SUBMISSION

VICTORIAN GAS SUBSTITUTION ROADMAP
4 AUGUST 2021

EUAA
Energy Users Association of Australia

INTRODUCTION

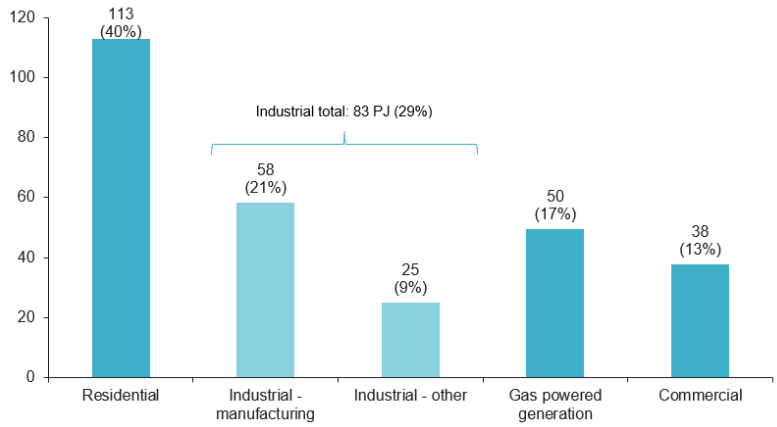
The Energy Users Association of Australia (EUAA) is the peak body representing Australian commercial and industrial energy users. Our membership covers a broad cross section of the Australian economy including significant retail, manufacturing, building materials and food processing industries. Combined our members employ over 1 million Australians, pay billions in energy bills every year and in many cases are exposed to the fluctuations and challenges of international trade.

Being energy intensive business, our members are highly exposed to movements in both gas and electricity prices and have been under increasing financial stress due to escalating energy costs. These increased costs are either absorbed by the business, making it more difficult to maintain existing levels of employment or passed through to consumers in the form of increases in the prices paid for many everyday items.

The EUAA welcome this opportunity to make a submission to the Victorian Gas Substitution Roadmap Consultation Paper (Consultation Paper). Our submission will provide an industrial gas user perspective and focus on the issues of greatest importance to them.

Of all states, Victoria is the most reliant on gas. As the recently published Infrastructure Victoria Interim Report[1] highlights, gas is central to our industrial and manufacturing base and critical to electricity generation.

Figure 5 Victorian gas consumption for energy, by sector, PJ and % total (2018-19)



Therefore, the scale of change required can't be underestimated and that while technologies may exist to replace residential gas use, the situation is not as clear for large industrial gas users. Therefore, a sector by sector approach is likely to be required, as this statement taken from the Infrastructure Victoria report emphasises.

> *"Our initial scenario analysis indicates that a diversified approach to gas sector decarbonisation is needed. No single technology is a silver bullet, and not all technologies are ready to be deployed at scale."*

As we discuss the issues of net zero targets and gas substitution with member companies, a number of themes have emerged.

[1] In December 2020, the Victorian Government requested that Infrastructure Victoria provides advice on the future of Victoria's gas networks under a range of net zero emissions targets by 2050. https://www.infrastructurevictoria.com.au/homepage-infrastructure-victoria/resources/

Net Zero Emissions by 2050

The EUAA accept there is growing ambition to achieve net zero emissions by 2050 and that in order to achieve this, the entire energy value chain will undergo significant change and/or disruption.

Within this net zero framework we also recognise that consumption of natural gas and the use of existing gas infrastructure is likely to change over time. Ironically, since LNG exports linked domestic gas prices to the volatility of international gas markets, many industrial gas users have been forced to seriously consider their long-term exposure to this fuel source irrespective of net zero targets.

While some have begun plans to move away from natural gas, for many others there is no easy exit strategy. Therefore, in the same way that there are "hard to abate sectors" as we move to net zero emissions (especially scope 1 and 2 emissions) there will be "hard to substitute" gas reliant sectors that will require specific, targeted approaches. We would welcome a detailed examination of this issue including identification of those "hard to substitute' sectors and development of sector specific approaches as the gas substitution roadmap is developed.

Within the context of net zero by 2050, a number of members have expressed surprise that blue and grey hydrogen are being considered. The primary reason a large industrial gas user would switch from gas to hydrogen, biomethane or move to full electrification would be to reduce their emissions profile. In the case of hydrogen, using anything other than green hydrogen would simply be swapping one emission source (gas) to another (blue/grey hydrogen).

One member had this to say regarding blue/grey hydrogen:

> *" This does not produce a cheap or sustainable outcome for consumers"*

Stranded asset risk:

There are stranded asset risks on both sides of the gas meter. Pipeline operators are facing stranded asset risk as gas use reduces over time as governments strive for net zero targets. A "big bet" is being placed on hydrogen or other renewable gases filling the gap but this is far from guaranteed. With net zero targets potentially leading to reduced gas usage and doubt over the ability of renewable gas to replace this lost volume, a likely scenario is that a smaller number of customers will be left to pay for the remaining regulated gas pipeline infrastructure.

With this in mind we need to contemplate a scenario where a dwindling number of gas customers, both large and small, are left paying an increasingly large proportion of the regulated gas pipeline bill. Therefore, we see merit in a discussion on the potential for accelerated depreciation for existing regulated gas pipeline infrastructure that would reduce the burden on those gas customers who are unable to switch to viable alternatives.

Industrial gas users are also facing stranded asset risk where they have significant capital invested in plant and equipment that is reliant on gas. Even if hydrogen were to emerge as a viable fuel switching opportunity, existing plant and equipment may not be compatible, leaving the customer with a choice of either significant re-investment or plant closure.

It is important to note that unlike renewable energy that can be gradually mixed into the electricity system and used by customers, hydrogen can't. As much as there are limits on the amount of hydrogen that can be run through existing pipelines (currently 10% in existing steel pipe), the same can be said for end use applications. In most cases, end use applications need to be completely re-configured to accept a new fuel source such as hydrogen (less so for biogas).

This does not lend itself to a gradual build-up of hydrogen use but a series of "step changes" to the quantity of hydrogen being received by the customer. This will make any transition, and the costs, very lumpy.

Due to the capital intensity of making these changes and long investment cycles involved (i.e. 20+ years) the transition to hydrogen will be a multi decade task, during which time companies need to navigate a highly uncertain environment where change has become the new norm. The role of governments to act as a safety net (i.e. investment underwriter) to help reduce these risks must be central to the transition.

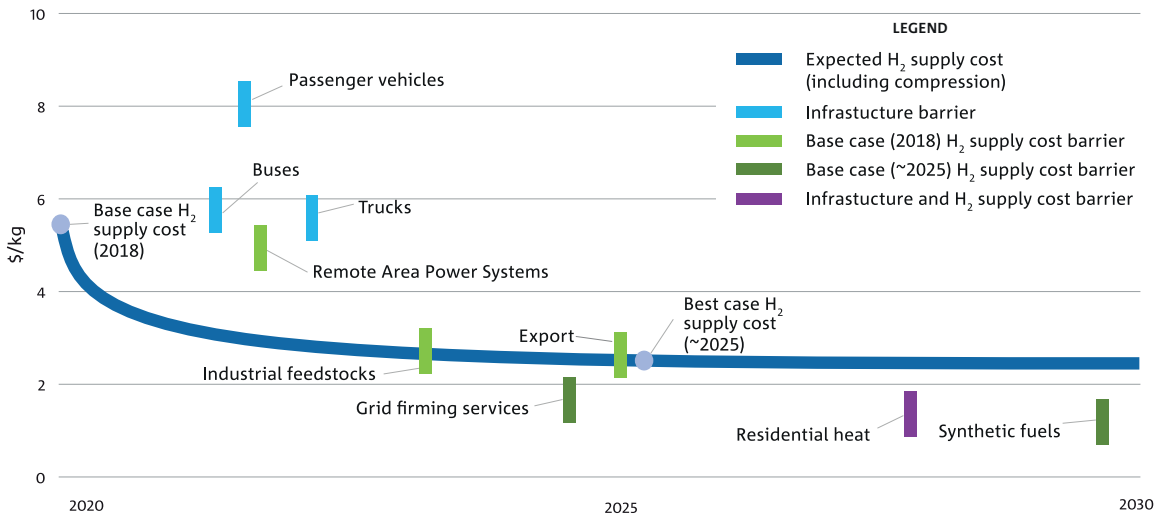
Hydrogen cost curve:

Many people are bullish about the future hydrogen cost curve. Indeed, there are a growing number of "desk top" studies that are pointing to $1KG hydrogen by 2050[2]. They all require electrolyser costs to come down and seriously cheap renewables (i.e. $30Mwh). Additionally, a growing area of discussion is the water intensity of green hydrogen.[3] Green hydrogen requires access to a cheap, high quality water source, and lots of it and the assumption seems to be that access to this key ingredient will be free, have zero social impact and has no opportunity costs associated with it.

Elsewhere we have seen governments set an aspirational target of $2Kg[4] . While this is a laudable goal, a target price of $2Kg is still expensive compared to natural gas, even at $10Gj.

The chart below is taken from the CSIRO National Hydrogen Roadmap[5] and while still representing a bullish outlook for the cost of hydrogen (along with identifying some opportunities), it also identified significant barriers.

Hydrogen competitiveness in targeted applications



The following comment, taken from the same report indicates a significant level of government investment and "an appropriate policy framework" would be required.

> *Barriers to market activation stem from a lack of infrastructure required to support each application and/ or the cost of hydrogen supply when compared to other energy carriers (e.g. batteries) and feedstocks (e.g.*

[2] Report on Bloomberg New Energy Finance analysis of potential hydrogen cost curves https://www.greencarcongress.com/2021/04/20210407-bnef.html
[3] The discussion on the water intensity of making green hydrogen and social, environmental and economic impacts has only just begun https://www.jdsupra.com/legalnews/water-resource-considerations-for-the-84603/
[4] https://www.industry.gov.au/policies-and-initiatives/growing-australias-hydrogen-industry
[5] https://www.csiro.au/en/work-with-us/services/consultancy-strategic-advice-services/csiro-futures/futures-reports/hydrogen-roadmap

natural gas). ***It is expected however, that development of an appropriate policy framework could create a 'market pull' for hydrogen. Investment in infrastructure, hydrogen production, storage and transport is then likely to follow.***

Even then the ability of hydrogen to replace gas for many applications is still in doubt. Even more doubt exists around its ability to replace gas for high temperature industrial applications. We discuss our concerns regarding a proposed "market pull" approach later in this submission (concern over premature policy response).

An EUAA member relayed this recent conversation:

> *"We recently had discussions with a producer about hydrogen gas and they indicated that without subsidies the cost of hydrogen is likely to be in the order $25/GJ + transport. My understanding is that although the technology may get more efficient over time a lot of this cost is due to the electricity requirement and that comes to down to physics and the amount of energy required to split a water molecule so even if they get extremely efficient the cost is unlikely to get much lower. I strongly believe there is a lot more R&D required in this space and it needs to happen now. It takes decades to develop some of this technology let alone having the changes flow through businesses."*

The following table is taken from "Australia's National Hydrogen Strategy"[6] and emphasises the point being made by this member company; being that hydrogen still has a long way to go to be a competitive fuel for most large industrial processes. However, it does identify where some logical entry points could be, notably as a replacement for diesel.

Breakeven price points

This table shows the delivered prices hydrogen would need to achieve against competitor fuels.

Competitor fuel service	**Hydrogen breakeven price** ($/ kg H_2)
Drive 100 km using petrol (retail price $1.43/ L)[ii]	$13.31
Drive 100 km using diesel (retail price $1.50/ L)[iii]	$11.21
Deliver 1 GJ heat using natural gas (wholesale price approximately $10/ GJ)[iv]	$1.20

The Consultation Paper has a strong focus on hydrogen, prompting a number of member companies to express concern that other aspects of the Substitution Road Map are not getting appropriate attention. Many have expressed a desire to see more discussion on fuel efficiency while some think opportunities associated with other renewable gas should be given more consideration. One member had this to say:

> *"Why is such low consideration given to other renewable gas? The paper is too heavy on Hydrogen. Many sectors (such as pulp and paper) could act as a large host to and supplier of, biomethane to the market from either biomass or waste. There is no co-ordinated effort here to develop these."*

[6] Australia's National Hydrogen Strategy was produced by the COAG Energy Council Hydrogen Working Group, Chaired by Chief Scientist, Alan Finkel AO. https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf

Electrification of industry:

The following table, taken from the Infrastructure Victoria Interim Report[7] (page 27) identifies four possible scenarios to achieve net zero emissions for gas in Victoria by 2050, all of which look to either achieve full electrification of industry (or near to it) or have hydrogen as a significant contributor replacing gas in the existing system.

Table 2 Scenarios to achieve net zero emissions for gas use in Victoria by 2050

Scenario A: Zero emissions electrification – no natural gas	Scenario B: Net zero emissions electrification supported by natural gas	Scenario C: Zero emissions hydrogen with biogas and electrification	Scenario D: Net zero emissions hydrogen with biogas and electrification
• Almost full electrification using renewable sources, utility-scale battery storage and some pumped hydroelectric • Very little natural gas except where it is irreplaceable – and none by 2050 • No CCS by 2050	• Extensive electrification with renewable sources, significant small-medium battery storage and limited pumped hydroelectric • Some natural gas to support the renewable electricity system and some industrial uses • Made net zero by CCS and offsets	• Hydrogen using renewable sources really takes off as a substitute for natural gas • Some waste to energy, biogas and renewable electricity sources with some battery storage • No CCS • No natural gas by 2050	• Hydrogen using both renewable sources and coal with CCS • Some waste to energy and biogas and renewable electricity sources with some battery storage • No natural gas by 2050

While we appreciate this is an initial assessment and that no cost benefit modelling has been completed, we would urge the Victorian Government and Infrastructure Victoria to consider full electrification costs, on both sides of the meter.

Upstream of the customer, the cost associated with fortifying the grid in many areas will be significant. When we add the cost of additional storage, technologies to support system strength and significant additional generation costs, the total cost of "electrifying everything" will become significant.

As an example, a recent directions paper released by the Victorian Government (Victorian REZ Development Plan Directions Paper[8]) identified that at least $10.102B will need to be spent on grid upgrades and technology to support system strength (i.e. batteries and synchronous condensers) over the next decade to help accommodate the expected growth in renewable energy (and assuming gas continues to play a role).

To "de-gas" the system and electrify industry would require an exponentially larger sum to be spent. We look forward to this discussion so all stakeholders can understand the full system costs of options being proposed.

To further emphasise this point, the following table presented by AEMO as part of a recent Consumer Forum summarises 5 scenarios that make up the 2022 Integrated System Plan (ISP). These scenarios could be a useful basis from which to start a full system cost study of electrification under net zero targets and what AEMO have described as a Hydrogen Superpower scenario, both of which align with government objectives.

As can be seen under the Hydrogen Superpower scenario (which also incorporates a net zero emissions scenario) we would see electricity consumption increase by more that 300% on current levels, meaning unprecedented levels of investment, and therefore costs, to be borne by consumers.

[7] https://www.infrastructurevictoria.com.au/homepage-infrastructure-victoria/resources/
[8] https://www.energy.vic.gov.au/__data/assets/pdf_file/0016/512422/DELWP_REZ-Development-Plan-Directions-Paper_Feb23-updated.pdf

	Slow Change	Steady Progress	Net Zero 2050	Step Change	Hydrogen Superpower
DEMAND					
Electrification					
– % of road transport that is EV by 2040	22%	44%	52%	58%	76%
– % of residential EVs still relying on convenience charging by 2040	68%	61%	57%	47%	40%
– Industrial electrification by 2040	-25 TWh	8 TWh	32 TWh	45 TWh	66 TWh
– Residential electrification by 2040	0 TWh	0 TWh	6 TWh	9 TWh	10 TWh
Energy efficiency savings by 2040	16 TWh	25 TWh	30 TWh	44 TWh	44 TWh
Underlying Consumption					
– NEM underlying consumption by 2040	184 TWh	245 TWh	276 TWh	279 TWh	329 TWh
– H2 consumption (domestic), 2040	0 TWh	0 TWh	2 TWh	15 TWh	64 TWh
– H2 consumption (export), including green steel, 2040	0 TWh	0 TWh	0 TWh	0 TWh	221 TWh
– Total underlying consumption by 2040	**184 TWh**	**245 TWh**	**278 TWh**	**294 TWh**	**614 TWh**
SUPPLY					
Distributed PV Generation	47 TWh	51 TWh	61 TWh	66 TWh	83 TWh
% of household daily consumption potential stored in batteries	4%	12%	17%	32%	35%
% of underlying consumption met by DER by 2040 *	26%	21%	22%	22%	13%
Estimate of % coal in generation mix by 2040 *	50%	20-25%	15-20%	5%	0%
Estimate of NEM emissions production by 2040 (MT CO2-e)	TBD	TBD	55 (~40% of 2020 NEM emissions)	10 (~7% of 2020 NEM emissions)	1 (~1% of 2020 NEM emissions)

Level of change

Clearly a whole of supply chain cost benefit analysis needs to be undertaken before any substantive policy decisions are made. We trust this assessment will take place along with deep consultation with industrial gas users to understand the decisions they will need to make and costs they will need to bear.

Within this context, it appears the ability of industry to fuel switch seems to be overestimated or even taken for granted. Even where there are alternatives to gas we still need to consider investment cycles, asset write off and balance sheet impairment, location issues (such as planning and environmental constraints), on-site process requirements etc.

An EUAA member recently provided this perspective:

> *"If we were to look at the cost of replacing our natural gas fired boilers like for like then off the top of my head I would estimate a cost in the ballpark of $35-50M which would make it one of the largest capital projects we have undertaken and wouldn't increase our production capacity or enable new production capability (i.e. not a business growth project). That is if we were to replace it with natural gas boilers. I would expect this would be more expensive for electrical steam boilers since it is a less mature technology. I believe most of our sites run ~5MW natural gas boilers with one site operating 3x roughly that size. This would mean replacing 1 gas boiler with 5 smaller electric boilers which would all have their own efficiency losses and I think would overall have a higher capex to thermal energy output ratio."*

Fuel efficiency is one of the many open questions at this stage when industrial gas users investigate fuel switching, specifically gas to electric. One member observed:

> *"Most of these exercises seem to step around the efficiency loss by electrifying, directly conflicting with the energy productivity paradigm we drive in our business. One thermal megawatt is not directly replaced by one electric megawatt. If you are buying or building capacity you will need to oversize to counter this fuel efficiency loss."*

Another EUAA member provided this perspective:

> *"Scale of electrical boilers on the market currently is too small. High temperature heat pump technology looks promising and may be able to reliably deliver temperatures of ~85°C but anything above that is basically still experimental. If high temp heat pump technology improves that could be a real game changer in terms of electrification. Our processes regularly require temperatures of up to 200°C and steam pressures up to 16 bar. High temp heat pumps cannot technically and reliably deliver this yet let alone economically."*

Further to this, while there may be opportunities to replace gas with an electrical alternative (i.e. low temperature heat) some industries that require continuous high temperature heat such as bricks (1,000 degrees) and alumina calcination (>1,000 degrees) are not suited to electrification. There are also industrial users who require gas as an essential feedstock (i.e. ethane for plastic production and methane for fertiliser production) of which there is no viable alternative.

Switching fuels is not a simple task and the decision industrial gas users may be faced with is not to switch fuels but to slowly wind down their gas reliant plant and switch location and/or jurisdiction. Therefore, unless these industries are to be allowed to wither and die we believe we will still need to keep some parts of the gas network going for the foreseeable future. This view aligns with "Scenario B" from the Infrastructure Victoria Interim Report.

<u>Electricity generation and the ongoing role of gas:</u>

As we have noted in an earlier part of this submission, the cost of removing gas and fully electrifying the system will be extremely costly as the Infrastructure Victoria Interim Report states[9] (page2 31 & 32)

> *"Scenario A requires significant upgrades to electrical infrastructure across the whole network to accommodate increased demand and storage requirements. This scenario has significant renewable generation capacity in north-west Victoria, which would be under-utilised without upgrades to transmission lines. High-capacity electrical infrastructure in the Latrobe Valley would also be under-utilised, as coal-fired power stations are closed and the electricity they generate is removed from the grid.*
>
> *The significant additional electrical infrastructure needed to supply power around the state from Renewable Energy Zones would see an increase in bushfire risk, which could be reduced by burying overhead transmission lines in bushfire areas. Transmission lines were assumed to be above ground in areas of low bushfire risk due to the very significant cost of burial. This, however, may have other amenity impacts.*
>
> *Scenario A relies on hydro power to level out peak demand. There is a technical risk there are not enough locations in Victoria with the topography required to support hydro power. However, hydro power can be sourced from other states to provide backup with the use of state interconnections (for example, TasNetworks' Bass Strait Interconnector or the Snowy 2.0 hydro project in NSW)."*

Given this, the EUAA still see a critical role for gas fired power stations in the National Electricity Market for the foreseeable future. While batteries are improving in terms of cost and volume and will play an important role in intra-day reliability and system strength it is not clear that they will be able to provide the long-duration (inter-day) services of traditional generation.

[9] https://www.infrastructurevictoria.com.au/homepage-infrastructure-victoria/resources/

The Infrastructure Victoria Report points out that Victorian based hydro power opportunities are limited. While some level of hydro power can be imported these assets will be in strong demand, especially if/when other states move down the gas substitution pathway.

In particular, we would be very concerned if existing gas fired power stations were forced out of the market prematurely (i.e. before the end of their economic life) by government mandate only to require additional cost to be incurred to build new, non-gas assets to replace them. This would be an economically inefficient outcome and potentially risk the reliability of the Victorian energy system.

Need to preserve existing industries:

Not surprisingly the Consultation Paper has a focus on building future industries (i.e. Hydrogen, bio-gas etc) but speaks little about transitioning existing industries and preserving existing jobs. We would like to see a balanced discussion in future papers that seeks to achieve the dual outcomes of preserving existing industries while fostering new ones.

The need for policy clarity:

The transition from a centralised thermal generation fleet to a decentralised renewable energy generation fleet has been occurring over the last 20 years. This transition has accelerated recently to the point where significant issues are emerging in the NEM. This transition has largely impacted electricity markets (and end use) and hasn't been helped by a fragmented and at times chaotic policy environment. Now we have net zero targets being pursued which has serious implications for both electricity and gas markets with a similar fragmented and chaotic policy environment now impacting gas.

The following extract from the Infrastructure Victoria Interim Report[10] (page 36) identifies a range of areas where we can learn from international experience. In particular we note that the last dot point says the transition takes 30 years (we agree), and that "interventions that affect many customers or involve changing consumer behaviour should start early."

> Across the jurisdictions included in this analysis – the United Kingdom, the Netherlands, Canada (western provinces) and Japan – there are some lessons for Victoria.
>
> - **There is as yet no single clear pathway to net zero 2050 for gas** – none of the comparison jurisdictions have yet committed to fully decommission their gas networks. Jurisdictions are instead using a range of policy levers and investing in multiple alternative technologies to keep their options open.
> - **Energy efficiency is a 'no regrets' measure which can be undertaken now** – jurisdictions are focused on increasing gas use efficiency and reducing gas use to provide short-term emissions reduction benefits and lower costs while keeping other options open.
> - **Longer-term investments are aimed at diversifying options in an uncertain future** – while investments in CCS and substitution with hydrogen and/or biomethane involve some risk, they can open up future transition pathways for gas.
> - **A long-term carbon price or emissions regulation** may be required to attract capital commitments for large-scale CCS and other capital-intensive projects. CCS will take significant policy support and government action to become a feasible pathway for gas decarbonisation. Governments can play an important role in directly funding CCS projects and coordinating clusters of CCUS customers.
> - **Policies and regulations across the Victorian Government need to align with net zero targets** – aligning policies and regulations across government will provide a strong framework to deliver net zero targets over time, and allow for all infrastructure and network investment decisions to be compatible with pathways towards net zero.
> - **Gas infrastructure transition is a long-term commitment** – jurisdictions expect to take at least 30 years to upgrade or decommission infrastructure and complete their transition to net zero gas.
>   - Major energy system reform requires changes to regulations, safety rules, consumer tariffs, workforce skills and training, and supply chains.
>   - Changes are likely to take many years to achieve widespread acceptance, so interventions that affect many customers or involve changing consumer behaviour should start early.

[10] https://www.infrastructurevictoria.com.au/homepage-infrastructure-victoria/resources/

This creates a dilemma for governments. By picking hydrogen as the winner, which the Consultation Paper implies the Victorian Government have, then significant changes to a range of policy and regulation (including those impacting the built environment) needs to commence now, even though there is significant doubt on the future cost and technical viability of the fuel.

An EUAA member had this to say recently which sums up the frustration being felt by many:

> *"If we had a boiler that was reaching end of life today we would be faced with a very tough decision. On the one hand the Federal Government is saying 'gas fired recovery' and targeting low gas prices. On the other hand we are watching every state and territory have a net zero 2050 target and wondering what that means for the future of natural gas.*
>
> *If we replace a gas boiler today we want to assume at least 25 years of life out of it. That puts us at 2046 at the earliest. If we are targeting net zero then there is probably going to be a combination of two things affecting the overall cost of natural gas at that time 1) supply – there will probably be less natural gas around 2) carbon credits – there will probably be some form of policy (or more likely policies varying state to state) that will require purchasing carbon credits or offsets so that any natural gas that is burnt is offset by carbon sequestered elsewhere (it's 'net zero carbon emissions' not 'zero carbon emissions'). Comparing the lifecycle cost of one type of boiler to another is very difficult at the moment and is not helped by policy uncertainty and a disorderly transition from fossil fuels to renewables."*

Finally, members have noted that nothing in the Consultation Paper talks about how we can establish a liquid financial and physical market with concerns raised that we may be doomed to repeat what has happened with the domestic natural gas market that is plagued by immature market development and dominated by a small number of highly influential players.

Since LNG export commenced, domestic gas users have been at the mercy of global LNG prices and the market power of exporters. This could have been avoided with a thoughtful domestic reservation policy (i.e. such is the case in WA). While not an immediate issue, we urge policy makers to consider these issues as markets begin to develop.

Concern over premature policy response.

Paradoxically, while there is a need for policy clarity there is also concern over premature or ill-conceived policy responses. For example, a number of gas users are becoming increasingly concerned that when it comes to policy options that government will forge ahead with a Renewable Energy Target (RET) style subsidy scheme for green gas, specifically hydrogen. In the absence of any economic impact or cost benefit modelling on this policy, many industrial gas users are concerned this will be very expensive at a time when they are feeling the strain of record high gas prices.

It must be remembered that at the start of the RET, the cost gap between fossil fuels and renewable energy was about 100% (i.e. energy from thermal plant was about $45Mwh while energy from a renewable energy project was about $90Mwh). This cost gas was bridged over time (about 15 years), using proven technologies such as wind and more recently solar. The cost gap between hydrogen and gas is up to 250% and there is an expectation this gap will be bridged in 10 years with relatively new technology.

While recognising the work already done on the National Hydrogen Road Map[11], it seems clear to us that a nationally consistent road map needs to be established that sets out the building blocks for both gas substitution and net zero by 2050. If hydrogen is to be pursued, and there is good reason to do so, it must be done in a way that transitions existing industries while pursuing the growth of new ones.

It appears that logical entry points for hydrogen already exist. For example, we understand that hydrogen powered heavy transport is already cost competitive with the diesel power equivalent. This would lend itself to focussing on replacing diesel power public transport with hydrogen equivalents or looking at heavy road transportation. Replacing diesel generation in remote mining sites and/or communities also seems a logical place to start given the cost competitiveness of hydrogen over diesel generation.

Innovator or Fast Follower.

One of the biggest questions being asked is should we be an innovator in this space or take advantage of being a fast follower? There is a lot of hype about Australia taking the lead on hydrogen and becoming a "Hydrogen Superpower". While not dismissing this possibility, we are yet to be convinced we can achieve the scale to drive technical innovation here due to limited market size and the fact that significant R&D and trial processes have already commenced internationally. We can still be a hydrogen super power as a technological fast follower because the sun and wind we will use to create green hydrogen aren't going anywhere.

[11] https://www.csiro.au/en/work-with-us/services/consultancy-strategic-advice-services/csiro-futures/futures-reports/hydrogen-roadmap

RESPOSES TO KEY QUESTIONS

Key issue	Question	EUAA response
Key issue 1 Maintaining electricity reliability with new sources of demand	What policies are needed to ensure that the electricity network can reliably serve new sources of demand from hydrogen production, electric vehicles and electrification of gas demand?	This is one of a number of a multi-billion dollar questions raised by the Consultation Paper and is similar to questions being asked regarding the transition to a net zero electricity system. We would suggest that a number of policy options being considered as part of the ESB Post 2025 Market project are worthy of further consideration, albeit they are not sufficiently developed at this point in time. One of the key issues for consumers in this transition is the fair allocation of cost and risk. In an era where profits are being privatised we should not continue to see the socialisation of all costs and risk.
	What is the role for gas-fired power generation and hydrogen in maintaining electricity reliability?	We firmly believe that gas-fired power generation has a key role to play in maintaining reliability and stability of the grid. The role for hydrogen is far less clear, predominantly due to the significant cost differential between hydrogen and gas. While hydrogen may not be a "reticulated" fuel in Australia it may be prove to be a useful way of storing and exporting wind and solar energy.
Key issue 2 Transitioning to more sustainable gaseous fuels with minimal disruption to end-users	What are the key technical challenges in converting existing gas networks to accommodate more sustainable gaseous fuels?	We are not experts in this area so won't comment on the technical issues but will draw you to our comments in the first half of this submission regarding stranded asset risks. Again, we would also not there are significant technical challenges (and cost) on both sides of the meter that need to be considered.
	What are the potential costs and opportunities in switching to more sustainable gaseous fuels for consumers?	The only reason industrial gas users would switch fuel would be to meet various sustainability goals (including net zero targets) or to ensure their international competitiveness in the instance of carbon driven boarder adjustments. Therefore, any price premium they will be prepared to pay for technology would need to be lower than the cost and availability of carbon offsets.
Key issue 3 Maintaining the reliability, affordability and safety of gas supply	What are the affordability, reliability and safety considerations related to gas supply and gas infrastructure, both in the short term and during a long-term transition to a decarbonised gas sector?	We draw your attention to comments made in the first half of this submission relating to stranded asset risk, hydrogen cost curve and electrification of industry. Given the importance of gas to the economy and the level of capital already invested in gas intensive use, the transition will be a multi decade undertaking where governments will need to play an active role to help participants manage risk.
	What policies are needed to ensure that the gas system continues to operate reliably and safely and remain affordable for end-users during the transition?	We are not experts in this area, however it is clear that there would need to be significant work on a range of new standards. The Infrastructure Victoria Interim Report highlights numerous examples of these, of which we concur.
Key issue 4 Supporting Victoria's workforce, industry and institutions that support them	What workforce skills and industry capabilities are required to transition to new and emerging energy sources?	While recognising the upside of "future jobs and industries" we should not ignore the jobs and industries we already have. We would hope to see a balanced approach by governments where a just transition occurs for all participants.
	How can government, industry and unions best work together, including through the Victorian TAFE and Training system, to help to build these skills and capabilities, and support existing workers through the transition?	We have no comments to make in this area.
	How do we maximise local job opportunities, including for industry training centres such as that operated by the Plumbing Industry Climate Action Centre, to prepare workers for the future?	We have no comments to make in this area.
Key issue 5	What key uncertainties should the Roadmap take into account, and	As outlined in the first half of this submission, stranded asset risk, the hydrogen cost curve, electrification (including the full value chain) of industry, hard to abate or hard to substitute sectors and policy and regulatory uncertainty are all

Managing uncertainty in the transition	what is the government's role in reducing these uncertainties?	fundamental risks. Governments can play a strategic role through encouraging R&D in target areas (including customer transition), it can look to be an asset underwriter to reduce long-term risks for consumers and it can set clear policy and regulation with clear sunset/transition dates and fair grandfathering.
Key issue 6 Transitioning the Victorian economy efficiently and equitably	How can we ensure that the costs of the transition to lower emissions energy sources are borne equitably?	As argued before, profits are becoming privatised while cost and risks remain socialised. This is unfair and in many cases places costs and risks onto those who are least able to manage them; being consumers. Recognising that consumers will ultimately pay for everything, applying the principle of causer pays will help guide government as to who should bear cost and risk in the first instance. As a general rule, the more of these costs and risks that are exposed to market forces, as opposed to being included in a regulated asset base, the better off consumers will be in the long run. As previously stated, governments can also play a role in supporting the market through measures such as asset underwriting, capital grants and R&D funding.
	How can we help low-income and vulnerable households manage any upfront costs in changing energy sources?	We have no comments to make in this area.
	What are the barriers for households in improving the efficiency of their use of gas heating, cooking and hot water and/or switching to solar/pump hot water in existing homes?	We have no comments to make in this area.
	What are the opportunities for the Victorian Energy Upgrades program to incentivise efficient gas use, thermal upgrades of building (e.g. insulation) and electrification?	We have no comments to make in this area.
	What issues and elements do you see as most important to improve the energy and emissions performance of new homes?	We have no comments to make in this area.

We would welcome further, detailed discussions with both the Victorian Government and Infrastructure Victoria as the Gas Substitution Plan is developed and hope that we can play a positive role is helping the Victorian Government achieve its objectives while ensuring consumers are treated fairly and costs are minimised wherever possible.

Andrew Richards
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