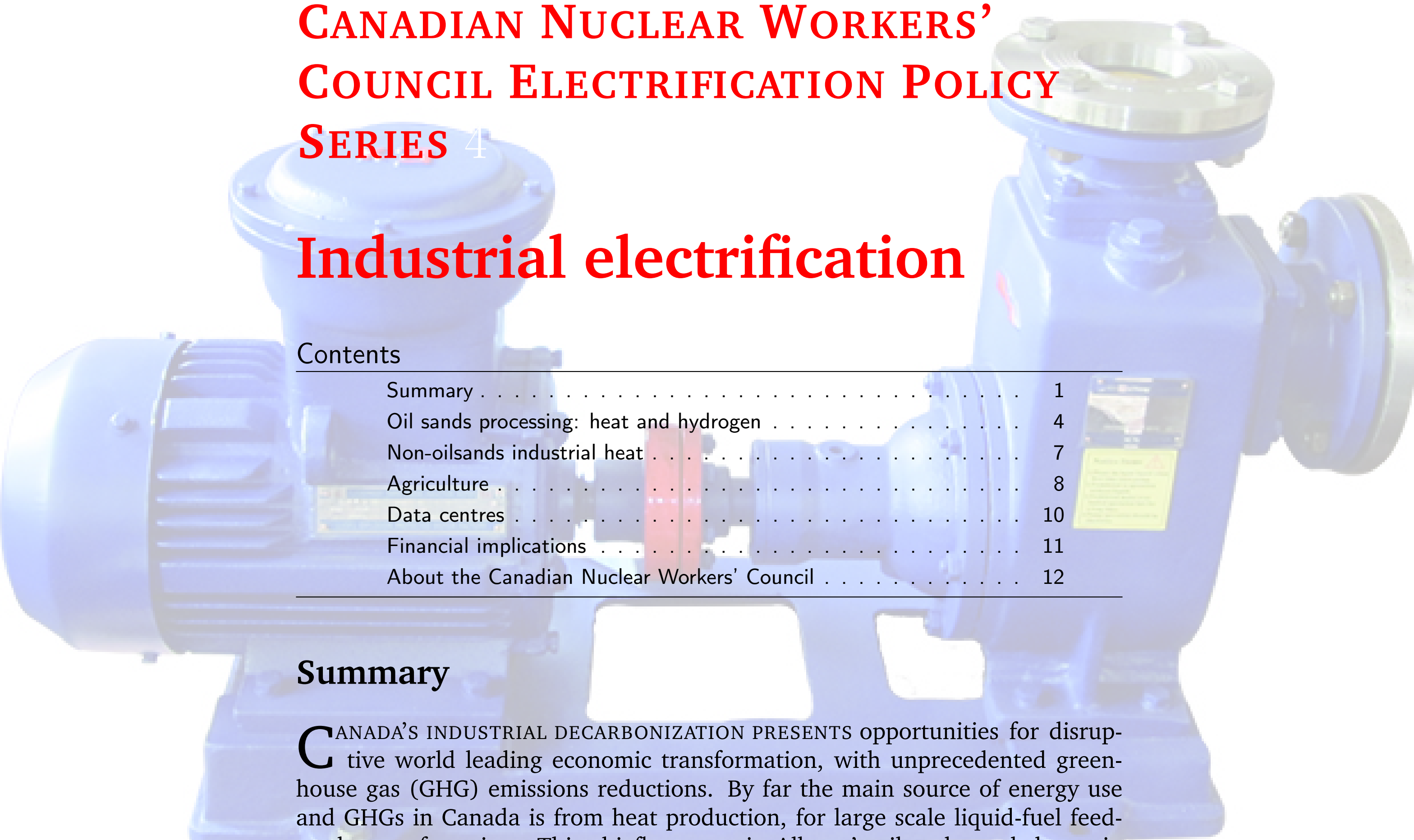

# Canadian Nuclear Workers' Council Electrification Policy Series 4

# Industrial electrification

## Contents



## Summary


Canada's industrial decarbonization presents opportunities for disruptive world leading economic transformation, with unprecedented greenhouse gas (GHG) emissions reductions. By far the main source of energy use and GHGs in Canada is from heat production, for large scale liquid-fuel feedstock manufacturing. This chiefly occurs in Alberta's oilsands, and the main energy usage, and GHG emissions source, is burning natural gas to provide heat and chemicals for the main stages of oilsands processing. These consist of separating bitumen from sand and manufacturing hydrogen.

Electrifying these is not practical. Rather, replacing gas with a non-emitting heat source opens new energy and chemicals markets for oilsands operators, whether they are currently in the power generation business or not. Many are; in fact, oilsands-colocated power generation facilities make up most of Alberta's baseload electrical supply. Their role in general electrification will involve their business shifting more to power generation, which, depending on future conditions, may acquire greater importance as an Alberta export product.

Alberta represents a special case for industrial electrification, in two ways. First, electrification would be "indirect." It would not involve replacing current processes with electrified ones, but as mentioned would involve companies changing business focus—from producers of liquid energy to producers of electrical energy, non-hydrocarbon polymers and associated products, and industrial gases. Second, Alberta is Canada's largest emitting province by far, and its hydrocarbons sector Canada's largest emitting industry, also by far. For these reasons, this report will consider Alberta's oilsands as a separate category from industrial electrification in Alberta and the other Canadian provinces.

Main electrification opportunities are found in the following sub-sectors:

1. Oil sands processing: heat and hydrogen. Primarily Alberta.
2. Industrial hot water. All provinces and territories.
3. Conventional agriculture. All provinces and territories.
4. Controlled environment agriculture. All provinces and territories.
5. Data centres. All provinces and territories.

**Non emitting vs low emitting heat for Alberta: the reality** The bulk of industrial GHGs in Canada are related to Item 1 in the list above, oilsands extraction and processing. In that case, emissions reduction prospects involve either finding another source of heat to separate oil from sand and hydrogen from methane, or continuing with using natural gas as the heat source but doing so more efficiently. The first alternative offers disruptive quantum-leap emissions reductions; the second represents a more politically feasible approach, with a much smaller role for electrification, and far less dramatic emissions reductions.

The first alternative—finding a new source of heat—is the only one that can deliver emissions reductions on the scale required to meet provincial and federal reductions targets within an acceptable time frame. The only commercially available technology capable of providing adequate reliable emissions-free heat is nuclear fission. In Alberta, where the bulk of oilsands activity occurs, much oilsands processing is co-located with power generation; heat and power are "co-generated." Electrifying oilsands heat in these cases would necessarily involve replacing current generation with some non-emitting type.

Renewable energy of the type commonly put forth as a replacement for fossil-generated electricity could only perform the industrial heating task if the latter were done with electric resistance, or some combination of electric resistance and heat pump. The output characteristics of wind and solar power in Alberta rule them out as serious industrial power and heat sources. There really is no alternative to fission.

**Industrial heat in the rest of Canada** Non-oilsands emissions reductions opportunities in industry also relate to heat. Of these, CNWC is happy to see the major opportunities already being pursued—in Ontario steelmaking operations, which today represent the single-largest source of provincial GHGs. The rest can and should be attacked with electric resistance and heat pumps.

Characterization of disparate industrial loads presents an interesting challenge. Fig 1 gives a breakdown of large Ontario users, as defined by the provincial electricity system operator. As you can see, there is distinct daily seasonality in most categories. Were many of these to switch from the main non-electricity energy source (natural gas) to electric, how would their load curves change?

**Government support a mixed bag** The CNWC applauds the federal and Ontario government support for the ArcelorMittal Dofasco electric arc furnace in Hamilton. This is the only way to decarbonize steelmaking. However, by the time that facility is electrified the CIPK of Ontario grid electricity will be significantly higher than it is today. The government support was not contingent on that. From the federal government's perspective, fully decarbonizing the facility, hence the success of the project and value for money, depends on the emission intensity of the grid.

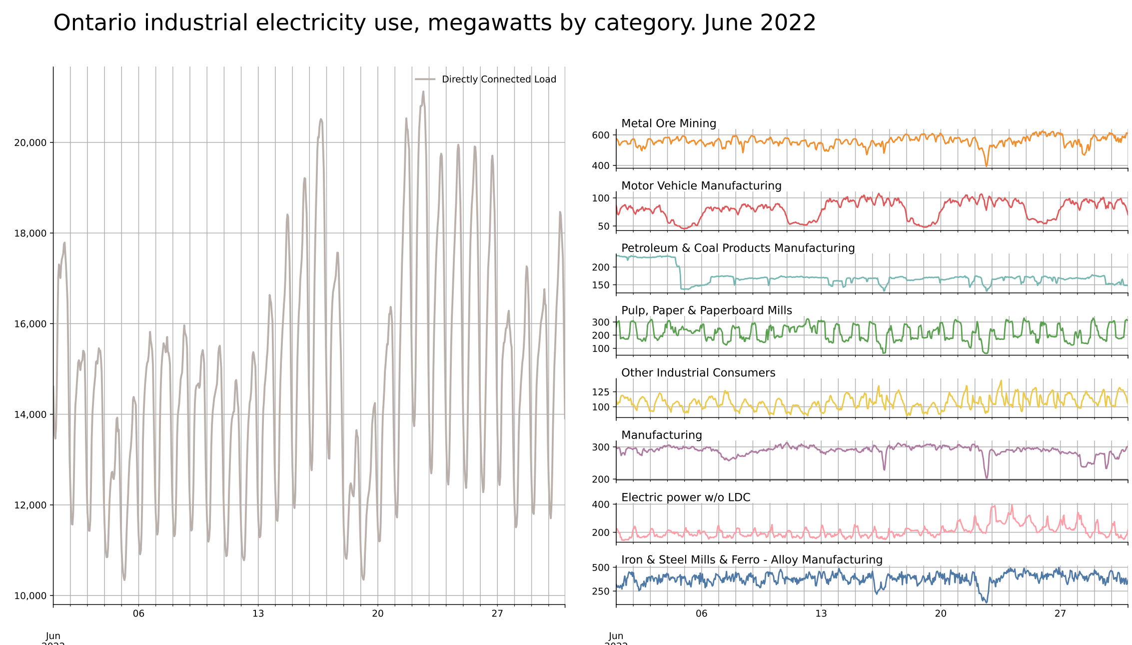


Figure 1: With comprehensive electrification, which of the industrial subcategories would be most affected? How would they be affected?

# Oil sands processing: heat and hydrogen

## Finding a non emitting source of process heat

THE HIGHEST-EMITTING "COGENERATION"-CATEGORIZED power generation facility in Alberta is the Muskeg River Cogeneration Station near Fort McMurray. Electrically it is rated at 202 MW. According to the Environment Canada Large Emitters database,[1] it emitted 1.38 million tons of $CO_2$ in 2019. (Only the Alberta coal and converted gas-fired steam power generating plants emitted more.) For a standalone power generating plant, these numbers would imply a facility of 262 MW, with a CIPK of 600 grams, running all through the 8,760 hours of the year.

However, Muskeg River is, as mentioned, a cogen plant. In 2019, the power generation side of Muskeg River generated at an average of 173 MW,[2] 85 percent of capacity. This would imply a facility with a total capacity of roughly 900 MW thermal, of which roughly two-thirds are for power generation and the rest process heat.[3]

Decarbonizing a Muskeg River–size facility on the basis of renewable energy with gas backup would be simply not viable. The RE side would have to use electrical resistance, and the gas side would have to be sized so that gas could supply the entire combined heat and power demand when wind and solar are not available—i.e., at its current size. Given the Alberta wind power output profile—low annual capacity factor, high standard deviation, and strong correlation of output among the 26 provincial wind farms—the gas "backup" would in reality be the main power source, with much throttling to accommodate wind/solar rises and falls. It is doubtful that the significantly increased costs of such an arrangement would compensate for the marginally lower GHGs.

The only viable source of emissions-free heat is nuclear fission.

**Bulk hydrogen** For any hydrogen-based energy approach to be both viable and a solution to $CO_2/NO_x/SO_x$, hydrogen must be water derived, using a non-emitting energy source. Only nuclear fission can do this at scale. Abundant

[1] Environment Canada emitting facilities database, website https://data.ec.gc.ca/data/substances/monitor/greenhouse-gas-reporting-program-ghgrp-facility-greenhouse-gas-ghg-data/

[2] source: emissionTrak™Alberta power stats database.

[3] At 600 grams CIPK, the power generation side of Muskeg River would have in 2019 produced 909,000 tons of $CO_2$ ($173\ MW \times 8,760\ hrs\ per\ year = 1.515\ billion\ kWh.\ That\ result \times 600\ g/kWh = 909,288\ tons$). As mentioned, Environment Canada reports 1.38 million tons $CO_2$ from that facility in that year, so we assume the difference, 470,712 tons, came from the process heat side of Muskeg River. One cubic meter of natural gas transforms into 1,878 grams $CO_2$ when burned, so the 470,712 tons represent $470,712,000,000\ grams \div 1,878\ g/m^3\ natural\ gas = 250,645,000\ m^3\ natural\ gas \times 10\ kWh/m^3 = 2.506\ billion\ kWh\ thermal\ energy \div 8,760\ hrs = 286\ MW\ capacity$. Assume the power conversion efficiency of the powergen to be 33 percent, and $202\ MW\ electrical\ capacity = 613\ MW\ thermal$.

and cheap pure uncontaminated hydrogen, i.e., hydrogen from water splitting, makes fuel cells viable. Fuel cell cars would have none of the range and charge-time problems associated with battery-electrics.

At this time (Thursday Aug 04 2022) it is still debated which electric power-train technology—fuel cell or battery—will eventually predominate in the market. However, of the two, BEV overwhelmingly predominates today. While this document does not attempt to predict the future, it is safe to say that "hydrogen economy" predictions—which are essentially identical today to the ones that emerged in the 1970s—will not come true unless and until there is a major wave of new nuclear construction for the purpose of producing hydrogen. While this would be a happy development from CNWC's point of view, it is unrealistic to suppose at this time that a fleet of new nuclear plants would be built solely to produce hydrogen. It is much more likely that any new nuclear construction would be for the sole purpose of power generation, and that is the assumption in this Policy Position.

The only true hydrogen economy that exists today is in the Alberta upgrading business, and that has been discussed above. Were Alberta to decarbonize oilsands upgrading with nuclear-generated hydrogen, the province would have a fleet of nuclear assets ready for redeployment into (likely) electricity generation or (possibly) ultra high purity gas manufacturing if and when the oilsands are wound down due to climate concerns. At that point, it would be clearer what role fuel cell–based electrification would be able to play.

In Alberta, looking much more near term, the term "SMR" could use a reframing—from Steam Methane Reformation (hydrogen-from-methane, which is how all hydrogen in Alberta is made today) to its proper meaning: Small Modular Reactor. This, plus replacing gas-fired heat with nuclear heat for separating bitumen from sand, is a direct near-term solution to the bulk of provincial $CO_2$.

Water-derived hydrogen (and oxygen) are feedstocks for ultra-pure industrial gases, another growth market. Alberta is a centre of world class chemical engineering expertise, and does not lack the human capital required for such an enterprise. There could be economy-transforming potential in such an approach.

The customers here would be oilsands operators, both the pre-liquefaction processors and of course hydrogen production and heat for upgrading. That would represent the owners/operators of half the current Alberta power generation fleet (the "cogeneration" category), plus upgraders. Often these are the same company. The first step would be developing a solution to the heat side of the equation—sizing an SMR so that it could be a one-for-one swap with the current gas-fired cogen facility.

## Industrial hot water

THIS SECTION COVERS NON–POWER GENERATION, non-oilsands industrial hot water.[4] Applications include food processing and food processing sanitation, drywall/gypsum manufacturing, truckwash/carwash facilities, and bottle washing.

Industrial hot water in Canada is mostly fossil fired today, due to cost. Fig 2 shows Ontario gas usage; note the size of the Industrial category. To the extent that there is some overlap with commercial DHW, it represents a significant portion of Canada's annual GHGs. While applications vary, the logic of electrification (which, we must remember, is for the purpose of decarbonization) requires that replacement energy be both non emitting and cheap. This narrows alternatives down to bulk electricity generation technology capable of meeting these criteria. Again, only large hydro and nuclear have proven themselves.

The CNWC recommends federal and provincial government support for conversion of fossil fired industrial hot water facilities to heat pump or electric resistance if necessary.

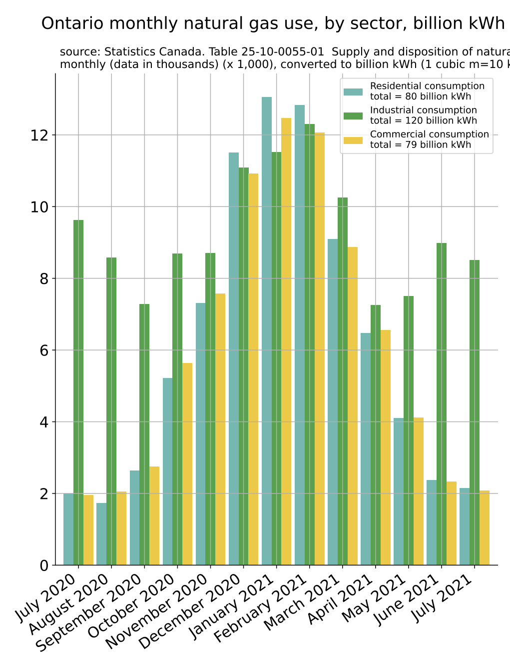


Figure 2: What proportion of Ontario industrial natural gas usage is for hot water?

[4] "Industrial water use" Statistics Canada. https://www150.statcan.gc.ca/n1/en/catalogue/16-401-X

# Non-oilsands industrial heat

STEELMAKER ARCELORMITTAL DOFASCO'S PLANT IN HAMILTON will over the coming years be the scene for one of Canada's largest electrification projects. The plant today is based on blast-basic oxygen furnace (BOF) technology, which uses metallurgical coal as a carbon source. The plan is to replace BOF with a combination of direct iron reduction and electric arc furnace (DRI/EAF) technology. AArcelorMittal Dofasco (AMD) Hamilton currently emits about 5 million tons of $CO_2$ per year, and is currently Ontario's single largest source of emissions. (Five million tons is about the same amount that Ontario's entire power generation sector currently emits every year.)

When the conversion to DRI/EAF is complete, emissions at AMD Hamilton will have been reduced by roughly 60 percent, or 3 million tons. Ontario's two next biggest emissions sources after AMD Hamilton are also steelmakers: Stelco's Lake Erie facility in Haldimand (3.3 million tons annually), and Algoma Steel in Sault Ste. Marie (2.6 million). In the top 20 large emitters in the province, not counting the steelmakers, 2 are landfills. The rest are either cement/lime plants or petrochemical (refineries and industrial gas manufacturing), to which processes GHG emissions are inherent.

This means the opportunities for industrial decarbonization are quite limited. The biggest opportunity by far for Ontario is to simply copy AMD Hamilton, and implement DRI/EAF technology at the Stelco and Algoma steel plants.

Across Canada, decarbonization opportunities are similarly limited, and thereby "easier" in terms of a single technological fix. The largest source of emissions by far is the Alberta oil sands. The bulk of these are related to producing heat and hydrogen. Natural gas is the primary input with these; in the case of hydrogen manufacturing, gas is both energy source and feedstock. Decarbonizing heat and hydrogen production at scale is feasible only with nuclear fission.

As mentioned, AMD says the Hamilton conversion will reduce annual emissions by 3 million tons. We fear that estimate is based on the current $CO_2$ Intensity Per Kilowatt-hour (CIPK) of Ontario electricity, which during high demand (i.e., high gas) hours on summer days already exceeds 100 grams. When Pickering goes out of service, Ontario's electric grid CIPK could easily be double that, with spikes approaching 300 grams on very hot days.

# Agriculture

## Conventional agriculture

FARMING IN CANADA IS HEAVILY DIESEL POWERED. Diesel and gasoline comprise by far the most energy use in grain, pulse, and oilseed operations; see Fig 3 for the situation with pulses. Electrifying heavy mobile equipment such as combines from the grid requires wire management. GridCON, a John Deere project featuring an innovative spool that enables full field coverage from a single connection, could be an early glimpse into full-electric large scale farming.[5]

While grid connection would be the most viable way to electrify these operations in the case of heavy equipment like combines, battery electrification may be more suitable for the numerous smaller scale energy-use applications on farms. The GridCON (or equivalent) connection would of course enable charging in these cases.

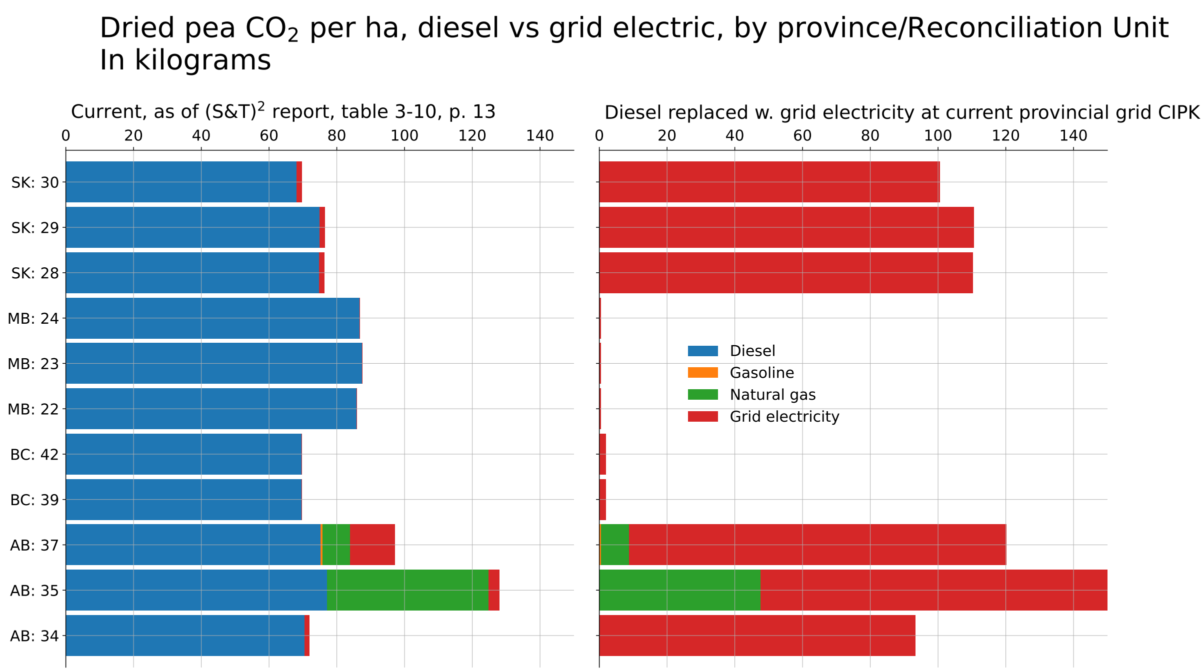


Figure 3: Emissions per hectare, Canadian dried pea production

It should go without saying that the success of electrification in reducing GHGs depends on the CIPK of the grid that provides the electricity. As you can see in Fig. 3, replacing diesel powered farm equipment with electric in Alberta would actually be counterproductive. That is because Alberta's average grid

[5] John Deere has also partnered with the eastern-US utility National Grid to test an electric backhoe.

CIPK is currently over 500 grams. Electrifying dried pea production in Manitoba or British Columbia, on the other hand, would virtually decarbonize that activity in those provinces: their grid CIPKs are 2 and 12 grams, respectively.

Should lifecycle carbon content become an issue in pulse and pulse product marketing, the data illustrated in Fig. 3 would be favourable to pulse producers in Manitoba and BC, and not at all favourable to those in Alberta. Current Alberta policies in Alberta implicitly intended to lower the CIPK of the Alberta grid have achieved only very marginal reductions, and likely will do little to address the disparity shown in the right-hand plot in Fig. 3.

In addressing the challenge of dramatically reducing grid CIPK, there is no alternative to nuclear.

## Controlled Environment Agriculture

Skyrocketing diesel and gasoline prices have driven up the cost of produce, creating an opportunity for local growers in Canada to compete with imported produce in winter by using Controlled Environment Agriculture (CEA). A steady supply of reliable energy makes it possible for CEA facilities to have 15 growing seasons per year, thereby approaching volume parity with traditional agriculture by trading land area for season frequency.

CEA is the agricultural analog of nuclear power: its land footprint is tiny, its transportation supply chain is minimal, as is its waste footprint. Energizing CEA facilities with predominantly nuclear-generated electricity would represent the lowest-footprint solution to the problems of climate change–related food and energy security: GHGs from agriculture and energy, the two largest source categories in the world, would be virtually eliminated, along with supply chain impacts resulting from climate change itself.

The greatest energy use in indoor farming is heating. If all heating were electric, then all energy in indoor farming would be electric. This has the potential to be virtually emissions-free, but if and only if most or all of the grid basis power is nuclear.

Electrification-wise, the implications for CEA are identical to those for all electric heating: the optimal situation would be to harness geothermal or air-source energy for "baseload" temperature control, then "top up" with resistance. Thermal storage in building mass (drywall, concrete, etc.) is economically viable above a certain size threshold (2 million square feet, according to one commercial offering, but the cost of electricity is the driving variable).

## Data centres

THE EXPLOSION OF DATA this century has created a new industry just for storing and diseminating it. Canada is well suited for hosting data centres, which are electricity intensive and which have significant cooling loads. Air conditioning demand during extreme summer heat in the southern U.S., where many large data centres are located, severely stresses grids in that part of the world. This could create an opportunity for Canada.[6]

Natural Resources Canada estimated in early 2020 that that data centres account for 1 percent of Canada's total electrical demand. Most electrical energy (60 percent) goes toward performing computations; the rest primarily for cooling. Canada's climate makes this country an attractive data centre location in light of the latter consideration. As demand for ever-faster computations per second increases, so does electrical load.[7] That estimate was made prior to the Covid pandemic, which saw data centre demand rise due to the informatics requirements of working from home and the increase in demand for cloud services. While the precise impact of these developments on activity in Canada has yet to be comprehensively quantified, it is safe to say that whatever increased demand occurred as the result of the further digitization of workplaces will be a permanent feature.

As with every other source of new demand, electric grids in Canada must have the supply to meet it. This supply must be zero emitting. Given that a data centre is a large 24/7 load with very low tolerance for outages, it should go without saying that the electrical supply for a data centre must be suited to meet baseload demand. Again, CNWC recommends governments be realistic about what really constitutes a baseload supply, and plan for zero-emitting generation expansion.

[6] Quebec is already a popular location for data centres, given its cheap abundant hydropower. However, its popularity has produced so many applications for grid connections that Hydro Quebec has had to dampen expectations with warnings about lack of generating capacity.

[7] See https://www.nrcan.gc.ca/energy-efficiency/products/product-information/data-centres/13741.

# Financial implications

INDUSTRIAL ELECTRIFICATION WOULD EXPAND the importance of municipal electric utilities, as would urban electrification. Utilities' duties would increase to include meeting very large locational demands. Their capital additions would greatly increase, but so would revenue. Mobile power as a service, described above beginning page **??**, would account for a significant portion of both capital additions and revenues.

It must be stressed again that municipal governments would experience significant increase in demand for services. Their duties would now include those currrently performed by fuel retailers and gas utilities. All energy the latter provide today would come from generating plants via the transmission system and then through the distribution grid.

Of course, the revenue to pay for the energy would come from ratepayers. But it is unlikely this transition would occur as the result of mandates. It could only occur if current consumers of combustible fuel found an economic benefit in electrification—that is, if electricity were priced so that it were less expensive to use it than its combustible alternatives.

The primary combustible fuel in this category is natural gas, the price of which is difficult to predict, but which has in recent years seen spectacular swings in response to market and geopolitical circumstances. Price volatility could return for this commodity, as U.S. grids transition to more intermittent sources that require gas backup, a development that will stress gas supply in winter. Recent and growing calls to phase out natural gas could gain traction, which gives industrial gas users little choice but to electrify.

In this area, governments must be realistic about what could replace gas as an industrial energy source. CNWC recommends strategic and holistic planning in government financial and energy departments/ministries, which include industry representatives, and which take into account industrial capital requirements in light of realistic energy alternatives.

The CNWC recommends establishing a standard for measuring the ability of financed equipment to meet the twin goals of providing reliable clean power in bulk and at a cost to the end user that represents a viable alternative to combustible fuel. The "clean" portion of the standard should aim for zero emissions. The "affordable" portion should aim for at least parity with current per-kilowatt-hour prices of combustible fuels in the targeted applications (transport and heating).

## About the Canadian Nuclear Workers' Council

### "The collective voice of organized labour in the nuclear industries"

The CNWC has been the collective voice of Unionized Workers across Canada's Nuclear Industry for more than 27 years. Our Member Unions represent Workers in uranium mines and mills, nuclear fuel fabrication, nuclear power plant (NPP) operation and maintenance, NPP construction and refurbishment, medical isotope production, nuclear research and development, nuclear waste management and decommissioning.

The CNWC believes that nuclear power is a proven, reliable and non-GHG emitting source of electricity that will continue to support our clean energy future.

All CNWC policy positions can be found at https://cnwc-cctn.ca/policy-positions/.

Bob Walker,

National Director

Content in this document was prepared for CNWC by S.E. Aplin.