Comments on:

Pathways to Decarbonization

A report by the Independent Electricity System Operator (IESO) to the Minister of Energy
to evaluate a moratorium on new natural gas generation in Ontario and
to develop a pathway to zero emissions in the electricity sector.

https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization

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Executive Summary

The IESO's *Pathways to Decarbonization* report considers scenarios for how Ontario might: (i) meet the province's electric power needs by 2035 without new fossil-fired generation; and (ii) meet the anticipated demand growth, until 2050, with net-zero greenhouse gas emissions.

The Ontario Ministry of Energy has requested feedback on the Pathways report, notably on the report's six "no-regret" recommendations "that reflect the scope and magnitude of the effort needed to support an orderly energy transition while maintaining a reliable and affordable electricity system for Ontarians." The Ministry has posed questions on nine topics. This document provides the responses of the Boltzmann Institute, an Ontario-based think tank that seeks to help eliminate harmful emissions from human energy use.

The Pathways report correctly identifies the transition away from fossil-fuelled space heating in Ontario's buildings as a major decarbonization challenge. An assumed large-scale conversion of space heating to air source heat pumps (ASHPs) is the prime factor in the report's projected near tripling of electric power peak demand by 2050. Expansion of generation, transmission and distribution capacity to meet that demand would be very costly and challenging to achieve. Nevertheless, the Boltzmann Institute believes that the IESO has significantly underestimated the demand from ASHPs on very cold days – for several days per year, electrification of space heating would create far greater peak demand than the IESO's contemplated system could supply.

The Boltzmann Institute proposes another path to net-zero. Instead of relying on electrically powered ASHPs, this path would involve widespread deployment of district heating, whereby low-grade heat is distributed to buildings through a network of water pipes. District heating is dominant in many parts of the world. It can exploit heat otherwise rejected to the environment by thermal power plants, industry and other sources; it can also use surplus power and heat from the sun. Furthermore, thermal energy storage (TES), at about one percent of the cost of electricity storage, can efficiently buffer between large temporal mismatches of heat supply and demand. Early estimates suggest the cost of this alternative for Ontario would be well under half of the many hundreds of *billions* of dollars estimated as the cost of the electrification alternative.

These considerations inform the Boltzmann Institute's responses to the Ministry of Energy's nine questions. The paraphrased questions and brief summaries of our full responses are these:

Q1. How can regulatory processes be streamlined to accelerate infrastructure buildout?

R1. The proposed massive buildout of electrical infrastructure – albeit underestimated – would be greatly abated by deployment of district heating, thus also diminishing arguments in favour of streamlined electricity regulation. Nevertheless, a regulatory framework for thermal energy, supportive of rapid, widespread deployment of district heating, is needed.

Q2. What are your expectations for early consultations regarding the planning and siting of new electrical generation and storage facilities?

R2. Unhurried, well-informed consultation is desirable. It should embrace integrated planning and siting of district heating infrastructure and the much reduced electrical infrastructure needed when district heating is given priority over ASHPs.

Q3. Should early investments be made in clean energy resources, even if power costs rise?

R3. Early investments should fully align with a viable long-term net-zero strategy. The proposed "low-carbon" fuels will likely be incompatible with net-zero (see R5), expensive, and in short supply. Investing instead in district heating will reduce power demand more efficiently than adding supply. Lower infrastructure costs, use of otherwise wasted heat, and inexpensive thermal energy storage will keep consumer costs of district heating comparable to gas heating. Using thermal power stations for combined heat and power (CHP) will enable greater use of intermittent renewables and lower the cost of electricity.

Q4. How can the costs of new clean electricity infrastructure be reduced?

R4. The simple answer is to build less of it – reduce electricity demand by implementing less-costly, widespread district heating instead of promoting ASHPs.

Q5. What are the prospects for using hydrogen or other low-carbon fuels for electricity generation?

R5. The prospects may not be good. There's little evidence to support the premise that truly low-carbon hydrogen or other fuels could be economically produced in significant quantities. To the extent they can be available they should be reserved for applications other than generating electricity, e.g., marine and heavy-duty road transport.

Q6. How could energy efficiency programs be enhanced to meet electricity system needs and how should programming be targeted?

R6. Energy efficiency programs should be guided by careful analysis of long-term strategic alignment, short-term objectives, industrial capacity, societal cost efficiency, social equity and total life-cycle costs and GHG emissions. Consumer-focused programs will be more costly and less effective than utility-scale efforts to harvest and use otherwise wasted heat. By implementing district heating (with TES) at scale, more than 50% of the energy from thermal electric generation, including nuclear, and possibly 40% of waste heat from industry could be made useful. This would much reduce the need for electricity to power ASHPs.

Q7. What are your thoughts regarding further investment in hydroelectric generation?

R7. Large remote hydroelectric plants involve significant environmental and other risks. They should be avoided. Smaller run-of-river hydroelectric projects are not so risky. They should be constructed if life-cycle comparisons with alternatives show them to be advantageous.

Q8. How can transmission corridors be preserved and lines built quickly and cost-effectively?

R8. Develop a comprehensive, integrated plan for both electricity and thermal energy infrastructure that minimizes the need for new transmission corridors and lines. Given R7, long transmission lines to northern Ontario should not be built. Prioritize widespread build-out of district energy to reduce electricity demand. Use the combination of nuclear CHP, TES and "grid-forming" capabilities to enable a higher fraction of renewable generation close to load centres, including distribution connected, without curtailment.

Q9. Additional feedback?

R9. Lacking in Ontario is the capability and capacity to implement widespread district heating, costing in the order of $100 billion over 25 years (much less than the $400 billion plus implied by the *Pathways* report if heating is electrified). In many cases, the district heating investments can be recovered through normal rate structures and reduce the need for escalation in electricity prices. A few percent of such investment should be applied to developing the needed capability and capacity.

This document ends with three appendices.

Appendix 1 provides some detail about district energy, the generic term for district heating and district cooling. The above responses to the nine questions focus on district heating, now the source of more than ten times the emissions from district cooling (which involves the delivery of cold water to buildings). District cooling will be come more important as temperatures rise. Its implementation should always be considered along with district heating. Appendix 1 includes an overview of thermal energy storage, whose simplicity, low costs, and reliability over extended periods make it perhaps the most important feature of district energy systems.

Appendix 2 elaborates the Boltzmann Institute's concern that the estimate of peak demand for electric power in the *Pathways* report is a severe underestimate.

Appendix 3 concerns energy sources, including for district heating. It has sections on windpower and photovoltaic electricity generation, solar thermal, waterpower, bioenergy, nuclear, renewable natural gas, and hydrogen.

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1. Introduction

We applaud the IESO's efforts to provide Ontarians with a view of how the challenge of reaching net-zero greenhouse-gas emissions by 2050 can be met. The IESO's analysis in Pathways to Decarbonization [1] (Pathways) is timely and, as it should be, provocative. As will be seen from what follows, the Boltzmann Institute takes issue with the analysis chiefly because of its focus on meeting the challenge with more and more expensive electricity generation and distribution. This is perhaps understandable because of IESO's mandate as the province's main electricity planner and manager [2].

The IESO notes correctly that space heating within Ontario's buildings is the greatest of many challenges to be faced. The Boltzmann Institute believes that by pursuing a strategy that better matches the *quality* of energy to the needs of individual uses of energy, and by *reusing* energy as its quality is degraded, Ontario can achieve a net-zero economy and a zero emissions electricity sector at far lower economic, social and environmental costs than the IESO has suggested. With its sharp focus on electric power, the Pathways study has ignored an alternate, lower cost strategic option that is being applied at large scale in Europe and elsewhere. That alternate option is to meet society's need for thermal energy at moderate temperatures – e.g., for space heating and domestic hot water (DHW) – not with electricity, but through the use of thermal energy services and infrastructure (see box, below).

The scale and choices of new electricity generation contemplated in the Pathways report are founded on some key assumptions (explicit and implicit) whose validity is questionable. The invalidity of one or more of those assumptions could have huge impacts on the appropriateness / adequacy of the Pathways scenarios and "no-regret" recommendations. By our estimates, the order of magnitude of these impacts is a 36 GW underestimation of needed generation capacity and over $200 billion of investments. Research and analysis provided herein shows that some particular assumptions in the Pathways report are almost certainly not valid and that the implications are consistent with our estimates above.

Whether or not our conclusions regarding the IESO's assumptions are immediately accepted, the great magnitude of the potential consequences warrants – even demands – a careful analysis of the likelihood that each assumption is valid (or not) and the corresponding implications and risks for Ontario's economic and energy systems future. Absent such analysis, it would be premature to judge the validity of the IESO's "no-regret" recommendations.

The generic term **district energy** (DE) embraces a wide range of *thermal energy services and infrastructure* that use pipes (generally water or steam) to deliver heat (or cold), most importantly for space heating and DHW but also for other applications. Included under the DE umbrella are district heating (DH), district cooling (DC), their combination DHC, thermal energy storage (TES), and seasonal TES (STES). DE technology has evolved through multiple generations from its origins over a century ago. The level of DE maturity is comparable to that of electric power technology, although the capability, maturity and availability of expertise in Canada lag far behind Europe. For a DE overview, see Appendix 1.

2. Responses to Questions

From the Ministry of Energy's **Proposal Summary** (https://ero.ontario.ca/notice/019-6647):

> **The IESO's Report Recommendations:**
>
> The IESO's report provides "no-regret" recommendations that reflect the scope and magnitude of the effort needed to support an orderly energy transition while maintaining a reliable and affordable electricity system for Ontarians.
>
> These recommendations from the IESO include:
>
> - The acceleration of current efforts to acquire new non-emitting supply, including the implementation of recent conservation and demand management directives.
> - Beginning the planning and siting work for new nuclear, long-duration storage and waterpower facilities, as well as transmission infrastructure, to allow for faster implementation.
> - Innovation and investment in low carbon fuels, such as clean hydrogen, as they are untested at scale. Further work and investment are needed to determine if they can replace some of the flexibility that natural gas currently provides the system.
> - Galvanizing collaboration amongst stakeholders, including Indigenous communities.
> - Ensuring that regulatory, approval and permitting processes are ready to manage future investment at scale.
> - Establishing an open, transparent and traceable process to measure progress and demonstrate the results of decisions and actions taken along the way.
>
> **Consultation Questions:**
>
> The Ministry of Energy is seeking feedback on the report and, in particular, the IESO's "no-regret" recommendations. We are particularly interested in comments and responses on the following questions:

We quote and respond to each of the Ministry's questions on the following subsections. Supporting materials and analysis are provided in the Appendices.

In these comments, footnotes are indicated by Latin superscripts; Latin numbers in [ ] indicate references, listed at the end. If not otherwise noted, quoted text in boxes is from [1].

2.1 Regulatory requirements

From the Ministry's **Proposal Summary**:

> 1. The IESO's Pathways Study recommends streamlining regulatory, approval and permitting processes, citing that it can take five to 10 years to site new clean generation and transmission infrastructure.
>
> **What are your thoughts on the appropriate regulatory requirements to achieve accelerated infrastructure buildout? Do you have specific ideas on how to streamline these processes?**

The IESO's Pathways report implicitly assumes that to achieve net-zero the Ontario economy must rely on very aggressive electrification. Based on arguments below, we do not believe that assumption is valid. The adoption of an alternative, lower cost, lower risk pathway not considered by the IESO would lead to significantly different regulatory requirements for build-out of quite different infrastructure (notably, district energy).

> "In the development of a pathway to a decarbonized grid, the IESO adopted a more aggressive electrification demand forecast. The Pathways scenario illustrates a system designed to meet winter peaks that are almost three times higher than those we experience today. As a result, the system would likely require an additional 69,000 MW of non-emitting supply and 5,000 MW in demand reductions from conservation."

About 29 GW of the additional 69 GW of non-emitting supply contemplated in the Pathways scenario would be to power electric heat pumps, mostly air source heat pumps (ASHPs), used for space heating of buildings on the coldest days.[1] We believe that, by assuming unrealistic technology improvements (see Appendix 2), the IESO has actually underestimated the peak demand due to ASHPs by 31 GW or more. **Dropping that optimistic but unsupportable assumption could raise the required additional non-emitting supply to 105 GW or more.**

Attempting such massive expansion of the electric power system to support large-scale use of ASHPs would be an expensive mistake. A much more efficient, economical and feasible alternative would be to implement thermal networks (district energy) to meet the needs of most non-rural buildings for space heating and domestic hot water. Some agricultural and industrial applications (e.g., drying, greenhouses, food processing) could also use district energy for much / all of their heat.[2]

1 Figures 10 and 11 of [1] indicate winter peak demand growing about 25 GW more than summer peak demand. Absent a detailed breakdown in the Pathways report, we take this to represent the peak demand from heat pumps. Allowing for 15% peak reserve capacity gives 29 GW of required dependable non-emitting generation. To the extent that, in the IESO modeling, the winter peak due to electric vehicle (EV) charging exceeds the summer peak, our inference of 25 GW for heat pumps will be too high; but that would mean an even greater underestimate of peak demand than we are suggesting. For analysis of the peak demands for EV charging, see the comments submitted by Boltzmann Institute member Richard Gilbert.

2 Discussion and analysis of a pathway that will address Ontario's energy needs through a combination of electrification and large-scale district energy are provided in Appendix 1 and separate comments, which include discussion of costs, submitted by Boltzmann Institute member John Stephenson.

We believe that thermal networks could yield economic electricity demand reductions, not foreseen by the IESO, amounting to at least 80% of the contemplated peak demand for ASHPs. Using the Pathways assumptions, thermal networks could avoid 20 GW of the roughly 25 GW peak electricity demand for heating. If the unrealistic assumption of ASHP performance improvements is dropped, 80% penetration of thermal networks could avoid 40 GW of the adjusted 56 GW of peak heating demand. Allowing for 15% reserve, the need for new electricity generation would then be reduced from 69 GW to 46 GW (or, more likely, 105 GW to 59 GW). The reduced electrical demand, and other benefits from integration of the electric and thermal energy systems, described below, would alleviate the need for streamlined regulatory, approval and permitting processes.

While the above analysis assumes district energy replaces just 80% of ASHPs, increasing the replacement to nearly 100% could reduce peak electric power demand by an additional 11 GW. Reducing heating with ground source heat pumps from 30% to 20%, switching them to district energy, would reduce peak power demand an additional 2.7 GW. The cost of achieving this increased district energy infrastructure usage should be a small fraction (perhaps one quarter) of the cost of the avoided power system expansion.

Ample zero-emissions thermal energy (heat) for delivery to consumers through thermal networks could be economically recovered from a wide range of existing and future sources. Those sources of otherwise wasted heat include thermal power stations, data centres, supermarkets, ice rinks, waste water, solar thermal collectors, and many more. Using nuclear power stations for cogeneration, or combined heat and power (CHP), has been recently recommended by the International Energy Agency [3] and the OECD's Nuclear Energy Agency [4]; see also [5]. The Pickering and Darlington Nuclear Generating Stations, for example, reject twice as much thermal energy to Lake Ontario as the electrical energy they supply to the Ontario grid; thermal networks could conserve a large portion of that thermal energy and economically deliver it to where it is needed.

Present regulatory, approval and permitting processes for thermal energy systems at both the provincial and municipal levels in Ontario are not conducive to large-scale implementation of district energy or the joint optimization of electrical and thermal energy systems, e.g., through strategic adoption of CHP for many thermal power stations (including new and existing nuclear). Often existing regulations, designed with objectives unrelated to district energy, have the effect of preventing or restricting implementation and expansion of district energy systems. For example, municipal regulations are typically written to govern use of rights-of-way by common utilities – water, sewer, hydro, gas, telecom and even old steam-based district heating – but not modern, low-temperature district energy. The absence of supportive regulations for shared thermal energy systems often results in projects failing to proceed.[3]

Organizational, policy and regulatory structures for thermal energy systems are well established in European countries and elsewhere. In Nordic countries (e.g., Denmark, Sweden, Finland), district energy supplies up to 99% of space and water heating for large cities. Their workforces

3 See, e.g., https://douglasworts.ca/?page_id=342 for a well-documented example.

have corresponding capability, maturity and capacity. Those countries should be looked to for examples of what might be appropriate for Ontario.

The IESO is seeking streamlined permitting and approvals processes that it considers imperative for the power system to be expanded in a timely manner:

> "**Permitting and approvals must be streamlined**: In Canada, it can take many years to build new energy infrastructure; the IESO's experience is that it can take four to five years for new wind and solar generation, 10 years for transmission networks and even longer for large, capital-intensive infrastructure. Stakeholders, communities, experts and infrastructure developers have made it clear that processes need to be enhanced and streamlined if Canada wants to build energy infrastructure at the scale needed to reliably decarbonize. It is imperative for all levels of government to review their processes, including the Impact Assessment Act, the Environmental Assessment Act, and siting approval and permitting processes."

We have demonstrated that the IESO has, through use of an unrealistic assumption, severely underestimated the peak demand that would result from conversion of natural gas space heating to electric heat pumps. The IESO has also ignored the alternative of implementing district energy systems to provide heating for most non-rural buildings instead of electric heat pumps. This alternative would be far less costly, more efficient and more feasible. By configuring thermal power stations – especially nuclear – for combined heat and power (CHP), the sale of otherwise wasted heat could supply much of the heat needed for district energy and also moderate the cost of electricity. Other benefits of integrated electric power and district energy systems are discussed on pages below.

Overall societal costs and risks will be minimized by maximizing the adoption of district energy and minimizing the residual need for electric power system expansion. Adopting such an alternate pathway would significantly alter the conditions and criteria for strategic expansion of electricity generation, transmission and storage. Nuclear CHP stations could become dispatchable; TES could diminish the need for electric storage (battery and pumped); new large hydroelectric stations may not be needed; constraints on renewable generation could be reduced; and transmission infrastructure needs could also be quite different and smaller in scale.

The need to prepare for a net-zero energy system is certainly urgent, but it is equally urgent that the pathway be prudently chosen. We believe that the most prudent pathway will involve highly integrated electrical and thermal networks, with district energy meeting most of Ontario's need for heat in the buildings sector.

Question responses and recommendations:

R–1.1 Revise the Ontario Energy Board Act to expand the OEB mandate to include the thermal energy sector. The OEB should regulate operation of the electric and thermal energy systems to ensure they function in an efficient, integrated manner. The Ontario Consumer Protection Act should also be revised accordingly. This need not mean regulation of thermal energy prices, but there needs to be a regulatory framework that sets ground rules for thermal energy systems and encourages the establishment of local district energy utilities and their eventual operation integrated with each other and with CHP thermal generating stations.

R–1.2 Draft and enact a new Act, comparable to the Electricity Act, to provide a governance framework for large-scale thermal energy systems in Ontario, including large-scale sources of thermal energy (including CHP, solar thermal collectors, geothermal, industrial, etc.), thermal energy transmission lines, large-scale thermal energy storage (TES) (including seasonal TES (STES)), and district energy local distribution companies.

R–1.3 Either expand the IESO's responsibility to encompass province-wide thermal energy systems and their optimal integration with the electric power system, or establish a new non-profit entity with primary responsibility for province-wide thermal energy systems. In the latter case, efficient integration of thermal and electricity systems would be a responsibility of the OEB. This proposal would follow the model of electricity local distribution companies (LDCs), keeping local district energy companies (public and/or private) independent of the organization responsible for province-wide (or grid-scale) thermal energy systems.

R–1.4 Systematically review and revise provincial and municipal regulations to ensure they are supportive of implementation, expansion and integration of district energy systems (including sources of thermal energy, TES, STES, and thermal transmission and distribution systems) and do not unnecessarily or inadvertently impede district energy projects at small or large scales.

2.2 Planning and Siting

From the Ministry's **Proposal Summary**:

> 2. The IESO's Pathways Study recommends beginning work on planning and siting for new resources like new long-lived energy storage (e.g., pump storage), nuclear generation and waterpower facilities.
>
> **What are your expectations for early engagement and public or Indigenous consultations regarding the planning and siting of new generation and storage facilities?**

Implementation of thermal energy systems, as introduced above, would substantially reduce the need for long-lived (electrical) energy storage (e.g., pump storage) and new nuclear and hydroelectric generation, relative to the scenarios of the Pathways report.

New and refurbished nuclear generation will still be needed, but smaller nuclear units (SMR, MMR) configured for CHP would ideally be located close to centres of heat demand instead of in remote locations from which heat transmission may not be economical. Planning for thermal networks and CHP should thus be priority considerations for siting.

When a nuclear station is configured for CHP, reactor thermal output can be maintained steady at or near 100 percent. Any heat not immediately needed to generate electricity can be diverted to the thermal network. Without affecting the reactor, electric power output can be adjusted rapidly by using valves to control the amount (and temperature) of steam that is diverted from the turbines to the thermal network. Heat sent to the thermal network can be delivered to customers for immediate use and/or held in high-capacity thermal energy storage (TES) for later use. A thermal network with properly sized TES would probably accept whatever heat was made available by derating electricity generation in CHP in its service area.

> "... phasing gas generation out of the system will require ingenuity and the implementation of new technologies to reorient our current system, which is grounded in the flexibility that natural gas generators provide."

Using nuclear stations only for electric power limits their ability to rapidly follow demand. Configuration of nuclear stations for combined heat and power (CHP) would substantially remove this limitation and give nuclear stations comparable flexibility to natural gas generators. Integration with thermal networks and TES also enables nuclear CHP stations to rapidly compensate for fluctuating supply from renewable energy resources such as wind turbines and solar photovoltaics (PV). Instead of curtailing renewables, or buffering their output with expensive battery storage, the electrical output of nuclear CHP units can be reduced and nuclear-produced heat sent instead to much less expensive and higher capacity TES and STES.

Question responses and recommendations:

R–2.1 Undertake a new net zero pathway study that considers both thermal energy and electric power systems, designed and functioning in an integrated manner, to optimally meet customer needs for reliable heat and electricity. The new study should assess the potential for rapid implementation of large-scale thermal energy infrastructure (including CHP, TES, thermal transmission and distribution), and a reduced need for new electricity generation and long-lived storage. Inclusion of nuclear CHP should enable improved utilization of renewables, justifying a greater portion of new supply being renewable and a reduction of short-lived (battery) electricity storage.

R–2.2 The Pathways report acknowledged the risk of limited supply of RNG and hydrogen. Published literature and our analyses (see below and Appendix 3) indicate that waterpower, RNG and hydrogen are likely to entail very significant GHG emissions – they are not as low-carbon as implied. To ensure that public and Indigenous consultations are founded on reliable information, require advance preparation and publication of in-depth evidence and analyses to quantify the potential availability, GHG emissions (all scopes), cost and risks associated with waterpower, bioenergy, RNG and hydrogen for any generation that would use those sources.

R–2.3 Initiate early engagement of key energy sector stakeholders to develop a common understanding of and commitment to the concepts and benefits of a strategic change from natural gas to district energy, instead of ASHPs, for moderate temperature heating applications. The transition envisioned is comparable to the transition, in the 1960s, from oil-based space heating, with fuel delivery by truck, to space and water heating by natural gas delivered through a transmission and distribution pipe network.

R–2.4 Do not proceed with public or Indigenous consultations regarding planning and siting of new generation and storage facilities until the implications of the new study proposed in R–2.1 are understood and there is stakeholder buy-in (R–2.3). We expect that the advantages of the alternate pathway resulting from R–2.1 will lead to significantly different needs for new generation and storage, with corresponding implications for planning and siting of generation, storage and transmission infrastructure.

R–2.5 Following substantial progress on R–2.1, R–2.2 and R–2.3, initiate public education to develop a broad appreciation of the opportunities and implications of implementing thermal networks to meet space and water heating needs for most non-rural buildings. The public, Indigenous people and interest groups should understand the economic, environmental and other benefits and risks of siting new nuclear CHP close to heat demand centres; and they must have opportunity for input into trade-off decisions regarding additional wind and solar PV versus major hydroelectric projects.

2.3 Clean energy resources

From the Ministry's **Proposal Summary**:

> 3. The IESO's Pathways Study shows that natural gas-fired generation will need to continue to play an important role in the system for reliability in the short to medium term. The IESO's assessment shows that most of the projected Ontario demand in 2035 can be met with the build out of non-emitting sources, but some natural gas will still be required to address local needs and provide the services necessary to operate the system reliably.
>
> **Do you believe additional investment in clean energy resources should be made in the short term to reduce the energy production of natural gas plants, even if this will increase costs to the electricity system and ratepayers? What are your expectations for the total cost of energy to customers (i.e., electricity and other fuels) as a result of electrification and fuel switching?**

The Pathways Study conclusion that natural gas-fired generation will be needed on an ongoing basis was a consequence of the limited focus on meeting Ontario's energy needs with electricity. We believe that consideration of an alternate pathway (see R–2.1) that includes large-scale deployment of district energy, and integration with the electric power system through CHP, would point to significant reduction or even elimination of the need for ongoing natural gas-fired generation. Such an alternate pathway would also, as discussed above, enable increased use of clean energy resources while maintaining system reliability.

With CHP, great value is derived from heat that has, until now, been rejected as waste. Not only would use of that heat avoid the need for costly imports and consumption of natural gas, revenue from the sale of heat could lower the cost of electricity. The cost of heating buildings would be comparable to the present cost of gas heating; significant costs for building retrofits and electrical system upgrades needed for conversion to ASHPs could be avoided; and electricity rates and consumption would both be reduced relative to the all-electric scenarios.

The Pathways report states: "We therefore contemplated a decarbonized supply mix by 2050 with contributions from new nuclear, conservation, demand response, renewables and storage. The mix also includes low-carbon generation such as hydrogen and renewable natural gas – currently emerging technologies – at scale." Regarding hydrogen, the Pathway scenario assumes "Clean Hydrogen for Thermal - Blue and Green".

> "Carbon capture and storage CCS was considered unlikely given the technical and economic challenges of using it on peaking plants. RNG is considered unlikely because of the scarcity of RNG resources in Ontario; the potential RNG in the province is about 2.5% of the total amount of natural gas used."
>
> "• Economic adoption of Hydrogen at scale will most likely require Blue Hydrogen to be imported into Ontario where production and CO2 sequestration occurs outside of the province and the H2 imported into Ontario
> • Subject to available geological storage for captured CO2, very large scale blue H2 production will most likely be the most economic low carbon hydrogen"

The IESO has acknowledged that carbon capture and storage (CCS) is an emerging technology that may fail to become viable at scale [6]. The production of blue hydrogen (produced by steam methane reforming of natural gas, with CCS) can also not be relied upon. Moreover, recent research concludes that use of blue hydrogen may result in much greater GHG emissions than just burning natural gas [7]. It would thus not be credible to assume that RNG or blue hydrogen will be low-carbon fuels available in substantial quantity. Green hydrogen, produced by electrolysis, might be a viable low-carbon fuel, but the cycle electricity => hydrogen => electricity would only be about 30% efficient. Any green hydrogen might be best reserved for industrial (e.g., steel) and heavy transportation applications. The proposal that hydrogen and renewable natural gas could be used at scale for electricity generation is thus a high risk proposition, not consistent with either net zero electricity or the stated objective of reliable system operation.

Question responses and recommendations:

R–3.1 The supply of low-carbon fuels will likely be limited, at best, and they will be more urgently needed in other sectors. The proposed replacement of gas plants with hydrogen fuelled gas turbines would involve significant risks to capacity and reliability due to uncertain availability of sufficient, economically priced, truly low-carbon hydrogen. It should be accepted that natural gas generation will need to end by 2035 instead of converting to other fuels. To minimize stranded assets, construction of new natural gas plants should be kept to the absolute minimum needed to maintain power system reliability until 2030.

R–3.2 Early investments should fully align with a viable long-term net-zero strategy. That long-term strategy should seek an optimal balance between district energy and electric heat pumps to serve space heating, DHW and other applications of low temperature heat. (The scale of power system expansion required to meet peak heating loads in the absence of large-scale district energy does not seem feasible or affordable.) To enable rapid deployment of district energy, before heat becomes available from large-scale CHP generating stations, consider small-scale CHP (possibly portable), co-located with district energy systems and powered by biofuels, RNG or even natural gas. Once other heat sources become available, they should support district energy expansion and those small-scale CHP facilities could transition to an emergency back-up role to ensure continued district energy availability during power system brown-outs or outages.

R–3.3 Where feasible, existing thermal power stations should be converted to CHP to make the otherwise wasted heat available for district energy and/or other uses, thereby reducing the cost of electricity, GHG emissions and growth of electrical demand. Implementation of CHP at nuclear stations will enable them to buffer intermittent supply from renewables (wind, solar PV), thus improving capacity factors and economics. (The flexibility of variable output CHP can be improved further by the inclusion of TES.) New renewable generation should be installed as aggressively as possible to exploit the variable electrical output capabilities of nuclear CHP as it comes online.

R–3.4 With district energy, we expect that consumers will incur no net increase in the cost of space heating, DHW and other low temperature applications relative to current costs with natural gas – this applies for the entire period to 2050. The unit cost of electricity will inevitably rise due to still-necessary rapid expansion of electricity generation, transmission and distribution for electrification of parts of the economy not served by district energy. Conversion to non-emitting sources will also contribute to higher electricity costs. International competition for labour, materials and equipment will be intense, creating risks that expanding capacity in a timely manner may not be possible and that, contrary to Pathways assumptions, unit costs will rise in spite of manufacturing and technology advances.

2.4 Investment needs and cost impacts

From the Ministry's **Proposal Summary**:

> 4. The IESO's Pathways Study highlights emerging investment needs in new electricity infrastructure due to increasing electricity demand over the outlook of the study. The IESO pathway assessment illustrates a system designed to meet projected demand peaks almost three times the size of today by 2050, at an estimated capital cost of $375 billion to $425 billion, in addition to the current system and committed procurements. Please see supporting materials for illustrative charts on capacity factor and cost by resource type.
>
> **Are you concerned with potential cost impacts associated with the investments needed? Do you have any specific ideas on how to reduce costs of new clean electricity infrastructure?**

The IESO findings quoted in the box to the right involved the assumption of significant increased demand due to ASHPs. However, as discussed above, the peak demand by 2035 due to ASHPs, all with electric resistance supplementary heat, would likely be 5 to 15 GW greater than the IESO has projected.[4] The proposed 8 GW of natural gas generation would be far from sufficient to maintain reliability; neither would there be sufficient time to expand the transmission and distribution infrastructure. If a priority were put on district energy, in the Toronto and York regions in particular, then peak demand might be reduced as much as 10 GW by 2035 relative to the IESO's estimate.

One mitigating approach, advocated by Enbridge and others, is to install ASHPs with natural gas supplementary heat, or even natural gas-powered ASHPs.[5] That would limit peak electricity demand, but it would only be a short term solution. As discussed above, subsequent conversion from natural gas to RNG or hydrogen would not significantly reduce, and may even increase,

> "Our analysis found that Ontario will need about 8,000 MW of natural gas in 2035 to maintain reliability. If the CER were to define the EOPL as 25 years, then Ontario would only have approximately 2,000 MW of natural gas available; most existing facilities will reach the 25-year mark on or before 2035, except for York Energy Centre (2037), Green Electron (2042), and Napanee (2045). This would be insufficient to maintain reliability. In addition, an EOPL of 25 years or less would force the retirement of Portland's Energy Center and York Energy Center, which are vital to reliability in Toronto and York region. These plants can only be retired if they are replaced by some combination of new generation or transmission. Our analysis finds that sufficient new transmission could not be built in the region by 2035." [6]

4 The Pathways report provides insufficient detail on modeling for us to be more precise. Supplementary heat other than electric resistance could avoid our estimated increase of the 2035 peak load, but use of natural gas, RNG or hydrogen would have to cease by 2050 in order to achieve net zero GHG emissions, leaving resistance heating as the only fallback – unless most building ASHPs are replaced by net zero district energy by 2050.

5 If the efficiency of natural gas use to directly power ASHPs is greater than 45 percent then, in the short term when marginal production of Ontario electricity is almost always from natural gas, natural gas-powered ASHPs would result in less GHG emissions than electric-powered ASHPs. But that option is not recommended because the emissions would not drop as electricity becomes clean.

GHG emissions. Use of those gases would have to cease by 2050, leaving electric ASHPs and resistance heating or conversion to district energy as the only long term options.

Question responses and recommendations:

R–4.1 Yes, we are concerned. As discussed above, we believe that the peak electricity demand, by 2050, of the Pathways scenarios has been seriously underestimated. Pursuit of heating electrification with ASHPs would actually, by 2050, result in demand peaks more than four times the size of today. It does not seem credible that the electric power system could be expanded to reliably supply such demand peaks. Neither would it make economic sense – except for a few very cold days each year, over 35 GW of that expanded capacity would be unused. Reducing demand for heat through building retrofits would be about as costly as the avoided power system expansion; moreover, experience in Canada and elsewhere indicates that it is unrealistic to expect retrofits to reduce average energy demand for existing buildings by more than about one percent per year [8]. We propose that the only rational way forward will be to minimize the deployment of ASHPs by aggressively implementing district energy and encouraging GSHPs where they would be more feasible than district energy.

R–4.2 There has been considerable promotion of hybrid heating systems – ASHPs with gas-fired supplementary heat used in cold weather (when the ASHP COP becomes less efficient (low COP) and/or the heat pump capacity becomes insufficient). Although hybrid heating systems can yield modest reductions of GHG emissions, they are not consistent with a long-term path to net zero. More thorough analysis should be undertaken of the short- and long-term implications of hybrid heating systems and the results used to better inform decisions regarding short- and long-term strategy for space and DHW heating solutions. Proponents' claims that converting from natural gas heating to an ASHP or hybrid heating system would be a good short-term option for reducing GHG emissions need to be carefully examined since most additional electricity supply planned in Ontario for the next decade will be from gas-fired generating stations, operating at about 45% efficiency.

R–4.3 Until now, campaigns promoting the use of ASHPs have failed to identify the long-term cost implications for the electric power system due to the increased peak demand created by ASHPs. In the short-term, as long as Ontario summer electricity peak demand remains higher than winter peaks, power system expansion may not be required. But beyond that, providing peak power for new ASHPs will require system expansion – generation, transmission and distribution – at a cost of about $10,000 per kW. The peak load increases created by cold climate ASHPs for detached houses could average over 12 kW (41,000 BTU/hr) per unit, with a consequential power system expansion cost over $120,000 per ASHP. The more rapidly ASHPs are installed, the sooner the transition to winter peaking will occur. The power system expansion costs due to ASHPs should be included in a comprehensive economic analysis of electrification of the economy and compared to the alternative of converting to district energy and CHP.

2.5 Hydrogen and other low-carbon fuels

From the Ministry's **Proposal Summary**:

> 5. The IESO's Pathways Study recommends that for a zero-emissions grid by 2050, investment and innovation in hydrogen (or other low-carbon fuels) capacity could be required to replace the flexibility that natural gas currently provides the electricity system.
>
> **Do you have any comments or concerns regarding the development and adoption of hydrogen or other low-carbon fuels for use in electricity generation? What are your thoughts on balancing the need for investments in these emerging technologies and potential cost increases for electricity consumers?**

Question responses and recommendations:

R–5.1 Consistent with our responses in section 2.3, above, we believe that planning reliance on hydrogen and other low-carbon fuels for electricity generation would involve excessive risk of failure to achieve net zero by 2035 (or later). There is, at present, inadequate evidence and analysis to give confidence that those fuels could be produced in significant quantities and without significant GHG emissions. Large-scale CCS may not prove both viable and economical. Nonetheless, we would support ongoing research, mostly funded by the gas industry, into the affordable production and use of low-carbon fuels for which the evidence and analysis demonstrate net zero GHG emissions for the entire cradle-to-grave process. Such research should also address the relative merits of reserving and using such fuels for applications other than producing electricity – e.g., marine and heavy-duty road transportation. Considering the relative risks and benefits to Ontario consumers, as opposed to national or multi-national corporations, public research funding for low-carbon fuels should be much less than new funding allocated to improve Ontario's capability, maturity and capacity for implementing much lower risk district energy (including CHP, TES, and other elements).

R–5.2 Investing aggressively in CHP and district energy, which are mature technologies, would be the least cost and lowest risk way of keeping Ontario consumers' energy costs (including electricity) low. A concerted effort should be put into identifying opportunities for direct use of heat instead of producing heat from electricity. This includes investigating increased collection and use of solar heat using flat panel and/or concentrating solar thermal collectors and thermal energy storage at temperatures suitable for industrial applications. All such collection, storage and direct uses of heat could greatly reduce the need for electric energy and peak power and the associated costs. In short, consumers' energy costs, including electricity, in the future net zero economy will be best controlled by collecting and using GHG-free thermal energy as an alternative to electricity wherever that is practicable.

2.6 Energy Efficiency

From the Ministry's **Proposal Summary**:

> 6. The IESO's Pathways Study recommends greater investment in new non-emitting supply, including energy efficiency programs.
>
> **Following the end of the current 2021-2024 energy efficiency framework how could energy efficiency programs be enhanced to help meet electricity system needs and how should this programming be targeted to better address changing system needs as Ontario's demand forecast and electrification levels grow?**

Careful consideration must be given to the motivations for energy efficiency. The solar energy incident on the Earth is 10,000 times more than all the energy used by humanity [9]. So there is no shortage of energy, but we need to change where we draw the energy from and use it more wisely.

Electrification is widely viewed as the primary path to net zero GHG emissions. For that to work, the electricity must be net zero: nuclear, wind, solar PV, and (mostly) run-of-river water power. Electricity storage (batteries, pumped water, compressed air, and others) has the potential to buffer between the intermittent supply of renewable power and demand fluctuations. But the expense of batteries makes them useful for only 4 to 12 hour storage, and the potential capacity of other storage options is small compared to the need.

> "While current Save on Energy programs are on track to achieve all feasible energy efficiency within the current framework, expanded targets post-2024 need to be established. Offerings should be expanded to include efficient electrification and move away from time-bound CDM Frameworks to an enduring model that adapt funding and targets to Ontario's achievable potential. Discussions regarding appropriate targets and models should begin now to better leverage CDM as a resource to respond to evolving system, market, and customer needs."

The primary energy supply for renewable electricity – ultimately the sun – is abundant and free. If used immediately, the efficiency of renewable electricity generation can be considered 100%. The efficiency will be reduced if renewable electricity must be curtailed due to lack of demand, storage capacity or system constraints. When storage is used, the efficiency will become that of electricity => storage => electricity. Curtailment of wind, solar PV and water power has been significant on the Ontario power system [10]. Means to reduce the need for storage and curtailment of renewable electricity would directly improve efficiency.

Thermal generation stations in Ontario produce electricity with efficiencies in the range 30% to 50%. As discussed above, much of the residual heat that is presently rejected to the environment (water or air) as waste by thermal stations could be put to good use. Using the heat would avoid the use of other energy sources, including electricity, to produce heat. The overall energy efficiency could then be as high as 90% – a huge improvement. The associated electrical demand reduction, including through avoidance of ASHPs, would be in addition to the

IESO's projected 4,650 MW of demand reduction in 2050 through conventional conservation and demand management (CDM) measures. Due to their high capacity factors and low efficiencies, converting nuclear stations to CHP would have the greatest payoff. Such conversion would also enable nuclear stations to vary their electrical output as needed to avoid curtailment of renewable power and the use of electrical storage – nuclear CHP would thus improve the operational efficiency of renewable generation.

Energy efficiency is likely to be most cost efficient and successful if undertaken at a systemic level. For example, the mandated transition from internal combustion engines to battery-powered electric motors will achieve improved efficiency for all light vehicles. The level of efficiency gain will then be determined by the efficiency of electric power generation [11].

Much of the demand that conventional efficiency measures would seek to reduce relates to buildings: space heating and cooling, DHW, lighting and appliances.

Conversion to more efficient lighting and appliances will be best achieved by setting efficiency requirements that manufacturers must meet. If inefficient products are no longer available, then the natural replacement cycle will ensure progressively improved efficiency of in-service products. For example: clothes dryers should all be heat pump-based condensing dryers with no external vents; stoves should have induction elements; lighting should be LED. To achieve faster results, require product standards to change sooner. Don't allow inefficient products in new buildings.

More complete analysis of conservation options for space heating and cooling and DHW is needed. Measures such as air sealing, installation of smart thermostats and upgraded insulation might seem relatively simple, but there is a severe shortage of industrial capacity (workforce, competency, commitment, low-GHG materials) to carry out this work. Aggressive efforts in Europe to improve the energy efficiency of existing buildings, with government support up to 110% [12], have only been able to achieve about 1% energy savings per year [13]. There is also a serious social equity issue, since wealthier people are much more likely to undertake such upgrades and take advantage of government supports than those who are less advantaged.

Heat pump water heaters (HPWHs) are a good example where more complete analysis is needed. HPWHs heat water by drawing heat from the surrounding area – typically, conditioned indoor space. During much of the year, that heat must be provided by the space heating system – most often gas or electric. If space heating is by gas, then through the heating season a gas water heater will often be more efficient than the combination of gas furnace and HPWH. If space heating is electric resistance, then through the heating season a HPWH would be equivalent to electric resistance water heating. During warm weather the situation reverses: a HPWH will cool the surrounding space and reduce the need for air conditioning. In warm climates, HWPHs will offer clear advantages, but how a HPWH in Ontario would alter overall energy efficiency, GHG emissions and costs may vary depending on the circumstances of each residence. Any attempt to do such analysis would be highly affected by the assumptions made regarding the future of the electric power system and electricity costs. (Assuming district energy is not available, a GSHP would be the next best option, in which case it could also efficiently provide the heat for DHW.)

When one considers that district energy can provide space heating and cooling and DHW almost entirely with recovered heat (and cold) it becomes important to investigate to what extent conventional energy efficiency measures are warranted. When does the cost of those measures exceed the cost of recovering, storing and delivering heat that would otherwise be wasted? The Boltzmann Institute has started work on a federally funded project to consider that question [14], but much more work will be needed.

Question responses and recommendations:

R–6.1 Energy efficiency programs should be guided by careful analysis of long-term strategic alignment, short-term objectives, industrial capacity, societal cost efficiency, social equity and total life-cycle costs and GHG emissions (all scopes). Analyses should consider the potential for thermal networks to provide sustainable clean energy at lower cost than the combination of electrification and building-based efficiency measures.

R–6.2 Decisions regarding short-term efficiency measures should include consideration of the short-term marginal GHG emissions of the Ontario electric power system, for which the IESO plans much greater use of natural gas generation over the next decade. Short-term electrification may be far less beneficial for reducing GHG emissions than would be inferred by using the average GHG emissions of the power system instead of the marginal emissions. Low emission power sources that keep the average emissions low are already utilized as much as possible. Power for increased demand will be mostly from burning natural gas at about 45% efficiency; converting those stations to CHP and providing the thermal energy to buildings could double the total energy delivered.

R–6.3 To control the growth of peak demand, consider a peak demand adjustment for all electricity customers similar to the present global adjustment peak demand factor for Class A customers. Make sure that building owners understand the cost implications of increasing (or decreasing) their peak demand through electrification (e.g., EV chargers, heat pumps, water heaters, condensing dryers, solar collectors (PV and/or thermal)). For residences, set a threshold (say 15 kW) below which there will be no peak demand charge.

2.7 Hydroelectric generation

From the Ministry's **Proposal Summary**:

> 7. The IESO's Pathways Study includes a scenario for over 650 MW of new large hydroelectric capacity to meet system needs in 2050.
>
> A recently released assessment estimates that there may be potential to develop 3,000 to 4,000 megawatts of new hydroelectric generation capacity in northern Ontario and 1,000 megawatts in southern Ontario.
>
> **What are your thoughts on the potential for development of new hydroelectric generation in Ontario by private-, Indigenous- and government-owned developers?**
>
> **While the capital costs for hydroelectric generation may be higher than nuclear, wind, solar, and natural gas, do you support investing in large scale hydroelectric assets that may operate for over a hundred years?**

Potential large hydroelectric generation opportunities identified by Ontario Power Generation in its recent assessment [15] are presented as though they would "avoid greenhouse gas emissions". However, it is widely recognized that the construction, changes to land and water resources, and operational processes associated with large hydroelectric projects can result in very significant GHG emissions, in both the short-term and long-term. For more discussion and references, see Appendix 3.

Large, remote hydroelectric projects also involve significant economic, political and reliability risks, as has been more than evident with the Muskrat Falls project in Newfoundland. That project has seen the cost roughly double, and backup (fossil-fuelled) supply must be maintained due to unreliable transmission and long repair times. Although agreements were signed with indigenous communities, methyl mercury pollution downstream is still a concerning issue.

Smaller run-of-river hydroelectric projects, without significant dams and reservoirs, generally do not suffer the issues discussed above.

Due to the unpredictable challenges and impacts of long-term climate change, including impacts on rainfall and ecosystems, hydroelectric assets should not be counted on to reliably produce power for a hundred years or more. As has happened with the Colorado river basin and Lake Mead, water may dry up surprisingly fast. GHG emissions or other environmental impacts may be deemed unacceptable, forcing sites to be restored (as best possible) to their natural states. Remediation may be very costly.

Question responses and recommendations:

R–7.1 Run-of-river hydroelectric projects, whether by private-, Indigenous- or government-owned developers should be considered on a level footing with wind and solar PV projects. In all cases, decisions should be based on cost, full life-cycle environmental impacts (GHG and other), availability, reliability, sustainability, societal benefits, risks and uncertainties.

R–7.2 For reasons expressed above, we do not support investing in large hydroelectric assets involving dams and reservoirs in otherwise undeveloped areas.

2.8 Transmission corridors and lines

From the Ministry's **Proposal Summary**:

> 8. The IESO's Pathways Study suggest that significant transmission capacity will be needed to help balance intermittent sources of electricity (e.g., wind and solar) and to ensure cost-effective supply can be delivered to meet growing demands from electrification and economic growth.
>
> Transmission will also be required to balance intermittent supply with dispatchable supply (such as natural gas and energy storage) and meet demand in regions with retiring assets.
>
> **What steps should be taken to ensure that transmission corridors can be preserved and lines can be built as quickly and cost effectively as possible?**

The requirements for new transmission will depend on what generation facilities are needed and where they are sited. Our responses, above, emphasize the potential to reduce the need for new generation by deploying district energy at large scale. To enable economic transport of thermal energy to where it is needed, nuclear CHP power stations should be sited reasonably close to centres of demand for moderate temperature heat – typically, cities, but also some industrial sites. SMRs might even be sited within or directly adjacent to the areas they serve. Some existing transmission corridors could accommodate district heating transmission lines and become energy corridors, thus reducing pressure on other land uses.

Solar thermal collectors are another good source of heat for district energy (see [16], and links and references therein). Even better, combined solar PV and thermal (PVT) panels yield full amounts of both electricity and heat. These should be installed aggressively[6] in areas where the heat can be used, and fully integrated into district energy systems and their STES so heat collected during the summer can be used in the winter. PV output would be distribution-connected, reducing the need for transmission expansion. Standalone solar systems (PV and/or thermal) should not be encouraged, since their unit cost will be about double that of large installations, and they will have no economic access to long-term storage.

Question responses and recommendations:

R–8.1 Prioritize strategies and measures that will minimize the need for transmission system expansion, including new corridors, lines and circuits. This will include prioritizing direct use of thermal energy wherever feasible, instead of using electricity to produce heat.

6 In Berlin, for example, solar collectors are required on all new buildings and existing buildings if significant parts of the roof are replaced: https://www.solarwende-berlin.de/solarwende-berlin-fremdsprachenseiten/solarwende-en-english-solar-energy-in-berlin.

R–8.2 Consistent with R–7.2, above, there should be no new transmission lines or corridors established to new large hydroelectric sites involving dams and reservoirs.

R–8.3 Renewable wind and solar generation facilities should be sited close to major loads, and distribution-connected wherever feasible, to minimize the need for new or expanded transmission. Solar thermal or PVT should be preferred over solar PV, since the energy collected per m^2 of collector could be four times greater [17].

R–8.4 Develop and apply “grid-forming” capabilities [18] to enable integration of a growing fraction of renewables into the power system without compromising stability or reliability.

2.9 Additional feedback

From the Ministry's **Proposal Summary**:

> 9. **Do you have any additional feedback on the IESO's "no-regret" recommendations?**

The IESO's "no-regret" recommendations logically followed from a study with limited scope and some implausible assumptions. Most significantly, the assumption that ASHP improvements would result in high efficiency on even the coldest days led to projected peak power demand in 2050 that is about 31 GW lower than we believe is realistic. But neither is it realistic to contemplate expanding the electric power system to supply over 30 GW that would be needed only a few days per year. Because cold spells can last more than one day, meeting that peak heating demand with electrical storage would not be feasible. The only credible, and much more efficient and affordable, alternative is to provide heat using thermal energy systems, as discussed extensively above.

For Canada and Ontario to achieve the benefits of thermal energy systems, significant investments must be made to develop local expertise and capacity comparable to what other jurisdictions, such as the Nordic countries, already have. The scope of needed expertise is wide and deep, spanning all the way from strategic governance to intricate details of the diverse involved technologies. Sufficient capacity is needed to provide leadership and support for thermal energy sector investments possibly exceeding $100 billion in Ontario by 2050.

(Those thermal energy sector investments would produce big savings, since they would reduce the need for electricity sector investments by $200 billion or more and would have much lower operational costs. Much of the thermal infrastructure capital investment can be recovered through competitive rates for district heating service, whereas the electrification options will contribute strongly to an increase in electricity rates.)

Question responses and recommendations:

R–9.1 Since the need for thermal energy is comparable to the need for electrical energy, we propose that, with no risk of regret, thermal energy systems should be recognized and given priority as critical infrastructure just as the electrical power system already is.

R–9.2 Establish a strategic initiative to build the capability and capacity to implement district energy for almost all non-rural buildings in Ontario. The investment in capability and capacity development should be commensurate with construction and operation of district energy infrastructure that might cost on the order of $100 billion over 25 years. A suitable Ontario government investment in capability and capacity development might be $2.5 billion over 25 years, or $100 million per year.

Appendix 1
District Energy

From Wikipedia:

> "**District heating** [...] is a system for distributing heat generated in a centralized location through a system of insulated pipes for residential and commercial heating requirements such as space heating and water heating." [19]
>
> "**District cooling** is the cooling equivalent of district heating. Working on broadly similar principles to district heating, district cooling delivers chilled water to buildings like offices and factories needing cooling." [20]

District energy embraces both district heating and district cooling. An integrated district energy system can have significant efficiency benefits relative to independent district heating and district cooling systems. These systems provide: reliable end-to-end thermal energy services including acquisition / recycling of heat / cold from diverse sources; thermal energy storage (TES)[7] with a wide range of capacities and charge / discharge times from hours to years; transmission and distribution piping systems; and in-building energy transfer stations.

District energy systems can be small, serving just a few buildings, to very large, spanning and connecting major metropolitan regions. Modern, low temperature systems can economically provide district energy services to most non-rural buildings, large and small.

Early district heating systems operated at temperatures exceeding 100 C, originally with steam and later pressurized hot water. Modern systems achieve lower costs and much greater efficiency by operating at lower temperatures, typically 70 C or lower for direct heating applications and even at ambient ground temperature (with uninsulated plastic pipes) for low density communities. Ambient temperature systems require connected buildings to have water-to-water heat pumps that function much like ground source heat pumps, but that can achieve higher efficiency (COP ≈ 4) through centralized management.

"The UNEP report ***District Energy in Cities: Unlocking the Potential of Energy Efficiency and Renewable Energy*** identifies modern district energy as the most effective approach for many cities to transition to sustainable heating and cooling, by improving energy efficiency and enabling higher shares of renewables." [21] The following quotes are from this comprehensive report, which we highly recommend in full:

> "DISTRICT HEATING is undergoing a resurgence as cities identify its ability to efficiently transform the municipal heating supply to be more cost-effective, cleaner and lower carbon, as well as more local, renewable and resilient. District heating can enable higher penetrations of variable renewable energy sources, such as wind and solar, in the electricity

7 TES used for district energy systems should not be confused with high temperature TES systems used, like batteries, to store electric power and return electric power.

system, using large-scale heat pumps, combined heat and power (CHP), boilers and thermal storage. Such balancing is a cornerstone of energy policies in Denmark and Germany, and several provinces in China are examining the synergy between district heating and high levels of wind generation."

"DISTRICT COOLING has huge potential to reduce soaring electricity demand from air conditioning and chillers, which can present problems at times of peak load and require expensive transmission system upgrades, electricity capacity additions and decentralized backup generators to deal with prolonged blackouts."

"USING ENERGY SOURCES such as fossil fuels or nuclear-powered electricity to provide space heating, hot water or cooling is inefficient and a waste of resources. District energy is the only way to utilize low-exergy, low-grade waste heat or free cooling sources for these end-uses in buildings."

"Local electricity utilities can benefit from the distributed cogeneration that district energy often provides. In Bergen, electricity companies, facing capacity concerns and network strains, supported the development of district heating because it reduced reinforcement costs and provided additional revenues. The local district heating industry association was created mostly by electricity suppliers. London, Seattle and Tokyo also are investigating the incorporation of electricity suppliers into district energy networks, utilizing waste heat from substations and transit lines."

Denmark is a world leader in district energy [22]. A 2019 report [23] from Aalborg University notes the importance of integrating district energy with other parts of the energy system:

"District heating systems should become integrated with other parts of the energy system. This happens through flexible production at Combined Heat and Power (CHP) plants complementing fluctuating renewable electricity production; use of waste heat from industry and services; and use of electricity in large-scale heat pumps and electric boilers during hours of high production of fluctuating renewable energy."

Thermal Energy Storage

Large-scale TES, including seasonal TES (STES), is one of the most important features of district energy systems [24][25][26][27][28].

To provide perspective:

- Raising the temperature of 4 km^3 of water by 25° C (a typical ΔT) would store more thermal energy than the energy obtained by burning natural gas to heat buildings across Ontario for the entire heating season.
- Collecting all that thermal energy from the sun would require about 200 km^2 of solar thermal collectors. Much of the land beneath those collectors could continue to be used for other purposes.
- About 80% as much thermal energy is rejected to Lake Ontario by the Pickering and Darlington Nuclear Generating Stations each year.

- TES can also be used for cold storage, which supports efficient district cooling and could greatly diminish peak electricity demand in hot weather.
- The volume of Ontario's natural gas storage facilities is about 12 km^3.

The scale of TES and solar thermal collectors actually needed would be much less than the above numbers because heat (and cold) can be collected and reused throughout the year from a wide variety of sources.

For similar capacity, the cost of thermal energy storage is about one percent of the cost of battery electric storage (BES). TES systems can be designed with storage durations from hours to years whereas economical BES storage durations currently range from 4 to 12 hours.

Heat from year-round sources, such as nuclear CHP, and from intermittent or seasonally variable sources, such as solar thermal, can be accumulated in TES year round and drawn down as needed to accommodate diurnal, weekly and seasonal demand variations.

The following figure from [29] shows concepts for large-scale STES, some or all of which might be technically and economically desirable in Ontario. (TTES and BTES are already used in Ontario, although not yet at community-wide or regional scale.)

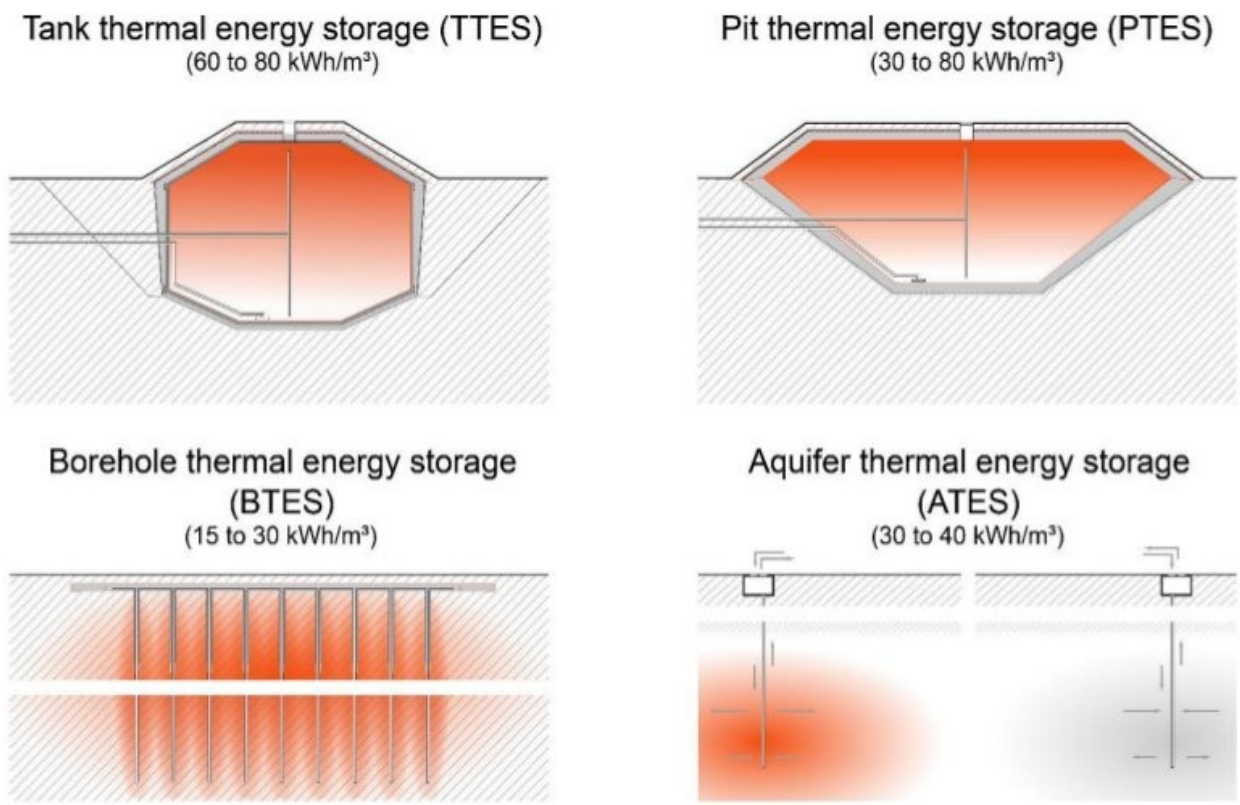


Figure 56: Overview of available underground thermal energy storage concepts (Sources: Solites)

Appendix 2
Peak demand for heating

ASHP Cold Weather Performance

Tab 2 of [30] explicitly and repeatedly states a key Pathways assumption:

> "• Assumption of air source heat pump technological improvement over the outlook period to enable:
>
> ○ operation in potential coldest weather
>
> ○ maintenance of coefficient of performance in potential coldest weather
>
> • Assumption is phased in:
>
> ○ over a 9 year transition period;
>
> ○ incremental 1/9 (11%) per year increase over baseline;
>
> ○ 100% effect by target year;"

The origin of this assumption can be traced through references [31] and [32] to [33], the last of which simply states “Heat pump performance is assumed to improve over time”. No arguments are provided to give credence to the above-quoted assumption details. We argue below that the assumption defies physics.

The laws of thermodynamics make the theoretical maximum efficiency of ASHPs, when operating in heating mode, decrease with the outdoor temperature [34]. The Carnot efficiency formula dictates that the coefficient of performance (COP) must decrease by at least 1.5 as the outdoor temperature drops from 0 C to −20 C (assuming the output temperature is 57 C, a generally accepted temperature for heated coils of indoor fan-coil units for ducted ASHP systems). Real ASHPs will be worse; although a growing fraction of ASHPs may be capable of operating in the coldest weather, their heat output will not increase to match the demand for heat, resulting in the use of, or switching to, supplementary electric resistance heat with a COP of 1. (We exclude the option of gas-fired supplementary heat (including “low-carbon” gases – see Appendix 3), since that would not be compatible with achieving net zero GHG emissions.)

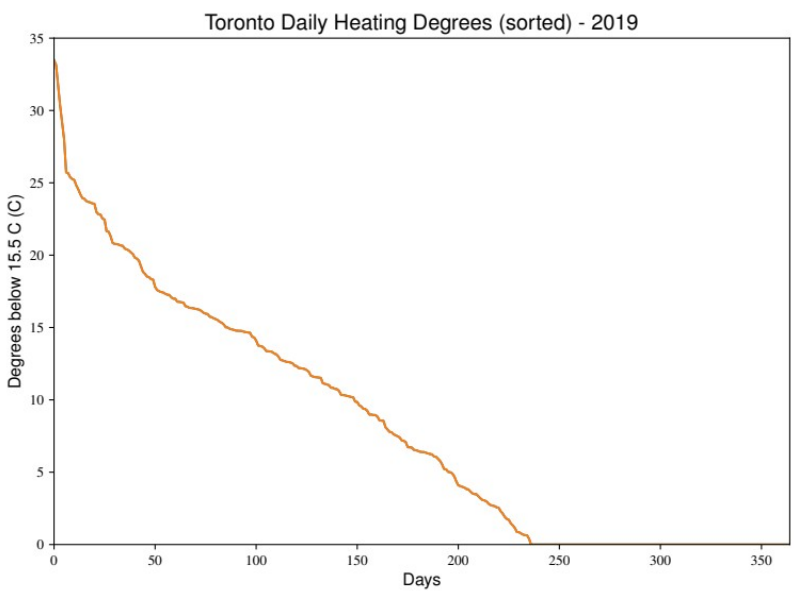
Another consideration is that ASHPs are not immune to degradation over time. We have been unable to find any empirical studies of long-term cold climate ASHP degradation, but a study of real-world degradation of home air conditioners and heat pumps [35] suggests a typical capacity degradation of 5 percent per year. Higher capacity units had even higher degradation rates. It is reasonable to infer that such reduction in capacity (i.e., heat output) would imply lower COP values and, on cold days, increased reliance on supplementary heat. A systematic literature review of ASHP field trials found that many factors contribute to performance objectives not being met [36].

Combined, the above considerations make it very likely that the average effective COP (including use of electric resistance supplementary heating) on the coldest winter days in Ontario will be close to 1 – i.e., ASHPs will provide no or minimal efficiency benefit over resistance heating on the coldest days. The peak electrical demand for heating will thus be very close to the heat now provided by combustion of natural gas on the coldest days (suitably scaled to account for expected changes in overall building heat demand by 2050).

Peak Demand for Electrification of Natural Gas Heat

Using temperature data from weather.gc.ca and natural gas usage data from [37] we can estimate the Ontario peak heating load supplied by natural gas in recent years. Some crude but conservative assumptions then allow us to estimate the peak electrical demand in 2050 that would result from wholesale conversion from natural gas combustion to a mix of ground source heat pumps (GSHPs) and ASHPs with supplementary electric resistance heating.

Heat demand for buildings is generally accepted to increase linearly with the number of degrees by which the outdoor temperature is below some base temperature. Using 15.5 C as the base, 2019 data for Toronto yield the figure below. Summing gives 2,987 heating degree days (HDD) for the year. The average temperature of the coldest day, January 30, was −18 C, yielding 33.5 HDD for that one day or 1.12 percent of the annual HDD.



The total natural gas energy used for space heating in Ontario in 2019 was 139 TWh (obtained by dividing PJ values for natural gas space heating from [37] by 3.6), implying January 30 usage of 1.56 TWh. We will assume: gas heating efficiency of 0.8; conversion from gas heating to electricity with 30% GSHPs at COP=3 and 70% ASHPs at COP=1 (on Jan. 30); and 1% annual demand growth for 30 years[8]. Applying these factors, and dividing by 24 hours per day, yields the projected 2050 peak day electric power demand for GSHP and ASHP heating to replace natural gas heating: **56 GW**. (Intraday peak heating demand could be 10%

8 The 1% annual demand growth is taken from the IESO's 2022 Annual Planning Outlook: https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook. We acknowledge the potential for building efficiency improvements to reduce the heating-driven demand growth, but do not wish to dispute here the IESO's demand growth assumption apart from the effect of ASHP cold-weather performance.

higher but might be mitigated by demand management.) This is more than twice the Pathways projection of about 25 GW.

The above numbers are subject to many sources of uncertainty, but those uncertainties will not materially change the conclusion that the Pathways estimate of heat pump peak demand is a severe underestimate. The attendant Pathways underestimate of costs likely exceeds $200 billion (31 GW * ($400 billion / 69 GW) plus distribution system upgrade costs). Providing for a 15% dependable reserve would make the cost underestimate even larger.

Appendix 3
Energy Sources

The Pathways Study considers wind, solar PV, waterpower, bioenergy, nuclear, renewable natural gas (RNG) and hydrogen as sources low-carbon energy for generating electricity. The first four of these are renewable energy, the latter two are not since the fuel sources will be depleted over time. Storage is included to allow buffering between supply and demand; and conservation and demand management are considered to reduce the demand for energy and peak power.

"Batteries and pumped hydroelectric storage were used as proxies for storage more generally."[6] Storage technologies that cycle electricity => storage => electricity will always incur losses to the environment (as heat), returning less energy than they were charged with. Since they are net consumers of energy, it would be inappropriate to consider them energy sources. Green hydrogen (produced by electrolysis) used to produce electricity for the grid falls into this category, but green hydrogen could legitimately be considered an energy source for other applications, e.g., for transportation.

Key concerns regarding energy sources are: full life-cycle GHG emissions and other environmental harms associated with their use; reasonable limits on their availability; and long-term sustainability of their production and use [38]. Future climate changes may have significant impacts on the cost, environmental impacts, and resilience of different sources of renewable energy [39].

Wind and Solar PV

There is broad consensus that wind and solar PV will cause far less GHG emissions than combustion of fossil fuels for generating electricity.

Land use is increasingly of concern as a significant impact. The land required for wind power in the USA is about 2 km^2/MW_e, while solar PV requires about 0.2 km^2/MW_e [40]. However, wind turbines must be widely spaced, leaving most of the land usable for other purposes. Solar PV land impact can be minimized by installing on rooftops and above productive farmland – even increasing crop productivity [41][42]. There is evidence that wind and solar PV power generation may be complementary in the Great Lakes region [43], making it best to have both.

Wind turbines have a direct immediate warming effect on local, near-surface temperatures, especially at night [44]. There has been a history in Ontario of strong emotional / political objections to wind turbines, both onshore and offshore, due to visual, noise, vibration and other concerns. However, wind has great potential as one of the most environmentally benign energy sources; Germany for example, will make 2% of its surface area available for wind power [45].

An uncertain risk worth noting is that climate changes may cause output from wind turbines, especially in the north, to decline in the coming decades [39].

Solar Thermal

The sun is by far the most plentiful and reliable source of energy on Earth. The sun shines about the same number of hours each year everywhere on the planet. However, ground-level sunlight varies due to differing cloud cover, and the solar flux normal to the ground decreases as one moves north or south away from the equator.

Solar thermal collectors can yield about three times the energy of PV panels per unit area, with zero operational GHG emissions. Temperatures as high as 1,500 C can be achieved with concentrating solar collectors [46], often used to produce electric power but also to produce synthetic fuels and for other industrial applications [47]. Just as interesting are solar collectors that heat water to below 150 C [48]. Deployed at readily achievable scale, these latter systems, combined with STES, can provide all or a substantial fraction of the heat needed to maintain annual balance of a district energy system.

Small solar thermal systems serving individual buildings can be installed for DHW and/or heating swimming pools. Swimming pools are an ideal application because there is no need for separate storage. Large solar thermal systems will generally need to be paired with some form of TES, with a great variety of options available for operation at different temperatures, capacities and storage durations [49].

Ground source heat pump systems that use borehole heat exchangers are often thought of (as the name implies) as using the ground as a source of heat. But the thermal conductivity of the earth / rock is typically so low that the borehole(s) will get progressively colder year-over-year as more heat is withdrawn for winter heating than is returned from summer air conditioning. Such cooling of boreholes causes annual GSHP performance (capacity and COP) to steadily worsen. Solar thermal collectors are a good option for efficiently adding heat to the system to restore annual balance or even boost the borehole temperature to optimize the GSHP performance. This can be done for small (single building) GSHP systems and also for large shared systems (i.e., district energy).

Waterpower

Although waterpower is an abundant renewable energy source for production of electricity, it often involves very significant GHG emissions. As has already become evident from the major drought in the western United States, there is risk that power will not be reliably available for the long term from large or small hydroelectric facilities – that risk is difficult to quantify at this time.

Large hydroelectric projects involving dams and reservoirs, such as contemplated in [15] for northern Ontario, require large land area and have significant GHG emissions [50],[51],[52]. In early years, during and after commissioning, emissions per MWh_e can exceed the emissions of natural gas power generation with combined cycle gas turbines. In the long term, such hydroelectric projects may have about 40 percent of the emissions of natural gas generation – far from net zero. Hydroelectric projects with dams and reservoirs also cause other environmental harms of significant concern [53].

Due to the significant land impacts, the need for new roads and major transmission lines, and the significant GHG emissions, the large hydroelectric development opportunities identified in [15] should be considered undesirable for a net zero Ontario electric power system.

Bioenergy

Ultimately, the energy source for bioenergy must be the sun and the conversion of solar energy to chemical energy via photosynthesis. In Ontario, photosynthesis captures and saves as chemical energy only about 1 Wm^{-2} [54]. Moreover, most of that energy is consumed by the plants themselves and significant energy expenditures (and GHG emissions) would be required to harvest, process and transport biofuels for use in electricity generation. There are thus severe constraints on sustainable availability and use of bioenergy, including land requirements well in excess of 1 km^2/MW.

The International Renewable Energy Agency provides this guidance [55]: “Bioenergy for power generation may have a role in achieving the net zero target. However, bioenergy electricity generation should be limited to projects that use low-cost and sustainably-sourced residues and waste, provide dispatchable electricity, are combined with heat or BECCS, or that act as a transitional fuel by co-firing in existing power facilities.”

Where bioenergy can be obtained from waste products – municipal, farm, forestry, etc. - it makes great sense to use that waste. Indeed, there is the potential for use of woody biomass residues for CHP or for heating to generate revenues that would support sustainable forestry with net GHG benefits. But attempting to source bioenergy beyond waste products is not recommended. Combined use of bioenergy and CCS (BECCS) faces significant challenges and success should not be taken for granted [56].

Nuclear

Nuclear energy likely offers the greatest potential for net zero electricity production, but the global supply of uranium is limited. For long-term fuel supply, there will be a need to develop breeder reactors – this should be started soon and not left for later generations.

In the near term, efforts should focus on efficiency. With CANDU reactors, more than twice as much heat is rejected into lakes than is made available as electric power. With small modular reactors (SMRs) under development, the efficiency should be closer to 50 percent.

With both CANDU and SMR reactors, priority should be put on making good use of the otherwise rejected heat, both to derive value that could reduce the cost of electricity and to reduce the need for and expense of new electricity generation. The obvious way to do this is to configure all nuclear stations for CHP and to embrace large-scale adoption of district energy for non-rural buildings [4][57].

Renewable Natural Gas

The Canadian Gas Association[9] defines: “Renewable Natural Gas - RNG is natural gas produced from organic waste from farms, forests, landfills, and water treatment plants. The gas is captured, cleaned, and injected into pipelines to be used in the same way as natural gas from any other source.”

Appendix B of the Pathways report [6] states: “RNG is considered unlikely because of the scarcity of RNG resources in Ontario; the potential RNG in the province is about 2.5% of the total amount of natural gas used. With technology or market innovation this situation could change, however it is risky to assume that it will.”

The International Renewable Energy Agency cautions: “Technologies for capturing carbon should not be a tool for propping up the weak business case for continued fossil fuel use but they do have a role in addressing aspects of emissions reduction that other technologies cannot. [...] In the power sector, renewables outcompete fossil fuels with CCS in terms of levelised costs of electricity (LCOE) and, in contrast to renewables, no significant capacity has been built to-date. CCS for fossil fuel-based power production is not economically justifiable for new projects and the financial case for retrofit appears marginal.” [58]

Since RNG is a processed form of bioenergy, as discussed above, the same issues and recommendations apply. Of particular note is that, due to costs and risks, there should be no reliance on CCS (as in BECCS) to avoid GHG emissions from combustion of RNG.

Hydrogen

Hydrogen is not a readily available source of energy; it must be produced by exploiting other sources of energy discussed above. Once produced, hydrogen can be transported and used for a wide variety of purposes with zero (or minimal) GHG emissions.

For extensive analysis of hydrogen’s potential, we recommend the IEA report [59].

Most of the hydrogen produced today is from natural gas using steam methane reforming (SMR); this is referred to as blue hydrogen. Production of blue hydrogen and its use for generating electricity would likely result in significantly greater GHG emissions than just burning natural gas, without CCS, to produce electricity [59][60]. Blue hydrogen should thus not be considered a low-carbon fuel.

Green hydrogen can be produced from water and electricity using electrolysis [61]. If the electricity is net zero, e.g., wind, solar and nuclear, then the green hydrogen produced can be a low-carbon fuel. There is need and potential for greatly expanded production of green hydrogen, especially from renewable power sources that would otherwise be curtailed.

No matter how it is produced, hydrogen is likely to remain much more valuable for purposes other than electricity generation. Use of hydrogen for electricity generation should thus be limited to deep reserve provisions.

9 https://www.cga.ca/natural-gas-101/the-renewable-natural-gas-opportunity/

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