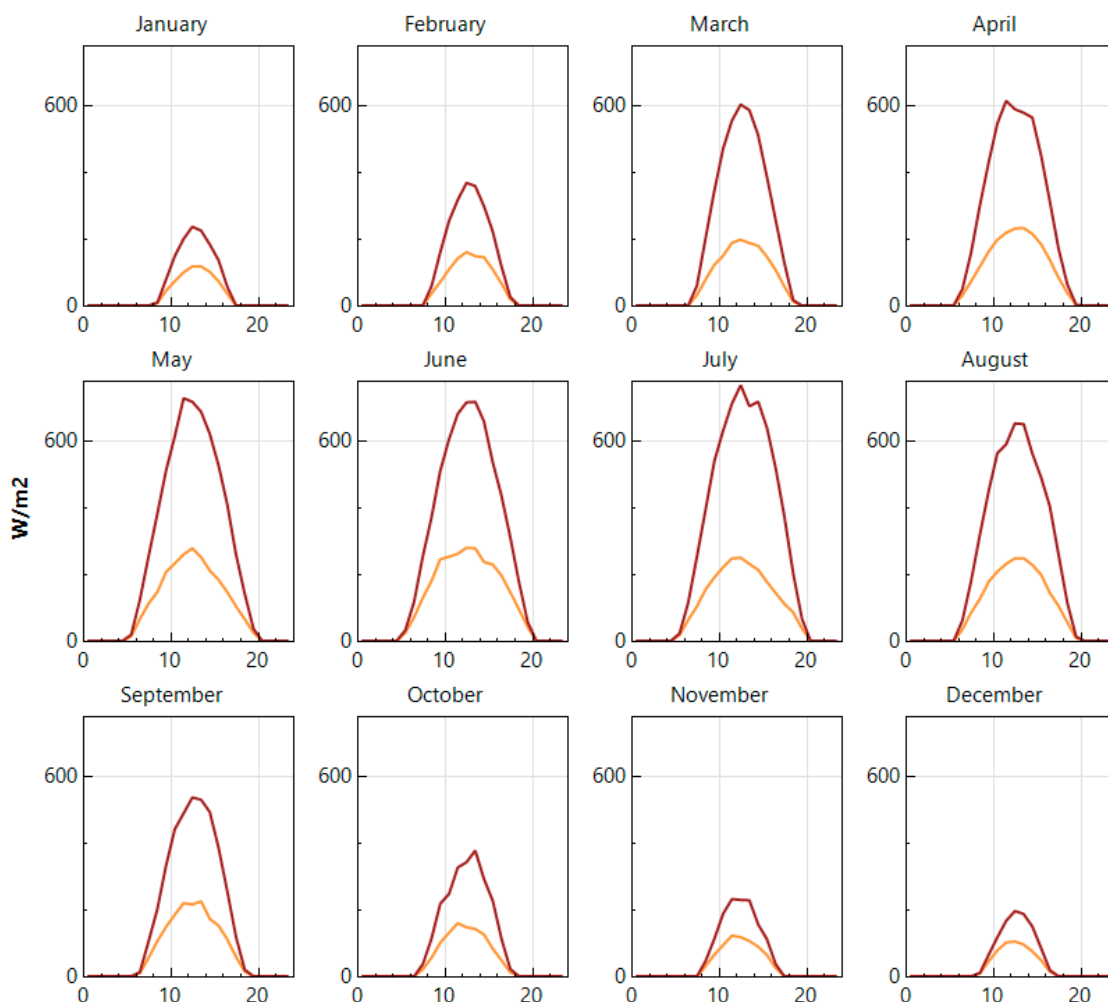
Parameters		Input	Source
Location and Resources	Solar Resource Library	Sault Ste. Marie MI, Station ID 971207	NSRDB [54]
	Global horizontal	3.83 kWh/m <sup>2</sup> /day	NSRDB [54]
System Design	System nameplate capacity (kWdc)	6.9,20.6	Sized to meet load
	Module type	Standard	Default
	DC to AC ratio	1.1	Default
	Inverter efficiency	96%	Default
	Array type	Fixed open rack	Default
	Inclination	31°	Optimal for annual generation for location
	Azimuth	180°	
			Default
Losses	Soiling	2%	Default
	Shading	0%	Unshaded
	Snow	3%	Southern Ontario [55,56]
	Mismatch	0%	Assuming optimizer or microinverter [57]
	Wiring	2%	Default
	Connections	0.5%	Default
	Light-induced degradation	1.5%	Default
	Nameplate	0%	Assuming positive power tolerance [58]
	Age	0%	Default
	Availability	3%	Default
	Total system losses	11.44%	Default
Lifetime and Degradation	Annual AC degradation rate	0.50%	Default
Financial Parameters	Analysis Period	25 years	Default
	Inflation Rate	2.5%	Default
	Sales Tax, % of total direct cost	6% MI, 13% ONT	Local rate
	Insurance rate (annual)	0%	Included under personal property on most insurance, 0.5% default [58]
	Property tax	0%	Default

For each PV system the total cost is calculated. Then, economics for a home owner in all six scenarios are determined for systems (1) without PV, (2) those with PV, (3) homes without PV and gas without a heat pump (HP), (4) homes with combined utilities with PV and without a heat pump, (5) homes with combined utilities without PV and without a heat pump, and finally (6) homes with combined utilities with PV and a heat pump. The solar resources are acquired from the National Solar Radiation Database (NSRDB) [54].

Finally, the net savings, year one return on investment (ROI), simple payback calculated in years, and the internal rate of return (IRR) are determined. Simple payback for the PV+HP is calculated in comparison to the no PV and no HP case, based on the annual value of the PV generation minus the cost difference between heating with gas and a HP.

### 3. Results

The solar resource for the regions is shown in Figure 3 as a function of the time of day for a representative day for each month throughout the year.



**Figure 3.** The diffuse irradiance (in orange) and global irradiance (in red) measured in  $\text{W}/\text{m}^2$  as a function of hours in a representative day for 12 months.

As can be seen in Figure 3, the available irradiance during the heating months is modest and from November through February has a substantial fraction of diffuse irradiance due to heavy cloud cover. In addition, it should be pointed out that much of this reduced solar energy is not collected because of snow losses. Thus, to match the load with these solar fluxes involves large PV systems. On both sides of the border, the PV systems for are sized at 6.9 kW without a HP, with the addition of a HP these increase to 20.6 kW. Annually they produce 9130 kWh and 20,611 kWh, respectively.

The total system costs for the different scenarios are shown in Table 4. As can be seen in Table 4, the PV systems are slightly more expensive in Ontario than Michigan coming in at \$3.10/W and \$3.30/W, respectively. This discrepancy is due in part to taxes and grid interconnection costs being roughly 10 cents per W higher in Ontario. With the addition of a HP system to electrify the heating both PV systems more than double in cost to be \$43,854 in the U.S. and \$49,029 in Canada. These costs represent a substantial investment for the average consumer as in the U.S. the average family has \$40,000 in savings, across savings accounts, checking accounts, money market accounts, call deposit accounts, and prepaid cards [59], and the Canadian savings rate is even lower [60]. Interconnection fees in Canada are calculated on a case by case basis [61]. Per email correspondence with Electrical



Engineering Tech Matthew Grigg with PUC, micro-generator Offer to Connect packages range from \$1000–1500 and over 10 kW \$5000–10,000 CAD.

**Table 4.** PV systems costs in MI and Ontario with and without HP. Interconnection fee for Cloverland Electric Coop installations included in install cost is \$100 [62], for systems less than 10 kW for PUC analysis includes \$1000, and for systems over 10 kW \$5000.

System Costs	MI		ONT		MI+HP		ONT+HP	
	\$	\$/W	\$	\$/W	\$	\$/W	\$	\$/W
Module	3795	0.55	3795	0.55	8580	0.55	8580	0.55
Inverter	2760	0.40	2760	0.40	5460	0.35	5460	0.35
Ground mount and BOS	4140	0.60	4140	0.60	9360	0.60	9360	0.60
Labor	5950	0.86	5950	0.86	10,020	0.64	10,020	0.64
Installer margin and overhead	3450	0.50	3450	0.50	7800	0.50	7800	0.50
Grid interconnection	100	0.01	754	0.11	100	0.01	3775	0.24
Shipping	552	0.08	552	0.08	1248	0.08	1248	0.08
Sales tax	627	0.09	1358	0.20	1286	0.08	2786	0.18
Total gross cost	21,374	3.10	22,759	3.30	43,854	2.81	49,029	3.14

The impact of the U.S. Federal income tax credit on system costs is shown in Table 5. Base estimates are for ground mounted fixed tilt PV arrays sized to Sault Saint Marie load profile. Costs assume a run of no more than 30 m and generation assumes a 100% solar window with 11.44% system losses. As can be seen in Table 5, as expected the ITC in the U.S. makes a substantial difference in the capital costs of the systems saving American consumers roughly \$10,000 in the HP case.

**Table 5.** PV system cost comparison including the U.S. Federal income tax credit.

System Summary	MI, ITC	MI, No ITC	ONT TOU	ONT Tiered	MI+HP ITC	MI+HP No ITC	ONT+HP TOU	ONT+HP Tiered
Estimated PV cost	\$21,373	\$21,373	\$22,759	\$22,759	\$43,854	\$43,854	\$49,029	\$49,029
22% Federal income tax credit	\$4700				\$9650			
Net PV cost	\$16,673				\$34,204			
HP cost					\$6500	\$6500	\$6500	\$6500
Total System cost	\$16,673	\$21,373	\$22,759	\$22,759	\$40,704	\$50,354	\$55,529	\$55,529

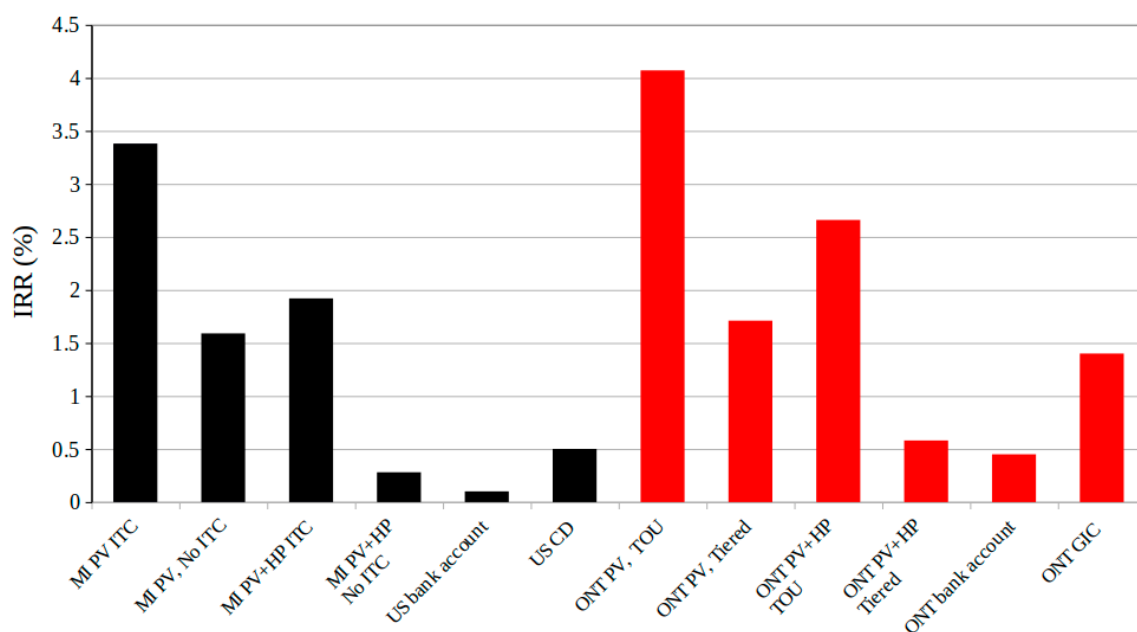
Finally, the economics for the six systems are summarized in Table 6. Base estimates are for ground mounted fixed tilt PV arrays sized to Sault Saint Marie load profile. Costs assume a run of no more than 30, and generation assumes a 100% solar window with 11.44% system losses. PV generation and economic analysis are conducted with NREL's System Advisor Model software [57]. Currently, if PUC customers install PV they must be on the tiered rate. The PUC TOU rate is not currently offered to customers with a PV system.

**Table 6.** PV system cost comparison including the US Federal income tax credit.

System Summary	MI, ITC	MI, No ITC	ONT TOU	ONT Tiered	MI+HP ITC	MI+HP No ITC	ONT+HP TOU	ONT+HP Tiered
Electricity bill w/o PV	\$1141	\$1141	\$1365	\$1277	\$2213	\$2213	\$2636	\$2592
Electricity bill w/ PV	\$288	\$288	\$94	\$352	\$287	\$287	(\$236)	\$236
Electricity savings	\$853	\$853	\$1271	\$925	\$1926	\$1926	\$2872	\$2356
Natural gas cost	\$609	\$609	\$703	\$703	\$0	\$0	\$0	\$0
Electricity w/o PV + gas w/o HP	\$1750	\$1750	\$2068	\$1980	\$1750	\$1750	\$2068	\$1980
Combined utilities w/ PV, w/o HP	\$897	\$897	\$797	\$1055	N/A	N/A	N/A	N/A
Combined utilities w/ PV, w/ HP	N/A	N/A	N/A	N/A	\$287	\$287	(\$236)	\$236
Net savings	\$853	\$853	\$1271	\$925	\$1463	\$1463	\$2304	\$1744
Year one ROI	5.1%	4.0%	5.6%	4.1%	3.6%	2.9%	4.1%	3.1%
Simple payback (years)	16.7	20.5	15.5	20.2	19.7	24.1	18.1	23.2
IRR	3.4%	1.6%	4.1%	1.7%	1.9%	0.3%	2.7%	0.6%

Table 6 shows that all of the systems have a simple payback time shorter than the lifetime under warranty that indicates all cases provide a positive return. This is verified with the net savings and year one return on investments that are all in the single digits and range from 2.9% to 5.1%. The most appropriate economic indicator is the internal rate of return (IRR). For the PV+HP systems in the U.S. the systems provide an IRR of 1.9% and in Canada they provide 0.6%. As can be more easily seen in Figure 4, the IRR is higher for the PV alone, but the PV+HP systems provide a positive IRR and reduce the risk of natural gas price escalations in the future. For PV systems alone, the inclusion of the ITC in the U.S. increases the IRR by more than 1.7% and decreases the payback time by 3.8 years. In Ontario electricity savings are substantially enhanced with TOU pricing instead of the tiered rates. As TOU pricing will encourage load shifting and lower costs for the grid [63] and as shown here substantially increase the potential return for installing solar-powered HPs, thus radically reducing GHG emissions for residential heating in Ontario. The paybacks are generally shorter and IRRs higher for Canadians than Americans living in Sault Saint Marie. These IRRs are compared to benchmark bank account interest rates and certificate of deposit (CD) rates in the U.S. [64] and Guaranteed Investment Certificate (GIC) rates in Canada [65] that are available in banks in Sault Saint Marie in both countries. Overall, all PV and HP cases provide better IRR in the U.S. and Canada than savings accounts (even high interest savings) at the local benchmark banks. CDs and GICs can provide a higher return than the worst cases of PV+HP in both countries. The ITC improves the economics considerably, but the TOU pricing in Ontario provides the best outcome. This indicates a policy priority of encouraging TOU pricing. Future work is needed to determine the impact of such pricing in the U.S. on these systems.

With the addition of the HP, the overall net savings increase for all systems and rate structures in both countries were comparable to the PV alone case. The simple payback times increase and the IRRs drop. It should be pointed out that in the HP systems powered with PV in Canada under the TOU pricing, the electric bill would go up, but the natural gas bill being eliminated still provides net savings and in fact a better IRR than the tiered rate. Currently, if PUC customers install PV they must be on the tiered rate. The PUC TOU rate is not currently offered to customers with a PV system and is an area that appears to be the most promising means of better matching the costs of the systems with the cost consumers pay. Previous research has shown customers will shift their use, reducing costs for the utility [66]. Clearly, small policy changes in Ontario that would encourage PV and the electrification of heating with PV+HP systems would be to adopt policy for a TOU rate. The additional investments needed to push the IRRs into the low single digits, but as can be seen in Table 6, all systems provide positive ROI and as Figure 4 shows economically attractive IRRs over the lifetime of the project. In the U.S. inclusion of the ITC makes both PV and PV+HP more profitable than all offerings at the bench mark bank, while in Canada the same is true for TOU pricing. Overall, all projects are profitable for the homeowners.



**Figure 4.** Comparison of IRR for the various PV and PV+HP scenarios in Sault Saint Marie with “high interest” savings accounts and CD and GICs in the U.S. (black) and Canada (red), respectively.

#### 4. Discussion

This study has shown that under current economic conditions, residents of northern Michigan and Southern Ontario can profitably install solar PV to provide all of their electric and heating needs. This is consistent with earlier research on PV in northern Michigan, which found profitability for small PV systems [67]. Given that the PV systems are sized to cover 100% of the total loads, this would make the buildings net-zero energy and provide a simple method to reduce their greenhouse gas emissions. This is particularly critical with heating, which is dominated by fossil fuels [68]. While the payback times are long, and the returns modest, they are higher than what average consumers can earn on savings accounts, certificates of deposit, or bonds as shown in Figure 4. This is noteworthy given that a PV system can be considered a stable, long-term investment, hedging against inflation and price rises in electricity and gas. There are risks associated with such systems, but they are either minor and covered by existing insurance (e.g., theft or destruction from an accident), warranties, or are extremely low probability (e.g., government law changing and not grandfathering in rules the system was deployed under). Another risk that would be considered low probability is a radical decrease in fossil fuel prices. The opposite is indeed far more likely. For example, in Canada, the probability that gas prices will increase is substantial given the recent announcement by the Prime Minister Justin Trudeau that Canada would achieve net-zero by 2050 using several approaches, including continued price increases on pollution [69]. There is a high possibility that similar policies to reduce GHG emissions in the U.S. will also increase natural gas prices. All future gas price increases render the economic analysis in this study conservative. The ROI and IRR values should thus be viewed as minimums for investments in PV+HP systems in these regions. This analysis assumed 25 years, but it is well known that PV systems outlast this value and with good usage, proper maintenance, and suitable installation conditions a minimum lifespan of 25 years can also be expected for the HP [70]. Even for those not expecting to stay in their home for 25 years the investment is still sound. Past research has shown that PV systems can increase home values more than the cost of the PV system [71], so even those considering moving can consider these long-term green investments.

This study has several limitations. First, although for the U.S. the Upper Peninsula in MI represents one of the worst locations for solar flux, it also has high utility rates, so generalizing the results to all of the U.S. cannot be done. Future work is needed in

this area. Generally speaking, the cases presented here are considered conservative in both cost and performance even when excluding natural gas cost escalation. To keep the analysis as transparent as possible, no electricity price escalation was considered, which is an extremely conservative assumption for PV cost analysis. In addition, installed PV costs decline at approximately 5% per year [2,3], and the degradation rate applied is taken from a southern climate even though colder climates reduce degradation [72,73]. Thus, economics on the PV-side are also minimum IRRs. Comparing these IRRs to PV-only systems tend to be lower (e.g., in the Canadian case, Sow et al. found, after 2016, the IRRs were high single digit to double digit returns for PV in most major cities) [74]. It is well established that those in Michigan would all profit from PV-only systems [67]. It should be pointed out, however, that in this study the PV systems needed to provide for both the electric and thermal loads are much larger than those in previous studies and they thus have a much larger potential for GHG emissions reductions. Estimates were likewise conservative on the HP side of the analysis. For example, changing the estimate of fuel efficiency for natural gas furnaces to 85% adds 0.2% to IRR on HP systems. While many local factors will influence heat pump efficiency, cold-climate performance has notably improved in recent years [75,76]. Furthermore, given that winters are expected to continue warming due to climate change [77–81], seasonal heat pump efficiency will increase and the total need for heating will decrease, suggesting that the PV systems here are oversized for the lifetime of use and thus more expensive than necessary. In addition, the snow losses historically measured for PV systems may also be reduced. Future work is needed to probe the optimal HP size given the potential for short term small investments in electric space heaters to cover the progressively more infrequent extreme cold days. The analysis here also represents a fuel-switching scenario, where the choice is to continue using existing natural gas equipment or switch to a heat pump. If the capital costs for a new gas furnace were included in the baseline comparison, the economics would be better still.

It is necessary to note that the net metering policy applied in all cases is a key driver in the economic success of these systems as they were modeled here. A critique of being too generous against net metering is that it does not take into account temporal differences between generation and consumption [82,83]. For residential PV systems, more generation is usually fed into the grid than self-consumed [84], and this effect is heightened with heat pumps in northern climates; for example, in this case where 67% of generation occurs in the sunniest six months and 79% of heat demand occurs in the darkest six months (October through March). On the other hand, net metering can be critiqued as too stingy, as the VOS is greater than net metering rates in the U.S. [11] and more than likely higher in Canada as well (although future work is needed to verify this).

In the configurations presented here, the homeowner is paying 75–90% less to the utility for electricity while still relying on a grid connection. The so-called “utility death spiral”, where distributed PV leads to higher prices which leads to more distributed PV, is a function of maintaining a volumetric pricing model (\$/kWh) for distribution even though costs are largely fixed and/or a function of capacity (\$/kW) [85,86]. A switch to greater fixed prices or capacity tariffs has been shown to be detrimental to prosumer PV economics [87] even though cross-subsidization is negligible at low penetration rates [88]. The problem becomes more pronounced at higher penetrations [88,89] and can also apply to high capacity appliances (like air conditioning or heat pumps) [90]. Utilities that increase fixed rates, however, risk encouraging grid defection. For example, studies have shown that both home owners [49] and small business owners [91] in the U.P. would currently profit from grid defection using hybrid systems comprising PV, cogen or generators, and a modest battery bank [92,93]. Likewise, natural gas could be used more efficiently than a furnace using a heat-driven heat pump [94] or an engine-driven compressor [95], potentially improving the economics for natural gas heating. The limitation is that these hybrid systems lock-in natural gas to provide heating and some electricity and can only provide marginal GHG reductions, so they are inferior technical solutions from a climate perspective than the PV+HP systems investigated here. This is not to say there are not

integration solutions—community energy systems with high penetration rates of heat pumps can economically integrate high levels of PV using a combination of demand response, storage, and curtailment [96,97]. Realizing these solutions require novel policies and business models, in concert, developed around distributed generation as opposed to the legacy model of centralized generation and one-way power flow [98]. In the immediate term, TOU pricing, smart demand controls, and storage all assist PV heat pumps to scale and integrate with the grid [40,99–101]. To optimize the system, considerable future work is needed to improve both thermal and electrical efficiency while also pushing electric demand to both the middle of the day (e.g., with smart appliances, heat pump controls, and existing thermal storage) and when possible to the higher solar flux months. Finally, when applying these results to other locations in North America, it should be pointed out that there are significant inconsistencies in interconnection and net metering policies, within states and even within individual companies [102]. Clear and consistent national level policy in both Canada and the U.S. would be expected to speed the transition to PV+HP systems while reducing costs for consumers and GHG emissions.

This paper is an initial investigation into the economic potential for heat pumps in cold North American markets, and more detailed modeling is required for complete techno-economic analysis. In a follow-up study, hourly heat pump loads, self-consumption of PV generation, peak inflow and outflow, and alternative electricity pricing models will be analyzed [103]. These details also enable analysis on the primary energy savings, which are critical given the energy carriers being compared (electricity and heat), and can be further extended into detailed GHG emissions reductions based on various grid portfolios from solar heat pumps. Other heat pump configurations should be investigated as well, such as ground source, which have higher efficiencies and can enable seasonal storage of solar energy [104,105].

Finally, this study has shown that the rhetoric describing the transition to renewable energy as a high cost, such as the Wood Mackenzie analysis claiming the cost of shifting the U.S. power grid to 100 percent renewable energy would be \$4.5 trillion [106], is misleading. Previous work has shown the wealthy could profit from large-scale PV deployment in the U.S. [107], and yet referring to the cost of a transition to renewable energy [108] remains the primary means of discourse. Some authors have pointed out that with the reduction in renewable energy technology prices such a conversion could be done with no costs [109] or even for less than it saves [110]. Instead, as this study has shown decarbonizing both the grid and the heating system should be viewed as an investment opportunity for all citizens.

## 5. Conclusions and Policy Implications

This study has shown that residents of both northern Michigan and Southern Ontario can profitably install residential solar to provide for all of their electric needs. PV systems to meet average loads were 6.9 kW without a HP and more than tripled to 20.6 kW to provide the needed electricity for the HP. Annually, these PV systems would produce 9130 kWh for the PV system alone and 20,611 kWh for the PV system to cover the HP additional load. The costs of PV and HP have been reduced enough that they now positive economic investments that yield a net savings and year one return on investments that are all in the single digits and range from 2.9% to 5.1%. In the current policy regime and current costs, an American installing a PV+HP would enjoy an internal rate of return of 3.4% and in Canada a PV+HP system would earn 0.6%. The IRR is higher for the PV alone, but the PV+HP systems provides not only a positive IRR and reduce the risk of natural gas price escalations in the future, but also eliminate all carbon emissions from heating. The current U.S. ITC has a large impact on the economics of PV systems, where alone the inclusion of the ITC in the U.S. increases the IRR by more than 1.7% and decreases the payback time by 3.8 years. Maintaining this ITC reduces the costs of the PV+HP systems by ten thousand dollars, which is approximately enough to be invested by the average American savings. In Ontario, the PV+HP systems IRR goes from marginally positive to



economically attractive when the electricity savings are substantially enhanced with TOU pricing instead of the tiered rates. Converting from tiered to TOU will encourage load shifting that will decrease electric costs as well as PV+HP investing that has the potential to radically reduce GHG emissions. Thus, policies encouraging TOU pricing would be expected to be both economically and environmentally beneficial as well as accelerate the electrification of the heating system.

The results of this study clearly show that for the first-time consumers can both electrify their heating loads using a heat pump and still profitably power their homes with solar energy in North America. This gives northern homeowners a clear and simple method to reduce their GHG emissions by making an investment that pays for itself over time. The current economics of these systems are not only positive, they are higher than what consumers can earn on their savings accounts and potentially CDs or GICs. It is time to stop emphasizing renewable energy costs, but rather start considering both residential PV and solar-powered heat pumps as 25-year investments in financial security and environmental sustainability.

**Author Contributions:** Conceptualization, J.M.P.; methodology, N.S. and J.M.P.; software, J.M.P.; validation, N.S. and J.M.P.; formal analysis N.S. and J.M.P.; investigation, N.S. and J.M.P.; resources, J.M.P.; data curation, N.S. and J.M.P.; writing—original draft preparation, N.S. and J.M.P.; writing—review and editing, N.S. and J.M.P.; visualization, J.M.P.; project administration, J.M.P.; funding acquisition, J.M.P. All authors have read and agreed to the published version of the manuscript.

**Funding:** This research was supported by the Witte Endowment.

**Institutional Review Board Statement:** Not applicable.

**Informed Consent Statement:** Not applicable.

**Acknowledgments:** The authors would like to acknowledge technical support from D. Cramer, helpful conversations with A. Kantamneni.

**Conflicts of Interest:** The authors declare no conflict of interest.

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