Sector coupling: the hydrogen economy and implications for gas and electricity markets

What is sector coupling and why is it relevant?

Sector coupling is the process of linking different sectors of the economy, especially different energy sectors, for the purpose of fostering synergies between their respective networks and markets. Recent technological development and interest in the low carbon economy has highlighted the increasing links between sectors such as electricity, gas (natural gas and hydrogen) and opportunities for greater integration (manufacturing, transportation etc). Hydrogen has the potential to become a key technology in this context, bringing the opportunity to create Australian strategic value chains.

Many of the use cases of a hydrogen economy involve interaction with one or more of natural gas, electricity and transport. This is being borne out in various multi-sector trials around the world, such as the EnergiePark in Germany or Hystock in the Netherlands.

As the hydrogen economy is in its formative phase compared to these other sectors, there is a natural benefit for hydrogen project proponents to consider how the sector can efficiently integrate with other sectors, not least to assist in the necessary scale-up of hydrogen production and demand that will support ongoing cost reductions.

Hydrogen sector coupling increases economic efficiency. Using the existing gas infrastructure allows the avoidance of important amount of investment in electricity networks, batteries and electricity end-uses, while diminishing the risk of stranded assets in the gas infrastructures.

Hydrogen sector coupling increases security of supply. It provides flexibility to the energy system as a whole (along with demand-response, batteries…), covering energy demand peak and/or failure and is an effective solution to store intermittent renewable power (instead of curtailing it).

Terms of reference

This paper is designed to provide background for participation in the Australian Hydrogen Council (AHC) energy regulatory market reform. It presents an overview of potential barriers for hydrogen interfacing with electricity and gas markets due to market design / regulations; and considers:

- What areas are worth investigating further / pushing for reform; and
- Which matters should be the focus of the industry bodies as opposed to other parties?

It also briefly considered the merits of a more integrated set of governance arrangements as one way to support these interfaces.

Governance overview

Existing gas and electricity governance follow similar patterns but are “parallel” rather than integrated. There are separate objectives, laws and rules for each. The only integrated gas and electricity legislation is in respect of the retail sector. This is focussed on the supply of gas and electricity to small customers, especially households and has less relevance for hydrogen at this stage.

Around a decade ago, when Australia appeared on the brink of establishing a carbon pricing mechanism, it was considered likely that gas would be a critical transitional fuel and that the demand for gas from the electricity sector was likely to increase significantly as coal-fired plants were replaced by CCGTs.

Accordingly, some consideration was given to whether there were elements of the gas and electricity markets that required greater alignment. Subsequent policy and commercial developments significantly reduced the likelihood of this outcome and in general neither regulators nor stakeholders were inclined to prioritise this specific goal amongst all the other reform priorities. For example, while the terms of reference of the AEMC's East Coast gas market scoping study, included an objective to better understand…the potential opportunities benefits and costs of further integration between the electricity and gas markets[i]", the final report for the study noted that stakeholders had not given clear feedback that urgent action to address inconsistencies between the two markets was required[ii].

The lesson for hydrogen project proponents looking for specific alignment between hydrogen sector regulatory settings and gas and electricity is that ongoing consistent feedback to policymakers of why this alignment is valuable and meets regulatory objectives is likely required. Embedding alignment into the governance through changes to national gas and electricity objectives (including merging them and adding hydrogen as a third sector) would assist with this goal but is likely to require sustained and substantial advocacy.

Action: Establishing the economic and societal case for sectoral alignment as a precursor for regulatory reform.

Framework for analysis

The framework for analysis is to consider some plausible scenarios where hydrogen projects interact or potentially interact with the existing reticulated gas system or electricity grid. So standalone transport applications for hydrogen such as fuel cells for cars are not in themselves relevant. For each scenario a range of potential barriers to commercial viability are considered. Below are the scenarios and the types of barriers under consideration.

Scenarios

Five scenarios are considered; two look at hydrogen linking with the natural gas network, one looks at the internal issues for a hydrogen hub, where existing gas pipeline rules may be relevant and the final two look at hydrogen linking with the electricity grid.

- Scenario A: hydrogen injection into the gas network, both blending a small proportion of hydrogen and full conversion
- Scenario B: Gas as a feedstock for hydrogen production via steam methane reforming

- Scenario C: Hydrogen hub – where hydrogen is physically transported and traded by different participants within one industrial precinct.
- Scenario D: Electrolysis of surplus renewable energy
- Scenario E: Storage model – Electrolysis plus storage plus reconversion to electricity for grid export

Barriers

Barriers fall into two main categories: absolute or “hard” barriers that preclude an activity, and economic or “soft” barriers that inhibit an activity.

1. **Hard barriers** are formal legislative or rules-based barriers that preclude potentially economical uses of hydrogen in conjunction with the gas and electricity systems.

2. **Soft barriers** cover a range of inhibiting factors that undermine the economic viability of an activity. They can be divided into three broad types:

a) Lack of clarity as an inhibiting factor. This is where it is unclear how hydrogen or hydrogen assets would be treated under a regulatory framework, or where there is a risk of major future regulatory change. The economic impact of greater risk is that investors in hydrogen assets require a higher cost of capital.

   Lack of clarity is not always a negative – some proponents may prefer to move forward with the freedom that ambiguity or lack of regulatory guidance brings, on the basis that if they can establish a commercial case, they may be better placed to defend their approach in a future regulatory review.

   Consistency of regulatory treatment is also preferred by most investors, although having to manage multiple, varying regulatory frameworks may also be framed as a cost burden, making it more of a Type B barrier

b) An inability to realise full commercial value. This may be due to distortions in the gas or electricity sectors – in most cases these are likely to have been identified, so need to be considered in the context of what is preventing them being addressed. These are likely to be revenue issues, but unnecessary cost burdens could also be considered here.

c) Other factors that result in hydrogen not being currently commercially viable even though it might be in the future. This could include the “valley of death” that new industries face as they move from R&D through to demonstration plants and full-scale deployment.

   The Australian government already has vehicles for supporting early stage commercialization of energy projects including hydrogen: ARENA and CEFC, albeit AHC has identified greater funding for their hydrogen streams would be useful. Alternatively, it could include lack of financial recognition of externalities associated with substitute fuels. Again, this whole area is both politically sensitive and the kinds of instruments that could address this are well understood.

d) Insufficient coordination between system operators: development planning and network investment being done separately for gas and electricity systems is unlikely to allow transparency and a cost-efficient determination of needs and location for hydrogen development. This barrier also refers to a lack of coordination in the operation of gas and electricity networks (e.g. between TSO and DSO; at TSO level; at DSO level).

The main considerations of this paper are the barriers that fall under items 1, 2a and 2b above.

Action: Ranking barriers to hydrogen deployment based on evolving businesses cases and sector preferences will determine where efforts should be concentrated.

Analysis: Summary table

Scenario	Hard barriers	Soft barriers – lack of regulatory clarity	Soft barriers – distortions to true commercial value
Scenario A: hydrogen injection into the gas network	No, although pure hydrogen network not practical under existing regs	Hydrogen typically not covered by existing regs. On balance would be preferable to do so	No
Scenario B: Gas as a feedstock for hydrogen production	No	No	None specific to hydrogen
Scenario C: Hydrogen hub	No	Possibly around pipelines	No
Scenario D: Electrolysis of surplus renewable energy	No	None major, but integrated planning could be useful	
Scenario E: Energy storage model	no	Energy storage of all types subject to some regulatory issues – AEMO has proposed a rule change. Consider also use of geological storage.	Potentially the market price cap, but may not be realistic to seek change just for hydrogen

Hydrogen and gas sector coupling

Scenario A: hydrogen injection into the gas network

There are two stages of hydrogen injection into existing gas networks. The first stage is a blending of a small proportion of hydrogen with natural gas. Tests indicate that up to about 10-15 per cent hydrogen, existing end use appliances will continue to function without major concerns. Several projects around Australia and internationally are trialling this approach.

Full conversion of existing pipeline networks to hydrogen is a different proposition and is many years off. Far more testing of existing reticulated networks to ensure they could carry pure hydrogen safely (it would have a higher leakage rate due to the smaller molecules, for example) and changeover of end appliances would be required.

ENA asked Johnson Winter and Slattery (JWS) to review existing state and territory legislation and regulation for any barriers to injecting hydrogen into existing gas networks[iii]. In general, they found that there were no hard barriers, i.e. prohibitions on doing so. Typically, this was because the issue of hydrogen injection was not specifically addressed. An area that may require further investigation is whether the blended gas is compliant with the standards set out in AS 4564-2011*, Specifications for general purpose natural gas*.

Some soft barriers were identified. These usually stemmed from the fact that many legislative or regulatory provisions referred to “natural gas” and this excluded manufactured hydrogen. The implications of this differ depending on the stage of injection, i.e. hydrogen blending or pure hydrogen. While the barriers are more significant for the latter the prospects for this are many years off (though see scenario C below).

Participation in the facilitated markets and the gas bulletin board is predicated on the commodity being traded being natural gas. This could make it difficult to inject hydrogen into the transmission network for delivery to customers the other side of the hub (for the STTMs) or into the Victorian DWGM system, as physical transfers would be expected to have to been bought and sold in the relevant market.

In the short term, trials of hydrogen blending are expected to take place downstream of the hub points via injection at the distribution network level, which will avoid these issues.

A pure hydrogen network appears unlikely to be covered by various state and territory acts that facilitate the operation of a reticulated gas network serving the general public, and where by necessity parts of the network pass under private land or property. These may include loss of ownership of pipelines under another party’s land, the ability to enter land or occupy public roads to carry out maintenance, the ability to enter premises to read meters, various safety prohibitions to protect the gas network from damage from excavation and other risks, prohibitions against unauthorised connections and so on. In short, it is not really practical to own and operate a pure hydrogen network in the absence of these regulations.

In most of these cases, the simplest regulatory solution to these issues is a regulatory instrument prescribing hydrogen as a “gas” for the purposes of the relevant Acts.

Naturally, this area is a key focus of the several gas distribution businesses that are engaged in hydrogen blending trials as well as the relevant industry associations (ENA and APGA). From an advocacy priority perspective, it makes sense for them to lead, with general support from other hydrogen proponents.

Scenario B: Gas as a feedstock for hydrogen production

Currently the major hydrogen production method in use globally is steam methane reforming – i.e. where natural gas is a feedstock. Given this is analogous to existing industrial uses of gas there is are no obvious hard or material soft barriers. Any soft barriers that may be attributed are generic to those facing gas users more generally, such as the following:

- Facilitated market design may influence decisions re location.
- Accessing gas from existing pipelines can be challenging. Conversely if you're a foundation customer for a new pipeline you can secure firm access (subject to *Force majeure*).
- Export market now dominates market outcomes.

SMR is not considered to be a major source of future hydrogen, notwithstanding a large pilot project under way in Victoria, the Hydrogen Energy Supply chain (this uses gasified brown coal from the Latrobe Valley). One of the reasons for low growth expectations for SMR processes is its carbon emissions. These could be addressed through Carbon capture and storage, as the HESC is considering doing to if it moves to commercial production. CCS projects such as Carbon Net and the CO2CRC Otway project have been under development for several years and do not appear to be subject to material regulatory barriers.

Dedicated hydrogen pipelines

Scenario C: Hydrogen hub

As noted in scenario A above, there are various challenges with owning and operating a pure hydrogen network. In a hydrogen hub scenario, there are likely to be a mix of production, storage and use facilities in close physical proximity and with connecting pipelines. In one sense, then, this may be a pure hydrogen network. However, there are likely to be mitigating factors, such as: hubs will likely benefit from government support; the pipelines will be on private land (albeit potentially different parties); there will be a small number of parties connected, so individual contracts can address many of the concerns.

There is also a question of whether the pipelines in this scenario could fall into the general gas pipeline regulatory regime. JWS note that Part 23 (non-scheme pipelines) contains provisions that do not apply to hydrogen (because it does not meet the relevant definition of gas), but they are silent on whether parts 8-12 could apply[iv]. If they could, then hydrogen pipelines could potentially be subject to a coverage application. This in turn may constitute a soft barrier if existing customers' projects could be undermined by having to share access with a third party. In practice, it seems likely that access arrangements would be thrashed out in the creation of the hub and so a successful coverage application appears a remote possibility.

Hydrogen and electricity sector coupling

Scenario D: Electrolysis of surplus renewable energy

In this scenario, an electrolyser is co-located with a renewable generator such as a wind farm or solar PV plant in order to benefit from cheap, potentially surplus electricity. It's assumed that the hydrogen is then used on site or transported elsewhere (see above for discussion of pipeline-related issues). The advantage of co-location rather than simply plugging into the grid elsewhere is the ability to benefit from electricity output that might otherwise be curtailed due to grid congestion or security constraints. Additionally, if the generator is subject to unfavourable marginal loss factors, then it can obtain more value for its output by utilising it on site.

On the face of it there are few regulatory issues specific to this scenario. A review of the NER applicable to registered generators does not appear to preclude a generator diverting some of its output to another use provided this takes place on its side of the connection point. After all, most generators self-consume to some extent, and this output is not required to be traded in the market or subject to dispatch. Clearly, in this scenario, the generator has to comply with dispatch instructions and also with direction from AEMO. From time to time this could impact its ability to supply the electrolyser, but this scenario is not predicated on full utilisation of the electrolyser in any case.

Following their emergence as a feature of the integrated system plan (ISP), development of several Renewable Energy Zones (REZs) have been proposed. These appear to be supported at least in principle by the relevant state governments. REZs would be particularly appropriate places for this scenario and could support the development of hydrogen hubs. If a hydrogen production facility wanted to utilise the output of several nearby generators, each with their own individual connection point then it would need to be connected to them via the shared grid and either appoint a retailer, or if of sufficient scale, register as a market customer. Neither of these options present as a hard barrier. Nor are they realistically a material soft barrier – there are consequences, including costs such as TUOS and market fees, that follow, but these are just a normal element of being part of the grid and there does not seem to be a case for exemption or changing the rules for hydrogen projects.

An integrated planning approach would assist with the development of this scenario. A detailed review of jurisdictional planning requirements has not been carried out, but there are no obvious reasons for those to contain material barriers – there may be some general provisions about matters such as distances between different types of assets, but these should not add major costs to any co-location project. As governments are generally supportive of and have plans for developing a hydrogen economy in their jurisdiction, ministerial discretion may also assist.

Currently the planning process for where REZs are located is the ISP, and this does not contain any assumptions about hydrogen development. The process does allow for stakeholder input and AEMO seeks information about major prospective loads. Additionally, the ESB's Health of the NEM report states that "the future of the ISP will need to start considering ***integrated planning*** of gas development, ***hydrogen development*** and more immediately infrastructure to support the rollout of electric vehicles[v]"(emphasis added). While unlikely to be a decisive factor in the growth of the sector, advocating for integrated planning of hydrogen in the ISP is one option. There is some risk that a multi-sector integrated planning approach puts a lot of emphasis on the "one source of the truth" that is AEMO's modelling team.

Scenario E: Storage model

This scenario is similar to Scenario D, except that the co-located project also includes a turbine or fuel cell that can convert hydrogen back to electricity for exporting to the grid. This allows the project to function (at least partly) as an energy storage system (ESS). Other ESS types include batteries and pumped hydro.

AEMO has identified a number of anomalies and inefficiencies with the current regulatory arrangements in the NEM for utility-scale, grid-connected ESSs. To address this, they have lodged a rule change proposal with AEMC[vi]. The rule change is currently "pending" so the process has not commenced yet.

The current arrangements require a large-scale ESS to register as both a generator (so it can export to the grid) and a market customer (so it can import to the grid). This creates an additional regulatory burden, including the following issues:

- Lack of clarity in regarding how to register and participate in the NEM. Currently, ESS proponents need to refer to various AEMO explanatory guidelines and factsheets to understand how their facilities may participate in the NEM.
- Increased operational complexity and inefficiency involved in treating a single asset as two components., such as having to submit separate energy bids/offers and FCAS offers and for the scheduled load and scheduled generating unit;
- Technical requirements (applicable at the grid connection point) that are not symmetrical for the same asset, e.g. ramp rates.
- Complicated IT arrangements for registered participants and AEMO.

There is also ambiguity about whether an ESS should pay transmission use of system (TUOS) charges. In some cases, it seems TNSPs are charging them for TUOS as they are registered as a customer. AEMO also charges them various fees and a share of ancillary service costs as both a generator and a customer, although AEMO does not consider there is any double counting in this.

AEMO's proposal (noting that even if the AEMC do consider the issues merit a change to the rules, they may choose to make a "more preferable" version of the rule) is to create a new registration category for ESSs that they term a bi-directional resource provider (BRP). This would address many of the regulatory issues above. They propose that BRPs would not pay TUOS (although a BRP connected to the distribution network would pay DUOS).

Importantly for hydrogen, AEMO's proposal also covers what they call "hybrid" connections, where an ESS is co-located with either a generator or a large load, or both. The generator + ESS combination appears likely in the case of a hydrogen based ESS. There will need to be some management of hybrid registration so that a large user could not game the registration system by adding a small ESS, claiming they are now a hybrid BRP and avoiding TUOS, but this is a matter of detail.

In general, the AEMO proposal would be a positive regulatory reform for all ESS types, including hydrogen and is an obvious area for advocacy by hydrogen proponents. Given the current arrangements allow an ESS to connect to the NEM, they are a soft rather than a hard barrier.

Most other aspects of the NEM do not present material soft barriers to a hydrogen ESS project. Any ESS needs a strong arbitrage signal for the value of its storage role. The NEM's energy-only market with high price cap ($15,000/MWh) and low price floor($-1,000/MWh) leave significant scope for arbitrage. Arguably the arbitrage role would be better supported by raising or removal of the price cap. Previous academic research has identified that an efficient price cap under a high renewables mix could be in the order of $60,000/MWh, in order to ensure reliability on rare occasions where demand-supply balance is especially tight. This is the situation that a hydrogen ESS might be most relevant for – it is expected to struggle to compete with batteries for short term storage, so is typically seen as long-term seasonal or even multi-year storage[vii]. Arguing for the removal or at least a quadrupling of the price cap simply to support the possibility of a hydrogen ESS is a case of the tail wagging the dog; however, for stakeholders who support such a move in any case, the fact that it can support emerging technologies that governments have indicated they would like to see developed is useful.

A recent development in the NEM reform program is the COAG Energy council's decision to implement an out-of-market capacity reserve. Arguably this is a substitute for a sufficiently high price cap to attract investment in very infrequently used resources. The reserve is understood to be effectively a multi-year RERT contracting process. On the face of it there should be no barrier to a hydrogen ESS participating in the reserve procurement process and in any case, it is apparently intended only as an interim measure. Nevertheless, it would be worth checking that the reserve is designed in an appropriately technology neutral manner.

Action: Outline a future vision which clarifies expectations of regulatory change / reform and who is best placed to lead change.

Other issues

Long-term storage will require a suitable storage medium. There are various options including conversion to liquids or solid, but conversion adds cost and the lowest cost large-scale storage is use of natural geological formations such as salt caverns. There is a potential read across to the storage requirements for CCS, however, it is not prudent to simply seek to crowbar hydrogen into a regulatory framework designed for carbon dioxide. Work to confirm whether the CCS storage regulatory framework is suitable for hydrogen is likely required to support any advocacy to extend the framework to hydrogen

Electrolysis requires water as the feedstock. Australian jurisdictions generally have a well-developed water entitlements framework, with scope for trading, but this area has not been examined.

Action: The interactions on water resources and storage requirements requires examination.

Conclusions

While the research underpinning the analysis is not exhaustive, it appears there are few if any hard barriers to the development of a hydrogen economy. This is borne out by the policy sections of numerous hydrogen development plans, which mostly focus on standardised, consistent regulatory frameworks and a range of positive support measures such as those briefly outlined in part C of the soft barriers section above.

In terms of soft barriers, the priorities appear to be in ensuring hydrogen injection into existing gas networks is covered by the regulatory frameworks, that pipeline regulation (or the lack of it) does not inhibit the use of pipelines to transport hydrogen between different production/storage/usage facilities with potentially different owners at hydrogen hubs; and supporting the development of an appropriate framework for ESSs in the NEM. Of these the first is already being led by the ENA and its members, so it is the other two that may need greater stakeholder focus.

For the avoidance of doubt this review is not a substitute for a full legal review of potentially relevant legislation and regulation or detailed recommendations for hydrogen-specific regulation. Accordingly, hydrogen proponents may wish to advocate for prioritisation of such a review, along the lines set out by Clayton & Utz in their paper for the Australian Hydrogen Strategy[viii].

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[i] Gas market scoping study – terms of reference, AEMC, 2013
[ii] Gas market scoping study – a report for the AEMC, K Lowe, July 2013
[iii] Report on the injection of hydrogen and biogas into gas distribution networks, Johnson Winter and Slattery, 2018.
[iv] JWS report
[v] Health of the NEM 2019, Energy Security Board, February 2020, p40
[vi] ERC0280 Integrating Energy Storage Systems (ESS) into the National Electricity Market (NEM), AEMO, August 2019
[vii] The promise of seasonal storage, DNV GL, 2020
[viii] Hydrogen Industry Legislation, Clayton Utz, November 2019