Renewable Hydrogen in the SWIS

Response to Consultation Paper

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Introduction:

It is timely that Energy Policy WA have released the Renewable Hydrogen Consultation Paper of October 2022.

The authors of this document are researchers and businessmen with several decades of experience in the renewable power generation field, particularly, solar, diesel-hybrid plants and inverter manufacturing.

Numerous rapid developments are occurring across the globe driven by;

a) Steep declines in the costs of renewables disrupting the incumbent power utilities
b) Rising political acceptance of the threats and risks of climate change
c) International tensions i.e. the Russia Ukraine conflict / USA – China competition
d) Supply chain and globalization issues driven by Covid and other factors
e) Rapid developments in electrochemical energy storage across many industries

As a team, lead by the Chief Author, we imported into Australia the first practical fuel cell, a USA constructed phosphoric acid technology rated at 3 kW fuel using ethanol with reformer (to hydrogen). This was installed at Murdoch University for evaluation along with the control and power conversion from DC to AC developed in WA.

When replying to the questions proposed by Consultation paper, we may be referring you to relevant parts of our recently issued study titled "Hydrogen vs Natural Gas, how soon?" see Appendix A, Pages 11 – 39.

In general we agree with the objectives around development of hydrogen applications. Our answers to the question posed are included immediately below.

Question 1:

What are some examples of an objective or objectives that could be used to assess the benefits, cost's and impacts of a Renewable Hydrogen Target for SWIS based electricity generation ?

Enhancing reliability and stability of the SWIS with clean energy is an immediate and ongoing requirement, as

a) the amounts of VRE will keep **increasing across the SWIS** and even more VRE will be needed for the production of green hydrogen.
b) The complex issues in Collie are causing power instabilities leading to possible imminent use of diesel engines for peaking power
c) Development of a skill base, that incrementally underpins much larger generation of hydrogen and ammonia in the NW.

So the current situation that the SA grid, Image 1(even when connected to the NEM) is experiencing is a mild preview of what is expected for the isolated SWIS grid.

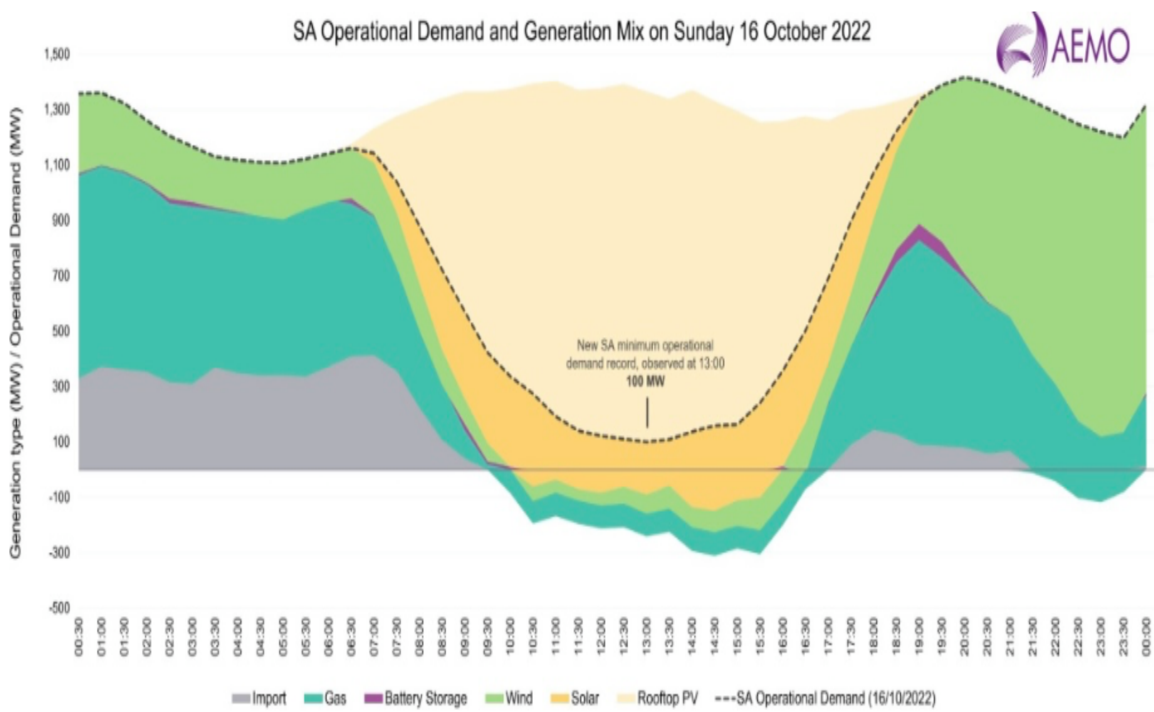


Image 1

The curtailment or "negative" cost of VRE energy could be easily redirected to green hydrogen production and storage whilst reducing its production cost and reducing the evening peak load, adding capacity credit for Frequency Regulation and Spinning reserve (actually "non spinning") as we will see later.

The experience gained with developing green hydrogen short duration storage, long duration storage and eventually seasonal storage when 85%VRE is reached will be invaluable (see page 10 of "Hydrogen VS Natural gas" document, Appendix A).

Question 2:

How might other uses of renewable hydrogen be accommodated under a Renewable Hydrogen Target certificate scheme? How might Government otherwise support and/or encourage other use cases for hydrogen?

WA is in a "privileged" gas reservation situation, but the rest of Australia and the world is not. The temperature escalation problem (see pages 1 to 7, fig. 6 and Appendix A in H2 VS Nat. Gas document) could disrupt the market quite severely. The encouragement for a green hydrogen use with a well-constructed Certificate scheme should work. However the stated model targets of 1%, 5% and 10% are quite modest given that even 10% in say 10 years time would be about 300 MW only.

Other Uses:

What is inevitable is the action of private / international capital that will enhance the adoption such as the Murchison Hydrogen project in Kalbarri (see page 10 of doc Appendix A).

1. Given the conditions and circumstances for green hydrogen production would be best suited to the NW we would advise to look for other hard to abate areas. Development of an electrified freight train system to the Pilbara could be powered by green hydrogen and remove substantial haulage from the WA carbon cycle.
2. For smaller distributed systems we note that both the electrolysers and advanced fuel cells are about 60% efficient. A 10 MWe output system will generate close to 10 MWthermal energy. This high-grade waste heat can be recovered in various co-located industries such as hospitals, food and beverage industries, thus offsetting other electrical consumption.

A concern about the "imposed liability" scheme is that it applied penalties on the generators rather than providing incentives. A SWIS "guarantee off-take contract" should prove an example for the financial institutions and private industry for the take-off of this industry and the beginning of de-escalation of costs.

Question 3:

What role do you believe renewable hydrogen can play in the decarbonisation of electricity generation? To what extent will a Renewable Hydrogen Target for electricity generation in the SWIS assist in achieving the decarbonisation objectives of the State Government?

A State organization such as the WA SWIS is in a prime position to show the escalation of green hydrogen in electricity generation, along with rigorous standards have to be adopted and controlled. WA is rich in both solar and wind power and it should be clear that the SWIS is a very small grid by international standards, almost a large micro grid.

Therefore the SWIS will be progressively dominated by VRE and supporting / ancillary technologies such as electrochemical storage for short term support with demand side management are well advanced.

Green Hydrogen, at the 5MW to 20 MW scale can assist the SWIS as smaller distributed systems for local network support.

The EU Standards (becoming International) with participation of Australia's Clean Energy Regulator seem to be the most advanced at the moment and it should serve well to the green hydrogen and/or ammonia export market. As a power generator, the SWIS should investigate the work the Australian government is doing in conjunction with International partnership for Hydrogen and Fuel Cells in the Economy (IPHE).

Question 4:

What role can the infrastructure associated with the production of renewable hydrogen (i.e. renewable electricity generation facilities, electrolysers, transport and storage infrastructure) play in the broader SWIS?

The SWIS can provide leadership in developing the infrastructure and facilities such as storage and transport, electrolyser and fuel cell equipment specification and man power skills. See Image 2.

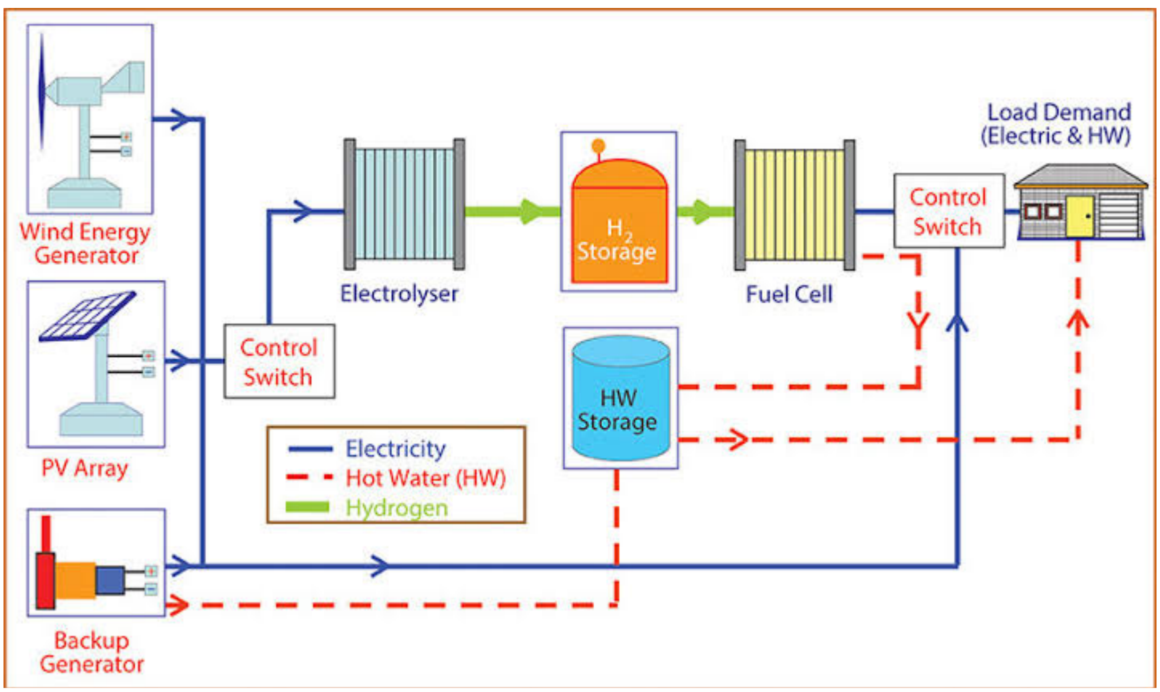


Image 2 Green H2 System

It is well known that one of the largest technical challenges with hydrogen is storage. Therefore early adoption of green hydrogen in the SWIS should be aimed at generation and consumption being co-located. This will likely discourage small systems say under 100kW and promote larger installations.

Its already noted that very large scale green hydrogen and ammonia projects are already planned for the NW.

These developments can promoted skills and supply chain support in WA, initially at least at the lower end of complexity. The Government should be looking at add rapidly to the human capital base by promoting TAFE and University level courses around this industry.

It should be noted that the hydrogen industry is sophisticated and requires breadth and depth in technical skills. For example Solid Oxide Fuel cells require specialized ceramics and the electrolyte technology is especially so, quote:

"Popular SOFC electrolyte materials include yttria-stabilized zirconia (YSZ) scandia stabilized zirconia (ScSZ) and gadolinium doped ceria (GDC). The electrolyte material has crucial influence on the cell performances. Detrimental reactions between YSZ electrolytes and modern cathodes such as lanthanum strontium cobalt ferrite (LSCF) have been found."

Question 5:

To the extent you are able please reflect on some of the technical issues, challenges and considerations in the utilization of hydrogen in the generation of electricity. To what extent can these technical issues and challenges be overcome? How should this impact on the consideration of a Renewable Hydrogen Target for electricity generation in Western Australia?

Although the transition to a 5% green hydrogen to natural gas in OCGT is reasonable, it will be of the most utmost importance to transition to far more efficient fuel cells which is the (non combustion) technology of preference for green hydrogen (see Appendix A pages 18 and 19 of the document).

It is particularly important when the generation is coming from a storage source, as the generator will always be operating at part load where gas turbines perform poorly and fuel cells excel. It will be important to consider what type of fuel cell technology is most suitable for this application either high temperature solid oxide or the low temperature more flexible proton exchange membrane (PEM). This depends on the electrical capacity required.

A co-location of fuel cells generation plant at the Kalbarri, WA Murchison Hydrogen plant would seem an attractive approach (Acceleration page 31 of document Appendix A). The planned project has considered exporting green hydrogen to the adjacent gas pipeline so instead or as well as, could provide green hydrogen and storage to power fuel cells and the SWIS grid.

Proponents should be clear about the issues of injecting H2 into existing pipelines. H2 is the smallest molecule and can escape quite readily from enclosures. Also if we inject, say, 5% by volume into a natural gas service it should be understood that the energy content does not follow the same relationship.

It could be a direct connection for SWIS grid application of green hydrogen thus reducing heavy regulatory conditions of a mixed natural gas-hydrogen supply pipeline with complex origin certification.

Question 6:

Do you believe a renewable hydrogen electricity generation certificate-based scheme represents an efficient and effective means to deliver a Renewable Hydrogen Target for electricity generation in the SWIS? Please explain your answer.

It's considered that are several drawbacks to a Certificate based scheme.

- First the grid and energy markets are so volatile and likely to remain so that Certificate valuation will be complex.
- Secondly the Certificate system needs to be in place for a substantial time, say 5-8 years minimum as the investors need some certainty around the process.
- Thirdly uncertain Certificates with penalties (liabilities) could become a disincentive.
- Fourth the scheme should not entice investors who would be otherwise investing in low cost solar or wind or add other storage to divert the investment. This may happen whereby other subsidies / grants get combined with what is fundamentally a higher cost technologies.
- Fifth: Other new storage options with beneficial long duration capabilities may be artificially frozen out of the SWIS.
- Finally as green H2 should be a carbon reduction investment and WA centric Certificate may be more or less attractive than any / international National Carbon Certificates.

Question 7:

What are some other approaches which could be considered alongside a renewable hydrogen electricity generation certificate scheme that would provide a framework to deliver on the objectives or outcomes sought?

Probably the most effective schemes would be those which apply at the national level. In some countries such as India accelerated depreciation is allowed for certain green investments.

The recent USA IRA Act provides for trading of Tax Losses between project developers and taxable entities. This type of scheme is typically not used in Australia.

One suggestion is to bring an incentive scheme as close as possible to the market prices that would be paid for peaking power and then add a type of extra FIT (Feed in tariff) that would start high in Year 1 of the scheme, say 2024 and the decline linearly over 5 to 10 years. This would attract early investors.

Question 8:

Is the proposed approach of certification, deemed liability and certificate transfer an efficient and effective way to deliver on the intent of the Renewable Hydrogen Target for electricity generation? Are there alternative approaches which could better deliver on the objectives?

See Question 7 answers above. In short we typically prefer an incentive scheme for investors rather than a penalty. The liability if applied would typically apply to the main generators being public (taxpayer) owner.

Question 9:
What are the benefits, costs and impacts of an exemptions regime for a Renewable Hydrogen Target for electricity generation?

While recognizing the benefits the very volatile utility environment setting a set target over a 5 to 10 year time period may be difficult to control and avoid distortions.

Question 10:

Should the Renewable Hydrogen Target for electricity generation consider alternative renewable fuels as eligible for the creation of Renewable Hydrogen Electricity Generation Certificate? Why or why not?

It is well recognized that only solar and wind are very mature low cost VRE while most of the incoming new "low carbon" technologies are still in early commercialization.

Hydrogen can be seen as a fuel and a storage mechanism so this new policy should permit other new fuels and long duration storage.

Ammonia is another fast emerging fuel and the large ocean going vessels are already moving to green ammonia as a fuel. Engine manufacturers such as MAN and Mitsubishi are offering ammonia engines. This fuel, as one example, should be included.

Question 11: (what level 1%, 5%, 10%)

Please consider the benefits, costs and implications of a 1%, 5% and 10% Renewable Hydrogen Target for electricity generation in the SWIS on your business or industry, and provide commentary on how you would expect to react from a commercial and investment perspective to each target level.

At the low percent levels we are talking annual increments of just 5 to 10 MW. If this is a limit then this will be a disincentive to many investors. It will take substantial time and effort to locate, specify and finance a project. Investors may be less interested if the project does not have. A clear runway.

Rather than committing to a % level we suggest that the SWIS use its critical load goals for meeting peak loads due to coal supply deficiencies say 200MW.

For green hydrogen it could start with a modular size electrolizer-fuel cell system of 5,10 or 20MW that could be gradually duplicated over a period of time reaching 200MW. This 20MW size is becoming increasingly popular in the growing FC market.

Question 12:
At a whole-of-economy and / or sectoral level, what do you consider to be some of the benefits, costs and implications of a 1% target, a 5% target, and a 10% target?

In our view a 10% target is both quite low and somewhat artificial, over an assumed period of 10 years.

Question 13:
Is the suggested approach of a medium term aggregate target, with annual entity targets, an efficient and effective means to achieve the objectives of the Renewable Hydrogen Target for electricity generation in the SWIS? Why or why not?

As described above we believe that the market and the rate of international technology developments will be very unpredictable and difficult to blend into a state only target.

Question 14:
To what extent should banking and borrowing of liabilities be permitted under the scheme? What are the benefits and costs of a borrowing mechanism as described in the paragraph above?

Banking and borrowing, i.e. creating a liquid market will accelerate the uptake.

Question 15:
How soon do you believe a Renewable Hydrogen Target for electricity generation in the SWIS could be feasibly delivered from a technical perspective (i.e. if cost

was not a consideration)? Please reflect on your own organisation and/or sector when providing your answer.

Various international manufacturers already offer complete systems and many countries are implementing bespoke systems. For example Saudi Arabia have large ambitions for H2.

Saudi Arabia Green H2 Project:

Renewables-based hydrogen is a key focus of technological and economic experiments in the futuristic Saudi city of Neom. Neom features a US$5 billion green hydrogen project that is a joint venture between Neom, Riyadh-based ACWA Power, and Pennsylvania-based Air Products. Expected onstream in 2025, the project's 4 GW renewable capacity would make it the world's largest renewable hydrogen-to-ammonia facility in the world, producing 1.2 million tons per year of green hydrogen—roughly equivalent to 5 million barrels of oil per year in energy terms. (In comparison, the Saudi annual crude oil production volume is about 12 million barrels per day.)

Question 16:
Similar to the above, how soon do you believe a Renewable Hydrogen Target for electricity generation in the SWIS could be feasibly delivered from a commercial or economic perspective (i.e. if cost was a consideration)? Please reflect on your own organisation and/or sector when providing your answer.

In short, the most logical match for an initially expensive energy would be in peaking power, balancing and possibly load shifting to some extent.

Question 17:
Over what period of time do you believe is an appropriate ramp up period for the Renewable Hydrogen Target for electricity generation in the SWIS? In providing your answer reflect on the actions your organisation and / or sector would need to take to participate in the scheme.

There should be an approximate 12-month planning and industry preparation phase and the time frame should be about 5 years then opened to the general market. A 10-year period will probably induce developers to wait a few years to see what happens.

Question 18:
In the short (<5 years), medium (5-15 years) and long (15+ years) term, where do you expect the cost of production of renewable hydrogen to move from the estimated levels of today? What do you expect to be the drivers of this change?

Large scale adoption for utilities will depend on

a) Use of higher power Fuel cells (MW Scale) i.e. Molten Carbonate and Solid Oxide.
b) Increased efficiencies and scale for electrolyzers.

Heat recovery may improve economics. Storage should be generally discouraged. Below are projected costs including for Australia (Source Bloomberg, with USD).
See also pages 23, 24 and 25 Appendix A.

Figure 5: Estimated delivered hydrogen costs to large-scale industrial users, 2030

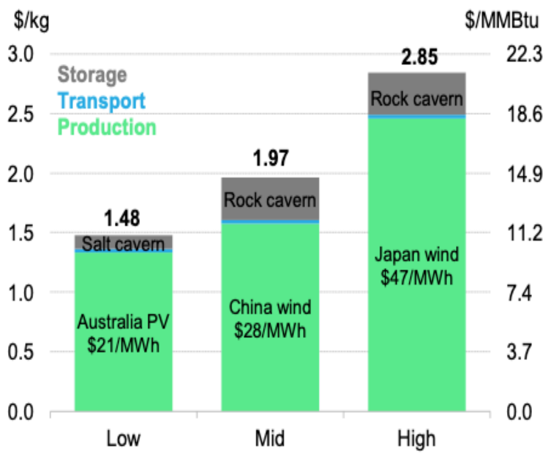
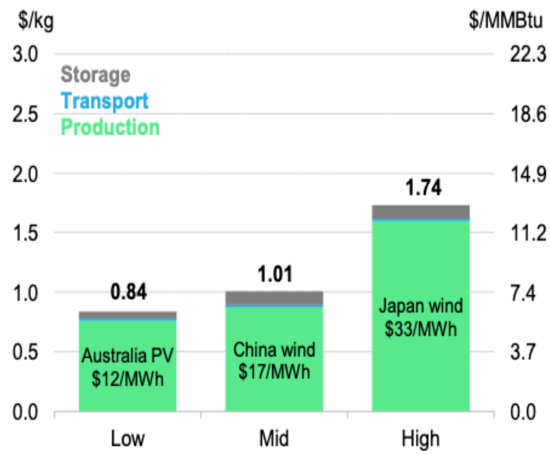


Figure 6: Estimated delivered hydrogen costs to large industrial users, 2050



Source: BloombergNEF. Note: Power costs depicted are the LCOE used for electrolysis, and are lower than the BNEF's standard LCOE projections in 2050 due to savings from integrated design of the electrolyzer and generator, and anticipated additional learning from increased renewable deployment for hydrogen production. Production costs are based on a large-scale alkaline electrolyzer with capex of $135/kW in 2030 and $98/kW in 2050. Storage costs assume 50% of total hydrogen demand passes through storage. Transport costs are for a 50km transmission pipeline movement. Compression and conversion costs are included in storage. Low estimate assumes a salt cavern, mid and high estimate a rock cavern for both 2030 and 2050.

Questions 19,20,21

There seems no doubt that massive international investment will go into green ammonia and green hydrogen. This will be driven by some very large industries such as maritime shipping, aircraft industry and mineral processing (say green steel).

It remains that these industries will tolerate higher H2 costs than competing against VRE with other storage options being progressed.

Appendix A: Hydrogen vs Natural Gas: How Soon?

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1.0 A Preview of Climate Change

Each of the last four decades has been successively warmer than any decade preceded it since 1850 (IPCC) [1]. In early 2022 the IPCC (with 195 member countries) finalized in the second part of the Sixth Assessment Report *Climate Change: Impacts*, *Adaptation and Vulnerability,* the Working Group II contribution, see fig 1.

1.1 Scientific Background:

In 2007, the year the IPCC received the Nobel Peace Prize, following the IPCC's fourth assessment report noted, and the Chair Dr Pauchauri commented:

"Continued greenhouse gas emissions at or above current rates would cause further warming and induce many changes in the global climate system during the 21st century that would very likely be larger than those observed during the 20th century" end quote.

Fifteen years later the IPCC Chair, Dr. Hoesung Lee [2], made these remarks at the October 13th 2022 Gulbenkian Prize award:

"Global warming of 1.5°C and 2°C will be exceeded during this century unless immediate, rapid, and large-scale reductions in greenhouse gas emissions – which suffocate our planet – occur in the nearest future".

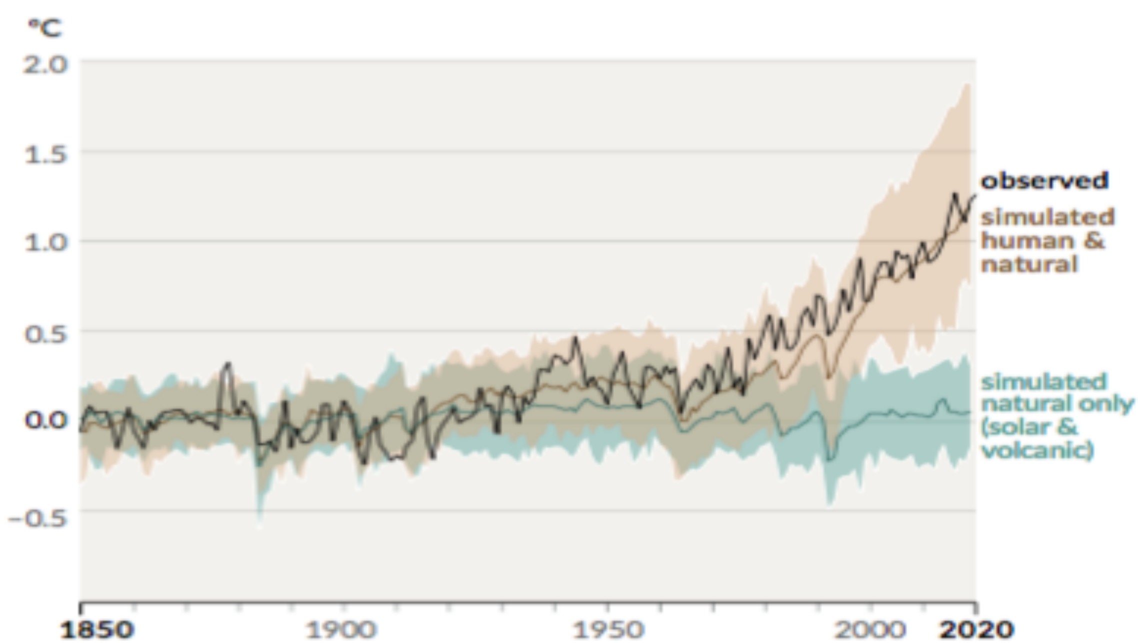


Fig. 1.Temperature rise, natural and human (IPCC)

1.2 Financial Institution Perspective:

Further direct confirmation of climate change impacts comes from global insurance associations. The CEO of the Australian Insurance Council reported in Oct 2022,[3]

"The societal impacts are being felt in every corner of world, and the cost of extreme weather events will be unlike anything we have experienced. According to work undertaken for the Insurance Council by the McKell Institute, here in Australia the costs of extreme weather events are expected to reach $35.24 billion a year by 2050.

In mature markets like the United Kingdom, with well-defined net-zero pathways, it is estimated that up to 70 per cent of all underwriting will support transition-related assets and technologies by 2050. Underwriting opportunities will shift considerably in Australia too, where we are expected to require approximately $2.5 trillion of investment in transition activities over the next three decades".

1.3 Public Policy:

In December 2015, 195 States signed up to the Paris Agreement. This is the most important pact for international cooperation on tackling climate change, and countries are taking steps to deliver on it. The UK, Norway, France and New Zealand are some of the countries that have legally committed to reach net zero emissions by 2050.

The 2015 Paris Agreement committed each of its 195 state signatories to pledge what they will individually do to reduce or limit their greenhouse gas emissions by 2025 or 2030; their so-called Nationally Determined Contributions (NDCs). Taken together, however, the current NDCs of all nations are not enough to put the world on track to limit global warming to 'well below 2°C'.

Analysis published by Climate Action Tracker estimates that the current NDC pledges for 2030 are consistent with a global emissions pathway that would lead to a world that is 2.4°C warmer on average at the end of the century, than it was at pre-industrial levels. This is far from being in line with the Paris Agreement, which aims to limit warming to well below 2°C and pursue best efforts to keep it to 1.5°C.

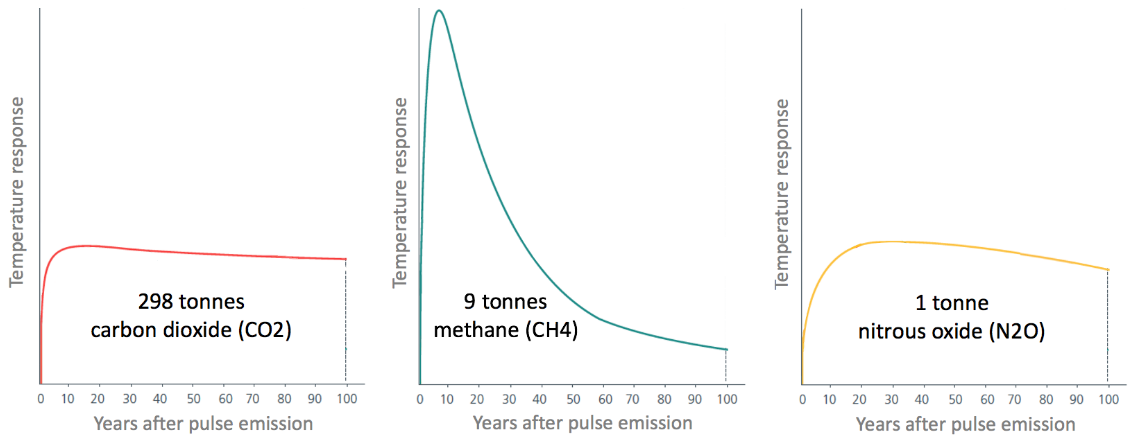
In short the strongest action taken to date has not been by government but by industry and the financial communities who have objectively analysed risk and are actively implementing mitigation and counter measures directly for their own industries.

1.4 Global Warming Contributions:

As understanding and acceptance of global warming becomes more widespread the implications of different industries and their impacts becomes more transparent. These understandings will have a great impact on existing dominant industries such as the fossil fuel sectors.

The general narrative is that CO2 is the problems and that decarbonization activities need to focus on this area. While partly true this does not fully explain the global warming problem.

Of the current 1.44 C temperature rise problem to date the major contributors to temperature increases have been CO2 by 0.8C (56%), fugitive methane by 0.5C (35%) and others (9%). Methane is a powerful GHG with 85-times the warming of CO2 over a 20-year time frame.



Source [4]: The charts appearing in this article are based on the IPCC's current estimated GWPs. Scientists from NASA's Goddard Institute for Space Studies (GISS) have estimated GWPs for CH4 of up to 33 for 100 years and up to 105 for 20 years.

Flares, or fires lit at oil and gas wells to burn off excess gas that cannot be transported and sold, are a common sight at oil fields around the world. Some are even visible from space. But a new study published in the journal *Science* found that the process is not eliminating nearly as much methane as assumed.
"Our findings indicate that flaring is responsible for five times more methane entering the atmosphere than we previously thought," says Genevieve Plant, lead author and assistant research scientist at the University of Michigan.

Approximately 25% of net global warming has occurred in recent decades is due to methane 9. The methane problem is likely to have very substantial disruptive effects in Australia and especially Western Australia.

1.5 Global Impacts:

The following figure 2, shows the global cycle of carbon anthropogenic fluxes 2011-2020 average in GtC/yr. These are emissions from fossil fuels (grey) and land use (yellow), the uptake by oceans (dark green) and vegetation (light green) plus the largest being the atmosphere (light blue).

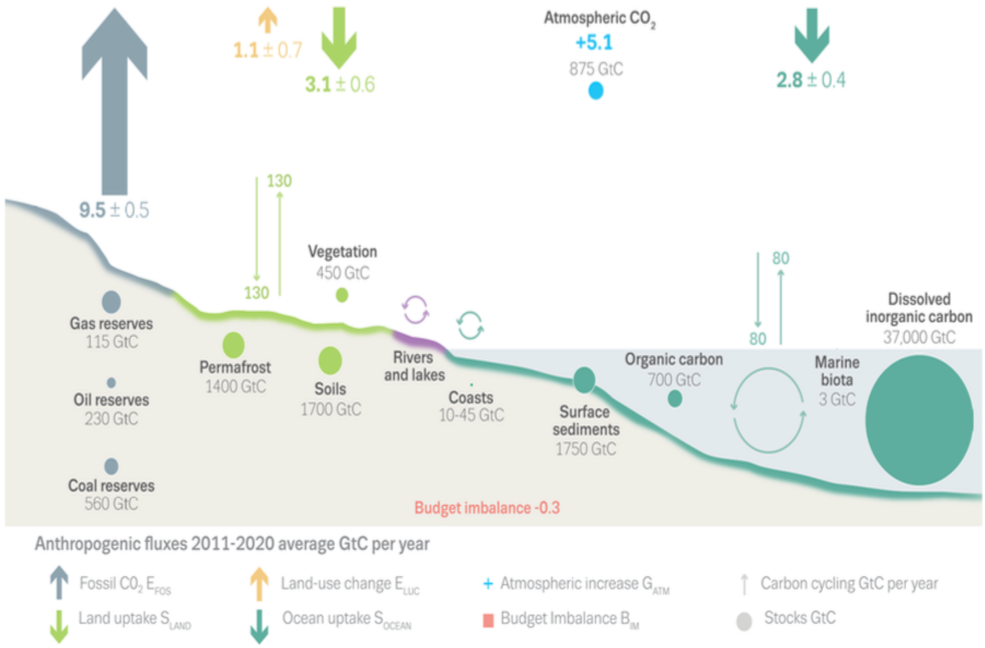


Fig.2. Global carbon cycle (P. Friedlingstein. et al.)

The IPCC Summary for Policymakers[1] has developed five illustrative scenarios that cover the range of possible future developments of anthropogenic drivers of climate change starting 2015 (fig 3). They start with;

- high and very high GHG emissions (SSP3-7 and SSP5-8.5) and CO2,
- intermediate GHG emissions (SSP2-4.5) and
- very low and low GHG emissions and CO2 emissions declining to net zero around or after 2050,
- followed by negative CO2 emissions (SSP1-1.9 and SSP1-2.6).

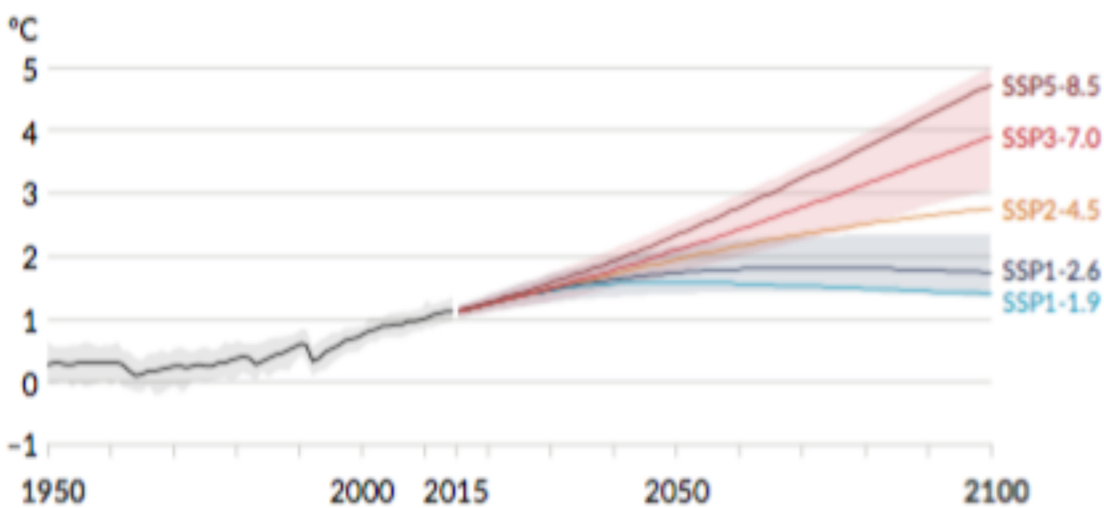


Fig.3. Global surface temperature change (IPCC)

It also shows the global temperature change relative to 1950-2100 under the 5 different scenarios.
Note that the temperature remains level under the two best scenarios (SSP1-1.9) and (SSP1-2.6) only. The annual mean global near surface temperature for each year between 2022 and 2026 is predicted to be between 1.1 and 1.7C higher than industrial levels (average over the years 1850-1900). Global surface temperature will continue to increase until at least mid-century under all emissions scenarios considered

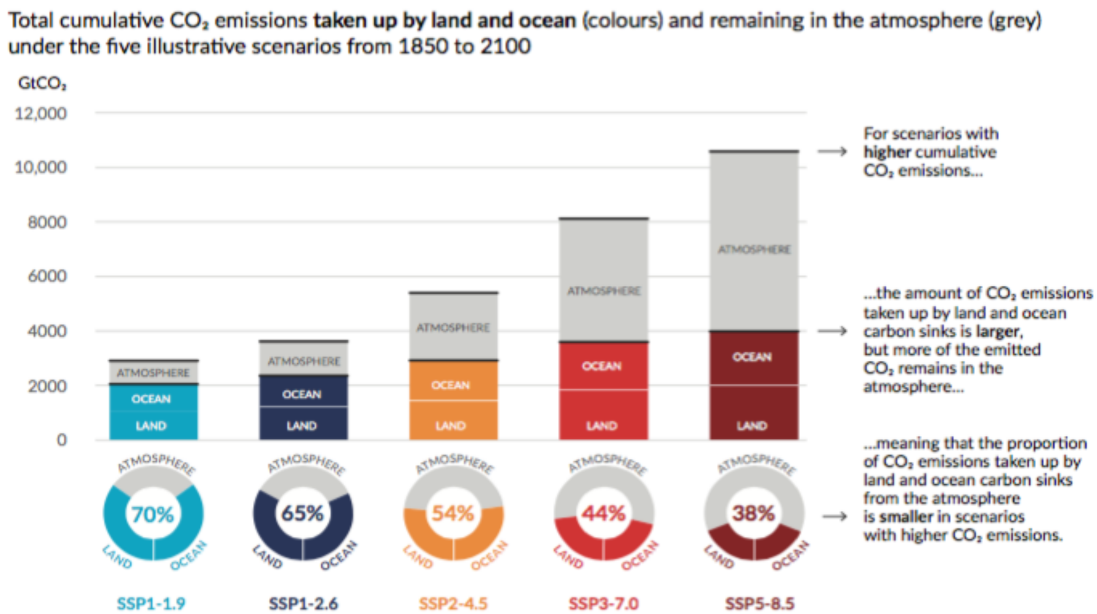


Fig.4. Proportion of emissions taken up diminishes (IPCC[1])

Global warming of 1.5C and 2C will be exceeded during the 21st century unless deep reductions in CO2, methane and other greenhouse gas emissions occur in the coming decades.

Given we are observing climatic change in 2022, we can expect worse climatic conditions to follow. As emissions and temperature rise, the accumulation of CO_2 and methane in the atmosphere increase disproportionally as emissions taken up by land and ocean sinks will not cope, the situation becomes irreversible with runaway temperatures (SSP2-4.5, figs. 3&4).

It is generally accepted that many of these changes, due to past and future GHG emissions, will be irreversible for centuries if not millennia, especially changes in the ocean, ice sheets and global sea level. Human activities affect all the major climate system components, with some occurring over the coming decades and others over many centuries into the future. The following figure 5 shows the global emissions to 2020 by sectors and countries.

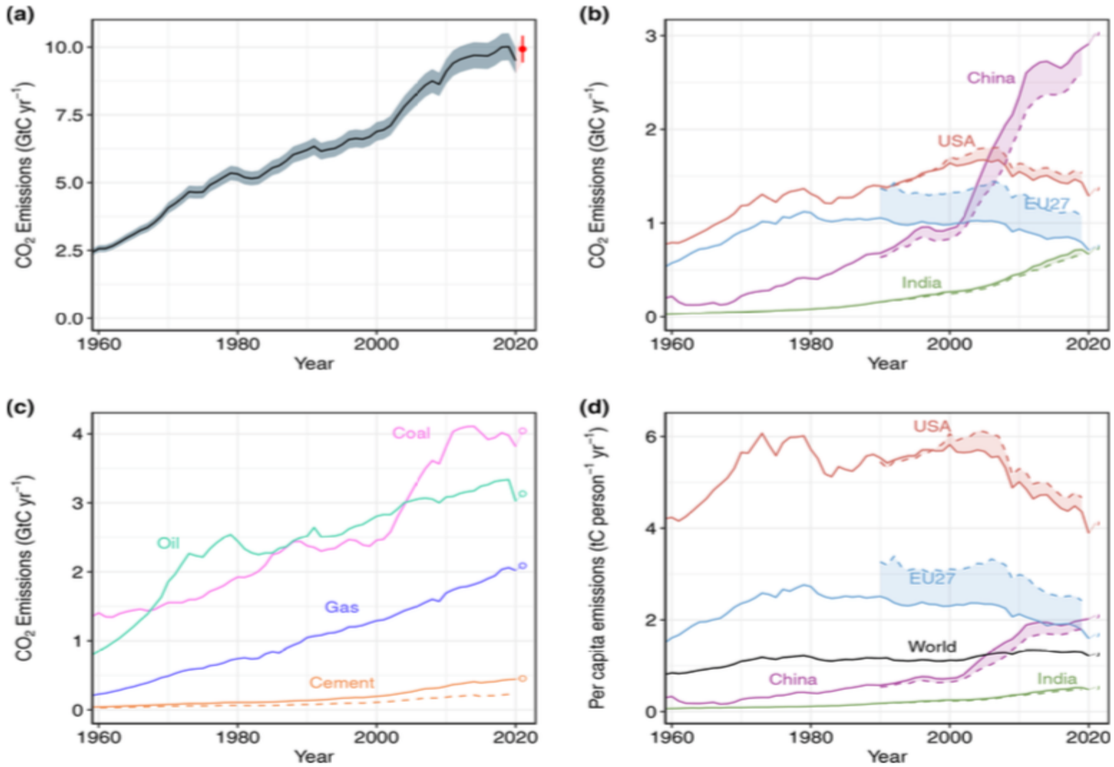


Fig. 5. CO_2 emissions by sector & country (Friedlingstein)

In a world trying to limit GHG emissions both China and India are very prominent as heavy emitting countries (Fig.5b).

2.0 Australian Position:

Australia's share of global CO2 emissions from domestic use of fossil fuels is about 1.5% and when including fossil fuel exports it grows to 5%. This carbon footprint is equivalent to the total emissions of Russia, which is ranked as the fifth largest CO2 emitter globally. Australia is now the largest coal (thermal +metallurgical) and natural gas (LNG) exporter in the world (Climate analytics [9] "Evaluating the significance of Australia's global fossil carbon footprint")

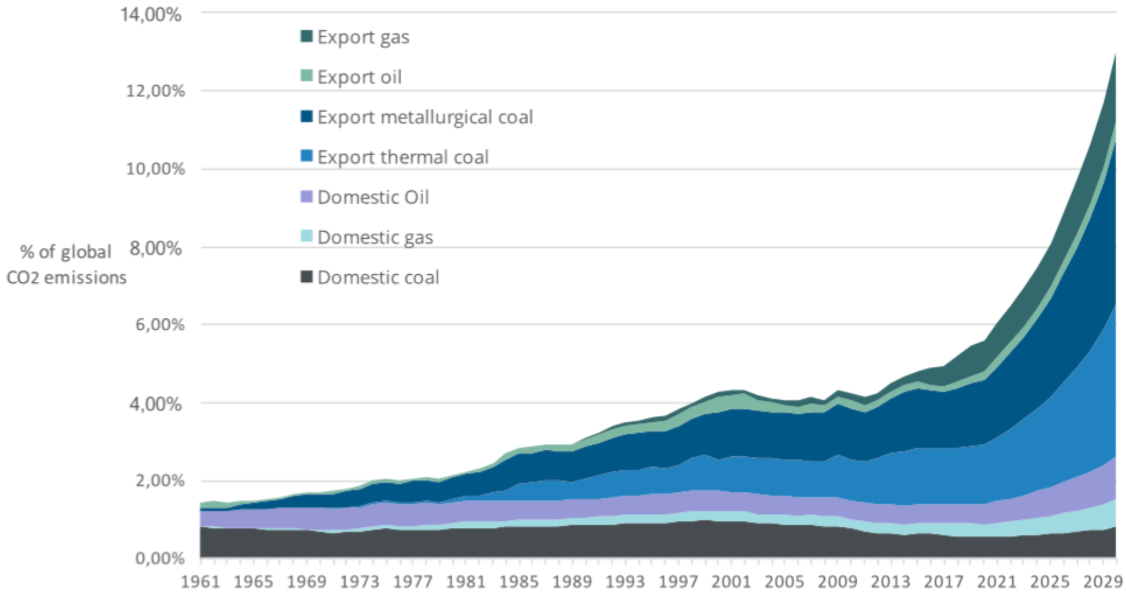


Fig.5e. Australia's domestic and exports projection of emissions of CO2e (Climateanalytics) 12

On current trends Australia's exports of these fossil fuel exports will grow substantially in the next decade.

This projection leads us to the situation of irreversible runaway global temperatures (see SPP 2-4.5 in figures 3 and 4). It takes Australia's global emissions from 5% in 2022 to 13% in 2029.

According to the Emissions Gap Report of COP26, Australia's current emissions pledges are on the 2.8C track, putting us in SPP2-4.5 scenario (figs. 3&4). In October 2022 Australia signed up to a global pledge to cut methane emissions by 30% by 2030 from 2022 levels. "Methane is 24% of Australia's emissions and globally Australia is the 11th highest emitter" (Chris Bowen Minister for Climate and Energy 23 Oct 2022).

The 43% reduction promised by the government is insufficient to achieve a 1.5C trajectory by 2030. A 50% reduction will be under 2C but we need to be at a 76% reduction to keep under 1.5C by 2030. This is the SSP1 2.6 scenario of figures 3&4 (Melbourne University Climate Energy College). The next figure 5e shows the breakdown of the necessary reductions.

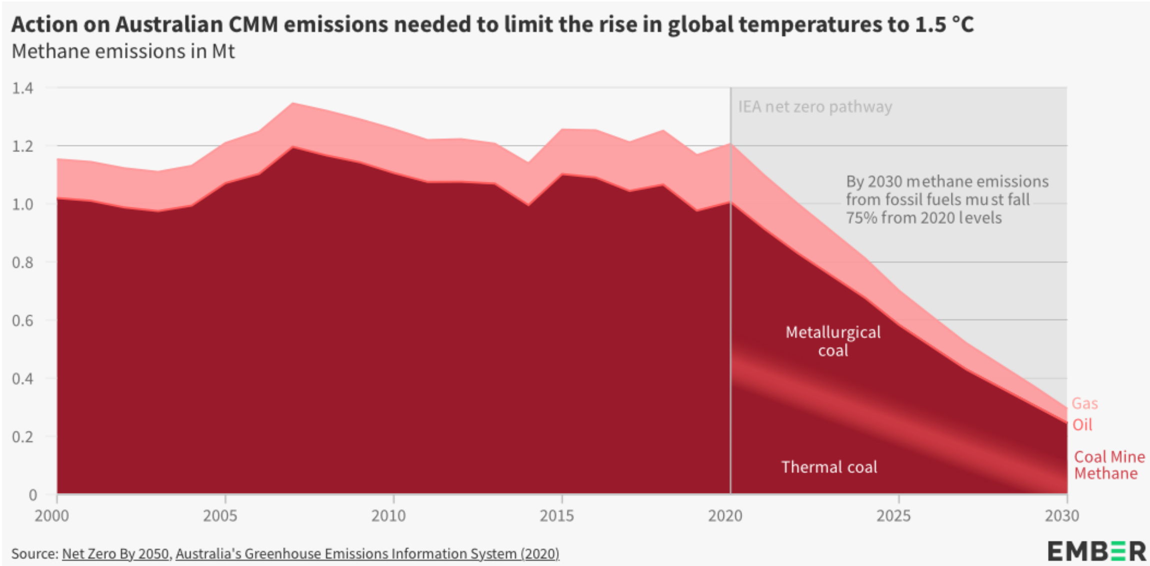


Fig. 5e. Actions to keep to 1.5C drop on Methane by 75% by 2030. “Aust. Coal Mines can deliver 2/3 of methane cuts” (EMBER Oct. 2022) [16]

2.1 Fossil fuels in Australia

Under these circumstances Australia’s support for opening new coalmines is contradictory to what the IPCC modeling calls for. Obvious Australia is ranked third after China and Russia for the number of coalmines under development, highlighting the potential for domestic emissions to rise even further with methane.

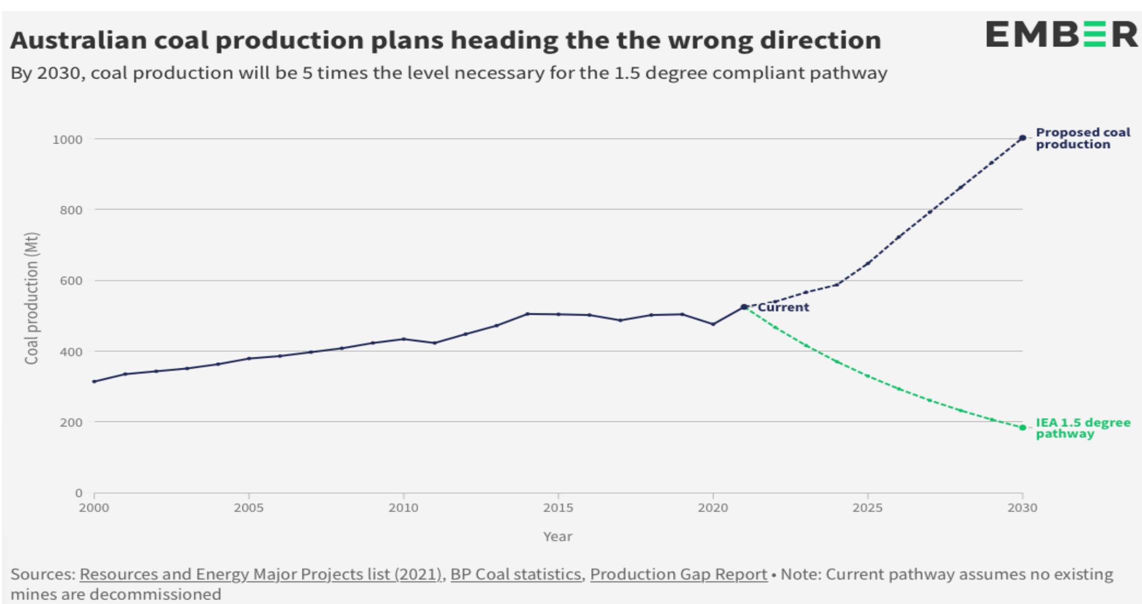


Fig. 5f. “Tackling Aust. Coal mine problem” (EMBER 2022) [17]

Methane coal emissions from open cut and underground mines in QLD and NSW in 2019 amounted to 8% of all emissions according to the government, however the EIA says it could be 16% after satellite observations evidence. Figure 5g shows the magnitude of these emissions compared with those of oil and gas.

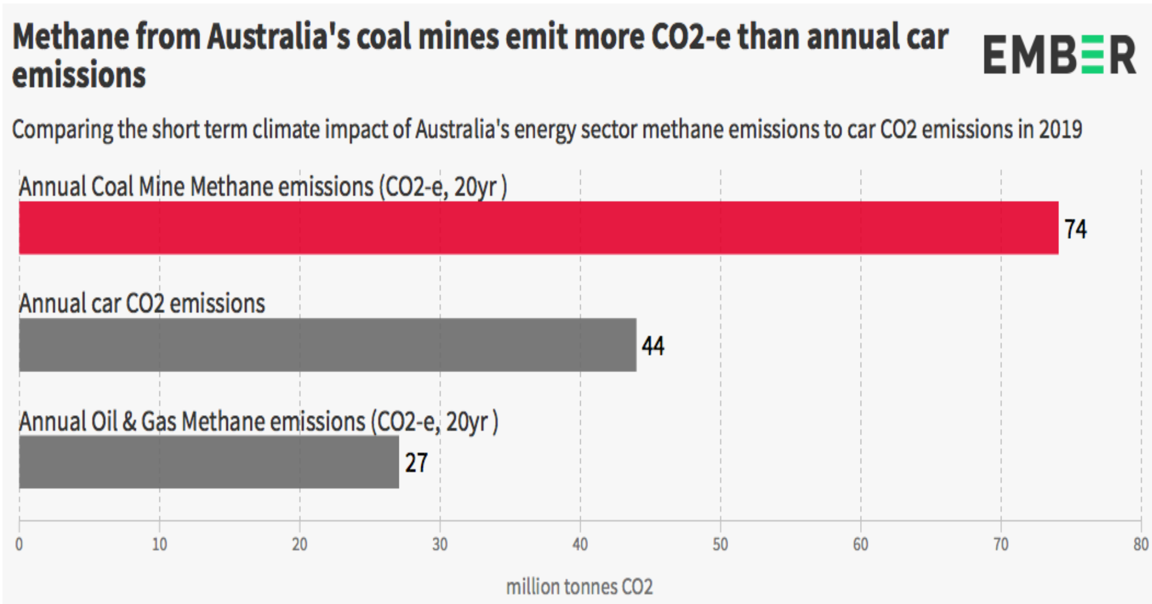


Fig. 5g. Aust. (QLD & NSW) Methane emissions (EMBER) [14]

The annual methane emissions from coalmines overwhelm those of car, oil and gas emissions put together. The expansion in the exploitation of fossil resources that Australia is planning is not consistent with efforts to combat climate change and is not consistent with the Paris Agreement goals.

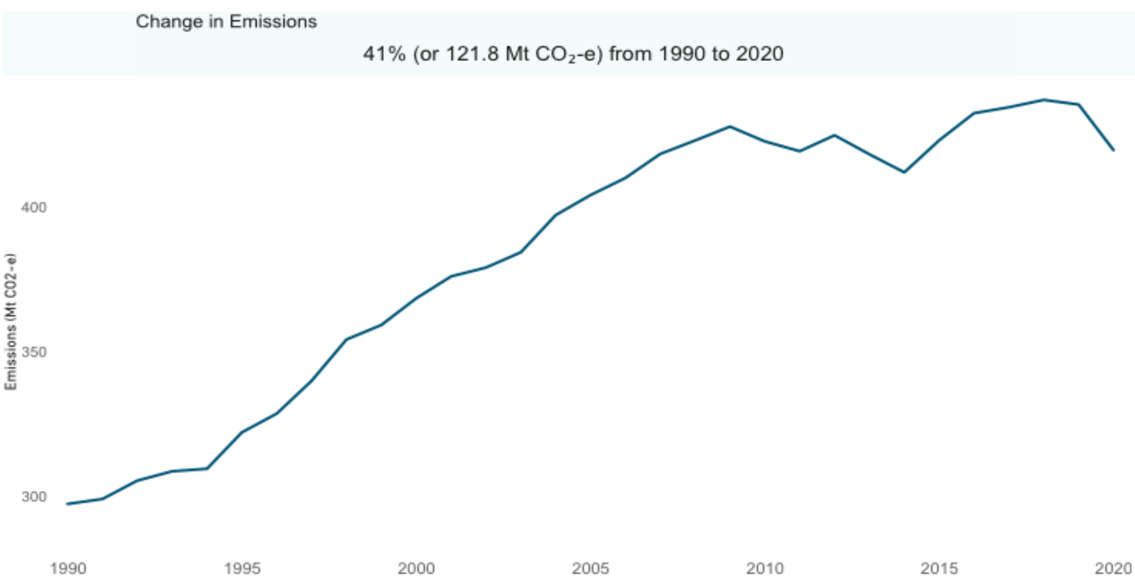


Fig.5h. Australia’s Energy CO2e emissions growth 1990-2020 (dcceecw.gov.au) 15

Australia's GHG emissions in the energy sector are growing at the alarming rate of 41% (122Mt) from 1990 to 2020. The graph shows the rate of energy growth from 1990 to 2020.The drop in 2012 -2014 was due to the Federal Governments carbon pricing regime and the drop in 2020 was due to COVID.

The highest rates of growth in the energy sector are the three resource states Qld 137% (68Mt), WA 143% (47Mt) and NT 196% (9Mt). The Qld figures are due to coal and gas while WA and NT are due entirely to gas. These states face the biggest challenges.

Electricity generation is the major contributor to methane and CO2 emissions globally. It is now being replaced steadily by variable renewable energy in many places like Australia, USA, and others, with very low emissions and at lower cost. This can be achieve for about 85% of the grid, backed up with storage from 0.5hr to 12hr electrochemical sources (such as balancing batteries, home storage, grid electric vehicle battery fleets) and also pumped storage where Snowy 2.0 will offer 72 hours duration.

Beyond the 85% level longer duration storage including seasonal is required (NREL[5]). We suggest chemical storage systems such as green ammonia and green hydrogen.

3.0 Chemical Storage Systems:

While green hydrogen is currently too expensive and may not be able to compete with electrochemical storage in many applications hydrogen is necessary for the production of many products such as ammonia for fertilizers. Green hydrogen, produced by low cost renewables can be used for ammonia the reduction of iron to produce green steel, oil refining, shipping and also energy storage.

The generation of electricity with green hydrogen although initially more expensive can be done without GHG emissions by utilizing renewable energy (including curtailed) to produce hydrogen by electrolyzing water and further use of fuel cells to generate electricity.

The optimum location in 2020's for a green hydrogen power plant will be co-located with a fertilizer or steel reducing plant. In some locations the electrolizer's operational variability can be utilized for grid balance; storage and transport can be shared. All this can be done with almost zero operating emissions.

A clear immediate example of this is the planned renewable energy Murchison Hydrogen 5 GW fertilizer production plant which could be connected to the WA SWIS 4 GW grid at Kalbarri, WA. Note the fertilizer power plant is larger than the entire WA SWIS.

3.1 Hydrogen vs. Natural Gas in Australia

Currently it is not cost effective to generate electrical power with green hydrogen. This is particularly in WA as it has to compete with local reserved price natural gas at around **A$6/GJ** producing electricity with a combined cycle gas turbine (CCGT) at around **A$43/MWh**. Alternatively in WA electricity can be produced with an open cycle gas turbine (OCGT) at **A$70/MWh** (with no price on carbon emissions on both). About 90% of WA's gas powered electricity is generated with OCGT.

Eastern Australia has to buy gas at international prices and if we assume a lower price of **A$14/GJ** this translates to about **A$100/MWh** with CCGT.

If green hydrogen costs can be reduced to**A$2/kg** electricity production would be competitive with east Australia when converted by fuel cells at **A$92/MWh** (we explain these values in pages 26&27). To compete with natural gas CCGT in WA it would have to be~**A$1/kg**. No storage of hydrogen is included, i.e. production and consumption is co-located.

As a comparison, the price of green hydrogen in the US through the Inflation Reduction Act (IRA), President Bidens public energy policy, is **A$0.56/kg** converted to electricity with a fuel cell at **A$26/MWh.** The key question is whether and when green hydrogen can get to **A$2/kg**. If Australia (not WA) wants to sell green hydrogen in the international market, these are the price to broadly achieve.

Comparing green hydrogen storage co-located with a fertilizer plant at a production cost **A$92/MWh** with battery storage capex at A$250,000/MWh it shows the potential relevance of green hydrogen storage for power generation integrated to the grid.

Compared with the much lower renewable energy electricity costs in 2030 at A$20-**A$30/MWh**. It makes it necessary to minimize the storage in every case.

If WA takes no similar action to the USA's IRA, it will continue the unabated use of carbon emitting natural gas at A$43MWh with high emitting (CO2 and fugitive methane) open cycle gas turbines in lieu of green hydrogen energy storage to balance the grid.

It is also relevant to consider the future of natural gas is in the Net Zero 2050. Because of its carbon (methane) intensity and cost, the International Energy Agency (IEA) Net Zero **pathway projects rapid collapse of the LNG trade** at the global level, which will be differently felt in different regions. Australia is to be affected fastest being the world largest LNG exporter (fig. 6).

3.2 Analysis of natural gas, CCS and green hydrogen

The obvious problem is that natural gas is a fossil fuel (methane) and as such emits greenhouse gases; fugitive emissions during extraction and carbon dioxide post combustion thus increasing the ambient temperature and affecting the climate.

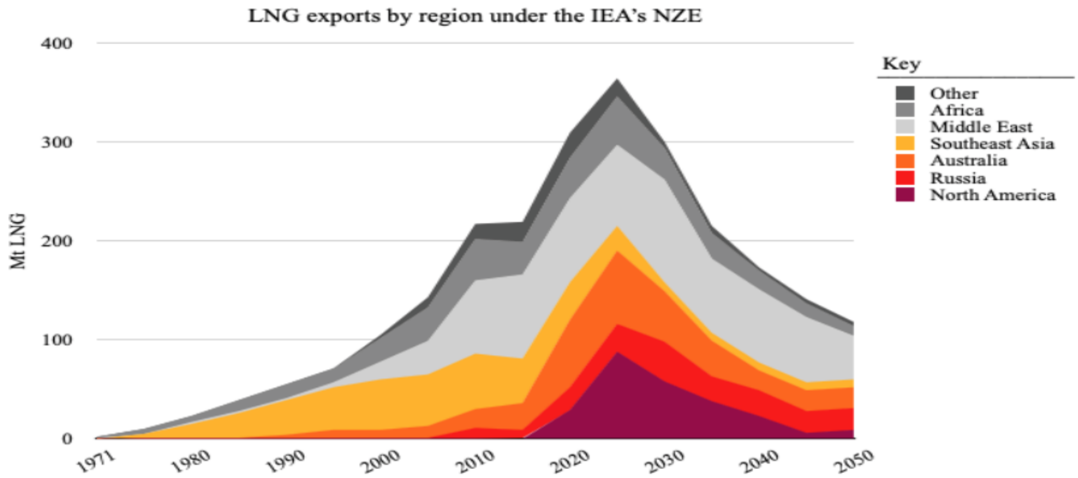


Figure 14: LNG exports by region under the IEA's NZE

Source: (IEA, 2021d).

Fig.6. LNG exports by regions to Net Zero to 2050 (IEA 2021)

A second problem is that when it is extracted by fracking (a far more expensive system) apart from the fugitive emissions from great number of drilling holes it can in some cases contaminate aquifers affecting farming and town water.

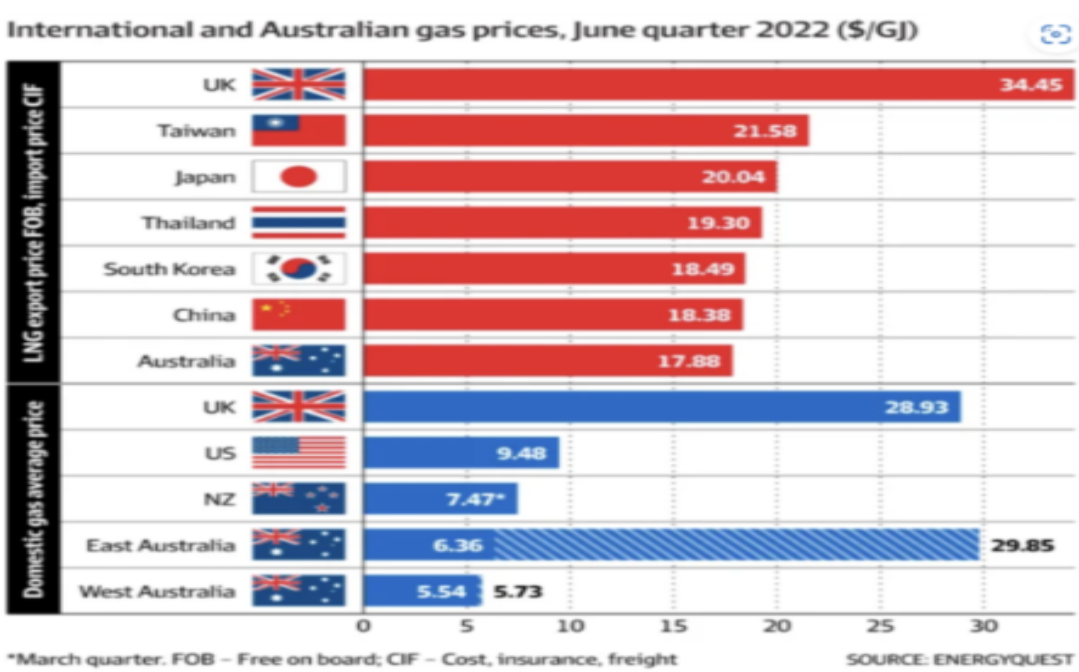


Fig. 7. (A$) EnergyQuest 2022

A third issue is that as it is produced in only a few countries in the world that makes it politically vulnerable. The fourth problem is its price, natural gas has had a huge price variability in the last 5 years but far more intense in the last 2 years (Fig 7). To get a complete picture of the real price of natural gas in different parts of the world, is that a carbon tax is added to the above prices according to the CO2 content in US$ per metric ton of CO2 equivalent (Fig.8).

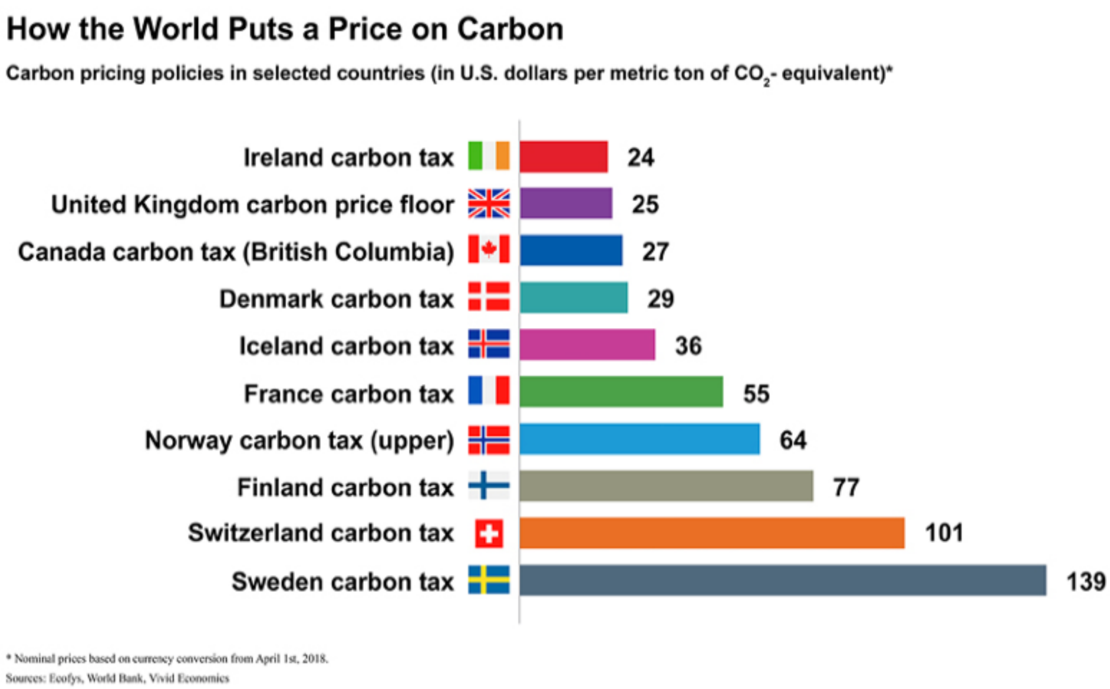


Fig. 8. (US$) ARUP 2020

In 2030 with a carbon price at US$150/t and landing 15Mtpa of green hydrogen in Germany will be market competitive in the EU. The National Renewable Energy Laboratories (NREL) in the US arrives at lower price of US$66/t for carbon within the US with an 85% renewable energy grid.

The Green Hydrogen Task Force White paper (RMI 2022) estimate that the production costs of green hydrogen are expected to fall from US$2.10/kg to US$1.50/kg in 2030 and the landed cost of green hydrogen from Western Australia in the EU including transport and storage is expected to fall from US$3.80/kg in 2024 to US$2.50 in 2030. However, there would need to be a subsidy for first movers risk during the first 5 to 6 years.

The US EIA and RMI analysis project the costs to 2030 of green hydrogen imported to the EU compared to grey and blue hydrogen including production, storage and transport (Fig.9).

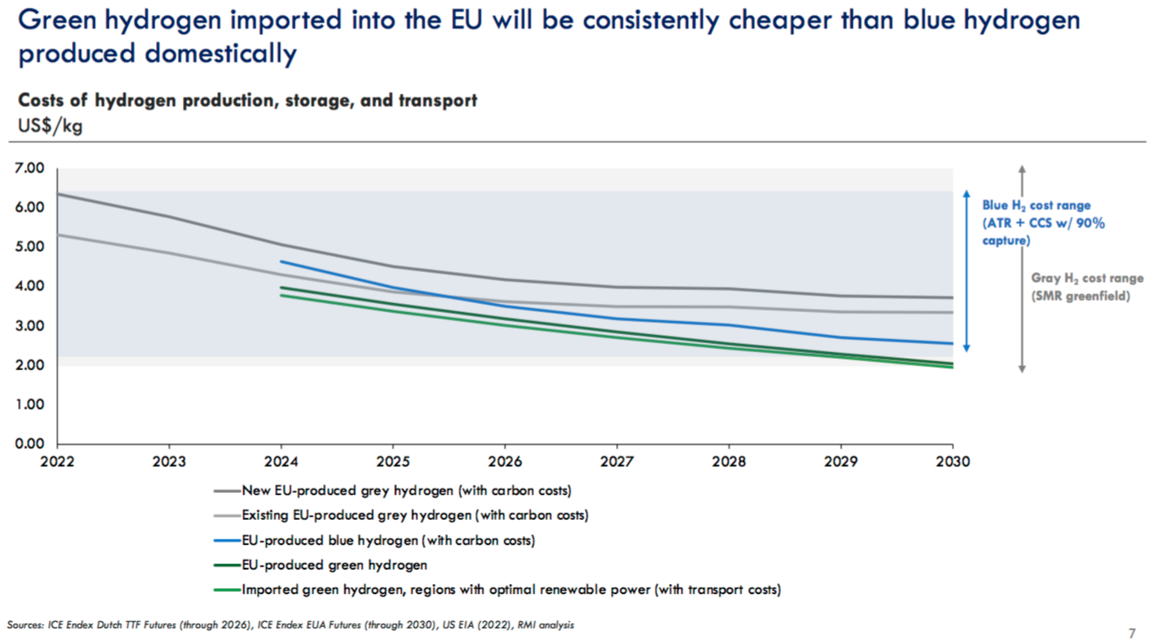


Fig.9. US EIA and RMI and FFI3 2022

The Inflation Reduction Act (IRA) of the USA passed in August 2022 offering a tax credit of US$3.0/kg for green hydrogen has had an extraordinary effect on the price, dropping from the present US$3.39 (blue column) to US$0.39 (orange column) making it immediately cheaper than the conventional natural gas derived grey hydrogen of US$0.99 to US$1.54/kg (grey horizontal column). Figure 10.

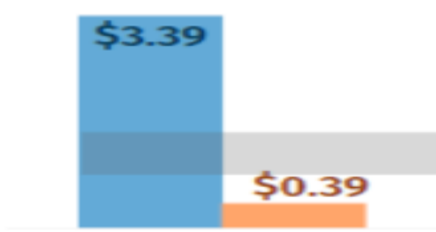


Figure 10. US$ per kg. (Rhodium [7] Group 4)

This is a momentous move by the US that will affect all competing natural gas producers such as Australia, particularly for their exports. The export plans for brown, grey hydrogen with CCS to Japan and South Korea will be disrupted due to a lower price and free emissions green hydrogen from the US.

It is also interesting to see what the EU ETS price projected rise is when compared to the natural gas price as it returns to some normality (figure 11).

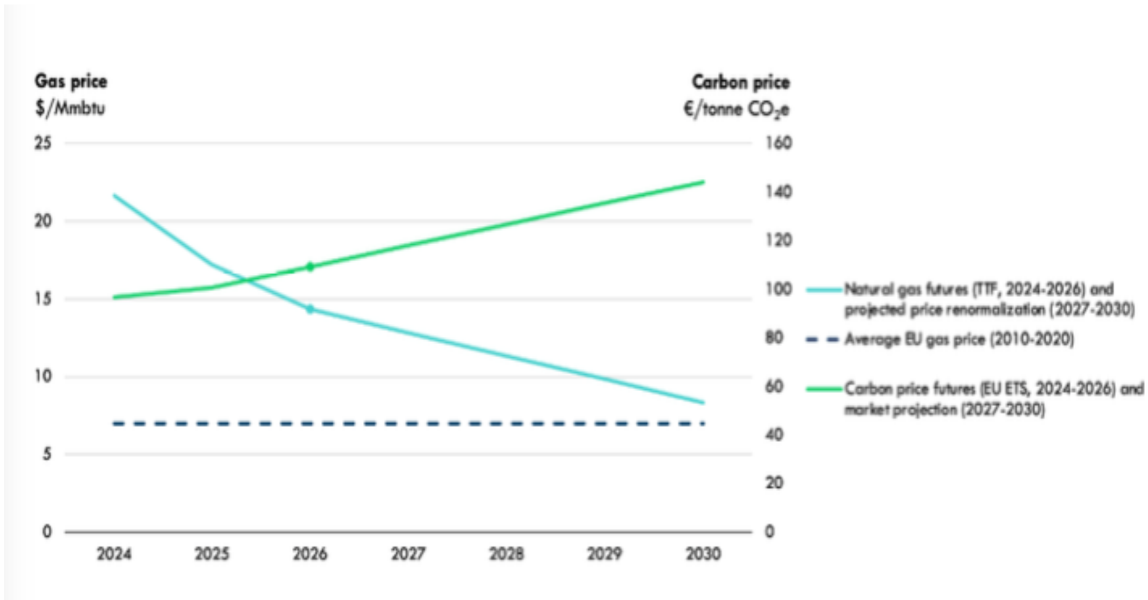


Fig 11. Green Hydrogen White Paper RMI FFI[3] 2022

Notice that not all countries have a carbon tax including Australia and USA, however the USA has recently introduced the IRA tax credit in lieu of a carbon tax.
This situation makes it necessary for world markets to look at accelerating policy alternatives to be competitive in the green hydrogen market.
The fifth problem is that profits are so high (Fig. 12) providing very good returns to shareholders that moving away from this fuel investment is difficult and may limit the investment in alternatives unless a super profit tax is implemented (as in the UK recently) and/or invested in clean alternative in hydrogen such as the US IRA tax credit.

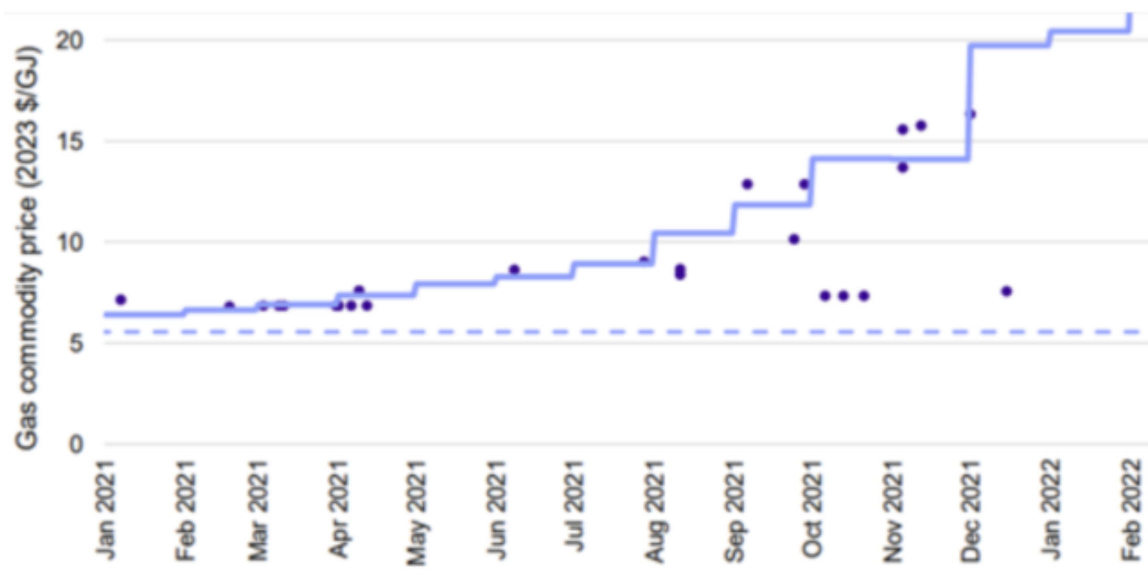


Fig. 12. Nat Gas Profits. Thick blue line is domestic price. Dotted line is cost. (I. Verrender Oct 2022))

Shareholders nowadays have a sincere concern with climate change as shown by the superannuation retirement funds (offer of non-fossil investment options), BHP (sold off natural gas investments) and very recently by Origin Energy (sold off Beetaloo Basin fracking exploration gas field).

As banks have avoided financing any new coal power stations it is reasonable to expect similar situations would occur with costly natural gas Combined Cycle Gas Turbines (CCGT) plants with CCS (we know that CCS after combustion at low pressure is difficult to capture) or the lower cost Open Cycle Gas Turbines (OCGT) with free CO2 release and poor efficiency (30%) to operate.

If Australia follows the IRA policy or a similar one it could drastically change things for Woodside, Santos, Chevron, Shell and Origin as they could become stranded asset investments in the near future. The market is already compromised by the USA IRA action. It would leave only the low cost WA gas market in Australia and a reduced LNG export to those countries that have not already adopted their own green hydrogen production, all before 2030.

Australia as world's top natural gas exporter is making extraordinary profits for the time being (fig.12). It is an expected logical move for the gas companies to move to green hydrogen as they have the expertise and the infrastructure to do so. The case for blue hydrogen is clearly a dubious value as explained further on this paper.
The majority of countries in the world do not have natural gas so they are considering improving efficiency, electrification with renewables and hydrogen. So do we need natural gas or a green hydrogen industry?

The most important consideration is that once the lower price of green hydrogen is reached it will be stable and not subject the price variability of natural gas. The sooner we get to the lower price of green hydrogen the safer the environment will be.

So what are the alternatives?

4.0 Electricity Parity Price

Electricity being the largest fossil fuel user, is already been displaced by the lower cost clean alternatives of solar, wind and moving water, however these new options require storage for periods when they are not available. The new Li ion batteries powering the large expected fleet of electric vehicles and more bulky sodium ion will be able to provide energy for transition periods of +12hrs.

Pumped hydro and compressed air where geographically possible will be the lowest cost long duration storage to use. For seasonal variations a different storage is required and this could be liquid hydrogen powering large efficient fuel cells (FC) that have higher efficiency than counterpart technologies (fig. 13).

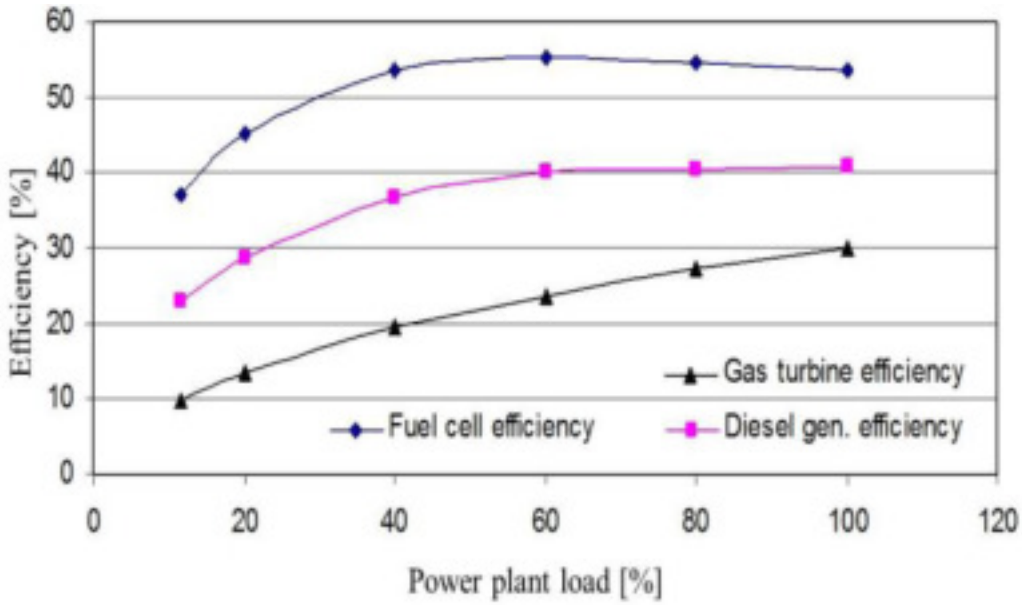


Fig. 13. Part-load efficiency comparison (ADVISIAN[8])

The part-load efficiency is very important for seasonal storage, as the power demand will be generally low for long duration periods with peaks rarely occurring.

Electricity cost comparison

	Reference units		Energy units	
Electricity - Renewable farm	40	\$/MWh	11.1	\$/GJ
Electricity - Large user	100	\$/MWh	27.8	\$/GJ
Electricity - Residential	240	\$/MWh	66.7	\$/GJ
Fuel cell (η = 65%) with \$2/kg	92	\$/MWh	25.6	\$/GJ

Fig. 14. Price of electricity with Renewables, Natural gas (A\$14/GJ, CCGT, no CCS, no Carbon price), Residential grid and Green H2 (\$2/kg by 2030) solid oxide fuel cell (65% eff.)

4.1 ADVISIAN (2021) forecast for 2030.

The table above (Fig. 14) shows that renewable electricity is far cheaper followed by hydrogen Solid Oxide Fuel (FC) all with zero emissions, followed by Combined Cycle Gas Turbine (CCGT) with CO2 emissions. It is expected that natural gas prices on the East coast will trend upwards towards $14/GJ by 2030 (ADVISIAN).

What is clear is that hydrogen at A$2/kg or A$92/MWh in 2030 will be cheaper than natural gas (at A$14GJ or A$100/MWH east Australia) for power generation. Although still significantly costlier (at A$92/MWh) than renewables hydrogen is a good optional storage partner for it when hydro at A$50/MWh is not available.
So it is quite possible that by 2030 or earlier green hydrogen could become competitive with natural gas in power generation, the largest CO2 emitting application. This is occurring without a carbon tax on CO2 (as in Europe) or a tax credit (as in USA) on hydrogen; any of these could accelerate climate repair. It could leave natural gas as stranded asset in this application.

4.2 Thermal Price Parity:

It is interesting to see the value of hydrogen when it is used in combustion to produce direct heat as distinct from producing electricity as we saw previously. Here only the efficiency of combustion applies; it is higher than combustion plus electricity generation. So it makes it harder for hydrogen to compete in thermal applications as natural gas has approximately three times the heating value of hydrogen.

Combustion value of fuels

If hydrogen is combusted for heat value it competes with coal and natural gas as heat providers. The relationship between hydrogen cost (on mass basis) as compared with other fuels is provided below.

	Reference units		Energy units	
Hydrogen	5	$/kg	41.7	$/GJ
Hydrogen	3	$/kg	25.0	$/GJ
Hydrogen	2	$/kg	16.7	$/GJ
Hydrogen	1.5	$/kg	12.5	$/GJ
Hydrogen	1	$/kg	8.3	$/GJ
Nat. gas - Large user (East coast)			8-10	$/GJ
Nat. gas - Small user			15 - 30	$/GJ
Coal - Large user	70	$/ton	3 - 5	$/GJ
Ammonia	535	$/ton	28.8	$/GJ
Petrol / Gasoline	1.40	$/L	40.0	$/GJ
Diesel (for trucking)	1.25	$/L	32.4	$/GJ
Nat. gas @ $10/GJ with carbo	100	$/ton CO	15.5	$/GJ

Fig. 15. Thermal Price Parity (ADVISIAN 2021)

In this application natural gas has been generally the fuel of choice. However, not listed in the table (Fig.15) is the electric arc furnace (and other electric thermal options) that would still be the lowest cost and cleaner option with an efficiency of 70% so this would equate to the renewable energy electric of A$40MWh/0.7 = A$57MWh or A$16/GJ.

Hydrogen when combusted can yield 120MJ/kg. It is possible to compare the thermal value for different supply prices.
For large consumers the cost of natural gas on the East coast of Australia ranges between $8 and A$10/GJ. It is expected (ADVISIAN) to trend upwards towards A$14/GJ by 2030. Presently in September 2022 it is at an extraordinary A$27/GJ.
From the table above the price of green hydrogen at $2/kg or $16.7/GJ is not yet competitive with a large user (East coast) at 8-$10/GJ. It would have to drop to $1.1/kg to do so (ADVISIAN). However, lets consider possible additional costs:

4.3 Carbon Price, Offsets, Fugitive emissions, Tax Credits

A recent study by NREL shows that "an 85% carbon-free or renewable energy mix can be achieved at a cost of avoided CO2 emissions of US$66 (A$94) per tonne or less, regardless of the power system (NREL)". This leaves all the Nordic countries including France with a favourable position for the adoption of hydrogen immediately. The IRA4 tax credit US$3/tonne on hydrogen in the US increases the list of immediate hydrogen adopters.
Although Australia does not have a carbon price, GHG emitting companies can offset their emissions by buying carbon credits. The June 2022 price was ~A$35/tonne (US$24.5) of CO2 or $0.035/kg of CO2.

4.3.1 Electrical application

0.18kg/CO2/kWh:0.5 (generation efficiency)=0.36kgCO2/kWhe , at $0.035/kgCO2 = $0.0126/kWh or $12.60/MWh or a 12.6% increase to the Electricity Larger user (see table) to $112.6/MWh or 27.8/GJ+12.6% = $31.3/GJ for natural gas. So the fuel cell at $2/kg (2030) of hydrogen would be price competitive in 2030 with the fuel cell at lower $25.6/GJ with hydrogen.

4.3.2 Thermal application

The specific CO2 emission from burning natural gas is 0.18kgCO2/kWh:0.8 (combustion efficiency)=0.225kg/CO2/kWh, at x$0.035/kgCO2 = 0.79c/kWh or 0.22c/MJ or $2.20/GJ increasing the cost of fuel use by 22% from A$10 to $12.20/GJ in the table for the natural gas large user. This makes it comparable to a hydrogen price at A$1.5/kg (2030) or 12.5 $/GJ in the thermal application in the same table.

4.3.3 H2Perth project

Planned by Woodside, BGC Construction Company and Centurion transport is a pilot plant producing green hydrogen at A$11/kg.

5.0 Fugitive Emissions.

Methane emissions are widely underreported and likely to be quite high (Climateanalytics7). It is estimated that methane leakage amounts to 9% of the WA gas resource (apo.org.au). The Gorgon natural gas field in Western Australia has a 14%CO2 content (plus methane fugitives) and the WA government set it a target of capturing 80% of the CO2. This target has not been reached by far; estimates are much lower than that. However, assuming 80% CCS is reached that would leave a 2.8% of fugitive CO2 that would have to be added to all natural gas applications (with their own 9% methane emissions) in Australia.

Being pre-combustion emissions it affects all applications even exports. This high value of 2.8% fugitives will result in well over 10-15% of CO2 added emissions to every thermal and electrical application closing the gap even further for the thermal application and over riding the electrical application.
So the pricing of A$2/kg (2030) of hydrogen would be price competitive for electrical applications and have to drop approximately to A$1.5/kg only for thermal applications.

6.0 Australia and other countries, the big question WHEN?

As a comparative measure the US has recently (Aug. 2022) approved the "Inflation Reduction Act" (IRA4) that provides a tax credit of US$3/kg for green hydrogen. So looking at the graph below, the US with a price of US$0.39/kg is already very competitive as the green hydrogen (at US$2.0 is considered competitive segmented line) in their market. Australia could do something similar but providing a smaller, approximately A$2.0/kg or US$1.4 or about half of the US tax credit.

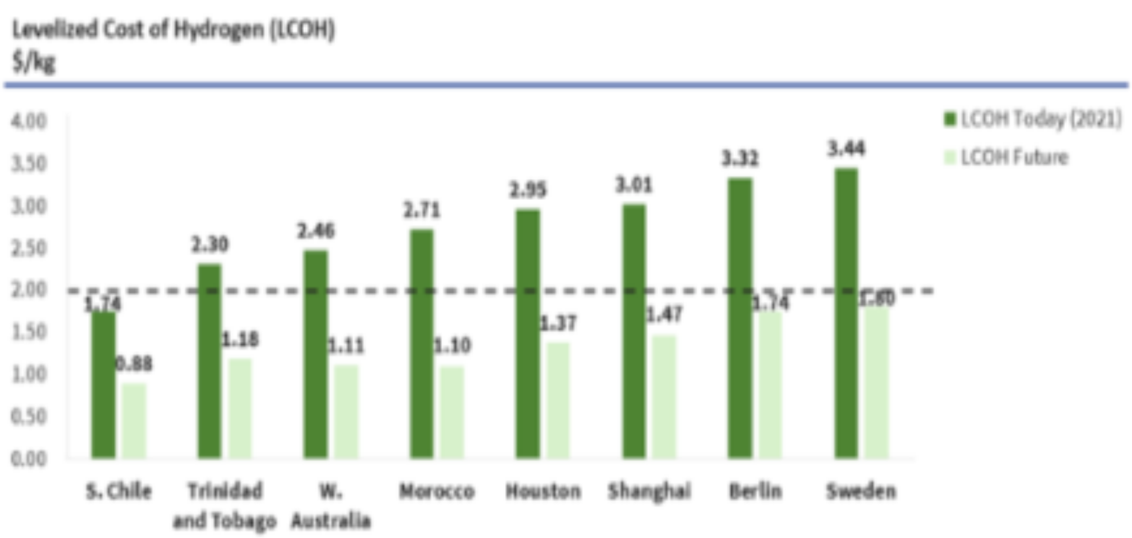


Fig.16. Levelized Cost of Hydrogen (US$. LCOH) RMI 2021

The above figure 16 is the present (dark green) and future costs of green hydrogen (in US$) for different countries indicating that US$2/kg (A$2.85/kg) as the competitive value for green hydrogen and showing that Western Australia's present cost is US$2.46 or A$3.51 with a potential future (2030) cost of US$1.1 or A$1.55. This coincides with projections from CSIRO (Hydrogen Roadmap [10] and Gen Cost 2030 Solar PV) and ANU (20208) projections.

Compression and storage of hydrogen will add A$0.6 to A$1.56 for these locations. Electrolizer capital expenditure A$1,000/kW today, A$286 in the future; System efficiency 49.5 kWh today 44/kWh in the future (RMI).

The new demand for H2 is inviting natural gas producers to make brown or grey H2 releasing CO2 as produced today cheaply at around A$2.50/t. They will now offer new blue (CCS) hydrogen to compete with green H2 but policy, effectiveness of CCS, fugitive emissions and the availability of underground storage for CO2 capture is not going to be easy for most locations.

The case for blue hydrogen is diminished further due to the variability of natural gas prices or shall we say due to the **certainty of green hydrogen price.**

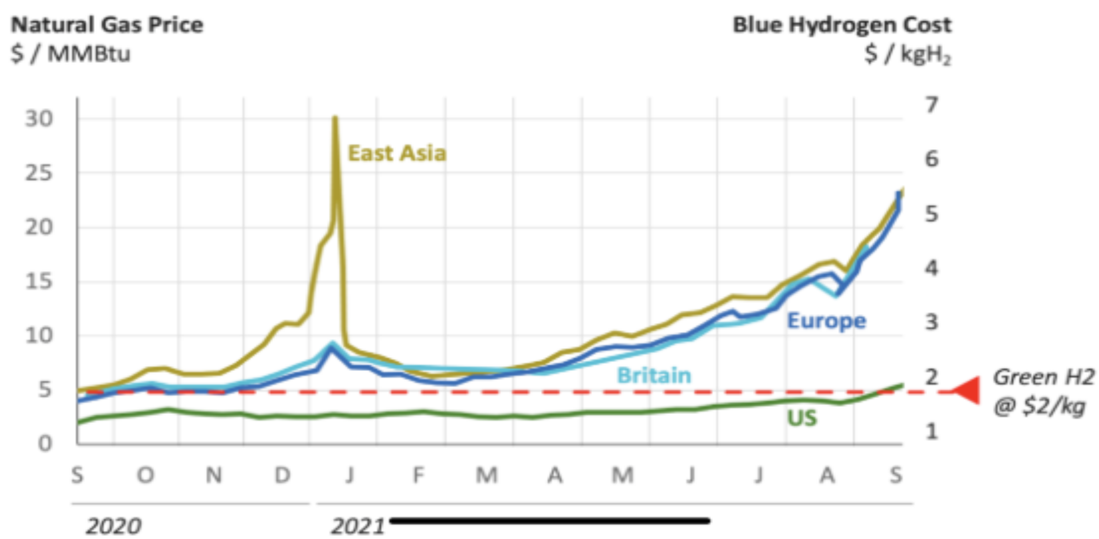


Fig. 16a. World gas price variability. (RMI) 2022 [16]

The Forward price for LNG on the east coast of Australia is shown in the following figure 16b.

Fig16b. Historical and Forward pricing for LNG in east coast of Australia ($A Nov.2022)

A recent study by Cornell and Stanford Universities[9] shows that natural gas with 1.54% of fugitive emissions, when producing blue hydrogen (with its own CCS losses) has only 18% to 25% less emissions than grey hydrogen and has higher emissions than natural gas when burning. At higher methane fugitive emissions say 3.5% (average for USA) blue hydrogen has only 9% to 12% less emissions than grey hydrogen, all this at higher costs.

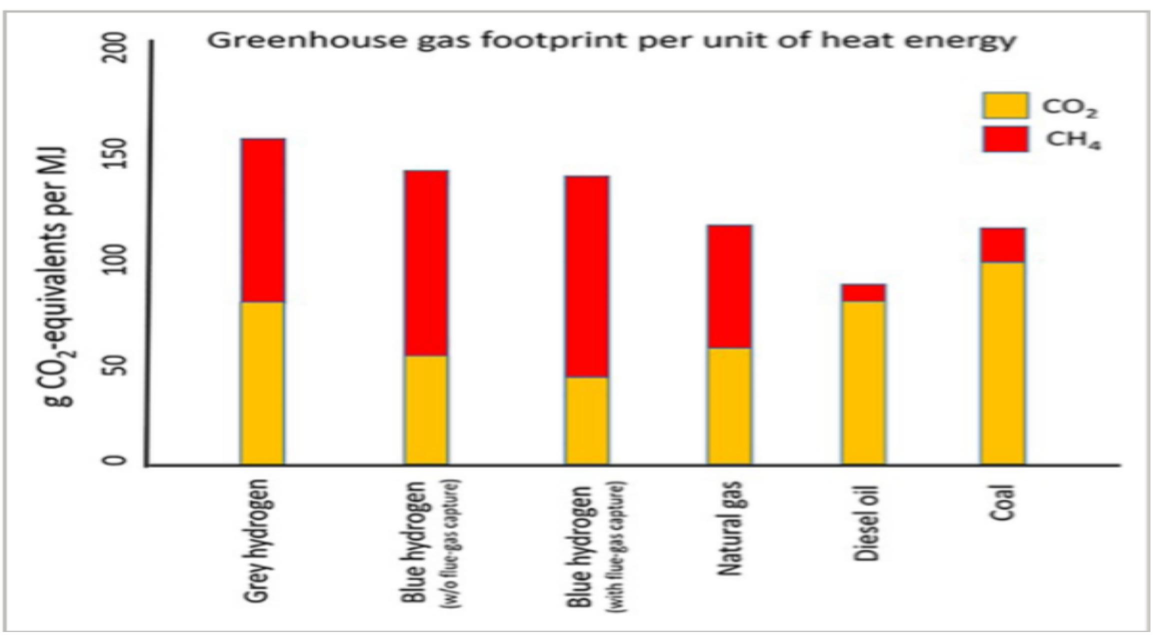
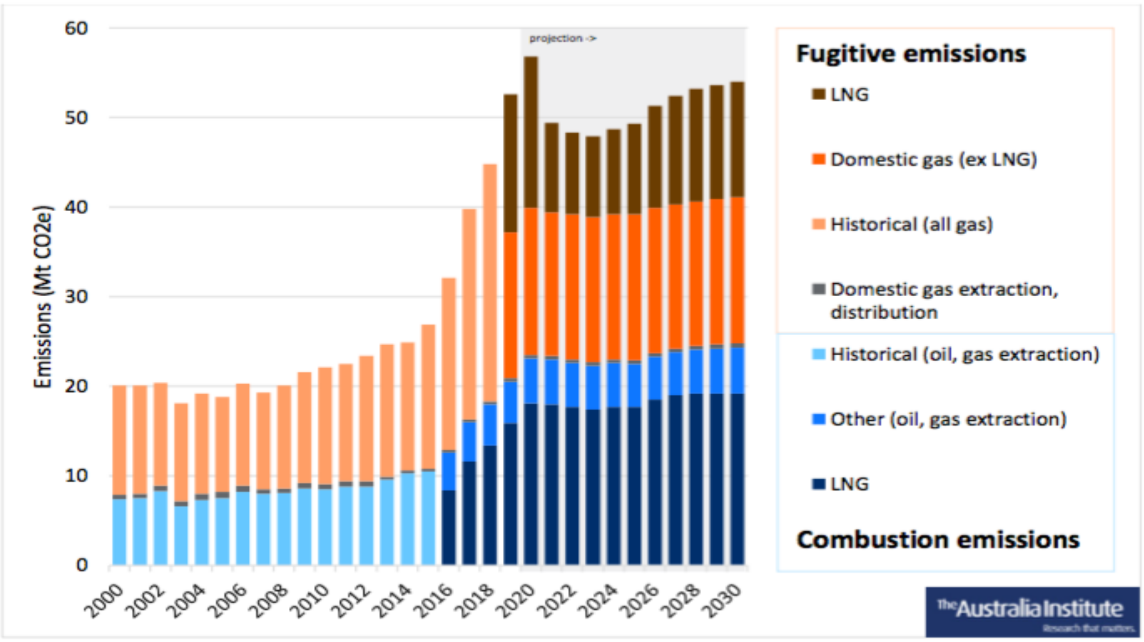


FIG. 17. Green hydrogen with Methane leakage rate at 3.5% (Cornell & Stanford Uni. 2021)

As a comparison it is estimated that WA's methane leakage emissions amount to 9%[11]of the entire volume of gas resource (apo.rg.au p. 43). **The red columns of the above graph for methane (CH4) would be 2.5 times higher.**



Source: Department of Environment and Energy (2019) Australia's emissions projections 2019,

Fig. 17a. Australia's Gas industry emissions, Fugitive (top half, orange & brown) and Combustion (bottom half, dark blue & Light blue)

So when hydrogen is needed (steel reduction, ammonia production, fuel refining, shipping fuel and energy storage) green is the colour to choose. When considering burning for heat applications, grey hydrogen (with highest emissions) and blue hydrogen [12] (dominated by methane emissions) are not suitable climatically and more expensive for the task. Natural gas will be less polluting (but still polluting) than grey and blue but not less than green. **Actually there will be no place for grey nor blue hydrogen once green hydrogen comes to the market.**

In a recent interview by "Upstream" Equinor's Vice President Henrik Solgaard indicated that it is only possible to capture 98% of CO2 with CSS but normally 90% so there will always be significant fugitive levels of methane and CO2. CCS is generally done at the wellhead when gas it at pressure, it is difficult to capture after combustion applications when the gas is at low pressure. Satisfactory underground storage should be reasonably close to the wellhead.

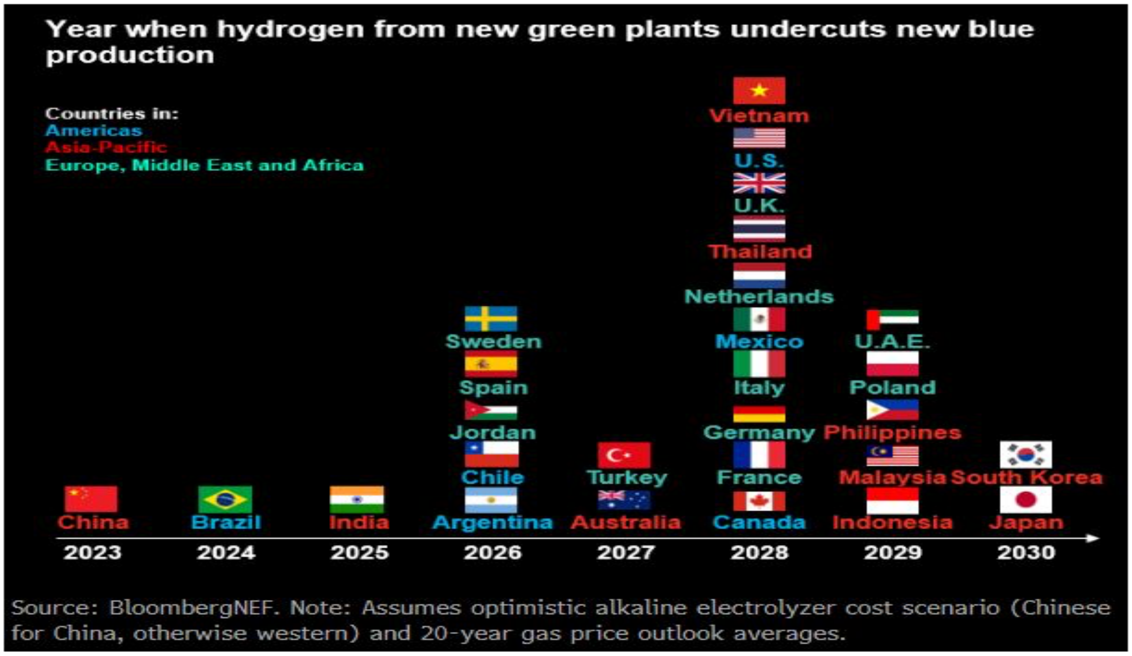


Fig.18. When green hydrogen undercuts blue hydrogen

What is certain is that hydrogen production from methane reforming (SMR) with CCS will increase in cost, increase GHG (mainly methane) emissions and remain subject to natural gas price volatility, whilst green hydrogen will continue to drop on price and remain accessible and certain to most countries with good renewable resources. However, large gas companies will start the hydrogen market with blue (which they should not and just stay with grey) and gradually move to green as electrolizers drop in price and when sufficient more renewables are in place. LNG is almost free (0.35%) of CO2 as it freezes at minus 31C and methane at minus 83C but the fugitive methane and production CO2 when liquefying remain in the country of origin. BloombergNEF (Fig.18) has predicted when green hydrogen plants will undercut new blue hydrogen production by the following country-timelines.

China has already started their "100GW Renewable Energy Hydrogen Roadmap by 2030". The 2022 demand of 30GW for hydrogen is a start and with only 1GW of green hydrogen in operation today it is a huge task, however, provincial governments are even more ambitious, the province of Inner Mongolia (with good renewable energy resources) aims to produce 500,000 tons of green hydrogen by 2025. China expects green hydrogen to overtake brown, grey, blue hydrogen by 2030. China's expenditure in hydrogen-related R&D has surged six fold between 2018 and 2019 surpassing the USA and Europe combined (Merics and Intl. Energy Agency and Mission Innovation). Electrolyser costs in China are about a third of those fabricated in the west. Policy is driving China's green hydrogen market.

NEL, Norway's largest electrolyser manufacturer forecasts green hydrogen price to match natural gas derived hydrogen by 2025.

In view of the political situation with the war in the Ukraine and the diminishing supply of natural gas from Russia and its current prohibitive price the EU is accelerating the development and import of green hydrogen as early as 2025, even at higher prices. It expects to import ~20 million tons by 2030 of which over 30% is expected from Australia.

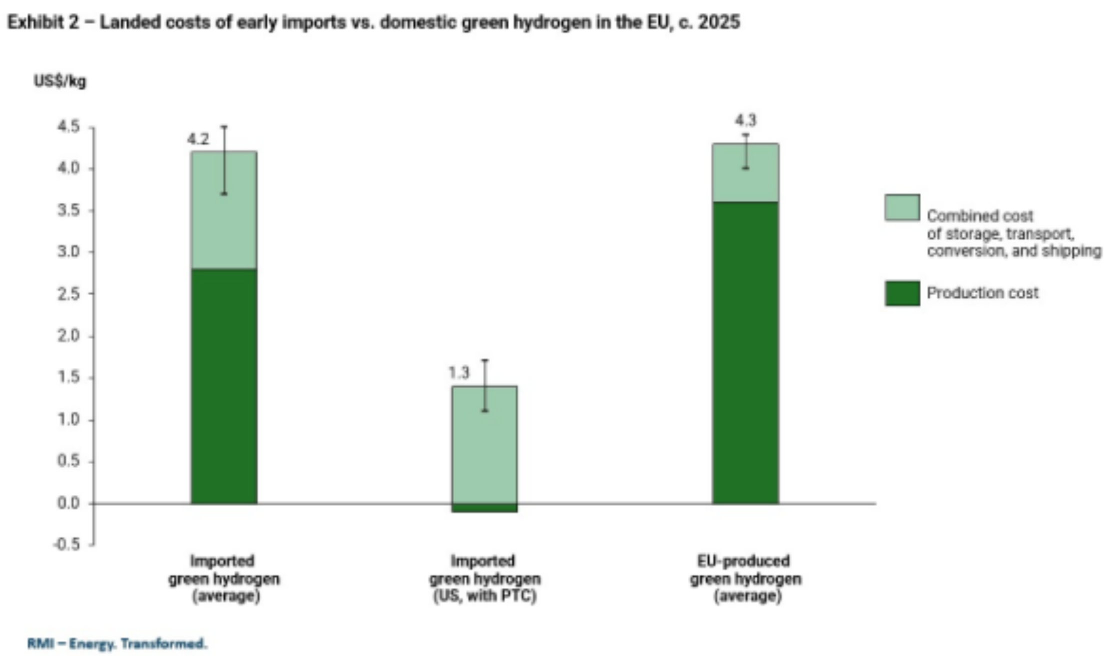


Fig. 19. Landed price of Green hydrogen in EU[13] (RMI.Oct.202210)

6.1 AccelerationR

The adoption of hydrogen sooner can be achieved by:

- Co-location of hydrogen production for ammonia-fertilizer manufacturing with power generation, storage and the grid.
- Site selection of good combined solar and wind resources.
- Grid connected site to make use of curtailed renewables at low cost or negative pricing.

The extra amount of solar and wind energy required for hydrogen will see a doubling or tripling the amount of renewables required just to replace existing fossil fuel plants let alone with the new hydrogen demand. The fabrication of electrolizers could hold back the adoption of hydrogen, as the total installed capacity today is 0.3GW powered by renewable energy and with a projected 40GW to be commissioned by 2030 according to Bloomberg NEF. This pales in comparison to the 850GW of electrolizers required by 2030 for hydrogen to play its part in a net zero world (RMI).

6.2 Green Hydrogen as Long (and short) Duration Storage

In a 2021 NREL[5] long duration (>36hrs) storage study for grids with 85% renewables, the lowest cost options was a natural gas CCGT with CCS and hydrogen systems with geological storage with fuel cells, pumped hydro (PHES) and compressed air. The problem with these systems is that we have already questioned natural gas and the CCS process due to unavoidable leakage (see Cornell and Stanford Univ. study[12]) and one is not going to find hydrogen suitably located geological caverns most times, suitable for compressed air nor PHES locations.

However, it is quite possible to rely on fertilizer plants connected to the grid with access to stored hydrogen or ammonia. For example, the planned Murchison green hydrogen fertilizer plant with a generation capacity of 5GW (equal to the SWIS capacity or close to it) and 3GW electrolizers could vary the loads accordingly whilst supplying power to the SWIS in an intermittent way. Having these co-located hydrogen sources makes it convenient also for shorter duration storage.

The fact that the fertilizer plant produces green ammonia (NH3) it could also be used as long duration storage with the convenience and efficiency that it can be used directly for power generation without the need to a re-conversion to hydrogen. Ammonia can be easily stored for long periods. All of these green hydrogen storage possibilities for power generation would be ~ A$100/MWh for co-located fertilizer or steel plants whilst alternative battery storage (A$250,000/MWh not suitable for long duration) would be well above that cost. These arrangements could be financially positive using peak load supply, capacity credit, local policies as well as convenient tariffs and trading curtailment energy at zero or negative costs from VRE plants.

7.0 Conclusion

Green hydrogen will be close pricewise to replacing natural gas in electric power generation to support renewables before 2030 and only close to replacing it in thermal applications. Once green hydrogen is competitive with natural gas it will be universally adopted as it's price will be stable compared to the price variability of fossil fuels. The sooner it is adopted the better for the environment.

As there is no penalty in Australia for emitting CO2 a market relationship has been established with off sets. These offsets could be invested in companies that produce green hydrogen, thus closing the gap. A tax credit similar to the US but only of around A$2.0/kg (US$1.40) of hydrogen could make it a close competitor sooner, well before 2030.
Green hydrogen or ammonia co-located plant (producing fertilizer, green steel, refining oil, shipping, etc) could also solve the energy storage for the long duration periods. It is important that policies are established very early to accelerate the installation of the infrastructure required to produce green hydrogen such as electrolizers, large fuel cells, compression and liquefying equipment.

CCS is not a solution to produce blue hydrogen. In fact we show that natural gas should peak in this decade and may have no place afterwards. Chile has already established the plan to become the lowest price exporter of green hydrogen in the world, not having natural gas but abundant solar and wind, green hydrogen has become a priority for them.

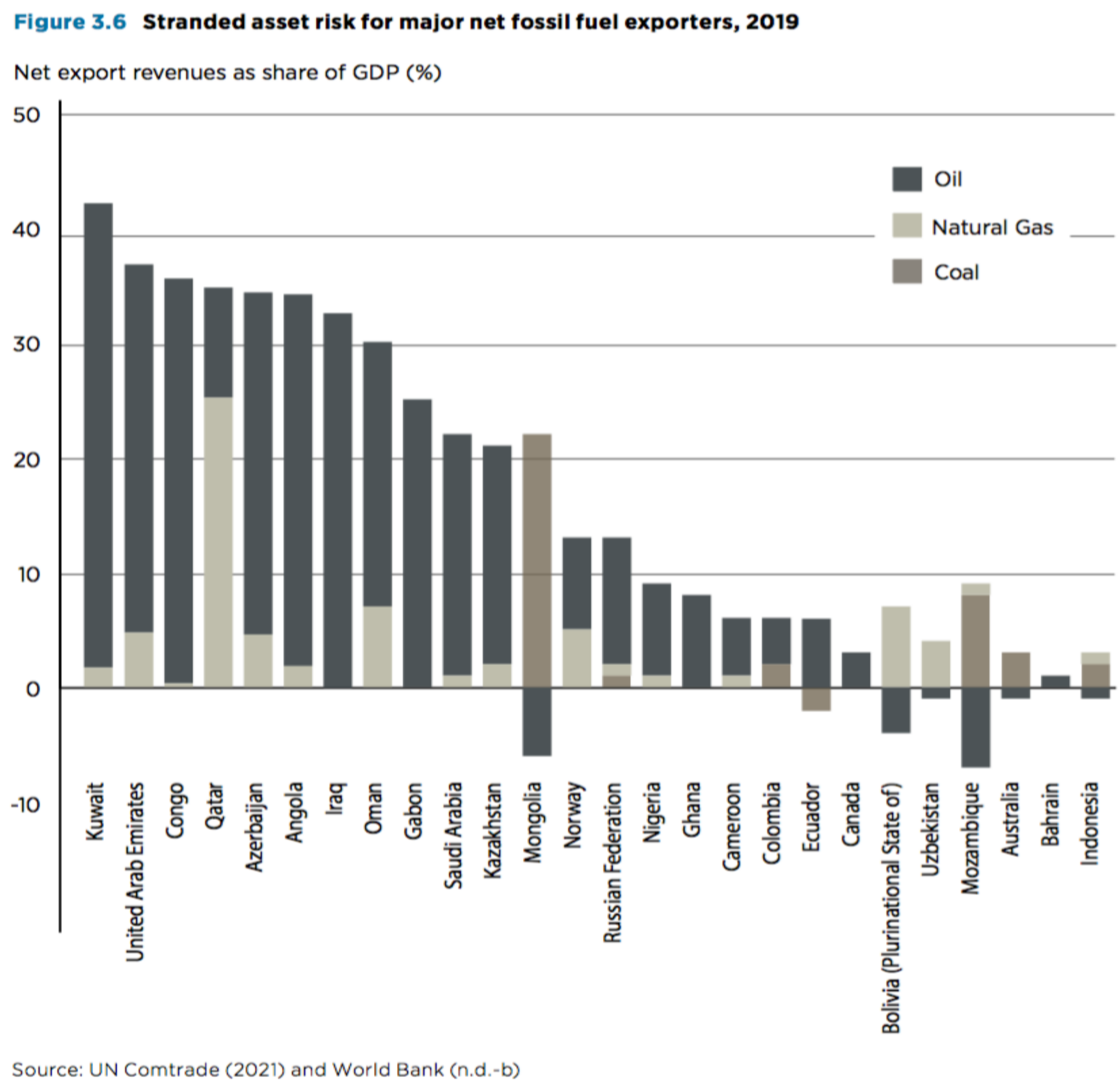
Saudi Arabia, the UAE, Oman and North African countries with abundant solar energy are already in the race. Australia can play an important role.

Actions needed:

1- No new coal mines or mine expansions
2- Phase out thermal coal mines
3- Reduce methane pollution from existing mines
4- Replace metallurgical coal by green hydrogen for iron ore reduction, responsible for 8% of world emissions (Australia exports 54% of the global iron ore market).
5- Replace ammonia production from fossil fuels that emit 1.8% of global emissions by using green hydrogen.
6- Replace shipping fossil fuels (3% of world's emissions) with green ammonia and use it as energy storage to balance renewable energy variability in the grid.
7- Replace aluminum production emissions from natural gas of 6.5% of Australia's (3% of the world's) GHG emissions by using electric renewable energy for the calcination process.
8- Plan to commence replacement of inefficient (25-30%) OCGT with doubly efficient (50-60%) fuel cells operating on green hydrogen for power generation
9- The majority of existing global fossil reserves should remain in the ground.

Appendix B: Stranded Assets

The geopolitics of green hydrogen will have a huge impact on the GDP of fossil fuel exporting countries with the risk of assets being stranded as shown in the following figure of the World Bank.



Stranded Asset risk of major fossil fuel exporters. World Bank 2019

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