ONTARIO SOCIETY OF PROFESSIONAL ENGINEERS

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Hon. Todd Smith
Minister of Energy
10th Floor, 77 Grenville St.,
Toronto, ON M7A 2C1

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Accelerating Growth in Hydrogen Energy Through Electricity Rate Options

Dear Minister Smith:

The Ontario Society of Professional Engineers (OSPE) is the advocacy body and voice of the engineering profession. Ontario currently has more than 85,000 professional engineers, 250,000 engineering graduates, 6,600 engineering post-graduate students and 37,000 engineering undergraduate students.

The Ministry of Energy proposes to offer reduced rates to produce low-emission hydrogen when the power system has surplus generation capacity. The Ministry proposes to provide three potential rate design options:

> Option 1: The Industrial Conservation Initiative (ICI) program rules would be adjusted to allow hydrogen (H_2) producers with an average monthly demand of at least 50 kW to become eligible for the ICI program. The ICI program reduces the electricity rates for the whole year if a participant reduces load during the 5 highest demand hours in the year. Those 5 hours are determined after the fact at the end of the year. Therefore, the participant must anticipate the high demand hours in advance. This means participants must reduce their load on more than the 5 highest demand hours to ensure they have successfully reduced load on the highest 5 hours to receive the largest rate reduction.
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> Option 2: H_2 producers would be allowed to co-locate electrolyzers at an electricity generating facility and pay the generating facility directly for the electricity they use. The rate that will be paid to generators including any lost income from the global adjustment (GA) account has not yet been determined.
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> Option 3: A dedicated stream of H_2 producers would get a lower interruptible rate provided they reduce demand over a fixed number of hours, several times a year.

OSPE supports the government's effort to establish low emission hydrogen energy infrastructure by designing an electricity rate option specifically for hydrogen producers. OSPE also agrees that rules should be established to ensure the lower rate is justified and the incremental energy supplied by the electricity system for hydrogen production results in a reduction in emissions compared to the steam methane reforming process now used for hydrogen production.

OSPE strongly recommends Option 3 provided that the "interruptible electricity rate" and "total annual interrupted hours" are reasonable. Option 3 is the preferred option because it will:

a. Achieve the lowest electricity cost for hydrogen producers without causing electricity system cost transfers between consumer groups,
b. Achieve the lowest greenhouse gas emissions from electrolytic hydrogen production,
c. Achieve the highest operating capacity factors for the electrolyzers,
d. Allow electrolyzers to be located closer to their hydrogen loads,
e. Minimize the need for financial support from the federal and provincial governments, and
f. Most importantly provide energy price certainty which will facilitate project financing.

All of the 6 items above are necessary to ensure commercial success for low emission hydrogen production. Additional details on why OSPE strongly recommends Option 3 is provided later in this document.

Before presenting comments on each option, OSPE wishes to summarize some power system characteristics that will impact each of the options differently.

Generation Considerations

Generation is not homogeneous. Ontario has several technologies that have different performance and emission characteristics. The dispatch order (the order in which they produce power on increasing consumer demand) is based on the marginal cost of electricity production. That order is then modified for safety, operability, reliability, and environmental reasons using minimum offer or floor prices on the offered quantities of energy for each technology.

The marginal cost of production is a combination of input fuel price, variable operating & maintenance costs and production taxes levied by government on a volumetric basis (per kilowatt-hour or megawatt-hour). For plants that cannot change load (some hydroelectric plants and most nuclear plants) the marginal cost of production is suppressed and becomes deeply negative. Effectively this means the plants are willing to pay a very high price per MWh to keep producing to avoid a costly plant outage.

To ensure public safety, power system operability reliability and to minimize environmental emissions, the minimum offer price, called a floor price, is established by the IESO market rules for each technology. When the IESO energy market clearing price falls below the power plant's floor price, that plant must shut down and allow other plants with lower floor prices and greater value to the public to keep operating.

The wholesale electricity market also has a minimum market energy price of negative $2,500 per MWh and a maximum market energy price of plus $2,500 per MWh. When the low extreme price is approached the IESO operator exercises administrative authority to decide which remaining plants operate and which get shut down to ensure public safety and to avoid a power system collapse. When the high extreme price is approached the IESO operator exercises administrative authority to order the local distribution companies to interrupt less critical consumer loads to avoid a power system collapse. Those interrupted loads will be placed on a rotating blackout schedule if there is sufficient generation operating.

Table 1 below summarizes the minimum offer prices or floor prices for various generation technologies.

Table 1
Energy Market Minimum Offer Prices or Floor Prices for Various Generation Technologies

Generation Technology	Minimum Offer Price	Remarks
Bio-mass (Wood Pellet) Plant	Input fuel cost (above $60 /MWh)	Plant self-curtails based on market price
Natural Gas Peaker Plant	Input fuel cost plus carbon tax (above $30 /MWh)	Plant self-curtails based on market price
Natural Gas CCGT	Input fuel cost plus carbon tax (above $20 /MWh)	Plant self-curtails based on market price
Flexible Large Hydro	$14.4 /MWh	Plant self-curtails based on market price
Flexible Medium Hydro	$6.2 /MWh	Plant self-curtails based on market price
Flexible Small Hydro	$5.6 /MWh	Plant self-curtails based on market price
Flexible Very Small Hydro	$4.8 /MWh	Plant self-curtails based on market price
Large Utility Solar Farm	-$3 /MWh	IESO curtails plant automatically
Large Wind Farm (top 90%)	-$3 /MWh	IESO curtails plant automatically
Flexible Nuclear (Bruce top 35%)	-$5 /MWh	IESO curtails plant automatically
Large Wind Farm (lower 10%)	-$15 /MWh	IESO curtails plant automatically
Inflexible Nuclear	-$2,500 /MWh	IESO curtails plant manually
Inflexible Hydro	-$2,500 /MWh	IESO curtails plant manually
Small Solar and Small Wind	No floor prices	No curtailment

Table 1 notes: (1) CCGT means Combined Cycle Gas Turbine (more efficient than a peaker plant).
(2) “Flexible” means the plant can raise and lower output at IESO’s request.
(3) CCGT plants have operating emissions of about 400 kg CO_2 per MWh of output.
(4) Peaker plants have operating emissions of about 600 kg CO_2 per MWh of output.
(5) Natural gas fuel costs above are for 2021. 2022 prices have risen significantly.
(6) Some legacy natural gas plants do not pay carbon taxes at the present time.

Emission Considerations

The carbon dioxide (CO_2) emissions that result from electrolyzer operation depends on the generation source that provides the incremental input energy. A typical low temperature electrolyzer of commercial efficiency will consume about 55 MWh of electricity per Mg H_2. If the incremental input energy is zero-emission, then the H_2 produced by the electrolyzer will also be zero-emission. However, if the incremental input energy for the electrolyzer comes from a CCGT gas plant, the emissions for that

Mg of H_2 will be 55 MWh x 400 kg CO_2 /MWh = 22,000 kg or 22 tonnes of CO_2 for each 1 Mg of H_2. The present primary method of producing H_2 is the steam methane reforming process which emits about 12 kg CO_2 per kg H_2 or 12 tonnes of CO_2 for each 1 Mg H_2. Therefore, an electrolyzer operating solely on natural gas CCGT generated electricity emits 180% more carbon dioxide emissions than the present steam methane reforming process that does not have carbon capture and storage.

To ensure there is a reduction in emissions of CO_2 to produce H_2 using electrolyzers, at least 55% of the incremental electricity used by the electrolyzers, over the operating period of interest, must come from zero-emission sources. Using the average carbon intensity of the electricity system as a whole is not the correct indicator for determining carbon emissions from electrolyzer hydrogen production.

Power System Cost Considerations

Electricity is one of the more expensive forms of energy, so it is used mainly where it has inherent advantages for the consumer that overcomes the cost premium. The applications include powering motors to operate mechanical devices including compressors and fans, and for powering lights and electronic devices. Some electricity is also supplied to applications where the advantages of using electricity overcome its higher cost relative to alternatives like fossil fuels (eg: some industrial, commercial, and residential heating applications that value zero-emissions at the point of use).

In the past the size of the power system has been built primarily to supply electricity applications described above. More recently, electric battery technology has advanced sufficiently that electric cars with their higher efficiency motors now have lower fuelling costs per distance driven than gasoline and diesel fuelled cars. This is a new load that is growing along with new greenhouse lighting loads as more crops are grown inside environmentally controlled buildings rather than outside.

Power system installed capacity for generation, transmission and distribution is determined by the highest expected peak electricity demand plus a reserve to accommodate several realistic contingencies. During off-peak periods, there is no additional installed capacity needed to supply off-peak energy. However, our current OEB approved electricity rates are structured so that the rate for any energy taken out of the power system must include a fair portion of the fixed costs of the installed capacity of the power system regardless of when that energy is consumed. The OEB's current rate policies assign some of the power system fixed costs to the volume of electricity used rather than as a fixed monthly charge or a peak power demand charge. This results in electricity volumetric rates (cents/kWh) that are much higher than the true marginal cost of producing electricity.

Regulators decide what is a fair allocation of fixed costs to the volumetric energy rate. If all consumers had the same load profiles and the same reliability needs, then spreading the fixed costs volumetrically by kWh energy consumption would likely be "fair" to most people. However, some new relatively large loads are now appearing on the power system that have much lower reliability needs. These loads are more flexible and impose much lower (even zero) additional fixed costs on the power system because these loads can be curtailed (turned off) when the load demand on the system is high.

For example, most of the energy consumed by electric vehicles (EVs) can be supplied when installed capacity is idle (ie: off-peak). During off-peak hours these loads do not impose additional installed capacity demands on the power system compared to traditional electrical loads which must operate during peak hours. EV loads are flexible because they have significant on-board energy storage. Most

EVs do not need to be recharged during on-peak demand periods and most do not need to be charged every day. This flexibility in the timing of EV charging demand places much lower fixed cost demands on the power system because very little additional installed capacity is needed to serve them. For EV owners pricing electricity by time of use is relatively easy and inexpensive and provides EV owners the option of charging on-peak and paying the much higher electricity price for the required installed generation, transmission, and distribution capacity, or, off-peak at a lower price.

Electrolyzers that produce H_2 are even more flexible than EVs because they can shut down during peak demand hours. Electrolyzers can operate economically at less than 100% operating capacity factor, provided that they can qualify for low electricity prices. Electrolyzers can easily curtail production during the power system's peak demand hours and even during power system contingencies such as a generator failure or low renewable energy production. The ability of electrolyzers to shut down during all hours when the power system is short of capacity means that they impose no fixed costs on the power system.

In exchange for agreeing to be interrupted or to self-curtail during system peak load periods, or other power system contingencies, these flexible loads should be able to enjoy lower electricity prices because they have lower reliability requirements.

> **A new policy that sets the electricity rates commensurate with the reliability requirements of the load is important if the government wishes to reduce emissions to the environment through the use of low emission hydrogen. In a low-emission power system about 90% of the total cost of service is a fixed cost related to installed capacity, which is directly proportional to the reliability requirements of the loads. Loads that do not require power during periods when the power system is stressed and is deficient in installed capacity, should be able to extract surplus electricity at other times at the prevailing marginal cost of production. For a low emission electricity system that is typically about 10% of the normal retail price of electricity for loads that require reliable electricity.**

<u>Comments on the Specific Rate Design Options for Hydrogen Producers</u>

<u>Option 1: Expanding membership in the ICI Program</u>

Expanding the ICI program would lower electricity bills for hydrogen producers, however, the ICI program has a few rules that can create unmanageable surprizes in the hydrogen producer's electricity bill. These are:

1A – The proposed qualification is 50 kW of average power demand. If the average power demand fell short in any year, the participant would be disqualified for an entire year. The resulting electricity cost increase would create serious hardships for the hydrogen producer because electricity is a significant component of the total cost of operating the business. The preferred qualification criteria would be to use the rated installed capacity of the electrolyzer facility not the average operating demand. This is especially important during the early years of new technology when teething problems can take time to fix and would reduce the average power demand, potentially below the qualification level.

1B – The current ICI program assesses the power demand during the highest 5 hours of the year but the calculation occurs after the fact when the high 5 demand hours for the year are known with certainty. If any of those 5 hours were missed by the consumer and the demand had not been reduced, the impact on the bill is significant for the entire subsequent year. The resulting electricity cost increase would create serious hardships for the hydrogen producer because electricity is a significant component of the total cost of operating the business. The preferred assessment criteria is for the IESO to establish the curtailment hours in advance so hydrogen producers can plan for the power reduction and not be surprised after the fact. This may necessitate the IESO establishing a larger number of pre-planned curtailment hours each year so that the highest 5 hours are captured with a high degree of certainty.

1C – As the electricity supply mix changes and consumer load profiles change the highest 5 hours not only move to different days and hours but the system demand on many more days will be close to the highest 5 hours for the year. This results in the need to avoid production on a growing number of days in high demand seasons (typically on cold winter days and hot summer days). The resulting reduced capacity factor of the hydrogen production facility will result in a higher cost per volume of hydrogen produced because the fixed costs of the electrolyzer facility are a significant component of the total cost of producing hydrogen. This problem will be much less of a concern if the change suggested in 1B above is implemented.

If the Ministry of Energy does not accept changing the qualification and assessment criteria in the ICI program, then an alternative that would help mitigate unmanageable cost increases for a whole year would be to change the annual qualification and assessment period from 1 year to a more frequent period. Ideally that would be the monthly billing period, so that if a participant misses either the average power demand or the highest 5 hours in the evaluation period they are not penalized for an entire year. The minimum average power consumption may also need to be adjusted for each of the new evaluation periods because average load profiles may vary from month to month.

<u>**Option 2: Co-locating Electrolyzers at Generating Plants**</u>

This option expects that curtailed generation at the plant site will be used to produce hydrogen at that site. However, there are a few problems with this option. These are:

2A – The dispatch order for generation determines the operating and curtailment periods that the generating facility experiences. The curtailment periods then establish the available maximum capacity factor that the electrolyzer will be able to achieve at that generation site. The generation technology at the site will also determine the marginal cost of energy at that site. Some examples follow:

- Natural gas plants have the highest curtailment rate (up to 80%) which will allow the electrolyzers to operate at up to 80% capacity factor. However, the natural gas plants also have the highest marginal cost of production and the resulting CO_2 emission rates will be almost double compared to making hydrogen using the steam methane reforming process.
- The largest hydroelectric plants have a relatively low curtailment rate (less than 20% until 2030) which will limit the operating time for the electrolyzers. These hydro plants have a moderate marginal cost of production (positive $14.4 /MWh). For hydro plants the marginal cost of production is primarily determined by the government's production tax called the gross revenue charge (GRC) which is levied as a volumetric rate (per MWh). The government could either

lower the GRC or redesign it as a fixed annual charge. That would lower the marginal cost of production for hydro plants.
- The smallest hydroelectric plants have a relatively low marginal cost of production (positive $4.8 /MWh) but they have a low curtailment rate (below 10%) which will limit the operating time of the electrolyzers.
- Large wind farms and utility solar have a low marginal cost of production (negative $3 /MWh) but they also have modest curtailment rates (below 25%) which will limit the operating time of the electrolyzers.
- The flexible nuclear plants have a low marginal cost of production (negative $5 /MWh) but they also have very low curtailment rates (below 1%) which will limit the operating time for the electrolyzers.

The operating times for the electrolyzers can be improved by allowing the electrolyzer facility to purchase surplus low emission electricity on the IESO wholesale market when energy prices are favourable even if the co-located generating plant is not being curtailed. However, this will only help financially if the global adjustment (GA), transmission, distribution and regulatory charges that are applied volumetrically (i.e.: per kWh or MWh) are waived.

2B – The electricity cost that must be paid to the generating facility may be significantly higher than that generating facility's marginal cost of producing energy. All generating facilities currently get a portion of their fixed costs covered by the global adjustment account when they provide electricity to the power system or when they are curtailed by the IESO. Whether the Ministry of Energy expects the hydrogen producers to pay any of those power system fixed costs have not been identified. Electrolyzer produced hydrogen is expected to cost significantly more than steam methane reformed hydrogen based on current retail electricity volumetric rates.

To make low-emission hydrogen competitive with the steam methane reforming process, the cost of electricity needs to be close to the marginal cost of production of the low emission generating plants. This price treatment can be justified if the electrolyzer facilities do not use electricity when the power system is stressed – typically during high demand periods and during power system contingencies.

2C – The location of the generating plants may not be ideal for distributing the hydrogen fuel to most of their customers. The generating plant's own hydrogen consumption for generator cooling is limited.

<u>Option 3: Lower Interruptible Rate for Hydrogen Producers</u>

Details of this option are not yet available including items such as the energy price, the number of hours each year when electricity will not be available and what requirements must be met by a hydrogen production facility to qualify for the lower electricity rate. However, this option has the potential to create a business environment that results in a strong economic case to produce low-emission hydrogen. The key is to ensure the power system's incremental cost of serving the hydrogen facility is reflected accurately in the cost charged for energy for the electrolyzer facility and to make that cost as low as possible using reasonable curtailment rules.

3A - Achieving the lowest electricity cost for hydrogen producers without causing electricity system cost transfers between consumer groups

A low emission power system has very low fuel cost. Most costs are fixed regardless of the amount of electricity that is used. The cost of a low emission power system is almost entirely (about 90%) determined by the installed capacity needed to serve the highest or peak demand. The rest of the year the capacity is idle to varying degrees. The period of greatest idle capacity is typically the spring and fall evening hours, however, significant idle capacity is available every night all year round. Idle capacity is also available from time to time during peak load periods when we have strong winds and bright sunshine.

To avoid transferring power system cost unfairly between consumer groups, the input electricity for the electrolyzers should be charged at its marginal cost of production for a unit of energy. Fortunately, that price is the IESO wholesale market energy price without any other markups. By no other markups we mean no global adjustment, transmission, distribution or regulatory charges as long as the electrolyzer facility agrees to interrupt production when electrical generation, transmission or distribution capacity is insufficient to meet prevailing consumer loads.

3B - Achieving the lowest greenhouse gas emissions from electrolytic hydrogen production

The IESO wholesale market dispatches power plant output based on the lowest offer prices that just meets demand. All generating stations are paid their contracted energy price in two ways. The first funding stream is the wholesale market energy price for the electricity that is produced. The second funding stream is a payment from the global adjustment account equal to the contracted price minus the wholesale market energy price. This arrangement ensures that all generating plants offer their energy at their marginal cost of production for the energy. This also ensures the lowest cost plants get dispatched first. Fortunately, the lowest marginal cost plants are all zero-emission plants in Ontario.

What this dispatching arrangement means is that as long as the IESO wholesale market energy price is at or below $14.4/MWh, the incremental energy production is all zero-emission from hydroelectric, solar, wind and nuclear plants.

If the electrolyzers operate only when the market energy price is at or below $14.4/MWh the hydrogen produced from that electricity is also zero-emission or green hydrogen.

3C - Achieving the highest operating capacity factors for the electrolyzers

Prior to the refurbishment program for Darlington and Bruce nuclear plants, the power system operated at or below $14.4/MWh about 60% of the hours of the year. That means an electrolyzer of modest size could operate at up to 60% capacity factor using only zero-emission electricity. Electrolyzers can operate economically at 60% operating capacity factor if the electricity they use is available at $14.4/MWh or less.

During the nuclear refurbishment program and especially after the Pickering Nuclear plant retires at the end of 2025, there will be less surplus zero-emission electricity and fewer hours each year when wholesale energy prices will be at or below $14.4/MWh. However, after the small modular nuclear reactors are commercialized and deployed in the post 2030 period, the amount of the surplus zero-emission electricity will increase again. A very low emission power system will produce significant amounts of surplus zero-emission electricity. For a power system that has 95% carbon free generation, about 15% to 25% of the electricity that can be produced will be zero-emission surplus electricity that will be available at or below $14.4/MWh in Ontario, assuming the current policies for the gross revenue charge for hydroelectric plants remains the same.

As larger electrolyzers are installed, they will use up all the available surplus zero-emission electricity during more operating hours of the year. The operating capacity factor for the electrolyzers will therefore decline if only zero-emission electricity is used. An alternative strategy to maintain an economic capacity factor for the electrolyzers is to pay more than $14.4/MWh for the energy. As long as the time operating using natural gas generation (i.e.: electricity prices above $14.4/MWh) is less than 45% of the total operating time assuming the electrolyzers operate at full power, then the total emissions from hydrogen production will be less than using the current steam methane reforming process to make hydrogen.

In 2021 the hours available at or below various electricity prices were:

- 36% of the hours at or below $14.4/MWh all incremental electricity use is zero-emission
- 43% of the hours at or below $20/MWh
- 60% of the hours at or below $30/MWh
- 78% of the hours at or below $40/MWh

3D - Allowing electrolyzers to be located closer to their hydrogen loads

The cost of transporting hydrogen is significant so allowing electrolyzers to be installed close to their hydrogen customers and allowing them to connect to either the transmission or distribution system will facilitate the development of a zero-emission hydrogen energy industry.

3E - Minimizing the need for financial support from the federal and provincial governments

We can significantly reduce the need for government support to establish a hydrogen energy industry if we treat hydrogen producers as energy suppliers under special rules. We can allow them to make use of surplus low emission electricity to produce hydrogen and help facilitate decarbonization of other sectors of the economy. Hydrogen producers would not need to pay for any of the fixed costs of meeting peak electrical loads as long as they shut down production when the electricity system is stressed.

3F - Providing energy price certainty which will facilitate project financing

Project financing will be facilitated if one of the major cost inputs to hydrogen production is stable, known and predictable. The present and future wholesale market energy price can be forecasted accurately based on the planned generation technology mix and consumer load demand. Both of these are published by the IESO annually for typically 20-year periods.

Summary

The present government, IESO and OEB electricity pricing policies are a barrier to decarbonization because they allow low-emission generation to sit idle while consumers use lower cost fossil fuels for their other energy needs. A change in those pricing policies for hydrogen producers will facilitate the development of a zero-emission hydrogen energy industry in Ontario.

To make a strong economic case to produce low-emission hydrogen using electrolyzers will require a low electricity price, a high electrolyzer capacity factor and close proximity of the electrolyzers to their hydrogen consumers (customer sites or consumer hydrogen filling stations).

All of these conditions can be met if the Ontario government and the OEB allow hydrogen electrolyzer operators to:

1. Access surplus low-emission electrical energy at the wholesale market energy price or a proxy of that price. The proxy price can be fixed for a period of time and adjusted periodically to align with changing wholesale market conditions like we do now with regulated price plans for small electricity consumers.
2. Reduce the volumetric GRC for large hydro plants or alternatively by redesigning the GRC to be a fixed annual charge rather than a volumetric charge.
3. Allow electrolyzer operators to use electricity from curtailed natural gas CCGT plants for up to 45% of their total production during the interim period from 2022 until 2035, until sufficient clean generation replaces our natural gas-fired generating plants.

To legitimately provide the lowest possible cost of electrical energy to hydrogen producers, the electricity used for hydrogen production needs to be subject to interruption when electrical capacity (generation, transmission or distribution) is scarce. The electricity price should be based on the wholesale market marginal cost of production with no other markups. That price policy will ensure:

- The electrolyzers will operate economically
- the cost impact of electrolyzers on the power system is negligible, and
- no power system cost transfers between consumer groups will occur.

Some opportunities may exist to supply thermal energy for hydrogen production at generating stations that have high temperature thermal energy available as part of their electricity production processes (eg: natural gas plants, bio-mass plants and nuclear plants). Thermal energy input to high temperature electrolyzers can reduce their electricity requirements for hydrogen production. Unfortunately, high temperature electrolyzers are typically more expensive than low temperature electrolyzers

Thank you for the opportunity to provide feedback on your policy proposal. OSPE would be pleased to elaborate on any points in our submission. If you have any additional questions, please contact Sara Mehraban, Policy Analyst, smehraban@ospe.on.ca.

Sincerely,

Sandro Perruzza

Sandro Perruzza
Chief Executive Officer
Ontario Society of Professional Engineers

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