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Using surplus electricity to produce green hydrogen

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Abstract

This paper explores the prospects for the production of electrolytic hydrogen from the increasing amounts of surplus electricity anticipated from highly renewable electricity systems. Wind spill was evaluated using data obtained from a simulation of a transitional New Zealand electricity system incorporating 2500 MW of wind installed capacity. Electricity surpluses totalled 3663 GWh over a 3 year period (average 1221 GWh/y), with a peak 30-min surplus of 1093 MW. Hydrogen production from an 1100 MW plant was 66,597 tonne, at a conversion efficiency of 58.5%. Practical scenarios informed by spill-duration curve analysis were then investigated for 100-1100 MW electrolyser installed capacities. Hydrogen production ranged from 5261 – 22,199 tonne/y, with an energy content of 187 - 740 GWh/y. Financial evaluation, with electricity priced at zero, indicated a levelised cost of hydrogen energy of 3.4 – 9.6 c/kWh, compared to a 2017 wholesale price for natural gas of 2.24 c/kWh. An increase in the carbon price from $NZ 79/t-$CO_2$e to $NZ 397/t-$CO_2$e was estimated for hydrogen produced in this manner to be financially competitive with natural gas. Key issues regarding future hydrogen production from surplus electricity are discussed and further research topics identified.

1. Introduction

As the proportions of wind, solar and other variable generation in electricity systems expand, electricity surpluses will increase. Hydrogen production via electrolysis provides a proven option for utilising and storing such potentially stranded energy, which may either be returned to the electricity grid, or directly utilised elsewhere in the energy system as a combustible fuel. Many PV-hydrogen and wind-hydrogen hybrid systems e.g. [1,2] incorporate a fuel-cell for generating electricity from temporarily stored hydrogen. For this option, round-trip efficiencies of approximately 30% have been reported [3]. Improved system efficiencies may be obtained by incorporating heat recovery into the system in a combined heat and power approach, as has been proposed for remote area power applications [4, 5]. Hydrogen may also be used as a fuel in both gas turbines and Otto-cycle (‘diesel’) generators, with round trip efficiencies of approximately 25%. Alternatively, the direct use of hydrogen as a combustible fuel achieves considerably greater round-trip efficiencies, and is receiving increasing attention. Combustion options include injection into gas grids [6-8], use in hot water heating [9], and use in cooking applications [9-12]. Conversion efficiencies for cook stoves of 60%-80% may be expected [11, 13].

Three commonly known electrolysis process exist, namely alkaline electrolysis (AEL), polymer electrolyte membrane or proton exchange membrane (PEM) electrolysis and solid oxide electrolysis (SOE) [14, 15]. Both AEL and PEM systems are commercially available, and PEM electrolysers had reached MW scale by 2017 [16]. The SOE technology is presently considered to be at the laboratory testing and demonstration phase with a relatively low lifetime (<10,000 hrs) [14]. Electrolyser efficiencies range from 54-84% for AEL and 52-82% for PEM [16, 17]. Electricity requirements of 44.7, 50.4 and 55.3 kWh/kg-H_2 [18, 19] have been reported for electrolysis, and future energy consumption values equivalent to 52.4 – 69.5 kWh/kg-H_2 for AEL and 50.0 – 58.5 kWh/kg-H_2 for PEM predicted [14]. Compression, where required, will require additional energy consumption, but for low pressure applications e.g. 3.3 bar for storage, cooking and heating [9] and 13.8 bar for use in cook stoves [11] the electrolyser operating pressure is sufficient and no additional compression is needed. It has been suggested that where high pressure hydrogen is required that it makes best sense to operate electrolysers at relatively low pressures (e.g. 10-40 bar), followed by a separate hydrogen compressor [2]. However, a PEM electrolyser can produce hydrogen at 80 bar pressure which can be fed directly into a hydrogen pipeline [20]. In contrast, vehicle fuelling applications require compression to 350-950 bar [21]. A range of compression energy requirements from 1.7 to 6.4 kWh/kgH_2 has been reported [21]. The cold start capabilities, turn-down ratios and stop-start limits of electrolysers are key factors when the electricity supply is variable and intermittent. Cold start times have been described as taking 'minutes to hours' for AEL systems and 'seconds to minutes' for PEM systems [14], and 30-60 minutes also given for AEL [2]. Minimum electrical load requirements of 20% of rated capacity for AEL and 5% of rated capacity for PEM systems have been reported [16], although it has been suggested elsewhere that higher pressure (30 bar) AEL technology should be able to operate down to 5-10% of rated capacity [2]. Ideally electrolysers should be operated continuously, however intermittent operation is possible. A manufacturers limitation for an advanced AEL electrolyser of no more than 5000 stops and starts in order to meet lifetime and efficiency criteria, plus lifetimes of 60,000-90,000 hrs, have been reported [22, 23]. In contrast, PEM systems are considered suitable for dynamic stop and start operation, with degradation a function of operating hours rather than cycling, and with estimated lifespans of 20,000-60,000 hrs [23-25]. Typical PEM efficiencies are 62%-82% (LHV basis) [25]. Improved lifetimes of 90,000-100,000 hrs for all three electrolyser technologies are anticipated over the next 10-20 years [23, 25]. Presently PEM systems generally cost twice as much as AEL systems, but future costs close to those for AEL systems are widely anticipated [20, 23-25].

Oxygen produced during the electrolysis process may be vented to the atmosphere in situations where this is acceptable or utilised as a commercially valuable by-product. Present and potential applications include steel making (in blast furnaces and electric arc furnaces), glass melting, thermal electricity generation, synthesis gas ($CO+H_2$) production via gasification, and medical care [26]. Additional uses for oxygen include welding and aerobic wastewater treatment. The theoretical yield is 8 kg-O_2/kg-H_2.

Hydrogen reticulation infrastructure is now mature, with about 3000 km of hydrogen pipelines reported to be in place globally, including 1600 km in Europe [27]. More recently a new 180 mile (288 km) pipeline has expanded the length of the hydrogen network in the Gulf Coast region of the USA to over 600 miles (960 km) [28]. Pipelines have historically utilised epoxy-coated mild steel [27], but increasingly, polyethylene is being specified [6, 29]. The gas network in the city of Leeds, England is presently being replaced with polyethylene piping - a move which is compatible with a proposal to eventually phase-out fossil-gas in favour of a 100% hydrogen system [6].

In a recent study on the potential for hydrogen production in New Zealand using wholesale grid electricity and assuming 85% electrolyser utilisation, the estimated cost of green hydrogen for a system including transmission and storage in a tank was 0.23 $NZ/kWh (HHV basis) [30]. When operating only during times of low electricity prices, the hydrogen cost was reduced to 0.076 $NZ/kWh. In a simulation of hydrogen production for an offshore wind farm in the UK, Hill et. al. [31] determined a levelised cost of gas (LCOG) of 8.38 €/kg for an AEL system and 10.49 €/kg for a PEM system. This analysis included a range of electricity costs and the system included desalinisation, electrolysis, compression, pipeline and salt cavern storage. A German electricity system with high PV and wind penetrations was modelled by [32], and 10 nodes producing large electricity surpluses identified. Estimated annual hydrogen production using PEM technology was 189,000 tonne, at a cost of 3.63-5.81 €/kg, using a range of electricity prices. The system included electrolysis, compression, pipelines and storage in salt caverns. To the best of our knowledge no similar studies on the use of surplus electricity in New Zealand have been published.

The objectives of this paper are: a) to evaluate the amount of potentially stranded wind electricity available from a highly renewable New Zealand electricity system; b) to predict the hydrogen production from such a system; c) to determine the financial cost of this hydrogen; and d) to discuss the potential uses for hydrogen and future research needs.

2. Methods

Wind electricity production and dispatch data in MW per 30-min for the period January 2013 to December 2015 were obtained from a simulation of the New Zealand electricity system incorporating 2500 MW of wind, conducted under the GREEN Grid project (Josh Schipper, pers. comm. January, 2019). For further details of the simulation the reader is referred to [33, 34]. The 2500 MW scenario was selected to facilitate comparison with previous modelling of a 100% renewable electrical system for New Zealand [35, 36]. Surpluses were determined by difference between supply and demand, and a surplus-duration curve developed from a frequency analysis using 10 MW intervals (bins). An electrolysis energy requirement of 55 kWh/kg was adopted from [14] and a hydrogen-duration curve developed from a frequency analysis using 200 kg/h bins. Hydrogen energy was determined using the lower heating value (LHV) of 120 MJ/kg. The levelised cost of energy (LCOE) was calculated according the formula given below [37]:

$$LCOE = \frac{Total\ Present\ Value\ Lifetime\ Cost}{Total\ Present\ Value\ Lifetime\ Energy\ Production}$$

$$= \frac{I - T\sum_{i=i}^{N}\frac{D}{(1+r)^i} + (1-T)\sum_{i=1}^{N}\frac{(1+CE)^{i-1}C_i}{(1+r)^i} - \frac{R}{(1+r)^N}}{E_A\sum_{i=1}^{N}\frac{1}{(1+r)^i}}$$

Where:

I is the investment in electrolysis plant ($NZ);
T is the tax rate;
D is the depreciation rate of the investment, for the purpose of understanding any depreciation tax shield;
r is the discount rate;
N is the number of years over which the analysis was conducted;
CE is the annual cost escalation of the operation and maintenance cost, C_i;
R is the plant's residual value ($NZ); and,
E_A is the hydrogen energy (MWh/year, LHV basis).

A future unit capital cost of €500/kW(installed capacity) was taken from [38] and converted to $NZ784.31/kW using an exchange rate of 0.6375 (BNZ; 5 Feb, 2019). A plant lifetime of 20 years was adopted. Operating expenses (C_i) were taken as 5% of CAPEX annualised, and incremented by CE = 2.5% per annum to account for CPI. A discount rate of r = 6% was adopted. The tax rate was set to zero (i.e. T = 0), thus any reduction in profit before tax due to depreciation was not considered in terms of a reduced tax requirement. Reduction in tax from operational expenditure was also not considered and the residual value of the electrolyser was taken as zero (i.e. R = 0). The analysis assumed that the cost of electricity to produce the hydrogen was zero, since it would otherwise be curtailed (i.e. spilled). This is discussed further in the next section.

3. Results and Discussion

3.1 Wind spill characteristics

Electricity surpluses totalled 3663 GWh over the 3-year period (average 1221 GWh/y), with a peak 30-min surplus of 1093 MW. The annual patterns of energy spill over the study period were characterised by considerable variation. Relatively extended periods where little or no surpluses occurred were observed as well as periods of considerable surplus (Fig. 1a). The former may be more clearly seen by noting the plateaux regions in Fig. 1b, which tended to occur during the first 4-6 months of each year. For 2013 the spill was considerably lower than for 2014 and 2015. The average level of spill in the present study was relatively high in comparison with previously modelled levels for 100% renewable New Zealand electricity systems of 229 GWh/y with 2230 MW wind [35], and 98-333 GWh/y with 2494 MW wind [36]. This emphasises that spill levels will vary considerably with the composition and operation of future electricity systems and in particular, how the hydro lakes are managed.

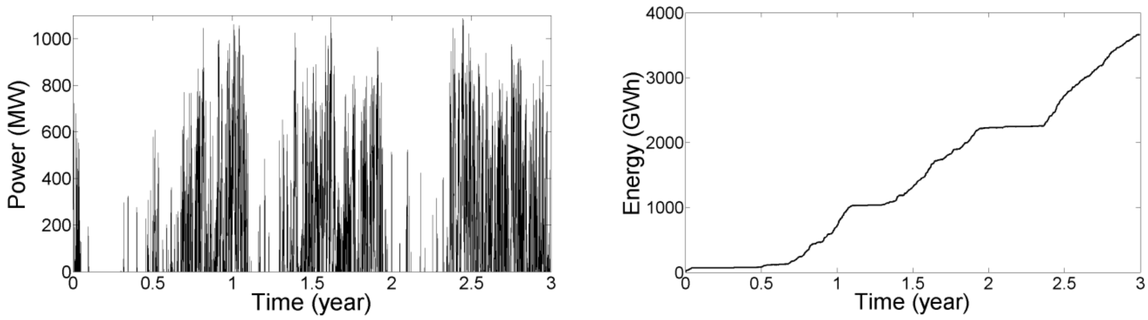

Figure 1: Wind spill from a New Zealand electricity system with 2500 MW wind;
a) as produced; b) cumulative

During periods of high spill frequency, there were relatively few gaps (Fig. 2a). Of the 690 spill events which occurred during the study period over 337 had durations of 6 h or greater, with a maximum period of contiguous spill of 8.75 days (Figs. 2a-b). Both the long-term and short-term spill patterns have significant implications for the selection, sizing, operation and financial performance of an electrolysis plant. An AEL plant with one start and stop per day would operate for less than 13.5 years due to cycling issues [22], whereas as noted above a PEM plant is able to tolerate more a more variable mode of operation.

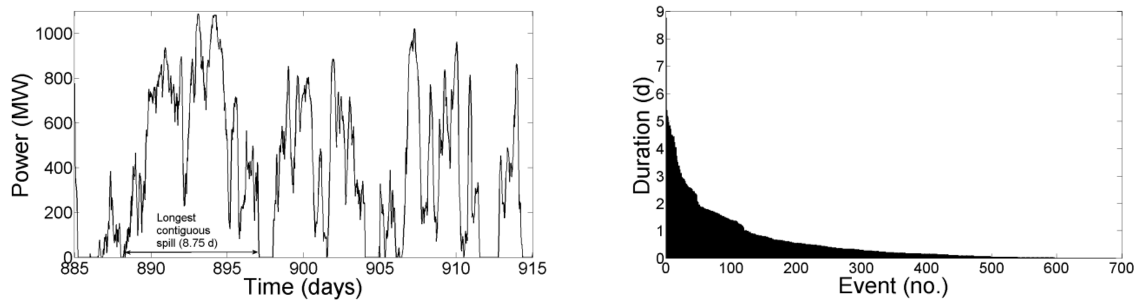

Figure 2: a) spill sequence during a 30-day high spill period; b) duration of all spill events

In this study half-hourly spill events occurred only 39% of the time and very high magnitude events happened only occasionally (Fig. 3a). For example, peaks of 700 MW and above were observed only 5% of the time. This indicates the need for careful consideration of plant installed capacity, and the prospect of shaving the more infrequently occurring peaks.

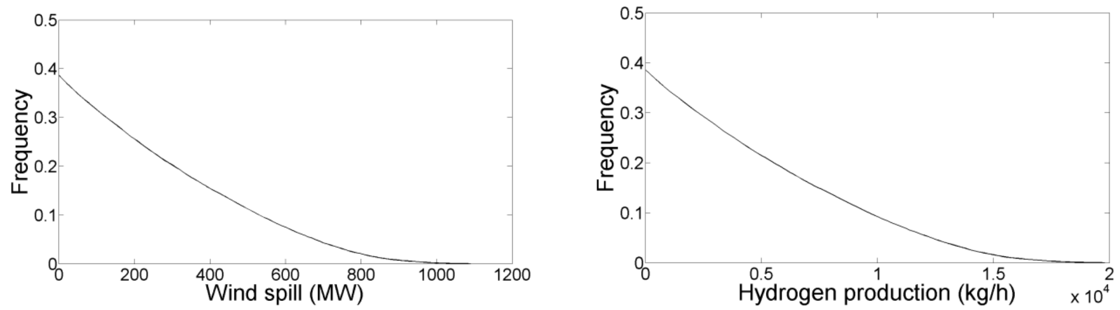

Figure 3: a) Spill-duration pattern (10 MW bins); b) Hydrogen production-duration pattern (200 kg/h bins)

3.2 Hydrogen production

Based on the wind spill patterns observed, PEM technology was considered most suitable for further invesigation. The maximum possible hydrogen production was 66,597 tonne at a conversion efficiency of 58.5%. The frequency of hydrogen production rates followed the same pattern of for wind spill and showed for example that rates above 12,200 kg/h occurred less than 5% of the time (Fig. 3b). Given the infrequent occurrence of large spill peaks, hydrogen production for electrolyser installed capacities from 100-1100 MW, whereby peaks were progressively shaved, was investigated. Production was found to range from 5,261 - 22,199 tonne/y, with an energy content of 187 - 740 GWh/y. If converted back to electricity using a fuel cell at 50% efficiency, this would supply 93 - 370 GWh/y to the grid. A plot of hydrogen production vs installed capacity shows the pattern of diminishing hydrogen production with increasing installed capacity (Fig. 4a). Since the graph flattens out beyond 700-800 MW, but CAPEX increases in a linear fashion (Fig. 4a), going above this in order to capture additional energy may not be attractive. In all cases elecrolyser utilisation was 39% but electrolyser capacity factors improved from 13% to 35% as installed capacity decreased (Fig. 5a). The peak shaving from limiting electrolyser installed capacity to 700 MW is illlustrated in Fig. 5b. A decision on plant size was not made at this stage however but deferred until the financial analysis for all scenarios was determined.

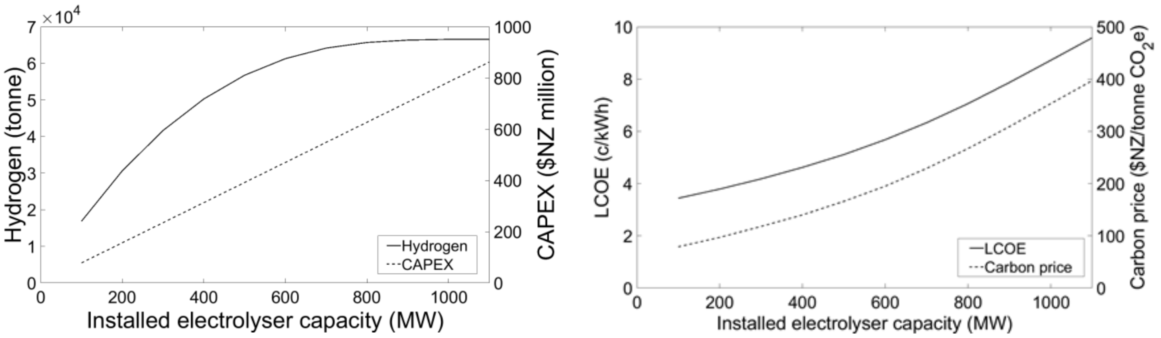

Figure 4: a) Hydrogen production and CAPEX vs electrolyser installed capacity; b) LCOE as a function of electrolyser installed capacity

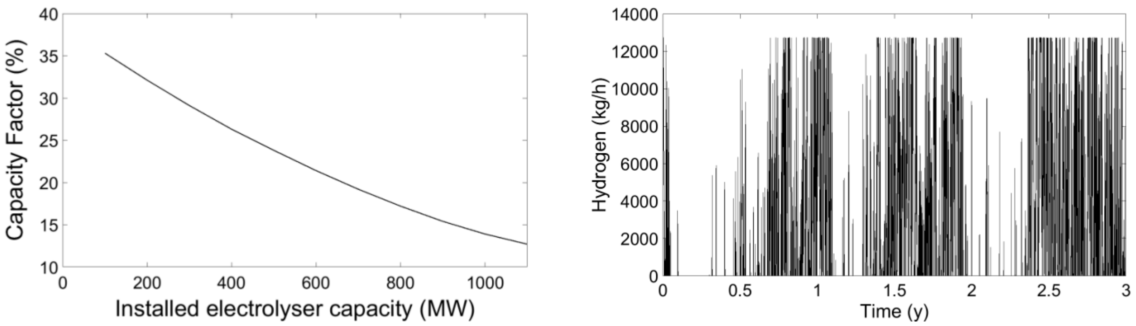

Figure 5: a) Electrolyser capacity factors; b) Hydrogen production from a 700 MW electrolyser

3.3 Financial analysis

Financial evaluation, with electricity priced at zero, gave a levelised cost of hydrogen energy ranging from 3.4 – 9.6 c/kWh (Fig. 4b), compared to a 2017 wholesale price for natural gas of 2.24 c/kWh [39]. The increase in LCOE with installed capacity was due to the electrolyser plant operating for less time at the higher capacities, since proportionally less curtailed wind energy was available. This shows the importance of matching the electrolyser plant size to the expected market price for hydrogen. The necessary carbon price to bring the cost of natural gas up to that for hydrogen ranged from \$NZ79/t-CO_2e - \$NZ397/t-CO_2e depending on the installed electrolyser capacity (Fig. 4b). These prices are compared to those from previous studies in Table 1 and may also be related to petrol at 25.6 c/kWh (\$2.30/l; April, 2019).

Table 1: Comparative hydrogen production costs

Study	Total cost (c-NZ/kWh)	Electrolysis cost (c-NZ/kWh)	Comments
Grube et. al. [31]	17.1-27.3 [a]	14.8-22.8 [a]	Range of electricity prices and grids
Hill et. al. [30]	39.4 [a]; 49.4 [a]	-	Offshore plant
Concept Consulting [29]	9.0 [b]; 27.2	2.4 [c]; 4.9 [d]	LHV basis
This study	**-**	**3.4 – 9.6**	-

Note: [a] converted at 0.6375 €/\$NZ; [b] when targeting only low electricity prices; [c] future, electrolyser costs only; [d] 2019, electrolyser costs only

The present study has thus indicated prices of a similar order of magnitude to previous studies and provides preliminary evidence that there is considerable potential to produce hydrogen from spill at low financial cost. We note here that the assumption of zero residual value for the plant is conservative and has resulted in a somewhat higher LCOE than might otherwise be the case.

In terms of capital investment, for a 700 MW electrolyser plant the total capital cost (*I*) was estimated at $NZ549 million. A linear increase in CAPEX was assumed (Fig. 4a) on the basis that electrolyser plant tends to be supplied in modular fashion. Reductions in CAPEX for large installations may be possible and this would improve the financial viability of the operation. Increased electrolyser lifetimes will also improve future financial viability. In the present study the maximum utilisation of 3390 h/y translates to a 22 year lifetime for a PEM plant. However, for smaller installations geographically dispersed across a number of wind farms, and potentially solar farms, economies of scale may be lost.

4. Future research and key issues

Detailed modelling of electrolyser operation is needed in order to more accurately predict the hydrogen yield under conditions where the electricity supply fluctuates in magnitude and is intermittent. Such modelling has been reported by [5]. Complementary pilot studies of electrolyser operation, particularly on the impacts of stop/start operation on plant lifetime and efficiency will provide valuable information under local conditions. Whilst the present study showed that long periods of uninterrupted operation could occur, there were also a significant number low-level non-contiguous spill periods. Water supply and pre-treatment needs must be addressed and oxygen capture and utilisation more fully explored.

In terms of end uses for the hydrogen produced it makes best thermodynamic sense to utilise it directly as a combustible fuel. However fuel cell/CHP plants are capable of high efficiencies as noted and are recommended for further investigation. In terms of providing a future dry year reserve the amounts available from this study are relatively small, and provide an inefficient route compared to pumped hydro energy storage. Export potential exists for hydrogen and an acceptable price for the Japanese market equivalent to 15.8 c-kWh (LHV basis) has been reported [30]. Taking liquefaction, storage and shipping costs, plus losses, into account, additional costs were estimated at 6.6-8.6 c-kWh (derived from information in [30]), resulting in an estimated export range from the present study of 10.0-18.2 c-kWh.

The cost of excess electricity to produce hydrogen was considered to be zero in this study, as it would otherwise have been curtailed. However, this does raise the question of whether a utility would invest in such a plant knowing that some of its output would be curtailed due to the operation of the electricity market. Effectively the wind plant's capacity factor would be reduced and the investment less financially attractive. However, the prospect of producing, and selling, hydrogen with the surplus wind may make the investment more attractive in the first place. Further work on the lifetime economics of combined wind farm and electrolyser plant investment would be a useful avenue to pursue to understand the potential for large scale wind and hydrogen electrolyser development to help meet New Zealand's future renewable energy needs. Something else to be aware of in the LCOE results is that they are for hydrogen energy only. While this may have some applications, such as combustion, it does not account for storage (both cost and efficiency reduction) and transport. Moreover, if the desired end product is electricity, it does not account for conversion back to electricity (via fuel cells) either. This analysis should be undertaken in the future. Storage, transport, and fuel cell conversion or combustion give rise to a number of scenarios, such as transporting via electricity and electrolyser conversion near the site of use, versus gas storage on site at the wind farm and transporting the hydrogen to the end use site. This would require a paper itself to consider.

Given the uncertainties which exist over the future composition and operation of the New Zealand electricity system, and the increasing financial cost of hydrogen produced from spill as electrolyser installed capacity increases, an approach to hydrogen production from spill based on the installation of small modular units is suggested. This is consistent with the electrolyser plant capacities presently available and would enable developments to proceed at a rate compatible with electricity system development and evolving market prices for hydrogen.

5. Conclusions

The wind spill from a simulated New Zealand electricity system incorporating 2500 MW of wind installed capacity was estimated at 1200 GWh/y, with a peak 30-min surplus of 1093 MW. Wind spill occurred for approximately 39% of the time over the study period, and was characterised by variable patterns and numerous non-contiguous periods. PEM electrolyser technology was considered to be most suitable under these circumstances. Potential hydrogen production ranged from 5261 - 22,199 tonne/y, with an energy content of 187 - 740 GWh/y, for scenarios utilising 100 - 1100 MW of PEM electrolyser installed capacities,

A levelised cost of hydrogen energy of 3.4 – 9.6 c/kWh, with electricity priced at zero, was estimated for hydrogen production at electrolyser pressure. This compares to a range of 2.4 – 22.8 c/kWh derived from previous studies and to a 2017 wholesale price for natural gas of 2.24 c/kWh. An increase in the carbon price to \$79/t-CO_2e to \$397/t-CO_2e was estimated for hydrogen produced in this manner to be financially competitive with natural gas.

Further research is needed to more accurately model electrolyser operation under conditions of rapidly fluctuating electricity supply, to conduct pilot trials under stop/start conditions and to assess ancillary issues such as water treatment and oxygen utilisation. Detailed financial analysis of hydrogen production as an integral part of a wind farm operation in a highly renewable electricity system is recommended.

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