Assessing The Long Term Costs Of Blue And Green Hydrogen under Zero-Emissions Objectives

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Abstract—Low carbon hydrogen can be produced using a range of technologies. Green hydrogen is produced using electrolysis and renewable electricity, while blue hydrogen is produced using steam methane reforming (SMR) with carbon capture and storage (CCS). Recent studies and strategies have compared these technologies but have not assessed the effects of lower-than-perfect CCS capture rates on long term cost competitiveness. This paper computes the amount of emissions that would occur under different carbon dioxide capture rates, and the relative costs of blue and green hydrogen under different scenarios for carbon costs and for lifetimes of production facilities. Our analysis gives insights into the cost competitiveness of blue versus green hydrogen under strengthening climate policy over time. Our assessment takes into account expected hydrogen production opportunities and costs in Australia, and parameters in the Japanese Hydrogen Strategy. We find that while blue hydrogen (from fossil fuels, with CCS) is generally cheaper to produce now, green hydrogen is likely to improve its cost competitiveness over time. Tightening carbon constraints will raise the possibility that blue hydrogen production assets could become stranded.

Keywords—hydrogen, renewable energy, natural gas, carbon capture and storage (CCS), steam methane reforming, electrolysis

I. INTRODUCTION

Australia's national hydrogen strategy[1] argues that Australia should be at the forefront of the global hydrogen race. The strategy takes a technology-neutral approach, by not favouring any one way of making "clean" hydrogen. The hydrogen strategy uses the term "clean hydrogen" for hydrogen produced from renewable electricity (i.e. green H2), and from coal or gas with carbon capture (i.e. blue H2).

But it matters whether hydrogen is produced from renewable electricity or fossil fuels. While the fossil fuel route is currently cheaper, it could end up emitting substantial amounts of carbon dioxide. Also, establishing hydrogen production facilities with carbon capture would mean additional expenditure on equipment with long lifetimes required for cost competitiveness. This is risky, as the capital would be wasted if the market for emissions-intensive hydrogen collapsed. This could happen either through public attitudes or a global imperative to move to zero-emissions energy systems. And this may mean that these facilities could become stranded assets.

Many reports, including Commonwealth of Australia [1], Bruce, et al. [2] and IEA [3], assume a "best-case" scenario where 90-95% of carbon dioxide is captured from fossil fuels. Many of the reports utilise an International Energy Agency technical report for their modelling of carbon capture and storage (CCS) [4]. This includes IEA [3], which was a report prepared to coincide with the 2019 G20 meeting in Japan and the Australian Hydrogen Roadmap.

The issues that arise when there are lower-than-perfect capture rates (i.e. below 90%) were not examined in the strategy [1,2] or by the IEA [3]. This is a concern as most CCS projects have captured very little to date. And the IEA technical report [4] provides examples of technologies where the 'best-case' capture rates are below 60%.

Our analysis focuses on two key issues. The first is the amount of emissions that would occur if the best-case capture rates are not achieved. The second part of the analysis focuses on the costs of electrolysis and steam methane reforming (SMR) over different lifetimes. Using different lifetimes allows us to assess the cost of hydrogen for the case where climate action occurs and SMR becomes a stranded asset.

Whether facilities could become stranded assets is an issue that has not been accounted for in previous assessments. However, it is an issue that is very relevant for comparisons between blue and green hydrogen. For example, the Japanese Hydrogen Roadmap specifies that in the interim period (i.e. early 2020s) Japan will demand hydrogen produced using fossil fuels. However, the Japanese Hydrogen Roadmap also specifies demand for green hydrogen from electrolysis by 2030. This means that there could be less than 10 years to make the transition to green hydrogen, which is an issue as the lifetime of SMR facilities used in key reports is 25 years.

II. METHODOLOGY AND DATA

To make comparisons between the different technologies that can produce hydrogen we use the levelized cost of hydrogen (LCOH). This allows us to apply carbon prices and compare costs over different lifetimes. The technologies that we focus on are a selection of those described in IEAGHG [4]. This provides four technological case studies, which are: SMR without CCS (Base case), SMR with CCS from shifted syngas (Case 1A), SMR with CCS from PSA tail gas (Case 2A), and SMR with CCS from flue gas (Case 3).

Case 1A and 2A have CO2 capture rates of 56% and 54%. Case 3 has a capture rate of 90%. Note that we have used the same labels as in IEAGHG [4] for comparability.

A. *Calculating emissions for different capture rates*

High rates of carbon capture are technically possible but have not been achieved to date. To illustrate why carbon-free hydrogen matters, we have calculated the emissions for the case where Australia produces 12 million tonnes of hydrogen for export per year. This is equivalent to about 30% of Australia's current liquefied natural gas (LNG) exports and in line with production estimates in the national strategy. We use capture rates of 90-95%, 80% and 60% to display what would occur. The emissions for lower capture rates are notable. These results are presented in section 3A.

B. *Estimating the levelised cost of hydrogen using different technologies*

To illustrate the range of issues that will drive the cost competitiveness of blue and green hydrogen, we estimate the levelised cost of hydrogen (LCOH) for a range of technologies. The LCOH is computed as follows:

$$\text{LCOH} = (a + c) / P \quad (1)$$

with a being the annual capital repayment, c are the operation and maintenance costs and P is the annual production of hydrogen. The annual capital repayment is determined by the cost of capital, the lifetime of the capital and the installed capital price. We calculate the LCOH for different lifetimes to account for the issue of short lived, stranded assets. To compare the LCOH produced using SMR to green hydrogen we apply a carbon price of \$26/tCO2, which is the current EU carbon price.

TABLE I. COMPARISON OF TECHNOLOGIES AND KEY PARAMETERS

Key parameters	***Technology case/specification***			
	Base case	***Case 1A***	***Case 2A***	***Case 3***
	SMR without CCS	***SMR with CCS from shifted syngas***	***SMR with CCS from PSA tail gas***	***SMR with CCS from flue gas***
Hydrogen produced (kt/year)	74.85	74.85	74.85	74.85
Capital cost (million \$)	196.64	232.13	260.03	351.20
Start up costs (million \$)	59.74	71.43	79.53	107.15
Fixed operating costs (million \$/year)	8.68	10.08	10.83	13.27
Variable operating costs (million \$/year)	82.23	84.89	85.60	90.24
Revenue from electricity sales (million \$/year)	7.60	1.14	-0.82	0.33
Cost of CO2 Transport and Storage (million \$/year)	NA	4.46	4.36	7.66
CO2 emissions (tCO2/year)	673.33	308.25	322.06	73.90
CO2 emissions (kg CO2/kg H2)	9.00	4.12	4.30	0.99
CCS capture rate (%)	NA	56	54	90

Table I presents the key parameters that we have used in the calculation of the LCOH for the four SMR technologies. Also presented are the CO2 capture rates and the emissions per kilogram of hydrogen produced.

III. ANALYSIS

A. *Level of emissions for different capture rates*

Figure 1 compares the emissions intensity of different fuels with and without CCS. The emissions intensity of hydrogen produced from coal and gas changes notably based on the assumed capture rate. At 90-95% capture rates, coal- and gas-based hydrogen is much less carbon-intensive than traditional fossil fuel uses. But a capture rate of 60% means hydrogen from coal has a similar emissions-intensity to burning natural gas directly.

To place this in context, consider the case where only 60% of the carbon dioxide was captured, hydrogen from gas and coal would lead to an additional 7.8% and 17.9% of current Australian emissions, respectively. As noted previously, this is based on the case of Australia producing 12 million tonnes of hydrogen for export per year.

Fig. 1. Emissions intensity of fuels with and without CCS. (*Source: authors' calculations*)

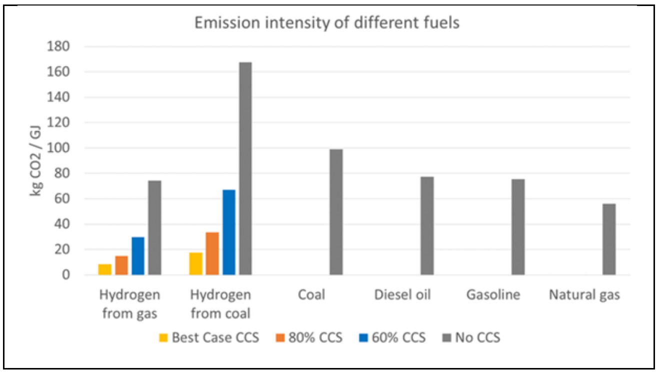
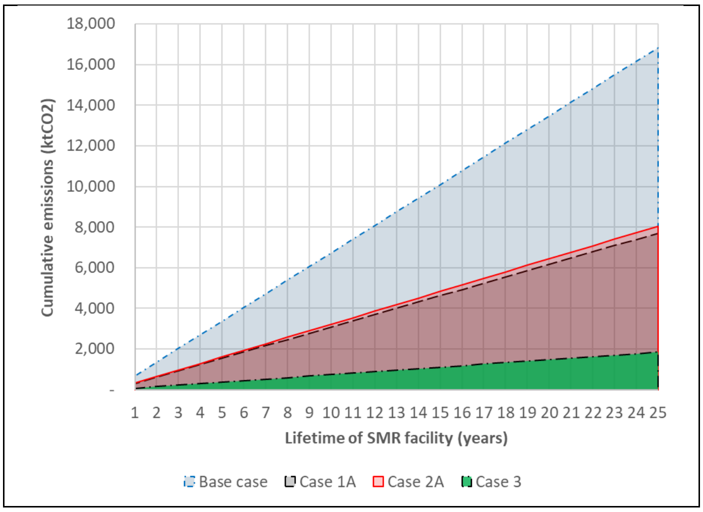


Fig. 2. Cumulative emissions of four different SMR facilities over the lifetime of the facility. (*Source: authors' calculations, using data from IEAGHG*)



To understand how the differences in capture rates impact emissions over the lifetime of an SMR facility, Figure 2 presents the cumulative emissions of the four different SMR facilities over 25 years. Over the full lifetime of these facilities, the difference in cumulative emissions is large. Cumulative emissions range from 1,848 ktCO2 for case 3 to 16,833 ktCO2 for the base case. This shows that the decision between brown, blue and green hydrogen is important as the difference in emissions is large. This is especially the case when the full lifetime of the facility is accounted for (as in Figure 2).

Note that these hydrogen numbers are for production only; the emissions intensity is higher for exported hydrogen and we will calculate this in the final paper.

B. Levelised cost of hydrogen using different technologies

Figure 3 shows our initial analysis of the LCOH for the four types of SMR facilities over different lifetimes. We compare these costs to the target import price for hydrogen from the Japanese Hydrogen Strategy (JHS). This target price was based on the landed cost of liquefied natural gas with a price of carbon. We also included a current and future price of hydrogen from a PEM electrolyser [2].

The amount of time to pay for the capital cost of the facility is the key driver of the LCOH across the assumed lifetime of the facilities. This determines the shapes of the curves shown in Figure 3.

Based on the JHS target of importing green hydrogen by 2030 and a build time of 3 years, there are 7 years to make the transition. We assume that 2030 is the key year for this transition, based on the JHS and an assumption that public attitudes will result in a global imperative to move to zero-emissions energy systems.

For a lifetime of 7 years, none of the SMR with CCS facilities achieve the JHS target price of $1.99. Using the JHS price as a threshold means that SMR with capture rates of 56%-54% (i.e. case 1A and 2A) need to operate for longer than 9-13 years to be cost competitive. The facility with the best capture rate (i.e. case 3 with 90%) would need to operate for longer than 25 years to be cost competitive. In comparison to the future best-case PEM cost, having a lifetime of greater than 4-11 years is crucial for cost competitiveness.

Figure 4 shows an additional scenario where there is a strengthening of climate policy over time. This is reflected by an increase of the carbon price applied to the emissions from SMR facilities. In this case, a carbon price of $26/tCO2 for the 1st year of operation increases to $100/tCO2 for the 25th year of operation. A linear fit for the years in between 1 ($26/tCO2) and 25 ($100/tCO2) is used.

In this case, none of the SMR facilities achieve the JHS target price. Using the future best-case PEM cost, only the base case SMR facility (with a lifetime greater than 4 years) and case 1A SMR facility (with a lifetime between 9 and 19 years) are cost competitive. The lowest LCOH that the case 3 SMR facility (with a 90% capture rate) achieves is $2.58/kg when there is a lifetime of 15 years. The LCOH below and above this increases due to the impact of a short lifetime or a higher carbon price.

These examples show that there is a risk of stranded assets based on tightening carbon constraints and the potential for a limited lifetime of SMR facilities.

Fig. 3. Levelised Cost of Hydrogen (LCOH) from Steam Methane Reforming with a fixed carbon price. (*Source: authors' calculations, using data from IEAGHG*)

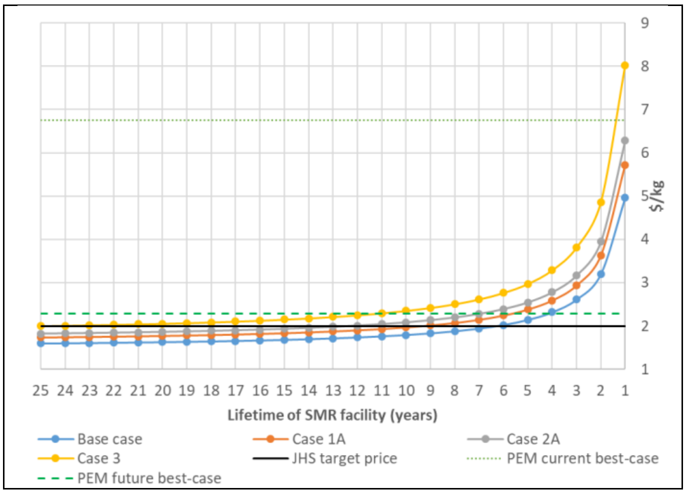
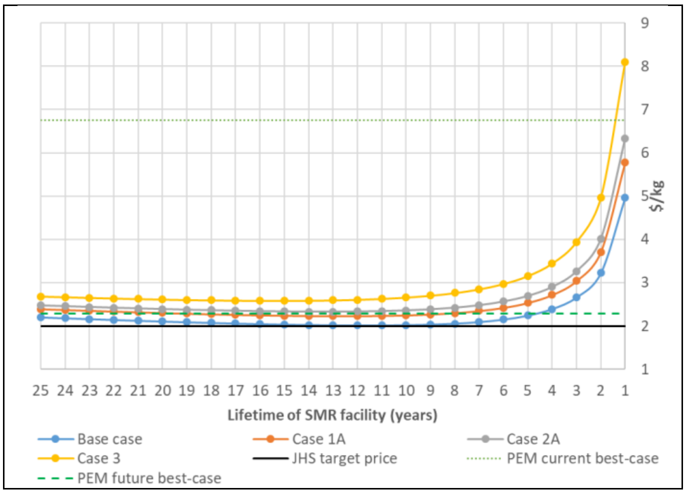


Fig. 4. Levelised Cost of Hydrogen (LCOH) from Steam Methane Reforming with an increasing carbon price. (*Source: authors' calculations, using data from IEAGHG*)



IV. Conclusion

Right now, producing hydrogen from fossil fuels is cheaper than from renewables. This is the case with carbon capture and storage and if a carbon price is in place for remaining emissions. This is especially so where there are fossil fuel reserves that have no alternative use and where there is ready access to geological storage for carbon dioxide. In Australia for example there are extensive readily accessible lignite coal reserves, and captured carbon could be stored in multiple sites geographically close to coal reserves. There are also plentiful gas reserves could be turned into hydrogen.

However, recent analyses and strategies such as the Australian hydrogen strategy and the IEA's hydrogen roadmap have not accounted for the case where lower capture rates than theoretically possible occur and where remaining carbon dioxide is subject to a carbon price.

The emissions that occur with lower capture rates (54%-60%) are large relative to the energy in hydrogen end uses and need to be considered when comparing options for producing hydrogen.

When these factors are accounted for, hydrogen produced using renewable energy may be more cost effective, and there is a risk of blue hydrogen production facilities becoming stranded assets.

Also, the technical lifetime of blue hydrogen with CSS facilities are long and may be longer than the window of opportunity for exports to countries that look set to demand hydrogen for import, as reflected in the Japanese Hydrogen Strategy. We find that even with a 90% capture rate, an SMR facility that can be used for only 25 years or less would not achieve cost competitiveness as defined by the Japanese Hydrogen Strategy.

The risk of stranded assets suggests that investors and governments in potential large-scale hydrogen producing and exporting countries, such as Australia, need to be conscious of lock-in to remaining carbon dioxide emissions and the risk of stranded assets that flow from this. For governments, these considerations suggest caution in public infrastructure investment for blue hydrogen. Governments should also rule out future subsidies for blue hydrogen and exempting companies that invest in blue hydrogen from carbon policies. The risk of stranded assets reinforces the need to support R&D into green hydrogen.

The long-term future for the hydrogen economy is likely to lie with green hydrogen. This will provide big opportunities for countries that have large scale low cost renewable energy potential, opportunities for processing facilities and a suitable investment framework. The prerequisite for such industries to be viable outside of niche applications are reductions in the cost of electrolysis, and further reductions in the cost of large-scale renewable energy production.

Acknowledgment

The authors declare no conflicts of interest.

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