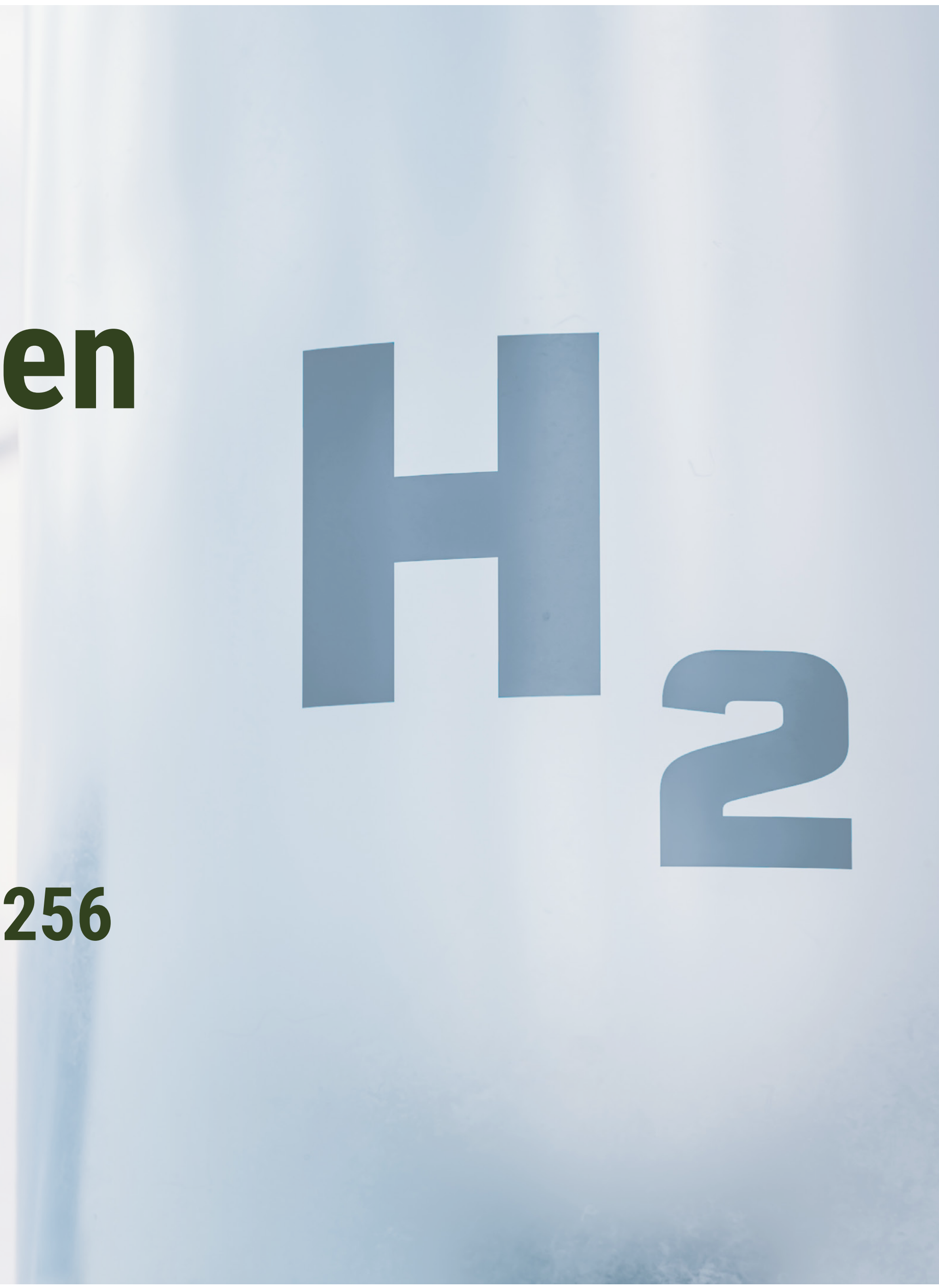
AUC
Alberta Utilities Commission

Hydrogen Inquiry Report



Proceeding 27256
June 30, 2022

Alberta Utilities Commission
Hydrogen Inquiry
Final Report
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1 Executive summary

1. On March 23, 2022, the Government of Alberta issued an order-in-council directing the Alberta Utilities Commission (AUC or the Commission) to inquire into and report to the Minister of Energy on matters relating to hydrogen blending into natural gas distribution systems. The following is a summary of the Commission's findings, observations and considerations for options for this inquiry, based on feedback from stakeholders on a variety of hydrogen blending related issues and its own expertise.

2. The Commission first reviews proposed amendments to relevant legislation. Amending the definition of "gas" in the *Gas Utilities Act* to reference "up to 20 per cent hydrogen by volume blended within a low-pressure natural gas distribution system" and including this definition in the *Gas Distribution Act* by reference appears to be the most efficient way to enable hydrogen blending at the distribution level and provide clarity to stakeholders.

3. The Commission finds that any significant changes to existing franchise rights should be avoided until the implications of hydrogen blending are better understood. An amendment to the *Gas Distribution Act* could be considered to clarify that the inclusion of the definition of "gas" does not expand the exclusive rights and duties of existing franchise area approval holders. It is also premature to determine whether gas distributors should have exclusive rights to pure hydrogen systems.

4. Generally, the Commission is of the view that competitive retailers (including the default supply provider) should be responsible for procuring hydrogen where an adequate competitive market for hydrogen exists, but that further study is required to determine this. In the event that an adequate competitive market for hydrogen does not exist, hydrogen procurement could be performed by distributors until one does. As a result, amending the function of a gas distributor in the *Roles, Relationships and Responsibilities Regulation* to include the procurement of hydrogen could be considered.

5. Next, the Commission explores the responsibilities of agencies involved in aspects of hydrogen regulation in Alberta. The current allocation of responsibilities between relevant Alberta agencies is capable of accommodating hydrogen development and its integration in the low-pressure distribution system. However, to reduce any ambiguity by multiple agencies regulating various aspects of hydrogen, a government-initiated review of agency responsibilities, with input from hydrogen proponents, could be considered.

6. The Commission then considers safety issues. For hydrogen blending to be successful, public safety and reliability is paramount, including relevant safety and reliability standards. Government funded and delivered education initiatives targeting safety and other positive attributes of hydrogen use could be considered to promote public acceptance and ensure that a well-informed public perception of hydrogen exists.

7. The Commission considers it important to harmonize and clarify hydrogen regulations with federal and provincial governments to support the development of national and provincial codes and standards. In that respect, development of a Canadian standard to more specifically provide checklists and details to address issues associated with hydrogen piping and blending would be helpful.

8. The Commission also finds that safety and engineering assessments should be conducted before hydrogen is blended into distribution systems. As part of a government-initiated review involving agencies with regulatory oversight of hydrogen development, consideration could be given to establishing a process for approval of engineering assessments prior to a project proceeding.

9. Next, the Commission considers blending thresholds. Safety concerns, costs and end-user impacts should be examined when determining how much hydrogen to blend into a system and the Commission finds that a cautious approach is reasonable in this regard. The Commission is of the view that a maximum blending threshold of 20 per cent by volume, with no minimum threshold, is reasonable, but pilot projects should start at lower levels.

10. The Commission then reviews delivery of services to rural natural gas consumers. Blending hydrogen with natural gas for rural distribution systems would be more challenging and less practical. The Commission is of the view that the focus, at least initially, should be on hydrogen integration within larger municipal systems. Further, there likely should not be a regulatory requirement for rural utilities, nor for any gas utility or gas co-operative, to blend hydrogen.

11. Next, the Commission explores regulated and competitive segments of hydrogen blending. The Commission considers that a slow, phased approach to hydrogen blending is reasonable because further study is required to fully understand the safety and integrity concerns, the impact of hydrogen on competitive retailers and pricing, determination of the components of the hydrogen market that will be regulated or competitive, the impact hydrogen might have on home appliances and furnaces, and other factors. In addition, the overall costs of hydrogen blending, and potential rate shock to customers must be considered.

12. The Commission considers that the natural gas distribution utility (distribution utility) should have authority over the blending function and be permitted to recover blending facility costs through its revenue requirement and rates. All other hydrogen market segments (production, storage and transportation) likely require further study and a better understanding of the impact on customers, but the Commission does not see any obvious impediments as to why the competitive market cannot ultimately provide these functions. There may be merit to the utility producing and procuring hydrogen on a short-term basis for any early hydrogen blending pilot projects absent competitive alternatives, with those costs recovered in distribution rates.

13. The Commission finds that a regulated natural gas utility should, absent the exceptions listed above, be limited to hydrogen blending and distribution functions.

14. Finally, the Commission considers factors that regulatory agencies should consider when assessing hydrogen blending. It is important for regulators to take into account public interest factors when assessing hydrogen blending projects and the respective costs including assessments of cost-benefit analysis, safety, reliability, environmental impacts, emissions targets,

carbon tax considerations, economic efficiency, and rate impacts to consumers. Hydrogen blending is a rapidly evolving industry, with many technical, safety and regulatory considerations that require further study before broad implementation can be realized.

15. As hydrogen blending is new to the province, consideration should be given to leveraging the experience of other jurisdictions. With a clear focus on safety and reliability, it may be reasonable to move forward with targeted pilot projects to better ascertain the impact of hydrogen blending, emissions reductions, carbon intensity of various hydrogen options and resulting carbon offset, and cost information.

16. The Commission is of the view that it is premature to consider whether capital and commodity costs for hydrogen blending should be allocated among all customers, to customers in a specific geographic area or to customers receiving the hydrogen. Only prudently incurred distribution infrastructure costs to enable hydrogen blending should be borne by ratepayers. The Commission considers that if hydrogen blending is clearly established to benefit all Albertans, including making progress towards meeting provincial emissions reduction targets, then a postage stamp style rate may be a considered approach to explore in the future.

17. The Commission recognizes that the short-term adoption and support for hydrogen blending faces cost and rate impact challenges. As hydrogen blending costs are not expected to be at parity with carbon tax savings in the near future and to ensure hydrogen blending targets outlined in the Alberta Hydrogen Roadmap are met, the Government of Alberta may need to establish a clear policy. This could include objectives and requirements for distribution utilities to allow the Commission to place a greater emphasis on social and environmental factors when assessing the merits of hydrogen blending costs for inclusion in distribution rates. The inclusion of the incremental costs that customers would be required to bear should be balanced against the affordability of utility service for customers.

18. The Alberta government may want to consider supports for customers such as credits, tax rebates or subsidies as mechanisms to reduce the burden on individual citizens during the early stages of hydrogen blending when costs are greater than carbon tax savings. Absent such government subsidization or policy direction, the benefits of emission reductions and carbon tax savings of hydrogen blending may not be sufficient to outweigh the cost burden in the short term, and therefore making the inclusion of these costs in customers’ rates harder to justify.

19. Further study is required to assess the technical and economic feasibility of different types of hydrogen (e.g., green, grey, blue) in order to properly allocate costs and apply the proper offset to carbon tax based on lower carbon emission intensity.

2 Introduction and background

20. On March 23, 2022, the Government of Alberta issued Order-in-Council 70/2022[1] directing the AUC to inquire into and report to the Minister of Energy on matters relating to hydrogen blending into natural gas distribution systems. The order-in-council can be found in Appendix 3. This report has been prepared to address the requirements outlined in the order-in-council.

21. On March 25, 2022, the Commission initiated the Hydrogen Inquiry process by issuing a notice and Bulletin 2022-05: *Hydrogen Inquiry*.[2] These documents outlined the scope of the inquiry and included a comment matrix to assist parties when making submissions. Bulletin 2022-05 explained that the inquiry will explore the following key issues related to hydrogen in natural gas distribution systems:

- Legislation.
- Delivery of services to municipal and rural natural gas consumers.
- Safety.
- Blending standards and thresholds.
- Competition and franchises issues.
- Factors that regulatory agencies should consider when assessing hydrogen blending projects and costs.
- Rate impacts related to capital and commodity cost treatment.
- Rate impacts related to cost allocation.
- Other issues.

22. Matters that were identified as being out-of-scope in Bulletin 2022-05 are listed and predominately discussed in Section 3.8.

23. In response to the notice and Bulletin 2022-05, the Commission received submissions from:

- Natural gas distribution companies.
- Current or planned hydrogen producers.
- Natural gas providers, users and other industry participants.
- Customer groups, municipalities, associations and not-for-profit organizations.

24. A list of the proceeding participants can be found in Appendix 2.

25. The Commission also engaged UniversalPegasus International to assist in the Hydrogen Inquiry by preparing a report detailing information about hydrogen blending in natural

1 O.C. 70/2022, March 23, 2022.
2 Exhibit 27256-X0004, Notice - Hydrogen inquiry; Exhibit 27256-X0005, Bulletin 2022-05 - Hydrogen inquiry; and Exhibit 27256-X0006, Comment matrix for hydrogen inquiry submissions.

gas distribution systems.[3] Parties were granted the opportunity to file comments regarding the UniversalPegasus International report and UniversalPegasus International filed responses to these comments.

26. The remainder of this section outlines background information related to blending hydrogen in natural gas distribution systems, including an overview of government policy and the Alberta Hydrogen Roadmap (Hydrogen Roadmap), hydrogen characteristics, natural gas distribution systems in Alberta, and natural gas competitive and retail supply to customers.

2.1 Government policy and the Hydrogen Roadmap

27. Recent federal, provincial and municipal policies have emphasized the importance of reducing greenhouse gas emissions. Canada and 195 other countries agreed to reduce greenhouse gas emissions by 30 per cent below 2005 levels by 2030 under the Paris Agreement.[4] The Canadian *Net-Zero Emissions Accountability Act* was established to enshrine Canada's commitment to achieve net-zero greenhouse gas emissions by 2050 in legislation and establish Canada's 2030 emissions targets under the Paris Agreement.[5] In Alberta, the City of Edmonton and The City of Calgary (Calgary) have declared climate emergencies and are taking steps to reduce greenhouse gas emissions. The adoption of hydrogen as a fuel source has been identified to have significant potential in contributing towards established emissions goals.

28. The Hydrogen Roadmap, published on November 5, 2021,[6] highlighted Alberta as being well-positioned to engage in the emerging global hydrogen economy. Alberta is one of the world's largest hydrogen manufacturers and Canada's largest producer of hydrogen, producing approximately 2.4 million tonnes each year.[7]

29. In 2019, Alberta's greenhouse gas emissions were 275.8 million tonnes of carbon dioxide, with oil and gas production accounting for 51 per cent of emissions, power generation accounting for 11 per cent, and transportation accounting for 12 per cent.[8] The Government of Alberta established the *Methane Emission Reduction Regulation*, which sets targets for reducing methane emissions from oil and gas activities by 40 to 45 per cent below 2012 levels by 2025 and put in place measures to enhance the measuring, monitoring, and reporting of methane emissions.[9] It is estimated that large-scale hydrogen integration into Alberta's energy infrastructure could lower provincial greenhouse gas emissions by 14 million tonnes per year by 2030, which would represent a reduction of five per cent of Alberta's 2019 emissions.[10]

30. The Hydrogen Roadmap identified the need for policy actions to support emerging hydrogen markets, such as enabling hydrogen blending into natural gas distribution systems. As a result, the Government of Alberta sought to identify existing legislative and regulatory schemes

3 Exhibit 27256-X0070, UniversalPegasus International report.
4 Exhibit 27256-X0009, Alberta Hydrogen Roadmap, PDF page 10.
5 https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/net-zero-emissions-2050/canadian-net-zero-emissions-accountability-act.html
6 Exhibit 27256-X0008, Alberta Hydrogen Roadmap - Executive Summary (2021) and Exhibit 27256-X0009, Alberta Hydrogen Roadmap (2021).
7 Exhibit 27256-X0009, Alberta Hydrogen Roadmap, PDF page 12.
8 Exhibit 27256-X0009, Alberta Hydrogen Roadmap, PDF page 10.
9 Exhibit 27256-X0009, Alberta Hydrogen Roadmap, PDF page 13.
10 Exhibit 27256-X0008, Alberta Hydrogen Roadmap Executive Summary, PDF page 9.

governing natural gas distribution systems and retail services that could act as a barrier to enabling hydrogen blending up to 20 per cent by volume into natural gas distribution systems in Alberta.[11]

31. Hydrogen blending is identified in the Hydrogen Roadmap as an opportunity to begin decarbonizing the natural gas distribution system, while gradually shifting to higher blending levels. This is expected to create new demand for hydrogen which would support investment from hydrogen suppliers and provide learning opportunities for the natural gas distribution system to transition towards higher-blend volumes and pure hydrogen networks.[12] The immediate transition to hydrogen blending at low-blend levels is considered necessary to build knowledge and identify system-wide barriers such as technology, infrastructure, codes, and standards.[13]

32. The Hydrogen Roadmap suggested that existing natural gas distribution infrastructure is considered to be capable of accommodating the introduction of hydrogen into provincial natural gas distribution systems without significant infrastructure upgrades, lowering initial investment risk and creating new demand. Hydrogen blending is anticipated to start at low levels and gradually expand over time when distribution infrastructure and end-use equipment are proven to successfully operate with hydrogen. Early advancements would involve pilot and demonstration projects, providing an indication of safe hydrogen blending levels in different parts of regional distribution networks.[14]

33. In December 2021, the Alberta Department of Energy hosted an industry consultation session regarding the utilization of hydrogen and renewable natural gas. The primary goal of the session was to facilitate the development of a market for hydrogen produced with natural gas in Alberta. Discussion centered around blending thresholds, cost treatment of hydrogen and blending into the low-pressure distribution system.

2.2 Hydrogen characteristics

34. The Hydrogen Roadmap identifies hydrogen as a versatile energy carrier that is expected to play an important role in the lower carbon energy future because when hydrogen is combusted, it emits no greenhouse gases. As a result, hydrogen's use as a fuel, including when blended with natural gas, has the potential to reduce greenhouse gas emissions.[15] Although hydrogen is not a greenhouse gas, some studies[16] recommend assessment of the environmental impact of hydrogen releases, which may offset some of the gains associated with a transition to hydrogen.

35. Hydrogen is typically bound with other elements in molecular form, such as water, hydrocarbons (for example, methane), and biomass, which require the implementation of one of

11 Exhibit 27256-X0008, Alberta Hydrogen Roadmap Executive Summary, PDF page 18 and Province of Alberta, Order in Council, March 23, 2022, PDF page 2.
12 Exhibit 27256-X0009, Alberta Hydrogen Roadmap, PDF page 35.
13 Exhibit 27256-X0009, Alberta Hydrogen Roadmap, PDF page 35.
14 Exhibit 27256-X0009, Alberta Hydrogen Roadmap, PDF page 35.
15 Exhibit 27256-X0009, Alberta Hydrogen Roadmap, PDF page 35.
16 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1067144/atmospheric-implications-of-increased-hydrogen-use.pdf

several different processes to produce hydrogen. The level of emissions from hydrogen production, if any, depend on the production method used. Natural gas-based steam methane reforming is the most common and historically cost-effective method for hydrogen production, contributing to over half of the world's hydrogen production. This production method converts hydrocarbons and steam into hydrogen and carbon monoxide. Other methods of hydrogen production include autothermal reforming, which uses natural gas, water, and oxygen to produce hydrogen; and electrolysis, which could use renewable and non-carbon emitting power (such as solar, wind, hydroelectric, geothermal and nuclear energy).[17]

36. Hydrogen is often described by different colours depending on how it is produced. Commonly referenced types of hydrogen include:

- Green hydrogen, produced with renewable electricity and no carbon dioxide emission during the production process.
- Grey hydrogen, produced with fossil fuels (such as natural gas) and the production process's carbon dioxide is eventually released to the atmosphere.
- Blue hydrogen, produced with fossil fuels (such as natural gas), however, unlike grey hydrogen, the production process's carbon dioxide is captured, utilized or stored.

37. New hydrogen production facilities proposed in Alberta include Air Products Canada Ltd.'s (Air Products) clean hydrogen energy complex which utilizes autothermal reforming with carbon capture. In addition, IEPS Canada Ltd. (IEPS) is proposing to build a hydrogen production facility that will use electrolytic technology to convert water into 99.9 per cent pure hydrogen and oxygen. Kiwetinohk Energy Corp. (Kiwetinohk) also identified plans to produce hydrogen with solar, wind and natural gas energy in Alberta. Other hydrogen projects, such as a Suncor Energy and ATCO Ltd. proposal to develop 300,000 tonnes per year, have also been announced.

38. Hydrogen has a lower volumetric energy density[18] than natural gas. The heating value[19] of hydrogen is approximately 12 megajoules per cubic metre, or one third that of natural gas, which is approximately 39 megajoules per cubic metre. As a result, to deliver the same amount of energy while blending hydrogen, pipelines and distribution networks would need to increase system pressure to increase the density of the blended mixture flowing through the pipeline.[20]

39. Other different characteristics between hydrogen and natural gas include reactions with some metals, explosivity, flammability, ignition and diffusivity. Hydrogen also has a smaller molecular size than natural gas, which some parties suggest may create additional concerns with leaks. Many of these different characteristics are further discussed in Section 3.3 and require consideration when determining how to blend hydrogen into natural gas distribution systems. Although not studied in this inquiry, there are technologies that could potentially be utilized to

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[17] Exhibit 27256-X0009, Alberta Hydrogen Roadmap (2021), PDF page 20.
[18] Volumetric energy density is the amount of energy contained within a given volume.
[19] Heating value is the amount of heat obtained when fuel of a specific quantity is combusted.
[20] Hydrogen Strategy for Canada, Seizing the Opportunities for Hydrogen, A call to Action, December 2020, PDF page 85.

extract pure hydrogen from a blended distribution system stream for use in fuel cells or other applications.[21]

40. Hydrogen blends can also influence the accuracy of existing gas meters. Some studies have shown that gas meters would not need to be tuned for low hydrogen blend levels; however, further validation testing may be needed.[22]

41. While downstream of the meter appliance safety is outside of the scope of this inquiry, some sources identified that the different characteristics of hydrogen may require modifications such as new burners if hydrogen blending is implemented.[23] Further, while the blending of hydrogen in high-pressure natural gas utility pipelines is out of scope of this inquiry, equipment such as turbines, compressors and boilers can also be impacted by hydrogen blends. For example, hydrogen produces more water vapour than natural gas for the same amount of energy delivered when combusted, which may lead to more condensation in boilers.[24]

2.3 Natural gas distribution systems in Alberta, including gas co-operatives

42. Natural gas is found in underground gas reservoirs, where it is extracted and gathered by energy exploration and development companies. Natural gas is then processed and transported by gathering pipelines to transmission pipelines.[25] Alberta's natural gas is typically about 95 per cent methane. The natural gas stream often contains small amounts of ethane, propane, butane and other heavier hydrocarbons, as well as trace amounts of nitrogen, carbon dioxide, oxygen, hydrogen and other impurities.

43. In Alberta, transmission pipelines transport high-pressure natural gas to industrial users, other pipeline systems and pressure reducing gate stations leading to distribution systems. Gate stations typically operate with an inlet pressure in the range of 2,000-7,000 kilopascals (kPa) and an outlet pressure of roughly 400 kPa. There are roughly 5,000 gate stations across the province. Some of the gate stations serve single customers and some serve thousands of customers. Further, some of those distribution systems are interconnected and some are not.

44. In most circumstances, producers deliver directly into the high-pressure gas transmission pipelines, although historically, there have been situations where producer gas has been delivered directly into low-pressure distribution systems.

45. Distribution utilities deliver natural gas to customers at a low pressure, below 700 kPa, with regulated or competitive retailers buying gas from marketers and producers to sell to customers at either regulated or contract rates.[26]

[21] https://www.osti.gov/scitech/servlets/purl/1219920

[22] Hydrogen Strategy for Canada, Seizing the Opportunities for Hydrogen, A call to Action, December 2020, PDF page 85.

[23] Hydrogen Strategy for Canada, Seizing the Opportunities for Hydrogen, A call to Action, December 2020, PDF pages 85.

[24] Hydrogen Strategy for Canada, Seizing the Opportunities for Hydrogen, A call to Action, December 2020, PDF pages 85-86.

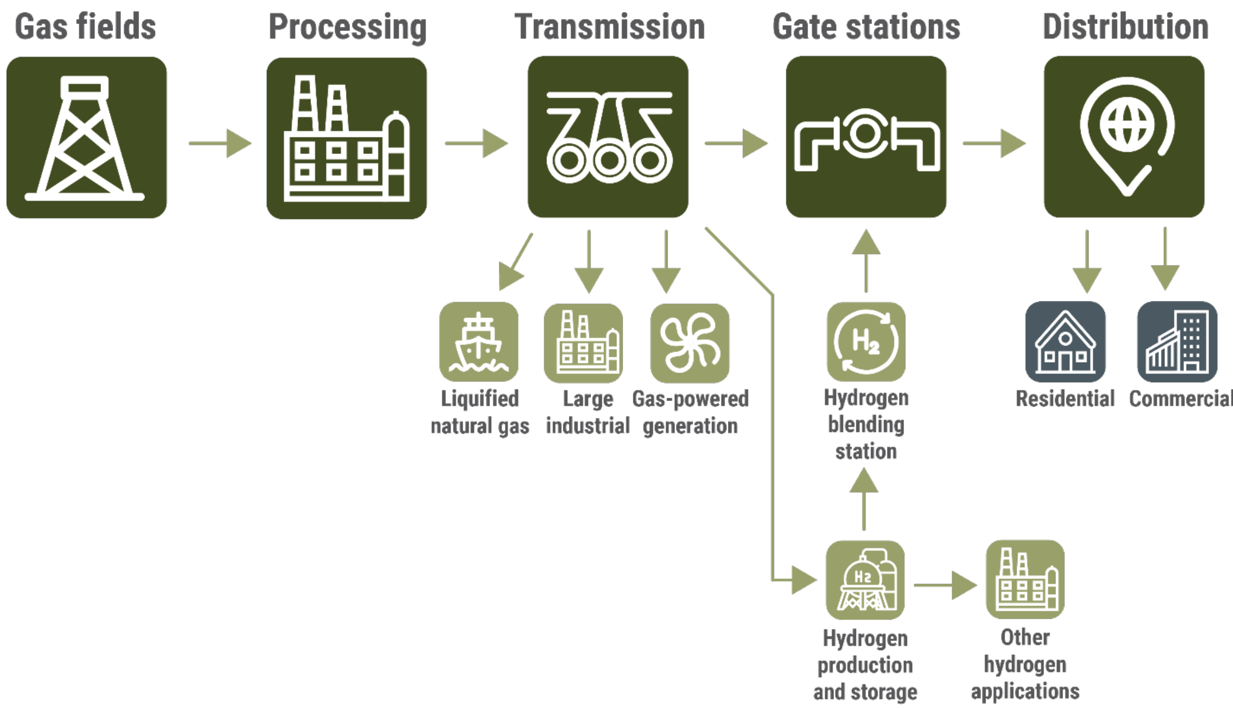
[25] https://ucahelps.alberta.ca/natural-gas-energy-market.aspx

[26] https://ucahelps.alberta.ca/natural-gas-energy-market.aspx

46. Distribution utilities are responsible for managing gas quality on their distribution systems. If the distribution utility is unable to resolve a gas quality issue with a customer, the customer may file a complaint with the Commission to address their concerns.

47. If hydrogen were to be blended with the natural gas within the distribution system, additional components would be required, including a source of hydrogen and blending stations connected to gate stations. The figure below illustrates the general natural gas supply chain in Alberta, including hydrogen being blended into the distribution network:

Figure 1. Alberta natural gas and hydrogen supply chain



48. Natural gas is consumed at over one million metered sites in Alberta, including most houses and businesses that utilize the fuel primarily for heat and hot water.[27]

49. The Commission oversees both intra-provincial gas transmission and distribution systems.[28] With respect to natural gas transmission pipelines, NOVA Gas Transmission Ltd. (NGTL) and ATCO Pipelines have signed an integration agreement where there is one set of rates and services structure for Alberta, while each utility maintains separate ownership, management, and operation of their assets. NGTL is responsible for rate-related and contract matters with customers under the combined Alberta system. NGTL's revenue requirement and rates are regulated by the Canada Energy Regulator. ATCO Pipelines' costs, which are included in NGTL's rates through a monthly charge, are regulated by the AUC. The AUC also considers any facility applications filed by ATCO Pipelines.

27 https://www.auc.ab.ca/distribution-rates/
28 https://www.auc.ab.ca/gas-utility-pipeline-decisions/

50. A regulated distribution utility has the opportunity to recover prudently incurred service costs, including earning a fair return on investment, in order to provide utility customers with safe, reliable service now and in the future, and to encourage continued investment in the utility industry.[29] The Commission is responsible for ensuring that natural gas service is safe and reliable, and that rates charged are just and reasonable, and reflect the costs of delivering the service.

51. The distribution systems that supply natural gas directly to a customer's home are owned by distribution utilities. Their responsibilities include connecting and disconnecting customers, building new services, operating and maintaining distribution infrastructure, replacing distribution infrastructure that has reached the end of its service life, sending distribution charges to retailers, providing meter reading services, and implementing technology to maintain safe and reliable service. A distribution utility recovers its costs for providing these services through distribution charges on a customer's utility bill from their retailer. The Commission regulates distribution charges for distribution utilities through performance-based regulation.[30]

52. Instead of traditional cost-of-service rate regulation, which sets rates based on the costs utilities are expected to incur in a given year, performance-based regulation calculates rates annually using an incentive-based formula. Performance-based regulation is intended to imitate competition by providing incentives for the utility to reduce costs while maintaining reliability. As a result, utility rates are kept lower than they might otherwise have been for customers. Alberta has five-year performance-based regulation terms.[31]

53. Quality of service standards including billing and metering, safety performance, energy response time and call answering are enforced by AUC rules. Gas quality receipt standards for gas entering the distribution system from external sources of production (e.g., provision for renewable natural gas) are included in the utility rate schedules. Most gas entering the ATCO Gas (ATCO) distribution system flows from the ATCO transmission system that has gas quality overseen under the terms and conditions of the NGTL system under the provisions of an integration agreement between ATCO and NGTL.

54. The Commission is also in charge of approving new transmission pipeline construction, issuing licences for pipeline construction, operation, abandonment and removal, reviewing and approving pipeline routing, and establishing rules and regulations for gas utility pipeline design, construction, operation and abandonment.[32]

55. For gas distribution pipelines operated at pressures less than 700 kPa, approval from the Commission is not required under the *Pipeline Act*. As such, the Commission does not issue licences for low-pressure distribution pipelines. All standards related to the design, construction, operation, maintenance, quality assurance, plant records, surveys and as-built drawings for rural gas utilities and low-pressure distribution pipelines are set and enforced by Alberta Agriculture's Rural Utilities Branch under the *Gas Distribution Act*. The Rural Utilities Branch utilizes the

[29] https://www.auc.ab.ca/distribution-rates/
[30] https://www.auc.ab.ca/distribution-rates/
[31] https://www.auc.ab.ca/distribution-rates/
[32] https://www.auc.ab.ca/gas-utility-pipeline-decisions/

Technical Standards and Specification Manual for Gas Distribution Systems[33] and adopts the CSA Z662, Oil and Gas Pipeline Systems (CSA Z662) standards.

56. On an annual basis, the Rural Utilities Branch compiles as-built construction data for low-pressure gas providers. When it comes to low-pressure gas distribution line routing within cities and towns, the municipality examines the routing through public thoroughfares and assigns facility line routing accordingly. The Commission is responsible for regulating low-pressure distribution pipeline rates and has the jurisdiction to investigate and settle distribution-related disputes. The Commission is required to resolve ongoing safety and operation concerns on these low-pressure pipelines under the provisions of the *Gas Utilities Act*.[34]

57. ATCO and Apex Utilities Inc. (Apex) are the two primary investor-owned distribution utilities in Alberta. Other natural gas distributors include natural gas co-operatives, municipally owned gas utilities, and First Nations' gas utilities.[35]

58. ATCO's natural gas distribution system serves the majority of customers in Alberta and covers almost two-thirds of the province, while Apex provides distribution utility service to over 82,000 customers (residential, rural, commercial and industrial) in excess of 90 communities across Alberta.[36] Other distribution companies are located in smaller rural areas and range from a few hundred to a few thousand consumers.

59. Co-operatives and community natural gas distributors are locally owned and operated. The locally elected board (for co-operatives) or council (for municipalities and First Nations) govern the utility on behalf of the co-operative members or community ratepayers. Most are non-profit, and all function on the principle that any surpluses be reinvested in the utility (i.e., there are no dividends or profits paid out). The board or council sets the rates, which include the cost of gas flowed through monthly from Gas Alberta Inc. (Gas Alberta) and may include fixed and/or variable fees to pay the utility's operation and administration costs.[37] Co-operatives and community natural gas distributors will often use multiple receipt points for the natural gas that they distribute. Some distribution utilities also have a franchise agreement with a municipality, granting the utility, for a specific period of time, the right to supply customers within the municipality's jurisdiction (or service territory) in return for a franchise fee that is paid to the municipality.

60. The Federation of Alberta Gas Co-operatives Ltd. (Federation) stated that it has 80 member utilities comprised of 52 natural gas co-operatives, five rural municipalities, 16 municipalities and seven First Nations utilities. The member utilities are supplied natural gas by a total of 730 individual gate stations, with the average member utility having approximately nine gate stations supplying its designated franchise area.[38]

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33 Technical Standards and Specification Manual for Gas Distribution Systems: Safety, Design, Construction, Operation and Maintenance of Natural Gas Distribution Systems in Alberta, Sith Edition, November 2010. https://open.alberta.ca/dataset/6fe277ce-b92c-4dbf-aaf6-eaa413c652cb/resource/c0771dbe-ade4-4423-9bbf-0d6dcff32723/download/2010-technical-standards-specification-manual-2010.pdf

34 https://www.auc.ab.ca/gas-utility-pipeline-decisions/

35 https://ucahelps.alberta.ca/natural-gas-energy-market.aspx

36 https://www.apexutilities.ca/about/about-apex-utilities/

37 https://www.fedgas.com/YourGasBill

38 Exhibit, 27256-X0079, Federation of Alberta Gas Co-ops comments on UPI Report, PDF page 2.

2.4 Natural gas competitive and retail supply to customers

61. The section below explains the differences between default (i.e., regulated) gas supply providers and competitive natural gas retailers and how natural gas is supplied to customers.

62. Both the default gas supply providers[39] and competitive retailers purchase natural gas from marketers and sell it to customers at either regulated or contract rates. A customer has the right to obtain gas services from a retailer or default supply provider for delivery to the customer by the gas distributor in whose service area the customer's place of consumption is located. The gas distributor shall transport gas within the service area on behalf of the customer or the retailer or default supply provider at the rates approved by the Commission.[40] A gas distributor may, with the approval of the Commission, authorize a person to act as the default supply provider in the gas distributor's service area.[41] Competitive retailers cannot sell natural gas to customers within the co-operative or certain community franchise areas because these distributors are granted a franchise under the provisions of the *Gas Distribution Act* and have exclusive right to supply customers with gas supply aggregated by Gas Alberta in their respective franchise areas.[42]

63. The Commission approves the methodology by which default supply providers procure energy for their customers and how the rate will be calculated. The tariffs are based on natural gas purchases made by retailers on an open, competitive market that is not regulated by the Commission.[43]

64. The charge on utility bills for energy is based on the consumption of gas during the billing period, which is calculated per gigajoule. This energy charge does not include the costs for services associated with natural gas distribution to consumers' homes or businesses.[44]

65. Rates charged by competitive retailers will vary. Customers' gas costs will rise or fall in response to natural gas market prices and usage. Additional fees may include a fixed charge to recover costs that do not fluctuate with usage, such as administration, pipeline design and installation, and meters, and a variable charge to recover costs that vary with consumption, such as labour, materials, and supplies.[45]

66. Purchases and deliveries of natural gas to Albertans may be performed by one company that handles both purchasing and delivery, or by two companies: one that supplies natural gas and the other that owns and operates the distribution pipeline system and delivers the gas to customers.[46]

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39 As permitted under Section 28.1 of the *Gas Utilities Act,* ATCO Gas and Pipelines Ltd. North and South services has authorized Direct Energy Regulated Services, a business unit of Direct Energy Marketing Limited, to perform the default gas supply provider function in its services area; Apex Utilities Inc. performs the function for its service areas.

40 Section 28.1, *Gas Utilities Act*.

41 Section 2, *Default Gas Supply Regulation*.

42 https://www.fedgas.com/YourGasBill

43 https://www.auc.ab.ca/current-gas-rates-and-terms-and-conditions/

44 https://www.auc.ab.ca/current-gas-rates-and-terms-and-conditions/

45 https://www.fedgas.com/YourGasBill

46 https://www.gasalberta.com/gas-market/gas-rates-in-alberta

67. The following organizations purchase natural gas supplies for eventual sale to end-use consumers in Alberta:

- Gas Alberta buys natural gas on behalf of its utility customers and keeps a diverse gas supply portfolio that includes daily and monthly indexed supplies and direct purchases from producers. Gas Alberta establishes the monthly pooled gas pricing to recover its costs.

- Direct Energy Regulated Services, a business unit of Direct Energy Marketing Limited (Direct Energy), is a default supply provider that buys indexed supplies on a daily and monthly basis for sale to customers in ATCO Gas North and ATCO Gas South franchise zones. Consumers may contract with Direct Energy Regulated Services under their default gas rate, which is regulated by the Commission.

- Apex is a distribution utility that acts as a retailer when it performs the default supply provider function of procuring natural gas to its franchise territories' customers. Consumers may contract with Apex under their default gas rate, which is regulated by the Commission.

- Competitive retailers have been offering their natural gas products to consumers in Alberta since 1998, such as in ATCO and Apex franchise territories. These retailers offer both fixed-price and market-priced commodities (including a premium) at rates they believe will appeal to Albertans.[47]

3 Discussion of issues

68. A discussion of issues raised by parties and the Commission's findings, observations and considerations for options are provided in this section. The issues are organized as follows:

- Proposed amendments to relevant legislation.
- Allocation of responsibilities of regulatory agencies.
- Safety.
- Hydrogen blending thresholds.
- Delivery of services to rural natural gas consumers.
- Regulated and competitive segments of hydrogen blending.
- Factors that regulatory agencies should consider when assessing hydrogen blending.
- Conclusion and areas for future study.

69. While several parties participated and provided submissions expressing various positions, limited conclusive evidence was provided on most topics.

[47] https://www.gasalberta.com/gas-market/gas-rates-in-alberta

3.1 Proposed amendments to relevant legislation

70. This section first discusses potential changes to the *Gas Utilities Act* and the *Gas Distribution Act* to provide clarity around hydrogen blending in low-pressure distribution systems and the use of the term "natural gas" in various legislation. It then examines the potential impacts of legislative amendments on existing franchises. Finally, possible amendments to the *Public Utilities Act* and the *Roles, Relationships and Responsibilities Regulation* are discussed.

3.1.1 Gas Utilities Act and Gas Distribution Act

71. Currently, the *Gas Utilities Act* and the *Gas Distribution Act* do not explicitly reference hydrogen. In its Hydrogen Roadmap, the Government of Alberta identified amendments to this legislation as necessary to remove a key roadblock for hydrogen blending into natural gas distribution systems.[48]

72. The *Gas Utilities Act* provides the AUC with authority to regulate gas utilities, including the ability to establish just and reasonable rates. It also governs the provision of gas services to customers by gas distributors and default supply providers. The *Gas Distribution Act* enables the Rural Utilities Branch of Alberta Agriculture to set standards for the design, construction, operation and maintenance of rural gas utilities and low-pressure distribution systems. It also deals with various franchise matters including takeover by an urban gas utility and compensation issues related to annexation of a franchise area. Amendments to the *Gas Utilities Act* and *Gas Distribution Act* would provide certainty related to accommodating hydrogen blending in the existing regulatory scheme.

73. Several parties provided comments on the legislative amendments required to enable hydrogen blending in low-pressure distribution systems. In general, amendments to the existing legislative scheme are seen as necessary to remove barriers to hydrogen blending, clarify the AUC's authority with respect to regulating hydrogen and provide certainty and predictability to stakeholders. Parties identified an overarching need to amend the definition of "gas" in the *Gas Utilities Act* to include hydrogen and/or hydrogen blending in some capacity. Some parties also recommended that a similar definition of "gas" be included in the *Gas Distribution Act*.

74. The positions taken by the parties varied, but generally two competing themes emerged:

- Legislative amendments to the *Gas Utilities Act* and *Gas Distribution Act* should reflect a broader range of gaseous substances. This would enable the exploration of other gaseous energy substances and accommodate future technologies and customer behaviour changes while reducing the need for frequent legislative amendments.
- More narrow and focused changes to the legislation should be made to avoid inadvertently affecting hydrogen production or the existing competitive market for hydrogen for industrial use, and creating an uneven playing field by having utility ratepayers subsidize one player in the marketplace.

75. The Commission considers that amendments to the *Gas Utilities Act* and *Gas Distribution Act* would provide clarity to stakeholders regarding hydrogen blending in the existing regulatory scheme. Amending the definition of "gas" in the *Gas Utilities Act* to

48 Exhibit 27256-X0009, Alberta Hydrogen Roadmap (2021), PDF page 46.

reference hydrogen blending and including this definition in the *Gas Distribution Act* by reference appears to be the most efficient way to enable hydrogen blending and its inclusion in the low-pressure distribution system. The following definition could be considered:

Table 1. Existing and proposed definition of "gas" in the Gas Utilities Act

Existing definition in the Gas Utilities Act	Proposed definition
(e) "gas" means all natural gas both before and after it has been subjected to any treatment or process by absorption, purification, scrubbing or otherwise, and includes all fluid hydrocarbons not defined by clause (i) as oil;	(e) "gas" means (i) all natural gas both before and after it has been subjected to any treatment or process by absorption, purification, scrubbing or otherwise, and includes all fluid hydrocarbons not defined by clause (i) as oil; and (ii) a blend of any of the substances referenced in subclause (e)(i) with up to 20 per cent hydrogen by volume blended within a low-pressure natural gas distribution system;

76. The proposed definition would leverage the existing and well-established regulatory framework for natural gas and provide certainty and consistency in terms of how blended hydrogen is regulated. Certain parties expressed a concern that legislative amendments may unintentionally broaden the scope of regulation to include high-pressure hydrogen distribution and transmission pipelines serving industrial customers and the production of hydrogen in the competitive market. However, the Commission considers that a targeted amendment to the definition of "gas" to include "up to 20 per cent hydrogen by volume blended within a low-pressure natural gas distribution system" would reduce the likelihood of these unintended consequences occurring.

77. Although several parties advocated for more generic amendments to the definition of "gas" such that the legislation would apply to gaseous energy generally, the Commission considers that this could capture alternative energy sources and hydrogen in a manner that is beyond the scope of this inquiry. Further, implementing a narrower amendment at this stage with a blending threshold up to 20 per cent supports a more incremental approach to the integration of blended hydrogen within utility distribution systems and is in line with what is generally accepted as a reasonable initial maximum blending threshold from a safety and customer impact perspective, as further discussed in Section 3.4. The Commission considers this approach to be reasonable given that hydrogen use for this purpose is relatively new and there remain important safety and pipeline integrity considerations.

78. The Commission recognizes that the Hydrogen Inquiry's order-in-council requested that the Commission investigate hydrogen blending into gas distribution systems up to 20 per cent blending by volume. If it is the legislature's intention to capture energy sources beyond a certain percentage of hydrogen blended with natural gas at the distribution level, consideration may be given to including a definition that references gaseous energy generally and avoids reference to a percentage blended by volume and to the low-pressure distribution system. Alternatively, it could explicitly include other energy sources. The Commission acknowledges that this approach may reduce the need for more frequent amendments to adapt to future changes in technology and changing customer demands as stakeholders work towards meeting emissions targets. However, should this approach be taken, caution is needed to avoid unintended consequences.

79. The reference to “natural gas” without definition in various acts including the *Gas Utilities Act*, *Gas Distribution Act*, *Alberta Utilities Commission Act* and *Municipal Government Act* was also identified as a potential opportunity to provide legislative clarity. While the term is not used extensively throughout this legislation, consideration could be given to some minor amendments to reflect the reality of hydrogen blending. In particular, the reference to “natural gas service” in the *Gas Distribution Act* and *Municipal Government Act* could be revised to simply refer to “gas service” so that hydrogen blending is more clearly contemplated.

80. Parties also disagreed on how hydrogen infrastructure and commodity costs should be treated. A competing view emerged related to whether future legislative amendments should support the blending of hydrogen itself as part of the gas distribution or transmission function and included in customer utility rates or whether this should be treated as a separate “midstream” type function.[49] Some parties support the treatment of hydrogen infrastructure and commodity costs as system costs and recoverable from all ratepayers, at least initially.[50] In contrast, further consultation, analysis and study of the proper methods of cost allocation across all customers is thought to be warranted prior to implementing legislative changes.[51] The Federation was of the view that its members’ customers should not bear the costs of implementing a blended fuel source.[52]

81. The Commission does not consider it necessary to implement legislative changes setting out how hydrogen infrastructure and commodity costs will be treated from a rates perspective. The expansion of the definition of “gas” proposed above will result in the inclusion of hydrogen blending in distribution systems through gas distribution rates, which will use the existing regulatory framework for natural gas. This will also allow hydrogen pilot projects to proceed while further study of potential rate impacts can be undertaken. Once a clear and well-informed policy is developed, more specific guidance can be included in a subsequent legislative amendment or within an AUC rule if necessary. Further discussion of cost treatment is provided in Section 3.7.

3.1.2 Franchise agreements

82. Distribution utilities in Alberta operate within defined service areas. Service providers are granted “franchise areas” with respect to their operations in rural Alberta. These franchise areas typically exclude all urban municipalities, where a service provider will normally acquire the right to operate within a particular urban municipality through a municipal franchise agreement. While municipal franchise agreements are approved by the Commission, franchise areas are approved by the chief officer.[53]

83. Some parties provided comments on the potential impact of legislative amendments on existing franchises, including the required changes to franchise agreements to accommodate hydrogen blending in the distribution system.

[49] Exhibit 27256-X0055, City of Calgary Submissions for Comments Matrix ID 27256, PDF page 4.
[50] Exhibit 27256-X0061, ATCO Gas' Hydrogen Inquiry Submission, PDF pages 23-24.
[51] Exhibit 27256-X0065, City of Calgary Reply Comments, PDF page 8.
[52] Exhibit 27256-X0022.01, Federation Statement and Matrix Comments, PDF page 4.
[53] The Deputy Minister of the Ministry of Agriculture and Rural Development or employee of that department designated by the Minister.

84. The Federation submitted that except for changes in legislation that acknowledge that hydrogen may be added to or blended with natural gas to varying percentages, no other change to existing legislation impacting member-owned natural gas co-operatives or rural municipal utilities is needed. It recommended avoiding broad changes to legislation that may alter the current rural natural gas franchise system.[54]

85. ATCO and Apex supported amendments to the *Gas Utilities Act* to include a provision modifying existing franchise agreements and similar instruments province-wide to clarify that a gas distributor's obligation to exclusively provide natural gas distribution service includes the distribution of hydrogen.[55] They suggested that this would be more efficient than amending agreements on a community-by-community basis and provide greater certainty for related investment. ATCO and Apex also submitted that reviewing the calculation of franchise fees under existing franchise agreements, to the extent they may be affected by the introduction of hydrogen, would also be prudent. Conversely, a more incremental approach was recommended by Air Products: changes to franchise agreements at the pilot phase should be limited to the distribution of the blended product through existing natural gas infrastructure in those areas approved for pilot projects (given that there is not sufficient information or experience to properly inform large-scale amendments to the legislative regime or existing franchise agreements).

86. Given that the inclusion of hydrogen in Alberta's low-pressure distribution system is in the development phase, the Commission finds that any significant changes to existing franchise rights should be avoided until the implications of this development are better understood.

87. A person proposing to construct a rural gas utility must first apply for a franchise area approval under Section 16 of the *Gas Distribution Act*. Pursuant to Section 18 of the *Gas Distribution Act*, a distributor holding a franchise area approval has both the exclusive right and duty to offer and provide gas service to all potential consumers within the distributor's franchise area. The inclusion of the proposed definition of "gas" in the *Gas Distribution Act* by reference to the *Gas Utilities Act* would expand the exclusive right and duty of franchise area approval holders to include the distribution of hydrogen blended up to 20 per cent. To avoid this implication without first requiring an application for amendment under Section 19 of the *Gas Distribution Act*, a new subsection could be added to Section 18 to say:

> (5) Notwithstanding subsection (1), the exclusive rights and duties of a distributor holding a franchise area approval that was granted before (DATE OF LEGISLATION CHANGE) do not include the distribution of blended hydrogen without subsequent amendment of the franchise area approval pursuant to Section 19.

88. This would maintain existing franchise area rights granted to distributors while avoiding broad changes to the legislation that may alter the current rural natural gas franchise system. In the event a distributor wants to expand its rights and duties to include the provision of blended hydrogen, it would be free to apply for an amendment to an existing approval under Section 19.

89. Regarding ATCO and Apex's proposal to legislatively amend existing franchise agreements to include hydrogen generally, the Commission does not consider this to be necessary. Doing so would be inconsistent with an incremental approach to accommodating

[54] Exhibit 27256-X0022.01, Federation Statement and Matrix Comments, PDF Page 4.
[55] Exhibit 27256-X0057, AUI Comment Matrix for Hydrogen Inquiry Submission – 2022-04-26, PDF Page 6, and Exhibit 27256-X0061, ATCO Gas' Hydrogen Inquiry Submission, PDF Page 15.

blended hydrogen in distribution systems and, while outside the scope of this inquiry, could result in unintended consequences for hydrogen in the competitive sphere. For example, while it likely makes sense for a gas distributor's rights and duties under a franchise agreement to include the distribution of blended hydrogen, it is not only premature but beyond the scope of this inquiry to determine whether ATCO and Apex should have exclusive rights to pure hydrogen systems. Should parties to existing franchise agreements determine that changes are required to accommodate the distribution of blended hydrogen, any necessary amendments can be agreed upon and submitted to the Commission for approval. This will ensure that those granting franchise rights, such as municipalities, have the opportunity to consider any secondary impacts of blended hydrogen, including potential changes to distribution systems within their municipality and how franchise fees should be calculated.

3.1.3 Public Utilities Act

90. Amendments to the *Public Utilities Act* were proposed by certain parties. Air Products submitted that to avoid hydrogen production or pure hydrogen pipelines being captured by the *Public Utilities Act*, it should be clarified that assets used solely for the production and transport of hydrogen, whether or not used in conjunction with hydrogen blending, would not constitute a "public utility" for the purposes of the *Public Utilities Act*.

91. Given that the definition of a "public utility" in the *Public Utilities Act* is relatively broad and references being "directly or indirectly to or for the public," it could be interpreted as applying to hydrogen production and assets used solely for the purpose of hydrogen transport. However, the *Public Utilities Act* also provides the Commission with broad discretion to declare anything that is a public utility, not a public utility. This clause could prevent any unintended regulation related to hydrogen production and assets used solely for the purpose of hydrogen transport, making legislative amendments unnecessary. The Commission notes, however, that there could be circumstances where a pure hydrogen pipeline or hydrogen production facility may need to be regulated as a public utility. The *Public Utilities Act*, as currently drafted, provides sufficient flexibility to deal with these and other scenarios where regulatory oversight may be required.

3.1.4 Roles, Relationships and Responsibilities Regulation

92. Parties also proposed amendments to the *Roles, Relationships and Responsibilities Regulation*. The *Roles, Relationships and Responsibilities Regulation* under the *Gas Utilities Act* sets out the functions of gas distributors as compared to retailers and default supply providers related to the gas distribution system. Under this regulation, retailers and default supply providers are responsible for providing "gas services" to their customers which is defined in the *Gas Utilities Act* to mean:[56]

> (i) the gas that is provided and delivered, and
>
> (ii) the services associated with the provision and delivery of the gas, including
>
> (A) arranging for the exchange or purchase of the gas,
>
> …

[56] *Gas Utilities Act*, Section 28(i).

93. ATCO and Apex submitted that with amendments to the definition of "gas" in the *Gas Utilities Act*, amendments to this regulation would also be required to reflect that the procurement of hydrogen will be the responsibility of distributors until the AUC determines that an adequate competitive market exists (at which time this responsibility should shift to retailers).[57] Calgary disagreed with this submission on the basis that it considers this function to already be captured under the regulation, making further legislative changes unnecessary.

94. The Commission considers that it is unclear whether an adequate competitive market for hydrogen exists and that further study is required in this regard. At present, there does not appear to be evidence of transparent trading platforms for hydrogen such as those that have been developed for natural gas. In the event there is not a sufficient competitive market or a presence of competitive retailers to procure hydrogen for blending into the distribution system, the Commission agrees with ATCO and Apex that this function should be performed by distributors. Once an adequate competitive market is established, this function should shift to retailers similar to the existing arrangement for natural gas. The functions of a gas distributor under the *Roles, Relationships and Responsibilities Regulation* include a responsibility to:[58]

> (b) make decisions about building, upgrading and improving the gas distribution system for the purpose of providing safe, reliable and economic delivery of gas to customers in the service area served by the gas distribution system;

95. While this provision may be broad enough to include the procurement of hydrogen for blending into distribution systems, given the more specific reference to "arranging for the exchange or purchase of the gas" in setting out the responsibilities of a retailer, a legislative amendment to provide clarity may be helpful. This could be achieved by adding the following to the function of a gas distributor in Section 4(1) of the *Roles, Relationships and Responsibilities Regulation*:

> (q) assume responsibility for the procurement of hydrogen for blending into distributions systems until the Alberta Utilities Commission determines that a sufficient competitive retail market for hydrogen exists such that this can be facilitated by retailers.

96. Setting an end date for this provision to be in effect may be problematic given the uncertain timelines of pilot projects and subsequent larger-scale hydrogen use in distribution systems; however, the proposed amendment would allow the AUC to periodically consider whether a sufficient competitive retail market for hydrogen exists, which can be communicated through an AUC rule, providing stakeholder clarity until this legislative provision can be rescinded.

3.2 Allocation of responsibilities of regulatory agencies

97. This section discusses the allocation of responsibilities among relevant Alberta agencies related to hydrogen and hydrogen blending in gas distribution systems.

98. Both the Rural Utilities Branch of Alberta Agriculture and the AUC have oversight over low-pressure distribution lines. The Rural Utilities Branch is responsible for setting and

57 Exhibit 27256-X0057, AUI Comment Matrix for Hydrogen Inquiry Submission – 2022-04-26, PDF Page 7.
58 *Roles, Relationships and Responsibilities Regulation*, Section 4(1)

enforcing all standards related to the design, construction, operation, maintenance, quality assurance, plant records, surveys and as-built drawings for rural gas utilities and low-pressure distribution pipelines under the *Gas Distribution Act*. On an annual basis, the Rural Utilities Branch compiles as-built construction data for low-pressure gas providers.

99. The Commission is required to resolve ongoing safety and operation concerns on these low-pressure pipelines under the provisions of the *Gas Utilities Act* and also maintains regulatory oversight over distribution utility rates.

100. A number of other agencies are also involved in various aspects of hydrogen regulation including the Alberta Energy Regulator and Alberta Environment and Parks. Alberta Municipal Affairs also has oversight of downstream of the meter piping.

101. The following table highlights several of the roles and responsibilities of parties in order to facilitate hydrogen blending in natural gas distribution systems.

Table 2. Roles and responsibilities of various parties to facilitate hydrogen blending

Party	Role and responsibility
Alberta Municipal Affairs	• Oversee safety readiness of downstream of the meter piping
Safety Codes Council	• Responsible for accrediting, overseeing, and monitoring the compliance of 450 municipalities, agencies, corporations, and regional service commissions in administering the *Safety Codes Act* and the *Gas Code Regulation* • Provide oversight of safety codes activities such as permitting and inspections • Engage sub-councils in evaluating new and emerging issues in the safety codes system and making recommendations to Alberta Municipal Affairs
Alberta Boilers Safety Association (ABSA)	• Administers Alberta's pressure equipment safety programs under the *Safety Codes Act* with authority to enforce pressure equipment safety • Pressure equipment operates at pressures greater than 15 psi (103 kPa) and is designed in accordance with the *Pressure Equipment Safety Regulation* while equipment operating at less than 15 psi is under the *Gas Code Regulation* • The ABSA board of directors reports to the Minister of Municipal Affairs • ABSA obtains its authority from the *Boilers Delegated Administration Regulation* • ABSA works closely with the Safety Codes Council
Rural Utilities Branch	• Oversee technical aspects of hydrogen-blended distribution systems including setting and enforcement of standards for design, operations, maintenance, quality assurance, plant records, surveys and as-built drawings
Alberta Environment and Parks	• Industrial approvals for hydrogen production under *Environmental Protection and Enhancement Act*
Alberta Energy Regulator	• Licencing and oversight of pure hydrogen pipelines

Party	Role and responsibility
Alberta Utilities Commission	• Rate regulation to approve revenue requirements for low-pressure distribution utilities (ATCO and Apex) • Oversight of terms and conditions of service standards[59]
Distribution utilities	• Complete engineering assessments to ensure safety and integrity of hydrogen blending in gas distribution systems, including piping, fittings, pressure regulators, metering, line heaters, odorization, blending equipment and leak detection programs • Justification of operation and maintenance, and capital project costs
Canadian Standards Association and American Society of Mechanical Engineers	• Develop standards
Other	• Production, storage and transmission of hydrogen

102. In general, parties consider the current allocation of responsibilities between relevant Alberta agencies to be sufficient to accommodate the initial stages of hydrogen development and blending in the low-pressure distribution system. However, parties expressed a need for clear delineation of roles in addition to co-ordination and consistency between agencies. Further, submissions encouraged that applicable agencies work together to ensure that regulations are clear, adaptable and do not impede development. Submissions also emphasized that to avoid unnecessary regulatory overlap and confusion, the technical regulator for gas utility pipelines carrying hydrogen should be the same as the technical regulator for gas utility pipelines carrying natural gas because the pipelines will most often carry both commodities.

103. While the Commission considers that the current allocation of responsibilities between relevant Alberta agencies is capable of accommodating hydrogen development and its integration in the low-pressure distribution system, areas for improvement exist. For example, the existing allocation of responsibilities between the Rural Utilities Branch and the AUC results in a scenario where one agency is primarily responsible for technical regulation over low-pressure distribution pipelines while the other oversees economic regulation. A risk of uncertainty exists where the costs for a project approved by one regulator are assessed for prudency by another.

104. Similarly, ATCO explained that small-scale hydrogen production falls under the jurisdiction of Alberta Environment and Parks and requires approval under the *Environmental Protection and Enhancement Act.* ATCO considered that this creates ambiguity between Alberta Environment and Parks' authority to regulate such projects from a technical perspective and the authority of the distribution system's rate and technical regulators.

105. To reduce any uncertainty or ambiguity created by multiple agencies regulating various aspects of hydrogen, a government-initiated review involving those agencies with input from hydrogen proponents could be considered. This initiative might involve an exploration of the respective roles of each agency in hydrogen regulation including opportunities for co-ordination

59 Terms and conditions of service is a contract between the distribution utility and its customers that details how the natural gas distribution service will be provided.

and transfer of responsibilities. Consideration could be given to a single agency assuming responsibility over both the technical and rate regulation of the low-pressure distribution system. Alternatively, some type of co-ordinated review process could be established where a project is assessed in a single review by all relevant agencies, each bringing their unique areas of expertise.

106. Another outcome of a government review process could be the establishment of a memorandum of understanding or similar document that is made publicly available. Clearly setting out the applicable responsibilities of each agency and leveraging opportunities for consolidating roles will help reduce ambiguity and provide additional certainty to stakeholders.

107. Since the development of hydrogen and its integration in the low-pressure distribution system can be accommodated through the current regulatory framework, a government-initiated review would not be expected to act as an impediment to hydrogen blending or increase regulatory burden on utilities and other stakeholders. Rather, further study would allow pilot and other projects to proceed while opportunities for additional regulatory efficiencies are explored.

3.3 Safety

108. The Commission views safety as a critical issue with respect to hydrogen blending. Due to the differences between hydrogen and natural gas, the introduction of hydrogen into natural gas networks may have an impact on pipelines, gas properties and safety systems, metering equipment, and end-use equipment and appliances.[60]

109. One of the key differences between hydrogen and natural gas is that hydrogen has a lower volumetric energy density. The specific gravity of natural gas is approximately 0.60 whereas the specific gravity of hydrogen is roughly tenfold less at 0.07. The heating value of hydrogen is approximately 12 megajoules per cubic metre or one third that of natural gas at approximately 39 megajoules per cubic metre. As a result, to deliver the same amount of energy while blending hydrogen, pipelines and distribution networks would need to increase system pressure to increase the density of the blended mixture flowing through the pipeline. Since the operating pressure of a pipeline system is generally constrained by factors such as material design, pipe condition and leak history, the effective impact of hydrogen blending is expected to be a reduction in pipeline capacity. Pipeline design ultimately limits the pressure rating, which may limit the amount of hydrogen that is able to be blended.[61]

110. The small molecule size of hydrogen has given rise to an expectation that hydrogen will escape more rapidly than natural gas through any leaky portion of a piping system. However, some studies have reached experimental conclusions that leak volumes associated with blended hydrogen in low-pressure threaded piping systems are similar to those of natural gas.[62] In the event of a release, hydrogen will typically rise and disperse rapidly because of its low specific gravity thereby potentially reducing the risk of ignition at ground level. In the circumstance of a

[60] Hydrogen Strategy for Canada, Seizing the Opportunities for Hydrogen, A call to Action, December 2020, PDF page 84.
[61] Hydrogen Strategy for Canada, Seizing the Opportunities for Hydrogen, A call to Action, December 2020, PDF page 85.
[62] Hormaza Mejia, Brouwer, J., & MacKinnon, M., "Hydrogen leaks at the same rate as natural gas in typical low-pressure gas infrastructure," International Journal of Hydrogen Energy, vol. 45, pp. 8810-8826, 2020.

leak with low concentrations of hydrogen in natural gas, the lower density of hydrogen has been reported by some analysts to reduce the overall energy released in the event of ignition.[63]

111. Another difference is how hydrogen reacts with some metals. One of the impacts to pipelines and components exposed to hydrogen is embrittlement, where some metals can degrade when exposed to hydrogen over long periods. Embrittlement can lead to the development or growth of crack-like defects that can reduce the service life of the pipeline or component. The effects of hydrogen embrittlement depend on the type of steel and on operating conditions, including the hydrogen concentration, operating pressure and pressure cycling. In the Hydrogen Strategy for Canada, other metallic pipes, including iron (ductile, cast and wrought) and copper are identified as being free from embrittlement concerns, as are the polyethylene, polyvinylchloride and elastomeric materials more common in recently installed natural gas distribution networks.[64]

112. In addition, differences exist with respect to gas properties such as explosivity, flammability, ignition, dispersion and ability to add odorants for leak detection for hydrogen blends versus pure natural gas systems.[65] More specifically, hydrogen has a wider flammability range, higher laminar flame speed and lower minimum ignition energy compared to natural gas, which could, as some parties suggested, create more dangerous conditions if leaks are undetected.

113. Many parties stressed the importance of public safety and reliability and that changes may be required to safety and reliability standards of all natural gas distribution pipeline service providers to accommodate hydrogen blending into distribution systems. This section first outlines general safety concerns with respect to hydrogen blending followed by a review of submissions related to safety and reliability standards. Finally, a discussion of whether distribution utilities should be required to perform an engineering assessment of their pipeline systems to assess the risk of blending hydrogen into the natural gas stream is provided.

3.3.1 General safety concerns with respect to hydrogen blending

114. Parties identified a number of general safety concerns related to hydrogen blending including distribution safety and reliability standards, pipeline embrittlement, impacts to equipment such as meters, valves, gaskets and seals, public perception of safety, appliance and end-user impacts, and blending safety in transmission systems.

115. Apex stated that the tenets of delivering safe and reliable service would not change regardless of the volume of hydrogen blended into a distribution system. Similarly, it submitted that all natural gas distribution pipeline service providers should be held to the same safety and reliability standards, regardless of whether the provider implements hydrogen blending projects. ATCO considered that any provider pursuing hydrogen blending projects should be required to meet the same safety and reliability standards currently applicable for natural gas service.

63 Mark Crowther, "HyHouse: Safety Issues Surrounding Hydrogen as an Energy Storage Vector," Kiwa Gastech, Cheltenham, UK, 2015.

64 Hydrogen Strategy for Canada, Seizing the Opportunities for Hydrogen, A call to Action, December 2020, PDF pages 84-85.

65 Hydrogen Strategy for Canada, Seizing the Opportunities for Hydrogen, A call to Action, December 2020, PDF page 85.

116. Air Products agreed that natural gas providers who wish to provide blended hydrogen should be held to a high safety standard but stressed that existing natural gas pipeline systems are not optimized to transport hydrogen. It considered there to be unique safety and technical considerations involved with the distribution of blended hydrogen gas that do not exist with the transportation of natural gas. Air Products submitted that the safety and reliability of any hydrogen blending program must be carefully considered and it recommended systematic component reviews. It raised concerns with pipeline embrittlement, the increased flammability of hydrogen, legacy system leaks due to the smaller size of hydrogen molecules compared to natural gas, and a lack of approved odorant for hydrogen use. It noted that hydrogen burns almost invisibly which creates additional safety risks and recommended that more research be done to determine the best public safeguards.

117. ATCO maintained that existing safety codes and standards provide a framework for safe hydrogen blending on a system-by-system basis. In response to the safety concerns raised by Air Products, ATCO stated that:[66]

- Hydrogen blends and pure hydrogen would leak at the same rate as natural gas from typical natural gas distribution infrastructure.[67]
- Nitrogen oxides resulting from combustion of natural gas/hydrogen blends in typical natural gas domestic appliances stay steady or decrease.
- ATCO's natural gas distribution system is approximately 75 per cent composed of polyethylene, which is compatible with hydrogen and hydrogen-blended natural gas.
- A portion of ATCO's system is steel which may be susceptible to hydrogen-related pipeline embrittlement; however, the low operating pressures on the distribution system makes concerns with embrittlement and fatigue crack growth from hydrogen largely immaterial.
- The effectiveness of odorant in natural gas/hydrogen blends and pure hydrogen has been validated.
- Appropriate burner design can ensure that hydrogen burns with a visible flame.

118. ATCO maintained that most of its distribution system would be compatible with hydrogen-blended service with minimal to no modifications (including customer piping and appliances) and that the majority of its distribution system would also be compatible with pure hydrogen service with some modifications.

119. Other parties also emphasized the importance of safely introducing hydrogen blending. IEPS explained that it will be critical that hydrogen is both introduced and perceived by the public to be introduced in a safe manner. It stated that the perception of safety risk may be one of the largest public barriers to introducing hydrogen into Alberta and any reasonable steps to address that perception should be taken. The Federation expressed similar concerns with public perception of hydrogen safety and supported a government delivered and funded public education program around the relative safety and other positive attributes of hydrogen use.

[66] Exhibit 27256-X0063, 2022-05-03 ATCO's Reply Submission, PDF pages 9-13.
[67] Exhibit 27256-X0077, 2022-06-20 ATCO Gas' Comments - UPI Report - June 2022, PDF pages 2-4.

120. The Office of the Utilities Consumer Advocate (UCA) submitted that public safety and reliability are of paramount importance and must be subject to intense scrutiny. It stated that there is a need to ensure that the percentage blend of hydrogen does not pose harm to residential appliances nor result in affordability issues for the most vulnerable and that the current level of safety and reliability must be maintained. The UCA stressed that safety does not merely apply to natural gas infrastructure, pipelines, compressors, and meter stations, but also to storage, other infrastructure, and consumer devices that were designed to burn natural gas, not hydrogen.

121. In reply, ATCO acknowledged that public trust in hydrogen is contingent on meeting the safety expectations of Albertans and stated that it is addressing technical and safety aspects through its Fort Saskatchewan Blending Project. This includes speaking with impacted stakeholders, gathering data on their piping and appliances, complying with all technical and safety codes and standards, conducting various engineering and risk assessments, a robust appliance testing program, as well as close consultation with the City of Fort Saskatchewan and with the Rural Utilities Branch of Alberta Agriculture.

122. ATCO also stated that it has extensively tested the performance of hydrogen blends on traditional appliances and is safely blending up to 20 per cent hydrogen by volume into the homes of two ATCO employees with no reported issues with safety, appliances or reliability of hydrogen blends for heating and cooking. ATCO noted that other jurisdictions have operated for decades with hydrogen delivery through existing town gas[68] distribution systems, including Hawaii with up to 15 per cent hydrogen, Hong Kong with up to 52 per cent hydrogen, and Singapore with up to 65 per cent hydrogen. However, ATCO noted that there is much to learn about hydrogen in the Alberta context.

123. Gradient Thermal Inc. (Gradient) submitted that its space and water heating appliances are compatible with natural gas/hydrogen blends and noted that it is developing a pure hydrogen-fuelled syncFURNACE.

124. While the Commission recognizes that existing distribution systems may be compatible with blended hydrogen with minimal to no modifications, it also accepts that there are unique safety and technical considerations involved with blending hydrogen into the distribution system. Accordingly, for hydrogen blending to be successful, public safety and reliability is paramount, as is ensuring that relevant safety and reliability standards reflect hydrogen-specific considerations, as further discussed in Section 3.3.2.

125. While outside the scope of this inquiry, ensuring safety downstream of the meter, including in appliances utilizing blended hydrogen, is crucial. Consideration of appliance compatibility, visibility of flames and the use of odorants is necessary. While Alberta Municipal Affairs oversees safety issues downstream of the meter, the Commission recognizes that pilot projects will play an important role in studying and testing the safety of hydrogen blending and considers that further study in this area is required. Further discussion of appliance safety is provided in Section 3.8.

126. The Commission also agrees that public perception of safety is necessary to gain support for hydrogen blending. To achieve this outcome, government funded and delivered education initiatives targeting the relative safety and other positive attributes of hydrogen use could be

68 ATCO described town gas as a synthetic heating fuel typically manufactured from coal or oil.

considered. This aligns with the implementation measures outlined in the Hydrogen Roadmap which aims to improve public literacy on the broader use of hydrogen.

3.3.2 Safety and reliability standards

127. Several parties identified specific concerns with safety and reliability standards for hydrogen blending in natural gas pipelines. This issue is also highlighted in the Hydrogen Roadmap which acknowledges that public safety must be prioritized by creating hydrogen codes, standards and regulatory requirements which should be harmonized with other jurisdictions to ensure Alberta's competitiveness across the hydrogen economy.

128. The majority of the submissions acknowledge that existing technical, safety and reliability standards may require updating for hydrogen blending. Several parties described the applicability of safety standards, including CSA Z662 and noted that CSA Z662 is under review to be amended to address hydrogen and hydrogen-blended service. Some parties stated that additional information is required and that alignment between transmission and distribution companies is needed. ATCO explained that the CSA Z662 update has recently undergone public review and is expected to be published in mid-2023. ATCO stated that this update would include a more prescriptive and mandatory engineering assessment framework for hydrogen and hydrogen blending and would ultimately guide the establishment of a safe limit.

129. Apex submitted that in compliance with Section 2(1) of the *Gas Distribution Act*, it follows the Government of Alberta's *Technical Standards and Specification Manual for Gas Distribution Systems*, which identifies that the latest edition of CSA Z662 should be considered as the principal guideline for the design, construction and operation of distribution systems. ATCO added that in general, CSA Z662 is intended to establish requirements and minimum standards for the design, construction, operation, pipeline system management, and abandonment of pipeline systems, and that the current edition is applicable for hydrogen and hydrogen-blended service. ATCO stated that all distribution pipeline service providers must meet all applicable portions of CSA Z662 for a given service (e.g., natural gas, hydrogen-blended natural gas, hydrogen, etc.) and that existing hydrogen pipeline infrastructure in Alberta was designed, constructed and is being operated in accordance with this standard.

130. With respect to whether additional changes are required to safety and reliability standards, Apex stated that technical safety and reliability standards, such as those covered in CSA Z662 and CSA B149.1,[69] may require updating as industry experience with hydrogen evolves. It added that changes are not required to existing safety and reliability standards applicable to natural gas distribution, such as AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors* or Alberta Energy Regulator Directive 071: *Emergency Preparedness and Response Requirements for the Petroleum Industry*.

131. Air Products noted that the percentage of hydrogen that may be blended without requiring significant upgrades to the distribution system (and the associated costs) may differ for each distribution utility system, depending on the age of infrastructure, materials and end uses. Air Products expected that changes to safety and reliability standards may be necessary to accommodate hydrogen blending for the residential and commercial heating market but

[69] CSA B149.1, Natural Gas and Propane Installation Code.

submitted that any such changes would need to be informed by further research and a detailed engineering assessment of the pipeline systems of each distribution utility.

132. Kiwetinohk stated that if legislative changes to the definition/specification of gas are made, changes would be required to safety and reliability standards of all natural gas distribution pipeline service providers. It also explained that confidence in the regulatory process from the consumer's perspective requires broader consultation and implementation. Similarly, ENMAX Corporation and ENMAX Energy Corporation (ENMAX) stated that safety and reliability standards would need to be amended to accommodate the inclusion of hydrogen into the natural gas distribution system to ensure leakage of hydrogen into the atmosphere is minimized to the greatest extent practical. Direct Energy also submitted that changes are likely required to meet specific safety standards.

133. The UCA also agreed that changes are required to safety and reliability standards given the highly flammable nature of hydrogen and the limited amount of experience with hydrogen blending in natural gas distribution systems. It stated that the establishment of hydrogen codes, standards and regulations must be completed, whether implemented by the CSA or a similar agency and that consideration must also be given to consumers.

134. The Federation submitted that there is inadequate information to comment on safety and reliability issues, but conceptually, safety and reliability standards require review when the practical application of blended hydrogen is studied and considered.

135. NGTL stressed that alignment is needed between transmission and distribution companies to ensure that hydrogen can be safely transported through both systems. It considered stakeholder and industry collaboration on modelling and testing to understand impacts and necessary updates to safety systems to be vital. It also emphasized the need for uniform, international, hydrogen-specific technical standards for plants, equipment and hydrogen as a product and considers that development and alignment of codes and standards for hydrogen blending would help to ensure the safe and efficient development and transportation of hydrogen. Air Projects agreed with this position and stated that the Government of Alberta should make use of relevant information gained from industry consultations on blending service standards, whether by the CSA or other organizations or jurisdictions.

136. The Commission supports the philosophy outlined in the Hydrogen Roadmap regarding the prioritization of public safety by creating hydrogen codes and standards and regulatory requirements. Further, alignment of codes and standards, and regulatory harmonization with other jurisdictions will be crucial to ensuring hydrogen blending safety and reliability. The Commission considers it important to harmonize and clarify hydrogen regulations with federal and provincial governments to support the development of national and provincial codes and standards. In that respect, development of a Canadian standard to more specifically provide checklists and details to address issues associated with hydrogen piping and blending would be helpful.

137. ASME B31.12[70] is an American standard from the American Society of Mechanical Engineers that applies to construction, operation, and maintenance requirements for piping, pipelines, and distribution systems in hydrogen service. A Canadian standard could result in a

[70] American Society of Mechanical Engineers standard ASME B31.12, Hydrogen Piping and Pipelines.

standard similar to ASME B31.12 or could refer to that standard. This approach has historic precedence wherein CSA Z662 makes frequent reference to ASME B31.3, Process Piping. Another example is that Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* references ASME B31.3, Process Piping with respect to line heater installations. In the interim, ASME B31.12 could be adopted to guide projects for hydrogen blending in distribution systems.

138. The Commission understands that the 2023 update to CSA Z662 is expected to more formally reference the need to complete an engineering assessment for hydrogen blending infrastructure and pipelines but may fall short with respect to specific details. This would mean that the onus on the engineering assessments would fall to the individual pipeline system operators and that the regulatory agency with oversight would subsequently be required to analyze those engineering assessments and make findings on the results. This could increase the required regulatory expertise, training requirements and associated costs, for both the pipeline operators and regulatory agencies, that might be somewhat alleviated with more prescriptive standards.

3.3.3 Requirement to perform an engineering assessment prior to blending hydrogen

139. The majority of parties agreed that before any blending occurs on the distribution system, distribution utilities should be required to perform an engineering assessment of their pipeline systems to assess the risk of blending hydrogen into the natural gas stream.

140. Apex and ATCO stated that an engineering assessment for hydrogen service is mandatory under the current version of CSA Z662. ATCO stated that CSA Z662 is intended to be used by persons competent to make technical judgments in the areas related to engineering, safety and environmental protection. They added that CSA Z662, by way of an engineering assessment, would be used to establish the maximum, safe, allowable percentage of hydrogen by volume for a given system and to assess the risks of hydrogen blending. As such, Apex stated that there is an existing expectation for distribution utilities to perform an engineering assessment of pipeline systems prior to introducing hydrogen as part of the due diligence and compliance for safety, performance and quality assurance as described in CSA Z662 and established through the *Technical Standards and Specification Manual for Gas Distribution Systems* and the *Gas Distribution Act*.

141. With respect to the CSA Z662 update, Apex and ATCO expect that it will include a more prescriptive engineering assessment framework for introducing hydrogen into existing natural gas systems, which will ultimately guide the establishment of the maximum, safe, allowable percentage of hydrogen by volume for a given system. Apex stated that distribution utilities would continue to ensure that the safety and reliability of the systems they operate remain paramount, and that the utilities will complete full assessments of system capabilities and operational practices to ensure safety and reliability is achieved, including the completion of engineering assessments that are compliant with CSA Z662. ATCO stated that because this is mandatory within CSA Z662, all proposed projects that include hydrogen or hydrogen blending, must meet the requirements of CSA Z662 and therefore, there is no need for additional provincial measures to be implemented in addition to what is contained within CSA Z662 and established through the *Gas Distribution Act* and the *Technical Standards and Specification Manual for Gas Distribution Systems*.

142. Air Products submitted that hydrogen causes embrittlement or cracking in the welds of pipelines under certain operating conditions, depending on the metallurgy[71] of the piping. It noted that distribution of a blended hydrogen product through pipelines initially optimized for natural gas requires a thorough systematic, component-by-component review to ensure safe operation at the desired blend level. It stated that this would typically include an assessment of whether the specific steel metallurgy properties will be susceptible to embrittlement, as well as ensuring the soft goods, such as gaskets and valve packings, are compatible with hydrogen and will not leak. Air Products stressed that it is important that public confidence in hydrogen as an alternate fuel source is maintained and strongly supported utilities being required to engage in an independent detailed engineering assessment of their pipelines prior to blending hydrogen. Air Products agreed with ATCO and Apex that the current and soon-to-be updated CSA Z662 is relevant and should be reviewed and considered before determining whether any additional provincial assessment requirements should be adopted but cautioned that CSA Z662 should not be used as a basis to allow distribution system owners to establish their own blending percentages.

143. The UCA, IEPS, ENMAX, Calgary and the Transition Accelerator agreed that distribution utilities should be required to perform an engineering assessment of their pipeline systems to assess the risk of blending hydrogen into the natural gas stream. The UCA stated that an engineering assessment should be completed to identify and assess risks associated with blending hydrogen into the natural gas stream as well as any costs related to blending, including changes to operations and maintenance. The UCA added that a detailed safety risk assessment must be conducted for Alberta conditions and the accuracy of gas meters must also be examined. The UCA further stated that natural gas must currently comply with specifications for heating value and applicable pipeline gas specifications to avoid contamination of the gas stream and to ensure the optimum operation of gas turbines and equipment and submitted that the same must be required of hydrogen and hydrogen blending. Calgary added that it expected all necessary risk assessments would be undertaken before blended gas would be approved for distribution.

144. The Canadian Hydrogen and Fuel Cell Association (CHFCA) also submitted that utilities should perform an engineering assessment of their pipeline systems to assess the risk of blending hydrogen into the natural gas stream. The engineering assessment should also include the end users (not just the transmission pipelines or distribution networks) so that residents can have confidence that proponents have done their due diligence to ensure that the introduction of hydrogen blending is a seamless process that does not inconvenience them. In the same manner, Direct Energy stated that distributors should do their due diligence when it comes to safety.

145. Similarly, the Federation submitted that if studies show that there are increased risks associated with the delivery of a blended hydrogen natural gas, then a risk assessment would be required that might include an engineering assessment. It added that if Federation members were mandated to deliver blended hydrogen natural gas, engineering studies should be funded by the provincial government.

146. The Commission agrees with the majority of parties and finds that safety and engineering assessments should be conducted before hydrogen is blended into distribution systems. Given that there is no accepted technical standard at this time, the engineering assessment should be

71 Metallurgy is part of materials science and engineering that involves the study of the physical and chemical behaviour of metals.

done by an independent engineering firm, unless the utility has the technical expertise and experience to conduct its own engineering assessment. A determination of who should bear these costs requires further consideration. Given the public safety considerations associated with hydrogen blending, the safety and engineering assessment could include:

- A systematic, component-by-component review to ensure the safe operation of the distribution system at the desired blend level.
- Pipeline integrity and pipeline operations manuals.
- Pipeline stress analyses.
- Metallurgical susceptibility to hydrogen embrittlement.
- Technical data supporting the compatibility of soft goods, such as gaskets and valve packings, with hydrogen and hydrogen-blended products.
- Pipeline age and leak history.
- Assessment of any increased leak potential due to the different gas properties.
- Leak detection equipment.
- Assessment of metering, pressure regulation, and odorization.
- Assessment of the site proposed for blending including space provisions for incremental metering and control systems for hydrogen blending, hydrogen storage if required, and any additional buildings or structures, incremental noise, environmental implications/mitigation and public notification/consultation.
- Downstream of the meter house piping, while outside the scope of this inquiry, could include:
    - Gas interchangeability assessment including heating value and Wobbe index.[72]
    - Appliance compatibility and assessment of combustion stack including increased water.
- Consideration of potential daily and seasonal fluctuations in gas quality.

147. In Section 3.2, the Commission identified that a government-initiated review could be considered to reduce uncertainty or ambiguity created by multiple agencies regulating various aspects of hydrogen. As part of that review, consideration could be given to establishing a process for approving engineering assessments prior to a project proceeding.

148. The Commission recognizes that at higher blending levels, safety concerns may increase. Some parties stated that CSA Z662 is being amended to include a more prescriptive and mandatory engineering assessment framework for hydrogen and hydrogen blending and to guide the establishment of a maximum blending threshold. Further discussions about blending levels are discussed in Section 3.4.

[72] Wobbe index is an indicator of the interchangeability of fuel gases.

3.4 Hydrogen blending thresholds

149. The Commission asked parties whether there should be a specified amount of hydrogen blended into the natural gas distribution system or whether it should be at the discretion of the distribution system owner to establish criteria for its system. There were generally three distinct views with respect to maximum blending thresholds (i) leave it to the discretion of the distribution system owner, (ii) a guideline or flexible blending threshold may be useful, and (iii) a firm maximum blending threshold is required. Several parties also raised concerns with requirements for minimum blending thresholds, including in industrial applications. These issues are discussed in the sections below.

3.4.1 Maximum blending threshold

150. Several parties opposed the imposition of a maximum blending threshold and suggested that it should be left to the discretion of the distribution system owner. ATCO and Apex raised concerns that maximum blending thresholds would introduce a new barrier to the optimization of hydrogen-blended systems and transition towards pure hydrogen distribution systems, contrary to the decarbonization target established by the Government of Alberta. Both supported utilities having the flexibility to maximize blend rates where possible, noting that greenhouse gas emissions decrease at an accelerating rate with increased hydrogen blend rates. ATCO submitted that the maximum blended amount for any given system would be governed by CSA Z662 and as such, there would be no need for legislation to establish a maximum blending threshold from a safety perspective which, in any event, would likely rely on CSA Z662.

151. Similarly, Kiwetinohk stated that the blending amount should be at the discretion of the distribution system owner according to what the market dictates adding that safety considerations and communication of standards to customers are critical. ENMAX submitted that given the unique circumstances of each distribution system, it should be left to the owners' discretion to establish criteria for its system. It noted that it may be more difficult and costly to accommodate higher levels of hydrogen blending depending on the system.

152. Calgary submitted that as long as there is a clear separation between (i) the blending function and the marketing of blended gas function and (ii) the gas transmission and distribution function, the system owner can establish blending standards for its own operational purposes, subject to applicable requirements and standards.

153. The Consumers' Coalition of Alberta (CCA) stated that hydrogen blending is currently not cost effective but is driven by a desire to de-carbonize the system, and therefore it is concerned that targets would be politically, not economically driven. The CCA added that there may be engineering limits for distribution utilities as a whole and variability in engineering between distribution utilities, and therefore, flexibility is likely required.

154. The Transition Accelerator did not recommend maximum blending thresholds but submitted a report that stated that hydrogen can be mixed with natural gas at up to 15 per cent by volume in pipelines serving residential and commercial buildings with minimal impact on infrastructure or fuel cost. In the report, the Transition Accelerator recommended that work be done to explore the use of up to 100 per cent hydrogen for residential and commercial buildings and for heat and/or power generation.

155. Several parties supported the use of a guideline or flexible maximum blending threshold. Direct Energy stated that thresholds should be established but distributors should have flexibility within their system to ensure safety. It also considered that blending standards should not be prescriptive on commodity type, but rather should be determined by market and supply availability.

156. The UCA submitted that because hydrogen blending is in its infancy in Alberta, a specific standard of hydrogen blended into the natural gas distribution system should be established. It noted that research and pilots in other jurisdictions have shown that between 15 and 20 per cent hydrogen can be mixed into the natural gas distribution system without adverse impacts and stated that research and pilot projects should be initiated in Alberta, with an initial low percentage of hydrogen to allow utilities and consumers to adjust to these changes. The UCA further stated that starting out with a maximum blending threshold of five to 15 per cent hydrogen would allow flexibility to ensure that end users are not negatively impacted, and safety is prioritized.

157. Similarly, IEPS stated that in the absence of any extensive operating history, some general rules and guidelines should be put into place in the early stages of hydrogen blending. It added that once operational history has been established, distribution owners should have the right to appeal any particular standard and regulators should have the discretion to vary that standard if it is convinced that it would be in the public interest.

158. Certain parties supported the establishment of a firm maximum blending threshold, at least initially. Air Products recommended that conservatively low blend levels be initially progressed on a pilot basis to ensure that the blended gas can be safely and affordably delivered with no adverse consumer impacts. Air Products recommended that similar to the approach taken by the Ontario Energy Board, incremental increases be permitted up to a maximum blending threshold set by legislation, with regulatory oversight and third-party assessments undertaken at each incremental blend level.

159. Air Products disagreed that distribution utility owners should be provided with discretion to establish blending standards for their systems (subject only to the provisions of CSA Z662), or the use of a carbon intensity metric for the natural gas system and considered these options to be a risk to safety and reliability. It added that if there are any ratepayer impacts, it would be difficult to show that the benefits are accruing to those customers who have borne the costs if the utility company can dynamically change their blends at any time throughout their system. Air Products stated that this approach would short circuit the methodical review needed to ensure that a particular hydrogen blend level applied to a specific segment of the distribution system will not adversely impact those customers.

160. Similarly, the Federation stated that the amount of hydrogen blended with natural gas should be regulated and not left to the discretion of the distributor, but that there is insufficient data for it to comment on what the blending levels should be. CHFCA submitted that there should be a discussion in this regard, with the specified amount arrived at by consensus.

161. The Commission acknowledges ATCO and Apex’s concern regarding potential barriers to the adoption of higher percentages of hydrogen in blending systems if a maximum threshold were implemented but notes that blending levels above 20 per cent are outside the scope of this inquiry.

162. The Commission believes that completion of an engineering assessment of all aspects of the distribution system in accordance with standards such as CSA Z662 is an important tool to be used when considering a distribution system's ability to blend hydrogen. In that respect, the Commission considers that certain materials, layouts, vintages and appliances may be found to safely facilitate higher maximum blending thresholds after completion of a thorough review. Conversely, other systems or portions of systems may require upgrades before incorporating higher blending levels. For example, a subdivision developed within the last 10 years using polyethylene gas mains and new appliances might be a good candidate for consideration, whereas a 50-year old steel system with a history of leaks and old appliances could warrant more investigation. The Commission finds safety concerns, costs and end-user impacts to be important considerations when determining how much hydrogen to blend into a system. Likewise, a cautious approach is reasonable when establishing a blending threshold, as is the establishment of a firm maximum blending threshold by volume.

163. Consistent with the Hydrogen Roadmap, stakeholders supported an initial maximum blending threshold of 15 to 20 per cent when considering safety and customer impacts. The Hydrogen Roadmap added that "introducing [hydrogen blended with natural gas] at blend volumes of up to 15 to 20 percent generally does not require device retrofits from the end customer, while also leveraging existing gas distribution networks with minimum physical changes required."[73] Therefore, the Commission finds that a maximum blending threshold of 20 per cent by volume is reasonable. Notwithstanding, this finding is only with respect to a maximum blending threshold and does not suggest that pilot projects should start at this level. The phased implementation of hydrogen blending will be discussed further in Section 3.6.

164. With respect to implementing a maximum blending threshold, as discussed in Section 3.1, changes could be made within the *Gas Utilities Act* to the definition of gas (and included by reference in the *Gas Distribution Act*) to include a maximum blending threshold of up to 20 per cent hydrogen by volume within a low-pressure distribution system. This would provide clarity to industry and consumers and if it is determined that this maximum blending threshold should be changed in the future, it would not be overly burdensome to update the legislation.

3.4.2 Minimum blending threshold

165. Several parties raised concerns with minimum hydrogen blending thresholds, including in industrial applications.

166. The Federation submitted that many industrial applications, including machinery and equipment, are not compatible with a natural gas and hydrogen blend, which would impact its members, their domestic customer base, and their industrial customers. The Federation explained that its members do not have infrastructure that would allow segregation of these services and that in many cases, Federation members have been serving industrial customers pursuant to contracts that specifically address natural gas quality. It also noted that currently, none of these contracts provide that the Federation member can deliver a natural gas and hydrogen blend.

167. Cancarb Limited (Cancarb) stated that the addition of hydrogen would likely have detrimental effects on both sides of its business. For its carbon black business, the addition of hydrogen would change the properties of its carbon black and not allow it to meet customer

[73] Exhibit 27256-X0009, Alberta Hydrogen Roadmap (2021), PDF page 35.

specifications. On the power generation side, Cancarb anticipated that hydrogen would increase its emissions and cause problems with its operating permit. Cancarb submitted that if the mandate to make this change applies to more than just home-heating, the impact on petrochemical feedstock supply for the chemical industry must be considered in detail.

168. Air Products submitted that it is premature to establish a system-wide minimum blending threshold until proper reviews are completed, and it is determined that the benefits to ratepayers of hydrogen blending outweigh the associated costs. Similarly, Direct Energy submitted that the government has a role in setting the minimum blending threshold, ensuring there are clear definitions, but should not be picking winners and losers. It added that consideration should be given to industries that would require 100 per cent natural gas use as their input in production.

169. ATCO responded that initial blending projects would blend hydrogen on distribution systems and not transmission systems, such as the ones that serve most customers with industrial process loads. ATCO added that over time, it expected to work with industrial customers on pilot projects and study this issue further. ATCO stated that these pilot projects would be developed in concert with customers and reviewed by the utilities' regulators to ensure the safeguarding of the public interest.

170. The Commission does not believe that a minimum blending threshold should be established at this time due to the limitations and capabilities of some distribution systems, the potential impacts on customers and the potential costs that may be incurred. Further, as discussed in Section 3.5, factors such as geography, proximity to hydrogen production, compatibility of the distribution system, and demand levels due to population also point to the requirement of a minimum blending threshold being premature.

3.5 Delivery of services to rural natural gas consumers

171. There are significant differences between large urban and rural natural gas systems. Many parties submitted that hydrogen blending is not practical or cost effective in small towns and rural utility systems. Some of the factors identified as influencing practicality and cost effectiveness included geography, proximity to hydrogen production, compatibility of the distribution system, and demand levels due to population.

172. Air Products submitted that the introduction of hydrogen blending is likely best suited to more urban areas and those near an established source of hydrogen, while the cost effectiveness of blending hydrogen in small municipalities and rural utility systems located far from a production source or other hydrogen off-takers is likely more challenging. It questioned the economic viability of hydrogen projects in small municipalities and rural areas given the lower demand and requisite investment in infrastructure, including transmission pipelines, compression stations and blending stations. It added that at higher blending levels, there is likely a need to replace existing distribution system infrastructure and end-use customer appliances, further challenging the potential viability of hydrogen blending.

173. The Federation questioned the practicality of introducing hydrogen into rural utility systems and noted the acknowledgment in the Hydrogen Roadmap that hydrogen use is currently limited to large scale or centralized industrial applications. It predicted that the application of hydrogen blending would remain limited to centralized use (i.e., contained within an urban

natural gas distribution system), and considered the infrastructure and technology to blend sufficient quantities of hydrogen into natural gas for distribution to be in an early development stage. The Federation also explained that its members use multiple receipt points for the natural gas that they distribute which creates additional complications for the distribution of blended hydrogen in rural Alberta. It stated that until there is capacity to transport blended hydrogen at high pressure, there is practically no source of blended hydrogen for Federation members to purchase and so further study and discussion is required.

174. Conversely, IEPS submitted that electrolysers may offer a simple, cost-effective solution to introduce hydrogen service into small towns and rural Alberta.

175. The Commission agrees that there are significant differences affecting the practicality of implementing hydrogen blending in smaller municipalities and rural utility systems due to factors such as geography, proximity to hydrogen production, compatibility of the distribution system, and demand levels due to lower population densities as compared to ATCO and Apex, both investor-owned utilities. The Commission notes the submission of the Federation that the large number of gate stations required to supply smaller rural utility systems increases both the complexity and costs of trying to assess the risks, practicality, efficiency, and cost-effectiveness of a proposed transition to hydrogen blending in these systems.

176. In light of these challenges, the Commission is of the view that the focus, at least initially, should be on hydrogen integration within larger municipal systems. In the future, solutions may emerge that make blending hydrogen into rural systems more practical.

177. The majority of parties do not support requiring smaller rural utilities to blend hydrogen if they are located far from a source of hydrogen or the infrastructure costs are prohibitive. The reasons provided include that:

- Utilities should be permitted the flexibility to determine the most prudent pathway to achieve government mandates (Apex, ATCO, Direct Energy).
- It is not practical (the Federation).
- It must be economically acceptable to the public (IEPS).
- It should be left to evolve organically (Direct Energy).
- It would result in a cost disadvantage to ratepayers in those service areas and this could result in higher costs for consumers (UCA).
- Hydrogen blending should start low and go slow, starting with pilot projects near an established source of hydrogen (Air Products).

178. The CCA added that this issue would be a political decision, not an economic one.

179. The Commission agrees with the majority of submissions that there likely should not be a requirement for rural utilities, nor for any gas utility or gas co-operative, to blend hydrogen, especially if they are located far from a source of hydrogen or if the expected benefits, including social and environmental benefits, do not outweigh the infrastructure costs. With respect to rural Alberta, it appears that there are other complications with the distribution of blended hydrogen such as the need to blend hydrogen with natural gas at multiple sources, which would make

compliance with such a requirement impractical. Further discussion about minimum blending thresholds is provided in Section 3.4.2.

3.6 Regulated and competitive segments of hydrogen blending

180. This section discusses submissions from parties on the role of the regulated and competitive segments of the hydrogen market. First, it outlines an approach that the Government of Alberta may want to consider for implementing hydrogen blending. Then it assesses what components of the hydrogen market (i.e., storage, production facilities, high-pressure pipelines, distribution pipelines and the hydrogen commodity price) could be regulated or left to competitive market forces.

3.6.1 Phased approach to hydrogen blending

181. Parties generally supported either a more aggressive timeline or a go-slow approach for the development of hydrogen blending.

182. ATCO and Apex proposed a two-stage approach, where the utilities would procure hydrogen as an additive to the natural gas stream, recovering costs through distribution rates until supply becomes more available and hydrogen procurement would then transition to retailers. ATCO and Apex also suggested that small-scale (less than 5,000 kilograms per day), utility-owned hydrogen production may be necessary to facilitate operational pilot projects to test technical and economic feasibility in ATCO's broader service area. Some parties expressed concerns with this approach and argued that the function of gas utilities should be limited to blending and providing low-pressure distribution service to customers.

183. Conversely, Air Products advocated for a "start low, go slow" approach to the development of hydrogen blending. It suggested that the first phase should involve limited pilot projects and other research and development activities to assess the cost-effectiveness and technical feasibility of hydrogen blending, which may be best administered through the delivery charge. Air Products recommended that conservatively low blend levels be initially progressed on a pilot basis to ensure that the blended gas can be safely and affordably delivered with no adverse consumer impacts. It added that consideration of future phases is not necessary at this time and can be assessed once the merits of proceeding with larger-scale hydrogen blending have been adequately demonstrated. Air Products also stated that:

- The free market should drive the development of the hydrogen sector.
- The implementation of blended hydrogen for residential and commercial heating must be cautious, with the level of hydrogen increasing only as information on reliability becomes available.
- Limited, targeted changes should be applied to clarify roles and regulation.

184. Several parties, including IEPS, Kiwetinohk, the Transition Accelerator, Direct Energy and the UCA, disagreed with the timing suggested by Air Products and instead submitted that a decision should be made as soon as possible regarding what should be provided by regulated versus competitive hydrogen producers.

185. The UCA and the CCA stated that hydrogen blending into the natural gas system would initially be more costly than traditional natural gas supply. The UCA added that hydrogen blending should be simultaneously phased in across the province to avoid cross-subsidization. The UCA considers that industry and investors should lead the implementation of hydrogen communities, and the early phases should be unregulated and open to innovation.

186. While there appears to be support for two different approaches to the development of the hydrogen market, the Commission considers a slower, phased approach to hydrogen blending to be reasonable. This is because further study is required to fully understand the safety and integrity concerns regarding the introduction of hydrogen in natural gas distribution systems, hydrogen blending thresholds, the impact of hydrogen on competitive retailers and pricing, determination of the components of the hydrogen market that will be regulated or competitive, the impact hydrogen might have on home appliances and furnaces, and a myriad of other factors. In addition, the overall costs of hydrogen blending, and potential rate shock to customers should be considered. Before full-scale hydrogen blending is implemented, detailed consideration of the above issues and a clear regulatory framework is likely required.

3.6.2 Components of the hydrogen market that should be regulated or left to competitive market forces

187. This section discusses what components of the hydrogen market could be regulated or left to competitive market forces. These components include hydrogen production facilities, above ground and underground hydrogen storage facilities, both for hydrogen production and distribution utility purposes, pure hydrogen transmission (high-pressure) pipelines, blending stations, existing or new distribution pipelines (low-pressure) used to transport blended hydrogen, and whether the commodity of hydrogen should be procured and provided to customers by retailers similar to the current natural gas market.

188. In general, parties supported the establishment of clear boundaries regarding the responsibilities of regulated distribution utilities and the role of the competitive market. Some parties expressed a concern that any utility involvement in hydrogen production could act as an impediment to the development of the competitive hydrogen marketplace. Others asserted that retailers should be responsible for buying hydrogen.

189. ATCO and Apex recommended the following in this regard:

- Production facilities should be regulated in a limited context. In the absence of large-scale, low-cost, low-carbon hydrogen, production facilities should be owned and operated by the utility and subject to AUC regulation to the degree that they are required to allow small-scale, localized hydrogen production. Otherwise, they should be left to the competitive market.
- Above-ground hydrogen storage facilities should be regulated in a limited context similar to production facilities.
- Utility required storage services should be regulated by the AUC, which would assess the prudence of any storage-related costs incurred by any utility contracting for them. Once retailers take over the procurement of hydrogen, their commercial interests would determine whether underground storage is needed.

- A single (or very few) large hydrogen pipeline network(s), regulated with costs subject to AUC review, would be best to enable low-cost access to low-carbon hydrogen supply. However, individual hydrogen producers and consumers should not be prevented from entering into commercial agreements that may entail non-regulated pipelines.
- Blending stations should be included in natural gas distribution infrastructure and regulated.
- Natural gas distribution systems should continue to be regulated when they distribute hydrogen in conjunction with or in substitution for natural gas.

190. Many parties disagreed with ATCO and Apex on the extent of what should be regulated. Air Products maintained that the only hydrogen-related assets that should be regulated are low-pressure blending stations and low-pressure distribution systems for blended gas serving residential and commercial customers. Given the existing competitive market for larger-scale hydrogen production, it was not clear to Air Products why utilities would be required to engage in small-scale production. Air Products submitted that development and operation of other supply chain components is best left to private industry. However, it added that a determination of what should be provided by regulated or competitive providers of hydrogen is likely not required at this time. Air Products considered it premature to broadly consider the administration of commodity costs for hydrogen blending, until hydrogen blending is studied, proven safe and reliable, and it is shown that the benefits outweigh the costs, given that hydrogen blending through the existing natural gas distribution system would result in incremental costs.

191. Direct Energy submitted that blending facility costs could be regulated as part of transmission and distribution rates, while commodity costs and procurement should be provided by the competitive retailer based on the percentage of hydrogen requested by customers. Direct Energy stated that service areas should be maintained, the function of the default supplier should remain, and pilot projects should be administered through a request for proposal process. Further, a separate market for the environmental aspects of the gaseous energy (hydrogen and/or renewable natural gas) should be allowed to exist independently of the gaseous energy itself.

192. ENMAX, IEPS, the UCA, the CCA and Calgary opposed the commodity cost of hydrogen being a regulated utility system cost and instead supported allowing the hydrogen market to develop competitively. ENMAX and Kiwetinohk submitted that each retailer should be able to set their own price for hydrogen based on a competitive market.

193. ENMAX submitted that assets linked to the distribution of hydrogen should be regulated, and that the incumbent regulated utility should have the right to control the timeline and percentage of hydrogen introduced into the stream, with a gradual introduction by distribution utilities to minimize price increases and rate shock. Further consideration would be required to determine costs that should be included in the regulated revenue requirement of natural gas utilities versus what costs should be left to the competitive marketplace.

194. IEPS suggested that utilities should manage the receipt and blending of hydrogen into the distribution system, with competitive hydrogen producers responsible for delivering hydrogen to its customers with access to the existing natural gas distribution system under fair and reasonable rules. It further suggested that well-defined application requirements for hydrogen production, storage and transportation facilities should be established.

195. The UCA and the CCA submitted that utilities should not be allowed to build infrastructure related to upstream transportation, development, production and the storage of hydrogen. They believe that the competitive market for hydrogen should function similarly to the competitive market for natural gas, where producers supply the gas product to the wholesale market, retailers buy it, and transmission and distribution companies deliver it.

196. Calgary recommended a separation of (i) the blending and the marketing of blended gas functions and (ii) the gas transmission and distribution functions. Calgary suggested that hydrogen-related operations should be treated as a midstream or upstream function, separate from gas distribution operations, with a hydrogen market that provides flexibility to natural gas transmission and distribution operators, midstream operators and producers. It maintained that current gas transmission and distribution utilities should only be permitted to recover hydrogen-related costs from ratepayers if the costs were: technically necessary to modify existing gas transmission and distribution systems and operations to carry gas blended with hydrogen (but excluding the blending function itself), used and useful in the public service, prudently incurred and would result in just and reasonable rates. Calgary urged the Commission to consider the competitive retail impacts of blending hydrogen into gas distribution systems before determining whether the costs of hydrogen should be utility system costs during the early stage of hydrogen blending.

197. In response to Calgary, ATCO submitted that leaving hydrogen blending in the hands of midstream companies would inevitably require blending hydrogen into the gas transmission system, which could negatively impact high-pressure pipeline compression materials and customers.

198. In general, the Transition Accelerator submitted that an open-access hydrogen market is required, particularly one that considers the carbon intensity of hydrogen, and allows for fair value of the carbon intensity to be applied to hydrogen pricing and carbon credits where appropriate. It explained that the market should allow for purchase agreements that account for carbon intensity in a similar manner to the electricity market that allows for power purchase agreements for low-carbon electricity.

199. The Federation submitted that hydrogen blending should utilize existing infrastructure as a means to mitigate the cost prohibitive aspect of hydrogen blending in rural natural gas distribution systems.

200. The Commission believes that the existing services permitted to be provided by regulated distribution utilities could frame the longer-term goals of hydrogen blending.

201. The Commission considers that it would be reasonable for the distribution utility to manage and be responsible for the blending of hydrogen into its natural gas system due to the potential safety and integrity concerns related to hydrogen, while ensuring the blend of natural gas and hydrogen adequately provides service to customers without interruption to home appliance, furnace or other required uses. Introducing a third party to be responsible for blending hydrogen potentially creates an unnecessary safety risk to customers. Reasonable and necessary incremental costs directly related to hydrogen blending into the natural gas distribution system would be recoverable by the utility, which would ultimately be passed on to the utility’s customers through the rates it pays for utility service.

202. All other hydrogen market segments (production, storage and transportation) likely require further study and a better understanding of the impact on customers, but the Commission does not see any obvious impediments as to why the competitive market cannot ultimately provide these functions. Costs related to production of natural gas and storage generally falls outside of the current rate-regulated framework for natural gas delivery in the province. The Commission considers that the introduction of hydrogen aligns with the existing treatment of distribution and commodity costs of natural gas. As such, hydrogen production and facility costs are likely best provided by the competitive market.

203. Similarly, the Commission is of the view that retailers (including the default supply provider) should be responsible for procuring hydrogen. The Commission recognizes that evolving markets are sensitive to price signals, and this should be considered as legislation and policy develop to avoid frustrating competitive initiatives. The Government of Alberta may want to consider further study to better assess the current competitive environment for hydrogen.

204. Given the uncertainty of current legislation with respect to hydrogen and other factors examined in this inquiry, the Commission noted in Proceeding 26616[74] that the opening and closing 2023 rate base and customer rates of ATCO and Apex may be subject to adjustments in the future with respect to the introduction of hydrogen-related costs into their respective distribution systems.[75] ATCO forecast capital costs for hydrogen pilot projects and studies of $25.2 million and $28.2 million for 2022 ad 2023, respectively, plus operation and maintenance costs of $0.4 million in 2022 and $1.5 million in 2023.[76] The Commission deferred consideration of forecast hydrogen program expenditures until jurisdictional concerns and legislative amendments are addressed. As such, the immediate impact on distribution rates is still unknown.

205. With respect to hydrogen procurement and pricing, Direct Energy, the UCA, the CCA, Calgary, Air Products and the Federation maintained that it is premature to consider these issues until a determination is made that the benefits outweigh the costs. The Federation also stated that further studies are required regarding safety, reliability and cost/benefit analysis to producers, distributors and customers before discussing hydrogen procurement and pricing options. While IEPS submitted that waiting to ensure that all technical questions are addressed, before considering procurement issues, would significantly delay the creation of markets and supply.

206. The Commission agrees that there are issues regarding safety and reliability of hydrogen blending that could be addressed before procurement and pricing options are determined but acknowledges IEPS's submission that any unwarranted or unnecessary delays could materially impact investment required to promote supply and demand for hydrogen blending. Accordingly, hydrogen procurement and pricing issues could be subject to further study subsequent to technical studies regarding safety and reliability.

207. Until there is a better understanding of the availability of hydrogen supply, it may be premature to make specific recommendations on who should procure hydrogen. However, the Commission recognizes that there could be merit to the utility procuring hydrogen on a short-term basis for any early hydrogen blending pilot projects. The Commission recognizes that some parties opposed the commodity cost of hydrogen being a utility system cost. However, it

74 Proceeding 26616, ATCO Gas and APEX 2023 Cost-of-Service Review.
75 Exhibit 26616-X0086, AUC letter - Preliminary jurisdictional issues hydrogen projects and Exhibit 26616-X0102, AUC letter- Preliminary jurisdictional issues - hydrogen projects.
76 Exhibit 26616-X0018, ATCO Gas 2023 Cost-of-Service Application, PDF page 166.

also recognizes that, given the potential for a hydrogen market to evolve, any inclusion of costs in rates related to the procurement of hydrogen by the distribution utility should only be allowed on an interim basis.

208. The commodity cost of natural gas is provided by competitive retailers and the default supply provider to customers on the natural gas system. In general, the Commission considers that the functions of a regulated distribution utility should, absent the exceptions listed above, be limited to hydrogen blending and distribution functions.

3.7 Factors that regulatory agencies should consider when assessing hydrogen blending projects and related costs

209. This section explores factors that regulatory agencies should consider when assessing hydrogen blending projects and related costs. It first describes general considerations and then discusses the increase of costs to natural gas service as it relates to hydrogen blending. Finally, it discusses approaches for cost recovery of hydrogen-related costs, including rate impacts.

3.7.1 General regulatory considerations when assessing hydrogen blending projects and related costs

210. Parties generally agreed that regulatory agencies should take into account various public interest factors when assessing hydrogen blending projects and the respective costs, including a cost-benefit analysis, safety, reliability, environmental impacts, emissions targets and carbon tax considerations, economic efficiency, and rate impacts to consumers.

211. NGTL and Air Products recommended collaboration between the Government of Alberta and other provinces and the federal government in the development of legislative and regulatory frameworks for hydrogen. However, Air Products cautioned against adopting approaches used in other jurisdictions that do not reflect the unique circumstances of the Alberta market, which could impose restrictions on the existing competitive market for hydrogen in Alberta.

212. The Commission recognizes the need for regulatory certainty and a well-defined regulatory framework for hydrogen and considers that further study in this area is required, as described in Section 3.2.

213. Some parties highlighted the importance of conducting a cost-benefit analysis.

214. CHFCA encouraged regulators to consider that hydrogen blending projects are investments and submitted that the scope of cost-benefit analyses should not only encompass financial and emissions considerations, but economic opportunities arising from early-mover status as well, including export opportunities.

215. The UCA submitted that it is important that rate impacts to consumers are considered prior to implementation of hydrogen blending because these costs would impact utility consumers far into the future. Air Products and the UCA suggested that the overall economic efficiency of hydrogen blending compared to other market demands for hydrogen should be studied, having regard to both the costs of hydrogen blending and the anticipated environmental impacts, including reduction in greenhouse gases and federal carbon tax considerations.

216. Similarly, ENMAX suggested that when projects are applied for, detailed costs should be provided, both for the applied-for option and other viable options that were considered. ENMAX added that the AUC may be in the best position to establish a minimum set of criteria that should be included in the evaluation of future hydrogen projects and a new Commission rule could outline the details.

217. Other parties provided more extensive suggestions of what regulators should consider. ATCO suggested consideration of the following when evaluating proposed hydrogen blending investments:

- Government direction on decarbonization.
- *Net-Zero Emissions Accountability Act* targets, including for 2025, 2030, 2040 and 2050.
- Government price signals such as the carbon tax, which is forecast to increase to $8.94 per gigajoule by 2030.
- Long-term development of the hydrogen market, both in Alberta and in other jurisdictions.
- Customer drivers and demands.
- Alternative analysis for expenditures brought forward to the Commission, including the comparison between utilizing the existing gas system versus electrification and other gaseous energy products.

218. Air Products suggested that regulatory agencies consider:

- System capacity and measurement systems.
- Environmental impacts.
- Economic efficiency (for instance, carbon dioxide reduction benefits from the combustion of hydrogen need to be quantified, along with system upgrade costs, to determine the cost per metric ton of carbon dioxide reduced).
- Carbon tax and emission reduction should be considered by the Commission in evaluating blending projects, including conducting stakeholder consultations.
- The additional gas consumption that will be required in light of the lower volumetric density of hydrogen.
- The costs associated with storage systems to accommodate intermittent renewable hydrogen manufacture or seasonal storage requirements.
- The cost of end-user appliance or commercial equipment upgrades necessary to safely accommodate the proposed blend level.

219. Regarding the effects of hydrogen use on reducing the amount of carbon taxes, IEPS noted that those communities choosing to blend hydrogen would reduce their natural gas consumption and be rewarded through lower carbon taxes. Direct Energy also submitted that the carbon tax is a factor that should be examined at the provincial and federal levels and that consumers choosing to use less carbon intensive energy (hydrogen or renewable natural gas) should pay a lower carbon tax given their lower emissions.

220. The Edmonton Region Hydrogen HUB encouraged the AUC to consider ways to allow utility companies to explore low-cost pathways to net-zero energy systems, such as allowing investments in hydrogen projects, hydrogen blending and pure hydrogen into the gas distribution system.

221. Most parties recognized that blending hydrogen into natural gas distribution systems is a significant endeavour that has ramifications for the utility and customers. In addition to the factors above, they stated that regulatory agencies should consider safety and reliability when assessing hydrogen blending projects and costs. Certain parties also advocated for consistency in terms of the factors considered for hydrogen and hydrogen blending and natural gas projects, and submitted that these factors should be the same for all distribution utilities including rural and gas co-operative customers. Parties also suggested that regulatory agencies look to other jurisdictions where blending has been successful, such as the United Kingdom.

222. The Commission agrees with parties that it is important for regulators to consider public interest factors when assessing hydrogen blending projects and the respective costs including assessments of cost-benefit analysis, safety, reliability, environmental impacts, emissions targets and carbon tax considerations, economic efficiency and rate impacts to consumers. Further, many parties expressed concerns about the increase in costs for customers/ratepayers as a result of hydrogen blending and this is discussed further in Section 3.7.2.

223. The Commission considers that it is imperative that all regulatory agencies understand relevant technical and customer impacts, and work together to advance hydrogen blending development and deployment in a cost-effective manner. Regulatory agencies should ensure that any distribution utility or gas co-operative that plans to introduce hydrogen are subject to a detailed safety and engineering assessment as discussed in Section 3.3.3. Further, there may be merit in a phased approach to hydrogen blending where a gradual introduction of hydrogen occurs before ramping up the percentage of hydrogen that is blended into the natural gas stream to as much as 20 per cent, as discussed in Section 3.6.

224. The Commission is also of the view that tariffs will likely need to be amended to accommodate hydrogen blending, with the factors identified by Air Products requiring further study.

225. As hydrogen blending is new to the province, the Commission is of the view that consideration of pilot projects and the experience of hydrogen blending in other jurisdictions will likely be of assistance to the hydrogen blending roll-out in Alberta. With a clear focus on safety and reliability, it may be reasonable to move forward with targeted pilot projects to better ascertain the impact of hydrogen blending, emissions reductions, different carbon intensity of various hydrogen options and resulting carbon offset, and cost information. Ultimately, a robust hydrogen market is expected to develop if proper price signals are provided for investment and the roles of regulated and competitive participants are clearly defined.

226. As such, the Commission considers that it may be beneficial for the Government of Alberta to communicate to customers the potential short-term challenges compared to the long-term benefits of emission reductions from hydrogen blending. In rate proceedings, the Commission is responsible for assessing rates as “just and reasonable” and approving a utility’s

applied-for costs for providing safe and reliable utility service to customers.[77] One of the considerations for inclusion of costs in rates would generally be a cost-benefit analysis that takes into account social and environmental effects. As hydrogen blending costs are not expected to be at parity with carbon tax savings in the near future and to ensure hydrogen blending targets outlined in the Hydrogen Roadmap are met, the Government of Alberta may need to establish a clear policy. This could include objectives and requirements for distribution utilities to allow the Commission to place a greater emphasis on social and environmental factors when assessing the merits of hydrogen blending costs for inclusion in distribution rates. The inclusion of the incremental costs that customers would be required to bear should be balanced against the affordability of utility service for customers. In addition, the impact of hydrogen blending on home appliances will need to be fully investigated. The siting of blending facilities will need to be assessed from a safety perspective and will require landowner consultation, which could involve a co-ordinated approach amongst various regulatory agencies as noted in Section 3.2.

3.7.2 Increasing the cost of natural gas service

227. Parties expressed concerns that implementing hydrogen blending would result in incremental costs for customers/ratepayers and suggested that this factor should be considered by regulatory agencies when assessing hydrogen blending projects and costs.

228. The Transition Accelerator suggested that the environmental benefits of hydrogen blending at 20 per cent be considered as needed to accomplish targets. While outside the scope of the inquiry, it suggested that the AUC consider emissions targets and align them with federal legislation timelines, allowing utilities to begin planning for optimal solutions and cost-effective pathways to meet targets, minimizing ratepayer impacts. The Transition Accelerator added that in a net-zero energy system, hydrogen is a credible alternative to natural gas, but based on a November 2020 Industrial Heartland Report, it is significantly more expensive ($10-$14/gigajoule or $1.40 to $2/kilogram hydrogen). It stated that a successful transition to hydrogen as a zero-emission heating fuel would require society to accept either a higher cost for heating fuels (offset, in part, by thermal efficiency improvements) or a decline in hydrogen price with scale of deployment and technological innovation.[78]

229. ATCO noted that the price on greenhouse gas emissions will influence the pace of greenhouse gas emissions reduction and that carbon pricing, as implemented under the *Greenhouse Gas Pollution Pricing Act*, is forcing all natural gas utilities in Canada to advance alternatives to the status quo. It explained that under the *Greenhouse Gas Pollution Pricing Act*, carbon taxes for natural gas consumers would increase by $15/tonne/year, from $50/tonne ($2.63/gigajoule) in 2022 to $170/tonne ($8.94/gigajoule) in 2030. When applied to the approximately 270 petajoules currently used by ATCO customers, the total annual carbon tax collected in 2030 is forecasted to be approximately $2.4 billion. At present, the price of natural gas inclusive of carbon taxes is lower than the cost of decarbonizing space and water heating; however, ATCO expected that natural gas commodity prices with hydrogen blending costs will reach cost parity around 2030. ATCO submitted that given long lead times required to transition to alternative technologies, it is prudent for utilities to act now to maintain affordability for customers as carbon taxes continue to rise.

77 *Gas Utilities Act*, Section 6(1).
78 Exhibit 27256-X0037, Industrial Heartland Report, PDF page 64.

230. Similarly, Air Products submitted that, when using hydrogen price values from the Transition Accelerator, the cost to produce and supply blue hydrogen on a volumetric basis would exceed the cost savings from the reduced carbon levy and natural gas price until the carbon levy approaches the 2030 price of $170 CAD/metric ton. It added that this assumed lower blend concentration levels, and that at higher blend levels, there would be further substantive, incremental costs to retrofit existing infrastructure and utilities. Air Products noted that the carbon emission reductions from blending would not be significant until higher blend thresholds are implemented. It stressed that there should be a careful assessment of the costs and benefits related to such higher blend levels.

231. The Commission recognizes that the short-term adoption and support for hydrogen blending faces cost and rate impact challenges. The Commission is mindful that Albertans are facing significant affordability challenges, with Alberta's inflation at 7.1 per cent in May 2022.[79] In addition, the Bank of Canada raised the benchmark interest rate on June 1, 2022, by 50 basis points to 1.5 per cent,[80] increasing interest rate payments for many Albertans. Further, natural gas in May 2022 fluctuated on a daily basis between approximately $5.90 to $8.40 per gigajoule,[81] and the price of regular gasoline for vehicles from late February to the end of May averaged $1.79 per litre.[82] The high inflationary economic environment may impede customers' ability to pay the increased costs associated with hydrogen blending as the cumulative impact of living expenses is now significantly greater than recent levels.

232. The Commission considers that hydrogen blending in natural gas distribution systems will result in incremental costs to customers to recover investment in hydrogen production, storage, transmission, blending facilities, procurement, engineering assessments of distribution systems, and downstream inspections of home appliances, and hydrogen studies. As noted in the November 2020 Industrial Heartland Report submitted by the Transition Accelerator, hydrogen is more expensive ($10-$14/gigajoule or $1.40 to $2/kilogram hydrogen) than natural gas largely because in Alberta hydrogen is predominantly made from natural gas. It is unclear what the impact is on the commodity price of hydrogen due to recent increases in natural gas prices.[83] The total costs to customers are uncertain, as are the methods of recovery of these costs. Any additional increases to Alberta's utility rates or prices could have material consequences for Albertans.

233. The Commission also notes that the Industrial Heartland Report suggested that the economic viability of blue hydrogen could be enhanced by the income that can be generated by selling carbon dioxide for enhanced oil recovery (estimated at $20/tonne carbon dioxide) or from generating Emission Performance Credits under Alberta's Technology Innovation and Emission Reduction Program ($40/tonne carbon dioxide in 2021). As a result, blue hydrogen production costs could be reduced to $0.32/kg hydrogen. Credits could also be generated from the federal clean fuel standard associated with reducing greenhouse gas emissions.[84]

234. The Commission also observes that the supplemental report filed by Air Products raises significant concerns regarding the costs versus benefits of hydrogen blending. Air Products filed

[79] https://www150.statcan.gc.ca/n1/daily-quotidien/220622/t002a-eng.htm
[80] https://www.bankofcanada.ca/2022/06/fad-press-release-2022-06-01/
[81] https://www.gasalberta.com/gas-market/market-prices
[82] https://www.globalpetrolprices.com/Canada/Alberta/gasoline_prices/
[83] Exhibit 27256-X0037, Industrial Heartland Report, PDF page 15
[84] Exhibit 27256-X0038, Role for Hydrogen Report, PDF page 11.

a report that stated that a 20 per cent fraction only represents about seven per cent in energy terms (due to the difference in energy density), which means blending could achieve, at best, only seven per cent carbon dioxide emissions reduction.[85] Adding hydrogen to the gas distribution system results in an incremental cost to customers. A German climate think-tank, Agora Energiewende, calculated in a study last year that adding 20 per cent hydrogen to the gas grid would increase consumer heating costs by 33 per cent in 2030.[86] The Commission recognizes that while the percentage increases may differ from those in Alberta, the costs increases underpin rate shock and affordability concerns for customers associated with hydrogen blending.

235. The Commission is of the view that the Alberta government may want to consider supports for customers such as credits, tax rebates or subsidies as mechanisms to reduce the burden on ratepayers until the costs of hydrogen blending reaches parity with expected carbon tax savings in 2030. Absent such government subsidization or policy direction, the benefits of emission reductions and carbon tax savings of hydrogen blending may not be sufficient to outweigh the cost burden in the short term, and therefore making the inclusion of these costs in customer's rates harder to justify.

3.7.3 Cost recovery of hydrogen-related costs, including rate impacts

236. This section discusses submissions about how hydrogen-related costs should be recovered by utilities. As noted in Section 3.1, a regulated distribution utility has the opportunity to recover prudently incurred service costs, including earning a fair return on investment, in order to provide utility customers with safe, reliable service now and in the future, and to encourage continued investment in the utility industry.[87] Currently, distribution utilities are regulated under performance-based regulation, which uses a formula applied to revenue to set rates. Costs are delinked from revenue for a period of time under this framework. However, costs and revenues are being relinked in the 2023 cost-of-service review proceedings before the Commission to set going-in rates for the next term of performance-based regulation starting in 2024. In a letter dated February 28, 2022,[88] the Commission noted that the opening and closing 2023 rate base and 2023 customer rates of ATCO and Apex may be subject to adjustment in the future associated with introducing hydrogen into their respective distribution systems.

237. The commodity of natural gas is either provided by a competitive retailer or default supply provider. Currently in Alberta, the Commission approves monthly rates for default supply providers in line with a previously approved methodology which outlines how the providers will procure energy for their customers and how their rates will be calculated, based on Alberta legislation and regulations.

238. The Commission is responsible for ensuring that natural gas distribution service is safe and reliable, and that rates charged are just and reasonable.

239. Additional considerations are required to determine how the costs of blending hydrogen into the natural gas distribution system should be recovered.

85 Exhibit, 27256-X0067, Global Hydrogen Trade to Meet the 1.5C Climate Goal: Part II — Technology Review of Hydrogen Carriers, PDF page 3.
86 Exhibit, 27256-X0067, Global Hydrogen Trade to Meet the 1.5C Climate Goal: Part II — Technology Review of Hydrogen Carriers, PDF page 4.
87 https://www.auc.ab.ca/distribution-rates/
88 Exhibit 26616-X0102, AUC letter - Preliminary jurisdictional issues - hydrogen projects.

240. The views of parties varied with respect to how prudently incurred distribution infrastructure costs to enable hydrogen blending and procurement costs should be recovered from customers. These views ranged from such costs being properly borne by all customers, to customers in a specific geographic area, to the specific customers receiving the hydrogen. Other parties were of the view that it is premature to make that determination.

241. ATCO and Apex argued that the incremental costs associated with the introduction of hydrogen on a per-customer basis should be kept to a minimum, with the benefits of carbon tax savings equally shared. ATCO stated that the allocation of related costs and benefits can be initially addressed via rate design to ensure the social and environmental benefits are realized equitably across all communities in Alberta. Apex and ATCO suggested that to ensure decarbonization is realized in all communities in Alberta, a province-wide postage stamp rate design[89] could be employed to help mitigate the rate impact of connecting lower-emission gaseous energy to geographically distant systems.

242. ATCO and Apex also submitted that all costs related to pilot projects and technical testing of the system should be recovered through distribution rates, with any credits or associated carbon tax reductions accumulated to the utility. Kiwetinohk stated that the capital and commodity costs (net of any direct cost recovery) of pilot projects should be included in a distribution utility’s rate base.

243. Similarly, Apex maintained that all operating and capital costs for pipelines and related facilities required for the procurement (commodity and system balancing) and delivery of hydrogen should be recovered from all gas distribution customers in Alberta. Apex stated that a rebate, funded by a prospective Alberta carbon tax and/or the Technology Innovation and Emissions Reduction Fund could be offered to help alleviate financial impacts to customers. Apex explained that the rebate, which may be administered by distribution utilities, would be applied at the distribution charges-level to offset some of the incremental charges to customers and that funding payments to the utilities could be made at regular intervals to ensure the utility is not financially stressed for cashflow. Apex added that if costs for achieving emissions reductions from hydrogen blending are recovered through ratepayers, then no protection is required for competitive retailers or default rate natural gas providers in the short run, but as the hydrogen industry evolves, this issue would need to be re-evaluated.

244. Conversely, Air Products stated that further study of the incremental costs and practical considerations associated with large-scale hydrogen blending implementation needs to take place before rate designs can be properly considered. Air Products added that it is premature to consider whether capital and commodity costs for hydrogen blending should be allocated among all customers, to customers in the geographic area or to the specific customers receiving hydrogen. However, at the pilot stage, Air Products maintained that the hydrogen-related costs to be recovered from ratepayers should be limited to the costs of procuring and sourcing the commodity, incremental capital, and operations and maintenance costs associated with the blending station and any downstream low-pressure distribution pipelines, offset by any government grants and subsidies. Air Products recommended that regulated utilities not be

89 A postage stamp rate is a method of cost allocation where a rate is the same anywhere on the system, regardless of the geographical region in the province.

allowed to build or recover costs from ratepayers associated with hydrogen production assets, as this would create an unlevel playing field in the competitive market.

245. Other parties submitted that various portions of the costs for hydrogen blending should be allowed to be recovered.

246. Direct Energy stated that upgrades to distribution infrastructure (from a safety/technical perspective) to allow for hydrogen blending should be the only aspect that is allowed through cost recovery. Direct Energy submitted that for established communities, blending costs should go into transmission and distribution rates for all customers in the geographic area, and for a new community, the cost should be allocated to that community. It added that the cost of the hydrogen commodity should be left to the market once there is enough liquidity.

247. ENMAX submitted that infrastructure costs related to the distribution of hydrogen-blended natural gas be recovered from ratepayers. If the investment is considered to be in the public interest and demonstrates a direct benefit to the customer base, distribution utility pilot projects should be recovered from ratepayers. ENMAX added that applicants should seek government financing whenever possible and that how capital and commodity costs should be allocated needs further discussion.

248. IEPS stated that it initially assumed that the costs of adding hydrogen would be borne by the users of that system, and that while province-wide hydrogen targets would be economically beneficial for producers, it was concerned that forcing the public to use hydrogen could create a backlash against blending that would not be politically sustainable. However, in its reply submission, IEPS noted that if all customers were to share the costs of blending hydrogen, the early-days per capita costs would be significantly less than what it had initially assumed, and the economic burden of a hydrogen blending target might be more readily accepted by the public, resulting in a rapid uptake of hydrogen.

249. The UCA stated that natural gas ratepayers should not be funding the capital costs of launching the hydrogen blending market and that production facilities should be driven by competitive market forces. It added that the prudency of the investment in hydrogen blending must be assessed prior to the discussion of cost recovery but that any costs determined to be prudent for distribution and transmission of hydrogen should be socialized across appropriate ratepayers.

250. The CCA submitted that a decision must be made as to whether costs should be shared among all Albertans, all ratepayers, or solely those in locations where hydrogen is blended. Due to the high cost of hydrogen, either a mandatory purchase requirement or a subsidised approach will be needed, where costs will be paid by either taxpayers or ratepayers. The CCA submitted that only the prudently incurred costs required for modifying the distribution system to handle hydrogen should be borne by ratepayers. Finally, the CCA stated that Alberta should leverage the experience of other jurisdictions with pilot projects to determine risks, costing, and other issues.

251. Calgary submitted that, if it was possible to identify costs incurred exclusively by consumers of blended hydrogen, then those consumers should exclusively bear those costs. Any subsidies associated with hydrogen blending should be supplied through other channels as a matter of government policy. Pilot projects should be evaluated on a case-by-case basis for the inclusion of costs in natural gas distribution rates. Before adopting any cost allocation methods,

the Commission should establish, as soon as possible, cost allocation principles, with consultation and input from all affected stakeholders.

252. The Federation stated that customers of its members should not bear the costs of implementing a blended fuel source.

253. The Transition Accelerator submitted that consideration should be given to minimize the overall cost to utility ratepayers and maximizing public good, potentially mirroring the existing natural gas market systems. It suggested that sharing costs to initiate the transition to hydrogen blending may be required because of the high initial costs and recognizing that the benefits of lower emissions flow to all Albertans.

254. If hydrogen becomes a commodity subject to the AUC's jurisdiction, NGTL anticipated that the AUC would consider issues such as hydrogen blending cost treatment and cost allocation. It also anticipated that the Commission would apply the same principles that have guided and continue to guide the AUC's decisions on these issues for natural gas distribution and pipelines under its jurisdiction.

255. The Commission recognizes that there are significant concerns about how the costs to blend hydrogen into the natural gas distribution system should be recovered. The Commission considers that if hydrogen blending is clearly established to benefit all Albertans, including making progress towards meeting provincial emissions reduction targets, then a postage stamp style rate may be considered in the future. However, the Commission agrees with Air Products that it is premature to consider whether capital and commodity costs for hydrogen blending should be allocated among all customers, to customers in a specific geographic area or to customers receiving the hydrogen.

256. The Commission is of the view that only prudently incurred distribution infrastructure costs to enable hydrogen blending should be borne by ratepayers. Further, the distribution utilities are best able to own and operate blending facilities because they have the responsibility to ensure safety and reliability associated with providing distribution service, including managing quality of gas and blending thresholds, and the integrity of their natural gas distribution systems. However, consideration could be given to minimizing the overall cost to utility ratepayers – rebates, government grants and subsidies are some options to help alleviate financial impacts to customers. As noted earlier, the costs that will be included in gas distribution rates will be subject to a future rates proceedings pending legislative change to accommodate hydrogen blending, but a determination of what specific costs are to be recovered will be based on which specific components of the hydrogen market are being regulated and which are provided competitively.

257. The Commission agrees with the parties that the current competitive natural gas market is the model that should be used for the competitive procurement of hydrogen over the long term, but in its infancy, the utilities might be required to procure hydrogen. An open-access hydrogen market would be ideal, where customers are able to choose carbon intensity of hydrogen options, with pricing and carbon credits applied based on hydrogen type. However, a determination on the process for hydrogen procurement requires further study.

3.7.3.1 Cost allocation of different types of hydrogen

258. During hydrogen production, the level of emissions, if any, depend on the method used. As noted in Section 2.2, commonly referenced types of hydrogen include green, grey and blue hydrogen. Some parties supported that costs should be allocated in the same manner for each type of hydrogen, while others supported different cost allocation methodologies.

259. Apex and IEPS stated that the costs associated with green, blue or grey hydrogen should all be allocated in the same manner, with customers allowed to choose between these hydrogen sources. Apex submitted that utilities should be provided the flexibility to pursue various hydrogen colours to meet decarbonization mandates.

260. Direct Energy, the UCA, and CHFCA disagreed with that approach and submitted that costs should be allocated differently, recognizing that the extraction and refinement technologies used for green, blue or grey hydrogen are different, and therefore, the costs and carbon offsets may warrant distinct treatment. These parties suggested that hydrogen should be evaluated by its emissions intensity, and not its method of generation. Calgary maintained that more technical and economic information would be required to assess whether green, blue or grey hydrogen should be allocated in the same way.

261. ATCO suggested that the hydrogen production method (or colour) should not be a consideration for the AUC. Rather, it stated that, consistent with other jurisdictions, thresholds for carbon intensity of hydrogen production should be established, with the thresholds declining over time. Consideration could be given to establishing incentives or penalties for meeting or failing to meet hydrogen carbon intensity thresholds when hydrogen supply is procured; however, this must be balanced against costs to end users associated with hydrogen supply. ATCO submitted that any incentives or penalties should not hinder hydrogen blending and pilot projects in the early phases of hydrogen blending.

262. Although emissions targets are out-of-scope in this inquiry, the Commission considers that the focus of any government policy should prioritize carbon emission reductions. The Commission is of the view that further study may be required to assess the technical and economic feasibility of green, blue or grey hydrogen in order to properly allocate costs and apply the proper offset to carbon tax based on lower carbon emission intensity.

3.8 Conclusion and areas for future study

263. This report provides the Commission’s findings, observations and considerations for options on legislation, safety, and regulatory factors, which should assist the Government of Alberta’s work towards introducing a framework for hydrogen blending in natural gas distribution systems. The findings, observations and considerations are based on feedback from stakeholders on a variety of hydrogen blending-related issues and the Commission’s own expertise.

264. While numerous parties participated and provided submissions expressing various positions, limited conclusive evidence was provided on most topics. The Commission recognizes that hydrogen blending is a rapidly evolving industry, with many technical, safety and regulatory considerations that require further study before broad implementation can be realized.

265. Areas of future study identified by parties that were not examined in prior sections of the report included items outside the scope of this inquiry, such as pure hydrogen distribution systems, renewable natural gas, emissions targets that should be established, appliance safety, the blending of hydrogen in high-pressure natural gas utility pipelines, and pure hydrogen pipelines serving industrial customers. These topics are touched on below.

266. Numerous parties submitted that further consideration of pure hydrogen, renewable natural gas, and emissions targets are required.

267. The Transition Accelerator submitted that pure hydrogen pipelines and gas distribution system emissions targets should be considered, and that attention should be given to establishing a competitive open-access hydrogen market.

268. ATCO submitted that it is imperative to ensure that the full scope of decarbonization tools or gaseous energy substances are accommodated and that limiting these to hydrogen blending would result in roadblocks to decarbonization and innovation. ATCO also noted that homebuilders and developers have also been preparing for the energy transition for some time by exploring lower greenhouse gas emissions solutions and that these solutions are required to align with government policy. It stated that examples of these solutions include significantly more energy efficient building envelopes, electric vehicle ready housing, hybrid gas/electric heating, ventilation and air conditioning systems, geothermal technologies, electric heat pumps and solar photovoltaic generation.

269. While pure hydrogen and renewable natural gas are outside the scope of this inquiry, the Commission recognizes that the Hydrogen Roadmap identified the exploration and advancement of pure hydrogen communities and networks as a long-term action to implementation step[90] and considers that there may be significant benefits to further studying pure hydrogen, renewable natural gas and other decarbonization alternatives. Similarly, while emissions targets are outside the scope in this inquiry, the Commission agrees with parties that it would be beneficial if future government policy prioritized carbon emission reductions. The Commission suggests that hydrogen blending in the natural gas distribution system for use in buildings should be co-ordinated with any developments and standards related to electrification to ensure that any risks of stranded natural gas assets are mitigated. Further, the focus of provincial and federal government efforts should be to maximize carbon emission reductions, while being agnostic to the specific technology or approach to meet these ends.

270. Several parties raised concerns regarding the impact that hydrogen blending might have on appliance functionality, safety, and the associated costs. Apex stated that the performance of end-use appliances should be studied to understand at what point retrofits or replacements are required and that the Government of Alberta could consider creating a program evaluating and retrofitting or replacing natural gas appliances with appliances that can accept higher blending rates up to pure hydrogen. Similarly, ATCO submitted that the Government of Alberta should consider a hydrogen ready appliance standard to minimize long-term costs as the natural gas distribution system transitions to pure hydrogen. Gradient submitted that regulatory certainty is required on the timing of pure hydrogen distribution to allow time to develop and commercialize appliances.

[90] Exhibit 27256-X0009, Alberta Hydrogen Roadmap (2021), PDF page 46.

271. The Commission notes that Alberta Municipal Affairs has oversight over matters downstream of the meter and is the agency legislatively tasked to receive reports of accidents or damage caused by gas installation or gas equipment. Appliance safety is an important consideration for blending and could be examined further. However, the Commission agrees that safety, including for appliances, should be prioritized. Additional investigation into appliance safety and hydrogen-ready appliance standards could be conducted.

272. Other suggested areas of future study include the impact of adding hydrogen to the pipeline system for industrial facilities; using existing infrastructure such as natural gas storage reservoirs and transmission systems for blended hydrogen;, and carbon capture utilization and storage to ensure secure, permanent storage sites for carbon dioxide created by hydrogen production. NGTL asserted that technical and safety challenges may arise at higher blended hydrogen concentrations in natural gas transmission systems and that further research is required to understand these challenges. The Commission recognizes that further study of these areas will be beneficial.

273. Several parties also suggested that further action be taken following the conclusion of the Hydrogen Inquiry to assess impacts on Alberta end users as further information on the federal and provincial hydrogen roadmaps becomes available. Parties suggested that the AUC might host a technical session to better understand aspects of producing, blending and delivering hydrogen into the natural gas distribution system. In addition, continued stakeholder engagement and communication of next steps would be valuable. The Commission agrees that additional consultation may be necessary as the Government of Alberta moves forward with the Hydrogen Roadmap and hydrogen blending in low-pressure gas distribution systems.

274. Several parties identified that numerous other jurisdictions globally have experience with blending hydrogen into natural gas distribution systems. This base of experience provides a robust data set to support further investigation.

Appendix 1 – Glossary and list of acronyms

Acronym or term	Description or name in full
Air Products	Air Products Canada Ltd.
ABSA	Alberta Boilers Safety Association
Apex	Apex Utilities Inc.
ATCO	ATCO Gas
Cancarb	Cancarb Limited
Calgary	The City of Calgary
CCA	the Consumers' Coalition of Alberta
CHFCA	the Canadian Hydrogen and Fuel Cell Association
CSA Z662	CSA Z662, Oil and Gas Pipeline Systems
Direct Energy	Direct Energy Marketing Limited
Distribution utility	Natural gas distribution utility
ENMAX	ENMAX Corporation and ENMAX Energy Corporation
Federation	The Federation of Alberta Gas Co-operatives Ltd.
Gas Alberta	Gas Alberta Inc.
Gradient	Gradient Thermal Inc.
Hydrogen Roadmap	the Alberta Hydrogen Roadmap
IEPS	IEPS Canada Ltd.
kPa	Kilopascals
Kiwetinohk	Kiwetinohk Energy Corp.
NGTL	NOVA Gas Transmission Ltd.
UCA	The Office of the Utilities Consumer Advocate

Appendix 2 – Proceeding participants

(return to text)

Name of organization (abbreviation) Company name of counsel or representative
Air Products Canada Ltd. (Air Products) Reynolds, Mirth, Richards & Farmer LLP
Apex Utilities Inc. (Apex) The City of Leduc
ATCO Gas (ATCO) Bennett Jones LLP
The Canadian Hydrogen and Fuel Cell Association (CHFCA)
Cancarb Limited (Cancarb)
Capital Power Corporation
The City of Calgary (Calgary) McLennan Ross Barristers & Solicitors
City of Fort Saskatchewan
Consumers' Coalition of Alberta (CCA) Wachowich & Co.
Direct Energy Marketing Limited (Direct Energy)
ENMAX Corporation and ENMAX Energy Corporation (ENMAX)
Federation of Alberta Gas Co-operatives Ltd. (Federation)
Gradient Thermal Inc. (Gradient)
Heartland Generation Ltd.

Name of organization (abbreviation) Company name of counsel or representative
IEPS Canada Ltd. (IEPS)
Kiwetinohk Energy Corp. (Kiwetinohk)
NOVA Gas Transmission Ltd. (NGTL)
Office of the Utilities Consumer Advocate (UCA)
QUEST Canada
Rockpoint Gas Storage Canada Ltd.
Suncor Energy Inc.
Transition Accelerator Edmonton Region Hydrogen HUB City of Edmonton Strathcona County

Alberta Utilities Commission Commission panel N. Jamieson, Panel Chair M. Oliver J. McCarthy Commission staff R. Watson (Commission counsel) K. Macnab (Commission counsel) W. MacKenzie B. Shand M. McJannet A. Anderson F. Alonso H. Shamji Consultant UniversalPegasus International

Appendix 3 – Order-in-Council 70/2022

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Appendix
3_Order-in-Council_2C

(consists of 3 pages)

O.C. 070/2022

MAR 2 3 2022

Province of Alberta
Order in Council

ORDER IN COUNCIL

Approved and ordered:

Slakhani

Lieutenant Governor
or
Administrator

The Lieutenant Governor in Council

(a) orders the Alberta Utilities Commission to inquire into and report to the Minister of Energy on matters relating to hydrogen blending into gas distribution systems, in accordance with the terms of reference in the attached Schedule,

and

(b) determines that the Alberta Utilities Commission has the power to make orders relating to costs under section 21(1) of the Alberta Utilities Commission Act with respect to a hearing or proceeding under the inquiry referred to in clause (a).

CHAIR

For Information only

Recommended by: Minister of Energy

Authority: Alberta Utilities Commission Act (section 8)

Schedule

Terms of Reference for an Inquiry into and Report to the Minister of Energy on Matters Relating to Hydrogen Blending into Gas Distribution Systems

WHEREAS the Alberta Recovery Plan and Natural Gas Vision and Strategy articulated an ambition to incorporate clean hydrogen into Alberta's current energy portfolio;

WHEREAS the Government of Alberta announced the Hydrogen Roadmap in 2021;

WHEREAS the Hydrogen Roadmap identified that Alberta is well positioned to participate in a global hydrogen economy;

WHEREAS Alberta has the opportunity to significantly grow its energy sector, increase productivity, and create jobs through development of the hydrogen economy;

WHEREAS the adoption of clean hydrogen has the potential to significantly reduce greenhouse gas emissions by 2030;

WHEREAS the Hydrogen Roadmap announced that Alberta will enable hydrogen blending into gas distribution systems;

WHEREAS the Government of Alberta seeks to identify existing legislative and regulatory schemes currently governing gas distribution systems and retail services which may operate as a barrier to enabling hydrogen blending into gas distribution systems in Alberta up to 20 percent blending by volume; and

WHEREAS in order to permit the Government of Alberta to consider a full range of options on important issues relating to enabling hydrogen blending into gas distribution systems in Alberta and impacts on consumers, it is desirable that an inquiry be conducted by the Alberta Utilities Commission (AUC);

THEREFORE the following terms of reference apply in respect of the inquiry into and report to the Minister of Energy on matters relating to hydrogen blending into gas distribution systems:

1. The Alberta Utilities Commission (AUC) shall inquire into the following matters for the purposes of gathering information and to make findings or provide observations or considerations for options on:

   (a) the role of regulated natural gas distribution systems and unregulated competitive markets for hydrogen blending into gas distribution systems up to 20 percent blending by volume;

   (b) the impacts of hydrogen blending into gas distribution systems, including

      (i) impacts on the delivery of services to municipal and rural natural gas consumers,

      (ii) competitive retail impacts,

(iii) potential rate impacts, and

(iv) impacts on utility cost recovery for hydrogen blending, with reference to section 37 of the *Gas Utilities Act* and any other relevant legislation, including the *Public Utilities Act;*

(c) the safe and reliable delivery of blended hydrogen through gas distribution systems, including potential harmonization with municipal or other relevant safety standards;

(d) options to address regulatory ambiguity, remove unnecessary regulatory barriers, and improve certainty as required to enable hydrogen blending into gas distribution systems;

(e) areas for future study relating to hydrogen blending into gas distribution systems.

2. In conducting the inquiry, the AUC shall hear from interested parties.

3. The AUC shall

(a) make findings or provide observations or considerations for options, as it deems appropriate, based on its analysis of the evidence received during the inquiry and in accordance with these terms of reference, and

(b) submit its report to the Minister of Energy not later than June 30, 2022.