Date: May 22, 2020

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

BRIEFING NOTE FOR DECISION

PREPARED FOR: Honourable Bruce Ralston, Minister of Energy, Mines and Petroleum Resources

ISSUE: Creative Energy request for consent to amalgamate

BACKGROUND:

Creative Energy Vancouver Platforms Inc. (Creative Energy) is a steam utility serving more than 200 customers in the downtown Vancouver area. In June 2018, Creative Energy filed an application with the British Columbia Utilities Commission (BCUC) for a Certificate of Public Convenience and Necessity (CPCN) to construct a new steam plant within BC Place Stadium and to refurbish its existing steam plant at 720 Beatty Street (the CPCN project). The CPCN project would enable a land developer to proceed with an office tower project above and adjacent to the existing steam plant, in space that is surplus to the requirements of the utility. The total capital cost of the CPCN project is estimated to be $53.1 million, of which Creative Energy will be responsible for only $15 million, with the land developer subsidizing Creative Energy for the remainder.

The June 2018 application to the BCUC also proposed a series of twelve corporate reorganization steps that are required to facilitate the CPCN project and the office tower project. The proposed corporate reorganization includes the amalgamation of Creative Energy and a new subsidiary of Creative Energy's parent company. The amalgamated company would continue delivering the steam utility service and would be a regulated public utility under the *Utilities Commission Act* (UCA).

Under section 53 of the UCA, a public utility must not amalgamate with another person unless Cabinet consents to the amalgamation. Before consenting to the amalgamation, Cabinet must receive a report from the BCUC that includes an opinion that the amalgamation would be beneficial and in the public interest.

After a regulatory process that included a public notice and workshop, three rounds of information requests and final and reply arguments, on March 5, 2020 the BCUC approved:

- Creative Energy's request for a CPCN; and
- the proposed corporate reorganization steps.

On April 3, 2020, the BCUC submitted to the Minister of Attorney General a report that included its findings on the application and its opinion that the amalgamation of Creative Energy and the new subsidiary is beneficial and in the public interest (https://www.bcuc.com/Documents/Proceedings/2020/DOC_57737_2020-04-03-CreativeEnergy-PanelReport-to-LGIC.pdf).

The request is time sensitive. Creative Energy has asked for Cabinet approval of its amalgamation request by the end of June 2020, so that it can complete the corporate reorganization steps and proceed with the CPCN project in accordance with its latest project plans.

DISCUSSION:

The BCUC found that the proposed amalgamation is beneficial and in the public interest even though the public interest benefits associated with the proposed amalgamation are limited to:

- enabling the tax cost of the land held by Creative Energy to be increased in accordance with the federal *Income Tax Act*, thereby avoiding double taxation in the event of the property being sold in the future; and
- avoidance of an alternative approach that would involve winding-up the utility and be more complex and costly.

Similarly, the BCUC found that the proposed corporate reorganization, as a whole, would result in no significant benefits to the public or ratepayers.

The BCUC did find that there would be important, direct benefits to the public from the CPCN project and office tower project, which would not go forward unless the proposed corporate reorganization, including the amalgamation, was approved. Those direct benefits include improved air quality, beautification of Expo Boulevard, the creation of a large plaza and the provision of additional retail space.

The BCUC also found that, even more important than these public benefits, are the benefits provided to Creative Energy's ratepayers. For a cost of $15 million and a relatively modest impact on rates of 4.1 percent, Creative Energy and its ratepayers would be provided with significantly improved plants and facilities. Therefore, while not directly related to the proposed corporate reorganization inclusive of the amalgamation, the BCUC found that the benefits associated with approval of the CPCN and the proposed corporate reorganization are significant and would have a long-term positive impact on ratepayers and the community surrounding the utility.

The BCUC did raise one issue in its report: Pacific Centre Limited (PCL) had initiated a BC Supreme Court proceeding against Creative Energy in which PCL sought to enforce a right of first purchase that it states it was granted in relation to the land where Creative Energy's existing steam plant is located. That issue has now been resolved; on April 30, 2020, PCL's application was dismissed.

RECOMMENDATION:

s.13

s.13

Honourable Bruce Ralston
Ministry of Energy, Mines and Petroleum Resources

June 8, 2020
Date

DRAFTED BY:
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APPROVED BY:
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Dave Nikolejsin, DM ✓

Date: June 4, 2020
CLIFF: 111332
XREF: 111121

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

BRIEFING NOTE FOR DECISION

PREPARED FOR: Honourable Bruce Ralston, Minister of Energy, Mines and Petroleum Resources

ISSUE: COVID-19 Relief and Stimulus Opportunities for the Oil and Gas Sector

BACKGROUND:

The Canadian oil and gas industry has been impacted by two major events in the last two months – the COVID-19 pandemic (which has disrupted operations and reduced global energy demand significantly) and a steep drop in oil prices as a result of competition for market share by Russia and Saudi Arabia. The Minister has formed a Joint Working Group with industry executives to discuss potential responses to these twin crises.

The BC portion of the Western Canadian Sedimentary Basin primarily produces natural gas. However, BC is exposed to the global oil market due to the importance of natural gas condensate as a high-value natural gas by-product. In recent years, many producers have focused on drilling wells that produce significant volumes of natural gas condensate to support their development economics. Condensate accounted for significantly more royalty revenue for the Province in 2019 than natural gas. The price of condensate is closely linked to the price of oil.

DISCUSSION:

Industry, through direct requests from companies and industry associations, and through the initial discussions of the Joint Working Group, has requested the Province consider a range of fiscal and regulatory interventions to preserve companies' cashflow and stave off bankruptcies.

Ministry of Energy, Mines and Petroleum Resources (the Ministry) analysis shows that s.13 [redacted]
s.13

s.13 [redacted] The Canadian Association of Petroleum Producers (CAPP) has indicated that, in the absence of government action, there will likely be reduced investment and production in BC.

In response to COVID-19, BC has rolled out a range of relief measures, including allowing the deferral of certain taxes to September 30, 2020, delaying the scheduled increase in the provincial

Carbon Tax by one year, extending the transitional provisions of the CleanBC Industrial Incentive Program by one year, and cutting the School Tax portion of property taxes for most commercial and industrial property classes by 50%. The federal government has also announced a series of relief measures, including the Canada Emergency Wage Subsidy to help firms retain employees through a payroll subsidy.

In addition to these broad measures, the provincial and federal governments have targeted support specifically to the oil and gas sector:

- On April 17, 2020 the federal government announced a package of fiscal measures to assist the oil and gas sector. These include providing up to $120M in funding to BC to clean up orphan and/or inactive oil and gas wells, providing up to $750M to create a new proposed Emissions Reduction Fund to reduce emissions in Canada's oil and gas sector (with a focus on methane), and expanding eligibility for the new Business Credit Availability Program.
- On May 13, 2020 the Province announced new programming that will support the clean-up of oil and gas sites in BC. This programming will utilize the $120 million in funding announced by the federal government on April 17 and will offset industry costs to meet their regulatory obligations.
- The Oil and Gas Commission (OGC) has taken some steps to provide relief to the sector, including deferring the payment due date for the 2019/20 annual Pipeline Liability Levy from 30 days to 90 days, postponing invoicing of the Orphan Liability Levy, and suspending the application timeline to extend a permit or authorization, which postpones expiry of a permit while the suspension is in effect.

s.13

This note itemizes all other relief or stimulus requests received from the oil and gas industry, to date, and the Ministry's current recommendations or commentary. Appendix A outlines industry-requested relief measures that the Ministry does not recommend, including the supporting rationale. Appendix B outlines requests for measures that require further consideration and/or Ministry analysis, including longer-term measures to support economic recovery and stimulus.

RECOMMENDATION:

s.13

CLIFF: 111322

Approved / Not Approved

Minister Ralston
Ministry of Energy, Mines and Petroleum Resources

June 05, 2020
Date

DRAFTED BY:
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APPROVED BY:
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Page 07 of 39 to/à Page 08 of 39

Withheld pursuant to/removed as

s.13 ; s.17

Date: June 1, 2020
CLIFF: 111366

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

BRIEFING NOTE FOR INFORMATION

PREPARED FOR: Honourable Bruce Ralston, Minister of Energy, Mines and Petroleum Resources

ISSUE: Compliance mechanisms under British Columbia's Low Carbon Fuel Standard

BACKGROUND:

The *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* and the Renewable and Low Carbon Fuel Requirements Regulation, known collectively as British Columbia's Low Carbon Fuel Standard (BC-LCFS), is part of a strategic approach introduced in 2008 to reduce British Columbia's (BC) reliance on non-renewable fuels, reduce the environmental impact of transportation fuels, and spur growth in the low carbon fuel industry in BC. The BC-LCFS policy is a market intervention tactic critical to achieving the Province's greenhouse gas reduction targets.

The BC-LCFS sets increasingly stringent carbon intensity reduction targets each year, which forces fuel suppliers to progressively decrease the average carbon intensity of the fuels they supply in BC. Supplying higher carbon intensity fuels, such as fossil-based gasoline and diesel, incurs debits while supplying lower carbon intensity fuels, such as hydroelectricity or biodiesel, generates credits. To achieve compliance, fuel suppliers must generate or acquire enough credits to offset their debits for a given compliance period. Credits do not expire and can be traded or banked for future compliance periods.

There are seven suppliers of gasoline and diesel in BC that need credits to offset their debit obligations. These suppliers typically generate credits by blending renewable liquid fuels – ethanol, biodiesel, and renewable diesel – into gasoline and diesel. This compliance pathway becomes increasingly expensive as the renewable content increases and suppliers face both real and perceived limits to further blending.

There are also more than forty low carbon fuel suppliers that generate credits only, including several large suppliers of natural gas, electricity, and propane. These suppliers do not create debits and can therefore sell their credits in the credit market.

There are three primary mechanisms for fuel suppliers to acquire credits for compliance or generate revenue:

- Supply low carbon fuels;
- Purchase credits from other fuel suppliers; and
- Enter into Part 3 Agreements.

<u>Supply low carbon fuels</u>
Credits are generated from the supply of lower carbon fuels, such as ethanol, biodiesel, hydrogenation-derived renewable diesel, electricity, hydrogen, liquified natural gas, compressed natural gas (CNG), and propane. The quantity of credits generated is proportional to the magnitude of carbon intensity reductions realized from the supply of the low carbon fuel relative to the prescribed carbon intensity

target in that compliance period. For example, a kilogram of fossil-based CNG will generate fewer credits than a kilogram of renewable-based CNG, which has a lower carbon intensity.

Purchase credits

Fuel suppliers can buy and sell credits in the credit market. Typically, low carbon fuel suppliers sell their credits to the seven major suppliers that incur debits. In the past twelve months, approximately 245,000 credits were sold at an average price of $283 per credit.

Part 3 Agreements

Fuel suppliers can obtain credits by entering into a Part 3 Agreement to undertake actions that increase the use of low carbon fuels sooner than would occur without the agreed-upon action. The number of credits allocated in an agreement is usually related to the expected capital expenditure of the project. Many agreements are not directly related to carbon intensity reductions because they reward actions that are required to enable the supply of fuel. All projects must have a reasonable possibility of reducing the amount of CO_2e emissions resulting from the use of Part 3 fuels. To ensure that it is clear that Part 3 Agreements are intended to provide extra incentive to implement an action, the statutory director is authorized to issue credits for actions in which the resulting fuel supply will also generate credits. Total credits under each year's Part 3 Agreements are limited to twenty-five percent of the previous year's total debits. Part 3 Agreements to-date have led to fuel supplier commitments to invest over $450 million in eligible projects and initiatives (See Appendix A).

DISCUSSION:

Beginning July 1, 2013, the BC-LCFS set increasingly stringent annual carbon intensity reduction targets that require significant behavioural changes by both the major fuel suppliers and the low carbon fuel suppliers. Each compliance mechanism by itself cannot be expected to generate enough carbon intensity reductions to achieve the reduction targets. Conventional low carbon fuel supply, such as ethanol blended in gasoline, is limited by cost as well as real and perceived technical and logistical barriers. Other low carbon fuels, such as electricity, hydrogen, and renewable natural gas, currently lack sufficient demand because their consumption relies on the adoption of new vehicle technologies. Overall, fuel suppliers are facing a credit shortfall and a resulting steady increase in the price of credits, which tends to be passed on as an increase in consumer fuel prices.

The fuel supply industry is capital-intensive with high barriers to entry, leading to slow adoption, adaptation and change. Most opportunities to produce low carbon fuel in BC will rely on first-of-a-kind technologies and business plans. Investors perceive significant risks in this emerging bio-economy, including risks dealing with feedstock, technology, plant construction, markets and regulations/ government policies. These risks, in combination with events or conditions (e.g. a pandemic, oil market collapse, credit crisis, rising costs, natural disasters, etc.) that slow down the growth of an economy make it challenging for most investors to justify investments in transformative projects to produce new bio-products.

Industry experts and stakeholders have identified that the provision of up-front financial support through Part 3 Agreements can be critical in mitigating risk.

The subject matter experts that are the sources of most innovative bio-technologies are chronically short of funding. As a result, the ability to obtain and monetize credits while a facility is being constructed, but before it is commissioned, may be especially important for the smaller companies, in the absence of alternative provincial or federal funding programs for emergent technology. Part 3 Agreements are also a strong signal that there is government support for the project, reassuring the project proponent as well as the investment community that government agrees with the developer on the benefits of successful project completion.

Healthy credit prices make Part 3 Agreements attractive to investors and encourage investment in BC. In California, it is not possible to generate credits until after a plant is commissioned, which poses a heavy financial burden on smaller companies in the interim. While capital can be abundant in global markets, most of this capital is highly risk-averse. The technology and market risk associated with upfront support in financing the development of advanced biofuels and low carbon fuel plants is critical because they are generally capital intensive. Part 3 Agreements are an effective tool for providing this support because it ensures the capital spending is focused on directly supporting the Government's objectives.

Part 3 Agreements were introduced as a strategic approach to help overcome these barriers and accelerate market transformation. Projects already supported through Part 3 Agreements enable reductions through the increased supply of low carbon fuels and have already led to significant investment to transform the BC fuel market without the use of taxpayer dollars. Part 3 Agreements have supported private investment in new fuels and blends that have high market risks. Fuel suppliers have confirmed that Part 3 Agreement support helps mitigate the perceived risks and ensure that there is an internal corporate focus on the need for these projects. Market risks include the high cost of the infrastructure needed to offer these new products to consumers, the uncertainty in demand for these new products, and the risk that the new infrastructure becomes a stranded asset. Part 3 Agreements play a central role in creating new, long-term compliance pathways while the twenty-five percent credit limit ensures that the carbon intensity reduction requirements are not unnecessarily weakened.

The Part 3 Agreement program has succeeded in accelerating market transformation in the BC fuel market. It has been critical to suppliers for mitigating project risk and has led to actions occurring sooner than they would have without the support. For example, a Part 3 Agreement with Chevron Canada Limited supported a significant upgrade at the largest fuel storage and distribution terminal on Vancouver Island to enable ethanol blending. Due to the Part 3 Agreement, the supplier was able to overcome the logistical constraints associated with fuel delivery to Vancouver Island more than five years before they would have implemented the upgrade in the absence of support.

In many cases, major initiatives would not have occurred at all without the support of Part 3 Agreements. This is the case for the co-processing Part 3 Agreement undertaken by Parkland Refining (BC) Ltd. Co-processing refers to the conversion of biogenic feedstocks at existing petroleum refineries to produce renewable gasoline and diesel. Part 3 Agreement support was crucial in helping to mitigate the large upfront capital costs and the financial risks associated with using renewable feedstocks in existing refinery equipment. This unprecedented initiative has been so successful that the Canadian Fuels Association is now looking at co-processing at refineries across Canada as a major compliance pathway for the federal Clean Fuel Standard. Moreover, Parkland Refining (BC) Ltd. is now exploring the potential to use made-in-BC feedstocks, such as tall oil and waste sewage sludge, for co-processing at their Burnaby refinery and is anticipating investing more than $300 million in the initiative over the next five years.

Despite the slowdown in overall economic activity as a result of the COVID-19 pandemic, fuel suppliers have indicated that Part 3 Agreements will continue to incent investment in low carbon fuels, further demonstrating their effectiveness at advancing market transformation and importance in mitigating risk and uncertainty. New projects being considered for support this year include an agreement with the

s.21

Ministry staff are actively reviewing Part 3 Agreement policy to improve the program's rigour, equity, effectiveness, and transparency. An improved program structure is being developed that will strengthen the competitiveness of the application process while ensuring that reductions are achieved at the lowest possible cost, thus minimizing pricing impacts to consumers. Ministry staff are also developing new application protocols for projects, to leverage the success of past projects and spur additional investment in low carbon fuels.

s.13

Attachment: Appendix A - Projects supported under Part 3 Agreements

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APPENDIX A – Projects supported under Part 3 Agreements

The following table lists the projects supported under Part 3 Agreements, identifies the supplier associated with the project, and the estimated project budget where applicable. Some projects do not have an estimated budget because credit support was informed from either the expected emissions reductions enabled through the completion of the project or similar projects already underway or completed by other suppliers. Many of these agreements include the Ministry's intent to enter into further agreements to support multi-year projects until they are complete.

Project	**Year(s)**	**Status**	**Part 3 fuel supplier(s)**	**Initial Budget Estimate (millions)**
Infrastructure upgrades to enable the transfer of ethanol from marine transport for blending and distribution	2014	Complete	Suncor	s.21
Deployment of B100 biodiesel infrastructure	2014	*Cancelled*	s.21	*N/A*
Infrastructure upgrades to enable the supply of ethanol-blended gasoline to Vancouver Island	2014 - 2015	Complete	Chevron	s.21
Scrap-It incentive for the replacement of an older internal combustion engine vehicle with an electric vehicle or a hydrogen fuel cell vehicle	2014 - 2019	Underway	Shell	
Testing bio-oil for compatibility with refinery infrastructure to produce conventional gasoline and diesel with renewable content	2015	Complete	Chevron	*N/A*
Development and deployment of new fuel technology to produce renewable diesel	2015	*Cancelled*	s.21	*N/A*
s.21				*N/A*
Fuel switching: Use of renewable natural gas rather than conventional natural gas to manufacture petroleum gasoline and diesel	2015 - 2019	Underway	Parkland Refining	*N/A*
Construction and operation of hydrogen fuelling infrastructure and the production of low carbon intensity hydrogen	2015 - 2019	Underway	Hydrogen Technology & Energy Corporation	s.21
Testing and production of conventional gasoline and diesel with co-processed renewable content	2016 - 2019	Underway	Parkland Refining	
Deployment of mid-level biodiesel blends (B20)	2016 - 2019	Underway	Parkland Refining	*N/A*

Deployment of mid-level ethanol blends (E15) at retail locations	2017	*Cancelled*	s.21	*N/A*
Testing and supply of biodiesel blends in winter operability zones	2017 - 2019	Underway	Husky	s.21
Testing and supply of biodiesel blends in winter operability zones	2017 - 2019	Underway	Federated Co-operatives Limited	
Testing and supply of biodiesel blends in winter operability zones	2017 - 2019	Underway	Elbow River Marketing	
Deployment of high-level ethanol blends (E85) at a retail location	2017 - 2019	Underway	Federated Co-operatives Limited	
Installation of fuelling infrastructure and supply of mid-level biodiesel blends (B20)	2017 - 2019	Underway	Cowichan Bio-Diesel Co-op	
Installation of electric vehicle charging infrastructure	2018 - 2019	Underway	BC Hydro	
Installation of storage and distribution infrastructure, and supply of E85 and HDRD	2018 - 2019	Underway	Federated Co-operatives Limited	
Co-processing testing and support at refinery	2018 - 2019	Underway	Husky / Tidewater Midstream	
Testing and production of conventional gasoline and diesel with co-processed renewable content from woody biomass	2018 - 2019	Underway	Imperial Oil	
Testing and production of conventional gasoline and diesel with co-processed second generation biocrude (from tall oil and sewage sludge)	2018 - 2019	Underway	Parkland Refining	
Construction of a retail site offering hydrogen refuelling and electric vehicle charging	2018 - 2019	Underway	Shell	*N/A*
Providing households with rebates for purchase of level-2 electric vehicle chargers (ZAPBC)	2018 - 2019	Underway	Shell	s.21
Feasibility study of an HDRD production facility	2018 - 2019	Underway	s.21	
Delivering E10 to s.21 fuel terminal	2018 - 2019	Underway		
Installing and supporting public level 3 fast chargers for electric vehicles	2018 - 2019	Underway	Suncor	s.21
Total investment (reported from 18 of 23 completed or underway projects)				**$454.6**

† http://www.parklandcap.ca/wp/wp-content/uploads/2019/03/Parkland-News-SPR19web.pdf

Date: June 10, 2020
CLIFF: 111369

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

BRIEFING NOTE FOR INFORMATION

PREPARED FOR: Honourable Bruce Ralston, Minister of Energy, Mines and Petroleum Resources

ISSUE: Federal Clean Fuel Standard development delayed due to COVID-19

BACKGROUND:

Environment and Climate Change Canada (ECCC) has been consulting on the development of a federal Clean Fuel Standard (CFS) since November 2016. The CFS will be implemented in stages over 2022 to 2023, with the objective of reducing annual greenhouse gas (GHG) emissions by up to 30 million tonnes by 2030.

The CFS will cover all fossil fuel use in Canada. Regulations will be grouped into three categories, liquid fuels, solid fuels and gaseous fuels. The liquid fuels regulations are being developed first and are scheduled to come into force in 2022, with implementation of the solid and gaseous fuels regulations to follow in 2023.

The proposed regulation for liquid fuels was initially scheduled to be published in *Canada Gazette I* in June 2020. Delays due to COVID-19 have pushed this expected date back to Fall 2020. A 75-day comment period will follow the publication of the proposed regulations. The CFS regulations for liquid fuels are now expected to come into force in mid-2022, with the regulations for solid and gaseous fuels to follow in 2023, although specific dates are not yet indicated in ECCC materials.

DISCUSSION:

The Ministry of Energy, Mines and Petroleum Resources (EMPR) has participated in extensive CFS consultations since their start in 2016. Michael Rensing, Director of Low Carbon Fuels, has been involved due to his experience developing, implementing and administering the BC Renewable and Low Carbon Fuel Requirements Regulation (BC-LCFS) since 2010. He and his staff continue to participate in consultations and to monitor the progress of the CFS.

The CFS regulations for liquid fuels share many principles with the BC-LCFS. The CFS takes a lifecycle approach, and it is anticipated that in order to achieve the 30 million tonnes of reductions, the regulations will require the carbon intensity of liquid fuels to be reduced by 10-12% by 2030. In comparison, by 2030 the BC-LCFS will require a 20% reduction in carbon intensity.

s.16

As the BC-LCFS has created a well-established, high value market for low carbon fuel credits, fuel suppliers may tend to supply their low carbon fuels to the BC market in order to receive both CFS and BC-LCFS value for their products, and to meet the increasing stringency of the BC-LCFS.

Unlike the BC-LCFS, ECCC intends to award credits for GHG reductions throughout the fossil fuel supply chain. Whereas low carbon renewable fuels must be consumed within Canada to generate CFS credits, credits for fossil fuel improvements upstream (e.g., carbon capture, enhanced oil recovery, methane reductions, electrification) and downstream (e.g., carbon capture, co-generation, and co-processing of biocrudes) can be used for compliance even if the product is exported.

Canadian fossil fuel producers export a significant amount of their product and will retain the CFS credits created by these fuels under the current proposed regulations. This allows oil producing and refining companies to generate a large number of CFS credits without the use of low carbon renewable fuels.

As currently proposed by the CFS, co-processing of renewable feedstocks in fossil fuel refineries is considered as a refinery improvement, rather than the production of a biofuel. Therefore, the CFS creates an advantage for co-processed fuels over pure biofuels, as there is no requirement under the CFS for where or how the co-processed fuels must be used in order to generate credits.

Subtle changes in wording on the CFS website over the course of its development indicate that ECCC may be shifting the focus of the regulations from the original intention of incenting a broad range of lower carbon fuels, towards incenting innovation and adoption of clean technologies in the oil and gas sector. s.16

s.16

CONCLUSION:

The development of the CFS has been delayed by up to 6 months due to COVID-19. It is still uncertain whether this will affect the implementation date of the regulations expected in 2022. The Low Carbon Fuels Branch of EMPR continues to be involved in consultations and to monitor the ongoing development of the CFS and its implications for BC.

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MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

BRIEFING NOTE FOR INFORMATION

PREPARED FOR: Honourable Bruce Ralston, Minister of Energy, Mines and Petroleum Resources

ISSUE: Small Modular Reactor Roadmap for Nuclear Power

BACKGROUND:

Natural Resources Canada, Alberta, Saskatchewan, Ontario, New Brunswick, the Northwest Territories and Nunavut developed a *Small Modular Reactor (SMR) Roadmap* to meet the *Pan-Canadian Framework on Clean Growth and Climate Change* objectives to reduce emissions from electricity generation and encourage electrification. The *SMR Roadmap* aims to foster innovation and establish a long-term vision for the nuclear industry, to assess the characteristics of different SMR technologies, and examine their alignment with Canadians' requirements and priorities.

SMR designs being investigated by the Canadian Nuclear Safety Commission have design capacities between 3 and 300 Megawatts (MW), compared to a capacity range of 500 – 900 MW for conventional reactors in Canada, and the world's largest nuclear plant, the 7,965 MW Kashiwazaki-Kariwa plant in Japan. SMRs work using the same principles as conventional nuclear fission reactors. A fission reactor creates a self-sustained nuclear chain reaction of a fissile fuel (i.e. Uranium-235 or Plutonium-239) which causes the fuel's nuclei to split into lighter elements and to release energy. The energy converts to heat within the reactor, which is removed by a fluid or gas coolant. A steam turbine is commonly used to convert the thermal energy into electricity.

SMRs are smaller designs in which the reactor vessel is manufactured in a plant rather than on-site. These reactor designs have been proposed to allow these reactors to be deployed in a larger variety of settings and to overcome the financial and safety barriers associated with conventional reactors. The main applications in Canada are: on-grid power in provinces phasing out coal power generation; off-grid combined heat and power for heavy industry; power and district heating for off-grid communities; and desalination in remote communities.

As part of the CleanBC Plan, the Province and BC Hydro are undertaking numerous programs to promote electrification and reduce emissions. British Columbia (BC)'s *Clean Energy Act* (CEA) has an objective "to achieve British Columbia's energy objectives without the use of nuclear power." This currently precludes the deployment of SMRs within BC. BC Hydro exceeds the CEA requirement and generates electricity that is 98% clean. BC Hydro is currently forecast to have an electricity surplus into the mid-late 2030s and is not currently seeking any additional supply of grid-connected electricity.

Another form of nuclear energy currently under development is fusion technology. It is important to distinguish between fission and fusion nuclear processes. While fission releases energy by splitting atoms, fusion generates large amounts of energy by fusing small atoms into larger ones (i.e., the process in stars). Commercialization of fusion technology would significantly transform the world's energy and industrial heat generation. Fusion energy is anticipated to be able to deliver clean, safe and on-demand power at industrial scale, providing firm, baseload power without radioactive waste.

A commercial fusion power plant would compete favourably with all other energy generation technologies, dispatchable or otherwise, producing energy at a lower cost than most fossil fuel and renewable energy sources. One kilogram of hydrogen fuel converted by fusion technology would provide enough power for approximately 10,000 homes for one year (equal to 100,000 MWh). The equivalent amount of energy would require 55,000 barrels of oil (or 10,000 tons of coal), which would also produce 23,628 tonnes of CO2e.

At this point, fusion technology is still at an early stage of development and significant technological hurdles remain. Amidst a global race to develop fusion energy, General Fusion, a Burnaby BC based company, is seeking to develop the first commercially-viable fusion power plant, using magnetized target fusion. This involves creating and manipulating a vortex and magnetically-confined plasma fuel to create fusion conditions. Heat from the fusion reaction is captured and used to generate emissions free electricity via a steam turbine.

DISCUSSION:

Putting aside the CEA prohibition on using nuclear energy in BC, there are limited opportunities for SMRs in BC and there would likely be significant concerns regarding deployment. BC Hydro's current and forecast surplus is expected until the 2030's. When additional energy is needed in the future, BC has significant additional untapped clean energy resources such as wind, solar and geothermal energy that could be developed. BC Hydro's current Integrated Resource Plan will be focusing on how to meet CleanBC goals through electrification using the forecast electricity surplus. New generation options will not be a focus.

If commercialized, SMRs could address appropriate loads that are not connected into the provincial energy grid such as mining operations or remote communities, or to support the transmission grid by generating closer to loads in the future. However, the current business case for SMRs is not attractive. Only with broad development and deployment of SMRs are capital costs expected to fall to be comparable or less than conventional nuclear reactors[1]. In addition, the operating costs of SMRs are expected to be higher than those for conventional large reactors on a unit energy basis. SMR plants are likely to have similar fixed costs and not benefit from the economies of scale achieved by large plants.

Opposition and concerns with respect to SMRs are likely to be similar to conventional nuclear reactors focusing on safety and waste. Many proposed SMR designs use passive cooling systems to increase the safety and decrease the risk of runaway nuclear chain-reactions that can

[1] Small modular reactors: Can building nuclear power become more cost-effective, March 2016. Ernst & Young LLP. Accessed June 3, 2020: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/665300/TEA_Projects_5-7_-_SMR_Cost_Reduction_Study.pdf

melt the reactor core. In addition, some designs are considering reactor designs that would reduce the amount of waste material produced. Regardless, it is likely there will be concerns regarding safety and the storage of spent nuclear fuel to be address before deployment of SMR in BC. Each SMR design will need to be evaluated for these considerations.

MINISTRY RESPONSE:

Staff from the Ministry of Energy, Mines and Petroleum Resources will continue to participate in Federal-Provincial-Territorial collaboration on energy technologies and will monitor the activities of the SMR Roadmap and technological development of SMRs. The focus of CleanBC is to transform BC's economy by reducing greenhouse gas emissions to meet the province's climate commitments, while supporting affordability for people. BC is forecast to have an electricity surplus into the 2030's. The province of BC continues to invest in promising new energy technologies, clean technology and solutions through the Innovative Clean Energy Fund.

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Innovative Clean Energy Fund

APPROVED BY:
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Fazil Mihlar, DM ✓

Date: June 10, 2020
CLIFF: 111386

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

BRIEFING NOTE FOR DECISION

PREPARED FOR: Honourable Bruce Ralston, Minister of Energy, Mines and Petroleum Resources

ISSUE: Inclusion of Demand Response Standards in Amendment 7 of the Energy Efficiency Standards Regulation

BACKGROUND:

The Ministry prepared amendments to the Energy Efficiency Standards Regulation (EESR) to support CleanBC in late 2019/20. The proposed Amendment 7 to the EESR includes new and updated standards for residential windows, residential gas boilers, commercial gas boilers, computers and monitors, and several regulatory upkeep changes that have been requested by stakeholders. To reduce new regulatory impacts during the COVID-19 pandemic, Amendment 7 has been put on hold until fall 2020. This delay provides an opportunity to include additional equipment standards in Amendment 7 to support behind the meter opportunities articulated in the BC Hydro Comprehensive Review Phase 2.

Increasing electrification to meet CleanBC goals will require new grid infrastructure. The cost of this infrastructure (paid ultimately by ratepayers), as well as the associated environmental impacts, can be reduced by shifting demand to times when the system has more capacity to provide service. One method for prompting this shift in homes is through voluntary time-of-use rates. Another is through direct load control (DLC)—where customers can receive a reduction in their bill in exchange for letting the utility manage their non-essential loads such as water heaters. Both measures are known as ‘demand response.’ Direct load control provides more certainty than responses to time-of-use rates, and more capacity savings, particularly during peak times.

The BC Hydro Comprehensive Review Advisory Committee has recommended pursuing options to enable DLC. Good candidates for residential load control include water heaters (because the tank holds enough hot water to last a few hours without power) and electric vehicle charging (because charging can usually be delayed from the high demand evening period to the low demand nighttime period). Water heaters present a modest opportunity that is ready for development. Electric vehicle (EV) charging presents a significant opportunity but requires market transformation prior to development.

DISCUSSION:

In 2019, an alliance of utilities and other organizations from the US Pacific Northwest developed a roadmap for DLC. The standardization of hardware and communication protocols was identified as a key part of enabling cost-effective DLC. For a utility to control an appliance such as a water heater, they need to ‘speak the same language.’ A standardized communication protocol titled CTA-2045 was developed as this ‘common language.’ It can be used for residential electric storage tank water heaters as well as other behind the meter equipment such as EV charging stations and thermostats.

The CTA-2045 communication interface is comparable to a USB socket, but designed specifically for household appliances. The CTA-2045 plug integrates into an appliance's control board. An appliance with a CTA-2045 interface is then *easily convertible* into a demand response capable appliance. A communication device, supplied separately, must be plugged into the CTA-2045 interface to create a demand response appliance. This approach allows appliances to be sold as "easily convertible units" without significant incremental costs or privacy impacts. Homeowners who don't want to participate simply don't plug in the communication device.

In a classic chicken-or-egg problem, manufacturers won't develop or sell CTA-2045 compliant products unless there is a demand for them via utility DLC programs, yet it is not worthwhile for utilities to set up DLC programs unless there are sufficient demand response capable water heaters installed. Setting a regulatory requirement that all electric storage tank water heaters sold must meet the communications protocol will jumpstart this process. As appliances are replaced at the end of their service life, new, easily convertible demand response units will be installed. The sooner a standard is put in place, the larger the available pool of potential participants will be and the larger the 'resource potential' to utilities.

Electric Storage Tank Water Heaters

A DLC electric storage tank water heaters (EWH) initiative is underway in the Pacific Northwest. Washington State has passed legislation requiring all EWHs sold after January 1, 2022 to be equipped with a CTA-2045 communications port and has canvassed British Columbia (B.C.) and other jurisdictions to follow suit. If B.C. were to adopt a similar regulation, it would align with Pacific Coast Collaborative objectives, as well as the Clean Grid Initiative with Washington, and send a clear signal to manufacturers to provide a greater range of compliant products.

The CTA-2045 communications port is a low-cost addition to a standard EWH (about $20). Staff have done a preliminary cost-benefit analysis for a regulation (see Appendix). The analysis shows a resource potential of 148 Megawatt (MW) by 2050. The regulation would have a cost burden in the near term, but significant benefits in the long term. The net present value will become positive in the mid-2030s and will increase to about $100 million by 2050. However, unlike most energy efficiency regulations where both costs and benefits accrue to anyone buying a compliant product, in this case the benefits would accrue only to those who choose to participate in DLC programs, and to ratepayers (through reduced electricity system costs).

Introducing a standard for water heaters would also provide a learning opportunity for utilities; allowing them to launch and perfect DLC programs in advance of the larger-scale opportunity with EV charging.

A DLC standard for EWHs could be introduced in Amendment 7 of the EESR, with an effective date aligned with Washington State. This would require an expedited stakeholder consultation and would delay Amendment 7 until early 2021. The effects of the delay will be decreased electricity savings from the computers and monitors standard, reduced regulatory transition time for window and boiler manufacturers, and a delay of stakeholder-requested housekeeping updates.

Alternatively, introduction of a DLC standard for EWHs could be included in Amendment 8, scheduled for 2023. Although the long-term benefits from a later DLC EWH standard would be similar, it would reduce alignment with Washington State and reduce the 'early learning' benefits for future EV DLC programs. It would also be a lost opportunity to act immediately on a key BC Hydro Comprehensive Review Phase 2 action.

Electric Vehicle Charging

BC Hydro recently completed a demand response pilot on EV charging equipment. The pilot demonstrated that EVs have a very high impact on peak demand but can be managed with a DLC program. Both the individual loads and the total number of devices are significantly larger for EVs than for EWH. The report estimates that electrification of all light-duty vehicles with home-based charging could add an additional peak load as high as 3,000 MW. The technology profile indicates that EV charging demand response technology is in its infancy, with limited commercially viable options and limited uptake of open communication standards. For this reason, staff recommend introducing regulations on a slower timeline than for water heaters.

OPTIONS:

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RECOMMENDATION:

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Approved / Not Approved

___________________________ June 23, 2020 _______________

Bruce Ralston, Minister
Ministry of Energy, Mines and Petroleum Resources

Date

DRAFTED BY:
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Energy Efficiency Standards Engineer
Energy Efficiency Branch

APPROVED BY:
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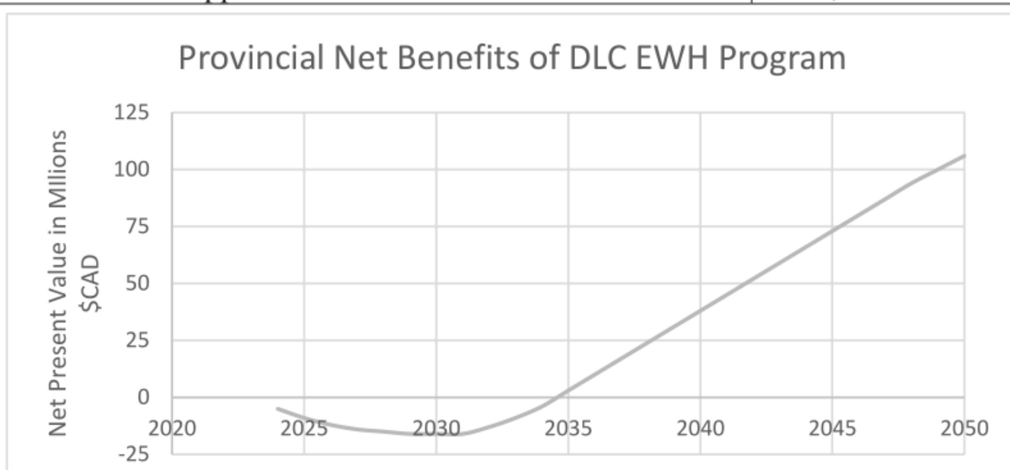
Appendix

Summary of cost-benefit analysis for regulation requiring CTA-2045 in all new and replacement residential electric storage water heaters

Total Resource Potential	
DLC EWH Regulation Effective Date	January 1, 2022[1]
Total Resource Potential by 2035	310 MW
Total Resource Potential by 2050	560 MW
Program Resource	
Program Start	January 1, 2024[2]
Program Participation Rate	26.5%[3]
Resource Potential by Participation by 2035	80 MW for 1-3 hrs.
Resource Potential by Participation by 2050	148 MW for 1-3 hrs.
Program Benefits[4]	
Avoided cost of distribution capacity 2024-2050	$25/kw-yr.
Avoided cost of distribution capacity 2032-2050	$75/kw-yr.
Avoided cost of generation capacity 2024-2050	$60/kw-yr.
Avoided cost of generation capacity 2032-2050	$123/kw-yr.
Program Costs[3]	
CTA-2045 Port on EWH	$20/EWH
Communication Module	$95 to $15
Program Marketing	$150 to $25
Program Administration	$1,000,000 per year
Manufacturer Support	$500,000



[1] Assumption based on alignment with Washington State regulation.
[2] Assumption based on a sufficient pool of water heaters available.
[3] Program participation rates and costs from CTA-2045 Water Heater Demonstration Report, Bonneville Power Administration: https://www.bpa.gov/EE/Technology/demand-response/Documents/Demand%20Response%20-%20FINAL%20REPORT%20110918.pdf
[4] Marginal cost data obtained from BC Hydro Fleet Electrification Rate Application: https://www.bcuc.com/Documents/Proceedings/2019/DOC_55145_B-1-BCH-Fleet-Electrification-Rate-Appl.pdf

Date: June 11, 2020
CLIFF: 111431

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

BRIEFING NOTE FOR INFORMATION

PREPARED FOR: Honouable Bruce Ralston, Minister of Energy, Mines and Petroleum Resources

ISSUE: Meeting with Ian Anderson, President and CEO of Trans Mountain Corporation for an update on the Trans Mountain Expansion Project

BACKGROUND:

The Trans Mountain Expansion Project (TMEP), an interprovincial, federally regulated pipeline project under the Canadian Energy Regulatory (CER), will twin the existing 1150 kilometre (km) pipeline within the existing right-of-way, where possible, from Edmonton to Vancouver. The existing pipeline has a sustainable capacity of 300,000 barrels per day (bbl/d) and the new pipeline will have a sustainable capacity of 590,000 bbl/d.

TMEP was initially approved by the Governor-in-Council (GIC) in November 2016 and again in June 2019 after the Federal Court of Appeal (FCA)[1] quashed the federal approval in August 2018 citing inadequate consultation by Canada with Indigenous peoples and failure by CER to fully consider marine impacts.

On February 4, 2020 the FCA[2] rejected the applications from four Indigenous groups who sought judicial review of the June 2019 GIC decision to issue the Certificate of Public Convenience and Necessity for TMEP concluding that Canada's decision was reasonable and that federal approvals for TMEP continue to be valid. The FCA further elaborated on specific consultation concerns such as meaningful consultation, obligation of participants, and that Indigenous groups cannot tactically use the consultation process to try to obtain a *de facto* veto.

Trans Mountain Corporation (TMC) received its British Columbia (B.C.) Environmental Assessment Certificate in January 2017.

On April 6, 2017 B.C. signed an Agreement with Kinder Morgan that provides for revenue sharing; and the establishment of a project office and manager to work with line agencies to facilitate a timely and efficient regulatory and decision-making process for all provincial regulatory matters related to TMEP or the Mainline System (existing pipeline).

DISCUSSION:

TMEP is organized into 7 spreads (Attachment 1 – map). Spreads 1 and 2 are in Alberta, with Spreads 3 to 7 in B.C. Spreads 6 and 7 are in the Lower Mainland, and spread 7 includes the Burnaby Terminal, Burnaby Mountain Tunnel and Westridge Marine Terminal.

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[1] *Tsleil-Waututh et al. v Attorney General of Canada et al.*, 2018 FCA 153
[2] *Coldwater et al v. Canada (Attorney General),* 2020 FCA 34

TMEP requires provincial permits from Ministry of Forests, Lands, Natural Resource Operations and Rural Development; Ministry of Environment and Climate Change Strategy (including B.C. Parks); Ministry of Transportation and Infrastructure; the BC Oil and Gas Commission; and the Agricultural Land Commission. As of June 8, 2020, TMEP requires 1524 provincial permits of which 726 have been issued, 533 are in review and 265 have not yet been submitted by TMC.

At this point, provincial permits are the most significant component for TMEP to proceed on time and on schedule. Many of the provincial permits required relate to construction on the TMEP critical path, meaning that delays will have the direct effect of delaying the TMEP in-service date. Other permits, if delayed will cause construction cost increases as contractors develop less efficient schedules to work around permits not issued in accordance with ordinary service standards. A single delayed permit can lead to significant construction work around costs and time delays.

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COVID-19 and the resultant declarations of emergencies, nationally and provincially, have created additional elements of uncertainty and concern affecting provincial permitting and First Nations consultation related to TMEP. First Nations have raised concerns over transient workers on construction sites across B.C. (including TMEP) and the spreading of viruses. TMC has released its protocols for COVID-19 and stated that the company and its construction contractors are following all advice from government and health officials while maintaining the uninterrupted operation of the pipeline and the safe construction of TMEP.

Permitting agencies are aware of TMC's 2020 construction schedule that is targeting a mechanical completion date of 2022 with planned construction starts for the following:

- Contractors are completing pre-construction checks for utilities, surveying and flagging in all spreads, and in June 2020 TMC initiated mobilization for spreads 3 and 4;
- Valemont work camp is under construction, early works are proceeding at some pump stations and temporary infrastructure sites;
- Kingsvale Transmission Line (near Merritt B.C.) – construction in progress; and
- Kamloops Urban Area Project. Permitting is on track. June 1, 2020 TMC publicly announced construction preparation has begun; will take about seven months to complete, bringing economic benefits to the region (Attachment 2 – New Release).

The construction schedule consists of multiple special projects in the Nlaka'pamux Nation Tribal Council (NNTC) and S'ólh Téméxw Stewardship Alliance (STSA) territory. While consultation with most First Nations potentially impacted by TMEP has followed the "Haida" model, TMC and B.C. have established working arrangements with NNTC and STSA. Ministry analysis indicates that about 40 percent of permit applications are in NNTC and STSA consultation areas.

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MINISTRY RESPONSE:

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Attachments:
Attachment 1 – Map
Attachment 2 – TMC News Release – Kamloops Urban Area Project

DRAFTED BY:	**APPROVED BY:**
Olga Klimko, Director	Julie Chace, Executive Director✓
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Attachment 1- Map

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*This map shows the approximate location of the PPBoR sheets that have been approved by the Board. Approval of all pre-construction conditions may still be outstanding. Check the Board's website for most current information. † No PPBoR's for the reactivation segments. Map produced by the NEB, April 2018. The map is a graphical representation intended for general informational purposes only.

Attachment 2 – TMC News Release – Kamloops Urban Area Project

Trans Mountain Expansion Starts Work in Kamloops

https://www.transmountain.com/news/2020/trans-mountain-expansion-starts-work-in-kamloops

Jun 1, 2020

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Date: June 16, 2020
CLIFF: 111496

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

BRIEFING NOTE FOR DECISION

PREPARED FOR: Honourable Bruce Ralston, Minister of Energy Mines and Petroleum Resources

ISSUE: Fuel Price Transparency Act Regulation

BACKGROUND:

The *Fuel Price Transparency Act* (the Act) was brought into force on March 9, 2020. On that date, the BC Utilities Commission (BCUC) was named Administrator of the Act. As the Administrator, the BCUC is be responsible for collecting and publishing information about the gasoline and diesel market in British Columbia (BC). The BCUC has launched a website to provide the public with more information about the Act, the role of the Administrator, and the components that influence fuel prices in BC. This site uses information gathered during the 2019 BCUC inquiry into the fuel market and public source data.

Work is underway to develop a regulation under the Act that would require companies active in the gasoline and diesel markets to provide regular reports to the BCUC. s.13
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Consultations with industry on the proposed regulations were conduced between May 25th and June 15th.

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DISCUSSION:

Consultation Feedback

The paper published to support consultation on the regulation proposed a range of data elements to be collected across the fuel supply chain from refining, through transportation and storage, to retail. Feedback was sought from industry on the proposed scope of data to be collected as well as the practicalities of implementing the reporting system under consideration. This involved telephone interviews with companies that had participated in the BCUC inquiry in 2019 as well as the solicitation of detailed written comments.

Several themes have emerged based on the interviews and initial review of the detailed written comments.

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______________________________ July 7, 2020 ______________
Minister Ralston Date
Ministry of Energy, Mines and Petroleum Resources

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______________________________ July 7, 2020 ______________
Minister Ralston Date
Ministry of Energy, Mines and Petroleum Resources

DRAFTED BY:
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Date: June 22, 2020
CLIFF: 111521

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

BRIEFING NOTE FOR DECISION

PREPARED FOR: Honourable Bruce Ralston, Minister of Energy, Mines and Petroleum Resources.

ISSUE: Modifications to the CleanBC Go Electric Hydrogen Fuelling and Fleet Program

BACKGROUND:

The CleanBC Go Electric Hydrogen Fuelling and Fleet Program (the Program) introduced financial support for British Columbia (B.C.) fleets to purchase hydrogen fuel cell electric vehicles (FCEVs) in February 2019. The Program has a budget of $1.1 million (M) and is delivered on behalf of the Ministry of Energy, Mines and Petroleum Resources (the Ministry) by the Canadian Hydrogen and Fuel Cell Association (CHFCA). The intention of the fleet rebate was to kickstart the light-duty FCEV market in B.C. by providing added rebates for FCEVs given their very early market stage when compared with battery and plug-in hybrid electric vehicles.

The program is focused on FCEVs in fleets in order to increase the visibility of FCEVs to the public and to increase consumer trust and awareness of the technology. The Ministry is using the program to gather feedback from users regarding FCEV deployments to understand the challenges and opportunities for FCEVs. The fleet rebate also supports the existing hydrogen refuelling stations receiving as high a load as possible, thus supporting their viability.

The program has two streams:

1) Operations and Evaluation: provides a rebate of up to $20,000 to applicants to provide their experience on the use of an FCEV in their fleet. The applicant is required to provide two reports (after one and two years of vehicle use) detailing the use and experience from the owners, operators and driver’s perspective. This stream had five rebates available.

2) Vehicle Capital: provides a rebate of 35% of the selling price of the vehicle up to a maximum of $20,000 per vehicle. Initially, the stream offered a rebate of 35% of the manufacturer suggested retail price (MSRP) up to a maximum of $20,000, but the Ministry modified the category in May 2019 to vehicle selling price. This was as a result of the special pricing Toyota offers on the Mirai, which has an MSRP of $73,870 but a selling price of approximately $31,000. The change means the Mirai is eligible for a $10,850 rebate from the program as opposed to $20,000.

Participation in the program excludes applicants from participating in the Go Electric vehicle rebate program. However, both the Go Electric program and the Federal government’s iZEV program have MSRP caps that preclude the Toyota Mirai and Hyundai Nexo (MSRP of $73,000) from being eligible for those programs’ rebates. Additionally, both vehicles are also eliminated from Quebec’s $8,000 rebate for the FCEVs due to the Quebec $60,000 MSRP cap.

In 2019, four Operations and Evaluation rebates and six Vehicle Capital rebates were issued totalling $200,000. To date in 2020, there are six Vehicle Capital rebates pending, totalling $100,000. The fleet rebate has approximately $820,000 in funds remaining.

DISCUSSION:

Ministry staff recently engaged with the CHFCA, Toyota and Hyundai (the only two automakers offering FCEVs for purchase in Canada) to solicit feedback on the performance of the program. Feedback focused on the rebate level and the need for program promotion and awareness.

Both Toyota and Hyundai expressed interest in reducing the rebate amount to ensure a longer program duration as demand for FCEVs builds in B.C. Hyundai indicated that the Nexo has a high MSRP and requested that the rebate not be lowered drastically. However, Toyota is planning to deliver more vehicles than Hyundai in 2020, due to a stockpile of approximately 160 Mirai in Vancouver, and requested the rebate apply to as many vehicles as possible. Toyota favoured reducing the rebate by approximately half.

Both automakers requested that an information bulletin or rack card be developed regarding the program that can be used by the automakers and their dealers when discussing the sale of FCEVs with B.C. fleets. To-date, the FCEVs in BC and the FCEV program rebate have not been the subject of public marketing efforts. Toyota and Hyundai are interested in starting public advertising campaigns on their FCEVs in July 2020, and would like to include the rebate information in those campaigns. Ministry staff are proposing to adjust the FCEV rebate to 35% of selling price to a maximum of $8,000 per FCEV in advance of the automakers’ campaigns.

OPTIONS:

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[signature] July 7, 2020

Honourable Bruce Ralston
Minister of Energy, Mines and Petroleum Resources

Date

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