Alternative Energy Carriers for Remote Geothermal Sources

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Australia's geothermal industry will soon be ready to scale up its capacity from pilot-scale projects of one MW or less, to demonstration plants of several tens of MW. These scales are too small to justify construction of high-capacity long-distance electricity transmission lines connecting to the national grid. As illustrated in Figure 1, Australia's primary geothermal sources are much closer to the national Compressed Natural Gas (CNG) pipeline network than they are to the national electricity grid. This paper presents an assessment of the prospect of using large-scale electrolysis to convert the output of a geothermal demonstration plant to hydrogen and then to methane for direct injection into existing CNG transmission pipelines. The methanation step involves the consumption of carbon dioxide from CNG processing plants – a byproduct that would otherwise be vented to the atmosphere. A summary of energy flows is given towards the end of this paper, The key advantage of the use of hydrogen and methane as alternative energy carriers is that it would circumvent the dilemma: "What comes first -- commercially viable electricity transmission lines or a successful industrial scale demonstration plant?".

Keywords: geothermal source, electrolysis, hydrogen, methanation, CNG transmission pipelines

Outline of assessment

The assessment that we present here arose from the need to quantify and clarify the technical, engineering and economic feasibility of using an alternative energy carrier to transport energy from a geothermal source in northern South Australia (SA) to major energy consumers located in Olympic Dam and Adelaide. The outcome and conclusions from our assessment can be generalised to other regions.

For our quantitative assessment, we assumed that the net power from a geothermal demonstration plant would be 50 MWe. This provided the basis for estimating the scale of the electrolysis stack, the maximum rate of feedwater consumption, the hydrogen yield, and in turn, the maximum methane flow that would be injected into an existing CNG pipeline.

The following sections outline the main components of the system that we assessed: the water that is fed into the electrolysis system, the electrolysis system and its associated cooling system, and the methanation processing plant.

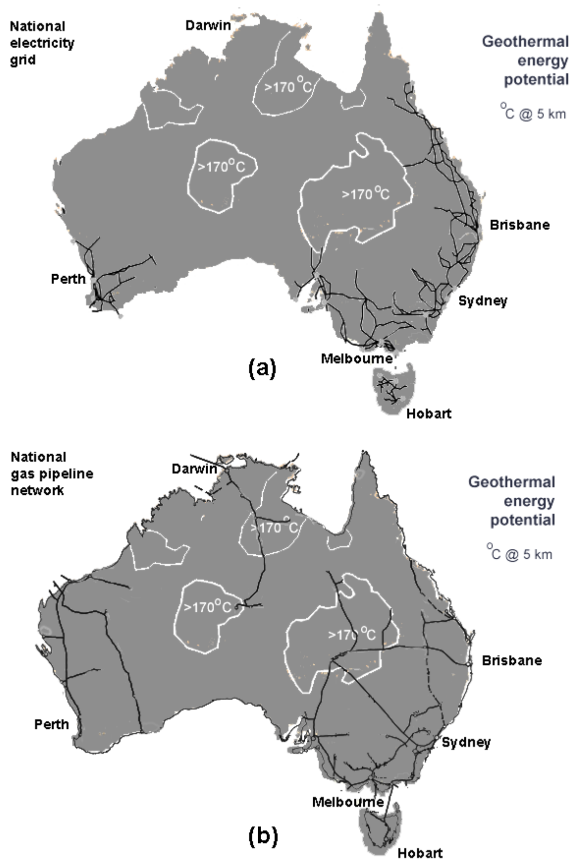

Figure 1: Australia's coastal electricity grid (a) is distant from primary geothermal sources, but overlaps with the national CNG transmission pipeline network (b). [Geothermal data adapted from AGEC (2009), electricity and gas networks adapted from ACCC (2008)]

Feedwater production

The feedwater for the electrolysis process is required to be purer than the groundwater that is typically available in central Australia. Figure 2 shows a proposed geofluid distillation plant that could be used to deliver a sufficient quantity of distilled water for input to the electrolysis process.

Electrolysis plant

The proposed electrolysis plant is based on an array of type 5040 electrolysers from StatOil Hydro's Hydrogen Technologies (previously Norsk Hydro)[1]. Each such unit yields an output of 0.135

1 We discarded the prospect of high temperature electrolysis ("HTE") because commercial systems are not yet available, and the marginal energy

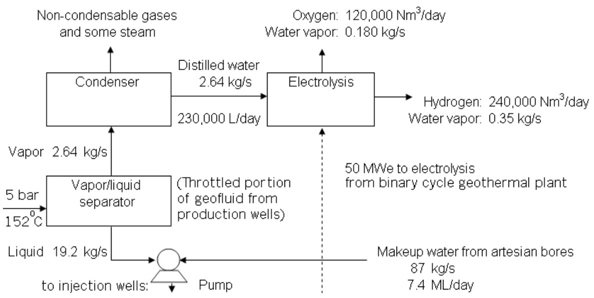

Figure 2: Proposed feedwater processing plant flow diagram

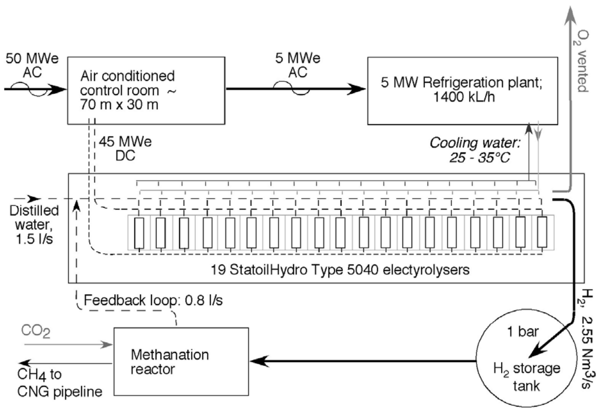

Figure 3: Proposed electrolysis plant layout

Nm^3/s (485 Nm^3/h) of hydrogen, and consumes 2330 kW, from a DC power supply of 5150 amps.

Waste heat from this electrolysis plant is removed by cooling water, in a water cycle that is completely separate from the feedwater production process. This cycle requires a means of reducing the temperature of the cooling water temperature by 10 °C. For this, we propose a refrigeration plant. We chose this after considering other more energy-efficient, options, including evaporative cooling (which would consume excessive groundwater) and underground pipe networks (which would have a high capital cost invested in an immovable infrastructure).

In theory, the methanation step shown in Figure 3 is optional. In practice it is likely to be the key to a successful alternative carrier implementation. We reached this conclusion based on consideration of the prospects for (1) direct use of hydrogen yield, (2) blending the hydrogen yield with CNG for transmission as HCNG and (3) methanation.

Prospects for direct use of hydrogen yield

In future, there may be opportunities for direct use of the hydrogen yield from an electrolysis plant such as the one proposed here. These may include domestic and export markets for 99.9% pure hydrogen. For example, McLellan (2009) presented an assessment of the prospect of large scale domestic consumption of hydrogen in the mining sector, but it is unlikely that such opportunities will arise within the proposed time frame for implementation of an alternative carrier scheme.

Prospects for transmission as HCNG

A quantitative assessment of the maximum hydrogen yield from the electrolysis plant relative to typical CNG flows, led us to consider direct injection of hydrogen for transmission as HCNG in a proportion of 5% H_2 to 95% CNG by volume.

Our assessment of the effects of a blend of 5% hydrogen on the physical properties of HCNG fuel did not reveal any major limitations. Standards compliance would be near the limits of current gas pipeline content requirements, the risk to modern domestic appliances would be negligible, and the risk to gas engines would be small, while gas turbines would require a stable proportion of hydrogen. In contrast, our assessment of the effects of HCNG blends on the structural integrity of the existing CNG pipeline infrastructure led us to conclude that these could be significant limiting factors.

Hydrogen containment engineering is more stringent and challenging than CNG containment. The cost of new hydrogen pipelines of a given diameter are up to twice those of CNG pipes of the same diameter (Ball and Weitschel, 2009). Existing hydrogen pipelines in refineries and chemical plants to date have performed well (Zawierucha and Rana, 2005), but these pipelines are generally in small diameter, (Thompson and Bernstein, 1977), made from low strength steel, (Hayden, 2007) and operate at low pressures. Experience with such pipelines offers little guidance on the potential performance of high-pressure hydrogen transmission pipelines.

In contrast to containment of pure hydrogen, there presumably exists a theoretical proportion of hydrogen in an HCNG blend below which the marginal increase in engineering stringency is negligible. Our consideration of such issues as embrittlement, ductility, fracture toughness, fatigue life, fracture propagation, pressure (Haeseldonckx and D'haeseleer, 2007), and exposure duration, led to the conclusion that there would be a substantial risk that even a 5% blend might detrimentally affect the CNG pipeline steel in the long term. This risk would have to be taken into consideration when determining the operating, inspection and maintenance schedules for hydrogen-carrying pipelines.

conversion efficiency increase is very small for the low temperature range of 150-200 ºC at 5km that is typical of Australia's primary geothermal sources (Balta et al 2009).

Methanation

Methanation involves conversion of hydrogen and carbon oxides to methane. The two main reactions are:

$CO + 3H_2 \leftrightarrow CH_4 + H_2O \quad \Delta H = -206$ kJ/mol (1)

$CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O \quad \Delta H = -165$ kJ/mol (2)

Both reactions are reversible and exothermic and both require a catalyst.

Reaction 1 (using carbon monoxide) is used on an industrial scale to produce synthetic gaseous fuel. A prominent example is the Great Plains Synfuels Plant in North Dakota, which converts lignite coal to methane at a rate of 1.5 billion Nm^3 per year.

Reaction 2 was discovered in the early 1900's by Paul Sabatier, and is often cited as the method for removing astronaut-exhaled CO_2 from space lab "air". It has not been developed on a large industrial scale to date, but researchers in Japan are working towards this end (Hashimoto et al 2009). The key advantage of using reaction 2 is that CO_2 is available in abundance at Moomba's gas processing facility, as a byproduct gas that is otherwise vented to the atmosphere.

Figure 4 shows a flow diagram for implementing reaction 2 in the context of the electrolysis plant.

Two or more methanation reactors in series would be required to ensure better than 90% conversion performance. Alternatively, the separation step at the bottom of the flow diagram could be used to reduce the delivered hydrogen proportion to a negligible amount.

Further work is required to confirm the ways and means by which suitably scalable methanation reactors can be built and applied for an electrolysis plant such as that outlined in Figure 3.

The output from a 45 MW electrolysis plant is estimated to yield an amount of methane equivalent to 2% by volume of the flow of natural gas from Moomba to Adelaide. This amount could lead to a net reduction of overall national greenhouse gas emissions, via displacement of natural gas from CO_2-emissions-intensive sources.

Summary of energy flows

The geothermal energy harvesting subsystem generates 70 MWe but loses 20 MWe in parasitic losses. Similarly, of the remaining 50 MWe the electrolysis plant loses 5 MWe in the cooling system. The remaining 45 MWe is converted to hydrogen and then to methane with a net efficiency of 56%. The methane yield (available for sale) is about 2.5 Nm^3/s, or 8.3 TJ/day if the plant is operated at full capacity.

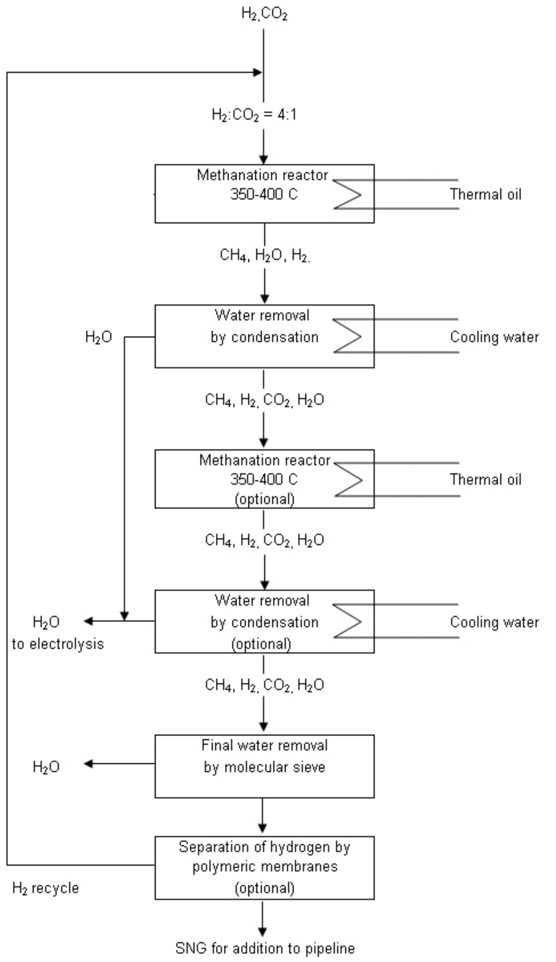

Figure 4: Proposed methanation flow diagram.

Relative cost assessment

The capital cost of the installed electrolysis and refrigeration plant and associated pipework is estimated to be of about 70 million dollars. This compares favourably with the hundreds of millions of dollars that would be required to construct a high-capacity long-distance electricity transmission line. For example, the cost of upgrading the SA – Victoria interconnector is expected to be about 400 million dollars, for a distance of about 300 km. This advantage is greatest if the geothermal plant is co-located with a CNG pipeline. The cost effectiveness of the electricity-to-methane process would have to be evaluated in detail on a case-by-case basis for each new demonstration geothermal plant, and would be influenced by the accessibility of CO_2 stocks as well as distance to electricity and pipeline networks.

By way of an example, the break-even electricity production cost (amortized capital cost compared to energy sales) for the 50 MWe electrolysis-based electricity consumer, is similar to the break-even production cost of a 400 MW geothermal plant sending electricity down a 400 MW 400 km electricity transmission line, despite the electricity to methane energy losses and despite the difference in the value of electricity and methane per unit of energy. This is because such a transmission line would cost over three times the cost of the electrolysis plant.

Summary and conclusions

We reviewed the prospect of converting electrical energy from demonstration geothermal plants to hydrogen. We propose a system in which this energy would be shared in the ratio of 9:1 between an electrolysis plant and a refrigeration plant. An additional methanation step is required to avoid the risks posed by adding pure hydrogen to the existing CNG infrastructure. Apart from the the methanation reactor, all of these components are available as off-the-shelf items. Only the methanation reactor requires additional detailed design and further work to ensure the viability of this system. This system appears to offer a cost-effective circumvention of the geothermal business development dilemma: “What comes first -- commercially viable electricity transmission lines or a successful industrial scale demonstration plant?”.

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